BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

OPENING COMMENTS OF VOTE SOLAR, THE LARGE-SCALE SOLAR ASSOCIATION AND THE SOLAR ENERGY INDUSTRIES ASSOCIATION ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PORTFOLIO AND RELATED POLICY ACTIONS

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Pursuant to the November 6, 2019 Ruling by the Assigned Administrative Law Judge Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions (Ruling), as amended by a November 19, 2019 E-mail Ruling, Vote Solar, the Large-scale Solar Association (LSA) and the Solar Energy Industries Association (SEIA) submit the following comments.

I. INTRODUCTION

Vote Solar, LSA and SEIA recognize that the adoption of a Reference System Portfolio (RSP) is a key step in California's Integrated Resource Planning (IRP) process that will guide the development of individual integrated resource plans to be filed by load-serving entities (LSEs) and be used by the California Independent System Operator (CAISO) for the development of the 2020-2021 Transmission Plan. We appreciate that the 2017-2018 IRP process was the first iteration of a new statewide planning process that engaged many diverse LSEs as well as other parties. One of the key lessons learned over the past two years is that the RSP must be robust from a reliability perspective and must position California to achieve the ambitious goals set forth in Senate Bill (SB)100. If the RSP does not result in a reliable system and if it delays the procurement of the zero-carbon energy needed to be on the path to the SB 100 goals, then the plans that follow – the individual LSE IRPs, the aggregated Preferred System Portfolio, and the CAISO 2020-2021 Transmission Plan – will be deficient.

We have previously observed that the 2017-2018 IRP process did not result in the timely early procurement authorizations that might have prevented the need to continue the operation of

3,750 MW of antiquated once-through cooling (OTC) fossil power plants beyond 2020.[1] In that context, we expressed our concern that the need for new capacity resources must be anticipated far enough in advance to allow new clean resources to fill such needs. We are hopeful that the more granular near-term modeling in the 2019-2020 IRP will ensure that clean resources can fill all future resource needs.

The current Ruling acknowledges that the coming retirement of the Diablo Canyon nuclear plant units in 2024 and 2025 will lead to the need for additional capacity resources. The RSP and the Commission's follow-up policy actions will need not only to anticipate these retirements but assure that early and effective action is taken by LSEs or a backstop authority to ensure that clean replacement capacity is in place well in advance of the planned retirements of the two Diablo Canyon units.[2]

Vote Solar, LSA and SEIA urge the Commission to take early action associated with the adoption of the 2019-2020 RSP to ensure that sufficient clean Resource Adequacy (RA) resources are in place to enable the planned retirement of the OTC power plants and Diablo Canyon and to respond to other contingencies such as reduced import capability and the early retirement of other fossil resources.[3]

For reasons provided in more detail below, Vote Solar, LSA and SEIA recommend the Commission take the following actions in its decision on the 2019-2020 Reference System Portfolio:

1) Adopt a 30 million metric tons (MMT) greenhouse gas emission reduction target for California's electric sector;

2) Adopt a 30 MMT Alternate Reference System Portfolio that focuses on the procurement of solar paired with storage, as described further in these comments, as the basis for reaching the GHG emissions target for 2030 and for use as the reliability and policy-driven base cases for the next CAISO Transmission Planning Process (TPP).

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[1] See October 31, 2019 Comments of Vote Solar and SEIA on the Revised Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023.

[2] The Ruling at page 24 states that "the Commission may need to take additional actions now to ensure the replacement capacity for Diablo Canyon."

[3] We share the CAISO's concerns about the use of 2,000 MW of generic capacity in the Reference System Plan. See the November 27, 2019 Ex Parte Communication of the California Independent System Operator.

3) Recognize that the risks of developing large quantities of hybrid solar and battery storage projects can be reasonably managed and do not require changes to the RSP developed using the RESOLVE model.

II. DISCUSSION OF A 30 MMT 2030 GREENHOUSE GAS REDUCTION TARGET FOR THE ELECTRICITY SECTOR

During the 2017-2018 IRP process, California enacted SB 100. The statute requires the electric sector in California to meet retail electric load with 100% carbon-free resources by 2045. In addition, then Governor Brown issued an executive order which established a statewide goal to "achieve carbon neutrality as soon as possible, and no later than 2045, and maintain and achieve negative emissions thereafter."[4]

It is important that the 2019-20 IRP process take into account both the SB 100 goals and the commitment to economy-wide carbon neutrality by 2045. To that end, the Commission staff and its consultant, E3, conducted a SB 100 2045 Framing Study as part of the IRP process.[5] One purpose of the Framing Study was to inform the Commission as to how the longer-term SB 100 goals for 2045 should inform the appropriate 2030 GHG planning target that the Commission needs to adopt for the 2019-2020 IRP. The study acknowledged that near-term resource procurement decisions should be influenced by changes to the electricity sector that are necessary to achieve SB 100's longer-term goals for economy-wide decarbonization.[6]

The electrification of buildings, transportation and industry, as well as hydrogen electrolysis, have been identified by the California Energy Commission (CEC) as key elements of a decarbonization strategy and also as drivers of increasing electricity loads through 2045. Beneficial electrification will create a need for higher levels of renewable energy procurement both prior to 2030 and continuing through 2045.[7] The production of large quantities of hydrogen through electrolysis could provide an alternative pathway to carbon neutrality that provides a different form of system flexibility. This pathway also significantly increases electric load. Both

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[4] Executive Order B-55-18, September 10, 2018

[5] *2019-20: Preliminary IRP Results*, CPUC Energy Division, October 4, 2019. Pages 106-123.

[6] *Id*. Page 107.

[7] *Deep Decarbonization in a High Renewable Future*, California Energy Commission, June 2018 CEC-500-2018-012

pathways to carbon neutrality will require exponentially increased quantities of renewable energy through 2045.[8]

The SB 100 Framing Study identifies Resource Adequacy/Planning Reserve Margin as the principal system constraint driving the need for more resource procurement through 2030. After 2030, GHG emission reduction becomes the dominant constraint that impacts portfolio optimization.[9] These findings suggest that an optimal solution to co-optimize the costs of providing resource adequacy and reducing GHG emissions would be the accelerated procurement through 2030 of hybrid resource adequacy/carbon reduction resources – primarily solar generation paired with battery storage systems.

The SB 100 Framing Study recognizes that there is considerable implementation uncertainty in achieving GHG reduction targets in other economic sectors.[10] Increases in light-duty vehicle GHG emissions in California were observed in 2017 and uncertainty has increased regarding the implementation of more rigorous fuel economy standards. Further GHG reductions over the next decade from the additional procurement of renewable electricity represent a reasonable low-cost hedge against those uncertainties in other sectors. Such a hedge has become increasingly attractive as the cost of solar and storage have both declined significantly in recent years.

The SB 100 Framing Study concludes that a resource build under a more ambitious 2030 GHG reduction target of 30 MMT is more in line with 2045 GHG reduction goals. In fact, all three of the scenarios examined in the Framing Study, show that achieving a 2030 target of between 30 and 38 MMT is necessary to put the state on the trajectory necessary to reach the 2045 goals.[11] (See the figure below, from the SB 100 Framing Study.)

For these reasons, Vote Solar, LSA and SEIA recommend that the Commission adopt the 30 MMT target for 2030 and a Reference System Portfolio consistent with that goal.

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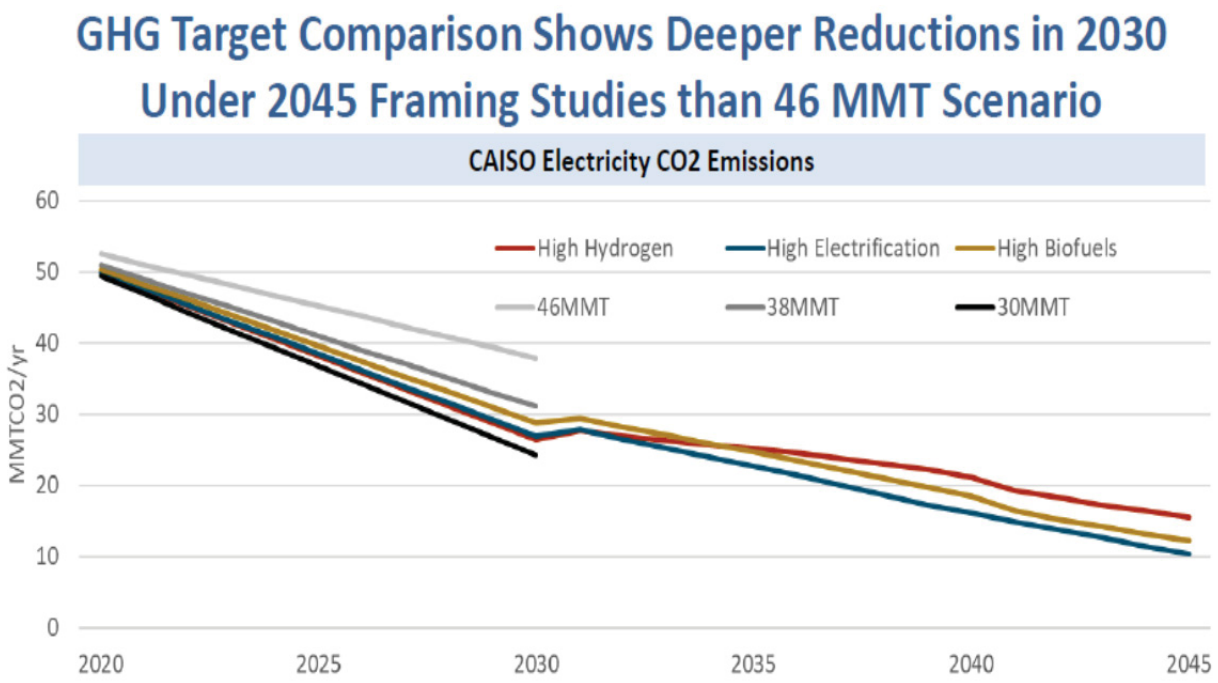
8 *Ibid*. The high electrification scenario requires 425 terrawatt hours of electricity in 2045 and the high hydrogen scenario requires 459 terrawatt hours.

