BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	Rulemaking 20-05-003 (Filed May 7, 2020)

THE MUSSEY GRADE ROAD ALLIANCE COMMENTS ON THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED 2023 PREFERRED SYSTEM PLAN AND TRANSMISSION PLANNING PROCESS PORTFOLIOS

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Pursuant to the October 5, 2023, Administrative Law Judge's Ruling Seeking Comment on Proposed 2023 Preferred System Plan and Transmission Planning Process Portfolios ("Ruling"),[1] the Mussey Grade Road Alliance ("MGRA") submits these opening comments. As requested by the Ruling, the comments are organized in the order in which topics appear in the Ruling.

1. SUMMARY OF RECOMMENDATIONS

- To avoid inaccurate modeling results, Energy Division Staff should update the current Inputs and Assumptions document to align lithium-ion battery prices with the 2023 NREL ATB's advanced- or moderate-scenario battery prices because these prices are the closest to public manufacturer battery prices.
- The Commission should adopt the 25 MMT Core portfolio as the PSP after removing pumped storage from the portfolio.
- The Commission should transmit the 25 MMT Core portfolio as both the reliability and policy-driven base case scenario to be analyzed by the CAISO in the 2024-2025 TPP after removing pumped storage from the San Diego study area because:[2]

[1] R.20-05-003, Administrative Law Judge's Ruling Seeking Comment on Proposed 2023 Preferred System Plan and Transmission Planning Process Portfolios (October 5, 2023), available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K522/520522241.PDF.
[2] See Section 3 for supporting citations and calculations for this recommendation.

- The development team for the only pumped storage project in the San Diego study area estimates that its pumped storage project would cost approximately 50% more than a battery storage project of identical size.
- The proposed San Diego Study Area pumped storage project does not have a valid preliminary FERC permit.
- A pumped storage project in the San Diego Study Area would not be cost effective and cannot achieve the 2028 pumped storage online date that RESOLVE selected.

- The Commission should order long-duration energy storage battery procurement at gas-fired generation sites, but only with sufficient guardrails to ensure that ratepayers benefit from the procurement.
- The Commission should issue a procurement order for 2,000 MW of clean NQC that rewards early renewable procurement and incentivizes voluntary renewable procurement by LSEs going forward.

2. PSP CONSIDERATIONS (RULING SECTION 2 – PP. 12-35)

MGRA supports the Ruling's adoption of the 25 MMT Core portfolio as the PSP. The portfolio will allow the CAISO to plan for step-change reductions in greenhouse gas ("GHG") emissions and will enable the load serving entities ("LSE") to use their procurement plans without changes. Section 2.1 further details the reasons for MGRA's support.

While the Commission should adopt the 25 MMT Core Portfolio, MGRA has significant concerns about the inputs and assumptions for the modeling. The inputs and assumptions largely determine the modeling outputs making the selection of inputs and assumptions one of the most important tasks in the modeling process. MGRA submitted detailed comments on the Draft Inputs and Assumptions ("Draft I&A") in June.[3] It appears that Energy Division Staff ("ED") made updates to the latest set of inputs and assumptions based on MGRA's recommendations

[3] *See* Attachment A, The Mussey Grade Road Alliance Informal Comments on the 2022-2023 Integrated Resource Plan Draft Inputs and Assumptions Document And Webinar Slides ("MGRA Informal Comments on Draft I&A")(June 21, 2023).

that appear in the Inputs and Assumptions: 2022-2023 Integrated Resource Planning published in October ("October I&A").[4] ED Staff updated the pumped storage capital costs and the pumped storage weighted average cost of capital in alignment with MGRA's data, analysis, and recommendations.

- Pumped storage capital cost was updated to the NREL ATB's median cost class, Class 8.[5]
- Pumped storage weighted average cost of capital was updated to from 5.4% to 8.1%.[6]

MGRA appreciates these updates. The Section 2.1 and its subsections make two additional recommendations regarding electricity storage resources that are critical for achieving accurate modeling results.

In addition to these updates, MGRA recommends that the Commission remove pumped hydroelectric storage ("pumped storage"), from the PSP before transmitting it to the CAISO for the reasons detailed in Section 3.

2.1 MGRA supports the Ruling's recommendation that the 25 MMT Core portfolio be selected as the Preferred System Plan portfolio. (Ruling Section 2.1 – pp. 19-23)

As the Ruling recommends, the Commission should select the 25 MMT Core scenario as the PSP. The 25 MMT Core scenario reduces GHG emissions more than other portfolio options[7] and enables the LSEs to procure the generation resources that best fit their individual needs. Because the LSEs' plans serve as the basis for the 25 MMT Core portfolio, the portfolio also is

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[4] R.20-03-005, Inputs and Assumptions: 2022-2023 Integrated Resource Planning ("October I&A") (October 5, 2023), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf.
[5] October I&A, p. 73.
[6] October I&A, p. 74.
[7] Lower GHG emissions are likely due to the LSEs' over procurement of storage in their IRPs.

informed by commercial interest, which will likely result in more streamlined procurement and development of new renewable resources.

During the October 20, 2023, IRP workshop one of the portfolio differences between the "least cost" scenario and the "core" scenario that ED and E3 highlighted was the higher-than-required battery storage procurement and solar procurement by LSEs in the core portfolio compared to the least cost portfolio. The LSE procurement decisions to purchase more storage capacity than called for in the Least Cost portfolio align with MGRA's analyses in Sections 2.1 and 2.3, which show the October I&A overestimated the price of battery storage in 2025 by at least 43% and more than 43% in 2026 and 2027.[8] LSEs' procurement division's attempt to find the lowest cost renewable energy resource portfolio and their individual IRPs indicate that their battery storage cost forecasts are lower than the IRP's October I&A and as a result their models select more battery procurement than the RESOLVE model.

If the Commission adopts the 25 MMT Core portfolio as the PSP, then the most concerning short-term consequences of the inaccurate battery pricing will be averted, however, as the ruling notes, "The PSP portfolio, once adopted by the Commission, serves a number of purposes and use cases..."[9] The Ruling goes on to state that while there are other uses too, the PSP impacts, at a minimum, LSE planning, CAISO TPP, the Avoided Cost Calculator, Aliso Canyon analyses, and the SB 100 analysis.[10] For this reason, if there is not enough time to correct the battery pricing in the October I&A and re-run the modeling to finalize the 25 MMT Core portfolio for the PSP base case transmitted to the CAISO, ED Staff should correct the

[8] October I&A, p. 67-68, ("the overnight capital cost trajectories from NREL 2023 ATB were delayed through 2027, as shown in Figure 6 below.").
[9] Ruling, p. 12.
[10] Ruling, p. 12-13.

battery pricing and remodel the PSP after transmitting the reliability and policy base case for the TPP.

2.2 The IRP's Inputs and Assumptions Document Needs to be Updated to Ensure Accurate Modeling Results (Ruling Section 2, pp.16-17)

MGRA provided ED with informal comments on the IRP 2023 Draft Inputs and Assumptions ("Draft I&A").[11] The October I&A was released with the RESOLVE and SERVM modeling results. After reviewing the October I&A, MGRA has noted updates that align with its recommendations in the informal comments. The October I&A corrected the pumped storage capital cost and weighted average cost of capital modeling inputs in alignment with the data provided by MGRA. These corrections are appreciated.

Many components of the October I&A appear accurate and MGRA appreciates the significant time and energy that Energy Division Staff ("ED") put into the document. However, MGRA has noted a handful of changes to the I&A that were made between the release of the draft and final versions that do not align with the best available data. The most significant change appears to be to the capital cost changes for lithium-ion batteries. In the near term (i.e., 2025) the October I&A lists 2025 battery pricing that is 43%-49% higher than current manufacturers quotes for 2025 battery installations.[12]

Lithium-ion battery price inputs are one of the most important modeling inputs because battery prices impact the cost effectiveness of all variable energy generators, the viability of alternatives to lithium-ion batteries, the timeline for and quantity of storage resources procured, and the timeline for procurement of or retirement of other resource types. In short, the inaccurate

[11] *See* Attachment A, MGRA Informal Comments on Draft I&A.
[12] See Table 1 and Figure 1.

battery price assumptions produce a domino effect of inaccurate outputs – not just with regards to storage procurement – but throughout all RESOLVE outputs. ED should update the October I&A to align with the best available lithium-ion battery pricing data as discussed in the following sections.

