

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**



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Order Instituting Rulemaking to
Continue Oversight of Electric
Integrated Resource Planning and
Procurement Processes

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Rulemaking 25-06-019

**JOINT COMMENTS OF
SONOMA CLEAN POWER AUTHORITY
AND PENINSULA CLEAN ENERGY AUTHORITY
ON THE ORDER INSTITUTING RULEMAKING**

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In accordance with Rule 6.2 of the Rules of Practice and Procedure of the California Public Utilities Commission (“Commission”), Sonoma Clean Power Authority (“SCPA”) and Peninsula Clean Energy Authority (“PCE”) (collectively the “Joint CCAs”), respectfully submit the following opening comments on the *Order Instituting Rulemaking*, issued July 2, 2025 (“OIR”).

I. INTRODUCTION

SCPA is the public power provider for customers in Sonoma and Mendocino Counties, serving a population of nearly a half-million citizens. SCPA is the only power provider in California offering a 100% 24/7 renewable energy product generated purely from within its service territory. SCPA intends to build upon this by providing all customers with 85% greenhouse gas (“GHG”)-free energy - accounted for on an hourly basis - by 2026. SCPA is also leading an initiative called the Geothermal Opportunity Zone (“GeoZone”) to leverage public-private partnership to accelerate the construction of local geothermal resources and a research partnership with PCE and Princeton University to apply decision-making under uncertainty principles to California’s grid planning. Based on this experience, SCPA is well poised to offer feedback to inform the Integrated Resource Plan process.

PCE is the fifth Community Choice Aggregation (“CCA”) program, serving San Mateo County, each of San Mateo County’s twenty incorporated cities, and the City of Los Baños since 2016. PCE supplies electricity to approximately 300,000 customer accounts, including 97.5 percent of all residential and commercial accounts in PCE’s service territory. Peninsula Clean Energy is developing a portfolio capable of serving all customer load with 100% renewable in all hours. PCE’s perspective is strongly shaped especially by efforts to procure resources to serve hard-to-decarbonize hours and the characteristics of 100% renewable portfolios. Emerging technologies, such as advanced geothermal and offshore wind, are likely to play a key role in this portfolio, driving a keen interest in flexible transmission planning that can accommodate departures from planning assumptions.

The Joint CCAs’ comments on the OIR include the following recommendations:

- The Integrated Resource Plan (“IRP”) should incorporate decision-making under uncertainty (“DMUU”) into the selection of the state’s Preferred System Plan (“PSP”) through the following steps:
 - Instead of focusing on a deterministic least-cost solution for selecting the PSP, the Commission should seek to select a PSP that is both low cost and low risk and robust at providing reliability and affordability through a range of uncertain futures;
 - Collaborate with the CEC on characterizing the range of uncertainty in the future load forecast by creating a low and high planning scenario;
 - Add DMUU capability, such as the Robust Optimization (“RO”) technique demonstrated in SCPA and PCE’s sponsored research, to the IRP expansion model by 2026;
 - Include the identification of risks and uncertainty for DMUU in a stakeholder process; and
 - Reprioritize IRP team staffing and budget, or if necessary, seek additional funding to dedicate to DMUU given its ability to reduce risks for ratepayers and improve stability of PSP;
- The Commission should collaborate with the California Independent System Operator (“CAISO”) on a transparent and stakeholder-driven process to reform

IRP and transmission planning processes to comply with Order 1920 from the Federal Energy Regulatory Commission (“FERC”) with the following considerations:

- Originate all three scenarios required by Order 1920 in the Commission’s IRP process;
- Adopt a universal 20-year planning horizon for all transmission planning—including years between the more comprehensive studies that comply with Order 1920;
- Improve the ability to identify synergies between policy upgrades and economic and reliability driven upgrades;
- The Commission should identify opportunities to advance the representation of deliverability for future grid conditions and to maximize utilization of existing and planned infrastructure;
- The Commission should account for market dynamics in IRP decisions and proactively identify opportunities to mitigate impacts to affordability; and
- The Commission should improve data accessibility, particularly with inputs and results of production cost modeling and more granular load data, to enable external stakeholder engagement.

II. OPENING COMMENTS

A. The Commission Should Incorporate Decision-making Under Uncertainty into the Selection of the Preferred System Plan

The Joint CCAs request the Commission to add a discrete focus to the scope of the new IRP proceeding that incorporates decision-making under uncertainty into selection of the state’s PSP, especially for use in the Transmission Planning Process (“TPP”). Uncertainty has never been greater—with federal policy changes, load growth from data centers and electrification, potential regionalization, and technology innovation. A plan cost-optimized around mid-case assumptions, as is done today, will not necessarily be affordable or reliable as conditions change. Instead of relying on the false precision represented in a single cost optimization, the IRP should seek to identify a portfolio that is both low cost and robust under uncertainty. DMUU is a set of techniques that allows risk and uncertainty to explicitly inform the optimization of a model.

