ALJ/JF2/mef 8/17/2021

FILED
08/17/21
11:55 AM

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

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON PROPOSED PREFERRED SYSTEM PLAN

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Attachment A: Powerpoint slides summarizing RESOLVE analysis

Attachment B: Powerpoint slides summarizing SERVM analysis

Attachment C: Methodology for Resource-to-Busbar Mapping & Assumptions for The Annual Transmission Planning Process

Summary

This ruling provides a summary of analysis conducted by Commission staff to recommend key elements of the preferred system plan (PSP), including a preferred resource portfolio, for use in integrated resources planning (IRP) and procurement, as well as to be analyzed by the California Independent System Operator (CAISO) in the 2022-2023 Transmission Planning Process (TPP).

This ruling and its attachments summarize the analysis.[1] The ruling describes how and why load serving entities' (LSEs') plans submitted in September 2020 are expected to fall short of meeting the greenhouse gas (GHG) and reliability targets, due to a collective insufficiency of planned new capacity. However, Commission staff analyses and reliability modeling on the portfolios using updated assumptions from the procurement requirements of Decision (D.) 21-06-035 on mid-term reliability (MTR) and rounding out the last two years of the ten-year planning horizon, should largely achieve the Commission's reliability and GHG goals for 2030.

A workshop to explain the analysis and recommendations, and to answer questions, will be held in late August 2021; the workshop details will be shared with the service list of this proceeding and posted on the Commission's Daily Calendar.

Interested parties are invited to comment on this ruling, the questions embedded in it, and its attachments, by no later than September 27, 2021. Parties who have conducted their own modeling analyses to support their comments

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[1] The attachments to this ruling, as well as other supporting materials, will be posted at the following link on the Commission's web site, for parties' convenience: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials

may also present their modeling results in the September 27, 2021 comments. Reply comments are invited by no later than October 11, 2021.

1. Introduction / Background

On or by September 1, 2020, 44 LSEs filed their individual integrated resource plans, to be evaluated and approved or certified by the Commission. Instructions for the filing of the individual IRPs were contained in D.18-02-018, D.19-04-040, and D.20-03-028. The individual IRPs contained information, in both narrative and spreadsheet form, about the electricity resources that the LSEs plan to rely on out through the year 2030.

One of the most important purposes of the Commission's IRP process is to take the individual IRPs, aggregate them, and evaluate the aggregated portfolio against the overall electric system needs of California, and particularly the CAISO system. The aggregated portfolio is compared against reliability and GHG constraints, while seeking to meet those constraints at the lowest reasonable cost to ratepayers. The aggregation of the individual LSE portfolios also serves to determine if there are gaps in the collective portfolio that will require action by the Commission to address.

2. Aggregation of LSE Plans

This section of the ruling describes the general process Commission staff used to aggregate the portfolios of the individual LSEs filed on September 1, 2020. Attachment A contains more detail.

The individual IRPs all included LSE-specific information on planned GHG reductions, reliability resources, imports and exports, impacts on disadvantaged communities, and estimated costs.

As part of their individual IRPs, all LSEs filed Resource Data Templates (RDTs) containing information about the resources they currently use or are planning to use to serve their customer load. LSEs also submitted Clean System Power (CSP) calculators to estimate the GHG and criteria pollutant emissions of their planned portfolios.

Contained in the RDTs is information about baseline and existing resources, resources contracted for and in development, and planned resources for which there is no current contract.

To analyze the RDTs, Commission staff built a tool to aggregate the portfolios and check errors, called the "RDT error checking, aggregation, and reallocation tool" or RECART. RECART performed the following functions: combining the filings into one dataset; producing LSE-specific workbooks that tracked errors; and performing diagnostics for staff to use when analyzing LSE filings. RECART compiled energy and capacity resources under contract, contracted resources by technology type and LSE, and aggregated new resources that were either in development or planned for future purchase.

Commission staff spent considerable time and effort iterating with individual LSEs through up to six re-submission requests from September 2020 through February 2021, to correct and clarify existing and planning contract information provided by the LSEs. This effort ensured that the Commission was working from plans that fully reflect LSE planning and priorities.

Commission staff combined several datasets to create a full list of baseline and planned resources to be online in future years. Those datasets include the following:

- An updated baseline of resources that are online and delivering to CAISO, or are in development with executed and approved contracts, which consists of:
  - The baseline of existing and "in development" resources from the reference system plan (RSP) updated

with additional projects that have achieved commercial operation in the CAISO market; and

  - Additional contracted resources included in the RDTs with executed and approved contracts as of June 30, 2020;

- Compiled portfolios of new resources, both in development with contracts executed and approved after June 30, 2020 and planned for future development.

Commission staff also quality controlled these datasets through the following processes, to avoid duplication and verify accuracy:

- A comparison of the RSP baseline with the CAISO generator lists showing new resources online since the RSP baseline was compiled, in order to confirm or supplement new development resources;
- Extensive reconciliation and error checking to remove duplicates, correct errors, and validate data sources, such as the Western Electricity Coordinating Council Anchor Data Set.

Commission staff assembled these sources, checked for overlap and double counting, and created one curated list of resources.

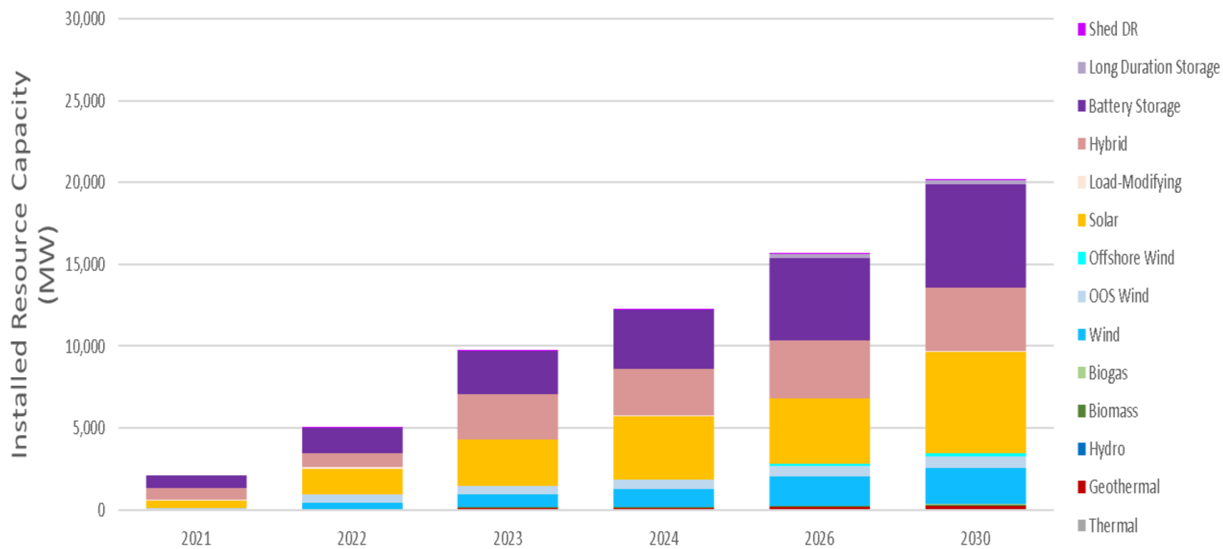
Commission staff also worked with the California Energy Commission (CEC) staff to develop RDTs for publicly-owned utilities (POUs) that are within the CAISO footprint, to reflect existing contracts held by POUs and create an accurate picture of all resource planning across the CAISO.

According to D.20-03-028, LSEs were required to submit plans that met their portion of both the 46 million metric ton (MMT) statewide GHG target by 2030, adopted by the Commission in that decision, as well as plans that met their portion of a 38 MMT or lower GHG target.

The aggregated portfolios meeting both the 46 MMT GHG target and the 38 MMT GHG target were then used as the starting point for modeling to develop and recommend the PSP for use in the TPP.

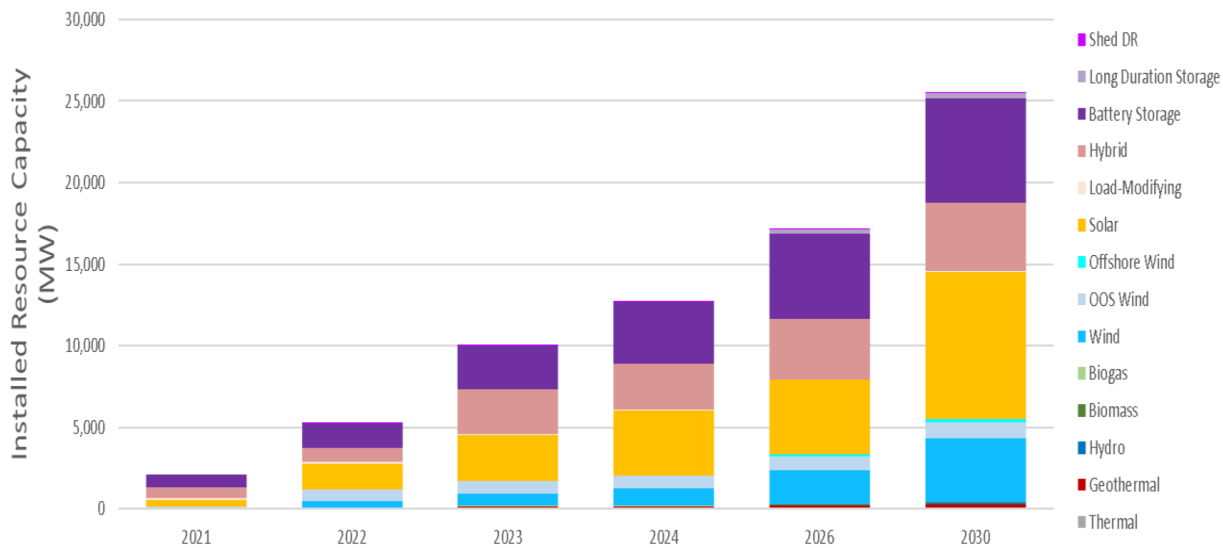
Figures 1 and 2 below show the new resource buildout associated with both the 46 MMT and 38 MMT individual plans of all LSEs. All of these resources are incremental to the updated baseline described above.[2]

Figure 1. New Resource Buildout Associated with the Aggregated 46 MMT Plans



[2] Paired generation/storage in Figures 1 and 2 below refers to resources that LSEs entered as "New Hybrid" in their RDTs.

Figure 2. New Resource Buildout Associated with Aggregated 38 MMT Plans



The total GHG emissions of the aggregated CSP calculators submitted in LSE plans came in under the targeted GHG emissions amounts. Both of these lower GHG amounts are caused by several LSEs submitting plans that achieve emissions levels lower than their individual benchmarks.

The analysis conducted in the RESOLVE model includes assumptions about all CAISO LSEs, including those POUs whose procurement does not fall within the Commission's IRP oversight. It should be noted that although those POUs make up less than 10 percent of the load within the CAISO, the Commission's IRP analysis plans for the full CAISO area, and any shortfalls in reliability and GHG emissions reductions are covered in the planning for Commission LSEs, though they may be caused by POUs. Parties are asked to comment on how this situation should be addressed in comments on this ruling.

The resource buildout differences between the 46 MMT and 38 MMT portfolios of the LSEs are relatively small between now and 2024 (under 500 megawatts (MW)), exceed 1,000 MW in 2026, and total approximately 5,400 MW by 2030. The additional resources added by LSEs in the second half of the decade are a mix of resources, including geothermal, wind (including out-of-state (OOS) and offshore wind), solar, hybrid renewable and storage resources, and battery storage, along with smaller amounts of biomass, biogas, demand response, and long-duration storage.

The diversity of resources planned to meet both the 46 MMT and 38 MMT targets is greater in the plans of the community choice aggregators (CCAs) than for investor-owned utilities (IOUs) or electric service providers (ESPs). CCAs are also tending to plan for higher amounts of GHG-free resources, including renewables. ESPs generally showed very little difference in terms of new planned procurement amounts between their 46 MMT and 38 MMT plans, indicating a reliance on prospective contracting with existing GHG-free resources to lower their emissions, a potentially risky strategy if those existing resources are contracted by other LSEs.

In general, the portfolio size and composition of the aggregated portfolios are generally consistent with the RSP adopted in D.20-03-028, but they include more resources with higher net qualifying capacity (NQC) than the RSP. The aggregated portfolios include more technology types than the RSP, but the amounts of diverse resources being planned for (*e.g.*, geothermal, long-duration storage, offshore wind, OOS wind, and biomass) are generally smaller than what was recently required by the Commission in the MTR decision (D.21-06-035). LSE plans were also developed prior to D.21-06-035 and thus do not contain the required MTR procurement amounts and attributes.

3. Reliability Analysis of Aggregated LSE Plans

The primary purposes of production cost modeling (PCM) in the IRP proceeding are to ensure that system reliability, operational performance, emissions, and operating costs of a given portfolio are expected to meet IRP requirements and to confirm that expectations of future resource dispatch and operation are supported across a distribution of probable scenarios of weather and resource performance. In particular, PCM is used to ensure that expectations of reliability and GHG emissions are reasonable, given expected operations of the system across all hours of a year, and not just a snapshot, peak season, or peak time of the day. Attachment B to this ruling provides more detail on the PCM conducted and leading to this ruling.

To transform LSE plans into inputs for PCM, Commission staff began with the PCM baseline and electric demand inputs used to produce the TPP portfolios sent to the CAISO for their 2021-2022 TPP. Staff updated the baseline resource fleet as described above, then replaced RESOLVE planned capacity with capacity included in the aggregated LSE 46 MMT and 38 MMT portfolios to generate the aggregated LSE plans. Staff used PCM analysis to confirm whether the aggregated LSE plans met the requirements of the commission, namely achieving a reliable electricity system as well as the GHG targets.

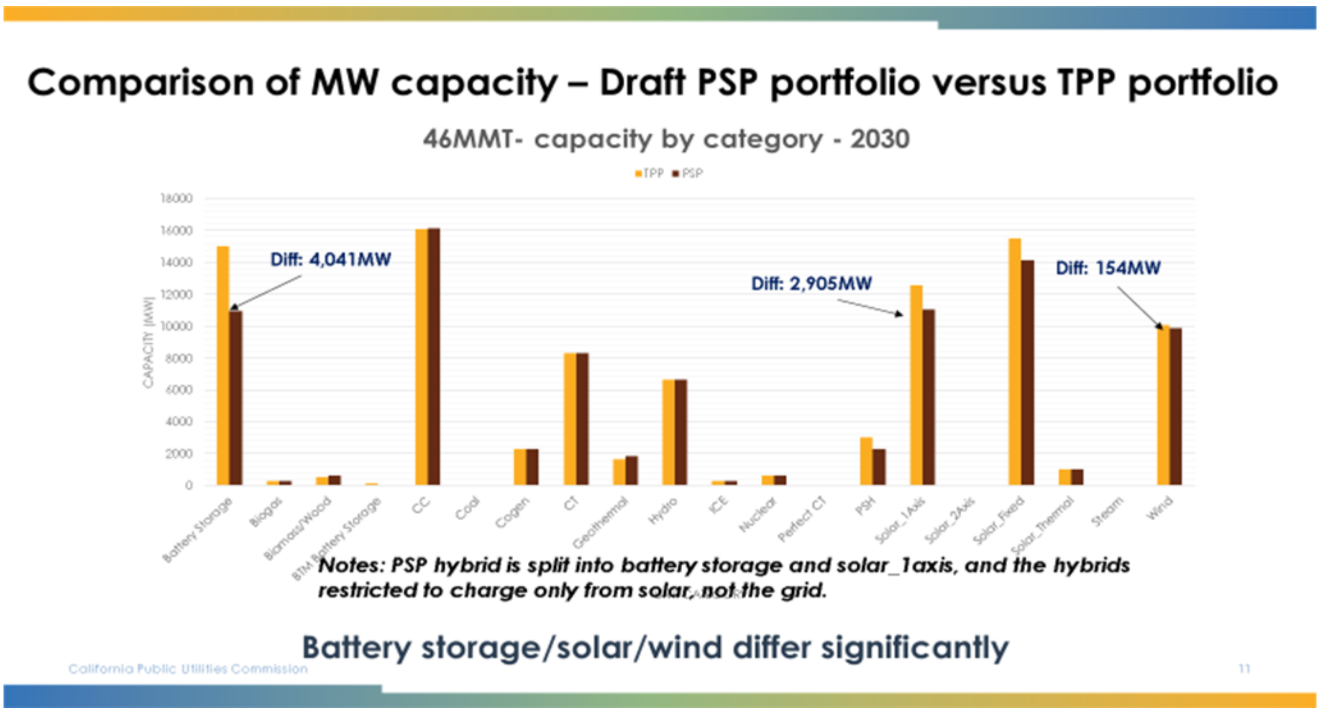
Full reliability and GHG analysis through PCM found that the aggregated LSE plans failed to meet reliability targets (Loss of Load Expectation (LOLE) equivalent to 0.1 or less, meaning one or fewer loss of load events in ten years) and GHG targets. Additional capacity was needed on top of the baseline resources and LSE planned procurement to meet the reliability and GHG targets. Neither the 46 MMT nor the 38 MMT aggregated portfolios met reliability targets, although the 46 MMT aggregated portfolios met the GHG target. The 38 MMT portfolio resulted in GHG emissions about 5.5 MMT higher than the target. Table 1 shows the results of PCM analysis of both portfolios, for study years 2026 and 2030.

Table 1. LOLE Results from Aggregated LSE Plan Portfolios

Reliability Metrics	46MMT 2026	46MMT 2030	38MMT 2026	38MMT 2030
LOLE (expected outage events/year)	0.36	0.68	0.29	0.41
Loss of Load Hours (hours/year)	0.76	1.63	0.61	0.94
LOLH/LOLE (hours/event)	2.09	2.38	2.07	2.26
Expected Unserved Energy (MWh)	1,436.66	2,468.93	1,176.91	1,364.54
Annual load (MWh)	255,116,344	265,501,285	255,094,310	258,290,192
normalized EUE (%)	5.631E-06	9.299E-06	4.614E-06	5.283E-06

The aggregated LSE plan portfolios failed to meet GHG and LOLE targets due to insufficient new capacity. The GHG results contrast with the GHG results from the aggregated CSP calculators submitted by LSEs, which may indicate an over-reliance on existing resources by some LSEs, to the extent that LSEs are planning for more existing resources than actually exist in the baseline. By comparison, the portfolio sent to the CAISO for the 2020-2021 TPP included greater quantities of battery storage, pumped storage hydro, and solar resources, as shown in Figure 3 below. For example, there was a difference of 4,041 MW in the quantity of overall battery storage and 2,905 MW of single axis solar, relative to the TPP portfolio. Overall, the aggregated LSE plan portfolios were insufficient to meet reliability and GHG requirements.

Figure 3. Capacity in 46 MMT Aggregated LSE Plans
Compared to Comparable TPP Portfolio



Attachment B to this ruling contains more detailed information about the PCM analysis conducted on the aggregated LSE plans.

4. Capacity Expansion Modeling to Augment LSE Plans

As articulated in D.20-03-028, Commission staff's analysis of the aggregated LSE plans assumed that a 38 MMT target was a reasonable goal to set in the PSP that would benefit from further analysis based on actual procurement planning by LSEs. The Commission further articulated in D.21-06-035 that a 38 MMT GHG limit for 2030 should be adopted as the PSP, as long as the resource mix resulted in a system with a 0.1 LOLE or less. Therefore, Commission staff began by subjecting the 38 MMT aggregated plan to additional capacity expansion modeling and production cost modeling.

Since the aggregated 38 MMT LSE plans portfolio failed to meet GHG and LOLE requirements through 2030, additional capacity was required to bring the portfolio into compliance with IRP requirements. Commission staff utilized the RESOLVE model to conduct additional analysis to determine what resources may be needed to supplement the resources contained in the aggregated 38 MMT LSE plan portfolios.

Most parties are familiar with the RESOLVE model because it is the capacity expansion model that has been used since the first IRP cycle to form the RSP and/or PSP adopted by the Commission. Before being used in this round of analysis, several updates were made to the model, as described below. Many of these updates are important for and related to transmission constraints that affect the TPP analysis that will be conducted by the CAISO in its 2022-2023 TPP. Updates included the following (*see* Attachment A to this ruling for more details on RESOLVE updates):

- Code base was updated overall;
- Lithium-ion battery and pumped storage are now modeled by multiple resources so they can be included in deliverability constraints;
- Transmission upgrade limits were enforced to limit transmission build to CAISO-determined levels;
- Solar resources were consolidated to align with battery locations as a step towards representing co-located and hybrid resources and to make incorporation of storage resources easier;
- New CAISO deliverability data was incorporated for peak and off-peak resources, with updated transmission constraints, and resource-specific output factors;
- OOS wind on new transmission and offshore wind were updated to be fully deliverable;
- Wind-transmission interactions for Wyoming and New Mexico wind imports were constrained based on CAISO revised transmission limits;

- Resource costs were updated to the latest data vintage of standard IRP data sources; and
- Federal production tax credit (PTC) and investment tax credit (ITC) schedules were updated to reflect statutory and Internal Revenue Service guidance as of December 2020 and the solar annual build constraints were updated to reflect the updated ITC schedule.

Once these updates were completed, Commission staff used the RESOLVE model to construct additional scenarios that could be potential candidates for a PSP that meets the reliability and emissions standards, to be considered further by the Commission.

As a preliminary matter, to be utilized by the CAISO in the TPP process, the portfolio needs to address a ten-year planning horizon, which for the 2022-2023 TPP would mean planning through 2032. The individual IRPs were only required to identify resources through 2030, so RESOLVE was used to select additional resources for the remaining two years to round out the ten-year planning timeframe.

A GHG target for 2032 was assigned by analyzing additional modeling study years in RESOLVE of 2035, 2040, and 2045, and then interpolating a GHG target for 2032 using those additional years plus 2030.

In addition, because the MTR decision (D.21-06-035) was adopted after the filing of the individual IRPs, Commission staff added the required resources or resource attributes, as applicable, from the 11,500 MW of NQC ordered in that decision as a component of the portfolios.

The impact of the MTR decision was implemented with a number of changes in the RESOLVE modeling. First, the planning reserve margin (PRM) was aligned with the 2024 “high need” scenario adopted in D.21-06-035, which uses a PRM of 22.5 percent. Load adders were also added to account for the managed peak impact of the 2020 CEC Integrated Energy Policy Report (IEPR) demand forecast (instead of 2019) and the high electrification scenario (instead of the mid-case). Additional thermal generation retirements were also applied, for units over 40 years in age. The unspecified import assumption was reduced from 5,000 MW to 4,000 MW. In 2028, 1,000 MW NQC of geothermal and 1,000 MW NQC of long-duration storage were forced into the portfolio as a proxy for the 2,000 MW of long lead-time (LLT) resources required in D.21-06-035. These assumptions were left in the model to persist after 2026.

After augmenting the aggregated portfolios submitted by the LSEs on September 1, 2020 with the additional two years of resources and the MTR requirements, Commission staff analyzed the following scenarios in RESOLVE. Unless otherwise noted, all scenarios utilized the demand forecast[3] from the CEC's 2019 IEPR:

- A 38 MMT GHG target in 2030 without LSE plans included; this is essentially a re-run of a reference system portfolio with updated assumptions, and is intended for comparison purposes only;
- A 38 MMT GHG target in 2030 with LSE plans incorporated, along with the MTR resources of 11,500 MW, and resource augmentation for 2031 and 2032 (referred to as the "38 MMT Core Portfolio");
- Several 38 MMT GHG target sensitivities built off of the 38 MMT Core Portfolio, as follows:
    - 38 MMT Core with the 2020 IEPR mid-demand load forecast;

[3] The particular forecast utilized was the IEPR mid-demand, mid-additional achievable energy efficiency (AAEE), and mid-additional achievable PV (AAPV) case, as agreed upon between the Commission, the CEC, and the CAISO as the "single forecast set" basis established in a 2010 memorandum of understanding, for comparable analysis by each agency.