9 Preliminary IRP Results, *Op. cit.*, page 117.

10 *Id*., page 120.

11 November 6 Proposed RSP presentation at Slides 162-166.



III. DISCUSSION OF A PROPOSED 30 MMT ALTERNATE REFERENCE SYSTEM PORTFOLIO

The Ruling has proposed the adoption of an 46 MMT Alternate Scenario which it claims "more closely approximates expected reality of electricity sector conditions."[12] The Ruling assumes that there will be limitations on the annual buildout of solar capacity in the early years and has modeled a maximum annual buildout of approximately 2,000 MW per year from 2021 through 2023. Vote Solar, LSA and SEIA observe that this is below the 3 GW annual build the state already achieved in 2014 in support of the Renewable Portfolio Standard goal of 33% renewables by 2020. We believe that a pace of solar deployment in the range of 3 to 5 GW per year is achievable in the 2022-2024 time frame, if strongly supported by state regulators This also would allow the state to maximize its use of the federal Investment Tax Credit (ITC), which the modeling in both this IRP and the prior 2017-2018 iteration have shown is the least-cost procurement strategy for California to reach its 2030 GHG reduction goals. In this regard, we submit that the Commission should modify the determination made in D.18-02-018 not to direct the early procurement of renewables that would have maximized the benefits of the solar ITC

[12] See Ruling, page 12.

and the wind production tax credit, and perhaps could have avoided the need to extend the OTC retirement dates.

Vote Solar, LSA, and SEIA have examined the CAISO's interconnection queue for hybrid solar and storage projects, and we conclude that the limitations imposed in the 46 MMT Alternate Scenario are not based on a factual analysis of current market conditions. The current CAISO interconnection queue shows that 30,245 megawatts of hybrid solar and storage projects are seeking interconnection. Projects totaling 4,779 megawatts have either executed interconnection agreements or are in negotiations with the transmission-owning utility. Another 4,660 megawatts of projects have completed Phase 1 and Phase 2 interconnections studies and are ready for negotiation of interconnection agreements.[13] Clearly, there is an ample supply of hybrid solar plus storage project opportunities to assure a competitive market for procurement by California's load serving entities.

Vote Solar, LSA and SEIA accept that there may be a time constraint that may limit the quantity of new renewable energy projects that can deliver power by the summer of 2021. However, after 2021 we see no justification for limiting the annual amount of procurement of solar projects paired with storage or other renewable resources. For modeling purposes, it may be reasonable to assume a multi-year glide path to reach the quantities of resources identified in the RESOLVE model.[14]

Fundamentally, the schedule for the procurement of new resources should be determined by the need to maintain a reasonable planning reserve margin and to meet GHG reduction targets. In fact, we see potential advantages to the "over-procurement" of clean energy resources during the IRP planning period. Earlier procurement will result in lower levels of cumulative GHG emissions during the 2020 to 2030 timeframe. In addition, early procurement will enable California to benefit from the federal tax credits which are scheduled to phase down through 2023. "Over-procurement" of storage capacity could also be beneficial in that it will create a more competitive market for ramping capacity during periods when there may be scarcity due to a decline in the availability of imports. An analysis of "over-procurement" was conducted by

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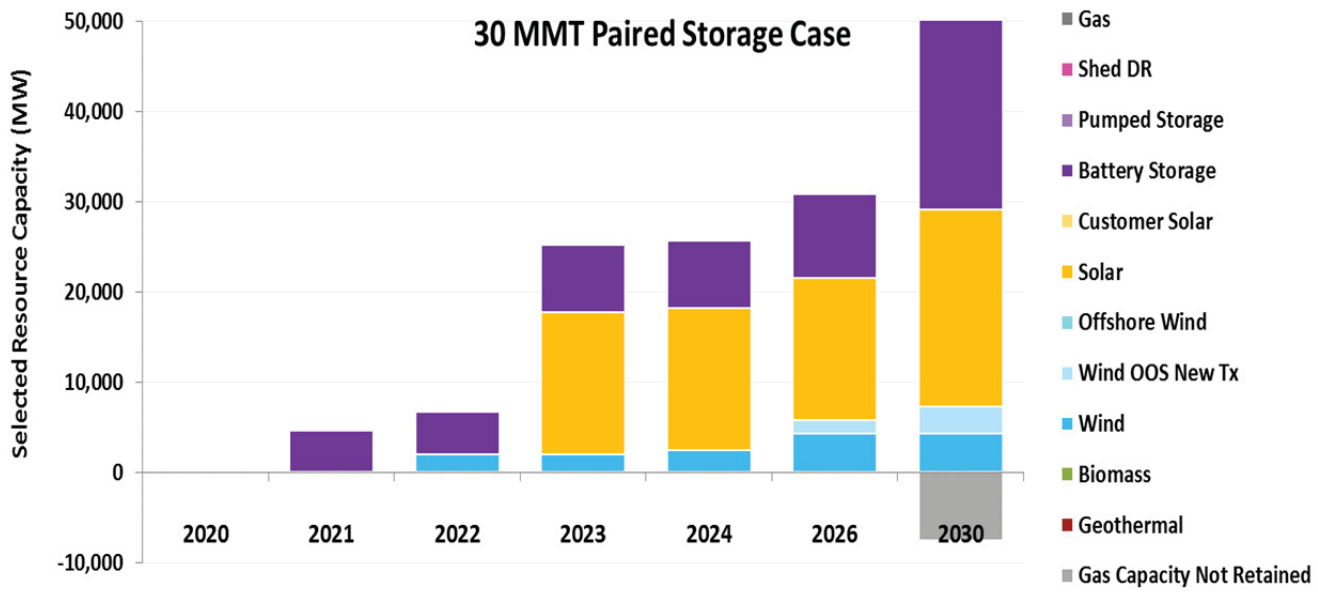
[13] Our analysis of the CAISO interconnection queue is included as Attachment A to these comments.

[14] If there is no constraint on the annual solar buildout, the RESOLVE model places most of the solar resources in 2023, the year with the least-cost combination of declining solar costs and the availability of the higher ITC.

Clean Power Research for the Minnesota Solar Pathways Initiative and it was shown to be economical and otherwise beneficial.[15]

We see no reason to set arbitrary limits on annual solar project development post-2021 either in the 46 MMT Alternate Scenario or any other scenario chosen as the RSP. New resource procurement by LSEs should be guided by the adopted Preferred System Portfolio which would be based on the system needs to meet aggressive GHG reduction goals and maintain system reliability.

In order to meet the 2030 GHG constraint of 30 MMT, Vote Solar, LSA and SEIA have assembled a 30 MMT Alternate Scenario. This scenario is based on the staff's 30 MMT case with paired storage costs, as shown below. This reduces storage costs by assuming that batteries also qualify for the ITC through 2023. We emphasize that the least-cost scenarios that the staff modeled, regardless of the 2030 target, are those in which storage costs are reduced through the pairing of solar and storage.



A major limitation in the RESOLVE modeling in this cycle is that paired solar plus storage resources are not a candidate resource. As a result, the timing of RESOLVE's selection of solar and battery resources is not coordinated, as they would be if paired solar-storage units were a candidate resource. The staff's 30 MMT paired storage case selects significant battery

[15] The *Minnesota Solar Potential Analysis Report,* November 2018 (.pdf download – 99 pages)

resources to meet the 2021 capacity needs, then a large amount of solar in 2023 to access the ITC and meet the 2030 carbon constraint (see the left side of Table 1 below). We have revised this build-out to advance the solar deployment to pair correctly with most of the battery capacity. We have assumed 4 GW of paired solar-storage deployment in 2022 and 5 GW in 2023, with the paired battery capacity assumed to be 65% of the solar capacity. The 65% ratio of nameplate battery storage capacity to nameplate solar capacity is derived from the average capacities for paired solar plus storage resources in the interconnection queue.[16] As noted above, there already are more than enough paired solar-storage projects in the interconnection queue to have robust competition for a deployment of this size.