The October I&A also includes inaccurate assumptions about pumped storage. The most concerning is the assumption of a 12-hour duration. Pumped storage facilities can provide 12-hour duration storage, but only for a single day. Thus, ED should update the pumped storage assumptions to account for this performance and reliability weakness of pumped hydroelectric storage resources.

The following sections discuss MGRA's recommended changes to the October I&A on battery pricing and pumped storage performance characteristics.

2.2.1 The Final Inputs and Assumptions for the IRP modeling includes battery price forecasts 43% higher than market prices.

The Draft I&A stated that it would use the NREL ATB lithium-ion battery prices for the basis for the IRP's I&A[13] and that "modifications to the ATB cost trajectory were made to reflect current market conditions and substantial impacts on the supply chain."[14] The modifications increased the battery energy and battery capacity prices causing the Draft I&A battery prices to be substantially higher than the 2022 NREL ATB.

Between the publication of the Draft I&A and October I&A, NREL published an updated ATB for 2023. The 2023 NREL ATB substantially increased battery price compared to the 2022

[13] Draft I&A, p. 80, ("New to the 2022- 2023 IRP, both utility-scale and BTM Li-ion battery storage relies on storage cost assumptions from NREL ATB.") available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/draft_2023_i_and_a.pdf.
[14] Draft I&A, p. 81.

ATB. ED updated its battery assumptions with the 2023 NREL ATB costs while leaving the battery price escalator in place even though the escalator was designed for the 2022 NREL ATB. The 2023 NREL ATB battery prices combined with the escalation factors that had been applied to the 2022 NREL ATB battery prices have caused the October I&A to far exceed available market prices for lithium-ion batteries.

Table 1 and Figure 1 below show the IRP's October I&A lithium-ion battery prices, the 2023 NREL ATB battery prices, and the current Tesla price quote[15] for battery storage. Each price listed corresponds to a 2025 online date. Please note that to provide an accurate comparison MGRA converted NREL's 2021 dollars to 2022 dollars because the October I&A uses 2022 dollars.[16] This conversion reduced the difference in price between the 2023 NREL ATB price assumption and the October I&A price assumption. Even with this conversion, the October I&A prices significantly exceed the 2023 NREL ATB prices.

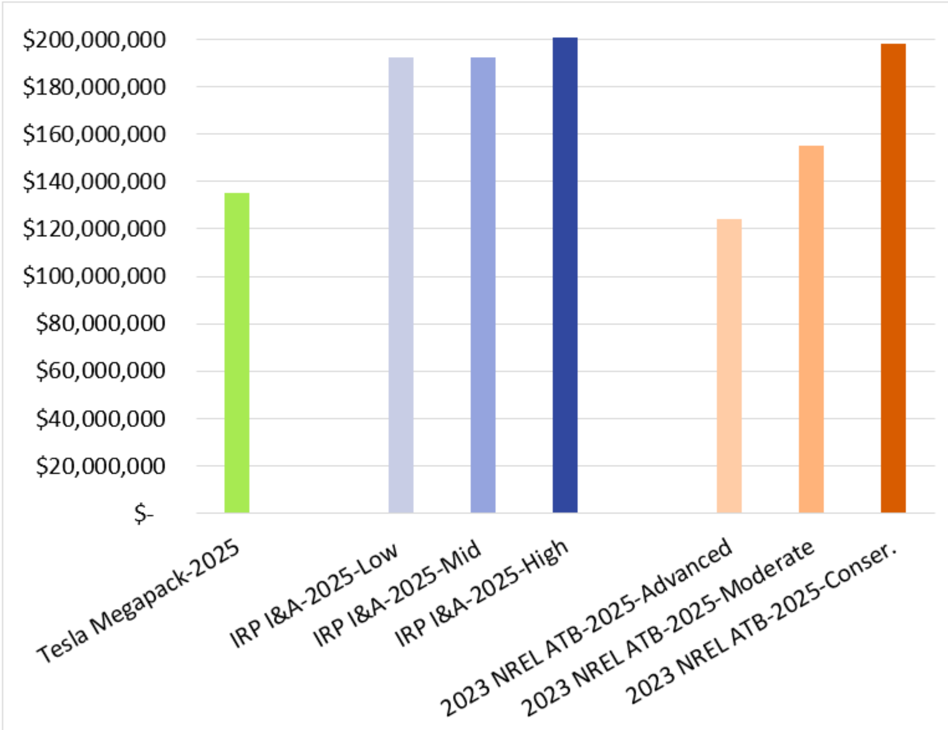
Table 1: Battery Prices (100 MW, 4 hour) - Tesla, NREL, IRP (all prices for 2025 year)

Source/Year/Scenario	MW	MWh	Duration	Date	Energy ($/kwh)	Power ($/kw)	Price	% of Megapack $
Tesla Megapack-2025	99.9	399.4	4	Q2 2025			$ 135,197,860	100%
IRP I&A-2025-Low	100	400	4	2025	$ 391	$ 363	$ 192,700,000	143%
IRP I&A-2025-Mid	100	400	4	2025	$ 391	$ 363	$ 192,700,000	143%
IRP I&A-2025-High	100	400	4	2025	$ 408	$ 379	$ 201,100,000	149%
2023 NREL ATB-2025-Advanced	100	400	4	2025	$ 252	$ 233	$ 124,171,686	92%
2023 NREL ATB-2025-Moderate	100	400	4	2025	$ 310	$ 311	$ 155,107,130	115%
2023 NREL ATB-2025-Conser.	100	400	4	2025	$ 402	$ 375	$ 198,379,879	147%

[15] Tesla Megapack Order Page [last accessed October 29, 2023], 99.9 MW, 399.4 MWh, 102 Megapacks, Installation included, Site Location California, Desired Delivery Date Q2 2025, Estimated Price $135,187,860, available at https://www.tesla.com/megapack/design.

[16] The NREL ATB prices were increased by 8% in alignment with inflation reported between 2021 and 2022 according to the U.S. Bureau of Labor Statistics's inflation calculator, see https://data.bls.gov/cgi-bin/cpicalc.pl.

Figure 1: Battery Prices (100 MW, 4 hour) - Tesla, NREL, IRP (all prices for 2025 year)



The table shows that the October I&A lithium-ion battery price exceeds the market price (i.e., Tesla quote for Q2 2025)[17] by 43% to 49%. Of the three IRP scenarios and the three NREL ATB scenarios, the Tesla price estimate is closest to the NREL ATB "advanced" price scenario. For this reason, the IRP's October I&A should be updated to align with the 2023 NREL ATB's advanced battery price and remove the escalator that was designed for the 2022 NREL ATB. This recommendation is further supported by the subsections below and should be used for all future IRA modeling.

Three factors combined to cause the inaccurate lithium-ion battery prices in the October I&A: dropping market prices, increased ATB forecast prices, and the retention in the October I&A of a near-term lithium-ion storage escalator.

[17] Tesla Megapack Order Page [last accessed October 29, 2023], 99.9 MW, 399.4 MWh, 102 Megapacks, Installation included, Site Location California, Desired Delivery Date Q2 2025, Estimated Price $135,187,860, available at https://www.tesla.com/megapack/design.

2.2.1.1 The cost of stationary storage has decreased significantly since the publication of the Draft A&I.

First, there are multiple data points that show the market prices of stationary storage are falling. The 2023 NREL ATB does not appear to fully account for the falling market prices. The falling market prices align with MGRA's analysis in informal comments.

