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D4. Exhibits to Letter P27, Margaret Osa

17 July 2019 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

In June each Supervisor received a letter requesting an immediate moratorium on all use permits for Industrial Wind turbine developments in Shasta County, including the Fountain Wind project.

We ask the Board to adopt the requested moratorium and solicit input from Shasta County residents regarding the changes needed in County ordinances. The moratorium request provided you with numerous reasons why we believe this is the best course of action.

The residents located within our rural Community Centers deserve the same considerations and protections as the urban residents and should not be left to defend against these types of industrial developments alone.

Studies show that Big Wind developers have been testing the potential for wind power in eastern Shasta County since the Hatchet Ridge development in 2005. These studies also reflect how Big Wind developers will continue to target Shasta County rural areas without the proper updates outlined in the County ordinances. P27-79

Each of these turbines, standing at close to 600 feet, is an industrial factory and Shasta County has not taken the time to adequately study or address the proper General Plan, Zoning Code, or Open Space updates needed for these types of industrial developments.

Many of our members have conducted extensive research regarding the impacts of these types of industrial developments and are willing to volunteer our time to assist Shasta County through a Community Planning Action Committee in making the necessary updates we are requesting.

We are willing to work with the County Planning Department, Commissioners, and Board of Supervisors in updating the General Plan, Zoning Code, and Open Space Plan.

These updates are needed to adequately address and safeguard communities regarding these unique types of developments.

We will continue our outreach efforts, to every district within Shasta County, since we believe public feedback from all of the Shasta County residents is needed to address these types of industrial developments across Shasta County.

Board of Supervisor Public Comments – October 6th, 2020

My name is Maggie Osa and I am speaking in opposition the Fountain Wind Project

The review of the Draft Environmental Impact Report validates that it does not provide the needed modeling, data analysis, and out-reach to other governmental agencies for the decision-makers to make an informed decision regarding the Fountain Wind project.

The recent PG&E bankruptcy safety, maintenance, and hardening efforts are not even mentioned and the reliability issues at the Round Mountain sub-station are only discussed as outside and on-going work. The draft report indicates that the safety and reliability issues are someone else's responsibility and that the denial or approval of the Fountain Wind project would not be related and/or affected by the other safety, reliability, and hardening work. Shasta County is being irresponsible by not considering these safety, maintenance, and reliability issues on the transmission grid.

Shasta County did nothing to reach out to the other governmental agencies, CALISO, PG&E, nor the CPUC, regarding how the Fountain Wind project would exacerbate the reliability issues at the Round Mountain Sub-station nor did they obtain the current status from PG&E regarding hardening or safety upgrades in and around the Project area. The Applicant and County indicate that the CPUC is responsible for safety of the transmission grid but they also state that the Fountain Wind project is not regulated by the CPUC since they are not a public utility. You can't have the residents caught between decisions from approving agencies so who is responsible? Who in Shasta County has the authority to make the decision regarding the safety and reliability of the transmission grid without the required data, modeling, or coordination from the other governmental agencies? How will Shasta County obtain the required modeling and data analysis to make any informed decision regarding these areas without the required input from the CPUC, CALISO, or PG&E? P27-80

Without the required modeling, data analysis, and out-reach to the governmental agencies the decision-makers cannot make informed decisions regarding the safety, peace, morals, comfort, and general welfare of the residents within and working in the neighborhood. To do any less in analyzing the required data would be negligent.

Without the required modeling, data analysis, and coordination across governmental agencies the draft and final environmental reports lack an accurate and complete environmental setting per CEQA requirements. Also, the lack of the proper assessments mentioned leads to a lack of necessary mitigation and improperly stated mitigation measures as found throughout the draft report.

Please vote no when this project comes before for a vote.

Reference:
Fountain Wind Project Draft Environmental Impact Report, dtd July 2020.

Board of Supervisor Public Comments – September 15th, 2020

My name is Maggie Osa and I am speaking in opposition the Fountain Wind Project

The release of the DEIR validates this is the wrong project in the wrong area for so many reasons.

The summary of the Wildfire impacts, with mitigation, which goes from 'Potentially Significant' to 'less than significant' is an absurd assessment!

Page 3.16-17 of the DEIR states: "Therefore, due to the **increase in potential sources of ignition,** Project construction and decommissioning could increase the risk of surrounding communities, exposure to pollutant concentrations from wildfire and the uncontrolled spread of wildfire to a level that is **substantially higher than existing baseline conditions,** which **would** result in a potentially significant impact".

Remembering the 'baseline conditions' are Very High Fire Hazard Zone and Tier 2 & 3 which are assigned the highest in the state and now the Applicant wants to go substantially higher.

1) It is clear the statements 'increase the wildfire to level that is substantially higher than existing baseline conditions validates you must deny the use permit per Zoning Plan Section 17.92.020.F for health and safety alone.
2) How can you add 'substantially higher than existing baseline conditions' then indicate you can mitigate to 'less than significant' just by following common sense practices to prevent wildfires?

If the **Fountain Wind project were not under consideration** we would still be assigned a "Very High Fire Hazard Severity Zone (CAL FIRE) and the Tier 2 & 3 (CPUC) classification. The facts are that approving the special use permit will only add thousands of potential ignition points that don't exist in the project area now.

In addition, the Fountain Wind Project clearly goes against Shasta County's FS-1 General Plan objective – "Protect development from wildland and non-wildland fires by requiring new development projects to incorporate effective site and building design measures commensurate with level of **potential risk presented by such a hazard and by discouraging and/or preventing development from locating in high risk fire hazard areas**." As we know there no measures that will add **less potential risk** in the development of the project.

Your denial of the use permit and 'No Project' vote validates that you are not willing to introduce any types of developments from locating in the high risk fire hazard area. As we witness the fire destruction today to levels that are unprecedented, triggering PTSD across the region, confirms that the No Project vote is the only vote!

P27-81

Reference:

Fountain Wind Project Draft Environmental Impact Report, dtd July 2020, pages 3.16-13 & 3.16-17.

BOS meeting 14 Jan 2020

Good morning Chairwoman and Supervisors,

My name is Maggie Osa, I am here to continue to state my objection to the Fountain Wind Project

The CPUC provides a report each year on the progress of the **Renewables Portfolio Standards (RPS)**. The 2019 annual report indicates in general, retail sellers either met or exceeded the 29% interim RPS target, and many are on track to achieve their 2017-2020 compliance period requirements. They have not only meet their 2020 targets but the three Investor Owned Utilities' are on track to meet their 60% 2030 RPS procurement mandate.

The three large IOU's are currently forecasted to continue to **surpass RPS** requirements and have **excess procurement for the next 6 years at least**. The CPUCs projected excess power will also cost California ratepayers. In 2018 alone, California paid Arizona $18 million to take excess power off the grid to make it more stable. How much more money will California ratepayers have to pay other states to take excess power off the grid?

With regards to development of 1 turbine. It is estimated for one 600 foot turbine that the **nacelle weighs 72 tons**, the **tower 220 tons**, and **the blades 42 tons**. A single turbine **requires over 334 tons** of steel, cooper, and aluminum. P27-82

The 2018 CEQA Guidelines have added two areas Energy and Wildfires.

The first consideration under the Energy section that needs to be addressed **- Results in potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources, during project construction or operation?**

Based on the 2019 CPUC report indicating the RPS goals continue to exceed expectations and the energy resources used to produce just one turbine show the **unnecessary consumption of the energy resources both during construction and operation**.

The significant environmental, social, and cultural impacts from the Fountain Wind Project will be felt for decades to come and the area will never be able to recover. **The Fountain Wind project cannot be justified and should not be considered for approval by a statement of overriding considerations**.

I ask you to vote **no** on the special use permit when it becomes before you for a vote. Thank you for your time.

1 October 2019 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa

I would like to request that the Board of Supervisors place the moratorium regarding industrial wind turbines in Shasta County as an agenda item for discussion.

I want to continue my comments from last session about the size of these industrial developments in relation to the current structures surrounding the project site.

1) The Fountain Wind Project Concrete foundations measure approximately 80 feet in diameter. Spread footing buried underground to a depth of approximately 10 – 15 feet. Some foundations will need to be cabled into the bedrock, some up to 50 feet, to stabilize the foundations. There is **no structure within Shasta County**, not even the current Hatchet Ridge Wind development that is near the size of these proposed turbines.

Currently in Ontario Canada court proceedings are taking place between Chatham-Kent residents and the Ministry of the Environment. The province and three wind turbines companies have been charged under the Environmental Protection Act. P27-83

Residents claim their drinking water has been contaminated by the construction and development of wind turbines in Chatham-Kent.

The three companies are charged under the EPA with "unlawfully discharging contaminants, including black shale and potentially hazardous metals into the natural environment in an unlawful manner that caused or is likely to cause an adverse effect." The charges are for allegedly "failing to take all reasonable care to prevent the installation and operation of the wind turbines" and the two wind farms, which resulted in the well water contamination.

The hydrology surrounding and within the Fountain Wind Project site is very complex with various streams, natural springs, wells, creeks, and ditches. Local residents surrounding, this project site, rely **solely** on these water resources. Contamination of our only water resource would make our properties **uninhabitable.** We have no back-up water supply!

The residents surrounding the Fountain Wind project site, just as the claimant's in the Ontario case, believe that these industrial construction sites are unable to mitigate the risks and will contaminate our water resources releasing industrial contaminants, disrupt coal deposits in and near the construction site with blasting, and release numerous hazardous metals and materials, causing environmental impacts and health concerns that will forever affect members of the communities and their properties.

Per the Shasta Country Framework for Planning "Past experiences in Shasta County and elsewhere have shown that responding to adverse change after the fact is not a viable alternative" and should not be the planning method for these types of developments.

Board of Supervisors Public Comments for 2 June 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

On May 29th, the CPUC unanimously voted to approve the PG&E $58 billion dollar reorganization plan even though they **remained critical of PG&E's track record on safety**.

During this approval process many stakeholders were highly critical of the decision without higher levels of government control over PG&E's safety practices. Community members voiced concerns that the decision did not protect ratepayers and victims of the fires. The community members **did not see the focus on prevention of further wildfires** and also the planned power shut-offs. They have also criticized PG&E for their criminal conduct and they want them held accountable.

PG&E has stated they need to invest $40 billion over the next five years in their infrastructure, **much of it to prevent future wildfires**.

So based on the facts of PG&E's failed wildfire prevention efforts Shasta County must resolve some urgent questions before making a decision regarding the use permit.

1) How do you know if any of the critical $40 billion infrastructure upgrades needed are at or near the project site? P27-84
2) How will the Fountain Wind Project add to the already existing infrastructure failures?
3) How does the Fountain Wind Project affect the Round Mountain Sub-station thermal overload and over voltage issues and will it make it safer for the surrounding communities?
4) How will the **new wildfire risk**, introduced by the Fountain Wind Project, be addressed to ensure the safety of the communities?
5) If the Fountain Wind developers believe they will not introduce any additional wildfire risk then why is the land owner installing **dip tanks only in the turbine project area** and not their entire timber forested area?

Through the bankruptcy it has been proven that PG&E has caused multiple wildfires killing more than 100 people. Shasta County needs to let PG&E execute their $40 billion upgrades over the next 5-10 years and then evaluate if their safety results have improved before they consider turbine special use permits in the future.

Without time to do a safety evaluation, with a proven track record over several years by PG&E, I don't see how Shasta County can even consider introducing **yet another wildfire risk** to an area already known as one of the highest wildfire areas in the state.

I ask that you deny the Fountain Wind Project use permit for the safety, healthy, and well-being of the community members.

Board of Supervisors Talking Points – 3 Mar 2020

Good morning Chairwoman and supervisors, my name is Maggie Osa

I continue to emphasize that the Fountain Wind developers nor Shasta County have any authority over the PG&E transmission grid safety issues and cannot do anything to mitigate or resolve the issues.

In a recent article the bankruptcy judge, William Alsup, lambasted PG&E again, by stating "I'm going to do everything I can to protect the people of California from more deaths and destruction from this **convicted felon**."

In the heated hearing the judge stated the company is once again in violation of its probation due to its handling of the fire threat following the natural-gas pipeline in 2010.

The judge said PG&E had failed to achieve full compliance with those terms, and weighed whether to impose additional conditions in the **interest of public safety**. The judge expressed frustration with the company because they are **still not in compliance with state law** and he also took the time to challenge PG&Es efforts to inspect and repair **hundreds of thousands of miles** of power lines throughout its **70,000 square miles** of service territories.

Previously I provided you information that PG&E **failed to meet their 2019 Wildfire Mitigation Plan by 13%.** As has been shown by PG&E's bankruptcy **providing a plan** does **not result in historical facts**. P27-85

So now with the release of the 2020 Wildfire Mitigation Plan PG&E in February they also provide a **Cautionary Statement Concerning Forward-Looking Statements** – indicating "This news release includes **forward-looking statements that are not historical facts**, including statements about the beliefs, expectations, estimates, future plans and strategies of PG&E including but not limited to the Utility's 2020 Wildfire Mitigation Plan.

The bankruptcy judge, who is the closest person reviewing all of the PG&E documentation, referred to PG&E as a **convicted felon,** stating the lack of safety progress by PG&E. PG&E themselves state that over the next 12 to 14 years, approximately 7,100 miles of transmission lines will be hardened in high fire-threat areas such as ours.

PG&E needs to be in **compliance with the law** and **provide historical factual data, over a several year period, relating to their on-going reliability and safety record, specifically in all of the high wildfire prone and forested communities.**

PG&E's bankruptcy and on-going safety issues provides **overwhelming documentation** for Shasta County **to deny the special use permit for the Fountain Wind Project putting the safety of the residents first.**

<u>Board of Supervisors Talking Points – 4 Feb 2020</u>

Good morning Chairwoman and supervisors, my name is Maggie Osa

Last week I spoke to you about the CAISO Round Mountain thermal overload and overvoltage issues.

In 2008 when the Hatchet Wind Development was under the CEQA review Shasta County received input from the Transmission Agency of Northern California (TANC). TANC is the largest owner and project manager of the California-Oregon Transmission Project.

In the notification TANC stated that "previous interconnection studies done by PG&E relative to projects located in the same area and interconnected with PG&E 230-kV facilities in the area have indicated that the injection of power from these projects could have a detrimental impact on the amount of power that could be imported into California from the Pacific Northwest over the 500-kV grid." TANC contacted CAISO for a copy of the requested studies and had not received anything at the time.

TANC indicated "in the absence of those studies quantifying the impacts or associated mitigation costs of the project, on the existing 500-kV grid, they pointed out that the Hatchet Ridge, **<u>and similar projects</u>**, will <u>likely increase the cost of rebuilding or re-conductoring</u> <u>existing 230-kV lines</u> to maintain appropriate import levels and related performance objectives for potentially affected public facilities." P27-86

Shasta County planning department provided the following response – "Comment noted. Because PG&E is the owner and operator of the 230kV line in the project vicinity, and will also be the owner of the proposed switch yard, any responsibility for re-conductoring or upgrading transmission lines to the area will be the sole responsibility of PG&E."

So now CAISO is working to upgrade and resolve some of the same issues outlined 10 years ago at the Round Mountain Sub-station which were outlined by TANC in 2008. As stated, adding similar projects further decreases the amount of power being imported and continues to increase the rebuilding or re-conductoring cost of the existing 230-kV lines. The very lines the Fountain Wind project propose to tie into at the project site.

I have provided you with excerpts from the CAISO Transmission plan regarding the Round Mountain Sub-station issues and the proposed timeline to resolve those issues for you to review the facts.

As I stated previously the Fountain Wind developers **nor** Shasta County have **<u>any</u> authority over the PG&E transmission grid safety issues and cannot do anything to mitigate or resolve the issues.** Resolving these issues will take years, as stated by PG&E and CAISO themselves. I ask you to not add additional unnecessary wildfire risk to the already unstable and antiquated PG&E grid and vote No when the Fountain Wind project comes before you for a vote.

Board of Supervisors Public Comments for 5 May 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

Recently Anthony Girolami, a partner at the law firm Stoel Rives, LLP, which represents more than 20 utility-scale wind developers indicated that project delays could prevent companies from the production tax credit. Girolami said his clients started receiving force majeure notices from Asian wind turbine component suppliers at the end of February.

Force majeure – literally "superior force" in French – is a clause commonly included in a contract that allows a party temporary relief from having to fulfil its obligations in case of an extreme events, like a war or global pandemic. The clause is included for unexpected disasters like COVID-19 but **suppliers aren't providing their clients with a timeline for how long their force majeure periods are going to last**. In addition numerous industry analysts indicate the renewable energy markets will be hit with a "domino effect' of delays through the global supply chain and uncertainty about the future.

These supply delays will impact the tax production credits and have Big Wind developers flocking to Washington to take part in the monies presented in the recent stimulus relief bills. P27-87

I emphasize with the tremendous strain and overwhelming circumstances that you need to consider regarding the health, safety, and continued economic strains on Shasta County due to the COVID-19 pandemic.

All the issues, outlined in the two moratorium requests, show this is not the right project for this location. **I ask that you deny the Fountain Wind Project use permit** for the 'safety, health, and quality of life issues' for the residents now and in the future.

Please stay safe and healthy!

5 November 2019 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa

2019 marks the anniversaries of some the most recent tragic Fires of the North state which includes 27 years since the Fountain Fire. The residents in the area still suffer from some of the same heartache, loss, grief, and stress as other survivors today from the recent wildfires.

As outlined in our moratorium request one of the major opposition points to the proposed Fountain Wind project is introducing YET another unnecessary fire risk, in an area already identified as Extreme. The moratorium request also outlines the CASIO 2019 Transmission plan for the Round Mountain sub-station which is out for competitive solicitation for upgrades due to Thermal overload and over voltage issues which will not be completed until late 2024 - 2025.

The CPUC had an emergency meeting with Bill Johnson, the PG&E CEO, who stated these blackouts could continue up to 10 years. Mr. Johnson also disclosed that PG&E was still years away from sufficient upgrades to its grid. The Fountain Wind project wants to do the 'tie-in' into the unreliable and insufficient PG&E transmission grid and then walk away without any indication that they are part of the problem. There are NO modern technologies, mitigation measures, or plans that the developer can provide to convince the residents that they will not add additional unnecessary risk to an already critical situation. P27-88

The PG&E mitigation measures shown in the recent blackout failed yet again to protect communities. PG&E needs to document the completed maintenance work to their antiquated transmission grid and Shasta County representatives CAN NOT consider the PG&E grid reliable or sufficient to handle any additional renewable power as outlined by Fountain Wind. Adding Fountain Wind power to an unreliable and insufficient grid, as outlined by the grid owner themselves, only puts the residents and communities in another deadly situation. Shasta County should be in the business of ensuring that the required maintenance of the failing transmission grid are one of the top priorities for the communities and residents.

Commission President Marybel Batjer stated "The loss of power endangers lives…..and imposes additional burdens on our most vulnerable populations." Residents adjacent to the development area have been without power for 10 of the 31 days in October due to the PG&E blackouts. The PG&E blackout maps show the Fountain Wind project in the same area that PG&E indicates is the highest risk and plans to cut power first.

We will continue to present you with information that under the circumstances the Fountain Wind project, the buildings, and facilities are putting the health, safety, morals, comfort and general welfare of the residents and community at an unnecessary risk.

<u>Board of Supervisors Public Comments for 7 April 2020</u>

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

PG&E has pleaded guilty to 84 counts of involuntary manslaughter and it marks the <u>second</u> time this decade that the company's neglect has culminated in it being deemed a criminal. PG&E already is serving a five-year criminal probation imposed after it was convicted of six felony counts for falsifying records and other safety violations underlying a natural gas explosion that blew up a neighborhood and killed eight people in San Bruno, CA.

Since the grisly deaths from the Camp Fire, and the destruction of over 18,000 structures, PG&E has hired Johnson as the new CEO to shape up its culture. Johnson hailed the plea agreement as a sign that PG&E is "working to create a better future for all concerned. We want wildfire victims, our customers, our regulators and leaders to know that the lessons we learned from the Camp Fire remain a driving force for us to <u>transform this company</u>." Johnson has previously acknowledged that it will take <u>many years</u> to pull that off while PG&E pours an estimated <u>$40 billion into badly needed upgrades</u>. P27-89

In reality the Fountain Wind developers are considered sub-contractors since they are required to do the tie-in to the PG&E transmission lines.

With PG&E's **continued criminal activity**, and the judge's statement regarding they are still **not in compliance with the state law**, <u>would you hire PG&E as the primary contractor to do the work to keep your families safe?</u>

The facts cannot be overlooked regarding the safety issues with the PG&E grid for the Fountain Wind, or similar projects. I ask you to do the right thing and deny the use permit.

7 Jan 2020 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

I would like to report that on December 17th, 2019, the **Humboldt County Board of Supervisors denied the special use permit for the Terra-Gen Wind energy project**, with a 4-1 vote. The Humboldt Planning Commissioners previously denied the project with a 4-2 vote on November 21st.

The Terra-Gen project proposed **only 47 turbines**, each more than 600 feet tall, to be installed atop Bear and Monument Ridges. Even with the increased mitigation measures proposed by the developer, and promises of employee training programs within the region, they could not overcome the negative impacts that would be created in the region for decades to come. They also could not overcome **the passion of the residents to stop these unnecessary industrial developments surrounding their homes and sacred lands**. P27-90

Since the Fountain Wind project has nearly twice as many turbines as the Terra-Gen project it will have a significantly greater environmental impact. The Terra–Gen project identifies some of the same social objections and environmental impacts that can't be resolved.

The Fountain Wind Project is proposing at least 72 turbines, at 600 feet or taller. These turbines rank 21st with some of the tallest skyscraper structures within California competing with Los Angeles and San Francisco.

The Pit River Tribe has also submitted a resolution in opposition to the Fountain Wind Project, due to the sacred ties within the development area, just as the Wiyot Tribe did against the Terra-Gen project.

The Fountain Wind project social, health, and environmental impacts, including bird and bat deaths, native plant destruction, hydrology impacts, increased wildfire threats, PG&E bankruptcy impacts, grid instability and lack of maintenance resulting in wildfires, the Round Mountain thermal overload and over voltage issues, decline in property values, health issues, are only multiplied by the increased size of the project.

With that we need to ask:

1) **What further efforts can be made to conserve energy statewide without the additional destruction by industrial wind developments?** "Why would we build these big industrial wind turbines so we can light-up billboards across the state without looking at additional conservation efforts first?
2) What data are being brought forth by Big Wind developers that they have exhausted all the **repowering efforts** and not **causing further devastation and destruction** of **environmentally sensitive, wildfire prone forested, and undeveloped areas**?

I am hoping you also take the time to study these issues and deny the requested use permit for the Fountain Wind Project when it is brought before you for a vote.

<u>Board of Supervisors Public Comments for 9 June 2020</u>

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

As Shasta County representatives I empathize with the enormity of the overwhelming events in the last four months due to the COVID-19 pandemic and protests due to tragic death of George Floyd.

The COVID-19 pandemic has brought financial destruction to numerous business' that have closed their doors for good or are still struggling to survive. This financial destruction for the local business communities will only add to the budget shortfalls for the County as you begin to look for new cash flows from other sources. During this time I ask that you don't fall prey to the financial enticements from the Fountain Wind Developers.

As I have stated numerous times the Fountain Wind Developers do not have any authority over the PG&E territories that are in dire need of repairs and upgrades. We are now entering the new season of wildfires and PG&E is still struggling to secure its grid from causing more wildfires and has been stymied in their attempts to set-up micro grids to power substations during fire-prevention blackouts. The Fountain Wind project site, as with the local communities, will be the first area that the blackouts will occur, and lasting the longest, as they did during last year's wildfire season.

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PG&E has not yet existed bankruptcy and they still have over $40 billion to invest over the next five years in their infrastructure, **much of it to prevent future wildfires**.

Butte County DA pursued charges and PG&E is pleading guilty to 84 counts of manslaughter where no one is really being held accountable. Shasta County cannot separate PG&E's bankruptcy, safety issues, needed transmission grid upgrades, or manslaughter pleas in the review process of this industrial special use permit request.

The $50 million proposed to Shasta County and the $1 million to the local communities by the Fountain Wind Developers is a bribe to develop in one of highest wildfire prone areas in the state **already proven unsafe by PG&E actions alone**.

I ask that you deny the Fountain Wind Project user permit because it is detrimental to the health, safety, peace, morals, comfort, and general welfare of persons residing or working in the neighborhood, and it will be detrimental or injurious to property or improvements in the neighborhood and to the general welfare of the County.

Board of Supervisors Talking Points – 10 Dec 2019

Hi, my name is Maggie Osa.

I continue to stand against the proposed Fountain Wind Project and plan to provide you information regarding the many problems of industrial wind turbine developments.

In attending the community meeting held by ConnectGen, the new project managers for Avangrid of the Fountain Wind Project, they provided a flyer indicating that Wind Turbines have NO effect on property values.

The reality is Big Wind knows the impacts to property values and on small rural communities, so much so that some of the developers are willing to pay plaintiffs who file lawsuits to stop their projects. Many communities see these payments as 'Bribery' to get the community members in line with these types of developments.

In November 2019, Expedition Wind was approved for a wind turbine development in Kansas. Plaintiffs filed a lawsuit opposing the project, which was the second development in that area, and in response the company offered various settlements, including buying their property for 1 ½ times its value for those who live within the footprint of the development. Also, plaintiffs who live within a mile of the development were offered an initial payment of $5,000 and annual payments of $2,000. Those who live up to 5 miles of the development were offered a single payment of $2,500; and those more than 10 miles away a single payment of $1,000. P27-92

If Big Wind is so adamant that Industrial wind turbines have no effects then why are they willing to pay landowners?

I don't claim to be an expert in all the problems surrounding industrial wind turbine developments but I have already completed hundreds of hours of research regarding industrial wind turbines.

Some of the topics cover shadow flicker, blinking lights, setback requirements, low frequency and infrasound impacts, decibel requirements, accidents, fires, wildlife impacts, heath issues, ice throw, native cultural devastation, wind turbine syndrome, view shed, tourism and recreational impacts, property values, water aquifer damage, wind disturbance issues, lifeline helicopter limitations, bat deaths, golden and bald eagle deaths, and other raptor deaths, PG&E bankruptcy including the transmission grid instability and blackouts, California renewable portfolio, repowering wind turbines efforts, Shasta County General Plan and Zoning, electricity price increases, toxic mining efforts of rare earth metals needed for wind turbines, curtailing renewable power on California grid and paying other states as much as $18M in 2018 alone to take excess power off our grid.

These problems are complex and not all will be addressed through the CEQA process but still need to be resolved before this project can be approved.

<u>Planning Commissioners Public Comment 9 April 2020</u>

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

Last week I spoke to you regarding the requirement for PG&E to provide **documented historical facts** regarding planned wildfire and transmission grid safety efforts that will take years to resolve.

CALISO completed the competitive solicitation from the 2018-2019 transmission planning process for the Round Mountain Substation, where the ISO identified the project due to a **reliability driven need** for the transmission project.

On February 28th of 2020 CAISO released the Round Mountain 500K-V Dynamic Reactive Support Project Sponsor Selection. The report describes the competitive solicitation process conducted by CAISO for the Round Mountain 500 kV area dynamic reactive support project, for which the ISO has solicited proposals for 500 MVAr of dynamic reactive support devices to be installed in either of two alternative configurations connected either (1) to the 500 kV transmission lines between Round Mountain Substation and Table Mountain Substation owned by PG&E or (2) separately to Round Mountain Substation at 230 kV and to Table Mountain Substation at 230 kV.

The result of this competitive solicitation process is that the ISO has selected LS Power Grid California, LLC (LSPGC) with the **latest in-service date** of **June 1, 2024**. P27-93

As been shown the PG&E antiquated and unreliable transmission grid including the Round Mountain transmission project only adds **another reliability driven and safety issue** that will only be acerbated by Fountain Wind project.

The Associated Press recently reported that PG&E was **fined** $2.1 billion dollars by the California regulator. The increased fine includes $200 million ear marked for people who lost family members, homes, and business in wildfires caused by PG&E during 2017 & 2018.

More than 81 thousand claims have been filed in the 2019 bankruptcy case.

We all must learn from the past tragedies and **not even consider introducing** any additional wildfire risk into one of the highest rated areas in the state.

The **documentation is overwhelming** and Shasta County must deny the use permit for the Fountain Wind project.

9 Sept 2019 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

We ask the Board again to champion the Industrial Wind Turbine moratorium soliciting input from all of Shasta County residents regarding these types of industrial developments.

We appreciate receiving the feedback regarding information of the General Plan and County Zoning codes however we whole hardly still believe they are inadequate on how to address large scale industrial wind turbine developments.

Passage of the moratorium is warranted for various reasons and I will name just a few of the issues. P27-94

1) The increased wildfire threat (which include material transports, construction, operation, and maintenance) and the State continued ongoing efforts to reduce the wildfire risk, some of which have not been discussed or implemented.
2) The lack of an area specific or countywide emergency evacuation plans with some ingress and egress currently down to one lane within the project site.
3) The devastation to our wildlife, local Bald eagle, spotted owl, other avian impacts, and ground wildlife.
4) The destruction to the local Native American heritage and history
5) The latest CAISO Transmission upgrade Plan includes the Round Mountain Sub-station, identify the grid instability, thermal overload and over voltage issues, exacerbated by the intermittent generation of renewable energies, won't be completed until late 2024
6) The on-going PG&E bankruptcy with outline efforts to shed existing renewable power purchase agreements and the estimated years needed by PG&E to address their maintenance issues, with the most recent Wall Street Journal article indicating they know about the risk which caused the recent Camp Fire
7) The lack of adequate County Zoning codes, General Plan, and Open Space updates and the need to solicit public input regarding Industrial Wind Turbine developments.
8) The Shasta County jail is the tallest building within the County, standing at 8 stories totaling 135 feet. These industrial wind turbine developments will be over 4 times taller than the County jail, as close to some property lines as 1,100 feet with up to 100 turbine developments surrounding our rural community centers.

We will continue to bring these types of issues, and others to this board, until action is taken to address Large Scale Industrial developments within Shasta County.

13 August 2019 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

We ask the Board again to adopt the requested moratorium and solicit input from Shasta County residents regarding these types of industrial developments.

Two areas we believe that are in direct conflict are the General Plan and County Zoning codes. According to the Shasta County General Plan in the Energy section

Important renewable energy sources in Shasta County include solar, hydroelectricity, biomass, and cogeneration. There is also potential for development of wind, geothermal, and waste-to-energy as alternative sources of energy production. P27-95

So I ask just a few Wind Turbine development questions?

1) What areas in the County will they be prohibited?
2) How is a small, medium, and large scale wind energy conversion system defined in the current zoning?
3) Considering the current fire hazard ratings are forested areas the best place for continued development?
4) Separate from Big Wind input what should be the required set-backs and how does turbine height effect any changes?
5) How does the County certify that the power will benefit Shasta County, or are we just a development site for power going elsewhere devastating our landscape and communities to benefit someplace else?
6) What information does the County have regarding the 2018 WHO health impacts regarding industrial turbine noise and other related health issues?
7) What requirements have been put into place by the County regarding liability insurance for these types of projects in light of the recent PG&E bankruptcy?
8) What additional requirements are needed with regards to the CAISO Transmission grid upgrades at the Round Mountain sub-station regarding thermal overload and voltage instability issues?
9) What safeguards have the County put into place regarding decommissioning and reclamation plan costs required and how will the County safeguard these funds needed by the developer?

During a previous Public Comment period Supervisor Rickert requested the General Plan and Zoning Codes be reviewed in relation to the moratorium request. The CIO FWP members request the results of that review be made available to the CIO FWP Chairperson Beth Messick.

I have spoken to numerous residents throughout Shasta County and they are stating these turbine developments are a done deal because Shasta County just wants the money. So we ask the Board to support the moratorium and stop the appearance that it is just about the money.

17 July 2019 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

In June each Supervisor received a letter requesting an immediate moratorium on all use permits for Industrial Wind turbine developments in Shasta County, including the Fountain Wind project.

We ask the Board to adopt the requested moratorium and solicit input from Shasta County residents regarding the changes needed in County ordinances. The moratorium request provided you with numerous reasons why we believe this is the best course of action.

The residents located within our rural Community Centers deserve the same considerations and protections as the urban residents and should not be left to defend against these types of industrial developments alone.

Studies show that Big Wind developers have been testing the potential for wind power in eastern Shasta County since the Hatchet Ridge development in 2005. These studies also reflect how Big Wind developers will continue to target Shasta County rural areas without the proper updates outlined in the County ordinances. P27-96

Each of these turbines, standing at close to 600 feet, is an industrial factory and Shasta County has not taken the time to adequately study or address the proper General Plan, Zoning Code, or Open Space updates needed for these types of industrial developments.

Many of our members have conducted extensive research regarding the impacts of these types of industrial developments and are willing to volunteer our time to assist Shasta County through a Community Planning Action Committee in making the necessary updates we are requesting.

We are willing to work with the County Planning Department, Commissioners, and Board of Supervisors in updating the General Plan, Zoning Code, and Open Space Plan.

These updates are needed to adequately address and safeguard communities regarding these unique types of developments.

We will continue our outreach efforts, to every district within Shasta County, since we believe public feedback from all of the Shasta County residents is needed to address these types of industrial developments across Shasta County.

<u>Board of Supervisors Public Comments for 16 June 2020</u>

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

The Associated Press published an article indicating that PG&E will bring in 11 new board members as part of their bankruptcy overhaul. This overhaul of 11 of the 14 directors will oversee decisions made by PG&E management to shake up a **corporate culture that has emphasized shareholder profits over the safety of the 16 million people who rely on it for power**.

Previous board decisions resulted in the **neglect of the utility's aging electrical grid** and allowed it to fall into disrepair, igniting catastrophic wildfires killing more than 100 people and destroyed more than 27,000 homes in 2017/18.

Also on Friday, June 13th, the San Francisco city attorney, Dennis Herrera, filed a legal protest against PG&E's plan accusing the utility of using a **new ratepayer charge to raise $7.5 million in bankruptcy-related costs**. Even though the CPUC approved PG&E's reorganization plan, Mr. Herrera alleges the utility's proposed plan to secure funds through **a new charge to ratepayer bills,** which aims to borrow money at lower rates to fund the bankruptcy. PG&E wants to add a new charge to ratepayer bills with hopes that customers will be paid back, which they can't guarantee. **Again**, the proposal shifts all the risk to the ratepayers and it leaves the CPUC with no recourse to alter this arrangement in the years ahead – regardless of any future bankruptcies, negligent or criminal behavior, or financial schemes and gimmicks leaving no protections for the ratepayers. P27-97

Mr. Herra called the plan a "**complex financial scheme**," noting that because this is no guarantee that PG&E can actually earn back the money, and leaves the risk entirely on the ratepayers, which is in violation of AB 1054, the state's new wildfire liability law.

PG&E must complete their bankruptcy, ensure a successful transition with their new board members focused on ratepayers and not shareholders, and give the state enough time to **hold PG&E accountable, not with just a proposed plan, but with documented historical records over several years.**

Because PG&E does not have the trust of the ratepayers Shasta County needs to take the time to evaluate PG&E success and/or failures upon exiting their bankruptcy or witness the state proceed with a take-over based on any additional failures.

Based on PG&E neglected transmission grid actions alone I ask you deny the Fountain Wind project when it comes before you for a vote.

References:

San Francisco city attorney files legal protest again PG&E plan
https://www.ktvu.com/news/san-francisco-city-attorney-files-legal-protest-against-pge-plan

PG&E reaches bankruptcy deal with California Governor 3/20/2020 Business News
https://www.cnbc.com/2020/03/20/pge-reaches-bankruptcy-deal-with-california-governor.html

<u>Board of Supervisors Talking Points – 17 Dec 2019</u>

Good morning Chairman and supervisors, my name is Maggie Osa

The PG&E bankruptcy has brought to light the overwhelming transmission grid instability issues and on-going lack of maintenance to meet renewable power goals.

Governor Newsom threatens to block the PG&E bankruptcy exit because the company fails to address most of the issues that have been raised, **including sufficient financial stability to make major safety investments.** The Governor outlined that PG&E has been mismanaged, **failing to make adequate investments in fire safety and fire prevention, and neglected critical infrastructure.** He also indicated the current plan will not be positioned to provide safe, reliable, and affordable electric service.

State Senator Bill Dodd, who authored the wildfire fund legislation, stated "**We all know that we can't trust PG&E to do the right thing or even follow the law**" and that "we need to achieve systemic change in the structure and governance of PG&E to ensure safe, reliable power.

Recently in the Wall Street Journal article – '**Safety Is Not a Glamorous Thing'** outlined that in 2015 the CPUC overseeing PG&E opened an inquiry into whether the state's largest utility put enough priority on safety. The article indicates that the CPUC prioritized rates, green power, with the wildfires exposing the safety shortcomings. PG&E has been found guilty of violating safety regulations for gas pipelines, with the investigation by the CPUC showing they falsified safety records for 5 years. PG&E equipment also is blamed for causing more than **1,500 California wildfires** between June 2014 and Dec 2017 alone. P27-98

Over several years PG&E neglected their safety, maintenance, and critical infrastructure and there is enough blame to go around regarding the proper oversight and priorities. These issues will take years to fix, with some estimates as high as $40 Billion over 4 years.

In Dec 2018 the CEQA process added two areas for potential impacts, wildfire and energy. The developers will state in their studies and arguments that the environmental and economic benefits of this renewable project outweigh the impacts to the development area. The Fountain Wind developers have **no authority over the PG&E transmission grid safety issues and cannot do anything to resolve them. We cannot keep doing the same thing and expect different results.**

With PG&E violating the public trust, and falsifying records, how can we trust any proposed interconnection site for the Fountain Wind project to be safe? We are asking – How many more lives need to be lost for the sake of money?

We ask that you deny the use permit, putting the safety of the community first. The PG&E **transmission issues MUST be resolved** and they need to establish a proven record that they can provide safe and sufficient energy for their communities.

So in closing I want to wish you a Merry Christmas and a safe New Year!

13 August 2019 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

We want to thank Supervisor Rickert for taking time in her busy schedule to accept our invitation to listen to the community concerns at the CIO FWP.

Numerous people relate to opposition issues as "It's all relative".

I want to continue my comments from last week about the size of these industrial developments in relation to the Shasta County Jail……and some other structures.

So, as a reminder,

The Fountain Wind Project is proposing up to 100 industrial developments standing at 591 feet tall. In comparison here are some facts related to these sky scraper size industrial turbine developments. P27-99

Sacramento CA – population of 501,901 (2017)

The Wells Fargo Center is the tallest building at 430 feet standing with 31 stories.

San Francisco population of 884,363 (2017)

56 of the 472 high rises are at least 400 feet tall.

They have 26 skyscrapers that rise at least 492 feet.

The San Francisco skyline is currently ranked second in the Western United States, after Los Angeles, and sixth in the United States.

San Diego, Population of 1.42 Million (2017)

The One America Plaza stands at 500 feet with 34 stories.

San Diego has over 150 high rises which are mostly in the downtown district
In the city there are 32 buildings that stand taller than 300 feet. In the 1970's, (FAA) Federal Aviation Administration began restricting downtown building height to a maximum of 500 feet.

These are some relative facts.

These sky scraper industrial turbine developments are
1) 160 feet taller than **all** the buildings in Sacramento

2) 100 feet taller, and 4 times as many, as 26 skyscrapers in San Francisco

3) 91 feet taller than **all** the buildings on the San Diego sky line.

Many rural residents moved from these cities due to the industrial sky scraper developments and are looking for a quieter, slower, paced life to enjoy nature and the outdoors.

So I ask the question…….Is this how we will see Shasta County in the future…..competing with some of the tallest skylines in California.

Public comments for the Shasta County Board of Supervisors – 18 Aug 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

It is very disheartening that Shasta County would release the Fountain Wind DEIR, containing over 2,000 pages, to be reviewed in a 45 day window during the COVID-19 pandemic when much of Shasta County is still shut-down or facilities are on a very limited access.

Your message is conflicting at best. Stay at home to stop the spread of COVID-19 but you must take time to make an appointment at the libraries, Hill County Community Health Clinic, or the Planning Department to review 2,000 plus pages and state your objections regarding the second largest industrial project since the Shasta Dam.

The release of the DEIR and soon to be FEIR only benefits the developer who wants a decision so they can obtain the tax benefits and get their project approved with little objection. Many residents near the development site believe the decision to approve the special use permit is already a done deal. They also believe the COVID-19 restrictions are limiting participation in the reviews and comments.

The moratorium request clearly outlines the various health risk, and other issues, due to COVID-19, but as we are now witnessing in the daily news just how devastating these impacts are effecting our everyday lives. Along with a health crisis the nation is dealing with an educational crisis of if or when children should go back into their classrooms, opening restaurants for dine-in seating, getting people back to work so they can pay their rent and mortgages, being separated from family members for extended periods of time and including what will be the process on how to cast our vote for our next President. Trillions of dollars have already been allocated on keeping families and businesses afloat with trillions more in consideration for the near future. P27-100

The stress, depression, and health related issues due to the COVID-19 crisis has completely overwhelmed many people. Even with the release of the EIRs and public hearings I would not be surprised if the County received very little participation since everyone is dealing with their own pressing matters in order make ends meet from pay check to pay check, how to reconnect with their families, and educate their children.

This is not the right project for our forested area nor is it the right time for these types of reviews by the residents and community members. Please vote no when the Fountain Wind Project is brought before for a vote.

Board of Supervisors Public Comments for 19 May 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

Due to the COVID-19 pandemic the plea and sentencing hearing for PG&E's guilty plea on **85 felony counts** of manslaughter involving the Camp Fire has been rescheduled to June 16^{th} and will be handled via tele video.

In the same week PG&E announced that over **70,000 wildfire victims** appear to support the company's plan of the reorganization which includes the **largest bankruptcy settlement in U.S. history** at $13.5 billion dollars.

Over the last 18 months this Board has gained knowledge of PG&E's bankruptcy due to the lack of maintenance and transmission safety issues that have resulted in multiple fires and needless deaths. I previously outlined PG&E's "Wildfire Prevention Plan" does not provide the needed "historical safety results" to consider such a project as the Fountain Wind industrial development.

In addition to the PG&E bankruptcy issues the COVID-19 pandemic has shut down nearly the entire World resulting in over 300,000 deaths. The pandemic has driven the Nation, the state of California, and Shasta County, into a financial crisis that will take years to recover while closing some businesses forever. The monies proposed by the Fountain Wind developers as their "payoff" will be pennies compared to the unresolved PG&E maintenance and transmission safety issues, and now the COVID-19 health risks that will be brought into the area due to the proposed construction if approved. P27-101

The Montgomery Creek, Round Mountain, Wengler, Big Bend, Burney, and Oak Run, are small communities compared to Paradise however the **PG&E transmission grid safety issues, lack of maintenance, and the Round Mountain Sub-station upgrade are just as real and are still unresolved as stated by PG&E themselves**.

We cannot continue to do business as usual, to gain unnecessary power to an antiquated transmission grid, without the necessary upgrades and safety measures put into place by PG&E with measured success over time to ensure the surrounding communities are safe.

I ask that you deny the Fountain Wind Project use permit for the 'safety, health, and quality of life issues' for the residents now and in the future.

19 November 2019 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa

The Fountain Wind developers would like to present their case that it is all about meeting California's renewable energy goals by 2045. The reality is "it is all about the money".

As stated by ConnectGen, the new project managers for Fountain Wind contracted by Avangrid, Big Wind projects are hard to find in California and they feel they have a leg up since they are already in a land lease agreement. "Despite California's ambitious push to replace fossil fuels with other energy sources developers indicate there's been a slowdown, including the fact that the state's big utility companies have already bought most of the energy they need to meet their next target for 2020. In addition PG&E stated in their bankruptcy they have met their renewable energy requirements until 2030 and have not been looking to purchase any additional power.

The executive director of the Center for Energy Efficiency and Renewable Technologies, V. John White, states the new renewable energy purchases are "basically at a standstill" in California. That's because the best wind spots in California – including the San Gorgornio Pass – have already been developed, and it's cheaper to build new wind developments than repower old ones. P27-102

Traveling to Southern California we went through the Tehachipi area where there are over 4,7000 turbines. Several hundred of the turbines were not even turning and have old and antiquated technology that need to be repowered with newer technologies that is more efficient. As an example Wintec Energy replaced 212 turbines from 1982 with 35 larger machines outside Palm Springs. Those were then replaced with 5 even larger machines. Today, the five turbines generate 6 times as much energy as the original 212.

Per recent PG&E bankruptcy proceedings the lion's share of the financial profits are handed over to the shareholders leaving the ratepayers left to deal with the devastating loss of their communities and even their lives.

As we are witnessing the **multi-billion** dollar Big Wind giants that want to search across California, for new wind developments, because it is cheaper to devastate small rural communities, than repowering thousands of antiquated turbines, in the already established highest wind and less wildfire prone regions.

The developers themselves need to be the advocates to advance California legislation, and coordinate a clearinghouse, with the help of the CPUC, to **exhaust all efforts to repower the old antiquated turbines first** within California, and across the Country, even at the higher cost.

The approval of the Fountain Wind project will cause **yet another unnecessary environmental and culturally devastated small rural community to deal with the loss where we have the most to lose.** If these types of efforts are not implemented it is clear to see it really is about the money!

Board of Supervisors Public Comments for 21 April 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

The Citizens in Opposition to the Fountain Wind Project have submitted their second request for Shasta County officials to place a moratorium on industrial wind turbines due to the on-going COVID-19 global pandemic. I believe the first moratorium request issues still **remain unresolved** and haven't been addressed regarding the 'safety, health, and quality of life issues' of the residents within Shasta County.

Two discussion areas today are the PG&E bankruptcy and the COVID-19 pandemic.

As stated by Governor Gavin Newsom "This is the end of business as usual for PG&E". California is requiring a state-appointed "operational observer" to oversee the company's **progress on safety** before existing bankruptcy.

The safety issues, due to the lack of maintenance, brought forward by PG&E's bankruptcy can't be denied any longer or resolved by any developers. P27-103

- PG&E's transmission grid is antiquated and needs several years and approximately $40 billion in upgrades.
- PG&E has plead guilty to 84 counts of manslaughter, due to their negligence, and is not in compliance with the state law.
- TANC identified the grid instability issues, when they responded to the Shasta County Hatchett Ridge scoping comments in 2007, which were never resolved.
- The Round Mountain Substation is now under contract for upgrades until 2024, due to reliability issues, which include the 230 kV lines for the Fountain Wind project.

Since the recent unprecedented events of the PG&E bankruptcy, representing the biggest utility bankruptcy in U.S. history, and the collapse of global markets around the world due to the COVID-19 pandemic Shasta County representatives will need **more information not yet available** to make a decision regarding these type of projects.

During this time of numerous crises I ask the Shasta County representatives **to put the moratorium in place** enabling adequate time, and data, to evaluate the 'safety, health, and quality of life issues' for the residents.

Board of Supervisors Public Comments for 21 July 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

PG&E has been out of bankruptcy only two weeks and is again being held responsible for the Kincade fire from 2019, due to problems with their transmission lines that ripped through Sonoma County. Fire officials say the PG&E transmission lines are responsible for destroying 374 homes and other buildings, and causing nearly 100,000 people to flee.

Earlier this year Senator Mike McGuire introduced SB 1312, which passed full senate in late June, to hold utilities accountable for grid hardening, modernization and vegetation management by expediting these improvements which will ensure power shutoffs have a smaller footprints and shorter duration. Senator McGuire states "PG&E, in particular, is years behind in grid modernization and hardening and this bill will advance an expedited schedule to make **desperately needed modernizations and improvements to their system**. The bill, along with previous state actions, will ensure these devastating shutoff events do not continue to **disrupt and endanger the lives of Californians**. Last fall cannot become the new normal."

McGuire said SB 1312 does the following to strengthen the existing PSPS process:

P27-104

- Require that IOUs identify power lines that are more likely to cause power shutoff events or wildfires.
- Require IOUs to include details about the lines that cause the power shutoffs in their after-event reports, including how many miles of lines were impacted and how many circuits were impacted. This will allow state agencies to truly pinpoint and develop a fix-it plan.
- Require IOUs to harden their infrastructure that caused the power shutoff event and report back to the CPUC on their progress one year after the shutoff event. Currently, utilities are behind in their hardening and vegetation management.
- Require the CPUC to hold hearings to determine whether a power shutoff event is in accordance with standards and authorize the Commission to levy fines if needed.
- Prohibit IOUs from charging Californians for electricity not provided during a power shutoff event when power is cut.
- Authorize the California Office of Emergency Services (OES), CAL FIRE, and the CPUC to create consistent procedures for power shutoff events in the best interest of Californians by collaborating on what each agency needs, including the notification process, guidelines on how lines will be re-powered, and what the footprint of the outage will be.
- Require that IOUs identify and harden power lines that are more likely to cause PSPS events or wildfires within a four year timeline instead of the 12-14 years proposed by PG&E.

SB 1312 outlines that **modernization efforts are desperately needed to the unsafe PG&E grid.** The Fountain Wind project will only exacerbate the existing unsafe conditions and must be denied when brought to you for a vote.

References

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PG&E Transmission Lines Started Kincade Fire in Sonoma County: Cal Fire
https://www.nbcbayarea.com/news/local/pge-transmission-lines-started-kincade-fire-cal-fire/2327466/

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http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB1312

Board of Supervisors Public Comments for 24 Mar 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

I spoke to you regarding the overwhelming documentation and the transmission grid safety and maintenance issues by PG&E.

In an article published by the LA Times, on Monday March 23, PG&E **plead guilty to 84 counts of involuntary manslaughter** related to the Camp Fire. They also plead guilty to **one count of causing a fire violation** of the state penal code.

The CPUC and the Department of Forestry and Fire Protection concluded that poorly maintained PG&E equipment sparked that blaze. The Commission noted PG&E failed to do climbing inspections of the century-old tower that malfunctioned, where there was "visible wear", but that PG&E crews had not climbed the tower since at least 2001.

The climbing inspections on the failed tower "is a violation of PG&E's own policy requiring climbing inspections on towers where recurring problems exist" investigators wrote. That inspection would have identified the small metal hook, and its timely replacement, that could have prevented the ignition of the Camp Fire. P27-105

In 2019 PG&E admitted in federal court that its equipment probably caused 10 wildfires in Northern and Central California.

As documented the one count of fire violation of the state penal code resulted in 84 deaths.

The **documentation is overwhelming** that years of maintenance upgrades, and billions of dollars, are required for PG&E to harden their century old transmission grid to ensure safety.

Since the **Fountain Wind Project will <u>tie into</u> the poorly maintained PG&E transmission grid** Shasta County **must deny** the use permit for the Fountain Wind project.

Public comments for the Shasta County Board of Supervisors – 25 Aug 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

Now with the DEIR for the Fountain Wind project released we begin to see the overwhelming impacts the proposed project will continue to introduce to our area.

1) The number of proposed turbines will be no more than 72 however they will be the **tallest turbines in the US**! These monstrosities will stand at 679 feet tall and will compete with the tallest skylines in San Francisco and Los Angeles ranking the 16th tallest structures overall towering within 1,800 feet of homes.
2) The PG&E bankruptcy is never mentioned even though this has now become our "new environment". The mention of the PG&E Fire Prevention Plan in the Wildfire section as part of the mitigation plan carries no weight for the safety of the communities. Since PG&E existed their bankruptcy in June they are once again admitting that their equipment caused the Kincaid fire of 2019 due to maintenance issues. Their on-going PSPS events further indicate how the utility expects to rely on these outages to prevent its outdated grid from starting more deadly fires.
3) The Round Mountain Sub-station upgrades are mentioned indicating that it only affects the 500 kV lines and is separate from the Fountain Wind project. The fact is the thermal overload and overvoltage issues also effect the 230/115/60&70 kV lines and the upgrades will not be completed until mid-2024 at the earliest. P27-106

The DEIR indicates that the "CPUC regulates services and utilities and assures California's access to safe and reliable utility infrastructure and services". Through the bankruptcy it has been proven that PG&E is not alone in their lack of oversight regarding safety and maintenance issues. This Board witnessed some of those very concerns in this chamber during one of the CPUC meetings. In addition the CPUC has also shown their lack of proper oversight to 'safe and reliable utility infrastructure and services" so much that Senators have requested a separate investigation into the CPUC due to the lack of oversight.

This Board can no longer hide from the realities or our 'new environment' and be complacent with 'business as usual' to meet renewable energy goals. Please **vote No** when the Fountain Wind project is brought before you for a vote. You must give PG&E and the CPUC time to execute their required repairs to the antiquated transmission grid before adding any additional renewable projects that will only exacerbate the issues already identified.

Board of Supervisors Talking Points – 28 Jan 2020

Good morning Chairwoman and supervisors, my name is Maggie Osa

In December I spoke to you about how Governor Newsom outlined that PG&E has been mismanaged, **failing to make adequate investments in fire safety, and prevention, and neglected critical infrastructure.** I also provided you with information from The Wall Street Journal article "Safety is not a Glamourous Thing' indicating that the CPUC also failed to provide proper oversight into PG&E's mismanagement by placing emphasis on rates and green energy.

On January 15th Democratic Assemblyman Adam Gray, proposed assigning a state auditor to dig deeper into the CPUC to 'analyze what went wrong at the agency.' The review is to determine whether the regulators **lax oversight** enabled the neglect of PG&E's infrastructure that triggered catastrophic wildfires, extensive blackouts, and yet another bankruptcy, this time costing the utility $50 Billion in losses. Mr. Gray indicates that PG&E deserves plenty of blame for neglecting to upgrade its power system but states that '**government incompetence is also part of the story'**. Mr. Gray asserts the commission '**knew about the decaying and outdated condition of PG&E's infrastructure, yet they failed to act."**

In addition PG&E recently reported it failed to meet several commitments outlined in the fire-prevention plan that was approved by the commission last year. The plan was for tree-trimming efforts and power line inspections among other things. The report stated it only completed 46 of 53 specific commitments in the plan. The 13% shortfall to meet the fire-prevention plan commitments **yet again** identifies the shortfalls of the safety efforts by PG&E. P27-107

In Dec 2018 the CEQA process added the 'wildfire' category after the Camp fire devastation. As been shown PG&E **continues to show they are NOT meeting** their own fire-prevention plans. As I stated previously the Fountain Wind developers **nor** Shasta County have **any authority over the PG&E transmission grid safety issues and cannot do anything to mitigate or resolve the issues.** The proposed investigation into the lax oversight into the CPUC shows that there is extensive work to be done to ensure the communities safety.

Shasta County cannot **separate** the **safety issues nor the increased wildfire risks** imposed by the Fountain Wind Project **outside** of the PG&E transmission issues, the lax oversight from the CPUC, nor the CAISO Round Mountain Sub-station thermal overload and overvoltage issues that will take several years before they are resolved.

These facts alone show that the Fountain Wind project will be detrimental and increases the wildfire risk to the residents in Shasta County and we ask that you 'take the correct action by voting No when the Fountain Wind Project comes before you for a vote' putting the safety of the Shasta County communities first.

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

Shasta County is again dealing with another COVID-19 shut-down with businesses and families struggling to keep their doors open while determining how to get through to the next pay check.

Since March local community meeting places have been shut down due to the Governor's shut down order, not only once but twice without any indication of when the reopening will begin. It is impossible to understand how the developer and county officials can continue with their on-site environmental studies, meetings with various consultants, developer travel efforts or outreach efforts by the developer to the community that are needed to develop such an enormous project. P27-108

The Citizen's in Opposition to the Fountain Wind project submitted a second moratorium request outlining the various health risk due to COVID-19 in April with no action from the County. The devastating effects of the COVID-19 impacts outlined in the moratorium request are now being realized.

To work through a project such as the Fountain Wind is nearly impossible during normal operating times however the COVID-19 world-wide pandemic is unprecedented. To release the DEIR and FEIR, while in a COVID-19 shut-down pandemic, will only benefit the developer (which is what they are counting on) and keeps only the residents and communities in lock-down with no recourse.

Since the only people who are being restricted from meeting are the community members who are directly affected at the project site.

I again request you place all wind turbine developments on a moratorium until the COVID-19 pandemic has been resolved and communities can begin to operate normally again.
The Fountain Wind Project is deemed non-essential and the residents are not getting our due process as to why this project must be denied when brought to you for a vote.

P27-108 cont.

<u>Board of Supervisors Public Comments for 30 June 2020</u>

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

I have provided you some excerpts from "The Camp Fire Public Report" provided by the Butte County District Attorney at the recent hearings.

The Preface states that 84 souls were lost in the most horrific way imaginable – burned to death. It also states that early in the investigation it became clear that as we began to collect terabytes of data from a **<u>facially cooperative</u>** **<u>PG&E</u>** that more **broad based and intrusive subpoenas** would be needed to dig out data from the extensive PG&E files including its vendor files. Additionally as PG&E witnesses, past and present, were being contacted for interviews, we found PG&E has hired attorneys to represent them and **encourage silence.**

Butte County, partnering with the California Attorney General, decided a special investigative criminal grand jury needed to be sworn in. The criminal grand jury meet in secrecy for the next year and heard nearly 100 witnesses, reviewed approximately 1600 exhibits, and produced some 6000 pages of transcript. Since they were sworn to secrecy they could not tell their employers, friends, or family what they were working on.

Pages 11-19 of the report indicates that the Camp Fire also directly cause the deaths of the following 84 persons which you have the copies of now. P27-109

In the conclusions section of the report, and I quote, "The evidence developed during this investigation clearly established that the **<u>reckless actions</u> of PG&E created the risk of a catastrophic fire** in the Feather River Canyon, that PG&E **<u>knew</u> of that risk and PG&E <u>ignored</u> the risk by not taking any action to mitigate the risk**."

At the hearing Judge Michael Deems said "if these crimes were attributed to an actual human person rather that a corporation the anticipated sentence would be 90 years to be served in state prison. As a corporation, PG&E cannot be sentenced to prison. The only punishment to court is authorized to impose is fine.

Shasta County faced our own tragedies during the Carr Fire when eight lives were lost with families still recovering today due to **one spark** from a flat tire. The stark difference between the Carr and Camp fires is that PG&E, as a corporation, **knew, created, and chose to ignore the fire risk** to increase the profits of their shareholders.

Once you read this report **you will need to decide if PG&E has proven that they have your trust** to be able to **<u>safely</u>** connect and distribute the power generated by the Fountain Wind Project?

Please take time to read the information I have provided and you will see that the Fountain Wind project must be denied when brought to you for a vote.

Emotional Chico court hearing ends with PG&E fined nearly $4 million for the Camp Fire.
https://krcrtv.com/news/local/emotional-chico-court-hearing-ends-with-pge-fined-nearly-4-million-for-the-camp-fire

The Camp Fire Public Report (pdf)
Butte County District Attorney – dtd June 16th 2020

Planning Commission Talking Points 14 Nov 2019

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

We understand the CEQA process regarding the Use Permit for the Fountain Wind Project. We have been presenting information at each of the Board of Supervisors meetings and plan to present some of the same information to this commission.

We continue to work with the Board of Supervisor regarding the moratorium for industrial wind turbine developments which all of you have received copies of that request. We do not believe these industrial turbine developments are appropriate for Shasta County in the highest rated wildfire zones in the State.

The CPUC had an emergency meeting with Bill Johnson, the PG&E CEO, who stated these blackouts could continue up to 10 years. Mr. Johnson also disclosed that PG&E was still years away from sufficient upgrades to its grid. The Fountain Wind project wants to do the 'tie-in' into the unreliable and insufficient PG&E transmission grid without acknowledging that they will become part of the problem. There are NO modern technologies, or mitigation measures that the developer can provide that will reduce the additional risk to an already critical situation. The Fountain Wind developer has **no control of the overall PG&E grid** and **CAN NOT** provide mitigation measures to address the upgrades required by PG&E. P27-110

Residents adjacent to the development area have been without power for 10 of the 31 days in October due to the PG&E blackouts. The PG&E blackout maps show the Fountain Wind project in the same area that PG&E indicates is the highest risk and plans to cut power first.

The PG&E wildfire mitigation measures, shown in the recent blackout, failed yet again to protect communities. PG&E needs to document the completed maintenance work to their antiquated transmission grid and Shasta County representatives CAN NOT consider the PG&E grid reliable or sufficient to handle any additional renewable power as outlined by Fountain Wind. Adding Fountain Wind power to an unreliable and insufficient grid, as outlined by the grid owner themselves, only puts the residents and communities in another deadly situation.

The community members will continue to provide evidence that under SCC 17.92.025(G) this project does not meet the requirements for approval. We will document that the establishment, operation or maintenance of the of the Fountain Wind project, including the buildings and facilities would under the circumstances of the particular use, be **detrimental to the health, safety, peace, morals, comfort, and general welfare of persons residing or working in the neighborhood, and will be detrimental or injurious to property or improvements in the neighborhood or to the general welfare of the County.**

Planning Commissioners Public Comments – October 8th, 2020

My name is Maggie Osa and I am speaking in opposition the Fountain Wind Project

The review of the Draft Environmental Impact Report validates that it does not provide the needed modeling, data analysis, and out-reach to other governmental agencies for the decision-makers to make an informed decision regarding the Fountain Wind project.

The recent PG&E bankruptcy safety, maintenance, and hardening efforts are not even mentioned and the reliability issues at the Round Mountain sub-station are only discussed as outside the Project DEIR and on-going work. The draft report indicates that the safety and reliability issues are someone else's responsibility and that the denial or approval of the Fountain Wind project would not be related and/or affected by the other safety, reliability, and hardening work. Shasta County is being irresponsible by not considering these safety, maintenance, and reliability issues on the transmission grid.

Shasta County did nothing to reach out to the other governmental agencies, CALISO, PG&E, nor the CPUC, regarding how the Fountain Wind project would exacerbate the reliability issues at the Round Mountain Sub-station nor did they obtain the current status from PG&E regarding hardening or safety upgrades in and around the Project area. The Applicant and County indicate that the CPUC is responsible for safety of the transmission grid but they also state that the Fountain Wind project is not regulated by the CPUC since they are not a public utility. You can't have the residents caught between the decisions from approving agencies so who is responsible? Who in Shasta County has the authority to make the decision regarding the safety and reliability of the transmission grid without the required data, modeling, or coordination from the other governmental agencies? How will Shasta County obtain the required modeling and data analysis to make any informed decision regarding these areas without the required input from the CPUC, CALISO, or PG&E? P27-111

Without the required modeling, data analysis, and out-reach to the governmental agencies the decision-makers cannot make informed decisions regarding the safety, peace, morals, comfort, and general welfare of the residents within and working in the neighborhood. To do any less in analyzing the required data would be negligent.

Without the required modeling, data analysis, and coordination across governmental agencies the draft and final environmental reports lack an accurate and complete environmental setting per CEQA requirements. Also, the lack of the proper assessments mentioned leads to a lack of necessary mitigation and improperly stated mitigation measures as found throughout the draft report.

Please vote no when this project comes before for a vote.

Reference:
Fountain Wind Project Draft Environmental Impact Report, dtd July 2020.

9 Jan 2020 – Planning Commission Mtg

Good morning Chairman and Commissioners

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

I would like to report that on December 17th, 2019, the **Humboldt County Board of Supervisors denied the special use permit for the Terra-Gen Wind energy project**, with a 4-1 vote. The Humboldt Planning Commissioners previously denied the project with a 4-2 vote on November 21st.

The Terra-Gen project proposed **only 47 turbines**, each more than 600 feet tall, to be installed atop Bear and Monument Ridges. Even with the increased mitigation measures proposed by the developer, and promises of employee training programs within the region, they could not overcome the negative impacts that would be created in the region for decades to come. They also could not overcome **the passion of the residents to stop these unnecessary industrial developments surrounding their homes and sacred lands**. P27-112

Since the Fountain Wind project has nearly twice as many turbines as the Terra-Gen project it will have a significantly greater environmental impact. The Terra–Gen project identifies some of the same social objections and environmental impacts that can't be resolved.

The Fountain Wind Project is proposing at least 72 turbines, at 600 feet or taller. These turbines rank 21st with some of the tallest skyscraper structures within California competing with Los Angeles and San Francisco.

The Pit River Tribe has also submitted a resolution in opposition to the Fountain Wind Project, due to the sacred ties within the development area, just as the Wiyot Tribe did against the Terra-Gen project.

The Fountain Wind project social, health, and environmental impacts, including bird and bat deaths, native plant destruction, hydrology impacts, increased wildfire threats, PG&E bankruptcy impacts, grid instability and lack of maintenance resulting in wildfires, the Round Mountain thermal overload and over voltage issues, decline in property values, health issues, are only multiplied by the increased size of the project.

With that we need to ask:

1) **What further efforts can be made to conserve energy statewide without the additional destruction by industrial wind developments?** "Why would we build these big industrial wind turbines so we can light-up billboards across the state without looking at additional conservation efforts first?

Planning Commission Public Comments – September 10th, 2020

My name is Maggie Osa and I am speaking in opposition the Fountain Wind Project

The release of the DEIR validates this is the wrong project in the wrong area for so many reasons.

The summary of the Wildfire impacts, with mitigation, which goes from 'Potentially Significant' to 'Less than significant' is an absurd assessment!

Page 3.16-17 of the DEIR states: "Therefore, due to the **increase in potential sources of ignition,** Project construction and decommissioning could increase the risk of surrounding communities, exposure to pollutant concentrations from wildfire and the uncontrolled spread of wildfire to a level that is **<u>substantially higher than existing baseline conditions</u>**, which **would** result in a potentially significant impact".

Remembering the 'baseline conditions' are Very High Fire Hazard Zone and Tier 2 & 3 which are assigned the highest in the state and now the Applicant wants to go substantially higher. P27-113

1) It is clear the statements '<u>increase the wildfire to level that is substantially higher than existing baseline conditions</u> validates you must deny the use permit per Zoning Plan Section 17.92.020.F for health and safety alone.
2) How can you add '<u>substantially higher than existing baseline conditions'</u> then indicate you can mitigate to 'less than significant' just by following common sense practices to prevent wildfires?

If the **Fountain Wind project were not under consideration** we would still be assigned a "Very High Fire Hazard Severity Zone (CAL FIRE) and the Tier 2 & 3 (CPUC) classification. The facts are that approving the special use permit will only add thousands of potential ignition points that don't exist in the project area now.

In addition, the Fountain Wind Project clearly goes against Shasta County's FS-1 General Plan objective – "Protect development from wildland and non-wildland fires by requiring new development projects to incorporate effective site and building design measures commensurate with level of **potential risk presented by such a hazard and by discouraging and/or <u>preventing development from locating in high risk fire hazard areas</u>**." As we know there no measures that will add **less potential risk** in the development of the project.

Your denial of the use permit and 'No Project' vote validates that you are not willing to introduce any types of developments from locating in the high risk fire hazard area. As we witness the fire destruction today to levels that are unprecedented, triggering PTSD across the region, confirms that the No Project vote is the only vote!

<u>Reference:</u>

Fountain Wind Project Draft Environmental Impact Report, dtd July 2020, pages 3.16-13 & 3.16-17.

Planning Commission Talking Points 9 Jan 2019

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

In the recent Humboldt County wind project decision, the special use permit was denied by the Planning Commissioners and Board of Supervisors, we do not believe these industrial turbine developments are appropriate for Shasta County.

We have received the feedback regarding information of the General Plan and County Zoning codes **however we still believe they are inadequate on how to address large scale industrial wind turbine developments. The developers do not present themselves as a "public utility" and the general terms "public energy" have no boundaries or safeguards for the communities as outlined in the Small Wind Energy section of the Shasta County Code.**

1) The increased wildfire threat (which include material transports, construction, operation, and maintenance) and the State's continuing efforts to reduce the wildfire risk, **some of which have not been discussed or implemented**.
2) The lack of a countywide emergency evacuation plans, or wildfire safety council, with some ingress and egress currently **down to one lane** for members within the project communities. P27-114
3) The devastation to our wildlife, local Bald eagle, spotted owl, other avian impacts, and ground wildlife.
4) The irreversible destruction to the local Native American heritage and history.
5) **The CAISO Transmission upgrade Plan includes the Round Mountain Sub-station**, identify the grid instability, thermal overload and voltage issues, exacerbated by the intermittent generation of renewable energies, won't be completed until late 2024
6) The on-going **PG&E bankruptcy** with outline efforts to shed existing renewable power purchase agreements and the estimated years needed by PG&E to address their maintenance issues, with the most recent Wall Street Journal article indicating they know about the risk which caused the recent Camp Fire. As stated previously **the developer does not have any control over already identified maintenance issues in the PG&E territories.**
7) The lack of adequate County Zoning codes, General Plan, and Open Space updates.
    a. These industrial wind turbines, at 600 feet, are competing with San Francisco and Los Angeles which tied the ranking as the 21st tallest building. At 650 feet they move up to the 16th tallest. These are not farms but skyscraper industrial complexes so where are the protections for the rural communities and its members?

We will continue to bring these types of issues, and others to this board, until action is taken to address Large Scale Industrial developments within Shasta County.

The moratorium will enable Shasta County adequate time to evaluate, study, review, and make informed decisions to determine if it is even appropriate for any additional Wind Development projects to be considered in the County. The moratorium will allow the Shasta County Planning Commission and Elected Representatives to be proactive, and not reactive to additional wind development requests, giving them time to hold public hearings, update the General Plan and the Shasta County Zoning codes appropriately.

The proposed Fountain Wind IWTs, situated on the eastern mountain range, would have a tremendous negative visual and aesthetic impact on this County since it would be seen from every community across Shasta County and neighboring Counties, including the heavily traveled I-5 corridor. Future Wind Energy Conversion System developments could populate our beautiful mountain ranges with the industrial blight of 600ft tall industrial wind turbines.

CAISO Transmission Grid upgrades are currently underway for the Round Mountain Substation. Round Mountain 500kV Dynamic Reactive Power Support has been approved and will be out for Competitive Solicitation Mid 2019 to solve an existing voltage instability and thermal overload issue at the substation and along its interconnections and transmission paths. The upgrades aren't due to be completed until late 2024. Adding the Fountain Wind power would only exacerbate the existing problem.

The PG&E bankruptcy could affect California's renewables in the future. Per PG&E 2018 RPS Procurement Plan & Previous advice letter 5163-E, PG&E has no need for additional RPS until **after 2030.**

In 2017-2018 California has experienced some of the most deadly and destructive wildfires in its history. It has been documented by Cal Fire that there are numerous areas within Shasta County , including the proposed Fountain Wind Development Site, that are identified by High(4) and Very High(5) priority landscapes for reducing wildfire risk of our forested landscapes. In light of the recent and on-going Community Wildfire Prevention & Mitigation Report, dtd February 22, 2019, and recognizing the need for urgent action, Governor Gavin Newsom Issued Executive Order N-05-19 on January 9, 2019. The Executive Order directs CAL FIRE, in consultation with other state agencies and departments, to recommend immediate, medium and long-term actions to help prevent destructive wildfires with emphasis to protect vulnerable populations. Nearby Shingletown with the same topography as the project site, was listed as the number one priority. Introducing additional unnecessary wildfire risks, such as IWT developments (including all phases – material delivery, construction, operation and maintenance), into High(4) and Very High(5) fire hazard zone forested areas, undermines the Governor's Executive Order and does nothing to reduce our wildfire risk but will only add to it. No amount of increased risk is acceptable when even one spark in a windy forested areas such as ours can easily lead to another Carr or Camp fire tragedy.

P27-114 cont.

7 Jan 2020 – Board of Supervisors Mtg

Good morning Chairman and Supervisors

Hi! My name is Maggie Osa and I am a member of the group, Citizens in Opposition to the Fountain Wind Project.

I would like to report that on December 17th, 2019, the **Humboldt County Board of Supervisors denied the special use permit for the Terra-Gen Wind energy project**, with a 4-1 vote. The Humboldt Planning Commissioners previously denied the project with a 4-2 vote on November 21st.

The Terra-Gen project proposed **only 47 turbines**, each more than 600 feet tall, to be installed atop Bear Ridge and Monument Ridge. Even with the increased mitigation measures proposed by the developer, and promises of employee training programs within the region, they could not overcome the negative impacts that would be created in the region for decades to come **or the passion of the residents to stop the unnecessary industrial developments surrounding their homes and sacred lands**. P27-115

Since the Fountain Wind project has nearly twice as many turbines as the Terra-Gen project it will have a significantly greater environmental impact. The Terra–Gen project identifies some of the same social objections and environmental impacts that can't be resolved.

The Fountain Wind Project is proposing at least 72 turbines, at 600 feet or taller. These turbines rank 21st of the tallest skyscraper structures within California competing with Los Angeles and San Francisco.

The Pit River Tribe has also submitted a resolution in opposition to the Fountain Wind Project, due to the sacred ties within the development area, just as the Wiyot Tribe did against the Terra-Gen project.

The Fountain Wind project social, health, and environmental impacts, including bird and bat deaths, native plant destruction, hydrology impacts, increased wildfire threats, PG&E bankruptcy, grid instability and maintenance resulting in wildfire, the Round Mountain thermal overload and over voltage issues, decline in property values, health issues, are only multiplied by the increased size of the project.

With that we need to ask:

1) **What further efforts can be made to conserve energy statewide without the additional destruction for industrial wind developments?** "Why would we build these big industrial wind turbines so we can light-up billboards across the state without looking at additional conservation efforts first?

Planning Commission Talking Points – 9 April 2020

My name is Maggie Osa in opposition to the Fountain Wind Project

I continue to state that PG&E cannot provide **documented historical facts** regarding the safety of their transmission grid, and as stated by PG&E themselves will take years to resolve, with $40 billion in badly needed upgrades.

In addition CALISO completed the competitive solicitation from the 2018-2019 transmission planning process for the Round Mountain Substation, where the ISO identified the project due to a **reliability driven need** for the transmission project.
http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf

On February 28th of 2020 CAISO released the Round Mountain 500K-V Dynamic Reactive Support Project Sponsor Selection. The ISO has selected LS Power Grid California, LLC (LSPGC) with the **latest in-service date** of **June 1, 2024**.
http://www.caiso.com/Documents/RoundMountain500kVAreaDynamicReactiveSupportProject-ProjectSponsorSelectionReport.pdf#search=Round%20Mountain%20sub%20station P27-116

The reliability and safety driven issues at the Round Mountain substation, nor PG&E pleading guilty to 84 counts of involuntary manslaughter due to faulty equipment, cannot be overlooked. These safety and reliability issues must be resolved completely before you can make a decision regarding the Fountain Wind, or similar projects.

Fountain Wind developers will be the sub-contractors for the tie-in to the 230kV PG&E lines which are also affected by the Round Mountain Substation upgrades.

With PG&E's **continued** criminal activity, including the judge's statement indicating they are still not in compliance with state law, would you hire PG&E as the primary contractor to do the work to keep your families safe?

Everyone must learn from several of the past tragedies, and the **documentation is overwhelming,** regarding the criminal activity and unreliable PG&E transmission grid.

I request Shasta County deny the use permit for the Fountain Wind project when it comes before you for a vote.

Planning Commissioners Public Comments for 9 July 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

I have provided you some excerpts from "The Camp Fire Public Report" provided by the Butte County District Attorney at the recent hearings.

The Preface states that 84 souls were lost in the most horrific way imaginable – burned to death. It also states that early in the investigation it became clear that as we began to collect terabytes of data from a **facially cooperative PG&E** that more **broad based and intrusive subpoenas** would be needed to dig out data from the extensive PG&E files including its vendor files. Additionally as PG&E witnesses, past and present, were being contacted for interviews, we found PG&E has hired attorneys to represent them and **encourage silence.**

Butte County, partnering with the California Attorney General, decided a **special investigative criminal grand jury** needed to be sworn in. The criminal grand jury **meet in secrecy** for the next year and heard nearly 100 witnesses, reviewed approximately 1600 exhibits, and produced some 6000 pages of transcript. P27-117

Pages 11-19 of the report indicates that the Camp Fire also directly cause the deaths of the following 84 persons which you now have copies.

In the conclusion section of the report, "The evidence developed during this investigation clearly established that the **reckless actions of PG&E created the risk of a catastrophic fire** in the Feather River Canyon, that PG&E **knew of that risk and PG&E ignored the risk by not taking any action to mitigate the risk**." The Restitution section states "**PG&E was entrusted by the People of the State of California to provide safe and reliable electricity. PG&E took advantage of that position of trust and was able to generate billions of dollars in profit.**"

At the hearing Judge Michael Deems said "if these crimes were attributed to an actual human person rather that a corporation the anticipated sentence would be 90 years to be served in state prison.

Shasta County faced our own tragedies during the Carr Fire when eight souls were lost and families still recovering today due to **one spark** from a flat tire. The stark difference between the Carr and Camp fires is that PG&E, **knew, created, and chose to ignore the fire risk** to increase the profits of their shareholders.

Please take time to read the information I have provided. The Fountain Wind project must be denied when brought to you for a vote because PG&E, through their bankruptcy, has proven they are not trustworthy, have years of overdue maintenance work, costing over $40 billion dollars'. So I ask you "Will PG&E have your trust to safely connect and distribute the power generated by the Fountain Wind Project? "

Planning Commissioners Public Comments for 11 June 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

On May 29th, the CPUC unanimously voted to approve the PG&E $58 billion dollar reorganization plan even though they **remained critical of PG&E's track record on safety**.

During this approval process many stakeholders were highly critical of the decision without higher levels of government control over PG&E's safety practices. The community members **did not see the focus on prevention of further wildfires** and also the planned power shut-offs.

PG&E has stated they need to invest $40 billion over the next five years in their infrastructure, **much of it to prevent future wildfires**.

So based on the facts of PG&E's failed wildfire prevention efforts Shasta County must resolve some urgent questions before making a decision regarding the use permit.

1) How do you know if any of the critical $40 billion infrastructure upgrades needed are at or near the project site? P27-118
2) How will the Fountain Wind Project add to the already existing infrastructure failures?
3) How does the Fountain Wind Project affect the Round Mountain Sub-station thermal overload and over voltage issues and will it make it safer for the surrounding communities?
4) How will the **new wildfire risk**, introduced by the Fountain Wind Project, be addressed to ensure the safety of the communities?
5) If the Fountain Wind developers believe they will not introduce any additional wildfire risk then why is the land owner installing **dip tanks only in the turbine project area** and not their entire forested areas?

Through the bankruptcy it has been proven that PG&E has caused multiple wildfires killing more than 100 people. Butte County DA pursued charges and PG&E is pleading guilty to 84 counts of manslaughter where no one is really being held accountable.

Shasta County **cannot separate** PG&E's bankruptcy, safety issues, needed transmission grid upgrades, or manslaughter pleas in the review process of this industrial special use permit request. Shasta County needs to let PG&E execute their $40 billion upgrades over the next 5-10 years and then evaluate if their safety results have improved before they consider special use permits for industrial turbines in the future.

Without time to do a safety evaluation, **with a proven track record over several years by PG&E**, Shasta County should not even consider introducing **yet another wildfire risk** to an area already known as one of the highest wildfire areas in the state.

I ask that you deny the Fountain Wind Project use permit for the safety, healthy, and well-being of the community members.

<u>Planning Commissioners Public Comments for 11 June 2020</u>

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

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Without time to do a safety evaluation, **with a proven track record over several years by PG&E**, Shasta County should not even consider introducing **yet another wildfire risk** to an area already known as one of the highest wildfire areas in the state.

I ask that you deny the Fountain Wind Project use permit for the safety, healthy, and well-being of the community members.

Planning Commission Talking Points – 12 Mar 2020

Good morning Chairman, Commissioners, and staff my name is Maggie Osa opposed to the Fountain Wind Project

I continue to emphasize that the Fountain Wind developers nor Shasta County have any authority over the PG&E transmission grid safety issues and cannot do anything to mitigate or resolve the issues.

In a recent article the bankruptcy judge, William Alsup, lambasted PG&E again, by stating "I'm going to do everything I can to protect the people of California from more deaths and destruction from this **convicted felon**."

In the heated hearing the judge stated the company is once again in violation of its probation due to its handling of the fire threat following the natural-gas pipeline in 2010.

The judge said PG&E had failed to achieve full compliance with those terms, and weighed whether to impose additional conditions in the **interest of public safety**. The judge expressed frustration with the company because they are **still not in compliance with state law** and he also took the time to challenge PG&Es efforts to inspect and repair **hundreds of thousands of miles** of power lines throughout its **70,000 square miles** of service territories. P27-120

It has been documented that PG&E **failed to meet their 2019 Wildfire Mitigation Plan by 13%.** As has been shown by PG&E's bankruptcy **providing a plan** does **not result in historical facts**.

So now with the release of the 2020 Wildfire Mitigation Plan PG&E in February they also provide a **Cautionary Statement Concerning Forward-Looking Statements** – indicating "This news release includes **forward-looking statements that are not historical facts**, including statements about the beliefs, expectations, estimates, future plans and strategies of PG&E including but not limited to the Utility's 2020 Wildfire Mitigation Plan.

The bankruptcy judge, who is the closest person reviewing all of the PG&E documentation, referred to PG&E as a **convicted felon,** stating the lack of safety progress by PG&E. PG&E themselves state that over the next 12 to 14 years, approximately 7,100 miles of transmission lines will be hardened in high fire-threat areas such as ours.

PG&E needs to be in **compliance with the law** and **provide historical factual data, over a several year period, relating to their on-going reliability and safety record, specifically in all of the high wildfire prone and forested communities.**

PG&E's bankruptcy and on-going safety issues alone provide **overwhelming documentation** for Shasta County **to deny the special use permit for the Fountain Wind Project putting the safety of the residents first.**

Planning Commissioners Comments for 13 Aug 2020

My name is Maggie Osa and I'm speaking in opposition to the Fountain Wind Project.

PG&E had been out of bankruptcy only two weeks and is again being held responsible for the Kincade fire from 2019, due to problems with their transmission lines that ripped through Sonoma County. Fire officials say the PG&E transmission lines are responsible for destroying 374 homes and other buildings, and causing nearly 100,000 people to flee.

Earlier this year Senator Mike McGuire introduced SB 1312, which passed full senate in late June, to hold utilities accountable for grid hardening, modernization and vegetation management by expediting these improvements which will ensure power shutoffs have a smaller footprints and shorter duration. **Senator McGuire states "PG&E, in particular, is years behind in grid modernization and hardening** and this bill will advance an expedited schedule to make **desperately needed modernizations and improvements to their system**. The bill, along with previous state actions, will ensure these devastating shutoff events do not continue to **disrupt and endanger the lives of Californians**. Last fall cannot become the new normal." P27-121

McGuire said SB 1312 does the following to strengthen the existing PSPS process:

- Require that IOUs **identify power lines** that are more likely to cause power shutoff events or wildfires.
- Require IOUs to include details about the lines that cause the power shutoffs in their after-event reports, including **how many miles of lines were impacted and how many circuits were impacted**. This will allow state agencies to truly pinpoint and develop a fix-it plan.
- Require IOUs to harden their infrastructure that caused the power shutoff event and report back to the CPUC on their progress one year after the shutoff event. **Currently, utilities are behind in their hardening and vegetation management.**
- Require the CPUC to hold hearings to determine whether a power shutoff event is in accordance with standards and authorize the Commission to levy fines if needed.
- Prohibit IOUs from charging Californians for electricity not provided during a power shutoff event when power is cut.
- Authorize the California Office of Emergency Services (OES), CAL FIRE, and the CPUC to create consistent procedures for power shutoff events in the best interest of Californians by collaborating on what each agency needs, including the notification process, guidelines on how lines will be re-powered, and what the footprint of the outage will be.
- **Require that IOUs identify and harden power lines that are more likely to cause PSPS events or wildfires within a four year timeline instead of the 12-14 years proposed by PG&E**.

BUTTE COUNTY DISTRICT ATTORNEY
MICHAEL L. RAMSEY
District Attorney
MARK MURPHY
Chief Deputy District Attorney
JUAN DIAZ
Chief Investigator

THE CAMP FIRE PUBLIC REPORT

P27-122

A SUMMARY OF THE CAMP FIRE INVESTIGATION

June 16, 2020

"To do Justice, as no one is above the Law, nor beneath its protection"
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PREFACE

During the early morning hours of Thursday, November 8, 2018, the Cal Fire Captain in charge of the Jarbo Gap station in the Feather River Canyon could hear the “Jarbo Winds” as they were known locally begin to howl as he got up to fix breakfast for his crew. As he fixed that breakfast he started to hear what he thought was rain begin to hit the roof and sides of the fire station. He started to look outside when the wind took the door from his hand. He discovered it wasn’t rain he was hearing, but pine needles from the surrounding forest forcibly pelting the outside of the station. He went back inside to continue fixing breakfast, but was interrupted as the station’s dispatch radio feed went off alerting him to a possible fire in the Canyon.

The Cal Fire crew immediately rolled out of the station up Highway 70 and the Canyon, past the small enclave of Pulga and up river to the Poe Dam. Arriving above PG&E’s Poe Dam just before sunrise, the Captain and crew saw the beginnings of a conflagration under the PG&E high voltage power line on the ridge top across the river from them. The sight sent a chill through the Captain and crew because they could see the fire was already exploding toward the south and west riding the Jarbo Winds, which were so high the Captain struggled to remain upright. The Captain radioed into his headquarters with urgency in his voice – his crew would never be able to get in front of this fire to control it and in a prophetic understatement he told dispatchers: “This has the potential of a major incident.”

In less than an hour, the fire had torn through Pulga and the mountain hamlet of Concow and reached the eastern outskirts of Paradise – throwing softball-sized embers ahead to the north into Magalia and over the town into the Butte Creek Canyon on the west side. Paradise and its residents were hit from three side by massive walls of fire. Chaos and confusion reigned. Thousands of homes and businesses were lost in the matter of a couple of hours. A town of some 26,000 people was utterly destroyed. P27-122 cont.

Eight-four souls were lost in the most horrific way imaginable – burned to death.

Within a few hours of the fire, Cal Fire arson investigators began to make their way to where the responding Captain had seen the start of the fire. Traveling up Camp Creek Road (from which the Camp Fire took its quirky name), the investigators came to what appeared to be the fire’s beginning. The ground under what was PG&E’s transmission tower #27/222 showed clear signs of the fire’s beginning and a burnt path toward the southwest. Looking up, the investigators saw a detached line hanging down into the steel superstructure of the high-voltage transmission tower.

Something had broken - and sent the live 115 kilovolt (kV) power line (also known as a conductor) to arc against the steel tower and shower molten steel and aluminum metal onto the grass and brush below. A painstakingly detailed arson investigation began.

Within a few hours, the Cal Fire investigators had begun to reach their preliminary conclusions that the Camp Fire was started by the failure of a suspension hook holding up an insulator string which in turn held up the highly energized line. The investigators had found the broken iron hook, also known as a “C hook”, and it appeared to have not just broken, but had worn through after a great deal of time hanging in the windy environs of the Feather River Canyon.

The investigators reached out to the Butte County District Attorney’s Office on November 9, 2020 and discussed their initial findings with the office – including their concern that a PG&E helicopter had been seen hovering above the suspect tower.

The Butte County District Attorney’s Office had had past dealings with PG&E and its criminal violations of failing to clear vegetation from its lines which sparked fires. The office also knew PG&E was a federal felon for its criminal actions leading to the San Bruno gas line explosion.

A directive was given the Cal Fire arson investigators that the DA’s office was opening a joint investigation with them and to treat the fire origin site as a crime scene and to prevent anyone, including PG&E, from entering. (The Cal Fire investigators had already started the process of securing the scene with private security.)

And so began the Camp Fire Investigation. . .

The next week Cal Fire arson investigators directed PG&E linemen under their close scrutiny to begin the dismantling of tower 27/222 and seized relevant portions for evidence. Later, Butte County District Attorney investigators teamed with Cal Fire arson investigators to examine other power lines in the vicinity of the suspect tower. Evidence from those surrounding towers was seized with the assistance of experienced linemen from PG&E under the close scrutiny of a loaned Federal Bureau of Investigation (FBI) Evidence Team.

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Prosecutors were taken from normal day-to-day business in the office and assigned to oversee the investigation. Thus began the arduous task of gathering information from PG&E and others to determine the who, what, how and why of the Camp Fire.

Early into the investigation it became clear that as we began to collect terabytes of data from a facially cooperative PG&E that more broad based and intrusive subpoenas would be needed to dig out data from the extensive PG&E files including its vendor files. Additionally as PG&E witnesses, past and present, were being contacted for interviews, we found PG&E has hired attorneys to represent them and encourage silence.

We partnered with the California Attorney General who assigned experienced prosecutors to assist in the investigation and it was decided a special investigative criminal grand jury should be sworn to subpoena evidence and examine reluctant witnesses under oath. This grand jury was in addition to the regular “watchdog grand jury” that is sworn in every June in Butte County. This special grand jury of 19 ordinary Butte County citizens was selected from 100 summoned potential jurors and sworn in on March 25, 2019.

As an investigatory grand jury, it was the duty of the jurors to sift through all the evidence, hear the witnesses and keep an open mind as to whether there truly was any criminal liability on the part of anyone for causing the Camp Fire. This dedicated group of citizens then meet in secrecy for the next year and heard nearly 100 witnesses, reviewed approximately 1600 exhibits, and produced some 6000 pages of transcript. It cannot be overemphasized the patience and sacrifice of these citizens, meeting once to twice a week for almost a year. And since they were sworn to secrecy, they were not even able to tell their employers, friends and family what they were so diligently working on. Even more amazing was their dedication to their important work to seek justice. Such was their dedication that only three grand jurors were unable to finish their term.

The remaining 16, after their months of hard work and review of all matters, returned an Indictment finding sufficient evidence to charge the Pacific Gas and Electric Company with 85 felony counts – one count of unlawfully and recklessly causing the Camp Fire as a result of its gross negligence in maintaining its power line, and 84 individual counts of involuntary manslaughter naming each of the persons directly killed in the Camp Fire by PG&E's criminal negligence. The Indictment also included three special allegations for PG&E's causing great bodily injury to a firefighter; causing great bodily injury to more than one surviving victim; and causing multiple structures to burn (listed as approximately 18,804 structures). (See attached Indictment.)

PG&E, who had been represented by criminal defense attorneys during the investigation and Grand Jury proceedings, was informed of the Indictment and decided to plead guilty "as charged" to all counts – thereby agreeing the evidence of its criminal negligence has been established beyond a reasonable doubt.

The following Camp Fire Public Report is a summary of the massive undertaking to determine if there was sufficient evidence to convict PG&E of its criminal behavior which lead to the Camp Fire and the awful destruction that followed. The Report also forms the core of legal documents filed with the Butte County Superior Court today to establish the Factual Basis for the pleas by PG&E to the Indictment and the People's Statement in Aggravation for the sentencing of the defendant corporation.

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INTRODUCTION

On November 8, 2018, a fire started underneath a PG&E transmission tower near Camp Creek Road, not far from the town of Pulga in Butte County, California. The fire quickly raged out of control, travelled to the town of Concow within an hour, and to Paradise – seven miles from the point of ignition – in less than 1.5 hours. Seventeen days later, on November 25, 2018, what had become known as the Camp Fire was finally declared 100% contained. It had burned 153,336 acres and destroyed approximately 18, 800 structures.[1] Some 589 structures were damaged.[2] A total of 84 lives were lost as a direct result of the fire and at least two civilians and one firefighter suffered great bodily injury. {Attachment – Camp Fire Presentation}

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I. INITIAL TIME LINE

On November 8, 2018 at 6:15 a.m., the PG&E Grid Control Center (GCC)[3] in Vacaville documented an "interruption" on the energized Caribou-Palermo 115kV transmission line in the Feather River Canyon.

At approximately 6:20 a.m. on November 8, 2018, a PG&E Hydro Division employee[4] driving eastbound on Highway 70 observed a "bright light" above a ridgeline as he approached the Pulga Bridge. Initially the employee believed the bright light to be the sun rising behind the ridgeline; however, as he continued driving, he realized the source of the bright light was a fire underneath the PG&E transmission lines on a ridge on the north side of the Feather River. The employee noted the fire appeared to be at the base of a transmission tower. In that area of the Feather River Canyon cell phone service is not available. The employee used his PG&E radio to contact PG&E employees at the Rock Creek Powerhouse and reported the fire. These employees then called 911 and were transferred to the Cal Fire Emergency Communications Center (ECC) in Oroville. The 911 call from the Rock Creek Switching Station was received by Cal Fire ECC at 6:25:19 a.m.

At approximately 6:30 a.m., an employee of the California Department of Transportation (Cal Trans) arrived at the Cal Trans Pulga Station for work. While in the parking lot of the Pulga Station he observed a fire under a PG&E transmission tower northeast of the Pulga Station and took a photograph of it. The photograph {Attachment 001} showed a fire emanating out from

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[1] 13,696 single family residences, 276 multi-family residences, 528 commercial structures, and 4,293 other structures were destroyed according to Cal Fire.

[2] 462 single family residences, 25 multi-family residences, and 102 commercial structures were damaged according to Cal Fire.

[3] The GCC is the consolidated hub for all transmission operations for PG&E. GCC monitors the Supervisor Control and Data Acquisition (SCADA) for all transmission lines at all times. Any problem on any PG&E transmission line triggers an immediate alert in the GCC.

[4] Throughout this report the names of local current/ former PG&E employees are not used. The Butte County District Attorney's Office believes, based upon anger and frustration within the community, that disclosure of the identity of involved PG&E personnel living and/or working in the area may expose those personnel to harassment, threats or violence.

under transmission Tower :027/222[5] (Tower 27/222) of the Caribou-Palermo 115kV transmission line (Caribou-Palermo line).

At 6:29:55 a.m., the initial Cal Fire notification went out to Captain Matt McKenzie at the Concow/Jarbo Gap Station. By 6:35 a.m., two Cal Fire engines from the Concow/Jarbo Gap Station were on Highway 70 headed eastbound toward Pulga. Captain McKenzie and his firefighters first observed the fire just before reaching the Pulga Bridge. The two engines continued on Highway 70 to the Poe Dam to assess the fire and formulate a plan of attack. From above the Poe Dam on the south side of the Feather River, at 6:44 a.m., Captain McKenzie observed that the fire was burning under the electric transmission lines on the ridge on the north side of the Feather River. Based upon the location of the fire {Google Earth map of 27/222 area and Pulga.}as well as the high wind speed and direction, Captain McKenzie concluded there was no available route to attack the fire. Captain McKenzie immediately realized that the community of Pulga was in danger and dispatched his second engine to evacuate the residents of that community. From his position on Highway 70, Captain McKenzie took measure of the fire (and a photograph {Attachment 002})) and requested additional resources be deployed to the west to stop the fire at Concow Road. During his initial report to the ECC, based upon his observations of the fire, the topography, and the wind, Captain McKenzie warned, "this has the potential of a major incident." (An hour later, at 7:44 a.m., the fire reached the Town of Paradise, a distance of approximately seven miles.)

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At approximately 6:38 a.m., PG&E employees at the Rock Creek Powerhouse informed the GCC of the fire burning near the Poe Dam in the vicinity of the transmission lines. At approximately 6:40 a.m., the GCC notified the Transmission Line Supervisor for the Table Mountain District[6] of the fire. The Transmission Line Supervisor dispatched a troubleman to immediately perform an emergency air patrol of the Caribou-Palermo line. The troubleman located and documented damage on Caribou-Palermo line Tower 27/222 at 12:00 p.m. on November 8, 2018.[7]

At approximately 6:48 a.m. fire watch cameras on Flea Mountain and Bloomer Hill {Attachment – Google Earth map} recorded a plume of smoke east of Concow and west of Pulga. {Fire

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[5] According to PG&E naming convention, a transmission line name is based upon the starting point and ending point of the line. The Caribou-Palermo line starts at the Caribou Powerhouse and ends at the Palermo substation. Tower numbers are determined by the distance from the start of the line in miles and the sequential number of towers. The Caribou-Palermo line is divided into two segments; Caribou-Big Bend and Palermo-Big Bend. The inclusion of a colon (:) before the tower number denotes the Caribou-Big Bend segment. On the Caribou-Big Bend segment the tower numbering starts at the first tower coming out of the Caribou Powerhouse (:000/001) and ends with the last tower before the Big Bend Substation (:037/303). Tower 27/222 is located in the 27th mile away from the Caribou Powerhouse and is the 222nd structure in the line. On the Palermo-Big Bend segment the tower numbers begin with the last tower before the Palermo Substation (000/001) and ends with the first tower after the Big Bend Substation (016/130). {Attachment – Google Earth Map of C-P}

[6] PG&E's electrical transmission grid is divided into geographic districts. Each district is supervised by a Transmission Line Supervisor. The transmission lines in the Feather River Canyon are within the Table Mountain District.

[7] At 12:01 p.m. a Cal Fire investigator spotted and photographed a helicopter from a local charter helicopter firm hovering above tower 27/222. Based upon the tail number of the helicopter it was confirmed this was the helicopter performing the emergency inspection of the Caribou-Palermo line.

Watch Camera Bloomer, Fire Watch Camera Flea} Cal Fire monitors initially attributed the plume of smoke to the Camp Fire. Later Cal Fire monitors and investigators determined the smoke plume was not associated with the Camp Fire and was caused by a separate and unrelated fire. Utilizing mapping tools Cal Fire investigators determined the plume of smoke had arisen from an area near the intersection of Concow Road and Rim Road in eastern Concow. The fire was named the Camp B Fire.

II. ORIGIN AND CAUSE INVESTIGATIONS

Cal Fire assigned a team of highly trained and experienced "Origin and Cause" investigators from around California to assist the local Butte Unit investigators. Cal Fire also retained and assigned subject matter experts to assist with the investigation. The investigators were divided into two teams. One team was assigned to investigate the Camp Fire. The second team was assigned to investigate the Camp B Fire.

Cal Fire investigators determined the origin of the Camp Fire was the dry brush below Tower 27/222 of the Caribou-Palermo line, an electrical transmission line owned and operated by PG&E. Tower 27/222 was determined to be a "Transposition" tower[8] {Attachment – Krelle 3D model download and open with Adobe Acrobat Pro}. With the assistance of a licensed electrical engineer, Cal Fire investigators determined the cause of the Camp Fire was electrical arcing between an energized "jumper" conductor (power line) and the steel tower structure. {Attachment - Framework of transposition tower} Investigators determined a "C hook" that linked an insulator string connected to the jumper conductor to the transposition arm of the tower failed, allowing the energized jumper conductor to make contact with the steel tower structure. {Attachment 004} The ensuing electrical arcing between the jumper conductor and steel tower structure caused the aluminum strands of the conductor to melt as well as a portion of the steel tower structure.[9] The molten aluminum and steel fell to the brush covered ground at the base of the steel tower structure. {Attachment 005} This molten metal ignited the dry brush.

Cal Fire investigators determined the Camp B Fire originated to the west of Concow Road south of the intersection of Concow Road and Rim Road in a geographical bowl. The area of origin was under the right of way of the Big Bend 1101 12kV distribution line. The area of origin was approximately 2.6 miles west of the origin of the Camp Fire. At the area of origin investigators located a broken conductor from the Big Bend 1101 12kV distribution line and a fallen Ponderosa pine tree. Burn patterns on the Ponderosa pine indicated the tree had contacted a live electrical line. {Attachment 006} PG&E records show a documented outage on the Big Bend 1101 12kV circuit at 6:45 a.m. on November 8, 2018. Investigators determined the Camp B Fire was ignited when the Ponderosa pine tree toppled over onto and broke the energized Big Bend 1101 12kV distribution line. The Ponderosa pine and its stump were examined and analyzed by a certified arborist[10] retained by Cal Fire. The arborist determined that the Ponderosa pine was

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[8] A transposition tower is a transmission tower that changes the relative positions of the conductors (power lines) to each other to maintain electrical balance. Transposition towers are placed at intervals along the transmission line.
[9] Aluminum melts at approximately 1200 degrees Fahrenheit, steel melts at approximately 2700 degrees Fahrenheit. The electrical engineer estimated the temperature of the electrical arc between the conductor and the steel structure between 5,000 and 10,000 degrees Fahrenheit.
[10] International Society of Arboriculture Board Certified Master Arborist.

diseased and dying prior to November 8, 2018.[11] However, the arborist determined the disease was internal and likely would not have been visible to PG&E tree inspectors during their vegetation management inspections. According to the arborist the disease likely only would have been discoverable by an advanced inspection.[12]

Before the Camp B Fire grew large enough to escape its geographical bowl, it was passed over and consumed by the Camp Fire. Based upon fire indicators and patterns within the Camp B Fire and recordings from the fire watch cameras, Cal Fire investigators determined that the Camp B Fire had little, or no, effect on the Camp Fire.

III. INJURIES AND LOST LIVES

In support of the great bodily injury enhancements, evidence was presented of two civilians and one fire fighter who were severely burned during the Camp Fire.

Victim 1, an adult female, was located in Concow by a Cal Fire crew in the area trying to locate another reportedly trapped victim. As the engine was trying to leave the area, visibility was near or at zero, when suddenly the smoke cleared briefly. In that moment, the Captain of the fire crew saw an arm appear from between two vehicles. The Captain and his crew stopped and located the badly burned female victim. Lying beside the female victim was a deceased male. The deceased male was later identified as the female victim's roommate. The Captain described how he and his crew repeatedly checked the male roommate futilely hoping to find signs of life. The Cal Fire crew rescued the female victim. According to the Captain, when Victim 1 was lifted into the engine, her skin sloughed off due to the severity of her severe burns. She was taken to a medical evacuation area for transport to a hospital.

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Victim 2, an adult female, was located in Paradise with her husband. Victim 2 and her husband had been trying to flee the fire but were overtaken. Victim 2 and her husband took shelter behind a boulder but both were severely burned. Victim 2 and her husband were rescued by Cal Fire and taken to a medical evacuation area for transport to a hospital. According to the Cal Fire Captain, who supervised that rescue and evacuation, Victim 2 also had skin sloughing off as she was taken from an engine and placed into an ambulance. Both Victim 2 and her husband were transported to the UC Davis Medical Center Burn Unit. Victim 2's husband ultimately succumbed to his burn injuries.

Victim 3, an adult male, was a Cal Fire Captain. The Captain described that as he and his crew were preparing to do a back fire operation to create a fire break east of Clark Road and south of Rattlesnake Flats Road, northeast of Butte College, the fire changed direction and, fueled by high winds, "exploded." As the fire came rushing towards them, the Captain held strands of barbed wire up to allow his crew to quickly escape into the safety of a clearing. After his crew was safely through the fence, the Captain attempted to go through the fence. As he was going

[11] The arborist also consulted with a professor of Dendrochronology at the Indiana State University Dendro Lab.
[12] An advanced inspection would entail use of diagnostic tools such as a mallet, a resistograph or a sonic tomogram and generally only occurs when anomalies or outward signs of disease or decay are observed during the visual inspection.

through the fence the Captain's gear caught on the barbed wire. As a result, the fire overran his position and the Captain was severely burned. The Captain was medically evacuated to UC Davis Medical Center Burn Unit. All members of his crew survived with only minor injuries.

The Camp Fire also directly[13] caused the deaths of the following 84 persons: {Attachment – Camp Fire Victim Locations download and open with Google Earth Pro}

Joyce Acheson – Ms. Acheson, who was 78 years old, was found deceased in her home at 1250 Elliot Road, Unit 17, in the Town of Paradise. Ms. Acheson was of limited mobility, and lived in an area that was closed off to public access, thereby preventing any caregiver from getting to her.

Herbert Alderman – Mr. Alderman was 80 years old and was found deceased inside his home at 5775 Deanna Way in the Town of Paradise. A severely sprained ankle prevented his mobility at the time of the fire, and he made several phone calls to friends seeking rescue before he perished.

Teresa Ammons – Ms. Ammons was 82 years old. She was found deceased outside her home at 6674 Pentz Road, Unit 112, in the Town of Paradise. The evidence indicated Ms. Ammons died while attempting to flee the fire as she was found just outside her trailer with her purse nearby.

Rafaela Andrade – Ms. Andrade was 84 years old and was found deceased inside her home at 6664 Moore Road in the Town of Paradise. She could not walk without the assistance of a walker, and did not have the ability to evacuate on her own.

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Carol Arrington – Ms. Arrington was 88 years old. Ms. Arrington was found deceased inside her home at 1866 Stark Lane in the Town of Paradise.

Julian Binstock – Mr. Binstock was 88 years old. The remains of Mr. Binstock and his dog were located in the shower of his residence at 5900 Canyon View Drive in the Town of Paradise.

David Bradburd – Mr. Bradburd was 70 years old. Mr. Bradburd was found near 6028 Dubarry Lane, in the Town of Paradise. Mr. Bradburd was found within 400 feet of his residence on Pentz Road, near a power line knocked down by the fire. Based upon the evidence, Mr. Bradburd was fleeing the fire when he died.

Cheryl Brown – Ms. Brown was 75 years old. Ms. Brown was found deceased in her home at 1387 N-B Lane in the Town of Paradise. Ms. Brown was found seated in a recliner next to her husband, Larry Brown.

Larry Brown – Mr. Brown was 72 years old. Mr. Brown was found deceased in his home at 1387 N-B Lane in the Town of Paradise. Mr. Brown was found seated in a recliner next to his wife, Cheryl Brown.

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[13] Only persons who died within the Camp Fire footprint on November 8, 2018 from fire-related injuries; or who were medically evacuated from within the Camp Fire footprint on November 8, 2018 to medical facilities and subsequently died as a result of fire-related injuries were counted as direct victims.

Richard Brown – Mr. Brown was 74 years old. Mr. Brown was found deceased under his pickup truck outside his residence at 13377 Eleran Lane in the community of Concow. Based upon the physical evidence, Mr. Brown tried to hide from the fire under his truck.

Andrew Burt – Mr. Burt was 36 years old. Mr. Burt was found deceased just outside of the front passenger side door of a minivan. The minivan was located facing north in the 5000 Block of Edgewood Road, approximately .3 miles south of Mr. Burt's residence at 5236 Edgewood Lane in the Town of Paradise. The remains of Mr. Burt's dog were found next to Mr. Burt. Based upon the evidence, Mr. Burt had been in the minivan attempting to escape the fire when the minivan was overcome by the fire. There were three other vehicles containing the remains of four other victims near the minivan.

Joanne Caddy – Ms. Caddy was 75 years old. Ms. Caddy was found deceased inside her home at 13812 West Park Drive in the community of Magalia.

Barbara Carlson – Ms. Carlson was 71 years old. Ms. Carlson was found deceased in her residence at 5577 Heavenly Place in the Town of Paradise. Ms. Carlson's remains were comingled with those of her sister, Shirley Haley.

Vincent Carota – Mr. Carota was 65 years old and found deceased inside his residence at 5471 South Libby Road in the Town of Paradise. Mr. Carota was a partial leg amputee without a vehicle.

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Dennis Clark, Jr. – Mr. Clark was 49 years old. Mr. Clark was found deceased in the passenger seat of a car with his mother Joy Porter deceased in the driver's seat. Their vehicle was in a line of three other vehicles found facing north in the 5000 block of Edgewood Lane in the Town of Paradise. The vehicle was located approximately .3 miles south of Mr. Clark and Ms. Porter's residence on Sunny Acres Road, off of Edgewood Lane.

Evelyn Cline – Ms. Cline was 81 years old. Ms. Cline was found deceased in her residence at 578 Roberts Drive in the Town of Paradise. She was physically immobile and unable to leave her home without assistance.

John Digby – Mr. Digby was 78 years old and found deceased inside his residence at 6920 Clark Road, Unit #3, in the Town of Paradise.

Gordon Dise – Mr. Dise was 66 years old and was found deceased inside his home at 2735 Eskin Maidu Trail in Chico (Butte Creek Canyon.). According to his daughter, who fled the house with her father, he went back in their home for something and never made it back out.

Paula Dodge – Ms. Dodge was 70 years old. Ms. Dodge was found deceased between two cars in the carport of her residence at 5152 Pentz Road in the Town of Paradise. Ms. Dodge's husband, Randall Dodge, was found deceased next to her. Based upon the evidence, Mr. and Ms. Dodge were attempting to flee the fire.

Randall Dodge – Mr. Dodge was 66 years old. Mr. Dodge was found deceased between two cars in the driveway of his residence at 5152 Pentz Road in the Town of Paradise. Mr. Dodge's wife, Paula Dodge, was found deceased next to him. Based upon the evidence, Mr. and Ms. Dodge were attempting to flee the fire.

Andrew Downer – Mr. Downer was 54 years old. Mr. Downer was found deceased outside the front door of his residence at 8030 Skyway, Unit A, in the Town of Paradise. Based upon the evidence, it appears Mr. Downer died while attempting to flee the fire. He was a wheelchair bound amputee and was unable to drive.

Robert Duvall – Mr. Duvall was 76 years old. Mr. Duvall was found deceased in the passenger seat of his truck. No one else was located in the truck. The truck was in a line of three vehicles found facing north in the 5000 block of Edgewood Lane in the Town of Paradise. The vehicle was located approximately .3 mile north of Mr. Duvall's residence on Sunny Acres Road, off of Edgewood Lane. A second vehicle registered to Mr. Duvall and containing the remains of Mr. Duvall's girlfriend, Beverly Powers, was located nearby.

Paul Ernest – Mr. Ernest was 72 years old. Mr. Ernest and his wife attempted to escape the fire by driving quads[14] off road through a canyon. When their escape route was blocked by a rock formation, Mr. Ernest and his wife were overtaken by the fire. Both were severely burned, and airlifted to UC Davis Medical Center Burn Unit in Sacramento. Mr. Ernest passed away from his injuries on August 5, 2019, nearly 9 months after the fire. He never left the extended care medical facility in Sacramento, after being transferred there from the UC Davis Burn Unit.

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Rose Farrell – Ms. Farrell was 99 years old. Ms. Farrell was found deceased on the front porch of her residence at 1378 Herman Way in the Town of Paradise. Her wheelchair was found near Ms. Farrell.

Jesus Fernandez – Mr. Fernandez was 48 years old. Mr. Fernandez was found on the ground between two vehicles on Broken Glass Circle near Vista Ridge Road in Concow. Mr. Fernandez was the roommate of burn Victim 1 (above). Victim 1 believed Mr. Fernandez died shortly before her rescue.

Jean Forsman – Ms. Forsman was 83 years old and found deceased inside her residence at 13747 Andover Drive in the community of Magalia.

Ernest Foss, Jr. – Mr. Foss was 63 years old. Mr. Foss was found deceased outside of his residence at 5236 Edgewood Lane in the Town of Paradise. Mr. Foss was found with his oxygen tank. The evidence indicates Mr. Foss, who had limited mobility, was attempting to flee the fire at the time of his death.

Elizabeth Gaal – Ms. Gaal was 80 years old and found deceased inside her residence at 5393 Sawmill Road, Unit # 27 in the Town of Paradise.

Sally Gamboa – Ms. Gamboa was 69 years old. Ms. Gamboa was located deceased in a field/clearing behind her residence at 1560 Sunny Acres Road in the Town of Paradise. Based upon the evidence, Ms. Gamboa died while attempting to flee the oncoming flames.

[14] All terrain sport utility vehicles

James Garner – Mr. Garner was 63 years old. Mr. Garner was found deceased inside his residence at 6284 Woodbury Drive in the community of Magalia. Earlier on the morning of November 8, 2018, Mr. Garner had engaged in multiple telephone calls with his sister and nephew.

Richard Garrett – Mr. Garrett was 58 years old. Mr. Garrett was found deceased among trees not far from a residence at 4238 Schwyhart Lane in the community of Concow. Based upon the physical evidence Mr. Garrett was actively running from the fire when he was overtaken and killed by the flames.

William Godbout – Mr. Godbout was 79 years old and found deceased inside his residence at 3831 Camelot Lane in the community of Concow.

Shirley Haley – Ms. Haley was 67 years old. Ms. Haley was found deceased at 5577 Heavenly Place in the Town of Paradise. Ms. Haley's remains were found comingled with the remains of her sister, Barbara Carlson.

Dennis Hanko – Mr. Hanko was 56 years old and found deceased inside his residence at 5081 Wilderness Way, Unit 3A, in the Town of Paradise.

Anna Hastings – Ms. Hastings was 67 years old. Ms. Hastings was found deceased in her residence at 8391 Montna Drive in the Town of Paradise. She was disabled, with severe scoliosis, and unable to drive.

Jennifer Hayes – Ms. Hayes was 53 years old. Ms. Hayes was found deceased in her residence at 5683 Scotty Lake Drive, in the Town of Paradise.

Christina Heffern, Ishka Heffern and Matilde Heffern – Christina Heffern was 40 years old. Ishka Heffern, the daughter of Christina, was 20 years old. Matilde Heffern, the mother of Christina Heffern, was 68 years old. All three were located in their residence at 1865 Norwood Drive in the Town of Paradise. Their remains were located commingled in the bathtub of their residence. The Hefferns placed a 911 call as the fire approached their home. Somehow the phone line remained open as the house, and the three women, burned as helpless Cal Fire ECC dispatchers listened to their screams.

Louis Herrera – Mr. Herrera was 86 years old and found deceased inside of his home at 2376 Clearview Drive in the Town of Paradise. The remains of Mr. Herrera's wife, Dorothy Lee-Herrera, were also found in the residence.

Evva Holt – Ms. Holt was 85 years old and was found deceased in a burned vehicle near the intersection of Pearson Road and Stearns Road in the Town of Paradise, approximately 1.8 miles from Ms. Holt's residence.

TK Huff – Mr. Huff was 71 years old. Mr. Huff was located deceased outside of his residence at 13471 Green Forest Lane in the community of Concow. Mr. Huff only had one leg and generally used a wheelchair. Mr. Huff's wheelchair was found approximately 10 feet away from Mr. Huff. The physical evidence indicated Mr. Huff tried to escape the flames by dragging himself along the ground.

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Gary Hunter – Mr. Hunter was 67 years old. Mr. Hunter was located deceased inside of his residence at 13554 Andover Drive in the community of Magalia. He had limited mobility, due to a stroke, and could not walk without assistance.

James Kinner – Mr. Kinner was 83 years old. Mr. Kinner was located deceased inside his residence at 5237 Black Olive Drive in the Town of Paradise.

Dorothy Lee-Herrera – Ms. Lee-Herrera was 93 years old. Ms. Lee-Herrera was found deceased in her residence at 2376 Clearview Drive in the Town of Paradise. The remains of Ms. Lee-Herrera's husband, Louis Herrera, were also found in the residence.

Warren Lessard – Mr. Lessard was 68 years old. Mr. Lessard was found deceased on the front porch of his residence at Athens Way and South Park Drive in the community of Magalia.

Dorothy Mack – Ms. Mack was 88 years old and found deceased inside her residence at 6674 Pentz Road, Unit 19, in the Town of Paradise.

Sara Magnuson – Ms. Magnuson was 75 years old. Ms. Magnuson was found deceased inside her residence at 1812 Drendel Circle in the Town of Paradise. Based upon the physical evidence it appears Ms. Magnuson wrapped herself in a wet carpet and sheltered in the bathtub in an attempt to save herself.

Dolores Joanne Malarkey – Ms. Malarkey was 90 years old. Ms. Malarkey was found deceased in her residence at 432 Plantation Drive in the Town of Paradise. The remains of Ms. Malarkey's husband, John Malarkey, were also found in the residence.

P27-122 cont.

John Malarkey – Mr. Malarkey was 89 years old and was found deceased in his residence at 432 Plantation Drive in the Town of Paradise. The remains of Mr. Malarkey's wife, Joanne Malarkey, were also found in the residence.

Christopher Maltby – Mr. Maltby was 69 years old. Mr. Maltby was found deceased in his residence at 1040 Buschmann Road in the Town of Paradise.

David Marbury – Mr. Marbury was 66 years old. Mr. Marbury was found deceased inside his residence at 1481 Sun Manor, Unit A, in the Town of Paradise.

Deborah Morningstar - Ms. Morningstar was 65 years old and found deceased inside of her residence at 5848 Black Olive Drive, Unit 3, in the Town of Paradise. She was unable to drive, which prevented her from being able to flee.

Helen Pace – Ms. Pace was 84 years old. Ms. Pace was found deceased inside her residence at 6674 Pentz Road in the Town of Paradise. She had medical issues, which limited her ability to leave her home.

Joy Porter – Ms. Porter was 72 years old. Ms. Porter was found deceased in the driver's seat of her car with her son, Dennis Clark Jr., in the passenger seat. Their vehicle was in a line of three other vehicles found facing north in the 5000 block of Edgewood Lane in the Town of Paradise. The vehicle was located approximately .3 miles south of Mr. Clark and Ms. Porter's residence on Sunny Acres Road, off of Edgewood Lane.

Beverly Powers – Ms. Powers was 64 years old. Ms. Powers was found deceased in the driver's seat of a pickup truck registered to her boyfriend, Robert Duvall. The vehicle was in a line of three other vehicles found facing north in the 5000 block of Edgewood Lane, approximately .3 miles south of Mr. Duvall and Ms. Powers residence on Sunny Acres Road. One of the other two vehicles contained the remains of Mr. Duvall.

Robert Quinn – Mr. Quinn was 74 years old and found deceased in his residence at 5684 Clara Lane in the Town of Paradise.

Joseph Rabetoy – Mr. Rabetoy was 39 years old and found deceased in his residence at 5580 Angel Drive in the Town of Paradise. He had no means of escape as he didn't have a vehicle.

Forrest Rea - Mr. Rea was 89 years old and found deceased in his residence at 1909 Dean Road in the Town of Paradise.

Vernice Regan – Ms. Regan was 95 years old. Ms. Regan was found deceased outside of her home at 102 Magnolia Drive in the Town of Paradise.

Ethel Riggs – Ms. Riggs was 96 years old. Ms. Riggs was located deceased inside of her residence at 220 Berry Creek Drive in the Town of Paradise. Ms. Riggs spoke with her grandson via phone at least twice on the day of the fire and told him because the power was out she was unable to get her car out of the garage. Ms. Riggs told the grandson she could not reach the manual release for the garage door, and even if she could, she was not strong enough to raise the door. P27-122 cont.

Lolene Rios – Ms. Rios was 56 years old. Ms. Rios was found deceased in the basement of her home at 750 Meyers Lane in the Town of Paradise, along with the remains of her four dogs and two cats.

Gerald Rodrigues – Mr. Rodrigues was 74 years old and found deceased inside of his residence at 5436 Clark Road, Unit 14, in the Town of Paradise.

Frederick Salazar, Jr. – Mr. Salazar was 76 years old. Mr. Salazar was found deceased in his residence at 5303 Sawmill Road in the Town of Paradise. The remains of Mr. Salazar's wife, Phyllis Salazar, were also found in the residence.

Phyllis Salazar – Ms. Salazar was 72 years old. Ms. Salazar was found deceased in her residence at 5303 Sawmill Road in the Town of Paradise. The remains of Ms. Salazar's husband, Frederick Salazar, Jr., were also found in the residence.

Sheila Santos – Ms. Santos was 64 years old and found deceased in her home at 5471 S. Libby Road, Unit 34, in the Town of Paradise.

Ronald Schenk – Mr. Schenk was 74 years old. Mr. Schenk was found deceased in his home at 5471 S. Libby Road, Unit 33, in the Town of Paradise.

Berniece Schmidt – Ms. Schmidt was 93 years old. Ms. Schmidt was found deceased inside of her residence at 14175 Citadel Way in the community of Magalia with the remains of her cat and a kitten.

John Sedwick – Mr. Sedwick was 82 years old. Mr. Sedwick was found deceased on the front porch of his residence at 13816 Glover Lane in the community of Magalia.

Don Shores - Mr. Shores was 70 years old. Mr. Shores was found deceased in a recliner in his residence at 6778 Ishi Drive in the community of Magalia. The remains of Mr. Shores' wife, Kathy Shores, were found in an adjacent recliner. Also located with Mr. and Ms. Shores were the remains of two dogs and two cats.

Kathy Shores – Ms. Shores was 65 years old. Ms. Shores was found deceased seated in a recliner in her residence at 6778 Ishi Drive in the community of Magalia. The remains of Ms. Shores' husband, Don Shores, were found in an adjacent recliner. Also located with Mr. and Ms. Shores were the remains of two dogs and two cats.

Judith Sipher – Ms. Sipher was 68 years old. Ms. Sipher was found deceased in her residence at 1005 Village Parkway in the Town of Paradise.

Larry Smith – Mr. Smith was found severely burned in the driveway of his home at 6428 Rocky Lane in the Town of Paradise. Mr. Smith was rescued and transported to the UC Davis Medical Burn Center. Mr. Smith succumbed to his injuries while still in the hospital 17 days later. Mr. Smith was 80 years old.

Russell Stewart – Mr. Stewart was 63 years old and found deceased inside of his home at 6884 Pentz Road in the Town of Paradise.

P27-122 cont.

Victoria Taft – Ms. Taft was 67 years old and found deceased inside of her home at 5883 Copeland Road in the Town of Paradise.

Shirlee Teays - Ms. Teays was 90 years old. Ms. Teays was found deceased inside of her residence at 9289 Skyway Road, Unit 15, in the Town of Paradise. She appears to have been holding or hugging a framed photograph.

Joan Tracy – Ms. Tracy was 82 years old. Ms. Tracy was found deceased inside of her home at 5326 Sawmill Road in the Town of Paradise.

Unknown – The remains of this unknown victim were found comingled with the remains of another victim in Concow. Attempts at identification are still being made.

Ellen Walker – Ms. Walker was 72 years old and found deceased inside of her home at 4220 Schwyhart Lane in the community of Concow.

Donna Ware – Ms. Ware was 86 years old and found deceased inside her home at 5783 Waco Lane in the Town of Paradise.

Isabel Webb – Ms. Webb was 68 years old. Ms. Webb was found deceased inside her home at 1449 Sleepy Hollow Lane in the Town of Paradise.

Marie Wehe – Ms. Wehe was 78 years old. Ms. Wehe was found deceased inside a burned truck on the side of Windermere Lane in the community of Concow approximately .3 mile east of Ms. Wehe's residence on Windermere Lane.

Kimber Wehr – Ms. Wehr was 53 years old and found deceased inside her residence at 5908 Del Mar Avenue in the Town of Paradise. She was unable to drive due to a neurological disability, and was unable to flee the fire on her own.

David Young – Mr. Young was 69 years old. Mr. Young was found deceased with two unidentified animals inside his mini-van. The mini-van was found crashed into a tree near the intersection of Hoffman Road and Jordan Hill Road in the community of Concow. The vehicle was located approximately 1.5 miles west of Mr. Young's residence on Hog Ranch Road in the community of Concow. Based upon the evidence, Mr. Young crashed while fleeing the oncoming fire. Mr. Young and the two animals were found in the cargo area of the mini-van. The autopsy determined Mr. Young survived the crash, but was killed by the fire.

IV. BACKGROUND OF THE FAILED COMPONENT

a. History of the Caribou-Palermo 115kV Transmission Line

According to historical reports[15] provided by PG&E, the section of the Caribou-Palermo line that runs in the Feather River Canyon from the Caribou Powerhouse to the Big Bend Substation, was built between 1919 and 1921 by the Great Western Power Company. What is now known as the Caribou-Palermo line was originally part of a 165kV transmission line that carried electricity from the Caribou Powerhouse to the Valona Substation in Contra Costa County.[16] PG&E acquired the Caribou Powerhouse and the entire Caribou-Valona 165kV transmission line (Caribou-Valona line) when it purchased Great Western Power Company in 1930. According to the reports, sometime during the 1960s the Caribou-Palermo line was converted to 115kV. According to the reports, there were eleven segments[17], including the Caribou-Big Bend segment, of the original Caribou-Valona transmission line still in service in 2018. P27-122 cont.

Despite the fact that PG&E has owned the Caribou-Big Bend portion of the Caribou-Palermo line since 1930, the evidence established PG&E did not catalogue or replace the original

[15] In April 2017 cultural resources specialists from PG&E produced a document entitled "National Register of Historic Places Inventory and Evaluation of Eleven Transmission Lines Associated with the Historic Alignment of the Caribou-Valona Transmission Corridor (NRHP Inventory and Evaluation). The NRHP Inventory and Evaluation was updated in October, 2018 by Cardno Inc. The NRHP Inventory and Evaluation includes a 2018 report entitled "DPR 523 Form" produced by the California Department of Parks and Recreation (DPR Report).

[16] Using a current map, the original Caribou-Valona line ran parallel to the Feather River from Caribou-Road through the Feather River Canyon, passing to the east of Oroville to Palermo. South of Palermo the line ran parallel to State Route 70 thru Sacramento. From south of Sacramento the line ran parallel to Interstate 80 to Vallejo. The line crossed the bay from Vallejo to Valona parallel to the current Carquinez Bridge on Interstate 80. The total length of the line was 1368 steel towers and 186 miles.

[17] As the electrical transmission grid has grown and substations were added the original Caribou-Valona line was divided into segments (sometimes referred to as circuits in PG&E historical documents) corresponding to the substations. The eleven segments still in use in 2018 were the Caribou-Palermo line, Paradise-Table Mountain, Palermo Pease, Pease-Rio Oso, Rio Oso-West Sacramento, Brighton-Davis, Brighton-Davis (idle), Vaca-Suison-Jamison, Ignacio-Mare Island #1, Oleum-G #1 and Oleum-G #2.

conductors,[18] insulators or attachment hardware[19] on many of the towers in the original Caribou-Big Bend section of the transmission line.

Many components on Tower 27/222 were identified by PG&E as original Great Western Power components because they matched components included in the original Great Western Power Company schematic drawings for construction of the transmission line. Among those components were the insulators hung from C hooks[20]. The records provided by PG&E clearly established the insulator string hanging from the C hook that broke on November 8, 2018 was an original 1921 insulator. Other components, such as the C hooks and the conductor, either did not completely match the original records[21] or PG&E did not possess original records.[22]

Evidence established that, with the exception of add-on hanger brackets which were added to the ends of the transposition arms to replace worn hanger holes, the transposition components on Tower 27/222, including the transposition arms, C hooks, insulator strings and jumper conductor, were original components in service since 1921. The evidence further established that despite owning Tower 27/222 since 1930, PG&E had little or no information about the 97-year-old conductor and the hooks, original hanger holes and bolted-on hanger hole plates supporting that conductor.

P27-122 cont.

b. <u>C Hook and Hanger Hole Wear</u>

The broken C hook{Attachment 7} and the transposition arm {Attachment 8}on which it had been hung were collected as evidence by Cal Fire investigators[23]. The transposition arm was identified as the left "phase" arm of Tower 27/222 {Attachment – 3D model w/ left phase highlighted}. This left phase arm had a bolted-on hanger hole plate which showed substantial wear where the broken hook had hung.

Cal Fire investigators also collected as evidence the right phase transposition arm and its still-connected (hung) C hook from Tower 27/222. .{Attachment 9} While examining the right phase C hook, Cal Fire investigators observed a "channel" had been worn into that hook where it hung from the bolted-on hanger plate hole of that transposition arm. {Attachment 10} The wear channel was similar to the channel cut into the broken left phase C hook. Similarly the right

[18] In layman's terms, a "conductor" is known as a power line or wire.
[19] Hot end attachment hardware attaches the insulators to the conductor. Cold end attachment hardware attaches the insulators to the tower/structure/pole. {Attachment – illustrative photo}
[20] Also known as "Suspension hooks." C hooks are part of the cold end attachment hardware.
[21] The plans for the original Great Western Power transposition towers included a schematic, dated October 11, 1912, of an Ohio Brass suspension hook with a raised B on the right face of the hook. The relevant hook from Tower 27/222 matched the schematic except the raised B was on the left face of the hook.
[22] PG&E responded to questions about the make, model and manufacturer of the conductor on Tower 27/222 by referring to an April 1922 article written by W. A. Scott in Engineering World entitled "Great Western Power Co.'s 165,000-Volt Transmission Line".
[23] The front portion of the C hook that broke off was never recovered. Cal Fire personnel spent several days meticulously searching the area below Tower 27/222 and could not locate that broken piece. It was noted however that area was on a steep rocky slope which ran off toward the Feather River Canyon.

phase hanger hole showed substantial wear where the hole and hook connected. {Attachment 11}

Investigators also noted there were original hanger holes on both the left and right transposition arms that showed extensive wear. It was obvious the bolted-on hanger plates with their holes were replacements for these original hanger holes indicating that PG&E was aware that the hooks and holes were rubbing on each other causing wear. The wear patterns observed on the hanger holes is described as "keyholing."

As a result of the observations of the Cal Fire investigators, an inspection of other transposition towers[24] on the Caribou-Palermo line was initiated by the Butte County District Attorney. Based upon the historical records and the C hooks and hanger holes from Tower 27/222, investigators from Cal Fire and the Butte County District Attorney's Office concluded that any more than 3/16" space between top of the C hook and top of the hole indicated wear to either the C hook or the hanger hole, or both[25]. In January 2019, investigators from the Butte County District Attorney's Office flew the Caribou-Palermo line in a county helicopter and documented transposition towers on which the gap between the top of the C hook and the top of the hanger hole were substantially larger than 3/16."

From the helicopter, investigators located wear to C hooks and hanger holes on three other transposition towers on the Caribou-Palermo line between the Caribou Powerhouse and the Big Bend Substation. The towers were identified as tower numbers 20/160, {attachment – 20/160 wear}24/199 {Attachment – 24/199 wear} and 35/281. {Attachment – 35/281 wear} This wear was similar to that found on the C hooks and hanger holes on Tower 27/222. Subsequently, Butte County District Attorney investigators and Cal Fire investigators, along with Jon McGormley - an engineer and failure analysis expert,[26] further inspected each of these three towers. Investigators and Mr. McGormley also identified a fourth transposition tower, tower number 32/260, {attachment – 32/260 wear} on which there appeared to be very little wear between the C hooks and hanger holes. Tower numbers 20/160, 24/199, 27/222 and 35/281 were all located on ridgelines and exposed to the wind. Tower 32/260 was located in a valley where it was protected from the wind.

P27-122 cont.

During the inspection of one of the four towers - Tower 24/199 - investigators noted that, similar to Tower 27/222, bolted-on hanger plate holes had been added to the transposition arms and the C hooks were hanging from those hanger holes instead of the original hanger holes of the transposition arm. This again indicates that PG&E was aware of the wear on C hooks and

[24] Because transposition towers have unique physical characteristics, investigators focused only on transposition towers. Transposition towers on the Caribou-Big Bend section are distinguished from other towers by the T mast atop the tower and the transposition arms on the source side of the tower. Towers 20/160, 24/199, 32/260 and 35/281 were transposition towers identical to Tower 27/222.

[25] According to the original schematics of the transposition towers the C hooks were 15/16" thick at the point of contact and the hanger holes were 1 1/8" in diameter. The hooks were intended to fit snugly into the holes.

[26] Jon McGormley was retained by Cal Fire and is an engineer and failure analysis expert with Wiss, Janney, Elstner Associates (WJE). WJE is a global firm of engineers, architects and materials scientists with a division focused on failure analysis.

hanger holes. It appeared to investigators that, at some previous time, the jumper conductor on Tower 24/199 {Attachment – 24/199 jumper} had been shortened and spliced together using a parallel groove connector. PG&E has no records of when or why this work was done. Investigators further observed the right phase[27] insulator string appeared to be less aged than the left phase insulator string and, as a result of the shorter jumper conductor, was not hanging plumb. From the ground, investigators also observed black marks on the tower leg nearest the right phase insulator string. This was indicative of arcing due to faulty or broken equipment. On the ground below Tower 24/199, investigators found an old insulator string.[28]

With the assistance of PG&E[29], investigators seized C hooks and transposition arms from two of the three towers[30] with obvious wear and the tower without obvious wear. Seizure of all of the C hooks and transposition arms was catalogued and documented by a Federal Bureau of Investigation (FBI) Evidence team. Of the four towers, Tower 24/199 was found to be the most similar to Tower 27/222 in terms of topography, meteorology and wear. The right phase C hook from Tower 24/199 was the most worn C hook found on any of the towers.

The C hooks, transposition arms, and hanger plate holes from Towers 27/222 and 24/199 were sent to the Metallurgy Unit of the FBI Laboratory at Quantico, Virginia for metallurgical analysis by their recognized metallurgical experts. The C hooks were examined for defects. No defects were found. The broken left phase C hook from Tower 27/222 and the most worn right phase C hook from Tower 24/199 were determined to be malleable cast iron. The least worn C hooks from Towers 27/222 and 24/199 were determined to be forged, plain carbon steel. The broken C hook from Tower 27/222, the most worn hook from Tower 24/199, and a less worn hook were tested for hardness.[31] The testing determined there was a significant difference in hardness between the most worn malleable cast iron hooks, and the least worn forged plain carbon steel hook. The transposition arms were also examined and analyzed, and all four transposition arms and the bolted on hanger brackets were found to be made of galvanized plain carbon steel.[32]

P27-122 cont.

The FBI Lab scanned all of the hooks and transposition arms. The scans were used to build 3D models of each of the components. {Attachment – 3D models}

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[27] The term phase relates to the connection between the tower structure and the conductors. The Caribou-Big Bend section has three conductors and three phases; left, center and right.

[28] This was not unusual. Under numerous towers on the Caribou-Palermo line investigators found discarded insulator strings, insulator bells, conductor line and steel members.

[29] Any work on an electrical transmission tower requires special training and equipment. Investigators were unable to identify any qualified persons to perform the work. As a result, investigators had to rely on PG&E personnel to remove the relevant components from Tower 27/222 in November, 2018 and Towers 20/160, 24/199 and 32/260 in March, 2019.

[30] The C hooks and transposition arms from the fourth tower, 35/281, were replaced by PG&E in February, 2019. Those C hooks and transposition arms were seized by Cal Fire and BCDA investigators from a PG&E evidence storage facility.

[31] The Superficial Rockwell HR30TW hardness test was used to determine hardness.

[32] All of the transposition arms and hanger brackets were tested for hardness utilizing the Rockwell HRBW hardness test.

The metallurgist at the FBI Lab also analyzed the wear patterns on the C hooks and hanger holes (both original holes and the added brackets). The metallurgist determined that as a result of rotational body on body wear, the edge of the hanger holes had cut a channel into the C hooks and the C hooks had worn away the bottom of the hanger holes elongating the holes[33]. {Attachment – Camp Fire Presentation 3:29-3:46} On the broken C hook from Tower 27/222 it was determined the channel had cut approximately 14/16" {Attachment – FBI lab photo of break} into the hook before the remaining metal broke under the weight of the insulator string and jumper conductor.[34] On the most worn C hook from Tower 24/199 it was determined that the channel had cut approximately 12/16" channel into the hook.

Under microscopic analysis, the FBI Metallurgist also observed the channeling of the right phase C hook from Tower 24/199 showed a distinct change in angle. The metallurgist testified it was her opinion the distinct change in angle could have been caused by shortening of the jumper conductor which changed the position and angle of the insulator string attached to the C hook.

The FBI data, along with LIDAR scans[35] of Towers 27/222 and 24/199, was forwarded to Jon McGormley. Using this information, Mr. McGormley was able to build a computer model of Tower 27/222. The model took into account the differing hardness of the C hooks and hanger holes.[36] Working with meteorologist Kris Kuyper[37], Mr. McGormley and his team created a wind load model of the Feather River canyon, enabling them to calculate that the wear on the broken C hook from Tower 27/222, as well as the most worn C hook from Tower 24/199, was consistent with approximately **97 years of rotational body on body wear**. [38] {Attachment – Camp Fire Presentation 3:52-3:54} P27-122 cont.

V. INSPECTION AND PATROL POLICIES

State and federal regulatory requirements dictate PG&E must establish and follow set guidelines for patrol, inspection and maintenance of its overhead electric transmission lines. The 2012 Quanta Technology "Transmission Line Inspection Procedures Final Report"[39] outlined the

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[33] Known as keyhole wear or "keyholing."
[34] According to PG&E written response to CPUC data request SED-007 question 2 each suspension hook supports approximately 142.8 pounds.
[35] Lidar scans were performed by the Cal Fire Lidar Team.
[36] The hardness of the individual metals involved plays a significant role in body on body wear. Metallurgical data from the FBI Laboratory was provided and fed into the model. The Superficial Rockwell HR30TW results for the C hooks and the Rockwell HRBW results for the transposition arms were converted using ASTM E140 for comparison purposes. On the Vickers Kg/mm2 the broken hook from 27/222 scored 114 for hardness, the most worn hook from 24/199 scored 119 for hardness and the least worn hook scored 222, the transposition arm and bracket from 27/222 scored 134 and 152 for hardness, the transposition arm and bracket associated to the most worn hook on 24/199 scored 120 and 138 for hardness and the transposition arm and bracket associated to the least worn hook scored 118 and 152 for hardness.
[37] Kris Kuyper is the former Chief Meteorologist for Action News in Chico. Kuyper was retained as an expert by the Butte County DA.
[38] The transposition arms metal (around the original hanger holes) was less hard than the bolted-on hanger plate hole metal. The original hanger holes showed significantly more keyhole wear than the bracket holes.
[39] Quanta Technologies is a multi-national electrical utility consulting company. Quanta Technologies was retained by PG&E in 2011 to review the ETPM. This report was commissioned by, and paid for by, PG&E.

various regulatory requirements. Among these requirements is CPUC General Order (GO) 165. Section IV of this General Order states "[e]ach utility shall prepare and follow procedures for conducting inspections and maintenance activities for transmission lines."[40]

Since 2005, PG&E electric transmission inspection, patrol, and maintenance policies have been set forth in the "Electric Transmission Preventative Maintenance Manual" (ETPM). According to the ETPM: "Inspection and patrol procedures are a key element of the preventive maintenance program. The actions recommended in this manual reduce the potential for component failure and facility damage and facilitate a proactive approach to repairing or replacing identified, abnormal components."

a. 1987 Inspection and Patrol Bulletin

Prior to the implementation of the ETPM in 2005, inspection and patrol policies were documented in "bulletins". The oldest bulletin provided by PG&E was dated November 1, 1987[41], and entitled "Routine Patrolling and Inspection of Transmission Lines." This bulletin stated patrols are performed "to ensure that the transmission facilities are in good repair in order to maintain a high standard of service, reliability, and safety, and the patrol policy is consistent with GO95.[42]" In this 1987 bulletin, the terms "patrol" and "inspection" were used interchangeably.

The 1987 policy divided PG&E's electrical transmission system into 4 parts: Class A circuits, Class B circuits, Class C circuits, and Underground. For overhead circuits,[43] the patrol or inspection cycles were determined by the class designation of the circuit. A PG&E troubleman,[44] who worked in the Feather River Canyon between 1987 and 1995, established the Caribou-Palermo line was considered a "Class B Circuit." As such, under the 1987 policy the Caribou-Palermo line was required to be patrolled three times each year: one ground patrol and two aerial patrols. In addition, the 1987 policy required climbing inspections of five percent of the tower structures per year; and an infrared patrol[45] every five years. According to the 1987 policy bulletin, all patrols of transmission lines were to be completed by a "Transmission Troubleman." This policy ensured that every overhead transmission structure would be climbed at least once every 20 years. Because PG&E inspection/patrol records prior to 2000 are not available, it is unknown if Tower 27/222 was one of the towers subjected to a climbing inspection between 1987 and 1994.

P27-122 cont.

Appendix A to the 1987 policy bulletin contained a checklist of "Conditions to be noted when patrolling lines." One of the conditions to be noted was "Worn hardware and connectors."

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[40] The California Independent System Operator (CAISO) "Transmission Control Agreement" and Western Electricity Coordinating Council (WECC) standard FAC-501 also require PG&E to have and follow written policies for inspection and maintenance of electrical transmission lines.

[41] The 1987 bulletin was the sixth revision of an existing policy bulletin and replaced the fifth revision which was published December 1, 1984 according to the face page of the 1987 bulletin. Based upon interviews with PG&E linemen from the 1970s and 1980s it is believed that the original policy bulletin was published 1972-75.

[42] GO95 is General Order of the CPUC number 95. GO95 establishes building, maintenance and replacement regulations for electrical transmission.

[43] A circuit is the path electrical current flows. In the 1980s PG&E referred to transmission lines as circuits. Distribution lines are still referred to as circuits. Transmission lines are now referred to as lines.

[44] See Section VII "Troublemen and Training" below for the definition of the position of Troubleman.

[45] An infrared patrol uses infrared, thermal cameras to identify hot spots on the line. Hot spots may indicate a defect or weakness on the line.

Through interviews with transmission lineman, troublemen, and engineers, it was established the C hooks were technically part of the "cold end attachment hardware."

Former PG&E Transmission Line Supervisors from 1987 noted the checklist inclusion of "worn hardware" was a result of a 1987 PG&E Laboratory Test Report[46] documenting a worn C hook and hanger hole from a Bay Area transmission tower[47]. Photos of the worn C hooks and holes were distributed to troublemen in all of the PG&E regions for training purposes, and inspection of C hooks and hanger holes was made a specific priority during inspections/ patrol.

b. 1995 Inspection and Patrol Policy

The 1987 policy remained in effect until it was replaced by the "ES Guideline" in 1995. The 1995 ES Guideline made substantial changes, specifically separating out patrols from inspections. Inspection frequency was determined by a transmission line score on an "Inspection Frequency Checklist" and drastically reduced the frequency and thoroughness of inspections. The Caribou-Palermo line was reduced from three patrol/inspections (one ground/two aerial) per year to one ground inspection every 24 months and one aerial inspection every 24 months. Required routine climbing inspections were eliminated. Climbing inspections would only occur if "triggered" by one or more specific findings listed as triggers.

c. 2005 ETPM Inspection and Patrol Procedures

The 1995 policies remained in effect until they were replaced by the ETPM in 2005. According to the ETPM section entitled General Inspection and Patrol Procedures, "[t]hese inspection and patrol procedures were developed as a key element of the preventative maintenance program. The recommended actions were selected to reduce the potential for component failures and facility damage and to facilitate a proactive approach to repairing or replacing identified, abnormal components." P27-122 cont.

The ETPM differentiated between inspections and patrols, and established definitions for each. According to the 2005 ETPM in the Detailed Overhead (OH) Inspections section:

> "A detailed ground, aerial or climbing inspection of the asset[48] looks for abnormalities or circumstances that will negatively impact safety, reliability, or asset life. Individual elements and components are carefully examined through visual and/or routine diagnostic tests and the abnormal conditions of each are graded and/or recorded.
>
> Overhead line facilities are to be inspected in accordance with the provisions in Section 2.0 of this manual. The inspections are to include detailed visual observations, operational readings, and component testing to identify abnormalities or circumstances that will negatively impact safety, reliability or asset life."

The 2005 ETPM **Patrols** of overhead transmission assets section states that:

> "The QCR's[49] primary responsibility in an overhead electric facility is to visually observe the electric facilities, looking for obvious structural problems or hazards without the use

[46] The Laboratory Test Report was published approximately nine months before the Inspection and Patrol Bulletin. This Laboratory Test Report is described more fully in Section XVII "Knowledge of Risk/Consequence."
[47] Based upon historical records it is believed that the tower was part of the original Caribou-Valona line built 1918-1921.
[48] An asset is a structure, pole or tower.
[49] QCR is Qualified Company Representative. See section VII-"Troublemen and Training" for more information.

of measuring devices, tools, or diagnostic tests, and to record that the facilities have been patrolled."[50]

The ETPM adopted verbatim the 1995 policy on climbing inspections and triggers. According to section 3.4:

> "A climbing inspection is a detailed, supporting structure based observation of the facilities installed to determine if there are any abnormal or hazardous conditions that adversely impact safety, service reliability or asset life, and to evaluate when each identified abnormal condition warrants maintenance."
>
> Climbing inspections may also be required for specific structures or components to properly assess a condition found during a ground or aerial inspection or patrol that could not be adequately assessed during the inspection of patrol."

As of the 2005 ETPM, the Caribou-Palermo line was reduced to only being inspected once every five years and patrolled once per year in non-inspection years. (This reduction again is from the three patrol/inspections per year prior to 1995.)

The 2006 revision of the ETPM appears identical to section 2 of the 2005 ETPM and identifies the "Best View Position" for individual components on a transmission structure.[51] According to Table 2.3-1 the best position to view insulators and hardware is aerial inspection (not patrol), ground inspection above 10', and climbing inspection. The terms "aerial inspection" and "ground inspections above 10'" were not specifically defined in the ETPM. According to former PG&E personnel, an "aerial inspection" is significantly more detailed than an "aerial patrol" and requires a helicopter to fly 360 degrees around each structure at an altitude and speed which allows for detailed inspection of the structure components. A ground inspection above 10' involves the use of a bucket truck to lift the QCR to allow for close inspection of the top part of the structure. P27-122 cont.

d. Patrol and Inspections Subsequent to the 2005 ETPM

Since 2005 the ETPM has been revised on multiple occasions[52]. The revisions have not changed the inspection or patrol cycles or the requirements for inspections and patrols. At the time of the Camp Fire, the third revision of the ETPM, issued May 12, 2016 was in use. Shortly after the Camp Fire, on November 20, 2018, the 4th revision of the ETPM[53] was published. Among other changes, the fourth revision of the ETPM incorporated new requirements for the prioritization and correction of safety hazards in Tier 2 and Tier 3 high fire threat areas identified in the 2018 CPUC Fire Threat Map.[54] These changes were required by amendments to GO95 by the CPUC, which took effect in January 2018.[55]

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[50] See Section VII "Troublemen and Training" below for the definition of the position of QCR.

[51] Copies of the 2005 ETPM provided by PG&E were missing page 2-4.

[52] Revised editions of the ETPM were published in October 2006, April 2009, January 2011, December 2014, May 2015, May 2016 and November 2018

[53] Although the May 2016 revision was the sixth revision of the ETPM, PG&E did not start numbering revisions until the December 2014 edition, which was designated revision one.

[54] On January 19, 2018, the CPUC adopted and published the CPUC Fire-Threat Map. The Fire-Threat Map identified elevated (Tier 2) and extreme (Tier 3) fire threat areas in the State of California.

[55] In conjunction with the Fire-Threat Map, the CPUC amended GO 95 to add regulations to enhance fire safety in Tier 2 and Tier 3 fire threat areas.

e. The 2012 Quanta Report

The 2012 Quanta Technologies "Transmission Line Inspection Procedures Final Report" was a "comprehensive review of Pacific Gas and Electric's (PG&E) current standards and practices used for ground patrol inspection of overhead transmission lines."[56] According to the report, the ETPM was "found to be a comprehensive, well written document that adhered to its purpose to "ensure uniform and consistent required procedures for patrols, inspections, equipment testing, and condition assessment of electric transmission line facilities." Quanta did not, and the report did not, evaluate the actual use, or non-use, of the ETPM by PG&E.

The evidence clearly established that PG&E did not, in fact, follow the procedures and requirements established in the ETPM. Based upon the evidence, it is reasonable to conclude that sections of the ETPM relating to inspections and patrols of overhead electric transmission lines were simply a façade created to meet the requirements of the regulators and the CAISO[57].

VI. REDUCTION OF UNIT COSTS FOR INSPECTIONS AND PATROLS

Although there were no changes to the frequency of inspections and patrols between the 2005 and 2018 ETPMs, the evidence established PG&E considered further reducing the frequency of inspections and patrols. According to 2013 internal PG&E PowerPoint, a committee was formed to explore opportunities to reduce costs by reducing the frequency of inspections and patrols and examine said "unit costs." According to the "Problem Statement:"

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> "Tline[58] patrols/inspection have not been modified in approximately 10 years relative to frequency and work methods. There may be opportunities to reduce costs by 1) changing frequency of patrols/inspections or 2) finding more efficient work practices. Benchmarking PG&E's practices against other utilities may identify potential opportunities for efficiency savings."

Under the heading "Business Objectives:"

> Define improvements in our frequency, tools or processes to find efficiencies in the patrols/inspections.
> Perform benchmarking and analysis to measure current practices
> Determine frequency of patrols/inspections (are we doing more than industry standard)
> Analyze current patrols/inspections work methods (i.e. crew size)

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[57] California Independent System Operator Corporation. CA ISO is a private, non-profit corporation that manages the high voltage power grid and the wholesale energy market for most of California. CA ISO was created in 1997 as part of an effort to restructure the wholesale electric industry in California. CA ISO is not a regulator. CA ISO's power over electric transmission utilities derives from the Transmission Control Agreement entered into between CA ISO and the utilities. In the Transmission Control Agreement the utilities agree to, among other things, properly maintain electric transmission lines, provide CA ISO with all current maintenance policies (referred to as a Transmission Owner Maintenance Practices (TOMP)). Failure to comply with the terms of the Transmission Control Agreement could be a breach of contract.

[58] PG&E abbreviation for Transmission line

Under the heading "Scope"

Patrols and Inspections for Transmission Lines
Frequency of patrols/inspections
Work methods/practices (tools, crew size, processes)
Unit costs measurement

Emails obtained from PG&E established committee members subsequently met with other electrical utilities for the purpose of benchmarking inspection and patrol practices of those utilities and submitted to a national electrical utilities association a patrol and inspection survey to be distributed to and completed by its members. This was done despite the fact the 2010 Quanta Technologies "Structures" Report[59] included data on patrol and inspection frequency gathered from a survey of 104 electrical utilities worldwide conducted in 2003 by the International Council on Large Electrical Systems, also known as Cigre'[60]. According to the Cigre' study 74% of the companies utilized "Walking" inspections, 63% utilized "Climbing" inspections and 66% utilized "Helicopter" inspections. The average inspection period for each type of inspection was 1.4 years for walking, 1.5 years for helicopter and 4.2 years for climbing.

The lack of change in inspection and patrol frequency in subsequent revisions of the ETPM indicates that reduction of inspection and patrol frequency was not approved. The committee was also exploring opportunities to reduce costs by finding more efficient work practices. A key component of this inquiry was "Unit cost measurement." The evidence indicates that PG&E reduced costs by reducing the unit cost for each inspection and patrol. The evidence shows that this was accomplished by reducing the thoroughness of the inspections and patrols.

P27-122 cont.

Review of internal PG&E documents, including emails, and interviews with PG&E personnel determined that the unit cost for inspection and patrol is calculated based upon the time that a troubleman spends inspecting an individual structure. Based upon interviews it was established that each year PG&E determines an average unit cost for each type of inspection or patrol. The unit cost would be translated into time and multiplied by the total number of structures on an individual line. The result would be the time allotted for the inspection or patrol of that transmission line. Prior to the start of each calendar year each transmission region headquarters was provided a list of inspections and patrols, including the allotted time, scheduled for the following year. The inspection and patrol budgets for each transmission region headquarters was based upon the total allotted time for all scheduled inspections and patrols. The evidence established that the Business Finance Department of the Electric Transmission Division sent monthly budget reports tracking spending, both monthly and year to date, for inspection and patrol against budget allocations. The reports were color-coded - red for over budget and green for under budget. The evidence also established that salary incentives (bonuses) of Transmission Line Supervisors and Transmission Superintendents was, at least partially, based upon compliance with the inspection and patrol budget.

Based upon the evidence, PG&E reduced costs of inspection and patrol by reducing the amount of time budgeted for the inspections and patrols. As expected, the result of these reductions was less thorough and less complete inspections and patrols.

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[59] In 2009 PG&E hired Quanta to evaluate its electrical transmission system. In 2010 Quanta submitted to PG&E the Transmission Line Component Management Report which included the Structures Report.

[60] Cigre is an international association of electrical transmission companies located in Paris, France. Cigre was established in 1921 and claims 1250 member organizations from 90 countries.

VII. TROUBLEMEN AND TRAINING

a. Creation of the Troubleman Program

The evidence established the inspection and patrol of the transmission lines is done by the "Troublemen." Similar to the inspection and patrol policy, the position of Troubleman has evolved and changed. Based upon interviews with former PG&E employees from the 1980s, the evidence established the position of Transmission Troubleman was created in the mid-1980s. The earliest reference to troublemen in documents provided by PG&E is found in the 1987 "Routine Patrolling and Inspection of Transmission Lines" policy bulletin.

According to the original Transmission Line Supervisors interviewed, the Transmission Troubleman position was initially intended to be a qualified and experienced transmission line expert. According to one of the original Transmission Lines Supervisors the "intent here was to have people that knew exactly what to look for, how to establish priorities on repairs, and would, would keep it operating." In addition to the physical demands and climbing requirements of the position, the Troublemen were also expected to take ownership of individual transmission lines and be accountable for the continued safe and reliable operation of that line.

b. Troubleman Training

P27-122 cont.

The 1987 "Routine Patrolling and Inspection of Transmission Lines" policy memo established training requirements for the new Transmission Troublemen[61]. In the late 1980s, training for Transmission Troublemen included periodic meetings of all of the Transmission Line Supervisors and Troublemen. At these meetings issues and problems were shared and discussed. According to one of the original Transmission Line Supervisors, a supervisor was designated to document and/or collect all of the examples presented at the meetings in order to compile a training manual for future Transmission Troublemen. According to several of the original Transmission Line Supervisors and Troublemen, an inspection checklist was developed based in part on the information being shared at these meetings. Appendix A to the 1987 "Routine Patrolling and Inspection of Transmission Lines" policy memo appears to be the earliest form of the checklist.

In addition to eliminating routine climbing inspections, reducing the frequency of inspections, and creating an Inspection Frequency Checklist, the 1995 ES Guideline eliminated the training requirement for troublemen. Notwithstanding that, the training requirement was dropped from the ES Guideline, the evidence does show that PG&E had created a Troubleman training program. According to one of the former PG&E employees involved in the creation of the 1995

[61] "It is the responsibility of each Region to ensure proper training of personnel conducting line patrols. This is to be accomplished through use of periodic training classes for all transmission troublemen and any other personnel who may be called upon to patrol. The training should include a review of this bulletin, other T&D bulletins as appropriate, patrol safety, Engineering Drawing 022168, and G.O. 95 requirements. The use of available videotapes (spacer damage, infrared patrolling, etc.) is encouraged. Particular attention should be given to the specific items listed on the code sheet that is provided with this bulletin. The Transmission and Distribution Department will assist the Regions in setting up and conducting the training classes."

ES Guideline, one of his duties from 1995 until 2005, was to provide direct annual training on inspection and patrol policies and requirements to all Troublemen. According to this former employee, a decision was made in 2005 to eliminate direct training of Troublemen. Instead, the Transmission Line Supervisors were provided training and expected to train the Troublemen under their supervision.

In December 1997, PG&E filed its first "Transmission Owner Maintenance Practice (TOMP) with the CA ISO[62]. In the TOMP the term "Troubleman" was replaced with the term "Inspector". According to the definition of terms, an Inspector is a "PG&E employed inspector commonly referred to as "troubleman."

In the 2002 "Transmission Owner Maintenance Practice" (TOMP) the term Inspector was replaced with "Qualified Company Representative (QCR). According to the Definition of Terms, a QCR is "a person, who by reason of training and work experience is able to complete an accurate assessment of the electric transmission facilities that he/she is asked to inspect." The required training and work experience necessary to be considered a QCR was never defined.

In the first version of the ETPM (2005), the term Troubleman does not appear. Instead, the ETPM continues the use of the term QCR. The 2005 ETPM definition of a QCR differed from the definition in the TOMP – "A Company representative who, by knowledge, required training, and/or work experience, is able to prepare an accurate and complete assessment of electric transmission facilities." The definition of a QCR continued to evolve through each revision of the ETPM. According to the 2018 ETPM a QCR is "A company representative, who, by knowledge, required training and/or work experience, is able and allowed to perform a specific job. For the purposes of this manual, QCR refers to an employee qualified to prepare an accurate and complete assessment of electrical transmission facilities." The ETPM does not define the knowledge, training of work experience required of a QCR.

P27-122 cont.

Every QCR who has inspected or patrolled the Caribou-Palermo line since the publication of the ETPM in 2005 was interviewed. All of the QCRs denied having receiving any formal training on how to perform an inspection or patrol. According to all of the QCRs, any inspection and patrol training was limited to filling out reporting forms and notifications for any issues identified during an inspection or patrol. All of the QCRs asserted that the only training on how to perform an inspection or patrol was via informal mentoring by other, more experienced, Troublemen.

[62] California Independent System Operator Corporation. CA ISO is a private corporation that operates the high voltage grid in California. CA ISO monitors the flow of power in transmission lines that providers use, operate wholesale electricity markets for energy and ancillary services, and maintain transmission maintenance standards. Transmission owners (TO's) mutually agree to contract with them. CA ISO was created by the State of California in 1997 in an effort to restructure the wholesale electric industry in California.

The evidence also established that some of the QCRs performing inspections and patrols of the transmission lines in the Feather River Canyon had little or no transmission line experience before becoming a Troubleman.[63]

Although PG&E documents and management personnel assert that troublemen receive training on the requirements of the position, the troublemen themselves unanimously denied having received any formal training on conducting inspections and patrols and assessing wear. The troublemen also denied being provided with any records (for example tower schematics) specific to the transmission lines being inspected. The lack of specific training and records was especially significant for troublemen inspecting the Caribou-Palermo line. The hanger holes, according to the original schematics, were 1 1/8" in diameter and the C hooks were 15/16" thick at the contact point. On other Feather River Canyon transmission lines the C hooks were the same size but the hanger holes were significantly larger. The evidence established that the Troublemen's lack of knowledge of the different sized hanger holes contributed greatly to the failure of PG&E to recognize the degree of wear on the C hook on Tower 27/222.

The evidence established that, despite the lofty goals of the originators of the troubleman position, and the designation of QCR by PG&E, by 2007 the inspections and patrols of the Caribou-Palermo line were being conducted by inexperienced, untrained and unqualified troublemen. Both of the "Detailed Ground Inspections (2009 and 2014) and seven of the ten Annual Air Patrols on the Caribou Palermo were completed by troubleman who had little or no prior transmission experience, and no formal training on performing inspections and patrols. This is contrary to the third Revision of the ETPM which requires that the "QCRs must be thoroughly familiar with all of the facilities, equipment, safety rules and procedures associated with the facilities and equipment." Under the ETPM the QCRs are supposed to be looking at components and estimating wear by percentage of material lost. In order to judge material loss a troubleman would have to know what a component looked like at 100%. The majority of the troubleman sent to inspect and patrol the Caribou-Palermo line had no idea what the C hooks and hanger holes were supposed to look like. Because of their lack of knowledge, experience, and training, the troubleman could not have been expected to identify the wear. The overwhelming evidence clearly established that troublemen and linemen inspecting and patrolling the Caribou-Palermo line did not meet the standards established in the ETPM.

P27-122 cont.

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[63] One former troubleman assigned to the Caribou-Palermo line admitted that although he was a journeyman lineman, he worked in distribution (almost 30 years) and had never worked as a transmission lineman prior to becoming a transmission troubleman. Another troubleman assigned to the Caribou-Palermo line was also a distribution lineman prior to becoming a transmission troubleman and admitted his only experience with transmission lines above 60kV was during his apprenticeship. According to a former Table Mountain HQ Transmission Line Supervisor, this Troubleman had so little experience with transmission lines that he was assigned to work with the transmission lineman until the Supervisor was forced by the union to allow the troubleman to conduct inspections and patrols. Another former troubleman assigned to the Caribou-Palermo line had worked on transmission lines as a journeyman lineman until PG&E split distribution and transmission in the mid-80s. The former troubleman worked in distribution exclusively for over twenty years before becoming a transmission troubleman.

VIII. FAILURES IN MAINTENANCE, REPAIR AND REPLACEMENT RECORD KEEPING ON THE CARIBOU-PALERMO LINE

As part of the Camp Fire Investigation, all maintenance/repair/replacement records for the Caribou-Palermo line were requested and obtained from PG&E. Any and all records received from PG&E pertaining to Towers 27/222 and 24/199 were reviewed in depth. The only records of any maintenance/repair/replacement located for these towers related to the replacement of parallel groove connectors[64] {Attachment – parallel groove connector} on each tower in 2016.

a. Hanger Brackets

During the investigation it was observed that "hanger brackets" (bolted add-on brackets for hanger plates for the hole that the C hooks hung from) {Attachment – add-on hanger bracket} had been added to the transposition arms of towers 27/222 and 24/199. Similar hanger brackets were not found on other transposition towers and the brackets were not shown on the original plans for the transposition arms. After being removed from the towers, the transposition arms were examined. Some of the original hanger holes displayed significant "keyhole" wear. {Attachment – significant keyhole wear} PG&E was unable to produce any records of when, why, and by whom the hanger brackets had been added. Based upon the keyhole wear observed on the original hanger holes, the only reasonable conclusion to be drawn was someone at PG&E at some time in the past had noticed the keyhole wear and was concerned enough to take action.

b. Parallel Groove Connectors

As previously mentioned, during the inspection of Tower 24/199 investigators noticed a parallel groove connector on the jumper conductor. {Attachment – parallel groove connector on 24/199 jumper} It appeared to investigators that, at some previous time the jumper conductor had been shortened and spliced together using the parallel groove connector. Investigators also observed that the right phase insulator string appeared to be less aged than the left phase insulator and, as a result of the shorter jumper conductor, was not hanging plumb. From the ground, investigators also observed black marks on the tower leg nearest the right phase insulator string. On the ground below Tower 24/199, investigators found an old insulator string. The old insulator string was complete except for the C hook.

PG&E was unable to produce any records of when, why, and by whom the parallel groove connector had been added to the jumper. No explanation was provided as to why the parallel groove connector on the jumper conductor was not replaced when all of the other parallel groove connectors in the tower were replaced in 2016. PG&E was also unable to produce any records as to the replacement of the insulator. Based upon the observations of investigators, the only reasonable conclusion that could be drawn is that at some time in the past the jumper conductor made contact with the tower leg, causing the blackening observed on the tower leg. This damaged the jumper conductor, necessitating the removal of a portion and replacement of the insulator. It was also clear, based upon the change in the wear pattern on the C hook observed by the FBI metallurgist, the C hook was not replaced when the jumper conductor was shortened and the insulator changed.[65]

P27-122 cont.

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[64] Parallel groove connectors are used to connect two parallel pieces of power line (conductor).

[65] According to PG&E and all transmission lineman interviewed, it was standard practice to replace the used C hook when replacing an insulator string. While inspecting the Caribou-Palermo line in February and March 2019

Although no records were found to explain why, the evidence established that as part of a scheduled Detailed Ground Inspection in 2009, the troubleman assigned to complete the inspection of the Caribou-Palermo line was instructed to document all towers with parallel groove connectors and create work orders for replacement of the parallel groove connectors. In total, the "Transmission Line Inspection Datasheet" completed by the troubleman as part of the report of the 2009 Detailed Ground Inspection, lists 85 towers for "Rpl Connectors." For each tower, a notification number was assigned and a "Corrective Work Form" was generated. Copies of these Corrective Work Forms for towers 24/199 and 27/222 were obtained during the investigation. Replacement of the parallel groove connectors was designated, according to the Corrective Work Forms as "Priority F – Schd Compl Yr 1+."[66] At the time the Corrective Work Forms were created, the April 2009 revision of the ETPM was in effect. The priority code F did not exist in the 2009 ETPM. The priority codes listed in the 2009 ETPM were A, C, G and P. Prior to the April 2009 revision of the ETPM, numerical (as opposed to letter) priority codes were used. The priority code F did not come into existence until the 2011 revision of the ETPM. According to the 2011 version of the ETPM, Priority Code F is defined as "Corrective action is recommended within 24 months from the date the condition is identified, except for nominations notifications or system wide initiatives identified by Asset Strategy (e.g., bridge bonding, shunt splicing), which can have due dates beyond 24 months."

According to the Corrective Work Forms for Towers 27/222 and 24/199, the parallel groove connectors were re-assessed during the 2011 Annual Air Patrol. A note dated August 16, 2011, states "per (troubleman) on 8/1/11 during patrol OK to move out 2 yrs." On November 10, 2009,[67] PG&E Applied Technology Services (ATS)[68] published a Lab Test Report entitled "Analysis of bolted aluminum transmission connectors from various PG&E sites." Based upon the ATS Lab Test Report the problems identified were internal to the connector. There is nothing in the report documenting any outward signs of the interior wear. The question of how a troubleman flying in a helicopter could assess the wear inside the bolted connectors was never answered[69].

P27-122 cont.

A note on both Corrective Work Forms dated January 10, 2012, states "move required end date to 11/30/2015." No explanation is given as to why the required end date was moved back three years. PG&E addressed this issue in a Data Response to CPUC. According to PG&E's written explanation, the Corrective Work Forms were initially assigned priority code G – required repair/replacement within 12 months. On October 4, 2009, the priority code was changed to Priority B – required repair/replacement within three months in the PG&E SAP system. According to PG&E, the priority code was changed again on October 27, 2009, to Priority F.

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investigators noted another tower in which the insulator strings had recently (post Camp Fire) been changed but the C hooks were re-used.

[66] In a written response to a CPUC data request PG&E wrote "Between 10:41 a.m. and 10:42 a.m. on October 4, 2009, all 85 notifications were changed from Priority Code G to Priority Code B conditions by {name redacted}, the same PG&E contractor who changed the Priority Code on LC Notification 103995542. Between 5:38 p.m. and 5:39 p.m. on October 27, 2009, all 85 notifications were changed from Priority Code B to Priority Code F conditions by {name redacted}."

[67] Approximately three months after the completion of the 2009 Detailed Ground Inspection of the Caribou-Palermo line.

[68] Applied Technology Services is PG&E's internal engineering and scientific research lab. ATS was previously known as the PG&E Department of Engineering Research.

[69] Interior wear on parallel groove connectors may cause the connector to show excessive heat in an infrared inspection. None of the Annual Air Patrols included infrared inspections.

Also according to PG&E's written response to the CPUC, because the replacement of the connectors was a Priority F and was "for nominations[,] notifications[,] or systemwide initiatives identified by Asset Strategy (e.g., bridge bonding, shunt splicing), which can have due dates beyond 24 months" no documentation or reason was required for re-assessment. The quoted language is from the 2011 version of the ETPM. The 2009 version of the ETPM stated "Any reassessment must have sound business or technical supporting reasons and documentation on file and recorded in SAP." No explanation was ever provided as to how and why a priority code and exception which did not come into existence until January 2011, was being applied in October 2009.

This raised serious questions as to the accuracy of the few maintenance/repair/replace records PG&E was able to locate. The final note on the Corrective Work Form is dated June 29, 2016, and reads that the connectors were replaced on June 18, 2016. There is no record as to why the parallel groove connector on the jumper conductor of Tower 24/199 was not replaced.

In total, almost seven years elapsed between the identification of the defective parallel groove connectors on the Caribou-Palermo line and the replacement of those connectors. At least ten years elapsed from the time replacement of parallel groove connectors were identified as a fire[70] mitigation. No valid explanation for the extended amount of time was ever provided.

P27-122 cont.

c. <u>The "Deteriorated Transmission Equipment Replacement Program."</u>

In 2007, PG&E introduced the "Deteriorated Transmission Equipment Replacement Program." According to internal documents, the Deteriorated Transmission Equipment Replacement Program was included in PG&E's capital spending five-year plan and was funded through 2015.

PG&E was unable to produce any documentation as to the budget or eligibility requirements for the Deteriorated Transmission Equipment Replacement Program. Although the name of the program implied that the program was established to replace deteriorated equipment, no records of funding or eligibility requirements for the program were found. During interviews and testimony of PG&E employees familiar with the program, it was simply a "bucket" of money available to fund capital improvements on transmission lines regardless of the condition of the line or its components. Based upon the evidence the name Deteriorated Transmission Equipment Replacement Program did not accurately depict the true nature of the program.

d. <u>The Caribou-Palermo 7/55-8/64 Replacement Towers project</u>

A portion of the Caribou-Palermo line was nominated for replacement through this program by the Maintenance and Construction Engineer[71] (M&C Engineer) assigned to the North Area[72]. According to a PG&E internal budget document "Request for Advance Authorization of Expenditures in Accordance with Capital Expenditures Policy," $800,000 was initially requested

[70] Parallel groove connectors were identified as a fire risk in the October 2006 Risk Analysis of Urban Wild Land Fires. See section XVII – "Knowledge of Risk/Consequence" for details re: the 2006 Risk Analysis.

[71] Although the job title was Engineer this person was not an engineer and had no engineering education or experience. This person described his position as "You're kind of a liason between the field crews and both civil and electrical engineers."

[72] Includes Sacramento District, Table Mountain District, Eureka District and Lakeville District

"for preliminary engineering and purchase of long lead-time material to replace conductor and tower structures on a section of the Caribou-Palermo line between structures 7/55 and 8/64.[73]" {Attachment – Google Earth Map showing 7/55-8/64} The initial Advance Authorization specifically stated:

> "There have been multiple conductor failures on this line due to conductor being annealed[74] and parting.[75] Since 2002 there have been 8 event reports created on this line. 5 of which was equipment related failures."
>
> "It is very time consuming and costly to correct any failures that occur in this dilapidated line section, especially during the winter months when failures are more likely."
>
> "The probability of that failure is imminent due to the age of both the towers and the conductor."
>
> "The intent of this project is to be pro-active and replace this deteriorated line section in a controlled and planned manner instead of under emergency conditions."

The initial Advance Authorization for $800,000 was not approved by PG&E's Electric Asset Strategy Division, and instead, upon re-writing and re-submission, was reduced to $200,000 by the then Director of the Electric Asset Strategy Division. The second Advance Authorization did not include the descriptor "dilapidated" or the prediction of imminent failure but did state: "Replace deteriorated structures, conductor, insulators, and hardware between structures 7/55 and 8/64." The second Advanced Authorization was approved. The project was named the "Caribou-Palermo 7/55-8/64 RPL Towers" project.

P27-122 cont.

A "Project Manager"[76] was assigned to this project. According to internal PG&E documents, between 2007 and 2009 the Project Manager spent almost $800,000 conducting engineering studies of the proposed new tower sites and preparatory work, including building a road to allow access to the proposed new tower sites. In 2009, the project was canceled as, according to internal emails, "this project fell below the cut line for 2010 approved projects." According to a 2014 email from a member of PG&E's Capital Accounting Department the project "was canceled due to Asset Management's reprioritization and is not expected to be resumed." During an email chain, starting on November 2, 2009 and ending on January 22, 2010, the Project Manager made the following arguments for continuing and completing the Caribou-Palermo 7/55-8/64 RPL Towers project to the Program Manager[77] assigned to that major work category:

> "If it is not funded for permitting etc., we could be picking up these towers out of the Feather River Canyon when they fall over."

[73] On the southside of the Feather River between Caribou Road and Beldon.
[74] According to the M&C Engineer "annealed usually means a little more brittle."
[75] The M&C Engineer also identified the conductor as copper and not aluminum because "we wouldn't put shunts on aluminum."
[76] A project manager is a person assigned to supervise a specific project.
[77] PG&E divides electrical transmission work (repair/replace/maintain/improve) into "major work categories" (also referred to by PG&E personnel as budgetary "buckets"). The program manager oversees all projects within a major work category.

> "We have already notified FERC[78] of the project and it will not look good if towers we have identified as deteriorated fall over in the canyon because we did not perform the work due to funding."

Despite the representations of the Project Manager the project was not reinstated by the Program Manager.

During interviews with investigators and testimony, the author of the Advance Authorizations[79] and the Project Manager separately asserted they had no factual basis for the statements about the condition of the Caribou-Palermo line towers and downplayed the statements as exaggerations made while advocating for a project.

e. The Rock Fire

A Corrective Work form[80] was located for replacement of a failed connector on Tower 11/87 in September of 2008. The Corrective Work Form was generated based upon a non-routine patrol of the Caribou-Palermo line generated by a power interruption on the line on September 30, 2008.

On September 30, 2008, at approximately 2:30 p.m., the Plumas National Forest Headquarters received a report of a fire near the Rock Creek Dam. {Attachment – Google Earth map of Rock Creek Dam} The fire was named the Rock Fire. This fire burned approximately five acres in the Plumas National Forest. Origin and Cause investigators from the United States Forest Service (USFS) investigated the fire and determined the origin to be directly below Tower 11/87 of the Caribou-Palermo line. The Rock Fire was determined to have been caused by an equipment failure, specifically the failure of a connector on a jumper line, on Tower 11/87. PG&E records obtained by the USFS investigators showed PG&E experienced an interruption on the Caribou-Palermo line at approximately 2:02 p.m. on September 30, 2008. No records of a root cause investigation of the failure of the connector were found. Consistent with PG&E's practice, as supported by the evidence, PG&E did not conduct climbing or aerial inspections on other Caribou-Palermo line towers with similar connectors.

P27-122 cont.

f. Tower Collapse

On December 21, 2012, a catastrophic failure occurred on the Caribou-Palermo line that generated six corrective work forms. Five towers, 22/187 through 23/191, collapsed and a sixth tower, 23/192, {Attachment – Google Earth map of towers} was badly damaged to the extent that it needed to be replaced.

A PG&E Civil Engineer investigated the incident and did not author a report, but did communicate his conclusions in an email. He determined Tower 22/188 initially collapsed causing a domino effect that pulled down towers 22/187, 22/189, 23/190 and 23/191. He concluded the collapse of Tower 22/188 was caused by the failure of the "stub angles"[81] possibly due to strong wind and/or icing wet ground conditions. No formal "Root Cause Analysis" was

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[78] It appears that this is a reference to a Federal Energy Regulatory Commission (FERC) rate case. In support of requests for rate increases PG&E files a rate case with FERC. To justify the proposed rate increase in the rate case PG&E lists planned capital projects with cost projection. Projects are generally forecasted five years in the future.
[79] A former Maintenance and Construction (M&C) engineer.
[80] A PG&E form generated by field personnel to document and describe problems, defects, wear or other conditions on transmission assets requiring maintenance/repair/replacement.
[81] The stub angles connect the foundation to the base of the tower.

conducted. Although he concluded his analysis by stating "Due to this failure phenomenon, it would be advisable to inspect towers with similar line angle on this line to ensure no other foundations had experienced similar uplift during same wind storm." The evidence established none of the other Caribou-Palermo line tower foundations were inspected. Again, this is consistent with PG&E's practice of not following up on clearly established potential safety and/or maintenance issues.

The six towers were temporarily replaced by a "Shoe Fly," consisting of fifteen wooden poles, constructed along Camp Creek road. {Attachment – Google Earth map of Shoe Fly} The Shoe Fly was completed by January 30, 2013. The Shoe Fly remained in service until the six towers were permanently replaced. The six towers were eventually, permanently, replaced by modern H-Frame tubular steel pole structures in 2016.

g. Center Phase Conductor on Tower 24/200

On January 10, 2014, a PG&E employee doing "crew work" documented a problem on the center phase conductor on Tower 24/200. Pictures attached to the Corrective Work Form appear to show a damaged conductor. In addition, the photos appear to show damage to the corona shield[82] (part of the hot end attachment hardware) and melting on the conductor below the corona shield. Another photograph appeared to show a piece missing from another section of the conductor and blackening on the conductor a few inches from that missing piece. The Corrective Work Form stated the conductor was repaired on 5/1/2014, but did not indicate that either the hot end attachment hardware generally, or the corona shield specifically, were replaced. No records were found indicating a root cause analysis was ever done to determine the cause of the damage to the conductor and corona shield.

P27-122 cont.

h. Broken J Hook

On October 19, 2016, a J hook in Tower 11/99 broke when a member of a PG&E contractor painting crew attempted to use a cross brace attached to the J hook for support. According to the PG&E report on the incident "I[]t appears as though about 20% of the thickness of the bolt had been compromised through corrosion." Although the incident was reported to and investigated by PG&E, nonetheless true to the company's practice, the failure of the J hook did not cause inspections of J hooks in other similar towers.

IX. INSPECTION AND PATROL OF THE CARIBOU-PALERMO LINE

Based upon PG&E records and flight records obtained from their contracted helicopter company, the evidence established inspections and patrols of the Caribou-Palermo line did not comply with the standards set forth in the ETPM and did not meet the requirements of the law or the regulatory agencies.

Routine inspection and patrol records for the Caribou-Palermo line were obtained back to 2001. According to PG&E, no inspection or patrol records prior to 2001 could be located. Based upon the inspection and patrol records the evidence established that the Caribou-Palermo line was subjected to "Detailed Ground Inspections" in 2001, 2003, 2005, 2009 and 2014. Based upon

[82] Corona discharge is the leakage of electric current into the air around high voltage conductors. A corona shield is a disc of conductive material designed to absorb the destructive corona discharge and protect the attachment hardware.

the inspection and patrol records the evidence established the Caribou-Palermo line was subjected to “Annual Aerial Patrols” in 2001, 2002, 2004, 2006-2008, 2010-2013, 2015-2018. There is no record of any climbing inspections, detailed ground inspections above 10’ or aerial inspections conducted on the Caribou-Big Bend section of the transmission line. All of the inspection and patrol records were reviewed and all of the troublemen/linemen who conducted the inspections and patrols were interviewed.

Because it was the last “Detailed Ground Inspection” of the Caribou-Palermo line prior to the Camp Fire, the 2014 Detailed Ground Inspection became a focus of the investigation. The 2014 Detailed Ground Inspection was memorialized in a 60-page “Report” which included an “Operational Control Ticket,” a “Transmission Line Data Inspection Sheet,” a “Priors” list[83] and a “Transmission Object List.”[84] According to the report, the detailed ground inspection was completed between August 5, 2014 and August 13, 2014 by a troubleman and a lineman. Four issues that necessitated the creation of a Corrective Work Form were documented in the report: flashed insulator bells were found on tower numbers 21/180A, 26/215 and 16/129 and a broken insulator bell was observed on tower number 27/226. The report was signed by both the troubleman and the lineman on August 28, 2014 and the Transmission Line Supervisor on September 3, 2014. The evidence established that the lineman was assigned to “assist” with the inspection because the troubleman, who was nearing retirement, was no longer physically able to hike/climb to many of the towers on the Caribou-Big Bend section of the line. The evidence also established that the troubleman and lineman were also assigned to take line clearance measurements (which included date, time and air temperature) at pre-determined intervals along the transmission line to determine compliance with new NERC clearance guidelines. P27-122 cont.

The 2014 Detailed Ground Inspection Report was subjected to intense scrutiny. PG&E records, including troubleman and lineman daily timecards, were obtained for comparison against the report. The evidence established the following:

1) The detailed ground inspection started on July 24, 2014 and ended on August 27, 2014. Although the report states that the physical inspection of the Caribou-Palermo occurred on August 5, 6, 7, 13, and 14; emails, records and interviews established that an unknown, and undocumented number of towers was inspected on August 27.

2) In addition to the troubleman and lineman, four linemen whose names do not appear in the report assisted with the inspections on August 27, 2014. According to emails and helicopter records, prior to August 27, 2014, the Transmission Line Supervisor scheduled a helicopter to fly the lineman to difficult to reach towers. Four additional lineman were assigned to assist with inspections on August 27, 2014. No records

[83] A list of previously documented issues pending an open corrective work form.

[84] The Transmission Object List lists every structure on the transmission line. In 2014 each structure was identified by its tower number, a SAP equipment ID number, a physical description of the structure and the GPS coordinates for the structure. For each structure the list has an Inspection Result section in which the QCR checks the applicable box and a notes section for the QCR to write any notes about the structure or record any problems/issues/defects observed.

indicate which towers were inspected on August 27, 2014 and which lineman inspected which tower.

3) The allotted time[85] for the 2014 Caribou-Palermo Detailed Ground Inspection was 89.5 hours. Based upon time cards, 121 hours were initially billed to the Caribou-Palermo Detailed Ground Inspection. After the inspection was complete, a secretary changed billing records to re-assign hours billed to the inspection of the Caribou-Palermo line to lower the total hours billed to the Caribou-Palermo Detailed Ground Inspection to 91 hours.

4) The lineman assigned to assist with the 2014 Detailed Ground Inspection of the Caribou-Palermo line had previously completed some troubleman training but focused mainly on "Switching." The lineman did not recall receiving any training on performing inspections and patrols other than informal training by troublemen. No evidence was found to establish the four other linemen who performed inspections had previously completed any training on inspection and patrol. Additionally, the evidence established the lineman did not complete his inspections under the supervision of the troubleman. The evidence established that the troubleman divided the Caribou-Palermo line between himself and the lineman, and each conducted an independent inspection of the towers in the assigned section. The lineman was assigned to inspect the Caribou-Big Bend section of the line.

5) Recall the six steel towers numbered 22/187 through 23/192 ceased to exist in December 2012 due to the catastrophic failure and were replaced by a "Shoe Fly" consisting of 15 wood poles in January 2013 until the towers were permanently replaced in 2016. However, according to this 2014 report, those missing towers were physically inspected in August 2014, including a previously documented issue on tower 22/188. The previously documented issue on Tower 22/188 was the replacement of the parallel groove connectors identified during the 2009 Detailed Ground Inspection.

6) The lineman assigned to assist with the 2014 Detailed Ground Inspection of the Caribou-Palermo line was not trained to complete the ground clearance measurements. According to PG&E policy, clearance measurements must include the measurement, and the date, time and air temperature when the measurement was taken. Although the report shows the clearance measurements were done concurrently with the inspection, the evidence established they were not. The lineman said he was not initially instructed to perform the clearance measurements and did not do so during his initial inspection. He went on to say it was not until after he had completed his inspection of the Caribou-Big Bend section of the line and submitted his report that he was told to perform clearance measurements. He stated he was ordered[86] to return to the field and perform the clearance measurements. He

P27-122 cont.

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[85] The amount of time budgeted for each inspection/patrol. See section VI – "Reduction of Unit Costs for Inspections and Patrols" and subsection A – Expense Budget of section XI – "Budgetary Considerations"
[86] The lineman was not clear about who ordered him.

> stated he was not initially told he needed to record the time of each measurement. According to the lineman, he returned to the Caribou-Big Bend Section of the line with the "Transmission Object List" and obtained the measurements. He stated he then added the measurements and air temperature to the already completed "Transmission Objects List." He then submitted his report a second time and was informed of the requirement to record the time of each measurement. He said that he then estimated the time he had taken the measurements and added those time estimates to his report. The result was the dates and times of the clearance measurements documented in his reports were not accurate.

Written documents clearly establish the Table Mountain Transmission Line Supervisor knew the dates inspected on the Transmission Object List were wrong. Written documents also clearly established that he knew that for some of the towers the name of the inspector conducting the inspection was wrong. The evidence also establishes he knew the line clearance measurements did not occur on the dates listed on the Transmission Object List. Despite specific knowledge the report was not accurate; the Transmission Line Supervisor approved and signed the report.

Although the investigative team did not scrutinize other patrols and inspections of the Caribou-Palermo line to the extent devoted to the 2014 Detailed Ground Inspection, similar issues were found in other inspection and patrol reports. The 2009 Detailed Ground Inspection of the Caribou-Palermo line was conducted by the same troubleman who conducted the 2014 Detailed Ground Inspection. There is evidence that a lineman, who was not mentioned or listed in the 2009 report, assisted with that inspection also.

P27-122 cont.

The 2012 Annual Air Patrol Report was also found to be inaccurate. In 2012, another troubleman, was assigned to complete the patrol. According to the date-inspected line on the report, this troubleman started his patrol on August 6, 2012. The patrol was interrupted at Tower 16/130 due to “fire.” The remainder of the patrol was completed by yet another troubleman. However, the report only lists the assigned troubleman and lists the “Date Inspection Completed” as August 6, 2012. In an email dated August 13, 2012 from the assigned troubleman to the Transmission Line Supervisor, the troubleman stated he would be going out on medical leave and had updated the subsequent troubleman on the “caribou-palermo partially flown on 8-6…not complt’d do to the fire in the canyon.” According to the assigned troubleman, he was unable to complete the patrol prior to going out of medical leave and the another troubleman completed the patrol sometime after August 21, 2012.

One former troubleman admitted he did not like flying the Feather River Canyon transmission lines and, whenever possible, assigned an available lineman to complete the routine air patrols. According to the former troubleman, after the lineman completed the air patrol the troubleman would use the lineman’s notes to complete the patrol report and submit the report as if the former troubleman had personally completed the patrol.

The evidence also established during the 2013 and 2015 Annual Aerial Patrols of the Caribou-Palermo line, which were completed by different troublemen, towers 22/187 through 23/192, which ceased to exist in December 2012, were "inspected" and the pre-existing condition (parallel groove connectors) on Tower 22/188 was checked.

The inspection and patrol records clearly established that between 2001 and 2018 aerial patrol by helicopter was the primary method of inspection and patrol for the Caribou-Palermo line. As such, the thoroughness of aerial patrols of the Caribou-Palermo line was examined closely. The evidence established the thoroughness of the aerial patrols declined through the years.

Troublemen assigned to inspect the Caribou-Palermo line from 1987 through 2018 were interviewed regarding the thoroughness of air patrols. A former troubleman who conducted air patrols prior to 2001, described helicopter patrols of the Caribou-Palermo line as taking one to one and half days. One former troubleman explained his protocol for aerial patrols included instructing the pilot to fly low enough and slow enough that the troubleman could step out onto a tower if necessary. On a report of the 2001 Annual Air Patrol was a handwritten note "10 hrs." According to the former troubleman who performed the 2001 air patrol, 10 hours was the approximate flight time for the patrol of the Caribou-Palermo line.

During the investigation, helicopter flight records from 2011 through 2018 for Caribou-Palermo line aerial patrols were obtained from a local helicopter company contracted by PG&E to assist with aerial patrols. According to that company, flight records and billing records prior to 2011 no longer existed.

In 2011, flight records document 3.2 hours for the aerial patrol of the Caribou-Palermo line. In 2012, the aerial patrol of the Caribou-Palermo line was interrupted by fire and complete records for the patrol were not located.[87] In 2013, a troubleman completed aerial patrols of the Caribou-Palermo line, Caribou-Westwood and Palermo-Pease transmission lines (990 total structures) in 7.6 hours. In 2015, a troubleman completed the aerial patrols of the Caribou-Palermo line, Cresta-Rio Oso, Oroville-Thermalito-Table Mt #1, Oroville-Thermalito-Table Mt #3, Oroville-Table Mt (CDWR), Hamilton Branch-Chester, Collins Pine Tap and Palermo-Pease transmission lines (1,430 total structures) in 6.1 hours. In 2016, a troubleman completed the aerial patrols of the Caribou-Palermo line, Grizzly Tap, Cresta-Rio Oso, Butte Valley-Caribou and Plumas Sierra Tap transmission lines (1050 total structures) in 6.8 hours. In 2017, a troubleman completed the aerial patrols of the Caribou-Palermo line, Butt Valley-Caribou and Hamilton Branch-Chester transmission lines (813 total structures) in 4.9 hours. In 2018, a troubleman completed the aerial patrols of the Caribou-Palermo line, Grizzly Tap, Grizzly Tap SVP, Plumas-Sierra Tap, Butt Valley-Caribou and Caribou #2 transmission lines (1708 total structures) in 5.7 hours. P27-122 cont.

A retired PG&E employee, who spent over 30 years in the Electrical Transmission Division reviewed the flight records. This former employee had been involved in the drafting of the 1995 inspection policy memo and the ETPM and the troublemen training program from 1995 to 2005. This former employee stated the flight records reflected the aerial patrols are "fly bys" not patrols or inspections. One recently retired troubleman admitted when doing aerial patrols he was only confirming the structures and components were "standing upright".

All of the troublemen who performed aerial patrols on the Caribou-Palermo line since 2012 and the current Transmission Line Supervisor assigned to Table Mt. Headquarters, were shown photographs, both the January 31, 2019 BCDA photographs and PG&E WSIP[88] photographs, of worn C hooks and hanger holes. All of the troublemen consistently denied it was possible to see and assess the wear on the C-hooks and hanger holes during aerial patrols.[89] The Transmission Line Supervisor asserted that, based upon wind and topography, it was not safe for the helicopters to fly low enough and slow enough to enable the troublemen to see and assess the C-hooks and hanger holes. The troublemen also denied it was possible to assess the wear on the C hooks and hanger holes during a detailed ground inspection. The ETPM corroborates the troublemen on both. According to Table 2 in section 1 of the ETPM the best view positions for assessing insulators and hardware do not include ground inspections nor aerial patrols. Only climbing inspections or lifted bucket inspections above 10 feet in the air would give the appropriate best view for assessment of insulators and their connectors.

Since the enactment of the ES Guideline E-TSL-G013 in 1995, **climbing inspections have only occurred "as triggered."** The specific language regarding triggers has changed very little since 1995. Appropriate "triggers" for climbing inspections were covered in section 2.1.3 of the ETPM (emphasis added):

> **Triggers** are **specific conditions** that **require** follow-up inspections and/or maintenance scheduled by the supervisor, independent of the routine schedule.
>
> The following triggers can be applied to one unit of inspection or many units, either grouped or spread over a line section/area:
>
> - **Component defects identified by inspection**
> - **Component failure (including failure in like components)**
> - **Components proven defective by testing**
> - **Wire/structure strike**
> - **Burned area or high fire hazard**
> - **Failures caused by natural disaster or storm**
> - Third-party observations and complaints
> - Marginal capability components of a re-rated line section
> - Known, recurring conditions that jeopardize line integrity
> - Suspected vegetation clearances less than required or less than legal vegetation clearances, or concerns about fast growth of vegetation

P27-122 cont.

Despite the facially mandatory language, "specific conditions that **require**," many PG&E employees who were interviewed, including electric transmission troublemen, linemen and support personnel expressed an understanding that an occurrence or discovery of a specific condition did not necessarily trigger climbing inspections. The evidence clearly established that on the Caribou-Palermo line, PG&E interpreted the mandate of "require" as discretionary. The maintenance/repair/replacement records established that since 2007 many of the "required"

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[88] Wildfire Safety Inspection Program – an "enhanced" post Camp Fire inspection of all PG&E electric transmission structures. See section X – Comparison of Caribou-Palermo With Other Transmission Lines for details on the WSIP and analysis of WSIP results.

[89] All of the troublemen also denied knowing the sizes of the hanger holes and C hooks. Therefore, even if the troublemen had looked at the C hooks and hanger holes, without knowledge as to their respective sizes, the troublemen would not have been able to assess wear.

triggers occurred. Some of the triggers (e.g. failures caused by storm, fires under the transmission line) have occurred multiple times. The evidence established the following triggers documented in PG&E records between 2007 and 2018:

- 2008 Lightning Complex fires (burned under and around transmission line)
- 2008 Rock Fire (started by failure of connector on Caribou-Palermo line Tower 11/87)
- 10/17/08 - failure to underarm jumper
- 2009 identification of parallel groove connectors on 83 towers (defective components)
- 2009 ATS Lab Test Report identifying defects in installation of parallel groove connectors
- 2012 fire which caused delay of 2012 Annual Air Patrol
- 2012 tower collapse (defective component)
- 1/10/14 - Unknown Failure/Locked Out causing interruption, no cause determined
- 2/7/15 – storm damage
- 12/10/15 Sustained outage. Found center phase guy wire tie down broken. North phase top insulator unpinned @ structure 23/194.
- 10/19/16 failure of a J hook in structure 11/99.
- 1/9/17 Storm related emergency due to (6) lockouts on the Caribou Palermo line. Non-routine air due to line locked out, crew found problem of floating center phase conductor at tower 24/200.
- 1/10/17 storm damage, conductor repaired.
- 2/1/17 storm related interruptions. "Non-routine airs due to momentary outages, fault location 10/79, found hold insulator hold down parted at structures 8/67 and 11/89, will create notifications for repairs."
- 2/21/17 "Non-routine air patrol due to strom related momentarys [sic]. After several relays GCC placed non-test on line and line went to lock-out." "Per [Troubleman] on 2/21/17 during storm damage: Air patroled [sic]fault area and found hardware loose on tower 3/28 but not sure if this was part of the problem, re-energized line and held."
- 3/2/18 "Investigate relay that occurred on 3/1/18 @11:43. Found damaged insulator on structure 37/301. Created notification to replace insulators."

P27-122 cont.

Between January 1, 2017 and February 21, 2017 there were at least nine documented storm related interruptions on the Caribou-Palermo line and at least six equipment failures. Based upon the evidence neither the individual events nor the cumulative events were deemed sufficient to trigger climbing inspections on the Caribou-Palermo line.

Although several PG&E transmission line employees referred to the ETPM as "The Bible" and asserted strict compliance with the standards and policies of the ETPM, the totality of the evidence shows that on the Caribou-Palermo line, the ETPM was not followed. Because PG&E had inexperienced, untrained and uninformed personnel conducting inspections and patrols under unrealistic time constraints, the inspections and patrols did not spot defects and wear.

On June 26, 2018, a PG&E work order requiring climbing inspections of all Caribou-Palermo line structures was issued by a PG&E Tower Department supervisor. The supervisor was interviewed. The supervisor could not provide any reason or rationale for the work order. Specifically, the supervisor stated that the work order was requested by someone else and his job was simply to compile the information into a template report and forward the template report to the appropriate work group.

PG&E was unable to provide any further information. "PG&E's inspection records do not identify the factors that led to the selection of the Caribou Palermo 115 kV Transmission Line as one of the lines selected for climbing inspections as part of this effort. PG&E understands that the age of lines was a factor that was considered in their selection."[90]

Beginning in September 2018 climbing crews from the PG&E Tower Department climbed and inspected 80 towers on the Caribou-Palermo line. The vast majority of the towers climbed and inspected were on the Palermo-Big Bend section of the Caribou-Palermo line. "PG&E understands that the reason these approximately 80 towers were selected first and the order in which they were inspected was determined by the Tower Department based on various considerations, including weather conditions and crew availability."[91]

All of the towers climbed in September and October 2018 were subjected to WSIP enhanced inspection starting in December 2018. The WSIP enhanced inspections documented problems and defects on numerous towers that were not discovered/detected/documented during the September 2018 climbing inspections.

P27-122 cont.

The fact that PG&E has no explanation for how or why or by whom the decision to conduct climbing inspections was made is disturbing but not unusual. Numerous decisions and policies were investigated. As to many decisions and policies, PG&E was unable to provide any documentation as to who made the decision, how the decision was made and upon what the decision was based. This inability to determine who made decisions and upon what those decisions were based, frustrated efforts to identify individuals potentially personally liable for policies that lead to the conditions which caused the Camp Fire.

X. COMPARISON OF CARIBOU-PALERMO WITH OTHER TRANSMISSION LINES

Although the undetected problems on the Caribou-Palermo line were bad, the evidence established that the Caribou-Palermo line was only marginally worse than other comparison transmission lines. Records from post-Camp Fire enhanced inspections of other, similar lines clearly established PG&E's problems were systemic as opposed to local.

The evidence established by early afternoon on November 8, 2018, a PG&E troubleman on an emergency air patrol of the Caribou-Palermo line had identified and photographed the equipment failure on Tower 27/222. Within six days PG&E initiated climbing inspections of the Caribou-Palermo line and other similar transmission lines. The initial inspections were named the "Nine

[90] PG&E written response to CPUC Data Request 008, Question 1.
[91] PG&E written response to CPUC Data Request 008, Question 1.

Lines Inspections.[92]" PG&E records established that by November 14, 2018 the inspections were underway. The evidence showed the inspectors were specifically focused on C hook and hanger hole wear. By early December the Nine Lines Inspection program was superseded by the Wildfire Safety Inspection Program (WSIP). The WSIP involved enhanced (climbing and drone) inspections of all electrical transmission lines within higher wildfire risk areas. The WSIP inspections "identified thousands of conditions requiring repairs on PG&E's system that had not been previously identified."[93]

As a result of the WSIP, and at the request of the CPUC, an independent engineering company named Exponent was retained to review the data from the WSIP. According to its website "Exponent is a multi-disciplinary engineering and scientific consulting firm that brings together more than 90 different disciplines to solve engineering, science, regulatory and business issues facing our clients." Based upon historical records, Exponent has a longstanding relationship with the CPUC and has conducted failure analysis investigations of previous PG&E incidents.

According to interviews with Dr. Brad James, PhD in Metallurgical Engineering and Failure Analysis expert at Exponent, Exponent was tasked to confirm whether the Caribou-Palermo line had significantly more repair tags when compared to other lines and to discover the reasons behind the high volume of high priority repair tags.

Exponent published its final report, entitled "PG&E Caribou-Palermo Asset Condition Investigation" to PG&E and the CPUC on November 1, 2019. A copy of the report was obtained via Grand Jury Subpoena.

P27-122 cont.

According to the Exponent report the comparison lines were chosen from a list of transmission lines based on four criteria:

- 115 or 230kV lines only
- Elevations greater than 1,000 feet
- Single circuit steel lattice towers
- Tier 2 or Tier 3 fire zones

Other criteria that were also applied included mountainous terrain and wind exposure. Based upon the criteria only transmission lines in running through low population, rural areas were chosen. There were no transmission lines from the Bay Area, Central Valley or central coast chosen for comparison.

Among the conclusions reached by Exponent are the following:

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92 The nine lines were identified as the Caribou-Palermo line, the Drum-Rio Oso #1 line, the Pitt #1-Cottonwood line, the Caribou #2 line, the Caribou-Plumas Jct line, the Colgate-Alleghany line, the Fulton-Hopland line, the Hat Creek #1-Westwood line and the Keswick-Trinity line.

93 CPUC Data Request: SED-007, Response to Question 6.

- The Caribou-Palermo line was confirmed to have greater post–Camp Fire high-priority ("A" + "B") repair tag[94] counts than all selected comparison lines, as well as an increased per-structure high-priority tag rate when normalized[95] for the number of steel lattice towers.
- Other lines adjacent to Caribou-Palermo line such as Bucks Creek–Rock Creek–Cresta (BCRC), Cresta–Rio Oso (CRO), and Paradise–Table Mountain (PTM) had the second, fourth, and fifth highest post–Camp Fire high-priority tag counts, respectively, when normalized for steel lattice towers. Pit #4 Tap (P4T) had the third highest normalized high-priority tag count. It is not near Caribou-Palermo line.
- Wear was the most commonly observed post–Camp Fire damage mechanism for Caribou-Palermo line "A" tags and second most commonly observed damage mechanism for "B" tags. Nearly all Caribou-Palermo line wear-related tags were associated with cold-end hardware. Cold-end hardware wear issues were likely caused by repeated conductor and insulator movement over time.
- Caribou-Palermo line, BCRC, and CRO lines, each located within the North Fork Feather River Canyon, exhibited high-priority cold-end hardware wear tag counts more than three times higher than the next highest comparison line when normalized for steel lattice towers.
- Caribou-Palermo North experiences higher annual average wind speeds than non-adjacent comparison lines. Lines analyzed within the North Fork Feather River Canyon may have increased wear tag rates associated with longer-duration high-wind conditions. No apparent correlation between wear tags and temperature, precipitation, or peak wind speed (50-year return) was observed.
- From 2001 to November 2018, the Caribou-Palermo line was subjected to similar ground inspection and patrol frequencies as comparison lines. These inspections and patrols yielded comparable normalized high-priority tag counts between Caribou-Palermo line and comparison lines.
- The Caribou-Palermo line had more normalized equipment-based outages between 2007 and 2018 than approximately 80 percent of the other WSIP transmission lines.
- Caribou-Palermo line and other North Fork Feather River Canyon lines appear to have a unique set of factors that contributed to increased rates of high-priority cold-end hardware tags relative to other comparison lines. Factors such as design (link connectors and a relatively large number of non-tensioned insulated conductors), long-duration exposure to higher winds, age, and historical

P27-122 cont.

[94] A report that documents a problem found, assigns a priority code to that problem and requests repair/replacement. PG&E Corrective Work Forms (CWF) are commonly referred to as tags. CWFs/tags are also referred to as notifications, especially in Transmission Asset Management.
[95] Normalization is a statistical analysis used for comparison purposes. Exponent divided the number of tags on a transmission line by the number of towers in the transmission line in order to compare transmission lines with disparate numbers of towers.

inspection methodologies likely all contributed to these cold-end hardware wear issues.

Although Exponent did not complete a forensic root cause analysis of the C hook that failed on Tower 27/222, when questioned Dr. James stated "That said, things like wear, things like fatigue do have a time component because the more times you rub that metal against each other, the more chance you have to – create wear. The more times you cyclically load the spring in your garage door, the longer you do that, the more chance you are going to initiate a fatigue crack and eventually grow it."

The Exponent report analyzed historical (2001-2018) high priority tags[96]. Consistent with the statements of the troublemen and linemen who have completed all inspections and patrols on the Caribou-Palermo line, Exponent found no high priority tags for cold end attachment hardware wear. Exponent also examined historical (2001-2018) inspection and patrol records for all of the comparison transmission lines. Exponent did not find any high priority tags for cold end attachment hardware on any of the comparison lines. This evidence established that the local Table Mountain District troublemen and linemen were not doing less than the troublemen and linemen assigned to other districts involved in the study.

Although the primary focus was cold end attachment hardware wear, the Exponent report also analyzed all Priority A and B "tags" generated by the WSIP. Priority A and B tags were "binned"[97] by component type and damage mode.

P27-122 cont.

Organized by component type, on the Caribou-Palermo line there were actually more tags (all Priority B) generated for "Foundation" issues than "Cold End Hardware." There were also tags generated for steel frame issues, insulator issues and conductor issues.

Organized by damage mode, there were more tags generated on the Caribou-Palermo line for soil movement (associated with foundation) than wear (exclusively associated with cold end attachment hardware). The other damage mode tags included bent, loose, missing, broken and corrosion.

The fact the troublemen and linemen missed that tower foundations were buried and portions of the steel structures were bent, loose, broken or missing contradicted the assertions of PG&E employees that inspections and patrols were being conducted pursuant to the requirements of the ETPM.

Tower 27/221 best illustrates this lack of attention and thoroughness. On September 11, 2018, during the Annual Air Patrol of the Caribou-Palermo line, the troubleman noticed that a "hold down insulator anchor" on Tower 27/221 had failed. The troubleman noted the problem on his report and created a Corrective Work Form for repair of the hold down insulator anchor. On November 11, 2018, during the Camp Fire origin and cause investigation, the electrical engineer retained by Cal Fire noted and photographed the failed hold down insulator anchor on Tower 27/221. The electrical engineer also noted the arm of the transmission tower to which the hold

[96] Issues that would be considered A or B priority under the current version of the ETPM
[97] In layman's terms the tags were separated, sorted and organized by category.

down insulator anchor should have been attached was bent and two of the steel members of the arm were buckled. No corrective work form for the arm was located. The troubleman **only** created a corrective work form for the hold down insulator anchor. According to PG&E policy, as explained by multiple transmission troublemen, supervisors and specialists, corrective work forms are problem specific and if there are multiple problems in a tower each problem gets a separate corrective work form.

The Exponent report also compared the number of post-Camp Fire A and B tags with the comparison lines. Except for tags related to foundation issues, Exponent did not separate and organize the tags from the comparison lines. According to the Exponent report there were previously undocumented issues on all of the comparison lines. The only reasonable conclusion to be drawn from this data is that inspections and patrols on other lines are only marginally more thorough than those done on the Caribou-Palermo line. This conclusion was corroborated by Exponent's comparison of A and B tags across maintenance districts. According to the Exponent report the post Camp Fire normalized A and B tags for comparison lines in the Table Mountain maintenance district (referred to as Table Mountain Headquarters by PG&E personnel) were not inconsistent with those of comparison lines in the Sacramento and Lakeville maintenance districts.

Based upon the totality of the evidence regarding the ETPM and inspections and patrols the only reasonable conclusion to be drawn was the Caribou-Palermo line specifically and the Table Mountain District in general are not outliers. The evidence established the lack of thorough inspections and patrols on the Caribou-Palermo line was a systemic problem not a local problem. Based upon the evidence the only reasonable conclusion was that in low population density mountainous areas, the PG&E Electrical Transmission Division was not following the standards and procedures established by the ETPM. As a result in those areas PG&E was not complying with the standards and procedures submitted to the regulatory agencies and required by regulation.

P27-122 cont.

XI. BUDGETARY CONSIDERATIONS

Financial records from 2007 through 2018 obtained from PG&E, the CPUC and FERC clearly established PG&E had consistently increased its budget for maintenance, repair and replacement of transmission assets[98]. The central issue in the FERC litigation over PG&E's 2018 Transmission Owner's Rate Case request was how that money was being spent. In the "Summary of the Prepared Rebuttal Testimony of {Vice President of Electrical Asset Management}"[99] then PG&E Vice President of Electrical Asset Management states: "PG&E makes these investments to address deteriorating electric system infrastructure and to address equipment that has reached the end of its useful life and system designs that no longer meet operational requirements." The PG&E Senior Director, Transmission Asset Management at the time, also provided testimony in the FERC litigation. In the "Rebuttal Testimony of {Senior Director, Transmission Asset Management}"[100] it was stated:

> "PG&E must repair or replace assets that are approaching the end of their service lives, that are deteriorating, or that have failed. Replacement and repair of PG&E's assets are essential to maintaining and improving PG&E's transmission service to its customers. PG&E expects that replacement-related capital work will continue to grow as PG&E's assets continue to age. A significant part of PG&E's transmission infrastructure was constructed in the years following World War II, with some assets being even older. In addition, PG&E has one of the largest investor-owned fleet of hydroelectric facilities in the Country. By and large, these facilities are located remotely from PG&E's load centers. Many of these facilities—and their related transmission assets—were constructed in the early 1900s. Due to an increasingly large number of these assets nearing the end of their useful service lives, capital investment will shift significantly, from capacity increase-related projects, to lifecycle replacement projects."

P27-122 cont.

However, the evidence gathered during the Camp Fire Investigation contradicted the FERC testimony of both Vice President of Electrical Asset Management and Senior Director, Transmission Asset Management. PG&E was **not** using the money to replace the oldest and most deteriorated transmission assets.

Because of limited available resources, the investigation was unable to fully analyze PG&E's financial records and assumed all figures were correct. The investigation instead focused on how, where and why the money was being spent. The evidence established the maintenance/repair/replace budget was primarily based upon "reliability metrics[101]."

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[98] During litigation relating to PG&E's 2018 Transmission Owner Tariff (TO18) rate case, PG&E represented that from 2007 ($405,739,000) through 2016 ($1,124,457,000) electrical capital expenditures increased every year except 2013 (decreased app. $20,000,000 from 2012) and 2016 (decreased app. $7,000,000 from 2015). In total, spending increased $734,812,000 between 2007 and 2015 (the high spending mark), or an average of $81,645,777 per year.

[99] Exhibit PGE-0037, FERC Docket No. ER16-2320-002.

[100] Exhibit PGE-0038

[101] Reliability metrics measure how often a power line is out of operation, how long it is out of operation and how many customers are affected by that outage. SAIDI, SAIFI, CAIDI, ACOF and ACOD were the performance metrics used.

The evidence established PG&E electrical transmission expenditures were divided into two budget categories: 1) capital and 2) expense. The capital budget for the electric transmission division of PG&E was funded through customer rates which were determined by FERC "rate cases.[102]" The expense budget was funded by the company. Any money spent on the expense budget potentially reduced the amount of profit of the company. In general, inspection, patrol and maintenance of electrical transmission assets were paid from the expense budget. Replacement of electrical transmission assets was paid from the capital budget. FERC rate cases, and PG&E's future capital budgets, were based upon PG&E's projections of capital projects. The evidence established that, for budget purposes, all components of the electrical transmission system were considered "assets."

A. Expense Budget

Based upon PG&E internal records and interviews of electrical transmission employees, including a former employee of the PG&E Business Finance Department, it was established the budget for inspection and patrol of the transmission lines was controlled by the Business Finance Department. Each year the Business Finance Department set an inspection and patrol budget for each of the PG&E transmission maintenance divisions. That budget was based upon the allotted time for all of the inspections and patrols scheduled for that year. The allotted time for each inspection and patrol was based upon the specific time allotted for a troubleman to spend on a single structure (e.g. tower or pole). To compute the time allotment for a transmission line, the single-structure time-allotment was multiplied by the number of structures in the transmission line.

P27-122 cont.

The time allotted to be spent on a single structure was a system-wide constant and did not take into account the physical location of any specific structure or the amount of time necessary to travel from structure to structure. For example, the time allotment assumed the inspection of a tower on the Caribou-Palermo line, parts of which could be accessed only by hiking a steep trail, would take the same amount of time as inspecting a tower in the Central Valley, located directly adjacent to a public roadway.

When questioned about the time allotments for inspections and patrols, a former employee of the Business Finance Department who was intimately involved in the allotment process, admitted he had no knowledge or experience with inspections and patrols, and based the allotments solely on dividing up the overall electric transmission expense budget. This former employee also asserted the Transmission Line Supervisors and Superintendents were consulted regarding the proposed allotments. The Transmission Line Supervisors and Superintendents interviewed denied having any input or control over the time allotted for inspections and patrols.

Although denied by the involved employees, emails between the Table Mountain Headquarters secretary and several troublemen indicated the troublemen were not able to complete some

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[102] A rate case is the utility's explanation and justification for a rate increase. In layman's terms, the utility lists all of the capital projects the utility deems necessary and their projected costs. If the total cost of all of the projects is higher than the projected amount to be collected from customers, the utility requests a rate increase and files a rate case. The rate increase is based upon the difference between projected costs and projected collections from customers. The rates which PG&E is allowed to charge customers includes a profit margin defined by FERC.

inspections in the time allotted. For example, the 2014 Detailed Ground Inspection of the Caribou-Palermo line was allotted 89.5 hours. PG&E records showed, before the secretary re-assigned hours billed by the troubleman to other projects, that the troubleman and five linemen actually spent 121 hours completing the inspection. When asked, a former Transmission Line supervisor asserted that because of the artificially constrained budget, his district was constantly under pressure to limit the hours necessary to complete thorough inspections and patrols of transmission lines.

During this same time period internal PG&E emails indicate the expense budget for electrical transmission was being reduced. An October 2015 email noted: "For the overhead tower inspections, I don't think we would be able to do any repairs and incur land costs shown in item three and four in 2015." The email includes a chart of projects with the 2015 and proposed 2016 budgets. Item three in the chart is "Severe deterioration repair (tower department)."

In an August 2016 email regarding a transmission expense budget meeting from a manager in Business Finance to a Senior Director of Transmission Lines, it was stated: "The purpose of the meeting is to obtain Leadership guidance on *which* items to pursue and *when.* This input is important given the Expense reduction pressures being pushed down on Transmission Operations for 2017." One of the people involved invited to this meeting was the former Business Finance employee assigned to track unit costs for the transmission inspection and patrol budgets. When questioned by investigators, the former Business Finance employee conceded one way to reduce budget for inspections and patrols is to reduce the unit cost. According to the employee, the unit cost is reduced by reducing the time allotted for inspection/patrol of each transmission asset.

P27-122 cont.

During this same time period, internal PG&E documents establish the "T Lines Patrols and Inspection Continuous Improvement Charter" was formed. The T Lines Patrols and Inspection Continuous Improvement Charter was a committee made up of PG&E personnel from the transmission line division, asset management, asset strategy and business finance. One of the specific mandates of the committee was evaluation of the feasibility of reducing costs by changing the frequency of inspections and patrols or finding more efficient work practices.

Based upon the totality of the evidence, specifically the reductions in times allotted for patrol and inspection, the internal emails indicating budget reductions and the formation of a committee to investigate reducing patrol and inspection costs, the only reasonable conclusion was that PG&E achieved expense budget cost savings by reducing the thoroughness of inspections and patrols.

PG&E also reduced its expense budget by charging expense projects to the capital budget. Moving projects from the expense budget benefits PG&E in two ways. First, every expense budget dollar saved was an additional dollar of potential profit. Second, the customers (ratepayers) pay over 100% of each dollar spent on capital improvements that brings in additional profit. Based upon internal emails and interviews with engineers involved in the planning and management of transmission projects, it was common for PG&E to look for ways to bootstrap expense budget projects on to capital budgets projects. Hypothetically, for example, instead of paying $1000 from the expense budget to fix a component, PG&E would pay $10,000 from the capital budget to replace the component. The $1,000 saved from the expense budget becomes profit and the company charges the customers $10,500[103] for capital improvement of the component.

The evidence established that PG&E personnel were consistently looking for ways charge expense budget projects to the capital budget. In a 2018 email from a PG&E civil engineer to a supervisor in the Transmission Line Asset Strategy Department of Transmission Asset Management, the civil engineer wrote:

> "I understand Asset Strategy has been working on a new way to define unit of capital to make it easier to capitalize a partial replacement on tower sections (e.g. footing, crossarm, etc…). We are replacing the top part of a distorted tower under emergency and was wondering if that could be considered a unit of capital and capitalize the project for corporate accounting purposes."

Based upon interviews with various PG&E personnel it was established that PG&E, as is common with large companies, had developed company accounting rules. Application of these rules determines if a project is charged to the expense budget or the capital budget. In general the rules hold that maintenance and repair are paid from the expense budget and replacement is paid from the capital budget. The above email indicates a move within PG&E to blur the lines between repair and replace to allow some repairs to be charged to the capital budget. P27-122 cont.

Another example occurred after the cancellation of the 2007 project to relocate ten deteriorating towers on the Caribou-Palermo line. The original Advance Authorization (AA) requested $800,000. Only $200,000 was approved. Once the project moved forward, the $200,000 budget was quickly surpassed. By the time the project was cancelled in 2009 almost $800,000 had been spent. A portion of that money was spent constructing an access road along the proposed new route of the ten new towers. According to internal emails obtained, the money spent to construct the new access road was charged as a capital improvement on another, adjacent transmission line. According to the former PG&E Director of Electric Asset Strategy who approved the 2007 AA, the rest of the money spent on the canceled project should have been charged to the expense budget. Internal emails establish that PG&E made an effort to find ways to charge the remainder of the money spent on the canceled project to the capital budget. A 2013 email from the former Maintenance and Construction Engineer (M&C) Engineer in charge of the project stated:

> "Looks like we will be forced into trying to Capture the $650K+/- that has been spent on the now canceled project for relocating Towers 6/53 to 7/65 from the non-accessible River side to Hwy side that (Project Manager) was managing.
>
> In order to not have to Expense the dollars spent we will be required to perform the following work."

[103] The extra $500 added to the $10,000 is the FERC allowed profit margin that PG&E would charge on capital improvements.

The email goes on to list the proposed work which mainly consisted of replacing insulators on the towers that Maintenance and Construction Engineer had previously described in the Advance Authorization as deteriorated. The work did not include replacement of the deteriorated conductor (annealed and parting) or any of the deteriorated hardware.

In a subsequent, 2014 email regarding the canceled project, the former M&C Engineer stated:

> "In order to try and capture the $900K that was spent for nothing, Asset Management decided that we would just replace the Insulators and Hardware on the section of towers that were initially going to be relocated."

In a 2016 email regarding the canceled project the former M&C Engineer stated:

> "This work was deemed by *{the Sr. Director of Transmission Asset Management}*in order not to end up expensing $800,000 that was spent by *{Project Manager}* on an original job started by *{former Table Mountain TLine Supervisor}* to relocate this section of towers."

When asked about these emails, the former M&C Engineer denied he was instructed to find ways to capitalize the money already spent and asserted that he was lying in the emails in order to get necessary work done quickly. As to the 2013 and 2014 emails, he stated the recipient of the emails, the Transmission Line Supervisor at Table Mountain Headquarters, distrusted engineers, so he lied and put blame on Asset Management in order to avoid argument. When asked about the 2016 email, which was directed to an engineer in Asset Management, the former M&C Engineer replied that the Sr. Director of Transmission Asset Management was not involved in the project and he invoked the name of the Sr. Director of Transmission Asset Management to speed up the process. This person is the same former M&C Engineer who wrote the original AA and the approved AA and now claims that his description of the condition of the relevant Caribou-Palermo line structures and conductor was unsupported and exaggerated for the purpose of securing funding for the project. In a 2016 email to the Transmission Line Asset Strategist, who canceled the 2007 project, the former M&C Engineer stated: P27-122 cont.

> "The only thing that after reading the below that came to my mind would be to also add life expectancies on some of our older lines that we purchased from other utilities. Caribou-Palermo (old Caribou-Golden Gate) for example…Built roughly in 1907. This line is in a very remote area. Access is extremely limited. Conductor was deemed annealed several years back. Line has tons of splices in it. Some spans have 5 splices within said span. Most of the upper line section is subject to rockslides that have taken this line out in the past. Restoration time is lengthy..
>
> Just one example, but I feel we should identify lines or line sections that meet this type of criteria and add them to our mitigation plan or part of future complete structure replacements…"

B. Capital Budget and Comparative Risk Analysis (RIBA)

For the capital budget, the evidence established PG&E employed "comparative risk analysis" to determine the budgetary priority of potential capital projects. Based upon interviews with several current and former PG&E employees who were involved in risk analysis, it was established PG&E has traditionally used some form of comparative risk analysis. Comparative Risk Analysis balances the probability of risk against the probability of consequence; and depends upon accurate projections and analysis of both. One of the former employees interviewed was the former Senior Vice President of PG&E. According to the former Senior Vice President of PG&E when he arrived at PG&E in 2007 the company was using comparative risk analysis, which he disapproved because of its subjective nature[104]. The former Senior Vice President of PG&E tried to install an objective risk model focused solely on the probability of failure. The former Senior Vice President of PG&E left PG&E in 2011.

The evidence established in 2014 PG&E again began using comparative risk analysis for capital funding. Since 2014 PG&E has used the Risk Informed Budget Allocation (RIBA). Based upon internal documents and interviews, the evidence established that under RIBA, capital projects were evaluated for funding based upon safety, environmental and reliability impacts that were scored based upon a complex matrix. According to a Manager in Transmission Asset Management, and one of the persons actively involved in the RIBA scoring process in 2014, reliability is "more about the customer impacts. So number of customers, the duration of outages, large cities, metropolitan areas. It's what we call critical locations. This can be anywhere from towns to cities." P27-122 cont.

For each category (safety, reliability, environment), a project would score between 1 and 10,000. The scores for the three categories were combined with the result being a project score between 3 and 30,000. The final score, according to the Manager in Transmission Asset Management, represents the "consequence if we don't complete the project." Once all of the proposed projects are scored the projects are ranked high to low by total score. RIBA scoring determined whether a project that is not mandated by a regulator was funded for the coming year, RIBA scoring and ranking was independent from and occurred after a project had been included in a FERC rate case.

Based upon the evidence, projects were used in FERC rate cases to justify rate increases and then, later, not funded because of a low RIBA score.

As examples, in 2014 three proposed projects on the Caribou-Big Bend section of the Caribou-Palermo line were scored under RIBA; the TL[105] Relocate 10 Towers project, the Replace 5 Damaged Towers project, and the 115kV NERC Alert. Through internal documents and witnesses it was determined that the TL Relocate 10 Towers project was the 2007 project to replace and relocate the ten deteriorating towers that had been canceled in 2009. By 2014 the only portion of the project active was the replacement of insulators so that the money spent on the project prior to cancellation could be charged to the Capital Budget. Based upon internal

[104] Relative risk analysis is a form of comparative risk analysis.
[105] TL is abbreviation for Transmission Line.

documents and witnesses, it was established that the Replace 5 Damaged Towers project referred to the replacement of the five towers that collapsed in December of 2012. Based upon internal documents and witnesses it was established that the 115kV NERC Alert project referred to the 2013 Caribou-Big Bend NERC project.

According to the "Risk scoring for baselined projects" the Replace 5 Damaged Towers total risk score was 180. The total risk score for the Replace 5 Damaged Towers project was explained in a February 2014 email from a RIBA team member[106] to the Senior Director of Transmission Asset Management in 2014. According to the RIBA team member:

> "<200 score because there is no likely large environmental event (if structures fail, it will be likely due to heavy rain and no wildfires are possible then). Also no likely public safety issue with live wires down because it is in a remote area. Reliability score is not that high because although the likelihood of failed structures happening is high, the affected customers are likely in the order of >1K."

According to the RIBA scoring sheet for the Replace 5 Damaged Towers project the person(s) scoring the project felt that the failure of the Shoe Fly "Probably could happen this next season." On the "Frequency/time-to-impact taxonomy" the project scored 6 out of 7 possible points.

In 2014 the Manager in Transmission Asset Management took part in the RIBA scoring. In addition she was the "Program Manager" for the Replace 5 Damaged Towers project. Based upon the 2014 RIBA scoring records the Manager in Transmission Asset Management stated that the Replace 5 Damaged Towers project scored the lowest possible scores of 1 for safety and environmental and scored 178 for reliability. According to the Manager in Transmission Asset Management the safety score was justified because the "worst reasonable direct impact," (WRDI) "basically in the particular case, would a structure fall down and hit somebody" was negligible because of the "remote" location of the Shoe Fly poles. According to the Manager in Transmission Asset Management, despite the written statements from 2014 documenting concern for the long term reliability of the Shoe Fly, the Shoe Fly was "temporary permanent" and it was not felt to be a danger to collapse. A former Transmission Specialist for PG&E and the person who was in charge of the construction of the Shoe Fly, was also asked about the Shoe Fly. According to the former Transmission Specialist, the Shoe Fly was only designed to be in place for a few months with the expectation that permanent replacement towers would be erected the following summer of 2013. Notes in the RIBA scoring sheet under the category reliability category of "Frequency[107]" corroborate the former Transmission Specialist. The former Transmission Specialist was also corroborated by an October 2013 email from the former M&C Engineer to multiple people. In the email the former M&C Engineer states "I do not believe there was a PO[108] created under MWC 70[109] yet for that replacement project that is now sitting

P27-122 cont.

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[106] The position/job title of the RIBA team member was never determined.
[107] The "Frequency" category measures how often a problem is expected to occur.
[108] In layman's terms, a project proposal.
[109] MWC is an abbreviation of Major Work Category. Each major work category is identified by a number. In this case the proposed project falls with major work category number 70. All PG&E electric transmission work projects are assigned to a major work category for accounting purposes.

on Wood poles and was not intended for long term reliability." The project was assigned a frequency score of 6 out of 7 possible with the note "Probably could happen this next season."

No records were ever located to support The RIBA team member's conclusion that the Shoe Fly poles would most likely fail due to heavy rain. According to the Manager in Transmission Asset Management, The RIBA team member was an expert on the RIBA process who was assigned to assist "the engineer walk through the process." Based upon the records the Manager in Transmission Asset Management identified the engineer as the engineer most familiar with the overall project and assigned to do the RIBA scoring for the project. According to an undated PG&E Org Chart, the engineer assigned to score the project was a Senior Engineer assigned to Transmission Asset Development and reported directly to the Manager in Transmission Asset Management. According to the notes on the scoring sheet, as interpreted by the Manager of Transmission Asset Development, "the concern here is the note says that the structures would go down during rainy and wet storm. And what's not shown here is that the wildfire is not likely, because on the wet ground not likely to have wildfire." No records in support of Senior Engineer's conclusion were ever located.

On the other hand, the TL Relocate 10 Towers project scored 581. According to the scoring sheet, the Senior Engineer was also the engineer assigned to score this project. Despite the fact that by 2014 the scope of the project was limited to the replacement of insulators so that money spent on the project prior to cancellation could be charged to the Capital Budget, the project scored 18 points out of 10,000 possible points for safety[110]. Despite the fact that the project involves the same Caribou-Palermo line the Reliability Risk Score is 562. 434 of those points are justified because "WRDI is possible contact with public leading or to other facilities causing potential injuries to few employees" according to the notes on the scoring sheet.

P27-122 cont.

The 2014 RIBA scoring is used to highlight the subjective nature of the comparative risk analysis. Because they are subjective the risk scores are easily manipulated. PG&E was highly motivated to complete the TL Relocate 10 Towers project in order to be able to charge the budget overruns, money already spent, to the capital budget. By 2014 the Replace 5 Damaged Towers project was about future spending. The best example of the manipulation is the WRDI justifications. One of the oft-stated justifications for the TL Relocate 10 Towers Project was the fact that the ten towers were located in a remote, inaccessible location. The towers were so inaccessible that PG&E had to use helicopters to fly personnel to the towers. Also, there was no evidence that any of the ten towers was on the verge of collapse according to the 2009 email from the manager who cancelled the project in 2009. On the other hand, the Shoe Fly was built on Camp Creek Road and any, or all of those poles, could reasonably be expected to fall down within a year.

Another example of manipulation of facts in the 2014 RIBA was the RIBA team member's conclusion, apparently based upon the Senior Engineer's scoring note that "structures would go down only if it is rainy and wet"; and restated several times by the Manager in Transmission Asset Management that the wood Shoe Fly poles would probably only collapse during heavy rain

110 18 times the safety score for the Replace 5 Damaged Towers project

thereby minimizing the chance of a wildfire. This statement was made in 2014, in the middle of a historic drought.

PG&E's own records clearly establish wind has long been classified as one of the top causes of structure failure on both transmission and distribution lines. PG&E's own records also establish the Feather River Canyon is known for high and sometimes extreme winds. Based upon PG&E wind records, the Exponent Report stated "Maximum (or peak) wind speeds in the areas of the chosen lines are generally found to vary between 60 to 100 mph, as measured and reported in "Extreme Wind Speed Estimates Along PG&E Transmission Line Corridors" across one-minute time intervals and at an elevation of 33 feet above ground level, over a 50-year return period." According to data pulled from the Jarbo Gap RAWS[111] by Meteorologist Kris Kuyper the highest number of high wind events occur in the month of October.

The inherent weakness of comparative risk analysis is its subjective nature. Data can be manipulated to achieve a desired result. Based upon the evidence the 2014 RIBA process exposes the manipulation of comparative risk analysis by PG&E personnel.

C. Transmission Asset Management

The examination of the 2014 RIBA scoring also highlighted the central role of Transmission Asset Management (TAM) in the development and execution of the capital budget. The former Senior Director was replaced as Senior Director of Transmission Asset Management in 2017. The Senior Director of Transmission Asset Management who assumed the position in 2017 explained the role of Transmission Asset Management:

> "My team's responsibility for managing those assets would be to track performance of the operation of the assets and ultimately make recommendations for enhanced -- future enhancements for those assets, investments that would occur over the next five to ten years both to replace aging infrastructure, enhance existing infrastructure for greater operational flexibility as well as increased capacity to meet NERC reliability plan and standards."
>
> "My job is to identify future work, future planned capital work. Our process has a bias towards identifying work approximately six years out.

In 2017, shortly after the new Senior Director of Transmission Asset Manager took over, TAM published the Electric Transmission Overhead Steel Structure Strategy Overview (2017 Strategy Overview). The document was written by a Senior Engineer assigned to Transmission Asset Strategy (TAS) within TAM. According to the Senior Engineer, the function of TAS is to review conditions reported from the field, study performance of the assets, apply criteria and develop a strategy for replacement or repair. According to the Senior Engineer the "conditions reported from the field" are the notifications/tags generated by the troublemen, linemen and towermen[112]. The "criteria" listed by the Senior Engineer include the age of the asset, environmental risk, safety risk, reliability risk.

P27-122 cont.

[111] Remote Automated Weather Station. See section XVI "Drought and Wind"
[112] Towermen work only on the steel structure of the tower.

According to the Senior Engineer, prior to the 2017 Strategy Overview neither a comprehensive plan for tower risk nor a tower risk database existed at PG&E. The Senior Engineer's statement was corroborated by internal emails obtained from PG&E. A June 10, 2016 email from a Manager in Transmission Line and Substation Asset Strategy[113], to a group of PG&E employees including the Senior Engineer, appears to be the genesis of the 2017 Strategy Overview. This email regarded a "Comprehensive Plan for Towers." According to the text the email was follow-up to a meeting held earlier in the day. The stated goal of the meeting was "Develop a Comprehension Plan for Tower Risk with emphasis on steel corrosion risks. Plans should include maintenance plans, detail inspection specifications, repair vs. replace criteria, capital and expense cost estimates, risk database, update Standards." Based upon the evidence, the only reasonable conclusion to be drawn is that, despite the fact that PG&E decisions were allegedly based upon risk analysis, until 2017 PG&E had no consistent and comprehensive risk database or policy for evaluating risk.

According to the 2017 Strategy Overview "The Transmission Line Steel Structure strategy will manage the asset life cycle (e.g. Create, Utilize, Maintain, Renew (replace), and Dispose) based on risk. The renew asset life cycle is based on proactive cost replacements for high-risk assets. For medium risk assets, it is based on reactive replacements following asset failures." The "high risk," "medium risk" theme continues throughout the 2017 Strategy Overview. Although not mentioned in the quoted sentence, there is also a "low risk" category. The appendix to the 2017 Strategy Overview includes an "Asset One Page Summary T-Line Strategy From A PAS 55 Framework." The summary consisted of five different charts. Although she is the author of the 2017 Strategy Overview, the Senior Engineer asserted that she was not familiar with the charts and was unable to explain the charts or their significance. According to the Senior Engineer the One Page Summary was prepared by her supervisor and attached to her work. The final chart, which has no title, appeared to summarize PG&E TAM risk strategy. According to the chart, for low risk assets the strategy was "run to failure" with "minimal patrol to continuously assess risk," "no maintenance," and "only replacement no repairs." For high risk assets the strategy was "condition base and cause evaluation," "extensive patrol with more frequency," "minimum req[114] maintenance" and "replace/repair."

P27-122 cont.

During interviews and testimony, TAM personnel stated that the high, medium and low risk categories applied to components of the transmission lines and not the entire lines. Insulators were identified as an example of a low risk component. All current TAM personnel disavowed the term "run to failure" during interviews and testimony.

Shortly after publication of the 2017 Strategy Overview PG&E published the 2018 TD-8101 – Transmission Line Overhead Asset Management Plan (2018 AMP). According to the Senior Engineer the 2018 AMP was written by multiple engineers, including herself. The "Document Owner" listed on the 2018 AMP is the Senior Director of Transmission Asset Management.

[113] At the time The Senior Engineer's direct supervisor
[114] abbreviation of required.

The 2018 AMP included a modified version of the TAM Risk Strategy chart found in the Appendix of the 2017 Strategy Overview. According to the preface to the chart:

> "The characteristics and condition of each transmission line overhead asset inform the risk and approach to replacement and operation, as well as patrol and maintenance frequency, as shown in" the charts

For low risk assets the strategy is "run to maintenance," with "low degree or patrol with minimal frequency to continuously assess risk," and "corrective maintenance." For high-risk assets, the strategy is "preventative maintenance and cause evaluation," with "high degree of patrol with more frequency," and "preventative maintenance." The 2018 AMP also includes a table entitled "Risk and Replacement Strategy per Asset." The Risk and Replacement Strategy per Asset table identifies individual components of the, identifies the risk for each component and defines the replacement strategy for each component. Overhead conductor is listed as a "high to medium" risk with the replacement strategy "preventative maintenance for high risk" "run to maintenance for medium risk." Steel structures are listed as high risk with the replacement strategy "preventative maintenance."

The most relevant difference between the chart in the 2017 Strategy Overview and the chart in the 2018 AMP is the replacement of "Run to Failure" with "Run to Maintenance." When asked about "Run to Failure" TAM employees tended to distance themselves from the phrase and criticize the phrase as being undefined although the term "Run to Failure" appears to be an industry standard and was discussed as an appropriate strategy for some components of the electrical transmission system in the 2010 Quanta studies. When asked to define "Run to Maintenance" most TAM employees identified failure as the trigger to maintenance. Based upon the evidence it appears that the change from failure to maintenance was semantical only. P27-122 cont.

As Senior Director of Transmission Asset Management the witness was responsible for overseeing the organization within PG&E responsible for managing assets of transmission and substation infrastructure and overseeing risk management within electrical transmission. As the manager of transmission assets, he played a sponsor role for new capital projects to replace to replace infrastructure. Transmission infrastructure was defined as transmission structures, conductor, insulators, circuit breakers, substation busses and transformers.

According to the Senior Director of Transmission Asset Management, information from the field, in the form of notifications/tags generated as a result of inspections and patrols, play a role in identifying potential projects to be included in the five year plan. According to the 2018 AMP "Transmission line overhead asset performance is primarily tracked through two factors: historical line outages and maintenance and inspection found notifications." The Senior Director of Transmission Asset Management conceded the quality of the input received from the field has an impact on the overall asset strategy. The Senior Director of Transmission Asset Management also conceded problems not identified by field representatives would never be brought to the attention of TAM. As a result projects to repair or replace those problems would never be planned. The Senior Director of Transmission Asset Management also conceded that as of 2018, other than the NERC Project there were no projects planned through 2022 on the Caribou-Big Bend section of the Caribou-Palermo line.

Although PG&E policy, as defined in documents like the 2017 Strategy Overview and the 2018 AMP and explained by TAM personnel, represented that decisions were made based upon a combination of performance information and patrol and inspection findings, the evidence indicated that performance information played an oversized role and patrol and inspection findings were insignificant. As a result of years of reductions of frequency and thoroughness of patrols and inspections, problems were not being identified. Based upon the WSIP and the Exponent report it was clear that on the Caribou-Palermo line and comparable lines, PG&E troublemen were not identifying problems.

The evidence established decisions regarding repair or replacement of transmission assets could not have been based upon non-existent patrol and inspection notifications. As such, then the decisions were being made solely on asset performance information. Performance information consisted of a complex series of reliability metrics (SAIDI, SAIFI, CAIDI, ACOD, ACOF). The evidence established these reliability metrics were a statistical analysis of outage data. This information was required to be tracked and reported yearly to CPUC, CA ISO, WECC, NERC and FERC. In general, all of the reliability metrics measured either the number or the effect, or both, of power outages per year. Effect is measured by either the number of customers who lose power as a result of the outage or the duration of the outage or both. The evidence established that the Caribou-Palermo line had only one dedicated customer (a powerhouse) who could be effected by an outage.

P27-122 cont.

Information regarding transmission asset conditions was based upon information received from the field. This includes notifications/tags generated by troublemen, linemen and towermen during inspections and patrols, both routine and non-routine). According to the Senior Director of Transmission Asset Management, TAM relied upon notifications/tags to identify potential preventative maintenance projects. After substantial discussion the Senior Director of Transmission Asset Management conceded that the fact that if troublemen, linemen and towermen did not inspect specific components of the transmission assets, it would affect the reliability of the information upon which TAM was making decisions. Specifically he conceded that because nobody was looking for wear on cold end attachment hardware and therefor, no notifications/tags were being generated for replacement of cold end attachment hardware there were, as of November 8, 2018, no projects in the foreseeable future for the replacement of cold end attachment hardware.

Although there were no specific plans to replace cold end attachment hardware the Senior Director of Transmission Asset Management asserted that plans were being made to perform preventative maintenance on the Caribou-Palermo line. According to the Senior Director of Transmission Asset Management, the NERC Project included non-NERC required preventative maintenance on the Caribou-Palermo line. When confronted with the Project Scope document for the NERC Project the Senior Director of Transmission Asset Management was unable to identify any non-required work. According to the Senior Director of Transmission Asset

Management the non-required preventative maintenance was not included in the Project Scope document but that plans were being made to perform the preventative maintenance. However, no records or plans for any preventative maintenance projects on the Caribou-Palermo line were located through 2022.

Another concept, which came up repeatedly in interviews and testimony of TAM personnel was "bundling." Based upon the evidence, for PG&E, bundling meant doing multiple projects on a transmission asset or line at the same time. According to the Senior Director of Transmission Asset Management TAM decisions were, in part, "informed by the most cost-effective approach for our customers." Having crews do multiple projects at once is much more cost effective than having multiple crews make multiple visits to the asset or line. An example of bundling occurred in 2018 on the Parkway-Moraga 230kV transmission line. The line had been de-energized so that the tower department[115] could fix a tower. While the line was de-energized the line department[116] performed preventative maintenance by replacing insulators.

Bundling often involved the intertwining of capital budget and expense budget projects. Based upon internal PG&E emails and interviews with PG&E personnel, it appeared PG&E bundled expense budget projects with capital budget projects in order to charge the expense budget costs to the capital budget project.

Despite their preference for bundling projects there is no evidence of any intent to bundle any preventative maintenance projects to the 2013 NERC Alert Project.

P27-122 cont.

The only reasonable conclusion to be drawn from the totality of the evidence is that PG&E was employing a run to failure strategy on the entirety of the Caribou-Big Bend section of the Caribou-Palermo line. Pursuant to the run to failure strategy, PG&E only applied a low degree or patrol with minimal frequency to continuously assess risk, and only performed corrective maintenance.

XII. SAFETY, RELIABILITY AND ENVIROMENT

The phrase "Safety, Reliability, Environment" appears consistently in PG&E documents, regulatory filings and public pronouncements. Members of the Electric Transmission Asset Management interviewed said safety, reliability and environment are the criteria by which all project decisions are judged. The Senior Director of Transmission Asset Management testified:

> "In terms of how PG&E quantifies consequences, we usually categorize it in a number of areas focused on safety, impact reliability, impact to the environment are some examples."
>
> "An analysis starts with defining a risk event, and that's really defining what is that event that we believe could have exposure from a public safety reliability environmental standpoint, and then quantifying the potential drivers for that event, and the associated consequences for that event."

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[115] The tower department deals solely with the steel transmission structures. Employees are called Towermen.
[116] The line department deals with energized components (conductor, insulators, hot and cold attachment hardware) of the transmission system. Employee are called Linemen.

All members of TAM were asked which of the three criteria was considered the most important. They unanimously replied safety. The evidence, however, contradicted that assertion. The evidence showed disparate treatment of transmission assets based upon the reliability metrics.

The most basic example of disparate treatment based upon reliability metrics was the 500kV transmission lines. According to PG&E personnel the 500kV lines are the backbone of the electrical transmission system and an outage on a 500kV can potentially affect millions of customers. According to the ETPM, all 500kV structures were subjected to detailed ground inspections every three years. "Critical" 500 kV structures were subjected to climbing inspections every three years and as triggered. "Non-Critical" 500 kV structures were subjected to climbing inspections every twelve years and as triggered. All 500 kV structures were also subjected to yearly patrols. In contrast, 115 kV structures were subjected to detailed ground inspections every five years, air patrols in non-detailed ground inspection years and are never subjected to climbing inspections.

Another example of disparate treatment based upon reliability metrics established by evidence developed during this investigation was the Bay Waters power towers. Since 2005, the Bay Waters towers had their own classification in the ETPM. Although the ETPM refers to the Bay Waters Foundation Inspection, numerous PG&E documents and TAM personnel established the special treatment extended to the entire tower. Some documents limited the Bay Waters towers to only towers that were actually in the water but other documents and information from some TAM personnel indicated the Bay Waters towers included all towers in the Bay Area. The justification given by TAM personnel for the special treatment of the Bay Waters towers is the highly corrosive effect of salt on steel structures. When asked why special treatment was afforded to Bay Area steel towers but not steel towers along the Sonoma, Mendocino, Humboldt, Monterrey and San Luis Obispo coasts, TAM personnel were unable to explain the difference.

P27-122 cont.

The final example of disparate treatment based upon reliability metrics established by the evidence arose out of a 2018 PG&E Lab Report on the hanger plates from the Parkway-Moraga 230 kV transmission line. According to the Lab Report, the hanger plates were submitted by the Supervisor, T-Line Construction, T-Line M&C Central-Bay Maintenance. When questioned, the supervisor stated wear was observed on the hanger plates while replacing insulators on the Parkway-Moraga line in the spring of 2018. There was no mention made of the C hooks and none were preserved. According to the supervisor a tower on the Parkway-Moraga was damaged in a mudslide and needed to be repaired. In order to repair the tower the line had to be de-energized. While the line was de-energized, a decision was made to proactively replace all of the "old" insulators and hardware. The Parkway-Moraga line was built after World War II in 1946. The insulators and hardware were assumed, because PG&E has no definitive records, to be 72 years old. In contrast, the Caribou-Palermo line was 91 years old when it was de-energized for over a month in December 2012 and January 2013 as a result of tower collapse. There is no record of PG&E doing any preventative or proactive maintenance on the Caribou-Palermo line while it was de-energized. According to PG&E, the reason no preventative or proactive maintenance was done was that the winter weather was not conducive to working in the Feather River Canyon.

A former PG&E Transmission Line Supervisor who, during his career in transmission lines, worked in almost all of the transmission line maintenance districts was asked if he had noticed a difference in the way transmission lines were inspected and maintained based upon a local population base. The former supervisor responded "We're kind of out-of-sight, out of mind up there," "We're always fighting the political battle," "But if something flips the screen down there [the Bay Area] they get a lot of attention."

XIII. RISK MANAGEMENT

Prior to the Camp Fire, risk management for electric transmission was supervised by TAM. During his testimony the Senior Director of Transmission Asset Management at the time of the Camp Fire, stated that the formulation of strategies by TAM relied, in part, on the assessment of risk. He defined "Risk" as "the probability and consequence of an event occurring." He defined probability as the "likelihood of something happening" and consequence as "the impact of that event occurring." He defined consequence as the result of an event occurring measured by impact on safety, impact on reliability and impact on the environment.

The Camp Fire investigation focused on two types of risk; risk of equipment failure and risk of fire.

A. Risk of Equipment Failure

The recommendations of the 2010 Quanta reports focused on ways to minimize the risk of equipment failure. In summary, the Quanta reports stated wear is a product of age and failure is a product of wear. All of the complex statistical analysis in the Quanta reports boiled down to the fact a large percentage of PG&E's transmission assets were very old and needed extra attention. Despite hiring Quanta to assess and analyze its transmission assets and make recommendations, PG&E ignored those recommendations. According to internal PG&E documents, in 2010 a committee was assigned to review and comment on the Quanta reports. Numerous current and former TAM personnel who were part of that committee were interviewed. None of the former committee members could recall who made the decision to disregard the recommendations of Quanta or why. The Senior Director of Transmission Asset Management, who was not on the committee and was not assigned to TAM in 2010 testified regarding the Quanta reports:

> "The Quanta study did not look at asset data from those utilities but rather business practices from those utilities. The only age information and corresponding failure data that was used in that study was associated with the subset of assets that failed in a two-year period within PG&E and made some assumptions that made the statistical analysis incorrect. So it wasn't sufficient for us to justify significant amounts of investments in the future, and we needed to do additional analysis in order to build the case for our regulators to be able to justify requesting authorization to be able to make additional investments in the infrastructure based on the results of that bullet point at a later date."