SCPA and PCE have sponsored research at Princeton University’s ZERO Lab, headed by Professor Jesse Jenkins as Principal Investigator, to demonstrate the feasibility and impact of applying DMUU to California’s IRP process. Appendix A includes a preliminary summary of the research’s findings. Most notably, the research has found that the deterministic approach to planning used today could lead to spiraling electricity costs and serious reliability issues if future conditions diverge from their mid-cases such as scenarios with high load growth and limited out-of-state resource availability¹. By applying a DMUU technique known as RO, the modeling in the research selects more flexible portfolios that maintain affordability and reliability through uncertain future conditions. The primary feature of these more robust portfolios is more proactive investment in in-state transmission upgrades that enable interconnection of a diverse set of resources².

Deterministic modeling does not select these more robust portfolios because they appear to have a slight cost premium³—but the savings provided by the deterministically selected portfolio are predicated on all uncertainties being at their mid-case which is not a realistic expectation. The results shared in Appendix A demonstrate that although a deterministic optimization is lowest-cost under mid-case assumptions, it exposes California ratepayers to an unacceptable level of cost and reliability risk. DMUU techniques such as RO allow decision-makers and stakeholders to transparently discuss the tradeoffs of cost and risk in selecting a deterministic or more robust portfolio, which is not possible today.

¹ See Figure 4 in Appendix A – modeling shows a deterministic plan could lead to scenarios with costs exceeding over \$65 billion per year, compared to robust plans that cap risk exposure to less than \$20 billion per year.

² See Figure 1 in Appendix A – the primary difference in robust portfolios is a large increase in the scope of selected transmission upgrades.

³ See Figure 2 in Appendix A – in a deterministic mid-case scenario, robust portfolios appear to add less than \$1 billion per year in costs (almost all related to transmission)

DMUU is not a completely new concept to the Commission or the IRP venue. The April 26, 2024 ruling on identifying the need for centralized procurement⁴ characterized the range of uncertainty in benefits and costs for increasing penetration of forced-in offshore wind. The results allowed stakeholders and decision-makers to trade-off the risk of significant cost to ratepayers with the potential benefits of offshore wind market transformation. Although narrowly focused on offshore wind and different than the RO technique applied in Princeton ZERO Lab’s research, the explicit treatment of uncertainty in the central procurement decision revealed risks that would not have been identified in a deterministic analysis.

The scoping memo for the new IRP proceeding provides an opportunity to establish DMUU as the methodology for identifying forthcoming PSPs. There are several specific steps the Joint CCAs request the Commission to consider in working towards a more robust DMUU-derived PSP:

- **Establish expectation that PSP is both low cost and low risk:** As stated in the OIR, the “IRP process strives to maintain reliability at the least cost.”⁵ Given the inherent difficulty in identifying what’s truly “least cost” given the level of uncertainty, and the issues described above with deterministic optimization, the Commission should instead endeavor to identify a PSP that is not least cost from a deterministic perspective, but both low cost and low risk when assessed across future uncertainty. A PSP should be robust at providing both reliability and affordability through a range of uncertain futures.
- **Collaborate on characterizing uncertainty range of load forecast:** The CEC provides a single “planning” load forecast for the IRP through its Integrated Energy

⁴ <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M530/K323/530323853.PDF>

⁵ OIR on page 4

Policy Report (“IEPR”) process. Understanding the range of uncertainty of the state’s load forecast is critical to applying DMUU for the PSP and would be an important tool in informing other decisions in the IRP venue. The Joint CCAs request the Commission revisit the Memorandum of Understanding (“MOU”) with the CEC and the CAISO⁶ to collaborate on creating a low and high bookend load forecast alongside the existing planning forecast to characterize the range of uncertainty. Unlike the “baseline” and “reliability” forecasts currently provided by the CEC, these forecasts would be specifically intended for IRP and calibrated to provide a reasonable range of expected long-term load growth.

- **Add DMUU capability to the IRP’s capacity expansion model:** The Joint CCAs request the Commission prioritize adding DMUU capability to the IRP’s capacity expansion model by 2026. The Commission should work with its consultant to evaluate the appropriate DMUU methodology to apply, but the RO technique employed in Princeton ZERO Lab’s research has several advantages: 1) it ultimately results in a single robust portfolio that can be selected and submitted to CAISO to study through the existing transmission planning process; 2) it provides a transparent way to evaluate the trade-offs of cost and risk; and 3) the research has proven that it is feasible to solve and apply in the IRP optimization. After building DMUU capability, the Commission should commit to including a robust portfolio in its submission to CAISO—preferably as the PSP, but at a minimum as an alternative. It’s important to note that the scenario analysis used in the existing IRP process (and thus far used as the basis for a sensitivity portfolio) is not a substitute for DMUU: scenarios are

⁶ <https://www.caiso.com/documents/iso-cec-and-cpuc-memorandum-of-understanding-dec-2022.pdf>

predominantly used as a learning exercise, do not directly influence decision-making, and do not characterize the dynamics of multiple uncertainties and decisions in modeling.