In informal comments MGRA noted that BNEF forecast rapidly falling battery storage prices between now and 2026.[18] Additionally, the EV battery market demand affects the stationary storage market. When there is a reduced EV battery demand, the stationary storage market will have more battery cells available for stationary purposes. In the last month, multiple vehicle manufacturers have reduced their EV demand forecasts resulting in less demand pressure on battery suppliers.[19]

One example of the falling prices in the stationary storage market can be calculated using the data in the Draft I&A. The Draft I&A stated that "the current quoted price for a 5-MW, 4-hr Tesla Megapack is $1,900+/kW (pre-tax)."[20] As of today, Tesla quotes a 10% lower price for the same battery configuration.[21] The rapid price reduction of stationary storage suggests that MGRA's analysis in its informal comments is accurate.

Because the 5 MW system discussed above is not a utility-scale system, the $/kW is not the best quote for IRP modeling purposes. Instead, the storage size used for the comparison in

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[18] *See* Attachment A, MGRA Informal Comments on Draft I&A, p. 11.
[19] Volkswagen *see*, https://electrek.co/2023/09/26/volkswagen-cites-slow-demand-reason-ev-production-cuts/, GM *see* https://electrek.co/2023/10/24/gm-delays-equinox-ev-and-electric-trucks-ultium-bolt-update-in-q3/, Ford *see*, https://electrek.co/2023/10/13/fords-f-150-lightning-michigan-ev-plant-losing-shift/.
[20] Draft I&A, p. 81.
[21] Tesla Megapack Order Page [last accessed October 29, 2023], 4.9 MW, 19.6 MWh, 5 Megapacks, Installation included, Site Location California, Desired Delivery Date Q3 2024 (earliest possible), Estimated Price $8,344,960, available at https://www.tesla.com/megapack/design, ($8,344,960/4,900 kw = $1,703/kW; *and*
1 – ($1,703/kW / $1900/kw) = 10% reduction in price quoted).

Table 1 is a 100 MW, 4-hour storage system. Pricing for that size system will produce a more accurate estimate for a utility scale system and demonstrates that the October I&A battery costs are too high.

2.2.1.2 NREL increased battery storage prices in its 2023 ATB and thereby eliminated the need for further adjustments in the IRP's October I&A.

NREL significantly increased its lithium-ion battery prices in its 2023 ATB as compared to its 2022 ATB.[22] NREL's ATB battery price increases between 2022 and 2023 are illustrated in the table below.

Table 2:NREL ATB price forecast increases between 2022 to 2023

Battery Energy Capital Cost ($/kWh)	2025	2030	2035	2040
Advanced	7%	24%	21%	17%
Moderate	28%	39%	35%	30%
Conservative	30%	15%	11%	7%
Battery Power Capital Cost ($/kW)	**2025**	**2030**	**2035**	**2040**
Advanced	28%	49%	45%	42%
Moderate	15%	7%	10%	13%
Conservative	57%	59%	53%	48%
Note: 2020 dollars set to 2021 dollars for 2022 and 2023 ATB (i.e., 4% inflation)				

NREL increased the forecast price for every year and every scenario for both cost components (i.e., energy and power). These increases in forecast price appear to have over-adjusted the pricing because as shown in Table 1 above, Tesla's current prices are most closely aligned with NREL's 2025 advanced scenario pricing than with any other price scenario. Because of the

[22] All calculations and comparisons regarding the 2022 ATB versus the 2023 ATB are based on 2021 dollars. The 2022 ATB used 2020 dollars. The 2023 ATB used 2021 dollars. To complete a comparison, the 2020 dollars were converted to 2021 dollars by increasing the 2020 dollars by 4% to account for 2020 to 2021 inflation. This resulted in a narrowing of the difference in reported dollar amounts between the 2022 and 2023 ATBs. Even with the gap between the numbers reduced to account for inflation, the 2023 ATB significantly increased the price forecast for lithium-ion batteries.

similarity between current market prices and NREL's lowest price forecast scenario, no additional adjustments to the NREL pricing should have been made in the October I&A.

2.2.1.3 With the adoption of the significantly higher battery prices found in the 2023 NREL ATB, the ED Staff escalation formatted for the 2022 ATB prices should be eliminated.

The Third reason that the October I&A overestimates lithium-ion prices is the retention of the escalation that ED made to the 2022 NREL ATB battery prices. The Draft I&A explains the basis for a two-part escalation it made to the 2022 NREL ATB in the following way:

> Data reported by the International Monetary Fund (IMF) on feedstock material prices show that since Q1 2019, many rare-earth metals critical to the production of Li-ion batteries, including lithium, manganese, nickel, and cobalt, have more than doubled in price, outpacing inflation. These price increases are roughly 50% greater than those observed for conventional feedstocks, such as aluminum, iron, and copper.[23]

While that may have been true at some point when the Draft I&A was researched and written, it is no longer accurate. Figure 2 below shows the current price of metals referenced in the I&A as a percentage of the January 2019 prices.

[23] October I&A, p. 50.

Figure 2: Metal Price: Percent of Jan 2019 Price[24]

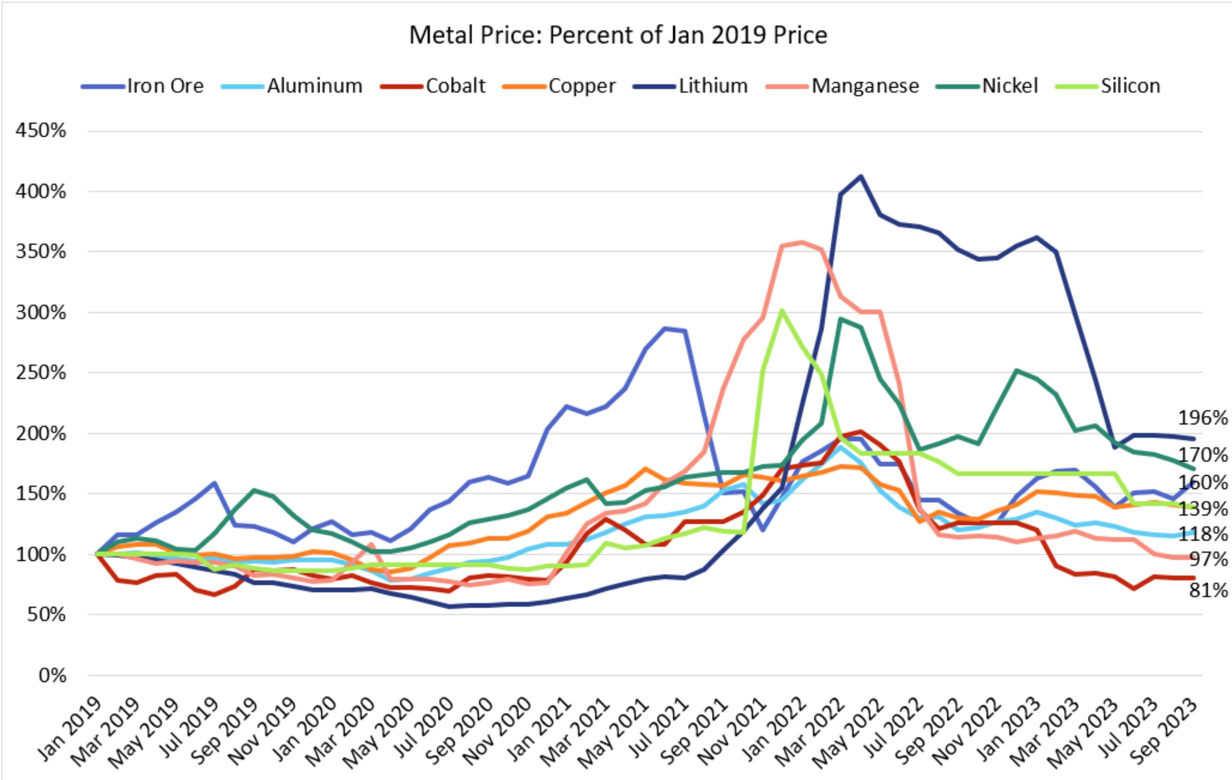

Figure 2 uses the same data source referenced in the Draft I&A and October I&A, the IMF's commodity price data.[25] First, each of the metals important for battery manufacturing have decreased significantly since the beginning of 2023. For example, lithium prices have dropped by 46% since January 2023. Perhaps more interestingly, the price of cobalt is now just 81% of the January 2019 cobalt price. This likely demonstrates the effect of LFP batteries – batteries that do not use cobalt – rapidly taking market share from NMC batteries.

