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BEFORE THE
ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
COMMISSION OF THE STATE OF CALIFORNIA

In the matter of,
   )
   ) Docket No. 15-IEPR-06
   )
2015 Integrated Energy Policy )
Report (IEPR) __________________

LEAD COMMISSION WORKSHOP ON

RENEWABLE PROGRESS, CHALLENGES, AND OPPORTUNITIES

CALIFORNIA ENERGY COMMISSION
FIRST FLOOR, ART ROSENFELD HEARING ROOM
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

MONDAY, MAY 11, 2015
10:00 A.M.

Reported By:
Kent Odell
APPEARANCES

Commissioners

Chair Robert Weisenmiller, Lead Commissioner for Electricity and Natural Gas

Andrew McAllister, Lead Commissioner 2015 IEPR

Karen Douglas, Lead Commissioner for Siting, Desert Renewable Energy Conservation Plan, and Compliance and Enforcement

David Hochschild, Lead Commissioner for Renewables

CEC Staff Present

Suzanne Korosec, Deputy Director, Renewable Energy Division


Angela Gould, Lead, RPS Verification and Compliance Unit

Kevin Barker, Chief of Staff to Chair Weisenmiller

Presenters/Panel Members Present

Keith Casey, Vice President, Market and Infrastructure Development, California Independent System Operator

Scott Murtishaw, Energy Advisor to President Picker, California Public Utilities Commission

Dennis Peters, California Independent System Operator

Laura Wisland, Union of Concerned Scientists

Manal Yamout, Advanced Microgrid Solutions

Steven Kelly, Independent Energy Producers Association

Graham Beatty, Poseidon Water

Christen Blum, Pacific Gas & Electric

Jennifer Kelly, PacifiCorp

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Presenters/Panel Members Present (Cont.)

John Dennis, Director of Power System Planning and Development, Los Angeles Department of Water and Power

Tim Tutt, Government Affairs Representative, Sacramento Municipal Utility District

Tanya DeRivi, Director of Government Affairs, Southern California Public Power Authority

Scott Tomashefsky, Regulatory Affairs Manager, Northern California Power Authority

Tony Andreoni, Director of Regulatory Affairs, California Municipal Utilities Association

Chari Worster, ORA

Claire Halbrook, Pacific Gas & Electric Company

Daniel Kim, Westland Solar Park

Nancy Rader, California Wind Energy Association

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Rachel Gold, Large Scale Solar Association

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Also Present

Ray Tingle, Sierra Club

Jan Reed
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MS. RAITT: Welcome to today’s IEPR Commissioner Workshop on Renewable Progress, Challenges, and Opportunities.

I’m Heather Raitt, the Program Manager for the IEPR.

I’ll begin by going over the usual housekeeping items. Restrooms are in the atrium. A snack room is on the second floor, at the top of the stairs.

If there’s an emergency and we need to evacuate the building, please follow staff to Roosevelt Park, which is across the street, diagonal to the building.

Today’s workshop is being broadcast through our WebEx conferencing system and parties should be aware that you’re being recorded.

We’ll post the audio recording on the Energy Commission’s website in a few days, and a written transcript in about a month.

We have a full agenda today and I’d like to ask the speakers to please limit your presentations to the time allotted. This will help make sure that we can get through all the material and that all the speakers have the time they need.

At the end of the discussion of 50 percent
renewables target, and at the end of the day there will be an opportunity for public comments. We’re asking parties to limit their comments to three minutes so that the maximum number of participants have an opportunity to speak.

We’ll take comments first from those in the room, followed by people participating on WebEx and, finally, from those who are phone-in-only.

For those in the room who would like to make comments, please fill out a blue card and give it to me. When it’s your turn to speak, please come to the center podium and speak in the microphone. It’s also helpful to give the court reporter your business card.

For WebEx participants, you can use the chat function to tell our WebEx coordinator that you’d like to make a comment during the public comment period, and we’ll either relay your comment or open the line at the appropriate time.

For phone-in-only participants, we’ll open your lines after hearing from the in-person and WebEx participants.

If you haven’t already, please sign in at the entrance to the hearing room. Materials for this meeting are available on the website and hardcopies are on the table at the entrance.
Written comments on today’s topics are due May 26. The workshop notice explains the process for submitting comments.

And with that, I’ll turn it over to the Commissioners for opening remarks.

COMMISSIONER MC ALLISTER: Well, great. Thank you, Heather.

My name is Andrew McAllister. I’m the Lead Commissioner on this IEPR this year, also over energy efficiency here, at the Commission.

And we have a great agenda. I want to thank staff and everybody for all their input on it. It’s going to be a really action-packed day.

I see some familiar faces in the audience and I know you’re going to contribute lots of substance to this, both today and in your comments.

In general, the word to describe renewables these days is kind of wow. So much going on, so much innovation, so much economic feasibility improvement.

And just opening up all sorts of potentials for helping us get to our long-term goals on carbon intensity and, yeah, our overall energy goals, both in the energy grid and just be across that into the transportation sector, and across our economy, really.

So, really transformative, potentially, and I
I want to thank our -- everybody here, up at the dais, and just introduce everybody. At least give them -- they’ll each have an opportunity to speak. But just thank the ISO, Keith Casey is here with us, and Scott Murtishaw, from the PUC.

So, I want to thank our sister agencies for coming and really helping us unpack this complex and very interesting topic.

Commissioner Hochschild, who is the lead on renewables, and Commissioner Douglas whose also very interested in this, and has been working, doing incredible work on the DRECP, as many of you know.

So, all of us are going to be very interested in the conversation here as it unfolds today, and beyond, as we put together the IEPR document, itself.

So, just raising it up to 50,000 feet or so, the context here, obviously, is our three big goals that the Governor announced earlier this year, 50 percent of our electricity sources from renewables, half of the petroleum used for transportation, cars and trucks, and doubling the impact of our energy efficiency efforts.

And those three goals really are kind of the triumvirate of goals that we have, that are all necessary. Maybe the holy trinity, maybe we should call
it, that are all necessary. Three legs of the stool, pick your metaphor, I guess, but they’re all necessary to get us to where we need to go. And renewables is really critical to that.

So, as we move forward, I would just ask everyone to think integration. That’s obviously going to be one of the, if not the major themes today, how can we really scale up and make sure that those electrons behave themselves, and get to where they need to go.

You know, as far as I know, the laws of physics still apply, so that hasn’t been innovative. We pretty much know what those little guys are going to do, and they’re pretty predictable, and they have been, and that’s unlikely to change.

So, we just want to make sure that the grid can operate reliably well and provide the level of service that we’re used to, as we scale up and look for the best opportunities, and deploy them in the most economic fashion.

So, I want to thank all of our panelists sort of preemptively, and really great set of minds on this topic today, and looking forward to everyone’s comments going forth.

And I think I will pass it to Commissioner Hochschild, for his opening comments, if you have any.
Great.

COMMISSIONER HOCHSCHILD: Thank you, Commissioner McAllister. So, just at a high level, I think it’s worth noting there’s nothing about the challenge of getting to 50 percent renewables that’s outside the realm of a solvable problem.

What we’re doing is achievable. It’s complex, but it’s achievable. And a lot of people said we couldn’t get to 20 percent, or 33 percent. And we’re, you know, at 25 percent now, and fully contracted to get to 33 percent.

And our challenge is how to keep this progress moving forward, as friction-free as possible.

Many of you kind of heard my manifesto on renewables before, but just to reiterate, the goal of what we’re doing, in my view, is more than just carbon reduction. It’s also to incubate the clean energy economy of the future and create that market certainty that helps grown the industry.

And we’re seeing this, obviously, with electric cars, and solar, and wind, and so many other technologies that have their birthplace in California, and have been spreading rapidly around the country and the world. And so, I think there’s a lot we can all feel proud of. And it’s important that we just keep
going and keep the collaboration, as well, which I think has been excellent between all the agencies.

So with that, I’ll turn it over to my colleague, Commissioner Douglas.

COMMISSIONER DOUGLAS: Hi, good morning, everyone, welcome to the Energy Commission. And thank you to Commissioner McAllister and the staff team for organizing this workshop.

I’ll just make a couple brief comments. You know, we are at the early stages, still, of what is going to be a very significant, very major transformation of our energy sector, and electricity sector.

And we have already achieved levels of renewable energy in a timeframe that would have seemed almost unbelievable even five, six, seven years ago. So, we are building on a record of tremendous success. We’re seeing continued innovations, continued changes, continued surprises and huge, you know, yes, challenges, but huge opportunities looking forward.

And so I think my interest, as I listen to this, and all that we have teed up for us to hear about, and consider, and public comment today is a couple things. It’s to get this perspective on challenges and opportunities, as they’re being teed up for us at this
moment, in this workshop. And also, to reflect on how we move forward, take advantage of these opportunities, while also realizing that the really amazing visions in front of us are something that we need to build towards.

You know, we don’t have the magic wand to make everything happen at once, so what is the strategy, how do we move forward to achieve this reality in a way that makes sense, and keeps the lights on and, you know, continues to focus on reliability, and speed of transformation, and getting to these big and incredible opportunities.

So, really interesting. I’m looking forward to hearing from everyone today.

COMMISSIONER MC ALLISTER: Great, thank you very much.

I wanted to point out that Chair Weisenmiller hopes to be here later, but had a conflict at the beginning here. But we’ll hope to have his presence in a little bit, later this morning.

Next, I want to go to Keith Casey, VP at the California ISO.

MR. CASEY: Thank you, Commissioner McAllister. First off, thank you for including the ISO up here at the dais. Appreciate the opportunity. And it’s a very interesting agenda and I look forward to the
presentations on this.

You know, when you look at the Governor’s goals for 2030, we really are set to really lead the world on renewable energy and carbon reduction strategies.

And that’s pretty exciting. And it also comes with a lot of responsibility because we have an opportunity to really show the world how to do this the right way, rather than be a poster child for how not to do it.

And as we address the challenges and think about the strategies for how we achieve these very aggressive, but very doable goals, we should be thinking about how can we do this in the most reliable, cost-effective manner to the benefit of all the ratepayers here in California.

And when I think of that, I think of two key themes that I think needs to be part of that strategy. One is the value of regionalism. You know, when you look at climate changes, in general, and strategies for dealing with them, it goes beyond California, obviously. And I really feel that we are at a juncture where we really need to be thinking about how we can achieve our policies, taking advantage of the diversity that’s out there, across the west. Both in terms of the renewable resources, as well as the integration resources that are
out there. And I think there’s untapped potential there that we really need to get after.

The other theme is when you talk about the three 50s, the 50 percent renewable, 50 percent reduction in petroleum, doubling energy efficiency, again the target here is bringing down greenhouse gases. And we need to think about how those goals, in each of those sectors interact with each other. Because I think there’s a lot of potential to tap carbon reduction strategies in other sectors, like transportation, to actually leverage that to help with the integration challenges we have in the electricity sector.

But doing that really requires taking a more holistic approach to these policy initiatives, and understanding the interactions, and adapting as we go along. Because we’re going to learn as we go along. And we don’t want to be locking in overly-prescriptive policies that in the end turn out not to be the best solution. We have to take things in incrementally, and learn as we go along.

So, those are just a couple of themes I’ll throw out there. And, like I said, I really appreciate the opportunity to be here, and look forward to the presentations and discussions.

COMMISSIONER MC ALLISTER: Thanks a lot, Keith.
And finally, last but not least, Scott Murtishaw, who’s in President Picker’s Officer, over at the California Public Utilities Commissions. Thanks for being here, as well.

MR. MURTISHAW: All right. And thank you, and to everyone else at the Energy Commission for inviting us to participate.

Part of the theme of today’s workshop is not just challenges, but progress that we’ve made towards meeting the 33 percent RPS target so far.

And people who followed the investor-owned utilities’ data know that to get to 33 percent, it has really not been that painful. Any predictions of doomsday, and lack of reliability, or loss of reliability have just not come to pass.

We have San Diego Gas & Electric already having 38 percent renewables under contract by 2020. And they’re saying they’re at 33 percent this year. The other utilities are well on their way to 33 percent by 2020. And, in fact, if you acknowledge that they can bank any excess RPS credits, or RECs prior to 2020, they’re really there today.

So, getting to 33 was relatively easy. Fifty percent, though, from the modeling that we’ve seen, does represent a sort of step change in the challenges of
integrating those renewables, and the possible costs, and potentially threats to reliability.

Keith Casey mentioned the fact that regionalism is a valuable on electric grids, and the introduction of the energy imbalance market is a step in the right direction. And other balancing authorities have expressed interest in joining, as well.

I think further efforts to expand coordination between balancing authorities, or even integrating balancing authorities would greatly simplify the challenges in front of us.

There was also a very recently released study, from Lawrence Berkeley Lab, about strategies for preserving the value of renewables. And it looked separately at wind and solar.

And what it found overall is that two things really stand out in terms of preserving the value of solar, in particular. Storage, of course, and we all know that storage technologies are beginning to take off under PUC-driven programs, like the Self-Generation Incentive Program, and our storage procurement targets that exist as a separate target for all of the investor-owned utilities.

And the other was real-time pricing. Which to me it’s a little frustrating that some utilities, like

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Georgia Power, have had real-time pricing for large commercial and industrial customers for decades. I think it’s time to take a serious look at real-time pricing for at least larger customers in California. And with the growing prevalence of electric vehicles and even home storage devices, like Tesla’s recent announcement, you know, I think that even at least making that available to residential and small commercial and industrial customers is something that we need to get started on right away.

Finally, I would just say, as we get to 50 percent or beyond sometimes tough choices have to be made about reliability. And as some of you may know, President Picker issued an alternate decision that would approve the Carlsbad Energy Center. He would approve 500 megawatts of gas-fired peaking resources.

And it’s obvious that fast-ramping gas can help integrate more renewables. And whether they’re absolutely necessary or not is debatable.

But it’s also important to keep it in perspective. The 500-megawatts of peaker plants, and by definition they would have low-capacity factors, would contribute about 0.1 percent to the State’s greenhouse gases on an annual basis.

So, if that’s something -- you know, we think
may be necessary to preserve liability, especially in liability-constrained areas, sometimes those are hard choices that have to be made.

That’s really all I have to say. I look forward to hearing everyone’s comments and learning about everyone’s ideas for moving to 50 percent and beyond.

COMMISSIONER MC ALLISTER: Great. Well, thanks for being so concrete, everybody, and we’ve gotten the agenda ten minutes ahead, which is very -- yeah, how about that? That’s an uncommon occurrence, I think. At least in IEPR’s that I’ve lead. I don’t know what that means.

So, I’ll kick it back to Heather and Suzanne.

MS. RAITT: Yeah, so our first speaker is Suzanne Korosec, the Deputy Director for the Renewable Energy Division. Thanks.

MS. KOROSEC: Good morning, everyone. Welcome, happy Monday.

Today I’m going to report on progress that’s been made on recommendations and action items from the Energy Commission’s Renewable Action Plan, which was adopted as part of the 2012 IEPR update, in February of 2013.

So, the Action Plan built on some analysis in the 2011 IEPR to identify the main challenges facing
renewable development in California. And based on that analysis, the 2011 IEPR came up with five overarching strategies to support renewables.

These were identifying high-priority areas in the State for renewable development, evaluating the costs and benefits of renewable projects, reducing the time and cost of interconnection and integration, promoting incentives for renewables that created in-State jobs, and in-State economic benefits.

And, finally, coordinating state and federal financing and incentives programs for critical stages in the renewable development continuum, including research, development, demonstration, pre-commercialization, and then deployment.

So, the 2012 Renewable Action Plan built on these five strategies and identified 31 specific actions that needed to be taken.

Since we have such a full agenda today, I’m keeping this at a very high level, not a lot of detail. And, also, we did not do an exhaustive analysis of all of the activities over the past couple of years that have been done in support of these recommendations.

So, if it appears I’ve missed something that’s important, please include that in your written comments for the workshop, and for our colleagues at other
agencies. If there’s something your agency is doing
that affects these recommendations, please contact me
and let me know about that, so that we can make sure
that we include that in our record.

So, starting with strategy one, which was to
identify preferred areas for renewable development. The
recommendations included working with local governments
and utilities to include renewable DG in their planning
processes.

Coordinating with local governments to develop
preferred zones for renewables of all sizes and
technology types, not just distributed generation.

To broaden the Energy Commission’s electricity
planning process beyond 2020, to look at the
implications of renewable targets higher than 33
percent.

And continuing efforts to develop renewables on
State properties.

Recommendation one proved to be very timely.
Since that was put into place, we’ve had several
initiatives that have been launched to identify
preferred areas for renewable development.

Assembly Bill 327 was signed in 2013. It
requires the IOUs to file distribution resource plans
that identify the best locations for DG, from a utility
perspective. That will help developers to understand
the higher value places to put their projects.

And the PUC’s also published a guidance document
for preparing these plans, which have to be filed by the
IOUs by July of this year.

CALISO has started a yearly process to identify
available deliverability for DG projects. And the IOUs
are posting renewable option mechanism maps that help
project developers see potential project sites. The map
show areas on the facility system that either do or
don’t have capacity for DG, which helps developers see
how expensive a project might be, and how long it might
take to get interconnection.

To help build a bridge between utility planning
and local land use planning, the Energy Commission is
working on a distributed energy resource pilot study.
The goal there is to show developers how expensive --
excuse me, better coordination between utility and local
planning processes can make markets for distributed
resources more effective.

And, finally, the Energy Commission has
published several reports on the location-specific value
of renewable DG projects. Two that are on the Energy
Net Simulation tool, which helps to identify low-impact
interconnection sites. And one that looks at whether
locating projects in certain areas can reduce utility
system costs and impacts.

Recommendation two was to identify renewable
zones of all sizes and types. The priority was to use
the existing built environment, first, following by
areas with minimal environmental or habitat value, such
as marginal or impaired ag lands.

So, this was really meant to build on experience
we got through the DRECP. And to begin by identifying
zones in the Central Valley because of the economic
disadvantages in that area, and also because of the
opportunity to repurpose ag lands.

We’ve made some good progress on this
recommendation. Obviously, the largest effort has been
the DRECP, the unprecedented coordination between
utilities, local governments, other State agencies and
various stakeholders, which has allowed development
zones to be created in the DRECP area.

The Energy Commission staff have been using
datasets from the DRECP to develop and make overlays for
environmental screening for statewide projects.

The Energy Commission is also working on a study
of the San Joaquin Valley as a gateway to expand the
DRECP work to other regions of California.

And the Energy Commission has also provided
about five and a half million dollars in grants to local
governments, through the Renewable Energy and
Conservation Planning Grants Program, to develop general
plans and zoning ordinances that help to develop
renewable resources.

Recommendation three targeted the need for
planning efforts beyond 2020, given the need -- excuse
me, the interest in higher renewable targets, and the
uncertainty about continued operation of the State’s
nuclear plants, both of which proved a bit prescient.

Some of the analysis going on in this area, we
have the Pathway Study, which was commissioned by the
Energy Agencies and the Air Resources Board. It was
completed in January. There was some updated
information posted in April.

This included multiple scenarios to evaluate a
range of possible 2030 GHG emission reduction targets,
on our way to meeting the 2050 GHG targets.

That study found that it’s possible to reduce
GHG emissions from 26 to 38 percent, from 1990 levels,
by 2020, using more energy efficiency, more renewables,
electrification of buildings and vehicles, and reducing
the carbon content of liquid fuels.

The CALISO’s 2015-2016 transmission planning
process is looking at several renewable portfolios for
2030, including one that specifically models a 50 percent RPS. And this analysis is expected to begin in August of 2015.

And the DRECP is continuing to look at future scenarios, including potential central station renewable development in 2014, in the DRECP area.

Number four was on renewables on State properties. In 2011, we issued a report called Developing Renewable Generation on State Properties. It recommended a goal of installing 2,500 megawatts of renewables on State properties, with targets along the way of 833 megawatts by 2015, and 1,666 megawatts by 2018.

And this was based on an inventory of potential at State properties, State lands, and properties with potential for wholesale generation.

However, according to the Department of General Services’ Renewable Energy Directory, there’s about 43 megawatts of renewables installed. We’ve got about 8 megawatts in the pipeline. So, clearly, we have a very long way to go.

The majority of the installed and planned projects are less than a megawatt in size, so this indicates we might be needing to focus more on using large properties, with potential for wholesale
generation to achieve that 2,500 megawatt goal.

Next is strategy two, which was to maximize the value of renewables by appropriately assessing benefits and costs. So, areas where we saw the need for improvement were in the RPS procurement process, residential rate design, improving the transparency of renewable generation costs, and making the connection between renewables and transportation electrification to encourage EV charging at key times.

So, for recommendation number five, under this, there’s been some progress on the POU procurement side as a result of the requirements that POUs adopt and implement renewable resource procurement plans for the RPS. And that they procure enough eligible resources to meet their RPS targets.

Also, CEC staff have found, in general, that the POUs have improved their planning for and acquisition of renewable generation.

There’s been less progress on some of the actions that were identified under this recommendation, particularly that RPS procurement by the IOUs and POUs should consider a wider variety of integration, like integration costs and benefits, interconnection costs, ability to provide reliability services, geographic diversity and technology diversity.
The PUC did release -- excuse me -- did evaluate RPS procurement reform, starting in October 2012. Released a decision in November 2014, on the 2014 RPS procurement plans that adopted findings related to certain elements of RPS procurement. But it didn’t really address the items that we had identified in our Action Plan.

Also, under the new RPS OIR, that opened in February, the PUC is considering proposed revisions to its RPS calculator to include, among other things, an integration adder, which is consistent.

For recommendation number six, on residential rate restructuring, the PUC will be considering a proposed decision in the residential rate reform proceeding, I believe at the May Business Meeting. I’m not certain.

After tiered rates are flattened to be simpler and more consistent with the underlying cost of service, customers will then be offered time varying rate options, along with some marketing and education to help them understand and respond to those new rates.

The tier flattening is supposed to begin in 2015, and the IOUs are going to propose default time of use rates by 2018, that will take effect in 2019.

Recommendation seven was to improve the
transparency of renewable generation costs. We’ve made some progress on that as it relates to distributed generation. The CEC’s doing a study on how the costs of renewable DG vary based on location. And our ongoing distributed energy resource pilot study, that I mentioned earlier, is looking at the value of DG, and other distributed resources in helping to meet State policy goals.

However, we still need additional work on the action item to improve the CEC’s data collection process, to really better track available, publicly available information on the costs of recently-built renewable projects.

Recommendation eight recognized the importance of electrifying the transportation system to meet our GHG reduction goals, but also the benefit of encouraging EV charging during times of low load, and high wind energy, to help increase the value of wind energy.

The recommendation also emphasized the need for transportation electrification in disadvantaged communities because they often face disproportionate impacts from burning fossil fuels.

So, there’s been quite a bit of progress on this recommendation. These are some of the projects we are funding. Since the plan was adopted, our Alternative
and Renewable Fuel and Vehicle Technology Program has awarded close to $40 million for plug-in electric vehicle infrastructure. This includes charging stations for multi-unit dwellings, workplaces, and highways.

And this slide is specifically awards made by the program that are in environmentally high risk communities, or areas with environmental justice indicators, for charging infrastructure at transit sites, hospitals, apartments and community associations.

The program has also awarded more than $30 million for electric trucks and buses in sensitive port areas, some of the projects highlighted here.

In the 2015-16 Investment Plan for the program, we did eliminate funding for some of the light-duty EV deployment because there’s been a large amount of greenhouse gas reduction funding that’s been given to the Air Resources Board for their Clean Vehicle Rebate Project, and that’s covering the light-duty area.

We’ve also made progress on the action item to develop greater links between planning for renewable energy, distribution system, and ZEVs, and also to support the U.S. Department of Defense’s work on vehicle-to-grid demonstrations.

In May of 2014, the CEC published the California...
Statewide Plug-In Electric Vehicle Infrastructure Assessment, with the assistance of NREL. We’ve also completed ten regional plug-in electric vehicle planning grants. And our staff meet monthly with each of the planning regions to coordinate and help them with lessons learned.

The Alternative and Renewable Fuel and Vehicle Technology Program also held solicitations for Alternative Fuel Readiness Plans, and ZEV Readiness, with 24 awards, totaling more than five and a half million.

And our R&D division is managing a contract to co-fund a vehicle-to-grid demonstration project by USDOD, which is scheduled for completion in March of 2016.

So, strategy three, as you can see by the number of recommendations under integration and interconnection, were really some of the major challenges we identified in the 2011 and 2012 reports. These were divided into three categories, transmission interconnection, distribution interconnection and grid level integration.

So, starting with recommendation nine, this was to consider environmental and land use factors in the renewable scenarios that are used in procurement and
transmission planning.

The Energy Agencies has been working closely to identify areas in the State with high renewable potential, and relatively low environmental conflicts, as well as areas that are very sensitive that we want to avoid.

The Energy Commission’s working with the PUC, and the ISO, and other agencies to identify environmental issues with new projects. We’re involved in analyzing the most appropriate areas for generation and transmission to coordinate and streamline renewable project permitting.

We’ve recommended that environmental and land use information, that we got from the DRECP, should be incorporated into the renewable scenarios that are being used in the PUC’s Long-Term Procurement proceeding, and also the CALISO’s transmission plan process.

And the Energy Commission is working with the PUC on inputs into the RPS Calculator, and the potential to include environmental or land use screens.

In the 2014 IEPR update, we recommended that the State should improve the ability to perform landscape scale analysis. And we’re working with local State and Federal partners, and other stakeholders to look at the available data and develop the ability to do this kind
of analysis.

This is focused on outside of the DRECP area. It includes the Western U.S., and potential international partners that are in the Western Interconnect. And this work is going to continue under the 2015 IEPR.

For recommendation number ten, the 2013 IEPR listed 17 transmission projects that we were tracking, that would help with renewable integration. Since then, CALISO has approved two more major transmission projects in the 2013-2014 Transmission Plan.

So, of the 17 projects in the 2013 IEPR, four are now operating. One was removed from the list. And with the two new projects, we’re now tracking 14 projects.

CALISO’s 2014-15 Transmission Plan did not identify any need for any new transmission projects to support the 33 percent RPS, given the projects that are already approved or going through the CPUC process.

Recommendation 11 was streamlining transmission permitting. We held a workshop at the CEC, as part of the 2013 IEPR, in May of 2013, to talk about the lack of synchronization between renewable generation and transmission planning.

And the workshop participants felt that the
CALISO’s generator, interconnection, and deliverability allocation procedures, and the annual transmission plan process really represent a big improvement in how new policy-drive transmission projects are identified.

But because these processes don’t guarantee that transmission will be built by the time the generation is commercially available, the 2013 IEPR did recommend that the Energy Agencies evaluate the cost effectiveness, the prudency, and alternatives for requiring full deliverability for future renewable generation to meet RPS requirements.

The PUC’s RPS Calculator proceeding is conducting a special scenario for the CALISO to use in its 2015-2016 Annual Transmission Plan that will address the 50 percent RPS portfolio by 2030.

And because it’s important to consider environmental information early in the transmission planning process, to help identify transmission corridors that can be permitted, the Energy Commission funded a consultant report to look at the environmental feasibility of transmission alternatives that are being considered by the CALISO to address reliability, and other issues as a result of the San Onofre closure.

The report did find that most of the transmission projects being considered will face serious
challenges in their land use permits.

Moving on to distribution interconnection, recommendation number 12 was to address the lack of transparency in utility distribution planning processes.

Some progress on this recommendation. The utilities will be filing the Distribution Resource Plans by July of this year, as I said, as part of the AB327 proceeding.

Related to that effort is a working group called The More than Smart Working Group, and it’s led by CALISO staff. It includes the utilities, the Energy Commission, the PUC, and other stakeholders. And this is an offshoot of a paper entitled “More than Smart”, that was published by Greentech Leadership Group, that describes a framework to improve the distribution grid.

The working group is focused on developing a transparent distribution plan that’s integrated with all other State energy planning. And it’s talking about how to integrate the new distribution resource plans into other planning efforts, like the long-term procurement plans, the transmission planning process, utility rate cases and the IEPR.

And the working group gives regular updates at PUC workshops, held under the distribution resource plan proceeding.
Recommendation number 13 was about disaggregating the Energy Commission’s demand forecast between the utility planning area level to give stakeholders location-specific information on demand.

The first step for this recommendation was providing forecast results by climate zone. And the 2013 IEPR, our forecast did include 16 climate zones, along with the usual eight planning areas.

And for the 2015 IEPR, we’re expanding the number of climate zones to 20 and we’re redefining the planning areas to be more consistent with the balancing authority areas in the State.

We also plan to continue to look at further disaggregation in future forecasts, depending on the availability of data.

Recommendation 14 was to create a statewide renewable data clearing house to help coordinate land use planning and utility system planning at both the distribution and transmission levels.

We’ve, unfortunately, seen very little progress on this recommendation. And part of the issue is the success of this recommendation depends on the availability of public data. And as we all know, data collection in the energy sector is complex. It’s contentious. And until enough useful data is publicly
available, we’re really limited in our ability to
provide a statewide clearing house.