Although the Senior Director of Transmission Asset Management was dissatisfied with the Quanta reports, information from the Quanta reports was used and cited in numerous subsequent TAM documents, including documents produced by himself.

P27-122 cont.

PG&E internal documents and reports and a report filed with the CPUC clearly established PG&E was aware of the risk of equipment failure. In an undated internal PG&E draft report entitled "Transmission Overhead Conductors[117]" it was stated, "The major root cause of conductor failures is Equipment Failure (35%)." The report also stated inspections and maintenance performed according to the ETPM "are not preventing equipment failure due to wear, corrosion and other factors on conductors and associated equipment (splices)." The report also addressed the use of infrared inspections on transmission conductor: "In most cases, Infrared Inspections identify faults with components just prior to failure. Ariel (sic) inspections are conducted annually. This proactive approach yields little results." No final copy of this report was located and it is unknown why this report was drafted and to whom this report was distributed.

In another undated, unattributed internal report entitled "EO[118] Transmission OH[119] White Paper[120]" the effects of equipment failure was again discussed. Whereas the Transmission Overhead Conductors was focused on conductor failure and how to mitigate/reduce the number of conductor failures, the EO Transmission OH White Paper focused on outages and how to reduce outages to improve reliability metrics. According to the OH White Paper, at the time of writing, conductors 105 years old were still in service. According to the OH White Paper, "The root causes of about 85% of the outages due to conductors from 2007 to 2012 can be attributed to trees, hardware, conductor, wind and snow…" Under the heading "Existing Conductor Strategy" the report reflects the strategy "is primarily Run to Failure (RTF), supplemented by" "periodic condition assessment and maintenance" and "program of targeted reliability improvements focusing on poorly performing lines which contribute the most to SAIFI."

P27-122 cont.

In November, 2017 PG&E filed the 2017 Risk Assessment and Mitigation Phase Report (RAMP)[121] with CPUC. Chapter 10 of the RAMP was dedicated to, non-wildfire risks of the electric transmission overhead system. The RAMP looked at the known risks (identified as risk drivers) to the electric transmission system and explains how PG&E is mitigating those risks. The RAMP identified "Equipment Failure – Connectors/Hardware" as a significant risk. "Deterioration of connectors, splices or other connecting hardware that results in wire down events. This driver was associated with 28 out of 279 (10.0 percent) wire down events from 2012-2016, or an average of 5.7 events per year." Efforts to mitigate the risk of Equipment Failure – Connectors/Hardware are divided into past (2016), present (2017-2019) and future

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[117] The author of the report is not identified and was not identified during the investigation. Based upon content it appears the report was written in 2013

[118] EO is the PG&E abbreviation for Electric Operations.

[119] OH is the PG&E abbreviation for Overhead.

[120] The author of the report is not identified and was not identified during the investigation. Based upon content it appears the report was written in 2014

[121] Although not specific to equipment failure, the RAMP stated "Much of PG&E's transmission infrastructure was constructed in the years following WWII. As such, many assets are nearing "end of useful life". As these of assets near the end of their expected useful lives, PG&E will need to increase its level of asset replacements to avoid degradation in overall customer reliability and system performance." Construction of the Caribou-Palermo line began in the months (six months) following WW1.

(2020-2022). The mitigations listed are "Inspection and Maintenance," "Overhead Conductor Replacement" and "Insulator Replacement."

The 2018 AMP also addressed equipment failure. The 2018 AMP used and defined the term "Risk Driver." The definition includes reference to equipment failure:

> "A risk driver is defined as an element which alone or in combination with other drivers has the intrinsic potential to give rise to risk (which can be a single risk or multiple risks). There are 83 risk drivers related to transmission overhead line assets. Though there are many risk drivers, common drivers for transmission line overhead assets include equipment failure, vegetation, natural hazards (wind, snow, earthquakes, etc.) and third-party contact. These risk drivers enable PG&E to evaluate the controls that are in place and to strategically allocate resources to programs that strengthen these controls or create new controls to mitigate these risks."

According to the 2018 AMP "Conductor or connector/hardware failures account for 37% of all wire down events." The AMP also stated 25% (26 of 103) of wire down events 2013-2017 were caused by failure of "connector/hardware and 42% (44 0f 103) of wire down events 2013-2017 were caused by conductor failures.

The documents prove beyond any doubt that PG&E was aware of the risk of equipment failure causing conductor failure or "wire down events." The undated draft Transmission Overhead Conductors established that at least one person within PG&E TAM was aware that inspections and patrols being done pursuant to the ETPM were doing very little to identify and prevent equipment failures. P27-122 cont.

B. <u>Risk of Fire</u>

Since, at least 2007, fire has been identified as the number one risk for PG&E. Chapter 11 of the 2017 RAMP stated:

> "PG&E defines wildfire risk as: PG&E assets may initiate a wildland fire that endangers: the public, private property, sensitive lands, and/or leads to long-duration service outages.
>
> PG&E has designated wildfire as an enterprise risk (in addition to being a top safety risk) since 2006. This risk is reviewed annually by the Safety, Nuclear and Operations, Committee of PG&E's Board of Directors. PG&E's exposure to wildfire risks continues to escalate despite increasing investment in compliance and public safety programs given various environmental and human factors. The most notable investments are the T&D routine VM work and the CEMA VM work related to the drought and the ongoing tree mortality state of emergency.
>
> The CEMA work investment alone amounts to $190 million in 2016 and$208 million in 2017.14 Environmental variations, such as drought conditions or periods of wet weather that drive additional vegetation growth and wildfire fuel increases, can influence both the likelihood and severity of a wildfire event.

Although vegetation management is rightfully a focus of PG&E's fire mitigation efforts, equipment failure was also identified as a significant fire risk. According to PG&E statistics included in the RAMP, 33% of fires initiated by PG&E assets were caused by equipment failure. Vegetation management caused 37% of fires initiated by PG&E assets. The RAMP breaks equipment failure into three categories: 1) conductor; 2) connector/hardware; and, 3) other. Equipment failure – connector/hardware is defined in the RAMP as "Failure of connectors, splices, or other connecting hardware resulting in wire down and fire ignition." Equipment Failure – Connector/Hardware risk driver accounts for 6 percent of 243 ignitions, or 15.5 per year.

Similar to Chapter 10 discussed above, Chapter 11 of the RAMP identified fire mitigation efforts as past (2016), present (2017-2019) and future (2020-2022). Although the RAMP listed extensive fire mitigation efforts done, being done, or planned to be done, none directly addresses the risk of connecting hardware failure.

The 2017 RAMP was not the first PG&E document that connected equipment failure – connectors/hardware to fire. The draft Transmission Overhead Conductors cited fire risk in a discussion of the "Bolted Connector Program." The Bolted Connector Program was apparently[122] a name given to the replacement of bolted, parallel groove connectors, which began prior to 2009. As to the Bolted Connector Program the report sets forth: "M&C[123] only replacing bolted connectors during routine or emergency work with to those components identified during infra-red inspection or in areas identified as high fire risk." P27-122 cont.

PG&E records also document a previous equipment failure – connector/hardware on the Caribou-Palermo line. The 2007 Rock Fire was caused by the failure of a connector on a Caribou-Palermo line.

The evidence clearly establishes, beyond a doubt, PG&E was aware of the causal relationship between fire and equipment failure on transmission towers. The vast majority of PG&E initiated fires were caused by something (a tree, an animal, a person, the ground, or a steel structure) coming into contact with an energized conductor. The entire purpose of the electric transmission system is to move electricity from point A to point B through the conductor. The entire purpose of all of the components of the overhead transmission system, except the conductor, is to keep the conductor safely hanging in the air. Essential to keeping the conductor hanging in the air is the hardware that connects the conductor to the structure. PG&E knows that if that hardware breaks the result is a wire down event. Despite all of this knowledge PG&E did absolutely nothing to identify and replace the worn hardware essential to keeping the conductor safely in the air.

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[122] This is the only reference to the Bolted Connector Program found in records provided by PG&E. Based upon the description of the program it refers to the replacement of bolted, parallel groove connectors.
[123] Maintenance and Construction

XIV. <u>San Bruno</u>

Early in the Camp Fire Investigation, San Mateo County District Attorney Stephen M. Wagstaffe generously and graciously assigned Senior Inspector James Haggarty to assist in this investigation. Senior Inspector Haggarty was the lead investigator on the San Bruno explosion and an expert on investigating PG&E. Senior Inspector Haggarty immediately began seeing parallels between PG&E Gas Transmission operations prior to the San Bruno explosion and PG&E Electric Transmission operations prior to the Camp Fire.

On September 9, 2010, a PG&E gas transmission line buried beneath a residential neighborhood in the City of San Bruno ruptured and exploded. The explosion and ensuing fire killed eight people, destroyed 35 structures and damaged many more. In 2014, after three years of investigation by city, county, state and federal law enforcement PG&E was federally indicted for multiple federal felony counts. PG&E was later found guilty of five felony counts by a federal jury in the Northern District of California. A transcript of the jury trial testimony and copies of all admitted exhibits were obtained from the Federal District Court in San Francisco. During that trial, testimony established two relevant factual issues: 1) PG&E record keeping was flawed; and, 2) PG&E inspection policies for the gas transmission lines were budget dependent.

During the San Bruno investigation and subsequent trial, the flaws in PG&E's historical records were exposed. Evidence established that for many of the older gas transmission lines PG&E had few records. Many of those gas transmission lines had been acquired from other gas companies and PG&E never made an effort to examine, evaluate and catalogue the components of those lines. Instead, PG&E used "assumed values" instead of inspecting the actual line to determine true values.

P27-122 cont.

Similarly, during the Camp Fire investigation the evidence established that the Caribou-Palermo line was purchased from Great Western Power in 1930, and PG&E never made any effort to examine, evaluate and catalogue the line components. [124]

The San Bruno investigation also established that PG&E was making inspection policy decisions based on budget. Testimony and documents presented during the Federal jury trial clearly established in the years prior to the San Bruno explosion, PG&E used the least expensive inspection method to inspect older gas transmission lines, including the San Bruno line that ruptured and exploded. The chosen inspection method was less expensive in two ways: 1) it was less expensive to execute; and, 2) it was not designed to actually detect pipe integrity flaws that would require immediate and costly repair or replacement. Prior to the Camp Fire, for the Caribou-Palermo line PG&E utilized the least expensive inspection method (air patrols) in a

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[124] In a written response to a CPUC data request PG&E states "PG&E has not historically maintained an inventory of suspension hooks or their manufacturers, age or material composition. As a result, PG&E does not have an inventory of all transmission and distribution facilities in the entire PG&E service territory organized by location and the presence of suspension hooks similar to the Incident Location 1 suspension hook. Suspension hooks are common hardware on transmission structures and occasionally are used on distribution structures. In PG&E's service territory, there are in excess of 50,000 steel transmission structures, most of which have multiple suspension hooks of some type supporting insulators and other equipment. There are also suspension hooks on many of the nearly 100,000 non-steel transmission structures in PG&E's service territory. There are more than two million distribution poles in PG&E's service territory."

manner guaranteed not to detect any problems that would require immediate and costly repairs. Because troublemen were not finding safety problems requiring repairs, PG&E was able to devote capital budget funds to projects focused on improving reliability metrics.

The evidence uncovered during the investigation and presented during trial clearly established the San Bruno explosion was the direct result of the fact that, because of faulty record keeping, PG&E was unaware of the potential threat/defect in the San Bruno pipe. Because PG&E intentionally used an inspection method that could not detect the potential threat/defect, the threat/defect was not found.

XV. THE BUTTE FIRE

On September 9, 2015, a pine tree fell onto an energized PG&E distribution line in Amador County sparking the Butte Fire. The Butte Fire burned over 70,000 acres in Amador and Calaveras Counties, killed two people and destroyed hundreds of structures. Cal Fire conducted an investigation of the origin and cause of the Butte Fire. PG&E was not criminally prosecuted for the Butte Fire. A civil suit was brought against PG&E by the victims of the Butte Fire in the Sacramento County Superior Court. Early in the Camp Fire Investigation, records from the Butte Fire civil suit, including investigative reports and deposition transcripts, were obtained and reviewed.

The investigation into the Butte Fire focused on the PG&E vegetation management practices in the Stockton Division. Similar to the ETPM in the transmission division, PG&E had written policies for distribution vegetation management. Much like the Camp Fire investigation, the evidence uncovered during the Butte Fire investigation established as a result of reductions of the vegetation management budget, the written vegetation management policies were not being followed; vegetation management inspections and patrols were being conducted by unqualified, untrained, inexperienced personnel;[125] and PG&E was instructing those tree inspectors to ignore all but the most dangerous conditions. Additionally the evidence established PG&E had no quality assurance programs to monitor and evaluate the vegetation management program. As with the transmission inspection and patrol policies in effect at the time of the Camp Fire, PG&E relied solely on the observations of unqualified, untrained and inexperienced inspectors to identify dangerous conditions.

P27-122 cont.

XVI. DROUGHT AND WIND

Since at least 2013, PG&E was aware of increased risk of catastrophic wildfires. Chapter 11 of the 2017 RAMP begins:

> "Extreme weather, extended drought and shifting climate patterns have intensified the challenges associated with wildfire management in California. Environmental extremes, such as drought conditions followed by periods of wet weather, can drive additional

[125] The vegetation management program was conducted by hired contractors.

> vegetation growth (fuel) and influence both the likelihood and severity of extraordinary wildfire events.
>
> Over the past five years, as we have seen across California, inconsistent and extreme precipitation, coupled with more hot summer days, have increased the wildfire risk and made it increasingly more difficult to manage.
>
> The risk posed by wildfires has increased in PG&E's service area as a result of an extended period of drought, bark beetle infestations in the California forest and wildfire fuel increases resulting from record rainfall following the drought, among other environmental factors. Other contributing factors include local land use policies and historical forestry management practices. The combined effects of extreme weather and climate change also impact this risk."

According to the United States Geological Survey[126] three of the five worst droughts[127] in California history have occurred since 2001. The three droughts listed are 2001-2002, 2007-2009 and 2012-2016. According to the U.S Drought Monitor[128] in 2012 the Feather River Canyon was classified as "Abnormally dry." By 2013 the Feather River Canyon was classified as "Severe Drought." By 2014, and through 2015, the Feather River Canyon was given the highest drought classification: "Exceptional Drought"

According to an internal PG&E presentation from late 2013 entitled "Wild Fire –Enterprise Risk", PG&E was already aware of the heightened fire risk. "Wild Fire risk in California is increasing due to weather conditions and resulting record low fuel moisture content. Fire activity has seen a significant increase in 2013 as compared to 2012 with PG&E responding to 36% more fires YTD. Acreage impact as compared to 2012 is almost doubled." P27-122 cont.

According to the presentation PG&E created "administrative zones for areas at highest risk of a major wildland fire and proactively addresses these areas through operational and asset management standards. Current administrative wildland fire boundaries encompass geographies which exhibit a combination of active fire history, fire prone vegetation, terrain that promotes rapid fire spread, and/or locations specified by existing regulations for special treatment." The presentation includes a map of "Wildfire Administrative Areas at PG&E." The Feather River Canyon, from approximately Beldon to Lake Oroville appears to fall within a Wildfire Administrative Area. Under the title "Lessons Learned: Previously-Approved Mitigation Activities" bolted connector inspection/replacement is listed with the note "Wild Fire zones are now a consideration for program rollout prioritization."

Also in 2013 PG&E published the "Wild Fire Administrative Zones in PG&E's Service Area" map. According to this map the Feather River Canyon is falls within an "Other Wildfire Area." In 2014 PG&E Transmission Asset Strategy compiled a list of all transmission structures located within the boundaries of a designated wild fire area. Approximately 85 towers on the Caribou-Palermo line between the Butte-Plumas County line and the Big Bend Substation were included

126 ca.water.usgs.gov
127 measured by precipitation and runoff
128 https://droughtmonitor.unl.edu

on the list. Tower 27/222 for some unknown reason was not on the list, but Towers 22/187 through 23/192 (which did not exist in 2014 because they had collapsed in 2012) were listed.

According to PG&E documents, including publicly available reports, PG&E has its own meteorological department and continuously monitors data from both its own weather stations and government weather stations. The closest weather station to Tower 27/222 is the Jarbo Gap RAWS[129]. Meteorologist Kris Kuyper analyzed data from the Jarbo Gap RAWS, as well as other government sources including the National Oceanic and Atmospheric Administration and the U.S. Drought Monitor and PG&E. According to Kuyper's analysis, although the winter of 2016-17 was very wet and broke the 2012-16 drought, the winter of 2017-18 was dry "abnormally dry." Although the season as a whole was abnormally dry, March and April were wet. As a result of spring rains, native grasses grew in abundance. In May the rain disappeared.[130] From June 1, 2018 through November 8, 2018, there was no measurable rain in Paradise.[131]

Because of the lack of rain, by November 8, 2018 the EDDI[132] listed the Feather River Canyon in the ED3 or ED2 drought categories[133]. Based upon the lack of rain and the EDDI statistics, Kuyper opined that the dry air was "taking moisture from the plants, draining the plants of their moisture, making them even drier than they should have been." As a result, on November 8, 2018 the Feather River Canyon was approaching "record dry levels of fuel (trees, shrubs, bushes, grasses).[134]

According to data from the Jarbo Gap RAWS station from 9:13pm on November 7, 2018 until 5:13am on November 8, sustained winds were between 24 mph and 32 mph with gusts between 41 mph and 52 mph. According to Kuyper this wind pattern was not unusual for Jarbo Gap. Based upon analyzing six years of wind data from the Jarbo Gap RAWS Kuyper determined that Jarbo Gap experiences this wind pattern approximately 20 times per year,[135] the majority of which occur from October through February.[136]

According to Kuyper, the Jarbo Gap winds occur as the result of a difference in atmospheric pressure between east of the Sierra Nevada and west of the Sierra Nevada. Higher pressure over the Great Basin in Nevada forces air west, towards lower pressure on the west side of the Sierra Nevada. The Sierra Nevada blocks this, except through gaps and passes such as the Feather River Canyon. The air is then channeled through the gaps and passes, which accelerates the flow of air. Cold air flowing downhill also causes acceleration.

P27-122 cont.

[129] Remote Automated Weather Station
[130] Average rainfall in Paradise area in May is approximately. 5". May, 2018 rainfall for Paradise was .14".
[131] Average rainfall in Paradise area in October is approximately 3".
[132] Environmental Demand Drought Index, esrl.noaa.gov
[133] On a scale of 0 – 4. 0 being normal, ED2 is defined as "Severe Drought." ED3 is defined as "Extreme Drought." 4 being "Exceptional Drought."
[134] https://gacc.nifc/oncc/fuelsFireDanger.php
[135] From 2013-2019, 118 individual events with wind gusts over 45mph, 66 individual events with wind gusts over 50 mph.
[136] October averages more than 5 events per month, November averages under 2.

Internal PG&E records established PG&E has known since the mid-1980s that high winds constitute a serious threat to its electric transmission assets. In 1990, PG&E Research and Development published the "Extreme Wind Speed Estimates Along the PG&E Transmission Line Corridors" report. The report was the result of a five year study, recommended by the CPUC, "to assess the adequacy of PG&E's power wind loading design criteria" after five separate incidents in which transmission line assets were toppled during wind storms in 1982 and 1983. The report mainly focused on the 500kV transmission line corridors. According to the report "Electric transmission lines in the PG&E service area were originally designed to withstand wind loadings associated with 1-minute average gusts to 57 miles per hour (mph). The report concludes the original PG&E wind loading criteria for transmission lines was inadequate at some locations and needed upgrade. According to the reports, from November 1984 through November 1985 PG&E had wind meters installed at the Cresta Reservoir and the Rock Creek Reservoir in the Feather River Canyon. Both locations recorded gusts in excess of 50 mph hour in November, 1984 (54.6 mph) and February, 1985 (70.9 mph).

In 1999, PG&E Technical and Ecological Services published an updated "Extreme Wind Speed Estimates Along the PG&E Transmission Line Corridors." The report stated "Electric transmission lines throughout the PG&E service area were originally designed to withstand wind loadings of 70 miles per hour." No explanation was given as to why the original wind loading design increased from 57 miles per hour (as stated in the 1990 report) to 70 miles per hour between 1990 and 1999. Although not stated as a justification for the update, the report did note that severe storms in January, March and December of 1995 caused approximately $100 million damage to electrical transmission and distribution systems. The report mainly focused on the 500kV transmission line corridors and Bay Area, while noting a lack of wind data from the Sierra Nevada and northeastern areas. The report did include the 1984-85 wind speed data from the Rock Creek and Cresta reservoirs.

P27-122 cont.

The 1999 report included a section entitled "Santa Ana Type Winds." According to the report Santa Ana type winds occur because "High pressure frequently forms in the Great Basin area of the Rockies in the vicinity of Utah and Nevada during winter months. When pressure builds beyond a critical point, air spills through the mountain gaps, gaining momentum as it flows to lower elevations." The report recognized although mainly thought to be a Southern California phenomenon, Santa Ana type winds do occur in Northern California, mainly in the Tehachapi region near Bakersfield.

In 2015, PG&E Applied Technology Services published the "Extreme Wind Speed Estimates Across the PG&E Service Territory" report. This report updated and built upon the previous wind reports. According to the report "major wind storms" occurred in December, 2005, January, 2008, October, 2009 and January 2010. The report did not mention the December, 2012 wind event that toppled five Caribou-Palermo line towers.[137]

The 2015 wind report refers to "Offshore/Northerly Wind Events." According to the report:

[137] According to historical wind data for RAWS available at https://wrcc.dri.edu the maximum wind gust speed recorded by Jarbo Gap RAWS on December 21, 2012 was 30 miles per hour.

> These events occur when surface high pressure develops north or east of the territory, which sometimes occurs as storm systems bypass California to the north and drop southeast of the territory generally east of the Sierra Nevada. This pattern produces a northerly to easterly pressure gradient and offshore winds. When flowing downhill these winds are known as 'katabatic' winds and are also named by geographic location in some instances (e.g. Diablo, Mono).

The wind report does not recognize the Feather River Canyon/Jarbo Gap winds. The wind report does conclude:

> "The quality and precision of the data is proportional to the density of weather stations in the analysis and is generally higher in the Bay Area and Central Valley where station coverage is robust and lower in the Sierra Nevada and Coastal Ranges. Since wind speeds were produced from the RAWS in the more remote terrain in the Sierra Nevada and north and south Coast Ranges and since RAWS are more often located in more exposed terrain, the isotachs[138] … typically represent ridge top winds."

According to the report the "most notable offshore wind event in recent history occurred on November 30 to December 1, 2011, which produced katabatic winds across the Sierra Nevada and the elevated terrain of the Bay Area and Central Coast. Wind gusts from 40-60 mph were observed across the central and southern Sierra Nevada foothills…" According to historical wind data from the National Oceanic and Atmospheric Administration gusts of 66 mph were recorded at Jarbo Gap on November 30, 2011.

The report also concluded "Offshore or Northerly wind events are typically associated with extreme fire danger and can be strong enough to produce widespread damage to distribution and transmission infrastructure."

This natural phenomenon has been occurring for many years. Exponent also analyzed the wind in the Feather River Canyon. According to the Exponent Report, the Caribou-Big Bend section of the line experienced the highest average wind speed, the highest average time at high wind conditions and the highest percentage of towers that experience more than 605 hours of high wind conditions per year of the comparison transmission lines.

During its investigation, the CPUC asked PG&E if PG&E had "ever done a wind loading study" on Tower 27/222. In its written response[139] PG&E stated "A wind loading study was completed as part of the initial installation of the transmission line between 1919 and 1921" and "PG&E's understanding based on its records is that no additional wind loading studies were performed on the two towers (27/222 and 27/221) since the installation of the transmission line between 1919 and 1921. PG&E's transmission line design criteria do not require analysis on structures for which no significant work is proposed." According to the design criteria listed in PG&E's written response, the towers were designed to withstand winds of approximately 56 miles per hour. During the short period of time that wind meters were installed at the Cresta Reservoir and

P27-122 cont.

[138] An isotachs is a line on a map connecting points of equal wind speed.
[139] CPUC Data Request SED-002, Question 27.

the Rock Creek Reservoir in the Feather River Canyon, PG&E recorded wind gusts over 70 miles per hour. From 2013 to 2019 the Jarbo Gap RAWS station recorded wind gusts over 50 miles per hour over 60 times. Despite the fact the towers of the Caribou-Palermo line were routinely subjected to winds at or near their design criteria, PG&E never inspected or tested any of the towers or components for wind damage.

Based upon the meteorological data, PG&E knew that the Feather River Canyon was a drought ravaged tinderbox. Based on their own reports, PG&E also either knew or should have known the Feather River Canyon experiences katabatic winds during the fall when the fire danger is highest. Despite its own meteorological data, PG&E chose not to replace the aged and deteriorating conductor and components on the Caribou-Palermo line.

XVII. PUBLIC SAFETY POWER SHUT-OFF

On November 6, 2018, PG&E issued a Public Safety Power Shut-Off (PSPS) notice to approximately 70,000 PG&E customers in nine California counties, including Butte. The PSPS notified customers of potential de-energization of power lines on November 8, 2018, based upon meteorological forecasts. On November 6 and November 7 PG&E went to great lengths to notify customers in the nine counties of the potential de-energization[140] on November 8, 2018. On November 8, 2018 PG&E decided not to de-energize power lines.

An initial focus of the Camp Fire Investigation was the decision by PG&E not to de-energize power lines in the Feather River Canyon prior to ignition of the Camp Fire on November 8, 2018.

The PG&E PSPS Policy was enacted in September, 2018. A PSPS guide was published on the PG&E website {Attachment - Public-Safety-Power-Shutoff-Policies-and-Procedures-September-2018}in September 2018. PG&E's PSPS Policy was enacted based upon a CPUC decision in July, 2018[141] to allow electrical utilities to pro-actively de-energize[142] at-risk power lines during wind events. The PSPS guide publicly available on the PG&E website broadly described the meteorological conditions necessary for de-energization. The publicly available PSPS guide used the term "power lines" and did not differentiate between distribution and transmission lines or by voltage or area.

Based upon the meteorological data, {Attachment - Jarbo Gap Weather Station Readings} the conditions in the Feather River Canyon in the hours prior to the failure of the C hook on Tower 27/222 exceeded the wind conditions necessary for de-energization under the publicly posted PSPS guidelines.

However, the Butte County DA obtained copies of the PSPS policy filed by PG&E with the CPUC. The actual PSPS policy was much more detailed and specific than the guide published

P27-122 cont.

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[140] In layman's terms shutting off the power.
[141] CPUC Resolution ESRB-8.
[142] In layman's terms shutting off the power during high wind events to avoid fires caused by contact between energized power lines and objects such as vegetation.

on PG&E's public website. As opposed to the publicly posted PSPS guide, the official PG&E PSPS policy differentiated between transmission and distribution lines. The actual policy specifically and explicitly exempted all 115kV, 230kV and 500kV transmission lines from the PSPS. After comparing the PSPS guide published on the website with the actual PSPS policy, it appears the authors of the public PSPS guide, in an effort to make the guide understandable to the average PG&E customer, simplified the policy to an extent that became misleading.

Additionally, the transmission and distribution lines in the Feather River Canyon were not within the area of PSPS program. According to internal PG&E documents, inclusion of 115kV transmission lines in the new PSPS program was initially considered. The committee drafting the PSPS policy explored three transmission line options: 1) all 70kV and below; 2) all 115kV and below; 3) all 70kV and below and some 115kV depending upon factors such as location within high fire threat areas. Ultimately the committee settled on all 70kV transmission lines and below and exempted all 115kV transmission lines from the PSPS program. PG&E did not provide any written documents explaining or justifying this decision. However, based upon all the documents provided, there was no evidence the decision to exempt all 115kV transmission lines and above was reckless or criminally negligent. Based upon the 2018 PG&E PSPS policy, the Caribou-Palermo line was not subject to de-energization prior to the ignition of the Camp Fire and was therefore not included in any PSPS. However if PG&E had included 115 kV lines, the Caribou-Palermo line should have been included based on the extreme wind conditions in the Feather River Canyon.

P27-122 cont.

XVIII. KNOWLEDGE OF RISK/CONSEQUENCE

Internal PG&E documents show that by 2006 PG&E was aware that equipment failure (risk) causes fires. According to the October 2006 Risk Analysis of Urban Wild land Fires, written by the PG&E Enterprise Risk Management Committee, in 2005 PG&E electrical equipment failures caused 20 fires. That same document defined the Urban Wild Land Interface area as the "geographical area where structures and other human development meets or intermingles with wild land or vegetative fuels" and lists aging infrastructure as a potential "gap" in PG&E's fire mitigation efforts. Another potential gap identified by PG&E is "our asset strategy to address urban wildland fires is limited." To mitigate this potential gap the report included the following "Proposed Solutions:"

- Identify urban wildfire geographic area
- Identify quick result items such as:
  - Perform patrols/inspections just before fire season
  - Replace parallel groove (PG) connectors
  - Inspect equipment that could be high risk.

The 2009 Enterprise Risk Management Urban Wildland Fire Risk Review report written for the Executive Management Committee specifically listed as fire risk drivers:

- Failure to perform quality inspections or workmanship
- Inadequate procedures relating to fire danger
- Failure to consider local conditions in design standards

Improperly maintained equipment
Failure to replace aging equipment.

Under "Current Mitigation Activities," the report specifically listed "Equipment maintenance and replacement programs, including patrols and inspections."

These themes were repeated in Enterprise Risk Management (ERM) reports for several years.

"EMC: Electric T&D Asset Road Map," an internal PG&E document believed to have been published within the company in 2010, stated:

> "For more than twenty years, PG&E's asset management practices have focused on maximizing the utilization of T&D[143] assets and reducing capital investments to the greatest extent possible. Only recently has the Company utilized an alternate approach that places a higher value on reliability and operational flexibility of the electric T&D system. It is recommended that PG&E continue this current approach to pursue a combination of measures designed to upgrade and modernize its aging electric T&D assets."

In the section of the document entitled "Aging Assets" it is stated:

> "While much has been done in the last several years to improve the design, maintenance and operations of the system, the Company's electric T&D assets comprise an aging system that it operated close to its design capacity limits. Many of our electric T&D facilities were installed in the 1950s and planned lifetime design for these facilities is 40 years. Continuing to rely on aging facilities has increased the Utility's risk of equipment failure and extended service interruptions. Additionally, the repair time and costs for failed equipment is much higher than planned replacement."

P27-122 cont.

In December 2018, in response to questions from the Honorable William Alsup, Judge of the United States District Court, Northern District of California, PG&E submitted to the Federal District Court a list of all fires caused by PG&E 2014-2017. 2017 {Attachment – PGE caused fire 2014-17}. According to the list there were eighteen fires caused by equipment failures on transmission lines.

The list submitted to the Federal District Court did not include the 2008 Rock Fire and the 2018 Murphy Fire,[144] both of which occurred in the Feather River Canyon and both of which were caused by equipment failures on transmission lines. The Rock Fire was caused by the failure of a connector on a tower on the Caribou-Palermo line. The Murphy Fire was caused by the failure of a connector on a tower on the Caribou-Table Mountain 230kV transmission line. In both fires the failure of a connector allowed an energized jumper conductor to make contact with the steel tower structure and sent a shower of molten metal onto dry vegetation at the base of the tower.

In the 2017 RAMP, PG&E clearly identified equipment failure as a known cause of fire. According to section C of Chapter 11, Drivers and Associated Frequency, there were an average of 243 fires per year during 2015-16 causes by PG&E. Of those 243, on average 82.5 (33%)

[143] PG&E abbreviation for Transmission and Distribution
[144] The Murphy Fire occurred on August 6, 2018. The origin of the fire was directly below a PG&E transmission tower – not the Caribou-Palermo line – just west of Belden in the Feather River Canyon. The fire was caused by equipment failure – specifically failure of a connector – which allowed an energized 230kV conductor to come into contact with steel tower structure.

were caused by equipment failure. Equipment failure caused fires are broken down into Conductor (29.5 per year), Connector/Hardware (15.5 per year) and Other (37.5 per year).

The evidence clearly established PG&E has been aware of the risk/consequence connection between equipment failure and fire since at least 2005. Similarly, the evidence also clearly establishes that PG&E was aware of the risk/consequence connection between aging infrastructure and equipment failure.

In 2009 PG&E retained Quanta Technologies to review, assess and critique the electrical transmission system. In 2010 Quanta submitted to PG&E the Transmission Line Component Management Report. The report was divided into a series of individual reports. Each report focused on a component of the electrical transmission system. Not all of the reports were relevant to the risk of equipment failure on transmission towers.

Relevant individual reports and information in those reports was summarized:

Transmission Line Component Management Executive Summary

> "As part of a comprehensive effort to manage its infrastructure PG&E Transmission Asset Management has begun study of all components of transmission line infrastructure, both overhead and underground, to develop an understanding of the component behavior over its installed service life. The intent of this effort is to ultimately develop an understanding of what the expected service life of line components should be, given normal operating and maintenance practices of the service life. This understanding also drives decisions of what the "normal" operating and maintenance practices should be to allow a component to survive to an "end of service life" condition, barring external events that cause sudden or catastrophic failure of a component (e.g. severe weather event, vehicular impact)."

> "Certain aspects of a utility maintenance program can be characterized as following a "run to failure" philosophy. The practice of allowing equipment to fail often applies to utility equipment that is large in total population but low in overall impact to the system and/or customer reliability."

> "Run to failure as a maintenance philosophy has a place in the overall maintenance program of a utility. The equipment managed under this philosophy, however, is generally high volume, low risk facilities. Operational risk, technical effectiveness, and financial considerations drive the determination."

P27-122 cont.

Conductor and Fittings

> "Based on PG&E conductor inventory data, the average age of 115 kV copper conductor on the PG&E system is 75 years. Conductor other than copper at 115 kV averages 36 years of age.[145]"

> "The overall age of conductor is a concern to most utility asset managers and the concern is based primarily in lack of knowledge of what is to be expected from aging conductor."

[145] The conductor on Tower 27/222 was aluminum.

> "Greatest risk of failure in transmission conductors is thought to be with the oldest steel reinforced conductors[146]."

Insulators

> "…the failure rate of porcelain increases at a faster rate as they age beyond 50 or so years. Nonetheless, even with increasing failure rate, porcelain is only projected to a rate of 0.06 failures per at age 60."

> "Industry has come to expect a service life for porcelain and glass insulators beyond 50 years. The service life is contingent of course on the original quality and proper application of the units."

> "…lack of data consistency and accuracy result in the need for many assumptions to address data voids. Accurate information on insulator type (porcelain, glass, poly), vintage, manufacture, date of installation, and location is critical to building a dataset that will facilitate meaningful statistical analysis over the service life of the material."

Structures

> 63% of the 104 electrical utilities surveyed utilized routine climbing inspections as part of inspection policy. The average inspection period for climbing inspections was 4.2 years.

> 44.4% of PG&E 115kV structures were installed prior to 1931.

> Component service life was calculated based upon condition and environment. Environment was further divided by "Mild," "Avg." and "Severe." For "Twr attachments : Susp/Jumper." for the condition "Wear" and environment "Wind run" the component life in years is Mild – 80 years, Avg – 57 years, and Severe – 35 years.

> "With recognition of the issues associated with aging infrastructure, more attention is expected to be given to steel tower condition throughout the industry."

> "Inspection, repair, and refurbishment of steel structures and associated components (guys, anchors, foundations, etc.) are a critical part of the ongoing maintenance and management of the transmission infrastructure. Normal aging and deterioration, coupled with years of inadequate inspection and maintenance, put many structure at a point of less that desired structural integrity."

> "A comprehensive maintenance and inspection program for an aging structure population should include a diagnostic testing component, particularly when structures reach and age threshold that is appropriate. That threshold varies by many factors: geographic location and associated environmental conditions, age of infrastructure, proximity to other infrastructure, historical performance of similar vintage structures in the company, etc."

P27-122 cont.

[146] Steel reinforced conductor has a solid steel core to increase the strength of the conductor. The conductor on Tower 27/222 was steel reinforced.

> "An effective strategy for structure and foundation management would include elements such as:
>
> > Routine visual inspections by ground patrol and aerial patrol as part of general line inspection process,
> >
> > Comprehensive climbing inspection at 3-5 year intervals,
> >
> > ….
> >
> > Laboratory testing of components removed from service as part of repair or replacement work to determine overall condition and remaining strength of material."
>
> "For a population of structures and foundations such as exists at PG&E, the leading criterion for determining inspection and testing targets, would initially be age. With a structure population age span of over 100 years (according to inventory records), a programmed sampling of the population over 80 years of age to test structure and foundation integrity would be an appropriate beginning."
>
> According to Figure 9.1[147] the only structures still in use at the time of the report that were built prior to 1923 (87 years of age at time of report) were 115kV structures. According to a footnote to Figure 9.1 and subsequent figures in section 9, there are 6908 115kV structures for which PG&E has no age data. According to other PG&E reports there are 18,800 115kV structures in the PG&E inventory.

P27-122 cont.

The evidence developed during this investigation clearly establishes that PG&E essentially ignored the recommendations of the Quanta Reports. PG&E did not adopt any new policies or procedures for inspection of the oldest transmission assets. There is no evidence of a programmed sampling of the oldest structures and foundations. Even the collapse of five Caribou-Palermo line structures in 2012 did not cause PG&E to take a closer look at one of their oldest transmission assets. In 2010 the TLine Structures Committee met to review the Quanta Reports. Neither The Senior Engineer nor the former Transmission Specialist, members of the TLine Structures Committee and "Required Attendees" of the 2010 meeting, had any recollection of the alleged meeting or any recommendations regarding the Quanta Reports made by the committee. Neither was able to shed any light on the question as to why the recommendations of the Quanta Reports were not adopted. According to the Senior Director of Transmission Asset Management, who was not involved in the TLine Structure Committee at the time of Quanta Reports, the recommendations of the Quanta Reports were ignored because "we could not rely on the information in the Quanta study." The Senior Director explained:

> "The Quanta study did not look at asset data from those utilities but rather business practices from those utilities. The only age information and corresponding failure data that was used in that study was associated with the subset of assets that failed in a two-year period within PG&E and made some assumptions that made the statistical analysis incorrect. So it wasn't sufficient for us to justify significant amounts of investments in the

[147] A line graph displaying the age distribution of PG&E transmission structures.

> future, and we needed to do additional analysis in order to build the case for our regulators to be able to justify requesting authorization to be able to make additional investments in the infrastructure based on the results of that bullet point at a later date."

The Senior Director of Transmission Asset Management also stated "I didn't have high confidence in the Quanta study so we intended to do additional benchmarking and collaboration in the industry in order to come up with more robust information."

In addition to general knowledge of the problems of wear and failure in aging infrastructure, PG&E had specific knowledge that C hooks and hanger holes suffer rotational body on body wear as far back as 1987.

According to internal PG&E documents, in 1987 a transmission line crew noticed concerning wear patterns on both the C hooks and the hanger holes on the Oleum-G transmission line[148]. The transmission line supervisor removed the C hooks and hanger holes from the tower structure and sent them to the PG&E Lab for analysis. The PG&E lab evaluated the C hooks (referred to as J hooks in the report) and hanger holes (referred to as attaching plates) and issued a Laboratory Test Report on February 9, 1987. According to the report "Both of the J-Hooks and their attaching plates had grooves worn in them and there was concern that they may not be able to hold the weight of insulator strings that are suspended from them." The lab report included photographs of the C hooks and the hanger holes. Figure 1 of the report is a picture of one of the C hooks. According to the caption to Figure 1 "As shown in the Figure above a wear pattern was formed in the bowl-saddle of the J-hook. This was possibly caused by the insulator string swinging in the wind over a period of time." Figure 2 of the report is a photograph of one of the hanger holes. According to the caption to Figure 2 "This figure shows the key-hole wear in the plate eye caused by the J-hook while in service." P27-122 cont.

In 2011, PG&E transmission line crews working in the South Bay, observed similar wear on hanger holes on the Jefferson-Hillsdale transmission line. Photographs were taken of the wear and sent to PG&E engineers. After reviewing the photographs a Supervising Engineer responded via email "Looking at the photo of the hanger plate. I would recommend changing it to a new plate. It appears that there is a groove cutting into the plate probably caused by years of rubbing between the c-hook and the plate."

In March of 2018, PG&E transmission line crews working on a transmission line in the East Bay observed similar wear on hanger holes. The transmission line supervisor, removed the hanger plates from service and sent them to the PG&E Lab for review and analysis. On June 20, 2018, the PG&E Lab issued a report entitled "Metallurgical Evaluation of Insulator Suspension Plates from the Parkway-Moraga 230 kV line at structure 020/115. The report found that "the wear was attributed to wind-driven swinging of the insulators (wind-sway)." The report opined a wear rate of .007" per year and a useful life of the hanger plates of 97-100 years based upon the wear rate and the expected strength of the remaining metal.

The evidence establishes that PG&E is aware that wear increases with age, the possibility of equipment failure increases relative to the amount of wear, and, ignition of a fire is a definite

[148] The Oleum-G transmission line is located in Contra Costa County, just south of the Carquinez Bridge and near the community of Valona. The Oleum-G line is one of the segments of the original Caribou-Valona line still in service. It is believed, but not confirmed that the tower from which the C hooks and hanger holes were removed was an original, 1921 Caribou-Valona tower and the worn C hooks were vintage 1921.

possible consequence of equipment failure. It is clear, based upon the internal PG&E documents that PG&E has clearly understood, at least since 2006, the correlation between aging infrastructure and fire.

The Quanta Reports and internal PG&E reports clearly established a connection between wear and inspection/patrol. From the October 2006 Risk Analysis of Urban Wild land Fires through the 2017 RAMP inspection and patrol are specifically listed mitigation to fire threat. Since 2005 PG&E electric transmission inspection, patrol and maintenance policies are set out in the Electric Transmission Preventative Maintenance Manual (ETPM). According to section 1.2 of the ETPM "Inspection and patrol procedures are a key element of the preventive maintenance program. The actions recommended in this manual reduce the potential for component failure and facility damage and facilitate a proactive approach to repairing or replacing identified, abnormal components."

XIX. PERSONAL LIABILITY FOR PG&E EXECUTIVES

During the course of the Camp Fire investigation, many witnesses from PG&E were interviewed and examined under oath by the Grand Jury. Many, many internal discussions were had as to whether there was sufficient evidence to indict any individual PG&E personnel or executives. It was finally determined based on the current state of the law in California and the facts discovered during the investigation that there was insufficient evidence to proceed against individuals. P27-122 cont.

A. The Law:

Many people have heard of or understand the concept of "Respondeat superior" (Latin for "Let the Master answer") in which an organization's top executives are held **vicariously liable** for the actions/omissions of their subordinates regardless of the executive's personal participation or knowledge. However this is a **civil concept** that does not apply in **criminal** cases. The leading California case in the area of **corporate officer criminal liability** is *Sea Horse Ranch, Inc. v. Superior Court* (1994) 24 Cal. App. 4th 446, which states: "[A]n officer of a corporation is not criminally answerable for any act of a corporation in which he [or she] is not personally a participant. In the context of negligent homicide such an officer would be said not to be liable unless he or she was personally aware of the omissions or other behavior that gives rise to the criminal negligence. The decisions involving criminal liability of corporate officers, either expressly or impliedly, focus either on the officer's direct participation in illegal conduct, or his or her knowledge and control of the illegal behavior. **The mere fact of the officer's position at the apex of the corporate hierarchy does not automatically bestow [criminal] liability**."

B. The Facts:

Based upon the forensic analysis of the failed "C" hook from the suspect tower, it was the opinion of the experts consulted that the wear which caused the hook to break occurred gradually over almost 100 years. It is our belief the wear had been visible for at least 50 years. Over the past 50 years scores of PG&E employees should have been in a position to observe the wear. However, none of the employees documented the wear. Since nobody apparently noticed the wear, it would be impossible to prove any single person was negligent. Additionally PG&E

culture made decision-making "by committee" a standard, virtually eliminating individual responsibility. A "silo mentality" also pervaded the company in which departments and management groups did not share information, goals, tools, priorities and processes with each other. (E.g. The PG&E Tower Division took responsibility for maintenance of the steel tower structures. The PG&E Line Division took responsibility for the maintenance of the power lines. The "C" hooks seemed to fall between their two responsibilities – i.e. neither took responsibility for the hooks, assuming the other division was responsible, which left the hooks as orphan equipment.)

C. Conclusion:

Many of the decisions that ultimately lead to the Camp Fire were made in the 1980s, 1990s and 2000s. It would be almost impossible to prove a person making decisions in 1995 knew the decision was creating the risk of a catastrophic fire over 20 years later and either disregarded or ignored that risk. **But the corporation as an entity is tasked with that knowledge and reckless behavior and was so indicted.**

P27-122 cont.

XX. ELEMENTS OF THE OFFENSES

Unlawfully Causing a Fire to a Structure/Forest land (Pen Code § 452(c))

a. PG&E set fire to, or burned, or caused the burning of a structure or forest land or property;
b. PG&E did so **recklessly**;
c. The fire burned an inhabited structure or the fire caused great bodily injury to another person.

Definition of Recklessly

A corporation acts recklessly when:

a. It is aware that its actions present a substantial and unjustifiable risk of causing a fire.
b. It ignores that risk
c. Ignoring the risk is a gross deviation from what a reasonable person would have done in the same situation.

Involuntary Manslaughter (Pen. Code §192(b))

a. PG&E had a legal duty to the decedents
b. PG&E failed to perform that legal duty;
c. PG&E's failure was **criminally negligent**;
d. PG&E's failure caused the death of decedents

Definition of Criminal Negligence

a. Criminal negligence involves more than ordinary carelessness, inattention, or mistake in judgment. A corporation acts with criminal negligence when:

i. It acts in a reckless way that creates a high risk of death or great bodily injury;
ii. A reasonable person would have known that acting in that way would create such a risk.

b. In other words, a corporation acts with criminal negligence when the way it acts is so different from how an ordinarily careful person would act in the same situation that its act amounts to disregard for human life or indifference to the consequences of that act.

XXI. DUTY

On September 24, 2016, the Governor signed 2016 Cal SB 1028. SB 1028 added Chapter 6 to division 4.1 of the California Public Utilities Code. One of the newly created sections was 8386, which took effect on January 1, 2017. Section 8386 created a statutory duty on electrical utility companies. Section 8386(a) states "Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment."

California Public Utilities Code section 451, enacted in 1951 and amended in 1977, states "Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." P27-122 cont.

The California Public Utilities Commission promulgates regulations known as General Orders (GO). GO 165 section IV states "Each utility shall prepare and follow procedures for conducting inspections and maintenance activities for transmission lines."

GO 95 includes multiple rules that apply to electrical transmission line safety, including:

1) Rule 31.1
Electrical supply and communication systems shall be designed, constructed, and maintained for their intended use, regard being given to the conditions under which they are to be operated, to enable the furnishing of safe, proper, and adequate service. For all particulars not specified in these rules, design, construction, and maintenance should be done in accordance with accepted good practice for the given local conditions known at the time by those responsible for the design, construction, or maintenance of communication or supply lines and equipment.
2) Rule 31.2
Lines shall be inspected frequently and thoroughly for the purpose of ensuring that they are in good condition so as to conform with these rules. Lines temporarily out of service shall be inspected and maintained in such condition as not to create a hazard.
3) Rule 18
Each company (including electric utilities and communications companies) is responsible for taking appropriate corrective action to remedy potential violations of GO 95 and Safety Hazards posed by its facilities.

4) Rule 44.3
   Lines or parts thereof shall be replaced or reinforced before safety factors have been reduced (due to factors such as deterioration and/or installation of additional facilities) in Grades "A" and "B" construction to less than two-thirds of the safety factors specified in Rule 44.1 and in Grade "C" construction to less than one-half of the safety factors specified in Rule 44.1. Poles in Grade "C" construction that only support communication lines shall also conform to the requirements of Rule 81.3A. In no case shall the application of this rule be held to permit the use of structures or any member of any structure with a safety factor less than one.

P27-122 cont.

XXII. CONCLUSION

The evidence developed during this investigation clearly established that the reckless actions of PG&E created the risk of a catastrophic fire in the Feather River Canyon, that PG&E knew of that risk and PG&E ignored the risk by not taking any action to mitigate the risk.

The C hook that broke was at least 97 years old. The exact age of the C hook is unknown because PG&E has no record of the hook. Ninety-seven (97) years is assumed because the Caribou-Valona transmission line, of which the Caribou-Palermo line is a segment, went into service in 1921. The records from the Great Western Power Company establish the entire line was built between 1918 and 1921. There are no records of when each tower was built. It is possible Tower 27/222 was built in 1918 and the C hook had been hanging for 100 years as of November 8, 2018. The same is true of the insulator string and the jumper conductor hanging from the C hook.

PG&E also has no records, and no idea, by whom the C hook was made, and more importantly, of what type of metal and how the C hook was made. The type of metal and the process of manufacture are what determines the hardness of metal. The transposition towers were designed to allow for movement of the conductor and insulator. The fact the C hook was constantly rubbing back forth against the hanger hole was known. The concept of body-on-body wear from constant rubbing together of two metals is a long established and well known phenomenon. Also long established and well known is the fact the various hardness of the metals rubbing together plays a key role in the body-on-body wear. The fact that PG&E relied on a 97-100 year old C hook it knew nothing about to hold an energized 115kV conductor is, by itself, negligent and reckless.

It is also disturbing that PG&E's only information of the composition of the conductor running through Tower 27/222 comes from a 1922 article in an engineering journal. A conductor is the wire that carries electricity from Point A to Point B. A conductor is the most important component of the transmission system. Everything else in the transmission system is designed around the conductor. PG&E has owned the Caribou-Palermo line since 1930. Based upon the lack of records PG&E has never made any attempt to inventory and catalogue the conductor. The fact that PG&E was using a 97-100 year old conductor for which they knew almost nothing is evidence of absolute indifference on the part of PG&E.

Perhaps even more disturbing is the fact the conductor was aluminum reinforced with a steel core. 452.3 kcmil Aluminum Conductor Steel Reinforced to be exact. According to the Quanta report the average age of non-copper conductor was 36 years and the "greatest risk of failure in transmission conductors is thought to be with the oldest steel reinforced conductors" Although PG&E knew almost nothing about the conductor they did know it was at least 97 years old and made of steel reinforced aluminum. Despite this knowledge, PG&E did nothing and made no plans to replace that conductor. Even though because of updated NERC guidelines, PG&E was forced to replace conductor on some segments of the Caribou-Big Bend section, they elected to leave in place the 97-year-old aluminum steel reinforced conductor in other areas. The fact that the Senior Director of Transmission Asset Management preached the cost effective value of bundling projects but had no plans through 2022 to replace the 97-year-old aluminum, steel-reinforced conductor speaks volumes. What it says is that PG&E fully intended to run that conductor to failure. A reasonable person doesn't need an electrical engineer or Quanta Technologies to tell him that failure of an energized 115kV is extremely dangerous. PG&E's decision to leave the 97-year-old aluminum, steel-reinforced conductor in service was extraordinarily reckless.

In addition to basic engineering principles and common sense, PG&E had actual knowledge that both the C hooks and the hanger holes suffer wear and would eventually break if not replaced. At some unknown point between 1921 and 2018 somebody added the hanger plate brackets to Tower 27/222. Although there are no records of when or why the hanger plate brackets were added the only reasonable conclusion, based upon the wear observed on the original hanger holes, is somebody noticed the wear and was concerned enough to take action.

P27-122 cont.

In 1987 PG&E had absolute knowledge of the wear to both the C hooks and hanger holes. The photographs in the 1987 Laboratory Report document channeling on the C hooks and key holing on the hanger holes similar to what was found on the Caribou-Palermo line. The similarities are not surprising because the transmission line on which the C hooks and hanger holes were found, the Oleum G line, was also part of the original Caribou-Valona line. The fact PG&E chose to only perform tensile strength testing in 1987 and did not subject the hooks and hanger plates to metallurgical analysis tends to show PG&E was not concerned with the wear or the expected useful life of the hooks and holes. Although in 1987 the evidence indicated at least some action was taken based upon the observed wear on the C hooks and hanger holes, when similar wear was found on hanger holes on the Jefferson-Hillsdale transmission line in 2011 the only action taken was the replacement of the hanger plates. According to the email string a PG&E Engineer correctly surmised that this wear was "probably caused by years of rubbing between the c-hook and the plate." Based upon the reaction, or lack thereof, to the photographs of the wear it appears that the wear was neither a surprise nor was it considered a major issue by PG&E engineers.

In 2018 the discovery of keyhole wear on hanger plates on the par transmission line caused enough concern that the Transmission Line Supervisor sent the plates to the PG&E lab for analysis and evaluation. Unlike in 1987, in 2018 the lab actually did a metallurgical evaluation. A PG&E lab scientist, with a PhD in Material Science and Engineering, used the available data to opine the keyhole wear was occurring at a rate of .007 inches per year. Based upon the average wear rate, the PG&E lab scientist determined the useful life of those hanger plates to be between 97 and 100 years. PG&E now had scientific confirmation of the body-on-body wear caused by the constant movement of the C hooks within the hanger holes and had an estimate of average wear per year. Nothing was done. The report was not distributed through the company and no targeted inspections of older C hooks and hanger holes were ordered. Based upon this report, a reasonable person, knowing they had C hooks which were 90+ years old hanging in hanger holes that were 90+ years old would have taken immediate action to determine the condition of those hooks and holes. The fact PG&E did nothing is evidence of complete and absolute indifference to the inherent danger of a C hook or hanger hole breaking.

Knowledge of the danger inherent in a C hook or hanger hole breaking is firmly established in PG&E documents. Since at least 2006, PG&E has recognized bad things, especially fire, happen when equipment failures occur on transmission lines. Everything in the overhead electric transmission system is designed to keep the conductor hanging in the air and away from persons or objects it could harm. Despite this knowledge PG&E put almost no effort into ensuring the components that keep the extremely dangerous overhead transmission lines hanging safely in the air were safe. Based upon the assertions of the PG&E personnel assigned to inspect and patrol the Caribou-Palermo line, it was not possible to assess the condition of the C hooks and hanger holes from either the ground or a helicopter flying 30 to 40 miles per hour a couple hundred feet above the line. Although claims it was impossible to assess the condition of the C hooks and hanger holes from a helicopter were completely discredited by BCDA investigators, the results of the post Camp Fire "enhanced" inspections and the Exponent Report clearly establish this was not solely a Caribou-Palermo line or Table Mountain Headquarters problem. This was a systemic PG&E problem.

P27-122 cont.

During the post Camp Fire inspections, worn C hooks and worn hanger holes were found throughout the PG&E Overhead Transmission System. Despite the knowledge C hooks and hanger holes wear over time and despite the knowledge of the danger inherent in the failure of a C hook or hanger hole, the evidence clearly established nobody in PG&E was inspecting C hooks and hanger holes.

Despite the efforts of PG&E personnel to distance the company from the "Run to Failure" model, the evidence clearly establishes quite the opposite. PG&E had knowledge of the potential consequences of failure of the nearly 100-year-old C hooks, yet PG&E continued its policy of "Run to Failure."

Because nobody was looking at and assessing the C hooks and hanger holes, there were very few, if any, notifications/tags generated for worn C hooks or hanger holes. As a result, the need for replacement of C hooks and hanger holes never came to the attention of Transmission Asset Management. The lack of verified records for many of the older, acquired transmission lines made the problem worse. In large population areas PG&E was staffed by experts, trained and qualified engineers and specialists having decades of experience. In less populated areas, Transmission Line Management was almost completely dependent upon less qualified Troublemen, Linemen and Towermen and other personnel. For approximately ten years the

M&C engineer assigned to the rural northern area was not an actual engineer and had no engineering education, training or background.

Very little effort was made to audit the lack of findings of line personnel. Equipment failure related outages were repaired as they occurred and no effort was made to investigate the root cause of the failure. Transmission Asset Management essentially employed a strategy of either intentional or incompetent ignorance.

In essence, in 1930 PG&E blindly bought a used car. PG&E drove that car until it fell apart. The average reasonable person understands the basic proposition that older equipment needs more attention. A reasonable person doesn't buy a used car blindly and without at least a test drive. A reasonable person doesn't drive that used car for 200,000 miles without, at the very least, changing the oil and rotating the tires. A reasonable person has the common sense to know that service and maintenance become more important as the car ages and the miles accumulate.

This is, in essence what PG&E did. PG&E bought a used transmission line in 1930. PG&E knew next to nothing about the transmission line and made no attempt to learn about the line. PG&E ran the line for 88 years with minimal maintenance and repair. But for the Camp Fire, PG&E would have continued using the line with minimal maintenance and repair. Catastrophic failure of the Caribou-Palermo line was not an "if" question; it was a "when" question.

Although Quanta Technologies is well known and well respected in electrical utilities circles, the conclusions and recommendations of the 2010 Quanta Reports were essentially common sense findings. The basic findings of Quanta were that PG&E's infrastructure was aging and continued use required increased inspections and maintenance. According to the Senior Director of Transmission Asset Management, the Quanta Reports were discredited because of issues with tower failure data. The PG&E criticisms of the Quanta Reports may have been well founded, but the areas criticized have very little relevance to the ultimate conclusion that the transmission assets were old and needed more attention and care. PG&E obviously didn't take issue with the Quanta conclusions about the age of the transmission infrastructure. Transmission Asset Management continued to cite the Quanta age data and conclusions in subsequent internal and regulatory documents for the next seven years.

P27-122 cont.

The evidence established that despite common sense and the Quanta Report, PG&E went the opposite direction. PG&E internal emails and documents established that by 2007 PG&E was aware of the aging electric transmission infrastructure problem. Former employees of the predecessor departments to the current Transmission Asset Management established PG&E was aware of its aging electric transmission infrastructure problem by the early 1990s.

Despite its knowledge that many of its assets were built prior to World War 2 and despite its lack of knowledge of the components of acquired electric transmission lines, PG&E had consistently reduced the frequency and thoroughness of inspections and patrols on those lines. In other, more populated areas, PG&E routinely used the fact that transmission lines were built after World War 2 to justify repair and replacement.

The 2014 RIBA process demonstrated how PG&E manipulated data to achieve desired results. It is beyond reasonable comprehension that a project to replace temporary poles not expected to stand through the winter scored lower for safety than an unnecessary project proposed solely to allow PG&E to transfer money spent from the expense budget to the capital budget. The fact that PG&E minimized and, ultimately, ignored a serious safety issue is reckless and negligent. The fact that they did so in the middle of a historic drought in an area known for consistent, extreme winds, is criminally negligent.

Despite its knowledge that its transmission assets were nearing the end of useful life and deteriorating PG&E decreased the expertise of the persons doing the inspections. This pattern continued after and in spite of the Quanta Reports. This is the exact opposite of how a reasonable person would have been expected to respond. The evidence clearly demonstrated PG&E understood the relationships between age of components and wear, wear and equipment failure and equipment failure and fire, but unlike a reasonable person, devoted less time and qualified personnel to inspecting the oldest assets.

This trend continued even in the face of the devastating effects of climate change. According to data from the US Geological Survey three of the four worst droughts in the recorded history of California have occurred since 2001. PG&E risk analysis reports, both internal and regulatory have consistently identified wildfire as the number one enterprise risk since 2006. The evidence clearly established PG&E was aware of the drought and the danger of catastrophic fire by 2013. Internal PG&E documents established that in 2013 PG&E identified the Feather River Canyon as a high fire danger area. Despite its knowledge of the increasing risk, the evidence established PG&E not only did nothing to mitigate the fire risk in the Feather River Canyon, it ignored known fire dangers for years.

P27-122 cont.

Prior to 2006 PG&E had identified parallel groove connectors as a fire danger. In PG&E's 2006 "Risk Analysis of Urban Wild land Fires", the replacement of the parallel groove connectors is listed as a proposed mitigation. Unfortunately the proposal was only applied to Urban-Wildland Interface areas, which PG&E limited to the Bay Area. In the Feather River Canyon hundreds of known fire threats were left in transmission towers until 2016. Although the parallel groove connectors were ultimately replaced before causing a known fire, the fact those connectors remained in use for ten years, through two historic droughts, shows the complete disregard and indifference to the potential consequences by PG&E.

PG&E electrical transmission policies and records prior to the Camp Fire mirrored PG&E gas transmission policies prior to the San Bruno catastrophe. The investigation of the San Bruno catastrophe established that prior to the explosion, PG&E gas transmission had made very little effort to investigate and catalogue the components of the acquired gas transmission assets. Instead PG&E relied on assumed values. The San Bruno investigation also established PG&E intentionally was using the least expensive method of inspection in the least expensive manner. The chosen inspection method also saved money because problems that are not found do not need to be repaired. The investigation also established records relating to inspections, both justifying methods of inspection and the inspection reports, were fraudulent.

Somehow, the lessons of San Bruno were not learned on the electric transmission side. The evidence established that despite the lessons of San Bruno on the electrical transmission side, since 2010 PG&E has continued to rely on assumed values, the least expensive method of inspection and done nothing to ensure the veracity of inspection reports. The tragedy of San Bruno somehow had no effect on the electric transmission division. The five felonies for which PG&E was convicted changed nothing on the electric transmission side.

The philosopher George Santayana is credited with saying "Those who cannot remember the past are condemned to repeat it." By ignoring the lessons of San Bruno PG&E condemned itself to another catastrophe. Based upon its own history PG&E knew it was creating a high risk of causing a catastrophic fire but, unlike a reasonable person, chose to ignore that risk.

Because of PG&E's reckless and negligent decisions to unreasonably ignore risk, 18,804 structures, including almost 14,000 residential structures were destroyed – and 84 Butte County citizens needlessly lost their lives.

XXIII. SENTENCING

The court's sentencing options are limited. As a corporation PG&E cannot be incarcerated and PG&E has indicated that it will decline probation. The only punishment available to the court is to fine PG&E. The maximum fine for a violation of Penal Code section 192(b) is $10,000. The maximum fine for a violation of Penal Code section 452 is $50,000. Based upon the foregoing the People urge the court to impose the maximum possible fines.

P27-122 cont.

A. RESTITUTION

The People request that the court reserve jurisdiction over restitution and set a hearing in six months to review restitution in light of PG&E's bankruptcy proceedings. In the wake of the Camp Fire many civil suits were filed against PG&E by the victims of the Camp Fire. Subsequently PG&E filed for bankruptcy in the Federal Bankruptcy Court in San Francisco. All Camp Fire civil suits and claims have been transferred to the Federal Bankruptcy Court. As of December 31, 2019, it is estimated that over 90% of the eligible Camp Fire victims have filed claims in the Federal Bankruptcy Court. PG&E has entered into a settlement agreement with all claimants in the Federal Bankruptcy Court.

Based upon consultation with bankruptcy experts in the California Attorney General's Office, the People believe any restitution order issued by this court would be discharged in the bankruptcy proceedings. PG&E filed for bankruptcy under Chapter 11. A Chapter 11 reorganization produces a plan detailing how much various debts will be reduced. (11 U.S.C. § 1123(a)(3).) The plan applies to all debts that "arose before the date" of the confirmation of the plan by the bankruptcy court. (11 U.S.C. § 1141(d)(1)(A).) A debt arises at the time of the "conduct giving rise to the debt." (4 Collier Bankruptcy Practice Guide (2018) § 76.03A.)

The Supreme Court has ruled that criminal restitution qualifies as a debt for bankruptcy purposes. (See *Pennsylvania Dept. of Public Welfare v. Davenport* (1990) 495 U.S. 552, 564.) Thus, restitution may be reduced or discharged in a Chapter 11 plan unless an exception applies. An exception exists for criminal fines and restitution. (11 U.S.C. § 523(a)(7); *Kelly v. Robinson* (1986) 479 U.S. 36, 53.) But the exception applies only to "individual" debtors. (11

U.S.C. § 1141(d)(2).) And exceptions for individual debtors do not apply to corporate debtors. (See Garrie v. James L. Gray, Inc. (5th Cir. 1990) 912 F.2d 808; In re Spring Valley Farms (11th Cir. 1989) 863 F.2d 832, 834; Yamaha Motor Corp. v. Shadco (8th Cir. 1975) 762 F.2d 668, 670.) As one bankruptcy court put it, "It is almost undebateable and universally held that a corporate Chapter 11 debtor is not subject to the" exceptions that apply to individual Chapter 11 debtors. (In re Push & Pull Enterprises, Inc. (N.D.Ind. 1988) 84 B.R. 546, 548 (N.D.Ind. 1988).)

Of the exceptions that apply to corporations, none includes criminal restitution. The closest exception deals with debts owed on money or property obtained by fraud. (11 U.S.C. § 1141(d)(6).) In short, criminal restitution owed by a corporation for a crime committed before the bankruptcy petition is filed is a debt that may be reduced or discharged as part of a Chapter 11 reorganization. The one court to have considered this issue reached the same conclusion. (See In re Wisconsin Barge Lines, Inc. (E.D. Mo. 1988) 91 B.R. 65, 67-68.)

Thus, any restitution owed by PG&E to persons harmed by the Camp Fire will be subject to reduction or discharge in a Chapter 11 reorganization. Any restitution order by this court is limited in fact, if not in law, to the final order of the Federal Bankruptcy Court and this court should await the outcome of the pending Bankruptcy proceedings.

B. Factors In Aggravation

California Rule of Court 4.421 defines factors the court may consider in making a sentencing determination. Under Rule 4.421 the court may consider the following relevant factors:

(a) Factors relating to the crime

> **(1)** The crime involved great violence, great bodily harm, threat of great bodily harm, or other acts disclosing a high degree of cruelty, viciousness, or callousness;

PG&E is pleading to 84 felony counts of Involuntary Manslaughter in violation of Penal Code section 192(b) and one count of Unlawfully Causing a Fire in violation of Penal Code section 452. PG&E is also admitting Special Allegations involving Great Bodily Injury to a firefighter and two civilian victims.

The facts establish a callous disregard for the safety and property of the citizens of Butte County.

> **(3)** The victim was particularly vulnerable;

There are almost 50,000 victims of the Camp Fire. All of those people relied upon PG&E to provide safe electric power. Despite years of extreme drought, consistently high down canyon winds and the knowledge equipment failure on high voltage transmission lines can

P27-122 cont.

cause fires, PG&E ignored warning signs and did the absolute minimum to mitigate the fire danger.

The most vulnerable population were the mobility challenged and the elderly. People like Rafaela Andrade, Andrew Downer, Rose Farrell, Helen Pace, Ethel Riggs and Kimber Wehr had no ability to escape the fire. Those and other lives depended upon PG&E doing its statutory and moral duty.

> **(4)** The defendant induced others to participate in the commission of the crime or occupied a position of leadership or dominance of other participants in its commission;

PG&E, although an inchoate entity, nonetheless operates only through the actions of its employees. Through a corporate culture of elevating profits over safety by taking shortcuts in the safe delivery of an extremely dangerous product – high-voltage electricity – PG&E certainly lead otherwise good people down an ultimately destructive path.

> **(9)** The crime involved an attempted or actual taking or damage of great monetary value;

By saving money on needed maintenance, repairs, replacements was able to generate profits in the billions of dollars.

> **(11)** The defendant took advantage of a position of trust or confidence to commit the offense.

PG&E was entrusted by the People of the State of California to provide safe and reliable electricity. PG&E took advantage of that position of trust and was able to generate billions of dollars in profit.

(b) Factors relating to the defendant

> **(2)** The defendant's prior convictions as an adult or sustained petitions in juvenile delinquency proceedings are numerous or of increasing seriousness;

In 2016 PG&E was convicted of multiple federal felonies as a result of the 2010 explosion of a PG&E gas transmission pipe in the City of San Bruno. The San Bruno explosion killed eight people, destroyed 35 residential structures and damaged many additional residential and commercial structures. The felonies for which PG&E was convicted related to inspection policies, procedures and record keeping. Eight years later, as a result of similar reckless and criminal inspection policies, procedures and record keeping PG&E stands convicted of 84 counts of manslaughter.

P27-122 cont.

(4) The defendant was on probation, mandatory supervision, post release community supervision, or parole when the crime was committed;

PG&E was on federal probation on November 8, 2018. On January 26, 2017, PG&E was granted five years' probation in United States District Court, Northern District of California case number 0971 3:14CR00175-001 TEH.

(5) The defendant's prior performance on probation, mandatory supervision, post release community supervision, or parole was unsatisfactory.

Special condition of probation number 1 states "While on probation, PG&E shall not commit another Federal, State, or local crime." While on probation, as a result of policies similar to those for which PG&E was convicted, PG&E has continued to cause disasters, including the 2015 Butte Fire, the 2017 Wine Counties Fire, the 2017 Honey Fire, the Camp Fire and, most recently, the Kincaide Fire in 2019.

C. Factors in Mitigation

P27-122 cont.

a) Factors relating to the crime Factors relating to the crime include that:

(1) The defendant was a passive participant or played a minor role in the crime;

Not applicable

(2) The victim was an initiator of, willing participant in, or aggressor or provoker of the incident;

Not applicable

(3) The crime was committed because of an unusual circumstance, such as great provocation, that is unlikely to recur;

Not applicable

(4) The defendant participated in the crime under circumstances of coercion or duress, or the criminal conduct was partially excusable for some other reason not amounting to a defense;

Not applicable

(5) The defendant, with no apparent predisposition to do so, was induced by others to participate in the crime;

Not applicable

(6) The defendant exercised caution to avoid harm to persons or damage to property, or the amounts of money or property taken were deliberately small, or no harm was done or threatened against the victim;

Not applicable

(7) The defendant believed that he or she had a claim or right to the property taken, or for other reasons mistakenly believed that the conduct was legal;

Not applicable

(8) The defendant was motivated by a desire to provide necessities for his or her family or self; and

Not applicable

(9) The defendant suffered from repeated or continuous physical, sexual, or psychological abuse inflicted by the victim of the crime, and the victim of the crime, who inflicted the abuse, was the defendant's spouse, intimate cohabitant, or parent of the defendant's child; and the abuse does not amount to a defense.

Not applicable

P27-122 cont.

(b)Factors relating to the defendant Factors relating to the defendant include that:

(1) The defendant has no prior record, or has an insignificant record of criminal conduct, considering the recency and frequency of prior crimes;

Not applicable

(2) The defendant was suffering from a mental or physical condition that significantly reduced culpability for the crime;

Not applicable

(3) The defendant voluntarily acknowledged wrongdoing before arrest or at an early stage of the criminal process;

PG&E plead guilty as charged to the Indictment at arraignment.

(4) The defendant is ineligible for probation and but for that ineligibility would have been granted probation;

Not applicable

(5) The defendant made restitution to the victim; and

PG&E has agreed to restitution to victims of the Camp Fire as part of a civil settlement in the Federal Bankruptcy Court.

(6) The defendant's prior performance on probation, mandatory supervision, postrelease community supervision, or parole was satisfactory.

Not applicable

(c) Any other factors statutorily declared to be circumstances in mitigation or which reasonably relate to the defendant or the circumstances under which the crime was committed.

Not Applicable

P27-122 cont.

D. <u>Conclusion</u>

The factors in aggravation greatly outweigh the factors in mitigation. For this reason the court should impose the greatest sentence allowed under the law – the maximum fines of $10,000 for each of the 84 counts of manslaughter and the maximum fine of $50,000 for the count of Unlawfully Causing a fire.

Pacific Gas and Electric Company®

Meredith E. Allen
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September 24, 2020

Leslie Palmer
Director, Safety and Enforcement Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Dear Mr. Palmer:

As required by Resolution ESRB-8 and in accordance with Ordering Paragraph 1 of California Public Utilities Commission (CPUC) Decision (D.) 19-05-042, Pacific Gas and Electric Company (PG&E) respectfully submits a compliance report for the proactive de-energization event that was initiated on September 7, 2020 and fully restored for those who could receive power on September 10, 2020. This report has been verified by a PG&E officer in accordance with Rule 1.11 of the Commission's Rules of Practice and Procedure. P27-123

If you have any questions, please do not hesitate to call.

Sincerely,

Meredith E. Allen

Meredith E. Allen
Senior Director, Regulatory Relations

cc: Anthony Noll, SED
ESRB_ComplianceFilings@cpuc.ca.gov
EnergyDivisionCentralFiles@cpuc.ca.gov

PG&E Public Safety Power Shutoff (PSPS) Report to the CPUC
September 7-10, 2020 De-energization Event

Executive Summary

Beginning late on Monday, September 7 and lasting into Thursday, September 10, 2020, PG&E implemented a PSPS event in order to mitigate catastrophic wildfire risk presented by offshore winds combined with critically dry fuels. In total, the de-energization impacted 171,947 customers[1] in 22 counties across Northern California and a small area of PG&E's service territory to the south.

This de-energization report, required under CPUC Resolution ESRB-8, presents key information including the rationale, sequence of events, and activities for this PSPS event.[2]

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Operational elements

Consistent with PG&E's obligations to provide electric service while protecting public safety, PG&E initiates a PSPS event only as a last resort after considering many factors. Some of the many factors that affected the decision to de-energize circuits for this event included:

- PG&E Fire Potential Index (FPI) meteorology models indicated high and widespread critical fire danger and high potential for large fire growth based on dry fuels, low humidity, high wind speeds, high air temperatures, land type, and historical fire occurrences.
- Forecasted offshore wind gusts of 45-60 mph with some areas locally higher were expected to result in high Outage Producing Wind (OPW) probability, with wind-driven damages creating potential sources of ignition in tinder dry conditions following an extended period of hot weather and numerous dry lighting caused active fires statewide.
- External validation of PG&E's high-risk weather forecasts from external sources including the National Weather Service Red Flag Warnings issued across PG&E's service territory, the Northern and Southern California Predictive Services offices of the Geographic Area Coordination Centers significant fire potential outlook indicating high risk with 'wind' ignition triggers, the NOAA Storm Prediction Center's Fire Weather Outlook indicating elevated to critical fire risk across the West Coast, and escalating pressure gradients between Redding and Sacramento (a recognized precursor for most historic catastrophic fires in Northern and Central California).

PG&E activated its Emergency Operations Center near noon on Friday, September 4. Anticipated extreme fire risk weather conditions worsened as the weekend progressed and PG&E and external agency forecasts confirmed the growing fire risk with consensus. After extensive analysis and preparation, PG&E made the decision to proceed with de-energization of the identified geographic scope of the event on Monday, September 7. (See Figure 1 for PSPS event scope.) Transmission and distribution de-energizations began late Monday evening.

On Monday night and throughout Tuesday, September 8, the predicted wind events unfolded as expected with associated low relative humidity. Based on forecasts and real-time observations from networks of weather stations and field personnel observers, PG&E began declaring "all clear" for the safe start of patrol and restorations activities in localized areas starting Tuesday afternoon through Wednesday morning. The localized approach to issuing multiple all clears is with the intent to begin restoration in any areas where it is safe to do so as quickly as possible.

[1] Customers refers to active service points (meters).

[2] The analysis, data and figures in this report are based on the best and most current information PG&E has at this time and are subject to amendment as a result of additional analyses and quality control assessments following submission of the report.

Restoration

Upon the weather All Clears, PG&E used approximately 1,900 personnel and 28 helicopters to identify any safety concerns and make necessary repairs prior to restoration. PG&E had planned to utilize 60 helicopters for this event but could not do so due to unsafe flying conditions caused by smoke from major wildfires. No mutual aid resources were utilized due to the size of the event. Power was restored to customers as patrols were completed. Several circuits were inaccessible to PG&E due to on-going wildfires or access restrictions from the local fire agency, so those circuits could not be restored promptly.

PG&E was able to restore electrical service to 97% of all customers who could be safely restored on September 9, and all customers served by accessible circuits on September 10. Customers on several circuits were not able to be restored quickly because active fires hampered safe access for inspection and restoration, or because equipment damages caused by the high winds required repair before restoration. The remaining customers were restored at later dates as PG&E crews were able to gain access to the assets for patrols and restoration.

Electrical equipment damage from fire weather

During safety patrols prior to service restoration, PG&E crews discovered a total of 83 instances of wind-related damage and hazard conditions. These included:

- Damages (required necessary repairs or replacements to PG&E equipment) – 59 instances, 17 caused by vegetation and 42 caused by wind
- Hazards (conditions that might have caused damages or posed an electrical arcing risk had PG&E not de-energized) – 24 cases

These damages and hazards are shown in Figure 2 below.

P27-123 cont.

Customer elements of the PSPS event

A total of 171,947 customers were affected by the PSPS event. This included:

- 168,581 distribution customers
  - 148,675 residential, including 10,383 medical baseline
  - 18,418 commercial & industrial
  - 1,488 other customers
- 18 transmission customers including Community Choice Aggregators.

PG&E used an extensive set of tools to communicate with customers and public safety partners within and beyond the guidelines set by the CPUC (D.19-05-042). Notifications reflected the unique weather conditions and timing forecasts for the different geographic areas. Notifications were available in English and in 12 non-English languages.

- Customer notifications included PSPS Watch and Warning announcements, beginning 48 hours before the start of de-energization;
- Customer notification content was streamlined, including providing potentially impacted addresses via maps and address look-up, estimated window for the de-energization time, estimated duration of the weather event, estimated time of restoration (ETOR), and links to important resources for customers;
- PG&E successfully deployed a new, automated process for post-de-energization customer notifications that provided more accurate Estimated Time of Restoration (ETOR) based on field intelligence and automated notifications once Restoration was complete, which gave customers timely and relevant information during the event;

- PG&E's website content was clear, translated, and remained stable throughout the event, with a peak hourly hit rate of approximately 2.5 million hits on PG&E's main website on September 6 at 1900 (although the website was capable of serving over 12 million hits per hour);
- PG&E broadened in-event engagement with 37 multi-cultural media partners and over 200 Community Based Organizations (CBOs) to provide situational updates and share resources that they could use to expand our reach and translations of communications (e.g., provided a social media resource site with translated infographics that can be used by these organizations);
- PG&E supplemented use of social media (which received 2.6 million impressions) by working with Google to issue SOS alerts in impacted areas, which highlighted PSPS outage information on Google products, including alert banners in Search and Maps with references to PG&E website / available resources; and
- PG&E conducted 3 live-streamed public briefings, public official and tribal liaison briefings, and ran advertising about the PSPS event in 22 counties.

PG&E provided extensive support for Medical Baseline (MBL) customers and customers with Access & Functional Needs (AFN) during the event, including:

- Of the 10,383 MBL customers in-scope, PG&E successfully notified 10,218 MBL customers. Notification attempts included repeated automated hourly calls requesting confirmation of receipt of notifications, live agent calls and in-person visits for those that did not confirm receipt of their notifications. Starting on the evening of September 6, PG&E reached 58 MBL customers using live agent phone calls and made 1,037 physical visits to individual customers to attempt to alert them before the start of PSPS de-energization[3];
- Worked with one Meals on Wheels organization and five food banks throughout the impacted areas. Meals on Wheels completed wellness checks on 250 homebound seniors and provided an additional meal during PSPS events. PG&E reimbursed food banks that provided over 9,000 food replacement boxes for customers who experienced food loss during the event (and up to three days after the event);
- Worked in partnership with the California Foundation for Independent Living (CFILC) and CBO network to assist AFN customers during the event, including providing 174 food vouchers and 91 hotel vouchers;
- Delivered approximately 550 batteries to AFN customers before and during this event through the new Portable Battery Program and Disability Disaster Access and Resources Program.

PG&E operated 50 CRCs in 18 counties over 3 days to support customers and communities during this PSPS event.

- These included five indoor sites, 21 micro-sites (open air tents) and 24 mobile sites supported by vans, located in open spaces such as community parking lots. CRC locations were publicized by PG&E, local officials and media and CBO partners.
- Most CRCs remained open until service was restored in each host county. Seven CRCs closed early due to smoke conditions and/or evacuations and 14 remained open longer to support customers and communities facing extended fire problems.
- Overall, about 9,100 customers visited PG&E's 50 CRC locations.

P27-123 cont.

[3] Customers may have confirmed receipt of their notifications in multiple channels (e.g. automated notification and/or door knock and/or live agent calls); therefore, the counts of total attempted and successful notifications are not mutually exclusive

PG&E coordinated with local, state and tribal agencies, first responders and regulators in a number of ways, including:

- Public safety partner notifications began 72 hours before the start of PSPS de-energizations, continuing regularly throughout the event;
- Hosted regular state executive briefings (twice daily) and cooperator calls system-wide (twice daily for public safety partners), and local and tribal partners (daily);
- Provided PG&E staff liaisons (Agency Representatives, Public Information Officers and GIS Technical Specialists) to work directly with local executives and EOCs and resolve any operational issues such as CRC locations.

<u>PSPS Scope Mitigation</u>

PG&E used a variety of preparation and mitigation strategies to reduce the scope of this PSPS event, with the result that this PSPS affected approximately 50% fewer customers than the comparable de-energization that would have occurred in 2019 using the tools and mitigations available at that time. These 2020 mitigation measures included:

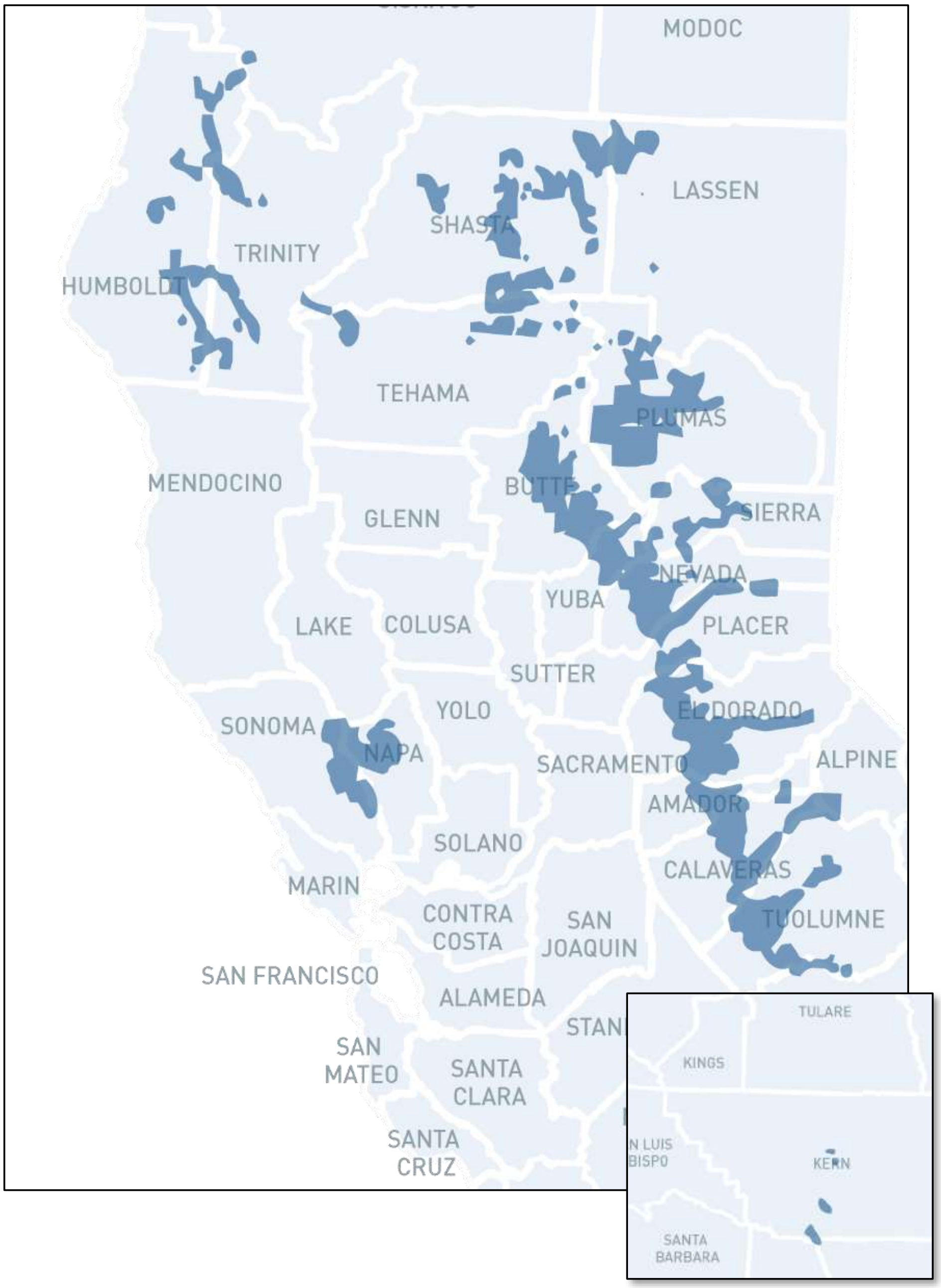
- Improved meteorology analytical tools and guidance have enabled more granular forecasting of Fire Potential Index and Outage Producing Winds across PG&E's territory, with the result that this PSPS scope affected almost 134,000 fewer customers.
- Humboldt Bay Generating Station and transmission reconfiguration enabling PG&E to isolate the Humboldt Bay plant and the 16 substations and communities around it to operate in an islanded fashion, able to support 61,000 customers who would otherwise be de-energized without transmission support.
- Use of new distribution sectionalization devices and switching to de-energize portions of circuits with more precision around the areas of risk and while keeping other portions of circuits and their customers, energized.
- Use of temporary generation at three substations and two microgrids to support almost 8,000 customers who would otherwise have been de-energized. PG&E had 56 additional substations ready to be energized[4].
- Provision of temporary generation units to provide backup power for 18 end-use customers including seven hospitals and medical facilities, three firefighter camps, and two water treatment and pumping facilities.

PG&E was able to execute this PSPS event under challenging circumstances. Command and emergency operations teams worked under remote, virtual conditions due to COVID-19. Ground crews faced operational constraints due to both physical spacing and work speed limitations associated with COVID-19 and the challenges of smoke and heat. We share the burdens of COVID-19 and adverse real-time environmental conditions with our customers, neighbors and communities and we are pleased that we were able to make this event smaller, shorter, and smarter to ease the burden and disruption of de-energization to protect public safety.

P27-123 cont.

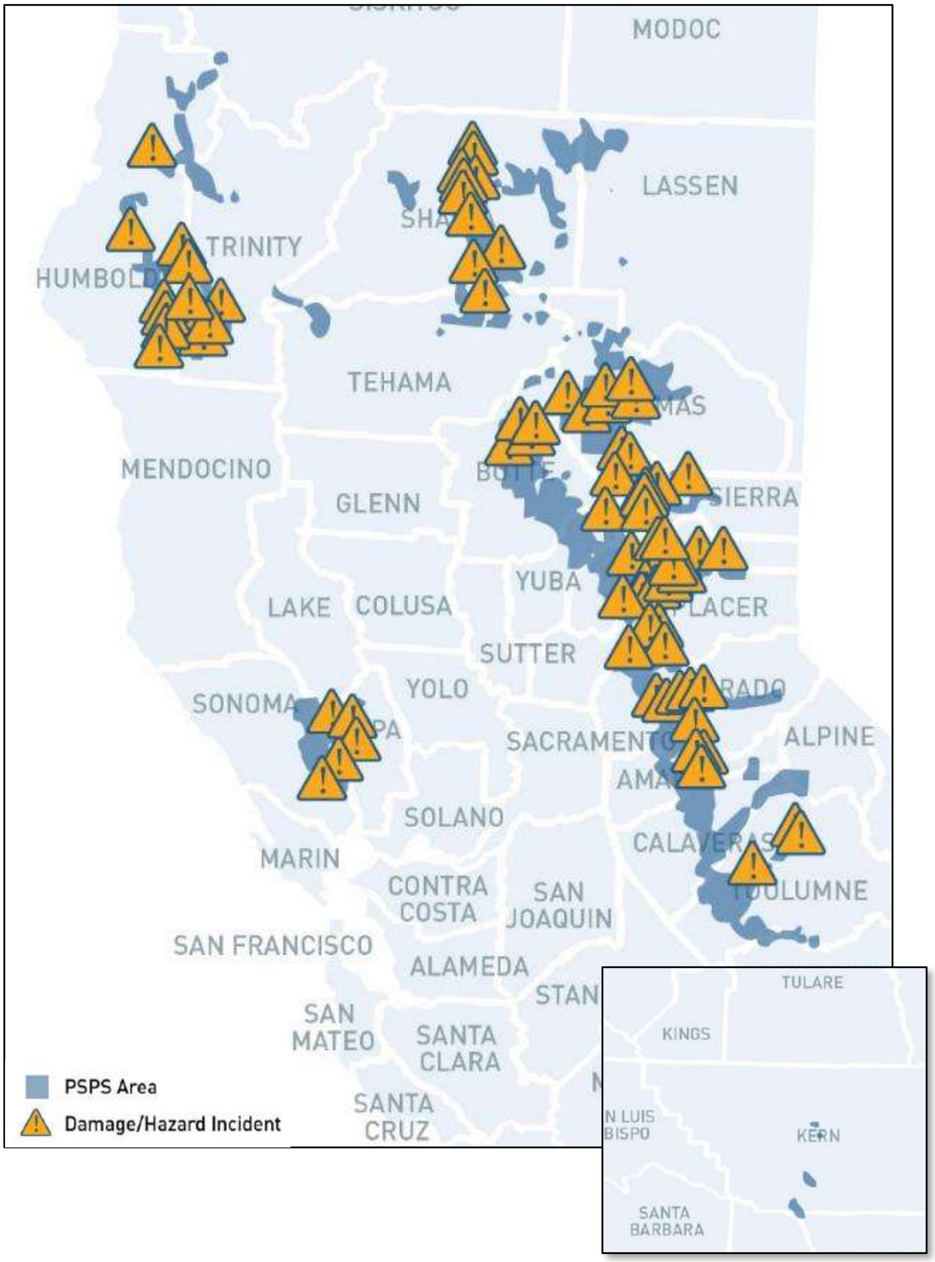
[4] Ready in this context is defined as operational within 48 hours.

Figure 1: Map of September 7-10 De-energization Footprint



P27-123
cont.

Figure 2: Equipment Damages and Hazards from the High Winds Relative to the De-energization Footprint



P27-123 cont.

Section 2 – Explanation of PG&E's Decision to De-energize

All factors considered in the decision to de-energize, including wind speed, temperature, humidity and vegetation moisture in the vicinity of the de-energized circuits.

Response:

The decision to de-energize for public safety is not based on a single factor. PG&E considers many factors, including meteorological data (which can be found at the end of this section under Detailed Meteorological Timeline) and the following factors:

- PG&E Fire Potential Index (FPI) widespread R5 ratings indicating critical fire danger and high potential for large fire growth based on fuel moisture, humidity, wind speed, air temperature, land type, and historical fire occurrences.
- Forecasted widespread gusts of 45-60 mph with some areas forecast for locally higher winds in elevated terrains.
- PG&E's Large Fire Probability (LFP) model identification of areas on both PG&E's distribution and transmission systems where there was high wind-driven outage probability combined with high probability of a large fire if an ignition were to occur.
    - On the distribution system, the Distribution Large Fire Probability Model (LFP_D) is a product of PG&E's Outage Producing Wind (OPW) model and FPI models. The LFP_D model provides hourly outputs at 2 km model resolution and highlights locations that have concurrence of an increased probability for large fires and increased probability of wind-related outages on PG&E's distribution system.
    - On the transmission system, the Transmission Large Fire Probability Model (LFP_T) is the product of PG&E's Transmission Operability Assessment (OA) model and FPI models. The LFP_T model provides hourly forecast outputs for each transmission structure. The model highlights locations that have both an increased probability for large fires and increased probability of wind-related failures on PG&E's transmission system.
- External validation of PG&E forecasts, including:
    - NWS issuance of Excess Heat Warnings followed by issuance of Red Flag Warnings, noting minimum daytime humidity of 5-15% with poor overnight recovery and Wind Advisories noting "down tree limbs and power lines possible" and "fuels are record dry!".
    - Predictive Services unit of the Northern California Geographic Area Coordination Center (GACC) 7-Day Significant Fire Potential Outlook designation of zones across Northern California as "High Risk" with Critical Burn Environment and wind Ignition Triggers and further noting, "Very dry air mass and strong N-NE winds from dry cold front following intense heat wave will bring widespread High Risk conditions to North Ops this afternoon through Wed morning" and, "Due to the extreme fuel dryness alone, large fire potential is heightened across the entire region and rates of spread/fire intensity will be significantly enhanced when ignitions occur in locations with strong winds and/or within steep terrain."
    - Predictive Services unit of the Southern California GACC 7-Day Significant Fire Potential Outlook designation of zones in the southern portion of PG&E's territory as "High Risk" with Critical Burn Environment and wind Ignition Triggers and further noting, "There will also be a high risk for large fire due to strong offshore winds and single digit humidity across all of Southern California from the mountains westward Tuesday afternoon through Wednesday afternoon" and, "Dead fuel moisture will be extremely low through this weekend and records will be set."

P27-123 cont.

- The National Oceanic and Atmospheric Administration's (NOAA) Storm Prediction Center's Fire Weather Outlook indicating widespread Elevated and Critical fire-weather conditions across California
- Pressure gradients between Redding and Sacramento escalating in magnitude from 4mb to 8mb, indicating increased strength of northly winds, along with pressure gradients between San Francisco and Winnemucca around -16mb, exceeding levels of concern and indicating strong easterly component; ensembles indicated increased certainty as the event neared
- Current wildfire activity across the state including the Lightening Complex Fires, Oak Fire, August Complex Fire, Hobo Fire, Red Salmon Complex, North Complex and Creek Fire and noting containment levels and proximity of active fires to planned de-energization scope

- Additional transmission line assessment, including:
  - Based on the foundation of PG&E's LFP_T model for transmission, each transmission line within or traversing the weather footprint is assessed based on localized meteorology data, probability of failure using structure level asset data, consequence measures of the impact of a potential wildfire, vegetation risk based on spatial attributes from LiDAR (e.g., tree height, slope, aspect, outage history, front row), open high priority repairs, and idle line status. As a result of the transmission asset analysis, select transmission lines were determined to be below risk thresholds based on the forecasted weather conditions and, therefore, the risk reduction benefit of de-energizing these lines did not outweigh the risk to public safety. These lines were approved to stay in service to minimize customer impacts. The lines deemed to be at a higher risk of catastrophic wildfire remained in scope
  - Further, a Power Flow Analysis is conducted in coordination with the California Independent System Operator (CAISO) on the in-scope transmission lines to analyze any potential downstream impacts of load shedding, coordinate with California Independent System Operator (CAISO), and confirm solution feasibility with Transmission System Protection.
- The public safety impacts of de-energizing were considered through understanding of the total count of impacted customers, including the impact on medical baseline customers, critical facilities, back up generation capabilities of critical facilities that pose societal impact risks if de-energized (e.g., critical infrastructure), and generating capabilities via back up power or advanced switching solutions for

P27-123 cont.

An explanation of the decision to de-energize, including an explanation of alternatives considered and mitigation measures used to decrease the risk of utility caused wildfires in de-energized area

Response:

In light of the meteorological information indicating the potential for catastrophic wildfire and the customer impacts from mitigating that risk through de-energization, PG&E considered whether alternatives to de-energizing, such as additional vegetation management and disabling automatic reclosers, could adequately reduce the risk of catastrophic wildfire to obviate the need for de-energization.

- Hazard tree mitigation efforts on PSPS potentially affect circuits were ongoing in the days leading up to the event and remained in progress up through the day of de-energization.
- Pre-patrols of impacted facilities were also ongoing in the days leading up to the time of de-energization.
- Automatic reclosing had been disabled in Tier 2/Tier 3

- All SIPT crew resources were deployed for real-time observations and fire response

Given the forecasted high windspeeds which have the potential for vegetation/flying debris coming in to contact with power lines, it was determined that these other measures were not adequate alternatives to mitigate the risk of catastrophic wildfire, and that the shutting off of power was necessary to do so.

Further, PG&E reviewed the efforts to mitigate adverse impacts on the customers and communities in areas where power shutoffs were likely. These efforts included:

- Advanced notifications to impacted customers
- Community Resource Centers
- Temporary generation solutions to reduce and mitigate customer impacts
- Sectionalizing to reduce customer impacts
- Restoration crew readiness for patrols and restoration upon the weather clearing

An explanation of how the utility determined that the benefit of de-energization outweighed potential public safety risks

Response:

Based on the protocols and factors described in this section, PG&E determined there was an imminent and significant risk of strong winds impacting PG&E assets, and a significant risk of large, catastrophic wildfires should ignition occur. PG&E determined alternatives to de-energization were not adequate to reduce this risk and that the public safety risk of catastrophic wildfire outweighed the public safety impacts of the proposed de-energization scope. In making this decision, PG&E reviewed of all steps that had been taken or that were in progress to mitigate adverse impacts on customers. PG&E determined that a PSPS was warranted and necessary to reduce the risk of catastrophic wildfire for public safety by mitigating the risks of a catastrophic wildfire and approved the decision to de-energize. P27-123 cont.

Additional Information - Detailed Meteorological Timeline

Wednesday, September 2: External agency forecast discussions monitored by the PG&E Meteorology team noted the following.

- The NWS San Francisco/Monterey 03:25 PST area forecast discussion began to highlight the potential for north to northeast winds Monday night into Tuesday.
- The North Ops Predictive Service office in Redding issued their 7-day Significant Fire Potential Forecast at 07:45 PST, highlighting warmer conditions, 15-20 degrees above average Sun- Tues (Sept 6 -8), with Relative Humidity (RH) of 5-15% with only 20-40% nighttime recovery; no high risk triggers were indicated for the potential event timing. The North Ops office noted in discussion that one forecast model was indicating a chance of a moderate N-NE wind event for Mon-Tue.
- On the North Ops interagency call at 08:45 PST call with the NWS offices in their jurisdiction, the Sacramento NWS noted that 30% of their models were indicating the chance for a northerly wind event early next week (Sept 7, 8, 9). NWS Monterey said there was a possibility of a headline in the fire weather forecast that afternoon, and worried about the potential for the “inside slider” that could increase fire weather concerns over the North Bay Hills. There was consensus on the call of significant concern over any offshore winds directly following a significant heat wave expected to unfold in the coming days.

- At 14:07 PST Sacramento NWS office began mentioning the potential for a northeast wind event in their forecast discussion, and the need to keep an eye on model runs considering how dry fuels will be following a significant heatwave.
- At 14:21 PST, Sacramento NWS introduced the potential for elevated fire concerns with north winds early next week.

Global model runs continued to show major discrepancies in the forecast, with the American, Global Forecast System (GFS) showing no event, and the European model (ECMWF) indicating a legitimate possibility for an offshore wind event that could lead to a possible PSPS.

PG&E's 7 Day Public Safety Power Shutoff (PSPS) Potential forecast was issued noting that while strong winds were not anticipated at the time, the forecast would need to be closely monitored for escalation as more data became available; the PG&E forecast also noted the presence of significantly dry fuels, particularly on the heels of the heatwave, increasing the risk for fire weather concerns

Thursday, September 3: External agency forecast discussions monitored by the PG&E Meteorology team noted the following.

- The San Francisco Bay NWS office 03:49 PST area forecast discussion highlighted the weekend heatwave and coordination to issue an excessive heat watch. It also noted the latest two operational runs of the ECMWF continued to show a late fall pattern with the upper level low dropping east of the forecast area, setting up an offshore wind event. They noted forecast confidence was low but the uncertainty of the event required monitoring as the transition was coming on the heels of the heatwave. Their timing of concern was late Monday into Tuesday.
- The 04:51 PST Sacramento NWS office Fire Weather Planning Forecast continued to mention elevated wildfire concerns for Monday-Tuesday.
- The San Francisco/Monterey NWS office did not mention any risk in the planning forecast on September 03.
- The North Ops Predictive Services published their 7-day Significant Fire Potential Outlook at 07:50 PST, with no area high risk triggers, and continued moderate risk service area wide.
- On the North Ops 08:45 PST coordination call with the NWS offices in their jurisdiction, North Ops mentioned models were picking up the upper level low dropping more, and that historically this set-up could provide lower RHs than models suggested. Sacramento, Monterey/San Francisco, Eureka, and Western Region NWS were all unanimous in watching the inside slider, but highlighting model uncertainty.

P27-123 cont.

During the afternoon, the warning coordination meteorologist from Monterey NWS reached out to PG&E Meteorology to collaborate on what each office was seeing. Both offices agreed that there were major discrepancies in the global models, but it could be a very concerning situation if offshore winds developed with fuels critically dry and existing fires still burning.

PG&E's 7 Day PSPS Potential forecast continued to show no escalation in the territories' geographic zones, but made further mention similar to agency partners that the event was being shown in some models and required close monitoring on the heels of the heatwave.

Friday, September 4: External agency forecast discussions monitored by the PG&E Meteorology team noted the following.

- The San Francisco Bay Area and Sacramento NWS offices' area forecast discussions mentioned the potential for issuing a Fire Weather Watch for Monday and Tuesday due to hot temperatures, drying fuels, and the potential for an offshore wind event.
- The Sacramento NWS 03:25 PST Fire Weather Planning Forecast indicated north to east winds late Monday night into Wednesday evening, bringing elevated fire weather concerns.

- The San Francisco/Monterey NWS offices' Fire Weather Planning Forecast was issued at 04:51 PST, highlighting a possible light-moderate offshore wind event Monday night into Tuesday for the North Bay and East Bay Hills.
- The North Ops Predictive Services office published their 7-day Significant Fire Potential Outlook at 06:56 PST, highlighting High Risk days with fire risk triggers due to winds in zone areas NC02 (Tue/Wed), NC04 (Tue/Wed), NC05 (Tue/Wed), NC06 (Mon/Tue/Wed), NC07 (Tue/Wed), NC08 (Mon/Tue). The associated discussion had a headline and high confidence for, "High Risk East and Central areas Mon night thru Wed due to Dry Cold Frontal Passage," noting unusually dry dead fuels, gusty winds, and low RH in these areas.

PG&E meteorologists issued the PG&E 7 Day Public Safety Power Shutoff (PSPS) Potential forecast, continuing to highlight the risk for an offshore flow event leading to PSPS and noting that a potential forecast update later in the day could indicate a change in PSPS status once the first PG&E Mesoscale Modeling System (POMMS) high-resolution model covering the early portion of the event becomes available. As expected, an updated PG&E 7 Day Public Safety Power Shutoff (PSPS) Potential forecast was issued with the forecast updated to 'Elevated' in geographic zones 2, 3, 4, 5, 8 and 9 indicating potential for a PSPS event 4 days away. The forecast discussion stated, "Confidence is increasing regarding a potential offshore wind event developing overnight Monday night and continuing through Wednesday. The PSPS Potential Forecast is now showing Elevated for Zones 2, 3, 4, 5, and 8 Tuesday and Wednesday with Zone 9 in Elevated on Wednesday. The start of the event is still 4 days away, so magnitude and location of the event is still uncertain at this time." PG&E Meteorology continued to evaluate incoming data from the high-resolution POMMS model and other weather models, and later that evening, issued another PG&E 7 Day Public Safety Power Shutoff Potential forecast update to 'PSPS Watch' in Geographic Zone 2, 3, 4, 5, 8, and 9 as confidence had increased in the forecast.

Overnight, PG&E Meteorology reviewed the latest high-resolution model data and received the first model run results with its forecasting period extending through the full duration of the event. Using this model run, PG&E Meteorology was able to draft the first fully-informed PSPS scope. P27-123 cont.

Saturday, September 5: External agency forecast discussions monitored by the PG&E Meteorology team noted the following.

- The San Francisco/Monterey NWS issued an area forecast discussion at 03:35 PST mentioning, "gusty offshore winds are possible locally in the hills starting Monday evening. A Fire Weather Watch has been issued for the North Bay Mountains, East Bay Hills from Monday evening through Wednesday morning." The office's Fire Weather Planning Forecast echoed the concern for the event, noting the possibility for an offshore wind event mainly focused over the North and East Bay Hills.
- The Sacramento NWS issued the Fire Weather Planning Forecast at 03:10 PST, and like San Francisco/Monterey NWS, advertised a Fire Weather Watch Monday night through Wednesday morning due to gusty northerly and easterly winds and poor humidity values. The office followed up with the 04:35 PST Area Forecast Discussion, also noting, "Critical fire weather concerns late Monday night through early Wednesday," and noted that the Fire Weather Watch is in effect from Monday evening through Wednesday morning.
- The North Ops Predictive Services office published their North Ops 7-day Significant Fire Potential Outlook at 07:28 PST, warning of high risk fire triggers due to wind in zone areas NC02 (Mon/Tue), NC03A (Mon), NC03B (Mon/Tue), NC04 (Tue), NC05 (Mon/Tue/Wed), NC06 (Mon/Tue), NC07 (Tue/Wed), and NC08 (Mon/Tue).
- On the North Ops 08:45 PST interagency coordination call with the NWS offices in their jurisdiction, most offices felt the forecast was on track. Monterey noted that they were anticipating the high-resolution WRF runs would provide a better understanding.

PG&E Meteorology issued the PG&E 7 Day PSPS Potential forecast with continued 'PSPS Watch' in Geographic Zones 2, 3, 4, 5, and 8 for Tuesday and Wednesday, and Geographic Zone 9 on Wednesday.

Overnight, PG&E used the most recent high-resolution POMMS model run to revise the PSPS scope. Based on this model run and the model runs that had been monitored and evaluated throughout the day, the revised scope incorporated small shifts in the model data relative to PSPS guidance thresholds, with reductions in some areas and additions in others.

Up until this point in time, operational models had remained relatively consistent with the strength of the system, with most models concurring that the Redding to Sacramento pressure gradient would peak near 4mb during the event.

Sunday, September 6: PG&E Meteorology continued to monitor the possibility of an offshore wind event on the 8th and 9th. The PG&E 7 Day Public Safety Power Shutoff (PSPS) Potential forecast continued to include Geographic Zones 2, 3, 4, 5, and 8 for Tuesday and Wednesday, and Geographic Zone 9 on Wednesday.

External agency forecast discussions monitored by the PG&E Meteorology team noted the following.

- The North Ops 7-day Significant Fire Potential Outlook forecast continued to include High Risk with wind ignition triggers for the September 7-9 timeframe for most areas across Northern California.
- The NWS Storm Prediction Center (SPC) issued a Day 2 Fire Weather Outlook with elevated to critical risk covering most of the PG&E territory.
- On the North Ops interagency coordination call with the NWS offices in their jurisdiction, the NWS offices mentioned upgrading Fire Weather Watches to Red Flag Warnings through the day. There was consensus that the latest weather models trended the trajectory of the upper level weather system farther west, which would increase the wind strength.

The September 6 1200 UTC ECMWF operational weather model results showed significantly increased strength of the incoming weather system. This was the third model run in a row indicating an upward an increased trend in system strength. For example, over the prior 36 hours, the forecasted peak Redding-to-Sacramento pressure gradient had nearly doubled from ~4mb to ~8mb. The ECMWF ensemble showed much decreased uncertainty around the event, providing more confidence that the stronger solutions would materialize.

P27-123 cont.

Through the day, other forecast models such as the GFS trended stronger as well. PG&E Meteorology communicated these changes into the EOC and indicated that the next scope of the event, which could be created based on the upcoming overnight model run, would likely increase due to a very late ramp-up from the weather models.

As expected, a new scope was produced overnight to capture expanded and increased risk of strong winds producing risk of outage activity (potential sources of ignitions) along with high FPI (i.e., increased probability of large fires) based on the recent and consistent strengthening trends shown in global and PG&E POMMs weather model data. Along with expansion to include lager portions of the Central and Northern Sierra and pockets of Humboldt, Trinity and Sonoma Counties, a new area of risk (i.e., Time Place) introduced to scope for the area north and east of Shasta Lake.

Monday, September 7: Meteorology continued to monitor both global and high-resolution forecast models for any run-to-run changes.

External agency forecast discussions monitored by the PG&E Meteorology team noted the following.

- The Sacramento, Bay Area and Eureka NWS offices all had Red Flag Warnings in place across much of Northern California through September 9 for gusty winds and low RH.
- The North Ops 7-day Significant Fire Potential Outlook forecast continued to advise High Risk for wind and mentioned, “Very dry air mass and strong N-NE winds from dry cold front following intense heat wave will bring widespread High Risk conditions to North Ops this afternoon through Wed morning.” All zones were included as High Risk for September 8 and all but NC01, NC03A, NC06 and NC08 for September 9.

- The NWS Storm Prediction Center forecast showed elevated to extreme fire weather conditions for vast portions of PG&E's territory.

At this point in time, over 3.8 million PG&E customers were covered by the North Ops footprint and more than 1.3 million PG&E customers were covered by the NWS RFW footprint.

In the afternoon, based on the latest weather forecast model information, observations, and agency forecasts, PG&E made the decision to move forward with de-energizing the recently expanded scope of the PSPS event, which had been localized to cover approximately 172,000 PG&E customers.

PG&E's 7 Day PSPS Shutoff Potential forecast was updated to 'PSPS Warning' in Geographic Zones 1, 2, 3, 4, 5, 8, and 9 for September 8 and 9.

Overnight, as phased and localized de-energization start times approached, PG&E Meteorology met with the PG&E EOC Incident Commander on an ongoing basis to review the latest weather model intel and confirm that conditions within the PSPS scope had not changed.

<u>Tuesday, September 8:</u> A strong offshore wind event unfolded mostly as expected and PG&E Meteorology continued to monitor observed weather conditions, review updated forecast models and track potential times to declare "All Clear" in localized areas when the weather would subside, making it safe to be begin patrols and restoration. times.

PG&E issued the PG&E 7 Day PSPS Potential forecast with 'PSPS Warning' maintained in the same areas.

PG&E participated in conference calls hosted by North Ops and attended by National Weather Service offices from across California. There was agreement that the forecast remained on track for gusty winds and low relative humidity to continue into the morning of September 9th, but the most critical period would be the morning of September 8.

External agency forecast discussions monitored by the PG&E Meteorology team noted the following.

- RFWs from multiple NWS offices remained in place across northern California through the morning of September 9.
- The North Ops 7-Day Significant Fire Potential Outlook continued to advertise High Risk with a wind ignition trigger with no change in areas or timing.

Near 1430 PST, improved meteorological conditions observed through weather stations and forecast model data indicating fire risk weather would not return indicated that it was safe to declare the "All Clear" for patrols and restorations in portions of the Humboldt and southern Sierra areas of the PSPS scope.

During the evening and overnight, meteorology continued to brief the EOC Incident Commander on a regular cadence. Additional "All Clears" were issued for the majority of the event scope overnight.

<u>Wednesday, September 9:</u> PG&E continued to monitor weather conditions and supported the "All Clear" decisions for the final areas of the de-energization scope throughout the morning with the final "All Clear" issued just before noon.

Meteorological forecasts indicated no return of strong wind events over the next week. The Public 7-day PSPS forecast was adjusted to 'Not Expected' for all zones and stated, "North-northeast winds have subsided and will continue to diminish through the day. The all clear has been given for crews to begin patrolling and re-energizing lines in all areas."

NWS RFWs remained in effect at that time, but we're allowed to expire later in the day.

P27-123 cont.

<u>Section 3 – Time, Place, and Duration</u>

The time, place and duration of the event and whether the areas affected by the de-energization are classified as Zone 1, Tier 2, or Tier 3 per the definition in General Order 95, Rule 21.2-D.

Response:

In summary, the PSPS event occurred over the timeframe of September 7, 2020 – September 10, 2020 including areas of the Sierra Nevada, Humboldt region, North Bay and Kern County.

Appendix A lists circuits de-energized along with the following for each circuit:

- Communities served
- De-energization date / time
- Restoration date / time
- General Order (GO) 95, Rule 21.2-D Zone 1, Tier 2, or Tier 3 classification,

P27-123 cont.

Section 4 – Affected Customers

The number of affected customers, broken down by residential, medical baseline, commercial/industrial and other.

Response:

A total of 171,947 customers were impacted[5] during the PSPS event. The total amount of customers impacted includes approximately 7,600 customers who were powered by microgrids during the event. Of the customers on microgrids approximately 3,300 did not experience an outage. The total impact number does not include the approximate 61,000 customers served by the Humboldt Generating Station which were effectively "islanded" and thus not impacted by the PSPS event.

Of the customers impacted, a total of 168,581 distribution customers were de-energized (this total does not include the 3,348 microgrid customers who did not experience an outage), including 148,675[6] residential, 10,383 medical baseline, 18,418 commercial/industrial, and 1,488 other customers. A total of 18 transmission customers were impacted.

Appendix A lists circuits de-energized along with the following information for each circuit:

- Total number of customers affected
- Residential customers affected
- Medical Baseline customers affected
- Commercial/industrial customers affected
- Other[7] customers affected

P27-123 cont.

[5] Impacted customers include customers who experienced short outages due to microgrid switching as well customers who were on microgrids who did not experience an outage due to temporary generation.

[6] 'Residential' customers include Medical Baseline Customers

[7] 'Other' includes customers that do not fall under the residential or commercial / industrial categories such as governmental agencies, traffic lights, agricultural facilities, and prisons.

Section 5 – Damage to Overhead Facilities

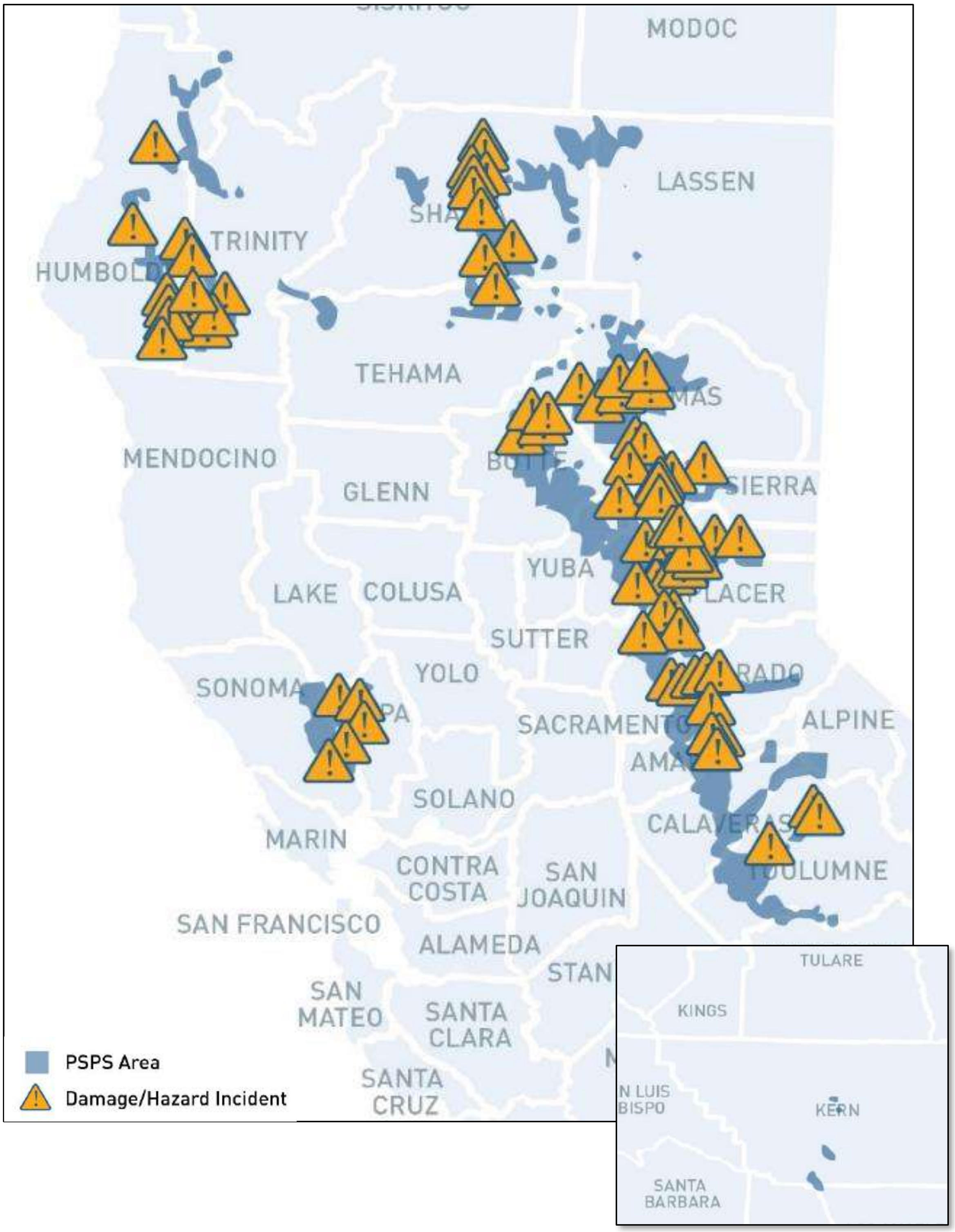
Describe any wind-related damage to overhead powerline facilities in the areas where power was shutoff.

Response:

During safety inspections and patrols of the de-energized circuits prior to restoring power, PG&E discovered a total of 83 instances of wind-related damage or hazard issues. Damages are conditions that occurred during the PSPS event, likely wind-related, resulting in necessary repairs or replacement of PG&E's asset, such as a wire down or fallen pole. Hazards are conditions that might have caused damages or posed an electrical arcing risk had PSPS not been executed, such as a tree limb found suspended in electrical wires. In each case of damage, PG&E repaired or replaced the damaged equipment prior to re-energizing. Hazards were cleared prior to re-energizing. P27-123 cont.

- 59 cases of damages
  - 17 damage cases where vegetation was identified as the cause
  - 42 damage cases of wind-caused asset damage
- 24 cases of hazards

Figure 3: Map of September 7-10 Damage/Hazard Incidents Overlaid on De-energization Footprint



P27-123 cont.

Figure 4: Image of Vegetation Related Damage in Nevada County – Falling Treetop Damaged Primary Overhead Conductor and Broke Crossarm

Figure 5: Image of Veg Related Hazard in Sierra County – Tree Branch Caught in Multiple Overhead Phases

Figure 6: Image of Veg Related Damage in Shasta County – Fallen Tree That Caused Two Primary Overhead Wires Down

P27-123 cont.

Section 6 – Customer Notifications

Provide a description of the customer notice and any other mitigation provided by PG&E. Include a copy of all notifications, the timing of notifications, the methods of notifications and who (IOU or public safety partner) made the notification. If PG&E failed to provide notifications according to the timelines set forth in the CPUC PSPS Guidelines (see D.19-05-042), include an explanation of the circumstances that resulted in such failure.

Response:

A description of customer notice, including explanation of failures to provide notifications according to the timelines set forth by the CPUC PSPS Guidelines (see D.19-05-042) is provided below. A summary of additional communication measures and channels are also summarized. A copy of all notifications including timing and method is provided in Appendix B. A copy of the notification messages is included in Appendix C.

Notifications

Leading up to and during PSPS events, PG&E sent automated notifications via call, text and email to Public Safety Partners and impacted customers in accordance with timelines set forth by the CPUC PSPS Guidelines (D.19-05-042) in relation to the unique forecasted weather timing for different geographic areas. Notifications sent prior to de-energization included the following information: potentially impacted addresses, estimated window the de-energization time, estimated duration of the weather event, estimated time of restoration (ETOR),[8] links to resources for customers (e.g., PSPS updates webpage with CRC information, resources for customers with access and functional needs). Notifications were provided to customers in English, and they included a way to get event information in 12[9] non-English languages. Customers with their language preference set received in-language (translated) notifications. P27-123 cont.

For each automated notification sent to non-Medical Baseline customers, two additional retries are commenced in 10-minute intervals. For Medical Baseline customers, PG&E continues issuing notifications every hour until confirmation of the notification is received (up to 9 p.m. or when PG&E suspends).

Below describes PG&E's notifications sent to customers for this event.

Advanced Public Safety Partner Notifications: 72-48 hours prior to PSPS

- Around 0900 on Saturday, September 5, PG&E sent Advanced notification messages to approximately 1,300 Public Safety Partners.
- In an effort to provide all other affected populations notice earlier than the 48-24 hours prior to de-energization guideline, PG&E intended to send notice to the approximately 103,000 customers known to be impacted at that time at around 2000 on September 5. However, PG&E's notification vendor encountered a file processing issue resulting in only a portion of the 103,000 notifications being sent. To avoid sending notifications in the middle of the night, the

[8] The initial ETOR provided to customers prior to de-energization is based on the forecasted timing of the end of the weather event and PG&E's goal to restore power within 12 daylight hours of weather clearing.

[9] Spanish, Chinese (Mandarin and Cantonese), Vietnamese, Tagalog, Korean, Russian, Arabic, Punjabi, Farsi, Japanese, Khmer and Hmong.

notifications were not re-attempted when the issue was determined, but sent the next morning around 0900 on September 6. [10,11]

Advanced Watch Notifications: 48-24 hours prior to PSPS

- Around 1800 on Sunday, September 6, PG&E sent Watch notification messages to the approximately 102,500 impacted customers based on the scope known at that time. From the previously notified population of approximately 103,000 customers, this population included a reduction of approximately 36,700 customers removed from scope based on changes in weather, and an addition to scope of approximately 36,200 customers based on the completion of initial Transmission impacts.

Advanced Watch Notification: < 24 hours prior to PSPS

- Around 0900 on Monday, September 7, PG&E sent Watch notification messages to approximately 66,000 new customers identified to be in scope based on weather changes increasing the event size overnight.
- Cancellation notifications were also sent to customers removed from scope. Customers served by a microgrid were also notified they may have a short duration outage while switching takes place to enable them to be served by a microgrid.

Advanced Warning Notification: Imminent

- Around 1900 on Monday, September 7, PG&E sent Warning notifications to the event's total customer impact of approximately 172,000 customers prior to their de-energization overnight. The 172,000 total impacted customers included the aforementioned scope increase due to weather changes as well as additional impacts identified through the completion of the Transmission Power Flow Assessment.
- A second Warning notification was sent to Kern county customers on the morning of 9/8 as their de-energization was planned for later that day.

P27-123 cont.

[10] Out of courtesy to our customers, PG&E intends to avoid sending notifications to customers overnight. On a case-by-case basis PG&E, however, may send notifications during these hours if we determine there is a need.

[11] PG&E requested root cause and corrective action assessments from the vendor and worked with the vendor to ensure similar issues were not encountered again during the event and in the future.

Table 1: Customer Notification Timeline Summary Prior to De-Energization

Minimum Timeline	Approximate Time	Approximate Notifications Sent[12]	Message	Notes
72-48 hours	9/5 0900	1,300 public safety partners	Advanced	PG&E sent advanced notifications to Public Safety Partners identified to be impacted at the time.
	9/5 2000 9/6 0900	103,000 customers + 500 local community representatives	Watch	PG&E attempted to send early notification to all impacted populations prior to the required 48-24 hour minimum timeframe, however, PG&E's notification vendor encountered an issue resulting in only a portion of the 103,000 intended notifications going out that evening; To avoid sending notifications overnight, notifications were re-sent in full the next morning around 0900 on 9/6.
48-24 hours	9/6 1800	102,500 customers + 450 local community representatives	Watch	Notification of approximately 102,500 customers known in scope at this time included a reduction of ~36,700 customers from weather changes and an increase of ~36,200 customers from transmission impacts since the last notified population of ~103,000 customers.
< 24 hours	9/7 0900	66,000 customers	Watch	Weather changes expanding the scope of the event came in overnight from 9/6 to 9/7; The 66,000 incremental customers added to scope were sent Watch notifications on the morning of 9/7; Scope of weather expanded overnight and identified as of the morning of 9/7; These customers were sent a watch notification to these net new customers upon their identification.
Imminent	9/7 1900	172,000 customers + 600 local community representatives	Warning	Warning notifications were sent to the final scope of 172,000 impacted customers prior to overnight de-energization; Final scope included increased impacts from weather expansion and results of the Transmission Power Flow Analysis.
	9/8 1400	600 customers	Warning	A second Warning notification was sent to customers impacted in Kern county prior to their de-energization on 9/8.

P27-123 cont.

[12] Includes unreachable customers with no contact information; Counts of approximate customer notifications include public safety partner customers of record and all affected populations; Local community representatives contacted cover public safety partner notifications sent through PG&E's agency notification system; All values are approximate.

De-Energization Initiated: Warning / Imminent Notification:

PG&E sent Imminent notifications (referred to as "Warning" notifications) to customers when forecasted conditions showed that a safety shutoff was confirmed, and that it is going to happen soon. Whenever possible, Warning notifications are sent approximately four to 12 hours in advance of the power being shutoff, which serves as PG&E's De-Energization Initiated notifications. In these notifications, customers see an estimated time when their power will be shut off and the estimated times power is expected to be restored.

Restoration in Progress: All Clear Notification

PG&E plans to send automated notifications to customers when their area is declared all clear to safely begin patrols and restoration. However, this automation enhancement had not been fully deployed at the time of this event, limiting PG&E's ability to send these automated notifications. The automation has since been completed after this event, and PG&E will use this capability in future events. For this event, PG&E sent ETOR notifications in lieu of Weather All Clear Notifications.

Restoration in Progress: ETOR Notification

For this event, PG&E used a new, automated process based on field intelligence to update ETORs for customers. After the weather has cleared, PG&E sends event update notifications to customers with updated estimated times of restoration (ETOR) in two scenarios:

1. Weather Event is Over and PG&E Begins Patrolling: Customers receive an updated ETOR based on field intelligence, which may be sooner or later than original ETOR provided during the PSPS Weather Event.
2. Weather Event is Over and Damage Found During Patrols of Equipment: Customers receive an updated ETOR accounting for repair time.

P27-123 cont.

Providing individualized updates at the segment level on a circuit, gave customers more timely and accurate information to plan accordingly.

For this event, notifications were also sent to customers that could not be restored due to visibility/access issues from active fires. PG&E also identified customers that were impacted by the active fire. For these customers, PG&E transitioned out of PSPS messaging into fire outage-related notifications.

Restoration Complete Notification

Restoration complete notifications were automatically sent to customers when the customers were safely restored. This was done using an automated process that issued customer notifications every 15 minutes upon restoration of service.

Explanation in cause of false-negative communications (No advanced notice prior to de-energization)

The CPUC does not provide a definition of false-negative communications. PG&E defines a false negative communication as a customer that was impacted and did not receive notification notice prior to de-energization start date/time.

Approximately 2,300, including approximately 140 medical baseline customers, customers de-energized did not receive direct notifications prior to de-energization. This was primarily due to the following reasons:

- A different sectionalizing device or circuit breaker was used that was different than planned
- No valid contact information on file during the event[13]

[13] After the event, PG&E sent postcards to these customers indicating they did not receive a notification directly from PG&E due to invalid or no contact information and encouraged them to update their contact information for future notifications.

Explanation in cause of false-positive communications
The CPUC does not provide a definition of false-positive communications. PG&E defines a false positive communication as a customer that was not impacted, was notified that de-energization would occur (e.g., received Warning notification), and did not receive cancellation notice prior to de-energization start date/time.[14]

Approximately 1,500 customers received a Warning notification without a cancellation prior to the planned de-energization start date/time. PG&E was unable to provide cancellation notices to customers primarily for the following known reasons which are still undergoing analysis;

- Advanced switching solutions which were able to remove customers from the planned de-energization scope
- Customer mapping issues leading to customers being incorrectly identified as impacted

For those customers where positive or affirmative notification was attempted, an accounting of the customers (which tariff and/or access and functional needs population designation), the number of notification attempts made, the timing of attempts, who made the notification attempt (utility or public safety partner) and the number of customers for whom positive notification was achieved.

Response:

P27-123 cont.

During PSPS events, Medical Baseline customers receive automated calls, text and e mails at the same intervals as the general customer notifications. PG&E provides unique PSPS Watch and PSPS Warning notifications to Medical Baseline Program participants[15] and additional calls and texts at hourly intervals until the customer confirms receipt of the automated notifications by either answering the phone, responding to the text or opening their email. If confirmation is not received, a PG&E representative visits the customer's home to check on the customer (referred to as the "door knock" process) in parallel to the continuation of hourly notification retries.[16] If the customer does not answer, a door hanger is left at the home to indicate PG&E made a visit. In each case, the notification is considered successful.[17] At times, PG&E may also make Live Agent phone calls in parallel to the automated notifications and door knocks, as an additional attempt to reach the customer prior to and/or after de-energization.

In this PSPS event, 10,383 medical baseline customers were ultimately de-energized. Notifications to Medical Baseline customers initiated at the same intervals with all customers. In the early evening of September 6, the Medical Baseline customer door knock process commenced for those customers that had not confirmed receipt of their automated notifications. The door knocks and Live Agent calls continued on September 7 prior to de-energization. After de-energization, PG&E also continued Live Agent wellness calls to attempt to reach customer that still had not confirmed receipt of their notifications.

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[14] PG&E excludes customers on temporary generation that were notified they were being served by a microgrid and did not experience a switching outage

[15] Including Medical Baseline Program customers that are master metered tenants (e.g., renters or tenants in mobile home park).

[16] Until late evening (approximately 9 pm) or PG&E suspends

[17] For Medical Baseline customers, the in-person door knock visit where a door hanger is left, but no contact made with the customer is considered "successful contact," but not confirmed as "received." If the representative makes contact with the customer, this is considered "received."

On a twice daily basis, PG&E also continued sharing the lists of the medical baseline customers that had not confirmed receipt of their notifications with county and tribal emergency operations centers within their jurisdictions.

The following table reference metrics associated with the notifications provided to impacted Medical Baseline customers:

Table 2: Outcomes of Notifications to Impacted Medical Baseline Customers

Count	Type of Notifications to Impacted Medical Baseline Customers (based on SPID)	Description
10,383	**Total Impacted Medical Baseline Customers**	Customers on the Medical Baseline Program that were de-energized[18]
10,245	**Total Attempted Notifications**	Includes automated notifications sent via phone, text and email, in-person door knock visit attempts and/or Live Agent phone calls
138	*Total Notifications Not Attempted*	*Total Medical Baseline customers without an attempted notification*[19]
10,218	**Total Successful Notifications**	One of the following occurs: Customer answers the phone or voice message is left, text message is delivered or response to text is received, e-mail is delivered or opened, or a link within the e-mail is clicked, door knock answered, door hanger left, live agent call contact made with customer

Table 3: Count and Type of Additional Notifications to Impacted Medical Baseline Customers

Count	Type of Additional Notifications to Impacted Medical Baseline Customers (based on SPID)	Description
1,037	**Total In-Person Visit / Door Knocks**	Door Knock attempts to impacted customers where PG&E made contact with the customer and/or left a door hanger[20]
58	**Live Agent Phone Calls**	Contact made with customers via Live agent calls prior to de-energization

P27-123 cont.

[18] Excludes counts of Medical Baseline customers that are tenants of a master metered account

[19] See page 22 regarding PG&E's explanation of false-negative communications resulting in no direct notifications to approximately 2,300 customers, including approximately 140 medical baseline customers prior to de-energization.

[20] Customers may have confirmed receipt of their notifications in multiple channels (e.g. automated notification and/or door knock and/or live agent calls); therefore, the counts of total attempted and successful notifications are not mutually exclusive

Additional Information - Other Channels of Communication

To alert the public in advance of the PSPS event, PG&E maintained both a media and online presence, which included significant improvements to content, stability and navigation since 2019 events. PG&E also engaged with additional key stakeholders, including Community Based Organizations (CBOs), Critical Facilities, and Google.

Media Engagement

From the time PG&E announced the potential PSPS event to the time customers were restored (between September 5 and September 10, 2020), PG&E engaged with customers and the public through the media as described below.

- Issued nine news releases and three media advisories containing information and updated details about the PSPS event;[21]
- Provided event information to approximately 5,700 news outlets via Business Wire's national media list, which includes approximately 600 California news outlets, on a regular and ongoing basis. This included 51 multi-cultural news outlets throughout Northern California and Bay Area regions. These organizations provided in-language (translated) event updates to their viewers/readers in over 20 languages, including languages spoken by communities that occupy significant roles in California's agricultural economy (e.g., Mixteco).
- Participated in media interviews to provide situational updates and preparedness messages for the PSPS event;
- Coordinated directly with 37 multicultural media organizations with established contracts to issue event updates on their platforms (e.g., radio, TV, social media);
- Conducted 3 live-streamed PG&E PSPS Public Briefings, including an American Sign Language (ASL) interpreter. These briefings were promoted on social media and in media advisories, and streamed on PG&E's YouTube Channels[22] and portions were live streamed on local TV news channels (e.g., KCRA and ABC 7). Presenters included Incident Commander, a meteorologist and a Customer Care representative. Audience included customers, stakeholders and reporters and event included live Q&A from select reporters;
- Maintained a regular and ongoing social media presence on Twitter, Facebook, Instagram and Nextdoor issuing 138 social media posts, which had approximately 2.6 million total impressions and over 125,000 total engagements;[23]

P27-123 cont.

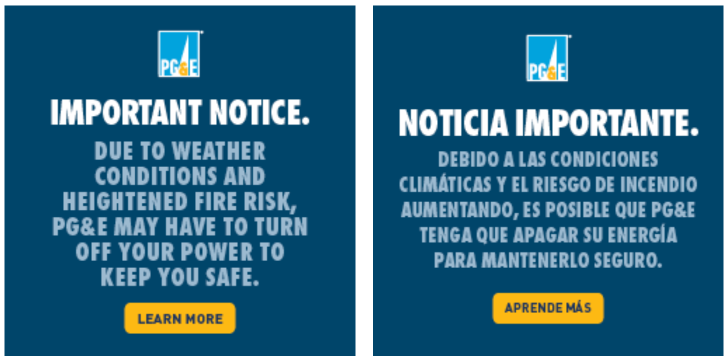
[21] www.pge.com/en/about/newsroom/newsreleases/index.page

[22] https://www.youtube.com/user/pgevideo/videos

[23] Sample Social Media Posts–
- PSPS Criteria: https://twitter.com/PGE4Me/status/1303175546424229888/photo/1
- De-Energization Start: https://twitter.com/PGE4Me/status/1303183633994387459
- CRCs: https://twitter.com/PGE4Me/status/1303374404274061317

- Augmented customer outreach with dedicated PSPS paid advertising messages in 22 impacted counties before and during the event using digital banners in English and Spanish placing approximately 1.2 million impressions.[24] See Figure 7 below for an example of the digital banner advertisements used.

Figure 7: Sample Digital Banner Advertisements Used During September 7 PSPS Event



P27-123 cont.

<u>PG&E Website</u>

During this PSPS event, [25] PG&E provided event updates on <u>www.pge.com</u>, and implemented tools to drive traffic to and maintain stability of the PSPS emergency website / event updates page, <u>www.pge.com/pspsupdates</u>.

Before this PSPS event, PG&E significantly updated our website, establishing a new emergency website for scalability and stability. PG&E's main webpage, pge.com, had the capacity to serve 12 million hits per hour, and PG&E's emergency website, which maintains the PSPS event update information, had the capacity to serve 240 million hits per hour. During this event, pge.com hit rate peaked on September 6 at 1900 with approximately 2.45 million hits per hour, and the emergency website with PSPS update information peaked on September 7 at 1900 with approximately 1.69 million hits per hour.

The following content was available on PG&E's PSPS event-updates page:

- Straightforward and simplified event information with clear updates about the planned scope of the event, including location (e.g., list of impacted, cities, counties and tribes), duration of the

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[24] English advertisements placed in all 22 impacted counties had ~1.05M impressions and 0.1% Click Through Rate (CTR). Spanish advertisements placed in 16 counties had ~150,000 impressions and 0.2% Click Through Rate (CTR).

[25] From the time PG&E announced the potential PSPS event to the time customers were restored (between September 5 and September 10, 2020)

event, including estimated times of de-energization and re-energization at the individual address level, and overall for the event;

- Improved maps, including one place to toggle between the PSPS planned outage maps and actual outage maps and more detailed, parcel-level view of the areas planned for de-energization;
- Address lookup tool in the same map tool that a customer and the public could use to identify specific PSPS impacts;
- Information by county with the ability to download maps and lists of impacted areas, and view general customer impacts;
- Details of Community Resource Centers (CRCs), including locations listed by count, resources available at each center, type of CRC offered (e.g., indoor, mobile or micro) and operating hours;
- Links to additional resources for customers, including links to PG&E's EV charging locater map, locations of Independent Living Centers, resources for people with access and functional needs, backup power safety tips, medical baseline program information, and more; and
- Survey to provide input about the website and event communications.

Over the course of the event, PG&E's website (pge.com) had almost 957,000 unique visitors, 1.2 million visits, and 2 million total page views. PG&E's emergency website (pgealerts.alerts.pge.com), including PSPS event updates webpage,[26] had over 1.1 million unique visitors, almost 1.7 million visits and over 4 million page views. PG&E translated its emergency website in six languages in addition to English: Spanish, Chinese, Korean, Vietnamese, Tagalog and Russian.[27] P27-123 cont.

Other Community Engagement

- Community Based Organizations (CBO) Engagement: In 2020, PG&E established a new, dedicated point of contact to engage with CBOs during a PSPS event. PG&E offered our newly signed resource-based CBOs a daily training during the event (from Saturday September 5 through Monday September 7) so that they were able to quickly provide resources and reporting expectations. In addition, informational and resource CBO partners were invited to a once daily cooperator calls hosted by PG&E to provide a situational update about the latest scope of the event and an overview of the services available to AFN populations for the CBOs to share with their constituents. PG&E engaged with over 200 CBOs during the event, sharing courtesy notification updates, press releases and other relevant information that they could share with their constituents to expand our reach of communications (e.g., providing a social media resource site with translated infographics that can be used by these organizations).
- Critical Facility Engagement: In 2020, PG&E modified its notifications process provided to critical facilities. PG&E now requests critical facilities to confirm receipt of the automated notifications. If these customers did not confirm receipt of the automated notification, PG&E representatives based in PG&E's local Operations Emergency Centers (OEC) or Customer Relationship Managers (CRMs) made direct calls to the PSPS contacts to ensure they were aware

[26] The PSPS Event Updates page is at the following link: pgealerts.alerts.pge.com/updates. PG&E also uses the following shorten URL for the same site: www.pge.com/pspsudpates

[27] The following number of unique visitors were made to the translated versions of the emergency website of the PSPS updates website (www.pge.com/pspsupdates) from September 5 to September 10: English–527,349, Spanish–996 Chinese–1,355, Tagalog–85, Russian–119, Vietnamese–117, Korean–110.

of the potential event, and provided localized support for other public safety partners, such as water agencies and emergency hospitals.

Prior to and during this event, in recognition of the unique challenges posed by the potential confluence of a PSPS event and COVID-19, PG&E provided pre-staged backup power to support select COVID-19 hospitals identified by the California Hospital Association (CHA) and Hospital Council of Northern and Central California to minimize the disruption to hospital patients and scheduling during the pandemic. PG&E details the backup power staged to customers for this specific event in Section 13 below.

- Google SOS Alerts: PG&E provided PSPS event information to Google which issued Google SOS alerts to the public. PSPS outage information was provided on Google products, including alert banners in Search and Maps with references to PG&E website / available resources.

Event Support for Customers with Access and Functional Needs (AFN)

PG&E provided a variety of resources to customers with access and functional needs before and during this event. Three of the four programs and partnerships described below are new arrangements established to support our customers during 2020 PSPS events.

- Disability Disaster Access and Resource Program: PG&E continued its collaboration with the California Foundation for Independent Living Centers (CFILC)[28] to implement the new Disability Disaster Access and Resources (DDAR) Program during the event. Through this program, local Independent Living Centers (ILCs) provided aid to seniors and/or people with disabilities who rely on power for medical or independent living needs.[29] Through CFILC, PG&E aid to AFN customers included delivery of a total of 528[30] backup portable batteries to qualifying customers who need power during a PSPS, arranging 91 hotel stays to give needy customers an energized place to stay during the outage, coordinating transportation for 9 customers, and providing 174 food vouchers. Some of these resources provided through CFILC were an outcome of Medical Baseline customer-related escalated that were received by PG&E in the EOC during the event. CFILC also sent out communication to their constituents to alert them to the available resources.

- Portable Battery Program: Just prior to this PSPS event, PG&E launched its Portable Battery Program (PBP). This program provides fully subsidized portable battery systems for low-income customers that live in Tiers 2 and 3 high fire-threat districts (HFTD) and are enrolled in the Medical Baseline program. During this event, we delivered 15 portable batteries to eligible customers, with a total of 23 units delivered across the entire PG&E service territory prior to and during this PSPS event.

- Food Bank Partnerships: For the first time during PSPS events, PG&E funded local food banks to provide food replacement to families during the event and three days following service restoration. For this event, we partnered with five local food banks that served 11 impacted counties to provide almost 9,000 boxes of food replacement for families. To help keep the Food

P27-123 cont.

[28] CFILC is a registered 501(c)(3) non-profit organization that increases access and equal opportunity for people with disabilities by building the capacity of Independent Living Centers (ILCs) throughout California. ILCs are grassroots organizations run by, for, and about people with disabilities. CFILC's membership includes 23 of California's 28 ILCs and 56 of the state's 58 counties.

[29] Customer may participate regardless of their enrollment in PG&E's Medical Baseline Program, and their individual needs are assessed directly with CFILC.

[30] The total backup portable batteries include 454 batteries delivered prior to the PSPS event and 74 batteries delivered during the PSPS event.

Bank of Nevada County energized, PG&E deployed a large battery trailer to their warehouse, enabling them to continue providing more than 1,110 boxes to families during this event.

- Meals on Wheels Partnerships: PG&E initiated a partnership with Meals on Wheels to provide additional support and services to customers in need during PSPS events. For this PSPS event, we partnered with a Nevada County-Based Meals on Wheels organization, Gold Country Senior Services that supported 250 seniors with an additional meal daily for the duration of the event. Meals on Wheels also completed in-person visits / wellness checks and provided event information to the seniors they serve, including sharing CRC location details.

PG&E is working to deliver more batteries to qualifying customers, and establish agreements with additional food banks and community Meals on Wheels programs to provide support for customers with access and functional needs during PSPS events.

Communications to Customers with Limited English Proficiency

PG&E provided translated customer support through its customer notifications, website, call center, social media and engagement multicultural media partnerships. Information and communications were offered in 12[31] non-English languages, and customers who had set their language preference received in-language (translated) notifications.

PG&E's website offers PSPS preparedness toolkits in 12 non-English languages covering topics including the medical baseline program application and fact sheets on PSPS, CWSP program, medical baseline program, and more.

Customers with limited English proficiency could access translation services through PG&E's call center. PG&E displayed its call center phone number at the top of its PSPS event webpage, highlighting that translation services are available in over 200 languages. During this PSPS event, PG&E's call center provided translation services in 26 different languages. P27-123 cont.

For 2020 PSPS events, PG&E has significantly increased support and engagement with multi-cultural media organizations to maximize the reach of in-language communications to the public during the event. Leading up to the PSPS event, we engaged with 37 multicultural media organizations covering the 12 languages above and languages spoken by communities that occupy significant roles in California's agricultural economy (e.g., Mixteco). We trained these organizations on the translation resources we have available to streamline coordination during the PSPS event. Throughout the event, we provided regular communications with these media outlets to provide information and updates on PSPS.

We developed and distributed translated social media infographics that were available in 12 languages. Figure 8 includes samples of these infographics shared. A few highlights from this coordination include:

- KBBF-Radio, based in Santa Rosa, offered news segments on PSPS in Spanish and Mixteco. We participated in a live, 30-minute Spanish interview during the PSPS event;
- KBTV-Crossings TV, based in Sacramento, produced a 10 second TV advertisement by using the in-language social media infographic "Learn More about PSPS" in Chinese (Cantonese and Mandarin), Vietnamese, Tagalog, Hmong, Punjabi, Japanese and Russian;
- Radio Bilingue, based in Fresno, offered news segments on PSPS in Spanish. We participated in a live, 15-minute interview after the PSPS event;
- KTSF-TV, based in San Francisco, created a dedicated webpage (www.ktsf.com/pge-psps) to provide PSPS updates to their Chinese audiences in the Bay Area (North Bay) throughout the event; and

[31] Spanish, Chinese (Cantonese & Mandarin), Vietnamese, Tagalog, Korean, Russian, Japanese, Farsi, Punjabi, Arabic, Khmer, and Hmong.

- KSJZ-Korean American Radio, based in San Jose, published all our news releases in Korean and aired them during their programming.

Figure 8: Sample Translated Infographics Shared with Multicultural Media

P27-123 cont.

Section 7 – Local Community Representatives Contacted

The local communities' representatives the IOU contacted prior to de-energization, the date on which they were contacted, and whether the areas affected by the de-energization are classified as Zone 1, Tier 2, or Tier 3 as per the definition in General Order 95, Rule 21.2-D.

Response:

Appendix D lists local government, tribal representatives, and community choice aggregators contacted prior to de-energization, the initial date on which these stakeholders were contacted, and whether the areas affected by de-energization are classified as Zone 1, Tier 2 or Tier 3 as per the definition in GO 95, Rule 21.2-D. Dates marked with an asterisk are representatives who received multiple notifications during the event.

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Section 8 – Local and State Public Safety Partner Engagement

A description and evaluation of engagement with local and state public safety partners in providing advanced outreach/notification during the PSPS event

Response:

On September 4, PG&E's Meteorology Team updated the weather forecast on www.pge.com/weather to "elevated" in certain parts of the service territory. Local PG&E representatives used live phone calls to notify cities, counties and tribes that PG&E was monitoring for an increased potential of a PSPS event. Notifications continued to state and local Public Safety Partners, and the first CalOES PSPS State Notification Form was submitted that evening communicating the activation of PG&E's EOC. Notice to Public Safety Partners continued into and was fully completed on the morning of September 5 as noted in Section 6 of this report.

Local and State Agency and First Responder Engagement:

While PG&E's EOC was active, PG&E coordinated with local and state agencies and first responders (cities, counties, and tribes) in the following ways:

- Submitted the PSPS State Notification Form to CalOES and sent emails to the CPUC at key event milestones.
- Sent automated text, email and phone calls to cities, counties, tribes and Community Choice Aggregators. These notifications included the estimated shutoff and restoration times and links to maps and other information.
- Hosted twice-daily State Executive Briefings with state agencies to provide the latest event information and answer questions.
- Hosted the daily Systemwide Cooperators Call, which all Public Safety Partners in the service territory were invited to join.
- Hosted twice-daily Tribal Cooperators Calls with potentially impacted tribes to provide the latest event information and answer questions.
- Conducted ongoing coordination with local County OES and tribal contacts through dedicated Agency Representatives. This included providing the latest event information, coordinating on Community Resource Center locations and resolving local issues in real-time.
- Offered PG&E Agency Representative to be embedded in-person or virtually in local EOCs. However, no counties requested embedded support for this event.
- Conducted direct engagement with over 100 Public Information Officers (PIOs) from counties, cities and tribal communities, including sharing nine news releases and three media advisories via a purpose-built email box.
- Offered remote support from GIS Technical Specialists to help navigate the PG&E GIS tools and maps. No counties or tribes requested GIS Technical Specialist support for this event.
- Provided maps, situation reports, critical facility lists and medical baseline customer lists via the PSPS Portal at the time of the initial notification and throughout the event.

P27-123 cont.

Starting on September 5, PG&E remotely hosted a CalOES Emergency Services Coordinator for San Francisco County, who attended PG&E's Command and General staff meetings and Operational and Planning meetings. Additionally, a Program Manager at the California Public Utilities Commission, was also remotely embedded and joined the same meetings starting on September 8.

Community Choice Aggregator (CCA) Engagement:

Four CCAs were in scope for this PSPS event: Pioneer Community Energy, Redwood Coast Energy Authority, Sonoma Clean Power and Marin Clean Energy (MCE). Throughout the event, PG&E's CCA Relations Managers provided the CCAs dedicated individual support, fielded questions and shared situational updates. On September 4, CCA Relations Managers contacted the affected CCAs to warn of the possibility of the impending PSPS event. The CCAs received advanced notifications through PG&E's public safety partner agency notification system, were invited to PG&E's daily cooperator calls to receive situational updates, and had access to PSPS Portal with event information (e.g., maps, impact lists, situation reports).

Communications and Water Provider Engagement:

Impacted communications and water providers received advanced notifications through PG&E's automated customer notification system, were invited to PG&E's daily cooperator calls to receive situational updates, and also had access to PSPS Portal with event information (e.g., maps, impact lists, situation reports). Communications providers were provided support from PG&E's Critical Infrastructure Lead (CIL), and water providers received escalated support through PG&E's local Operations Emergency Center (OEC).

P27-123 cont.

Publicly Owned Utilities (POUs) and Transmission-level Customer Engagement:

PG&E's Critical Infrastructure Lead (CIL) notified impacted publicly-owned utilities of the event. They received automated notifications through PG&E's customer notification system once transmission-level impacts were determined. PG&E's Grid Control Center (GCC) operators made live calls to these customers before both de-energization and re-energization. POUs were invited to PG&E's daily cooperator calls to receive situational updates, and had access to PSPS Portal with event information (e.g., maps, impact lists, situation reports).

Following the submission of this PSPS De-Energization Report, PG&E will provide the report to Public Safety Partners for review and feedback.

Section 9 – Complaints Received & Claims Filed

The IOU shall summarize the number and nature of complaints received as the result of the de-energization event and include claims that are filed against the IOU because of de-energization.

Response:

Complaints

From September 4, 2020 through September 18, 2020, PG&E did not receive any written, phone or e-mail complaints related to PSPS from the CPUC. Complaints received are reconciled on a monthly basis and subject to change.

Claims

From September 4, 2020 to September 17, 2020, PG&E received 33 claims for the September 7-10 PSPS event. The claims received are broken down into the following categories:

Table 4: Count and Type of Claims Received

Number of Claims	Description of Claims
18	Food Loss
9	Property Damage
5	Business Interruption / Economic Impact
1	Property Damage with Business Interruption / Economic Impact

P27-123 cont.

Section 10 – Power Restoration

The timeline for power restoration (re-energization,) in addition to the steps taken to restore power as required in Resolution ESRB-8;

Response:

Prior to restoration activities, PG&E pre-positions field resources and prepares helicopters in anticipation of the "weather all clear" to begin patrols. The PG&E Incident Commander and meteorology team monitor real-time and forecasted weather conditions based on weather models, weather station data, and field observations. Using this incoming information, all clears are issued by fire index area (FIA) in a phased approach to restore customers as soon as possible. A map of the PG&E's FIA's can be found in Appendix E. PG&E issued the weather all clear by FIA based on weather stations that have been developed to allow meteorologists to quickly assess the latest fire weather observations across each FIA. This allows for more granular, faster all clear decisions to be made based on real-time meteorology information.

As weather all clears are issued, PG&E patrols electrical facilities to identify and repair or clear any damage or hazards before re-energizing. Using the Incident Command System (ICS) as a base response framework, each circuit was assigned a taskforce consisting of supervisors, crews, troublemen, and inspectors. This structure allowed PG&E to patrol and perform step restoration in alignment with the centralized control centers.

Over the course of restoration PG&E issued 10 separate all clears and utilized approximately 1,900 personnel and 28 helicopters to identify any safety concerns and make necessary repairs prior to restoration. PG&E had planned to utilize 60 helicopters for this event but could not do so due to unsafe flying conditions caused by smoke from major wildfires. No mutual aid resources were utilized due to the size of the event. Power was restored to customers as patrols were completed. Several circuits were inaccessible to PG&E due to on-going wildfires or access restrictions from the local fire agency and could not be restored during the PSPS event.

P27-123 cont.

PG&E issued weather all clears at the following times and restored all customers that were served by accessible circuits on September 10. The remaining customers were restored at later dates as PG&E crews were able to gain access to the assets for patrols and restoration.

Weather All Clears were issued at the following dates and times by Fire Index Area:

Table 5: Weather All Clears Issued

Impacted FIAs	Weather All Clear Date and Time
100, 112, 113, 320, 348, 370	09/08/2020 1430
290	09/09/2020 0123
345, 240, 241, 249	09/09/2020 0217
247, 285, 340, 130, 230, 105, 115, 120, 238	09/09/2020 0419
330, 350, 354, 380, 154	09/09/2020 0521
335, 360, 244, 180, 246	09/09/2020 0612
175, 280, 282, 438	09/09/2020 0759
248	09/09/2020 0945
445, 448	09/09/2020 1056
651	09/09/2020 1143

For any circuits that require more than 24 hours to restore, the utility shall explain why it was unable to restore each circuit within this timeframe in its post event report.

Response:

PG&E was unable to restore the following circuits primarily due access issues caused by the wildfires that either started or grew during the weather event or due to visibility issues caused by heavy smoke and fog which did reduced the amount of aerial patrols PG&E had planned to perform. The reasons PG&E was unable to restore each circuit within 24 hours of the weather all clear are listed in the table below. P27-123 cont.

Table 6: Circuits with restoration time that exceeded 24 hours

Circuit Name	Primary reason the utility was unable to restore the circuit within 24 hours
ALLEGHANY 1101	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
BANGOR 1101	Fire agency requested circuit not be re-energized
BIG BEND 1101	Fire agency requested circuit not be re-energized
BRIDGEVILLE 1101	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
BUCKS CREEK 1101	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
CALISTOGA 1101	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
CEDAR CREEK 1101	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
CHALLENGE 1101	Fire agency requested circuit not be re-energized
CHALLENGE 1102	Fire agency requested circuit not be re-energized
CLARK ROAD 1102	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
CURTIS 1703	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
FORT SEWARD 1121	Fire agency requested circuit not be re-energized
FROGTOWN 1702	Restoration delayed due to repairs / correction of PSPS hazard or damage found on assets to be restored
HOOPA 1101	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
KANAKA 1101	Fire agency requested circuit not be re-energized
LOW GAP 1101	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
ORO FINO 1102	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
PIKE CITY 1102	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
PLACERVILLE 2106	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
PUEBLO 2103	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
SILVERADO 2104	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
STANISLAUS 1701	Inability to utilize planned helicopter resources due to smoke / fog / other visibility concerns
WYANDOTTE 1103	Fire agency requested circuit not be re-energized
WYANDOTTE 1105	Fire agency requested circuit not be re-energized
WYANDOTTE 1107	Fire agency requested circuit not be re-energized

P27-123 cont.

<u>Section 11 – Community Assistance Locations</u>

The IOU shall identify the address of each community assistance location during a de-energization event, describe the location (in a building, a trailer, etc.), describe the assistance available at each location, and give the days and hours that it was open.

Response:

During this event, PG&E established 50 Community Resource Centers (CRCs) in 18 counties. When a PSPS event occurs, PG&E opens CRCs to provide impacted customers and residents a space that is safe, energized and air-conditioned or heated (as applicable) with the standard operating hours of 0800 to 2200. Visitors were provided with PSPS event information by dedicated staff, ADA-compliant restrooms/hand washing stations, physically distanced tables and chairs, power strips to meet basic charging needs (including charging for cell phones, laptops and small medical devices), and Wi-Fi and cellular service access. The following supplies were available at each location: water, non-perishable snacks, bagged ice, batteries and blankets. The CRCs are designed to meet the following criteria: Americans with Disabilities Act (ADA) and environmentally compliant, site owner approval, Wi-Fi and cellular service access, 1-2 acres of flat and (preferably) paved areas for outdoor locations, backup generation availability, and open typically between 0800 to 2200 from the time power is shut off until the time electric service is restored. CRC locations were published on our website, shared on social media, shared with state and county officials and news media, and shared with AFN customers through our CFILC and media partners.

<u>COVID-19 Considerations:</u>
We adapted our approach to CRCs to reflect appropriate COVID-19 health considerations and state and county guidelines, including requiring facial coverings, physical distancing and limits on the number of visitors at any time based on capacity limits of the location. At indoor CRCs, temperature checks were required for entry, and tables and chairs had physically distant spacing. At outdoor CRCs, supplies were handed out so customers could "grab and go," and seating was only available for customers needing medical equipment charging.

P27-123 cont.

<u>Local Government Coordination on Site Selection and Closure</u>:
During this PSPS event, PG&E's dedicated Liaisons closely coordinated with the potentially impacted counties and tribes to review the proposed scope of the event and receive agreement on the selected locations for the CRCs based on the anticipated areas of de-energization. This included phone calls and emails on Friday, September 4 and Saturday, September 5 to the potentially impacted jurisdictions identified at that time, to share list of CRC locations within each county or tribe with a request for input to confirm mobilization of the CRC. Most CRC locations were pre-identified, with the county/tribe having provided input in advance of the 2020 wildfire season; however, some sites had to be newly procured where PG&E was unable to make successful contact with property owners and/or a CRC needed to be set up closer to the impacted customer areas. PG&E reviewed feedback from the counties and tribes and worked collaboratively to implement those locations for the event. PG&E also confirmed operating hours with local governments, tribes and site owners to implement any operational changes to the standard operation hours (8am – 10pm) for public health or safety reasons (e.g., local curfew, inability to access, safety issues). For this event, there were no changes to the standard operating hours.

PG&E ultimately received final agreement from counties and tribes on the operating hours, types and locations identified and mobilized. Four counties declined to have CRCs set up in their counties for various reasons, such as relatively small scope of impact in their jurisdiction and/or anticipated evacuations.[32] PG&E coordinated with local governments to gain their agreement to close the sites within their jurisdictions.

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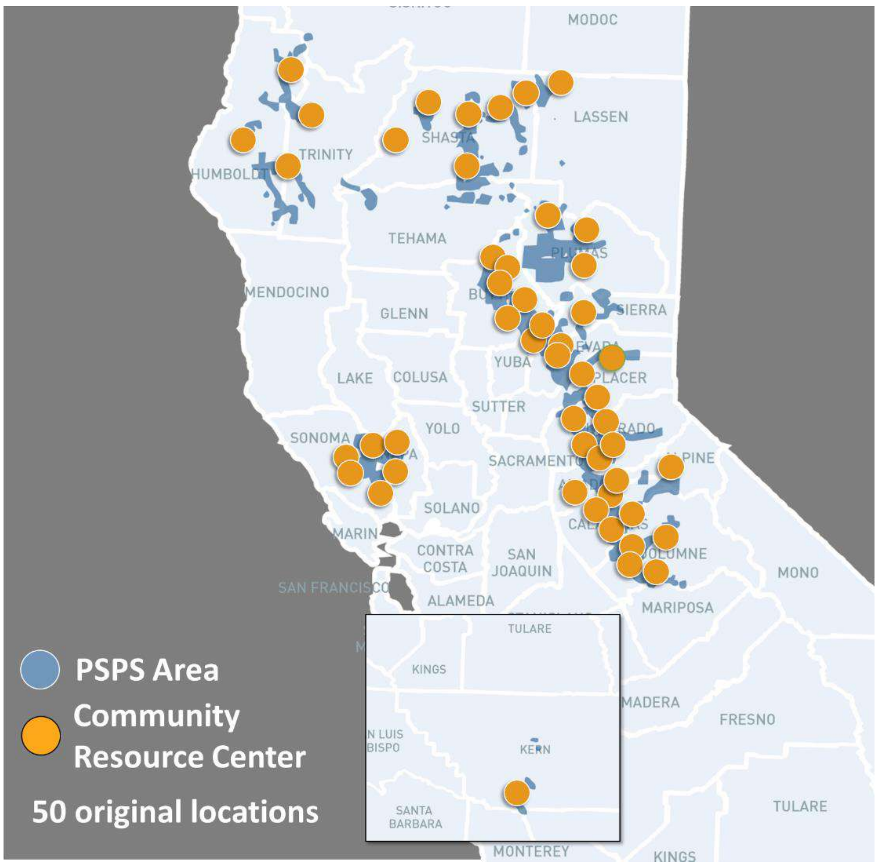
[32] Four counties that confirmed to not set up a CRC in their jurisdiction due to limited impact: Lake, Mariposa, Siskiyou and Tehama

Location, Type and Timeline of CRCs:
PG&E provided a total of 50 CRCs in 18 counties over the course of three days throughout the impacted areas in the territory – almost double the number of CRCs mobilized during the October 23, 2019 event, which was a comparable event size in terms of customers impacted. CRCs were open from 0800 to 2200 PST. The following is a map that depicts the locations of the CRCs, including an overlay of the areas impacted:

Figure 9: Location of Community Resource Centers Available During September 7 Event



Of the 50 CRCs, five were indoor (hardened) sites, and the remaining were outdoor in temporary locations, including 21 microsites (open air tents) and 24 mobile sites (e.g., Sprinter van). The outdoor CRCs were in open spaces such as parking lots at a shopping center, school, park, fire departments, places of worship, community or recreation center, and fairgrounds. All sites were ADA-compliant.

With de-energization beginning for most affected customers overnight on Monday night September 7, all 46 CRC sites were open and available to the public starting at 0800 PST on Tuesday September 8; Four sites opened later in the afternoon that day due to having been added late in the prior evening.

PG&E provided updates to the public and local partners on the CRC locations, hours of operations and resources available through state agency calls, press releases, website, and social media outlets, including PG&E's main channels (Facebook, Twitter, Nextdoor), as well as in local divisions by customer account representatives.

CRCs remained open until service had been restored in each host county.

P27-123 cont.

- A total of seven CRCs closed early at various times due to smoke and fire-related evacuations in three counties: Butte, Trinity and Yuba.
- On the evening of September 9, after restoration was complete in 11 counties,[33] 31 CRCs (excluding those that were evacuated) were demobilized.
- On September 10, 14 sites remained open to the public in seven counties (excluding those that were evacuated).[34]
- Restoration was complete for all customers mid-day on September 10, and all CRCs were demobilized (closed) then.[35]
- One CRC location remained open in El Dorado County through September 12 due to the request of the County OES to accommodate potential evacuees due to the nearby fires.

<u>Customer Visitation</u>: Overall, approximately 9,100 people visited one of PG&E's 50 CRC sites over the course of this PSPS event. Some customers returned to the CRCs across multiple days. Customer attendance was highest in Plumas County at three micro-sites at the Safeway in Quincy, Greenville Jr./Sr. High School in Greenville and the Holiday Market in Chester with approximately 1,700, 700 and 600 visitors, respectively. Of the 50 CRC locations, four had fewer than 10 visitors during the event, though one of these locations (Foothill Volunteer Fire Department in Yuba County) was evacuated the same afternoon due to nearby smoke/fires.

The following pictures illustrate PG&E's micro and mobile CRCs for this event:

Figure 10: PG&E CRC in Saint Helena at Saint Helena Catholic School (Napa County)

Figure 11: PG&E CRC in Hydesville at Hydesville Community Church (Humboldt County)

P27-123 cont.

See Appendix F for further details on the CRCs that PG&E mobilized during the PSPS event, including specific locations, dates and times available, and total attendance for each location.

[33] 11 counties with CRCs demobilized after restoration was complete on September 9: Alpine, Amador, Calaveras, (4 of 5 CRCs in El Dorado, Kern, Lassen, Nevada, Placer, Shasta, Sonoma, and Tuolumne

[34] Seven counties with CRC demobilized after restoration was complete on September 10: Butte, El Dorado, Humboldt, Napa, Plumas, Sierra, and Trinity

[35] Following the PSPS event, one CRC (Southside Oroville Community Center in Butte County) was moved to an indoor location at the request of the Butte County OES department to support the potential evacuees due to the fires. This location is not captured in this report.

<u>Section 12 – Sectionalization</u>

Describe how sectionalization was considered/ implemented and the extent to which it impacted the size and scope of the de-energization event

Response:

PG&E was able to implement sectionalization during this PSPS event to reduce customer impacts. PG&E de-energized portions of 73 de-energized circuits, as opposed to the entire circuit. By using new and existing sectionalizing devices to de-energize only portions of these circuits, customer impacts of this PSPS event were reduced by 53,143.

P27-123 cont.

Section 13 – Mitigations to Reduce Impact

In summary, this event was approximately 50% smaller than the estimated impact of the same weather footprint had it occurred in 2019 with the tools and measures available to PG&E at that time.

Meteorological Guidance: Meteorology guidance established for 2020 includes improvements in granularity to both the Fire Potential Index (FPI) and the Outage producing wind (OPW) component. The result is a more focused (smaller) area identified as exceeding distribution risk guidance, with the result that this PSPS scope affected almost 134,000 fewer customers in combination with Transmission Line Scoping and Segmentation.

Transmission Line Scoping: Transmission line scoping for 2020 utilizes the same updated FPI as the distribution scoping process. In addition, the transmission asset analysis is more granular than 2019 with assets analyzed against guidance at the structure level.

Transmission Line Segmentation: Transmission lines are segmented at SCADA switches when possible if only a portion of a line is required to be de-energized to due PSPS. Leaving segments of transmission lines energized allows PG&E to still reduce fire risk where needed and provide service to stations fed off the non-impacted segments during the PSPS events. PG&E has installed over 30 transmission line SCADA switches in 2020. During this event transmission segmentation enabled nine substations to remain energized by only de-energizing transmission lines segments rather than whole transmission line.

Distribution Switching: Distribution switching plans were created to maintain service to more customers when radially served distribution customers who are not in the high-risk area, but lines serving them pass-through the high-risk area may be able to be energized via back-tie switching on the distribution system.

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Sectionalization: New automated distribution switches have been installed near the border of the high-risk fire areas to reduce customer impacts when in-scope for PSPS. PG&E has installed over 600 of these switches in 2020.

Temporary Generation**:** During this event, PG&E utilized its rented fleet of temporary generators to mitigate the impacts of PSPS on its customers. Temporary generators were used to energize indoor community resource centers (CRCs), substations that could safely deliver power to thousands of customers, temporary microgrids that kept the lights on for shared services supporting community critical needs, and intensive care unit (ICU) hospitals and other facilities serving public safety.

- Substation Temporary Generation: PG&E used temporary generation to energize certain substations whose transmission sources had to be shut off for safety, but which could otherwise safely deliver power to customers. During this event Brunswick substation (serving Grass Valley in Nevada County), Willow Creek substation (serving Willow Creek in Humboldt County), and Hoopa substation (serving Hoopa in Humboldt County) were energized with temporary generation, serving over 7,400 customers. In these substations and – additional locations, PG&E pre-installed equipment to facilitate faster interconnection of the temporary generation.
    - Brunswick substation energized 4191 customers in Grass Valley (Nevada County).
    - Willow Creek substation energized 2174 customers in Willow Creek (Humboldt County) for the duration of the event. The substation was energized on September 6 (the day before PSPS de-energization) to provide capacity support for the potential heat event. Customers supported by this effort did not experience an outage during the PSPS event.
    - Hoopa substation energized 1192 customers in Hoopa (Humboldt County) for the duration of the PSPS event. The substation was energized on September 6 (the day prior to PSPS de-energization) to provide capacity support for the potential heat event. Customers supported by this effort did not experience an outage during the PSPS event.

PG&E had 56 additional substations ready to be mobilized and energized with temporary generation if needed[36]. However, due to the scope and timing of the event, no additional substations were energized.

- Temporary Microgrids**:** PG&E safely provided power to portions of two de-energized communities where we pre-installed equipment to safely island and energize temporary microgrids. The objective of temporary microgrids is to enable some community resources to continue serving the surrounding population during PSPS events where it is safe to do so. PG&E targets safe-to-energize locations in towns most likely to be impacted by PSPS events for development of temporary microgrids. These microgrids utilize pre-installed interconnection hubs to safely and rapidly interconnect temporary generation.

  During this event, PG&E energized temporary microgrids in Shingletown (Shasta County) and Angwin (Napa County) with temporary generation.

  - The temporary microgrid in Angwin (Napa County) energized 48 customers, including a local CAL FIRE station, student housing, medical/dental clinic, post office, and bank.
  - The temporary microgrid in Shingletown (Shasta County) energized 78 customers, including a medical facility, fire station, gas station, market, and restaurants for approximately 7 hours before shutting down due to generator mechanical issue. A replacement generator was delivered and installed, re-energizing Shingletown for the remainder of the event.

- Backup Power Support: In locations outside of the areas energized by Substation Temporary Generation and Temporary Microgrids, PG&E utilized temporary generation to energize intensive care unit (ICU) hospitals identified in partnership with the California Hospital Association (CHA) and Hospital Council of Northern and Central California (HC) that were more likely to experience a PSPS event and did not have an existing mitigation in place or feasible given their location. Other individual facilities were also identified to mitigate active risks to public safety and emergency response operations.

  - Backup Power Support for Intensive Care Unit (ICU) Hospitals: During this event, PG&E used temporary generation to energize six ICU hospitals that had been pre-identified by CHA and HC in Napa, Tuolumne, and Shasta counties. PG&E also energized an ICU hospital in Nevada County by using temporary generation at the Brunswick substation.
  - Additional Backup Power Support for Public Safety: PG&E used temporary generation as backup power support for two water treatment and pumping facilities, a skilled nursing facility, and three sites serving wildfire first responders. These facilities did not have sufficient functioning backup generation to maintain critical operations during the event and reached out to PG&E requesting assistance.

    While as a general policy, PG&E does not offer temporary generation backup power support to individual facilities, it may make exceptions when feasible to respond to circumstances impacting public safety. PG&E responded to these requests in accordance with this policy.

- Islanding: In some cases, PG&E can leverage islanding capabilities in areas where transmission PSPS cut-off power to an area with generation to serve a portion of the distribution load. These situations require that the distribution lines are not in a high-risk fire area exceeding the mereological PSPS guidance and can thus be energized. PG&E's Humboldt island was able to be leveraged in the September 7 event due to PG&E transmission lines feeding the Humboldt area

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[36] Ready in this context is defined as operational within 48 hours.

being in scope for the event. During 2020, PG&E performed upgrades to the Humboldt Bay Generating Station to enable the plant to be safely islanded during emergency situations including PSPS.

Table 7: Substation Temporary Generation

Substation temporary generation	Generation deployed	Customers energized
Brunswick	20 MW	4191 customers[37]
Hoopa	4.5 MW	1192 customers
Willow Creek	6 MW	2174 customers
Total	**30.5 MW**	**7557 customers**

Table 8: Temporary Microgrids

Temporary Microgrid	Generation deployed	Customers energized
Angwin	500 kW	48 customers[38]
Shingletown	500 kW; replaced with 2 MW following mechanical issues	78 customers[39]
Total	**2.5 MW**	**126 customers**

Table 9: Backup Power Support

County	Site Type	Generation deployed	Reason Deployed
Napa	ICU Hospital	150 kW	COVID-19 Pandemic Response (pre-identified by CHA and HC)
Nevada	ICU Hospital	See Brunswick substation	COVID-19 Pandemic Response (pre-identified by CHA and HC)
Tuolumne	ICU Hospital	105 kW	COVID-19 Pandemic Response (pre-identified by CHA and HC)
Tuolumne	ICU Hospital	1.25 MW	COVID-19 Pandemic Response (pre-identified by CHA and HC)
Shasta	ICU Hospital	300 kW	COVID-19 Pandemic Response (pre-identified by CHA and HC)
Shasta	ICU Hospital	300 kW	COVID-19 Pandemic Response (pre-identified by CHA and HC)
Sierra	Water treatment/pumping facility	200 kW	Mitigate risk to public health/safety
Plumas	Fairgrounds (hosting firefighting command base)	1 MW	Mitigate risk to emergency response
El Dorado	Skilled nursing facility	125 kW	Mitigate risk to public health/safety
Kern	Water treatment/pumping facility	25 kW	Mitigate risk to public health/safety
Plumas	Fire station	100 kW	Mitigate risk to emergency response
Napa	Fire station	20 kW	Mitigate risk to emergency response
Total Backup Power Deployed		**3.6 MW (2.1 MW for ICU hospitals)**	

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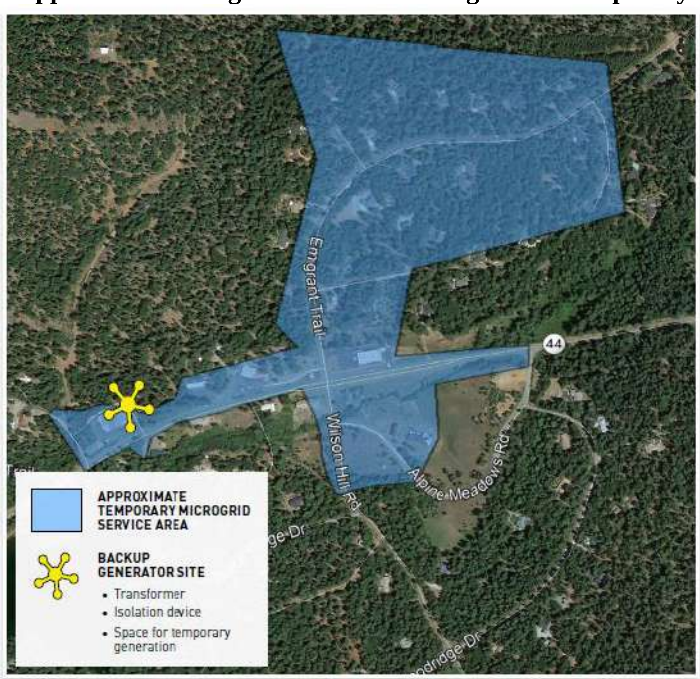
[37] Including Intensive Care Unit (ICU) hospital

[38] Including a local CAL FIRE station, student housing, medical/dental clinic, post office, and bank

[39] Including a medical facility, fire station, gas station, market, and restaurants

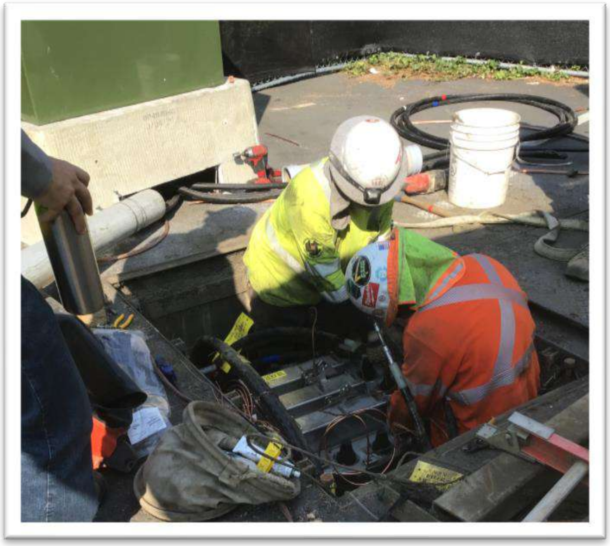
Figure 12: Approximate Energization Area of Angwin Temporary Microgrid

Figure 13: Approximate Energization Area of Shingletown Temporary Microgrid



P27-123 cont.

Figure 14: Installation of Temporary Switch in Vault to Enable Temporary Generation at ICU Hospital



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Section 14 – Lessons Learned from Event

After the EOC de-activated, EOC sections participated in after action reviews with the on-call teams who participated in the PSPS event. After the section specific after-action reviews were held, the command and general staff gathered for a section wide 'hotwash' to debrief on the event pluses and deltas, share items identified in the section specific after-action reviews and identify themes that should be addressed at the EOC level. Some of these items included:

Virtual EOC Environment

PG&E executed the September 7 event using a remote EOC activation. PG&E also exercised PSPS events in the virtual EOC environment three times in 2020 and applied learnings from this experience during the September 7 event. Even with these learnings, PG&E's virtual environment during September 7 EOC event lacked sufficient virtual status boards to replace the situational awareness capabilities of an in-person EOC activation. PG&E is working to improve and update the process to share information and status across the virtual EOC.

Situation Report

PG&E implemented a new PSPS situation report process in 2020 which leverages a technology platform that is new to PG&E. The PSPS situation report contains the latest information about the PSPS event through the planning, de-energization and restoration phases of the PSPS event. During the PSPS event PG&E recognized the need for additional training on this platform for EOC personnel to be able to be self-sufficient in utilizing this tool. PG&E will further leverage video-based trainings for EOC personnel so that the information in the situation report can be utilized broadly across the EOC teams.

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All Clear and Estimated Time of Restoration (ETOR) Process

During this event PG&E implemented two new process pertaining to all clear recording and estimated time of restoration notifications. During the event PG&E teams saw opportunity to further integrate the two processes to allow for further flexibility and streamlining of customer notifications. PG&E held working sessions with the key stakeholders after the event to design and refine the two processes which would allow PG&E to communicate more accurate ETOR's to the customers shortly after the weather all clears are declared.

Section 15 – Proposed Updates to ESRB-8

PG&E continues to work through the implementation of the de-energization guidelines and appreciates that there may be continued opportunity to refine certain aspects of the guidelines. PG&E will continue to actively engage with stakeholders and the open proceedings at the Commission and has no further suggestions at this time.

P27-123 cont.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

SECTION 3 & 4 – TIME, PLACE, DURATION AND AFFECTED CUSTOMERS

P27-123
cont.

Appendix A: TIME, PLACE, DURATION AND AFFECTED CUSTOMERS

Circuits labeled as "non-HFTD" are located outside of the CPUC High Fire-Threat District (HFTD). These circuits or portions of circuits are impacted for one of two reasons: (1) indirect impacts from transmission lines being de-energized or (2) the non-HFTD portion of the circuit are conductive to the HFTD at some point in the path to service.

Circuits with an asterisk (*) were sectionalized during the event to further reduce customer impact.

Several circuits show restoration times after September 10 as PG&E crews were not able to access these lines due to fire related access issues during PSPS restoration.

Table A-1. Distribution Circuits De-Energized During the September 7-10 PSPS Event

Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
ALLEGHANY 1101*	9/7/2020 21:57	9/10/2020 16:31	ALLEGHANY, DOWNIEVILLE, GOODYEARS BAR, SIERRA CITY	Partially Outside HFTD, Tier 3, Tier 2	1028	865	161	22	2
ALLEGHANY 1102*	9/7/2020 21:57	9/9/2020 15:28	ALLEGHANY, WASHINGTON	Tier 3	151	127	24	3	0
ALPINE 1101*	9/7/2020 23:03	9/9/2020 17:34	ANGELS CAMP, BEAR VALLEY	Partially Outside HFTD	276	271	5	2	0
ALPINE 1102*	9/7/2020 23:03	9/9/2020 17:33	ANGELS CAMP, BEAR VALLEY	Partially Outside HFTD	303	269	34	4	0
ANTLER 1101	9/8/2020 1:08	9/9/2020 10:08	LAKEHEAD	Partially Outside HFTD, Tier 3, Tier 2	913	771	126	53	16
APPLE HILL 1103	9/8/2020 1:15	9/9/2020 16:06	CAMINO, PLACERVILLE	Partially Outside HFTD, Tier 3, Tier 2	1260	1094	160	74	6
APPLE HILL 1104	9/8/2020 1:13	9/9/2020 14:24	CAMINO, PLACERVILLE, POLLOCK PINES	Partially Outside HFTD, Tier 3, Tier 2	2413	2232	171	157	10
APPLE HILL 2102	9/8/2020 1:08	9/9/2020 18:00	CAMINO, FAIR PLAY, GRIZZLY FLATS, MOUNT AUKUM, PLACERVILLE, POLLOCK PINES, SOMERSET	Partially Outside HFTD, Tier 3, Tier 2	4375	3999	336	292	40
BANGOR 1101*	9/7/2020 16:55	9/11/2020 16:04	BROWNSVILLE, DOBBINS, OREGON HOUSE, RACKERBY	Tier 3, Tier 2	291	263	26	21	2
BIG BEND 1101*	9/7/2020 15:34	9/10/2020 18:01	OROVILLE	Tier 3, Tier 2	234	208	24	16	2
BIG BEND 1102*	9/7/2020 22:34	Not restored due to fire access issues	BERRY CREEK	Tier 3	318	277	35	11	6
BIG MEADOWS 2101	9/7/2020 21:53	9/9/2020 17:02	ALMANOR, CANYON DAM, CHESTER, GREENVILLE, LAKE ALMANOR, PRATTVILLE, WESTWOOD	Partially Outside HFTD, Tier 2	2538	2270	264	94	4
BONNIE NOOK 1101*	9/7/2020 23:27	9/9/2020 13:20	ALTA, COLFAX, DUTCH FLAT, GOLD RUN	Tier 3	486	413	65	19	8
BONNIE NOOK 1102*	9/7/2020 23:27	9/9/2020 14:50	ALTA	Tier 3	521	453	61	20	7

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Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
BRIDGEVILLE 1101*	9/8/2020 0:16	9/10/2020 16:21	BRIDGEVILLE	Partially Outside HFTD, Tier 3, Tier 2	86	69	12	4	5
BRIDGEVILLE 1102*	9/8/2020 0:27	9/10/2020 19:48	BLOCKSBURG, BRIDGEVILLE, CARLOTTA	Partially Outside HFTD, Tier 3, Tier 2	262	219	28	11	15
BRUNSWICK 1102	9/7/2020 22:09	9/9/2020 16:57	GRASS VALLEY, NEVADA CITY	Partially Outside HFTD, Tier 3, Tier 2	1378	800	578	62	0
BRUNSWICK 1103	9/7/2020 15:09	9/9/2020 18:50	NEVADA CITY	Partially Outside HFTD, Tier 3, Tier 2	3177	2459	706	107	12
BRUNSWICK 1104	9/7/2020 15:09	9/9/2020 18:08	GRASS VALLEY, NEVADA CITY	Partially Outside HFTD, Tier 3, Tier 2	2508	2176	330	143	2
BRUNSWICK 1105	9/7/2020 22:10	9/9/2020 17:03	GRASS VALLEY, NEVADA CITY	Partially Outside HFTD, Tier 3, Tier 2	3675	3403	266	218	6
BRUNSWICK 1106	9/7/2020 22:10	9/9/2020 18:54	GRASS VALLEY	Partially Outside HFTD, Tier 3, Tier 2	4480	4257	212	279	11
BRUNSWICK 1107	9/7/2020 15:10	9/9/2020 17:23	GRASS VALLEY	Partially Outside HFTD, Tier 3, Tier 2	2650	2248	394	155	8
BRUNSWICK 1110	9/7/2020 15:10	9/9/2020 17:03	GRASS VALLEY, NEVADA CITY	Partially Outside HFTD, Tier 2	3048	2643	402	179	3
BUCKS CREEK 1101*	9/7/2020 21:53	9/10/2020 19:06	OROVILLE, STORRIE	Tier 3, Tier 2	4	0	3	0	1
BUCKS CREEK 1102*	9/7/2020 21:53	9/10/2020 13:33	BELDEN, QUINCY, STORRIE	Tier 3, Tier 2	120	52	66	4	2
BUCKS CREEK 1103*	9/7/2020 21:53	9/10/2020 16:51	QUINCY	Tier 3, Tier 2	311	262	49	5	0
BURNEY 1101	9/8/2020 2:09	9/9/2020 13:07	BURNEY, CASSEL, JOHNSON PARK	Partially Outside HFTD, Tier 2	1761	1527	205	143	29
BURNEY 1102	9/8/2020 2:09	9/9/2020 13:11	BURNEY	Partially Outside HFTD, Tier 2	522	392	126	39	4
BUTTE 1105*	9/7/2020 22:33	9/9/2020 19:45	CHICO	Tier 3, Tier 2	266	245	19	19	2
CAL WATER 1102*	9/8/2020 19:13	9/9/2020 12:12	BAKERSFIELD	Partially Outside HFTD, Tier 2	13	0	10	0	3
CALISTOGA 1101*	9/7/2020 20:08	9/10/2020 11:50	CALISTOGA	Partially Outside HFTD, Tier 3, Tier 2	1549	1220	227	52	102
CALISTOGA 1102*	9/7/2020 21:22	9/9/2020 16:59	CALISTOGA	Partially Outside HFTD, Tier 3, Tier 2	919	678	177	20	64

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Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
CEDAR CREEK 1101	9/8/2020 0:03	9/10/2020 15:33	BELLA VISTA, BIG BEND, MONTGOMERY CREEK, OAK RUN, ROUND MOUNTAIN	Tier 3, Tier 2	731	650	75	49	6
CHALLENGE 1101	9/7/2020 21:43	Not restored due to fire access issues	CHALLENGE, CLIPPER MILLS, LA PORTE, STRAWBERRY VALLEY	Tier 3, Tier 2	668	576	92	39	0
CHALLENGE 1102	9/7/2020 21:43	9/11/2020 17:25	BROWNSVILLE, CHALLENGE, DOBBINS, FORBESTOWN	Tier 3, Tier 2	827	723	102	73	2
CHESTER 1101*	9/7/2020 21:53	9/9/2020 16:35	CHESTER	Partially Outside HFTD, Tier 2	939	741	197	41	1
CHESTER 1102*	9/7/2020 21:53	9/9/2020 16:36	CHESTER	Partially Outside HFTD, Tier 2	651	506	143	29	2
CLARK ROAD 1102	9/7/2020 22:02	9/10/2020 17:43	OROVILLE, PARADISE	Partially Outside HFTD, Tier 3, Tier 2	1093	944	127	90	22
COLUMBIA HILL 1101*	9/7/2020 15:26	9/9/2020 15:36	CAMPTONVILLE, NEVADA CITY, NORTH SAN JUAN	Tier 3, Tier 2	1126	986	126	84	14
CRESCENT MILLS 2101	9/7/2020 21:39	9/9/2020 18:31	CRESCENT MILLS, GREENVILLE, TAYLORSVILLE	Partially Outside HFTD, Tier 2	838	689	119	50	30
CURTIS 1701	9/7/2020 18:05	9/8/2020 19:27	SONORA	Partially Outside HFTD, Tier 2	1792	1213	571	114	8
CURTIS 1702	9/7/2020 23:08	9/9/2020 14:03	SONORA, SOULSBYVILLE, TUOLUMNE	Partially Outside HFTD, Tier 3, Tier 2	4307	3808	486	366	13
CURTIS 1703	9/7/2020 23:10	9/9/2020 15:48	GROVELAND, JAMESTOWN, SONORA	Partially Outside HFTD, Tier 3, Tier 2	3734	3171	535	233	28
CURTIS 1704	9/7/2020 23:05	9/9/2020 14:11	COLUMBIA, SONORA	Partially Outside HFTD, Tier 3, Tier 2	2492	2188	290	214	14
CURTIS 1705	9/7/2020 23:14	9/9/2020 11:34	SONORA, SOULSBYVILLE, TUOLUMNE	Partially Outside HFTD, Tier 3, Tier 2	2742	2298	438	266	6
DESCHUTES 1101*	9/8/2020 0:56	9/9/2020 8:58	OAK RUN	Tier 3, Tier 2	24	23	1	1	0
DIAMOND SPRINGS 1106*	9/7/2020 18:28	9/9/2020 10:02	PLACERVILLE	Tier 2	68	64	4	6	0
DOBBINS 1101*	9/7/2020 21:43	9/9/2020 11:45	CAMPTONVILLE, DOBBINS, OREGON HOUSE	Partially Outside HFTD, Tier 3, Tier 2	857	738	101	63	18
DRUM 1101*	9/8/2020 1:42	9/9/2020 17:35	ALTA, BAXTER, EMIGRANT GAP	Tier 3	188	140	42	4	6
DUNBAR 1101*	9/7/2020 20:38	9/9/2020 13:01	GLEN ELLEN, KENWOOD, SANTA ROSA	Partially Outside HFTD, Tier 3, Tier 2	2528	2359	142	235	27

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Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
DUNBAR 1103*	9/7/2020 20:25	9/9/2020 12:33	GLEN ELLEN, SONOMA	Partially Outside HFTD, Tier 3, Tier 2	272	199	51	5	22
EAST QUINCY 1101	9/7/2020 21:39	9/9/2020 17:55	QUINCY	Partially Outside HFTD, Tier 3, Tier 2	1501	1242	250	79	9
EL DORADO PH 2101	9/8/2020 1:21	9/9/2020 17:53	GRIZZLY FLATS, KYBURZ, PACIFIC HOUSE, PLACERVILLE, POLLOCK PINES, SOMERSET, TWIN BRIDGES	Partially Outside HFTD, Tier 3, Tier 2	4552	4282	262	301	8
EL DORADO PH 2102	9/8/2020 1:19	9/9/2020 11:03	POLLOCK PINES	Tier 3	1581	1444	136	107	1
FORESTHILL 1101*	9/8/2020 2:06	9/9/2020 14:44	FORESTHILL	Tier 3, Tier 2	2206	2059	146	178	1
FORESTHILL 1102*	9/8/2020 2:06	9/9/2020 15:21	FORESTHILL	Tier 3, Tier 2	420	398	22	21	0
FORT SEWARD 1121	9/8/2020 0:12	9/13/2020 14:02	ALDERPOINT, ZENIA	Partially Outside HFTD, Tier 2	196	160	32	11	4
FORT SEWARD 1122	9/8/2020 0:14	Not restored due to fire access issues	ALDERPOINT, BLOCKSBURG, GARBERVILLE	Partially Outside HFTD, Tier 2	89	71	16	1	2
FROGTOWN 1701*	9/7/2020 23:15	9/9/2020 11:40	AVERY, DOUGLAS FLAT, MURPHYS, SHEEP RANCH	Tier 3, Tier 2	1251	1108	123	85	20
FROGTOWN 1702*	9/7/2020 23:44	9/9/2020 16:04	VALLECITO	Tier 2	318	263	52	14	3
FRUITLAND 1142*	9/8/2020 0:42	9/9/2020 9:05	MYERS FLAT	Partially Outside HFTD	44	40	2	1	2
GANSNER 1101	9/7/2020 21:39	9/9/2020 19:23	KEDDIE, MEADOW VALLEY, QUINCY	Partially Outside HFTD, Tier 3, Tier 2	1677	1352	317	72	8
GRAYS FLAT 0401*	9/7/2020 21:39	9/9/2020 17:32	TWAIN	Tier 2	121	100	21	6	0
HAMILTON BRANCH 1101	9/7/2020 21:53	9/9/2020 18:57	CHESTER, LAKE ALMANOR, WESTWOOD	Partially Outside HFTD, Tier 2	2337	2133	202	104	2
HOOPA 1101*	9/8/2020 0:32	9/9/2020 15:16	HOOPA, ORLEANS, SOMES BAR, WEITCHPEC	Partially Outside HFTD, Tier 2	585	469	112	9	4
KANAKA 1101*	9/7/2020 14:31	Not restored due to fire access issues	FEATHER FALLS, FORBESTOWN, OROVILLE	Tier 3, Tier 2	581	526	48	40	7
LAMONT 1102*	9/8/2020 19:10	9/9/2020 12:25	BAKERSFIELD	Tier 2	5	0	5	0	0
LOW GAP 1101*	9/8/2020 0:30	9/10/2020 16:42	BRIDGEVILLE, MAD RIVER, RUTH, ZENIA	Partially Outside HFTD, Tier 2	700	591	107	27	2
MAPLE CREEK 1101	9/8/2020 0:29	9/9/2020 14:37	KNEELAND, KORBEL	Partially Outside HFTD, Tier 2	137	94	34	4	9
MC ARTHUR 1101	9/8/2020 2:10	9/9/2020 13:17	BIEBER, FALL RIVER MILLS, LITTLE VALLEY, MCARTHUR, NUBIEBER	Partially Outside HFTD, Tier 2	1323	956	231	71	136
MC ARTHUR 1102	9/8/2020 2:11	9/9/2020 13:21	FALL RIVER MILLS, MCARTHUR	Partially Outside HFTD, Tier 2	274	173	63	6	38

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Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
MIDDLETOWN 1101*	9/7/2020 22:08	9/9/2020 19:35	CALISTOGA, MIDDLETOWN	Tier 3	82	62	19	1	1
MIWUK 1701	9/7/2020 23:02	9/9/2020 12:29	LONG BARN, MI WUK VILLAGE, TUOLUMNE, TWAIN HARTE	Tier 3, Tier 2	3632	3379	248	199	5
MIWUK 1702	9/7/2020 23:02	9/9/2020 11:51	SONORA, TWAIN HARTE	Tier 3, Tier 2	3760	3504	252	244	4
MOUNTAIN QUARRIES 2101*	9/7/2020 18:46	9/9/2020 15:44	COOL, GARDEN VALLEY, GEORGETOWN, GREENWOOD	Partially Outside HFTD, Tier 3, Tier 2	1774	1619	147	120	8
NOTRE DAME 1103*	9/7/2020 23:10	9/9/2020 19:49	PARADISE	Tier 2	14	7	7	0	0
NOTRE DAME 1104*	9/7/2020 16:14	9/9/2020 19:34	CHICO, FOREST RANCH	Partially Outside HFTD, Tier 3, Tier 2	226	194	29	13	3
ORO FINO 1101	9/7/2020 23:06	9/9/2020 15:08	MAGALIA	Tier 3	2275	2199	70	264	6
ORO FINO 1102	9/7/2020 23:08	9/10/2020 16:23	BUTTE MEADOWS, FOREST RANCH, MAGALIA, STIRLING CITY	Tier 3, Tier 2	1968	1833	123	159	12
PARADISE 1103*	9/7/2020 14:44	9/9/2020 12:52	PARADISE	Partially Outside HFTD, Tier 3	62	60	2	2	0
PARADISE 1104	9/7/2020 22:02	9/9/2020 20:09	PARADISE	Partially Outside HFTD, Tier 3, Tier 2	1872	1654	216	138	2
PARADISE 1105	9/7/2020 21:57	9/9/2020 17:48	MAGALIA, PARADISE	Partially Outside HFTD, Tier 3	1347	1117	229	98	1
PARADISE 1106	9/7/2020 21:53	9/9/2020 12:40	PARADISE	Partially Outside HFTD, Tier 3	402	344	57	20	1
PEORIA 1705*	9/7/2020 23:13	9/9/2020 12:11	JAMESTOWN, SONORA	Partially Outside HFTD, Tier 2	706	652	54	98	0
PIKE CITY 1101	9/7/2020 21:57	9/9/2020 20:01	CAMPTONVILLE, NORTH SAN JUAN	Tier 3	384	339	43	27	2
PIKE CITY 1102	9/7/2020 21:57	9/10/2020 14:06	CAMPTONVILLE	Tier 3	24	15	8	1	1
PINE GROVE 1102*	9/7/2020 23:05	9/9/2020 13:42	FIDDLETOWN, PINE GROVE, PIONEER, SUTTER CREEK, VOLCANO	Tier 3, Tier 2	3458	3168	278	265	12
PINECREST 0401*	9/8/2020 0:21	9/9/2020 12:31	PINECREST	Partially Outside HFTD, Tier 3, Tier 2	205	176	29	2	0
PIT NO 1 1101*	9/8/2020 2:14	9/9/2020 12:59	FALL RIVER MILLS, MCARTHUR	Partially Outside HFTD, Tier 2	841	630	169	42	42
PIT NO 3 2101*	9/8/2020 1:05	9/9/2020 12:50	BIG BEND, BURNEY	Partially Outside HFTD, Tier 2	150	103	42	6	5
PIT NO 5 1101	9/8/2020 0:41	9/9/2020 9:56	BIG BEND	Tier 2	109	79	28	4	2
PIT NO 7 1101	9/8/2020 1:28	9/9/2020 14:44	MONTGOMERY CREEK, ROUND MOUNTAIN	Tier 2	2	1	1	0	0

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Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
PLACERVILLE 1109*	9/8/2020 1:12	9/9/2020 14:19	PLACERVILLE	Partially Outside HFTD, Tier 2	502	406	94	28	2
PLACERVILLE 1111	9/8/2020 1:11	9/9/2020 11:06	PLACERVILLE	Partially Outside HFTD, Tier 2	1087	814	263	59	10
PLACERVILLE 1112	9/8/2020 1:12	9/9/2020 13:37	PLACERVILLE	Partially Outside HFTD, Tier 2	2052	1682	367	117	3
PLACERVILLE 2106	9/8/2020 1:10	9/10/2020 13:58	COLOMA, GARDEN VALLEY, GEORGETOWN, KELSEY, PLACERVILLE	Tier 3, Tier 2	5139	4750	363	341	26
PUEBLO 2102*	9/8/2020 4:07	9/9/2020 10:48	NAPA	Tier 3	42	28	13	2	1
PUEBLO 2103*	9/7/2020 4:25	9/10/2020 9:02	NAPA	Tier 3	11	3	4	0	4
RACETRACK 1703	9/7/2020 15:03	9/9/2020 14:22	COLUMBIA, SONORA	Partially Outside HFTD, Tier 3, Tier 2	3413	2882	521	271	10
RACETRACK 1704	9/7/2020 23:03	9/9/2020 13:41	JAMESTOWN, SONORA	Tier 2	659	616	37	53	6
RINCON 1101	9/8/2020 3:06	9/9/2020 18:04	SANTA ROSA	Partially Outside HFTD, Tier 3, Tier 2	3649	3429	205	288	15
RINCON 1102	9/8/2020 3:17	9/9/2020 10:01	SANTA ROSA	Partially Outside HFTD, Tier 2	4558	4332	224	243	2
RINCON 1103	9/8/2020 3:14	9/9/2020 14:16	SANTA ROSA	Partially Outside HFTD, Tier 3, Tier 2	2020	1923	82	123	15
RINCON 1104	9/8/2020 3:07	9/8/2020 22:13	SANTA ROSA	Partially Outside HFTD, Tier 3, Tier 2	3951	3677	270	238	4
RISING RIVER 1101	9/8/2020 2:08	9/9/2020 14:33	CASSEL, HAT CREEK, OLD STATION	Partially Outside HFTD, Tier 2	696	579	98	27	19
SALT SPRINGS 2101	9/7/2020 23:03	9/9/2020 17:38	ARNOLD, BEAR VALLEY, PIONEER	Partially Outside HFTD, Tier 2	384	330	53	5	1
SALT SPRINGS 2102*	9/7/2020 23:04	9/9/2020 18:58	ARNOLD, CAMP CONNELL, DORRINGTON	Tier 3, Tier 2	1973	1896	74	32	3
SAN BERNARD 1101*	9/8/2020 19:11	9/9/2020 13:08	ARVIN, BAKERSFIELD	Partially Outside HFTD, Tier 2	16	1	8	0	7
SANTA ROSA A 1104*	9/8/2020 1:42	9/9/2020 11:27	SANTA ROSA	Tier 3, Tier 2	456	284	165	21	7
SHADY GLEN 1101*	9/7/2020 18:45	9/9/2020 10:41	COLFAX	Tier 2	22	20	2	2	0
SHADY GLEN 1102*	9/7/2020 18:32	9/9/2020 15:57	COLFAX, GRASS VALLEY	Partially Outside HFTD, Tier 3, Tier 2	667	605	60	61	2

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Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
SILVERADO 2102*	9/7/2020 21:55	9/9/2020 17:14	NAPA, SAINT HELENA	Partially Outside HFTD, Tier 3, Tier 2	344	199	76	6	69
SILVERADO 2103*	9/8/2020 3:37	9/9/2020 9:39	KENWOOD	Tier 3	3	0	3	0	0
SILVERADO 2104*	9/7/2020 22:04	9/10/2020 11:48	ANGWIN, CALISTOGA, DEER PARK, POPE VALLEY, SAINT HELENA	Partially Outside HFTD, Tier 3, Tier 2	2350	1973	233	103	144
SILVERADO 2105*	9/7/2020 21:47	9/9/2020 16:59	CALISTOGA, SAINT HELENA	Partially Outside HFTD, Tier 3	159	133	11	5	15
SPANISH CREEK 4401*	9/7/2020 21:39	9/9/2020 18:15	CRESCENT MILLS	Tier 2	34	31	3	1	0
SPAULDING 1101*	9/8/2020 1:42	9/9/2020 16:49	EMIGRANT GAP, SODA SPRINGS	Partially Outside HFTD, Tier 3, Tier 2	160	82	69	4	9
SPRING GAP 1702	9/8/2020 0:21	9/9/2020 13:33	COLD SPRINGS, LONG BARN, PINECREST, STRAWBERRY	Partially Outside HFTD, Tier 3, Tier 2	1473	1325	146	30	2
STANISLAUS 1701	9/7/2020 23:05	9/10/2020 21:42	ARNOLD, AVERY, HATHAWAY PINES, MURPHYS	Tier 3, Tier 2	1785	1590	190	104	5
STANISLAUS 1702	9/7/2020 23:07	9/9/2020 13:52	ARNOLD, AVERY, HATHAWAY PINES, MURPHYS	Tier 3, Tier 2	4882	4577	304	168	1
SUMMIT 1101*	9/8/2020 1:37	9/9/2020 18:03	SODA SPRINGS	Partially Outside HFTD, Tier 2	1048	959	83	19	6
SUMMIT 1102	9/8/2020 1:37	9/9/2020 18:53	NORDEN, SODA SPRINGS	Partially Outside HFTD, Tier 2	286	209	77	2	0
TAMARACK 1101	9/8/2020 1:37	9/9/2020 15:38	SODA SPRINGS	Partially Outside HFTD, Tier 2	421	383	32	7	6
TAMARACK 1102	9/8/2020 1:37	9/9/2020 12:43	SODA SPRINGS	Partially Outside HFTD	135	107	22	2	6
TAR FLAT 0401*	9/7/2020 23:05	9/8/2020 20:04	SONORA	Partially Outside HFTD, Tier 3, Tier 2	344	335	9	23	0
TAR FLAT 0402*	9/7/2020 23:05	9/9/2020 11:17	SONORA	Partially Outside HFTD, Tier 3, Tier 2	476	412	64	27	0
TEJON 1102*	9/8/2020 19:08	9/9/2020 15:45	LEBEC	Partially Outside HFTD, Tier 2	592	478	100	32	14
TEJON 1103*	9/8/2020 19:03	9/9/2020 13:25	ARVIN	Partially Outside HFTD, Tier 2	15	4	10	0	1
TIGER CREEK 0201*	9/7/2020 23:06	9/9/2020 9:53	PIONEER	Tier 3, Tier 2	14	3	11	0	0
VOLTA 1101	9/7/2020 15:25	9/9/2020 18:45	MANTON, MILL CREEK, MINERAL, PAYNES CREEK, RED BLUFF, SHINGLETOWN	Partially Outside HFTD, Tier 3, Tier 2	1289	1080	175	63	34

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Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
VOLTA 1102	9/7/2020 15:25	9/9/2020 19:06	SHINGLETOWN	Partially Outside HFTD, Tier 3, Tier 2	2558	2375	172	224	11
WEIMAR 1101*	9/8/2020 1:10	9/9/2020 17:54	COLFAX	Tier 2	27	24	3	2	0
WEST POINT 1101	9/7/2020 23:05	9/9/2020 11:40	PIONEER, VOLCANO	Tier 3, Tier 2	1750	1687	59	120	4
WEST POINT 1102	9/7/2020 23:04	9/9/2020 14:38	GLENCOE, MOKELUMNE HILL, MOUNTAIN RANCH, RAIL ROAD FLAT, WEST POINT, WILSEYVILLE	Partially Outside HFTD, Tier 3, Tier 2	2808	2555	227	182	26
WHITMORE 1101*	9/7/2020 17:29	9/9/2020 16:01	OAK RUN, WHITMORE	Tier 3, Tier 2	311	276	29	18	6
WILDWOOD 1101*	9/9/2020 10:07	9/9/2020 10:09	PLATINA, WILDWOOD	Tier 2	125	89	33	4	3
WILLOW CREEK 1101*	9/8/2020 0:28	9/9/2020 13:49	BLUE LAKE, WILLOW CREEK	Partially Outside HFTD, Tier 3, Tier 2	180	142	29	6	9
WYANDOTTE 1103*	9/7/2020 22:46	Not restored due to fire access issues	BERRY CREEK, OROVILLE	Partially Outside HFTD, Tier 3, Tier 2	1350	1235	108	127	7
WYANDOTTE 1105	9/7/2020 18:04	9/7/2020 18:13	OROVILLE	Partially Outside HFTD, Tier 2	516	496	19	70	1
WYANDOTTE 1107*	9/7/2020 22:20	9/13/2020 8:52	OROVILLE	Partially Outside HFTD, Tier 3, Tier 2	945	885	42	93	18
				Total	**168,581**	**148,675**	**18,418**	**10,383**	**1,488**

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Table A-2. Transmission Circuits De-Energized During the September 7-10 PSPS Event

Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
APPLE HILL #2 TAP	9/8/20 1:33	9/9/20 12:32	Transmission Line	Tier 2					
BEARDSLEY 115KV TAP	9/8/20 1:03	9/9/20 10:23	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
BRIDGEVILLE-COTTONWOOD 115 kV	9/8/20 0:35	9/9/20 10:09	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2	1		1		
BRIDGEVILLE-GARBERVILLE 60 kV	9/7/20 16:46	9/10/20 14:14	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
BRUNSWICK #1-115KV TAP	9/8/20 2:38	9/9/20 10:36	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
BRUNSWICK #2-115KV TAP	9/8/20 2:38	9/9/20 10:38	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
BURNEY 60KV TAP	9/8/20 2:08	9/9/20 12:57	Transmission Line	Partially Outside HFTD					
BURNEY FOREST PRODUCTS 230KV TAP	9/8/20 2:33	9/9/20 10:28	Transmission Line	Partially Outside HFTD					
BUTTE VALLEY-CARIBOU 115 kV	9/7/20 21:26	9/9/20 17:08	Transmission Line	Partially Outside HFTD, Tier 2					
CARBERRY SW STA-ROUND MOUNTAIN 230 kV	9/8/20 2:31	9/9/20 12:15	Transmission Line	Tier 3, Tier 2					
CARIBOU #2 60 kV	9/7/20 21:39	9/9/20 17:18	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
CARIBOU-PLUMAS JCT 60 kV	9/7/20 21:39	9/9/20 17:18	Transmission Line	Partially Outside HFTD, Tier 2	2		1		1
CARIBOU-TABLE MOUNTAIN 230 kV	9/7/20 22:59	9/9/20 16:54	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
CARIBOU-WESTWOOD 60 kV	9/7/20 21:54	9/9/20 16:23	Transmission Line	Partially Outside HFTD, Tier 2	6		1		5
CISCO GROVE 60KV TAP	9/8/20 1:37	9/9/20 12:37	Transmission Line	Partially Outside HFTD					
COLGATE-ALLEGHANY 60 kV	9/7/20 21:57	9/9/20 12:37	Transmission Line	Tier 3, Tier 2					
COLGATE-CHALLENGE 60 kV	9/7/20 21:44	9/9/20 10:54	Transmission Line	Tier 3, Tier 2					
COLLINS PINE 60KV TAP	9/7/20 21:54	9/9/20 16:23	Transmission Line	Partially Outside HFTD, Tier 2	1		1		
DEER CREEK-DRUM 60 kV	9/8/20 1:44	9/9/20 10:59	Transmission Line	Tier 3					

P27-123 cont.

Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
DONNELLS-MI-WUK 115 kV	9/8/20 1:03	9/9/20 10:23	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
DRUM-GRASS VALLEY-WEIMAR 60 kV	9/8/20 2:00	9/9/20 10:45	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
DRUM-HIGGINS 115 kV	9/8/20 2:38	9/9/20 17:44	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
DRUM-RIO OSO #1 115 kV	9/8/20 2:38	9/9/20 10:36	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
DRUM-RIO OSO #2 115 kV	9/8/20 2:38	9/9/20 10:38	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
DRUM-SPAULDING 60 kV	9/8/20 1:42	9/9/20 12:33	Transmission Line	Tier 3, Tier 2					
DRUM-SUMMIT #1 115 kV	9/8/20 2:16	9/9/20 13:09	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
DRUM-SUMMIT #2 115 kV	9/8/20 2:17	9/9/20 13:02	Transmission Line	Partially Outside HFTD, Tier 3, Zone 1, Tier 2					
ELDORADO-MISSOURI FLAT #2 115 kV	9/8/20 1:33	9/9/20 12:32	Transmission Line	Partially Outside HFTD, Tier 3, Zone 1, Tier 2					
FORBESTOWN 115KV TAP	9/7/20 21:32		Transmission Line	Tier 3					
FRENCH MEADOWS-MIDDLE FORK 60 kV	9/8/20 2:14	9/9/20 12:40	Transmission Line	Tier 3					
HAMILTON BRANCH-CHESTER 60 kV	9/7/20 21:54	9/9/20 16:23	Transmission Line	Partially Outside HFTD, Tier 2					
HAT CREEK #1-PIT #1 60 kV	9/8/20 2:07	9/9/20 12:59	Transmission Line	Tier 2					
HAT CREEK #1-WESTWOOD 60 kV	9/8/20 2:05	9/9/20 13:11	Transmission Line	Partially Outside HFTD, Zone 1, Tier 2					
HUMBOLDT-TRINITY 115 kV	9/7/20 17:06	9/10/20 12:04	Transmission Line	Partially Outside HFTD, Tier 2					
KANAKA TAP 115 kV	9/7/20 21:32		Transmission Line	Tier 3, Tier 2					
KILARC-CEDAR CREEK 60 kV	9/8/20 0:59	9/9/20 13:15	Transmission Line	Tier 3					
KM GREEN 115KV TAP	9/7/20 23:52	9/9/20 10:04	Transmission Line	Tier 2	1				1
MALACHA TAP 230 kV	9/8/20 2:15	9/9/20 12:45	Transmission Line	Tier 2					

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cont.

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Circuit Name	De-Energization Date and Time	Restoration Date and Time	Key Communities	HFTD Tier(s)	Total Customers	Residential Customers	Commercial / Industrial Customers	Medical Baseline Customers	Other Customers
MAPLE CREEK-HOOPA 60 kV	9/7/20 16:50	9/10/20 12:21	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
MIDDLE FORK #1 60 kV	9/8/20 2:14	9/9/20 11:44	Transmission Line	Tier 3					
MIDDLE FORK-GOLD HILL 230 kV	9/8/20 2:17	9/9/20 11:16	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
PARADISE-TABLE MOUNTAIN 115 kV	9/7/20 22:05	9/9/20 18:34	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
PIT #1-COTTONWOOD 230 kV	9/8/20 2:33	9/9/20 10:28	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2	1		1		
PIT #1-HAT CREEK #2-BURNEY 60 kV	9/8/20 2:08	9/9/20 12:57	Transmission Line	Partially Outside HFTD, Tier 2					
PIT #1-MCARTHUR 60 kV	9/8/20 2:09	9/9/20 12:55	Transmission Line	Partially Outside HFTD, Tier 2					
PIT #3-CARBERRY SW STA 230 kV	9/8/20 2:27	9/9/20 12:20	Transmission Line	Partially Outside HFTD, Zone 1, Tier 2	1		1		
PIT #3-PIT #1 230 kV	9/8/20 2:22	9/9/20 12:31	Transmission Line	Partially Outside HFTD, Zone 1, Tier 2	1		1		
SALT SPRINGS-TIGER CREEK 115 kV	9/7/20 23:52	9/9/20 10:04	Transmission Line	Tier 3, Tier 2					
SAND BAR 115KV TAP	9/8/20 1:03	9/9/20 10:23	Transmission Line	Tier 3					
SLY CREEK TAP 115 kV	9/7/20 21:32		Transmission Line	Tier 3					
SPAULDING #3-SPAULDING #1 60 KV LINE	9/8/20 1:42	9/9/20 12:33	Transmission Line	Tier 2					
SPAULDING-SUMMIT 60 kV	9/8/20 1:37	9/9/20 12:37	Transmission Line	Partially Outside HFTD, Tier 2	1		1		
SPI (BURNEY) 230KV TAP	9/8/20 2:22	9/9/20 12:31	Transmission Line	Tier 2					
SPRING GAP 115KV TAP	9/8/20 1:03	9/9/20 10:23	Transmission Line	Tier 3					
TRINITY-MAPLE CREEK 60 kV	9/7/20 16:58	9/10/20 12:15	Transmission Line	Partially Outside HFTD, Tier 2	3		3		
WEIMAR #1 60 kV	9/8/20 2:06	9/9/20 10:54	Transmission Line	Tier 3, Tier 2					
WEST POINT-VALLEY SPRINGS 60 kV	9/8/20 0:25	9/9/20 10:15	Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
WOODLEAF-PALERMO 115 kV	9/7/20 21:32		Transmission Line	Partially Outside HFTD, Tier 3, Tier 2					
				Total	**18**	**-**	**11**	**-**	**7**

P27-123 cont.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

SECTION 6 – CUSTOMER NOTIFICATIONS SENT

P27-123 cont.

Appendix B: CUSTOMER NOTIFICATIONS SENT

The following details the automated notifications sent to Public Safety Partners, Critical Facilities, Medical Baseline Customers and all other populations during the PSPS event. Notifications sent to customers of record are based on unique Service Point IDs (SPIDs) for each notification campaign. Notification counts provided for local community representatives (also referred to as Public Safety Partner agency notifications) are based on total contacts that received these notifications.

Table B-1. Summary of Customer Notifications

Notification Type	Notification Campaign Name	Notification Launch Date and Time	Total Customer Notifications Attempted (by SPID)[1]*	Medical Baseline Customer Notifications Attempted (by SPID)	Total Customers Successfully Notified (by SPID)*
Advanced 72-48 Hour Watch	TP1_09072020_T-66_All_PSPS_09072020	9/5/20 9:18 AM	153	-	148
Advanced 72-48 Hour Watch	TP2_09072020_T-66_All_PSPS_09072020	9/5/20 9:21 AM	366	-	362
Advanced 72-48 Hour Watch	TP3_09072020_T-66_All_PSPS_09072020	9/5/20 9:26 AM	167	-	166
Advanced 72-48 Hour Watch	TP4_09072020_T-66_All_PSPS_09072020	9/5/20 9:27 AM	60	-	58
Advanced 72-48 Hour Watch	TP5_09072020_T-66_All_PSPS_09072020	9/5/20 9:28 AM	7	-	7
Advanced 72-48 Hour Watch	TP6_09072020_T-66_All_PSPS_09072020	9/5/20 9:28 AM	2	-	2
Advanced 72-48 Hour Watch	TP7_09072020_T-66_All_PSPS_09072020	9/5/20 9:28 AM	20	-	20
Advanced 72-48 Hour Watch	SWN_Local Community Representative Public Safety Partner Agency Notification*	9/5/20 10:23 AM	508	-	508
72-48 Hour Watch	TP1_09072020_Watch_MMT_PSPS_09072020	9/5/20 8:06 PM	7	7	7
72-48 Hour Watch	TP1_09072020_Watch_Medical Baseline_PSPS_09072020	9/5/20 8:07 PM	1,419	1,419	1,401
72-48 Hour Watch	TP1_09072020_Watch_Non Medical Baseline_PSPS_09072020	9/5/20 8:09 PM	16,239	-	14,411
72-48 Hour Watch	TP2_09072020_Watch_MMT_PSPS_09072020	9/5/20 8:10 PM	38	38	36
72-48 Hour Watch	TP2_09072020_Watch_Medical Baseline_PSPS_09072020	9/5/20 8:12 PM	3,088	3,088	3,068
72-48 Hour Watch	TP2_09072020_Watch_Non Medical Baseline_PSPS_09072020	9/5/20 8:18 PM	44,215	-	35,963
72-48 Hour Watch	TP3_09072020_Watch_MMT_PSPS_09072020	9/5/20 8:20 PM	27	27	23
72-48 Hour Watch	TP3_09072020_Watch_Medical Baseline_PSPS_09072020	9/5/20 8:24 PM	1,914	1,914	1,897
72-48 Hour Watch	TP3_09072020_Watch_Non Medical Baseline_PSPS_09072020	9/5/20 8:30 PM	27,417	-	23,526
72-48 Hour Watch	TP4_09072020_Watch_MMT_PSPS_09072020	9/5/20 8:32 PM	1	1	1
72-48 Hour Watch	TP4_09072020_Watch_Medical Baseline_PSPS_09072020	9/5/20 8:35 PM	511	511	506
72-48 Hour Watch	TP4_09072020_Watch_Non Medical Baseline_PSPS_09072020	9/5/20 8:38 PM	5,015	-	4,013
72-48 Hour Watch	TP5_09072020_Watch_MMT_PSPS_09072020	9/5/20 8:38 PM	1	1	1
72-48 Hour Watch	TP5_09072020_Watch_Medical Baseline_PSPS_09072020	9/5/20 8:39 PM	222	222	211
72-48 Hour Watch	TP5_09072020_Watch_Non Medical Baseline_PSPS_09072020	9/5/20 8:39 PM	368	-	287
72-48 Hour Watch	TP6_09072020_Watch_Non Medical Baseline_PSPS_09072020	9/5/20 8:40 PM	54	-	52
72-48 Hour Watch	TP7_09072020_Watch_MMT_PSPS_09072020	9/5/20 8:40 PM	2	2	2
72-48 Hour Watch	TP7_09072020_Watch_Medical Baseline_PSPS_09072020	9/5/20 9:02 PM	103	103	101
72-48 Hour Watch	TP7_09072020_Watch_Non Medical Baseline_PSPS_09072020	9/5/20 9:02 PM	2,624	-	2,443

P27-123 cont.

[1] * Local Community Representatives / Public Safety Partner Agency Notification counts unique contacts (not SPIDs)

Notification Type	Notification Campaign Name	Notification Launch Date and Time	Total Customer Notifications Attempted (by SPID)[1]*	Medical Baseline Customer Notifications Attempted (by SPID)	Total Customers Successfully Notified (by SPID)*
48-24 Hour Watch	SWN_Local Community Representative Public Safety Partner Agency Notification*	9/6/20 5:43 PM	457	-	457
48-24 Hour Watch	TP1_09072020_C01_Watch_Non Medical Baseline_PSPS_09072020	9/6/20 6:08 PM	45,345	-	42,484
48-24 Hour Watch	ID564553_PSPS_090720_C01_Broadnet_for_Transmission	9/6/20 6:11 PM	16	-	16
48-24 Hour Watch	TP2_09072020_C01_Watch_Non Medical Baseline_PSPS_09072020	9/6/20 6:22 PM	23,077	-	21,804
48-24 Hour Watch	Direct Email to Transmission Customers Without Phone	9/6/20 6:34 PM	11	-	11
48-24 Hour Watch	TP3_09072020_C01_Watch_Non Medical Baseline_PSPS_09072020	9/6/20 6:38 PM	15,435	-	14,564
48-24 Hour Watch	TP4_09072020_C01_Watch_Non Medical Baseline_PSPS_09072020	9/6/20 6:47 PM	660	-	347
48-24 Hour Watch	TP5_09072020_C01_Watch_Non Medical Baseline_PSPS_09072020	9/6/20 6:51 PM	1,142	-	1,032
48-24 Hour Watch	TP6_09072020_C01_Watch_Non Medical Baseline_PSPS_09072020	9/6/20 6:54 PM	718	-	651
48-24 Hour Watch	TP7_09072020_C01_Watch_Medical Baseline_PSPS_09072020	9/6/20 6:56 PM	191	191	190
Door Knock	N/A	9/6/20 6:57 PM	2,156	2,156	1,387
48-24 Hour Watch	TP1_09072020_C01_Watch_Medical Baseline_PSPS_09072020	9/6/20 7:00 PM	2,896	2,896	2,857
48-24 Hour Watch	TP2_09072020_C01_Watch_Medical Baseline_PSPS_09072020	9/6/20 7:03 PM	1,532	1,532	1,522
48-24 Hour Watch	TP3_09072020_C01_Watch_Medical Baseline_PSPS_09072020	9/6/20 7:06 PM	787	787	779
48-24 Hour Watch	TP4_09072020_C01_Watch_Medical Baseline_PSPS_09072020	9/6/20 7:10 PM	5,447	345	4,764
48-24 Hour Watch	TP5_09072020_C01_Watch_Medical Baseline_PSPS_09072020	9/6/20 7:13 PM	46	46	45
48-24 Hour Watch	TP6_09072020_C01_Watch_Medical Baseline_PSPS_09072020	9/6/20 7:16 PM	37	37	36
48-24 Hour Watch	TP7_09072020_C01_Watch_Non Medical Baseline_PSPS_09072020	9/6/20 7:18 PM	5,673	-	5,393
< 24 Hour Watch	TP1-8_09072020_Watch_Non Medical Baseline_PSPS_09072020	9/7/20 9:37 AM	61,621	-	58,046
< 24 Hour Watch	TP1-8_09072020_Watch_Medical Baseline_PSPS_09072020	9/7/20 10:13 AM	4,223	4,223	4,167
< 24 Hour Watch	TP1-8_09072020_Watch_MMT_PSPS_09072020	9/7/20 10:17 AM	78	78	67
< 24 Hour Watch	ID564565_PSPS_090720_D01_Broadnet_for_Transmission	9/7/20 11:28 AM	23	-	23
< 24 Hour Watch	ID564567_PSPS_090720_D01_BTransmissionV2	9/7/20 12:55 PM	5	-	5
< 24 Hour Watch	Direct Email to Transmission Customers Without Phone	9/7/20 4:28 PM	24	-	24
Live Agent Calls	N/A	9/7/20 5:44 PM	356	356	170
< 24 Hour Watch	ID564573_PSPS_090720_D02_Broadnet_for_Transmission	9/7/20 6:33 PM	17	-	17
Imminent / Warning	SWN_Local Community Representative Public Safety Partner Agency Notification*	9/7/20 6:33 PM	572	-	572
< 24 Hour Watch	Direct Email to Transmission Customers Without Phone	9/7/20 7:06 PM	12	-	12
Imminent / Warning	TP1-8_09072020_D02v3-Warn_CC1_PSPS_09072020	9/7/20 7:13 PM	1,144	-	1,129
Imminent / Warning	TP1-8_09072020_D02v3-Warn_MedBase_PSPS_09072020	9/7/20 7:21 PM	10,278	10,278	10,137
Imminent / Warning	TP1-8_09072020_D02v3-Warn_Non-MedBase_PSPS_09072020	9/7/20 7:33 PM	159,876	-	146,429
Cancel	TP1-8_09072020_Cancel_MMT_PSPS_09072020-1520	9/7/20 7:55 PM	12	12	12
Imminent / Warning	TP1-8_09072020_D02v3-Warn_MMT_PSPS_09072020	9/7/20 7:55 PM	132	132	106
Cancel	TP1-8_09072020_Cancel_All_PSPS_09072020-1520	9/7/20 7:57 PM	19,144	1,325	17,646
Cancel	TP1-8_09072020_Cancel_All_PSPS_09082020-1100	9/8/20 1:35 PM	1,333	82	1,188
Imminent / Warning - Kern	TP6_09072020_Warning_Non Medical Baseline_PSPS_09072020	9/8/20 2:09 PM	607	-	557
Imminent / Warning - Kern	TP6_09072020_Warning_Medical Baseline_PSPS_09072020	9/8/20 2:11 PM	32	32	31

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Notification Type	Notification Campaign Name	Notification Launch Date and Time	Total Customer Notifications Attempted (by SPID)[1]*	Medical Baseline Customer Notifications Attempted (by SPID)	Total Customers Successfully Notified (by SPID)*
Restoration	Multiple	9/8/20 4:12 PM	132,036	7,861	94,981
ETOR	Multiple	9/8/20 4:25 PM	88,288	5,577	56,613
ETOR	SWN_Local Community Representative Public Safety Partner Agency Notification*	9/8/20 6:25 PM	556	-	556
Microgrid	ID564683_MB_09082020_BN	9/8/20 6:36 PM	5,327	367	4,486
Microgrid	ID564722_TP1_8_09072020_D_02_Rev05_MG_PSPS_09092020_0800	9/9/20 8:00 AM	3,008	205	2,692
Restoration	SWN_Local Community Representative Public Safety Partner Agency Notification*	9/11/20 8:23 AM	568	-	568

P27-123 cont.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

SECTION 6 – CUSTOMER NOTIFICATION SCRIPTS

P27-123 cont.

September 7-9, 2020
Public Safety Power Shutoff
Event Notifications

P27-123 cont.

PG&E

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* Public Safety Partners, communication providers, water agencies, emergency hospitals and publicly-owned utilities receive this advanced notification.
** Medical Baseline Program Participants receive unique PSPS Watch and PSPS Warning notifications, but all other notifications align with all other customers.
*** As-needed only.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

City, County, Tribal and Community Choice Aggregator (CCA) Notifications

P27-123 cont.

PG&E will make every attempt to provide notice to cities, counties, tribes, CCAs, first responders and other agencies in advance of notifying customers through:

- Calls
- Text Messages
- Emails

These notifications are sent based on potential PSPS impacts to PG&E electric service within an agencies jurisdiction and are not tied to a specific PG&E account. Agencies will also receive notifications specific to their accounts if their service may be interrupted during a PSPS event.

The following outlines the various notifications PG&E will send prior to, during and after a PSPS event:

1. **Advanced Notification**
2. **PSPS Watch**
3. **PSPS Warning**
4. **Cancellation Notification**
5. **Weather All Clear**
6. **Power Restoration**

City, County, Tribal and CCA

1 Advanced Notification | 2 PSPS Watch | 3 PSPS Warning | 4 Cancellation Notification | 5 Weather All Clear | 6 Power Restoration

PHONE/VOICE

This is P G and E calling on [DATE] with a Public Safety Power Shutoff outage alert. On [DATE], power may be shut off in portions of your jurisdiction for safety. Due to current weather forecasts, your area is under a Watch for a P S P S. Shut off for this event is estimated to begin between [TIME] on [DATE] and [TIME] on [DATE]. Restoration is estimated to be complete on [DATE] by [TIME]. Actual shutoff and restoration times may change depending on weather or equipment conditions. Maps and event information by agency are available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available. We will continue to provide updates, this will include a Warning alert if we have determined it is necessary to turn off power.

P27-123 cont.

TEXT

PSPS Outage Alert. We may turn off power for safety between [TIME] [DATE] and [TIME] [DATE] and complete restoration by [TIME] [DATE]. Weather can affect these times. Event info by agency available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

EMAIL

SUBJECT: PG&E PSPS Outage Alert: Power shutoffs may be required for safety in your area

Due to current weather forecasts, your area is currently under a Watch for a Public Safety Power Shutoff (PSPS). Below is the estimated shutoff and restoration for this event:

- **ESTIMATED EVENT SHUTOFF:** Starting between [TIME] on [DATE] and [TIME] on [DATE]. We expect weather to improve beginning at [TIME] on [DATE]. After severe weather has passed, we will inspect equipment before restoring power.
- **ESTIMATED RESTORATION:** [DATE] by [TIME].

Actual shutoff and restoration times may change depending on weather and equipment conditions.

Maps and event information by agency can be found at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

Thank you,

PG&E Liaison Officer

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

City, County, Tribal and CCA

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 Weather All Clear — 6 Power Restoration

PHONE/VOICE

This is P G and E calling on [DATE] with a Public Safety Power Shutoff outage alert. On [DATE], power may be shut off in portions of your jurisdiction for safety. Due to current weather forecasts, your area is under a Watch for a Public Safety Power Shutoff. Shut off for this event is estimated to begin between [TIME] on [DATE] and [TIME] on [DATE]. Restoration is estimated to be complete on [DATE] by [TIME]. Actual shutoff and restoration times may change depending on weather or equipment conditions. Maps and event information by agency are available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available. We will continue to provide updates, this will include a Warning alert if we have determined it is necessary to turn off power.

P27-123 cont.

TEXT

PSPS Outage Alert. We may turn off power for safety between [TIME] [DATE] and [TIME] [DATE] and complete restoration by [TIME] [DATE]. Weather can affect these times. Event info by agency available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

EMAIL

SUBJECT: PG&E PSPS Outage Alert: On [DATE] power shutoffs may be required for safety in your area

Due to current weather forecasts, your area is currently under a Watch for a Public Safety Power Shutoff (PSPS). Below is the estimated shutoff and restoration for this event:

- **ESTIMATED EVENT SHUTOFF:** Starting between [TIME] on [DATE] and [TIME] on [DATE]. We expect weather to improve beginning at [TIME] on [DATE]. After severe weather has passed, we will inspect equipment before restoring power.
- **ESTIMATED RESTORATION:** [DATE] by [TIME].

Actual shutoff and restoration times may change depending on weather and equipment conditions.

Maps and event information by agency can be found at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

Thank you,

PG&E Liaison Officer

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

City, County, Tribal and CCA

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 Weather All Clear — 6 Power Restoration

PHONE/VOICE

This is P G and E calling on [DATE] with a Public Safety Power Shutoff outage alert. Due to current weather forecasts, your area is under a Warning for a Public Safety Power Shutoff and we will be required to turn off power to prevent a wildfire. Shut offs for this event will begin between [TIME] on [DATE] and [TIME] on [DATE]. Restoration is estimated to be complete on [DATE] by [TIME]. Maps and event information by agency are available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

TEXT

PSPS Outage Alert. We will turn off power for safety between [TIME] [DATE] and [TIME] [DATE] and complete restoration by [TIME] [DATE]. Weather can affect these times. Event info by agency available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

P27-123 cont.

EMAIL

SUBJECT: PG&E PSPS Outage Alert: Shutoffs in your area will start soon for safety

To protect public safety, PG&E has upgraded the Public Safety Power Shutoff (PSPS) to a Warning. High temperatures, extreme dryness and high winds, will require us to turn off power to help prevent a wildfire. Below is the estimated shutoff and restoration for this event:

- **ESTIMATED EVENT SHUTOFF:** Starting between [TIME] on [DATE] and [TIME] on [DATE]. We expect weather to improve beginning at [TIME] on [DATE]. After severe weather has passed, we will inspect equipment before restoring power.
- **ESTIMATED EVENT RESTORATION:** [DATE] by [TIME].

Maps and event information by agency can be found at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

Thank you,

PG&E Liaison Officer

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

City, County, Tribal and CCA

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 Weather All Clear — 6 Power Restoration

PHONE/VOICE

This is P G and E calling on [DATE] with a Public Safety Power Shutoff alert. Forecasted weather conditions have improved and we are not planning to turn off power for public safety in your area. Maps and event information by agency are available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

TEXT

PG&E PSPS Alert. Forecasted weather conditions have improved and we are not turning off power for public safety in your area. Event info by agency available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

P27-123 cont.

EMAIL

SUBJECT: PG&E PSPS Notification: Power shutoff in your area is canceled

Forecasted weather conditions have improved and we are NOT planning to turn off power for public safety in your area.

Maps and event information by agency can be found at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

Thank you,

PG&E Liaison Officer

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

City, County, Tribal and CCA

1	2	3	4	5	6
Advanced Notification	PSPS Watch	PSPS Warning	Cancellation Notification	Weather All Clear	Power Restoration

PHONE/VOICE

This is P G and E calling on [DATE] with a Public Safety Power Shutoff outage alert. Weather conditions have improved, and crews are inspecting equipment to determine how quickly we can safely restore power. Restoration for the entire P S P S event is estimated to be complete on [DATE] by [TIME], depending on equipment damage. Restoration information by agency is available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

TEXT

PSPS Outage Alert: Weather conditions have improved, crews are inspecting equipment and restoring power. Restoration for the entire PSPS event is estimated to be complete on [DATE] by [TIME], depending on equipment damage. Restoration info by agency available at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

P27-123 cont.

EMAIL

SUBJECT: PG&E PSPS Outage Alert: Crews are inspecting equipment

Weather conditions have improved and crews are inspecting equipment to determine how quickly we can safely restore power. We apologize for the disruption and we appreciate your patience.

Restoration for the entire P S P S event is estimated to be complete on [DATE] by [TIME], depending on equipment damage.

Maps and event information by agency can be found at [URL] and [URL]. These links are for public safety partner use only. Please do not share event information before it is publicly available.

Thank you,

PG&E Liaison Officer

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

City, County, Tribal and CCA

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 Weather All Clear — 6 Power Restoration

PHONE/VOICE

This is P G and E calling on [DATE] with a Public Safety Power Shutoff alert. Crews have successfully restored power to all customers within your jurisdiction. If you are still receiving reports of outages, please instruct customers to visit p g e dot com backslash outages or call 1 800 7 4 3 5 0 0 2. We apologize for the disruption and we appreciate your patience.

TEXT

PG&E PSPS Alert: Crews have successfully restored power within your jurisdiction. If you are still receiving reports of outages, please instruct customers to visit pge.com/outages or call 1-800-743-5002.

P27-123 cont.

EMAIL

SUBJECT: PG&E PSPS Notification: Power restored

Crews have successfully restored power to all customers within your jurisdiction. We apologize for the disruption and we appreciate your patience. If you are still receiving reports of outages, please instruct customers to visit pge.com/outages or call 1-800-743-5002. Restoration info by agency available at [URL] and [URL].

Thank you,

PG&E Liaison Officer

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

General Customer, Critical Facility and Medical Baseline Notifications

P27-123 cont.

We will attempt to reach potentially impacted customers through automated calls, texts and emails using all contact information we have on file. We will also post event-specific information on pge.com and social media channels, as well as keep local news, radio outlets and community based organizations informed and updated.

Public Safety Partner Customers that have a facility identified as potentially affected will receive an advanced notification with facility information (in addition to the notifications sent to agencies as described in the previous section). This includes police and fire facilities, communication providers, water agencies, emergency hospitals and publicly-owned utilities.

Medical Baseline Program Participants will also receive unique PSPS Watch and PSPS Warning notifications. These messages include customized phone, text and email messages that request confirmation that the notification was received. Additionally, PG&E sends hourly notifications to those customers who have not confirmed receipt and conducts site visits if notifications were not previously confirmed.

The following outlines the various notifications PG&E will send prior to, during and after a PSPS event:

1. **Advanced Notification**
2. **PSPS Watch**
3. **PSPS Warning**
4. **Cancellation Notification**
5. **PSPS Update**
6. **Weather All Clear**
7. **Power Restoration**

KEY:

- Telecom Providers, Water Agencies, Emergency Hospitals, Publicly-Owned Utilities
- General Customers
- Medical Baseline Program Participants
- All Customers

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Telecom Providers, Water Agencies, Emergency Hospitals, Publicly-Owned Utilities

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

PHONE/VOICE (SINGLE PREM)

This is PG&E calling with a PSPS outage alert. On [DATE], your power may be shut off for safety. To replay this message at any time, press #. Due to current weather forecasts [ADDRESS] is currently under a Watch for a Public Safety Power Shutoff. Weather forecasts including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. ESTIMATED SHUTOFF TIME: [DAY] [DATE] between [TIME] and [TIME]. Shutoff times may be delayed if winds arrive later than forecast. We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power. ESTIMATED RESTORATION TIME: [DAY], [DATE] by [TIME] This restoration time may change depending on weather conditions and equipment damage. Maps showing the areas potentially affected by a shutoff can be found at [URL]. PSPS Portal users can log in at [URL]. **These are for public safety partner use only. **PLEASE DO NOT SHARE THESE LINKS**.** We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. If this is not the correct phone number for [ADDRESS], press 2. Press # to repeat this message. Thank you. Goodbye.

P27-123 cont.

PHONE/VOICE (MULTI PREM)

This is PG&E calling with a PSPS outage alert. On [DATE], your power may be shut off for safety. To replay this message at any time, press #. Due to current weather forecasts, [NUMBER of SPIDs FOR MULTI PREM] of your meters are currently under a Watch for a Public Safety Power Shutoff. Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. The estimated shutoff time for [ADDRESS #1] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. The estimated shutoff time for [ADDRESS #2] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. Changes in weather can affect shutoff times. Restoration times may change depending on weather conditions and equipment damage. Please get ready to write down the following information. Details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters can be found online at pge.com/myaddresses. On the website you will be asked to enter your phone number [XXX-XXX-XXXX] plus a 4-digit PIN. Your PIN number is: [ZZZZ]. To repeat how to get details for all of your affected meters, press *. Maps showing the areas potentially affected by a shutoff can be found at [URL]. PSPS Portal users can log in at [URL]. **These are for public safety partner use only. **PLEASE DO NOT SHARE THESE LINKS**.** We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. If this is not the correct phone number for the addresses provided, press 2. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *. Thank you. Goodbye.

Telecom Providers, Water Agencies, Emergency Hospitals, Publicly-Owned Utilities

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert [DATE]: PG&E may turn off power for safety at [ADDRESS] on [DATE]. Estimated shutoff: [TIME]–[TIME]. Estimated restoration: [DATE] by [TIME]. Weather can affect these times. Maps for public safety partners at [URL] or log in at [URL].

TEXT (MULTI PREM)

PG&E PSPS Outage Alert [DATE]: PG&E may turn off power for safety to [NUMBER of SPIDs FOR MULTI PREM] of your meters. Est. shutoff as early as: [DATE] [TIME]-[TIME]. Est. restoration: [DATE] by [TIME]. Weather can affect these times. Meter list: [pge.bz/12345] Safety partner maps: [URL] or log in at [URL].

P27-123 cont.

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: On [DATE] power shutoffs may be required for safety

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Watch

Due to current weather forecasts, your area is currently under a Watch for a Public Safety Power Shutoff.

Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire.

ADDRESS: [ADDRESS, CITY, STATE, COUNTY]

ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME]

Shutoff times may be delayed if winds arrive later than forecast.

We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power.

ESTIMATED RESTORATION: [DAY], [DATE] by [TIME]

Restoration time may change depending on weather and equipment damage.

Maps showing the areas potentially affected by a shutoff can be found at [URL]. PSPS Portal users can log in at [URL]. **These are for public safety partner use only. PLEASE DO NOT SHARE THESE LINKS.**

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. Weather forecasts change frequently. Shutoff forecasts will be most accurate the day of the potential outage.

CONTINUED ON NEXT PAGE

Telecom Providers, Water Agencies, Emergency Hospitals, Publicly-Owned Utilities

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (SINGLE PREM) CONT.

If this is not the correct email address for [ADDRESS], please call 1-800-743-5000.

RESOURCES TO HELP YOU PREPARE

- Maps showing the areas potentially affected by a shutoff can be found at [URL]. These are for public safety partner use only. **PLEASE DO NOT SHARE THIS LINK.**
- PSPS Portal users can log in at [URL]. **These are for public safety partner use only. PLEASE DO NOT SHARE THIS LINK.**
- To learn more about Public Safety Power Shutoffs, including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report it immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery.

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

Telecom Providers, Water Agencies, Emergency Hospitals, Publicly-Owned Utilities

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: On [DATE] power shutoffs may be required for safety

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Watch

Due to current weather forecasts, your area is currently under a Watch for a Public Safety Power Shutoff.

Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. Maps showing the areas potentially affected by a shutoff can be found at [URL]. PSPS Portal users can log in at [URL]. **These are for public safety partner use only. **PLEASE DO NOT SHARE THESE LINKS****

NUMBER OF METERS AFFECTED: [NUMBER of SPIDs FOR MULTI PREM]

****Due to email size limits a maximum of 50 meter locations is shown****

[VIEW ALL AFFECTED LOCATIONS/DOWNLOAD A LIST OF ALL AFFECTED LOCATIONS]

1.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.
2.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.

(Repeat for first **50** premises that would be affected)

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. Weather forecasts change frequently. Shutoff forecasts will be most accurate the day of the potential outage.

If this is not the correct email address for the addresses provided, please call 1-800-743-5000.

P27-123 cont.

CONTINUED ON NEXT PAGE

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Telecom Providers, Water Agencies, Emergency Hospitals, Publicly-Owned Utilities

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM) CONT.

RESOURCES TO HELP YOU PREPARE

- Maps showing the areas potentially affected by a shutoff can be found at [URL]. **These are for public safety partner use only. PLEASE DO NOT SHARE THIS LINK**.
- PSPS Portal users can log in at [URL]. **These are for public safety partner use only. PLEASE DO NOT SHARE THIS LINK.**
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

P27-123 cont.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

IVR LIVE (SINGLE PREM)

This is PG&E calling with a PSPS outage alert for Medical Baseline customers. On [DATE], your power may be shut off for safety. To continue in English press 1. To replay this message at any time, press #. Due to current weather forecasts [ADDRESS] is currently under a Watch for a Public Safety Power Shutoff. Weather forecasts including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. ESTIMATED SHUTOFF TIME: [DAY] [DATE] between [TIME] and [TIME]. Shutoff times may be delayed if winds arrive later than forecast. We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power. ESTIMATED RESTORATION TIME: [DAY] [DATE] by [TIME]. This restoration time may change depending on weather conditions and equipment damage. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. If this is not the correct phone number for [ADDRESS], press 2. Press # to repeat this message. Thank you. Goodbye.

P27-123 cont.