  - 38 MMT Core with the 2020 IEPR mid-demand load forecast mixed with the 2020 IEPR high electric vehicle (EV) load forecast;
  - 38 MMT Core with a high electrification demand forecast for both managed and unmanaged EV profiles, based on a high electrification demand scenario developed by Commission staff using the PATHWAYS model in 2020 for modeling purposes;
  - 38 MMT Core with an assumption that developers do not invest to a level significant enough by end of 2025 to access safe harbor provisions of the offshore wind ITC, making projects ineligible for the full ITC benefits;
  - 38 MMT Core with high solar and battery storage cost assumptions; and
  - 38 MMT Core with MTR non-persistence assumption to test portfolio changes if the MTR "high need" scenario reliability drivers are reduced similar to the previously-established IRP planning assumptions.
- A 46 MMT GHG target in 2030, based on LSE plans and augmented with the 11,500 MW of MTR NQC and 2031 and 2032 resources (referred to as the "46 MMT Core Portfolio");
- A 30 MMT GHG target in 2030, based on the LSE plans designed to achieve the 38 MMT target, augmented with the 11,500 MW of MTR NQC, 2031 and 2032 resources, and additional resources necessary to achieve the lower 30 MMT GHG target (referred to as the "30 MMT Core Portfolio"); and
- 30 MMT Core with a high electrification demand forecast, based on a high electrification demand scenario developed by Commission staff using the PATHWAYS model in 2020 for modeling purposes.

Attachment A to this ruling provides the detailed results of the major scenarios studied. Figure 4 and Table 2 below summarize the resource buildout results for the 38 MMT Core scenario. By 2030, RESOLVE's 38 MMT Core results indicate that all reliability and GHG constraints are largely being met through a combination of aggregated LSE planned resources and the additional resources required in D.21-06-035. The only additional RESOLVE-selected resources being selected above and beyond LSE plans and D.21-06-035 requirements in 2030 are 286 MW of utility-scale solar to meet the GHG target. By 2030, because LSEs were not asked to plan beyond 2030, all additional resources were selected by RESOLVE.

Figure 4. New Resource Buildout of 38 MMT Core (cumulative MW)

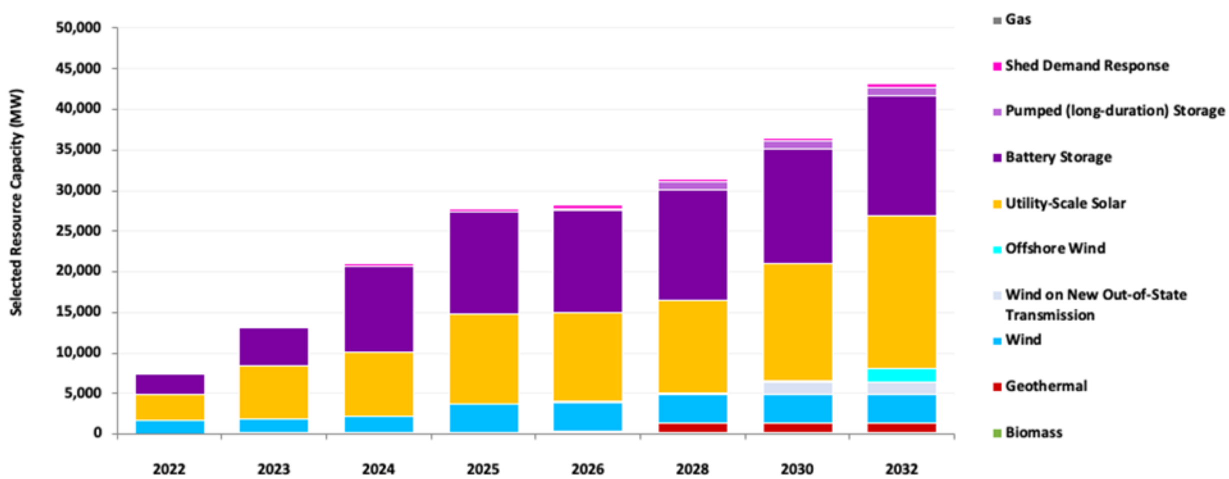


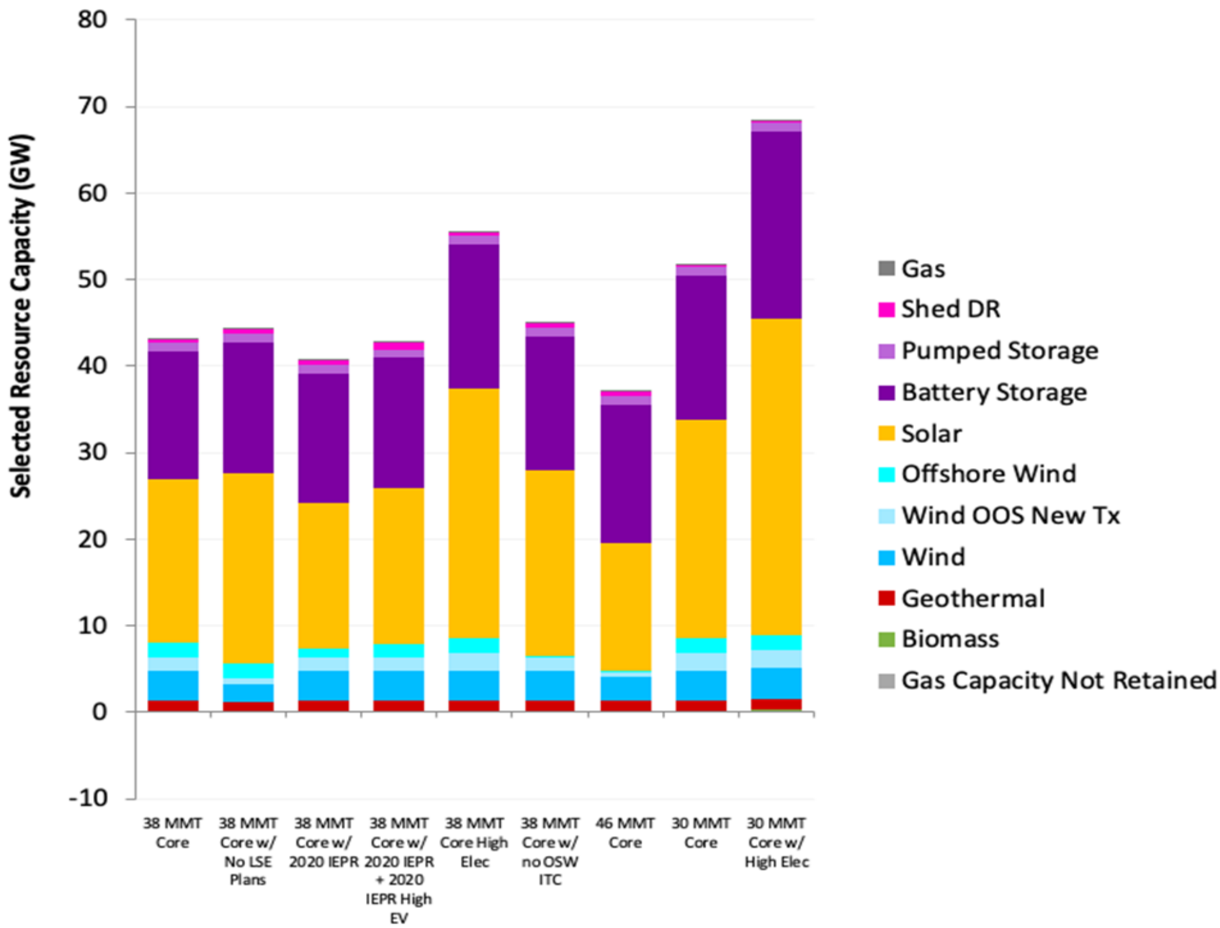
Table 2. New Resource Buildout of 38 MMT Core (Cumulative MW)

Resource Type	2022	2023	2024	2025	2026	2028	2030	2032
Gas	-	-	-	-	-	1	1	1
Biomass	34	65	83	107	107	134	134	134
Geothermal	14	114	114	114	184	1,160	1,160	1,160
Wind	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553
Wind on New Out-of-State Transmission	-	-	-	-	0	0	1,500	1,500
Offshore Wind	-	-	-	-	120	195	195	1,708
Utility-Scale Solar	3,094	6,549	7,750	11,000	11,000	11,397	14,457	18,883
Battery Storage	2,565	4,604	10,617	12,553	12,553	13,609	14,086	14,751
Pumped (long-duration) Storage	-	-	-	-	196	1,000	1,000	1,000

Resource Type	2022	2023	2024	2025	2026	2028	2030	2032
Shed Demand Response	151	151	353	441	441	441	441	441
Total	**7,577**	**13,224**	**20,988**	**27,768**	**28,154**	**31,489**	**36,527**	**43,131**

Figure 5 below shows the resource buildout differences in various sensitivity scenarios.

Figure 5. Summary of New Resource Buildout in Sensitivity Scenarios in 2032 (Cumulative MW)



Key resource buildout differences by 2030 in the sensitivity scenarios compared to the 38 MMT Core scenario include:

- For the 38 MMT Core without LSE plans, an additional 1,161 MW due largely to more solar and battery storage capacity, and less in-state wind and OOS wind on new transmission capacity;

- For the 38 MMT Core using the 2020 IEPR mid demand forecast, 2,385 MW of fewer resources due to less solar and offshore wind capacity and slightly more capacity from battery storage and shed demand response;
- For the 38 MMT Core using the 2020 IEPR mid with High EVs, 405 MW of fewer resources due to slightly less solar and offshore wind capacity and slightly more capacity from battery storage and shed demand response;
- For the 38 MMT Core with high electrification with managed EV portfolio, an additional 12,374 MW due to more capacity from solar, OOS wind on new transmission, and battery storage capacity;
- For the 38 MMT Core without the offshore wind ITC, and additional 1,767 MW due to more solar and battery storage capacity, and less offshore wind capacity;
- For the 46 MMT Core, 6,141 MW of fewer resources due to less solar, in-state wind, out-of-state wind on new transmission, and offshore wind capacity, and more capacity from battery storage;
- For the 30 MMT Core, an additional 8,551 MW due largely to more solar, out-of-state wind on new transmission, and battery storage capacity, as well as slightly less shed demand response capacity; and
- For the 30 MMT Core with high electrification, an additional 25,237 MW due largely to more solar and battery storage capacity, and to a lesser extent more in-state wind, out-of-state wind on new transmission, and biomass capacity, as well as slightly less shed demand response capacity.

Table 3 below identifies several key cost metrics associated with the 38 MMT Core scenario and other sensitivities described in this ruling.

Table 3. Scenario Cost Metrics

Scenario	Revenue Req't ($MM in Present Value)	Total Resource Cost ($MM in Present Value)	Levelized Revenue Req't ($MM)	Levelized Total Resource Cost ($MM)	Levelized Average Rate (cts/kWh)
38 MMT Core	$ 844,337	$ 905,213	$ 45,527	$ 48,809	19.3
38 MMT Core w/ No LSE Plans	$ 841,125	$ 902,002	$ 45,354	$ 48,636	19.2
38 MMT Core w/ 2020 IEPR	$ 839,282	$ 902,413	$ 45,254	$ 48,658	19.5
38 MMT Core w/ 2020 IEPR + 2020 IEPR High EV	$ 842,737	$ 905,868	$ 45,441	$ 48,845	19.4
38 MMT Core High Elec	$ 914,689	$ 973,062	$ 49,320	$ 52,468	18.6
38 MMT Core w/ no OSW ITC	$ 845,109	$ 905,986	$ 45,569	$ 48,851	19.3
46 MMT Core	$ 843,816	$ 904,692	$ 45,499	$ 48,781	19.3
30 MMT Core	$ 845,925	$ 906,802	$ 45,612	$ 48,895	19.3
30 MMT Core w/ High Elec	$ 916,174	$ 974,547	$ 49,400	$ 52,548	18.6

5. Reliability Analysis of the 38 MMT Core Scenario

The aggregated LSE Plans portfolios, supplemented with RESOLVE portfolios, on top of the baseline resources, produced a portfolio of resources for the 46 MMT Core and 38 MMT Core scenarios, as well as several sensitivity cases. Commission staff focused on the 38 MMT Core portfolio and incorporated it into SERVM for further analysis. The process for translating RESOLVE portfolios for PCM analysis was performed in steps and then validated by comparison between RESOLVE and PCM results.

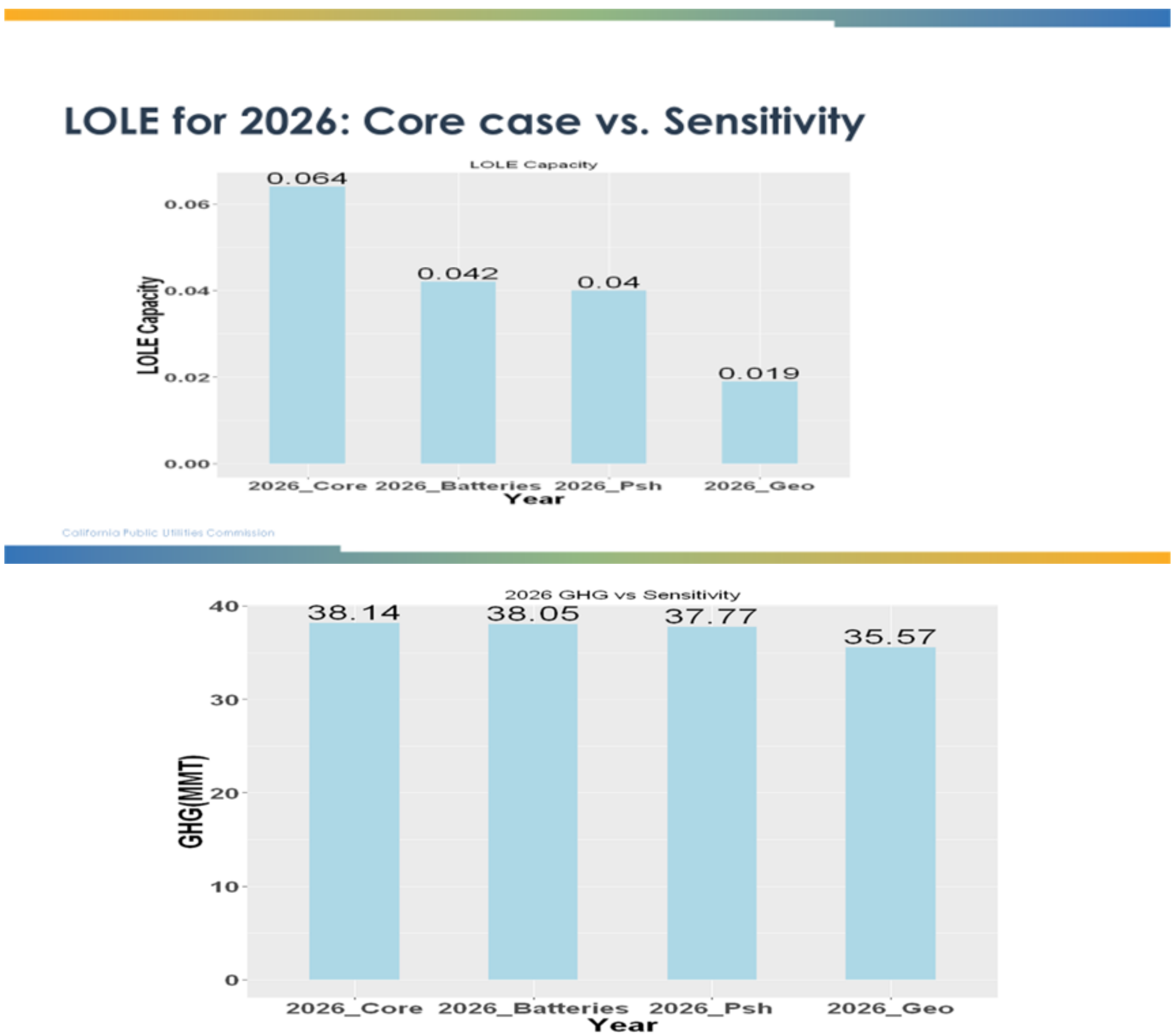
PCM results confirmed that the 38 MMT Core portfolio meets LOLE and GHG targets in 2026 and 2030. Commission staff conducted additional modeling in the 2026 study case in order to determine the effect of the required timelines adopted in D21-06-035, specifically around potential delays in developing LLT resources between 2026 and 2028, as provided for in that decision. Table 4 below demonstrates that the 38 MMT Core case achieves LOLE targets and is very close to the GHG targets for the CAISO area (31.1 MMT pro-rated for CAISO only).

Table 4. SERVM Analysis of 38 MMT Core Portfolio:
Emissions and Reliability Results

Reliability and GHG Metrics	38MMT 2026	38 MMT 2030
LOLE (expected outage events/year)	0.064	0.054
LOLH (hours/year)	0.21	0.15
LOLH/LOLE (hours/event)	1.76	1.72
EUE (MWh)	292.28	187.45
Annual load (MWh)	255,345,985	265,753,062
normalized EUE (%)	1.145E-06	7.054E-07
GHG (MMT)	38.14	34.67

PCM analysis demonstrated that the 38 MMT Core portfolio is reliable in 2026 and 2030. To further explore the uncertainty and risk associated with potential delay in some LLT resource development, Commission staff conducted additional sensitivity modeling, demonstrating that meeting the 2026 timeline in D.21-06-035 instead of 2028 significantly lowers GHG emissions and mitigates LOLE risk. Figure 6 below shows these sensitivity results.

Figure 6. 2026 GHG and LOLE RESULTs in LLT Sensitivities



Attachment B to this ruling contains more detailed information about the PCM analysis conducted on the 38 MMT Core scenario as well as the sensitivity analysis.

6. Proposed Preferred System Portfolio

Based on the reliability and GHG results of the SERVM analysis conducted on the 38 MMT Core Portfolio, and the modest cost different relative to the 46 MMT Core Portfolio identified in RESOLVE, this ruling recommends that the 38 MMT Core Portfolio be adopted by the Commission as the PSP. The 38 MMT

Core Portfolio, by 2032, includes the equivalent of 74 percent RPS resources and 87 percent GHG-free resources in compliance with Senate Bill (SB) 100 goals. Parties are invited to comment on the appropriateness of this recommendation.

The practical implications of the 38 MMT Core portfolio being adopted as the PSP are several:

- 38 MMT will become the new GHG limit adopted by the Commission for GHG emissions from the electricity sector in 2030. Thus, individual LSEs will, for at least the next cycle of IRP, be required to meet their individual proportional benchmarks associated with this overall electric sector limit on GHG emissions.
- The 38 MMT Core Portfolio will be mapped to transmission busbars for use by the CAISO as the reliability base case in its TPP beginning with the 2022-2023 cycle.
- Any resources associated with the PSP, or resource attributes thereof, will be expected to be developed by the LSEs. Their procurement will need to match their emissions and reliability responsibilities associated with the PSP by 2030 and in the interim years.
- Any transmission identified by the CAISO as needed to deliver the resources contained in the PSP, within the CAISO footprint, will be assumed to be built and paid for by all ratepayers out of the transmission access charge (TAC).

This ruling also suggests that the Commission strongly consider adoption of the 38 MMT Core scenario with 2020 IEPR assumptions and the 2020 IEPR high EV load forecast. Not only would this scenario conform with the latest IEPR, but it would also move IRP toward planning for a higher electrification future, which may be prudent given the importance of electrification for meeting the state's climate goals. This scenario has not yet been fully analyzed for reliability in SERVM, but such reliability analysis will be performed on any scenario that the Commission is considering in a future proposed decision, after also incorporating feedback from parties on the scenarios summarized in this ruling.

7. Transmission Planning Process Issues

7.1. Proposed TPP Portfolios

As already stated above, if the 38 MMT Core Portfolio is adopted by the Commission as the PSP, the portfolio would be transmitted to the CAISO as both the reliability and policy-driven base case scenario to be analyzed by the CAISO in the 2022-2023 TPP.

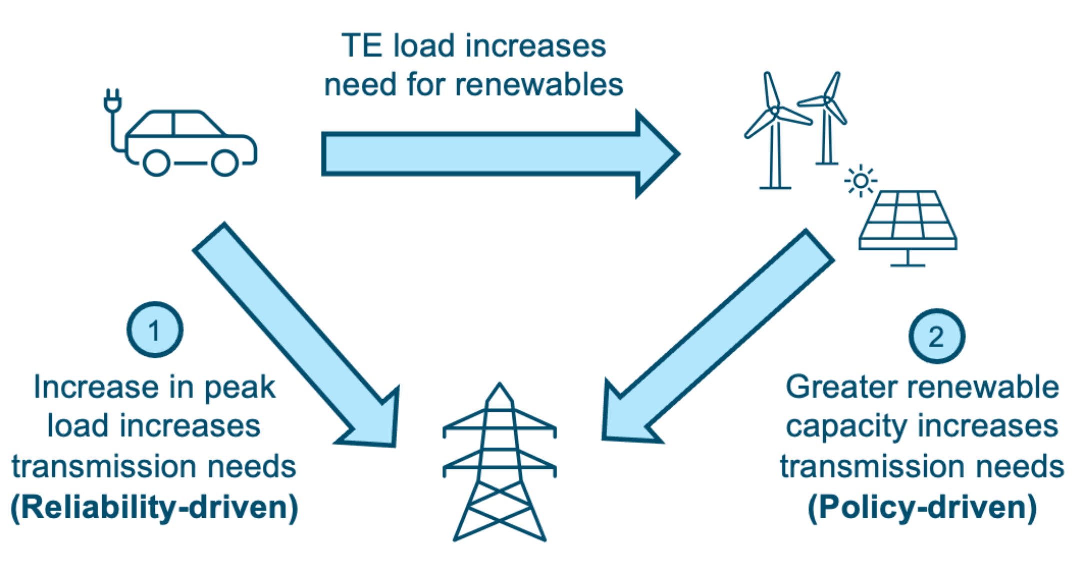
As a reminder, in the 2021-2022 TPP cycle, the CAISO is analyzing the 46 MMT portfolio adopted by the Commission in D.21-02-008 as the reliability and policy-driven base case. The sensitivity portfolios still under study as part of the 2021-2022 TPP cycle include a 38 MMT sensitivity portfolio, as well as a portfolio with 8 gigawatts (GW) of offshore wind designed to test the grid needs to support buildout of offshore wind resources at various locations by 2030.

For the 2022-2023 TPP, this ruling proposes the option of transmitting one additional sensitivity portfolio to be analyzed by the CAISO for transmission needs in the future. This sensitivity portfolio is designed around two key factors: a 30 MMT GHG emissions limit in 2030, and the use of the high electrification demand assumptions developed by Commission staff using the PATHWAYS model in 2020 for modeling purposes. Combining these sets of aggressive assumptions is designed to push the transmission system to its limits and identify the next potential transmission investments needed to achieve higher penetrations of zero-emissions resources at the same time as load is increasing due to electrification of buildings and transportation, as California proceeds on the trajectory toward a carbon neutral electricity system by 2045.

This recommended sensitivity portfolio was built using RESOLVE, with 2030 as the primary planning year. The GHG target is 30 MMT in 2030, and approximately 27.7 by 2032. Interpolation between 2030 and 2045 will be consistent with the approach used in the 2045 "framing scenarios" studied during the 2019 RSP development to meet SB 100 and 2050 economy-wide decarbonization goals. The load forecast is based on the 2020 IEPR high electrification scenario.

Transportation electrification is an important element of this portfolio because it can impact infrastructure needs in two ways, as depicted in Figure 7 below.

Figure 7. Transportation Electrification Impacts on Transmission Needs



Assessment of this portfolio can provide important insight on transmission needs. Local capacity issues may be significant in a high electrification future, especially in constrained areas like the Los Angeles (LA) Basin. In addition, through the transmission busbar mapping process, the state can assess any potential land-use constraints associated with the high electrification sensitivity resource/transmission buildout. More importantly, if the Commission decides at some point in the future to move toward a lower GHG target with high electrification demand, the combined lead time associated with CEC, CAISO, and Commission planning processes and the building of the generation and transmission infrastructure means that planning for this future will need to begin now.