That said, there are some current data sources
that are useful for planning. In May 2014, the PUC
published a decision with rules for providing access to
energy usage data to local governments, and researchers,
and State and Federal agencies, when that access was
consistent with State law, and when it doesn’t conflict
with consumer confidentiality concerns.

As part of the Rule 21 proceeding, California
IOUs are now required to file quarterly net energy
metering interconnection reports.

The Energy Commission is continuing to collect
and post renewable energy statistics and data on our
Energy Almanac and our Tracking Progress web pages. And
there are several California counties that have begun
posting useful information on where renewable projects
are filing for permits.

The last recommendation under distribution
interconnection, number 15, was the need for advanced
inverters that provide fast and flexible control of
output to help integrate and manage increasing amounts
of distributed PV.

There’s been quite a bit of work done on this.

In January 2013, the CEC and the PUC formed the Smart
Inverter Working Group to develop technical recommendations on inverter-based distributed resources to support operation of the distribution system.

And the working group includes utilities, inverter manufacturers, renewable developers, government and other organizations. They’ve held weekly conference calls since this began in 2013.

So, recommendations are being developed in three phases. The first phase defined autonomous functions that were adopted by the PUC in December of 2014. Those will be implemented by mid-2016. They include the items here, anti-islanding, low- and high-voltage, and frequency ride through, volt VAR control, default and emergency ramp rates, and providing reactive power.

In phase two, the working group developed a plan to implement the ability of distributed resource systems to include communications, and some of the requirements for interacting with utilities with those communications.

The phase two document was submitted by the group to the PUC staff in February of 2015, and the PUC is coordinating with the IOUs on implementation.

In March 2015, the group began working on phase three recommendations. These include the more advanced inverter functions, emergency alarms, ancillary
services, storage-specific functions, the ability to respond to pricing, and ancillary services signals.

So next are the grid level integration recommendations. Number 16 was to establish a forward procurement mechanism for three to five years ahead, to give revenue streams for flexible capacity resources, to integrate renewables in a way that would allow all resources, like DR storage, natural gas plants to compete on a level playing field.

The PUC’s long-term procurement plan, in 2014, was focused on flexibility issues at the 10-year forward horizon. But CEC staff tell me that the efforts of some parties to develop satisfactory forward projections of flexibility requirements were considered unsatisfactory, I think was the word that was used, or unconvincing.

And the PUC terminated this portion of the 2014 LTPP in March of 2015. Instead, they’ve initiated a model development effort for the balance of 2015 to improve the models for use in the upcoming 2016 LTPP.

In early 2014, the PUC established the Joint Reliability Plan rulemaking that looked at whether to extend resource adequacy requirements from a one-year forward to a three-year forward horizon.

And in October 2014, PUC staff issued a report summarizing several workshops. But the parties were
really opposed to mandating the current interim method of setting forward flexibility requirements, so the PUC suspended this portion of the Joint Reliability Plan rulemaking. So, very little progress on this recommendation.

Number 17 focused on developing a comprehensive package of tariffs, rules and performance requirements for integration services. Right now, CALISO is working very closely with stakeholders to develop wholesale DR products that can participate directly in the market.

And in April, they held education forums on energy storage and aggregation of distributed resources to clarify the existing requirements, rules and market products for these resources to participate in ISO markets.

Later this spring, the ISO will start a stakeholder process to identify specific enhancements needed to the rules and products for these resources also to participate in markets.

CALISO has also developed detailed roadmaps for energy storage, demand response, energy efficiency. These include pathways to bring more of these resources into the system over the next several years, and the activities and the milestones that are needed for that to happen.
Number 18 focused on regional solutions for renewable integration. As Mr. Casey mentioned, this is an important part of integrating renewables.

So, here we’ve seen some major progress. CALISO and PacifiCorp announced a partnership, in February 2013, to develop an energy imbalance market that would operate across participating balancing areas.

The EIM began operating in November 2014. NV Energy plans to join the EIM in the fall of 2015. And by the fall of 2015, EIM will cover seven western states.

I neglected to include on this slide, but also Puget Sound Energy will be participating starting in October of 2016.

Also, Arizona Public Service is considering joining. In mid-April they submitted a report to the Arizona Corporation Commission that identified significant cost savings for APS customers from their participation in the EIM.

It’s an important integration tool. It allows participants to leverage resources across an entire region. CALISO recently announced that the total gross benefits of the EIM to date is more than $11 million.

Another regional issue is, in April CALISO announced an MOU with PacifiCorp to explore PacifiCorp
becoming a participating transmission owner in CALISO. And this is another regional approach that will benefit California and the West by sharing resources throughout the region. As a side note, this will also allow electricity that’s generated within or scheduled into PacifiCorp area to quality as a bundled product, eligible for bucket one in the RPS program.

The last recommendation under integration was about making sure natural gas plants could be called on, when they’re needed, to help integrate renewables. In 2013, Columbia Grid released a study on electric transmission system reliability issues, with limitations on gas supply to electric generators along the I-5 corridor. It found that the electric transmission system performed very acceptably under stressed conditions.

In a workshop on natural gas issues, as part of the 2013 IEPR, ISO stated that short-term operational coordination between natural gas supply and electricity production in California has been occurring with very few incidents.

And the 2013 IEPR also included a report on natural gas infrastructure that talked about gas and electric system interactions. And we’re going to be continuing that discussion in the 2015 IEPR.
In March of 2014, FERC issued an order requiring all interstate pipelines to set up a system to post offers to buy excess capacity to help improve the flow of natural gas to gas-fired generators.

And in July of 2014, E3 did a report on natural gas infrastructure adequacy in the west. It found it’s technically feasible to meet the variable gas demands needed to integrate high penetrations of renewables.

Also in 2014, PG&E and SoCal Gas submitted biannual advice filing letters to the PUC, demonstrating they have adequate backbone capacity to meet both current and forecasted demand.

And CEC staff is continuing to monitor FERC proceedings dealing with natural gas/electricity harmonization issues.

Finally, the CEC put out a solicitation in January of this year to evaluate whether renewable integration can be supported by the natural gas system without improvements or changes, and what changes or improvements would be needed to increase the percentage of renewables.

Moving on to strategy four, this focused on economic development opportunities from supporting renewable projects and technologies. And the Energy Commission had a very strong role in workforce
development and education when we were distributing ARRA funds from 2009 to 2012. And we continue to be committed to workforce development.

Through our R&D division we funded the California Smart Grid Center at Sac State University to develop a strategic plan for smart grid workforce development that was completed in February 2013.

And the market facilitation of our EPIC R&D Program provides funding for strengthening the clean energy workforce by creating tools and resources that connect the industry to the labor market.

The California Workforce Investment Board has a five-year strategic plan that recognizes the importance of clean energy jobs in California. It identifies a wide variety of green trades, ranging from carpenters and electricians, to solar installers.

And California has great success in jobs, particularly in the solar industry. The Solar Energy Industry Association’s National Solar Job Census, for 2014, showed that California has more than 50,000 solar jobs, which is about 30 percent of the solar jobs nationwide.

In addition to programs that were funded under the American Recovery Act, California also has the Clean Technology and Renewable Energy Partnership Academies.
These were established in 2011, with additional funding that was made available, starting in 2013, of $8 million a year through 2017, for about a hundred academies that are focused on green energy and technologies. We developed guidelines for that program. The academies are available to students in grade 9 through 12. They provide career technical education in energy or water conservation, and renewable energy.

Finally, the California Workforce Investment Board has received $3 million in Prop 39 funds to develop and implement a competitive grant program for eligible workforce training organizations to prepare disadvantaged youth, Veterans and others for employment in clean energy fields.

Strategy five focused on providing funding during key stages of the Renewable Research and Development Continuum, and to coordinate financing and incentive programs to provide the most value.

Recommendations 23 through 26 focused on advancing research and development for existing and co-located renewable technologies, for innovative renewable technologies, for integration, and for renewable project siting.

The primary action items here were to make sure that our process was publicly vetted, that the State
leveraged co-funding opportunities, that we avoided
duplication, and that we published all research results
on our website.

So, our R&D Division has awarded more than $200
million to research projects that support the
recommendations in the 2012 Action Plan. And consistent
with those recommendations, each award was evaluated
through a public process. The results were published on
our website, provided to all interested stakeholders,
and we do continue to leverage other funding
opportunities, when available, and to strike to avoid
duplication.

For recommendation 23, we funded 41 projects,
totaling $70 million. These include projects to reduce
installation and maintenance costs, to improve
reliability and performance, to develop community scale
bioenergy, do environmental impact assessment and
mitigation. We’re looking at opportunities for
synergies from combining renewable technologies. We’re
reducing the cost of distributed PV, integrating
advanced inverter technologies and smart grid
components, and identifying strategies to make bioenergy
projects more economic.

To advance innovative renewable technologies, we
funded projects more than $20 million, to bring
innovative technologies closer to commercialization, and to look at the potential for technologies that are further out on the horizon.

We’re developing tools to support market facilitation, to verify the performance of innovative technologies. And we’re developing technologies in the areas of biomass conversion, offshore wind, concentrating solar power, small hydro and geothermal.

Other projects are looking at strategies to reduce peak demand, to minimize the environmental impacts of energy generation, and bring technologies to market that provide increased environmental benefits.

For 25, this is promoting R&D for renewable integration. This is where we really have focused the bulk of the funding, 75 projects totaling $109 million. These are projects to integrate intermittent generation, to improve solar and wind forecasting, to develop smart grid technologies, and micro grids, and to improve energy storage technologies.

And we’ve also funded applied research projects on storage, grid planning tools, and distribution system upgrades. And then technology, demonstration and deployment projects for renewable-based micro grids to demonstrate the benefits of local renewable generation.

Recommendation 26 was for proactive siting of
renewable projects. We funded 21 projects, totaling around $9 million, to reduce and resolve environmental barriers to renewable deployment, to develop new technology designs, and studies, and decision support tools to avoid impacts to environmentally sensitive areas, and to provide environmental analysis to support identifying preferred areas for renewable development, such as the San Joaquin Valley.

We’re also looking at the vulnerability of the electricity system to climate change, and identifying adaptation options.

The other recommendations under strategy five focused on financing issues. These are recommendations we’ve not seen much progress. We should probably evaluate how and when to raise these issues again.

Certainly, the extension of Federal tax credits remains a major issue, particularly for solar. The Federal Investment Tax Credit is currently at 30 percent for residential and commercial systems that were placed in service before December 31st, of 2016. After that, the commercial credit drops to 10 percent and the residential credit drops to zero, which is likely going to have an effect on residential solar development.

There’s also continuing concern with the boom/bust cycles we see with the Federal Production Tax.
Credit. Congress goes back and forth between expiring
and extending the PTC, which has really adversely
affected the wind industry.

And although we’ve made no progress on creating
a clean energy financing working group, or evaluating
the property tech exclusion, we have seen some movement
on helping to finance customer-side renewable projects.

In 2013, Senate Bill 96 directed the California
Alternative Energy and Advanced Transportation Financing
Authority, or CAEATFA, to develop the PACE Loss Reserve
Program to reduce the risk to mortgage lenders from
residential PACE financing that’s for energy efficiency
or distributed renewable installations.

The Energy Commission provided $10 million for
CAEATFA’s loss reserve. And this program makes first
mortgage lenders whole for any losses in a foreclosure
or a forced sale that’s attributed to a PACE lien.

As of March 2015, there were more than 24,000
residential PACE financings, that were valued at about
$500 million, that were covered by this program. No
claims on the loss reserve to date. CAEATFA initially
estimated the loss reserve would last 8 to 12 years, but
they’re reevaluating that program now that it’s been
active for almost a year.

Recommendation number 30 was related to the
Energy Commission’s Clean Energy Business Financing Program, which was funded under ARRA. Unfortunately, the program experienced some difficulties with projects that were not achieving their goals. And, eventually, the program was just too difficult for the CEC, given the structure of our organization as a government agency versus the demands of private sector loans.

We’re now working on transferring the funds to Department of General Services. We hope to have that transfer completed sometime this year.

Finally, recommendation number 31. This was to develop a marketing and outreach plan for the Energy Conservation Assistance Account Program because few local entities were actually taking advantage of the program to install renewable projects, because the requirements for the energy payback periods didn’t accommodate longer payback periods that you see with renewable installations.

But in 2013, the loan payback period was changed in statute from 15 to 20 years. This has allowed more loan applicants, with solar projects, to participate in the program. Since 2013, we have funded 26 ECCA loans that include PV installations. So, the local agencies clearly are more interested in taking advantage of the program.
And the program has received additional funds as a result of Prop 39, and also from the Greenhouse Gas Reduction Fund, both of which, now the programs have lower interest rates, 1 percent or 0 percent. And I think these lower interest rates for the ECCA-Ed and the ECAA-GGRF may also make the loans more attractive for renewable energy projects.

So, thanks for hanging in there through 31 long recommendations. So, some really quick conclusions here. We’ve seen really good progress on identifying preferred areas for DG and utility scale development, including the Distribution Resource Plan proceeding, the CEC’s Distributed Energy Resource Pilot Study, on the utility scale from the DRECP and local planning grants.

We’ve also made progress on electrifying the transportation system, evaluating the connections between EVs and renewable integration. California now has more than 9,300 charging stations, which is the largest nonresidential network in the nation.

We’ve deployed more than 10,000 light-duty EV cars and trucks, and 150 medium- and heavy-duty EV trucks.

We’re doing the Vehicle-to-Grid project with the USDOD.

We’ve also made progress in advanced metering --
inverter protocols, excuse me, with the work that’s being done by the Smart Inverter Working Group.

And the energy imbalance market is providing good regional solutions to renewable integration by allowing sharing of reserves and integration across a larger geographic regions.

Last, the Energy Commission has funded a wide variety of R&D projects that is helping to support renewable integration, and identify and mitigate environmental impacts of renewable development.

So, that’s the good news. But there are areas that we’d like to see some additional work on going forward.

First, renewables on State property. As I said, we had a target of 2,500 megawatts. We’re at 43 installed, eight in the pipeline, so we’ve got a long way to go. As a State, we’ve been a renewable leader for decades and our public buildings and our State lands really need to reflect that leadership.

The next areas where we need more progress are in transparency of renewable cost information and transparency of distribution planning processes.

We need to improve our ability to track publicly-available information on renewable project costs that will help us understand cost trends and
drivers, and help support distribution planning.

And the energy agencies and utilities need to continue evaluating how to improve coordination and integration of the DG procurement programs, the long-term procurement plans, smart grid deployment plans, and transmission planning so that distribution planning is at least as transparent as transmission planning.

The Renewable Action Plan recommendation to develop clear rules, tariffs and performance requirements for integration services needs to be pursued. We need to fully leverage automated DR, energy storage, and other distributed resources to provide integration services and then, finally, workforce development.

Many of the action items in the plan were under the purview of other agencies, and because we’re not a workforce development agency, we haven’t been closely been following these efforts. So, more progress may have been made than we’re aware of.

But like all industries in California, the energy industry is facing a lot of retirements as the Boomer Generation goes out of the system.

And as we move towards higher and higher percentages of renewables, we need to make sure we have the well-trained workforce in place to support our
renewable energy goals.

So that concludes my presentation. As I mentioned earlier, if there’s anything I’ve missed, please include that in your written comments. And I’m happy to answer any questions from the dais.

COMMISSIONER MC ALLISTER: Thanks, Suzanne. That was terrific. I debated kind of taking a break in the middle to let people ask questions up to the point. So, hopefully, everybody’s not super-saturated and has been taking notes so you can remember.

So much progress, really quite impressive. And thanks for that update.

I wanted to just highlight one thing, that many of the sort of areas where we need more progress have to do with the availability of information. And so, I think that’s just an ongoing theme that we’re seeing, both at my instigation, but I think by many -- with much agreement across the stakeholders that we need to figure out ways to get better information into the policy process. Into the process at the agencies, themselves, but also at the stakeholders so that they can come up with innovative solutions to those problems.

And the distribution planning, I think the distribution level engagement is particularly where the cutting edge is that needs to be -- and better
information can enable that in the marketplace and in
the policy arena.

Let’s see, I wanted to give Chair Weisenmiller a
chance to say -- he was able to join us, which is great.
Thank you very much.

And then I want to ask our colleagues from the
ISO, the PUC if there were any things that you wanted to
highlight from Suzanne’s presentations. We talked about
all the agencies. But given that you’re here on the
dais, it would be great to maybe put additional context
or shine around some of the points that Suzanne made in
her presentation.

So, I’ll start with Chair Weisenmiller.

CHAIR WEISENMILLER: I worked with Commissioner
Peterman on the initial Renewable Action Plan. And, you
know, certainly appreciated her energy and vision there.
And it’s good to have this sort of progress report.

Obviously, there’s still a lot to do. Although
there’s been, as you noted, a fair amount of progress in
some areas. And certainly want to thank Suzanne for
that comprehensive presentation.

COMMISSIONER MC ALLISTER: Either order I think
is fine. Keith, you want to go first?

MR. CASEY: Well, first off, Suzanne, an
excellent presentation. I was really impressed with the
level of both the scope and details that you had on
these various recommendations.

    Just with regard to recommendation 16, which
relates to kind of a joint effort between the PUC and
ISO to develop a forward-capacity, or forward-
procurement mechanism to deal with flexibility, I think
you accurately characterized the state of those efforts.

    A couple of additional comments on that. One of
the things we’re focused on, now, with regard to
flexibility is coming up with a more durable, robust
definition of when we talk about flexibility in the
system, what do we mean by it?

    We developed a very simplistic, interim
definition, but we really need to evolve that to really
get more sophisticated in how we define it.

    And, importantly, part of that definition needs
to include downward flexibility. And I think, as we get
into the presentations today, you’ll hear a lot of
discussion about how can we get more downward
flexibility out of the existing fleet of resources we
have out there, particularly the gas fleet.

    And when we look at the integration challenges
with the duck curve, and how we deal with over-
generation in the belly of the duck, how do we get the
minimum load of the generation that we need to have
online and the gas generation down to the lowest levels possible.

So, I think actually setting some definitions on downward flexibility, that might include a definition around minimum load requirements, could go a long ways to setting a structure to actually get the capability from the gas fleet to meet those requirements.

And I think the three-year requirement goes hand-in-hand with that. We have a lot of generating companies come to the ISO to talk about what’s possible, the art of the possible with their existing gas fleet. And there’s a lot of potential there to reduce minimum load, to get additional flexibility at a relatively low cost. But they’re asking, where’s the business model to finance this?

And I think a three-year requirement around flexibility would be an excellent tool to provide a revenue stream where plants can actually invest in those kinds of technologies.

COMMISSIONER MC ALLISTER: Keith, do you have any idea sort of what percentage of the energy supply we’re talking about here? You know, I mean I imagine it’s the load duration curve, it’s one kind of end of it where those resources are needed.

But, you know, if we’re talking about the need
for specific resources, you know, short period of time for ramping before and after the belly of the duck, or whenever it’s needed, you know, that’s one kind of thing.

MR. CASEY: Yeah.

COMMISSIONER MC ALLISTER: What percentage of time are we talking about?

MR. CASEY: I would say most of the time that, you know, the ramping issue that you see in the duck curve is not a one-day-a-year thing. It’s a very persistent pattern. The summer gets much better. As the loads go up in the summer, you don’t see that dramatic ramp issue we have. So, it’s predominantly in the spring and fall months where we have the most significant duck shape, if you will.

So, we really need the flexibility in the system to be able to deal with that day in and day out.

COMMISSIONER MC ALLISTER: I guess I’m just thinking sort of hours-per-year kind of thing, when you’re really having to lean on those resources. A couple hours in the morning and afternoon, say, or --

MR. CASEY: Yeah, I would say in terms of needing to rely on the gas fleet to manage the ramping challenge, right now that is the resource we have that has flexibility. And, clearly, we need to move away
from that if we’re going to be successful in meeting these carbon goals, and get flexibility elsewhere in the system.

You know, recommendation 17 talked about some of the progress we’re making with demand response. We’ve got a long ways to go with demand response. Despite all our efforts, we haven’t even moved the needle on it. And that’s incredibly frustrating and embarrassing that California can’t do more in advancing demand response.

Clearly, storage is another opportunity. And, certainly, the regional diversity, getting a more coordinated dispatch with combined balancing areas can help to mitigate that ramping challenge as well.

So, there are a lot of other resources out there, but until we develop them in meaningful ways, we’re going to be dependent on the gas fleet to manage this.

COMMISSIONER MC ALLISTER: Yeah, okay, thanks a lot. I think that business model point is really incredibly important. And in 2013, we actually talked about demand response a lot, and it was one of the issues that we were trying to move the needle on. And I think we got a little bit of progress, but it’s kind of a market question that we need to, I think, elevate the conversation and rethink maybe, again.
CHAIR WEISENMILLER: Yeah, I was just going to, for the rest of the group, you and I sat through the discussion at PG&E about potentially cycling Diablo Canyon down at night to deal with, again, sort of over-generation issues. And I’m sort of surprised that they were talking about maybe going down as far as 50 percent. But, obviously, I can’t say those studies have gotten very far along.

COMMISSIONER MC ALLISTER: Yeah, that was very surprising to me, as well, and I’m kind of interested in the technical analysis of what that actually looks like but, great.

Did you want to say anything else, Keith?

MR. CASEY: No.

COMMISSIONER MC ALLISTER: Thanks a lot.

So, Scott, I wanted to give you an opportunity. Or anybody, actually. But, Scott, wanted to kind of give you the opportunity to jump in where you think appropriate.

MR. MURTISHAW: Well, first, I’d just say kudos to the Energy Commission staff for accurately summarizing a tremendous amount of activity at the PUC. Because we have been doing a lot over the last couple of years on all of these fronts.

I’ll just respond to a couple of things in
particular. One, to note on the distribution resources plan rulemaking, this was recommendation number 12, the utilities are supposed to submit their initial applications for their first distribution resource plans in July. So, we’re all waiting with baited breath at the PUC to see what, exactly, the utilities submit, see what the similarities and differences are.

But we know that because this is just the first time that we’re initiating this process, we have to expect to start small. It’s going to take probably two or three years before we get a sense of how to really implement distribution resource planning in a more proactive way across the entire service territories of these very large utilities.

So, it’s going to be important to pilot test some ideas and to start small.

And then I would also say that, you know, at least in terms of using demand response and storage to provide more services to the grid, one company in particular that I’ve been following for a couple of years now, Power Tree, which does an integrated PV, electric vehicle charging and storage all as one package. It’s a very ambitious set of services that they’re trying to package together.

But they’ve been really struggling, working with
the ISO and PG&E on all of the metering requirements,
and the tariffs, and the charges and fees associated
with imports and exports, as the storage provides or can
provide power to the grid.

And my understanding is that a lot of progress
has been made, but sometimes the pioneer just has to
work through a lot of challenging and complex issues.
And once those are resolved, I hope we can see a more
rapid expansion of those kinds of services from behind
the meter.

And on the residential rate reform proceeding,
there is a draft decision out there. It was scheduled
for the May 21st meeting. But at an all-party meeting
last week, Commissioner Florio announced that he intends
to issue an alternative, which we still have not seen.
So, at this point I think we’re going to see a fairly
significant delay before we can take that matter up for
a vote.

COMMISSIONER MC ALLISTER: Thanks a lot, Scott.
Let’s see, I guess, you know, I agree that
demand response, you know, with everybody, that a lot of
the issues with demand response aren’t -- really,
they’re not technology. We have great technology and
plenty of firms who really want to go out there and make
things happen.
And I guess, what’s the state of the conversation on sort of how to -- is that conversation going to be elevated to help cut through some of the transaction costs that they’re facing out there? Because I know on a larger scale, in the wholesale market there’s also some activity within the territory, but they’re also a different beast kind of, but two sides of a similar coin.

So, I guess I’m wondering sort of what’s the state of that conversation in the DR proceedings over at the PUC?

MR. MURTISHAW: Well, yeah, a couple of things. I haven’t really worked on demand response. I haven’t followed those proceedings that closely.

I know that Commissioner Picker, at our last meeting, expressed some frustration with the fact that several of the parties, who are active in the demand response proceeding, all signed onto a joint stipulation last year, proposing to move out supply side DR even further into the future. You know, not actually implementing it for several more years.

And, of course, the Federal court cases have thrown some of the framework around supply side DR up in the air. So, getting that resolved as quickly as possible will be useful.
But President Picker has been somewhat frustrated with the lack of either urgency or ambition that some of the parties are showing towards moving, in a more forceful way, towards supply side DR that can complement our more price-responsive programs.

COMMISSIONER MC ALLISTER: Okay, thanks a lot. And I want to just give President Picker major kudos for the more than smart activity. I mean that’s been, I think, really groundbreaking and started a lot of discussions that were kind of happening on the sly, but he’s really centralized that and gotten the right people at the table to have that discussion, and it’s going to pay off big dividends, I think.

CHAIR WEISENMILLER: Yeah. No, I was just going to say that Commissioner Florio’s on point on demand response. As you indicated, I think everyone was shocked that the settlement for demand response basically would take longer than World War II to get results, and tried to accelerate that.

And, certainly, Florio’s staff is sort of on it full time at this point. But as you said, there’s a lot that -- you know, we haven’t really seen the needle move on these programs in the last three years. So, it would be good to get some progress.

COMMISSIONER Mc ALLISTER: So, open it up to
COMMISSIONER DOUGLAS: So, I just had a couple of comments, really not questions. You know, I think it’s in the nature of a high-level summary to make some things sound like they’re done and done. And I just wanted to flag that in the area of, you know, environmental planning and how that should be used in decision making for energy and other kinds of -- electricity and other kinds of infrastructure that, you know, we had a workshop last year. I see a number of people in this room who participated in that workshop. We had really good, a really broad-based panel discussion, we had really great representation from the PUC and the ISO providing input on, and some really good information on how the agencies currently coordinate around these questions. You know, environmental information, planning on the procurement side, planning on the transmission side, actual decisions. And we did not make any concrete recommendations about process changes in that workshop.

We got a lot of really good input and we’re going to build on it with a workshop later this summer. And Suzanne can probably tell me the date, I don’t have it off the top of my head, but she probably does.

MS. KOROSEC: I think Heather probably has it,
COMMISSIONER DOUGLAS: Oh, all right. Well, sorry, Suzanne, I didn’t mean to test you.

But, you know, I know that people bring a lot of ideas and strong opinions to this conversations. I hope folks, who are sitting there in the audience with those ideas and opinions, will bring them to the workshop that we’re going to have later this summer. And Heather will help me with the date in a moment.

But I wanted to say a couple things about it. You know, one is that we’re hoping to have some follow-on onto the discussion of how the State should use this kind of information in making decisions.

I also wanted to say that, and just clarify that one of the things that we are hoping will happen, and hoping will provide us with some ideas going forward is a stakeholder-based effort that would look at where there are some least conflict, or high-potential areas in the San Joaquin Valley.

We, the Energy Commission, are not leading any initiative in that area. But the question will become, you know, let’s say that there is some consensus on really good opportunities for renewable energy development, whether that’s in the desert, or in the San Joaquin Valley, or other parts of the State, or even out
of the State, how might we go about using that
information? How might we think about it? What do we
do with it?

I’m also hoping to invite some people with a
more regional perspective. And so, hopefully, we will
that. But that is forthcoming, so you didn’t miss
anything. And, hopefully, we’ll get some participation.

Heather, when is it?

MS. RAITT: Oh, it’s July 23rd.

COMMISSIONER DOUGLAS: July 23rd. So, hope to
see you there, if you’re interested. Thanks.

COMMISSIONER MC ALLISTER: Thanks. Okay, great.
Well, so let’s see, let’s go to -- I guess we have open
stakeholder discussion now or, Suzanne, did you want to
call up --

MS. KOROSEC: Yeah, so I’ll go ahead and
introduce that real quick.

COMMISSIONER MC ALLISTER: Okay.

MS. KOROSEC: So, I’m going to ask folks to come
up here. We had several folks who asked to be part of
the discussion. We’ve got Chari Worster, Claire
Halbrook, Daniel Kim, Laura Wisland, Nancy Rader, Peter
Miller, Rachel Gold, Steven Kelly, and Obadiah
Bartholomy.

So, if you could come up to the table, we’ve got
little tents there for you to write your names to help
our court reporter to keep track of who’s talking.

We do have a few extra seats. I think three.
So, we can accommodate three additional participants, if
there’s someone here who would really like to
participate in this discussion.

We’re also going to provide 15 minutes at the
end of the second half of this discussion, which is
happening after lunch, for comments from folks that are
not sitting at the table.

So, while everyone’s getting seated and doing
your nameplates, Governor Brown, in his inaugural
address, announced the target of increasing renewable
electricity from one-third to 50 percent.

It’s an ambitious goal, but we’ve already seen
records being set for increasing amounts of renewables
delivering into the ISO grid each year. I believe there
have been days when renewables have actually delivered
as much as 40 percent of the energy into the CALISO
area.

There’s a lot of interest in how to implement
this target, several bills being considered at the
Legislature, lots of discussion between the energy
agencies. So, we want to hear stakeholder opinions on
the target, suggestions for how best to implement it,
and what are some of the challenges.

We have about 90 minutes for this discussion, 45
before lunch, 45 after. So, please, focus your comments
on the questions that went out with the notice. I’m
going to post those on the screen here, in a second.