As the stationary storage battery market shifts to some combination of sodium-ion batteries, iron-flow batteries, and iron-air batteries, lithium prices may drop in a similar fashion to that of cobalt. Alternatively, the price of lithium may continue to drop simply because the

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[24] Data Source for Figure: IMF Monthly Data Jan 2019 to September 2023, available at https://data.imf.org/?sk=471DDDF8-D8A7-499A-81BA-5B332C01F8B9&sId=1390030341854.
[25] *Ibid.*

current above-normal lithium prices encourage producers to increase supply to attempt to gain access to higher profits.

Finally, the October I&A's statement about the inflation level of battery metals prices compared to iron and copper is no longer accurate. Iron prices are 160% of January 2019 prices and copper prices are 139%. These price increases are similar to the average price change of battery metals since January 2019. These data suggest that the supply of metals will continue to track demand. Even though prices may be more volatile over the coming decade as the battery market matures, the learning curve in battery research and manufacturing will continue to drive down the cost of electricity storage despite temporary price spikes of various battery components.

The inaccurate battery assumption in the October I&A appears to have been caused by the significant increase to lithium-ion battery prices in the 2023 NREL ATB, combined with the falling lithium-ion market prices, and the retention of the battery price escalator that had been designed for and applied to the 2022 NREL ATB prices. These combination of factors resulted in the October I&A forecast of 2025 battery prices exceeding the market price by 43% to 49%, as shown in Table 1 and Figure 1 above.

ED should update the October I&A battery prices by removing the Staff-defined price escalator. MGRA is particularly concerned about the inaccurate lithium-ion battery price assumption because not only is battery pricing 43% too high in 2025 because of the price escalator, the October I&A holds the 2025 pricing *"through 2027."*[26] By the end of 2027 the 43% error will likely have expanded significantly. One supporting reason for this belief is that

[26] October I&A, p. 75 (emphasis added).

several new and less expensive battery technologies are at the brink of commercial availability. These storage technologies will be discussed in the following section.

2.3 The October I&A battery prices need to be lowered to account for new and lower-cost battery technology and to enable accurate IRP modeling results.

Several new battery technologies have been analyzed by ED and E3 in the CPUC IRP Zero-Carbon Technology Assessment's ("IRP Tech Assessment").[27] The IRP Tech Assessment found that several technologies are on the brink of commercialization and will be less expensive than today's stationary storage options.[28] Sodium-ion battery storage is reported to be more cost-effective than today's widely available options and is already in production.[29]

The IRP Tech Assessment Table 4-1 shows the IEA's definitions of technological readiness level ("TRL").[30] The IRP Tech Assessment recommends that technologies with high TRLs be considered for inclusion in IRP modeling (i.e., 8 and higher). The IEA recently increased the TRL for sodium-ion batteries to the level 8-9 (commercial adoption) because the two largest battery producers in China, BYD and CATL, have announced that they intend to supply sodium-ion batteries to EV manufacturers by the end of 2023.[31] Supply of sodium-ion batteries is forecast to possibly reach 100 GWh by 2030 with approximately 30 manufacturing plants currently in operation.[32] Wood Mackenzie has estimated pack prices for CATL's sodium-

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[27] E3, CPUC IRP Zero-Carbon Technology Assessment (September 2022), Figure 4-4, p. 69, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/cpuc-irp-zero-carbon-technology-assessment.pdf.
[28] *Ibid.*
[29] *See* Attachment A, MGRA Informal Comments on Draft I&A., pp. 13-14.
[30] E3, CPUC IRP Zero-Carbon Technology Assessment (September 2022), Table 4-1, p. 55.
[31] IEA, Global EV Outlook 2023, pp. 59-60, available at https://iea.blob.core.windows.net/assets/dacf14d2-eabc-498a-8263-9f97fd5dc327/GEVO2023.pdf.
[32] *Ibid.*

ion batteries to be approximately 30% less expensive than LFP batteries. Currently, LFP batteries are the lowest cost lithium battery chemistry.[33]

The October I&A does not state which lithium price scenario it uses in the RESOLVE and SERVM modeling. MGRA recommends that all IRP modeling use the lithium-ion battery "Advanced" price scenario in the 2023 NREL ATB because the advanced scenario price level for the 2025 year is the closest to the 2025 market prices being offered today.[34] Further, because of the increase in low-price electricity storage options such as sodium-ion batteries, the "Advanced" price forecast will be unlikely to represent the lowest-cost option for stationary storage by 2025. The October I&A does not include prices for sodium-ion or iron-flow batteries, nor does it include a breakout of lithium-iron phosphate battery prices within the lithium-ion battery segment. The IRP Tech Assessment forecasts that several long-duration storage options will have lower-price points than the lithium-ion battery category and would work well in utility-scale electricity storage conditions.[35] SMUD is already moving forward with procurement and installation of 2 GWh of iron-flow batteries, which demonstrates that iron-flow batteries will likely become widely available in the near term.[36]

MGRA recommends that the October I&A lithium-ion I&A battery prices be updated to align with the 2023 NREL ATB's "advanced" price scenario, because the advanced price scenario best represents the future costs of lithium-ion batteries in the near term when considering also the price of lower-cost lithium-ion battery alternatives.

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[33] Wood Mackenzie, see https://www.woodmac.com/siteassets/article-images/2023/q1/sodium-ion-cost-versus-lithium-based-.png?width=1800&height=0&mode=crop&center=0.5,0.5, 1 - ($90/kWh / 133/kWh) = 0.3233 = 32%
[34] See Table 1.
[35] E3, CPUC IRP Zero-Carbon Technology Assessment (September 2022), Figure 4-4, p. 69.
[36] Sacramento utility rolls out its first long-duration grid batteries. (2023, September 18). Canary Media. https://www.canarymedia.com/articles/long-duration-energy-storage/sacramento-utility-rolls-out-its-first-long-duration-grid-batteries.

2.4 Pumped Storage with a 12-hour duration must be derated after the first day when operating for consecutive days.

In addition to battery pricing concerns, the October I&A should update an error in the pumped storage assumptions. MGRA's informal comments on the I&A detailed a major performance handicap of 12-hour duration pumped storage and reiterates it here.[37] Pumped storage can only perform at a shorter duration than 12 hours.[38] A pumped storage system can only discharge for 10.7 hours at full nameplate capacity each day if it will be expected discharge daily.[39] Because 12-hour pumped storage needs more than 12 hours to re-fill the upper reservoir, a complete discharge and charge cycle cannot occur within a 24-hour period. Thus, a 12-hour duration pumped storage facility cannot perform at its peak-rated capacity for more than a single day. Thus, during consecutive days of operation, a 12-hour pumped storage facility operates like a 10.7-hour storage facility on day 2 and beyond. Thus, the nameplate capacity of a 12-hour storage facility should be derated to 10.7 hours.