The sensitivity portfolio would need to be responsive to several relevant statutes and executive orders and actions, including:

- SB 350 (De León, 2015), requiring a 50 percent renewables portfolio standard (RPS) by 2030, doubling of energy efficiency, transportation electrification, and the IRP process;
- SB 32 (Pavley, 2016), requiring a 40 percent reduction of 1990 GHG emissions by 2030;
- SB 100 (De León, 2018), increasing the RPS mandate to 60 percent by 2030 and setting a 2045 target for renewable and zero-carbon resources to supply 100 percent of retail sales and electricity procured for all state agencies;
- Executive Order B-55-18, establishing a new statewide goal "to achieve carbon neutrality as soon as possible, and no later than 2045, and achieve and maintain net negative emissions thereafter;"
- Executive Order N-79-20, establishing a statewide goal of phasing out the sale of new gasoline-powered cars and trucks in California and requiring that 100 percent of in-state sales of new passenger cars and trucks are to be zero-emissions by 2035; and
- Governor Newsom's July 9, 2021 letter request to the Commission to establish a more ambitious greenhouse gas electricity target in the IRP process, to ensure that state efforts are driving toward achieving emissions reductions as soon as possible.

RESOLVE results indicate that the combination of lower GHG targets and higher loads due to electrification leads to significant additional solar and battery storage buildout in the sensitivity portfolio compared to the 38 MMT Core Portfolio. These resources total about 25 GW more by 2032 in the sensitivity portfolio. This portfolio has not yet undergone PCM analysis. Figures 8 and 9 and Table 5 below show the selected resources and comparison with the 38 MMT Core portfolio.

Figure 8. Selected Resources – 30 MMT Portfolio with High Electrification

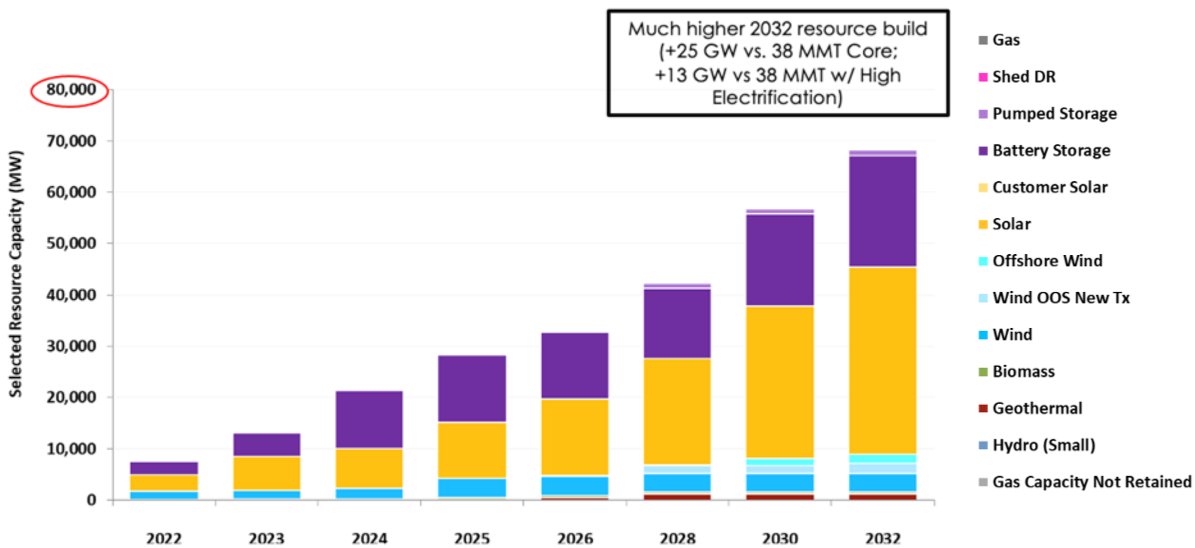
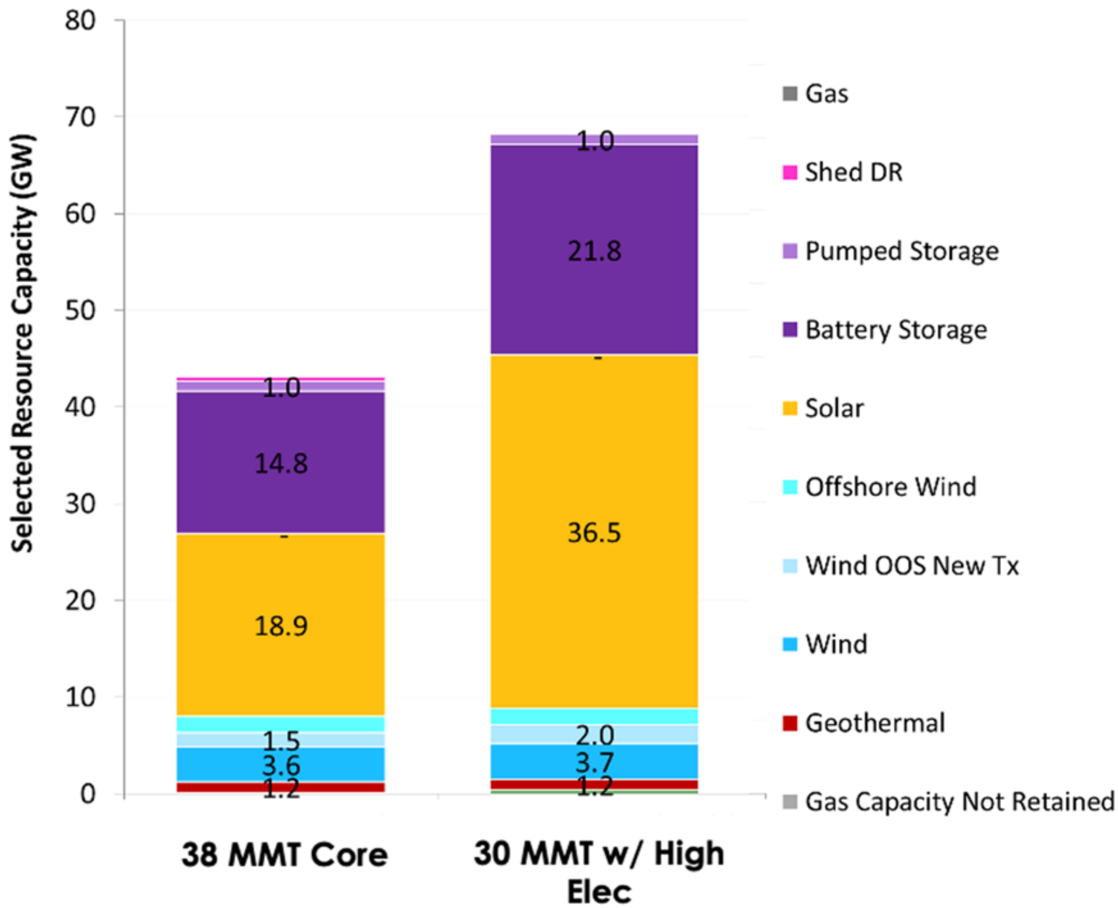


Table 5. 2032 Resource Composition of the 30 MMT Portfolio with High Electrification

Resource Type	Capacity Amount (MW)
Biomass	373
Geothermal	1,156
Wind	3,687
OOS Wind on New Transmission	1,970
Offshore Wind	1,708
Solar	36,552
Battery Storage	21,775

Resource Type	Capacity Amount (MW)
Pumped Storage	1,001
Shed DR	176
Total Resources	**68,368**

Figure 9. Comparison of New Resource Buildout in 2032 between the 30 MMT Portfolio with High Electrification and the 38 MMT Core Portfolio



Several issues must be addressed before the CAISO can study the 30 MMT with High Electrification portfolio as a sensitivity. CAISO has never used two sets of load forecast assumptions in an individual TPP. The transmittal of this portfolio would require the CAISO to do so because the base case assessment would utilize the 2021 IEPR load forecast and the policy-driven sensitivity assessment would have to use an alternative high electrification load forecast, if agreed to by the CEC, CAISO, and this Commission.

Given the above factors, the Commission, CEC, and CAISO staff are currently assessing the options for developing a high electrification forecast for use in the 2022-2023 TPP. Specific factors that need to be addressed include:

- Appropriateness of the PATHWAYS model forecast for a high electrification analysis and whether additional modifications are required.
- Implications of deviating from the interagency single forecast set (SFS) agreement.
- Consistency with the RESOLVE assumptions to develop the 30 MMT with high electrification sensitivity portfolio.
- RESOLVE modifications needed to update the sensitivity portfolio.
- Mapping of EV load to plausible specific locations within the CAISO system, given that distribution is unlikely to be uniform.
- Understanding of to what extent a more granular EV load distribution is necessary for CAISO analysis.
- How and when EV load mapping to transmission locations would occur.
- Timing implications for the State's SB 100 goals if a 30 MMT high electrification sensitivity is not considered in the 2022-2023 TPP.

7.2. Storage Projects as Transmission Upgrade Alternatives and Other Options for Procurement for System Benefit

This section discusses some results from the 2020-2021 TPP[4] that identified two transmission projects that can potentially be replaced by appropriately-sited

[4] *See* the CAISO-approved plan at the following link: http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf

battery storage, both in Pacific Gas and Electric Company's (PG&E's) service area:

- A 95 MW 4-hour storage resource on the Kern-Lamont 115 kilovolt (kV) system;
- A 50 MW 4-hour storage resource at the Mesa 115 kV substation.

The CAISO determined that these storage resources would mitigate identified reliability needs and would be lower cost than the two previously-approved transmission upgrades. This reflects Commission guidance for the CAISO to identify non-transmission alternatives in the same manner that operational solutions are often selected in lieu of transmission upgrades. These also appear to be the first storage projects that the CAISO itself (and not a participating transmission owner) has initially identified as acceptable non-transmission alternatives within the TPP.[5]

The CAISO has put the two transmission projects "on hold" pending development of storage resources at the required locations. If the storage resources are not built, the CAISO will pursue the more expensive transmission projects.

However, there is not currently a process in place or a methodology to assess and compel the development of specific resources at specific locations. In addition, there is no current CAISO mechanism for storage resources to serve as transmission assets in a way that enables developers to recover costs through the

[5] In the 2017-2018 TPP, PG&E proposed the Oakland Clean Energy Initiative, which the CAISO approved in that TPP cycle, but that has been subsequently withdrawn by PG&E. *See* the CAISO-approved plan at the following link: http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

TAC. The CAISO, in its approved TPP, assumes that these proposed storage projects would receive market revenues through a power purchase agreement.

In several TPP stakeholder meetings, parties have raised questions and concerns about ambiguities of a storage facility providing market services and getting market revenues, while also serving as a transmission facility, especially during periods of high load when prices are likely high. Getting storage built at these specific locations to provide multiple services will require a high degree of creativity by developers and potential Commission involvement, though it is not totally clear how.

This ruling seeks party input on whether and how the Commission should act to encourage development of these two storage resources at these specific locations, as well as similar opportunities that may arise in the future.

In addition, this ruling solicits party input on the broader challenges this example illustrates. The November 2020 Procurement Framework Staff Proposal explores how the provision of clear guidance from the planning track of IRP may not be sufficient to ensure optimal procurement outcomes. In this storage/transmission example, the problem is one of ratepayer benefits being evident yet, due to the way costs are recovered for transmission projects, there are unlikely to be commercial incentives for any single entity to conduct the procurement. The Procurement Framework Staff Proposal identifies possible options to address a similar problem for large and/or LLT resources:[6] all LSEs could be required to pay for procurement for system benefit (also referred to as

[6] *See* Section 7.2.2 of the Procurement Framework Staff Proposal, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track

"mutual benefit procurement") and be allocated a portion of the benefits and the costs. Any LSE could apply to conduct such procurement on behalf of all LSEs and be granted conditional approval by the Commission for cost recovery. These concepts are similar to the current cost allocation mechanism (CAM), with the main difference being that all LSEs, and potentially non-LSE procurement entities, could conduct the procurement rather than solely the IOUs.

The Commission could establish a new non-bypassable charge for system benefit procurement of new resources needed for policy or reliability reasons. The Commission could then allow applications for cost recovery via the charge, from entities who have contracts with, or can develop resources, that are needed for collective benefit but that face market barriers such as above-market costs, locational specificity, or other development risks.

Parties are invited to comment on how to develop such options, or better alternatives, to address both the storage/transmission examples in this section, as well as large, LLT, or other complex resource types.

7.3. Busbar Mapping

In order to be analyzed in the CAISO TPP process, the recommended portfolios must have each resource mapped to a busbar location on the transmission system. The "resource to busbar mapping" or "busbar mapping" process translates geographically-coarse portfolios to plausible network locations for additional TPP modeling by applying specific rules and criteria.

Commission staff propose to build on the progress in prior TPP cycles with the following updates:

- Utilizing new CAISO transmission deliverability data for available transmission headroom for full capacity deliverability status (FCDS) and off-peak deliverability status (OPDS);

- Incorporating new CAISO transmission constraints definitions different from the nested-transmission zones used in the previous mapping cycle;
- For non-battery busbar mapping, incorporating busbar-level granularity of commercial interest rather than zonal-level of commercial interest;
- For all resources, incorporating expected online dates for commercial interest into the mapping criteria for allocation to busbars;
- Improving the implementation process of the busbar mapping criteria to better capture mapped resources' compliance with the criteria and to incorporate the latest stakeholder inputs and updated data sets;
- Updating the battery busbar mapping steps to account for the locational information for battery resources that will be provided by RESOLVE;
- Removing the 90 percent transmission utilization limit used in mapping battery resources to busbars in the previous TPP cycle; and
- For co-located battery and solar PV resources, removing the transfer of FCDS status from the solar PV resources to the battery resources, based on new CAISO transmission deliverability data.

The complete busbar mapping process and updates are described in Attachment C to this ruling. Busbar mapping will be conducted concurrently with finalizing the PSP. Consequently, the ability to revise the mapping of resources to ensure complete consistency with the PSP may be limited if the PSP recommendation changes significantly.

8. Procurement Implications

Based on the reliability and GHG analysis conducted on the 38 MMT Core Portfolio in SERVM, it appears that the individual LSE plans, if actualized, along with the Commission's MTR requirements for procurement contained in

D.21-06-035, should largely achieve the Commission's reliability and GHG goals for 2030.

The procurement implications of this statement warrant further exploration, because it is uncertain whether such guidance, along with existing markets and programs, is sufficient to ensure meeting the 2030 goals or whether additional Commission action is required to ensure the LSE plans are actualized. This sort of question was explored in the November 18, 2020 ALJ ruling in this proceeding[7] providing a Staff Proposal for a Resource Procurement Framework in IRP and via comments from parties in response to questions posed in the February 22, 2021 ALJ ruling on MTR.[8] To make progress on this specifically in the context of the development of the PSP portfolio, the following procurement process steps will need to be addressed with particular attention to how they should be implemented for procurement designed to produce GHG emissions reductions, in addition to reliability capacity procurement:

- Need determination:
  - Methodology to use and applied to which years in the planning horizon;
  - Whether only to determine need for new resources or consider procurement action that also includes contracting with existing resources (similar to RPS and resource adequacy);
  - Whether to determine the procurement need, if any, in terms of resource attributes or specific resource types.

[7] The November 18, 2020 ALJ ruling, its attachment, as well as workshop slides and recording are available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track

[8] Available at: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=367037415

- Need allocation: Methodology to identify responsibility for procurement based on a "causer pays" principle; Considering that analysis of resource need in this proceeding is CAISO-wide, procurement need allocation should also account for the responsibility of POUs in the CAISO, in addition to the Commission's LSEs;
- Procurement entities: whether self-provision by LSEs is required or optional, or whether some form of central procurement should take place;
- Cost allocation: methodology for allocating costs to the extent that procurement is performed by an entity on behalf of others; and
- The compliance, monitoring, and enforcement arrangements for the procurement.

One way to approach these steps is to focus the procurement actions associated with the portfolio on requiring LSEs to procure and deliver all of the resources or GHG-free resource attributes of the resources designated as "planned" in the individual IRPs. In other words, one action the Commission could take is to make procurement of the individual IRP planned resources a requirement for each LSE. This would directly resolve the steps of need determination, need allocation, and directing procurement entities, as posed above. This requirement could also be accompanied by a penalty for failure to achieve the capacity and/or energy requirements. The Commission could also consider a backstop procurement requirement and cost allocation arrangements, similar to those provisions included in D.21-06-035 and D.19-11-016.

This potential "bottom up" approach to procurement is distinct from the more "top down" approach of previous IRP procurement orders that have determined the overall procurement need, required resource attributes at the system level, and allocated the procurement to each LSE on a pro-rata basis.

Comment is invited on the "bottom up" approach above as an alternative to the "top down" approach taken in D.19-11-016 and D.21-06-035.

It is notable that this "bottom up" approach would not account for the resources in the preferred system portfolio that are in excess of the LSEs' individual IRPs and the Commission's MTR requirements, such as the amount of solar resources selected by RESOLVE in 2030 and 2032. Parties may also wish to comment on whether and how the Commission should require procurement of those resources.

Further, potential incremental procurement action specific to 2023 needs, as well as potential need for fossil-fueled resources and long lead-time resources, are discussed in separate sections below. The procurement cost modeling sensitivity results also suggest that the Commission may want to consider directing additional procurement for 2026 in the event that all of some of the LLT resources ordered in D.21-06-035 are delayed to 2028, as provided for in that decision.

Parties' input will also be helpful on whether GHG-reduction-driven procurement action should be sought now as part of the PSP at all, or whether it can be addressed by a programmatic approach to be developed during the next cycle of IRP, as contemplated by the Procurement Framework Staff Proposal and some parties' comments in response to it.

9. Potential for Acceleration of Mid-Term Reliability Procurement

As many parties are likely already aware, on Friday, July 30, 2021, Governor Newsom issued a Proclamation of a State of Emergency (Proclamation) in response to the significant and accelerating impacts of climate change in California. The Proclamation, among other things, states that:

> "2. … The California Energy Commission is directed, and the California Public Utilities Commission and the CAISO [California Independent System Operator] are requested, to work with the State's load serving entities on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day.
>
> 13. The California Public Utilities Commission is requested to exercise its powers to expedited Commission actions, to the maximum extent necessary to meet the purposes and directives of this proclamation, including by expanding and expediting approval of demand response programs and storage and clean energy projects, to ensure that California has a safe and reliable electricity supply through October 31, 2021, to reduce strain on the energy infrastructure, and to ensure increased clean energy capacity by October 31, 2022.
>
> 15. The California Energy Commission, in consultation with the California Air Resources Board, the CAISO, and the California Public Utilities Commission, shall identify and prioritize action on recommendations in the March 2021 Senate Bill 100 Joint Agency Report, and any additional actions, that would accelerate the State's transition to carbon-free energy."

Though the Proclamation is focused primarily on electricity needs by 2022, there is also ongoing reliability concern about 2023 and beyond. Notwithstanding revisions that were made to D.21-06-035 in response to parties' concerns about the feasibility of procurement by 2023, this ruling proposes to revisit whether procurement of capacity counting toward the 11,500 MW of NQC should be accelerated to 2023, instead of 2024 or 2025, and/or whether additional capacity is needed. One option would be to require up to 4,000 MW of incremental NQC resources online by June 1, 2023, instead of the current requirement for 2,000 MW of NQC in 2023. The CEC has conducted reliability analysis for the next several years and most of the implications of that analysis, particularly for 2022 and including the possibility of accelerating procurement already ordered in D.19-11-016 and D.21-06-035, will be addressed in the Commission's summer reliability rulemaking (Rulemaking (R.) 20-11-003). Here parties' comments are requested on shifting or increasing MTR procurement for 2023 and beyond.

10. Need for Fossil-Fueled Procurement

D.21-06-035 deferred the decision on whether procurement of fossil-fueled resources was necessary for mid-term reliability, pending additional analysis on the need from Commission and CEC staff. The proposed decision had, like D.19-11-016, limited consideration of new fossil-fueled capacity to existing sites and had not contemplated any development at new sites. The Commission also discussed potential reasons why fossil-fueled capacity may be necessary, such as:

- Uncertainty about performance of batteries considering rapidly increasing penetration, and associated risk of overreliance on batteries;
- The ability of certain natural gas facilities to expand quickly or inexpensively at existing sites, particularly if additional permitted capacity is available, to mitigate project development risk of other new resources;
- Most capacity expansion modeling to date in IRP shows the need to retain most thermal capacity throughout the planning period. Therefore, new capacity may be needed to maintain the continued reliability of the natural gas and combined heat and power (CHP) fleet at current capacity as older units retire.

These factors should be taken in the context that the existing thermal fleet of capacity resources contains approximately 20 GW of the best available natural gas technology, largely built since 2000. After upcoming planned retirements, the gas fleet will still contain up to 7 GW of existing capacity that is over than 20 years old and may have challenges with respect to economic viability, operational reliability, or environmental impacts during the next ten years. With the exception of planned retirements, the gas fleet has remained unchanged in IRP modeling, which is likely an unrealistic assumption in the absence of some amount of procurement for recontracting, repowering, and refurbishment.

To the extent that gas capacity remains needed for reliability, there may be an opportunity for targeted procurement to improve reliability and reduce GHG and local pollutant emissions by replacing the least efficient gas units operating today.

To determine whether the system needs additional new fossil-fueled capacity in order to ensure system reliability in the mid-decade, Commission staff have been working with the CEC to assess the reliability of the system. The CEC's study is modeling the CAISO system and the reliability benefits provided by the new procurement ordered in D.21-06-035. The study will assess whether additional procurement is necessary and quantify the reliability benefit different combinations of resource types would provide toward any identified gap.

The CEC presented its study design and assumptions at a July 8-9, 2021 IEPR Joint Agency Workshop on Summer 2020 Electric and Natural Gas Reliability. The CEC will hold an additional workshop in late August 2021 to share the results of this study. As this study will be a key element of the need determination for new thermal capacity, parties in this proceeding are invited to attend the CEC workshop and comment directly on the study to the CEC as part of the IEPR. Parties are also invited to comment on the study's implications for Commission action on procurement requirements for LSEs in response to this ruling.

11. Role and Definition of Renewable Hydrogen in Fossil-Fueled Procurement

During the development of the MTR requirements ultimately adopted in D.21-06-035, there were proposals designed to encourage a transition away from natural gas and toward the use of "green" or "renewable" hydrogen. If the Commission requires new fossil-fueled capacity at existing sites, this ruling proposes that some portion of the capacity be eligible or required to be met by "green" or "renewable" hydrogen, with the suggested definition and eligible sources included below.

Currently, the State, as well as the Commission, lacks an adopted definition of renewable or green hydrogen, though the issue is within the scope of R.13-02-008. SB 1369 (Skinner, 2018) included a definition of "green electrolytic hydrogen" for purposes of that Article.[9] Establishing a comprehensive definition for renewable hydrogen is addressed in pending legislation (SB 18, Skinner). Since the issue is in flux, this ruling proposes that any eligible renewable hydrogen projects meeting procurement ordered in this proceeding would be consistent with the Commission's recent decision (D.21-06-005) in the self-generation incentive program (SGIP) regarding the use of renewable hydrogen for behind-the-meter electricity generation. The SGIP decision did not definitively define renewable hydrogen, but identified the types of renewable hydrogen that would be eligible for SGIP incentives.

Ordering Paragraph (OP) 1 of D.21-06-005 updates the SGIP program to:

> "Define eligible renewable hydrogen fuel as hydrogen produced at a SGIP project site, or delivered to a SGIP project

[9] SB 1369 added Public Utilities Code Section 400.2, which states: "For the purposes of this article, "green electrolytic hydrogen" means hydrogen gas produced through electrolysis and does not include hydrogen gas manufactured using steam reforming or any other conversion technology that produces hydrogen from a fossil fuel feedstock."

> site by vehicle or dedicated pipeline, that was produced through non-combustion thermal conversion of biomass, or electrolysis using 100 percent renewable electricity, as defined by the Renewables Portfolio Standard, with the addition of large hydropower and excluding purpose-grown crops; require, if the renewable electricity is not generated on-site, the purchase program or load serving entity to provide bundled Renewable Energy Credits to the electricity purchaser." (OP 1, g.)