Try to keep your comments to two to three
minutes apiece, so that everyone has a chance to talk,
and so that we can get through all the questions in our
allotted time.

Our moderator is Angie Gould, who leads our RPS
Verification and Compliance Unit.

COMMISSIONER MC ALLISTER: Suzanne, I can tell
that you used to be the lead on the IEPR. You seem very
familiar in this role, so thanks very much.

MS. KOROSEC: You’re welcome.

COMMISSIONER MC ALLISTER: Yeah. Okay, go
ahead, Angie, yeah.

MS. GOULD: Thank you, Suzanne. My name is
Angie Gould and, again, I work in the Renewable Energy
Division here at the California Energy Commission.

And thank you to everyone at the table for
joining me today. And, you know, as we said, we’re
limited on time so we’ll just jump right in.

Starting with the first question, what should a
50 percent renewable policy framework look like? How
much should it rely on what is already in place versus a complete redesign of the existing policy structure.
Should it replace the current renewables portfolio standard requirement or work in tandem with it.

And I thought I would start with those who are actually required to meet the RPS, which is the utilities. So, Claire or Obadiah, could one of you start?

MS. HALBROOK: Hi, everyone. I’m Claire Halbrook, with Pacific Gas & Electric Company. I’m in our State Agency Relations organization and that cover climate policy in a number of the agencies.

So, I actually think Chair Weisenmiller said it best when he and a number of the other agency leads in March filed or offered an op ad in the Sacramento Bee, entitled “More Renewable Energy Brings More Challenges”.

And it said that, “Overall, we must make sure that our investments focus on reducing greenhouse gas emissions, improve reliability, and keep costs competitive. More of the same policies will not do the trick”.

And so, I think that’s really great insight for the conversation today. That while renewable energy investments must certainly be part of California’s efforts to achieve our future greenhouse gas emissions
reduction goals, you know, the discussion should really
focus on how we design the optimal suite of greenhouse
gas emissions reduction strategies that look across the
sectors, and complement one another.

And I think also, in the Energy Commission’s
fact sheet that was released following the Governor’s
Inaugural Address, it explained that in reaching a
higher renewable energy goal it could be achieved in
several ways. Including optimizing clean energy
technologies, efficiency, demand management programs
according to costs and system benefits.

So, we should really look at how this higher
renewable energy goal fits within our broader greenhouse
gas emissions reduction goals. And particularly, as we
talk about regional coordination, how it fits in with
USEPA’s Greenhouse Gas New Source Performance Standards,
for both new and existing sources.

So, as we talk about that regional coordination,
understanding that there are -- the regions, with whom
we hope to coordinate, will be facing some new
requirements themselves, and that may affect their
ability to import and export, and interact with
California.

MR. BARTHOLOMY: Thanks, Claire. Obadiah Bartholomy, with SMUD. And I would just like to say,
with regard to this question I think you’ll find that all of the utilities that are going to be speaking on this issue are not -- are in support of maintaining the current Renewable Portfolio Standard framework, but complementing that with a broader framework that’s more focused on cost-effective carbon reduction.

I think the five large utilities, over the last year, have been working very closely on trying to come up with a policy framework, we’ve termed a clean energy standard, that would focus on setting specific carbon reduction goals aligned with where the State needs to go from a carbon reduction stand point.

And we recognize it would be very challenging to completely replace the RPS policy, as a policy framework. So, this has been designed to work to complement that policy. And, really, to heighten the focus on cost effectiveness and on creating the right economic signals for investment in additional energy efficiency, additional transportation electrification, and making sure that our renewables investment are really balanced, from a cost-effectiveness stand point, with those other very critical strategies for reducing carbon for the State.

MS. GOULD: Thank you. Do any of the generator representatives have a response?
MR. KELLY: Yeah, this is Steven Kelly with the Independent Energy Producers Association. And in some sense I find it kind of ironic that we’ve just extolled how well the RPS program has worked for California in developing new renewables. And just when we get to the point where it’s really doing well, the proposal is to let’s get rid of it.

This is kind of typical of California. And I really urge people to say on course on this.

What makes the California RPS work well is that there are clear standards, definitions of eligibility, clear standards of performance, and there’s penalties for noncompliance, which is very important. And that has compelled people to move forward in an aggressive manner, over the last seven years, to develop the green portfolio that we have today.

There’s nothing that says that you can’t expand on what we have today to meet the 50 percent goal. And, usually, when I hear proposals about that we have to change everything going forward, it’s a proposal that has no standards, no compliance obligations, and no penalties for nonperformance.

So, I’d really be hesitant, as a policymaker, to endorse that kind of approach without more substance to it.
MS. GOLD: Rachel Gold, for the Large Scale Solar Association. I want to second everything Steven just said.

And I would not that we’ve seen how the RPS is working and really proven to get, online, cost-effective renewables that are producing clean energy for the State. And so, to the points that were made earlier about market signals, the RPS is a clear, and proven and effective strategy of bringing renewable online, letting the market innovate and bring down costs by sending those signals to the market.

And in the areas where we can do better is sending additional signals to other kinds, you know, complementary strategies, including storage, more demand response, ensuring that those who want to provide ancillary services with other clean strategies have the market mechanisms to make that effective, and business models that work.

So, we see the RPS as a proven pathway to success for the State in reaching 50 percent and beyond. And for being critical to meeting our greenhouse gas reduction goals.

And I think that it’s a mechanism that can be used as a backbone to an overall State strategy for meeting our larger goals. But it’s critical that we
don’t throw it out at this point, it’s been really important for a robust market.

COMMISSIONER MC ALLISTER: Do you have any concrete ideas about how to sort of layer over some of the reliability and ancillary services issues? You know, you referred to it as a backbone. But sort of add those on in a way that provides clarity and sort of apples-to-apples comparisons across all the resources, you know, renewable and nonrenewable?

As we count those kilowatt hours, you know, they have to contain the right things in terms of the level of service and the types of services that they include, so we can compare and make sure we’re following the economic approach, as well.

MS. GOLD: I think our perspective is that we have to start at looking at our current system and seeing what we can use better and more effectively. I think that’s the first step that we can take in terms of moving effectively towards our carbon reduction goals.

So we know that, for example, the energy markets, there’s room for them to be optimized. There’s room for renewables to be dispatched in closer to real-time. And, you know, we’ve moved towards those pieces in implementing the 15-minute market, but there’s certainly more that we can do.
And aligning some of those market signals from the energy markets, then, with the procurement practices will be necessary in terms of what the State desires, either through the long-term planning process in making those signals and requirements more clear or the, you know, revenue streams that are coming out of the CALISO’s market.

Steven?

MR. KELLY: Yeah, if I could add to that, we have a standard of procurement which is kind of least cost/best fit. And while a lot of us kind of assume that that was originally going to take into account integration capabilities of renewables, storage capabilities of renewables, up until the last couple of years it seemed to be it was only least-cost kind of performance for selection in the procurement process. Which drives all of the renewables that are at least grid connected.

So, we have a tool, least cost/best fit, which can be adjusted and should be adjusted to take account of those factors that policymakers and the utilities need to see in renewables as a development.

If integration or the ability to balance a resource is something that is of higher value than not, and that was integrated into the procurement process,
you’ll see more and more renewables develop projects that have that capability.

The problem is that that stuff has not been there, yet, really, and it should have been.

COMMISSIONER MC ALLISTER: Thanks. I want to let Nancy go ahead, sorry.

MS. RADER: Thanks. Nancy Rader, with California Wind Energy Association. First, I just wanted to echo, ditto the comments that Steven and Rachel made.

The California Pathway Study and other studies show we need to achieve 50 percent renewables to meet our greenhouse gas goals. I don’t know why we would want to change horses right now, when we have a policy that’s been really, extraordinarily successful in delivering renewables, 10,000 megawatts of central station, and 1,000 megawatts of wholesale DG.

But I want to underscore the fact that the RPS has always -- has never really been a least cost, price-only competition. There have always been other values. And it’s really only recently, since the utilities have procured, really over-procured what they needed to meet the interim RPS goals, they over-procure with a bunch of solar, that we really fell behind in some of those values.
But like Steven said, there is a place, least cost/best fit, for every single indirect and direct cost, and benefit of each renewable technology. And we’re seeing the PUC rapidly catch up, after the slew of procurements were made, integration cost adder, intravalue was adopted for the 2014 solicitation. And we’re going to work on and finalize the California-specific value for the 2015 procurement cycle.

They’re moving towards a capacity valuation and some of the utilities are already doing a capacity valuation approach that reflects the declining capacity value as penetration increases on the system.

And the utilities, of course, have been making changes of their own on the time of delivery of values during the day, which are also changing as solar penetration increases.

And so, these changes are likely, I think, to produce a more balanced portfolio of procurements going forward. And I think the value of the RPS calculator really can’t be understated in terms of looking to see how we can best combine renewables to lower the total overall costs and lower the operational challenges. It’s really essential to optimize the mix in order to minimize the operational challenges that you have to deal with.
And I think the PUC is making a whole lot of progress on that front and getting a lot more sophisticated there.

MS. WISLAND: Are we going in a circle or can we just jump in?

MS. GOULD: You can just jump in.

MS. WISLAND: Okay. This is Laura Wisland with USC, Union of Concerned Scientists.

I want to echo a lot of what Nancy, and Steven, and Rachel said about the RPS program providing a lot of needed market certainty both for developers, as well as grid planners. I mean, we are making significant transformational investments to our electricity grid, really thinking very differently about how we consume electricity, and generate electricity and build electricity generation infrastructure.

And without having a long-term number out there in the future, even if it has a lot of flexibility in terms of timing, I think it’s really important to drive that research, and development and planning that is essential to happen.

So, when we start talking about moving away from something like that, towards something much more open-ended, that’s simply driven by greenhouse gas reductions, while I see the benefit to thinking about
the entire electricity system from a GHG perspective, I really worry about losing, first of all, a lot of time arguing about what that specific number is. And if we have to boil that down to a carbon budget for each utility, how long that process is going to take, and how much time we might waste in the meantime.

But then, even if we do do that, losing that certainly. So, that’s my biggest concern with going to just a simply GHG approach.

And then, of course, we’ve been working on renewable energy for decades in this State, for many more reasons besides just reducing carbon. So, I think it’s important to keep those benefits in mind as we think through what the next, best tranche of renewables look like.

The other piece on integration that I’ll mention now, but I’m going to talk about later in my presentation on reliability, is that in addition to squeezing out more flexibility with our existing gas fleet, in the context of integrating renewables, I also think we need to start thinking about the services that the renewable generation can provide in terms of flexibility.

I think there is a lot of potential there that has not really been discussed. We’ve been focusing on
demand response and storage technologies, which is
great. But let’s not forget that renewable generators
can actually provide some of those services as well, and
that needs to -- so, if we go down that pathway, I think
we need to be thinking about what is it about our energy
markets that may be holding renewables back from
thinking about the services they could provide to the
grid? And what is it about the way we’re contracting
for those renewables that makes that type of behavior
more risky and how can we rethink that?

MS. GOULD: Thank you. And does anyone else
have any responses to other comments made?

MR. MILLER: Peter Miller, with the National
Resources Defense Council. And I guess I’ll jump on the
bandwagon, as well, and just acknowledge the
extraordinary success that we’ve had so far from the
RPS.

It’s been a tremendously successful program. I
think pretty much everybody’s acknowledged that. And
that’s great news.

We think that an alternative framework could
work going forward. Something that the utilities have
been working on, a clean energy standard, is certainly a
plausible alternative. Obviously, it would need to
be -- have much more fleshed out, specific targets,
timetables, requirements, obligations.

At the same time, and I think other speakers have mentioned this, there’s been a tremendous amount of investment, both legislative, regulatory staff, and stakeholders as well in developing the RPS framework that we’ve got. There are guiding regulations and parties are well-aware of that, and there’s been a lot of staff resources put into that.

And I think we should be cognizant of that and thoughtful about whether a new framework provides the benefits that would be justified by the additional time, and effort and resources it would take to develop that new framework. Not just at the Legislature, but at the agencies as well. And I’m sure all of you up at the dais are well-aware of constraints on time and staff resources.

That said, clearly, we’re moving into a new era. The key issues to get to 33 percent were can we build a lot of renewables and is it going to cost far too much? And we answered those questions quite confidently that, yeah, we can build a lot of resources and, no, it’s not going to cost too much.

But we’re now faced with the challenge of integrating renewables on a grid that’s going to be, by 2030, primarily renewable-dominated, not fossil-
dominated. And that’s the big challenge we face going forward.

So, to the extent that we continue with the RPS framework, I think it does need to be modified, adjusted to take into account those principle challenges we face going forward.

Not all of the changes will be made within the RPS framework. Some of them, the parties have already mentioned, are with how we calculate least cost/best fit. And I’m forgetting the bill number, but there was a bill passed last year that specifically directed the PUC to address integration costs and include those in the calculator. I think that’s an important task.

And there are, obviously, other policies and planning efforts underway about transmission planning, and expansion of the ISO, and EIM, that are outside of the RPS. They’re going to be critical to getting to success.

But that said, I think our tendency would be to stick with the RPS, since it is working, and because of the big investment and figure out if, and how we can make that work for the challenges going forward.

MR. CASEY: If I could, just on this particular topic, ask the panel a question. I appreciate Steven’s comment and I think it resonated with most of the panel
here. If it ain’t broke, don’t fix it.

But when you look at where we are today relative to the 33 percent goal, we have about 7,000 megawatts of solar on the transmission system right now.

The only resource being developed over the next five to six years, to get to 33 percent, is one technology in one State, solar PV in California. We’re literally doubling our solar capacity from 7,000 to 14,000, over the next five to seven years.

So, I guess I would ask the question, when we talk about the integration challenges, and I think you all know the over-generation challenge that solar PV presents, and the study work that’s been out there, is the current RPS framework going to perpetuate more of the same? And do we need changes to it, to facilitate a more regional procurement approach where we can take advantage of the diversity of renewable resources that are out there.

We have amazing wind capabilities throughout the west. But the question is, are the current RPS buckets really going to facilitate that kind of regional diversity?

And another question is what about the distribution resources and the contribution they can make to a 50 percent goal?
Right now, we’re focusing on central station transmission resources, but do we need to be thinking about the contributions the distribution system can make to meeting that goal, as well?

That doesn’t have to be answered now, if it can be dealt with later.

MS. WORSTER: This is Chari, from ORA. So, I think we agree with what most everyone had said about the possible challenges to achieving 50 percent goal.

However, we believe that working with the current structure, tandem with the current structure is a good starting point. There’s regulatory certainty. Utilities and generators have already spent years understanding the current policy framework.

There’s a procurement process which just was currently updated to a more streamlined process.

We have the multi-year compliance periods which allow for more flexibility, and this reduces the incentives of over-procurement. It also promotes renewable energy production that is actually used in California.

However, I do agree that we do have certain issues that we may have to look at and it’s the bucket. And specifically, the second bucket where we believe it inhibits the use of out-of-state renewable energy.
So that said, I think that a good starting point would be to use what we currently have and just build on that.

MS. GOULD: Okay. And actually, I think this might be a good time to just -- I think we’re discussing it a bit anyway, to jump into question two.

What are the operational challenges of a 50-percent renewable policy framework?

Let’s see, did you want to start, Steven?

MR. KELLY: Yeah, regarding the challenges and I think, Keith, you raised a really good point. But I don’t think it’s so much the paradigm, the RPS paradigm overall that’s a problem. I mean, the E3 studies that everybody looks out to 2030 says that we have a challenge operationally if we don’t change what we’re going to do.

Fine, we got that. There are changes that can be done without throwing the baby out with the bathwater here.

And I think the real place to focus, as I alluded to in my prior comments is, is the least cost/best fit methodology failing? And if so, why? Because that should be flexible enough to address the concerns that we’re seeing out even on a ten-year timeframe.
Recognizing that when you actually build renewables, they tend to come on lumpy additions, and you’re going to get blocks of stuff coming in, and when you forecast based on that stuff, things look a little out of kilter.

But there are other -- there are things that we can do to improve the least cost/best fit methodology to make sure that we have the resources that match what we need, without actually undermining the buckets concept. Because the primary purpose of the buckets concept was to mitigate the risk of litigation on a commerce clause provision when last time the RPS was reformed. That still stands, probably. So, just that’s where that came from.

But we could keep those buckets and move forward under that framework, and perfect the least cost/best fit stuff.

I’ll talk later about, you know, how to gobble up the excess over-generation later today, which is another way to deal with the over-generation concern or problem that you’re seeing operationally. That fix those problems without eliminating the RPS framework overall, that we’ve developed over the last 15 years.

MS. GOULD: Do the utilities have a response?

MR. BARTHOLOMY: Sure. So, a couple of
comments. To the point about over-generation, really, that’s one of the key reasons that we’re interested in coming up with a framework that allows for a commensurate amount of utility investment in carbon-reduction strategies that can deal with over-generation.

So, in particular, transportation electrification. If you look at what utilities spend in transportation electrification versus what we’re spending in renewables, or what the State as a whole is spending in transportation electrification, we’re doing some wonderful things there. But we’re spending something on the order of $1 to $3 billion per year in RPS procurement, and our premiums associated with that. And that’s before we even get into costs for renewables integration.

We’re spending a tiny, tiny fraction of that on transportation electrification or on building electrification, which was also called for as a strategy, one of the forks in the road in the E3 Pathways analysis. We’re spending zero on that. Both of those approaches could help us deal with over-generation issues and reduce carbon emissions from the transport and natural gas sectors.

But we don’t have any policy framework that allows us to shift some of that $1 to $3 billion a year,
or what will be something quite a bit more than that in
the future, towards those strategies that allow for
renewables integration and carbon reduction at the same
time.

Specifically, with the current set of renewables
that we’ve got and the issues that we have associated
with reliability there, probably the biggest issue, and
I now we’re working to address this with the development
of smart inverters, but having power system event, where
we end up with a loss of, potentially, as much as 3,000
megawatts of PV going offline in reaction to a
disturbance on the grid, is a significant issue. And we
need to make sure that the PV that’s being built out
over the next six to seven years is adequately designed
to respond to grid disturbances in a way that enhance
reliability. So, I think that’s critical and needs to
be ensured in that procurement.

And I think as we get into more of those
renewables providing grid services back, we’re going to
see some balancing impact on costs of renewables, where
we have very low cost today, but almost no asks in terms
of grid services back from those renewables.

The second issue I wanted to highlight is in
particular, for a lot of the publicly-owned utilities
that have a lot of large hydro in their systems, we’re
going to be faced with fairly decent chunks of the year where we are spilling hydro in order to make room for renewables on our system.

And from a greenhouse gas reduction stand point, that has very limited value to us as a policy, and really speaks to the need to think about cost-effectiveness of carbon reduction more broadly than just from your renewable strategies.

COMMISSIONER HOCHSCHILD: Actually, if I could jump in and ask a question, or within the question you posed.

So, just to reiterate my opening comments, I said, greenhouse gas emissions in California, reducing those, is a sort of absolutely necessary but wholly insufficient outcome. Even if we stop all the emissions today, you know, California’s six and a half percent of the country’s emissions, and less than one percent of global emissions. Part of the goal has to be market transformation.

And I think, when you look at policies like the RPS and the CSI, providing that certainty that’s allowed investment to flow into the clean energy sector, and bring down the cost reductions to the point -- we have actually met with Apple last week and, you know, they just procured a 280-megawatt project that they told me
was cheaper than gas power from PG&E. And that’s -- I know all that cost reduction’s a function of the market certainty.

But the piece I wanted to ask, really the utilities first, but others as well. We’ve been focusing on the 50-percent policy, what should that look like? But what about the nonrenewable procurement, are there ways that you can think of that the State could -- we, as policymakers, could be encouraging that procurement, to the extent it has to happen, to be designed better to support the renewable procurement?

If that makes sense.

Because, for example, I’m told by colleagues at the ISO that there are many gas contracts where the number of starts and stops are, you know, limited. And even when there’s no technology barrier, for contractual reasons, you know, renewables get curtailed when that’s really just a contractual, rather than a technical barrier.

I mean, other thoughts like that, any comments on that question?

MS. HALBROOK: Sure. So, I would certainly speak to the first part of what you were mentioning around the need for sort of a global solution to the greenhouse gas emission issue.
And I think we’re seeing right now, you know, very successfully with the Cap and Trade Program here in California having linked with Quebec, and now pending linkage with Ontario, that some of these market-based programs around, that are focused on greenhouse emissions, are an excellent way to encourage that. You know, not only within our own -- the confines of our own country but, globally, to come up with these linkages. And seeing what the EU is doing, as well, with their carbon program and trying to sort of tighten up their carbon budget as well.

But I think, as what Obadiah mentioned earlier, around creating a greenhouse gas emissions target for the utilities, for the electric sector, would really serve, I think, to help address some of the concerns around the operational challenges we see with renewables. Where, really, these GHG reduction strategies can sort of compete, side by side, all of the costs and all of the benefits.

I think as what Laura mentioned earlier that, you know, with the renewables program here in California, with the RPS, we’re not just specifically speaking to, okay, it’s a greenhouse gas reduction program. It has a number of co-benefits, as well.

And so this GHG program, we could certainly see
a world in which we attempt to value some of those co-
benefits that they offer, or at least sort of enumerate
them and compare them side by side, rather than looking
directly at the electric sector.

And I think Obadiah made some great comments
about the need for additional transportation
electrification, and electrification of other end uses
as well.

MR. BARTHOLOMY: And just to speak to your
question on procurement, for us going forward, really
all of our procurement is renewable or related to
integrating renewables. So, thinking about whether
that’s new storage facilities, new distributed storage
approaches, new flexible gas plants, or changes to our
existing plants to allow more flexibility within those,
that’s really where the focus of any nonrenewable
procurement is at this point.

I think, though, there has been some procurement
in the past, in terms associated with those contracts,
that are creating some of the challenges with limited
flexibility on the grid today. And I don’t know exactly
all of the political constraints on renegotiating those
contracts, but that would be a key strategy, I think,
for us to kind of open up the floor a little bit and
allow for more of that solar generation to come on
without curtailment.

MS. GOULD: Any final thoughts from environmental or ratepayer reps?

MS. WISLAND: Yeah, I want to speak to that issue because we’ve been doing a lot of work on this.

So, on this question of what can we do to the other parts of the electricity portfolio to create more flexibility and make them more clean energy-friendly. I think that it’s pretty important to take a look -- to take -- to do an assessment of our existing gas fleet, or maybe where we think we’re going to be in 2024, or 2025, 2030 and understand how those plants are going to be operated per the contracts they have now, and whether those contracts aren’t going to make sense for what we think our electricity portfolio -- the way we think our electricity portfolio is going to have to function in the future.

So, it seems like there is a lot of inefficiencies in the current way some of the gas plants are operated and I think that step, that’s like the low-hanging fruit. Let’s make sure that these plants are being responsive to what else is happening on the grid.

I think the ISO is doing some analysis on that right now. But it would be really helpful for the results of that analysis to make its way into the long-
term procurement planning process at the PUC, where we’re having these discussions about whether we need additional gas and what value that would provide. So, I think that’s step number one.

And so, I’m going to present a little bit later about which types of gas plant flexibility may be most valuable to the system. Basically, what we’re seeing is that reducing the minimum generation level is probably going to get you the biggest bang for your buck in terms of reducing renewable curtailment, and helping integrate renewables. But we can talk more about that later.

I think we also should be thinking about comparing the costs and the value of increasing -- making investments to increase the flexibility of the existing gas fleet versus making investments in other types of non-fossil flexibility. Which one is going to get us more renewable integration? Which one is going to get us more greenhouse gas reduction? And which one is going to get us better costs benefits? That’s an important valuation to do.

And then, from a policy perspective, if we think there is value to thinking through procurement strategies for the non-fossil resources to provide flexibility, you know, the way I think we do that is we have some sort of overarching carbon goal that’s
impacting all of our procurement. So when we look out
ten years, and think about everything we need on the
system, we’re thinking about it through a carbon lens.
So, I think we kind of need both. We need an RPS and we
also need some sort of overarching carbon strategy to be
driving the other 50 percent of the investment.

And I think the Governor’s Executive Order is
kind of heading us in that direction, anyway.

CHAIR WEISENMILLER: Yeah. No, I was going to
note, obviously there’s been a lot of reference to the
State-of-the-State 50 percent goal. But, obviously,
that’s within the context of the recent Executive Order
setting an overall goal of where we need to go, as
opposed to just a standalone.

And that’s certainly integrated to get the
State-of-the-State together into one coherent policy.

COMMISSIONER MC ALLISTER: I’m going to take
advantage of -- oh, I’m sorry, was something else going
to speak?

I was going to take advantage of having PG&E and
SMUD right next to each other, and do a little compare
and contrast, so apologies in advance for that.

But I guess we’ve talked a bit about all the
various complementary things that need to happen, demand
side, small-scale generation and large-scale generation,
and how, you know, those need to be orchestrated in a way that makes sense. Certainly have a lot of interest in leveraging the opportunities in efficiency in the built environment to create the head room that we need for some of the demand side technologies that are going to increase load.

And, you know, we want to be able to supply all of the above with renewables, wherever possible, and manage that process in a way that enhances reliability, even. Not just preserves it, but actually enhances it.

So, I guess I’m wondering, sort of if you could give us your respective ideas about how easy it is for you to make the right decisions in the near-term, medium-term to sort of do that? Get the investment to the right places, to focus on the built environment, to look at how to absorb some of the forward investments you need to make in the distribution grid, for example, to enable all that.

And on the transportation side, for example, it’s going to drive some distribution grid investment.

What does that process look like at SMUD and also what does that process look like at PG&E? I think they’re different. But how different, I guess, is my question? And functionally, time frames and sort of what needs to happen in terms of critical path?
MS. HALBROOK: Sure, I think I can speak mostly
to sort of what we see as the critical next step forward
at PG&E.

We’re currently supporting a bill that’s moving
through the Legislature, Assembly Bill 802, which would
help the utilities have, specifically, access to code
savings from existing buildings.

So, I was fortunate enough to hear CPUC
President Picker speak last week at the Navigating the
American Carbon World Conference. And he really
commented on the fact that the electric sector is
approximately -- you know, electric generation
approximately 20 percent of our statewide emissions, but
the built environment is 30 percent, and transportation
being about 40 percent.

And so, we really agree with that and we think
that within our own service territory approximately 70
percent of the existing energy efficiency potential is
in that to-code savings. So, it’s something that we
think is sort of a critical next step to begin progress
towards the Governor’s goals, and to help us with that
additional procurement that you mentioned, as well.

MR. BARTHOLOMY: And I guess I would say that we
are also supportive of moving to a to-code type of a
framework. Though, generally, we try to follow as
closely as we can on what the investor-owned utilities are doing. There’s a huge body of work on energy efficiency accounting frameworks. And we report annually to the CEC and try to do our best to make sure that we’re aligned with what’s done statewide for energy efficiency.

I would say it’s interesting, when we look at the numbers of how much we’re willing to spend on energy efficiency and how much we’re willing to spend on renewables, that we are willing to sign contracts for renewables that cost almost twice the price of what we can get energy efficiency for.

So, when you think about getting at that built environment, the policy signals are really misaligned to utilities, with an RPS framework that’s disconnected from how much we’re willing to look at cost effectiveness of energy efficiency.

Those two don’t fit in the same box and, really, there’s very little discussion across the organization about how can we make those tradeoffs because we have completely separate policy frameworks for them.

Similar discussion can be had around transportation electrification and around distributed generation. Each of those is looked at in a unique policy lens and we don’t think about cost effectiveness
of those resources against each other, which might allow us to direct more investment towards the demand size measures that you mentioned, and more investment on our distribution grid, more investment in our local economies.

COMMISSIONER MC ALLISTER: I want to give everybody else an opportunity to chime in on this.

MR. KIM: My name is Daniel Kim, with the Westland Solar Park. I want to thank the Commissioners for allowing us to speak on these issues.

And I think the thing that I’d like to add to this conversation is really the importance and, actually it follows, I think, with the conversation about built environment and how to reduce greenhouse gas emissions, and energy costs.

And that is in water. Water delivery represents about 25 percent of the total usage of energy in California. And it is likely to increase given the fact that we are, you know, forecasted to see extended drought periods as a result of climate change.

And as the Westlands Water District is looking at delivery of water to its farmers, and Westland Solar Park is looking at the retirement of thousands of acres of marginally impaired farmland, and converting it to solar generation there is a lot of co-benefits that can
be created as a result of looking at this water energy
nexus.

And that’s not something that typically, I
think, gets folded into these conversations about the
RPS. And it definitely is not part of the dialogue that
occurs in transmission planning. But it should be
because if we’re missing out on that ability to
integrate what are likely to be the two largest policy
issues facing California, because you can’t build an
economy without water, and you can’t deliver water
without energy.

So, I’d like to just make those points to this
discussion.

MS. GOULD: Any of the other generator
representatives, before we break for lunch?

MS. GOLD: I just wanted to comment specifically
on the issue of over-generation and PV that’s come up a
couple of times in this conversation.