- **Include identification of risks and uncertainty for DMUU in a stakeholder**

process: The Commission should include the identification of risks and uncertainties relevant to applying DMUU to the PSP as part of a stakeholder process. This stakeholder process can run alongside the existing process of vetting inputs and assumptions and include a discussion of both the scope of risks and uncertainties to model and the approach to characterizing each uncertainty's range.

The Joint CCAs recognize that the Commission's IRP team is heavily burdened with many different competing high-profile priorities and may not have the funding or personnel for adding DMUU to the IRP process. Given the potential large-scale benefits to ratepayers from reducing risk through application of the DMUU, the Joint CCAs urge the Commission to identify a strategy for resourcing DMUU. The Commission could consider changing to a biennial process for providing the CAISO portfolios, look for opportunities to free up resources by reducing the precision of the current deterministic plan, or consider requesting additional funding through a supplemental non-bypassable charge. An important consideration is that once deployed, DMUU should result in PSPs that change less between cycles—as the resulting plan will be more accommodating to changes in input assumptions. This will ultimately reduce the resource requirements for planning and be responsive to previous feedback from the CAISO supporting consistency in IRP portfolios year after year⁷.

⁷ Page 3 of [CAISO Opening comments on 2025-26 TPP](#), Page 2 of [CAISO Comments on 2023 PSP](#), and pages 2-3 of [CAISO Comments on ALJ Ruling on 2023 PSP](#)

B. The Commission Should Collaborate with CAISO on a Transparent and Stakeholder Process for Process Changes to Comply with Federal Regulatory Energy Commission Order 1920

The Joint CCAs support the Commission’s proposal in the OIR scoping memo to use the IRP proceeding to inform its role in CAISO’s compliance with Order 1920 from the Federal Energy Regulatory Commission⁸. Thus far, the CAISO has held only one stakeholder briefing on FERC 1920, which was primarily informational⁹. The Joint CCAs encourage the Commission to collaborate with the CAISO on providing transparency and opportunities for stakeholder input on how the IRP and Transmission Planning Process (“TPP”) will evolve in response to Order 1920. The Joint CCAs provide the following initial input on opportunities that the Commission and CAISO should consider:

- **Originate all Order 1920 scenarios in Commission’s IRP process:** FERC Order 1920 requires CAISO to develop three distinct plausible long-term scenarios at least once during a five-year planning period¹⁰. The Commission should endeavor to originate all three Order 1920 portfolios in the IRP process facilitated through a stakeholder process, rather than relying on CAISO to make its own adjustments from a single PSP portfolio. Originating the scenarios at the Commission allows for a comprehensive analysis of the trade-offs between state policy objectives, cost, and risk. At least one of the three scenarios should either represent a robust portfolio developed using DMUU techniques described above. Including this scenario, which will entail larger transmission needs, will better facilitate CAISO’s analysis of long-term transmission requirements and provide opportunities to right-size upgrades.

⁸ Page 13 of OIR

⁹ The [FERC Order No. 1920-A Compliance Update Stakeholder Workshop](#) on March 13, 2025

¹⁰ [FERC Order 1920](#) paragraph 559 (page 413)

- Adopt a universal 20-year planning horizon:** FERC Order 1920 requires CAISO’s long-term transmission plan to identify needs over a 20-year horizon¹¹. CAISO’s proposal during its March 2025 briefing on Order 1920 proposed a 20-year comprehensive study every four years and 10-year studies in intervening years. Given that many upgrades under consideration have extended timeframes and Senate Bill 887’s requirement that the Commission’s resource portfolios extend through at least 15 years, the Joint CCAs asks the Commission to work with CAISO on adopting a universal 20-year planning horizon for all transmission studies. As suggested in the DMUU section above, the Joint CCAs would be supportive of moving from annual to biennial studies if resources are too constrained to facilitate a comprehensive 20-year study each year.
- Improve ability to identify synergies between policy upgrades and economic and reliability driven upgrades:** FERC Order 1920 requires CAISO to consider seven discrete benefits in long-term transmission planning, including factors such as improved reliability, production cost savings, and reduced congestion¹². Under the current CAISO process, the evaluation of policy upgrades and reliability or economic upgrades are done separately. Policy upgrades are not necessarily credited with reliability or economic benefits—and alternatives to increase their size or scope as a mitigation to existing congestion and reliability issues are not explicitly evaluated. An example is congestion on Path 15: a potential opportunity to reduce congestion on Path 15 could be to invest in policy-driven upgrades that allow more resources to interconnect in Northern California. However, recent economic studies are narrowly

¹¹ FERC Order 1920 paragraph 859 (page 624)

¹² FERC Order 1920 paragraph 720 (page 521)

focused on increasing power flow on Path 15 itself, and any policy-driven upgrades are not credited with their contribution to reducing congestion and curtailment. The Commission and CAISO should use compliance with FERC Order 1920 as a catalyst for exploring new tools and processes to identify synergies between policy-driven transmission needs and economic and reliability needs.

The Joint CCAs expect that CAISO's compliance with Order 1920 and pursuit of the opportunities above will require changes to the Commission's MOU with the CEC and CAISO. The Joint CCAs encourage the Commission to proactively work with the CEC and CAISO on updating the MOU to maintain close cross-agency coordination on the IRP and TPP.