It is possible that the October I&A did not make the revisions that MGRA recommended because the 12-hour duration characteristic is difficult to update, and the update may occur in future iterations of the RESOLVE model. In the short term (i.e., this modeling cycle), MGRA recommends a work-around that should have a similar effect. ED can reduce the ELCC of a 12-hour pumped storage facility by 11% to 89%.[40] This ELCC update is not as accurate as a decrease to the nameplate capacity would be. A nameplate capacity reduction would more

[37] Attachment A, MGRA Informal Comments, Section 1.4, pp. 8-9.
[38] Oregon State University, K. Webb, Section 3, p. 63, ("the ratio of discharging to charging time is equal to the round-trip efficiency."), available at https://web.engr.oregonstate.edu/~webbky/ESE471.htm.
[39] 10.7 hours to discharge / 0.80 efficiency = 13.375 hours to charge; 10.7 hours + 13.375 hours = 24.075 hours needed for full charge and discharge cycle.
[40] 10.7 hours / 12 hours = 0.891667 = 89%.

accurately define the capabilities of a 12-hour pumped storage resource than the current inputs and assumptions.

MGRA requests that ED reduce the 12-hour duration pumped storage ELCC by 11%. Until this is completed, the modeling of pumped storage will remain inaccurate.

3. CAISO TPP (RULING SECTION 3 – PP. 35-40)

The Ruling proposes transmitting the 25 MMT Core portfolio to CAISO to be used as the base case portfolio for the CAISO TPP. MGRA supports the Ruling's recommendation that the Commission transmit the PSP for use as the reliability- and policy-driven base case portfolio if the pumped storage and battery assumption are corrected and the portfolio is updated with a new modeling run using the corrected inputs and assumptions.

The 25 MMT Core portfolio represents a good option for the TPP because it will enable the CAISO to complete transmission planning using the LSEs' preferred procurements. Incorporating the LSEs' preferences should accelerate their clean energy procurement.

MGRA also supports the Ruling's recommendation that the High Gas Retirement sensitivity be transmitted to CAISO to determine what transmission will be needed to enable the retirement of several gigawatts of gas-fired powerplants.

However, before the PSP is transmitted to the CAISO, the busbar mapping of pumped storage needs to be corrected. The preliminary busbar mapping makes inaccurate assumptions about project viability of pumped storage facilities in the SDG&E study area. While RESOLVE selected Riverside East for pumped storage, it appears ED staff manually selected the SDG&E study area for pumped storage busbar mapping.

The only proposed pumped storage facility in the SDG&E study area is estimated to cost significantly more than the October I&A pumped storage assumption and cannot be permitted, designed, and built in the timeline assumed in the RESOLVE modeling (i.e., 2028).[41] For that reason, the pumped storage facility should be removed from the 25 MMT Core portfolio before the Commission transmits the portfolio to the CAISO.

3.1 Pumped Storage should be eliminated from the SDG&E study area because the costs of the SDG&E study area's proposed pumped storage project significantly exceed RESOLVE cost assumptions.

The October I&A pumped storage cost assumptions conflict with the pumped storage location in the preliminary busbar mapping. The error should be corrected before the Commission transmits the PSP to the CAISO for the TPP analysis.

In informal comments MGRA highlighted the significant difference between the NREL ATB pumped storage price forecast and the Draft I&A pumped storage price assumptions.[42] The October I&A reflected updates similar to the recommendations made by MGRA. The data provided in informal comments also highlighted the much higher cost of a proposed pumped storage project in the SDG&E Study Area, San Vicente Energy Storage facility ("SVES"), compared to average pumped storage project costs.[43] The 2022 NREL ATB average pumped storage project costs were $3,512/kW and the SVES mid-range cost is $4,500/kW.[44]

[41] *See* Attachment B, *A Pumped Hydroelectric Energy Storage Analysis: Pumped Hydroelectric Storage Compared to Other Long-Duration Storage Options for California*, ("MGRA Pumped Storage Report") (September 2023).
[42] R.20-05-003, The Mussey Grade Road Alliance Informal Comments on the 2022-2023 Integrated Resource Plan
Draft Inputs and Assumptions Document and Webinar Slides (June 21, 2023).
[43] *See* Attachment A, MGRA Informal Comments on Draft I&A, Figure 1, p. 3.
[44] *Ibid.*

The October I&A set the capital cost of pumped storage at $3,647.[45] The mid-range price of SVES at $4,500/kw is 23% higher than the October I&A assumption. This means the only pumped storage in the SDG&E Study Area is far more expensive than the pumped storage selected by RESOLVE. The proposed SVES is also just an 8-hour duration storage facility.[46] The October I&A assumes pumped storage to be 12-hours in duration, a 50% higher duration than the SVES duration. Because of SVES's significantly higher cost and significantly lower storage duration compared to the October I&A pumped storage, the SVES facility bears little resemblance to the pumped storage modeled by RESOLVE. For this reason, pumped storage should not be considered for busbar mapping in the SDG&E study area. However, in the preliminary busbar mapping released on October 26, 2023, it appears that ED staff manually shifted the RESOLVE-selected pumped storage from the Riverside East area to the SDG&E study area. Table 3 below shows the relevant rows of the preliminary busbar mapping.

Table 3: IRP Preliminary Busbar Mapping (selected rows)[47]

RESOLVE Resource Name	Resource Type	Portfolio Resource Summary (2030)	In-Development Resources			Mapped Generic (2030)		
		TOTAL	FCDS	EODS	Total	FCDS	EODS	Total
Riverside_East_Pumped_Storage	LDES	298.6	-		-	-		-
San_Diego_Pumped_Storage	LDES	-	-		-	299		299.0

The SVES facility is similar to an 8-hour battery storage facility with the caveat that a pumped storage facility has a much lower round trip efficiency compared to battery storage, 75%

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[45] October I&A, Table 47, p. 73.

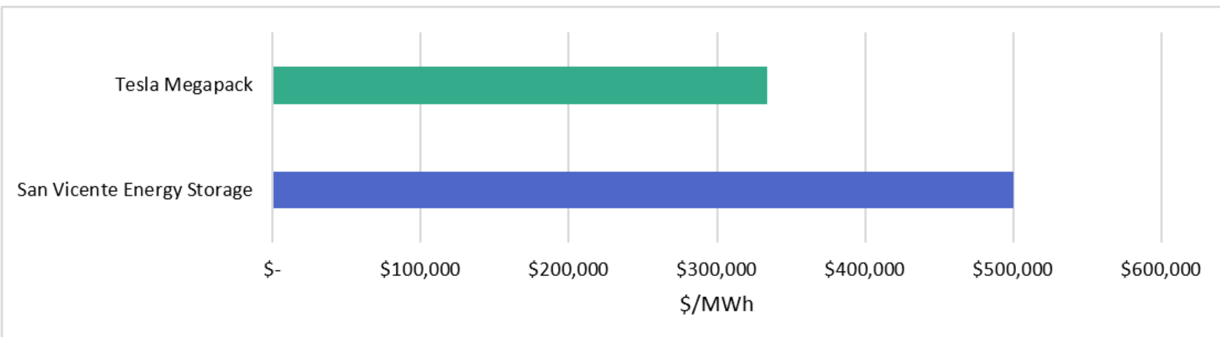
[46] *See* Attachment B, A Pumped Hydroelectric Energy Storage Analysis: Pumped Hydroelectric Storage Compared to Other Long-Duration Storage Options for California, ("MGRA Pumped Storage Report") (September 2023), p. 39.

[47] R.20-05-003, Dashboard for Preliminary Mapping of Proposed 24-25 TPP Base Case (October 26, 2023), available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp.

versus 85%.[48] Thus, if an 8-hour pumped storage facility were to cost the same as an 8-hour battery storage facility, the battery storage facility would provide a better value to ratepayers.

The proposed SVES facility is forecast to cost between $2 and $2.5 billion.[49] That forecast is for 4,000 MWh of energy storage.[50] Tesla offers price quotes on Megapack battery installations up to 3,916 MWh.[51] The current quote for a 3,916 MWh Megapack is $1.307 billion including installation in California in Q3 2024.[52] Figure 3 below shows the cost per MWh of a Tesla Megapack compared to SVES using the assumption that the cost of SVES would be at the bottom of the $2 to $2.5 billion range.