And I wanted to highlight that we have an
incredible solar resources that we’ve been effectively
harnessing through our procurement in the RPS thus far.
And, you know, we see over -- obviously, the reliability
of the system is key now, in going forward at all times,
but we see this issue of a very predictable solar curve
throughout the year as something that can be harnessed
to help meet the needs of electrification of the
building sector, of electrification of the
transportation sector, of the electrification of our
water transportation needs and desalinization needs.

And those are all incredible opportunities for
the State to take advantage of our solar resource, which
we can now provide with a variety of solar technologies,
solar PV and solar thermal. And with cost reductions
that have declined dramatically, 78 percent over the
last five years.

So, there are significant steps to be taken. We
don’t think those are technological barriers. But
rather looking at, as Laura already mentioned, some of
the contractual barriers, the minimum generation levels,
how we’re designing time-of-use rates, and how we’re
asking all resources when they bid in to provide the
necessary grid services.

And PV generators, along with solar thermal
generators, can provide a lot of the -- many grid-
friendly services, including VAR support, and frequency
response. And a number of our renewable technologies
can do these and provide these services reliably. We
need to ask them to do so. They have the technical
capabilities and are ready to provide it.

MS. GOULD: Okay, and one final comment from
Steven.

MS. RADER: I have one, too, but go ahead.

MR. KELLY: Okay. Yeah, I just wanted to follow up on this idea or the comment related to energy efficiency and renewables as if it’s a tradeoff. And I actually view them as complements.

And, you know, you can achieve fairly significant energy efficiency goals while having a very robust RPS. If energy efficiency is as cheap and effective as suggested, they should be doing more. You don’t have to wait to get rid of an RPS to do that, you should do it now.

But I would point out that, you know, the other component of the Governor’s proposal, which is critical to what we’re talking about, is the electrification of the transportation sector.

And you’re not going to electrify the transportation sector with energy efficiency. And if you want to electrify it with clean resources, you’re going to electrify it with renewables.

And the decision to invest in the renewables has to be made well in advance of the time that you want the electrification of the transportation sector to have occurred so that you can get the dollars in place, and the investment in place to make that happen.
If you wait until 2028 and say, well, let’s electrify the transportation sector, it ain’t gonna happen. Some of those decisions have to be made relatively soon.

So, I just want to point out that, you know, energy efficiency and renewables are complements in an overarching portfolio. Renewables has an important place to play in the electrification of the transportation sector, which probably energy efficiency can’t necessarily solve, although it drops overall demand and provides some residual power there.

And that’s what we ought to be focusing on is how to get the investment in place, in time to make that happen.

MS. RADER: Well said, Steven. I totally agree with that. I just wanted to echo Mr. Kim’s comments, as well, that we not forget about the water savings associated with non-thermal renewables, saving the water associated with gas, which is not insignificant.

I also just wanted to underscore the importance of accessing that flexibility that we have on the system now. We actually superimposed an ISO slide, showing the amount of flexible resources on the system, superimposed it on the duck. And there’s twice as much. I mean, there’s twice as much on the system, today, as we need.
for 2020 duck neck. It’s just that we can’t access those.

And so, it’s just critical that we find a way to break into that, including for load following down. I was glad to hear your remarks on that.

So, that’s all for now. I do have some comments on your questions, though, for later. Thanks.

COMMISSIONER MC ALLISTER: Great. Any comments from the dais before we break for lunch? Great, okay.

MS. GOULD: Okay, thank you everybody. We’ll start with question three after lunch, at 1:15.

COMMISSIONER MC ALLISTER: At 1:15, all right. Thanks.

(Off the record at 12:05 p.m.)

(On the record at 1:17 p.m.)

COMMISSIONER MC ALLISTER: All right, are we ready to pick it back up here. Thanks, everybody. Hope everybody had a great lunch. There are so many great culinary options in the neighborhood so, hopefully, you found one of them. Yeah, exactly, a lot of people ate sandwiches at La Bou, I think.

Okay, so let’s pick up where we left off. I think we’re on question three.

MS. GOULD: Yes.

COMMISSIONER MC ALLISTER: Great.
MS. GOULD: Okay, thank you, everyone.

So, question three is, should a 50 percent renewable policy maintain the current RPS policy of technology neutrality or should it favor technologies that provide specific benefits to the system?

And I was thinking we could potentially start with some of our environmental or ratepayer rates, because we haven’t heard from you in a while.

MS. WORSTER: Hi. So, ORA sports technology neutrality for as long as the costs and benefits of any given technology of the system can be accurately quantified and assessed.

If not, then we would support a more strategic system-wide approach. I’m not really sure how. But, yeah, I think our first approach would be, you know, would be to support technology neutrality.

MS. GOULD: And how about the generator representatives?

MS. GOLD: Rachel Gold, with the Large-Scale Solar Association. We would support technology neutrality.

And I think one of the things that we can improve upon in the RPS process is continue to refine the various metrics by which different technologies are assessed. So that, if we’re looking for different
services from renewables, then spending more time on
defining what those look like, and what the parameters
and requirements we need are, and then feeding that into
the procurement process.

And the reason for that is that that’s going to
provide better ability for the market to respond more
creatively and to bring in low-cost options from a
variety of different technologies.

And I think that if you get into mandating
specific procurement, from specific types of
technologies, you can end up not getting what the system
needs. So, we would definitely be aligned with ORA on
that.

MR. KELLY: Yeah, this is Steven Kelly, with
IEP. And I would share that sentiment.

I mean, the benefits to the system, in our view,
are attributes that ought to be embedded into the
procurement process or identified, and they provide
values that should be reflected in the procurement
process.

So, you can identify and procure to maximize the
value of those benefits, without having to go down to a
technology-specific kind of procurement practice, in our
view.

MS. GOULD: And how about the utilities?
MR. BARTHOLOMY: I think we’re supportive of technology neutrality, but hope that distributed generation can be amongst the technologies that we’re being neutral about.

MS. HALBROOK: Sure. I mean, I think I would also currently echo the point on the importance of technology neutrality to sort of encourage competition, and drive down prices, and help with some of the innovation that we were talking about earlier in the introduction section.

But I think the other thing to keep in mind is our energy policies, as a whole, and the fact that there is certainly a lack of technology neutrality in some of the very specific procurement mandates we have that exist outside of the RPS.

So, to also, you know, take a look at those. And as we revisit all of our energy policy, looking to post-2020 and into 2030, of how we look at all of these things and how they complement one another.

MS. GOULD: Nancy, did you have a comment?

MS. RADER: Well, I pretty much answered the question in my first remark, I think, that we are -- that the RPS is technology neutral and it always has striven to value the costs and benefits. In that sense, it’s not technology neutral. It gives technologies
appropriate credit for their costs and benefits. And I think that’s the way to go because it drives competition in the right direction, towards the values that we need.

I thought I might take the opportunity to respond to Mr. Casey’s question on the buckets, and regional diversity.

I wanted to say that I think the current bucket structure can accommodate a fair chunk of out-of-state renewables. And I think there’s some folks in Wyoming that are counting on that.

And I think dynamic scheduling can also accommodate some out-of-state renewables.

But I also want to say that a lot of that diversity we can get from in-state. Wind energy is a very good complement to solar and we have a lot of wind resources in-state.

I want to segue, then, to the DRECP, briefly, just to highlight our concerns with the draft plan that would put on the order of 75 percent of the wind resources, in the DRECP area, off limits, would prohibit wind development of about 75 percent of the area with the best wind resources.

So, we’re quite concerned that our ability to diversify the portfolio with in-state resources is going to be really hampered if the DRECP goes through anywhere
close to where it is.

And then, finally, obviously expanding the regional footprint of the ISO would further expand that. And that new line that’s going to go into Nevada will help with that.

We see that as a separate question, though, and one that has perhaps more to do with gaining flexibility in the integration resources, as much as, if not more so than the out-of-state renewable resources. So, thank you.

MR. KIM: Daniel Kim, with Westland Solar Park. And I would echo Nancy’s comments, as well, on diversity. The geographic diversity is a key, I think, factor that needs to be taken into consideration in California, aside from whether or not we choose a technology or we go down a path of technology preferences.

Because if we’re not accommodating a robust geographically diverse renewable system, and when I refer to that I mean both Central California, and Northern California, and Southern California, we’re in effect, I think, creating a -- or actually making decisions on what technologies we’re going to choose to go with. Because we’re eliminating the ability of certain types of technologies that work very well in the
Central Valley that are not being allowed to participate
in the RPS.

MS. GOULD: Thank you. Peter?

MR. MILLER: Well, I’ll just jump in. Again, it
seems to be broad agreement on the question of
technology neutrality.

Our preference, we think this has worked well in
the past, set performance standards and let the various
technologies compete. That drives costs down and
ensures that the State is meeting its needs in terms of
performance.

Specific carve-outs are things that concern us
for particular technologies. We think that there’s
really an opportunity to really focus on the State’s
goals in terms of market needs.

Identifying those are sometimes a challenge, but
feel that that’s generally the best way to proceed.

MS. GOULD: Thank you.

COMMISSIONER MC ALLISTER: I want to just follow
up with something that Obadiah said, and maybe get
Peter’s view of this, as well.

So, you know, we have a lot of legacy --
whenever we sort of get to some design of this new
regime, whether it’s sort of built, really, RPS 50
percent, or whether it’s slightly modified, or
significantly modified, we’ll have a lot of legacy, small-scale rooftop, behind-the-meter DG.

And I’m wondering, I think I heard you say you’d like to include those systems as within the 50 percent. I guess I’m wondering if you have some sort of next-run-down kind of ideas about, you know, what size above which, below which, you know, whether -- you know, if you have a lot of technical issues with respect to sort of metering and being ready for prime time to report in the system, and that kind of thing.

I’m wondering who, on the panel, has thought about that and possibly how that would look in practice?

MR. MILLER: I can jump in on that because we actually just had an internal discussion last week on this. It’s an interesting question about whether and how to include DG solar in the RPS. It traditionally hasn’t. To an extent there’s a tradition there. And the focus has been on large-scale projects, wholesale projects.

And there’s clearly a lot of interest in including it. It’s renewable. And by that metric, alone, there’s a good argument to be made to including it.

But there are a lot of complications, as well. And I guess I would say it’s worth noting that not
including DG solar or, more generally, distributed renewables in the RPS isn’t as big a change, isn’t as big an impact as one might think because they already come out of the denominator. The kilowatt hours already come out of the denominator. So, you’re effectively getting 50 percent credit, as 50 percent RPS, for that distributed generation.

Other issues that come up are, one, do we adjust the target? Fifty percent renewables is an ambitious target. But if we’re including additional distributed renewables, does that want us to increase the target? And in particular, are we including existing distributed renewables or just incremental?

But the distributed market’s going pretty well. There’s high growth there and I think there’s expectations it will continue. So, there’s an argument to be made that we might want to raise the target if we include it.

There’s also an important issue around ownership of the renewable attribute, or the REC. And if someone has marketed a rooftop solar system, in particular, on the basis of you get -- you’re consuming clean, renewable electricity, and then those RECs are sold off and credited to the utility for purposes of RPS compliance, by law that person can no longer claim to
have clean renewables. They’re just getting system power. And the utility is getting credit for the renewables.

And I don’t know, and that may make a difference for particular homeowners. It may well make a difference for some businesses who want to be seen as consuming clean renewables.

The FTC would probably have something to say about that and there’s some legal issues to resolve there.

So, it’s a complicated, there’s a variety of things. I think we’re open to that option. Want to make sure that the State keeps pushing forward and has a suitably ambitious policy, and doesn’t run into legal issues down the road.

MR. BARTHOLOMY: I agree with most of what Peter said. And I would say, yeah, we need to figure out how we are going to meter these systems, and who gets to lay claim to the renewable attributes. So, definitely agree with that.

I guess my comment was meant to be to the point that currently these resources are treated the same as a renewable energy credit from anywhere in the WEC. And the benefits from local distributed generation are pretty tremendous. And if you stack them up against all
the renewable resources that we’re trying to procure
under the RPS, they should float up towards the top in
terms of a preferred resource. And, yet, we treat them
either in that third category, which significantly
devalues them, or as an offset against the denominator
which devalues them even further.

So, I guess that really was what the point was,
too, is that we should treat them as we value them and
really count them in the category one resource.

COMMISSIONER MC ALLISTER: Does SMUD take the
RECs, if they interconnect, or how does that -- what’s
your --

MR. BARTHOLOMY: So, as a condition of our
incentive program, we claim the renewable energy credits
from the systems and we also require metering as a
condition for participating in the incentive program.

COMMISSIONER MC ALLISTER: Okay. Thanks to you
both.

Anybody else?

MS. GOLD: Rachel Gold, for the Large-Scale
Solar Association, again.

I think a couple of things I wanted to say about
this issue, it’s one that we’ve been doing a lot of
thinking and talking about. And first is that we think
that, you know, solar, distributed or wholesale, can
provide benefits, a variety of benefits.

And then, there’s an important place for all sizes of renewable generation in meeting our emissions target at the State.

That being said, I think we have to be a little bit more specific about what we’re talking about, when we talk about distributed generation.

Currently, there are distributed generation projects, of many sizes, that are structured as wholesale transactions, and fall into the bucket one category. And those transactions are fully participating in the market.

And I think where the disagreement comes up is what and how behind-the-meter resources should be treated. And we see those pathways and drivers as two very different markets.

So, we have a targeted set of policies for wholesale renewable generation, and that includes a variety of technologies. And we have a set of policies for behind-the-meter generation that drive a very different market that’s based on consumer interest, largely, and different policies supporting that.

And we’re concerned that by conflating the two, not only do you get into the important issues that Peter raised around double counting, and proper metering, but
that because they’re driven by very different kinds of incentives and markets, they will -- pushing them together is simply not an effective policy.

So you might, instead of expanding the pie in terms of overall renewables in the State, actually shrink both markets by conflating the two. So, that’s it.

MS. WISLAND: This is Laura, from UCS. I wanted to jump in, as well.

I’ll just go out and say I don’t think -- if we consider DG not RPS, I don’t think we should include existing facilities. I just don’t think that really gets us anywhere.

If you look at the bank of excess renewables that the IOUs, at least, have procured, I have not taken a look at the muni numbers any time recently, there’s a significant amount of excess electricity for the RPS already banked.

If you add on the ability of behind-the-meter solar to contribute to whatever margin is left to get to 50 percent, it becomes a lot smaller. It’s actually really exciting, and surprising to me when I looked at those numbers, to see how far along we already are to a 50 percent, not including behind-the-meter. So, I just think it’s something -- it’s important to think about
that.

I’ll also just say that it’s a little bit strange that we’re having this conversation because I think the proposed amendments to the POU regulations for the RPS program are considering allowing behind-the-meter, POU-owned RECs to count for bucket one.

And, you know, obviously, this is a live issue. It’s a live issue in the Legislature. The fact that this is moving forward at the CEC, just for the POUs, just for a certain type of behind-the-meter, is a little bit awkward. And I feel like if we talk about this issue, we should probably talk about it as a compliance tool for all the utilities, not just POU-owned facilities.

COMMISSIONER MC ALLISTER: So, that’s a great point. I’m going to invite -- so we are -- we have an open IEPR proceeding. This is within the IEPR and I think everybody’s views of that discussion are very, very welcome to get onto the record and, you know, into the IEPR as a policy recommendation that potentially could help integrate this discussion and raise the level to get more consistency. So, thanks for that.

MS. GOULD: And just a quick note, the POU regulations that are in play right now, today is the final day of the written comment period so, you know,
please, if you have any comments, you have several hours
to submit them.

And also, if you make specific comments on them
here, we have to respond to them in the final statement
of reasons. So, I ask you to take pity on me and put
written comments in.

But if we could -- if we can move along to
question four, because we are pretty short on time.

Should renewable procurement, under a 50 percent
renewable policy framework, differ from current
procurement practices? And if so, how?

I was wondering if I could start with the
utilities to talk about the different procurement
practices already in place for retail sellers and for
POUs.

MR. BARTHOLOMY: I think the key thing that I
raised the point on earlier was that it would be nice to
be able to look at the cost effectiveness of that
renewable procurement against other carbon-reducing
activities. And to have something built into that RPS
procurement process, that structurally does that within
the utility, would be an improvement on the current
process especially if it would allow trading off against
procurement targets, within the RPS, for other things
that the State has acknowledged are critical to meeting
our long-term carbon goals that the electric utilities are going to play a strong role in.

MS. HALBROOK: I would echo Obadiah’s comments. I think Steven Kelly made a great point, earlier, about the role of renewable energy and electric vehicle charging. And I think, currently, the real challenge there is these are dealt with in very separate proceedings. Although, we have already acknowledged that they very much complement one another and need to be thought of as sort of one in the same.

And I think I would just agree with Obadiah about the need to look at all GHG-reduction technology side by side, and the costs and benefits that they provide, rather than a specific type of technology.

MR. KELLY: Yeah, this is Steven Kelly, with IEP. I don’t think the percentage of the policy actually is the determining factor here.

I mean, so what surprises me in looking back at the history of the procurement that has occurred, primarily at the PUC, has been the -- over the last three or four years we’ve had a focus on intermittent resources, and the potential problems that they provide from an operational perspective.

But if you look at the procurement outcomes, the most recent RPS outcomes, all most all of it is that
type of resource that is perpetuating that kind of problem.

I’m always struck by the fact that there are very little baseload renewables, geothermal, biomass that get selected. So, it’s not the percentage so much that drives that outcome, I think.

But it’s the Renewable Portfolio Standard was thought by many to be a portfolio of renewables. And what we tend to do is buy usually the least cost at that time, and if that continues to be least cost over four or five procurement cycles, you end up with a bunch of that stuff. And then we have potential for problems looking forward, if you forecast that out for ten years. Which is kind of where we find ourselves today.

So, I think there could be changes. I think it can be encapsulated, as I’ve said earlier, on least cost/best fit methodologies to perfect those selection processes. But I don’t think it’s a function of 50 percent versus 33 percent.

MR. CASEY: Could I take that a bit further? Steven, what do you think needs to change to better reflect the all-in integration cost of different technologies going forward?

I know a lot of work’s been done on the RPS calculator. Has it gone far enough? Do we need more?
MR. KELLY: Well, we haven’t gone very far because now we have an imputed number which is, I think, 3 bucks per kilowatt hour, or something like that, for this next -- or this current cycle of procurement. I don’t know if that’s going to change the outcomes, you know, I just don’t know.

We’re in the process of trying to get a finer handle on what those potential integration costs are, and those should be included in the 2016 RPS RFOs. The procurements that actually occur in 2016.

So, we’ll see. I mean, I’m hopeful. I mean, I think everybody down at the PUC, across the board, has advocated for a more sophisticated approach to integration cost adders, and integration of those into the procurement process. So, everybody seems to be on board with that.

I don’t know if the direction we’re going is going to solve the problem or not but, hopefully, it will.

COMMISSIONER MC ALLISTER: So, I want to just dig into that a little bit more. So, you know, so on a very pragmatic level what would you anticipate, or any of you on the panel, that those RFO documents would have to include that they do not currently include? Like what would the -- you know, would it be different kinds
of ancillary services? Would it be deliverability?

What would the kind of -- what would drive, then, the
configuration of projects that bid into it to increase
their probability of getting selected under some
modified least cost/best fit?

MR. KELLY: Well, one of the factors, for
example, is the extent to which you might have to ramp
up a gas-fired unit, right. What are the costs
associated with that to support an intermittent
resources? I think that’s one of the components of what
an integration cost adder might be.

When we have transmission cost adders, that are
kind of also included in procurement, so that’s kind of
over there and that’s another input into the process.

So, this is what does it take to integrate this
resource based on its delivery point, and so forth, to
the system reliably.

And most of this stuff, to be honest, is not
terribly transparent to me. So, I’ll just say that
right out. I mean, we work on a lot of this stuff in
what’s called the RPS calculator proceeding down there,
for planning purposes. But when it comes to procurement
practices, as a stakeholder, I don’t ever see that level
of detail.

COMMISSIONER MC ALLISTER: Yeah, maybe Scott,
I’m sure you’re more familiar with this than any of us here.

MR. MURTISHAW: Well, I’d make a couple of points. And, Steven, you actually alluded to this earlier.

As the utilities update their capacity values for solar, as the more solar we have on the system, the less capacity it effectively provides, and as they update TOD values for energy that will suppress the value for solar.

Because under the existing least cost/best fit framework the utilities do not accept bids just purely on the basis of cost. I mean, I think a lot of people in the room know that. It’s the cost versus the benefit in terms of the capacity provide, any transmission upgrade costs that are associated with a particular project, and the delivery profile from the resources.

And I agree that we are, you know, probably two or three years behind where we would like to be in terms of having a real integration cost adder. But the reason, at least at this point, that you don’t see many resources, other than wind or solar, winning in these competitive RFOs for renewables is that with solar coming in at some of the bids less than 6 cents a kilowatt hour, and geothermal being -- and you probably
know these numbers, Steven -- significantly higher than
that, you’d have to have integration adders on the order
of $30 to $40 a megawatt hour before geothermal starts
winning on a least cost/best fit basis. At least with
the capacity values and TOD values that solar is
receiving to date.

But I assume that the utilities, in the coming
RFOs, they should be making adjustments to those TOD
values and capacity values.

MS. RADER: I think all of that’s correct, what
Mr. Murtishaw said. I think, you know, the least
cost/best fit equation, the adjusted net market
calculation has placeholders for all of those values,
ancillary services, capacity value, everything’s in
there. It’s just a matter of updating them to keep up
with the current portfolio and how that changes those
values.

And that’s what we’re behind on. And as I said
before, a lot of it is because the utilities went kind
of hog wild on solar before we had a chance to think
about it. Really, that’s what happened.

I think if that program had happened more
gradually, we would have actually kept pace. We just
sort of got ahead of ourselves.

But I just want to say, you know, there has not
been a winning wind contract in quite a while. Okay, but you don’t hear the wind industry complaining that the RPS doesn’t work. We still believe in the RPS framework. We believe if we get this values right that we’re going to start winning again, that we’re going to see some baseload served. We want to get, particularly, existing baseload. We believe in this framework. We think the PUC is doing a fabulous job catching up and upgrading. We really like the calculator.

So, I think it’s really important to recognize that things are changing. A lot is happening down in energy division land, and we think it’s all for the good.

COMMISSIONER MC ALLISTER: Excellent.

MS. WORSTER: Can I chime in?

COMMISSIONER MC ALLISTER: Yeah, go ahead.

MS. WORSTER: This is Chari, from ORA. So, I totally agree with you that we need to determine the time of delivery factors. We need to properly determine the ELCC capacity.

But also, I think what we also need to address is, and it’s very real, is the proper valuation of over-generation. I mean, we’ve not addressed that. But if we focus on like, for example, the DG and stuff there is -- the duck curve is very real. There is going to be
over-generation.

And I don’t think we’ve properly evaluated, you know, over-generation.

MS. GOLD: I’d just like to weigh in here. And I think, you know, one of the -- and we’re very supportive of the development of the integration cost data and, currently, there’s some good work underway to improve that interim matter, and we’ve been very supportive of that happening.

Every resource wants to feel like all of their costs and benefits are valued fairly. And so, we see progress being made in that area.

But when it comes to integration costs, we have to be very aware of where and how we count them and to acknowledge that we’re not starting with a perfect system. There are many ways that our current system is inefficient. And attributing all of those costs to variable energy resources obscures the pictures of the costs and benefits that each resource can provide.

So with that in mind, we think that there does need to be updating of how provision of ancillary services are valued, how renewables can participate in meeting flexible RA needs, among others, to help flesh out the equation for those resources in the RPS procurement.
And that includes figuring out what happens with the valuation of resources that are co-located with storage. That’s an area that’s not very clear in the procurement right now, and I think there’s more work to do there.

MR. KIM: One quick comment, Daniel Kim, with Westland Solar Park. I just wanted to highlight that the ability to have an adequate transmission system that allows for the delivery of renewable energy, consistent with what I believe were, you know, the RETI principles of building out the foundation lines it will, in my opinion, have the opportunity to answer some of these questions about grid integration.

Granted, you know, there’s going to be integration problems locally, but I think with the system that we have currently we kind of exacerbate that integration because we have all the renewables in one geographic location, without the ability to transmit that adequately over, you know, 33 percent to other geographic areas where is load. And not focusing development of renewable generation close to load, that isn’t just purely behind the meter.

So, I think that those are opportunities where policy in the renewable energy calculator discussions can be revisited.
MS. GOULD: Okay, let’s move on to --

MR. CASEY: If I could --

MS. GOULD: I’m sorry.

MR. CASEY: -- just to talk a little bit about

the transmission, and I’ll get to a question on it.

Part of the challenge we have, from a transmission

planning stand point, is renewable development can

happen in so many places, at so many levels. If you

built transmission all over the State, just in case,

we’d have exorbitant transmission costs.

So, we rely on a coordinated process with the

PUC, in terms of developing the RPS portfolios, and

considering the transmission implications of those

portfolios into that to try to manage that issue.

But as somebody noted earlier today, one of the

things we’re exploring in the context of the 50 percent

portfolios is should we require that high standard of

transmission deliverability that, to date, the utilities

have required in their procurement of renewables?

Which is really, you know, can those renewables

be delivered to the load on a peak demand day, with two

major transmission contingencies on the system? It’s a

very high standard.

And it drives more transmission than would be

required under a less lenient -- or a more lenient
So, I was just curious if you all had any thoughts on that particular standard with regard to a 50 percent portfolio?

MS. RADER: Well, I’ll go again. That’s another thing that the calculator’s just doing some fabulous work on, with the CALISO’s help, is to look at when it does make sense to make a renewable deliverable. And we think it’s not going to be a lot of the time.

As long as we can get most of the power in, without curtailment, that’s really what we need. And to go that extra mile really adds a lot of cost. And so, the calculator’s going to look at that tradeoff between the additional RA value you get from the renewable versus the cost of the deliverability upgrade.

And we think that’s huge for ratepayers, to look at that. And that’s one of the real big benefits of the calculator.

COMMISSIONER MC ALLISTER: Can I follow up on that? So, maybe I’ll just ask a very simple question. How afraid are you, really, of curtailment?

MS. GOLD: When we have been looking at this issue of over-generation and utilizing our midday solar resources, one of the things that we are finding is we need to change the way we think about renewables on the
And that means having renewables more fully participate in the overall markets. And that means instead of thinking about curtailing renewables, thinking about dispatching renewables. And I think UCS will probably speak to some of this, as well.

But there are ways that we can get additional services out of variable energy resources that may require some curtailment, but that can be an overall benefit to the system.

And so, those costs and benefits need to be analyzed more closely and we need to think about how to utilize and dispatch our overall system more effectively. And part of that may come with some curtailment, but it can benefit the system as a whole.

MS. GOULD: And I’m sorry, we wanted to allow some time for public comment at the end of this discussion, so we have one whole extra question to get to. So, I was wondering if everybody could -- I’ll just go down the line and you can touch on question five, maybe keep it to 30 seconds to a minute, if you can. Or if you don’t have anything on question five and you want to touch on one of the previous questions you didn’t get to speak your peace on, go ahead.

And so, I’ll just start with Daniel Kim and go...
MR. KIM: Daniel Kim, with Westlands, again.

Just wanted to make final points regarding the -- in the case of renewables in the Central Valley, in particular solar is the technology of choice that we’re talking about, the -- you know, there are a lot of co-benefits that, as I pointed out earlier, that the agricultural community can gain from seeing this development occur.

But one of the things that, I think from kind of a planning stand point, that should be more adequately integrated into the RPS calculator, maybe through the ISO planning process, is the benefits having solar further on the west, and when I mean west, I mean I’m talking about kind of Northern California, west side, you know, the time of day is going to be -- and coincident peak is going to be different.

I think those are attributes that maybe aren’t fully considered as both, you know, from a reliability stand point, as well as from energy delivery stand points.

So, I would just highlight that and I’ll fill in the rest of my comments in written form.

MS. RADER: Okay, Nancy Rader. The question asks what are the roles of DG, energy efficiency, EV, et cetera, in achieving a renewable -- a 50 percent
renewables target?

I don’t see it -- I don’t think those things having a role in achieving the 50-percent goal, per se.

Rather, I think we need to look at the interrelationships between all these things. I mean, the Pathways Study showed we need pretty much all of these things to meet our goals, right.

So, we know we need 50 percent renewables, more or less. So, we need to study the interrelationships. And I think that’s what the planning that’s happening down at the PUC is going to allow us to do.

I think once we -- the most important thing is to optimize that renewable portfolio to minimize the operational challenges. That’s key and that is the least-cost way to address your operational challenges.

Then we take the remaining operational challenges into the long-term planning process, and we look and see, okay, what’s the best way to get that flexible capacity, whatever it may be.

And so, I see these things interrelating, but I don’t see them happening, you know, sort of integral to the RPS.

MR. KELLY: This is Steven Kelly, with IEP. And I think as we move from 33 to 50 percent goal, it’s important to realize that the purpose is to realize
improvement, environmental improvement, which maintaining grid reliability. So, we all know that.

So, it doesn’t necessarily do any good to count the same old stuff we did before, in a different manner, and let it count against an RPS goal. It makes no sense to me why you would do that.

So, we need to make sure that the elements in the RPS that are going to be counted against the RPS are real, and actionable, and measurable, that accurate accounting is going on.