C. The Commission Should Identify Opportunities to Advance the Representation of Resource Deliverability to Prepare for Future Grid Conditions and Maximize Utilization of Infrastructure

The Joint CCAs request the Commission add a discrete focus to the scope of the new Integrated IRP proceeding for identifying opportunities to advance the representation of resource deliverability to prepare for future grid conditions and maximize the utilization of existing infrastructure. The Commission and CAISO currently use high system need (“HSN”) deliverability studies as the basis for determining the eligibility of a resource to contribute resource adequacy, reserving grid capacity, gatekeeping the interconnection queue, and identifying the need for transmission upgrades. These HSN deliverability studies are representative of a small subset of hours and are predominately driven by conditions during statewide heat waves with the Los Angeles Basin as a load sink. While these HSN studies are a reasonable approximation of grid constraints driving reliability conditions today, they are not representative of reliability conditions as the state transitions to a winter peak.

HSN deliverability constraints are making it impossible to build new resources in Northern California¹³, including geothermal projects that can both alleviate the growing problem of Path 15 congestion and provide critical support for future reliability needs in the winter. Because grid constraints exist in a small subset of hours that prevent Northern California resources from delivering power to Los Angeles in HSN deliverability conditions, the current process dictates that these resources are ineligible for resource adequacy (even in non-summer months that are not represented in HSN studies) and are not selected as part of the PSP unless accompanied by HSN grid upgrades that might only be necessary for select hours.

Ultimately, changes to the representation and implications on resource deliverability will involve significant coordination with the CAISO and Commission's Resource Adequacy proceeding. However, the Joint CCAs believe it's prudent to begin identifying opportunities to advance the representation of deliverability in the IRP proceeding, given the long-term planning horizon and direct impact to the scale and scope of needed transmission upgrades. Opportunities could include options such as challenging the need for HSN deliverability for resource adequacy during non-summer months or developing more sophisticated tools for assessing reliability needs and contributions across varying grid conditions. The Commission should seek a solution that maintains reliability, maximizes utilization of existing infrastructure, and promotes the development of resources needed for California's long-term needs.

D. The Commission Should Account for Market Dynamics in IRP Impacting Affordability

The Joint CCAs request the Commission add a discrete focus to the scope of the IRP that characterizes market dynamics and informs IRP decisions on how to reduce the risk of

¹³ See CAISO Points of Interconnection Heatmap, which shows no deliverability in Northern California based on last study <https://www.caiso.com/poi-heatmap/>

conditions that concentrate market power and drive-up costs for ratepayers. The current IRP process identifies infrastructure and portfolio needs through the eyes of a central planner—with minimal consideration for the types of market dynamics that can increase the cost of procurement. Below are a few illustrative examples of how market dynamics are leading to costs for load serving entities (“LSEs”) beyond what is represented in IRP modeling:

- **Interconnection scarcity:** The current approach to building “just enough transmission, just in time” leaves no room for conditions to deviate from plan or headroom for competition. Resultantly, interconnection capacity is currently scarce and developers with interconnection and resources eligible to meet procurement order requirements have concentrated market power that allow them to sell projects at prices far exceeding the bottom-up cost estimates used for IRP.
- **Firm capacity costs:** Reforms to the resource adequacy process, including an increased Planning Reserve Margin (“PRM”), the revised counting for energy storage in slice of day (“SOD”), and the transition of capacity to the State Reliability Reserve had led to an increased dependency on the state’s entire remaining natural gas fleet for meeting collective resource adequacy requirements. Given that the price of resource adequacy can be driven by the last marginal unit, the complete utilization of the state’s available natural gas fleet has driven up resource adequacy costs far beyond the bottoms-up cost used in IRP for estimating the cost of retaining natural gas capacity. Correspondingly, the value of clean resource portfolios that would reduce dependency on the entire fleet are undervalued and approval of their supporting infrastructure delayed.
- **Limited battery storage revenues:** The rapid scale-up of battery storage from IRP procurement orders alongside the absence of natural gas retirements has reduced

volatility in CAISO and limited revenues for LSEs from battery storage market participation¹⁴. Without market revenues, the net costs of battery storage contracts are far higher than anticipated for LSEs and battery storage procurement beyond mandates is uneconomic. These market signals are misaligned with the IRP modeling that identifies an incremental need for storage procurement.

The Joint CCAs ask the Commission to take steps in the IRP proceeding to proactively identify and plan for market dynamics like the issues described above—particularly dynamics that adversely impact affordability. Potential mitigations could include completing a comprehensive assessment of available resource supply and interconnection before ordering procurement, incorporating a buffer in transmission planning to leave room for flexibility and competition, and prioritizing planning for portfolios that reduce dependency on the entire available natural gas fleet.