IVR LIVE (MULTI PREM)

This is PG&E calling with a PSPS outage alert for Medical Baseline customers. On [DATE], your power may be shut off for safety. To continue in English press 1. To replay this message at any time, press #. Due to current weather forecasts, [NUMBER of SPIDs FOR MULTI PREM] of your meters are currently under a Watch for a Public Safety Power Shutoff. Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. The estimated shutoff time for [ADDRESS #1] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [ETOR DAY], [ETOR DATE] by [ETOR TIME]. The estimated shutoff time for [ADDRESS #2] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [ETOR DAY], [ETOR DATE] by [TIME]. Changes in weather can affect shutoff times. Restoration times may change depending on weather conditions and equipment damage. Please get ready to write down the following information. Details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters can be found online at pge.com/myaddresses. On the website you will be asked to enter your phone number [XXX-XXX-XXXX] plus a 4-digit PIN. Your PIN number is: [ZZZZ]. To repeat how to get details for all of your affected meters, press *. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. If this is not the correct phone number for the addresses provided, press 2. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *****. Thank you. Goodbye.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

IVR VOICE MESSAGE (SINGLE PREM)

This is PG&E calling on [DAY, DATE] at [TIME] with a PSPS outage alert for Medical Baseline customers. On [DATE], your power may be shut off for safety. Your response is required. To hear this message in another language call [1-800-XXX-XXXX] Due to current weather forecasts [ADDRESS] is currently under a Watch for a Public Safety Power Shutoff. Weather forecasts including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. ESTIMATED SHUTOFF TIME: [DAY] [DATE] between [TIME] and [TIME]. Shutoff times may be delayed if winds arrive later than forecast. We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power. ESTIMATED RESTORATION TIME: [ETOR DAY], [DATE] by [TIME] This restoration time may change depending on weather conditions and equipment damage. Because you are enrolled in our Medical Baseline program, your response is required. Please call [XXX-XXX-XXXX] to confirm you have received this message. We will continue to attempt to reach you and may visit your home if you do not respond. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning alert if we have determined it is necessary to turn off your power. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging If this is not the correct phone number for [ADDRESS], call 1-800-743-5000. Thank you. Goodbye.

P27-123 cont.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

IVR VOICE MESSAGE (MULTI PREM)

This is PG&E calling on [DAY, DATE] at [TIME] with a PSPS outage alert for Medical Baseline customers. On [DATE], your power may be shut off for safety. Your response is required. To hear this message in another language call [1-800-XXX-XXXX]. Due to current weather forecasts, [NUMBER of SPIDs FOR MULTI PREM] of your meters are currently under a Watch for a Public Safety Power Shutoff. Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. The estimated shutoff time for [ADDRESS #1] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME] The estimated shutoff time for [ADDRESS #2] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. Changes in weather can affect shutoff times. Restoration times may change depending on weather conditions and equipment damage. Details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters can be found online at pge.com/myaddresses. On the website you will be asked to enter your phone number [XXX-XXX-XXXX] plus a 4-digit PIN. Your PIN number is: [ZZZZ]. Because you are enrolled in our Medical Baseline program, your response is required. Please call [XXX-XXX-XXXX] to confirm you have received this message. We will continue to attempt to reach you and may visit your home if you do not respond. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. If this is not the correct phone number for the addresses provided, call 1-800-743-5000. Thank you. Goodbye.

P27-123 cont.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert - Medical Baseline Customers [DATE]: PG&E may turn off power for safety at [ADDRESS] on [DATE]. Est Shutoff: [TIME]-[TIME]. Est Restoration: [DATE] by [TIME]. Weather can affect shutoff & restoration times. Info&Languages: pge.com/pspsupdates Reply w/ "1" to verify receipt.

TEXT (MULTI PREM)

PG&E PSPS Outage Alert – Medical Baseline Customers [DATE]: PG&E may turn off power for safety to [NUMBER of SPIDs FOR MULTI PREM] of your meters. Est shutoff: [DATE] [TIME]-[TIME]. Est restoration: [DATE] by [TIME]. Weather can affect these times. Meter list: [pge.bz/12345] Info&Languages: pge.com/pspsupdates Reply w/ "1" to verify receipt.

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: On [DATE] power shutoffs may be required for safety

HEADER LINKS:

español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربى Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Watch

Due to current weather forecasts, your area is currently under a Watch for a Public Safety Power Shutoff.

Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire.

ADDRESS: [ADDRESS, CITY, STATE, COUNTY]

ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME]

Shutoff times may be delayed if winds arrive later than forecast.

We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power.

ESTIMATED RESTORATION: [DAY], [DATE] by [TIME]

Restoration time may change depending on weather and equipment damage.

CONTINUED ON NEXT PAGE

P27-123 cont.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (SINGLE PREM) CONT.

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. Weather forecasts change frequently. Shutoff forecasts will be most accurate the day of the potential outage.

If this is not the correct email address for [ADDRESS], please call 1-800-743-5000.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

RESOURCES TO HELP YOU PREPARE

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips, visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery.

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

P27-123 cont.

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: On [DATE] power shutoffs may be required for safety

HEADER LINKS:

español 中文 tiếng việt Tagalog 한국어 русский язык
عربى فارسی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Watch

Due to current weather forecasts, your area is currently under a Watch for a Public Safety Power Shutoff.

Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire.

NUMBER OF METERS AFFECTED: [NUMBER of SPIDs FOR MULTI PREM]

****Due to email size limits a maximum of 50 meter locations is shown****

[VIEW ALL AFFECTED LOCATIONS/DOWNLOAD A LIST OF ALL AFFECTED LOCATIONS]

1.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.
2.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. Weather forecasts change frequently. Shutoff forecasts will be most accurate the day of the potential outage.

If this is not the correct email address for the addresses provided, please call 1-800-743-5000.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

CONTINUED ON NEXT PAGE

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM) CONT.

RESOURCES TO HELP YOU PREPARE

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips, visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery.

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

General Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

PHONE/VOICE (SINGLE PREM)

This is PG&E calling with a PSPS outage alert. On [DATE], your power may be shut off for safety. To continue in English press 1. To replay this message at any time, press #. Due to current weather forecasts [ADDRESS] is currently under a Watch for a Public Safety Power Shutoff. Weather forecasts including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. ESTIMATED SHUTOFF TIME: [DAY] [DATE] between [TIME] and [TIME]. Shutoff times may be delayed if winds arrive later than forecast. We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power. ESTIMATED RESTORATION TIME: [DAY] [DATE] by [TIME]. This restoration time may change depending on weather conditions and equipment damage. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. If this is not the correct phone number for [ADDRESS], press 2. Press # to repeat this message. Thank you. Goodbye.

PHONE/VOICE (MULTI PREM)

This is PG&E calling with a PSPS outage alert. On [DATE], your power may be shut off for safety. To continue in English press 1. To replay this message at any time, press #. Due to current weather forecasts, [NUMBER of SPIDs FOR MULTI PREM] of your meters are currently under a Watch for a Public Safety Power Shutoff. Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire. The estimated shutoff time for [ADDRESS #1] is [DAY] [DATE] between [TIME] and [ESTIMATED SHUTOFF END TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. The estimated shutoff time for [ADDRESS #2] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. Changes in weather can affect shutoff times. Restoration times may change depending on weather conditions and equipment damage. Please get ready to write down the following information. Details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters can be found online at pge.com/myaddresses. On the website you will be asked to enter your phone number [XXX-XXX-XXXX] plus a 4-digit PIN. Your PIN number is: [ZZZZ]. To repeat how to get details for all of your affected meters, press *. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. If this is not the correct phone number for the addresses provided, press 2. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *. Thank you. Goodbye.

P27-123 cont.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

General Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

P27-123 cont.

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert [DATE]: Due to weather PG&E may turn off power for safety at [ADDRESS] on [DATE]. Estimated shutoff: [TIME]-[TIME]. Estimated restoration: [DATE] by [TIME]. Weather can affect shutoff & restoration. Info&Other languages: pge.com/pspsupdates Reply w/ "1" to verify receipt.

TEXT (MULTI PREM)

PG&E PSPS Outage Alert [DATE]: PG&E may turn off power for safety to [NUMBER of SPIDs FOR MULTI PREM] of your meters. Est shutoff as early as: [DATE] [TIME]-[TIME]. Est restoration: [DATE] by [TIME]. Weather can affect shutoff & restoration times. Meter list: [pge.bz/12345]. Info&Other languages: pge.com/pspsupdates Reply w/ "1" to verify receipt.

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: On [DATE] power shutoffs may be required for safety

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربى Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Watch

Due to current weather forecasts, your area is currently under a Watch for a Public Safety Power Shutoff.

Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire.

ADDRESS: [ADDRESS, CITY, STATE, COUNTY]

ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME]

Shutoff times may be delayed if winds arrive later than forecast.

We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power.

ESTIMATED RESTORATION: [DAY], [DATE] by [TIME]

Restoration time may change depending on weather and equipment damage.

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. Weather forecasts change frequently. Shutoff forecasts will be most accurate the day of the potential outage.

CONTINUED ON NEXT PAGE

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

General Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (SINGLE PREM) CONT.

If this is not the correct email address for [ADDRESS], please call 1-800-743-5000.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

RESOURCES TO HELP YOU PREPARE

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips, visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery.

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

General Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: On [START DATE] power shutoffs may be required for safety

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Watch

Due to current weather forecasts, your area is currently under a Watch for a Public Safety Power Shutoff.

Current weather forecasts, including high winds and dry conditions, may require us to turn off your power to help prevent a wildfire.

NUMBER OF METERS AFFECTED: [NUMBER of SPIDs FOR MULTI PREM]

****Due to email size limits a maximum of 50 meter locations is shown****

[VIEW ALL AFFECTED LOCATIONS/DOWNLOAD A LIST OF ALL AFFECTED LOCATIONS]

1.	ADDRESS: [ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.
2.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [ETOR DAY], [ETOR DATE] by [ETOR TIME] Restoration time may change depending on weather and equipment damage.

(Repeat for first 50 premises that would be affected)

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. This will include a Warning notification if we have determined it is necessary to turn off your power. Weather forecasts change frequently. Shutoff forecasts will be most accurate the day of the potential outage.

If this is not the correct email address for the addresses provided, please call 1-800-743-5000.

CONTINUED ON NEXT PAGE

P27-123 cont.

General Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM) CONT.

For more information visit [pge.com/pspsupdates] or call 1-800-743-5002.

RESOURCES TO HELP YOU PREPARE

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips, visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery.

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Medical Baseline Program Participants

1 Advanced Notification | 2 PSPS Watch | 3 PSPS Warning | 4 Cancellation Notification | 5 PSPS Update | 6 Weather All Clear | 7 Power Restoration

IVR LIVE (SINGLE PREM)

This is PG&E calling with a PSPS outage alert for Medical Baseline customers. Shutoffs start between [TIME] and [TIME] for safety. To continue in English press 1. To replay this message at any time, press #. To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning. Weather forecasts including high winds and dry conditions, will require us to turn off your power at [ADDRESS] to help prevent a wildfire. SHUTOFF TIME: [DAY] [DATE] between [TIME] and [TIME]. Shutoff times may be delayed if winds arrive later than forecast. We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power. ESTIMATED RESTORATION TIME: [DAY], [DATE] by [TIME]. This restoration time may change depending on weather conditions and equipment damage. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. Press # to repeat this message. Thank you. Goodbye.

P27-123 cont.

IVR LIVE (MULTI PREM)

This is PG&E calling with a PSPS outage alert for Medical Baseline customers. Shutoffs start between [TIME] and [TIME] for safety. To continue in English press 1. To replay this message at any time, press #. To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning. Weather forecasts including high winds and dry conditions, will require us to turn off the power for [NUMBER of SPIDs FOR MULTI PREM] of your meters to help prevent a wildfire. The estimated shutoff time for [PREMISE ADDRESS #1] is [ESTIMATED SHUTOFF START DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. The estimated shutoff time for [ADDRESS #2] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. Changes in weather can affect shutoff times. Restoration times may change depending on weather conditions and equipment damage. Please get ready to write down the following information. Details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters can be found online at [pge.com/myaddresses]. On the website you will be asked to enter your phone number [XXX-XXX-XXXX] plus a 4-digit PIN. Your PIN number is: [ZZZZ]. To repeat how to get details for all of your affected meters, press *. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *. Thank you. Goodbye.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

IVR VOICE MESSAGE (SINGLE PREM)

This is PG&E calling on [DAY, DATE] at [TIME] with a PSPS outage alert for Medical Baseline Customers. Shutoffs start between [TIME] and [TIME] for safety. Your response is required. To hear this message in another language call [1-800-XXX-XXXX]. To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning. Weather forecasts including high winds and dry conditions, will require us to turn off your power at [ADDRESS] to help prevent a wildfire. SHUTOFF TIME: [DAY] [DATE] between [TIME]-[TIME]. Shutoff times may be delayed if winds arrive later than forecast. We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power. ESTIMATED RESTORATION TIME: [DAY], [DATE] by [TIME] This restoration time may change depending on weather conditions and equipment damage. Please call [XXX-XXX-XXXX] to confirm you have received this message. We will continue to attempt to reach you and may visit your home if you do not respond. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. Thank you. Goodbye.

P27-123 cont.

IVR VOICE MESSAGE (MULTI PREM)

This is PG&E calling on [DAY, DATE] at [TIME] with a PSPS outage alert for Medical Baseline customers. Shutoffs start between [TIME] and [TIME] for safety. Your response is required. To hear this message in another language call [1-800-XXX-XXXX]. To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning. Weather forecasts including high winds and dry conditions, will require us to turn off the power for [NUMBER of SPIDs FOR MULTI PREM] of your meters to help prevent a wildfire. The estimated shutoff time for [ADDRESS #1] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. The estimated shutoff time for [ADDRESS #2] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. Changes in weather can affect shutoff times. Restoration times may change depending on weather conditions and equipment damage. Details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters can be found online at pge.com/myaddresses. On the website you will be asked to enter your phone number [XXX-XXX-XXXX] plus a 4-digit PIN. Your PIN number is: [ZZZZ]. Please call [XXX-XXX-XXXX] to confirm you have received this message. We will continue to attempt to reach you and may visit your home if you do not respond. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. Thank you. Goodbye.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert - Medical Baseline Customers [DATE]: PG&E will turn off power for safety at [ADDRESS]. Est shutoff: [DATE] [TIME]-[TIME] Est restoration: [DATE] by [TIME] depending on weather & damage. More info & other languages: pge.com/pspsupdates Reply w/ "1" to verify receipt.

TEXT (MULTI PREM)

PG&E PSPS Outage Alert – Medical Baseline Customers [DATE]: PG&E will turn off power for safety to [NUMBER of SPIDs FOR MULTI PREM] of your meters. Est shutoff as early as: [DATE] [TIME]-[TIME]. Est restoration: [DATE] by [TIME] depending on weather & damage. Meters: [pge.bz/12345]. Info&Languages: pge.com/pspsupdates Reply w/ "1" to verify receipt.

P27-123 cont.

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: Shutoffs start between [TIME]-[TIME] for safety

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربى Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Warning

To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning.

Current weather forecasts, including high winds and dry conditions, will require us to turn off your power to help prevent a wildfire.

ADDRESS: [ADDRESS, CITY, STATE, COUNTY]

ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME]

Shutoff times may be delayed if winds arrive later than forecast.

We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power.

ESTIMATED RESTORATION: [DAY], [DATE] by [TIME]

Restoration time may change depending on weather and equipment damage.

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

CONTINUED ON NEXT PAGE

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (SINGLE PREM) CONT.

RESOURCES TO HELP YOU PREPARE

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, including Community Resource Centers where you can charge devices, visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips, visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: Shutoffs start between [TIME]-[TIME] for safety

HEADER LINKS:

español 中文 tiếng việt Tagalog 한국어 русский язык
عربى فارسى Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Warning

To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning.

Current weather forecasts, including high winds and dry conditions will require us to turn off your power to help prevent a wildfire. P27-123 cont.

NUMBER OF METERS AFFECTED: [NUMBER of SPIDs FOR MULTI PREM]

****Due to email size limits a maximum of 50 meter locations is shown****

[VIEW ALL AFFECTED LOCATIONS/DOWNLOAD A LIST OF ALL AFFECTED LOCATIONS]

1.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.
2.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.

Repeat for first 50 premises that would be affected)

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. Weather forecasts change frequently.

CONTINUED ON NEXT PAGE

Medical Baseline Program Participants

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM) CONT.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

RESOURCES TO HELP YOU PREPARE

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, including Community Resource Centers where you can charge devices, visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips, visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery.

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

General Customer

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

PHONE/VOICE (SINGLE PREM)

This is PG&E calling with a PSPS outage alert. Shutoffs start between [TIME] and [TIME] for safety. To continue in English press 1.To replay this message at any time, press #. To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning. Weather forecasts including high winds and dry conditions, will require us to turn off your power at [ADDRESS] to help prevent a wildfire. SHUTOFF TIME: [DAY] [DATE] between [TIME] and [TIME]. Shutoff times may be delayed if winds arrive later than forecast. We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power. ESTIMATED RESTORATION TIME: [DAY], [DATE] by [TIME]. This restoration time may change depending on weather conditions and equipment damage. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. Press # to repeat this message. Thank you. Goodbye.

P27-123 cont.

PHONE/VOICE (MULTI PREM)

This PG&E calling with a PSPS outage alert. Shutoffs start between [TIME] and [TIME] for safety. To continue in English press 1.To replay this message at any time, press #. To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning. Weather forecasts including high winds and dry conditions, will require us to turn off the power for [NUMBER of SPIDs FOR MULTI PREM] of your meters to help prevent a wildfire. The estimated shutoff time for [ADDRESS #1] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY], [DATE] by [TIME]. The estimated shutoff time for [ADDRESS #2] is [DAY] [DATE] between [TIME] and [TIME]. The estimated restoration time is [DAY],[DATE] by [TIME]. Changes in weather can affect shutoff times. Restoration times may change depending on weather conditions and equipment damage. Please get ready to write down the following information. Details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters can be found online at pge.com/myaddresses. On the website you will be asked to enter your phone number [XXX-XXX-XXXX] plus a 4-digit PIN. Your PIN number is: [ZZZZ]. To repeat how to get details for all of your affected meters, press *. We recommend all customers have a plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. For planning resources or more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *. Thank you. Goodbye.

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General Customer

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

P27-123 cont.

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert [DATE]: PG&E will turn off power for safety at [ADDRESS] on [DATE]. Est. shutoff: [TIME]-[TIME] Est. restoration: [DATE] by [TIME] depending on weather & equipment damage. More info & other languages: pge.com/pspsupdates Reply w/ "1" to verify receipt.

TEXT (MULTI PREM)

PG&E PSPS Outage Alert [DATE]: PG&E will turn off power for safety to [NUMBER of SPIDs FOR MULTI PREM] of your meters. Est. shutoff as early as: [DATE] [TIME]-[TIME]. Est. restoration: [DATE] by [TIME] depending on weather & equipment damage. Meter list: [pge.bz/12345] Info & other languages: pge.com/pspsupdates Reply w/ "1" to verify receipt.

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: Shutoffs start between [TIME]-[TIME] for safety

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربى Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Warning

To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning.

Current weather forecasts, including high winds and dry conditions, will require us to turn off your power to help prevent a wildfire.

ADDRESS: [ADDRESS, CITY, STATE, COUNTY]

ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME]

Shutoff times may be delayed if winds arrive later than forecast.

We expect weather to improve by [TIME] on [DAY], [DATE]. After weather has improved, we will inspect equipment before restoring power.

ESTIMATED RESTORATION: [DAY], [DATE] by [TIME]

Restoration time may change depending on weather and equipment damage.

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

CONTINUED ON NEXT PAGE

General Customer

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (SINGLE PREM) CONT.

RESOURCES TO HELP YOU PREPARE

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, including Community Resource Centers where you can charge devices, visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips, visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

General Customer

1	2	3	4	5	6	7
Advanced Notification	PSPS Watch	PSPS Warning	Cancellation Notification	PSPS Update	Weather All Clear	Power Restoration

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: Shutoffs start between [TIME]-[TIME] for safety

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Warning

To protect public safety, PG&E has upgraded the Public Safety Power Shutoff Watch to a Warning.

Current weather forecasts, including high winds and dry conditions will require us to turn off your power to help prevent a wildfire.

NUMBER OF METERS AFFECTED: [NUMBER of SPIDs FOR MULTI PREM]

****Due to email size limits a maximum of 50 meter locations is shown****

[VIEW ALL AFFECTED LOCATIONS/DOWNLOAD A LIST OF ALL AFFECTED LOCATIONS]

1.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.
2.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.

(Repeat for first 50 premises that would be affected)

We recommend all customers plan for an extended outage. We will provide daily updates until the weather risk has passed or power has been restored. Weather forecasts change frequently.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

P27-123 cont.

CONTINUED ON NEXT PAGE

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

General Customer

1	2	3	4	5	6	7
Advanced Notification	PSPS Watch	PSPS Warning	Cancellation Notification	PSPS Update	Weather All Clear	Power Restoration

EMAIL (MULTI PREM) CONT.

RESOURCES TO HELP YOU PREPARE

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, including Community Resource Centers where you can charge devices, visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips, visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast, visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

PHONE/VOICE (SINGLE PREM)

This is PG&E calling with a PSPS outage alert. To continue in English press 1. Forecasted weather conditions have improved and we are not planning to turn off power for public safety at [ADDRESS] on [DAY] [DATE]. For more information visit pge.com/pspsupdates or call 1-800-743-5002. Press # to repeat this message. Thank you. Goodbye.

PHONE/VOICE (MULTI PREM)

This is PG&E calling with a PSPS outage alert. To continue in English press 1. Forecasted weather conditions have improved and we are not planning to turn off power for public safety to [NUMBER OF SPIDs FOR MULTI PREM] of your meters. The meters at the following addresses: [ADDRESS #1], [ADDRESS #2], [ADDRESS #3] will not be turned off. Please get ready to write down the following information. To view details for all [NUMBER of SPIDs FOR MULTI PREM] of your canceled meters, visit pge.com/myaddresses and enter this phone number [XXX-XXX-XXXX] plus the following 4-digit PIN [ZZZZ] when prompted. To repeat how to get details for all of your affected meters, press *. For more information visit pge.com/pspsupdates or call 1-800-743-5002. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *. Thank you. Goodbye.

P27-123 cont.

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert [DATE]: Forecasted weather conditions have improved & we are not turning off safety at [ADDRESS] on [DATE]. More info & other languages: pge.com/pspsupdates

TEXT (MULTI PREM)

PG&E PSPS Outage Alert [SYSTEM DATE]: Forecasted weather conditions have improved & we are not turning off power for safety to [NUMBER of SPIDs FOR MULTI PREM] of your meters. Meter list: [pge.bz/12345]. More info & other languages: pge.com/pspsupdates

All Customers

1. Advanced Notification
2. PSPS Watch
3. PSPS Warning
4. Cancellation Notification
5. PSPS Update
6. Weather All Clear
7. Power Restoration

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: Your power shutoff is canceled

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Cancellation

Forecasted weather conditions have improved and we are NOT planning to turn off power for public safety at: [ADDRESS, CITY, STATE, COUNTY] on [DAY], [DATE]

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123
cont.

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: Your power shutoff is canceled

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Cancellation

Forecasted weather conditions have improved and we are NOT planning to turn off power for public safety at the following locations:

NUMBER OF METERS CANCELED: [NUMBER of SPIDs FOR MULTI PREM]

Due to email size limits a maximum of 50 meter locations is shown

[VIEW ALL CANCELED LOCATIONS/DOWNLOAD A LIST OF ALL CANCELED LOCATIONS]

CONTINUED ON NEXT PAGE

All Customers

1	2	3	4	5	6	7
Advanced Notification	PSPS Watch	PSPS Warning	Cancellation Notification	PSPS Update	Weather All Clear	Power Restoration

EMAIL (MULTI PREM) CONT.

1.	ADDRESS: [ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.
2.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.

(Repeat for first 50 premises that would be affected)

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

PHONE/VOICE (SINGLE PREM)

This is PG&E calling with a PSPS outage alert. To continue in English press 1. Power remains off at your location at [ADDRESS] to help prevent a wildfire. Crews will restore power as soon as it is safe to do so. ESTIMATED RESTORATION TIME: [DAY] [DATE] by [TIME]. This restoration time may change depending on weather conditions and equipment damage. We recommend all customers have a plan for an extended outage. We will provide daily updates until your power has been restored. For more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. We apologize for the disruption and we appreciate your patience. To opt out of call notifications to this number for the remainder of this outage, press 2. Press # to repeat this message. Thank you. Goodbye.

P27-123 cont.

PHONE/VOICE (MULTI PREM)

This is PG&E calling with a PSPS outage alert. To continue in English press 1. To replay this message at any time, press #. Power remains off for [NUMBER of SPIDs FOR MULTI PREM] of your meters to help prevent a wildfire. Crews will restore power as soon as it is safe to do so. The estimated restoration time for [ADDRESS #1] is [DAY], [DATE] by [TIME]. The estimated restoration time for [ADDRESS #2] is [DAY], [DATE] by [TIME]. Restoration times may change depending on weather conditions and equipment damage. Please get ready to write down the following information. To view details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters, visit pge.com/myaddresses and enter this phone number [XXX-XXX-XXXX] plus the following 4-digit PIN [ZZZZ] when prompted. To repeat how to get details for all of your affected meters, press *. We recommend all customers have a plan for an extended outage. We will provide daily updates until your power has been restored. For more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. We apologize for the disruption and we appreciate your patience. To opt out of call notifications to this number for the remainder of this outage, press 2. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *. Thank you. Goodbye.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

All Customers

1	2	3	4	5	6	7
Advanced Notification	PSPS Watch	PSPS Warning	Cancellation Notification	PSPS Update	Weather All Clear	Power Restoration

P27-123 cont.

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert [DATE]: Power remains off at [ADDRESS] to help prevent a wildfire. Estimated restoration: [DATE] by [TIME] depending on weather & equipment damage. More info & other languages: pge.com/pspsupdates. Reply STOP to STOP text alerts for this outage.

TEXT (MULTI PREM)

PG&E PSPS Outage Alert [DATE]: Power remains off at [NUMBER of SPIDs FOR MULTI PREM] of your meters to help prevent a wildfire. Estimated restoration: [DATE] by [TIME] depending on weather & equipment damage. Meter list: [pge.bz/12345]. More info & other languages: pge.com/pspsupdates. Reply STOP to STOP text alerts for this outage.

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: Estimated restoration time

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Update

Power remains off at your location to help prevent a wildfire. We apologize for the disruption and we appreciate your patience. Crews will restore power as soon as it is safe to do so.

ADDRESS: [ADDRESS, CITY, STATE, COUNTY]

ESTIMATED RESTORATION: [DAY], [DATE] by [TIME]

Restoration time may change depending on weather and equipment damage.

We recommend all customers plan for an extended outage. We will provide daily updates until your power has been restored. Weather forecasts change frequently.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

ADDITIONAL RESOURCES

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, including Community Resource Centers where you can charge devices visit pge.com/pspsupdates.

CONTINUED ON NEXT PAGE

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (SINGLE PREM) CONT.

- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: Estimated restoration time

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Outage Update

Power remains off at the locations below to help prevent a wildfire. We apologize for the disruption and we appreciate your patience. Crews will restore power as soon as it is safe to do so. Get the latest restoration information for each of your locations below.

NUMBER OF METERS AFFECTED: [NUMBER of SPIDs FOR MULTI PREM]

****Due to email size limits a maximum of 50 meter locations is shown****

[VIEW ALL AFFECTED LOCATIONS/DOWNLOAD A LIST OF ALL AFFECTED LOCATIONS]

1.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY],[DATE] by [TIME] Restoration time may change depending on weather and equipment damage.
2.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.

(Repeat for first 50 premises that would be affected)

We recommend all customers plan for an extended outage. We will provide daily updates until your power has been restored. Weather forecasts change frequently.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

CONTINUED ON NEXT PAGE

P27-123 cont.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM) CONT.

ADDITIONAL RESOURCES

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, including Community Resource Centers where you can charge devices visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

PHONE/VOICE (SINGLE PREM)

This is PG&E calling with a PSPS outage alert. To continue in English press 1. Weather conditions have improved, and crews are inspecting equipment to determine how quickly we can safely restore power at your location [ADDRESS]. ESTIMATED RESTORATION TIME: [DAY] [DATE] by [TIME]. This restoration time may change depending on equipment damage. We recommend all customers have a plan for an extended outage. We will provide daily updates until your power has been restored. For more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. We apologize for the disruption and we appreciate your patience To opt out of call notifications to this number for the remainder of this outage, press 2. Press # to repeat this message. Thank you. Goodbye.

P27-123 cont.

PHONE/VOICE (MULTI PREM)

This is PG&E calling with a PSPS outage alert. To continue in English press 1. To replay this message at any time, press #. Weather conditions have improved, and crews are inspecting equipment to determine how quickly we can safely restore power to [NUMBER of SPIDs FOR MULTI PREM] of your meters. The estimated restoration time for [ADDRESS #1] is [DAY], [DATE] by [TIME]. The estimated restoration time for [ADDRESS #2] is [DAY], [DATE] by [TIME]. These restoration times may change depending on equipment damage. Please get ready to write down the following information. To view details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters, visit pge.com/myaddresses and enter this phone number [XXX-XXX-XXXX] plus the following 4-digit PIN [ZZZZ] when prompted. To repeat how to get details for all of your affected meters, press *. We recommend all customers have a plan for an extended outage. We will provide daily updates until your power has been restored. For more information visit pge.com/pspsupdates or call 1-800-743-5002. If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging. We apologize for the disruption and we appreciate your patience. To opt out of call notifications to this number for the remainder of this outage, press 2. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *. Thank you. Goodbye.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert [DATE]: Weather conditions have improved, and crews are inspecting equipment to safely restore power at [ADDRESS]. Estimated restoration: [Date] by [TIME] depending on equipment damage. More info & other languages: pge.com/pspsupdates Reply STOP to STOP text alerts for this outage.

TEXT (MULTI PREM)

PG&E PSPS Outage Alert [DATE]: Weather has improved, and crews are inspecting equipment to safely restore power to [NUMBER of SPIDs FOR MULTI PREM] of your meters. Estimated restoration: [DATE] by [TIME] depending on equipment damage. Meter list: [pge.bz/12345]. Info & Languages: pge.com/pspsupdates. Reply STOP to STOP text alerts for this outage.

P27-123 cont.

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: Crews are inspecting equipment

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Equipment Inspections

Weather conditions have improved, and crews are inspecting equipment to determine how quickly we can safely restore power. We apologize for the disruption and we appreciate your patience.

We expect your service at: [ADDRESS, CITY, STATE, COUNTY] to be fully restored by [DAY], [DATE] by [TIME] depending on if any repairs are needed.

We will provide daily updates until your power has been restored.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

ADDITIONAL RESOURCES

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.
- To view city/county level information, including Community Resource Centers where you can charge devices visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.

CONTINUED ON NEXT PAGE

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (SINGLE PREM) CONT.

- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips visit pge.com/generatorsafety.
- For generator safety tips visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

All Customers

1	2	3	4	5	6	7
Advanced Notification	PSPS Watch	PSPS Warning	Cancellation Notification	PSPS Update	Weather All Clear	Power Restoration

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: Crews are inspecting equipment

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: PSPS Equipment Inspections

Weather conditions have improved, and crews are inspecting equipment to determine how quickly we can safely restore power. We apologize for the disruption and we appreciate your patience.

NUMBER OF METERS AFFECTED: [NUMBER of SPIDs FOR MULTI PREM]

****Due to email size limits a maximum of 50 meter locations is shown****

[VIEW ALL AFFECTED LOCATIONS/DOWNLOAD A LIST OF ALL AFFECTED LOCATIONS]

1.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.
2.	ADDRESS: [PREMISE ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID] ESTIMATED SHUTOFF: [DAY], [DATE] [TIME]-[TIME] Shutoff times may be delayed if winds arrive later than forecast. ESTIMATED RESTORATION: [DAY], [DATE] by [TIME] Restoration time may change depending on weather and equipment damage.

(Repeat for first 50 premises that would be affected)

We will provide daily updates until your power has been restored.

For more information visit pge.com/pspsupdates or call 1-800-743-5002.

ADDITIONAL RESOURCES

- If you rely on power to operate life-sustaining medical devices or have access and functional needs, additional support may be available. For more information, visit pge.com/disabilityandaging.

CONTINUED ON NEXT PAGE

P27-123 cont.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM) CONT.

- To view city/county level information, including Community Resource Centers where you can charge devices visit pge.com/pspsupdates.
- To look up additional addresses that may be affected, visit pge.com/addresslookup.
- To view a general area map of the potential outage area, visit pge.com/pspsmaps.
- Get outage tips and a sample emergency plan at pge.com/outageprep.
- For generator safety tips visit pge.com/generatorsafety.
- To learn more about Public Safety Power Shutoffs including the criteria used to turn off power, visit pge.com/psps.
- For a 7-day Public Safety Power Shutoff forecast visit pge.com/pspsweather.
- If you see a downed power line, assume it is energized and extremely dangerous. Report immediately by calling 911.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

PHONE/VOICE (SINGLE PREM)

This is PG&E calling on [DAY, DATE] at [TIME] with a PSPS outage alert. To continue in English press 1. Crews have successfully restored power at [ADDRESS]. If your power is still out in this location, please visit pge.com/outages or call 1-800-743-5002. We apologize for the disruption and we appreciate your patience. Press # to repeat this message. Thank you. Goodbye.

PHONE (MULTI PREM)

This is PG&E calling on [DAY, DATE] at [TIME] with a PSPS outage alert. To continue in English press 1. Crews have successfully restored power to [NUMBER of SPIDs FOR MULTI PREM] of your meters. The meters at the following addresses: [ADDRESS #1], [ADDRESS #2], [ADDRESS #3] have been restored. Please get ready to write down the following information. To view details for all [NUMBER of SPIDs FOR MULTI PREM] of your affected meters, visit pge.com/myaddresses and enter this phone number [XXX-XXX-XXXX] plus the following 4-digit PIN [ZZZZ] when prompted. To repeat how to get details for all of your affected meters, press *. If your power is still out at any of these locations, please visit pge.com/outages or call 1-800-743-5002. We apologize for the disruption and we appreciate your patience. Press # to repeat this message. To repeat how to get details for all of your affected meters, press *. Thank you. Goodbye.

TEXT (SINGLE PREM)

PG&E PSPS Outage Alert [DATE]: Crews have successfully restored power at your location, [PREMISE ADDRESS]. If your power is still out in this location, please visit pge.com/outages or call 1-800-743-5002. For other languages: pge.com/pspsupdates

TEXT (MULTI PREM)

PG&E PSPS Outage Alert [DATE]: Crews have successfully restored power to [NUMBER of SPIDs FOR MULTI PREM] of your meters. Meter list: [pge.bz/12345]. For other languages: pge.com/pspsupdates

P27-123 cont.

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (SINGLE PREM)

SUBJECT: PSPS Outage Alert: Power restored

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: Power Restored

Crews have successfully restored power at: [ADDRESS, CITY, STATE, COUNTY]. We apologize for the disruption and we appreciate your patience. If your power is still out in this location, please visit pge.com/outages or call 1-800-743-5002.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

P27-123 cont.

EMAIL (MULTI PREM)

SUBJECT: PSPS Outage Alert: Power restored

HEADER LINKS:
español 中文 tiếng việt Tagalog 한국어 русский язык
فارسی عربی Hmoob ខ្មែរ 日本語 ਪੰਜਾਬੀ

HEADLINE: Public Safety Power Shutoff

SUBHEAD: Power Restored

Crews have successfully restored power at the following locations:

NUMBER OF METERS RESTORED: [NUMBER of SPIDs FOR MULTI PREM]

****Due to email size limits a maximum of 50 meter locations is shown****

[VIEW ALL RESTORED LOCATIONS/DOWNLOAD A LIST OF ALL RESTORED LOCATIONS]

CONTINUED ON NEXT PAGE

All Customers

1 Advanced Notification — 2 PSPS Watch — 3 PSPS Warning — 4 Cancellation Notification — 5 PSPS Update — 6 Weather All Clear — 7 Power Restoration

EMAIL (MULTI PREM) CONT.

1.	ADDRESS: [ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID]
2.	ADDRESS: [ADDRESS, CITY, STATE, COUNTY] METER ID: [METER ID] SERVICE AGREEMENT: [SERVICE AGREEMENT ID]

(Repeat for first 50 premises that would be affected)

We apologize for the disruption and we appreciate your patience.

If your power is still out, please visit pge.com/outages or call 1-800-743-5002.

Thank you,

PG&E Customer Service

Message sent at [DATE, TIME]

NOTE: To protect against spam, some email providers may delay delivery

Some of the measures included in this email are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

P27-123 cont.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

All Customers: Microgrid Update Notification***

PHONE/VOICE

This is PG&E calling with a PSPS outage alert. For information in another language call 1-800-743-5002. Weather conditions have improved and crews are inspecting equipment to determine how quickly we can safely restore power to the electric grid. As we work to transition you from backup power to the electric grid, you will experience a power outage of up to four hours. For updates and information in more languages, visit pge.com/backuprestoration or call 1-800-743-5002. Thank you. Goodbye.

All Customers: Wildfire Impact Notification***

PHONE/VOICE

Hello, this is Pacific Gas and Electric company calling with an important update on wildfire related power outages in your area. At this time, fire fighting agencies have not determined that it's safe for PG&E crews to begin entering the impacted areas to assess our system. As soon as PG&E is granted access to the impacted areas, we will begin inspections and restore power as soon as it is possible to do so safely. Restoration time depends on the extent of damage to our equipment. As additional information becomes available, updates will be provided. You can also visit our Outage Map on pge.com/outage, or call our Outage Information line at 1-800-743-5002. Thank you for your patience as we work to safely restore your service.

P27-123 cont.

*** As-needed only.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Transmission and Wholesale Customer Notifications

P27-123 cont.

PG&E will make every effort to provide notifications to Transmission-level and Wholesale Customers through:

- Automated/Live Calls
- Text Messages
- Emails

PG&E will continue to support these customers through two PG&E contacts:

- Critical Infrastructure Lead (CIL) automated notification and/or Customer Relationship Manager leading up to the de-energization
- Grid Control Center (GCC) operators during de-energization and re-energization

The following outlines the various notifications PG&E will send prior to, during and after a PSPS event:

1. **PSPS Watch 2-Days** (Automated Notification Approx. Two Days Before Event)
2. **PSPS Watch 1-Day** (Automated Notification Approx. One Day Before Event)
3. **PSPS Warning** (Live Call - No Script)
4. **Fault Duty Event** (Live Call - As Needed)
5. **Power Restoration** (Live Call)

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Transmission and Wholesale Customers

1 PSPS Watch 2-Days (Automated Notification Approx. Two Days Before Event) — 2 PSPS Watch 1-Day (Automated Notification Approx. One Day Before Event) — 3 PSPS Warning (Live Call - No Script) — 4 Fault Duty Event (Live Call - As Needed) — 5 Power Restoration (Live Call)

PHONE (RECORDING)

This is an important safety alert from Pacific Gas and Electric Company, calling on [DATE]. Gusty winds and dry conditions, combined with a heightened fire risk, are forecasted in the next [NUMBER OF HOURS] hours and may impact transmission-level electric service. If these conditions persist, PG&E may need to turn off power for safety. Please have your emergency plan ready in case we need to turn off power for public safety. Outages could last for multiple days. We will continue to monitor conditions and will contact you with further updates. If you have any specific questions or concerns, please contact the PG&E Transmission Grid Control Center at [PHONE NUMBER]. For more information, including regular updates, please visit pge.com/psps. Thank you.

P27-123 cont.

1 PSPS Watch 2-Days (Automated Notification Approx. Two Days Before Event) — 2 PSPS Watch 1-Day (Automated Notification Approx. One Day Before Event) — 3 PSPS Warning (Live Call - No Script) — 4 Fault Duty Event (Live Call - As Needed) — 5 Power Restoration (Live Call)

PHONE (RECORDING)

This is an important safety alert from Pacific Gas and Electric Company, calling on [DATE]. Gusty winds and dry conditions, combined with a heightened fire risk, are forecasted in the next [NUMBER OF HOURS] hours and may impact transmission-level electric service. If these conditions persist, PG&E may need to turn off power for safety. Please have your emergency plan ready in case we need to turn off power for public safety. Outages could last for multiple days. We will continue to monitor conditions and will contact you with further updates. If you have any specific questions or concerns, please contact the PG&E Transmission Grid Control Center at [PHONE NUMBER]. For more information, including regular updates, please visit pge.com/psps. Thank you.

Transmission and Wholesale Customers

1 **PSPS Watch 2-Days** (Automated Notification Approx. Two Days Before Event)
2 **PSPS Watch 1-Day** (Automated Notification Approx. One Day Before Event)
3 **PSPS Warning** (Live Call - No Script)
4 **Fault Duty Event** (Live Call - As Needed)
5 **Power Restoration** (Live Call)

PHONE (LIVE CALL)

This is [NAME] at PG&E calling regarding grid conditions expected to commence [TIME, DATE] due to Public Safety Power Shutoff events. These events will cause significant power flow deviations that may have a significant impact on the fault duty at your point of interconnection. We do not expect your facility to lose power during the current event, but we do anticipate a fault duty drop that should be evaluated in order for your protective equipment to continue to operate as designed. Please have your facility's Protection Engineer or 3rd party protection contractor contact PG&E System Protection Engineering at [PHONE NUMBER] as soon as possible. PG&E's Protection Engineering will give your protection specialist the anticipated fault duty needed for protection settings during this event. Thank you.

P27-123 cont.

1 **PSPS Watch 2-Days** (Automated Notification Approx. Two Days Before Event)
2 **PSPS Watch 1-Day** (Automated Notification Approx. One Day Before Event)
3 **PSPS Warning** (Live Call - No Script)
4 **Fault Duty Event** (Live Call - As Needed)
5 **Power Restoration** (Live Call)

PHONE (LIVE CALL)

This is [NAME] at PG&E calling regarding grid conditions. PG&E has restored all services back to normal operations for this Public Safety Shutoff event. If you have made any changes to your fault duty settings for this event, do reset it to normal operations. Should you have any questions, please have your facility's Protection Engineer or 3rd party protection contractor contact PG&E System Protection Engineering at [PHONE NUMBER] for support.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX D

SECTION 7 – LOCAL COMMUNITY REPRESENTATIVES CONTACTED

P27-123 cont.

Table D-1. Local Community Representatives Contacted

Dates marked with an asterisk are representatives who received multiple notifications during the event

Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Alpine County	General	Tier 2/3	9/6/2020*
Alpine County	Undersheriff (24-hour)	Tier 2/3	9/6/2020*
Alpine County	OES Director (24-hour)	Tier 2/3	9/6/2020*
Alpine County	City Hall, Designated POC	Tier 2/3	9/6/2020*
Alpine County - Bear Valley Fire Department	General (24-hour)	Tier 2/3	9/6/2020*
Alpine County - Fire Department	General (24-hour)	Tier 2/3	9/6/2020*
Alpine County - Sheriff's Office	Dispatch (24-hour)	Tier 2/3	9/6/2020*
Alturas Rancheria of Pit River Tribe	Chairperson	Tier 2/3	9/5/2020*
Amador County	Dispatcher	Tier 2/3	9/4/2020
Amador County	OES Director	Tier 2/3	9/4/2020*
Amador County	Dipatcher	Tier 2/3	9/4/2020*
Amador County	County Administrative Officer	Tier 2/3	9/5/2020*
Amador County	OES Director	Tier 2/3	9/5/2020*
Amador County	Chair of the Board	Tier 2/3	9/5/2020*
Amador County	OES Coordinator (24-hour), Designated POC	Tier 2/3	9/5/2020*
Amador County	Fire Chief	Tier 2/3	9/5/2020*
Amador County	Unit Chief	Tier 2/3	9/5/2020*
Amador County - CAL FIRE	Local Cal Fire	Tier 2/3	9/5/2020*
Amador County - Sheriff's Office	Sheriff (24-hour)	Tier 2/3	9/5/2020*
Amah Mutsun Tribal Band	Chairman	Tier 2/3	9/7/2020*
American Indian Council of Mariposa County (Southern Sierra Miwuk Nation)	Tribal Chair	Tier 2/3	9/6/2020*
Arvin	Arvin Fire (24-hour)	N/A	9/5/2020
Arvin	Dispatcher	N/A	9/4/2020*
Arvin	City Manager; Designated POC	N/A	9/5/2020*
Arvin	Emergency (24-hour)	N/A	9/5/2020*
Auburn	City Manager; Designated POC	Tier 2/3 and Zone 1	9/5/2020
Auburn	Mayor	Tier 2/3 and Zone 1	9/5/2020*
Auburn	Local Cal Fire	Tier 2/3 and Zone 1	9/5/2020*
Auburn	Fire Chief	Tier 2/3 and Zone 1	9/5/2020*
Auburn	Police Chief	Tier 2/3 and Zone 1	9/5/2020*
Bakersfield	Dispatcher	N/A	9/4/2020*
Bakersfield	City Hall; Designated POC	N/A	9/5/2020*
Bakersfield	General; Designated POC (24-hour)	N/A	9/5/2020*
Bakersfield	Deputy Chief (24-hour)	N/A	9/5/2020*
Bakersfield	Deputy Chief (24-hour)	N/A	9/5/2020*
Bakersfield	General; Designated POC (24-hour)	N/A	9/5/2020*
Bakersfield	Deputy Chief (24-hour)	N/A	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Bakersfield - California Highway Patrol	Supervisory	N/A	9/4/2020*
Bear River Band of Rohnerville Rancheria	Vice Chairperson	Tier 2/3	9/5/2020*
Bear River Band of Rohnerville Rancheria	Chairman	Tier 2/3	9/5/2020*
Bear River Band of Rohnerville Rancheria	Chairperson	Tier 2/3	9/5/2020*
Bear River Band of Rohnerville Rancheria	Tribal Secretary	Tier 2/3	9/5/2020*
Bear River Band of Rohnerville Rancheria	Vice Chairperson	Tier 2/3	9/5/2020*
Berry Creek Rancheria	Chairman	Tier 2/3	9/5/2020*
Big Lagoon Rancheria	Chairperson	Tier 2/3	9/5/2020*
Big Valley Band of Pomo Indians	Executive Assistant (24-hour)	Tier 2/3	9/5/2020*
Big Valley Band of Pomo Indians	Tribal Chairman (24-hour)	Tier 2/3	9/5/2020*
Big Valley Band of Pomo Indians	Tribal Administrator (24-hour)	Tier 2/3	9/5/2020*
Big Valley Band of Pomo Indians	Deputy Tribal Administrator (24-hour)	Tier 2/3	9/5/2020*
Blue Lake Rancheria	Chairperson	Tier 2/3	9/5/2020*
Blue Lake Rancheria	Fire Chief	Tier 2/3	9/5/2020*
Blue Lake Rancheria	On Duty Supervisor	Tier 2/3	9/5/2020*
Buena Vista Rancheria of Me-Wuk Indians	EOS Director (24-hour)	Tier 2/3	9/5/2020*
Buena Vista Rancheria of Me-Wuk Indians	Chairperson	Tier 2/3	9/5/2020*
Butte County	Dipatcher	Tier 2/3	9/4/2020
Butte County	Dipatcher	Tier 2/3	9/4/2020
Butte County	OES Director	Tier 2/3	9/4/2020
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	Probation Officer	Tier 2/3	9/5/2020*
Butte County	General CAL FIRE (24-hour)	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	Emergency Services Officer	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	Sheriff	Tier 2/3	9/5/2020*
Butte County	General Services Director	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	Chief Administrative Officer; Designated POC	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	Assistant Director	Tier 2/3	9/5/2020*

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cont.

Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Butte County	General	Tier 2/3	9/5/2020*
Butte County	General	Tier 2/3	9/5/2020*
Butte County	Director	Tier 2/3	9/5/2020*
Butte County	Public Health Director	Tier 2/3	9/5/2020*
Butte County - CAL FIRE	Dipatcher	Tier 2/3	9/4/2020*
Butte County - Sheriff's Office	Dipatcher	Tier 2/3	9/4/2020
Butte Tribal Council	General	Tier 2/3	9/5/2020*
CAL FIRE - Madera, Mariposa and Merced Counties	Dispatcher	Tier 2/3	9/7/2020*
CAL FIRE - Tuolumne and Calaveras Counties	Captain	Tier 2/3	9/5/2020*
Calaveras County	County Executive Officer	Tier 2/3	9/5/2020*
Calaveras County	OES	Tier 2/3	9/5/2020*
Calaveras County	Local Cal Fire (24-hour)	Tier 2/3	9/5/2020*
Calaveras County	Fire Chief	Tier 2/3	9/5/2020*
Calaveras County	Chair of the Board	Tier 2/3	9/5/2020*
Calaveras County	OES Director (24-hour), Designated POC	Tier 2/3	9/5/2020*
Calaveras County - Sheriff's Office	Non-Emergency (24-hour)	Tier 2/3	9/5/2020*
California State University, Sonoma	Dispatcher	Tier 2/3	9/4/2020
California Valley Miwok Tribe	Chairperson	Tier 2/3	9/5/2020*
Calistoga	Mayor	Tier 2/3 and Zone 1	9/5/2020*
Calistoga	City Manager; Designated POC	Tier 2/3 and Zone 1	9/5/2020*
Calistoga - Fire Department	General (24-hour)	Tier 2/3 and Zone 1	9/5/2020*
Calistoga - Police Department	General (24-hour)	Tier 2/3 and Zone 1	9/5/2020*
Chaushila Yokuts	Charman	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Executive Manager (24-hour)	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Surveillance (24-hour)	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Tribal Adminstrator	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Gaming Director (24-hour)	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Deputy CEO	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Facilities Manager	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Seascape Manager	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	General	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Chairperson	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	General	Tier 2/3	9/5/2020*
Cher-Ae Heights Indian Community of the Trinidad Rancheria	Casino General Manager	Tier 2/3	9/5/2020*
Chicken Ranch Rancheria	Tribal Administrator (24-hour)	Tier 2/3	9/5/2020*
Chicken Ranch Rancheria	Chairperson	Tier 2/3	9/5/2020*
Chicken Ranch Rancheria	Facilities Manager (24-hour)	Tier 2/3	9/5/2020*
Chicken Ranch Rancheria	Security Manager (24-hour)	Tier 2/3	9/5/2020*
Chicken Ranch Rancheria	Facilities Manager (24-hour)	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Chico	Dipatcher	Tier 2/3	9/4/2020
Chico	General	Tier 2/3	9/5/2020*
Chico	Police Chief	Tier 2/3	9/5/2020*
Chico	City Manager; Designated POC	Tier 2/3	9/5/2020*
Chico	Mayor	Tier 2/3	9/5/2020*
Chico	Fire Chief	Tier 2/3	9/5/2020*
Chico	General	Tier 2/3	9/5/2020*
Chico	General	Tier 2/3	9/6/2020*
China Lake Naval Weapon PD	Dispatcher	Tier 2/3	9/4/2020
Cloverdale	Mayor	Tier 2/3	9/5/2020*
Cloverdale	Police Chief (24-hour)	Tier 2/3	9/5/2020*
Cloverdale	District Director	Tier 2/3	9/5/2020*
Cloverdale	Fire Chief (24-hour)	Tier 2/3	9/5/2020*
Cloverdale	City Manager; Designated POC (24-hour)	Tier 2/3	9/5/2020*
Cloverdale	Lieutenant (24-hour)	Tier 2/3	9/5/2020*
Cloverdale	Director of Public Works (24-hour)	Tier 2/3	9/5/2020*
Cloverdale	Assistant City Manager (24-hour)	Tier 2/3	9/5/2020*
Cloverdale - Police Department	Officer	Tier 2/3	9/4/2020
Cloverdale Rancheria	General	Tier 2/3	9/5/2020*
Cloverdale Rancheria	Vice Chairperson	Tier 2/3	9/7/2020*
Cloverdale Rancheria	Chairperson	Tier 2/3	9/7/2020*
Cloverdale Rancheria	Tribal Treasurer (24-hour)	Tier 2/3	9/7/2020*
Colfax	City Manager; Designated POC (24-hour)	Tier 2/3	9/5/2020*
Colfax	Mayor	Tier 2/3	9/5/2020*
Colfax - Fire Department	General	Tier 2/3	9/5/2020
Colfax - Sheriff's Office	Substation (24-hour)	Tier 2/3	9/5/2020
Cortina Rancheria	Chairperson	Tier 2/3	9/7/2020*
Cotati	Sergeant	Tier 2/3	9/4/2020
Coyote Valley Band of Pomo Indians	Chairman	Tier 2/3	9/7/2020*
Coyote Valley Band of Pomo Indians	Tribal Administrator	Tier 2/3	9/7/2020*
Coyote Valley Band of Pomo Indians	Vice Chairperson	Tier 2/3	9/7/2020*
Delano	Dispatcher	N/A	9/4/2020
Dry Creek Rancheria Band of Pomo Indians	Vice Chairperson	Tier 2/3	9/5/2020*
Dry Creek Rancheria Band of Pomo Indians	Fire Chief (24-hour)	Tier 2/3	9/5/2020*
Dry Creek Rancheria Band of Pomo Indians	CEO (24-hour)	Tier 2/3	9/5/2020*
Dry Creek Rancheria Band of Pomo Indians	Security Director (24-hour)	Tier 2/3	9/5/2020*
Dry Creek Rancheria Band of Pomo Indians	Chairman (24-hour)	Tier 2/3	9/5/2020*
Dumna Wo-Wah Tribal Government	Chairperson	Tier 2/3	9/7/2020*
Dunlap Band of Mono Indians Historical Preservation Society	President	Tier 2/3	9/5/2020*
El Dorado County	Chief Administrative Officer	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
El Dorado County	OES Director; Designated POC	Tier 2/3	9/5/2020*
El Dorado County	Sheriff	Tier 2/3	9/5/2020*
El Dorado County	Chair of the Board	Tier 2/3	9/5/2020*
El Dorado County	Health and Human Services	Tier 2/3	9/5/2020*
El Dorado County	Fire Chief	Tier 2/3	9/5/2020*
El Dorado County - Office of Emergency Services	General (24-hour)	Tier 2/3	9/5/2020*
El Dorado County - Office of Emergency Services	General (24-hour)	Tier 2/3	9/5/2020*
Elem Indian Colony	Tribal Administrator	Tier 2/3	9/5/2020*
Elem Indian Colony	Chairman	Tier 2/3	9/5/2020*
Elem Indian Colony	Env Director	Tier 2/3	9/5/2020*
Enterprise Rancheria of Maidu Indians	Tribal Administration (24-hour)	Tier 2/3	9/5/2020*
Enterprise Rancheria of Maidu Indians	Chairwoman	Tier 2/3	9/5/2020*
Enterprise Rancheria of Maidu Indians	Casino Director of Security (24-hour)	Tier 2/3	9/5/2020*
Federated Indians of Graton Rancheria	Grants Administrator (24-hour)	Tier 2/3	9/5/2020*
Federated Indians of Graton Rancheria	Tribal Preservation Officer (24-hour)	Tier 2/3	9/5/2020*
Federated Indians of Graton Rancheria	Vice Chairperson	Tier 2/3	9/5/2020*
Federated Indians of Graton Rancheria	Chairman	Tier 2/3	9/5/2020*
Federated Indians of Graton Rancheria	TANF Director (24-hour)	Tier 2/3	9/7/2020*
Fort Independence Reservation	Chairperson	Tier 2/3	9/5/2020*
Grass Valley	Fire Chief (24-hour)	Tier 2/3	9/5/2020*
Grass Valley	Police Chief	Tier 2/3	9/5/2020*
Grass Valley	City Manager; Designated POC	Tier 2/3	9/5/2020*
Grass Valley	Mayor	Tier 2/3	9/5/2020*
Greenville Rancheria	Vice Chairperson	Tier 2/3	9/5/2020*
Greenville Rancheria	Chairman	Tier 2/3	9/5/2020*
Grindstone Rancheria	TA	Tier 2/3	9/7/2020*
Grindstone Rancheria	Chairman	Tier 2/3	9/7/2020*
Guidiville Rancheria	Chairperson	Tier 2/3	9/5/2020*
Habematolel Pomo of Upper Lake	Tribal Administrator	Tier 2/3	9/5/2020*
Habematolel Pomo of Upper Lake	EPA Director	Tier 2/3	9/5/2020*
Habematolel Pomo of Upper Lake	Chairperson	Tier 2/3	9/5/2020*
Haslett Basin Traditional Committee	Chairman	Tier 2/3	9/6/2020*
Healdsburg	Dispatcher	Tier 2/3	9/4/2020*
Honey Lake Maidu	General	Tier 2/3	9/5/2020*
Hoopa Valley Tribe	Assistant Chief	Tier 2/3	9/5/2020*
Hoopa Valley Tribe	Chairman	Tier 2/3	9/5/2020*
Hoopa Valley Tribe	OES Director	Tier 2/3	9/5/2020*
Hopland Rancheria	General	Tier 2/3	9/5/2020*
Hopland Reservation	Chairperon	Tier 2/3	9/5/2020*
Humboldt County	Fire Safe Council	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Humboldt County	General	Tier 2/3	9/5/2020*
Humboldt County	Corrections Lieutenant (24-hour)	Tier 2/3	9/5/2020*
Humboldt County	OES Manager (24-hour)	Tier 2/3	9/5/2020*
Humboldt County	State Assemblymember	Tier 2/3	9/5/2020*
Humboldt County	Chair of the Board	Tier 2/3	9/5/2020*
Humboldt County	General	Tier 2/3	9/5/2020*
Humboldt County	Sheriff (24-hour)	Tier 2/3	9/5/2020*
Humboldt County	Community Development Service; Designated POC	Tier 2/3	9/5/2020*
Humboldt County	Operations Lieutenant (24-hour)	Tier 2/3	9/5/2020*
Humboldt County	Local Cal Fire	Tier 2/3	9/5/2020*
Humboldt County	General	Tier 2/3	9/5/2020*
Humboldt County	County Health and Human Services	Tier 2/3	9/5/2020*
Humboldt County	County Administrative Officer	Tier 2/3	9/5/2020*
Humboldt County	General	Tier 2/3	9/5/2020*
Humboldt County	Fire Chief (24-hour)	Tier 2/3	9/5/2020*
Humboldt County	General	Tier 2/3	9/5/2020*
Humboldt County	State Senator	Tier 2/3	9/6/2020*
Indian Canyon Mutsun Band of Costanoan	Chairperson	Tier 2/3	9/5/2020*
Ione	Dispatcher	Tier 2/3 and Zone 1	9/4/2020
Ione Band of Miwok Indians	Chairperson	Tier 2/3 and Zone 2	9/5/2020*
Ione Band of Miwok Indians	Vice Chairperson	Tier 2/3 and Zone 3	9/5/2020*
Jackson Rancheria	Chairperson	Tier 2/3	9/5/2020*
Jackson Rancheria	Tribal Council Administrative Assistant	Tier 2/3	9/5/2020*
Karuk Tribe	Chairman	Tier 2/3	9/5/2020*
Karuk Tribe	Tribal Administrator	Tier 2/3	9/5/2020*
Karuk Tribe	Historic Preservation Officer	Tier 2/3	9/5/2020*
Kawaiisu Tribe	Chairperson	Tier 2/3	9/5/2020*
Kern County	Emergency Supervisor	Tier 2/3	9/4/2020*
Kern County	OES Manager	Tier 2/3	9/4/2020*
Kern County	CAO; Designated POC	Tier 2/3	9/5/2020*
Kern County	Manager; Designated POC	Tier 2/3	9/5/2020*
Kern County	Emergency (24-hour)	Tier 2/3	9/5/2020*
Kern County	General (24-hour)	Tier 2/3	9/5/2020*
Kern County - Office of Emergency Management	Emergency Supervisor (24-hour)	Tier 2/3	9/6/2020*
Kern County - Office of Emergency Services	Emergency (24-hour)	Tier 2/3	9/5/2020*
Kern County - Sheriff's Office	Emergency (24-hour)	Tier 2/3	9/5/2020*
Kern Valley Indian Council	Chairperson	Tier 2/3	9/5/2020*
Kern Valley Indian Council	Historic Preservation Officer	Tier 2/3	9/5/2020*
Lake County	OES Emergency Director; Designated POC (24-hour)	Tier 2/3	9/5/2020*
Lake County	Administrator	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Lake County	County Administrative Officer	Tier 2/3	9/5/2020*
Lake County	CAL FIRE (24-hour)	Tier 2/3	9/5/2020*
Lake County	Under Sheriff	Tier 2/3	9/5/2020*
Lake County	Sheriff	Tier 2/3	9/5/2020*
Lake County	Chair of the Board	Tier 2/3	9/5/2020*
Lake County	Lieutenant	Tier 2/3	9/5/2020*
Lake County	Dispatch; Designated POC (24-hour)	Tier 2/3	9/5/2020*
Lassen County	CAO; Designated POC	Tier 2/3	9/6/2020*
Lassen County	CAL FIRE (24-hour)	Tier 2/3	9/6/2020*
Lassen County	General (24-hour)	Tier 2/3	9/6/2020*
Lassen County	General	Tier 2/3	9/6/2020*
Lassen County - Sheriff's Office	General (24hour)	Tier 2/3	9/6/2020*
Laytonville Rancheria	Housing Director	Tier 2/3	9/5/2020*
Laytonville Rancheria	Chairperson	Tier 2/3	9/5/2020*
Loomis	Substation (24-hour)	Tier 2/3	9/7/2020*
Loomis	Mayor	Tier 2/3	9/7/2020*
Loomis	Town Manager; Designated POC	Tier 2/3	9/7/2020*
Loomis	Fire Chief	Tier 2/3	9/7/2020*
Lower Lake Rancheria	Chairman	Tier 2/3	9/5/2020*
Lower Lake Rancheria	Vice Chairperson	Tier 2/3	9/5/2020*
Lytton Rancheria	OES Director	Tier 2/3	9/5/2020*
Lytton Rancheria	Chairwoman	Tier 2/3	9/5/2020*
Lytton Rancheria	Tribal Administrator	Tier 2/3	9/5/2020*
Manchester-Point Arena Rancheria	Chairman	Tier 2/3	9/5/2020*
Manchester-Point Arena Rancheria	Tribal Administration	Tier 2/3	9/5/2020*
Manchester-Point Arena Rancheria	Tribal Council	Tier 2/3	9/5/2020*
Mariposa County	Sheriff Office Sergeant	Tier 2/3	9/7/2020
Mariposa County	OES Director	Tier 2/3	9/7/2020*
Mariposa County	Emergency Services (24-hour)	Tier 2/3	9/7/2020*
Mariposa County	OES Director	Tier 2/3	9/7/2020*
Mariposa County	Director	Tier 2/3	9/7/2020*
Mariposa County	Sherriff Deputy	Tier 2/3	9/7/2020*
Mariposa County	County Administrative Officer (24-hour)	Tier 2/3	9/7/2020*
Mariposa County	General	Tier 2/3	9/7/2020*
Mariposa County	Public Information Officer (24-hour)	Tier 2/3	9/7/2020*
Mariposa County	Battalion Chief (24-hour)	Tier 2/3	9/7/2020*
Mariposa County	GIS Tech (24-hour)	Tier 2/3	9/7/2020*
Mariposa County	OESCoordinator (24-hour)	Tier 2/3	9/7/2020*
Mariposa County	General	Tier 2/3	9/7/2020*
Mariposa County	Special Operations (24-hour)	Tier 2/3	9/7/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Mariposa County	Cal FIRE Chief	Tier 2/3	9/7/2020*
Mariposa County	Division Chief (24-hour)	Tier 2/3	9/7/2020*
Mariposa County - Fire Department	General	Tier 2/3	9/7/2020*
Mariposa County - Fire Department	Emergency Command Center (24-hour)	Tier 2/3	9/7/2020*
Mariposa County - Health and Human Services	Public Health Officer (24-hour)	Tier 2/3	9/7/2020*
Mariposa County - Sheriff's Office	Emergency Dispatch (24-hour)	Tier 2/3	9/7/2020*
Marysville	Fire Chief	N/A	9/5/2020
Marysville	City Manager; Designated POC	N/A	9/5/2020*
Marysville	Mayor	N/A	9/5/2020*
MCE Community Choice Energy (MCE)	Chief Operating Officer	Tier 2/3	9/5/2020*
MCE Community Choice Energy (MCE)	Director of Public Affairs	Tier 2/3	9/5/2020*
MCE Community Choice Energy (MCE)	CEO	Tier 2/3	9/5/2020*
Mechoopda Indian Tribe	Vice Chairwoman	Tier 2/3	9/5/2020*
Mechoopda Indian Tribe	Councilmember	Tier 2/3	9/5/2020*
Mechoopda Indian Tribe	Chairman	Tier 2/3	9/5/2020*
Middletown Rancheria	Vice Chairwoman	Tier 2/3	9/5/2020*
Middletown Rancheria	Chairman	Tier 2/3	9/5/2020*
Mishewal-Wappo of Alexander Valley	Chairperson	Tier 2/3	9/5/2020*
Mooretown Rancheria	Chairman	Tier 2/3	9/5/2020*
Mooretown Rancheria	Casino Operations	Tier 2/3	9/5/2020*
Muwekma Ohlone Indian Tribe	Vice Chairwoman	Tier 2/3	9/5/2020*
Napa County	Emergency Coordinator (24-hour)	Tier 2/3	9/5/2020*
Napa County	General	Tier 2/3	9/5/2020*
Napa County	Local Cal Fire	Tier 2/3	9/5/2020*
Napa County	Info Systems Specialist	Tier 2/3	9/5/2020*
Napa County	Non-Emergency (24-hour)	Tier 2/3	9/5/2020*
Napa County	Sheriff	Tier 2/3	9/5/2020*
Napa County	General	Tier 2/3	9/5/2020*
Napa County	County Executive Officer	Tier 2/3	9/5/2020*
Napa County	OES Coordinator	Tier 2/3	9/5/2020*
Napa County	Chair of the Board	Tier 2/3	9/5/2020*
Napa County	General	Tier 2/3	9/5/2020*
Napa County	Emergency Services Manager	Tier 2/3	9/5/2020*
Nevada City	Police Chief	Tier 2/3 and Zone 1	9/5/2020*
Nevada City	General	Tier 2/3 and Zone 1	9/5/2020*
Nevada City	City Manager; Designated POC	Tier 2/3 and Zone 1	9/5/2020*
Nevada City	Mayor	Tier 2/3 and Zone 1	9/5/2020*
Nevada County	OES Manager; Designated POC	Tier 2/3	9/5/2020*
Nevada County	Chief	Tier 2/3	9/5/2020*
Nevada County	Division Chief (24-hour)	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Nevada County	OES Director	Tier 2/3	9/5/2020*
Nevada County	General	Tier 2/3	9/5/2020*
Nevada County	General (24-hour)	Tier 2/3	9/5/2020*
Nevada County	General	Tier 2/3	9/5/2020*
North Fork Rancheria	Vice Chairman	Tier 2/3	9/5/2020*
North Fork Rancheria	Tribal Council	Tier 2/3	9/5/2020*
North Fork Rancheria	Tribal Council	Tier 2/3	9/5/2020*
North Fork Rancheria	Chairman	Tier 2/3	9/5/2020*
Northern Band of Mono Yokuts	Chairman	Tier 2/3	9/5/2020*
Noyo River Indian Community	General	Tier 2/3	9/9/2020*
Ohlone Indian Tribe	General	Tier 2/3	9/5/2020*
Oroville	Dipatcher	Tier 2/3	9/4/2020
Oroville	City Manager; Designated POC	Tier 2/3	9/5/2020*
Oroville	City Administrator	Tier 2/3	9/5/2020*
Oroville	Mayor	Tier 2/3	9/5/2020*
Oroville - Fire Department	General (24-hour)	Tier 2/3	9/5/2020*
Paradise	General	Tier 2/3 and Zone 1	9/5/2020*
Paradise	General	Tier 2/3 and Zone 1	9/5/2020*
Paradise	General	Tier 2/3 and Zone 1	9/5/2020*
Paradise	Town Manager; Designated POC	Tier 2/3 and Zone 1	9/5/2020*
Paradise	Mayor	Tier 2/3 and Zone 1	9/5/2020*
Paradise	General CAL FIRE (24-hour)	Tier 2/3 and Zone 1	9/5/2020*
Paskenta Rancheria	Chairman	Tier 2/3	9/5/2020*
Peninsula Clean Energy (PCE)	Director of Customer Care	Tier 2/3	9/5/2020*
Petaluma	Dispatcher	Tier 2/3	9/4/2020
Picayune Rancheria (Chukchansi Tribe)	Chairperson	Tier 2/3	9/5/2020*
Pinoleville Reservation	Chairperson	Tier 2/3	9/6/2020*
Pioneer Community Energy (PIO)	Marketing and Government Affairs Manager	Tier 2/3	9/5/2020*
Pit River Tribes	General	Tier 2/3	9/5/2020*
Pit River Tribes	Chairperson	Tier 2/3	9/5/2020*
Pit River Tribes	Chairperson	Tier 2/3	9/5/2020*
Pit River Tribes	Tribal Housing Authority	Tier 2/3	9/5/2020*
Placer County	Envir. Utilities Manager	Tier 2/3	9/5/2020*
Placer County	Lieutenant - PCSO	Tier 2/3	9/5/2020*
Placer County	Deputy Director	Tier 2/3	9/5/2020*
Placer County	IT Supervisor	Tier 2/3	9/5/2020*
Placer County	Sergeant - PCSO	Tier 2/3	9/5/2020*
Placer County	Deputy Director	Tier 2/3	9/5/2020*
Placer County	Battalion Chief	Tier 2/3	9/5/2020*
Placer County	Duty Officer	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Placer County	Battalion Chief	Tier 2/3	9/5/2020*
Placer County	Deputy Director	Tier 2/3	9/5/2020*
Placer County	Sergeant - PCSO	Tier 2/3	9/5/2020*
Placer County	Assistant Chief	Tier 2/3	9/5/2020*
Placer County	Building Maintenance Superintendent	Tier 2/3	9/5/2020*
Placer County	Assistant Director	Tier 2/3	9/5/2020*
Placer County	County Executive Officer	Tier 2/3	9/5/2020*
Placer County	IT Manager	Tier 2/3	9/5/2020*
Placer County	Lieutenant - PCSO	Tier 2/3	9/5/2020*
Placer County	Placer Facilities Mgt Emergency Line	Tier 2/3	9/5/2020*
Placer County	Battalion Chief	Tier 2/3	9/5/2020*
Placer County	Battalion Chief	Tier 2/3	9/5/2020*
Placer County	Health Officer	Tier 2/3	9/5/2020*
Placer County	IT Supervisor	Tier 2/3	9/5/2020*
Placer County	Emergency Command Center (24-hour)	Tier 2/3	9/5/2020*
Placer County	General	Tier 2/3	9/5/2020*
Placer County	Main Telecom Number	Tier 2/3	9/5/2020*
Placer County	Sergeant - PCSO	Tier 2/3	9/5/2020*
Placer County	Sergeant - PCSO	Tier 2/3	9/5/2020*
Placer County	OES Asst Director; Designated POC (24-hour)	Tier 2/3	9/5/2020*
Placer County	Em Services Specialist	Tier 2/3	9/5/2020*
Placer County	Em Services Coord	Tier 2/3	9/5/2020*
Placer County	Program Manager	Tier 2/3	9/5/2020*
Placer County	Lieutenant - PCSO	Tier 2/3	9/5/2020*
Placer County	Lieutenant - PCSO	Tier 2/3	9/5/2020*
Placer County	Sheriff Dispatch (24-hour)	Tier 2/3	9/5/2020*
Placer County	Roads Manager	Tier 2/3	9/5/2020*
Placer County	CIO	Tier 2/3	9/5/2020*
Placer County	Deputy Chief	Tier 2/3	9/5/2020*
Placer County	Director	Tier 2/3	9/5/2020*
Placer County	IT Manager	Tier 2/3	9/5/2020*
Placer County	Battalion Chief	Tier 2/3	9/5/2020*
Placer County	Battalion Chief	Tier 2/3	9/5/2020*
Placer County	Lieutenant - PCSO	Tier 2/3	9/5/2020*
Placerville	Dipatcher	Tier 2/3 and Zone 1	9/4/2020
Placerville	City Manager; Designated POC	Tier 2/3 and Zone 1	9/5/2020*
Placerville	OES Director	Tier 2/3 and Zone 1	9/5/2020*
Placerville	Police Chief	Tier 2/3 and Zone 1	9/5/2020*
Placerville	Station 19 (24-hour)	Tier 2/3 and Zone 1	9/5/2020*
Placerville	Mayor	Tier 2/3 and Zone 1	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Plumas County	Special Operations Sergeant	Tier 2/3	9/4/2020*
Plumas County	Sheriff Office Dispatcher	Tier 2/3	9/4/2020*
Plumas County	Sheriff Office Dispatcher	Tier 2/3	9/4/2020*
Plumas County	General	Tier 2/3	9/5/2020*
Plumas County	Director (24-hour)	Tier 2/3	9/5/2020*
Plumas County	CAO; Designated POC	Tier 2/3	9/5/2020*
Plumas County	Public Works Director	Tier 2/3	9/5/2020*
Plumas County	USFS PNF Dispatch (24-hour)	Tier 2/3	9/5/2020*
Plumas County	Main Office	Tier 2/3	9/5/2020*
Plumas County	MHOAC (24-hour)	Tier 2/3	9/5/2020*
Plumas County	Dispatch	Tier 2/3	9/5/2020*
Plumas County	OES Director (24-hour)	Tier 2/3	9/5/2020*
Potter Valley Tribe	Tribal Treasurer	Tier 2/3	9/5/2020*
Potter Valley Tribe	Tribal Chairman	Tier 2/3	9/5/2020*
Potter Valley Tribe	Environmental Director	Tier 2/3	9/5/2020*
Red Bluff	Fire Chief	Tier 2/3	9/5/2020*
Red Bluff	City Manager; Designated POC	Tier 2/3	9/5/2020*
Red Bluff	CAO; Designated POC	Tier 2/3	9/5/2020*
Red Bluff	Mayor	Tier 2/3	9/5/2020*
Red Bluff	City Administrator; Designated POC	Tier 2/3	9/5/2020*
Redding Rancheria	Public Works (24-hour)	Tier 2/3	9/5/2020*
Redding Rancheria	Public Works (24-hour)	Tier 2/3	9/5/2020*
Redding Rancheria	Safety Manager	Tier 2/3	9/5/2020*
Redding Rancheria	Chairman	Tier 2/3	9/5/2020*
Redwood Coast Energy Authority (RCEA)	Director of Power Resources	Tier 2/3	9/5/2020*
Redwood Coast Energy Authority (RCEA)	Account Services Manager	Tier 2/3	9/5/2020*
Redwood Coast Energy Authority (RCEA)	General	Tier 2/3	9/5/2020*
Redwood Valley Rancheria	Tribal Administrator (24-hour)	Tier 2/3	9/5/2020*
Redwood Valley Rancheria	Chairperson	Tier 2/3	9/5/2020*
Robinson Rancheria	Vice Chairperson	Tier 2/3	9/5/2020*
Robinson Rancheria	Chairperson	Tier 2/3	9/5/2020*
Robinson Rancheria	Member at-large	Tier 2/3	9/5/2020*
Robinson Rancheria	Tribal Administrator	Tier 2/3	9/5/2020*
Rohnert Park	Mayor	Tier 2/3	9/6/2020
Rohnert Park	Deputy Chief	Tier 2/3	9/6/2020*
Rohnert Park	City Manager; Designated POC	Tier 2/3	9/6/2020*
Rohnert Park	Deputy Chief	Tier 2/3	9/6/2020*
Rohnert Park - Police Department	General (24-hour)	Tier 2/3	9/6/2020*
Rohnert Park - Public Safety	Lieutenant	Tier 2/3	9/4/2020*
Round Valley Reservation	Chief of Police	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Round Valley Reservation	Tribal Business Administrator	Tier 2/3	9/5/2020*
Round Valley Reservation	Tribal President	Tier 2/3	9/6/2020*
Saint Helena	Mayor	Tier 2/3	9/5/2020*
Saint Helena	Police Chief (24-hour)	Tier 2/3	9/5/2020*
Saint Helena	City Manager; Designated POC	Tier 2/3	9/5/2020*
Saint Helena	Fire Chief	Tier 2/3	9/5/2020*
Salinan Tribe of Monterey, San Luis Obispo and San Benito Counties	Chairperson	Tier 2/3	9/5/2020*
San Francisco Public Utilties Commission	Utility Specialist CleanPowerSF	Tier 2/3	9/5/2020*
San Francisco Public Utilties Commission	Emergency Planning and Security	Tier 2/3	9/5/2020*
San Luis Obispo County Chumash Council	Chairperson	Tier 2/3	9/5/2020*
Santa Rosa	Mayor	Tier 2/3	9/7/2020*
Santa Rosa	Emergency Preparedness Coordinator; Designated POC (24-hour)	Tier 2/3	9/7/2020*
Santa Rosa	Fire	Tier 2/3	9/7/2020*
Santa Rosa	Lieutenant	Tier 2/3	9/7/2020*
Santa Rosa	City Manager; Designated POC	Tier 2/3	9/7/2020*
Santa Rosa	Fire Chief (24-hour)	Tier 2/3	9/7/2020*
Santa Rosa	Planning and Economic Development Director	Tier 2/3	9/7/2020*
Santa Rosa	Assistant Fire Marshal	Tier 2/3	9/7/2020*
Santa Rosa	Lieutenant	Tier 2/3	9/7/2020*
Santa Rosa	City Manager	Tier 2/3	9/7/2020*
Santa Rosa	Public Information Officer	Tier 2/3	9/7/2020*
Santa Rosa	Deputy Emergency Preparedness Coordinator (24-hour)	Tier 2/3	9/7/2020*
Santa Rosa	Police Chief	Tier 2/3	9/7/2020*
Santa Rosa	General	Tier 2/3	9/7/2020*
Santa Rosa	Battalion Chief	Tier 2/3	9/7/2020*
Santa Rosa	Admin Sergeant	Tier 2/3	9/7/2020*
Santa Rosa	Deputy Fire Chief	Tier 2/3	9/7/2020*
Santa Rosa - Police Department	Dispatcher	Tier 2/3	9/4/2020
Santa Rosa - Santa Rosa Junior College Police Department	Dispatcher	Tier 2/3	9/4/2020
Santa Rosa Rancheria	Chairperson	Tier 2/3	9/5/2020*
Santa Rosa Rancheria	Vice Chairperson	Tier 2/3	9/5/2020*
Santa Rosa Rancheria	Chairperson	Tier 2/3	9/5/2020*
Santa Ynez Band of Chumash Indians	Environmental Director	Tier 2/3	9/7/2020*
Santa Ynez Band of Chumash Indians	General	Tier 2/3	9/5/2020*
Santa Ynez Band of Chumash Indians	Tribal Administrator	Tier 2/3	9/5/2020*
Scotts Valley Band of Pomo Indians	Chairman	Tier 2/3	9/5/2020*
Scotts Valley Band of Pomo Indians	Finance Officer (24-hour)	Tier 2/3	9/5/2020*
Scotts Valley Band of Pomo Indians	PIO (24-hour)	Tier 2/3	9/5/2020*
Sebastopol - Police Department	Dispatcher	N/A	9/4/2020

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	Captain	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	OES Director	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	Fire Chief	Tier 2/3	9/5/2020*
Shasta County	Supervisor	Tier 2/3	9/5/2020*
Shasta County	Undersheriff	Tier 2/3	9/5/2020*
Shasta County	OES	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	CEO; Designated POC	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	Chair of the Board	Tier 2/3	9/5/2020*
Shasta County	District Director	Tier 2/3	9/5/2020*
Shasta County	Sergeant	Tier 2/3	9/5/2020*
Shasta County	ECC	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	General	Tier 2/3	9/5/2020*
Shasta County	Supervisor	Tier 2/3	9/5/2020*
Shasta County	Local Cal Fire	Tier 2/3	9/5/2020*
Shebelna Band of Mendocino Coast Pomo Indians	Chairperson	Tier 2/3	9/5/2020*
Sherwood Valley Band of Pomo Indians	Tribal Administrator (24-hour)	Tier 2/3	9/5/2020*
Sherwood Valley Band of Pomo Indians	Chairman	Tier 2/3	9/7/2020*
Sherwood Valley Band of Pomo Indians	Tribal Chairperson	Tier 2/3	9/7/2020*
Shingle Springs Rancheria	Assistant Police Chief	Tier 2/3	9/5/2020*
Shingle Springs Rancheria	Chairwoman	Tier 2/3	9/5/2020*
Shingle Springs Rancheria	Housing Director	Tier 2/3	9/5/2020*
Shingle Springs Rancheria	Police Chief	Tier 2/3	9/5/2020*
Sierra County	Supervisor	Tier 2/3	9/5/2020*
Sierra County	OES Director (24-hour)	Tier 2/3	9/5/2020*
Sierra County	Chair of the Board	Tier 2/3	9/5/2020*
Sierra County	Superintendent	Tier 2/3	9/5/2020*
Sierra County	OES Coordinator; Designated POC	Tier 2/3	9/5/2020*
Sierra County	Fire Chief (24-hour)	Tier 2/3	9/5/2020*
Sierra County	Sheriff (24-hour)	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Sierra County	Fire Chief (24-hour)	Tier 2/3	9/5/2020*
Sierra County	Supervisor	Tier 2/3	9/5/2020*
Sierra County	Dispatch Supervisor (24-hour)	Tier 2/3	9/5/2020*
Sierra County	General	Tier 2/3	9/5/2020*
Sierra County	General	Tier 2/3	9/5/2020*
Sierra County	General	Tier 2/3	9/5/2020*
Sierra County - Office of Emergency Services	General	Tier 2/3	9/5/2020*
Sierra County - Sheriff's Department	General	Tier 2/3	9/5/2020*
Sierra County - Sheriff's Office	General	Tier 2/3	9/5/2020*
Sierra Mono Museum	Director	Tier 2/3	9/6/2020*
Sierra National Forest	Dispatcher	Tier 2/3	9/7/2020
Siskiyou County	CAL FIRE (24-hour)	Tier 2/3	9/7/2020*
Siskiyou County	County Executive Officer; Designated POC	Tier 2/3	9/7/2020*
Siskiyou County	General	Tier 2/3	9/7/2020*
Siskiyou County	General	Tier 2/3	9/8/2020*
Sonoma Clean Power (SCP)	Account Executive	Tier 2/3	9/5/2020*
Sonoma Clean Power (SCP)	CEO	Tier 2/3	9/5/2020*
Sonoma Clean Power (SCP)	Director of Customer Care	Tier 2/3	9/5/2020*
Sonoma County	Department of Emergency Services Duty Officer	Tier 2/3	9/4/2020*
Sonoma County	Sheriff Office Dispatcher	Tier 2/3	9/4/2020*
Sonoma County	County Administrator	Tier 2/3	9/5/2020*
Sonoma County	General (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	Deputy Director (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	Sheriff	Tier 2/3	9/5/2020*
Sonoma County	Mayor (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	OES Director	Tier 2/3	9/5/2020*
Sonoma County	General	Tier 2/3	9/5/2020*
Sonoma County	Chair of the Board	Tier 2/3	9/5/2020*
Sonoma County	Emergency Manager (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	General	Tier 2/3	9/5/2020*
Sonoma County	Communications & Engagement Coordinator (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	City Manager; Designated POC (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	Main Office	Tier 2/3	9/5/2020*
Sonoma County	Sheriff's Liaison (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	Public Health Officer (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	Community Alert & Warning Manager (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	Costal Valleys EMS (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	EMS Dispatch (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	Sheriff Dispatch (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	Communications & Engagement Coordinator	Tier 2/3	9/5/2020*

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Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Sonoma County	Emergency Coordinator (24-hour)	Tier 2/3	9/5/2020*
Sonoma County	General	Tier 2/3	9/5/2020*
Sonoma County - REDCOM Dispatch	Dispatcher	Tier 2/3	9/4/2020
Sonora	Sergeant	Tier 2/3	9/5/2020
Sonora	City Administrator	Tier 2/3	9/5/2020*
Sonora	Fire Chief; Designated POC	Tier 2/3	9/5/2020*
Sonora	Police Chief (24-hour)	Tier 2/3	9/5/2020*
Sonora	Mayor	Tier 2/3	9/5/2020*
Stanislaus National Forest	Dispatcher	Tier 2/3	9/5/2020*
Stanislaus National Forest	Dispatcher	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Housing Director	Tier 2/3	9/5/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Chairman	Tier 2/3	9/5/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Secretary	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Member-at-Large	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Teasurer	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Director Environemntal Planning	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Vice Chairman	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Member-at-Large	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Tribal Administrator	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Director Emergency Services (24-hour)	Tier 2/3	9/7/2020*
Stewarts Point Rancheria (Kashaya Pomo)	Member-at-Large	Tier 2/3	9/7/2020*
Strawberrry Valley Rancheria	Chairperson	Tier 2/3	9/5/2020*
Susanville Indian Rancheria	Chairwoman (24-hour)	Tier 2/3	9/5/2020*
Susanville Indian Rancheria	Administrator (24-hour)	Tier 2/3	9/5/2020*
Susanville Indian Rancheria	Emergency Services Specialist (24-hour)	Tier 2/3	9/5/2020*
Table Mountain Rancheria	Tribal Administrator	Tier 2/3	9/5/2020*
Table Mountain Rancheria	Cultural Resources Director	Tier 2/3	9/5/2020*
Table Mountain Rancheria	Chairperson	Tier 2/3	9/5/2020*
Tehama County	OES Director (24-hour)	Tier 2/3	9/5/2020*
Tehama County	Communications Supervisor	Tier 2/3	9/5/2020*
Tehama County	OES Deputy Director (24-hour)	Tier 2/3	9/5/2020*
Tehama County	CAL FIRE (24-hour)	Tier 2/3	9/5/2020*
Tejon Indian Tribe	Chairperson	Tier 2/3	9/5/2020*
Tejon Indian Tribe	Tribal Administrator	Tier 2/3	9/5/2020*
The Mono Nation	General	Tier 2/3	9/5/2020*
The Mono Nation	General	Tier 2/3	9/5/2020*
Traditional Choinumni Tribe (East of Kings River)	Chairman	Tier 2/3	9/5/2020*
Trina Marine Ruano Family	Representative	Tier 2/3	9/5/2020*
Trinity - Office of Emergency Services	General	Tier 2/3	9/5/2020*
Trinity - Sheriff's Office	General	Tier 2/3	9/5/2020*

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cont.

Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Trinity County	Program Manager	Tier 2/3	9/6/2020*
Trinity County	Local Cal Fire	Tier 2/3	9/6/2020*
Trinity County	CAO; Designated POC	Tier 2/3	9/6/2020*
Trinity County	OES Manager (24-hour)	Tier 2/3	9/6/2020*
Trinity County	District Ranger, TRMU	Tier 2/3	9/6/2020*
Tsungwe Council	Chairman	Tier 2/3	9/5/2020*
Tubatulabal Tribe	Chairman	Tier 2/3	9/5/2020*
Tubatulabal Tribe	Vice Chair	Tier 2/3	9/5/2020*
Tule River Indian Tribe	Chairman	Tier 2/3	9/5/2020*
Tule River Indian Tribe	Executive Assistant	Tier 2/3	9/5/2020*
Tuolumne Band of Me-Wuk Indians	OES Director (24-hour)	Tier 2/3	9/5/2020*
Tuolumne Band of Me-Wuk Indians	Chairperson	Tier 2/3	9/5/2020*
Tuolumne Band of Me-Wuk Indians	Tribal Security Chief (24-hour)	Tier 2/3	9/5/2020*
Tuolumne Band of Me-Wuk Indians	Tribal Fire Chief	Tier 2/3	9/5/2020*
Tuolumne Band of Me-Wuk Indians	Chief Administrative Officer	Tier 2/3	9/5/2020*
Tuolumne County	Dispatcher	Tier 2/3	9/5/2020
Tuolumne County	OES Coordinator	Tier 2/3	9/5/2020*
Tuolumne County	County OES Coordinator; Designated POC	Tier 2/3	9/5/2020*
Tuolumne County	OES	Tier 2/3	9/5/2020*
Tuolumne County	County Administrator	Tier 2/3	9/5/2020*
Tuolumne County	Fire Chief	Tier 2/3	9/5/2020*
Tuolumne County - CAL FIRE	Local Cal Fire	Tier 2/3	9/5/2020*
Tuolumne County - Office of Emergency Services	Main Office	Tier 2/3	9/5/2020*
Tuolumne County - Sheriff's Department	Sheriff	Tier 2/3	9/5/2020*
Tuolumne County Fire Department	Emergency Command Center (24-hour)	Tier 2/3	9/5/2020*
United Auburn Indian Community	Councilmember	Tier 2/3	9/5/2020*
United Auburn Indian Community	Councilmember	Tier 2/3	9/5/2020*
United Auburn Indian Community	Chairman	Tier 2/3	9/5/2020*
United State Forest Service - Plumas County	Dispatcher	Tier 2/3	9/4/2020*
Wailaki Tribe	Chairperson	Tier 2/3	9/5/2020*
Washoe Tribe	Councilmember	Tier 2/3	9/5/2020*
Washoe Tribe	Chairperson	Tier 2/3	9/5/2020*
Wilton Rancheria	General	Tier 2/3	9/5/2020*
Wilton Rancheria	General	Tier 2/3	9/7/2020*
Winnemem Wintu Tribe	Spiritual Leader	Tier 2/3	9/5/2020*
Wintu Tribe of Northern California	Chairman	Tier 2/3	9/5/2020*
Wiyot Tribe	Chairman	Tier 2/3	9/5/2020*
Wiyot Tribe	Tribal Administration	Tier 2/3	9/5/2020*
Wiyot Tribe	Tribal OES	Tier 2/3	9/5/2020*
Wukchumni Tribal Council	Chairperson	Tier 2/3	9/5/2020*

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cont.

Organization/Jurisdiction	Title	Classification (Tier 2/3, Zone 1)	Date
Yosemite National Forest	Dispatcher	Tier 2/3	9/7/2020
Yuba County	County Executive Officer	Tier 2/3	9/5/2020*
Yuba County	Emergency Manager (24-hour); Designated POC	Tier 2/3	9/5/2020*
Yuba County	Local Cal Fire	Tier 2/3	9/5/2020*
Yuba County	General	Tier 2/3	9/5/2020*
Yuba County	Health Administrator	Tier 2/3	9/5/2020*
Yuba County	General	Tier 2/3	9/5/2020*
Yuba County	General	Tier 2/3	9/5/2020*
Yurok Tribe	Director, Public Works	Tier 2/3	9/5/2020*
Yurok Tribe	Director, Office of Self-Governance	Tier 2/3	9/5/2020*
Yurok Tribe	THPO	Tier 2/3	9/5/2020*
Yurok Tribe	Director, Council Support Services	Tier 2/3	9/5/2020*
Yurok Tribe	Chairman	Tier 2/3	9/5/2020*
Yurok Tribe	Deputy OES Director	Tier 2/3	9/5/2020*
Yurok Tribe	Vice Chairman	Tier 2/3	9/5/2020*

P27-123
cont.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX E

SECTION 10 – FIRE INDEX AREAS MAP

P27-123
cont.

Appendix E: Fire Index Areas Map

Figure E-1. Fire Index Areas Map

P27-123 cont.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

SECTION 11 – COMMUNITY ASSISTANCE CENTER LOCATIONS

P27-123 cont.

Appendix F: List of PG&E Community Resource Centers

The table below provided details of the 50 CRCs that PG&E mobilized during the PSPS event, including specific locations, dates and times opened and closed, and total attendance for each location.

Table F-1. Community Resource Centers Provided by PG&E

#	County	Site Name	Address	Site Type (Indoor, Micro, Mobile)	Date and Time First Opened	Date and Time Deactivated	Total Attendance
1	Alpine	Bear Valley Transportation Center	132 Bear Valley Rd, Bear Valley	Outdoor - Microsite	Sept 8, 2020 0800	Sept 9, 2020 2200	177
2	Amador	St. Katharine Drexel Parish	11361 Prospect Dr, Jackson	Outdoor - Mobile	Sept 8, 2020 0800	Sept 9, 2020 2100	26
3	Amador	Faith Lutheran Church	22601 CA-88, Pioneer	Outdoor - Mobile	Sept 8, 2020 0800	Sept 9, 2020 2100	84
4	Butte	Berry Creek Elementary	286 Rockerfeller Rd, Berry Creek	Outdoor - Microsite	Sept 8, 2020 0800	Sept 8, 2020 1430	25
5	Butte	American Veterans Store	15474 Forest Ranch Way, Forest Ranch	Outdoor - Microsite	Sept 8, 2020 0800	Sept 10, 2020 1530	491
6	Butte	Strip Mall	14144 Lakeridge Court, Magalia	Outdoor - Microsite	Sept 8, 2020 0800	Sept 9, 2020 0900	138
7	Butte	Southside Oroville Community Center	2959 Lower Wyandotte Rd, Oroville	Outdoor - Microsite[2]	Sept 8, 2020 0800	Sept 12, 2020 1500	14
8	Butte	Craig Memorial Congregational Church	5665 Scottwood Rd, Paradise	Outdoor – Microsite	Sept 8, 2020 0800	Sept 9, 2020 0900	37
9	Calaveras	Chapel in the Pines	2286 Cedar Ln, Arnold	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	505
10	Calaveras	Murphys Fire Department	58 Jones St, Murphys	Indoor – Hardened	Sept 8, 2020 0800	Sept 9, 2020 2200	49
11	Calaveras	Saint Matthew's Episcopal Church	414 Oak St, San Andreas	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	8
12	Calaveras	Veterans of Foreign Wars post 3322	202 Spink Rd, West Point	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	280
13	El Dorado	Cool Shopping Center	5020 Ellinghouse Dr, Cool	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2000	79
14	El Dorado	Buffalo Hill Center	6023 Front Street, Georgetown	Outdoor – Mobile	Sept 8, 2020 0800	Sept 10, 2020 1200	354
15	El Dorado	El Dorado Fairgrounds	100 Placerville Dr, Placerville	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	106
16	El Dorado	Knotty Pine Lanes	2667 Sanders Dr #1, Pollock Pines	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	240
17	El Dorado	Pioneer Park	6740 Fairplay Rd, Somerset	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	52
18	Humboldt	Hydesville Community Church	3296 CA-36, Hydesville	Outdoor – Mobile	Sept 8, 2020 0800	Sept 10, 2020 1600	47
19	Humboldt	Yurok Tribal Office	90 State Route 96, Weitchpec	Outdoor – Microsite	Sept 8, 2020 0800	Sept 10, 2020 1600	129
20	Kern	Lebec Post Office	2132 Lebec Rd, Lebec	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 1900	63

P27-123 cont.

[2] This site was originally an outdoor location and, at the request of the County OES, moved indoor and remained open through September 12

#	County	Site Name	Address	Site Type (Indoor, Micro, Mobile)	Date and Time First Opened	Date and Time Deactivated	Total Attendance
21	Lassen	Big Valley High School	400 Bridge St, Bieber	Outdoor – Mobile	Sept 8, 2020 1600	Sept 9, 2020 2100	198
22	Napa	Pacific Union College – Track and Field Parking Lot	1 Angwin Ave, Angwin	Outdoor – Mobile	Sept 8, 2020 0800	Sept 10, 2020 1300	109
23	Napa	Highlands Christian Fellowship	970 Petrified Forest Rd, Calistoga	Outdoor – Mobile	Sept 8, 2020 0800	Sept 10, 2020 1300	225
24	Napa	Saint Helena Catholic School	1255 Oak Ave, St Helena	Outdoor – Mobile	Sept 8, 2020 0800	Sept 10, 2020 1300	278
25	Nevada	Sierra College Grass Valley	250 Sierra College Drive, Grass Valley	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2100	314
26	Nevada	Nevada City Elks Lodge	518 State Highway 49, Nevada City	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2100	141
27	Placer	Alta Fire Protection District Community Hall	33950 Alta Bonnynook Rd, Alta	Indoor - Hardened	Sept 8, 2020 0800	Sept 9, 2020 2200	73
28	Placer	Freight Depot Parking Lot	7 N Main St, Colfax	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	54
29	Placer	Canyon View Assembly Church	23221 Foresthill Rd, Foresthill	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	237
30	Plumas	Holiday Market	271 Main St, Chester	Outdoor - Microsite	Sept 8, 2020 0800	Sept 10, 2020 2100	623
31	Plumas	Greenville Jr-Sr High School	117 Grand St, Greenville	Outdoor - Microsite	Sept 8, 2020 0800	Sept 10, 2020 2100	717
32	Plumas	Safeway - Quincy	20 E Main St, Quincy	Outdoor - Microsite	Sept 8, 2020 0800	Sept 10, 2020 1500	1692
33	Shasta	Calvary Chapel Church	37477 CA Highway 299, Burney	Outdoor - Microsite	Sept 8, 2020 1500	Sept 9, 2020 2100	86
34	Shasta	French Gulch Community Church	11420 Tom Green Mine Rd, French Gulch	Outdoor - Microsite	Sept 8, 2020 0800	Sept 9, 2020 2100	12
35	Shasta	Lakehead Lions Hall	20814 Mammoth Dr, Lakehead	Indoor - Hardened	Sept 8, 2020 0800	Sept 9, 2020 2100	44
36	Shasta	Inter - Mountain Fairground	44218 A Street, McArthur	Outdoor – Mobile	Sept 8, 2020 1300	Sept 9, 2020 2100	32
37	Shasta	Montgomery Creek Elementary School	30365 CA Highway 299, Montgomery Creek	Outdoor - Microsite	Sept 8, 2020 0800	Sept 9, 2020 2100	152
38	Shasta	Lassen Landing	7355 Black Butte Road, Shingletown	Outdoor - Microsite	Sept 8, 2020 0800	Sept 9, 2020 2100	203
39	Sierra	Downieville Community Hall	322 Main St, Downieville	Indoor - Hardened	Sept 8, 2020 0800	Sept 10, 2020 2030	144
40	Sonoma	Costco Wholesale	1900 Santa Rosa Ave, Santa Rosa	Outdoor - Microsite	Sept 8, 2020 0800	Sept 9, 2020 2100	22
41	Sonoma	Luther Burbank Center for the Arts	50 Mark West Springs Rd, Santa Rosa	Outdoor – Microsite	Sept 8, 2020 1200	Sept 9, 2020 2100	1
42	Sonoma	First Congregational Church of Sonoma	252 W Spain St, Sonoma	Outdoor – Microsite	Sept 8, 2020 0800	Sept 9, 2020 2100	26

P27-123 cont.

#	County	Site Name	Address	Site Type (Indoor, Micro, Mobile)	Date and Time First Opened	Date and Time Deactivated	Total Attendance
43	Trinity	Burnt Ranch School District	251 Burnt Ranch School Rd, Burnt Ranch	Outdoor – Microsite	Sept 8, 2020 0800	Sept 10, 2020 1500	9
44	Trinity	Southern Trinity High School	600 Van Duzen Rd, Mad River	Outdoor – Microsite	Sept 8, 2020 0800	Sept 10, 2020 1100	23
45	Tuolumne	Columbia Elementary School	22540 Parrotts Ferry Rd, Columbia	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	164
46	Tuolumne	Mary Laveroni Park	18930 Main St, Groveland	Outdoor – Microsite	Sept 8, 2020 0800	Sept 9, 2020 2200	231
47	Tuolumne	Mother Lode Fairgrounds	220 Southgate Drive, Sonora	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	178
48	Tuolumne	Eproson Park	22901 Meadow Dr, Twain Harte	Outdoor – Mobile	Sept 8, 2020 0800	Sept 9, 2020 2200	131
49	Yuba	Foothill Volunteer Fire Department	16796 Willow Glen Rd, Brownsville	Outdoor - Microsite	Sept 8, 2020 0800	Sept 8, 2020 1500	6
50	Yuba	Alcouffe Center	9185 Marysville Rd, Oregon House	Indoor - Hardened	Sept 8, 2020 0800	Sept 8, 2020 2200	96

P27-123 cont.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX G

MAXIMUM WIND GUSTS

P27-123
cont.

Appendix G: Maximum Wind Gusts

The table below shows the maximum wind gust recorded by weather stations in the general timeframe and vicinity of the PSPS location.

Table G-1. Maximum wind gusts from September 7 – 9

County	Maximum Wind Gust (mph)	Station ID	Station Name
Butte	66	JBGC1	JARBO GAP
Inyo	66	FMRC1	FIVE MILE
Sonoma	66	PG652	Santa Fe Geothermal
Siskiyou	63	ATRC1	SLATER BUTTE
Kern	62	AT714	WX6HNX-4 Grapevine CHP
Contra Costa	61	SJS02	Mt. Diablo
Los Angeles	60	SE678	SCE Magic Mtn Truck Trail
Napa	56	PG358	Knoxville
Shasta	56	PG451	Melton Road
Nevada	54	PG824	Lake Spaulding
Orange	54	SNPC1	MISSION VIEJO ORANGE
Placer	54	HLLC1	HELL HOLE
San Bernardino	54	KEED	Needles, Needles Airport
San Diego	53	ANEC1	ALPINE
Tehama	52	PG193	Ponderosa Sky
Marin	50	NBRC1	BIG ROCK
Riverside	50	WWAC1	WHITEWATER
Ventura	50	SE277	SCE Happy Camp Rd
Yolo	50	PG490	Bald Mountain Tower
Yuba	50	PKCC1	PIKE COUNTY LOOKOUT
Mono	49	SE397	SCE Benton Valley
Lake	48	WISC1	COUNTY LINE
Modoc	48	ATSC1	DEVILS GARDEN
Plumas	46	CHAC1	CASHMAN
Solano	46	KSUU	Fairfield / Travis Air Force Base
Humboldt	45	PG343	Alder Point Road
San Luis Obispo	45	PG175	Camino Del Capitan
Colusa	44	PG301	Bartlett Springs Road
Merced	43	CF031	SR-152 San Luis Reservoir
El Dorado	42	PG481	American River Overlook
San Joaquin	42	CF132	I5 North of SR-12
Trinity	42	MDDC1	MAD RIVER

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County	Maximum Wind Gust (mph)	Station ID	Station Name
Imperial	41	TNSC1	MOUNTAIN SPRINGS GRADE
Lassen	41	LDRC1	LADDER BUTTE
Amador	40	PG178	Tiger Penstock Top
Monterey	40	PG360	Williams Hill
Santa Clara	40	SJS04	Umunhum South
Glenn	39	PG662	Chrome
Sacramento	39	KSMF	Sacramento International Airport
San Mateo	39	PG784	Lake Drive
Alameda	38	RSPC1	ROSE PEAK
Stanislaus	38	F5661	Crows Landing
Tuolumne	38	MOUC1	MOUNT ELIZABETH
Del Norte	36	SHXC1	SHIP MTN
Fresno	36	MTQC1	MOUNTAIN REST
San Francisco	36	F2543	FW2543 San Francisco
Mendocino	35	MASC1	MENDOCINO PASS
Santa Cruz	35	PG370	Ormsey Cutoff Trail
Kings	33	KNLC	Lemoore Naval Air Station - Reeves Field
Sierra	33	PG387	Road 108
Calaveras	31	PG334	Hodson Road
San Benito	31	SRTC1	SANTA RITA
Outside CA	29	KHAF	Half Moon Bay Airport
Alpine	28	LIB03	MULI296 - Woodfords
Santa Barbara	28	AV377	KC6OYN Santa Barbara
Tulare	28	TT033	IRAWS 4 (CAMP WHITTSET)
Mariposa	26	CVBC1	CATHEYS VALLEY
Madera	25	MTTC1	MINARETS
Sutter	20	E9574	Yuba City

P27-123 cont.

VERIFICATION

P27-123 cont.

I, undersigned, say:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification for that reason.

I have read the foregoing "PG&E Public Safety Power Shutoff Report to the CPUC" for the events of September 7-10, 2020, and I am informed and believe the matters stated therein are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed at San Francisco, California this 23rd day of September, 2020.

Michael Lewis

MICHAEL LEWIS
Interim President
PACIFIC GAS AND ELECTRIC COMPANY

June 11, 2019

CERTIFIED MAIL RETURN RECEIPT REQUESTED

Shasta County Board of Supervisors
Attn: Supervisor Mary Rickert – District 3
1450 Court Street, Suite 308B
Redding, CA 96001-1673

Dear Supervisor Rickert,

Action Requested

Respectfully and formally request that the Board of Supervisors adopt an immediate moratorium on all County 'Use Permits' for large scale Wind Energy Generation Developments, and/or Wind Energy Systems, or (Industrial Wind Turbine [IWT] Developments), including the permit for the proposed Fountain Wind Project (UP-16-007) in Shasta County. If the Fountain Wind Project will not be included in the moratorium we request that you NOT APPROVE the project if it is presented to you for a vote.

I represent the members of the citizen action group, Citizens in Opposition to the Fountain Wind Project (CIO FWP), which is opposed to the Fountain Wind Project, and any other industrial scale wind turbine developments in the scenic and forested high fire hazard zones of Shasta County. In addition to requesting the moratorium this letter outlines a few of the many reasons we oppose the Fountain Wind Project and similar projects within the County. We have enclosed articles and copies of ordinances and zoning laws adopted by other communities that have been proactive in prohibiting or otherwise appropriately limiting such developments in those counties. We would gladly come along side Shasta County in any way possible, such as a County Wide Planning Advisory Committee, to help develop the appropriate General Plan and Zoning Code modifications for Industrial Wind Energy developments. P27-124

Adopting the moratorium would allow the County Planning Department, Commissioners, and the Board of Supervisors, time to study and make changes to the County's General Plan and Zoning Codes for industrial scale wind developments within the County. Shasta County Code (SCC) does not currently address any type of Large Scale Wind Energy Conversion System and these unique types of developments should not be lumped into the "Unclassified" or "Timberland" development language of "Public Utility" without the proper due diligence of developing appropriate General Plan and Zoning Code updates; the applicant identifies themselves as a Wind Energy Generation Development not a Public Utility. Nor should they be developed under SCC 17.88.035 which addresses small wind energy systems and is wholly inadequate for these unique industrial developments. Many communities throughout the Country have developed specific zoning regulations because of the unique issues inherent with these types of developments. Due to Shasta Country's lack of proper Energy Siting Regulations or Ordinances for these types of developments, approving any further projects of this type under the current zoning code will likely lead to litigation for years to come. These Industrial Wind Turbine developments do not support the Shasta Country General Plan objectives regarding the quality of life for Shasta County residents, particularly for those in the Rural Community Centers. The General Plan recognizes that the Rural Community Centers provide opportunities for persons desiring to live in

June 11, 2019

CERTIFIED MAIL RETURN RECEIPT REQUESTED

an environment characterized by few, if any urban services, and in close proximity to the surrounding natural environment. The natural, as opposed to the man-made environment, is the dominant theme in Rural Community Centers, and physical access to the natural environment for living and recreational purposes is an important element of daily life in them. Placing Industrial Wind Turbines in these environments is diametrically opposed to the General Plan's objectives for these areas.

The moratorium would also give the County time to study the impacts of the recent wildfires on the County's General Plan and Zoning, and time for the County to further study ways to reduce wildfire risk throughout the County. This is a more prudent course of action rather than rushing through the CEQA process to approve large scale industrial developments, like the Fountain Wind Project, in high fire hazard zones before any comprehensive countywide plan for such developments is completed. Shasta County should also consider whether additional electrical power is needed within the County and adopt an approach similar to what San Bernardino County recently did (only allowing such projects if the power is needed for local communities). The moratorium would also allow the County to revisit its Open Space Plan, which clearly does not call for building hundreds or thousands of 600 foot tall or taller wind turbines (newly developed turbines are nearly 800 feet tall) on the heavily forested ridges surrounding the City of Redding and through the rest of Shasta County. Clearly the big wind turbine developers have zeroed in on Shasta County because of a lack of clear Zoning and General Plan guidelines, after being roundly rejected by other counties in California and throughout the country (and elsewhere in the world). A countywide planning process, including potential General Plan Amendments and Zoning code changes, are sorely needed before Shasta County area turns into another Altamont Pass, Tehachapi, or San Gorgonio Pass, each of which has several thousand turbines now. Industrial Wind Turbine developments here, if allowed, will destroy Shasta County's scenic value forever, increase the already high fire danger, cause precipitous drops in property values (and tax revenues), and cause tourism, and other related businesses to fail, in an area already drastically suffering from the recent fires.

This moratorium would not necessarily be a decision up or down on the proposed Fountain Wind Project. Instead, it would simply be a moratorium to allow the County time to study the issues on a countywide basis. It would allow the County time to adopt appropriate changes to its General Plan, Zoning, other regulations, and revisit its Open Space Plan to determine whether the ridgelines surrounding Redding and throughout the County should be preserved instead as forested Open Space. We also ask that the Board, if it is not willing for some reason to adopt the moratorium, and perform the necessary studies to address these issues countywide, to nonetheless "stay" the process relative to the Fountain Wind Project and put the issue of any further industrial scale wind development in the County on the ballot so that the County residents have a voice regarding this important issue. We anticipate that the public will likely vote to ban any further large Industrial Wind Turbine developments within the County once they are made aware of what they will look like along the ridgetops around Redding and other parts of the County, the increased wildfire risk they cause as well as the many other significant environmental impacts associated with them. Per the Shasta Country Framework for Planning "Past experiences in Shasta County and elsewhere have shown that responding to

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adverse change after the fact is not a viable alternative" and should not be the planning method for these types of developments.

The reasons we oppose the Fountain Wind Project and any similar projects in the heavily forested foothills surrounding Redding include the fact that the proposed turbines would each be up to 591 feet tall, which is almost as tall as the Shasta Dam (603 feet) and nearly twice as tall as the Statue of Liberty. Apart from the existing dams, these new turbines would by far be the largest structures in the County, and unlike the dams, would be visible from nearly everywhere in Redding, the I-5 corridor and throughout Shasta County. Such turbines, would ruin the views to the East for all Shasta County residents, destroying the beautiful vistas forever--vistas that have been enjoyed by all County residents, as well as tourists and other visitors, for the last 150 years. In addition, we believe that such industrial scale developments in what is among the highest rated fire hazard zones in the State, is ill advised, particularly after the Carr, Delta, Camp, and Hirz fires that resulted in massive loss of life and billions of dollars of damages, from which the County is still trying to recover from. A similar fire in the Eastern foothills where the Fountain Wind Project is proposed, burned in the early 1990's (the Fountain Fire). The area is now an artificial forest of highly flammable pines 30-50 feet tall that were planted after the Fountain Fire. Ironically, the "Fountain Wind" Project is named after the "Fountain" fire, which at the time was the worst fire in Shasta County history. That area can and will likely burn again during the life of the project, even if the cause is natural, and this time, another Fountain fire could easily burn into Bella Vista and Redding from the East, or the other direction into Burney, just like the Carr fire, which started over the mountains in Whiskeytown and burned several miles into Redding from the West. Yet the County has done no comprehensive studies or planning with respect to such countywide dangers since the Carr, Delta, Hirz, and Camp fires this past summer. In addition there is no countywide emergency evacuation plan, or any evacuation plan for the specific area of the proposed Fountain Wind Project, which just adds to the dangers of proceeding with this or other similar developments at this time.

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Shasta County already has more "green energy" than most other counties (due to extensive hydroelectric facilities in the County). We are not against green power, or even wind turbines in general--we are simply saying that such development is inappropriate in view of Redding and in the high fire hazard zones of Shasta County. This County, moreover, does not need the electricity generated by further wind developments in the County. Why should County residents see their treasured views and native cultural heritage destroyed, the ruin of the semi-rural nature of the County that led them to live here in the first place, the devastation of protected wildlife and natural resources, and be forced to accept increased fire danger and risk to their homes and their very lives, all so that developers from outside the County can reap millions of dollars at our expense?

We presented a moratorium request to the Planning Commission on May 9th 2019 and we're directed by the Planning Department Director to make our request directly to the Board of Supervisors. Because we believe that all Shasta County residents are affected by these types of developments, and should have an opportunity to address this issue, we are bringing our request for a moratorium before all members of the Board for approval. We also encourage the Board to formally inform all residents of Shasta County of this request for a moratorium, and to solicit public input. The Planning Department provided formal notice of the proposed

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Fountain Wind Project to residents within two miles of the project site, and a one day posting in local newspapers, even though every resident of the County will be negatively impacted. Due to the loss of the beautiful views to the East of Redding and throughout Shasta County, and the fact the turbines will create blight for all county residents for the rest of their lives and potentially ruining the beauty of the area for generations, all Shasta Country residents need to be engaged in these decisions. Due to the limited news outlet postings and small community area notifications, the majority of Shasta County residents and communities will not realize the full impacts of the proposed Fountain Wind Project, or future developments, until it's too late to object. The first notice that most County residents would otherwise receive is the sight of dozens of giant turbines being constructed, ruining their views and communities forever. We ask that the County be proactive, adopt the moratorium, and take time to study these issues with input from County residents, environmental experts, other agencies/governments, and from other stakeholders such as PG&E, CPUC, CAL FIRE, amongst others. The contributors to the Cal Fire's Community Wildfire Prevention & Mitigation Report, developed in response to the Governor's Executive Order N-05-19, should also be solicited for input and who may not otherwise participate in the limited CEQA process for industrial wind developments in high fire hazard zones like the Fountain Wind Project. A more comprehensive, countywide, planning process in needed here, before the next disaster happens.

The result of the moratorium effort would likely lead to substantial cost and time savings for both Shasta County and wind developers as well because, many of the issues and impacts would have already been addressed before specific projects are sited and proposed to county planners. Potential developers would already know the County guidelines and/or restrictions, such as no Industrial Wind Developments in Fire Hazard Zones 4 & 5, and would aid the developer in deciding if it is worthwhile to pursue a development within the County. The moratorium would also streamline efforts within the Planning Division because county planners would not be dealing with the larger countywide issues posed by IWT Use Permits on a case-by-case basis. Shasta County should develop and publish their own Energy Siting Regulations and Ordinance updates, predetermined to the fullest extent possible and based on sound scientific data, in updated General Plan amendments and zoning, specific to large scale wind developments in the county. Future IWT applicants would still have to go through the CEQA process but the appropriately zoned areas and other restrictions outlined by the County would have already been addressed. Many of the issues that might have had significant environmental impacts would also have already been resolved to the fullest extent possible. As an example, knowing that wind turbine development were prohibited in areas inhabited by spotted owls, and eagles, such as the area of the proposed Fountain Wind Project, would eliminate that significant environmental impact and cause the developer to seek a more appropriate site early on in the development process.

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In addition, the local electrical grid can't handle and doesn't need the added unpredictable power that the Fountain Wind project and other future projects would generate at this time. The California Independent System Operator (CAISO) 2019 Transmission Grid upgrades are currently underway for the Round Mountain Substation. The Round Mountain 500kV Dynamic Reactive Power Support upgrade has been approved by

CAISO and the CPUC and will be out for competitive solicitation mid-2019 to address existing voltage instability and thermal overload issue at the substation and all along its interconnections and transmission paths. The upgrades aren't due to be completed until late 2024 at the earliest. Adding the Fountain Wind, or any wind generated power, at this time, would only exacerbate the existing problem and increase the risk of fires due to thermal overload or over voltage conditions. It has also come to light in recent PG&E lawsuits and bankruptcy proceedings that PG&E has neglected necessary maintenance and upkeep of its infrastructure, including adequately burying power lines in high fire risk areas that will take years to fully address. Adding power to their systems would simply be unsafe at this time considering reports that PG&E has been responsible for many of the recent fires in the State. Per PG&E 2018 RPS Procurement Plan, and previous PG&E advice letter 5163-E to the CPUC, PG&E has no need for additional RPS until after 2030. PG&E is seeking to cancel or renegotiate its current Power Purchase Agreements (PPAs) for renewable energy, including existing wind turbine developments, such as Hatchet Ridge, as part of its bankruptcy proceedings and power management strategies. It would be wise to wait for PG&E to emerge from bankruptcy before approving any further projects in Shasta County, as the entire situation with PG&E, the power grid, power needs, state laws, pricing, maintenance backlog, safety culture, etc. may all soon change.

Cal Fire rates our area and the area of the proposed Fountain Wind Project, as High Fire Hazard Zones 4&5 which are the highest in the State. In 2017-2018 California experienced some of the most deadly and destructive wildfires in its history. Recognizing the need for urgent action, Governor Gavin Newsom issued Executive Order N-05-19 on January 9, 2019. In response, to the Governor's Executive Order Cal Fire developed the ongoing Community Wildfire Prevention & Mitigation Report, dated February 22, 2019. The Executive Order directs Cal Fire, in consultation with other state agencies and departments, to recommend immediate, medium and long-term actions to help prevent destructive wildfires with an emphasis to protect vulnerable populations such as those around the proposed Fountain Wind project site. Nearby Shingletown, with the same topography as the proposed site, was listed as the number one priority within the State. Introducing additional unnecessary wildfire risks, such as the Fountain Wind development (including all phases – material delivery, construction, operation and maintenance), into High (4) and Very High (5) fire hazard zone forested areas, undermines the intent of the Governor's Executive Order and does nothing to reduce our wildfire risk, but will only add to it. We do not believe Industrial Wind Turbine developments should be considered in the forested areas in Shasta County already identified as having High to Very High Fire Hazard Zones. No amount of increased risk is acceptable when even one spark, in a windy forested areas such as ours, could easily lead to another Carr or Camp Fire tragedy.

The Board of Supervisors should not consider the Hatchet Ridge Industrial Wind Farm as a precedent due to the numerous project differences and the various events and risks that have come to light since that project was approved, including last summer's fires.

Passage of a moratorium is warranted at this time because of the issues we have outlined above: the increased wildfire threat and ongoing State efforts to reduce it, the lack of an area specific or countywide

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emergency evacuation plans, the devastation to our wildlife and local Bald eagle, spotted owl and other avian impacts, the damage to our Native American heritage and history, the CAISO Transmission Plan 2018-2019 upgrades and grid instability issues including thermal overload that won't be completed until late 2024, the PG&E bankruptcy and its efforts to shed existing renewable power purchase agreements (PPAs) and the time needed to address their maintenance issues, the fact that PG&E has enough renewable energy until at least 2030 and is not soliciting for any additional renewables through 2019 and maybe further out, and the lack of adequate County Zoning codes and General Plan updates with public input for IWT developments.

We also respectfully submit that the Fountain Wind and other Industrial Wind Turbine developments are not consistent with the current Shasta County General Plan, Zoning Codes, and Open Space guidance. Per SCC 17.92.025(G) the Fountain Wind Project needs to meet all four listed criteria for approval; however, it meets none of them: (1) it is Not consistent with the General Plan and any applicable specific plan(s), (2) it does not have a demonstrable need, (3) is not justified when compared to alternatives, and (4) the establishment, operation or maintenance of the requested subject use (IWTs), buildings or facilities would under the circumstances of the particular use, be detrimental to the health, safety, peace, morals, comfort, and general welfare of persons residing or working in the neighborhood, or [would] be detrimental or injurious to property or improvements in the neighborhood or to the general welfare of the County.

In sum, we respectfully and formally request an immediate moratorium on all Country Use Permits for large scale Wind Energy Generation Developments, Wind Energy Systems, and/or Industrial Wind Turbine Developments, including the permit for the proposed Fountain Wind Project (UP-16-007) in Shasta County until all of the above-referenced issues can be adequately addressed. For further information, you can contact the CIO FWP's representative, Beth Messick, at (530) 472-1463. You are also encouraged to visit our website at www.stopfw.com . P27-124 cont.

We have enclosed the following materials for your review and information: 1) The CIO FWO June Community Meeting Announcement with the group Goals and Purpose information , 2) The Community Wildfire Prevention & Mitigation Report (45 Day Report in response to California Governor N-05-19), 3) The Marion County Ordinance Law for Wind Energy Conversion System Ordinance, 4) The San Bernardino article puts a stop to Big Wind development, 5) The DRAFT Morgan County Wind Energy Siting Regulations Ordinance, and 6) 2018-2019 ISO Transmission Plan Round Mountain Substation 500 kV Project description

Thank you for your time and attention to this matter, and we look forward to your response and prompt action regarding the foregoing.

Sincerely,

Beth Messick on behalf of the
Citizens in Opposition to the Fountain Wind Project (CIO FWP)
P.O. Box 116
Montgomery Creek, CA 96065

June 11, 2019

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cc:
Paul Hellman, Shasta County Planning Division
cc w/o Enclosures:
Shasta County Planning Commissioners
Lio Salazar Fountain Wind Project Lead

Enclosures:

The CIO FWO June Community Meeting Announcement
Community Wildfire Prevention & Mitigation Report (45-Day Report)
Marin County Law Order_3548_wecs.pdf
San Bernardino County Resolution Article
Morgan County Wind Energy Siting Regulations Ordinance – DRAFT
2018-2019 ISO Transmission Plan Round Mountain Substation 500 kV Project description

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DRAFT 5-1-19

MORGAN COUNTY, ILLINOIS

ORDINANCE NO. 2019 - ________

WIND ENERGY CONVERSION SYSTEMS SITING REGULATIONS ORDINANCE

P27-125

I. INTRODUCTION

A. Title

This Ordinance shall be known, cited and referred to as the Morgan County Wind Energy Siting Regulations Ordinance.

B. Authority and Adoption

1. On May 4, 2009, at an open public meeting and after due consideration and deliberation by the members of the Morgan County Board of Commissioners (the "Board" or "County Board") and after public input was considered, the County Board adopted the Morgan County Wind Energy Siting Regulations Ordinance, known as the "2009 Wind Energy Siting Conversion Systems Regulations Ordinance".
2. At the May 6, 2019 open, public County Board Meeting, the Chair of the County Board announced that a copy of the draft 2019 Wind Energy Siting Regulations Ordinance, which contains amendments to the 2009 Wind Energy Siting Conversion Systems Regulations Ordinance, would be made available for public inspection for a thirty (30) day period and that in June 2019 the County Board would hold open, public meetings to consider and then take action regarding the adoption of the Ordinance. On May 6, 2019, the draft 2019 Wind Energy Siting Regulations Ordinance was made available for public inspection via a post on the County's website and copies were made available at the Morgan County Clerk's office.
3. At an open public meeting conducted on June __, 2019, the County Board considered the regulations set forth below in this Ordinance, which was prepared by special counsel for the Morgan County Board of Commissioners (Michael T. Jurusik and Sheryl H. Churney of Klein, Thorpe and Jenkins, Ltd.), and, at each public meeting, the Morgan County Board of Commissioners provided the County staff and the public with opportunities to review and provide comments on the regulations; and
4. At an open public meeting held on June __, 2019, after discussion and consideration of this Ordinance and consideration of the comments provided by County staff and the public, the Morgan County Board of Commissioners voted to approve / not approve and adopt / not adopt this Ordinance; and

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5. The Morgan County Board of Commissioners are authorized to enact the regulations set forth below in the Ordinance in accordance with the statutory authority set forth under applicable laws (e.g., Article VII, Section 7 of the Illinois Constitution of 1970, the Illinois Counties Code, 55 ILCS 5/ et seq. and the Illinois Open Meetings Act, 5 ILCS 120/ et seq.), including but not limited to Section 5-12020 of the Illinois County Code (55 ILCS 5/5-12020), and have taken all necessary actions at open public meetings, have posted and published all required public notices prior to voting on this Ordinance.

C. Findings and Purpose

Findings and Purpose. This Ordinance has been adopted for the following purposes after the Board made the following determinations and findings:

1. To assure that any development and production of wind-generated electricity in Morgan County is safe and effective;

2. To facilitate economic opportunities for local residents;

3. To promote the supply of wind energy in support of Illinois' statutory goal of increasing energy production from renewable energy sources;

4. To adopt regulations to govern the construction, installation, operation and removal of wind energy systems to enhance the protection of the health, safety and welfare of the County's residents, property owners, business owners and the public within the County's planning and zoning jurisdiction; and

5. To adopt the general zoning regulations and add certain new regulations, such as plan review fee reimbursement regulations, to ensure that the financial costs incurred by the County in the review of new development wind energy proposals are paid by developers and property owners of such projects.

The Chairman and Board of Commissioners of Morgan County, Illinois find that it is in the best interests of the County residents, the property owners and the businesses of the County, as well as the general public, to enact the Code Amendments as set forth below; and

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II. DEFINITIONS

A. "Applicant" means the entity person who submits to the County, pursuant to Section V (Siting Approval Permit Application) of this Ordinance, an application for the siting of any WECS or Substation.

B. "County Board" means the Morgan County Board of Commissioners.

C. “Fall Zone” means the area, defined as the farthest distance from the WECS Tower base, in which a guyed WECS Tower will collapse in the event of a structural failure. This area is less than the total height of the structure.

D. “Feeder Line” means any power line that carries electrical power from one or more wind turbines or individual transformers associated with individual wind turbines to the point of interconnection with the electric power grid.

E. “Financial Assurance" or “Financial Security” means reasonable assurance from a credit worthy party, examples of which include a surety bond (e.g., performance and payment bond), trust instrument, cash escrow, or irrevocable letter of credit.

F. “Meteorological Tower” means those towers which are erected primarily to measure wind speed and direction plus other data relevant to siting a WECS Project. For purposes of this ordinance, Meteorological Towers do not include towers and equipment used by airports, the Illinois Department of Transportation, or other similar applications or government agencies, to monitor weather conditions.

G. “Operator” means the person or entity responsible for the day-to-day operation and maintenance of a wind energy conversion system, including any third party subcontractors.

H. “Owner” means the person or entity or entities with an equity interest in a wind energy conversion system, including their respective successors and assigns. The Owner does not mean (i) the property owner from whom land is leased for locating a wind energy conversion system (unless the property owner has an equity interest in a wind energy conversion system); or (ii) any person holding a security interest in a wind energy conversion system solely to secure an extension of credit, or a person foreclosing on such security interest, provided that after foreclosure, such person seeks to sell a wind energy conversion system at the earliest practicable date.

I. “Plans Commission / Board of Appeals” means the five (5) member board appointed by the presiding officer of the County Board with the advice and consent of the County Board pursuant to 55 ILCS 5/5-12010 and authorized to act, conduct meetings and public hearings and make and issue findings and recommendations and final decisions on matters within its statutory jurisdiction in accordance with the applicable provisions of the Illinois Counties Code (55 ILCS 5/5-1200 *et seq*.).

J. “Primary Structure" means, for each property, the structure that one or more persons occupy the majority of time on that property for either business or personal reasons. Primary Structure includes structures such as residences, commercial buildings, hospitals, and day care facilities. Primary Structure excludes ancillary structures such as hunting sheds, storage sheds, pool houses, unattached garages and barns.

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K. “Professional Engineer" means a qualified individual who is licensed as a professional engineer in any state in the United States.

L. “Property Line” means the boundary line of the area over which the entity applying for a WECS permit has legal control for the purposes of installation of a WECS. This control may be attained through fee title ownership, lease, easement, or other appropriate contractual relationship between the WECS Project developer or Owner and landowner.

M. “Public Conservation Lands” means land owned in fee title by County, state or federal agencies and managed specifically for conservation purposes, including but not limited to County, state and federal parks, state and federal wildlife management areas, state scientific and natural areas, and federal wildlife refuges and waterfowl protection areas. Public conservation lands do not include private lands upon which conservation easements have been sold to government agencies or non-profit conservation organizations. Public conservation lands also do not include private lands for which the owners have entered into contractual relationships with government or non-profit conservation organizations for conservation purposes.

N. “Regional Planner” means the Morgan County employee who performs planning and development related duties and other duties as assigned by the Morgan County Commissioners. Also known as the “Morgan County Planner”.

O. “Siting Approval Permit” means a permit approved by the County Board, after a public hearing, allowing a particular use at a specified location subject to compliance with certain specified special conditions as may be required by the County Board.

P. “Substation" means the apparatus that connects the electrical collection system of the WECS(s) and increases the voltage for connection with the utility's transmission lines.

Q. “Transmission Line” means those electrical power lines that carry voltages of at least 69,000 volts (69 KV) and are primarily used to carry electrical energy over medium to long distances rather than directly interconnecting and supplying electric energy to retail customers.

R. “Wind Energy Conversion System" ("WECS") means all necessary devices that together convert wind energy into electricity, including the rotor, nacelle, generator, WECS Tower, electrical components, WECS foundation, transformer, and electrical cabling from the WECS Tower to the Substation(s).

S. “WECS Project" means the collection of WECSs and Substations as specified in the Siting Approval Permit application pursuant to Section V of this Ordinance.

T. “WECS Tower" means the support structure to which the nacelle and rotor are attached.

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U. "WECS Tower Height" means the distance from the rotor blade at its highest point to the top surface of the WECS foundation.

V. "Wind Turbine" means any piece of electrical generating equipment that converts the kinetic energy of moving wind into electrical energy through the use of airfoils or similar devices to capture the wind.

Within this Ordinance, the words "Applicant, Operator or Owner" when used collectively or individually or in any combination shall include any and all successor(s) in interest to each of those individuals.

III. APPLICABILITY

A. This Ordinance governs the siting of WECSs and Substations that generate electricity to be sold to wholesale or retail markets.

B. Owners of WECSs with an aggregate generating capacity of 0.5MW or less who locate the WECS(s) on their own property are not subject to this Ordinance.

IV. PROHIBITION

A. No WECS or Substation governed by Section III(A) (Applicability) of this Ordinance shall be constructed, erected, installed, or located within the County, unless prior siting approval has been obtained for each individual WECS and Substation or for a group of WECSs and Substations under a joint siting application pursuant to this Ordinance. P27-125 cont.

V. SITING APPROVAL PERMIT APPLICATION

A. To obtain siting approval, the Applicant must first submit a Siting Approval Permit application to the County.

B. The Siting Approval Permit application shall contain or be accompanied by the following information:

1. A WECS Project Summary, including, to the extent available: (a) a general description of the project, including (i) its approximate overall name plate generating capacity, (ii) the potential equipment manufacturer(s), (iii) type(s) of WECS(s), (iv) the number of WECSs, and name plate generating capacity of each WECS, (v) the maximum height of the WECS Tower(s) and maximum diameter of the WECS(s) rotor(s), (vi) the number of Substations, (vii) a project site plan, project phasing plan and project construction timeline plan, and (viii) the general location of the project; and (b) a description of the Applicant, Owner and Operator, including their respective business structures;

2. The name(s), address(es), and phone number(s) of the Applicant(s), Owner and Operator, and all property owner(s), if known, and

documentation demonstrating land ownership or legal control of the property;

3. A Site Plan for the installation of WECSs showing the planned location of each WECS Tower, including legal descriptions for each site, guy lines and anchor bases (if any), Primary Structure(s), Property Lines (including identification of adjoining properties), setback lines, public access roads and turnout locations, Substation(s), electrical cabling from the WECS Tower to the Substation(s), ancillary equipment, third party transmission lines, the location of any wetlands, flood plain, drainage ditches, scenic and natural areas within one thousand five hundred (1,500) feet of the proposed WECS, the location of all known communications towers within two (2) miles of the proposed WECS, and the layout of all structures within the geographical boundaries of any applicable setback;

4. A permit application filed with the Federal Aviation Administration;

5. A proposed Decommissioning Plan for the WECS Project;

6. All required studies, reports, certifications, and approvals demonstrating compliance with the provisions of this Ordinance;

7. An Agricultural Impact Mitigation Agreement (AIMA) between Owner and the Illinois Department of Agriculture;

8. The topographic map shall include the WECS Project site and the surrounding area;

9. Any other information normally required by the County as part of its permitting requirements for siting buildings or other structures;

10. Waivers from the setback requirements of Section VI (Design and Installation), Subsection H (Setback) below executed by the participating land owners and/or the non-participating property owners bearing a file-stamp from the County Recorder of Deeds Office confirming that the waiver was recorded against title to the affected real property.

11. Any other information requested by the County or the County consultants that is necessary to evaluate the siting application and operation of the WECS Project and to demonstrate that the WECS Project meets each of the regulations in this Ordinance, including the Siting Approval Permit standards set forth below.

C. The Applicant shall notify the County of any changes to the information provided in Section V(B) above that occur while the Siting Approval Permit application is pending; and

D. The Applicant shall submit twelve (12) copies of the Siting Approval Permit application to the Morgan County Regional Planner.

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VI. DESIGN AND INSTALLATION

A. Design Safety Certification

1. WECSs shall conform to applicable industry standards, including those of the American National Standards Institute ("ANSI"). Applicants shall submit certificates of design compliance that equipment manufacturers have obtained from Underwriters Laboratories ("UL"), Det Norske Veritas ("DNV"), Germanischer Lloyd Wind Energie (“CGL"), or an equivalent third party. All turbines shall be new equipment commercially available; no used or experimental equipment shall be used in the WECS Project without the approval of a variance by the Plans Commission / Board of Appeals or the County Board.

2. Following the granting of siting approval under this Ordinance, a structural engineer shall certify, as part of the site development permit or construction permit application, that the foundation and tower design of the WECS is within accepted professional standards, given local soil and climate conditions.

B. Controls and Brakes

All WECSs shall be equipped with a redundant braking system. This includes both aerodynamic overspeed controls (including variable pitch, tip, and other similar systems) and mechanical brakes. Mechanical brakes shall be operated in a fail-safe mode. Stall regulation shall not be considered a sufficient braking system for overspeed protection.

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C. Electrical Components

All electrical components of the WECS shall conform to applicable local, state, and national codes, and relevant national and international standards (e.g. ANSI and International Electrical Commission).

D. Aesthetics and Lighting

The following items are recommended standards to mitigate visual impact:

1. Coatings and Coloring: Towers and blades shall be painted white or gray or another non-reflective, unobtrusive color. Black blades are acceptable for mitigation of icing.

2. Signage, including anything in the tower or nacelle, shall comply with other county ordinances pertaining to signage.

3. Turbine Consistency: To the extent feasible, the WECS Project shall consist of turbines of similar design and size, including tower height. Further, all turbines shall rotate in the same direction. Turbines shall also be consistent in color and direction with nearby facilities.

4. Lighting: Projects shall utilize minimal lighting. No tower lighting other than normal security lighting shall be permitted except the best available technology allowed by the FAA. The Applicant, Owner or Operator meet with the Regional Planner, or his/her designee, every five (5) years to review current standards of lighting technology, and the Applicant, Owner or Operator shall upgrade and implement new lights consistent with the then-current FAA-approved state-of-the-art lighting technology to minimize light pollution and glare caused by the WECS Towers.

5. Intra-project Power and Communication Lines: All power lines used to collect power from individual turbines and all communication lines shall be buried underground until same reach the property line or a substation adjacent to the property line.

E. Compliance with the Federal Aviation Administration (FAA)

The Applicant, Owner or Operator for the WECS shall comply with all applicable FAA requirements and shall provide documentation evidencing compliance to the Regional Planner.

F. Warnings

1. A reasonably visible warning sign concerning voltage must be placed at the base of all pad-mounted transformers and Substations.

2. Visible, reflective, colored objects, such as flags, plastic sleeves, reflectors, or tape shall be placed on the anchor points of guy wires and along the guy wires up to a height of fifteen (15) feet from the ground.

G. Climb Prevention

1. All WECS Towers must be unclimbable by design or protected by anti-climbing devices such as:

a. Fences with locking portals at least six (6) feet high; or

b. Anti-climbing devices twelve (12) feet vertically from the base of the WECS Tower.

H. Setback Requirements

1. WECS Towers shall be set back at least one thousand three hundred twenty feet (1,320) for participating land owners and fifteen hundred feet (1,500) for non-participating property owners from any Primary Structure. The distance for the above setback shall be measured from the point of the Primary Structure foundation closest to the WECS Tower to the center of the WECS Tower foundation. The owner of the Primary Structure may waive this setback requirement; but in no case shall a WECS Tower be located closer to a Primary Structure than one and one-tenth (1.10) times the WECS Tower Height or within the Fall Zone of the

P27-125 cont.

WECS Tower.. Each waiver of the above setback requirements shall be set forth in a written waiver executed by the participating land owner and/or the non-participating property owner and filed with the County Recorder of Deeds Office against title to the affected real property.

2. All WECS Towers shall be set back a distance of at least one and one-tenth (1.10) times the WECS Tower Height from public roads, third party above ground utility and other transmission lines, and communication towers in existence as of the approval date of the WECS Tower application unless waived in writing by the affected property owners and utility company or the County may waive this setback requirement. Distance shall be measured from the center of the WECS Tower foundation to the closest point on such above-ground public electric power line, third party transmission line, telephone line and center of the base of the communication tower.

3. All WECS Towers shall be set back a distance of at least one and one-tenth (1.10) times the WECS Tower Height or the Fall Zone, whichever is greater from adjacent Property Lines. The affected adjacent property owner may waive this setback requirement. Each waiver of the above setback requirement shall be set forth in a written waiver executed by the participating land owner and/or the non-participating property owner and filed with the County Recorder of Deeds Office against title to the affected real property.

4. All WECS Towers shall be set back a distance of at least seven hundred fifty (750) feet from the Property Line of any Public Conservation Lands, and a distance of at least one thousand five hundred (1500) feet from any river bluff located on public or private property of any platted community which enforces its own government. Distance shall be measured from the closest corporate limit boundary line to the center of the WECS Tower foundation.

5. The Applicant, Owner or Operator does not need to obtain a variance from the County upon waiver by either the County or property owner of any of the above setback requirements. Any waiver of any of the above setback requirements shall run with the land and be recorded as part of the chain of title in the deed of the subject property.

I. Compliance with Additional Regulations

Nothing in this Ordinance is intended to preempt other applicable state and federal laws and regulations.

J. Use of Public Roads

1. An Applicant, Owner or Operator proposing to use any County, municipality, township or age road(s), for the purpose of transporting WECS or Substation parts and/or equipment for construction, operation, or maintenance of the WECS(s) or Substation(s), shall:

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a. Identify all such public roads; and

b. Obtain applicable weight and size permits from relevant government agencies prior to construction.

2. To the extent an Applicant, Owner or Operator must obtain a weight or size permit from the County, municipality, township or village, the Applicant, Owner, or Operator shall:

a. Conduct a pre-construction baseline survey to determine existing road conditions for assessing potential future damage; and

b. Any proposed public roads that will be used for construction purposes shall be identified and approved by the respective Road District Commissioner and the County Engineer prior to the granting of the Siting Approval Permit. Traffic for construction purposes shall be limited to these roads. All overweight and/or oversized loads to be transported on public roads will require a permit from the respective highway authority. Any road damage caused by the transport of the facility's equipment, the installation, maintenance, or removal, must be completely repaired to the satisfaction of the Road District Commissioner and the County Engineer. The Road District Commissioner and County Engineer may choose to require either remediation of road repair upon completion of the WECS Project or are authorized to collect fees for overweight and/or oversized load permits. Further, financial assurance in an amount to be fixed by the Road District Commissioner to insure the Road District or the County that future repairs are completed to their satisfaction shall be provided. If required, said financial assurance shall be in place prior to granting the Siting Approval Permit.

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3. Construction Phase Road Use Agreements. Prior to the granting of a Siting Approval Permit, the Applicant, Owner or Operator shall enter into a Construction Phase Road Use Agreement covering the construction phase of the WECS Project with the County, if construction of the WECS Project will require use of County roads and roadway appurtenances. The Applicant, Owner or Operator may be required to make pre-construction improvements and shall be required to repair and improve the roads and roadway appurtenances following construction of the WECS Project. The Applicant, Owner or Operator shall also be required to provide financial security in a form acceptable to the County before pre-construction road improvements are made (if required) or before construction of the WECS Project may begin. The term of any Construction Phase Road Use Agreement shall not exceed three (3) years. If the Applicant, Owner or Operator does not start construction of the WECS Project within one (1) year of the date of execution of the Construction Phase Road Use Agreement, then the agreement shall be subject to an annual review on the first and second years of the date of its execution and the County may

require amendments to the agreement based on existing conditions. The failure of the Applicant, Owner or Operator to amend the agreement as requested by the County shall be grounds for revocation of the Siting Approval Permit issued for the WECS Project.

4. Operational Phase Road Use Agreements. Prior to the issuance of a Certificate of Use and Occupancy, the Applicant, Owner or Operator shall enter into an Operational Phase Road Use Agreement with the County covering the Applicant's, Owner's or Operator's use of, maintenance of and improvements to public roads and roadway appurtenances during the ongoing operations of the WECS Project. An Operational Phase Road Use Agreement shall be in place while the WECS Project remains in operation and the term of any Operational Phase Road Use Agreement shall not exceed three (3) years. The Applicant, Owner or Operator shall also be required to provide financial security in a form acceptable to the County during the Operational Phase of the WECS Project.

5. Decommissioning Phase Road Use Agreements. Prior to the issuance of a Certificate of Use and Occupancy, the Applicant, Owner or Operator shall enter into a Decommissioning Phase Road Use Agreement with the County covering the Applicant's, Owner's or Operator's use of public roads and roadway appurtenances to dismantle the wind farm facility and repairs and improvements required after the dismantling of the WECS facilities are complete. The Applicant, Owner or Operator, not the County, shall bear the financial risks associated with damage caused to County roads and roadway appurtenances when the WECS Project is dismantled or reconstructed or re-configured with new turbines. The County, in its discretion, shall determine the type of Financial Security and shall select a consultant(s) to assist the County to determine the amount of Financial Security, whether in the form of a payment and performance bond or other surety bond or irrevocable letter of credit or cash escrow, to be funded to assure sufficient financial resources exist to repair and improve public roads and roadway appurtenances at the time the wind farm facility is decommissioned. The cost of such consultant(s) shall be paid for by the Applicant, Owner or Operator. If an irrevocable letter of credit or surety bond (performance and payment bond) is selected, the original of the irrevocable letter of credit or surety bond shall be retained by the County. If a cash escrow is selected, the cash escrow shall be held and managed by an independent third party (e.g., escrow agent or title company) on behalf of the County, subject to escrow instructions that incorporate the applicable decommissioning and repair / replacement / restoration obligations of this Agreement as executed by the County and the WECS Owner and/or Operator. The bond or other surety must be provided by an AA or AAA rated entity. The adequacy of the financial security being held shall be re-evaluated on the following schedule: P27-125 cont.
    a. Years 5 and 10 of operation;
    b. Years 13, 16, 19, 22, 25 of operation; and
    c. After the 25th year of operation, annual re-evaluation.

6. Start of project operation shall begin upon the issuance of the first Certificate of Occupancy for the turbines which comprise the WECS Project.

7. All repairs and improvements to public roads and roadway appurtenances shall be subject to the prior approval of the County before being made and shall also be subject to inspection and acceptance by the County after such repairs and improvements are completed. The County's Road Agreement, and any further agreements contemplated therein, regarding the maintenance and repair of public roads and highways, must be approved and adopted by the County Board prior to the Board's approval of any Siting Approval Permit applications related to the construction of the proposed WECS Project.

K. Site Assessment

The Applicant, Owner and/or Operator of the WECS Project, at their expense, shall provide soil boring reports to the County Engineer with respect to each WECS Tower location, as part of its site development permit or construction application. The Applicant, Owner and/or Operator of the WECS Project shall follow the guidelines for Conservation Practices Impact Mitigation submitted by the Morgan County Soil and Water Conservation District (or equivalent regulatory agency). Also the grading plans for the proposed substations must be approved by the Morgan County Soil and Water Conservation District prior to the issuance of any site development permit or construction for the construction of said substations.

L. Communications Analysis; Interference

1. The Applicant, Owner and/or Operator of the WECS Project, at their expense, shall have a third party, qualified professional (after submission of resume and relevant work experience), approved by the Regional Planner, conduct an appropriate analysis of the television reception documenting the television stations that are received within one and one-half (1 ½) miles of the footprint of the WECS Project. The results of said study shall be public record and will serve as a baseline reading for television reception conditions prior to the construction of the WECS Project and shall be submitted as part of the Siting Approval Permit application.

2. The Applicant, Owner and/or Operator of the WECS, at their expense, shall have a third party, qualified professional (after submission of resume and relevant work experience), approved by the Regional Planner, conduct a communications analysis that indicates that the E9-1-1 communications, emergency communications or official County and local municipal communications reception shall not be negatively impacted or influenced by the proposed wind power facility. Said communication analysis shall be public record and shall be submitted as part of the Siting Approval Permit application.

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3. The Applicant shall minimize or mitigate interference with electromagnetic communications, such as radio, telephone, microwaves or television signals, caused by the operation of the WECS. The Applicant shall provide the applicable microwave transmission providers and local emergency service provider(s) (911 operators) copies of the WECS Project Summary and Site Plan, as set forth in Section V(B)(1) and V(B)(3) of this Ordinance. To the extent that the above provider(s) demonstrate a likelihood of interference with its communications resulting from the WECS(s), the Applicant shall take reasonable measures to mitigate such anticipated interference. If, after construction of the WECS, the Owner or Operator receives a written complaint related to the above-mentioned interference, the Owner or Operator shall take commercially reasonable steps to respond to the complaint.

4. If, after construction of the WECS, the Owner or Operator receives a written complaint related to interference with local broadcast residential television, the Owner or Operator shall take commercially reasonable steps to respond to the complaint. A summary of complaint and subsequent response from Owner/Operator shall be forwarded to the Morgan County Board of Commissioners for review. Once the construction is complete and a television reception complaint is received by the Regional Planner, who will have thirty (30) calendar days to verify the complaint, the Applicant, Owner and/or Operator of the WECS Project will be given fifteen (15) calendar days to respond, in writing (validation date). Said response shall be addressed and forwarded to both the Regional Planner and the complainant. Such response shall include but not be limited to the following: an acknowledgment that the complaint is considered by the Owner/Operator to be valid. If considered valid by the Owner/Operator: an explanation, including a time line, as to what the Owner/Operator intends to do about the complaint. The Applicant, Owner and/or Operator of the wind power facility will be given an additional fifteen (15) calendar days from the validation date to resolve said TV reception issue. If considered invalid by the Owner/Operator, an explanation, including supporting documentation and expert opinions, as to why the Owner/Operator believes the complaint is not valid. Television reception complaints must be filed within six (6) months from the date each wind turbine generator goes online. P27-125 cont.

M. Noise Levels

Noise levels from each WECS or WECS Project shall be in compliance with applicable Illinois Pollution Control Board (IPCB) regulations. The Applicant, through the use of a qualified professional, as part of the Siting Approval Permit application process, shall appropriately demonstrate compliance with the above noise requirements. The Applicant, Owner and/or Operator of the WECS Project, at their expense, shall have a third party, qualified professional (after submission of resume and relevant work experience), approved by the Regional Planner, conduct an appropriate analysis of the noise impact to nearby properties. The sound pressure level generated by a WECS shall comply with all Illinois Pollution Control Board (IPCB) noise regulations. A modeling analysis of the proposed site shall be included in the application predicting the sound pressure in accordance with the best available practices. The program generating the modeling must take into account not only topography, but also prevailing winds, temperature, air density, ground cover, and other effects which contribute to the distance that sound can travel. The modeling must be submitted to the County as part of the Siting Approval Permit application. To demonstrate compliance with the IPCB regulatory limits, the modeling must perform its analysis from the noise emitting property to the property line of the neighboring property. A "0" background ambient noise level shall be used for all modeling. After a WECS is completed and operational, the Applicant, Owner and/or Operator of the WECS Project, at their expense, shall have a third party, qualified professional (after submission of resume and relevant work experience), approved by the Regional Planner complete a sound pressure analysis of the existing conditions. The analysis shall be completed and returned to Regional Planner within sixty (60) calendar days. The Applicant, Owner and/or Operator of the WECS Project must immediately cease any violation of the IPCB regulations unless said violation is excused and waived in writing by the affected landowners and occupants. All analyses and studies are subject to approval of the Regional Planner and are a matter of public record. Once the WECS Project has been constructed, the Applicant, Owner and/or Operator of the WECS Project shall provide evidence to the Regional Planner that the wind farm, as constructed, meets all the noise levels, rules and regulations established by the IPCB.

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N. Agricultural Impact Mitigation

All required agreements, studies, reports, certifications and approvals demonstrating compliance with the provisions of this ordinance, federal and state laws, and administrative provisions. Including, but not limited to, consultation reports with the Illinois Department of Agriculture and the Illinois Department of Natural Resources, emergency plan, and evaluation of the geotechnical stability of the site for supporting all the necessary structures. All impacted agricultural land, whether impacted during construction, operation, or decommissioning activities, must be remediated pursuant to the terms of between the Applicant and the Illinois Department of Agriculture.

O. Avian and Wildlife Impact Study

The Applicant, Owner and/or Operator of the WECS Project, at their expense, shall have a third party, qualified professional (after submission of resume and relevant work experience), approved by the Regional Planner, conduct an avian and wildlife impact study and submit said study to the Regional Planner as part of the Siting Approval Permit application. Prior to the substantial completion of the physical aerial erection of the wind turbines, the Applicant, Owner and/or Operator of the WECS Project shall develop to the reasonable satisfaction of the Illinois Department of Natural Resources ("IDNR") and the United States Fish and Wildlife Service ("USFWS") (to the extent the IDNR and the USFWS choose to participate in the process), a professional monitoring program of reasonable duration and scope, consistent with common practice in the wind power industry, to assess migratory bird mortalities resulting from the operation of the wind power facility. The monitoring program shall be undertaken at owner's expense and shall be performed at the direction of a qualified independent professional to be mutually agreed upon by the aforesaid parties in good faith. Such monitoring program shall commence upon the substantial completion of the physical aerial erection of the wind turbine generators, unless otherwise mutually agreed to by the Applicant, Owner and/or Operator of the WECS Project, IDNR and USFWS (to the extent the IDNR and the USFWS choose to participate in the process). If the results of the monitoring program demonstrate the need, the Applicant, Owner and/or Operator of the WECS Project shall work with IDNR and USFWS (to the extent IDNR and USFWS each, respectively, choose to participate) to develop an appropriate response, including the potential further study and implementation of practicable mitigation measures that may either directly or indirectly minimize migratory bird mortality or increase bird populations. The Applicant, Owner and/or Operator of the WECS Project shall follow the guidelines suggested by the Illinois Department of Natural Resources ("IDNR") and United States Fish and Wildlife Services ("USFWS") Endangered Species Consultation program

P. Height

The total height of a WECS tower shall be six hundred (600) feet or less.

Q. As-Built Map and Plans.

Upon completion of each phase of the WECS Project, the Applicant, Owner or Operator shall deliver As-Built Maps, Site Plan and Engineering Plans for the WECS Project that have been signed and stamped by a Professional Engineer and a licensed Surveyor.

R. Engineer's Certificate.

The WECS Project engineer's certificate shall be completed by a structural engineer registered in the State of Illinois and shall certify that the WECS tower and foundation design is compatible with and appropriate for each turbine design proposed to be installed and that the specific soils at the site can support the apparatus, given local soil and climate conditions. All commercially installed wind turbines must utilize self-supporting, tubular towers. Smaller co-generators of 40 kilowatts or less, however, may use lattice construction towers, but must meet all other standards contained in this subsection. Said engineer's certificate shall be public record and shall be submitted as part of the Siting Approval Permit application.

S. Certificate of Utility Power Contracts.

Each certificate shall detail the power purchase contracts and power transmission contracts, or documentation that the WECS Project will be a merchant facility. Documentation shall be provided to the Regional Planner prior to the issuance of a site development permit or construction.

T. Conformance With Approved Application and Plans.

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The Applicant, Owner and/or Operator of the WECS Project shall construct the project in substantial conformance with a County-approved submitted Siting Approval Permit application(s) and all accompanying plan(s) and design documents. The Applicant, Owner and/or Operator of the WECS Project shall be bound by any and all proposals and representations made under oath at the public hearing(s) before the County Board (or its Plans Commission / Board of Appeals, as required by state law), which shall be considered as supplementary conditions of the Siting Approval Permit granted by the County, even if not directly specified herein. Nothing contained herein shall be deemed to preclude the agricultural, commercial or industrial use of the balance of the subject property not occupied by the WECS Project. Said agricultural use will be considered as being the principal use of the subject property notwithstanding adoption of a special use ordinance and the construction and operation of one or more WECS on a given lot or parcel of land, at locations approved by the County pursuant to Siting Approval Permit approval on a Site Plan Map.

U. Siting Approval Permit for WECS Projects.

1. Siting Approval Permit Standards. Pursuant to 55 ILCS 5/5-12020, this Ordinance establishes standards for the siting approval of a WECS Project, each WECS Tower(s) and its Substation(s) and related facilities, which require approval of the County Board, after at least one (1) public hearing, before a WECS Project, WECS Tower, Substation and related facilities can be constructed, installed and operated within Morgan County.

2. Authority and Public Hearing. The County Board shall render final decisions on all WECS Siting Approval Permit applications. If a WECS siting application is approved, the County Board will pass an ordinance that confirms the approval and may stipulate in the ordinance any conditions and restrictions imposed on the WECS Project. Prior to issuing its final decision on a WECS Siting Approval Permit application, the County Board shall hold a public hearing on the application in accordance with the applicable provisions of the Illinois Counties Code, including but not limited to Section 5-12020 (Wind Farms) (55 ILCS 5/5-12020) and the provisions of this Ordinance, including Article XIV. (Fee Schedule And Permitting Process) below.

3. Siting Approval Permit Standards. The County Board may approve a WECS Project Siting Approval Permit application, if it finds:
   a. The establishment, maintenance or operation of the WECS Project will not be detrimental to or endanger the public health, safety, morals, comfort or general welfare;
   b. The WECS Project will not be injurious to the uses and enjoyment of other property in the immediate vicinity for the purposes already permitted, nor substantially diminish and impair property values of surrounding properties;
   c. The establishment of the WECS Project will not impede the normal and orderly development and improvement of the surrounding properties;
   d. Adequate public utilities, access roads, drainage and/or necessary facilities have been or will be provided;

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e. Adequate measures have been or will be taken to provide ingress and egress so designed as to minimize traffic congestion in the public streets;
f. The proposed WECS Project is not contrary to the objectives of the current comprehensive plan of the County (if any); and
g. The WECS Project shall, in all other respects, conform to the applicable regulations of this Ordinance and the zoning district in which it is located (if a zoning ordinance is in effect), except as such regulations may, in each instance, be modified pursuant to the recommendations of the Plans Commission / Board of Appeals and approved by the County Board.

4. Siting Approval Permit Conditions and Restrictions. The County Board may stipulate such conditions, guarantees and restrictions, upon the establishment, location, construction, maintenance, and operation of the WECS Project as are deemed necessary for the protection of the public interest and to secure compliance with the standards and requirements of this Ordinance. In all cases in which a WECS Project is granted for a WECS Project, the County Board shall require such evidence and guarantees as it may deem necessary as proof that the conditions and restrictions stipulated in connection therewith are being and will be complied with. At a minimum, each approved WECS Project shall be subject to the following conditions:
   a. Each Applicant, Owner or Operator shall have the WECS Project inspected annually by qualified wind power professionals, approved by the Regional Planner, and shall submit a certificate from said professionals reciting the annual maintenance done on the facility and stating that the facility is in good working condition and is not a hazard to the public. Failure to submit such annual certificate shall be grounds for revocation of the Siting Approval Permit by the County Board.
   b. The Applicant, Owner or Operator shall obtain all necessary access easements and necessary utility easements prior to construction of the WECS Project or any phase of the WECS Project that is dependent on such easements, copies of which shall be submitted to the Regional Planner.
   c. No appurtenances shall be connected to any WECS Tower except in accordance with this Ordinance and as approved as part of a Siting Approval Permit or an amended Siting Approval Permit.
   d. Restriction on Project Real Estate. Unless the required waiver is obtained from the adjacent property owner, the Applicant, Owner or Operator shall not convey, subdivide, transfer or otherwise alter the lot lines of any portion of the real estate on which a WECS Tower is proposed or already improved with a WECS Tower that will cause or create a setback violation or nonconformity under the applicable regulations of this Ordinance, including Section VI (Design and Installation), Subsection H (Setback) above.

5. Revocation.

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a. In any case where a Siting Approval Permit has been approved for a WECS Project, the Applicant, Owner or Operator shall apply for a site development permit and a construction permit from the County and all other permits required by other government or regulatory agencies and commence and actively pursue construction of the Project within thirty-six (36) months from the date of the granting of the Siting Approval Permit. If the Applicant, Owner or Operator fails to apply for a site development permit and a construction permit from the County and all other permits required by other government or regulatory agencies and/or fails to commence and actively pursue construction of the Project within the thirty-six (36) month period, then without further action by the County Board, the Siting Approval Permit authorizing the construction and operation of the WECS Project shall be automatically revoked and void. Upon written request supported by evidence that the Applicant, Owner or Operator has diligently pursued issuance of all necessary government and regulatory permits for the Project and that any delay in commencement of construction of the Project is due to conditions out of his/her/its control, the County Board, in its sole discretion, may extend the above thirty-six (36) month period by passage of an ordinance that amends the Siting Approval Permit.

b. A Siting Approval Permit may be revoked by the County Board if the WECS Project is not constructed, installed and/or operated in conformance with the County-approved Project plans, the regulations of this Ordinance and the stipulated Siting Approval Permit conditions and restrictions The County Regional Planner will be responsible for advising the County Board, in writing, of any violation(s) and the County Board may then schedule and conduct a public hearing to consider revoking the Siting Approval Permit. Notice of the violation(s) will be provided to the Applicant, Owner or Operator along with a notice of the public hearing time, date and location. At the public hearing, the Applicant, Owner or Operator will have an opportunity to respond to the violation(s). After conducting the public hearing, the County Board shall then render a final decision on whether to revoke the Siting Approval Permit or not. If it decides to revoke the Siting Approval Permit, the County Board will pass an ordinance that memorializes the revocation.

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6. Expiration. A Siting Approval Permit approval for a WECS Project shall be deemed to authorize only the particular construction and operational activities related to the WECS Project and shall expire if the WECS Project construction and operational activities (i.e., construction and operation of the WECS and Substation(s)) and its related facilities shall cease for more than twelve (12) consecutive months for any reason, excluding any time period where the WECS Project or any component of the WECS Project, including any individual WECS or Substation, is inoperable due required or ongoing, active construction, maintenance, repairs, replacement or rehabilitation work.

7. Transferability. Prior to any change in ownership or operation of a WECS Project, an application for an amended Siting Approval Permit must be filed with the County and approved by the County Board after a public hearing. The phrase "change in ownership or operation of a WECS Project" includes any kind of assignment, sale, lease or other conveyance of ownership or operating control of the WECS Project or any portion thereof. An application for an amended Siting Approval Permit shall be prepared, executed and submitted by or on behalf of the Applicant, current Owner and/or current Operator, and the prospective Owner and/or prospective Operator who are the successors in interest to the WECS Project or are obtaining any kind of ownership interest under an assignment, sale, lease or other conveyance of ownership or operating control of the WECS Project or any portion thereof. The application shall disclose the identity of those persons (or entities) who are the prospective successors in interest to the WECS Project or who are obtaining any kind of assignment, sale, lease or other conveyance of ownership or operating control of the WECS Project or any portion thereof, and shall include evidence that demonstrates the prospective Owner(s) and/or prospective Operator has sufficient financial resources, and adequate WECS operational experience and resources to comply with each of the conditions, restrictions and obligations contained in the original Siting Approval Permit, the conditions, restrictions and obligations set forth in this Ordinance and any other applicable County, state and federal laws relating to the construction, installation and operation of the WECS Project. Upon request, the prospective Owner(s) and/or prospective Operator shall submit any additional evidence that demonstrates its/their ability to comply with any additional or amended conditions, restrictions and obligations relating to the construction, installation and operation of the WECS Project that may be contained in an amended Siting Approval Permit to be considered by the County Board. The approval of an amended Siting Approval Permit by the County Board shall be subject to the prospective Owner(s) and/or prospective Operator agreeing to accept and comply with all conditions, restrictions and obligations contained in the original Siting Approval Permit, any additional or amended conditions, restrictions and obligations contained in the amended Siting Approval Permit, this Ordinance and applicable County, state and federal laws.

8. Modification: Any modification of a WECS Project that alters or changes the essential character or operation of the WECS Project in a way not intended at the time the Siting Approval Permit was granted, or as subsequently amended, shall require a new Siting Approval Permit. The Applicant, current Owner and/or current Operator, or authorized representative, shall apply for an amended Siting Approval Permit prior to any modification of the WECS Project. The Regional Planner will review the proposed modification and shall provide to the County Board a written opinion as to whether the proposed modification represents an alteration or change in the essential character or in the operation of the WECS Project as approved. The Applicant, current Owner and/or current Operator, or authorized representative, of the WECS Project shall provide

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the Regional Planner with all the necessary information related to the WECS Project in order for the Regional Planner to prepare his/her written opinion. In determining whether a proposed modification of a WECS Project alters or changes the essential character or operation of the WECS Project in a way not intended at the time the Siting Approval Permit was granted, or as subsequently amended, the Regional Planner's decision shall be based on the following criteria: (a) the information and documents on file with the County relating to the approval of the original Siting Approval Permit or any modification thereto; (b) the ordinance(s) approving the original Siting Approval Permit or any modification thereto; (c) the information and documents relied upon by the Regional Planner in preparing his/her opinion; (d) the scope and nature of the existing uses of the property; and (e) any additional information and documents relating to the proposed modification of the Siting Approval Permit provided by the Applicant, current Owner and/or current Operator, or authorized representative. If the Regional Planner determines that the proposed modification will not alter or change the essential character or operation of the original WECS Project, as approved, a new Siting Approval Permit shall not be required.

V. Additional Terms and Conditions

1. Technical submissions as defined in the Professional Engineering Practice Act of 1989 (225 ILCS 325/4(w)) and contained in the application filed for Special Use shall bear the seal of an Illinois Professional Engineer for the relevant discipline.

2. The County may retain a qualified, independent code inspector or professional engineer both to make appropriate inspections of the WECS Project during and after construction and to consult with the County to confirm that the construction, substantial repair, replacement, repowering and/or decommissioning of the WECS Project is performed in compliance with applicable electrical and building codes. The cost and fees so incurred by the County in retaining said inspector or engineer shall be promptly reimbursed by the Applicant, Owner and/or Operator of the WECS Project. No Certificate of Use and Occupancy shall be issued for a WECS Project until the turbine has been inspected by said code inspector and the Regional Planner has been provided as-built surveys prepared by a licensed surveyor to show that all setback requirements have been met. No wind turbine generator shall become operational until a Certificate of Use and Occupancy is issued by the Regional Planner.

3. The Applicant, Owner and/or Operator of the WECS Project shall provide locked metal gates or a locked chain are installed at the access road entrances of all the wind turbine generator locations if requested by the landowner. An exception may be made when the landowner has filed a written statement with the Regional Planner which states that the owner does not want a locked metal gate installed and has provided a signed liability waiver to the County.

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4. The Special Approval Permit granted to the Applicant, Owner and/or Operator of the WECS Project shall bind and inure to the benefit of the Applicant, Owner and/or Operator, its successors and assigns. If any provision in this Ordinance is held invalid, such invalidity shall not affect any other provision of this Ordinance that can be given effect without the invalid provision and, to this end, the provisions in this Ordinance are severable.

5. A violation of the terms and conditions herein shall constitute a violation of the Siting Approval Permit granted herein and shall be grounds for revocation of the Siting Approval Permit by the County Board.

6. The Applicant, Owner and/or Operator of the WECS Project shall supply written proof of an approved entrance, from the appropriate governing road and highway jurisdictions or the Illinois Department of Transportation, to the Regional Planner prior to the issuance of any site development permit or construction s for the proposed WECS Project.

7. The County Engineer shall determine which WECSs would be required to have necessary ice sensors installed.

8. No wind turbine generator shall be installed in any location where its proximity with existing fixed broadcast, retransmission, or reception antenna for radio, television, or wireless phone or other personal communication systems would produce electromagnetic interference with signal transmission or reception. The wind turbine generator shall not be installed in a location along the major axis of existing microwave communications link where its operation is likely to produce electromagnetic interference in the link's operation.

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W. Nonconforming Use and Structures

1. This Ordinance has established specific requirements for WECS which must be satisfied before the County Board may approve a WECS Project siting approval permit application. However, it is understood and anticipated that circumstances beyond the control of the Owner or Operator of the WECS may cause the WECS to become noncompliant with the provisions of this Ordinance. Recognizing both the legitimate interest of those who lawfully established such a nonconformity and the need to protect the public health, safety, comfort, and general welfare, the provisions of this subchapter are intended to provide for the regulation of nonconforming uses, lots and structures within the following:

   a. It is the intent of this subchapter to permit nonconforming uses to continue until they are removed or until they become a risk to public safety and/or health.
   b. It is the intent of this subchapter that nonconforming structures shall not be enlarged upon, expanded or extended, unless they are brought into compliance with then-current regulations, subject to reasonable exceptions listed below.

2. Any nonconforming structure which received a Siting Approval Permit from the County Board prior to becoming nonconforming, may be continued only in accordance with the following:

   a. Nonconforming Structures: No nonconforming structures shall be:

      i. Added to or enlarged in any manner that increases the nonconformity, except as allowed under the exceptions below;
      ii. Moved or relocated, in whole or in part, that increases the nonconformity, except as allowed under the exceptions below; or
      iii. Renewed if abandoned for a period of twelve (12) continuous months. The term "abandoned" does not apply to any structure that is not in use or operation due to on-going construction, maintenance, repair or replacement work.

   b. Nonconforming Use of a Structure: Nonconforming use of a structure may be:
      i. Used for its intended uses and operations, subject to the provisions of this subsection.
      ii.

   c. Damage: Restoration or Reconstruction. A nonconforming structure may be:
      i. Restored or reconstructed to its original size, height and dimensions, if damaged or destroyed, subject to compliance with applicable then-current state or federal laws governing the construction and operation of WECS. Said restoration or reconstruction shall be upon (a) the original foundation, if feasible, or (b) the location of the original foundation, or (c) a new location that does not increase the nonconformity.
      ii. A WECS Tower may be restored or reconstructed at its original location where it existed prior to a non-participating property owner constructing his/her/its Primary Structure within the fifteen hundred feet (1,500) setback requirement or a participating property owner constructing his/her/its Primary Structure within the one thousand three hundred twenty feet (1,320) setback requirement of Section VI (Design and Installation), Subsection H (Setback) above, subject to compliance with applicable then-current state or federal laws governing the construction and operation of WECS.

   d. Exceptions:
      i. Structural alterations or repairs of a nonconforming structure required by law shall be permitted.

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ii. No nonconforming structure shall be structurally altered or enlarged in such a manner that would further increase the nonconformity, except that structural alterations or operational components related with normal maintenance, repairs and replacements may be permitted where there is no increase in the existing encroachments or the increase results in a *de minins* (two (2) percent (2%) expansion of the encroachments.

iii. Provided that the result is to change the status of a structure or use from nonconforming to conforming, such structure or use may be:

a. Structurally altered;
b. Added to or enlarged;
c. Moved or relocated, in whole or in part;
d. Expanded or extended;
e. Changed; or
f. Restored or reconstructed.

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VII. OPERATION

A. Maintenance

1. Annual Report. The Owner or Operator of the WECS must submit, on an annual basis on the anniversary date of the siting approval application, an operation and maintenance report to the County. The report shall contain the following information: (i) a description of any physical repairs, replacements or modification(s) to the WECS and/or its infrastructure; (ii) complaints pertaining to setbacks, noise, appearance, safety, lighting and use of any public roads received by the Owner and/or Operator concerning the WECS and the resolution of such complaints; (iii) calls for emergency services, including the nature of the emergency and how it was resolved; (iv) status of liability insurance; (v) a summary of repairs, maintenance and service calls to the WECS; (vi) copies of any new structural engineering reports issued for the WECS; and (vi) any other information that the County might reasonably request. P27-125 cont.

2. Annual Project Review; Fee. Within thirty (30) calendar days of the receipt of each annual report, the Regional Planner, or his/her designee, shall review it, conduct an on-site field inspection of the WECS Project and within sixty (60) calendar days of the receipt of the report, provide a summary of the report and its on-site field inspection to the Board or any successor committee designated to oversee zoning issues. The County shall charge a fee for this annual review in the amount of Five Hundred Dollars ($500.00) per WECS Project. This fee shall be paid by the Applicant, Owner or Operator at the time of the annual report submission. Failure to provide the annual report and the required fee shall be considered a cessation of operations. The Applicant, Owner or Operator of a WECS Project shall provide the Regional Planner, or his/her designee, with access to the WECS Project for the purposes of required

building inspections and on-site field review(s). Failure to provide access shall be deemed a violation of this Ordinance.

3. Re-Certification. Any physical modification to the WECS that alters the mechanical load, mechanical load path, or major electrical components shall require re-certification under Section VI(A)(1) of this Ordinance. Like-kind replacements shall not require re-certification. Prior to making any physical modification (other than a like-kind replacement), the Owner or Operator shall confer with a relevant third-party certifying entity identified in Section VI(A)(1) of this Ordinance to determine whether the physical modification requires re-certification.

B. Coordination with Emergency Responders:

1. The Applicant, Owner or Operator shall submit to the local emergency responders a copy of the Site Plan, Standard Operating Procedures (SOPs) and Standard Operating Guidelines (SOGs) for the wind power facility so that the local police, fire protection district and rescue units that have jurisdiction over each tower site may evaluate and coordinate their emergency response plans with the Applicant, Owner or Operator of the WECS Project. In addition, the Applicant, Owner or Operator of the WECS Project shall provide training for, and the necessary equipment to, local emergency response authorities and their personnel so that they can properly respond to a potential emergency at the WECS Project. Special equipment to be provided includes, but is not limited to, permanently installed rescue equipment such as winches, pulleys, harnesses, etc.

2. The Applicant, Owner or Operator shall cooperate with all local emergency responders to develop an emergency response plan.

3. Nothing in this section shall alleviate the need to comply with all other applicable fire/emergency laws and regulations.

C. Water, Sewer, Materials Handling, Storage and Disposal

1. All solid wastes related to the construction, operation and maintenance of the WECS shall be removed from the site promptly and disposed of in accordance with all federal, state and local laws.

2. All hazardous materials related to the construction, operation and maintenance of the WECS shall be handled, stored, transported and disposed of in accordance with all applicable local, state and federal laws.

3. The WECS Project shall comply with existing septic and well regulations as required by the Morgan County Health Department and the State of Illinois Department of Public Health.

D. Shadow Flicker

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1. Prior to the issuance of a permit, the Owner or Operator must present to the County Plans Commission / Board of Appeals, a Model Study presenting a conservative number of hours shadow flicker may appear on a Primary Structure of a non-participating property owner. Shadow flicker shall not exceed thirty (30) hours per calendar year on any Primary Structure using the Model Study information.

2. The Owner or Operator, at its cost, shall use commercially reasonable efforts to remedy and reduce shadow flicker affecting any property owner(s) who is not a participant in the WECS Project, where the property or properties receive more than thirty (30) of shadow flicker in a calendar year by promptly undertaking measures such as purchasing and installing trees and/or other vegetation plantings, screening or awnings on the affected property owner's property in a manner that remedies and reduces shadow flicker.

E. Signage

Signage regulations are to be consistent with ANSI and AWEA standards. A reasonably visible warning sign concerning voltage shall be placed at the base of all pad- mounted transformers and substations.

F. Drainage Systems

The Applicant, Owner or Operator will repair, in a prompt and timely manner, all waterways, drainage ditches, agricultural drainage systems, field tiles, or any other private and public infrastructure improvements damaged during construction, maintenance and operation phases of the WECS Project.

G. Complaint Resolution

The Owner or Operator of the WECS Project shall, at the Owner's and Operator's expense and in coordination with the County, develop a system for logging and investigating complaints related to the WECS Project. The Owner or Operator of the WECS Project shall resolve such complaints on a case-by-case basis and shall provide written confirmation to the Regional Planner. All costs and fees incurred by the County in attempting to or resolving complaints shall be reimbursed by the Owner or Operator of the WECS Project. The Owner or Operator of the WECS Project shall also designate and maintain for the duration of the WECS Project either a local telephone number or a toll-free telephone number and an email address as its public information / inquiry / and complaint "hotline" which shall be answered by a customer service representative 24/7 basis. The Owner or Operator of the WECS Project shall post the telephone number(s) and email address(es) for the customer service representative(s) in an prominent, easy to find location on their websites and at the WECS Project site on signage.

VIII. RESERVED

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IX. RESERVED

X. PUBLIC PARTICIPATION

Nothing in the Ordinance is meant to augment or diminish existing opportunities for public participation.

XI. LIABILITY INSURANCE AND INDEMNIFICATION

Commencing with the issuance of site development or construction permits, the Applicant, Owner and/or Operator of the WECS Project shall maintain a current general comprehensive liability policy and automobile liability coverage covering bodily injury, death and illness, and property damage with limits of at least Five Million Dollars ($5,000,000.00) per occurrence and Twenty Million Dollars ($20,000,000.00) in the aggregate during the life of the WECS Project. Such insurance may be provided, pursuant to a plan of self-insurance, by a party with a net worth of Fifty Million Dollars ($50,000,000.00) or more. The County and its officers, appointed and elected officials, employees, volunteers, attorneys, engineers and agents (the “County Affiliates”) and all affected Road Districts and their officers, appointed and elected officials, employees, volunteers, attorneys, engineers and agents (the “Road District Affiliates”) shall be specifically named as an additional insureds on the insurance certificate(s), endorsement(s) and policies for all aspects of the WECS Project for both ongoing and completed operations and for all automobiles owned, leased, hired or borrowed by the Applicant, Owner and/or Operator for the WECS Project. The coverage shall contain no special limitations on the scope of protection afforded to the County and the County Affiliates or the affected Road Districts and the Road Districts’ Affiliates. The insurance coverage of the Applicant, Owner and/or Operator shall be primary as respects the additional insureds. The Applicant, Owner and/or Operator of the WECS Project shall file the original certificate of insurance, endorsements and polices with the Regional Planner prior to the issuance of a Certificate of Use and Occupancy and annually thereafter.

The Applicant, Owner and Operator shall defend, indemnify and hold harmless the County and its officers, appointed and elected officials, employees, volunteers, attorneys, engineers and agents (collectively and individually, the “Indemnified Parties”) from and against any and all claims, demands, losses, suits, causes of action, damages, injuries, costs, expenses and liabilities whatsoever, including reasonable attorney’s fees, except to the extent arising in whole or in part out of negligence or intentional acts of such Indemnified Parties (such liabilities together known as “liability”) arising out of Applicant, Owner and/or Operator selection, construction, operation and removal of the WECS and affiliated equipment including, without limitation, liability for property damage or personal injury (including death), whether said liability is premised on contract or on tort (including without limitation strict liability or negligence). This general indemnification shall not be construed as limiting or qualifying the County’s other indemnification rights available under the law.

XII. DECOMMISSIONING AND SITE RECLAMATION PLAN REQUIRED

At the time of Permit application, the County and the Applicant, Owner or Operator must formulate a Decommissioning and Site Reclamation Plan to ensure that the WECS

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Project is properly decommissioned. The decommissioning and site reclamation plan shall be binding upon all successors of title to the land. A signed decommissioning and site reclamation plan must be submitted to the County Planner prior to the granting of the permit. The Applicant or subsequent Project Owner and/or Operator shall ensure that the WECS facilities are properly decommissioned within twelve (12) months of the end of the WECS Project life or the facility abandonment. The Applicant or subsequent Project Owner's and/or Operator's obligations shall include removal of all physical material of the project improvements to a depth of forty eight (48) inches beneath the soil surface and the restoration of the area as near as practicable to the same condition prior to construction.

A. A Decommissioning and Site Reclamation Plan shall be prepared by an independent Illinois Certified Professional Engineer and shall include:

1. Provisions describing the triggering events for decommissioning the WECS Project;

2. A description of the methodology and cost to remove all above ground and below ground WECS facilities of the approved Siting Approval Permit;

3. Provisions for the removal of all above ground and below ground WECS facilities of the approved Siting Approval Permit;

4. Methodology and cost to restore all areas used for construction, operation and access to a condition equivalent to the land prior to the WECS construction;

5. A work schedule and a permit list necessary to accomplish the required work;

6. Methodology to identify and manage any hazardous or special materials.

7. Proof that the necessary amount and form of Financial Security has been received by the County in the form of a surety bond (performance and payment bond), irrevocable letter of credit or a cash escrow account that names Morgan County as the beneficiary. If an irrevocable letter of credit or surety bond (performance and payment bond) is selected, the original of the irrevocable letter of credit or surety bond shall be held by the County. If a cash escrow is selected, the cash escrow shall be held and managed by an independent third party (e.g., escrow agent or title company) on behalf of the County, subject to escrow instructions that incorporate the applicable decommissioning and repair / replacement / restoration obligations of this Agreement as executed by the County and the WECS Owner and/or Operator. The amount of Financial Security shall be equal to the positive difference between the total cost of all decommissioning and restoration work and the net salvage value of all removed WECS equipment or materials, plus a ten percent (10%) contingency, as adjusted by the County after input from the County's

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engineer (the "Decommission Security"). To determine that amount, the WECS Owner and/or Operator and the Morgan County Board shall: (a) obtain bid specifications provided by a professional structural engineer; (b) request estimates from construction / demolition companies capable of completing the decommissioning of the WECS Project; The Morgan County engineer, an independent engineer of the County's choosing, and the Regional Planner will review all estimates and make a recommendation to the Morgan County Board for an acceptable estimate. Morgan County reserves the right to pursue other estimates; (c) certification of the selected estimate by a professional structural engineer. All costs to secure the estimates will be funded by the WECS Owner and/or Operator.

8. A provision that the terms of the decommissioning plan shall be binding upon the WECS Owner and/or Operator and any of their successors, assigns, or heirs;

9. Confirmation by affidavit that the obligation to decommission the WECS facilities is included in the lease agreement for every parcel included in the Siting Approval Permit application. A list of all landowners should be kept current and affidavits shall be secured from future WECS Owners and/or Operator and landowners stating their financial understanding;

10. A provision that allows for the county to have the legal right to transfer applicable WECS material to salvage firms; P27-125 cont.

11. Identification of and procedures for Morgan County to access the Financial Assurances; and

12. A provision that Morgan County shall have access to the site, pursuant to reasonable notice to affect or complete decommissioning. A portion of the Decommission Security will be required to be held for one (1) year past the decommissioning to settle any potential disputes.

B. Provisions triggering the decommissioning of any portion of the WECS Project due to abandonment:

1. Inactive construction for twelve (12) consecutive months or if there is a delay in obtaining electrical certification for twelve (12) consecutive months, unless a signed document is provided by the utility company claiming responsibility for the delay.

2. If no electricity is generated by an individual WECS Tower / wind turbine or the entire WECS Project for twelve (12) consecutive months after electricity is initially generated, unless the inactivity is due to required or ongoing, active maintenance, repairs, replacement or rehabilitation work and written proof is provided that new parts have been ordered and will be received within six (6) months. The Regional Planner shall have access to records in order to determine the electric generation of every turbine.

3. The principal company dissolves or chooses to walk away from the WECS Project.

4. If any part of an individual turbine or the WECS Project falls into disrepair, is in threat of collapsing or any other health and safety issue.

C. Provisions for the removal of structures, debris and cabling; both above and below the soil surface:

1. Items required to be removed include but are not limited to: turbines, transformers, foundation pads, electrical collection systems and transporters, underground cables, fencing, access roads and culverts. A landowner must sign an agreement if they wish for the access roads or culverts to remain.

D. Provisions for the restoration of soil and vegetation:

1. All affected areas shall be inspected, thoroughly cleaned and all construction related debris shall be removed.

2. Items required to be restored include but are not limited to: windbreaks, waterways, site grading, drainage tile systems and topsoil to former productive levels.

a. In work areas involving decommission from expansion of turbine crane pads, widening access roads or any other work areas, the topsoil must be first removed, identified and stored separate from other excavated material for later replacement as applicable.

b. The 48-inch below-surface excavation area shall be filled with clean sub-grade material of similar quality to that in the immediate surrounding area.

c. All sub-grade material will be compacted to a density similar to surrounding grade material.

d. All unexcavated areas compacted by equipment used in decommissioning shall be de-compacted in a manner that adequately restores the topsoil and sub-grade material to the proper density consistent and compatible with the surrounding area.

e. Where possible, the topsoil shall be replaced to its original depth and surface contours.

f. Any topsoil deficiency and trench settling shall be mitigated with imported topsoil that is consistent with the quality of the effected site.

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3. Disturbed areas shall be reseeded to promote re-vegetation of the area to a condition reasonably similar to the original condition. A reasonable amount of wear and tear is acceptable.

4. Restoration measurements shall include: leveling, terracing, mulching and other necessary steps to prevent soil erosion; to ensure establishment of suitable grasses and forbs; and to control noxious weeds and pests.

5. Items required to be repaired after decommissioning include but are not limited to: roads, bridges and culverts.

6. An independent drainage engineer shall be present to ensure drainage tiles, waterways, culverts, etc. are repaired as work progresses.

7. A soil erosion control plan shall be approved by the Morgan County Soil and Water Conservation District.

8. All Stormwater management, floodplain and other surface water codes and ordinances shall be followed.

E. Estimating the costs of decommissioning:

1. Costs shall include but not be limited to engineering fees, legal fees, accounting fees, insurance costs, decommissioning and site restoration.

2. When factoring the WECS salvage value into decommissioning costs, the authorized salvage value may be deducted from decommissioning costs if the following standards are met:

   a. The net salvage value shall be based on the average salvage price of the past five (5) consecutive years, this includes any deconstruction costs.

   b. The maximum allowable credit for the salvage value of any WECS shall be no more than the estimated decommissioning costs of removal of the above ground portions of that individual WECS or up to seventy percent (70%) of the total estimated decommissioning costs, whichever is greater.

3. Adjustments to the financial assurance amount that reflect changes in the decommissioning costs and salvage values shall be submitted every five (5) years and shall be adjusted for inflation and other factors. The amount of the Decommission Security shall be adjusted accordingly within six (6) months of receiving the updated information as determined by an Illinois professional engineer. Failure to provide financial assurance as outlined herein shall be considered a cessation of operation.

4. When determining salvage values, demolition costs, transportation costs and road permits shall be a consideration.

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5. If salvage value items are removed prior to decommissioning, then the Decommission Security may be adjusted to provide a credit.

F. Financial assurance:

1. The County shall have immediate access, upon written notice to the Owner and/or Operator, to use the Decommission Security if:

   a. The WECS Owner and/or Operator fails to address a health and safety issue in a timely manner; or

   b. The WECS Owner and/or Operator fails to decommission the abandoned turbine(s) or the entire WECS Project in accordance with the Decommissioning and Site Reclamation Plan.

2. The Applicant and/or WECS Owner and/or Operator shall grant perfected security in the Decommission Security by use of a control agreement establishing the County as an owner of record pursuant to the Secured Transit Article of the Uniform Commercial Code, 810 ILCS 9/ *et seq*.

3. The County Board or its escrow agent shall release the Decommission Security when an WECS Owner or Operator has demonstrated and Morgan County concurs that decommissioning has been satisfactorily completed, or upon written approval of the County to implement the decommissioning plan. Ten percent (10%) of the Decommission Security shall be retained one (1) year past the date to settle any outstanding concerns.

4. Any interest accrued on the Decommission Security that is over and above the total value as determined by the Illinois professional structural engineer shall go to the WECS Owner and/or Operator.

5. The Applicant shall identify procedures for Morgan County to assess the financial assurances, particularly if it is determined that there is a health and/or safety issue with the WECS and the principal company fails to adequately respond as determined by the County Board.

6. The County shall be listed as a debtor but shall not be responsible for any claims against the WECS Owner or Operator.

7. The Applicant shall agree that the sale, assignment in fact or at law, or other transfer of the Applicant's financial interest in the WECS shall in no way effect or change the Applicant's obligation to continue to comply with the terms, covenants and obligations of this agreement and agrees to assume all reclamation liability and responsibility of the WECS.

8. Morgan County and its authorized representatives have the right of entry onto the WECS premises for the purpose of inspecting the methods of reclamation or for performing actual reclamation if necessary.

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XIII. REMEDIES

A. The Applicant's, Owner's, or Operator's failure to materially comply with any of the above provisions shall constitute a default under this Ordinance.

B. Prior to implementation of the applicable County procedures for the resolution of such default(s), the appropriate County body shall first provide written notice to the Owner and Operator, setting forth the alleged default(s). Such written notice shall provide the Owner and Operator a reasonable time period, not to exceed sixty (60) calendar days, for good faith negotiations to resolve the alleged default(s).

C. If the County determines in its discretion, that the parties cannot resolve the alleged default(s) within the good faith negotiation period, then applicable County ordinance provisions addressing the resolution of such default(s) shall govern.

XIV. FEE SCHEDULE AND PERMITTING PROCESS

A. Fees

1. Upon submittal of the application for a WECS, the Applicant shall submit a check to Morgan County in the amount of Fifty Thousand Dollars ($50,000.00) ("Plan Review Deposit"). These funds shall be placed in a guaranteed money market account and will be used to compensate and reimburse the County for actual, documented costs incurred during the review process for the WECS application. Should the actual, documented costs to the County exceed Fifty Thousand ($50,000.00), the Applicant shall be responsible for those additional costs and shall remit additional funds to the County within fifteen (15) calendar days of receipt of a request from the County. Any amount remaining in the money market account after the County completes the application process and pays all bills and invoices shall be refunded to the Applicant.

2. The application for a Siting Approval Permit must be accompanied by a consideration fee in the amount of one thousand One Thousand Dollars ($1,000.00), required for each wind tower with turbine.

3. Upon approval of a Siting Approval Permit by the County Board, a fee of Twenty-Five Dollars ($25.00) per vertical foot, (being the measurement from the base of the wind turbine to the hub), per turbine, is due upon issuance of the Notice of Construction by the Owner or Developer of the wind energy system, or upon the commencement of the construction of the wind energy system.

B. Review of Siting Approval Permit Application

1. Review by the County Board:

a. The Regional Planner shall review the application for completeness with the requirements of this Ordinance in a

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preliminary investigation and issue a written report to the County Board.

b. Upon completion of this preliminary investigation and report, the Regional Planner shall schedule a date for a public hearing before the Plans Commission / Board of Appeals.

c. Notice Requirements: The County shall comply with the public hearing notice requirements contained in Section 5-12020 (Wind Farms) of the Illinois Counties Code (55 ILCS 5/5-12020). In the event that Section 5-12020 does not provide specific notice requirements, then the County will comply with the then-current public hearing notice requirements of Section 5-12009.5 (Special Uses) (55 ILCS 5/5-12009.5), which as of the approval date of this Ordinance require: There must be at least thirty (30) calendar days' notice before the hearing. The notice must include the time, place and date of the hearing and must be published in a newspaper published in the township or road district where the property is located. If there is no newspaper published in the township or road district where the property is located, the notice must be published in a newspaper of general circulation in the County. The notice must also contain: (i) the particular location of the property for which the Siting Approval Permit is requested by legal description and by street address, or if there is no street address, by locating the property with reference to any well-known landmark, highway, road, thoroughfare, or intersection; (ii) whether the petitioner or applicant is acting for himself or herself or as an agent, alter ego, or representative of a principal and the name and address of the principal; (iii) whether the petitioner or applicant is a corporation, and, if so, the correct names and addresses of all officers and directors of the corporation and of all stockholders or shareholders owning any interest in excess of 20% of all of the outstanding stock or shares of the corporation; (iv) whether the petitioner or applicant, or his or her principal, is a business or entity doing business under an assumed name, and, if so, the name and residence of all actual owners of the business or entity; (v) whether the petitioner or applicant, or his or her principal, is a partnership, joint venture, syndicate or an unincorporated voluntary association, and, if so, the names and addresses of all partners or members of the partnership, joint venture, syndicate or unincorporated voluntary association; and (vi) a descriptive statement of the proposed WECS Project.

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In addition to any other notice required by this Section, the County must give at least fifteen (15) calendar days' notice before the hearing to: (i) any municipality whose boundaries are within 1-1/2 miles of any part of the property proposed as a WECS Project; and (ii) the owner or owners of any land adjacent to or immediately across any street, alley or public right-of-way from the property proposed as a WECS Project.

The petitioner or applicant must pay the cost of the publication of the notice required by this Section.

d. The Plans Commission / Board of Appeals shall hold the public hearing and review and consider the Siting Approval Permit application, allow oral and written testimony of the Applicant and its consultants, any interested parties, the County staff and the County's consultants and all other written submittals received during the public hearing. After the public hearing, the Plans Commission / Board of Appeals shall issue its written recommendation and deliver it to the County Board.

e. The County Board shall conduct an open, public meeting at which it reviews and considers the recommendation of the Plans Commission / Board of Appeals and then the Board will ether grant or deny the application in accordance with the provisions of Section 5-12020 of the Illinois Counties Code (55 ILCS 5/5-12020). If the County Board approves the Siting Approval Permit application, such approval may be with or without conditions and restrictions. The County Board may also return the application to the Plans Commission / Board of Appeals to conduct another public hearing to require and evaluate additional information from the Applicant and its consultants, any interested parties and the County staff and the County's consultants in order to respond to any issues or concerns raised by the County Board before making its final decision. In such case, the Plans Commission / Board of Appeals shall issue a supplemental written recommendation and deliver it to the County Board.

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f. If the County Board approves the application, it shall approve by ordinance a Siting Approval Permit with or without conditions and restrictions and affix the Board's seal upon the ordinance approving the Siting Approval Permit together with the signature of the County Board's Chairman and the Morgan County Clerk. If it disapproves, the County Board shall set forth its reasons in its records and provide the applicant with a copy.

C. Terms and Limitations of Siting Approval Permit

1. Permit Effective Date

The Siting Approval Permit shall become effective upon approval of the ordinance by the County Board.

2. Failure to Commence Construction or Operation

See Subsection U (Siting Approval Permit for WECS Projects) of Article VI (Design And Installation) above.

3. Revocation of Siting Approval Permit

See Subsection U (Siting Approval Permit for WECS Projects) of Article VI (Design And Installation) above.

XV. VARIANCE AND MODIFICATION:

A. Standards for Granting Variances

1. Where an applicant demonstrates that a provision of this Ordinance would cause unnecessary hardship, delay or impediments to the development of a WECS Project if strictly adhered to, and where, in the opinion of the Chair of the County Board, because of topographical or other conditions peculiar to the site, a departure may be made without destroying the intent of such provisions, the County Board, after input from the Regional Planner and the Plans Commission / Board of Appeals, may authorize a variance, if the variance complies with the following provisions:

a. The requested variance is required for the development of the WECS Project, and the failure to obtain the requested variance would result in a practical difficulty or unnecessary hardship for the applicant;
b. The granting of the requested variance will not be materially detrimental or injurious to any adjacent property;
c. The granting of the requested variance will not violate the general spirit and intent of this Ordinance.

2. Any variance thus authorized is required to be approved by ordinance passed by the County Board and be entered in the minutes of the County Board's meeting, and the reasoning on which the variance was justified must be described in the minutes as well.

B. Application for Variance

1. An applicant for a variance shall file a request for a variance with the Chairman of the County Board within at least ten (10) calendar days prior to the next regularly-scheduled County Board meeting. The County Board shall refer the application to and place the applicant's request on the agenda for the next Plans Commission / Board of Appeals meeting for scheduling of a public hearing.

2. The burden of proof shall rest with the applicant to clearly establish that the requested variance satisfies the criteria for granting such a variance under this Ordinance.

C. Public Hearing

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The Plans Commission / Board of Appeals shall conduct a public hearing on the application, after publication of notice is made in accordance with the provisions of Section 5-12009 of the Illinois Counties Code (55 ILCS 5/5-12009), and shall issue its written recommendation to the County Board.

D. Approval and Conditions

The County Board may grant or deny the application after receiving and considering the written recommendation of the Plans Commission / Board of Appeals in accordance with the provisions of Section 5-12009 of the Illinois Counties Code (55 ILCS 5/5-12009). In granting a variance, the County Board may impose such conditions and restrictions upon the applicant and the property benefiting from the variance as may be necessary to reduce or minimize any potentially negative impacts on any adjacent properties, and to carry out the general purpose of this Ordinance, which conditions and restrictions shall be set forth in the ordinance approving the variation.

XVI. INTERPRETATION

The provisions of these regulations shall be held to the minimum requirements adopted for the promotion and preservation of public health, safety and general welfare of County of Morgan. These regulations are not intended to repeal, abrogate, annul or in any manner interfere with existing regulations or laws of the County of Morgan nor conflict with any statutes of the State of Illinois, except that these regulations shall prevail in cases where these regulations impose a greater restriction than is provided by existing statutes, laws or regulations. P27-125 cont.

XVII. SEVERABILITY

If any section, paragraph, clause, phrase or part of this Ordinance is for any reason held invalid by any court or competent jurisdiction, such decision shall not affect the validity of the remaining provisions of these regulations, and the application of those provisions to any persons or circumstances shall not be affected thereby.

XVIII. REPEAL

All ordinances and regulations and amendments thereto enacted and/or adopted by the County Board that are inconsistent with the provisions of this Ordinance are repealed, as of the effective date of this Ordinance. Except as to the regulations set forth above in this Ordinance, all other ordinances and regulations of Morgan County, Illinois, as amended, shall remain in full force and effect. The repeal of any prior ordinance or its amendments does not affect or impair any act done, offense committed or right accruing, accrued or acquired or liability, penalty, forfeiture or punishment incurred prior to the time enforced, prosecuted or inflicted.

XIX. CERTIORARI PROCEDURE

In regard to any final decision by the County Board or any final decision by any other County Board, commission or committee with final decision-making authority and jurisdiction under this Ordinance, any person aggrieved may petition the Circuit Court of

Morgan County, Illinois, for a writ of certiorari or administrative review or other judicial relief as provided by applicable statutory or common law.

XX. EFFECTIVE DATE

This Ordinance shall be in full force and effect from and after its passage, publication and approval as required by law.

XXI. ENACTMENT; PRIOR UPDATES

The Ordinance Regulating The Siting Of Wind Energy Conversion Systems In Morgan County, Illinois was initially enacted by the Morgan County Board of Commissioners with the adoption Ordinance No. 09-08 on May 4, 2009. Since its initial enactment, this Ordinance has been updated as follows: None; except for the amendments set forth above in this Ordinance.

Passed this _____ day of _________, 2019.

____aye ______________________________
Bradley A. Zeller, Chairman

____aye ______________________________
Bill Meier, Member

____aye ______________________________
Ginny Fanning, Member

Certification: __________________________
Jill Waggener, County Clerk

P27-125 cont.

ORDINANCE NO. 3548

ORDINANCE OF THE MARIN COUNTY BOARD OF SUPERVISORS ADOPTING AMENDMENTS TO MARIN COUNTY CODE TITLE 22 (DEVELOPMENT CODE)

* *

SECTION I: FINDINGS

The Marin County Board of Supervisors hereby finds and declares the following:

I. WHEREAS, on June 24, 2003, the Marin County Board of Supervisors certified the Marin County Development Code (Title 22) Final Supplemental Environmental Impact Report (FSEIR) and adopted various text amendments to the Marin County Code (Marin County Board of Supervisors Ordinance No. 3380). That action updated and combined the Subdivision and Zoning ordinances previously codified under Marin County Code Titles 20 and 22, respectively, into a single comprehensive code under Title 22 (Development Code).

II. WHEREAS, on November 6, 2007, the Marin County Board of Supervisors certified a Final Environmental Impact Report (FEIR) for the Countywide Plan (CWP) update prior to adoption of the 2007 CWP. The certified CWP FEIR updates the 1994 EIR and 2003 FSEIR as those documents apply to the Development Code. The 2007 certified FEIR adequately evaluated the 2003 Development Code, which functions as an implementing program to the CWP. P27-126

III. WHEREAS, on November 6, 2007, the Marin County Board of Supervisors adopted the 2007 Countywide Plan update, which includes policies promoting the adoption of energy efficiency technologies, including low-carbon and renewable fuels and zero emission technologies and the development of renewable energy resources.

IV. WHEREAS, the proposed WECS text amendments will implement the following Countywide Plan (CWP) policies promoting energy efficiency and encouraging the use of renewable and alternative energy resources, while avoiding conflicts between land uses, preserving and enhancing the natural environment, protecting the visual characteristics of the environment, and ensuring the orderly and beneficial development of the unincorporated areas of Marin County.

A. AIR-4.1 Reduce Greenhouse Gas Emissions. Adopt practices that promote improved efficiency and energy management technologies; shift to low-carbon and renewable fuels and zero emission technologies.

B. EN-2.1 Protect Local Renewable Resources. Preserve opportunities for development of renewable energy resources.

C. EN-2.3 Promote Renewable Energy. Facilitate renewable technologies through streamlined planning and development rules, codes, processing, and other incentives.

V. WHEREAS, to implement the CWP policies promoting energy efficiency and encouraging the use of renewable and alternative energy resources, the Marin County Community Development Agency initiated proposed text amendments that would modify the following chapters/sections pertaining to Wind Energy Conversion Systems (WECS) regulations contained in the Marin County Development Code (Title 22):

A. Section 22.32.180 – Wind Energy Conversion Systems (WECS);

B. Section 22.130.030 W. Definitions "W." WECS;

C. Section 22.20.060 E.4. – Height Measurement and Height Limit Exceptions;

D. Chapter 22.08 – Agricultural and Resource-Related Districts, Section 22.08.030, Table 2-1 – Allowed Uses and Permit Requirements for Agricultural and Resource-Related Districts;

E. Chapter 22.10 Residential Districts, Section 22.10.030, Table 2-3 – Allowed Uses and Permit Requirements for Single-Family Residential Districts and Table 2-4 – Allowed Uses and Permit Requirements for Multi-Family Residential Districts;

F. Chapter 22.12 – Commercial and Industrial Districts, Section 22.12.030, Table 2-6 – Allowed Uses and Permit Requirements for Commercial Districts and Table 2-7 – Allowed Uses and Permit Requirements for Commercial and Industrial Districts; and

G. Chapter 22.14 – Special Purpose and Combining Districts, Section 22.14.030, Table 2-9 – Allowed Uses and Permit Requirements for Special Purpose Districts.

P27-126 cont.

VI. WHEREAS, the proposed text amendments that would modify corresponding sections pertaining to Wind Energy Conversion Systems (WECS) regulations contained in the Marin County Development Code (Title 22) are summarized below:

A. Section 22.32.180 - Wind Energy Conversion Systems (WECS):

This Section establishes permit requirements for planned district and non-planned district zones and sets standards for the development and operations of WECS in compliance with Marin County policies and State and Federal laws to allow and encourage the safe, effective and efficient use of WECS to reduce consumption of utility supplied electricity. It establishes development standards for "Small", "Medium", and "Large" WECS as defined in the proposed text amendments found in Section 22.130.030 W. Definitions "W." WECS. In general: (1) Small WECS, Small WECS in the APZ zoning district and Small Roof-Mounted and Small Non-Grid-Tied Agricultural WECS, located in parcels with a minimum lot size of one acre in the ARP zoning district and all other planned zoning districts that are not identified in Section 22.32.190.A.1.b. and Small WECS, located in conventional agricultural zoning districts and Small Roof-Mounted and Small Non-Grid Tied Agricultural WECS located in parcels with a minimum lot size of one acre in conventional non-agricultural zoning districts, may be ministerial in nature and approved by a Building Permit, with exceptions to standards considered through the Design Review process; (2) Small WECS, Small Roof-Mounted and Small Non-Grid-Tied Agricultural WECS, located in parcels that are less than one acre in the ARP zoning district and all other Small WECS in planned zoning district zones that are not identified herein or in Section 22.32.190.A.1.a. and Small WECS, located in parcels that are less than one acre in all other conventional non-agricultural zoning districts and Small Freestanding WECS in conventional agricultural zoning districts that are no identified herein or in Section 22.32.180.A.2.a., require Design

Review approval, with exceptions to standards considered through the Use Permit process; (3) Medium WECS require Design Review approval, with exceptions to standards considered through the Use Permit process; (4) Large WECS, (allowed only in Agricultural Zoning Districts A3-A60, ARP, and APZ) will require Master Plan/Precise Development Plan or Use Permit/Design Review approvals. This Section establishes appearance, visibility, and operational standards for all WECS, including, but not limited to, siting criteria, safety measures, and avian protection. It establishes noise levels based on County noise standards. It sets application submittal requirements, including siting and design plans, wind measurement studies, bird and bat studies, visual simulations and acoustical analyses.

B. Sections 22.08.030, 22.10.030, 22.12.030 and 22.14.030 – Allowed Uses and Permit Requirements:

The tables identified in the following sections of the Development Code contain proposed modifications to reflect the allowable use of land and land use permit requirements in the respective zoning districts as they pertain to Small, Medium, and Large WECS: Section 22.08.030, Table 2-1 – Allowed Uses and Permit Requirements for Agricultural and Resource-Related Districts; Section 22.10.030, Table 2-3 – Allowed Uses and Permit Requirements for Single-Family Residential Districts and Table 2-4 – Allowed Uses and Permit Requirements for Multi-Family Residential Districts; Section 22.12.030, Table 2-6 – Allowed Uses and Permit Requirements for Commercial Districts and Table 2-7 – Allowed Uses and Permit Requirements for Commercial and Industrial Districts; and Section 22.14.030, Table 2-9 – Allowed Uses and Permit Requirements for Special Purpose Districts.

P27-126 cont.

C. Section 22.20.060 E.4. – Height Measurement and Height Limit Exceptions:

The proposed text amendments eliminate reference to WECS from this section because the proposed text amendments provide specific height standards for Small, Medium, and Large WECS.

D. Section 22.130.030 W. Definitions "W" WECS

This section provides definitions of technical terms specific to the development and operation of WECS. WECS land use is defined as any machine that converts and then stores or transfers the kinetic energy in the wind into a usable form of mechanical or electrical energy. The WECS consists of all parts of the system, including the base or foundation, tower, wind turbine, generator, rotor, blades, supports, and transmission equipment. The energy may be used on site or distributed into the electrical grid.

VII. WHEREAS, the Marin County Planning Commission finds that the Marin County Community Development Agency - Planning Division prepared an Initial Study, pursuant to the requirements of the California Environmental Quality Act (CEQA) for the project, which determined that potential physical impacts are avoided or mitigated to a point where no significant adverse environmental impacts will result and that there is no evidence that the project, as conditioned, will have a significant effect on the environment.

VIII. WHEREAS, the Marin County Planning Commission held a duly noticed public hearing on November 23, 2009, continued the public hearing to January 11, 2010, and held a re-noticed continued public hearing on April 26, 2010.

IX. WHEREAS, on April 26, 2010, after conduct of a continued public hearing, the Planning Commission continued the hearing to June 14, 2010, and directed staff to revise the WECS text amendments and the resolutions pursuant to the issues raised by the Planning Commission and in accordance with the Planning Commission's direction.

X. WHEREAS, on June 14, 2010, after conduct of a continued public hearing to review and consider testimony in favor of, and against, the proposed Negative Declaration of Environmental Impact, the Clerical and Minor Corrections and Minor Modifications to the proposed Negative Declaration of Environmental Impact, and the comments and responses thereto, the Planning Commission found that the proposed WECS text amendments to the Marin County Development Code (Title 22) project would not result in any potential, significant environmental impacts, and qualifies for a Negative Declaration of Environmental Impact in compliance with the California Environmental Quality Act (CEQA), the State CEQA Guidelines, and the County's CEQA process and passed a resolution recommending adoption by the Board of Supervisors of a Negative Declaration of Environmental Impact for the proposed project.

XI. WHEREAS, on June 14, 2010, after conducting a continued public hearing to consider the merits of the proposed WECS text amendments and hear testimony in favor of, and in opposition to, the amendments, the Marin County Planning Commission recommended approval of the amendments to the Board of Supervisors.

XII. WHEREAS on July 27, 2010 the Marin County Board of Supervisors conducted a duly-noticed public workshop and continued the hearing to August 10, 2010 to consider the merits of the project, and hear testimony in favor of, and in opposition to, the project. P27-126 cont.

XIII. WHEREAS, the Marin County Board of Supervisors finds that the proposed WECS text amendments to the Marin County Development Code (Title 22) implements the goals, policies and programs of the Marin Countywide Plan (CWP), which are necessary to protect the public health, safety, and welfare of residents and businesses in the unincorporated areas of Marin County.

XIV. WHEREAS, the Marin County Board of Supervisors finds that the proposed WECS text amendments are consistent with the pertinent goals and policies of the CWP for the following reasons:

A. The proposed project is consistent with the current CWP land use designations and density of development and zoning classifications, and the proposed project, consisting of proposed text amendments relative to the land use and development standards of WECS, will not alter or modify the CWP land use designations or density of development governing the conventional and planned zoning districts in the Coastal, Inland Rural, City Centered, and Baylands corridors.

B. The proposed WECS text amendments to the Development Code (Title 22) set development standards and require studies relating to the assessment of natural resources for future proposed projects to assure that future WECS are sited, designed and operated in such a manner as to avoid significant impacts on environmental resources, including special-status species and their habitats. Specifically, the proposed text amendments:

- Protect wetlands and habitat for special-status species and migratory species of the Pacific flyway;
- Include resource preservation through the environmental review process in accordance with the California Environmental Quality Act;

- Limit development in areas that contain essential habitat for special-status species, wetlands, baylands, and coastal and riparian habitats;
- Protect wildlife movement corridors including riparian corridors, shorelines, and ridgelines;
- Preserve sensitive riparian corridors, wetlands, and baylands to protect bird nesting activities;
- Establish and restrict land use in Wetland Conservation Areas (WCAs);
- Establish and restrict land use in Stream Conservation Areas (SCAs); and
- Require coordination with trustee agencies and local environmental groups for reducing impacts to birds and bats.

(CWP Policies BIO-1.1, BIO-1.3, BIO-2.1, BIO-2.2, BIO-2.4, BIO-2.5, BIO-2.8, BIO-3.1, BIO-4.1, BIO-4.2, BIO-5.1, and BIO-5.2)

C. The proposed WECS text amendments to the Code set development standards and establish site and design requirements, which restrict development of WECS in geologically unstable areas or where there are threats to life or property, and restrict development in such areas to minimize adverse impacts. Marin County standard submittal requirements for development of future WECS could require submittal of a preliminary Soils Reconnaissance and/or Detailed Soils Investigation and Report based upon test borings and prepared by a registered soils engineer or registered engineering geologist, if County staff determines that a potential soils program or geophysical related hazard exists. Therefore, the project would be consistent with policies related to avoidance of geologic hazards. (CWP Policies CD-2.8, EH-2.1, EH-2.2, EH-2.3

P27-126 cont.

D. The proposed WECS text amendments provide strict siting and design criteria and development standards to preserve the visual quality of the natural and built environment where future WECS might be constructed. These criteria and standards expand design guidelines for the construction and use of future WECS projects and are designed to substantially reduce and minimize potential impacts to scenic views or conflicts with County aesthetic or visual policies or standards. The proposed text amendments prohibit the illumination of the turbine or tower except to comply with Federal Aviation Administration (FAA) standards. The proposed design and site standards would protect visually prominent ridgelines and require appropriate siting and setbacks. Submittal requirements require visual simulations to better understand the visual implications of proposed WECS. The proposed amendments will improve area aesthetics by requiring the restoration of disturbed sites. The proposed WECS text amendments ensure that the effects of potential aesthetics and visual resources are considered in the earliest planning stages. The proposed text amendments will facilitate the project review process to assure that visual resources will not be adversely impacted by the future construction, installation and operation of WECS. (CWP Policies DES-1.2, and DES-4.1)

E. The proposed WECS text amendments recognize the rapidly expanding technological advancements that are making wind turbines increasingly more efficient, quiet, safe, and cost effective and the State's electricity supply shortage and its programs to encourage the adoption of small wind energy systems ordinances and to limit obstacles to their use. (CWP Policies AIR-4.1, EN-2.1, and EN-2.3)

F. The proposed WECS text amendments will implement the 2007 Countywide Plan (CWP) noise programs, which establish benchmarks for allowable noise exposure from stationary noise sources for purposes of planning and siting land uses. Consistent with CWP noise policies and programs, the proposed text amendments limit the noise level of future WECS to a maximum of 50 dBA during daytime hours (7:00 AM to 10:00 PM) and 45 dBA during nighttime hours (10:00 PM to 7:00 AM) as measured at any point along the common receiving property lines of adjacent properties, except during short-term events such as utility outages and severe weather and wind storms and construction or maintenance operations. In addition, the text amendments require submittal of acoustical analysis if necessary with project-specific noise mitigation measures. (CWP Goal NO-1 and Policies NO-1.1 and NO-1.3)

G. The proposed WECS text amendments reinforce the CWP policies intended to protect agriculturally-zoned lands by providing standards and procedures for the future construction and use of WECS in order that through County review of specific projects the construction and use of WECS will not directly or indirectly have an adverse effect on agricultural resources, operations, or contracts. The proposed amendments encourage the future installation and use of WECS that would be supportive of agricultural production and land uses. The development standards would facilitate the future construction, installation and operation of Small WECS, up to 100 feet in total height, that are not grid-tied and are solely used to pump water for agricultural uses on parcels 10 acres and larger in size as a permitted use not subject to County discretionary review, subject to avoidance of significant impacts to wildlife as verified by a submitted Bird and Bat Study. Any future construction and use of discretionary Small, Medium and Large WECS would be subject to the County's review and CEQA process for evaluation of any adverse effects on agricultural resources, values or production. Future construction and operation of WECS could provide electricity for agricultural production and operation on properties in the unincorporated areas of Marin County. Proposed amendments prohibit installation of WECS where not allowed by the provisions of a Williamson Act Contract. (CWP Policies AG-1.3, AG-1.4, AG-1.6, AG-1.7, and AG-1.8) P27-126 cont.

XV. WHEREAS, the Marin County Planning Commission finds that WECS are currently allowed in the Coastal Zone through application of Chapter 22.71I of the Marin County *Interim* Development Code. In accordance with Article V of the 2003 Marin County Development Code (Title 22), the proposed WECS Development Code amendments would not take effect in the coastal zone until the Local Coastal Program (LCP) update is adopted by the California Coastal Commission (CCC).Though the CCC will have to approve the proposed text amendments as they relate to zoning standards in the Coastal Zone, the County of Marin, as the principal permit authority, is the Lead Agency under the California Environmental Quality Act (CEQA), and the CCC is a Responsible Agency. Land located within the Coastal Zone will continue to be regulated by relevant provisions of the Marin County *Interim* Development Code.

XVI. WHEREAS, the Marin County Planning Commission determines that the following findings in accordance with the provisions of the Marin County Development Code, Chapter 22.06 (Establishment of Zoning Districts) and Chapter 22.116 (Development Code, Zoning Map, Community Plan, and Countywide Plan Amendments), and pursuant to Marin County Development Code Section 22.116.050 (A.) and (C.), can be made to approve the proposed amendments to the Development Code (Title 22).

A. The proposed text amendments are consistent with the goals, policies, objectives, and programs of the Countywide Plan (CWP) as stated in Findings IV and XIII above and are necessary to further the implementation of the CWP policies promoting energy efficiency and encouraging the use of renewable and alternative energy resources while ensuring the orderly planned growth and protection of natural resources and the environment.

B. The proposed amendments are internally consistent with other applicable provisions of the Marin County Development Code (Title 22).

C. The proposed amendments will not be detrimental to the public interest, health, safety, convenience, or welfare of the County.

SECTION II: AMENDMENTS TO THE MARIN COUNTY DEVELOPMENT CODE (TITLE 22)

NOW, THEREFORE, BE IT RESOLVED that the Marin County Board of Supervisors hereby adopts an Ordinance, which would incorporate the following text amendments to the Marin County Development Code (Title 22) as they pertain to:

Section 22.32.180 - Wind Energy Conversion Systems (WECS); P27-126 cont.

Sections 22.08.030, 22.10.030, 22.12.030 and 22.14.030 – Allowed Uses and Permit Requirements;

Section 22.20.060 – Height Measurement and Height Limit Exceptions; and

Section 22.130.030 W. Definitions "W" WECS.

The proposed changes are shown in Exhibit "A" of this ordinance.

NOW, THEREFORE, BE IT FURTHER RESOLVED that the Marin County Board of Supervisors finds that the applicability of the proposed amendments to existing projects that are in the development review process shall be determined by the requirements of Marin County Code Section 22.01.040.F.

SECTION III: EFFECTIVE DATE

This Ordinance shall be and is hereby declared to be in full force and effect as of thirty-five (30) days from and after the date of its passage. The Ordinance shall be published once before the expiration date of fifteen (15) days after its passage, with the names of the Supervisors voting for and against the same in the Marin Independent Journal, a newspaper of general circulation published in the County of Marin.

SECTION IV: VOTE

PASSED AND ADOPTED at a regular meeting of the Board of Supervisors of the County of Marin, State of California, on the 10th day of August 2010, by the following vote, to wit:

AYES:	SUPERVISORS:	Susan L. Adams, Harold C. Brown, Jr., Charles McGlashan, Steve Kinsey, Judy Arnold
NOES:	NONE	
ABSENT:	NONE	

Judy Arnold
PRESIDENT, BOARD OF SUPERVISORS

ATTEST:

M Attymel
CLERK

P27-126 cont.

EXHIBIT "A"

PROPOSED TEXT AMENDMENTS
MARIN COUNTY DEVELOPMENT CODE (TITLE 22)

22.32.180 – Wind Energy Conversion Systems (WECS)

This Section establishes permit requirements for planned district and non-planned district zones and standards for the development and operation of Wind Energy Conversion Systems (WECS) in compliance with Marin County policies and State and Federal laws and allows and encourages the safe, effective, and efficient use of WECS in order to reduce consumption of utility supplied electricity.

A. Permit requirements. Small and Medium Wind Energy Conversion Systems (WECS) are allowed in all zoning districts, except the RF (Floating Home Marina) zoning district, subject to the following general requirements. Large WECS are allowed only in agricultural zoning districts (A3-A60, ARP, APZ) with a minimum lot size of 20 acres, subject to the following general requirements.

1. **Planned Zoning Districts.**

a. Small WECS in the APZ zoning district and Small Roof-Mounted and Small Non-Grid-Tied Agricultural WECS, located in parcels with a minimum lot size of one acre in the ARP zoning district and all other planned zoning districts that are not identified in Section 22.32.190.A.1.b., are allowed as a ministerial permit subject to the development standards in Section 22.32.180.B.1. and Section 22.32.180.B.5.

P27-126 cont.

b. Small Roof-Mounted and Small Non-Grid-Tied Agricultural WECS, located in parcels that are less than one acre in the ARP zoning district and all other Small WECS in planned zoning district zones that are not identified herein or in Section 22.32.190.A.1.a., shall require Design Review approval subject to the development standards in Section 22.32.180.B.2. and Section 22.32.180.B.5.

c. Medium WECS, located in planned district zones, shall require Design Review approval, subject to the development standards in Section 22.32.180.B.3. and Section 22.32.180.B.5.

d. Large WECS, located in planned district zones, shall require the approval of a Master Plan and Precise Development Plan subject to the development standards and requirements outlined in Section 22.32.180.B.4. and Section 22.32.180.B.5., unless the Master Plan and Precise Development Plan requirements are waived in compliance with Section 22.44.040 (Waiver of Master Plan/Precise Development Plan Review) and a Use Permit and Design Review are required instead.

2. **Conventional Zoning Districts.**

a. Small WECS, located in conventional agricultural zoning districts and Small Roof-Mounted and Small Non-Grid Tied Agricultural WECS located in parcels with a minimum lot size of one acre in conventional non-agricultural zoning districts, are allowed as a ministerial permit subject to the development standards outlined in Section 22.32.180.B.1. and Section 22.32.180.B.5.

b. Small WECS, located in parcels that are less than one acre in all other conventional non-agricultural zoning districts and Small Freestanding WECS in conventional agricultural zoning districts that are not identified herein or in Section 22.32.180.A.2.a., shall require Design Review approval subject to the development standards outlined in Section 22.32.180.B.2. and Section 22.32.180.B.5.

c. Medium WECS, located in conventional zoning districts, shall require Design Review approval subject to the development standards outlined in Section 22.32.180.B.3. and Section 22.32.180.B.5.

d. Large WECS, located in conventional zoning districts, shall require Use Permit and Design Review approval subject to the development standards outlined in Section 22.32.180.B.4. and Section 22.32.180.B.5.

P27-126 cont.

3. **Summary of Permit Requirements.**

TABLE 3-8
WECS PERMIT REQUIREMENTS

	Small						Medium	Large
	Roof-Mounted		Non-Grid-Tied Agricultural Uses			Freestanding	Freestanding	Freestanding
Parcel Size (Acres)	<1	≥1	<1	≥1 – <10	≥10	Not applicable	Not applicable	≥20
RF (Floating Home Marina) Zoning District	Not Allowed	Not Allowed	Not Allowed	Not Allowed	Not Allowed	Not Allowed	Not Allowed	Not Allowed
A3-A60 Zoning Districts	Ministerial[1]	Ministerial[1]	Ministerial[1]	Ministerial[1]	Ministerial[1]	Ministerial[1]	Design Review[2]	Use Permit/Design Review[4]
APZ Zoning District	Ministerial[1]	Ministerial[1]	Ministerial[1]	Ministerial[1]	Ministerial[1]	Ministerial[1]	Design Review[2]	Master Plan/PDP[3,4]
ARP Zoning District	Design Review[2]	Ministerial[1]	Use Permit/Design Review[2]	Design Review[2]	Ministerial[1]	Design Review[2]	Design Review[2]	Master Plan/PDP[3,4]
A2 and all Other Zoning Districts	Design Review[2]	Ministerial[1]	Use Permit/Design Review[2]	Design Review[2]	Ministerial[1]	Design Review[2]	Design Review[2]	Not Allowed

[1] Exceptions to standards in Table 3-9 shall be considered through the Design Review Process.
[2] Exceptions to standards in Table 3-9 shall be considered through the Use Permit Process.
[3] If Master/Precise Development Plan requirement is waived, Use Permit and Design Review will be required.
[4] Exceptions to standards in Table 3-9 shall be considered through the permit process.

4. **Time limits.** The approval for a Large WECS shall be granted for a term of not less than 10 years, except that an approval shall lapse if a Large WECS becomes inoperative or abandoned for a period of more than one year. The approval for a Small or Medium WECS shall be for an indefinite period, except that an approval shall lapse if a Small or Medium WECS becomes inoperative or abandoned for a period of more than one year.

5. **Applicability.** In addition to the provisions of Section 22.32.180, all other applicable provisions of this Development Code shall apply to a new WECS land use. In the event there is any conflict between the provisions of this section and any other provision of this Development Code, the more restrictive provision shall apply.

6. **Meteorological towers (Met Towers).** For the purpose of the Wind Energy Conversion System Ordinance, meteorological towers are those towers which have been temporarily installed to measure wind speed and directions plus other data relevant to siting WECS. Installations of temporary (up to one year) meteorological towers shall be considered through the Temporary Use Permit process pursuant to Chapter 22.50 (Temporary Use Permits).

B. Development standards.

1. **Small WECS (Ministerial).** A Building Permit for a Small WECS located in an agricultural zoning district pursuant to this Section shall be issued by the Agency Director upon submission of a Building Permit application containing the information specified in applicable sections of this Development Code and a determination by the Agency Director that the proposed use and development meets the development standards in Section 22.32.180.F. and Sections 22.32.180.G.1., G.2., G.5., G.6., G.7., and G.9.a. Before issuance of a building permit, the County shall record a notice of decision against the title of the property stipulating that the WECS must be dismantled and removed from the premises if it has been inoperative or abandoned for a period of more than one year.

P27-126 cont.

2. **Small WECS (Discretionary).**

   a. Small WECS shall be subject to the development standards in Section 22.32.180.B.5., Table 3-9. Exceptions to the standards in Section 22.32.180.B.5., Table 3-9 for Small WECS shall be considered through the Use Permit process pursuant to Chapter 22.48 (Use Permits).

   b. Small WECS shall comply with the development standards and requirements contained in Section 22.32.180.C. through Section 22.32.180.H.

3. **Medium WECS.**

   a. Medium WECS shall be subject to the development standards in Section 22.32.180 B.5., Table 3-9. Exceptions to the standards in Section 22.32.180 B.5., Table 3-9 for Medium WECS shall be considered through the Use Permit process pursuant to Chapter 22.48 (Use Permits).

   b. Medium WECS shall comply with the development standards and requirements contained in Section 22.32.180.C through Section 22.32.180.H.

4. **Large WECS.**

   a. Large WECS shall be subject to the development standards in Section 22.32.180.B.5., Table 3-9. Exceptions to the standards in Section 22.32.180 B.5., Table 3-9 for Large WECS shall be considered through the Master Plan process pursuant to Chapter 22.44 (Master Plans and Precise Development Plans) or Use Permit process pursuant to Chapter 22.48 (Use Permits).

   b. Prior to approval, Large WECS are subject to submittal of a comprehensive WECS Environmental Assessment prepared by a qualified consultant approved by the Marin County Environmental Coordinator. The WECS Environmental Assessment shall be prepared in consultation with the County to determine the development capabilities and physical and policy constraints of the property. The WECS Environmental Assessment shall include a mapped inventory and data base of the biological and physical characteristics of the project area. The WECS Environmental Assessment shall include a mapped delineation of the project site's sensitive environmental areas including, but not necessarily limited to: earthquake fault zones, geological hazardous areas, wetlands, watercourses and water bodies, prime agricultural lands, special status species habitats, prominent ridgelines, view corridors, and wind zones. The WECS Environmental Assessment shall include a Bird and Bat Study, as defined in Section 22.32.180.G.9. Based upon the findings, constraints, conclusions and recommendations of the WECS Environmental Assessment, specific requirements for siting and design shall be identified.

   c. Large WECS shall comply with the development standards and requirements contained in Section 22.32.180.C. through Section 22.32.180.H.

   d. The maximum number of Large WECS that is allowed per parcel shall be established through the permit process.

P27-126 cont.

5. **Summary of Development Standards.**

TABLE 3-9
WECS DEVELOPMENT STANDARDS

	Small				Medium			Large
	Roof-Mounted	Non-Grid-Tied Agricultural Uses		Freestanding	Freestanding			Freestanding
Total Height	≤ 10 feet (above roof line)	≤ 40 feet	> 40 – ≤100 feet	≤ 40 feet	>40 – ≤ 100 feet	>100 – ≤ 150 feet	>150 – ≤ 200 feet	>200 feet
Min. Height of Lowest Position of Blade Above Grade	Not applicable	15 feet	15 feet	15 feet	15 feet	30 feet	30 feet	30 feet
Max. Rotor Blade Radius (HAWT)/ Max. Rotor Blade Diameter (VAWT)	7.5 feet/5 feet	0.5 x tower height/5 feet	0.5 x tower height/5 feet	0.5 x tower height/5 feet	0.5 x tower height	0.5 x tower height	0.5 x tower height	Project specific
Min. Setback from Tip of Blade to Property Line	0.5 x total height	0.5 x total height	0.5 x total height	0.5 x total height	1 x total height	1.5 x total height	2 x total height	2 x total height
Max. Units/Parcel	1	1	1	1	2	2	2	Project specific
Min. Unit Separation	Not applicable	Not applicable	Not applicable	Not applicable	1 x tower height	1 x tower height	1 x tower height	Project specific
Min. Setback from Habitable Structures	Not applicable	1 x total height	1 x total height	1 x total height	1 x total height	1 x total height	1 x total height	2 x total height
Min. Setback from Prominent Ridgeline	Not applicable	Not applicable	Minimum of 300 feet horizontally or 100 feet vertically	Not applicable	Minimum of 300 feet horizontally or 100 feet vertically	Minimum of 300 feet horizontally or 100 feet vertically	Minimum of 300 feet horizontally or 100 feet vertically	Minimum of 300 feet horizontally or 100 feet vertically

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C. **Public notice.** Where required, a Notice of the required application(s) shall be provided in compliance with Section 22.118.020 (Notice of Hearing or Administrative Action).

Notice of a discretionary permit application for any WECS within five miles of Federal, State, or regional park property shall be provided to the superintendent of the appropriate park.

D. **Site and design requirements:**

1. **General standards.** No Small, Medium, or Large WECS or supporting infrastructure shall be allowed:

   a. Within five times the total height or 300 feet, whichever is greater, of a known nest or roost of a listed State or Federal threatened or endangered species or California Department of Fish and Game designated bird or bat 'species of special concern' (unless siting of the WECS preceded nest or roost establishment) based on the findings and conclusions of the required Bird and Bat Study as defined in Section 22.32.180 G.9.

b. Within five times the total height or 300 feet, whichever is greater, of a known or suspected avian migratory concentration point based on the findings and conclusions of the required Bird and Bat Study as defined in Section 22.32.180 G.9.

c. Within 1.5 times the total height or 100 feet, whichever is greater, of a Stream Conservation Area (SCA), a Wetlands Conservation Area (WCA), a State or Federal listed special status species habitat area, a designated archaeological or historical site, or a water course, wetland, pond, lake, bayfront area habitat island, or other significant water body with suitable avian habitat based on the findings and conclusions of Bird and Bat Study as defined in Section 22.32.180 G.9.

c. Where prohibited by any of the following:
   1. The Alquist-Priolo Earthquake Fault Zoning Act.
   2. The terms of any conservation easement or Williamson Act contract.
   3. The listing of the proposed site in the National Register of Historic Places or the California Register of Historical Resources.

E. Appearance and visibility:

In addition to any conditions which may be required by Master Plan and Precise Development Plan or Design Review and Use Permit approvals, Small, Medium, and Large WECS shall comply with the following design standards:

1. WECS shall be located downslope a minimum of 300 feet horizontally or 100 feet vertically, whichever is more restrictive, from a visually prominent ridgeline, unless it can be demonstrated through submittal of a County accepted Wind Measurement Study that no other suitable locations are available on the site. If this is the case, then the Wind Study will be one amongst all other standards that would be evaluated in considering whether and where the WECS application should be approved within the ridge setbacks.

2. WECS shall be designed and located to minimize adverse visual impacts from public viewing places, such as roads, trails, scenic vistas, or parklands and from adjacent properties.

3. No wind turbine, tower, or other component associated with a WECS may be used to advertise or promote any product or service. Brand names or advertising associated with any WECS installation shall not be visible from offsite locations. Only appropriate signs warning of the WECS installation are allowed.

4. Colors and surface treatments, materials and finishes of the WECS and supporting structures shall minimize visual disruption. Exterior materials, surfaces, and finishes shall be non-reflective to reduce visual impacts.

5. Exterior lighting on any WECS or associated structure shall not be allowed except that which is specifically required in accordance with Federal Aviation Administration (FAA) regulations. Wind tower and turbine lighting must comply with FAA requirements and be at the lowest intensity level allowed.

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6. WECS shall be located in a manner which minimizes their visibility from any existing Federal parklands.

7. All new electrical wires and transmission lines associated with WECS shall be placed underground except for connection points to a public utility company infrastructure. This standard may be modified by the Director if the project area is determined to be unsuitable for undergrounding of infrastructure due to reasons of excessive grading, biological impacts, or similar factors.

8. Construction of on-site access routes, staging areas, excavation, and grading shall be minimized. Excluding the permanent access roadway, areas disturbed due to construction shall be re-graded and re-vegetated to as natural a condition as soon as feasibly possible after completion of installation.

9. All permanent WECS related equipment shall be weather-proof and tamper-proof.

10. If a climbing apparatus is present on a WECS tower, access control to the tower shall be provided by one of the following means:

    a. Tower-climbing apparatus located no closer than 12 feet from the ground;

    b. A locked anti-climb device installed on the tower; or

    c. A locked, protective fence at least six feet in height that encloses the tower.

11. WECS shall be equipped with manual and automatic over-speed controls. The conformance of rotor and over-speed control design and fabrication with good engineering practices shall be certified by the manufacturer.

12. Latticed towers shall be designed to prevent birds from perching or nesting on the tower.

13. The use of guy wires shall be avoided whenever feasible. If guy wires are necessary, they shall be marked with bird deterrent devices as recommended by the U S Fish and Wildlife Service or the California Department of Fish and Game.

P27-126 cont.

F. **Noise.** Small, Medium, and Large WECS shall not result in a total noise level that exceeds 50 dBA during the daytime (7:00 AM to 10:00 PM) and 45 dBA during the nighttime (10:00 PM to 7:00 AM) as measured at any point along the common property lines of adjacent properties except during short-term events such as utility outages, severe weather events, and construction or maintenance operations, as verified by specifications provided by the manufacturer.

G. **Application submittal requirements.** Small, Medium, and Large WECS permit applications shall include, but may not be limited to, the following information:

1. A plot plan of the proposed development drawn to scale showing:

a. Acreage and boundaries of the property;

b. Location of all existing structures, their use and dimensions within five times the height of the proposed WECS;

c. Location within a distance of five times the total height of the proposed WECS of all wetlands, ponds, lakes, water bodies, watercourses, listed State or Federal special status species habitats, habitat islands, and designated archaeological or historical sites;

d. Location of all proposed WECS and associated structures, and their designated use, dimensions, and setback distances;

e. Location of all areas to be disturbed by the construction of the proposed WECS project including access routes, trenches, grading and staging areas; and

f. The locations and heights of all trees taller than 15 feet within five times the height of the proposed WECS and the locations, heights, and diameters (at breast height) of all tress to be removed.

2. Elevations of the components of the proposed WECS.

3. A description of the measures taken to minimize adverse noise, transmission interference, and visual and safety impacts to adjacent land uses including, but not limited to, over-speed protection devices and methods to prevent public access to the structure.

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4. A post-installation erosion control, revegetation, and landscaping plan.

5. Standard drawings and an engineering analysis of the system's tower, showing compliance with the Uniform Building Code (UBC), the International Building Code (IBC) or the California Building Code and certification by a professional mechanical, structural, or civil engineer licensed by this state. However, a wet stamp shall not be required, provided that the application demonstrates that the system is designed to meet the UBC or IBC requirements for wind exposure D, the UBC or IBC requirements for Seismic Zone 4, and the requirements for a soil strength of not more than 1,000 pounds per square foot, or other relevant conditions normally required by a local agency.

6. A line drawing of the electrical components of the system in sufficient detail to allow for a determination that the manner of installation conforms to the National Electric Code.

7. Written evidence that the electric utility service provider that serves the proposed site has been informed of the owner's intent to install an interconnected customer-owned electricity generator, unless the owner does not plan, and so states so in the application, to connect the system to the electricity grid.

8. Wind Measurement Study. A wind resource assessment study, prepared by a qualified consultant approved by the Marin County Environmental Coordinator, may be required. The study shall be performed for a minimum 6-month period during prime wind season, at the proposed site prior to the acceptance of an application. The study may require the installation

of a meteorological tower, erected primarily to measure wind speed and directions plus other data relevant to appropriate siting. The study shall include any potential impacts on, or in conjunction with, existing WECS within a minimum of two miles of the proposed WECS site.

9. Bird and Bat Study. Before issuance of County building or planning permit approvals:

   a. All WECS projects shall require the submittal of a Bird and Bat Study prepared by a qualified consultant approved by the Marin County Environmental Coordinator using the "California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development" (California Energy Commission and California Department of Fish and Game), or any superseding State or Federal Guidelines, the State Natural Diversity Data Base, Partners in Flight Data Base, the Migratory Bird Treaty Act, the Bald and Golden Eagle Protection Act, and field data and counts from local environmental groups. The Bird and Bat Study shall identify any listed State or Federal threatened or endangered species, California Department of Fish and Game designated bird or bat 'species of special concern', or raptors found to nest or roost in the area of the proposed WECS site. The study shall identify periods of migration and roosting and assess pre-construction site conditions and proposed tree removal of potential roosting sites. The Community Development Agency will maintain an inventory of all Bird and Bat Studies that are filed pursuant to the requirements of the WECS ordinance on the Agency's website. If the Bird and Bat Study for a proposed ministerial Small WECS project finds that there is a potential for impacts to any listed State or Federal threatened or endangered species or California Department of Fish and Game designated bird or bat 'species of special concern' found to nest or roost in the area of the proposed WECS site, the project will become discretionary and require a Resource Management and Contingency Plan as described in G.9.b. below. P27-126 cont.

   b. Small, Medium, and Large WECS projects shall require the Bird and Bat Study to include a Resource Management and Contingency Plan to: (1) provide for pre-approval and post-construction monitoring and reporting; and (2) provide mitigation to reduce bird and bat mortality rates, if necessary.

10. Visual Simulations. Visual simulations taken from off-site views, including from adjacent properties, as determined by the Community Development Agency shall be submitted showing the site location with the proposed WECS installed on the proposed site.

11. Project-Specific Acoustical Analysis. A project-specific acoustical analysis may be required that would simulate the proposed WECS installation to assure acceptable noise levels and, if necessary, provide measures to comply with applicable County noise standards.

H. Post approval requirements. Small, Medium, and Large WECS permit applications shall be subject to the following:

1. A post-construction avian and bat monitoring program may be required of the owner during periods of nesting, roosting, foraging, and migration. The application of this requirement shall be in accordance with criteria established by a governmental agency, such as the U. S. Fish and Wildlife Service (USFWS) or the California Department of Fish and Game (CDFG), or by PRBO Conservation Science. The required monitoring program shall be conducted by a professional biologist or an ornithologist approved by the Marin County Environmental Coordinator. Monitoring protocol shall be utilized as set forth in the "California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development" (California Energy Commission and California Department of Fish and Game). Operation of a WECS determined to be detrimental to avian or bat wildlife may be required to cease operation for a specific period of time or may be required to be decommissioned.

2. Before issuance of a building permit, the owner/operator of any discretionary WECS shall enter into a WECS Decommissioning and Reclamation Plan and Agreement with the County, outlining the anticipated means and cost of removing the WECS at the end of its serviceable life or upon becoming a discontinued use if it remains inoperable for a period of more than one year . The owner/operator shall post suitable financial security as determined by the County in order to guarantee removal of any WECS that is non-operational or abandoned. The plan must include in reasonable detail how the WECS will be dismantled and removed. The WECS must be dismantled and removed from the premises if it has been inoperative or abandoned for a period of more than one year. The WECS Decommissioning and Reclamation Plan (Plan) shall include removal of all equipment and may require removal of all foundations and other features such as fencing, security barriers, transmission lines, disposal of all solid and hazardous water in accordance with local, State and Federal regulations, and access roads to the satisfaction of the Director. The Plan shall include restoration of the physical state as existed before the WECS was constructed, and stabilization and re-vegetation of the site as necessary to minimize erosion. The owner/operator, at his/her expense shall complete the removal within 90 days following the one-year period of non-operation, useful life, or abandonment, unless an extension for cause is granted by the Director or a plan is submitted outlining the steps and schedule for returning the WECS to service to the satisfaction of the Director. The WECS Decommissioning and Reclamation Plan Agreement shall be recorded by the Community Development Agency against the title of the property.

3. Any encumbrances placed on a parcel or parcels due to the installation of a WECS system shall remain in effect for as long as the WECS is on the site, and these encumbrances shall hold equal weight and be cumulative with respect to other limitations on the development of the parcel or parcels. Such encumbrances may not be the basis for granting variances or any other exception to the Marin County Development Code or Marin Countywide Plan regardless of any other additional development constraints imposed on the parcel or parcels. It is the owner's due diligence responsibility to ensure the siting of the WECS will not impose future development restrictions that are unacceptable to the owner.

4. Construction monitoring of individual projects may be required to include, but not be limited to, surveys and/or inspections as needed, to ensure on-site compliance with all permit requirements, until implementation of requirements is complete.

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5. Upon the completion of construction and before final inspection, solid and hazardous wastes, including, but not necessarily limited to, packaging materials, debris, oils and lubricants, shall be removed promptly from the site and disposed of in accordance with all applicable County, State and Federal regulations. No hazardous materials shall be stored on the WECS site.

22.130.030 – Definitions of Specialized Terms and Phrases.

W. Definitions, "W."

Wind Energy Conversion System (WECS) (land use). This land use is defined as any machine that converts and then stores or transfers the kinetic energy in the wind into a usable form of mechanical or electrical energy. The WECS consists of all parts of the system, including the base or foundation tower, wind turbine, generator, rotor, blades, supports, and transmission equipment. Additional WECS definitions include:

Small Wind Energy Conversion System. This land use is defined as: (1) any small freestanding WECS up to 40 feet in total height above grade; (2) a roof-mounted WECS utilizing a horizontal-axis wind turbine (HAWT) or a vertical-axis wind turbine (VAWT) and not exceeding 10 feet in height above the roof line of the structure; or (3) a non-grid-tied WECS used solely to pump water for agricultural uses and not exceeding 100 feet in total height above grade.

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Medium Wind Energy Conversion System. This land use is defined as any WECS project between 40 feet and 200 feet in total height above grade.

Large Wind Energy Conversion System. This land use is defined as any WECS project greater than 200 feet in total height above grade.

Avian Migratory Concentration Point. Avian migratory concentration point refers to both the place of departure and the destination of birds from one region to another, especially as a result of seasonal or periodic movement in order to breed, seek food, or to avoid unsuitable weather conditions.

Guy Wires. Wires used to secure wind turbines or towers that are not self-supporting.

Habitat Island. A habitat island refers to an isolated area of land generally surrounded by water that provides valuable foraging and roosting habitat for resident and migratory birds and wildlife, particularly during winter and early spring months.

Horizontal Axis WECS. A horizontal-axis wind turbine (HAWT) is an energy conversion system whose rotor axis is substantially parallel to the wind flow. The main rotor shaft and electrical generator is at the top of a tower and must be pointed into the wind.

Meteorological Tower (Met Tower). For the purpose of the Wind Energy Conversion System Ordinance, meteorological towers are those towers which have been temporarily installed to measure wind speed and directions plus other data relevant to siting WECS.

Rotor Blade. The part of a wind turbine that interacts with wind to produce energy. It consists of the turbine's blades and the hub to which the blades attach.

Tower. The tower is the support structure, including guyed monopole and lattice types, upon which a wind turbine or other mechanical device is mounted as part of a wind energy system.

Tower Height (WECS). The tower height is the height from natural grade to the upper-most fixed portion of the tower excluding the length of any vertical axial-rotating turbine blade.

Total Height (System Height). The total WECS height is the height from natural grade to the fixed portion of the tower and includes the highest vertical length of any extensions above grade, such as the rotor blades when being operated.

Vertical Axis WECS. A vertical-axis wind turbine (VAWT) is an energy conversion system whose rotor axis is substantially perpendicular to the wind flow. The main rotor shaft is arranged vertically and the turbine does not need to be pointed into the wind to be effective.

Wind Turbine. A wind turbine is a rotating machine which converts the kinetic energy in wind into mechanical energy, which is then converted to electricity.

Wind Turbine Generator. A wind turbine generator converts mechanical energy into electrical energy by means of attaching a generator to a rotating part of a wind turbine. P27-126 cont.

22.20.060 – Height Measurement and Height Limit Exceptions.

E. Exceptions to height limits:

4. Spires, towers, water tanks, etc. Chimneys, cupolas, flag poles, gables, monuments, spires, towers (e.g., transmission, utility, etc.), water tanks, similar structures and necessary mechanical appurtenances may be allowed to exceed the height limit established for the applicable zoning district, subject to the following standards.

   a. The structure shall not cover more than fifteen percent of the lot area at any level.

   b. The area of the base of the structure shall not exceed one thousand six hundred square feet.

   c. No gable, spire, tower or similar structure shall be used for sleeping or eating quarters or for any commercial purpose other than that which is incidental to the allowed uses of the primary structure.

   d. No structure shall exceed a maximum height of one hundred fifty feet above grade, except for parcels in the A2 or IP zoning districts.

22.08.030 – Agricultural District Land Uses and Permit Requirements

TABLE 2-1
ALLOWED USES AND PERMIT REQUIREMENTS
FOR AGRICULTURAL AND RESOURCE-RELATED DISTRICTS

	A2 Agriculture Limited	A3 to A60 Agriculture and Conservation	ARP Agriculture Residential Planned	
AGRICULTURAL, RESOURCE AND OPEN SPACE USES				
Agricultural accessory activities	P	P	P	
Agricultural accessory structures	P	P	MP	22.32.030
Agricultural processing uses	P/U	P/U	MP/MU	
Commercial gardening	P	P	P	
Crop production	P	P	P	
Dairy operations	P	P	P	22.32.030
Fish hatcheries and game reserves	--	P	MP	
Livestock operations, grazing	P	P	P(4)	22.32.030
Livestock operations, large animals	P(4)	P(4)	P(4)	22.32.030
Livestock operations, sales/feed lots, stockyards	U	P	MP(4)	22.32.030
Livestock operations, small animals	(4)	(4)	P(4)	22.32.030
Mariculture/aquaculture	P	P	MP	
Mineral resource extraction	--	U	MU	Chapter 23.06
Nature preserves	P	P	P	
Timber Harvesting	U	U	U	Title 23
Water conservation dams and ponds	P	P	MP	
Small WECS	P	P	MP	22.32.180
Medium WECS	P	P	MP	22.32.180
Large WECS	--	U	MU	22.32.180
MANUFACTURING AND PROCESSING USES				
Cottage industry	U	U	MU	22.32.060
Recycling - Scrap and dismantling yards	U	U	MU	

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22.10.030 – Residential District Land Uses and Permit Requirements.