I think there was some discussion, earlier, about the need to address ownership so that that accounting can occur in a proper manner, and the integrity of the system holds.

And I’ll just reemphasize if, you know, you’re counting stuff that has already been occurring for ten years, in a different way, in order to achieve the goal, you haven’t achieved any benefits. And that’s what we have to be aware of.

MS. GOLD: I just want to pause and reflect that, you know, the fact that we’re having this conversation here, in California, is pretty incredible. And I, personally, am very proud to be a Californian and be working on these issues.

And we have challenges to address in meeting 50
percent, but I think they’re achievable. And I think there are many complementary strategies, including efficiency, and distributed generation, and storage that we need to do a better job of bringing together to meet our overall emissions targets.

And that ensuring that parallel processes are working towards the same end goal is something that we need to keep our eyes on.

MS. HALBROOK: So, I think all of these technologies have an incredibly important role to play in our future greenhouse gas emissions reduction goal for 2030. And I think I would just be wary of any sort of siloed mandates of a specific renewables target, and a specific energy efficiency target, and a specific DG target, and a specific micro grid target. Because that seems --

COMMISSIONER MC ALLISTER: You forgot storage.

MS. HALBROOK: Oh, and specific storage. We already have that.

And so, I think that that’s just something that I would be wary of. And there’s some outstanding modeling efforts that are going on in California today. Obviously, the E3 Pathways work has gotten a lot of air time today. But the California Times model at UC Davis, Jeff Greenblatt’s work at LBNL on the Cal Gaps Model,
the work by David Roland-Holst with the BEAR Model at UC Berkeley. You know, we can’t just look at one model and think that it has all of the answers. Specifically, when they’re all trying to achieve goals in different ways and include a variety of different input assumptions.

So, I just think we really need our policymaking to be informed by a lot of these great analytical tools that are out there. I know that the ISO is embarking on some work, as well. And I would just encourage everyone to really take a look at those.

And I believe the E3 Pathways work, in evaluating their 50 percent renewables, does include some distributed generation in that target, as well. So, looking more into that and how they did they’re accounting would be valuable.

MR. BARTHOLOMY: I’d just like to say that I think the achievement of the carbon goals by California is incredibly important for showing leadership within the U.S., and within the world.

And I feel like a critical aspect of that influence that we’ll have with our policies comes down to the cost effectiveness of those policies. And the more we end up with our siloed targets for each of these resources, the more challenging it is to come up with
integrated planning frameworks, where we’re doing
tradeoffs and maybe pushing certain targets out a few
years, and focusing our investment efforts on things
that can reduce carbon and help to integrate renewables.

I feel like the RPS policy has been very
successful at driving large renewables and we know it
can do that. For us, it’s a question of should we be
spending more of the resources today in the kinds of
technologies that are going to help us as we get to the
very long-term carbon goals.

And a lot of these here, there are opportunities
for us to do more in distributed generation, in energy
efficiency, in transportation electrification. And most
of our focus at this point, in terms of dollars spent,
is in the RPS area.

So, I think we need to look at balancing those
and really focusing on the cost effectiveness of carbon
reduction as we think about this policy going forward.

MR. MILLER: Peter Miller. And I’ll just say
thank you for the opportunity to speak today. I think
that there’s, you know, tremendous opportunity out
there. The ability to call on technological innovation
is astounding these. You know, you can put out a
mandate and two days later, you know, we’ll have a new
technology that meets it, at half the price you thought
it was going to be. It’s amazing.

And the real challenge we face is developing policies to get us there in ways that are successful. And to me, being able to speak on a panel with three energy agencies represented at the dais, is a real example of the kind of policy integration and coordination that we need to have to be successful.

Tough choices about whether to have siloed targets or, you know, one big, integrated target. And you can make mistakes in either direction. Too many little boxes and too complicated on one side.

But the kind of conversation that we’re having today and the ability that I see from members of the dais to work across agency boundaries is really critical, I think, to allowing us to succeed. So, thank you.

MS. WORSTER: So, there are challenges to achieving the 50 percent goal. And one of them would be grid flexibility. And so, I think it is important to consider the costs and benefits of other programs, like DG, energy storage, EV, in order to provide additional flexibility.

But also with regard to DG, I think it’s also important to be -- we have to be cautious about the net metering rules, so that those ratepayers that do not
have distributed generation do not subsidize ratepayers who already have DG.

Ms. Wiland: Let’s see, just to close, I wanted to say a couple of things about curtailment, which may not come up in the next panel.

I think, as Rachel said, curtailment actually can be a really valuable and cost effective tool for the grid. We have to be really careful, but we also have to not try to manage the system so that we have zero percent curtailment. So, we’re building a gas plant to get rid of that little extra percentage. There is a cost benefit analysis there that I think it’s important to have.

On the issue of renewables being able to provide some of this flexibility, when they otherwise would be curtailed, that means it’s more valuable to them.

The one policy kink there is that the way we count renewables for the RPS is megawatt hours generated to meet retail sales, not to meet any sort of ancillary service requirements. So, I haven’t quite figured out how to change the statute to open the door up for renewables to do that. But I think that’s going to be an important policy thing to be thinking about.

In terms of just bigger picture, we’re talking about whether the RPS is the right policy mechanism
going forward. I think that’s the right conversation to have. But really, at the end of the day, all of the models that Claire mentioned show that we’re going to need at least 50 percent clean electricity on the system to power our system.

Including, and I think for the E3 Pathways, I think it was like 50 percent wholesale plus DG, so they actually went beyond that.

So, as we think about tradeoffs and talk about cost effective policies to reduce GHGs, I do think it’s valuable to talk about that in the short term. And it may be because at the least the IOUs have so much renewable bank, they can actually afford to go slower on renewables and move faster on vehicle electrification, even if they do have that 50 percent target out there, because they do have so much bank.

But I think in the long run we’re not going to be able to afford to say either/or, electrification or clean energy. It’s going to have to be both.

COMMISSIONER MC ALLISTER: Great. Well, thanks, everybody for your comments.

I think there’s been a great discussion here today and I like -- and I’ll pick out one theme that I feel like we’ve heard in different ways, from different perspectives, and that’s this need to unpack. You know,
not just rely uniquely on a kilowatt hour, on an energy
basis, but unpack what’s actually being delivered and
kind of move renewables, you know, from sort of maybe
it’s late adolescence into full adulthood, or something.
But kind of, you know, going to the big leagues and
compete with all the skills that it can bring to bear,
that they can bring to bear.

So, I’m very happy to see such engaged
stakeholders and such a high level of discussion here.
I, too, am very proud to be a Californian and having
this conversation. And I think it’s -- you know, I work
with a lot of energy offices across the country and
they’re always just astounded at not only does our
energy office have 650 FTEs, but we don’t even do many
of the things that they do.

So, you know, many states have half an FTE, or
five FTEs, or something like that. So, we’re able to
really do things here.

And I want to just -- well, actually, I think
Commissioner Hochschild, you have a comment you wanted
to make, as well?

COMMISSIONER HOECHSCHILD: Just a very brief
comment. First of all, I just want to thank all the
panelists for a very, very fruitful discussion.

You know, in football you don’t throw the ball
to where the receiver is, you throw it to where the receiver’s going. And at a minimum, I think that’s kind of the policymaker challenges in just looking at all of the evolution that’s happening.

And I just wanted to highlight, the model to date has been, you know, generation follows load, right. And I think we’re entering an area where, to some extent, you know, load will follow generation.

And I work with a lot of home builders in my role here, and one of the things we’re seeing now is the all-electric home. So, with City Ventures, a builder in L.A., that’s doing these all-electrics, they get rid of the furnace, the switch over the gas furnace to electric. The dryer, the stove, and so forth. And that saves $4,500 on the construction of a new home in avoided costs of running the pipe to the house. You know, you can see a trend like that and they’re taking off.

And, you know, I just bought an electric bike two weeks ago. And it’s actually funny, I’ve got a nine-year-old daughter, and I have a little kid attachment, and I’m on this bike and I’m passing this guy who looks like he’s racing the Tour de France. I just passed him up the hill. I don’t think he saw that I had an electric bike, but I felt great.
But, you know, if something like that becomes standard in the future and electric cars, you know, Tesla coming out with a $35,000 car that goes 200 miles on a charge, you know, in 18 months. Right, this is where we’re headed.

All of these things have to be factored in, in terms of how much, actually, baseload we’re going to need, how flexible we can be, and it’s difficult. It’s a difficult challenge because some of that’s unknowable.

But I do feel very bullish about the electrification trend in general, and where technology can go in terms of us being more nimble. Overseeing new construction, now, for KB Homes, and other of these, these smart refrigerators that, you know, they know you’re on a time-of-use rate, and they’ll pre-cool to that peak period and then be off. Or when they run, the defrost cycle on the refrigerator is flexible.

So, these kinds of things, I mean there is going to be, I think, more and more nimble flexibility on the appliance side and the usage side.

But all that’s got to be factored into this as well, so --

COMMISSIONER MC ALLISTER: So, thanks for that.

MR. CASEY: Yeah, I just wanted to offer some good news on some of the suggestions here.
One on the role that renewables can play in integrating renewables, a bit of good news on that front is we’re actually seeing, quite consistently, a significant amount of renewables providing economic bids into our market today. And they are getting dispatched to help with the over-generation situation.

So there are contract provisions that, in the utilities’ contracts, that enable that kind of economic bidding. And the ISO is fully supportive of that. We completely agree that the policy shouldn’t be zero curtailment of renewables.

And there’s a proceeding, a long-term procurement proceeding at the PUC, where there’s lots of analysis that we are providing to show the incremental benefit you can get from allowing some level of renewable curtailment, without undermining, of course, your RPS objectives. But reducing reliance on the gas fleet for that.

Another bit of good news with regard to regionalism. You’ve heard a lot of discussion about the energy imbalance market. And we’ve already see in, you know, the limited five months it’s been in operation, that when we have over-generation conditions on the system, and we do have them, the duck curve is alive and well, that we’re actually seeing next flows out of the
ISO into PacifiCorp, where they’re actually able to take some of that surplus power off of us, instead of us having to curtail it.

So, these are all very encouraging signs on the value regionalism can play. And as this over-generation issue becomes more and more prevalent, having a deep liquid market for that surplus energy is going to be critically important. So, I’ll stop there.

COMMISSIONER MC ALLISTER: Thanks, Keith.

Scott, do you want to have some final comments for this panel?

MR. MURTISHAW: Well, I think, just given the time constraints, I think we’ve probably -- I’m happy to just let things move on and hear from the next panel.

COMMISSIONER MC ALLISTER: Great. So, yeah, I wanted to just build on something Commissioner Hochschild said where, you know, this fifth question really wasn’t about, you know, one-to-one tradeoffs between efficiency and renewables, not at all in fact.

And I think the idea was to talk about how they interact and how we really need both ends of the supply chain, and everything in between for everything to work together. You know, standards are going to be really important in terms of interoperability. Communication technologies are going to be really important.
All sorts of fundamental technologies that, you know, mostly exist already, but we’ve got to figure out how to get them cost effectively into our appliances, and our power plans, and everything in between.

And so, there are some great technologies, really cutting edge stuff, in the marketplace today. Fuel switching, big, big, big issue in terms of, you know, where this new electric load is going to be offsetting, locally, what’s currently local combustion.

And so, we need that headroom in the system. And what is the optimal point? How do we avoid massive investments in the distribution grid, where we can by using controls and, you know, micro grid type technologies, demand response and efficiency.

So, I think the problem that we’re trying to get out with that fifth question is really how to have the discussions in an integrated way? And I think we already started to talk about this. And so that they are all moving forward, and parallel, and actually talking to each other so that we end up in a place where we kind of know what impact is going to happen, from which source, and how are they going to relate?

And I think, also, one thing we do -- another thing that we do here in the IEPR, every time, is the demand forecast. We do various forecasts,

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transportation fuels, natural gas, electricity, et cetera. And, you know, that’s -- the discussion is actually almost broader than even that these days. And so, we need good data, good information to make the forecast really work. But we also have to make sure that just on the ground, in the business environment that people are installing the right technologies that can actually operationalize all of this stuff.

So in any case, I think that’s the kind of ideation that I think we’d like to have in comments, certainly what we’re trying to get at with the question five there.

And I know many of you are thinking about these in greater depth than, certainly, I am. So, we’d really like to see some -- you know, your best ideas in the comments, when you submit.

Okay, so with that, thanks Angie, appreciate it. And we’ll move on to the next panel.

Oh, we have some space --

MS. GOULD: We have space for public comment.

COMMISSIONER MC ALLISTER: Public comment, okay, great.

MS. GOULD: And, sorry, if I could ask you all to remain at the table just in case -- I’m sorry, in case somebody has a question for somebody who’s on the
MS. RAITT: So, if anybody did want to have --
make comments on this panel, the issues and challenges
of the 50 percent renewable target, I don’t have any
blue cards, but you could come up to the microphone and
introduce yourself.

MR. TINGLE: Hello, I’m Ray Tingle, from Sierra
Club. Just a few quick comments.

First of all, Sierra Club, as many of the
participants in the panel have mentioned, really does
support continuing the basic structure of the RPS for
all of the many great reasons that were cited.

We also think there’s some -- well,
philosophically, we’re supporting technology neutrality.

Still, there’s some strategic reasons to support a
diversity of technologies, geographic diversity, project
size diversity.

And in that context, we especially would like
some policies to be set up to fully value wholesale
distributed generation because it can be close to load,
incurs very little environmental damage, quick to
permit, local jobs, all those kind of reasons.

Another thing is I think the State’s making some
great progress on the smart inverters and those are
really going to help out in terms of parts of the
integration challenge that we have.

In addition to that, to the extent that the utilities all have to come up with the flexible resources behind the scenes, and pay for those, to integrate particularly solar, why not take some of that money and provide incentives to those customers that are developing their solar resources. Have them put storage at the same time, and thereby lessen the growth of the belly of the duck getting larger, basically.

On the over-generation issue, and I don’t know if the CEC’s doing this right now, but I think it might be beneficial, in addition to all the other potential solutions out there for dealing with over-generation, to maybe fund a grant, working with CALISO and utilities to do an electrolysis pilot with fuel cells. And just start getting some experience as using that as one of the potential solutions. It’s not a silver bullet, but I think it does hold some potential.

And then, lastly, I just wanted to refer to Rocky Mountain Institute’s recent report, “The Economics of Load Defection”. And I think that’s a very significant report that just came out.

And I think, along with Commissioner Hochschild’s comments about we need to look to where -- really need to look to where we’re going and, of course,
we’re all trying to do that.

But the potential there for load losses over
time, with the advent of more solar with storage, I
think is very real and it’s going to come. They even
forecast in one market where load reduction could come
down to as much -- as little as 25 percent of business
as usual by 2030.

So, as we’re looking at RPS, and everything
we’re doing, we need to look at it in the context of
what’s the scenario going to be in 2030, and 2040 and
2050?

Thank you very much.

COMMISSIONER MC ALLISTER: Thanks. Thanks for
being here.

Any other commenters? Tim Tutt?

MR. MILLER: If I could jump in. I’d note that
there is an electrolysis pilot that SoCal Gas is
sponsoring. I think they’ve gotten some money from DOE.
And just a response that we think that’s a great
initiative, test it out, and a new technology to
generate renewable hydrogen.

COMMISSIONER MC ALLISTER: Great, thanks.

MR. TUTT: Hello, Tim Tutt, from SMUD. At the
risk of being accused of a double credit because SMUD’s
on the panel, I just wanted to say a few things about --
COMMISSIONER MC ALLISTER: Hometown advantage, that’s okay.

MR. TUTT: I mean, first, we heard talk about DG being included in the RPS today. And I just wanted to point out that it is already included, it is already eligible for the RPS, both existing and any ongoing, new DG is already eligible.

So, I think SMUD would look askance at any kind of proposals or change which said that the existing DG that we have already submitted to the CEC for RPS compliance is no longer part of the RPS structure. I think that should still remain part of the RPS structure.

Second, the --

MR. CASEY: Can I ask a clarifying question?

MR. TUTT: Yes.

MR. CASEY: You’re talking about behind-the-meter DG?

MR. TUTT: Yes. It’s already included in our RPS compliance for the first compliance. It’s bucket three.

And I would point out, in that regard, that there’s at least one POU, that I’m aware of, that has the same thing, behind-the-meter DG that has been registered with REGIS, certified by the CEC that they’re
not going to fully count for the RPS because of the way
the categories work. It’s not a limited percentage of
your overall renewable procurement. It’s a limited
percentage of your PCC 1, 2 plus 3 procurement.

So, an early actor that has a lot of
grandfathered resources can’t include as much bucket
three recourses as somebody who’s waited to get their
procurement going now. That early action is being
devalued by the way the categories work right now.

Then another questions is whether or not these
DG resources, if they were fully included, would
exacerbate the net load curve issue. And I’d just like
to point out that these resources, existing and new
ones, are already there, already generating and
contributing to the net load issue.

So, including them more fully in the RPS is
really -- there should be an argument for including them
more fully, rather than excluding them in favor of
additional renewables that would tend to exacerbate the
issue.

And finally, I guess I’d just be wary about
arguments that say existing resources shouldn’t count.
As I said, DG’s already included. If the question is
whether we want the RPS to foster new renewables, then
that should be in place for all resources.
shouldn’t be one set of rules for DG and another set for new resources.

So, I guess I don’t think that’s every going to happen. I think nobody would want all of the existing success of the RPS, and it has been successful, to suddenly not count in favor of adding a bunch of new resources. So, I just think that should be avoided.

Thank you.

COMMISSIONER MC ALLISTER: Thank you for being here.

MS. RAITT: Yeah, we have one person, Jan Reed.

MR. REED: Hello?

MS. RAITT: Go ahead, Jan.

MR. REED: Yeah, I just had a comment about, I believe it was item number three, concerning renewables. And there was some comment made about energy efficiency. And to me, it’s kind of a risk management situation. The question isn’t which is better, renewables, or energy efficiency, or demand response, et cetera, but what is the proper mix of them.

All of these different types of resources and different types of programs have different risk and we need to diversity the risk for the ultimate benefit of
ratepayers. That’s my comments.

COMMISSIONER MC ALLISTER: Thank you very much.

MS. RAITT: Okay, we’ll open up the phone lines for just a moment. Please mute your line if you didn’t want to make comments. And if you do want to make comments, we’re unmuting the lines and you can make a comment.

Okay, I’m not hearing any. So, I think I’d like to thank the panelists. And go ahead and take your seats and we’ll get the next panel up here.

COMMISSIONER MC ALLISTER: Thanks, everybody. Really appreciate your spending the bulk of your day with us, very helpful.

MS. RAITT: If the Renewables and Reliability Panel could come up to the table, that would be great. So, we’re just assembly at the tables before we get back, started with the discussion.

MR. BARKER: Okay, so we’ll go ahead and get started. So, thanks to the panelists. Some of you guys are doing double time here. And I think this panel will actually be kind of an extension of a lot of the conversations that we’ve had earlier today.

And so, the focus here is to talk more about over-generation. Where we were calling this kind of the over-gen, or I think I was initially calling this the
over-gen panel, but right around the time we were pulling the panel together UCS put out a pretty interesting paper. And where we were calling it over-gen, they were calling it renewables and reliability.

So, thanks for the paper and letting us steal the name.

So, when I think about renewables, I started here at the Energy Commission in 2007. And in 2007, we had already had, let’s say, an RPS. Whether active or not, we’ve had an RPS for about five years. So, in 2007, I think our renewable percentage was about 13 percent.

And then, two years later, our RPS had been, let’s say, active for now seven years, and our renewable percentage was 10.9 percent.

So, over the course of the two years, when I first started here, we actually -- because of load growth and with a lot of the contracting that we had been doing, up until then we really hadn’t seen anything online.

And then, you know, following that year we had the huge ARRA push, which we all know quite well, having helped with a lot of those projects from the Governor’s office.

And I guess I would like to think now we’re becoming even more successful, right. So, we’re at
about 25 percent renewables. What’s interesting, and this kind of came up earlier today, but let’s say the first 10 or so percent of renewables, the profile was more of the baseload, so that was having the geothermal, sort of even your small hydro, your biomass.

And then the next 15 percent, that’s really been more of the wind and solar. And so, we’re seeing definitely a shift in resource profiles.

And so the next incremental, from 25 to 33 percent, is probably going to be filled more with intermittent renewables. So, that’s something to keep in mind.

I think we’ve also been very successful, if the whole goal of RPS is actually to de-carbonize the grid, we’ve been very successful. So, AB 32 is a goal of carbon emissions to that of 1990 levels, and that is sort of industry-sector wide.

I think we can be happy, we can be pretty proud that on the electricity sector, we’re actually 20 percent below where our emissions were in the electricity sector in 1990.

So I think on the electricity side, they’ve really been doing their part. And that’s both by increasing renewables, but also by divesting and not re-contracting with coal.
So when we think of over-generation, I think in the past we’ve been scared. We’ve been looking at it as an issue or a problem. But I think the panel here today, a lot of the panelists look at it sort of also as an opportunity.

And, you know, how can we reduce -- how can we find, let’s say, excess load that could then help suck some of those renewables? But I think we also need to keep in mind actually the magnitude.

And so, how we’re going to start with that is by a presentation by the ISO to talk about, really, the issues.

And so, when folks -- we do have a gentleman from Poseidon. So, when folks talk about desalinization as an opportunity to suck up some of that load, let’s think about the magnitude.

When we do talk about electrification, the transportation sector, let’s think about the magnitude. So, about 600,000 cars charging all at the same time is only 1,000 megawatts.

So, when we’re looking at, you know, over-generation issues, let’s say in the kind of baker’s dozen, you know, the 13,000-megawatt level, that’s a whole lot of cars. So, it’s something to keep in mind, about the magnitude.
So, kind of how we’re going to lay out this panel is we’re going to receive a presentation from the ISO, going over sort of identifying what they’re seeing at the ISO, both today and the also looking kind of in the 2024 timeframe.

And then we’ll have a presentation from UCS, going over sort of the opportunities that they see as we increase renewables.

And then, we have a number of panelists that will give us, I think, kind of an interesting perspective both on what we can do with our existing resources, but then also changes in contracting going forward, opportunities to provide demand response. And some of them do have presentations, as well.

So with that, I’d like to kind of turn it over to Dennis to start with their presentation.

MR. PETERS: Sure. Thanks, Kevin, and thanks to the CEC for convening this really important conversation and for including the ISO in the panel.

So, you really took the words out of my life, in terms of the way you -- I like the way you framed the panel as, yeah, certainly there are challenges. And we’re going to talk about, you know, just in this brief presentation what we’ve seen, what we are looking to in 2020 and 2024.
But, yes, there’s definitely opportunities. And so, I liked the way you framed that, Kevin.

So, let’s go to the first slide here. Maybe. This is the song and dance portion of the presentation.

MS. RAITT: Sorry, Dennis, I’m having some technical problems here.

MR. PETERS: Ah, there we go. We’ve all talked about some of the history here. I mean, I recall starting at the ISO 15 years ago and we were in the middle of an energy crisis. And then ten years ago we saw this big boost to renewable, put AB32. Five years ago we were at 20 percent and five years from now we’ll be at 33 percent. And now, we’re talking about 50 percent in 2030. So, in terms of development in such a short period of time in this 100-year-old industry, it’s just been an incredible development.

You know, and kind of the idea of some challenges and opportunities, so certainly some challenges there with we’ve seen rapid growth in utility-scale renewables, a rise in consumer-owned solar. We’ve got the Governor’s 50 percent goal. But then, the challenges create opportunities, so opportunities in California and the West. And I’ll go through those in a few slides.

So, in terms of just kind of the numbers,
utility-scale and consumer-owned renewables, right now capacity-wise, at least now on the ISO’s balancing authority area, about 6,400 megawatts of wind and 7,100 megawatts of solar. And we’re seeing new solar peaks literally every month. We’ve surpassed 6,000 megawatts in terms of peak on solar. And as was mentioned earlier, we expect to see solar projects double in the next five to seven years, and definitely on track for 33 percent, for 2020.

And then on the other side of the meter, in terms of consumer solar, that’s growing fast as well, about 2,500 megawatts of consumer solar.

And when I saw it’s invisible to the ISO, it’s invisible in terms of forecasting. It’s sort of embedded in the load forecast. It makes it difficult, sometimes, for forecasting and for operations.

And then, of course, what we already talked about, the 50 percent goal, what is that? You know, we’ve been doing some work on that, others have been doing work on that in terms of what does that mean? Is that 50 percent RPS? Is that 50 percent overall renewables? So, that remains to be seen.

The next slide. So, what’s an ISO presentation without a duck, a duck curve. So, show of hands from anybody who hasn’t seen the duck curve. No, I’m
kidding.

So, as Keith mentioned, the duck curve is alive and well. And I think everyone understands kind of the basics of this and how it works. So, I just think I’ll try to give some updates in terms of the two big challenges for grid operations being, you know, over-generation and ramping. You know, we talk about this panel as we’re going to focus on -- we didn’t call it over-generation, but we were talking about over-generation.

We can’t forget that ramping is also an issue that’s out there, as well.

MR. CASEY: Dennis, just with regard to the duck curve, this is based on a 33-percent renewables. And as you look at the duck curve under higher RPS, the belly of the duck sinks and sinks. You see here it’s about 12,000 megawatts.

We actually, in some of the worst hours, under a 40 percent RPS, see the belly of the duck go negative. Which means if you shut everything off on the system, you still couldn’t accommodate all the renewables.

So, you know, Kevin made the point about scale. That’s another data point for you on scale here. So, I promise I won’t keep interrupting you.

MR. PETERS: No, I appreciate it. Thanks,
Keith.

Just, so, we all know the over-gen, obviously caused by the increased amount of solar in the middle of the day, and the inability to curtail -- or non-dispatchable resources, like geothermal, nuclear hydro, CHP. And, certainly, it causes some reliability problems in terms of, you know, if we had to turn off any plants that maybe we needed later for ramping purposes, and don’t have that ability to restart. In terms of some of the economic curtailment potential, you know, generators paying others to take energy.

And then what, really, no one wants to see is exceptional amounts of curtailed renewable resources.

But just to give you an idea of kind of where, you know, this curve here is showing a March 31st date, and let’s keep that as this is looking at the 33 percent.

In 2014, we actually saw net demand dip much lower than what we expected it to be in 2014. You can see kind of the red dot there, we went below 15,000 megawatts and we weren’t expecting to get anywhere near that until 2015, 2016.

Then on the ramping side of things, we’ve already seen, in December of last year, as much as a 10,000-megawatt ramp, and we expect that to grow to
13,000-megawatt ramp by 2020.

Okay, next slide. This is just a summary of the curtailment, some manual renewable curtailments that we saw in 2014, sort of in February through April. The highest amount there was 749 megawatts curtailed for 90 minutes.

The next slide. So, just kind of looking out to 2020, so what’s causing the over-generation and the increased ramping, I mean sort of the supply side, you know, increased amount of particularly solar on the system in the middle of the day. And then, on the other side is decreased load on the customer side.

So, with the increase in solar DG, we expect by 2020 to see loads decreased by 3,000 megawatts. So, with that the gross load goes down.

Then net demand, which is our -- that’s essentially our duck curve, which is the gross load minus the utility-scale solar and wind, we expect that to drop by four to five thousand megawatts, due to more utility-scale solar.

And we expect that we would need at least four to five thousand megawatts of additional resources in order to get 3,000 to 4,000 megawatts of downward dispatchability.

We heard Keith mention this morning, early,
we’re going to have a need for more downward dispatchability. And, primarily, it will be that the reason for the additional megawatts of resources to get to 3,000 to 4,000 due to the minimum load on resources. And again, I mentioned this on the previous slide, that the evening three-hour ramp is expected to grow to 13,000 megawatts by 2020.

This is sort of complicated slide here. As part of the CPUC’s long-term procurement plan proceeding, we looked at 2024. We did five scenarios, and this is part of the 2014 LTPP.

We did a trajectory case, sensitivity on that without Diablo Canyon. And we did a high load case. We did a 40 percent RPS in 2024 and a 40 percent RPS, with expanded preferred resources. We sort of picked this one as kind of, you know, most likely to show the big difference between what you see in terms of if you had unlimited curtailment, just what you could potentially see in terms of over-generation at 40 percent RPS.

So, you can see there’s 822 -- that’s 800 plus -- can’t help being an engineer -- 822 hours where we see curtailment and that’s as high as 12,000 megawatts. And that’s in a 40 percent RPS scenario in 2024.

You know, so the number of -- here we get into
the opportunities, the solutions here. You know, and I’d categorize solutions really kind of into three areas, load, procurement, and better regional coordination.

So we just kind of list a few there. Certainly, storage is a game changer, a place to sink some of this additional generation.

Targeted efficiency, energy efficiency, so energy efficiency that’s in those -- particularly in the -- when I say by targeted, you know, those evening hours when we’ve got the big ramps. We don’t necessarily need more energy efficiency in the middle of the day when you’ve got a low net load, net demand.

Demand response. You know, we’ve typically always thought of demand response as, you know, shutting off load. You know, we need a place to sink all that additional generation. So, we need to start thinking in terms of DR up and not just down.