The right side of Table 1 below summarizes the proposed buildout schedule for our 30 MMT Alternate Scenario. The staff's 30 MMT paired storage case selected 15,724 MW of new solar projects by 2023 and an additional 6,080 MW of solar in 2024-2030, for a total of 21,804 MW in 2030 as the optimal portfolio to meet the 30 MMT GHG target by 2030. The proposed 30 MMT Alternate Scenario that we have developed smooths out the procurement pathway to reach the 15,724 MW by 2026 and 21,804 MW by 2030.

The 30 MMT Alternate Scenario which we are proposing also establishes a "Paired Storage" target for each of the years in the planning horizon, with all of the solar assumed to be paired with storage whose capacity is 65% of the solar nameplate, as indicated by the current interconnection queue Additional storage capacity selected by RESOLVE is assumed to be standalone storage; an increase in standalone storage of about 500 MW per year through 2026 appears adequate to meet the state's capacity needs. As shown in the table, there also is additional storage in the 2024-2026 period, compared to the RESOLVE results, which should remove the need for the 2,000 MW of "generic" capacity in the staff's proposed RSP. The amount of standalone storage (7,079 MW) to be procured in 2030 is the difference between the total amount of battery storage in the 30 MMT default scenario (21,251 MW) and the amount of hybrid storage procured over the forecast period (14,172 MW).

[16] The ratio of storage capacity to nameplate solar capacity is 65% based on the current CAISO interconnection queue.

Table 1: Vote Solar - LSA - SEIA 30 MMT Alternate Scenario

All figures are MW.

	Staff 30 MMT paired storage		VS - LSA - SEIA 30 MMT Alternate		
			Battery		
Year	Battery	Solar	Standalone	Paired	Solar
2021	4,608	0	500	1,300	2,000
2022	4,801	0	1,000	3,900	6,000
2023	7,528	15,724	1,500	7,150	11,000
2024	7,528	15,724	2,000	8,174	12,575
2026	9,290	15,724	3,000	10,221	15,724
2030	21,251	21,804	7,079	14,172	21,804

Table 2 below compares the total resource costs (TRC) for the proposed 46 MMT RSP, the staff's 30 MMT Reference case, and our recommended 30 MMT Alternate RSP. We base the costs for our recommended RSP on the TRC for the 30 MMT Paired Storage sensitivity case. Our 30 MMT Alternate RSP has only about 56% of the incremental TRC as the 30 MMT Reference case, and is just $710 million per year (1.6%) more expensive than the staff's proposed 46 MMT RSP. This does not factor in that the staff's proposed 46 MMT RSP excludes the costs for the 2,000 MW of "generic" capacity in 2026 that the staff found to be needed in its production cost modeling. The early adoption of solar in the 30 MMT Paired Storage case also results in fewer GHG emissions in the interim years, as shown in Table 2. This table also shows the levelized annual TRC for each scenario.

Table 2: GHG Emissions and TRC Comparisons

Year	Staff 46 MMT Proposed RSP	30 MMT Reference	30 MMT Paired Storage
GHGs *(million tons/yr)*			
2020	45.0	45.0	45.0
2021	42.3	43.4	43.5
2022	39.6	41.2	41.4
2023	38.9	34.3	33.5
2024	40.1	36.5	36.1
2026	42.9	34.3	34.3
2030	37.9	24.3	24.3
TRC ($ *billions/yr*)	45.339	46.603	46.050

III. RISKS OF DEVELOPING LARGE QUANTITIES OF HYBRID SOLAR AND BATTERY STORAGE PROJECTS CAN BE MANAGED.

The Ruling raises the question of whether it is a problem that RESOLVE selects large quantities of solar and battery storage projects for the RSP. The Ruling identifies five potential risks associated with the predominance of solar and storage in the RSP: 1) the availability of the solar and storage resources, 2) the costs assumptions for these resources utilized in RESOLVE, 3) the declining capacity value of the resources with greater levels of penetration, 4) the operational risk of battery storage being used for load following and resource adequacy, and 5) the lack of diversification of selected new resources.

As detailed below, Vote Solar, LSA and SEIA do not believe that there are any serious concerns about the risks associated with the selection of large quantities of solar and battery storage in the modeling used for the RSP.

A. Availability of Solar Photovoltaics and Battery Storage Systems

With respect to availability, solar photovoltaic modules are an international commodity with a wide diversity of suppliers. Global markets for solar modules have been growing robustly over the past 20 years without significant supply bottlenecks.[17] At the end of 2018, photovoltaic installations worldwide totaled 503 GW - an increase of 100 GW over 2017 levels. Even the very robust quantities of solar forecast in our 30 MMT Alternate Scenario would not require more than 5% of the worldwide supply of modules in any year. The National Renewable Energy Laboratory (NREL) notes that the supply chain for solar modules including silicon refining, ingot and wafer production, cell conversion and module assembly are all global enterprises. [18] NREL observes that the long-term growth of the photovoltaic manufacturing industry will likely be more reliant on integration with storage technologies than on cost reductions.

We have noted previously the well-developed pipeline of hybrid solar and storage projects in the CAISO interconnection queue. The quantities in the queue represent more than twice the amount of megawatts that would be procured under our 30 MMT Alternate Scenario. While the CAISO queue does not specify the battery technology included in the hybrid projects it is reasonable to assume that the majority of the projects use lithium ion batteries. However, as

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[17] https://www.nrel.gov/docs/fy19osti/73948.pdf

[18] *Ibid.*

the cost of alternative chemistries decreases it is also reasonable to expect there will be more diversity in battery types.

As with photovoltaic modules, the growth in the market for lithium ion batteries has been robust. The lithium ion battery market is expected to exceed more than $92 billion by 2024 at a compound annual growth rate of 16.5% during the forecast period. [19] Both the surge in Electric Vehicle demand and the emerging market for stationary battery systems is driving growth in the production of lithium ion batteries. In response to the demand, suppliers in multiple regions of the world are ramping up battery production capacities.[20]

There is neither evidence nor analysis showing any realistic risk of a lack of available solar and battery resources during the planning period.

B. Future Costs of Solar and Battery Resources

The costs for solar and battery resources used in the RESOLVE base case model are likely to be conservative, that is, to overestimate the cost of solar and battery technologies. RESOLVE uses the 2018 NREL Annual Technology Baseline to determine the capital and operating costs of solar PV resources for each forecast year. The report provides three capital cost trajectories.

Vote Solar, LSA and SEIA believe that the NREL low-cost trajectory is most closely aligned with recent market trends for the pricing of energy from utility-scale solar projects.[21] A recent example of pricing in California is the power purchase agreement negotiated by the Los Angeles Department of Water and Power with the owners of a dispatchable 400 MW solar plus storage project in the Mojave Desert at an average energy price of $31/MWh flat for 20 years.[22] Lazard in its most recent LCOE Report shows the unsubsidized levelized cost of energy for a utility-scale solar power plant ranging from $32 to $42 per MWh.[23] Based on this recent information about PV pricing trends as well as the fact that the solar paired with storage cases are the lowest-cost cases modeled in this round of the IRP, the Commission should adopt the

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[19] https://www.marketresearchengine.com/lithium-ion-battery-market1.

[20] *Ibid.*

[21] https://www.renewableenergymagazine.com/panorama/bnef-solar-and-wind-reach-parity-with-20191029.

[22] Meeting Agenda Los Angeles Water and Power Commissioners, Sept 10, 2019, Item 21.

[23] Lazard's Levelized Cost of Energy Report 13.0, November 7, 2019.

paired storage case as the Reference System Portfolio in this IRP cycle.

The pricing of battery storage has plunged dramatically during the past year. Bloomberg NEF recently reported that the levelized cost of electricity for lithium-ion batteries had declined by 35% since the first half of 2018.[24] The RESOLVE model currently uses battery cost information from the 2018 Lazard Levelized Cost of Service (LCOS) Report V. 4.0. The more recent Lazard LCOE V. 5.0 LCOS report has just been released.[25] It shows dramatic reductions in costs. The magnitude of cost reductions from 2018 to 2019 for battery storage technologies makes it prudent for staff to update the battery cost assumptions in RESOLVE. If that is not possible, then it provides another reason to adopt the Paired Storage case as the Reference System Portfolio.

As evidenced above, it is more likely that prices for solar and battery systems will continue to decline than for prices to remain unchanged as is assumed by the RESOLVE High Cost PV sensitivity. Thus, we view the risk of cost increases for solar and storage technologies to be minimal.

C. Future Capacity Value of Battery Storage Systems

Vote Solar, LSA and SEIA do not dispute that there is a relationship between the capacity value of a four-hour battery and the amount of penetration of battery storage systems in the wholesale market. However, we do not believe that with the expected battery deployment level over the next five years there should be any degradation from the 100% capacity value currently provided by resource-adequacy eligible battery storage systems whether paired with solar or not.