TABLE 2-3
ALLOWED USES AND PERMIT REQUIREMENTS FOR
SINGLE-FAMILY RESIDENTIAL DISTRICTS

LAND USE (1)	PERMIT REQUIREMENT BY DISTRICT					See Standards in Section:
	RA Residential Agriculture	RR Residential Restricted	RE Residential Estate	RI Residential Single-Family	RSP Residential Single-Family Planned	
AGRICULTURAL, RESOURCE AND OPEN SPACE USES						
Agricultural accessory structures	P	--	P	P	MP(4)	22.32.030
Commercial gardening	P	--	P	P	MP	
Dairy operations	P(6)	--	--	--		22.32.030
Fish hatcheries and game reserves	--	--	--	--	MU(4)	
Livestock operations, grazing	--	--	--	--	MU(4,5)	22.32.030
Livestock operations, large animals	(5)	--	(5)	--	MU(4,5)	22.32.030
Livestock operations, sales/feed lots, stockyards	--	--		--	MU(4,5)	22.32.030
Livestock operations, small animals	(5)	(5)	(5)	(5)	MP(5)	22.32.030
Mariculture/aquaculture	--	--	--	--	MU(4)	
Nature preserves	--	--	--	--	MP	
Plant nurseries, with on-site sales	U	U	U	U	MU	
Plant nurseries, without on-site sales	P	P	P	P	MP	
Small WECS	P	P	P	P	MP	22.32.180
Medium WECS	P	P	P	P	MP	22.32.180
Large WECS	--	--	--	--	--	22.32.180

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cont.

TABLE 2-4
ALLOWED USES AND PERMIT REQUIREMENTS FOR MULTI-FAMILY RESIDENTIAL DISTRICTS

LAND USE (1)	PERMIT REQUIREMENT BY DISTRICT				See Standards in Section:
	R2 Residential Two Family	RMP Residential Multiple Planned	RX Residential Mobile Home Park	RF Floating Home Marina	
AGRICULTURAL, RESOURCE AND OPEN SPACE USES					
Agricultural accessory structures	P	MP(4)	--	--	22.32.030
Commercial gardening	P	MP(4)	--	--	
Dairy operations	--	MU(4)	--	--	22.32.030
Fish hatcheries and game reserves	--	MU(4)	--	--	
Livestock operations, grazing	--	MU(4,5)	--	--	22.32.030
Livestock operations, large animals	--	MU(4,5)	--	--	22.32.030
Livestock operations, sales/feed lots, stockyards	--	MU(4,5)	--	--	22.32.030
Livestock operations, small animals	(5)	MP(5)	--	--	22.32.030
Mariculture/aquaculture	--	MU(4)	--	--	
Nature preserves	--	MU	--	--	
Plant nurseries, with on-site sales	U	MU	--	--	
Plant nurseries, without on-site sales	P	MP	--	--	
Small WECS	P	MP	MP	--	22.32.180
Medium WECS	P	MP	MP	--	22.32.180
Large WECS	--	--	--	--	22.32.180

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22.12.030 – Commercial/Industrial District Land Uses and Permit Requirements.

TABLE 2-6 - ALLOWED USES AND PERMIT REQUIREMENTS FOR COMMERCIAL DISTRICTS

LAND USE (1)	PERMIT REQUIREMENT BY DISTRICT				See Standards in Section:
	VCR Village Commercial Residential	**RMPC** Residential Commercial Multiple Planned	**C1** Retail Business	**CP** Planned Commercial	
AGRICULTURAL, RESOURCE, AND OPEN SPACE USES					
Agricultural accessory structures	--	MU(5)	--	--	22.32.030
Commercial gardening	P	MP(5)	P	MP	
Fisheries and game reserves	--	MU(5)	--	--	
Livestock operations, grazing	--	MU(4, 5)	--	--	22.32.030
Livestock operations, large animals	--	MU(5)	--	--	22.32.030
Livestock operations, small animals	--	MU(4, 5)	--	--	22.32.030
Mariculture/aquaculture	--	MU(5)	--	--	
Nature preserves	--	MU	--	--	
Plant nurseries, with on-site sales	P	MU(5)	P	MP	
Plant nurseries, without on-site sales	P	MP	P	MP	
Small WECS	P	MP	P	MP	22.32.180
Medium WECS	P	MP	P	MP	22.32.180
Large WECS	--	--	--	--	22.32.180

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TABLE 2-7
ALLOWED USES AND PERMIT REQUIREMENTS
FOR COMMERCIAL AND INDUSTRIAL DISTRICTS

LAND USE (1)	PERMIT REQUIREMENT BY DISTRICT					See Standards in Section:
	AP Admin and Professional	OP Planned Office	H1 Limited Roadside Business	RCR Resort and Commercial Recreation	IP Industrial Planned	
AGRICULTURAL, RESOURCE AND OPEN SPACE USES						
Commercial gardening	--	--	P	--	--	
Plant nurseries	--	--	P	--	--	
Small WECS	P	MP	P	MP	MP	22.32.180
Medium WECS	P	MP	P	MP	MP	22.32.180
Large WECS	--	--	--	--	--	22.32.180

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cont.

22.14.030 – Special Purpose District Land Uses and Permit Requirements.

TABLE 2-9
ALLOWED USES AND PERMIT REQUIREMENTS
FOR SPECIAL PURPOSE DISTRICTS

LAND USE (1)	PERMIT REQUIREMENT		See Standards in Section:
	OA Open Area	**PF** Public Facilities	
AGRICULTURAL, RESOURCE, AND OPEN SPACE USES			
Agricultural accessory structures	P	--	22.32.030
Commercial gardening	P	--	
Crop production	P	--	
Dairy operations	P(3)	--	
Fish hatcheries and game reserves	P	--	
Livestock operations, grazing	P	--	
Nature preserves	P(2)	U(2)	
Water conservation dams and ponds	P	--	
Small WECS	P	P	22.32.180
Medium WECS	P	P	22.32.180
Large WECS	--	--	22.32.180

KEY TO PERMIT REQUIREMENTS		
Symbol	Permit Requirement	Procedure is In Section:
P	Permitted use.	
U	Conditional use, Use Permit required.	Chapter 22.48
MP	Permitted use, Master Plan/Precise Development Plan required.	Chapter 22.44
MU	Conditional use, Use Permit required where authorized by Master Plan/PDP.	Chapter 22.44
--	Use not allowed. (See 22.02.020.E regarding uses not listed.)	

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Comment Letter P27

Community Wildfire Prevention & Mitigation Report

In response to Executive Order N-05-19

Prepared by:

California Department of Forestry and Fire Protection

P27-127

With Assistance From:

Governor's Office of Emergency Services

California National Guard

California Government Operations Agency

Governor's Office of Planning and Research

Department of Finance

California Natural Resources Agency

February 22, 2019

Contributors

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Governor's Office of Planning and Research

California Natural Resources Agency

Strategic Growth Council

Office of State Fire Marshal

California Air Resources Board

California Department of State Parks

California Department of Fish and Wildlife

California Department of Public Health

California Energy Commission

California Public Utilities Commission

California Department of Transportation

California Department of Industrial Relations

Sierra Nevada Conservancy

University of California Berkeley

University of California Cooperative Extension (UCANR)

Humboldt State University

California Forest Management Task Force

US Forest Service PSW Research Station

Natural Resources Conservation Service

North Coast Regional Water Quality Control Board

Central Valley Regional Water Quality Control Board

Lahontan Regional Water Quality Control Board

Los Angeles Regional Water Quality Control Board

California Fire Chief's Association

California Environmental Justice Alliance

Morongo Fire District

The Nature Conservancy

Resources Legacy Fund

Pacific Forest Trust

California League of Cities

California Fire Safe Council

The Red Cross

California Licensed Foresters Association

Sierra Forest Legacy

Trinity County Fire Safe Council

Lower Mattole Fire Safe Council and Mattole Restoration Council

Watershed Research and Training Center

ForEverGreen Forestry

The Fire Restoration Group

Mendocino/Humboldt Redwood Company

Green Diamond Resource Company

Sierra Pacific Industries

California Cattlemen's Association

Town of Portola Valley

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Executive Summary

California experienced the deadliest and most destructive wildfires in its history in 2017 and 2018. Fueled by drought, an unprecedented buildup of dry vegetation and extreme winds, the size and intensity of these wildfires caused the loss of more than 100 lives, destroyed thousands of homes and exposed millions of urban and rural Californians to unhealthy air.

Climate change, an epidemic of dead and dying trees, and the proliferation of new homes in the wildland urban interface (WUI) magnify the threat and place substantially more people and property at risk than in preceding decades. More than 25 million acres of California wildlands are classified as under very high or extreme fire threat, extending that risk over half the state.

Certain populations in our state are particularly vulnerable to wildfire threats. These Californians live in communities that face near-term public safety threats given their location. Certain residents are further vulnerable given factors such as age and lack of mobility. The tragic loss of life and property in the town of Paradise during the recent Camp Fire demonstrates such vulnerability.

Recognizing the need for urgent action, Governor Gavin Newsom issued Executive Order N-05-19 on January 9, 2019. The Executive Order directs the California Department of Forestry and Fire Protection (CAL FIRE), in consultation with other state agencies and departments, to recommend immediate, medium and long-term actions to help prevent destructive wildfires.

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With an emphasis on taking necessary actions to protect vulnerable populations, and recognizing a backlog in fuels management work combined with finite resources, the Governor placed an emphasis on pursuing a strategic approach where necessary actions are focused on California's most vulnerable communities as a prescriptive and deliberative endeavor to realize the greatest returns on reducing risk to life and property.

Using locally developed and vetted fire plans prepared by CAL FIRE Units as a starting point, CAL FIRE identified priority fuel reduction projects that can be implemented almost immediately to protect communities vulnerable to wildfire. It then considered socioeconomic characteristics of the communities that would be protected, including data on poverty levels, residents with disabilities, language barriers, residents over 65 or under five years of age, and households without a car.

In total, CAL FIRE identified 35 priority projects that can be implemented immediately to help reduce public safety risk for over 200 communities. Project examples include removal of hazardous dead trees, vegetation clearing, creation of fuel breaks and community defensible spaces, and creation of ingress and egress corridors. These projects can be implemented immediately if recommendations in this report are taken to enable the work. Details on the projects and CAL FIRE's analysis can be found online at http://calfire.ca.gov/fire_prevention/downloads/FuelReductionProjectList.pdf , which will remain updated in the coming months. The list of projects is attached to this report as Appendix C.

CAL FIRE has also worked with over 40 entities including government and non-government stakeholders to identify administrative, regulatory and policy actions that can be taken in the next 12 months to begin systematically addressing community vulnerability and wildfire fuel buildup through rapid deployment of resources. Implementing several of these recommended actions is necessary to execute the priority fuel reduction projects referenced above. Other recommendations are intended to put the state on a path toward long-term community protection, wildfire prevention, and forest health.

The recommendations in this report, while significant, are only part of the solution. Additional efforts around protecting lives and property through home hardening and other measures must be vigorously pursued by government and stakeholders at all levels concurrently with the pursuit of the recommendations in this report. California must adopt an "all of the above" approach to protecting public safety and maintaining the health of our forest ecosystems.

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It is important to note that California faces a massive backlog of forest management work. Millions of acres are in need of treatment, and this work—once completed—must be repeated over the years. Also, while fuels treatment such as forest thinning and creation of fire breaks can help reduce fire severity, wind-driven wildfire events that destroy lives and property will very likely still occur.

This report's recommendations on priority fuel reduction projects and administrative, regulatory, and policy changes can protect our most vulnerable communities in the short term and place California on a trajectory away from increasingly destructive fires and toward more a moderate and manageable fire regime.

Current Setting

While wildfires are a natural part of California's landscape, the fire season in California and across the West is starting earlier and ending later each year. Climate change is considered a key driver of this trend[1]. Warmer spring and summer temperatures, reduced snowpack, and earlier spring snowmelt create longer and more intense dry seasons that increase moisture stress on vegetation and make forests more susceptible to severe wildfire[2]. The length of fire season is estimated to have increased by 75 days across the Sierras and seems to correspond with an increase in the extent of forest fires across the state[3].

Climate change is acting as a force-multiplier that will increasingly exacerbate wildland fire issues over the coming decades[4]. The state can expect to experience longer fire seasons, increased frequency and severity of drought, greater acreage burned and related impacts such as widespread tree mortality and bark beetle infestation[5]. Decades of fire suppression have disrupted natural fire cycles and added to the problem.

California's forest management efforts have not kept pace with these growing threats. Despite good forest management work completed by the state and federal government and private landowners each year, our collective forest management work each year is currently inadequate to improve the health of millions of acres of forests and wildlands that require it. It is estimated that as many as 15 million acres of California forests need some form of restoration[6].

As wildfire threats have worsened over the last two years, wildfire response, preemptive fire prevention, and vegetation management to reduce fire severity and contain erratic wildfire have been intensified. Further action is imperative. While restoring forest health and resilience will take decades to achieve, the immediate actions recommended in this report can immediately begin to protect our most vulnerable communities.

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[1] (Flannigan et al 2000; Westerling, 2016)
[2] (Mote, 2005; Westerling, 2016)
[3] (Westerling, 2016)
[4] Simulations for California's Fourth Climate Change Assessment: Projecting Changes in Extreme Wildfire Events with a Warming Climate. http://www.climateassessment.ca.gov/techreports/docs/20180827-Projections_CCCA4-CEC-2018-014.pdf
[5] California Tree Mortality Task Force: Synthesis of Research into the Long-Term Outlook for Sierra Nevada Forests following the Current Bark Beetle Epidemic http://www.fire.ca.gov/treetaskforce/downloads/WorkingGroup/White_paper_on_recovery_06-12-18.pdf
[6] Forest Carbon Plan 2018

While it is not possible to eliminate wildfire risks in California, focused and deliberate action can protect communities and improve forest and fuels conditions to enable a more moderate and healthy wildfire cycle that can coexist with Californians.

Significant barriers to this work exist. Forest thinning and fuels reduction are expensive, and funding limitations constrain what can be achieved. Given this reality, it is critically important to focus funding and efforts on protecting vulnerable communities in high fire risk areas, utilizing no-cost and low-cost solutions where possible. For example, mobilizing the private sector by providing incentives to incorporate fuels reduction in commercial forest management on private lands can be an important part of this effort.

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Recommendations

Most urgently, this report identifies priority projects that can be implemented immediately to help protect our state's most vulnerable communities. While some communities are vulnerable to fire due to their location next to forests and wildlands, that vulnerability can be magnified by socioeconomic factors such as population age, car ownership, and lack of ingress or egress corridors.

To identify these priority projects, CAL FIRE developed a methodology to characterize communities' relative vulnerability. This methodology incorporates physical wildfire risks around communities and socioeconomic characteristics of these communities to understand the relative vulnerability of each community. This methodology integrates three primary analyses:

1. Identification of vulnerable communities based on the socioeconomic characteristics of communities that indicate vulnerability to wildfire;
2. Identification of priority fuel reduction projects based on existing CAL FIRE Unit Plans. Each of these Unit Plans has identified priority projects based on the place-specific expertise of CAL FIRE Unit personnel working in each region of the state; and
3. Evaluation of wildfire risk within the proposed project area.

A detailed explanation of this methodology is found in Appendix A.

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In addition to recommending priority projects for immediate implementation, this report recommends broader solutions for state government to consider in the immediate, near, and longer terms to ensure the work continues in a systematic way. Recommended short-term actions in this report encompass actions that can be taken immediately. Proposed mid-term actions are targeted for completion between July and December of this year. Long-term recommendations may be initiated quickly but will require more than a year to implement.

In developing these recommendations for action, CAL FIRE considered:

1. Actions needed to advance work before the peak of fire season later this year;
2. Work already underway in other venues; and
3. Actions that will prevent and mitigate wildfires to the greatest extent possible with an emphasis on environmental sustainability and protection of public health.

These efforts are meant to complement efforts already underway:

a. The Governor's Forest Management Task Force was created in June 2018 to coordinate actions needed across government. It is anticipated the Forest Management Task Force will continue to be a centralized hub of organizing and coordinating actions recommended under this report.
b. The Commission on Catastrophic Wildfire Cost and Recovery was established pursuant to SB 901 (Dodd, Chapter 626, Statutes of 2018). The Commission is tasked with making recommendations by July 2019 related to the costs of catastrophic wildfire, how these costs should be socialized in an equitable manner, and the potential to establish a fund to address the costs associated with catastrophic wildfires.
c. The California Public Utilities Commission's (CPUC) Wildfire Proceeding was initiated in 2018. Among other things, in coordination with CAL FIRE the CPUC's process will formalize enhanced wildfire mitigation plans currently under development by the electrical utilities pursuant to SB 901.
d. The 2018 Strategic Fire Plan is California's current plan for reducing community wildfire risk. The California Board of Forestry, the policy-setting body within CAL FIRE, recently updated California's Strategic Fire Plan[7]. That plan identifies priorities for CAL FIRE including evaluation of wildfire risk, working with property owners and local governments to plan for and mitigate those risks, and determining resource needs to response to fire outbreaks.
e. The 2018 State Hazard Mitigation Plan was developed by the California Office of Emergency Services (OES). CAL FIRE contributed to the recent update to California's Hazard Mitigation Plan[8], which contains specific information on hazard risk assessment, and tracks progress on various mitigation efforts developed in recent years.
f. The California Forest Carbon Plan released in 2018 summarized current and projected forest conditions and directed actions to achieve healthy and resilient wildland and urban forests and maintain forests as a carbon sink.

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[7] State Board of Forestry and Fire Protection, 2018 Strategic Fire Plan (August 22, 2018), available online at http://cdfdata.fire.ca.gov/pub/fireplan/fpupload/fpppdf1614.pdf.
[8] California State Hazard Mitigation Plan (September 2018), Chapter 8 "Fire Hazards: Risks and Mitigation," available online at https://www.caloes.ca.gov/HazardMitigationSite/Documents/011-2018%20SHMP_FINAL_Ch%208.pdf.

SUMMARY TABLE OF RECOMMENDATIONS

	Recommendation	Priority	Lead	Type
1	Direct CAL FIRE Units to complete priority fuel reduction projects.	I	CAL FIRE	Administrative
2	Authorize incident response to implement rapid treatment of fuels.	I	CAL FIRE	Administrative
3	Increase housing availability for fuel crew staff.	I	OES	Administrative
4	Suspend regulatory requirements as needed to complete fuels reduction projects in 2019.	I	All regulatory agencies	Regulations
5	Assess funding and personnel capacity within CAL FIRE and other departments and determine areas for additional investment and administrative actions to maximize effectiveness of current workforce.	I	CAL FIRE / CCC / DPR / CAL HR	Administrative
6	Align community education campaigns across all state and local entities.	I	Forest Management Task Force	Policy
7	Execute State Agency MOU for fuels reduction.	M	All relevant agencies	Policy
8	Identify options for retrofitting homes to new wildland urban interface standards.	M	CAL FIRE	Policy
9	Create incentives for fuels reduction on private lands.	M	All regulatory agencies	Regulations
10	Continue developing methodology to assess communities at risk.	M	CAL FIRE	Administrative
11	Jumpstart workforce development for forestry and fuels work.	M	CAL FIRE / CARB	Administrative
12	Develop mobile data collection tool for project reporting.	M	CAL FIRE	Administrative
13	Coordinate with air quality regulators to enable increased use of prescribed fire.	M	CAL FIRE / CARB	Administrative
14	Develop technology tools to enable real time prescribed fire information sharing.	M	Forest Management Task Force	Policy
15	Certify the California Vegetation Treatment Program Environmental Impact Report.	L	Board of Forestry and Fire Protection	Administrative
16	Develop scientific research plan regarding management and mitigation with funding recommendations.	L	Forest Management Task Force	Policy
17	Provide technical assistance to local governments to enhance or enable fire hazard planning.	L	Forest Management Task Force	Policy
18	Update codes governing defensible space and forest and rangeland protection.	L	CAL FIRE	Regulations
19	Request the Board of Forestry and Fire Protection review the Forest Practice Act and Rules and make recommendations on changes needed to restore forest health.	L	Board of Forestry and Fire Protection	Regulations

Key: Priorities are identified as follows: I = immediate term, M = medium term, L = long term

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Immediate Actions: These recommended actions would begin immediately to protect vulnerable communities before the height of the coming fire season.

1. Direct CAL FIRE Units to complete priority fuel reduction projects to protect public safety.

   CAL FIRE has identified priority fuels reduction projects that can be initiated almost immediately to protect the lives, health, property, and natural resources using the community vulnerability methodology described above and in Appendix A. CAL FIRE shall work, to the extent feasible, with other public agencies, landowners, and the communities themselves to implement these projects.

   The list of priority projects impacting vulnerable communities will be maintained on CAL FIRE's website and updated regularly so the status of each project is reported publicly. The list is attached at Appendix C.

2. Authorize incident response to implement rapid treatment of fuels.

   Deploy emergency responders to complete fuels reduction projects to protect vulnerable communities. CAL FIRE and the National Guard will establish incident bases in proximity to vulnerable community centers and coordinate fuels treatment operations from those bases utilizing the Incident Command System. The Incident Command System provides a complete, functional command organization that CAL FIRE and the National Guard will use to ensure the effectiveness of command and crew safety.

3. Increase housing availability for fuel crew staff.

   Provide additional state housing for seasonal state employees working on forest management and fuels reduction. These entry level employees are not highly compensated, and often have challenges finding affordable housing in areas where they work. OES should coordinate identifying additional housing for staff both in the short-term for work in 2019 and then a long-term plan for temporary housing.

4. Suspend regulatory requirements as necessary to protect public safety through the priority fuels reduction projects identified by CAL FIRE in this report.

   Numerous laws and regulations govern fuels reduction projects, and implementation often requires coordination with, and approval from,

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various state and local agencies. Typical environmental compliance, permitting requirements, licensing requirements, and state contracting laws and regulations, should be streamlined where possible to facilitate project implementation.

5. <u>Assess funding and personnel capacity within CAL FIRE and other departments and determine areas for additional investment and administrative actions to maximize effectiveness of current workforce.</u>

   Expanding the state's work to reduce public safety risks from wildfires and manage forests depends on adequately resourcing this work and providing the tools required to optimize state agency performance of this work.

   CAL FIRE should identify whether staffing levels are sufficient, and current staffing locations remain appropriate to efficiently mitigate wildfires early, and effectively contribute to the state's goal of treating 500,000 acres annually, as set forth in the Forest Carbon Plan.

   This task should also include:
   a. Recommendations on how the additional resources requested in the Governor's January Budget should be deployed if approved by the Legislature.
   b. Reviewing reimbursement rates and cost share agreements for CDCR and CCC project work. Identify where additional resources are needed.
   c. Reviewing classifications, work week and levels of administrative support for CAL FIRE staff.
   d. Identifying and working with other land management agencies who may need additional fuels management staff (for example, State Parks).
   e. Review of purchasing for items such as vehicles with associated changes to purchasing policies.
   f. Restarting work on CAL FIRE's firefighter classification consolidation proposal with California Department of Human Resources (CalHR).

6. <u>Align community education campaigns across all state and local entities.</u>

   The Forest Management Task Force should work on coordinated messaging for all entities providing direct funding or grants for public education campaigns. This should include coordinated messaging for Cal Volunteer and OES grants pursuant to AB 72 (Committee on Budget,

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Chapter 1, Statutes of 2019) as well as all other state agencies, including CAL FIRE. Education campaigns should be rolled out consistently throughout the state.

Mid-Term Actions: The recommended actions are designed to be completed by the end of this year.

7. Execute State Agency MOU for fuels reduction.

   Direct all relevant state agencies and departments to develop and sign a memorandum of understanding (MOU) committing the capabilities of each agency towards the common goals of fuel reduction and protection of vulnerable populations, and environmental sustainability.

   Direct the MOU agencies to utilize social media channels and other avenues to communicate the value of defensible space and other actions homeowners can take to protect against wildfire prior to the peak of wildfire season in 2019.

8. Identify options for retrofitting homes to new Wildland Urban Interface standards.

   a. CAL FIRE should identify options for incentivizing home hardening to create fire resistant structures within the WUI and with a focus on vulnerable communities.
   b. The Forest Management Task Force should immediately begin work to identify actions for retrofitting homes in the WUI with a focus on vulnerable communities. The Forest Management Task Force should also develop a comprehensive plan to bring existing housing stock up to new building code standards for the Wildland Urban Interface with a priority on vulnerable communities. The Forest Management Task Force should work with the Department of Insurance to seek input from the insurance industry on potential rebates or incentives for homeowners.
   c. Additionally, as provided in Assembly Bill 2911 (Friedman, Chapter 641, Statutes of 2018), CAL FIRE, and the Director of Housing and Community Development, should develop a list of low-cost retrofits that provide comprehensive fire risk reduction to protect structures from fires spreading from adjacent structures or vegetation and to prevent vegetation from spreading fires to adjacent structures.

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9. <u>Create incentives for fuels reduction on private lands.</u>

   Direct the Board of Forestry and Fire Protection to create or modify regulations to incentivize private landowners to engage in fuels reduction projects. This may include allowing removal of sufficient medium and large size trees or reducing after-harvest leave tree requirements sufficiently. These should be pursued through the emergency rule making process whenever possible.

   Non-industrial private landowners often do not have the resources to actively manage their forests, and may often be the same vulnerable populations needing protection from wildfire. Small non-industrial private landowners make up approximately 25 percent of California's forest land owners and managers, almost twice as much as private industrial forest lands.

10. <u>Continue developing methodology to assess communities at risk.</u>

    The methodology used to identify priority projects provides a robust assessment of near-term projects that can be implemented before the 2019 fire season. However, long-term planning and decision-making efforts to reduce wildfire risk require consideration of additional factors. Therefore, this methodology should serve as the basis for ongoing assessment methods to evaluate short and long-term wildfire risk reduction strategies across the state, with specific attention to identifying vulnerable communities.

    The Forest Management Task Force should establish an interagency team with experience in spatial analysis, technology support, environmental management, public health, climate change, and social vulnerability to develop the methodology enhancements needed to inform the long-term planning needs of both state and local agencies.

11. <u>Jumpstart workforce development for forestry and fuels work.</u>

    a. Identify specific opportunities to develop and incentivize workforce training programs for implementation by the end of 2019. The goal is to increase the number of properly trained personnel available to do fuels reduction and forest management and restoration work in the private sector.

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12. Develop mobile data collection tool for project reporting.

Procure a mobile fuel reduction data collection application to be used by all land management departments and agencies to increase accuracy and ease of data collection in the field.

13. Coordinate with air quality regulators to enable increased use of prescribed fire.

Uncontrolled wildfires can cause far more harmful air quality and public health impacts than prescribed burns because they often burn much more vegetation and last longer than prescribed burns. However, prescribed burns must still be managed to minimize emissions. To increase the scale of prescribed burns while protecting air quality:

a. CAL FIRE should coordinate with the CARB to explore updates to state air quality regulations to facilitate prescribed burns. Examples could include changes in how prescribed burns are accounted for in air quality calculations and allocating burn permits on a project, rather than parcel or landowner, basis.
b. In addition to examining state regulations, CAL FIRE and CARB should also coordinate with the U.S. Environmental Protection Agency to identify changes in federal air quality regulations that would facilitate prescribed burns.
c. CAL FIRE should coordinate with local and regional air districts to develop multi-year smoke management plans and burn permits for public purpose burning to help reduce costs and complexity for burners.

14. Develop technology tools to enable real time prescribed fire information sharing.

The Prescribed Fire Information Reporting System (PFIRS) should be officially recognized as the state's reporting tool to underscore the need for a common reporting and permitting tool across all agencies and private burners involved with prescribed fire. PFIRS should be funded and developed as the tool to support, facilitate and track prescribed fire efforts statewide. All state agencies and departments should be directed to use prescribed fire to obtain permitting and report through PFIRS, and federal land managers should be encouraged to use it for reporting. The reporting system is currently used by CARB, CAL FIRE, and the U.S. Forest Service.

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<u>Longer-term Actions: These actions are designed to begin quickly, but likely require more than a year to complete.</u>

15. <u>Certify the California Vegetation Treatment Program Environmental Impact Report.</u>

    Beyond the priority fuels treatment projects that CAL FIRE will implement in 2019, CAL FIRE and other land managers must increase the pace and scale of vegetation treatment throughout California. To that end, CAL FIRE and the Board of Forestry are preparing the California Vegetation Treatment Program Environmental Impact Report (CalVTP EIR) to identify and minimize environmental impacts associated with vegetation treatment. Once completed, CAL FIRE and other agencies will be able to rely on that document to streamline the environmental review process for future treatment projects.

    To maximize the streamlining value of the CalVTP EIR, other agencies with regulatory authority over vegetation treatment activities should be directed to engage in its development. CAL FIRE and the Board of Forestry should invite agencies within the California Natural Resources Agency and California Environmental Protection Agency to: P27-127 cont.

    a. In the immediate term, identify subsequent permitting processes that may apply to vegetation treatment projects.
    b. In the mid-term, develop streamlined permitting recommendations if it is determined that environmental compliance not covered by the CalVTP EIR will preclude projects from timely completion.

16. <u>Develop a scientific research plan for wildfire management and mitigation, with funding recommendations.</u>

    The Forest Management Task Force should develop a research plan with funding prioritization. Topics that should be considered include:

    a. Leverage the Governor's Request for Innovative Ideas (RFI2).
    b. Best management practices in the face of a changing climate and our understanding of forest health and resilience.
    c. Use of LiDAR, satellite and other imagery and elevation data collection, processing and analysis for incorporation into state management plans and emergency response.
    d. Funding for collaborative research to address the full range of wildfire related topics. Important research investments could include both

basic and applied research as well as social science to better understand social vulnerability, human behavior, land use, and policies that support resilience in communities that coexist with fire and mitigate impacts on life and property.

e. Research and development on new WUI building test standards in future research programs including the use of damage inspection reports from recent fires.

17. <u>Provide technical assistance to local governments to enhance or enable fire hazard planning.</u>

With the expansion of urban development into wildland areas, firefighting becomes more dangerous and costly, and the consequences of wildfires to lives and property become more severe. Local governments control land use decisions that can minimize those dangers. CAL FIRE and other state agencies have information and expertise that can support local governments in making safer choices. To enable land use planning that minimizes fire risks:

a. Assist the Governor's Office of Planning and Research in identifying specific land use strategies to reduce fire risk to buildings, infrastructure, and communities and in updating the "Fire Hazard Planning, General Plan Technical Advice Series," as provided in Assembly Bill 2911 (Friedman, Chapter 641, Statutes of 2018).
b. Work with Cal OES and the Standardized Emergency Management System Advisory Committee to develop robust local evacuation planning models for high or very high Fire Hazard Severity Zones based upon best practices from within California.
c. Provide technical assistance to support land use planning efforts to limit development in high fire hazard areas, as well as technical assistance to support mitigation activities that minimize risk to existing communities, with specific attention to vulnerable communities.

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18. <u>CAL FIRE should update codes governing defensible space and forest and rangeland protection.</u>

a. Review the penalty for non-compliance with defensible space code, establishing a fixed compliance date in lieu of three-inspection process. Include vacant land provisions.
b. Review enforcement the full 100 feet of defensible space around a structure when the structure is closer than 100 feet from the parcel line.

c. Consider the home and the first 0-5 feet as the most critical and hardened aspect of home hardening and defensible space. Consider requiring ignition resistant building material, only allow bark and hardscape, not trees or shrubs in this area.
d. Consider science-based regulation of wood piles and wood fences.

19. <u>Request the Board of Forestry and Fire Protection review the Forest Practice Act and Rules and make recommendations on changes needed to protect public safety and restore forest health.</u>

The Forest Practice Act, and regulations that implement it, currently contain rules that limit fuel hazard reduction activities. The rules could be updated to facilitate non-commercial fuel reduction projects. The Board should consider where existing exemptions could be expanded further to prevent and mitigate wildfires with an emphasis on environmental sustainability and protection of public health.

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Appendix A – Methodology to assess vulnerable communities

Summary

The 2018 Strategic Fire Plan for California[9], and the National Cohesive Wildland Fire Management Strategy[10] provide a set of goals and strategies that includes: fire adapted communities, safe and effective wildfire response, and resilient landscapes. Despite recent accelerated investment and resources, the vast amount of work and time required to achieve strategic goals necessitates an approach that best protects lives and property in the **near-term**, while simultaneously working over the **long-term** to create more resilient communities and landscapes that will allow Californians to live sustainably in the State's fire-prone landscapes. **Near-term needs include increasing the pace of fuel reduction in and near communities at risk, improving compliance with defensible space requirements, and improving fire resistance of both existing and new structures in the WUI**. In the longer term, a landscape-scale approach that marries forest health treatments with targeted community protection activities will be needed to fully address the scope of fire management issues in California.

Living sustainably in the fire-prone landscapes of California will require broad recognition of the inevitability of fire, which will in turn necessitate enhanced investment in and novel approaches to risk evaluation, fuel management, forest health, land use planning and community adaptation. As we move headlong through the 21st century, fire managers and landowners in California are challenged to effectively utilize available resources and tools to create resilient landscapes, reduce loss of life and property, and stem rising management costs, while enhancing our compatibility with the fire environment in which we live. Applying limited resources necessitates identification of the most vulnerable communities in which to begin this work. P27-127 cont.

Methods for assessing vulnerable communities

The following section provides a general description of the methods used to incorporate both wildfire risk and socioeconomic conditions of the communities that fuel reduction projects are designed to reduce

The overall goal of the analysis was to construct a framework that provides an assessment of wildfire risk and populations at risk from wildfire impacts. The

[9] 2018 Strategic Fire Plan for California.
http://cdfdata.fire.ca.gov/fire_er/fpp_planning_cafireplan
[10] National Cohesive Wildland Fire Management Strategy.
https://www.forestsandrangelands.gov/strategy/thestrategy.shtml

methodology consists of three main steps: a) identification of priority fuel reduction projects; b) evaluation of wildfire risk within the proposed project area; and c) evaluation of the socioeconomic characteristics of communities that projects are intended to protect.

For the initial step, CAL FIRE Units were asked to identify priority fuel reduction projects for their Units that would reduce wildfire risk to nearby communities. Project boundaries were incorporated into a GIS database for analysis.

Socioeconomic Analysis

Socioeconomic factors were based on evaluating conditions that are associated with populations at risk to wildfire. Some populations may experience greater risk to wildfire based on socioeconomic factors that lead to adverse health outcomes and their ability to respond to a wildfire. The factors chosen for this analysis were previously identified in CAL FIRE's Forest and Range Assessment and through a study conducted by Headwater's Economics (Table 1). Data for each socioeconomic variable was from the U.S. Census Bureau's American Community Survey (ACS) and organized by census tract.

Table 1. Socioeconomic variables considered to represent populations at risk to wildfire impacts

Socioeconomic Variables	**Description**
Families in poverty	Percentage of families in the census tract living below the poverty line
People with disabilities	Percentage of people in census tract estimated to have a disability; based on self-reporting
People that have difficulty speaking English	Percentage of people in the census tract estimated to have difficulty speaking English
People over 65	Percentage of people in the census tract over the age of 65
People under 5	Percentage of people in the census tract under the age of 5
Households without a car	Percentage of families in the census tract without a car

Data Sources: American Community Survey (ACS); California Building Resilience Against Climate Effects (CalBRACE) Project (2016).

For each project, the number of nearby communities was identified, represented by communities that were within a 5-mile buffer of each project boundary. For each community within the buffer, census track data was averaged for each of the socioeconomic variables. This resulted in a table that

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provides a description of the socioeconomic characteristics of each community that is associated each proposed project. In addition, a composite socioeconomic index was generated that represented the average across all socioeconomic variables. The socioeconomic index ranges from 0 to 100.

Wildfire Risk Analysis for Proposed Projects
Wildfire risk was then characterized by intersecting the Unit proposed fuel reduction projects with the following spatial data layers:

- SRA – State Responsibility Areas
- WUI – Wildland Urban Interface (WUI Interface, WUI Intermix, and WUI Influence Zone)
- CAL FIRE Priority Landscape for Reducing Wildfire Risk to Ecosystems
- CAL FIRE Priority Landscape for Reducing Wildfire Threat to Communities

Each of these data layers is described in greater detail below.

An overlay of project boundaries was done to determine the percentage of the project area in State Responsibility Area (SRA) and within WUI. WUI was represented by varying degrees of housing density that are associated with WUI Interface, WUI Intermix, and WUI Influence zones.

The proposed project boundaries were then intersected with CAL FIRE's Priority Landscape for Reducing Wildfire Risk to Ecosystems ("Ecosystems PL"). The Ecosystems PL combines resource assets (water supply, carbon storage, standing timber, site quality, and large trees) with a set of threats (fire threat – fuel hazard and fire probability and Fire Return Interval Departure). This PL prioritizes watersheds for potential treatment to reduce wildfire risk based on threats and assets to forested lands. The ranking varies from 1 (least risk) to 5 (greatest risk). Lands such as conifer woodlands (e.g. juniper and pinyon-juniper), oak woodlands (blue oak woodland, valley oak woodland, coastal oak woodland, etc.), shrublands, grasslands, were not included. In addition, only forested lands with a fire return interval departure (FRID) of class 2 or greater were included. This ensures that the areas most in need of treatment to restore natural fire regimes and improve ecological functions are prioritized. For this analysis, only ranks 3, 4, and 5 were used to designate high priority areas for reducing wildfire risk to ecosystems. Each proposed project was overlaid with the Ecosystems PL to determine the percent of each project area that was associated with high wildfire risk to ecosystem services. P27-127 cont.

Next the proposed projects were intersected with CAL FIRE's Priority Landscape for Reducing Wildfire Risk to Communities ("Communities PL"). The Communities PL identifies where communities (people and associated infrastructure) are at greatest risk from wildfire. Housing density within the Wildland Urban Interface is used to represent community assets. Areas with lower housing density receive a lower value and areas of higher housing density receive a higher value. The threat to communities is derived from CAL FIRE's Fire Hazard Severity Zones. Combining asset and threat rankings produces a priority landscape where areas with higher housing density and higher fire hazard receive the highest score. For this analysis, only ranks 3, 4, and 5 were used to designate high priority areas for reducing wildfire risk to communities. Each proposed project was overlaid with the Communities PL to determine the percent of each project area that was associated with high wildfire threat to communities.

A composite Wildfire Risk Index was also generated that represented the average across all wildfire risk variables (WUI, Ecosystems PL, and Communities PL). The wildfire risk index ranges from 0 to 100. Results characterizing wildfire risk for each proposed project are described on the CAL FIRE website.

Detailed Data Layer Information for Methodology to Assess Communities at Risk

This appendix provides detailed information on the sources, selection and construction of each of the data layers used in this analysis.

State Responsibility Area

CAL FIRE has a legal responsibility to provide fire protection on all State Responsibility Area (SRA) lands, which are defined based on land ownership, population density and land use. For example, CAL FIRE does not have responsibility for densely populated areas, incorporated cities, agricultural lands, or lands administered by the federal government.

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Wildland Urban Interface (WUI)

Wildland Urban Interface (WUI) –The line, area, or zone where structures and other human development meet or intermingle with undeveloped wildland or vegetative fuels[11].

CAL FIRE Priority Landscape for Reducing Wildfire Threat to Communities

This Priority Landscape (PL) prioritizes lands where communities (people and associated infrastructure) are at risk from wildfire to direct efforts at reducing wildfire risk in these areas.

[11] http://www.nwcg.gov/pms/pubs/glossary

Ranking

The ranking varies from 1 (least risk) to 5 (greatest risk). Housing density derived from FRAP's WUI layer is used to rank assets. Threat is determined using California Fire Hazard Severity Zones.

Assets

The asset to be protected in this PL is communities, which are defined by housing densities. Less dense areas receive lower value and higher densities receive higher value. The classes of density are:

- 0 = No houses
- 1 = 0 - 0.05 housing unit per acre
- 2 = 0.051 - 0.200 housing unit per acre
- 3 = 0.201 - 1 housing unit per acre
- 4 = greater than 1 housing unit per acres

Threats

The threat to the communities is Fire Hazard Severity, derived from CAL FIRE's Fire Hazard Severity Zones. The zone ranking is:

- 1 = moderate severity
- 3 = high severity
- 5 = very high severity

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Final Ranking:

The ranked asset and ranked threat were combined to derive the final ranked priority landscape. The results were ranked from the lowest risk of 1 to the highest risk of 5.

CAL FIRE Priority Landscape for Reducing Wildfire Risk to Forest Ecosystem Services

This Priority Landscape (PL) prioritizes watersheds for potential treatment to reduce wildfire risk based on threats and assets to forested lands.

Ranking

The ranking varies from 1 (least risk) to 5 (greatest risk). Lands such as conifer woodlands (e.g. juniper and pinyon-juniper), oak woodlands (blue oak woodland, valley oak woodland, coastal oak woodland, etc.), shrublands, grasslands, were not included. In addition, only forested lands with a fire return interval departure (FRID) of class 2 or greater were included. This ensures that the areas most in need of treatment to restore natural fire regimes and improve ecological functions are prioritized.

Assets

Surface water value: Watersheds (HUC12s) were ranked based on surface drinking water value from the USDA Forest Service's Forests to Faucet data, https://www.fs.fed.us/ecosystemservices/FS_Efforts/forests2faucets.shtml

Carbon storage: Estimated amount of carbon in the forest that is in living trees above the ground was spatially imputed into a GIS layer from Forest Service FIA data by Wilson et al. (2013) using a gradient nearest neighbor (GNN) technique. See Wilson, B.T., C.W. Woodall, and D.M. Griffith, *Imputing forest carbon stock estimates from inventory plots to a nationally continuous coverage.* Carbon Balance and Management, 2013. 8(1): p. 15.

Standing timber: Shows the estimated commercial timber volume on lands available for harvesting. Standing Timber was primarily derived from LEMMA Structure Maps (https://lemma.forestry.oregonstate.edu/data/structure-maps) that also used Forest Service FIA data and a GNN methodology (2012 vintage). LEMMA commercial timber volume was reduced for areas of high fire severity burns through 2017 (from FRAP), BAER imagery for areas of high severity wildfires that have occurred in 2018 from: https://fsapps.nwcg.gov/afm/baer/download.php), and Aerial Detection Survey data of areas of high tree mortality (also subsequent to 2012). Lands not available for timber harvest were removed, including southern California and South Central Coast counties with no viable timber processing facilities.

P27-127 cont.

Site quality: This shows the productivity of timberland, based upon potential volume of wood (i.e. cubic feet) that can be produced per acre in a year. Site Class GIS data was produced by Wilson from Forest Service FIA data (using the same methods as for the Carbon storage layer), based upon FIA attribute SITECLCD – site productivity class code. It shows the potential timber volume produced at culmination of mean annual increment, in the standard classes used by the USFS.

Large trees: Derived from FRAP vegetation layer FVEG15 (WHRSIZE), which in turn (for this attribute) came from CALVEG data of the USFS. Tree size class scores were 1 = (6-11" DBH); 3 = (11-24" DBH); and 5 = (over 24" DBH).

Threats

Fire Threat: FRAP fire threat data (fthrt18_1) was derived from a combination of FRAP surface fuels data and large fire probability from the Fire Simulation (FSim) system developed by the US Forest Service Missoula, Montana Fire Sciences Laboratory.

Fire Return Interval Departure (FRID): FRID shows the deviation from historic averages of fire occurrence. FRID from USFS Region 5 was used to prioritize areas most in need of treatment. FRID scores of 2, 3, and 4 were assigned scores of 1, 3, and 5 respectively.

Composite Ranks

All assets were combined and the result ranked from 1 to 5 to derive a composite asset. Likewise, all threats were combined the results ranked from 1 to 5 to create a composite threat. The composite asset layer and composite threat ranks were then combined and classified to a final priority landscape rank for each 30m pixel.

P27-127 cont.

Appendix B – Maps

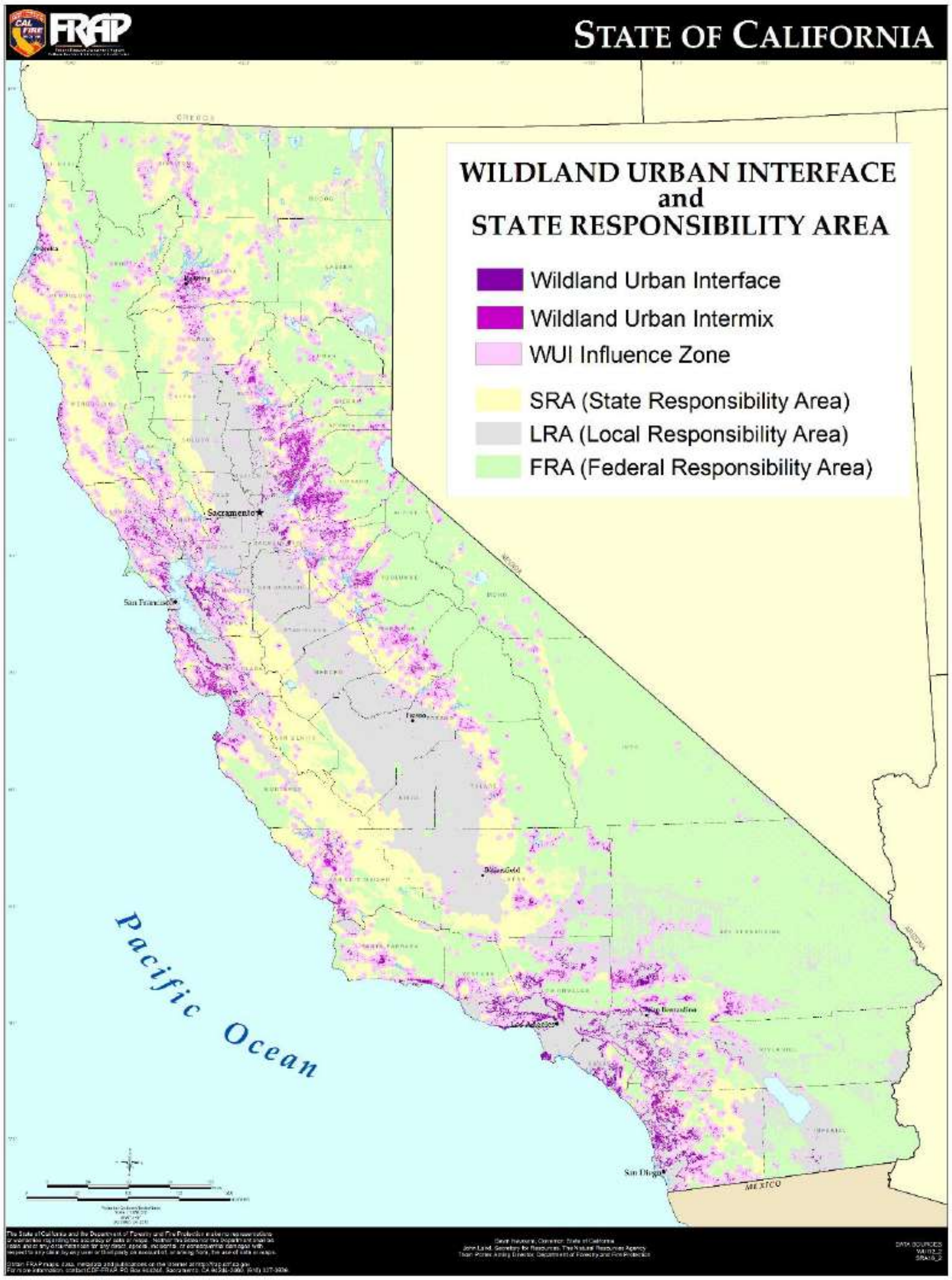

Figure 1: California's Wildland Urban Interface.

P27-127 cont.

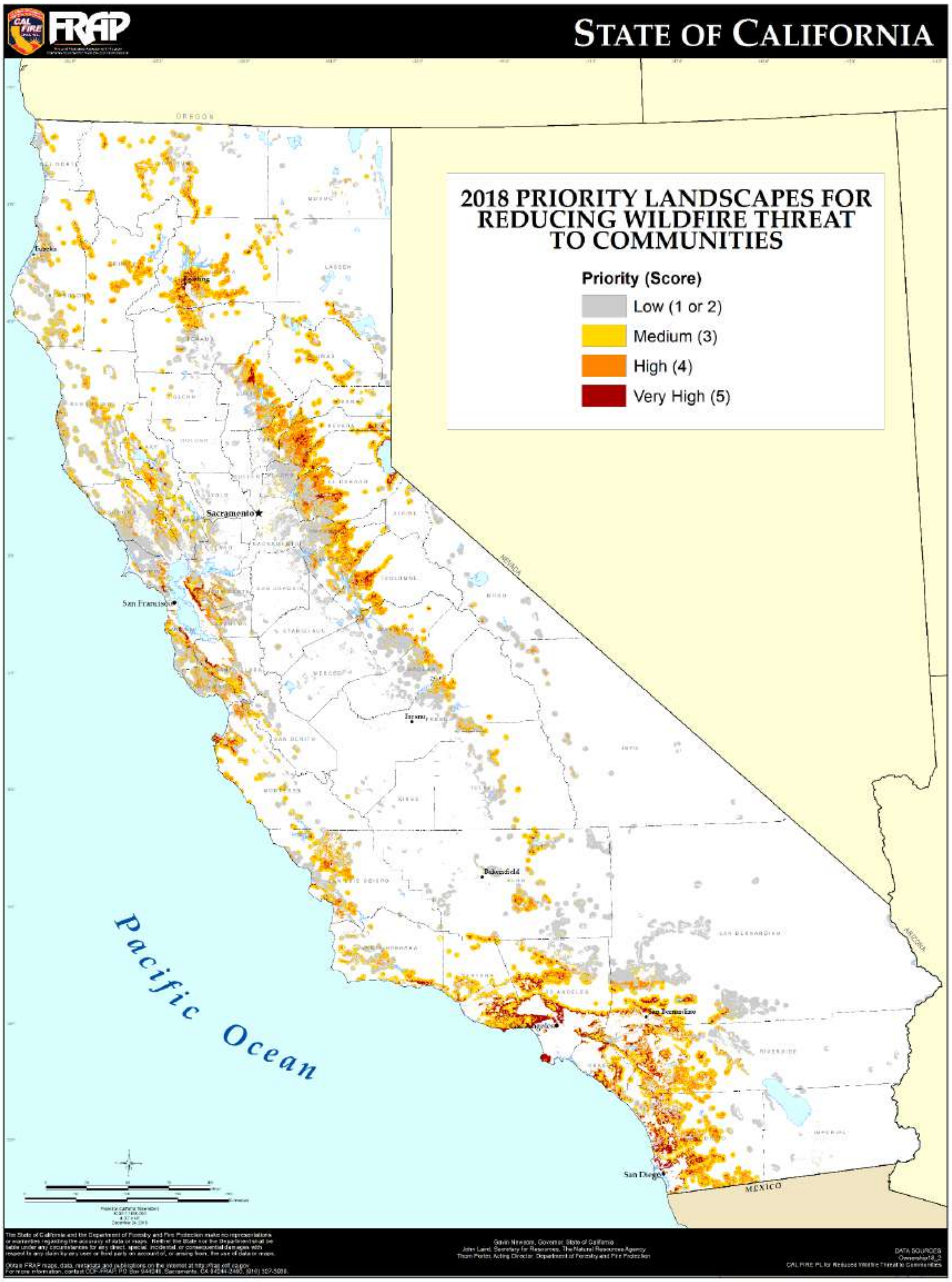

Figure 2: Priority Landscapes for Reducing Wildfire Threat to Communities.

P27-127 cont.

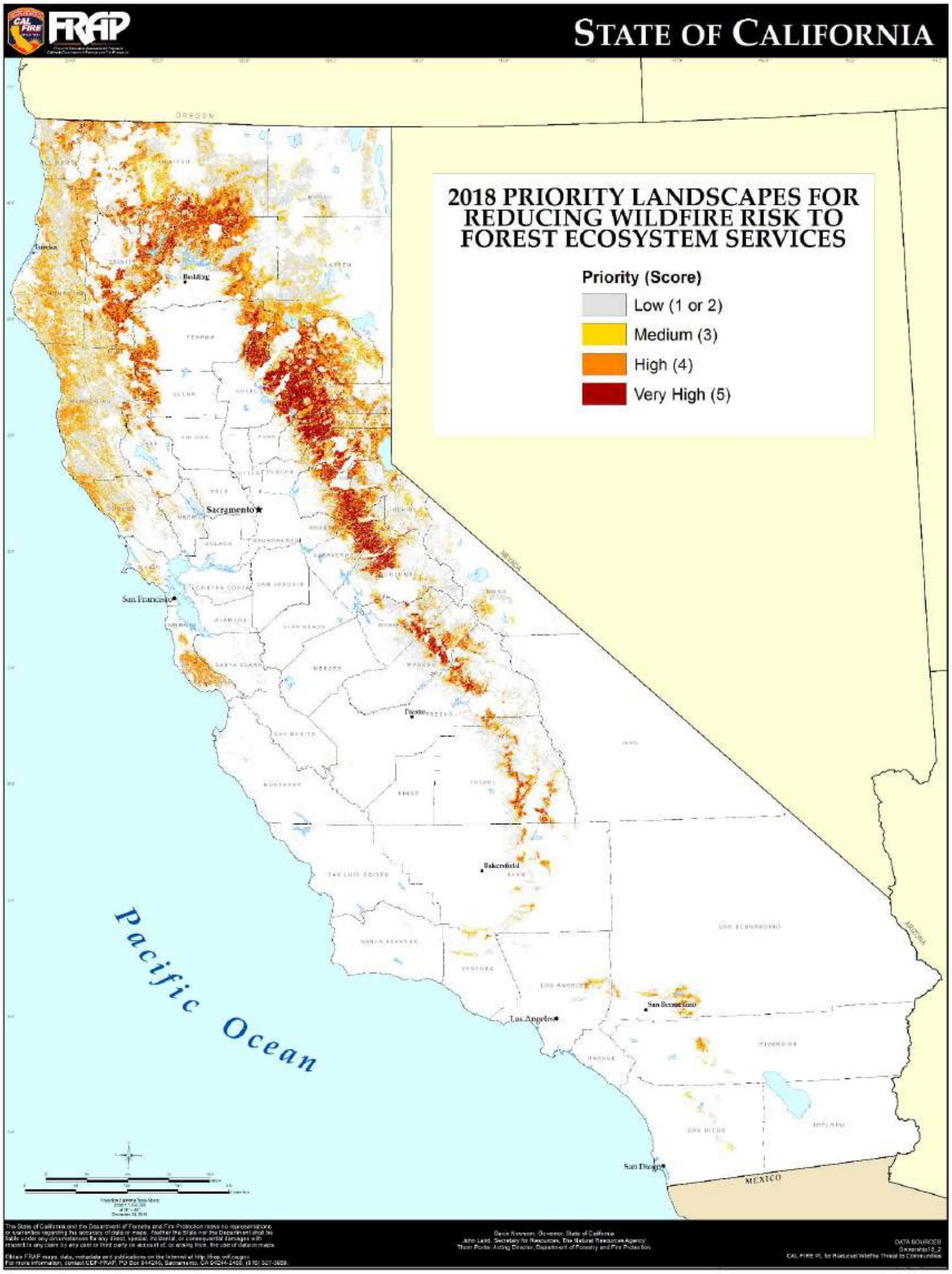

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Figure 3: Priority Landscapes for Reducing Wildfire Threat to Communities.

Appendix C – CAL FIRE Priority Fuel Reduction Project List

#	Project Name	CAL FIRE UNIT	Acres	Number of Communities	Affected Population	Socio-economic Score (SES)	Fire Risk Score (FRS)	Final Summary Score
1	Hwy 44 Fuel Break	SHU	1,124	3	8,833	90	86	88
2	Kings Mountain Roadside	CZU	467	18	271,096	88	84	86
3	Rush Creek	FKU	181	1	2,973	71	99	85
4	San Juan Canyon Fuel Reduction	BEU	2,277	4	54,067	116	53	85
5	Martin Ranch Fuel Break	LMU	57	4	3,957	69	98	83
6	Santa Barbara Foothill Community Defensible Space	SBC	1,960	5	127,516	98	64	81
7	Musick Fuel Break	FKU	393	5	12,677	62	95	79
8	Bridgeville FR	HUU	18	1	4,143	66	87	76
9	North Orinda Fuel Break	SCU	1,760	30	561,223	96	56	76
10	West Redding Fuels Reduction	SHU	3,091	7	114,607	84	67	75
11	Guatay Community Fuel Break	MVU	128	15	221,282	85	66	75
12	China Gulch Fuel Break	SHU	530	8	88,610	84	66	75
13	Forbestown Ridge	BTU	1,673	8	14,950	92	58	75
14	North Fork American River Fuelbreak	NEU	4,373	13	77,319	65	84	74
15	Shaver Springs	FKU	78	4	12,677	62	86	74
16	El Granada Quarry Park Fuel Break	CZU	250	10	100,433	85	62	73
17	Blue Rush Fuel Break	FKU	82	1	2,973	71	75	73
18	State Route 17 Fuel Break	SCU	454	8	72,462	58	88	73

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#	Project Name	UNIT	Acres	Number of Communities	Affected Population	Socio-economic Score (SES)	Fire Risk Score (FRS)	Final Summary Score
19	Painted Cave Community Defensible Space	SBC	1,742	7	84,232	79	66	73
20	Willits Fuels Reduction	MEU	11,965	3	13,120	88	55	72
21	San Marcos Pass	SBC	3,096	7	84,342	79	62	70
22	Grist Fuel Break	MMU	102	3	13,097	79	60	69
23	Crest Community Fuel Break	MVU	60	3	5,278	71	66	68
24	Beal Fuel Break	FKU	728	6	12,677	62	74	68
25	Aptos, Buzzard, Hinkley Ridgetop and Roadside	CZU	1,036	16	112,505	73	58	66
26	Ukiah Fuels Reduction	MEU	26,541	10	39,195	95	34	65
27	Lake Shastina Fuels Treatment	SKU	759	3	7,231	87	36	62
28	Ponderosa West Grass Valley Defense Zone	NEU	1,238	9	54,776	67	56	61
29	Big Rock Prescribed Burn	LAC	431	8	44,440	52	66	59
30	Metcalf Gap	MMU	44	4	10,131	79	37	58
31	Palo Colorada Fire Access Roads	BEU	6,843	4	9,556	77	37	57
32	Laurel Springs-Hennicksons Ridge	BEU	4,368	1	5,933	64	48	56
33	Elk Creek Fuel Break	TGU	953	2	4,868	98	3	50
34	Palo Corona Fuel Reduction	BEU	10,428	9	59,585	82	11	46
35	Highway 41 Vegetation Management Plan	MMU	4,621	7	28,737	84	4	44

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April 2, 2020

CERTIFIED MAIL RETURN RECEIPT REQUESTED

Shasta County Board of Supervisors
1450 Court Street, Suite 308B
Redding, CA 96001-1673

Re: Proposed Fountain Wind Project and Demand for Moratorium on All Such Projects Pending Resolution of the Global COVID-19 Pandemic

Dear Supervisor Rickert,

Last June, the citizens action group, Citizens in Opposition to the Fountain Wind Project ("Stop Fountain Wind"), respectfully and formally requested that the Board of Supervisors adopt an immediate moratorium on all County Use Permits for large scale Wind Energy Generation Developments and/or Wind Energy Systems, including the application for a use permit for the proposed Fountain Wind Project (UP-16-007) in Shasta County. We were told at the time that the Board refused to even put the request for a Moratorium on its agenda, or discuss it publicly. The reason given was that there was no imminent threat to the public health, safety or welfare posed by the project at that time, although there was no public meeting, public discussion, or finding to that effect made by the Board. We strongly disagreed then, and still disagree now, but the world has changed since then, and a moratorium is needed now for an additional and different reason. **The project application does not represent an essential business activity, and simply cannot be properly processed and considered at this time under CEQA, or the project built, while there is a COVID-19 virus pandemic spreading in Shasta County, and throughout California, the USA, and the rest of the world. Just continuing to process the application under CEQA, with numerous meetings, site visits, studies, human interaction, and related travel and activity, will significantly increase the potential spread of the virus here in Shasta County and beyond, which can only lead to additional serious illnesses and deaths of local citizens, including potentially county employees and staff that are tasked with processing the application, as well as consultants, third parties, and the general public.** P27-128

We begin by noting that all of the original reasons for a moratorium still remain and fire risk has probably increased since last June (there is even heightened fire risk now, there has still been no comprehensive County planning or zoning amendments to address the placement of industrial wind turbine developments in the highest fire risk zones in the State, even after the Carr, Camp, Delta, and Hirz fire tragedies, and the County has taken no action to place limits on such developments even after the loss of many lives from massive fires in Northern California, the burning of thousands of homes, the destruction of countless businesses and livelihoods, and the complete devastation of a good part of the County). But as if that were not enough for the Board to take some action to protect its citizens from the dangers posed by putting massive wind turbines, known to cause forest fires, in the highest fire danger zones in the County, there is now an additional crisis and danger to public health and safety that the Board simply cannot ignore.

We are now at the beginning of a global pandemic due to the rapid spread of the COVID-19 virus around the world. The virus is spreading quickly here in California, and has recently reached Shasta County. The virus is much more contagious and deadly than the flu. Hundreds of thousands of people have been infected worldwide, and many thousands have died. Health systems in various places have become overwhelmed. Shasta County has recently declared a public health emergency, and under orders from Governor Gavin Newsome, the entire State of California is subject to a "shelter-in-place" order. Public meetings are essentially forbidden, non-essential businesses have been closed, and other directions and orders have been issued to slow the spread of the virus. National guidelines have also been issued to the public, and various states of emergency have been declared at the national, state, and local levels in various jurisdictions around the country, including international travel bans, and directions to bar all non-essential travel and other activity.

To continue to even process the Fountain Wind project application under CEQA at this time would present an imminent danger to the health, safety, and welfare of the Board of Supervisors, its staff, the Planning Commission and its staff, other county employees, consultants, and experts, and to the public. All of the various meetings, field trips, site investigations and studies, require human interaction and travel that puts those involved at greater risk of contracting the virus, and by extension, puts the public at large at greater risk given that all such project-related activity could spread the virus throughout the county planning department and the community. Further processing of the project permit application through the CEQA process is, by definition, non-essential business activity that in the interest of public health, and due to the imminent danger to the health, safety and welfare of Shasta County residents, should be immediately shut down until the virus no longer poses a risk in Shasta County to those who live and work here.

P27-128 cont.

Furthermore, the County does not have the power under CEQA (a state law) to alter CEQA requirements, and dispense with required public meetings, and the ban on such meetings also inhibits public comment and participation in efforts to study or oppose the project. Such public and private meetings are currently banned by state and national directives to slow the spread of the virus.

In addition, the Board should recognize the fact that the entire draft EIR that is currently being prepared will need to be re-done, if not scrapped entirely, because any EIR will now have to address the potential impacts of the project on public health and potential spread of the virus. These types of projects would be the largest construction projects in Shasta County history since the construction of Shasta Dam with hundreds of workers brought in from outside the county, any number of which could either be infected with the virus, or contract it and spread it during construction or operation of the project. All kinds of additional studies will have to be undertaken and prepared to address various potential impacts of the project on the potential spread of COVID-19. **The Board should understand that these types of studies cannot be prepared at this time, or considered by the Board in the next few months as part of an EIR, because not enough is known about the virus at this early stage of the pandemic.** For example, all means of transmission are not yet known, the infection rate is not yet known, the prevalence in the community is not yet known, no complete cures or widely approved treatments are yet available, there is no vaccine, the rate of spread by various activities is not yet known, and there are no approved procedures for "social distancing" and other means of stopping the spread on large construction sites, and for all of the many activities necessary to plan and build such a massive project. It is likely that such studies and reports necessary for such an EIR cannot be developed until the end of the pandemic and the complete defeat of the virus by means of a vaccine or otherwise, which might be years away. It is not even known whether the virus may become seasonal, like the flu, such that it is impossible at this time to devise plans for construction and operation of such massive projects in a manner that will keep the virus from spreading in the event it reoccurs or becomes seasonal. In short, all necessary studies that would be required to be included in an EIR to address the impact of the proposed project in light of the COVID-19 pandemic cannot be prepared at this time, and certainly not until much more is known about the virus and the pandemic has run its course. At the same time, continuing to process the application now puts planning staff, other county employees, and the public at greater risk of contracting or spreading the virus, and for no purpose, since the studies that will be necessary to consider much less approve the project cannot really be done yet. Thus, the only wise course is to issue a moratorium, to protect the public health, safety, and welfare, until the pandemic has run its course and more is known.

The COVID-19 pandemic is also having impacts on the operations of PG&E, including the possibility of further electricity curtailments, and delay in much needed safety improvements to PG&E's equipment and power grid. FERC offices have recently closed. There is no telling how many impacts the COVID-19 virus may have, and how many additional studies would need to be done to address such issues in an EIR for a project such as this so early in the pandemic. During the pandemic, fire crews, police, PG&E personnel, and others, may be sick or at greater risk of contracting or spreading the virus. Huge wind developments tie into the power grid, and interactions will be necessary with PG&E, private contractors, and public agencies, all of which may be negatively impacted by the virus. Adding massive construction activity in high risk fire areas, as well as burdening an already weakened electrical infrastructure with a new project, would be ill advised in the middle of a public health crisis. And, of course, all of this may put the public at even greater risk of out-of-control wildfires during the pandemic, making it a particularly bad time for a major construction project in a high fire risk zone, while at the same time imposing additional risks from the virus itself on vulnerable communities. Many of the residents in the inter-mountain area where the project is proposed, are elderly with pre-existing conditions.

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Moreover, not only is there a risk of spreading the virus, but also, due to the pandemic, controlled burns are already being postponed, and fire agencies across the West are cancelling or delaying programs aimed at preventing catastrophic wildfires. Thus, these same communities also face increased fire dangers during the pandemic. The impacts of this too would also need to be addressed in any revised EIR. The real point is that the full extent of the impacts of COVID-19 on a project such as this, and increased health risks to the public posed by such a project, cannot be known at this time, or adequately assessed, so early in the pandemic. Nor can the risks posed by actually building the project in the middle of the pandemic, be adequately addressed so early in the pandemic. Processing the application now would be fruitless, and would also take resources away from public efforts to address the health crisis and its immediate impacts. For example, public planners should be spending their time addressing any medical needs, potential construction of temporary hospitals, conversions of hotels to house virus patients, and other potential fallout from the public health crisis, not devoting their time and attention to projects that are not essential to the community (and in this case, would actually impose great risks on the community). And at the same time public officials are dealing with the pandemic and its adverse impacts, we are also headed into another fire season after a particularly dry winter (no rain in February for the first time on record), while the pandemic continues to spread. Local fire departments as well as Cal Fire and PG&E must deal with potentially sick employees, as well as implement new procedures to slow or prevent the spread of the virus among their workforces while dealing with a new host of wildfires that are sure to erupt this summer. This is not the time to waste valuable resources, and pose additional risks to the health of county staff, to process an application for a non-essential business activity that realistically cannot be adequately addressed in the middle of a public health crisis.

Accordingly, since the planning process itself, not to mention construction, during a global health crisis and pandemic poses so many challenges and risks to the public health, safety, and welfare, including imminent risk of serious harm and even death to a plethora of county employees and other local residents, and since those risks cannot be adequately mitigated or even fully studied for purposes of an EIR so early in the pandemic, we respectfully request that the Board immediately issue a moratorium on Fountain Wind and all other such projects until the end of the pandemic. We also call upon the proponent of the project to do the right thing and simply withdraw their application in the interest of protecting the public health, safety and welfare, and consider submitting a new application, if any, after the pandemic is over. We fully understand that this may be months or years from now, but the Board's interests should always be to protect the public health and indeed the very lives of its citizens first and foremost, and in this instance, this can best be done by an immediate moratorium.

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Please place this request for a moratorium on the Supervisors agenda for a decision as soon as possible, notifying Beth Messick regarding the proposed date. If the Board does not believe this matter rises to the level of an agenda item decision, we request that response be presented to the CIO FWP in writing.

For further information, you can contact Stop Fountain Wind's representative, Beth Messick, at (530)472-1463. You are also encouraged to visit our website at www.stopfw.com.

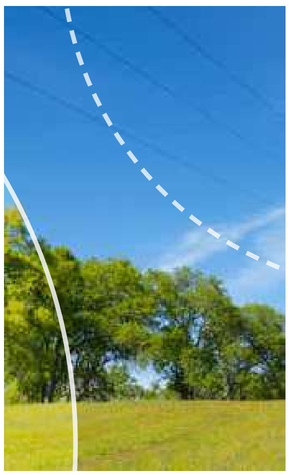
Sincerely,
Beth Messick on behalf of the
Citizens in Opposition to the Fountain Wind Project (CIO FWP)
P.O. Box 116
Montgomery Creek, CA 96065

cc:
Paul Hellman, Shasta County Planning Division
Shasta County Planning Commissioners
Matt Pontes, County Executive Officer
Rubin Cruse, Jr, County Counsel
James Ross, Asst. County Counsel
Lio Salazar Fountain Wind Project Lead

Comment Letter P27

2018-2019

TRANSMISSION PLAN


P27-129


California ISO

March 29, 2019
Version: Board Approved-Updated

Foreward to Board-Approved 2018-2019 Transmission Plan

At the March 27, 2019 ISO Board of Governors meeting, the ISO Board of Governors approved the 2018-2019 Transmission Plan.

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Executive Summary

The California Independent System Operator Corporation's 2018-2019 Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to address grid reliability requirements, identify upgrades needed to successfully meet California's policy goals, and explore projects that can bring economic benefits to consumers. In doing so, the plan relies heavily on key inputs from state agencies in translating legislative policy into actionable policy-driven inputs.

This plan is updated annually, and culminates in an ISO Board of Governors (Board) approved transmission plan that identifies the needed transmission solutions and authorizes cost recovery through ISO transmission rates, subject to regulatory approval, as well as identifying non-transmission solutions that will be pursued in other venues as an alternative to building additional transmission facilities. It is prepared in the larger context of supporting important energy and environmental policies while maintaining reliability through a resilient electric system.

The transmission plan is developed through a comprehensive stakeholder process and relies heavily on coordination with key energy state agencies – the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) – for key inputs and assumptions regarding electricity demand side forecast assumptions as well as supply side development expectations. The latter has become even more critical than in the past, as the grid planning requirements are shifting from focusing on accessing renewable generation, to also include accessing the necessary integration resources to effectively operate the grid in a future of high volumes of renewable generation and a declining natural gas-fired generation fleet.

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The aggressive pace of the electric power industry transformation in California continues to set the context for the ISO's annual transmission plan, where the focus is recalibrated each year to reflect the status of a range of issues at that time. This year's transmission plan continues to reflect those changing circumstances and the specific needs emerging at this particular point in time. Key trends in this year's transmission plan include the following:

- The progress made through past transmission plans to address reliability issues overall and planning for the retirement of once-through-cooling generation – including the San Onofre Nuclear Generating Station – continue to result in relatively modest transmission reinforcement needs. Despite relatively flat load forecast growth currently projected over the planning period, new reliability challenges have emerged driving the need for system reinforcements on a case-by-case basis, however;
- Consistently declining load forecasts issued annually by the CEC – especially for the one-in-ten peak load forecasts affected by weather normalization processes – led to a three year comprehensive program of re-evaluation of previously-approved upgrades ending with the 2017-2018 transmission planning process. The downward pressure on peak demand load growth and energy consumption was compounded by higher than anticipated development of behind-the-meter solar photovoltaic generation. Behind-the-meter solar has reduced the summer peak loads traditionally occurring in mid-day in

many parts of the state and is steadily shifting them towards the unaffected load levels occurring later in the day when solar production has dropped off. The 2018-2019 effort focused on reviewing several projects that required additional study and consideration before final determinations could be made. As in the the 2017-2018 planning cycle, this year's efforts entailed both canceling and re-scoping projects to more effectively and efficiently meet needs. Project reviews will continue going forward in future planning cycles on a case-by-case basis as warranted;

- Sustained emphasis on minimizing environmental impacts of the electricity industry and reducing greenhouse gas emissions continue to drive more integrated solutions to emerging needs that rely on combinations of preferred and conventional resources, as well as transmission, although the relatively modest requirements of the 2018-2019 transmission plan afforded few opportunities for these solutions;
- Transmission needed to access renewable generation development to achieve the state's 33 percent RPS goal by 2020 and 50 percent RPS goal by 2030 have largely been identified and are moving forward. This year's planning studies included reliability and economic studies performed meeting 50 percent RPS goals. Given past years' studies of transmission system capacity, and additional approvals of policy-driven transmission not being needed to achieve 50 percent RPS, policy analysis this year was performed on a sensitivity basis for portfolios achieving approximately 57 percent RPS levels. New transmission requirements to achieve 50 percent RPS standards were greatly reduced from expectations only a few years ago due to the much higher than anticipated development of behind-the-meter solar generation. While this generation does not count directly towards RPS measures, it reduces the amount of energy served by the grid. With 2030 RPS requirements now shifting to a 60 percent RPS goal, direction from the CPUC's integrated resource planning process for the 2019-2020 planning cycle is anticipated to be consistent with the higher RPS goal;
- In the course of the 2018-2019 planning cycle, the stakeholders submitted frequent feedback on renewable policy-related issues critical of the resource planning assumptions and outcomes provided by the CPUC to the ISO for transmission planning purposes. This feedback included comments critical of the consideration of energy-only renewable generaton to meet a portion of future RPS requirements. The ISO is accordingly continuing its coordination with the CPUC staff, and also referred these stakeholders to the appropriate CPUC proceedings;
- The 2018-2019 transmission planning cycle was heavily tasked with informational studies to help inform future transmission planning at the ISO and resource planning at the CPUC. These studies took the form of informational "special studies" such as the consideration of improving access to hydro generation in the Pacific Northwest, or by significantly increasing the scope of studies such as the 10 year Local Capacity Technical Study to not only establish local capacity requirements, but identify alternatives. Further, a subset of those alternatives were fed into the the economic study process as potential economic-driven transmission;

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cont.

- The longer term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined in the CPUC integrated resource planning process as well as in ISO studies conducted outside of the annual transmission planning process for purposes of supporting CPUC efforts. The uncertainty regarding the extent to which gas-fired generation will be needed to meet system and flexible capacity requirements necessitated taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements;
- Significant development interest in new transmission, including proposals for energy storage facilities seeking regulated cost of service revenue streams, was shown by potential project sponsors seeking to press ahead of the pace of resource planning. An impressive number of requests for consideration of proposed reliability-driven and economic-driven proposals were submitted, with the majority being examined in this planning cycle. The basis for many of the submissions were project sponsor assumptions regarding resource planning outcomes that went beyond the direction received from the CPUC given the current status of its integrated resource planning process, or views on planning standards that exceeded the ISO's approved planning standards. As well, as noted earlier, the ISO applied conservative (*i.e.* "modest") values to the benefits associated with reducing local gas-fired generation requirements due to the uncertainty regarding the need for those resources for system or flexible requirements; this also impacted the ISO's assessments of the economic viability of many of these projects; P27-129 cont.
- A number of stakeholder proposals for battery storage projects cited the ISO's stakeholder initiative regarding how storage procured as a regulated cost of service transmission asset (or SATA) could also access market revenues when not needed for reliability. This initiative has been placed on hold to consider further refinements to the ISO's storage participation model. The ISO nonetheless assessed the economic benefits they could provide, assuming that if appropriate, procurement could also be investigated as market-based local capacity resources through CPUC procurement processes;
- The ISO and respective neighboring planning regions received six Interregional Transmission Project submissions for consideration in this transmission planning cycle, which is the first year of the biennial interregional coordination process the ISO has established with our neighboring planning regions. Three of these were carried forward and studied in the economic study phase of this year's transmission planning prcess to assess if they could provide more efficient or cost-effective solutions than regional projects for meeting identified needs. The economic assessments of these projects are affected by the same considerations discussed above for regional proposals, and accordingly none have been selected for approval in this planning cycle; and,
- Overall, the 2018-2019 Transmission Plan includes a modest increase in new reliability needs, continued refinement and downsizing of previously approved projects that required further analysis from the 2017-2018 transmission planning cycle, and a great deal of forward-looking studies and study methodology refinements to inform future

transmission planning processes, including CPUC integrated resource planning issues. The ISO's efforts to increase opportunity for non-transmission alternatives, particularly preferred resources and storage, continues to be a key focus of the transmission planning analysis – which in this planning cycle focused more on developing supportive tools and methodologies than the assessment of these resources due to the relatively modest needs for transmission system reinforcement.

Our comprehensive evaluation of the areas listed above resulted in the following key findings:

- The ISO identified 11 transmission projects with an estimated cost of approximately $607.4 million as needed to maintain transmission system reliability. Several of these projects also entail a combination of preferred resource procurement and transmission upgrades working together to meet those needs;
- In reviewing previously approved projects in the PG&E service territory that were identified in the last planning cycle as needing more review, six projects are recommended to be canceled, paring between $440 million and $550 million from the ISO transmission capital program estimated costs. One other project will continue to be on hold pending reassessment in future cycles.
- The ISO's analysis indicated in this planning cycle that the authorized resources, forecast load, and previously-approved transmission projects working together continue to meet the forecast reliability needs in the LA Basin and San Diego areas. However, due to the inherent uncertainty in the significant volume of preferred resources and the timing of other conventional mitigations, the situation is being continually monitored in case additional measures are needed;
- Given past studies of transmission system capabilities to achieve RPS levels beyond 33 percent, no policy-driven transmission was considered for approval in this planning cycle to achieve a 50% RPS – efforts focused on sensitivity studies for higher levels of RPS based on the CPUC's IRP reference plan 42 MMT portfolio, and those studies did not identify the need for additional policy-driven transmission to meet that portfolio;
- Two economic-driven transmission project with an estimated capital cost of $37 million is recommended for approval, providing energy cost savings by alleviating local congestion and eliminating the need for local capacity requirements;
- The ISO tariff sets out a competitive solicitation process for eligible reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the plan. Two transmission projects in this transmission plan include facilities eligible for competitive solicitation through the ISO's competitive solicitation process.

Progress also continued in the 2018-2019 Transmission Plan in exploring issues emerging as the generation fleet continues to transform as the state pursues greenhouse gas reduction goals. The ISO's informational special studies undertaken in the planning process were primarily focused on supporting future resource planning processes.

P27-129 cont.

Summaries of the transmission planning process and some of the key collaborative activities with the CPUC and the CEC are provided below. This is followed by additional details on each of the key study areas and associated findings described above.

The Transmission Planning Process

The transmission plan primarily identifies three main categories of transmission solutions: reliability, public policy and economic needs. The plan may also include transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects or provide for merchant transmission projects. The ISO also considers and places a great deal of emphasis on the development of non-transmission alternatives, both conventional generation and in particular, preferred resources such as energy efficiency, demand response, renewable generating resources and energy storage programs. Though the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive plan, these can be identified as the preferred mitigation in the same manner that operational solutions are often selected in lieu of transmission upgrades. Further, load modifying preferred resource assumptions are also incorporated into the load forecasts adopted through state energy agency activities that the ISO supports, and provide an additional opportunity for preferred resources to address transmission needs.

The transmission planning process is defined by three distinct phases of activity that are completed in consecutive order across a time frame called a planning cycle. The planning cycle begins in January of each year, with the development of the study plan – phase 1. Phase 2, which includes the technical analysis, selection of solutions and development of the transmission plan for approval by the ISO Board of Governors, extends beyond a single year and concludes in March of the following year. If Phase 3 is required, engagement in a competitive solicitation for prospective developers to build and own new transmission facilities identified in the Board-approved plan, it takes place after the March approval of the plan. This results in the initial development of the study plan and assumptions for one cycle to be well underway before the preceding cycle has concluded, and each transmission plan being referred to by both the year it commenced and the year it concluded. The 2017-2018 planning cycle, for example, began in January 2017 and the 2017-2018 Transmission Plan was approved in March 2018.

P27-129 cont.

Storage as a Transmission Asset accessing Market Revenues

The bulk of the grid-connected storage in California has been developed as maket-based resources. While the ISO has long recognized and studied the possibility of strorage also being acquired as a transmission asset, the ISO understanding was that such storage was precluded from participating in the electricity market and accessing market revenues. On January 19, 2017, FERC issued its policy statement “Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery” clarifying that such electric storage resources could receive cost-based rate recovery for certain services (such as transmission or grid support services or to address other needs identified by an RTO/ISO) while also receiving market-based revenues for providing separate market-based services, subject to a number of issues and concerns being addressed.

Accordingly, the ISO began a stakeholder initiative to address the implementation concerns set out in the policy statement. This initiative has been placed on hold, however, as a number of related and impactful issues are currently being explored for storage more generally through a separate and ongoing initiative – the ISO's Energy Storage and Distributed Energy Resources (ESDER 4) initiative. Nonetheless, the ISO has assessed the economic benefits the bulk of these submitted projects could provide, assuming that if appropriate, procurement could be investigated as market-based local capacity resources through CPUC procurement processes.

Planning Assumptions and State Agency Coordination

The 2018-2019 planning assumptions and scenarios were developed through the annual agency coordination process the ISO, CEC and CPUC have in place and performed each year to be used in infrastructure planning activities in the coming year. This alignment effort continues to improve infrastructure planning coordination within the three core processes:

- Long-term forecasts of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR),
- Biennial long term procurement plan (LTPP) proceedings, now replaced by the integrated resource planning (IRP) proceedings conducted by the CPUC, and
- Annual transmission planning processes performed by the ISO.

P27-129 cont.

In this coordination effort, the agencies considered assumptions such as demand, supply and system infrastructure elements, and the RPS generation portfolios proposed by the CPUC.

The CPUC's input was communicated via a a decision[1] on February 8, 2018 at the end of the first year of the 2017-2018 Integrated Resource Planning cycle, which adopted the integrated resource planning process and also provided resource planning assumptions to the ISO. A 50 percent RPS portfolio, based on the CPUC's "default" scenario and aligned with the SB 350 goal of 50 percent RPS by 2030 was communicated for purposes of reliability planning. This portfolio was also used for economic study purposes. Anticipating higher renewable generation requirements going forward, the CPUC communicated a portfolio based on its "42 MMT scenario" that results in approximately a 57 percent RPS as a sensitivity portfolio for policy-driven planning efforts. The CPUC declined to provide a "base" portfolio for actual project approval purposes, which was considered unnecessary, given past transmission planning studies and steadily declining estimates of the amount of grid-connected renewables necessary to achieve the 50 percent by 2030 goal. The 42 MMT scenario ultimately proved to be more

[1] CPUC Decision, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

aligned with the target of 60 percent RPS established by SB 100, which came into effect on September 10, 2018 and which will be taken into account in future planning cycles.

These assumptions were further vetted by stakeholders through the ISO's stakeholder process which resulted in this year's study plan.[2]

The ISO considers the agencies' successful effort coordinating the development of the common planning assumptions to be a key factor in promoting the ISO's transmission plan as a valuable resource in identifying grid expansion necessary to maintain reliability, lower costs or meet future infrastructure needs based on public policies.

Beyond coordinating study assumptions, the ISO also undertook a major informational special study in the 2018-2019 transmission planning cycle in response to a request from Robert B. Weisenmiller, Chair of the CEC and Michael Picker, President of the CPUC. Please refer to the Informational Study discussion below.

Key Reliability Study Findings

During the 2018-2019 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure compliance with applicable NERC reliability standards and ISO planning standards and tariff requirements. The analysis was performed across a 10-year planning horizon and modeled a range of on-peak and off-peak system conditions. The ISO's assessment considered facilities across voltages of 60 kV to 500 kV, and where reliability concerns existed, the ISO identified transmission solutions to address these concerns or assessed the ability of previously approved projects to meet those needs. This plan proposes approving 11 reliability-driven transmission projects representing an investment of approximately $607.4 million in infrastructure additions to the ISO controlled grid, all of which are located in the PG&E service territory. These are comprised of 9 smaller projects each less than $50 million totaling $168 million and two dynamic voltage support projects[3] totaling $440 million.

P27-129 cont.

The two dynamic reactive support projects are eligible for the ISO's competitive solicitation process.

In addition to the identification of new reliability requirements, the ISO also reviewed a number of previously approved transmission projects in the PG&E service territory, which had been identified in previous planning cycles as needing further evaluation. These reviews looked not only at canceling projects where changing circumstances no longer supported the need for the project, but re-scoping of projects where needs still existed and changing circumstances could lead to more effective and economic solutions:

[2] The 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, March 30, 2018, is available at: http://www.caiso.com/Documents/Final2018-2019StudyPlan.pdf

[3] Further review of the engineering detail for the termination of the Round Mountain 500 kV Reactive Project is required due to siting issues at Round Mountain for the project. Board of Governor approval is recommended, and the additional detail will be posted as an addendum to the transmission plan. The competitive procurement process for the project will commence after that has taken place.

- Six transmission projects with cost estimates totaling $440 to $550 million that were found to be no longer required and are recommended to be canceled.
- One project will continue to be on hold pending reassessment in future cycles.

Going forward, individual projects will continue to be considered for review on a case by case basis, as the need arises.

Renewables Portfolio Standard Policy-driven Transmission Assessment

As noted above, the CPUC's input was communicated via a decision[4] on February 8, 2018 at the end of the first year of the 2017-2018 Integrated Resource Planning cycle, which adopted the integrated resource planning process and also provided resource planning assumptions to the ISO. Anticipating higher renewable generation requirements going forward, the CPUC communicated a portfolio based on its "42 MMT scenario" that results in approximately a 57 percent RPS as a sensitivity portfolio for policy-driven planning efforts. The CPUC declined to provide a "base" portfolio for actual project approval purposes, which was considered unnecessary, given past transmission planning studies and steadily declining estimates of the amount of grid-connected renewables necessary to achieve the 50 percent by 2030 goal.

The ISO has accordingly performed policy-driven study assessments of the 42 MMT scenario as a sensitivity with the results being provided to the CPUC for future resource planning purposes, and the ISO is not recommending any new transmission solutions at this time for policy purposes. P27-129 cont.

A summary of the various transmission elements already underway for supporting California's renewables portfolio standard is shown in Table 1. These elements are composed of the following categories:

- Major transmission projects that have been previously-approved by the ISO and are fully permitted by the CPUC for construction;
- Additional major transmission projects that the ISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the permit approval process; and
- Major transmission projects that have been previously approved by the ISO but are not yet permitted.

[4] CPUC Decision, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

Table 1.1-1: Elements of 2018-2019 ISO Transmission Plan Supporting 50% Renewable Energy Goals

Transmission Facility	In-Service Date
Transmission Facilities Approved, Permitted and Under Construction	
West of Devers Reconductoring	2021
Sycamore – Penasquitos 230 kV Line	Completed
Additional Major Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted	
None at this time	
Policy-Driven Transmission Elements Approved but not Permitted	
Lugo – Eldorado series cap and terminal equipment upgrade	2020
Warnerville-Bellota 230 kV line reconductoring	2023
Wilson-Le Grand 115 kV line reconductoring	2020
Suncrest 300 Mvar SVC	2019
Lugo-Mohave series capacitors	2020
Additional Policy-Driven Transmission Elements Recommend for Approval	
None identified in 2018-2019 Transmission Plan	

P27-129 cont.

Key Economic Study Findings

The ISO's economic planning study is an integral part of the ISO's transmission planning process and complements the reliability-driven and policy-driven analysis by exploring economic-driven network upgrades that may create opportunities to reduce ratepayer costs within the ISO. The studies used a production cost simulation as the primary tool to identify potential economic development opportunities and in assessing those opportunities. While reliability analysis provides essential information about the electrical characteristics and performance of the ISO controlled grid, an economic analysis provides essential information about transmission congestion which is a key input in identifying potential study areas, prioritizing study efforts, and assessing benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load, and minimizing or resolving transmission congestion can be cost effective to the ratepayer if solutions can be implemented to generate savings that are greater than the cost of the solution. Other end-use ratepayer cost saving benefits such as reducing local capacity requirements in transmission-constrained areas can also provide material benefits. Note that other benefits and risks – which cannot always be quantified – must also be taken into account in the ultimate decision to proceed with an economic-driven project.

In the economic planning analysis performed as part of this transmission planning cycle in accordance with the unified planning assumptions and study plan, approved reliability and policy network upgrades and those recommended for approval in this plan were modeled in the economic planning database. This ensured that the results of the analysis would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan.

Due to a convergence of circumstances, the ISO undertook far more economic planning analysis than typical, or set out in the ISO tariff. Beyond screening congestion results to select key focus areas for economic studies:

- The ISO received a number of economic study requests;
- A number of proposed reliability projects cited material economic benefits that could warrant moving forward;
- Several interregional transmission projects were submitted; P27-129 cont.
- In conjunction with the expanded 10-year local capacity technical study the ISO undertook in this planning cycle – examining not only the need and the characteristics of the need but alternatives to reduce local gas-fired generation capacity requirement - the ISO selected a subset of local capacity areas for detailed economic analysis where options appeared potentially viable.

As well, a number of the above proposals and submissions overlapped, necessitating a comprehensive approach. While the ISO tariff allows the ISO to limit the number of economic evaluations to five or less, the ISO studied proposals in 12 study areas, considering 25 alternatives overall, and with the largest area study addressing 8 separate stakeholder-submitted proposals.

The ISO's studies were impacted by certain conditions existing in this planning cycle:

- The longer term requirements for gas-fired generation for system and flexible capacity requirements continues to be examined, both in the CPUC integrated resource planning process as well as ISO studies – studies conducted outside of the annual transmission planning process for purposes of supporting CPUC efforts. As no actionable direction has yet been set regarding the future of the existing gas-fired generation fleet, the uncertainty necessitated taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements;
- A number of project sponsors based their submissions on assumptions went beyond the policy direction received from the CPUC given the current status of its integrated

resource planning process, that were far less conservative in valuing local capacity requirement reductions, or that applied planning standards that exceeded the ISO's approved planning standards.

The project sponser and stakeholder views on these issues are being communicated to the CPUC, as appropriate, and being considered regarding the need to address some of the concerns in stakeholder initiatives. However, these issues are not reasonably addressed inside the planning process itself which is conducted on the basis of the tariff and standards currently in effect.

In summary, two projects were found to be needed as economic-driven projects in the 2018-2019 planning cycle:

- Giffen Line Reconductoring Project, estimated to cost less than $5 million, to reduce generator pocket congestion.
- Pease LCR Reduction Project, the looping in of the Pease-Marysville 60 kV line into the East Marysville 115 kV substation, estimated to cost $32 million and eliminating the need for local capacity requirements in the Pease sub-area.

Several paths and related projects will be monitored in future planning cycles to take into account improved hydro modeling, further consideration of suggested changes to ISO economic modeling, and further clarity on renewable resources supporting California's 50 percent renewable energy goals.

P27-129 cont.

Interregional Transmission Coordination Process

The ISO's 2018-2019 transmission planning cycle marks the beginning of the second biennial cycle since these coordination processes were put in place addressing the requirements of FERC Order No. 1000. This cycle reflects the complete transition from old process to new, taking into account the status of the policy drivers and the progress achieved in implementing the new interregional processes.

Six interregional transmission projects were submitted into the bieenial process. Of those, three were screened and fed into the ISO's economic study process for further analysis.

The ISO's economic planning study is an integral part of the ISO's transmission planning process and complements the reliability-driven and policy-driven analysis by exploring economic-driven network upgrades that may create opportunities to reduce ratepayer costs within the ISO. This aligns with the requirement to examine if proposed interregional transmission projects that may provide more economic and cost-effective solutions than regional proposals for meeting identified needs. None of the three projects studied in this cycle were found to be more economic and cost-effective solutions than regional proposals for meeting identified needs.

Non-Transmission Alternatives and Preferred Resources

The ISO has routinely emphasized exploring preferred resources[5] and other non-transmission alternatives to conventional transmission to meet emerging reliability needs. Through reliance on existing resources as a matter of course as potential mitigations for identified needs, area-specific studies[6] and continued efforts to refine understanding of the necessary characteristics for resources such as slow response demand response to provide local capacity[7], the ISO's applications have expanded in this planning cycle beyond the ISO's original methodology[8] set in place some years ago. Further, in this 10-Year Local Capacity Technical Study developed in this year's transmission planning cycle, the ISO provided detailed information regarding the characteristics of the local capacity area needs that are the basis for assessing non-transmission and preferred resource solutions. The ISO is also continuing to support the implementation of solutions for transmission needs consisting of combinations of transmission reinforcements and procurement of preferred resources in the LA Basin, in Oakland, and the Moorpark sub-area. A number of storage proposals have also been studied in this year's transmission planning process, although none were found to be needed given the limited transmission system reinforcement requirements in this year's cycle, and the conservative approaches taken in this planning cycle in assessing the value of resources that would be focused on replacing existing gas-fired generation. Please refer to section 8.2.

Informational Studies

P27-129 cont.

As in past transmission planning cycles, the ISO undertook additional informational studies to help inform future transmission planning or resource procurement processes.

Reliance on Gas-fired Generation in Local Capacity Areas

The ISO undertook to conduct additional analysis of local capacity requirements in local capacity areas, to help inform resource planning issues. First, the 10-Year Local Capacity Study conducted as part of this cycle was expanded to include detailed information regarding the characteristics of the local capacity area needs that are the basis for assessing non-transmission and preferred resource solutions. Second, transmission or other hybrid alternatives

[5] To be precise, "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The term is used more generally here consistent with the more general use of the resources sought ahead of conventional generation.

[6] See generally CEC Docket No. 15-AFC-001, and see "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

[7] Further analysis of the necessary characteristics for "slow response" demand response programs was undertaken initially through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC. See "Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop," presentation, October 4, 2017, http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

[8] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf.

were developed for half of the area and sub-area needs, selected on a prioritized basis. These first two steps were considered to be of use in future resource procurement processes. Third, a subset of those areas and sub-areas were fed into the ISO's economic study process to assess the viability of moving forward with some level of local capacity requirement reduction on the economic basis used to assess transmission development.

Northwest Hydro

The ISO undertook a major informational special study in the 2018-2019 transmission planning cycle in response to a request from Robert B. Weisenmiller, Chair of the CEC and Michael Picker, President of the CPUC. The request was received by letter[9] on February 15, 2018, requesting that the ISO undertake specific transmission sensitivity studies considering the potential to increase the transfer of low-carbon supplies to and from the Northwest. This resulted in an extensive coordination effort among state agencies and a host of potentially affected owners and operators, as well as other stakeholders. The ISO acknowledges and appreciates the broad support and effort on behalf of many that went into that study. Please refer to chapter 7.

Longer term system and Flexible Capacity Requirements

The ISO has updated in the transmission plan the system-wide results from prior years' PLEXOS studies of the need for the existing gas-fired generation fleet for system capacity and flexibility requirements, as well as the production cost modeling benefits of large (hydro) storage. The system and flexibility requirements studies also help inform the ISO's participation in the CPUC's integerated resource planning processes. Note that the storage studies were limited to production cost modeling, and not a comprehensive review, as storage projects were also studied as economic study requests in the transmission planning process itself.

Note that in previous planning cycles, the ISO undertook frequency response studies and reported on associated modeling improvement efforts as a special study. Given the significance of that work, these efforts have now been moved to an ongoing study process inside the annual planning cycle despite not being a tariff-based obligation.

The additional informational "special" studies conducted in parallel with the transmission planning cycle provide additional clarity on issues that need to be considered in developing future policy direction or further analysis.

P27-129 cont.

Conclusions and Recommendations

The 2018-2019 Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately meet California's policy goals, address grid reliability requirements and bring economic benefits to consumers. This year's plan identified 13 transmission projects, estimated to cost a total of approximately $644.4

[9] Letter of February 15, 2018 to Steve Berberich, ISO, http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf.

million, as needed to maintain the reliability of the ISO transmission system, meet the state's renewable energy mandate, and deliver material economic benefits.

The ISO has also identified 6 previously approved transmission projects that are recommended to be canceled, and one remains on hold requiring further evaluation in future planning cycles before applications proceed for construction permitting.

The additional informational studies conducted in parallel with the transmission planning cycle provide additional clarity on issues that need to be considered in developing future policy direction or further analysis.

P27-129 cont.

Chapter 1

1. Overview of the Transmission Planning Process

1.1 Purpose

A core ISO responsibility is to identify and plan the development of solutions to meet the future needs of the ISO controlled grid. Fulfilling this responsibility includes conducting an annual transmission planning process (TPP) that culminates in an ISO Board of Governors (Board) approved, comprehensive transmission plan. The plan identifies needed transmission solutions and authorizes cost recovery through ISO transmission rates, subject to regulatory approval. The plan also identifies non-transmission solutions that will be pursued in other venues to avoid building additional transmission facilities if possible. This document serves as the comprehensive transmission plan for the 2018-2019 planning cycle.

As in recent transmission planning cycles, the ISO has prepared this plan in the larger context of supporting important energy and environmental policies and assisting the transition to a cleaner, lower emission future while maintaining reliability through a resilient electric system. That future is not only being planned on the basis of transitioning to lower emission sources of electricity, but on evolving forecasts and expectations being set for transitions in how and when electricity is used. While each year's transmission plan is based on the best available forecast information at the time the plan is prepared, the ISO has also had to consider and adapt to changing forecasts to ensure a cost effective and reliable transmission system meeting the demands placed on it in these rapidly changing times. P27-129 cont.

In this regard, the transmission plan continues to be somewhat of a bellwether of the changing demands placed on the transmission system and the broader range of conditions the transmission system will need to address and manage than in past transmission plans. It also reflects the need to adapt plans as circumstances change and new inroads are made on the broader electricity context in California – and energy footprint overall.

The transition to a generation fleet with significantly increased renewables penetration and "duck curve" issues, combined with increasing variability in net sales patterns due to behind-the-meter generation and other load-modifying behaviors, are both driving the ramping needs and flexible generation requirements within the electricity market, and are having a pronounced impact on the transmission grid as flow patterns change on a daily and seasonal basis from traditional patterns. As these other changes, including growth in behind-the-meter generation, have been occurring more rapidly than originally anticipated only a few short years ago, both the techniques relied upon to assess system needs and certain previously planned projects themselves continue to evolve.

Each year's transmission plan is a product of timing, reflecting the particular status of various initiatives and industry changes in the year the plan is developed, as well as the progress in parallel processes to address future needs. The 2018-2019 Transmission Plan is heavily influenced by the success in past transmission planning cycles to address historical reliability issues as well as those triggered by more recent events, the progress made toward meeting 50 percent renewable portfolio standard (RPS) goals, and the ongoing development of various state agency processes and proceedings to address escalating renewable energy targets established by SB 350. Goals established in the more recent SB 100 will be taken into account through further coordination with state agencies, moving towards the 2019-2020 trasnmission planning cycle. The emerging issues and challenges are discussed in more detail in section 1.2 below, Impacts of the Industry Transformation.

Within this context, the transmission plan's primary purpose is to identify – based on the best available information at the time this plan was prepared – needed transmission facilities based upon three main categories of transmission solutions: reliability, public policy, and economic needs. A transmission plan may also identify any transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects, or provide for merchant transmission projects. In recommending solutions for identified needs, the ISO takes into account an array of considerations. Furthering the state's objectives of a cleaner future plays a major part in those considerations.

The ISO identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards and Western Electricity Coordinating Council (WECC) regional criteria, and ISO transmission planning standards. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2018-2019 planning cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to verify compliance with applicable NERC reliability standards. The ISO performed this analysis across a 10-year planning horizon and modeled summer on-peak and off-peak system conditions. The ISO assessed the transmission facilities under ISO operational control, ranging in voltage from 60 kV to 500 kV. The ISO also identified plans to mitigate observed concerns considering upgrading transmission infrastructure, implementing new operating procedures, installing automatic special protection schemes, and examining the potential for conventional and non-conventional resources (preferred resources including storage) to meet these needs.

P27-129 cont.

Since implementing the current transmission planning process in 2010, the ISO has considered and placed a great deal of emphasis on assessing non-transmission alternatives, both conventional generation and, in particular, preferred resources such as energy efficiency, demand response, renewable generating resources, and those energy storage solutions that are not transmission. Although the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades. For example, the ISO previously determined that a combination of transmission upgrades and preferred resources in concert would provide the most effective local capacity requirement replacement for the Oakland Generation Station, should that plant retire, and also meet the future needs in the Santa Clara sub-area as generation employing once-through-cooling in that sub-area retires. Further, load modifying preferred resource assumptions incorporated into the load forecasts adopted through state energy agency activities provide an additional opportunity for preferred resources to address transmission needs.

To increase awareness of the role of preferred resources, section 7.3 summarizes how preferred resources will address specific reliability needs. In addition, discussion throughout chapter 2 show the reliance on preferred resources to meet identified needs on an area-by-area study basis.

This transmission plan documents ISO analyses, results, and mitigation plans.[10] These topics are discussed in more detail below.

Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support state and federal directives. In recent transmission planning cycles, the focus of public policy analysis has been predominantly on planning to ensure achievement of California's renewable energy goals. The trajectory to achieving the 33 percent renewables portfolio standard set out in the state directive SBX1-2 has been largely established, and the focus in this plan shifted to the objectives of SB 350 – in particular, the 50 percent RPS by 2030 objective. Accordingly, the California Public Utilities Commission (CPUC) provided to the ISO renewable generation portfolios reflecting 50 percent RPS[11] for reliability and economic study purposes, and a higher portfolio representing approximately 57 percent[12] as a sensitivity case for policy-driven analysis. These portfolios pre-dated, but are aligned with the direction subsequently established with SB 100[13] becoming law in September, 2018. The ISO expects that the results of this sensitivity study will be helpful in future CPUC integrated resource planning efforts that will also take into account SB 100 direction. P27-129 cont.

Economic-driven solutions are those that provide net economic benefits to consumers as determined by ISO studies, which includes a production simulation analysis. Typical economic benefits include reductions in congestion costs and transmission line losses and access to lower cost resources for the supply of energy and capacity. As renewable generation continues to be added to the grid, with the inevitable economic pressure on other existing resources, economic benefits will also have to take into account cost effective mitigations of renewable integration challenges as well as potential reductions to the generation fleet located in local capacity areas. To assist future CPUC resource planning processes, the ISO undertook in this planning cycle a

[10] This document provides detail of all study results related to transmission planning activities. However, consistent with the changes made in the 2012-2013 transmission plan and subsequent transmission plans, the ISO has not included in this year's plan the additional documentation necessary to demonstrate compliance with NERC and WECC standards but not affecting the transmission plan itself. The ISO has compiled this information in a separate document for future NERC/FERC audit purposes. In addition, detailed discussion of material that may constitute Critical Energy Infrastructure Information (CEII) is restricted to appendices that the ISO provides only consistent with CEII requirements. The publicly available portion of the transmission plan provides a high level, but meaningful, overview of the comprehensive transmission system needs without compromising CEII requirements.

[11] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

[12] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

[13] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

more in-depth analysis of local capacity requirements, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs.

In addition to undertaking the aforementioned analyses required by the tariff, the ISO also conducted a "special study" at the request[14] of the chairman of the California Energy Commission (CEC), and the president of the CPUC, investigating the potential benefits of improved transfer capability between the ISO and hydro resources in the Pacific Northwest. Please refer to chapter 7.

1.2 Impacts of the Industry Transformation

As state efforts continue to reduce the carbon footprint and other environmental impacts of the electricity industry, the ISO must address a growing range of considerations to ensure those objectives are enabled and ensure overall safe, reliable, and efficient operation through its planning process. These efforts include the continued growth of renewable generation on the ISO system whether grid-connected or behind-the-meter at end customer sites, the phase out of using coastal water for once-through-cooling at thermal generating stations, and a growing range of strategies, policy priority areas, emerging technologies and risks and opportunities to either achieve energy use reductions or impacts on energy consumption. Many of these are no longer stand-alone solutions – they can achieve great outcomes if properly planned and implemented in concert with the right volumes of other mitigations, or fail to provide the expected benefits if implemented in isolation or carelessly.

P27-129 cont.

These trends, including the continued rapid expansion of behind-the-meter solar generation, have created new and more complex operating paradigms for which the ISO must consider in planning the grid, as discussed in the 2017-2018 Transmission Plan. In its transmission planning processes, the ISO is therefore having to consider factors and trends reaching beyond the more specific and well-defined challenges of the past, such as the phasing out of gas-fired generation relying on coastal waters for once-through cooling as well as the early retirement of the San Onofre Nuclear Generating Station and the planned retirement of Diablo Canyon Nuclear Generating Station in 2024.

These new challenges and potential solutions must also consider the emergence of new policy and operating frameworks that will be relied upon to develop and coordinate the supply of, and demand for, electricity in the future.

The changing generation resource fleet inside California and the continued exploration of regionalism as a means to maximize the benefits of renewable generation development is both changing the nature of interchange with the ISO's neighboring balancing authority areas and increasing the variability in flows on a more dynamic basis. The continued growth in participation in the ISO's energy imbalance market is resulting in more dynamic import and export conditions.

[14] Letter of February 15, 2018 to Steve Berberich, ISO, http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf.

The rest of this subsection discusses a number of the emerging issues and factors together with the inputs considered in this transmission planning cycle, as well as the other actions being taken to advance the understanding or implementation of those issues in the future — whether special study activities, ISO policy initiatives or regulatory proceedings.

1.2.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

Base Forecasts

The ISO continues to rely on load forecasts and load modifier forecasts prepared by the California Energy Commission (CEC) through its Integrated Energy Policy Report (IEPR) processes. The combined effects of flat or declining gross load forecasts and reductions in those net load forecasts due to behind-the-meter generation and energy efficiency programs continue to significantly impact the planning process:

- Declining net peak loads have led to the review of several previously-approved load growth-driven transmission projects, particularly in the PG&E area[15].
- The increasing variable loading on the transmission system is resulting in more widely varying voltage profiles, resulting in an increased need for reactive control devices to maintain acceptable system voltages.
- The rapid deployment of behind-the-meter generation is driving changes in forecasting, planning and operating frameworks for both the transmission system and generation fleet. P27-129 cont.

The rapid acceleration of behind-the-meter rooftop solar generation installations in particular has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — to shift to a time outside of the traditional daily peak load period. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted out of the window when grid-connected solar generation is available. This is an issue that has been progressing through subsequent IEPR processes, having first been noted in the CEC's 2015 effort.

The ISO's 2017-2018 Transmission Plan described in detail the progress made year-after-year in coming to terms with the refinements in forecasting techniques to address the issue, and the steps the ISO took to accommodate the evolution of the issue in each transmission plan.

These efforts have now resulted in the development of the California Energy Demand Forecast 2018-2028 (CED 2017) that the ISO is using in the 2018-2019 transmission planning process. This forecast includes full hourly load forecasting models for both consumption and load modifiers, and this information will play a key role in the more complex analysis of emerging

[15] Because most of PG&E's low voltage sub-transmission facilities are under ISO operational control, there are a relatively large number of previously approved small and substantially unrelated projects in the PG&E area that were predominantly load-growth driven. This enabled the ISO to conduct a more programmatic approach in reviewing those projects in the 2015-2016 transmission planning cycle and again in this planning cycle. In contrast, the ISO has focused on a more case-by-case basis on a smaller number of larger and more heavily inter-related projects in the SDG&E and SCE service areas mitigating the loss of the San Onofre Nuclear Generating Station and once-through-cooling thermal generation retirements.

system needs and the effectiveness of use-limited preferred resources as part of meeting those needs.

Further Drivers

Through the Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiative, the ISO has been actively engaged in enhancing the ability of distributed energy resources (DERs) to participate in the ISO markets.

At the same time, the CPUC is emphasizing the role and integration of DERs into the planning and procurement framework of its jurisdictional utilities. These issues are being considered both in the CPUC's current Distribution Resources Plan proceeding, and identified in the 2017-2018 Integrated Resource Planning proceeding as an issue for future optimization in the subsequent 2019-2020 proceeding, as discussed in more detail below.

Further consideration of a range of industry trends and needs also drive an increased range of uncertainty about future requirements—with energy efficiency programs driving demand in one direction, but decarbonizing other sectors such as transportation potentially causing increased demand in new and previously unseen consumption patterns.

Also, the ISO will continue to explore the possibility for demand-side management tools to play a role in mitigating local reliability needs; those processes are considered as part of the resource planning processes discussed in the next subsection.

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1.2.2 Resource Planning

Resource planning has informed past planning cycles by focusing primarily on informing policy-driven transmission needs to support state policy objectives on the development of renewable generation, and the role local resources—whether conventional or preferred resources—can play in meeting local reliability needs.

Regarding the former, the ISO and the CPUC have a memorandum of understanding under which the CPUC provides the renewable resource portfolio or portfolios for ISO to analyze in the ISO's annual TPP. The portfolio development has transitioned from the CPUC's previous long term procurement plan proceedings to the current integrated resource planning (IRP) proceedings.

Integrated Resource Planning Process

The CPUC issued a decision[16] on February 8, 2018 at the end of the first year of the 2017-2018 Integrated Resource Planning cycle, which adopted the integrated resource planning process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

The IRP process took into account the specific objectives established for the electricity industry through the Clean Energy and Pollution Reduction Act of 2015, and the broader state objectives

[16] CPUC Decision, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

regarding reducing greenhouse gas emissions that are expected to reach beyond the requirements already set for the electricity industry.

Through the 2017 IRP effort, the CPUC established a 50 percent RPS “default” scenario that, as directed in the decision, was subsequently transmitted to the ISO to be used in the 2018-2019 TPP reliability assessment.

Further, a statewide electric sector GHG reduction target of 42 million metric tons (MMT) by 2030 was selected as the basis for a “42 MMT Scenario” reference plan for the load serving entities to consider in developing their individual plans as part of the 2018 process. This 42 MMT Scenario portfolio was transmitted to the ISO to be used as a sensitivity in the 2018-2019 TPP policy-driven assessment to identify Category 2 transmission solutions based on the Reference System Plan. No base portfolio was transmitted to the ISO for use in the 2018-2019 TPP policy-driven assessment, *e.g.*, the CPUC direction enabled analysis for information purposes, but not as the basis for approval of policy-driven transmission in this 2018-2019 transmission planning cycle. The decision also noted the expectation that once the “preferred system plan” is adopted through the 2018 IRP effort, it will be utilized as a policy-preferred portfolio in the subsequent transmission planning process to identify Category 1 policy-driven transmission needs. The ISO expects that portfolio to also be more aligned with the 60% RPS goal set out in SB 100.

Clean Energy and Pollution Reduction Act of 2015

On October 7, 2015 Governor Jerry Brown signed into law SB 350, the Clean Energy and Pollution Reduction Act of 2015 authored by Senator Kevin De León. The bill established the following goals:

- By 2030, double energy efficiency for electricity and natural gas by retail customers
- 50 percent renewables portfolio standard (RPS) by 2030
    - Existing RPS counting rules remain unchanged
    - Requires LSEs to increase purchases of renewable energy to 50 percent by December 31, 2030
    - Sets interim targets as follows
        - 40 percent by the end of the 2021-2024 compliance period
        - 45 percent by the end of the 2025-2027 compliance period
        - 50 percent by the end of the 2028-2030 compliance period

SB 350 creates a pathway to increased levels of renewable generation and lower greenhouse gas emissions.

The 100 Percent Clean Energy Act of 2018

On September 10, 2018 Governor Jerry Brown signed into law SB 100, the 100 Percent Clean Energy Act of 2018 also authored by Senator Kevin De León.

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Among other provisions, SB 100 built on existing legislation including SB 350 and revised the above-described legislative findings and declarations to state that the goal of the program is to achieve the 50 percent renewable resources target by December 31, 2026, and to achieve a 60 percent target by December 31, 2030. The bill also requires that retail sellers and local publicly owned electric utilities procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kilowatthours of those products sold to their retail end-use customers achieve 44 percent of retail sales by December 31, 2024, 52 percent by December 31, 2027, and 60 percent by December 31, 2030. This bill also states that it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. The bill requires that the achievement of this policy for California not increase carbon emissions elsewhere in the western grid and that the achievement not allow resource shuffling.

As this legislation came into effect well after the CPUC's 2017 integrated resource planning activities and the ISO's analysis of the renewable generation portfolios provided by the CPUC were underway, the specific measures set out in SB 100 were not incorporated directly into the 2018-2019 transmisson planning cycle. However, as noted earlier, the CPUC's 42 MMT scenario renewable generation portfolios achieved a higher GHG goal than the 50 percent RPS requirement by 2030, and is approximately equivalent to a 57 percent RPS.

Market pressure on gas-fired generation fleet – and new expectations on the fleet

The significant amount of new renewable generation added to the grid continues to put downward economic pressure on the existing gas-fired generation fleet, and this is expected to be exacerbated as renewable generation is added in the future. Further, the long term requirements established by SB 100 moving to GHG-free electricity sets the direction for the eventual retirement of gas-fired generation and replacement with other non-GHG-emitting resources. Reliance on gas-fired generation in local capacity areas, and in particular in disadvantaged communities, continues to be of increasing concern.

The initial 2017-2018 two-year cycle of the CPUC's integrated resource planning process did not address potential gas-fired generation retirement beyond the known retirements and the retirement plans of generation currently relying on once-through-cooling. The ISO's planning assumptions in the 2018-2019 cycle took a somewhat more aggressive approach by maintaining the assumptions in previous plans – derived from the previous CPUC Long Term Procurement Plan processes – that gas-fired generation would retire at the end of a 40 year life, unless a power purchase arrangement extended that timeline. However, it was recognized that a transmission plan recommendation for a project's approval based solely on the more aggressive retirement assumptions would be unlikely, and would need to be considered on a case-by-case basis.

Continuing with past efforts, the ISO has conducted additional studies on a largely informational basis to provide better insights and understandings of the opportunities and issues associated with gas-fired generation retirement – from both a local and system perspective.

To understand the risk of a material amount of similarly situated generation retiring more or less simultaneously, ostensibly for economic reasons, the ISO initiated special studies in the 2016-

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cont.

2017 transmission planning cycle, with additional analysis extending into the 2017-2018 time frame, to assess the risks. Those studies did not find new geographic areas of concern exposed to local reliability risk if faced with retirements at levels that approached the limit of acceptable system capacity outside of the pre-existing local capacity areas. The studies did identify potential system-wide reserve margin issues emerging in the 2028 time frame with as little as 1000 to 2000 MW of retirements beyond the current planned retirements. The system-wide implications have been updated in this planning cycle and are discussed in chapter 7. These studies are also part of the ISO's analysis supporting the CPUC's integrated resource planning process, in which these issues are being considered and addressed.

The downward economic pressure on the gas-fired generation fleet not under long-term contract has also raised local capacity concerns and renewed focus on finding alternatives that would reduce local resource capacity requirements in specific local capacity areas. For example, on January 11, 2018, the CPUC adopted Resolution E-4909, authorizing PG&E to procure energy storage or preferred resources to address local deficiencies and ensure local reliability, which resulted in 567.5 MW of battery storage being approved by the CPUC on November 8, 2018. The ISO is working with utilities to incorporate energy storage, preferred resources, and transmission upgrades to achieve an overall comprehensive and economic solution to local needs. While targeting alternatives to achieve overall reductions in local capacity requirements may be an area of new policy direction from the state, the ISO is considering how to address these concerns as potential economic studies in this and future planning cycles. In particular, the ISO undertook a more comprehensive study of local capacity areas in this planning cycle examining both the load shapes and characteristics underpinning local capacity requirements, and evaluating alternatives for those needs even if it is unlikely that the economic benefits alone would outweigh the costs. Please refer to chapter 5 and chapter 6.

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Study efforts focusing on reducing costs to consumers by reducing local capacity requirements and shifting away from reliance on gas-fired generation for those needs will need to take into account the current and future economics of existing local capacity resources, the renewable integration benefits the generation may provide and the system need to retain that generation, and other criteria and characteristics that can make certain generators in the existing fleet more or less advantageous in prioritizing study efforts and in committing to alternatives to reduce local capacity needs. Proximity to disadvantaged communities must also be taken into account.

Coordination with CPUC Resource Adequacy Activities

Along with other drivers, the shifting of the net sales peak to later hours – largely due to the higher than once forecasted development of behind-the-meter solar generation – combined with steadily increasing volumes of grid-connected solar generation has led to the need to broadly revisit resource planning assessments and certain ISO transmission assessment methodologies that underpin resource planning efforts. This has become most apparent in considering the alignment of long term integrated resource planning efforts with the CPUC's administration of the state's resource adequacy program. While longer term planning studies have focused on more granular approaches of studying comprehensive forecasts and load and resource profiles, the near term resource adequacy programs have focused on methodologies to tabulate resource characteristics to guide short term resource contracting of existing resources to meet near term needs. While expanding from focusing on system and local capacity to also incorporate flexibility, *e.g.*, ramping, needs helps address certain issues, resources need to be considered in the context of the load profiles being served, and the other resources being acquired – which has led to the incorporation of effective load carrying capability methodologies being pursued by the CPUC.

Along with other stakeholders, the ISO has supported and encouraged a broader review of the current resource adequacy framework in the CPUC's current Resource Adequacy proceeding. In the CPUC's "Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years", the Commission noted that:

> *"[g]iven the passage of time and the rapid changes occurring in California's energy markets, it may be worthwhile to re-examine the basic structure and processes of the Commission's [resource adequacy] program."*[17]

The ISO strongly supports this re-examination and provided several proposals to improve the fundamental structure of the CPUC's resource adequacy program especially in light of the transforming grid. To effectively and efficiently maintain grid reliability while incorporating greater amounts of preferred and intermittent clean, green resources, the resource adequacy program must ensure both procurement of the right resources in the right locations and with the right attributes, and the procurement of a resource adequacy portfolio that meets the system's energy needs all hours of the year. Simply stacking resource capacity values to meet an hourly forecast peak is no longer relevant and not a prudent long-term resource adequacy practice given the system's growing reliance on intermittent and availability limited resources. P27-129 cont.

To help reform the resource adequacy program, the ISO proposed the CPUC implement multi-year resource adequacy procurement requirements for system, local and flexible resources. The ISO also recommended that the CPUC (1) modify its adopted effective load carrying capacity values to ensure proper counting of resource adequacy resources and their contribution to reliability, (2) adjust system resource adequacy demand forecasts based on increased load variability, and (3) set local resource adequacy requirements to account for availability-limited resources. In all, these proposals are designed to ensure resources have the right capabilities and are available when and where needed to meet system needs across the year. In 2018, the CPUC decided to implement a multi-year procurement requirement for local resource adequacy capacity. As a result, the primary focus of the CPUC resource adequacy proceeding was on developing implementation details for the new multi-year resource adequacy framework. The ISO will continue to participate in the CPUC's resource adequacy proceeding to ensure that a workable multi-year procurement framework is adopted and to advance other program improvements.

In parallel, the ISO is conducting a review of existing ISO "backstop" procurement mechanisms. On January 12, 2018, the ISO filed a tariff amendment with the Federal Energy Regulatory Commission to improve its "risk of retirement" capacity procurement mechanisn (ROR CPM) designation process – which addresses an identified need a year hence, but where the

[17] *Order Instituting Rulekmaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2010 Compliance Years,* CPUC Proceeding No. R.17-09-020, at p. 3 (OIR), October 4, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747674.PDF.

generation is at risk of retiring during the intervening year – by making it more efficient and workable. Among other things, the proposed tariff amendments establish a revised framework that will allow the ISO, in specific circumstances, to signal its intent to designate a resource needed for reliability earlier in the year. On April 12, 2018, FERC rejected the ISO's January 12, 2018 filing to enhance the process for ROR CPM designations. One of the key features of the ROR CPM proposal was to create a new window each spring, in addition to the existing window each fall, for resources to request a ROR CPM designation. In its order FERC found that a spring window could result in front-running the RA process, price distortions and interference with bilateral RA procurement. In its order FERC noted that the ISO had initiated a stakeholder process to review RMR and CPM issues and strongly encouraged the ISO and stakeholders to adopt a holistic, rather than piecemeal, approach and encouraged the ISO to propose a package of comprehensive reforms.

Following the FERC order, the ISO included in its RMR and CPM Enhancements stakeholder initiative the substantive issues that were considered in the ROR CPM process enhancements initiative. The RMR and CPM Enhancements initiative will consider changes to the RMR and CPM paradigms, including review of the RMR tariff, agreement and process and clarifying and aligning the use of RMR and CPM procurement. Some of the key items under discussion are:

- Merge ROR CPM procurement and RMR procurement into one procurement mechanism under the RMR tariff.
- Consider modifications to CPM compensation above the CPM soft-offer cap.
- Make RMR units subject to a must offer obligation.
- Update the rate of return for RMR resources.
- Provide flexible and system RA credits from RMR resources.
- Lower banking costs for RMR invoicing.
- Streamline and automate RMR settlement process.

The ISO has held working group meetings on May 30, 2018, August 27, 2018, and November 1, 2018 to gather input from stakeholders. The working group meetings were well attended, including attendance by CPUC staff. Stakeholders discussed the various items that are within the scope of the initiative. The ISO issued a draft final proposal in January 2019 and has targeted taking a proposal to the ISO Board of Governors in March 2019.

As well, on October 29, 2018, the FERC approved a limited interim change to the pro forma RMR agreement that effective September 1, 2018, applies to new RMR designations and allow the ISO to terminate the interim form of agreement effective at the end of the contract year and immediately re-designate RMR resources under the new substantive RMR agreement for the following contract year. The right to immediately re-designate would not apply to RMR resources under RMR agreements currently in effect.

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Impact of Evolving Resource Fleet on Transmission Assessments supporting Resource Adequacy Programs

The same drivers leading to the development of effective load carrying capability (ELCC) methodologies in considering the usefulness of particular resources in meeting load requirements also affect ISO transmission assessment methodologies that underpinned resource planning efforts. In particular, the methodology used to consider the deliverability of various resources, such that the resources can provide capacity into the state's resource adequacy program, was developed at a time where the bulk of the capacity – gas-fired generation in particular – was fully dispatchable. Comparatively small levels of renewable generation were treated as incremental to the "core" of other dispatchable resources, and incorporated into deliverability methodologies taking into account their output characteristics, which were also relied upon by the CPUC in assessing Qualifying Capacity levels.

However, with the significant levels of both grid-connected and behind-the-meter generation being developed, this incremental approach is no longer viable either in determining the contribution of these resources to resource adequacy needs or transmission deliverability assessments, especially in considering additional procurement. The shift indicated the need to revisit the application of the deliverability methodology used by the ISO to both award "full capacity deliverability status" for local and system capacity purposes, and to assess deliverability in transmission planning and reliability studies. The ISO has addressed the impact by augmenting its existing deliverablity methodology – which from a technical tools perspective has not materially changed – by identifying the need for additional scenarios to be considered in the study process and revisiting certain study assumptions to ensure reasonable results meeting the original objectives of the deliverablity assessments. Please refer to chapter 3.

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Other Renewable Integration Issues and Initiatives

As the amount of renewable generation on the ISO system grows – whether grid-connected or behind-the-meter at end customer sites – the ISO must address a broader range of considerations to ensure overall safe, reliable and efficient operation. Specifically, the changing nature and location of generation resources and their diurnal output pattern combined with evolving load profiles, change the resulting demands on the transmission system.

The ISO currently conducts a range of studies to support the integration of renewable generation, including planning for reliable deliverability of renewable generation portfolios (chapter 4), generation interconnection process studies conducted outside of the transmission planning process but closely coordinated with the transmission planning process, and renewable integration operational studies that the ISO has conducted outside of the transmission planning process – but which are now being incorporated into the transmission planning processes as supplemental information. These latter studies form the basis of determinations of system - capacity and related flexibility - needs discussed earlier.

The genesis of the ISO's analysis of flexibility needs was the CPUC 2010-2011 Long-term Procurement Plan (LTPP) proceeding, docket R.10-05-006, wherein the ISO completed an initial study of renewable integration flexible generation requirements under a range of future scenarios, and the ISO has continued to analyze those issues. The ISO's efforts have led to a number of changes in market dispatch and annual resource adequacy program requirements, including considering uncertainty in the market optimization solution and developing flexible resource adequacy capacity requirements in the state's resource adequacy program. In addition to those promising enhancements, the ISO launched a stakeholder process to address a number of potential areas requiring further refinement. Of particular concern is ensuring the system maintains and incentivizes sufficient fast and flexible resources to address uncertainty and flexibility from an infrastructure perspective since "the flexible capacity showings to date indicate that the flexible capacity product, as currently designed, is not sending the correct signal to ensure sufficient flexible capacity will be maintained long-term."[18] This effort is also expected to consider if and how the transmission service necessary to ensure access to flexible capacity needs to be assessed — the "flexible capacity" equivalent of deliverability assessed for local and system capacity.

Past special study efforts and other initiatives have, in addition to the above, have also led to the need to review and upgrade generation models used in frequency response studies discussed in more detail below. This builds on the frequency response analysis the ISO conducted in the 2015-2016 planning cycle, where the ISO observed that simulated results varied from real-time actual performance – necessitating a review of the generator models employed in ISO studies. The frequency response studies themselves have now been elevated from the "special study" category to an annual study expected to be conducted each year for the foreseeable future. Please refer to chapter 6.

Non-Transmission Alternatives and Preferred Resources

Building on efforts in past planning cycles, the ISO continues to make material strides in facilitating use of preferred resources to meet local transmission system needs.

The ISO's approach, as noted in previous transmission plans, has focused on specific area analysis, and testing the effectiveness of the resources provided by the market into the utility procurement processes for preferred resources as potential mitigations for reliability concerns.

This approach is set out in concept in the study plan for this planning cycle, developed in phase 1 of the planning process as described below. It has built on and refers to a methodology the ISO presented in a paper issued on September 4, 2013,[19] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[20] — energy efficiency, demand response, renewable generating resources, and energy storage — by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional

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[18] Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 Supplemental Issue Paper: Expanding the Scope of the Initiative, November 8, 2016, at p.3, available at http://www.caiso.com/Documents/SupplementalIssuePaper-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf.

[19] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf.

[20] To be precise, the term "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The ISO uses the term more generally here consistent with the preference for certain resources in lieu conventional generation.

generation infrastructure. In addition to developing a methodology the ISO could apply annually in each transmission planning cycle, the paper also described how the ISO would apply the proposed methodology in future transmission planning cycles. That methodology for assessing the necessary characteristics and effectiveness of preferred resources to meeting local needs was further advanced and refined through the development of the Moorpark Sub-area Local Capacity Alternative Study released on August 16, 2017.[21] In addition, the ISO has developed a methodology as discussed in section 6.6 of the 2017-2018 ISO Transmission Plan for examining the necessary characteristics for slow response local capacity resources – a subset of preferred resources – which both builds and expands on the analysis framework of preferred resources. These efforts, with the additional detail discussed below, help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential alternatives to meeting identified needs. The ISO must also consider the cost effectiveness and other benefits these alternatives provide.

Although the Board does not "approve" non-transmission (*e.g.*, preferred resource capacity) solutions, the ISO can identify these solutions as preferred solutions to transmission projects and then work with the appropriate local regulatory authorities to support their development. This is particularly viable when the transmission solution does not need to be initiated immediately and where time can be set aside to explore the viability of non-conventional alternatives first while relying on a more conventional transmission alternative as a backstop.

In examining the benefits preferred resources can provide, the ISO relies heavily on preferred resources identified through various resource procurement proceedings as well as proposals received in the request window and other stakeholder comment opportunities in the transmission planning processes.

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<u>High potential areas:</u>

Each year's transmission plan identifies areas where reinforcement may be necessary in the future, but immediate action is not required. The ISO expects developers interested in developing and proposing preferred resources as mitigations in the transmission planning process to review those areas and highlight the potential benefits of preferred resource proposals in their submissions into utilities' procurement processes. To assist interested parties, each of the planning area discussions in chapter 2 contain a section describing the preferred resources that are providing reliability benefits, and the ISO has summarized areas where preferred resources are being targeted as a solution or part of a solution to address reliability issues in section 8.3. Further, as noted earlier, the ISO has expanded the scope of the biennial 10 year local capacity technical requirements study to provide additional information on the characteristics defing the need in the areas and sub-areas, to further facilitate consideration of preferred resources. Please refer to chapter 6.

[21] *See generally* CEC Docket No. 15-AFC-001, and *see* "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

Energy storage:

In addition to considering energy storage as a potential transmisision solution, the ISO also considers storage solutions under the overall preferred resource umbrella in transmission planning. The ISO is also engaged in a number of parallel activities to facilitate energy storage development generally, including past efforts to refine the generator interconnection process to better address the needs of energy storage developers. An additional refinement is the ISO studies of the benefits of large scale energy storage can have on addressing flexible capacity needs. This analysis began in the 2015-2016 transmission planning cycle, and was updated and expanded, including consideration of locational benefits, in the 2016-2017 cycle. In 2017, the ISO conducted additional analysis as an extension of the 2016-2017 planning cycle. This work has helped inform the ISO's participation in CPUC integrated resource planning proceedings, and documenting these results in the ISO's transmission plans helps provide broader visibility to stakeholders of these results.

Storage also played a major role in the assessment of the viability of preferred resource alternatives in the Moorpark Sub-area Local Capacity Alternative Study, as well as the Oakland Clean Energy Initiative and the Dinuba storage project approved in the 2017-2018 Transmission Plan.

This has led to the evaluation of a number of specific storage project submissions in this 2018-2019 Transmission Plan looking at both local and system benefits, as discussed in section 4.9.

The market and regulatory framework for storage that is meeting energy market and transmission system needs is also evolving. Utilization of electric storage resources is a significant issue to the ISO, given the industry development underway and the potential for electric storage to play a growing role in supporting the transmission system, as well as a growing role supporting renewable integration.

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Existing procurement mechanisms can support and have supported storage resources providing these services through the ISO's wholesale markets coupled with procurement directed by the CPUC. This approach ensures that system resources or resources within a transmission constrained area operate together to meet grid reliability needs, and enables the resource to participate more broadly in providing value to the market. In the case of electric storage resources, procurement also may result in distribution-connected resources and behind-the-meter resources that do not participate in the ISO's wholesale markets. In the system resource context, the storage resource would be functioning primarily as a market resource, with contractual obligations to the off-taker to provide certain services supporting local reliability.

The ISO has also studied in past planning cycles a number of potential applications of energy storage as transmission assets, and in that evaluation, assumed the energy storage would not be able to provide other market services and access other market-based revenue streams. This paradigm shifted on January 19, 2017, when FERC issued its policy statement "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery"[22] clarifying the ability of electric storage resources to receive cost-based rate recovery for

[22] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017), at P 9, https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-2.pdf.

transmission or grid support services while also receiving market-based revenues for providing separate market-based services.

The ISO's activities resulting from the policy statement are discussed in section 1.2.3 below.

Use-limited resources, including demand response:

The ISO continues to support integrating demand response, which includes bifurcating and clarifying the various programs and resources as either supply side or load-modifying. Activities such as participating in the CPUC's demand response-related proceedings support identifying the necessary operating characteristics that demand response should have to fulfill a role in meeting transmission system and local capacity needs.

Further analysis of the necessary characteristics for "slow response" demand response programs was undertaken initially through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC.[23]

This work has helped guide the approach the ISO is taking in the more comprehensive study of local capacity areas in this planning cycle examining both the load shapes and characteristics underpinning local capacity requirements, discussed earlier in this section.

1.2.3 Storage as a Transmission Asset

The ISO has studied in past planning cycles a number of potential applications of energy storage as transmission assets, and in that evaluation, assumed the energy storage would not be able to provide other market services and access other market-based revenue streams.

The ISO had relied on the Federal Energy Regulatory Commission's (FERC's) guidance that transmission assets – and in particular electric storage as a transmission asset – could serve a transmission function such as addressing thermal loading and providing voltage support. In the context of the ISO's transmission planning process, the ISO previously studied a number of potential electric storage projects as reliability solutions in the form of transmission asset models. Consistent with past FERC direction, the ISO assumed that such projects, as transmission assets, were precluded from participating in energy or ancillary services markets.

On January 19, 2017, FERC issued its policy statement "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery" to:

> *"provide guidance and clarification regarding the ability of electric storage resources to receive cost-based rate recovery for certain services (such as transmission or grid support services or to address other needs identified by an RTO/ISO) while also receiving market-based revenues for providing separate market-based services.* [24]*"*

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[23] See "Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop," presentation, October 4, 2017, http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

[24] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017), at P 9, https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-2.pdf.

The policy statement also sets out a number of concerns that would need to be addressed in order to enable this outcome.

Accordingly, the ISO began a stakeholder initiative to address the implementation concerns set out in the policy statement. This initiative considers using electric storage to provide certain grid services as a transmission facility, with all or a portion of costs recovered through the transmission access charge. This initiative is exploring issues around electric storage resources seeking to receive cost-based rate recovery for providing transmission services as a transmission asset and receiving market-based revenues for providing separate non-transmission, market-based rate services.

The ISO had initially targeted a first quarter of 2019 Board of Governor decision for the results of the initiative. However, despite the significant progress made over the last year, the ISO identified that this initiative needed to be held until broader market participation issues for storage and other non-generator resources (NGRs) can be developed within the ongoing fourth iteration of the ISO's Energy Storage and Distributed Energy Resources (ESDER 4) initiative. A central issue for SATA awards – to maintain reliability via maintaining a reliable state of charge in realtime when a SATA is called upon for market participation – also needs to be explored for storage functioning as a market-based local capacity resource. In addition, bidding and cost allocation rules would need adjustment to allow for optimizing costs between charging and discharging—necessitating assigning opportunity costs to storage, which are not currently available in the NGR framework.

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Nonetheless, the ISO's evaluation of ratepayer benefits can consider market revenues in the context of storage participating as a market resource under a power purchase agreement, when considering storage also addressing a transmission need as a local capacity resource. Please refer to chapter 4.

1.2.4 System Modeling, Performance, and Assessments

System modeling requirements and emerging mandatory standards

Exploring an increased role for preferred resources to address both traditional and emerging needs poses new technical challenges. The grid is already being called upon to meet broader ranges of generating conditions and more frequent changes from one operating condition to another, as resources are committed and dispatched on a more frequent basis and with higher ramping rates and boundaries than in the past. This necessitates managing thermal, stability, and voltage limits constantly and across a broader range of operating conditions.

Also, this has led to the need for greater accuracy in planning studies, and in particular, to the special study initiative undertaken in the 2016-2017 planning cycle reviewing all generator models for use in dynamic stability studies and frequency response analysis.

The efforts undertaken in the previous planning cycle and continued through this cycle in 2017 reaffirmed the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. (Refer to section 6.4.) However, the effort also identified underlying challenges with obtaining validated models for a large – and growing – number of generators that are outside of the bounds of existing NERC mandatory standards and for which the ISO is dependent on tariff authority. The ISO will be continuing with its efforts, in coordination with the Participating Transmission Owners, to collect this important information, as well as pursuing additional regulatory measures to ensure validated models are provided by generation owners.

Southern California Reliability and Gas-Electric Coordination

As in previous transmission plans, the ISO placed considerable emphasis in this planning cycle on requirements in the Los Angeles basin and San Diego areas. The ISO has expanded the focus in past planning cycles on addressing the implications of the San Onofre Nuclear Generating Station's early retirement and the anticipated retirement of once-through-cooling gas fired generation to also consider the impact of the uncertainty regarding the Aliso Canyon gas storage facilities on local area gas supply. The high expectations of preferred resources being part of a comprehensive solution, which also includes transmission reinforcement and conventional generation, has resulted in the ISO analyzing the role of preferred resources in that area.

Successfully mitigating reliability concerns remains dependent on materially higher levels of preferred resources in the future than have previously been achieved. Given the uncertainty regarding forecast resources materializing as planned, the ISO is continuing to monitor the progress of the forecast procurement of conventional and preferred resources and ISO-approved transmission upgrades underway. Chapter 2 touches on these issues.

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1.3 Structure of the Transmission Planning Process

The annual planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. For example, the 2017-2018 planning cycle began in January 2017 and concluded in March 2018.

Phase 1 includes establishing the assumptions and models for use in the planning studies, developing and finalizing a study plan, and specifying the public policy mandates that planners will adopt as objectives in the current cycle. This phase takes roughly three months from January through March of the beginning year.

In Phase 2, the ISO performs studies to identify the solutions to meet the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 12 months and ends with Board approval of the transmission plan. Thus, phases 1 and 2 take 15 months to complete. Identifying non-transmission alternatives that the ISO is relying upon in lieu of transmission solutions also takes place at this time. It is critical that parties responsible for approving or developing those non-transmission alternatives are aware of the reliance being placed on those alternatives.

Phase 3 includes the competitive solicitation for prospective developers to build and own new regional transmission facilities identified in the Board-approved plan. In any given planning cycle, phase 3 may or may not be needed depending on whether the final plan includes regional transmission facilities that are open to competitive solicitation in accordance with criteria specified in the ISO tariff.

In addition, the ISO may incorporate into the annual transmission planning process specific transmission planning studies necessary to support other state or industry informational requirements to efficiently provide study results that are consistent with the comprehensive transmission planning process. In this cycle, these focus primarily on grid transformation issues and incorporating renewable generation integration studies into the transmission planning process.

1.3.1 Phase 1

Phase 1 generally consists of developing and completing the annual unified planning assumptions and study plan. Continuing with the timelines and coordination achieved in past planning cycles, the generating resource portfolios used to analyze public policy-driven transmission needs were developed as part of the unified planning assumptions in phase 1 for the 2018-2019 planning cycle.

The unified planning assumptions establish a common set of assumptions for the reliability and other planning studies the ISO performs in phase 2. The starting point for the assumptions is the information and data derived from the comprehensive transmission plan developed during the prior planning cycle. The ISO adds other pertinent information, including network upgrades and additions identified in studies conducted under the ISO's generation interconnection procedures and incorporated in executed generator interconnection agreements (GIA). In the unified planning assumptions the ISO also specifies the public policy requirements and directives that it will consider in assessing the need for new transmission infrastructure.

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Development of the unified planning assumptions for this planning cycle benefited from further coordination efforts between the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and the ISO, building on the staff-level, inter-agency process alignment forum in place to improve infrastructure planning coordination within the three core processes:

- Long-term forecasts of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR);
- Biennial Integrated Resource Planning (IRP) proceedings conducted by the CPUC; and,
- The Annual Transmission Planning Process (TPP) performed by the ISO.

That forum resulted in improved alignment of the three core processes and agreement on an annual process to be undertaken in the fall of each year to develop planning assumptions and scenarios to be considered in infrastructure planning activities in the upcoming year. The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolio standard (RPS) portfolios discussed in more detail below, which are a key assumption.

The results of that annual process fed into this 2018-2019 transmission planning process and was communicated via a ruling in the 2017 cycle of the 2017-2018 IRP process[25]. These process efforts continued in 2018 emphasizing the broad load forecast impacts of distributed generation and other material changes in customer needs and considering renewable integration challenges and the market impacts of increased renewable generation on the existing conventional generation fleet.

The ISO added public policy requirements and directives as an element of transmission planning process in 2010. Planning transmission to meet public policy directives is also a national requirement under Federal Energy Regulatory Commission (FERC) Order No. 1000. It enables the ISO to identify and approve transmission facilities that system users will need to comply with specified state and federal requirements or directives. The primary policy directive for the last number of years' planning cycles has been California's renewables portfolio standard. As discussed later in this section, the ISO's study work and resource requirements determination for reliably integrating renewable resources is continuing on a parallel track outside of the transmission planning process, but the ISO has continued to incorporate those requirements into annual transmission plan activities.

The ISO formulates the public policy-related resource portfolios in collaboration with the CPUC, and with input from other state agencies including the CEC and the municipal utilities within the ISO balancing authority area. The CPUC, as the agency that oversees the bulk of the supply procurement activities within the ISO area, plays a primary role formulating the resource portfolios. The ISO reviews the proposed portfolios with stakeholders and seeks their comments, which the ISO then considers in determining the final portfolios.

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The resource portfolios have played a crucial role in identifying needed public policy-driven transmission elements. Meeting the renewables portfolio standard has entailed developing substantial amounts of new renewable generating capacity, which in turn required new transmission for delivery. The ISO has managed the uncertainty as to where the generation capacity will locate by balancing the need to have sufficient transmission in service in time to support the renewables portfolio standard against the risk of building transmission in areas that do not realize enough new generation to justify the cost of such infrastructure. This has entailed applying a "least regrets" approach, whereby the ISO first formulates alternative resource development portfolios or scenarios, then identifies the needed transmission to support each portfolio, and then selects for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios.

As we move closer to the 33 percent renewables portfolio standard compliance date of 2020, the focus is shifting to the higher requirements set by SB 350 and will now shift onward to SB 100 in future planning cycles. Accordingly, the ISO's focus in the 2018-2019 planning cycle was to confirm the effectiveness of current plans for achieving the 50 percent renewables portfolio standard established by SB 350 for 2030 and conducting sensitivities that will support higher

[25] CPUC Decision, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF referring to the Feb 20, 2018 Unified Resource Adequacy and IRP Inputs and Assumptions document: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF.

levels of renewables to accommodate GHG reduction goals that go beyond the 2030 50 percent RPS established by SB 350. This latter effort was reflected in the policy-driven sensitivity study discussed in chapter 4.

The study plan describes the computer models and methodologies to be used in each technical study, provides a list of the studies to be performed and the purpose of each study, and lays out a schedule for the stakeholder process throughout the entire planning cycle. The ISO posts the unified planning assumptions and study plan in draft form for stakeholder review and comment. Stakeholders may request specific economic planning studies to assess the potential economic benefits (such as congestion relief) in specific areas of the grid. The ISO then selects high priority studies from these requests and includes them in the study plan published at the end of phase 1. The ISO may modify the list of high priority studies later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

1.3.2 Phase 2

In phase 2, the ISO performs all necessary technical studies, conducts a series of stakeholder meetings and develops an annual comprehensive transmission plan for the ISO controlled grid. The comprehensive transmission plan specifies the transmission solutions required to meet the infrastructure needs of the grid, including reliability, public policy, and economic-driven needs. In phase 2, the ISO conducts the following major activities:

- Performs technical planning studies described in the phase 1 study plan and posts the study results;
- Provides a request window for stakeholders to submit reliability project proposals in response to the ISO's technical studies, demand response, storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs, Location Constrained Resource Interconnection Facilities project proposals, and merchant transmission facility project proposals;
- Evaluates and refines the portion of the conceptual statewide plan that applies to the ISO system as part of the process to identify policy-driven transmission elements and other infrastructure needs that will be included in the final comprehensive transmission plan;
- Coordinates transmission planning study work with renewable integration studies performed by the ISO for the CPUC integrated resource planning proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff section 24.4.6.6(g);
- Reassesses, as needed, significant transmission facilities starting with the 2011-2012 planning cycle that were in GIP phase 2 cluster studies to determine — from a comprehensive planning perspective — whether any of these facilities should be enhanced or otherwise modified to more effectively or efficiently meet overall planning needs;

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- Performs a “least regrets” analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[26] which is intended to minimize the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner;
- Identifies additional category 2 policy-driven potential transmission facilities that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle;
- Performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan;
- Performs technical studies to assess the reliability impacts of new environmental policies such as new restrictions on the use of coastal and estuarine waters for power plant cooling, which is commonly referred to as once through cooling and AB 1318 legislative requirements for ISO studies on the electrical system reliability needs of the South Coast Air Basin;
- Conducts stakeholder meetings and provides public comment opportunities at key points during phase 2; and,
- Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan that the ISO posts in draft form for stakeholder review and comment at the end of January and presents to the Board for approval at the conclusion of phase 2 in March.

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Board approval of the comprehensive transmission plan at the end of phase 2 constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities, and the economic-driven facilities specified in the plan. The Board’s approval enables cost recovery through ISO transmission rates of those transmission projects included in the plan that require Board approval.[27] As indicated above, the ISO solicits and accepts proposals in phase 3 from all interested project sponsors to build and own the regional transmission solutions that are open to competition.

By definition, category 2 solutions identified in the comprehensive plan are not authorized to proceed after Board approval of the plan, but are instead re-evaluated during the next annual cycle of the planning process. At that time, based on relevant new information about the patterns of expected development, the ISO will determine whether the category 2 solutions

[26] In accordance with the least regrets principle, the transmission plan may designate both category 1 and category 2 policy-driven solutions. Using these categories better enables the ISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key factors that materially affect the determination of what transmission is needed. Section 24.4.6.6 of the ISO tariff specifies the criteria considered in this evaluation.

[27] Under existing tariff provisions, ISO management can approve transmission projects with capital costs equal to or less than $50 million. The ISO includes such projects in the comprehensive plan as pre-approved by ISO management and not requiring Board approval.

satisfy the least regrets criteria and should be elevated to category 1 status, should remain category 2 projects for another cycle, or should be removed from the transmission plan.

As noted earlier, phases 1 and 2 of the transmission planning process encompass a 15-month period. Thus, the last three months of phase 2 of one planning cycle will overlap phase 1 of the next cycle, which also spans three months. The ISO will conduct phase 3, the competitive solicitation for sponsors to compete to build and own eligible regional transmission facilities reflected in the final Board-approved plan.[28]

1.3.3 Phase 3

Phase 3 takes place after Board approves the plan if there are projects eligible for competitive solicitation. Projects eligible for competitive solicitation include regional reliability-driven, category 1 policy-driven, or economic-driven transmission solutions, except for regional transmission solutions that are upgrades to existing facilities. Local transmission facilities are not subject to competitive solicitation.

This requires one clarification in the consideration of storage that may be found to be needed as a transmission asset. Note that the determination of eligibility is made at the end of Phase 2, and before the competition is held. Transmission connected resources are resources that are connected to the ISO controlled grid, with Regional resources being greater than 200 kV, and Local resources being lower than 200 kV. Storage as a transmission asset may be connected to the transmission system at a level that differs from the transmission issue it has been identified to resolve, just like other transmission assets. For example, the ISO may identify a Regional need, but identify storage – as a transmission asset - connecting at a Local level as the best solution or as a possible solution. Notwithstanding the treatment for allocation to transmission access charges, the ISO has consistently interpreted eligibility criteria to be more, not less supportive of competition, and therefore considers a "greenfield" solution such as a storage transmission asset to be eligible for competition if it can be met equally well by a local or regional facility, but is not eligible for competition if only a local facility will meet the need.

P27-129 cont.

If the approved transmission plan includes regional transmission facilities eligible for competitive solicitation, the ISO will commence phase 3 by opening a window for the entities to submit applications to compete to build and own such facilities. The ISO will then evaluate the proposals and, if there are multiple qualified project sponsors seeking to finance, build, and own the same facilities, the ISO will select an approved project sponsor by comparatively evaluating all of the qualified project sponsors based on the tariff selection criteria. Where there is only one qualified project sponsor, the ISO will authorize that sponsor to move forward to project permitting and siting.

[28] These details are set forth in the BPM for Transmission Planning, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Transmission%20Planning%20Process.

1.4 Interregional Transmission Coordination per FERC Order No. 1000

Beginning in January 2018 a new biennial Interregional Transmission coordination cycle was initiated. Following guiding principles largely developed during the 2016-2017 Interregional Transmission Coordination cycle, the ISO along with the other Western Planning Regions[29] continued to participate and advance interregional transmission coordination within the broader landscape of the western interconnection. These guiding principles were established to ensure that an annual exchange and coordination of planning data and information was achieved in a manner consistent with expectations of FERC Order No. 1000. They are documented in the ISO's Transmission Planning Business Practice Manual as well as in comparable documents of the other Western Planning Regions. Since the 2018-2019 interregional coordination cycle was initiated, the Western Planning Regions have held one Annual Interregional Coordination Meeting on February 22, 2018 to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[30]

The ISO hosted its submission period in the first quarter of 2018 in which proponents were able to request evaluation of an interregional transmission project (ITP). The submission period began on January 1 and closed March 31st with six interregional transmission projects being submitted to the ISO. Of the six project submitted, four projects were submitted into the 2016-2017 cycle and were resubmitted into the 2018-2019 cycle. The submitted projects are shown in Figure 1.4-1. Following the submission and successful screening of the ITP submittals, the ISO coordinated its ITP evaluation with the other relevant planning regions, NTTG and WestConnect.

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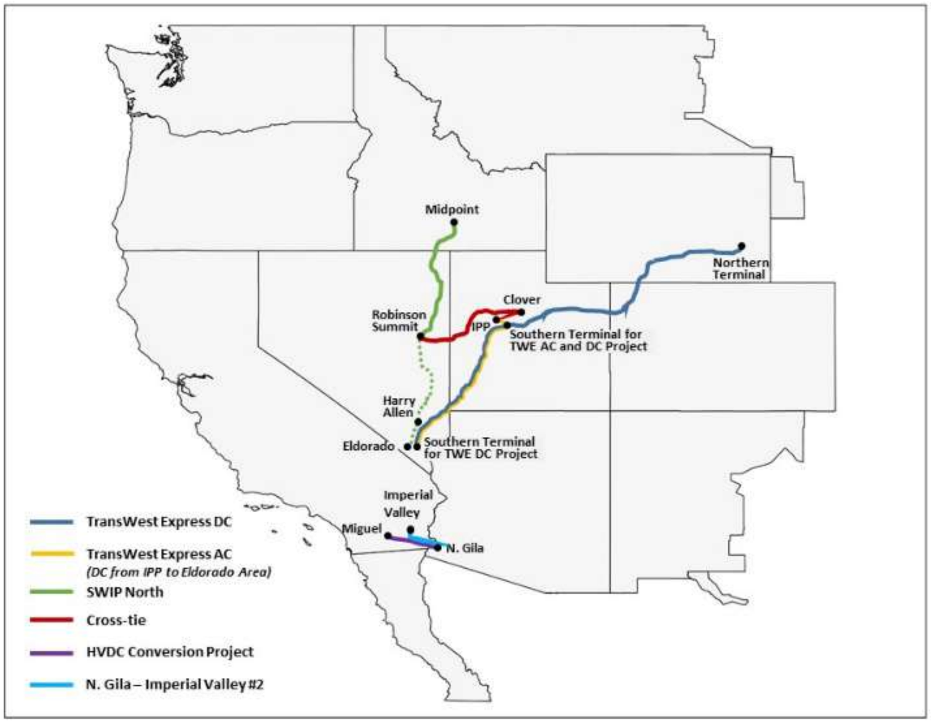
[29] Western planning regions are the California ISO, ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect.

[30] Documents related to the 2018-2019 interregional transmission coordination meetings are available on the ISO website athttp://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=433645F0-E680-4861-94F5-4CD23C3D46E1 .

Figure 1.4-1: Interregional Transmission Projects Submitted to the ISO



As discussed earlier in this chapter, state directives continue to focus on increasing California's renewable energy goals beyond 33 percent. In its 2016-2017 and 2017-2018 planning cycles the ISO performed a special study that considered the interregional transmission projects submitted to the ISO in the context of the 50% RPS that had been established at that time. The ISO concluded its consideration of these special studies in it 2017-2018 planning cycle and documented its results in it 2017-2018 transmission plan[31].

Moving forward into the 2018-2019 interregional coordination cycle, the ISO has considered the proposed projects in its 2018-2019 transmission plan but only as per the processes identified in the ISO tariff. More information regarding the ISO's consideration of the proposed projects can be found in Chapter 5.

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[31] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf; See Chapter 6 "Special Reliability Studies and Results"

1.5 ISO Processes coordinated with the Transmission Plan

The ISO coordinates the transmission planning process with several other ISO processes. These processes and initiatives are briefly summarized below.

Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

In July 2012, FERC approved the GIDAP, which significantly revised the generator interconnection procedures to better integrate those procedures with the transmission planning process. The ISO applied the GIDAP to queue cluster 5 in March 2012 and all subsequent queue clusters. Interconnection requests submitted into cluster 4 and earlier will continue to be subject to the provisions of the prior generation interconnection process (GIP).

The principal objective of the GIDAP was to ensure that going forward the ISO would identify and approve all major transmission additions and upgrades to be paid for by transmission ratepayers under a single comprehensive process — the transmission planning process — rather than having some projects come through the transmission planning process and others through the GIP.

The most significant implication for the transmission planning process at this time relates to the planning of policy-driven transmission to achieve the state's renewables portfolio standard. In that context, the ISO plans the necessary transmission upgrades to enable the deliverability of the renewable generation forecast in the base renewables portfolio scenario provided by the CPUC, unless specifically noted otherwise. Every RPS Calculator portfolio the CPUC has submitted into the ISO's transmission planning process for purposes of identifying policy-driven transmission to achieve 33 percent RPS has assumed deliverability for new renewable energy projects.[32] More recently, the portfolio provided to the ISO via the CPUC's integrated resource planning proceeding for consideration in the 2018-2019 transmission planning cycle identified both deliverable generation (full capacity deliverability status) and energy-only generation by area.

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Through the GIDAP, the ISO then allocates the resulting MW volumes of transmission plan deliverability to those proposed generating facilities in each area that are the most viable based on a set of project development milestones specified in the tariff.

As set out in Appendix DD (GIDAP) of the ISO tariff, the ISO calculates the available transmission plan deliverability (TPD) in each year's transmission planning process in areas where the amount of generation in the interconnection queue exceeds the available deliverability, as identified in the generator interconnection cluster studies. In areas where the amount of generation in the interconnection queue is less than the available deliverability, the transmission plan deliverability is sufficient. In this year's transmission planning process, the ISO considered queue clusters up to and including queue cluster 11.

Interconnection customers proposing generating facilities that are not allocated transmission plan deliverability, but who still want to build their projects and obtain deliverability status, are

[32] RPS Calculator User Guide, Version 6.1, p. A-17. ("In prior versions of the RPS Calculator (v.1.0 – v.6.0), all new renewable resources were assumed to have full capacity deliverability status (FCDS).") Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5686.

responsible for funding needed delivery network upgrades at their own expense without being eligible for cash reimbursement from ratepayers.

The GIDAP studies for each queue cluster also provide information that supports future planning decisions. Each year, the ISO validates the capability of the planned system to meet the needs of renewable generation portfolios that have already been provided. The ISO augments this information with information about how much additional generation can be deliverable beyond the previously-supplied portfolio amounts with the results of the generator queue cluster studies. The results are provided each year to the CPUC for consideration in developing the next round of renewable generation portfolios.

Distributed Generation (DG) Deliverability

The ISO developed a streamlined, annual process for providing resource adequacy (RA) deliverability status to distributed generation (DG) resources from transmission capacity in 2012 and implemented it in 2013. The ISO completed the first cycle of the new process in 2013 in time to qualify additional distributed generation resources to provide RA capacity for the 2014 RA compliance year.

The ISO annually performs two sequential steps. The first step is a deliverability study, which the ISO performs within the context of the transmission planning process, to determine nodal MW quantities of deliverability status that can be assigned to DG resources. The second step is to apportion these quantities to utility distribution companies — including both the investor-owned and publicly-owned distribution utilities within the ISO controlled grid — who then assign deliverability status, in accordance with ISO tariff provisions, to eligible distributed generation resources that are interconnected or in the process of interconnecting to their distribution facilities.

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In the first step, during the transmission planning process the ISO performs a DG deliverability study to identify available transmission capacity at specific grid nodes to support deliverability status for distributed generation resources without requiring any additional delivery network upgrades to the ISO controlled grid and without adversely affecting the deliverability status of existing generation resources or proposed generation in the interconnection queue. In constructing the network model for use in the DG deliverability study, the ISO models the existing transmission system, including new additions and upgrades approved in prior transmission planning process cycles, plus existing generation and certain new generation in the interconnection queue and associated upgrades. The DG deliverability study uses the nodal DG quantities specified in the base case resource portfolio that was adopted in the latest transmission planning process cycle to identify public policy-driven transmission needs, both as a minimal target level for assessing DG deliverability at each network node and as a maximum amount that distribution utilities can use to assign deliverability status to generators in the current cycle. This ensures that the DG deliverability assessment aligns with the public policy objectives addressed in the current transmission planning process cycle and precludes the possibility of apportioning more DG deliverability in each cycle than was assumed in the base case resource portfolio used in the transmission planning process.

In the second step, the ISO specifies how much of the identified DG deliverability at each node is available to the utility distribution companies that operate distribution facilities and interconnect distributed generation resources below that node. FERC's November 2012 order stipulated that FERC-jurisdictional entities must assign deliverability status to DG resources on a first-come, first-served basis, in accordance with the relevant interconnection queue. In compliance with this requirement, the ISO tariff specifies the process whereby investor-owned utility distribution companies must establish the first-come, first-served sequence for assigning deliverability status to eligible distributed generation resources.

Although the ISO performs this new DG deliverability process as part of and in alignment with the annual transmission planning process cycle, its only direct impact on the transmission planning process is adding the DG deliverability study to be performed in the latter part of Phase 2 of the transmission planning process.

Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[33] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution on this sensitive area — that additional measures should be taken to protect CEII information. Accordingly, the ISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the ISO's public website. Rather, this information can be accessed only through the ISO's market participant portal after the appropriate nondisclosure agreements are executed.

Planning Coordinator Footprint

The ISO released a technical bulletin that set out its interpretation of its planning authority/planning coordinator area in 2014, [34] in part in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities.

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Beginning in 2015, the ISO reached out to several "adjacent systems" that are inside the ISO's balancing authority area and were confirmed transmission owners, but which did not appear to be registered as a planning coordinator to determine whether they needed to have a planning coordinator and, if they did not have one, to offer to provide planning coordinator services to them through a fee based planning coordinator services agreement. Unlike the requirements for the ISO's participating transmission owners who have placed their facilities under the ISO's operational control, under the planning coordinator services agreement the ISO is not responsible for planning and approving mitigations to identified reliability issues – but only verifying that mitigations have been identified and that they address the identified reliability concerns. In essence, these services are provided to address mandatory standards via the planning coordinator services agreement, separate from and not part of the ISO's FERC-approved tariff governing transmission planning activities for facilities placed under ISO

[33] ISO tariff section 20 addresses how the ISO shares Critical Energy Infrastructure Information (CEII) related to the transmission planning process with stakeholders who are eligible to receive such information. The tariff definition of CEII is consistent with FERC regulations at 18 C.F.R. Section 388.113, *et. seq*. According to the tariff, eligible stakeholders seeking access to CEII must sign a non-disclosure agreement and follow the other steps described on the ISO website.

[34] Technical Bulletin – "California ISO Planning Coordinator Area Definition" (created August 4, 2014, last revised July 28, 2016 to update URL for Appendix 2), http://www.caiso.com/Documents/TechnicalBulletin-CaliforniaISOPlanningCoordinatorAreaDefinition.pdf.

operational control. As such, the results are documented separately, and do not form part of this transmission plan.

The ISO has executed planning coordinator services agreements with Hetch Hetchy Water and Power and the Metropolitan Water District, and the ISO has conducted the study efforts to meet the mandatory standards requirements for these entities within the framework of the annual transmission planning process. In Q4 2017 the ISO executed a planning coordinator services agreement with the City of Santa Clara, doing business as Silicon Valley Power (SVP) and began providing those services in 2018. Through a two-year implementation plan the ISO will collect all required information to fulfill its planning coordinator responsibility for SVP.

Finally, the ISO is also providing planning coordinator services under a separate agreement to Southern California Edison for a subset of its facilities that are not under ISO operational control but which were found to be Bulk Electric System as defined by NERC.

At this time, the ISO is not anticipating offering these services to other parties, as the ISO is not aware of other systems inside the boundaries of the ISO footprint requiring these services.

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Chapter 2

2 Reliability Assessment – Study Assumptions, Methodology and Results

2.1 Overview of the ISO Reliability Assessment

The ISO annual reliability assessment is a comprehensive annual study that includes:

- Power flow studies;
- Transient stability analysis; and,
- Voltage stability studies.

The annual reliability assessment focus is to identify facilities that demonstrate a potential of not meeting the applicable performance requirements specifically outlined in section 2.2.

This study is part of the annual transmission planning process and performed in accordance with section 24 of the ISO tariff and as defined in the Business Process Manual (BPM) for the Transmission Planning Process. The Western Electricity Coordinating Council (WECC) full-loop power flow base cases provide the foundation for the study. The detailed reliability assessment results are provided in in Appendix B and Appendix C.

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2.1.1 Backbone (500 kV and selected 230 kV) System Assessment

Conventional and governor power flow and stability studies were performed for the backbone system assessment to evaluate system performance under normal conditions and following power system contingencies for voltage levels 230 kV and above. The backbone transmission system studies cover the following areas:

- Northern California — Pacific Gas and Electric (PG&E) system; and
- Southern California — Southern California Edison (SCE) system and San Diego Gas and Electric (SDG&E) system.

2.1.2 Regional Area Assessments

Conventional and governor power flow studies were performed for the local area non-simultaneous assessments under normal system and contingency conditions for voltage levels 60 kV through 230 kV. The regional planning areas are within the PG&E, SCE, SDG&E, and Valley Electric Association (VEA) service territories and are listed below:

- PG&E Local Areas
    - Humboldt area;
    - North Coast and North Bay areas;
    - North Valley area;
    - Central Valley area;

  - Greater Bay area;
  - Greater Fresno area;
  - Kern Area; and
  - Central Coast and Los Padres areas.
- SCE local areas
  - Tehachapi and Big Creek Corridor;
  - North of Lugo area;
  - East of Lugo area;
  - Eastern area; and
  - Metro area.
- Valley Electric Association (VEA) area
- San Diego Gas Electric (SDG&E) local area

2.1.3 Peak Demand

The ISO-controlled grid peak demand in 2018 was 46,424 MW and occurred on July 25 at 5:27 p.m. The following were the peak demand for the four load-serving participating transmission owners' service areas:

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PG&E peak demand occurred on July 25, 2018 at 6:34 p.m. with 19,245 MW;

SCE peak demand occurred on July 6, 2018 at 4:54 p.m. with 24,244 MW;

SDG&E peak demand occurred on August 8, 2018 at 5:02 p.m. with 4,399 MW; and

VEA peak demand occurred on July 23, 2018 at 3:26 p.m. with 146 MW.

Most of the ISO-controlled grid experiences summer peaking conditions and thus was the focus in all studies. For areas that experienced highest demand in the winter season or where historical data indicated other conditions may require separate studies, winter peak and summer off-peak studies were also performed. Examples of such areas are Humboldt and the Central Coast in the PG&E service territory.

2.2 Reliability Standards Compliance Criteria

The 2018-2019 transmission plan spans a 10-year planning horizon and was conducted to ensure the ISO-controlled-grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, Western Electricity Coordinating Council (WECC) regional criteria, and ISO planning standards across the 2019-2028 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2018-2019 study.

2.2.1 NERC Reliability Standards

2.2.1.1 System Performance Reliability Standards

The ISO analyzed the need for transmission upgrades and additions in accordance with NERC reliability standards, which provide criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following TPL NERC reliability standards are applicable to the ISO as a registered NERC planning authority and are the primary drivers determining reliability upgrade needs:

- TPL-001-4 Transmission System Planning Performance Requirements[35]; and
- NUC-001-3 Nuclear Plant Interface Coordination.

2.2.2 WECC Regional Criteria

The WECC TPL system performance criteria are applicable to the ISO as a planning authority and sets forth additional requirements that must be met under a varied but specific set of operating conditions.[36]

2.2.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO transmission facilities.[37] These standards:

- Address specifics not covered in the NERC reliability standards and WECC regional criteria;
- Provide interpretations of the NERC reliability standards and WECC regional criteria specific to the ISO-controlled grid; and,
- Identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

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35 Analysis of Extreme Events or NUC-001 are not included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

36 https://www.wecc.biz/Standards/Pages/Default.aspx

37 http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

2.3 Study Assumptions and Methodology

The following sections summarize the study methodology and assumptions used for the reliability assessment.

2.3.1 Study Horizon and Years

The studies that comply with TPL-001-4 were conducted for both the near-term[38] (2019-2023) and longer-term[39] (2024-2028) per the requirements of the reliability standards. Within the identified near and longer term study horizons the ISO conducted detailed analysis on years 2020, 2023 and 2028.

2.3.2 Transmission Assumptions

2.3.2.1 Transmission Projects

The study included existing transmission in service and the expected future projects that have been approved by the ISO but are not yet in service. Refer to Table 8.1-1 and Table 8.1-1 of chapter 8 (Transmission Project Updates) for the list of previously approved projects that are not yet in service. Projects put on hold were not modeled in the starting base case. Previously approved transmission projects that were not included in the base cases are identified below in the local area assessments.

Also included in the study cases were generation interconnection related transmission projects that were included in executed Large Generator Interconnection Agreements (LGIA) for generation projects included in the base case.

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2.3.2.2 Reactive Resources

Existing and new reactive power resources were modeled in the study base cases to ensure realistic voltage support capability. These resources include generators, capacitors, static var compensators (SVCs) and other devices. Refer to area-specific study sections for a detailed list of generation plants and corresponding assumptions. Two of the key reactive power resources that were modeled in the studies include the following:

- All shunt capacitors in the SCE service territory; and,
- Static var compensators or static synchronous compensators at several locations such as Potrero, Newark, Humboldt, Rector, Devers and Talega substations.

For a complete resources list, refer to the base cases available at the ISO Market Participant Portal secured website (https://portal.caiso.com/Pages/Default.aspx).[40]

38 System peak load for either year one or year two, and for year five as well as system off-peak load for one of the five years.

39 System peak load conditions for one of the years and the rationale for why that year was selected.

40 This site is available to market participants who have submitted a non-disclosure agreement (NDA) and is approved to access the portal by the ISO. For instructions, go to http://www.caiso.com/Documents/Regional%20transmission%20NDA.

2.3.2.3 Protection System

To help ensure reliable operations, many special protection systems (SPS), safety nets, UVLS and UFLS schemes have been installed in some areas. Typically, these systems trip load and/or generation by strategically tripping circuit breakers under select contingencies or system conditions after detecting overloads, low voltages or low frequency. The major new and existing SPS, safety nets, and UVLS included in the study are listed in Appendix A.

2.3.2.4 Control Devices

Several control devices were modeled in the studies. These control devices are:

- All shunt capacitors in SCE and other areas;
- Static var compensators and synchronous condensers at several locations such as Potrero, Newark, Rector, Devers, and Talega substations;
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects (note the PDCI Upgrade Project – to 3220 MW – was approved in 2017); and,
- Imperial Valley flow controller; (e.g., phase shifting transformer).

For complete details of the control devices that were modeled in the study, refer to the base cases that are available through the ISO Market Participant Portal secure website.

2.3.3 Load Forecast Assumptions

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2.3.3.1 Energy and Demand Forecast

The assessment used the California Energy Demand Updated Forecast, 2018-2030 adopted by California Energy Commission (CEC) on February 21, 2018.

During 2017, the CEC, CPUC and ISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2017 IEPR final report, adopted on February 21, 2018, based on the IEPR record and in consultation with the CPUC and the ISO, recommended using the Mid Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Photovoltaic (AAPV) scenario for system-wide and flexibility studies for the CPUC LTPP and ISO TPP cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low AAEE and AAPV scenario for local studies has since been considered prudent.

The 1-in-10 load forecasts were modeled in each of the local area studies. The 1-in-5 coincident peak load forecasts were used for the backbone system assessments as the backbone system covers a broader geographical area with significant temperature diversity. More details of the demand forecast are provided in the discussion sections of each of the study areas.

In the 2018-2019 transmission planning process, the ISO used the CEC energy and demand forecast for the base scenario analysis identified in section 2.3.8.1. The ISO conducts sensitivities on a case by case basis and to comply with the NERC TPL-001-4 mandatory reliability standard, these and other forecasting uncertainties were taken into account in the sensitivity studies identified in section 2.3.8.2. The ISO has continued to work with the CEC on the hourly load forecast issue during the development of 2017 IEPR.

2.3.3.2 Self-Generation

Baseline peak demand in the CEC demand forecast is reduced by projected impacts of self-generation serving on-site customer load. Most of the increase in self-generation over the forecast period comes from PV. Statewide, self-generation PV capacity is projected to reach 26,000 MW in the low demand case by 2030[41]. In 2018-2019 TPP base cases, the both baseline PV and AAPV generation production were modeled explicitly.

PV Self-generation installed capacity for mid demand scenario by the PTO and forecast climate zones are shown in Table 2.3-1.

Table 2.3-1: Mid demand baseline PV self-generation installed capacity by PTO[42]

PTO	Forecast Climate Zone	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PG&E	Central Coast	305	337	368	397	425	451	477	501	525	549
	Central Valley	972	1083	1194	1300	1402	1501	1594	1684	1771	1857
	Greater Bay Area	1203	1353	1510	1665	1820	1969	2110	2241	2363	2476
	North Coast	319	350	382	412	441	467	490	511	528	543
	North Valley	210	231	251	271	289	306	321	336	349	361
	Southern Valley	1153	1279	1403	1520	1634	1744	1851	1957	2063	2169
	PG&E Total	4163	4632	5109	5565	6009	6437	6844	7230	7599	7955
SCE	Big Creek East	310	350	392	432	473	513	553	593	633	674
	Big Creek West	193	213	234	254	273	292	309	325	340	355
	Eastern	709	793	878	961	1044	1126	1208	1291	1376	1466
	LA Metro	1196	1362	1543	1728	1915	2100	2276	2439	2588	2724
	Northeast	485	541	601	660	720	779	835	889	939	987
	SCE Total	2892	3259	3647	4035	4426	4810	5182	5537	5877	6206
SDG&E	SDG&E	1010	1108	1198	1277	1349	1417	1482	1545	1608	1673

Output of the self-generation PV were selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

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[41] http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-03/TN222287_20180120T141708_The_California_Energy_Demand_20182030_Revised_Forecast.pdf

[42] Based on self-generation PV calculation spreadsheet provided by CEC.

2.3.3.3 Additional Achievable Photovoltaic (AAPV)

The California Energy Demand (CED) Forecast 2018-2030 also includes AAPV. AAPV is incremental to the PV in the baseline forecast and, used in developing the managed forecast. In 2018-2019 TPP base cases, the AAPV was modeled explicitly similar to the baseline PV self-generation. Table 2.3-2 below shows AAPV installed capacity for Mid-Low and Mid-Mid Scenarios for each IOU planning areas.

Table 2.3-2 AAPV installed capacity (MW) for PG&E, SCE and SDG&E planning areas[43]

Year	PG&E		SCE		SDG&E	
	Mid-Low	Mid-Mid	Mid-Low	Mid-Mid	Mid-Low	Mid-Mid
2019	-	-	-	-	-	-
2020	66	75	63	72	11	13
2021	131	150	127	146	23	26
2022	197	226	193	221	34	39
2023	263	301	258	295	46	53
2024	329	376	324	370	58	66
2025	395	452	390	445	70	80
2026	462	528	456	521	82	93
2027	528	603	520	595	93	107
2028	592	677	585	669	105	120

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Output of the AAPV was selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

2.3.4 Generation Assumptions

Generating units in the area under study were dispatched at or close to their maximum power (MW) generating levels for the peak demand bases cases. Qualifying facilities (QFs) and self-generating units were modeled based on their historical generating output levels. Renewable generation was dispatched as identified in section 2.3.4.2.

2.3.4.1 Generation Projects

In addition to generators that are already in-service, new generators were modeled in the studies depending on the status of each project.

[43] https://efiling.energy.ca.gov/GetDocument.aspx?tn=222398

2.3.4.2 Renewable Generation

The CPUC issued a decision[44] on February 08, 2018 which adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

Based on the proposal voted on and adopted by the CPUC, a “Default Scenario” was transmitted to the ISO to be used in the 2018-2019 TPP reliability assessment. The Unified Inputs and Assumptions document[45] described the Default Scenario which corresponds to 50% RPS. Renewable resources under development with CPUC-approved contracts with the three investor-owned utilities were assumed to be part of the baseline assumptions while creating the Default Scenario portfolio. The ISO worked with the CPUC to identify such resources and model these in the reliability assessment base cases. The ISO supplemented this scenario with information regarding contracted RPS resources that are under construction as of May 2018.Generation included in this year’s baseline scenario as described in Section 24.4.6.6 of the ISO Tariff was also included in the 10-year Planning Cases. Given the data availability, generic dynamic data may be used for the future generation.

2.3.4.3 Thermal generation

For the latest updates on new generation projects, please refer to CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html). The ISO also relies on other data sources to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases. Table A2-1 of Appendix A lists new thermal generation projects in construction or pre-construction phase that were modeled in the base cases.

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2.3.4.4 Hydroelectric Generation

During drought years, the availability of hydroelectric generation production can be severely limited. In particular, during a recent drought year the Big Creek area of the SCE system has experienced a reduction of generation production that is 80% below average production. The Big Creek area is a local capacity requirement area that relies on Big Creek generation to meet NERC Planning Standards.

2.3.4.5 Generation Retirements

Existing generators that have been identified as retiring are listed in table A2-1 of Appendix A. These generators along with their step-up transformer banks are modeled as out of service starting in the year they are assumed to be retired.

In addition to the identified generators the following assumptions were made for the retirement of generation facilities:

[44] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

[45] http://www.cpuc.ca.gov/General.aspx?id=6442451972

- Nuclear Retirements – Diablo Canyon was modeled offline based on the OTC compliance dates;
- Once Through Cooled (OTC) Retirements – As identified in section 2.3.1;
- Renewable and Hydro Retirements – Assumed these resource types stay online unless there is an announced retirement date; and,
- Other Retirements – Unless otherwise noted, assumed retirement based resource age of 40 years or more.

2.3.4.6 OTC Generation

Modeling of the once-through cooled generating units, shown in Table 2.3-3, followed the compliance schedule from the State Water Resources Control Board's (SWRCB) policy on OTC plants with the following exceptions:

- generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology; and,
- all other OTC generating units were modeled off line beyond their compliance dates.

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cont.

Table 2.3-3: Once-through cooled generation in the California ISO Balancing Authority Area

Generating Facility	Owner	Existing Unit/ Technology[46] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[47] (MW) and Technology[48] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
Humboldt Bay	PG&E	1 (ST)	12/31/2010	9/30/2010	52	163 MW (10 ICs)	9/28/2010	Retired 135 MW and repowered with 10 ICs (163 MW)
		2 (ST)	12/31/2010		53			
Contra Costa	GenOn	6 (ST)	12/31/2017	April 30, 2013	337	Replaced by 760 MW Marsh Landing power plant (4 GTs)	May 1, 2013	New Marsh Landing GTs are located next to retired generating facility.
		7 (ST)	12/31/2017		337			
Pittsburg	GenOn	5 (ST)	12/31/2017	12/31/2016	312	Retired (no repowering plan)	N/A	
		6 (ST)	12/31/2017		317			
Potrero	GenOn	3 (ST)	10/1/2011	2/28/2011	206	Retired (no repowering plan)	N/A	
Moss Landing	Dynegy	1 (CCGT)	12/31/2020* (see notes at far right column)	N/A	510	The State Water Resources Control Board (SWRCB) approved mitigation plan (Track 2 implementation plan) for Moss Landing Units 1 & 2.	N/A	The State Water Resources Control Board (SWRCB) approved OTC Track 2 mitigation plan for Moss Landing Units 1 & 2.
		2 (CCGT)	12/31/2020* (see notes at far right column)	N/A	510			
		6 (ST)	12/31/2020 (see notes)	1/1/2017	754	Retired (no repowering plan)	N/A	
		7 (ST)	12/31/2020 (see notes)	1/1/2017	756	Retired (no repowering plan)	N/A	
Morro Bay	Dynegy	3 (ST)	12/31/2015	2/5/2014	325	Retired (no repowering plan)	N/A	
		4 (ST)	12/31/2015	2/5/2014	325	Retired (no repowering plan)	N/A	
	PG&E	1 (ST)	12/31/2024	2025	1122		N/A	

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[46] Most of the existing OTC units, with the exception of Moss Landing Units 1 and 2, are steam generating units.

[47] The ISO, through Long-Term Procurement Process and annual Transmission Planning Process, worked with the state energy agencies and transmission owners to implement an integrated and comprehensive mitigation plan for the southern California OTC and SONGS generation retirement located in the LA Basin and San Diego areas. The comprehensive mitigation plan includes preferred resources, transmission upgrades and conventional generation**.**

[48] IC (Internal Combustion), GT (gas turbine), CCGT (combined cycle gas turbine)

Generating Facility	Owner	Existing Unit/ Technology[46] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[47] (MW) and Technology[48] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
Diablo Canyon Power Plant		2 (ST)	12/31/2024	2025	1118	PG&E plans to replace with renewable energy, energy efficiency and energy storage.		On June 21, 2016, PG&E has announced that it planned to retire Units 1 and 2 by 2024 and 2025, respectively.
Mandalay	GenOn	1 (ST)	12/31/2020	2/6/2018	215	SCE plans to replace with renewable energy and storage	SCE's filing for replacement resources is at the CPUC, pending review and further actions.	Mandalay generating facility was retired on February 6, 2018.
		2 (ST)	12/31/2020	2/6/2018	215			
Ormond Beach	GenOn	1 (ST)	12/31/2020		741	To be retired (no repowering)	N/A	NRG California South LP has informed retirement of Ormond Beach generating facility effective October 1, 2018
		2 (ST)	12/31/2020	10/1/2018	775			
El Segundo	NRG	3 (ST)	12/31/2015	7/27/2013	335	560 MW El Segundo Power Redevelopment (CCGTs)	August 1, 2013	
		4 (ST)	12/31/2015	12/31/2015	335	Retired (no repowering)	N/A	Unit 4 was retired on December 31, 2015.
Alamitos	AES	1 (ST)	12/31/2020	12/31/2019	175	640 MW CCGT on the same property	4/1/2020	
		2 (ST)	12/31/2020	12/31/2019	175			
		3 (ST)	12/31/2020	12/31/2020	332			
		4 (ST)	12/31/2020	12/31/2020	336			
		5 (ST)	12/31/2020	12/31/2020	498			
		6 (ST)	12/31/2020	12/31/2019	495			
Huntington Beach	AES	1 (ST)	12/31/2020	10/31/2019	226	644 MW CCGT on the same property	3/1/2020	
		2 (ST)	12/31/2020	12/31/2020	226			
		3 (ST)	12/31/2020	11/1/2012	227			

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Generating Facility	Owner	Existing Unit/ Technology[46] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[47] (MW) and Technology[48] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
		4 (ST)	12/31/2020	11/1/2012	227			Units 3 and 4 were retired in 2012 and converted to synchronous condensers in June 2013 to operate on an interim basis. On December 31, 2017, these two synchronous condensers were retired.
Redondo Beach	AES	5 (ST)	12/31/2020		179	To be retired	N/A	
		6 (ST)	12/31/2020		175			
		7 (ST)	12/31/2020	9/30/2019	493			
		8 (ST)	12/31/2020		496			
San Onofre Nuclear Generating Station	SCE/ SDG&E	2 (ST)	12/31/2022	June 7, 2013	1122	Retired (no repowering)	N/A	
		3 (ST)	12/31/2022		1124			
Encina	NRG	1 (ST)	12/31/2017	3/1/2017	106	500 MW (5 GTs) Carlsbad Energy Center, located on the same property as the Encina Power Plant.	Q4 2018	The State Water Resources Control Board approved extension of compliance date for Units 2 through 5 to December 31, 2018 due to delay of in-service date for Carlsbad Energy Center
		2 (ST)	12/31/2017	12/31/2018[49]	103			
		3 (ST)	12/31/2017	12/31/2018	109			
		4 (ST)	12/31/2017	12/31/2018	299			
		5 (ST)	12/31/2017	12/31/2018	329			
South Bay (707 MW)	Dynegy	1-4 (ST)	12/31/2011	12/31/2010	692	Retired (no repowering)	N/A	Retired 707 MW (CT non-OTC) – (2010-2011)

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[49] The State Water Resources Control Board approved extending the compliance date for Encina Units 2 to 5 for one year to December 31, 2018 due to delay of Carlsbad Energy Center in-service date.

2.3.4.7 LTPP Authorization Procurement

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTTP Tracks 1 and 4 were considered along with the procurement activities to date from the utilities. Table 2.3-4 provides the local capacity resource additions and the study year in which the amounts were first modeled based on the CPUC LTPP Tracks 1 and 4 authorizations. Table 2.3-5 provides details of the study assumptions using the utilities' procurement activities to date, as well as the ISO's assumptions for potential preferred resources for the San Diego area.

Table 2.3-4: Summary of 2012 LTPP Track 1 & 4 Authorized Procurement

LCR Area	LTTP Track-1		LTTP Track-4[50]	
	Amount (MW)(1)	Study year in which addition is to be first modeled	Amount (MW) (1)	Study year in which addition is to be first modeled
Moorpark Sub-area	290	2021	0	N/A
West LA Basin / LA Basin	1400-1800	2021	500-700	2021
San Diego	308	2018	500-800	2018

Notes: Amounts shown are total including gas-fired generation, preferred resources and energy storage

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[50] CPUC Decision for LTPP Track 4 (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF)

Table 2.3-5: Summary of 2012 LTPP Track 1 & 4 Procurement Activities to date

	LTPP EE (MW)	Behind the Meter Solar PV (NQC MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
SCE's procurement for the Western LA Basin51	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark Sub-area52	6.00	5.66	0.50	0	262	274.16
SDG&E's procurement	22.4*	0	25**-84*	33.6*	80053	881-940

Notes:

* Proxy preferred resource and energy storage assumptions are based on the maximum total amount of 140 MW that SDG&E is soliciting based on its 2016 RFO for Local Capacity Requirements Decision established by the CPUC via D.14-03-004 (the "Track 4" Decisions). These were updated upon SDG&E's filing of final procurement selection for preferred resources and energy storage at the CPUC later in 2016 time frame.

** Based on the CPUC draft Scenarios and Assumptions for the 2016 LTPP and the 2016-2017 Transmission Planning Process, 25 MW was assumed initially for the energy storage for San Diego and this amount can be increased (up to the net amount of the ceiling for preferred resources and energy storage subtracting other assumptions for LTPP related for preferred resources) if needed.

*** Pio Pico (300 MW) and Carlsbad Energy Center (500 MW) were approved by the CPUC as part of SDG&E-selected procurement for LTPP Tracks 1 and 4.

2.3.5 Preferred Resources

According to tariff Section 24.3.3(a), the ISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. In response, the ISO received demand response and energy storage information for consideration in planning studies from Pacific Gas & Electric (PG&E). PG&E provided a bus-level model of PG&E's demand response (DR) programs for the inclusion in the Unified Planning Assumptions and 2018-2019 study plan.

Methodology

The ISO issued a paper[54] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The general application for this methodology is in grid area situations where a non-conventional

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[51] SCE-selected RFO procurement for the Western LA Basin was approved by the CPUC with PPTAs per Decision 15-11-041, issued on November 24, 2015.

[52] SCE-selected RFO procurement (A. 14-11-016) for the Moorpark sub-area is currently at the CPUC for review and consideration.

[53] The CPUC, in Decisions 14-02-016 and 15-05-051 approved PPTAs for the Pio Pico and Carlsbad Energy Center projects.

[54] http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the ISO's transmission plan as an alternative to the conventional transmission or generation solution.

In previous planning cycles, the ISO applied a variation of this new approach in the LA Basin and San Diego areas to evaluate the effectiveness of preferred resource scenarios developed by SCE as part of the procurement process to fill the authorized local capacity for the LA Basin and Moorpark areas. In addition to these efforts focused on the overall LA Basin and San Diego needs, the ISO also made further progress in integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified.

As in the 2017-2018 planning cycle, reliability assessments in the current planning cycle will consider a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies will also incorporate the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the CPUC Default RPS Portfolio and a mix of preferred resources including energy storage based on the CPUC LTPP 2012 local capacity authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and "behind the meter" distributed or self-generation that is embedded in the CEC load forecast.

For each planning area, reliability assessments were initially performed using preferred resources other than energy-limited preferred resources such as DR and energy storage to identify reliability concerns in the area. If reliability concerns were identified in the initial assessment, additional rounds of assessments were performed using potentially available demand response and energy storage to determine whether these resources are a potential solution. If these preferred resources are identified as a potential mitigation, a second step - a preferred resource analysis was then be performed, if considered necessary given the mix of resources in the particular area, to account for the specific characteristic of each resource including use or energy limitation in the case of demand response and energy storage. An example of such a study is the special study the ISO performed for the CEC in connection with the Puente Power Project proceeding to evaluate alternative local capacity solutions for the Moorpark area[55]. The ISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

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Demand Response

Section 6.6 of the ISO 2017-2018 Transmission Plan provided a status update on the progress to identify the necessary characteristics for slow response local capacity resources, such that the resources can be relied upon to meet reliability needs. For long term transmission expansion studies, the methodology described above was utilized for considering fast-response DR and slow-response PDR resources[56].

[55] https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf

[56] For local capacity requirement studies, slow response DR will be utilized once the necessary characteristics have been accepted in the CPUC's RA proceedings, as indicated in the CAISO's comments in the RA proceeding.

The DR Load Impact Reports filed with the CPUC on April 3, 20l7, and other supply-side DR procurement incremental to what is assumed in the Load Impact Reports, serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the load impacts that supply-side DR has on the system. The following table describes the total supply-side DR capacity assumptions[57].

Table 2.3-6: Existing DR Capacity Range in Local Area Reliability Studies

Supply-side DR (MW):	PG&E	SCE	SDG&E	All IOUs	Assumed Market	Assumed 30 minute responsive
Load Impact Report, 1-in-2 weather year condition portfolio-adjusted August 2027 ex-ante DR impacts at ISO peak						
BIP	300	610[58]	6.74	917	RDRR	Yes
AP-I		50[59]	0.0	50	RDRR	Yes
AC Cycling Res[60]	61	56	7.18	124	PDR	Yes
AC Cycling Non-Res	0	20[61]	1.79	22	PDR	Yes
CBP	103[62]	143[63]	8.44	254	PDR	No
Other procurement program DR						
SCE LCR RFO,[64] post 2018		5.0		5	RDRR	Yes
DRAM[65] 2017	56.4	56.2	12	125	PDR[66]	No
DRAM[65] 2018	79.5	88.5	13.9	182		
DRAM[65] 2019	90.1	99.2	15.7	205		

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DR capacity was allocated to bus-bar using the method defined in D.12-12-010, or specific bus-bar allocations provided by the IOUs. The DR capacity amounts were modeled offline in the initial reliability study cases and were used as potential mitigation in those planning areas where reliability concerns are identified.

57 http://www.cpuc.ca.gov/General.aspx?id=6442451972

58 D.16-06-029 authorizes SCE to use existing BIP funds to gain 5 MW of incremental load impact for the program.

59 D.16-06-029 authorizes SCE to use existing AP-I funds to gain 4 MW of incremental load impact for the program.

60 AC Cycling programs include Smart AC (PG&E), SDP (SCE), and Summer Saver (SDG&E)

62 D.16-06-029 approved PG&E's request to terminate its AMP program. It is assumed that 82 MW from PG&E's AMP program will migrate to PG&E's CBP program.

63 D.16-06-029 approved SCE's request for an extension of its AMP program through 2017. However, it is assumed that 93 MW from SCE's AMP program will migrate to its CBP program by 2026.

64 SCE LCR RFO refers to procurement authorized in D.14-03-004 with contract approved in D.15-11-041

65 Demand Response Auction Mechanism (DRAM) is a 4-year pilot program with contract lengths set at a maximum of one year.

66 Although the 2017 DRAM solicitation could include a mix of Reliability Demand Response Resource (RDRR) and Proxy Demand Resource (PDR), for modeling we will assume it is all PDR absent more definitive information.

The following factors were applied to the DR projections to account for avoided distribution losses.

Table 2.3-7: Factors to Account for Avoided Distribution Losses

	PG&E	SCE	SDG&E
Distribution loss factors	1.067	1.051	1.071

Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the ISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs as shown in Table 2.3-8. Energy storage that will be procured by SCE and SDG&E to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision is subsumed within the 2020 procurement target. The transmission-connected storage projects approved in the 2017-2018 Transmission Plan as regulated transmission asset were modeled.

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Table 2.3-8: Total Energy Storage Procured to-Date[67]

Domain	Transmission- connected	Distribution- connected	Customer- connected
SDG&E	40	44	31
SCE	55	195	251
PG&E	30	17	0
Total	125	256	282

These storage capacity amounts were modeled in the initial reliability base cases using the locational information as well as the in-service dates provided by CPUC.

2.3.6 Firm Transfers

Power flow on the major internal paths and paths that cross balancing authority boundaries represents the transfers modeled in the study. Firm Transmission Service and Interchange represents only a small fraction of these path flows, and is clearly included. In general, the northern California (PG&E) system has 4 major interties with the outside system and southern California. Table 2.3-9: Major paths and power transfer ranges in the Northern California assessment lists the capability and power flows modeled in each scenario on these paths in the northern area assessment[68].

[67] http://www.cpuc.ca.gov/General.aspx?id=6442451972

[68] These path flows were modeled in all base cases.

Table 2.3-9: Major paths and power transfer ranges in the Northern California assessment[69]

Path	Transfer Capability/SOL (MW)	Scenario in which Path was stressed
Path 26 (N-S)	4000[70]	Summer Peak
PDCI (N-S)	3220[71]	
Path 66 (N-S)	4800[72]	
Path 15 (N-S)	-5400[73]	Summer Off Peak
Path 26 (N-S)	-3000	
Path 66 (N-S)	-3675	Winter Peak

For the summer off-peak cases in the northern California study, Path 15 flow was adjusted to a level close to its rating limit of 5400 MW (S-N). This is typically done by increasing the import on Path 26 (S-N) into the PG&E service territory. The Path 26 was adjusted between 1800 MW south-to-north and 1800 MW north-to-south to maintain the stressed Path 15 as well as to balance the loads and resources in northern California. Some light load cases model Path 26 flow close to 3000 MW in the south-to-north direction which is its rating limit.

Similarly, Table 2.3-10: Major Path flow ranges in southern area (SCE and SDG&E system) assessment lists major paths in southern California along with their current Transfer Capability (TC) or System Operating Limit (SOL) for the planning horizon and the target flows to be modeled in the southern California assessment.

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69 The winter coastal base cases in PG&E service area will model Path 26 flow at 2,800 MW (N-S) and Path 66 at 3,800 MW (N-S)

70 May not be achievable under certain system loading conditions.

71 PDCI Upgrade Project – to 3220 MW – was approved in 2017

72 The Path 66 flows was modeled to the applicable seasonal nomogram for the base case relative to the northern California hydro dispatch.

73 May not be achievable under certain system loading conditions

Table 2.3-10: Major Path flow ranges in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Target Flows (MW)	Scenario in which Path was stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
PDCI (N-S)	3220	3220	
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 9,600	Summer Peak
San Diego Import	2,850	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	400	0 to 250	Summer Peak
Path 45 (S-N)	800	0 to 300	Off Peak

P27-129 cont.

2.3.7 Operating Procedures

Operating procedures, for both normal (pre-contingency) and emergency (post-contingency) conditions, were modeled in the studies.

Please refer to the website: http://www.caiso.com/thegrid/operations/opsdoc/index.html, for the list of publicly available Operating Procedures.

2.3.8 Study Scenarios

2.3.8.1 Base Scenarios

The main study scenarios cover critical system conditions driven by several factors such as:

Generation:

Existing and future generation resources are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 2.3.4.

Demand Level:

Since most of the ISO footprint is a summer peaking area, summer peak conditions were evaluated in all study areas. With hourly demand forecast being available from CEC, all base scenarios representing peak load conditions, for both summer and winter, represented hour of the highest net load. The net peak hour reflects changes in peak hours brought on by demand modifiers. Furthermore, for the coincident system peak load scenarios, the hour of the highest net load were consistent with the hour identified in the CEC demand forecast report. For the non-coincident local peaks scenarios, the net peak hour may represent hour of the highest net load for the local area. Winter peak, spring off-peak, summer off-peak or summer partial-peak were also studied for areas in where such scenarios may result in more stress on system conditions. Examples of these areas are the coastal sub-transmission systems in the PG&E service area (e.g. Humboldt, North Coast/North Bay, San Francisco, Peninsula and Central Coast), which were studied for both the summer and winter peak conditions. Table 2.3-11 lists the studies that were conducted in this planning cycle.

Path flows:

For local area studies, transfers on import and monitored internal paths were modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, major import and internal transfer paths were stressed as described in section 2.3.4.9 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable. Table 2.3-11 summarizes these study areas and the corresponding base scenarios for the reliability assessment.

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cont.

Table 2.3-11: Summary of study areas, horizon and peak scenarios for the reliability assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2020	2023	2028
Northern California (PG&E) Bulk System	Summer Peak Spring Off-peak	Summer Peak Spring Off-peak	Summer Peak Spring Off-peak Winter off-Peak
Humboldt	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Light Load	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer/Winter Peak Spring Light Load	Summer/Winter Peak Spring Off-Peak	Summer/Winter Peak

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cont.

2.3.8.2 Sensitivity study cases

In addition to the base scenarios that the ISO assessed in the reliability analysis for the 2018-2019 transmission planning process, the ISO assessed the sensitivity scenarios identified in Table 2.3-12. The sensitivity scenarios are to assess impacts of specific assumptions on the reliability of the transmission system. These sensitivity studies include impacts of load forecast, generation dispatch, generation retirement and transfers on major paths.

Table 2.3-12: Summary of Study Sensitivity Scenarios in the ISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2020	2023	2028
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-
Off peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-	-
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off-peak with heavy renewable output	-	VEA Area	-
Retirement of QF Generations	-	-	PG&E Local Areas

P27-129 cont.

2.3.9 Contingencies

In addition to the system under normal conditions (P0), the following contingencies were evaluated as part of the study. These contingencies lists have been made available on the ISO secured website.

Single contingency (Category P1)

- The assessment considered all possible Category P1 contingencies based upon the following:
- Loss of one generator (P1.1)74
- Loss of one transmission circuit (P1.2)
- Loss of one transformer (P1.3)
- Loss of one shunt device (P1.4)
- Loss of a single pole of DC lines (P1.5)

Single contingency (Category P2)

- The assessment considered all possible Category P2 contingencies based upon the following:
- Loss of one transmission circuit without a fault (P2.1)
- Loss of one bus section (P2.2)
- Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
- Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

Multiple contingency (Category P3)

The assessment considered the Category P3 contingencies with the loss of a *generator unit* followed by system adjustments and the loss of the following:

- Loss of one generator (P3.1)75
- Loss of one transmission circuit (P3.2)
- Loss of one transformer (P3.3)
- Loss of one shunt device (P3.4)
- Loss of a single pole of DC lines (P3.5)

74 Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

75 Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

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cont.

Multiple contingency (Category P4)

The assessment considered the Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5) attempting to clear a fault on one of the following:

- Loss of one generator (P4.1)
- Loss of one transmission circuit (P4.2)
- Loss of one transformer (P4.3)
- Loss of one shunt device (P4.4)
- Loss of one bus section (P4.5)
- Loss of a bus-tie-breaker (P4.6)

Multiple contingency (Category P5)

The assessment considered the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following:

- Loss of one generator (P5.1)
- Loss of one transmission circuit (P5.2)
- Loss of one transformer (P5.3)
- Loss of one shunt device (P5.4)
- Loss of one bus section (P5.5)

Multiple contingency (Category P6)

The assessment considered the Category P6 contingencies with the loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results.

Multiple contingency (Category P7)

The assessment considered the Category P7 contingencies for the loss of a common structure as follows:

- Any two adjacent circuits on common structure76 (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme Event contingencies (TPL-001-4)

As a part of the planning assessment the ISO assessed Extreme Event contingencies per the requirements of TPL-001-4; however the analysis of Extreme Events have not been included

76 Excludes circuits that share a common structure or common right-of-way for 1 mile or less.

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cont.

within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

2.3.10 Study Methodology

As noted earlier, the backbone and regional planning region assessments were performed using conventional analysis tools and widely accepted generation dispatch approaches. These methodology components are briefly described below.

2.3.10.1 Study Tools

The GE PSLF program is the main study tool for evaluating system performance under normal conditions and following the outages (contingencies) of transmission system components for post-transient and transient stability studies. PowerGem TARA was used for steady state contingency analysis. However, other tools such as DSA tools software may be used in other studies such as voltage stability, small signal stability analyses and transient stability studies. The studies in the local areas focus on the impact from the grid under system normal conditions and following the Categories P1-P7 outages of equipment at the voltage level 60 through 230 kV. In the bulk system assessments, governor power flow was used to evaluate system performance following the contingencies of equipment at voltage level 230 kV and higher.

2.3.10.2 Technical Studies

P27-129 cont.

The section explains the methodology that were used in the study:

Steady State Contingency Analysis

The ISO performed power flow contingency analyses based on the ISO Planning Standards77 which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the ISO controlled grid and with select contingencies outside of the ISO controlled grid. The transmission system was evaluated under normal system conditions NERC Category P0 (TPL 001-4), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category P1-P7 (TPL 001-4) contingencies against emergency ratings and emergency voltage range.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)78. Examples of these outages are combined cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

Line and transformer bank ratings in the power flow cases are updated to reflect the rating of the most limiting component. This includes substation circuit breakers, disconnect switches, bus position related conductors, and wave traps.

[77] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf

[78] Per California ISO Planning standards Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

The contingency analysis simulated the removal of all elements that the protection system and other automatic controls are expected to disconnect for each contingency without operator intervention. The analyses included the impact of subsequent tripping of transmission elements where relay loadability limits are exceeded and generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations unless corrective action plan is developed to address the loading and voltages concerns.

Power flow studies are performed in accordance with PRC-023 to determine which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in the Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities below 200 kV that must meet PRC-023 to prevent potential cascade tripping that may occur when protective relay settings limit transmission load ability.

Post Transient Analyses

Post Transient analyses was conducted to determine if the system is in compliance with the WECC Post Transient Voltage Deviation Standard in the bulk system assessments and if there are thermal overloads on the bulk system.

Post Transient Voltage Stability Analyses

Post Transient Voltage stability analyses was conducted as part of bulk system assessment for the outages for which the power flow analyses indicated significant voltage drops, using two methodologies: Post Transient Voltage Deviation Analyses and Reactive Power Margin analyses.

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Post Transient Voltage Deviation Analyses

Contingencies that showed significant voltage deviations in the power flow studies were selected for further analysis using WECC standards of 8% voltage deviation for P1 events.

Voltage Stability and Reactive Power Margin Analyses

As per WECC regional criterion, voltage stability is required for the area modeled at a minimum of 105% of the reference load level or path flow for system normal conditions (Category P0) and for single contingencies (Category P1). For other contingencies (Category P2-P7), post-transient voltage stability is required at a minimum of 102.5% of the reference load level or path flow. The approved guide for voltage support and reactive power, by WECC TSS on March 30, 2006, was used for the analyses in the ISO controlled grid. According to the guideline, load is increased by 5% for Category P1 and 2.5% for other contingencies Category P2-P7 and studied to determine if the system has sufficient reactive margin. This study was conducted in the areas that have voltage and reactive concerns throughout the system.

Transient Stability Analyses

Transient stability analyses was also conducted as part of bulk area system assessment and local for critical contingencies to determine if the system is stable and exhibits positive damping of oscillations and if transient stability criteria are met as per ISO Planning Standards.

2.4 PG&E Bulk Transmission System Assessment

2.4.1 PG&E Bulk Transmission System Description

The figure below provides a simplified map of the PG&E bulk transmission system.

Figure 2.4-1: Map of PG&E bulk transmission system

The 500 kV bulk transmission system in northern California consists of three parallel 500 kV lines that traverse the state from the California-Oregon border in the north and continue past Bakersfield in the south. This system transfers power between California and other states in the northwestern part of the United States and western Canada. The transmission system is also a gateway for accessing resources located in the sparsely populated portions of northern California, and the system typically delivers these resources to population centers in the Greater Bay Area and Central Valley. In addition, a large number of generation resources in the central California area are delivered over the 500 kV systems into southern California. The typical

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cont.

direction of power flow through Path 26 (three 500 kV lines between the Midway and Vincent substations) is from north-to-south during on-peak load periods and in the reverse direction during off-peak load periods. However, depending on the generation dispatch and the load value in northern and southern California, Path 26 may have north-to-south flow direction during off-peak periods also.The typical direction of power flow through Path 15 (Los Banos-Gates #1 and #3 500 kV lines and Los Banos-Midway #2 500 kV line) is from south-to-north during off-peak load periods and the flows can be either south-to-north or north-to-south under peak conditions. The typical direction of power flow through California-Oregon Intertie (COI, Path 66) and through the Pacific DC Intertie (bi-pole DC transmission line connecting the Celilo Substation in Washington State with the Sylmar Substation in southern California) is from north-to-south during summer on-peak load periods and in the reverse direction during off-peak load periods in California, which are the winter peak periods in Pacific Northwest.

Because of this bi-directional power flow pattern on the 500 kV Path 26 lines and on COI, both the summer peak (N-S) and spring off-peak (S-N) flow scenarios were analyzed, as well as peak and off-peak sensitivity scenarios with high renewable generation output and low gas generation output. Post transient contingency analysis was also performed for all flow patterns and scenarios (seven base cases and three sensitivity cases). Transient stability studies were performed for the selected five cases: three base cases – 2020 and 2028 Summer Peak and 2023 Spring off-Peak and two sensitivity cases with high renewable and low gas generation output - 2020 Summer Peak and 2023 Spring off-Peak.

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2.4.2 Study Assumptions and System Conditions

The northern area bulk transmission system study was performed consistent with the general study methodology and assumptions described in section 2.3. The ISO-secured website lists the contingencies that were performed as a part of this assessment. In addition, specific methodology and assumptions that are applicable to the northern area bulk transmission system study are provided in the next sections. The studies for the PG&E bulk transmission system analyzed the most critical conditions: summer peak and spring off-peak cases for the years 2020, 2023 and 2028; and winter off-peak peak case for 2028. In addition, 3 sensitivity cases were studied: the 2020 Summer Peak case with high renewable and low gas generation output, 2023 Spring off-Peak case with high renewable and low gas generation output and 2023 Summer Peak with high CEC forecasted load . All single and common mode 500 kV system outages were studied, as well as outages of large generators and contingencies involving stuck circuit breakers and delayed clearing of single-phase-to-ground faults. Also, extreme events such as contingencies that involve a loss of major substations and all transmission lines in the same corridors were studied.

Generation and Path Flows

The bulk transmission system studies use the same set of generation plants that are modeled in the local area studies. The total generation in each of the local planning areas within the PG&E system are provided in Section 2.5.

Since the studies analyzed the most critical conditions, the flows on the interfaces connecting northern California with the rest of the WECC system were modeled at or close to the paths' flow limits, or as high as the generation resource assumptions allowed. Due to retirement of several large OTC power plants in northern California, flow on Path 26 between northern and southern California was modeled in the 2028 summer peak case significantly below its 4000 MW north-to-south rating. Table 2.4-1 lists all major path flows affecting the 500 kV systems in northern California along with the hydroelectric generation dispatch percentage in the area.

Table 2.4-1: Major import flows and Northern California Hydro generation level for the northern area bulk study

BASE CASE	Scenario Type	Description	COI MW	Path 15 MW	Path 26 MW	PDCI MW	N.Cal Hydro, %
PGE-Bulk-2020-SP	Base Line	2020 Summer peak load conditions. Peak load time -hour ending 19:00	4800 N-S	1600 N-S	3700 N-S	2700 N-S	80%
PGE-Bulk-2020-SpOp	Base Line	2020 Spring off-peak load conditions. Off-peak load time - hour ending 12:00	2800 S-N	120 N-S	3700 N-S	300 N-S	56%
PGE-Bulk-2023-SP	Base Line	2023 Summer peak load conditions. Peak load time - hour ending 19:00	4800 N-S	1260 N-S	3100 N-S	2800 N-S	80%
PGE-Bulk-2023-SpOP	Base Line	2023 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	2420 S-N	700 S-N	2900 N-S	300 N-S	42%
PGE-Bulk-2028-SP	Base Line	2028 Summer peak load conditions. Peak load time - hour ending 19:00	4800 N-S	470 N-S	400 N-S	2240 N-S	80%
PGE-Bulk-2028-SpOP	Base Line	2028 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	2500 S-N	220 S-N	1420 N-S	300 N-S	34%
PGE-Bulk-2028-WOP	Base Line	2028 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	120 N-S	2520 N-S	3000 N-S	300 N-S	70%
PGE-Bulk-2020-SP-HiRenew	Sensitivity	2020 Summer peak load conditions with high renewables and minimum gas	4800 N-S	1280 N-S	3700 N-S	2840 N-S	76%
PGE-Bulk-2023-SP-Hi CEC	Sensitivity	2023 Summer peak load conditions with high CEC forecasted load	4800 N-S	1330 N-S	3400 N-S	2800 N-S	89%
PGE-Bulk-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with high renewables and minimum gas	3670 S-N	50 N-S	3970 N-S	240 N-S	40%

All power flow cases included certain amount of renewable resources, which was dispatched at different levels depending on the case studied. The assumptions on the generation installed capacity and the output are summarized in Table 2.4-2.

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Table 2.4-2. Generation Assumptions – PG&E Bulk System

Description	Battery Storage		Solar		Wind		Hydro		Thermal: incl. geo, nuclear, bio	
	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2020 Summer peak load conditions. Peak load time -hour ending 19:00	177	16	3,935	583	1,796	717	9,932	7,822	23,443	16,882
2020 Spring off-peak load conditions. Off-peak load time - hour ending 12:00	177	2	3,935	3,923	1,796	119	9,932	5,967	23,443	8,367
2023 Summer peak load conditions. Peak load time - hour ending 19:00	186	4	4,202	184	1,802	1,197	10,003	7,970	22,981	18,394
2023 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	186	4	4,202	3,741	1,802	73	10,003	4,568	22,981	6,919
2028 Summer peak load conditions. Peak load time - hour ending 19:00	186	8	4,202	183	1,802	1,179	10,003	8,069	20,570	15,901
2028 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	186	4	4,202	3,871	1,802	78	10,003	4,403	20,570	4,798
2028 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	186	4	4,202	115	1,802	316	10,003	6,592	20,570	11,427
2020 Summer peak load conditions with high renewables and minimum gas	177	157	3,935	3,450	1,796	1,409	9,932	7,791	23,443	9,475
2023 Summer peak load conditions with high CEC forecasted load	186	8	4,202	1,211	1,802	201	10,003	8,613	22,981	18,643
2023 spring off-peak load conditions with high renewables and minimum gas	186	4	4,202	3,802	1,802	1,128	10,003	4,440	22,981	7,410

Load Forecast

P27-129 cont.

Per the ISO planning criteria for regional transmission planning studies, the demand within the ISO area reflects a coincident peak load for 1-in-5-year forecast conditions for the summer peak cases. Loads in the off-peak case were modeled at approximately 50-60 percent of the 1-in-5 summer peak load level. The light load cases modeled the lowest load in the PG&E area that appears to be lower than the off-peak load. Table 2.4-3 shows the assumed load levels for selected areas under summer peak and non-peak conditions. The table shows gross PG&E load in all the cases studied and the load modifiers: Additional Achievable Energy Efficiency, output of the Behind the Meter solar PV generation, and it also shows the load for irrigational pumps and hydro pump storage plants if they are operating in the pumping mode. In the base cases, pumping load is modeled as negative generation. Net load is the gross load with the Additional Achievable Energy Efficiency and the output of the Behind the Meter solar PV generation subtracted and the pumping load added.

Table 2.4-3: Load and Load Modifier Assumptions – PG&E Bulk System

BASE CASE	Scenario Type	Description	Gross PG&E Load	AAEE	Behind the Meter PV		Net Load	Demand Response		Pumps (Irrigaiton and pump-storage)
					Installed	Output		Total	D2	
			MW	MW	MW	MW	MW	MW	MW	MW
PGE-Bulk-2020-SP	Base Line	2020 Summer peak load conditions. Peak load time -hour ending 19:00	26,992	474	4,698	846	**25,672**	505	298	597
PGE-Bulk-2020-SpOp	Base Line	2020 Spring off-peak load conditions. Off-peak load time - hour ending 12:00	13,902	325	4,698	3,711	**9,866**	505	298	1,527
PGE-Bulk-2023-SP	Base Line	2023 Summer peak load conditions. Peak load time - hour ending 19:00	29,229	1,145	6,272	191	**27,893**	509	298	609
PGE-Bulk-2023-SpOP	Base Line	2023 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	13,903	659	6,272	5,268	**7,976**	509	298	1,539
PGE-Bulk-2028-SP	Base Line	2028 Summer peak load conditions. Peak load time - hour ending 19:00	30,540	2,114	8,547	220	**28,206**	511	298	612
PGE-Bulk-2028-SpOP	Base Line	2028 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	15,696	1,198	8,547	7,215	**7,283**	511	298	1,542
PGE-Bulk-2028-WOP	Base Line	2028 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	15,589	1,273	8,547	0	**14,316**	511	298	612
PGE-Bulk-2020-SP-HiRenew	Sensitivity	2020 Summer peak load conditions with high renewables and minimum gas	27,052	463	4,698	4,651	**21,938**	505	298	597
PGE-Bulk-2023-SP-Hi CEC	Sensitivity	2023 Summer peak load conditions with high CEC forecasted load	29,296	0	6,272	849	**28,447**	509	298	609
PGE-Bulk-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with high renewables and minimum gas	13,938	655	6,272	6,197	**7,086**	509	298	1,539

Existing Protection Systems

Extensive SPS or RAS are installed in the northern California area's 500 kV systems to ensure reliable system performance. These systems were modeled and included in the contingency studies. Comprehensive details of these protection systems are provided in various ISO operating procedures, engineering and design documents.

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2.4.3 Assessment and Recommendations

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standards requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The ISO study assessment of the northern bulk system yielded the following conclusions:

- The starting cases used Security Constrained Generation Dispatch. Thus, no Category P0 overloads were observed on the PG&E Bulk system on the facilities 230 kV and above. However, there were three Category P0 overloads of the 115 kV lines; one in the 2028 Summer Peak case (Palermo-Wyandet) and two in the 2020 Spring off-Peak case (Wilson-Le Grand and Smyrna-Atwell Island). Heavy loading above 95% under normal system conditions was observed on one 230 kV line (Cayetano-Lone Tree), on one 230/70 kV transformer (Helm) and one 115 kV transmission line (Cheny-Panoche). There were also seven 70 kV line overloads under normal system conditions in the off-peak cases. Five overloads were identified on the 60 kV lines under summer peak normal conditions, and additional three 60 kV overloads were identified in the sensitivity peak cases. The overloads on the 230/70 kV transformer and the 115 kV and below systems and their mitigation measures are discussed in the local area sections of the report. The same transmission lines were also overloaded with single and double contingencies. Overloads of these facilities were either due to high generation, or for the lower voltages, some were radial lines overloaded due to high load at the end of the line. The 60 kV and 70 kV facilities are not considered to be Bulk Electric System (BES), therefore, considering that they were overloaded under normal system conditions, their overloads are not discussed here further. These overloads are considered in the local area studies.

- Two Category P1 overloads were identified under summer peak conditions in the base cases. These overloads were observed on the two circuits in the same corridor: Round Mountain-Table Mountain # 1 and # 2 500 kV lines with an outage of the parallel circuit. In addition, one transformer, Gates 500/230 kV, was identified as overloaded with a Category P1 contingency in the 2023 sensitivity off-Peak case with high renewable and minimum gas generation output. Also, Table Mountain 500/230 kV transformer may become heavily loaded in the same sensitivity case with a Category P1 contingency.
- Under a Category P2 contingency, Round Mountain-Table Mountain # 1 500 kV line may also overload. This Category P2 contingency includes an outage of the parallel 500 kV Round Mountain-Table Mountain 500 kV circuit. There were no additional Category P2 contingency overloads on the Bulk System.
- Under Category P3 contingencies with an outage of one of the Diablo Canyon generating units and another transmission facility, in addition to the facilities that were overloaded under Categories P0 and P1, Malin-Round Mountain # 1 500 kV line was identified as overloaded in the sensitivity peak cases, and as heavily loaded in the base peak cases. Other facilities that may overload under Category P3 contingencies studied include the Cottonwood –Round Mountain # 3 230 kV line, the Henrietta 230/115 kV transformer and the Henrietta-Leprino 115 kV transmission line. All these overloads were identified in the sensitivity cases. It was assumed that there were no system adjustments between the contingencies.
- Thirty-nine P6 overloaded facilities were identified in the studies in the base cases. Out of these, sixteen overloads were identified under summer peak conditions including three 500/230 transformers at the same substation (Metcalf). Twentythree facilities were overloaded under off-peak conditions, including two 500/230 kV transformers at the same substation (Gates). Out of these facilities, three were also overloaded under peak load conditions. Twelve Additional facilities were identified as overloaded only in the sensitivity cases: nine in the peak cases, three in the off-peak and one both in the peak and off-peak sensitivity cases. In the P6 studies, no generation re-dispatch was assumed after the first contingency.
- Twelve overloaded or heavily loaded facilities were identified with the 500 kV double contingencies in the same corridors, nine under peak, and three under off-peak conditions in the base and sensitivity cases.

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cont.

- High voltages were observed on 500 kV system in Central California after Diablo Canyon Power Plant retires. Low voltages were observed on the WAPA's Maxwell 500 kV Substation for COI 500 kV double line outages under peak load conditions.
- No voltage deviation or reactive margin concerns were identified in the studies. It was assumed that all appropriate RAS are in service for all double line outages that were studied.

Dynamic stability studies used the new WECC composite load model to reflect more accurate load composition and load parameters. The composite load model included distributed solar PV generation modeled with the latest models that are more detailed than the distributed generation models used previously.

The studies showed that some renewable projects tripped due to under-voltage, under-frequency or other dynamic issues. This generation tripping could be due to modelling issues. In addition, some load and distributed generation was tripped off with three-phase faults by the composite load model due to low voltages. Some small generators located close to the simulated three-phase faults went out-of-step with double contingencies and were tripped. Also, several contingencies indicated some under-voltage load tripping. Dynamic stability studies used the new WECC TPL criteria that included transient voltage recovery. No criteria violations were identified in the studies.

The following table summarizes the overloaded facilities and the options for their mitigation.

Table 2.4-4: Overloaded facilities and contingencies causing thermal overload

Overloaded Facility	Loading % (Baseline Scenarios)							Loading % (Sensitivity Scenarios)			Project & Potential Mitigation Solutions
	2020 Summer Peak	2023 Summer Peak	2028 Summer Peak	2020 Spring Off-Peak	2023 Spring Off-Peak	2028 Spring Off-Peak	2028 Winter Off-Peak	2023 SP High CEC Forecast	2023 SpOP Hi Renew & Min Gas Gen	2020 SP Heavy Renewable & Min Gas Gen	
500 kV LINES											
MALIN-ROUND MTN # 2 500 kV	P3	P3						P3		P3	Reduce COI flow according to seasonal nomogram
ROUND MTN –TABLE MTN #1 500 kV	P1, P2, P3, P6	P1, P2, P3, P6	P1, P2, P6					P1, P2, P3, P6		P1, P2, P3, P6	Reduce COI flow according to seasonal nomogram or bypass ser caps on the remaining Round Mtn-Table Mtn 500 kV line if overload
ROUND MTN-TABLE MTN # 2 500 KV	P1, P3, P6	P1, P3, P6	P1, P3, P6					P1, P3, P6		P1, P3, P6	
CAPTAIN JACK-OLINDA 500 kV	P6, P7	P6, P7	P6, P7					P6, P7		P6, P7	Reduce COI flow according to seasonal nomogram
MIDWAY-VINCENT # 1 500 kV				P6					P6	P6	flow on Path 26 is N-S in off-peak cases, not enough generation at Midway to trip. Need to review RAS for Path 26 contingencies
MIDWAY-VINCENT # 2 500 kV				P6					P6	P6	
MIDWAY-WHIRLWIND # 3 500 kV				P7					P7	P7	
500/230 kV TRANSFORMERS											
OLINDA 500/230 kV x-former				P6, P7	P6, P7	P6, P7			P6, P7		Reverse flow on Olinda x-former in off-peak cases. Reduce Shasta generation aftet first contingency if overload. No overload with Table Mtn 500/230 kV RAS
TABLE MTN 500/230 kV x-former							P6		P7		Reverse flow on Table Mtn x-former in off-peak cases, don't bypass series capacitors on Table Mnt-Vac Dix to reduce flow
METCALF 500/230 kV x-former #11, 12 or 13			P6							P6	increase generation in San Jose after 1st contingency, trip load in San Jose if overload persists
GATES 500/230 kV # 1 or 2 x-former						P6			P1, P6		Reverse flow on Gates x-former in off-peak cases. Decrease generation at Mustang and/or Mc Call after first contingency. Develop Operational Procedure to reduce generation to avoid overload with single contingency

P27-129 cont.

Overloaded Facility	Loading % (Baseline Scenarios)							Loading % (Sensitivity Scenarios)			Project & Potential Mitigation Solutions
	2020 Summer Peak	2023 Summer Peak	2028 Summer Peak	2020 Spring Off-Peak	2023 Spring Off Peak	2028 Spring Off Peak	2028 Winter Off-Peak	2023 SP High CEC Forecast	2023 SpOP Hi Renew & Min Gas Gen	2020 SP Heavy Renewable & Min Gas Gen	
230 kV LINES											
COTTONWD E-ROUND MTN 230kV #3	P7	P6, P7	P6, P7		P6			P3, P6, P7	P6	P6, P7	Reduce COI flow according to seasonal nomogram, or upgrade the line if economic
COTTONWD E-ROUND MTN 230kV #2		P7	P6, P7					P6, P7		P7	Reduce COI flow according to seasonal nomogram
COTTONWD E-ROUND MTN 230kV #1		P7	P6, P7					P6, P7		P7	
TABLE MTN-RIO OSO 230 kV	P6, P7										Terminal equipment upgrade will eliminate high loading
CAYETANO- LONETREE 230 kV			P6					P6			reduce generation in Contra Costa area, if overload
LAS POSITAS-NEWARK 230 KV		P6	P6					P6			
CAYETANO- N. DUBLIN 230 kV		P6	P6					P6			
NEWARK-LOS ESTEROS 230 kV								P6			adjust SVP phase shifter
GOLD HILL-LODI 230 kV					P6	P6			P6		Table Mtn 500/230 kV x-former RAS assumed for off-peak cases. Winter rating used for the winter case. Reduce generation at Ralston, MiddleFork and Collervl. Separate the system
GOLD HILL-EIGHT MILE 230 kV					P6	P6	P6		P6		
BELLOTA-WEBER 230 kV						P6	P6				Reduce Collerville or Electra generation if overload.
WEBER-TESLA 230 kV						P6	P6				
BELLOTA-TESLA 230 kV						P6	P6				
EIGHT MILE-TESLA 230 kV				P6	P6	P6	P6		P6		Reduce generation in Lodi and Feather River - Ralston if overload, or upgrade the facilities if economic or overload still remains.
STAGG-EIGHT MILE 230 kV				P6	P6	P6	P6		P6		
STAGG H - STAGG F BRK 230 kV						P6	P6				
STAGG D - STAGG F BRK 230 kV							P6				
STAGG-TESLA E 230 kV					P6	P6	P6		P6		
PANOCHE - DS AMIGO 230 kV									P6		Decrease generation at Tranquility if overload
LOS BANOS-PANOCHE #1 230 kV									P6		
LOS BANOS-PANOCHE #2 230 kV									P6		
MOSSLANDING-LAS AGUILAS 230 kV									P6	P6	Decrease generation at Las Aguilas if overload
MOSSLANDING-METCALF 230 kV # 1 or 2				P6							decrease generation at Moss Landing power plant if overload
230/115 kV TRANSFORMERS											
NEWARK 230/115 kV #11		P6	P6					P6			May be mitigated by adjusting SVP phase shifter
115 kV LINES											
DELTA - CASCADE 115 kV	P7	P7						P6, P7		P7	adjust Weed Phase Shifter or limit COI flow within seasonal nomogram
PEASE-E.MRSVLE-OLIVH 115 kV	P6, P7										South of Palermo Project. Prior to the project: limit COI import within nomogram
DRUM-BRUNSWICK -RIO OSO 115 kV		P6, P7								P6, P7	reduce Drum generation if overload
DRUM-BRUNSWICK -Dutch Flat 115 kV		P7								P6, P7	
NEWARK-NRS 115 kV		P6	P6				P6	P6		P6	also overloads for local contingencies. May be mitigated by adjusting NRS phase shifter

P27-129
cont.

As can be seen from Table 2.4-4, no Category P0 overloads were observed on the PG&E Bulk system on the facilities at 230 kV and above. Heavy loading above 95% under normal system conditions was observed on one 230 kV line (Cayetano-Lone Tree). The same facility may also overload with multiple contingencies. In addition, there were three facilities that may overload with single contingencies. The same facilities may also overload with multiple contingencies. Two additional facility may overload with Category P3 contingencies. There were twelve facilities that may overload with Category P7 contingencies, one of them only in the sensitivity cases. Twenty four transmission facilities may overload only with Category P6 contingencies.

An approved transmission project (South of Palermo Transmission Reinforcement) will mitigate one Category P6 and P7 overload that may occur under peak conditions in 2020. Upgrading terminal equipment on one substation that will be performed as a part of the transmission system maintenance will address another Category P6 and P7 overload. Prior to the approved transmission solutions being completed, congestion management may be used.

No voltage deviation or reactive margin concerns were identified in the studies.

The ISO-proposed solutions to mitigate the identified reliability concerns are the following:

- Manage COI flow according to the seasonal nomograms.
- Implement RAS to bypass series capacitors on the Round Mountain-Table Mountain 500 kV lines # 1 and # 2 if any of these lines overloads.
- For overloads that are managed with congestion management or operating within the defined path nomograms, upgrades could be considered if congestion is observed in the production simulation and the upgrades are determined to be economic-driven. The following lines were identified as being overloaded with the reliability mitigation plans being congestion management and operating path flows within the nomograms:
    - Cottonwood- Round Mountain 230 kV # 1, #2 and # 3 transmission lines
    - Moss Landing-Las Aguilas 230kV transmission line
- Upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line.
- Implement congestion management after first contingency for Category P6 overloads.
- If the Moss Landing and/or Metcalf power plants retire, the mitigation plan for Category P6 contingencies in the Metcalf-Tesla-Moss Landing-Los Banos area that result in losing the 500 kV source will be needed.
- Develop a project to install reactive support on the 500 kV network in the north and in the south of the PG&E system to mitigate high and low voltages.

The load in WECC, including the ISO, was modeled with the WECC composite load models in the dynamic stability studies. The load was modeled according to the current WECC composite load model Phase II with the stalling of single-phase air-conditioners enabled. Parameters of the composite load model were selected according to the WECC recommendations and research. In addition to loads, behind-the-meter distributed generation (solar PV) was explicitly modeled as well. Dynamic stability studies used the new WECC Transmission Planning criteria that included transient voltage recovery.

The following conclusions can be made from the dynamic stability studies:

- Due to high voltages in the power flow cases, some renewable units may be tripped.

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- Several renewable generation projects were tripped by low or high voltage, or low or high frequency with three-phase faults close to the units, which is most likely a modeling issue.
- Composite load model tripped some fraction of load with 3-phase faults because of low voltages.
- Some under-voltage load tripping may occur due to stalling of single-phase air-conditioning load with three-phase faults.
- No criteria violations were identified. Some slow voltage recovery was observed on the low voltage buses at the end of the feeders, which is not a criteria violation.
- Low transient voltages due to stalling of induction motor load around Gates were identified. Installing dynamic reactive support in the area (Gates 500 kV substation) may help also for these issues.
- More work is required on the load and distributed generation modeling, including modeling and studies with momentary cessation of inverters. The ISO is working with the PTOs and generation owners on the improving the models and on the model parameters to achieve more accurate study results.

The studies identified high voltages on the 500 kV Diablo, Gates and Midway buses starting from when Diablo Canyon Power Plant retires, currently scheduled for 2025. The Diablo Canyon Power Plant was modeled off-line in the 2028 cases. Voltage on the Diablo 500 kV bus may become as high as 550 kV under normal system conditions after the Diablo Canyon Power Plant retires, which is above the required limit. The studies did not identify any insufficient reactive margin issues.

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Additional reactive support is required, preferably dynamic to both absorb reactive power under normal system conditions and supply reactive power with contingencies as needed. Dynamic reactive support in the northern part of the PG&E system also may be needed to avoid under-voltage load tripping in southern Oregon with three-phase faults in northern PG&E that was observed in dynamic stability studies. Dynamic reactive support in southern PG&E also may be needed to prevent momentary cessation of the inverters on the solar PV generators that was identified in the Gates area in the studies of momentary cessation of inverters.

High voltages were also identified on the sub-transmission system under off-peak conditions, mainly due to large amount of renewable generation connecting to this system. The requirement for the new renewable generation projects to maintain at least 0.95 lead/lag power factor at the Point of Interconnection may mitigate high voltages. Having the ability to absorb reactive power will reduce voltages in the sub-transmission system.

Also, the studies identified that voltage at the Maxwell 500 kV Substation in the Northern area may become too low with some contingencies. The most critical was double outage of the Round Mountain-Table Mountain 500 kV lines # 1 and # 2 when the voltage at Maxwell may become as low as 487 kV under peak load conditions. Maxwell Substation is owned by WAPA, and according to the WAPA Operational standards, 500 kV system voltages should be above

495 kV. Under the off-peak load conditions with all facilities in service, voltage at the Maxwell Substation may become as high as 547 kV.

Detailed assessment of the need and requirements of the voltage support was assess in both the northern (Round Mountain area) and southern (Gates area) of the PG&E area 500 kV system as follows.

Round Mountain 500 kV Dynamic Reactive Support

An assessment of reactive support in the Round Mountain area of the northern portion of the PG&E 500 kV system was conducted. The detailed assessment is included in Appendix B.

High voltage issues at Round Mountain 500 kV substation bus occur frequently in real-time operation under non-peak conditions when the COI flows are typically lower. High voltage issues have resulted in limited clearance opportunities to do maintenance work on system elements and in some cases the clearance had to be cancelled to bring the element back in service to address voltage issues. The worst condition occurs under the N-1 contingency of Round Mountain 500/230 kV transformer which is a 3-winding transformer with 4 x 47.7 Mvar reactor connected to its tertiary winding. The loss of the transformer disconnects the reactors and as a result high voltage condition worsens. Round Mountain bus voltage under N-0 and N-1 conditions in a 2019 minimum load case are 549 kV and 554 kV respectively.

To address the issue, a device with 500 Mvar reactive absorption rating is assumed at Round Mountain 500 kV bus. The reactive device is sized to bring the voltage close to 540 kV which is PG&E's maximum normal operating voltage. The studies showed that with reactive device in service, the voltage at the Round Mountain 500 kV bus drops to 538 kV and 541 KV under N-0 and N-1 conditions, respectively.

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In addition to high voltage issues under light loading conditions, Round Mountain bus voltage varies significantly on a daily basis with the output of solar generation in California which results in COI flow changes on a daily basis. The hourly voltage fluctuations are expected to increase in future with more solar integration in California and the expansion of EIM in the northwest. To address the voltage variability at Round Mountain 500 kV bus, the recommended reactive device should be a dynamic device to be able to actively manage the voltage as the need for reactive support changes based upon the flows on COI.

The analysis of the study results demonstrates the need for a dynamic device at Round Mountain to absorb up to 500 Mvar reactive power. The benefits of the Round Mountain voltage support device having a dynamic range to inject reactive power is discussed in the following section.

The maximum voltage drop at Round Mountain 500 kV bus occurs following the trip of PDCI under a scenario in which both PDCI and COI are highly dispatched. This scenario is more severe under spring off-peak load conditions and is expected to happen typically in the evenings when imports from northwest are high to manage the evening ramp and the higher flows in the non-solar hours. The study results show that following the PDCI contingency and after all the automatic switching of the existing reactive devices (post transient condition), the voltage drop at Round Mountain 500 kV bus is around 35 kV. To prevent voltage from dropping below low end of emergency operating voltage of 495 kV, system operators keep the pre-contingency voltage quite high to ensure acceptable post contingency voltage. Having high voltage on 500 kV system will result in high voltages on 230 kV and to some degree the 115 kV and 60/70 kV lower voltage networks. High voltages across the PG&E system have been observed in real-time and planning studies under light load conditions that poses ongoing challenges for system operations. A dynamic device that has both reactive and capacitive range at Round Mountain, will enable system operations to be able to set the pre-contingency system voltages at lower values so that the post-contingency reactive power injection at Round Mountain 500 kV bus will support the voltage within acceptable ranges for normal operations and after the contingency. Study results show that with 500 Mvar injection from Round Mountain dynamic reactive device, the voltage drop after PDCI outage will be only 18 kV.

The results show that the voltage in the area ranged between 488 kV and 558 kV in the existing system which is outside the acceptable range, especially on the high voltage. After implementing the Round Mountain ±500 Mvar dynamic voltage support, the voltage in the area ranged between 503 kV and 548 kV which is within acceptable range. Further review of the engineering detail for the termination of the Round Mountain 500 kV Reactive Project is required due to siting issues at Round Mountain for the project. Board of Governor approval is recommended, and the additional detail will be posted as an addendum to the transmission plan. The competitive procurement process for the project will commence after that has taken place. The reactive device is to be installed in a minimum of two equally-sized blocks independently connected to the 500 kV to accommodate maintenance and contingencies of the reactive device.. The reactive power support is required to provide continuous dynamic reactive power support over the complete range of the capability (unless the facility experienced a planned or forced outage). It can be one of the following types of devices: SVC (Static VAR Compensator) with Thyristor Switched Capacitors (TSC), STATCOM (Static Synchronous Compensator), or Synchronous Condenser. An appropriately sized and configured inverter associated with a battery storage project could also provide the reactive support. Voltage support requirements would take precedence over any other operation of the battery storage facility. The estimated cost of the project is $160 million to $190 million with and expected in-service date of June 2024.

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Gates 500 kV Dynamic Reactive Support

An assessment of reactive support in the Gates area of the southern portion of the PG&E 500 kV system was conducted. The detailed assessment is included in Appendix B.

The studies showed that after the retirement of Diablo Canyon Power Plant, high voltages are expected in the south of the PG&E system, particularly on the Diablo and Gates 500 kV buses under all system conditions. The studies also showed voltages above 540 kV on the Gates 500 kV bus under off-peak system conditions with all facilities in service prior to the Diablo Canyon Power Plant retirement. The most critical cases appeared to be 2028 Spring off-peak or 2028 Winter off-peak. Even for the conditions when all transmission facilities are in service, 500 kV voltages are expected to rise up to 552 kV on the Diablo 500 kV bus and up to 548 kV on the Gates 500 kV bus. Analysis also showed that for a single outage (P1) of one of the Diablo – Midway 500 kV lines, voltage on the Diablo 500 kV bus may reach 554 kV. Voltages also exceeded 554 kV on the Diablo bus and 551 kV on the Gates bus for double outages of the Los Banos 500/230 kV transformer and one of 500 kV lines in the area for the 2028 off-peak conditions. Such normal and emergency voltage levels would clearly exceed the voltage criteria for the 500 kV system.

According to the ISO Planning Standards[79], voltage on the Diablo Canyon 500 kV bus should be between 512 and 545 kV both under normal and contingency conditions. Voltages on all the other 500 kV buses in the PG&E system should be between 518 and 550 kV under normal conditions and between 473 and 550 kV under contingency conditions. Along with these standards, PG&E Operations monitors and maintains the voltage based on the O-59 Operating Procedure. This procedure has voltage limits on 500 kV as from 525 kV to 540 kV under normal system conditions and from 495 kV to 551 kV for contingency conditions. For the purpose of proposing high voltage mitigations, to be more conservative, the high voltage operating limits identified in O-59 were considered.

In addition, dynamic stability studies showed large loss of load due to stalling and tripping of induction motors with three-phase faults in the Fresno area, especially with the faults close to the Gates and Midway 500 kV Substations. Studies of three-phase faults in an assumption of momentary cessation of inverters on the solar PV plants showed unstable system performance for some cases studied, if the faults are on the Gates 500 kV bus and the inverters have relatively high voltage when they go to momentary cessation (0.9 per unit) and relatively long recovery delay (5 seconds).

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Adding voltage support in the area will mitigate both high voltages after the Diablo Canyon Power Plants retires as well as high voltages under off-peak conditions prior to its retirement, and will also mitigate dynamic stability issues with three-phase faults and induction motor stalling and tripping.

It is recommended to install an SVC with TSC or STATCOM capable of absorbing around 800 Mvar of reactive power. An 800 Mvar shunt reactor on Gates also appeared to be sufficient to reduce voltage both on the Diablo 500 kV bus and on all 500 kV buses in the area to the required limits for all the cases and contingencies studied. This reactive support should have either continuous regulation or steps to satisfy other system conditions when voltages in the 500 kV system in the Southern PG&E area are not as high and when the full range of the reactive power absorption is not needed.

Power flow studies did not show low voltages in the south of the PG&E system that would require reactive support that would produce reactive power; however similar to the hourly flows of COI in the Round Mountain Reactive Support assessment, flows in the southern portion of the PG&E bulk system will vary through out the day with the continued addition of solar generation. In addition, the dynamic stability studies showed large loss of load due to stalling and tripping of induction motors with three-phase faults in the area and also possibility of momentary cessation of inverters that might cause system instability.

[79] California ISO Planning Standards http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf#search=iso%20planning%20standard

The studies showed that dynamic reactive support installed at the Gates 500 kV Substation may reduce amount of the load lost due to stalling or tripping of induction motor load with faults. For an outage of the Gates-Midway 500 kV line with a three-phase fault under 2028 Summer peak load conditions, amount of load lost in PG&E reduced from 445 MW to 295 MW with installation of an SVC with TSC capable of producing reactive power. The same result was with a STATCOM instead of SVC.

Dynamic stability studies were also performed to investigate if installation of dynamic reactive support on the Gates 500 kV Substation may help to improve momentary cessation of the inverters on the solar PV plants and prevent instability caused by momentary cessation. For these studies, a 2020 Summer Peak case with high renewable generation output was selected since it had high amount of solar PV in the Fresno area and high air-conditioning load. An outage of the Gates-Midway 500 kV line with a three-phase fault was studied. Momentary cessation of the inverters was assumed to occur at the 0.9 per unit voltage with a 5 second delay. The ramp at which inverters recover was assumed to be 0.2 per unit per second. The performance of a STATCOM in the dynamic stability studies was better than an SVC.

The study results indicated that a +/- 800 Mvar dynamic reactive device at Gates is required to address the high voltage and to improve dynamic performance. The recommendation is to approve installation of a total of +/-800 Mvar of dynamic reactive support on the Gates 500 kV bus. The reactive device is to be installed in a minimum of two equally-sized blocks independently connected to the 500 kV to accommodate maintenance and contingencies of the reactive device. The reactive power support is required to provide continuous dynamic reactive power support over the complete range of the capability (unless the facility experienced a planned or forced outage). It can be one of the following types of devices: SVC (Static VAR Compensator) with Thyristor Switched Capacitors (TSC), STATCOM (Static Synchronous Compensator), or Synchronous Condenser. An appropriately sized and configured inverter associated with a battery storage project could also provide the reactive support. Voltage support requirements would take precedence over any other operation of the battery storage facility.The ISO recommends the Gates 500 kV Dynamic Reactive support project with an estimated cost of $210 million to $250 million with an in-service date of no later than June 2024 so as to be in-service prior to the retirement of the Diablo Canyon Power Plant in 2025.

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2.4.4 Request Window Proposals

Projects submitted to the ISO through the Request Window for the PG&E Bulk System are shown in Table 2.4-2

.Table 2.4-2 Request Window Submissions

Project Name	Proponent	Size/capacity	Cost Estimate	Operational Date
Round Mountain 500 kV Substation Voltage Support	PG&E	+/-500 Mvar STATCOM	$160M-$190M	December 31, 2024
Gates 500 kV Substation Voltage Support	PG&E			
Option l-Gates500kV	PG&E	+/-lOOOMvar STATCOM	$241M-$291M	December 31, 2024
Option II Gates500kV	PG&E	+/-500 Mvar STATCOM and -500 Mvar shunt reactors	Slightly lower than Option 1	December 31, 2024
Option Ill Gates500kV	PG&E	+0/1000 Mvar STATCOM and +350 Mvar shunt capacitors	Slightly lower or equal to Option 1	December 31, 2024
Round Mountain Dynamic Reactive 500 kV Transmission System	NEET West	+/-300 Mvar SVC or STATCOM	$75M	December 1, 2024
Gates or Diablo Dynamic Reactive 500 kV Transmission System	NEET West			
Option l-Diablo 500kV	NEET West	+100 /-275 Mvar SVC or STATCOM	$65M	December 1, 2024
Option II Gates 500 kV	NEET West	+100 /-250 Mvar SVC or STATCOM	$65M	December 1, 2024
Option Ill Gates500kV	NEET West	+150 /-450 Mvar SVC or STATCOM	$75M	December 1, 2019
500/230 lkV Chorro Junction Sustation on Diablo-Gates 500 kV line	California Transmission Development, LLC	+/-500 Mvar SVC		June 1, 2023
500kV Wells Place Substation on Round Mountain – Table Mountain #1 Line	California Transmission Development, LLC	+/-500 Mvar SVC		June 1, 2023
Southwest lntertie Project – North	Great Basin Transmission, LLC	+/-2000MW Transmission Line	$525M	December 31, 2022

<u>Round Mountain 500 kV Substation Voltage Support Project</u>

This project was submitted in the 2018 Request Window as a transmission solution to resolve the issue of high voltage in the 500 kV in Northern California under off-peak conditions and low voltage under peak load conditions and contingencies. The project was proposed by a PTO.

The proposed project consists of:

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- A single +/- 500 Mvar STATCOM providing reactive support with continuous and controlled capability. The STATCOM can provide dynamic support to the grid.
- As part of this project, Round Mountain 500 kV bus will be converted to three bays of BAAH, which will also allow for the connection of the STATCOM.
- Install four 500 kV breaker and associated switches
- Connect lines and bank to the new BAAH
- Build a bus to connect the reactive support equipment
- Install new control building for the new equipment, if the space in the existing 500 kV control building is not adequate
- Upgrade protection to BAAH configuration
- Obtain permit and relocate the security fence
- Grade the new area

The estimated cost of the proposed Round Mountain Reactive Support 500 kV system is approximately $104 million for the voltage support equipment procurement and installation and approximately $54 million for upgrades to Round Mountain Substation to accommodate the installation. Total cost is estimated between $160 million and $190 million. The estimated in-service date of December 31, 2024.

The ISO reviewed this proposal and recommended the Round Mountain 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

P27-129 cont.

Gates 500 kV Voltage Support Project

The following project was submitted in the 2018 Request Window as a transmission solution to resolve the issue of high voltage in the 500 kV in Central California under off-peak conditions when Diablo Canyon Power Plant retires. The project was proposed by a PTO. Various options were considered in the submittal.

Option 1 includes the following:

- Install two +/- 500 Mvar STATCOM segments providing a total of 1000 Mvars capacitive and 1000 Mvars inductive reactive support with continuous and controlled capability. Both STATCOMS could operate independently, providing redundancy and provide dynamic support to the grid even when one is out of service.
- Install one 500 kV breaker and associated switches in Bay 2
- Build new partial bay (two breakers) with breakers and switches on the West side of the bus
- Build a bus to connect the reactive support equipment
- Install breakers and reactive support equipment protection scheme in the existing 500 kV control building

- Relocate the security fence
- Grade the new area

The expected costs for the project are: $190M for the voltage support device procurement and installation and $50M for the upgrades to the Gates substation to accommodate the installation. Total estimated cost of the project is between $240M and $290M.

Option 2 includes the following:

- Install one +/-500 Mvar STATCOM and -500 Mvar shunt reactors at Gates 500 kV Substation. the proponent indicated that the hybrid system will provide a good balance of inductive and capacitive dynamic reactive support in addition to discrete inductive capability that could be controlled by the STATCOM. This hybrid system also provides redundancy in addressing the most critical condition which is high system voltages.
- Install one 500 kV breaker and associated switches in Bay 2
- Build new partial bay (two breakers) with breakers and switches on the West side of the bus
- Build a bus to connect the reactive support equipment
- Install breakers and reactive support equipment protection scheme in the existing 500 kV control building
- Relocate the security fence
- Grade the new area

The expected costs for the project might be slightly lower than Option 1 as the cost of the devices could be slightly lower. However, actual cost would still need to be determined based upon the desired shunt reactor number of steps (i.e. 2 X 250 Mvar).

Option 3 includes the following:

- Install one +0/-1000 Mvar SVC and +350 Mvar shunt capacitors at Gates 500 kV Substation. the proponent indicated that the hybrid system will provide a good balance of continuous and controlled inductive dynamic reactive support in addition to discrete capacitive reactive capability, controlled by the SVC. One initial drawback of this option is that the entire inductive reactive support is provided by the SVC, and in the event of a total SVC system failure the entire grid support would be lost. As part of the evaluation it could be investigated if installing two SVCs with separate controllers would be a better option or other methods of redundancy.
- Install one 500 kV breaker and associated switches in Bay 2
- Build new partial bay (two breakers) with breakers and switches on the West side of the bus
- Build a bus to connect the reactive support equipment

P27-129 cont.

- Install breakers and reactive support equipment protection scheme in the existing 500 kV control building
- Relocate the security fence
- Grade the new area

The expected costs of this option might be slightly lower or equal to the cost of Option 1 as the cost of the SVC and shunt capacitor devices could be slightly lower. However, the desired level of redundancy required for the SVC would also impact the final cost for this option.

The estimated in-service date of the project is December 31, 2024.

The ISO reviewed this proposal and recommended the Gates 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

Round Mountain Dynamic Reactive 500 kV Transmission System

This was submitted in the 2018 Request Window as a transmission solution to resolve voltage stability concerns at or close proximity to the Round Mountain 500 kV Substation under anticipated 2020, 2023, and 2028 summer peak and off-peak conditions. The project was proposed by a non-PTO, NextEra Energy Transmission West, LLC. (NEET West) as a Reliability Transmission Project.