E. The Commission Should Improve Data Accessibility to Enable External Stakeholder Engagement

The Joint CCAs request the Commission prioritize improving data accessibility as part of the scope of the IRP proceeding. As demonstrated by the research detailed in Appendix A, external stakeholders are growing increasingly sophisticated at developing parallel models and demonstrating new techniques, testing hypotheses, and providing insightful guidance to the IRP process. The Joint CCAs appreciate the Commission’s current practice of publishing comprehensive RESOLVE data, including all the inputs, configuration options, and outputs of the capacity expansion model. Likewise, the system reliability model datasets provide a consistent set of inputs that are incredibly useful for modeling by external stakeholders.

¹⁴ See Figure 2.23 (page 26) of CAISO’s 2024 Special Report on Battery Storage – average battery revenues have dropped from \$103/kW-yr in 2022 to \$53/kW-yr in 2024.
<https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf>

However, there are many datasets used in the IRP process that are not as accessible, such as outage assumptions and operational parameters used in SERVM, granular SERVM outputs, and more geographically granular load data. The Joint CCAs ask the Commission to create an inventory of relevant datasets for IRP modeling and ask stakeholders for feedback with the goal of providing a complete dataset that enables parallel modeling.

III. CONCLUSION

The Joint CCAs thank the Commission for the opportunity to submit these opening comments and for the Commission's consideration of the matters discussed herein.

Dated: August 1, 2025

Respectfully submitted,

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**APPENDIX A
TO
OPENING COMMENTS OF THE
SONOMA CLEAN POWER AUTHORITY
ON THE ORDER INSTITUTING RULEMAKING**

Transmission Planning Under Uncertainty: Preliminary Findings of Research Sponsored by Sonoma Clean Power and Peninsula Clean Energy at Princeton University

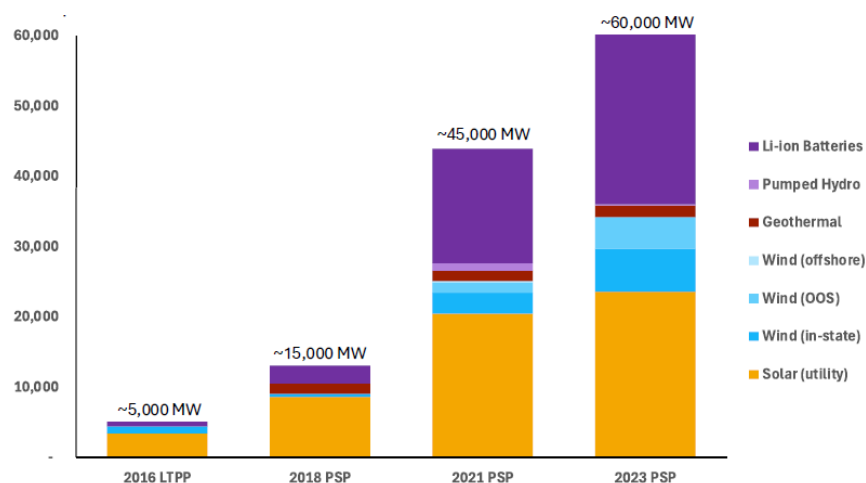
Background

Interconnection capacity is the primary factor limiting the pace at which California’s power providers can decarbonize the grid today. Clean energy technologies are increasingly cost-effective thanks to innovation, federal policy support, and significant improvements in supply chains (including new domestic sources). However, limitations in state infrastructure and planning processes mean new clean energy projects face untenable 7+ year timeframes to interconnect—if they are allowed to interconnect at all. Projects with an interconnect benefit from the high demand for clean resources (reinforced by state procurement mandates) and the scarcity of interconnection that enables them to name their price for prospective buyers. The key advantage of independent power producers competing against each other to deliver the best quality and highest value projects for California ratepayers is not realized when interconnection capacity is so severely limited.

Today’s limited interconnection capacity is a result of historic planning processes not foreseeing the current need for transmission capacity. The limitations of capturing future conditions in deterministic planning is directly illustrated in Figure 1, which is a graph by Aaron Burdick from Energy and Environmental Economics (E3) showing the evolution of California’s expectation for capacity additions through time for just the year 2030. Whereas the 2016 plan forecasted only 5 GW of additions between 2018 and 2030, the latest 2023 plan anticipates 60 GW (a twelve-fold increase). Due to the long-term nature of transmission upgrades, many of the limitations in interconnecting resources today can be traced to mischaracterizing the potential needs less than ten years ago. It’s important that this same mistake is not made again; otherwise, California will continue to see long-lasting infrastructure limitations for growth and competition in its energy market, which could have dire affordability consequences. Although CAISO’s recent reforms to the interconnection process address some of the mechanical constraints of studying and allocating capacity (which is needed), they also raise the stakes for getting state grid planning right: the CAISO will now only admit projects to the interconnection queue in areas that have existing or planned capacity in the state’s plan.