We note that the preliminary IRP results report provides an illustrative battery storage ELCC curve.[26] This curve shows stair-step decreases in capacity value as battery storage penetration reaches certain thresholds. While this reduction in value is directionally understood there needs to be more transparent analysis to determine the details of any battery storage ELCC curve. Such analytical work will be important in the future, but there is no need to change the trajectory of near-term procurement at this juncture.

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[24] https://about.bnef.com/blog/battery-powers-latest-plunge-costs-threatens-coal-gas/#_ftn1

[25] https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf

[26] 2019-20: Preliminary IRP Results, CPUC Energy Division, October 4, 2019, page 49.

D. Operational Risks of Battery Storage Deployment

Battery storage systems provide multiple benefits to the electric system and to energy end-users. The CAISO and the European-based Renewable Grid Initiative have identified the following benefits provided by battery storage systems: 1) storing and smoothing renewable generation thus enabling the integration of variable renewables, 2) reducing greenhouse gas emissions, 3) improving the reliable operation of transmission and distribution grids, 4) balancing grid supply and demand, 5) deferring costly investments in transmission, distribution and generation infrastructure, 6) reducing demand for peak electricity generation, 7) lowering wholesale electricity prices by peak shaving and creating price arbitrage opportunities, 8) reducing end-use consumer demand charges and 9) providing back-up power.[27] Many of these use cases anticipate daily cycling of the battery systems; all of these use cases offer needed and important benefits to the California electric system. The future challenge will be to determine how best to operate storage to maximize these benefits.

Battery manufacturers are well aware of these requirements and the need to provide performance guarantees and warranties to assure market access. The Lazard Levelized Cost of Storage V. 5.0 provides detailed information about the expected operational parameters for batteries in the various use cases.[28] We believe that the operational requirements for battery systems are best managed through clear contractual obligations between the battery resource developer and the offtaker.

Battery storage systems will serve a critical role in decarbonized electric systems around the world. We are pleased to see that the California ISO and leading European Transmission System Operators and European NGOs have jointly laid out a collaborative agenda for responsibly increasing their deployment. We believe that the operational risks of battery storage systems will be managed best through their deployment in many locations and in various use cases, as well as through the sharing of learning about best practices to maintain durable, reliable performance.[29]

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[27] Energy Storage, Perspectives from California and Europe, California ISO and Renewables Grid Initiative, October 2019.

[28] https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf

[29] The CAISO and Renewable Grid Initiative white paper provides a list of 10 recommendations for collaborative study on page 30.

E. Lack of Diversification of Selected New Resources

Vote Solar, LSA and SEIA understand the concept of resource diversification being beneficial to the electric system along various dimensions including geographic diversity, the financial diversity of resource providers, and the diversity of power technologies. The concept of maintaining sufficient operating reserves to withstand contingencies is well developed among energy system planners and is incorporated in security-constrained economic dispatch. While the concept of diversification is easy to understand, we see no compelling quantitative analysis in this proceeding to indicate that the levels of solar and battery deployment envisaged in our proposed RSP with a 30 MMT 2030 goal creates any unreasonable risk.

We recognize that there are longer-term opportunities to develop out-of-state and offshore wind projects, advanced geothermal technologies and emerging technologies like wave and tidal generation, and we support the continued evaluation of these longer-term options. The 2019-2020 planning process did evaluate adding new transmission to access out-of-state wind as well as opportunities for offshore wind development in several locations along the California coast. There was a positive economic benefit from adding new out-of-state transmission in the 30 MMT scenario. The incremental annual TRC is reduced from $1,242 million to $1,182 million in the case where 6 GW of out-of-state wind is developed. However, as we have observed, a much larger benefit is created by pairing solar with storage. The incremental TRC in our proposed 30 MMT Alternate was about $700 million compared to the staff's proposed RSP with a 46 MMT target. While we support continued evaluation of diversity benefits in future iterations of the IRP, we recommend against adjusting the selected resources in the 2019-2020 IRP.

IV. ANSWERS TO SELECTED QUESTIONS

7. *Provide any comments on the results from the major scenarios or sensitivities analyzed by Commission staff to develop the RSP recommendation.*

See the discussion above about the value of treating paired solar and battery systems as candidate resources. Early procurement of solar plus storage while the federal investment tax credit is in place can yield significant value to the electric system and ratepayers.

9. *Comment on the manual addition of 2,000 MW of "generic effective capacity" in order to produce a portfolio with an LOLE result of less than 0.1. Would you recommend a different way of depicting the reliability gap in the portfolio?*

The use of 2,000 MW of generic effective capacity is problematic. The CAISO has explained the problems well in its *ex parte* communication to the Commission.[30] We agree with the CAISO recommendation that RESOLVE modeling should re-optimize the RSP by removing OTC resources after 2020 and limiting import energy to match the resource adequacy limit for imports (5,000 MW).

10. *Do you support the 46 MMT Alternate Scenario as the basis for the GHG emissions goal for 2030 to be affirmed by the Commission. Why or why not?*

No. The 46 MMT Alternate Scenario fails to put the State on the path to meeting the SB 100 goal of meeting 100% of retail load with carbon-free resources by 2045. The 46 MT Alternate also fails to provide for a reliable electric system. Instead it requires the assumption that the equivalent of 2,000 MW of generic effective capacity will be procured somehow later in the 2020 decade. These are not acceptable outcomes.

11. *Are your concerned about the risk of overreliance on solar as part of the recommended portfolio? Why or why not?*

No. See the detailed discussion above.

12*.* *Are you concerned about the risk of overreliance on battery storage as part of the recommended portfolio? Why or why not?*

No. See the detailed discussion above.

13. *Is the retention of most or all of the current thermal generation fleet reasonable and realistic? Why or why not?*

It is not reasonable or realistic to assume that "most or all" of the current thermal generation fleet will be retained, particularly if the 30 MMT GHG target is adopted as we recommend. We do not believe that full retention of the current gas fleet is necessary to maintain reliability.

As the State adds to its portfolio of clean resources to meet the GHG reduction target for 2030, capacity factors at gas plants will decline even for the most efficient plants in the fleet, and battery storage will supply an increasing share of the ramping and peaking capacity that gas-fired units now supply. Nonetheless, we agree that there will be a need to keep a significant share of

[30] Notice of ex parte communication by the California Independent System Operator in R. 16-02-007 (November 27, 2019).

the most efficient gas plants available to provide contingency reserves during extended periods of low solar and wind output until other solutions are found.

The RESOLVE scenarios show relatively moderate retirements of existing gas-fired capacity by 2030, even with the 30 MMT GHG target. For example, the 30 MT case with lower paired storage costs retires about 7.6 GW of gas capacity in 2030.[31]

Vote Solar, LSA and SEIA are concerned that the staff's RESOLVE base case presents an inaccurate picture of the future economics of gas-fired generation in California, due to its use of a draft CEC IEPR forecast of burner-tip gas prices for gas-fired electric generation (EG) that is both in error and unreasonably low.

The CEC IEPR gas forecast erroneously assumes that today's intrastate gas transportation rates for EGs will not escalate at all in the future, not even with inflation.[32] In reality, intrastate gas transportation rates for EG plants in California have escalated at about 15% per year since the San Bruno pipeline explosion in 2010, driven by a combination of increasing costs for safety-related investments and declining throughput due, in significant part, to the growth in renewable electric generation and the state's carbon reduction goals.

Two major new studies completed this year have documented that sharp escalations in intra-California gas transportation rates will continue in the future.[33] One of these studies, done by Gridworks with funding from PG&E and the Energy Foundation succinctly summarizes the challenge that the state faces with keeping future gas rates affordable:

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[31] *See* November 6 Proposed RSP presentation, at Slide 111.

[32] The draft forecast appears to be based on tariffed intrastate transportation rates as of April 2019 for Pacific Gas & Electric (PG&E) and from about 2017 for Southern California Gas (SoCalGas). There is no change assumed in these rates in all forecast years after 2019. The CEC's IEPR gas forecast models are found at: https://ww2.energy.ca.gov/assessments/ng_burner_tip.html. This link has the CEC's gas price forecast workpapers for its forecasts in April 2018, March 2019, April 2019, and October 2019, and earlier. For example, if you open the 2019 IEPR forecast from October (or any other version), intrastate rates are shown on the PG&E, SoCalGas, and SDG&E tabs of the spreadsheet. For example it shows $1.6971 for the EG transportation rate in cell F3 of the "PG&E" tab. That is the April 2019 PG&E rate. If you go to the "Mid-Demand Monthly" tab, in column BH you will see that rate in all months from January 2017 through December 2036. Thus, the (nominal $/Dth) burnertip prices in column BI include that single rate for all future months.

[33] Energy and Environmental Economics, "Draft Results: Future of Natural Gas Distribution in California," presented at the CEC Staff Workshop for CEC PIER-16-011 on June 6, 2019. Hereafter, "E3 Gas Study." Available at https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdf. Also Gridworks, *California's Gas System in Transition: Equitable, Affordable, Decarbonized and Smaller* (September 19, 2019), available at https://gridworks.org/initiatives/cagas-system-transition/, hereafter "Gridworks Study."

