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WATT Coalition Comments Urging Inclusion of Grid Enhancing Technologies to Reduce Cost and Increase Pace of Grid Transformation to Support Renewable Energy Integration Goals in SB 100 Joint Agency Report Docket No. 19-SB-100

September 15, 2020

The WATT (Working for Advanced Transmission Technologies) Coalition is pleased to offer the following comments on the SB 100 Joint Agency Report.

The WATT Coalition is a group of companies interested in facilitating the adoption of advanced technologies on the US electric transmission system that improve reliability, lower cost, and accelerate decarbonization, benefiting American citizens and businesses. The WATT coalition has six members and these companies offer technologies including Advanced Power Flow Control, Dynamic Line Ratings (DLR), and Topology Optimization:

Ampacimon is a global leader in grid monitoring solutions that utilize patented sensors and software to increase the capacity of transmission and distribution assets. Their dynamic line rating systems, with grid monitoring sensors and software, have been deployed worldwide.

Lindsey Manufacturing Company provides innovative and cost saving products to the global electric utility industry. Lindsey is an industry leader in transmission line monitors and software for measuring and forecasting dynamic line ratings and line capacity. They produce a variety of other systems designed to enhance grid resiliency and optimize distribution networks.

LineVision provides utility solutions that leverage advanced sensors and analytics to increase the capacity, flexibility, and reliability of overhead lines. Their non-contact monitoring systems provide real-time situational awareness and anomaly detection, unlock additional capacity on existing lines, and provide condition-based health analysis to optimize asset management and grid reliability.

NewGrid is a software firm that provides transmission topology optimization tools and services. NewGrid's software automatically identifies grid reconfigurations to route power flow around congested or overloaded transmission facilities (it is, in a sense, a "Waze" for the grid), increasing the transfer capability of the grid and delivering savings and increased reliability and resilience.

Smart Wires develops and implements technologies that advance the delivery of electricity around the world. With their technology, electric utilities can maximize transfer capacity on their grids, creating a more flexible and efficient network. Their power flow control technology dynamically controls transmission line reactance to direct power away from overloaded lines onto lines with spare capacity.

WindSim has developed a wind farm design software based on computational fluid dynamics that optimizes wind turbine placement. Using accurate simulations, WindSim software can more realistically capture terrain effects on wind conditions than many traditional technologies. WindSim Power Line (WPL) is a a state-of-the-art forecast solution for overhead line operations and provides transmission owners an enhanced view of the conditions of their transmission lines by modeling wind at high-spatial resolution and computing thermal interactions (using IEEE-738) for every transmission span on which the system is deployed.

Grid Strategies LLC serves as the convener of the WATT Coalition.

The WATT Coalition recognizes that the California electricity grid will require significant development over the coming decade to meet the many and varied SB 100 goals. Historically, utilities, system operators, and regulators assumed the transmission grid was essentially "fixed" in capacity and configuration. This assumption ignores the capabilities offered by advanced transmission technologies which allow physical transmission assets to be actively managed to provide more transmission capacity, reduce grid congestion, provide higher reliability and resilience and improve the integration of renewable generation. By using the Grid Enhancing Technologies (GETs) offered by the WATT Coalition to fully utilize the grid's capacity, California can reduce the total resource build and cost while accelerating progress toward meeting SB 100 requirements in a non-disruptive and socially-just way.

This response provides:

1. Evidence of the quantifiable impact GETs are having on electric grids across the globe
2. Explanation of the non-quantifiable benefits GETs provide, such as improved reliability and resiliency
3. Recommendations for CEC staff to consider as they develop the Joint Agency Report

1. GETs can drive billions of dollars of consumer savings and accelerate decarbonization efforts

GETs can move GWs, save billions of dollars for consumers and abate tens of millions of metric tons of CO_2 in the next 5 years. The evidence in this section, all substantiated by publicly available data, establishes that projects using commercially available GETs help utilities cost-effectively accelerate the energy transition. Leveraging GETs to unlock network capacity yields outsize benefit by allowing greater deliverability of existing renewable generation and by simplifying the network upgrades associated with new generation interconnection. This simplification results from fewer expensive, long-lead new line builds and reconductors, which are often delayed by extensive permitting and land acquisition processes. By reducing the total resource build (both generation and storage), California will be able to dramatically reduce carbon emissions on an even faster timeline than current SB 100 projections, bringing significant public health and economic benefit to the most at-risk populations.