The state’s current electric system planning process is deterministic. Hundreds of assumptions are made for the cost and availability of different technologies, and an optimization model is used to select a cost-optimal portfolio. The selected portfolio is only cost-optimal if the hundreds of assumptions end up being accurate. But the inputs to these models are impossible to predict with any precision: things like load growth, trajectories of technology cost declines, tax credits, viability of emerging technologies, etc. The current process is not well equipped to study how alternative portfolios might be more robust against uncertainty. The selected portfolio could appear minimally cheaper than a portfolio with more diverse resources or more transmission flexibility, but those alternative portfolios may be much more cost-effective across an array of outcomes that vary from the assumptions used for the deterministic cost optimization.

Figure 1. Graph from Aaron Burdick of E3 on Nameplate Capacity Additions by 2030 (relative to a 2018 baseline) Across Evolving Plans¹⁵



Sonoma Clean Power (SCP) and Peninsula Clean Energy (PCE) sponsored research from Princeton University’s ZERO Lab to assess the cost and benefits of energy system planning in California that is responsive to uncertainty, rather than being optimized to a single set of deterministic assumptions. The Princeton ZERO Lab is led by Dr. Jesse Jenkins and is one of the nation’s leading energy systems research labs. Princeton led much of the modeling supporting policy in the Inflation Reduction Act and published research on the impact of transmission constraints to realizing its benefits. Dr. Jenkins has also published research on decision-making under uncertainty (DMUU) methods applied to energy system modeling. The primary researcher for the project is PhD Candidate Gabe Mantegna, who previously worked as a Senior Consultant at E3 and ran SB 100 modeling for California.

Study Setup & Results

Princeton has developed a fully functional capacity expansion model for California mirroring the capabilities of E3’s RESOLVE model that is currently used by the CPUC. Princeton’s model was developed using their open-source GenX platform. Princeton demonstrated that its GenX model was able to fully reproduce the portfolio and transmission upgrade recommendations as RESOLVE given a deterministic set of assumptions—which gave the project confidence that observations from the research are reliable and that the resulting model could be relied on as the basis for portfolio and transmission decisions California is making today. A key priority for SCP and PCE was that the project was not just an “academic exercise” but something that created a tool that could be immediately put to use for state planning and regulatory advocacy.

After benchmarking its GenX model, Princeton developed a formulation for applying decision-making under uncertainty to the model’s optimization. Princeton evaluated a number of DMUU methods and ultimately recommended applying a technique called “robust optimization” (RO). RO is a DMUU technique of optimizing a system against varying degrees of downside risk.

¹⁵ Graph is from the “Planning the Grid without a Crystal Ball” presentation given by Aarn Burdick of Energy Environmental Economics at the planning under uncertainty summit hosted by SCP and PCE on June 25, 2025 in Sacramento, California

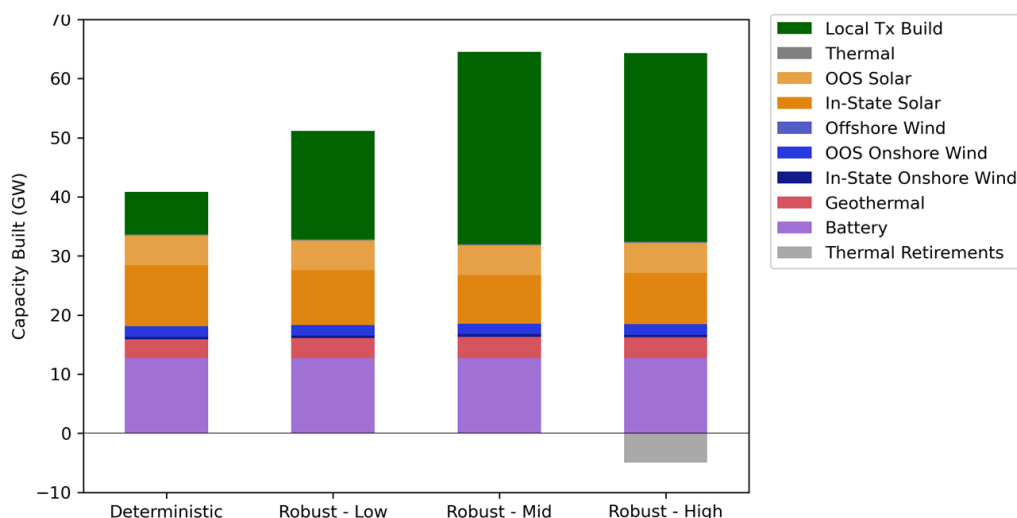
Unlike other DMUU techniques, RO is not dependent on subjective characterizations of uncertainty distribution—but rather enables decision-makers to tune their risk tolerance for downside scenarios and understand the resulting costs and benefits of that decision.

Princeton worked with SCP and PCE on identifying the uncertainties to include in the scope of the optimization. Sensitivity analysis was completed to ultimately inform the uncertainties that were included in the DMUU optimization. Examples include high/low load growth, continuation/expiration of federal tax credits, large range of available out-of-state resources, availability of emerging technologies like next-generation geothermal, range of offshore wind viability (including none), and business-as-usual vs increased costs for maintaining natural gas capacity.