> *The simple fact is that meeting California's GHG reduction goals, a statewide priority and absolute necessity to combat climate change, inevitably means a substantial decline in gas throughput in the state.*
>
> *At the same time that gas demand is projected to decline over time, the costs of operating a safe and reliable gas delivery system in California have been increasing.*[34]

The study shows that intrastate gas rates will increase significantly for all classes of gas customers, including EG plants, and that it is the remaining residential gas customers who will face the largest increases, unless the state adopts a comprehensive, carefully-planned set of mitigation measures.

These measures include accelerated depreciation, reduced investments and targeted retirements, securitization, and cost allocation and rate design changes for gas distribution costs. The Gridworks Study shows that these mitigations could have a significant impact to reduce the escalation in future rates for residential and other small customers, but would not have a major impact in reducing the escalation in EG rates.[35]

These important new studies show conclusively that assuming zero future escalation in today's gas transportation rates produces an unrealistic forecast that fails to reflect the reality of California's gas industry, either in the recent past or going forward. SEIA has submitted detailed comments to the CEC on this major problem with the draft IEPR gas forecast; these comments are included as Attachment A to these comments. In those comments SEIA recommended that the IEPR forecast should assume that current intrastate rates will increase at real escalation rates of 9% per year to 2025, then 4% thereafter to 2050 (in nominal terms, this would be 11% per year to 2025, then 6% per year thereafter, assuming 2% inflation). This recommendation is consistent with the EG rate scenarios in the Gridworks Study even with the best-case suite of mitigations that have yet to be adopted.[36]

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[34] Gridworks Study, at page 1.

[35] The Gridworks Study acknowledges, at page 14, that the severe increases in residential rates could generate future pressure to shift costs from small customers to large users such as EG plants, further increasing EG rates. The Gridworks Study states that such a re-allocation of costs would need to be "carefully considered" given that it would increase electric rates and could shift carbon emissions to out-of-state EG plants.

[36] *See, e.g.*, Figure 9 on page 14 of the Gridworks Study.

SEIA and Vote Solar used these escalation rates to develop a revised long-term gas forecast that we have submitted recently for the record in the IDER proceeding, R. 14-10-003, which is revising the Avoided Cost Calculator used to assess the cost-effectiveness of distributed energy resources (DERs).[37] This forecast is well above even the High Gas scenario that staff developed as a possible input assumption for this IRP cycle (but has not run as even a sensitivity case). We are providing this forecast, which is in nominal dollars, as Attachment B, and recommend its use in the final RSP.

Commission staff commented in the recent workshop on the draft RSP that they may be constrained to use the CEC IEPR gas forecast as the result of an agreement with the CEC. Vote Solar, LSA and SEIA note that the draft RSP uses the draft CEC IEPR forecast; we urge the Commission to coordinate with the CEC to ensure that the final IEPR gas forecast assumes a realistic escalation in transportation rates.

The Commission has already issued a final decision that is contrary to the draft IEPR's forecast of no future escalation in intrastate transportation rates: D. 19-09-025 in the PG&E GT&S rate case adopted significant increases in PG&E's gas transportation rates for the years 2019-2022. As set forth in the rates adopted in this order, from 2019 through 2022, PG&E's backbone rates will increase by an average of 16% per year and the local transmission rate for EG customers will increase at 4% per year.[38] It unreasonable for the Commission to adopt a gas forecast that does not escalate intrastate transportation rates, when it has already decided to increase those rates.

We have run RESOLVE for a 30 MMT case with our recommended higher gas prices. The impact of the higher gas prices on the resources selected was relatively modest, with a small increment of several hundred MWs of additional solar in 2030. The most significant impact was a significant substitution of imported power for the more expensive in-state gas generation. In 2030, with higher intra-California gas prices, the in-state gas plant capacity factor diminishes to just six percent (6%), with a corresponding reduction in criteria air pollution in California communities located near existing gas plants.

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[37] R. 14-10-003, *Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association and Vote Solar* (October 7, 2019), at pp. 18-31 and Attachment RTB-2.

[38] *See* D. 19-09-025, rates at Appendix H, Tables 5-12. Average backbone rates on the Redwood and Baja paths will increase from $0.54 in 2019 to $0.84 per Dth in 2022, and EG-LT rates will increase from $1.58 per Dth in 2019 to $1.78 per Dth in 2022.

16. *Should the Commission take steps to support the development of at least one pumped storage facility in California? If so what steps?*

Yes. Long-duration storage will be necessary to economically integrate increasing quantities of variable output generation. Long-duration storage can be supplied by multiple storage technologies including pumped hydroelectric storage, compressed air storage, flow batteries and through hydrogen production. We believe that it is important to model long-duration storage (e.g. 12 hours and 24 hours) as part of the Joint Agencies SB 100 reporting process and through the CAISO transmission plan. We would not object to the Commission providing policy-driven sensitivities built around specific long-duration storage projects for consideration in the CAISO TPP.

17. *Are there other actions the Commission should take specifically with respect to replacement capacity for the Diablo Canyon nuclear plant?*

Yes. The Commission should adopt the 30 MMT Alternate we have recommended as the Reference System Plan. To replace the Diablo Canyon units, without exacerbating state GHG emissions, the Commission should authorize additional procurement of clean, renewable resource adequacy (RA) capacity as soon as possible.

19. *Comment on the recommendation to use the 46 MMT Alternate Scenario as the reliability and policy-driven base cases for the next CAISO TPP.*

We are opposed to the Commission adopting the 46 MMT Alternate Scenario as the reliability and policy-driven base cases for the next CAISO TPP. We agree with the CAISO in its recommendation that the staff needs to re-optimize its proposed RSP by removing the OTC power plants and making adjustments to the quantities of imported energy.

20. *Comment on the recommendations for policy-driven sensitivities around curtailment in particular transmission zones and the associated impact on EO or full deliverability for renewables.*

We believe the Commission should replace its emphasis on energy only (EO) transmission capabilities in the policy-driven sensitivities with assessment of how to achieve greater Full Capacity Deliverability Status (FCDS) for renewable energy. The sensitivities should also focus on the need for longer-duration energy storage and model transmission solutions that will enable the timely development of these resources. For example, one

interesting opportunity is to examine the opportunities for more integration of the CAISO and LADWP balancing areas with access to new storage being contemplated in Utah.

V. CONCLUSION

Vote Solar, LSA and SEIA thank the Commission for its work to establish a reliable Reference System Portfolio for the 2019-2020 IRP. The Commission should adopt the 30 MMT Alternate scenario presented above, which is built around paired solar-storage resources and sets the electric sector on a course to achieve its climate targets – something the 46MMT clearly will not accomplish. We urge the Commission to take immediate bold steps to procure additional resources to ensure that the State can make significant progress in meeting our vitally important GHG goals.

Respectfully submitted this December17, 2019, San Francisco, California.

/s/ R. Thomas Beach

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3326/032/X213448.v1

[39] In accordance with Rule 1.8(d), SEIA's representative is authorized to sign these comments on behalf of Vote Solar and LSA.

ATTACHMENT A

Solar Energy Industries Association And Vote Solar Comments on 2019 IEPR Workshop on the *Revised Natural Gas Price Forecast and Draft Outlook Electricity Modeling and Results*

I. Introduction and Summary

The Solar Energy Industries Association (SEIA)[1] and Vote Solar[2] appreciate the opportunity to comment on the California Energy Commission's (CEC) *Revised Natural Gas Price Forecast and Draft Outlook Electricity Modeling and Results* for the 2019 Integrated Energy Policy Report (IEPR). The IEPR natural gas forecast is a critical input into the work of the CEC and other responsible state energy agencies such as the California Public Utilities Commission (CPUC). SEIA's and Vote Solar's ongoing involvement in the CPUC's ongoing Integrated Resource Planning (IRP) proceeding, in which the CEC's 2019 IEPR natural gas forecast will be used, has surfaced a significant concern with the draft forecast and motivated these comments. We also provide our feedback on a number of less significant technical issues with the draft forecast.

Our major concern is that the draft natural gas forecast does not include any projection of future increases in the tariffed cost of intrastate transportation within California. The forecast simply uses the current tariffed rate and assumes that this rate will apply without change in nominal terms for the next twenty years. The draft forecast appears to be based on tariffed intrastate transportation rates as of April 2019 for Pacific Gas & Electric (PG&E). For Southern California Gas (SoCalGas), the intrastate rates used are significantly lower than current rates, and appear to date from about 2017. The CEC IEPR forecast shows no change in these rates in years after 2019.

As discussed below, this assumption of no future escalation in intra-California gas transportation rates is no longer tenable, given both the rapid escalation in these rates over the last decade and the certainty that these increases will continue. These sharp increases are driven by the dual realities of increasing costs and declining throughput as California tries to meet the dual goals of both enhanced safety and carbon reduction. We respectfully submit that this issue needs to be addressed, because intrastate transportation costs now comprise a significant portion

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[1] SEIA is the national trade association of the United States solar industry. The views contained in these comments represent the position of SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

[2] Vote Solar is a non-profit advocacy organization working to foster economic opportunity, promote energy security and fight climate change by making solar a mainstream energy resource.