Advanced power flow control

DNV GL conducted a study on the economic benefits of deploying advanced power flow control on the PJM system and evaluated a 2026 network with 30% of its energy sourced from renewable resources.[1] DNV GL found that using advanced power flow control in addition to conventional solutions could reduce the overall capital investment required for 30% renewables by 2026 by 40%, saving $1.8 billion.

In Europe, UK Power Networks leveraged modular power flow control to free up 95 MW of network capacity while saving their consumers £8 million compared with the traditional alternative of building costly and disruptive substations and underground cabling.[2] National Grid Electricity Transmission are leveraging modular power flow control to increase power transfers by 1.5 GW, saving consumers £387 million compared to traditional approaches to network expansion.[3] RWTH Aachen University recently completed a study that identified €5.5 billion in benefits for a €400 million investment of modular power

[1] https://www.smartwires.com/papers/

[2] https://www.smartwires.com/2019/09/30/smart-wires-ukpn/

[3] https://www.smartwires.com/2019/11/26/nget-release/

flow control on the German grid.[4] In all of these examples, the driving force for grid upgrade was to enable more renewable generation interconnection to meet portfolio mandates. Power flow control solutions can be implemented faster and less expensively than grid expansion or rebuild because they are standardized products, deployable in existing substations, generally avoiding the time and cost of environmental permitting and land acquisition.

TransGrid, the transmission owner for New South Wales, identified a AUD $5.6 M project that could increase the Victoria – New South Wales interface transfer capacity by 26 MW, providing AUD $1.79 million/year of market benefit.[5] ElectraNet, the transmission owner for South Australia, identified a constraint that limited area exports[6]. By resolving an overload on a 132 kV circuit, they could take advantage of spare capacity on their 275 kV system that runs in parallel. This is a very common issue in grids all over the world when parallel lines are different voltages – the lower voltage lines typically overload first, meaning that the higher voltage lines cannot be fully utilized. An investment of AUD $5.9 M could increase transfers by 17 MW, which is valued at AUD $1.3 million/year.

Dynamic Line Rating

A Dynamic Line Rating (DLR) study performed by Oncor Electric Delivery Company (Oncor) showed that a sizeable amount of congestion mitigation could be obtained with as little as 5 to 10% increase in capacity over the existing line ratings.[7] Oncor estimated that DLR technologies deployed on five percent of ERCOT transmission lines, would yield approximately $20 million in savings from congestion reduction, equivalent to a 3% reduction in congestion costs.

A PJM study evaluated a $0.5 million DLR deployment on three sections of a highly congested transmission line. Using historical weather conditions, PJM determined that the dynamic ratings provided a net congestion cost savings of $4.2 million annually.

AEP and the Southwest Power Pool (SPP) identified opportunities for a DLR system on a 2.1-mile segment of a transmission line that could save approximately $18,000 during just 300 minutes of real-time grid congestion, equating to several million dollars annually. In 2017, AEP tested a DLR system which showed increased capacity over ambient-adjusted ratings over 90% of the time.[8]

Elia, the Belgium transmission system operator, studied DLR systems on eight of ten critical transmission interconnectors with France and the Netherlands during the winter of 2014–2015.[9,10] After this initial study, Elia deployed a utility-wide DLR system on 30 transmission lines, helping them increase exchange capacities with their surrounding countries (France, Netherlands, Luxembourg, and Germany). In a single

[4] https://www.iaew.rwth-aachen.de/go/id/ihcvs?lidx=1#aaaaaaaaaaihdea
[5] https://www.aer.gov.au/system/files/TransGrid%20-%20Frontier%20Economics%20-%20Appendix%20T%20Return%20on%20debt%20transition%20letter-%20R%20-%20Z%20-%20January%202017.zip
[6] https://www.aer.gov.au/system/files/ElectraNet%20%E2%80%93%20ENET013%20%E2%80%93%20ElectraNet%20%E2%80%93%20Attachment%2011%20%E2%80%93%20Service%20Target%20Performance%20Incentive%20Scheme%20%E2%80%93%20March%202017.pdf
[7] https://www.smartgrid.gov/files/SGDP_Transmission_DLR_Topical_Report_04-25-14_FINAL.pdf
[8] https://watttransmission.files.wordpress.com/2018/10/cigre-gotf-2018-ngn-pjm-aep-linevision-final.pdf
[9] https://watttransmission.files.wordpress.com/2018/01/ampacimon-dynamic-ratings-increase-efficiency_belgium-transmission-grid.pdf
[10] http://www.ampacimon.com/wp-content/uploads/2016/09/Cigre_C2_PS1__20161.pdf

4-hour period, Elia identified $0.26 million of congestion savings provided by the DLR system deployment, which enabled 33 MW of additional import.