The proposed project consists of:

- A new ± 300 Mvar SVC (or STATCOM) connected to a new 500 kV bus through a single 500/23.2 kV step-up transformer, with a rating of approximately 340 MVA.
- A new 500 kV tie line connecting the high-side bus of the SVC (or STATCOM) step up transformer to PG&E's existing Round Mountain 500 kV substation, with a line rating of approximately 380 Amps Normal/Emergency.
- A new bay position at the Round Mountain 500 kV bus consisting of two new 500 kV breakers.

The estimated cost of the proposed Round Mountain Dynamic Reactive 500 kV Transmission System is approximately $75 Million in 2018 dollars. This cost excludes any incumbent costs for interconnection of proposed facilities. The estimated in-service date is December 1, 2024.

The ISO reviewed this proposal and recommended the Round Mountain 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

Gates or Diablo Dynamic Reactive 500 kV Transmission System

This project was submitted in the 2018 Request Window as a transmission solution to resolve the issue of high voltage in the 500 kV in Central California under various system conditions when Diablo Canyon Power Plant retires. The project was proposed by a non-PTO, NextEra Energy Transmission West, LLC. (NEET West) as a Reliability Transmission Project.

The project includes several following alternatives.

Diablo Dynamic Reactive 500 kV Transmission System Alternative

P27-129
cont.

This alternative of the project includes:

- +100 /-275 Mvar SVC or STATCOM connected to the existing PG&E's Diablo Substation, which has breaker-and-a-half configuration
- 320 MVA 500/23.2 kV transformer,
- Tie-line: 350 A at 500 kV
- Circuit breaker at Diablo: 3000 A/63 kA (Interruptible)

Installation of a SVC or STATCOM at Diablo resolves the high voltage concerns at both Diablo and Gates Substations.

Gates Dynamic Reactive 500 kV Transmission System Alternative I

This alternative of the project includes:

- +100 /-250 Mvar SVC or STATCOM connected to the existing PG&E's Gates Substation, which has breaker-and-a-half configuration
- 290 MVA 500/23.2 kV transformer,
- Tie-line: 320 A at 500 kV
- Circuit breaker at Gates: 3000 A/63 kA (Interruptible)

This alternative mitigates only high voltage issues at the Gates Substation after the Diablo Canyon Power Plant retires. P27-129 cont.

Gates Dynamic Reactive 500 kV Transmission System Alternative II

This alternative of the project includes:

- +150 /-450 Mvar SVC or STATCOM connected to the existing PG&E's Gates Substation, which has breaker-and-a-half configuration
- 550 MVA 500/23.2 kV transformer,
- Tie-line: 610 A at 500 kV
- Circuit breaker at Gates: 3000 A/63 kA (Interruptible)

This alternative resolves the high voltage concerns at both Diablo and Gates Substations.

The estimated cost of the proposed Diablo Dynamic Reactive Transmission System is $65 million, Gates Alternative I is $65 million, and Gates Alternative II is $75 million in 2018 dollars. These costs exclude any incumbent costs for interconnection of proposed facilities.

The estimated in-service date is of the project is December 1, 2024.

The ISO reviewed this proposal and recommended the Gates 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

500 kV/230 kV Chorro Junction Substation

The following project was submitted in the 2018 Request Window as a transmission solution to address high voltage violations on the Gates and Diablo 500 kV buses. Additionally, the proponent indicated that the 500 kV/230 kV Chorro Junction Project would provide dynamic reactive support capable of absorbing or injecting VARS to provide transient stability for faults at the Midway, Tracy, and Tesla 500kV substations. The project was proposed by a non-PTO, California Transmission Development, LLC, an affiliate of LS Power as a Reliability Transmission Project.

The 500 kV/230 kV Chorro Junction Project would break the Diablo Canyon - Gates 500 kV transmission line at the Diablo Canyon - Mesa 230 kV & Morro Bay – Mesa 230 kV line crossing and interconnect both 500 kV lines in a new four-position ring bus substation located on property adjacent to and just west of the 230 kV line crossings. A +/- 500 Mvar Static Var Compensator would connect to a third position in the 500 kV ring bus. A 500/230 kV transformer will connect the fourth position of the 500 kV ring bus to the new five-position 230 kV ring bus at Chorro Junction Substation. The Project would break the Morro Bay - Diablo Canyon 230 kV and Morro Bay – Mesa 230 kV transmission lines and loop them into the new 230kV ring bus. The Diablo Canyon – Mesa 230 kV line will be left as is.

The Project aims to address the high voltage and possible dynamic instability issues on the 500 kV system in Southern PG&E bulk system by:

- Connecting the 500 kV system to loads on 230kV system and;
- Installing a +/- 500 Mvar Static Var Compensator on the 500 kV bus to provide reactive support by absorbing reactive power.

A commercial operation date of June 1, 2023 was proposed.

The ISO reviewed this proposal and recommended the Gates 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

500 kV Wells Place Substation

This project was submitted in the 2018 Request Window as a transmission solution to address high voltage violations on the 500 kV transmission system in Northern California. Additionally, the proponent indicated that the 500 kV Wells Place Substation Project would provide dynamic reactive support capable of absorbing or injecting reactive power to provide transient stability for contingencies otherwise resulting in tripped load and also would also protect against possible low voltage conditions under contingency conditions for Heavy Summer peak conditions with high COI flows in North to South direction.

The project was proposed by a non-PTO, California Transmission Development, LLC, an affiliate of LS Power, as a Reliability Transmission Project.

The 500 kV Wells Place Substation Project would break the Round Mountain – Table Mountain #1 500 kV transmission line at approximately the midpoint of the transmission line (45 miles south of Round Mountain) and interconnect both 500 kV lines in a new three-position ring bus substation located on property adjacent to and just east of the 500 kV corridor. A +/- 500 Mvar Static Var Compensator would connect to a third position in the 500 kV ring bus. The Round Mountain – Table Mountain #2 500 kV line would be left as is.

P27-129
cont.

The Project aims to address the high voltage issues and possible transient stability and low voltage issues on the 500 kV system in Northern California by installing a +/- 500 Mvar Static Var Compensator on the new 500 kV bus created by looping in Round Mountain – Table Mountain #1 line.

A commercial operation date June 1, 2023 was proposed.

The ISO reviewed this proposal and recommended the Round Mountain 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

Southwest Intertie Project - North (SWIP - North)

The project was submitted in the 2018 Request Window as a transmission solution to address thermal overloads on the 500 kV and 230 kV systems in northern California and to improve low voltage issues in northern California during summer peak conditions with high COI N-S flows. The project was proposed by a non-PTO, Great Basin Transmission (GBT), LLC, an affiliate of LS Power, as a Reliability Transmission Project. The project was also submitted as part of an economic study request as set out in chapter 4 and an interregional transmission project as set out in chapter 5.

The SWIP transmission project is an approximately 500-mile, 500 kV single circuit AC transmission line that connects the Midpoint 500 kV substation in southern Idaho, the Robinson Summit 500 kV substation, and the Harry Allen 500 kV substation.

The proponent indicated that SWIP is expected to have a bi-directional WECC-approved path rating of approximately 2,000 MW, and that in addition to addressing the reliability needs identified in ISO Transmission Plan, the SWIP is an important regional project, and a critical component to spur additional development of renewable power generation resources throughout the western United States. P27-129 cont.

SWIP-North is the proposed 275-mile northern portion of the SWIP that would connect Robinson Summit with Midpoint (near Twin Falls, Idaho), and includes a 500 kV 35% fixed series capacitor bank near each terminus.

Figure 2.4-2 SWIP - North Preliminary Route

Upon completion of SWIP - North, a capacity sharing arrangement would be triggered between GBT and NV Energy across the existing ON Line (Midpoint to Harry Allen) and SWIP - North. GBT will retain control of approximately 1000 MW of the planned 2000 MW capacity in both directions on SWIP - North, and will have a contract path to the ISO at Harry Allen. Therefore, this submittal contemplates the availability of 1000 MW of capacity from Midpoint to Harry Allen available to the ISO.

The proposed operation date of the project is December 31, 2022.

The planning level cost of the project is $525 Million in 2018 dollars. This cost includes 500 kV series capacitors, interconnection costs and some additional planning level contingency. It does not include any network upgrades that may or may not be identified by interconnection studies.

The ISO reliability assessment did not identify any reliability needs that the the SWIP – North Project was required to mitigate.

P27-129 cont.

The ISO considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and Northern Tier Transmission Group (NTTG) planning regions, respectively. The SWIP - North line is not physically connected to ISO-controlled facilities. Please refer to chapter 5. The scheduling capacity from the Harry Allen end of the ISO's approved Harry Allen-Eldorado transmission line to Robinson Summit also creates opportunity for the submitted project to provide benefits to the ISO, in which case the ISO can select to participate in the project – if that is found to be the preferred solution to meeting the ISO's regional need.

2.4.5 Recommendations

The bulk system assessment identified a number of P1 to P7 contingencies that result in transmission constraints. The recommended solutions to mitigate the identified reliability concerns are the following:

- Manage COI flow according to the seasonal nomograms
- Implement SPS to bypass series capacitors on the Round Mountain-Table Mountain 500 kV lines # 1 and # 2 if any of these lines overloads.

For overloads that are managed with congestion management or operating within the defined path nomograms, upgrades could be considered if congestion is observed in the production simulation and the upgrades are determined to be economically-drive. The following lines were identified as being overloaded with the reliability mitigation plans being congestion management and operating path flows within the nomograms

- Cottonwood- Round Mountain 230 kV # 1, #2 and # 3 transmission lines
- Moss Landing-Las Aguilas 230kV transmission line

Other proposed mitigation solutions for thermal overloads are the following:

- Upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line
- Implement congestion management after first contingency for Category P6 overloads.
- If the Moss Landing and/or Metcalf power plants retire, the mitigation plan for Category P6 contingencies in the Metcalf-Tesla-Moss Landing-Los Banos area that result in losing the 500 kV source will be needed.

In addition to the identified thermal overloads, high voltages were observed on the 500 kV system in Central California after Diablo Canyon Power Plant retires. In the northern part of the 500 kV system high voltages were observed under normal system conditions, and low voltages observed with contingencies. To address voltage issues identified in central and northern PG&E bulk system two projects are recommended for approval.

- Gates 500 kV Dynamic Voltage Support
- Round Mountain 500 kV Dynamic Voltage Support.
    - Further review of the engineering detail for the termination of the Round Mountain 500 kV Reactive Project is required due to siting issues at Round

P27-129 cont.

Mountain for the project. Board of Governor approval is recommended, and the additional detail will be posted as an addendum to the transmission plan. The competitive procurement process for the project will commence after that has taken place.

P27-129 cont.

2.5 PG&E Local Areas

2.5.1 Humboldt Area

2.5.1.1 Area Description

The Humboldt area covers approximately 3,000 square miles in the northwestern corner of PG&E's service territory. Some of the larger cities that are served in this area include Eureka, Arcata, Garberville and Fortuna. The highlighted area in the adjacent figure provides an approximate geographical location of the PG&E Humboldt area.

Humboldt's electric transmission system is comprised of 60 kV and 115 kV transmission facilities. Electric supply to this area is provided primarily by generation at Humboldt Bay power plant and local qualifying facilities. Additional electric supply is provided by transmission imports via two 100 mile, 115 kV circuits from the Cottonwood substation east of this area and one 80 mile 60 kV circuit from the Mendocino substation south of this area.

Historically, the Humboldt area experiences its highest demand during the winter season. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and winter peak conditions that reflect different load conditions mainly in the coastal areas.

P27-129 cont.

2.5.1.2 Area-Specific Assumptions and System Conditions

The Humboldt Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Humboldt Area study are provided below.

Table 2.5-1: Humboldt load and generation assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
HMB-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	116	2	19	1	112	4	3	0	0	0	0	0	5	0	259	176
HMB-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	122	5	32	0	117	4	3	0	0	0	0	0	5	0	259	174
HMB-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	130	9	48	0	121	4	3	0	0	0	0	0	5	0	259	175
HMB-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – weekend morning.	76	2	19	15	59	4	3	0	0	0	0	0	5	0	259	65
HMB-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – weekend morning.	77	3	32	26	47	4	3	0	0	0	0	0	5	0	259	25
HMB-2020-WP	Baseline	2020 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	145	2	19	0	143	4	3	0	0	0	0	0	5	0	259	172
HMB-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	139	4	32	0	134	4	3	0	0	0	0	0	5	0	259	173
HMB-2028-WP	Baseline	2028 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	163	9	48	0	155	4	3	0	0	0	0	0	5	0	259	172
HMB-2023HS-SP-P7	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	121	0	32	0	120	4	3	0	0	0	0	0	5	0	259	90
HMB-2020-HR-P7	Sensitivity	2020 summer peak load conditions with hi renewable dispatch sensitivity	81	2	19	19	59	4	3	0	0	0	0	0	5	0	259	164
HMB-2023-HR-P7	Sensitivity	2023 summer peak load conditions with hi renewable dispatch sensitivity	77	3	32	31	42	4	3	0	0	0	0	0	5	0	259	29

P27-129 cont.

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of the approved projects identified in Table 2.5-2 that were not modeled in the study scenario base cases.

Table 2.5-2: Humboldt Approved Project not Modeled in Base Case

Project Name	TPP Approved In	Current ISD
Bridgeville – Garberville No. 2 115 kV Line	2011-2012 TPP	Jan 2024

2.5.1.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E Humboldt Area has identified several reliability concerns consisting of thermal overloads under Category P6 contingencies. The areas where additional mitigation requirements were identified are discussed below.

Within the Humboldt Area there were a number of P6 contingencies that resulted in overloads were observed in the base and sensitivity scenarios. The overloaded facilities and contingencies were related to Non-BES facilities per the ISO Planning Standards so no mitigation has been recommended for approval.

Summary of review of previously approved projects

There is one previously approved active project in the Humboldt area not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. Table 2.5-3 shows the final recommendation for this one project not modeled in the study cases:

Table 2.5-3: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
Bridgeville – Garberville No. 2 115 kV Line	P6

Details of the review of previously approved projects not modeled in study cases are presented in Appendix B.

2.5.1.4 Request Window Submissions

There are no Request Window Submissions for the Humboldt Area.

P27-129
cont.

2.5.1.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1.2, about 4 MW of AAEE and more than 32 MW of installed behind-the-meter PV reduced the Humboldt Area load in winter 2023. This year's reliability assessment for Humboldt Area included "2023 Sumer peak with high CEC forecast" and "2020 Summer peak with high renewable" sensitivity cases for which modeled no AAEE. Comparison between the reliability issues identified in the 2023 winter peak baseline case and the sensitivity cases shows that following facility overloads are potentially avoided due to reduction in net load.

Table 2.5-4: Reliability Issues in Sensitivity Studies

Facility	Category
Humboldt – Bridgeville 115 kv Line	P6
Humboldt – Trinity 115 kv Line	P6
Humboldt – Humboldt JT 60 kv Line	P1
Eureka – Humboldt Bay 60 kv Line	P1
Carlotta – Rio Dell TP 60 kv Line	P1
Carlotta – Swains Flat 60 kv Line	P1
Swains Flat – Bridgeville 60 kv Line	P1
Bridgeville – Fruitland JT 60 kv Line	P0
Fruitland – Fort Seward 60 kv Line	P1
Fort Seward – Garberville 60 kv Line	P0

P27-129 cont.

Furthermore, 4 MW of demand response are modeled in Humboldt. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, but didn't completely alleviate the overloads.

2.5.1.6 Recommendation

Based on the studies performed for the 2018-2019 Transmission Plan, several reliability concerns were identified for the PG&E Humboldt. These concerns consisted of thermal overloads and voltage concerns under Categories P6 contingency conditions. There are no new projects recommended for approval.

In regards to the previously-approved on-hold project, one project was on hold in the Humboldt Area that is recommended to be canceled in this cycle.

- Bridgeville – Garberville No. 2 115 kV Line project

There are no new projects recommended for approval in the Humboldt area.

2.5.2 North Coast and North Bay Areas

2.5.2.1 Area Description

The highlighted areas in the adjacent figure provide an approximate geographical location of the North Coast and North Bay areas.

The North Coast area covers approximately 10,000 square miles north of the Bay Area and south of the Humboldt area along the northwest coast of California. It has a population of approximately 850,000 in Sonoma, Mendocino, Lake and a portion of Marin counties, and extends from Laytonville in the north to Petaluma in the south. The North Coast area has both coastal and interior climate regions. Some substations in the North Coast area are summer peaking and some are winter peaking. A significant amount of North Coast generation is from geothermal (The Geysers) resources. The North Coast area is connected to the Humboldt area by the Bridgeville-Garberville-Laytonville 60 kV lines. It is connected to the North Bay by the 230 kV and 60 kV lines between Lakeville and Ignacio and to the East Bay by 230 kV lines between Lakeville and Vaca Dixon.

North Bay encompasses the area just north of San Francisco. This transmission system serves Napa and portions of Marin, Solano and Sonoma counties.

P27-129 cont.

The larger cities served in this area include Novato, San Rafael, Vallejo and Benicia. North Bay's electric transmission system is composed of 60 kV, 115 kV and 230 kV facilities supported by transmission facilities from the North Coast, Sacramento and the Bay Area. Like the North Coast, the North Bay area has both summer peaking and winter peaking substations. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and winter peak conditions that reflect different load conditions mainly in the coastal areas.

2.5.2.2 Area-Specific Assumptions and System Conditions

The North Coast and North Bay Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Coast and North Bay Area study are provided below.

Table 2.5-5: North Coast and North Bay load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	NCNB-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,571	23	388	56	1,492	16	10	0	0	0	0	0	25	12	1,534	709
2	NCNB-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,621	46	552	6	1,569	16	10	0	0	0	0	0	25	12	1,534	709
3	NCNB-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,695	88	811	0	1,607	16	10	0	0	0	0	0	25	12	1,534	705
4	NCNB-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – weekend morning.	734	17	388	306	411	16	10	0	0	0	0	0	25	3	1,534	704
5	NCNB-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – weekend morning.	751	34	552	464	253	16	10	0	0	0	0	0	25	2	1,534	702
6	NCNB-2020-WP	Baseline	2020 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,600	22	388	0	1,578	16	10	0	0	0	0	0	25	12	1,534	707
7	NCNB-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,182	23	388	0	1,159	16	10	0	0	0	0	0	25	3	1,534	709
8	NCNB-2028-WP	Baseline	2028 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,731	86	811	0	1,645	16	10	0	0	0	0	0	25	12	1,534	707
9	NCNB-2023HS-SP	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	1,621	0	552	6	1,615	16	10	0	0	0	0	0	25	12	1,534	709
10	NCNB-2020-HR	Sensitivity	2020 summer peak load conditions with hi renewable dispatch sensitivity	1,182	23	388	384	775	16	10	0	0	0	0	0	25	3	1,534	709
11	NCNB-2023-HR	Sensitivity	2023 summer peak load conditions with hi renewable dispatch sensitivity	751	34	552	547	170	16	10	0	0	0	0	0	25	2	1,534	707
12	NCNB-2028-QF	Sensitivity	2027 summer peak load conditions with QF retirement sensitivity	1,695	88	0	0	1,607	16	10	0	0	0	0	0	25	12	1,534	701

P27-129
cont.

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.2.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E North Coast North Bay Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously approved projects. The areas where additional mitigation requirement were identified are discussed below.

In the Near-term planning horizon a number of overloads were observed that will be addressed when the previously approved projects are complete and in-service. In the interim, the ISO will continue to rely on operational action plans to mitigate the constraints.

The following new overloads were observed in the North Coast and North Bay area.

Bus Upgrade – Fulton 115kV

Category P2 of a bus-tie breaker failure results in an overload on the Bellvue=Pennigrove 115kV line. The overload is due to both the Fulton-Santa Rosa #1 and Fulton-SantaRosa #2 getting tripped as a result of the P2 contingency. The ISO is working with PG&E to rearrange the termination of the lines on the bus sections. If this is not feasible the alternative will be to install a sectionalizing breaker in the Fulton 115 kV bus. The estimated cost of the sectionalizing breaker is $10 to 20 million. The ISO will continue to work with PG&E with further assessment in the next planning cycle. P27-129 cont.

Bus Upgrade – Lakeville 115kV

Category P2 of a bus-tie breaker failure results in an overload on the STHELNJ1 - PUEBLO 115kV Line.

To mitigate the contingency will require the installation of a sectionalizing breaker to be installed on 115 kV bus section “D”at Lakeville. The estimated cost of the bus upgrade is $10 to 15 million. The ISO will continue to monitor the load forecast in this area with further assessment in the next planning cycle..

Protection Upgrade – Fulton 115kV

Category P5 contingency of a failure of non-redundant relay causes an overload on multiple 60kV and 115kV for a fault on the Fulton 230 KV BUS #1. The ISO recommends PG&E to install redundant protection at Fulton substation.

Details of the reliability assessment are presented in Appendix B.

2.5.2.4 Request Window Submissions

There were no project submissions in the North Valley area in the 2018 request window.

2.5.2.5 Consideration of Preferred Resources and Energy Storage

As presented in section 2.5.2, about 54 MW of AAEE and more than 113 MW of installed behind-the-meter PV reduced the North Coast North Bay Area load in 2022. This year's reliability assessment for North Coast North Bay Area included a "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 69 MW less behind-the-meter PV output. A comparison between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case shows that facility overloads shown in Table 2.5-6 are potentially avoided due to the reduction in net load:

Table 2.5-6: Reliabillity Issues in Sensitivity Studies

Facility	Category
Cache J2-Redbud J2 115 kV Line	P6
Indian Valley-Lucern J1 115kV Line	P6

Furthermore, about 13 MW of demand response and 10 MW of battery energy storage are modeled in North Coast North Bay Area. These resources are modeled offline in the base case and are used as potential mitigations as needed. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads. P27-129 cont.

2.5.2.6 Recommendation

Based on the studies performed for the 2018-2019 Transmission Plan, several reliability concerns were identified for the PG&E North Coast North Bay Area. These concerns consisted of thermal overloads and voltage concerns under Categories P1 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the North Coast North Bay area.

2.5.3 North Valley Area

2.5.3.1 Area Description

The North Valley area is located in the northeastern corner of the PG&E's service area and covers approximately 15,000 square miles. This area includes the northern end of the Sacramento Valley as well as parts of the Siskiyou and Sierra mountain ranges and the foothills. Chico, Redding, Red Bluff and Paradise are some of the cities in this area. The adjacent figure depicts the approximate geographical location of the North Valley area.

North Valley's electric transmission system is composed of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. The 500 kV facilities are part of the Pacific Intertie between California and the Pacific Northwest. The 230 kV facilities, which complement the Pacific Intertie, also run north-to-south with connections to hydroelectric generation facilities. The 115 kV and 60 kV facilities serve local electricity demand. In addition to the Pacific Intertie, one other external interconnection exists connecting to the PacifiCorp system. The internal transmission system connections to the Humboldt and Sierra areas are via the Cottonwood, Table Mountain, Palermo and Rio Oso substations.

Historically, North Valley experiences its highest demand during the summer season; however, a few small areas in the mountains experience highest demand during the winter season. Accordingly, system assessments in this area included technical studies using load assumptions for these summer peak conditions.

2.5.3.2 Area-Specific Assumptions and System Conditions

The North Valley Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured marker participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Valley Area study are provided below.

P27-129 cont.

Table 2.5-7: North Valley load and generation assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
NVLY-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 18:00.	970	15	254	48	907	36	28	0	0	0	103	39	1,774	1,472	1,064	821
NVLY-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:00.	1,012	29	353	51	932	37	28	0	0	0	103	69	1,774	1,470	1,064	821
NVLY-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 18:00.	1,012	29	353	51	932	37	28	0	0	0	103	69	1,774	1,450	1,064	785
NVLY-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – hours ending 12:00.	319	11	254	201	108	36	28	0	0	0	103	7	1,774	778	1,064	250
NVLY-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	320	21	353	297	2	37	28	0	0	0	103	0	1,774	486	1,064	748
NVLY-2023-SP-HiCEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	1,012	0	353	51	961	37	28	0	0	0	103	93	1,774	1,451	1,064	815
NVLY-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	320	21	353	350	51	37	28	0	0	0	103	0	1,774	423	1,064	886
NVLY-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	941	15	254	252	675	36	28	0	0	0	103	69	1,774	1,472	1,064	351
NVLY-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	1,012	29	353	51	932	37	28	0	0	0	103	0	1,774	1,339	1,064	651

P27-129 cont.

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.3.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E North Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P1 to P7 contingencies most of which are addressed by previously approved projects. The remaining issues are only under sensitivity scenario and in the long term so ISO continues to monitor those issues and will mitigate them if the issues are identified in future assessments.

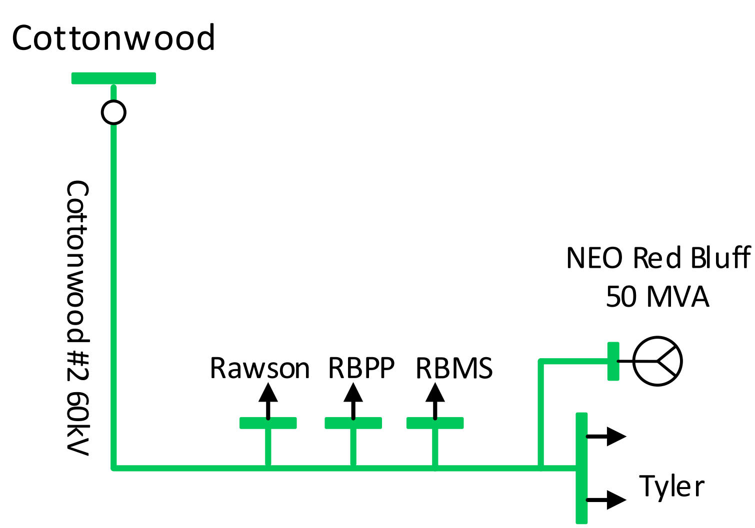
The following new overloads and voltage issues were observed in the North Valley area.

Tyler 60 kV Shunt Capacitor Project

Figure 2.5-1 shows the schematic diagram of the area served radially by Cottonwood #2 60 kV line. Voltage deviation issues were identified in the area in last year's reliability assessment in the medium to long term under P1 contingency of losing NEO Red Bluff 50 MW generator. In this year's assessment, in addition to voltage deviation that occurs in all 3 study years, there are voltage range issues as well as overload on Cottonwood #2 60 kV line in the long. The reason for overload is due to low voltage following the contingency. The ISO is recommending the approval of the "Tyler 60 kV Shunt Capacitor Project" with the scope of installing 2x10 Mvar capacitor bank at Tyler 60 kV bus to address both voltage criteria violations and thermal overload issues. The estimated cost of this project is between \$5.8M to \$7.0M and in-service date is May 2022.

P27-129 cont.

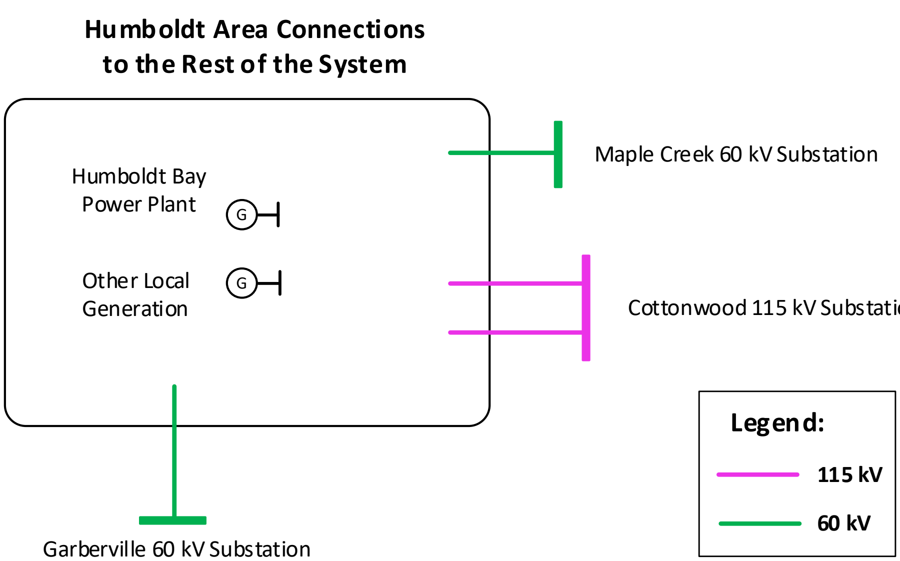
Figure 2.5-1: Area with voltage deviation issue following generator outage



Cottonwood 115kV Bus Sectionalizing Breakers Project

Figure B2.3-3 shows the schematic diagram of the area impacted by the bus tie-breaker (P2-4) contingency on Cottonwood 115 kV bus. The main issue is in the Humboldt area in which such contingency trips two of the 115 kV lines supplying Humboldt area. With two 115 kV lines tripped, the 60 kV connection between Cascade and Humboldt area experiences significant overload. To address the issue, The ISO is recommending approval of the "Cottonwood 115 kV bus Sectionalizing Breakers" project so that both 115 kV connections to Humboldt area are not tripped due to the bus tie-breaker fault. The estimated cost of this project is $8.5M to $10.5M and in-service date is May 2022.

Figure 2.5-2 Area impacted by Bus tie-breaker (P2-4) contingency on Cottonwood 115 kV bus



Details of the reliability assessment are presented in Appendix B.

2.5.3.4 Request Window Submissions

There were two project submissions in the North Valley area in the 2018 request window by PG&E.

- Tyler Shunt Capacity Project
- Cottonwood 115 kV Bus Sectionalizing Breakers

The Tyler Shunt Capitor Project and the Cottonwood 115 kV Bus Sectionaling Breaker projects were reviewed above and are recommended for approval.

P27-129 cont.

2.5.3.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1, about 23 MW of AAEE and around 190 MW of installed behind-the-meter PV reduced the North Valley Area load in 2022 by about 9%. This year's reliability assessment for North Valley Area included "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 40 MW less behind-the-meter PV output. A comparison of the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case shows that following facility overloads are potentially avoided due to reductions in net load:

Table 2.5-8: Reliability Issues in Sensitivity Studies

Facility	Category
Cascade - Cottonwood 115 kV Line	P6
Palermo - Wyandotte 115 kV Line	P6
Keswick - Cascade 60 kV	P2
Sycamore Creek - Notre Dame - Table Mountain 115 kV Line	P2
Table Mountain - Butte #1 115 kV	P2
Paradise - Table Mountain 115 kV	P2

P27-129 cont.

Furthermore, more than 36 MW of demand response is modeled in North Valley Area. These resources are modeled offline in the base case and are used as potential mitigations as needed. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.3.6 Recommendation

Based on the studies performed in the 2018-2019 transmission planning cycle, several reliability concerns were identified for the PG&E North Valley Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the North Valley area.

To address reliability concerns not associated and addressed by previously approved projects, the ISO recommends approval for the following two projects in the North Valley area.

- Tyler 60 kV Shunt Capacitor
- Cottonwood 115 kV Bus Sectionalizing Breaker

2.5.4 Central Valley Area

2.5.4.1 Area Description

The Central Valley area is located in the eastern part of PG&E's service territory. This area includes the central part of the Sacramento Valley and it is composed of the Sacramento, Sierra, Stockton and Stanislaus divisions as shown in the figure below.

Sacramento Division

The Sacramento division covers approximately 4,000 square miles of the Sacramento Valley, but excludes the service territory of the Sacramento Municipal Utility District and Roseville Electric. Cordelia, Suisun, Vacaville, West Sacramento, Woodland and Davis are some of the cities in this area. The electric transmission system is composed of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Two sets of 230 and 500 kV transmission paths make up the backbone of the system.

Sierra Division

The Sierra division is located in the Sierra-Nevada area of California. Yuba City, Marysville, Lincoln, Rocklin, El Dorado Hills and Placerville are some of the major cities located within this area. Sierra's electric transmission system is composed of 60 kV, 115 kV and 230 kV transmission facilities. The 60 kV facilities are spread throughout the Sierra system and serve many distribution substations. The 115 kV and 230 kV facilities transmit generation resources from north-to-south. Generation units located within the Sierra area are primarily hydroelectric facilities located on the Yuba and American River water systems. Transmission interconnections to the Sierra transmission system are from Sacramento, Stockton, North Valley, and the Sierra Pacific Power Company (SPP) in the state of Nevada (Path 24).

P27-129 cont.

Stockton Division

Stockton division is located east of the Bay Area. Electricity demand in this area is concentrated around the cities of Stockton and Lodi. The transmission system is composed of 60 kV, 115 kV and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. Lodi is a member of the Northern California Power Agency (NCPA), and it is the largest city that is served by the 60 kV transmission network. The 115 kV and 230 kV facilities support the 60 kV transmission network.

Stanislaus Division

Stanislaus division is located between the Greater Fresno and Stockton systems. Newman, Gustine, Crows Landing, Riverbank and Curtis are some of the cities in the area. The transmission system is composed of 230 kV, 115 kV and 60 kV facilities. The 230 kV facilities connect Bellota to the Wilson and Borden substations. The 115 kV transmission network is located in the northern portion of the area and it has connections to qualifying facilities generation located in the San Joaquin Valley. The 60 kV network located in the southern part of the area is a radial network. It supplies the Newman and Gustine areas and has a single connection to the transmission grid via a 115/60 kV transformer bank at Salado.

Historically, the Central Valley area experiences its highest demand during the summer season. Accordingly, system assessments in these areas included technical studies using load assumptions for the summer peak conditions.

2.5.4.2 Area-Specific Assumptions and System Conditions

The Central Valley Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured market participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Valley Area study are provided below.

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cont.

Table 2.5-9 Central Valley load and generation assumptions

Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
CVLY-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 19:00.	4,067	71	1,037	0	3,996	102	59	0	841	0	0	0	0	0	3,939	1,221
CVLY-2020-SpOP	Baseline	2020 spring off-peak load conditions. Off-peak load time - hours ending 12:00.	1,460	52	1,037	820	588	102	59	0	841	832	0	0	0	0	3,939	1,177
CVLY-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	3,876	71	1,037	1027	2,778	102	59	0	841	832	0	0	0	0	3,939	653
CVLY-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:00.	4,251	141	1,354	0	4,110	103	59	0	841	0	0	0	0	0	3,939	1,221
CVLY-2023-SpOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,460	105	1,354	1137	218	103	59	0	841	742	0	0	0	0	3,939	130
CVLY-2023-SP-Hi-CEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	4,251	0	1,354	0	4,251	103	59	0	841	0	0	0	0	0	3,939	1,252
CVLY-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	1,460	105	1,354	1340	15	103	59	0	841	800	0	0	0	0	3,939	145
CVLY-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 19:00.	4,519	268	1,741	0	4,251	104	59	0	841	0	0	0	0	0	3,939	1,252
CVLY-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	4,519	268	1,741	0	4,251	104	59	0	841	0	0	0	0	0	3,939	1,252

P27-129 cont.

The transmission modeling assumptions were consistent with the general assumptions described in section 2.3 with an exception of the approved project shown in Table 2.5-10 which was not modeled in the base cases.

Table 2.5-10: Central Velley Approved Project not Modeled in Base Case

Project Name	TPP Approved In	Current ISD
Atlantic – Placer 115 kV Line	2012-2013 TPP	Dec 2021

2.5.4.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E Central Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P0 to P7 contingencies most of which are addressed by previously approved projects. The areas where additional mitigation requirement were identified are discussed below.

In the Near-term planning horizon a number of overloads were observed that will be addressed when the previously approved projects are complete and in-service. In the interim, the ISO will continue to rely on operational action plans to mitigate the constraints.

The following new overloads and voltage issues were observed in the Central Valley Valley area.

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cont.

Vaca – Plainfield 60 kV Line Overload

The load at Plainfield and Winters substation is forecast to increase and reach around 32 MW by year 2023 and 34 MW by year 2028. The ISO is recommending PG&E to reconfigure Plainfield substation and connect load bank #1 to the E. Nicolaus substation. The ISO will continue to monitor the load forecast in this area in future planning cycles.

Details of the reliability assessment are presented in Appendix B.

Summary of review of previously approved projects

There was one previously approved project in the Central Valley Area that was not modeled in the study cases **Error! Reference source not found.** below shows the recommendation for the project not modeled in the study cases.

Table 2.5-11: Recommendations for previously approved projects not modeled in the study cases

Project Name	Recommendation
Atlantic – Placer 115 kV Line	Cancel

Details of the review of previously approved project not modeled in study cases are presented in Appendix B. High level discussion of the project review and recommendation is provided below:

Atlantic-Placer 115 kV Line

Figure 2.5-3 shows the 115 kV system from Drum to Gold Hill to El Dorado PH substations. The entire load in the area is currently served from two 230/115 kV transformers at Gold Hill, the Drum – Higgins 115 kV line, and 6 generating units connected to the system in the area. This project was put on hold in the 2016-2017 transmission planning process and was recommended to remain on-hold in last year's planning cycle to perform further assessment. In summary similar issues as identified in previous planning cycles were identified in this area in the 2018-2019 transmission planning process reliability assessment.

- P6 and P2 contingencies that trips both Gold Hill 230/115 kV transformers under peak load will causes voltage collapse in the area.
- P2-4 contingency on Gold Hill 115 kV bus causes severe overload on Drum – Higgins 115 kV line. The reason is that the contingency opens both the Gold Hill – Placer lines from Gold Hill end while the load on the double tap connections to these lines such as Horseshoe will remain connected, which is significantly beyond the capacity of the Drum – Higgins 115 kV line.

Figure 2.5-3 The 115 kV Transmission System from Drum to Gold Hill

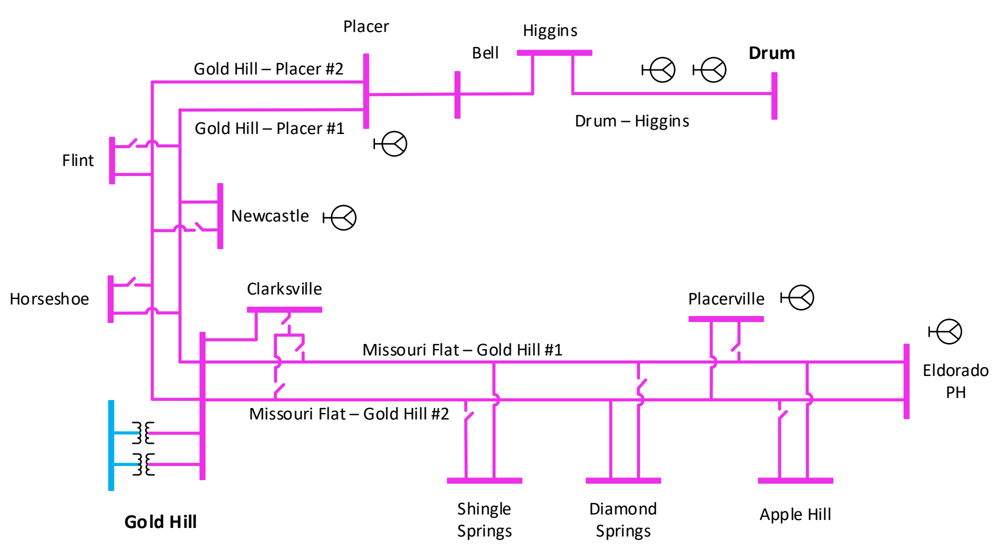
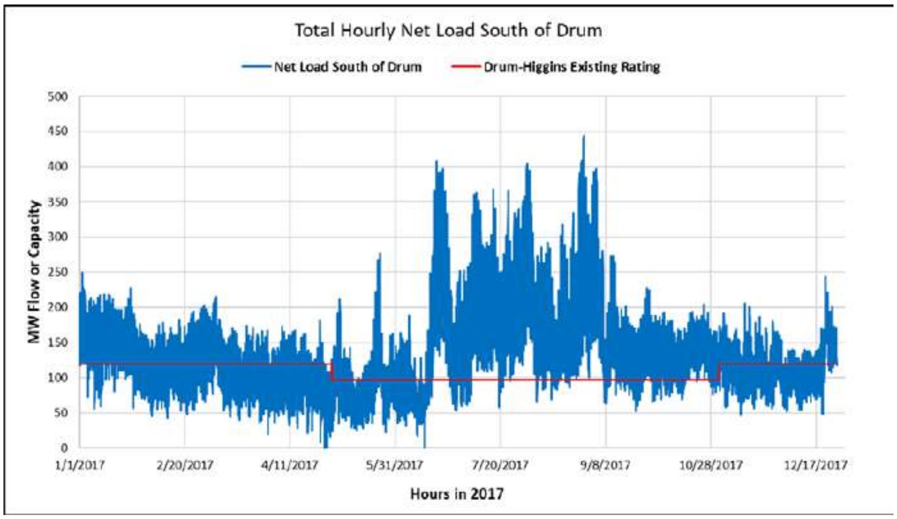


Figure 2.5-4 shows the hourly total flow on two Gold Hill transformers and Drum–Higgins 115 kV line in 2017along with the existing summer and winter emergency ratings of Drum Higgins line. The graph shows that almost at any time, if one Gold Hill transformer is taken out for maintenance, the contingency of the next transformer causes overload on the Drum–Higgins 115 kV line.

P27-129 cont.

Figure 2.5-4 Hourly total flow on Gold Hill Transformers and Drum-Higgins 115 kV Line in 2017



Another aspect of existing transmission system in the area is that the P7 contingency of both Missouri Flat – Gold Hill 115 kV lines will result in consequential tripping of the entire load connected to the 115 kV network from Gold Hill to El Dorado PH that could reach 160 MW under peak conditions. While this is not a criteria violation, it should be taken into account in developing transmission plan for the area.

P27-129 cont.

A P2-1 overload on Missouri Flats – Gold Hill lines 115 kV were identified in last year's analysis and was addressed by switching load in the area. This year's results show that given the load growth in the area, the P2-1 overload shows up in the long term.

Alternatives to Atlantic – Placer 115 kV Project:

Considering the above results, 3 alternatives were considered to address the identified constraints:

Alternative 1: Upgrade Drum-Higgins 115 kV line

This Alternative is feasible with a cost estimate of around $81M. The estimates assume that the parallel conductor sections will only be replaced with a single conductor.

Alternative 2: Add a third 230/115 kV transformer at Gold Hill

This Alternative is feasible with a cost estimate of around $22M.

Alternative 3: Bring another source to the Placerville/Shingle Spring area utilizing the existing 230 kV network in the area. This alternative is under review by PG&E for feasibility assessment and cost estimate.

The ISO is recommending to cancel the Altlantic Placer 115 kV project and to approve the installation of a third 230/115 kV transformer at Gold Hill substation with an estimated cost of $22 million and an in-service date of 2024.

The ISO will continue to monitor the load in the Placerville and Eldorado area to address the forecast P2-1 overloads in the 2028 timeframe and continue to assess the feasibility of alternative 3 to address the P2-1 and P7 if required in future planning cycles.

2.5.4.4 Request Window Submissions

There were two projects submitted into the 2018 Request Window.

Tesla 230 kV Bus Series Reactor

PG&E submitted the Tesla 230 kV Bus Series Reactor project in the 2018 Request Window. The Tesla substation is connected to the bulk transmission system via five 500 kV lines and fourteen 230 kV Lines. In addition, Tesla Substation has three 500/230 kV and two 230/115 transformer banks. Due to the number of bulk system connections and its relative proximity to generation facilities, Tesla has had issues with high fault current levels. PG&E's System Protection Department has identified a need to reduce the fault current on the Tesla 230 kV Bus due to overstressed Circuit Breakers. This concern is significant since the level will exceeded the maximum PG&E system design limit of 63 kA. The short circuit duty study identified 11 breakers at Tesla 230kV bus overstressed during certain fault condition, and this project is to mitigate the overstressed breaker issues without replacing these breakers. It will also maintain electrical worker safety from arc flash or inadequate personal grounding and will reduce the risk of equipment failure from a fault.

There are existing bus reactors between Tesla 230 kV bus sections C-D and D-E, which are 8 ohms and 4 ohms equivalent, respectively. The project proposes to:

P27-129 cont.

- Replace existing reactors with 18 ohm equivalent bus reactors between bus sections C-D and D-E
- Re-arrange various 230 kV line connections on the Tesla 230kV Bus
- Make protection system upgrades as required

This project is expected to cost between $24 million to $29 million. The in-service date for this prject is May 2023. The ISO recommends the approval of the Tesla 230 kV Bus Series Reactor project.

Weber – Manteca 230 kV Project

NextEra Energy Transmission West, LLC (NEET West) proposed the Weber – Manteca 230 kV project to address the P2-4 issues at Bellota and Tesla substations and to mitigate Weber load loss following the P6 contingency. This project is expected to cost $35 million (excluding any incumbent cost) with an estimated in-service date of December 2024.

The ISO is currently working with PG&E to evaluate substation upgrade options to address P2-4 issues at Bellota and Tesla substations. In the short term, the ISO recommends SPS to address the issue. A Benefit to Cost Ratio (BCR) analysis will be required to justify the economic benefits of preventing load loss under P6 contingency that is not a reliability criteria violation.

2.5.4.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1, about 160 MW of AAEE and more than 800 MW of installed behind-the-meter PV reduced the Central Valley Area load in 2022 by about 11%. This year's reliability assessment for the Central Valley Area included the "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 170 MW less behind-the-meter PV output. Comparisons between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case show that the facility overloads shown in Table 2.5-12 are potentially avoided due to reduction in net load:

Table 2.5-12: Reliability Issues in Sensitivity Studies

Facility	Category
Drum - Higgins 115 kV line	P7
Stanislaus-Melones-Manteca 115 kV Line No. 1	P2
Tesla - Tracy 115 kV Line	P2, P6
Eldorado - Missouri Flat 115 kV No. 1 Line	P2-1
Stanislaus-Melones-Manteca 115 kV Line	P2
Bellota - Riverbank - Melones 115KV Line	P2
Stanislaus-Melones-Riverbank 115 kV Line	P2
Drum - Grass Valley - Weimar 60 kV Line	P3

P27-129 cont.

Furthermore, more than 100 MW of demand response and 34 MW of battery energy storage are modeled in the Central Valley Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.4.6 Recommendation

Based on the studies performed for the 2018-2019 Transmission Plan, several reliability concerns were identified for the PG&E Central Valley Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Central Valley area.

In regards to the previously-approved on-hold projects, one project was on hold in the Central Valley Area that is recommended to be canceled in this cycle.

- Atlantic-Placer 115 kV Line project

The following two new project are recommended for approval in the Central Valley area.

- Gold Hill 230/115 kV Transformer Addition project
- Tesla 230 kV Bus Series Reactor project

2.5.5 Greater Bay Area

2.5.5.1 Area Description

The Greater Bay Area (or Bay Area) is at the center of PG&E's service territory. This area includes Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco counties as shown in the adjacent illustration. To better conduct the performance evaluation, the area is divided into three sub-areas: East Bay, South Bay and San Francisco-Peninsula.

The East Bay sub-area includes cities in Alameda and Contra Costa counties. Some major cities are Concord, Berkeley, Oakland, Hayward, Fremont and Pittsburg. This area primarily relies on its internal generation to serve electricity customers. The South Bay sub-area covers approximately 1,500 square miles and includes Santa Clara County. Some major cities are San Jose, Mountain View, Morgan Hill and Gilroy. Los Esteros, Metcalf, Monta Vista and Newark are the key substations that deliver power to this sub-area. The South Bay sub-area encompasses the De Anza and San Jose divisions and the City of Santa Clara. Generation units within this sub-area include Calpine's Metcalf Energy Center, Los Esteros Energy Center, Calpine Gilroy Power Units, and SVP's Donald Von Raesfeld Power Plant. In addition, this sub-area has key 500 kV and 230 kV interconnections to the Moss Landing and Tesla substations. Lastly, the San Francisco-Peninsula sub-area encompasses San Francisco and San Mateo counties, which include the cities of San Francisco, San Bruno, San Mateo, Redwood City and Palo Alto. The San Francisco-Peninsula area presently relies on transmission line import capabilities that include the Trans Bay Cable to serve its electricity demand. Electric power is imported from Pittsburg, East Shore, Tesla, Newark and Monta Vista substations to support the sub-area loads.

Trans Bay Cable became operational in 2011. It is a unidirectional, controllable, 400 MW HVDC land and submarine-based electric transmission system. The line employs voltage source converter technology, which will transmit power from the Pittsburg 230 kV substation in the city of Pittsburg to the Potrero 115 kV substation in the city and county of San Francisco.

The ISO Planning Standards were enhanced in 2014 to recognize that the unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages for extreme events that are beyond the level that is applied to the rest of the ISO controlled grid.

2.5.5.2 Area-Specific Assumptions and System Conditions

The Greater Bay Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission

P27-129
cont.

modeling assumptions for various scenarios used for the Greater Bay Area study are provided in Table 2.5-143.

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3 with the exception of the following previously approved project which is not modeled in the base cases:

Table 2.5-13: Greater Bay Area previously approved projects not modeled in base case

Project Name	TPP Approved In	Current ISD
Jefferson – Stanford #2 60 kV Line	2010-2011 TPP	On-Hold

P27-129 cont.

Table 2.5-14 Greater Bay Area load and generation assumptions

Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
GBA-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 18:00.	8,741	127	1,323	192	8,422	183	95	5	21	4	263	97	0	0	7,848	5,118
GBA-2020-WP	Baseline	2020 winter peak load conditions. Peak load time - hours ending 19:00.	7,901	122	1,323	0	7,779	183	95	5	21	0	263	11	0	0	7,848	3,174
GBA-2020-SpOP	Baseline	2020 spring off-peak load conditions. Off-peak load time - hours ending 12:00.	5,072	92	1,323	1045	3,935	183	95	5	21	21	263	13	0	0	7,848	1,684
GBA-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	7,320	127	1,323	1310	5,883	183	95	5	21	21	263	176	0	0	7,848	1,896
GBA-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:00.	9,121	253	1,900	275	8,593	184	95	5	21	3	263	136	0	0	7,848	4,742
GBA-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 18:00.	8,192	199	1,900	19	7,974	184	95	5	21	0	263	8	0	0	7,848	4,226
GBA-2023-SpOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	5,109	187	1,900	1596	3,326	184	95	5	21	20	263	5	0	0	7,848	527
GBA-2023-SP-Hi-CEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	9,121	0	1,900	275	8,846	184	95	5	21	3	263	122	0	0	7,848	5,477
GBA-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	5,109	187	1,900	1881	3,041	184	95	5	21	21	263	140	0	0	7,848	281
GBA-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 18:00.	9,514	480	2,795	281	8,753	184	95	5	21	2	263	55	0	0	7,848	4,091
GBA-2028-WP	Baseline	2028 winter peak load conditions. Peak load time - hours ending 19:00.	8,618	473	2,795	0	8,145	184	95	5	21	0	263	28	0	0	7,848	3,269
GBA-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	9,514	480	2,795	281	8,753	184	95	5	21	2	263	55	0	0	7,848	4,142

P27-129
cont.

2.5.5.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E Greater Bay Area identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies, most of which are addressed by previously approved projects. The areas where additional mitigation requirements were identified are discussed below.

Christie-Sobrante 115 kV Line Reconductor

Categories P2 and P7 contingency overloads were identified in the Oleum-Martinez 115 kV system. The P2 overloads are due to loss of supply from Sobrante. The P7 overloads are due to loss of Sobrante-G 115 kV DCTL. The ISO is recommending approval of the “Christie-Sobrante 115 kV Line Reconductor" project which includes reconductoring of the limited sections of the line. The estimated cost of this project is $10.5M and the forecast in-service date is 2022. In the interim, the area will rely on the operating action plan. There may be an opportunity to perform this work in conjunction with the previously approved North Tower Looping Project.

Regarding the overloads resulting from P2 contingencies at the Sobrante substation, PG&E has notified the ISO that the Sobrante 115 kV bus is currently undergoing an upgrade as part of another PG&E project. This other project is expected to rearrange and swap lines between Sobrante 115 kV bus sections D and E. The ISO will continue to monitor issues resulting from P2 contingencies at Sobrante 115 kV in future cycles.

P27-129 cont.

Moraga-Sobrante 115 kV Line Reconductor

Categories P2 overloads were identified on the Moraga-Sobrante 115 kV line starting in 2020. The ISO is recommending approval of the “Moraga-Sobrante 115 kV Line Reconductor" project. The estimated cost of this project is between $12M to $18M and an in-service date of 2023 is forecast. In the interim, the area will rely on the operating action plan.

Ravenswood 230/115 kV Transformer #1 Limiting Facility Upgrade

Categories P2 and P6 contingency overloads in baseline and P1 and P3 overloads in sensitivity scenarios were identified on the Ravenswood 230/115 kV transformer #1. The transformer rating is limited by rating of substation equipment. The ISO is recommending approval of the “Ravenswood 230/115 kV LineTransformer #1 Limiting Facility Upgrade " project which includes upgrading of the limiting substation equipment on the Ravenswood 230/115 kV LineTransformer #1. The estimated cost of this project is between $1.5M to $2.0M and in-service date is forecast of December 2018.

Summary of review of on-hold projects

The previously approved project shown in Table 2.5-15 was put on hold in the last cycle but is recommended for cancellation in this planning cycle.

Table 2.5-15: Recommendation for Previously Approved on-hold Projects

Project Name	Recommendation
Jefferson – Stanford #2 60 kV Line	Cancel

Details of the review of previously approved on-hold projects are presented in Appendix B.

Below is the high level discussion of the review of the on-hold project:

Jefferson - Stanford #2 60 kV Line

The *Jefferson - Stanford #2 60 kV Line* project was put on hold due load uncertainty in the area. Some 60 kV lines and 115/60 kV transformers in Peninsula area were found to be overloaded in all peak and sensitivity cases for P6 and P7 contingencies due to the interim configuration implemented for not modeling this project. The interim configuration avoids potential P1 contingency overload in the area. The load in the Stanford 60 kV system continues to remain uncertain. As such, the ISO recommends to cancel Jefferson - Stanford #2 60 kV Line project.

To address the P6 contingency the ISO is recommending an operating solution to to open Bair-Cooley Landing 60 kV lines following the first contingency for P6 overloads.

To address the P7 contingency the ISO is recommending Jefferson 230 kV Bus Upgrade project to keep Jefferson-Martin 230 kV cable in-service following the P7 contingency of the Monta Vista-Jefferson 230 kV lines. The estimated cost of the alternaive is $6 to 11 million with an in-service date of 2022.

P27-129 cont.

2.5.5.4 Request Window Submissions

The ISO received two submissions in the 2018 Request Window in the Greater Bay Area.

Request Window Submission - Cayetano 230 kV Energy Storage

NextEra Energy Transmission West, LLC (NEET West) proposed the Cayetano 230 kV Energy Storage targeting thermal overloads in the Contra Costa-Newark 230 kV corridor as a reliability need. NEET West proposed four projects which included combinations of 100 to 300 MW of energy storage in the Tri-valley area and Las Positas-Newark 230 kV line rerating. A summary of the four proposals is shown in Table 2.5-16.

Table 2.5-16: Cayetano 230 kV Energy Storage Proposed Options

Proposal	Energy Storage	Transmission Upgrade
1A	50 MW Battery Storage @ North Dublin 50 MW Battery Storage @ Vineyard 150 MW Battery Storage @ Newark	None
2A	150 MW Battery Storage @ Vineyard 150 MW Battery Storage @ Newark	None
1B	50 MW Battery Storage @ North Dublin 50 MW Battery Storage @ Vineyard	Increase Las Positas-Newark Emergency Rating
2B	150 MW Battery Storage @ Vineyard	Increase Las Positas-Newark Emergency Rating

The overloads observed in the Conta Costa-Newark 230 kV corridor were starting around 2023 and were mainly driven by higher load in the overall Mission division and high generation in the Contra Costa area. The ISO will continue to monitor Mission division load increases in the future load forecast. Hence, the ISO will not evaluate the proposed Cayetano 230 kV Energy Storage in this TPP cycle.

Request Window Submission - Delta Reliability Energy Storage

Tenaska, Inc. proposed the Delta Reliability Energy Storage targeting thermal overload on the Tesla-Delta Switch Yard 230 kV Line identified as a constraint for Contra Costa LCR Sub-area. In the 2018-2019 transmission planning process the Contra Costa LCR Sub-area was not selected to assess alternatives to reduce or eliminate the requirement for gas-fired generation to address the LCR requirement. As such, the ISO will not evaluate the proposed Delta Reliability Energy Storage in this TPP cycle.

2.5.5.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.5.2, about 250 MW of AAEE and more than 1900 MW of installed behind-the-meter PV reduced the Greater Bay Area load in 2023 by about 6%. This year's reliability assessment for Greater Bay Area included the "high CEC forecast" sensitivity case for year 2023 which modeled no AAEE. Comparisons between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reduction in net load:

P27-129 cont.

Table 2.5-17: Reliability Issues in Sensitivity Studies

Facility	Category
Cayetano-Lone Tree (Lone Tree-USWP) 230kV Line	P2
Cayetano-Lone Tree (Lone Tree-USWP) 230kV Line	P7
FMC-San Jose 'B' 115 kV Line	P2
Las Positas-Newark 230kV Line	P2
Los Esteros-Nortech 115 kV Line	P2
Newark-Kifer 115kV Line	P2
Newark-Kifer 115kV Line	P7
Newark-Northern Receiving Station #1 115kV Line	P1
Newark-Northern Receiving Station #1 115kV Line	P2
North Dublin-Cayetano 230kV Cable	P2
NRS-Scott No. 1 115 kV Line	P2
Oleum - North Tower-Christie 115 kV (North tower sub to North Tower Jt2)	P2
Oleum - North Tower-Christie 115 kV (North tower sub to North Tower Jt2)	P7
Ravenswood 230/115kV Transformer #1	P1
San Mateo-Belmont 115kV Line	P5
San Mateo-Belmont 115kV Line	P7
Scott-Duane 115 kV Line	P2

Furthermore, about 184 MW of demand response and 5 MW of battery energy storage are modeled in the Greater Bay Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

Preferred resources as potential mitigation are also identified for areas of additional mitigation requirements as discussed in section 2.5.5.3. The areas for which preferred resources are identified as a recommended solution or as a potential mitigation solution for areas currently relying on interim operational action along with high-level size of resource needed to mitigate reliability issues are shown in Table 2.5-18.

Table 2.5-18: Areas preferred resources are identified as potential solutions

Area	Overloaded Facility	Category	Need		Location
			Peak (MW)	Duration (Hr)	
San Jose 115 kV	Metcalf 230/115 kV banks	P2	240	6	Swift

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cont.

2.5.5.6 Recommendation

Based on the studies performed in the 2018-2019 transmission planning cycle Transmission Plan, several reliability concerns were identified for the PG&E Greater Bay Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Greater Bay area.

Two projects were submitted through Request Window in the Greater Bay Area in this cycle. The ISO did not evaluate both submissions in this cycle due to the reliability issues being seen to start around the fifth year only and the modeling of significantly higher load in the area compared to previous cycles and the LCR sub-area not selected to assess alternatives to reduce or eliminate the requirement in this cycle.

The previously approved project, "Oakland Clean Energy Initiative (OCEI)", is recommended to have a scope change in regards to classification of the energy storage portion of the project and identify a minimum need at Oakland L substation. The CAISO's original approval of the OCEI project included 10MW / 4 hour energy storage part to be a transmission asset and additional 10 MW-24 MW of preferred resources sited within the Oakland C and Oakland L 115 kV substation pocket. The CAISO recommends to no longer explicitly require this energy storage to be a transmission asset to allow for the most cost-effective combination of resources. Also, the CAISO clarifies that of the total resource mix (20 MW/120 MWh) to be sited within the Oakland C and Oakland L 115 kV substation pocket, no less than 7 MW/28 MWh should be either located at the Oakland L substation or interconnected via the PG&E distribution system to the CAISO-controlled grid at Oakland L.

P27-129 cont.

In regards to the previously-approved on-hold projects, one project was on hold in the Greater Bay Area that is recommended to be canceled in this cycle.

- Jefferson - Stanford #2 60 kV Line project

The following four new project are recommended for approval in the Greater Bay Area.

- Christie-Sobrante 115 kV Line Reconductor
- Moraga-Sobrante 115 kV Line Reconductor
- Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade
- Jefferson 230 kV Bus Upgrade project

2.5.6 Greater Fresno Area

2.5.6.1 Area Description

The Greater Fresno Area is located in the central to southern PG&E service territory. This area includes Madera, Mariposa, Merced and Kings Counties, which are located within the San Joaquin Valley Region. The adjacent figure depicts the geographical location of the Fresno area.

The Greater Fresno area electric transmission system is composed of 70 kV, 115 kV and 230 kV transmission facilities. Electric supply to the Greater Fresno area is provided primarily by area hydro generation (the largest of which is Helms Pump Storage Plant), several market facilities and a few qualifying facilities. It is supplemented by transmission imports from the North Valley and the 500 kV lines along the west and south parts of the Valley. The Greater Fresno area is composed of two primary load pockets including the Yosemite area in the northwest portion of the shaded region in the adjacent figure. The rest of the shaded region represents the Fresno area.

The Greater Fresno area interconnects to the bulk PG&E transmission system by 12 transmission circuits. These consist of nine 230 kV lines; three 500/230 kV banks; and one 70 kV line, which are served from the Gates substation in the south, Moss Landing in the west, Los Banos in the northwest, Bellota in the northeast, and Templeton in the southwest. Historically, the Greater Fresno area experiences its highest demand during the summer season but it also experiences high loading because of the potential of 900 MW of pump load at Helms Pump Storage Power Plant during off-peak conditions. The largest generation facility within the area is the Helms plant, with 1212 MW of generation capability. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and off-peak conditions that reflect different operating conditions of Helms. Significant transmission upgrades have been approved in the Fresno area in past transmission plans, which are set out in chapter 8. P27-129 cont.

2.5.6.2 Area-Specific Assumptions and System Conditions

The Greater Fresno Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are provided below.

Table 2.5-19 Greater Fresno Area load and generation assumptions

S. No.	Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	GFA-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 18:00.	3,248	62	920	0	3,186	59	29	156	2402	0	13	5	1892	1766	1,453	1,185
2	GFA-2020-SpOP	Baseline	2020 spring off-peak load conditions. Off-peak load time - hours ending 12:00.	1,035	45	920	727	263	59	29	156	2402	2238	13	1	1892	-560	1,453	453
3	GFA-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	3,212	62	920	911	2,239	59	29	156	2402	2378	13	9	1892	1775	1,453	609
4	GFA-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:00.	3,430	123	1,165	0	3,307	60	29	156	2402	0	13	9	1892	1744	1,453	1,199
5	GFA-2023-SpOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,051	91	1,165	978	(18)	60	29	156	2402	1987	13	0	1892	-561	1,453	226
6	GFA-2023-SP-Hi-CEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	3,430	0	1,165	0	3,430	60	29	156	2402	0	13	5	1892	1685	1,453	1,232
7	GFA-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	1,051	91	1,165	1153	(193)	60	29	156	2402	2045	13	9	1892	-550	1,453	717
8	GFA-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 18:00.	3,676	233	1,568	0	3,443	60	29	156	2402	0	13	9	1892	1799	1,453	1,227
9	GFA-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	3,676	233	1,568	0	3,443	60	29	156	2402	0	13	0	1892	1799	1,453	1,239

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cont.

2.5.6.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E Greater Fresno Area has identified several reliability concerns consisting of thermal overloads under Category P1 to P7 contingencies most of which are addressed by previously approved projects. The areas where additional mitigation requirements were found to be needed are discussed below.

Borden-Madera 70 kV Area overloads

There were several P6 overloads found in this area. The contingency causing the overloads are not BES and limiting elements are also not BES, therefore no mitigations were developed for these overloads.

Wilson-Atwater 115 kV Area overloads

There were several P6 and P7 overloads found in this area in all Baseline scenarios. The mitigation identified for the P6 contingencies is to do Operational Switching following the first contingency. The P7 overloads are mitigated by the Atwater SPS.

Kerckhoff 115 kV Area overloads

There were several P6 overloads identified in this area in all Baseline scenarios. The overloads are mitigated by the Kerckhoff SPS.

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Coalinga 70 kV Area overloads

There were Category P2 and P7 overloads identified on Gates230/70kV TB #5 and on sections of the Schindler-Huron-Gates 70 kV line (Huron Junction to Cal flax substation & Schindler to Five point switching station) in the spring off-peak scenarios. This is due the dispatch of generation in the area and can be mitigated by redispatching generation in the area.

Panoche 115 kV Area overloads

There were P1, P2 and P6 overloads identified in this area for all 2020 and 2023 Spring off-peak scenarios. Generation re-dispatch is the preferred mitigation.

McCall 115 kV Area overloads

There were P2, P6 and P7 overloads identified in this area for the 2028 Baseline scenario as well as the High CEC sensitivity scenario. We will continue to monitor future load forecasts in the area in future planning cycles.

Reedley 70 kV Area overloads

There was a Category P1, P2, P3, and P6 overloads seen in all the Baseline scenarios in the area. The use the previously approved 7 MW Energy storage at Dinuba 70 kV substation in the Reedley 70 kV Reinforcement project addresses the reliability needs for this area. Current in Service date is May 2021.

P5 overloads

There were P5 Contingency of the Gregg 230 KV BAAH Bus #2 that overloaded several 115 kV and 230 kV lines in the base and sensitivity scenarios. The ISO is recommending PG&E to add redundant relay protection as the preferred mitigation.

Mendota 115kV Area and Coalinga 70kV Voltage concerns

In the 2028 Summer Peak baseline scenario, some low voltages were identified for Category P2, P3 and P6 contingencies. The ISO will continue to monitor future load forecasts for this issue.

Summary of review of on-hold projects

The previously approved project shown in Table 2.5-20 was put on hold in the last cycle but is recommended for cancellation in this planning cycle.

Table 2.5-20: Recommendation for Previously Approved on-hold Projects

Project Name	Recommendation
Gates-Gregg 230 kV Line Project	Cancel

Details of the review of previously approved on-hold projects are presented in Appendix B.

Below is the high level discussion of the review of the on-hold project:

Gates-Gregg 230 kV Line

The Gates-Gregg 230 kV Line project was approved in the 2012-2013 transmission planning process as a Reliability Driven Project with renewable integration benefits. The reliability-driven need for the line was to increase the pumping opportunities at the Helms pumped storage/generation facility to ensure there would be adequate water available when the generation was called upon to support local area loads. The 2012-2013 transmission planning process identified that the availability of pumping would begin to decrease in the 2023 timeframe with inadequate pumping opportunities to provide sufficient water for generation to meet reliability needs in Fresno local area by the 2029 timeframe. The original cost estimate for the project was $115 to $145 million.

In the 2016-2017 transmission planning process the ISO reviewed the need for the Gates-Gregg 230 kV Line project. The assessment determined the reliability need had been deferred by at least 10 years due to the change in load characteristics in the area allowing increased pumping from the HELMS facility to allow for generation during peak loading conditions in the area. There were renewable integration benefits due to increased pumping conditions; however these were not found to provide adequate economic benefits. There was uncertainty of the renewable integration benefits that may need further assessment for the determination of the need for the Gates-Gregg 230 kV Line project, in particular the CPUC Integrated Resource Plan (IRP) and the CEC IEPR Energy Demand Forecast. The project was put on hold in the 2016-2017 transmission planning process.

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cont.

The project was also reviewed in the 2017-2018 transmission planning process. The load forecast, profile and load modifier assumptions (DER) in the 2017-2018 TPP were consistent with those of the 2016-2017 TPP assessment when the ISO put the project on hold. PG&E has confirmed that while the project is on hold it is continuing to accrue carrying costs since March 2017 when the 2016-2017 Transmission Plan was approved by the ISO Board of Governors. With this, if the project remains on hold and is cancelled in future cycles no additional costs associated with leaving it on hold. With this the project remained on hold.

The reliability need for the project has been reassessed in the 2018-2019 transmission planning process indicating similar to the reviews in the previous cycles that the reliability need has been deferred by more than 10 years. To assess the renewable integration benefits, the ISO confirmed the Fresno area system capability to supply the area load that was determined in the 2016-2017 transmission planning process.

- 1980 MW - Existing system with approved upgrades; and
- 2605 MW - With the Gates-Gregg 230 kV Line project

In addition to the power flow analysis that determined the system capabilities above, in this year's planning cycle, the ISO performed Transient Stability analysis. The assessment did not identify any transient issues that the line mitigated.

Based upon the 2028 forecasted load profile for the Fresno area, using the system capabilities of the transmission system to supply the load in the Fresno area the periods of time when the HELMS pumping would be limited were determined.

illustrates the load duration curve for the Fresno area with the HELMS pumping load for one pump, two pump and three pumps operating between the hours of 10 am and 4 pm when system curtailment is forecast to occur. The output of the HELMS pumps are not variable in the pumping mode and as such are either 0 MW or 305 MW per pump when operated in the pumping mode. The area in blue represents the period of time that the HELMS pumps would not be able to operate due to the Fresno area load profile and the transmission system capability.

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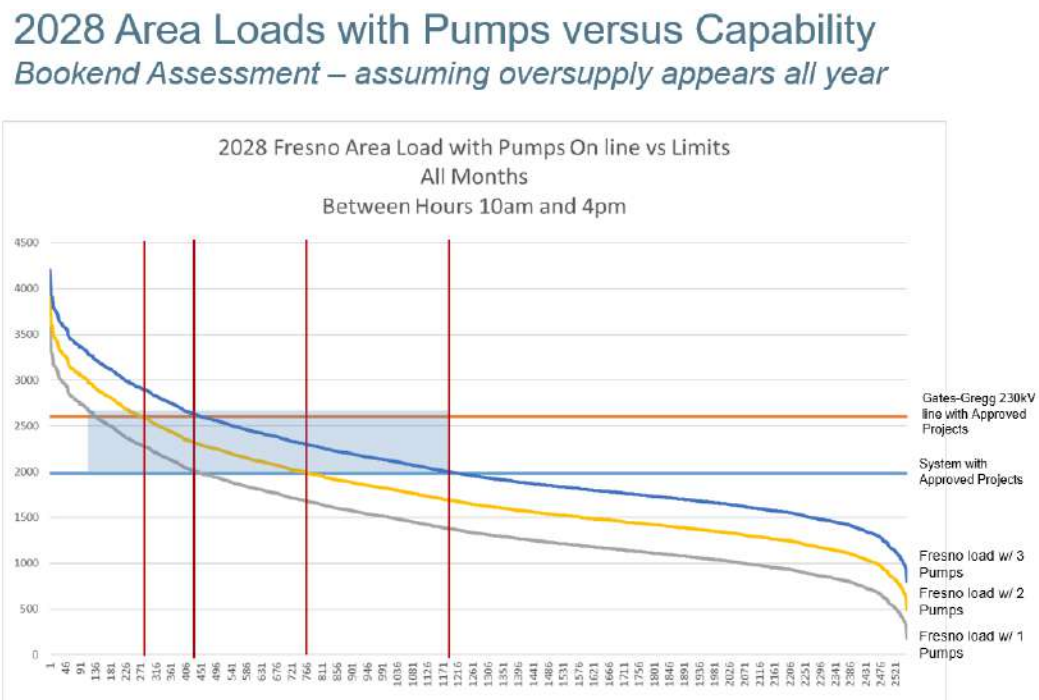
Figure B 2.5-2 2028 Fresno Area Loads with Pumps vs Capability for a full year between the hours of 10am and 4pm



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Based on the hours identified in Figure B 2.5-2 that the pumps would not be able to operate, assuming system over supply conditions occur for all hours that the pumping is not available the MWh of curtailment that could have been avoided and the estimated value of the avoided pumping per year is as follows:

- MWh where pumping not available without Gates-Gregg 230 kV Line
  - (775 hours * 300 MW) + (470 hours*300MW)+ (275 hours * 300 MW)
  - 456,000 MWh of curtailment
- Value of Pumping for Avoided Curtailment
  - At $40/MWh estimated cost of curtailment
    - 456,000 MWh * $40/MWh
    - $18.24 million/year estimated value of curtailed energy
  - At $66/MWh estimated cost of curtailment
    - 456,000 MWh * $66/MWh
    - $30.1 million/year estimated value of curtailed energy

- At $100/MWh estimated cost of curtailment
  - 456,000 MWh * $100/MWh
  - $45.6 million/year estimated value of curtailed energy

The values above assumes that system oversupply conditions resulting in renewable curtailment to occur for all hours that the pumping is unavailable due to the transmission system capability for the forecast area load profile with the pumping load. System over supply conditions are not forecast to occur for all hours between 10 am and 4 pm, particularly in the summer. Further assessment using the forecast of curtailment identified in the production simulation analysis in Chapter 4 was done using the hourly profile and MW of curtailment. The MWh of when pumping would not be available and system oversupply occurs resulted in the following:

- MWh where pumping not available without Gates-Gregg 230 kV Line 3
  - 228,510 MWh of curtailment
- Value of Pumping for Avoided Curtailment
  - At $40/MWh estimated cost of curtailment
    - 120,960 MWh * $40/MWh
    - $9.14 million/year estimated value of curtailed energy
  - At $66/MWh estimated cost of curtailment
    - 120,960 MWh * $66/MWh
    - $15.1 million/year estimated value of curtailed energy
  - At $100/MWh estimated cost of curtailment
    - 20,960 MWh * $100/MWh
    - $22.9 million/year estimated value of curtailed energy

The current estimate cost of the Gates-Gregg 230 kV Line project is from $200 to 250 Million. Table B2.5-21 shows the benefit to cost ratio of the avoided curtailment of the Gates-Gregg 230 kV line based upon the above economic analysis for oversupply for all hours and the expected hours of oversupply from production cost simulation when the HELMS pumps would be curtailed due to the transmission system capability.

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Table B2.5-22 Benefit to Cost Ratio (Ratepayer Benefit per TEAM) of Gates to Gregg 230 kV Line

Gates-Gregg Project						
Avoided Curtailment Benefit						
Avoided Curtailment Benefits	Pumping Not Available Assuming Overssupy for All Hours			Pumping Not Available with Expected Overssupy Hours		
	At $40/MWh estimated cost of curtailment	At $66/MWh estimated cost of curtailment	At $100/MWh estimated cost of curtailment	At $40/MWh estimated cost of curtailment	At $66/MWh estimated cost of curtailment	At $100/MWh estimated cost of curtailment
Net Curtailment Saving ($million/year)	$18.24	$30.10	$45.60	$9.14	$15.10	$22.90
PV of Curtailment Savings ($million)	$251.73	$415.40	$629.31	$126.14	$208.39	$316.04
Capital Cost						
Capital Cost Estimate ($ million)	$250			$250		
Estimated “Total” Cost (screening) ($million)	$325			$325		
Benefit to Cost						
PV of Savings ($million)	$251.73	$415.40	$629.31	$126.14	$208.39	$316.04
Estimated “Total” Cost (screening) ($million)	$325.00			$325.00		
Benefit to Cost	0.77	1.28	1.94	0.39	0.64	0.97

The assumption that system oversupply conditions would occur during all hours that HELMS pumping would be limited due to the transmission system capability overstates the amount of curtailment that could be avoided with the Gates-Gregg line in-service. Using the expected oversupply from the production simulation analysis to determine the avoided curtailment when the HELMS pumping would be limited due to the transmission system capability is more appropriate. With a value of curtailment of $40/MWh the Benefit to Cost Ratio (BCR) would be 0.39 and a value of curtailment of $100/MWh the BCR would be 0.97. The average value of curtailment currently is estimated closer to $40/MWh. With this the economic benefit of the Gates-Gregg 230 kV Line project is below a BCR of 1.0. With this the economic benefit of the avoided curtailment is not enough to justify the Gates-Gregg 230 kV Line project and accordingly the recommendation is to cancel the project.

P27-129 cont.

2.5.6.4 Request Window Submissions

Kingsburg-Leemore Reconductoring

PG&E submitted Kingsburg-Leemore Reconductoring project into the 2018 Request Window. The project consistes of reconductoring approximately 8.3 miles of the Kingsburg – Lemoore 70 kV Line between Hanford Switching Station and Lemoore Substation, with 715 AAC conductor or an equivalent conductor. This reconductoring project is proposed to increase load serving capability and provide additional reliability for electric customers in Fresno and Kings Counties. There is no reliability criteria issue identified in the reliability assessment and this project was submbitted as BCR project.

This project would reduce the number and duration of sustained outages for the customers served by the Lemoore Substation, due to an outage of Henrietta – Lemoore 70 kV Line.

This project is expected to cost between $12.2M - $14.6M. PG&E indicated that the BCR for this project would be greater than 1.0; however based upon the current information provided by PG&E and considering the load profiles in the area, the Benefit to Cost Ratio is 0.54 which is not sufficient to justy the project. PG&E Operations also provided information regarding potential voltage violations following P1 contingencies which the ISO did not observe the voltage issues in the reliability assessment.

The ISO has requested additional information from PG&E regarding the voltage violations of this proposed reconductoring project. The ISO will continue to work with PG&E and conduct further assessment of the need for this upgrade in the next planning cycle.

P27-129 cont.

2.5.6.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.6.2, about 123 MW of AAEE reduced the Greater Fresno Area load in 2023 by about 3.4%. This year's reliability assessment for the Greater Fresno Area included the "high CEC forecast" sensitivity case for the year 2023 which modeled no AAEE. Comparisons between the reliability issues identified in the 2023 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reductions in net load:

Table 2.5-23: Reliability Issues in Sensitivity Studies

Facility	Category
Reedley 115/70kV TB #1	P1
Reedley 115/70kV TB #1	P2
Herndon-Ashan 230kV line	P5
GWFHEP to Contadina 115 kV line	P5
McCall 230/115 kV TB #3	P5
Borden 230/70kV TB #1	P6

Furthermore, about 60 MW of demand response is modeled in Greater Fresno Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.6.6 Recommendation

Based on the studies performed in the 2018-2019 transmission planning cycle, several reliability concerns were identified for the PG&E Greater Fresno Area. These concerns consisted of thermal overloads and voltage concerns under Categories P1 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Greater Fresno Area.

In regards to the previously-approved on-hold project, one project was on hold in the Greater Fresno Area that is recommended to be canceled in this cycle.

- Gates-Gregg 230kV Line project.

One project was submitted through Request Window in the Greater Fresno Area in this cycle; the ISO has requested additional information to further assess the project. The ISO will continue to work with PG&E and conduct further assessment of the need for this upgrade in the next planning cycle.

P27-129
cont.

2.5.7 Kern Area

2.5.7.1 Area Description

The Kern area is located south of the Yosemite-Fresno area and north of the southern California Edison's (SCE) service territory. Midway substation, one of the largest substations in the PG&E system, is located in the Kern area and has 500 kV transmission connections to PG&E's Diablo Canyon, Gates and Los Banos substations as well as SCE's Vincent substation. The figure on the left depicts the geographical location of the Kern area.

The bulk of the power that interconnects at Midway substation transfers onto the 500 kV transmission system. A substantial amount also reaches neighboring transmission systems through Midway 230 kV and 115 kV transmission interconnections. These interconnections include 230 kV lines to Yosemite-Fresno in the north as well as 115 and 230 kV lines to Los Padres in the west. Electric customers in the Kern area are served primarily through the 230/115 kV transformer banks at Midway, Kern Power Plant (Kern PP) substations and local generation power plants connected to the lower voltage transmission network.

2.5.7.2 Area-Specific Assumptions and System Conditions

The Kern Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are provided below:

P27-129 cont.

Table 2.5-24 Kern Area load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	KERN-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 19:00.	1,935	34	431	0	1,901	76	57	2	673	0	0	0	18	7	2,222	1,899
2	KERN-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:00.	2,039	67	512	0	1,973	77	57	0	520	0	0	0	18	6	2,212	1,905
3	KERN-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 19:00.	2,183	127	587	0	2,056	77	57	0	520	0	0	0	18	6	2,212	1,906
4	KERN-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – hours ending 12:00.	857	24	431	340	492	76	57	2	673	532	0	0	29	14	3,298	529
5	KERN-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	866	50	512	430	386	77	57	0	520	407	0	0	29	9	3,288	567
6	KERN-2023-SP-HiCEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	2,039	0	512	0	2,039	77	57	0	520	0	0	0	18	13	2,212	2,126
7	KERN-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	866	50	512	507	309	77	57	0	520	421	0	0	29	21	3,288	717
8	KERN-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	1,935	34	431	426	1,475	76	57	2	673	628	0	0	29	9	3,298	567
9	KERN-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	2,183	127	587	0	2,056	77	57	0	520	0	0	0	18	6	2,212	1,906

P27-129
cont.

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.7.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E Kern Area identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously approved projects and/or continued reliance on existing summer setups for the area.

2.5.7.4 Request Window Submissions

There were no request window submissions for Kern Area.

2.5.7.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.7.2, about 67 and 127 MW of AAEE reduced the Kern Area net load by 3 and 6% in 2023 and 2028 respectively . This year's reliability assessment for Kern Area included the "high CEC forecast" sensitivity case for year 2023 which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2023 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reduction in net load: P27-129 cont.

Table 2.5-25: Reliability Issues in Sensitivity Studies

Facility	Category
Kern-WestPark # 1 115 kV	P3
Kern-WestPark # 2 115 kV	P3
Kern Oil Jn to Kern Water 115 kV	P3
Kern PP 230/115 kV # 3, 4 and 5	P6
Kern PP 230/115 kV # 5	P6
Kern PP- Tevis J1 115 kV line section	P2
Kern PP- Tevis J2 115 kV line section	P2
Taft 115/70 kV bank # 2	P3
Midway-Wheelerridge 230 kV lines	P2/P6

Furthermore, about 76 MW of demand response and 2 MW of battery energy storage are modeled in Kern Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, didn't completely alleviate the overloads.

2.5.7.6 Recommendation

Based on the studies performed for the 2018-2019 Transmission Plan, several reliability concerns were identified for the PG&E Kern Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects, PG&E maintenance projects, generation redispatch or continued reliance on existing summer setups for the area.

P27-129 cont.

2.5.8 Central Coast and Los Padres Areas

2.5.8.1 Area Description

The PG&E Central Coast division is located south of the Greater Bay Area and extends along the Central Coast from Santa Cruz to King City. The green shaded portion in the figure on the left depicts the geographic location of the Central Coast and Los Padres areas.

The Central Coast transmission system serves Santa Cruz, Monterey and San Benito counties. It consists of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Most of the customers in the Central Coast division are supplied via a local transmission system out of the Moss Landing Substation. Some of the key substations are Moss Landing, Green Valley, Paul Sweet, Salinas, Watsonville, Monterey, Soledad and Hollister. The local transmission systems are the following: Santa Cruz-Watsonville, Monterey-Carmel and Salinas-Soledad-Hollister sub-areas, which are supplied via 115 kV double circuit tower lines. King City, also in this area, is supplied by 230 kV lines from the Moss Landing and Panoche substations, and the Burns-Point Moretti sub-area is supplied by a 60 kV line from the Monta Vista Substation in Cupertino. Besides the 60 kV transmission system interconnections between Salinas and Watsonville substations, the only other interconnection among the sub-areas is at the Moss Landing substation. The Central Coast transmission system is tied to the San Jose and De Anza systems in the north and the Greater Fresno system in the east. The total installed generation capacity is 2,900 MW, which includes the 2,600 MW Moss Landing Power Plant, which is scheduled for compliance with the SWRCB Policy on OTC plants by the end of 2020.

The PG&E Los Padres division is located in the southwestern portion of PG&E's service territory (south of the Central Coast division). Divide, Santa Maria, Mesa, San Luis Obispo, Templeton, Paso Robles and Atascadero are among the cities in this division. The city of Lompoc, a member of the Northern California Power Authority, is also located in this area. Counties in the area include San Luis Obispo and Santa Barbara. The 2400 MW Diablo Canyon Power Plant (DCPP) is also located in Los Padres. Most of the electric power generated from DCPP is exported to the north and east of the division through 500 kV bulk transmission lines; in terms of generation contribution, it has very little impact on the Los Padres division operations. There are several transmission ties to the Fresno and Kern systems with the majority of these interconnections at the Gates and Midway substations. Local customer demand is served through a network of 115 kV and 70 kV circuits. With the retirement of the Morro Bay Power Plants, the present total installed generation capacity for this area is approximately 950 MW. This includes the recently installed photovoltaic solar generation resources in the Carrizo Plains, which includes the 550 MW Topaz and 250 MW California Valley Solar Ranch facilities on the Morro Bay-Midway 230 kV line corridor. The total installed capacity does not include the 2400 MW DCPP output as it does not serve the load in the PG&E's Los Padres division.

P27-129 cont.

2.5.8.2 Area-Specific Assumptions and System Conditions

The Central Coast and Los Padres areas study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Coast and Los Padres areas study are provided below.

P27-129 cont.

Table 2.5-26 Central Cost and Los Padres Area load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV Installed (MW)	BTM-PV Output (MW)	Net Load (MW)	Demand Response Total (MW)	Demand Response D2 (MW)	Battery Storage (MW)	Solar Installed (MW)	Solar Dispatch (MW)	Wind Installed (MW)	Wind Dispatch (MW)	Hydro Installed (MW)	Hydro Dispatch (MW)	Thermal Installed (MW)	Thermal Dispatch (MW)
1	CCLP-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 20:00.	1,253	23	324	0	1,231	29	16	0	841	0	0	0	0	0	3,939	1,237
2	CCLP-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 20:00.	1,298	46	403	0	1,252	29	16	0	841	0	0	0	0	0	3,773	1,221
3	CCLP-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 20:00.	1,356	86	487	0	1,270	29	16	0	816	0	0	0	0	0	3,773	1,252
4	CCLP-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – hours ending 12:00.	655	17	324	256	382	29	16	0	841	832	0	0	0	0	3,939	1,177
5	CCLP-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	653	34	403	339	281	29	16	0	841	742	0	0	0	0	3,773	130
6	CCLP-2020-WP	Baseline	2020 winter peak load conditions. Peak load time - hours ending 19:00.	1,188	22	324	0	1,166	29	16	0	841	0	0	0	0	0	3,939	1,228
7	CCLP-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 18:00.	1,225	25	403	4	1,197	29	16	0	841	0	0	0	0	0	3,939	1,176
8	CCLP-2028-WP	Baseline	2028 winter peak load conditions. Peak load time - hours ending 19:00.	1,292	85	487	0	1,207	29	16	0	816	0	0	0	0	0	3,773	1,252
9	CCLP-2023-SP-HiCEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	1,298	0	403	0	1,298	29	16	0	841	0	0	0	0	0	3,773	1,252
10	CCLP-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	653	34	403	399	220	29	16	0	841	800	0	0	0	0	3,773	145
11	CCLP-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	1,105	23	324	321	761	29	16	0	841	832	0	0	0	0	3,939	653
12	CCLP-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	1,226	86	487	0	1,134	29	16	0	816	0	0	0	0	0	3,773	1,122

P27-129
cont.

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with the exception of approved projects shown in Table 2.5-27 which were not modeled in the base cases:

Table 2.5-27: Central Coast / Los Padres approved projects not modeled in base case

Project Name	TPP Approved In	Current ISD
Midway-Andrew Project	2012-2013 TPP	Jun-2025
Morro Bay 230/115 kV Transformer Project	2010 TPP	Apr-2019
Diablo Canyon Voltage Support Project	2012-2013 TPP	Dec-2019

2.5.8.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E Central Coast and Los Padres areas have identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously approved projects.

The areas where additional mitigation requirements were identified are discussed below.

P27-129 cont.

Crazy Horse-Salanis 115 kV Lines

Category P6 contingency overloads were identified in the Salinas 115 kV system. PG&E has identified that the overloaded lines have been identified in their maintenance plans to be rebuilt. The ISO is recommending PG&E to review the maintenance schedule for these lines, and when the lines are rebuilt as a part of the maintenance plan, the ISO recommends that the rating be increased to address the overloads. Until the maintenance upgrades for these facilities are in place, the ISO recommends PG&E install a SPS to mitigate the reliability constraints.

Summary of review of previously approved projects

There are three previously approved active projects in the Central Coast/Los Padres area, out of which all three projects were not modeled in the study cases due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. Table 2.5-28 shows final recommendation for the three projects not modeled in the study cases:

Table 2.5-28: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
Midway-Andrew Project	Hold
Morro Bay 230/115 kV Transformer Project	Cancel
Diablo Canyon Voltage Support Project	Cancel

Details of the review of previously approved projects not modeled in study cases are presented in Appendix B.

Below is the high level discussion of projects recommended to proceed with the revised scope:

Midway-Andrew Project

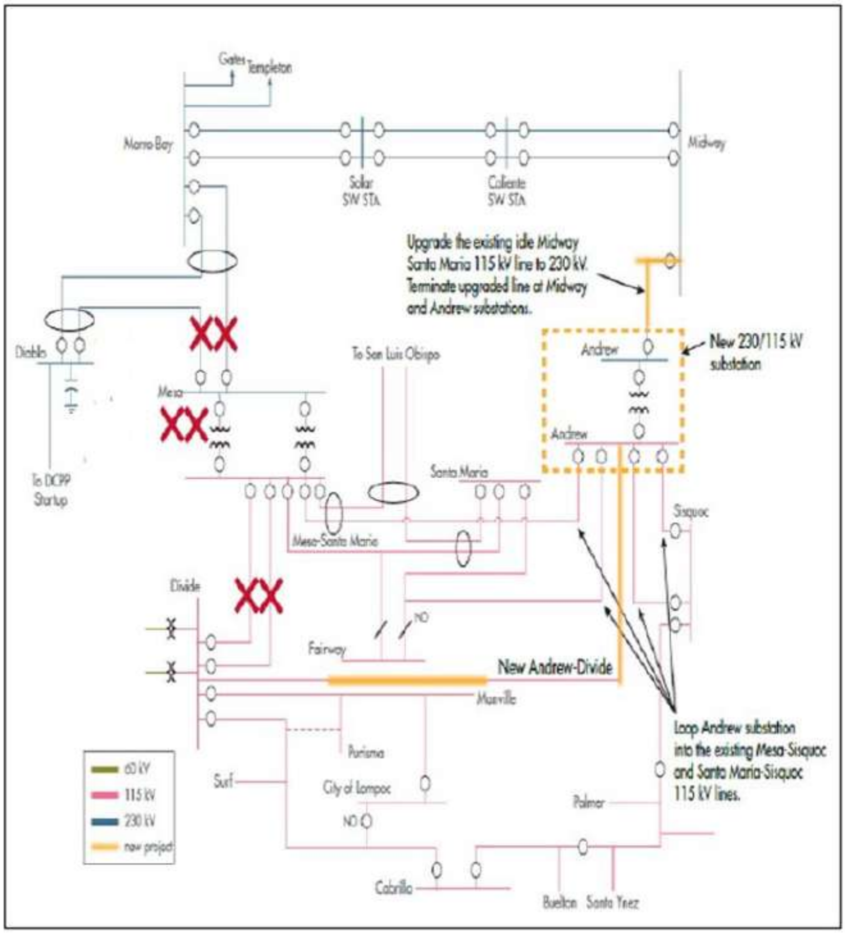
The previously approved Midway-Andrew 230 kV project approved in the 2012-2013 TPP. The Midway-Andrew 230 kV project was not modelled in the base case in order to assess additional alternatives due to increases in the estimated cost and potential feasibility issues identified for the implementation of the project. The reliability assessment identified severe P2 and P6 thermal overloads in the 115 kV system supplied from the Mesa substation. In addition, the load forecast and profile in the area does not provide periods for maintenance to facilities where the next contingency would not result in load loss in the area.

Original Scope:

- Build new 230/115 kV Andrew substation
- Upgrade existing Midway-Santa Maria 115 kV line to 230 kV and build new Andrew-Divide 115 kV line.
- 2012-2013 TPP estimated cost: $120 to $150 million
- Current estimated cost: $215 to $215 million
- Current in-service date: June 2025

P27-129 cont.

Figure 2.5.8-1: Midway-Andrew 230 kV Project Original Scope.



The need for mitigation in the area is still required. The ISO assessed potential alternatives for the project. This project can be split into two sections, North of Mesa, where the ISO is considering repurposing one of the 500 kV lines from Midway to Diablo after the retirement of the Diablo Canyon Power Plant in 2025. The second section is South of Mesa where the ISO is considering reinforcing the 115 kV system and adding a capacitor for voltage support. These section alternatives can be combined to address several P2 and P6 reliability needs in the area as a whole.

P27-129 cont.

- North of Mesa Upgrade Alternatives
  - <u>Alternative 1</u>: Increase the Winter emergency rating of San Luis Obispo (SLO) – Santa Maria 115 kV line to 170 MVA, increase the Winter emergency rating of SLO – Mesa 115 kV line to 130 MVA, and install 50 Mvar capacitor bank at Mesa or SLO, and install SPS to shed load if P6 occurs under peak load.

- o <u>Alternative 2</u>: Build Andrew 230/115 kV substation, energize Diablo – Midway 500 kV line at 230 kV and connect to Andrew substation, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations.

- South of Mesa Upgrade Alternatives
  - o <u>Alternative 1</u>: Increase the Winter emergency rating of Sisquoc - Santa Ynez 115 kV line to 120 MVA, install 20 Mvar capacitor bank at Cabrillo, and install SPS to shed load if P6 occurs under peak load
  - o <u>Alternative 2</u>: Increase the Summer emergency rating of Sisquoc - Santa Ynez 115 kV line to around 160 MVA and install SVC at Cabrillo
  - o <u>Alternative 3</u>: Build a new greenfield 115 kV line from Divide to Mesa or other substations.
  - o Alternative 4: Reconductor the Sisquoc - Santa Ynez 115 kV line, install 20 Mvar capacitor bank at Cabrillo, and install SPS to shed load if P6 occurs under peak load

Due to uncertainty of potential generation development and transmission alternatives in the area, further assessment of the conversion of one of the 500 kV lines from Midway-Diablo will be required in 2019-2020 transmission planning process. As identified above, the Midway-Andrew 230 kV project can be separated into two projects. The North of Mesa Upgrade is the portion of the project that is dependant on the potential conversion of one of the 500 kV lines from Midway-Diablo. The need and alternatives of the South of Mesa Upgrade is independent from North of Mesa Upgrade. With this the ISO is recommending to rescope the Midway-Andrew project to Alternative 2 of the North of Mesa Upgrade, and rename the project to North of Mesa Upgrade. The estimated cost of the North of Mesa Upgrade is $114 to $144 million with an in-service date of 2026, after Diablo generation has retired and one of the 500 kV lines can be convered to 230 kV. The rescoping of the Midway-Andrew 230 kV project to the North of Mesa Upgrade project is recommended to remain on hold. P27-129 cont.

It has been determined that rerating of the Sisquoc - Santa Ynez 115 kV line is not feasible as identified in Alternatives 1 and 2.The ISO is recommending the approval of Alternative 4 of the South of Mesa Upgrade. The estimated cost of the $29.6 to $59.2 million with an in-service date of 2023.

<u>Morro Bay 230/115 kV Transformer Project</u>

The reliability assessment did not identify any P0, P1, or P3 overloads in the area following the loss of the Morro Bay 230/115 kV transformer. A maintenance outage review based on historical data indicated that reasonable opportunities are available to take the transformer out for maintenance. Therefore, it is recommended that the previously approved Morro Bay 230/1115 kV Transformer Project approved in the 2010 TPP be canceled.

<u>Diablo Canyon Voltage Support Project</u>

In the ISO 2012-2013 Transmission Plan, the Diablo Canyon Voltage Support Project was approved to install a +150 Mvar/-75 Mvar dynamic voltage support (SVC) at the Diablo Canyon 230 kV bus. Following a study of credible double circuit transmission line contingencies it was found that local area RAS would be sufficient to mitigate all thermal and voltage concerns in the DCPP area. The local RAS is an interim mitigation until such time that Midway – Andrew goes into service at which point DCPP will have retired. It is recommended that the local RAS be used as a mitigation until DCPP retires in 2025 and thus this project is recommended to be canceled.

2.5.8.4 Request Window Submissions

Crazy Horse-Salinas 115 kV Lines

Pacific Gas and Electric (PG&E) proposed this project within the Crazy Horse-Salinas system.

The scope of this project is to reconductor CHCSS-Natividad and Natividad-Salinas sections of the CHCSS-Salinas-Soledad #1 and #2 115 kV lines to achieve at least 800 Amps under summer emergency conditions.

This project protect would mitigate the Category P6 and P7. The estimated cost of the project is expected to cost between $35 million to $42 million.

As indicated above, PG&E has identified that the overloaded lines have been identified in their maintenance plans to be rebuilt. The ISO is recommending PG&E to review the maintenance schedule for these lines, and when the lines are rebuilt as a part of the maintenance plan, the ISO recommends that the rating be increased to address the overloads. Until the maintenance upgrades for these facilities are in place, the ISO recommends PG&E install a SPS to mitigate the reliability constraints.

Lopez to Divide 500/230 kV Transmission System Project

NextEra Energy Resources, LLC proposed the Lopez to Divide 500/230 kV Transmission System project

The Lopez to Divide 500/230 kV Transmission System project is intended to mitigate Category P6, P7, P5 and P2 contingencies. The project scope is to:

- Build a new Lopez 500 kV ring bus to loop into Diablo-Midway #3 500 kV line.
- Install a new 230 kV substation Lopez and a new 230 kV Divide bus.
- Construct a new 24 mile line from Lopez substation to Divide substation.
- Install Lopez 500/230 kV and Divide 230/115 kV Transformers.

The project is intended to address the post contingency thermal and voltage collapse issues for P5, P6 and P7 contingencies. The submission does not address feasibility issues, such as zoning and other local permissions required to construct the new lines.

This project would address similar reliability issues to the previously approved Midway-Andrew 230 kV project, particularly the North of Mesa Upgrade, that is recommended to remain on hold.

Los Padres ACAES Project

Hydrostor proposed a 175 MW – 200 MW Advanced Compressed Air Energy Storage ("A-CAES") project to be connected to the PG&E Mesa 230 kV switchyard for the purpose of meeting reliability needs in the Los Padres area in the vicinity of Mesa/Santa Maria (see the

P27-129
cont.

Needs Identification section below). This project also offers options to provide long duration storage to address transmission line contingencies. Hydrostor proposed a 200 MW to 300 MW, 4-hour duration A-CAES system, which at this scale Hydrostor indicated would be ideally positioned to cost-effectively eliminate local voltage collapse and significantly mitigate concerns with thermal overload in this part of the grid. Hydrostor also indicated that the expected net cost to the ISO of such a solution would be $190M to $320M depending on the scale of the project and the associated ability to provide additional market services to the ISO-administered market and/or receive contracted offtake as a storage/resource adequacy asset. In addition as configured in the submission, the project would not address all of the reliability needs in the area such as the P6 contingency of the 230/115 kV transformers at Mesa substation.

2.5.8.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.8.2, about 46 and 86 MW of AAEE reduced the Central Coast and Los Padres Area net load by 3 and 6% in 2023 and 2028 respectively . This year's reliability assessment for Central Coast and Los Padres Area included the "high CEC forecast" sensitivity case for year 2023 which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2023 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reduction in net load:

Table 2.5-29: Reliability Issues in Sensitivity Studies

Facility	Category
30915 MORROBAY 230 30916 SOLARSS 230 1 1	P6
36027 SALINAS1 60.0 36054 SNBRN JT 60.0 1 1	P2
36260 SISQUOC 115 36286 PALMR 115 1 1	P2
36264 S.YNZ JT 115 36288 ZACA 115 1 1	P2
36266 SNTA MRA 115 36269 FRWAYTP 115 1 1	P6
36286 PALMR 115 36288 ZACA 115 1 1	P2
36353 ESTRELLA 70.0 36356 PSA RBLS 70.0 1 1	P2
36358 ATASCDRO 70.0 36362 CACOS J2 70.0 1 1	P2
36362 CACOS J2 70.0 36364 CAYUCOS 70.0 1 1	P2

Furthermore, about 29 MW of demand response and 0 MW of battery energy storage are modeled in Central Coast and Los Padres Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, didn't completely alleviate the overloads.

2.5.8.6 Recommendation

Based on the studies performed for the 2018-2019 Transmission Plan, several reliability concerns were identified for the PG&E Central Coast and Los Padres Area. These concerns

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consisted of thermal overloads and voltage concerns under Categories P2, P6, P5 and P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Central Coast and Los Padres Area.

In regards to the previously-approved on-hold projects, two projects hold in the Central Coast and Los Padres Area are recommended to be canceled in this cycle.

- Morro bay 230/115 kV Transformer Project
- Diablo Canyon Voltage Support Project

In regards the previously approved Midway-Andrew 230 kV project the ISO is recommending rescoping the project to the following scope and renaming it to the North Mesa Upgrade project.

- Build Andrew 230/115 kV substation, energize Diablo – Midway 500 kV line at 230 kV and connect to Andrew substation, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations.

To address reliability constraints in the Central Coast and Los Padres Area, the ISO recommends approval the following project.

- South Mesa Upgrade

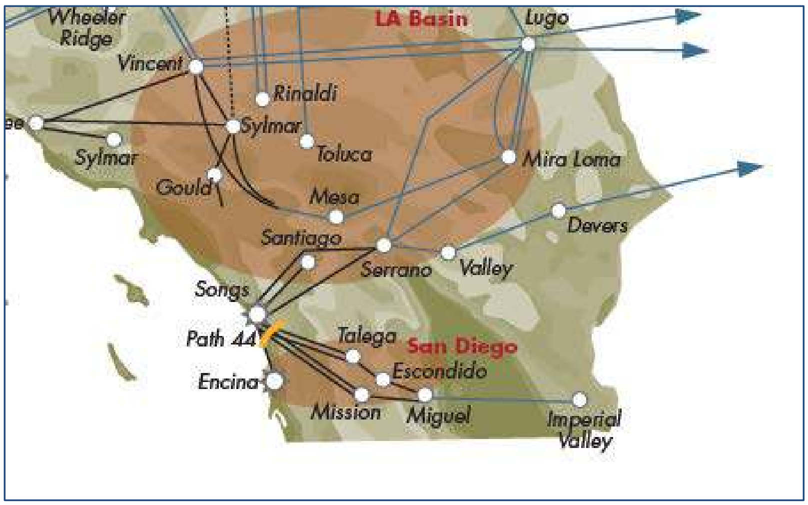
P27-129 cont.

2.6 Southern California Bulk Transmission System Assessment

2.6.1 Area Description

The southern California bulk transmission system primarily includes the 500 kV transmission systems of Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) companies and the major interconnections with Pacific Gas and Electric (PG&E), LA Department of Water and Power (LADWP) and Arizona Public Service (APS). Figure 2.6-1 provides an illustration of the southern California's bulk transmission system.

Figure 2.6-1: Southern California Bulk Transmission System



SCE serves about 15 million people in a 50,000 square mile area of central, coastal and southern California, excluding the City of Los Angeles[80] and certain other cities81. Most of the SCE load is located within the Los Angeles Basin. The CEC's gross load growth forecast for the SCE Transmission Access Charge (TAC) area is about 159 MW82 on the average per year; however, after considering the projection for mid additional achievable energy efficiency (AAEE) and additional achievable PV (AAPV) , the demand forecast is declining at an average rate of 130 MW per year[83]. The CEC's 1-in-5 load forecast for the SCE TAC Area includes the SCE service area, and the Anaheim Public Utilities, City of Vernon Light & Power Department, Pasadena Water and Power Department, Riverside Public Utilities, California Department of Water Resources and Metropolitan Water District of southern California pump loads. The 2028

P27-129 cont.

[80] The City of Los Angeles' power need is served by the Los Angeles Department of Water and Power.

[81] Cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Pasadena, Riverside and Vernon have electric utilities to serve their own loads. The City of Cerritos Electric Department serves city-owned facilities, public and private schools and major retail customers.

[82] Based on the CEC-adopted California Energy Demand Forecast 2018-2030 (Form 1.5c) – Mid Demand Baseline Case, No AAEE or AAPV Savings, February 2018 version

[83] Based on the CEC-adopted California Energy Demand Forecast 2018-2030 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE and AAPV Savings, February 2018 version

summer peak 1-in-5 forecast sales load, including system losses, is 22,814 MW[84]. The SCE area peak load is served by generation that includes a diverse mix of renewables, qualifying facilities, hydro and gas-fired power plants, as well as by power transfers into southern California on DC and AC transmission lines from the Pacific Northwest and the Desert Southwest.

SDG&E provides service to 3.4 million consumers through 1.4 million electric meters in San Diego and southern Orange counties. Its service area encompasses 4,100 square miles from southern Orange County to the U.S. and Mexico border. The existing points of imports are the South of SONGS[85] transmission path, the Otay Mesa-Tijuana 230 kV transmission line and the Imperial Valley Substation.

The 2028 summer peak 1-in-5 forecast load for the SDG&E area including Mid-AAEE and system losses is 4,405 MW. Most of the SDG&E area load is served by generation that includes a diverse mix of renewables, qualifying facilities, small pumped storage, and gas-fired power plants. The remaining demand is served by power transfers into San Diego via points of imports discussed above.

Electric grid reliability in southern California has been challenged by the retirement of the San Onofre Nuclear Generating Station and the expected retirement of power plants using ocean or estuarine water for cooling due to OTC regulations. In total, approximately 10,760 MW of generation (8,514 MW gas-fired generation and 2,246 MW San Onofre nuclear generation) in the region has been affected. A total of 4,662 MW of OTC-related electric generation has been retired since 2010. In the next three years, the remaining existing 6,138 MW of gas-fired generation is scheduled to retire to comply with the State Water Resources Control Board's Policy on OTC Plants. Some are scheduled to be replaced, such as Alamitos, Huntington Beach and Encina generation, albeit with lower capacity, through the CPUC long-term procurement plan for the local capacity requirement areas in the LA Basin and San Diego. Additionally, consistent with 2018-2019 transmission plan, the ISO has also taken into account the potential retirement of 2,194 MW of aging non-OTC and mothballed generation in the area.[86] P27-129 cont.

To offset the retirement of SONGS and OTC generation, the CPUC in the 2012 LTPP Track 1 and Track 4 decisions authorized SCE to procure between 1900 and 2500 MW of local capacity in the LA Basin area and up to 290 MW in the Moorpark area, and SDG&E to procure between 800 and 1100 MW in the San Diego area.[87] In May 2015, the CPUC issued Decision D.15-05-051 that conditionally approved SDG&E's application for entering into a purchase power and tolling agreement (PPTA) with Carlsbad Energy Center, LLC, for 500 MW. The Decision also

[84] Based on the CEC-adopted California Energy Demand Forecast 2018-2030 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE and AAPV Savings, February 2018 version

[85] The SONGS was officially retired on June 7, 2013.

[86] Includes generating units that are more than forty years of age, as well as units that have been mothballed by the owners.

[87] The CPUC Decisions D.13-02-015 (Track 1 for SCE), D.14-03-004 (Track 4 for SCE), D.13-03-029/D.14-02-016 (Track 1 for SDG&E), and D.14-03-004 (Track 4 for SDG&E).

required the residual 100 MW of requested capacity to consist of preferred resources or energy storage. In November 2015, the CPUC issued Decision D.15-11-041 to approve, in part, results of SCE's Local Capacity Requirements Request for Offers for the Western LA Basin. The Decision permitted SCE to enter into a PPTA for a total of 1812.6 MW of local capacity that includes 124.04 MW of energy efficiency, 5 MW of demand response, 37.92 MW of behind-the-meter solar photovoltaic generation, 263.64 MW of energy storage, and 1382 MW of conventional (gas-fired) generation. In this analysis, the ISO considered the authorized levels of procurement and then focused on the results thus far in the utility procurement process – which, in certain cases, is less than the authorized procurement levels.

As set out below, preferred resources and storage are expected to play an important role in addressing the area's needs. As the term "preferred resources" encompasses a range of measures with different characteristics, they have been considered differently. Demand side resources such as energy efficiency programs are accounted for as adjustments to loads, and supply side resources such as demand response are considered as separate mitigations. Further, there is a higher degree of uncertainty as to the quantity, location and characteristics of these preferred resources, given the unprecedented levels being sought and the expectation that increased funding over time will result in somewhat diminishing returns. While the ISO's analysis focused primarily on the basic assumptions set out below in section 2.6.2, the ISO has conducted and will continue to conduct additional studies as needed on different resources mixes submitted by the utilities in the course of their procurement processes.

P27-129 cont.

2.6.2 Area-Specific Assumptions and System Conditions

The southern California bulk transmission system steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to area load levels, load modifiers and generation dispatch assumptions for the various scenarios used for the southern California bulk transmission system assessment are provided below.

Table 2.6-1 Southern California bulk transmission load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2020 Summer Peak	Baseline	Summer peak load time (9/3 HE 16 PST)	26,112	511	2,400	1,561	24,040	436	502	70	6,899	3,588	4,204	1,515	1,216	414	19,660	7,370
B2	2023 Summer Peak	Baseline	Summer peak load time (8/31 HE 16 PST)	27,365	1,184	3,195	2,248	23,933	436	502	385	6,900	3,657	4,223	887	1,216	784	13,336	8,209
B3	2028 Summer Peak	Baseline	Summer peak load time (8/31 HE 16 PST)	28,445	2,462	5,296	3,260	22,722	436	502	409	9,687	5,134	4,372	918	1,257	364	13,942	6,908
B4	2020 Spring Light Loa	Baseline	Spring minimum net load time (4/9 HE 13 PST)	13,088	511	2,400	2,491	10,086	436	502	70	6,899	6,373	4,088	-	1,216	144	19,645	390
B5	2023 Spring Off-Peak	Baseline	Spring shoulder load time (4/17 HE 20 PST)	16,982	1,184	3,195	-	15,799	436	502	385	6,900	-	4,103	2,828	1,216	219	13,336	10,565
S1	2023 SP High CEC Loa	Sensitivit	2023 Summer Peak case with high CEC load forecast scenario	29,171	1,184	3,195	2,248	25,740	436	502	385	6,900	3,657	4,103	862	1,216	784	13,336	9,004
S2	2023 SOP Heavy Renewable Output & Min. Gas Gen.	Sensitivit	2023 Spring Off-Peak case with heavy renewable output and minimum gas generation commitment	21,478	1,184	3,195	2,248	15,799	436	502	385	6,900	6,772	4,103	2,828	1,216	12	13,336	8,111
S3	2020 SP Heavy Renewable Output & Min. Gas Gen.	Sensitivit	2020 Summer Peak case with heavy renewable output and minimum gas generation commitment	26,112	511	2,400	1,561	24,040	436	502	70	6,899	6,811	4,084	2,736	1,216	414	19,660	5,381

Notes:
DR and storage are modeled offline in starting base cases.

P27-129 cont.

Transmission Assumptions

All previously approved transmission projects were modeled in the southern California bulk transmission system assessment in accordance with the general assumptions described in section 2.3.

Path Flow Assumptions

Table 2.6-2 lists the transfers modeled on major paths in the southern California assessment.

Table 2.6-2: Path Flow Assumptions

Path	SOL/Transfer Capability (MW)	2020SP (MW)	2023SP (MW)	2028SP (MW)	2020 LL (MW)	2023 OP (MW)	2023SP w/High CEC Load (MW)	2023 OP Heavy Ren. (MW)	2023 SP Heavy Ren. (MW)
Path 26 (N-S)	4,000	3,887	3,779	3,629	278	290	4073	-1,262	2,557
PDCI (N-S)	3,220	3,220	3,220	3,220	-400	1,474	3,220	-1,000	3,220
SCIT	17,870	16,484	16,140	15,415	2,950	9,728	16,810	7,069	13,819
Path 46 (WOR)(E-W)	11,200	6,780	7,095	6,518	1,402	6,068	7,553	7,003	6,026
Path 49 (EOR)(E-W)	10,100	5,588	4,262	3,463	-262	3,506	4,287	3,301	4,978

P27-129 cont.

2.6.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix C.

Lugo-Victorville 500 kV thermal overload

The Lugo-Victorville 500 kV line was overloaded under several Category P6 conditions in the 2020 summer peak cases. The loading concern can be addressed in the operations horizon without relying on non-consequential load loss by such operational measures as re-dispatching resources and bypassing LADWP series capacitors after the initial contingency in accordance with existing operating procedures. The overload did not occur in the 2022 and 2027 cases due to the previously approved Lugo-Victorville 500 kV Transmission Line Upgrade Project.

The southern California bulk system assessment did not identify reliability concerns that require corrective action plans to meet TPL 001-4 requirements.

2.6.4 Request Window Project Submissions

The applicable local area sections below detail the request window submittals the ISO received in the current planning cycle and the results of the ISO evaluation.

2.6.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the southern California bulk transmission system assessment as follows.

- As indicated earlier, projected amounts of up to 2,462 MW of additional energy efficiency (AAEE), and up to 5,296 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 20 percent.
- The existing and planned fast-response demand response amounting 436 MW and energy storage amounting 409 MW were used to mitigate Category P6 related thermal overloads on Lugo-Victorville 500 kV line until the approved rating increase project is in service.
- Since no reliability issues that require mitigation were identified, incremental preferred resources and storage were not considered in the southern California bulk transmission system assessment.

2.6.6 Recommendation

The southern California bulk system assessment did not identify reliability concerns that require new corrective action plans to meet TPL 001-4 requirements. Loading concerns associated with the Lugo-Victorville 500 kV line will be addressed in the short term using existing operating procedures. In the longer term, the previously approved Lugo-Victorville 500 kV Transmission Line Upgrade Project will address the loading concern.

P27-129 cont.

2.7 SCE Local Areas Assessment

2.7.1 SCE Tehachapi and Big Creek Area

2.7.1.1 Area Description

The Tehachapi and Big Creek Corridor consists of the SCE transmission system north of Vincent substation. The area includes the following:

WECC Path 26 — three 500 kV transmission lines between PG&E's Midway substation and SCE's Vincent substation with Whirlwind 500 kV loop-in to the third line;

Tehachapi area — Windhub-Whirlwind 500 kV, Windhub – Antelope 500 kV, and two Antelope-Vincent 500 kV lines;

230 kV transmission system between Vincent and Big Creek Hydroelectric project that serves customers in Tulare county; and

Antelope-Bailey 230 kV system which serves the Antelope Valley, Gorman, and Tehachapi Pass areas.

The Tehachapi and Big Creek Corridor area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 2194 MW in 2028 including the impact of 841 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 229 MW of additional achievable energy efficiency (AAEE).

The ISO has approved the following major transmission projects in this area in prior planning cycles:

- San Joaquin Cross Valley Loop Transmission Project (completed);
- Tehachapi Renewable Transmission Project (completed);
- East Kern Wind Resource Area 66 kV Reconfiguration Project (completed); and
- Big Creek Corridor Rating Increase Project (in-service date: 2019).

2.7.1.2 Area-Specific Assumptions and System Conditions

The SCE Tehachapi and Big Creek Corridor Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the Tehachapi and Big Creek Corridor area study are provided below.

The SCE Tehachapi and Big Creek Corridor area study included five base and three sensitivity scenarios as described below.

P27-129
cont.

Table 2.7-1 Tehachapi and Big Creek Areas load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2020 Summer Peak	Baseline	2020 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	2,574.2	47.3	527.0	267.8	2,259.1	0	0	0	2,874	1,494	3,491	1,257	1,093	339	2,028	1,232
B2	2023 Summer Peak	Baseline	2023 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	2,709.9	109.2	527.0	344.2	2,256.5	0	0	0	2,873	1,523	3,494	734	1,093	331	2,029	1,232
B3	2028 Summer Peak	Baseline	2028 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	2,883.8	229.5	841.0	460.2	2,194.1	0	0	0	4,686	2,484	3,642	765	1,093	332	2,029	732
B4	2020 Spring Light Load	Baseline	2020 spring light load conditions. Off-peak load time – weekend morning.	1,428.5	47.3	527.0	453.5	927.7	0	0	0	2,874	2,514	3,491	0	1,093	1,002	2,028	-144
B5	2021 Spring Off-Peak	Baseline	2023 spring off-peak load conditions. Off-peak load time – weekend morning.	1,465.8	109.2	527.0	0.0	1,356.6	0	0	0	2,873	0	3,494	2,408	1,093	939	2,029	749
S1	2023 SP High CEC Load	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	2,842.7	109.2	527.0	344.2	2,389.3	0	0	0	2,873	1,523	3,494	734	1,093	889	2,029	1,477
S2	2023 SOP Heavy Renewable Output & Min. Gas Gen	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	1,656.8	109.2	527.0	191.0	1,356.6	0	0	0	2,873	2,836	3,494	2,408	1,093	586	2,029	375
S3	2020 SP Heavy Renewable Output & Min. Gas Gen	Sensitivity	2020 summer peak load conditions with hi renewable dispatch sensitivity	2,663.9	47.3	527.0	357.5	2,259.1	0	0	0	2,874	2,846	3,491	2,339	1,093	519	2,028	953

P27-129
cont.

Demand-Side Assumptions

The summer peak base cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table above provides the demand-side assumptions used in the Tehachapi and Big Creek Corridor area assessment including the impact of BTM PV and AAEE. The load values include distribution system losses.

Supply-Side Assumptions

The table above provides a summary of the supply-side assumptions modeled in the Tehachapi and Big Creek Corridor Area assessment including conventional and renewable generation, demand response and energy storage. A detailed list of existing generation in the area is included in Appendix A.

For the summer peak base cases, the ISO relied on previous analysis of real time Big Creek generation data from summer 2015 to represent the period of lowest hydro generation. Based on that, the ISO modeled total hydro generation of approximately 330 MW in the Big Creek area. For the light load and off peak base cases a high hydro generation level was modeled.

Transmission Assumptions

All previously approved transmission projects were modeled in the Tehachapi and Big Creek Corridor Area assessment in accordance with the general assumptions described in section 2.3.

2.7.1.3 Assessment Summary

P27-129 cont.

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE Tehachapi and Big Creek Corridor area steady state assessment identified several Category P6 related thermal overloads under contingency conditions. The identified issues can be mitigated in the operations horizon without relying on non-consequential load loss, by such operational measures as reconfiguring the system or re-dispatching resources after the initial or second contingency as discussed in Appendix B. As a result, system additions and upgrades were not identified as needed for the Tehachapi and Big Creek Corridor area.

The stability analysis performed in the Tehachapi and Big Creek Corridor area base case assessment identified several Category P5 transient issues. There are several protection projects coming into service to mitigate these issues as discussed in Appendix B.

2.7.1.4 Request Window Project Submissions

The ISO did not receive request window submissions for the SCE Tehachapi and Big Creek Corridor Area in this planning cycle.

2.7.1.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the SCE Tehachapi and Big Creek Corridor Area assessment as follows.

- As indicated earlier, projected amounts of up to 229 MW additional energy efficiency (AAEE), and up to 841 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 15 percent.
- The Tehachapi and Big Creek Corridor Area assessment did not identify a need for additional preferred and storage resources in the area.

2.7.1.6 Recommendation

The SCE Tehachapi and Big Creek Corridor area assessment identified several category P6 related thermal overloads. Operating solutions including dispatching existing and planned preferred resources and energy storage under contingency conditions are recommended to address these issues.

P27-129 cont.

2.7.2 SCE North of Lugo Area

2.7.2.1 Area Description

The North of Lugo (NOL) transmission system serves San Bernardino, Kern, Inyo and Mono counties. The figure below depicts the geographic location of the north of Lugo area, which extends more than 270 miles.

The North of Lugo electric transmission system is comprised of 55 kV, 115 kV and 230 kV transmission facilities. In the north, it has inter-ties with Los Angeles Department of Water and Power (LADWP) and Sierra Pacific Power. In the south, it connects to the Eldorado Substation through the Ivanpah-Baker-Cool Water-Dunn Siding-Mountain Pass 115 kV line. It also connects to the Pisgah Substation through the Lugo-Pisgah Nos. 1&2 230 kV lines. Two 500/230 kV transformer banks at the Lugo substation provide access to SCE's main system. The NOL area can be divided into the following sub-areas: north of Control; Kramer/North of Kramer/Cool Water; and Victor specifically.

P27-129 cont.

2.7.2.2 Assumptions and System Conditions

The North of Lugo area steady state and transient stability assessment was performed consistently with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the North of Lugo area study are provided below.

Table 2.7-2 North of Lugo Area load and generation assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV MW)		Net Load (MW)	Demand Response (MW)		Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed	Output		Fast	Slow		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2020 Summer Peak	1078	17	543	255	805	35	59	0	898	467	0	0	74	57	1381	1138
B2	2023 Summer Peak	1194	38	727	349	807	35	59	0	898	476	0	0	74	0	1381	1232
B3	2028 Summer Peak	1350	80	1006	483	787	35	59	0	1876	994	0	0	74	52	1381	1173
B4	2020 Spring Light Load	684	10.95	543	407	266	35	59	0	898	870	0	0	74	0	1381	512
B5	2023 Spring Off-peak	576	18.42	727	0	557	35	59	0	898	0	0	0	74	53	1381	986
S1	2023 SP High CEC Load	1259	38	727	349	872	35	59	0	898	476	0	0	74	0	1381	1235
S2	2023 SOP Heavy Renewable Output & Min. Gas Gen	576	18.42	727	0	557	35	59	0	898	882	0	0	74	53	1381	951
S3	2020 SP Heavy Renewable Output & Min. Gas Gen.	1078	17	543	255	805	35	59	0	898	886	0	0	74	57	1381	226

P27-129 cont.

All previously approved transmission projects were modeled in the North of Lugo area assessment in accordance with the general assumptions described in section 2.3. The following previously approved transmission upgrades were modeled in the 2020, 2023 and 2028 study cases:

- Victor Loop-in Project: Loop in the existing Kramer-Lugo Nos. 1&2 230 kV lines into Victor Substation.
- Kramer Reactor Project: Install two 23 Mvar reactors to the 12 kV tertiary winding of the existing 230/115 kV Nos. 1&2 transformers and one 45var shunt reactor at the Kramer 230 kV bus.

2.7.2.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The 2018-2019 reliability assessment of the North of Lugo area has identified several thermal overloads and low voltages issues under Category P6 contingencies. All of those issues can be mitigated in the operation horizon by relying upon the existing operating procedure or utilizing congestion management. Appendix B has a detailed discussion.

The transient stability assessment identified a voltage recovery and voltage dip violation following a Category P6 contingency with the existing RAS activated. The ISO recommends redispatching generation after the first contingency and reviewing the HDPP and Mohave Desert RAS schemes and modification if needed. P27-129 cont.

2.7.2.4 Request Window Project Submissions

The ISO received three request window submissions for the North of Lugo area in this planning cycle. Below is a description of the submissions followed by ISO comments and findings:

Control-Silver Peak 55 kV Line Rebuild

The project was submitted by Southern California Edison. The project consists of a tear down and rebuild of the existing Control-Silver Peak "A" and "C" 55 kV circuits as part of the SCE's Transmission Line Remediation Rating (TLRR) Program. The rebuild would take place from the SCE Control Substation to point of change of ownership with NVE. The estimated cost of the project is $60 to $75 million. The proposed in-service date is December 31, 2025.

The objectives of the proposed project include reduction in customer outages with the new shield wire, hardening of the circuits in a Cal Fire threat severity zone and reduction of weather related outages. The project would also reduce environmental impact due to the elimination of one circuit on a separate tower line. The ISO has reviewed the submittal and has not identified any concerns with the project. ISO approval is not required for SCE to proceed with this project.

Ivanpah to Control Segment 3 Rebuild & Derate

The project was submitted by Southern California Edison. The project consists of a tear down and rebuild of the existing Coolwater-Kramer 115 kV line with new double-circuit lines while derating the Kramer-Tortilla and Coolwater-SEGS-Tortilla 115kV lines as part of the SCE's Transmission Line Remediation Rating (TLRR) Program. The rebuild would take place from the SCE Kramer Substation to SCE Coolwater Substation. The estimated cost of the project is $35 to $50 million. The proposed in-service date is January 1, 2025.

The objectives of the proposed project include reduction in customer outages with the new shield wire, reduction of weather related outages and increased aesthetic impact for towers upgraded to a double circuit configuration. The ISO has reviewed the submittal and has not identified any concerns with the project. ISO approval is not required for SCE to proceed with this project.

<u>Ivanpah to Control Segment 4 Baker Ring Bus & Derate</u>

The project was submitted by Southern California Edison. The project consists of installing a ring bus at Baker Substation while derating the Coolwater-Dunn Siding, Dunn Siding-Baker, Baker-Mountain Pass, Mountain Pass-Ivanpah 115kV lines as part of the SCE's Transmission Line Remediation Rating (TLRR) Program for the purpose of mitigating electrical clearance issues on the SCE system in support of NERC reliability and in compliance with CPUC's General Order 95. The ring bus installation would take place at SCE's Baker Substation.

The proposed project on the Coolwater-Dunn Siding-Baker-Mountain Pass-Ivanpah 115 kV line consists of converting the tap bus configuration at Baker Substation into a ring bus that is normally closed. Under heavy loading condition where the line sagging poses potential clearance issues, the ring bus will open which will split the original line into Coolwater-Dunn Siding-Baker 115kV line and Ivanpah-Mountain Pass-Baker 115kV line, resulting in a reduced flow which effectively eliminates the overhead clearance issues.

Figure 2.7-1 Existing Configuration

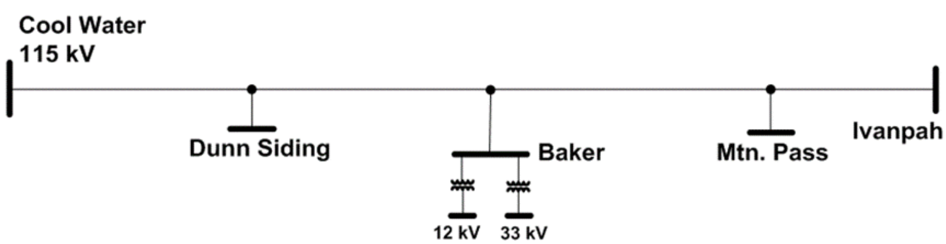
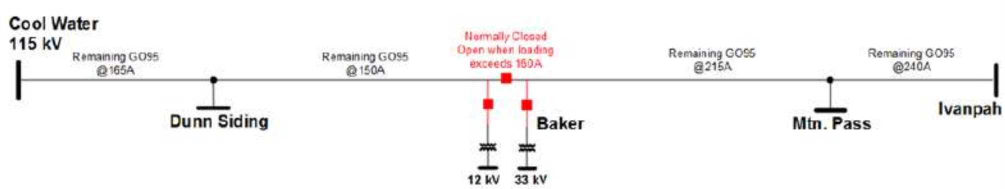


Figure 2.7-2 Proposed Configuration



P27-129
cont.

The estimated cost of the project is $8 to $15 million. The proposed in-service date is December 31, 2025.

The objectives of the proposed project include reduction of environmental impacts due to a reduction in line construction, and reduction of outages that impact all loads served out of the Baker, Dunn Siding and Mountain Pass substations. The ISO has reviewed the submittal and has not identified any concerns with the project. ISO approval is not required for SCE to proceed with this project.

2.7.2.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the North of Lugo area assessment as follows.

- Projected amounts of up to 80 MW additional achievable energy efficiency (AAEE), and up to 483 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 42 percent.
- The existing and planned fast-response demand response amounting to 94 MW was identified and available in the base and sensitivity cases, but did not need to be activated to address any local transmission concerns in this analysis.
- The NOL Area assessment did not identify a need for additional preferred and storage resources in the area.

2.7.2.6 Recommendation

The North of Lugo area assessment identified several category P6 related thermal overloads and low voltage issues. Operating solutions, including relying upon existing operating procedures and congestion management are recommended to address the issues.

The assessment also identified one transient voltage recovery and voltage dip violation for a category P6 contingency with existing HDPP and Mohave Desert RAS schemes. The ISO recommends rely on generation redispatch after the first contingency and reviewing the existing RAS schemes and modification if needed.

P27-129 cont.

2.7.3 SCE East of Lugo Area

2.7.3.1 Area Description

The East of Lugo (EOL) area consists of the transmission system between the Lugo and Eldorado substations. The EOL area is a major transmission corridor connecting California with Nevada and Arizona; is a part of Path 46 (West of River), and is heavily integrated with LADWP and other neighboring transmission systems. The SDG&E owned Merchant 230 kV switchyard became part of the ISO controlled grid and now radially connects to the jointly owned Eldorado 230 kV substation. Merchant substation was formerly in the NV Energy balancing authority, but after a system reconfiguration in 2012, it became part of the ISO system. The Harry Allen-Eldorado 500 kV line was approved by the ISO Board of Governors in 2014, is expected to be operational in 2020, and will be part of the EOL system.

The existing EOL bulk system consists of the following:

- 500 kV transmission lines from Lugo to Eldorado and Mohave;
- 230 kV transmission lines from Lugo to Pisgah to Eldorado;
- 115 kV transmission line from Cool Water to Ivanpah; and
- 500 kV and 230 kV tie lines with neighboring systems.

2.7.3.2 Area-Specific Assumptions and System Conditions

The East of Lugo area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the East of Lugo area study are provided below.

P27-129 cont.

Table 2.7-3 East of Lugo Area load and generation assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV MW)		Net Load (MW)	Demand Response (MW)		Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed	Output		Fast	Slow		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2020 Summer Peak	3.46	0	0	0	3.46	0	0	0	1254	652	0	0	0	0	525	330
B2	2023 Summer Peak	3.75	0	0	0	3.75	0	0	0	1254	665	0	0	0	0	525	330
B3	2028 Summer Peak	4.11	0	0	0	4.11	0	0	0	1889	1001	0	0	0	0	525	0
B4	2020 Spring Light Load	1.14	0	0	0	1.14	0	0	0	1254	1196	0	0	0	0	525	0
B5	2023 Spring Off-peak	2.56	0	0	0	2.56	0	0	0	1254	0	0	0	0	0	525	525
S1	2023 SP High CEC Load	3.96	0	0	0	0	0	0	0	1254	665	0	0	0	0	525	525
S2	2023 SOP Heavy Renewable Output & Min. Gas Gen	2.56	0	0	0	0	0	0	0	1254	1234	0	0	0	0	525	520
S3	2020 SP Heavy Renewable Output & Min. Gas Gen.	3.46	0	0	0	0	0	0	0	1254	1241	0	0	0	0	525	0

P27-129 cont.

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3. The transmission upgrade modeled in the 2020 study cases are:

- Harry Allen-Eldorado 500 kV transmission line

The transmission upgrades modeled in the 2023 and 2028 study cases are:

- Eldorado-Lugo 500 kV series capacitor and terminal equipment upgrade
- Lugo-Mohave 500 kV series capacitor and terminal equipment upgrade
- New Calcite 230 kV Substation and loop into Lugo-Pisgah #1 230 kV line
- Lugo-Victorville 500 kV terminal equipment upgrade and remove ground clearance limitations

2.7.3.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE East of Lugo area steady state assessment identified two Category P1 thermal overloads in the off-peak and /or sensitivity cases and one Category P6 system divergence issue in all cases. The thermal overloading issues could be mitigated by the previously approved transmission project, existing RAS and generation redispatch. The system divergence issue could be mitigated by an existing protection scheme. The stability analysis performed in the EOL Area assessment did not identify transient issues that require mitigation. P27-129 cont.

As a result, system additions and upgrades are not identified for the East of Lugo area.

2.7.3.4 Request Window Project Submissions

The ISO did not receive request window submissions for the SCE East of Lugo area in this planning cycle.

2.7.3.5 Consideration of Preferred Resources and Energy Storage

The SCE East of Lugo area is comprised of high voltage transmission lines and generation facilities with limited customer load, so the assessment did not identify a need for preferred resources and energy storage in the area.

2.7.3.6 Recommendation

The SCE East of Lugo area assessment identified two Category P1 thermal overloads. The issues can be mitigated by the previously approved transmission projects, existing RAS and generation redispatch. The assessment also identified one potential system divergence issue for a Category P6 outage which would be mitigated by an existing protection scheme.

2.7.4 SCE Eastern Area

2.7.4.1 Area Description

The ISO controlled grid in the SCE Eastern Area serves the portion of Riverside County around Devers Substation. The figure below depicts the geographic location of the area. The system is composed of 500 kV, 230 kV and 161 kV transmission facilities from Vista Substation to Devers Substation and continues on to Palo Verde Substation in Arizona. The area has ties to Salt River Project (SRP), the Imperial Irrigation District (IID), Metropolitan Water District (MWD), and the Western Area Lower Colorado control area (WALC).

The ISO has approved the following major transmission projects in this area in prior planning cycles:

- Path 42 Upgrade Project (2016);
- West of Devers Upgrade Project (2021), and
- Delaney-Colorado River 500 kV line Project (2021).

2.7.4.2 Area-Specific Assumptions and System Conditions

The SCE Eastern Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. The summer peak base cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The load values include distribution system losses. The spring light load and spring off-peak cases assume approximately 31 percent and 69 percent of the net peak load respectively. Specific assumptions related to study scenarios, load, resources and transmission that were applied to the Eastern area study are provided below.

P27-129 cont.

Table 2.7-4 Eastern Area load and generation assumptions

S. No.	Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Fast	Slow		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	20 Peak	Baseline	2020 summer peak load conditions on 9/3/2020 at hour 16	5,074	109	716	336	4,628	70	19	0	1409	733	586	212	0	0	4,350	2,233
2	23 Peak	Baseline	2023 summer peak load conditions on 8/31/2023 at hour 16	5,423	240	1,001	481	4,702	70	19	0	1659	879	602	126	0	0	4,350	2,661
3	28 Peak	Baseline	2028 summer peak load conditions on 8/31/2028 at hour 16	5,770	484	1,474	707	4,579	70	19	0	1657	878	602	126	0	0	4,350	2,612
4	20 Light Load	Baseline	2020 spring off peak load conditions on 4/9/2020 at hour 13	2,097	109	716	537	1,451	70	19	0	1409	1367	589	0	0	0	4,350	11
5	23 Off Peak	Baseline	2023 spring off peak load conditions on 4/17/2023 at hour 20	3,483	240	1,001	0	3,244	70	19	0	1659	0	602	415	0	0	4,350	3,222
6	20 Peak High CEC Load	Sensitivity	2020 summer peak load conditions with high CEC Load	5,714	240	1,001	481	4,993	70	19	0	1659	879	602	126	0	0	4,350	2,968
7	23 Off Peak HR	Sensitivity	2023 spring off peak load conditions with high renewable dispatch	3,964	240	1,001	481	3,244	70	19	0	1659	1606	602	415	0	0	4,350	2,098
8	20 Peak HR	Sensitivity	2020 summer peak load conditions with high renewable dispatch	5,074	109	716	336	4,628	70	19	0	1409	1378	586	392	0	0	4,350	425

P27-129 cont.

Transmission Assumptions

All previously approved transmission projects were modeled in the Eastern Area assessment in accordance with the general assumptions described in section 2.3.

2.7.4.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE Eastern area steady state assessment identified several Category P6 and P7 contingency-related thermal overloads. The issues identified can be mitigated in the operations horizon without relying on non-consequential load loss by such operational measures as curtailing generation before the contingency or reconfiguring the system after the initial or second contingency as discussed in Appendix B. The stability analysis performed in the Eastern Area assessment did not identify transient issues that require mitigation.

As a result, system additions and upgrades are not identified for the Eastern area.

2.7.4.4 Request Window Project Submissions

The ISO received a number of request window submissions for the SCE Eastern Area in this planning cycle. Below is a description of each proposal followed by ISO comments and findings.

P27-129 cont.

Etiwanda-Vista 230 kV Transmission Line Upgrade Project

The project was submitted by SCE and involves upgrading the existing Etiwanda-Vista 230 kV transmission line. SCE's Transmission Line Rating Remediation (TLRR) Program is scheduled to upgrade 5 out of the 18 conductor spans. SCE proposes to upgrade the remaining 13 spans to increase the line rating to a 4-hour emergency capacity of 3350 Amps. The project has an estimated cost of $3 to $6 million and expected operating date of December 31, 2021.

The project has not been found to be needed in this planning cycle. There was no overloading found on the line under N-1 or N-2 contingencies.

Mountainview RAS Modification

The project was submitted by SCE as an alternative lower cost option to the Etiwanda-Vista 230 kV Transmission Line Upgrade Project. The modified RAS has completely redundant and diversely routed communication facilities that will monitor the loading on the Etiwanda-Vista 230 kV line. It also includes supervisory logic to address RAS misoperation concerns. If a thermal overload is detected in a westbound direction on the line, the RAS will trip Mountainview and Sentinel generation accordingly until the thermal overload is relieved. The project has an estimated cost of $2 to $5 million, and the expected operating date is aligned with the West of Devers Project's operating date of December 31, 2021. The project has not been found to be needed in this planning cycle. There was no overloading found on the line under N-1 or N-2 contingencies.

Red Bluff-Mira Loma 500 kV Transmission Project

The project was submitted by NextEra Energy Transmission West LLC and involves construction of a new 139-mile 500 kV transmission line between Red Bluff 500 kV substation and Mira Loma 500 kV substation. The project has an estimated cost of $850 million and expected in-service date of December 1, 2024.

The need for this project was assessed as part of the 2016-17 and 2017-18 ISO transmission planning cycle and was not found to be needed. The project has also not been found to be needed for reliability reasons in this planning cycle. There was no overloading found in the Colorado River corridor under N-1 or N-2 contingencies after tripping generators by the Colorado River Corridor and Devers RAS. The project was also submitted as an economic study request as set out in chapter 4.

Red Bluff-Lugo-Victorville 500 kV Transmission Project

The project was submitted by NextEra Energy Transmission West LLC and involves construction of a new 154-mile 500 kV transmission line between Red Bluff 500 kV substation and Victorville-Lugo 500 kV transmission line tap with 50% compensation. The project has an estimated cost of $1.011 billion and expected in-service date of December 1, 2024.

The project has not been found to be needed in this planning cycle. There was no overloading found in the Colorado River corridor under N-1 or N-2 contingencies after tripping generators by the Colorado River Corridor and Devers RAS.

P27-129 cont.

Colorado River 230 kV Bus-Julian Hinds 230 kV

The project involves converting the existing privately owned Buck Blvd - Julian Hinds 230 kV generation tie-line into a network facility by way of segmenting the gen-tie line and connecting one terminal of both segments into the Colorado River Substation 230 kV bus. It creates a networked facility identified as Colorado River - Julian Hinds 230 kV line, and a revised 230 kV gen-tie line identified as Buck Blvd - Colorado River 230 kV line. The Colorado River - Julian Hinds 230 kV line would have 117 Smart Wires Power Guardian 700-1150 devices (~19.58 Ω/phase) in series with the line. These Power Guardians will be set to switch into injection mode to limit the power flow on the Julian Hinds - Mirage 230 kV line to avoid potential overloads. The project has an estimated cost of $67 million and expected in-service date of June 1, 2020.

The need for a similar project was assessed as part of the 2014-15 and 2016-17 ISO transmission planning cycle and was not found to be needed. The project with the inclusion of the Smart Wires devices was carried over and reviewed in this planning cycle, and again has not been found to be needed for reliability purposes. However, power flow analysis was performed on the project to determine if it should be further considered as an economic-driven project. It was found that with the project modeled in the 2017-2018 TPP S4 Heavy Renewables sensitivity case, with the Smart Wires devices on the Colorado River - Julian Hinds 230 kV line fully activated, the Julian Hinds - Mirage 230 kV line was heavily overloaded under contingency conditions. However, AltaGas has proposed a RAS that would open the overloaded line created by this proposed project during this contingency condition. While working with AltaGas in previous transmission cycles, the ISO has raised concerns about the use of a RAS to open this proposed transmission line. This new RAS would be in addition to the existing RAS that also drops over 1000 MW of generation. The ISO has also raised concerns that the new RAS proposed by AltaGas would leave the Blythe gas fired generation connected to the Colorado River 230 kV bus and would cause deliverability impacts on the existing generation in the area. AltaGas has requested that the ISO assess this deliverability impact with the proposed revisions to the ISO Generation Deliverability Methodology, once they are finalized. In the interim, AltaGas has also asked the ISO to reevaluate the economic benefits of their proposed project. Please see Chapter 4 for this analysis.

2.7.4.5 Consideration of Preferred Resources and Energy Storage

No additional grid-connected preferred resources or storage was modeled in the SCE Eastern Area, and the assessment did not identify a need for additional preferred and storage resources in the area.

2.7.4.6 Recommendation

The SCE Eastern area assessment identified several category P6 and P7 related thermal overloads. Operating solutions including curtailing generation before the contingency or reconfiguring the system after the initial or second contingency are recommended to address the issues.

P27-129
cont.

2.7.5 SCE Metro Area

2.7.5.1 Area Description

The SCE Metro area consists of 500 kV and 230 kV facilities that serve major metropolitan areas in the Los Angeles, Orange, Ventura counties and surrounding areas. The points of interconnections with the external system include Vincent, Mira Loma, Rancho Vista and Valley 500 kV Substations and Sylmar, San Onofre and Pardee 230 kV Substations. The bulk of SCE load as well as most southern California coastal generation is located in the SCE Metro area.

The Metro area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 18,192 MW in 2028 including the impact of 4,229 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 1,473 MW of additional achievable energy efficiency (AAEE).

The area had approximately 10,913 MW of grid-connected generation at the beginning of the current planning cycle of which a total of 6410 MW of generation has since been or is scheduled to be retired by the end of 2020 to comply with the state's policy regarding once-through-cooled (OTC) generation or for economic reasons. The California Public Utilities Commission (CPUC) has approved a total of 2,086 MW of conventional generation and preferred resources for the area to offset the local capacity deficiency resulting from the retirement of the San Onofre Generating Station and the OTC generating plants.

The ISO has approved the following major transmission projects in this area in prior planning cycles:

- Mesa 500 kV Substation (3/1/2022);
- Laguna Bell Corridor Upgrade (3/1/2022);
- Method of Service for Alberhill 500/115 kV Substation (6/1/2021);
- Method of Service for Wildlife 230/66 kV Substation (7/1/2023); and
- Moorpark-Pardee No. 4 230 kV Circuit Project (12/31/2020).

2.7.5.2 Area-Specific Assumptions and System Conditions

The SCE Metro Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for the various scenarios used for the SCE Metro Area assessment are provided in Table 2.7-5 below.

P27-129 cont.

Table 2.7-5: Metro Area load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2020 Summer Peak	Baseline	Summer peak load time (9/3 HE 16 PST)	19,887	317	2,000	940	18,630	287	384	70	12	6	0	0	10	0	9,712	4,543
B2	2023 Summer Peak	Baseline	Summer peak load time (8/31 HE 16 PST)	19,938	707	2,738	1314	17,917	287	384	385	12	6	0	0	10	0	6,022	4,653
B3	2028 Summer Peak	Baseline	Summer peak load time (8/31 HE 16 PST)	21,695	1473	4,229	2030	18,192	287	384	409	12	5	0	0	10	0	6,022	4,388
B4	2020 Spring Light Loa	Baseline	Spring minimum net load time (4/9 HE 13 PST)	7,392	105	1,882	1412	5,875	287	384	70	12	11	0	0	10	0	9,712	35
B5	2023 Spring Off-Peak	Baseline	Spring shoulder load time (4/17 HE 20 PST)	13,396	488	2,883	-	12,908	287	384	385	12	0	0	0	10	0	6,022	3,285
S1	2023 SP High CEC Loa	Sensitivity	2023 Summer Peak case with high CEC load forecast scenario	21,189	879	2,738	1314	18,996	287	384	385	12	6	0	0	10	0	6,022	4,853
S2	2023 SOP Heavy Renewable Output & Min Gas Gen	Sensitivity	2023 Spring Off-Peak case with heavy renewable output and minimum gas generation commitment	14,710	488	1,883	1314	12,908	287	384	385	12	11	0	0	10	0	6,022	1,888
S3	2020 SP Heavy Renewable Output & Min Gas Gen	Sensitivity	2020 Summer Peak case with heavy renewable output and minimum gas generation commitment	19,887	317	2,000	940	18,630	287	384	70	12	11	0	0	10	0	9,712	4,504

P27-129 cont.

Transmission Assumptions

All previously approved transmission projects were modeled in the Metro Area assessment in accordance with the general assumptions described in section 2.3.

2.7.5.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE Metro area steady state assessment identified several category P6 and one category P7 related thermal overloads under various contingency conditions. The issues identified can be mitigated in the operations horizon without relying on non-consequential load loss by such operational measures as reconfiguring the system or re-dispatching resources before or after the contingency as discussed in Appendix B.

The steady state assessment identified low voltages at Goleta substation in all summer peak cases under category P0, P1, P3 and P6 conditions. The 2020 summer peak assessment was performed assuming Ellwood and Ormond Beach generating facilities will be unavailable based on the notice NRG gave earlier this year announcing both facilities will be retired by the end of the current year. In response to local capacity needs identified by the ISO, the facilities are now under contract for their capacity, and NRG has recently withdrawn its notice and announced that it no longer intends to retire these generating facilities on the schedule set out in the notice. With these generating facilities available until the end of 2020, voltages at Goleta can be maintained within acceptable limits under normal and contingency conditions. P27-129 cont.

Beyond 2020, Ormond Beach is expected to retire in accordance with the OTC compliance schedule and Ellwood is expected to be replaced with preferred rescources and energy storage SCE is currently in the process of procuring to meet the local capacity need in the Santa Clara area. The ISO is working with SCE to ensure the selected portfolio of resources will address the low voltage issue in the longer term.

The stability analysis performed in the Metro Area assessment did not identify transient stability issues that require mitigation.

As a result, no new corrective action plans were found to be needed for the Metro area to meet TPL 001-4 requirements.

2.7.5.4 Request Window Project Submissions

The ISO did not receive request window submittals for the SCE Metro Area in this planning cycle.

2.7.5.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the SCE Metro Area assessment as follows.

- As indicated earlier, projected amounts of up to 1,473 MW of additional energy efficiency (AAEE), and up to 4,229 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 16 percent.
- The existing and planned fast-response demand response amounting 287 MW and energy storage amounting 409 MW were used in the base or sensitivity cases to mitigate category P6 related thermal overloads on Serrano 500/230 kV transformers and the Mesa-Laguna Bell No.1 230 kV line.
- Incremental preferred resources and energy storage are being considered in the Santa Clara area to address local capacity need.

2.7.5.6 Recommendation

The SCE Metro area assessment identified several thermal overloads under contingency conditions. Operating solutions, such as reconfiguring the system or re-dispatching resources before or after the contingency conditions as described in more detail in Appendix B, are recommended to address the thermal loading issues.

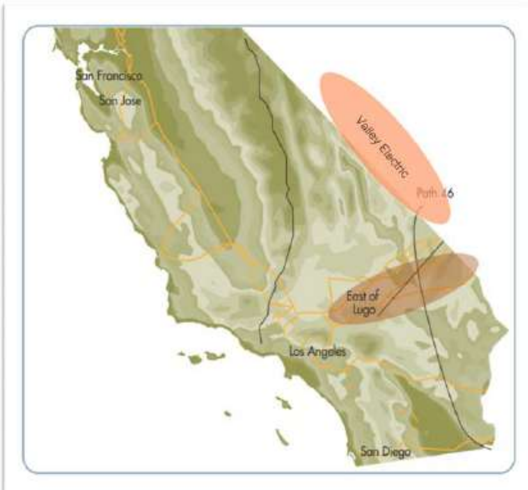
The assessment also identified low voltages at Goleta substation in all summer peak cases under category P0, P1, P3 and P6 conditions. Continued operation of Ellwood and Ormond Beach until 2021 will address the problem in the short-term. The ISO is working with SCE to ensure the selected portfolio of local capacity resources being procured to replace these facilities will continue to address the low voltage concern in the longer term.

P27-129 cont.

2.8 Valley Electric Association Area

2.8.1 Area Description

The Valley Electric Association (VEA) transmission system is comprised of 230 kV and 138 kV facilities under ISO control. GridLiance West Transco, LLC is now the Transmission Owner for the 230 kV facilities in the VEA area. All the distribution load in the VEA area is supplied from the 138 kV system which is mainly supplied through 230/138 kV transformers at Innovation, Pahrump and WAPA's Amargosa substations. The Innovation and Pahrump 230 kV substations are connected to the NV Energy's Northwest and WAPA's Mead 230 kV substations through two 230 kV lines.



The VEA system is electrically connected to neighboring systems through the following lines:

- Amargosa – Sandy 138 kV tie line with WAPA;
- Jackass Flats – Lathrop Switch 138 kV tie line with NV Energy (NVE);
- Mead – Pahrump 230 kV tie line with WAPA; and
- Northwest – Desert View 230 kV tie line with NV Energy.

2.8.2 Area-Specific Assumptions and System Conditions

The Valley Electric Association area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the VEA area study are provided below.

P27-129 cont.

Table 2.8-1: VEA Area load and generation assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV MW (MW) Installed	BTM-PV MW (MW) Output	Net Load (MW)	Demand Response (MW) Fast	Demand Response (MW) Slow	Installed Battery Storage (MW)	Solar Installed (MW)	Solar Dispatch (MW)	Wind Installed (MW)	Wind Dispatch (MW)	Hydro Installed (MW)	Hydro Dispatch (MW)	Thermal Installed (MW)	Thermal Dispatch (MW)
B1	2020 Summer Peak	152	0	0	0	152	0	0	0	15	7	0	0	0	0	0	0
B2	2023 Summer Peak	153	0	0	0	153	0	0	0	102	54	0	0	0	0	0	0
B3	2028 Summer Peak	164	0	0	0	164	0	0	0	1113	589	0	0	0	0	0	0
B4	2020 Spring Light Load	124	0	0	0	124	0	0	0	15	11	0	0	0	0	0	0
B5	2023 Spring Off-peak	108	0	0	0	108	0	0	0	102	0	0	0	0	0	0	0
S1	2020SP Load Addition & NNSS Reconfiguration	163	0	0	0	163	0	0	0	15	7	0	0	0	0	0	0
S2	2023SP Load Addition & NNSS Reconfiguration	181	0	0	0	181	0	0	0	102	54	0	0	0	0	0	0
S3	2023OP High Renewable	108	0	0	0	108	0	0	0	728	594	0	0	0	0	0	0

P27-129 cont.

All previously approved transmission projects were modeled in the Valley Electric Association area assessment in accordance with the general assumptions described in section 2.3. The transmission upgrades modeled in the 2020, 2023, and 2028 study cases are:

- New Sloan Canyon (previously named Bob) 230 kV switching station that loops into the existing Pahrump-Mead 230kV Line
- New Eldorado-Sloan Canyon 230kV transmission line
- The transmission upgrade only modeled in the 2023 and 2028 study cases is:
- Sloan Canyon-Mead 230kV line reconductoring.
- The transmission upgrade on hold and not being modeld in this TPP cycle is:
- New Charleston-Gamebird 138 kV transmission line

2.8.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

Amargosa Transformer Overload and Low Voltage Issues Mitigation

The Valley Electric Association area steady state assessment identified thermal overloads on the Amargosa 230/138 kV transformer and low voltage at 138 kV buses following multiple Category P1, P4 and P7 contingencies under various base and sensitivity scenarios. Several alternatives were proposed by the ISO or submitted through the Request Window Submission process to address the issue. The issue was mainly caused by the load growth and the power factor[88] . It was discovered that the power factors at 138kV side of most 138/24.95 kV distribution transformers were much less than 0.97 lagging. Correcting the power factors to 0.97 and installing a 10 Mvar shunt capacitor on the 138 kV system would mitigate the Amargosa transformer overloads and low voltage issues under the base scenarios.

P27-129 cont.

Another alternative would be to add a new 230 kV bus to the existing Gamebird 138 kV substation, loop the Pahrump-Bob SS 230 kV line into Gamebird substation, and install a new 230/138 kV transformer at Gamebird. This alternative would mitigate the Amargosa transformer overload in all base and sensitivity scenarios. The voltages at 138 kV buses would still be below 0.9 p.u. under the 2023 high load sensitivity scenario. However, correcting the power factors to 0.97 would address these low voltages.

The ISO will work with VEA and GWT to further investigate these alternatives.

Pahrump Transformer Overloads

The assessment identified thermal overloads on the remaining Pahrump 230/138kV transformer following a Category P6 contingency of the other Pahrump transformer and a few 138 kV lines under the 2028 base and 2023 sensitivity scenarios. The Gamebird 230/138 kV transformer

[88] CAISO Tariff Section 8.2.3.3 states that “All Loads directly connected to the CAISO Controlled Grid shall maintain reactive flow at grid interface points within a specified power factor band of 0.97 lag to 0.99 lead.”

addition discussed above would address these overloads. Alternatively, a RAS could be installed to curtail a portion of the Pahrump distribution load following the second contingency to mitigate the overloads.

In addition to the Amargosa transformer and Pahrump transformer overloads, the assessment identified several Category P1 and P6 related thermal overloads under the 2028 summer peak and 2023 off-peak high renewable sensitivity scenarios which could be mitigated by a previously identified generation-tripping RAS scheme or congestion management. The assessment also identified two Category P1 overloads under the 2020 summer peak high load and NNSS reconfiguration sensitivity scenario which could be mitigated by a new operating procedure, if necessary. Two system divergence issues under P6 contingency conditions were observed under various base and sensitivity scenarios and could be mitigated by the existing UVLS scheme.

The stability analysis performed in the VEA area assessment did not identify any transient issues that require mitigation.

2.8.4 Request Window Project Submissions

The ISO received four request window submissions for the Valley Electric Association area in this planning cycle. Below is a description of each submission followed by ISO comments and findings.

Amargosa Valley Reliability Improvement Project

The project was submitted by GridLiance West Transco, LLC (GWT). The scope of the project includes installing a new 230 kV bus and a 230/138 kV transformer at Valley Substation and building a new 40-mile 230 kV line between the new Valley 230 kV Substation and Innovation 230 kV Substation. The cost estimate provided is $41.5 million for a 40-mile 230kV rebuild and associated equipment. The expected in-service date is June 30, 2022.

The proposed project would increase the transmission capacity and reliability, and potentially facilitate the delivery of renewable generation out of Nevada into California. However, the issues could be mitigated by the existing UVLS, future Remedial Action Scheme (RAS) and congestion management which would have a lower cost and an earlier in-service date. It was also confirmed that the future RAS schemes would be consistent with the ISO RAS guidelines as stated in the ISO Planning Standards. It was also noticed that the proposed project would not eliminate any of the UVLS or future RAS schemes, rather it would only reduce the number of contingencies that required those schemes. In addition, the project could not mitigate the Amargosa bank overloads. For these reasons, the project was not found to be needed.

Pahrump Valley Loop-in Project

The project was submitted by GridLiance West Transco, LLC (GWT). The scope of the project includes building a new 230 kV switching station near Vista and looping into the Pahrump-Innovation 230 kV line; expanding the Charleston Park Substation to install a 230 kV bus and a 230/138 kV transformer; and building a new 11.2-mile Vista-Charleston Park 230 kV line. The cost estimate provided is $23.6 million for an 11.2-mile 230 kV line and associated equipment. The expected in-service date is September 30, 2022.

P27-129 cont.

The proposed project would mitigate the identified Amargosa bank and Pahrump transformer overloads and the low voltage issues. It would also potentially facilitate the delivery of renewable generation out of Nevada into California. However, compared to other alternatives which could also address the identified issues, this project scope included substantial greenfield construction and the cost was much higher. For these reasons, the project was not found to be needed.

Southwest Nevada Reliability Improvement Project

The project was submitted by GridLiance West Transco, LLC (GWT). The scope of the project includes rebuilding the Amargosa-Gamebird 138 kV line to 230 kV and extending the line to terminate at Arden 230 kV and Pahrump 230 kV instead. The new Arden-Pahrump 230 kV line would be approximately 63.5 miles. Sandy 138 kV Substation which tapped to the Amargosa-Gamebird 138kV line would be converted to 230 kV and tapped to the new Arden-Pahrump 230 kV line. The cost estimate provided is $65.4 million for the 63.5-mile 230 kV line rebuild and associated equipment. The expected in-service date is May 31, 2023.

The proposed project would result in Gamebird, Thousandaire and Charleston substations being served radially from Pahrump Substation. A single outage of Pahrump-Gamebird 138 kV line would result in 1/3 of VEA's distribution load being out of service. Thus, the project would have an adverse impact to the system reliability. For these reasons, the project was not found to be needed.

Gamebird-Charleston 230kV Transmission System Project

The project was submitted by NextEra Energy Transmission West, LLC (NEET West). The scope of the project includes expanding the Charleston Park Substation to install a 230 kV bus and a 230/138 kV transformer and building a 17-mile Gamebird-Charleston Park 230kV line. The estimated cost provided is $35 million. The expected in-service date is December, 2024.

The proposed project would mitigate the identified Amargosa bank and Pahrump transformer overloads and the low voltage issues. It would also potentially facilitate the delivery of renewable generation out of Nevada into California. However, compared to other alternatives which could also address the identified issues, this project scope included substantial greenfield construction and the cost was much higher. In addition, the project depended on the implementation of a future switching station which would not be in-service before the issue emerged. For these reasons, the project was not found to be needed.

2.8.5 Consideration of Preferred Resources and Energy Storage

The Valley Electric Association area assessment did not identify a need for additional preferred and storage resources in the area.

P27-129
cont.

2.8.6 Recommendation

The Valley Electric Association area assessment identified Amargosa 230/138 kV transformer thermal overloads and low voltage issues for Category P1, P4 and P7 outages under various base and sensitivity scenarios. The Pahrump 230/138 kV transformer was also found to be overloaded for Category P6 contingencies under both base and sensitivity scenarios. Adding a new 230kV bus to the existing Gamebird 138kV substation, looping the Pahrump-Bob SS 230 kV line into Gamebird substation, and installing a new 230/138 kV transformer at Gamebird appears to be the best solution for addressing the identified reliability concerns. The ISO will work with VEA and GWT to further investigate this alternative. The ISO will also coordinate with VEA on the power factor at the transmission and distribution interfaces.

P27-129 cont.

2.9 SDG&E Area

2.9.1 San Diego Local Area Description

SDG&E is a regulated public utility that provides energy service to 3.6 million consumers through 1.4 million electric meters and more than 873,000 natural gas meters in San Diego and southern Orange counties. The utility's service area spans 4,100 square miles from Orange County to the US-Mexico border, covering two counties and 25 communities.

The SDG&E system, includes its main 500/230 kV and 138/69 kV sub-transmission systems. The geographical location of the area is shown in the adjacent illustration. Its 500 kV system consists of the Southwest Powerlink (SWPL) and Sunrise Powerlink (SRPL) systems. The 230 kV transmission lines form an outer loop located along the Pacific coast and around downtown San Diego with an underlying 138 kV and 69 kV sub-transmission system. Rural customers in the eastern part of San Diego County are served exclusively by a sparse 69 kV system.

The ISO approved various transmission projects presented in chapter 8 for this area in previous planning cycles, which will maintain the area reliability and deliverability of resources while meeting policy requirement in the near future. Some of the major system additions are the Sycamore-Penasquitos 230 kV line, the synchronous condensers at SONGS and San Luis Rey, the Southern Orange County Reliability Enforcement (SOCRE), the phase shifting transformers at Imperial Valley, and the Suncrest SVC (static VAR compensator) project.

P27-129
cont.

The interface of San Diego import transmission (SDIT) consists of SWPL, SRPL, the south of San Onofre (SONGS) transmission path, and the Otay Mesa-Tijuana 230 kV transmission tie with CENACE. The San Diego area relies on internal generation and import through SDIT to serve electricity customers. The area has a forecasted 1-in-10 peak sales load of 4,681 MW in 2028 after incorporating a load reduction of 332 MW of additional achievable energy efficiency (AAEE) and 0 MW of forecast behind-the-meter photovoltaic (BTM PV) generation as the San Diego peak hour is shifted to HE19:00.

The area is forecast to have approximately 5,795 MW of grid-connected generation by the year 2020, including a total of 2069 MW renewable generation and 161 MW battery storage resources. The California Public Utilities Commission (CPUC) approved a total of 750 MW of conventional generation and preferred resources for the area to offset the local capacity deficiency resulting from the retirement of the San Onofre Generating Station and the Encina generating plants.

2.9.2 Area-Specific Assumptions and System Conditions

The steady state and transient stability assessments on the SDG&E main and sub-transmission systems were performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the five base cases, stability model data and contingencies that were used in the assessments. In addition, specific assumptions on load of demand-side and resources of supply-side in the baseline and sensitivity scenarios are shown in a table below.

Demand-Side Assumptions

The summer peak cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table below provides the load forecast assumptions including load reduction impact of BTM PV and AAEE on demand side. The load forecast provided by CEC are net demand values including load reduction and system losses. The summer light load and spring off-peak cases assume approximately 35 percent and 65 percent of the net peak load, respectively.

Supply-Side Assumptions

The table below also provides a summary of the supply-side assumptions modeled in the SDG&E main and sub-transmission systems assessments including conventional and renewable generation, and along with energy storage. A detailed list of existing generation in the area is included in Appendix A.

Transmission Assumptions

Transmission modeling assumptions on existing and previously planned transmission projects are consistent with the general assumptions described in section 2.3.

P27-129
cont.

Table 2.9-1: SDG&E load and generation assumptions

Case ID	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response*		Solar		Wind		Energy Storage		Thermal	
						Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	B1-20SP	Baseline	2019 Summer Peak Load	4524	71	1119	0	4,453	16	24	1,399	0	670	208	201	40	3,525	3,600
B2	B2-23SP	Baseline	2022 Summer Peak Load	4713	159	1395	0	4,554	16	24	1,399	0	670	7	201	40	3,525	3,616
B3	B3-28SP	Baseline	2027 Summer Peak Load	5013	332	1778	0	4,681	16	24	1,399	0	670	7	201	40	3,525	3,611
B4	B4-20LL	Baseline	2019 Spring Light Load (35% of the peak)	2341	23	1,119	862	1,456	16	24	1,399	1,357	670	7	201	-161	3,525	1,805
B5	B5-23OP	Baseline	2022 Spring Off-Peak (65% of the peak)	3959	134	1,395	0	3,825	16	24	1,399	0	670	34	201	-161	3,525	2,084
S1	S1-23SP HLOAD	Sensitivity	2023 High CEC Load Forecast & Peak-Shift	5005	159	1395	0	4,846	16	24	1,399	0	670	208	201	40	3,525	3,215
S2	S2-23OP HRPS	Sensitivity	2023 Spring off-peak with Heavy Reneable Output	5033	133	1395	1,074	3,825	16	24	1,399	1,343	670	342	201	-161	3,525	1,918
S3	S3-20SP HRPS	Sensitivity	2020 Summer peak with heavy reneable output	4524	71	1119	0	4,453	16	24	1,399	1,343	670	342	201	0	3,525	2,580

Note: Proxy Demand Response (DR) is modeled offline in starting cases.

P27-129
cont.

2.9.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B.

The 2018-2019 reliability assessments of the SDG&E main and its sub-transmission systems identified various reliability concerns consisting of thermal overload and voltage concerns. The assessment confirmed that these concerns could be mitigated in the operations horizon without relying on non-consequential load loss to meet applicable reliability standards in the planning horizon.

The steady state assessment of the baseline scenarios identified a total of eight thermal overload and voltage concerns under Category P1/P2/P3/P4/P6 contingencies in the SDG&E main systems and two thermal overload concerns under P1 and P3 contingencies in the SDG&E sub-transmission system. The sensitivity scenarios assessment identified similar or more severe concerns compared to the baseline scenarios. All of these concerns can be mitigated by previously approved projects and operational mitigations including remedial action scheme (RAS). The 30-minute emergency ratings of transmission facilities along with demand response and energy storage resources in the area can be relied upon under contingency in allowing operation actions including re-configuring the system, redispatching resources, reducing battery storage charing, and adjusting the phase shifting transformers at Imperial Valley substation. The stability analysis performed did not identify transient issues that require mitigation. Please refer to Appendix B for details on these concerns and associated mitigations. As a result, no new corrective action plan except operational mitigation has been found to be needed for the San Diego main and subtransmision systems to meet TPL 001-4 requirements. P27-129 cont.

2.9.4 Request Window Project Submissions

The ISO received a total of thirteen project submittals through the 2018 request window submission for the SDG&E main and sub-transmission systems. Below is a description of each proposal followed by ISO comments and findings.

Pala Sub-area LCR Reduction

SDG&E proposed this project as a reliability and an economic-driven transmission need to eliminate the LCR need for the Pala sub-area. The proposed scope is to upgrade Monserate–Morro Hill Tap 69 kV line (TL694A) and Morro Hill Tap-Melrose 69 kV line (TL694B). The project has an estimated cost of $25~37 million and an expected in-service date of June 2021.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on Monserate–Morro Hill Tap 69 kV (TL694A), Morro Hill Tap-Melrose 69 kV (TL694B), San Luis Rey-Ocean Ranch, and Ocean Ranch-Melrose 69kV lines can be eliminated by dispatching the 80 MW/200 MWh battery energy storage resources at Melrose and Avocado. The battery storage resources could potentially provide sufficient capacity and energy to eliminate the P6 overloads in the area without running the gas generation at Pala. Please refer to chapter 4 for the discussion of the areas and sub-areas selected for detailed analysis.

El Cajon Sub-area LCR Reduction

This project was proposed by SDG&E as a reliability and economic-driven transmission need to eliminate the LCR need for the El Cajon sub-area. The proposed scope is to upgrade Los Coches – El Cajon 69 kV line (TL631). The project has an estimated cost of $28~43 million and an expected in-service date of June 2023.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on the Los Coches–El Cajon 69 kV line can be eliminated by dispatching the resources in the local area including 7.5 MW/30 MWh battery energy storage facility and the gas generation at El Cajon. The economic analysis on the project's LCR reduction benefits can be found in Chapter 4.

Esco Sub-area LCR Reduction

SDG&E proposed this project as a reliability and an economic-driven transmission need to eliminate the LCR need for the Esco sub-area. The proposed scope is to add second 230/69 kV transformer at Artesian. The project has an estimated cost of $14~20 million and an expected in-service date of June 2023.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on Sycamore Canyon–Pomerado (TL6915 and TL6924) 69 kV lines can be eliminated by dispatching generation resource in the local area. Please refer to chapter 4 for the discussion of the areas and sub-areas selected for detailed analysis.

P27-129 cont.

Border Sub-area LCR Reduction

SDG&E proposed this project as a reliability and economic-driven transmission need to eliminate the LCR need for the Border sub-area. The proposed scope is reconductor Bay Boulevard–Imperial Beach 69 kV line (TL647). The project has an estimated cost of $6~10 million and an expected in-service date of June 2021.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on Bay Boulevard–Imperial Beach (TL647) 69 kV line can be eliminated by dispatching generation resources in the local area. The economic analysis on the project's LCR reduction benefits can be found in Chapter 4.

Southern California Regional LCR Reduction

SDG&E proposed this project as a reliability and economic-driven transmission need that is intended to reduce LCR need in the southern California region. The proposed scope is to construct a new Mission-San Luis Rey-San Onofre 230 kV line, install a 230 kV phase shifter station at Mission Substation, and upgrade various existing 230 kV lines (TL23004, TL23006, TL23022 and TL23023) in the San Diego area. The project has an estimated cost of $100~200 million and an expected in-service date of June 2023.

The ISO has not identified a reliability need for this project. The potential congestion in the Encina-San Luis Rey 230 kV system (TL23003 and TL23011) were identified during system off-peak conditions with heavy renewable generation output. The ISO's analysis confirmed that the congestions can be mitigated in the ISO market by redispatching generation in the San Diego area and LA Basin without resulting in significant congestion cost. More detail of economic analysis on the project can be found in Chapter 4.

Suncrest-Sycamore 230 kV_Transmission project

NextEra Energy Transmission West, LLC (NEET West) proposed the Suncrest – Sycamore 230 kV Transmission project targeting thermal overloads in the Suncrest–Sycamore 230 kV corridor as a reliability need. The proposed scope is to construct a new 27-mile 230 kV line from the Suncrest substation to the Sycamore 230 kV substation. The project has an estimated cost of $100 million and an expected in-service date of December 2024.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on the Suncrest–Sycamore 230 kV corridor can be eliminated by the existing RASs including newly implemented TL23054/TL23055 RAS and along with operation actions, such as adjustment of the IV phase shifting transformers, system reconfiguration, and generation redispatch in the baseline scenarios. Further assessment concluded that the preferred resources and the operation actions are adequate to mitigate the overload concerns identified in the sensitivity scenarios. For these reasons, the project was not found to be needed.

Sycamore 230 kV Energy Storage Project

NextEra Energy Transmission West, LLC (NEET West) proposed Sycamore 230 kV Energy Storage Project as a reliability transmission need to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest 500/230 kV transformers, and Miguel 500/230 kV transformers. The proposed scope is to build a 210 MW energy storage and connect it to the SDG&E Sycamore substation. The project has an estimated cost of $200 million and an expected in-service year of 2024.

P27-129 cont.

The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified in SWPL and SRPL can be eliminated by the operational measures including the RASs. For this reason, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4.

Westside Canal Reliability Center

Sempra Renewables proposed this energy storage project as a reliability transmission need to eliminate the P6 thermal overload concerns on the San Diego main system specifically targeting the Suncrest –Sycamore 230 kV lines. The proposed scope is to build a 268 MW energy storage with a faster response time provide reactive power support capability and interconnect it to the SDG&E Imperial Valley 230 substation. The project has an estimated cost of $304 million and an expected in-service year of 2021.

The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified in the area can be eliminated by the operational measures including the RASs discussed above. On the other hand, when the battery is operating in load mode, the battery project could worsen the thermal overload concerns in the neighboring systems even after the Imperially Valley- El Centro 230 kV line (S-Line) upgrade project is completed. For these reasons, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4.

Sycamore Reliability Energy Storage Proposed By NEET West

NextEra Energy Transmission West, LLC (NEET West) proposed this project as a reliability need to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest 500/230 kV transformers, and Miguel 500/230 kV transformers. The proposed scope is to build a 210 MW battery energy storage system (BESS) and interconnect it to the SDG&E Sycamore substation. The project has an estimated cost of $200 million and an expected in-service year of 2024.

The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified in SWPL and SRPL can be eliminated by the operational measures including the RASs. For this reason, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4.

Sycamore Reliability Energy Storage proposed By Tenaska, Inc.

Tenaska, Inc. proposed this project as a reliability need to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest 500/230 kV transformers. The Project is also proposed as an economic-driven project to reduce the LCR requirement for the San Diego sub-area. The proposed scope is to build a 350 MW/175~350 MWh battery energy storage system (BESS) and interconnect it to the SDG&E Sycamore substation. The project has an estimated cost of $108~178 million and an expected in-service date of December 2021.

The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified in SWPL and SRPL can be eliminated by the operational measures. For this reasons, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4. P27-129 cont.

Lake Elsinore Advanced Pump Storage Project

ZGlobal, on behalf of the Nevada Hydro Company, proposed the Lake Elsinore Advanced Pump Storage (LEAPS) project as a reliability need to resolve the overloads concerns identified in the San Diego main system. The Project was also proposed as an economic-driven project to reduce the LCR requirement for the San Diego sub-area. The LEAPS project consists of a 500/600 MW advanced pumped storage facility, two new 500 kV interconnecting transmission lines, two new 500 kV substations, three new 500/230 kV transformers, and three new phase shifting transformers. The project has an estimated cost of $1.76~2.04 billion and an expected in-service year of 2025.

The ISO has not identified a reliability need for this project. As discussed above, the power flow concerns identified in the SDG&E main system can be eliminated by the operational measures. For this reason, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4.

San Vicente Energy Storage Facility

City of San Diego proposed the San Vicente Energy Storage Facility (SVES) project as a policy-driven and economic-driven transmission need to reduce renewable generation curtailment and to increase market revenues. The project can provide significant reliability benefit to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest 500/230 kV transformers, and Miguel 500/230 kV transformers. The proposed energy storage plant is configured with four individual generating units (4x125MW) interconnected to the SDG&E's Suncrest-Sycamore 230 kV lines in two 230 kV generation interconnection line circuits. The project has an estimated cost of $1.5~2 billion and an expected in-service year of 2028.

The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified can be eliminated by the operational measures. For this reason, the project was not found to be needed as reliability project. The economic analysis on the project can be found in Chapter 4.

Otay-Otay Lake Tap 69 kV Reconductor Project

This project was proposed as a reliability transmission need to reconductor TL649A Otay-Otay Lake Tap 69 kV line and achieve a minimum continuous rating of 64 MVA. The estimated cost of the project is between $4 million and $6 million, and the expected in-service date is June, 2021.

The ISO has not identified a reliability need for this project. The P1 thermal overload concerns can be mitigated by relying on generation re-dispatch or curtailment.

2.9.5 Operational Modification and RAS Mitigations

Bypassing 500 kV Series Capacitors in SWPL and SRPL

A need for bypassing the existing 500 kV series capacitor banks in SWPL and SRPL under summer peak load conditions were identified in the 2014-2015 ISO transmission plan. Since then, this operational modification has been confirmed and utilized in the transmission reliability, generation interconnection, and local capacity requirement planning processes. With the development of renewable generation and the implementation of once-through-cooling generation retirement in the southern California region, the ISO continues to recommend bypassing the series capacitor banks in the ECO-Miguel TL50001 and Ocotillo-Suncrest TL50003 500 kV lines under normal system operating conditions after the planned Suncrest SVC project is in service by December 2019. The bypassing configuration would deliver maximum system benefits without causing parallel flow concerns on the CENACE system with the Imperial Valley phase shifting transformers. This operational modification would provide considerable incremental benefits including but not limited to increasing generation deliverability in the greater IV area, reducing local capacity requirement in the San Diego area and LA Basin, and boosting the transmission import capability into San Diego (SDIT).

P27-129 cont.

Modification on Existing Miguel Banks #80 and #81 RAS

This RAS scheme was recently modified to accommodate the system changes by tripping up to all of the renewable and conventional generation in the greater Imperial Valley area. The ISO suggests to further enhance the RAS performance and operational flexibility by adding a feature to bypass the 500 kV series capacitor banks in TL50001 ECO-Miguel 500 kV line prior to dropping the generation, in case the series capacitor banks are not bypassed under all normal system operating conditions. The 30-minute emergency ratings of the Miguel banks should also be relied upon under the P6 contingencies in allowing operating actions including re-configuring the system, redispatching resources, and adjusting the phase shifting transformers at Imperial Valley substation.

2.9.6 Consideration of Preferred Resources and Energy Storage

As indicated earlier, projected amounts of up to 332 MW energy efficiency (AAEE) and 1,778 MW installed capacity of distributed BTM-PV self-generation were used in the study scenarios for the San Diego area. The BTM-PV self-generation reduces a total of 853 MW of the San Diego load at HE16:00 on the southern California area peak hour, and 0 MW of the San Diego area peak load at HE19:00. The load reductions due to these preferred resources has shifted the San Diego peak load hour from HE16:00 to HE19:00, which avoided, deferred, or mitigated various significant reliability concerns identified in current and previous transmission planning cycles, including but not limited to:

- Various thermal overload concerns in SWPL and SRPL for various Category P1/P3/P6 contingencies
- Voltage instability in the San Diego and LA Basin for Category P3/P6 contingencies
- The south of San Onofre Safety Net taking action for Category P6 contingency
- Bay Boulevard–Silvergate-Old Town 230 kV path overloads for Category P6/P7 contingencies
- Miguel-Mission 230 kV path overloads for Category P6 contingencies
- SCE's Ellis 220 kV south corridor for Category P6 contingency
- Cross-tripping the 230 kV tie lines with CENACE for Category P3/P6 contingencies
- Imperial Valley – El Centro 230 kV tie line for Category P3/P6 contingencies

The operational and planned battery energy storage and demand response amounting to 161 MW and 40 MW, respectively, were used as potential mitigations in the base and sensitivity scenarios as needed. Utilization of the resources helped reduce some of the thermal overloads identified in the area.

In this planning cycle, no need for additional preferred resource and energy storage was identified as a cost-effective mitigation to meet reliability needs in the San Diego area. As alternatives to the recommended operational mitigation solutions, however, procuring additional amounts of preferred resources and energy storage in appropriate locations could be helpful to mitigate or reduce exposure to some of the reliability concerns.

P27-129
cont.

2.9.7 Recommendation

The assessments identified a total of eight thermal overload and voltage concerns under Category P1/P2/P3/P4/P6 contingencies in the SDG&E main system and two thermal overload concerns under P1 and P3 contingencies in the SDG&E sub-transmission system. The sensitivity scenarios assessment identified similar or more severe concerns compared to the base scenarios. In response to the ISO study results and proposed alternative mitigations, a total of thirteen project submissions were received through the 2018 request window. The ISO evaluated the alternatives and did not find a reliability need for these projects, and is recommending two operational mitigations as cost-effective mitigations to address the identified reliability concerns, along with preferred resources and energy storage. Below is a summary of the recommendations for the SDG&E area:

1. Bypassing 500 kV Series Capacitors in SWPL and SRPL
2. Modifications on existing Miguel Banks #80 and #81 RAS

P27-129
cont.

Chapter 3

3 Policy-Driven Need Assessment

3.1 Background

The CPUC issued a decision[89] on February 8, 2018 which adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals. The decision also established a 50 percent RPS "default" scenario to be transmitted to the ISO to be used in the 2018-2019 TPP reliability (and economic) assessment, and a 42 MMT Scenario portfolio to be used as a sensitivity in the 2018-2019 TPP policy-driven assessment to identify Category 2 transmission based on the Reference System Plan. The decision also stipulated that no base portfolio would be transmitted to the ISO as part of the 2018-2019 TPP policy-driven assessment, but that once the "preferred system plan" is adopted through the 2018 IRP effort, it will be utilized as a policy-preferred portfolio in the subsequent transmission planning process to identify Category 1 policy-driven transmission needs.

The CPUC used the RESOLVE model for creating the 42 MMT Scenario portfolio. This model assumed the renewable resources under development with CPUC-approved contracts with the three investor-owned utilities to be part of the baseline assumptions while creating this portfolio. The ISO worked with the CPUC to identify such resources and model[90] these in the policy-driven assessment base cases. The ISO supplemented this scenario with information regarding contracted RPS resources that are under construction as of May 2018. Because the CPUC adopted the 42 MMT Scenario portfolio to be assessed as a sensitivity in the 2018-2019 TPP policy-driven assessment, and specifically excluded a base portfolio for policy-driven analysis, the ISO is not recommending approval of any policy-driven transmission elements as part of the 2018-2019 TPP.

P27-129 cont.

3.2 Objectives of policy-driven assessment

The four key objectives of the policy-driven assessment were:

3. Study the transmission impacts of the sensitivity portfolio transmitted to the ISO.
    a. Capture reliability impacts.
    b. Test the deliverability of resources selected to be full capacity deliverability status (FCDS).
    c. Analyze renewable curtailment data.

89 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

90 http://docketpublic.energy.ca.gov/PublicDocuments/17-MISC-03/TN222569_20180215T155902_Energy_Commission_Staff_Proof_of_Concept_Report_to_CPUC_Staff.pdf

4. Evaluate transmission solutions (only Category 2 in this planning cycle) needed to meet state, municipal, county or federal policy requirements or directives as specified in the Study Plan.
5. Test the transmission capability estimates used in CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation.
6. Test deliverability of FCDS resources in the portfolio using new renewable output assumptions that take into account the new qualifying capacity calculations for solar and wind.

3.3 Key inputs and assumptions

The key inputs and assumptions for policy-driven assessment include transmission capability estimates for major renewable zones, renewable portfolios, transmission modeling assumptions and load assumptions.

3.3.1 Transmission modeling assumptions

The same transmission modeling assumptions used in ISO's Annual Reliability Assessments for NERC Compliance (all transmission projects approved by the ISO) were used in this analysis. Year-10 base cases used for 2018-2019 TPP annual reliability assessment were used as a starting point. Specific details are described in chapter 2 section 2.3.

Transmission modeling assumptions used in economic planning database described in chapter 4 section 4.6 were used to develop the policy-driven production cost simulation model. P27-129 cont.

3.3.2 Load modeling assumptions

The ISO identified severe conditions snapshots to be modeled based on high transmission system usage hours under high renewable dispatch in respective study areas, and the corresponding load levels were modeled in the respective power flow cases.

For deliverability studies performed as part of this policy-driven assessment, 2030 1-in-5 summer peak load and off-peak loads were tested.

3.3.3 Resource dispatch assumptions

For the reliability assessment, renewable resources were dispatched based on the identified snapshot.

For the deliverability assessment, renewable resource were dispatched according to the newly proposed deliverability methodology and dispatch assumptions.

For production cost modeling (PCM) simulations, the portfolio resources mapped to specific transmission substations were added to the ISO economic planning database described in chapter 4

3.3.4 Renewable Portfolio

As set out above, a 42 MMT Scenario portfolio was transmitted to the ISO to be used as a sensitivity in the 2018-2019 TPP policy-driven assessment to identify Category 2 transmission based on the Reference System Plan. No base portfolio was transmitted to the ISO as part of the 2018-2019 TPP policy-driven assessment.

Compared to the renewable portfolios transmitted to the ISO by the CPUC during the 2017-2018 transmission planning process, the portfolios transmitted to the ISO as part of 2018-2019 TPP contain several changes in terms of resource classification and the nature of modeling/mapping data. The key changes are as follows:

- “RESOLVE” model was used instead of the RPS calculator to select portfolio resources.
- CEC staff developed the locational mapping of resources. In the past the ISO had relied on queued generation information for mapping portfolio resources to specific substations.
- The portfolio now includes only the new generic (not contracted) resources. In the past, portfolios were comprised of contracted and generic resources. Contracted resources (on-line and planned) are now considered as baseline resources in RESOLVE model, so these resources are not part of the optimization.
- A mix of resources with Full Capacity Deliverability Status (FCDS) and Energy Only Deliverability Status (EODS) are selected as part of portfolios.
- The 2,000 MW of energy storage included in the portfolio is primarily for system-wide renewable integration purpose, so it does not have a material impact on deliverability and reliability studies being performed as part of the policy-driven assessment.

Figure 3.3-1 shows a comparison of the 42 MMT portfolio with the default portfolio modeled in the TPP reliability assessment. For the most part, the default portfolio appears like a subset of the 42 MMT portfolio. Table 3.3-1 lists the renewable resources selected as part of the 42 MMT portfolio.

P27-129 cont.

Figure 3.3-1: 42 MMT portfolio and default portfolio

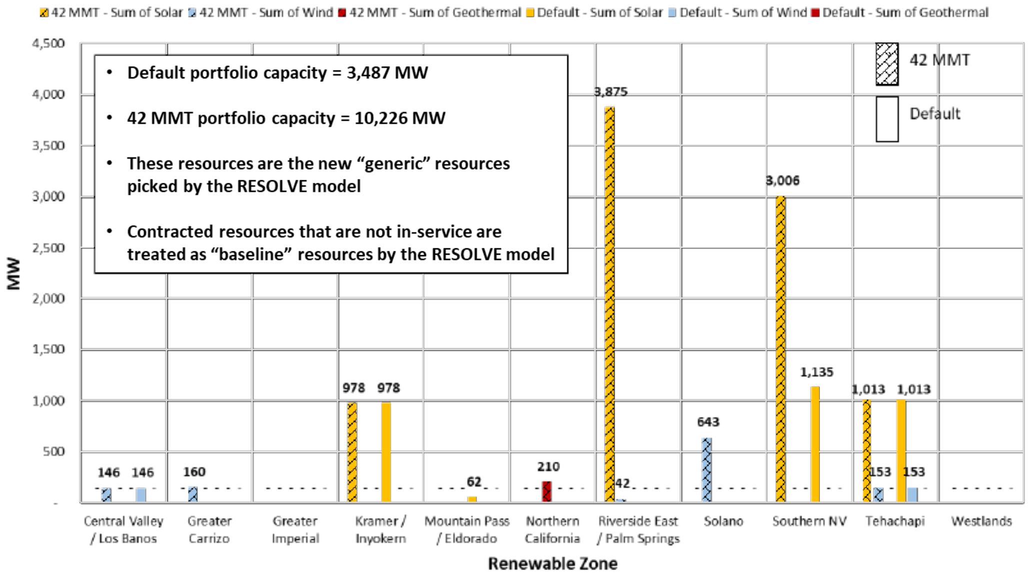


Table 3.3-1: 42 MMT portfolio resource summary

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)	TOTAL
Northern CA	-	-	210	210
Solano	-	643	-	643
Central Valley / Los Banos	-	146	-	146
Greater Carrizo	-	160	-	160
Tehachapi	1,013	153	-	1,166
Kramer & Inyokern	978	-	-	978
El Dorado, Mountain Pass, Southern NV	3,006	-	-	3,006
Riverside East & Palm Springs	3,875	42	-	3,917
TOTAL	8,872	1,144	210	10,226

The portfolio comprises of a mix of FCDS and EODS resources. Figure 3.3-2 and Table 3.3-2 show a breakdown of the portfolio by technology and by deliverability status of the resources. FCDS resources are predominantly selected in Central Valley-Los Banos, Kramer-Inyokern, Riverside East & Palm Springs, Southern Nevada and Tehachapi zones. EODS resources are selected in Greater Carrizo, Riverside East & Palm Springs, Solano and Southern Nevada.

P27-129 cont.

Figure 3.3-2: 42 MMT portfolio by technology and by deliverability status

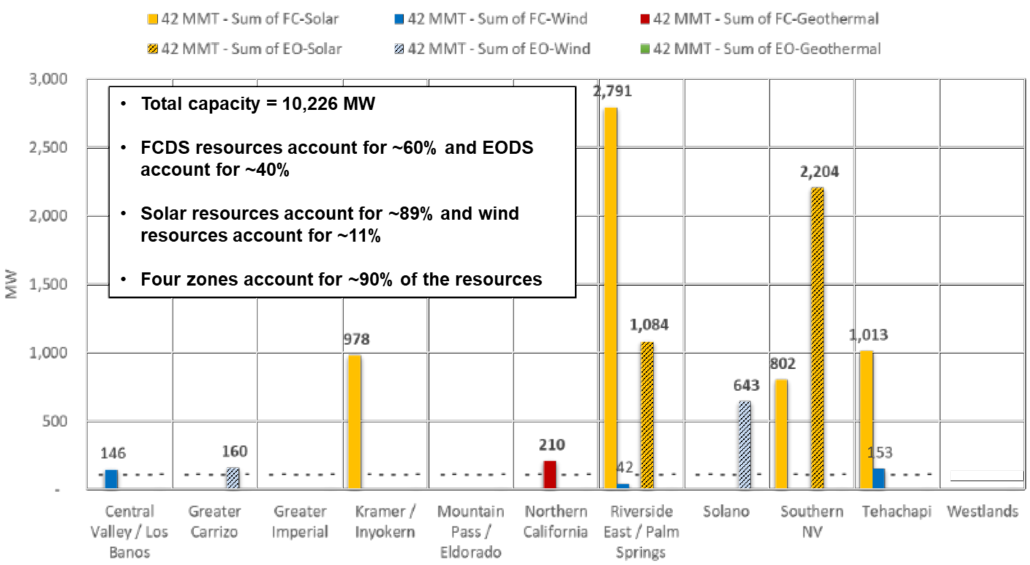


Table 3.3-2: 42 MMT portfolio resource summary by technology and by deliverability status

Renewable Zones	Solar (MW)		Wind (MW)		Geothermal (MW)	
	FCDS	EODS	FCDS	EODS	FCDS	EODS
Northern CA	-	-	-	-	-	210
Solano	-	-	-	643	-	-
Central Valley / Los Banos	-	-	146	-	-	-
Greater Carrizo	-	-	-	160	-	-
Tehachapi	1,013	-	153	-	-	-
Kramer & Inyokern	978	-	-	-	-	-
El Dorado, Mountain Pass, Southern NV	802	2,204	-	-	-	-
Riverside East & Palm Springs	2,791	1,084	42	-	-	-
TOTAL	**5,584**	**3,288**	**341**	**803**	**-**	**210**

P27-129
cont.

3.3.5 Mapping of portfolio resources to transmission substations

The ISO used the proposed resource mapping[91] provided by the CEC staff and made minor modifications to the suggested transmission locations.

The portfolios provided by the CPUC contained resource amounts at a geographic scale that was too broad for transmission planning analysis, which requires specific interconnection locations. CEC staff developed a proposed substation allocation by relying on information from the CPUC, the ISO, RETI 2.0 results, California Department of Fish and Wildlife, and U.S. Bureau of Land Management (Nevada). The ISO then relied on more specific information about interconnection challenges in some locations that resulted in changing the resource allocation to substations in Southern NV zone.

The objective of modeling generation projects connected to specific substations is not to endorse any particular generation project, but to streamline and focus the transmission analysis on the impact of certain amount of MW of generation modeled in the general area. In other words, transmission constraints observed for a specific generation build-out within a renewable zone should be independent of the specific projects that get built.

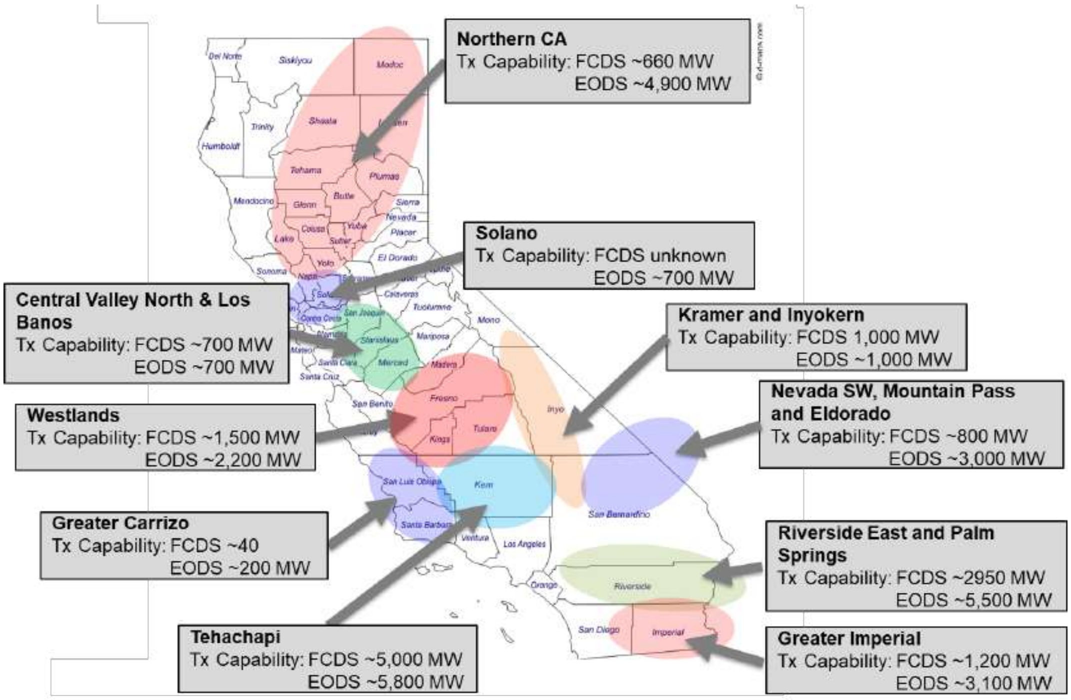
3.3.6 Transmission capability estimates and corresponding utilization in 42 MMT portfolio

The estimated available transmission capability to support future renewable generation is monitored annually through the ISO transmission planning process. The ISO relies on past transmission analysis from policy-driven assessments, special studies, generation interconnection studies and the work ISO performed in supporting the RETI 2.0 initiative. Figure 3.3-3 shows an approximate geographical representation of the information transmitted to the CPUC to assist in the RESOLVE modeling efforts in support of the IRP process and the 2018-2019 TPP. The EODS estimates shown in this diagram are inclusive of the FCDS estimates. For example, in Tehachapi zone FCDS estimate is 5,000 MW and EODS estimate is 5,800 MW. This should be interpreted as 5,800 MW is the estimated limit for selecting any mix of FCDS and EODS resources combined as long as FCDS resource selection does not exceed 5,000 MW.

P27-129 cont.

[91] https://efiling.energy.ca.gov/GetDocument.aspx?tn=222569

Figure 3.3-3: Transmission capability estimates provided as an input into IRP



P27-129 cont.

Figure 3.3-4 and Figure 3.3-5 show how the 42 MMT portfolio utilized the transmission capability estimates provided by the ISO. The estimated FCDS capability is fully utilized in some zones and considerable surplus remains elsewhere – the same applied for the EODS capability estimates and corresponding utilization. It is important to note that these transmission capability estimates are only one of the several deciding factors utilized for resources selection in the RESOLVE model.

Figure 3.3-4: Utilization of FCDS transmission capability estimates

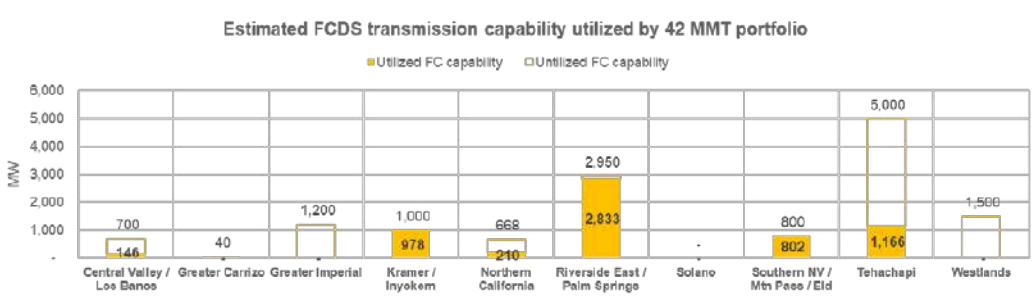
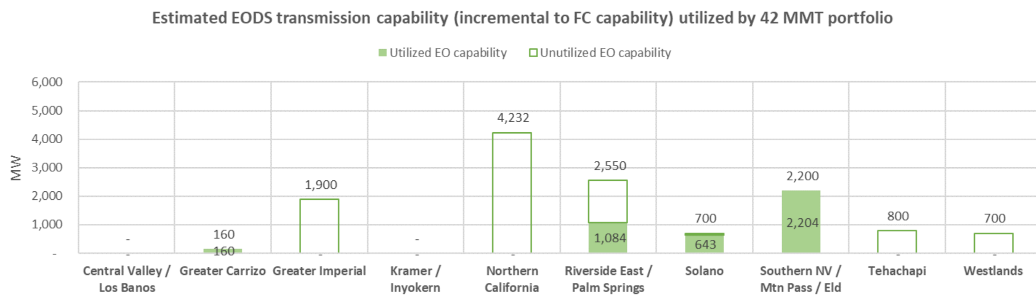


Figure 3.3-5: Utilization of EODS transmission capability estimates

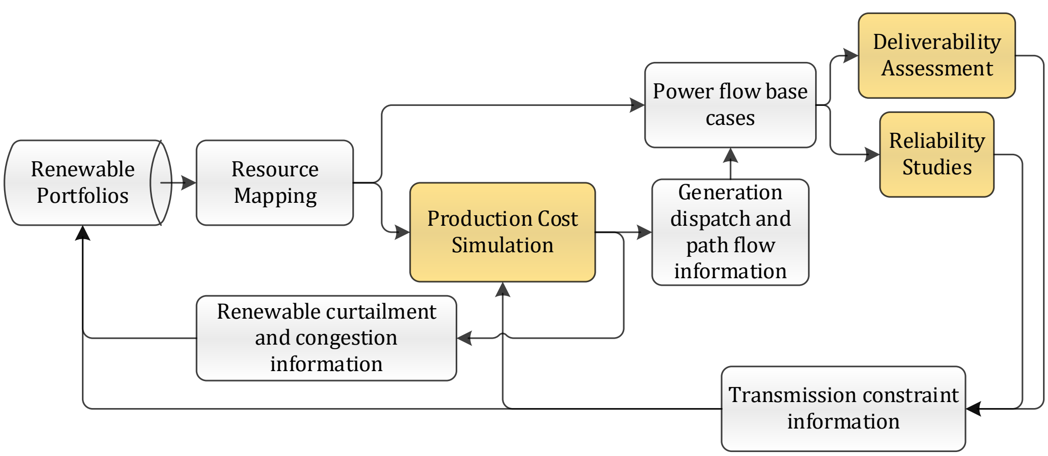


As part of the 2018-2019 TPP policy-driven assessment the ISO plans to refine the existing transmission capability estimates and provide these updated estimates as an input in support of the ongoing IRP process.

3.4 Study methodology and components

The policy-driven assessment is an iterative process comprised of three types of technical studies. These studies are geared towards capturing the impact of renewable build out on transmission infrastructure, identifying any required upgrades and generating transmission input for the next set of renewable portfolios to be selected through the appropriate CPUC proceeding (currently the IRP proceeding).

Figure 3.4-1: Policy assessment methodology and study components



P27-129 cont.

Production cost modeling simulation (PCM) study

Production cost modeling simulations were performed using the updated models to identify renewable curtailment and transmission congestion in the ISO BA system. Renewable curtailment can be caused by system constraints, such as over-generation and system ramping, or by transmission constraints. Two scenarios with different ISO export limitations were developed and simulated – (i) 2000 MW maximum net export from the ISO and (ii) no export limit from the ISO. The difference of renewable curtailment between the first and the second scenarios can be a good approximation of renewable curtailment related to transmission constraints within California. It should be noted, however, that the “no export limit” scenario may still have some renewable curtailment due to system constraints, but this should be relatively small. Production cost simulations were used to create hourly snapshots of the system to be used for reliability studies which involve power flow simulations.

Reliability studies (power flow simulations)

Reliability studies were performed in order to identify transmission system limitations above and beyond the constraints monitored in the production cost simulations. The 8,760 hours of snapshots created during production cost simulations were used to identify high transmission system usage patterns to be tested using the power flow models for reliability assessment. Power flow contingency analysis was performed in order to capture any additional area-wide constraints that need to be modeled in the production cost simulations in order to more accurately capture the renewable curtailment caused by transmission congestion.

P27-129 cont.

Deliverability assessment

The deliverability test is designed for resource adequacy counting purposes to identify if there is sufficient transmission capability to transfer generation from a given sub-area to the aggregate of ISO control area load when the generation is needed most. An essential step in deliverability assessment of this year’s policy-driven portfolio was to review the study methodology in order to adapt to the changing generation fleet characteristics and load profiles that are also leading to changes to resource counting methodology for resource adequacy purposes. The ISO relied on the capacity margin data and corresponding renewable resource output from the 2018 summer assessment data to adjust the dispatch assumptions in order to reflect the new resource counting methodology. This approach also included an enhancement of the methodology used to identify upgrades in the deliverability assessment. A detailed discussion of this proposed deliverability methodology is presented in section 3.5.

3.5 Deliverability assessment

The ISO initially developed a deliverability study methodology for resource adequacy purposes in 2004. The methodology was generally adopted in the CPUC’s Resource Adequacy (RA) proceeding in 2004. A generating resource must pass the ISO deliverability test under system summer peak load condition for its Qualifying Capacity (QC) to become Net Qualifying Capacity (NQC) that can be counted to meet the RA requirement. At that time, the generating resources were predominantly non-intermittent, such as thermal plants and hydro plants. The QC values used in the deliverability assessment were the respective maximum output for the resource. The adoption of 20 percent and 33 percent RPS targets led to a high volume of renewable generation interconnection requests to the grid; hence the methodology was expanded to account for intermittent resources. The QC values for wind and solar resources were calculated based on resource production exceedance values. Aligned with the QC calculation, the ISO developed the capacity assumptions for intermittent resources in the deliverability assessment based on the exceedance values during the same QC counting window in the summer months. The methodology has been applied in the ISO generation interconnection studies and transmission planning studies. Several policy driven transmission upgrades were identified and approved to support deliverability of 33 percent RPS portfolio.

Starting in 2018, the CPUC has replace the exceedance based QC calculation with an effective load carrying capability (ELCC) approach. As the resource portfolio keeps evolving toward a higher RPS target, energy efficiency, demand response and behind-the-meter distributed generation, both the characteristics of the load profile and the resource portfolio are going through a transformation which raise concerns about the overall utility of the current methodologies included in the QC approach and corresponding deliverability methodology. In response to this change, the ISO performed an informational study in the 2016-2017 TPP 50 percent RPS deliverability assessment that evaluated the deliverability methodology and experimented with modifications to the study assumptions in the deliverability assessment. The ISO has since summarized the previous work and reviewed the deliverability assessment from a broader perspective that involves the study methodology, upgrades identification and study process. The ISO team proposed modifications to the deliverability assessment methodology to stakeholders and tested the proposal on the 42 MMT portfolio.

P27-129 cont.

3.5.1 Proposed deliverability approach

The proposed deliverability assessment is a test under multiple system conditions – the highest system need scenario and the secondary system need scenarios, and to better align generation output assumptions with the time of day and time of year of those system needs. To select the scenarios, the ISO needs to obtain the forecasted hourly profiles for the gross consumption, behind-the-meter generation, and in-front-of-the-meter generation of the study year. The ISO relied on data from ISO 2018 summer loads and resources assessment, as this data was not available at the time from the CPUC's ELCC studies.

The ISO 2018 summer loads and resources assessment indicated that the ISO faced significant risk of encountering operating conditions that could result in operating reserve shortfalls. The hours with risk of operating reserve shortfalls in the 2018 summer assessment were used to establish the study assumptions for the highest and secondary system need scenarios. The 2018 summer assessment used a stochastic process to randomly generate 2000 unique scenarios – each representing a combination of forecasted 8,760 hourly load profiles and renewable generation levels based on historic annual weather patterns. By simulating the 2000 scenarios, the unloaded capacity margin was calculated for each simulated hour. The hours with unloaded capacity margin less than 6 percent were used to establish the deliverability assessment assumptions. The combination of the load, solar, wind and other transmission and generation conditions during these hours are most likely to result in a capacity shortage.

3.5.1.1 Highest System Need Scenario (HSN)

The 2018 summer assessment indicated that most of the MCUM hours are around hour ending 20:00, which aligns with the expected hours of highest load seen from the transmission grid. HE18 to 22 with UCM less than 6 percent in the 2018 summer assessment results were selected to be the highest system need window to examine intermittent generation output levels. Wind and solar outputs were examined during those hours and Table 3.5-1 shows the percentile output levels.

Table 3.5-1: Wind and Solar Output Percentile for HE18~22 & UCM<6 Percent Hours

		min	max	50%	60%	70%	80%	90%
wind	SDG&E	0%	86%	11.1%	16.3%	23.0%	33.7%	45.5%
	SCE	0%	88%	27.6%	36.9%	46.3%	55.7%	65.6%
	PG&E	0%	98%	29.8%	38.2%	52.5%	66.5%	78.2%
solar	SDG&E	0%	57%	0.0%	0.1%	1.7%	3.0%	7.6%
	SCE	0%	75%	1.9%	3.9%	7.0%	10.6%	14.8%
	PG&E	0%	70%	0.9%	4.1%	6.8%	10.0%	13.7%

The ISO proposed to use the 80th percentile, i.e. 20 percent exceedance, output level from hours of UCM<6 percent, or hours of loss of load events if ELCC data is available, between HE 18 and HE 22 in the summer months for the highest system need scenario. This is when the capacity is needed the most and it is critical to have higher certainty of wind and solar being deliverable during the time period. The value of 20 percent exceedance levels would be examined periodically and updated for use in the deliverability assessment.

P27-129 cont.

Table 3.5-2: Modeling Assumptions for Highest System Need Scenario

Selected Hours	HE18 ~ 22 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in ISO summer assessment)
Load	1-in-5 peak sale forecast by CEC
Non-Intermittent Generators	Pmax set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Pmax set to 20% exceedance level during the selected hours
Import	MIC data with expansion approved in TPP

The deliverability assessment then followed the steps in the current methodology. Deliverability constraints were identified and delivery network upgrades were identified for each constraint.

3.5.1.2 Secondary System Need Scenario (SSN)

The solar output level is very low in the highest system need hours. The highest system need scenario alone does not provide sufficient confidence that the solar resources are deliverable in all the hours when they are needed. A second scenario supplements the highest system need by testing deliverability when both the system load and the solar production are high. HE15 to 17 with UCM less than 6 percent in the 2018 summer assessment results were identified as relatively high solar output with a mild risk of capacity shortage. Wind and solar outputs were examined during these hours and Table 3.5-3 shows the percentile output levels.

Table 3.5-3: Wind and Solar Output Percentile for HE15~17 & UCM<6% Hours

		min	max	50%	60%	70%	80%	90%
wind	SDG&E	0%	69%	11.2%	16.6%	26.5%	40.8%	47.9%
	SCE	1%	70%	20.8%	24.8%	34.9%	57.4%	64.8%
	PG&E	1%	83%	16.3%	21.4%	44.7%	69.7%	76.8%
solar	SDG&E	2%	88%	35.9%	44.7%	58.0%	72.1%	75.4%
	SCE	17%	96%	42.7%	49.6%	51.8%	61.9%	86.3%
	PG&E	16%	91%	55.6%	61.6%	63.2%	74.6%	75.9%

P27-129 cont.

It was proposed to use the median, i.e. 50 percent exceedance, output level from hours of UCM<6 percent, or if ELCC data available, hours of LOLE events, between HE 15 and HE 17 in the summer months. During these hours, there is a mild risk of capacity shortage. It is reasonable to lower the requirement for being simultaneously deliverable. The value of 50 percent exceedance levels would be examined periodically and updated in the deliverability assessment.

The load is scaled from the 1-in-5 peak sale forecast by examining the hourly load and behind the meter generation data from CEC.

The highest imports that were selected for MIC calculation align with the highest system need hours. During the secondary system need hours, historical data show that total import is about 2000 MW lower than the highest need hours. For 2016 and 2017 summer, the highest import HE18-22 is 11,780 MW and the highest import HE15-17 is 9,142 MW.

Table 3.5-4: Modeling Assumptions for Secondary System Need Scenario

Select Hours	HE15 ~ 17 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in ISO summer assessment)
Load	1-in-5 peak sale forecast by CEC adjusted to peak consumption hour
Non-Intermittent Generators	Pmax set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Pmax set to 50% exceedance level during the selected hours
Import	Highest import schedules for the selected hours

3.5.1.3 Application of Highest System Need Scenario and the Secondary System Need Scenario study results

The highest system need scenario represents the time when a capacity shortage is most likely to occur. As a result, if the addition of a resource will cause a deliverability deficiency determined based on a deliverability test under the HSN scenario, then the constraint would be classified as either a Local Deliverability Constraint or an Area Deliverability Constraint. The upgrade needs identified in the transmission planning policy deliverability assessment would qualify as policy upgrades.

P27-129 cont.

The secondary system need scenario represents the time when the capacity shortage risk will increase if the intermittent generation - while capable of producing at a significant output level - is not deliverable. If the addition of a resource will cause a deliverability deficiency determined based on a deliverability test under the SSN scenario, and is not identified in the HSN scenario, then the constraint could be classified as an Area Deliverability Constraint following the classification guidelines in the BPM for the Generator Interconnection and Deliverability Allocation Procedures. The upgrade needs identified for SSN only in the transmission planning policy deliverability assessment would be recommended for approval only if the upgrades are identified in the policy powerflow and stability study or production cost simulation. Otherwise, the upgrades would be determined as not needed yet.

3.5.2 Deliverability assessment results

The proposed study approach was tested on the 42 MMT portfolio. The renewable generation designated as full capacity deliverability status was modeled with the assumptions in Table 3.5-2 and

Table 3.5-4. The energy only renewable generation in the portfolio was not dispatched in the assessment.

No deliverability constraints were identified in the highest system need scenario.

Deliverability constraints observed under the secondary system need scenario are shown in Table 3.5-5.

Table 3.5-5: Deliverability Constraints in 42 MMT Secondary System Need Scenario

Contingency	Overloaded Facilities	Flow
Kramer – Victor 230 kV No. 1 & 2	Kramer – Roadway 115 kV	123.62%
Kramer – Victor 230 kV No. 1 & 2	Kramer - Victor 115 kV	119.01%
Kramer – Victor 230 kV No. 1 & 2	Kramer 230/115 kV No. 1 & 2	114.43%

These overloads can be mitigated by adding generators to the existing RAS.

Based on the results, no transmission upgrades beyond what have already been approved previously are needed to support the deliverability of the 42 MMT portfolio.

3.6 Production cost simulation (PCM) study

P27-129 cont.

3.6.1 PCM assumptions

The 42 MMT portfolio described in Section 3.3.4 was utilized for the PCM study during this 2018-2019 TPP policy-driven assessment. Details of PCM assumptions and development can be found in Chapter 4. Similar to the changes made in the default portfolio study as described in Section 4.6.4, renewable resources in Kramer-Inyokern and Southern Nevada areas identified as generic in CPUC's portfolios were modeled at Lugo 500 kV and Eldorado 500 kV buses respectively because of the lack of a clear interconnection plan and the obvious local transmission constraints that were observed in the initial PCM simulations.

Two scenarios with different ISO net export limit were studied, 2000 MW limit and no export limit, in order to estimate transmission related curtailment.

3.6.2 PCM results

3.6.2.1 Congestion

Table 3.6-1 lists the congestion summary results of the scenario with 2000 MW ISO net export limit. The constraints in this list are ranked in the descending order of total number of hours of congestion. It should note that the results in Table 3.6-1 already reflect the modeling change of moving generic resources in Kramer-Inyokern and Southern Nevada areas to Lugo 500 kV and Eldoradao 500 kV buses respectively. Without this modeling change, congestion in SCE NOL-Kramer-Inyokern-Control zone, and in VEA zone would increase, compared to the congestion results for the default portfolio study discussed in chapter 4. This increase can be attributed to the incremental renewable generators identified in SCE's Kramer-Inyokern area and the VEA area in the 42 MMT portfolio.

P27-129
cont.

Table 3.6-1: Congestion summary – 2000 MW ISO net export limit

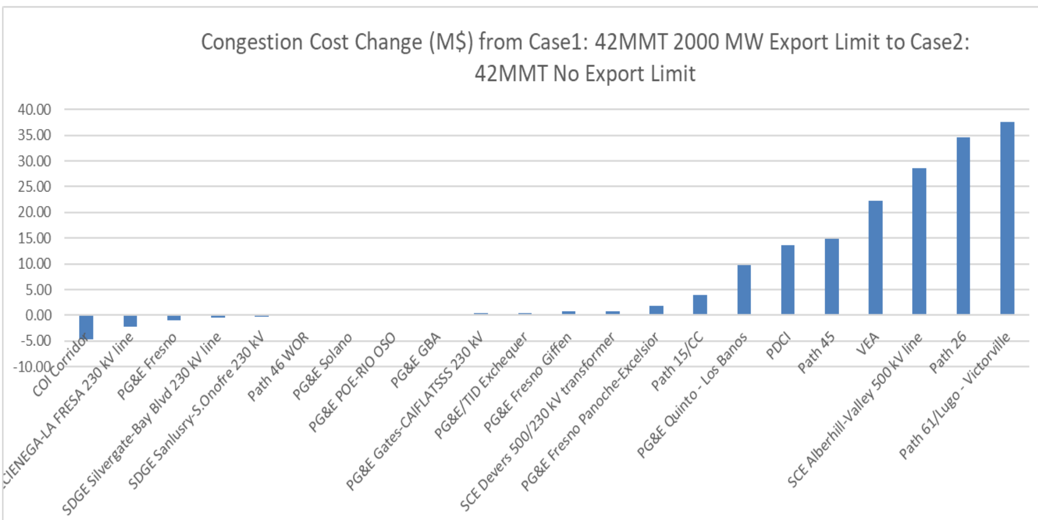
Aggregated Congestion	Congestion Cost ($M)	Congestion Duration (Hr)
Path 26	61.46	1,609
PG&E Fresno Giffen	0.49	1,597
Path 45	5.68	1,567
SCE NOL-Kramer-Inyokern-Control	1.44	1,130
PG&E/TID Exchequer	2.93	1,102
VEA	5.93	813
PG&E Fresno Panoche-Excelsior	1.27	650
PDCI	3.06	317
SCE Alberhill-Valley 500 kV line	26.89	279
SCE J.HINDS-MIRAGE 230 kV line	1.02	170
COI Corridor	9.51	154
SDGE Sanlusry-S.Onofre 230 kV	1.03	146
Path 61/Lugo - Victorville	0.26	133
SCE LCIENEGA-LA FRESA 230 kV line	4.89	101
PG&E Quinto - Los Banos	2.59	99
PG&E POE-RIO OSO	1.83	85
PG&E Fresno	1.11	73
Path 15/CC	3.47	55
SCE Devers 500/230 kV transformer	1.45	52
SDGE Silvergate-Bay Blvd 230 kV line	1.19	50
SCE Sylmar - Pardee 230 kV	0.19	26
SDGE IV-SD Import	0.32	18
Path 46 WOR	0.44	17
PG&E Solano	0.63	12
PG&E Delevn-Cortina 230 kV	0.15	11
PG&E GBA	0.16	10
SDGE-CFE OTAYMESA-TJI 230 kV line	0.04	8
PG&E Gates-CAlFLATSSS 230 kV	0.02	7
PG&E Humboldt	0.00	4
SCE Delaney-ColoradoRiver 500 kV	0.02	2
PG&E Table Mt.-Palermo 230 kV line	0.02	1
SDGE-CFE IV-ROA 230 kV line and IV PFC	0.00	1
SDGE N.Gila-Imperial Valley 500 kV line	0.00	1

P27-129
cont.

Aggregated Congestion	Congestion Cost ($M)	Congestion Duration (Hr)
SDGE Hoodoo Wash - N.Gila 500 kV line	0.00	1
Path 25	0.09	1
PG&E Summit-Drum 115 kV	0.08	1
Path 24	0.05	1

Figure 3.6-1 shows the changes in congestion from the scenario with 2000 MW ISO export limit to the scenario without an export limit for the ISO. While most of local transmission congestions remained unchanged or exhibited a slight change, congestion along major exporting corridors, such as PDCI, Path 45, and VEA's Bob SS – Mead 230 kV line increased. Path 26 (south to north direction) and SCE Alberhill-Valley 500 kV line (Valley to Alberhill direction) congestion increased mainly due to more renewable generators being able to remain online when no export limit was modeled. This resulted in higher flows along these two corridors. P27-129 cont.

Figure 3.6-1: Congestion changes between 2000 MW export limit and no export limit scenarios



3.6.2.2 Curtailment

Table 3.6-2 shows the total wind and solar generation output and the total curtailment in the two scenarios. Without enforcing an ISO net export limit, renewable curtailment reduced since the surplus generation can be exported to other regions. There were still 4.24 TWh of curtailment in the ISO's system, which were caused mainly by transmission constraints.

Table 3.6-2: Wind and Solar generation and curtailment

Scenario	42 MMT 2000 MW ISO Net Export Limit	42 MMT No Export Limit
Total Wind and Solar Generation (TWh)	82.92	96.50
Total Curtailment (TWh)	17.82	4.24

Figure 3.6-2 and Figure 3.6-3 show the wind and solar generation and curtailment by area for the 2000 MW Net Export Limit and No Export Limit scenarios, respectively. In terms of the magnitude of curtailment, the SCE Eastern and East of Lugo areas and the VEA area had the most curtailment in the 2000 MW Net Export Limit scenario. In terms of percentage, the VEA area and the SCE East of Lugo area had the highest percentages of curtailment, which was defined as curtailment divided by the summation of curtailment and generation.

Figure 3.6-3 compared the curtailment by area between these two export limit scenarios. The SCE Eastern area, the East of Lugo area and the VEA area had the most reductions of renewable curtailment when the net export limit was relaxed. This was because the solar generation in these areas could export to other regions through adjacent tie lines.

Figure 3.6-2: Wind and Solar generation and curtailment – 2000 MW Net Export Scenario

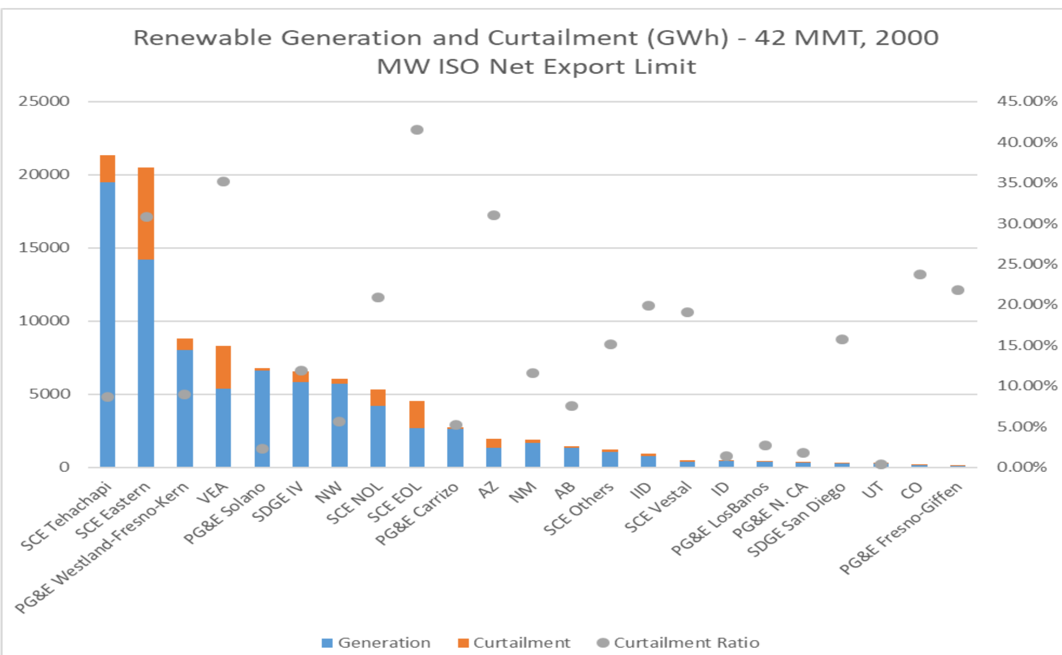


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Figure 3.6-3: Wind and Solar generation and curtailment – No Export Limit

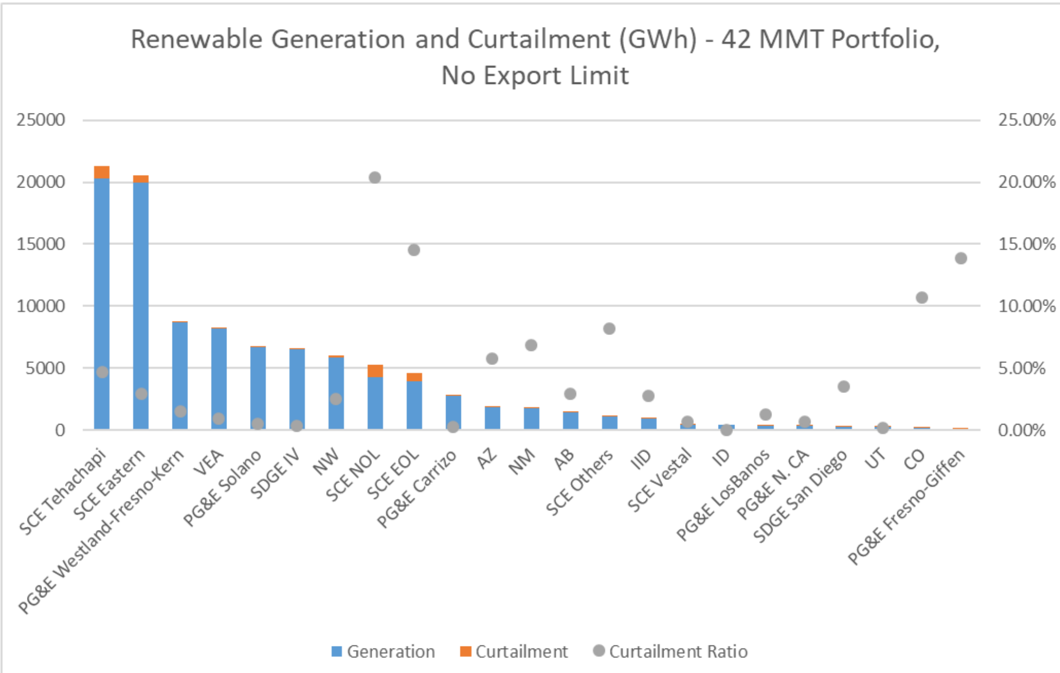
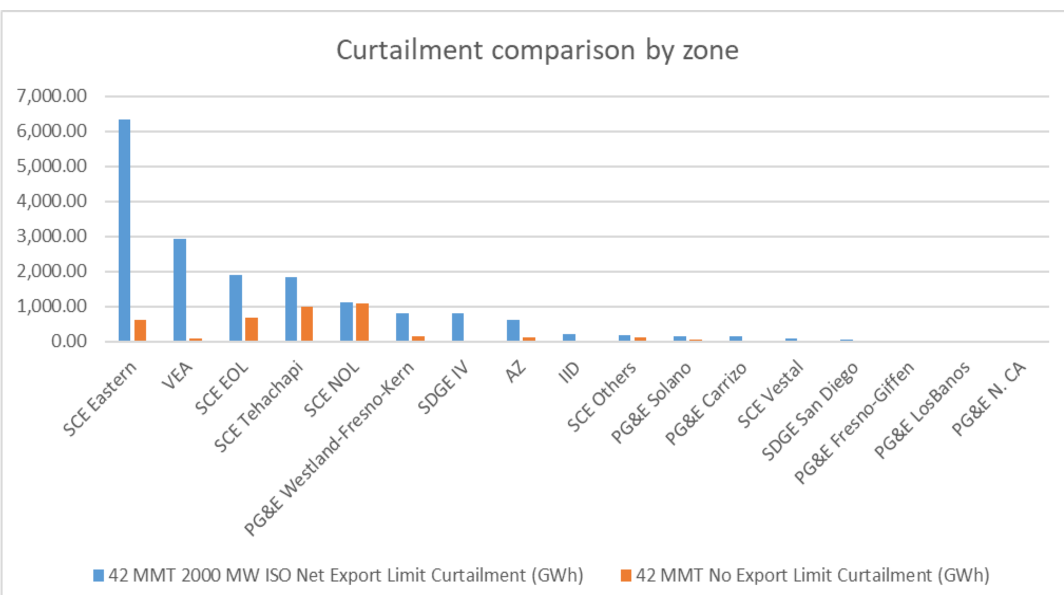


Figure 3.6-4: Curtailment changes between 2000 MW Net Export Limit and No Export Limit



P27-129 cont.

3.7 Powerflow study

3.7.1 Starting base cases

The ISO utilized the 2028 summer peak base cases developed for Northern California bulk system and Southern California Bulk system assessment described in Chapter 2. These two base cases were merged to create a consolidated ISO base case. The ISO team added the resources selected as part of the 42 MMT portfolio in the form of generic equivalent models. The team relied on the resource mapping provided by the CEC staff as explained in Section 0.

3.7.2 Snapshot identification for power flow studies

Production cost simulations were used to predict unit commitment and economic dispatch on an hourly basis for the study year, with the results used as reference data to predict future dispatch and flow patterns.

Certain hours that represent transmission system stress patterns due to high renewable dispatch in year 2028 were selected from the production cost simulation results with the objective of studying a reasonable upper bound on stressed system conditions.

The following critical factors were considered in selecting the stressed patterns:

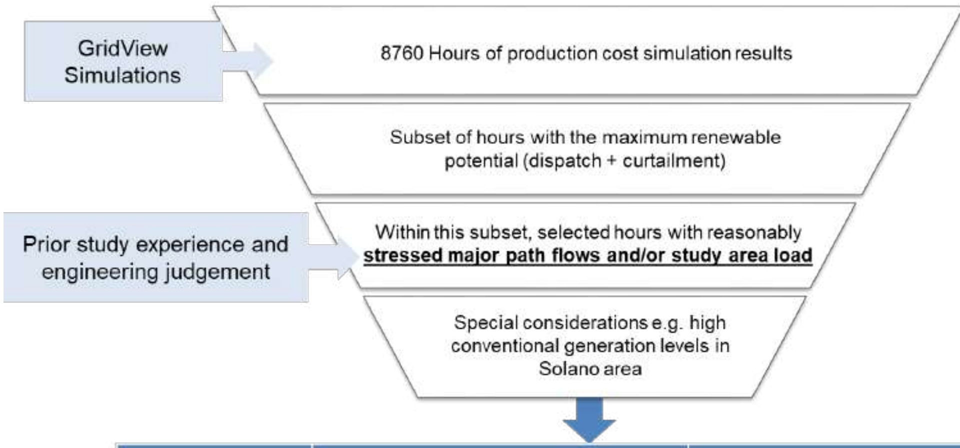
- renewable generation potential system-wide and within renewable study areas
- power flow on the major transfer paths in California

P27-129 cont.

For example, hours that were selected for reference purposes in Southern CA were during times of near maximum renewable generation potential within key study areas (Southern Nevada, Eldorado, Mountain Pass, GridLiance and Greater Kramer) and reasonably high South-to-North flow on Path 26 during these hours with high renewable potential.

A reliability assessment was performed based on a dispatch that modeled the renewable potential (the PCM output level plus the curtailment level) instead of only renewable output. The renewable curtailment in the production cost simulation could be due to ISO system-wide over-supply or transmission congestion, and the objective of the reliability assessment was to identify and examine the transmission system constraints. Therefore, in order to identify such constraints for screening purposes, the renewable dispatch in power flow cases was based on the available renewable production before curtailment that resulted from the security constrained economic dispatch model. This snapshot selection based on renewable potential allows for identification of new transmission constraints that were not modeled in production cost simulations. Figure 3.7-1 shows the process followed for the identification of snapshots and the specific snapshots identified for the in-state and out-of-state portfolios to be studied for potential reliability issues.

Figure 3.7-1: Snapshot selection for reliability assessment of portfolios



Scenario	Northern CA	Southern CA
42 MMT portfolio	August 17, 2028 Hr 21	April 25, 2028 Hr 13

P27-129 cont.

3.7.3 Powerflow results

3.7.3.1 Summary of Northern CA portfolio reliability assessment

For the Northern CA reliability assessment of the 42 MMT portfolio, the primary focus was on Solano area since this portfolio contains significant amount of EO wind resources (643 MW) in this area. Due to this focus on wind resource output, the stressed snapshot for Northern CA case was an hour 21 snapshot as indicated in Table 3.7-1. No solar resources were selected in Northern CA region as part of the 42 MMT portfolio.

Table 3.7-1 presents a summary of resource nameplate amounts selected in Northern CA zones. These values were modeled in the respective base cases for the purpose of this reliability assessment.

Table 3.7-1: Summary of portfolio resources in Northern CA

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
Northern CA	-	-	210
Greater Carrizo	-	160	-
Central Valley / Los Banos	-	146	-
Solano	-	643	-

Table 3.7-2 shows major overloads that were observed when portfolio resources in Solano were dispatched to ~90 percent of the nameplate capacity and conventional generation dispatch was at ~100 percent of the nameplate capacity in accordance with the corresponding snapshot hour (August 17, 2028 Hour 21) selected for the power flow study.

Table 3.7-2: Reliability issues observed in Solano zone

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
North Dublin – Cayetano 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	103.7%	Solano	Curtailment of conventional generation is adequate. Mitigation could be in the form of pre-contingency curtailment or a RAS action triggered by contingencies listed in this table.
Newark – Las Positas 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	111.5%		
Cayetano – Lone Tree 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	109.5%		
Newark – Las Positas 230 kV Line	Contra Costa – Moraga No. 1 and 2 230 kV lines	P7-1	103.5%		

Key findings from the Northern CA reliability assessment are:

- No area-wide transmission issue that would limit renewable generation was identified in the reliability assessment of the portfolio resources in the Northern CA region.
- Reliability issues observed in the Solano zone were caused by contingencies involving breaker faults at Contra Costa substation or the Contra Costa – Moraga No. 1 and No. 2 230 kV lines.
- Potential mitigations for these issues include (i) pre-contingency generation curtailment and (ii) remedial action schemes (RAS) to trip generation as result of a contingency.
- Either of the mitigation measures mentioned above are unlikely to result in renewable curtailment because curtailment of convention generation in this area was found to be adequate to mitigate the overloads listed in Table 3.7-2.

P27-129 cont.

3.7.3.2 Summary of Southern CA portfolio reliability assessment

As shown in Figure 3.7-1, April 25, 2028 Hour 13 was studied for evaluating the impact on the Southern CA system as a result of a large amount of solar resources in the portfolio in renewable zones in Southern CA.

Table 3.7-3 presents a summary of resource nameplate amounts selected in Southern CA zones. These values were modeled in the respective base cases for the purpose of this reliability assessment.

Table 3.7-3: Summary of portfolio resources in Southern CA

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
El Dorado, Mountain Pass, Southern NV	3,006	-	-
Kramer & Inyokern	978	-	-
Riverside East & Palm Springs	3,875	42	-
Tehachapi	1,013	153	-

3.7.3.2.1 Reliability issues observed in Eldorado, Mountain Pass and Southern NV

Table 3.7-4 shows the major overloads that were observed when the portfolio resources along with existing and contracted resources in Eldorado, Mountain Pass and Southern NV zones were dispatched to 98 percent of their nameplate capacity in accordance with the snapshot hour (April 25, 2028 Hour 13) selected for Southern CA region.

Table 3.7-4: Reliability issues observed in Eldorado, Mountain Pass and Southern NV zones

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Indian Springs Tap – Mercury Switch (VEA to NV Energy's Northwest 138 kV path)	Base case (N-0)	P0	305.00%	Southern NV	A phase shifting transformer limiting the flow towards NV Energy's Indian Springs substation or renewable curtailment (~1,300 MW)
Amargosa 230/138 kV Transformer	Base case (N-0)	P0	248.33%	Southern NV	Upgrade the existing transformer or add a new 230/138 kV transformer at Amargosa or renewable curtailment (~1,200 MW)
Innovation – Desert View 230 kV	Base case (N-0)	P0	347.48%	Southern NV	A combination of 230 kV upgrades on the GridLiance system (described in Table 3.7-5) combined with RAS and/or pre-contingency curtailment or renewable curtailment (~1,200 to ~1,500 MW)
Trout Canyon (Crazy Eyes) – Sloan Canyon (Bob) 230 kV	Base case (N-0)	P0	279.32%	Southern NV	
Northwest – Desert View 230 kV	Base case (N-0)	P0	232.39%	Southern NV	
Pahrump 230/138 kV Transformer No. 1	Base case (N-0)	P0	113.86%	Southern NV	
Pahrump 230/138 kV Transformer No. 2	Base case (N-0)	P0	108.13%	Southern NV	
Innovation 230/138 kV Transformer	Base case (N-0)	P0	108.07%	Southern NV	
Divergence	Desert View – Northwest 230 kV	P1	N/A	Southern NV	
Divergence	Innovation – Desert View 230 kV	P1	N/A	Southern NV	
Divergence	Pahrump – Innovation 230kV & Vista – Johnnie 138kV	P7-1	N/A	Southern NV	
Amargosa 230/138 kV Transformer	Pahrump – Innovation 230 kV	P1	283.43%	Southern NV	Upgrade the existing transformer or add a new 230/138 kV transformer at Amargosa or renewable curtailment
Northwest – Westside 230 kV	Northwest – Beltway 230 kV No. 2	P1	112.85%	Southern NV	

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cont.

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Ivanpah 230/115 kV Transformer Bank No. 1 or No. 2	Ivanpah 230/115 kV Transformer Bank No. 2 or No. 1	P1	116.06%	Southern NV, Eldorado and Mountain Pass	Pre-contingency curtailment and/or RAS to trip generation
Eldorado 500/230 5AA Transformer	Base case (N-0)	P0	107.14%	Southern NV, Eldorado and Mountain Pass	
Eldorado – Bob 230 kV	Eldorado 500/230 5AA Transformer	P1	123.02%	Southern NV, Eldorado and Mountain Pass	

The key observations for the Eldorado, Mountain Pass and Southern NV zones are:

- Most of the 3,006 MW modeled in Southern NV region was modeled at 230 kV substations in the GridLiance system.
- Several base case (N-0) and contingency (N-1 and N-2) transmission constraints observed in this area provide an explanation for a portion of the renewable curtailment observed in the initial PCM studies which modeled all the resources at the same locations as those assumed for power flow modeling in the same area.
- If some of the resources modeled at GridLiance substations are modeled at Eldorado substation, then the transmission constraints may not be as severe. But the ISO recognizes that the mapping effort carried out by the CEC staff indicated an environmental preference for GridLiance and VEA substations over Eldorado substation for connecting portfolio resources.

To account for the environmentally preferred locations in the Southern NV zone, the ISO tested a variety of upgrade options that can partially mitigate the transmission constraints observed in Table 3.7-4. Table 3.7-5 presents the upgrade options considered by the ISO and shows how each of these options would mitigate reliability issues in the Southern NV zone. The mitigation effectiveness was tested only in power flow studies in order to get directional insights about the scope and costs of upgrades that may be required if the objective is to eliminate most of the transmission constraints in this zone that could result in renewable curtailment. It is important to note that the elimination of all the constraints was not the objective, so upgrades with incremental additions to the scope were tested. PCM studies were not performed on the upgrade options listed in Table 3.7-5.

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cont.

Table 3.7-5: Southern NV conceptual upgrades tested for reliability performance

Option	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
I	• Phase shifting transformer at Mercury Switching Station to prevent overloads on NV Energy's 138 kV lines connected to Northwest 230/138 kV substation • Rebuild existing Pahrump – Sloan Canyon (Bob) 230 kV line to 926/1195 MVA normal/emergency rating and connect to Carpenter Canyon (Gamebird) and Trout Canyon (Crazy Eyes). • Rebuild existing Innovation – Desert View 230 kV line to 926/1195 MVA normal/emergency rating and add a 2nd circuit with the same rating. • Add 2nd 230 kV circuit Desert View – Northwest at 926/1195 MVA normal/emergency rating.	~$150 M	- Not all base case overloads can be eliminated - Some contingency overloads cannot be managed using RAS and pre-contingency curtailment - If Southern NV renewable capacity was reduced to ~2,000 MW from 3,000 MW, then very little transmission-driven curtailment is expected - With Southern NV dispatch reduced to 2,000 MW, Amargosa 230/138 kV bank overload still observed for a large number of contingency scenarios
II	In addition to Option I • Upgrade existing Desert View - Northwest 230 to 926/1195 MVA normal/emergency rating • Upgrade existing Pahrump - Innovation 230 kV to 926/1195 MVA normal/emergency rating	~$180 M	- Marginal improvement over Option I - With Southern NV capacity reduced to 2,000 MW, the number of contingencies causing Amargosa 230/138 kV bank to overload is almost cut into half
III	In addition to Option I • A new 230 kV substation at Vista • A new Vista - Charleston 230 kV line (926/1195 MVA normal/emergency rating) • Rebuild Vista - Pahrump 230 kV line to 926/1195 MVA normal/emergency rating	~$190 M	- Marginal improvement over option I - With Southern NV capacity reduced to 2,000 MW, Amargosa 230/138 kV bank overloads increased under this option with a large number of contingency scenarios resulting in an overload
IV	In addition to Option II, • A 2nd Pahrump - Sloan Canyon 230 kV line (926/1195 MVA normal/emergency) • 500 kV loop-in station at Sloan Canyon connecting to Harry Allen – Eldorado 500 kV line	~$300 M	- All base case overloads except Amargosa 230/138 kV bank overload can be eliminated. - Most contingency overloads are eliminated and the rest can be managed with a RAS - If Southern NV renewable capacity was reduced to ~2,000 MW from 3,000 MW, then very little transmission-driven curtailment is expected.

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Please note that the cost estimates listed above are highly conceptual in nature. Among these conceptual upgrades tested as part of this study,

- Option IV seemed to eliminate most of the reliability issues observed under ~3,000 MW renewables dispatch in Southern NV.
- Option I seemed to eliminate several base case overloads and reduced the severity of the remaining overloads under 3,000 MW Southern NV renewable dispatch.
- Options II and III showed marginal improvements over Option I
- When tested with a reduced capacity of ~2,000 MW in Southern NV, all the options seemed to address most of the reliability issues except for the Amargosa 230/138 kV bank overloads. This issue can be mitigated by upgrading the existing bank or by adding another bank at Amargosa depending on the feasibility of upgrading this WAPA facility.

The ISO performed this analysis in order to understand the extent of upgrades that may be required if we were to eliminate most of the transmission constraints resulting in renewable curtailment. The study also allowed us to understand the amount of resources that could be accommodated in this zone with some upgrades that would considerably reduce the possibility of renewable curtailment due to transmission constraints for Southern NV resources connecting to GridLiance system.

_3.7.3.2.2_ Reliability issues observed in Kramer and Inyokern (Greater Kramer)

Table 3.7-6 shows major overloads observed when portfolio resources along with existing and contracted resources in Kramer and Inyokern zone were dispatched to 98 percent of their nameplate in accordance with the snapshot hour (April 25, 2028 Hour 13) selected for the Southern CA region.

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Table 3.7-6: Reliability issues observed in Kramer and Inyokern zones

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Kramer – Victor 220 kV No. 1 and No. 2	Base case (N-0)	P0	142.02%	Kramer and Inyokern	Coolwater – Calcite – Lugo 230 kV line or renewable curtailment (~400 MW)
Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	Base case (N-0)	P0	103.53%	Kramer and Inyokern	Coolwater – Calcite – Lugo 230 kV line or renewable curtailment (~200 MW)
Kramer – Victor 220 kV No. 1 or No. 2	Kramer – Victor 230 kV No. 2 or No. 1	P1	184.64%	Kramer and Inyokern	RAS to trip generation after the contingency
Any three of the Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	Any of the Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	P1	102.87%	Kramer and Inyokern	RAS to trip generation after the contingency
Lugo 500/220 kV Transformer No. 1 or No. 2	Lugo 500/220 kV Transformer No. 2 or No. 1	P1	151.82%	Kramer and Inyokern	Existing RAS or bus reconfiguration
Divergence	Kramer – Victor 220 kV No. 1 and No. 2	P7	N/A	Kramer and Inyokern	Coolwater – Calcite – Lugo 230 kV line
Kramer – Victor 220 kV No. 1 and No. 2	Kramer – Victor 220 kV No. 1 and Kramer – Roadway 115 kV No. 1	P7	128.95%	Kramer and Inyokern	RAS to trip generation after the contingency
Lugo – Victor 220 kV line No. 1 and No. 2	Lugo – Victor 220 kV line No. 3 and No. 4	P7	154.35%	Kramer and Inyokern	RAS to trip generation after the contingency

Key observations for Kramer and Inyokern zone:

- Majority of resources in this zone were mapped to Kramer 230 kV substation based on the mapping work performed by the CEC staff.
- Reliability issues observed in this area provide an explanation for most of the renewable curtailment observed in the same area in PCM studies.
- High dispatch levels for the portfolio generation combined with more than 950 MW of behind-the-meter (BTM) solar generation modeled in this zone and dispatched for an Hour 13 snapshot resulted in transmission constraints. Kramer and Inyokern zone being a radial pocket can experience severe congestion due to high levels of BTM solar especially during off-peak hours.

The ISO tested a Coolwater – Calcite – Lugo 230 kV upgrade option to mitigate the reliability issues observed along Kramer to Victor and Victor to Lugo 230 kV corridor. Table 3.7-7 summarizes the upgrade option tested by the ISO.

P27-129 cont.

Table 3.7-7: Kramer and Inyokern conceptual upgrade tested for reliability performance

Upgrade	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
Coolwater – Calcite – Lugo 220 kV upgrade	Build a new 220 kV Calcite-Coolwater Transmission line Rebuild transmission structures and transmission conductor along the existing Calcite - Lugo 220 kV Transmission Line	~$480 M	Victor – Lugo 220 kV base case overloads are mitigated Kramer – Victor 220 kV base case overloads are reduced to 105%, so can be managed with modest amounts of curtailment All the contingency overloads can be mitigated by relying on RAS to drop generation

The Coolwater – Calcite – Lugo 220 kV upgrade would completely mitigate the Victor – Lugo 220 kV line overloads under base case scenario but cannot entirely mitigate the Kramer – Lugo 220 kV line overloads under base case scenario. With this upgrade, Lugo 500/230 kV transformer banks are expected to continue to overload under contingency conditions as shown in Table 3.7-6. An existing RAS and future modifications to this RAS could address this issue and reduce pre-contingency curtailment of renewables.

The Kramer – Victor 220 kV lines were overloaded to 105% of their normal rating in spite of the Coolwater – Calcite – Lugo 220 kV upgrade. These base case overloads indicate that the upgrade could reduce the curtailment of ~400 MW generation in some hours, but would not be able to support a larger increase in resources in this zone. P27-129 cont.

3.7.3.2.3 Reliability issues observed in Riverside East and Palm Springs

Table 3.7-8 shows major overloads observed when portfolio resources along with existing and contracted resources in Riverside East and Palm Springs zones were dispatched to 98% (for Solar) and 82% (for Wind) of their nameplate in accordance with the snapshot hour (April 25, 2028 Hour 13) selected for the Southern CA region.