However, for purposes of IRP procurement, this ruling proposes to modify one provision, in the last phrase of the above requirements, to account for the difference between using renewable hydrogen behind the meter and in a utility-scale power plant. Namely, the generating facility would be required to provide documentation to the procuring LSE that bundled renewable energy credits were retired for the electricity used to generate the renewable hydrogen used in the facility or provide other reasonably equivalent documentation if the electricity source is large hydropower.

The CEC is expected to address requirements for electricity generated by renewable hydrogen under the RPS program in the future, but that action has not yet occurred so the above requirement would be in place in the meantime.

Parties should note that this definition does not allow use of "directed" renewable hydrogen (*i.e.,* renewable hydrogen injected into the existing utility natural gas distribution system), because standards for injecting hydrogen into the gas distribution system is still under consideration and a tracking process for that hydrogen does not yet exist.[10] In addition, hydrogen production using non-combustion thermal conversion of biomass would be allowed as an eligible

[10] Establishing standards for safe injection of renewable hydrogen into gas distribution lines is still under consideration in R.13-02-008.

feedstock, which means that gasification and/or pyrolysis of woody biomass may be used to produce the renewable hydrogen. However, hydrogen produced from steam reformed biomethane would not be authorized, due to other higher priority direct uses for the limited supplies of biomethane for clean vehicle fuels and/or directly displacing natural gas use in industry.[11]

Further, this ruling proposes that to the extent the Commission ultimately orders procurement of resources fueled by natural gas, some percentage of the facilities be required to use a blend of renewable hydrogen at the beginning of the contract term, increasing the blend to 100 percent by the end of the contract period, or sooner.[12] The objective would be to help support a transition toward greater use of renewable hydrogen to replace natural gas. A variation on an option previously proposed by Commissioner Rechtschaffen in an alternate proposed decision on MTR would be to require 50 percent of the fossil-fueled facilities to utilize at least 30 percent renewable hydrogen when the contract term begins, 60 percent renewable hydrogen by 2031, and transition to 100 percent renewable hydrogen by no later than 2036.[13] The facility using renewable hydrogen would also be required to maintain or reduce the actual emission of nitrogen oxides (NOx) compared to the use of natural gas, and also to employ equipment to reduce NOx emissions, to the maximum extent possible.

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[11] *See* further discussion of this issue in D.21-06-021. In addition, as noted above, biomethane that is RPS-eligible would be eligible to be used to generate electricity for electrolysis that produces renewable hydrogen.

[12] Natural gas has a higher energy density than hydrogen (3:1), and, as a result, the reduction in GHG emissions is not linear. For example, using a 50 percent hydrogen blend reduces GHG emissions per kWh by about 20 percent and a 75 percent blend reduces GHG emissions by about 50 percent. *See* a General Electric White Paper on hydrogen as a fuel for gas turbines available at: www.ge.com/power/future-of-energy/

[13] Such a proposed requirement would be for blended fuel, not for an annual average volume of hydrogen.

Fuel cells may also utilize renewable hydrogen to generate electricity with the same hours of availability as electricity from a combustion turbine power plant, without NOx emissions. Accordingly, procurement from a fuel cell could also be used to satisfy any fossil-fueled procurement requirement, using the same renewable hydrogen percentages and timeframes as described above.

The proposal for these requirements for renewable hydrogen is intended to be consistent with the Governor's Proclamation, directing the Commission to accelerate work on deployment of new clean energy projects to decrease risk of capacity shortages and increase availability of carbon-free energy at all times of day.

12. Geographically-Targeted Procurement, including Related to Aliso Canyon Natural Gas Storage

D.21-06-035 discussed the need to continue coordinate planning for the long-term need for natural gas capacity, as well as the need to take into consideration the impacts on the use of the Aliso Canyon natural gas storage facility from continued reliance on natural gas-fired power plants. A number of parties in this proceeding have recommended that the Commission order geographically-targeted procurement to replace fossil-fueled generation, particularly in disadvantaged communities. The LA Basin has been suggested as a candidate for the first geographic area to be examined and the Commission has expressed its interest in further exploring this issue.

In the Aliso Canyon proceeding (Investigation (I.) 17-02-002), FTI Consulting is currently conducting an analysis to determine the impacts of a potential closure of Aliso Canyon in 2027 or 2035. The analysis focuses on the amount of additional winter peak natural gas demand equivalent that would be needed in 2027 and 2035 if Aliso Canyon is closed, and then evaluating several scenarios of potential resources that could help fill this shortfall, including electric resources.

There are several factors that make this a highly complex analysis. Fundamentally, the Aliso Canyon analysis is focused on natural gas capacity, which is a winter peaking requirement due primarily to heating load. IRP analysis is focused on peak electricity needs, which are summer peaking. Electricity needs are also increasingly defined in terms of the net peak, which typically occurs in the summer evening hours when solar energy output is waning and electric demand is increasing.

It is not clear how IRP planning and procurement interact with the demand on the gas system, particularly during the summer peak and net peak. Nor is it clear that augmenting electricity resources during the summer can help alleviate winter gas demand for Aliso Canyon storage.

In addition, more work is needed to determine which of the natural gas generation resources in the LA basin are dependent on Aliso Canyon gas storage resources for their operations and may face winter curtailments. At least some of these electric resources are under contract or ownership of the LA Department of Water and Power and not necessarily likely to be influenced by the Commission's IRP activities.

In addition, some natural gas generators in the LA basin are system resources that are typically addressed by IRP and procurement, while some are needed for local reliability in an electric-transmission-constrained local area. Further, because of this situation, the potential interactions between generation and storage resources may not be intuitive and may actually serve to worsen reliability or environmental impacts. For example, pairing battery storage with gas generation within the LA basin could, depending on local system operational needs, cause natural gas generation to operate more and not less, in order to optimize use of the storage for local reliability. Similarly, additional in-basin renewables could cause natural gas generation to operate more for renewable integration purposes. These operational complexities require further analysis before definitive conclusions can be drawn.

Finally, because of the expansion of the number of LSEs serving load in the LA basin, there are multiple potential entities whose IRP planning and procurement activities must be more closely coordinated with the usage of Aliso Canyon gas storage resources.

Once the FTI Consulting analysis for I.17-02-002 is complete, there will be additional joint planning activities that will be initiated in this proceeding to address procurement that may be helpful to alleviate reliance on Aliso Canyon. In the meantime, parties are invited to comment on whether there are initial actions the Commission should take this year, prior to the full Aliso Canyon analysis being completed, to address these interactions between the electricity and natural gas systems in the LA Basin. The request here is for initial, no-regrets strategies to make progress in a geographically-targeted manner.

If parties suggest particular local procurement actions, related to Aliso Canyon or more broadly, their proposals should explain the rationale, the potential impact of the proposal, the magnitude of procurement that is reasonable, the types of resources recommended, which LSEs should be required to procure, how costs should be recovered and/or allocated, and compliance and enforcement mechanisms.

13. Long Lead-Time Resources

D.21-06-035 addressed requirements for two types of LLT resources with the following attributes: long-duration storage and renewables with at least an

80 percent capacity factor. This ruling raises the question of whether further specific planning or procurement provisions should be made for two additional types of LLT resources: offshore wind and OOS wind. Previous analyses have indicated the need for development of at least several thousand MW of NQC from these resources, both for overall need for zero-emissions resources to meet the SB 100 goals, as well as for resource diversity purposes. Development of both types of wind resources at the scale necessary to meet SB 100 goals also would be associated with the need to build or upgrade significant amounts of transmission to support delivery of the resources to the CAISO. They are discussed further separately below.

13.1. Offshore wind

As noted in D.21-06-035, the recent announcement by the Biden Administration and Governor Newsom about the plan for offshore wind development in California is a very positive development and the Commission strongly supports including this technology as a default candidate resources for consideration alongside others, as expeditiously as possible.

The process to make this happen began in early 2020 and is due to conclude in 2022. In 2020, Commission staff worked with the Bureau of Ocean Energy Management (BOEM) and the National Renewable Energy Laboratory (NREL) to update California-specific offshore wind resource profile and cost assumptions, and made these available for informal stakeholder review.[14]

In addition, in D.21-02-008, the Commission already asked the CAISO to study an offshore wind sensitivity portfolio to evaluate the transmission needs

[14] Information from the August 27, 2020 Modeling Advisory Group webinar is available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials

and costs to interconnect approximately 8,000 MW of offshore wind at various potential locations including Humboldt, Diablo Canyon, and Morro Bay. This information is anticipated to be available in November 2021, after which it will be used for analysis in the next IRP cycle, which will provide support for consideration of additional amounts of offshore wind beyond that proposed in the PSP. We expect that the amount of offshore wind proposed here is material enough to prepare for potential future procurement of this resource without triggering a significant level of new transmission immediately.

The March 2021 SB 100 joint agency policy report to the Legislature also shows that offshore wind is likely to be needed in California's 100 percent clean energy portfolio by 2045. Commission staff are working closely with the state's Offshore Wind Task Force to coordinate and facilitate actions related to the development of offshore wind.[15]

Two discrete actions that the Commission could take to encourage additional focus on offshore wind development would be to:

- Address and preserve use of transmission deliverability rights in the central coast area, which can accommodate approximately 5 to 6 GW[16] of offshore wind generation, interconnecting in the area of the Diablo Canyon Power Plant that will be retiring by the end of 2025, and in the Morro Bay area, where gas-fired generation has already retired; and

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[15] The Task Force is facilitated by the CEC, and included the Commission, the Coastal Commission, State Lands Commission, Fish and Wildlife, Ocean Protection Council, and the Governor's Office of Planning and Research. Federal agencies include BOEM, Department of the Interior, and Department of Defense. Federal coordination with the state is led by BOEM.

[16] *See* CAISO 2020-2021 Transmission Plan, http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf, at 28.

- Include some amount of offshore wind into the reliability and policy-driven base case for the CAISO to analyze as part of the 2022-2023 TPP.

This ruling seeks feedback from parties on both of these ideas, and how they should be specifically targeted and addressed. Parties may also suggest additional actions the Commission should take specifically to facilitate offshore wind development.

13.2. Out-of-state wind

Several rounds of IRP RESOLVE modeling indicate the need for some amount of OOS wind resources from New Mexico, Wyoming, and/or Idaho. The reliability base case scenario transmitted to the CAISO for analysis in the 2021-2022 TPP, articulated in D.21-02-008, already included approximately 1,100 MW of OOS resources that were preliminarily determined to need new transmission development outside of the CAISO system.

There is uncertainty around the exact amount of resources that will ultimately be needed, and also the amount that can be imported through existing transmission. While some amount of OOS resources can likely be imported on existing transmission, it is likely insufficient to meet the need for OOS resources by 2030 and beyond. CAISO is currently studying in the 2021-2022 TPP the availability of transmission, both inside and outside of the CAISO system, to support OOS resources included in the reliability base case and policy-driven sensitivity portfolios. The draft results of this study will be available around November 2021, with findings finalized around February 2022.

Meanwhile, for purposes of this ruling, the assumption is that some amount of additional transmission development will be necessary to facilitate procurement of OOS renewable resources, including wind. There are several ways in which the Commission could act to support additional development of OOS renewables and the transmission to support them. Options include:

- Order procurement of a specific amount of resources from a particular state or states;
- Identify particular transmission projects, with specific end points, that should be developed to facilitate imported renewables;
- Work with other state and federal counterparts to ensure transmission siting and construction.

There may be other near-term actions that the Commission can take to facilitate access to additional OOS renewable resources. In considering the above actions and other potential actions, relevant factors may include:

- The certainty of the need. LSE plans included New Mexico and Pacific Northwest wind resources on existing transmission, but no OOS resources requiring new transmission.
- CAISO control/management. Some OOS transmission projects would likely sign a sponsor agreement with the CAISO and joint the transmission control area. Other projects would not be built to connect directly to the CAISO grid and the CAISO would therefore not have operational control over the facilities.
- Resource adequacy eligibility and the CAISO's long-term access to the OOS resources. OOS transmission projects that do not connect directly to the CAISO would rely on existing third-party transmission to connect to a CAISO intertie. Future access to these resources may therefore be dependent on third-party transmission availability and the duration of the contracts.
- System needs the projects would fulfill, additional benefits to the grid, and state policy goals that the projects could help achieve.
- If procurement need were to be found:

- The amount, timing, and specificity of the need;
- How the responsibility for the procurement need should be allocated among LSEs;
- Self-provision requirements or a central procurement entity to take on OOS resource procurement;
- Cost allocation; and
- Compliance, monitoring, and enforcement provisions.

14. Retention of Existing Resources

Another issue that is often raised in the context of the Commission's IRP planning and procurement activities is how to retain existing resources that are necessary to support system reliability, GHG outcomes, or both. As parties are well aware, most IRP modeling is focused on how and when new resources need to be developed. However, there is a need to ensure that existing efficient and clean resources are available to the system on an ongoing basis. This applies equally to renewables and fossil-fueled resources, including natural gas plants and CHP facilities.

In comments leading to D.21-06-035, some parties suggested the CHP resources require particular attention. One option suggested for retention of CHP resources was a rolling 24-month extension of CHP contracts. Revisiting baseline assumptions for CHP was also recommended. Parties should comment on these proposals and other ideas to support necessary retention of CHP resources.

In addition, there is the issue of retention of the larger existing natural gas fleet that is increasingly relied upon to meet emergency summer "net peak" reliability needs. This issue was also discussed in D.21-06-035 and in parties' comments addressing how to make contracts with existing facilities eligible for that procurement order. In reality, even if there is no net increase in the amount of fossil-fueled generation on the CAISO system, much of it is aging and should have the option to be replaced with more efficient units, in order to reduce its impact and continue performing its reliability function during the transition to greater amounts of zero-emitting resources. Another option already discussed in the Procurement Framework Staff Proposal from November 2020 and in parties' comments leading to D.21-06-035 was creating more of a programmatic approach to IRP, similar to resource adequacy and RPS, where existing or new resources can be used to meet an identified need. This concept will likely require more long-term planning and coordination between this proceeding and the resource adequacy rulemaking. In the meantime, parties responding to this ruling are invited to suggest specific actions the Commission should take this year to address these issues of retention of existing fossil-fueled resources.

15. Questions for Parties

This section contains questions to which parties are invited to respond in their comments on this ruling and its attachments. This list of questions is organized in the same manner as the ruling itself. Generally, parties should comment on topics in the order in which they appear in the ruling, and add any additional comments on topics not covered in the ruling at the end of their comments. Due to the time constraints associated with the adoption of the PSP and the busbar mapping of resources to send to the CAISO for TPP purposes, as well as issues associated with the urgency of developing new resources for reliability purposes prior to the summers of 2022 and 2023, parties are requested to limit their comments to a total of no more than 30 pages. That limit does not include modeling details, for parties intending to submit their independent analysis. Any modeling analysis submitted does not have a page limit. Reply comments shall be limited to no more than 15 pages.

1. Please comment on the individual IRP portfolio aggregation performed by Commission staff.
2. Comment on the reliability analysis of the aggregated 38 MMT LSE plans.
3. Comment on the appropriateness of the scenarios and sensitivities developed in RESOLVE to be considered as the preferred portfolio. Suggest any alternative sensitivities or changes to the analysis.
4. Comment on the SERVM analysis and results of the 38 MMT Core Portfolio.
5. Comment on the appropriateness of the 38 MMT Core Portfolio as the PSP.
6. Comment on whether the load forecast assumptions should be adjusted to include higher load, particularly related to EV adoption or high electrification more broadly.
7. Comment on the proposal to use the 38 MMT Core Portfolio as the reliability and policy-driven base case in the TPP.
8. Comment on the proposed policy-driven sensitivity portfolio for the TPP based on the 30 MMT GHG limit in 2030 with the high electrification load assumptions. Suggest any additional or alternative scenarios that should be analyzed as policy-driven sensitivities.
9. Comment on whether and how the Commission should act to encourage specific non-transmission alternatives to be built, if identified as part of the CAISO TPP process, both for the two specific projects identified in the 2020-2021 TPP, as well as in general for future such opportunities.
10. Comment on the options raised in Section 7.2 of this ruling to address procurement for system benefit more broadly. Suggest whether and how a particular cost recovery framework can be adopted quickly or discuss additional considerations that should be explored.
11. Comment on the busbar mapping approach.

12. Comment on whether the Commission should require the procurement of resources contained in the individual IRP filings and have LSEs face penalties and/or backstop procurement requirements with cost allocation arrangements, similar to those for D.19-11-016 and D.21-06-035.
13. Comment on whether you would prefer an approach where the Commission determines procurement need for GHG-free resources or the GHG-free attributes of resources at the system level and then uses a need allocation methodology to assign procurement to individual LSEs. If you propose this type of alternative approach, please address the following aspects:
    - Need allocation, by year
    - How to address new and existing resources
    - Whether procurement should be all-source or resource-specific
    - Resource attributes required (MW, MWh, percentage of GHG-free energy, etc.)
    - Duration (through 2030, 2032, interim milestones, etc.)
    - Cost allocation
    - Compliance, monitoring, and enforcement arrangements.
14. If you believe the Commission should take more of a programmatic approach to GHG-beneficial procurement, explain the process you recommend and your rationale.
15. Comment on whether and how much procurement required in D.21-06-035 should be accelerated to 2023 and/or suggest additional actions to facilitate additional resources in response to the Governor's Proclamation from July 30, 2021.
16. Comment on the CEC's MTR reliability analysis, the determinations regarding the need for fossil-fueled

generation resources, and the actions, if any, that the Commission should take as a result.

17. Comment on the definition of eligible renewable hydrogen proposed in this ruling.

18. Comment on the percentage of renewable hydrogen facilities that should be required, if any, and the timing of the transition from a blend to full renewable hydrogen combustion, including the option for inclusion of fuel cells. Discuss the feasibility and cost of achieving a 100 percent renewable hydrogen blend by 2036 in your comments.

19. Comment on proposed measures regarding NOx emissions from facilities using renewable hydrogen.

20. Comment on whether the Commission should take any initial actions on geographically-targeted procurement, particularly with respect to Aliso Canyon, or more broadly, and respond to the factors discussed in Section 12 of this ruling.

21. Comment on whether and how the Commission should act to preserve transmission deliverability rights in the central coast area that could be utilized for offshore wind or other resources.

22. Comment on the amount of offshore wind, if any, that should be included in the 2022-2023 TPP base case. Comment on how the results of the 2021-2022 TPP offshore wind sensitivity case should influence this issue.

23. Comment on whether and how the Commission should act to support the development of OOS renewables/wind and the transmission to deliver it. Be as concrete and specific as possible in your recommendations.

24. Comment on specific actions the Commission can take to ensure retention of existing resources needed both for reliability and/or GHG emissions purposes.

25. For any of the potential procurement requirements discussed in this ruling, allocation of need to LSEs is a required step. Comment on how the methodologies

should account for in-CAISO POU load and what steps the Commission should take to ensure those POUs bear their share of responsibility for reliability and GHG impacts.

IT IS RULED that:

1. Interested parties may file and serve comments in response to this ruling, its attachments, and its questions by no later than September 27, 2021. Parties shall address the topics in this ruling in the order in which they appear in the questions in Section 15 of this ruling. If there are additional items the party wishes to address, those additional comments should be included at the end of the filing. Comments shall not exceed 30 pages and parties need not address every question, but should instead focus on questions related to their priority issues.
2. Interested parties may file and serve their own independent modeling results for consideration by the Commission and other parties by September 27, 2021; modeling results do not have a page limit.
3. Interested parties may file and serve reply comments in response to this ruling and other parties' comments, by no later than October 11, 2021. Replies shall be limited to 15 pages.

Dated August 17, 2021, at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge

ATTACHMENT A

RESOLVE Preferred System Plan (PSP) Modeling Results

August 2021

California Public Utilities Commission

Contents

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RESOLVE Updates for 2021 PSP / 2022-23 Transmission Planning Process (TPP)

August 2021

Summary of RESOLVE Updates since Dec 2020 2021-22 TPP Release – Inputs Related Changes

Update Category	Purpose	Key Changes
Mid-term Reliability (MTR)	Align reliability need in portfolios with MTR need per D.21-06-035	• Higher planning reserve margin (PRM) and load adders • Lower imports • Thermal generation retirements • Minimum build for long-lead time resources ordered
Baseline Resources	Update baseline generators to latest available data	• Include previously proposed ground truthing updates[1] • Update Gen List to align with LSE plan data and MTR baseline, update NQC %'s to match MTR model / 2021 CPUC NQC List
Resource Costs and Potential	Update to latest data vintage of standard IRP data sources	• Resource costs updated to match 2020 NREL ATB, Lazard Levelized Cost of Storage 6.0, NREL offshore wind study • Updated federal PTC and ITC extension to reflect statute and IRS guidance; including 10-year safe harbor option for offshore wind resources • By default, up to 4.7 GW offshore wind was allowed starting in 2030 and up to 3 GW WY+NM wind on new Tx starting in 2026 and up to 68 GW after 2030
LSE Planned Resources	Allow modeling of LSE planned additions	• Input data updated to allow forcing in of 46 and 38 MMT aggregated additions from 2020 LSE IRP plans, with changes as needed to fit within updated transmission constraints

[1] ftp://ftp.cpuc.ca.gov/energy/modeling/IRP%20Model%20Improvement%20and%20GHG%20Groundtruthing_updated.pdf

Summary of RESOLVE Updates since Dec 2020 2021-22 TPP Release – Model Development Related Changes

Update Category	Purpose	Key Changes
Code Base Update	Incorporate the latest RESOLVE code and functionality into the IRP model	• Update the model functionality to include custom constraints and additional input data flexibility. *Used extensively for transmission deliverability constraints and LSE planned resources.* • Enable ability to model multiple reliability constraints and multiple ELCC surfaces for the same reliability constraint. *Battery ELCC curve implementation updated.* • Enable ability to model multiple emission types and constraints and more flexible emissions accounting. *Feature update not used in PSP analysis.*
Transmission Deliverability Constraints	Incorporate latest CAISO transmission deliverability methodology, transmission limits, and upgrade costs	• Update deliverability methodology to align with CAISO • Update on-peak and off-peak transmission deliverability capacity • Include technology-specific resource output factors that relate resource capacity to transmission capacity • Include Li-ion battery and pumped storage capacity under transmission constraints • Revise solar locations granularity, add locational information for batteries to match the solar location • Limit transmission build to CAISO-determined upgrade amounts • Introduce constraints on out-of-state wind and offshore wind to only be selected as fully deliverable resources

[1] ftp://ftp.cpuc.ca.gov/energy/modeling/IRP%20Model%20Improvement%20and%20GHG%20Groundtruthing_updated.pdf

Mid-Term Reliability Decision (D.21-06-035) RESOLVE Implementation

- **PRM**: aligned with MTR Need Determination Model[1] "High Need" scenario from 2024
  - Existing requirement (**~15%**) + 2019 RSP Development calibration adder of (***4.3%***) + Operating Reserves adder of (***1.5%***) + Climate Impact adder of (***1.8%***)
  - **Total PRM = *22.5%***
- **Load Adders**: Per High Need scenario, load adders were added[2] for the managed peak impact[3] of:
  - 1) 2020 vs. 2019 IEPR
  - 2) IEPR Low vs. IEPR Mid BTM PV and 3) High Electrification vs. Mid-Demand IEPR (both held at constant values after 2026)
- **Additional Thermal Retirements:** 40-yr age based applied up to and including 2026 (~1 GW nameplate CHP + peakers)
- **Unspecified imports:** drop from 5 GW to 4 GW in 2024 per High Need scenario
- **Long lead-time resources (LLTs)**: To reflect D.21-06-035 requirements and allowances, 1 GW (NQC) geothermal and 1 GW (NQC) long-duration storage were "forced-in" by 2028 and 2025-2027 reliability need was reduced to minimize PRM overcompliance based on the allowed LLT delay (between 2026 and 2028)
- **Resource NQCs**: RESOLVE NQCs for each resource category were updated to reflect the 2021 CPUC NQC List used by MTR Need Determination Model
- **Persistence of Assumptions**: By default, the "High Need" scenario assumptions persist beyond 2026, though non-persistence of those assumptions was run as a sensitivity