Topology Optimization

In 2018, The Brattle Group studied the benefits of topology optimization by looking at 20 real-time snapshots of the entire SPP system, representing a wide range of grid conditions. Ultimately, they found that topology reconfiguration options generated significant real-time production cost savings. These were extrapolated to annual figures from $18 - $44 million, based on historical congestion costs.[11]

In Europe, National Grid ESO (the Great Britain transmission system operator) investigated the feasibility and value of adopting existing topology optimization algorithms for their service territory. Using historical data, the study found that topology optimization could increase transfer capacity across large, heavily binding transmission constraints, such as into the London metropolitan area, by 3% to 12% even under outage conditions. This translates to production cost savings of £14 to £40 million (approximately $18 million to $52 million)[12] annually to end consumers.[13]

During the Polar Vortex event of 2014, the Midcontinent Independent System Operator (MISO) experienced record-setting high loads and a substantial number of unplanned generation outages due to extreme cold weather. Combined with extended planned transmission outages, these led to severe post-contingency transmission congestion and overloads affecting transmission utilities in the upper Midwest. The heavy congestion and overloads resulted in load energy prices in the affected areas that at times more than doubled the corresponding generation energy prices, increasing the cost of electricity in the affected areas by over $15 million in the first 10 weeks of 2014. The Brattle Group supported one of the impacted utilities with topology optimization analyses, identifying reconfiguration solutions that relieved much of the congestion and overloads. The performance of topology optimization under those severe conditions illustrate the resilience benefits of flow control technologies. [14]

2. GETs can improve the reliability and resiliency of the grid

In addition to the positive, quantifiable impact that low-cost, advanced technology offers, increasing efficiency and flexibility of the existing grid provides a host of reliability and resiliency benefits. The reliability and resilience of domestic infrastructure is critical to our national safety and the wellbeing of our economy. The intensity and frequency of natural and manmade threats to electric infrastructure is a major concern. Electric transmission owners must meet FERC/NERC reliability planning and operating criteria and anticipate potential system failures through comprehensive scenarios analysis.

GETs enable transmission operators to increase transfer capacity by resolving overloads. This is accomplished either redirecting power from an overloaded circuit/asset to one that is under-loaded

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[11] Ruiz, P., et al., "Transmission topology optimization: congestion relief in operations and operations planning," SPP Market Working Group Meeting, Oct 2018.

[12] Assumes historical exchange rate of approximately 1.3 USD per GBP.

[13] Annual constraint costs across the entire Great Britain totals approximately £ 340 million. See National Grid, Network Innovation Allowance Closedown Report, Transmission Network Topology Optimisation, project NIA_NGET0169, Jul 2017. (http://www.smarternetworks.org/project/nia_nget0169/documents)

[14] Tsuchida, B. and Gramlich, R., "Improving Transmission Operations with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives," filed with WATT Coalition Initial Comments, FERC Docket PL19-3, June 24, 2019. https://watttransmission.files.wordpress.com/2019/06/brattle-grid-strategies-paper-improvingtransmissionoperationwithadvancedtechnologies.pdf

(power flow control; topology optimization) or by increasing the static rating of a circuit/asset based on real-time conditions (dynamic line rating). This improves system reliability by resolving a potential failure scenario, or contingency.

FERC adopted NERC standards to ensure that, for relatively contained contingencies, the grid is able to function with little-to-no impact to service. However, designing and delivering a grid capable of withstanding large-scale disruptions has usually been considered cost-prohibitively expensive. Transmission owners are seeking creative ways to prepare for and respond to large-scale disturbances in order to minimize and contain the overall impact of such an event.

The grid was never designed for an N-10 contingency (simultaneous loss of 10 critical assets), but we are starting to experience the impacts of extreme weather events over large swaths of the grid. Having the ability to actively control the network provides transmission owners with incredibly valuable flexibility.