Economic dispatch of renewables, as Keith mentioned, that’s already helping somewhat. We’re starting to see more renewables bid in, put economic bids in and that helps, as well.

This morning, or the previous panel talked about decarbonizing transportation. That’s certainly additional load, at least if it’s in the right time.
during the middle of the day, particularly in these spring and fall months.

Retrofitting, you know, existing plants so they’d have lower P mins and more flexible. On the load side of things TOU rates, but aligning them more with grid conditions versus just geography. And deeper regional coordination.

You know, in terms of all these solutions, I mean a lot of us all are talking about it. We are looking at these kinds of things in initiatives at the ISO. The PUC is certainly talking about these things in various proceedings and we need to match those up, and make sure we get to what the best, most cost-effective solutions are.

And I think there’s kind of three areas for all of the solutions. You know, what’s the time it takes to implement it, what’s the cost, and then what’s the overall impacts. Those are the things to look at in all those areas of solutions.

And the last slide. Just, again, the regionalism. I mean, there’s great -- there’s a very timely solution, very high value. We’ve already seen the benefits of the EIM, the energy imbalance market with PacifiCorp. You know, the diverse assets, both in place for excess renewables out of California as well
as, you know, integration resources that are helpful to us in terms of integrating renewable resources. It leverages the ISO’s market systems.

And then, of course, in terms of the full participation, now we’re talking not just in terms of a small, you know, five-minute energy imbalance market, but now we can look a day ahead. There’s significant benefits there.

Of course, the studies are underway. We’ve got an MOU with PacifiCorp to look at this integration and a number of benefits. I mean, improve reliability through broader visibility, and consolidated planning, and there’s definitely a greater ability to add renewable generation to the system with a larger area, and lower operating costs. There’s a lot to still learn, but we’re moving forward.

So, I’ve probably taken enough time there, but thank you.

MR. BARKER: Thanks, Dennis.

You know, your presentation talked about a couple of key points, one’s curtailment. And maybe later, when we hear from IEP and PG&E, but to get sort of what have you guys been seeing is this -- you know, is the force curtailment as a paid-for curtailment? Is it not paid? And so, kind of your thoughts on that.
And also, with respect to downward flexibility.

And so, what -- can we take advantage of some of the assets that are already out there? And by doing, say, I don’t know, maybe minimal upgrades we can actually increase -- we can the P mins down, and so we can also help with some of that downward flexibility. That might be something worth exploring, too.

So, the next presentation, Laura, if you want to go ahead and kick off what you guys have seen.

MS. WISLAND: Sure. Okay, is my presentation up?

So, I’m Laura Wisland. I’m with the Union of Concerned Scientists. We’ve been working on renewable energy issues and renewable integration for a while now. I think Dennis set me up really well by explaining that this is not a technical issue.

Getting to 50 percent renewables in California is not a reliability issue. It’s an economic issue. The problem is really defined as we’re anticipating that there’s going to be a lot of curtailment on the system. A lot of the reason for that is we’re taking advantage of an amazing solar resource we have in California, that also happens to be relatively low cost. And I think it’s our challenge to figure out how to take advantage of as much solar as we can, in the middle of the day,
when it’s generating. And then, also bring on additional types of resources to smooth that generation over time and turn down the gas plants as much as possible, so we’re getting the commensurate greenhouse gas benefit.

So, the next slide, please. So, this is our version of the duck graph. And the reason why I wanted to show it like this is I think what’s missing from the ISO’s duck graph is what else is on the system that’s contributing to the over-generation.

So, certainly, all of this solar coming on in the middle of the day is contributing to the over-generation. But it’s exacerbated by the fact that we’re not able to turn down everything else and make room for that solar. There are resources that are crowding out that solar.

And which makes it -- which poses the question, why aren’t we able to take advantage of those low, marginal-cost resources? And are there things that we can be doing?

And what we’re finding through our own analysis is that there’s a lot of gas that could potentially be online in the middle of the day, not because we actually need the energy from those gas plants, but because we need the reliability services that they’re giving us,
that they’re providing to the grid.

And, certainly, we’re going to need to maintain reliability. So, I think one of our biggest challenges is figuring out how we could swap out some of the gas and use other types of resources, including the renewables, to provide some of those reliability services.

So, the next slide, please. So, this slide is just to go a little bit deeper on that and show you that assumptions for what else is on the system and what those things are providing really matters.

We have been using the same model, the production cost simulation model that the ISO’s been using in the LTPP process. And the graph that Dennis showed you with all the dots, showing all the curtailment that could happen in a 40-percent scenario, when we ran a sensitivity on that scenario, that removed a pretty important assumption that they were making on how to provide reliability services.

We saw curtailment go down by 40 percent. And this assumption that they’re making is called the regional generation requirement, which is not in law today, but it’s in anticipation of some NERC requirements that are going to require us to keep fast-acting grid services on the grid in specific local
areas.

And the way the ISO constructed this assumption in its modeling required that in every hour 25 percent of the electricity come from local sources. And those local sources had to be from conventional resources.

And, clearly, that made a big, big difference in the amount of curtailment on the system.

So, I’m not saying that the regional generation requirement isn’t important. But I think before we go too far down the pathway of providing reliability services with specific resources, we need to be thinking about why we’re making those assumptions. And whether, for instance, some non-fossil resources could contribute to those local generation requirements in a way where they wouldn’t also be generating on the system and crowding renewables out.

So, next slide, please. So, what I’m going to do really quickly, I only have ten minutes, is walk you through some preliminary analysis that we’ve been doing, using the same Plexos model on 50 percent scenarios.

And these results are going to be coming out in a public report, probably in June. But because a lot of the things that we’re learning from this analysis are very relevant to the conversation we’re having today, I thought it would be interesting to bring them up and
show you some of the quantitative evidence for the
things that we’re saying.

And I just also wanted to say that really the
brains behind these analyses is Jimmy Nelson. He’s
sitting right there.

So, because I won’t have time to go into a lot
of the assumptions, if you guys have questions about the
analysis, we can talk to you afterwards.

This slide is basically just some quantitative
evidence that providing downward flexibility and
downward reserves really is going to matter for the
amount of curtailment we see on the system.

So all we did in this scenario is take a 50-
percent RPS, in the ISO service territory, and remove
the downward reserve requirement, and curtailment went
down quite a bit.

And the way we’re defining downward reserves in
this model I think is important. Because people think
of downward reserves today as what we can buy and sell
in the ancillary service market, so regulation spin and
non-spin.

And here, we’re really talking about downward
regulation and load following.

So, I think this just shows us that this
figuring out how to provide these resources with as many
clean -- as many non-fossil generation sources as possible is going to be really important.

The next slide. So, what we did, to just get a sense of what types of resources could provide downward reserves, and what’s the relative value of having additional flexible gas provide these reserves, as opposed to having renewables provide these reserves.

And what we found is that actually renewables providing some of these reserves is very valuable. So, the flexible gas scenario that we have in here actually makes the gas -- the ISO’s gas fleet, in 2024, dramatically more flexible than the way it’s operating in the model, in the base case scenario.

And, specifically, we reduced the minimum up-time/down-time to two hours or less. We reduced the P min generation level by half. We doubled the ramp rate and we reduced the start/stop time profiles to one hour. And that’s how much curtailment we saw reduced by making all of those dramatic improvements to the flexibility of the gas fleet.

Conversely, with the renewables, we allowed the renewables to provide a maximum of 20 percent of their available generation in any hour to provide downward reserves. And just doing that allowed the curtailment to go down more than the flexible gas.
Now, obviously, there needs to be more analysis
down and we need to talk about the costs of each of
those tools. But I think it gives us some evidence to
have that discussion more fully in the long-term
procurement planning process, in the way we contract for
renewables, and the way we think about what are the most
valuable retrofits to our gas fleet that are really
going to help us integrated more renewables.

COMMISSIONER MC ALLISTER: Just a quick question
about the report. Is it going to have policy
recommendations for how to structure, say, you know,
that market or how to unpack the renewables to provide
those specific services?

MS. WISLAND: I think it’s going to have some.
And it’s going to have some examples of other balancing
area authorities that have been thinking about this
issue. But it’s not going to have a full package of
here’s everything that we need to do. That’s something
that we’ve been thinking a lot about and, hopefully,
we’ll have some follow-up work to do that.

COMMISSIONER MC ALLISTER: Thanks.

MS. WISLAND: Yeah. So, the last slide, this
is -- this slide, basically, the take home here is that
as we think through all of the different ways to lower
GHGs in the electricity sector, and the best and most
cost-effective ways to reduce renewables that gets you lower amounts of curtailment, and also maximize greenhouse gas reductions.

We do need to be not just jumping to the conclusion that by dramatically increasing the flexibility of the gas fleet we’re going to get a ton of benefit.

So, what you’re seeing here is on the left bars, for both the red and the blue, that’s the 50 percent renewables base case. The flexible gas is dramatically increasing the gas fleet in the way I just described.

The non-fossil solutions is we added one gigawatt each of storage, advanced demand response, and additional exports out of the ISO. We also removed the regional generation requirement and we allowed renewables to provide downward reserve.

So, admittedly, that’s empowering renewables and empowering non-fossil flexibility solutions to do a lot of work on the grid. But as you can see, if you do that, you get significant more benefit in terms of curtailment reduction from deploying these non-fossil resources than you do in dramatically increasing the flexibility of the gas system.

So again, you know, this is one scenario. There’s a lot to unpack here. But I think it shows us
that it’s worthwhile really thinking through the full range of benefits that these non-fossil solutions can provide.

Thanks, that’s it.

MR. CASEY: Just some follow-up questions. Just a clarification on the work that the ISO submitted in the LTPP. I believe the 25 percent gen requirement applied to San Diego and Southern California, but not PG&E, so it wasn’t system wide.

MS. WISLAND: There was an ISO 25 percent requirement.

MR. CASEY: Yeah, that’s what I’m talking about.

MS. WISLAND: And then there was also a 25 percent requirement for San Diego and Southern California Edison.

MR. CASEY: I’ll have to check on that. My understanding was it was just Edison in San Diego.

And one of the assumptions was imports could go to zero, net imports could go to zero. So, in the analysis that we did, showing over-generation, California historically has imported 25 percent of its energy needs.

This analysis assumes that we can export all the way where the ties are floating at zero, or basically. And it sounds like in some of the studies you did, you
took it even further to where we’re actually a net exporter during those over-generation periods, correct?

MS. WISLAND: Yeah, so in the slide that I showed that had the sensitivity on simply removing the regional generation requirements, we have the same assumptions on imports and exports that the ISO has. We did not change that assumption. So, simply removing the regional gen requirement reduced curtailed by 40 percent.

MR. CASEY: Yeah, okay.

MS. WISLAND: In the 50 percent analysis, that I was just showing with these later slides, the non-fossil solutions does include one gigawatt of net exports to the system.

MR. CASEY: I see, okay. Okay. And just to clarify on the driver for the 25 percent, admittedly it’s a proxy for having upward dispatch capability. Some of it’s related to the NERC standard on frequency response capability, that you have to have some emoted headroom per the standard. That if there’s an event on the system, you carry your fair share of frequency response.

But some of it’s related to local transmission contingencies. So, we keep generation online today, in critical areas. Especially with the loss of San Onofre,
where if we have a major transmission contingency, we need capability to go up quickly.

And I guess a question would be with regard to renewables, because these are contingency type events, are you actually looking at keeping renewables persistently under-performing in case you have a contingency where they would have to respond?

MS. WISLAND: I mean, we’re not recommending that in this analysis.

MR. CASEY: Yeah.

MS. WISLAND: I will say that in the sensitivity that we ran, that allowed renewables to provide reserves, we allowed them to provide downward reserves and upwards reserves. And the large majority of times where renewables actually did provide reserves, they were providing downward reserves. I think that just makes more sense for them, generally speaking, from an economic standpoint.

MR. CASEY: Right.

MS. WISLAND: But I wouldn’t -- I mean, it’s certainly possible for them to provide upward reserves. And if it penciled out economically, then they probably could.

MR. CASEY: Right.

MS. WISLAND: And on the regional gen
requirement, you know, there are a lot of really
important reasons why it’s necessary to have generation
in local areas. I think the point is that when we
figured out that this assumption made such a difference
to curtailment in the LTPP, and we submitted a data
request to the ISO, saying please give us more
information on how you got this 25 percent number,
because that really matters. And why you decided only
to allow conventional resources to participate.

It wasn’t a very straight forward answer and I
think that’s because we’re all moving into unchartered
territory about trying to understand how little local
generation we need to have on the system and ensure
reliability. And I think it just means that we need to
dig into this issue further and that we need to do more
analysis to figure out what that right number is.
Because the 25 percent really seemed like it was a
placeholder or it was a --

MR. CASEY: A proxy.

MS. WISLAND: A proxy, yes.

COMMISSIONER MC ALLISTER: So, I just want to
put a finer point on that. So, I mean, this seems like
something that would necessarily vary by area, really.
It really is a function of the particulars of the grid
in each particular load pocket, essentially.
MR. CASEY: Right.

COMMISSIONER MC ALLISTER: So I guess I’m wondering, you know, does the ISO sort of have ongoing analysis going on to see, you know, what the variation bars across the State might be around that 25 percent?

MR. CASEY: Yeah, we are looking at can we get more rigorous in terms of defining what the percentage is. It’s clearly not zero.

COMMISSIONER MC ALLISTER: Yeah.

MR. CASEY: Is 25 percent excessive? Again, my information from the ISO’s team was we only enforced it in San Diego and L.A., not system wide.

So, to answer your question, we will look to provide additional analysis on, you know, further clarifying what exactly is driving that need, and what is the right percentage.

But I did want to just clarify that, you know, this is really an upward capability that we’re talking about. Demand response could be a great resource for this, the right kind of demand response that it can be controllable, fast-acting.

You know, renewables could certainly do it as well. The challenge there, of course, is do you want to forego that level? Because this is typically contingency-based dispatch, do you want to consistently
have your renewables under-performing relative to what
they could do just to have that upward capability.

MS. WISLAND: Yeah. I mean, I would say in
terms of upward flexibility, it probably makes more
sense for something like a storage device that can, you
know, discharge really quickly to provide that service,
instead of renewables.

MR. CASEY: Yeah.

MS. WISLAND: I will also say, and I hope I
don’t screw this up, I’m looking at Jimmy, that in the
LTPP 40 percent, where we removed the regional gen
requirement, that was the biggest factor driving
curtailment. Because in that analysis the ISO was
allowing downward flexibility to come from other
generation in the rest of the WECC.

And in our 50 percent scenario we were -- that
analysis does not rely on the rest of the WECC for
reliability. And in that scenario, the provision of
downward reserves makes a much bigger difference in
terms of driving curtailment than the regional
generation requirement.

So, that seems like the first thing to deal with
is the downward flexibility piece.

MR. CASEY: Yeah.

COMMISSIONER MC ALLISTER: Thanks, Laura.
MR. BARKER: Thanks, Laura.

So, I think we’ll just kind of start by going down the aisle, staring here with Graham.

So, the month of April, I think it was kind of marked at the beginning of the month with a kind of groundbreaking Executive Order, and then I think it’s kind of closed with another piece.

And so, for the Executive Order that was released on April 1st, it’s dealing a lot with the drought issues. And so a number of folks have thought that, one, to deal with the drought there’s desalinization. And what can we get out? Is there opportunities to help with sort of the reliability issues that we’re seeing with desal, in a way killing two birds with one stone.

So, I guess I’ll turn it over to Graham to kind of walk through their technology. He’s with Poseidon Energy, who are about to go live with their project down in Carlsbad.

But then, also, you know, think through sort of the opportunities there with, obviously, the water requirement is really your prime goal, but what are some other flexibilities you have.

So go ahead, thanks.

MR. BEATTY: Yes, thank you very much. Yeah, so
my name’s Graham Beatty, with Poseidon Water. And thank you for the invitation to speak here today.

Large-scale desalinization is relatively new to California, so I’d like to first introduce Poseidon Water, our project in Carlsbad, just north of San Diego, and then finally discuss the energy opportunity overall.

Poseidon Water is a private company. We specialize in permitting, financing, constructing and operating large-scale water projects. We’ve been in the business for about 20 years. And today we are highly focused on seawater desalinization.

Governor Brown’s Executive Order on the drought, Article 17, calls for implementing WET, a Water Energy Technology Program with a special focus on desalinization and renewables.

And I just want to note that Poseidon Water is already committed to carbon neutrality. The desalinization process creates no additional greenhouse gases. And we’ll be purchasing carbon offsets for the power we do purchase from the grid.

A good place to start would be with the Carlsbad desalinization project, just north of San Diego. This is as a result of a long-term water purchase agreement with the San Diego County Water Authority, that recognized the need for a locally controlled, drought-
proof water supply.

The project produces 50 million gallons of drinking water, about eight percent of San Diego’s water supply, and is the largest, most advanced desalination plant in the Western Hemisphere.

I thought it would benefit the room to just show a few pictures of what a desalination plant looks like. Everyone has seen a Tesla, but no one quite knows what a desalination plant is.

If you go to the next slide, you’ll note that our project, in the bottom right you’ll see the Encina Power Plant. Our project is in the back of the power plant. It’s a brown field redevelopment. We took down some old oil tanks and constructed our facility.

The next slide, please. When it’s all constructed, it will look like a small warehouse, or even a library. You won’t be able to see it from the beach, you won’t be able to see it from the street. And no noise and no other kind of adverse effects to the locals there.

The next slide, please. One of the big advantages of desalination in California is that we can actually use existing infrastructure. So, without impacting the beaches, we can use a power plant intakes and outfalls. Once-through cooling is being outlawed in
California, but we can use that existing infrastructure
to pull in source water for the desalinization process.

The next slide, please. And we’ll leave it here
for the rest of the conversation. I have some
construction pictures, but in the interest of time we’ll
move forward.

I’d like to turn, now, to desalinization and
energy. Electricity consumption accounts for 50 percent
of our operation expense, and so we’re constantly
looking for new ways to optimize that cost. The process
of removing salt from ocean water is energy-intensive,
requiring 30 to 35 megawatts in Carlsbad.

Let’s put that in context. Our facility uses
less power than a modern data center, and it’s only 25
percent more power-intensive than exporting water to
Southern California.

So, the real opportunity today is that with
renewable power, desalinization really turns water into
a batter with demand response. We can engineer plants
that ramp up water production when there is a surplus,
and ramp down production to smooth the duck curve. With
on-site and off-site water storage, the excess water
will also serve demand by varying our production times.

Just as important, with desalinization as a
long-term power customer, we can provide renewable
developers with the revenue they need to build projects. However, many challenges exist with current regulations and direct access restrictions.

So, I’ll end with one final note here. Given this water/power nexus, in our view curtailing renewable energy generation is like not capturing stormwater when it rains and foregoing an opportunity for regional, locally-controlled, drought-proof water supply. Thank you.

MR. BARKER: So, what type of flexibility can you -- these are reverse osmosis, correct?

MR. BEATTY: Correct.

MR. BARKER: And so are there issues with running the pumps harder or faster than it’s designed? And if so, you know, does that hurt the maintenance of the facility, I guess? Also, and then what’s the speed at the level to which you -- so, if you’re at a 35-megawatt draw, how fast can you ramp down and at what point would be sort of the minimum capability?

MR. BEATTY: Yeah, in the desalination process, really, to think about it is you’re manufacturing water. So, at the push of a button you can ramp up or ramp down your production almost instantaneously.

The way we would envision it is we essentially over-engineer the plan so that when there is large
demand for water, or a large surplus of energy, we’d be able to accommodate that.

The State Water Board did just pass their Ocean Plan Amendment, which has given us regulations around ocean water desal. And so, for example, you cannot pull in water more than half-a-foot per second. But you can engineer around that. You can make your intakes larger. The preferred approach is a subsurface intake, essentially where you’re bringing ocean water below the surface.

But if you can’t do that, you can do a screened intake. And if you build it large enough, you won’t kind of like if you put a straw into a glass of water and you suck through it, if you try to get more of that water you’re going to increase the velocity. But if you put in ten straws and design a larger intake, then you can make sure that environmental mitigation and environmental ordinances won’t be impacted.

COMMISSIONER HOCHSCHILD: What is the cost difference between desal water and the other water contracts that San Diego is buying? If you’re able to disclose that, I don’t know if that’s --

MR. BEATTY: Yeah, sure. In rough terms, basically, the Metropolitan Water District can supply San Diego with an acre-foot of water, which is an acre,
a foot deep, for about $1,000 per acre foot.

We can produce water for about $2,000 per acre foot.

To put that into context, though, the rate of expense growth for imported water has been about 6.7 percent for the last 30 years, where we more or less rise with inflation. So, we do expect those lines to cross. Plus, you have the ability to turn on those pumps when you need it. You know, we’re not dependent on the snowpack. We don’t need rainfall. We turn on the switch and we have pure water.

COMMISSIONER HOCHSCHILD: And just out of curiosity, looking ahead at what the future can hold here, I mean how optimistic are you about the ability to bring down the cost of the process through new technology or greater scale?

MR. BEATTY: Yeah, desalination is a fairly mature technology. We think that if we can marry our projects with renewable projects, that that’s a great opportunity to take the components of the demand response debate off the table and have cheaper energy.

So, like I said, energy’s about 30 percent of our operating costs. So to the extent we can do that, that’s a big win for the water community.

COMMISSIONER MC ALLISTER: But given that this
is a pretty capital-intensive investment, what sort of capacity factor do you need to kind of make it worthwhile, make it pay. You know, if you’re getting two thousand bucks and it’s take or pay, you know, you sort of have an incentive to keep the thing running. And I’m wondering how flexible you can be?

MR. BEATTY: Well, it all depends on the customer. But as long -- for example, what we’re really talking about is over the course of a day. If we can ramp up production at one point during the day, and then ramp it down during the next point in the day, we’re still delivering the average amount of water that the customer needs.

COMMISSIONER MC ALLISTER: And that incremental investment isn’t as big, isn’t a deal breaker in terms of over-sizing a plant to do that?:

MR. BEATTY: That’s correct.

COMMISSIONER MC ALLISTER: Okay.

MR. BARKER: So, moving right along, I think it’s interesting because, Steven, your comments to the IEPR, you’ve talked about desal as an opportunity. But, you know, I’d be interested in sort of members of your association, what you see both on the conventional side and how they’re thinking about doing business kind of in the future, but then also your sort of large-scale
renewable representatives.

MR. KELLY: Okay, thanks Kevin. So, since this is the afternoon and this is a renewable and reliability panel, I did want to start my comments on things that don’t make sense to me, just to liven things up. And then get into the curtailment issues and the natural gas issues that came up.

COMMISSIONER MC ALLISTER: I thought you were supposed to be the expert, man. Steven, I don’t know if we have that much time.

(Laughter)

MR. KELLY: Let me start at the beginning. So, this is coming from the airport, flying back from Chicago in a snowstorm.

So, the one comment that I hear a lot is that too much renewables causes a reliability problem. And I fully understand that too little capacity or too little energy is a reliability issue.

Too much capacity and too much energy, I don’t think of it as a reliability problem. What I think of it is, is a management problem, or a procurement problem, or an operations pain that they’ve got to deal with, but it’s not a reliability problem.

And I think that’s important for us to remember as we move forward on this because that’s what we’re --
there are tools today to manage over-generation. The real problem is that nobody likes the answer. Curtailment or we’re going to pay Arizona Public Service to take our renewables if the price goes to zero or below. Nobody really likes that.

So, it brings me to kind of the observation, which we’ve filed in our IEPR comments, which is why is that the only solution?

This is exactly the type of power that California businesses want. In periods of over-generation, it is either zero or negative price, which means we’re paying other people to take it. Why aren’t we paying California businesses to take it, then? Why should we pay APS that? We should pay these guys to take it.

And it’s emissions free, essentially, in all cases. So, it’s the perfect stuff that we want. The problem is we don’t have the demand that can follow its generation and that’s what we have to focus on as we move forward.

We mentioned desalinization as a prime candidate for being able to utilize this resource. There are other uses, too. It’s dawned on me, recently, that the pumping load to pump excess water in wet years, back into the underground aquifers, would be a great use for
this. What’s missing is real-time pricing. What’s missing is an opportunity for California businesses, and particularly new businesses to take advantage of real-time prices, so when the price is zero, or is negative, they will do something. They will ramp up their operations to use this for a public benefit.

Desalinization to create water, pumping load to save water, just like storage facilities. And that’s missing today and we should work on that.

So, I wanted to then talk about some of the specifics that came up about curtailment, and it’s one of the issues, and it’s one of the solutions we have today, and why sometimes it works and sometimes it doesn’t.

The reality is today, except for some of the expiring QF contracts, I think most of the PPAs that are being negotiated today have curtailment provisions in them. Up to 200 hours, as I recall, the PUC standard. And people will negotiate around that. Some will negotiate more, some will negotiate less. It just drives the price.

One of the problems we’ve got is that the PPAs that everybody is executing from the intermittent side, a lot of them have PTCs that they get paid Federal money to continue to operate. So, there’s a nexus there
between what they’re getting paid for producing a kilowatt hour and what the payment is for curtailing. So, we’ve got to work that out on a contract basis. I think we have been doing that over the last couple years with the utilities.

COMMISSIONER MC ALLISTER: Hey, Steven, can I just jump in real quick?

MR. KELLY: Yeah.

COMMISSIONER MC ALLISTER: Can you comment on the -- like, how public is this information you’re talking about in the contracts and sort of like what do we know about that?

MR. KELLY: Well, typically, contracts are not public.

COMMISSIONER MC ALLISTER: How does the marketplace bring itself to understand what’s going on so that it can gauge its efforts going forward, I guess that’s all I’m saying?

MR. KELLY: We litigated for levels in the last two or three RPS plan proceedings. Originally, the utilities were asking for 100 percent curtailment rights. We argued that that is, from a commercial perspective, that’s infeasible. Because if people are facing the risk of 100 percent curtailment, they’ll never get the banks to finance a project.
So we worked that out over the course of a series of PUC proceedings. And I think the rule now is the pro forma standard contracts are about 200 hours. And then everybody negotiates around that. I don't ever see that detail.

MS. WISLAND: Also, just to get a sneak -- I mean, you can also look at the RPS procurement plans. There's a section in each of the RPS procurement plans that talks about how they deal with curtailment.

MR. CASEY: I think an important aspect of that is if you're curtailing in response to a negative price, which means you're getting paid not to generate, who collects that wholesale price?

Because if it's passed through back to the renewable owner, then I would argue they're indifferent. As long as that price is reflecting their loss opportunity of generating, they're indifferent to whether they operate or not.

And we've had examples, numeric examples where if the utility passed that price back to the generator and made them indifferent, the utility is still better off having the economic dispatch. So, it's a win/win for both, even if the utility passes back that wholesale price back to the developer.

So, you know, Steven's talking about 200 hours
in the context of the generator doesn’t get paid, if it
doesn’t produce.

MR. KELLY: Yeah, but some of them have to pay
for curtailment.

MR. CASEY: I know some of the utilities are
actually passing through those negative prices back to
the generator which makes it, you know, potentially
unlimited. Obviously, if you do too much, you’ll
undermine your RPS. But that’s an important aspect of
that discussion.

MR. KELLY: That’s correct.

COMMISSIONER MC ALLISTER: Yeah, thanks.

MR. KELLY: So, the other thing I wanted to real
quickly address is the role of natural gas, and the P
min issue, and so forth, that I heard come up.

First, one, you know, it’s hard to envision
today a world in which natural gas is not going to be
needed to help maintain the grid reliability. I mean,
we’re moving toward more storage. Storage is talked
about. The most we’re going to get by 2024, maybe, is
1,400 megawatts out of the PUC’s current storage
procurement process. E3 says that’s woefully inadequate
to meet the needs of what you’re going to need by 2030.

So, you’re going to need natural gas under all
the scenarios that I’m hearing about.
The question is how much, what is the P min at which they’re going to operate at and how do they -- can they sustain that?

And there’s a couple of things to be thinking about in regards to that. Most natural gas facilities, particularly ones that are existing and have come off contract, or even if they’re on contract, most of them are capacity contracts with tolling arrangements.

So, if they don’t get called by the ISO or the utilities, they don’t run. They operate at P mins. And that’s a situation where while they may be creating some GHG emissions over the course of the entire portfolio of GHG emissions for the State of California, it’s almost de minimis.

There is some interest in modifying the units that exist today to facilitate the lowering of their P mins. And one problem is that there are no market signals, really, to facilitate that to happen.

If you’re going to make what be a multi-million dollar investment to lower your P min on an existing natural gas facility, you’re going to want to know that you’ve got an opportunity to get a capacity payment for more than one year.

So, one of the things that we’ve been arguing for was a multi-year RA obligation, which is no longer
on the table today. That would have helped solve that problem because then natural gas generators would have had the incentive and the means by which they would retrofit their units to drop their P mins down to the technical feasible level.

In the absence of a revenue stream that they can see, that’s not likely to happen. I mean, it would be foolhardy to make that investment.

So, there’s a couple of things to fix the problem that Laura was talking about. Which is, yes, we can drop the P mins. But people need to see capacity signals that allow them the confidence that they’ll have the revenue stream to make the investment, to make the changes, even if they’re not going to operate on an hourly basis because that’s tolled. They may not care at that point.