– up to 40% for EG plants on the PG&E local transmission system[3] – of the burnertip cost of natural gas, and this percentage is highly likely to increase in the future. A failure to include a more realistic escalation than zero in future intrastate gas transportation rates may call into question other planning efforts in which the IEPR gas forecast is a key assumption, including the ongoing CPUC's IRP proceeding and other resource planning dockets.[4]

II. Comments

A. Escalation rates

California's ambitious goals to reduce greenhouse gas emissions to 40% below 1990 levels by 2030, and to be carbon neutral by 2045, will have major impacts on California's natural gas system that are now coming into focus. In particular, reaching the state's carbon reduction goals will result in a significant drop over time in natural gas use among all types of gas customers. Gas throughput on the PG&E and SoCalGas systems is already starting to decline, dropping by about 5% per year over the last five years, as shown in **Table 1**'s recorded data for 2013-2018 from the *2019 California Gas Report Supplement*.[5]

Table 1: *Recorded Statewide Gas Supply (MMcfd)*

Year	Throughput
2014	6,504
2015	6,399
2016	5,934
2017	5,862
2018	5,107
Average Annual Change	-5.9% per year

As the CEC is well aware, in recent years there have also been serious safety incidents on the California gas system – first, the 2010 San Bruno explosion of a PG&E gas transmission line that killed eight people and destroyed a neighborhood and, second, the 2015 well failure at SoCalGas' Aliso Canyon storage field that resulted in a major release of methane, with lengthy

[3] As an example using public data, in PG&E's current short-run avoided cost (SRAC) posting of QF energy prices, intrastate transportation costs presently comprise 43% of the posted burnertip cost of gas. See, for example, PG&E's October 2019 SRAC posting, which has a bidweek border commodity gas price of $2.32 per Dth (57%) and an intrastate transportation cost of $1.75 per Dth (43%). Available at https://www.pge.com/en_US/for-our-business-partners/energy-supply/prices-for-qualifying-facilities-and-eligible-combined-heat-and-power-facilities/prices-for-different-facilities.page?ctx=business.

[4] SEIA will be filing similar comments in December in the CPUC's IRP docket, R. 16-02-007, where the draft IEPR gas forecast for EG plants is being used. SEIA also has submitted testimony and an alternative long-term gas forecast in CPUC Docket R. 14-10-003, which is considering changes to the CPUC's avoided cost calculator (ACC). The ACC is used to assess the cost-effectiveness of demand-side, distributed energy resources (DERs) including energy efficiency, demand response, distributed generation including behind-the-meter solar, and behind-the-meter storage.

[5] Available at https://www.socalgas.com/regulatory/documents/cgr/2019_CGR_Supplement_7-1-19.pdf, see pages 12 to 16.

evacuations and adverse health impacts for nearby residents. As a result of San Bruno, the California gas utilities have made major investments in replacing and upgrading their gas transmission infrastructure. New regulations for gas storage fields after Aliso Canyon are likely to result in the decommissioning of some older storage fields and to raise future costs to store gas.[6] Largely driven by these safety-related investments, PG&E's adopted revenue requirement for its gas transmission and storage facilities has increased from $462 million in 2010[7] to the $1,580 million that the Commission just authorized for 2022 in D. 19-09-025, the final decision in the PG&E Gas Transmission & Storage rate case.[8] This is an average increase of 10.8% per year over 12 years.

Gas transportation rates paid by gas-fired electric generators (EGs) are calculated with the costs of the pipeline and storage infrastructure in the numerator and gas throughput in the denominator. With the numerator rising due to safety-related costs and the denominator decreasing as the result of programs to reduce carbon emissions, the result has been dramatic escalations over the last decade in the gas transportation rates paid by EG customers. For example, **Figure 1** shows PG&E's actual G-EG transportation rate from 2004 to 2018 (blue line), including the new G-EG rates adopted in September 2019 in D. 19-09-025 (yellow line).[9] The figure indicates that, during the 10-year period from 2009 to 2018, PG&E's G-EG rate escalated at an average rate of 25% per year. Over a somewhat longer 15-year period (2004 to 2018), the average escalation in the G-EG rate was 15% per year. The new rates for 2019-2022 just adopted in the PG&E GT&S rate case decision indicate that the escalation rate from 2009 to 2022 will average 16% per year (red dashes). Obviously, this rate escalation is roughly consistent with the 11% annual increase in revenue requirement (2010 to 2022) and the 6% annual decline in throughput (2014 to 2018) cited above.

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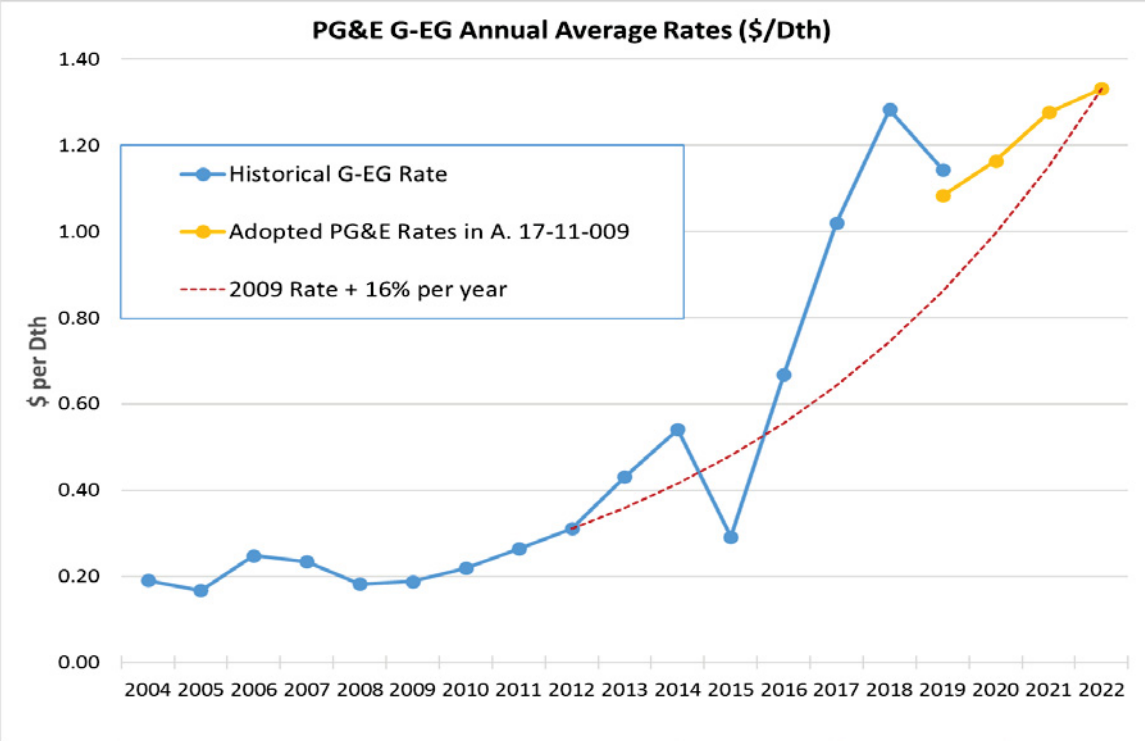
[6] See the Commission's recent approval of PG&E's plan to decommission two older storage fields, in D. 19-09-025, the final decision in the PG&E Gas Transmission & Storage rate case, A. 17-11-009.

[7] See D. 11-04-031, at p. 16.

[8] See D. 19-09-025, at Appendix E, Table 1.

[9] We note that these rates do not include certain additional charges, such as the municipal surcharge.

Figure 1



Two recent studies, including one for the CEC, have indicated that these sharp escalations in gas transportation rates in California are likely to continue.