Improving the utilization of existing lines becomes even more important when managing a compromised system. GETs can help transmission owners improve grid resilience by bringing the system back online faster and drop less load in the process. Incorporating GETs into the SB 100 transmission modeling toolkit will provide a means to meet renewable integration goals without sacrificing, and in fact while improving, the reliability and resiliency of the grid, all at a fraction of the cost of the system build-out without GETs.

3. Recommendations for Joint Agency Report

We have four key recommendations.

A. Consider GETs as a viable solution in the Joint Agency Report

These technologies are commercially available today and have effectively unlocked significant power transfers in grids across the world. WATT urges the joint agencies to consider transmission constraints and investments within the SB 100 modeling process, ideally including a co-optimization phase for transmission and generation planning, rather than evaluating both of these critical elements entirely separately. Without co-optimization, there are likely to be large redundancies and inefficiencies that ultimately lead to increased costs borne by California consumers.

Since the RESOLVE model is fundamentally a resource adequacy tool, the WATT Coalition does not recommend studying the impact of our technologies within this model. Instead, these technologies are more appropriately represented in models, such as those used by CAISO, that take into account the transmission system. More details on exactly how to model GETs are included later in this section.

The WATT Coalition recommends the CEC expand RESOLVE to incorporate basic transmission assumptions, including possibly a zonal representation of the CAISO market to more accurately capture the transmission constraints within this market. There are substantial efficiencies to be gained from constraint reduction and better representation of zonal modeling within CAISO. Utilizing GETs to increase transfer capacity by removing thermal constraints on the network reduces the infrastructure upgrade cost and time associated with bringing new renewable generation online. Increasing renewable penetration faster and cheaper will directly support the SB 100 objectives and accelerate progress along the path to 100% renewable power. Further, GETs technologies can be easily modeled within standard electric grid transmission planning software and analyses, facilitating their inclusion in ongoing SB 100 modeling.

Modeling GETs in Transmission Planning:

Advanced power flow control injects a voltage waveform in series with the line. For transmission planning purposes, this can be simply modeled as a change in line reactance. Modules for series reactors (increase line reactance) and series capacitors (decrease line reactance) are available in transmission planning software. Smart Wires can provide tools that survey an area of the grid, identify the best locations for advanced power flow control, and iterate through various installation sizes until the constraint is resolved.

Topology optimization software identifies reconfigurations of the transmission grid, implemented by opening or closing existing high-voltage circuit breakers. These reconfigurations can be readily validated, studied and represented in standard transmission planning software.

Dynamic line rating enables transmission operators to increase the capacity on a circuit beyond its static limit which in turn allows for higher currents. Favorable ambient weather conditions such as cooler temperatures and increased wind speeds above the conservative estimates in static assumptions are the drivers of this increased capacity. The impact of dynamic line rating is not typically modeled in long term transmission planning, but it is represented in operational models by changing the line current limits. Historical regional or local ambient weather data can be obtained and compared to static assumptions to understand and estimate long term impacts.

B. Consider adopting a "loading order" approach to network investment choices

The grid will need to be expanded, however there is a significant opportunity to first unlock the capacity that exists on today's infrastructure. Fully utilizing the existing capacity of the network is the most cost-effective means of enabling rapid, large-scale renewable energy integration in California.

We suggest that the joint agencies consider adopting a transmission planning "loading order" concept analogous to their generation dispatch loading order (which aims for lowest cost and lowest carbon first). In the transmission planning loading order, optimization of the existing grid is considered first, then grid reinforcement, and then grid expansion. Optimization of the existing grid could include using the following flexible, low-cost tools to resolve an anticipated problem: demand response (DR), distributed energy resources (DERs), energy efficiency (EE), energy storage, and GETs. Only once these options have been exhausted should traditional means of network reinforcement – reconductoring or rebuilding lines – be considered. And if those approaches are unable to resolve the constraint, then new infrastructure could be explored. This strategy will help ensure that California ratepayers see the lowest rate-impact possible while accruing the benefits of the clean energy transition, including less infrastructure through their communities or through protected areas.

Other markets have adopted similar transmission planning loader order mandates, including the German NOVA principle, described by transmission operator TransNetBW as "grid optimisation first, then grid strengthening before any further grid expansion."[15] The Independent Electric System Operator of Ontario, Canada (IESO) also uses a similar approach in their Scoping Assessment to determine the most appropriate planning process for any reliability need. The IESO differentiates between needs which

[15] https://www.transnetbw.com/en/world-of-energy/nova-principle

can be addressed by a mix of different options, such as conservation, generation, distribution or new technologies and those that can only be met with reconductors or new build.[16] While not strictly a loading order, this clear distinction and evaluation of optimization solutions to solve reliability needs is a valuable approach that IESO brings to their planning activities.