The Princeton DMUU model is set up with two stages: a first stage comprised of portfolio decisions before the end of 2030 and a second stage for portfolio decisions thereafter. Given their lead time and impact on the options available in the second stage, transmission decisions must be made in the first stage. The model is tested against various combinations of downside scenarios, with the goal of selecting first-stage decisions that minimize the cost impacts of the modeled downside scenarios. Princeton studied a “Robust – Low” case where one downside uncertainty is tested at a time, a “Robust – Mid” case where combinations of two downsides are tested, and a “Robust – High” with combinations of three downsides. Moving from a deterministic scenario to a “Robust – High” scenario can be seen as increasing the level of a portfolio’s “robustness”.

Importantly, Princeton found that the main result of adding robustness is an increased investment in transmission. Figure 2 shows how the decisions made in stage 1 evolve with increased robustness from a deterministic optimization (left) up to a portfolio robust across combinations of three downside risks (right – “Robust – High”). Although there are some changes in the composition of the resource portfolio, the main observed difference is the scale of transmission build-out. Transmission allows decisions in stage 2 to be much more flexible in responding to unexpected conditions compared to a portfolio optimized for a deterministic set of assumptions.

Figure 2. First Stage Portfolio Composition vs. Robustness



Increasing robustness isn't free and it's important to understand both the costs and benefits to properly calibrate RO. Figure 3 shows that the robust scenarios are more expensive than the deterministic portfolio. Figure 4 demonstrates the financial benefits of investing in more first stage costs – the tail risk on the deterministic scenario is nearly cut in half with the “Robust – Low” scenario and greatly reduced in the “Robust – Mid” scenario. Although the “Robust – High” scenario offers further reductions, it's much less measurable. The “Robust – Mid” results show that there is a “sweet spot” where future cost risks for California’s electric system can be largely mitigated with minimal near-term cost impact. That “sweet spot” demonstrates the ability to use RO to tune the trade-off of risk tolerance versus cost.

Figure 3. First Stage Costs vs. Robustness

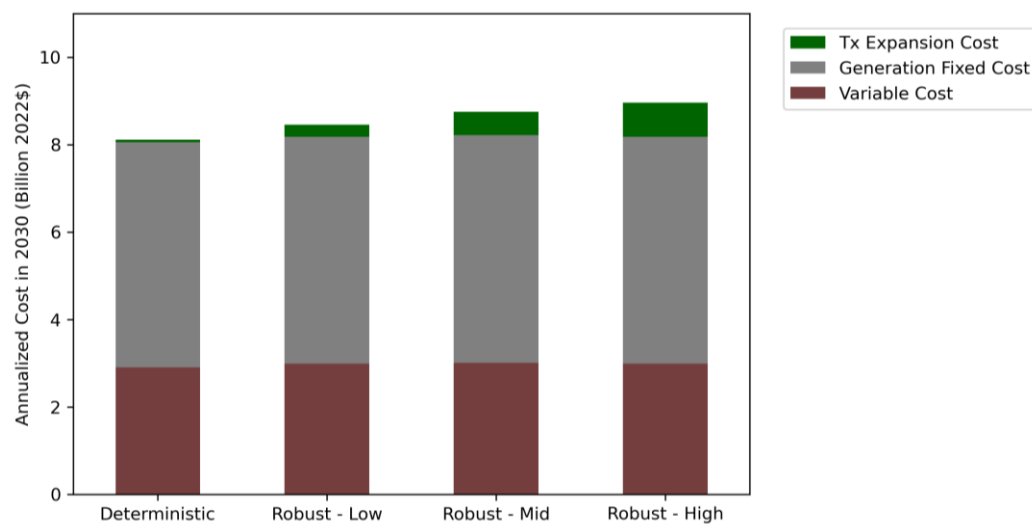
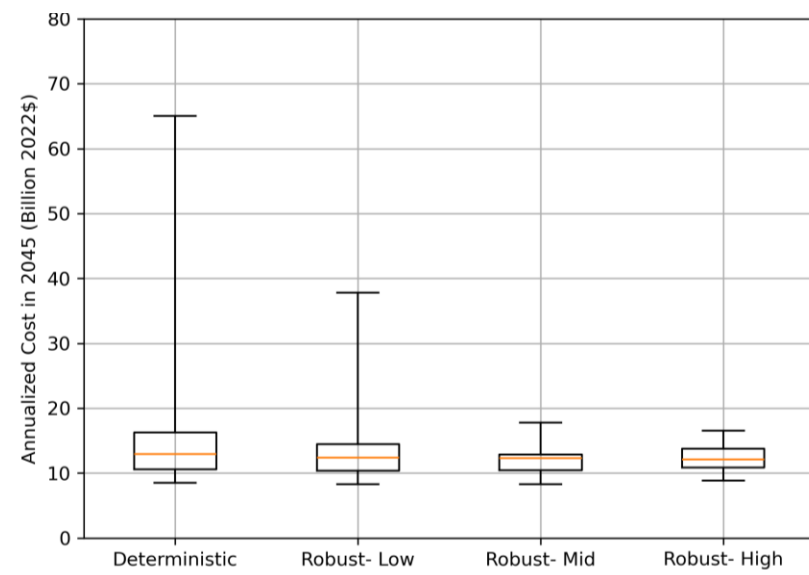