E3 Gas Study for the CEC. At a California Energy Commission (CEC) workshop on June 6, 2019, the consultants from Energy and Environmental Economics (E3) presented new work on the impact of California's carbon reduction goals on future natural gas rates in California, as part of a Public Interest Energy Research (PIER) grant.[10] The purpose of the study was to evaluate the implications of a low-carbon future in California for the customers of the natural gas system, including both economic and health impacts. This study reached the following major conclusions:

- Continuing to use fossil natural gas in buildings at today's levels of consumption will not meet the state's carbon reduction goals.
- Using renewable natural gas (RNG) to decarbonize buildings, by replacing fossil methane with RNG, would maintain gas throughput and could meet the state's climate goals, but would be an expensive strategy for the state.
- Building electrification is a lower-cost strategy to achieve the state's climate goals.
- Building electrification will further reduce gas throughput and raise rates for

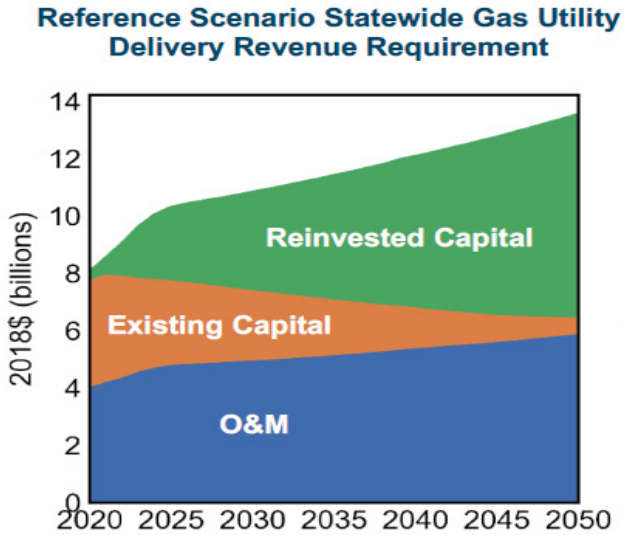
[10] E3, "Draft Results: Future of Natural Gas Distribution in California," presented at the CEC Staff Workshop for CEC PIER-16-011 on June 6, 2019. Hereafter, "E3 Gas Study." Available at https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdf.

remaining gas customers, in addition to the expected declines in EG gas use due to electric sector programs such as the RPS.

- A gas transition strategy is needed to reduce the costs of the gas system and protect consumers from high future rates.
- Building electrification improves air quality and health outcomes in urban centers.[11]

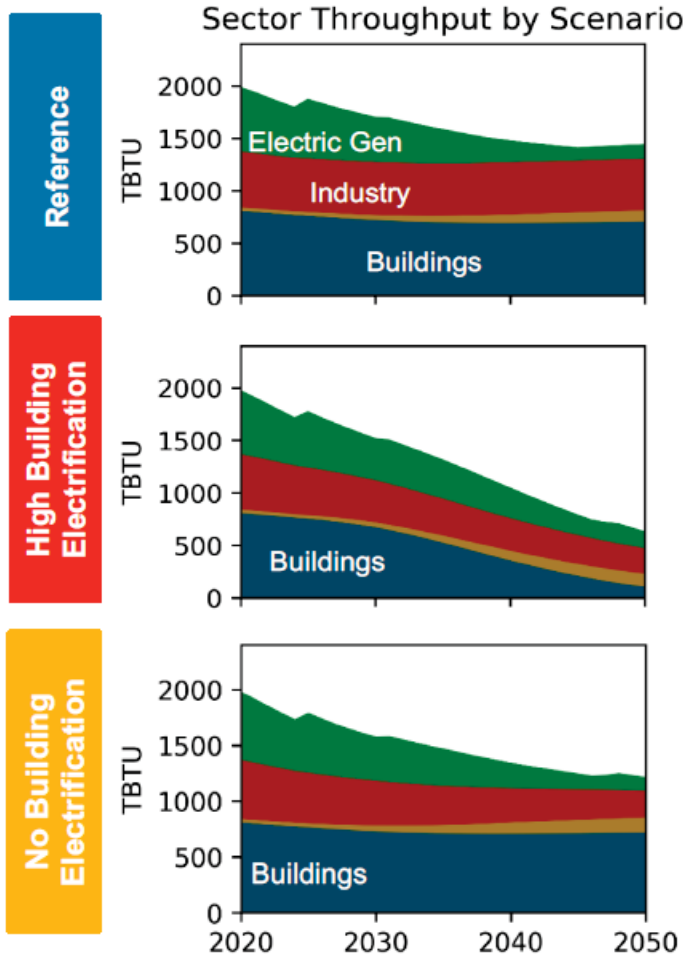
E3's study projects continued sharp increases in the revenue requirements for the gas utilities of 5% real per year (i.e. 5% above inflation) through 2025, due to continuing safety-related investments, then increasing at 1% real thereafter through 2050. See **Figure 2** below, which is Slide 22 from the E3 Gas Study. At the same time, in the favored high building electrification case, overall throughput on the gas system declines at about 3.5% per year from 2020-2050, with EG throughput dropping at 5% per year in all scenarios. See **Figure 3**, which is Slide 16 from the E3 Gas Study.

Figure 2: *Slide 22 from the E3 Gas Study*



[11] E3 Gas Study, at Slides 6 and 15.

Figure 3: *Slide 16 from the E3 Gas Study*



Assuming that EG customers' share of the overall revenue requirement changes in proportion to their share of the overall throughput, the E3 results suggest a long-term real escalation in EG rates in excess of 10% per year through 2025 (continuing the trend since at least 2010) and 5% to 10% per year after 2025, unless steps are taken to reduce future gas system revenue requirements. The E3 study suggests a number of steps that could be taken (but have yet to be adopted) to mitigate future rate increases, including the accelerated depreciation or targeted retirement of gas assets.

Gridworks Gas Study. On September 19, Gridworks released a new study, *California's Gas System in Transition: Equitable, Affordable, Decarbonized and Smaller.* The lead author of this study is former CPUC commissioner Mike Florio.[12] This work focuses on the transition strategies that could be used to mitigate the rapidly-growing gas rates that will result from the

[12] Available at https://gridworks.org/initiatives/cagas-system-transition/, hereafter "Gridworks Study." This study was funded jointly by PG&E and the Energy Foundation, with technical input from E3 and a broad group of stakeholders, including Tom Beach of Crossborder Energy, a consultant to SEIA who assisted in the preparation of these comments.

steep decline in gas throughput from widespread building electrification. The Gridworks Study's participants reviewed in detail and accepted the conclusion of the E3 Gas Study that a high building electrification scenario will be the least-cost way to meet the state's goals to reduce carbon emissions.[13] The study succinctly summarizes the challenge that the state faces with keeping future gas rates affordable:

> *The simple fact is that meeting California's GHG reduction goals, a statewide priority and absolute necessity to combat climate change, inevitably means a substantial decline in gas throughput in the state.*
>
> *At the same time that gas demand is projected to decline over time, the costs of operating a safe and reliable gas delivery system in California have been increasing.*[14]

The study shows that intrastate gas rates will increase significantly for all classes of gas customers, including EG plants, and that it is the remaining residential gas customers who will face the largest increases, unless the state adopts a comprehensive, carefully-planned set of mitigation measures. The report emphasizes that, as gas rates increase, this will only increase the incentive for residential customers to adopt electrification measures, further reducing gas throughput.[15] The Gridworks Study provides an in-depth discussion of a range of possible mitigation strategies that state policymakers could pursue to lower future rates for small customers, including accelerated depreciation, reduced investments and targeted retirements, securitization, and cost allocation and rate design changes for gas distribution costs. The Gridworks Study shows that these mitigations could have a significant impact to reduce the escalation in future rates for residential and other small customers, but would not have a major impact in reducing the escalation in EG rates.[16]

SEIA and Vote Solar submit that these important new studies show conclusively that assuming zero future escalation in today's gas transportation rates does not produce a useful forecast and does not reflect the reality of California's gas industry, either in the recent past or going forward. For example, based on future increases in intrastate rates that SEIA and Vote Solar believe are realistic, by the early 2030s the cost of intrastate transportation for some California EG plants could be as large as the commodity cost of gas at the California border.

With respect to EG rates, SEIA and Vote Solar recommend that the IEPR forecast should assume that current intrastate rates will increase at real escalation rates of 9% per year to 2025, then 4% thereafter to 2050 (in nominal terms, this would be 11% per year to 2025, then 6% per year thereafter, assuming 2% inflation). This recommendation is consistent with the EG rate scenarios in the Gridworks Study even with the best-case suite of mitigations that have yet to be

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[13] See Gridworks Study, at pp. 1 and 4-5.

[14] *Ibid*., at p. 1.

[15] *Ibid*., at pp. 1-2 and 9-10.

[16] The Gridworks Study acknowledges, at page 14, that the severe increases in residential rates could generate future pressure to shift costs from small customers to large users such as EG plants, further increasing EG rates. The Gridworks Study states that such a re-allocation of costs would need to be "carefully considered" given that it would increase electric rates and could shift carbon emissions to out-of-state EG plants.

adopted.[17] The Commission also should consider adopting substantial escalation rates for the intrastate gas transportation rates of other types of natural gas consumers, with the work from the E3 Gas Study and the Gridworks report as guides.

B. Impact of intrastate backbone rate escalation on NamGas results

The NamGas modeling is used to produce gas commodity prices at the PG&E city-gate market. The PG&E city-gate is downstream from the PG&E backbone transmission paths to the California-Arizona (Topock) and California-Oregon (Malin) border markets. PG&E's backbone transportation rates will be subject to the same influences discussed above for the intrastate rates downstream from the PG&E city-gate. PG&E's backbone rates also have escalated sharply over the last decade, and will continue to increase faster than inflation as throughput declines. It is not clear to SEIA and Vote Solar that NamGas is including realistic information about future increases in intrastate costs on the PG&E backbone system when computing an equilibrium set of prices and flows for the PG&E city-gate market.[18]

C. Double-counting certain intrastate rates

The CEC IEPR forecast for PG&E also appears to include double-count certain intrastate rate components. For PG&E, the CEC IEPR forecast includes intrastate transportation costs, in all years, of $0.80 per Dth for backbone EG customers and $1.70 per Dth for local transmission EG customers. The backbone EG cost appears to be based on the April 2019 PG&E G-EG-BB rate of $0.6798 per Dth plus, incorrectly, the Redwood backbone path MFV usage rate of $0.1160 per Dth. The Redwood path rate is upstream of the PG&E city-gate and thus these costs already are included in the CEC IEPR's PG&E city-gate forecast.