Pending release of the Joint Agency Report, the CEC and other relevant California agencies may consider adopting a similar "loading order" concept within their standard transmission planning processes.

C. *Perform social cost benefit analyses against multiple future scenarios*

Instead of a standard Cost Benefit Analysis (CBA), the CEC should consider adopting a social CBA as they model the pathways to achieve SB 100. The goal of a social CBA is to make sure a solution's impact on society is fully considered in the analysis, rather than focusing solely on the monetary costs weighed against monetary benefits.

Any CBA or other internal evaluation should be as comprehensive and transparent as possible, and include consideration of the following factors:

- Support for the achievement of government policy objectives
- Flexibility of the solution (its capability to adapt to changing situations)
- Deliverability of solution and risk of delays
- Disruption to the environment and communities by the works required to deliver the project
- Benefits of early delivery

Furthermore, it is critically important that the social CBAs for all proposed solutions are evaluated against multiple future scenarios. There is a high degree of uncertainty in today's energy landscape, particularly when considering the future needs of energy networks. Selecting an option that works well in one scenario but is a poor fit for others and has limited flexibility could lead to large stranded asset costs, which are ultimately borne by end customers. There are a number of examples of social CBA tools utilized by transmission utilities to inform their planning activities, including one presented by Smart Wires in 2018.[17] This evaluation is included in the Appendix and aimed to incorporate components that traditionally had non-monetary value but should be considered in decision making.

D. *Allow flexible solutions to be properly accounted for in scenario planning*

While SB 100 modeling already evaluates solutions against multiple scenarios, the existing processes likely do not adequately account for the value of flexible solutions, which can be adapted over time depending on how the future unfolds. Flexible solutions that can be adapted over time enable California utilities to defer large investment decisions to a future date when there is more certainty, to resolve short-term needs, and to minimize the risk of stranded assets in the future. However, the results of existing processes rarely capture the value of flexible solutions.

Consider an example where two solutions are being compared across two scenarios. The first solution is a traditional infrastructure project that will deliver a large discrete increase in capacity when delivered but is essentially fixed once in place. Examples include, new lines or cables, and new substations. The

[16] http://www.ieso.ca/en/Get-Involved/Regional-Planning/About-Regional-Planning/How-the-Process-Works#:~:text=During%20the%20IRRP%20process%2C%20if,while%20the%20IRRP%20process%20continues

[17] Longoria, et. al. "Trends in Transmission Planning Uncertainty and the Impacts and Value of Leveraging Flexible Investment Strategies and Technologies." CIGRE 2018.

second solution is a modular solution that can be deployed quickly and moved at a later date if needs change. Examples include, some battery solutions and GETs like modular power flow control.

The two scenarios are: (1) the need increases steadily over many years; and (2) the need initially increases but stays steady after only a few years.

In Scenario 1, the pursuit of the fixed solution requires a large upfront capital investment, whereas the flexible solution can be paid for over a longer time horizon as the deployment size is gradually increased, yielding significantly lower net present cost for the flexible solution. This is extremely important to California ratepayers who support cleaner, cheaper renewable generation but cannot afford to overpay for the system changes required to reliably integrate it.

In Scenario 2, the fixed solution results in a significant stranded investment. Alternatively, the flexible solution can be deployed in stages and halted when the need is no longer growing. This is potentially a significant difference in costs to consumers.