Table 3.7-8: Reliability issues observed in Riverside East and Palm Springs zones

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Devers – Red Bluff 500 kV No. 1 or No. 2	Devers – Red Bluff 500 kV No. 2 or No. 1	P1	119.88%	Riverside East	RAS to drop generation or pre-contingency curtailment
Devers 500/230 kV Transformer	Devers – Valley 500 kV No. 1 and No. 2	P1	101.91%	Riverside East	
Divergence	Devers – Red Bluff 500 kV No. 1 and No. 2	P7	N/A	Riverside East	Add portfolio generation to the existing RAS to drop generation

Key observations for Riverside East and Palm Springs zones:

- Majority of resources in this zone were mapped to Red Bluff and Colorado River 500 kV substations based on the mapping work performed by the CEC staff. A small fraction of resources were mapped to Devers 230 kV.
- Reliability issues observed in this area can be mitigated by either a RAS action or pre-contingency curtailment. The generation tripping required to mitigate these reliability issues is ~1,150 MW for the N-1 (P1) contingency and ~1,400 MW for the N-2 (P7) contingency listed in Table 3.7-8.

The need to trip large amounts of generation to mitigate reliability issues indicates that any additional resources in this zone could trigger significant renewable curtailment in certain hours or could trigger major upgrades if renewable curtailment is to be avoided.

3.7.3.2.4 Reliability issues observed in Tehachapi

Table 3.7-9 shows major overloads observed when portfolio resources along with existing and contracted resources in Tehachapi zone were dispatched to 98 percent (for Solar) and 82 percent (for Wind) of their nameplate in accordance with the snapshot hour (April 25, 2028 Hour 13) selected for Southern CA region.

Table 3.7-9: Reliability issues observed in Tehachapi zone

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Midway – Whirlwind 500 kV No. 3	Base case (N-0)	P0	120.42%	Tehachapi	Generation curtailment (~1,000 MW). Some of this curtailment can come from conventional resources.
Windhub 500/230 kV Transformer Bank No. 1 or 2	Windhub 500/230 kV Transformer Bank No. 2 or 1	P1	155.11%	Tehachapi	RAS to trip generation or bus reconfiguration at Windhub 500 kV
Windhub 500/230 kV Transformer Bank No. 3 or 4	Windhub 500/230 kV Transformer Bank No. 4 or 3	P1	109.74%	Tehachapi	
Midway – Whirlwind 500 kV No. 3	Midway – Vincent 500 kV No. 1 or 2	P1	105.07%	Tehachapi	RAS to trip generation

Key observations for Tehachapi zone:

- Majority of resources in this zone were mapped to Windhub and Highwind 230 kV substations based on the mapping work performed by the CEC staff.
- Reliability issues observed in this area can be mitigated by either a RAS action or pre-contingency curtailment.

P27-129 cont.

- Base case overload on Midway – Whirlwind 500 kV line no. 3 is caused by heavy South to North flow on Path 26 which is one of the most frequently congested paths as observed in PCM results presented in Section 3.6.2.2. Although renewable resource in Tehachapi greatly impact this constraint, resources in most of the Southern CA region could be curtailed to relieve this congestion.

3.8 Transmission Plan Deliverability with Recommended Transmission Upgrades

As part of the coordination with other ISO processes and as set out in Appendix DD (GIDAP) of the ISO tariff, the ISO calculates the available transmission plan deliverability (TPD) in each year's transmission planning process in areas where the amount of generation in the interconnection queue exceeds the available deliverability, as identified in the generator interconnection cluster studies. In areas where the amount of generation in the interconnection queue is less than the available deliverability, the transmission plan deliverability is sufficient. In this year's transmission planning process, the ISO considered queue clusters up to and including queue cluster 11. An estimate of the generation deliverability supported by the existing system and approved upgrades is listed in Table 3.8-1 through Table 3.8-3[92]. The transmission plan deliverability is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. For study areas not listed, the transmission plan deliverability is greater than the MW amount of generation in the ISO interconnection queue up to and including queue cluster 11.

P27-129 cont.

Table 3.8-1: Deliverability for Area Deliverability Constraints in SDG&E area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
East of Miguel constraint	Arizona	~3,566
	Baja	
	Imperial	
Imperial Valley transformer constraint	Imperial	~2,558

[92] The transmission plan deliverability is estimated relative to the last official renewable portfolio provided for TPP policy driven transmission need analysis. This portfolio was provided during the 2015-2016 TPP, so some amount of deliverability may have been utilized by renewable generation that has become operational.

Table 3.8-2: Deliverability for Area Deliverability Constraints in SCE area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
Desert Area Constraint	Mountain Pass	~7,800
	Riverside East	
	Imperial	
	Nevada C	
Lugo AA Bank capacity limit	Kramer	~990
	San Bernardino - Lucerne	
Lugo - Pisgah 220kV flow limit	San Bernardino – Lucerne	~450
Kramer- Victor/Roadway -Victor South of Kramer flow limit	Kramer	~350
Victor-Lugo South of Kramer flow limit	Kramer	~690
Antelope – Vincent flow limit	Tehachapi	~6,996
	Distributed Solar – SCE (Big Creek)	
Laguna Bell – Mesa flow limit	Non-CREZ	~1,488
Pardee – Santa Clara flow limit	Non-CREZ	~1,167

P27-129 cont.

Table 3.8-3: Deliverability for Area Deliverability Constraints in PG&E area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
Manning 500/230 kV Substation Deliverability Constraint	Westlands, Carizzo, non-CREZ	~2,101 to ~4,598
Gates 500/230 kV Bank #13 Deliverability Constraint	Westlands, Carizzo, non-CREZ	~2,871 to ~6,495
Gates-11C1504-Midway #3 230kV Line Deliverability Constraint	Westlands and Carizzo	~2,826 to ~3,956
California Flats-Gates 230kV Line Deliverability Constraint	Westlands and Carizzo	~1,539 to ~1,568
New Humboldt-Trinity-Cottonwood 115 kV Line	Non-CREZ	0
East Shore-San Mateo 230kV Re-conductor Deliverability Constraint	Non-CREZ	0
Delevan 500/230 kV Substation Deliverability Constraint	Solano, Carrizo, non-CREZ	~2202
New Bay Area Lines Deliverability Constraint (Contra Costa to Tesla and Newark 230 kV lines and Birds Landing Series reactors)	Solano, non-CREZ	~631 to ~709

3.9 Conclusion

This assessment provided an opportunity to study the transmission impacts of the 42 MMT portfolio. The ISO evaluated conceptual transmission solutions in renewable zones where a significant amount of transmission constraints were observed in the powerflow snapshot assessment and renewable curtailment was observed in PCM studies. This study was also used to test the transmission capability estimates used in the CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation. The ISO used this as an opportunity to test deliverability of FCDS resources in the portfolio using proposed new renewable output assumptions that take into account the new qualifying capacity calculations for solar and wind.

Key takeaways from the deliverability, PCM and powerflow analyses:

- The proposed deliverability assessment approach found that no transmission upgrades beyond what have already been approved previously would be needed to support the 42 MMT portfolio resources that were identified as FCDS resources. The proposed approach relies on multiple system conditions – the highest system need scenario and

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the secondary system need scenarios to better align generation output assumptions with the time of day and time of year of those system needs.

- Compared to the congestion results for the default portfolio study discussed in chapter 4, congestion on Path 26, in SCE NOL-Kramer-Inyokern-Control zone, and in VEA zone increased with the 42 MMT portfolio. This increase can be primarily attributed to the incremental renewable resources identified in Southern CA, specifically in the Kramer-Inyokern zone and the Southern NV zone in the 42 MMT portfolio.
- The ISO net export limit exhibited an inverse relationship with the energy being delivered out of Southern CA renewable zones. The Riverside East, Palm Springs, Eldorado, Mountain Pass and Southern NV zones experienced large reductions in renewable curtailment when the ISO net export limit was relaxed. The reason for reduction in curtailment was that the solar generation in these areas could export to other regions through adjacent tie lines.
- Powerflow snapshot assessment showed that portfolio resources in Northern CA (primarily in Solano) are unlikely to be curtailed due to transmission limitations. No area-wide transmission issue that would limit portfolio generation from interconnecting to the ISO controlled grid or from being dispatched was identified in the reliability assessment.
- Powerflow snapshot assessment in Southern CA indicated that portfolio resources in Southern NV, Eldorado, Kramer and Inyokern zones contribute to severe transmission overloading resulting in significant renewable curtailment. Conceptual upgrades primarily consisting of 230 kV system enhancements to the GridLiance system were tested using the resource mapping recommended by the CEC staff. These upgrades could effectively reduce the expected curtailment and could accommodate ~2,000 MW resources without triggering a large amount of renewable curtailment. The conceptual upgrade tested in Kramer-Inyokern zone is likely to avoid ~400 MW of renewable curtailment during hours when severe curtailment is expected.

The 42 MMT portfolio was transmitted to the ISO as a sensitivity portfolio. A large number of alternative transmission solutions were identified that would mitigate some or all of the transmission constraints identified. With the preliminary nature of the sensitivity portfolio provided and the wide range of potential solutions, none of the solutions are recommended to be designated as either Category 1 or Category 2 policy-driven transmission solutions. The key takeaways described above will be used to inform the development of future actionable renewable portfolios as described in the next section.

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3.10 Next steps

- The ISO has already used preliminary results from this study and the latest generation interconnection studies to provide input into current IRP proceeding. The ISO will update the transmission capability estimates and assist the CPUC with incorporating those into the RESOLVE model.
- The insights generated about renewable curtailment and conceptual upgrades in the Kramer-Inyokern, Eldorado, Mountain Pass and Southern NV zones will be provided to the CPUC as the renewable portfolios for 2019-2020 TPP cycle get finalized.
- The ISO will rely on the key findings from this study in coordinating with the CEC staff on mapping of portfolio resources in zones in which severe transmission constraints were observed in the PCM as well as the powerflow snapshot assessment.

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cont.

Chapter 4

4 Economic Planning Study

4.1 Introduction

The ISO's economic planning study is an integral part of the ISO's transmission planning process and is performed on an annual basis as part of the transmission plan. The economic planning study complements the reliability-driven and policy-driven analysis documented in this transmission plan, exploring economic-driven transmission solutions that may create opportunities to reduce ratepayer costs within the ISO.

Each year's study is performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan. The studies used a production cost simulation as the primary tool to identify potential study areas, prioritize study efforts, and to assess benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. This type of economic benefit is normally categorized as an energy benefit or production benefit. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The production cost simulation is conducted for all hours for each study year.

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Economic study requirements are being driven from a growing number of sources and needs, including:

- The ISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling,
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified in reliability analysis or to meet local capacity deficiencies,
- An "economic driven" transmission solution may be upsizing a previously identified reliability solution, or replacing that solution with a different project,
- Opportunities to reduce the cost of local capacity requirements – considering capacity costs in particular, and,
- Considering interregional transmission projects as potential alternatives to regional solutions to regional needs.

These more diverse drivers require a broader view of economic study methodologies and coordination between study efforts than in the past. This year's study requirements are further complicated by the "special" study the ISO conducted regarding the benefits of increased access to Pacific Northwest hydro resources, which, while conducted as an exploratory study and using assumptions outside of those for actual project approval, provide additional insights into the Pacific AC Intertie congestion that was the subject of an economic study request and an interregional transmission project submission. As well, the ISO conducted an exploratory economic study of potential reductions or elimination of local area and sub-area needs, which overlapped with the ISO's previous commitments to conduct a biennial 10-year local capacity requirements study; which also fell on this year.

All transmission solutions identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the production cost simulation database. This ensured that all economic planning studies would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan. The economic planning study was then performed to identify additional cost-effective transmission solutions to mitigate grid congestion and increase production efficiency within the ISO. Selection of preferred solutions at "reliability" and "policy" stages are initially based on more conventional cost comparisons to meet reliability needs, *e.g.* capital and operating costs, transmission line loss savings, etc. As consideration of more comprehensive benefits, *e.g*. broader application of the TEAM, are conducted at the economic study stage, this can lead to replacing or upscaling a solution initially identified at the reliability or policy stage. The potential economic benefits are quantified as reductions of ratepayer costs based on the ISO Transmission Economic Analysis Methodology (TEAM).[93]

The above issues resulted in stronger interrelationships between studies conducted under different aspects of the transmission planning process, and which are normally documented more discretely in specific chapters in the transmission plan. As a result, there are stronger linkages and cross-references between different chapters than in the past, with the economic study process becoming somewhat of a central or core feature to the overall analysis. These interrelationships are captured to some extent in Figure 4.1-1.

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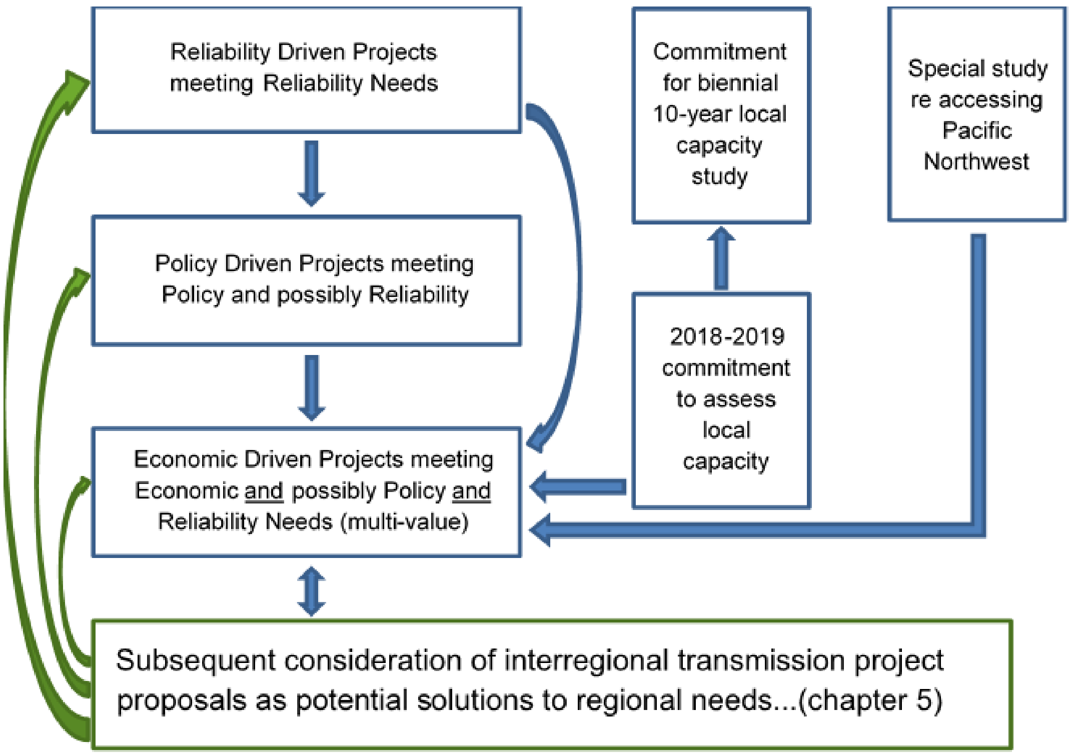
[93] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Figure 4.1-1: Interrelationship of Transmission Planning Studies



The production cost modeling simulations discussed thus far focus primarily on the benefits of alleviating transmission congestion to reduce energy costs. Other benefits are also taken into account on a case by case basis, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven. Local capacity benefits, *e.g.* reducing the requirement for local – and often gas-fired – generation capacity due to limited transmission capacity into an area can also be assessed and generally rely on powerflow analysis.

The more localized benefits discussed above were largely conceptualized around conventional transmission upgrades, with preferred resource procurement explored as an option where there was potential for those resources to be successful. With higher levels of renewable resource development and with the decline in the size of the gas-fired generation fleet, increased value is emerging for preferred resources, including storage, on a system basis regardless of local capacity and transmission congestion needs. Consideration of these new or increasing value chains creates additional complexity to economic analysis, and leads to supplementing transmission congestion analysis conducted on the GridView platform with additional platforms such as PLEXOS which provides better results for assessing system and flexible capacity benefits.

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4.2 Technical Study Approach and Process

Different components of benefits are assessed and quantified under the economic planning study. First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the “pre-project” and “post-project” study results, production benefits can be calculated from savings of production costs or ratepayer payments.

The production benefit includes three components of ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues. Such an approach is consistent with the requirements of tariff section 24.4.6.7 and TEAM principles. The calculation of these benefits is discussed in more detail in section 0.

Second, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a transmission solution for importing energy leads to a reduction of ISO system resource requirements, provided that out-of-state resources are less expensive to procure than in-state resources. The local capacity benefit corresponds to a situation where a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource.

P27-129 cont.

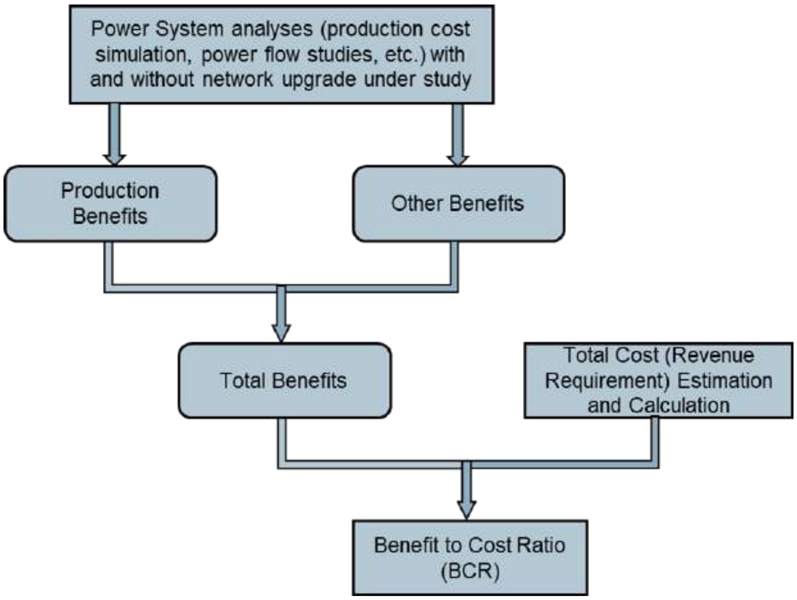
The production cost simulation plays a major role in quantifying the production cost reductions that are often associated with congestion relief. Traditional power flow analysis is also used in quantifying other economic benefits such as system and local capacity savings. Further, as noted above, platforms such as PLEXOS are proving useful in assessing impacts on system production costs.

In addition to the production and capacity benefits, any other benefits — where applicable and quantifiable — can also be included. However, it is not always viable to quantify social benefits into dollars.

Once the total economic benefit is calculated, the benefit is weighed against the cost, which is the total revenue requirement, as described in the TEAM document, of the project under study. To justify a proposed transmission solution, the ISO ratepayer benefit needs to be greater than the cost of the network upgrade. If the justification is successful, the proposed transmission solution may qualify as an economic-driven transmission solution. Note that other benefits and risks are taken into account – which cannot always be quantified – in the ultimate decision to proceed with an economic-driven transmission solution.

The technical approach of economic planning study is depicted in Figure 4.2-1. The economic planning study starts from an engineering analysis with power system simulations (using production cost simulation and snapshot power flow analysis). Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis, which is a financial calculation that is generally conducted in spreadsheets.

Figure 4.2-1: Technical approach of economic planning study



4.3 Financial Parameters Used in Cost-Benefit Analysis

P27-129 cont.

A cost-benefit analysis is made for each economic planning study performed where the total costs are weighed against the total benefits of the potential transmission solutions. In these studies, all costs and benefits are expressed in 2016 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net present values. By default, the proposed operation year is 2021 unless specially indicated.

4.3.1 Cost analysis

In these studies, the "total cost" is considered to be the present value of the annualized revenue requirement in the proposed operation year. The total revenue requirement includes impacts of capital cost, tax expenses, O&M expenses and other relevant costs.

In calculating the total cost of a potential economic-driven transmission solution, when necessary, the financial parameters listed in Table 4.3-1 are used. The net present value of the costs (and benefits) are calculated using a social discount rate of 7 percent (real) with sensitivities at 5 percent as needed.

Table 4.3-1: Parameters for Revenue Requirement Calculation

Parameter	Value in TAC model
Debt Amount	50%
Equity Amount	50%
Debt Cost	6.0%
Equity Cost	11.0%
Federal Income Tax Rate	21.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Depreciation Tax Treatment	15 year MACRS
Depreciation Rate	2% and 2.5%

In the initial planning stage, detailed cash flow information is typically not provided with the proposed network upgrade to be studied. Instead, lump sum capital cost estimates are provided. The ISO then uses typical financial information to convert them into annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. As an approximation, the present value of the utility's revenue requirement is calculated as the capital cost multiplied by a "CC-to-RR multiplier". For screening purposes, the multiplier used in this study is 1.3, reflective of a 7% real discount rate. This is an update to the 1.45 ratio used in previous transmission plans and set out in the ISO's TEAM documentation[94] that was based on prior experiences of the utilities in the ISO. The update reflects changes in federal income tax rates and more current rate of return inputs. It should be noted that this screening approximation is generally replaced on a case by case basis with more detailed modeling as needed if the screening results indicate the upgrades may be found to be needed.

In this planning cycle, the ISO recognized the need to adapt this approach in considering battery storage devices. As the "capital cost to revenue requirement" multiplier was developed on the basis of the long lives associated with transmission line, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values were developed for battery storage capital costs and those levelized annual revenue requirements were then compared to the annual benefits identified for those projects. This has the effect of the same comparative outcome, but adapts to both the shorter lifespans of battery storage and the varying lifespans of different major equipment within a battery storage facility that impact the levelized cost of the facility. This approach has been applied to the battery storage projects that received detailed analysis, set out section 0.

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[94] The ISO expects to update the TEAM documentation dated November 2, 2017 to reflect this change.

4.3.2 Benefit analysis

In the ISO's benefit analysis, total benefit refers to the present value of the accumulated yearly benefits over the economic life of the transmission solution. The yearly benefits are discounted to the present value in the proposed operation year before the dollar value is accumulated towards the total economic benefit. Because of the discount, the present worth of yearly benefits diminishes very quickly in future years.[95]

When detailed analysis of a high priority study area is required, production cost simulation and subsequent benefits calculations are conducted 10th planning year - in this case, for 2027. For years beyond 2026 the benefits are estimated by extending the 2027 year benefit with an assumed escalation rate.

The following financial parameters for calculating yearly benefits for use in determining the total benefit in this year's transmission planning cycle are:

- Economic life of new transmission facilities = 50 years;
- Economic life of upgraded transmission facilities = 40 years;
- Benefits escalation rate beyond year 2028 = 0 percent (real); and.
- Benefits discount rate = 7 percent (real) with sensitivities at 5 percent as needed.

4.3.3 Cost-benefit analysis

Once the total cost and benefit of a transmission solution is determined a cost-benefit comparison is made. For a solution to qualify as an economic transmission solution under the tariff, the benefit has to be greater than the cost or the net benefit (calculated as gross benefit minus cost) has to be positive. If there are multiple alternatives, the alternative that has the largest net benefit is considered the most economical solution. As discussed above, the traditional ISO approach is to compare the present value of annualized revenue requirements and benefits over the life of a project using standardized capital cost-to-revenue requirement ratios based on lifespans of conventional transmission. Given the relatively shorter lifespans anticipated for battery storage projects, battery storage projects were assessed by comparing levelized annual revenue requirements to annual benefits. As indicated above, the ISO must also assess any other risks, impacts, or issues.

P27-129 cont.

4.3.4 Valuing Local Capacity Requirement Reductions

As noted in chapter 1 and earlier in this chapter, the ISO recognizes that additional coordination on the long term resource requirements for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes. This is particularly important in considering how to assess the value to

[95] Discount of yearly benefit into the present worth is calculated by bi = Bi / (1 + d)i, where bi and Bi are the present and future worth respectively; d is the discount rate; and i is the number of years into the future. For example, given a yearly economic benefit of $10 million, if the benefit is in the 30th year, its present worth is $1.3 million based a discount rate of 7 percent. Likewise, if the benefit is in the 40th or 50th years, its present worth is $0.7 million or $0.3 million, respectively. In essence, going into future years the yearly economic benefit worth becomes very small.

ratepayers of proposals to reduce gas-fired generation local capacity requirements in areas where, based on current planning assumptions, the gas-fired generation is sufficient to meet the local capacity needs. If there are sufficient gas-fired generation resources to meet the local capacity needs over the planning horizon, there is not a need for reliability-driven reinforcement; rather, the question shifts to the economic value provided by the reduction in local capacity requirement for the gas-fired generation. However, it cannot be assumed that gas-fired generation no longer required for local capacity purposes will not continue to be needed for system or flexible capacity reasons, albeit through competition with other system resources. While future IRP efforts are expected to provide more guidance and direction regarding expectations for the gas-fired generation fleet at a policy level, without that broader system perspective available at this time, the ISO has taken a conservative approach in assessing the value of a local capacity reduction benefit when considering a transmission reinforcement or other alternatives that could reduce the need for existing gas-fired generation providing local capacity. In this planning cycle, the ISO therefore applied the differential between the local capacity price and system capacity price to assess the economic benefits of reducing the need for gas-fired generation when considering both transmission and other alternatives.

It was also recognized that the basis for the local price may depend on the circumstances within the local capacity area, with several scenarios set out in Table 4.3-2.

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Table 4.3-2: Scenarios for Consideration of Local Capacity Price Differentials

Scenario	Methodology (for this cycle)
If the local capacity area has a surplus of resources in the area and there is a reasonable level of competition in selling local RA capacity	The price differential between system and local capacity.
If there is only one (newer) generator in the area, and essentially no competition (or if all the units are needed and the oldest is still relatively new)	The price differential between system capacity and the full cost of service of the least expensive resource(s) may be the appropriate metric.
If there is only one older unit in the area that is heavily depreciated (or all the units are needed and if the newest is still relatively old)	Consider price the differential between the CPM soft offer cap and system capacity.*

Note *: If there is generation in an area or sub-area under an existing reliability must-run (RMR) contract, a sensitivity may be performed considering the difference between the cost of the RMR contract and the cost of system capacity.

These options are considered when needed on a case-by-case basis below and in the subsequent detailed analysis set out in section 4.9.

Northern California

For considering the benefits of local capacity requirement reductions in northern California, the differential between capacity north of Path 26 and local capacity was considered. The price of Greater Bay area generation local capacity based on the CPUC's most recent 2017 Resource Adequacy Report[96], which was published in August 2018, included a weighted average $2.22/kW-month for Greater Bay and $2.27/kW-month for the other PG&E areas. This results in

[96] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442458520

a $26,640/MW-Year and $27,240/MW-year price, respectively, for this capacity. Recognizing that local capacity in the Greater Bay area or the other PG&E local areas could also provide other benefits such as flexible and/or system capacity need, the net capacity values would be the difference between the local and system capacity price. The system weighted average is $2.09/kW-month, or $25,080/MW-year. Additionally, the CPUC also provided a system weighted average if the system resources are located in northern California (i.e., NP 26). The weighted average for system capacity value that is located in NP 26 is $2.15/kW-month, or $25,800/MW-year. The net capacity values for the Greater Bay and Other PG&E areas versus system or NP 26 resources are set out in Table 4.3-3 below.

P27-129 cont.

Table 4.3-3: Net capacity values for the Greater Bay and Other PG&E areas versus system or NP 26 resources

	Net capacity values (local – system)	Net capacity values (local – NP 26 system resources)
Greater Bay Area	$1,560/MW-year	$840/MW-year
Other PG&E Areas	$2,160/MW-year	$1,440/MW-year

Southern California

For considering the benefits of local capacity requirement reductions in southern California, the differential between capacity south of Path 26 and local capacity was considered. The price of San Diego area generation local capacity based on the CPUC's most recent 2017 Resource Adequacy Report, which was published in August 2018, included a weighted average $3.18/kW-month for San Diego and $3.48/kW-month for the LA Basin area. This results in a $38,160/MW-Year and $41,760/MW-year price, respectively, for this capacity. Recognizing that local capacity in the San Diego-Imperial Valley area or the LA Basin area could also provide other benefits such as flexible and/or system capacity need, the net capacity values would be the difference between the local and system capacity price. The system weighted average is $2.09/kW-month, or $25,080/MW-year. Additionally, the CPUC also provided a system weighted average if the system resources are located in southern California (i.e., SP 26). The weighted average for system capacity value that is located in SP 26 is $1.59/kW-month, or $19,080/MW-year. The net capacity values for the LA Basin and San Diego areas versus system or SP 26 resources are set out in Table 4.3-4 below.

Table 4.3-4: Net capacity values for the LA Basin and San Diego areas versus system or SP 26 resources

	Net capacity values (local – system)	Net capacity values (local – SP 26 system resources)
LA Basin	$16,680/MW-year	$22,680/MW-year
San Diego	$13,080/MW-year	$19,080/MW-year

4.4 Study Steps of Production Cost Simulation in Economic Planning

While the assessment of capacity benefits normally uses the results from other study processes, such as resource adequacy and local capacity assessment, production benefits are assessed through production cost simulation. The study steps and the timelines of production cost simulation in economic planning are later than the other transmission planning studies within the same planning cycle. This is because the production cost simulation needs to consider upgrades identified in the reliability and policy assessments, and the production cost model development needs coordination with the entire WECC and management of a large volume of data. In general, production cost simulation in economic planning has three components, which interact with each other: production cost simulation database (also called production cost model or PCM) development and validation, simulation and congestion analysis, and production benefit assessment for congestion mitigation.

PCM development and validation mainly include the following modeling components:

1. Network model (transmission topology, generator location, and load distribution)
2. Transmission operation model, such as transmission constraints, nomograms, phase shifters, etc.
3. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, renewable profiles.
4. Load model, including load profiles, annual and monthly energy and peak demand, and load modifiers such as DG, DR, and EE.
5. Market and system operation model, and other models as needed, such as ancillary service requirements, wheeling rate, emission, etc.

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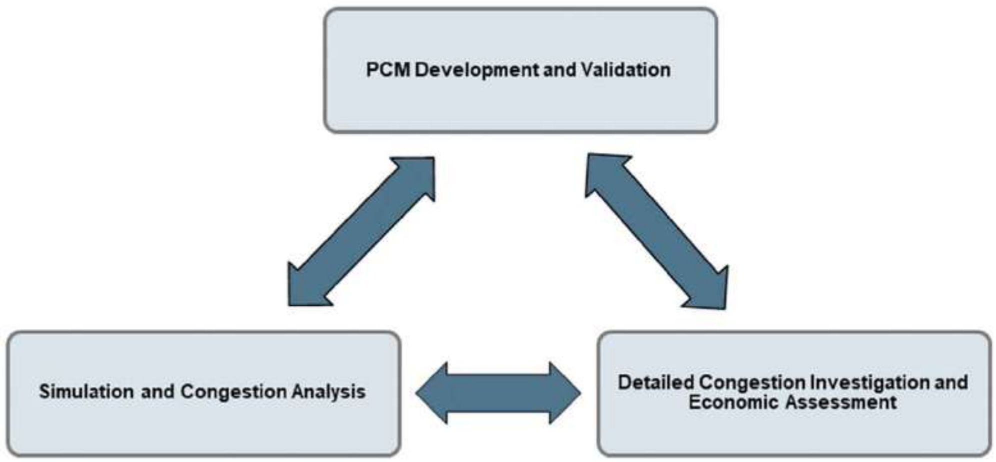
Congestion analysis is based on production cost simulation that is conducted for each hour of the study year. Congestion can be observed on transmission line or transformers, or on interfaces or nomograms, and can be under normal or contingency conditions. In congestion analysis, all aspects of results may need to be investigated, such as locational marginal price (LMP), unit commitment and dispatch, renewable curtailment, and the hourly power flow results under normal or contingency conditions. Through these investigations, congestion can be validated, or some data or modeling issues can be identified. In either situation, congestion analysis is used for database validation. The simulated power flow pattern is also compared with the historical data for validation purpose, although it is not necessary to have identical flow pattern between the simulation results and the historical data. There are normally many iterations between congestion analysis and PCM development.

In the detailed congestion investigation and economic assessment step, the ISO quantifies economic benefits for each identified transmission solution alternative using the production cost simulation and other means. From the economic benefit information a cost-benefit analysis is conducted to determine if the identified transmission solution provide sufficient economic benefits to be found to be needed. Net benefits are compared with each other where the net benefits are calculated as the gross benefits minus the costs to compare multiple alternatives that would address identified congestion issues. The most economical solution is the alternative that has the largest net benefit. In this step, the PCM and the congestion results are further validated.

Normally there are a number of iterations among these three steps through the entire economic planning study process. Figure 4.4-1 shows these components and their interaction.

Figure 4.4-1: Steps of production cost simulation in Economic planning



4.5 Production cost simulation tools and database

The ISO primarily used the software tools listed in Table 4.5-1 for this economic planning study.

Table 4.5-1: Economic Planning Study Tools

Program name	Version	Functionality
ABB GridView™	10.2.46	The software program is a production cost simulation tool with DC power flow to simulate system operations in a continuous time period, e.g., 8,760 hours in a study year (8784 hours for leap year)

The ISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The ISO may also develop a 5-year case for providing a data point in validating the benefit calculation of transmission upgrades by assessing a five year period of benefits before the 10-year case becomes relevant.

As discussed in chapter 7, the ISO also relies on PLEXOS analysis is considering system-wide resource issues outside of the ISO's tariff-based transmission planning process, in particular in support of the CPUC's integrated resource planning proceedings. While that analysis is often based on different forecast parameters and does not address intra-ISO transmission limits to the extent that the GridView analysis does, it can provide helpful comparisons of overall GridView results in some cases. Accordingly, the ISO has drawn occasional comparisons in this

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chapter between the results of the “special study” work documented in chapter 7 with the economic study results developed through GridView in this chapter.

4.6 ISO GridView Production Cost Model Development

This section summarizes the major assumptions of system modeling used in the GridView PCM development for the economic planning study. The section also highlights the major ISO enhancements and modifications to the TEPPC database that were incorporated into the ISO’s database. It is noted that details of the modeling assumptions and the model itself are not itemized in this document, but the final PCM is posted on the ISO’s market participant portal once the study is finalized.

4.6.1 Modeling assumptions

The ISO’s economic planning production cost model (PCM) used the Anchor Data Set (ADS) PCM v1.0 as a starting database and incorporated the validated changes in the consequent versions of ADS PCM case. Using this database the ISO developed the base cases for the ISO production cost simulation. These base cases included the modeling updates and additions, which followed the ISO unified planning assumptions and are described in this section.

4.6.2 Network modeling

The ADS PCM uses a nodal model to represent the entire WECC transmission network. However, the network model in the ADS PCM is based on a power flow case that is different from the ISO’s reliability power flow cases developed in the current planning cycle. The ISO took a more comprehensive approach and modified the network model for the ISO’s system to exactly match the reliability assessment power flow cases for the entire ISO planning area. The transmission topology, transmission line and transformer ratings, generator location, and load distribution are identical between the PCM and reliability assessment power flow cases. In conjunction with modeling local transmission constraints and nomograms, unit commitment and dispatch can accurately respond to transmission limitations identified in reliability assessment. This enables the production cost simulation to capture potential congestion at any voltage level and in any local area.

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4.6.3 Load demand

As a norm for economic planning studies, the production cost simulation models 1-in-2 weather conditions load in the system to represent typical or average load condition across the ISO transmission network. The California load data was drawn from the California Energy Demand Forecast 2018-2030, Revised Electricity Forecast adopted by California Energy Commission (CEC) on February 21, 2018.

Load modifiers, including DR, DG, and AAEE, were modeled as generators with hourly output profiles. The locations of the load modifiers were consistent with the reliability power flow cases.

4.6.4 Generation resources

Generator locations and installed capacities in the PCM are consistent with the 2018-2019 reliability assessment power flow cases, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

Renewable resources in Kramer-Inyokern and Southern Nevada areas identified as generic in CPUC's portfolios were modeled at Lugo 500 kV and Eldorado 500 kV buses respectively because of the lack of clear interconnection plan and the obvious local transmission constraints.

4.6.5 Transmission constraints

As noted earlier, the production cost database reflects a nodal network representation of the western interconnection. Transmission limits were enforced on individual transmission lines, paths (*i.e*., flowgates) and nomograms. However, the original TEPPC database only enforced transmission limits under normal condition for transmission lines at 230 kV and above, and for transformers at 345 kV and above.

The ISO made an important enhancement in expanding the modeling of transmission contingency constraints, which the original TEPPC database did not model. In the updated database, the ISO modeled contingencies on multiple voltage levels (including voltage levels lower than 230 kV) in the California ISO transmission grid to make sure that in the event of losing one transmission facility (and sometimes multiple transmission facilities), the remaining transmission facilities would stay within their emergency limits. The contingencies that were modeled in the ISO's database mainly are the ones that identified as critical in the ISO's reliability assessments, local capacity requirement (LCR) studies, and generation interconnection (GIP) studies. While all N-1 and N-2 (common mode) contingencies were modeled to be enforced in both unit commitment and economic dispatch stages in production cost simulation, N-1-1 contingencies that included multiple transmission facilities that were not in common mode, were normally modeled to be enforced in the unit commitment stage only. This modeling approach reflected the system reliability need identified in the other planning studies in production cost simulation, and also considered the fact that the N-1-1 contingencies normally had lower probability to happen than other contingencies and that system adjustment is allowed between the two N-1 contingencies. In addition, transmission limits for some transmission lines in the California ISO transmission grid at lower voltage than 230 kV are enforced.

Another critical enhancement to the production simulation model is that nomograms on major transmission paths that are operated by the ISO were modeled, including COI, Path 26, and Path 15. These nomograms were developed in ISO's reliability assessments or identified in the operating procedures.

Scheduled maintenance of transmission lines was modeled based on historical data. Only the repeatable maintenances were considered. The corresponding derates on transmission capability were also modeled.

PDCI (Path 65) south to north rating was modeled at 1050 MW to be consistent with the operation limit of this path identified by LADWP, which is the operator of PDCI within California.

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cont.

4.6.6 Renewable curtailment price

Multi-tiered renewable curtailment prices were used in 2018-2019 planning cycle PCM. The ISO's historical market data of LMP were used to develop the curtailment price profile, as shown in Table 4.6-1. This multi-tiered renewable curtailment price profile applies to all hours. Both GridView and PLEXOS production cost models use the same profile.

Table 4.6-1: Multi-tier Prices of Renewable Curtailment

Aggregated Curve	Segment 1	Segment 2	Segment 3	Segment 4	Floor price
Curtailment Price ($/MWh)	-15	-25	-50	-150	-300
Segment Capacity to be curtailed (MW)	0~2000	2000~7000	7000~12,000	12,000~18,000	>18,000

4.7 Production Cost Simulation Results

4.7.1 Congestion results

Based on the economic planning study methodology presented in the previous sections, a congestion simulation of ISO transmission network was performed to identify which facilities in the ISO controlled grid were congested.

The results of the congestion assessment are listed in Table 4.7-1. Columns "Cost_F" and "Duration_F" were the cost and duration of congestion in the forward direction as indicated in the constraint name. Columns "Cost_B" and "Duration_B" were the cost and duration of congestion in the backward direction. The last two columns were the total cost and total duration, respectively.

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Table 4.7-1: Potential congestion in the ISO-controlled grid in 2028

Area or Branch Group	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
VEA	MEAD S-BOB SS 230 kV line #1	0	0	28,506	1,580	28,506	1,580
Path 26	P26 Northern-Southern California	0	0	15,971	718	15,971	718
Path 26	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	8,525	287	8,525	287
Path 45	P45 SDG&E-CFE	294	199	5,716	1,295	6,009	1,494
COI Corridor	P66 COI	4,050	152	0	0	4,050	152
PG&E Quinto - Los Banos	QUINTO_SS-LOSBANOS 230 kV line #1	0	0	3,710	118	3,710	118
PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line, subject to PG&E N-1 Merced-Merced M 115/70 kV xfmr	3,613	1,350	0	0	3,613	1,350
PG&E Fresno Panoche-Excelsior	PANOCHE1-KAMM 115 kV line #1	0	0	2,748	641	2,748	641
PG&E POE-RIO OSO	POE-RIO OSO 230 kV line #1	2,148	87	0	0	2,148	87
Path 15/CC	GATES-GT_MW_11 500 kV line #1	0	0	1,730	37	1,730	37
SCE NOL-Kramer-Inyokern-Control	INYO 115/115 kV transformer #1	1,636	1,442	0	0	1,636	1,442
SDG&E Sanlusry-S.Onofre 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDG&E N-2 SLR-SO 230 kV #2 and #3 with RAS	1,327	161	0	0	1,327	161
SCE LCIENEGA-LA FRESA 230 kV line	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	1,236	48	1,236	48
SDG&E Silvergate-Bay Blvd 230 kV line	SILVERGT-BAY BLVD 230 kV line, subject to SDG&E N-2 Miguel-Mission 230 kV #1 and #2 with RAS	0	0	1,171	61	1,171	61

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cont.

Area or Branch Group	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
SCE J.HINDS-MIRAGE 230 kV line	J.HINDS-MIRAGE 230 kV line #1	1,103	178	0	0	1,103	178
COI Corridor	TBL MT D-RIO OSO 230 kV line, subject to PG&E N-2 TableMtn-Tesla and TableMtn-VacaDixon 500 kV	1,007	13	0	0	1,007	13
PG&E Fresno Giffen	GFFNJCT-GIFFEN 70.0 kV line #1	0	0	866	1,483	866	1,483
Path 46 WOR	P46 West of Colorado River (WOR)	802	26	0	0	802	26
PDCI	P65 Pacific DC Intertie (PDCI)	0	0	503	76	503	76
PG&E Solano	RPN JNCN-MANTECA 115 kV line #1	0	0	486	9	486	9
Path 26	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500 kV	0	0	449	21	449	21
Path 61/Lugo - Victorville	P61 Lugo-Victorville 500 kV Line	0	0	371	119	371	119
SDG&E IV-SD Import	SUNCREST-SUNCREST TP1 230 kV line, subject to SDG&E N-1 Eco-Miguel 500 kV with RAS	280	12	0	0	280	12
PG&E Delevn-Cortina 230 kV	DELEVN-CORTINA 230 kV line, subject to PG&E N-2 TableMtn-Tesla and TableMtn-VacaDixon 500 kV	225	12	0	0	225	12
SCE Sylmar - Pardee 230 kV	PARDEE-SYLMAR S 230 kV line, subject to SCE N-1 Sylmar-Pardee 230 kV	0	0	197	25	197	25
PG&E GBA	NRS 230/115 kV transformer #1	145	9	0	0	145	9
SDG&E IV-SD Import	SUNCREST-SUNCREST TP2 230 kV line, subject to SDG&E N-1 Sycamore-Suncrest 230 kV #1 with RAS	141	5	0	0	141	5

P27-129 cont.

Area or Branch Group	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
Path 15/CC	GT_MW_11-MIDWAY 500 kV line #1	0	0	118	5	118	5
SDG&E-CFE OTAYMESA-TJI 230 kV line	OTAYMESA-TJI-230 230 kV line #1	0	0	100	23	100	23
PG&E Fresno	SANGER-MC CALL 115 kV line #3	0	0	89	9	89	9
PG&E Table Mt.-Palermo 230 kV line	TBL MT D-PALERMO 230 kV line, subject to PG&E N-2 TableMtn-Tesla and TableMtn-VacaDixon 500 kV	84	1	0	0	84	1
PG&E Fresno	BORDEN-GREGG 230 kV line #1	0	0	81	12	81	12
Path 26	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #1 500 kV	0	0	58	3	58	3
SDG&E IV-SD Import	SUNCREST-SUNCREST TP2 230 kV line, subject to SDG&E N-1 Eco-Miguel 500 kV with RAS	52	2	0	0	52	2
PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line, subject to PG&E N-1 Merced-MrcdFLLs 70 kV	49	18	0	0	49	18
PG&E Fresno	SANGER-AIRWAYJ2 115 kV line #1	32	3	0	0	32	3
SCE Delaney-ColoradoRiver 500 kV	DELANY-COLRIVER 500 kV line, subject to SDG&E N-1 N.Gila-Imperial Valley 500 kV	25	2	0	0	25	2
SDG&E-CFE IV-ROA 230 kV line and IV PFC	IV PFC1 230/230 kV transformer #1	9	1	0	0	9	1
PG&E GBA	SN JSE A-SJB EF 115 kV line #1	7	1	0	0	7	1
PG&E GBA	MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	0	0	4	1	4	1

P27-129
cont.

Area or Branch Group	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
SDG&E N.Gila-Imperial Valley 500 kV line	N.GILA-IMPRLVLY 500 kV line, subject to SCE N-1 PaloVerde-ColoradoRiver 500 kV	2	1	0	0	2	1
PG&E Fresno	ATWELL_JCT-SMYRNA 115 kV line #1	1	8	0	0	1	8
SCE Devers 230/115 kV transformer	DEVERS 115/230 kV transformer #1	1	1	0	0	1	1
PG&E Fresno	BORDEN-GREGG 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	1	1	1	1
PG&E Humboldt	HUMBOLDT-TRINITY 115 kV line #1	0	1	0	0	0	1

Table 4.7-2 summarizes the potential congestion across specific branch groups and local capacity areas. The branch group or local area information was provided in the first column in Table 4.7-1. The branch groups were identified by aggregating congestion costs and hours of congested facilities to an associated branch or branch group for normal or contingency conditions. The congestions subject to contingencies associated with local capacity requirements were aggregated by PTO service area based on where the congestion was located. The results were ranked based on the 2028 congestion cost.

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Table 4.7-2: Aggregated potential congestion in the ISO-controlled grid in 2028

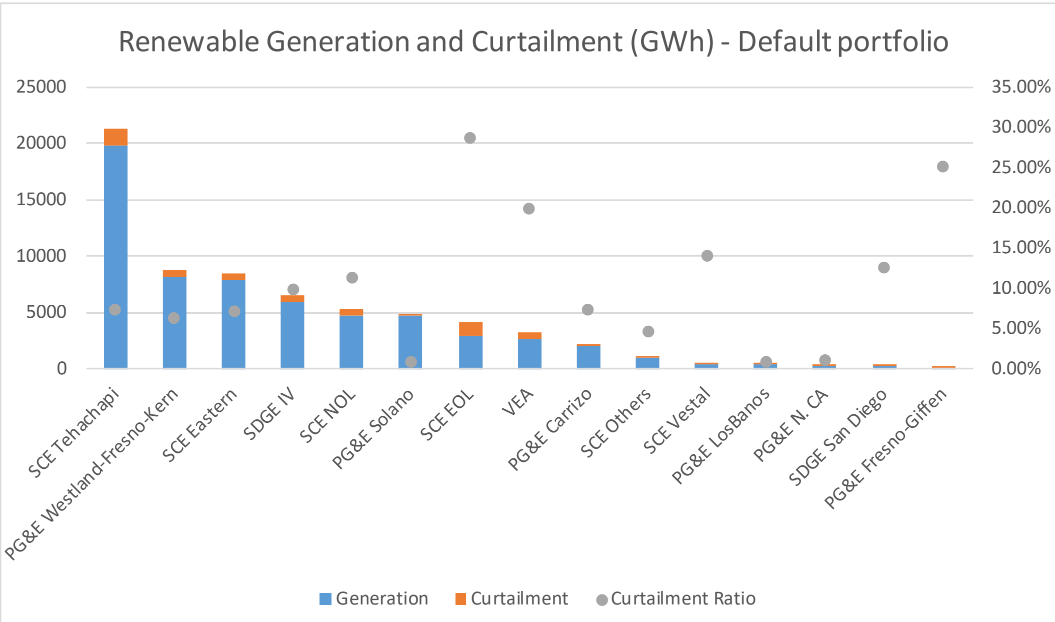
No	Aggregated congestion	2028	
		Costs (M$)	Duration (Hr)
1	VEA	28.51	1,580
2	Path 26	25.00	1,029
3	Path 45	6.01	1,494
4	COI Corridor	5.06	165
5	PG&E Quinto - Los Banos	3.71	118
6	PG&E/TID Exchequer	3.66	1,368
7	PG&E Fresno Panoche-Excelsior	2.75	641
8	PG&E POE-RIO OSO	2.15	87
9	Path 15/CC	1.85	42
10	SCE NOL-Kramer-Inyokern-Control	1.64	1,442
11	SDG&E Sanlusry-S.Onofre 230 kV	1.33	161
12	SCE LCIENEGA-LA FRESA 230 kV line	1.24	48
13	SDG&E Silvergate-Bay Blvd 230 kV line	1.17	61
14	SCE J.HINDS-MIRAGE 230 kV line	1.10	178
15	PG&E Fresno Giffen	0.87	1,483
16	Path 46 WOR	0.80	26
17	PDCI	0.50	76
18	PG&E Solano	0.49	9
19	SDG&E IV-SD Import	0.47	19
20	Path 61/Lugo - Victorville	0.37	119
21	PG&E Delevn-Cortina 230 kV	0.22	12
22	PG&E Fresno	0.20	33
23	SCE Sylmar - Pardee 230 kV	0.20	25
24	PG&E GBA	0.16	11
25	SDG&E-CFE OTAYMESA-TJI 230 kV line	0.10	23
26	PG&E Table Mt.-Palermo 230 kV line	0.08	1
27	SCE Delaney-ColoradoRiver 500 kV	0.03	2
28	SDG&E-CFE IV-ROA 230 kV line and IV PFC	0.01	1
29	SDG&E N.Gila-Imperial Valley 500 kV line	0.00	1
30	SCE Devers 230/115 kV transformer	0.00	1
31	PG&E Humboldt	0.00	1

P27-129
cont.

4.7.2 Renewable curtailment

Figure 4.7-1 sets out the renewable curtailment found in the default portfolio, by renewable energy zone within the ISO footprint. The total wind and solar curtailment in ISO's system in the study year (2028) in the default portfolio was about 7.47 TWh, which is about 9.2% of the total potential wind and solar energy.

Figure 4.7-1: Renewable Generation and Curtailment (GWh) - Default portfolio



4.7.3 Congestion analysis

In this planning cycle, detailed investigations were conducted on the constraints that may have a large impact on the bulk system and showed recurring congestion. Specifically, these constraints selected for further analysis are shown in Table 4.7-3. The detailed analysis results are in Section 0.

P27-129 cont.

Table 4.7-3: Constraints selected for Detailed Investigation

Aggregated congestion	Cost (M$)	Duration (Hours)	Reason for selection
Path 26	25.00	1,029	Path 26 south to north congestion increased from previous planning cycles, and was mostly caused by the large amount of renewable generation in Southern CA identified in the CPUC portfolio.
COI corridor	5.06	165	A continuation of work on COI congestion investigation. COI congestion increased from previous planning cycles.
PG&E Fresno Giffen	0.87	1483	Giffen congestion is an existing issue.
San Diego congestions	2.97	241	Includes Sanlusry-S.Onofre 230 kV, Silvergate-Bay Blvd 230 kV, and IV-SD import corridor congestions. These congestions were studied in detail as an effort to investigate potential LCR reduction in local areas.
SCE J.Hinds-Mirage	1.10	178	A continuation of work on this recurring congestion.

P27-129 cont.

Congestions in Table 4.7-3 were selected not solely based on congestion cost or duration, but by taking other considerations into account. Comparing the congestion and curtailment results, it was observed that some congestions with large cost or duration were driven by local renewable generators identified in the CPUC default renewable portfolio. Congestions in these areas were subject to change with further clarity of the interconnection plans of the future resources. Therefore, the congestions in these areas or zones were not selected for detail analysis in this planning cycle, particularly, in VEA and SCE EOL area, SCE NOL area, PG&E Fresno area, and PG&E Los Banos area. PG&E Fresno Giffen congestion was selected because the congestion in Giffen area is an existing issue.

Other constraints were also analyzed, but not at the same detailed level for different reasons as discussed below.

Most of the observed Path 45 congestion was in the direction from CFE to ISO, which is mainly due to the natural gas price difference across the border. Other factors that may impact the congestion include the renewable generation development in Imperial Valley area and its representation in the future 50% renewable portfolio, and the CFE's generation and load modeling. Further clarity of such factors will be required before detailed investigations need to be conducted. The ISO will continue to monitor the congestion on Path 45 in future planning cycles.

A detailed analysis was performed on the congestion on the Exchequer-La Grant 115 kV line in the 2015-2016 transmission planning cycle and no economic justification was identified. There is no change in circumstance for this constraint, therefore the ISO did not conduct further detailed studies.

Because Exchequer hydro generator is owned by non-ISO utilities, the majority of the benefits from mitigating the Exchequer-La Grant congestion would go to the generator owners rather than the ISO ratepayers. Therefore, the ISO did not conduct detailed economic analysis on Exchequer-La Grant congestion in this planning cycle. It will be monitored in the future planning cycles.

Path 15 and Central California congestion was observed mainly from south to north direction, and largely related to both Path 26 flow in south to north direction and renewable modeling in PG&E Fresno area. This congestion was further investigated in Path 26 study, but detailed economic assessment for mitigating the congestion was not conducted in this planning cycle since it requires further clarity of renewable modeling assumption in PG&E Fresno area and Southern California areas. The ISO will continuously and closely monitor and assess these congestions in the future planning cycles.

No detailed analyses on other congestions in Table 4.7-1 and were conducted as the congestions were not sufficient for justifying upgrades, based on either the studies in previous planning cycles or engineering judgement. They will be monitored in future planning cycles and will be studied as needed.

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cont.

4.8 Economic Planning Study Requests

As part of the economic planning study process, Economic Planning Study requests are accepted by the ISO, to be considered in addition to the congestion areas identified by the ISO. These study requests are individually considered for designation as a High Priority Economic Planning Study for consideration in the development of the transmission plan. These economic study requests are distinct from the interregional transmission projects discussed in chapter 5, but the interregional transmission projects discussed in chapter 5 may be considered as options to meeting the needs identified though the economic planning studies.

Other economic study needs driven by stakeholder input have also been identified through other aspects of the planning process as well – those are also set out here, with the rationale for proceeding to detailed analysis where warranted.

The ISO reviewed each regional study or project being considered for detailed analysis, and the basis for carrying the project forward for detailed analysis – or not – is set out in section 4.8. The section also describes how the study requests or projects selected for detailed analysis were studied, e.g. on a standalone basis or as one of several options of a broader area study.

4.8.1 California-Oregon Intertie Congestion and Southwest Intertie Project

The economic study request regarding California-Oregon Intertie Congestion and the Southwest Intertie Project – North project was submitted by LS Power Development, LLC. The Southwest Intertie Project - North (SWIP - North) project was also submitted as a reliability transmission project into the 2018 Request Window as set out in chapter 2 and an interregional transmission project as set out in chapter 5. P27-129 cont.

Study request overview

The study request is based on the day-ahead market congestion experienced on COI over the last several years, citing ISO Department of Market Monitoring reports. These values exceed the market congestion observed in the real time market, as well as in past ISO production simulation studies.

The Southwest Intertie Project - North (SWIP - North) project is comprised of a single circuit 500 kV transmission line from Midpoint substation (in Idaho) to Robinson Summit substation (in Nevada).

The request is for ISO to examine the causes of the historical actual day-ahead market congestion, and study the benefits of approximately 1000 MW of bidirectional transmission capacity between Midpoint and Harry Allen, which would be available to the ISO market upon completion of construction of SWIP - North.

Evaluation

Table 4.8-1 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-1: Evaluating study request – COI Congestion and SWIP - North

Study Request: Southwest Intertie Project - North		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Request is for ISO to study congestion on California Oregon Intertie (COI) and Pacific AC Intertie (PACI)	Economic studies performed by the ISO have identified congestion on COI and PACI; these congestion costs did not change significantly from previous transmission plans; and were previously found not to be sufficient to warrant transmission solutions in previous transmission plans. However, the day-ahead congestion being experienced over the past number of years is a concern, and the ISO is investigating potential to access Northwest hydro resources.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Request states that project offers policy benefits by allowing out of state renewables to help meet the new California RPS targets: 40% in 2024, 45% in 2027 and 50% in 2030. Project will allow geographical diversity to incremental RPS build out which will help reduce locational aspects of congestion caused by over generation. This will benefit ISO ratepayers with or without expansion of ISO's borders as this new line will provide a transmission path for out of state renewables to be either directly connected to or Pseudo Tied to the ISO Balancing Authority Area.	Project was studied in the informational 50% RPS and interregional transmission planning process and results are publicly available for consideration in resource planning processes.
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	Refer to earlier comment regarding "Identified Congestion".
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection Generators" above	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	Study request recommends that ISO improve the study model to quantify the actual "scheduling" congestion on ISO's PACI interface, a component that has not been included in prior cycles Adding SWIP - North relieves certain reliability and economic constraints related to imports across COI. This translates into incremental import capability into ISO. This increase in incremental import capability should be accounted for estimate of the Capacity Benefits of SWIP - North	The associated market interface issues need to be explored more fully before such benefits can be unilaterally incorporated into transmission capital decisions.

P27-129
cont.

Conclusion

While LS Power requested an economic study of its proposed project as well as of COI congestion, the issue the proposed project is seeking to address as a source of economic benefit is primarily congestion on the California-Oregon Intertie (COI). The ISO therefore considered the request to be an economic study request for increasing transfer capability over COI to eliminate or reduce potential congestion costs, for which the SWIP - North proposal may be means to mitigate.

The ISO considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and Northern Tier Transmission Group (NTTG) planning regions, respectively. The SWIP - North line is not physically connected to ISO-controlled facilities. Please refer to chapter 5. The scheduling capacity from the Harry Allen end of the ISO's approved Harry Allen-Eldorado transmission line to Robinson Summit also creates opportunity for the submitted project to provide benefits to the ISO, in which case the ISO can select to participate in the project – if that is found to be the preferred solution to meeting the ISO's regional need.

Given the expressed concerns regarding the day-ahead market congestion, the study request focusing on COI congestion was selected for additional study. Please refer to section 4.9.1 below.

4.8.2 Lake Elsinore Advanced Pumped Storage

The Nevada Hydro Company submitted the Lake Elsinore Advanced Pumped Storage project into the 2018-2019 transmission planning cycle through several venues:

- The project was first submitted to the ISO on February 14, 2018 on the basis of section 24.3.3 of the ISO's tariff, which provides an opportunity to provide input for consideration in the development of the draft Unified Planning Assumptions and Study Plan of, among other information, "Generation and other non-transmission alternatives, consistent with Section 24.3.2(a) proposed as alternatives to transmission solutions". Although section 24.3.2(a) refers to "The planning data and assumptions to be used in the Transmission Planning Process cycle, including, but not limited to, those related to Demand Forecasts and distribution, potential generation capacity additions and retirements, and transmission system modifications", *e.g*. study assumptions rather than potential solutions to needs identified through the study process, nonetheless the ISO indicated in the draft and final Unified Planning Assumptions and Study Plan[97] that it would consider the submission as an economic study request, and also suggested the proponent consider submitting the project in the 2018 Request Window specifying the ISO-identified reliability constraints the project could mitigate.
- The project was then submitted into the 2018 Request Window on October 1, 2018 purporting to address reliability needs in addition to providing other benefits. As set out

P27-129 cont.

[97] Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Draft, February 22, 2018, and Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Final, March 30, 2018

in chapter 2 and noted below, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by the operational measures. For this reason, the project was not found to be needed for reliability. The more comprehensive discussion of other potential benefits is provided below.

Study request overview

The LEAPS project is proposed to be located in Lake Elsinore, CA. Two interconnection options have been are proposed:

Option 1: SCE/SDG&E Connection

- This option interconnects the project at two points: (i) to SCE's transmission system at the proposed Alberhill[98] 500 kV substation and (ii) to SDG&E's transmission system by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation. If Alberhill is not approved, the connection point will be roughly one mile to the north-west at the proposed Lake Switchyard location.
- Approximate Project Cost = $2.04 billion

Option 2: SDG&E-only Connection

- Interconnecting to SDG&E's transmission by looping in the Talega – Escondido 230 kV line via the Case Springs 230 kV substation.
- Project Cost = $1.76 billion

Evaluation

Table 4.8-2 summarizes the benefits described in the submission and ISO's evaluation of the economic study request.

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[98] The Alberhill Substation Project was denied without prejudice by the CPUC at its environmental permitting process (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M228/K106/228106128.PDF)

Table 4.8-2: Evaluating study request – Lake Elsinore Advanced Pumped Storage Project

Study Request: Lake Elsinore Advanced Pumped Storage Project		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	LEAPS requested the ISO to evaluate congestion that was observed in the 2017-2018 transmission planning process for the following: P45 SDG&E-CFE OTAYMESA-TJI-230 230 kV line, subject to SDG&E N-1 Eco-Miguel 500 kV with RAS SUNCREST-SUNCREST TP2 230 kV line, subject to SDG&E N-1 Sycamore-Suncrest 230 kV #1 with RAS ENCINATP-SANLUSRY 230 kV line, subject to SDG&E N-1 EN-SLR 230 kV OTAYMESA-TJI-230 230 kV, subject to SDG&E N-1 Ocotillo-Suncrest 500 kV with RAS SYCAMORE TP2-SYCAMORE 230 kV line, subject to SDG&E N-1 Sycamore-Suncrest 230 kV#1 with RAS OTAYMESA-TJI-230 230 kV line, subject to SDG&E N-2 Sycamore-Suncrest 230 kV #1 and #2 with RAS MIGUEL-MIGUELMP 230 kV line, subject to SDG&E T-1 Miguel 500-230 kV #2 with RAS Nevada Hydro Company requested that TEAM analysis be performed by the ISO to assess the economic benefits provided by LEAPS to eliminate observed congestion and associated costs.	Economic studies performed by the ISO have identified congestion in San Diego area and on the corridor from IV area to San Diego area, and Path 45 as well. Detailed analysis for these congestions were conducted in this planning cycle, and the LEAPS project was studied as an alternative for congestion mitigation.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Nevada Hydo stated that LEAPS is an economic solution for integrating new renewables needed to meet 50% (now 60%) by 2030. Nevada Hydro also stated that TEAM analysis prepared by ZGlobal, Nevada Hydro's consultant, demonstrated that LEAPS provided economic benefits of between $34 and $51 million annually by providing storage of renewable energy that would otherwise be curtailed during oversupply conditions caused by 50% RPS portfolios. The stored energy can then be shifted to other peak-demand hours when renewable energy output is unavailable.	Detailed production cost simulation was conducted modeling LEAPS as set out in section 4.9.11.5.
Local Capacity Area Resource requirements	Nevada Hydro stated that LEAPS provided LCR capacity equal to 500 MW for the San Diego area with an estimated benefit of $38 million annually for local capacity reduction.	Please see further detailed analysis for local capacity benefits in section 4.9.11.5.

P27-129 cont.

Study Request: Lake Elsinore Advanced Pumped Storage Project		
Benefits category	Benefits stated in submission	ISO evaluation
Increase in Identified Congestion	Nevada Hydro requested that the ISO to assess whether the project can further reduce congestion observed on the ISO grid.	Refer to earlier comment regarding "Identified Congestion".
Integrate New Generation Resources or Loads	Nevada Hydro stated that LEAPS, like other transmission assets, enables better use of the existing transmission grid to interconnect projects needed to meet 50% criteria at lower overall cost to consumers because it reduces solar or wind overbuild capacity that will need to be procured by load-serving entities to meet their targets, as well as the associated interconnection cost. Nevada Hydro stated that LEAPS could provide between $51 and $81 million in annual benefits by reducing overbuild and related interconnection costs to meet 50% RPS. Nevada Hydro also stated that LEAPS has the capability to reduce overall production costs for the ISO for an estimated energy cost savings to consumers of between $40 and $89 million annually.	Detailed production cost simulation was conducted modeling LEAPS as set out in section 4.9.11.5.
Other	LEAPS provide the full range of ancillary services, including flexible capacity for load following needed by ISO to manage the uncertainty in VER forecasts between Day Ahead schedules and Real Time operations. Market revenues from providing energy and these ancillary services are proposed to offset any revenue requirement from the project and Initial TEAM analysis estimates this benefit to consumers to be between $38 and $60 million annually. • As described in Section 3.2 of Attachment A, LEAPS will provide reliability benefits by improving grid resiliency such as providing frequency response and voltage support to the grid. • As demonstrated in Section 3.1 of Attachment A, LEAPS will also mitigate ISO-identified overloads without having to rely on current mitigating measures include generation redispatch and/or load dropping.	The economic benefit of a number of the benefits discussed here are incorporated in the production simulation studies. No reliability requirements were identified in chapter 2 driving the need for the project.

P27-129 cont.

Conclusion

The LEAPS project is an alternative to reduce local capacity requirements for gas-fired generation in the San Diego sub-area and combined Imperial Valley/San Diego/LA Basin area, and those areas were selected for detailed analysis as discussed in section 4.8.7. Based on this and the economic study request as stated in the draft and final Unified Planning Assumptions and Study Plan, the project has therefore been included in the detailed analysis of those local capacity areas. Consideration as to, in reducing gas-fired generation local capacity requirements, whether LEAPS is providing transmission services such that the project could be considered a transmission asset or is providing local resource capacity services like a market resource is discussed in section 4.9.11.5 below. As the Federal Energy Regulatory Commission has recognized, an electric storage resource seeking cost recovery through transmission rates must demonstrate that it is operating as a transmission facility to address particular transmission needs.[99] That consideration does not drive or preclude, in itself, whether the ISO will perform the detailed analysis, as the ISO can and does consider non-transmission alternatives.

4.8.3 Red Bluff – Mira Loma 500 kV Transmission Project

Study request overview

The project was submitted by NextEra Energy Transmission West LLC as an economic study request and was also submitted into the 2018 Request Window as a potential reliability project. It involves the construction of a new 139-mile 500 kV transmission line between Red Bluff 500 kV substation and Mira Loma 500 kV substation. The project has an estimated cost of $850 million and expected in-service date of December 1, 2024. The assessment of the reliability need for this project is addressed in chapter 2.

P27-129 cont.

Evaluation

Table 4.8-3 summarizes the benefits described in the submission and ISO's evaluation of the study request.

99 *Nevada Hydro Company, Inc.* 164 FERC ¶61,197 at PP 24-25 (2018).

Table 4.8-3: Evaluating study request – Red Bluff – Mira Loma 500 kV Transmission Project

Study Request: Mira Loma – Red Bluff 500 kV Project		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Not addressed in submission	No benefits identified by ISO
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The project can support integration of renewable generation for the ISO. The Cluster 8 Phase 1&2 and Cluster 9 Phase 1 Interconnection Study Report identified several thermal overloads with all facilities in-service. This constraint is commonly referenced as the "West of Devers Area Deliverability Constraint". The project can integrate higher levels of renewable generation that were curtailed in ISO's 50% RPS "informational only" study, which indicated high potential for generation curtailment in Riverside County	This project can help to deliver renewable energy in SCE's Riverside East area, but may adversely impact other areas.
Local Capacity Area Resource requirements	The project supports Eastern LA Basin LCR Sub-Area process. The LCR need for the Eastern LA Basin sub-area is based on the need to mitigate post-transient voltage instability that is caused by the loss of the Alberhill – Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines. The LCR need to mitigate this post-transient voltage instability concern is determined to be approximately 2,230 MW (source: ISO TPP 2015-2016), which is to be met by available resources in the Eastern LA Basin sub-area.	The ISO's preliminary analysis found that although this line may help with the Eastern LA Basin voltage stability issue, reducing the Eastern LA Basin generation also adversely affects the overall LA Basin area LCR need. As a result the overall benefits are small compared to the expected cost of the project.
Increase in Identified Congestion	Not addressed in submission	Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection Generators" above	See "Delivery of Location Constrained Resource Interconnection Generators" above

P27-129 cont.

Study Request: Mira Loma – Red Bluff 500 kV Project		
Benefits category	Benefits stated in submission	ISO evaluation
Other	Study request states that the proposed project improve the reliability and thermal overloads of the existing 230 kV transmission network in the area of Devers, San Bernardino, El Casco, and Vista. The project can eliminate and/or minimize the congestion management cost. Presently, congestion management is used to mitigate thermal issues on the existing West of Devers 230 kV and 500 kV transmission network. Project would reduce the amount of congestion management necessary (including generation curtailments) to alleviate the thermal issue and consequently economic savings could be realized. The project will minimize continued reliance on the existing Special Protection Systems (SPS), specifically Inland SPS and West of Devers SPS, and continued reliance on operating procedures for voltage and thermal control. The project complements the integration of ISO approved participating transmission owner's projects and the approved competitive transmission solicitation projects. The project combats Reactive Power Deficiencies. With the continued load growth and addition of renewable generation in the Eastern area, voltage degradation to the system was observed. The inclusion of the project improved base case voltage issues. Part of the project's scope is to identify the need for additional voltage support at Red Bluff, Colorado River, and Serrano substations. This analysis will need to be conducted separately to determine an accurate amount of reactive support needed at these existing substations.	The West of Devers Project will upgrade the existing 230 kV transmission network in the area of Devers, San Bernardino, El Casco, and Vista and will address most if not all of these issues.

P27-129 cont.

Conclusion

The proposed project is an alternative that could reduce local capacity requirements in the Eastern LA Basin sub-area, and was selected for detailed analysis. Please refer to section 4.9.9.2 below.

4.8.4 Diablo Canyon to Ormond Beach and Redondo Beach (California Transmission Project)

Study request overview

The proposed California Transmission Project (CTP) is a 320 kV HVDC submarine cable that would utilize Voltage Source Converters (VSC) to interconnect with existing HVAC transmission facilities in both the Pacific Gas & Electric and Southern California Edison service areas. The cable would be routed offshore of California in the Pacific Ocean and will have three segments, two between Diablo Canyon and Ormond Beach with approximate lengths of 139 miles and 159 miles. One cable would be positioned farther out into the ocean than the other for potential future interconnection with offshore wind development. The third segment, running between Ormond Beach and Redondo Beach would be approximately 50 miles in length. See Figure 4.9-7 below.

The northern terminus of the CTP is proposed to be the Diablo Canyon 500 kV switching station and would utilize the two BAAH bay positions that will be vacated with the decommissioning of the Diablo Canyon Power Plant. There would be two 1,000 MW VSCs located on shore at Diablo Canyon with switching to enable flexible operations and maintenance while one VSC remains in operation. There would be two separate southern terminals for the CTP, one at Ormond Beach and one at Redondo Beach. At the southern terminals, there will be one 1,000 MW VSC to enable connection to the 220 kV bus at the SCE Ormond Beach 220 kV substation and one 1,000 MW VSC to enable connection to the SCE Redondo Beach 220 kV substation. Both 320 kV HVDC cables, rated at 1,000 MW each, originating at Diablo Canyon will connect to an on-shore HVDC station at Ormond Beach to allow for flexible operations and maintenance. There would be a single 320 HVDC cable running between Ormond Beach and Redondo Beach, also rated at 1,000 MW.

P27-129 cont.

Evaluation

Table 4.8-4 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-4: Evaluating study request – 1.8.4 Diablo Canyon to Ormond Beach and Redondo Beach (California Transmission Project)

Study Request: 1.8.4	Diablo Canyon to Ormond Beach and Redondo Beach (California Transmission Project)	
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	CTP will address specific PG&E area reliability issues found by the ISO in its preliminary reliability studies published on August 15, 20183. The ISO found 3 overloads on Path 26 which can be addressed by the CTP, see Table 1. The proposed mitigation is simply to reduce flow on Path 26, which would be accomplished through re-dispatch and/or exceptional dispatch resulting in higher costs. CTP as proposed, is in parallel with Path 26, adding 2,000 MW of transfer capacity under steady state conditions.	The project could address identified congestion on Path 26.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	One of the two undersea cables proposed by the project proponent is positioned farther out into the ocean than the other for potential future with offshore wind development.	Although there is no offshore wind in the CPUC provided renewable portfolio for the 2018-2019 TPP, future portfolios could include such resources.
Local Capacity Area Resource requirements	The project proponent states that the Project can provide a local capacity benefit to the LA Basin of 2,656 MW.	The proposed project connects to the ISO system at Diablo Canyon, Ormond Beach, and Redondo switchyards. Diablo Canyon is not located in an LCR local capacity area. With the planned Pardee-Moorpark #4 230 kV circuit, there will no longer be a Moorpark local capacity sub-area requirement, so Ormond Beach will no longer be located in an LCR area or sub-area. However, Redondo is located in the Western LA Basin LCR sub-area. The project could potentially provide approximately 1000 MW of LCR reduction benefits in the Western LA Basin.
Increase in Identified Congestion	See above	See above
Integrate New Generation Resources or Loads	See above	See above.
Other		

P27-129 cont.

Conclusion

The proposed project is an alternative to reducing Western LA Basin sub-area local capacity requirements. That sub-area was not selected for detailed analysis in this transmission planning cycle as discussed in section 4.8.7 and section 4.9.10. The proposed project is also an alternative that could reduce congestion on Path 26, which has been selected for detailed analysis. The project has been included in that analysis. Please refer to section 4.9.3.2 below.

4.8.5 Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV project

Study request overview

This proposed project was submitted as a reliability, economic, and policy-driven transmission project in the 2017-2018 transmission planning cycle, named San Diego/LA Basin Transmission Interconnection, and was intended to enhance reliability in the region, meet regulatory requirements, and mitigate needs caused by the possible closure of Aliso Canyon Natural Gas Storage facility. It was re-submitted into the 2018-2019 transmission planning cycle as an economic study request. The project could provide additional import capacity into the region through a new 500/230 kV transmission path between the LA Basin and San Diego/Imperial Valley areas, and reduce local capacity requirements in a highly populated region. The project includes:

- Building a new 500 kV transmission line from the planned Alberhill 500 kV substation in SCE to a new 500 kV Sycamore Canyon substation with a 500/230 kV transformer installed.
- Installing a 3rd 500/230 kV transformer at Suncrest Substation and building two 230 kV transmission circuits by looping existing Miguel–Sycamore Canyon 230 kV transmission line to the Suncrest 230 kV substation.

The preliminary cost estimate provided by the proponent is $500 million with a proposed in-service date of June, 2025.

Evaluation

Table 4.8-5 summarizes the benefits described in the submission and ISO's evaluation of the study request.

P27-129 cont.

Table 4.8-5: Evaluating study request – Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV

Study Request: 1.8.5	Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV project	
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Reduction in production costs	See section 4.9.11.4
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	By increasing the import capability of renewables into the ISO controlled grid and into LCR areas, a transmission upgrade can facilitate the integration of renewables and reduction in renewable energy curtailment to meet increasing renewable portfolio standard (RPS) goals. In quantifying the public-policy benefit of increased renewables, the breakdown of California generation by type was analyzed to calculate the percentage of renewable energy generated to serve ISO load.	The project would not be expected to substantially increase the transmission capability out of any renewable resource areas.
Local Capacity Area Resource requirements	By increasing import capabilities into an LCR area, a transmission upgrade can provide reliability benefits that otherwise would have to be purchased through LCR contracts. This LCR benefit is quantified as the difference between the LCR requirement before and after the transmission upgrade. This benefit is analyzed outside of the production cost model, using reliability models instead. LCR benefits were assessed by performing PV analysis with and without the proposed projects. The LCR benefit was determined from the additional load serving capability provided by the transmission upgrade. The $ per megawatt benefit to reduced local capacity requirement was based on the values used by ISO in its local capacity benefit evaluation of the S-line upgrade as part of the 2017/18 TPP. The high capacity benefit is valued at $75,720/MW-year and the low is half that at $37,860/MW-year.	See section 4.9.11.4
Increase in Identified Congestion	Reduction in production costs	See section 4.9.11.4
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection Generators" above	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	None	No benefits identified by ISO

P27-129 cont.

Conclusion

The proposed projects are alternatives for reducing the San Diego sub-area and combined Imperial Valley/San Diego/LA Basin area local capacity requirements and are included in the detailed analysis of those local capacity areas, which the ISO selected for detailed analysis. Please refer to section 4.9.11.4 below.

4.8.6 Colorado River 230 kV Bus - Julian Hinds 230 kV Project (Blythe Loop-in Project)

Study request overview

The project, with some subsequent modification, was submitted by AltaGas Services in the 2017-2018 transmission planning cycle and involves converting the existing privately owned Buck Blvd - Julian Hinds 230 kV generation tie-line into a network facility by way of segmenting the gen-tie line and connecting one terminal of both segments into the Colorado River Substation 230 kV bus. It would create a networked facility that would be turned over to ISO control, regulated cost-of-service cost recovery through the ISO transmission access charge, and identified as Colorado River - Julian Hinds 230 kV line. The remainder of the generation tie line would be identified as Buck Blvd - Colorado River 230 kV line, and would be treated as a generator interconnection. 117 Smart Wires Power Guardian 700-1150 devices (~19.58 Ω/phase) would be installed in series with the line on the Colorado River - Julian Hinds 230 kV line, and those along with termination facilities at Colorado River would also be placed under ISO operational control and costs recovered through ISO rates. These Power Guardians would be set to switch into injection mode to limit the power flow on the Julian Hinds - Mirage 230 kV line to avoid potential overloads. The proponent has estimated the capital cost to be included in the participating transmission owner's rate base to be $67 million with an expected in-service date of June 1, 2020. P27-129 cont.

Evaluation

Table 4.8-6 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-6: Evaluating study request – Colorado River 230 kV Bus - Julian Hinds 230 kV Project (Blythe Loop-in Project)

Study Request: 1.8.6	Colorado River 230 kV Bus - Julian Hinds 230 kV Project (Blythe Loop-in Project)	
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	The project creates production cost benefits	See section 4.9.4
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefits identified by ISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by ISO
Other	None	No benefits identified by ISO

Conclusion

Based on information and comments provided in the course of the 2017-2018 transmission planning cycle, the ISO committed at that time to re-examining this economic study request in this 2018-2019 transmission planning cycle. Please refer to section 4.9.4.

4.8.7 Local Capacity Requirement Reduction Benefit Evaluation

Study requirement

In the 2018-2019 transmission planning process, the ISO undertook a review of the existing local capacity areas to examine the local capacity needs in the ISO footprint and identify potential transmission upgrades that would economically lower gas-fired generation capacity requirements in local capacity areas or sub-areas. This review went beyond the traditional local capacity technical studies, including the biennial 10 year local capacity technical studies that are part of the ISO's ongoing study process, by examining characteristics of requirements in more detail, and examining possible mitigations. These studies were conducted under the economic analysis framework, as there is currently not a basis for identifying solutions on a reliability basis or policy basis. If there are sufficient local resources to maintain reliability, reducing the use of those resources is not necessary to meet NERC or ISO planning standards. Further, there are no applicable federal or state policies at this time that necessitate planning for reduced local

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cont.

capacity levels beyond state policies for generation relying on coastal waters for once-through-cooling, and those needs have been addressed in previous transmission plans.

It was recognized that actual viable economic-driven opportunities may be unlikely, but that even if that was the case, examining and understanding the needs – and the load, generation and system characteristics driving those needs, could be valuable in future resource procurement processes outside of the ISO's transmission planning process. In particular, the information regarding local requirement characteristics in all areas, and the scope of upgrades necessary to effect reductions in the areas selected for detailed studies - even if not currently economic - would be helpful to state policy makers and regulatory agencies in considering future policy direction or resource planning decisions.

Recognizing that a thorough and comprehensive review of transmission and hybrid alternatives for all local capacity areas in a single planning cycle was unrealistic, the ISO targeted this expanded study on exploring and assessing alternatives to eliminate or materially reduce requirements in "at least half" of the existing areas and sub-areas. The local capacity areas and sub-areas to be studied were prioritized based on the attributes of the gas-fired generation to provide other system benefits and on the gas-fired generation being located in disadvantaged communities.

This analysis therefore provided an overview of the local capacity requirements on the ISO system in greater depth than traditional local capacity requirements technical studies.

The studies were essentially carried out in two phases. The first phase consisted of:

- Examining the needs in all areas and sub-areas, with the characteristics of the needs being set out in more detail, which both provides the necessary information to inform consideration of other resource alternatives to meet the needs, and allowed the prioritization of the "more than half" areas and sub-areas for which transmission and hybrid mitigations would be explored.
- Prioritizing the areas and sub-areas, and selecting the "more than half" for which alternatives would be developed.
- Identifying and testing transmission and hybrid alternatives for that subset. The ISO did not studied the economics of "resource substitution", e.g. replacing one form of local capacity resource with another, as that is a resource procurement decision falling under the CPUC's procurement processes.

To prioritize and select the "more than half" areas for study of mitigations, the ISO screened existing areas and sub-areas, filtered out those that were already on the path to being eliminated, and prioritized the remainder to select the half that would receive in-depth analysis.

There are currently 10 active local capacity areas, and 53 distinct requirements considering both areas and sub-areas. This number will decrease to 41 distinct requirements by 2026 due to new already-approved transmission projects that will completely eliminate the LCR need in 12 sub-areas. A subset of the 41 remaining areas and sub-areas were selected for further study of potential economic-driven transmission solutions, through the prioritization process based on:

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- Local areas and sub-areas with announced retirements or units being mothballed that were not previously studied. The studies for these areas and sub-areas need to have a higher priority due to potential pending retirements.
- Local resources located in disadvantaged communities. Higher priority to local areas and sub-areas that rely on resources located in these communities.
- Type of resources. Higher priority will be given to local areas and sub-area that rely on resources that use natural gas and/or petroleum.
- Age of resources. Reduce reliance on old resources close to the end of their useful life. Reduction of resources (other than hydro, solar and wind) over 40 year old has priority.

As a result of the prioritization effort, 22 distinct area and sub-area needs listed in Table 4.8-7 by area were selected for consideration of transmission and hybrid alternatives, representing over 50% of total.

The results of this first phase are set out in Appendix G and also discussed in chapter 6, with other local capacity technical study issues.

The second phase consisted of selecting the most promising of the 22 areas and sub-areas for which alternatives were developed, for more detailed economic assessments of that subset in consideration of potential economic-driven projects for possible approval.

As discussed in chapter 6, alternatives to eliminate or materially reduce local capacity requirements in the 22 areas and sub-areas were developed, exploring not only the most limiting conditions and issues, but often exploring the "next level" of limitation that would be binding once the most limiting conditions were addressed. P27-129 cont.

Many of those alternatives are quite complex, relatively costly, and require further coordination with the CPUC's integrated resource planning framework and the longer term needs for gas-fired generation for system purposes before recommendations could be seriously considered. However, some of the less expensive and more modest upgrades identified do warrant further consideration as potential economic-driven transmission projects in this planning cycle, as well as other upgrades proposed by stakeholders that warrant detailed analysis.

Evaluation and Conclusions

Of the 22 areas and sub-areas examined, the subset identified in Table 4.8-7 have been selected for further detailed economic study for potential economic-driven recommendations, set out in section 4.9.

Table 4.8-7: Selection of Areas and Sub-areas for Examination of Alternatives and for Detailed Economic Analysis

	Areas and sub-areas selected for examination of potential alternatives – "more than half" of the areas and sub-areas.	Areas and sub-areas selected for detailed economic analysis in section 4.9
1	Sierra Area	
2	*- Pease*	*Selected for detailed economic analysis*
3	- South of Rio Oso	
	Bay Area (overall studied only if required)	
4	- Llagas	
5	- San Jose	
6	- South Bay-Moss Landing	
7	- Ames/Pittsburg/Oakland	
	Fresno (overall studied only if required)	
8	*- Hanford*	*Selected for detailed economic analysis*
9	- Herndon	
10	- Reedley	
11	Kern	
12	- Westpark	
13	*- Kern Oil*	*Selected for detailed economic analysis*
14	*LA Basin (combined with San Diego/Imperial Valley)*	*Selected for detailed economic analysis – See 17 and 18*
15	*- Eastern*	*Selected for detailed economic analysis*
	Big Creek/Ventura (overall studied only if required)	
16	*- Santa Clara*	*Selected for detailed economic analysis*
17	*San Diego/Imperial Valley (combined with LA Basin)*	*Selected for detailed economic analysis – see 14 and 18*
18	*- San Diego*	*Selected for detailed economic analysis – see 14 and 17*
19	*- El Cajon*	*Selected for detailed economic analysis*
20	*- Pala*	
21	*- Border*	*Selected for detailed economic analysis*
22	*- Esco*	

The remaining 19 distinct area and sub-area LCR needs not listed on Table 4.8-8 were found to have either lower priority or do not require any studies:

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- There was no need to study 6 sub-areas since they do not have any generation in the priority criteria: Eagle Rock, Fulton, Lakeville, Borden, Vestal and Rector.
- The remaining 13 LCR needs in other areas and sub-areas may be studied in future transmission planning cycles.

4.8.8 Potential Reliability Solutions with Potential Material Economic Benefits

The identification of reliability needs and potential mitigations to address those needs are set out in chapter 2. The identification of reliability needs includes the assessment of reliability needs expressed by stakeholders – who may have also submitted potential reliability request window submissions to address the concerns they identified - and the ISO's agreement or disagreement with those expressed concerns. The options to address various reliability needs can also include potential economic benefit. Generally, the determination of a reliability need and the selection of the preferred solution is addressed directly in chapter 2.

However, as noted in chapter 2, potential solutions can be proposed that require consideration of the potential for material economic benefits that would result in a revised or expanded solution being adopted as an economic-driven project that is also meeting the reliability need. A number of proposed projects were identified in chapter 2 as requiring further consideration of economic benefits and are set out in Table 4.8-8 below:

Table 4.8-8: Projects proposed as reliability solutions with potential economic benefits[100]

Storage Projects	Potential Economic Benefits
Cayetano 230 kV_Storage - SATA_Proposals (1-4) (NEET West) Four combinations of battery storage projects were proposed: 1. Option 1A: - 50 MW Battery Storage @ North Dublin - 50 MW Battery Storage @ Vineyard - 150 MW Battery Storage @ Newark 2.Option 1B: - 50 MW Battery Storage @ North Dublin - 50 MW Battery Storage @ Vineyard + increase Las Positas-Newark Emergency Rating 3. Option 2A: - 150 MW Battery Storage @ Vineyard - 150 MW Battery Storage @ Newark 4. Option 2B: - 150 MW Battery Storage @ Vineyard; + increase Las Positas-Newark Emergency Rating	The proposed projects purport to address a transmission reliability need, which could otherwise cause some level of congestion. Their effectiveness at addressing the reliability need was addressed in chapter 2. However, the projects are not effective for reducing sub-area local capacity requirements in the Contra Costa sub-area and the Contra Costa sub-area did not get selected for further detailed analysis. Consequently, no further analysis was undertaken.

[100] See chapter 2 for additional descriptions of the submitted projects. The table does not include projects submitted as also economic study requests, as those have already been addressed earlier in section 4.8.

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Storage Projects	Potential Economic Benefits
Sycamore 230 kV_Storage - SATA_Proposal (NEET West) Energy Storage connected to Sycamore 230 kV Substation - NEET West – build a new 230 kV bus outside the existing SDG&E Sycamore 230 kV substation. - NEET West – build a 210 MW energy storage and connect it to the new 230 kV bus outside the SDG&E Sycamore substation. - Incumbent – 230 kV cut in and connect to jumper line dead end structures outside of the Sycamore substation.	The proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, and was therefore included as an alternative in the detailed analysis for the San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area. Please refer to section 4.9.11.8 below.
San Vicente Energy Storage Project (City of San Diego) The San Vicente Energy Storage Project is a 500 MW pumped storage hydro plant built on the San Vicente reservoir in San Diego, CA. The project consists of four (4) generating units connected into a central 230 kV switchyard via four separate step-up transformers. The submission described two 230 kV lines connect the project switchyard to a switching station looping into both SDG&E's Suncrest to Sycamore Canyon 230 kV lines. However, the project proponent subsequently asked the ISO to change the point of interconnection to the Sycamore 230 kV substation.	The proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, and was included as an alternative in the detailed analysis for the San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area. Please refer to section 4.9.11.6 below.
Delta Reliability Energy Storage (Tenaska) The DRES Project is a proposed 100 MW x 4 hour discharge (400 MWh) energy storage project utilizing a Battery Energy Storage System (BESS) with a planned interconnection to the Delta Switchyard at 230 kV. Alternatively, a connection to the CC-Delta 230 kV line in the near vicinity of the Delta Switchyard can be considered. The project is proposed as a Storage As a Transmission Asset (SATA). For purposes of this submittal, the proponent assumed a 100 MW of BESS capacity to be placed in service in the fourth (4th) quarter of 2021 with a discharge duration of four (4) hours.	The proposed project is an alternative for the reduction of local capacity requirements in the Contra Costa sub-area, which did not get selected for further detailed analysis. Consequently, no further analysis was undertaken.
Sycamore Reliability Energy Storage (Tenaska) The SRES Project is a proposed 350-600 MW energy storage project utilizing a Battery Energy Storage System (BESS) with a planned interconnection to the Sycamore substation at 230 kV. Project is proposed as a Storage As a Transmission Asset (SATA). For purposes of this submittal, the proponent assumed a 350 MW BESS capacity placed in service in fourth quarter 2021 with a discharge duration of approximately 30 to 60 minutes, with potential expansion later up to 600 MW BESS at the project location.	The proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, and was included as an alternative in the detailed analysis for the San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area. Please refer to section 4.9.11.7 below.

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Storage Projects	Potential Economic Benefits
Los Padres ACAES Advanced Compressed Air Energy Storage (Hydrostor) The proposal provides options for a 175 MW – 200 MW of Advanced Compressed Air Energy Storage ("A-CAES") connected to the PG&E Mesa 230 kV switchyard and a 200 MW to 300 MW, 4-hour duration A-CAES system. The expected net cost to ISO of such a solution was estimated at $190M to $320M depending on the scale of the project and the associated ability to provide additional market services to the ISO-administered market and/or receive contracted offtake as a storage/resource adequacy asset.	The proposed project focuses on addressing a transmission reliability need and is discussed in Chapter 2. However, the project is not effective for reducing local capacity requirements, and no further analysis was undertaken.
Westside Canal Reliability Center (ConEd Clean Energy Businesses, formerly Sempra Renewables) ConEd Clean Energy Businesses submitted the Westside Canal Reliability Center -- Storage as Transmission Asset proposal for a 268 MW/4 hour battery energy storage reliability project interconnecting to the 230 kV Imperial Valley (IV) substation. Through a proposed Special Protection System (SPS), the BESS would operate in *load mode* in concert with existing, specified generation west of the overloaded elements. The combined generation increase west of the overload, and load increase via the BESS east of the overload is an alternative to mitigate potential overloading identified for the Suncrest-Sycamore Canyon 230 kV lines under contingency conditions. The BESS/SPS does not fully mitigate an overload identified for the S-line because the battery operating in load mode aggravates the issue. However, Con Ed Clean Energy Businesses mentioned that this issue would be rectified by the approved S-Line project. Furthermore, ConEd indicated that the proposed battery energy storage, when operating in *generation mode,* would be an effective solution to this issue and could serve as a stop-gap solution should S-Line construction be delayed.	The proposed project is an alternative to meeting combined San Diego/Imperial Valley/LA Basin area local capacity requirements, and was included as an alternative in the detailed analysis for the combined San Diego/Imperial Valley/LA Basin area. Please refer to section 4.9.11.9 below.
Southern California Regional LCR Reduction (SDG&E) SDG&E proposed this project as a reliability and economic-driven transmission need that is intended to reduce LCR need in the southern California region. The proposed scope is to construct a new Mission-San Luis Rey-San Onofre 230 kV line, install a 230 kV phase shifter station at Mission Substation, and upgrade various existing 230 kV lines (TL23004, TL23006, TL23022 and TL23023) in the San Diego area.	The proposed project was studied to determine if there were benefits to the San Diego sub-area or San Diego/Imperial Valley area. It was identified that the project only provided local capacity reduction benefits in the Western sub-area of the LA Basin. Notwithstanding that the Western sub-area of the LA Basin was not selected for detailed analysis of local capacity requirement reduction benefits, the results were provided in section 4.9.10 given that the benefits had been studied as part of the overall examination.

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4.9 Detailed Investigation of Congestion and Economic Benefit Assessment

The ISO selected the following branch groups and study areas for further assessment, listed in Table 4.9-1, after evaluating identified congestion, considering potential local capacity reduction opportunities and stakeholder-proposed reliability projects citing material economic benefits, and reviewing stakeholders' study requests, consistent with tariff section 24.3.4.2.

Facilities identified as potential mitigations in those study areas include stakeholder proposals from a number of sources; request window submissions citing economic benefits, economic study requests, and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements. Alternatives also include interregional transmission projects; three such projects were identified as potential options for study of economic benefits as set out in chapter 5:

- Southwest Intertie Project – North (SWIP - North)
- North Gila - Imperial Valley #2 500 kV Transmission Project (NG-IV#2)
- HVDC conversion

The stakeholder-proposed mitigations being carried forward for detailed analysis are set out in Table 4.9-1 for ease of tracking where and how these stakeholder proposals were addressed. The detailed analysis also considers other ISO-identified potential mitigations which have not been listed in Table 4.9-1.

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Table 4.9-1: Detailed Economic Benefit Investigation and related Stakeholder Proposals

Congestion area or branch group	Location and facilities	Reason & Direction
California-Oregon Intertie (COI)	Stakeholder-submitted alternatives include: SWIP - North – Interregional Transmission Project	Day ahead congestion experienced in real-time market operation
Giffen		Congestion from generation pocket to system
Path 26 Midway-Vincent	Stakeholder-submitted alternatives include: Ormond-Diablo Canyon	South to north congestion
Eastern SCE Area (outside of the Eastern LA Basin LCR sub-area)	Stakeholder-submitted alternatives include: Blythe Loop-in	Committed in the 2017-2018 transmission planning cycle to review additional information
Local Capacity Reduction Study Areas:		
Sierra Area		
Pease sub-area (Sierra)	Note PG&E provided suggestions.	Selected as potential LCR reduction possibility
Hanford sub-area (Fresno)		Selected as potential LCR reduction possibility
Reedley sub-area (Fresno)		

Congestion area or branch group	Location and facilities	Reason & Direction
Kern Oil sub-area (Kern)		Selected as potential LCR reduction possibility
Santa Clara Sub-area (Big Creek/Ventura Area)		Selected as potential LCR reduction possibility
Eastern sub-area (LA Basin)	Stakeholder-submitted alternatives include: Mira Loma – Red Bluff 500 kV Line (NextEra)	Selected as potential LCR reduction possibility
Western sub-area (LA Basin)	Stakeholder-submitted alternatives include: SDG&E Southern California Regional LCR Reduction Project	The study of this alternative was undertaken as part of the study of the San Diego reinforcements. As the option was found to primarily focus on lowering local capacity requirements in the Western sub-area of the LA Basin, the results were reported accordingly, notwithstanding the Western sub-area not being selected for detailed study.
San Diego sub-area (study in concert with the overall San Diego-Imperial Valley area)[101]	Stakeholder-submitted alternatives include: Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV project (PG&E and TransCanyon) similar to San Diego/LA Basin Transmission Interconnection submitted in the 2017-2018 transmission planning cycle Westside Canal Reliability Center (ConEd Clean Energy Businesses, formerly Sempra Renewables) Sycamore Reliability Energy Storage (Tenaska) Sycamore Substation Energy Storage (NEET West) LEAPS (Nevada Hydro) San Vicente Energy Storage (City of San Diego)	Selected as potential LCR reduction possibility

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[101] Since the San Diego sub-area is within the San Diego-Imperial Valley LCR area, the total LCR reduction benefits (or impacts) will be evaluated at the overall LCR level for the San Diego-Imperial Valley area. This is to ensure that the overall area impact (or benefits) are captured in the study.

Congestion area or branch group	Location and facilities	Reason & Direction
San Diego/Imperial Valley (studied in concert with LA Basin)[102] and considering benefits to San Diego sub-area	Stakeholder-submitted alternatives include: Westside Canal Reliability Center (ConEd Clean Energy Businesses, formerly Sempra) HVDC Conversion Project (SDG&E) – Interregional Transmission Project (Note – similar to Renewable Energy Express HVDC Conversion Project (SDG&E) – submitted in 2017-2018 transmission planning cycle North Gila - Imperial Valley #2 500 kV Transmission Project (ITC Grid Development and Southwest Transmission Partners, LLC) – Interregional Transmission Project Plus projects identified above for San Diego sub-area: Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV project (PG&E and TransCanyon) similar to San Diego/LA Basin Transmission Interconnection submitted in the 2017-2018 transmission planning cycle Westside Canal Reliability Center (ConEd Clean Energy Businesses, formerly Sempra Renewables) Sycamore Reliability Energy Storage (Tenaska) Sycamore Substation Energy Storage (NEET West) LEAPS (Nevada Hydro) San Vicente Energy Storage (City of San Diego)	Selected as potential LCR reduction possibility
El Cajon (San Diego/Imperial Valley)	Stakeholder-submitted alternative: El Cajon Sub-area Local Capacity Requirement Reduction Project (SDG&E)	Selected as potential LCR reduction possibility
Border (San Diego/Imperial Valley)	Stakeholder-submitted alternative: Border Sub-area Local Capacity Requirement Reduction Project (SDG&E)	Selected as potential LCR reduction possibility

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[102] The two areas are studied together to determine whether there are LCR impacts due to gas-fired generation requirement reductions to the other area.

This study step consists of conducting detailed investigation and modeling enhancements as needed. To the extent that economic assessments for potential transmission solutions are needed, the production benefits and other benefits of potential transmission solutions are based on the ISO's Transmission Economic Analysis Methodology (TEAM)[103], and potential economic benefits are quantified as reductions of ratepayer costs.

Determining Ratepayer Benefits

In the production benefit assessments, ISO ratepayer's benefits and WECC society benefits are calculated as:

- *ISO ratepayer's production benefit = (ISO Net Payment of the pre-upgrade case) – (the ISO Net Payment of the post-upgrade case)*
- *WECC society production benefit = (WECC Production Cost of the pre-upgrade case) – (the WECC Production Cost of the post-upgrade case)*
- *ISO Net Payment = ISO load payment – "ISO owned" generation profit – "ISO owned" transmission revenue*

The above calculation reflects the benefits to ratepayers – offsetting other ratepayer costs – of transmission revenues or generation profits from certain assets whose benefits accrue to ratepayers. These include:

- PTO owned transmission;
- Generators owned by the utilities serving ISO's load;
- Wind and solar generation or other resources under contract with an ISO load serving entity to meet the state renewable energy goal; and,
- Other generators under contracts of which the information is available for public may be reviewed for consideration of the type and the length of contract.

P27-129 cont.

These assets of course are not "owned" by the ISO. However, within production cost modeling, "ownership" is used to track which transmission's revenue and generator's profit will be counted to offset ratepayer's load-related payments, by defining those assets as "ISO owned" in the ISO's production cost model. Accordingly, the terms "ISO owned generation profit" or "ISO generator net revenue benefitting ratepayers" and "ISO owned transmission revenue" are used in the reporting of production cost modeling results in this section, to reflect those profits and revenues accruing to the benefit of ratepayers, and not to reflect actual ownership.

In addition to the production benefit, other benefits were also evaluated as needed. As discussed in section 4.1, other benefits are also taken into account on a case by case basis, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven.

All costs and payments provided in this section are in 2018 dollars.

[103] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Transmission Service

Table 4.9-1 contains a number of battery storage and pumped hydro storage projects. As discussed in chapter 1, an important consideration in evaluating storage projects as an option to meeting transmission needs is whether or not the storage facility is operating as transmission to provide a transmission service and meet transmission needs. In other words, is the resource functioning as a transmission facility? In making this assessment, considering prior FERC direction and the ISO tariff, storage as a transmission asset must:

- Provide a transmission function (*e.g*., voltage support, mitigate thermal overloads)[104];
- Meet an ISO-determined transmission need under the tariff (reliability, economic, public policy)[105]; and,
- ”Be the more efficient or cost-effective solution to meet the identified need”[106] and “If a transmission solution is required to meet an economic need, the ISO must determine if the benefits of the transmission solution outweigh the costs. The benefits of the solution may include a calculation of any reduction in production costs, congestion costs, transmission losses, capacity, or other electric supply costs, *resulting from improved access to cost-efficient resources”*[107] (emphasis added).

Further, if the storage meets the above parameters and is selected as a regional transmission solution to meet a transmission need, it would be subject to competitive solicitation.

This direction provides that the determination of eligibility for transmission asset – and regulated rate recovery through the ISO tariff – is not only based on if a transmission need is being met, but how the storage project is meeting the need. While the storage projects identified in Table 4.9-1 are concentrated in the San Diego/Imperial Valley area, a single determination is not sufficient as there are both common characteristics and differences in how the projects purport to meet the transmission need, including how local transmission needs would be met. As a result, it is necessary to consider this question individually for each storage project.

P27-129 cont.

Scope of Study Alternatives

Finally, it is important to reiterate that all regional transmission solutions – other than modifications to existing facilities, are subject to the ISO’s competitive solicitation process as set out in the ISO’s tariff. So, while many projects have been submitted with narrowly defined project scopes, the ISO is not constrained to only study those scopes without modification, or to study the projects exclusively on the basis under which the proponent suggested.

[104] *Western Grid Development, LLC,* 130 FERC ¶61,056 at PP 43-46, 51-52 *order on reh’g,* 133 FERC ¶61,029 at PP 11-18.

[105] *Nevada Hydro Company, Inc.,* 164 FERC ¶61,197 at PP 22-25 (2018).

[106] ISO Tariff Section 24.4.6.2., re selecting a transmission solution for an identified reliability need.

[107] ISO Tariff Section 24.4.6.7, re economic needs

4.9.1 California-Oregon Intertie (COI)

The production cost simulations in this planning cycle showed an increase in COI congestion from previous planning cycles. Two alternatives were studied to examine whether mitigating COI congestion could provide benefit to ISO's ratepayers:

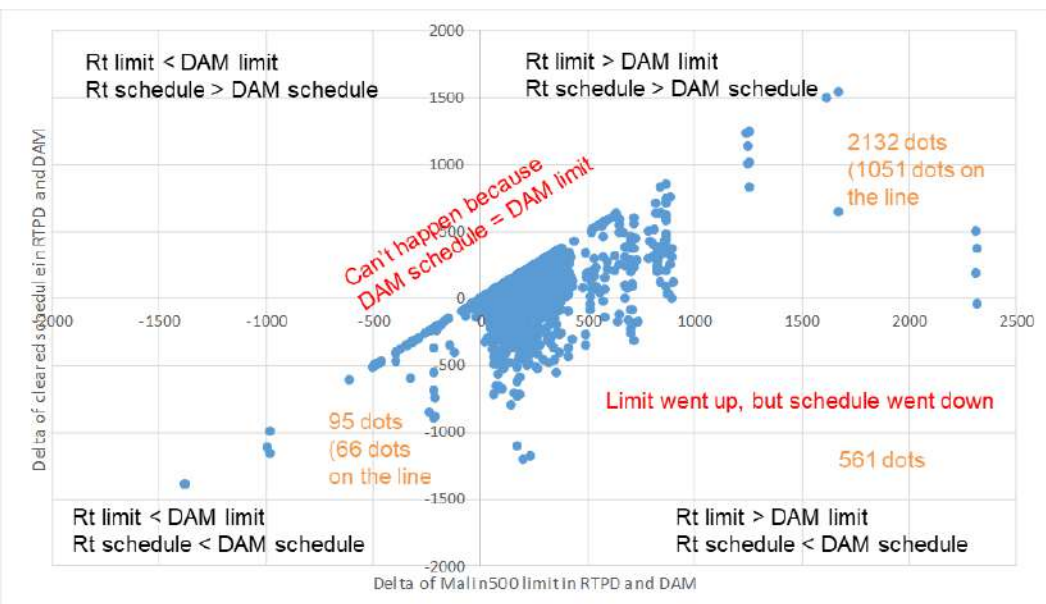
- Alternative 1: Model COI path rating at 5100 MW assuming the N-2 contingency of the two 500 kV lines between Malin and Round Mountain is conditional credible and with necessary revisions to existing SPS.
- Alternative 2: SWIP - North project.

The congestion observed in production cost modeling studies is based on physical congestion, with limits generally established by the physical capabilities. Stakeholders have observed an apparent disconnect in past ISO congestion studies, compared to the day-ahead congestion that has been observed in the ISO markets over the last number of years.

This issue was explored in part by examining the real time conditions when day ahead congestion was found to occur.

Figure 4.9-1 below presents a plot of the delta of Malin 500 kV cleared schedules (between real time and day ahead) versus the delta of the Malin 500 limits (between real time and day ahead) when the day ahead limit was binding, for the year 2016.

Figure 4.9-1: Cleared Schedules versus Limits, between Day Ahead and Real Time at Malin 500



Notes:

- When day ahead market is binding (the cleared schedule is equal to the limit), real time may not be binding
- The changes in cleared schedules from day ahead to real time are always less than the changes in limits (when day ahead is binding)

P27-129 cont.

Upon reviewing the circumstances of day-ahead congestion, the ISO has concluded that a material portion of that congestion relates to a number of reasons:

- Capacity exists, but is only released to the ISO market in real time (ETC rights)
- Capacity exists, but scheduling rights are not available to the ISO market at all despite not being used
- Over scheduling in day ahead market more than the scheduling limits and is corrected in real time
- Over scheduling in day ahead market at levels higher than intended in real time.
- Incomplete information of outside system and the locations of resources could impact calculation of physical flows, but physical flows are not generally binding, so this is likely not material

The first three observations were based on the real time limit climbing from the day-ahead, and the real time schedules climbing to match the new limit. The fourth conclusion was reflected by times where the limit climbs, but the real time schedules climb only a little, or decline.

The greatest opportunity is for the ISO market to gain access to the additional physical capacity that cannot currently be utilized in the ISO market. The ISO is accordingly investigating with its neighbors the possibility of accessing this capacity.

The analysis in this study therefore continues to focus on incremental gains in physical capacity – either by rating increases on the existing facilities or by system reinforcements.

P27-129 cont.

4.9.1.1 5100 MW COI path rating

As a part of the Pacific Northwest informational special study set out in chapter 7, the potential to increase the current WECC Path Rating of the COI from 4800 MW to 5100 MW without any material transmission upgrades was identified as a potential option. The increase in path rating could be achieved through changes to the criteria that was used to establish the current Path Rating. The 5100 MW path rating assumption was based on the investigation of potentially converting the N-2 contingency of the two 500 kV lines between Malin and Round Mountain to a conditional credible N-2 contingency with necessary revisions to existing SPS. The increase in the path rating would need to go through the WECC Path Rating Process for approval. Another option would be to include load shedding in California following the N-2 contingency, which would involve capital expenditures.

The following provides the economic assessment from the production cost simulation of increasing the COI path rating to reduce congestion on COI. The production benefit for ISO's ratepayers and the WECC overall production cost savings of increasing the COI path rating to 5100 MW are shown in Table 4.9-2.

Table 4.9-2: Production Cost Modeling Results for COI path rating at 5100 MW

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,466	-9
ISO generator net revenue benefitting ratepayers	2,526	2,525	-1
ISO owned transmission revenue	199	202	3
ISO Net payment	5,387	5,389	-7
WECC Production cost	16,875	16,876	-1

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

This shows that simply increasing the COI path rating did not bring net benefits to ISO's ratepayers. Further investigation of the COI congestion study results revealed that the majority of COI congestion occurred in the simulation during the hours when COI rating was derated due to scheduled maintenance, as shown in Figure 4.9-2. The path rating derates were determined based on the maintenance outages, and those derates were not impacted by the path rating increase.

The increase in the rating did have impacts in other hours, however. Table 4.9-3 shows the COI congestion changed with modeling the 5100 MW path rating. When the total congestion hours reduced, the congestion cost actually increased. This aligns with the overall result that the increased COI limit negatively impacted ISO ratepayers while having minimal impact on overall WECC production costs. P27-129 cont.

Figure 4.9-2: COI Limit and Flow in Default Portfolio Base Case

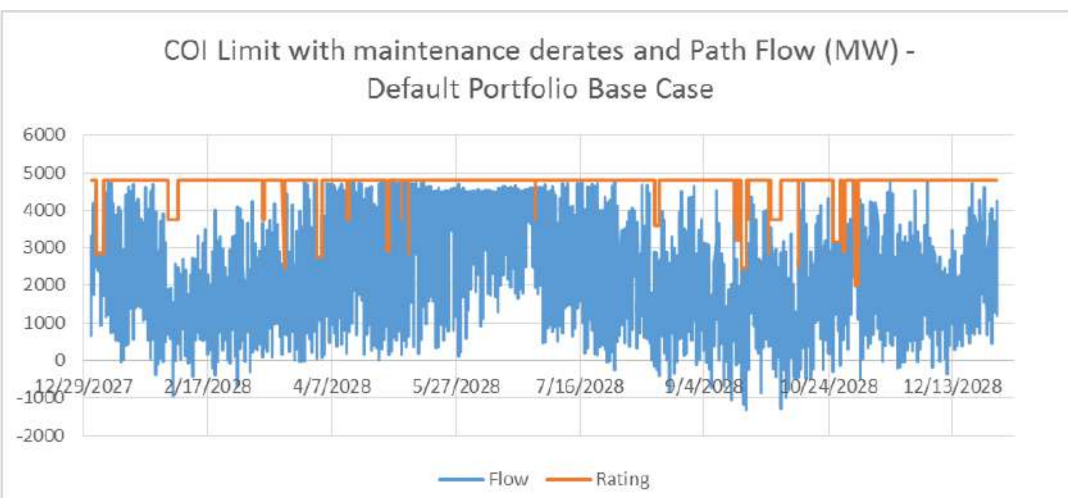


Table 4.9-3 COI congestion changes with modeling 5100 MW COI path rating

	Congestion hour	Congestion cost (M$)
Default portfolio Base case	165	5.06
COI 5100 MW	132	6.07

The congestion change was mainly due to the changes in generation dispatch in ISO areas, as shown in Figure 4.9-3. In Figure 4.9-3 and Figure 4.9-4, CIPB is the area defined in the production cost model for the PG&E Bay area, CIPV is the rest of PG&E areas outside the Bay area, CISC is the SCE area, and CISD is the entire SDG&E area including the San Diego and IV areas.

In modeling the 5100 MW COI rating, PG&E generation overall reduced slightly, particularly the thermal generation. However, the ISO system still needed thermal generation to provide ancillary services and energy in some hours, which resulted in thermal generation increases in Southern California. (Note that lowering congestion into a constrained area doesn't assure lower ISO ratepayer net benefits, as the downward change in LMP within the constrained area does not necessarily outweigh any increase in LMP over the load outside of the constrained area, and generation revenues and transmission revenues also have to be taken into account.)

As the result, the COI path rating increase to 5100 MW did not show benefit to the ISO's ratepayers in this planning cycle's production cost modeling studies.

Another factor to consider regarding potential benefits of COI upgrades or related projects is with respect to ability to access additional capacity from the Northwest that has been stored during energy surplus periods in California due to high solar output. Figure 4.9-4 shows that with the 5100 MW COI path rating modeled, generation output from Northwest regions did not change materially.

P27-129
cont.

Figure 4.9-3: Generation changes in ISO areas with modeling 5100 MW COI path rating

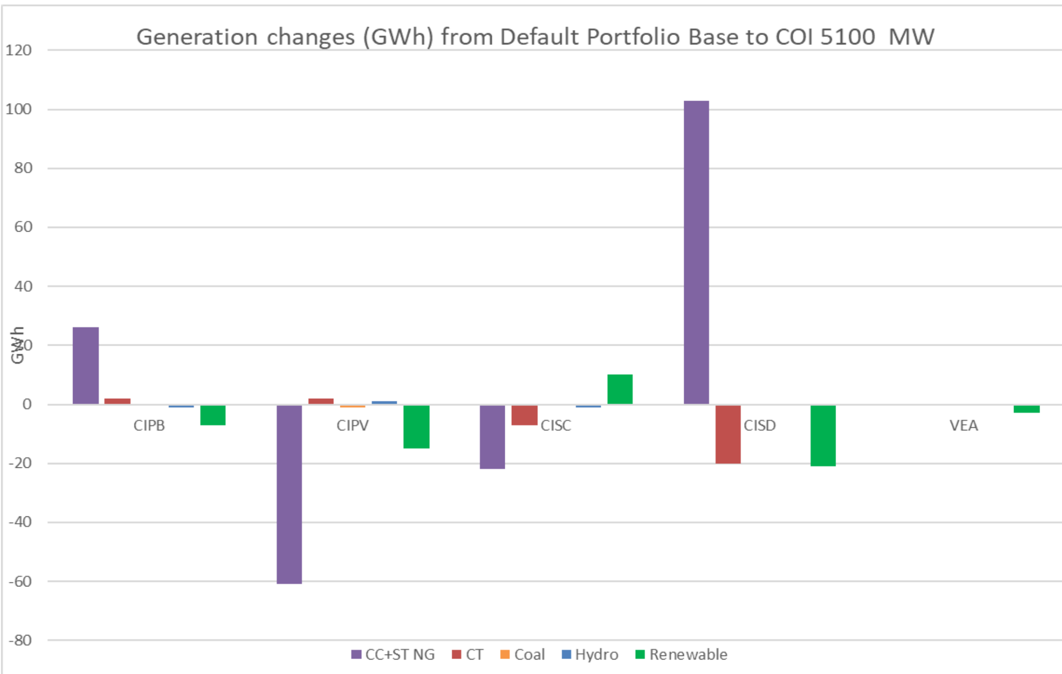
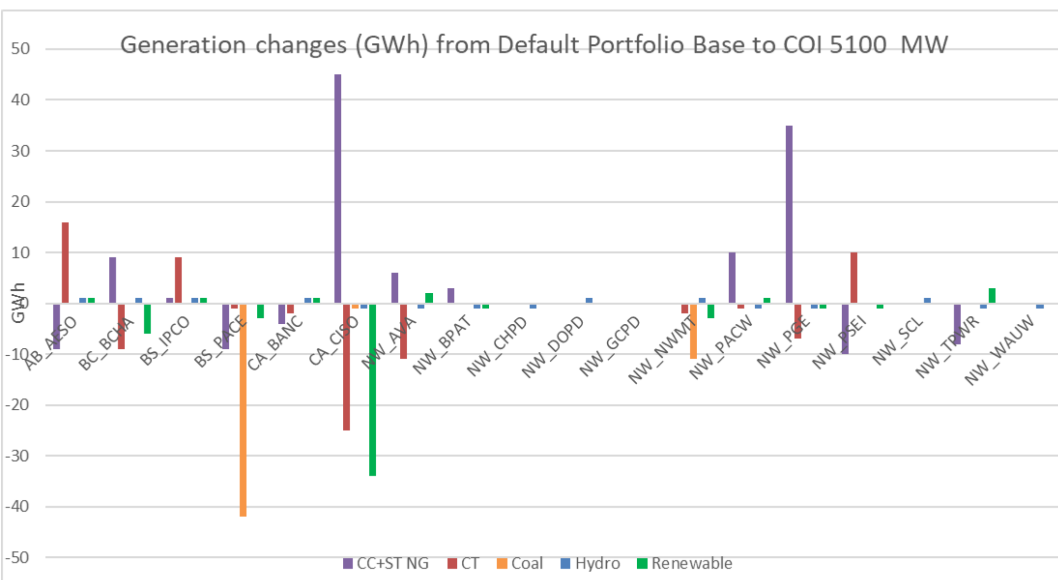


Figure 4.9-4: Northwest and California generation changes with COI 5100 MW path rating



P27-129
cont.

Conclusions

The study results do not support pursuing capital expenditures to achieve a path rating increase at this time. COI congestion and potential benefits of increasing the COI path rating were also investigated in the Pacific Northwest – California Transfer Increase Study, using different hydro conditions, as described in chapter 7. As set out in chapter 7, the issue of the path rating criteria will be monitored, and a path rating increase will be pursued if it can be achieved in the future without requiring capital expenditures.

4.9.1.2 SWIP - North project

The Southwest Intertie Project North (SWIP - North) was submitted as an economic planning study request by LS Power Development, LLC. The project was also submitted in the 2018 Request Window for reliability-driven alternatives as set out in chapter 2 and as an interregional transmission project as set out in chapter 5, in both cases by Great Basin Transmission (GBT), LLC, an affiliate of LS Power.

The SWIP - North transmission project is an approximately 500-mile, 500 kV single circuit AC transmission line that connects the Midpoint 500 kV substation in southern Idaho, the Robinson Summit 500 kV substation, and the Harry Allen 500 kV substation. SWIP - North is parallel to the California-Oregon Interconnection, SWIP - North was modelled in the production cost model to assess if there project provides ISO rate payer benefits per the TEAM methodology and the associated production cost benefits. More comprehensive descriptions are provided in chapter 2 and chapter 5.

The following provides the economic assessment for SWIP - North.

SWIP - North Production Benefits

The production benefit of SWIP - North project for ISO's ratepayers and the production cost savings are shown in Table 4.9-4.

Table 4.9-4: Production Cost Modeling Results for SWIP - North

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,495	-38
ISO generator net revenue benefitting ratepayers	2,526	2,529	-3
ISO owned transmission revenue	199	213	14
ISO Net payment	5,387	5,408	-21
WECC Production cost	16,875	16,869	6

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

These results demonstrate a net increase in ISO ratepayer costs, instead of a saving. They also demonstrate an overall benefit of SWIP – North in lowering production costs over the entire WECC footprint, which is consistent with the intent of production cost modeling to find the

P27-129 cont.

lowest overall production cost. In considering why ISO ratepayer costs were climbing while WECC production costs were declining, several issues appear to play a role. The SWIP - North line may not provide incremental import from Northwest regions during some hours when there is no energy surplus in those regions depending on resource and transmission assumptions in Northwest regions in the model. SWIP - North may allow more exports from California to other regions when there are renewable energy surplus within California. In addition, lower priced imports can result in increased profits to out-of-state generation and reduced profits to ISO owned generation in the ISO footprint whose profits accrue to ISO ratepayers.

Conclusions

The SWIP - North project, on a standalone basis and without support from other areas that may benefit from the project, was not supported by the findings in the 2018-2019 transmission planning studies. The ISO expects that dialogue will continue with neighboring planning regions as their own plans evolve, and as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement.

4.9.2 PG&E Fresno Giffen area

The PG&E Fresno Giffen area is a net generation pocket with total 39 MW of existing grid-connected solar PV generation. This generation may cause congestion on the Giffen to Giffen Junction 70 kV line, which is the radial connection to the rest of the system, depending on the seasonal rating of the transmission line. The ISO studied reconductoring the congested 70 kV line to completely mitigate the congestion. The production benefit results for ISO's ratepayers and the overall production cost savings are shown in Table 4.9-5.

Table 4.9-5: Production Cost Modeling Results for Giffen Line Reconductoring

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,443	14
ISO generator net revenue benefitting ratepayers	2,526	2,520	-6
ISO owned transmission revenue	199	198	-1
ISO Net payment	5,387	5,376	7
WECC Production cost	16,875	16,880	-5

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

As discussed in Section 4.6.6, multi-tiered renewable curtailment prices were used in this planning cycle. With such a curtailment price model, all wind and solar would have the same curtailment price, which varies based on the total curtailment amount. Curtailment can be caused by transmission constraints or system constraints, or both. This curtailment price model may potentially impact the results for areas like Giffen area, which has a radial connection to the

P27-129 cont.

system and a relatively small amount of renewable generation. In such areas, the renewable curtailment price would still be set based on the system total curtailment amount, although the dominate driver of the curtailment in the local area is the transmission constraint of the radial connection. Therefore, a sensitivity study assuming -$25 curtailment price for the entire year was conducted for Giffen upgrade. A negative $25 curtailment price was selected because the curtailment price in most hours when curtailment happened in the base case study was -$25 or less. The results are shown in Table 4.9-6.

Table 4.9-6: Production Cost Modeling Results for Giffen Line Reconductoring – negative $25 curtailment price

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,564	8,544	20
ISO generator net revenue benefitting ratepayers	2,596	2,595	-1
ISO owned transmission revenue	213	210	-3
ISO Net payment	5,756	5,740	16
WECC Production cost	16,908	16,903	5

Note that ISO ratepayer “savings” are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide “Savings” are a decrease in overall production cost. A negative saving is an incremental cost or loss.

P27-129 cont.

Both base case study and sensitivity studies showed that Giffen upgrade can provide ISO ratepayers with material benefits. The sensitivity did address concerns, however, with the counterintuitive direction of the WECC production cost results.

The present value of the benefit was calculated to be $49 million, using the lower annual benefit between the above two studies of $7 million and assuming a 40 year economic life. The estimated cost of the project is less than $5 million, which translates to a total cost of $6.5 million (present value of annualized costs) using the ISO’s 1.3 screening ratio. The benefit to cost ratio then is about 7.5, which provides sufficient economic justification for recommending approval for this project.

Conclusions

The ISO recommends proceeding with the Giffen line reconductoring project as an economic-driven transmission solution.

4.9.3 Path 26 Midway-Vincent

The production cost modeling results demonstrated congestion occurring on Path 26 when the flow was from south to north. Renewable generators in Southern California identified in the CPUC renewable portfolio were the main driver of the Path 26 congestion. Two alternatives of mitigating the congestion were studied:

- Alternative 1: Increase Path 26 south to north path rating to 4000 MW by assuming tripping southern generators under contingency conditions by an SPS; and upgrade the Whirlwind to Midway 500 kV line by bypassing the series capacitors and increasing the conductor rating to the same level as the other two 500 kV lines of Path 26.
- Alternative 2: The transmission component of the economic study request CTP DCPP project, which includes a three terminal DC line between SCE's Ormond Beach and Redondo substations and PG&E's Diablo substation. The offshore wind generation discussed in the study request was not considered in this analysis.

4.9.3.1 Path 26 south to north path rating increase to 4000 MW

Path 26 currently has a south to north path rating of 3000 MW. The economic assessment of the production cost benefits of potentially increasing the south to north path rating to 4000 MW was modeled in the production simulation. The increase in the path rating could be achieved with the installation of a remedial action scheme (RAS) to trip generation located south of Path 26 and load located north of Path 26 for certain contingencies. The RAS would be similar to the RAS used to achieve a path rating of 4000 MW in the north to south direction with generation tripped north of Path 26 and load tripped south of Path 26. The increase in the path rating would need to go through the WECC Path Rating Process for approval. The economic assessment from the production cost simulation to increase the Path 26 path rating to reduce congestion on Path 26 is provided below.

Path 26 South to North Path Rating Increase Production Benefits

The production benefit for ISO's ratepayers and the production cost savings are shown in Table 4.9-7.

Table 4.9-7: Production Cost Modeling Results for Path 26 path rating increase

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,445	12
ISO generator net revenue benefitting ratepayers	2,526	2,532	6
ISO owned transmission revenue	199	181	-18
ISO Net payment	5,733	5,733	0
WECC Production cost	16,875	16,877	-2

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

P27-129 cont.

Figure 4.9-5 and Figure 4.9-6 show the generation and congestion changes with modeling the Path 26 upgrade, respectively. With the south to north rating increase, Path 26 congestion can be significantly reduced, and correspondingly generation dispatch changed on both sides of Path 26. Renewable generation output did not change as much as thermal generation mainly due to the ISO net export limit was binding in about same amount hours as in the base case and caused renewable curtailment.

P27-129
cont.

Figure 4.9-5: Generation changes with Path 26 south to north path rating increase

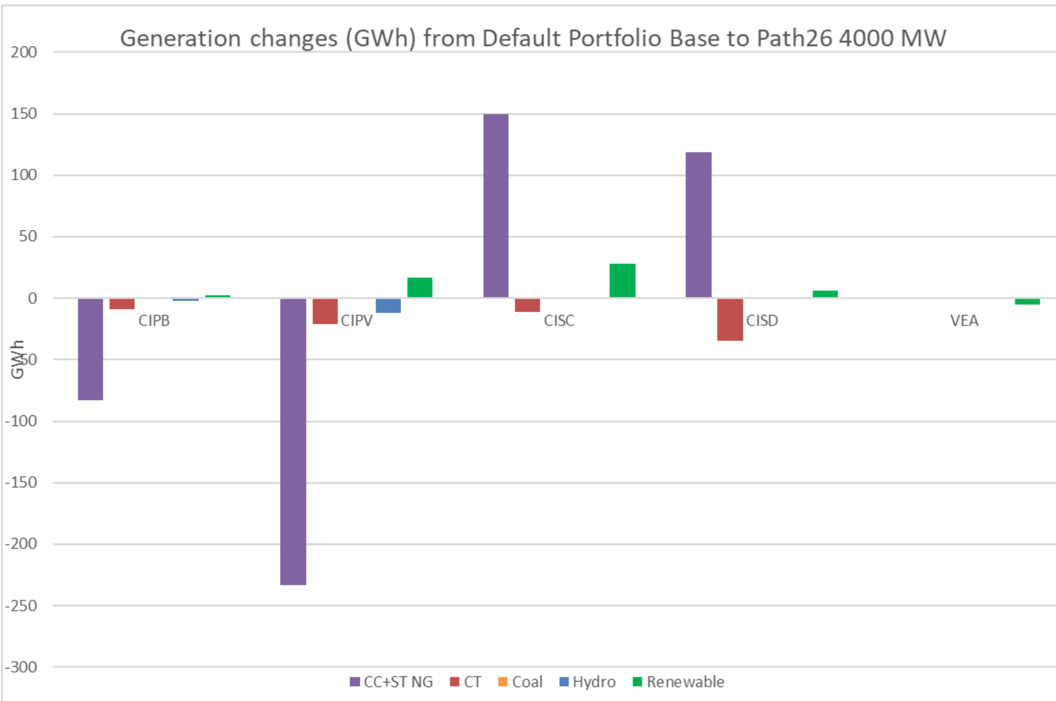
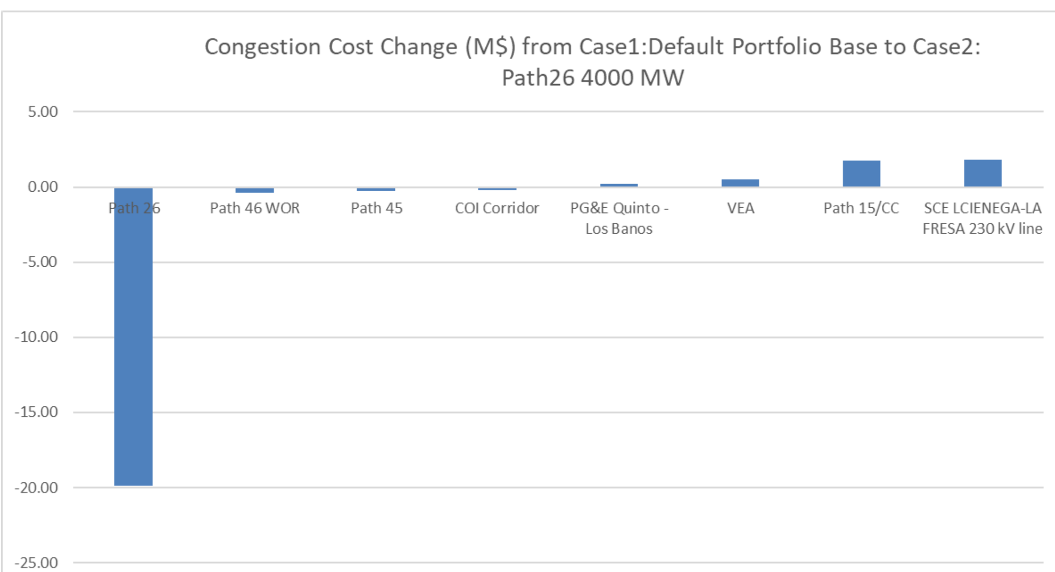


Figure 4.9-6: Congestion changes with Path 26 south to north path rating increase



P27-129
cont.

Conclusions

The study results do not support pursuing a path rating increase at this time. This will be further monitored and investigated in the future planning cycles.

4.9.3.2 Diablo Canyon to Ormond Beach and Redondo Beach (California Transmission Project)

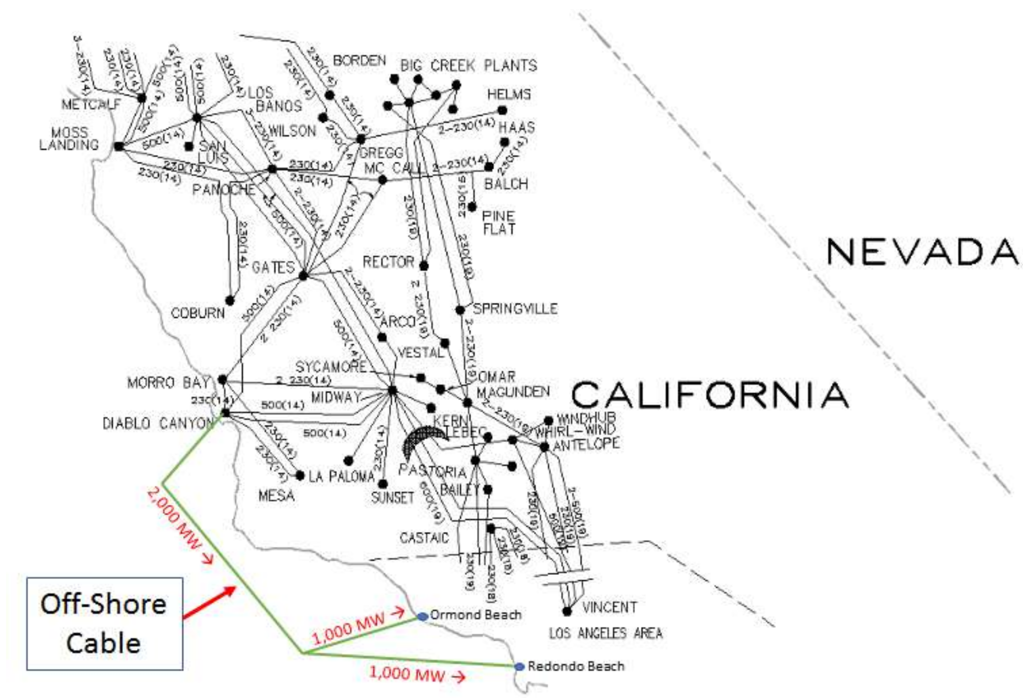
The proposed California Transmission Project (CTP) is a 320 kV HVDC submarine cable that would utilize Voltage Source Converters (VSC) to interconnect with existing HVAC transmission facilities in both the Pacific Gas & Electric and Southern California Edison service areas. The cable would be routed offshore of California in the Pacific Ocean and will have three segments, two between Diablo Canyon and Ormond Beach with approximate lengths of 139 miles and 159 miles. One cable would be positioned farther out into the ocean than the other for potential future interconnection with offshore wind development. The third segment, running between Ormond Beach and Redondo Beach would be approximately 50 miles in length. See Figure 4.9-7 below.

The northern terminus of the CTP is proposed to be the Diablo Canyon 500 kV switching station and would utilize the two BAAH bay positions that will be vacated with the decommissioning of the Diablo Canyon Power Plant. There would be two 1,000 MW VSCs located on shore at Diablo Canyon with switching to enable flexible operations and maintenance while one VSC remains in operation. There would be two separate southern terminals for the CTP, one at Ormond Beach and one at Redondo Beach. At the southern terminals, there will be one 1,000 MW VSC to enable connection to the 220 kV bus at the SCE Ormond Beach 220 kV substation and one 1,000 MW VSC to enable connection to the SCE Redondo Beach 220 kV substation. Both 320 kV HVDC cables, rated at 1,000 MW each, originating at Diablo Canyon will connect to an on-shore HVDC station at Ormond Beach to allow for flexible operations and maintenance. There will be a single 320 HVDC cable running between Ormond Beach and Redondo Beach, also rated at 1,000 MW.

The ISO studied this proposal without the wind generation because that generation was not part of the renewable portfolio provided by the CPUC.

P27-129 cont.

Figure 4.9-7: California Transmission Project



P27-129 cont.

<u>California Transmission Project Production benefits</u>

The production benefit for ISO's ratepayers and the production cost savings were shown in Table 4.9-8.

Table 4.9-8: Production Cost Modeling Results for CTP

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,468	-11
ISO generator net revenue benefitting ratepayers	2,526	2,551	25
ISO owned transmission revenue	199	188	-11
ISO Net payment	5,733	5,730	3
WECC Production cost	16,875	16,876	-1

Note that ISO ratepayer "savings" are a <u>decrease</u> in load payment, but an <u>increase</u> in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an <u>increase</u> in ISO owned transmission revenue. WECC-wide "Savings" are a <u>decrease</u> in overall production cost. A negative saving is an incremental cost or loss.

Figure 4.9-8 and Figure 4.9-9 show the generation and congestion changes that resulted from modeling the CTP project, respectively. Since the CTP project provides a parallel path to Path 26, Path 26 congestion can be significantly reduced, and correspondingly generation dispatch changed on both sides of Path 26. The overall impact of the CTP project on congestion and generation changes was similar to upgrading Path 26 rating as shown in the previous section. The magnitudes of changes in different location were different from the Path 26 path rating increase study because of the transmission topologies were different. ISO net export limit was still binding in about same amount hours as in the base case and caused renewable curtailment.

Figure 4.9-8: Generation changes with CTP project modeled

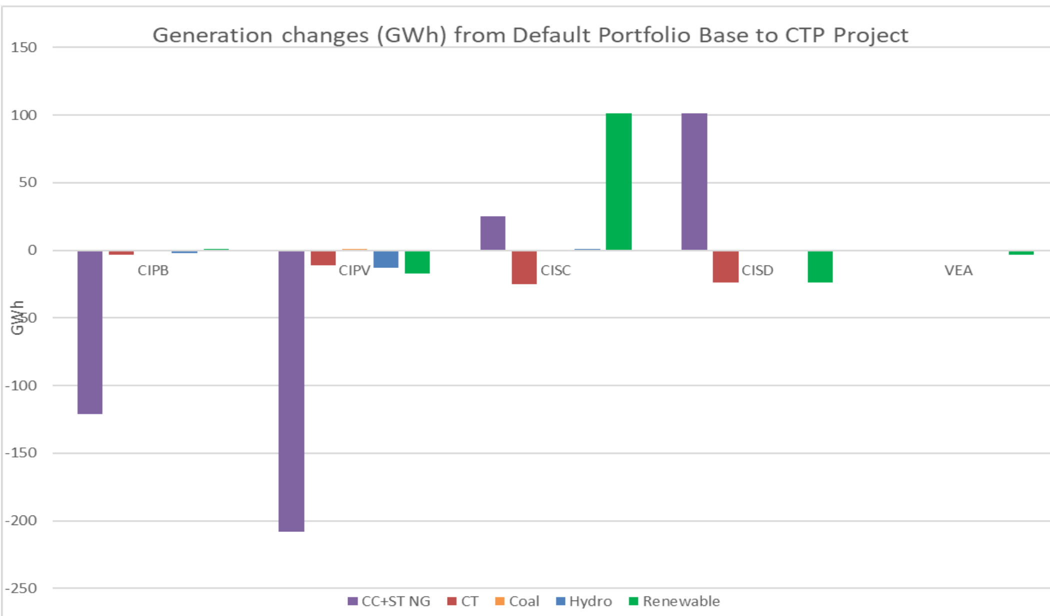


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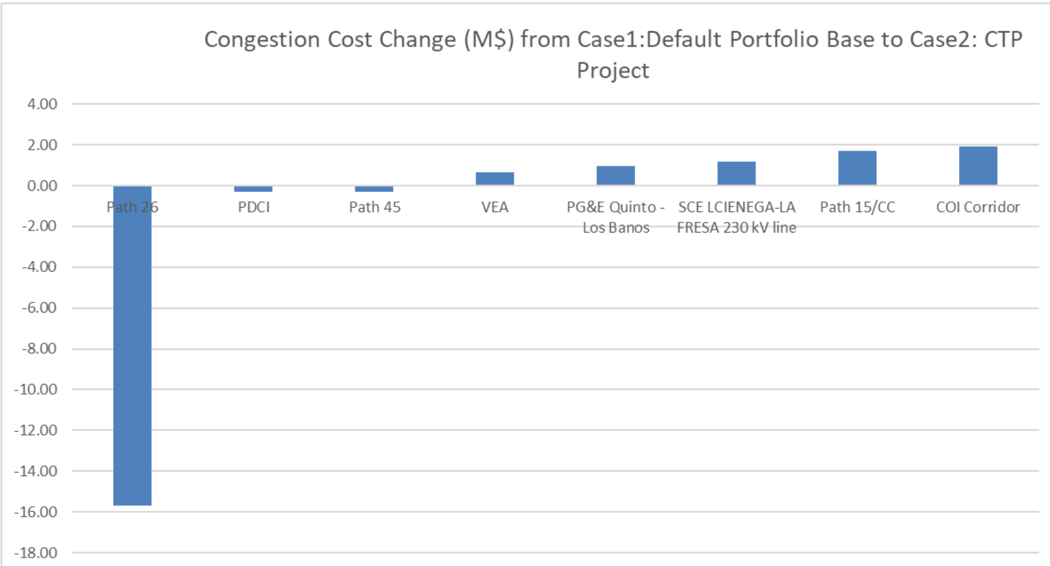
Figure 4.9-9: Congestion changes with CTP modeled



P27-129 cont.

Local Capacity Benefits:

The proposed project connects to the ISO system at Diablo Canyon, Ormond Beach, and Redondo switchyards. Diablo Canyon is not located in a local capacity area. With the planned Pardee-Moorpark #4 230 kV circuit, there will no longer be a Moorpark local capacity sub-area requirement, so Ormond Beach will no longer be located in an LCR sub-area. The overall Big Creek/Ventura area does have a significant local capacity requirement that can be met by resources connecting at Ormond Beach, and only about 300 MW of the overall need is met with GHG-emitting resources. While attributing this amount of benefit to the HVDC project appears overly precise, the ISO has nonetheless reflect a 300 MW potential local capacity requirement reduction benefit associated with the Big Creek/Ventura local area requirements in assessing the potential benefits of the project.

.Redondo is located in the Western LA Basin sub-area. While, as noted earlier, the Western LA Basin sub-area was not selected for detailed economic analysis – which would normally include a comparison of alternatives – the economic benefit of this project to potentially reduce local capacity requirements in the Western LA Basin sub-area was nonetheless estimated.

The Western LA Basin sub-area has been evaluated due to actual and planned OTC generation retirements in the last several transmission planning cycles, and because of the previous extensive evaluation and implementation for OTC generation and San Onofre Nuclear Generating Station (SONGS) retirements, the ISO did not select this sub-area for detailed study in this planning cycle as discussed in section 4.8.7. However, for purposes of this project's economic screening analysis, the ISO assumed that the project would provide approximately

1000 MW of LCR reduction benefits in the Western LA Basin sub-area. No costs were assumed for potential requirements for in-basin upgrades to address localized issues caused by the retirement of any generation the capacity of this project would replace. With the retirement of the OTC generation and SONGS, the retirement of additional generation in the Western LA Basin sub-area could cause localized transmission reliability concerns to be discovered if a detailed LCR study were to be performed on this proposed project.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-9, the benefit of local capacity reductions in the Western LA Basin sub-area and Big Creek/Ventura area are valued based on the cost range for the LA Basin.

Table 4.9-9: LCR Reduction Benefits for California Transmission Project

	California Transmission Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Western LA Basin and BC/Ventura) (MW)	1300	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$21.7	$29.5
LCR increase (San Diego – IV) (MW)	0	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$21.7	$29.5

P27-129 cont.

Cost estimates

The cost estimate provided by the project sponsor is $1,830 million for the proposed project. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", translates to a total cost of $2,379 million[108].

Benefit to Cost Ratio

In Table 4.9-10 the present value of the sum of the production cost and capacity benefits above are calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-10: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

California Transmission Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$3	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$3	
PV of Prod Cost Savings ($million)	$39	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$21.7	$29.5
PV of LCR Savings ($million)	$299.3	$406.9
Capital Cost		
Capital Cost Estimate ($ million)	$1,830	
Estimated "Total" Cost (screening) ($million)	$2,379	
Benefit to Cost		
PV of Savings ($million)	$338.6	$446.3
Estimated "Total" Cost (screening) ($million)	$2,379	
Benefit to Cost	0.14	0.19

P27-129 cont.

[108] The CTP project proponent provided a Project Net Present Value Cost including O&M, taxes, ROE and Debt at a 6% discount rate of $2.82 billion. For screening purposes and consistency, the CAISO applied the ISO's 1.3 factor to estimate the present value of the annualized revenue requirement, resulting in a lower value for the cost.

Conclusions

The economic benefits of the California Transmission Project are not sufficient on a standalone basis to support the project as an economic-driven transmission project based on the findings in the 2018-2019 transmission planning studies. The project provides other benefits for which the ISO is valuing with conservative assumptions at this time, due to uncertainty regarding the future reliance on gas-fired generation for system and flexible needs. The ISO expects that dialogue will continue as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement, and as system needs for other attributes the project may provide are further assessed.

4.9.4 Colorado River – Julian Hinds

The Colorado River– Julian Hinds 230 kV Project, also referred to as the Blythe Loop-in Project in various submissions, was submitted by AltaGas Services in the 2017-2018 transmission planning cycle.

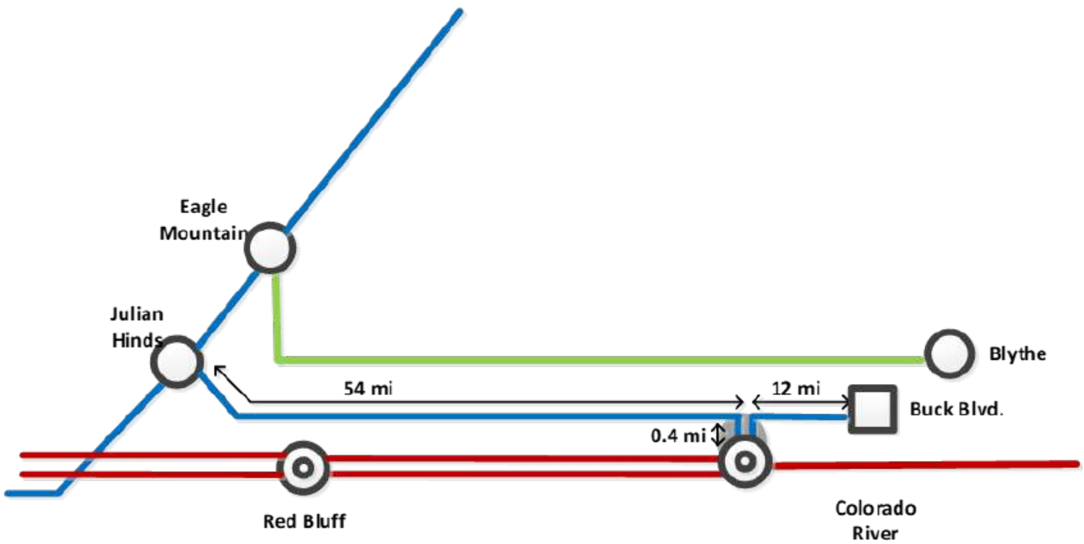
As discussed in section 4.8, the ISO agreed in the course of the 2017-2018 transmission planning cycle to review the project in the 2018-2019 transmission planning cycle, in light of AltaGas proposing modifications to the original scope late in the 2017-2018 planning cycle.

The proposed project consists of:

- Converting the existing privately owned Buck Blvd - Julian Hinds 230 kV generation tie-line into a network facility by way of segmenting the gen-tie line and connecting one terminal of both segments into the Colorado River Substation 230 kV bus. It creates a networked facility identified as Colorado River - Julian Hinds 230 kV line, and a revised 230 kV gen-tie line identified as Buck Blvd - Colorado River 230 kV line. P27-129 cont.
- Installing 117 Smart Wires Power Guardian 700-1150 devices (~19.58 Ω/phase) on the Colorado River - Julian Hinds 230 kV line in series with the line. These Power Guardians would be set to switch into injection mode to limit the power flow on the Julian Hinds - Mirage 230 kV line to avoid potential overloads.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-10: Colorado River – Julian Hinds 230 kV Project



The project cost was estimated by AltaGas at $67 million with an expected in-service date of June 1, 2020.

The Altagas proposal was submitted as a comprehensive package, including both the re-termination of the Blythe generation at the Buck Blvd substation to the Colorado River substation's 230 kV bus, and the creation of the Colorado River - Julian Hinds 230 kV line by also re-terminating the line running east from Julian Hinds to the Colorado River substation's 230 kV bus. Given the need to properly assess the benefits to ISO ratepayers of this proposal for a potential economic-driven transmission project, the ISO needed to study the benefits of the various components both individually and as well as collectively.

The ISO therefore studied the benefits of:

- Option 1: Re-terminating the line extending west from Buck Blvd substation to Colorado River, but leaving portion of line from approximately Colorado River to Julian Hinds de-energized and not terminated at Colorado River (and not installing the Smart Wires Power Guardian devices).
- Option 2: Looping in the Buck Blvd-Julian Hinds line into Colorado River as proposed.

As well, the ISO acknowledged the risk to ISO ratepayers if the gas-fired generation at Buck Blvd retired, especially if the bulk of the economic benefits were associated with the re-termination of the generation and the Colorado River-Julian Hinds transmission line provided little value. Therefore, a third option was studied:

P27-129 cont.

- Option 3: Re-terminating the portion of line from Julian Hinds into Colorado River, and leave the Buck Blvd substation disconnected and out of service. Note that assessing Option 3 requires a modified base case to be developed for comparative purposes, with the entire Julian Hinds - Buck Blvd 230 kV transmission line and Buck Blvd substation disconnected and de-energized.

The ISO therefore conducted its reliability and production cost modeling on five cases:

- Base case – Existing configuration
- Option 1 – Generation only
- Option 2 – Generation and line
- Modified Base – Julian Hinds – Buck Blvd out of service
- Option 3 – Line only

Reliability Considerations

The need for a similar project was assessed as part of the 2014-15 and 2016-17 ISO transmission planning cycles and was not found to be needed in those planning cycles. The project - now with the inclusion of the Smart Wires devices – was studied in this planning cycle and was not been found to be needed for reliability purposes in this planning cycle. In considering the viability of the project as a potential economic-driven transmission solution, , power flow analysis was performed on the project to test for any negative impacts. It was found that with the project modeled in the 2017-2018 TPP S4 Heavy Renewables sensitivity case, with the Smart Wires devices on the Colorado River - Julian Hinds 230 kV line fully activated, the Julian Hinds - Mirage 230 kV line was heavily overloaded under contingency conditions. However, AltaGas has proposed a RAS that would open the overloaded line created by this proposed project during this contingency condition. While working with AltaGas in previous transmission cycles, the ISO has raised concerns about the use of a RAS to open this proposed transmission line. This new RAS would be in addition to the existing RAS that also drops over 1000 MW of generation. The ISO has also raised concerns that the new RAS proposed by AltaGas would leave the Blythe gas fired generation connected to the Colorado River 230 kV bus and would cause deliverability impacts on the existing generation in the area. AltaGas has requested that the ISO assess this deliverability impact with the proposed revisions to the ISO Generation Deliverability Methodology, once they are finalized. In the interim, AltaGas has also asked the ISO to reevaluate the economic benefits of the proposed project. P27-129 cont.

Colorado River – Julian Hinds 230 kV Project Production benefits

The ISO conducted its production cost modeling for the five case described above.

In conducting the production costing the ISO identified that due to modeling interactions between the various affected areas containing renewable generation, the levels of local and system curtailment being experienced, and the algorithm used to select and price curtailed renewables, the economic benefits of the options were undervalued using the renewable curtailment multi-tier pricing model. To address this, sensitivities were also performed with a fixed curtailment price of negative $25 to screen those anomalies and provide a more accurate assessment of the benefits of the proposed configuration changes.

Table 4.9-11 shows the TEAM analysis results for this proposed project.

Table 4.9-11: Production Cost Modeling Results for Colorado River – Julian Hinds 230 Projects

	Pre project upgrade ($M)	Option 1		Option 2		Pre project upgrade ($M)	Option 3	
		Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)		Post project upgrade ($M)	Savings ($M)
ISO load payment	8564	8554	10	8554	11	8606	8614	-8
ISO generator net revenue benefitting ratepayers	2596	2598	2	2585	-11	2611	2612	1
ISO owned transmission revenue	213	210	-3	210	-3	210	213	3
ISO Net payment	5756	5746	9	5759	-3	5785	5789	-5
WECC Production cost	16908	16905	3	16904	4	16908	16909	-1

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Cost estimates:

The total cost estimate provided by AltaGas is $76 million for Option 2. The line termination upgrades at Colorado River 230 kV bus were estimated to be $25 million.

Benefit to Cost Ratio

In Table 4.9-12 the benefits are added and their present values are calculated based on a 40 year project life, and then benefit to cost ratios are calculated.

P27-129 cont.

Table 4.9-12: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

	Option 1	Option 2	Option 3
Production Cost Modeling Benefits			
Ratepayer Benefits ($million/ year)	$9	-$3	-$8
Net Market Revenue ($million/ year)	$0	$0	$0
Total PCM Benefits ($million/ year)	$9	-$3	-$8
PV of Prod Cost Savings ($million)	$121.93	-$44	-$111
Capital Cost			
Capital Cost Estimate ($ million)	$25	$76	$76
Estimated “Total” Cost (screening) ($million)	$33	$99	$99
Benefit to Cost			
PV of Savings ($million)	$121.93	-$44	-$111
Estimated “Total” Cost (screening) ($million)	$32.50	$99	$99
Benefit to Cost	3.75	-0.45	-1.12

Conclusions

Based on the ISO’s analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Moving the termination of the Buck Blvd substation (the Blythe Energy Center) from Julian Hinds to the Colorado River substation and de-energizing the remainder of the existing Buck Blvd-Julian Hinds transmission line – without regulated cost of service cost recovery for the line - provides the most benefit to ISO ratepayers from both a gross benefit and benefit to cost ratio perspective. These benefits are predicated on the Blythe Energy Center remaining in service into the future.
- Creating a Colorado River-Julian Hinds 230 kV circuit was not supported by the production cost results, whether the generation was in service and connected to Colorado River or was out of service.

P27-129 cont.

- These results will have to be reviewed once the ISO has finalized any changes to its parameters used in its deliverability methodology and assesses the deliverability impact of the proposed project taking the new deliverability methodology into account.

Local Capacity Reduction Study Areas

4.9.5 Pease Sub-area (Sierra)

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Pease sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2018-2019 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Pease Sub-area is in Appendix G, section 3.2.3.4.

The project would consist of the following:

- Loop in the Pease – Marysville 60 kV line into East Marysville 115 kV substation and install a 115/60 kV transformer at East Marysville substation plus 25 Mvar voltage support.

The planning estimate cost for this alternatives is $26 to $32 million.

Looping in of Pease-Marysville 60 kV line into East Marysville 115 kV substation Production benefit

The looping in of the Pease-Marysville 60 kV line into East Marysville 115 kV substation is not expected to provide production benefits. The Pease Sub-area is a local load pocket with the LCR requirement being for N-1-1 contingencies that result in local area overloads without the generation being on-line.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Pease sub-area.

The looping in of the Pease-Marysville 60 kV line into the East Marysville 115 kV substation was modeled in the 2028 long-term local capacity requirement study case for the Pease sub-area, resulting in the following:

- The local capacity requirement for gas-fired generation in the Pease sub-area was eliminated resulting in a reduction of approximately 92 MW.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and “north of path 26 system” resources. For the Pease Sub-area, these translated to values of $2,160/MW-year and $1,440/MW-year respectively. In addition within the Pease area, the 47.6 MW Yuba City Energy Center has been designated as a reliability must-run (RMR) generator at a cost of $3.714 million per year[109]. With this the difference between the RMR cost of $78,030

P27-129 cont.

[109] Yuba City energy Center 2022 Annual Fixed revenue Requirement (AFRR) from FERC RMR Settlement: https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=14845682

MW-year compared to the system cost of $25,080 MW-year for a difference of $52,950 MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-13 the benefit of local capacity reductions in the Pease area is valued based on the cost range for the Fresno area. :

Table 4.9-13 : Pease LCR Sub-area Reduction Benefits

Looping in of Pease-Marysville 60 kV line into East Marysville 115 kV substation			
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	RMR Cost versus System Capacity
LCR reduction benefit (Pease Sub-area) (MW)	92		
Capacity value (per MW-year)	$2,160	$1,440	$52,950
LCR Reduction Benefit ($million)	$0.2	$0.1	$4.9

P27-129 cont.

Cost estimates:

The current cost is about $26 million to $32 million for the suggested mitigation alternative. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $33.8 million to $41.6 million range.

Benefit to Cost Ratio

In Table 4.9-14 the present value of the capacity benefits above are calculated based on a 50 year project life, and then benefit to cost ratios were calculated for the range of the cost estimates.

Table 4.9-14 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Looping in of Pease-Marysville 60 kV line into East Marysville 115 kV substation			
Local Capacity Benefits			
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	RMR Cost
Net LCR Saving ($million/year)	$0.2	$0.1	$4.9
PV of LCR Savings ($million)	$2.74	$1.83	$67.23
Capitall Cost			
Capital Cost Estimate ($ million)	$32		
Estimated "Total" Cost (screening) ($million)	$42		
Benefit to Cost			
PV of Savings ($million)	$2.74	$1.83	$67.23
Estimated "Total" Cost (screening) ($million)	$41.60		
Benefit to Cost	0.07	0.04	1.62

P27-129 cont.

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project, and the differential between current capacity costs for the reliability must-run generator in the area, and the system capacity costs increase the benefit to cost ratio to 1.62. .

Conclusions

The East Marysville 115/60 kV project is recommended for approval to economically reduce the local capacity requirement in the Pease sub-area.

4.9.6 Hanford Sub-area (Fresno)

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Hanford sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2018-2019 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Pease Sub-area is in Appendix G, section 3.2.6.2.

Two alternatives were considered, consisting of the following:

- The reconductoring of the McCall-Kingsburg #1 115 kV line for an estimated cost of $9 million.
- The reconductoring of both the McCall-Kingsburg #1 and #2 115 kV lines for an estimated cost of $23.5 million.

Hanford alternative Production benefit

The two alternatives are to reconductor existing 115 kV lines to higher capacity and are not expected to provide production benefits. The Hanford Sub-area is a local load pocket with the LCR requirement being for N-1-1 contingencies that result in local area overloads without the generation being on-line.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Hanford sub-area.

The two alternatives were modeled in the 2028 long-term local capacity requirement study case for the Hanford sub-area, resulting in the following:

- The reconductoring of the McCall-Kingsburg #1 115 kV line reduced the Hanford Sub-area requirement by 39 MW from 125 MW to 86 MW. The estimated cost for this alternative is $9 million.
- The reconductoring of both the McCall-Kingsburg #1 and #2 115 kV lines eliminated the requirement in Hanford Sub-area. The estimated cost for this alternative is $23.5 million. P27-129 cont.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “north of path 26 system” resources. For the Hanford Sub-area, these translated to values of $2,160/MW-year and $1,440/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-15 the benefit of local capacity reductions in the Hanford area is valued based on the cost range for the Fresno area.

Table 4.9-15 : Hanford LCR Sub-area Reduction Benefits

	Reconductor McCall-Kingsburg #1 115kV line		Reconductor McCall-Kingsburg #1 and #2 115kV lines	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Hanford Sub-area) (MW)	39		125	
Capacity value (per MW-year)	$2,160	$1,440	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.1	$0.1	$0.3	$0.2

Cost estimates:

The current cost estimates, based on other actual projects, is about $9 million for the Reconductor McCall-Kingsburg #1 115 kV line alternative and $23.5 million for the Reconductor McCall-Kingsburg #1 and #2 115 kV line alternative.

Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $12 million for the Reconductor McCall-Kingsburg #1 115kV line alternative and $30.55 million for the Reconductor McCall-Kingsburg #1 and #2 115kV line alternative.

Benefit to Cost Ratio

In Table 4.9-16 the present value of the capacity benefits above are calculated based on a 50 year project life, and then benefit to cost ratios were calculated for the range of the cost estimates.

P27-129 cont.

Table 4.9-16 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

	Reconductor McCall-Kingsburg #1 115kV line		Reconductor McCall-Kingsburg #1 and #2 115kV lines	
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.1	$0.1	$0.3	$0.2
PV of LCR Savings ($million)	$1.16	$0.78	$3.73	$2.48
Capital Cost				
Capital Cost Estimate ($ million)	$9		$24	
Estimated “Total” Cost (screening) ($million)	$12		$30.55	
Benefit to Cost				
PV of Savings ($million)	$1.16	$0.78	$3.73	$2.48
Estimated “Total” Cost (screening) ($million)	$11.70		$30.55	
Benefit to Cost	0.10	0.07	0.12	0.08

Conclusions

Based on the ISO’s analysis, the identified benefits are not sufficient to support the alternatives studied in this planning cycle.

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Hanford sub-area for system reasons is achieved.

4.9.7 Kern Oil Sub-area (Kern)

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Kern Oil sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2018-2019 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Pease Sub-area is in Appendix G, section 3.5.7.4.

The project would consist of the following:

P27-129 cont.

- Reconductor sections of line between Kern Oil and Kern Oil Junction and increase the scope of the Kern Power-Kern Oil Junction upgrades as a part of the previously approved Kern 115 kV Reinforcement project from rerating to reconductoring sections of the line.

The planning estimate cost for this alternatives is $15 million.

Kern Oil Sub-area Alternative Production benefit

The proposed project is not expected to provide production benefits. The Kern Oil Sub-area is a local load pocket with the LCR requirement being for N-1-1 contingencies that result in local area overloads without the generation being on-line.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Kern Oil sub-area.

Reconductoring of sections of line between Kern Oil and Kern Oil Junction and increasing the scope of the Kern Power-Kern Oil Junction project from rerating to reconductoring sections of the line was modeled in the 2028 long-term local capacity requirement study case for the Pease sub-area, resulting in the following:

- The local capacity requirement for gas-fired generation in the Kern sub-area was eliminated, resulting in a local capacity requirement reduction of approximately 21 MW.

P27-129 cont.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and "north of path 26 system" resources. For the Kern Oil Sub-area, these translated to values of $2,160/MW-year and $1,440/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-17 the benefit of local capacity reductions in the Kern Oil sub-area is valued based on the cost range for the Kern area.

Table 4.9-17 : Kern Oil LCR Sub-area Reduction Benefits

Reconductor sections of line between Kern Oil and Kern oil Junction and increase the scope of the Kern Power-Kern Oil Junction from rerate to reconductor		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit Kern Oil Sub-area) (MW)	21	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.05	$0.03

Cost estimates:

The current cost is about $15 million for the suggested mitigation alternative. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $19.5 million range.

Benefit to Cost Ratio

In Table 4.9-18 the present value of the capacity benefits above are calculated based on a 50 year project life, and then benefit to cost ratios were calculated for the range of the cost estimates.

Table 4.9-18 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Reconductor sections of line between Kern Oil and Kern oil Junction and increase the scope of the Kern Power-Kern Oil Junction from rerate to reconductor		
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.05	$0.03
PV of LCR Savings ($million)	$0.63	$0.42
Capital Cost		
Capital Cost Estimate ($ million)	$15	
Estimated "Total" Cost (screening) ($million)	$20	
Benefit to Cost		
PV of Savings ($million)	$0.63	$0.42
Estimated "Total" Cost (screening) ($million)	$19.50	
Benefit to Cost	0.03	0.02

P27-129
cont.

Conclusions

The cost estimate range for this project is material, and, as discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources. Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Eastern sub-area for system reasons is achieved.

4.9.8 Big Creek/Ventura Area – Santa Clara Sub-area

In the Big Creek/Ventura area, gas-fired local capacity is declining significantly. Mandalay (560 MW) was retired in 2018 and Ormond Beach (1500 MW) is scheduled to retire at the end of 2020. Ellwood (54 MW) is also expected to retire when its short-term contract expires.

In the 2017-2018 transmission planning cycle, the ISO approved the Pardee-Moorpark 230 kV Transmission Project (ISD 12/31/2021) as an alternative to gas-fired local capacity that is needed to serve customers in the Ventura and Santa Barbara counties. Procurement of preferred resources and storage is underway in the Santa Clara sub-area to meet the remaining local capacity need.

Assessment of gas-fired generation requirement

Table 4.9-19 provides an assessment of expected gas-fired generation requirement in the Big Creek/Ventura area based on the results of the 2028 local capacity study that is included as Appendix G.

P27-129 cont.

Table 4.9-19: Assessment of Gas-fired Generation Requirement in the Big Creek/Ventura Area

Sub-Area	2028 LCR	Available Resource Capacity	Existing Gas-fired Generation Capacity	Gas-fired Generation Local Capacity Requirement	
	(MW)	(MW, NQC)	(MW, NQC)	MW	Percent of Existing Gas-fired Capacity
Rector	N/A	1,028	0	0	0%
Vestal	465	1,205	54	0	0%
Goleta	42+	>7 (+RFP)	0	0	0%
Santa Clara	318	>199 (+RFP)	184	184	100%
Moorpark	0	>223 (+RFP)	184	0	0%
Overall Big Creek Ventura	2251	>3505 (+RFP)	1696	<442	<26%

Notes:

Available capacity includes existing and already procured preferred resources and storage but does not include resources being procured under the current Santa Clara area RFP

2028 resource capacity values exclude Ormond Beach and Ellwood

Selection of area and sub-areas for this economic study

Based on the above assessment, Rector, Vestal, Goleta and Moorpark sub-areas will have no gas-fired generation requirement in 2028 because of the availability of sufficient hydro resources, the on-going procurement of preferred resources or the completion of the approved transmission project.

The Santa Clara sub-area was selected for this further assessment because all of the gas-fired generation in the area will be otherwise needed.

In the greater Big Creek-Ventura area itself, less than 442 MW of 1669 MW (or <26%) of existing gas-fired generation will be needed for local RA. The ongoing Santa Clara sub-area RFP is expected to lower the number to the 278-320 MW range (or 17%-19%). As such, the area was not selected for assessment in the current planning cycle.

Transmission alternative to lower gas-fired LCR in the Santa Clara sub-area

Table 4.9-20 summarizes the results of the 2028 local capacity study for the Santa Clara area. The local capacity requirement can vary depending on the location and reactive power capability provided to the transmission system by the new resource or resources that are being procured to fill the need.

Table 4.9-20: Santa Clara Sub-area 2028 LCR Study Results

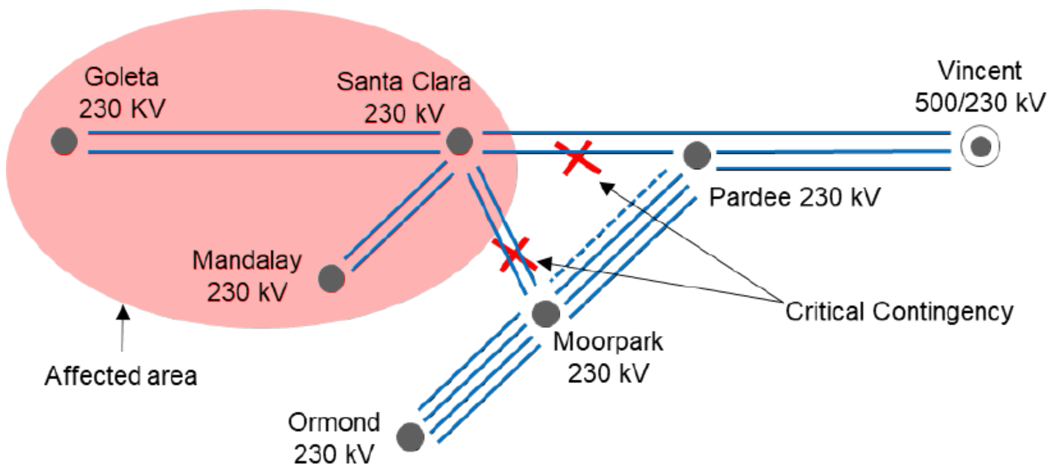
Critical Contingency	Limiting Facility/Condition	LCR (MW)
Pardee–Santa Clara 230 kV line followed by Moorpark–Santa Clara #1 and #2 230 kV DCTL	Voltage Collapse	318 (1)(2)

Note:
(1) 120 MW of generic resources with reactive capability were assumed at Goleta to meet the local capacity deficiency. For locational and reactive power effectiveness information, see http://www.caiso.com/Documents/2023LocalCapacityTechnicalAnalysisfortheSantaClaraSub-Area.pdf
(2) The LCR is sufficient to mitigate voltage collapse but it is not sufficient to mitigate overloading of the remaining line (Overload - 126%).

Figure 4.9-11 provides an overview of the transmission system in the Santa Clara and identifies the critical contingency and the affected area.

P27-129 cont.

Figure 4.9-11: Santa Clara Sub-area Transmission System



The following transmission upgrades were identified as a potential alternative to allow lower gas-fired generation requirements in the Santa Clara sub-area:

- Add reactive power device in the area; and
- Increase the rating of the four import lines into the area

Conclusions

The amount of potential reduction in gas-fired local capacity requirement resulting from the transmission upgrades, and the associated economic benefits, depend on the location and characteristics of the preferred resources that will be procured under the ongoing LCR RFP. SCE's target date for CPUC application filing for the LCR RFP is March 2019 with a CPUC decision anticipated later in the year. The technical and economic assessment of the transmission upgrades will be completed, likely in the 2019-2020 planning cycle, once the procurement process has been completed, in the 2019-2020 planning cycle.

4.9.9 Eastern Sub-area (LA Basin)

The Eastern sub-area in the LA Basin was selected for detailed study, as noted in section 4.8.7. One option was proposed by stakeholders to reduce local capacity requirements, and the ISO developed an additional option. These are set out below.

4.9.9.1 Mira Loma Dynamic Reactive Support

The ISO examined a potential transmission option for reducing gas-fired generation requirements in the Eastern LA Basin sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2018-2019 planning cycle. This option was developed by the ISO.

The project would consist of the following:

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cont.

- Install approximately 225 Mvar of dynamic reactive support (i.e., synchronous condenser) at Mira Loma Substation. The optimal location would be evaluated further if there is further consideration for this option.

The planning estimate for installing the 225 Mvar synchronous condenser is approximately $30 to $80 million.

<u>Mira Loma Dynamic Reactive Support Production benefit</u>

Installing dynamic reactive support at Mira Loma Substation is not expected to provide production benefits as the contingency driving the local capacity requirements is an "N-1, followed by N-2" contingency established in the ISO tariff's local capacity requirements reliability criteria. This contingency is an extreme event as defined in NERC standards, and the constraint would be expected to have minimal impact on production cost modeling.

<u>Local Capacity Benefits:</u>

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Eastern LA Basin LCR sub-area.

The 225 Mvar dynamic reactive support at Mira Loma Substation was modeled in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area, resulting in the following:

- The local capacity requirement for gas-fired generation in the San Diego – Imperial Valley area was reduced by approximately 350 MW. The limiting contingency was the overlapping N-1 of the Serrano – Valley 500 kV line, system readjusted, followed by an N-2 of the Devers – Red Bluff 500 kV lines, causing the potential post-transient voltage instability for the Eastern LA Basin sub-area.
- Since local capacity was reduced in the Eastern LA Basin sub-area with the dynamic reactive support modeled, the ISO evaluated potential local capacity impacts to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, then followed by an N-1 contingency for the Mesa – Lighthipe 230 kV line. The limiting transmission, the Mesa – Laguna Bell 230 kV line #1, remained within its emergency rating. Therefore, there was no local capacity impact to the Western LA Basin sub-area.

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The Mira Loma dynamic reactive support could potentially reduce local capacity need in the Eastern LA Basin sub-area by about 350 MW[110]. There would be no other local capacity impact due to this local capacity reduction in the Eastern LA Basin sub-area.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is

[110] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-21 the benefit of local capacity reductions in the Eastern LA Basin area is valued based on the cost range for the LA Basin:

Table 4.9-21: LCR Reduction Benefits for Mira Loma Dynamic Reactive Support

Mira Loma Dynamic Reactive Support		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Eastern LA Basin) (MW)	350	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.8	$7.9
LCR increase (Western LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$5.8	$7.9

Cost estimates:

The current cost, based on other actual projects, is about $30 million to $80 million for the suggested mitigation option. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $39 million to $104 million range.

P27-129 cont.

Benefit to Cost Ratio

In Table 4.9-22 the present value of the capacity benefits above are calculated based on a 50 year project life, and then benefit to cost ratios were calculated for the range of the cost estimates.

Table 4.9-22: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Mira Loma Dynamic Reactive Support		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$5.8	$7.9
PV of LCR Savings ($million)	$80.57	$109.55
Capital Cost		
Capital Cost Estimate ($ million)	$80	
Estimated "Total" Cost (screening) ($million)	$104	
Benefit to Cost		
PV of Savings ($million)	$80.57	$109.55
Estimated "Total" Cost (screening) ($million)	$104.00	
Benefit to Cost	0.77	1.05

The cost estimate range for this project is material, and, as discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources. Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Eastern sub-area for system reasons is achieved.

P27-129 cont.

4.9.9.2 Red Bluff – Mira Loma 500 kV Transmission Project congestion and capacity benefits

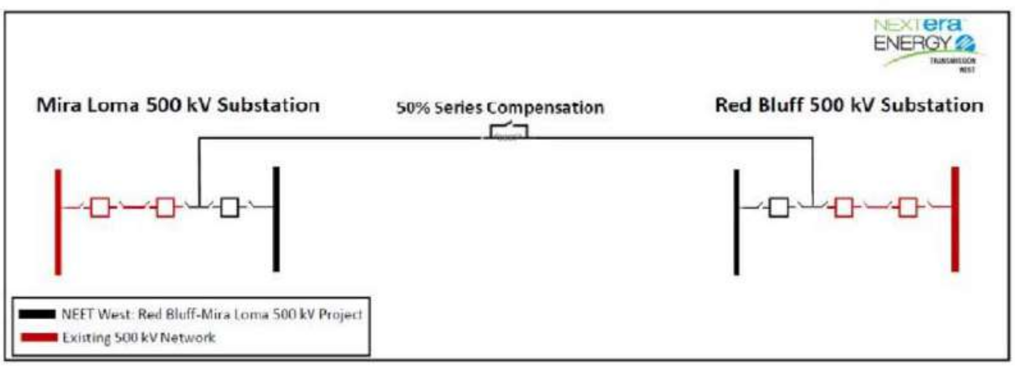
The Red Bluff – Mira Loma 500 kV Transmission Project was submitted by NextEra Energy Transmission West LLC (NEET West) as an economic study request and into the 2018 Request Window as a potential reliability project as noted in section 4.8. As set out in chapter 2, the ISO did not identify a reliability need for this project. The ISO subsequently examined the project for economic benefits.

The project proposal consists of:

- A new 500-kV transmission line (~139 mile) between the Red Bluff substation and the Mira Loma substation with 50% compensation, with line ratings of 3,421 MVA normal and 3,880 MVA emergency.
- Installation of 50% series compensation with the optimal location in the line yet to be determined from more detailed studies. The line series compensation would have a normal rating of 3,291 MVA and an emergency rating of 3,949 MVA.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-12: Red Bluff – Mira Loma 500 kV Transmission Project Configuration



The project's estimated capital cost is $850 million. A preliminary target date of Q4 2024 has been established, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

NEET West stated that the proposed project would address the Desert Area Constraint for interconnecting new renewable generation development, further renewable generation interconnection in the CPUC 42 MMT scenario, and lastly the LCR reduction benefit for the Eastern LA Basin sub-area.

Red Bluff – Mira Loma 500 kV Project Production benefit

Table 4.9-23 shows the TEAM analysis results for this proposed project.

P27-129 cont.

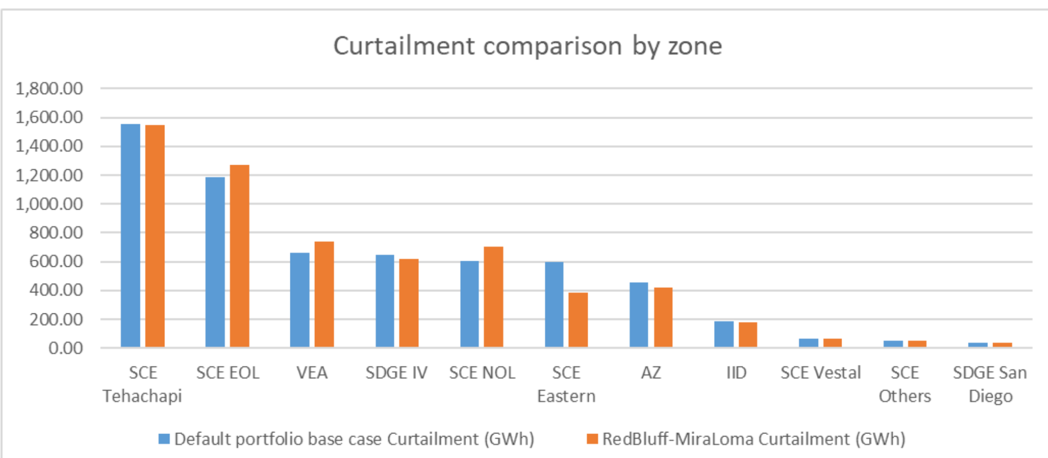
Table 4.9-23: Production Cost Modeling Results for Red Bluff - Mira Loma 500 kV Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8442	15
ISO generator net revenue benefitting ratepayers	2526	2525	0
ISO owned transmission revenue	199	206	8
ISO Net payment	5733	5710	23
WECC Production cost	16875	16866	9

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Production cost simulation results show that this project can reduce renewable curtailment in SCE's Eastern area (Riverside East, including Red Bluff and Colorado River substations). However, curtailment in other areas in Southern California, such as SCE's North of Lugo and East of Lugo areas and VEA area, may increase due to increased congestion on Path 26, Path 61 (Lugo to Victorville), and Bob SS-Mead. Figure 4.9-13 shows the changes of curtailment by zone. P27-129 cont.

Figure 4.9-13: Curtailment changes by zone with Red Bluff - Mira Loma Project modeled



Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the Eastern LA Basin LCR sub-area.

Modeling the proposed project in the 2028 long-term local capacity requirement study case for the Eastern LA Basin sub-area study resulted in the following:

- The Eastern LA Basin sub-area is subject to post-transient voltage instability due to the overlapping N-1 of Serrano – Valley 500 kV line, system readjusted, followed by an N-2 contingency of the Devers – Red Bluff 500 kV line. The amount of gas-fired generation local capacity requirement reduction in the Eastern LA Basin sub-area was found to be approximately 91 MW. The proposed project does not provide significant transmission improvement for this overlapping contingency because it is connected outside of the impacted area.
- Since the gas-fired generation could be reduced in the Eastern sub-area, the Western LA Basin sub-area local capacity needed to be checked to determine if there would be an adverse impact to its LCR need.
- The power flow study was first restored to normal condition. An N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line was then studied. This N-1-1 contingency caused an overloading concern on the Mesa-Laguna Bell 230 kV line. An additional 30 MW of local capacity south of Laguna Bell substation (Western LA Basin sub-area) was necessary to mitigate the loading concern.

P27-129 cont.

The proposed project potentially could reduce local capacity requirement in the Eastern LA Basin sub-area by about 91 MW[111,] and it was also identified that the Western LA Basin sub-area local capacity requirement would be adversely impacted and would need an additional 30 MW to mitigate the identified impact. The net local capacity benefits for the Eastern LA Basin sub-area are the difference between the local capacity cost increase in the Western LA Basin sub-area and the local capacity cost reduction in the Eastern LA Basin sub-area.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

[111] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

In Table 4.9-24 the benefit of local capacity reductions in the Eastern LA Basin sub-area and the Western LA Basin area are both valued based on the cost range for the LA Basin.

Table 4.9-24: LCR Reduction Benefits for the Mira Loma - Red Bluff Transmission Project

Mira Loma - Red Bluff 500 kV Line		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Eastern LA Basin) (MW)	91	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$1.5	$2.1
LCR increase (Western LA Basin) (MW)	30	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.5	$0.7
Net LCR Saving ($million/year)	$1.0	$1.4

Cost estimates:

The current cost estimate from NEET West is $850 million for the proposed project. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $850 million capital translates to a total cost of $1.233 billion.

Benefit to Cost Ratio

In Table 4.9-25, the present value of the sum of the production cost and capacity benefits above are calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

P27-129 cont.

Table 4.9-25: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Red Bluff – Mira Loma 500 kV Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$23	
ML-RB Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$23	
PV of Prod Cost Savings ($million)	$317.42	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$1.0	$1.4
PV of LCR Savings ($million)	$14.04	$19.09
Capital Cost		
Capital Cost Estimate ($ million)	$850	
Estimated "Total" Cost (screening) ($million)	$1,105	
Benefit to Cost		
PV of Savings ($million)	$331.46	$336.51
Estimated "Total" Cost (screening) ($million)	$1,105.00	
Benefit to Cost	0.30	0.30

P27-129 cont.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, the benefit to cost ratio was not sufficient for the ISO to find the need for this project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the LA Basin area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits assessed here - is best addressed within the IRP process.

4.9.10 Western Sub-area (LA Basin)

As discussed in section 4.8.7, the Western LA Basin sub-area was not selected for detailed analysis of alternatives for reducing gas-fired generation local capacity requirements in this cycle. However, proposals submitted for other reasons pointed in part to such reductions in this sub-area as part of those proposals' economic benefits, such as the Diablo Canyon to Ormond Beach and Redondo Beach "California Transmission Project" discussed in section 0 and section 4.9.3.2. Please refer to those sections for a discussion of the potential benefits.

P27-129 cont.

The Southern California Regional LCR Reduction Project was initially studied by the ISO for other reasons, as set out in section 4.8.8, but was found to only have local capacity benefits for the Western LA Basin sub-area, and the results are therefore set out below.

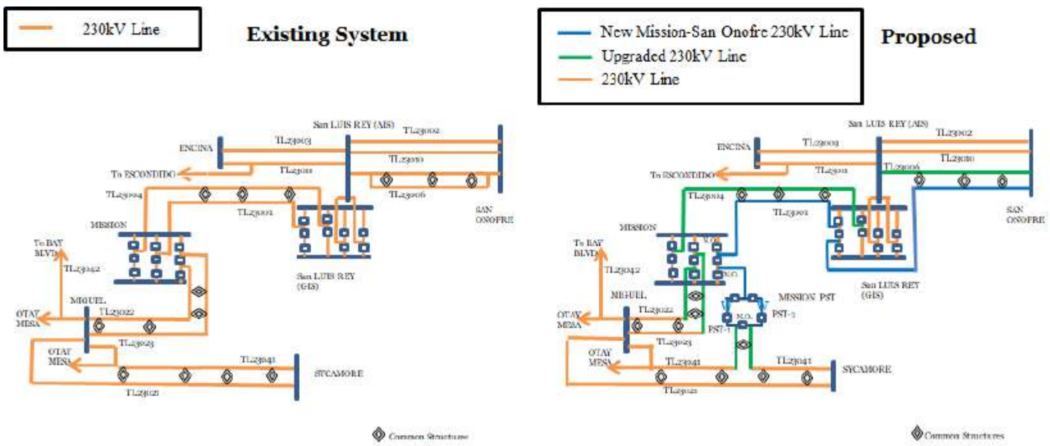
4.9.10.1 Southern California Regional LCR Reduction Project congestion and capacity benefits

The ISO examined the Southern California Regional LCR Reduction Project submitted by SDG&E in the 2018 Request Window, as set out in section 4.8.8. The project would consist of the following:

- Construct a new 230 kV line (2-1033ACSR), Mission-San Luis Rey- San Onofre, by utilizing the existing 230 kV facilities.
- Convert half of the existing 138kV switchyard (Bay 5 to Bay 9) to a 230 kV Phase Shifter Station at Mission Substation (2–600MW PSTs).
- Upgrade TL23004 (Mission-San Luis Rey), TL23006 (San Onofre-San Luis Rey), TL23022 (Miguel-Mission), and TL23023 (Miguel – Mission) with bundled 1033ACSR.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-14: Southern California Regional LCR Reduction Project Configuration



The project's estimated capital cost is between $100 million to $200 million. A preliminary target date of 2023 was estimated, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The upgrades were proposed by SDG&E as a Reliability Transmission Project. SDG&E stated that the proposed project would: P27-129 cont.

- Mitigate congestion for high San Onofre north bound flow for the P1 reliability violation of the San Luis Rey – Encina 230 kV line and San Luis Rey – Encina – Escondido 230 kV line
- Reduce regional capacity requirements (LCR) of 315 MW generation capacity necessary in 2023 for reliable operation in Orange County area. Increase the ability to deliver both in-state and out-of-state renewable resources into the load centers.
- Increase the transmission capacity, system reliability and operation flexibility in San Diego area.

Southern California Region LCR Reduction Project Production benefit

Table 4.9-26 shows the TEAM analysis results for this proposed project.

Table 4.9-26: Production Cost Modeling Results for Southern California Region LCR Reduction Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8465	-8
ISO generator net revenue benefitting ratepayers	2526	2525	-1
ISO owned transmission revenue	199	201	2
ISO Net payment	5733	5740	-7
WECC Production cost	16875	16878	-3

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

With this project modeled, it was observed that both thermal and renewable generation in the San Diego and Imperial Valley areas increased, because this project did help to reduce some transmission congestions in these areas. However, thermal and renewable generation in the SCE area decreased correspondingly, which resulted an increase in Path 26 congestion in South to North direction. Figure 4.9-15 and Figure 4.9-16 show the generation changes and the congestion changes with this project modeled. P27-129 cont.

Figure 4.9-15: Generation changes with S. Cal LCR Reduction Project modeled

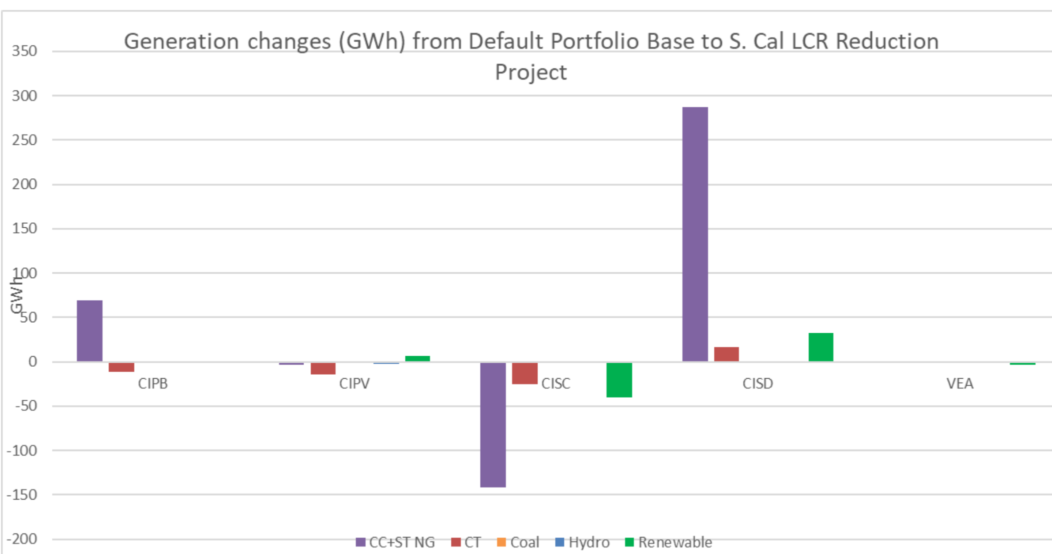
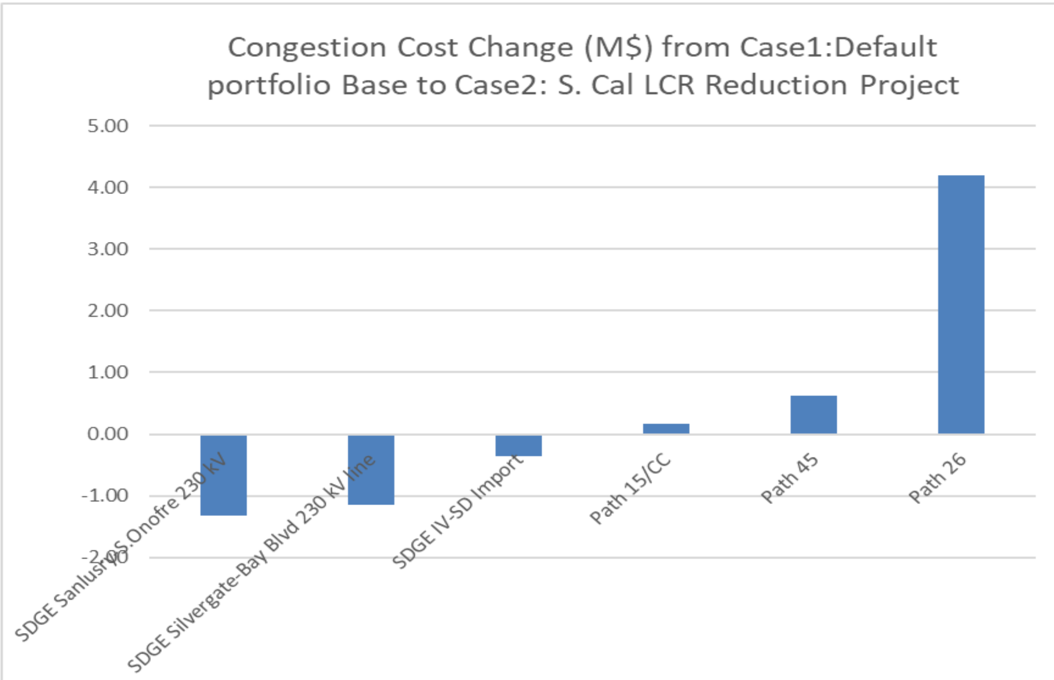


Figure 4.9-16: Congestion changes with S. Cal LCR Reduction Project modeled



P27-129 cont.

Local Capacity Benefits:

The ISO evaluated the project to determine whether it can help reduce the local capacity requirement in the Western LA Basin[112] sub-area. Modeling the proposed project to the 2028 LCR study case to evaluate for the Western LA Basin sub-area resulted in the following:

- The proposed Mission phase shifters were used in the study to send power to the Western LA Basin sub-area to help reduce local capacity need. The phase shifters were utilized to have a total of 850 MW northbound flow. The 850 MW flow is the limit to avoid overloading the Mission – San Luis Rey 230 kV line overloading concern.
- The Western LA Basin sub-area local capacity generation can be reduced by approximately 83 MW before the Mesa – Laguna Bell 230 kV line is overloaded under an overlapping outage of an N-1 of Mesa – Redondo 230 kV line, system adjustment then followed by an N-1 Mesa – Lighthipe 230 kV line.

[112] Note that the Western LA Basin sub-area has been evaluated due to actual and planned OTC generation retirements in the last several transmission planning cycles. Because of the previous extensive evaluation and implementation for OTC generation and San Onofre Nuclear Generating Station retirements, the ISO did not select this sub-area for study in this planning cycle as discussed in section 4.8.7.

- The proposed project potentially could reduce local capacity requirements for gas-fired generation in the Western LA Basin sub-area by about 83 MW.
- The ISO also checked for the potential impact to the San Diego – Imperial Valley local capacity need under an overlapping G-1 of TDM generation, followed by an N-1 of Imperial Valley – North Gila 500 kV line, or vice versa. It was determined that a southbound flow schedule of 40 MW on the Mission phase shifters would be sufficient to mitigate the potential overloading concern on the El Centro 230/92 kV transformer. Therefore, there is no impact to the local capacity requirement for the San Diego – Imperial Valley LCR area.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-27, the benefit of local capacity reductions in the Western LA Basin sub-area are valued based on the cost range for the LA Basin.

P27-129 cont.

Table 4.9-27: LCR Reduction Benefits for Southern California Region LCR Reduction Project

Southern California Region LCR Reduction Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Western LA Basin) (MW)	83	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$1.4	$1.9
LCR increase (San Diego – IV) (MW)	0	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$1.4	$1.9

Cost estimates

The current cost estimates from SDG&E range from $100 million to $200 million for the proposed project. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $100 million to $200 million capital translates to a total cost of $145 million to $290 million.

Benefit to Cost Ratio

In Table 4.9-28 the present value of the sum of the production cost and capacity benefits above are calculated based on a 40 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-28 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Southern California Region LCR Reduction Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$7	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	-$7	
PV of Prod Cost Savings ($million)	-$96	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$1.4	$1.9
PV of LCR Savings ($million)	$18.5	$25.1
Capital Cost		
Capital Cost Estimate ($ million)	$200	
Estimated "Total" Cost (screening) ($million)	$260	
Benefit to Cost		
PV of Savings ($million)	-$77.2	-$70.6
Estimated "Total" Cost (screening) ($million)	$260.00	
Benefit to Cost	-0.30	-0.27

P27-129 cont.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, the benefit to cost ratio was not sufficient for the ISO to find the need for this project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the LA Basin area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits assessed here - is best addressed within the IRP process.
- As this sub-area had not been selected for detailed analysis of alternatives, other potentially viable alternatives have not been developed and considered as alternatives. The ISO expects to complete detailed analysis of the remaining sub-areas that are dependent on gas-fired generation for meeting local capacity requirements in the next transmission planning cycle.

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cont.

4.9.11 San Diego/Imperial Valley Area (studied in concert with LA Basin) and San Diego Sub-area

Numerous stakeholder proposals were received as alternatives for reducing local capacity requirements in the San Diego/Imperial Valley area, as well as the San Diego sub-area. As noted in section 4.9, because the San Diego sub-area is within the San Diego-Imperial Valley LCR area, the total LCR reduction benefits (or impacts) were evaluated at the overall LCR level for the San Diego-Imperial Valley area. This was to ensure that the overall area impact (or benefits) were captured in the study.

4.9.11.1 S-Line Series Reactor

The ISO developed a series reactor alternative for reducing gas-fired generation in the overall San Diego-Imperial Valley LCR area and examined its benefits. The benefits are incremental to the benefits of upgrading the S-Line itself, which was approved by the ISO in the 2017-2018 transmission planning cycle. The originally approved S-line configuration being coordinated with the Imperial Irrigation District was a double-circuit 230 transmission line; the ISO studied the potential benefits of a series reactor on both that configuration and a single-circuit configuration, recognizing that the transmission line design and siting activities are in progress.

The project would consist of the following:

- Install an equivalent of 25-Ω line series reactor on the upgraded S-line (or 2x50-Ω if there are 2 lines in parallel); and
- Utilize the existing RAS and Imperial Valley phase shifters for mitigating the Sycamore Canyon – Suncrest 230 kV line in the San Diego bulk transmission sub-area.

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The transmission option of installing a 230 kV line series reactor is estimated to cost about $30 million. This estimate is based on an actual transmission project that included installation of a 50-Ω line series reactor on the Wilson-Warnerville 230 kV line in PG&E's service area.

S-Line Series Reactor Production benefit

Production cost benefits for this project were not explored, as the project focuses on reducing local capacity requirements and the production benefits are not expected to be material to a decision given the level of potential LCR reduction benefits and the forecast cost of the project.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the line series reactors on the S-line in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The gas-fired local capacity resource requirement for the San Diego – Imperial Valley area would be reduced by approximately 600 MW. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer. The result may still be subject to change pending the final design of the S-line upgrade or changes to the study assumptions regarding future generation retirements, new resource interconnection or changes in future load forecast from the CEC.

- Because local capacity requirements would be reduced in the San Diego-Imperial Valley area with the project in service, the ISO evaluated for potential local capacity impacts to the Western LA Basin sub-area as the LA Basin and San Diego-Imperial Valley areas are electrically dependent since the retirement of SONGS. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, then followed by an N-1 contingency for the Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 was found to be overloaded and an additional 200 MW of local capacity south of Laguna Bell Substation would be required to mitigate its overloading concern.

The S-line series reactors could potentially reduce local capacity need in the San Diego-Imperial Valley by about 600 MW[113], but it was also identified that the LA Basin area local capacity need is adversely impacted by about 200 MW. The net local capacity benefits for the San Diego-Imperial Valley area would need to have the benefits for the San Diego-Imperial Valley area subtracting the local capacity impacts in the Western LA Basin sub-area.

As discussed in section 4.3.4, local capacity requirement reductions in southern California area were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-29 the benefit of local capacity reductions in the San Diego-Imperial Valley area is valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

P27-129 cont.

[113] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

Table 4.9-29: LCR Reduction Benefits for the S-Line Series Reactor Project

S-Line Series Reactor Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	600	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$7.8	$11.4
LCR increase (Western LA Basin) (MW)	200	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$3.3	$4.5
Net LCR Saving ($million/year)	$4.5	$6.9

P27-129 cont.

Cost estimates:

The current cost estimate, based on an actual project, is about $30 million for the suggested mitigation option. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $39 million.

Benefit to Cost Ratio

In Table 4.9-30, the present value of the benefits is calculated based on a 40 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-30: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

S-Line Series Reactor Project		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$4.5	$6.9
PV of LCR Savings ($million)	$60.15	$92.15
Capital Cost		
Capital Cost Estimate ($ million)	$30	
Estimated “Total” Cost (screening) ($million)	$39	
Benefit to Cost		
PV of Savings ($million)	$60.15	$92.15
Estimated “Total” Cost (screening) ($million)	$39.00	
Benefit to Cost	1.54	2.36

Conclusions

The benefit to cost ratio of this project is encouraging notwithstanding the conservative value assigned to local capacity requirement reductions. The project will be considered in future planning cycles, once the design and configuration of the IID-owned S-Line upgrade is finalized.

Project development activities with IID have continued during the development of the transmission plan and after the above analysis was completed. The ISO is pursuing revisions to the scope of the previously approved S-Line Transmission Upgrade to consist of an appropriately sized single circuit 230 kV circuit, which provides the same local capacity requirement reduction value to the ISO as the original double-circuit line. As well, the ISO is updating the estimated cost to ISO ratepayers of the S-Line upgrade from $32 million to $40 million in light of revised costs estimates provided by IID. This increase in estimated cost would be offset by the savings of no longer needing a new line termination at the Imperial Valley Substation, which was required under the original double circuit configuration.

P27-129
cont.

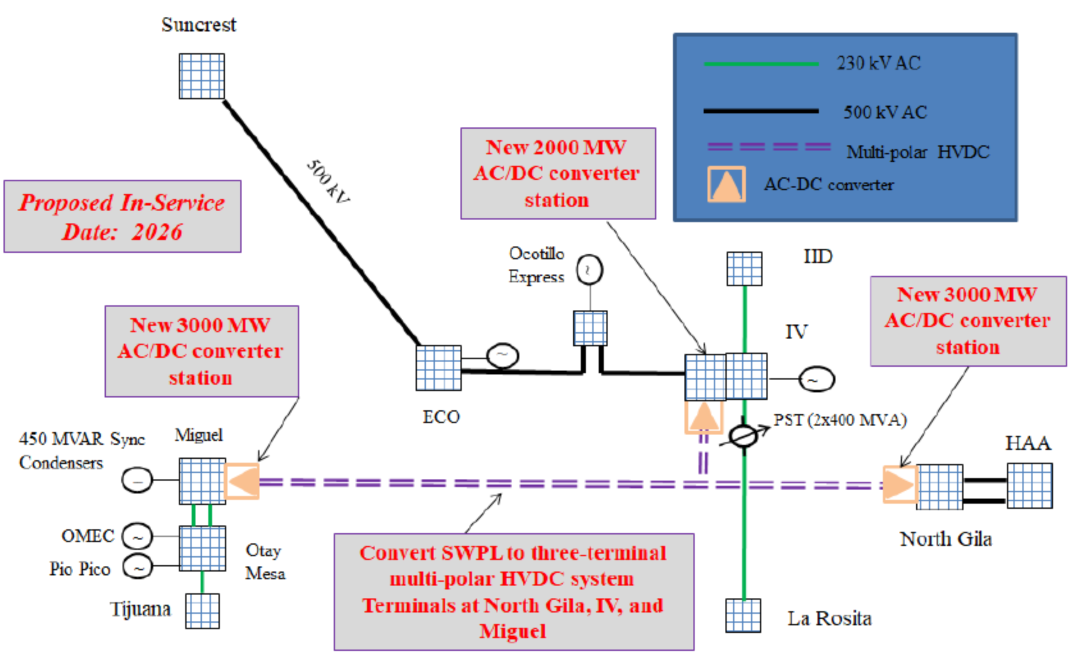
4.9.11.2 HVDC Conversion Project

The ISO examined the HVDC Conversion Project which was submitted by SDG&E as an interregional transmission project in the 2018-2019 transmission planning cycle, and had been previously submitted into the 2017-2018 transmission planning process Request Window as the “Renewable Energy Express”. The project would consist of the following:

- Convert a portion of the 500 kV Southwest Powerlink (SWPL) to a three-terminal HVDC system with two fully independent poles.
- Install terminals at or adjacent to North Gila, Imperial Valley, and Miguel Substations. Each pole will be capable of fully independent operation at its maximum rated capacity.
- The proposed capacity of the proposed HVDC system is 2x1500 MW, bi-directional, for a total transfer capacity of 3000 MW.
- Replace existing loop-in of Southwest Powerlink at ECO with Sunrise Powerlink to replace AC connectivity.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-17: HVDC Conversion Project Configuration



The project’s estimated capital cost is $700 to $900 million. SDG&E proposed a preliminary target date of 2026, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

P27-129 cont.

The upgrades were proposed by SDG&E as an interregional transmission project without requesting cost allocation between planning regions. SDG&E stated that the proposed project would provide significant regional and interregional benefits such as solving loop flow issues, increasing transfer capabilities to SDG&E and Southern California, aiding the integration of new transmission and generation projects, reducing Local Capacity Requirements (LCR) and Resource Adequacy (RA) requirements, and increasing the ability to deliver renewable resources (wind, solar, and geothermal) into the Southern California load centers.

As set out in chapter 2, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by the operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further economic benefits.

HVDC Conversion Project's Production benefit

Table 4.9-31 shows the TEAM analysis results for this proposed project.

Table 4.9-31: TEAM analysis for HVDC Conversion Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8,464	-7
ISO generator net revenue benefitting ratepayers	2526	2,515	-11
ISO owned transmission revenue	199	204	5
ISO Net payment	5733	5,746	-13
WECC Production cost	16875	16903	-28

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

It was observed in the simulation results that modeling the HVDC Conversion project increased congestion along the IV to San Diego corridor, mainly on the Suncrest to Sycamore corridor, and on Path 26, although SDG&E Bay Blvd-Silvergate and San Luis Rey to S. Onofre congestions were reduced, as shown in Figure 4.9-18. Renewable curtailment was reduced in the IV area, but increased in most of the other areas in Southern California, as shown in Figure 4.9-19.

P27-129
cont.

Figure 4.9-18: Congestion changes with modeling HVDC Conversion Project

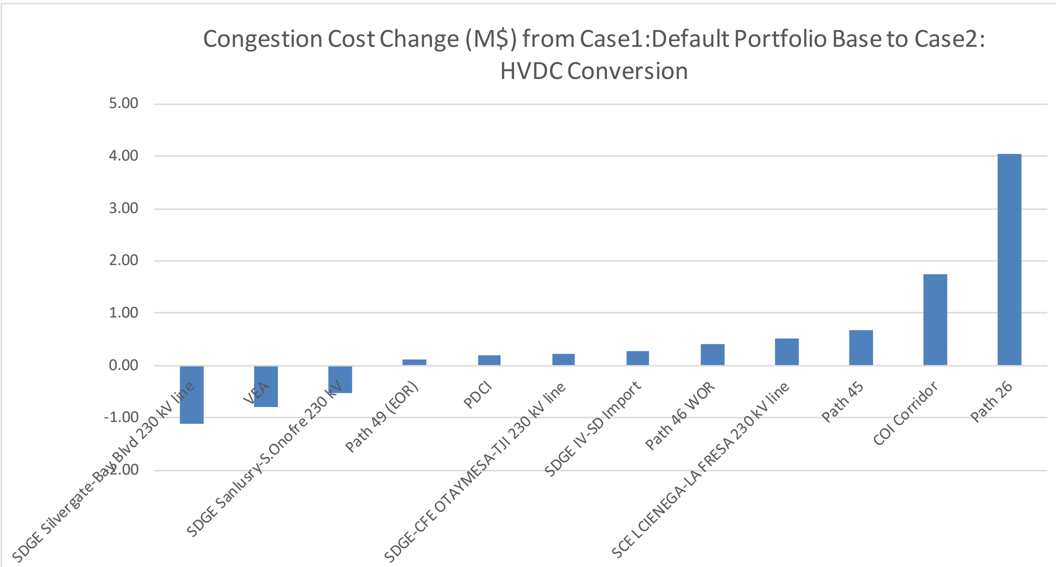
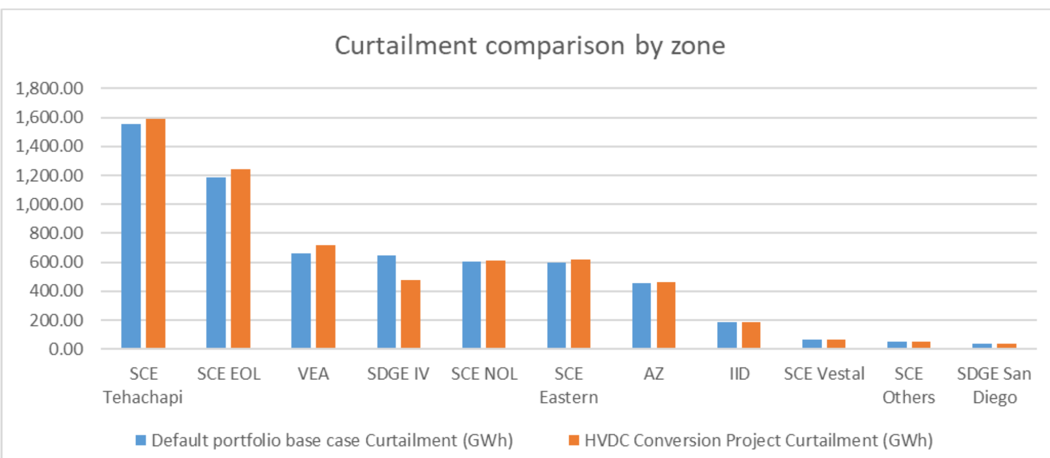


Figure 4.9-19: Curtailment changes by zone with modeling HVDC Conversion Project



P27-129 cont.

Local Capacity Benefits:

Modeling the HVDC Conversion Project in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- With the HVDC flow at 1650 MW, the Bay Blvd. – Silvergate 230 kV line was at its emergency rating under an N-2 contingency of Miguel-Mission 230 kV line, and the amount of gas-fired generation requirement reduction in the San Diego-Imperial Valley area was approximately 690 MW. Since the Bay Blvd. – Silvergate 230 kV line has only a two-hour duration for its emergency rating, the HVDC flow would need to be reduced further to 986 MW to reduce the Bay Blvd. – Silvergate 230 kV line flow to within its continuous rating, post-contingency.
- Since the gas-fired generation requirement could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needed to be checked to determine if there was an adverse impact to its LCR need. With the power flow model restored to normal condition, and with the HVDC at 1650 MW flow, an N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line caused an overloading concern on the Mesa-Laguna Bell 230 kV line. An additional 40 MW of local capacity south of Laguna Bell substation was needed to mitigate the loading concern.

The HVDC Conversion project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 690 MW[114], but it was also identified that the LA Basin area local capacity need would be adversely impacted by about 40 MW. The net local capacity benefits for the San Diego-Imperial Valley area are the difference between the local capacity cost increase in the LA Basin area and the local capacity cost reduction in the San Diego-Imperial Valley area.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-32, the benefits of local capacity reductions in the San Diego-Imperial Valley area are valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

P27-129 cont.

[114] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

Table 4.9-32: LCR Reduction Benefits for HVDC Conversion Project

	HVDC Conversion Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	690	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$9.0	$13.2
LCR increase (Western LA Basin) (MW)	40	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.7	$0.9
Net LCR Saving ($million/year)	$8.4	$12.3

Cost estimates:

The current cost estimates from SDG&E range from $700 to $900 million for the proposed project. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $900 million capital translates to a total cost of $1,170 million.

Benefit to Cost Ratio

In Table 4.9-33 the production benefit and the capacity benefits above are added, their present value is calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

P27-129 cont.

Table 4.9-33: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

HVDC Conversion Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$13	
HVDC Conversion Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	-$13	
PV of Prod Cost Savings ($million)	($179.41)	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$8.4	$12.3
PV of LCR Savings ($million)	$115.4	$169.2
Capital Cost		
Capital Cost Estimate ($ million)	$900	
Estimated “Total” Cost (screening) ($million)	$1,170	
Benefit to Cost		
PV of Savings ($million)	-$64	-$10
Estimated “Total” Cost (screening) ($million)	$1,170	
Benefit to Cost	-0.05	-0.01

P27-129 cont.

Conclusions

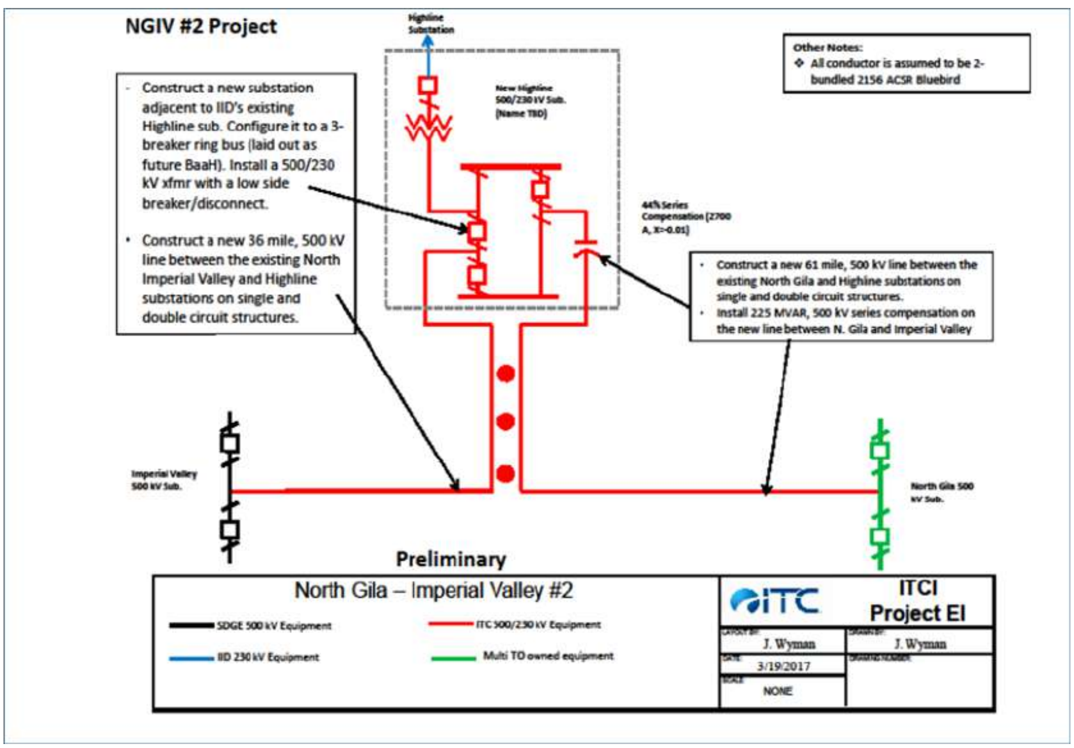
The benefit to cost ratio determined in this study does not support finding this project needed in this planning cycle. Further, the local capacity reduction benefits may be eroded if other options proceed that address the S-Line overload concern that presently sets the requirement for San Diego/Imperial Valley local capacity requirements. As the project relied heavily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC's integrated resource planning process.

4.9.11.3 North Gila – Imperial Valley #2 500 kV Transmission Project congestion and capacity benefits

The ISO examined the North Gila – Imperial Valley #2 500 kV Transmission Project which was submitted by ITC Grid Development and Southwest Transmission Partners, LLC as an interregional transmission project in the 2018-2019 transmission planning cycle as set out in chapter 5. The North Gila-Imperial Valley #2 500 kV Transmission Project was proposed as a 95-mile single circuit 500 kV AC transmission project between southwest Arizona and southern California. The proposed in-service date for the project is Q4 2022. The following figure illustrates the transmission configuration of the proposed project.

P27-129 cont.

Figure 4.9-20: North Gila - Imperial Valley #2 500 kV Line Configuration



The project's estimated capital cost for a single circuit line is $291 million. A preliminary target in-service date of Q4 2022 was proposed, and additional siting, permitting and design activities would be necessary to establish the feasibility of that target date.

The proponents stated that the proposed project would provide reliability benefits in addressing an overlapping G-1 (TDM) and N-1 (North Gila – Imperial Valley 500 kV line) contingency, economic benefits associated with reducing local capacity requirement, and increase transmission capacity for accessing generating resources in the Imperial Valley and Arizona areas.

As set out in chapter 2, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by the operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further economic benefits.

North Gila – Imperial Valley #2 500 kV Transmission Project's Production benefit

Table 4.9-34 shows the production cost modeling results for this proposed project.

Table 4.9-34: Production Cost Modeling Results for North Gila-Imperial Valley #2 500 kV Transmission Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8485	-27
ISO generator net revenue benefitting ratepayers	2526	2545	19
ISO owned transmission revenue	199	213	14
ISO Net payment	5733	5727	6
WECC Production cost	16875	16886	-11

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

It was observed in the simulation results that modeling NG – IV #2 line increased congestion in the SDG&E area and on Path 26, as shown in Figure 4.9-21. In turn, renewable curtailment increased in most areas in Southern California, as shown in Figure 4.9-22.

P27-129 cont.

Figure 4.9-21: Congestion changes with modeling NG-IV #2 line

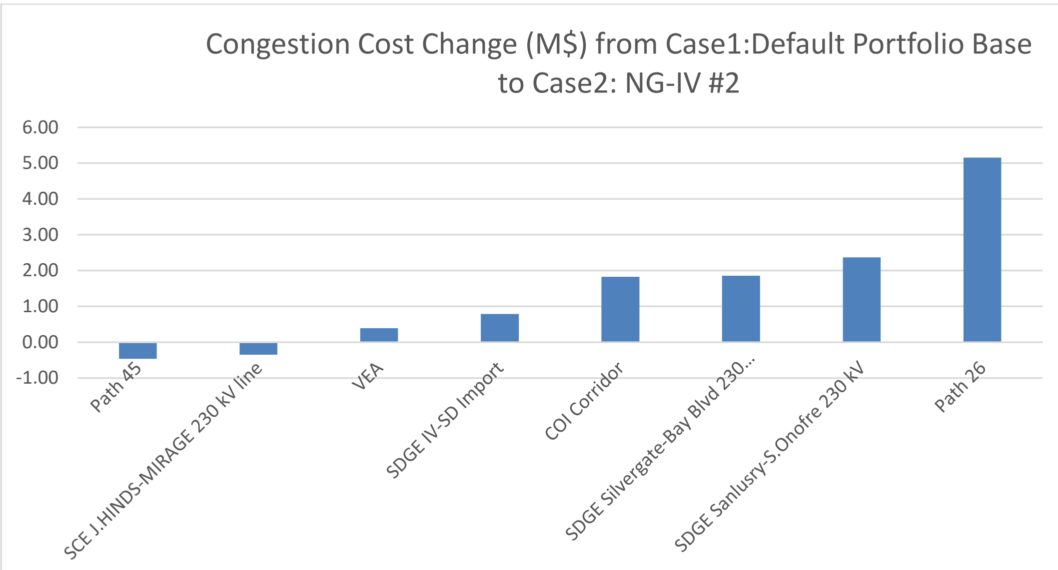
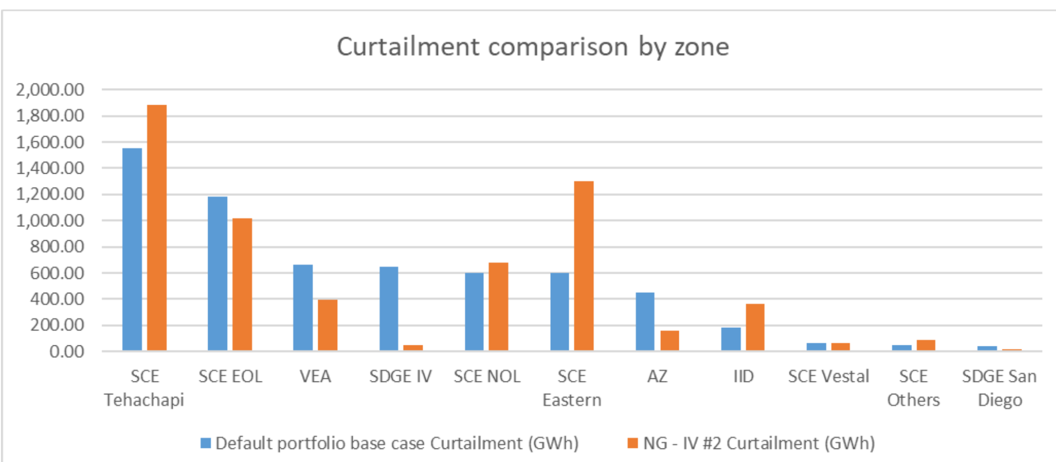


Figure 4.9-22: Curtailment changes by zone with modeling NG-IV #2 line



P27-129 cont.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the North Gila – Imperial Valley #2 500 kV line in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The LCR need for gas-fired generation in the San Diego – Imperial Valley area could be reduced by approximately 865 MW with reductions in the San Diego sub-area and Imperial Valley. The limiting contingency is the overlapping N-1 of the North Gila – Imperial Valley #1 500 kV line, system readjusted, followed by the North Gila – Imperial Valley #2 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer. If this transformer is upgraded, the next limiting element for further local capacity reductions was determined to be the Pilot Knob – Yucca 161 kV line, followed by the El Centro 230/161 kV transformer.
- Since local capacity would be reduced in the San Diego-Imperial Valley area with the project modeled, the ISO evaluated the potential local capacity impact to the Western LA Basin sub-area. With the study case restored to normal condition, an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, then followed by an N-1 contingency Mesa – Lighthipe 230 kV line, the Mesa – Laguna Bell 230 kV line #1 was overloaded by 1 percent. An increase in the Western LA Basin sub-area LCR need of 100 MW would mitigate the loading concern.

P27-129 cont.

The North Gila – Imperial Valley #2 500 kV line project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 865 MW[115], but would adversely impact the LA Basin area local capacity need by about 100 MW. The net local capacity benefits for the San Diego-Imperial Valley area are the difference between the local capacity requirement cost increase in the LA Basin area and the local capacity requirement cost reduction in the San Diego-Imperial Valley area.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

[115] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

In Table 4.9-35, the benefits of local capacity reductions in the San Diego-Imperial Valley area are valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

Table 4.9-35 : LCR Reduction Benefits for North Gila-Imperial Valley #2 500 kV Transmission Project

North Gila-Imperial Valley #2 500 kV Transmission Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	865	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$11.3	$16.5
LCR increase (Western LA Basin) (MW)	100	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$1.7	$2.3
Net LCR Saving ($million/year)	$9.6	$14.2

P27-129 cont.

Cost estimates:

The cost estimate provided by Southwest Transmission Partners, LLC is $291 million for the proposed project. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $291 million capital translates to a total cost of $378 million.

Benefit to Cost Ratio

In Table 4.9-36 the production benefit and the capacity benefits above are added, their present value is calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-36: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

NG-IV #2 500 kV Transmission Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$6	
NG-IV #2 500 kV Line Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$6	
PV of Prod Cost Savings ($million)	$82.80	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.6	$14.2
PV of LCR Savings ($million)	$133.12	$196.47
Capital Cost		
Capital Cost Estimate ($ million)	$291	
Estimated “Total” Cost (screening) ($million)	$378	
Benefit to Cost		
PV of Savings ($million)	$215.9	$279.3
Estimated “Total” Cost (screening) ($million)	$378	
Benefit to Cost	0.57	0.74

The benefit to cost ratio would be reduced if any potential negative impacts of the NG-IV #2 500 kV line were taken into account. The ISO’s reliability assessment demonstrated that the project would worsen the overload concerns identified in the San Diego import transmission and local 230 kV systems. This could potentially trigger reliability issues that need to be eliminated

P27-129 cont.

through additional capital investment. For example, the P6 overloads of Suncrest-Sycamore 230 kV lines (TL23054/TL23055) and the Miguel banks (#80/#81) could increase by 8~16% and 8~14% of their applicable ratings, compared to the system without the project. Similarly, the P6 overload of Silvergate-Oldtown 230 kV lines could increase by 5~12%. The existing potential overloads are planned to be mitigated by RAS and operating procedures, but could be insufficient to address the higher overloads identified in this study. In addition, the project would increase power flow via the CENACE system by about 4% for the P6 outages of any segment of the Imperial Valley-Sycamore path followed by the loss of any segment of the Imperial Valley-Miguel path, or vice versa, which increases exposure of cross-tripping one of the two 230 kV tie lines between SDG&E and CENACE. The ISO previously identified that the cross tripping may jeopardize reliability in the CENACE system and result in potential voltage instability in the Los Angeles Basin and the San Diego area.

Conclusions

The benefit to cost ratio determined in this study does not support finding this project needed in this planning cycle. Further, the project would require mitigations of the reliability concerns in the San Diego sub-area, and the benefits may be eroded if other options proceed that address the S-Line overload concern that presently sets the requirement for San Diego/Imperial Valley local capacity requirements. As the project relied heavily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC's integrated resource planning process. P27-129 cont.

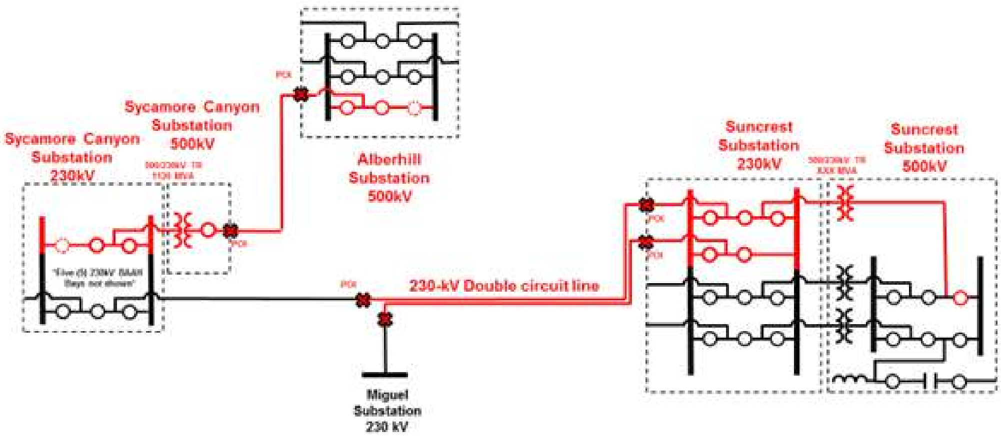
4.9.11.4 Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project congestion and capacity benefits

The ISO examined the Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project submitted by PG&E and TransCanyon as an economic study request. The project would consist of the following:

- Construct a new 500-kV transmission line from the proposed Alberhill substation to a new 500-kV Sycamore Canyon substation with a new 500/230-kV transformer at Sycamore Canyon substation. The CPUC denied the permit application for Alberhill substation project without prejudice in its environmental permitting process (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M228/K106/228106128.PDF). Since the Alberhill Substation Project was denied by the CPUC, PG&E and TransCanyon would need to modify the Request Window submittal to include the cost for a new switching station in lieu of the Alberhill substation.
- Install a third 500/230-kV transformer at Suncrest Substation and a new double circuit 230 kV transmission line that will loop the existing Miguel – Sycamore Canyon 230 kV transmission line to Suncrest substation.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-23: Alberhill to Sycamore plus Miguel to Sycamore loop into Suncrest 230 kV Project
Project Configuration



The proponents provided an estimated capital cost of $500 million. It is noted that this cost estimate does not include the cost to construct a potential new switching substation in lieu of SCE's Alberhill Substation Project. As noted earlier, the CPUC denied this project without prejudice at its environmental permitting process (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M228/K106/228106128.PDF). A preliminary target date of summer 2025 has been established, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date. P27-129 cont.

PG&E and TransCanyon stated that the proposed project would provide additional import capacity into the San Diego, enhance reliability, and reduce LCR requirements and the need to build additional generation in a highly populated area. Furthermore, PG&E and TransCanyon mentioned that the third transformer at Suncrest and the new 230 kV line that loops into the Suncrest substation would enhance the reliability of the 230 kV system under multiple contingencies and prevent overloads on the existing Sycamore Canyon-Suncrest 230 kV lines.

Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project Production benefit

Table 4.9-37 shows the production cost modeling results for this proposed project.

Table 4.9-37: Production Cost Modeling Results for Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV

	Pre project upgrade ($M)	**Post project upgrade ($M)**	**Savings ($M)**
ISO load payment	8457	8448	9
ISO generator net revenue benefitting ratepayers	2526	2519	-7
ISO owned transmission revenue	199	199	1
ISO Net payment	5733	5730	3
WECC Production cost	16875	16881	-6

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Figure 4.9-25 shows the generation and congestion changes within the ISO footprint with modeling Alberhill – Sycamore project, respectively. In these figures, CIPB is the area defined in the production cost model for the PG&E Bay area, CIPV is the rest of PG&E areas outside the Bay area, CISC is the SCE area, and CISD is the entire SDG&E area including the San Diego and IV areas.

The increase of SDG&E thermal generation was mainly from the thermal generators in the San Diego area, because the project helped to reduce the congestion on San Luis Rey to San Onofre line in the direction from SDG&E to SCE. SDG&E renewable generation reduced though because the project increased congestion on Bay Blvd to Silvergate line, which caused more curtailment in IV area.

P27-129 cont.

Figure 4.9-24: Generation changes with modeling Alberhill – Sycamore project

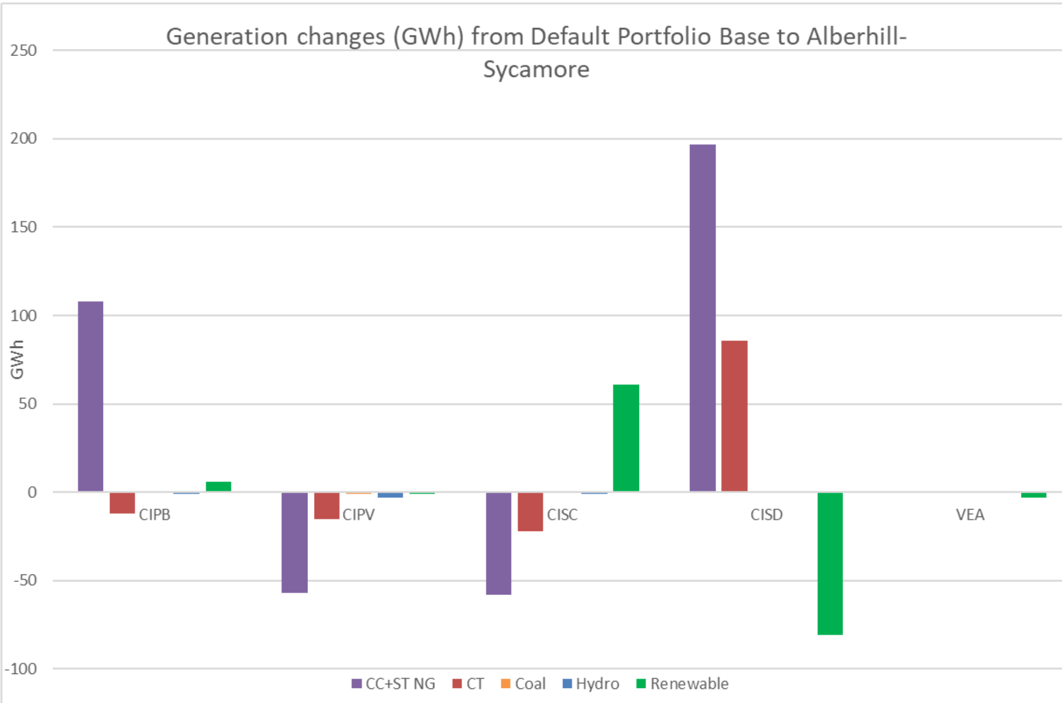
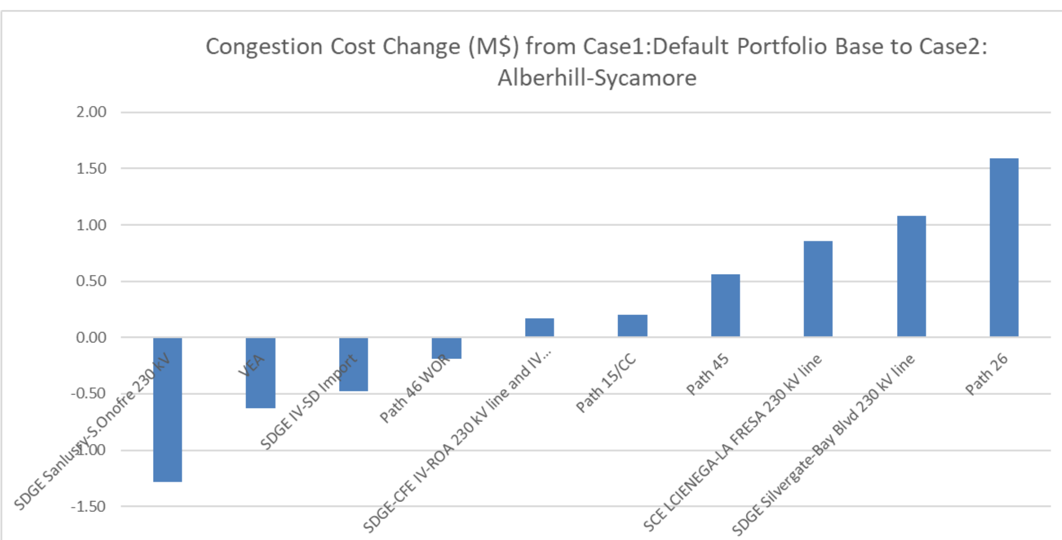


Figure 4.9-25: Congestion changes with modeling Alberhill – Sycamore project



P27-129 cont.

Local Capacity Benefits:

Modeling the proposed project to the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The amount of gas-fired generation could be reduced in the San Diego-Imperial Valley area by approximately 942 MW. This was established by the IID-owned El Centro 230/92 kV transformer reaching its rating limit under an overlapping G-1 (TDM) and N-1 of Imperial Valley – North Gila 500 kV line.
- Since the gas-fired generation could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needed to be checked to determine if there was an adverse impact to its LCR need.
- With the power flow model restored to normal condition, an overlapping contingency (N-1-1) was evaluated to determine impact to the LA Basin area LCR need. An N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line caused the Mesa-Laguna Bell 230 kV line to be overloaded. An additional 170 MW of local capacity south of Laguna Bell substation (Western LA Basin sub-area) was needed to mitigate this loading concern.

The proposed project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 942 MW[116], but it was also identified that the LA Basin area local capacity need would be adversely impacted and will need an additional 170 MW to mitigate the identified reliability concern. The net local capacity benefits for the San Diego-Imperial Valley area would be the difference between the local capacity cost increase in the LA Basin area and the local capacity cost reduction in the San Diego-Imperial Valley area.

P27-129 cont.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the San Diego area, these translated to values of \$13,080/MW-year and \$19,080/MW-year respectively. For the LA Basin, these translated to values of \$16,680/MW-year and \$22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-38 the benefit of local capacity reductions in the San Diego-Imperial Valley area is valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

[116] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

Table 4.9-38 : LCR Reduction Benefits for Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV

Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	942	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$12.3	$18.0
LCR increase (Western LA Basin) (MW)	170	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$2.8	$3.9
Net LCR Saving ($million/year)	$9.5	$14.1

Cost estimates:

The current cost estimate from PG&E and TransCanyon is $500.3 million for the proposed project. It is noted that the cost estimate assumed that the Alberhill substation would be approved by the CPUC for SCE to build. However, the CPUC denied without prejudice the Alberhill Substation Project in its environmental permitting process (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M228/K106/228106128.PDF). Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $500.3 million capital translates to a total cost of $725 million.

Benefit to Cost Ratio

In Table 4.9-38 the production benefit and the capacity benefits above are added, their present value is calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

P27-129 cont.

Table 4.9-39: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/ year)	$3	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$3	
PV of Prod Cost Savings ($million)	$41.40	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.5	$14.1
PV of LCR Savings ($million)	$130.91	$194.84
Capital Cost		
Capital Cost Estimate ($ million)	$500	
Estimated "Total" Cost (screening) ($million)	$650	
Benefit to Cost		
PV of Savings ($million)	$172.31	$236.24
Estimated "Total" Cost (screening) ($million)	$650	
Benefit to Cost	0.26	0.36

P27-129 cont.

Conclusions

The benefit to cost ratio determined in this study is not sufficient to find the project needed in this transmission planning cycle. As the project relied primarily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC's integrated resource planning process.

4.9.11.5 Lake Elsinore Advanced Pumped Storage (LEAPS) Project congestion and capacity benefits

The Lake Elsinore Advanced Pumped Storage (LEAPS) Project was submitted by Nevada Hydro on February 14, 2018 on the basis of section 24.3.3 of the ISO's tariff, which the ISO indicated would be considered an economic study request,[117] and into the 2018 Request Window on October 1, 2018 to address reliability needs in addition to providing other benefits. As set out in chapter 2, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further benefits, as an economic study request as stated in the final Unified Planning Assumptions and Study Plan[118].

The LEAPS Project ("Project") scope of work includes the following:

Option 1: Connection to both SCE and SDG&E

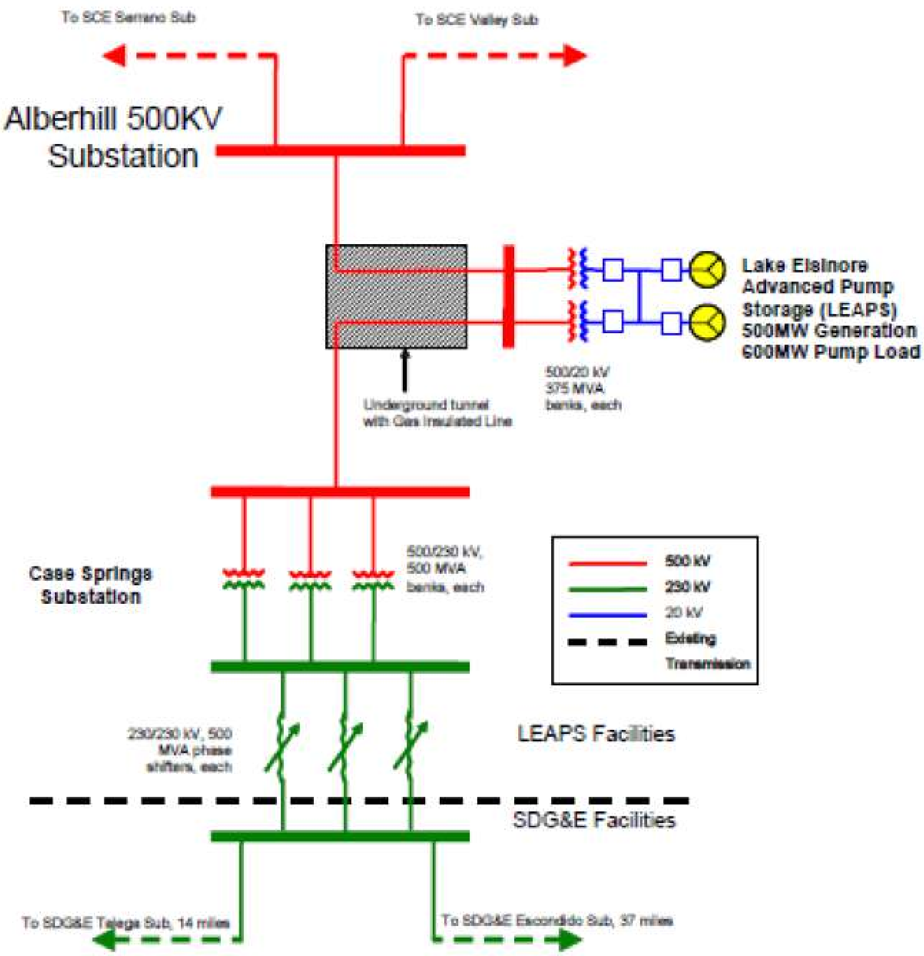
- This option interconnects the project at two points: (i) to SCE's transmission system at the proposed Alberhill 500 kV substation (if approved by the CPUC) and (ii) to SDG&E's transmission system by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation. If Alberhill is not approved, the connection point will be roughly one mile to the north-west at the proposed Lake Switchyard location. The following figure includes the transmission configuration for the proposed project.
- Approximate Project Cost = $2.04 billion

P27-129 cont.

[117] Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Draft, February 22, 2018.

[118] Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Final, March 30, 2018.

Figure 4.9-26: LEAPS Option 1 Configuration



Although the Nevada Hydro proposal does not propose an option of only the transmission development, considering the benefits provided by the transmission lines and phase shifters, and then the incremental benefits of the pumped hydro storage facility also enables a determination of the services being provided by each component of the proposed project. Accordingly, the ISO's analysis of the benefits was based on a phased approach:

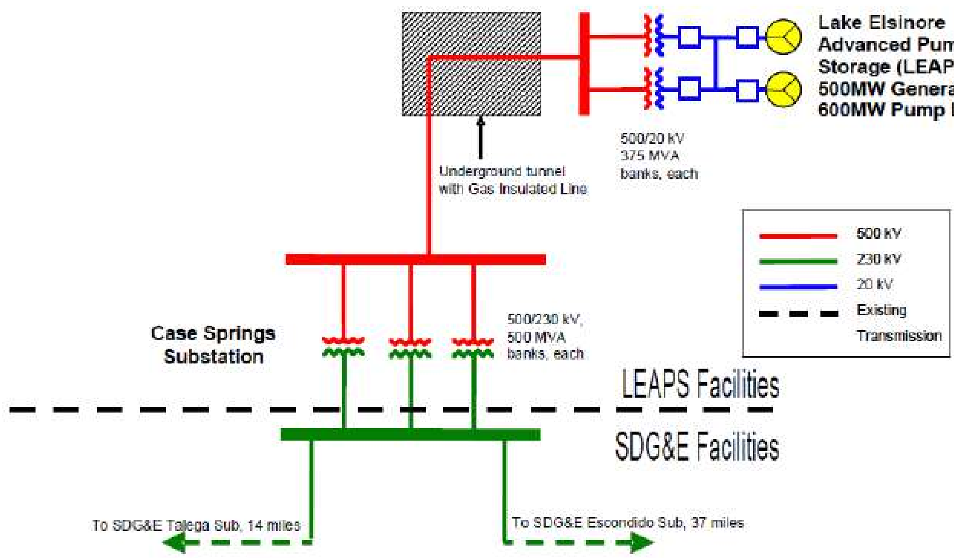
- Option 1a – the transmission development without the hydro pumped storage; and,
- Option 1b – the complete proposal, reflecting the addition of the hydro pumped storage facility to the transmission development.

P27-129 cont.

Option 2: Connection to SDG&E only

- Interconnecting to SDG&E's transmission by looping in the Talega – Escondido 230 kV line via the Case Springs 230 kV substation.
- Approximate Project Cost = $1.76 billion

Figure 4.9-27: LEAPS Option 2 Configuration



A preliminary target in-service date of 2025 has been proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The proponent stated that the proposed project would provide congestion mitigation benefits under various N-1 contingencies, economic benefits associated with reducing local capacity requirements, and renewable integration via the use of the pumped storage.

In the course of the reliability assessment set out in chapter 2, the ISO did not identify a reliability need for which a reinforcement in this area would be necessary. Although the pumped storage would be expected to provide reactive power in keeping with the ISO's reactive power requirements set out in the ISO's tariff, the ISO has not identified this as a specific need. Therefore, the analysis centered on the economic benefits LEAPS could provide.

The ISO's evaluation of economic study requests for potential approval of transmission solutions is based on the most current version of the ISO Transmission Economic Evaluation

P27-129 cont.

Methodology (TEAM)[119], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, the ISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the transmission approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by LEAPS identified in this analysis.

P27-129 cont.

LEAPS Project's Production Benefit

Table 4.9-40 shows the production cost modeling results for options 1a, 1b, and 2.

Table 4.9-40: Production Cost Modeling Results for LEAPS

	Pre project upgrade ($M)	Option 1a		Option 1b		Option 2	
		Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8456	1	8594	-137	8589	-132
ISO generator net revenue benefitting ratepayers*	2526	2529	3	2631	105	2624	99
ISO owned transmission revenue	199	198	-1	199	0	198	-1
ISO Net payment	5733	5729	4	5764	-31	5767	-34
WECC Production cost	16875	16878	-3	16838	37	16825	50

Note that ISO ratepayer "savings" are a <u>decrease</u> in load payment, but an <u>increase</u> in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an <u>increase</u> in ISO owned transmission revenue. WECC-wide "Savings" are a <u>decrease</u> in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $73 million--note that LEAPS net revenue is included in Table 4.9-44 and Table 4.9-45.

[119] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Figure 4.9-28 through Figure 4.9-33 show the generation and congestion changes with modeling the above three options of LEAPs project, all compared with the base case with the default portfolio. In these figures, CIPB is the area defined in the production cost model for the PG&E Bay area, CIPV is the rest of PG&E areas outside the Bay area, CISC is the SCE area, and CISD is the entire SDG&E area including the San Diego and IV areas.

With Option 1a modeled, which only considered the transmission component of the project, both the thermal and renewable generation dispatch in San Diego and IV areas increased, and the congestion in the same area decreased. SCE area generation decreased and Path 26 congestion from South to North increased.

With Option 1b modeled, which included the pumped storage, total renewable generation output increased within the ISO, because the pumped storage can absorb the surplus of renewable generation during the hours when renewable generation was otherwise curtailed. However, transmission congestion was not mitigated outside of the congestion in the SDG&E areas. As indicated in the footnote of Table 4.9-40, LEAPS pumped storage had positive net revenue. The main reason of the positive revenue of LEAPS pumped storage was that the LEAPS units normally pumped during the hours when renewable (mainly solar) output was high and LMP was relatively low, and generated during the hours when the LMP was relatively high. Figure 4.9-34 shows the pumped storage output in three typical days in April. This indicates that the positive net revenue is primarily due to arbitraging wholesale energy market prices.

With Option 2 modeled, the results were similar to the Option 1b results. The magnitude of changes in SCE and SDG&E areas were different between these two options mainly because the transmission configurations were different; hence, the impacts on generation dispatch were different. Also, the responses of rest of the system to the addition of the LEAPs project were slightly different in all three options.

P27-129 cont.