Figure 3: Tesla Megapack Cost versus San Vicente Energy Storage Cost



Prices for the Tesla Megapack decrease most quarters.[53] This shows that SVES would cost at least 49% more than Tesla's quote on a $/MWh basis.[54] SVES is the only proposed pumped

[48] October I&A, p. 131.
[49] Mussey Grade Road Alliance, Letter to the Federal Energy Regulatory Commission (FERC) (November 14,
2022), (The MGRA letter to FERC lists the most recent publicly disclosed estimate for a potential San Vicente
Pumped Storage project.), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221114-5410&optimized=false; *see also* Attachment B, MGRA Pumped Storage Report.
[50] 500 MW at 8-hour duration = 500MW x 8hr = 4,000 MWh.
[51] Tesla Megapack, available at https://www.tesla.com/megapack/design.
[52] Tesla Megapack, 979 MW, 3,916 MWh, $ 1,306,130,520, Q3 2024 online date available at https://www.tesla.com/megapack/design.
[53] *Ibid.*
[54] 1 – ($500,000 / $333,537) = 0.49908 = 49%

storage facility in the SDG&E study area. Thus, pumped storage busbar mapping in the SDG&E study area makes little sense.

For the reasons above, the Commission should not transmit any portfolios to CAISO for its TPP that include busbar mapping of pumped storage in the SDG&E study area. That pumped storage mapping would waste CAISO time and resources on an unviable pumped storage analysis – time and resources that would be paid for by ratepayers.

3.2 Pumped Storage should be eliminated from the SDG&E study area because the project cannot be completed by the year assumed in RESOLVE modeling.

In addition to the cost mismatch between SVES and the October I&A, SVES cannot meet the online date assumption in the PSP.

The SVES's preliminary permit from the Federal Energy Regulatory Commission ("FERC") expired on September 30, 2022.[55] MGRA has not found any additional dockets related to the San Vicente project since the prior FERC expiration.[56] According to a report from the National Hydro Association ("NHA"), a pumped storage facility that has yet to enter the FERC

[55] California State Water Resources Control Board Comments on Preliminary Permit Extension Request (November 21, 2022), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221121-5133&optimized=false.
[56] FERC Docket number P-14642 for the San Vicente Energy Storage Project, available at https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=p-14642&sub_docket=all&dt_from=2014-12-01&dt_to=2023-11-08&chklegadata=false&pagenm=dsearch&date_range=custom&search_type=docket&date_type=filed_date&sub_docket_q=allsub.

permitting process would be unlikely to achieve an online before 2030.[57] In contrast the 25 MMT Core portfolio selects 500 MW of pumped storage in 2028.[58]

Because a SVES is the only proposed pumped storage project in the SDG&E study area and because SVES does not meet the online date selected by RESOLVE, pumped storage should be removed from busbar mapping in the SDG&E study area before the 25 MMT Core Portfolio is transmitted to CAISO for the TPP.

4. PROCUREMENT (RULING SECTION 5 – PP. 48-51)

The Commission should order additional near-term clean net qualifying capacity ("NQC"). Section 4.1 details the benefits of new procurement. Section 4.2 highlights the statutory requirements that show the Commission must order new procurement. Section 4.3 discusses the need for 2,000 MW of additional capacity orders and the criteria that the Commission should require for LSEs' procurement. Section 4.4 lists the operational requirements that the Commission should establish for new long-duration energy storage ("LDES") at gas-fired generation facilities so that the LDES will benefit disadvantaged communities and ratepayers.

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[57] National Hydropower Association, NHA – Pumped Storage Development Council Challenges and Opportunities for New Pumped Storage Development (2017), p. 10, ("Under the current FERC licensing process, obtaining a new project license to construct can take three to five years, or even longer before the developer will have the authority to begin project construction. There is currently no alternative licensing approach for low-impact or closed-loop sites to shorten this time frame. In addition, a three- to five-year construction period is common for most large projects; furthermore, environmentally benign projects being developed to support renewable energy integration could take six to 10 years or longer to construct."), see https://www.hydro.org/wp-content/uploads/2017/08/NHA_PumpedStorage_071212b1.pdf.

[58] 2023 Proposed PSP and 2024-2025 TPP RESOLVE Analysis Slide Deck_FINAL V2 (November 3, 2023), Table 25 MMT Core Case Planned & Selected Capacity, p. 59, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2023-proposed-psp-and-2024-2025-tpp-resolve-analysis-slide-deck_final-v2.pdf.

4.1 The Commission will minimize costs by maximizing near-term solar and wind procurement.

The Ruling notes "the Commission does not actually have the authority to order natural gas retirements."[59] While that is true, the Commission can order LSEs to procure new renewable energy that could result in gas-fired generation becoming uneconomic. As the Ruling states, "[gas-fired generation] capacity factors will continue to decrease over time as zero marginal cost renewable energy generation offsets them in the CAISO's merit order dispatch stack."[60] The more renewable energy generation connected to the grid, the more likely gas-fired generators will voluntarily retire. For this reason, the Commission should continue to require LSEs to file lower MMT portfolios each cycle. In the next cycle, the Commission should require LSEs to file a 15 MMT portfolio and 5 MMT portfolio. These portfolios will give the Commission a greater range of options from which to select instead of limiting options to 5 MMT increments below the current MMT portfolios. Some LSEs are already on a path to achieving these low emissions levels before 2030.

In a worst-case scenario LSEs should still meet legislative procurement requirements. Public Utilities Code, § 454.53 (a) states that "[i]t is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 90 percent of all retail sales of electricity to California end-use customers by December 31, 2035."[61] Because the Commission does not know how much electricity demand will increase by 2035, the Commission should establish a significant buffer of carbon-free energy procurement to ensure compliance with statutory requirements. To accomplish state policy, the Commission should select the highest IEPR demand

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[59] Ruling, p. 38.
[60] Ruling, p. 38.
[61] Public Utilities Code, § 454.53 (a), available at https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=454.53.&lawCode=PUC, (unless otherwise noted all code reference are to the California Public Utilities Code).

forecast scenario for IRP planning purposes. If the Commission procures clean energy in alignment with the highest electricity demand forecast, ratepayers will benefit by likely receiving 90% or more carbon-free resources by 2035 even if electricity demand increases beyond the CEC's mid-range forecasts. Further, the LSEs and their customers will benefit by building renewable energy resources that qualify for the federal production tax credit ("PTC") of 2.75 cents/kWh and building battery storage that qualifies for an investment tax credit ("ITC") of up to 50% of installed cost.[62] Delays in clean energy procurement could increase costs for ratepayers because any projects that start construction after 2033 could qualify for smaller credits and zero credits after 2035. While the October I&A shows an illustrative levelized cost of energy ("LCOE") for utility scale solar that extends the Federal production and income tax credits beyond the 2033-2035 phase out, the full credits are not guaranteed beyond 2033.[63]

4.2 The Commission must accelerate procurement of wind and solar resources to reduce particulate pollution, reduce GHG emissions, reduce ratepayer costs, benefit disadvantaged communities and adhere to statutory requirements.

Clean energy costs less than fossil fuel-based energy as demonstrated by numerous sources including the October I&A. For example, Figure 4 below shows the October I&A forecasted costs for solar production through 2050. These costs are similar to Lazard's cost estimates even though Lazard lists the cost of solar and wind as low as $0/kWh after application of the PTC.[64] The PTC incentives should enable all LSEs to achieve 100% clean energy procurement by 2035 at minimal cost.

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[62] Federal Solar Tax Credits for Businesses (August 2023), available at https://www.energy.gov/eere/solar/federal-solar-tax-credits-businesses#_ednref6.
[63] October I&A, p. 48, (MGRA is aware that the October I&A forecasts that the phase out trigger for the tax credit may not occur until 2045.).
[64] Lazard, Levelized Cost of Energy + ("LCOE+")(April 2023), p. 3, available at https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/.