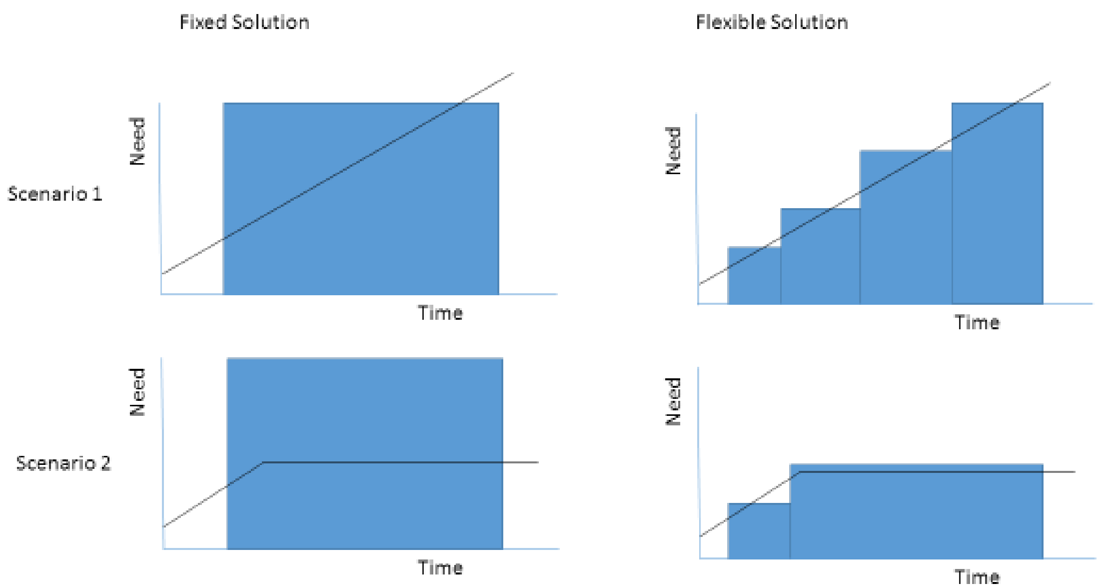

Figure 1: Comparison of Fixed and Flexible solutions across scenarios

For this to be considered in the analysis it is essential that the profile of deployment of a flexible solution is allowed to be tuned to fit the scenarios as part of the assessment. Traditional scenario planning frequently does not capture the value of flexibility as it assumes that once made, an investment decision cannot change over time as improved visibility of the need emerges.

4. Conclusion

Investments in GETs have provided large system impact and substantial economic savings for consumers around the world and will do the same for California. The WATT Coalition urges SB 100 staff to include GETs in their modeling, consider a “loading order” approach, incorporate a social CBA, and ensure flexible solutions are properly accounted for in scenario planning.

From congestion reduction to disaster response, GETs provide significant benefits to California ratepayers by enabling a more flexible, controllable network. Fully utilizing the capacity of the existing network is the most cost-effective means of enabling rapid, large-scale renewable energy integration in California and ensures that all ratepayers see the lowest rate impact possible while accruing the benefits of the clean energy transition.

Best Regards,

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Rob Gramlich

Executive Director

WATT Coalition

rgramlich@gridstrategiesllc.com

Appendix

The following is an example social Cost Benefit Analysis (CBA) tool, reproduced from the CIGRE 2018 technical paper, "Trends in Transmission Planning Uncertainty and the Impacts and Value of Leveraging Flexible Investment Strategies and Technologies" by Longoria, et. al.

Key	
	Input Cell
	Calculation Cell

Assumptions	
Real Discount Rate	5.50%
Inflation Rate	2.00%
Base year	2018

Project Year	Option 1			
	Benefits ($M)	Installed Solution Cost ($M)	Recurring Cost ($M)	Discounted Cash Flow
2018	2.00	8.00		6.00
2019			0.03	0.02
2020			0.03	0.02
2021			0.03	0.02
2022		2.00	0.03	1.52
2023			0.03	0.02
2024			0.03	0.02
2025		2.00	0.03	1.22
2026			0.03	0.01
2027			0.03	0.01
2028			0.03	0.01
2029			0.03	0.01
2030			0.03	0.01
2031			0.03	0.01
2032			0.03	0.01
2033			0.03	0.01
2034			0.03	0.01
2035			0.03	0.01
2036			0.03	0.01
2037			0.03	0.01
2038			0.03	0.01
Present Value ($M)	2.0	12.0	0.5	9.0

FIGURE 1: Project Option number 1 within the NPV Analysis tab. Benefits, installed cost, recurring costs are all input by the user. The spreadsheet calculates the discounted cash flow based on the inputs for discount rate, inflation rate and base year.