But the ISO cares because they want them there for a reliability asset and that makes perfect sense to us.

So, I just wanted to end -- I’ll end that now, and I’ll pass it to other parties.

COMMISSIONER MC ALLISTER: Thanks, Steven.

MR. CASEY: Just a clarification or a response to your comment about the reliability and over-gen. And I think we largely agree with you, the over-generation
issue is a societal policy issue. We can get really
good at curtailing renewables. And we’re going to make
sure that we have the right capacity on to meet the ramp
and keep the lights on. We’re not going to compromise
that.

So, we’re really highlighting this issue as
something we have to get ahead of from an environmental
stand point, in terms of success in meeting our GHG
goals, and really driving the solutions that need to
happen because there is no silver bullet here.

I think we’re all for getting the additional
flexibility from the gas fleet, but that’s not a silver
bullet. We’ve got to get load shift, demand response,
storage. There’s a whole bunch of things that have to
happen to address this.

So, I just wanted to reinforce your comment
about things that don’t make sense to you.

(Laughter)

MR. BARKER: So moving along, I’d like to hear
from PG&E. And, you know, we’ve heard that the
utilities, so probably all the IOUs, they’ve already
probably contracted to get the 33 percent. But, so
those are pretty much all tied up.

But what is -- what are you guys thinking about
as far as contracting for the next tranche to get to the
50 percent and your perspective on the over-gen
situation.

MS. BLUM: So, I’m Christin Blum and I’m part of
PG&E’s Renewable Transactions Team.

And there have been a lot of questions today
about what we’re doing on our contracting strategy. So,
I can definitely share what PG&E’s doing and how we’re
thinking about it.

So, first I’ll address at how we’re looking at
additional flexibility within our PPAs, and then how we
look at that as part of our least cost/best fit
evaluation criteria through our solicitations.

And I do just want to make one quick note. PG&E
procures renewables through a number of different
programs. We have a renewable mechanism, feed-in tariff
programs. Really, what I’m focused on today is our
modifiable PPA that we use in our annual solicitation.
So, there can be a little bit of difference in terms.

So, PG&E’s long been in support of having
economic curtailment provisions within our PPAs. It’s
important to avoid over-generation, reliability
curtailments from the ISO, as well as to protect our
customers from higher electricity costs.

Even with the loss of the REC, sometimes it can
make sense not to run a renewable resource if there’s
going to be large negative prices. And we want to avoid those for our customers.

Additionally, we are now seeking full dispatchability rights within our RPS PPAs. With the implementation of FERC 764, as well as just the growing amount of renewables on the grid, it really makes sense to have those dispatchable rights within our PPAs.

One of the constructs under the RPS rules is that it makes more sense for the utilities to generally sign long-term contracts. And so, these provisions are really important, in particular, because these are going to be 10, 20 year deals, and we’re only anticipating seeing more need for flexibility going forward.

So, diving into the actual curtailment provisions within our PPA, we generally have two types of curtailment provisions. The first, focused on reliability, those are curtailments issues by the ISO or the PTO, and those are unlimited in the PTA. They’re out of the control of PG&E in its merchant capacity.

The second type which we’re talking about today are the economic curtailment provisions. And so those can be in the form of a self-schedule, or an economic bid that results in a dispatch for less than the full forecasting output of the facility during that interval.

And so, in our 2014 form, we have unlimited
rights for economic curtailment, as well as we have full dispatchability. In the solicitation we ask for that to be the primary offer and then to also have a secondary offer with some limitations on curtailment, so that we could look at the difference in the economics between those two.

One main difference that has come up a little bit here is that the curtailments form the ISO or from the PTO are unpaid under the PPA. However, curtailments that are done at our call, PG&E is buyer, are paid a negotiated rate under the PPA.

And we really feel that this framework is going to work well for us to have this unlimited flexibility with our resources, as well to pay generators. There’s benefits for customers, it’s fair for generators and it results in a more efficient ISO market.

So, diving into those different stakeholders and kind of the benefits a little bit more, in the short term for our customers it provides, as I mentioned, the ability to avoid negative prices which, you know, can be significant for them.

In the longer term, having fully dispatchable resources will, you know, hopefully lead to a more efficient CAISO market and overall lower costs for everyone going forward.
Additionally, we do have provisions in the contract if an economic curtailment order is not followed. There are protections for customers such that the generator has to bear the cost of the negative pricing, any penalties or charges associated to the failure to comply, and they’re not paid for that generation. So, that’s how we protect customers through our economic curtailment provisions.

For generators, the provision is really meant to make them indifferent. You know, we understand that generators need some sort of revenue certainty in order to finance their projects. And, generally, what we’re seeing is that our terms work for the financing community, that the projects can get financed with these terms because generators are getting paid.

Additionally, because generators aren’t paid during periods of over-generation and reliability curtailments, it’s really in their interest to provide as much economic curtailment flexibility as possible, because that’s when they get paid. And it works out well for them.

And then, firstly, in terms of the ISO as a stakeholder, you know, we’re seeing more and more over-generation and negative pricing events, even in these very low hydro years. And so, we really see it as a
benefit to the overall market of providing more flexible renewables in. You know, these aren’t resources that are going to be, hopefully, self-scheduled. They’re going to be dispatchable and so, hopefully, that will lead to just a more efficient market.

So, in the limited time I have, that’s a general overview of how we’re looking at economic curtailment within our PPA.

I will say that our 2014 RPS solicitation is still ongoing. It’s up on our website. So, if you want to take a look at our solicitation protocol, as well as our pro forma PPA, it’s all up there and people can take a look if you have an interest in that.

And then, quickly, I’ll just run through how we use curtailment, intermittency, and dispatchability as part of our least cost/best fit evaluation criteria.

So, those three attributes are factored into both our net market value and our portfolio-adjusted value, when we value renewables.

For those that are less familiar with how we do this, the net market value is really meant to be the net of an offer’s cost versus its market benefit. So, regardless of who were to buy the contract, that would become the economic value in the market.

And then we take that and do some adders and

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adjustments to get at what is the value of that offer to PG&E, given our existing portfolio and our preferences.

So, for example, we have a preference to have resources within our service territory, so that’s one adjustment we make to get to portfolio-adjusted value.

So within net market value, the way that we look at our energy forward curves, that incorporates all of the things we’ve talked about today in terms of the duck curve and what we think the penetration of renewables will be in the future. That’s already factored into our energy forward curves.

Additionally, when an offer provides more flexibility to us, ability to be dispatched, that should increase the energy value of that offer to us. Because looking out in the future, when we see potentially negative prices in our forward curves, we would be able to avoid those if an offer had curtailment or dispatchability rights. So, that should increase the value, the energy value of an offer to us.

And then, lastly, regardless of how much curtailment or dispatchability rights we have, intermittent resources do create real costs for the grid.

And so, as people have mentioned today, this is the first year we’re using a non-zero integration adder.
It’s an interim adder, but that’s really meant to reflect the short-term costs of operating existing resources to integrate intermittent resources, as well as the long-term costs we’re going to have to address going forward.

And I think through the LTPP we’ll have a more permanent solution for an integration adder soon.

And then within portfolio-adjusted value, after we have that sort of market look at it, we do add an additional curtailment adder that reflects the cost to our portfolio of having a more limited resource in it.

So that can include anything, such as energy imbalance costs, you know, extremely volatility we might see in a spot market for ancillary services, or any other costs that we’re going to bear by having a more limited resource in our portfolio.

So, that’s kind of a quick overview of how we look at these items within the way we do our least cost/best fit evaluation and in our PPA.

COMMISSIONER MC ALLISTER: Thanks very much.

I’m curious, do you have any renewables contracts that provide additional ancillary services? Have you built in, you know, any sort of regulation or any other services in any renewables contract, sort of -- yeah.

MS. BLUM: So, in our renewables contract we get
all attributes that a project can offer. So, all of its
capacity, energy and ancillary services.

I am not involved in how we operationalize that.

But to the extent that there’s an ability to use those
in the market, we would have those rights under our PPA.

COMMISSIONER MC ALLISTER: Okay, thanks.

MR. BARKER: Thanks, Christin.

So, we’ve heard a little bit already today about
the energy imbalance market and also the -- not the
need, but the benefits of a regional approach. And so,
we’ve invited PacifiCorp to be here to -- you guys have
about six months of data from the energy imbalance
market and so, you know, what have you guys seen? And
also, what do you see kind of in the future in
forecasting in terms of over-generation.

MS. KELLY: Well, thanks for inviting us here
today. My name’s Jennifer Kelly, and I work in our
Short-Term Energy Supply Management Department in
PacifiCorp.

Joe Horner was originally going to be here.
He’s our Director of Energy Supply Management, and he
had another obligation, so I’m filling in for him.

I’ll do my best to speak to his slides. He’s
got a slightly different bent on things. He flies at a
higher level than I do. I’m down in the trenches most
of the time. So, I’ll do my best. And, certainly,
everybody here is flying at a much higher level than me,
too. I’m not so policy-oriented, but I’ll take any
questions that people have and I’ll do my best to answer
them.

So, I’m a little bit out of my element here.

We’re Portland based and so we’re not as much -- we’re
not yet, anyway, we’re not so California-centric. We
may be soon.

So, I’ll just provide a little bit of background
about PacifiCorp, for those who don’t know.

So, with the first slide, this is our service
territory and it’s spread over -- we have two million
customers, spread over a six-state region. It’s divided
into two different control areas, what we call PacWest,
which is basically the Pacific Northwest and California,
and PacEast, which is all the rest of it.

PacEast is, for the most part, predominantly
thermal. We have about 65 percent coal and 15 percent
natural gas.

PacWest, for the most part is largely renewable,
hydro and wind for the most part.

And you’ll notice, I should point out, the very
puny grey line between PacEast and PacWest is a
transmission constraint for us. And I’ll talk more
about that, but that is in large part why many of our
curtailments happen in PacEast.

So, the next slide, please. The vast majority
of our wind generation resources are in our PacEast
control area. And so, we do find ourselves in
situations where we’re over-generating and we can’t move
those resources to PacWest and, indeed, into California
as easily as we would like. We are seeing very dynamic
transfers, as Keith Casey has already mentioned. And we
are seeing benefits there, without a doubt.

But for the most part, the curtailing of our
projects is coming from those transmission restrictions.

We also have curtailments due to reliability
issues, but those are less, I’d say, than our
transmission restrictions.

We have 2,000 megawatts of wind on our system,
approximately 1,000 megawatts is owned and another 1,000
megawatts is purchased.

We have a peak of 10,000 megawatts of load.

Just to give you an idea, put that into perspective of
what we’re dealing with relative to our wind capacity
and our peak load, so we’re looking at 2,000 megawatts
capacity, again, to reiterate, and 10,000 megawatts of
load.

We have very little solar online. We have about
500 megawatts of solar coming on line in the next year
and a half that’s purchased solar.

We have approximately 100 megawatts of behind-
the-meter residential solar at the moment. It’s
increasing steadily. But it rains a lot in Portland, so
we don’t have quite the issue that you all have here in
California, for better or worse.

And so on to the next slide. So, Joe wanted me
to talk about the integration challenges that we’re
seeing with the renewables, as well as some of the
things that we’re trying to do to deal with it.

The list that you’ll see here isn’t anything
new. We’ve talked a lot of these things already today.
I don’t have a punchline, unfortunately.

But I will say that I’m very happy to hear a lot
of the conversation that is happening here today
relative to focusing on economic solutions, and making
renewables economic.

Because what we are focused on is keeping our
rates low for our customers and doing that in an
economic way. And we believe that bringing more
renewables into the market needs to happen in an
economic way.

And I’ve heard Laura to speak on that several
times, as well as others. So, that’s something of
critical importance to us. And, indeed, one of the reasons why we joined the energy imbalance market.

So, Joe’s first point, to limited or no dispatchability comes from the fact that half of our wind is owned and half is PPAs. And we don’t dispatch our PPAs.

I loved some of the things that Christin said. I mean, I took copious notes and I’m going to go back and talk to some of our contracts people. There are a lot of good ideas there.

But we only have about 800 megawatts of dispatchable wind. That’s wind that’s on AGC, that we can dispatch according to ISO DOTS, to the discharge operating targets. So, that limited our dispatchability.

The other big factor in limiting the dispatchability is the production tax credit, and the disincentive we have to not curtail our projects because of the lost production tax credits.

And that’s a really big deal for us and one of the reasons why our operators are very focused on not curtailing our projects is just for that reason. And so, until we can figure some kind of fix for that, I think that issue is here to stay, at least for us.

And we’ve already talked about -- Steve was
talking about this, the changes in system reliability. Those come largely from sudden changes in drops, and ramp up and ramp down from wind. And from largely when our forecast is different than what we were originally intending.

And so, when we see these ramps that we weren’t intending, and they happen quickly, and they happen fast, and they’re big drops, big magnitudes, that’s when we start seeing reliability issues. Most of the time we can fix those things.

But again, they happen mostly when our forecast is off. And a forecast is a forecast, it’s never right. And so, we are forever vulnerable to those. And forever will be vulnerable to forecast issues. Those are not going to go away. We just need to figure out how to deal with those in a more effective way.

The over-generation point. For us, we have a very different scenario than you all have in California. Our duck curve is -- well, we don’t really have a duck curve. But for in the springtime, I think that’s one of the things that speaks to why the symbiosis between PacifiCorp and CAISO is working is because we do have different systems, and we have different demands on our system than you do. And so, I think it can and has worked very well.
We see over-generation situations, particularly in the spring, when we can’t back our thermals down anymore and we have a lot of hydro on our system coming from high water flows in the spring. Sometimes we see floods. Not so much this year, but we have seen them in the past and we have a lot of water in our system.

We also have environmental constraints that don’t allow us to back our hydro down as much as we might like, particularly in the spring for fish runs. So, we have some environmental constraints that are limiting our ability to back down hydro, as well.

So, that’s what we’re looking at there. And I mentioned, already, the over-generation relative to our wind in PacEast, and not being able to move that out of PacEast into PacWest, and then down into California.

And all of those things lead to higher costs for us. And in terms of carrying higher reserves to account for the variability of wind, and soon to be solar.

And I also alluded to the fact that this forecast error also causes us issues, and we see differences in the -- the differences between our day-ahead forecast, and we’ve set up our system to work according to how much wind we’re expecting on the system in the day-ahead. And when that doesn’t happen in real time, or an hour ahead, we find ourselves in a world of
hurt. So, if those differences are large, we feel more
pain than if our forecast is right.

And so, on to our next slide. That’s one of the
reasons why we are doing a lot, and much of what I spend
my time doing is focusing on improving our forecasts,
and working with our forecasting vendor to improve these
forecasts to the best of our ability, and getting real-
time data from each of our turbines, MET data,
generation data, as well as increasing ramp -- improving
ramp forecasts and things of that nature.

So, both on a day-head basis and a real-time
basis, if we can reduce that error, we’re going to
reduce our costs associated with the variability in the
wind.

One of the other things we try to do is to take
the forecasts that we get from our vendor and put them
into daily dispatch models. So for many years we had a
forecast for our wind, and it was largely for our real-
time operators’ situational awareness, so they could see
what was coming at them and try to dispatch in real-
time. Dispatch our other units in a way to accommodate
wind.

But we’re not doing that so much anymore.

Although they’re still using it for that, what we’re
trying to do is be proactive and take the day-ahead
forecasts and put them into system models that will
dispatch our units economically.

We’re also taking probability forecasts, the P25
and the P75, and we’re putting them into models that
will calculate for us what our day-ahead reserve plan is
going to be so that we can dispatch our units, not just
according to generation needs, but also according to
reserve needs. And that generally varies based on the
reliability of the -- if the P25 and the P50 are very
narrow, we feel very confident about that forecast and
we feel better about scheduling fewer reserves.

If that spread is larger, then we don’t feel so
confident in that forecast and, you know, we might want
to look at keeping more reserves on our system during
those times.

Dispatch flexibility. I think what Joe’s
getting at here is just the fact that Steven Kelly
referred to, is that we rely on natural gas to make up
for the variability in our VERs. We don’t see that
going away.

We are in a situation where we are going to
retire our coal as time goes on. And we’re looking at
replacing that, not just with renewables, but also with
natural gas. That’s the reality of the economics for us
at the moment and that’s what we’re looking at in the
future.

We also have a tiny bit of natural gas storage. We don’t have a lot. We have one Bcf, which is a small, but what I’m told is a meaningful amount to our real-time operators. So that’s helpful on an intra-day basis. There are some issues associated with using it, and penalties and costs, which would be really nice to discuss more fully or vet some of those issues, fully, that don’t make it as easy to use as we would like.

And I know that Laura mentioned something related to that earlier, about looking at the long-term contracts with natural gas, and how best to fit that in with what we’re looking at in our forward vision.

And Keith Casey has already spoken to the benefits of the energy imbalance market and the value of having that outlet to transfer energy back and forth as we need it. And it has been a powerful tool for us.

And one of the reasons why we’re looking at, you know, moving to become a full CAISO member.

And, you know, as I mentioned earlier, the broader balancing authority areas, as you have a larger footprint, a larger diversity of generators, you know, the law of numbers, the variation is going to -- the geographic diversity will modify those variations between load and generation. And so, I think the larger
footprint we have, the better off we’re going to be.

The value of regionalism, I don’t know who coined that
term, but I liked it and it seemed to fit.

So, that’s all I have.

COMMISSIONER MC ALLISTER: Thanks very much for
being here, that’s super helpful, really. And you did
great. Welcome to California. You did great.

And I think this is a precursor of things to
come. You know, I think the ISO could probably state
that even more emphatically. But I think it’s really
nice to have just forthright, explicit integration
beyond our borders and all the diversity that that
entails. And, you know, hopefully, these mechanisms
can -- we can learn at each step and make them better as
we go forward. So, thanks very much.

MR. BARKER: So, another potential --

COMMISSIONER MC ALLISTER: Yeah, Kevin, I think
Scott had something to say, as well.

MR. BARKER: Oh, I’m sorry.

MR. MURTISHAW: Well, I guess I have a question
that maybe some combination of the folks from the ISO
and PacifiCorp can answer.

But I’m just curious if there have been any
modeling, yet, about the implications of full
integration with PacifiCorp and possibly other balancing
authority areas in WEC, and the over-gen problem.

So, we have the chart showing several instances of thousands of megawatts of over-gen in the spring, but how much does that go down with PacifiCorp integrated with the Cal ISO? Or do we even have a ballpark idea?

MR. CASEY: Well, we certainly have some anecdotal data on some of the transfers we’ve seen out of the ISO to PAC, just these past six months when we’ve had over-generation negative pricing. I don’t have the specific numbers on me. You know, but we’re seeing the economics moving in the right direction when we’re in that situation.

The ISO is conducting some analysis looking at, in the context of a 50-percent renewable, what are the incremental benefits to a regional coordinated dispatch versus an ISO-only dispatch. We hope to have that analysis done by the end of this year, which will shed some light on what we see as -- in terms of mitigating the over-generation, if we’re able to operate a coordinated system WEC-wide versus just the ISO trying to manage itself, how does it help to do that.

So I’m not aware, unless Dennis knows, I don’t think we have any specific numbers or studies to date, but we should have some by year end.

MR. BARKER: Some other solution to the belly of
the duck, but then also the neck of the duck, is demand
response. And so, if you can kind of talk through a
little bit about how you guys are aggregating loads to
address the situation. But then, also how do you see
things as ramping up in the future and what is the
potential out there?:

MS. MANAL: Yeah, absolutely. And I know
that -- I want to be cognizant about time, so I’m going
to take out, kind of rearrange my comments. I’m going
to try to keep it to a few minutes, so we have some time
for discussion. But if you guys want more, just tell
me.

We’ve talked a lot today about the challenges of
our success. Frankly, California’s been tremendously
successful. And because of that, we have to deal with
this whole new set of challenges and it’s refreshing,
actually.

And AMS, Advanced Microgrid Solutions, the
company that I’m representing, we are a living example,
we are one of many companies that this confluence of the
RPS, the 50-percent goal, demand response, and the
storage mandate. So just keep in mind that there’s
probably a dozen others out there doing different
things, slightly similar, but there’s a lot happening in
the space.
People often use the analogy that advanced demand response is where solar was probably about ten years ago. I think it’s slightly over-used, but it’s probably accurate. There’s a lot of potential here and I think we’re just scratching the surface.

So Keith, I heard what you said and, Kevin, what you said about scale. And this market segment has a huge potential. And I’m not even sure I can quantify it because we’re, frankly, figuring it out as we go in many respects, both on the regulatory side and in the market.

So what I’d like to do is just give a brief example of the projects that we’re building for Southern California Edison, and then highlight some of the advantages of behind-the-meter.

I think behind-the-meter resources, whether they be traditional demand response or behind-the-meter storage, have often been overlooked because they’ve historically been so small. You’d look at a 20 Kw system, a 25 Kw system, so it’s never really been viewed as a viable way to deal with some of our grid challenges.

But I think what we’ve seen, with Edison’s recent procurement of our product and several others, is that we now have this ability because of advancements in battery storage technology, because of advancements in
software to actually scale behind-the-meter resources in a way that provide benefits to the host customer, but also provide real grid benefits.

So, we’re currently building, in Southern California, in two load-constrained areas, in Irvine and West Los Angeles, 50 megawatts of what are essentially virtual power plants.

We go to large users of load. We install a battery on their system. The host customer realizes savings on their energy bill so it’s attractive to them. They have no upfront costs and they instantly realize benefits. And that is unique in and of itself, but it’s not the part that’s really going to transform the grid.

What transforms the grid is taking those aggregates of buildings, say 20 buildings to reach 10 megawatts, putting a software overlay on them and giving them to the utility in a way that they are firm, and fully dispatchable, and also resource adequate.

So, our initial applications are really for periods of peak demands, dropping load, and shifting the load instead of building a peaker, or upgrading transmission distribution lines by placing a system directly at the point of congestion.

When the utility dispatches are 50 megawatts, we’re able to take 50 megawatts instantly off the grid
for a four-hour period.

Now, the flip side of this is directly relevant to what we’re talking about today. You can also take this, to use our Edison contracts as an example, this 50 megawatts, charge when the utility wants you to, for as long as they want you to, and then discharge. Effectively shifting the peak to whenever we need it.

And so, if I could leave you guys with just one thing, because I did promise to be brief, I think that behind the meter DR, you know, advanced demand response storage, has a tremendous ability to not only move us towards our goals, but solve a lot of these challenges that we’re talking about today.

You know, they can scale like we never thought possible. They are exactly at the point of congestion. In many cases they don’t even require interconnection, you know, very simple interconnection. They are firm and they dispatchable. They defer, in some cases eliminate the need for transmission and distribution upgrades. They have a relatively simple path to market and they’re being procured right now.

So, I’ll end with that and I’m happy to answer any questions.

COMMISSIONER MC ALLISTER: Go ahead, Kevin.

Thanks for being here, Manal.
MR. BARKER: But I think we were planning -- we were planning on probably opening it up to other questions. But since we are way behind in time, you know, I’d like to just thank all the panelists for their comments and presentations. And I guess hand it back over to Heather.

MS. RAITT: And so, if the Commissioners are ready to move on to the next panel and thank our panelists. And if you could go ahead and take your seats and then we’ll have the next panel come up to the tables, please.

The next panel’s on the Update from the Publicly Owned Utilities on the Progress Toward Renewable Goals.

So, for folks on WebEx, we’ll just take a minute to reconfigure the room.

Okay, so our first speaker on this panel is John Dennis, from the Los Angeles Department of Water and Power.

MR. DENNIS: This is just to provide you with an update on our renewable portfolio projects and where we’re at.

These two slides that we have today give you an idea, a glimpse of our compliance period one, two and three, just showing our trajectory as we go from 20, up to 33 percent by 2020.
And what’s kind of interesting, as we see our compliance period one, we see a variety of projects that are there, about 900 megawatts of a combination of both small hydro, as well as wind projects that have made up the additions in compliance period one.

In compliance period two, you see largely filled in our plans currently in service, underway, or under construction right now, racing to meet the investment tax credit’s 745 megawatts.

And then, also, on our projection for compliance period three, we have a variety of solar, but also some small hydro and layering in three geothermal plant projects for 514 megawatts.

For SB1, or our net energy meter program, our solar incentive program, we have right now, currently, 15,500 customers signed up under that program. We’ve done about 2,500 of those customers in the last six months. A total of 129 megawatts are installed to date, and $257 million of incentives have been paid out towards that program.

And then you can see the goals that we’ve set there for the solar incentive program, 97 megawatts for compliance period one, 125 megawatts for period two, and then a residual of 56 megawatts for period three, with a total of 288 megawatts, a million dollars of incentives.
to be offered, as well as an overall goal of 310 megawatts by 2020.

The next slide. These are just our overall targets. As we’re doing this particular work, we’re also looking at a 15 percent energy efficiency goal. We’re seeing some sizeable reductions in CO2 emissions. Those two larger drops in the 2015, as well as the 2025 period, is the reduction of our coal and getting off our coal production.

And then also, as we see some other goals that we’ve just talked about, electrification, 2030, of 580,000 electric vehicles or the equivalent of those in Los Angeles, in our service territory at that time. And that’s going to be, as well, equivalence during that time.

So, we have a variety of challenges ahead of us. On September 16th, of 2014, we hit our all-time peak of 6,400 megawatts. Total, as far as our demand, we see about 1,400 megawatts of renewables that are currently in service to day. We’ve got 1,256 megawatts that are under construction as we speak and we’ve got 2,721 megawatts that are planned of renewables.

In addition to this, we have about 500 megawatts of demand response target ed by 2024, and 154 megawatts of energy storage in a variety of forms that is planned.
by also that timeframe.

And then, to just add a little bit more to that challenge, we’re also in the transition of our existing coastal plants to transition off ocean water for cooling our plants by 2029.

So, that’s just a quick snapshot. I believe that’s what we’re -- just wanted to share with you, with regards to our current status on the energy-metered program. We have sizeable challenges ahead of us.

As other notes, as we’ve looked at the future for 50 percent RPS, right now, when we hit 33 percent we see that our targets right now, as far as our current production, we’d curtail about .2 percent of that renewable energy when we hit 33 percent.

When we go to 40 percent load of renewable, we’d curtail about 1.5 percent.

But when we jump up to the 50 percent, we’re right there at that target, as an earlier chart had shown, one of the other presenters, we’re curtailing about 4.6 percent.

So, we do see some challenges as we work towards a 50 percent. We’re trying to see, again, not only an RPS goal, but also the possibilities of equivalent credits as we look towards not just the RPS goals, but also greenhouse reductions. Certainly, a great
obligation to ensure reliability to our customers.

But perhaps there’s opportunities as we look at this REACH for equivalent credits, as it would approach toward electrification, transportation, storage and energy efficiency opportunities. Thank you.

MS. RAITT: Okay, then our next speaker, I’ll just go in the order of the agenda, is Tim Tutt, from SMUD.

MR. TUTT: Thanks for the opportunity to be on the panel. I’m just going to run through a few slides that provide you information about where SMUD is in its RPS and SB1 compliance.

The next slide. This slide just shows sort of a historical background. It shows the growth in renewable procurement as a percentage of retail sales and the five largest utilities in California. And it just points out that SMUD has grown consistently over the historical period, from a distant third to first in renewable procurement. And we continue to grow and move forward in the future.

The next slide. This gives you a picture of our renewable portfolio in 2014. As you can see, there’s a mixture of resources there. We truly believe that procuring renewables should be a portfolio of resources, not depending on just one source.
I don’t know, hearing talk about the RPS calculator and changes in that today, I don’t know how you can structure -- I guess I should say, I’m sure you can structure a calculator with the right assumptions to get any mix of resources you want out of a procurement, if you fooled around with the assumptions enough.

We don’t do that. We just simply say we need a mixture of resources and our least cost/best fit is trying to find the cheapest resources that also give us that mixture.

COMMISSIONER MC ALLISTER: Tim, how do you -- do you have highly defined attributes that you’re looking for and some way for the bidders to demonstrate that they possess them?

MR. TUTT: No. It’s simply a case of agreeing amongst -- internally, amongst the company personnel, that it’s good to have some geothermal in our mix. It’s good to have some biomass in our mix so that we have -- and we’re not wholly dependent on one source of renewables.

COMMISSIONER MC ALLISTER: Okay, thanks.

MR. TUTT: The next slide. This shows the RPS status of SMUD for the first compliance period. As you can see, our obligation was about, a little over 6,000 gigawatt hours of renewables to meet the compliance
period requirement. We actually procured over 7,000 gigawatt hours of renewables during the period.

However, we only retired about just enough to make compliance, just 20 percent. So, we have an additional three percent that we have not retired. It doesn’t show up in some of the CEC data that we are above the 20 percent level in terms of actual procurement.

It’s an issue that we’d like to work with to change because we do want it to be shown that we are, you know, procuring as much renewable resources as we actually are.

We do preserve those unretired RECs just for the flexibility of potentially using them for another purpose, until we need them for potential retirement for the RPS.