[1] Available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track
[2] Load adders were only added to RESOLVE's PRM constraint. The load forecast used in RESOLVE's dispatch module (i.e. hourly load/resource balance, GHG emissions, etc.) was not changed
[3] The managed peak impact is the IEPR peak load net of demand side resource peak impacts

Transmission Updates: Limits and Constraints

- CAISO updated on-peak and off-peak transmission capability and included technology-specific transmission information
  - CAISO released a white paper in July 2021 entitled "Transmission Capability Estimates for use in the CPUC's Resource Planning Process" which documents the updated capability estimates
    - Available at: http://www.caiso.com/Documents/WhitePaper-2021TransmissionCapabilityEstimates-CPUCResourcePlanningProcess.pdf
  - New transmission constraint limits generally increase the amount of available capacity on the transmission system relative to the 2019 CAISO white paper values, though this is not true for every constraint
    - The new limits also include geographic areas that were not covered in the 2019 white paper
      - 2019 CAISO white paper available at: https://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf

Transmission Updates: Deliverability Methodology

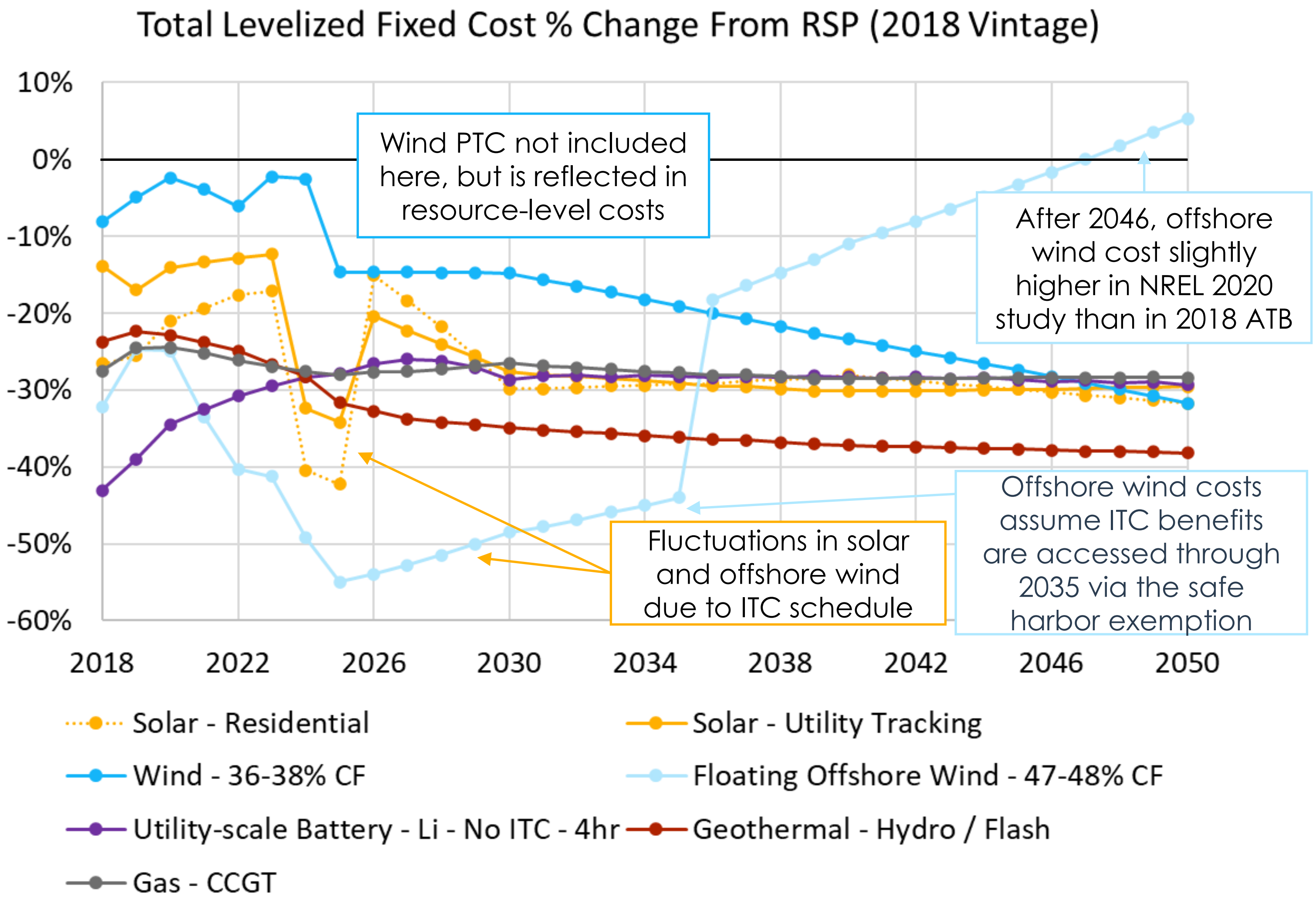
- RESOLVE has been updated to include three limits for each transmission constraint
  - On-Peak, Highest System Need (HSN) – represents net peak hours in early evening when solar output is low
  - On-Peak, Secondary System Need (SSN) – hours of very high demand, represents "shoulder" peak hours where solar output is usually more abundant
  - Off-Peak
- For a resource to receive full deliverability status, it must fit within the available transmission capacity
  - If economic, available transmission capacity can be expanded by CAISO-identified upgrades
  - RESOLVE incorporates resource-specific multipliers for each limit (HSN/SSN/off-peak)
- RESOLVE has also been updated to enforce the CAISO-identified upgrade build limits included in CAISO's 2021 new white paper

Transmission Updates: Storage + Solar

- Previous RESOLVE modeling did not consider interactions between storage and transmission constraints
  - Instead, interactions were addressed downstream in the bus-bar mapping process
- RESOLVE has been updated to:
  - Ensure that storage capacity has enough available transmission capacity to receive full deliverability
    - Lithium-ion battery and pumped storage resources were previous modeled as a single CAISO-wide resource; multiple resources are now modeled such that transmission limits in different areas of the CAISO grid can be considered
  - Model the interaction between storage charging and off-peak transmission limits by expanding off-peak transmission limits when storage is built
    - Storage consumes on-peak transmission capability
    - Storage creates off-peak transmission capability
  - Solar and battery locations aligned as a step towards modeling co-located and hybrid resources.
    - Full hybrid modeling out of scope
      - No interactions are modeled between solar and storage in hourly dispatch
      - Cost reductions from shared infrastructure are not modeled

Resource Costs

- Data source updated from 2018 (Reference System Plan, RSP) to 2020 vintage
  - Most generation technologies: NREL 2020 ATB
  - Offshore wind: NREL OCS Study BOEM 2020-048 [1](RSP: NREL ATB and E3 WECC study)
  - Storage (utility-scale and BTM Li-ion batteries): Lazard LCOS v6.0
- Other updates had smaller impacts on levelized costs compared to data source updates
  - ITC/PTC schedule, solar PV inverter loading ratio, financing lifetime, etc.
  - See details in Appendix



[1] For more information on this study, refer to 8/27/2020 Modeling Advisory Group material available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials

PSP Scenarios and Sensitivities

Overview of all scenarios and sensitivities

Summary of Core PSP Scenarios and Sensitivities

Scenario/Sensitivity Name	Purpose	Key Features
38 MMT Core (Proposed PSP)	Understand the CAISO system resources needs to meet the 38 MMT 2030 GHG target	• Accounts for D.21-06-035 • Utilizes a 38 MMT by 2030 GHG target • Accounts for the LSE plans for 38 MMT 2030 GHG target • Utilizes RESOLVE to select additional resources for 2031 and 2032 to complete 10-year planning timeframe • Utilizes the 2019 IEPR Mid load forecast and load profiles

Scenario/Sensitivity Name	Purpose	Key Changes from Proposed PSP (Similarities to Proposed PSP scenario shown in gold)
46 MMT Core	Understand the CAISO system resources needs to meet the 46 MMT 2030 GHG target	• Utilizes a 46 MMT by 2030 GHG target • Accounts for the LSE plans for 46 MMT 2030 GHG target
30 MMT Core	Understand the CAISO system resources needs to meet the 30 MMT 2030 GHG target	• Utilizes a 30 MMT by 2030 GHG target • Also accounts for the LSE plans for 38 MMT 2030 GHG target

Summary of PSP Sensitivities – High Electrification

Scenario/Sensitivity Name	Purpose	Key Changes from Proposed PSP (Similarities to Proposed PSP scenario shown in gold)

38 MMT with High Electrification (Managed Charging EV Profile)	Understand portfolio changes based on additional reliability and electric-sector GHG reduction needs if a high electrification future is assumed	• Updated loads to match 2020 CPUC High Electrification PATHWAYS scenario
		  • Higher transportation electrification, building electrification, and energy efficiency
		  • 2022-2032: Change from 2019 IEPR to High Electrification scenario
		  • 2033-2045: change from 2018 CEC High Biofuels to High Electrification Scenario
		• Also utilizes the 2019 IEPR Mid load profile for light-duty EVs

38 MMT with High Electrification (Unmanaged Charging EV Profile)	Understand portfolio changes based on additional reliability and electric-sector GHG reduction needs if a high electrification future is assumed	• Utilizes a load profile created by E3 for light-duty EVs which reflects an unmanaged charging behavior • All other inputs and assumptions are identical to the 38 MMT High Electrification (Managed Charging EV Profile)
30 MMT with High Electrification (Managed Charging EV Profile)	Understand portfolio changes based on additional reliability and electric-sector GHG reduction needs if a high electrification future is assumed with a 30 MMT GHG target	• Utilizes a 30 MMT by 2030 GHG target • All other inputs and assumptions are identical to the 38 MMT High Electrification (Managed Charging EV Profile)

Summary of PSP Sensitivities – Cost Sensitivities

Scenario/Sensitivity Name	Purpose	Key Changes from Proposed PSP (Similarities to Proposed PSP scenario shown in gold)

38 MMT with High Solar PV and Storage Costs	Understand portfolio changes based on higher cost trajectories for solar PV and battery storage resources	• Utilizes a higher cost trajectory for the solar PV and battery storage costs
		  • Uses the "conservative" scenario from the 2020 NREL ATB for the solar PV
		  • Uses the "High" cost trajectory from the NREL Cost Projections for Utility-Scale Battery Storage: 2020 Update[1]
		• All other inputs and assumptions are identical to the 38 MMT Core

38 MMT with No Offshore Wind ITC Extension	Understand portfolios changes if offshore wind developers are unable to make enough investments by 2025 to access the 10-year safe harbor provision that secures the ITC benefit for projects with online dates through 2035	• ITC extends only through 2025 for offshore wind • Beyond 2025 ITC drops from 30% to 0% • All other inputs and assumptions are identical to the 38 MMT Core

[1] For more information on this study, it is available at: https://www.nrel.gov/docs/fy20osti/75385.pdf

Summary of PSP Sensitivities – Policy Sensitivities

Scenario/Sensitivity Name	Purpose	Key Changes from Proposed PSP (Similarities to Proposed PSP scenario shown in gold)
38 MMT with No LSE Plans	Test portfolio changes if the resource build requirements to account for the LSE plans are not incorporated	• Does not account for the LSE plans for the 38 MMT by 2030 GHG target • All other inputs and assumptions are identical to the 38 MMT Core scenario

38 MMT with No MTR Persistence	Test portfolio changes if the MTR "high need" scenario reliability drivers are reduced closer to the previously established IRP assumptions
	
	This case represents system needs if there was a lower PRM (than 22.5%) with slightly lower load and higher imports
		• Beyond 2026 following changes are incorporated
		  • Removes ~1.8% "climate impacts" PRM adder, reducing the PRM from 22.5% to 20.7%
		  • Removes the "2019 IEPR Low BTM PV" load adder
		  • Removes the "High Electrification" load adder
		  • Increases unspecified imports capacity limit back up from 4 GW to 5 GW
		• All other inputs and assumptions are identical to the 38 MMT Core scenario

Summary of PSP Sensitivities – IEPR Load Forecast Sensitivities

Scenario/Sensitivity Name	Purpose	Key Changes from Proposed PSP (Similarities to Proposed PSP scenario shown in gold)

38 MMT with 2020 IEPR	Test portfolio changes if the 2020 IEPR load forecast is utilized	• Utilizes the 2020 IEPR Mid forecast
		  • Updates load forecasts for all load components
		  • Updates BTM solar and other BTM generation forecasts
		  • Updates BTM Storage forecast and ELCC values
		• Utilizes the 2020 IEPR Mid load profiles
		• All other inputs and assumptions are identical to the 38 MMT Core scenario

38 MMT with 2020 IEPR with 2020 IEPR High EV (Managed Charging EV Profile)	Understand portfolio changes based on additional reliability and electric-sector GHG reduction needs if a high electrification future manifests due to higher light-duty EV loads	• Utilizes the 2020 IEPR High forecast for light-duty EV load component • All other inputs and assumptions are identical to the 38 MMT with 2020 IEPR sensitivity
38 MMT with 2020 IEPR with 2020 IEPR High EV (Unmanaged Charging EV Profile)	Understand portfolio changes based on additional reliability and electric-sector GHG reduction needs if a high electrification future manifests due to higher light-duty EV loads	• Utilizes a load profile created by E3 for light-duty EVs which reflects an unmanaged charging behavior • All other inputs and assumptions are identical to the 38 MMT with 2020 IEPR with 2020 IEPR High EV (Managed Charging EV Profile) sensitivity

Proposed PSP (38 MMT Core Portfolio)

With LSE Plans

38 MMT Core portfolio overview

- **Purpose**: understand the CAISO system resources needs to meet the 38 MMT 2030 GHG target, accounting for the LSE plans for the 38 MMT goal and D.21-06-035
- **Key metrics to be discussed**:
  - Selected resources* throughout modeling period
  - Planning reserve margin highlights
  - GHG emissions
  - Selected resources beyond the 38 MMT LSE plans
  - Transmission selection details and insights

* Selected resources include A) baseline resources not in the CAISO transmission baseline, B) review + planned resources from LSE Plans, C) MTR resources, D) any other resources RESOLVE selects for reliability, GHGs, or economics

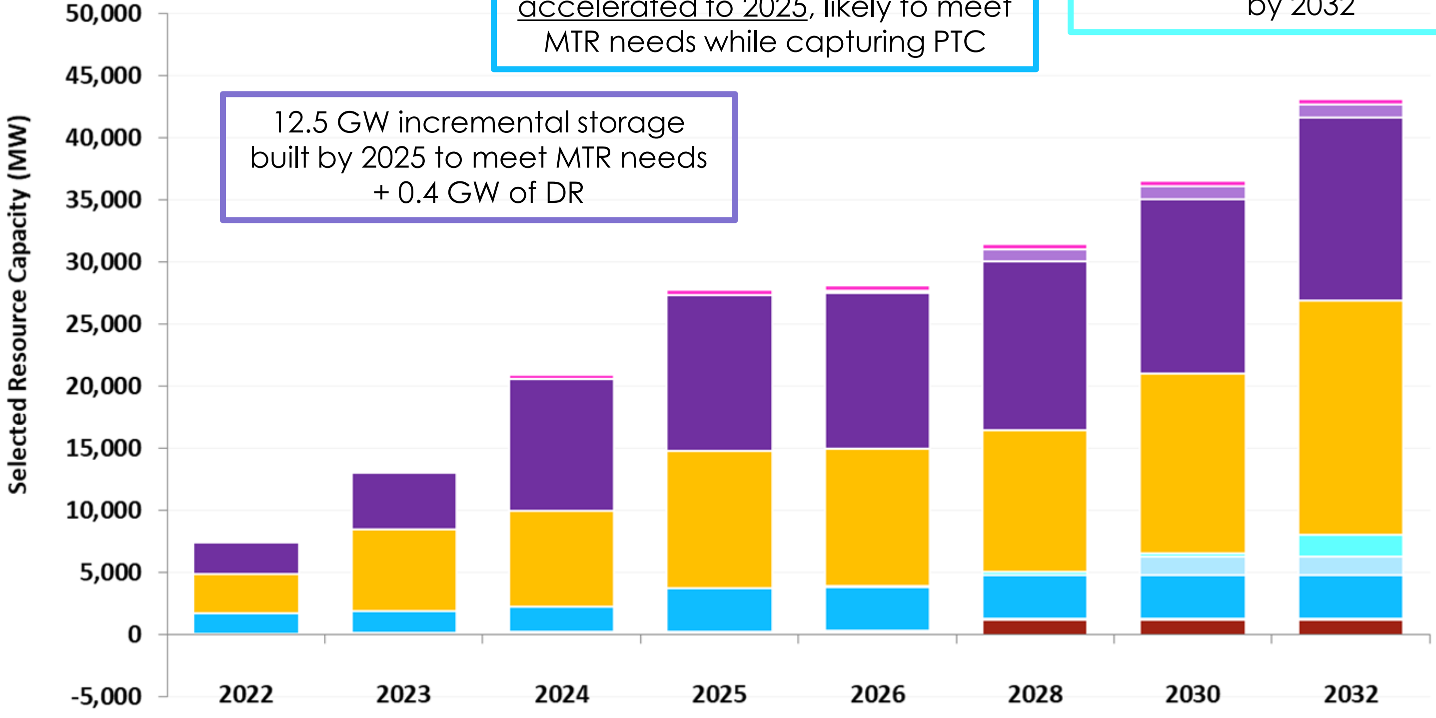
Selected resources – 38 MMT Core

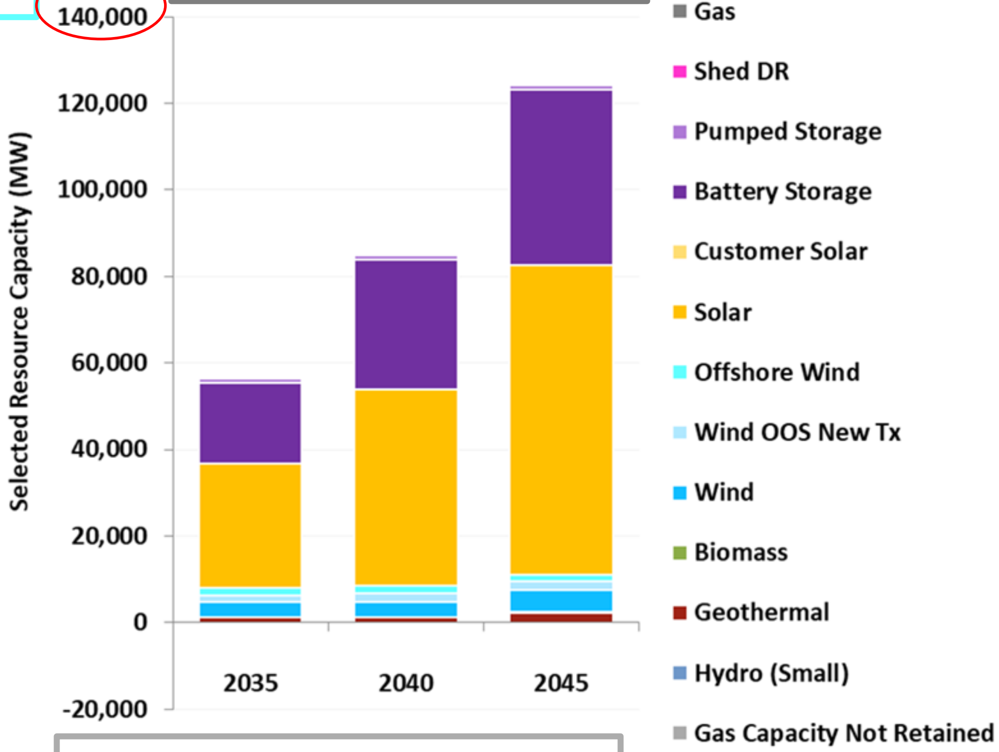
2030 wind capacity in LSE plans accelerated to 2025, likely to meet MTR needs while capturing PTC

Over 3 GW of out-of-state and offshore wind selected by 2032

Over 3 GW of out-of-state and offshore wind selected + 2.2 GW of geothermal by 2045

12.5 GW incremental storage built by 2025 to meet MTR needs + 0.4 GW of DR





Solar through 2024 driven by LSE plans, 11 GW solar deployed by 2025 (hitting annual deployment limit)

1.1 GW geothermal and 1 GW pumped storage selected per MTR order

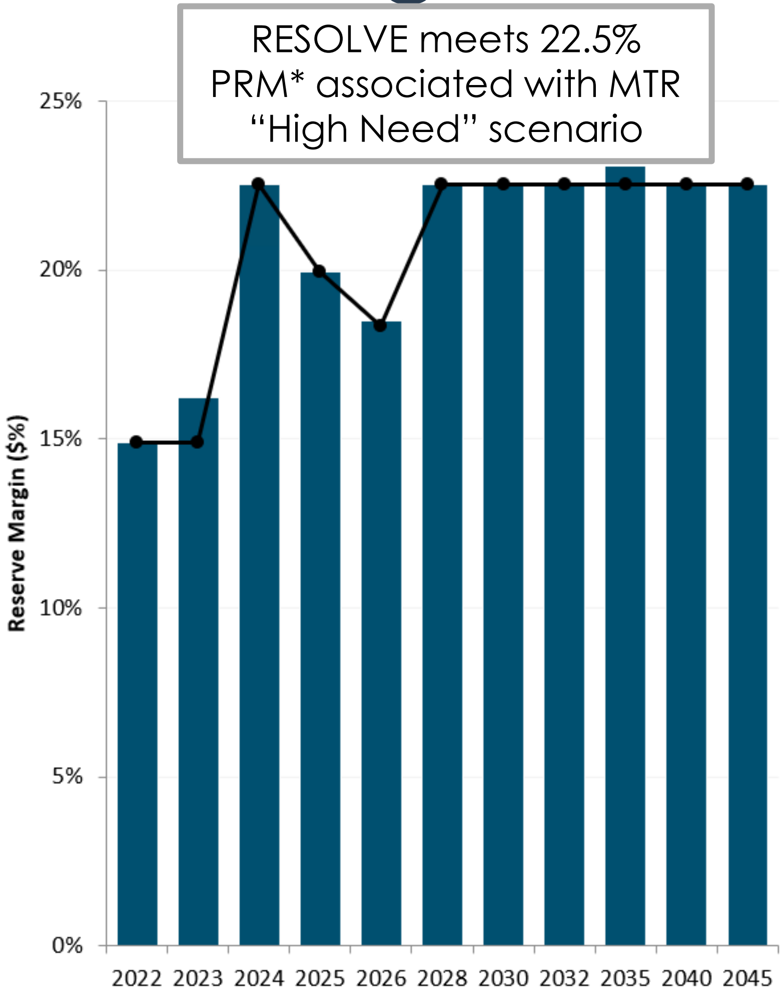
All gas retained through 2045 to meet higher PRM and ~40 MW of additional gas capacity by 2045