Section 1 - Monetized Costs and Benefits					Options to Evaluate		
	Department	Category	Section Weight	Calculation	Option 1	Option 2	Option 3
Benefits (enter in NPV tab)	Planning	System Impact	N/A	This should appear in the proper years of the NPV Analysis.			
	Compliance / Public Relations	Pollution Reduction		This should appear in the proper years of the NPV Analysis. Use the appropriate $/MWh for SO2, NOx, and CO2 based on fuel type and amount of generation (MWh) reduced.			
Costs (enter in NPV tab)	Planning/ Substation / Engineering / Land / Construction	Installed Solution Cost		Examples appear on NPV Analysis Example tab.			
	Planning / Operations	Recurring Cost		This should appear in the proper years of the NPV Analysis.			
				NET PRESENT VALUE ($M)	$8.96	$9.77	$49.92

FIGURE 2: Section 1, the Monetized Costs and Benefits. The net present value of each option appears in the columns on the right.

Section 2 - Non-monetized Project Components					Options to Evaluate		
	Department	Category	Section Weight	Calculation	Option 1	Option 2	Option 3
Benefits (larger scores indicate higher benefit)	Planning	Grid Resilience	11%	Higher ranking means more grid resilience.	8	5	9
	Planning	Planning Flexibility	12%	Cost of adapting option if largest impact planning scenario needs are realized. Can also be quantified in $. Higher ranking means higher scalability.	10	10	7
	Planning	Investment Flexibility	8%	Higher ranking means solution has higher capability of being redeployed	8	8	1
	Construction / Engineering / Substation	Construction Flexibility	11%	Higher ranking means more flexibility in scheduling clearances and/or shorter duration of clearances required.	8	9	3
	Operations	Operational Flexibility	9%	Is control needed? Is frequent switching needed? Can also be quantified in $ in terms of system benefit. Higher ranking means higher flexibility.	9	9	9
	Purchasing / Procurement	Supplier Safety, Experience, Quality, Service	9%	Higher ranking means better safety, experience, quality, service, etc.	7	7	9
Risks (larger scores indicate higher risk)	Land Dept	Permitting Risk	8%	Higher risk means higher ranking	5	4	7
	Regulatory / Regional Planning	Stakeholder Risk	7%	Higher risk means higher ranking	2	2	5
	Public Relations / External Affairs	Community Impact / Risk	8%	Higher risk means higher ranking	2	2	7
	Planning	Planning Risk	8%	Higher risk means higher ranking	1	1	5
	Construction / Engineering / Substation	Construction Risk	4%	Higher risk means higher ranking	4	3	8
	Operations	Operational Risk	6%	Higher risk means higher ranking	2	2	9
				TOTAL SCORE	8.02	7.92	5.19

FIGURE 3: Section 2 of the project scorecard: non-monetized project components. Users enter scores from 1 – 10 in the blue cells for each solution option they are evaluating.

	Grid Resilience	Planning Flexibility	Investment Flexibility	Construction Flexibility	Operational Flexibility	Supplier Safety, Experience, Quality, Service	Permitting Risk	Stakeholder Risk	Community Impact / Risk	Planning Risk	Construction Risk	Operational Risk	Total Score	Rank	Weight
Grid Resilience		1	0	1	1	-1	0	1	1	0	-1	0	3	14	10.6%
Planning Flexibility	-1		1	-1	1	1	1	1	-1	1	1	1	5	16	12.1%
Investment Flexibility	0	-1		-1	1	0	1	-1	1	0	1	-1	0	11	8.3%
Construction Flexibility	-1	1	1		0	0	1	1	-1	-1	1	1	3	14	10.6%
Operational Flexibility	-1	-1	-1	0		0	0	0	1	1	1	1	1	12	9.1%
Supplier Safety, Experience, Quality, Service	1	-1	0	0	0		-1	0	1	1	-1	1	1	12	9.1%
Permitting Risk	0	-1	-1	-1	0	1		0	0	1	1	-1	-1	10	7.6%
Stakeholder Risk	-1	-1	1	-1	0	0	0		-1	-1	1	1	-2	9	6.8%
Community Impact / Risk	-1	1	-1	1	-1	-1	0	1		-1	1	0	-1	10	7.6%
Planning Risk	0	-1	0	1	-1	-1	-1	1	1		0	1	0	11	8.3%
Construction Risk	1	-1	-1	-1	-1	1	-1	-1	-1	0		-1	-6	5	3.8%
Operational Risk	0	-1	1	-1	-1	-1	1	-1	0	-1	1		-3	8	6.1%

FIGURE 4: Users enter values into the top triangle of the matrix. Entering 1 indicates row criterion is more important than column criterion. An entry of -1 indicates the opposite. 0 indicates both criteria are equally important. The weights calculated in the far right column are input into the Section Weights column as seen in Figure 3.