And also, I’d like to point out we have about a thousand gigawatt hours and a little bit more of historic carryover, which we’ve applied for and haven’t yet received the final number determination of how much of that we’ll be eligible for.

The next slide. This, I just threw in to show you the impact of the drought, because the drought is a big topic these days. Our expected small hydro procurement, prior to 2014, when we say, you know, going
forward, a standard water year was about 250 gigawatt hours of small hydro. Our actual small hydro procurement in 2014 was about 80. So, that’s a 75 percent or so reduction in small hydro just because of the drought.

I think what that says to me is it’s important to recognize that variability in procurement. That’s going to affect wind and solar resources to some extent, as well. And make sure that you have that in your procurement plans in terms of making sure you’re compliant, and not just counting on a normal water year, for example. And also, it reinforces the importance of having a portfolio of resources so you’re not fully dependent on something that’s going to have that much variability.

The next slide. For compliance periods two and three, this again shows our projected retail sales and RPS requirement for those periods. And our committed procurement, that’s facilities that we already have under contract and are expecting to provide generation in those periods, although that can vary as I mentioned, shows that we are fully compliant and above compliance for compliance period two, when we finally get to the point of submitting our compliance period report.

And very close to compliance for compliance...
period three. And this is without counting any of the
carryover that we might have from the first compliance
period.

So, we’re feeling like we will be compliant with
that carryover, even if we don’t do some of the recent
activity that’s shown on the second -- on the right half
of this slide.

And first, we do have a large biomass, small
hydro contract that ended in 2014, so we’ve lost that
significant resource.

But we’ve extended contracts with the local
landfill and wind projects, and are grandfathered
biomethane contracts that began producing and coming
into our combined cycle power plant.

We have some new local dairy digesters and solar
that have begun producing. Most of that is counted in
that committed procurement category that you see there.

But we also are considering several new options
for wind, solar, geothermal and biogas. Again, trying
to make sure that not only are we compliant through
2020, but getting ready for the next tranche of
renewable requirements. Whether it’s an RPS, it’s just
a 50-percent target, it’s related to low carbon and
trying to -- continuing to decrease our carbon content
in our supply to be consistent with our board goals.
The next slide. A slide showing our SB1 status.

You can see here that we’ve got nearly 70 megawatts of SB1 projects installed at this point.

We see the SB1 requirement for us as a financial commitment, not a megawatt commitment. So in the end, we expect that we’ll be getting up somewhere close to 900, 100 megawatts before we use up the financial commitment that we have made under SB1.

You can see here, as well, that early on in the 2009 through 2011 years, we had significant growth in our commercial, our nonresidential SB1. More recently, that’s slowed down and we have continued strong growth in our residential sector.

And even in the case where both -- in both sectors our incentives are down to the last couple of steps in SB1, so they’re down to fairly low levels in both residential and commercial. And that’s important because if residential keeps growing, as we see it here, we haven’t been able to include the residential systems in our RPS procurement so far. The transaction costs have proven prohibitive. So, we’ll be losing that procurement as we move forward in RPS. Unless we can figure out a way to reduce those transaction costs.

The next slide.

CHAIR WEISENMILLER: Tim, one question. In
terms of the net energy metering caps, where are you relative to those?

MR. TUTT: We’re well below the net energy metering cap. I don’t have the exact number, Chairman Weisenmiller, but I think it’s probably -- we’re probably around one and a half percent, and our cap is 5 percent of our peak load.

CHAIR WEISENMILLER: And what about LADWP, what percentage are you, of your net energy metering cap?

MR. DENNIS: I think it’s about .4 percent, or something --

MR. TUTT: So then this is my final slide. I just wanted to point out that we’re still doing a lot of research to try to resolve some of the issues that have come up today for our service territory. Looking at new resources, the grid impacts that we’re all seeing, the mitigation alternatives, and system effects and policies.

You’ve seen some of that research in previous presentations and discussions amongst us and your research staff.

A couple of new ones. We’re looking at a 484 kilowatt solar canal project, covering the South Folsom canal to reduce -- to offset the pumping load there, and reduce evaporation, and help with the drought.
And we’re also doing a pilot biomass gasification project, or looking at developing that if the financial circumstances work out. And that’s sort of entirely new type of resource. It’s not landfill gas or digester gas, it’s gasification of biomass.

And then, we’ve done a lot of work over the last few years on developing better forecasting models and examining the effect of geographic variation.

I think we’re going to be rolling out, this year, some of those forecasting efforts on a distributed generation basis, so that our customers will be able to have a better idea from the potential production from a system they might install in their house, in a user-friendly manner.

And examining communications between PV inverters in the system to allow monitoring and possibly control. This is one of the questions we’ve had in the past about the fact that we have PV systems with an inverter meter, which is reasonably accurate, plus or minus five percent. And then in series with that, we’re installing a second meter, revenue quality. That’s a State requirement. And then it goes up the line like that.

At some point, with smart meters, we anticipate the potential at least for taking out that series second
meter, so that we can understand the generation from the system simply from the communication between the inverter and our smart meters.

We’re doing research, a variety of research on storage, house, neighborhood and system levels. Obviously, in electric vehicles, managed charging.

I’ve participating in some of those research projects with my own electric vehicles at SMUD. And we’re doing some demand response pilots and goals. I think our goal for demand response this summer is 10 megawatts of demand response and it’s supposed to increase from there going forward.

And that’s all I have, thank you.

CHAIR WEISENMILLER: Okay, Tim, one question.

If I recall correctly, SMUD’s participating in the “Smarter Than” effort, is that right?

MR. TUTT: The “More Than Smart Grid”?

CHAIR WEISENMILLER: Yeah.

MR. TUTT: We hosted a workshop. And I believe that we have staff monitoring and part of that, the committee’s looking at that, yes.

CHAIR WEISENMILLER: Yeah.

MR. TUTT: I’m not very familiar with how that work is going right now, but we are participating.

CHAIR WEISENMILLER: Yeah, I mean, that’s my
recollection of the meetings that I’ve been at. I believe there’s been a gentleman from your company there.

MS. RAITT: Okay. So, our next speaker is Tanya De Rivi, from the Southern California Public Power Authority.

MS. DE RIVI: Thank you very much, everyone. I’m the Director of Government Affairs for SCPPA, as we like to call ourselves, and will be covering, briefly, three main issues that I was asked to cover before I left for Barcelona and returned very late last night.

One on the RPS compliance filings, RPS beyond 33 percent, and the five percent NEM cap status of our SCPPA members.

SCPPA members for the RPS are working very hard towards meeting California’s 33 percent RPS target, under an overarching need to address climate change initiatives, and should be on track to meet interim RPS targets through 2020.

Some of our members are even ahead of pace. Pasadena Water and Power, for example, has met or exceeded both the State and its own 40 percent goal by 2020 RPS target, with renewables accounting for approximately 29 percent of their retail sales last year.
Anaheim Public Utilities had delivered approximately 33 percent of its retail load with renewables last year.

We also do have a member that serves a small, disadvantaged community in Southern California, who did not reach the first compliance period RPS target, given locally-adopted cost implementation measures under the RPS and having been fully resources already. Though, they anticipate being caught up with RPS targets in the second compliance period.

SCPPA would also like to take this opportunity to urge the Energy Commission to complete the verifications of the first compliance period filings as soon as possible. We’re nearly halfway through the second compliance period, without knowing whether the Energy Commission will deem our individual members in compliance with the RPS, leaving them with no opportunity to go back to make corrections, and little time to correct anything going forward.

RPS beyond 33 percent, up to 50 percent, SCPPA generally supports the clean energy standard framework envisioned by the big five, publicly- and investor-owned utilities, including one of our members, my alma mater, LADWP, which would allow for additional flexibility to meet emission reduction targets by employing various
programs and technologies that are best suited for each particular utility and its customers in the most cost-effective means possible.

Any effort to expand the RPS to 50 percent will require added flexibility in meeting such an aggressive target. Absent the clean energy standard framework, many utilities may be forced to over-procure, even if they are already fully resourced.

The State must understand issues with straining assets and being unable to recover costs in the market. Our customers, ultimately, are the ones having to pay for this. And our small- and medium-sized utilities, in particular, do not have the ability to spread added costs across millions of customers.

When Governor Brown announced the 350’s goal to be achieved by 2030, SCPPA immediately initiated an effort to, across our membership, develop a list of recommendations and comments to help policymakers in developing the associated policies and programs.

This list of recommendations, which I brought copies of, was developed working through several of our working groups, including our renewables working group, resource planning, public benefits, regulatory and energy storage across 187 of our SCPPA member utility staffers, then presented to our SCPPA board in February,
before being shared with State policymakers, including the Energy Commission.

For increasing electricity derived from renewables, up to 50 percent by 2030, SCPPA recommended four main goals. One is ensuring electric grid reliability and stability, including performing a comprehensive power resource gap analysis of what California would need to achieve 50 percent renewables, in coordination with regional reliability entities, and providing a safety valve mechanism to address instability or challenges to the reliable operation of the electric grid in the west.

Second was ensuring that costs to California ratepayers are affordable and remain so.

Third is allowing maximum electric utility industry flexibility to meet the goal, including the ability to ensure a diverse portfolio mix, and maximizing credit for distributed generation systems and geothermal, for example, broadening the definition of what is a renewable resource to encourage development of more projects, and harmonizing State policies with Federal goals, wherever possible, such as with biomethane. And incentivizing regional cooperation as is envisioned under the clean power plan by the Environmental Protection Agency.
And fourth, eliminating unnecessary barriers and
minimizing administrative overhead, particularly in
terms of streamlining certification and timeliness of
the verification process, as well as improving overall
data reporting obligation, which has doubled in recent
years alone, for our limited staff resources.

And I would be remiss if I did not again
highlight SCPPA’s very strong belief that all renewable
distributed generation resources should be counted as
bucket one, particularly given the State’s march towards
50 percent renewables by 2030.

Our members continue to believe that the current
bucket three RPS categorization undervalues and deters
further development of such resources under a declining
portfolio balance requirement cap.

California renewable resources should be valued
more highly than out-of-state renewable resources, under
California’s own RPS. Said differently, we now get
higher credit for out-of-state wind than we do for solar
in our own backyard. This isn’t right. A panel in the
desert should have the same value as a panel here at
home, on one of our own rooftops.

Particularly given how much sun we have in
Southern California, bucket one status for distributed
generation resources should be a statewide policy for
all utilities, including the IOUs.

Accessing a broader renewables market is the best and most cost-effective way for California utilities to meet such an ambitious goal.

I’m personally hopeful that, especially after a presumed 50 percent RPS program comes into effect, that the solar industry as a whole recognizes that there will be more than enough room for both small- and large-scale solar projects to succeed together for the benefit of California ratepayers.

And finally, on NEM excluding LADWP. I understand that we were requested to provide an update on where our members are in terms of meeting our net energy metering caps.

So, for the purposes of brevity, I calculated on average that SCPPA members are now at approximately 40 percent of the way towards their NEM caps. This, again, excludes LADWP.

That range covers a low for one utility around 10 percent and a high of around 60 percent, so there is still a long ways to go.

Again, most of the home ground solar is not even counted towards meeting the 33 percent by 2020 RPS target. And I want to note here that utilities generally use a system peak demand, with NEM programs...
catered to meet customers’ needs, as governed by their local government boards because this approach has worked well for their communities.

Not all municipal utilities have smart meter capabilities to even be able to capture individual customer peak demand for every single customer in any calendar year, necessary to be able to perform the aggregate customer peak demand calculation, which is now mandated upon the IOUs, following a lengthy CPUC proceeding.

And many of our members also do not have the staffing capabilities to perform such a complex computation, particularly those smaller systems that serve disadvantaged communities.

Next.

MS. RAITT: Okay, next is Scott Tomashefsky, from the Northern California --

CHAIR WEISENMILLER: I was just going to ask her to please docket the SCPPA comments.

MS. RAITT: Okay, Scott Tomashefsky.

COMMISSIONER MC ALLISTER: Scott and Tony, I actually have to leave. I just want to make sure everybody knows it’s not out of any disrespect. I have a hard conflict I can’t avoid. And I will listen to the recording later.
MR. TOMASHEFSKY: Thank you, appreciate it.

Thanks a lot, guys. Thanks for sticking it out with us for most of the day, as well.

COMMISSIONER MC ALLISTER: And thanks for everybody on this panel, as well, I really appreciate your being here.

MR. TOMASHEFSKY: And I was speaking to Angie at the break, and I thought rather than talk during the panel when you had seven people, I thought I’d give you like a 30-second snapshot here, on this end, in terms of flexibility, and the programs, and where things are going.

I think the main thing to keep in mind, at least at this juncture, is there are a lot of things that were discussed when we developed the RPS program through the legislative process, and then through the regulatory development here with the enforcement regulations.

And the notice on alternate compliance and flexible compliance was an important feature. And as I’ll talk about it for a minute or two once I get into my prepared remarks, that I won’t docket because it’s on handwritten notes, is flexibility really makes it possible for smaller entities to comply.

And without that, it would be virtually impossible in a lot of different ways. It becomes a
question of trying to figure out what your best
priorities are, and then dealing with aggregation and
the like.

But I’ll talk about that. And if you think
about the fact that you’ve got right now, not only are
we talking about the RPS, changing it to a 50 percent
objective, you’re really dealing with a climate program
that is also pending a pretty signification decision
from the Federal government on the clean power plant and
how that works with interrelationships. And that’s
really CALISO issues discussed all during the course of
the day.

There are an awful lot of loose ends that rely
us to be adaptable to try and figure out how that moves
forward.

So, as much as we want adaptation for climate
programs, I think we need adaptation when we look at the
renewable program when we go forward here.

So, I liked a lot of the tone of the comments
today, as far as not getting ahead of the fact that the
program is generally working pretty well. And,
actually, there’s not a lot of results out here to test
that official. Although, we have a pretty good idea of
where we’re going. So, those are important
considerations.
So from our stand point, if you look at the issues of flexibility, just a perfect example, the notion that one of our members, Truckee Donner, has the flexibility to avoid the bucket requirements because of its location to the ISO, vis-à-vis everything else. They have basically taken a percentage that had the State of California coming to Truckee to tell them how problematic it is that they’re dealing with coal contracts in 2006, to having a local decision to basically not go forward with that contract.

Today, in 2014, they will be close to 50 percent in terms of renewable development. That is only because of flexibility that’s provided to the program.

We have a lot of different examples of that, as well. It just can’t happen without that type of flexibility.

The Port of Oakland, another example. Basically, at zero percent, with the exception of a solar array along the runway as late as 2011. Their power content label for 2013 had them coming in at 46 percent.

So, when you start to look at the things that have been put in play and the decisions that are being made by each of these entities, without having it really being prescribed, you’re coming up with fairly
significant results and fundamental changes in terms of what the State is trying to accomplish on renewables going forward.

So, when we start to look at things like a 50 percent renewable, I think the answer is if you’re looking for someone to say no problem at all, I think it’s still challenging in terms of how we get there.

I think the framework is put in place for us to look at it from a positive way and move forward.

And Scott, just to your comments, when you were saying it was really easy to get to 33 percent, I would suggest it was attainable to get to it. Easy, not at all. In terms of the things that we had to fundamentally recalibrate to get to that point was -- I don’t want to downplay the importance of the things we’ve done. And that goes across both publics and investor-owned utilities. That is a power sector success story when you start looking at the things we’ve done. It’s not a bad story.

Looking at some of our members in terms of specifics, we have Palo Alto that is ready to be at a 50 percent renewable by 2017. They have engaged in a number of solar PPAs, that they’re getting them to that particular place. Not to mention the fact that they have a carbon neutral plan that’s been in play, by
council decision, since 2013.

You’ve got Santa Clara basically sitting at 33 this year, and they’ll be above 40 percent next year.

You have Alameda and Ukiah who have been regularly over 50 percent. And, in fact, the only reason they’re below 50 percent is in terms of flexibility. Taking some of the RECs, selling it to other members, so that they can actually made additional renewable purchases.

So even though the numbers are adjusting, the direction and objectives of the State in terms of moving forward with procuring renewables is going in the right direction. That’s exactly what the State wants. And the reason you can do that is because you’ve got the flexibility to be in there.

For our smallest members, we actually have an RFP on the street right now to look at 40 megawatts of solar PPAs starting in 2017. So, if anyone’s interested in responding to that, from NCPA perspective, you can go to our website. And CPA.com, you’ll actually find that RFP, if you’re interested. We’re certainly interested in hearing from you.

Those are the ways that we help our smaller members that may not have the megawatt bandwidth to actually make those investments by themselves. So those
are, again, good stories.

Challenges on how we’re dealing with those things, we have -- as you know, our two percent snowpack doesn’t get you a lot of hydro generation. And regardless of whether it’s large or small hydro, it’s still an important component of our carbon objectives, which is also front and center with respect to the things we’re doing here.

We also have, with our smallest members being tied to Federal power, hydro power projects, to the Central Valley Project, you do not have the ability to sell off retail sales, so you have to take those resources.

So, when you start to look at flexibility on why you can and cannot make certain targets, those are certain, important considerations when the water does flow. When the water doesn’t flow, we have other situations to deal with.

But if you’ve got a flush year, like we had I think in 2011, you can look at some of those renewable members and they’re close to 100 percent when you include full Federal hydroelectric power.

And certainly, from a cost-containment perspective, it’s not really a practical thing to get rid of that for purpose of meeting a statistical number.
Flexibility makes that work.

Turning over to net metering, I think, Chairman, you had the question in terms of percentages on net metering. Our aggregate number is about 2.6 percent. That ranges in the membership from about .6 to 6.2. The only one of our members that’s over the 5 percent threshold is Lompoc.

An interesting sidebar to that, though, is that peak load is based on a system peak for the year. Lompoc’s peaks in December.

So, if you look at the fact that their peak load in the summertime is significantly lower, it starts to change the understanding of what that five percent number means.

So, when we start to debate the issue of whether it should be coincident or non-coincident peak, there are other issues to think about. So, it’s not that straight forward in terms --

COMMISSIONER HOCHSCHILD: So, but Scott, just on that point. I mean, we hear a lot from the Legislature about ensuring there’s parity between the POUs and the IOUs. And the Governor, as you know, signed AB327 into law, which enshrines that aggregate customer peak demand, how that’s defined.

And what I’m hearing, I guess, from the woman
from SCPPA, part of the issue is just the ability to
capture the information necessary to make the
calculation.

So from your perspective, is that really the
barrier? I mean, if that were via smart meters or some
other support to allow the calculation to be made, I
mean what other rationale is there for a different
methodology?

Because, I mean this is kind of an issue of
care, obviously, to ensure there’s parity.

MR. TOMASHEFSKY: Yeah, you make a point in
terms of the technical aspects of what you can calculate
and what you can’t. If you had the analog data
available, it’s not going to give you that same type of
granularity that you might want to do.

But there is a secondary aspect to that. When
you start to look at the service territories that we
have, you know, they’re very focused. They’re one
climate zone, it’s one specific area, and they have
certain features that get clouded when you’re dealing
with a much larger service territory. Which is not a
knock to the service territory that’s larger. But there
are different climate zones and different dynamics
which, when aggregated up, provides you an opportunity
to do certain things.
So, when you start to look at just how you’re operating the system and looking at the impacts on your system, it’s a little bit different when you’re focusing on a very small area. You just don’t have that divergence that can sort of be softened, if you will, and with a larger service territory. So, that’s just one element of it.

So, it’s much easier for us to look at it from here it is, here’s our climate zone, we peak in the winter. It just doesn’t make sense for us. Truckee Donner peaks in the winter, not an issue, they don’t even have a summer peak.

So, it’s that type of thing, it’s just different. So, just have to give that some consideration. But you’re right, that is part one. You just can’t --

CHAIR WEISENMILLER: Yeah, I think the issue is not just where you stand on the NEM cap, but what do we need to do to actually move -- sort of moving further along the scale in terms of getting actual installations?

MR. TOMASHEFSKY: Well, we are seeing a lot of installations. But what you do see, though, just when you generally look at it, is the focus is not so much on the residential, per se, because the rate structure is
somewhat different. We’re not dealing with the tier 4, tier 1 issues quite the same way. And there’s differences, but not quite the same way.

We’re you’re finding activity occurring in a lot of our member locations is you’ve got the Big Box stores, with the large-scale installations, where you have one or two. And then you start to raise the question about whether that blows the CAP away.

And so when you have -- as you’re coming to the end of the program here, and looking at that five percent number, that’s now getting tested a little bit.

If you look at the number in aggregate, when I’m saying we’re 2.6 percent, I think PG&E’s number is in the area of -- it’s less than that, in terms of 2.4. But the scale that they’re dealing with is much greater.

So, when you go to a community and you say I want to go ahead and put this on a Wal-Mart, or an officer building, or whatever it is, you put one or two projects in there and you’ll add a significant amount of load to meeting that threshold.

So, it starts to raise that question. You start to get into the dynamics of how that impacts the system. And maybe it requires the rethinking in terms of what you’re trying to define with five percent. You know, that was kind of an arbitrary number to say once you get
to a certain point, then you’re going to have some
issues with your system.

And so, arbitrarily we said this is where we
should be. It started at .5 percent, went to 2 and a
half percent, went to 5, and there’s been discussions
about where that’s going.

CHAIR WEISENMILLER: Yeah, I think that part of
what people were trying to do is really jump start the
installations of solar.

MR. TOMASHEFKY: Yeah. Yeah, I would argue that
we’re not really behind in that regard. And the fact
that a lot of the commercial/industrial installations
are actually occurring in some of these areas is not
something we should shy away from. But it’s certainly
affecting the numbers.

One other thing I wanted to just share, in terms
of SB1, within our membership, our numbers, if I
calculated it correctly, we’re at about $45 million of
investments on that. And as Tim had mentioned, we look
at it more from a dollar investment perspective, rather
than a megawatt, just in terms of how the rebates have
been offered and how things have scaled down.

And I know we’ve had these conversations in the
past, but there’s certainly a lot of movement in that
direction and I think you’ll find even further positive
stories that come out of the 2014 --

COMMISIONER HOCHSCHILD: But just to recap, I mean and correct me if I have these numbers wrong, but this is from our last meeting. I mean, the IOUs are done with the CSI program. The POUs, as I recall, are about two-thirds of the way through the money and about a third of the way through the megawatts. Is that roughly ballpark? But that was my take home from the last time we --

MR. TOMASHEFSKY: Yeah, in aggregate.

COMMISIONER HOCHSCHILD: Yeah, for SB1.

MR. TOMASHEFSKY: Yeah, I don’t have the number on the megawatts, but we’re about 60 percent on the dollars.

COMMISIONER HOCHSCHILD: On the dollars.

MR. TOMASHEFSKY: Yeah. But you should see a significant bump up in 2014, just very similar with what’s been going on with everything else.

COMMISIONER HOCHSCHILD: Okay.

MR. TOMASHEFSKY: And you’ll get that report July 1st or so, within a week or so.

So, I think the story, itself, is a good one. I always cringe -- you know, in the ten years since I’ve left this building, I know one of the things I continue to hear is public power is not doing enough. And that
always makes me cringe. I mean, there’s always more you
can do. But in terms of commitment, I think you’ve
heard it from each of us here, whether it’s at the L.A.
and SMUD level, which goes at a different level than
most of us, there’s still a lot of activity. And we
find our role, and I imagine Tanya would say the same
with respect to SCPPA, is that there’s a lot of
aggregation and information sharing that we deal with,
with our smaller members, to make sure that everyone’s
going in the same direction. Even if the line may not
be quite as straight as you might like, it’s certainly
in the right direction.

So with that, I’ll end my comments. Thank you.

MS. RAITT: Okay, the next is Tony Andreoni,
from the California Municipal Utilities Association.

MR. ANDREONI: Thank you. Thank you for
inviting me here today. And I have to say, going last,
on the last panel has its advantages. Much of what has
already been said by my colleagues here on the panel
holds true for many of our, or most of our CMUA members.

In general, overall, regarding the RPS program,
you all probably can recall back to many of our members,
our individual utilities actually had fairly aggressive
RPS percentages on the books ahead of time, before SBX1-
2. So, many of our folks have been very aggressive as
far as procuring and making sure that they get to the 33 percent by 2020.

As you’ve heard, some have already been very successful in being able to do that.

In aggregate, for the first compliance period, from what we’ve looked at, we see all of our members, again in aggregate, meeting the 20 percent and beyond, actually exceeding the 20 percent.

And when you consider some of the historic carryovers, I know we still have to go through the verification process. We’re much closer to getting to the second phase of this, which is reaching the 25 percent.

So, our folks are going to continue to move along the path. They’re going to look at all potential areas to procure, whether they own it or whether they’re looking at other agreements, they’re working very hard in being able to do that.

As you heard earlier, they’re looking to be able to possibly count what’s behind the meter. There’s going to be a huge amount of solar, and with the 50-50-50 that’s being laid out, the amount of solar on the system is just going to increase by that amount.

And so, we’re trying to figure out, we’re going to be working through the RPS rule process, which
comments are due in, I think, the next 30 minutes. We will have our comments in to Angie on where we are and we’ll continue to work with CEC moving forward.

We do think it’s extremely important to continue this relationship and working on trying to find ways of meeting the goals, staying flexible, recognizing there’s just not a one-size-fits-all for all of our utilities.

The medium and smaller utilities that you’re not necessarily hearing from today, all do have challenges. And even though in aggregate we met the requirement, there are still some challenges that utilities have faced to make sure they can meet the percentages.

They’re definitely on track, though, to make sure they’re meeting the 33 percent by the 2020 time frame.

On the net energy metering, we were asked to just provide just an update. I think what you heard from SCPPA and NCPA covers many of our members.

With one caveat, we do have one of our members, at the Turlock Irrigation District, which you’ve all heard from in the past, they exceeded the five percent NEM cap. But they did not stop. They’re continuing to fund and they’ve been able to continue with their program and try to evenly distribute what’s available.

Up to the point of meeting the five percent, you know,
they’ve well exceeded the $20 million in what they’ve
provided as far as incentives.

They’re continuing, just this year alone, in
roughly two and a half million in providing incentives.
But again, you have to make sure that the overall system
is fair for all customers.

But we continue to work and make sure that the
solar program continues to add more, more resources.

So with that, I’ll stop there.

COMMISSIONER HOCHSCHILD: Really, just
appreciate your efforts there. I mean, I think there’s
a lot of focus on the Governor’s 50 percent goal.

But, you know, one of the other critical policy
objectives he set in his first term was a 12-gigawatt DG
goal as part of it.

And I was just there, the lowest impact form of
energy generation there is, is on a roof. You’re not
having to disturb land and so forth. So, very much
appreciate your efforts.

In fact, all of you for your testimony today.

CHAIR WEISENMILLER: Well, but again, I would
also remind everyone that we now have an Executive Order
that’s pretty sweeping in terms of where we need to get
to, in terms of greenhouse gas emissions. And,
certainly, you’re not going to do it all alone with
renewables. You know, you really have to look very seriously about what you can do to help us electrify transportation, and what you can do to really help us cut down on use of energy in buildings.

I mean, and I realize that you’re not particularly homogenous. I’ve heard the statistic that the top nine municipal utilities are at 97 percent of the sales. So, I mean, it’s pretty concentrated. Although, certainly, the PUC regulates like Kirkwood, and some other fairly small entities that don’t quite go through the PG&E or Edison process.

So, we’re sort of struggling with, you know, the sort of smaller entities.

MR. TUTT: If I make a comment? In response to your discussion about parity, Commissioner, it’s my understanding that at the retail seller or at the IOU world, they do have a different way of calculating the megawatt or the net metering cap. But they also have a 2017 date that, if they don’t reach that cap by then, they can move to what’s being described as a net energy metering 2.0 system still under development.

SMUD is internally looking at what might come after net metering for us, and doing a lot of analysis of grid requirements, distribution grid requirements, what we can do internally. But we don’t have that 2017
off ramp.

   We are going to be required to do net energy metering until we hit however our cap is defined. So, there’s parity that runs both ways.

   And in terms of, Chair Weisenmiller, jump starting the installations, we think our customers have done fairly well with our incentives to install them.

   As I’ve said, our residential customers in particular seem to be very interested with installing solar these days, with the new financial arrangements that have come out in the solar industry.

   But I can tell you that inside the utility there is this question of how do we -- how do we foster installations of a resource that really is only product content category three, and four the State’s RPS. That does come up. It doesn’t seem to have the value, from an RPS perspective, that we’d want for a local rooftop resource.

MS. RAITT: Okay, if we’re done with questions from the dais, then we can move on to public comment.

   So, if there are folks in the room who have comments, you can come up to the microphone and identify yourself. Nobody.

   And we have nobody on WebEx, so we can just open up the phone lines, briefly. If you’re on the phone
lines, please mute your line, unless you’d like to make
comments. Just one more moment.

All right, it sounds like we don’t have any
comments today.

COMMISSIONER HOCHSCHILD: All right, thanks
everybody for coming.

(Thereupon, the Workshop was adjourned at
4:39 p.m.)

--oOo--
REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 15th day of June, 2015.

[Signature]

Kent Odell
CER**00548
TRANSCRIBER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were transcribed by me, a certified was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 15th day of June, 2015.

Barbara Little
Certified Transcriber
AAERT No. CET**D-520