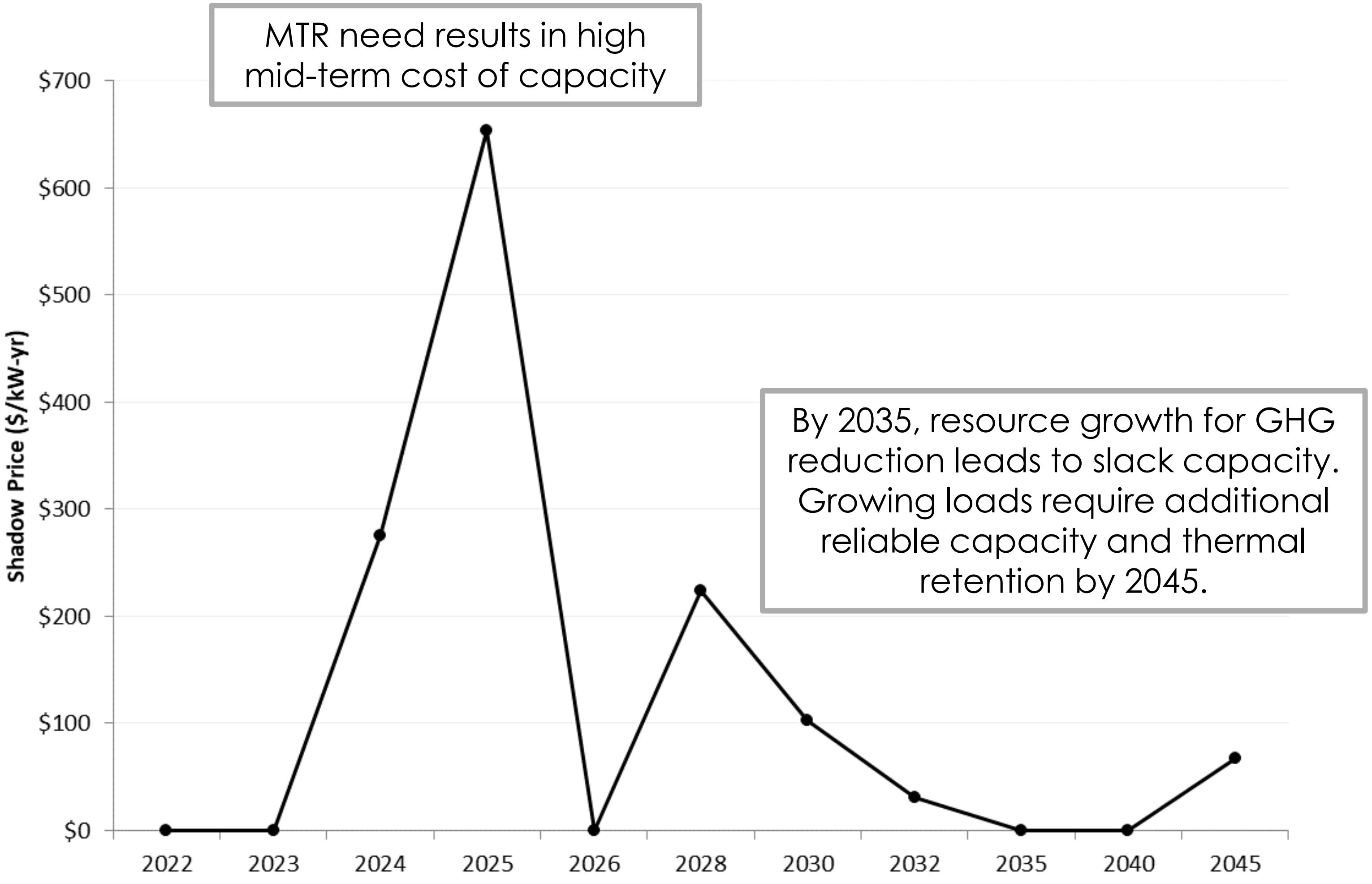
Selected resources – 38 MMT Core

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	1	1	1	1	1	37
Biomass	MW	34	65	83	107	107	134	134	134	134	134	134
Geothermal	MW	14	114	114	114	184	1,160	1,160	1,160	1,160	1,160	2,252
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553	3,553	3,553	5,053
Wind OOS New Tx	MW	-	-	-	-	0	0	1,500	1,500	1,500	1,970	1,970
Offshore Wind	MW	-	-	-	-	120	195	195	1,708	1,728	1,728	1,728
Solar	MW	3,094	6,549	7,750	11,000	11,000	11,397	14,457	18,883	28,675	45,319	71,419
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,565	4,604	10,617	12,553	12,553	13,609	14,086	14,751	18,718	30,076	40,738
Pumped Storage	MW	-	-	-	-	196	1,000	1,000	1,000	1,000	1,000	1,000
Shed DR	MW	151	151	353	441	441	441	441	441	441	441	441
Gas Capacity Not Retained	MW	-	-	-	-	-	-	-	(0)	(0)	(0)	(0)
Storage + DR	MW	**2,716**	**4,755**	**10,970**	**12,993**	**13,189**	**15,049**	**15,527**	**16,192**	**20,159**	**31,517**	**42,179**
Total Resources (Renewables + Storage + DR)	MW	**7,577**	**13,224**	**20,988**	**27,768**	**28,154**	**31,489**	**36,527**	**43,131**	**56,910**	**85,382**	**124,772**

- Resources selected by RESOLVE between 2030 and 2032, i.e., beyond the planning horizon of the current LSE plans:
  - ~4.5 GW solar PV, ~0.7 GW battery storage, ~1.5 GW offshore wind

Planning reserve margin – 38 MMT Core

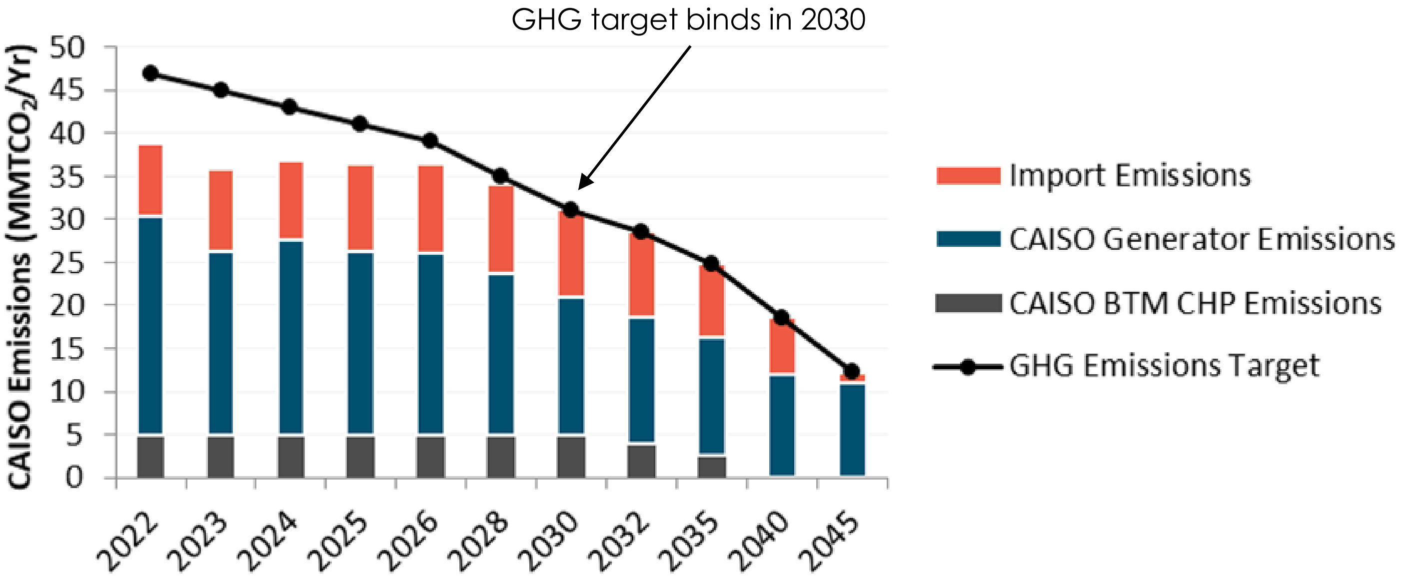


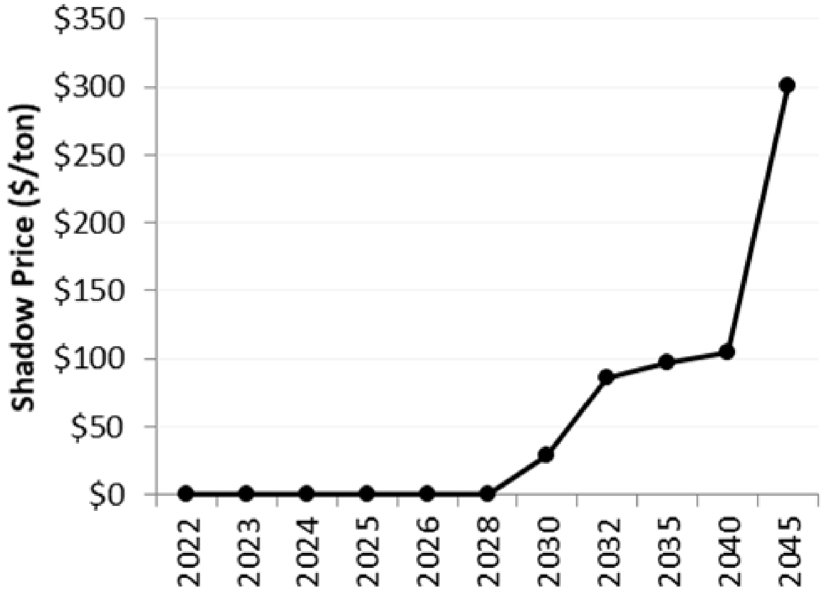


* PRM need is reduced in 2025-2027 to account for the allowed 2-yr delay in the 2 GW of LLT resource additions from 2026 to 2028, per D. 21-06-035. An ~18.5% PRM is achieved in 2026.

GHG emissions – 38 MMT Core

- Combination of MTR + LSE Plans + low cost solar + batteries results in emissions target being met at no incremental cost before 2030
- LSE plans **<u>do not meet the 2030 GHG target</u>** on their own (even with forcing LLTs + MTR on top)





What Does RESOLVE pick on top of 38 MMT LSE Plans?

Incremental Capacity Addition On Top of LSE Planned Resources

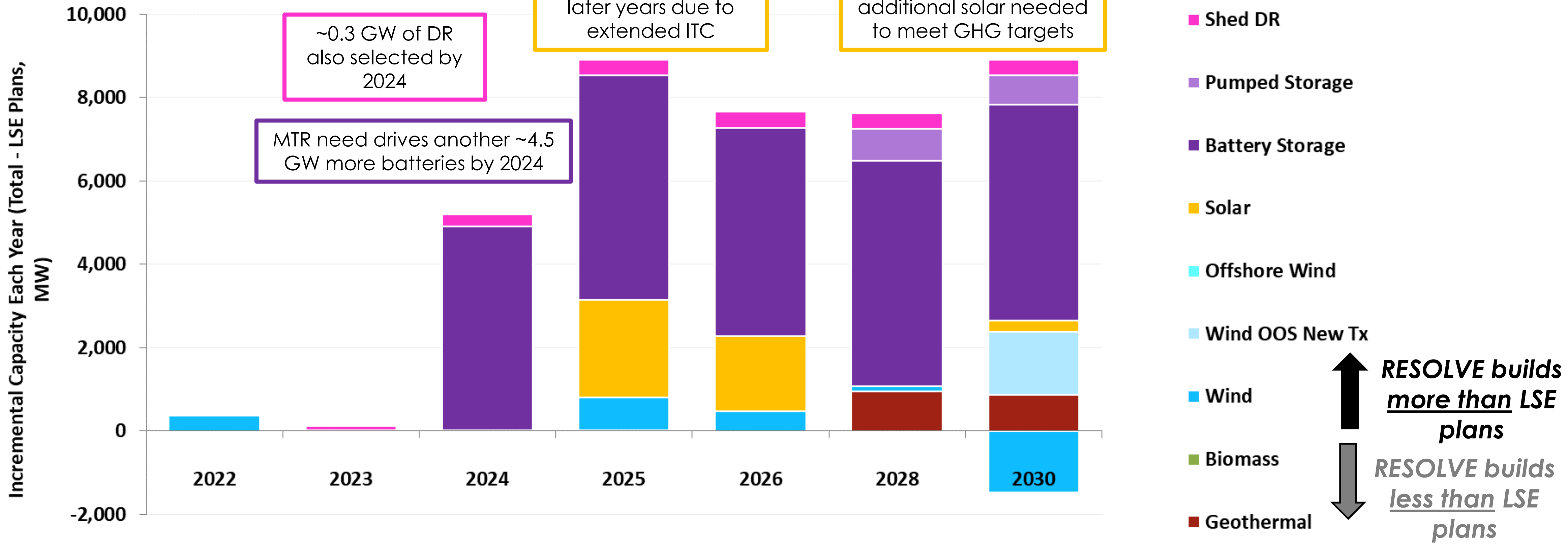
Technology Class	Unit	2022	2023	2024	2025	2026	2028	2030
Battery Storage	MW	-	-	4,882	5,377	5,009	5,406	5,183
Pumped Storage	MW	-	-	-	-	-	764	692
Biomass	MW	-	-	-	12	-	-	-
Shed DR	MW	-	89	288	375	375	376	376
Geothermal	MW	-	-	-	-	-	940	868
Solar	MW	-	-	-	2,344	1,793	-	286
Wind	MW	365	22	22	796	475	134	(1,478)
Offshore Wind	MW	-	-	-	-	-	-	-
Wind OOS New Tx	MW	-	-	-	-	-	-	1,500

- The incremental build is calculated in each year by subtracting the “minimum build requirements” due to the LSE plans from the selected resources in that year
  - Positive values indicate RESOLVE selecting more resources than was indicated in the LSE plans
    - The only instance of a negative delta, for the onshore wind, is because OOS wind is allowed to meet the LSE planned wind resources
    - The amounts differ from year to year because the amounts RESOLVE chooses to select beyond the LSE plans is not fixed

What Does RESOLVE pick on top of 38 MMT LSE Plans?

Solar additions in 2025 moved up from later years due to extended ITC

By 2030, RESOLVE selects a small amount of additional solar needed to meet GHG targets



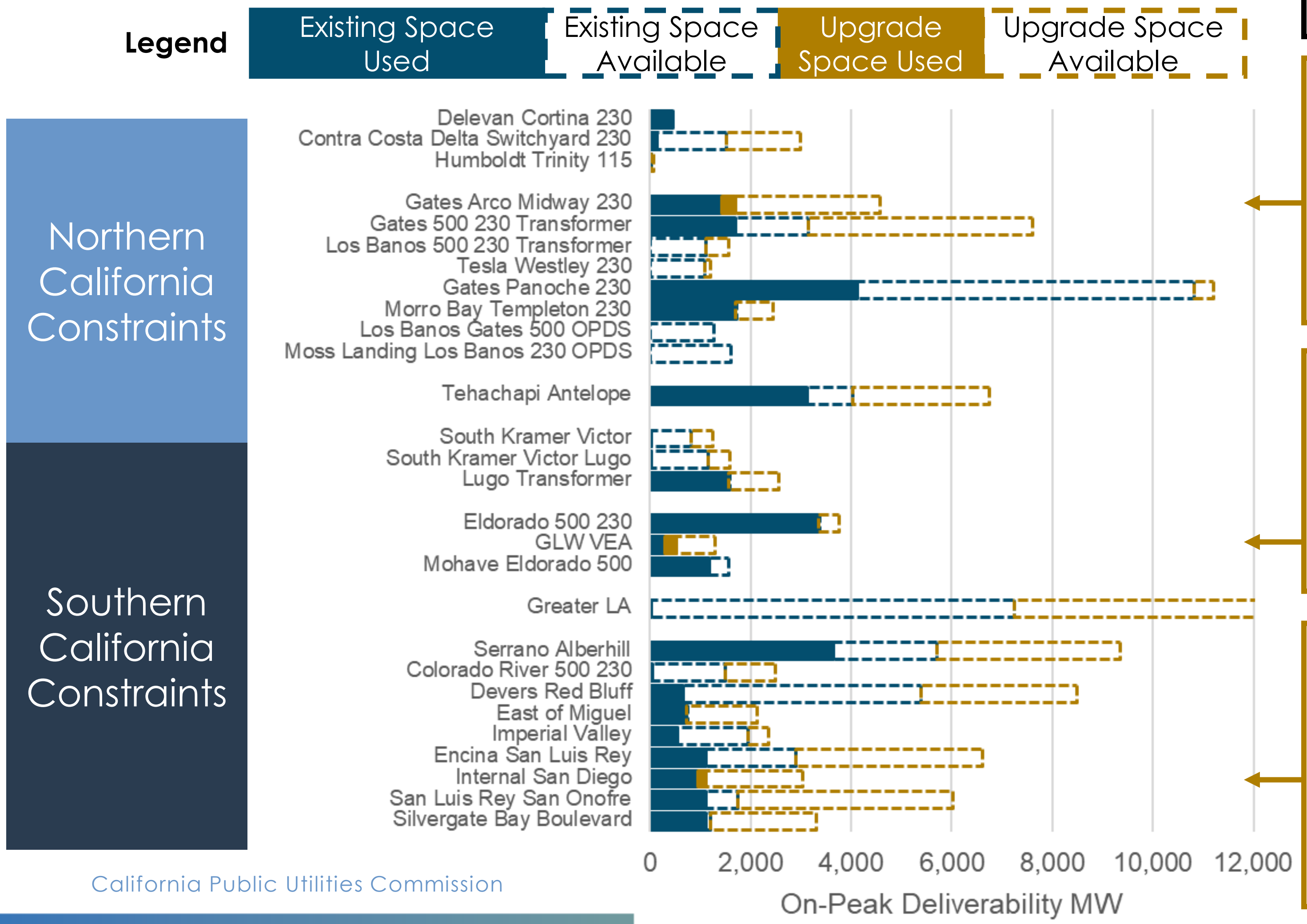
Graph shows the cumulative capacity RESOLVE builds on top of or earlier than LSE plans in each year

Wind is moved up to 2025 to meet MTR and for the extended PTC, but no incremental wind selected by 2030

Geothermal and long duration storage for MTR built on top of ~0.3 GW of each of these resources in LSE plans

1.5 GW of out-of-state wind on new transmission is selected in place of 1.7 GW of in-CAISO wind and out-of-state wind on existing transmission. Replacement driven by transmission constraints, wind resource limits, and the allowance of OOS Wind to meet the LSE plan need

On-Peak Transmission utilization and upgrades: 2032 – 38 MMT Core



Using the new CAISO transmission limits, RESOLVE results indicate that in many areas of the grid, available space will remain on existing transmission even with the buildout included in the 38 MMT Core portfolio

Midway – Gates 230kV Line

- Partial upgrade selected in 2032
  - 277 MW selected out of 3,137 MW on-peak (ADNU) max
- Limiting constraint for wind development, especially offshore wind – selection of Morro bay offshore wind in 2032 drives upgrade timing. Morro Bay-Templeton constraint also limits offshore development but has expensive upgrade.

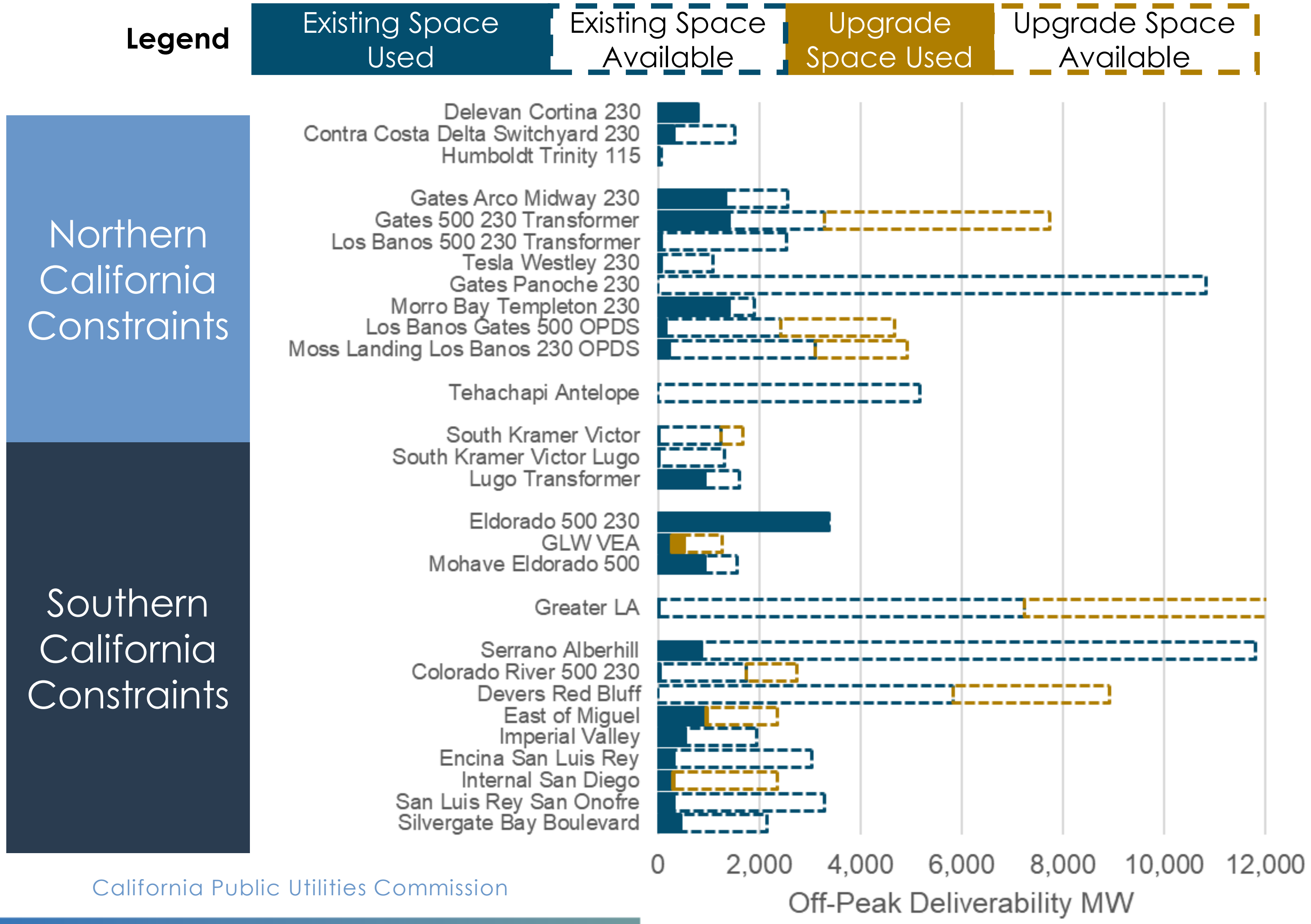
GLW VEA Area Constraint

- Partial upgrade selected in 2028
  - 221 MW selected of 1000 MW on-peak max
- Driven by diverse resources in GLW-VEA
  - Geothermal to meet long-lead-time MTR requirement in 2028, wind to meet LSE plan demand for wind

San Diego Internal Constraint

- Partial upgrade selected in 2028
  - 148 MW selected out of 2,067 MW on-peak max
- Limiting constraint for Imperial Geothermal development
  - Off peak limit on existing system only 290 MW; on peak limit is less limiting at 968 MW
  - ~500 MW batteries built by mid 2020s to expand off-peak limits

Off-Peak Transmission utilization and upgrades: 2032 – 38 MMT Core



- Off peak generally less limiting than on-peak in 2032 timeframe
  - Battery deployment expands off-peak transmission capability (via charging)

Transmission upgrades – full or partial?