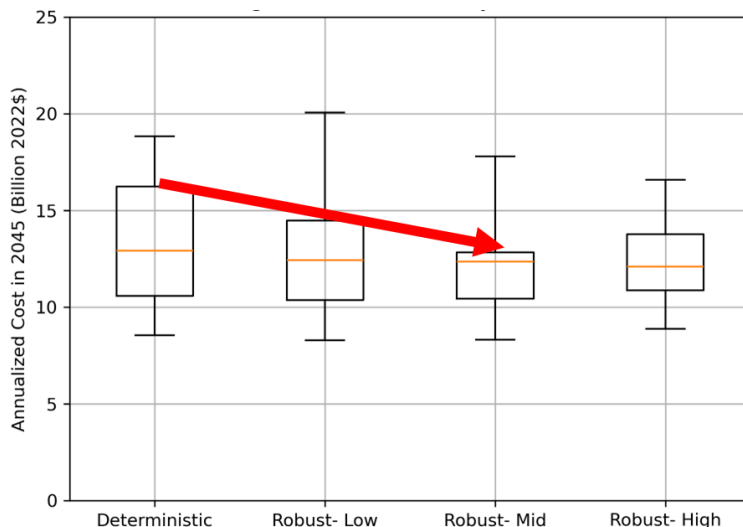
Figure 4. Second Stage Costs vs. Robustness



Like RESOLVE, Princeton’s GenX model estimates the cost of non-served energy (indicating conditions that incur blackouts with economic implications). The tail risk in the deterministic

and “Robust-Low” scenarios in Figure 3 are driven by scenarios of high load growth and limited resource availability that result in a large amount of non-served energy cost. Although including the economic impact of reliability in the model is the correct approach, the team has also looked at the impact of increased robustness on a cost distribution that excludes non-served energy cost—which is shown in Figure 5. The trend in the 75th percentile of second stage cost shows a noticeable improvement in the “Robust-Mid” case that easily outweighs the increased investment in transmission in the first stage (highlighted with red arrow).

Figure 5. Second Stage Costs vs. Robustness (Excludes Non-served Energy Costs)



Princeton has also developed a DMUU formulation that allows the impact of upside scenarios to be tested alongside RO. A benefit not captured in Figure 4 and Figure 5 is that increased transmission investment provides the state more flexibility to not only respond to poor outcomes but also be more opportunistic about unexpected opportunities. Princeton will include details about incorporating upsides in its research paper. Princeton also plans on testing more than two modeling stages and performing production cost modeling on the optimized portfolios before finishing the research project later this year. The GenX model, including the DMUU formulation and all input data, will be open-source and shared with SCP, PCE, and the energy system modeling community to build upon and use for planning purposes and further research following conclusion of the project.

Sacramento Summit – June 25, 2025

SCP and PCE convened a summit with 68 participants at the University of California’s Student and Policy Center in Sacramento to share Princeton’s research and facilitate a broader discussion of techniques and approaches to grid planning under uncertainty. Participants included regulators and state agencies (CPUC, CEC, CAISO), academia (Princeton, UC Berkeley, UC Merced, Stanford), peer utilities (CalCCA, Silicon Valley Clean Energy, PG&E, SCE), NGOs (CATF, TNC, Net-Zero California), energy modelers, and legislative staff.

In addition to Princeton’s research, the summit included four presentations from other members of the energy system modeling community pursuing similar initiatives. GridLab provided an

overview of techniques to quickly model and optimize systems that can deal with uncertainty and complexity. Stanford presented its approach to pro-active and more geographically granular transmission planning. E3 discussed its approach to supporting the Central Procurement Entity decision on offshore wind given uncertainty and discussed adaptive planning approaches. Berkeley shared the results of a case study in discussing how to handle uncertainty in California's grid planning. The presentations demonstrated weaknesses in the state's current process and toolbox, and the opportunity and value of more sophisticated approaches to energy system planning. SCP has prepared an event summary, including links to slides and notes captured during discussion available publicly online¹⁶.

A key takeaway from the research at the summit is that the state needs to be open to new approaches to energy system planning. The current deterministic approach is dangerously dependent on a single set of assumptions – as demonstrated in the downside tail for Figure 3. The state should consider adopting a DMUU approach to planning and prioritize mitigating future risks with near-term infrastructure investments. Increased investment in transmission should be seen through this lens; not necessarily as an incremental cost to ratepayers, but a reasonable investment in providing long-term protection from out-of-control system costs. Applying more sophisticated methods will require more resources, and the legislature should support increasing the personnel, tools, and budget for the CPUC Integrated Resource Plan team. The state should also prioritize providing comprehensive and standardized datasets that can be used by the stakeholder community in open-source tools to crowd-source innovation and new approaches to planning California's future grid.

¹⁶ Available at <https://sonomacleanpower.box.com/s/d1u6gju4bvjfyglnqr1iww3l78ik7re2>