Figure 4: Reprint of October I&A - Fig 7[65]

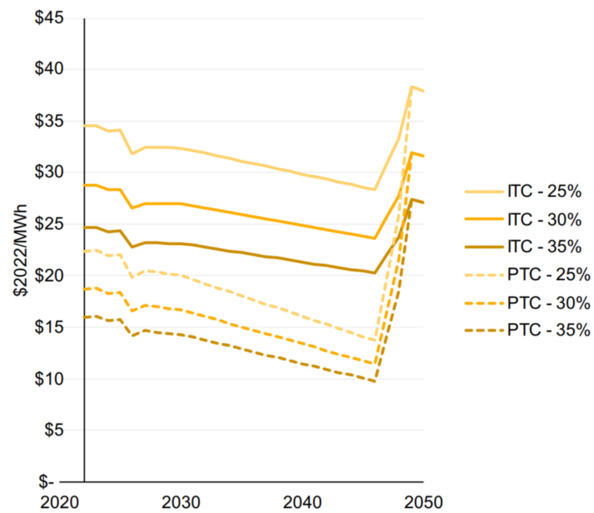

Figure 4 above shows that if the Commission waits to procure solar until 2040 instead of procuring all solar as soon as possible, California rate payers will save approximately half a cent in energy costs on the solar purchase. However, California ratepayers will *lose* the value of 15 years of reduced particulate pollution, reduced GHG emissions, and reduced energy costs compared to the higher-cost gas-fired generation. Figure 4 also shows that the total cost of solar generation will be less than $20/MWh.[66] The October I&A shows that just the fixed O&M for gas-fired generation is $38/MWh.[67] Thus, ratepayers will save money on every kWh of solar produced that qualifies for the IRA's PTC.

Returning to the half-cent difference between the cost of solar now versus the cost in 15 years, the cost difference is already an insignificant bill component compared to the total electricity rate paid by customers. For example, in SDG&E territory, as of January 2023, residential customers

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[65] October I&A, Figure 7, p. 69.
[66] October I&A, Figure 7, p. 69, (Assumes 30% and higher capacity factor which aligns with California solar capacity factors and is shown in 2 of 3 PTC assumptions in the I&A figure.).
[67] October I&A, Table 17, p. 30.

are charged 83 cents/kWh during summer on-peak hours.[68] Thus, a half cent difference in purchase price of solar now versus later is just one-sixth of one percent of the on-peak electricity rate.[69]

Another consideration for the Commission regarding the speed at which it requires 100% clean energy investment should be the costs of climate change to the state of California. A joint group of California agencies have calculated the total cost to California from climate change at $110 billion each year or $1.1 trillion each decade *without including wildfire costs*.[70] The faster that California decarbonizes its electricity system, the faster it will decarbonize its industrial, commercial, and transportation systems as well because each of those sectors depends on clean gird-supplied electricity to decarbonize. These decarbonization efforts will help to fight climate change and the costs thereof.

Much of the $1.1 trillion in climate change costs to Californians are health related and a significant portion of those health costs are born by fence line communities and disadvantaged communities. Section 454.52 requires that the Commission to "[m]inimize impacts on ratepayers' bills… [and] [m]inimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities."[71] Ratepayers pay many bills in addition to electricity bills including healthcare bills and property insurance bills. When including these bills in the cost-effectiveness calculation – bills that are increasing because of the effects of fossil-fuel use – the cost savings to ratepayers from additional clean energy deployment becomes even more significant and demonstrates that the Commission is required to order 100% carbon-free electricity "as soon as

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[68] SDG&E TOU-DR1 (January 1, 2023), p. 2, available at https://tariff.sdge.com/tm2/pdf/historical/ELEC_ELEC-SCHEDS_TOU-DR1_2023.pdf.
[69] 0.5cents / 83 cents = 0.00602 = 0.6%
[70] 2018 Statewide Summary Report California's Fourth Climate Change Assessment ("Climate Change Assessment"), Publication number: SUM¬CCCA4-2018-013, Table 6, p. 42 (110 billion per year x 10 years = 1.1 trillion per decade), available at https://www.climateassessment.ca.gov/.
[71] Section § 454.52 (D) and (I), available at https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=454.52.&lawCode=PUC
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possible" in conformance with Health and Safety Code §38562.2 and Public Utilities Code, § 454.53 (b)(2).[72]

4.3 The Commission should order additional resources to extend the deadline for LLT resources.

The Ruling asks parties to "comment on the MTR sufficiency analysis, its relationship to the two PFMs, and the proposal for 2,000 MW of additional MTR clean capacity procurement in 2028 in their responses to this ruling."[73] MGRA supports the additional 2,000 MW procurement and recommends specifics on how the procurement order can be issued to incentivize LSEs to accelerate their clean energy procurement for their portfolios.

Since 2019 the Commission has issued several procurement orders in the IRP proceeding (i.e., D.19-11-016, D.21-06-035, and D.23-02-040). These procurement orders first established a total MW of capacity required and then assigned procurement to LSEs based on individual LSEs' loads as percentages of the total load.[74] That procurement order framework did not account for LSEs' existing portfolios' reliability metrics, clean energy generation percentages, clean energy NQCs, or other relevant considerations. The Commission's orders assigned new procurement divorced from an evaluation of LSEs' portfolios. The unintended consequence of this procurement approach has been to incentivize LSEs to *minimize* clean energy procurement – or at the very least reduce clean energy procurement – until receiving orders from the

[72] Health and Safety Code §38562.2, available at https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=HSC&sectionNum=38562.2.; and Public Utilities Code, § 454.53 (b)(2), https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=454.53.&lawCode=PUC.

[73] Ruling, p. 49.

[74] D.23-02-040, p. 30, ("[T]he procurement requirements will be allocated among all LSEs currently serving load, utilizing a combination of both the 2023 year ahead resource adequacy forecasts and the energy load forecasts of individual LSEs from the 2022 IEPR for 2023."), available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF.

Commission. If an LSE procures clean energy or storage resources beyond the Commission's minimum requirements, that LSE has historically run the risk that the Commission will order the LSE to make duplicative procurements in the following months because the Commission's procurement orders do not credit LSEs for the contents of their existing generation and storage portfolios. Thus, the format of the Commission's procurement orders has likely slowed clean energy procurement in California although it is impossible to say by how much.

To avoid a similar outcome from the proposed 2,000 MW procurement related to delaying the LLT resource deadline, the Commission should use a simple metric to determine which LSEs should procure additional clean NQC by 2028. The Commission should tally each LSE's clean NQC for resources that are online or in development. Then the Commission should order the LSEs that have the lowest percentage of clean NQC, to procure the additional 2,000 MW of clean NQC. For example the Commission could make the order effective only for the LSEs with the lowest NQC that represent 25% of total system load. The procurement order capacity should be distributed among those LSEs such that each of the LSEs required to procure clean NQC will see the percentage of clean NQC in their portfolios increase to the same level as each of the other LSEs required to procure resources.

This new procurement order format will flip the incentives from the prior procurement orders. Instead of slowing voluntary procurement of clean resources, the order would demonstrate that LSEs that are clean energy leaders may never be ordered to procure energy. Thus, the clean energy procurement leaders are free to make their procurement decisions on their own timelines and avoid concerns about duplicative procurement orders from the Commission. Additionally, the if the LSEs are procuring resources on their own timelines instead of on a Commission-ordered timeline, the procurement pipeline will naturally smooth out instead of exhibiting the lumpiness caused by the Commission ordering every LSE to procure resources with identical commercial operation deadlines.

Other concerns may also be raised that would be solved by adopting the above procurement strategy. For example, some LSEs are close to providing 100% clean electricity service to customers.[75] If those LSEs are ordered to procure more clean energy and more reliability than is needed to serve their customers, then they will ultimately be supplying free resources to customers of other LSEs. That cost shift would be unfair to the customers of the LSEs that have exceeded the clean energy procurement standards of other providers. The Commission should reward accelerated procurement of clean energy, something the historical procurement framework does not do.