- RESOLVE is a linear optimization and cannot perform all-or-nothing upgrade decisions
  - It is therefore possible that RESOLVE can select a partial upgrade, which may not be feasible and would require subsequent analysis to confirm whether the full upgrade is cost-effective
    - Converting to a mixed-integer program to enable all-or-nothing upgrade decisions would potentially result in unacceptable model runtimes
- 38 MMT Core result: the three upgrades in the 2032 timeframe are all partial upgrades
  - Given that RESOLVE did not find it economical to select the full upgrade capacity, further analysis is necessary to determine whether each upgrade should move forward

Transmission upgrades (MW) – 38 MMT Core

Transmission Constraint	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Silvergate Bay Boulevard	-	-	-	-	-	-	-	-	-	-	1,833
San Luis Rey San Onofre	-	-	-	-	-	-	-	-	-	-	1,287
Internal San Diego	-	-	-	-	-	148	148	148	148	148	2,067
Encina San Luis Rey	-	-	-	-	-	-	-	-	-	-	134
Imperial Valley	-							-	-	-	-
East of Miguel	-							-	-	-	438
Devers Red Bluff	-							-	-	-	-
Colorado River 500 230	-							-	-	-	-
Serrano Alberhill	-							-	-	-	3,648
Greater LA	-							-	-	-	-
Mohave Eldorado 500	-	-	-	-	-	-	-	-	-	-	-
GLW VEA	-	-	-	-	-	221	221	221	221	221	221
Eldorado 500 230	-	-	-	-	-	-	-	-	-	-	400
Lugo Transformer	-								-	980	980
South Kramer Victor Lugo	-								-	-	-
South Kramer Victor	-								-	-	-
Tehachapi Antelope	-								-	-	2,700
Moss Landing Los Banos 230 OPDS	-								-	-	-
Los Banos Gates 500 OPDS	-								-	-	-
Morro Bay Templeton 230	-								-	-	-
Gates Panoche 230	-								-	-	378
Tesla Westley 230	-								-	-	-
Los Banos 500 230 Transformer	-	-	-	-	-	-	-	-	-	-	-
Gates 500 230 Transformer	-	-	-	-	-	-	-	-	-	-	-
Gates Arco Midway 230	-	-	-	-	-	-	-	277	277	277	277
Humboldt Trinity 115	-	-	-	-	-	-	-	-	-	-	-
Contra Costa Delta Switchyard 230	-	-	-	-	-	-	-	-	-	-	-
Delevan Cortina 230	-	-	-	-	-	-	-	-	41	41	1,340

Most upgrades cannot be built in early and mid 2020s due to construction time

Few upgrades through 2032; selected upgrades relatively inexpensive (see appendix for transmission upgrade costs)

SCE Eastern + SDG&E area constraints are unable to fully utilize the individual upgrades until significant need in 2045, because of multiple overlapping constraints

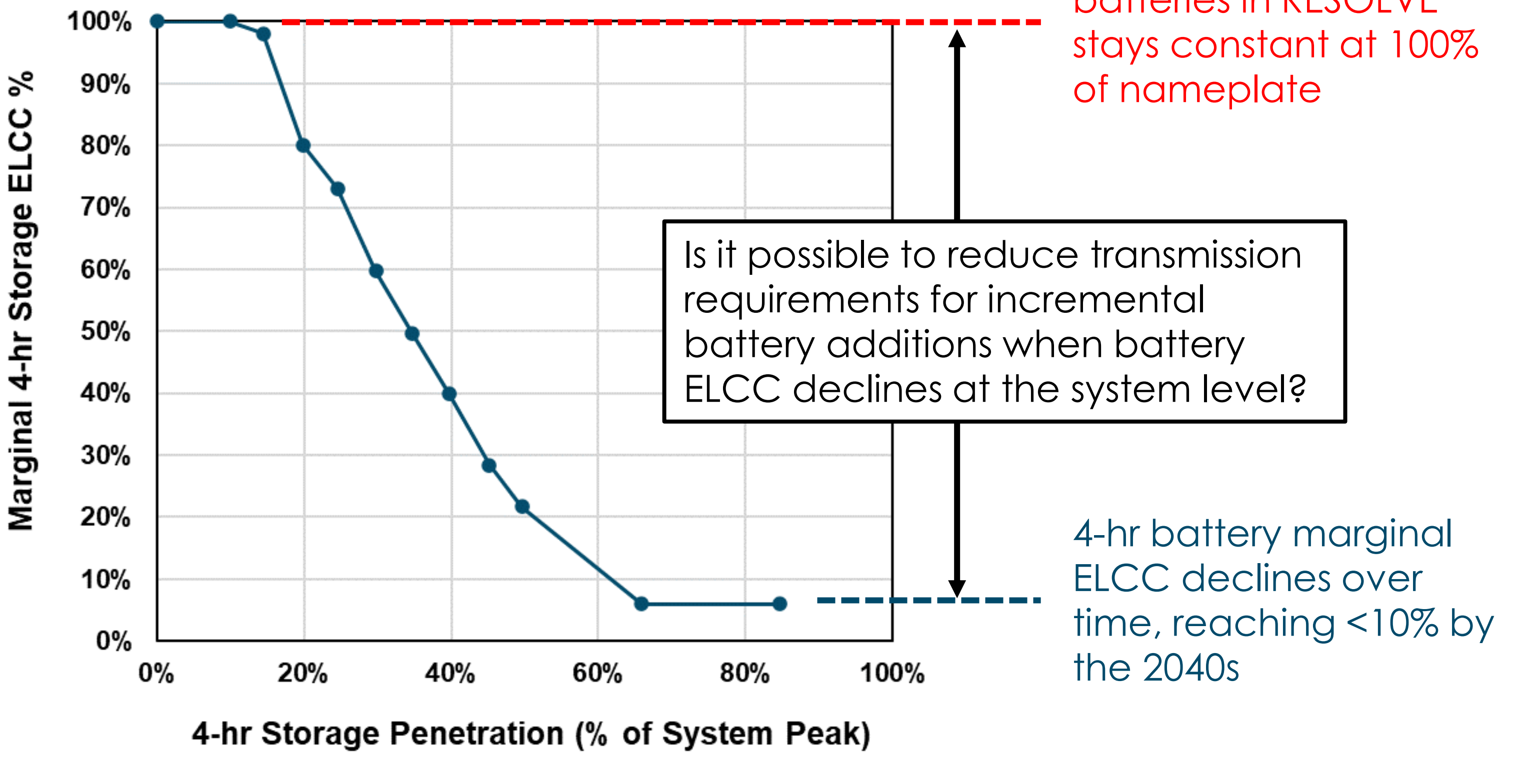
In general, there are fewer transmission upgrades selected vs. past RESOLVE analyses due to updated transmission limits and methodology

Most upgrades selected by 2045, albeit with large uncertainty on long-run transmission needs for incremental solar and batteries

Storage ELCC – Transmission connection

- Additional analysis is required to explore transmission needs for battery/short duration storage at high penetration levels
- Battery Effective Load Carrying Capability (ELCC) declines in part because sustained discharge for more than 4 hours is required to receive full resource adequacy credit
  - It may be possible to size on-peak transmission to longer discharge periods, potentially reducing transmission needs

Battery Storage ELCC Curve – 2019-2020 RSP Input and Assumptions[1]



[1] Curve is updated with more data points, enabled by RESOLVE updates described earlier. Data source remains as per Inputs and Assumptions, available at: ftp://ftp.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf

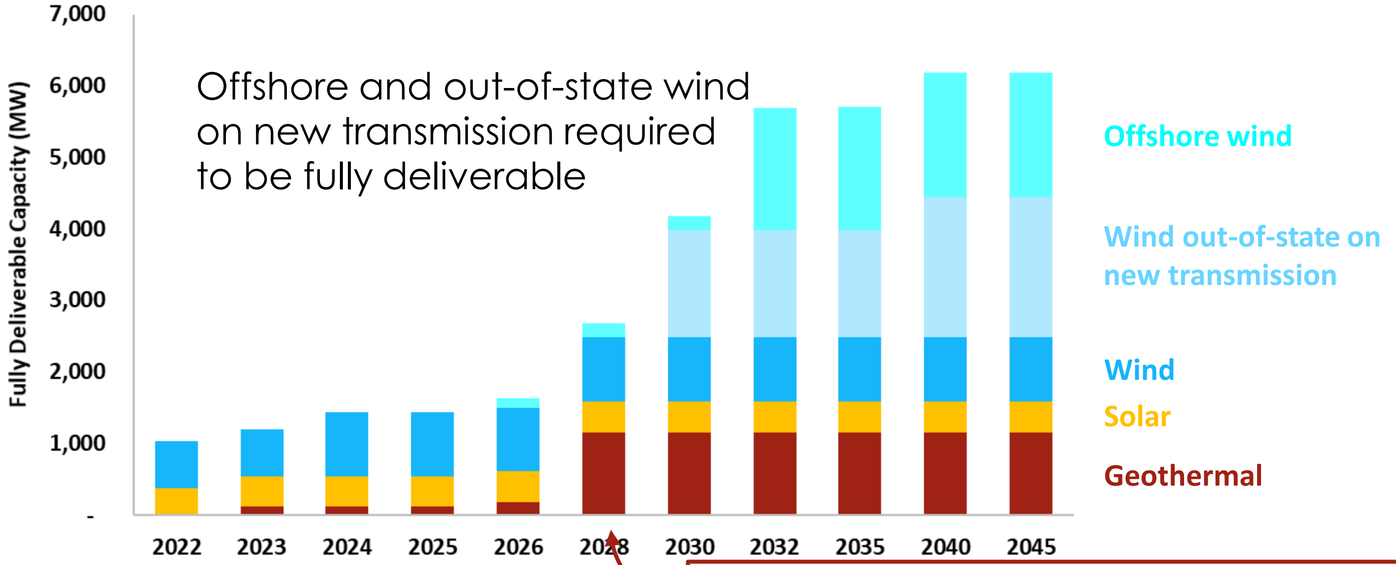
NOTE: These planning track assumptions are not the same as the marginal ELCCs for MTR procurement purposes that will be published by staff by 8/31/2021, as required by D.21-06-035

Fully Deliverable Capacity

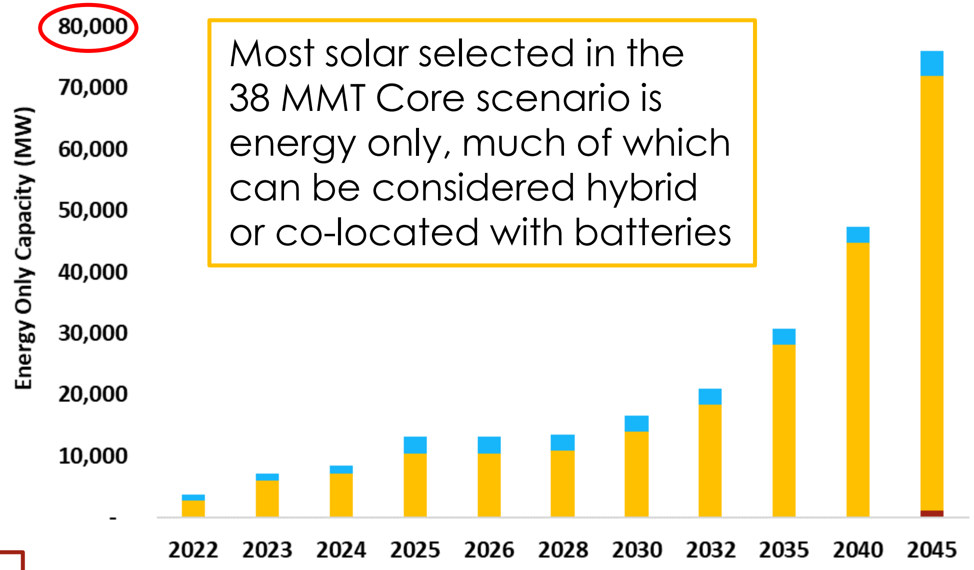
- Contributes to the planning reserve margin
- Uses both on-peak and off-peak transmission space
- RESOLVE will choose full deliverability if the benefits of a resource's planning reserve margin contribution outweigh costs of reserving on-peak transmission capacity
- All storage is fully deliverable (not shown below

Energy Only Capacity

- Does *not* contribute to the planning reserve margin
- Uses only off-peak transmission space
- RESOLVE will choose energy only if the benefits of a resource's planning reserve margin contribution do not outweigh costs of reserving on-peak transmission capacity



Geothermal required to be fully deliverable to satisfy mid-term (~2028) reliability order criteria



Key transmission observations

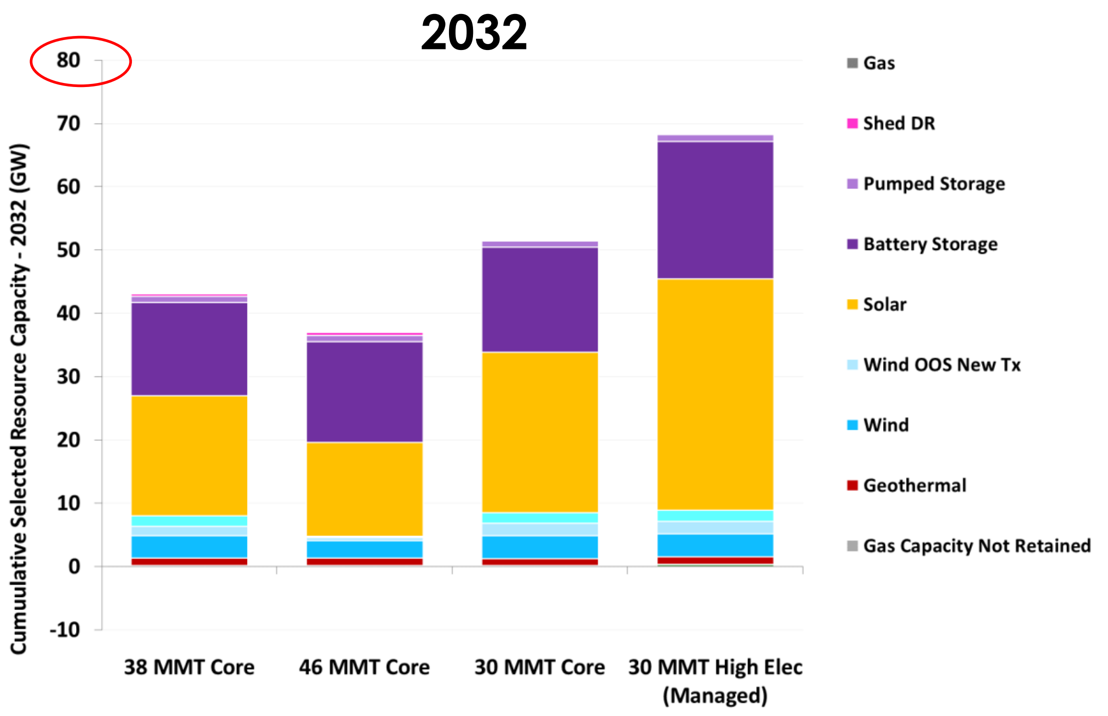
- In the 2032 timeframe transmission upgrades are driven by non-solar, non-battery resources
  - Solar and battery locations are flexible; wind and geothermal locations are not
  - Upgrades driven by solar and batteries observed in the 2040-5 timeframe, but transmission requirements for a high solar + battery future are uncertain
- Transmission upgrade sizing is typically larger than RESOLVE finds to be optimal
  - Resource potential limits or nearby/nested transmission limits tend to limit effectiveness of GW-size upgrades for wind or geothermal
- Out of state wind on new transmission is limited by key transmission constraints
  - Wyoming wind limited by the Mohave/Eldorado 500 kV constraint for which the CAISO study does not include any identified upgrade for RESOLVE to model
  - New Mexico wind is limited by the East of Miguel constraint, that RESOLVE generally sees as cost prohibitive to upgrade
  - Additional transmission capacity on the existing system may be available and would be valuable for resource diversity, especially after 2030
- SDG&E + Eastern SCE area has multiple overlapping constraints that limit resource development and also impede full utilization of individual transmission upgrades

Sensitivity Scenario Results

Scenario Definitions

- 38 MMT w/ No LSE Plans: 38 MMT GHG target in 2030 without LSE plans included; essentially a re-run of a reference system portfolio with updated assumptions, and is intended for comparison purposes only
- 38 MMT Core: 38 MMT GHG target in 2030 with LSE plans incorporated, along with the MTR resources of 11,500 MW, and resource augmentation for 2031 and 2032
- 38 MMT w/ 2020 IEPR: 38 MMT Core with the 2020 IEPR mid-demand load forecast
- 38 MMT w/ 2020 IEPR + 2020 High EV: 38 MMT Core with the 2020 IEPR mid-demand load forecast mixed with the 2020 IEPR high electric vehicle (EV) load forecast
- 38 MMT High Electrification: 38 MMT Core with a high electrification demand forecast for both managed and unmanaged EV profiles, based on a high electrification demand scenario developed by Commission staff using the PATHWAYS model in 2020 for modeling purposes
- 38 MMT No Offshore Wind ITC Extension: 38 MMT Core with an assumption that developers do not invest to a level significant enough by end of 2025 to access safe harbor provisions of the offshore wind ITC, making projects ineligible for the full ITC benefits
- 38 MMT High Solar and batteries Cost: 38 MMT Core with high solar and battery storage cost assumptions
- 38 MMT No MTR Persistence: 38 MMT Core with MTR non-persistence assumption to test portfolio changes if the MTR "high need" scenario reliability drivers are reduced similar to the previously-established IRP planning assumptions
- 46 MMT Core: 46 MMT GHG target in 2030, based on LSE plans and augmented with the 11,500 MW of MTR NQC and 2031 and 2032 resources
- 30 MMT Core: 30 MMT GHG target in 2030, based on the LSE plans designed to achieve the 38 MMT target, augmented with the 11,500 MW of MTR NQC, 2031 and 2032 resources, and additional resources necessary to achieve the lower 30 MMT GHG target
- 30 MMT High Elec: 30 MMT Core with a high electrification demand forecast, based on a high electrification demand scenario developed by Commission staff using the PATHWAYS model in 2020 for modeling purposes.

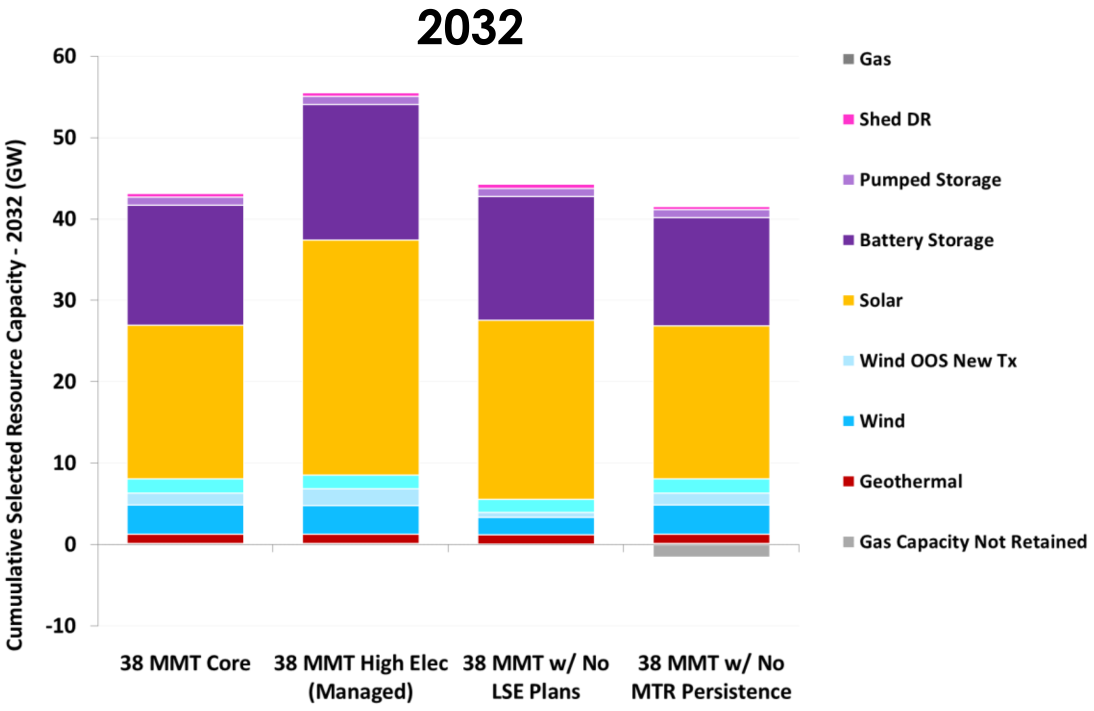
Summary of alternate GHG target sensitivities



Metrics	Unit	38 MMT Core	46 MMT Core	30 MMT Core	30 MMT w/ High Electrification
PV Total Resource Cost Delta Relative to LSE Plan Scenario	$MM	$905,213	-$521	+$1,589	+$69,334
Levelized Average Rate Delta Relative to LSE Plan Scenario	cts/ kWh	19.3	-0.0	+0.0	-0.7
New Transmission for Selected Resources (within CAISO), 2032	MW	646	266	646	646
Total GHG Abatement cost (GHG shadow price + CARB floor), 2032	$/tCO2	117	33	163	176
Res. Monthly Bill at 500 kWh/mo and 600 kWh/mo, 2032	$/mo	$126.1 $151.3	+$0.67[1] +$0.80	+$1.06 +$1.26	N/A[2]

[1] Residential monthly bill is slightly higher in the 46 MMT sensitivity because the resources procured for meeting D.21-06-035 already push the GHG emissions lower than 46 MMT, so the difference between achieving the resource build out is lower than the operating cost savings achieved from reduced usage of the thermal fleet
[2] Residential monthly bill for High Electrification will depend on how much the monthly usage increases due to adoption of electrification

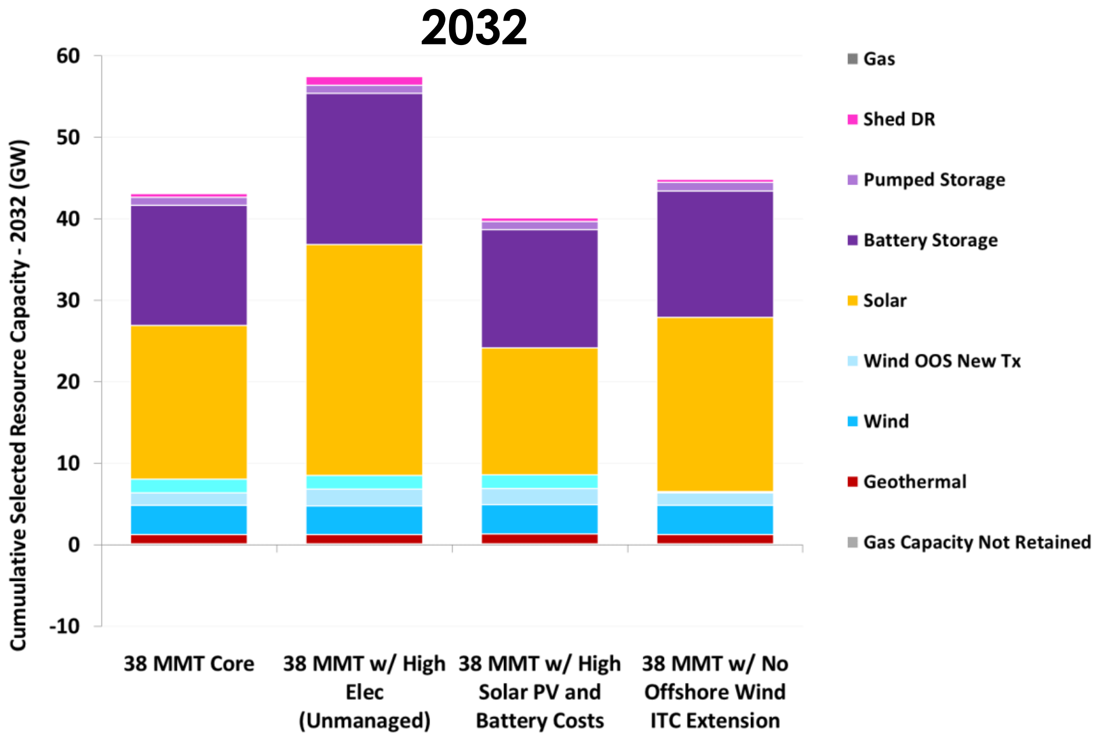
Summary of 38 MMT scenarios and sensitivities



Metrics	Unit	38 MMT Core	38 MMT w/ High Electrification (Core)	38 MMT w/o LSE Plans	38 MMT w/ MTR Non-Persistence
PV Total Resource Cost Delta Relative to LSE Plan Scenario	$MM	$905,213	+$67,849	-$3,211	-$843
Levelized Average Rate Delta Relative to LSE Plan Scenario	cts/ kWh	19.3	-0.7	-0.1	-0.0
New Transmission for Selected Resources (within CAISO), 2032	MW	646	527	256	646
Res. Monthly Bill at 500 kWh/mo and 600 kWh/mo, 2032	$/mo	$126.1 $151.3	N/A[1]	-$0.48 -$0.58	-$0.17 -$0.21

[1] Residential monthly bill for High Electrification will depend on how much the monthly usage increases due to adoption of electrification