Figure 4.9-28: Generation changes with LEAPS Option 1a

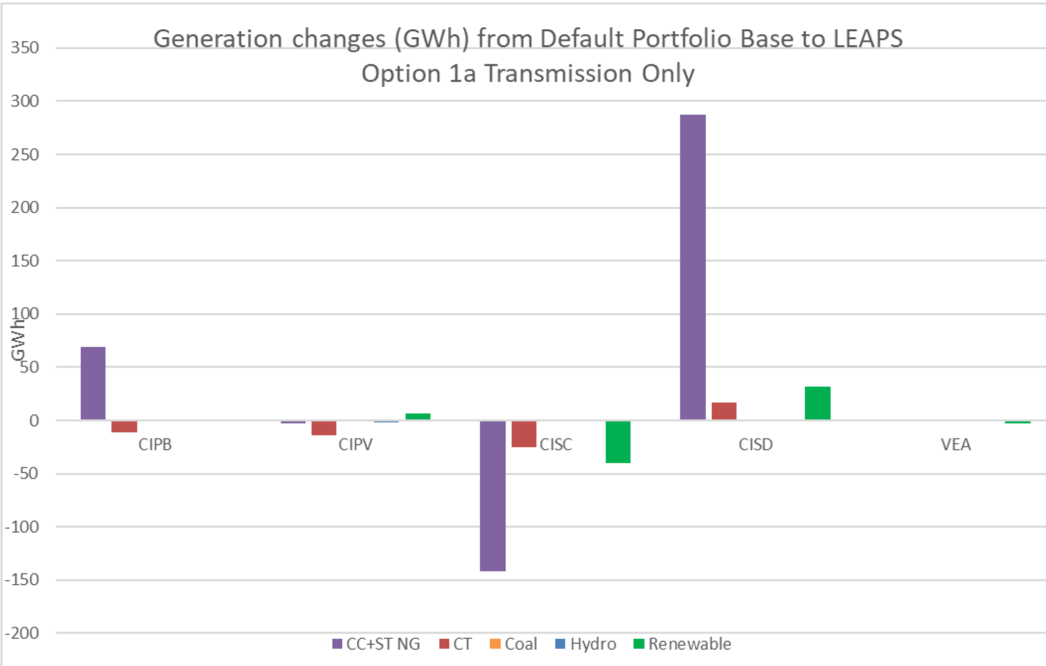
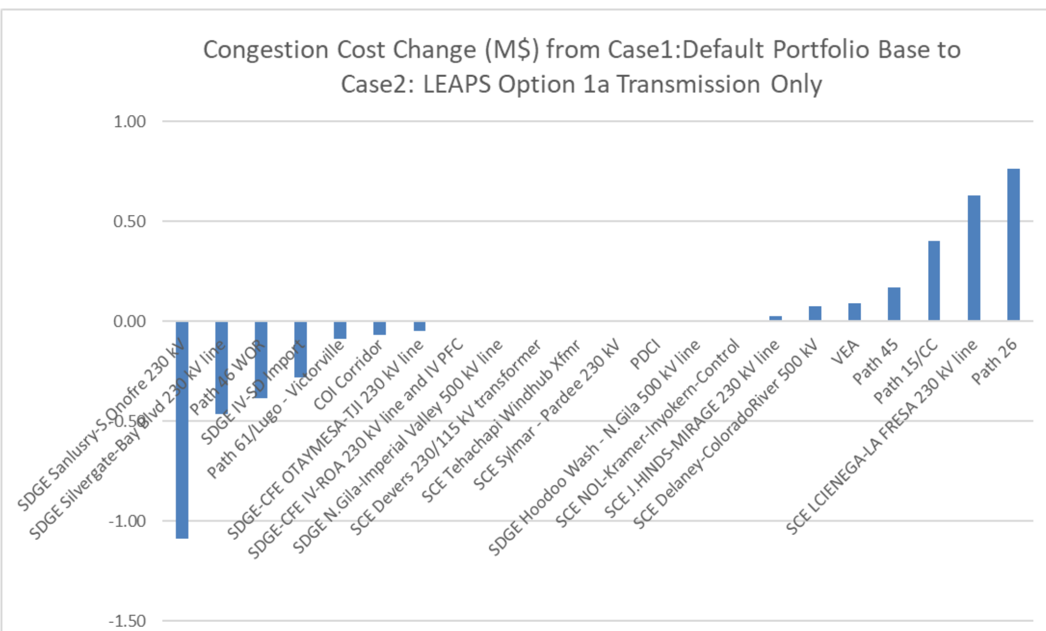
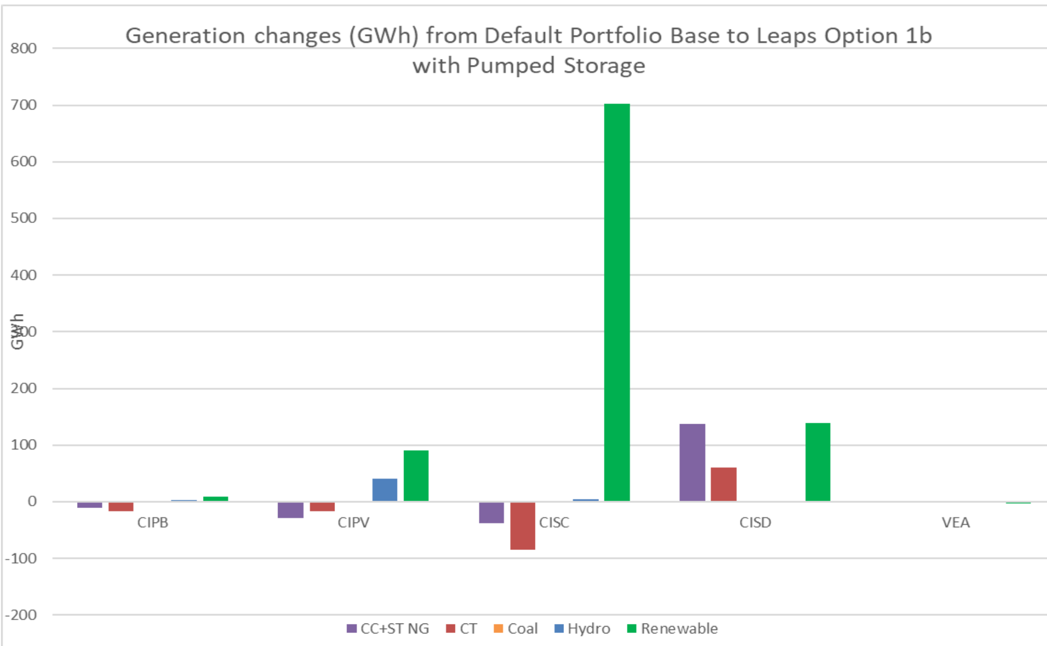


Figure 4.9-29: Congestion changes with LEAPS Option 1a



P27-129 cont.

Figure 4.9-30: Generation changes with LEAPS Option 1b



P27-129 cont.

Figure 4.9-31: Congestion changes with LEAPS Option 1b

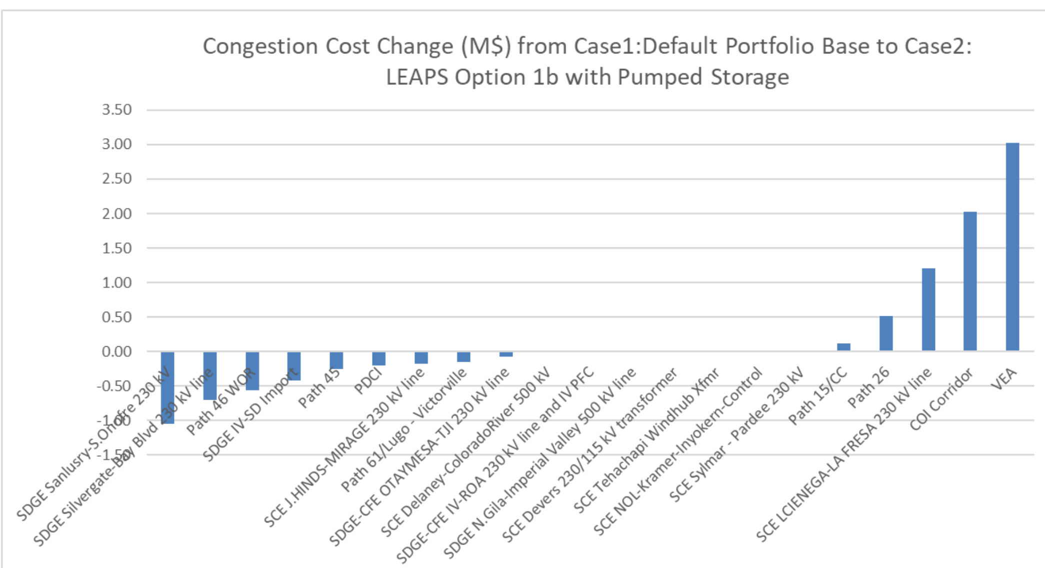


Figure 4.9-32: Generation changes with LEAPS Option 2

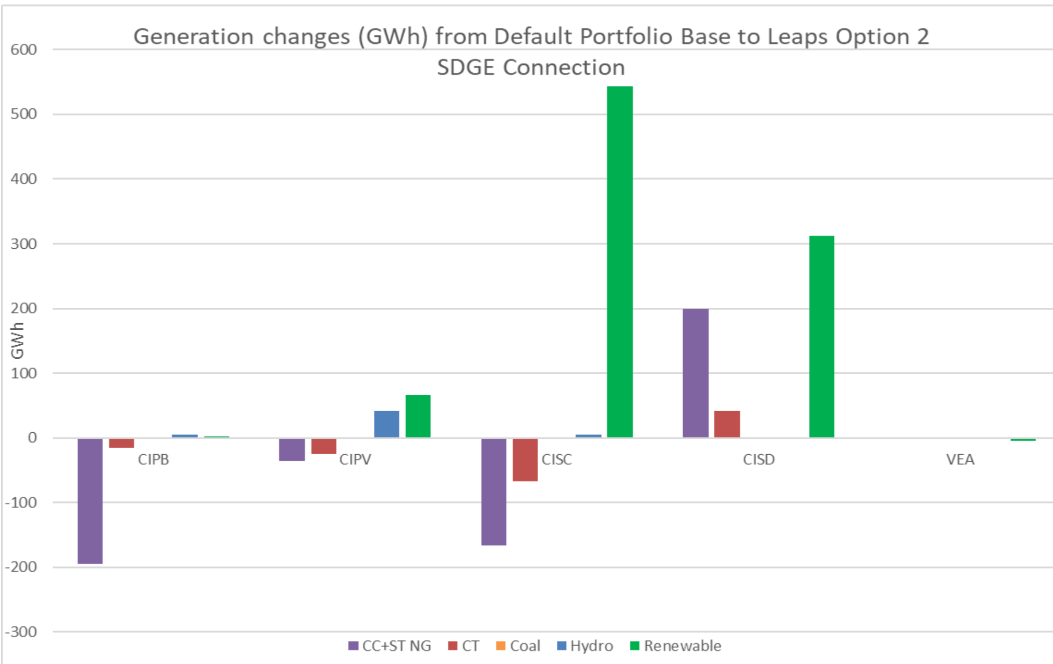
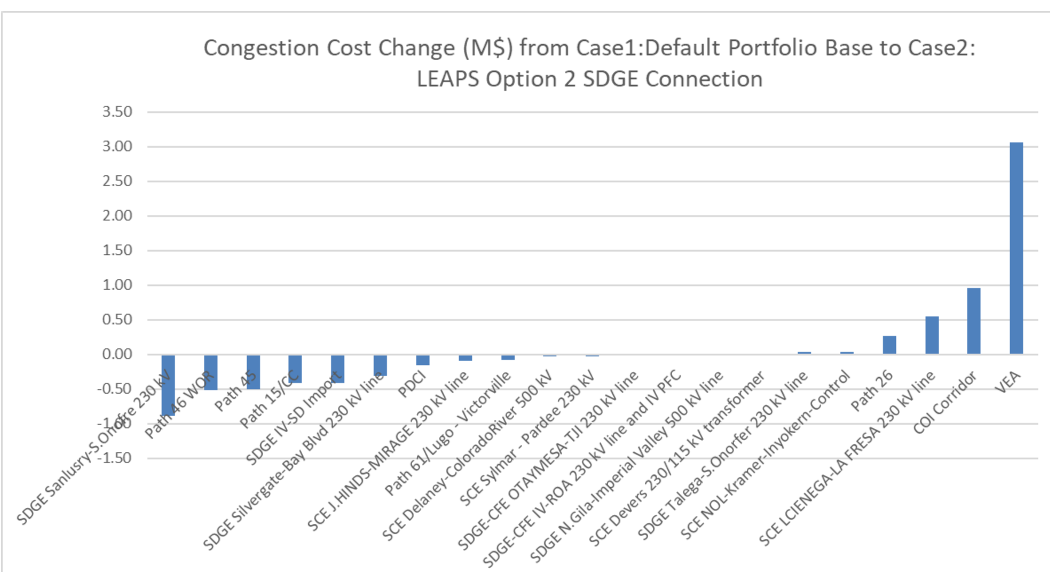
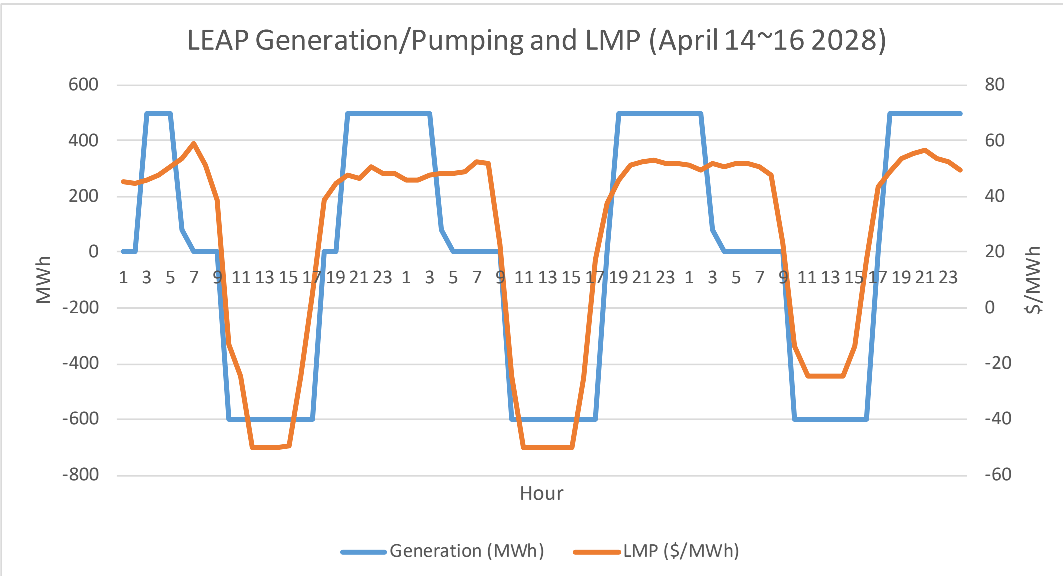


Figure 4.9-33: Congestion changes with LEAPS Option 2



P27-129
cont.

Figure 4.9-34: Pumped Storage output in typical days



P27-129 cont.

To more fully understand the nature of the GridView production cost modeling results and locational impacts, the ISO also examined the impact of modeling the LEAPS pumped storage facilities connected to the Lugo bus, which was chosen as a relatively unconstrained location in southern California. A comparison of these results is set out in Table 4.9-41.

Table 4.9-41: Production Cost Modeling Lugo Sensitivity for LEAPS

	Option 1b		Option 2		Lugo Connection (sensitivity)	
	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8594	-137	8589	-132	8591	-134
ISO generator net revenue benefitting ratepayers	2631	105	2624	99	2630	105
ISO owned transmission revenue	199	0	198	-1	197	-1
ISO Net payment	5764	-31	5767	-34	5764	-31
Storage net revenue		73		73		75
ISO Net payment including storage revenue		42		39		44
WECC Production cost	16838	37	16825	50	16842	33

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

While the ISO ratepayer benefits were consistent across all three options, the WECC production cost benefits appeared somewhat higher for the LEAPS Option 2 configuration. It appeared that the results were somewhat affected by the choice of renewable generation curtailed for system reasons and associated curtailment prices. To test the impact of the multi-tiered renewable curtailment model, the ISO conducted a sensitivity with the renewable curtailment price set at negative $25.

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Table 4.9-42: Production Cost Modeling Lugo Sensitivity for LEAPS with -$25 fixed renewable curtailment price

	Option 1b		Option 2		Lugo Connection (sensitivity)	
	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,659	-94	8,657	-92	8,656	-91
ISO generator net revenue benefitting ratepayers	2,677	81	2,667	72	2,674	78
ISO owned transmission revenue	206	-7	209	-5	208	-5
ISO Net payment	5,775	-20	5,781	-25	5,774	-18
Storage net revenue		68		67		70
ISO Net payment including storage revenue		48		42		52
WECC Production cost	16,852	55	16,856	52	16,855	53

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

The results of the production cost models are generally consistent within the multi-tiered renewable curtailment price model analysis whether the pumped storage is connected via Option 1b or Option 2, or located at Lugo. While there was somewhat of a variation in the Option 2 WECC production costs for the multi-tiered renewable curtailment price analysis, a review of the generation graphs provided in Figure 4.9-30 and Figure 4.9-32 suggested that the differences were driven by the selection of renewable generation for curtailment between Imperial Valley and within SCE's footprint, which in turn had other impacts on gas-fired generation dispatch, rather than due to the LEAPS pumped storage behaving markedly different in the function it provided. In the sensitivity with fixed renewable curtailment prices, the WECC production cost savings remained constant across all three cases; Option 1b, Option 2, or the Lugo sensitivity connection, supporting the original conclusion, with only minor variations as would be expected for different interconnection configurations.

In addition to the above comparison of LEAPS to the relatively unconstrained Lugo location, the ISO also considered the less location-dependent results available in its informational studies on the benefits of large (pumped hydro) storage. The ISO's informational study of the zonal system benefits of a generic 500 MW pumped storage facility was updated this year as set out in chapter 7, utilizing PLEXOS and a number of different planning assumptions, in particular using the CPUC's "hybrid conforming" generation portfolio coming out of its 2017-2018 integrated resource planning process. That "hybrid conforming" portfolio achieves a higher renewables

P27-129 cont.

portfolio standard that the CPUC default portfolio used in the 2018-2019 transmission planning cycle. That PLEXOS analysis demonstrated a total WECC production cost benefit of $46.4 million and a net revenue of $73.6 million per year. These results collectively are directionally consistent with the LEAPS study results, and further support the conclusion that the bulk of the production cost savings provided by the large pumped storage facility are largely system in nature.

From the production cost modeling results, it therefore appears that the production cost benefits are derived from the LEAPS facility essentially functioning as an energy or capacity resource in the ISO market. As the benefits seem consistent with the pumped storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits do not support the pumped storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area. These benefits are analyzed and considered exclusively as a ratepayer benefit.

Option 1 – Connecting to both SCE and SDG&E

Modeling the LEAPS (Option 1) in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- *Option 1a* – the transmission development alone, without the LEAPS pumped storage, provides about 443 MW of local (gas-fired) capacity requirement reduction benefits for the San Diego – Imperial Valley LCR area under the critical G-1/N-1 contingency of the TDM power plant (593 MW) and the Imperial Valley – North Gila 500 kV line.
- However, removing 443 MW of local gas-fired resources in the San Diego-Imperial Valley area without local capacity replacement would adversely impact the local capacity need in the Western LA Basin sub-area. Modeling the study case without the pumped storage and removing 443 MW of local capacity (gas-fired) resources in the San Diego-Imperial Valley area resulted in the need for an additional 150 MW of local capacity resources in the Western LA Basin sub-area to mitigate the overloading concern on the Mesa-Laguna Bell #1 230 kV line under an overlapping N-1-1 contingency of the Mesa-Redondo 230 kV line and the Mesa-Lighthipe 230 kV line.
- *Option 1b* – the pumped storage with the transmission development could reduce the gas-fired local capacity resource requirement for the San Diego – Imperial Valley area by approximately 514 MW in the San Diego area. The LEAPS pumped storage provides local capacity to the San Diego and San Diego-Imperial Valley area and can act to replace capacity otherwise provided by gas-fired generation in the area. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer.

P27-129
cont.

- Since local capacity could be reduced in the San Diego-Imperial Valley area with the project modeled, the ISO evaluated for potential local capacity impact to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, the followed by an N-1 contingency Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 flow was within its emergency rating. The Western LA Basin sub-area, and the overall LA Basin area local capacity need was not impacted by the proposed LEAPS project with transmission (Option 1b).
- Note that because the LEAPS connection to SCE is outside of the LA Basin area, the lack of impact on the Western LA Basin sub-area is driven by the potential power flow from LEAPS south into the SD&E system which then interacts with the LA Basin area needs. Also, the number of MW of gas-fired requirement reduction is slightly larger than LEAPS' capacity; this is due to the relative effectiveness of the point of interconnection compared to the gas-fired generation inside the SDG&E system.

Option 2 - Connecting to SDG&E Only

- By modeling the LEAPS (Option 2) in the 2028 long-term local capacity requirement study case, the gas-fired local capacity resources for the San Diego – Imperial Valley area could be reduced by approximately 533 MW in the San Diego area. The LEAPS pumped storage provides local capacity to the San Diego and San Diego-Imperial Valley area and replaces the gas-fired generation in the area. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer. The potential reduction in gas-fired generation local capacity requirement is larger than the capacity of the pumped hydro storage, and also larger than the benefit from Option 1, again supporting the increased effectiveness of the interconnection point in San Diego.
- Because local capacity is reduced in the San Diego-Imperial Valley area with the project modeled, the ISO evaluated for potential local capacity impact to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, the followed by an N-1 contingency Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 flow was within its emergency rating. The Western LA Basin sub-area, and the overall LA Basin area local capacity need was not impacted by the proposed LEAPS (Option 2).

The ISO notes that the local capacity benefits are a function of the amount of generating capacity of the pumped storage and the effectiveness of the interconnection point. While there are variations depending on relative effectiveness[120] of the configuration of the interconnection

P27-129 cont.

[120] Note that the effectiveness factors listed in the 2028 Local Capacity Technical Study described in section 6.1 and provided in Appendix G show a range for generation in the San Diego and Imperial Valley combined area of 11.88% to 25.42%. Effectiveness was measured as the impact on the flow on the constrained transmission facility as a percent of output from the local capacity resource. In other words, some existing resources are more than twice as effective as others at addressing the limiting constraint, due to the physical location of the resources.

to the grid and the location of the gas-fired resources being displaced as providers of local capacity, this is consistent with variations seen in the effectiveness of the resources currently providing the local capacity requirements in the San Diego/Imperial Valley area. The benefits therefore relate to substituting one type of local capacity resource – gas-fired generation – with another – the generating capacity of the pumped storage.

Valuing Local Capacity Requirement Reduction Benefits for Options 1a, 1b, and 2

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission solutions that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to assets such as storage, recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-43 the benefit of local capacity reductions in the San Diego-Imperial Valley area for each of the three options are valued based on the ranges for San Diego, and the impact for option 1a on the Western LA Basin sub-area is based on the cost range for the LA Basin.

Table 4.9-43: LCR Reduction Benefits for all Options

	Option 1a		Option 1b		Option 2	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego) (MW)	443		514		533	
Capacity value (per MW-year)	$13,080	$19,080	$13,080	$19,080	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.8	$8.5	$6.7	$9.8	$7.0	$10.2
LCR increase (LA Basin) (MW)	150		0		0	
Capacity value (per MW-year)	$16,680	$22,680	N/A	N/A	N/A	N/A
LCR increase cost ($million)	$2.5	$3.4	0	0	0	0
Net LCR Saving ($million/year)	$3.3	$5.1	$6.7	$9.8	$7.0	$10.2

P27-129 cont.

Further, the contingencies and potential overloads are observed to be “upstream“, easterly, of the San Diego area, and the connection of LEAPS into the San Diego area. The ISO has not identified a difference in the function being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

Option 1a: Nevada Hydro did not provide a separate cost estimate for the development of the transmission line project with associated switching substation cost without the LEAPS pumped storage. However, the cost for the development of the line can be estimated by removing the cost for the pumped storage facility from the Nevada Hydro Company’s website for the proposed project (http://leapshydro.com/wp-content/uploads/2017/10/Process-Costs-and-Financing.pdf). The cost estimate for the transmission facilities without the pumped storage is approximately $829 million. Applying the ISO’s screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the “total” cost”, the $829 million capital translates to a total cost of $1,202 million.

Option 1b: The current cost estimate from Nevada Hydro includes $2.04 billion for the proposed project Option 1. Applying the ISO’s screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the “total” cost”, the $2.04 billion capital translates to a total cost of $2.958 billion.

Option 2: The current cost estimate from Nevada Hydro includes $1.765 billion for the proposed project Option 2. Applying the ISO’s screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the “total” cost”, the $1.765 billion capital translates to a total cost of $2.559 billion.

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

The net present values of those annual revenue streams were estimated over 50[121] years as set out in Table 4.9-44.

P27-129 cont.

[121] 50-year life is used as this would have involved new construction for transmission project.

Table 4.9-44: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

	Option 1a		Option 1b		Option 2	
Production Cost Modeling Benefits						
Ratepayer Benefits ($million/year)	$4		-$31		-$34	
LEAPS Net Market Revenue ($million/ year)	$0		$73		$73	
Total PCM Benefits ($million/year)	$4		$42		$39	
PV of Prod Cost Savings ($million)	$55.20		$579.63		$538.23	
Local Capacity Benefits						
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$3.3	$5.1	$6.7	$9.8	$7.0	$10.2
PV of LCR Savings ($million)	$45.44	$69.70	$92.78	$135.35	$96.21	$140.35
Capital Cost						
Capital Cost Estimate ($ million)	$829		$2,040		$1,765	
Estimated "Total" Cost (screening) ($million)	$995		$2,448		$2,118	
Benefit to Cost						
PV of Savings ($million)	$100.64	$124.90	$672.42	$714.98	$634.44	$678.58
Estimated "Total" Cost (screening) ($million)	$994.80		$2,448		$2,118	
Benefit to Cost	0.10	0.13	0.27	0.29	0.30	0.32

P27-129 cont.

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. Because these include benefits that do not accrue directly to the benefit of ratepayers, who would fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-45: Benefit to Cost Ratios (Production Cost Savings – Information Only)

	Option 1a		Option 1b		Option 2	
Production Cost Modeling Benefits						
WECC PCM Cost Reduction ($million/year)	-$3		$37		$50	
LEAPS Net Market Revenue ($million/ year)	$0		$73		$73	
Total PCM Benefits ($million/ year)	-$3		$110		$123	
PV of Prod Cost Savings ($million)	-$41.40		$1,518.08		$1,697.49	
Local Capacity Benefits						
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$3.3	$5.1	$6.7	$9.8	$7.0	$10.2
PV of LCR Savings ($million)	$45.44	$69.70	$92.78	$135.35	$96.21	$140.35
Capital Cost						
Capital Cost Estimate ($ million)	$829		$2,040		$1,765	
Estimated "Total" Cost (screening) ($million)	$995		$2,448		$2,118	
Benefit to Cost						
PV of Savings ($million)	$4.04	$28.30	$1,610.87	$1,653.43	$1,793.71	$1,837.84
Estimated "Total" Cost (screening) ($million)	$994.80		$2,448		$2,118	
Benefit to Cost	0.00	0.03	0.66	0.68	0.85	0.87

P27-129 cont.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the LEAPS net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the LEAPS project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of LEAPS - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other non-transmission benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to LEAPS performing a transmission function operating to meet an ISO-identified transmission need:
  - There were no identified reliability needs in the planning horizon driving the need for the project;
  - The production cost benefits associated with the pumped storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
  - The local capacity benefits associated with the pumped storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

P27-129 cont.

4.9.11.6 San Vicente Energy Storage Project congestion and capacity benefits

The ISO examined the San Vicente Energy Storage Project submitted by the City of San Diego into the 2018 Request Window. As set out in chapter 2, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further benefits, recognizing that the proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, potentially reducing the local capacity requirements for gas-fired generation.

The San Vicente Energy Storage (“Project”) scope includes the following:

- The energy storage plant is configured with four individual generating units connected to the SDG&E-owned Sycamore 230 kV substation. Total generating capacity is 500 MW.
- Two 230 kV generation tie line circuits extend from the project switchyard to the proposed point of interconnection at Sycamore Canyon 230 kV substation.

The proponent provided an approximate project cost estimate of $1.5 billion to $2 billion. A preliminary target in-service date of Q1 2028 was proposed, and additional siting, permitting and design activities would be necessary to establish the feasibility of that target date.

The Project Proponent stated that the proposed project would provide the following benefits:

- System, flexible and local capacity needs
- Renewable integration via the use of pumped storage to minimize renewable resource curtailments
- Economic benefits associated with reducing local capacity requirements
- Reliability benefits for mitigating various overlapping N-1-1 contingencies

P27-129 cont.

The ISO’s evaluation of economic study requests for potential approval of transmission projects is based on the most current version of the ISO Transmission Economic Evaluation Methodology (TEAM)[122], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, however, the ISO conducted the economic study analysis for this project assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC’s integrated resource planning processes. Both sets of results are provided below.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery

[122] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by the San Vicente Energy Storage Project identified in this analysis.

San Vicente Energy Storage Project's Production benefit

Table 4.9-46 shows the production cost modeling results for this proposed project.

Table 4.9-46: Production Cost Modeling Results for the San Vicente Energy Storage Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8557	-100
ISO generator net revenue benefitting ratepayers *	2526	2602	77
ISO owned transmission revenue	199	199	0
ISO Net payment	5733	5756	-23
WECC Production cost	16875	16838	37

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $54 million--note that San Vicente net revenue is included in Table 4.9-48 and Table 4.9-49.

These results are aligned with the results found for the LEAPS pumped storage unit, which is relatively similarly situated with LEAPS having higher storage capacity (10 hour discharge at 500 MW output) compared to San Vicente (8 hour discharge at 500 MW output) reasonably accounting for LEAPS having generally higher ISO ratepayer net payment, WECC production cost, and pumped storage net revenue.

The ISO conducted detailed analysis and sensitivities of the LEAPS project to ascertain if the production cost modeling benefits were attributable generally to the participation of the resource in the ISO market, or if other factors were at play. That analysis led to the conclusion that the production cost benefits were derived from the LEAPS facility essentially functioning as an energy or capacity resource in the ISO market. Further, as the benefits seemed consistent with the pumped storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits did not support the pumped storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Given the alignment of results here for the San Vicente project the same conclusions apply to the San Vicente project.

P27-129 cont.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the San Vicente Energy Storage Project in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The local capacity requirement for gas-fired resources for the San Diego – Imperial Valley area could be reduced by approximately 690 MW in the San Diego area. Location is important in mitigating the critical contingency that triggers the need for local capacity resources. The San Vicente pumped storage is located nearer to the critical loading element, resulting in a greater effectiveness than the gas-fired resources currently providing local capacity. The proposed project provides local capacity to the San Diego and San Diego-Imperial Valley area and can act to replace capacity otherwise provided by gas-fired generation in the area. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer.
- Since local capacity is reduced in the San Diego-Imperial Valley area with the project modeled, the ISO evaluated for potential local capacity impact to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, the followed by an N-1 contingency Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 flow was within its emergency rating. The Western LA Basin sub-area, and the overall LA Basin area local capacity need was not impacted by the proposed San Vicente Energy Storage Project.

The ISO notes that the local capacity benefits are a function of the amount of generating capacity of the pumped storage and the effectiveness of the interconnection point. While there are variations depending on relative effectiveness[123] of the configuration of the interconnection to the grid and the location of the gas-fired resources being displaced as providers of local capacity, this is consistent with variations seen in the effectiveness of the resources currently providing the local capacity requirements in the San Diego/Imperial Valley area. The benefits therefore relate to substituting one type of local capacity resource – gas-fired generation – with another – the generating capacity of the pumped storage.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local

P27-129 cont.

[123] Note that the effectiveness factors listed in the 2028 Local Capacity Technical Study described in section 6.1 and provided in Appendix G show a range for generation in the San Diego and Imperial Valley combined area of 11.88% to 25.42%. Effectiveness was measured as the impact on the flow on the constrained transmission facility as a percent of output from the local capacity resource. In other words, some existing resources are more than twice as effective as others at addressing the limiting constraint, due to the physical location of the resources.

capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-47 the benefit of local capacity reductions in the San Diego-Imperial Valley area for this project are shown.

Table 4.9-47: LCR Reduction Benefits for San Vicente Energy Storage Project

San Vicente Energy Storage Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	690	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$9.0	$13.2
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$9.0	$13.2

Further, the contingencies and potential overloads are observed to be "upstream", easterly, of the San Diego area, and the connection of the project into the San Diego area. The ISO has not identified a difference in the function being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

The current cost estimate from the City of San Diego is a range of $1.5 billion to $2.0 billion for the proposed project. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $2.0 billion capital translates to a total cost of $2.6 billion. It is noted that the submitted project cost was based on the original point of interconnection to the Sycamore – Suncrest 230

P27-129 cont.

kV lines rather at the Sycamore Canyon 230 kV substation which would require a longer transmission line to connect.

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

The net present values of those annual revenue streams were estimated over 50 years as set out in Table 4.9-48.

Table 4.9-48 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

San Vicente Energy Storage Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$23	
San Vicente Net Market Revenue ($million/ year)	$54	
Total PCM Benefits ($million/year)	$31	
PV of Prod Cost Savings ($million)	$427.82	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.0	$13.2
PV of LCR Savings ($million)	$124.55	$181.69
Capital Cost		
Capital Cost Estimate ($ million)	$2,000	
Estimated “Total” Cost (screening) ($million)	$2,600	
Benefit to Cost		
PV of Savings ($million)	$552.38	$609.51
Estimated “Total” Cost (screening) ($million)	$2,600	
Benefit to Cost	0.21	0.23

P27-129 cont.

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. As these include benefits that do not accrue directly to the benefit of ratepayers, who would however fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-49 : Benefit to Cost Ratios (WECC Benefits per TEAM)

San Vicente Energy Storage Project		
Production Cost Modeling Benefits		
WECC PCM Cost Reduction ($million/year)	$37	
San Vicente Net Market Revenue ($million/year)	$54	
Total PCM Benefits ($million/year)	$91	
PV of Prod Cost Savings ($million)	$1,255.87	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.0	$13.2
PV of LCR Savings ($million)	$124.55	$181.69
Capital Cost		
Capital Cost Estimate ($ million)	$2,000	
Estimated “Total” Cost (screening) ($million)	$2,600	
Benefit to Cost		
PV of Savings ($million)	$1,380.42	$1,437.56
Estimated “Total” Cost (screening) ($million)	$2,600	
Benefit to Cost	0.53	0.55

P27-129 cont.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the San Vicente Energy Storage Project net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the San Vicente Energy Storage Project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of the San Vicente Energy Storage Project - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to the San Vicente Energy Storage Project performing a transmission function operating to meet an ISO-identified transmission need:
    - There were no identified reliability needs in the planning horizon driving the need for the project;
    - The production cost benefits associated with the pumped storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
    - The local capacity benefits associated with the pumped storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

P27-129 cont.

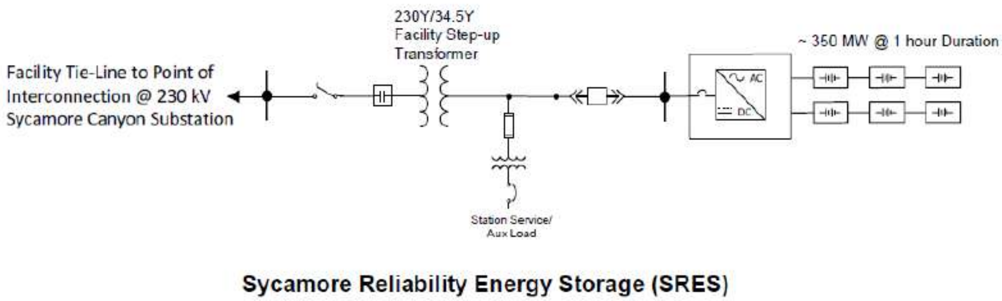
4.9.11.7 Sycamore Reliability Energy Storage (SRES – 381 MW) Project congestion and capacity benefits

The ISO examined the Sycamore Reliability Energy Storage (SRES) Project submitted by Tenaska to the 2018- Request Window. The project would consist of the following:

- Construct a 381[124] MW battery energy storage system (BESS) with one-hour discharge duration. It is noted that for local Resource Adequacy consideration, the resource would need to be available for at least 4 hours.
- Construct facility tie-line and grid interconnection to Sycamore 230 kV substation.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-35: Sycamore Reliability Energy Storage Configuration



The project's estimated capital cost ranges from $108 million to $178 million. It is noted that this cost estimate is only for 1-hour discharge battery energy storage. Additional cost would be needed to provide larger bank of batteries for a 4-hour duration as required for the local Resource Adequacy (RA) need. A preliminary target date of Q4 2021 was proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The project was proposed by Tenaska as a Reliability Transmission Project. The proponent was also seeking to qualify the proposed project as a SATA (Storage as a Transmission Asset) facility. Tenaska stated that the proposed project would increase the capacity, efficiency, reliability, and operating flexibility of the transmission system and to mitigate the reliability issues identified by the ISO in the 2018-2019 Transmission Planning Process. Tenaska stated that the proposed project effectively mitigates the N-1 or overlapping N-1-1 line overloading concern on the Sycamore-Suncrest 230 kV line without having to use the RAS for generation tripping. Lastly, the project was proposed to reduce potential congestion.

As set out in chapter 2, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by the operational measures. For this reason, the project was not found to be needed as a reliability-driven project.

[124] Tenaska provided a power flow model for a 381 MW battery energy storage system.

P27-129 cont.

The ISO subsequently examined the project for further benefits, recognizing that the proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, potentially reducing the local capacity requirements for gas-fired generation.

The ISO's evaluation of economic study requests for potential approval of transmission projects is based on the most current version of the ISO Transmission Economic Evaluation Methodology (TEAM)[125], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, however, the ISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by the Sycamore Reliability Energy Storage (SRES) Project identified in this analysis. P27-129 cont.

Sycamore Reliability Energy Storage (SRES) Project Production benefit

Table 4.9-50 shows the production cost modeling results for this proposed project.

[125] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.9-50: Production Cost Modeling Results for Sycamore Reliability Energy Storage Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8528	-71
ISO generator net revenue benefitting ratepayers*	2526	2590	65
ISO owned transmission revenue	199	200	1
ISO Net payment	5733	5738	-5
WECC Production cost	16875	16853	22

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $35 million--note that Sycamore Reliability Energy Storage net revenue is included in Table 4.9-54 and Table 4.9-55.

To more fully understand the nature of the GridView production cost modeling results and locational impacts, the ISO also examined the impacts of modeling the Sycamore Reliability Energy Storage Project connected to the Lugo bus, which was chosen as a relatively unconstrained location in southern California. A comparison of these results is set out in Table 4.9-51. These results show that the WECC production cost modeling results obtained if the same project were connected to the Lugo bus would be the same or better than if it were located at Sycamore, and with approximately the same net revenue earned by the storage facility.

P27-129 cont.

Table 4.9-51 Production Cost Modeling Sensitivity for Sycamore Reliability Energy Storage Project

	SRES Project		Lugo Connection (sensitivity)	
	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8528	-71	8534	-77
ISO generator net revenue benefitting ratepayers	2590	65	2590	64
ISO owned transmission revenue	200	1	197	-2
ISO Net payment	5738	-5	5748	-15
Storage net revenue		35		36
ISO Net payment including storage revenue		30		21
WECC Production cost	16825	22	16846	28

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

From the production cost modeling results, it therefore appears that the production cost benefits were derived from the Sycamore Reliability Energy Storage Project facility essentially functioning as an energy or capacity resource in the ISO market. As the benefits seem consistent with the storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits do not support the storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the proposed project at 381 MW, as provided by Tenaska in its power flow model to the ISO, to the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The IID-owned El Centro 230/92 kV transformer is at its rating limit under an overlapping G-1 (TDM) and N-1 of Imperial Valley – North Gila 500 kV line. The amount of gas-fired generation requirement reduction in the San Diego-Imperial Valley area is approximately 391 MW.
- Since the gas-fired generation could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needs to be checked to determine if there is adverse impact to its LCR need. The power flow study is restored to normal condition. An N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line. This N-1-1 contingency could cause an overloading concern on the Mesa-Laguna Bell 230 kV line. However, a check on the Mesa – Laguna Bell 230 kV line loading indicated that it is 99.9% at its emergency rating limit.

P27-129 cont.

The proposed project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 391 MW[126]. There was no identified local capacity impact to the LA Basin area as the replacement of gas-fired generation is the capacity from the proposed battery energy storage. The net local capacity benefits for the San Diego-Imperial Valley area is approximately 391 MW.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the

[126] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-52 the benefit of local capacity reductions in the San Diego-Imperial Valley area for this project are shown.

Table 4.9-52: LCR Reduction Benefits for Sycamore Reliability Energy Storage (SRES) Project

	Sycamore Reliability Energy Storage Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	391	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.1	$7.5
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$5.1	$7.5

Further, the contingencies and potential overloads are observed to be "upstream", easterly, of the San Diego area, and the connection of the Sycamore Reliability Energy Storage Project into the San Diego area. The ISO has not identified a difference in the service being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

The current cost estimate received from Tenaska is $108 million to $178 million for the proposed project. It is noted that the cost estimate assumes a maximum discharge of one hour only. For consideration for local capacity need, a resource would need to have at least a four-hour availability. The ISO, using the cost estimate provided by Tenaska, modified the cost estimate for a four-hour battery energy storage system, as shown in Table 4.9-53.

P27-129 cont.

Table 4.9-53: Cost Estimate Adjustments

Description	Planning Level Estimate for 1-hour BESS ($M)	Planning Level Estimate for 4-hour BESS ($M)
350 MW / 175-350 MWh BESS Facility (Design/Procure/Construct)	100 - 170	((100+170)/2)*4=540
Facility Tie-Line (Design/Procure/Construct/ROW Acquisition)	1	1
Grid Interconnection (assumes Substation tie-in)	7	7
Total	108 - 178	548

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Summing the production benefit and the capacity benefits described above yields the total benefits. The calculated levelized fixed cost for the project and the benefit to cost ratio are shown in Table 4.9-54.

P27-129 cont.

Table 4.9-54 Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Sycamore Reliability Energy Storage Project				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/ year)	-$5			
Sycamore RES Net Market Revenue ($million/ year)	$35			
Total PCM Benefits ($million/ year)	$30			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$5.1		$7.5	
Capital Cost				
Capacity (MW)	381			
Cost Estimate Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$548		$548
Capital Cost $/kW	$1,660	$1,438	$1,660	$1,438
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$130	$150	$130
Benefit to Cost				
Savings ($million/year)	$35	$35	$38	$38
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$130	$150	$130
Benefit to Cost	0.23	0.27	0.25	0.29

Note 1: The Lazard Capital Cost and Lazard Levelized Fixed Cost were based on "Lazard's Levelized Cost of Storage Analysis - Version 4.0, November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

Note 2: The Proponent Provided Capital Cost in $/kW was determined by dividing the Proponent Provided Capital Cost by the Capacity of the project.

Note 3: The Proponent Provided Levelized Fixed Cost was estimated by multiplying the ratio of the Proponent Provided Capital Cost divided by the Lazard provided Capital Cost times the $/kW-year Lazard Provided Levelized Fixed Cost.

P27-129 cont.

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. As these include benefits that do not accrue directly to the benefit of ratepayers, who would however fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-55: Benefit to Cost Ratios (Production Cost Savings – Information Only)

Sycamore Reliability Energy Storage Project				
Production Cost Modeling Benefits				
WECC PCM Cost Reduction ($million/ year)	$22			
Sycamore RES Net Market Revenue ($million/ year)	$35			
Total PCM Benefits ($million/ year)	$57			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$5.1		$7.5	
Capital Cost				
Capacity (MW)	381			
Cost Estimate Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$381		$381
Capital Cost $/kW	$1,660	$1,000	$1,660	$1,000
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$90	$150	$90
Benefit to Cost				
Savings ($million/year)	$62	$62	$64	$64
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$90	$150	$90
Benefit to Cost	0.41	0.69	0.43	0.71

Note 1: The Lazard Capital Cost and Lazard Levelized Fixed Cost were based on "Lazard's Levelized Cost of Storage Analysis - Version 4.0, November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

Note 2: The Proponent Provided Capital Cost in $/kW was determined by dividing the Proponent Provided Capital Cost by the Capacity of the project.

Note 3: The Proponent Provided Levelized Fixed Cost was estimated by multiplying the ratio of the Proponent Provided Capital Cost divided by the Lazard provided Capital Cost times the $/kW-year Lazard Provided Levelized Fixed Cost.

P27-129 cont.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the Sycamore Reliability Energy Storage Project net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the Sycamore Reliability Energy Storage Project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of the Sycamore Reliability Energy Storage Project - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to the Sycamore Reliability Energy Storage Project performing a transmission function operating to meet an ISO-identified transmission need:
    - There were no identified reliability needs in the planning horizon driving the need for the project;
    - The production cost benefits associated with the storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
    - The local capacity benefits associated with the storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide material benefits and benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

P27-129 cont.

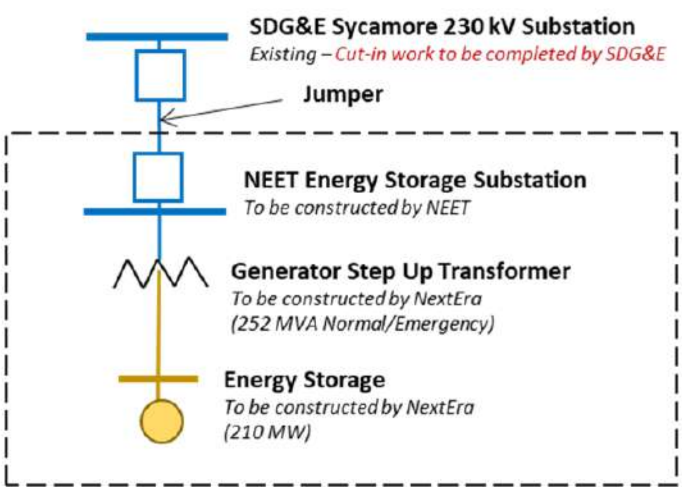
4.9.11.8 Sycamore 230 kV Energy Storage Project (SES – 210 MW) congestion and capacity benefits

The ISO examined the Sycamore 230 kV Energy Storage (SES) Project submitted by NextEra Energy Transmission West in the 2018 Request Window. The project would consist of the following:

- Build a new 230 kV bus outside the existing SDG&E Sycamore 230 kV substation.
- Build a 210 MW energy storage and connect it to the new 230 kV bus outside the SDG&E Sycamore substation.
- Cut in and connect to 230 kV jumper line dead end structures outside of the Sycamore substation.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-36: Sycamore 230 kV Energy Storage Project Configuration



The project's estimated capital cost was provided at $200 million. NEET West did not specify whether this cost estimate is for 4-hour discharging capability. For the purpose of this economic analysis, the ISO assumed that the proposed project would have 4-hour discharging capability based on per unit cost derived from other submitted 4-hour battery energy storage system. If this assumption is incorrect, additional costs would be needed to provide a minimum 4-hour duration as required for the local Resource Adequacy (RA) need. A preliminary target date of 12/1/2024 has been proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The project was proposed by NEET West as a Reliability Transmission Project. The proponent is also seeking to qualify the proposed project as a SATA (Storage as a Transmission Asset) facility. NEET West submitted the proposed as transmission alternative to the ISO-proposed solutions of utilizing existing operating procedures, Remedial Action Schemes, and dispatching

P27-129 cont.

of preferred resources to meet various reliability concerns in the 2018-2019 Transmission Planning Process. NEET West stated that the proposed project effectively mitigates various overlapping N-1-1 line or transformer overloading concerns without having to use the above-mentioned mitigations.

As set out in chapter 2, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by existing operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further benefits, recognizing that the proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, potentially reducing the local capacity requirements for gas-fired generation.

The ISO's evaluation of economic study requests for potential approval of transmission projects is based on the most current version of the ISO Transmission Economic Evaluation Methodology (TEAM)[127], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, however, the ISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below. P27-129 cont.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by the Sycamore 230 kV Energy Storage (SES) Project identified in this analysis.

Sycamore 230 kV Energy Storage (SES) Project Production benefit

Table 4.9-56 shows the TEAM analysis results for the proposed project.

[127] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.9-56: Production Cost Modeling Results for Sycamore 230 kV Energy Storage Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8494	-37
ISO generator net revenue benefitting ratepayers*	2526	2561	35
ISO owned transmission revenue	199	198	-1
ISO Net payment	5733	5736	-3
WECC Production cost	16875	16865	10

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $20 million--note that Sycamore 230 kV Energy Storage net revenue is included in Table 4.9-58 and Table 4.9-59.

These results are aligned with the results found for the Sycamore Reliability Energy Storage (SRES) Project, which is relatively similarly situated and has higher capacity of 381 MW compared to the Sycamore 230 kV Energy Storage Project's 210 MW. The difference in capacity, with a similar duration, reasonably accounts for the generally lower benefit results for the Sycamore 230 kV Energy Storage Project in terms of ISO ratepayer net payment, WECC production cost, and storage net revenue. P27-129 cont.

The ISO conducted a detailed analysis of the Sycamore Reliability Energy Storage (SRES) Project, including a sensitivity, to ascertain if the production cost modeling benefits were attributable generally to the participation of the resource in the ISO market, or if other factors were at play. That analysis led to the conclusion that the production cost benefits were derived from the Sycamore Reliability Energy Storage (SRES) Project essentially functioning as an energy or capacity resource in the ISO market. Further, as the benefits were consistent with the storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits did not support the storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Given the alignment of results here for the Sycamore Reliability Energy Storage (SRES) Project, the same conclusions apply to the Sycamore 230 kV Energy Storage Project.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the proposed project at 210 MW, as provided by NEET West in its power flow model to the ISO, to the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The IID-owned El Centro 230/92kV transformer is at its rating limit under an overlapping G-1 (TDM) and N-1 of Imperial Valley – North Gila 500 kV line. The amount of gas-fired generation requirement reduction in the San Diego-Imperial Valley area is approximately 230 MW.
- Since the gas-fired generation could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needs to be checked to determine if there is adverse impact to its LCR need.
- The power flow study was then restored to normal condition. An N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line was studied. This N-1-1 contingency could cause an overloading concern on the Mesa-Laguna Bell 230 kV line. However, a check on the Mesa – Laguna Bell 230 kV line loading indicated that it was within its emergency rating limit.

The proposed project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 230 MW[128]. There was no identified local capacity impact to the LA Basin area as the replacement of gas-fired generation is the capacity from the proposed battery energy storage. The net local capacity benefits for the San Diego-Imperial Valley area would be approximately 230 MW.

P27-129 cont.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-57 the benefit of local capacity reductions in the San Diego-Imperial Valley area for this project are shown.

[128] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

Table 4.9-57 : LCR Reduction Benefits for the Sycamore 230 kV Energy Storage Project

	NEET Sycamore 230 kV Energy Storage Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	230	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$3.0	$4.4
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$3.0	$4.4

P27-129 cont.

Further, the contingencies and potential overloads are observed to be “upstream“, easterly, of the San Diego area, and the connection of the project into the San Diego area. The ISO has not identified a difference in the service being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

The current cost estimate from NEET West is $200 million for the proposed project. It is noted that NEET West did not specify whether the cost is for one-hour or four-hour battery energy storage system. The ISO assumed that this cost is for a four-hour battery energy storage system at this time. For consideration for local capacity need, a resource would need to have at least a four-hour availability.

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Summing the production benefit and the capacity benefits described above yields the total benefits. The calculated levelized fixed cost for the project and the benefit to cost ratio are shown in Table 4.9-58.

Table 4.9-58: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

NEET Sycamore 230 kV Energy Storage Project				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/ year)	-$3			
NEET Sycamore 230 kV Energy Storage Net Market Revenue ($million/ year)	$20			
Total PCM Benefits ($million/ year)	$17			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	210			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$200		$200.0
Capital Cost $/kW	$1,660	$952	$1,660	$952
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost				
Savings ($million/year)	$20	$20	$21	$21
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost	0.24	0.42	0.26	0.45

Note 1: The Lazard Capital Cost and Lazard Levelized Fixed Cost were based on "Lazard's Levelized Cost of Storage Analysis - Version 4.0, November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

Note 2: The Proponent Provided Capital Cost in $/kW was determined by dividing the Proponent Provided Capital Cost by the Capacity of the project.

Note 3: The Proponent Provided Levelized Fixed Cost was estimated by multiplying the ratio of the Proponent Provided Capital Cost divided by the Lazard provided Capital Cost times the $/kW-year Lazard Provided Levelized Fixed Cost.

P27-129 cont.

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. As these include benefits that do not accrue directly to the benefit of ratepayers, who would however fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-59: Benefit to Cost Ratios (Production Cost Savings – Information Only)

NEET Sycamore 230 kV Energy Storage Project				
Production Cost Modeling Benefits				
WECC PCM Cost Reduction ($million/ year)	$22			
NEET Sycamore 230 kV Energy Storage Net Market Revenue ($million/year)	$20			
Total PCM Benefits ($million/year)	$42			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	210			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$200		$200.0
Capital Cost $/kW	$1,660	$952	$1,660	$952
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost				
Savings ($million/year)	$45	$45	$46	$46
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost	0.54	0.95	0.56	0.98

Note 1: The Lazard Capital Cost and Lazard Levelized Fixed Cost were based on "Lazard's Levelized Cost of Storage Analysis - Version 4.0, November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

Note 2: The Proponent Provided Capital Cost in $/kW was determined by dividing the Proponent Provided Capital Cost by the Capacity of the project.

Note 3: The Proponent Provided Levelized Fixed Cost was estimated by multiplying the ratio of the Proponent Provided Capital Cost divided by the Lazard provided Capital Cost times the $/kW-year Lazard Provided Levelized Fixed Cost.

P27-129 cont.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the Sycamore 230 kV Energy Storage Project net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the Sycamore 230 kV Energy Storage Project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of the San Vicente Energy Storage Project - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to the Sycamore 230 kV Energy Storage Project performing a transmission function operating to meet an ISO-identified transmission need: P27-129 cont.
    - o There were no identified reliability needs in the planning horizon driving the need for the project;
    - o The production cost benefits associated with the storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
    - o The local capacity benefits associated with the storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

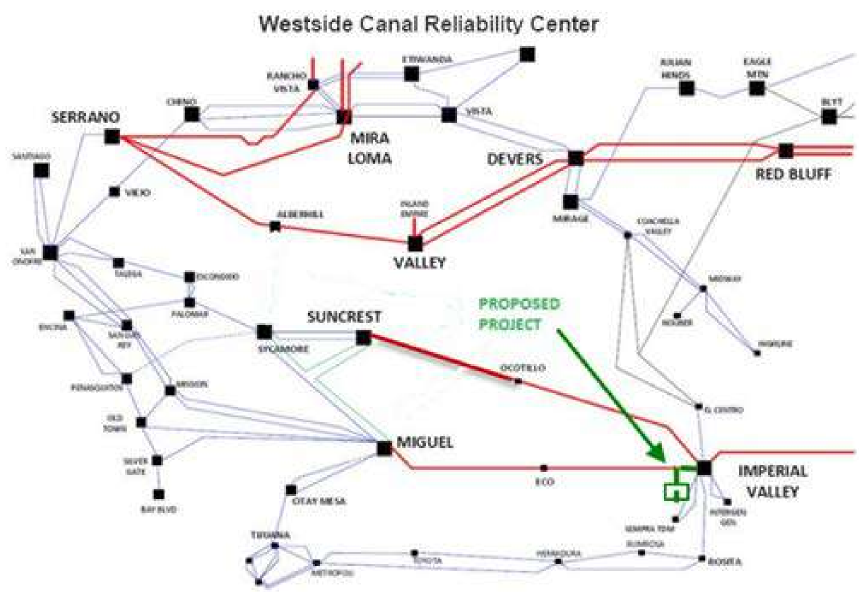
4.9.11.9 Westside Canal Reliability Center Project congestion and capacity benefits

The ISO examined submitted Westside Canal Reliability Center (Westside) Project submitted by ConEd Renewables[129] to the 2018 Request Window. The project would consist of the following:

- Construct a 268 MW battery energy storage system with 4-hour discharge capability with interconnection to the 230 kV Imperial Valley substation. The project would be located at south side of Mandrapa Rd/Westside Canal and directly south of the intersection of Mandrapa Rd and Liebert Rd in El Centro CA 92243. The point of interconnection for the proposed project would be at the 230 kV bus at the Imperial Valley Substation.

The following figure provides the general high-level location of the proposed project.

Figure 4.9-37: Westside Canal Reliability Center Configuration



The project's estimated capital cost was provided at $304 million. A preliminary target date of 12/31/2021 was proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The project was proposed by ConEd Renewables as a Reliability Transmission Project. The Project Proponent is also seeking to qualify the proposed project as a SATA (Storage as a Transmission Asset) facility. ConEd Renewables stated that the project is proposed to mitigate thermal overloads identified in the ISO's 2018-2019 Reliability Assessment results. Based on the information provided in the Request Window Submittal, the project is proposed to work in

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[129] The project was initially submitted by Sempra Renewables.

concert with a Remedial Action Scheme to dispatch effective generating resources in the San Diego – Imperial Valley area, and switching between charging (load) mode and discharging (generating) mode, depending on where the thermal constraint is located. The proponent also noted that in the charging mode, the proposed combination of the battery energy storage system and the Remedial Action Scheme does not fully mitigate identified contingency loading concerns for the S-line prior to implementation of its upgrade in the summer peak load case because the battery operating in charging mode would aggravate the loading concern. The proponent noted that this would not be an issue after the implementation of the S line upgrades. The proponent also suggested that the proposed battery energy storage system, working in discharging (generating) mode could be used as an alternative to the S line upgrade in the event that its construction is delayed.

As set out in chapter 2, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by the operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further benefits, recognizing that the proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, potentially reducing the local capacity requirements for gas-fired generation.

The ISO's evaluation of economic study requests for potential approval of transmission projects is based on the most current version of the ISO Transmission Economic Evaluation Methodology (TEAM)[130], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, however, the ISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below. P27-129 cont.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the

[130] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by the Westside Canal Energy Reliability Center Project identified in this analysis.

Westside Canal Reliability Center Project Production benefit

Table 4.9-60 shows the production cost modeling results for this proposed project.

Table 4.9-60: Production Cost Modeling Results for Westside Canal Reliability Center

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8504	-47
ISO generator net revenue benefitting ratepayers*	2526	2578	52
ISO owned transmission revenue	199	198	0
ISO Net payment	5733	5728	5
WECC Production cost	16875	16857	18

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $24 million--note that Westside Canal Reliability Center net revenue is included in Table 4.9-62 and Table 4.9-63.

These results are aligned with the results found for the Sycamore Reliability Energy Storage (SRES) Project, which is relatively similarly situated and has a higher capacity of 381 MW compared to the Westside Canal Reliability Center Project's 268 MW. The difference in capacity, with a similar duration, reasonably accounts for the generally lower benefit results for the Westside Canal Reliability Center Project in terms of ISO ratepayer net payment, WECC production cost, and storage net revenue.

The ISO conducted a detailed analysis of the Sycamore Reliability Energy Storage (SRES) Project, including a sensitivity, to ascertain if the production cost modeling benefits were attributable generally to the participation of the resource in the ISO market, or if other factors were at play. That analysis led to the conclusion that the production cost benefits were derived from the Sycamore Reliability Energy Storage (SRES) Project essentially functioning as an energy or capacity resource in the ISO market. Further, as the benefits seemed consistent with the storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits did not support the storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Given the alignment of results here for the Westside Canal Reliability Center Project, the same conclusions apply to the Westside Canal Reliability Center Project.

P27-129 cont.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the proposed project at 268 MW in discharging (generating) mode, as provided by ConEd Renewables in its power flow model to the ISO, to the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley area resulted in the following:

- The IID-owned El Centro 230/92 kV transformer is at its rating limit under an overlapping G-1 (TDM) and N-1 of Imperial Valley – North Gila 500 kV line. The amount of gas-fired generation local capacity requirement reduction in the San Diego-Imperial Valley area was found to be approximately 430 MW.
- Since the gas-fired generation could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needed to be checked to determine if there was an adverse impact to its LCR need. The power flow study was restored to normal condition, and an N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line was studied. This N-1-1 contingency could cause an overloading concern on the Mesa-Laguna Bell 230 kV line. A check on the Mesa – Laguna Bell 230 kV line loading indicated that it was at 101.1% of its emergency rating limit. To mitigate this loading concern, an additional 100 MW of local resource capacity was modeled south of the Laguna Bell substation.

The proposed project potentially could reduce local capacity need for gas-fired generation in the San Diego-Imperial Valley by about 430 MW[131]. There was an impact of an increase of 100 MW in local capacity requirement in the Western LA Basin sub-area. The net local capacity benefits for the San Diego-Imperial Valley area are the difference between the local capacity cost increase in the LA Basin area and the local capacity cost reduction in the San Diego-Imperial Valley area.

P27-129 cont.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin area, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

[131] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

In Table 4.9-61 the benefit of local capacity reductions in the San Diego-Imperial Valley area is valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

Table 4.9-61: LCR Reduction Benefits for Westside Canal Reliability Center Project

Westside Canal Reliability Center Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	430	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.6	$8.2
LCR increase (LA Basin) (MW)	100	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$1.7	$2.3
Net LCR Saving ($million/year)	$4.0	$5.9

Further, the contingencies and potential overloads are observed to be "upstream", easterly, of the San Diego area, and the connection of the project into the San Diego area. The ISO has not identified a difference in the function being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

It was noted that this proposed solution had a noticeably higher effectiveness in displacing other resources than the other storage projects evaluated in this planning cycle. However, its comparative effectiveness remained within the reasonable range of effectiveness factors[132] found for existing resources providing local capacity in the San Diego/Imperial Valley area.

Cost estimates:

The cost estimate from ConEd Renewables is $304 million for the submitted project.

[132] Note that the effectiveness factors listed in the 2028 Local Capacity Technical Study described in section 6.1 and provided in Appendix G show a range for generation in the San Diego and Imperial Valley combined area of 11.88% to 25.42%. Effectiveness was measured as the impact on the flow on the constrained transmission facility as a percent of output from the local capacity resource. In other words, some existing resources are more than twice as effective as others at addressing the limiting constraint, due to the physical location of the resources.

P27-129 cont.

<u>Benefit to Cost Ratios (Ratepayer Benefits per TEAM)</u>

Summing the production benefit and the capacity benefits described above yields the total benefits. The calculated levelized fixed cost for the project and the benefit to cost ratio are shown in Table 4.9-62.

Table 4.9-62: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

ConEd Renewables Westside Canal Reliability Center				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/ year)	$5			
Westside Canal Net Market Revenue ($million/ year)	$24			
Total PCM Benefits ($million/ year)	$29			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	268			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$304		$304.0
Capital Cost $/kW	$1,660	$1,134	$1,660	$1,134
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost				
Savings ($million/year)	$32	$32	$33	$33
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost	0.30	0.44	0.32	0.46

Note 1: The Lazard Capital Cost and Lazard Levelized Fixed Cost were based on "Lazard's Levelized Cost of Storage Analysis - Version 4.0, November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

Note 2: The Proponent Provided Capital Cost in $/kW was determined by dividing the Proponent Provided Capital Cost by the Capacity of the project.

Note 3: The Proponent Provided Levelized Fixed Cost was estimated by multiplying the ratio of the Proponent Provided Capital Cost divided by the Lazard provided Capital Cost times the $/kW-year Lazard Provided Levelized Fixed Cost.

P27-129 cont.

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. As these include benefits that do not accrue directly to the benefit of ratepayers, who would however fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-63: Benefit to Cost Ratios (Production Cost Savings – Information Only)

Westside Canal Reliability Center				
Production Cost Modeling Benefits				
WECC PCM Cost Reduction ($million/ year)	$18			
Westside Canal Net Market Revenue ($million/ year)	$24			
Total PCM Benefits ($million/ year)	$42			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	268			
Capital Cost Soruce	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$304		$304.0
Capital Cost $/kW	$1,660	$1,134	$1,660	$1,134
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost				
Savings ($million/year)	$45	$45	$46	$46
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost	0.43	0.62	0.44	0.64

Note 1: The Lazard Capital Cost and Lazard Levelized Fixed Cost were based on "Lazard's Levelized Cost of Storage Analysis - Version 4.0, November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

Note 2: The Proponent Provided Capital Cost in $/kW was determined by dividing the Proponent Provided Capital Cost by the Capacity of the project.

Note 3: The Proponent Provided Levelized Fixed Cost was estimated by multiplying the ratio of the Proponent Provided Capital Cost divided by the Lazard provided Capital Cost times the $/kW-year Lazard Provided Levelized Fixed Cost.

P27-129 cont.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the Westside Canal Reliability Center Project net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the Westside Canal Reliability Center Project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of the San Vicente Energy Storage Project - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to the Westside Canal Reliability Center Project performing a transmission function operating to meet an ISO-identified transmission need:
    - There were no identified reliability needs in the planning horizon driving the need for the project;
    - The production cost benefits associated with the storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
    - The local capacity benefits associated with the storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

4.9.12 San Diego Non-Bulk Sub-areas

SDG&E submitted three projects in the 2018 Request Window that would potentially reduce or eliminate local capacity requirements in the El Cajon, Border and Pala sub-areas.

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cont.

El Cajon Sub-area Local Capacity Requirement Reduction Project

The 2028 LCR study identified that the most critical contingency for the El Cajon sub-area was the Category C contingency of the Granite-Los Coches 69 kV Nos.1&2 lines, which would overload the El Cajon-Los Coches 69 kV line. The project proposed by SDG&E would reconductor the limiting Los Coches-El Cajon 69 kV line to a minimum continuous rating of 77 MVA. The estimated project cost provided by SDG&E is $28~$43 million.

However, the San Diego/Imperial Valley area local capacity requirement would also need to be reduced in order to reduce the need for the gas-fired generation in the El Cajon sub-area. Taking the lowest cost option for that constraint, the S-Line Series Reactor option described in section 4.9.11.1 would be one low cost option for accomplishing this reduction, and the cost of that project is estimated at $30 million. Combining the cost of the reconductoring project and the S-Line Reactor option would increase the cost to the point that the benefits of reducing the El Cajon sub-area local capacity requirements would not exceed the costs of the upgrades.

Without a broader strategy to reduce local capacity requirements in the Imperial Valley/San Diego area, it is not economic to proceed unilaterally on the proposed project.

Border Sub-area Local Capacity Requirement Reduction Project

The 2028 LCR study identified that the most critical contingency for the Border sub-area was the Category C outage of the Bay Boulevard-Otay 69 kV Nos.1&2 lines, which would overload the Imperial Beach-Bay Boulevard 69 kV line. The project proposed by SDG&E would reconductor the Imperial Beach-Bay Boulevard 69 kV line to a minimum continuous rating of 110 MVA. The estimated project cost provided by SDG&E is $6~$10 million. The project could potentially reduce the local LCR need from 70 MW to 18 MW.

P27-129 cont.

However, the San Diego/Imperial Valley area local capacity requirement would also need to be reduced in order to reduce the need for the gas-fired generation in the Border sub-area. Taking the lowest cost option for that constraint, the S-Line Series Reactor option described in section 4.9.11.1 would be one low cost option for accomplishing this reduction, and the cost of that project is estimated at $30 million. Combining the cost of the reconductoring project and the S-Line Reactor option would increase the cost to the point that the benefits of reducing the Border sub-area local capacity requirements would not exceed the costs of the upgrades.

Without a broader strategy to reduce local capacity requirements in the Imperial Valley/San Diego area, it is not economic to proceed unilaterally on the proposed project.

4.10 Summary and Recommendations

The ISO conducted production cost modeling simulations in this economic planning study and grid congestion was identified and evaluated; the congestion studies helped guide the specific study areas that were considered for further detailed analysis. Other factors, including the ISO's commitment to consider potential options for reducing the requirements for local gas-fired generation capacity, and prior commitments to continue analysis from previous years' studies, also guided the selection of study areas.

The ISO then conducted extensive assessments of potential economic transmission solutions consisting of production cost modeling and assessments of local capacity benefits. These potential transmission solutions included stakeholder proposals received from a number of sources; request window submissions citing economic benefits, economic study requests, and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements. Alternatives also included interregional transmission projects; three such projects were identified as potential options for study of economic benefits as set out in chapter 5:

- Southwest Intertie Project – North (SWIP - North)
- North Gila - Imperial Valley #2 500 kV Transmission Project (NG-IV#2)
- HVDC conversion

Overall, 11 areas, sub-areas, and transmission paths were studied, and potential benefits impacting a 12th area were also assessed for several projects. This entailed consideration of 25 proposals and alternatives. P27-129 cont.

The study results in this planning cycle were heavily influenced by certain ISO planning assumptions driven by overall industry conditions. In particular, the longer term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined, in the CPUC's integrated resource planning process, but actionable direction regarding the need for these resources for those purposes is not yet available. The uncertainty regarding the extent to which gas-fired generation will be needed to meet those system and flexible capacity requirements necessitated taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements. The ISO accordingly placed values on benefits associated with reducing local gas-fired generation capacity requirements primarily on the difference between the relevant local area capacity price and system capacity prices. This conservative assumption was a key difference between the economic benefits calculated in this study, and the economic assessments stakeholders provided in support of their projects. The ISO recognizes that the capacity value of many of these projects will need to be revised when actionable direction on the need for gas-fired generation for system and flexible needs is available.

The ISO's focus on ratepayer benefits, rather than broader WECC-wide societal benefits, was another difference between a number of stakeholder proposals.

A number of stakeholder proposals for battery storage projects cited the ISO's stakeholder initiative regarding how storage procured as a regulated cost of service transmission asset (or SATA) could also access market revenues when not needed for reliability. This initiative has been placed on hold to consider further refinements to the ISO's storage participation model. The ISO nonetheless assessed the economic benefits they could provide, assuming that if appropriate, procurement could also be investigated as market-based local capacity resources through CPUC procurement processes. However, the same conservative assumptions regarding local capacity benefits were applied.

Table 4.10-1 summarizes the overall economic planning study results in the 2018-2019 planning cycle.

Table 4.10-1: Summary of economic assessment in the 2018-2019 planning cycle

Congestion or study area	Benefits Consideration	Economic Justification
COI 5100 MW path rating increase	Production cost ratepayer benefits not sufficient	No
SWIP - North	Production cost ratepayer benefits not sufficient	No
Giffen Line Reconductoring Project	Production cost ratepayer benefits sufficient	Yes
Path 26 4000 MW South to North path rating increase	Production cost ratepayer benefits not sufficient	No
California Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Colorado River – Julian Hinds	Production cost ratepayer benefits not sufficient	No
Pease sub-area	Local capacity benefits not sufficient	No
Hanford sub-area (2 options)	Local capacity benefits not sufficient	No
Kern Oil sub-area	Local capacity benefits not sufficient	No
Mira Loma Dynamic Reactive Support	Local capacity benefits not sufficient	No
Red Bluff – Mira Loma 500 kV Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Southern California Regional LCR Reduction Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
S-Line Series Reactor	Production cost benefits sufficient, needs further assessment when S-	No

P27-129 cont.

Congestion or study area	Benefits Consideration	Economic Justification
	Line Upgrade configuration is finalized[133]	
HVDC Conversion	Production cost ratepayer benefits and local capacity benefits not sufficient	No
North Gila – Imperial Valley #2 500 kV Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Lake Elsinore Advanced Pumped Storage (LEAPS) Project (2 options)	Production cost ratepayer benefits and local capacity benefits not sufficient	No
San Vicente Energy Storage Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Sycamore Reliability Energy Storage (SRES) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Sycamore 230 kV Energy Storage (SES) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Westside Canal Reliability Center (Westside) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
El Cajon Sub-area Local Capacity Requirement Reduction Project	Local capacity benefits not sufficient – broader San Diego sub-area plan required	No
Border Sub-area Local Capacity Requirement Reduction Project	Local capacity benefits not sufficient – broader San Diego sub-area plan required	No

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133 The ISO is pursuing revisions to the scope of the previously approved S-Line Transmission Upgrade to consist of an appropriately sized single circuit 230 kV circuit, which provides the same local capacity requirement reduction value to the ISO as the original double-circuit line. As well, the ISO is updating the estimated cost to ISO ratepayers of the S-Line upgrade from $32 million to $40 million in light of revised costs estimates provided by IID. This increase in estimated cost would be offset by the savings of no longer needing a new line termination at the Imperial Valley Substation, which was required under the original double circuit configuration. The impact this change may have on benefits associated with other project proposals will be considered in future planning cycles.

In summary, one transmission solution – the Giffen Line Reconductoring Project, estimated to cost less than $5 million – was found to be needed as an economic-driven project in the 2018-2019 transmission planning cycle.

Several paths and related projects will be monitored in future planning cycles to take into account further consideration of suggested changes to ISO economic modeling, and further clarity on renewable resources and gas-fired generation supporting California's renewable energy goals.

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cont.

Chapter 5

5 Interregional Transmission Coordination

The ISO conducts its coordination with neighboring planning regions through the biennial interregional transmission coordination framework established in compliance with FERC Order No. 1000. The ISO's 2018-2019 transmission planning cycle marks the beginning of the second biennial cycle since these coordination processes were put in place, replacing other mechanisms that pre-dated FERC Order No. 1000. This cycle reflects the complete transition from old process to new, taking into account the status of the policy drivers and the progress achieved in implementing the new interregional processes.

The first biennial coordination process was conducted in conjunction with the ISO's 2016-2017 and 2017-2018 annual transmission planning cycles. As discussed in Chapter 1, state directives then and now continue to focus on increasing California's renewable energy goals beyond 33 percent, and it was necessary to transition to the new processes taking into account the activities underway and the status of policy direction at the time. Clearly, an outcome of SB 350 was the consideration that new investments in the state's electric transmission system would be required to achieve the renewable energy goals being established by the state. To assist in this effort, the ISO partnered with the CEC and the CPUC to conduct the Renewable Energy Transmission Initiative (RETI) 2.0. The ISO was uniquely positioned to participate in this process to help identify potential transmission opportunities that could access and integrate renewable energy opportunities from regions outside of California. Through its involvement in interregional coordination activities, the ISO considered the ITPs proposed in the 2016-2017 interregional coordination cycle as a reasonable measure to assess the potential out-of-state transmission opportunities for California and as such, proposed they be considered within the RETI 2.0 assessment framework. As a result, these ITPs were assessed and considered in the ISO's 2016-2017 and 2017-2018 planning cycles as "special studies" of the 50% RPS that had been established at that time. The ISO concluded its consideration of these special studies in its 2017-2018 planning cycle and documented its results in that transmission plan and a 2016-2017 transmission plan supplemental report.

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In the context of the ISO's completion of these "special studies", it is important to remind stakeholders that the ISO's consideration of the ITPs in the 2016-2017 interregional coordination cycle exceeded the study obligations the tariff requires of the ISO and other western planning regions (WPRs). In reality, the "special studies" performed by the ISO, while providing useful information for the California's RPS initiatives, went beyond obligations of Order No. 1000, as the ISO advised stakeholders during the 2016-2017 and 2017-2018 transmission planning cycles. Hence, that is why the ISO referred to them as "special studies".

Moving forward into the 2018-2019 interregional coordination cycle, the ISO has considered and documented its results of those ITPs that were proposed in its 2018-2019 transmission plan under the processes specified in the ISO tariff. This aligns with the policy direction and input received from the CPUC and CEC. Section 24 of the ISO tariff and the BPM for the Transmission Planning Process provide detail of the ISO's interregional coordination responsibilities. As such, chapter 5 of this transmission plan transmission plan intends to provide the reader with a clearer understanding of the interregional coordination process and how the ISO meets its Order No. 1000 interregional coordination responsibilities and presents its most current engagement with WECC on the Anchor Data Set.

5.1 Background on the Order No. 1000 Common Interregional Tariff

FERC Order No. 1000 broadly reformed the regional and interregional planning processes of public utility transmission providers. FERC issued its final rule in July 2011[134] and adopted certain reforms to the electric transmission planning and cost allocation requirements for public utility transmission providers. While instituting certain requirements to clearly establish regional transmission planning processes, Order No. 1000 also required improved coordination across neighboring regional transmission planning processes through procedures for joint evaluation and sharing of information among established transmission planning regions. These additional reforms affected the ISO's existing regional transmission planning process and resulted in the ISO collaborating more closely with neighboring transmission utility providers and planning regions across the Western Interconnection to develop a coordinated process for considering interregional projects. These regional and interregional reforms were designed to work together to ensure an opportunity for more transmission projects to be considered in transmission planning processes on an open and non-discriminatory basis both within planning regions and across multiple planning regions.

Although the ISO's prior tariff was largely compliant with order, some adjustments were necessary to fully align with the order's requirements in a number of areas, including the establishment of the ISO as one of four western planning regions established within the Western Interconnection. The ISO implemented these adjustments in early 2014. P27-129 cont.

Regarding interregional requirements, the WPRs developed a common interregional tariff that became effective in 2015. Through the common tariff and coordination efforts among the WPR members, certain business practices were developed for the specific purpose of providing stakeholders visibility and clarity on how the WPRs would engage in interregional coordination activities among their respective regional planning processes. Commensurate with each WPR's regional arrangement with their members, these business practices have been incorporated into their regional processes to be followed within the development of their regional plans. For the ISO, these business practices have been incorporated into the ISO's Business Practice Manual (BPM) for the Transmission Planning Process.

Commensurate with its activities in past planning cycles, the ISO has continued to play a leadership role in Order 1000 processes within the ISO's planning region, through direct coordination with the other WPRs and representing and supporting interregional coordination concepts and processes in public forums such as WECC. Although Order No. 1000 left some ambiguity regarding aspects of interregional coordination The WPRs have actively engaged to resolve conflicts and challenges that have arisen since the first coordination cycle was initiated in 2016. The ISO and other WPRs have continued to consider and forge new opportunities to

[134] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

facilitate coordination among its stakeholders and neighboring planning regions for the benefit of interregional coordination.

5.2 Interregional Transmission Projects

Interregional Transmission Projects have been considered in this transmission planning process on the basis that:

- The ITP must electrically interconnect at least two Order 1000 planning regions;
- While an ITP may connect two Order 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO's transmission planning process;
- When a sponsor submits an ITP into the regional process of an Order 1000 planning region it must indicate whether or not it is seeking cost allocation from that Order 1000 planning region; and,
- When a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess an ITP. This applies whether or not cost allocation is requested.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

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5.3 Interregional Transmission Coordination per Order No. 1000

Overall, the interregional coordination requirements established by Order No. 1000 are fairly straight-forward. In general, the interregional coordination order requires that each WPR (1) commit to developing a procedure to coordinate and share the results of their planning region's regional transmission plans to provide greater opportunities for the WPRs to identify possible interregional transmission facilities that could address regional transmission needs more efficiently or cost effectively than separate regional transmission facilities; (2) develop a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions; (3) establish a formal agreement to exchange among the WPRs, at least annually, their planning data and information; and finally (4) develop and maintain a website or e-mail list for the communication of information related to the interregional transmission coordination process.

On balance, the ISO fulfills these requirements by following the processes and guidelines documented in the BPM for the Transmission Planning Process and through its development and implementation of the TPP.

5.3.1 Procedure to Coordinate and Share ISO Planning Results with other WPRs

During each planning cycle the ISO predominately exchanges its interregional information with the other WPRs in two ways: (1) an annual coordination meeting hosted by the WPRs; and (2) a process by which ITPs can be submitted to the ISO for consideration in its TPP. While the annual coordination meetings are organized by the WPRs, one WPR is designated as the host for a particular meeting and in turn, is responsible for facilitating the meeting. The annual coordination meetings are generally held in February of each year, but in no event later than March 31. Hosting responsibilities are shared by the WPRs in a rotational arrangement that has been agreed to by the WPRs. The ISO hosted the 2018 meeting and NTTG is hosting the 2019 meeting.

In general, the purpose of the coordination meeting is to provide a forum for stakeholders to discuss planning activities of the west, including a review of each region's planning process, its needs and potential interregional solutions, update on Interregional Transmission Project (ITP) evaluation activities, and other related issues. It is important to note that the ISO and ColumbiaGrid planning processes are annual while the planning processes of NTTG and WestConnect are biennial. To address this difference in planning cycles, the WPRs have agreed to annually share the planning data and information that is available at the time the annual interregional coordination meeting is held; divided into an "even" and "odd" year framework. Specifically, the information which the ISO shares is shown in Table 5.3-1.

Table 5.3-1: Annual Interregional Coordination Information

Even Year	Odd Year
• Most recent draft transmission plan	• Most recent draft transmission plan
ITPs that: • Were being considered within the previous odd year draft transmission plan; • That are being considered within the previous odd year draft transmission plan for approval and/or awaiting "final approval" from the relevant planning regions; and, • That have been submitted for consideration in the even year transmission plan.	ITPs that: • Were being considered within the previous even year draft transmission plan; and, • That were considered in the even year draft transmission plan and approved by the ISO Board for further consideration within the odd year draft transmission plan.

5.3.2 Submission of Interregional Transmission Projects to the ISO

As part of its TPP the ISO provides a submission window during which proponents may submit their ITPs into the ISO's annual planning process within the current interregional coordination cycle. The submission window is open from January 1st through March 31st of every even numbered year. ITP submittals must indicate whether or not they are seeking cost allocation from the planning region, list all WPRs that they have submitted their ITP to, and include specific technical and cost information for the ISO to consider during its validation/selection process of the ITP. In order for the ISO to consider a proponent's project as an ITP, it must have been submitted to and validated by at least one other WPR. Once the validation process has been completed, each WPR is then considered to be a Relevant Planning Region. All Relevant Planning Regions consider the proposed ITP in their regional process. For the ISO, validated ITPs will be included in the ISO's Transmission Planning Process Unified Planning Assumptions and Study Plan for the current planning cycle and evaluated in that year's transmission planning process.

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5.3.3 Evaluation of Interregional Transmission Projects by the ISO

Once the submittal and validation process has been completed, the ISO shares its planning data and information with the other Relevant Planning Regions and develops a coordinated evaluation plan for each ITP to be considered in its regional planning process. The process to evaluate an ITP can take up to two years where an “initial” assessment is completed in the first or even year and, if appropriate, a final assessment is completed in the second or odd year. The assessment of an ITP in a WPR’s regional process continues until a determination is made as to whether the ITP will/will not meet a regional need within that Relevant Planning Region. If a WPR determines that an ITP will not meet a regional need within its planning region, no further assessment of the ITP by that WPR is required. Throughout this process, as long as an ITP is being considered by at least two Relevant Planning Regions, it will continue to be assessed as an ITP for cost allocation purposes; otherwise, the ITP will no longer be considered within the context of Order No. 1000 interregional cost allocation. However, if one or more planning regions remain interested in considering the ITP within its regional process even though it is not on the path of cost allocation, it may do so with the expectation that the planning region(s) will continue some level of continued cooperation with other planning regions and with WECC and other WECC processes to ensure all regional impacts are considered.

5.3.3.1 Even Year ITP Assessment

The even year ITP assessment begins when the relevant planning regions initiate the coordinated ITP evaluation process. This evaluation process constitutes the relevant planning regions’ formal process to identify and jointly evaluate transmission facilities that are proposed to be located in planning regions in which the ITP was submitted. The goal of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP that will be used by all relevant planning region(s) in their individual evaluations of the ITP(s). The relevant planning regions are required to complete the ITP evaluation process within 75 days after the ITP submittal deadline of March 31 during which a lead planning region is selected for each ITP proposal to develop and post for ISO stakeholder review, a coordinated ITP evaluation process plan for each ITP. Once the ITP evaluation plans are finalized, each relevant planning region independently considers the ITPs that have been submitted into its regional planning process.

As with the other relevant planning regions, the ISO assesses the ITP proposals under the ISO tariff. As illustrated in

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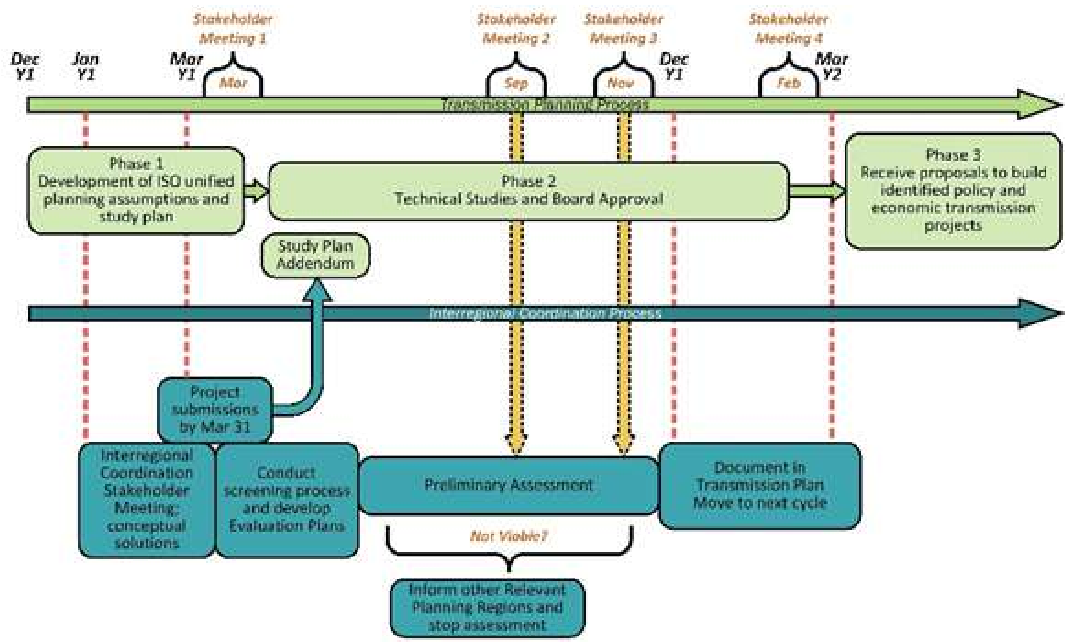
Figure 5.3-1 the ISO shares this information with stakeholders through its regularly scheduled stakeholder meetings, as applicable.

It is important to note that the ISO manages its assessment of an ITP proposal across the two year interregional coordination cycle in two steps. During the even year, the ISO makes a preliminary assessment of the ITP and once it completes that task, ISO must consider whether or not consideration of the ITP should continue into the next ISO planning cycle (odd year interregional coordination process). That determination can be made based on a number of factors including economic, reliability, and public policy considerations.

Figure 5.3-1: Even Year Interregional Coordination Process



The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation to continue or not continue assessment of the ITP in the odd year. The ISO Board's approval of the transmission plan is sufficient to enact the recommendations of the transmission plan.

5.3.3.2 Odd Year ITP Assessment

A recommendation in the even year transmission plan to continue assessing an ITP will initiate consideration of the ITP in the following, or odd year transmission planning cycle and as such, will be documented in the odd year transmission planning process, unified planning assumptions, and study plan. Similar to the even year coordination process shown in

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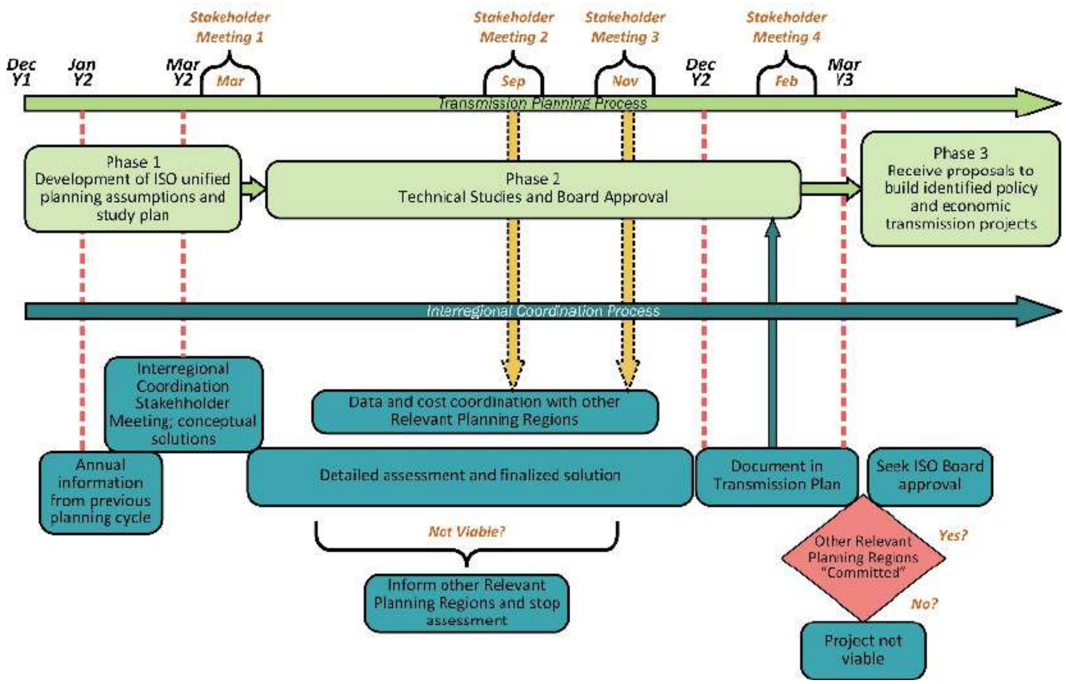
Figure 5.3-1, the ISO will follow the odd year interregional coordination process shown in Figure 5.3-2.

Figure 5.3-2: Odd Year Interregional Coordination Process



During the odd year planning cycle the ISO will conduct a more in-depth analysis of the project proposal, which will include consideration of the timing in which the regional solution is needed and the likelihood that the proposed interregional transmission project will be constructed and operational in the same timeframe as the regional solution(s) it is replacing. The ISO may also determine the regional benefits of the interregional transmission project to the ISO that will be used for purposes of allocating any costs of the ITP to the ISO.

If the ISO determines that the proposed ITP is a more efficient or cost effective solution to meet an ISO-identified regional need and the ITP can be constructed and operational in the same timeframe as the regional solution, the ISO will then consider the ITP as the preferred solution in the ISO transmission plan. The ISO will document its analysis of the ITP and the other regional transmission solutions.

Once the ISO selects an ITP in the ISO transmission plan the ISO will coordinate with the other relevant planning regions to determine if the ITP will be selected in their regional plans and whether or not a project sponsor has committed to pursue or build the project. Based on the information available, the ISO may inform the ISO Board on the status of the ITP proposal and if appropriate, seek approval from the board to continue working with all relevant parties associated with the ITP to determine if the ITP can viably be constructed. Determining viability

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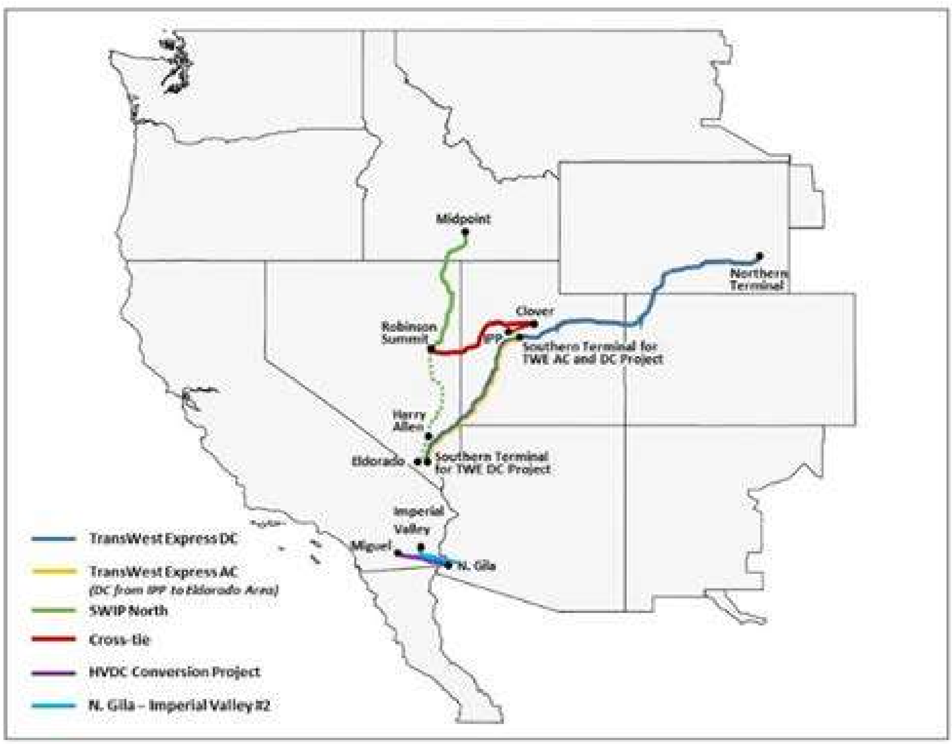
may take several years during which time the ISO will continue to consider the ITP it its transmission planning process and if appropriate, select it as the preferred solution. The ISO may seek ISO Board approval to build the ITP once the ISO receives a firm commitment to construct the ITP.

5.4 2018-2019 Interregional Transmission Coordination ITP Submittals to the ISO

The ISO hosted its 2018-2019 ITP submission period in the first quarter of 2018 in which proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2018-2019 transmission planning process. The submission period began on January 1st and closed March 31st where six interregional transmission projects and their documentation[135] were submitted for consideration by the ISO. Of the six projects submitted, four projects were submitted into the 2016-2017 interregional transmission coordination cycle and were resubmitted into the 2018-2019 cycle. The submitted projects are shown in Figure 5.4-1.

Figure 5.4-1 Interregional Transmission Projects Submitted to the ISO



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135 http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

Following the submission and successful screening of the ITP submittals, the ISO coordinated its ITP evaluation with the other relevant planning regions, NTTG and WestConnect, a result of which was the coordinated development of "ITP Evaluation Process Plan(s)" for each of the ITPs submitted to the ISO[136]. Given the intent of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP, these evaluation plans satisfy that intent and as such, fulfills Order 1000's requirement of the relevant planning regions to jointly coordinate regional planning processes that evaluate an the ITP. In doing so, the evaluation plans document a common framework, coordinated by the WPRs, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process. The ISO then utilizes this information in its development of all planning data and information that is required for the ISO to assess the ITP in its transmission planning process. Specifically, the information in the evaluation plans is considered an addendum to the approved Transmission Planning Process Unified Planning Assumptions and Study Plan.

5.4.1 2018-2019 Interregional Transmission Coordination ITP Submittals

During the course of this year's planning cycle, the ISO considered all six ITPs that were submitted during the ITP submission period. The proposed ITPs, their sponsor's identified need, and the ISO's identified need as determined by the ISO's assessment are summarized in Table 5.4-1. Where appropriate, additional assessment information in provided in section 0 through section 5.4.1.6.

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Table 5.4-1: ITPs Submitted into the 2018-2019 Submission Period

Proposed ITP	Sponsor Identified Need	Cost Allocation	ISO Identified Need in this Planning Cycle
Cross-Tie	Strengthen interconnection between PacifiCorp and Nevada; facilitate California's RPS and GHG needs	ISO, NTTG, WestConnect	None: Based on 2018-2019 plan assumptions
HVDC Conversion	Improve/remove existing reliability limitation; decrease San Diego and greater IV/San Diego LCR requirement	Not Requested	Reliability: None Economic: None - BCR less than 1.0
NG-IV#2	Decrease San Diego and greater IV/San Diego LCR requirement	ISO, WestConnect	Reliability: None Economic: None - BCR less than 1.0
SWIP - North	Economic, policy, reliability, reduce congestion on COI, facilitate access to renewables in PacifiCorp	ISO, NTTG, WestConnect	Reliability: None Economic: None - BCR less than 1.0
TransWest Express AC/DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions
TransWest Express DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions

[136] Id.

5.4.1.1 Cross-Tie Transmission Project

A summary of the ITP information submitted to the ISO is shown in Table 5.4-2.

Table 5.4-2: ITP Submittal Information for the Cross-Tie Transmission Project

Project Submitted To:	California ISO, Northern Tier Transmission Group ("NTTG") and WestConnect
Relevant Planning Regions:	NTTG and WestConnect
Cost Allocation Requested From:	California ISO, NTTG and WestConnect

Stated Purpose of the Project

The stated purpose of the Cross-Tie Project is that it would couple with the planned Gateway South Project (Aeolus – Clover), the existing One Nevada Line (Robinson Summit – Harry Allen) and the currently under construction Harry Allen – Eldorado 500 kV transmission project and would provide needed transmission capacity between the Intermountain West (Utah/Wyoming) region of NTTG and the Desert Southwest portion of WestConnect. The project proponent states that this additional transmission capacity would facilitate access between the significant renewable resources in Wyoming/Utah and diverse utility load profiles in Desert Southwest/California. Also, this interregional project would result in lowering the cost of RPS compliance for the Desert Southwest and California while enhancing opportunities to balance the renewable resource mix between the Desert Southwest, California and the Intermountain West. The project would also facilitate the ISO in meeting California's RPS and GHG requirements by providing transmission access to high capacity wind resources in Utah and Wyoming.

P27-129 cont.

Project Description

TransCanyon, LLC (TransCanyon) submitted the 213-mile Cross-Tie Transmission Project (Cross-Tie Project) for consideration as an ITP. The Cross-Tie project is a proposed 1500 MW, 500 kV HVAC transmission project that would be constructed between central Utah and east-central Nevada (see Figure 5.4-2), connecting PacifiCorp's proposed 500 kV Clover substation (in the NTTG planning region) with NV Energy's existing 500 kV Robinson Summit substation (in the WestConnect planning region). The proposed project would include series compensation at both ends of the Cross-Tie transmission line. In addition, series compensation would be needed on the existing Robinson Summit to Harry Allen 500-kV line along with phase shifting transformers at Robinson Summit 345-kV.

The project would be required to satisfy the requirements of the National Environmental Policy Act (NEPA) and the Bureau of Land Management (BLM). A significant portion of the routing of the line has been previously studied under the Southwest Intertie Project Environmental Impact Statement, which received federal approval in a Record of Decision published in 1994 but was not constructed. Further, the project would be subject to the state approval processes applicable for Nevada and Utah. According to TransCanyon, the project could be in-service as early December 2024.

Figure 5.4-2 : Cross-Tie Project Overview

P27-129 cont.

Reliability Assessment

None performed

Economic Assessment

None Performed

Conclusions

The stated purpose of the Cross-Tie Project is a transmission solution that would “provide needed transmission capacity between the Intermountain West (Utah/Wyoming) region of NTTG and the Desert Southwest portion of WestConnect” and “facilitate access between the significant renewable resources in Wyoming/Utah and diverse utility load profiles in Desert Southwest/California.” However the study assumptions and the reliability, policy, and economic regional assessments documented in this study do not support finding this project needed in this planning cycle.

5.4.1.2 HVDC Conversion Project

A summary of the ITP information submitted to the ISO is shown in Table 5.4-3.

Table 5.4-3: ITP Submittal Information for the HVDC Conversion Project

Project Submitted To:	California Independent System Operator (California ISO), WestConnect
Relevant Planning Regions:	California ISO, WestConnect
Cost Allocation Requested From:	Not requested

Stated Purpose of the Project

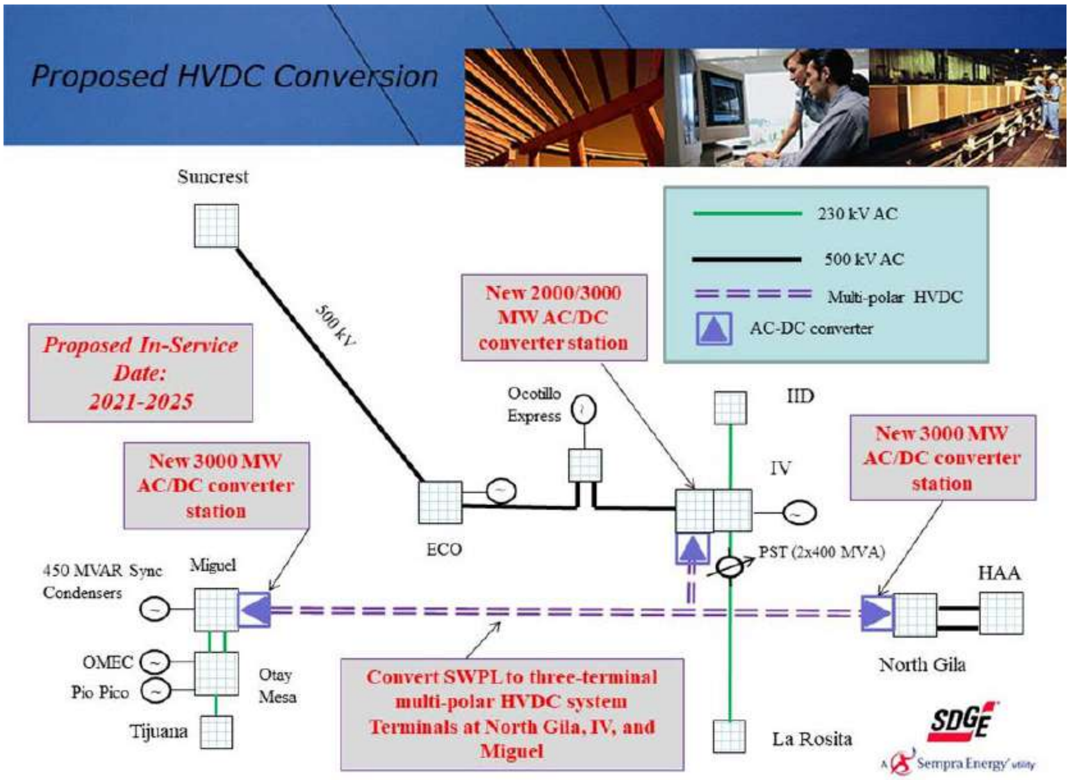
The stated purpose of the HVDC Conversion Project is that it would optimize the transfer capability on existing infrastructure leading significant interregional benefits such as solving an existing loop flow issue for multiple parties (APS, SDG&E, IID, and CENACE), reducing the interdependency of the southern West of River 500 kV system with IID's bulk power system, minimizing permitting and new ROW requirements, and integrating with newly installed synchronous condenser installations. The proposed project would be constructed within existing rights of way and within or adjacent to existing substations thus minimizing environmental and permitting related impacts.

P27-129 cont.

Project Description

San Diego Gas and Electric (SDG&E) submitted the HVDC Conversion Project to WestConnect and the California ISO as an ITP. The proposed project would convert a portion of the 500 kV Southwest Powerlink (SWPL) to a multi-terminal, multi-polar HVDC system with terminals at North Gila (500 kV), Imperial Valley (500 kV), and Miguel Substations (230 kV). A project map of the proposed project is shown in Figure 5.4-3.

Figure 5.4-3: HVDC Conversion Project



Reliability Assessment

The HVDC Conversion Project would be part of the SDG&E area and its reliability assessment was considered as part of the overall assessment of the existing LCR areas in the SDG&E and LA Basin areas. The details of these LCR results are documented in section 4.8.7 and section 4.9.11.2.

Economic Assessment

An economic assessment of the HVDC Conversion Project was performed to determine any economic benefits that could be assigned to this project. The results of the economic analysis is discussed in detail in Section 4.9.11.2.

Production Cost Assessment

Production cost analysis was performed with and without the HVDC Conversion Project transmission project to quantify any production cost benefits that would result from the project. In general the assessment showed that adding the project to the network would increase congestion along the IV to San Diego corridor and on Path 26. Renewable curtailment was

P27-129 cont.

reduced in the IV area but increased in most other southern California areas. The results of the production cost assessment showed an ISO Net Payment or cost to the ISO ratepayer of approximately -$13M/year. The net present value of these annual payments is approximately -$82.80M.

Local Capacity Benefits

A primary benefit that the HVDC Conversion Project transmission project could bring to ISO ratepayers is a reduction in LCR in the San Diego-Imperial Valley area. Studies with and without the HVDC Conversion Project transmission project were performed to assess the impact of this project on the LCR in the SDG&E and SCE areas. In general the results of the LCR analysis showed that the HVDC Conversion Project transmission project would reduce LCR need in the San Diego – Imperial Valley area by approximately 690 MW. However, due to the reduced generation dispatched in the SDG&E area, the LCR need in the western LA Basin increased by approximately 40 MW. The net LCR benefit of the HVDC Conversion Project transmission project is the difference between the LCR cost increase in the LA Basin and the LCR cost reduction in the San Diego-Imperial Valley area.

As discussed in section 4.3.4 the basis for the local price may depend on the circumstances within the local capacity area. For the evaluation of the HVDC Conversion Project transmission project the LCR reductions in southern California were valued as the difference between local and system capacity and between local and “south of path 26 system” resources. The results of the LCR analysis showed that the net LCR benefits that could be attributed to the HVDC Conversion Project transmission project would be $20.7M/year. The net present value of these annual LCR benefits would be approximately $284.6M.

P27-129 cont.

Benefit to Cost Ratio

The benefit to cost ratio is based on the results of the production cost and LCR analyses the net present value of their resultant benefits based on a 50 year project life. Based on the net present value of benefits discussed above the calculated benefit to cost ratio of the HVDC Conversion Project is:

- -0.05 for local versus system capacity cost
- -0.01 for local versus SP 26 capacity cost.

Conclusions

The benefit-to-cost ratio determined in this study does not support finding this project needed in this planning cycle. Further, the local capacity reduction benefits may be eroded if other options proceed that address the S-Line overload concern that presently sets the requirement for San Diego/Imperial Valley local capacity requirements. As the project relies heavily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC’s integrated resource planning process.

5.4.1.3 North Gila-Imperial Valley #2 Transmission Project

A summary of the ITP information submitted to the ISO for the North Gila-Imperial Valley #2 (NG-IV#2) Transmission Project is shown in Table 5.4-4.

Table 5.4-4: ITP Submittal Information for the North Gila-Imperial Valley #2 Transmission Project

Project Submitted To:	California Independent System Operator (California ISO), and WestConnect
Relevant Planning Regions[137]:	California ISO, and WestConnect
Cost Allocation Requested From:	California ISO, and WestConnect

Stated Purpose of the Project

The stated purpose of the NG-IV#2 project is that it would improve reliability for the southern California and southwest Arizona areas, especially for contingencies involving loss of the existing North Gila – Imperial Valley line, and increase the West of Colorado River (WECC Path 46) and East of Colorado River (WECC Path 49) transfer capability. The proponents state that from the Project would enable access to additional renewable resources in the solar and geothermal rich areas of Imperial Valley and Arizona to for the benefit of California's Renewable Portfolio Standard and Greenhouse Gas reduction targets. Also, the project may also provide quantifiable economic benefits in the form of production cost savings, congestion relief and reduced Local Capacity Requirements in the southern region of the ISO.

P27-129 cont.

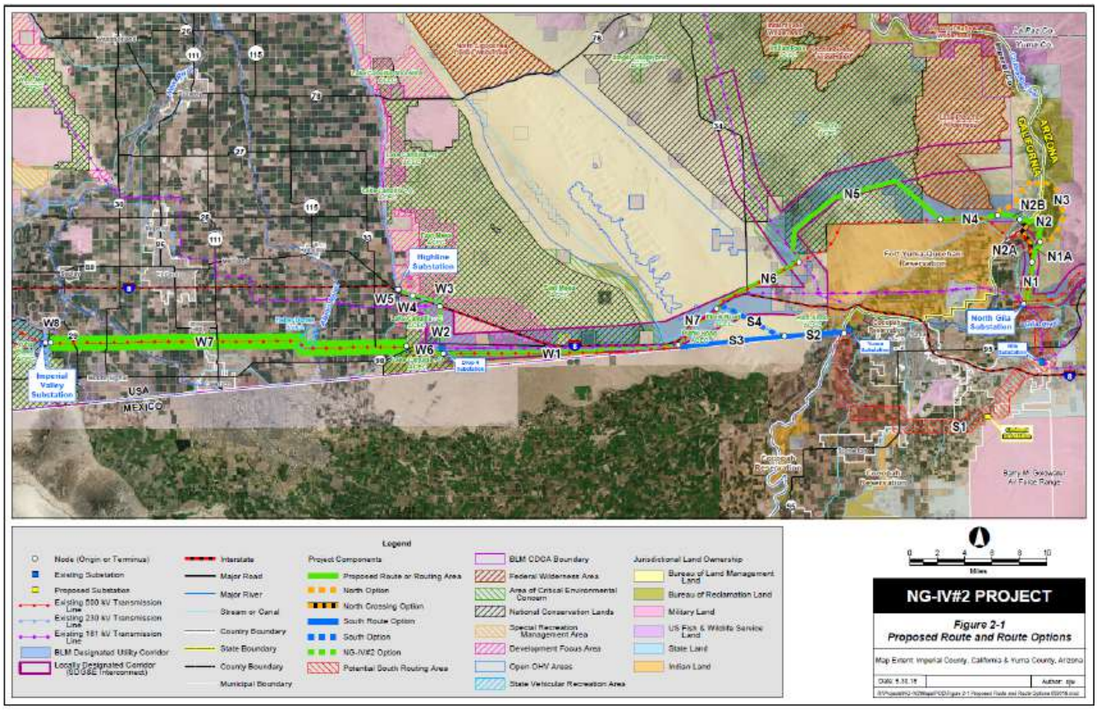
Project Description

Southwest Transmission Partners, LLC (Southwest Transmission Partners) and ITC Grid Development, LLC (ITC Grid Development) submitted the 97-mile North Gila-Imperial Valley #2 (NG-IV#2) Transmission Project for consideration as an ITP. The NG-IV#2 transmission project is a proposed 500 kV HVAC transmission project that could be constructed between southwest Arizona and southern California (see Figure 5.4-4). The line would parallel the existing North Gila-Imperial Valley line, also known as the Southwest Power Link (SWPL), and would connect the existing 500 kV North Gila substation (in the WestConnect planning region) with the existing 500 kV Imperial Valley substation (in the California ISO planning region) through an interconnection with a new 500/230 kV Highline substation (in the WestConnect planning region), interconnecting to the existing IID Highline 230 kV substation. It is expected that this project would become an additional component of the West of Colorado River path (Western Electricity Coordination Council (WECC) path 46) and could increase the East of Colorado River path (WECC path 49) transfer capability as well. Series compensation could be added to the project to balance flows between this new circuit and the existing SWPL line.

[137] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

The project submitters have initiated the National Environmental Policy Act (NEPA) process with several proposed alternative proposed routes and have a National Program team from BLM assigned and engaged to lead the NEPA process. According to Southwest Transmission Partners and ITC Grid Development, the project could be in-service as early as December 2022.

Figure 5.4-4 : North Gila-Imperial Valley #2 Transmission Project Overview



Reliability Assessment

The NG-IV#2 transmission project would be part of the SDG&E area and its reliability assessment was considered as part of the overall SDG&E area assessment which is discussed in detail in Section 2.9 of this transmission plan.

The reliability assessment of the SDG&E area without the NG-IV#2 project identified several system performance issues in SDG&E's main and sub-transmission systems. After consideration of proposed transmission solutions submitted to the ISO through its request window, the ISO found that non-transmission alternatives were the more cost effective or efficient regional solutions to meet the reliability needs identified in SDG&E area studies. An analysis of the SDG&E area with the NG-IV#2 transmission project was performed to assess the impact of the project on SDG&E's main and sub-transmission systems. The results of this assessment showed that the NG-IV#2 transmission project would increase flows into the SDG&E area and worsen identified system performance issues already identified in the regional assessment to the point that the identified regional solutions would no longer be sufficient to

P27-129 cont.

address the system performance issues identified in the regional assessment. Study results also showed that part of the increased flow into the SDG&E area would increase power flow across the CENACE system and negatively impact reliability in the CENACE system and result in potential voltage instability in the Los Angeles Basin and the San Diego area.

Economic Assessment

An economic assessment of the NG-IV#2 transmission project was performed to determine any economic benefits that could be assigned to this project. The results of the economic analysis is discussed in detail in Section 4.9.11.3.

Production Cost Assessment

A production cost analysis was performed with and without the NG-IV#2 transmission project to quantify any economic benefits that would result from the project. In general the assessment showed that the proposed project could bring an annual ISO Ratepayer Net Payment of approximately $6M/year. The net present value of these ISO ratepayer savings is approximately $82.80M.

Local Capacity Benefits:

A primary benefit that the NG-IV#2 transmission project could bring to ISO ratepayers is a reduction in LCR in the San Diego-Imperial Valley area. Studies with and without the NG-IV#2 transmission project were performed to assess the impact of this project on the LCR in the SDG&E and SCE areas. In general the results of the LCR analysis showed that the NG-IV#2 transmission project would reduce LCR need in the San Diego – Imperial Valley area by approximately 865 MW. However, due to the reduced generation dispatched in the SDG&E area, the LCR need in the western LA Basin increased by approximately 100 MW. The net LCR benefit of the NG-IV#2 transmission project is the difference between the LCR cost increase in the LA Basin and the LCR cost reduction in the San Diego-Imperial Valley area.

P27-129 cont.

As discussed in section 4.3.4 the basis for the local price may depend on the circumstances within the local capacity area. For the evaluation of the NG-IV#2 transmission project the LCR reductions in southern California were valued as the difference between local and system capacity and between local and “south of path 26 system” resources. The results of the LCR analysis showed that the net LCR benefits that could be attributed to the NG-IV#2 transmission project would be $23.8M/year. The net present value of these ISO ratepayer savings is approximately $329.6M

Benefit to Cost Ratio

The benefit to cost ratio is based on the results of the production cost and LCR analyses the net present value of their resultant benefits based on a 50 year project life. Based on the net present value of benefits discussed above the calculated benefit to cost ratio of the NG-IV#2 transmission project is

- 0.57 for local versus system capacity cost
- 0.74 for local versus SP 26 capacity cost

Conclusions

The benefit to cost ratio determined in this study does not support finding this project to be needed in this planning cycle. Further, the project would require mitigations of the reliability concerns in the San Diego sub-area, and the benefits may be eroded if other options proceed that address the S-Line overload concern that sets the requirement for San Diego/Imperial Valley local capacity requirements. As the project relies heavily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC's integrated resource planning process.

5.4.1.4 SWIP - North Project

A summary of the ITP information submitted to the ISO for the SWIP - North Project is shown in Table 5.4-5.

Table 5.4-5: ITP Submittal Information for the SWIP - North Project

Project Submitted To:	**California Independent System Operator ("California ISO"), Northern Tier Transmission Group ("NTTG") and WestConnect**
Relevant Planning Regions:	California ISO, NTTG and WestConnect
Cost Allocation Requested From:	California ISO, NTTG and WestConnect

P27-129 cont.

Stated Purpose of the Project

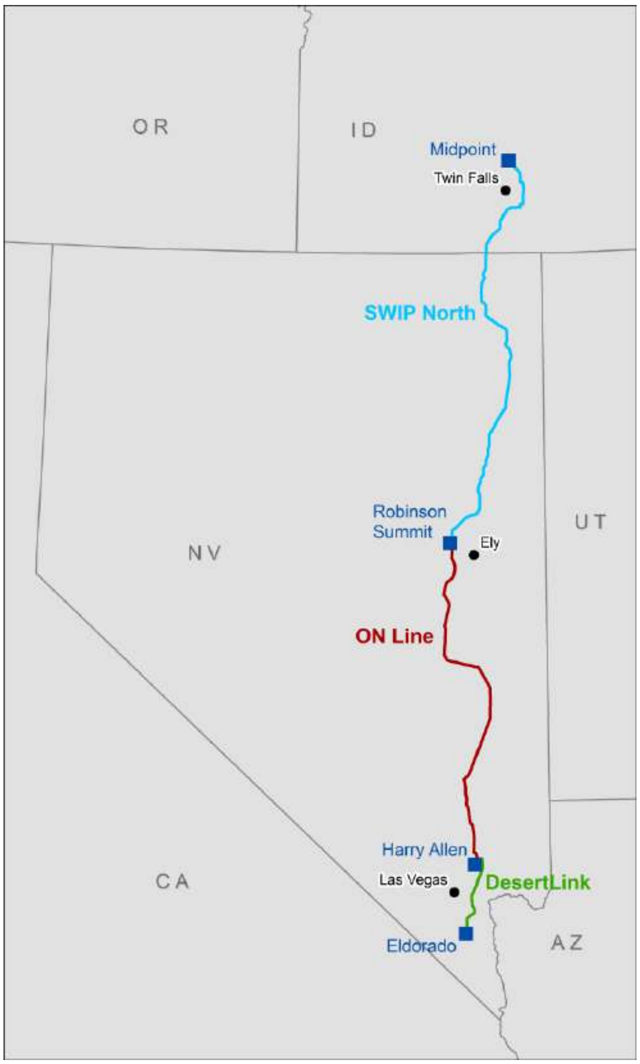
The stated purpose of the SWIP - North Project is that it would provide a new backbone for the western grid that would provide not only economic benefits, but additional reliability benefits and insurance against emergency outage scenarios. The proponent also states that the project would provide benefits related to congestion relief on COI, energy market value, integrating renewables that support GHG and RPS policy goals, EIM benefits, increased capacity benefits, increased load diversity, wheeling revenues, insurance value and reliability benefits.

Project Description

As set out in Chapter 2, the SWIP - North Project was submitted in the 2018 Request Window as a transmission solution to address thermal overloads on the 500 kV and 230 kV systems in northern California and to improve low voltage issues in northern California during summer peak conditions with high COI N-S flows. The project was also proposed by a non-PTO, Great Basin Transmission (GBT), LLC, an affiliate of LS Power, as a Reliability Transmission Project and as part of an economic study request as set out in chapter 4.

The SWIP - North Project connects the Midpoint 500 kV substation (in NTTG) to the Robinson Summit 500 kV substation (in WestConnect) via a 275-mile, 500kV single circuit AC transmission line (see Figure 5.4-5). The project is expected to have a bi-directional WECC-approved path rating of approximately 2000 MW. Upon completing a new physical connection at Robinson Summit a capacity sharing arrangement would be triggered between GBT and NV Energy across the already in-service ON-Line Project and SWIP-N that would provide GBT with control of ~1,000 MW bi-directional capacity between Midway and Harry Allen. P27-129 cont.

Figure 5.4-5: SWIP-N Map of Preliminary Route



Reliability Assessment

The SWIP - North project was considered in the system assessment of PG&E's bulk transmission system which is discussed in section 2.4.4 of this transmission plan. Based on the reliability assessments performed in this planning cycle, the ISO did not identify any reliability needs that the project was required to mitigate.

The ISO considers the SWIP - North project to be an ITP due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and NTTG planning regions, respectively, and is not physically connected to ISO-controlled facilities. The scheduling capacity from the Harry Allen end of the ISO's approved Harry Allen-Eldorado transmission line to Robinson Summit also creates opportunity for the submitted project to provide benefits to the ISO, in which case the ISO can select to participate in the project – if that is found to be the preferred solution to meeting the ISO's regional need.

Economic Assessment

An economic assessment of the SWIP - North transmission project was performed to determine any economic benefits that could be assigned to this project. The results of the economic analysis is discussed in detail in section 4.9.1.2.

Production Cost Assessment

A production cost analysis was performed with and without the SWIP - North project to quantify any economic benefits that would result from the project. These results showed that there would be a net increase in ISO ratepayer costs of approximately -$21M/year while at the same time an overall WECC benefit through lower production costs over the entire WECC footprint. It is worth noting that while ISO ratepayer costs increased and WECC production costs increased, the ISO concluded that the SWIP - North transmission project may not provide incremental import from Northwest regions during some hours when there is no energy surplus in those regions. While the presumption of this result depends on resource and transmission assumptions in northwest regional models, it appears that this project may allow more exports from California to other regions when there are renewable energy surpluses within California. In addition, lower priced imports can result in increased profits to out-of-state generation and reduced profits to ISO owned generation in the ISO footprint whose profits accrue to ISO ratepayers.

P27-129 cont.

Local Capacity Benefits

None performed

Benefit to Cost Ratio

None performed

Conclusions

The SWIP - North project, on a standalone basis and without support from other areas that may benefit from the project, was not supported by the findings in the 2018-2019 transmission planning studies. The ISO expects that dialogue will continue with neighboring planning regions as their own plans evolve, and as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement.

5.4.1.5 TransWest Express AC/DC Project

A summary of the ITP information submitted to the ISO for the TransWest Express AC/DC Project is shown in Table 5.4-6.

Table 5.4-6: ITP Submittal Information for the TransWest Express AC/DC Project

Project Submitted To:	**California Independent System Operator (California ISO), Northern Tier Transmission Group (NTTG), WestConnect**
Relevant Planning Regions[138]:	California ISO, NTTG, WestConnect
Cost Allocation Requested From:	California ISO, WestConnect

Stated Purpose of the Project

The stated purpose of the TWE AC/DC Project is that it would provide needed transmission capacity between the Desert Southwest and California regions, represented by ISO and WestConnect, and the Rocky Mountain region, represented by NTTG and WestConnect. This additional transmission capacity would facilitate access between diverse renewable resources and diverse utility load profiles. The proponent states that the TWE AC/DC Project would facilitate access to the Desert Southwest/California market to Wyoming's vast renewable wind resources and would lower the cost of RPS compliance for the Desert Southwest while simultaneously providing the vast solar resources in the Desert Southwest with access to Rocky Mountain regional markets, such as the Denver and Salt Lake City metro areas. P27-129 cont.

Project Description

The TWE AC/DC Project consists of a proposed 406-mile, phased 1,500/3,000 MW, ±500 kV, bi-directional, two-terminal, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and central Utah, and a 324- mile, 1,500 MW 500 kV alternating current transmission system with terminals in central Utah and southeastern Nevada.

The TWE AC/DC Project northern terminal will be interconnected at 230 kV to the existing PacifiCorp 230 kV transmission line between the Platte and Latham substations and the planned 500 kV Gateway West D.2 segment in the NTTG planning region, and to the 3,000 MW Chokecherry and Sierra Madre Wind Energy Project.[139] The TWE AC/DC Project design provides for connecting the northern terminal to the existing 230 kV Western Area Power Administration system in the WestConnect planning region near the Miracle Mile substation.

[138] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

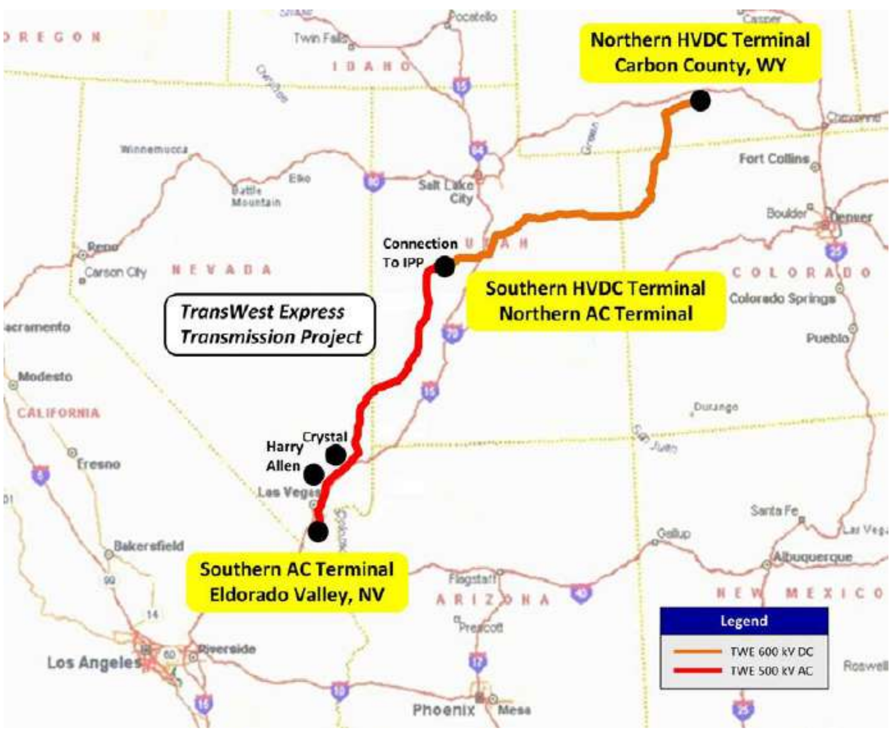
[139] The Chokecherry and Sierra Madre Wind Energy Project is being developed in two 1,500 MW phases by Power Company of Wyoming LLC, an affiliate of TransWest. More information about PCW and the CCSM Project is available at www.powercompanyofwyoming.com.

The TWE AC/DC Project's Utah, or southern DC, terminal will be interconnected to the 345 kV Intermountain Power Plant substation in the WestConnect planning region. The 500 kV AC line will connect the Utah terminal to the 500 kV McCullough substation and the 500 kV Mead to Marketplace transmission line in the WestConnect planning region.

The TWE AC/DC Project has an in-service date of 2022 and to date has obtained rights-of-way over all of the federal land along the route, which represents about 66% of the route. In 2016 and 2017, following eight years of environmental analysis under the National Environmental Policy Act, four federal agencies -- the Bureau of Land Management (BLM), U.S. Department of the Interior; Western Area Power Administration (WAPA), U.S. Department of Energy; United States Forest Service (USFS), U.S. Department of Agriculture; and the Bureau of Reclamation (BOR), U.S. Department of the Interior) -- issued records of decision finalizing and approving the route for the TWE Project on federal lands.[140] WAPA acted as a joint lead agency with the BLM on the Environmental Impact Statement (EIS) and is considering further participation in the TWE Project through its Transmission Infrastructure Program. The BLM and WAPA published the Final Environmental Impact Statement (FEIS) for the TWE AC/DC Project on May 1, 2015. The route for the TWE AC/DC Project is shown in Figure 5.4-6.

P27-129 cont.

Figure 5.4-6: TransWest Express AC/DC Project map



[140] See BLM ROD TransWest December 2016, WAPA ROD TWE Project, January 2017, USFS ROD TWE Project, May 2017, BOR ROD TWE Project, June 2017

Reliability Assessment

None performed

Economic Assessment

None performed

Conclusions

The stated purpose of the TWE AC/DC Project is to facilitate access between diverse renewable resources and diverse utility load profiles in California as well as facilitate access by the Desert Southwest/California market to Wyoming's vast renewable wind resources. As discussed in Chapter 2 of this transmission plan, California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and "informational" policy analysis for the 2018-2019 transmission planning cycle provide direction that all renewable procurement to achieve the 50% RPS goal to be considered by the California ISO's planning process be obtained from within California. In addition, the ISO's assessment of the need for public policy transmission solutions under the tariff did not identify a need for this project.

The ISO concluded that based on the study assumptions and regional assessments performed, a finding of need was not identified in this planning cycle for this project.

5.4.1.6 TransWest DC Project

A summary of the ITP information submitted to the ISO for the TransWest DC Project is shown in Table 5.4-7.

Table 5.4-7: ITP Submittal Information for the TransWest DC Project

Project Submitted To:	**California Independent System Operator (California ISO), Northern Tier Transmission Group (NTTG), WestConnect**
Relevant Planning Regions[141]:	California ISO, NTTG, WestConnect
Cost Allocation Requested From:	California ISO, WestConnect

Stated Purpose of the Project

The stated purpose of the TWE DC Project is that it would provide direct bidirectional transmission capacity from Wyoming wind resources and the diverse Rocky Mountain load centers to replace and support a portion of the Public Policy and Economic Regional Needs of the three planning regions. The proponent also states that the project would support meeting Regional Needs within the California ISO, NTTG, and WestConnect by providing "Public Policy"

P27-129 cont.

[141] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

and “Economic” benefits to each of the three Relevant Planning Regions and as defined by Arizona, California, and Nevada.

Project Description

The TWE DC Project is a proposed 730-mile, phased 1,500/3,000 MW, ±600 kV, bi-directional, two-terminal, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and southeastern Nevada.

The TWE DC Project northern terminal would be interconnected at 230 kV to the existing PacifiCorp 230 kV transmission line between the Platte and Latham substations and the planned 500 kV Gateway West D.2 segment in the NTTG planning region, and to the 3,000 MW Chokecherry and Sierra Madre Wind Energy Project. The TWE DC Project design would provide for connecting the northern terminal to the existing 230 kV Western Area Power Administration system in the WestConnect planning region near the Miracle Mile substation.

The TWE DC Project southern terminal would be interconnected to the 500 kV Eldorado substation in the ISO planning region. It also would also be interconnected to the 500 kV McCullough substation and the 500 kV Mead to Marketplace transmission line in the WestConnect planning region.

According to the project sponsor the TWE DC Project could be in-service as early as 2022 and to date has obtained rights-of-way over all of the federal land along the route, which represents about 66% of the route. In 2016 and 2017 the Bureau of Land Management (BLM), U.S. Department of the Interior; Western Area Power Administration (WAPA), U.S. Department of Energy; United States Forest Service (USFS), U.S. Department of Agriculture; and the Bureau of Reclamation (BOR), U.S. Department of the Interior) issued records of decision finalizing and approving the route for the TWE DC Project on federal lands. P27-129 cont.

A project map of the proposed project is shown in Figure 5.4-7.

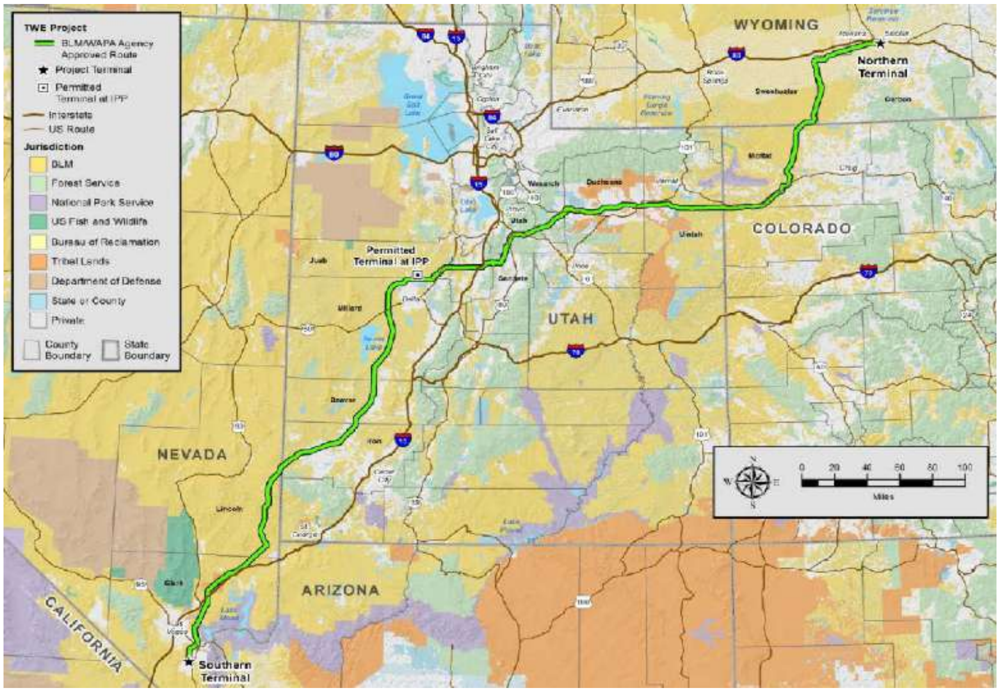
Reliability Assessment

None performed

Economic Assessment

None performed

Figure 5.4-7: TransWest Express DC Project Map



Conclusions

The stated purpose of the TWE DC Project is to provide direct bidirectional transmission capacity from Wyoming wind resources and would replace and support a portion of the Public Policy and Economic Regional Needs of the ISO. As discussed in Chapter 2 of this transmission plan, California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and "informational" policy analysis for the 2018-2019 transmission planning cycle provide direction that all renewable procurement to achieve the 50% RPS goal to be considered by the California ISO's planning process be obtained from within California. In addition, the ISO's assessment of the need for public policy transmission solutions under the tariff did not identify a need for this project.

The ISO concluded that based on the study assumptions and regional assessments performed a finding of need was not identified in this planning cycle for this project.

5.5 WECC Anchor Data Set

For a great deal of its history, WECC has provided data collection, coordination, and validation services for its members. Historically, this work has focused on power flow and stability models and data and has produced an annual power flow and stability base case data bank that is available to all members. However, since the mid-1990's many WECC members began to consider transmission oriented, security constrained economic assessments (production cost modeling) in their planning processes. While power flow and stability models and tools remain

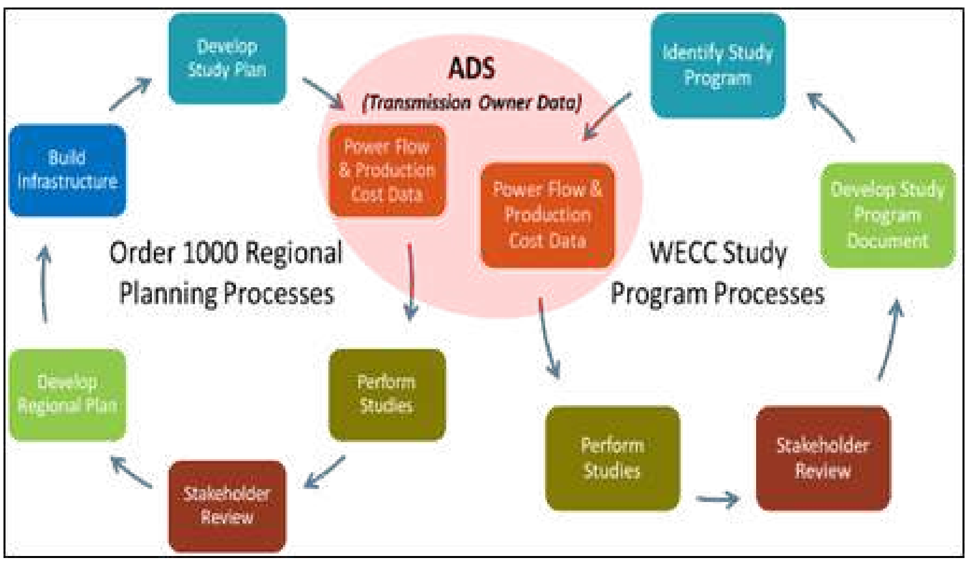
P27-129 cont.

the critical system performance tool for assessing system reliability, FERC Orders No. 890 and No. 1000 had within them embedded certain economic assessment requirements that transmission providers were obligated to meet. As a result, a need for west wide coordination, collection, and validation of production cost data has arisen. Although WECC has been proactive in its engagement to support its members in this area, a consistent and repeatable process for engaging and coordinating its member's information, in particular the Western Planning Regions, was seen to be lacking.

Order 1000 requires that each Western Planning Region, following its Order 1000 regional process, develop its own regional plan. Similarly, WECC completes their annual study program which considers reliability and adequacy across the western interconnection. Although the focus of the Order 1000 regional planning process and WECC's study program process are not necessarily the same, the Western Planning Regions recognized that the need for a common dataset of power flow and production cost information and a consistent and repeatable process for coordinating their data with WECC was in the best interest of the Western Planning Regions and WECC. To this end, in early 2016 the Western Planning Regions collaborated with WECC to develop the WECC Anchor Data Set (ADS). The objective of the ADS is to provide an avenue for the Western Planning Regions to coordinate data included in their Order 1000 regional plans with WECC and their stakeholders to facilitate a consistent and complete data for the benefit of all users (see Figure 5.5-1).

P27-129 cont.

Figure 5.5-1 - The ADS Links WPR/WECC Processes



The Western Planning Regions utilize the ADS to develop their planning cases and through their regional processes, provide current information to update the ADS in preparation for their next planning cycle. In turn, WECC utilizes the ADS to develop their study program cases for their annual study program. As a result, the ADS will reflect the most current information from their regional plans which in turn will provide WECC a foundational dataset based on Order 1000 regional processes from which their study program datasets can be developed.

Development of the ADS

Developing and implementing the ADS is a significant undertaking for WECC as its intended objective is to “re-write” its data collection process to include production cost information and clearly link power flow and load and resource information with the production cost information. WECC began developing the 2028 ADS dataset in early 2018. Commensurate with the developing the ADS dataset, the WECC Reliability Assessment Committee (RAC) formed the ADS Task Force, the members of which include representatives from the Western Planning Regions and other WECC member representatives. The ADSTF is actively engaged in implementation of the ADS and is charged with considering and proposing any recommended changes that may need to be considered to facilitate the successful implementation of the ADS.

Consistent with the ADS proposal, the first official version (version 1.0) of the 2028 ADS was completed and posted on June 29, 2018. Although the ADS proposal explored many of the processes that would need to be developed and implemented, during its effort to implement the ADS process the ADSTF learned that certain aspects of the ADS process had not been identified or clearly defined in the ADS proposal that was adopted by the WECC Board. As such, based on experience garnered in the development of the June 29 dataset, the focus of the ADSTF has been to identify, discuss, and recommend improvements and/or modifications that may need to be made to the ADS process to ensure that it will be consistent and repeatable. In particular, the ADSTF is providing leadership and direction in the following areas: P27-129 cont.

1. Develop the ADS Process Guide

   The ADS Process Guide, once developed, will be approved by the RAC and will contain all documentation associated with the ADS. This documentation includes but is not limited to the ADS process approval approved by the WECC Board and amended as is necessary to reflect the process, protocols, and data manuals associated with developing, modifying, and/or deleting information or data from the ADS dataset. The ADS Process Guide will also include the Power Flow Data Preparation Manual and the PCM Data Development and Validation Manual both of which provide, in unambiguous detail, an outline of the data requirements and submission procedures that are necessary to meet all data requirements of the ADS;

2. ADS Responsibility Assignment Matrix (RACI Matrix)

   Developing the ADS requires coordination between the transmission owners who provide the data to WECC; RAC and its subcommittees/workgroups that determine data requirements and validate data that is received, and WECC staff who collect and populate the ADS datasets. A RACI matrix is being developed to support the management of the ADS process by assigning responsibility for the various tasks of the ADS from the point that planning data and information is requested to its final representation in the ADS. The RACI matrix will be an integral part of the ADS Process Guide;

3. ADS Process Workflow

   Commensurate with the RACI matrix, the ADS process workflow is a project oriented milestone schedule that is being developed to facilitate coordination of the flow of data and information between the RACI matrix tasks and the ADS two-year cycle. The ADS process workflow will also be an integral part of the ADS Project Guide.

Why the ADS is Important to the ISO

The ISO supports developing and implementing the ADS and has remained actively engaged in this process over the last two planning cycles. In general, the Western Planning Regions consider full implementation of the ADS to be a significant step towards meeting their need of resolving existing data inconsistencies and applications, while facilitating a common dataset that accurately represents the regional plans of all four planning regions. Each year the ISO builds over 100 power flow cases to perform its reliability assessment of the ISO controlled grid. In addition, the ISO builds a detailed production cost model dataset from which it performs economic, policy, and other "special studies". Clearly, significant ISO resources are committed to developing these study models during each planning cycle and, as such, their accuracy is of paramount importance to that process. The ISO believes that the successful development and implementation of the ADS will yield, through a consistent and repeatable process, better coordinated and more accurate datasets that will maximize their use and minimize errors in WPR regional and WECC assessments.

P27-129 cont.

Chapter 6

6 Other Studies and Results

The studies discussed in this chapter focus on other recurring study needs not previously addressed in preceding sections of the transmission plan and are either set out in the ISO tariff or forming part of the ongoing collaborative study efforts taken on by the ISO to assist the CPUC with state regulatory needs. The studies have not been addressed elsewhere in the transmission plan. These presently include the reliability requirements for resource adequacy studies, both short term and long term, the long-term congestion revenue rights (LT CRR) simultaneous feasibility test studies, and a system frequency response assessment.

6.1 Reliability Requirement for Resource Adequacy

Section 6.1.1 summarize the technical studies conducted by the ISO to comply with the reliability requirements initiative in the resource adequacy provisions under section 40 of the ISO tariff as well as additional analysis supporting long term planning processes, being the local capacity technical analysis and the resource adequacy import allocation study. The local capacity technical analysis addressed the minimum local capacity area requirements (LCR) on the ISO grid. The resource adequacy import allocation study established the maximum resource adequacy import capability to be used in 2019. Upgrades that are being recommended for approval in this transmission plan have therefore not been taken into account in these studies.

P27-129 cont.

6.1.1 Local Capacity Requirements

The ISO conducted short- and long-term local capacity technical (LCT) analysis studies in 2018. A short-term analysis was conducted for the 2019 system configuration to determine the minimum local capacity requirements for the 2019 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria as required by the ISO tariff section 40.3. This study was conducted in January through April through a transparent stakeholder process with a final report published on May 15, 2018. For detailed information on the 2019 LCT Study Report please visit:

http://www.caiso.com/Documents/Final2019LocalCapacityTechnicalReport.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2023 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years respectively. The 2023 LCT Study Report was published on May 15, 2018 and for detailed information please visit:

http://www.caiso.com/Documents/Final2023Long-TermLocalCapacityTechnicalReport.pdf

The ISO also conducts a ten-year local capacity technical study every second year, as part of the annual transmission planning process. The ten-year LCT studies are intended to synergize with the CPUC long-term procurement plan (LTPP) process and to provide an indication of whether there are any potential deficiencies of local capacity requirements that need to trigger a new LTPP proceeding and, per agreement between agencies, they are done on every other year cycle.

The most recent ten-year LCR study was prepared in this year's 2018-2019 transmission planning process. The ISO undertook a more comprehensive study of local capacity areas in this planning cycle than in the past, examining both the load shapes and characteristics underpinning local capacity requirements, and evaluating alternatives for those needs even if it is unlikely that the economic benefits alone would outweigh the costs. A number of these alternatives received detailed economic evaluations in this planning cycle, as set out in chapter 4, to assess if they should be approved as economic-driven transmission solutions.

For detailed information about the 2028 long-term LCT study results, please refer to the stand-alone report in the Appendix G of the 2018-2019 Transmission Plan.

As shown in the LCT reports and indicated in the LCT manual, that the ISO prepares each year setting out how that year's LCT studies will be performed, 12 load pockets are located throughout the ISO-controlled grid as shown in Table 6.1-1, however only 10 of them have local capacity area requirements as illustrated in

Figure 6.1-1.

Table 6.1-1: List of Local Capacity Areas and the corresponding service territories within the ISO Balancing Authority Area

<table>
<tr><th>No</th><th>LCR Area</th><th>Service Territory</th></tr>
<tr><td>1</td><td>Humboldt</td><td rowspan="7">PG&E</td></tr>
<tr><td>2</td><td>North Coast/North Bay</td></tr>
<tr><td>3</td><td>Sierra</td></tr>
<tr><td>4</td><td>Stockton</td></tr>
<tr><td>5</td><td>Greater Bay Area</td></tr>
<tr><td>6</td><td>Greater Fresno</td></tr>
<tr><td>7</td><td>Kern</td></tr>
<tr><td>8</td><td>Los Angeles Basin</td><td rowspan="2">SCE</td></tr>
<tr><td>9</td><td>Big Creek/Ventura</td></tr>
<tr><td>10</td><td>Greater San Diego/Imperial Valley</td><td>SDG&E</td></tr>
<tr><td>11</td><td>Valley Electric</td><td>VEA</td></tr>
<tr><td>12</td><td>Metropolitan Water District</td><td>MWD</td></tr>
</table>

Figure 6.1-1: Approximate geographical locations of LCR areas

P27-129 cont.

P27-129 cont.

Each load pocket is unique and varies in its capacity requirements because of different system configuration. For example, the Humboldt area is a small pocket with total capacity requirements of approximately 160 MW. In contrast, the requirements of the Los Angeles Basin are approximately 8,000 MW. The short- and long-term LCR needs from this year's studies are shown in Table 6.1-2.

Table 6.1-2: Local capacity areas and requirements for 2019, 2023 and 2028

LCR Area	LCR Capacity Need (MW)		
	2019	2023	2028
Humboldt	165	169	170
North Coast/North Bay	689	553	883
Sierra	2,247	1,924	1,510
Stockton	777	439	507
Greater Bay Area	4,461	4,752	5,600
Greater Fresno	1,671	1,688	1,728
Kern	478	182	140
Los Angeles Basin	8,116	6,793	6,590
Big Creek/Ventura	2,614	2,792	2,251
Greater San Diego/Imperial Valley	4,026	4,132	3,908
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	25,244	23,424	23,287

Notes:
For more information about the LCR criteria, methodology and assumptions please refer to the ISO LCR manual.[142]
For more information about the 2019 LCT study results, please refer to the report posted on the ISO website.
For more information about the 2023 LCT study results, please refer to the report posted on the ISO website.
For more information about the 2028 LCT study results, please refer to the Appendix G of the 2018-2019 Transmission Plan.

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[142] "Final Manual 2019 Local Capacity Area Technical Study," December 2017, http://www.caiso.com/Documents/2019LocalCapacityRequirementsFinalStudyManual.pdf.

6.1.2 Resource adequacy import capability

The ISO has established the maximum resource adequacy (RA) import capability to be used in year 2019 in accordance with ISO tariff section 40.4.6.2.1. These data can be found on the ISO website[143]. The entire import allocation process[144] is posted on the ISO website.

The ISO also confirms that all import branch groups or sum of branch groups have enough maximum import capability (MIC) to achieve deliverability for all external renewable resources in the base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2028.

The future outlook for all remaining branch groups can be accessed at the following link:

http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2019-2028.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2021 to accommodate renewable resources development in this area that ISO has established in accordance with Reliability Requirements BPM section 5.1.3.5. The import capability from IID to the ISO is the combined amount from the IID-SCE_BG and the IID-SDGE_BG.

The 10-year increase in MIC from current levels out of the IID area is dependent on transmission upgrades in both the ISO and IID areas as well as new resource development within the IID and ISO systems, and, for the ISO system, on the West of Devers upgrades in particular. The increase to the target level is expected to take place when the West of Devers upgrades are completed and depends on all necessary upgrades being completed in both the ISO and IID areas. The ISO also notes that upgrades proposed to the IID-owned 230 kV S Line will increase deliverability out of the Imperial area overall and including from IID. The allocation of that deliverability in the future will be available to support deliverability of generation connecting either to the ISO controlled grid or the IID system based on the application of the ISO's tariff and business practices.

P27-129 cont.

6.2 Long-Term Congestion Revenue Rights Simultaneous Feasibility Test Studies

The Long-term Congestion Revenue Rights (LT CRR) Simultaneous Feasibility Test studies evaluate the feasibility of the fixed LT CRRs previously released through the CRR annual allocation process under seasonal, on-peak and off-peak conditions, consistent with section 4.2.2 of the Business Practice Manual for Transmission Planning Process and tariff sections 24.1 and 24.4.6.4

[143] "California ISO Maximum RA Import Capability for year 2019," available on the ISO's website at http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2019.pdf.

[144] See general the Reliability Requirements page on the ISO website http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

6.2.1 Objective

The primary objective of the LT CRR feasibility study is to ensure that fixed LT CRRs released as part of the annual allocation process remain feasible over their entire 10-year term, even as new and approved transmission infrastructure is added to the ISO-controlled grid.

6.2.2 Data Preparation and Assumptions

The 2017 LT CRR study leveraged the base case network topology used for the annual 2017 CRR allocation and auction process. Regional transmission engineers responsible for long-term grid planning incorporated all the new and ISO approved transmission projects into the base case and a full alternating current (AC) power flow analysis to validate acceptable system performance. These projects and system additions were then added to the base case network model for CRR applications. The modified base case was then used to perform the market run, CRR simultaneous feasibility test (SFT), to ascertain feasibility of the fixed CRRs. A list of the approved projects can be found in the 2018-2019 Transmission Plan.

In the SFT-based market run, all CRR sources and sinks from the released CRR nominations were applied to the full network model (FNM). All applicable constraints that were applied during the running of the original LT CRR market were considered to determine flows as well as to identify the existence of any constraint violations. In the long-term CRR market run setup, the network was limited to 60 percent of available transmission capacity. The fixed CRR representing the transmission ownership rights and merchant transmission were also set to 60 percent. All earlier LT CRR market awards were set to 100 percent, since they were awarded with the system capacity already reduced to 60 percent. For the study year, the market run was set up for two seasons (with season 1 being January through March and season 3 July through September) and two time-of-use periods (reflecting on-peak and off-peak system conditions). The study setup and market run are conducted in the CRR study system. This system provides a reliable and convenient user interface for data setup and results display. It also provides the capability to archive results as save cases for further review and record-keeping.

P27-129 cont.

The ISO regional transmission engineering group and CRR team must closely collaborate to ensure that all data used were validated and formatted correctly. The following criteria were used to verify that the long-term planning study results maintain the feasibility of the fixed LT CRRs:

- SFT is completed successfully;
- the worst case base loading in each market run does not exceed 60 percent of enforced branch rating;
- there are overall improvements on the flow of the monitored transmission elements.

6.2.3 Study Process, Data and Results Maintenance

A brief outline of the current process is as follows:

- The base case network model data for long-term grid planning is prepared by the regional transmission engineering (RTE) group. The data preparation may involve using one or more of these applications: PTI PSS/E, GE PSLF and MS Excel;

- RTE models new and approved projects and perform the AC power flow analysis to ensure power flow convergence;
- RTE reviews all new and approved projects for the transmission planning cycle;
- applicable projects are modeled into the base case network model for the CRR allocation and auction in collaboration with the CRR team, consistent with the BPM for Transmission Planning Process section 4.2.2;
- CRR team sets up and performs market runs in the CRR study system environment in consultation with the RTE group;
- CRR team reviews the results using user interfaces and displays, in close collaboration with the RTE group; and
- The input data and results are archived to a secured location as saved cases.

6.2.4 Conclusions

The SFT studies involved four market runs that reflected two three-month seasonal periods (January through March and July through September) and two time-of-use (on-peak and off-peak) conditions.

The results indicated that all existing fixed LT CRRs remained feasible over their entire 10-year term as planned. In compliance with section 24.4.6.4 of the ISO tariff, ISO followed the LTCRR SFT study steps outlined in section 4.2.2 of the BPM for the Transmission Planning Process to determine whether there are any existing released LT CRRs that could be at risk and for which mitigation measures should be developed. Based on the results of this analysis, the ISO determined in July 2018 that there are no existing released LT CRRs at-risk" that require further analysis. Thus, the transmission projects and elements approved in the 2018-2019 Transmission Plan did not adversely impact feasibility of the existing released LT CRRs. Hence, the ISO did not evaluate the need for additional mitigation solutions.

P27-129 cont.

6.3 Frequency Response Assessment and Data Requirements

As penetration of renewable resources increases, conventional generators are being displaced with renewable resources. Given the materially different operating characteristics of renewable generation, this necessitates broader consideration of a range of issues in managing system dispatch and maintaining reliable service across the range of operating conditions. Many of these concerns relate directly or indirectly to the "duck curve", highlighting the need for flexible ramping generation but also for adequate frequency response to maintain the capability to respond to unplanned contingencies as the percentage of renewable generation online at any time climbs and the percentage of conventional generation drops.

Over past planning cycles, the ISO conducted a number of studies to assess the adequacy of forecast frequency response capabilities, and those studies also raised broader concerns with the accuracy of the generation models used in our analysis. Inadequate modeling not only impacts frequency response analysis, but can also impact dynamic and voltage stability analysis as well.

The ISO has therefore been conducting studies and model collection and validation efforts over the past several years to identify priority areas for improving generation modeling in power flow and stability analysis. This effort is critical both due to identified areas of concern with the models and data presently available, as well as the increasing requirements in NERC mandatory standards.

The work conducted in the time frame of the 2017-2018 planning cycle have focused primarily on data collection and model validation. During 2018, the ISO has undertaken an effort to collect accurate modeling data from the generation owners. In response to the ISO requests, numerous data was received and many generation models were updated. These updates were reported to WECC and were included in the WECC Dynamic Master File. In the 2018-2019 planing cycle, the frequency response study was performed with the use of the updated generation models for the units for which the updated models were received. P27-129 cont.

In addition, the ISO Business Practice Manual (BPM) has been updated to include requirements to generation modeling data submittals. The ISO Tariff Section 24.8.2 requires "Participating Generators [to] provide the CAISO on an annual or periodic basis in accordance with the schedule, procedures and in the form required by the Business Practice Manual any information and data reasonably required by the CAISO to perform the Transmission Planning Process. . . ." Section 10 of the BPM establishes both: (1) what information and data must be submitted; and (2) the schedule, procedures, and format for submitting that information and data.

The ISO requires generating unit models in the GE-PSLF format and other technical information from participating generators, as identified in the generator data template that was developed by the ISO in 2018. Generator data templates for different categories of participating generators will be posted on the ISO website. The generator resource list identifying all participating generators by data category and submission phase also can be accessed on the ISO website. The BPM includes sanctions to the Generation Owners for not providing the requested data in time.

In the subsections below, the progress achieved and issues to be considered going forward has been summarized, as well as the background setting the context for these efforts and the study results from the 2018-2019 planing cycle.

6.3.1 Frequency Response and Over generation issues

The ISO's most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued on in the 2015-2016 ISO Transmission Plan built on the analysis. In the 2018-2019 transmission planning cycle the study was updated, using the latest dynamic stability models.

Reliability Standard BAL-003-1.1 (Frequency Response and Frequency Bias Setting)

On November 12, 2015 FERC approved Reliability Standard BAL-003-1.1 (Frequency Response and Frequency Bias Setting), as submitted by North American Reliability Corporation (NERC). This standard was an update of the Standard BAL-003-1 that created an obligation for balancing authorities, including the ISO, to demonstrate sufficient frequency response to disturbances that result in decline of the system frequency by measuring actual performance against a predetermined obligation.

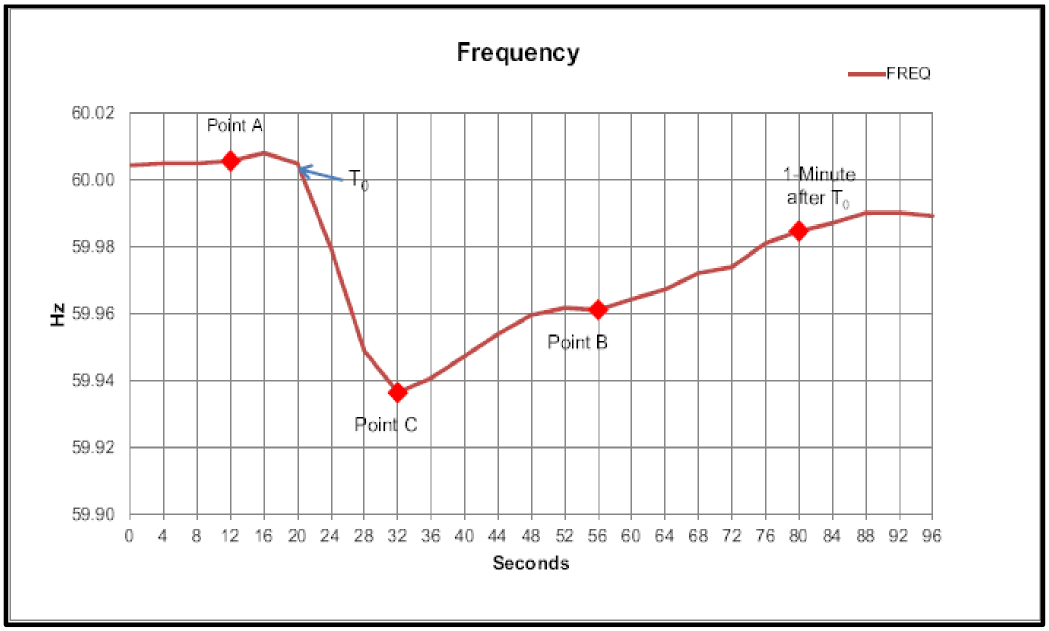
NERC has established a methodology for calculating frequency response obligations (FRO). A balancing authority's FRO is determined by first defining the FRO of the interconnection as a whole, which is referred to as the Interconnection Frequency Response Obligation (IFRO). The methodology then assigns a share of the total IFRO to each balancing authority based on its share of the total generation and load of the interconnection. The IFRO of the WECC Interconnection is determined annually based on the largest potential generation loss, which is the loss of two units of the Palo Verde Nuclear Generation Station (2,740 MW). This is a credible outage that results in the most severe frequency excursion post-contingency.

P27-129 cont.

To assess each balancing authority's frequency performance, NERC selects at least 20 actual disturbances involving drop in frequency each year, and measures frequency response of each balancing authority to each of these disturbances. Frequency response is measured in MW per 0.1 Hz of deviation in frequency. The median of these responses is the balancing authority's Frequency Response Measure (FRM) for the year. It is compared with the balancing authority's FRO to determine if the balancing authority is compliant with the standard. Thus, the BAL-003-1.1 standard requires the ISO to demonstrate that its system provides sufficient frequency response during disturbances that affected the system frequency. To provide the required frequency response, the ISO needs to have sufficient amount of frequency-responsive units online, and these units need to have enough headroom to provide such a response. Even though the operating standard measures the median performance, at this time planners assume that the performance should be targeted at meeting the standard at all times, and that unforeseen circumstances will inevitably lead to a range of outcomes in real time distributed around the simulated performance.

Figure 6.3-1 illustrates a generic system disturbance that results in frequency decline, such as a loss of a large generating facility. Pre-event period (Point A) represents the system frequency prior to the disturbance with T_0 as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 6.3-1: Illustration of Primary Frequency Response



The system frequency performance is acceptable when the frequency nadir post-contingency is above the set point for the first block of the under-frequency load shedding relays, which is set at 59.5 Hz.

Frequency response of the Interconnection (Frequency Response Measure or FRM) is calculated as

Where ΔP is the difference in the generation output before and after the contingency, and Δf is the difference between the system frequency just prior to the contingency and the settling frequency. For each balancing authority within an interconnection to meet the BAL-003-1.1 standard, the actual Frequency Response Measure should exceed the FRO of the balancing authority. FRO is allocated to each balancing authority and is calculated using the formula below.

P27-129 cont.

$$FRO_{BA} = FRO_{Int} \frac{Pgen_{BA} + Pload_{BA}}{Pgen_{Int} + Pload_{Int}}$$

The Interconnection Frequency Response Obligation changes from year to year primarily as the result of the changes in the statistical frequency variability during actual disturbances, and statistical values of the frequency nadir and settling frequency observed in the actual system events. Allocation of the Interconnection FRO to each balancing authority also changes from year to year depending on the balancing authority's portion of the interconnection's annual generation and load. The studies performed by the ISO in 2015 used the WECC FRO for 2016 that was determined as 858 MW/0.1 Hz and being on a conservative side, assumed that the ISO's share is approximately 30 percent of WECC, which is 257.4 MW/0.1 Hz. It remained the same for 2017. For 2019, the Western Interconnection FRO was also calculated as 858 MW/0.1 Hz, according to the NERC 2018 Frequency Response Annual Analysis4. Maximum delta frequency for the Western Interconnection for 2019 was calculated by NERC as 0.248 Hz. For 2018, it was calculated as 0.280 Hz.

The NERC frequency response annual analysis report that specifies Frequency Response Obligations of each interconnection can be found on the NERC website145.

The transition to increased penetration of renewable resources and more conventional generators being displaced with renewable resources does affect the consideration of frequency response issues. Most of the renewable resources coming online are wind and solar photovoltaic (PV) units that are inverter-based and do not have the same inherent capability to provide inertia response or frequency response to frequency changes as conventional rotating generators. Unlike conventional generation, inverter-based renewable resources must be specifically designed to provide inertia response to arrest frequency decline following the loss of a generating resource and to increase their output in response to a decline in frequency. While a frequency response characteristic can be incorporated into many inverter-based generator designs, the upward ramping control characteristic is only helpful if the generator is dispatched at a level that has upward ramping headroom remaining. To provide this inertia-like frequency response, wind and solar resources would have to have the necessary controls incorporated into their designs, and also have to operate below their maximum capability for a certain wind speed or irradiance level, respectively, to provide frequency response following the loss of a large generator. As more wind and solar resources displace conventional synchronous

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145 "2018 Frequency Response Annual Analysis," November 2018, https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2018%20Frequency%20Reponse%20Annual%20Analysis%20Info%20Filing.pdf#search=Frequency%20Response%20annual%20analysis

generation, the mix of the remaining synchronous generators may not be able to adequately meet the ISO's FRO under BAL-003-1.1 for all operating conditions.

The most critical conditions when frequency response may not be sufficient is when a large amount of renewable resources is online with high output and the load is relatively low, therefore many of conventional resources that otherwise would provide frequency response are not committed. Curtailment of renewable resources either to create headroom for their own governor response, or to allow conventional resources to be committed at a minimum output level is a potential solution but undesirable from an emissions and cost perspective.

Generation Headroom

Another metric that was evaluated in the ISO studies was the headroom of the units with responsive governors. The headroom is defined as a difference between the maximum capacity of the unit and the unit's output. For a system to react most effectively to changes in frequency, enough total headroom must be available. Block loaded units and units that don't respond to changes in frequency (for example, inverter-based or asynchronous renewable units) have no headroom.

The ratio of generation capacity that provides governor response to all generation running on the system is used to quantify overall system readiness to provide frequency response. This ratio is introduced as the metric Kt; the lower the Kt, the smaller the fraction of generation that will respond. The exact definition of Kt is not standardized.

For the ISO studies, it was defined as the ratio of power generation capability of units with responsive governors to the MW capability of all generation units. For units that don't respond to frequency changes, power capability is defined as equal to the MW dispatch rather than the nameplate rating because these units will not contribute beyond their initial dispatch. P27-129 cont.

2014-2015 and 2015-2016 Transmission Plan Study Results

The ISO assessed in the 2014-2015 and in 2015-2016 transmission planning processes the potential risk of oversupply conditions – a surplus of renewable generation that needs to be managed - in the 2020-2021 timeframe under the 33 percent renewables portfolio standard (RPS) and evaluated frequency response during light load conditions and high renewable production. Those studies also assessed factors affecting frequency response and evaluated mitigation measures for operating conditions during which the FRO couldn't be met.

The ISO 2014-2015 Transmission Plan[146] in section 3.3 and the ISO 2015-2016 Transmission Plan[147] in section 3.2 discuss reliability issues that can occur during oversupply conditions when inverter-based renewable generation output is high, and also describe frequency performance metrics and study results.

[146] "2014-2015 Transmission Plan," ISO Board Approved March 27, 2015, http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf

[147] "2015-2016 Transmission Plan," ISO Board Approved March 28, 2016, http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf

Studies performed in the previous transmission planning processes showed that the total frequency response from WECC was above the interconnection's frequency response obligation, but the ISO had insufficient frequency response when the amount of dispatched renewable generation was significant. When the study results and, in particular, response of some individual generation units was compared with the real time measurements during frequency disturbances, the results of the simulations did not match the actual measurements showing higher response to frequency deviations. Thus, the study results appeared to be too optimistic, and the actual frequency response deficiency may be higher than the studies showed.

6.3.2 2018-2019 Transmission Plan Frequency Response Study

Study assumptions and methodology

As in the previous ISO frequency response studies, this study concentrated on the primary frequency response, which occurs automatically prior to the AGC or operator actions. The contingency studied was an outage of two Palo Verde nuclear units, which is the most critical credible contingency in regards to frequency deviation. This contingency was studied in dynamic stability simulations for 60 seconds for all PG&E Bulk system cases in the 2018-2019 planning process. The most critical case that showed the lowest frequency appeared to be the 2023 Spring off-Peak sensitivity case with high renewable and low gas generation output. This case had relatively low level of conventional generation, which may present a challenge in meeting the FRO. Therefore, this case was studied in more details.

P27-129 cont.

Dynamic stability data used the latest WECC Master Dynamic File with the updates on the models received by the ISO at the time of the study. Missing dynamic stability models for the new renewable projects were added to the dynamic file by using typical models according to the type and capacity of the projects. The latest models for inverter-based generation recently approved by WECC were utilized. For the new wind projects, the models for type 3 (double-fed induction generator) or type 4 (full converter) were used depending on the type and size of the project. For the solar PV projects, three types of models were used: large PV plant, small PV plant and distributed solar PV generation. Distributed solar PV generation was modeled with the latest dynamic stability model DER_A. All the load in the WECC system was modeled with the composite load dynamic model that had the stalling of the single-phase air-conditiners enabled. The composite load model also included behind-the-meter distributed generation. This generation was modeled with the latest dynamic stability model DER_A, which is more detailed than the models for distributed solar PV generation used previously.

The goal of the study was to determine if the ISO can meet its FRO with the most severe credible contingency under the conditions studied. Other goals were to determine under which conditions the FRO may not be met.

In addition to evaluating the system frequency performance and the WECC and ISO governor response, the study evaluated the impact of unit commitment and the impact of generator output level on governor response. For this evaluation, such metrics as headroom or unloaded synchronized capacity, speed of governor response, and number of generators with responsive governors were estimated.

In addition to the 2023 Spring off-Peak with high renewable and low gas generation output starting case (Case 1), two more cases were studied. The first case (Case 2) was created by turning off the units for which governor response was unreasonable and re-dispatching their generation to the neighboring units. It was assumed that the units with the unreasonable governor response might have errors in their models. The response of the generators with responsive governors was considered to be unreasonable either when it was negative (generation decreases with decrease in frequency), or when it was too high – higher than 9%. With the standard governor droop of 5%, the response to the change in frequency equal to the maximum delta frequency of 0.248 Hz established by NERC will be approximately 8.3%. If the droop is 4%, the response to such change in frequency will be 10.3%. Since the change in frequency in the study was less than the maximum delta frequency and majority of the governors have the droop of 5%, it was assumed that the units with the response of higher than 9% might have errors in their models. The "suspicious" models will be reported to WECC so that they could be checked and the generators re-tested if it appears that the models are indeed erroneous. The second sensitivity case (Case 3) was the case with decreased headroom on the frequency responsive units. It was created from the Case 2. To achieve reduction in headroom, frequency responsive generators at the same station or hydro generators on the same river with the low output were turned off, and their output was re-dispatched to the units on the same station or the same river or to the neighboring non-responsive units.

A summary of the load and generation in the cases studied is shown in Table 6.3-1. As can be seen from the table, in these cases, renewable (solar PV and wind) generation dispatch was 39.4% of the total generation dispatch in the ISO and 17.7% of the total dispatch in WECC.

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Table 6.3-1: Generation and load in the cases studied and metrics of responsive generation

Case		2023 spring off-peak high renewables	Case 2 - high and negative response units off	Case 3 - reduced headroom
Load, including pumps and motors, MW	ISO, incl. MUNI	27,108	27,108	27,108
	Total WECC	92,609	92,609	92,609
Generation total dispatch , incl. DER, MW	ISO, incl. MUNI	29,483	29,531	29,531
	Total WECC	95,313	95,320	95,311
Generation with responsive governors, MW	ISO, incl. MUNI, dispatch	7,210	7,122	6,023
	ISO, incl. MUNI, capacity	9,515	9,108	7,851
	Total WECC, dispacth	30,974	31,009	27,519
	Total WECC, capacity	45,544	44,868	38,422
Renewable, non responsive, including DER, dispatch MW	ISO, incl. MUNI	11,615	11,615	11,615
	Total WECC	16,882	16,822	16,822
Conventional non responsive, MW	ISO, incl. MUNI	10,658	10,794	11,893
	Total WECC	47,457	47,489	50,970
Dispatch of responsive generation, % of capacity	ISO, incl. MUNI	75.8%	78.2%	76.7%
	Total WECC	68.0%	69.1%	71.6%
Kt – ratio of responsive generation to total, %	ISO, incl. MUNI	29.9%	28.9%	25.0%
	Total WECC	41.4%	41.1%	36.2%

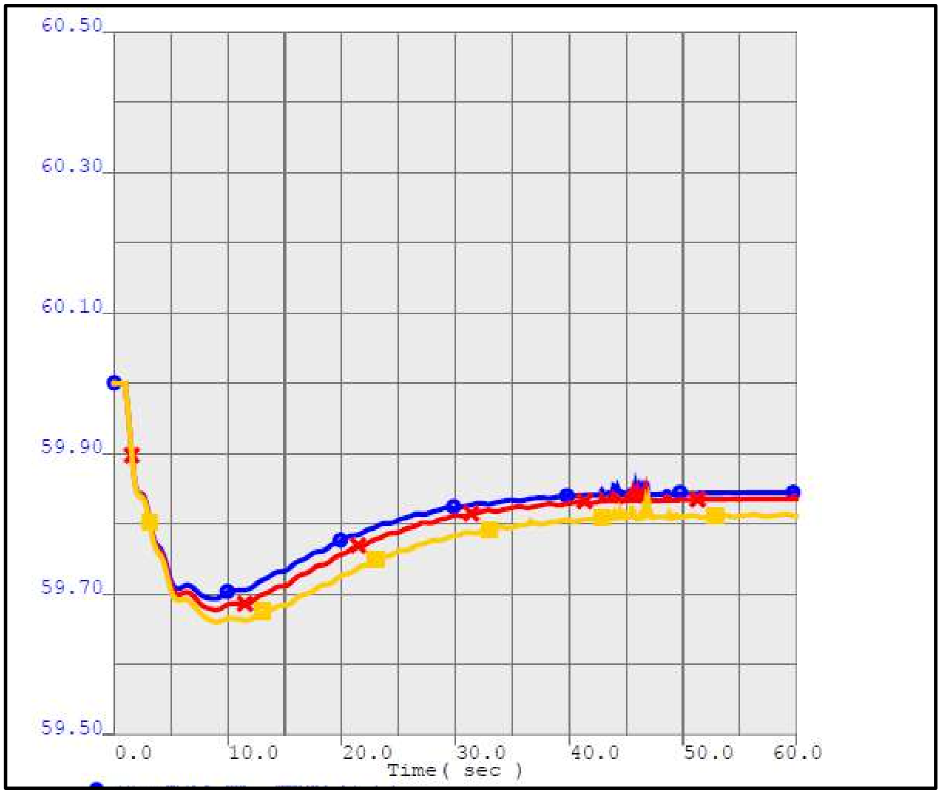
Study results

The dynamic simulation results for an outage of two Palo Verde generation units for the 2023 Spring Off-Peak case with high renewable generation output shows the frequency nadir of 59.675 Hz at 7.7 seconds (6.7 seconds after the disturbance) and the settling frequency after 60 seconds at 59.844 Hz. For Case 2, the frequency nadir is 59.670 Hz at 8.3 seconds (7.3 seconds after the disturbance) and the settling frequency after 60 seconds is at 59.835 Hz. For Case 3, the frequency nadir is 59.650 Hz at 9.seconds (8 seconds after the disturbance) and the settling frequency after 60 seconds is at 59.812 Hz.

The frequency plot for the Midway 500 kV bus for the three cases studied is shown in Figure 6.3-2. As can be seen from the plot, the lower is the headroom on the frequency responsive units, the lower is the nadir and the settling frequency, and the frequency nadir occurs at the later time. The curves slope after the disturbance, which depends on the system inertia appeared to be the same for all three cases.

P27-129 cont.

Figure 6.3-2: Frequency Plot for the Midway 500kV Bus



As can be seen fromFigure 6.3-2, the frequency nadir was above the first block of under-frequency relay settings of 59.5 Hz for all three cases. For this contingency, voltages on all the buses were within the required limits in all the cases studied.

The study evaluated the governor response of the units that had responsive governors. For the starting case, the highest response in MW was from large hydro units in Washington State, with the highest from Grand Coulee unit #22 at 64 MW and Grand Coulee unit #23 at 55 MW. These are large units (825 MW each) that were loaded only to approximately one-quarter and of their capacity in the base case. Other generation units that showed high governor response are the Intermountain coal-fired power plant in Utah operated by LADWP; and unit #4 of the San Juan coal plant in New Mexico, as well as hydro power plants in Alberta. If measured in percentage from the generator's capacity, an average response was 5.2 percent, but it varied from less than 1 percent for the units that were loaded up to their capacity to around 20 percent for the units that possibly had modeling errors.

For the starting case, total frequency response from WECC was 2,476 MW, or 1,587 MW/0.1Hz, which is well above the WECC Frequency Response Obligation. For the ISO - the response was 450 MW, or 288 MW/0.1 Hz, which is also above the ISO FRO of 257.4

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MW/0.1Hz. The calculated headroom in WECC was 14,580 MW with 656 frequency-responsive units, and in the ISO the headroom was 2,310 MW with 147 responsive units.

Such a significant difference in the relative ISO and WECC frequency response is explained by large amount of renewable, primarily inverter-based, generation in the ISO, and relatively small amount of the renewable generation in WECC modeled in the case.

For Case 2, total frequency response from WECC was 2,446 MW, or 1,482 MW/0.1Hz, which is also well above the WECC Frequency Response Obligation. For the ISO - the response was 442 MW, or 268 MW/0.1 Hz, which is above the ISO FRO of 257.4 MW/0.1Hz. The calculated headroom in WECC was 13,870 MW with 629 frequency-responsive units, and in the ISO the headroom was 1,990 MW with 142 responsive units.

For Case 3, total frequency response from WECC was 2,412 MW, or 1,283 MW/0.1Hz, which is also well above the WECC Frequency Response Obligation. For the ISO - the response was 463 MW, or 246 MW/0.1 Hz, which is below the ISO FRO of 257.4 MW/0.1Hz. The calculated headroom in WECC was 12,390 MW with 613 frequency-responsive units, and in the ISO the headroom was 1,910 MW with 139 responsive units.

The study results are summarized in Table 6.3-2.

Table 6.3-2: Frequency Study Results for an Outage of two Palo Verde Units

Case		2023 spring off-peak high renewables	Case 2 - high and negative response units off	Case 3 - reduced headroom
Headroom, MW	ISO, incl. MUNI	2,310	1,990	1,910
	Total WECC	14,580	13,870	12,390
Responsive units	ISO, incl. MUNI	147	142	139
	Total WECC	656	629	613
Response, MW	ISO, incl. MUNI	450	442	463
	Total WECC	2,476	2,446	2,412
Response, MW/0.1Hz	ISO, incl. MUNI	288	268	246
	Total WECC	1,587	1,482	1,283
Nadir, Hz		59.675	59.670	59.650
Settling frequecy, Hz		59.844	59.835	59.812
Kt – ratio of responsive generation to total, %	ISO, incl. MUNI	29.9%	28.9%	25.0%
	Total WECC	41.4%	41.1%	36.2%

Thus, the values of approximately 2,000 MW of the headroom and approximately 29 percent of the responsive generation capacity may be considered to be the minimum values to provide the sufficient frequency response from the ISO to meet the BAL-003 standard. However, it should be noted that these values were determined only for this particular case. In the case when the starting generation dispatch on the responsive units is lower, the minimum required headroom will appear to be higher.

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Results of the frequency studies from the 2015-2016 transmission plan showed that the required headroom at the ISO should be around 2500 MW for the ISO to meet its FRO, and the responsive generation capacity should be around 30%. Results of the frequency studies from the 2014-2015 transmission plan showed that the required headroom at the ISO should be around 4400 MW for the ISO to meet its FRO, and the responsive generation capacity should be also around 30%. The large number for the required headroom in the 2014-2015 studies was explained by the low generation dispatch on the responsive units in this case. Thus, the studies of the current transmission plan also show that the percentage of the frequency responsive capacity is a more universal measure for the expected frequency response than the headroom.

2018-2019 Study Conclusions

- The initial study results indicated acceptable frequency performance both within WECC and the ISO for the base case studied (Spring Off-Peak of 2023 with high renewable generation dispatch). Both WECC and the ISO frequency response was above the obligation specified in BAL-003-1.1.
- However, with lower commitment of the frequency-responsive units, frequency response from the ISO may fall below the Frequency Response Obligation specified by NERC. The study showed that when the headroom on the responsive units was decreased, frequency response of the ISO was insufficient.
- In the future when more inverter-based renewable generation will come online, frequency response from the ISO will most likely become insufficient.
- Compared to the ISO's actual system performance during disturbances, the study results seem optimistic because actual frequency responses for some contingencies were lower than the dynamic model indicated. Therefore, a thorough validation of the models needs to be performed to ensure that governor response in the simulations matches their response in the real life. The isuse that was observed in real system operation was withdrawal of the governor response that was not observed in the simulations.

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6.3.3 New NERC Standards MOD-032 and MOD-033 Modeling Requirements

NERC standards MOD- 032 and MOD -033 also set direction for improved generator modeling.

According to the NERC Standard MOD-032, each Balancing Authority, Planning Authority and Planning Coordinator should establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system. The NERC MOD-032 standard is related to the NERC Standard MOD-033. The MOD-032 standard requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 requires each Planning Coordinator to implement a documented process to perform model validation within its planning area. The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by FERC recommendations and directives.

Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner and Planning Coordinator according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner. If the Planning Coordinator or Transmission Planner has technical concerns regarding the data, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall either provide the updated data or explain the technical basis for maintaining the current data. Each Planning Coordinator shall make available models for its planning area reflecting the provided data to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide cases that include the Planning Coordinator's planning area. For the ISO, Transmission Planners and generation owners are responsible for providing the data, and the ISO is responsible for the model validation.

The purpose of the NERC Standard MOD-033-1 is to establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

The focus of validation in this standard is not Interconnection-wide phenomena, but events on the Planning Coordinator's portion of the existing system, although system-wide disturbances can also be used for model validation. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

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The MOD-033-1 standard requirements include comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other real-time data sources. Such model validation has to be done at least once in the 24 months. The standard includes guidelines needed to be used to determine unacceptable difference in the model's performance. The standard states that each Reliability Coordinator and Transmission Operator shall provide actual system behavior data to any Planning Coordinator performing validation such as, state estimator case or other real-time data necessary for actual system response validation.

The reliability standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. In accordance with the MOD-033 standard, the ISO developed a Power System Model Validation Process in 2017 that includes guidelines on how to perform model validation. It also includes a methodology of comparison of the ISO performance in planning power system model and dynamic stability response simulations to actual system behavior. These guidelines explain how to determine unacceptable differences in the evaluated performances for the planning power flow and dynamic model and how to resolve them. The Model Validation Process is followed by Reliability Coordinators, Transmission Operators and Transmission and Generation Owners.

6.3.4 Model Validation with Online Dynamic Security Assessment

The ISO is involved in a continuous model validation effort using real-time snapshots from ISO's online DSA (Dynamic Security Assessment). Voltage, frequencies and flows are compared with those observed in PMU and SCADA data. Model validation efforts have led to correction of baseload flags in the input dynamic data for DSA and modification of initialization rules to accommodate wind and solar models that are at very low or zero output in the state estimation solutions. Model validation is a continuous effort that is being conducted in collaboration with Peak Reliability.

The ISO also performed dynamic stability analysis of the disturbance that occurred on March 3, 2016 that caused the WECC–wide frequency to drop to about 59.84Hz.

The simulation results generally matched the measurements. The simulated frequency nadir was higher than the measured, which indicates that the simulated frequency response of the generators is too optimistic. Due to lack of measurements at generating plants, it could not be determined which generator models cause the discrepancy between the simulation and actual performance. The results demonstrated the need to perform field testing to verify generator dynamic models, and installing PMUs at the generating plant would greatly improve the model validation.

These studies are described in the 2017-2018 Transmission Plan. Validation of the dynamic stability models based on the recordings of the actual system disturbances in an on-going work performed by the ISO Grid Planning together with the Operation Engineering.

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6.3.4.1 2018-2019 Progress

The ISO has continued to work with Transmission Owners to collect the needed information from generators, and this effort has raised a number of challenges. The various standards requirements obligating the provision of validated data are complex:

NERC requires all generators connected to the Bulk Electric System and greater than 20 MVA (single unit) or 75 MVA (generating plant) comply with NERC data standards, and provide updated data at least every 10 years. However the NERC dynamic data validation standards only apply to generating units that are greater than 75 MVA, which appears to capture about 80% of grid-connected generation in the ISO footprint.

The WECC generating unit validation policy applies to generators greater than 10 MVA, which would address a further 17%.

The ISO also has certain tariff rights to generator information. Under the ISO Tariff Section 24.8.2, ISO can request generator modeling data on an annual or periodic basis, as identified in the ISO BPM for Transmission Planning Process. The ISO has added a new Section 10 to the BPM describing the process which is set to receive, validate and update generator modeling data used in the ISO transmission planning and reliability studies. This process addresses requirements for all ISO participating generators. The new section of the BPM includes participating generators classification according to which the data is requested and provided.

Participating generator modeling requirements identify five different categories of operational generating units. Each operational generating unit is identified and categorized by their ISO market Resource ID. Aggregate resources are identified and categorized by the parent market Resource ID. These categories are:

a. Category 1 - Participating generators connected to the Bulk Electric System (BES):
   1. Individual generating unit with nameplate capacity greater than 20 MVA, or
   2. Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity greater than 75 MVA.

b. Category 2 – Participating generators connected to facilities 60 kV and above, and not covered in category 1:
   1. Individual generating unit with nameplate capacity greater than 10 MVA, or
   2. Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity greater than 20 MVA.

c. Category 3 - Participating generators connected to BES or facilities above 60KV with generation output lower than the category 1 or 2 modeling requirement thresholds.
   1. Individual generating unit with nameplate capacity less than 10 MVA, or
   2. Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity less than 20 MVA.

d. Category 4 - Non-Net Energy Metered (non-NEM) participating generator connected to non-BES facilities below 60KV, but explicitly modelled as an individual generating unit in transmission planning power flow and stability studies.

e. Category 5 - Non-Net Energy Metered (non-NEM) participating generator connected to non-BES facilities below 60KV, modelled as an aggregate resource in transmission planning power flow and stability studies.

The ISO and PTOs are actively pursuing validated modeling data from all generators. The ISO has developed a data template that is being sent to the generation owners. The data templates have to be completed by generator owners for successful submission of data. They may also require submission of supporting documents. The data are submitted to the ISO based on the instructions in the BPM. The data requirements to each category of the generators are also described in the BPM.

The ISO will send a data request letter to the participating generator identifying the specific data requirements for the generating unit. The data request letter will contain instructions for the participating generator to identify the applicable category and phase of their resource, associated data requirements, compliance deadline, and process to submit data to the ISO and applicable PTO.

The process of the data collection is on-going and is being implemented in several stages. It will start in May 2019 with the data requests for the Category 1 generation units with the completion of the process for all the units planned for September of 2022.

Generating units that achieve commercial operation after September 1, 2018, must submit the required generator modeling data within one hundred and twenty calendar days of achieving

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commercial operation in the ISO market. The required data will be identified in the generator data template provided to the participating generator upon achieving commercial operation.

Under the ISO Tariff section 37.6.2, the ISO can apply penalty of $500/day for failure to submit requested data. The criteria for applying sanctions are listed in BPM. The penalty is to be applied to Scheduling Coordinator associated with resource ID of generating unit.

6.3.5 Next Steps

Efforts will continue to collect modeling data. After all the responses from the generation owners are received, the dynamic database will be updated. The ISO and the PTOs will perform dynamic stability simulations to ensure that the updated models demonstrate adequate dynamic stability performance. After the models are validated, they will be sent to WECC so that the WECC Dynamic Masterfile can be updated, and the updated models will be used in the future.

Future work will include validation of models based on real-time contingencies and studies with modeling of behind the meter generation. Further work will also investigate measures to improve the ISO frequency response post contingency. Other contingencies may also need to be studied, as well as other cases that may be critical for frequency response.

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cont.

Chapter 7

7 Special Reliability Studies and Results

In addition to the mandated analysis framework set out in the ISO's tariff described above, the ISO has also pursued in past transmission planning studies a number of additional "special studies" in parallel with the tariff-specified study processes, to help prepare for future planning cycles that reach further into the issues emerging through the transformation of the California electricity grid. These studies are provided on an informational basis only and are not the basis for identifying needs or mitigations for ISO Board of Governor approval.

7.1 Pacific Northwest – California Transfer Increase Study

On February 15, 2018, the ISO received a request from Robert B. Weisenmiller, Chair of the CEC and Michael Picker, President of the CPUC[148], that the ISO undertake specific transmission sensitivity studies within the 2018-2019 transmission planning process considering the potential to increase the transfer of low-carbon supplies to and from the Northwest. Expanded transmission capability, and increasing the transfer of low-carbon supplies to and from the Northwest in particular, was seen to be one of the multiple puzzle pieces that the agencies must examine to build a cumulative phase out strategy of Aliso Canyon usage and address potential impacts on the gas-fired generation fleet. The letter provided the following synopsis for the sensitivity study: P27-129 cont.

- Increase the Capacity of AC and DC Interties
- Increase Dynamic Transfer Capability (DTC)
- Implementing sub-hourly scheduling on PDCI
- Assigning Resource Adequacy (RA) Value to firm zero-carbon imports

The ISO worked collaboratively with CEC, CPUC, BPA, LADWP as well as other owners and operators of AC and DC interties to ensure alignment on all aspects of this informational special study. Details of the studies and analysis of the results are provided in Appendix H. A high level summary for each of the studies is provided in the following sections:

7.1.1 Increase the Capacity of AC and DC Interties

LADWP is performing an engineering and planning study to identify the system upgrades required to increase the PDCI transfer capability from 3,220 MW to 3,800 MW. The study includes a system impact assessment as well as identifying the required upgrades to the HVDC transmission line and the convertor station at Sylmar. Details of the study scope are provided in Appendix H and the study is expected to be completed by the end of Q3, 2019.

Given the timeline of LADWP studies, it was decided to use the existing ratings of the PDCI in this informational study.

[148] http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf

7.1.1.1 Near-term Assessment (Year 2023)

The focus of the near-term analysis was to assess the potential to maximize the utilization of the existing transmission system. Energy Transfer and Resource Shaping were the two scenarios studied with high intertie flows. The study showed that the N-S COI limit could be increased from 4,800 MW to 5,100 MW if the outage of two adjacent 500 kV lines is treated as conditionally credible. Otherwise, to increase the COI limit beyond 4,800 MW, some load in California must be shed to address reliability issues after the N-2 outage. A WECC path rating process is required to increase the rating of COI. In the existing WECC path rating process, the outage of two adjacent circuits is considered to be always credible. The WECC path rating process is under review and the updated process may include conditionally credible contingencies. The upgrading of the COI north to south path rating may take some time to accomplish through the WECC Path rating process but the studies indicated that limited capital updgrades would be required to reduce the congestion and and increase transfer capability from north to south on COI. The economic benefits of increasing the COI north to south transfer capabitliy were examined in section 4.9.1.1 of chapter 4.

PDCI flow is operationally limited to 1000 MW in the S-N direction by LADWP. The results of this study showed that there is potential to increase the S-N limit to 1,500 MW under favorable conditions.

7.1.1.2 Long-term Assessment (Year 2028)

The objective of the long-term assessment was perform production simulation to explore the benefits of higher intertie capacities in the long term. WECC Anchor Data Set (ADS) production cost model (PCM) was used as a starting point and was updated using the PNW hydro information provided by Northwest Power and Conservation Council (NWPCC). Production simulation was done for three PNW water scenarios; low, medium and high water condition with 100 TWh, 148 TWh, and 172 TWh of electricity generated in the year, respectively. Study results showed that the number of hours with COI congestion are 49, 349, and 1597 hours for how, medium and high scenarios. Medium hydro year was simulated with 5,100 MW COI limit and the congested hours decreased from 349 hours to 265 hours.

In the S-N direction, no congestion was observed on COI in any of the hydro conditions. However Path 26 was congested for more than 1,100 hours. PDCI modelled at its WECC path rating didn't show any congestion but a simulation with a 1,000 MW S-N PDCI limit indicated 67 hours of congestion under medium hydro conditions.

7.1.2 Increase Dynamic Transfer Capability (DTC)

Dynamic transfer capability refers to the capability of the PNW system to accommodate variations on 5-minute scheduling on PNW AC Interties (NWACI). Currently the DTC on NWACI is limited to 600 MW mainly to prevent excessive voltage fluctuations and reactive switching. The current manual RAS arming process could become another limitation on DTC at higher levels. The followings are potential solutions to address excessive voltage fluctuations to increase DTC:

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- Employ Real-time Allocation of DTC
- Apply DTC Limit to Actuals (instead of schedules)
- Use DTC Nomogram Instead of a Fixed Limit.
- Real-Time Voltage Assessment Tools
- Coordinated Voltage Controls (CVC)
- Control State Awareness and Analytics

Upon completion of the above assessment and implementation of the mitigation measures, there would be no limit on DTC and 5-minute scheduling will be similar to 15-minute scheduling. The details of the issues and BPA's plans to address them are provided in "BPA DTC Roadmap" in Attachment 1 of Appendix H.

7.1.3 Implementing sub-hourly scheduling on PDCI

PDCI scheduling is currently limited to hourly scheduling. Having 5-minute or even 15-minute scheduling capability on PDCI would facilitate further utilization of PNW hydro to supply California load especially during morning and evening ramps. To facilitate sub-hourly scheduling on PDCI, it is required to automate PDCI RAS as well as the AGC and EMS systems. A detailed system impact assessment on both BPA and LADWP systems is planned to be performed through a joint study. The outcome of that study will determine the next steps.

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7.1.4 Assigning Resource Adequacy (RA) Value to firm zero-carbon imports

Comparing the historical available capacity on COI and PDCI for RA contracts, with the actual RA showings indicates that except for summer months, the RA showings are less than available capacity. Historical data also show that while RA showings are lower than the capacity, the actual real time flows on COI and PDCI for some months are significantly higher than the RA showings and are closer to the available capacity. This may imply that the surplus energy in PNW will flow to California even without an RA contract. The future generation development scenarios in the Pacific Northwest system will potentially create uncertainty about the amount of available capacity and energy, increasing or decreasing, which can be exported to California in the longer term. This is due to the potential early retirement of coal units, load growth or a shift to more renewable integration in the Pacific Northwest. To ensure availability of Pacific Northwest resources to supply load in California in the long term, some market or policy initiatives and regulations may be required. Details of such market structures or policies were beyond the scope of this study. Market and policy initiatives such as the ISO's resource adequacy enhancement stakeholder initiative or the CPUC's integrated resource plan and resource adequacy proceedings may address some of the uncertainties of the Pacific Northwest resources to supply load in California in the long term.

7.1.5 Conclusions and Next Steps

To ensure availability of Pacific Northwest resources to supply load in California in the long term, some market or policy initiatives and regulations may be required. Details of such market structures, policies or regulations were beyond the scope of this study. The ISO has initiated a resource adequacy enhancements stakeholder initiative[149] that will include an assessment of the rules for import resource adequacy and a review of the maximum import capability. In addition the CPUC has ongoing resource adequacy[150] and integrated resource plan[151] proceedings. Stakeholders are encouraged to participate in these initiatives and proceedings.

The ISO will continue to monitor and participate in the WECC path rating process review. If the WECC path rating process is updated to recognize the concept of using the conditionally credible contingency of the adjacent 500 kV lines in the same right-of-way on separate towers, the ISO will work with the owners of the COI facilities to initiate a WECC path rating process to increase the rating of COI to 5,100 MW. The ISO will also continue to monitor the progress of LADWP on the identified further study work of PDCI and BPA on the dynamic transfer capability and implementing sub-hourly scheduling on PDCI.

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[149] http://www.caiso.com/informed/Pages/StakeholderProcesses/ResourceAdequacyEnhancements.aspx

[150] http://www.cpuc.ca.gov/RA/

[151] http://www.cpuc.ca.gov/irp/

7.2 System Capacity Requirements and Large Storage System Benefits

Over the past several transmission planning cycles, the ISO has conducted a number of special studies examining the system-wide needs for gas-fired generation capacity, and the benefits provided by potential large storage projects. These special studies were generally documented as two separate special studies, despite generally relying on common assumptions and modeling – and in particular, depending on analysis conducted using Energy Exemplar's PLEXOS production cost modeling software.

System-wide requirements for gas-fired generation capacity:

- The study examines the need for gas-fired generation capacity, together with the proposed renewable portfolio, to serve system load and meet reserve requirements to maintain the reliability of the ISO system.
- Note that the study of local capacity requirements, characteristics of those requirements, and potential mitigations to reduce the need for reliance on gas-fired generation is explored in the long term local capacity study in chapter 6, and detailed economic analysis of a number of those potential mitigations is explored in chapter 4.

System-wide benefits provided by large storage projects:

- The system-wide models developed for assessing grid capacity needs also provide useful insights in to the benefits provided by large storage on a system basis
- Note that storage projects are also being proposed in the in the tariff-based transmission planning cycle as potential reliability or economic solutions to addressing local needs, and with the potential for providing system-wide benefits as well. Please refer to chapter 4.

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The ISO recognizes that its PLEXOS modeling, which is primarily conducted for supporting the CPUC's integrated resource planning (IRP) process focusing on a system-wide basis, can continue also provide useful background and context to supplement the transmission planning studies and provide a broader perspective to stakeholders by being included in the transmission plan. It also continues to useful platform for sensitivities such as assessing the benefits of large storage from a system perspective.

The PLEXOS modeling results for both system-wide studies have been combined into a single report in the 2018-2019 Transmission Plan, setting out and based on a common set of assumptions developed for the two special studies.

7.2.1 Common Assumptions for the PLEXOS Modeling

As required by SB 350, the California Public Utilities Commission (CPUC) is leading the Integrated Resources Plan (IRP) process for its jurisdictional Load Serving Entities (LSEs). The 2017-2018 IRP cycle looks out to 2030 to develop a long-term resource procurement plan. The plan needs to achieve the state targets of greenhouse gas (GHG) emission reduction and Renewable Portfolio Standard (RPS).

The 2017-2018 IRP first developed a Reference System Plan (RSP) for the ISO service area. The RSP was developed for year 2018, 2022, 2026 and 2030 based on the following key assumptions:

- Demand: the California Energy Commission (CEC) 2017 Integrated Energy Policy Report (IEPR) load forest;
- New resources: new resources, including renewable, battery, demand response, and pumped storage, are selected based on least-cost rule using the RESOLVE capacity expansion model, subject to assumed resource potentials in specific regions;
- Transmission: the existing transmission capability only, therefore new resources are selected using both Full Capacity Deliverability Status (FCDS) capacity and Energy Only capacity; and
- Thermal generation resources: all existing thermal generation resources, except the once through cooling (OTC) thermal generation plants, the Diablo Canyon nuclear plant and the plants for which mothball or retirement plans have been announced, will stay on through 2030.

The CPUC directed the LSEs to develop their individual plans that conform to the RSP. The LSE IRP plans filed back to the CPUC deviate from the RSP significantly. The CPUC then combined the LSE IRP plans and made adjustments according to the existing transmission capabilities and assumed resource potentials in the regions. Based on that, the CPUC developed a Hybrid Conforming Plan (HCP) and proposed to adopt the HCP as the Preferred System Plan (PSP) of the 2017-2018 IRP process.[152] In the HCP, the CPUC not only made changes to the selection of new resources, it also retired all gas-fired thermal generation resources that are 40 year or older.

The ISO special studies documented herein use the assumptions of the CPUC IRP HCP and are for year 2030 only. Table 7.2-1 below summarizes the assumptions of the ISO generation resources in the RSP and the HCP in 2030.

P27-129 cont.

[152] The HCP data are available at http://www.cpuc.ca.gov/General.aspx?id=6442459406

Table 7.2-1: Assumptions of ISO Generation Resources in the RSP and the HCP in 2030

Capacity (MW)	RSP	HCP	Change
Battery	**3,429**	**2,480**	**-949**
1-hour	2,144	217	-1,927
4-hour	1,285	2,263	978
BTM PV	**19,295**	**19,295**	**0**
Renewable	**33,381**	**34,094**	**714**
Biomass	725	888	163
Geothermal	2,683	1,487	-1,197
Small Hydro	763	763	0
Solar	18,767	19,658	891
Wind	10,443	11,299	856
Thermal	**25,770**	**22,543**	**-3,227**
CCGT	15,720	14,642	-1,078
CHP	2,932	1,078	-1,854
GT	7,108	6,813	-295
ST	10	10	0
Gas			
Hydro	**6,890**	**6,890**	**0**
Pumped Storage	**1,831**	**1,831**	**0**
Demand Response	**1,752**	**1,752**	**0**
Import Capability	**10,341**	**10,341**	**0**

Transitioning from the RSP to the HCP, the total loss of capacity is 3,463 MW; 3,227 MW of that total loss is retirement of gas-fired thermal generation resources.

With the increase of solar and behind-the-meter (BTM) PV, the peak of net load[153] (load minus solar, BTM PV and wind generation) and the peak of net sales (load minus BTM PV) is shifting to the early evening hours, specifically hour-ending 19 to 21 (HE 19-21) in the summer. By then, grid connected solar will have near zero generation and wind will have generation output of around 25% of its installed capacity. Taking that into consideration, the capacity loss of generation available at time of net sales moving from the RSP to the HCP is actually about 4,995 MW. Also, the HCP has 5,649 GWh less renewable generation than the RSP, which results in even lower hourly renewable generation.

P27-129 cont.

[153] The ISO uses the term "net sales" to refer to the energy delivered to customers, adjusted for losses. "Gross consumption" is used to refer to the actual energy usage of the customers, before being reduced to net sales through the customer's use of behind-the-meter generation. "Net load" refers to the net sales, minus the output of the grid-connected renewable generation. This is the energy profile that the rest of the generation fleet – gas-fired generation, hydro, nuclear, etc. - must supply.

7.2.2 Development of PLEXOS Models

The ISO developed two PLEXOS models, one deterministic and one stochastic, to support the CPUC IRP process and to use for the special studies in this transmission planning cycle.

The deterministic model simulations produce detail results matching exactly with the 2017 IEPR load forecast and the inputs of renewable, battery, demand response, and pumped storage resources. The detailed deterministic results can be used for in-depth analyses of the causes of renewable curtailment, CO2 emission, capacity shortfall, etc.

The stochastic modeling examines a wide range of system conditions. Its multiple-iteration Monte Carlo simulations produce probabilistic results. It is especially useful to identify the likelihood and magnitudes of capacity shortages.

The two new IRP models were developed on the basis of the models developed in the past CPUC Long Term Procurement Plan (LTPP) proceedings.[154] During that process, the LTPP models were discussed thoroughly with the involved parties, made available to the public, and used by many other parties for various studies.

The new IRP models have similar structures as the LTPP models and share some parameters, such as the topology and some operating characteristics of generators. However, the new IRP models have most of the data updated, including the assumptions of the HCP as summarized in Table 1.2-1, and the data from the WECC ADS PCM dataset for non-ISO regions in the models.

P27-129 cont.

7.2.3 System Requirements for Gas-fired Generation Capacity

As the amount of renewable generation on the ISO system grows – whether grid-connected or behind-the-meter at end customer sites – and the OTC and nuclear plants continue to be phased out, the generation fleet is dealing with profound changes in the dynamics of market performance. These changes drive increased reliance on the gas-fired generation fleet and other resources for dynamic performance to support the operational needs of California's energy infrastructure and, at the same time, reduce the need for overall energy production from those resources.

The IRP HCP reflects the trend of reducing reliance on GHG-emitting gas-fired generation resources. It adopted the assumption that all gas-fired thermal generation resources 40 years or older will be retired before year 2030 together with the trimmed down renewable portfolio of the HCP. That is an aggressive assumption cutting into the supply fleet of the ISO system. This special study specifically focused on the sufficiency of supply in the ISO system in year 2030 with the IRP HCP.

[154] CAISO testimonies about production cost modeling filed into the CPUC 2014 LTPP proceeding http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf and http://www.caiso.com/Documents/Nov20_2014_Liu_StochasticStudyTestimony_LTPP_R13-12-010.pdf

7.2.3.1 Study Approach and Methodology

This study used both the deterministic and stochastic models, each for different purposes.

The deterministic modeling produced the details results showing how each MW of capacity is exactly utilized with hourly granularity when there is a capacity shortfall. The stochastic model Monte Carlo simulations produced the likelihood and magnitudes of capacity shortages in the ISO system. The local capacity adequacy requirements were assumed to be met in this analysis.

The deterministic simulation was run for one iteration and stochastic simulations were run for 500 iterations. Both simulations were run chronologically in hourly intervals for the whole year of 2030.

In the deterministic modeling, shortfalls occur when supply is insufficient to meet the combination of load and requirements of ancillary services and load following. When that happens, there is a priority order to use the available supply to meet load and the different reserve requirements, similar to that in the ISO market scarcity pricing mechanism. The supply will be used to meet load first, followed by regulation-up, frequency response, spinning, non-spinning, and load following-up. Therefore, supply shortfall occurs first in load following-up. If the shortfall is larger than load-following up requirements, it spills over to non-spinning, spinning, frequency response requirements, regulation-up and finally to unserved energy (load shedding).

The stochastic modeling adopted reliability metrics specified in the CPUC's IRP process through an Administrative Law Judge ruling, which defines:[155]

- A loss of load (LOL) event: a day with insufficient capacity to meet the sum of load and requirements for regulation, frequency response, and spinning reserve for at least one hour
- Loss of load expectation (LOLE) criterion: the average of LOL events of all iterations of full-year simulations should be no higher than 0.1 (day/year)

So, for 500-iteration (500 years) Monte Carlo simulations, 50 LOL events or fewer are allowed in order to meet the LOLE criterion.

7.2.3.2 Study Results and Analyses

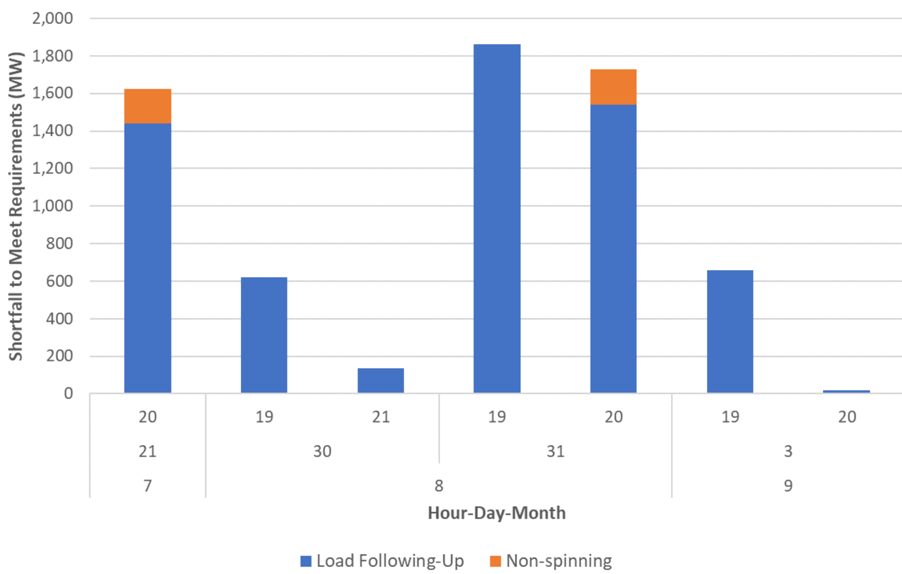
Deterministic Simulation Results

In the deterministic simulation, capacity shortfalls to meet load-following up and non-spinning reserve were found in 7 hours, as shown in Figure 7.2-1. All the hours are in the evening, between hour 19 and 21.

P27-129
cont.

[155] Administrative Law Judge Ruling Directing production Cost Modeling Requirements, September 23, 2016 (http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451199)

Figure 7.2-1: Capacity Shortfall Events in Deterministic Simulation



To understand how the supply capacity was utilized during the hours with capacity shortfalls, the hourly detailed results of August 31, 2030 were examined.

First, the overall load and supply balance was examined shown in Table 7.2-2.

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Table 7.2-2: ISO Load and Supply Balance on August 31, 2030

Hour	Load (MW)	Generation (MW)											Net Import (MW)	Reserve Shortfall	
		Total Generation	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage		Load Following-Up	NonSpin Reserve
1	32,447	22,227	0	6,683	616	0	335	6,894	84	5,252	0	2,363	10,221	0	0
2	30,705	20,510	0	6,096	590	0	335	6,894	0	5,231	0	1,363	10,195	0	0
3	29,396	19,055	0	6,027	590	0	335	6,894	0	5,205	0	4	10,341	0	0
4	28,802	19,006	0	6,055	573	0	335	6,894	0	5,149	0	0	9,796	0	0
5	28,843	18,830	0	6,125	573	0	335	6,894	0	4,903	0	0	10,013	0	0
6	28,891	19,283	71	6,197	580	0	332	6,894	0	4,483	0	726	9,608	0	0
7	31,436	26,035	2,822	5,370	543	0	252	6,161	0	10,886	0	0	5,402	0	0
8	32,316	28,820	6,722	5,471	516	0	252	1,041	0	14,819	0	0	3,496	0	0
9	37,093	35,585	10,446	5,471	523	0	252	2,039	0	16,853	0	0	1,508	0	0
10	41,783	40,473	13,504	5,507	516	0	252	2,125	0	18,571	0	0	1,310	0	0
11	43,973	42,656	15,255	5,585	516	0	252	1,245	0	19,804	0	0	1,317	0	0
12	46,472	45,079	15,763	5,720	523	0	252	2,834	0	19,987	0	0	1,393	0	0
13	48,735	47,412	15,953	6,014	523	0	252	4,037	0	20,632	0	0	1,323	0	0
14	48,994	47,732	14,578	6,310	533	0	252	5,587	0	20,472	0	0	1,262	0	0
15	49,024	47,812	12,815	6,881	554	0	252	6,891	0	20,419	0	0	1,212	0	0
16	48,525	45,948	9,867	9,187	628	0	332	6,889	199	18,846	0	0	2,577	0	0
17	47,619	42,847	6,400	10,878	719	0	1,312	6,889	813	15,835	0	0	4,772	0	0
18	45,953	39,100	2,524	12,667	1,078	0	3,456	6,890	1,831	10,644	10	0	6,853	0	0
19	44,635	35,729	65	13,493	1,078	1,168	3,811	6,890	1,831	5,523	10	1,858	8,907	1,862	0
20	45,811	36,167	0	13,609	1,078	1,168	3,866	6,890	1,831	5,504	10	2,210	9,644	1,538	189
21	43,689	33,348	0	13,393	1,071	0	3,772	6,890	1,831	5,827	10	554	10,341	0	0
22	40,204	30,019	0	12,537	747	0	2,189	6,890	1,831	5,821	4	0	10,185	0	0
23	36,718	27,724	0	11,198	734	0	1,949	6,891	1,340	5,609	4	0	8,995	0	0
24	33,472	24,919	0	10,034	695	0	1,061	6,891	581	5,657	0	0	8,552	0	0

P27-129 cont.

The ISO has significant renewable and BTM PV generation in the mid-day. This generation output went down starting in the afternoon. Thermal and hydro generation, storage and imports ramped up to fill in the gap at the same time.

Table 7.2-3 shows the breakdown of renewable generation. The two tables demonstrate that BTM PV and solar generation dropped quickly from hour 14 on. By hour 19-20, solar had almost no contribution to meeting the load and reserves. Wind was generating at about 25% of installed capacity.

With the increase of solar, and wind and BTM PV in the portfolio, the peak of net load – being served by other resources - shifted to the evening. The shortfalls occurred at hour 19 and 20 on August 31, 2030.

Table 7.2-3: ISO Hourly Renewable Generation on August 31, 2030

Hour	Biogas	Biomass	Geothermal	Small Hydro	Solar PV	Solar Thermal	Wind	Total
16	187	690	1,329	454	13,274	943	1,967	18,846
17	187	690	1,329	440	10,613	566	2,009	15,835
18	187	690	1,329	453	5,976	164	1,844	10,644
19	187	690	1,329	456	4	0	2,857	5,523
20	187	690	1,329	457	0	0	2,841	5,504
21	187	690	1,329	443	0	0	3,177	5,827

P27-129 cont.

As shown Table 7.2-4, the load modifiers reducing grid demand from customer gross consumption to net sales have some effect for hour 19, but not for hour 20. August 31, 2030 is a Saturday. Compared to the weekdays of the same week, the profile for August 31 had about 2,000 MW less Additional Achievable Energy Efficiency (AAEE), more than double the California Department of Water Resource (CDWR) pumping load, and higher Electric Vehicle (EV) charging load. The load after adjustment was actually higher than before for hour 20 and 21. All that made this Saturday a high net load day.

Table 7.2-4: ISO Hourly Load and Load Modifiers on August 31, 2030

Hour	Load Forecast	AAEE	Pump Load	EV	TOU	Load with Modifiers
16	51,565	4,596	1,158	681	-282	48,525
17	50,532	4,532	1,160	759	-299	47,619
18	48,486	4,194	1,159	795	-292	45,953
19	46,750	3,892	1,274	794	-292	44,635
20	45,791	3,714	1,394	2,630	-289	45,811
21	42,970	3,468	1,424	2,636	127	43,689

Because of the shift of the peak net load to the evening, the supply resources available to serve load and meet reserve and load-following requirements are not simply as indicated by the installed capacity in the HCP. Table 7.2-5 shows the utilization of all available supply capacity in the ISO during the evening hours on August 31, 2030.

Table 7.2-5: ISO Hourly Utilization of Available Supply Capacity on August 31, 2030

Hour	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage	Net Import
Generation and Import (MW)											
16	9,867	9,187	628	0	332	6,889	199	18,846	0	0	2,577
17	6,400	10,878	719	0	1,312	6,889	813	15,835	0	0	4,772
18	2,524	12,667	1,078	0	3,456	6,890	1,831	10,644	10	0	6,853
19	65	13,493	1,078	1,168	3,811	6,890	1,831	5,523	10	1,858	8,907
20	0	13,609	1,078	1,168	3,866	6,890	1,831	5,504	10	2,210	9,644
21	0	13,393	1,071	0	3,772	6,890	1,831	5,827	10	554	10,341
Provision of Upward Load-following and Reserves (MW)											
16	0	3,063	0	0	1,462	0	300	0	0	1,642	0
17	0	1,459	0	0	1,882	0	900	0	0	2,481	0
18	0	1,358	0	0	3,058	0	0	0	0	2,481	0
19	0	533	0	0	2,667	0	0	0	0	623	0
20	0	416	0	0	2,624	0	0	0	0	272	0
21	0	633	0	0	2,718	0	0	0	0	1,927	0
Outages (MW)											
16	0	28	0	0	301	0	374	0	0	0	0
17	0	616	0	0	298	0	0	0	0	0	0
18	0	616	0	0	298	0	0	0	0	0	0
19	0	616	0	0	333	0	0	0	0	0	0
20	0	616	0	0	321	0	0	0	0	0	0
21	0	616	0	0	321	0	0	0	0	0	0
Total Usage (MW)											
16	9,867	12,278	628	0	2,095	6,889	873	18,846	0	1,642	2,577
17	6,400	12,954	719	0	3,492	6,889	1,713	15,835	0	2,482	4,772
18	2,524	14,642	1,078	0	6,812	6,890	1,831	10,644	10	2,482	6,853
19	65	14,642	1,078	1,168	6,812	6,890	1,831	5,523	10	2,482	8,907
20	0	14,642	1,078	1,168	6,812	6,890	1,831	5,504	10	2,482	9,644
21	0	14,642	1,071	0	6,812	6,890	1,831	5,827	10	2,482	10,341
Total Available Capacity (MW)											
16	9,867	14,642	1,078	1,168	6,813	6,889	1,831	18,846	10	2,482	10,341
17	6,400	14,642	1,078	1,168	6,813	6,889	1,831	15,835	10	2,482	10,341
18	2,524	14,642	1,078	1,168	6,813	6,890	1,831	10,644	10	2,482	10,341
19	65	14,642	1,078	1,168	6,813	6,890	1,831	5,523	10	2,482	10,341
20	0	14,642	1,078	1,168	6,813	6,890	1,831	5,504	10	2,482	10,341
21	0	14,642	1,078	1,144	6,813	6,890	1,831	5,827	10	2,482	10,341

P27-129 cont.

The table demonstrates that:

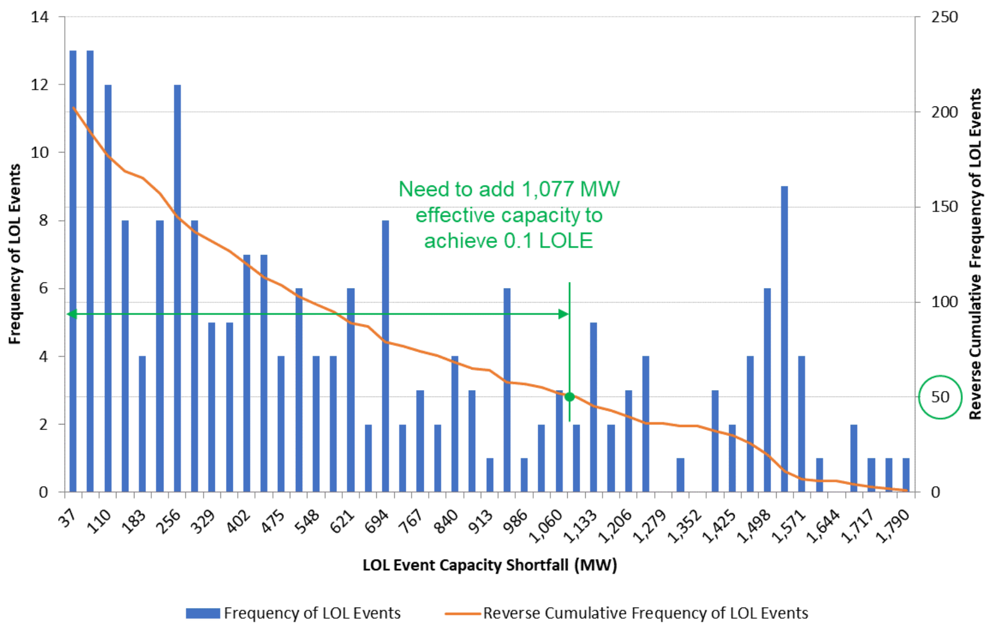
- About 5,000 to 7,000 MW capacity was needed to provide upward reserves and load-following services. Battery storage provided a large share of it as it was the most efficient among all the types of resources to do so;
- CCGT has about 4.2% capacity on outage and GT has 4.8%;
- Available capacity of renewable and BTM PV was dropping quickly;
- Available capacities of all types of resources, except import, were fully utilized in hour 19 and 20;
- Demand response had total capacity of 1,752 MW (see Table 1.2-1). Some of the demand response programs are not available on weekends. The available demand response capacity on August 31, 2030 was only 1,168 MW at hour 19 and 20; and,
- Net import for hour 19 and 20 was below the 10,341 MW maximum import capability, even though there is shortfall in supply.

The stochastic stimulation results provide an indication of the amount of gas-fired generation capacity the ISO needs to maintain the reliability of its system.

Stochastic Simulation Results

With the stochastic model, the Monte Carlo simulation was run for 500 iterations (years). The results were then measured against the reliability metrics as described in Section 1.2.3.1. The results show 202 LOL events in 500 years were identified, which is equivalent to about 0.4 LOLE. The frequency distribution (histogram) of the LOL events is plotted in Figure 7.2-2.

Figure 7.2-2: Histogram of LOL Events in 500 Iterations for Year 2030



To get to 0.1 LOLE, which is a maximum of 50 LOL events for this number of simulations, an additional 1,077 MW effective capacity was needed during the critical periods. Effective capacity is not simply installed capacity. It is the capacity that can be dispatched when it is needed, adjusted by outages to reflect the amount actually available.

The HCP assumed 3,227 MW gas-fired generation resources will be retired by 2030 based on the 40-year retirement rule (see Table 1.2-1). That led to the shortfall of 1,077 MW effective capacity. The ISO stochastic simulation results indicate that less than 2,150 MW gas-fired generation resources that are 40 years or older can be retired in order to meet the 0.1 LOLE reliability criterion.

P27-129 cont.

7.2.3.3 Conclusions

From the study results, it can be concluded that:

- The HCP does not have sufficient capacity to serve load and meet requirements of reserves and load-following serve, without adjusting the retirement assumption;
- Less than 2,150 MW out of 3,277 MW gas-fired generation resources that are 40 years or older can be retired – or would need to be replaced;
- If 1,077 MW effective capacity of other types of new resources, such as renewable, except solar, storage, demand response, and AAEE are added, all 3,277 MW gas-fired generation resources that are 40 years or older could be retired without causing reliability problems; and,

7.2.4 Benefits Analysis of Large Energy Storage

7.2.4.1 Introduction

In this 2018-2019 transmission planning cycle, the ISO has updated the production cost modeling study results of studies conducted in the previous two planning cycles regarding the system benefits of large (hydro) storage. However, the ISO has not updated the comprehensive assessment of the capacity benefits of these resources, as the comprehensive consideration of those benefits is being conducted within the CPUC's IRP process. In 2016-2017 and 2017-2018 transmission planning cycles, the ISO undertook information – only studies of the benefits large scale energy storage projects may provide to ratepayers in the ISO footprint as the state moves from the 33 percent RPS to a 50 percent RPS. The 2017-2018 effort consisted of additional sensitivities based on the cases studied in the 2016-2017 analysis, and did not move to the new models used in the 2017-2018 transmission plan for decision-making purposes P27-129 cont.

At the same time, large storage projects have been proposed to the ISO for consideration as potential reliability or local capacity requirement reduction mitigations, which need to be considered in the context of the formal tariff-based transmission planning process, and are discussed in chapter 4 of this transmission plan.

7.2.4.2 Study Approach

This study was conducted based on the assumptions set out in section 7.2.1.

Two new bulk energy storage resources – a 500 MW and a 1400 MW resource - were added in turn to the production simulation model developed with the CPUC 2017-2018 IRP Hybrid Conforming Plan (HCP) to evaluate its contribution to reduction of renewable curtailment, CO2 emission, and production cost.

In the previous cycles of transmission planning cycles, the bulk energy storage studies calculated the benefits of storage reducing the amount of renewable "overbuild" necessary to achieve the 50% RPS target. In the 2017-2018 IRP proceeding, sufficient renewable resources were selected that exceeded the RPS 50% target of the 2017-2018 IRP cycle even after considering curtailment.[156] In addition, there are also some "banked" renewable energy certificates (RECs) available to be used in 2030 taking the achieved level even higher. Therefore, the benefits of storage reducing the "overbuild" of wind and solar capacity were not calculated, and instead the GHG pricing addresses those benefits.

Assumptions for New Pumped Storage Resources

The pumped storage resources selected for this study were a 500 MW resource and a 1400 MW resource. Table 7.2-5 and Table 7.2-6 show the assumptions for the 500 and 1,400 MW pumped storage resources. The ISO made the assumptions based on a review of publically available information.

Table 7.2-5: Assumptions of the New 500 MW (Gen) Pumped Storage Resource

Item	Assumption
Number of units	2
Max pumping capacity per unit (MW)	300
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	250
Minimum generation capacity per unit (MW)	5
Pumping ramp rate (MW/min)	50
Generation ramp rate (MW/min)	250
Round-trip efficiency	83%
VOM Cost ($/MWh)	3.00
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	8
Upper reservoir minimum capacity (GWh)	2
Interval to restore upper reservoir water level	Monthly
Pump technology	Variable speed
Reserves can provide in generation and pumping modes	Regulation, spinning and load following
Reserves can provide in off-line modes	Non-spinning
Location	SCE zone

[156] See http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2.%20CPUC%20Staff%20Proposed%20Pref%20System%20Portfolio%20for%20IRP%202018_20190107final.pdf

P27-129 cont.

Table 7.2-6: Assumptions of the New 1,400 MW (Gen) Pumped Storage Resource

Item	Assumption
Number of units	4
Max pumping capacity per unit (MW)	422
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	350
Minimum generation capacity per unit (MW)	5
Pumping ramp rate (MW/min)	50
Generation ramp rate (MW/min)	250
Round-trip efficiency	83%
VOM Cost ($/MWh)	3.00
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	18.8
Upper reservoir minimum capacity (GWh)	2
Interval to restore upper reservoir water level	Monthly
Pump technology	Variable speed
Reserves can provide in generation and pumping modes	Regulation, spinning and load following
Reserves can provide in off-line modes	Non-spinning
Location	SCE zone

P27-129 cont.

Based on the assumptions, the pumped storage resource has a maximum usable storage volume that can support generation at maximum capacity for up to 12 hours without additional pumping. The resource can ramp from minimum to maximum generation in 1 minute and from minimum to maximum pumping in 5 minutes. It can provide ancillary services and load-following in both pumping and generation modes.

7.2.4.3 Study Results - System Benefits

Table 7.2-7 summarizes the simulation results of overall system impacts for the two configurations of pumped storage resources that were studied.

Table 7.2-7: Energy Balance and CO2 Emissions

Case	Hybrid Conforming Plan	500 MW Pumped Storage		1,400 MW Pumped Storage	
		Results	Change from Base	Results	Change from Base
ISO CO2 Emission (MM Ton)					
By In-ISO Generation	23.45	23.09	-0.36	22.51	-0.94
CCGT	18.94	18.75	-0.19	18.39	-0.55
CHP	2.63	2.62	-0.01	2.61	-0.02
GT	1.89	1.73	-0.16	1.52	-0.37
ST	0.00	0.00	0.00	0.00	0.00
From Import	17.91	17.89	-0.03	17.91	0.00
Import - NW	6.47	6.51	0.04	6.56	0.09
Import - others	11.45	11.38	-0.06	11.35	-0.09
Sum	41.37	40.98	-0.39	40.42	-0.95
CO2 Emission Offset	-2.80	-2.80	0.00	-2.80	0.00
Total	38.57	38.18	-0.39	37.62	-0.95
WECC-Wide CO2 Emission (MM Ton)	303.64	303.78	0.14	303.86	0.23
Native Load (GWh)	254,541	254,541	0	254,541	0
Retail Sales (GWh)	202,464	202,464	0	202,464	0
Total Generation (GWh)	205,590	204,963	-628	203,815	-1,776
BTMPV	36,301	36,301	0	36,301	0
CCGT	52,156	51,662	-494	50,700	-1,457
CHP	5,110	5,091	-19	5,077	-33
DR	17	13	-4	7	-10
GT	4,152	3,831	-321	3,400	-752
Hydro	19,380	19,380	0	19,380	0
Pumped Storage	-145	-346	-201	-697	-552
Renewable	89,135	89,549	415	90,181	1,046

P27-129
cont.

Case	Hybrid Conforming Plan	500 MW Pumped Storage		1,400 MW Pumped Storage	
		Results	Change from Base	Results	Change from Base
ST	0	0	0	0	0
Storage	-515	-519	-3	-534	-19
Net Import	48,951	49,579	628	50,727	1,776
Import - NW	15,114	15,200	86	15,320	206
Import - others	43,284	43,134	-151	43,072	-212
Export	-9,448	-8,755	693	-7,665	1,783
Renewable Generation (GWh)	103,083	103,497	415	104,131	1,049
In-State	90,649	91,063	415	91,697	1,049
Out-State (all OOS RPS generation)	12,434	12,434	0	12,434	0
RPS Achieved (excluding banked RECs)	52.5%	52.7%	0.2%	52.7%	0.5%
Renewable Curtailment (GWh)	3,328	2,913	-415	2,279	-1,049
Production Cost ($million)					
WECC	13,042	12,996	-46	12,926	-116
CAISO	2,869	2,818	-51	2,735	-134
In-ISO Generation CO2 Emission (MT/MWh)	0.114	0.113	-0.001	0.110	0.112
ISO Import CO2 Emission (MT/MWh)	0.307	0.307	0.000	0.307	0.307

Further, the performance of the pumped storage is set out in Table 7.2-8.

P27-129 cont.

Table 7.2-8: Performance of Pumped Storage

Values	500 MW Pumped Storage	1,400 MW Pumped Storage
Sum of Generation (GWh)	1,124	3,055
Sum of Pump Load (GWh)	1,355	3,680
Sum of Total Generation Cost ($000)	3,719	10,102
Sum of Pump Cost ($000)	11,521	42,457
Sum of Energy Revenue ($000)	71,901	186,388
Sum of Reserves Revenue ($000)	16,975	30,287
Sum of Net Revenue ($000)	73,636	164,116

7.2.4.4 Study Conclusions

Based on the results of the study, it can be concluded that:

- The new pumped storage resources brought significant benefits to the system, including:
    - o Reduced renewable curtailment;
    - o Lower production costs; and,
    - o The flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping processes.
- The new pumped storage resources also took advantage of low cost out-of-state energy during hours without renewable curtailment. They also resulted in higher net import to California and slightly increased CO2 emissions[157] within the California footprint.
- The net market revenue of the pumped storage resources provided a material contribution towards the levelized annual revenue requirements. However, pumped storage resources would need other sources of revenue streams, including consideration of capacity benefits, which could be developed through resource procurement and policy decisions.
- The annual system cost reductions (benefits), shown in Table 7.2-7, are not included in the net market revenue, but may be attributed to the pumped storage resources – especially in considering procurement policy.

The results of the study are sensitive to the assumptions, especially those listed in Table 7.2-1.

P27-129 cont.

[157] The slightly increased CO2 emissions result from the assumptions regarding the GHG adder relied upon in the study and the assumption that the pumped storage would pump when low cost energy is available regardless of source. Higher GHG adders or other restrictions on these pumping opportunities would mute this impact, albeit with some corresponding impact on benefits.

Chapter 8

8 Transmission Project List

8.1 Transmission Project Updates

Table 8.1-1 and Table 8.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous transmission plans, the ISO determined these projects were needed to mitigate identified reliability concerns, interconnect new renewable generation via a location constrained resource interconnection facility project or enhance economic efficiencies.

Table 8.1-1: Status of Previously Approved Projects Costing Less than $50M

No	Project	PTO	Expected In-Service Date
1	Estrella Substation Project	NEET West/PG&E[158]	Nov-23
2	Bellota 230 kV Substation Shunt Reactor	PG&E	Apr-19
3	Borden 230 kV Voltage Support	PG&E	May-19
4	Cascade 115/60 kV No.2 Transformer Project	PG&E	Jan-22
5	Clear Lake 60 kV System Reinforcement	PG&E	Feb-22
6	Coburn-Oil Fields 60 kV system project	PG&E	Feb-20
7	Contra Costa Sub 230 kV Switch Replacement	PG&E	Completed
8	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	Jun-19
9	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	May-19
10	Cortina No.3 60 kV Line Reconductoring Project	PG&E	Completed
11	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project	PG&E	Nov-21
12	Delevan 230 kV Substation Shunt Reactor	PG&E	Aug-20
13	Diablo Canyon Voltage Support Project	PG&E	Canceled
14	East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved)	PG&E	Apr-21

P27-129 cont.

[158] NEET West was awarded the 230 kV substation component of the project through competitive solicitation. PG&E will construct and own the 70 kV substation and associated upgrades.

No	Project	PTO	Expected In-Service Date
15	Fulton-Hopland 60 kV Line Project	PG&E	Mar-20
16	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	Dec-19
17	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	PG&E	Jan-21
18	Helm-Kerman 70 kV Line Reconductor	PG&E	Completed
19	Herndon-Bullard 115 kV Reconductoring Project	PG&E	Jan-21
20	Ignacio 230 kV Reactor	PG&E	Aug-19
21	Ignacio Area Upgrade	PG&E	Dec-23
22	Jefferson-Stanford #2 60 kV Line	PG&E	Canceled
23	Kearney – Hearndon 230 kV Line Reconductoring	PG&E	Jan-19
24	Kearney-Caruthers 70 kV Line Reconductor	PG&E	Apr-19
25	Kern PP 230 kV Area Reinforcement	PG&E	Apr-21
26	Lakeville 60 kV Area Reinforcement	PG&E	Dec-21
27	Lemoore 70 kV Disconnect Switches Replacement	PG&E	Completed
28	Lodi-Eight Mile 230 kV Line	PG&E	Completed
29	Los Banos-Livingston Jct-Canal 70 kV Switch Replacement	PG&E	Completed
30	Los Esteros 230 kV Substation Shunt Reactor	PG&E	Apr-20
31	Maple Creek Reactive Support	PG&E	Jul-22
32	Metcalf-Evergreen 115 kV Line Reconductoring	PG&E	May-19
33	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	Apr-22
34	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	Nov-26
35	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	Dec-22
36	Missouri Flat – Gold Hill 115 kV Line	PG&E	Completed
37	Monta Vista 230 kV Bus Upgrade	PG&E	Aug-20
38	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Mar-21
39	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	May-21
40	Morro Bay 230/115 kV Transformer Addition Project	PG&E	Canceled

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cont.

No	Project	PTO	Expected In-Service Date
41	Mosher Transmission Project	PG&E	Dec-20
42	Moss Landing–Panoche 230 kV Path Upgrade	PG&E	Jan-19
43	Newark-Lawrence 115 kV Line Limiting Facility Upgrade	PG&E	Dec-19
44	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	Jun-19
45	North Tower 115 kV Looping Project	PG&E	Dec-21
46	NRS-Scott No. 1 115 kV Line Reconductor[159]	PG&E	Mar-19
47	Oakland Clean Energy Initiative	PG&E	Aug-22
48	Oro Loma 70 kV Area Reinforcement	PG&E	May-20
49	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	Dec-20
50	Pease 115/60 kV Transformer Addition and Bus Upgrade	PG&E	Mar-20
51	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	May-22
52	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	Dec-20
53	Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects)	PG&E	May-21
54	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Jun-22
55	Rio Oso Area 230 kV Voltage Support	PG&E	Jun-22
56	Ripon 115 kV Line	PG&E	Apr-19
57	San Bernard – Tejon 70 kV Line Reconductor	PG&E	Dec-19
58	San Jose-Trimble 115 kV Series Reactors	PG&E	Feb-19
59	Semitropic – Midway 115 kV Line Reconductor	PG&E	Mar-21
60	Series Reactor on Warnerville-Wilson 230 kV Line	PG&E	Completed
61	South of San Mateo Capacity Increase	PG&E	May-19 & Mar-26
62	Stockton 'A' –Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	May-19
63	Trimble-San Jose B 115 kV Line Limiting Facility Upgrade	PG&E	Feb-19
64	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	Aug-22

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[159] The scope of this project has been modified to include reconductoring of both NRS-Scott #1 & #2 115 kV lines. Cost responsibility between PG&E and SVP has not been resolved – ISO approval does not pre-suppose the outcome of the dispute process underway at FERC.

No	Project	PTO	Expected In-Service Date
65	Vierra 115 kV Looping Project	PG&E	Feb-23
66	Warnerville-Bellota 230 kV line reconductoring	PG&E	Nov-23
67	West Point – Valley Springs 60 kV Line	PG&E	Dec-19
68	Wheeler Ridge Voltage Support	PG&E	Apr-21
69	Wheeler Ridge-Weedpatch 70 kV Line Reconductor	PG&E	Mar-19
70	Wilson 115 kV Area Reinforcement	PG&E	May-23
71	Wilson 115 kV SVC	PG&E	Dec-20
72	Wilson-Le Grand 115 kV line reconductoring	PG&E	Dec-20
73	2nd Escondido-San Marcos 69 kV T/L	SDG&E	Dec-20
74	2nd Pomerado - Poway 69kV Circuit	SDG&E	Jun-20
75	Bernardo-Ranche Carmel-Poway 69 kV lines upgrade (replacing previously-approved New Sycamore - Bernardo 69 kV line)	SDG&E	Sep-19
76	IID S-Line Upgrade[160]	SDG&E	Dec-21
77	Miramar-Mesa Rim 69 kV System Reconfiguration	SDG&E	Dec-20
78	Mission Bank #51 and #52 replacement	SDG&E	Jun-18
79	Reconductor TL 605 Silvergate – Urban	SDG&E	Dec-21
80	Reconductor TL663, Mission-Kearny	SDG&E	Jun-19
81	Reconductor TL676, Mission-Mesa Heights	SDG&E	Mar-19
82	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	Sep-21
83	Rose Canyon-La Jolla 69 kV T/L	SDG&E	Jan-19
84	San Ysidro 69 kV Reconductoring	SDG&E	Jun-22
85	Second Miguel – Bay Boulevard 230 kV Transmission Circuit	SDG&E	Jun-19
86	Suncrest 500/230 kV Transformer Rating Increase	SDG&E	Complete
87	Sweetwater Reliability Enhancement	SDG&E	Sep-20

P27-129 cont.

[160] The ISO is pursuing revisions to the scope of the previously approved S-Line Transmission Upgrade to consist of an appropriately sized single circuit 230 kV circuit, which provides the same local capacity requirement reduction value to the ISO as the original double-circuit line. As well, the ISO is updating the estimated cost to ISO ratepayers of the S-Line upgrade from $32 million to $40 million in light of revised costs estimates provided by IID. This increase in estimated cost would be offset by the savings of no longer needing a new line termination at the Imperial Valley Substation, which was required under the original double circuit configuration.

No	Project	PTO	Expected In-Service Date
88	TL13834 Trabuco-Capistrano 138 kV Line Upgrade	SDG&E	Dec-21
89	TL600: "Mesa Heights Loop-in + Reconductor	SDG&E	Dec-19
90	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	Jun-21
91	TL633 Bernardo-Rancho Carmel Reconductor	SDG&E	Sep-19
92	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Jun-19
93	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	Jun-20
94	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	Jun-26
95	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	Sep-20
96	Laguna Bell Corridor Upgrade	SCE	Mar-22
97	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-20
98	Method of Service for Wildlife 230/66 kV Substation	SCE	Jun-23
99	Eagle Mountain Shunt Reactors	SCE	Complete
100	PDCI Upgrade (to 3220 MW)	SCE	Complete
101	Lugo – Victorville 500 kV Upgrade (SCE portion)	SCE	Jun-21
102	Big Creek Rating Increase Project	SCE	Jun-19
103	Moorpark-Pardee No. 4 230 kV Circuit	SCE	Dec-20
104	Tie line Phasor Measurement Units	PG&E, SCE, VEA	Dec-20
105	Bob-Mead 230 kV Reconductoring	VEA	Dec-20

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cont.

Table 8.1-2: Status of Previously-Approved Projects Costing $50 M or More

No	Project	PTO	Expected In-Service Date
1	Delaney-Colorado River 500 kV line	DCR Transmission	Dec-21
2	Suncrest 300 Mvar dynamic reactive device	NEET West	Dec-19
3	Atlantic-Placer 115 kV Line	PG&E	Canceled
4	Cottonwood-Red Bluff No. 2 60 kV Line Project	PG&E	May-21
5	Gates #2 500/230 kV Transformer Addition	PG&E	Dec-19
6	Gates-Gregg 230 kV Line	PG&E/MAT	Canceled
7	Kern PP 115 kV Area Reinforcement	PG&E	Dec-23
8	Lockeford-Lodi Area 230 kV Development	PG&E	Dec-24
9	Martin 230 kV Bus Extension	PG&E	Oct-22
10	Midway – Kern PP #2 230 kV Line	PG&E	May-23
11	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)[161]	PG&E	On hold
12	New Bridgeville – Garberville No. 2 115 kV Line	PG&E	Canceled
13	Northern Fresno 115 kV Area Reinforcement	PG&E	Dec-20
14	South of Palermo 115 kV Reinforcement Project	PG&E	Nov-22
15	Vaca Dixon Area Reinforcement	PG&E	Dec-21
16	Wheeler Ridge Junction Substation	PG&E	May-24
17	Artesian 230 kV Sub & loop-in TL23051	SDG&E	Mar-20
18	South Orange County Dynamic Reactive Support – San Onofre (now 1-225 Mvar synchronous condenser)[162]	SDG&E	Complete
19	Southern Orange County Reliability Upgrade Project – Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	SDG&E	Mar-21

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[161] The Midway-Andrew 230 kV Project has been renamed the North of Mesa Upgrade, and remains on hold. The south of Mesa component has been separated into a standalone project named the South of Mesa Upgrade, and approval of that project is recommended in this 2018-2019 Transmission Plan.

[162] The South Orange County Dynamic Reactive Support project was initially approved in the 2012-2013 Transmission Plan and initially awarded to SDG&E as it was expected to be located in the San Onofre area in SDG&E's service territory. In 2014, the project was split due to siting issues, replacing two synchronous condensers at a single site with instead locating one at the San Onofre substation and the second being awarded to SCE and located in the Santiago substation. This was reflected in system modeling and noted on Page 159 and in Table 3.2.6 in the 2014-2015 Transmission Plan, but Table 7.1-2 (line number 5) was inadvertently not updated to reflect the change.

No	Project	PTO	Expected In-Service Date
20	Sycamore-Penasquitos 230 kV Line	SDG&E	Complete
21	Alberhill 500 kV Method of Service	SCE	Sep-22
22	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	Dec-20
23	Lugo-Mohave series capacitor upgrade	SCE	Dec-20
24	Mesa 500 kV Substation Loop-In	SCE	Mar-22
25	South Orange County Dynamic Reactive Support - Santiago Synchronous Condenser - SCE's component (1-225 Mvar synchronous condenser)[163]	SCE	Complete
26	Harry Allen-Eldorado 500 kV transmission project	DesertLink LLC	May-20

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[163] Refer to the preceding footnote.

8.2 Transmission Projects found to be needed in the 2018-2019 Planning Cycle

In the 2018-2019 transmission planning process, the ISO determined that 11 transmission projects were needed to mitigate identified reliability concerns; no policy-driven projects were needed to meet the 33 percent RPS. Two economic-driven projects were found to be needed. The summary of these transmission projects are in Table 8.2-1, Table 8.2-2, and Table 8.2-3.

A list of projects that came through the 2017 Request Window can be found in Appendix E.

Table 8.2-1: New Reliability Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Tyler 60 kV Shunt Capacitor	PG&E	2022	$5.8-$7M
2	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	2022	$8.5M-$10.5M
3	Gold Hill 230/115 kV Transformer Addition Project	PG&E	2022	$22M
4	Jefferson 230 kV Bus Upgrade	PG&E	2022	$6M-$11M
5	Christie-Sobrante 115 kV Line Reconductor	PG&E	2022	$10.5M
6	Moraga-Sobrante 115 kV Line Reconductor	PG&E	2023	$12M-$18M
7	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	2019	$0.1M-$0.2M
8	Tesla 230 kV Bus Series Reactor project	PG&E	2023	$24M-$29M
9	South of Mesa Upgrade	PG&E	2023	$29.6-59.2M
10	Round Mountain 500 kV Dynamic Voltage Support[164]	PG&E	2024	$160M-$190M
11	Gates 500 kV Dynamic Voltage Support	PG&E	2024	$210M-$250M

P27-129 cont.

[164] Further review of the engineering detail for the termination of the Round Mountain 500 kV Reactive Project is required due to siting issues at Round Mountain for the project. Board of Governor approval is recommended, and the additional detail will be posted as an addendum to the transmission plan. The competitive procurement process for the project will commence after that has taken place.

Table 8.2-2: New Policy-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
	No policy-driven projects identified in the 2018-2019 Transmission Plan			

Table 8.2-3: New Economic-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Giffen Line Reconductoring Project	PG&E	TBD	$5M
2	East Marysville 115/60 kV Project	PG&E	2022	$26-32M

P27-129 cont.

8.3 Reliance on Preferred Resources

The ISO has relied on a range of preferred resources in past transmission plans as well as in this 2018-2019 Transmission Plan. In some areas, such as the LA Basin, this reliance has been overt through the testing of various resource portfolios being considered for procurement, and in other areas through reliance on demand side resources such as additional achievable energy efficiency and other existing or forecast preferred resources.

As set out in the 2018-2019 Tranmission Planning Process Unified Planning Assumptions and Study Plan, the ISO assesses the potential for existing and planned demand side resources to meet identified needs as a first step in considering mitigations to address reliability concerns.

The bulk of the ISO's additional and more focused efforts consisted of the development of local capacity requirement need profiles for all areas and sub-areas, as part of the biennial 10 year local capacity technical study completed as part of this transmission planning cycle. This provides the necessary information to consider the potential to replace local capacity requirements for gas-fired generation, depending on the policy or long term resource planning direction set by the CPUC's integrated resource planning process.

As well, the ISO studied numerous storage projects proposed as providing reliability and economic benefits, as set out in chapter 2 and 4. Given the circumstances of this year's limited planning needs, there were few opportunities for development.

In addition to relying on the preferred resources incorporated into the managed forecasts prepared by the CEC, the ISO is also relying on preferred resources as part of integrated, multi-faceted solutions to address reliability needs in a number of study areas. P27-129 cont.

LA Basin-San Diego

Considerable amounts of grid connected and behind-the-meter preferred resources in the LA Basin and San Diego local capacity area, as described in Tables 2.7-5 and 2.9-1, were relied upon to meet the reliability needs of this large metropolitan area. Various initiatives including the LTPP local capacity long-term procurement that was approved by the CPUC have contributed to the expected development of these resources. Existing demand response was also assumed to be repurposed within the SCE and SDG&E areas with the necessary operational characteristics (i.e., 20-minute response) for use during overlapping contingency conditions.

Oakland Sub-area

The reliability planning for the Oakland 115 kV system anticipating the retirement of local generation is advancing mitigations that include in-station transmission upgrades, an in-front-of-the-meter energy storage project and load-modifying preferred resources. These resources are being pursued through the PG&E "Oakland Clean Energy Initiative" approved in the 2017-2018 Transmission Plan.

Moorpark and Santa Clara Sub-areas

As set out in section 2.7.5.3, the ISO is supporting the SCE's preferred resource procurement effort for the Santa Clara sub-area submitted to the CPUC Energy Division on December 21, 2017, by providing input into SCE's procurement activities and validating the effectiveness of potential portfolios identified by SCE. This procurement, together with with the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double circuit towers which was approved in the ISO's 2017-2018 Transmission Plan, will enable the retirement of the Mandalay Generating Station and the Ormond Beach Generating Station in compliance with state policy regarding the use of coastal and estuary water for once-through cooling.

8.4 Competitive Solicitation for New Transmission Elements

Phase 3 of the ISO's transmission planning process includes a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities. Where the ISO selects a regional transmission solution to meet an identified need in one of the three aforementioned categories that constitutes an upgrade to or addition on an existing participating transmission owner facility, the construction or ownership of facilities on a participating transmission owner's right-of-way, or the construction or ownership of facilities within an existing participating transmission owner's substation, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner.

The ISO has identified the following regional transmission solutions recommended for approval in this 2018-2019 Transmission Plan as including transmission facilities that are eligible for competitive solicitation:

Reliability-driven Projects: P27-129 cont.

- Gates 500 kV Dynamic Reactive Support Project
- Round Mountain 500 kV Dynamic Reactive Support Project

The descriptions and functional specifications for the facilities eligible for competitive solicitation can be found in Appendix I.

8.5 Capital Program Impacts on Transmission High Voltage Access Charge

8.5.1 Background

The purpose of the ISO's internal High Voltage Transmission Access Charge (HV TAC) estimating tool is to provide an estimation of the impact of the capital projects identified in the ISO's annual transmission planning processes on the access charge. The ISO is continuing to update and enhance its model since the tool was first used in developing results documented in the 2012-2013 transmission plan, and the model itself was released to stakeholders for review and comment in November 2018. Additional upgrades to the model have been made reflecting certain of the comments received from stakeholders.

The final and actual determination of the High Voltage Transmission Access Charge is the result of numerous and extremely complex revenue requirement and cost allocation exercises conducted by the ISO's participating transmission owners, with the costs being subject to FERC regulatory approval before being factored in the determination of a specific HV TAC rate recovered by the ISO from ISO customers. In seeking to provide estimates of the impacts on future access rates, we recognized it was neither helpful nor efficient to attempt to duplicate that modeling in all its detail. Rather, an excessive layer of complexity in the model would make a high level understanding of the relative impacts of different cost drivers more difficult to review and understand. However, the cost components need to be considered in sufficient detail that the relative impacts of different decisions can be reasonably estimated.

The tool is based on the fundamental cost-of-service models employed by the participating transmission owners, with a level of detail necessary to adequately estimate the impacts of changes in capital spending, operating costs, and so forth. Cost calculations included estimates associated with existing rate base and operating expenses, and, for new capital costs, tax, return, depreciation, and an operations and maintenance (O&M) component.

The model is not a detailed calculation of any individual participating transmission owner's revenue requirement – parties interested in that information should contact the specific participating transmission owner directly. For example, certain PTOs' existing rate bases were slightly adjusted to "true up" with a single rate of return and tax treatment to the actual initial revenue requirement incorporated into the TAC rate, recognizing that individual capital facilities are not subject to the identical return and tax treatment. This "true up" also accounts for construction funds already spent which the utility has received FERC approval to earn return and interest expense upon prior to the subject facilities being completed.