Even if the Commission does not use the exact format proposed above, it should consider procurement order formats that accelerate clean energy procurement instead of causing clean energy procurement to decelerate. MGRA supports a 2,000 MW clean NQC order that incentivizes voluntary clean energy procurement by all LSEs and rewards LSEs that have made early clean energy procurement decisions.

4.4 The Commission should procure battery storage resources at existing natural gas sites if threshold ratepayer protections are established.

The Commission should order procurement of LDES at existing gas-fired generation facilities, but must establish procurement standards, operational requirements, and gas-fired retirement deadlines to ensure that the LDES procurement benefits ratepayers and not just the owners of gas-fired generators. The following should be the minimum criteria set for LDES procurement at gas-fired generators.

[75] R.20-05-003, MCE Written Ex Parte Communication

First, the owner should not be allowed to charge the on-site batteries using the on-site gas-fired generators and the LDES should always have priority use of the grid interconnection. This means the storage resource will have exclusive use of the interconnection between 8 am and 4 pm to charge the battery using grid-supplied electricity and exclusive use of the interconnection between 4pm and midnight to discharge the battery. Between midnight and 8 am the site owner may still use the interconnection to deliver gas-fired-generator-produced electricity to the grid.

Second, the Commission must ensure that the installed batteries are used to their maximum potential. For years, California has seen large storage facilities sitting idle most of the year. The CEC reported that in 2017 that pumped storage facilities in California operated, on average, at just 14% of their designed capacities as shown in table below.[76]

Table 4: 2017 Pumped Storage Facility Capacity Factors

Plant Name	Capacity (MW)	2017 Capacity Factor (%)
Edward Hyatt Power plant	644	42
W. R. Gianelli PumpedStorage Plant	424	5
O'Neill Pumping-GeneratingPlant	28	0.04
Castaic Pumped StoragePlant	1682	4
Helms Pumped Storage Plant	1212	8
Balsam Meadows/Big Creek(Eastwood) Pumped Storage	200	24
Olivenhain-Hodges Storage Project	40	17
Average		**14**

To avoid new procurement of ratepayer-funded storage sitting idle as pumped storage frequently does, the Commission should require the gas-fired generators with on-site batteries to

[76] California Energy Commission, Tracking Progress - Energy Storage, Table 3, p. 6, available at https://www.energy.ca.gov/sites/default/files/2019-12/energy_storage_ada.pdf.

adhere to the following operational standards. The owner of the gas-fired generators that have installed batteries procured under a Commission order must:

(1) install battery storage on-site with a minimum battery power capacity equal to the grid interconnection capacity and at an energy capacity minimum of 4 hours;

(2) charge the battery to a 100% state of charge each day between the hours of 8 am and 4 pm.

(3) discharge the battery each day to a 5% state of charge between the hours of 4 pm and midnight;

(4) within 5 years of commercial operation of the on-site batteries, decommission the on-site gas-fired generation; and

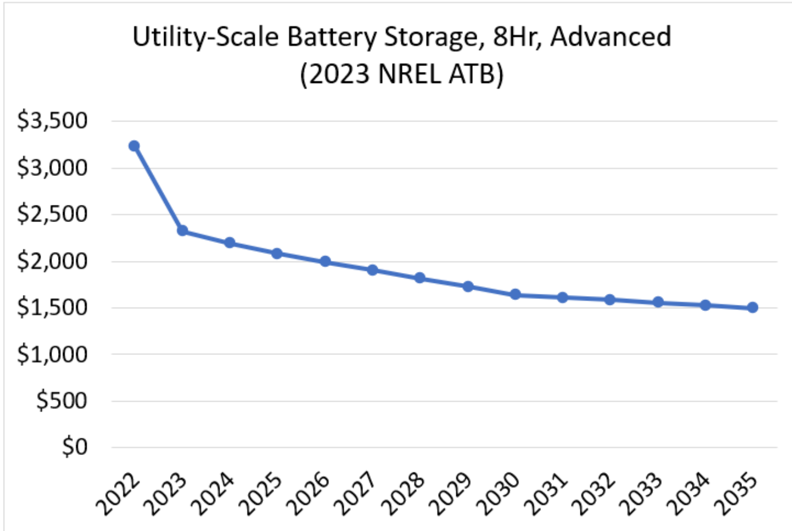
(5) within 2 years of decommissioning the on-site gas-fired generation, double the energy storage capacity at the site (i.e. to 8-hour duration).

Third, to comply with §454.52(a)(1)(I) the Commission must locate these gas-fired generator-sited battery facilities at gas-fired generators within disadvantaged communities.[77] Until all gas-fired generators in disadvantaged communities have been decommissioned, the Commission should only order procurement of batteries at gas-fired generation facilities that are in disadvantaged communities.

Finally, the Commission should establish a maximum contract length of 10 years to ensure that ratepayers do not pay a long-term contract rate for electricity storage at far above the future cost of storage. Figure 5 below shows the cost of storage forecast by NREL. NREL anticipates that by 2035 the cost of 8-hour battery storage will be less than half the cost of 8-hour storage in 2022.

[77] Public Utilities Code § 454.52(a)(1)(I), (The Commission must require LSEs IRPs to "[m]inimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities.").

Figure 5: 2023 NREL ATB Battery Costs 2022-2035 [78]



If an owner of a gas-fired generator fails to operate a facility in compliance with the above criteria, the Commission should levy a fine on that facility equal to 100% of the facilities' resource adequacy revenue generation for the year of the violation. The fine should be collected by the Commission and used to fund clean energy projects designed to eliminate gas-fired generation and natural gas use in disadvantaged communities. The CPUC's Disadvantaged Communities Advisory Group should be the body to select the projects and award funding.[79]

MGRA supports ordered procurement of battery storage at gas-fired generator locations if the Commission issues the order with the guardrails detailed above. The above criteria will ensure benefits for disadvantaged communities, ratepayers, and the environment. If the Commission does not adopt MGRA's recommendations, ratepayers may simply incur additional costs absent of benefits.

[78] 2023 NREL ATB, available at https://atb.nrel.gov/electricity/2023/index.
[79] CPUC, Disadvantaged Communities Advisory Group, *see* https://www.energy.ca.gov/about/campaigns/equity-and-diversity/disadvantaged-communities-advisory-group.

5. CONCLUSION

For the reasons stated above MGRA agrees with the Ruling's recommendation that the 25 MMT Core portfolio should be selected as the PSP and should be transmitted CAISO as the as both the reliability and policy-driven base case.

The October I&A should be updated to correct the battery cost assumptions to align with the NREL ATB's "advanced" capital cost scenario because that scenario most closely matches current manufacturer's publicly available battery prices.

Regarding additional procurement, MGRA supports both procurement proposals from the ruling with the following caveats. The Commission should order an additional 2,000 MW of clean NQC procurement by 2028 if the Commission structures the order to promote additional voluntary procurement from LSEs as described in the comments above. The Commission should also order procurement of battery storage at existing gas-fired generation if (1) the batteries are restricted from charging from on-site gas-fired generation (2) batteries have priority access to use the grid the interconnection and (3) batteries are required to be fully cycled once per day.

Finally, before the Commission transmits a portfolio to CAISO for TPP analysis, it should remove pumped storage from busbar mapping or at least remove pumped storage from the SDG&E study area. The analysis in these comments show that the only proposed SDG&E study area pumped storage project is approximately 50% more expensive than a battery storage project of identical size.

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ATTACHMENTS:

ATTACHMENT A:
Attachment A, The Mussey Grade Road Alliance Informal Comments on the 2022-2023 Integrated Resource Plan Draft Inputs and Assumptions Document and Webinar Slide, (June 21, 2023)

ATTACHMENT B:

Attachment B, A Pumped Hydroelectric Energy Storage Analysis: Pumped Hydroelectric Storage Compared to Other Long-Duration Storage Options for California, (September 2023)