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[17] See, for example, Figure 9 on page 14 of the Gridworks Study.

[18] We assume that the NamGas SoCalGas hub is the SoCal/Arizona border (e.g. Topock) market, not the SoCalGas citygate. Thus, there are no intrastate backbone paths upstream of the SoCalGas Hub.

III. Conclusion

SEIA and Vote Solar respectfully ask the Commission to revise the final IEPR gas forecast to include a realistic escalation in future intrastate gas transportation rates. The California natural gas industry is facing major changes as the state moves to limit substantially the emissions from burning fossil fuels, including natural gas. Gas throughput will be declining, and gas transportation rates will continue to escalate sharply, as they have for the last decade.

We appreciate the CEC's consideration of these comments.

Respectfully submitted,

/s/ Rick Umoff
Rick Umoff,
California State Director, SEIA

/s/ Ed Smelloff
Ed Smelloff
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/s/ R. Thomas Beach
R. Thomas Beach
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ATTACHMENT B

Summary of Revised Natural Gas Price Forecast

Color Key:	Forwards	*Interpolated*	Fundamental

Henry Hub

Year	Forward Market	EIA AEO 2019	IEPR 2019	Average Long-term	Blended Forecast
2019	2.73	3.09	3.09	3.09	2.73
2020	2.70	3.22	3.26	3.24	2.70
2021		3.20	3.43	3.32	*2.97*
2022		3.28	3.64	3.46	*3.24*
2023		3.49	3.76	3.63	*3.52*
2024		3.77	3.88	3.82	*3.79*
2025		4.11	4.00	4.06	4.06
2026		4.29	4.13	4.21	4.21
2027		4.41	4.27	4.34	4.34
2028		4.61	4.42	4.51	4.51
2029		4.73	4.59	4.66	4.66
2030		4.88	4.78	4.83	4.83
2031		4.97	4.96	4.96	4.96
2032		5.26	5.32	5.29	5.29
2033		5.46	5.50	5.48	5.48
2034		5.64	5.72	5.68	5.68
2035		5.82	5.92	5.87	5.87
2036		6.06	6.09	6.08	6.08
2037		6.23	6.28	6.25	6.25
2038		6.38	6.54	6.46	6.46
2039		6.55	6.68	6.61	6.61
2040		6.79	6.85	6.82	6.82
2041		6.92	6.96	6.94	6.94
2042		7.14	7.15	7.15	7.15
2043		7.40	7.26	7.33	7.33
2044		7.71	7.44	7.57	7.57
2045		8.01	7.55	7.78	7.78
2046		8.27	7.72	8.00	8.00
2047		8.58	7.91	8.25	8.25
2048		9.01	8.08	8.55	8.55
2049		9.40	8.29	8.84	8.84
2050		9.76	8.48	9.12	9.12

SoCalGas -- for SCE and SDG&E

Year	Forward Market	Forward Market Basis	Blended SoCal	GT-5NC Rate	Franchise Fee	Burnertip SoCal MPR
2019	2.93	0.20	2.93	0.67	0.04	**3.63**
2020	2.63	-0.07	2.63	0.74	0.04	**3.41**
2021		-0.07	*2.90*	0.82	0.04	**3.77**
2022		-0.07	*3.17*	0.91	0.04	**4.13**
2023		-0.07	*3.45*	1.01	0.05	**4.51**
2024		-0.07	*3.72*	1.12	0.05	**4.89**
2025		-0.07	3.99	1.25	0.06	**5.29**
2026		-0.07	4.14	1.32	0.06	**5.52**
2027		-0.07	4.27	1.40	0.06	**5.73**
2028		-0.07	4.44	1.48	0.06	**5.99**
2029		-0.07	4.59	1.57	0.07	**6.23**
2030		-0.07	4.76	1.67	0.07	**6.50**
2031		-0.07	4.89	1.77	0.07	**6.73**
2032		-0.07	5.22	1.87	0.08	**7.17**
2033		-0.07	5.41	1.99	0.08	**7.47**
2034		-0.07	5.61	2.11	0.08	**7.80**
2035		-0.07	5.80	2.23	0.09	**8.12**
2036		-0.07	6.01	2.37	0.09	**8.46**
2037		-0.07	6.18	2.51	0.09	**8.78**
2038		-0.07	6.39	2.66	0.10	**9.14**
2039		-0.07	6.54	2.82	0.10	**9.46**
2040		-0.07	6.75	2.99	0.10	**9.84**
2041		-0.07	6.87	3.17	0.10	**10.14**
2042		-0.07	7.08	3.36	0.11	**10.54**
2043		-0.07	7.26	3.56	0.11	**10.93**
2044		-0.07	7.50	3.77	0.12	**11.39**
2045		-0.07	7.71	4.00	0.12	**11.82**
2046		-0.07	7.93	4.24	0.13	**12.29**
2047		-0.07	8.18	4.49	0.13	**12.80**
2048		-0.07	8.48	4.76	0.14	**13.37**
2049		-0.07	8.77	5.05	0.14	**13.96**
2050		-0.07	9.05	5.35	0.15	**14.55**

PG&E

Year	Forward Market	Baja Path	Basis Forecast	Blended Citygate	G-EG Backbone Rate	G-EG All Others Rate	Franchise Fee	Burnertip PG&E BB	Burnertip PG&E LT
2019	3.67	0.74	0.94	3.67	0.23	1.10	0.04	**3.94**	**4.81**
2020	3.62	0.98	0.91	3.62	0.23	1.18	0.04	**3.88**	**4.84**
2021		1.11	1.04	*4.02*	0.23	1.26	0.04	**4.28**	**5.32**
2022		1.15	1.08	*4.33*	0.23	1.31	0.04	**4.60**	**5.68**
2023		1.28	1.21	*4.73*	0.25	1.45	0.05	**5.03**	**6.22**
2024		1.42	1.35	*5.14*	0.28	1.61	0.05	**5.47**	**6.80**
2025		1.58	1.51	5.56	0.31	1.79	0.06	**5.93**	**7.41**
2026		1.67	1.60	5.81	0.33	1.89	0.06	**6.20**	**7.77**
2027		1.77	1.70	6.05	0.35	2.01	0.06	**6.46**	**8.11**
2028		1.88	1.81	6.32	0.37	2.13	0.06	**6.76**	**8.51**
2029		1.99	1.92	6.58	0.39	2.25	0.07	**7.04**	**8.90**
2030		2.11	2.04	6.87	0.42	2.39	0.07	**7.36**	**9.33**
2031		2.24	2.17	7.13	0.44	2.53	0.07	**7.64**	**9.74**
2032		2.37	2.30	7.60	0.47	2.68	0.08	**8.14**	**10.36**
2033		2.51	2.44	7.92	0.50	2.85	0.08	**8.50**	**10.85**
2034		2.67	2.60	8.28	0.53	3.02	0.08	**8.89**	**11.38**
2035		2.83	2.76	8.63	0.56	3.20	0.09	**9.27**	**11.91**
2036		2.99	2.92	9.00	0.59	3.39	0.09	**9.68**	**12.48**
2037		3.17	3.10	9.36	0.63	3.59	0.09	**10.07**	**13.04**
2038		3.36	3.29	9.75	0.66	3.81	0.10	**10.51**	**13.66**
2039		3.57	3.50	10.11	0.70	4.04	0.10	**10.91**	**14.25**
2040		3.78	3.71	10.53	0.75	4.28	0.10	**11.38**	**14.91**
2041		4.01	3.94	10.88	0.79	4.54	0.10	**11.78**	**15.52**
2042		4.25	4.18	11.32	0.84	4.81	0.11	**12.27**	**16.24**
2043		4.50	4.43	11.77	0.89	5.10	0.11	**12.77**	**16.98**
2044		4.77	4.70	12.27	0.94	5.40	0.12	**13.33**	**17.79**
2045		5.06	4.99	12.77	1.00	5.73	0.12	**13.89**	**18.61**
2046		5.36	5.29	13.29	1.06	6.07	0.13	**14.48**	**19.49**
2047		5.68	5.61	13.86	1.12	6.43	0.13	**15.12**	**20.43**
2048		6.03	5.96	14.50	1.19	6.82	0.14	**15.83**	**21.46**
2049		6.39	6.32	15.16	1.26	7.23	0.14	**16.57**	**22.53**
2050		6.77	6.70	15.82	1.34	7.66	0.15	**17.31**	**23.63**