The tool does not attempt to break out rate impacts by category, e.g. reliability-driven, policy-driven and economic-driven categories used by the ISO to develop the comprehensive plan in its structured analysis, or by utility. The ISO is concerned that a breakout by ISO tariff category can create industry confusion, as, for example, a "policy-driven" project may have also addressed the need met by a previously identified reliability-driven project that was subsequently replaced by the broader policy-driven project. While the categorization is appropriately as a "policy-driven" project for transmission planning tariff purposes, it can lead to misunderstandings of the cost implications of achieving certain policies – as the entire replacement project is attributed to "policy". Further, certain high level cost assumptions are appropriate on an ISO-wide basis, but not necessarily appropriate to apply to any one specific utility. P27-129 cont.

8.5.2 Input Assumptions and Analysis

The ISO's rate impact model is based on publicly available information or ISO assumptions as set out below, with clarifications provided by several utilities.

Each PTO's most recent FERC revenue requirement approvals are relied upon for revenue requirement consisting of capital related costs and operating expense requirements, as well as plant and depreciation balances. Single tax and financing structures for each PTO are utilized, which necessitates some adjustments to rate base. These adjustments are "back-calculated" such that each PTO's total revenue requirement aligned with the filing.

Total existing costs are then adjusted on a going forward basis through escalation of O&M costs, adjustments for capital maintenance costs, and depreciation impacts. PTO input is sought each year regarding these values, recognizing that the ISO does not have a role regarding those costs.

To account for the impact of ISO-approved transmission capital projects, the tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

The ISO has also continued the practice from past cycles to base this year's analysis of future transmission projects on an average of 11% as the long term forecast return on equity. While stakeholders have suggested that a 10% return may be appropriate, the ISO has considered this as a lower bound. The overall return values for existing rate base assets are drawn from the PTO's actual approved revenue requirements. An updated estimate from the 2017-20178 transmission planning process has been provided for comparison.

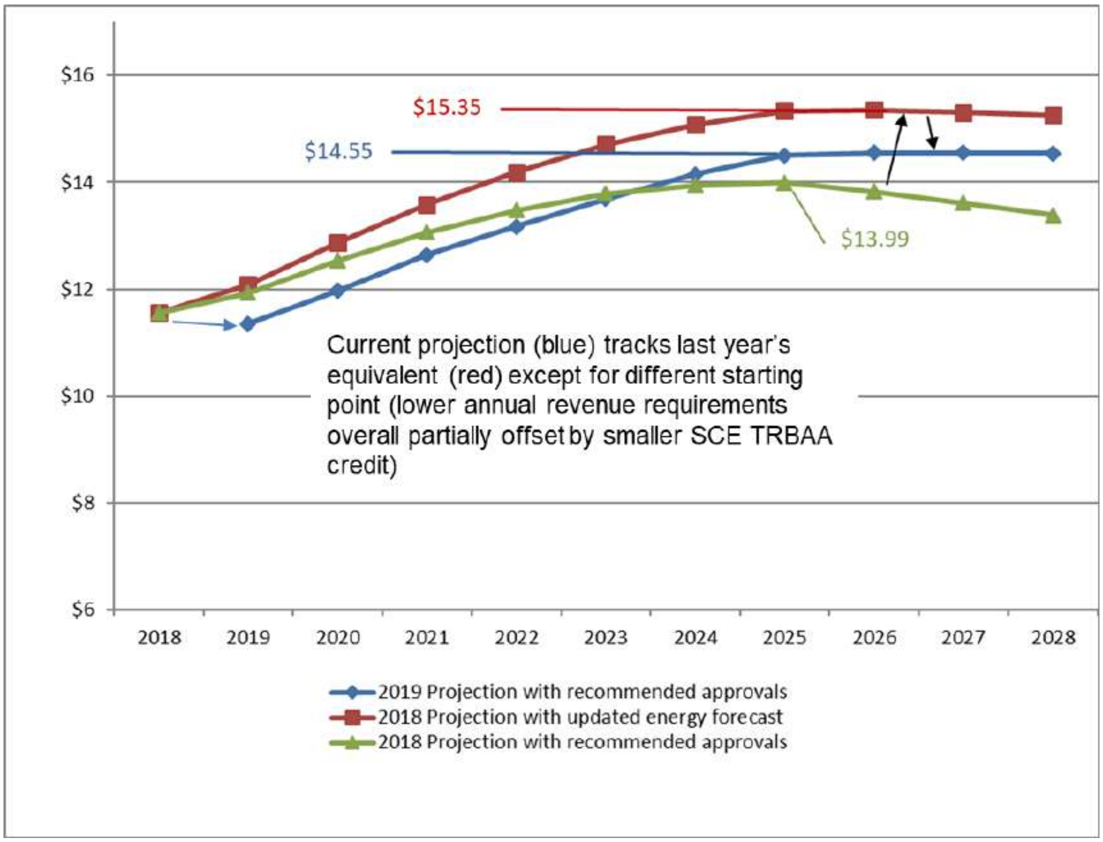
The estimate provided below reflects the latest updated costs for all previously approved projects and the revised scopes for projects with recommended scope changes. All projects recommended to be canceled have been removed from the estimate, and projects on hold are included in the estimate.

In cycles prior to the 2016-2017 Transmission Plan, adjustments had been made to maintain annual reliability-driven projects approvals above a certain threshold once it had been initially exceeded. However, consistent with the 2016-2017 Transmission Plan, only the cost of approved transmission projects and projects recommended to be approved have been included.

As in past planning cycles, a 1% load growth had been assumed in overall energy forecast over which the high voltage transmission revenue requirement is recovered for comparison purposes. However, a sensitivity was included in the 2017-2018 transmission plan reflecting a forecast year over year decrease of 0.31% in energy served, consistent with the CEC's 2016 IEPR forecast. The 2018-2019 results provided below were also based on this same year over year forecast for consistency in comparisons.

P27-129 cont.

Figure 8.5-1: Forecast of ISO HIgh Voltage Transmission Access Charge
Trended from First Year of Transmission Plan



In reviewing the latest estimate, several observations can be made. As noted in Figure 8.5-1, the 2019 TAC value for the 2019 projection is lower than the 2018 value from the 2018 projection. This stemmed from ower overall transmission revenue requirements, primarily for the investor-owned utilities. Other than the offset in initial TAC rates, the trend demonstrated last year remains relatively consistent with the trend this year, with new capital projects being recommended for approval in this plan being offset to some extent by canceled projects. Adjustments to federal income tax rates are also expected to have put downward pressure on the initial 2019 TAC rate as well as the impact of new capital additions.

P27-129
cont.

D5. Exhibits to Letter P45, Kelly Tanner

EX-99.1 6 d564947dex991.htm EX-99.1

Exhibit 99.1

GL Garrad Hassan

TECHNICAL SUMMARY OF A PORTFOLIO OF PROJECTS OF PATTERN ENERGY GROUP INC.

P45-159

Client	Pattern Energy Group Inc.
Contact	E. Daly
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4 HATCHET RIDGE WIND PROJECT

4.1 Introduction – Hatchet Ridge

The Hatchet Ridge wind project (referred to within this Section as the "Project"), is located in northern California near the town of Burney. The 101.2 MW Project has been operating since December 2010. An overview of the Project is provided in Table 4-1.

Table 4-1: Hatchet Ridge Project Overview

Location	Burney, California
Offtaker	Pacific Gas & Electric (PG&E)
Energy Purchase Arrangements	Power Purchase Agreement
Operator	Pattern Operators LP
Capacity [MW]	101.2
Turbine Type	Siemens SWT-2.3-93
No. of Turbines	44
Turbine Warranty Expiration	Expired
Turbine O&M Agreement	Third-party agreement with Outland Energy Services, expiring October 2015
COD	December 2010

GL GH conducted a pre-construction technical due diligence review as well as construction monitoring activities for the Project and reported its results in the Hatchet Ridge IE Report [9]. GL GH also inspected the operational Project in September 2011 and April 2013 and has been engaged by the Sponsor at various times since start of operations for review of specific technical issues related to the Project. The results of such previous work have been utilized to inform the current Report.

P45-159 cont.

4.2 Project Summary – Hatchet Ridge

4.2.1 Appreciation of Site

The Project site is located approximately 60 km northeast of Redding, CA, near the town of Burney. The Project turbines are located on a steep and narrow ridgeline which runs northwest to southeast, at elevations between approximately 1430 m and 1680 m above sea level. The general terrain at the site can be described as complex, with steep slopes on both sides of the ridge. A recovering burn area consisting of trees 2-4 m in height encompasses the site and extends approximately 20 km southwest. The general Project location and turbine layout is shown in Figure 4-1 and Figure 4-2 below.

P45-159 cont.

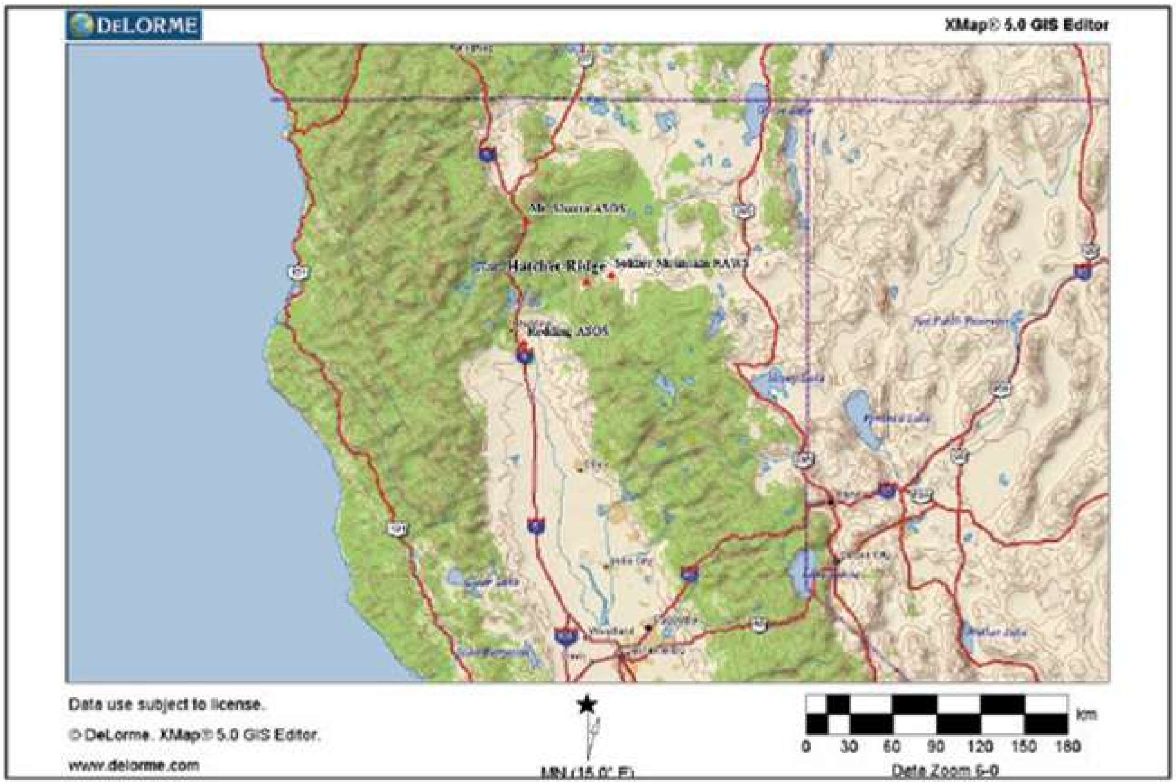

Figure 4-1: Hatchet Ridge General Project Location

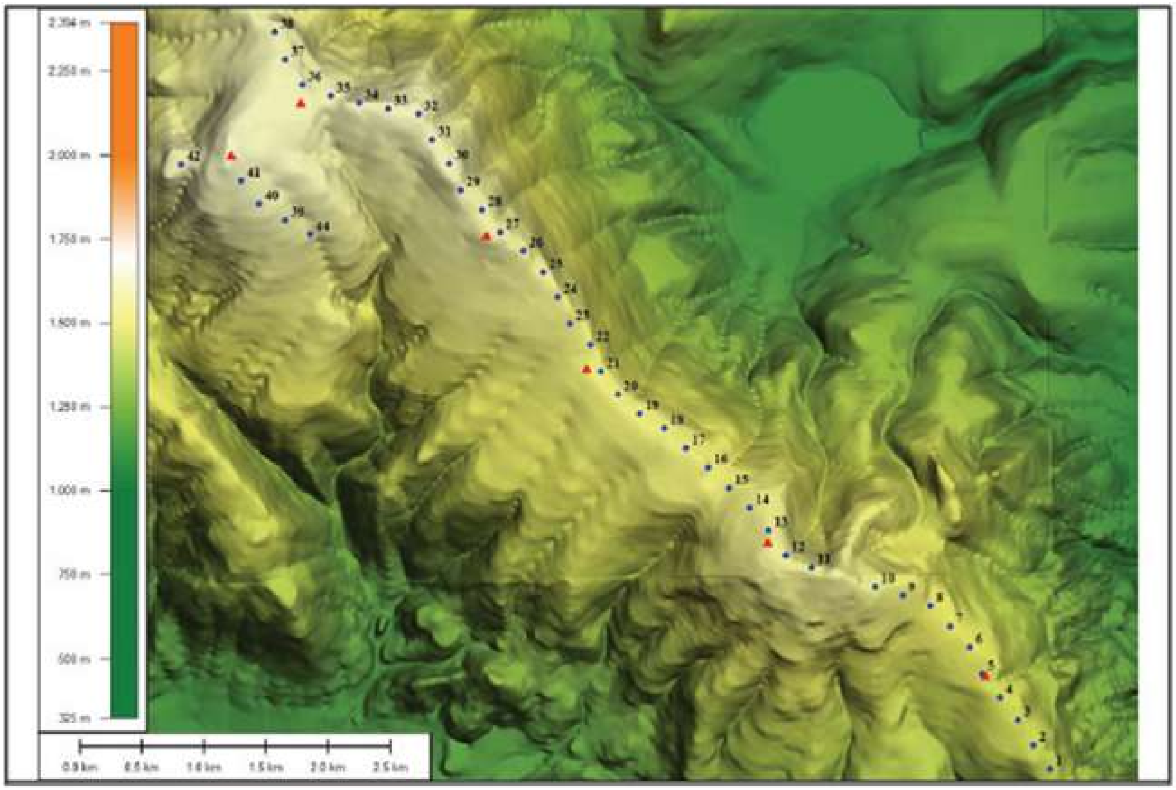

Figure 4-2: Hatchet Ridge Project Site Layout

P45-159 cont.

4.2.2 Interconnection and Power Purchase Agreements

The grid interconnection for the Project capacity is provided under a Large Generator Interconnection Agreement (LGIA) between the Project, Pacific Gas & Electric (PG&E), and California Independent System Operator (CAISO) [11]. The Point of Interconnection is the Project-built, PG&E-owned 230 kV Carberry Switching Station. The Project has demonstrated compliance with the technical requirements of the LGIA.

The Project sells energy output under a Power Purchase Agreement (PPA) with Pacific Gas & Electric (PG&E) [21]. GL GH considers that the technical terms of the PPA are within industry standards but notes that some technical risks are inherent in the PPA contractual conditions which cannot be described in this Report due to non-disclosure provisions.

4.2.3 Construction Contracts

The 44 SWT-2.3-93 wind turbines and associated equipment for the Project were supplied, erected, and commissioned under a Turbine Supply Agreement (TSA) with Siemens Energy, Inc. The TSA provided for certain warranties which expired in October 2012; however, outstanding claims from end of warranty inspections are pending.

Design, procurement, and construction of the Project BoP was performed by RES America Construction, Inc. (RES). The warranty associated with this work has since expired.

Both Siemens and RES are recognized as leading suppliers in the wind industry.

4.2.4 Operation and Maintenance Contracts

The Project initially operated under a Service and Maintenance Contract with Siemens Energy which has since expired. The Project executed a post-warranty Service and Maintenance Agreement (SMA) with Outland Energy Services, LLC (“Outland”) [14], under which Outland assumes turbine maintenance responsibilities at the Project until October 2015 with an optional term extension at Project discretion. GL GH has conducted a high-level review of the Outland SMA and considers that the key provisions of the agreement appear generally in line with industry standards. GL GH considers that Outland Energy Services has considerable experience offering wind turbine O&M services for a variety of turbine models and clients, and is capable of competently performing turbine O&M services for the Project. GL GH also notes that Outland was recently acquired by Duke Energy, a large utility and wind project owner. Outland has staffed the Project with a site Project Manager and six permanent turbine technicians, which GL GH considers appropriate.

Asset management, administrative and financial reporting, and budget oversight for the Project are provided under a Project Administration Agreement (PAA) between Pattern Operators LP and the Project [15]. A Management, Operations, and Maintenance Agreement (MOMA) [16] with Pattern Operators LP similarly covers the management, operation, and maintenance of the Project. GL GH considers the scope and terms of these agreements and the associated fees acceptable and in line with industry expectations.

P45-159 cont.

4.2.5 Wind Turbine Design and Suitability

The Project employs 44 Siemens SWT-2.3-93 turbines with an 80 m hub height. The turbines are equipped with a cold weather package that extends operation to -25°C and survival to -45°C. Siemens turbines are technologically conservative, as is clearly seen in their simple, robust designs with ample attention to maintainability. GL GH views Siemens as one of the major wind turbine manufacturers and a technical leader of the industry.

The SWT-2.3-93 is a widely-deployed IEC Class IIA machine with a solid track record and is considered by GL GH to be a “proven” turbine [70]. It is a three-bladed, horizontal-axis, upwind, variable-speed, pitch-regulated turbine. The turbine was awarded a Type Certificate based on IEC Class IIA conditions by DNV on 11 January 2007. GL GH expects that the turbine will achieve an average long-term turbine availability of 97.0% at the Project site.

GL GH received and reviewed the Climatic Conditions Review performed by Siemens for the Project site as well as other information provided by the Sponsor. Siemens concluded that site wind conditions and turbine spacing do not require the use of a wind sector management scheme. GL GH has reviewed the assumptions, methods, and results of the Siemens assessment and found them to be reasonable and consistent with the manufacturer’s generally conservative approach to site assessment. After reviewing the available information, GL GH agreed with the Siemens CCR conclusion that the SWT-2.3-93 turbine with an 80 m hub height and cold weather option is suitable for use at the Hatchet Ridge site.

In 2013, the Project purchased and installed a Siemens control software upgrade called High Wind Ride-Through (HWRT) on the Project turbines. According to Siemens, this feature allows the turbines to operate in winds of up to 30 m/s, increasing production and decreasing high wind hysteresis time. GL GH has reviewed a letter from the certification body DNV which indicates that the relevant load cases were considered and concludes that HWRT operation does not impact the structural integrity of the turbine. The DNV statement offers comfort that use of HWRT does not represent an additional turbine suitability risk.

4.2.6 BoP Design

The geotechnical study of the Project site determined that it is located in a region of low to moderate seismic activity; seismic considerations govern the foundation design. All turbines at the Project are supported on shallow depth concrete gravity foundations (spread footings) of regular octagon shape. Two different base widths are utilized based on the bearing capacity at the individual turbine sites. GL GH reviewed the geotechnical and structural design aspects of the turbine foundations at the Project and found them to be acceptable. A potential durability issue related to the tower base grout placement was identified which could lead to cracks; however, the Project is monitoring this item and reported no issues, and has also indicated that any cracks would be sealed when discovered. GL GH did not observed any cracks in these locations during its site visit and considers this solution satisfactory.

The Point of Interconnection (POI) is at the Project-built, PG&E-owned 230 kV Carberry Switching Station, in the existing PG&E Pit #3 – Round Mountain 230 kV transmission line. The Project electrical balance of plant includes the 34.5 kV collection system, a 230/34.5 kV collection substation, and an approximately 3.3-mile 230 kV transmission line connecting the substation to the 230 kV Carberry Switching Station. RES was responsible for engineering and construction of the electrical balance of plant and the PG&E switching station. GL GH considers that the electrical system design properly addresses compliance with LGIA requirements. Issues have been encountered with transmission line damage in heavy winds and icing conditions; however, the Project has implemented measures to address these problems (see Section 4.3.2 herein).

P45-159 cont.

GL GH considers the electrical and turbine foundation designs acceptable.

4.2.7 Project Construction and Completion

GL GH staff visited the Project site on 18 occasions between September 2009 and October 2010 to monitor the construction of the Project. GL GH additionally reviewed operational data and Project documentation. GL GH considers that Project construction was generally completed in accordance with the applicable contracts, engineering specifications, and industry standards. GL GH independently confirmed the Project declaration of COD in December 2010.

4.3 Project Operations – Hatchet Ridge

GL GH has undertaken a high-level review of the Project's operational history based on site visits, interviews with Project site staff, review of monthly operating reports (MOR), and review of other Sponsor-provided information.

The Project is staffed by a Facility Manager and an Assistant Facility Manager, as well as a permanent staff of Outland turbine technicians who provide monthly operational reports to the Project as part of their O&M responsibilities. End of warranty turbine inspections were conducted in 2012 with selected findings discussed in Section 4.3.2 herein. The Project subcontracts locally for required BoP maintenance.

Pattern manages the Project proactively and effectively, and appears to have constructive working relationships with its subcontractors.

4.3.1 Project Performance

GL GH has reviewed monthly operating reports (MOR) for the Project along with a summary of Project availability performance. Table 4-2 summarizes historical Project availability as reported by the Sponsor; GL GH has not independently verified the reported figures or the method and mechanics of their calculation.

Table 4-2: Hatchet Ridge Project Availability

Quarter	Turbine Availability [%]	BoP Availability [%]	Project Availability[2] [%]
Q1 2011	97.2	90.2	82.1
Q2 2011	97.9	98.4	94.9
Q3 2011	99.0	100.0	98.1
Q4 2011	98.6	98.2	94.5
Q1 2012	97.1	99.0	88.3
Q2 2012	98.3	100.0	97.2
Q3 2012	98.6	100.0	97.4
Q4 2012	98.9	91.0	78.3
Q1 2013	98.2	100.0	95.8
Q2 2013	97.1	100.0	93.7
Period Total / Average	**98.1**	**97.7**	**92.2**

1. Quarterly averages calculated from figures reported in the historical Project availability summary provided by the Sponsor.
2. Project availability reflects downtime associated with icing, high/low temperatures, site access, grid disturbances, curtailment and other downtime not attributable to turbine or BoP scheduled and unscheduled maintenance.

Combined turbine and BoP availability has averaged 95.8% since start of operations, which is in line with GL GH expectations. GL GH notes that reported turbine availability to date has been higher than the value projected for mature operation, while BoP availability has been lower than expected. The primary drivers behind reduced BoP availability were damage to the Project transmission system due to icing conditions and associated remedial measures (including required scheduled outages for preventative transmission line retrofits); such measures are reasonably anticipated to reduce such downtime in the future. Significant turbine icing downtime and lack of turbine access due to snow and ice comprise the bulk of the remaining downtime not considered under turbine and BoP availability; the Sponsor has indicated that such downtime is generally in line with assumptions in the operating plans.

P45-159 cont.

4.3.2 Project Maintenance History

In order to evaluate maintenance issues encountered at the Project, GL GH has reviewed documentation and information provided by the Sponsor, conducted site visits and reviewed on-site documentation, and discussed questions and results of the analyses with the Sponsor. The majority of system downtime at the Project has occurred as a result of damage to the Project infrastructure resulting from ice and snow accumulation and weather-related site access issues. A variety of other technical issues have also caused equipment downtime; the principle drivers for such downtime came as a result of the maintenance actions and technical issues discussed below.

- Scheduled Maintenance: Turbine scheduled maintenance has been completed in line with the maintenance schedule, with only minor deviations noted. Such deviations from baseline schedule are in part attributable to efforts to minimize work in turbines during the afternoons when energy production tends to increase, and a proactive approach to scheduling maintenance based on the differing seasonal conditions among the turbine sites; GL GH considers this approach beneficial. Scheduled BoP maintenance has also been completed with no significant issues noted, although minor discrepancies were discovered with two padmount transformers which will be more closely monitored (including additional oil sampling) for degradation.
- End of Warranty Inspection Claims: Seven gearboxes were determined to have excessive wear during end of warranty inspections. Intermediate shaft assemblies were replaced under warranty on three of these seven gearboxes, and the Sponsor has submitted warranty claims to Siemens and is in negotiations to determine an appropriate settlement for the remaining outstanding issues on these gearboxes. GL GH has reviewed a sample of the inspection documentation and considers that most issues identified are minor. GL GH therefore considers aggressive pursuit of such warranty claims to be beneficial to the Project, rather than an indicator of heightened technical risk.
- Other Gearbox Issues: High speed shaft bearings in two turbine gearboxes were flagged by the turbines' condition monitoring systems and subsequently replaced. Oil leakage from several gearbox breathers has also been observed, but does not appear to have caused significant turbine downtime. An alternative breather design was identified and retrofit during scheduled maintenance, and the Project reports the alternative breather is performing well.
- Other Main Component Failures: Two generators have been replaced at the site; one in response to a mechanical noise observed by a technician, and another due to an electrical fault. Another turbine required a replacement main bearing. GL GH has not received formal information on the root cause of these failures.
- Sensor Issues: The turbines have experienced recurring problems with three different sensors, particularly during periods of cold weather. Such nuisance faults appear to have been among the notable sources of turbine downtime in the early months of Project operation. Many of these sensors have been replaced and additional spares provided on site. For one sensor variety (gearbox oil level sensor), Siemens is testing different sensor models and will replace all such sensors with the preferred replacement variety at the Project.
- Transmission Line Failures: Large impacts to both production and availability at the Project were incurred due to damage to the Project transmission line during severe winter weather (icing and high winds). Significant downtime occurred in Q4 2010 and Q1 2011, and was caused by uplift and collapse of transmission line towers and contact between the upper ground/communication cables and lower power cables due to excessive snow and ice loads. The Project undertook several corrective measures including adding guy wires to existing transmission line support structures (January 2011), burying the two optical ground wires (October 2011), and adding additional transmission line support towers to reduce the spans in sections subject to the highest loading (one in January 2011 and nine more in October 2012). Two short outages during periods of extreme winds and significant icing were reported in December 2012 following the latest retrofits, and minor issues were found following the winter with some wooden support structures which are being monitored. GL GH reviewed the modifications and anticipates that they will enable the system to better withstand ice and snow conditions.
- Padmount Transformer Damage: A number of pad-mount transformers have been damaged to varying degrees by ice falling from the turbines. In most cases, no significant damage or downtime has resulted, however in three instances downtime ranging from a week to two months was incurred while awaiting replacement transformers. The Project now retains a spare padmount transformer at the Project site and plans to install protective ice shields in 2013 for the turbines most affected.

P45-159 cont.

- Ice Shedding: Ice shedding damage resulted in significant met tower downtime during initial Project operation. The Project has relocated all met tower sensor lines and cables and routed these cables through protective conduit, an ice shield has been installed over the down-tower equipment, the electrical equipment at the base of the met tower has been partly moved, and an additional ice shield plate was installed above the solar panel.
- Weather Downtime: Reported weather downtime was 3.8% for 2011 and 4.6% for 2012, primarily attributable to turbine icing and, to a lesser extent, lack of physical access to the turbine site due to snow and ice. The Sponsor is exploring the use of tracked snow vehicles to help prevent site access issues. The Sponsor has indicated that such downtime is generally in line with assumptions in the operating plans.
- Other Issues: Other minor sources of downtime have included sporadic faults in some cases related to sensor or icing issues, and turbine warm-up and restart following power outages. The Project submitted serial defect letters to Siemens on a number of minor components and the Sponsor has indicated that Siemens has provided parts or implemented other remedies for these issues.

Overall, it appears that there are no major issues affecting turbine availability at the Project, although there are some minor issues which have provided for sporadic downtime. The Project is taking prudent measures to mitigate the risk of BoP downtime resulting from ice and snow accumulation and shedding, which has been a large contributor to reduced Project availability. GL GH notes that a relatively small number of major turbine components have failed or required serious repair since the Project began operation, some of which were identified by the turbines' condition monitoring systems prior to complete component failure, minimizing turbine downtime. GL GH notes that Siemens did not provide root cause analyses for the observed failures, however. The Project currently has several pending warranty claims associated with end of warranty inspections, most notably for seven gearboxes with signs of excessive wear.

P45-159 cont.

4.3.3 Site Inspection

GL GH last visited the Project in April 2013 and found the Project to be in generally good condition. The Project was observed to be fully functional at the time of the site visit.

GL GH performed a turbine climb on randomly-selected turbine H-3. The turbine was undergoing its annual maintenance and appeared neat, clean, and in good operating condition. No evidence of gearbox oil leakage was detected, and the gearbox oil level sight glass indicated an acceptable level. Due to confined-space safety procedures, GL GH did not have the opportunity to thoroughly inspect the turbine hub; however, GL GH has no indication of technical issues in the hub. GL GH observed that the Project SCADA system was operational.

The Project O&M facility appeared to be in good condition and the Project staff indicated that the site was adequately stocked with routine spare parts. GL GH notes that no turbine major component spares (gearbox, generator, blades, etc.) are maintained at the site; however, a spare padmount transformer, grounding transformer, and substation breakers are on hand.

The Project roads and gates appeared to be in reasonably good condition. The turbine access roads showed some signs of erosion, which is expected given the winter weather conditions. The Project is performing upgrades to roads to improve water run-off and drainage and post construction re-vegetation efforts are continuing. GL GH observed the Project collection system and substation and found them to be in generally good condition. Minor ground settlement around the base of several newly installed transmission line poles was noted and should be evaluated by the Engineer of Record and corrected as appropriate. Minor padmount transformer damage from ice shedding was observed at several turbines; the Project anticipates installing ice shields in 2013.

4.3.4 Curtailment Directives Received

The Sponsor provided an excerpt from the Pattern OCC log showing a single curtailment event at the Project in July 2011 which limited the energy output to 30 MW for a duration of nine hours to accommodate emergency transmission line work by PG&E. This event had no impact on Project production due to low winds at the time of the event.

Three curtailments were reported in 2012, totaling approximately 4.5 hours and resulting in approximately 15 MWh lost production, and no further events were reported through July 2013.

4.4 Operating Plans – Hatchet Ridge

GL GH reviewed the technical inputs to the Project operating plans provided by the Sponsor [10], which extend for 25 years following COD. Although GL GH based its review on the 20-year Project design life, in general GL GH is of the opinion that it is possible to extend the service life of a wind project. See Appendix A for further discussion regarding wind farm service life extension. P45-159 cont.

The GL GH review included consideration of various technical O&M cost categories including budgeted turbine operation and maintenance (“O&M”) costs, balance of plant O&M costs, Project management and administration fees, administrative and outside services, environmental costs and utility expenses.

GL GH considers that the operating plans contain reasonable allocations for turbine O&M expense in the period from 2013 to 2020. GL GH uses a proprietary database to forecast unscheduled turbine maintenance over time, with a resulting sculpted profile that reflects increased failure rate of major components in the later years of the Project’s design life. In contrast, because of the uncertainties around the timing of major component replacements, the Sponsor uses a levelized approach to budget for turbine O&M costs. As a result, during the earlier years of operation, the Sponsor’s turbine maintenance budget exceeds GL GH’s expectations. During the latter half of the Project life, GL GH expects higher turbine maintenance costs than are reflected in the Sponsor’s budget.

The budgeted costs for Project management fees are in line with the annual fee under the MOMA and PAA with Pattern Operators. GL GH is of the opinion that the operating plans provide sufficient O&M expenditures for BoP maintenance, management and operation, administrative and outside services, and utilities for the design life of the Project. GL GH notes that the budgeted non-turbine technical expenditures are higher than actual expenses incurred in the historical quarters through Q2 2013.

The overall, levelized technical O&M budget given in the Sponsor’s operating plans is approximately 6% below GL GH estimates for the remainder of the 20-year design life, driven by differing turbine unscheduled maintenance assumptions. Across all operating cost categories (including the technical expenses described above, as well as non-technical expenses such as property tax, insurance, and land payments outside the scope of GL GH review), the overall Project operating expense in the operating plans is approximately 4% below GL GH estimates, with annualized total cost escalation in the Sponsor operating plans of approximately 1.1% as compared to approximately 2.0% in GL GH’s estimates for the period from 2014 to 2030. Given the disparity observed between the Sponsor’s turbine O&M budget and GL GH’s expectations, GL GH recommends an increase in the base case technical O&M allocation (which comprises approximately 54% of overall operating costs) of 6% starting in 2021. In addition, due to uncertainty in long-term operating costs for megawatt class wind turbines, GL GH typically recommends that investors consider a stress case which increases overall, annual operating expenses by 10% during the Project design life.

Overall, GL GH considers that generally appropriate amounts, commensurate with historical Project costs and contractual arrangements, have been budgeted in the near term, although GL GH anticipates higher turbine O&M costs in later Project years than Sponsor estimates. GL GH considers that the historical operating costs through Q2 2013 were within expectations for a project of this size and location.

4.5 Conclusion – Hatchet Ridge

The Hatchet Ridge Project employs 44 Siemens SWT-2.3-93 turbines near Burney, California, and has been operating since December 2010. The Project is operated by Pattern Operators LP, with specific maintenance work conducted by subcontractors, including Outland Energy Services as the post-warranty turbine O&M contractor. The Project sells energy output under a Power Purchase Agreement (PPA) with Pacific Gas & Electric.

GL GH has reviewed documentation provided by Siemens and agrees that the SWT-2.3-93 turbines with the cold climate package are suitable for the Project site. The Project has recently purchased and installed a Siemens control software upgrade called High Wind Ride-Through (HWRT) on the Project turbines to increase energy yield during periods of high winds. A statement from the certification body DNV offers comfort that use of HWRT does not represent a turbine suitability risk. GL GH additionally reviewed the electrical infrastructure and turbine foundation designs and found them to be acceptable.

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The Project, including the turbines and BoP facilities, appeared to be in good condition as of the last GL GH site visit in April 2013, and GL GH considers that technical issues are being properly addressed. There have been few notable unscheduled turbine maintenance issues at the Project since start of operations, while electrical BoP damage related to severe winter weather was a major driver for Project downtime in 2010 and 2011. Such damage caused significant downtime to the Project transmission line; GL GH has reviewed the repairs and modifications conducted by the Project and anticipates that they will enable the system to better withstand ice and snow conditions. Overall, the Project has taken appropriate measures to mitigate the risk of such BoP damage.

BoP downtime resulting from high winds and accumulation and shedding of ice and snow has been a large contributor to reduced Project availability and unscheduled BoP maintenance costs. As a result, BoP availability has been somewhat lower than expectations. GL GH notes, however, that reported turbine availability has been higher than the value projected for mature operation, such that combined turbine and BoP availability is in line with GL GH expectations. Significant turbine icing downtime as well as lack of site access due to winter weather have also been drivers for overall downtime; the Sponsor indicates that such additional downtime has generally been consistent with its assumptions in the operating plans. Overall Project availability since start of operations has averaged 92.2%.

GL GH reviewed the Project operating plans and considers that generally appropriate amounts, commensurate with contractual arrangements and historical Project costs, have been budgeted in the near term, although GL GH anticipates higher turbine O&M costs in later Project years than Sponsor estimates. GL GH considers that the historical operating costs through Q2 2013 were within expectations for a project of this size and location.

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SUPERIOR COURT OF CALIFORNIA

COUNTY OF SHASTA

In the Matter of the Determination of the Rights of the Various Claimants to the Waters of WILLOW CREEK STREAM SYSTEM, Shasta County, California.	NO. 87524 DECREE

The above-entitled cause having come on regularly for hearing, trial and determination on June 9, 1986, before this court sitting without a jury; all parties in interest in said proceeding having been duly and regularly notified of said hearing; the State Water Resources Control Board (hereinafter referred to as the "Board") having filed with the clerk of this court a certified copy of the Order of Determination together with the original evidence filed with or taken before the Board and certified by it; no written exceptions to the Order of Determination having been filed; attorney Daniel N. Frink, appearing on behalf of the Board, having moved for entry of a decree affirming the Order of Determination pursuant to Water Code Section 2762; no one appearing in opposition to the Board's motion; the Court having granted the motion for entry of a decree as requested by the Board; the Court now affirms

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said Order of Determination, except to the extent that it is modified herein for correction of clerical errors and changes of property ownership, and the Court renders this Decree determining the rights of all parties to this proceeding as follows:

IT IS ORDERED, ADJUDGED AND DECREED that the several rights of all existing claimants in and to the use of water of the Willow Creek Stream System in Shasta County, California are determined and established to be as hereinafter set forth:

Definitions

1. "Water Code" means the State of California Water Code.

2. "Stream System" means the Willow Creek Stream System. It includes Willow, Minnow, and Dunn Creeks and other tributaries from their headwaters to the outflow into Montgomery Creek in Shasta County, California. It also includes water in subterranean streams which flow in known and definite channels and which contribute to the Willow Creek Stream System.

3. "Claimant" means a party who has filed a proof of claim of water right in and to the use of water of Willow Creek Stream System, or who, having failed or refused to file such a proof of claim properly, has had his right determined pursuant to provisions of Water Code Section 2577.

4. "Directly apply to beneficial use" means the direct conveyance and application of water diverted to beneficial use without intermediate storage, except for reasonable regulatory storage used to create a convenient head for irrigation or other beneficial use as allowed herein.

5. "Seasonal storage" is defined as the collection of natural flow in a reservoir during a time of high stream flow, such

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as the winter and spring months, where such water is held and used during a time of deficient stream flow, such as the summer and fall months.

6. "Regulatory storage" is defined as the collection of a direct diversion of water to a reservoir in which water is held for less than 30 days before being withdrawn for the purpose of creating a convenient head for irrigation or other beneficial use allowed herein.

7. "Natural flow" means such flow as will occur at the point in a stream from the runoff of the watershed which it drains, from springs and seepage which naturally contribute to the stream, and from waste and return flow from dams, conduits, and irrigated land. Natural flow is distinguished from water released directly from storage for rediversion and use, or water imported from another watershed which is released directly to the natural channel for conveyance to the place of beneficial use.

8. "Watershed" means the drainage area or region which contributes to the water supply of a stream or lake. The watershed boundary of this adjudication is delineated on the State Water Resources Control Board map described below.

9. "Return flow" is that portion of applied irrigation water that finds its way after use back into a ditch, drain, or natural watercourse and becomes available for reuse by persons other than the original diverter.

State Water Resources Control Board Map

10. The State Water Resources Control Board map, hereinafter referred to as SWRCB map, was prepared by the Board from materials and information gathered in 1978, 1979, and at the

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hearing in 1983. It is entitled "Willow Creek Stream System, Showing Diversion and Irrigated Lands, Shasta County, California, Dated 1985". The SWRCB map comprises one sheet which is incorporated herein and attached hereto as a part of this decree.

General Entitlement

11. The claimants found in this proceeding to posses water rights are entitled to the use of water of the Willow Creek Stream System on the places of use described under their respective names in Schedule 1, and shown on the SWRCB map, from points of diversion described in Schedule 2. They are entitled to use water during the periods of time specified in paragraph 14 entitled "Season of Use" and in the amounts allotted from the various sources under the priorities and for the uses set forth after their respective names in Schedule 3, 4, and 5. The amount of water allotted shall be measured at the point of diversion from the stream system unless otherwise specified. Nothing contained herein shall be construed to allocate to any claimant a right to divert at any time from the Willow Creek Stream System more water than reasonably necessary for his beneficial use, nor to permit him a right to unreasonably impair the quality of natural flow.

Entitlement to Abandoned Water Originating in Another Watershed

12. The rights and entitlements of rightful users of imported water are not subject to this adjudication until: (1) the water has entered the channels of Willow Creek, its tributaries or subterranean streams flowing in known and definite channels and (2) the water is beyond the control of the original and rightful user. This adjudication does not in any way direct the amounts, sources, locations, or rates wherein return flow from such imported

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water shall augment the Willow Creek Stream System. When the return flow reaches the Willow Creek Stream System and flows beyond the control of the original and rightful users, it becomes subject to diversion and use by parties holding allotments of water as specified in this decree.

Priority Classes

13. The term "priority class" when used herein means a class of rights each one of which is equal in priority and correlative in right with all other rights of the same class appearing within the schedule. When available water is sufficient to supply only part of the entitlement of any specific priority class, said available supply shall be prorated in accordance with allotments in that priority class. Except as provided in Paragraphs 15 and 25, no priority class is entitled to use any water until all higher priority rights have been fully satisfied. Thus, within the same schedule, all rights of the Second Priority Class are inferior in priority and subordinate to all rights of the First Priority Class.

Season of Use

14. Allotments for irrigation shall be for continuous use from April 1 to November 1 of each year except as otherwise provided in Schedule 5. Allotments for domestic and stockwatering purposes shall be for continuous use throughout the year.

Domestic Use

15. Domestic use is limited to water applied exclusively for household purposes, watering of domestic animals and irrigation of up to one-half acre of yard, garden and family orchard. In accordance with Water Code Section 106, all parties named in

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Schedule 3 and 4 are allotted 500 gallons per day, at their place of use, on a year round basis for residential domestic use with priority over all other uses set forth in said schedules.

Stockwatering Use

16. Stockwatering use is limited to water required by commercial livestock.

Irrigation Use

17. Irrigation use is limited to the application of water for the purpose of meeting moisture requirements of growing crops.

Combined Uses

18. Claimants diverting water under allotments for irrigation use are entitled to use water for incidental domestic and stockwatering purposes incidental to the aforesaid major uses.

Domestic and Stockwatering Uses During the Nonirrigation Season

19. To provide water at the various places of use for domestic and stockwatering purposes during the nonirrigation season from November 1 to about April 1, all claimants in Schedules 3 and 4 are entitled to divert a sufficient amount of water in their priority class to offset reasonable conveyance losses and to deliver 0.01 cubic feet per second (cfs) at the place of use.

Equivalent Flow to Provide Adequate Head

20. All quantities of water allotted to the several claimants for direct application to beneficial use in Schedules 3, 4 and 5 are expressed in terms of continuous flow. However, such claimants may rotate the use of water with other related rights in the same stream group or for the specified purpose of use and thus apply water to the place of use at a greater rate than indicated by the quantity of continuous flow so allotted. The several claimants

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may divert, for limited periods of time, convenient "heads" to achieve the same purpose. Such practice of rotation or use of a convenient "head" shall not result in the use by any such claimant of a total quantity of water during any thirty-day period in excess of the equivalent of claimant's continuous allowance. It is further provided that such practice of rotation or use of convenient "heads" shall not cause an unreasonable interference in the regime and quantity of available natural flow to which others are entitled or which would adversely impact on the existing fisheries.

Instream Use in Willow Creek

21. Future activation of unexercised riparian rights and rights of future appropriators are subject to the maintenance of a minimum flow of 0.5 cfs in Willow Creek at the Fenders Ferry Bridge upstream of the confluence of Willow Creek with Montgomery Creek to provide protection of fish life.

Pre-1914 Appropriations

22. Phillip W. and Sharon A. Stanbro, Louis E. and Wilma C. Colbert, and Julius Gabriele are successors to pre-1914 appropriations as well as being owners of riparian land contiguous to Willow Creek. Since riparian water rights are accorded priority over the appropriative rights in this adjudication, and since all irrigated lands shown in Schedules 3 and 4 are riparian, no separate allotment is shown for the pre-1914 appropriative rights.

Riparian Rights

23. Riparian rights for irrigation are placed in the second priority classification in Schedules 3 and 4.

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Post-1914 Appropriations

24. The relative order of individual priority of appropriative rights initiated after December 19, 1914, is established by the date of filing of the application to appropriate water. Jurisdiction over post-1914 appropriations remains with the State Water Resources Control Board. When a license is issued to verify completion of an appropriative right in accordance with the terms and conditions of permits issued by the State Water Resources Control Board or its predecessor agencies, the licensee or the Board may petition the court for a supplemental decree confirming the right in accordance with the license. Post-1914 appropriations and a single stockpond certificate are summarized in Schedule 5. Diversion of water under these rights shall be in strict conformance with the permit and license terms specified by the Board. The riparian rights specified in Schedules 3 and 4 have priority over the post-1914 appropriative rights listed in Schedule 5. No diversion of water is permitted under the rights listed in Schedule 5 at any time it will interfere with diversion of water under the rights specified in Schedules 3 and 4.

Future Domestic Use by Present Claimants of Unexercised Riparian Rights

25. In addition to all rights described elsewhere in this document, the following parcels or property as designated on the SWRCB Map are riparian to Willow Creek or to a tributary of the Willow Creek Stream System: Puhlman parcel; H. Nancel parcel; Russell Wagner parcel; C. Harber parcel; Hallman parcel; Rodriguez parcel; Lincoln parcel; Durst parcel; Cal-Vest Properties, Inc. Parcels I, J, K, L, M, N, O, P, and Q; and Parcel R (now owned by J. C. and H. G. Truman). In accordance with Water Code Section

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owners of such parcels are allotted at their point of diversion on the stream to which they are riparian an amount not greater than 500 gallons per day throughout the year for residential domestic use with a priority equal to the rights described in paragraph 15 herein. All other unexercised riparian rights within the Willow Creek Stream System shall be defined and exercised in accordance with paragraph 26 below.

Unexercised Riparian Rights

26. All claimants and other persons not named in this decree owning land riparian to streams in the Willow Creek Stream System have unexercised riparian rights to the use of water; however, any right that is not defined in this decree shall be defined and exercised only in accordance with the provisions of this decree. Any person who holds unexercised riparian rights may apply to the court under paragraph 27 or to the Board under paragraph 28 for definition of a riparian right which is not defined in this decree at the time of such application. If the court finds that such person proposes diligently, reasonably and beneficially to exercise such right, the court shall define the right in terms consistent with such proposed reasonable beneficial use. Any riparian right defined pursuant to this paragraph shall be the subject of a supplemental decree and shall possess a priority as of the date of application to the court or to the Board, as the case may be. Riparian rights defined pursuant to this paragraph shall be subject (1) to all rights which are defined in this decree, including any supplemental decrees, as said decree exists on the date of application to the court or to the Board by a riparian claimant, and (2) to any appropriative right initiated by

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application, in accordance with Part 2 (commencing with Section 1200) of Division 2 of the Water Code, prior to the date of application to the court or to the Board by a riparian claimant.

Reserved Jurisdiction

27. The court reserves continuing jurisdiction, upon application of any party hereto, or successor in interest thereto, or upon its own motion or the motion of the State Water Resources Control Board, to review the decree and to change or modify the same as the interests of justice may require.

Changes in the Exercise of Rights

28. Any party who wishes to change or modify the exercise of his rights set forth in the decree may request the Board to investigate said change or modification. The Board shall notify all affected parties of its investigation and give them an opportunity to object to the proposed change. If an application to activate riparian rights is filed with the Board, notice shall be given in accordance with the notice provisions for appropriative applications as set forth in Water Code Section 1300 et seq. If any affected party objects to the proposed change or modification, the Board shall hold a hearing or other proceeding in lieu of hearing. Following its investigation the Board shall file its report which determines whether the proposed change or modification is in accordance with applicable law and which makes a recommendation regarding changes or modifications of the decree. Any changes or modifications of the decree recommended by the Board shall be entered, subject to court review and approval, as a supplemental decree. The Board shall be entitled to receive reimbursement for its expenses of such investigation. Proceedings

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on the apportionment of the expense shall be as nearly as may be in accordance with the provisions of Article 13, Chapter 3, Part 3, Division 2 of the Water Code, commencing with Section 2850. Nothing in this paragraph shall restrict any right which any person may have under any statute or common law to change or modify the exercise of his rights set forth in the decree.

Appointment of Watermaster

29. This court retains continuing jurisdiction to approve any watermaster proposed by the parties under this provision, or to appoint a replacement watermaster if the parties do not do so after an appointed watermaster ceases to perform duties under this decree. Any party to the adjudication or the State Water Resources Control Board may petition the court to approve or appoint a watermaster under this provision, or the court may take steps to do so on its own motion.

Water Right Disputes in Watermaster Service Area

30. If a watermaster service area is created in accordance with applicable law, the watermaster shall distribute the water in accordance with the decree. If a water rights dispute arises between users, the watermaster shall regulate those diversions as set forth in the decree and as necessary to settle the dispute. Any party who alleges that the watermaster is not regulating his water right in accordance with this decree may apply to the Board to investigate said allegations. The Board shall notify all affected parties of its investigation and give them an opportunity to respond to the allegations. If any affected party requests a hearing or other proceedings in lieu of hearing, the Board shall duly notice and schedule a hearing or other proceedings

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in lieu of hearing. Following its investigation the Board shall file its report which determines whether the watermaster has regulated the water right in accordance with the decree and which makes its recommendation to the Court for any change, modification, or clarification of the decree. Any change, modification, or clarification of the decree recommended by the Board shall be entered, subject to Court review and approval, as a supplemental decree. The Board shall be entitled to receive reimbursement for its expense of such investigation. Proceedings on the apportionment of expenses shall be as nearly as may be in accordance with the provisions of Article 13, Chapter 3, Part 3, Divsion 2 of the Water Code, commencing with Section 2850. Nothing in this paragraph shall restrict any right which any person may have under any statute or common law to seek enforcement of this decree or to seek any other relief.

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<u>Effects of the Decree</u>

31. Each and every claimant, his or her agents, successors, grantees and assigns, shall be and hereby are perpetually enjoined and restrained from doing anything in violation of the terms or provisions of the judgment and decree, and from diverting any water from said Willow Creek Stream System as defined herein at any time in excess of a quantity reasonably necessary for, and actually applied to, reasonable beneficial use, under and by reasonable methods of diversion and use, and from doing anything, directly or indirectly, that will obstruct or interfere with any right of another adjudged and decreed in this action.

32. This decree is conclusive as to the rights of all

existing claimants in the Willow Creek Stream System as defined herein.

33. This decree supersedes and modifies all inconsistent former judgments and decrees as to the rights to the flow of the Willow Creek Stream System. However, the judgment does not supersede rotation or ditch agreements consistent herewith.

34. Permits and licenses initiated by application under provisions of the Water Commission Act or the Water Code shall continue to be administered by the State Water Resources Control Board as in other cases. Upon issuance, revocation or authorized change in any permit or license in accordance with the California Water Code, and upon motion of the permitee, licensee or the Board, the Court shall enter a supplemental decree confirming the Board's action.

35. Except as provided by Paragraph 26, any claimant who has failed to appear and submit proof of his claim as provided in Chapter 3, Part 3 of Division 2 of the Water Code, shall be barred and estopped from subsequently asserting any rights heretofore acquired upon the Willow Creek Stream System as defined herein. Such claimants forfeit all rights to water therefore claimed on said stream system, other than as provided in this decree, unless entitled to relief under the laws of this state.

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Statements of Diversion and Use

36. All persons diverting water under water rights other than appropriative water rights initiated after December 19, 1914, are required to file Statements of Diversion and Use in accordance with Part 5.1 of Diversion 2 of the Water Code commencing with Section 5100.

Dated: JUL / 1986

J.H. REDMON
Judge of the Superior Court

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SCHEDULE 1
Description of Places of Use
of Water From Willow Creek Stream System*

Owner	Acres	Subdivision	Section	Township: Range MDB&M
Bertagna, Joseph and Marian L.	10	N1/2 of SE1/4	11	34N 1W
Bertagna, Paul J. and Mary E.	4	NE1/4 of SE1/4	11	34N 1W
Buffington, John L. Jr.	8	N1/2 of NW1/4	17	34N 1E
Bull, Charles E.	10	S1/2 of NE1/4	18	34N 1E
Colbert, Louis E. and Wilma C.	15	S1/2	18	34N 1E
Gabriele, Julius and Linda	5	SE1/4 of SE1/4	11	34N 1W
	7	SW1/4 of SW1/4	12	34N 1W
	12	NW1/4 of NW1/4	13	34N 1W
	6	NE1/4 of NE1/4	14	34N 1W
Total	30			
Gates, Robert L. and Marjorie S.	8	N1/2 of SW1/4	18	34N 1E
Harber, Virgil and Pauline	1	NW1/4 of SE1/4	11	34N 1W
Pacific Gas and Electric Co.	Stk.	S1/2 of SE1/4	11	34N 1W
Puhlman, Albert E. and Carol J.	Dom. & Stk.	NW1/4 of SW1/4	17	34N 1E
Stanbro, Phillip W. and Sharon A.	8	SE1/4 of SE1/4	18	34N 1E
Webb, Joyce J.	2	SW1/4 of SW1/4	1	34N 1W

*Also see Schedule 5

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SCHEDULE 2
Location of Points of Diversion

Name of Diversion System	Number of Diversion on SWRCB Map	Location of Point of Diversion: Legal Sub-Division in Which Diversion Occurs MDB&M	Reference Corner	Coordinate Distances from Reference Corner (in feet)	Township: Range MDB&M
Buffington	1	NE1/4 of NW1/4 Sec. 17	NW Sec. 17	S900 E2,600	34N 1E
Buffington	2	NE1/4 of NW1/4 Sec. 17	NW Sec. 17	S900 E1,900	34N 1E
Buffington	3	NE1/4 of NW1/4 Sec. 17	NW Sec. 17	S900 E1,400	34N 1E
Puhlman	4	NW1/4 of SW1/4 Sec. 17	SW Sec. 17	N2,200E1,200	34N 1E
Stanbro	5	SE1/4 of SE1/4 Sec. 18	SE Sec. 18	N1,100 0	34N 1E
Colbert	6	NW1/4 of SE1/4 Sec. 18	SE Sec. 18	N1,900 W1,500	34N 1E
Gates	7	NE1/4 of SW1/4 Sec. 18	SW Sec. 18	N1,800 E2,200	34N 1E
Gates	8	NE1/4 of SW1/4 Sec. 18	SW Sec. 18	N2,300 E2,300	34N 1E
Gates	9	NE1/4 of SW1/4 Sec. 18	SW Sec. 18	N2,600 E1,600	34N 1E
Gates	9a	NW1/4 of SW1/4 Sec. 18	SW Sec. 18	N2,600 E1,000	34N 1E
Gates	9b	NW1/4 of SW1/4 Sec. 18	SW Sec. 18	N1,500 E 600	34N 1E
Lincoln	10	SE1/4 of SE1/4 Sec. 13	SE Sec. 13	N1,300 W 700	34N 1W
Gabriele	11	NW1/4 of NW1/4 Sec. 13	NW Sec. 13	S1,300 E 900	34N 1W
Gabriele	11a	NE1/4 of NE1/4 Sec. 14	NE Sec. 14	S 700 W 200	34N 1W

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SCHEDULE 2
Location of Points of Diversion
(continued)

Name of Diversion System	Number of Diversion on SWRCB Map	Location of Point of Diversion: Legal Sub-Division in Which Diversion Occurs MDB&M	Reference Corner	Coordinate Distances from Reference Corner (in feet)	Town-ship: Range MDB&M
J. Bertanga	12	NW1/4 of SE1/4 Sec. 11	SE Sec. 11	N1,800 W1,500	34N 1W
P.&J.Bertanga	13	NW1/4 of SW1/4 Sec. 12	SW Sec. 12	N2,000 E 800	34N 1W
J. Bertanga	14	NE1/2 of SE1/4 Sec. 11	SE Sec. 11	N1,700 W 200	34N 1W
Harber, V. & P.	15	NW1/4 of SE1/4 Sec. 11	SE Sec. 11	N2,300 W1,400	34N 1W
Webb	16	SW1/4 of SW1/4 Sec. 1	SW Sec. 1	N 400 E1,100	34N 1W
Wheeler	17	SE1/4 of SW1/4 Sec. 11	SW Sec. 11	N 900 E1,800	34N 1W
Shaw	18	NW1/4 of NE1/4 Sec. 18	NE Sec. 18	S 800 W1,500	34N 1E
Klein	19	NW1/4 of NE1/4 Sec. 18	NE Sec. 18	S 200 W2,200	34N 1E
Truman	20	NW1/4 of NE1/4 Sec. 7	NE Sec. 7	S1,700 W 500	34N 1E
Bull	21	NW1/4 of NE1/4 Sec. 18	NE Sec. 18	S1,400 W1,700	34N 1E
Pacific Gas and Electric Co.	22	S1/2 of SE1/4 Sec. 11	--	--	34N 1W

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SCHEDULE 3
Allotments to Various Claimants
From Willow Creek

Name of Claimant	Diversion No. on SWRCB Map	Use	Area Served In Acres	Allotments in Cubic Feet Per Second	
				First Priority	Second Priority
Buffington, John L. Jr.	1	Domestic		Entire Flow of Spring	
	2	Domestic Irrigation	8	Entire Flow of Spring	
	3	Domestic		Entire Flow of Spring	
Bull, Charles E.	21	Domestic Irrigation Fire	10	Entire Flow of Spring	
Stanbro, Phillip W. and Sharon A.	5	Domestic & Stockwatering Irrigation	8	0.01	0.13
Colbert, Louis E. and Wilma C.	6	Irrigation	15		0.15
Gates, Robert L. and Marjorie S.	7,8 9	Domestic Irrigation & Rec.	6	0.01	0.06
Gabriele, Julius and Linda	11	Domestic Irrigation	30	0.01	0.30
Pacific Gas & Electric II Co.	22	Stockwatering		350 gal/day	
Bertagna, Joseph and Marian L.	12*	Domestic Irrigtion & Stockwatering	10	0.01	0.10
Harber, Virgil and Pauline	15	Domestic Irrigation	1	0.01	0.01

*The same place of use is served from Diversion 14 on Minnow Creek. Total diversion from both points shall not exceed 0.01 under first priority and 0.10 under second priority.

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SCHEDULE 4
Allotments to Various Claimants
From Minnow and Dunn Creeks

Name of Claimant	Diversion No. on SWRCB Map	Use	Area Served In Acres	Allotments in Cubic Feet Per Second	
				First Priority	Second Priority
Bertagna, Joseph and Marian L.	13*	Irrigation	10		0.10
	14*	Domestic		0.01	
		Irrigation	10		0.10
Bertagna, Paul J. and Mary E.	13	Irrigation	4		0.04
Webb, Joyce J.	16	Domestic		0.01	
		Irrigation	2		0.02

*The same place of use is served from Diversion 12 on Willow Creek. Total quantity diverted from Diversions 12, 13 and 14 shall not exceed 0.01 under first priority and 0.10 under second priority.

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SCHEDULE 5
Post-1914 Appropriative Water Rights

Name	Diversion No.	Application No.	Permit No.	Source	Use[1/]	Acres	Subdivision Section Township Range MDB&M	Allotment (afa)	Season of Use
Puhlman, Albert E. and Carol J.	4	SP 3242		Unnamed Stream	Stk		NW¼ of SW¼, Sec 17 34N, 1E	2.3	
Gates, Robert L. & Marjorie S.	9a, 9b,	25806	18103	Willow Creek & Two Unnamed Streams	Irr, Dom, Stk, Rec, Fire	2	N½ of SW¼ Sec 18, 34N, 1E	10	1/1-4/1
Lincoln, Richard G. & Michele L.	10	25805	18069	Unnamed Stream	Irr, Dom, Stk, Rec, Fire	10	SE¼ of SE¼, Sec 13 34N, 1W	20	11/1-4/1
Gabriele, Julius & Linda	11,11a	25856[2/]		Willow Creek & Unnamed Stream	Irr, Dom, Stk	30	SE¼ of SE¼, Sec 11; SE¼ of SW¼, Sec 12; NW¼ of NW¼, Sec 13; NE¼ of NE¼, Sec 14; 34N, 1W	14.4	11/1-4/1
Wheeler, Ernest L.	17	25879	18394	Unnamed Stream	Stk		SE¼ of SW¼, Sec 11, 34N, 1W	10	1/1-3/1
Shaw, Veldon et al.,	18	26243	18595	Unnamed Stream	Stk, Rec, Wildlife		NW¼ of NE¼, Sec 18 34N, 1E	10[3/]	1/1-3/1

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SCHEDULE 5 (con't)
Post-1914 Appropriative Water Rights

Name	Diversion No.	Application No.	Permit No.	Source	Use 1/	Acres	Subdivision Section Township Range MDB&M	Allotment (afa)	Season of Use
Klein, Frederick & Phyllis	19	26244	18418	Unnamed Stream	Irr, Dom, Rec, Fire Wildlife	3	NW¼ of NE¼ Sec 18 34N, 1E	3.0	1/1-3/1
Truman, John C. and Helen G.	20	26819		Dunn Creek	Rec, Fire		SE¼ of NE¼ Sec 7 34N, 1E	0.5	1/1-3/31

1/ Stk = Stockwater, Irr = Irrigation, Rec = Recreational, Dom = Domestic, Fire = Fire Protection, Wildlife = Wildlife Enhancement

2/ Application 25856 of Julius and Linda Gabriele also requests 4,000 gallons per day year round for domestic use, 375 gallons per day for stockwater use and 0.334 cubic feet per second from April 1 to October 15 for irrigation. The Gabrieles' direct diversion of water is also covered under riparian rights. The right to divert water to storage under Application 25856 is contingent upon issuance of a permit by the State Water Resources Control Board. The maximum amount to be diverted is not to exceed 137.4 acre-feet per annum.

3/ The pond is also primarily replenished by water from Childs-Bowley-Calkin Ditch.

P45-160 cont.

P45-160 cont.

Appendix E
Responses to Confidential Letter

Appendix E contains comments received in confidence from the Pit River Tribe. The comments and responses to them are being protected from public disclosure at the request of the Tribe. The contents of this Appendix E have been provided for consideration by decision-makers but have not been disclosed for public review.

Appendix F
Recipients of the Final EIR

APPENDIX F
Recipients of the Final EIR

Name/Contact	Affiliation
Lead Agency	
Hellman, Paul (Director)	Shasta County Department of Resource Management
Fieseler, Adam (Planning Division Manager)	Shasta County Department of Resource Management
Salazar, Lio (Senior Planner)	Shasta County Department of Resource Management
Federal Agencies	
Jim Richardson, Superintendent	National Park Service, Lassen Volcanic National Park
Kelley, Matthew P.	U.S. Army Corps of Engineers, Sacramento District, Redding Office
Mata, Jennifer	U.S. Department of Interior, Bureau of Land Management-Redding
	U.S. Department of Transportation, Federal Aviation Administration
Norris, Jennifer	U.S. Fish and Wildlife Service
Thomas Leeman, Deputy Chief Migratory Birds Program	U. S. Fish and Wildlife Service
Lassen National Forest Supervisor's Office	U.S. Forest Service
Stone, Alexander (U.S. Navy Pacific Fleet)	U.S. Navy, Military Training Routes
Local Agencies	
Hall, Cindy (District Secretary)	Burney Fire Protection District
Keady, Monte (Fire Chief)	Burney Fire Protection District
	California Highway Patrol- Redding Office
Northeast Information Center	California Historical Resources Information System
Berchtold, Dannas J.	Central Valley Regional Water Quality Control Board, Stormwater & Water Quality Certification Unit
Smith, Bryan	Central Valley Regional Water Quality Control Board, Stormwater & Water Quality Certification Unit
	City of Anderson, Planning Department
Russ Wenham	City of Anderson, Director of Engineering and Development
Vaupel, Larry	City of Redding, Development Services Department, Planning Division
Bryant, Garret	City of Redding, Airports
	City of Shasta Lake, Planning Department
	County of Lassen, Planning and Building Services
Curtis, Sean	County of Modoc, Planning Department
Wilson, Randy	County of Plumas, Planning Department
	County of Siskiyou, Planning Department

Name/Contact	Affiliation
Maze, Kristen	County of Tehama, Planning Department
Hubbard, Leslie	County of Trinity, Planning Department
	County of Trinity, Planning Department
Goodwin, Susan	Cow Creek Watershed Management Group
Millington, Mike (President)	Fall River Resource Conservation District
Waldrop, John	Shasta County Air Quality Management District
Morgan, Leslie (Assessor-Recorder)	Shasta County Assessor’s Office
	Shasta County Assessor/Recorder
	Shasta County Board of Supervisors Office
Chimenti, Joe	Shasta County Board of Supervisors- District 1
Moty, Leonard	Shasta County Board of Supervisors- District 2
Rickert, Mary	Shasta County Board of Supervisors- District 3
Morgan, Steve	Shasta County Board of Supervisors- District 4
Baugh, Les	Shasta County Board of Supervisors- District 5
	Shasta County, Clerk of the Board
Cruse, Rubin	Shasta County, County Counsel
Ross, James (Assistant County Counsel)	Shasta County, County Counsel's Office
Deckert, Andrew	Shasta County Department of Public Health
Minturn, Pat	Shasta County Department of Public Works
Fletcher, Dale (Building Division Manager)	Shasta County Department of Resource Management
Serio, Carla	Shasta County Department of Resource Management, Environmental Health Division
Cerami, Joe	Shasta County Economic Development Corporation
Pontes, Matthew	Shasta County, Executive Officer
Carroll, Theresa	Shasta County Fire Department (SCFD-71)
Zanotelli, Jimmy (Fire Marshal)	Shasta County Fire Department
	Shasta County Hazardous Materials Program, CUPA
Ramstrom, Karen	Shasta County, Health and Human Services Agency, Public Health Services
Tracy, Anna	Shasta County Library
	Shasta County Library, Anderson Branch
	Shasta County Library, Burney Branch
Buckalew, Darcy, (Administrative Office Manager)	Shasta County Mosquito and Vector Control District
Flores, Judy	Shasta County Office of Education
Chapin, James	Shasta County Planning Commission
Kerns, Steven	Shasta County Planning Commission
MacLean, Tim	Shasta County Planning Commission
Ramsey, Roy	Shasta County Planning Commission
Wallner, Patrick	Shasta County Planning Commission
Magrini, Eric	Shasta County Sheriff's Office
Lt. Tyler Thompson, Burney Patrol Station	Shasta County Sheriff's Office
Little, Dan	Shasta Regional Transportation Agency
Cloney, Jim	Shasta Union High School District

Name/Contact	Affiliation
Anderson, Chester	Western Shasta Resource Conservation District
State Agencies	
Bunn, David	California Department of Conservation
Babcock, Curt (Habitat Conservation Program Manager)	California Department of Fish and Wildlife
Hubbard, Kristin (Environmental Scientist)	California Department of Fish and Wildlife
Bradley, Mike (Region Chief)	California Department of Forestry and Fire Protection
	California Department of Forestry and Fire Protection
Lowe, Ken	California Department of Forestry and Fire Protection (CAL FIRE)
Rowe, Benjamin (SHU Unit Forester)	CAL FIRE
Solinsky, William D. (Bill), RPF #2297 (Forester III, THP Administration)	CAL FIRE
Gonzalez, Marcelino "Marci" (Local Development Review and Regional Transportation Planner)	California Department of Transportation (Caltrans)
Grah, Kathy	Caltrans District 2, Local Development Review MS6
Brown, Jeff	Caltrans Division of Aeronautics
Abou-Taleb, Moustafa	California Emergency Management Agency
	California Energy Commission, Media and Public Communications Office
Nelson, Patricia	California Governor's Office of Emergency Services
Gayle Totton	California Native American Heritage Commission
	California Public Utilities Commission
Stephen W. Watson, Lassen District Engineer, Drinking Water Field Operations Branch	California State Water Resources Control Board, Division of Drinking Water
Morgan, Scott	State Clearinghouse
Tribal Entities	
Self, Kyle (Chairperson)	Greenville Indian Rancheria of Maidu Indians
	Nor Rel Muk Nation
Shasta C. Gaughen, PhD (Tribal Historic Preservation Officer,)	Pala Band of Mission Indians
Anguirone, Jaime	Pit River Tribe
Baker, Zalynn (Director of Emergency Services)	Pit River Tribe
Davis, Radley (Member)	Pit River Tribe
Dunn, Agnes Maxine (Madesi Band, Elder)	Pit River Tribe
Fili, Ange	Pit River Tribe
Forest, Oliver W.	Pit River Tribe
Forrest-Perez, Natalie (Tribal Historic Preservation Officer)	Pit River Tribe
Gali, Morning Star (Tribal Historic Preservation Officer)	Pit River Tribe
Gemmill, Mickey (Chairperson)	Pit River Tribe
Hayward, James (Madesi Band)	Pit River Tribe
Lawrence Cantrell (Astugewi Band, Elder)	Pit River Tribe
McDaniels, Brandy (Madesi Band Cultural Representative for the Pit River Tribe)	Pit River Tribe
Wilkes, Wanda (Madesi Band, Elder)	Pit River Tribe

Name/Contact	Affiliation
White, Charles (Tribal Administrator)	Pit River Tribe
Yiamkis, Tony (Illmawi Band)	Pit River Tribe
Bennett, Frieda (Chairperson)	Quartz Valley Indian Community
Murphy, Barbara (Chair)	Redding Rancheria
Potter, Jack (Chairperson)	Redding Rancheria
	Roaring Creek Indian Rancheria
Difuntorum, Sami Jo (Cultural Resource Coordinator)	Shasta Indian Nation
Hall, Roy (Chairperson)	Shasta Indian Nation
Melany Johnson	Susanville Indian Rancheria
Whitehouse, Gene (Chairperson)	United Auburn Indian Community of the Auburn Rancheria
	United Tribe of Northern California, Inc.
Sisk-Franco, Caleen (Chief)	Winnemem Wintu Tribe
Mark Miyoshi, Tribal Historic Preservation Officer	Winnemem Wintu Tribe
	Wintu Educational and Cultural Council
	Wintu Tribe and Cultural Council
	Wintu Tribe and Toyon Wintu Center
Hayward, Kelli	Wintu Tribe of Northern California
McMaster, Wade (Chairman)	Wintu Tribe of Northern California
Baga-Weaver, Angel	
Scofield, Charis	
Organizations and Members of the Public	
Abbott, William	
Alconora, Lon	
Alward, Lon	
Alward, Lori	
Alward, Lyda	
Anguiano, James	
Armstrong, Bev	
Arthur, Damon (Multimedia Journalist)	Redding Record Searchlight
Ashurst, Bob (Chief Engineer)	KRCR TV News Channel 7
B., Linda	
B., Steve	
Baga, Heather	
Baier, Edmond	
Baker, Bryce	
Baker, Douglas	
Baker, Erin	
Baker, Nadine	
Baker, Traci	
Baldwin, Herb	
Baler, Irene	
Bates, Linda	

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Bauer, Sharon	
Baugh, Kandace	
Beaver, Linda	
Beaver, Marvin	Moose Camp
Becker, Sue	
Beckett, Jill	
Beeler, Heather	
Belak, Jon	National Audubon Society
Bennett, Jerry	
Benton, Crystal	
Benton, David	
Berditschevsky, Michelle (Founder Staff Conservation Consultant)	Mount Shasta Bioregional Ecology Center
Bergman, David	
Bertagne, Paul	
Bhoados, Steven & Leland	
Billings, Bruce	
Blaine, Dyann	Pattern Energy
Blake, Tamera	
Blaylor, Donna & Gerald	Teoxel
Bloom, Don	
Bob Rynearson	W.M. Beaty & Associates, Inc.
Bond, Richard and Joanne	
Boyan, Barbara	
Boyan, Craig	
Brady, Rita (Manager, Asset Management)	Pattern Energy
Bremer, Jim (Program Director)	Stephens Media Group
Brown, Erin	
Brown, Greg and Naomi	
Brown, Jeremy	
Brown, M Fred	
Brown, Naomi	
Brown, Paul	
Bryant, Stu	
Bucholz, John	-
Buelow, Teri	
Bulbolz, John	
Bullen, MaryKate	
Byers, Brook	
Byrd, Alice	
Camp, Catherine	
Campjon, Kerena	

Name/Contact	Affiliation
Cantrell, Teresa	
Carreno, Sabrina	
Carter, Nancy	
Cawker, Donna	
Celgwell, Forest	
Chamberlain, Mark	
Chavez, Fidel (Field Representative)	Carpenters Local 180
Clark, Cathy	
Clements, Janice	
Cobb, Debbie	
Cobb, Janet (Executive Director)	California Wildlife Foundation
Compton, Randy	
Cooper, Sue	Oak Run Elementary School
Cornwall, Chuck	
Crowder, Kelly	
D., Johnny	Mountain Gate Quarry
Danielson, Jeanne	Oak Run Lumber Co. LLC
Dickson, Kelly	
DiMaio, Christel	
DiMaio, Joan M.	
Dorroh, Lynn (CEO)	Hill Country Community Clinic - Health & Wellness Center
Douglas, Lorrie Kay	
Doveuson, John	Moose Camp
Duckett, Dawn	Carpenters Local 1599- Officer Manager/Bookkeeper
Edmonds, Leon	
Epperson, Ron	
Evans, Dwight	
Evans, William	
Fenimore, George	
Ferguson, Jon	Moose Camp Resident
Ferguson, Lynn	Moose Recreational Camp
Fiscus, Adam	
Flood, Laurie	
Forman, Justin	
Forster, Carol M.	
Forster, James	
Forster, James Richard & Carol Mallory Liv Trust	
Forster, Rick	
Foster, Sandy	
Freeman, Jonathon	
Frolich, Jennifer	
Frolich, Scott	

Name/Contact	Affiliation
Frost, Kelly Sr.	KQMS Newstalk 1400
Fuhrmann, Andreas	
Gable, John	Moose Camp
Garricy, Steven M.	
Garry, George	
Garwood, Joe	
Gheen, Pat	
Gifford, Jennifer	
Glaser, James	
Goland, Kristen	Pacific Wind Development, LLC
Good, Kathy	
Good, Mike	
Goolsby, J. Michael (CEO)	Better Neighborhoods, Inc.
Goot, Jimmy	
Goudreau, Paula	Redding Record Searchlight
Hagen, Bill	
Hallman, Barbra & David	Moose Camp
Halstead, Larry	
Hawkins, Greg	Fall River Joint Unified School District
Heaton, Cody and Pat	
Hemsted, Gary	Moose Camp
Henning, Nick	
Henrich, Pedro	
Holden, Amy	
Holden, Dean	
Holden, Richar	
Holsinger, Bob	
Hoppe, Happy	
Hultgren, Arne (Special Projects Forester, RPF #2581)	LandVest | Timberland
Hultgren, William	
Humphreys, Robert	
Hunt, Terry	
	Intermountain News
Jenkins, Deever	
Jenkins, Jeremiah	
Jim, Jessica	
Johnson, Steven J.	
Jones, Poup	
Kaiser, Anna	
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Keener, Scott	
Kelly, Kate	
Kernie, SJ	
Kerns, Joyce	
Kersten, Sharon	
	KKRN Community Radio
King, Paul	
Kloeppel, Robert	
Knauer, Chuck	Carpenters Local 1599
Knight, Michael	
Kuba, John	ConnectGen
Kuhs, Robert G.	
La Russa, Judy	East Valley Times
Lammers, John	
Lammers, Robert	
Lammers, Prudence	
Lancaster, Gail and Dwayne	
Langlois, Lionel	
Lankastea, Bill	
Larson, Dave	
Larson, Pam	
Lattin, Jess	
Leach, Steve	
Leaf, Seabrook	
Ledger, David (President)	Shasta Environmental Alliance
Lee, David	
Lettenback, Bob	
Libonati, Susan (President)	California Native Plant Society- Shasta Chapter
Livingston, John	Sierra Club
Loe, Bob	
Longbrake, Lee & Susan Westrup	
Loveness, Al	
Loveness, Linda	
Lynch, Gina	
Lynch, Robin	
Lynch, Ryan	
MacDonald, Keith	
MacDonald, Lisa	
Machado, Mary B. (Executive Director)	Shasta Voices

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Mahoney, Lee	
Mallory, Tim	Dogwood Acres, LLC
Marcks, Jen	
Marshall, Dennis	
Martin, Lindsay	
Matthews, Jessica	
Mayorga, Robert	
	Mayers Memorial Hospital
Mazzini, Jessie	
McCabe, Ed (Manager, Land Department)	Managing Director Better Neighborhoods
McDonald, Lisa	
McVey, Susan	
Melton, Toni	
Menka, Nazune	Rosette, LLP, Attorneys at Law
Meredith, Andrew	North State Builds
Meredith, Andrew	State Building Trades
Merriman, Joel (Director Bird-Smart Wind Energy Campaign)	American Bird Conservancy
Messick, Elizabeth L. ("Beth")	
Micheletti, Monica	
Mike	
Miller, Carol	
Miller, Kristi	
Miller, Nancy	
Miller, W. Robin	
Moore, Robyn	
Moskow, Angela	
	Mountain Echo
Mulhern, Lauren	Rosette, LLP Attorneys at Law
Murphy, Doug	
Murphy, Elizabeth	
Murphy, Hannah	
Murphy, Morgan	Moose Camp
Murphy, Spencer	
Murtha, Nicole	
Narducci, Gary and Sharon	
O'Brien, Beth	
Oliveira, Laureen	
ONETO, GARY & TINA	

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Osa, Joseph	
Osa, Margaret (Maggie)	
Ostrom, Bailey	
Owens, Lynn A.	
Palatino, Charles	
Palatino, Cynthia	
Phelps, Virginia	
Phillips, Brenda	Moose Camp
Pitz, David	
Poffinbarger, Megan	
Pooley, Dale	
Popejoy, Bill and Brenda	Moose Camp Recreation
Pressey, Brianna	
Prushko, John	
Pudlicki, Jeff	
Querner, Charles	
Quin, Only	
Rains, Randal	
Rains/Dyas, Samantha	
Rasmussen, Victoria	
Reynolds, RA	
Rice, Bill	
Robbins, Theresa	
Rosales, Carlos	Lake Shasta Caverns
Ross, Clay	Mountain Union Elementary
Rumboltz, Matt	
Rumboltz, Darlene	
Sannadan, Sheila (Legal Assistant)	Adams Broadwell Joseph & Cardozo
Sannadan, Sheila (Legal Assistant)	California Unions for Reliable Energy (CARE) c/o Adams Broadwell Joseph & Cardozo
Scott, Chad (Executive Director)	Shasta Builder's Exchange
Shaw, Steve	
Shillinglaw, Brian	Shasta Cascades Timberlands, LLC c/o New Forests
	Sierra Club, Shasta Group, Mother Lode Chapter
Simonis, Angela	
Simonis, Robert	
Skalland, Shari	-
Smith Power, Doreen	
Smith, Markham	

Name/Contact	Affiliation
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Sollid, Alan	
Sours, Judy	
Sours, Stan	
Spackman, Jeff	Moose Camp
Spiller, Tamora	
Stanford, David	
Stapp, Sandy	
Stein, Bruce	
Stephens, Laura	
Stephens, Rick	
Stockton, Tom	
Stoneback, Keith	
Stremple, Myrna Stuarts	
Stremple, Susan	
Stremple, Theresa	
Strieff, Randy	
Sturgeon, Olen	
Sublette, Karen	-
Swanson, Jeffery J.	Swanson | Moore Attorneys
Swarts, Myrna and Orvil	
Tanner, Kelly	
Tassen, Paula	
Tavares, Trudy	
Taylor, Gerald	
Taylor, Kaitlyn	
Taylor, Patricia	-
Thomas, Jason	Pacific Gas and Electric Company
Tinkler, Candace	Tinkler Family Trust
Tower, Fred	
Tyson, Jim	
Uiamkis, Tony	-
Venema, Dennis	
Vopat, Frank & Gudrun	Bales Mountain Quarry
Wadowski, Chuck (Engineer Senior Network Design)	Frontier Communications
Waldkirch, Lori	
Walker, Bill	
Wall, Janet	Audubon Society- Wintu Chapter
Wall, Lawrence	

Name/Contact	Affiliation
Walters, Raquel	
Walton, Debby	
Watson, Bill	
Watson, Evan	
Webb, Bruce	
Webb, Bruce and Wall, Janet (Co-chairs Conservation)	Wintu Audubon Society
Weiland, Susan Bond	
White, Brian	
White, Jaci	
Wiegand, Jim	
Willburn, Sandra	
Willett, Kathy	
Williams, Marvin and Linda	Moose Recreational Camp
Williams, Ralph	
Williams, Ralph & Mo	
	Wintu Audubon Society
Wolfin, Gregory	
Woltag, Henry	ConnectGen
Woodward, Ann	
Woodward, Anne Marie	
Woodward, David	
Wright, Gill (FAA Aircraft Dispatcher #3658363 VP Region 2)	California Pilots Association
Wyse, Joe Dr.	Shasta College
Xiong, Jarry	
Youngblood, B.	
Youngblood, L.	
Youngblood, Zera	

ABACHERLI JOHN DEAN SR & JANET E
ADAMS MARY LOU REVOCABLE TRUST
ADLER PAUL G DECEDENTS TRUST
ALLEN M T FAMILY TRUST
ANGEL WAYNE M & TRUDI BE 2001 TRUST
AREA H LLC
ARELLANO LORI L
ASHER JOHN S & CINDY J
AXELSON MARY E
BADGER DAVID D & DENA L

BAGA ANGEL M
BAGA JOE & SHEILA
BAKRICH MARK & WINDY
BALDWIN JASON
BARBER JASON M
BARKER JERRY ETAL
BARLOW CANDY
BARRY MICHAEL D
BARTIC KENNETH DEAN
BARTOLOMEI ROBERT DEAN & ANGELA

BAUER KEITH U & KAP J
BEARD RICHARD A TRUST 2017
BELL CASSANDRA & CARTER CASSANDRA
BENEKE NORMAN L & JENNIE
BENNETT JERALD D & JOYCE L
BERG & BERG ENTERPRISES LLC
BERTAGNA PAUL
BERTAGNA PAUL J TR ETAL
BICKLEY TERRY
BIG WHEELS RANCH
BLACK FAMILY CABIN LLC
BLACKBURN PATRICK & COWLES SEAN
BLAND DELORES & ROCKY MILTON
BLANKENSHIP STEVEN L
BLAYLOCK DONNA 2006 TRUST
BLAYLOCK DONNA A TR ETAL
BLISS ROBERT & BRANCH KEVIN
BLISS ROBERT V
BLOECHER JAMES
BOBO WILLIAM C & VIOLET P
BONE JESSICA MARIE
BOONE RANDY M & SUSANNE ETAL
BOTHWELL KRISTINA LYNN
BOTTS THOMAS JAMES
BOWMAN VERN L & DELLA M
BOYAN CRAIG & BARBARA BOYAN FAMILY TRUST
BRIGNARDELLO MARCELLO & TRACE
BROWER LYNN & COLLEEN
BROWN GREGORY & NAOMI LIVING TRUST
BROWN RICHARD M & M ANN
BRYAN DANIEL M & WENDY L
BUFFUM ANDY
BUFFUM GENE W & CHARLENE M TR ETAL
BULL BRADLY
BURANIS JOHN J REVOCABLE TRUST
BUREAU OF INDIAN AFFAIRS
BURNS FAMILY TRUST AGREEMENT
BURTON DAVID R & DEBRA R TR
BYRD ALICE LORAINE LIVING TRUST
C & C ESTATE PROPERTIES LLC
CALDWELL FAMILY REV TRUST OF 2002

CALDWELL FOREST B III
CALIFORNIA STATE OF
CAMERA JOHN
CAMP CHARLES WILLIAM
CANTRELL CAROL ETAL
CANTRELL KATRINA ANN
CARLTON JAMES WEBB
CARR DENNIS B
CARROLL MATTHEW & THERESA ETAL
CARROLL MATTHEW G & THERESA A
CATON JOHN R & KATHERINE A
CERLETTI KERRY E & TERESA DIANE
CHANG CHIA
CHANG JOHN
CHANG KHOU
CHASE WILBUR L
CHEYNE JAMES C & LORETTA M REVOCABLE TRUST
CHICOINE DON J & SYLVIA J
CHICOINE JOSEPH D & JAN M REV TRUST 2000 ETAL
CISNEROS CARMEN M TR
CITIZENS TELECOMMUNICATIONS
CLIFFORD TYLER C & JOELLE M
COBB RAYMOND H & VIVIAN K
COLE JOHN D JR FAMILY TRUST
COLLINS FRED A TRUST
COOK JOHN M & ANGELA M
COOPER MICHAEL D ETAL
CORTER TAMMY
CORTES JUAN & GUIZAR SALVADOR
CORTEZ ALBERTO CHAVEZ
COX GEORGIA M FAMILY TRUST
COX JAMES DAYTON ETAL
COYLE PATRICK WILLIAM ETAL
CRANE JEAN TERRELL TR
CRAVER KEVIN T & ERLINDA
CRIPPEN FAMILY TRUST
CUEVAS LUIS ARMANDO CUEVAS ETAL
CUMMINGS ROBERT V
DARNELL CARL JR
DAVID ADVENTURE LLC

DAVIES ALEX	GARDNER MONICA
DEBICKI TOMASZ	GEIL JAMES R & IANA R
DI MAIO COBY D & CHRISTEL	GHADIRI WOLFIEN
DICKEY MATTHEW J & TERESA M	GOLDMAN KAREN L & GERRY
DIDDOMENICO THOMAS	GOMEZ JOSE
DILL BILL J & JANE E REV TRST	GOMEZ-SACASA OSCAR & GOMEZ MYRIAN TRUST
DILLON DAVID B	GOODWIN DIANE
DINKINS FAMILY TRUST	GOODWIN LANNY G & KATHLEEN KELLEY
DIVERSIFIED CONSTRUCTION SERVICES INC	GOOSE VALLEY RANCH LLC
DIXON FAMILY TRUST	GORDON DONALD A & SUE T
DOAN JOHNNY & BROOKS BRIAN ALLEN	GOUCK DEAN PHILIP & JEANNE VERBIE
DOEPEL JAMES B	GOWER DAVID
EDSON JEREMY R	GRANSTROM SHAWN & GENA
ELAM MICHELE H TR ETAL	GRAY DANNY E LIVING TRUST
ELGIN CHARLENE	GREENWOOD JEFFERY A
ELLIOTT DANIEL	GROKENBERGER FAMILY TRUST 1999
ELLOWAY RANDAL & NOURA 2002 TRUST	GUFFEY LONNIE A & BRIGGS MARGARET E
ELMORE LORRAINE M	GUHY TERRI T
EPPERSON RONALD & THERESA TR ETAL	GUIMARAES EDUARD
ESLINGER GAYLEN E & KATHERINE K 1996 TRUSTS	GUTIERREZ ULDA E
EVANS KEITH & KATHERINE L	HACKLER JOHN SHERMAN & JEANNE LOUISE
EWIN ROY LEE & TAMMY D	HAGGETT MIKEL
FENIMORE GEORGE & JAN	HALCUMB CEMETERY DIST
FENIMORE GEORGE W III & JANEDYTHE J	HALCUMB PUB CEM DIST
FENNELL FRANCES J & DON F	HALL IVAN ALEXANDER III
FISHER GILBERT & MAYLE KATHRYN J	HAMUSEK BLOSSOM JAN ETAL
FITZGERALD FAMILY TRUST	HARBER FAMILY TRUST
FIVES CATHLEEN	HARNDEN MARILYN
FLAMBEAU RIVER PARTNERS	HARRIS TERRY L & BUDAY-HARRIS MARILYN S
FOLLETT RICHARD & KATHILYN	HARRISON TROY A ETAL
FOLLETT RICHARD W & KATHILYN W	HASKINS ERIC
FOUST DOUGLAS C	HASSINGER CAREY BENJAMIN TR
FRASER THOMAS H	HEARN MARY P
FREDRICKSON STEVE	HEATON ROBERT L FAMILY TRUST
FRUIT GROWERS SUPPLY COMPANY	HELLUM LAYNE GABRIEL
FRYER FRANCESCA B & JOHN C	HELMS ERIC E & SHELLIE D
FULLER JEFFREY L & LISA ANNE LIV TRUST ETAL	HENDERSON JAMES M & SANDRA E DVA
GALUSHA GREGORY D	HENNING FAMILY TRUST ETAL
GALUSHA GREGORY D	HENRICH FAMILY 2002 TRUST
GARBER/BERTAGNA TRUST DVA	HER CHAI
GARDENHIRE RONALD R & LINDA KAY	HEWITT KIM MARIE

HOLDEN RANSOM LEROY REV LIV TRUST
HOLDEN REBECCA
HUERTA MANUEL REYES
HUFF COLLETTE M
HUFFT TERRY & KATHRYN
HUITRIC ALBERT A ETAL
HUMCKE CHRIS J & JENNIFER L
HUTCHESON ALTON B & MELISSA A
ISMAEL MENDIVIL COVARRUBIAS ERIK
JACKSON MICHAEL & DENICORE LAURA
JENKINS JEREMIAH S
JENKINS STEVEN H ETAL
JOHN & SUSAN MCVEY REV LIV TRUST
JOHNSEN MARK L & CRYSTAL
JOHNSON LARRY
JOHNSON STEVEN J
JONES DAVID & DIANE
JONES PATRICK
JONES SANDRA
JORDAN WILLIAM ROBERT
JOSEPH SUMREAY
JUNKERSFELD ROBERT & CAROL
KEEFER MINNIE M ETAL
KEELER KIMBERLY J
KELLY JIM TRUST
KIMBERLING MARGARETTE L
KING PAUL S & BETH A
KIRK KELLEM & JESSICA
KLEIN JEFFREY F
KLOEPPEL ROBERT T 2000 FAMILY TRUST
KOENIG PAUL HARRY
KROCKER FAMILY REVOCABLE TRUST 2010 ETAL
KRUSE ROBERT & LORRAINE
KRUSE ROBERT D & JUANITA L
KUNKLER LARON L REVOCABLE TRUST OF 2007
KUTRAS GEORGE ETAL
LAFFAN DANIEL J & IVIE L
LAMMERS TRUST
LAMMERS VICTOR & HELEN M FAMILY TRUST
LAMMERS VICTOR & HELEN M FAMILY TRUST
LAND PEARL VENTURES LLC

LANGE ROLAND E JR
LANGE ROLAND E TRUST
LARABEE MELVIN & JOAN
LARABEE MELVIN H & JOAN M
LARRUCEA JESSICA
LAWRENCE RAYMOND & CINDY ANN
LEACH ELIZABETH S TR
LEE LA PET KOU
LEONARD REVOCABLE TRUST
LESLIE WARD J & SHIRLEY J TR
LIBBI TRUST
LOFARO JOSEPH PAUL ETAL
LOPEZ ULISSES
LOR NELSON
LOR YENG
LOVE JAMES MAKIN & GAYLE ANN
LOVENESS VINTON A & LINDA
LUNTEY KEVIN & DENISE
LUSTIG GOPALA KRISHNA
MACDONALD KEITH & LISA
MALAT KENNETH D
MALAT KIMBERLY REHFELD & JASON REHFELD
MALLORY MARGARET G MARITAL TRUST
MARCKS KIM & FROLICH JENNIFER
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MASON WAYNE NEAL
MASSEY REBECCA & MCCALL DEANNA
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MATTHEWS STUART W & MARY
MAZZINI FAMILY TRUST - TRUST A
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MCMILLAN 1999 FAMILY PARTNERSHIP LP
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MINTO FAMILY SPECIAL NEEDS TRUST
MONTGOMERY CREEK COMM CHURCH
MONTGOMERY ROXANNE & TILLOTSON VAUGHN
MONTGOMERY TRUST
MONTGOMERY WENDY M
MOORE KENNETH TRUST
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MORRISSEY JAMES & ADA LEA FAMILY TRUST ETAL
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MUCHA MELANIE M
MUKAI MARK S & MIDORI
MULDER TIFFANY
MURO CAROL R
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NEWELL JAMES
NEWTON JOHN O
NICHOLS AILEEN A & SHANE P
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NORGAARD ALVIN & ZENE
NORMAN ELENA TRUST
NORMAN SHARON A
OAK RUN LUMBER CO LLC
OAK RUN LUMBER CO LLC
OCONNELL SEAN
OLIVEIRA MAURO & CLAIR LAUREEN
OLSEN TIM
ONGACO ROMMEL D ETAL
ORR SURVIVORS SPOUSE FAM TRUST
OSA FAMILY TRUST
OSA FAMILY TRUST
OST MICHAEL & LINDA
OWENS LYNN A
P G & E
PACHECO SCOTT T ETAL
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RICHARD BRENT
RIDEOUT MARCIA JO
ROBERSON THOMAS K & RAMONA
ROBINSON LINDA

ROCKWELL MICHAEL & JAINY
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RUMRILL RAY JR & LOIS
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SHOEN PAUL F TR
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SNOW LARRY
SPARKS BARRY LEE
SPLAN T E & D E
SPUNG CAMERON
STATON MARE J LIVING TRUST
STENLUND TYSON & JAMIE
STEPHENS RICHARD L & PAMELA J
STEPHENSON ROSS GRAHAM TRUST OF 2013 ETAL
STEWART PATRICIA A & GARBER ADRIANNE
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TEAGUE TRISUSANTI LIVING TRUST
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THAI DAO HONG
THORN JOHN & HILL SHYLA LENORE
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TORIX KATHRYN ANN
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UNITED STATES OF AMERICA	WHEELING STACY J
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VANOY ROBERT D	WOODRUFF SARAH L
VARA OSUALDO JR	WOODWARD ANNE M REV TRUST ETAL
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VERRETTE TAMARA & PATRICK	WULFESTIEG CARL N & CLARA A
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VOORHEES GENELLE E REV TRUST	YANG PANG
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WAMPLER MARK A SR	ZDYBEL ROBERT J
WANAT BENJAMIN M & TEN BROECK MOLLY D	ZHOO YUGANG
WARREN LYNN LEWIS	ZIEMANN SAMUEL ROBERT
WATROUS STANLEY ROBERT	

Appendix G
Mitigation Monitoring and Reporting Program

Shasta County Department of Resource Management
Planning Division

FOUNTAIN WIND PROJECT

MITIGATION MONITORING AND REPORTING PROGRAM

April 2021

Use Permit No. UP 16-007
State Clearinghouse No2019012029

Prepared for:
Department of Resource Management
Planning Division

Prepared by:
Environmental Science Associates

Shasta County Department of Resource Management
Planning Division

FOUNTAIN WIND PROJECT

Mitigation Monitoring and Reporting Program

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ACRONYMS

APM	Applicant Proposed Measure
BBCS	Bird and Bat Conservation Strategy
CEQA	California Environmental Quality Act
CPM	Compliance Project Manager
EIR	Environmental Impact Report
EM	environmental monitors
FAA	Federal Avian Administration
FS	Field Supervisor
MMRP	Mitigation Monitoring and Reporting Program
NCR	Non-Compliance Report
NTP	Notice to Proceed
PFM	Petition for Modification
PM	Project Manager
Project	Fountain Wind Project
RFNTP	Request for NTP
SM	Site Managers
SWPPP	Storm Water Pollution Prevention Plan
TEWS	Temporary Extra Work Space
WEAP	Worker Environmental Awareness Program

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CHAPTER 1
Introduction

1.1 Introduction

This document describes the mitigation monitoring and reporting program (MMRP) to ensure effective implementation of the mitigation measures required for approval by Shasta County (County) of the application for a Use Permit (UP 16-007) by Fountain Wind LLC (Applicant) to construct, operate, maintain, and decommission the Fountain Wind Project (project). The MMRP includes measures proposed by the Applicant (APMs) and all mitigation measures identified by the County to avoid or substantially reduce the project's potential significant environmental impacts. The Shasta County Department of Resource Management, Planning Division is the Lead Agency under the California Environmental Quality Act (CEQA) (Pub. Res. Code §21000 et seq.) and its implementing regulations, the CEQA Guidelines (14 Cal. Code Regs. §15000 et seq.) for purposes of the EIR and this MMRP. This MMRP refers to the "Project Owner" rather than the "Applicant" to define the responsibilities of Fountain Wind LLC. Project Owner is defined for purposes of implementation of the mitigation measures and compliance with this MMRP as Fountain Wind LLC, its successors and assigns, and/or its contractors (such as third-party consultants).

This Draft MMRP is provided for purposes of disclosure. A Final MMRP will be prepared following certification of the EIR and imposition of conditions of permit approval.

1.2 Project Location and Overview

The approximately 4,464-acre project site consists exclusively of private property operated as managed forest timberlands. It also is within in a geographic area that is traditionally and culturally affiliated with the Pit River Tribe. The property is located approximately 1 mile west of the existing Hatchet Ridge Wind Project, 6 miles west of Burney, 35 miles northeast of Redding, immediately north and south of State Route (SR) 299, and near the private recreational facility of Moose Camp and other private inholdings. Other nearby communities include Montgomery Creek, Round Mountain, Wengler, and Big Bend. Access to the project site would be provided regionally and locally by Interstate 5 (I-5), approximately 35 miles to the west of the project site; SR 139, approximately 60 miles to the east of the project site; SR 299; Moose Camp Road; and three existing, gated logging roads that would be used to enter and leave the project site. Relevant Figures from the EIR are provided in **Exhibit A**, including the project site and the road network to be used for local access to and through the project site.

Fountain Wind LLC has applied for a Use Permit to construct, operate, maintain, and decommission a wind energy generation project (wind turbines and related infrastructure) in an unincorporated area of Shasta County. The project includes up to 72 wind turbines and associated transformers together with associated infrastructure and ancillary facilities that, collectively, would have a maximum total nameplate generating capacity of up to 216 megawatts (MW). Each of the wind turbines would be no more than 679 feet tall, as measured from ground level to vertical blade tip (total tip height), and would have a generating capacity of 3.0 to 6.2 MW.

Associated infrastructure and facilities would include: a 34.5-kilovolt (kV) overhead and underground electrical collector system to connect turbines together and to an onsite collector substation; overhead and underground fiber-optic communication lines; an onsite switching station to connect the project to the regional grid operated by Pacific Gas and Electric Company (PG&E); a temporary construction and equipment laydown area; 14 temporary laydown areas distributed throughout the project site to store and stage building materials and equipment, an operation and maintenance facility; up to four permanent meteorological (MET) towers; temporary, episodic deployment of mobile Sonic Detection and Ranging (SoDAR) or Light Detection and Ranging (LiDAR) systems within identified disturbance areas (e.g., at MET tower locations); two storage sheds; and three temporary batch plants. New access roads would be constructed within the project site, and existing roads would be improved. The project would operate year-round.

1.3 Monitoring Program

1.3.1 Authority

The County has broad regulatory authority pursuant to the police power to protect the public health, safety and welfare of its residents. As stated in the California Constitution, "A county or city may make and enforce within its limits all local, police, sanitary, and other ordinances and regulations not in conflict with general laws" (Cal. Const. at. XI, section 7). Land use and zoning regulations derive from this general police power. Relevant sources of authority include the California Planning and Zoning Law (Government Code §§65000 – 66035), the Mitigation Fee Act (Government Code §§66000 – 66008), CEQA, the County's General Plan, and the County Zoning Plan. MMRPs are adopted as part of conditions of approval of permits granted pursuant to Shasta County Code and are enforced as such.

CEQA requires the monitoring of mitigation measures to be implemented by a project. Public Resources Code Section 21081.6 requires a public agency to adopt a mitigation monitoring and reporting program when it approves a project that is subject to preparation of an EIR and where significant adverse environmental effects have been identified. CEQA Guidelines Section 15097 clarifies requirements for mitigation monitoring or reporting.

This MMRP includes mitigation measures identified in the Final EIR to avoid or substantially reduce the project's potential significant environmental impacts as well as measures proposed by the Applicant (APMs) to reduce anticipated environmental effects.

1.3.2 Purpose

An MMRP provides guidelines and procedures for environmental compliance of a project. This Draft MMRP has been prepared for purposes of disclosure. The Final MMRP for this project will be developed by the County in coordination with the Applicant and the County's Environmental Compliance Monitors. It will define the reporting relationships, provide information regarding the roles and responsibilities of the project's environmental compliance personnel, set out compliance reporting procedures, and establish a communication protocol. The communication information listed in the MMRP will be updated throughout construction.

The purpose of the MMRP is to ensure effective implementation of the mitigation measures and APMs identified in the EIR, as imposed by the County. It describes the logistics of the monitoring process and establishes protocols to be followed by the Project Owner and its subcontractors, and the County's Third-party Compliance Monitors. This MMRP includes:

- Procedures for approving minor project changes
- Procedures for dispute resolution
- Mitigation Measures and APMs that the Project Owner must implement as part of the project
- Actions required to implement these measures
- Monitoring requirements
- Timing of implementation for each measure

1.3.3 Implementation of MMRP

Implementation of the MMRP will end when the County determines there is no further need for County monitoring of the project. The project owner is required to perform post-construction monitoring for the project to satisfy mitigation measure requirements that are listed in the MMRP. It is expected that post-construction monitoring and implementation of the MMRP will continue for an appropriate amount of time to verify that post-construction requirements (e.g., revegetation) have been met and that the mitigation requirements to occur during operation, maintenance and decommissioning are implemented as intended.

1.4 Construction Schedule

Project construction is expected to last 18 to 24 months. Generally, construction would occur during daylight hours from 7 am to 5 pm but could vary during summer or winter months, to accommodate specific construction needs or site conditions, to avoid traffic or high winds, or to facilitate the project schedule. A detailed overall schedule for project construction, including the duration of work for key construction activities, is provided in Table 1-1, Construction Schedule.

Project-related construction activities (beyond such pre-construction activities as engineering, design, studies, and permitting) will not begin until the County's Project Manager has issued one or more Notices to Proceed (NTPs) covering the planned activities.

IMPORTANT: Before work can proceed on a work package, a Request for Notice to Proceed (RFNTP) must be made by the Project Owner and approved by the County Project Manager (see Section 4.3, Notice to Proceed Process). The mitigation measures and APMs listed in Section 6 include the locations where these requirements apply and which must be implemented prior to the commencement of construction. The Project Owner will work closely with its contractors to ensure that site-specific mitigation measures are clearly identified and implemented. County Third-Party Compliance Monitors will verify the implementation of mitigation measures prior to and during construction.

TABLE 1-1
CONSTRUCTION SCHEDULE

[Construction Schedule to be included in Final MMRP]

CHAPTER 2
Scope of Program

2.1 Mitigation Measures and Applicant Proposed Measures

The project will be subject to mitigation measures and APMs included in the Final MMRP. This Draft MMRP assumes those mitigation measures and APMs to be as identified in the Final EIR. Each RFNTP will provide the County with mitigation measures applicable to the phase of work and organized by each of the various implementation phases, which include, for example, site preparation, construction, operation and maintenance, and decommissioning.

2.2 Permits and Authorizations

The County is the Lead Agency for the project. However, the project facilities affect resources or require activities that are under the jurisdiction of or regulated by other agencies. Agencies that may require separate permits or approvals, and relevant contact information, are to be provided with the applicable RFNTP.

All required permits applicable to an RFNTP are to be secured and their terms and conditions implemented prior to undertaking any work that requires such permits. All permits acquired for a RFNTP shall be provided to the County prior to undertaking work authorized by any permits. The Project Owner will provide notice to the County of agency contacts, direction, and resolutions. Independently, and under their own authority and discretion, permitting agencies may implement their own monitoring and reporting schemes and undertake whatever enforcement actions they are authorized to pursue.

IMPORTANT: The status of required permits will be included in each request for an NTP. Copies of permits, including any permit requirements and stipulations, shall be provided to the County.

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CHAPTER 3
Roles and Responsibilities

3.1 Introduction

The Project Owner is responsible for implementing and maintaining all mitigation measures, and for obtaining and complying with all required permits. The Project Owner is responsible for ensuring that its agents and contractors comply with the MMRP. The Project Owner also is responsible for satisfying requests from jurisdictional agencies and will notify and copy the County on all correspondences related to final approvals and verifications for the project if not otherwise copied on the correspondence.

Standards for successful mitigation are implicit in some mitigation measures, such as obtaining non-discretionary permits or avoiding a specific impact entirely. Additional resource avoidance or impact minimization conditions may be imposed by applicable agencies with jurisdiction through their discretionary permit processes.

IMPORTANT: The Project Owner will inform the County Project Manager (County PM) in writing of mitigation measures that are not or cannot be successfully implemented. While the County recognizes the need for flexibility post-decision in response to changed circumstances, it believes changes should be the exception to the rule, and it intends to ensure that any proposed change is subject to rigorous standards. Consequently, some requested changes may qualify for the process set forth in the MMRP for minor project refinements (Section 4.6.1); others may require the submittal of an application to amend the use permit pursuant to County Municipal Code Section 17.92.025, as it may be amended from time to time.

The County, as the CEQA Lead Agency, is responsible for ensuring that all mitigation measures are implemented in a timely fashion as specified, and that the County PM verifies the Project Owner's compliance with mitigation measures. Other jurisdictional agency representatives may visit construction areas at any reasonable and safe time, and may require information regarding the status of compliance with particular mitigation measures or permits. All visitors, including regulatory agency personnel, must sign-in with the job site safety representative and receive the site safety briefing before entering work sites. Site visits to active work sites will be coordinated with the Project Owner's Compliance Project Manager and/or site representative ahead of time. Additional information on communication protocols is presented in Section 4, Procedures.

This section describes specific Project Owner and County roles and responsibilities for the project, and titles that will be assigned to personnel in these roles. A Roles and Responsibilities Organizational Chart will be provided in **Exhibit B** of the Final MMRP.

In addition, a list of designated personnel who will perform these and other monitoring roles, including their organization and contact information, will be included in **Exhibit C**. These personnel and their contact information will be updated as necessary throughout implementation of the MMRP to reflect personnel changes.

3.2 Project Owner Compliance Personnel

The Project Owner's personnel and contractors are responsible for implementing all project mitigation measures and the MMRP. It is the Project Owner's responsibility to comply with project requirements, plan construction activities in a manner that meets these requirements, document compliance activities and the results of mitigation, and implement the MMRP. The compliance personnel titles, and roles and responsibilities presented below represent a preliminary approach to the project. The titles for project personnel and their associated roles and responsibilities are subject to change and a single project personnel member may take on more than one role. The project organization chart included in Exhibit B, present personnel assigned to the roles, and relationships between the roles. If/when the organization structure changes, the organization charts will be updated.

3.2.1 Project Owner Project Manager

The Project Owner's Project Manager (PM) is identified in Exhibit B and shall be the owner's representative, with the lead and ultimate responsibility for implementing environmental requirements and compliance with the MMRP. The Project Owner PM is typically responsible for managing subcontractors that are providing construction services, as well as environmental services such as compliance monitoring. The Project Owner PM's responsibilities typically include:

- Managing all onsite contractors.
- Directing the development and implementation of preconstruction environmental mitigation, planning, permitting, and compliance activities; environmental inspection program; and environmental training.
- Ensuring compliance with and monitoring compliance of mitigation and other environmental requirements during construction.
- Monitoring and reporting post-construction restoration and compensation requirements.
- Communicating environmental requirements to the Project Owner Compliance Team and Construction Managers
- Communicating with the County Compliance Monitoring Team regarding environmental requirements, construction needs, and construction schedule changes
- Communicating with the jurisdictional agencies regarding environmental requirements, construction needs, and construction schedule changes
- Reporting the effectiveness of mitigation and regularly submitting required documentation and notifications to the County

- Providing leadership to correct any issues with environmental compliance

3.2.2 Project Owner Compliance Project Manager

The Project Owner Compliance Project Manager (CPM) is identified in Exhibit B and is typically responsible for overseeing compliance with the MMRP, and other project requirements. The CPM also will act as a liaison between environmental and construction staff. The CPM's typical responsibilities include:

- Ensuring compliance with mitigation and other environmental requirements during construction.
- Communicating environmental requirements to Construction Project Managers, Project Engineers, Superintendents, and Construction Foremen
- Communicating with the County Monitoring Team regarding environmental requirements, construction needs, and construction schedule changes
- Providing oversight of environmental monitoring
- Coordinating with construction management personnel
- Monitoring and reporting post-construction restoration and compensation requirements
- Resolving compliance issues
- Providing leadership to correct any issues with environmental compliance
- Identifying project changes requiring GIS updates to address work new work areas

3.2.3 Project Owner Field Supervisor

The Project Owner Field Supervisor (FS) is identified in Exhibit B and typically oversees the day-to-day environmental monitoring activities during construction. In addition, the FS will provide day-to-day direction to the Field Monitors and serve as the liaison between Project Owner construction management personnel and Field Monitors. Typical roles and responsibilities for the Project Owner FS include:

- Providing oversight of applicable mitigation requirements
- Coordinating with County and compliance personnel
- Coordinating with Project Owner construction management personnel
- Resolving compliance issues
- Scheduling field staff to support anticipated construction
- Providing day-to-day direction, oversight, and mentoring of Field Monitors and specialty monitors
- Clarifying mitigation requirements and County conditions to field staff
- Reviewing and providing QA/QC of daily monitoring reports

- Preparing summary reports
- Communicating with the County and regulatory agency personnel in the field, in coordination with subject matter experts, CLs, and ECs
- Conveying work stoppage information such as delay time
- Participating in tailboard meetings to focus construction and monitors on issues or resources

3.2.4 Project Owner Site Managers

The Project Owner will designate Compliance Site Managers (SMs) to be identified in Exhibit B who will assist with implementation of the environmental requirements and implementing the MMRP. The roles and responsibilities of the SMs consist of those that are delegated by the Project Owner PM, and in addition to sharing the delegated roles and responsibilities of the Project Owner PM, the typical roles and responsibilities of the SMs may include:

- Providing oversight of applicable mitigation requirements
- Coordinating with County and compliance personnel
- Providing oversight of environmental monitoring
- Coordinating with subject matter experts
- Coordinating with field leads
- Coordinating with construction management personnel
- Communicating and resolving elevated compliance issues with the Project Owner and the County Monitoring Team in the form of Temporary Work Space Requests, Minor Project Refinement Requests, and Project Modifications
- Coordinating mitigation plan changes with the Project Owner, appropriate agencies, and the County Monitoring Team
- Coordinating and preparing Compliance Documentation Tables

3.2.5 Project Owner Lead Biologist

The Lead Biologist (to be identified in Exhibit B) will be responsible for compliance with the biological mitigation measures, other biological project requirements, and mitigation plan implementation and for communicating and coordinating with the Project Owner PM and CPM. The Lead Biologist will be responsible for managing all biological staff and will provide project history and subject matter expertise. The Lead Biologist will provide support and oversight for the Field Supervisor and Field Monitors. The Lead Biologist also will be responsible for making recommendations regarding the monitoring approach and mitigation measure implementation. The Lead Biologist will be a point of contact for agency staff and responsible for working to resolve disputes. Other Lead Biologist responsibilities typically include:

- Providing oversight of applicable mitigation requirements

- Coordinating with the County, appropriate wildlife agencies, and compliance personnel
- Providing oversight of biological monitoring
- Coordinating with subject matter experts
- Coordinating with field leads
- Coordinating with construction management personnel
- Resolving compliance issues in coordination with the County, Project Owner PM, Project Owner CPM, and regulatory agencies
- Developing recommendations for compliance processes and protocols

3.2.6 Project Owner Field Monitors

Project Owner Field Monitors (FMs) (to be identified in Exhibit C) may change over the course of the project. FMs shall work closely with construction personnel in the field to implement mitigation and perform, or oversee, required monitoring tasks. The FMs shall be the primary field employees responsible for monitoring day-to-day environmental compliance. Project Owner FMs will primarily be biological monitors trained to monitor compliance with biological mitigation measures, as well as measures addressing other resources (e.g., storm water pollution prevention plan [SWPPP], fugitive dust) with the ability to coordinate with specialty monitors (e.g., cultural, tribal, paleontological) when needed. The FM’s responsibilities typically include:

- Understanding environmental project requirements and construction needs
- Taking direction from the Project Owner CPM, FS, and SMs
- Conducting or overseeing monitoring activities specified in project mitigation measures
- Implementing the MMRP
- Participating in daily tailboards
- Conducting preconstruction surveys/sweeps of the construction site and areas around equipment
- Verifying staking, flagging, or marking sensitive resources in the field
- Relocating biological resources under direction of qualified biologists/specialty monitors
- Placing 1-hour holds on construction, as needed
- Providing mitigation guidance, as needed
- Documenting non-compliance issues
- Coordinating with the FS, SMs, Project Owner CPM, and construction management, as needed
- Preparing daily monitoring reports

- Determining the effectiveness of mitigation and reporting whether adjustments need to be made to the Compliance Team

3.2.7 Project Owner Construction Contractors

Under the direction of the Project Owner, subcontracted construction crews are responsible for complying with mitigation measure requirements and the MMRP. Exhibit B will present the Roles and Responsibilities Organizational Chart, which will include the primary contractors that will be used on the project.

3.3 County Monitoring Team

3.3.1 County Project Manager

The County PM has overall responsibility for ensuring that the MMRP is implemented as adopted by the County. The County PM will determine the effectiveness of the MMRP based on the implementation of the processes prescribed in the MMRP and measures included in tables to be included in an appendix to each RFNTP. The County PM may delegates field monitoring and reporting responsibilities to third-party compliance monitors during construction and will oversee their work through regular status reports. The County PM will be notified of all noncompliance situations and may suggest measures to help resolve the issue(s).

IMPORTANT: The County PM will issue NTPs for construction of each work package identified by the Project Owner. However, the County's NTP does not authorize construction to start if additional approvals are required from other agencies and such approvals have not been obtained at the time of issuance of an NTP. No construction requiring a permit may occur on other jurisdictional lands without specific approval by those agencies.

3.3.2 County Monitoring Manager

The overall monitoring program will be administered under the direction and oversight of the County PM. The County may delegate monitoring and reporting responsibilities to a third-party monitor. The number of monitors and the frequency of site inspections during construction and decommissioning will depend on the number of concurrent activities and their locations with respect to sensitive resources and land uses, and compliance with project mitigation measures. During operations third party monitors may be utilized as needed.

The County Monitoring Manager's responsibilities typically include:

- Managing the County Monitoring Supervisor and communicating regularly with the County PM
- Reviewing County monitoring reports and discussing non-compliance issues with the County PM
- Reviewing reports and other documentation provided by the Project Owner for MMRP compliance
- Reviewing NTP Requests and Temporary Extra Work Space requests and submitting to County PM for approval and sign-off

- Acting as project liaison on the County's behalf to work with the Project Owner's public affairs staff and address community issues and concerns if and when they arise
- Working with Project Owner Compliance Personnel to resolve any issues and incidents
- Coordinating with other jurisdictional agencies as needed

3.3.3 County Monitoring Supervisor

The County Monitoring Supervisor will support the County PM and County Monitoring Manager by overseeing the day-to-day mitigation monitoring efforts. The County Monitoring Supervisor shall perform the delegated duties of the County Monitoring Manager. The responsibilities of the County Monitoring Supervisor typically include:

- Providing oversight of the County Environmental Monitors (field staff), including training, orienting, scheduling, coordinating and conducting routine monitoring activities described in the MMRP on behalf of the County
- Implementing the County's responsibilities for MMRP procedures, and verifying that the Project Owner fulfills its responsibilities
- Reviewing all pre-construction mitigation plans and preparing draft review memoranda for the County PM, and keeping a record of MMRP procedures
- Determining the appropriate frequency of site visits for County environmental monitors (EMs)
- Conducting regular visits at beginning of construction, with frequency adjusted as appropriate
- Verifying and documenting the Project Owner's compliance with all project requirements prior to, during, and following construction, and creating an independent record of project compliance
- Documenting any incidents with compliance, reporting them to the County PM, and tracking the project compliance record
- Reviewing all County and Project Owner monitoring reports
- Preparing MMRP compliance reports and submitting to the County
- Reviewing RFNTPs for Monitoring Manager's review and County's review and sign-off
- Reviewing the Project Owner's compliance reports for consistency with field observations and identifying and reconciling any inconsistencies
- Coordinating all aspects of the project with the Project Owner's Compliance Personnel
- Communicating directly with the Project Owner's Compliance Personnel regarding notification of County site visits, schedule updates, MMRP procedures, and any compliance incidents observed during site inspections
- Working with the County Monitors and Project Owner Compliance Personnel to resolve any compliance incidents.

3.3.4 County Environmental Monitors

County EMs shall be the primary field personnel for the County, and are responsible for verifying compliance with project requirements at the project sites as directed by the County Monitoring Supervisor. The County EMs will be the primary point of contact with in-field agency personnel on behalf of the County. County EMs will be an integral part of the project team and will stay apprised of construction activities and schedule changes, and will monitor construction activities for compliance with project mitigation measures. The County EMs will document compliance through field notes and will prepare reports documenting construction activities, progress, and compliance. The County EMs shall note any issues or problems with implementation of mitigation, notify the appropriate designated project members, and report problems to the County PM. The typical responsibilities of the County EMs include:

- Inspecting the project sites, documenting construction and compliance activities, and reporting any potential compliance incidents
- Preparing and submitting daily monitoring reports to the County Monitoring Supervisor, and relaying any important information about the project delivered in the field

IMPORTANT: The enforcement authority of the County EM in the field is limited to conditions posing imminent safety or resource endangerment concerns at a work location. The County EM is authorized to work with project personnel to temporarily stop work under these conditions if it is safe to do so. The Project Owner will address the identified issues. Only the County PM has authority to shut down the project completely.

3.4 Jurisdictional Agencies

Personnel from jurisdictional agencies may periodically visit the project site to verify compliance or to request information from the Project Owner regarding compliance with laws, regulations, and project permits identified in **Exhibit D**. All visitors, including regulatory agency personnel, must sign-in with the job site safety representative and receive the site safety briefing before entering work sites. Site visits to active construction sites will be coordinated with the Project Owner CPM and/or site representative ahead of time. The Project Owner is responsible for responding to requests from jurisdictional agencies and submitting permits and authorizations to County per applicable mitigation measures described in the MMRP. The Project Owner shall provide the County with documentation (i.e., email correspondence, letters, and/or memoranda) related to final agency approvals for the project if the County is not directly involved with the coordination effort and the agency approval is tied to mitigation measures. The Project Owner also shall provide any copies of permit amendments or modifications to the County and notify the County of any proposed changes in permit conditions. In addition, the County may contact jurisdictional agencies at any time regarding the project and to clarify agency requirements, permit conditions, or approvals relating to their jurisdiction, as needed. Prior to the County communicating with jurisdictional agencies, the County will notify the Project Owner PM or Project Owner CPM of the County's questions regarding the jurisdictional agency's requirements, permit conditions, or approval and the intention to contact the agency. If appropriate, the County may request that the Project Owner seek the requested clarification or invite the Project Owner to participate in the discussion in a manner that is mutually convenient with all parties; however, the County retains the authority to coordinate directly with other agencies regarding the project and permit conditions or plan review comments.

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CHAPTER 4
Procedures

This section addresses MMRP procedures for personnel identified in Section 3 that shall be implemented prior to, during, and following construction to facilitate successful implementation and documentation of project requirements. Procedures in this section include general communication guidelines, standard County practices, and documentation tools developed from experience with past projects that involved mitigation monitoring oversight.

4.1 Communication Guidelines

Good communication is essential to successful implementation of an environmental mitigation compliance program. To avoid project delays, the County and Project Owner environmental and construction representatives will interact regularly and maintain professional, responsive communications at all times. Project Owner environmental representatives will coordinate closely with County EMs throughout the monitoring effort to ensure that issues are addressed and resolved in a timely manner. To that end, this section provides a communication protocol for the timely and accurate dissemination of information to all levels of the project regarding surveys, plans, mitigation measures, construction activities, non-compliance incidents, and planned or upcoming work.

A list of current construction monitoring personnel and managers, identified by title, and with contact information will be provided in Exhibit C. An updated list will be distributed as needed to keep all parties informed of monitor and staff additions/changes, as well as construction scheduling changes. This list of personnel, subsequent updates, and construction schedule changes will be distributed to all persons on the list throughout the construction process.

4.1.1 Pre-Construction Compliance Coordination

The Project Owner is required by the terms of the mitigation measures and the permitting requirements of various other regulating agencies to prepare plans and obtain approval of these documents, in addition to performing various surveys and studies prior to construction. During this pre-construction process, the Project Owner will conduct meetings, conference calls, and site visits with technical representatives of the County and other agencies, and the Project Owner's environmental representatives as appropriate. The purpose of the pre-construction coordination process is to discuss document submittal status, document the findings of data reviews and jurisdictional agency approvals, review Project Owner submittals, and document the status of mitigation measures as they apply to the project. The goal of the pre-construction process is to complete all required actions so the County and other agencies, as appropriate, can issue NTP authorizations.

4.1.2 Communication Protocol During Construction

Daily Communication During Construction

Many of the problems that come up during construction can be resolved in the field through regular communication between County EMs, the Project Owner, and construction contractors. Field staff will be equipped with cell phones and will be available to receive phone calls at all times during regular construction hours provided cellular service is available at the particular work site. An alternative system of communication, including but not limited to two-way radio, satellite phone, or other reliable means, shall be established to allow immediate communication from locations where cellular service is not available. A project contact list will be included in Exhibit C. The organization chart in Exhibit B will illustrate the lines of communication to be used during construction. The following provides additional guidelines to ensure effective communication in the field.

County Environmental Monitors

The County EM's primary points of contact in the field are the Project Owner's FS and SMs. The County EMs will contact the Project Owner's FS and SMs if an activity is observed that conflicts with one or more of the mitigation measures, so that the situation can be corrected. If the County EM cannot immediately reach the Project Owner's FS and SMs, the Project Owner's CPM will be contacted to address the problem. Similarly, the County EM will contact the Project Owner's FS and SMs for information on where construction crews are working, the status of mitigation measures, and schedule forecasts. The County EM may discuss construction procedures directly with the construction contractors as long as a representative from the Project Owner's Compliance Personnel is present during the discussion. The County EM will contact the designated Project Owner representative if a problem is noted that requires action from the contractor. The County EM will not direct the contractor; however, the County EM has the authority to stop work, assuming it is safe to do so, if an activity poses an imminent threat to resources or puts a sensitive resource at undue risk.

Project Owner

The Project Owner will provide the County Monitoring Supervisor and EM with a list of construction monitoring personnel and construction supervisory staff to contact regarding compliance incidents. The contact list will include each person's title, responsibility, contact information, and whether their position is segment-specific. The contact list will be updated as new project personnel are assigned to the project and redistributed as necessary. The Project Owner will prepare and distribute a regular Compliance Reports for distribution to key project members, including the County. The County Monitoring Supervisor will review the report to ensure that the status of mitigation measures is consistent with observations in the field. Any questions regarding the status of mitigation measures will be directed to the Project Owner PM. The regular Compliance Reports also will be a tool to keep all parties informed of construction progress. Note that regular Compliance Reports will also be prepared by County EMs and regular Compliance Reports will be prepared by the County Monitoring Supervisor as described below.

Regular Progress Meetings During Construction

The Project Owner CPM will conduct regular meetings with construction managers, supervisors, environmental representatives, County EMs, and other appropriate staff to discuss work completed, work anticipated for the following period, and the status of mitigation measures. The meetings also will provide a forum for discussing environmental compliance issues or concerns.

Site Visit Coordination

Field personnel from both the Project Owner and the County shall coordinate site visits with the Project Owner SMs who is familiar with authorized construction activities, project requirements, and any restricted areas (i.e., dangerous conditions, unauthorized work areas, or the presence of sensitive resources). Conditions in the field may change rapidly and Project Owner field personnel must ensure that all field personnel are adequately informed of restricted areas, parking locations, communication procedures, and site-specific safety risks on an ongoing basis.

County EMs and the Monitoring Supervisor shall conduct routine site inspections. At a minimum, County EMs will notify a designated Project Owner FS and SMs prior to visiting the site. If contact cannot be made, County monitoring personnel will inspect open areas of the project site on foot. County field personnel shall at no time enter active construction project boundaries unless authorized or escorted by a member of the Project Owner Compliance Team.

4.1.3 Project Owner Reportable Events

Unanticipated events may occur that impact project personnel, public safety, or resources and may not be observed by the County EM. While these events may not result in a deviation from or violation of a mitigation measure or permit condition, it is important that these events be reported to the appropriate agencies and the County so they are in a position to respond to questions or concerns from the public or managers. Accordingly, the Project Owner CPM will immediately report these events to the County EM and to County and other regulatory agencies. The Project Owner EPM will submit to the appropriate agency, if any, and to the County a final electronic notification characterizing the event, actions taken, and outcomes. Any event that affects, or could potentially affect, project personnel or public health and safety is immediately reportable and would include the following examples:

- An occurrence that posed or could have posed a risk to public health and safety
- Any event requiring emergency response (police or fire)
- A “near miss” event involving construction equipment and, in the Project Owner CPM’s reasonable judgment, had the potential to result in serious bodily harm or death.
- Any fire caused by construction activities
- Inadequate traffic control resulting in an accident
- Any toppled piece of equipment

Any event that impacts, or poses an imminent risk to, a sensitive resource is immediately reportable and would include the following examples:

- Any event a mitigation measure failed to address
- A violation of a permit condition
- Any resource buffer incursion by construction personnel or significant non-compliance incident
- Any directed work stoppage or construction holds
- Discovery of unanticipated resources such as archaeological artifacts outside of known cultural sites

4.1.4 Questions and Clarifications

Questions and the need to clarify project requirements will periodically arise throughout the implementation process. Both the Project Owner and County shall submit important questions and clarifications in writing via email. Resolutions and any County determinations shall be documented in compliance and monitoring reports, and/or in email correspondence. Questions and clarifications that take an extended period of time to resolve shall be tracked by the County Monitoring Team until a resolution has been reached.

4.1.5 Requests for Documentation

The County Monitoring Team may periodically request written documentation and confirmations from Project Owner Compliance Personnel that will be entered into the project record. Requests for documentation and confirmations shall be submitted via email. If the information will take an extended period of time to gather, both the Project Owner and the County shall agree upon a timeframe to respond, and the request shall be tracked by the County Monitoring Personnel until a resolution has been reached.

4.1.6 Construction Schedule

The Project Owner shall inform the County Monitoring Team immediately of any delays in the construction schedule as laid out in each approved RFNTP that may affect the project and implementation of the approved RFNTP.

4.1.7 Dispute Resolution

Disputes or complaints may develop between the Project Owner and the County if there are conflicting interpretations of project requirements and procedures. It is expected that the MMRP will reduce or eliminate the potential for disputes; however, disputes may occur even with the best preparation. Any disputes or complaints shall first be addressed informally at the field level between the County EM and Project Owner FS and SMs, or during project progress meetings. Questions may be directed to other members of the Project Owner Compliance Personnel and the County Monitoring Team as needed.

If the dispute cannot be resolved informally in the field, the following procedures will be observed for dispute resolution between County staff and the Project Owner: Disputes and complaints should be directed to the County PM for resolution. Should this informal process fail, the County PM may initiate enforcement or compliance action to address deviations from the approved project.

4.2 Pre-Construction Compliance Verification

Prior to beginning construction, the Project Owner is required by the terms of the mitigation measures and the permitting requirements of various other regulating agencies to prepare plans and obtain approval of these documents, in addition to performing various surveys and studies prior to construction. The plans, surveys, studies, and other documentation required to be completed by the Project Owner before construction are listed in the mitigation measure in Section 6.

Other agencies may review documents prior to or concurrent with the County if required by the mitigation measures or permitting requirements. Compliance with all pre-construction mitigation measures presented will be verified prior to construction.

The County, Monitoring Manager, Monitoring Supervisor, and, if applicable and/or necessary, technical experts will review all mitigation plans and reports and provide comments, as applicable. As required by the mitigation measures and/or the County, resource agencies will also be involved in the review of applicable plans and reports and will provide comments. Comments on these documents will be provided to the County to ensure that they adequately accomplish the intended mitigation for impacts and meet the mitigation measure or permit requirements. Based on the Project Owner's construction plans, the County may authorize construction to begin on a phased basis and the County monitors will handle pre-construction compliance review accordingly. The County may issue NTPs for construction of each phase separately, as soon as preconstruction compliance is satisfactorily accomplished for that phase.

IMPORTANT: Compliance with all pre-construction mitigation measures will be verified prior to construction, and construction may not start on any work package before the Project Owner receives a written NTP from the County PM and other necessary approvals, if any. In addition, demarcation of approved disturbance areas and any resource exclusion areas must be validated in the field by the County EM prior to any construction activities authorized by the NTP. In general, the County will not issue an NTP until all pre-construction requirements have been fulfilled for a given phase. To save time, the Project Owner should identify all required additional work space needs for each phase of construction prior to the start of active construction, so that the locations and their use can be included in the NTP.

4.3 Notice to Proceed Process

The Project Owner is required to obtain County authorization prior to initiating project activities through the NTP process. The NTP process involves the Project Owner Compliance Personnel submitting an NTP request package to the County Monitoring Team, and the County PM issuing a NTP Authorization Letter. The County will not authorize construction to begin until all pre-construction requirements have been fulfilled for a given phase. To save time, the Project Owner should identify extra work space needs required for each phase of construction prior to the start of active construction, so that the locations and their use can be included in the NTP. Project activities may be authorized through one or more NTPs for separate project phases as determined necessary by the Project Owner Compliance Personnel and the County Monitoring Team. In general, an NTP request must include the following information:

- NTP request number; dated submitted to County; requested approval dated
- Anticipated start and end date for the proposed actions
- Detailed description of the proposed actions requested in the NTP
- Detailed description of the location, including maps, GIS data, photos, and/or other supporting documents. Maps showing all proposed work areas, access roads, and staging areas will be provided.
- Estimate of total new land disturbance associated with the project
- Anticipated equipment required for construction
- Verification that all mitigation measures have been met, apply, or do not apply to the work covered by the NTP request
- If compliance with some requirements cannot be met prior to NTP issuance, the reasons will be identified and noted in the NTP request
- Up-to-date resource surveys or a commitment to conduct surveys and submit results prior to construction
- Summary list of any previously authorized actions (if applicable) as detailed in NTP Authorization Letters

The County Monitoring Team shall review NTP requests to ensure the proposed actions are consistent with the Final EIR and final County decision, and to verify compliance with all pre-construction requirements applicable to a given NTP request. The County Monitoring Team may request additional information during the NTP review process as needed. Once it has been determined that all applicable pre-construction requirements have been completed and documented to the satisfaction of the County, the County PM will submit an NTP Authorization Letter to the Project Owner's PM. The NTP Authorization Letter will address any conditions of approval, and include applicable documentation as necessary for the authorized actions.

4.4 Compliance Reporting During Construction

The County EMs will perform compliance inspections throughout construction to ensure compliance with all applicable mitigation measures, plans, and conditions of approval from County. The County EM will document observations in the project area through field notes and digital photography. The photographs will be incorporated in regular reports and related to a discussion of specific construction or compliance activity. In addition, field logs documenting compliance of specific crews, construction activities, or resource protection measures will be maintained. Field logs will be used to prepare regular reports and to track and update the status of mitigation measures listed in Section 6.

Site visits by the County may be coordinated with the Project Owner CPM and/or SMs ahead of time, or be unannounced. All visitors, including regulatory agency personnel, must sign-in with the job site safety representative and receive the site safety briefing before entering work sites. Supplemental information provided by the Project Owner, including pre-construction submittals, survey reports, weekly reports, and agency correspondence also will be used to verify compliance.

4.4.1 Project Owner Regular Compliance Reports and Checklists

The Project Owner compliance team will prepare and distribute a regular environmental compliance status report for distribution to key team members, including the County. The County EM will review the reports to ensure that the status of mitigation measures is consistent with observations in the field. Questions regarding the status of mitigation measures will be directed to the Project Owner CPM and/or FS. The environmental compliance status report also will be a tool to keep all parties informed of construction progress.

Prior to the start of monitoring activities, the Project Owner shall provide a proposed schedule and format describing content and organization of Compliance Reports for County review and approval. The Compliance Report shall be a condensed, singular report that includes, but is not limited to the following components:

- Clear and specific description of construction activities and work locations
- Current project completion status
- Monitoring reports describing construction activities monitored with specific project locations and any findings or compliance incidents
- All non-compliance incidents reported during the reporting period, including date, detailed description, and corrective actions implemented
- Summary including locations of preconstruction or focused surveys conducted
- All new sensitive resources identified during surveys or construction monitoring for the subject reporting period
- Update of bird nesting activities and buffer distances
- Summary of special status wildlife or plant relocations, if any
- Any SWPPP-related corrective actions or maintenance observations identified during the subject week, including date, location, description, and resolution
- Any hazardous materials spills defined as reportable by project mitigation measures and/or plans
- List of personnel trained under the Worker Environmental Awareness Program (WEAP), including names and dates

4.4.2 County Compliance Reporting

The County EM will determine whether the observed construction activities are consistent with mitigation measures and project parameters as identified in the Final EIR. All observations and communications will be noted in a logbook, including photos. Deviations from mitigation measures, or approved plans will be considered non-compliant events and will be documented. Supplemental information provided by the Project Owner, including pre-construction submittals, survey reports, Compliance Reports, and agency correspondence also will be used to verify compliance.

4.4.3 Incident Reports

Incident Reports for Level 1-3 Incidents shall be prepared by the observing party (either the Project Owner or the County) and submitted to the alternate party within one business day of the observation. Level 1 Incidents will be reported through a brief email from the observing party. Level 2 Incidents will be reported through a Project Memorandum. Level 3 Incidents require preparation of a Non-Compliance Report (NCR). At a minimum, Incident Reports must include the following information:

- Incident Category
- Compliance Level (if applicable)
- Incident Start Date (i.e., date event began, if known, or initial observation date)
- Summary of Incident (i.e., description of the event or observation, personnel present, and actions taken to resolve the issue)
- Resolution Date (if known)

All incidents (Levels 1-3) shall be addressed in MMRP reports prepared by both the Project Owner and the County, and Incident Reports shall be attached to the MMRP reports for the applicable period. In addition to Incident Reports, incidents rising to the level of Noncompliance may require preparation of memoranda describing the event in greater detail and corrective actions necessary to bring the project back into compliance.

4.5 Incidents and Stop Work Orders

The goal of this MMRP is to plan for and avoid any non-compliance incidents that could occur during implementation; nonetheless, there is a potential for compliance incidents to arise due to a variety of factors. For the purposes of this MMRP, compliance incident levels are defined in **Table 4-1** below. This section addresses incidents that may occur and procedures that shall be followed to document them.

Table 4-1
Compliance Levels

Incident Level, Reporting Term, and Severity	Examples	Action	Follow-up
Level 0: Unanticipated Event *Definition*: An event that is outside the project's control.	Discovery of previously unknown cultural (archeological resource or feature) or significant paleontological resources. Identification of a special status species not anticipated based on analysis in the EIR. Encountering previously undocumented subsurface hazardous substances during excavation activities.	The Project Owner FS, SMs, or FMs onsite will stop work. Project Owner CPM or assigned designee will inform the County Monitoring Supervisor and any other relevant resource agencies. Project Owner CPM will work with the agencies to develop and implement an appropriate solution. The event will be documented Compliance Report.	The Project Owner Compliance Team and Contractor staff will implement the solutions as developed in cooperation with the appropriate agencies. Ultimately, the efficacy of the solutions will be documented by the FS, SMs, and FMs as construction activities resume.
Level 1: Minor Incident *Definition*: An event or observation that slightly deviates from project requirements, but does not put a resource at unpermitted risk.	Project personnel used an unapproved access road or turnaround area, but the site was previously disturbed and the action did not put a sensitive resource at risk. Soil or construction material was placed outside of an approved work area, but the material was removed at the end of the day.	An oral warning shall be provided by the County Monitoring Supervisor to the Project Owner CPM (or assigned designee). Corrective action shall begin by the next construction day. County Monitoring Supervisor also will briefly document the incident in a follow-up email. A Minor Incident will be included in the Compliance Report.	If corrective action is not initiated by the next construction day, the County Monitoring Supervisor will elevate the incident to the County Monitoring Manager who will review courses of action available and will notify the County PM if necessary. If allowed to continue, this non-compliance incident could result in a serious impact over time, and result in a Project Memorandum or Non-Compliance Report (NCR).
Level 2: Moderate Incident *Definition*: An event or observation that deviates from project requirements and puts a resource at risk, but is corrected without impacting the resource.	A fuel tank was stored overnight within specified limits of a water body without secondary containment, but did not result in release of hazardous materials. Mobilization of equipment or materials to a previously disturbed work site prior to receiving NTP authorization from the County. A diesel-powered vehicle not in use was observed idling for an extended period of time.	A verbal notice shall be given by the Project Owner FS, SMs or FMs, followed immediately by written documentation of the incident in a Project Memorandum sent by the County Monitoring Supervisor to Project Owner CPM (or assigned designee). Corrective action shall begin immediately if feasible.	If corrective action is not taken immediately or the corrective action is insufficient, the County EM shall notify the County PM, Monitoring Manager, and Monitoring Supervisor, who will review courses of action available, potentially including issuance of a Project Memorandum, NCR, and/or a Project Stop Work Order.
Level 3: Major Incident *Definition*: An event or observation that violates project requirements and impacts a resource. Repeated Compliance Deviations left unaddressed may also rise to a Level 3 incident.	Vegetation clearing and grading of a work site prior to receiving NTP authorization from the County. Soil or construction material was placed outside of an approved work area in an environmentally sensitive area. Erosion control BMPs failed during a storm and sediment was discharged into a sensitive area. Project vehicles entered a sensitive resource exclusion area and damaged a resource.	A verbal notice shall be given to the Project Owner FS, SMs, or FMs, followed immediately by a written NCR from the County Monitoring Manager to Project Owner CPM (or assigned designee). Corrective action shall begin immediately. Based on the severity of a given infraction or pattern of noncompliant activity, the County may direct that all or some portion of the work be stopped.	If a shutdown of construction or an activity is ordered, the construction or activity shall not resume until authorized by the County PM in writing. If corrective action is not taken immediately or the corrective action is insufficient, the County EM shall notify the County PM, Monitoring Manager, and Monitoring Supervisor, who will review courses of action available, potentially including a Stop Work Order.

4.5.1 Incident Categories

Incident categories for the project include compliance level incidents, Occupational Safety and Health Administration (OSHA)-recordable health and safety incidents, vehicle accidents that are related to project traffic closures, and public complaints.

Compliance Level Incidents

The Project Owner and County are responsible for evaluating compliance and addressing any inadequacies throughout implementation of the MMRP. Compliance incidents will be documented by assigning one of three compliance levels and associated terms. If all project requirements are observed being followed adequately, then the project will be at an acceptable compliance level and no further actions are required. A description of compliance levels that will be used for the project and examples of compliance level incidents are listed in Table 4-1.

When documenting compliance level incidents, the reporting party shall assign an initial compliance level that appropriately represents the severity of the incident based on factors including, but not limited to, the following:

- Scope of the deviation or violation
- Risk of impact to resources
- Actual impact to resources
- Number of repeated incidents
- How the incident could have been prevented

The need to change initially reported compliance levels may arise if the incident level was over or under-reported. The County PM shall make final determinations regarding the appropriate compliance level for each incident as needed, and the County Monitoring Team shall maintain a record of all incidents for the project that will be analyzed in the County Post-Construction and Final Monitoring Reports. In addition to the levels of compliance described in Table 4-1, the County may note events or observations that, if left unaddressed, could have the potential to affect compliance and become a compliance incident. The County typically will inform the Project Owner Compliance Personnel of such observations in the field. If such events or observations continue to occur following County's field notification to the Project Owner Compliance Personnel, and corrective action is not taken within the stated period, the County may issue a Project Memorandum (written warning) or Non-Compliance Report (NCR). A non-compliant event regarding environmental resources may involve other agencies, in which case, the County EM will:

- Confirm that the Project Owner has informed the applicable resource agency when non-compliant actions have the potential to harm an environmental resource or species (outside the reporting process associated with incidental takes as permitted by the resource agency).
- If timely notification is not made by the Project Owner, the County EM will contact the applicable resource agency.

If permit or resources issues are involved, the County and/or resource agencies may order work stoppages and the development of strategies for successful resource/species protection, consistent with the applicable permit or mitigation measure.

Health and Safety Incidents

The Project Owner's and the County's most important responsibility is maintaining safe working conditions and protecting the public, including workers, from exposure to hazards related to the project. Accordingly, the Project Owner will self-report health and safety incidents. Specific types of health and safety incidents to be reported are described below:

- A potential violation that poses a significant safety threat to the public and/or staff, contractors, or subcontractors.
- Any instance of fraud, sabotage, falsification of records and/or any other instances of deception by the Project Owner's personnel, contractors, or subcontractors that caused or could have caused a potential violation, regardless of the outcome.
- Incidents that (a) result in fatality or personal injury rising to the level of in-patient hospitalization and attributable or allegedly attributable to utility owned facilities; or (b) are the subject of significant public attention or media coverage and are attributable or allegedly attributable to Project Owner-owned facilities; (c) involve damage to property of the Project Owner or others estimated to exceed $20,000 that are attributable or allegedly attributable to Project Owner-owned facilities.

The Project Owner CPM will notify the County PM of these types of health and safety incidents within one business day of learning about the incident and provide an incident report with the Compliance Report for the project unless additional time is needed and the County agrees to an extension for submitting the final incident report. The Project Owner also will notify the County about traffic accidents within construction traffic control areas. In addition to the incidents described above, the County may request that the Project Owner report on other health and safety incidents that do not fall into one of the above-listed categories if the County determines that such reporting is necessary to ensure construction is completed in a safe manner. A report of a self-identified potential violation must include information about whether the potential violation has been corrected. If the potential violation has not been corrected before the Compliance Report is submitted, then the self-report must include a plan and schedule for correction. The self-identification and reporting requirement is separate from and independent of any existing reporting requirement(s) and does not relieve the Project Owner of its existing responsibility to correct such violations and safety-related conditions as soon as feasible. Health and safety incidents will not reflect negatively on the Project Owner's environmental compliance record unless a specific project requirement or plan requirement was violated.

Public Complaints

The public may take issue with one or more aspects of the project. The Project Owner will maintain a Project Information Line during construction and will assign a dedicated Public Liaison to the project that will be responsible for tracking and handling public complaints. Public complaints may be submitted formally to the Project Owner or the County through email or the

Project Information Line. Members of the public that have questions, concerns, or complaints on the project will be directed to the Project Owner Public Affairs Manager and Project Information Line, and contact information will be supplied as requested. Complainants who approach field personnel will be referred to the Project Information Line to formally submit their complaint. The Project Owner shall work with the County on best practices for handling public complaints that are received. The Public Liaison will respond to public complaints within 24 hours upon receipt. The County shall notify the Project Owner of public complaints received by the County to facilitate the Project Owner's timely response to these complaints and the Project Owner will add these to the electronic complaint log. The Project Owner shall make every reasonable effort to work with members of the public and correct actions leading to complaints, as feasible. The Project Owner also shall provide monthly summaries of the public complaints and how each complaint was addressed. The County PM will coordinate with the Project Owner CPM on the adequacy of corrective actions or additional measures to be implemented, as needed. Public complaints will not reflect negatively on the Project Owner's environmental compliance record unless a specific project requirement or plan requirement was violated.

4.5.2 Identifying Incidents

The Project Owner FS, SMs, FMs, and County EMs are primarily responsible for identifying and initially reporting incidents during inspection of the project site; however, compliance incidents also may be observed by other personnel in the field or during review of project reports. The County Monitoring Team also may identify compliance incidents through review of the Project Owner's compliance reporting. The Project Owner shall make every attempt to self-report any compliance incidents that occur.

4.5.3 Notification

The Project Owner and the County should notify one another of compliance incidents within one business day of the initial observation so compliance can be adequately addressed. Response procedures do not need to be finalized when initial notification is provided. Jurisdictional agencies also may require notification if incidents are documented that relate to their jurisdiction over the project. The Project Owner CPM or designee shall make all such notifications to each jurisdictional agency and will provide copies to the County of official notifications and submittals provided to other agencies or advise the County of notifications that were made to other agencies, as necessary. If the County believes additional notifications are required, the County may direct the Project Owner to provide those notifications or make those notifications in coordination with the Project Owner Compliance Personnel.

4.5.4 Stop Work Orders

When it is safe to do so, any Project Owner Compliance Personnel or the County Monitoring Team has the authority to issue Stop Work Orders to temporarily halt or redirect project activities if a sensitive resource is put in undue risk beyond previously authorized levels. In addition, the County Monitoring Team also may stop or redirect work if unauthorized project activities are observed, such as use of work area that has not been approved or is significant compliance risks remain unresolved. The County PM will make any final determinations regarding Stop Work Orders for the project.

4.6 Project Changes

At various times throughout project construction (following approval of final design plans), changes to the project requirements may be needed to facilitate construction or provide more effective protection of resources. When changes are necessary for specific field situations, the Project Owner and the County, in consultation with the applicable resource agencies, will work together to find solutions that avoid conflicts with adopted mitigation measures.

4.6.1 Minor Project Refinements

The County PM, along with the County Monitoring Team, will ensure that any process, to consider minor project changes that may be necessary due to final engineering or variances or deviations from the procedures identified under the monitoring program, is consistent with CEQA requirements.

- No project changes will be approved by the County PM if they:
  - would be located outside of the geographic boundary of the project study area,
  - create new or substantially more severe significant impacts, or
  - conflict with any mitigation measure or applicable law or policy.
- Minor project changes are strictly limited to changes that:
  - will not trigger other permit requirements unless the appropriate agency has approved the change, and
  - clearly and strictly comply with the intent of the mitigation measure or applicable law or policy.

This determination is ministerial, and shall be made by the County PM. The Project Owner must seek any other minor project changes by petition for minor modification of the use permit in accordance with S.C.C 17.92.025. Requests for staff approval of a minor project change must be made in writing and should include the following:

- A detailed description of the proposed minor changes, including an explanation of why the refinements are necessary, and a reference to the approved documents.
- Photos, maps, GIS data, and other supporting documentation illustrating the difference between the existing conditions in the area, the approved project, and the proposed minor changes.
- The potential impacts of the proposed minor changes, including a discussion of each environmental issue area that could be affected by the minor changes with accompanying verification that there will be no substantial increase in the severity of any previously identified significant impacts to resources affected by the project and no new significant impacts, after application of previously adopted mitigation.

- Whether the minor changes conflict with any applicant proposed measures or mitigation measures.
- Whether the minor changes conflict with any applicable guideline, ordinance, code, rule, regulation, order, decision, statute or policy.
- Water/wetland/storm water related resource information if the minor changes would result in any additional land disturbance, road distance or width, changes to jurisdictional delineation of waters, or changes to water protection best management practices.
- Date of expected construction at the minor changes site area.

The County PM may request additional information or a site visit in order to process the request. Possible examples of changes that may be approved by staff after final engineering include, but are not limited to:

- Adjusting the alignment of a project within the study area that was used in the EIR to avoid unanticipated impacts related to cultural artifacts, buried utility infrastructure, hazardous and toxic substances, and other land use impacts including effects on homeowners, so long as the adjustment does not create a new significant impact or a substantial increase in the severity of a previously identified significant impact.
- Adjusting the alignment of a project within the study area that was used in the original environmental analysis to avoid or adapt to conditions on the ground that vary from the conditions that existed at the time of the original environmental analysis, so long as the adjustment does not create a new significant impact or a substantial increase in the severity of a previously identified significant impact.

IMPORTANT: To initiate a project minor changes request, the Project Owner will prepare the appropriate supporting documentation and submit by email (electronic copy) to the County PM with a copy to the County Monitoring Manager. As soon as reasonably possible, the County Monitoring Team will review the request to ensure that all of the information required to process the minor project change is included, and then forward the request to the County PM for review and approval. The County PM may request a site visit from the County CPM, or may request additional information to process the request. In some cases, project minor changes may require approval by jurisdictional agencies as well. All approved minor change requests will be tracked in tabular format in the Compliance Reports.

Should a project change require a PFM, supplemental environmental review under CEQA may be required.

4.6.2 Temporary Extra Work Space

For the purposes of this MMRP, Temporary Extra Work Space (TEWS) is defined as a preexisting work space (i.e., no site preparation is required) that would be used by the Project Owner during construction for a period of up to 60 days, and that was not specifically identified and evaluated during the CEQA process. Anything required to be utilized for a period longer than 60 days will require a minor project change approval.

In the event that the Project Owner determines a need for a construction TEWS, it must submit such a request to the County, consistent with the communication protocol. The Project Owner will not be permitted to use a TEWS prior to receiving written authorization from the County. If appropriate, the Project Owner also will send a copy of the TEWS to affected jurisdictional agencies.

The Project Owner must demonstrate that:

1) The TEWS is located in a disturbed (void of vegetation) area with no sensitive resources or land uses onsite or within proximity of the proposed work space such that they may be significantly impacted by the work,
2) No ground-disturbing activities or site improvements will occur,
3) The Project Owner has permission of the applicable landowner to use the work space, and
4) Use of the TEWS will not result in any significant environmental impacts.

Following is a list of the specific information that the Project Owner would be required to submit with its TEWS request:

- Date of request
- Location of the TEWS (detailed description, including maps if required)
- Property owner of TEWS
- An explanation of the need for the TEWS
- An analysis that demonstrates no new significant impacts will result from use of the TEWS including: compaction contributing to runoff rates or other stormwater/watershed effects; observed existing impacts to the site, such as old oil spills or other potentially hazardous or polluting substances; abandoned vehicles, equipment, or other materials; or other sensitive resources.
- Biological surveys (prior to construction)
- Cultural resource survey if appropriate (if site is not paved)
- Duration and dates of expected use of the TEWS
- Details of the expected condition of the site after use

4.7 Compliance Tracking

Compliance with mitigation requirements will be tracked by the County. Important project procedures, such as formal requests and approvals, as well as incidents, also will be tracked throughout the project for record keeping and post-project analysis.

The County will track other important information for the project record as part of the County-prepared Monthly Monitoring Summary Report, including NTP requests and approvals, resolutions to important compliance risks that require follow-up, and documented incidents.

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CHAPTER 5
Records Management

Detailed regular reports would be prepared and submitted by the County environmental compliance monitoring team. These would include detailed information on construction activities, compliance activities observed by the Environmental Monitors and others documented by the Project Owner, any issues and their resolution, and photographs of relevant activities and conditions.

. Construction is not allowed to start in a particular area until the required pre-construction surveys and flagging/staking are completed per the MMRP, and the County environmental monitor has validated compliance. The Project Owner is to provide the County with written regular and annual reports of the project, which shall include progress of construction, resulting impacts, mitigation implemented, and all other noteworthy elements of the project. Regular status reports will be filed and used by the County Monitoring Manager to prepare a final environmental compliance report following the completion of construction and decommissioning. The final report will provide an overview of construction and a discussion of environmental compliance and lessons learned.

The public is allowed access to records and reports used to track the monitoring program. Monitoring records and reports will be made available by the County for public inspection on request, consistent with critical infrastructure requirements and requirements to protect cultural resources. .

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CHAPTER 6
Mitigation Monitoring Program Tables

6.1 Tracking Tables

Exhibit E presents the mitigation measures included in the Final EIR. The mitigation measures deemed applicable to implementation of a phase of the project will be presented in each RFNTP for County approval. The County will use expanded versions of the mitigation measure tables in the MMRP to assess those measures in an approved RFNTP to accurately track the status of mitigation measures during the pre-construction planning, construction monitoring, post-construction monitoring, and operation and maintenance sequences of the project. During construction, a copy of the mitigation measure table with measures to be implemented for an approved RFNTP during construction will be maintained by the Project Owner CPM, and all supervisory staff working on the project should be familiar with its contents. In addition, copies of all applicable plans compiled prior to construction as a result of the pre-construction measures shall also be kept on-site and all supervisory staff working on the project should be familiar with their contents.

6.2 Effectiveness Review

The County may conduct a comprehensive review of conditions which are not effectively mitigating impacts at any time it deems appropriate, including as a result of the Dispute Resolution procedure outlined in Section 4.2. If in review the County determines that any conditions are not adequately mitigating significant environmental impacts caused by the project, then the County in coordination with the jurisdictional agency(ies) may impose additional reasonable conditions to effectively mitigate these impacts.

6.3 Mitigation Measures

The mitigation measures in the MMRP constitute the project's environmental requirements and will be used to determine compliance with the MMRP. The tables (separated by environmental issue area) provided with each RFNTP and approved by the County will indicate the applicable resource of concern, the measure to be implemented, the monitoring requirement, and when the measure is to be implemented. As stated above, applicable mitigation measures in tables provided with each RFNTP will be sorted and divided into pre-construction measures, measures to be implemented during construction, and post-construction mitigation measures.

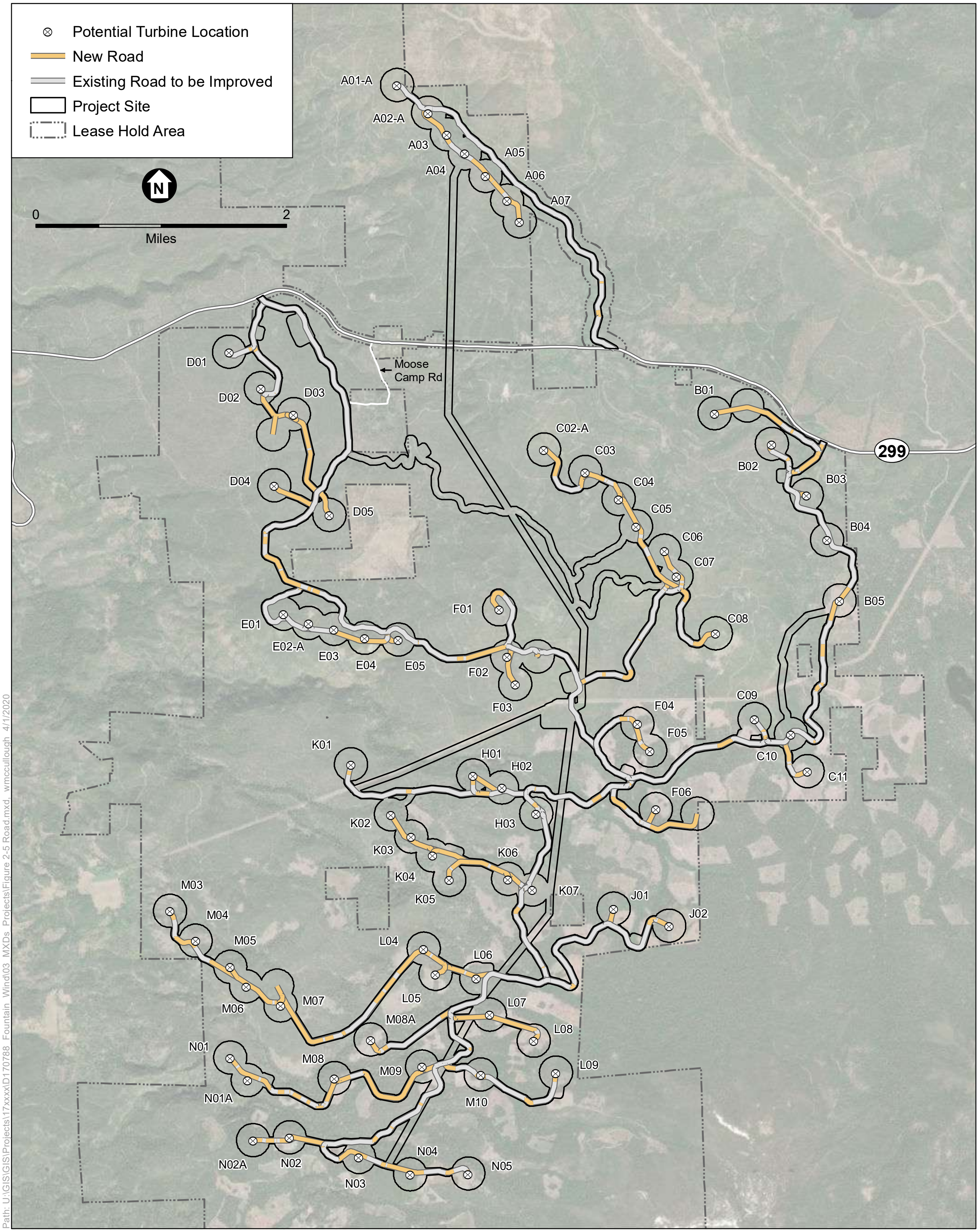
During construction, a copy of the mitigation measure tables with measures to be implemented during construction, as well as all applicable plans, should be kept with each construction crew, stored in a laptop, tablet, or binder, and all supervisory staff working on the project should be familiar with its contents. In addition, copies of all applicable plans compiled prior to construction as a result of the pre-construction measures shall also be kept with each crew, stored in a laptop, tablet, or binder, and all supervisory staff working on the project should be familiar with their contents. Each RFNTP will include a summary of the timing requirements for each applicable mitigation measure.

Certain mitigation measures require project-wide plans and other documents applicable to each of the project components. These plans, as available, will be presented in **Exhibit F**.

Exhibit A

EIR Figures (as referenced in this document)

Insert Figure: Project Site



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Fountain Wind Project

Figure 2-5
Road Network

ESA

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Exhibit B
Fountain Wind Project Roles and Responsibilities Organizational Chart

[Fountain Wind Project Roles and Responsibilities Organizational Chart to be provided in Final MMRP]

Exhibit C
Project Owner Field Monitors and Contact Information

[Project Owner Field Monitors and Contact Information to be provided in Final MMRP]

Exhibit D
List of Permitting Agencies

The following list of permitting agencies and approvals previously was provided as Draft EIR **Table 2-8**, *Summary of Permits and Approvals*. It is being provided here for informational purposes and will be updated as appropriate in the Final MMRP.

TABLE D-1
PERMITTING AGENCIES AND APPROVALS

Agency	Permit/Approval
Federal	
Federal Aviation Administration (FAA)	Notice of Proposed Construction or Alteration; Determination of No Hazard.*
U.S. Army Corps of Engineers (USACE)	Clean Water Act, Section 404 Nationwide Permit if jurisdictional waters of the U.S. could be affected by construction or operation of the Project.
U.S. Fish and Wildlife Service (USFWS)	Section 7 or Section 10 permits may be required if project results in take of a species listed under the federal Endangered Species Act (FESA).
State	
California Department of Forestry & Fire Protection (CAL FIRE)	Application for timberland conversion (Pub. Res. Code §4621 et seq.); approval of a timber harvesting plan (Pub. Res. Code §4582).
State Water Resources Control Board and/or Regional Water Quality Control Board (SWRCB and/or RWQCB)	Construction Stormwater General Permit; Notice of Intent to Comply with Section 402 of the Clean Water Act, SWPPP and SPCC Plan; Industrial Stormwater General Permit; Approval of O&M SWPPP and SPCC Plan. Section 401 certification if USACE determines jurisdictional waters of the U.S. would require a Clean Water Act Section 404 permit.
California Department of Fish and Wildlife (CDFW)	Streambed Alteration Agreement (Fish & Game Code §1600 et seq.); permit authorization if “take” of endangered, threatened, or candidate species could result incidental to an otherwise lawful activity (Fish & Game Code §2081).
California Department of Transportation	Oversize load permit(s) and variances for loads with a width over 15 feet and/or length over 135 feet. Encroachment Permit for utility line crossing state right-of-way.*
California Highway Patrol	Notification of Transportation of Oversize/Overweight Loads.*
California Public Utilities Commission	Approval of construction of switching station for transfer to PG&E (i.e., General Order 131-D).
Local	
Shasta County Air Quality Management District	Authority to Construct and/or Permit to Operate as needed.
Shasta County	Use Permit.
Shasta County Department of Resource Management, Environmental Health Division	Hazardous Materials Business Plan, septic system permit, well permit.*
Shasta County Building Division	Building and grading permits.*
Shasta County Hazardous Materials Program, CUPA	Hazardous Materials Business Plan and Permit for handling hazardous materials above threshold quantities (includes hazardous waste management).*
Shasta County, Public Works Department	Encroachment Permit.*

NOTE: * Typically processed as ministerial permits

Exhibit E
Applicant Proposed Measures and Project Mitigation Measures

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TABLE G-1
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
Aesthetics					
Impact 3.2-1: The Project would, unless mitigated, have a substantial adverse effect on a scenic vista or substantially degrade the character or visual quality of views from publicly accessible vantage points.	**Mitigation Measure 3.2-1: Project Design to Reduce Aesthetic Impacts at KOP 1** When finalizing the design for the Project, the Applicant shall site turbines to avoid placing turbines within the viewshed of KOP 1, or to reduce the visibility of turbines from KOP 1. For example, if the turbines were to be moved further downslope they would be less visible, from KOP 1. When submitting site plans to the County of Shasta to be approved, the Applicant shall demonstrate to the County that the impacts from KOP 1 have been avoided or reduced. The turbines shall be painted in accordance with manufacturer's and Federal Aviation Administration marking requirements. Commercial messages and symbols shall not be used on turbine structures. When the site plans are presented to the County for approval, the Applicant also shall present the type of turbine selected to the County so that the County may ensure that no commercial messages are used on the turbines.	Applicant to submit site and building plans that demonstrate compliance to the Shasta County Department of Resource Management (County) and to provide written verification that no commercial messaging is shown on the turbines. County to review site and building plans for compliance prior to construction and conduct on-site monitoring during construction to ensure measures are properly implemented.	Submit plans at least 60 days prior to construction at that site. Note: Construction may not commence prior to Shasta County approval and issuance of a building permit(s). Implement approved plans during construction	Final site design reduces or avoids impacts at KOP 1, that the selected turbine is painted in accordance with FAA requirement, and that no commercial messages are used.	Shasta County
Air Quality					
Impact 3.3-1: Construction, decommissioning, and site reclamation activities would generate pollutant emissions that could conflict or obstruct implementation of the applicable air quality plan.	**Mitigation Measure 3.3-1a: Tier 4 Final Emission Standards for Off-road Construction Equipment.** The Applicant (and/or its construction contractor[s]) shall require that all diesel-fueled off-road construction equipment of more than 50 horsepower used at the Project Site during construction, decommissioning, and/or reclamation activities meet USEPA Tier 4 Final emission standards. A compliance log shall be maintained by the Applicant and made available to the Shasta County Department of Resource Management upon request.	Applicant to prepare and submit initial log prior to construction or first building permit field inspection and thereafter to maintain compliance log and make it available to the County upon request. County to review compliance log and perform on-site monitoring to ensure compliance.	Compliance log to be maintained and Tier 4 Final emissions standards enforced throughout construction, decommissioning, and/or reclamation activities	All diesel fuel off-road construction equipment of more than 50 horsepower used at the Project Site during construction, decommissioning, and/or reclamation activities meets USEPA Tier 4 final emission standards.	Shasta County
	Mitigation Measure 3.3-1b: Idling Restrictions and Fuel Use. To ensure that idling time for on road vehicles with a gross vehicular weight rating of 10,000 pounds or greater does not exceed the five-minute limit established in Section 2485 of Title 13 California Code of Regulations, and that idling time for off-road engines does not exceed the five-minute limit established in Title 13 California Code of Regulations Section 2449(d)(3), the Applicant and/or its construction contractor(s) shall prepare and implement a written idling policy and distribute it to all equipment operators. Clear signage of these requirements shall be provided for construction workers at all access points to construction areas. The Applicant shall use CARB-certified alternative fueled (compressed natural gas [CNG], liquid propane gas [LPG], electric motors, or other CARB certified off-road technologies) engines in construction equipment where feasible.	Applicant to provide County with written idling policy, and documentation (date) that policy has been distributed to all equipment operators. Applicant to provide documentation demonstrating use of alternative fuels, or that use of alternative fuels are infeasible. County to conduct on-site monitoring to ensure compliance	Preparation and distribution of idling policy at least 30 days prior to construction. Implement policy and mitigation measure as defined throughout construction, decommissioning, and/or reclamation activities	Compliance with all components of the required idling policy and mitigation measure as defined.	Shasta County
Impact 3.3-2b: Construction, decommissioning, and site reclamation activities would generate NO_x emissions that could result in a cumulatively considerable net increase of ozone, for which the Project region is non-attainment of State ambient air quality standards.	**Mitigation Measure 3.3-2b:** Implement Mitigation Measures 3.3-1a (Tier 4 Final Emission Standards for Off-road Construction Equipment) and 3.3-1b (Idling Restrictions and Fuel Use).	See above	See above	See above	See above
Impact 3.3-2c: Construction, decommissioning, and site reclamation activities would generate PM_{10} emissions that would result in a cumulatively considerable net increase of PM_{10}, which the Project region is non-attainment of State ambient air quality standards.	**Mitigation Measure 3.3-2c: Fugitive Dust Controls.** The following AQMD Standard Mitigation Measures for fugitive dust shall be implemented during the construction, decommissioning, and reclamation phases by the Applicant and/or its contractor(s): • Options to open burning of vegetative material on the Project Site shall be used by the Applicant unless otherwise deemed infeasible by the AQMD. Examples of suitable options are chipping, mulching, and conversion to biomass fuel.	County to conduct on-site monitoring during construction, decommissioning, and reclamation phases to ensure the AQMD Standard Mitigation Measures are properly implemented.	Implement the AQMD Standard Mitigation Measures during the construction, decommissioning, and reclamation phases.	Compliance with all components of the identified AQMD Standard Mitigation Measures to reduce emissions of fugitive dust.	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
	• The Applicant shall be responsible for ensuring that all adequate dust control measures are implemented in a timely and effective manner during all phases of Project development and construction. • All material excavated, stockpiled, or graded should be sufficiently watered to prevent fugitive dust from leaving property boundaries and causing a public nuisance or a violation of an ambient air standard. Watering should occur at least twice daily with complete site coverage, preferably in the mid-morning and after work is completed each day. • All areas (including unpaved roads) with vehicle traffic should be watered periodically or have dust palliatives applied for stabilization of dust emissions. Use of dust palliatives (e.g., dust suppressant or dust control binder) shall not occur in any location where transmission to a waterway or sensitive habitat could occur, such as within 100 feet of a wetland or body of water. • All onsite vehicles should be limited to a speed of 15 miles per hour on unpaved roads. • All land clearing, grading, earth moving, and excavation activities on the Project Site shall be suspended when winds are expected to exceed 20 miles per hour. • All inactive portions of the development site should be seeded and watered until suitable grass cover is established. • The Applicant shall be responsible for applying (according to manufacturer 's specifications) nontoxic soil stabilizers to all inactive construction areas (previously graded areas that remain inactive for 96 hours) in accordance with the Shasta County Grading Ordinance. • All trucks hauling dirt, sand, soil, or other loose material should be covered or should maintain at least 2 feet of freeboard (i.e., minimum vertical distance between top of the load and top of the trailer) in accordance with the requirements of California Vehicle Code Section 23114. This provision shall be enforced by local law enforcement agencies. • All material transported off site shall be either sufficiently watered or securely covered to prevent a public nuisance. • During initial grading, earth moving, or site preparation, the Applicant shall be required to construct a paved (or dust palliative-treated) apron, at least 100 feet in length, onto the Project Site from the adjacent paved Highway 299. • Paved streets adjacent to the development site should be swept or washed at the end of each day to remove excessive accumulations of silt and/or mud that may have accumulated as a result of activities on the development site. • Adjacent paved streets shall be swept at the end of each day if substantial volumes of soil materials have been carried onto adjacent public paved roads from the Project Site. • Wheel washers shall be installed where project vehicles and/or equipment enter and/or exit onto paved streets from unpaved roads. Vehicles and/or equipment shall be washed prior to each trip. • Prior to final occupancy, the applicant shall reestablish ground cover on the construction site through seeding and watering in accordance with the Shasta County Grading Ordinance.				
Biological Resources					
Impact 3.4-1: Construction of the Project could, unless mitigated, cause a significant impact to special- status plant species.	**Mitigation Measure 3.4-1: Avoid and Minimize Construction Impacts on Special-Status Plants** To prevent adverse impacts to special- status plants, the Project Applicant shall implement the following measures if construction activities are to occur in the area not yet surveyed, or if vegetation removal and ground disturbing construction activities have not been completed within 5 years of the completion of rare plant surveys: a) A qualified biologist shall conduct a pre-construction survey for special-status plant species with the potential to occur within the unsurveyed area, or other areas if 5 years have passed since completion of rare plant surveys; or as otherwise approved by CDFW. The survey shall follow the procedures outlined in the CDFW (2018) rare plant survey protocol. b) If special-status plants are found to be present, plant populations shall be avoided using an appropriate (e.g., 20-foot or greater) buffer for the subject population during construction. The	County to review and approve Applicant biologist and ecologist qualifications. Applicant to provide County with pre-construction survey results and restoration and mitigation plan if applicable. County to conduct on-site monitoring during construction to ensure avoidance measures and/or the restoration and	Survey results and the restoration and mitigation plan (if applicable) shall be provided to the County and CDFW at least 14 days in advance of the initiation of construction activities within the area(s) surveyed. Avoidance measures and/or restoration and mitigation plan shall be implemented during construction.	Avoidance measures and/or the restoration and mitigation plan are properly implemented so that permanent and temporary impacts on special-status plants and their required constituent habitat elements are avoided and minimized. Compensation, by restoration or credits, is provided as approved by all required resource and local agencies if avoidance is not possible.	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
	buffer shall be staked, roped, and/or fenced off so as to be readily identifiable by construction workers as a buffer area to be avoided. c) Where special-status plant avoidance is not feasible, the applicant shall mitigate for the loss of plants through the implementation of the following: A qualified ecologist shall develop and implement a restoration and mitigation plan according to CDFW guidelines and in coordination with CDFW. At a minimum, the plan shall include collection of reproductive structures or plant salvage from affected plants, a full description of microhabitat conditions necessary for each affected species, seed germination requirements, restoration techniques for temporarily disturbed occurrences, assessments of potential transplant and enhancement sites, success and performance criteria (e.g., greater than 1:1 replacement of individual plants or the population area), include a minimum 3-year monitoring program, as well as measures to ensure long-term sustainability such as weeding or supplemental water. d) Survey results shall be provided to the Shasta County Department of Resource Management, Planning Division and CDFW at least 14 days in advance of the initiation of construction activities within the area(s) surveyed. The Shasta County Department of Resource Management, Planning Division shall, in coordination with CDFW, determine whether or not the survey(s) were conducted in accordance with CDFW plant survey protocol and measures b) and/or c) are to be implemented. Construction shall not begin in the surveyed area until the Shasta County Department of Resource Management, Planning Division has confirmed that the survey(s) were conducted in accordance with the protocol and, if necessary, that measures 3.4-1b and/or 3.4-1c have been implemented.	mitigation plan are properly implemented.			
Impact 3.4-2: Construction of the Project could, unless mitigated, cause a significant impact on nesting bald and golden eagles.	**Mitigation Measure 3.4-2: Avoid and minimize construction-related impacts to nesting eagles (January 1 to August 31).** To prevent adverse impacts to nesting eagles, the Project Applicant shall implement the following measures if construction activities are to occur during the nesting season: a) Conduct terrestrial preconstruction eagle nesting surveys to determine whether eagles are actively nesting or maintaining territories within 2 miles of the Project construction boundary. Surveys will be designed and carried out by a qualified biologist with experience in the natural history and nesting behavior of eagles, following USFWS and CDFW guidelines and protocols. Terrestrial surveys will include all suitable eagle nesting habitat within a 2-mile buffer surrounding the Project construction boundary, as accessible, and subsequent observations at known nests to assess territory occupancy and nesting activity by adult eagles. b) Results of preconstruction eagle nesting surveys will be reported to the Shasta County Department of Resource Management, Planning Division, USFWS, and CDFW by August 31 of the year in which the survey was conducted. The Shasta County Department of Resource Management, Planning Division shall, in coordination with resource agencies, determine whether or not the survey(s) were conducted in accordance with USFWS and CDFW guidelines and protocols. Construction shall not begin in the surveyed area until the Shasta County Department of Resource Management, Planning Division has confirmed that the survey(s) were conducted in accordance with appropriate protocols and, if necessary, that measure 3.4-2c has been implemented. c) If surveys document active eagle nests within the 2-mile survey buffer, the Project Applicant will coordinate with the County, USFWS and CDFW to define and implement recommended protective measures. Typical measures for working within 2 miles of eagle nests are to establish construction buffers (e.g., with flagging, rope, signage, or other similar barriers) in accordance with USFWS recommendations (National Bald Eagle Management Guidelines, 2007; Golden Eagle, 2013) for specific activities (e.g., vehicular traffic, construction work, etc.); and may be adjusted downward based on site-specific conditions following coordination with the USFWS Migratory Bird Program and CDFW.	County to review and approve Applicant biologist qualifications. Applicant to provide survey results to the County, USFWS, and CDFW. County to confirm the survey(s) were conducted in accordance with appropriate protocols and measures. County to conduct on-site monitoring during construction to ensure any recommended measures and buffer areas are properly implemented.	Applicant to provide survey results to the County, USFWS, and CDFW prior to construction by August 31 of the year in which the survey was conducted. Any avoidance measures shall be implemented by the Applicant during construction.	Preconstruction surveys demonstrate absence of active nests or all recommended measures and buffer areas are properly implemented in coordination with County, USFWS, and CDFW and construction-related impacts to nesting eagles are avoided and minimized.	Shasta County
Impact 3.4-3: Operation of the Project could, unless mitigated, result in significant adverse impacts to or direct mortality of bald and golden eagles.	**Mitigation Measure 3.4-3a: Avoid and minimize operational impacts on avian and bat species.** The Project Applicant will avoid and minimize operational impacts on eagles, other raptors, other birds and bats by enacting the following mitigation measures: a) Discourage raptor use of immediate vicinity of wind turbine generators by taking steps to reduce prey species' numbers, such as minimizing creation of prey habitat such as rock piles.	Applicant to provide County with evidence it has coordinated with USFWS, its staff responsible for operations have been trained in reporting avian and bat wildlife fatalities, and a protocol for staff has been developed.	Documentation of evidence to be provided to County prior to the start of operations. Measure to be implemented as defined throughout operations.	APLIC and Land Based Wind Energy Guidelines and Applicant's protocol for reporting fatalities are followed operational impacts on avian and bat species are minimized.	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
	b) Follow APLIC (2006, 2012) guidance for all energized Project components to minimize electrocution or collision with transmission lines. c) Follow Land-Based Wind Energy Guidelines (USFWS, 2012) for turbine design and best management practices that help to minimize eagle mortality and eliminate potential raptor perches; avoid guy wires on meteorological towers where possible. d) Prior to Project construction, the Applicant will coordinate with USFWS regarding potential impacts to eagles and demonstrate the Projects' compliance with the Bald and Golden Eagle Protection Act and the USFWS Eagle Conservation Plan Guidance (2013). e) All Project staff responsible for operations will be trained in reporting avian and bat wildlife fatalities, including those of bald and golden eagles, other raptors, and bats encountered during turbine maintenance and other regular activities on site. A protocol for project staff will be developed in coordination with CDFW and the County for appropriate handling and reporting fatalities.				
	Mitigation Measure 3.4-3b: Monitor avian and bat mortality rates during project operations. To accurately assess operational Project impacts on all avian species, including bald eagle, golden eagle, other raptors, and bats, and ensure the effectiveness of avian protection measures, the applicant will design and implement a post-construction mortality monitoring (PCMM) study. The PCMM will include the following elements: a) The duration of PCMM monitoring to assess ongoing impacts of operation will include post-construction monitoring for all avian species, with particular attention to eagles, other raptors, and bats. The PCMM monitoring will commence immediately following the beginning of commercial operation and continue for three years following the incorporation of all planned turbines and power generation. b) PCMM studies will be designed to meet a minimum overall detection probability for bald and golden eagles of 30 percent during the first three years of full operation. Additionally, the PCMM will include a mandatory incidental monitoring and reporting program for other raptors and bats for the life of the Project. c) Searcher efficiency trials and carcass persistence trials using large raptor carcasses or an appropriate, commercially available proxy will be implemented and used to calculate overall detection probabilities of eagle carcasses. Carcasses of other birds and bats will also be collected and reported. d) Monitoring will occur over all seasons of occupancy for the species being monitored. e) Applicant will provide an annual report of PCMM findings to the Shasta County Department of Resource Management, Planning Division, CDFW, and the USFWS. If a bald or golden eagle, other raptors or bats are detected during PCMM, and detections indicate <u>exceedance</u> of the following thresholds, the Applicant and relevant agencies will develop a plan to mitigate the impacts per the *Land-Based Wind Energy Guidelines* (USFWS, 2012).[1] • Bald eagle – injury or mortality to one or more bald eagles in any given year. • Golden eagle – injury or mortality to one or more golden eagles in any given year. • Other raptors – injury or mortality to six or more individuals of any sensitive raptor species in any given year, except northern goshawk. For northern goshawk, injury or mortality to two or more individuals in any given year. • Other special-status birds – documented injury or mortality that suggests a population-level impact to other special status bird species. • Bats – injury or mortality to three or more bats of a single species identified as Western Bat Working Group (WBWG) high priority (red) species (i.e., pallid bat, Townsend's bat, spotted bat, western red bat, or western mastiff bat) in any given year; or injury or mortality to six or	Applicant to monitor avian and bat mortality and provide annual reports of PCMM findings to the County, CDFW, and the USFWS.	Applicant will conduct monitoring and develop associated annual reports during operations for three years following the incorporation of all planned turbines and power generation.	Operational project impacts on all avian species are accurately assessed. County and resource agency recommended minimization measures are implemented.	Shasta County

[1] Injury and mortality thresholds for bald eagle, golden eagle, and California spotted owl stated above were developed based on the low expectation for species mortality during project operations. For northern goshawk, this species is not listed and no California wind farm mortality has been identified in California. Because this species is unlikely to be encountered, a threshold of two individuals was adopted. For other raptors, the adopted threshold was based on the regional populations of Coopers hawk, sharp-shinned hawk, and northern harrier, which are fairly healthy. For most raptor species, mortality to migrating individuals is not anticipated. This assessment was based on focused baseline surveys of the Project area, monitoring findings from the Hatchet Ridge Wind Project, and coordination with raptor experts. For uncommon bat species with low population numbers, four WBWG high priority species are considered to have a low to moderate potential to occur and a threshold of three individuals per species was adopted based their rarity and low encounter numbers at the Hatchet Ridge Wind Project. For two WBWG medium species, a threshold of six bats was adopted based on the absence of habitat in the Project area (western mastiff bat) or the greater abundance of the species (hoary bat).

TABLE G-1 (CONTINUED)
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	more bats of a single species identified as WBWG medium priority (yellow) species (i.e., hoary bat or silver-haired bat), in any given year. If thresholds are exceeded, the Applicant will implement minimization measures recommended by the County, CDFW, and/or USFWS to limit mortality. Precise measures that are applicable will depend upon the type and magnitude of the identified impact based on the behavior of the impacted species and Project-specific attributes that may be leading to increased mortality, and may include one or more of the following operational modifications, or other identified adaptive actions: • "Informed curtailment" of turbine speed (rapid shutdown of turbines when raptors are seen approaching. • Curtailment of operations during high risk periods for bats (low wind nights) or birds. • The use of low-intensity ultraviolet light and ultrasonic deterrence systems to deter birds and bats from approaching (AWWI, 2018). • The use of bird-specific visual cues, such as marking/painting, UV coating, reflectors, minimal turbine lighting, visual deterrence or lasers. • Habitat alterations that affect habitat quality or food availability on- or off-site, or alter availability of breeding habitat or roosts. • Removing select turbines that are problematic for target species. • Altering turbine speed to reduce mortality. • Temporary shutdown of select turbines during sensitive periods. • Operating select turbines only during daylight hours. • Acoustic cues such as acoustic harassment or an audible deterrence. • Other sensory cues, such as electromagnetism or olfactory cues.				
Impact 3.4-3: Operation of the Project could, unless mitigated, result in significant adverse impacts to or direct mortality of bald and golden eagles.	**Mitigation Measure 3.4-3c: Offset operational impacts on eagles through compensatory mitigation, if necessary.** a) If bald or golden eagle mortality occurs as a result of the Project, the Project Applicant will fund the retrofitting of electrical utility poles that pose a high risk of electrocution to eagles. Applicant will coordinate with the USFWS and follow the most current USFWS Eagle Conservation Plan Guidance (USFWS, 2013). If in coordination with USFWS an alternative compensatory mitigation measure is preferred to pole retrofitting, such alternative compensation measure (e.g., pole reframing or funding carcass removal from roadways) may be implemented. b) Any compensatory mitigation must occur within the same Eagle Management Unit as the Project, and must be completed within one year of any instance of documented take. c) Applicant will provide a report to the Shasta County Planning Department and USFWS documenting implementation of measures taken within one year of detection of the eagle take. d) Annually and after collection of 3 years of post-construction monitoring data, the Shasta County Department of Resource Management's will review the data and, in coordination with the Project Applicant, USFWS and CDFW, will determine which, if any, specific wind turbines generate disproportionately high levels of avian (including eagle) mortalities (based on evidence of statistically significant higher levels of mortality relative to other Project wind turbines). If specific wind turbines are found to result in disproportionately high avian mortalities based on collected data, the Project Applicant shall coordinate with the County to evaluate any feasible measures that can be implemented to reduce or avoid mortalities at those specific wind turbines. Furthermore, if mortalities involve eagles, the County will consider additional measures, including but not limited to carcass removal from roadways or funding for the acquisition of conservation easements on habitat that would provide nesting, foraging, or roosting bald and/or golden eagle habitat. e) If unauthorized take of a federal or state listed raptor occurs during project operation, the Project Applicant shall immediately notify the appropriate agency (CDFW and/or USFWS) by phone.	Applicant to provide County with documentation of coordination with USWFS and CDFW for implementation of any compensatory mitigation. Applicant to provide report to County and USFWS documenting implementation of measures. County to monitor and verify compensatory mitigation is implemented during construction as defined. In coordination with the Project Applicant, USFWS and CDFW, the County will determine which, if any, specific wind turbines generate disproportionately high levels of avian (including eagle) mortalities and evaluate any feasible measures to reduce or avoid mortalities.	Any compensatory mitigation and associated report must be completed within one year of any instance of a documented take. The County to annually review data, after collection of 3 years post-construction monitoring, to determine if any specific wind turbines generate disproportionately high levels of avian mortalities.	Implementation of appropriate compensatory mitigation measures to offset impacts if eagle mortality occurs.	Shasta County

TABLE G-1 (CONTINUED)
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	The Applicant shall submit a written finding to the appropriate agency and the County within two calendar days that describes the date, time, location, species and, if possible, cause of unauthorized take. The Applicant shall notify the County within three calendar days of the receipt of any USFWS and/or CDFW required or recommended actions resulting from the unauthorized take, including whether an incidental take permit and/or additional requirements is deemed necessary by either agency.				
Impact 3.4-4: Decommissioning of the Project could result in adverse impacts to nesting bald and golden eagles.	**Mitigation Measure 3.4-4:** Implement Mitigation Measure 3.4-2; Avoid and minimize construction-related impacts to nesting eagles (January 1 to August 31).	See Mitigation Measure 3.4-2			
Impact 3.4-6: Construction and decommissioning of the Project could result in adverse impacts on nesting raptors (other than goshawks).	**Mitigation Measure 3.4-6: Avoid and minimize construction-related impacts on nesting raptors (February 1 to September 15)** a) Where feasible, tree and vegetation removal activities shall be avoided in potential raptor nesting habitat during the avian nesting season (February 1 to September 15) during each year of construction. b) If construction is planned to occur during the avian nesting season from February 1 to September 15, pre-construction raptor nesting surveys shall be conducted by a qualified biologist to identify raptor nests within 500 feet of proposed work areas. A qualified biologist is defined as a person who is knowledgeable in the distribution, habitat, life history, and identification of Northern California birds, is familiar with the survey methods to locate and survey for active nests within the Project Site and can acquire any permits needed to survey for federally listed or state-listed birds, if such permits become necessary. c) Results of preconstruction raptor surveys will be reported to the Shasta County Department of Resource Management, Planning Division, USFWS, and CDFW by August 31 of the year in which the survey was conducted. The Shasta County Department of Resource Management, Planning Division shall, in coordination with resource agencies, determine whether or not the survey(s) were conducted in accordance with appropriate protocols and measure 3.4-6d is to be implemented. Construction shall not begin in the surveyed area until the Shasta County Department of Resource Management, Planning Division has confirmed that the survey(s) were conducted in accordance with appropriate protocols and, if necessary, that measure 3.4-6d has been implemented. d) If active raptor nests are found during pre-construction surveys, a 500-foot exclusion zone shall be established around the nest in which no work would be allowed until the young have successfully fledged or nesting activity has ceased. The determination of fledging or cessation of nesting shall be made by a qualified biologist with experience in monitoring raptor nests. Any sign of nest disturbances shall be reported to the Shasta County Department of Resource Management, CDFW and USFWS. In coordination with CDFW and/or USFWS, the County may modify the size of the exclusion zone depending on the raptor species and type of construction activity occurring near the nest. e) Specific to any proposed blasting activities, a qualified biologist will evaluate areas within 1,320 feet (1/4-mile) of blasting sites to identify nesting raptors. If active raptor nests are found during pre-construction surveys nest buffer distance that is applied during blasting activities may range from approximately 500 feet to 1,320 feet, depending upon the time of year, sensitivity of any identified nesting species, and site-specific conditions such as topography or dense vegetation. The determination of fledging or cessation of nesting shall be made by a qualified biologist with experience in monitoring raptor nests. Any sign of nest disturbances shall be reported to the Shasta County Department of Resource Management, CDFW and USFWS. In coordination with CDFW and/or USFWS, the County may modify the size of the exclusion zone depending on the raptor species and type of construction activity occurring near the nest.	County to review and approve Applicant biologist qualifications. Applicant to provide survey results to the County, USFWS, and CDFW. County to confirm the survey(s) were conducted in accordance with appropriate protocols and measures. County to conduct on-site monitoring during construction and decommissioning to ensure any recommended measures and buffer areas are properly implemented.	Applicant to provide survey results to the County, USFWS, and CDFW prior to construction by August 31 of the year in which the survey was conducted. Any avoidance measures shall be implemented by the Applicant during construction.	Preconstruction surveys demonstrate absence of active nests; or all recommended measures and buffer areas are properly implemented in coordination with County; USFWS, and CDFW and construction-related impacts to goshawks are avoided and minimized.	Shasta County
Impact 3.4-7: Construction and decommissioning of the Project could result in adverse impacts to nesting goshawks.	**Mitigation Measure 3.4-7a:** Implement Mitigation Measure 3.4-6 (Avoid and minimize construction-related impacts on nesting raptors (February 1 to September 15))	See Mitigation Measure 3.4-6			
	Mitigation Measure 3.4-7b: Avoid and minimize construction-related impacts to nesting goshawks (March 1 to August 15) a) Prior to any disturbance of forest habitats that fit the nesting criteria of northern goshawks, the Applicant will conduct acoustic surveys for northern goshawk during their nesting season (March 1–August 31) following methods outlined by Woodbridge and Hargis (2006) to assure species is not nesting or using the territory for nesting. If nesting goshawks are found, the nests would be avoided with a suitable buffer distance (minimum 500 feet) in coordination with CDFW.	Applicant to provide survey results to the County, USFWS, and CDFW. County to confirm the survey(s) were conducted in accordance with appropriate protocols.	Applicant to provide survey results to the County, USFWS, and CDFW at least 30 days prior to any disturbance of forest habitats that fit the nesting criteria of northern goshawks.	Preconstruction surveys demonstrate absence of active nests; or buffer areas are properly implemented in coordination with County, USFWS, and CDFW; and construction-related impacts to nesting raptors (other than goshawks) are avoided and minimized.	Shasta County

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	b) Results of preconstruction goshawk surveys will be reported to the Shasta County Department of Resource Management, Planning Division and CDFW. The Shasta County Department of Resource Management, Planning Division shall, in coordination with resource agencies, determine whether or not the survey(s) were conducted in accordance with appropriate protocols. Construction shall not begin in the surveyed area until the Shasta County Department of Resource Management, Planning Division has confirmed that the survey(s) were conducted in accordance with appropriate protocols.	County to conduct on-site monitoring during construction and decommissioning to ensure any buffer areas are properly implemented.	Any buffer areas shall be implemented by the Applicant throughout construction.		
Impact 3.4-8: Operation of the Project could result in mortality and injury to raptors (including goshawk), as a result of collisions with wind turbines and electrical transmission lines.	**Mitigation Measure 3.4-8:** Implement Mitigation Measure 3.4-3b (Monitor avian and bat mortality rates during project operations).	See Mitigation Measure 3.4-3b			
Impact 3.4-12: Site preparation and construction, operations and maintenance, and decommissioning and site restoration of the Project could result in habitat loss and water quality impacts on Pit roach, special-status amphibians and western pond turtle.	**Mitigation Measure 3.4-12:** Implement Mitigation Measure 3.12-1 (Water Quality Best Management Practices during Activities in and near Water) and Mitigation Measure 3.4-16b (Avoid or Minimize Impacts to Wetlands and Other Waters).	See Mitigation Measures 3.12-1 and 3.4-16b			
Impact 3.4-13: Operation and maintenance of the Project could result in direct mortality and injury to bats, including special-status species.	**Mitigation Measure 3.4-13:** Implement Mitigation Measure 3.4-3b (Monitor Avian and Bat Mortality Rates During Project Operations).	See Mitigation Measure 3.4-3b			
Impact 3.4-15: Site preparation and construction, operations and maintenance, and decommissioning and site restoration of the Project would result in adverse impacts to riparian habitat or other sensitive vegetation communities.	**Mitigation Measure 3.4-15a:** Implement Mitigation Measure 3.4-16b (Avoid and Minimize Impacts to Wetland and Other Waters).	See Mitigation Measure 3.4-16b			
	Mitigation Measure 3.4-15b: Compensate for Impacts to Rocky Mountain Maple Riparian Scrub Habitat. The Applicant shall implement a Reclamation and Revegetation Plan that includes detailed measures for the compensation, restoration, and/or enhancement of Rocky Mountain Maple Riparian Scrub Habitat on a per-acre basis. The standard for mitigation shall be no net loss. If restoration is selected as a method of compensatory mitigation, the Applicant shall prepare a riparian mitigation and monitoring plan as part of the Project's reclamation and revegetation plan and shall submit it to the County for review, determination of adequacy, and approval. Mitigation ratios shall be at a1:1 level. The Rocky Mountain Maple Riparian Scrub Habitat mitigation and monitoring plan shall be written by a qualified biologist and shall include the following elements, at minimum: a) goals of the plan and permitting requirements satisfied; b) planned riparian habitat restoration activities and locations, including the restoration of temporarily affected riparian habitat to preconstruction conditions; c) monitoring and reporting requirements (including monitoring period), and criteria to measure mitigation success; d) the plant species to be used, container sizes, and/or seeding rates, and a planting/seeding schedule; e) a schematic drawing depicting the location of plantings within mitigation areas; f) a description of the irrigation methodology, if needed; g) invasive weed control measures within Rocky Mountain Maple Riparian Scrub Habitat mitigation areas; h) a detailed monitoring program, to initially include quarterly or more frequent visits tapering to annual maintenance; d) remedial measures, should mitigation efforts fall short of established targets. j) identification of the party responsible for meeting the success criteria and providing for long-term conservation of the mitigation site. The Applicant shall consult with CDFW about the adequacy of the plan and may consult with other agencies, if the plan aims to fulfill multiple permitting and mitigation requirements.	County to review and approve Applicant biologist qualifications. Applicant to provide County with documentation of coordination with CDFW regarding the adequacy of the Reclamation and Revegetation Plan. County to review, determine adequacy, approve the Reclamation and Revegetation plan, and monitor implementation as defined during construction, operations and maintenance, and decommissioning.	Applicant to develop Reclamation and Revegetation Plan at least 30 days prior to construction activities; and implement the Plan during construction as defined.	Implementation of appropriate compensatory mitigation measures to offset impacts Rocky Mountain Maple Riparian Scrub Habit.	Shasta County

TABLE G-1 (CONTINUED)
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Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
Impact 3.4-16: Site preparation and construction, operations and maintenance, and decommissioning and site restoration of the Project could result in adverse impacts to wetlands and other waters.	**Mitigation Measure 3.4-16a:** Implement Mitigation Measure 3.12-1 (Water Quality Best Management Practices during Activities in and near Water)	See Mitigation Measure 3.12-1			
	Mitigation Measure 3.4-16b: Avoid and Minimize Impacts to Wetlands and Other Waters. The Applicant will avoid and minimize impacts on wetlands and other waters by implementing the following mitigation measures: a) Avoid direct and indirect impacts to wetlands and streams in final siting and design to the maximum extent feasible. b) Design stream crossings, including culverts, to pass a 100-year event without increasing average flow velocity or bed/bank scour potential. c) Monitor stream crossings in burn areas seasonally and maintain culverts and drains, since burned areas may experience sediment and debris loads that could result in clogged or blocked culverts. d) The Applicant shall also submit a site plan showing all aquatic resources and appropriate regulatory buffers or setbacks to Shasta County. e) The Applicant shall assign a qualified wetland scientist to mark all aquatic resources associated with the final project site plan. Temporary high visibility fencing, and signage may be used to help protect these areas. The qualified wetland scientist would also identify corresponding setbacks to aquatic resources, as required by Project permits. f) On a continuous basis, a qualified wetland scientist or biological monitor shall be assigned to visually inspect aquatic resources, and surrounding areas, for evidence of hydrologic loss in aquatic areas. g) Develop a Spill Prevention, Control, and Countermeasures (SPCC) Plan to minimize adverse impacts to wetlands.	County to review and approve Applicant wetland scientist qualifications. Applicant to submittal site plan showing aquatic resources and regulatory buffers or setbacks to Shasta County. Applicant to develop SPCC Plan and provide to County. County to monitor implementation as defined during construction.	Applicant to development plan at least 30 days prior to the start of construction and implement plan during construction, operations and maintenance, and decommissioning.	Documented avoidance and minimization of impacts to wetlands. Submission of site plan showing aquatic resources and regulatory buffers to County, and evidence of monitoring of wetland impacts by qualitied biologist. Successful implementation of SPCC plan.	Shasta County
Impact 3.16 cont.	**Mitigation Measure 3.4-16c: Compensate for Impacts to Wetlands and other Waters.** The Applicant shall implement a Reclamation and Revegetation Plan that includes detailed measures for the compensation, restoration, and/or enhancement of wetlands and other waters on a wetland type per-acre basis. The standard for mitigation shall be no net loss. If restoration is selected as a method of compensatory mitigation, the Applicant shall prepare a wetland mitigation and monitoring plan as part of the Project's reclamation and revegetation plan and shall submit it to the County for review, determination of adequacy, and approval. Mitigation ratios shall be calculated following USACE wetland mitigation procedures and shall be based on the actual impact acreage of final design per as-built construction drawings and the results of the preconstruction surveys. After review and approval by the County and pertinent regulatory agencies, mitigation shall be carried out at a ratio no less than 1:1, or another ratio approved by the appropriate jurisdictional agency, whichever is higher. The wetland mitigation and monitoring plan shall be written by a qualified biologist and shall include the following elements, at minimum: a) goals of the plan and permitting requirements satisfied; b) wetland restoration activities and locations, including the restoration of temporarily affected wetlands and other waters to preconstruction conditions; c) monitoring and reporting requirements (including monitoring period), and criteria to measure mitigation success; and d) remedial measures, should mitigation efforts fall short of established targets. e) Restored wetland and riparian habitat shall achieve at least 85 percent survival of individual plants and show progress toward achieving 100 percent of the required mitigation acreage following 5 years of site monitoring and maintenance. The Applicant shall consult with USACE and CDFW about the adequacy of the plan and may consult with other agencies, if the plan aims to fulfill multiple permitting and mitigation requirements.	Applicant to provide County with documentation of consultation with USACE and CDFW. Applicant to provide Reclamation and Revegetation Plan and wetland mitigation and monitoring plan (if applicable) to County for review of adequacy and approval. If a wetland mitigation and monitoring plan will be prepared, County to review and approve biologist author qualifications. County to monitor implementation of plans as defined during construction.	Applicant to provide Reclamation and Revegetation Plan and wetland mitigation and monitoring plan (if applicable) to County for review and approval at least 30 days prior to the commencement of construction activities. Applicant to implement plan(s) during construction, operations and maintenance, and decommissioning.	Implementation of appropriate compensatory mitigation measures to offset impacts to wetlands and other waters.	Shasta County

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Communications Interference					
Impact 3.5-1: The Project could cause intermittent interference to or freezing of television reception at some residences in the service area of the stations that broadcast over the Project Site.	**Mitigation Measure 3.5-1: Correct or mitigate conflicts with television signals.** Prior to issuance of a construction permit from the County, the Applicant shall send notifications, via certified mail or other means that documents receipt, to all property owners of residences within the service area of the stations that broadcast over the Project site notifying them of the potential for interference with “over-the-air” television signals received by antenna. The notification shall provide contact information and instructions so that recipients may file a complaint with the Shasta County Department of Resource Management, Planning Division if interference occurs. In the event that the County receives a verified complaint regarding television broadcast interference that is attributable to this Project, the Applicant will resolve receiver interference through coordination with property owners. Verification shall include a letter or report from a qualified third party supporting the conclusion that interference is attributable to the Project. The Applicant shall not be required to provide qualifying residents with better reception than they had before the construction and operation of the Project.	Applicant to provide County with notice to property owners and documentation of property owner receipt. In the event of a verified complaint, Applicant to provide County with evidence of resolution coordination with property owners including verification from third party.	Notifications to be mailed prior to issuance of a construction permit from the County. Applicant to resolve issues with property owners during operation.	Property owners are made aware of the potential for interference with “over-the-air” television signals received by antenna. Verified property owner complaints are resolved by Applicant.	Shasta County
Impact 3.5-3: None of the Project turbines would obstruct or prevent known point-to-point microwave relay station transmissions; however, interference could occur due to turbine location adjustments or currently unknown transmissions.	**Mitigation Measure 3.5-3: Correct or mitigate conflicts with microwave signals.** Prior to issuance of a construction permit from the County, the Applicant shall notify, via certified mail or other means that documents receipt, all owners of frequency-based communication stations and towers within 2 miles of the Project Site. The notification shall provide the locations of all turbines and shall provide contact information and instructions so that recipients may file a complaint with the Shasta County Department of Resource Management, Planning Division if interference occurs. In the event that the County receives a verified complaint regarding microwave transmission interference that is attributable to this Project, the Applicant will resolve receiver interference through coordination with owners of frequency-based communication stations and towers. Verification shall include a letter or report from a qualified third party supporting the conclusion that interference is attributable to the Project. Possible actions include the Applicant being responsible for installation of high-performance antennas at nearby microwave sites, if required. The Applicant shall not be required to provide qualifying owners with better signals than they had before the construction and operation of the Project.	Applicant to provide County notification to property owners and documentation of receipt. In the event of a verified complaint, Applicant to provide County with evidence of coordination with owners of frequency-based communication stations and towers including verification from third party.	Notifications to be mailed prior to issuance of a construction permit from the County. Applicant to resolve issues with property owners during operation.	Owners of frequency-based communication stations and towers within 2 miles of the Project Site are notified of the project. Verified owner complaints are resolved by Applicant.	Shasta County
Cultural and Tribal Cultural Resources					
Impact 3.6-1: The Project could cause a substantial adverse change in the significance of an archaeological resource pursuant to CEQA Guidelines Section 15064.5.	**Mitigation Measure 3.6-1a: Archaeological Monitoring Plan.** Prior to receiving a County grading permit for the Project, the Applicant shall retain a qualified archaeologist, defined as an archaeologist meeting the U.S. Secretary of the Interior’s Professional Qualification Standards for Archeology, to prepare an archaeological resources monitoring plan. Monitoring shall be required for all subsurface excavation work within 500 feet of the recorded boundaries of known archaeological resources. The plan shall include the following: 1. Training program for all construction personnel involved in ground disturbance; 2. Person responsible for conducting monitoring activities, including Native American monitors; 3. Person responsible for overseeing and directing the monitors; 4. How the monitoring shall be conducted and the required format and content of monitoring reports; 5. Physical monitoring boundaries (e.g., 500-feet radius of a known archaeological resource) and maps; 6. Schedule for submittal of monitoring reports and person responsible for review and approval of monitoring reports; 7. Protocol for notifications in case of encountering of archaeological resources, as well as methods of evaluating the encountered resources (e.g., identification, evaluation, arrangements); 8. Methods to ensure security of archaeological resources;	County to review and approve Applicant archaeologist qualifications. Applicant to provide County with archaeological resources monitoring plan. County to monitor implementation of plan as defined during construction.	Archaeological resources monitoring plan to be prepared prior to receiving a County grading permit for the project. Plan to be implemented during construction.	Compliance with all components of the approved plan and protection of archaeologically sensitive areas.	Shasta County

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	9. Protocol for notifying local authorities (i.e. Sheriff, Police) should site looting and other illegal activities occur during construction. If archaeological materials are encountered, all soil disturbing activities within 100 feet shall cease until the materials are evaluated. The archaeological monitor shall immediately notify the County of the encountered archaeological materials. The monitor shall, after making a reasonable effort to assess the identity, integrity, and significance of the encountered archaeological materials, present the findings of this assessment to the County. During the course of the monitoring, the archaeologist may adjust the frequency—from continuous to intermittent—of the monitoring based on the conditions and professional judgment regarding the potential to impact resources.				
	Mitigation Measure 3.6-1b: Inadvertent Discovery Protocol. If prehistoric or historic-era archaeological resources are encountered during Project implementation, either during monitoring or otherwise, all construction activities within 100 feet shall cease, and a qualified archaeologist, defined as an archaeologist meeting the U.S. Secretary of the Interior's Professional Qualification Standards for Archeology, shall inspect the find within 24 hours of discovery and notify the County of their initial assessment. If the County determines, based on recommendations from a qualified archaeologist and a Native American representative (if the resource is Native American related), that the resource may qualify as a historical resource or unique archaeological resource (as defined in CEQA Guidelines Section 15064.5) or a tribal cultural resource (as defined in PRC Section 21080.3), the resource shall be avoided if feasible. Consistent with Section 15126.4(b)(3), this may be accomplished through planning construction to avoid the resource; incorporating the resource within open space; capping and covering the resource; or deeding the site into a permanent conservation easement. If avoidance is not feasible, the County shall consult with appropriate Native American tribes (if the resource is Native American-related), and other appropriate interested parties to determine treatment measures to avoid, minimize, or mitigate any potential impacts to the resource pursuant to PRC Section 21083.2, and CEQA Guidelines Section 15126.4. This shall include documentation of the resource and may include data recovery (according to PRC Section 21083.2), if deemed appropriate, or other actions such as treating the resource with culturally appropriate dignity and protecting the cultural character and integrity of the resource (according to PRC Section 21084.3).	County to review and approve Applicant archaeologist qualifications. In the event of discovery, the Applicant shall engage in consultation with County and Native American tribes to determine treatment measures to avoid, minimize, or mitigate any potential impacts. County to conduct on-site monitoring to ensure proper implementation of protocol.	Implemented during construction.	Implementation of construction protocols avoid, minimize, or mitigate impacts to any inadvertently discovered potential prehistoric or historic-era archaeological resources.	Shasta County
Impact 3.6-2: The Project could disturb human remains, including those interred outside of formal cemeteries.	**Mitigation Measure 3.6-2: Inadvertent Discovery of Human Remains.** In the event human remains are uncovered during ground-disturbing activities (including construction, operations and maintenance, and decommissioning), the Project proponent or its contractor shall immediately halt work within a 100-foot radius, contact the Shasta County Coroner to evaluate the remains within 48 hours, and follow the procedures and protocols pursuant to Section 15064.5(e)(1) of the CEQA Guidelines. Health and Safety Code Section 7050.5 requires that no further disturbance shall occur until the County Coroner has made the necessary findings as to origin and disposition pursuant to Public Resources Code Section 5097.98. If the remains are determined to be of Native American descent, the coroner has 24 hours to notify the Native American Heritage Commission (NAHC). The NAHC will then identify the person thought to be the most likely descendent of the deceased Native American. The most likely descendent will make recommendations for means of treating, with appropriate dignity, the human remains and any associated grave goods as provided in Public Resources Code Section 5097.98.	In the event of discovery, the Applicant shall contact the coroner and notify the County, and depending on the coroner's findings, shall provide the County with documentation that it consulted with the most likely descendent of the deceased Native American. County to conduct on-site monitoring during construction to ensure proper implementation of the mitigation measure and descendent recommendations.	In the event human remains are uncovered, the Applicant will immediately halt work and contact the Shasta County Coroner to evaluate the remains and contact the County.	Proper treatment of human remains and any associated grave goods, with appropriate dignity, in the event human remains are encountered.	Shasta County
Impact 3.6-3: The Project would cause a substantial adverse change in the significance of a tribal cultural resource.	**Mitigation Measure 3.6-3a:** Implement Mitigation Measure 3.6-1a: Archaeological Monitoring Plan and Mitigation Measure 3.6-1b: Inadvertent Discovery Protocol	See Mitigation Measure 3.6-1a and 3.6-1b			
	Mitigation Measure 3.6-3b: Coordination with the Pit River Tribe during Project Development. Shasta County and the Applicant will facilitate a preconstruction meeting and field visit with the Pit River Tribe through the Tribe's chairperson and the Pit River Environmental Office to discuss "tribal cultural resources" as defined in Public Resources Code Section 21074 in the Project Site and identify ways to minimize impacts on these locations during construction. The site visit will focus on viewing the location of the Project facilities, describing Project construction and operation activities, and identifying potential cultural significant features.	The County and Applicant will facilitate a pre-construction meeting and field visit with the Pit River Tribe and the Pit River Environmental Office as described in the measure.	Prior to construction.	Coordination with Pit River Tribe and the Pit River Environmental Office regarding project facilities, describing Project construction and operation activities, and identification of potential cultural significant features.	Shasta County
	Mitigation Measure 3.6-3c: Detailed Recordation of Features Considered Culturally Significant to the Pit River Tribe.	The Applicant to provide documentation to the County that it has undertaken an	Prior to construction.	Detailed recordation of any ethnographic location in this manner will create a photographic and written record of the cultural	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
	The Applicant shall retain a professional ethnographic consultant to undertake a detailed recordation of any locations considered important to the Pit River Tribe. The recordation will commence prior to construction and will include photographic documentation of pre- and post-construction conditions of any identified culturally sensitive location. The information gathered as a result of field, interview, and research tasks will be compiled into a report that will be transmitted to the Pit River Tribe. Detailed recordation of any ethnographic location in this manner will create a photographic and written record of the cultural resource prior to construction of the Project, resulting in partial compensation for Project impacts.	ethnographic recordation and provide it to Pit River Tribe.		resource, resulting in partial compensation for project impacts.	
	Mitigation Measure 3.6-3d: Cultural Resources Monitoring Program with the Pit River Tribe during Construction. The Applicant shall offer and provide the opportunity for cultural resource monitors from the Pit River Tribe to monitor initial ground disturbing construction activities in areas identified by the Tribe as culturally sensitive. Monitors will have the authority to ensure that discrete sacred sites in the Project Site are avoided or that impacts on such localities are mitigated to the extent feasible, including but not limited to, avoidance or data recovery (as outlined in Mitigation Measure 3.6.1a. Inadvertent Discovery Protocol). The Pit River Environmental Office should coordinate with the appropriate Achumawi bands (Itsatawi and Madesi) to assign monitors. If the offer is accepted, the Applicant shall provide compensation commensurate with market rates based on the qualifications and experience of the cultural monitor(s). Prior to tendering an offer to the Tribe the Applicant shall provide a copy of the offer to the County for review, including but not limited to the proposed number of monitors to be employed, proposed construction schedule/hours during which monitors would be present on site, proposed level(s) of compensation, and other relevant details of the proposed cultural monitoring program.	The Applicant to provide documentation to the County that it has offered and provided the opportunity for cultural resource monitors from the Pit River Tribe, and if amenable to the tribe, has developed an associated Cultural Resources Monitoring Program in consultation with Pit River Tribe. County to conduct on-site monitoring during construction to ensure proper implementation of the Cultural Resources Monitoring Program.	Development of Cultural Resources Monitoring Program prior the commencement of construction. Implementation of the Cultural Resources Monitoring Program during construction.	Ensure that discrete sacred sites in the Project Site are avoided or that impacts on such localities are mitigated to the extent feasible	Shasta County
Hazards and Hazardous Materials					
Impact 3.11-3: During normal operation, equipment failure or an extreme event could lead to turbine failure, resulting in a potential hazard.	**Mitigation Measure 3.11-3: Mandatory Setbacks.** A minimum wind turbine setback of two times the total tip height shall be maintained from the exterior Project boundaries where the Project Site is adjacent to existing parcels of record that contain an off-site residence.	Applicant to provide County with final site plan. County to review final site plan and conduct on-site monitoring to ensure identified setbacks from adjacent existing parcels that contain a residence are maintained.	Submission of site plan at least 30 days prior to commencement of construction.	Potential hazards associated with equipment or turbine failure are reduced.	Shasta County
Impact 3.11-7: The Project could impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan.	**Mitigation Measure 3.11-7:** Implement the Traffic Management Plan that would be required by Mitigation Measure 3.14-3.	See Mitigation Measure 3.14-3			
Hydrology and Water Quality					
Impact 3.12-1: The Project would, unless mitigated, violate water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality during construction and decommissioning.	**Mitigation Measure 3.12-1: Water Quality Best Management Practices during Activities in and near Water.** To avoid and/or minimize potential impacts on water quality (and jurisdictional waters) during construction- and decommissioning-related project activities that would be conducted near (i.e., within 50 feet), in, or over waterways, the project contractor shall implement the following standard construction BMPs to prevent releases of hazardous materials and to avoid other potential environmental impacts: 1.In-stream construction shall be scheduled during the summer low-flow season to minimize impacts on aquatic resources. If instream construction takes place during higher flow seasons, the following measures shall be implemented: a. Minimize mechanized equipment use below top of bank of streams; b. Perform activities in accordance with all permit conditions and best practices; and c. Have environmental monitors on-site to monitor instream construction to ensure compliance with permit conditions and best practices. 2. All construction material, wastes, debris, sediment, rubbish, trash, etc., shall be removed from the Project Site daily during construction and decommissioning, and thoroughly at the	County to conduct on-site monitoring during construction and decommissioning to ensure proper implementation of the BMPs as defined.	During construction and decommissioning.	Successful implementation of BMPs to prevent releases of hazardous materials and to avoid other potential environmental impacts.	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
	completion of each of these phases. Debris shall be transported to an authorized upland disposal area. 3. Consistent with the Project's Hazardous Materials Business Plan (HMBP) and Spill Prevention Control and Countermeasures Plan (SPCC), construction workers shall receive training prior to construction/decommissioning and protective measures shall be implemented to prevent accidental discharges of oils, gasoline, or other hazardous materials to jurisdictional waters during fueling, cleaning, and maintenance of equipment, as outlined in the Project's HMBP. Equipment used to perform construction work on the Project Site shall be maintained in accordance with manufacturers' protocols, and, except in the case of failure or breakdown, equipment maintenance shall be performed off-site. Crews shall check heavy equipment daily for leaks; if a leak is discovered, it shall be immediately contained and use of the equipment shall be suspended until repaired. The source of the leak shall be identified, material shall be cleaned up, and the cleaning materials shall be collected and properly disposed. 4. Vehicles and equipment shall be serviced off-site, or, if on-site service is necessary, in a designated location a minimum distance of 100 feet from drainage channels and other waterways. Fueling locations shall be inspected after fueling to document that no spills have occurred. Any spills shall be cleaned up immediately.				
Impact 3.12-2: Blasting, if it occurs, could substantially degrade groundwater quality.	**Mitigation Measure 3.12-2: Best Management Practices for Blasting.** All activities related to blasting shall follow Best Management Practices (BMPs) to prevent contamination of groundwater including preparing, reviewing and following an approved blasting plan; proper drilling, explosive handing and loading procedures; observing the entire blasting procedures; evaluating blasting performance; and handling and storage of blasted rock. 1) ***Blasting Plan.*** Prior to conducting the first blast on the Project Site, the Applicant shall prepare and submit a detailed blasting plan to the Shasta County Department of Resource Management and the Shasta County Sheriff's Department. The blasting plan shall contain a complete description of how explosives will be safely transported and used at the site; evacuation, security and fire prevention procedures; blasting equipment list; and procedures for notification of nearby receptors. The blasting plan shall explain how the Applicant will comply with the requirements of 30 C.F.R. §§816.61 through 816.68 regarding the use of explosives to be consistent with the technical requirements of the statute. Procedures for notification shall include, but not be limited to, the following: a. At least 30 days before initiation of blasting, the operator shall notify, in writing, all residents or owners of dwellings or other structures located within 0.5-mile of the permit area describing how to request and submit a pre-blasting survey. Notification shall include posting a written notice within the Project Site, and on the County's public website describing how to obtain and submit a pre-blasting survey. b. A resident or owner of a dwelling or structure within 0.5-mile of any part of the permit area may request a pre-blasting survey. This request shall be made, in writing, directly to the operator or to the regulatory authority, who shall promptly notify the operator. The operator shall promptly conduct a pre-blasting survey of the dwelling or structure and promptly prepare a written report of the survey detailing the results. c. The operator shall determine the condition of the dwelling or structure and shall document any pre-blasting damage and other physical factors that could reasonably be affected by the blasting. Structures such as pipelines, cables, transmission lines, and cisterns, wells, and other water systems warrant special attention; however, the assessment of these structures may be limited to surface conditions and other readily available data. d. Prior to finalizing the blasting plan, the Applicant or designated operator shall consult with jurisdictional authorities tasked with protecting waters of the state and implement avoidance and minimization measures, as required by CDFW, USACE, and regional water quality (Section 401) regulatory permits prepared for the Project. A record of consultation and such protective measures shall be included in the blasting plan and/or incorporated by reference. 2) ***Loading practices.*** The following blast hole loading practices to minimize environmental effects shall be followed: a) Drilling logs shall be maintained by the driller and communicated directly to the blaster. The logs shall indicate depths and lengths of voids, cavities, and fault zones or other weak zones encountered as well as groundwater conditions.	The Applicant shall prepare and submit a detailed blasting plan to the County and Shasta County Sheriff's Department. Prior to finalizing the blasting plan, the Applicant or designated operator shall consult with jurisdictional authorities tasked with protecting waters of the state and implement avoidance and minimization measures to protect regional water quality. Applicant shall provide County with documentation that it notified, in writing, all residents or owners of dwellings or other structures located within 0.5-mile of the permit area. County to conduct on-site monitoring during blasting to ensure proper implementation of the blasting plan.	The blasting plan to be submitted to County and Sheriff Department at least 45 days prior to planned commencement of blasting activities. Notification to residents or owners of dwellings or other structures at least 30 days before initiation of blasting. Implementation of blasting plan during construction.	Development and implementation of the blasting plan to reduce the potential to substantially degrade groundwater quality.	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
	b) Explosive products shall be managed on-site so that they are either used in the borehole, returned to the delivery vehicle, or placed in secure containers for off-site disposal. c) Spillage around the borehole shall either be placed in the borehole or cleaned up and returned to an appropriate vehicle for handling or placement in secured containers for off-site disposal. d) Loaded explosives shall be detonated as soon as possible and shall not be left in the blast holes overnight, unless weather or other documented safety concerns reasonably dictate that detonation should be postponed. e) Loading equipment shall be cleaned in an area where wastewater can be properly contained and handled in a manner that prevents release of contaminants to the environment. f) Explosives shall be loaded to maintain good continuity in the column load to promote complete detonation. Industry accepted loading practices for priming, stemming, decking and column rise shall be attended to. 3) ***Explosive Selection.*** To reduce the potential for groundwater contamination when explosives are used, explosive products shall be selected that (a) are appropriate for site conditions and safe blast execution, and (b) have the appropriate water resistance for the site conditions present to minimize the potential for hazardous effect of the product upon groundwater. 4) **Prevention of Misfires.** Appropriate practices shall be developed and implemented to prevent misfires. 5) **Blast Rock Pile Management.** To reduce the potential for contamination, the interaction of blasted rock piles and stormwater shall be managed to prevent contamination of water supply wells or surface water.				
Impact 3.12-4: The Project would, unless mitigated, substantially increase siltation of waterways or provide substantial additional sources of polluted runoff during construction and decommissioning.	**Mitigation Measure 3.12-4:** Implement the water quality best management practices during activities in and near water that would be required by Mitigation Measure 3.12-1.	See Mitigation Measure 3.12-1			
Impact 3.12-5: The Project would, unless mitigated, conflict with implementation of the Central Valley Basin Plan.	**Mitigation Measure 3.12-5a.** Implement the water quality best management practices during activities in and near water that would be required by Mitigation Measure 3.12-1.	See Mitigation Measure 3.12-1			
	Mitigation Measure 3.12-5b: Implement the best management practices for blasting that would be required by Mitigation Measure 3.12-2.	See Mitigation Measure 3.12-2			
Noise and Vibration					
Impact 3.13-2: Construction, decommissioning, and site reclamation of the Project could result in the generation of a substantial temporary increase in ambient noise levels on and near the Project Site in excess of standards established in the Shasta County General Plan or the applicable standards of other agencies.	**Mitigation Measure 3.13-2: Noise-Reducing Construction Practices.** The Project Applicant shall ensure that the following measures are implemented during construction, decommissioning, and site reclamation activities to avoid and minimize construction noise effects on sensitive receptors: a) Construction vehicle routes shall be located at the most distant point feasible from noise-sensitive receptors. b) All heavy trucks shall be properly maintained and equipped with noise-control (e.g., muffler) devices, in accordance with manufacturers' specifications, at each work site during Project construction, decommissioning, and site reclamation to minimize heavy truck traffic noise effects on sensitive receptors. c) Haul trucks and delivery trucks shall prioritize use of the east access road, if available, over the west access road, and shall avoid use of the west access road during nighttime hours. d) Helicopter use shall be limited to a period of 2 weeks or less such that receptors are not impacted for a substantial period of time. e) Limit construction operations located within 2,500 feet of residences to daytime hours only. f) Residences within 2,000 feet of helicopter activity shall be notified of the timeline of proposed operations at least 2 weeks` prior to line stringing operations. g) Nighttime (10 p.m. to 7 a.m.) helicopter use and blasting shall be prohibited.	County to conduct on-site monitoring during construction, decommissioning, and site reclamation to ensure implementation of noise-reducing construction practices as defined.	During construction, decommissioning, and site reclamation.	Implementation of defined noise-reducing practices to reduce noise levels on and near the Project Site.	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
Impact 3.13-3: Construction, decommissioning, and site reclamation of the Project could generate groundborne vibration.	**Mitigation Measure 3.13-3: Charge Weight Limits on Blasting Activities.** The Project Applicant shall ensure that blasting contractors restrict charge weight per delay such that a performance standard of less than 0.3 in/sec PPV would result at any structures in the vicinity of the blasting area. This performance standard shall be established as a condition of contract and implemented by a licensed blasting contractor in possession of a Federal Explosives License/Permit, issued by the Bureau of Alcohol, Tobacco, and Firearms.	Applicant to provide documentation to County that performance standard has been established as a condition of contract to be implemented by the licensed blasting contractor.	Documentation provided at least 14 days prior to planned blasting activities. Blasting activities to occur during construction.	Implementation of charge weight limits to reduce the extent of groundborne vibration.	Shasta County
Transportation					
Impact 3.14-3: The Project would, unless mitigated, substantially increase safety hazards.	**Mitigation Measure 3.14-3: Traffic Management Plan.** Prior to the issuance of construction or building permits and prior to the removal of materials from the Project Site during decommissioning, the Applicant shall: 1. Prepare and submit a Traffic Control Plan to Shasta County Public Works Department and the Caltrans offices for District 2, as appropriate, for approval. The Traffic Control Plan must be prepared in accordance with both the Caltrans Manual on Uniform Traffic Control Devices and Work Area Traffic Control Handbook and must include, but not be limited to, the following: a. A plan for communicating construction/decommissioning plans with Caltrans, emergency service providers, and residents located in the vicinity of the Project Site. b. An access and circulation plan for use by emergency vehicles when lane closures and/or detours are in effect. If lane closures occur, provide advance notice to local fire departments and sheriff's department to ensure that alternative evacuation and emergency routes are designed to maintain response times. c. Timing of deliveries to/removals from the Project Site of heavy equipment and building materials; d. Directing vehicles, pedestrians, and bicyclists on SR 299 through the construction zone with a flag person; e. Providing detours to route vehicular traffic, bicyclists, and pedestrians around lane or shoulder closures, if they occur; f. Providing adequate parking for construction trucks, equipment, and workers in the designated staging areas within the Project Site; g. Placing temporary signage, lighting, and traffic control devices if required, including, but not limited to, appropriate signage along access routes to indicate the presence of heavy vehicles and construction/decommissioning traffic, and the placement of traffic cones to provide temporary left-turn lanes into Project driveways as needed;[2] h. Preserving access to existing ingress/egress points for all adjacent property at all times; and, i. Specifying both construction/decommissioning-related vehicle travel and oversize/overweight vehicle haul routes. 2. Obtain all necessary encroachment permits for the work within the road right-of-way or use of oversized/overweight vehicles that will utilize County-maintained roads, which may require California Highway Patrol or a pilot car escort. Copies of the approved traffic plan and issued permits shall be submitted to the Shasta County Public Works Department and Caltrans. 3. Consult with the Shasta County Public Works Department and Caltrans to identify any substantial construction activities on SR 299 that may overlap with construction of the Project (e.g., Caltrans SR 299 resurfacing project from Milepost 60.0 to 67.8). Coordinate with the contractor(s) of any identified project(s) to ensure that overlapping construction activities do not cause unnecessary delays on SR 299 or preclude the ability of large vehicles to access the Project Site.	The Applicant to submit the Traffic Management Plan to Shasta County Public Works and Caltrans for review and approval. County to conduct on-site monitoring during construction to ensure measures are properly implemented.	Development of Traffic Management Plan prior to issuance of construction permits. Implementation of Traffic Management Plan during construction.	Development and implementation of Traffic Management plan that reduces traffic safety hazards.	Shasta County
Impact 3.14-4: The Project would, unless mitigated, result in inadequate emergency access.	**Mitigation Measure 3.14-4:** Implement the Traffic Management Plan that would be required by Mitigation Measure 3.14-3 (Traffic Management Plan).	See Mitigation Measure 3.14-3			

[2] A left-turn lane warrant analysis was conducted for the three Project driveways, which is provided in Appendix H. The analysis found that left-turn lanes would be warranted during Project construction at all three Project driveways during the a.m. peak hour.

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
Wildfire					
Impact 3.16-1: The Project would, unless mitigated, substantially impair an adopted emergency response plan or emergency evacuation plan	**Mitigation Measure 3.16-1a:** Implement Mitigation Measure 3.14-3 (Traffic Management Plan)	See Mitigation Measure 3.14-3			
	Mitigation Measure 3.16-1b: Pre-Construction Coordination with CAL FIRE Prior to construction, the Applicant shall provide GIS files or other maps of the Project layout to CAL FIRE to facilitate aerial fire-fighting planning. The Applicant shall notify CAL FIRE of any changes to the Project layout or any maintenance that would require the use of helicopters or the use of equipment not previously identified on maps provided to CAL FIRE that could present a new, previously unidentified vertical obstacle to aerial firefighting. <u>The Applicant will identify a Project operations point of contact for CAL FIRE to coordinate with in the event aerial fire-fighting operations occur in the vicinity of the Project.</u>	Applicant to provide the County with documentation that it provided GIS files of project layout to CAL FIRE and notified CAL FIRE of any project changes.	Prior to construction.	Provision of GIS files and of project layout, and notice of any project changes, to CAL FIRE for identification of any new, previously unidentified vertical obstacle(s) to aerial firefighting.	Shasta County
Impact 3.16-2: The Project would, unless mitigated, exacerbate wildfire risks and expose people to pollutant concentrations or a significant risk of loss, injury or death from a wildfire or the uncontrolled spread of a wildfire.	**Mitigation Measure 3.16-2a: Fire Safety.** The Applicant and/or its contractors shall prepare and implement a Project-specific Fire Prevention Plan (FPP) to prevent an exacerbation of wildfire risk during both the Project construction and operation and maintenance phases. Prior to construction, the Applicant shall contact and consult with the Shasta Trinity Unit of CAL FIRE and the Shasta County Fire Department to determine the appropriate amounts of fire equipment to be carried on the vehicles and appropriate prevention measures to be taken. The Applicant shall submit verification of its consultation with the appropriate fire departments to Shasta County. The Applicant shall submit a draft FPP to the Shasta County Project Manager for approval when the building permit application is submitted. The County shall have an opportunity to make comments on and revisions to the FPP, which the Applicant shall incorporate into a revised FPP for approval. The Applicant shall make the approved FPP available to all construction crew members prior to construction of the Project. The FPP shall list fire safety measures including fire prevention and extinguishment procedures, as well as specific emergency response and evacuation measures that would be followed during emergency situations; examples are listed below. The FPP also shall provide fire-related rules for smoking, storage and parking areas, usage of spark arrestors on construction equipment, and fire-suppression tools and equipment. The FPP shall include or require, but not be limited to, the following: • Prior to construction, the Project applicant shall designate primary and alternate Fire Coordinators such that a Fire Coordinator is present at all times during Project construction. The Fire Coordinator shall be responsible for ensuring that crews have sufficient fire suppression equipment, communication equipment, shall lead and coordinate fire patrols, ensure that the required clearances are followed onsite, and ensure that all crew members receive training on the FPP and its components. • For vehicles within control of the contractor, the contractor shall require vehicle drivers to conduct a visual inspection of the vehicle for potential sparking risks prior to operation of the vehicle. This inspection should include, but not be limited to a check of tire pressure and an inspection for chains or other vehicle components that could drag while driving. For subcontractors or vendors where vehicles are not within the control of the contractor, the contractor or Applicant shall develop a standard brochure to send to vendors that shall provide educational materials about fire risks associated with vehicles and shall provide an inspection checklist. • The Applicant and/or its contractors shall have water tanks, water trucks, or portable water backpacks (where space or access for a water truck or water tank is limited) sited/available in the study area for fire protection. • During construction of the Project the Applicant and/or its contractors shall implement ongoing fire patrols during construction hours and for 1 hour after the end of daily construction and hotwork. • All construction crews and inspectors shall be provided with radio and/or cellular telephone access that is operational within the Project Site to allow communications with other vehicles and construction crews. All fires shall be reported immediately upon detection. • Require that all internal combustion engines, stationary and mobile, be equipped with spark arresters in good working order. • Require that light trucks and cars with factory-installed mufflers be used only on roads where the roadway is cleared of vegetation.	Applicant to submit to the County verification that it has contacted and consulted with the Shasta Trinity Unit of CAL FIRE and the Shasta County Fire Department. Applicant to submit Fire Prevention Plan to County for review, comment, and approval. County to review submittals and conduct on-site monitoring during construction to ensure measures are properly implemented.	Development of the Fire Prevention Plan prior to construction. Submittal of the draft Fire Prevention Plan to the Shasta County Project Manager for approval when the building permit application is submitted. Implementation of the Fire Prevention Plan during construction and operation.	Effective implementation would be demonstrated through compliance with all components of the Fire Prevention Plan; if ignition from Project construction activities is promptly reported to the fire department(s) with jurisdiction; and when it is safe to do so, any Project-caused ignition is suppressed immediately.	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
	• Require that equipment parking areas and small stationary engine sites are cleared of all extraneous flammable material. • Include a fire conditions monitoring program to monitor meteorological data during construction and operation. • Include a monitoring and inspection protocol for turbines and electrical infrastructure. • Include protocol for disabling re-closers and de-energizing portions of the electrical collection and transmission systems • Prohibit smoking in wildland areas, with smoking limited to paved areas or areas cleared of all vegetation. • All construction vehicles shall have fire suppression equipment. • The Applicant shall ensure that all construction workers receive training on the implementation of the FPP including how to conduct a fire patrol, proper use of fire-fighting equipment and procedures to be followed in the event of a fire, vegetation clearance and equipment usage requirements, turbine, and electrical equipment inspections. • As construction may occur simultaneously at several locations, each construction site shall be equipped with fire extinguishers and fire-fighting equipment sufficient to extinguish small fires. • The Applicant shall enforce a requirement that construction personnel park any vehicles within roads, road shoulders, graveled areas, and/or cleared areas (i.e., away from dry vegetation) wherever such surfaces are present at the construction site. • The Applicant and its contractor shall cease all non-emergency work during Red Flag Warning events. • The Applicant shall coordinate the finalization of road improvements (i.e. frequency of grading and vegetation clearance) with CAL FIRE and other emergency responders to ensure that sufficient ingress and egress exists onsite. • Prior to the initiation of construction, a designated inspector from the County shall inspect the Project Site to ensure that sufficient fire suppression equipment is present onsite, that the required vegetation clearances have been cleared, that a crew member training program has been created, that construction vehicles are equipped with fire suppression equipment, that spark arrestors are installed on construction equipment, that a fire conditions monitoring program has been developed, that a monitoring and inspection protocol has been developed, that a disabling and re-closing protocol has been developed, and that CAL FIRE was appropriately consulted regarding road improvements and ingress and egress. • During construction, the Applicant shall submit a weekly FPP compliance report that demonstrates the following: fire patrols have been conducted following construction, any new construction workers have received training on the implementation of the FPP, that non-emergency work is being halted appropriately during Red Flag Warnings, and that sufficient fire suppression equipment is present onsite. Successful implementation of Mitigation Measure 3.16-2a (Fire Safety) would be demonstrated by the development of an FPP in consultation with local fire authorities which is documented and submitted to Shasta County for review, any revisions, and final approval. Additionally, successful implementation of Mitigation Measure 3.16-2a would require that the Applicant and its contractor comply with all components of the FPP, that ignition from Project construction activities is promptly reported to the fire department(s) with jurisdiction, and that when it is safe to do so, any Project-caused ignition is suppressed immediately.				
Impact 3.16 cont.	**Mitigation Measure 3.16-2b: Nacelle Fire Risk Reduction.** Turbines shall be equipped with fire detection and prevention technology compatible with the manufacturer's operating requirements and will be maintained in good working order throughout the life of the Project. Turbines with electrical equipment in the nacelle shall have safety devices to detect electrical arc and smoke that use the best available technology for fire detection and suppression within turbines. The turbine design shall include the following components: 1. Early fire detection and warning systems; 2. Automatic switch-off and complete disconnection from the power supply system; and	Applicant to provide County with verification that turbine design includes fire detection and protection technology. County to conduct on-site monitoring to ensure measures are properly implemented.	Verification of turbine design prior to construction. Implementation of turbine design during construction and operation.	Inclusion of fire detection and prevention technology in turbines to be maintained in good working order throughout the life of the Project	Shasta County

TABLE G-1 (CONTINUED)
APPLICANT PROPOSED MEASURES AND PROJECT MITIGATION MEASURES
MITIGATION MONITORING AND REPORTING PROGRAM

Environmental Impact	Mitigation Measure/APM	Monitoring / Reporting Action	Implementation Schedule	Effectiveness Criteria	Verification Approval Party
	3. Automatic fire extinguishing systems in the nacelle of each wind turbine. 4. Additionally, turbines shall include lightning protection equipment such as grounding equipment, and a lightning measurement system. Lightning grounding systems shall consider site-specific conditions such as soil type and conductivity. Should any of these devices report an out-of-range condition, the device shall command a shutdown of the turbine and disengage it from the electrical collection system, and send a notice through the SCADA. The entire turbine shall be protected by current-limiting switchgear installed at the base of the tower. In the event of a lightning strike, an electrical inspection shall be conducted on the affected turbine to identify and address any damage to the turbine or electrical system that could result in subsequent fire risk.				
Impact 3.16 cont.	**Mitigation Measure 3.16-2c: Emergency Response Plan.** Prior to the submission of the building permit application, the Applicant shall prepare an emergency response plan to be reviewed and approved by Shasta County Planning, CAL FIRE, and the Shasta County Fire Department. Following approval of the plan, the Applicant and/or its contractors shall implement the requirements in the plan during all phases of construction and operation, as applicable. The emergency response plan shall describe the likely types of potential accidents or emergencies involving fire that could occur during both construction and operation, and shall include response protocols for each scenario. The plan shall include key contact information and a description of key processes, in the event of an emergency in order to alert relevant responders of the emergency, and how to control the emergency. The plan shall include crew member training in response, suppression, and evacuation. The training shall be coordinated by the designated Fire Coordinators. Prior to construction, the Applicant shall submit to the County a compliance report demonstrating that all crew members have been trained. As new construction crews or operation workers are brought onsite, the Applicant shall submit additional compliance reports demonstrating that they have been received training on the emergency response plan.	Applicant to develop and submit Emergency Response Plan for review and approval to the County, Shasta County Fire Department, and CALFIRE. Applicant to submit to the County a compliance report demonstrating that all crew members have been trained regarding the Emergency Response Plan. County to review submittals and conduct on-site monitoring to ensure measures are properly implemented.	Development and submittal of plan prior to the submission of the building permit application. Implementation during construction	Development and implementation of Emergency Response Plan	Shasta County
Impact 3.16-4: The Project would, unless mitigated, expose people or structures to significant risks, including adverse water quality effects or downslope or downstream flooding or landslides, as a result of runoff, post-fire slope instability, or drainage changes.	**Mitigation Measure 3.16-4:** Implement the Fire Safety measures that would be required by Mitigation Measure 3.16-2a (Fire Safety); implement the Nacelle Fire Risk Reduction measures that would be required by Mitigation Measure 3.16-2b; and implement the Emergency Response Plan that would be required by Mitigation Measure 3.16-2c.	See Mitigation Measures 3.16-21, 3.16-2b, and 3.16-2c			

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Exhibit F
Project-wide Plans and Other Documentation

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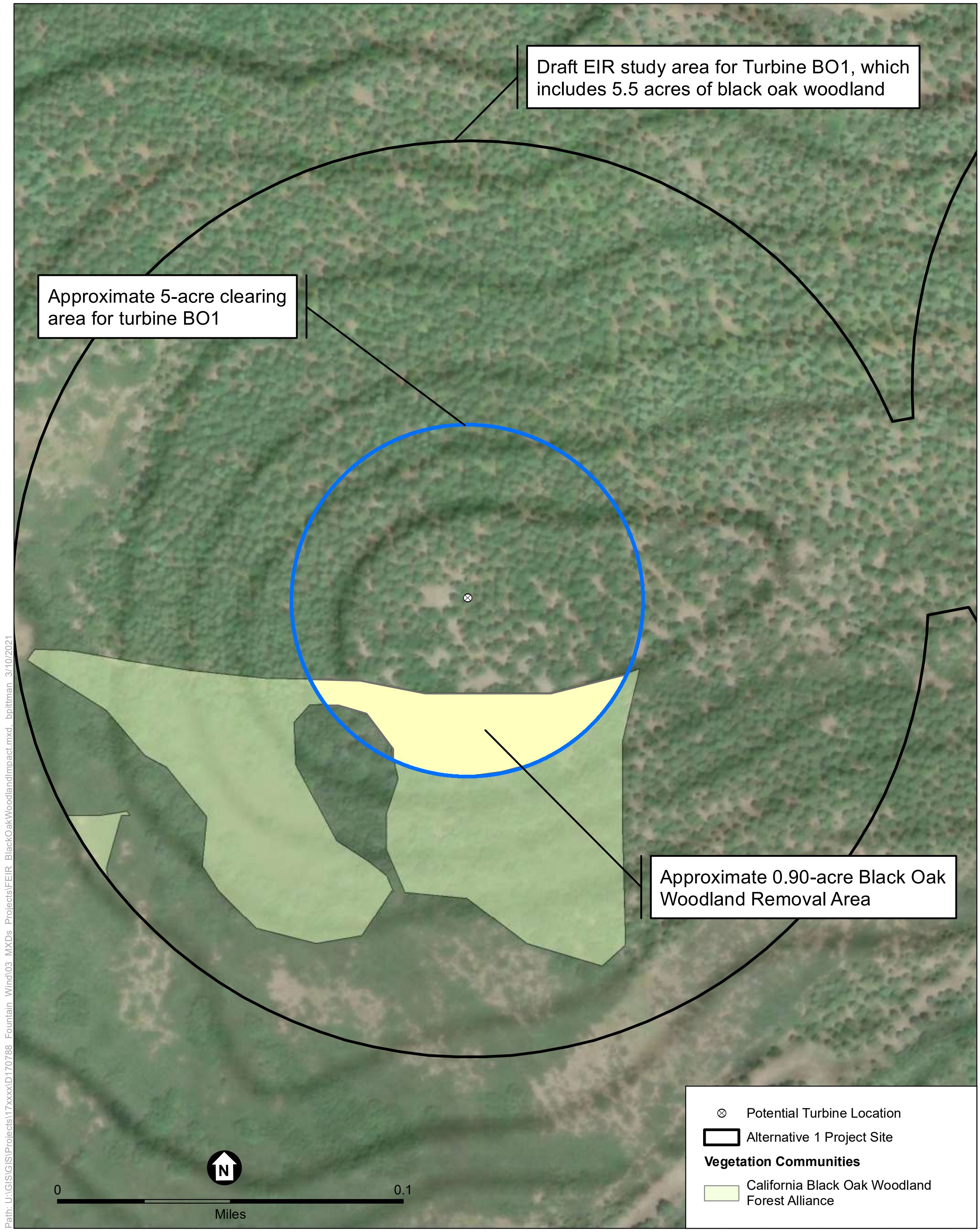
Appendix H
Figures



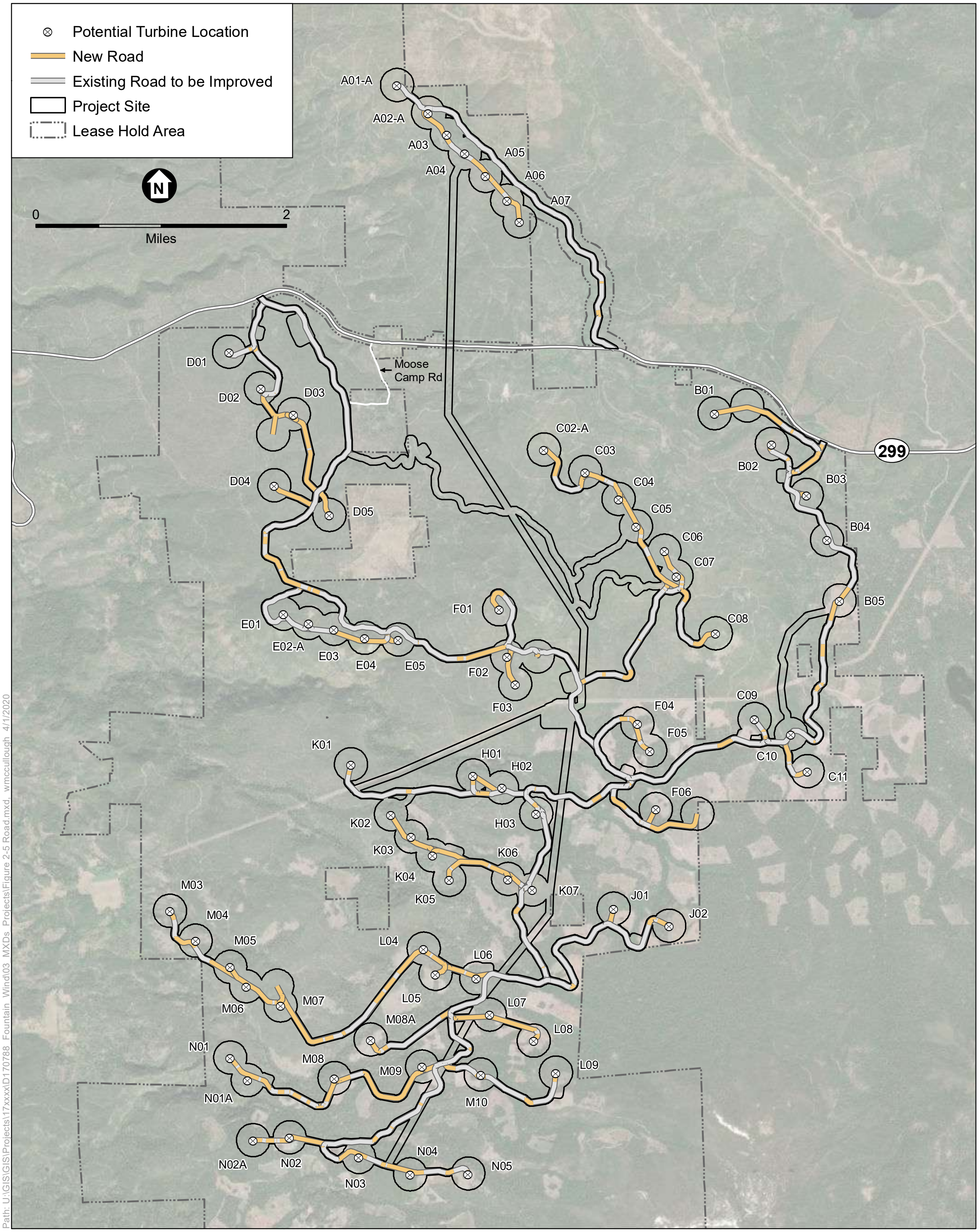
SOURCE: WEST Rare Plant & Natural Vegetation Communities Report; 2018/2019

Fountain Wind Project

Figure 1

Location of Black Oak Woodland Habitat within the Approximately 5-acre (263-foot Radius) Clearing Area for Turbine BO1

ESA



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Fountain Wind Project

Figure 2-5
Road Network

ESA