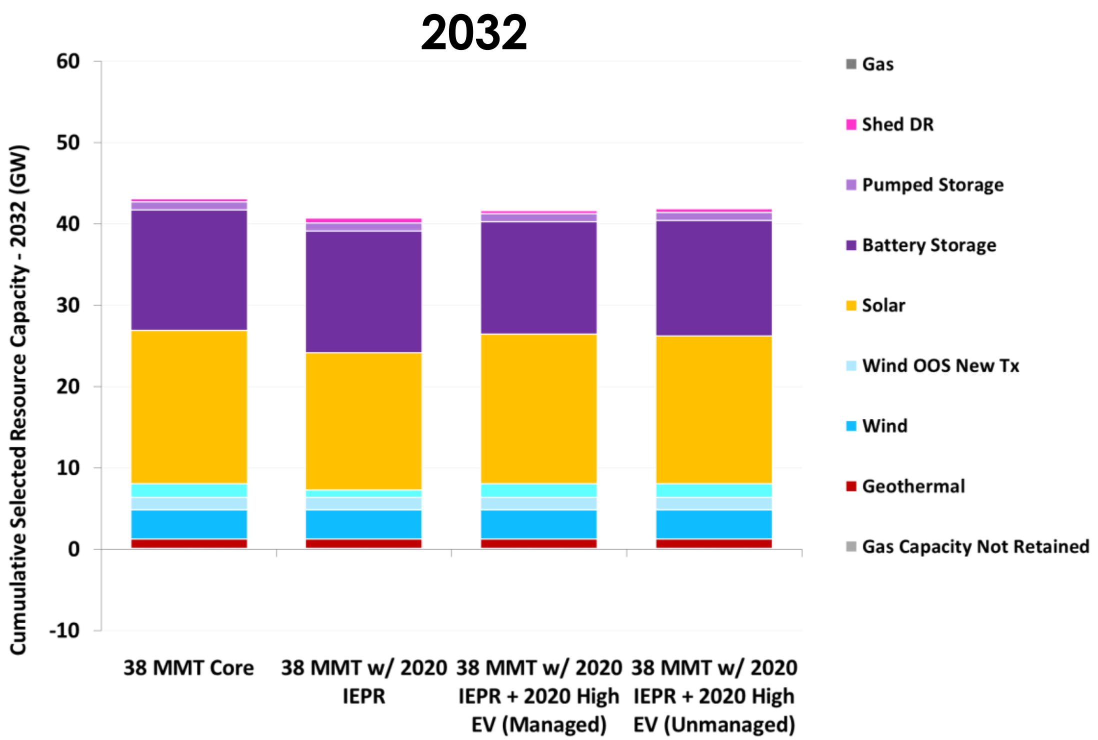
Summary of additional scenarios and sensitivities



Metrics	Unit	38 MMT Core	38 MMT w/ High Electrification (Unmanaged)	38 MMT w/ High PV and Battery Costs	38 MMT w/o OSW ITC Extension
PV Total Resource Cost Delta Relative to LSE Plan Scenario	$MM	$905,213	+$72,469	+$23,072	+$773
Levelized Average Rate Delta Relative to LSE Plan Scenario	cts/ kWh	19.3	-0.6	+0.1	+0.0
New Transmission for Selected Resources (within CAISO), 2032	MW	646	527	3,349	369
Res. Monthly Bill at 500 kWh/mo and 600 kWh/mo, 2032	$/mo	$126.1 $151.3	N/A[1]	+$0.52 +$0.62	+$0.07 +$0.08

[1] Residential monthly bill for High Electrification will depend on how much the monthly usage increases due to adoption of electrification

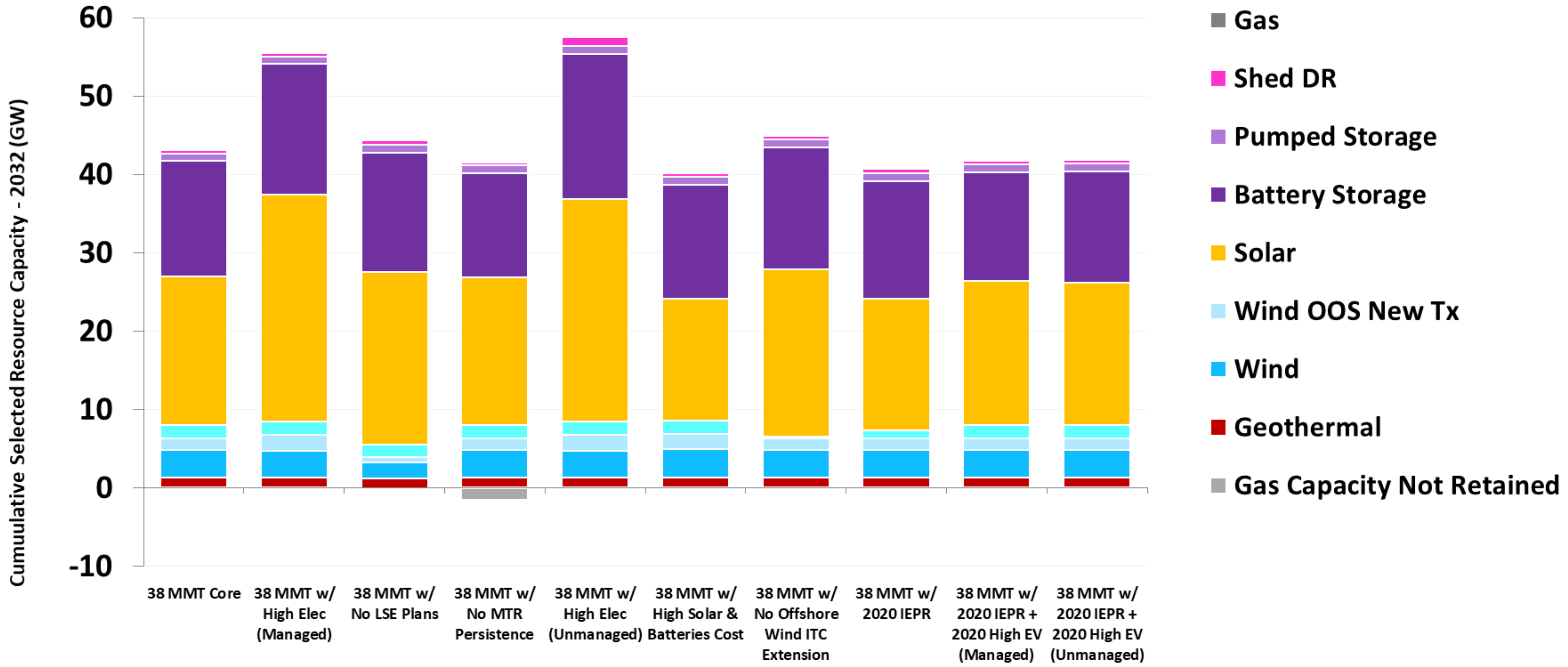
Summary of additional scenarios and sensitivities



[1] Residential monthly bill for High Electrification will depend on how much the monthly usage increases due to adoption of electrification

Metrics	Unit	38 MMT Core	38 MMT w/ 2020 IEPR	38 MMT w/ 2020 IEPR + 2020 High EV (Managed)	38 MMT w/ 2020 IEPR + 2020 High EV (Unmanaged)
PV Total Resource Cost Delta Relative to LSE Plan Scenario	$MM	$905,213	-$2,800	-$1,218	+$773
Levelized Average Rate Delta Relative to LSE Plan Scenario	cts/ kWh	19.3	+0.22	-0.01	+0.01
New Transmission for Selected Resources (within CAISO), 2032	MW	646	414	646	678
Res. Monthly Bill at 500 kWh/mo and 600 kWh/mo, 2032	$/mo	$126.1 $151.3	+$2.94 +$3.52	N/A[1]	N/A[1]

Summary of All Scenarios and Sensitivities



38 MMT with High Electrification (Managed Charging EV Profile)

With LSE Plans

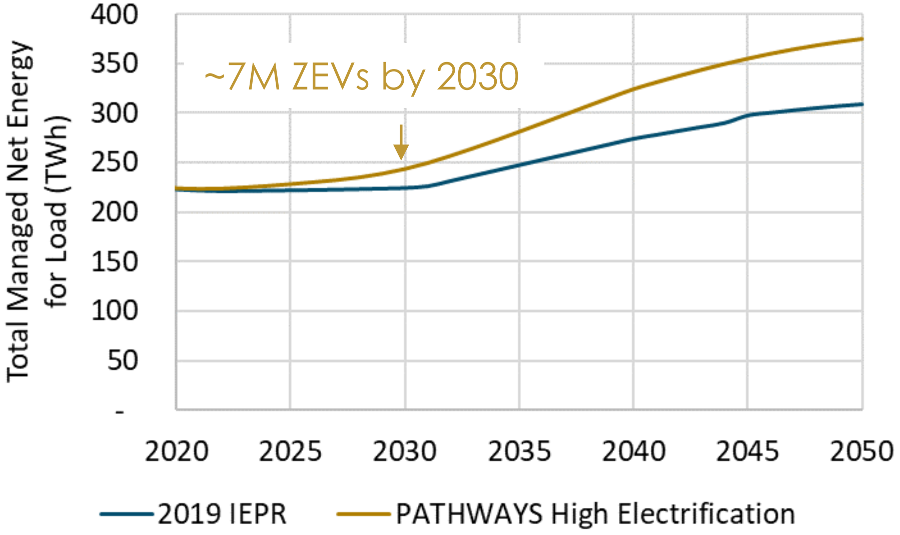
Updated 2020 High Electrification Scenario

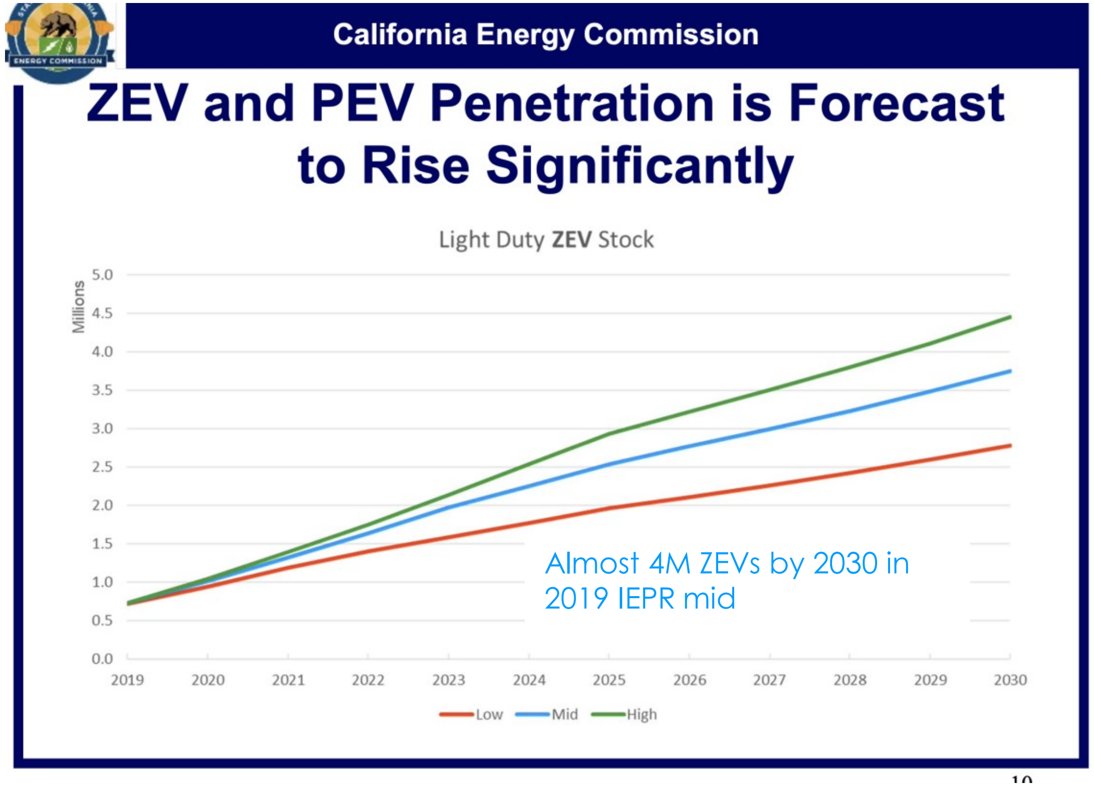
- Updated PATHWAYS High Electrification scenario is consistent with the 2020 E3 report for CARB on Achieving Carbon Neutrality in California (High CDR Case)

Measure	2030 Assumptions
Building EE	**High**: Harmonized with 2017 Scoping Plan EE
Industry EE	**High**: Harmonized with 2017 Scoping Plan EE
Smart Growth	**6% reduction** in per capita LDV VMT relative to 2017
Building Electrification	**50% of new sales** for water heaters and HVAC are heat pumps (~2 TWh)
Vehicle efficiency	**High**: retain federal waiver for CA mpg (new LDA are 45 mpg and LDTs 34 mpg in 2030)
Light-duty vehicle electrification	**7 million on-road ZEVs** (67% sales, 23 TWh)
Trucks & off-Road electrification	**15% MDV and 9% HDV BEVs** (60% and 22% sales, 15 TWh)
Clean Electricity	76% RPS (**30 MMT CO_2 statewide**)
Biofuels	**398 TBTU** (all available waste & residue feedstocks, including importing to CA population share of US feedstocks)
Pipeline Hydrogen	**5% blend by energy** (off-grid renewable electrolysis)
Non-Combustion	**40% reduction** in CH_4 and F-gases

High Electrification Sensitivity

Comparison of 2020 CPUC PATHWAYS High Electrification and 2019 IEPR Mid





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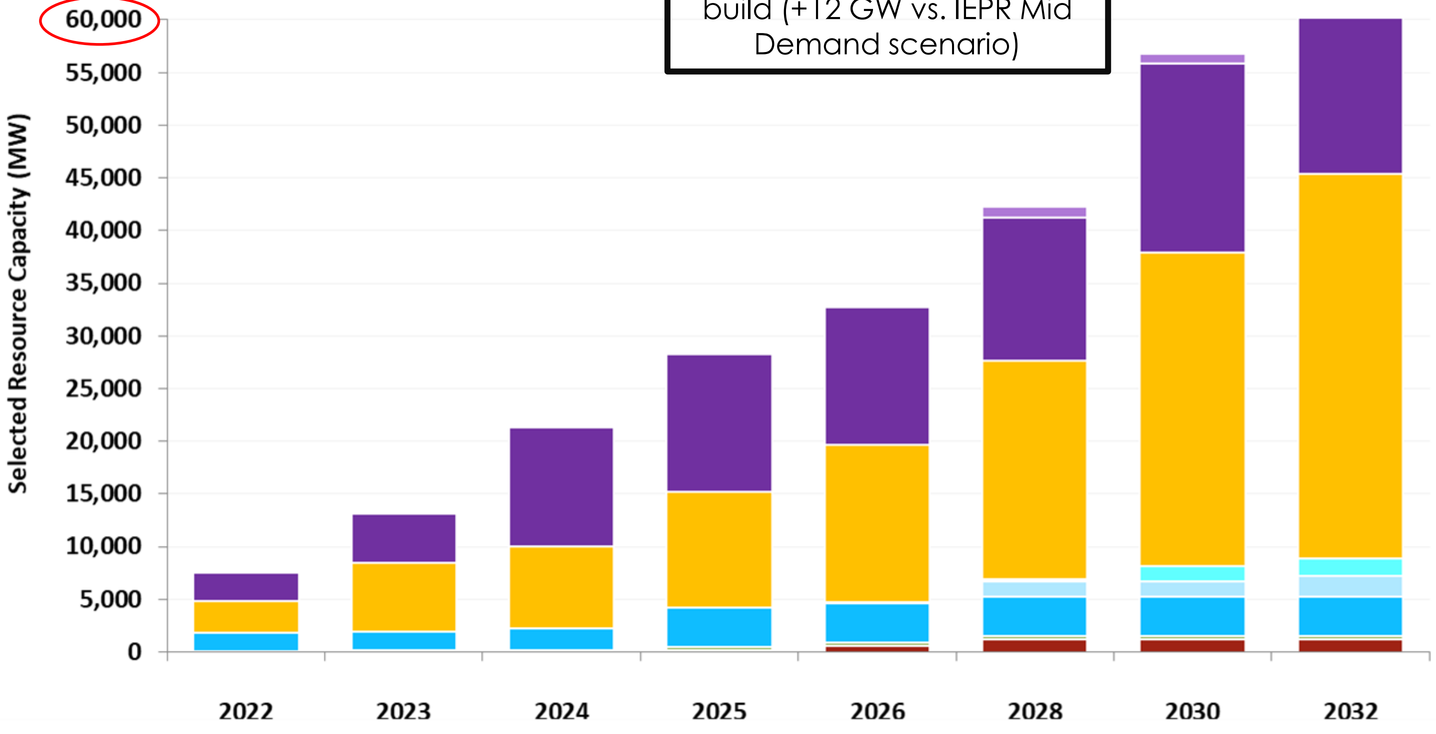
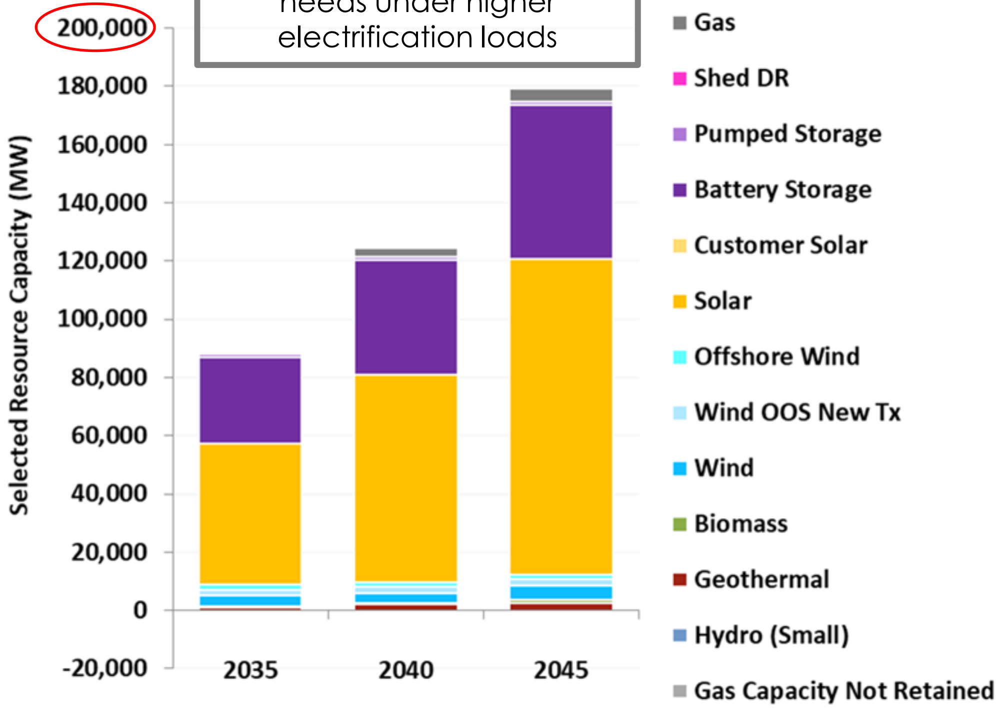
Selected resources – 38 MMT w/ High Electrification (Managed Charging)

Much higher 2032 resource build (+12 GW vs. IEPR Mid Demand scenario)



4.1 GW of new gas + 1.1 GW of biomass built by 2045 for resource adequacy needs under higher electrification loads



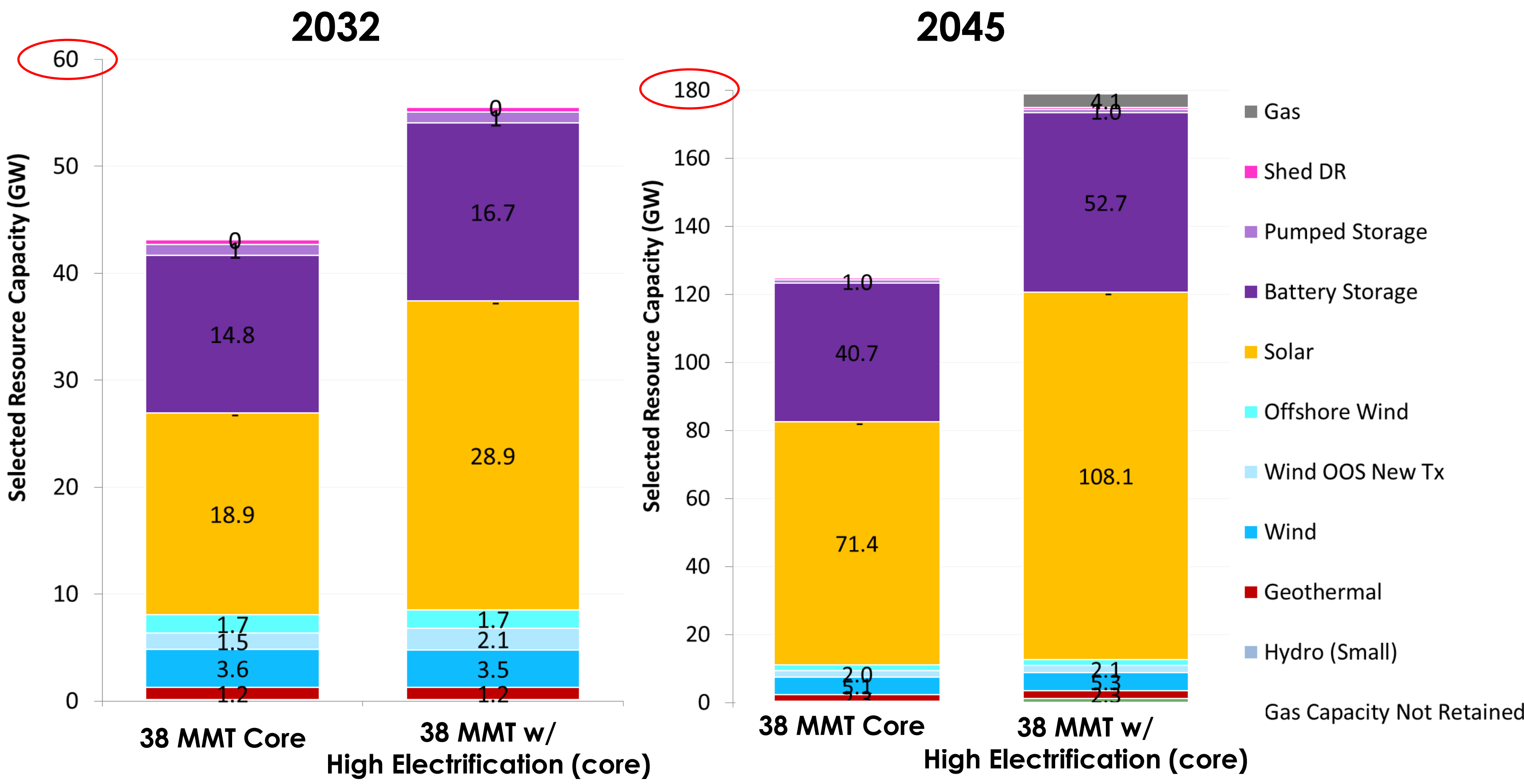
Selected resources – 38 MMT w/ High Electrification (Managed Charging)

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	0	0	0	0	2,578	4,120
Biomass	MW	34	65	83	107	107	134	134	134	134	134	1,147
Geothermal	MW	14	114	114	114	184	1,162	1,162	1,162	1,162	1,162	2,332
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,458	3,458	3,458	3,458	3,458	3,458	3,458	5,319
Wind OOS New Tx	MW	-	-	-	-	0	1,595	1,596	2,066	2,066	2,066	2,066
Offshore Wind	MW	-	-	-	-	120	195	1,431	1,708	1,728	1,728	1,749
Solar	MW	3,094	6,549	7,750	11,000	11,000	12,407	21,659	28,872	42,378	70,974	108,076
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,565	4,604	10,906	12,877	12,877	13,277	14,899	16,664	25,252	38,510	52,702
Pumped Storage	MW	-	-	-	-	196	1,000	1,000	1,000	1,000	1,000	1,000
Shed DR	MW	151	151	353	441	441	441	441	441	441	441	441
Gas Capacity Not Retained	MW	-	-	-	-	-	-	-	-	-	-	(0)
Storage + DR	MW	**2,716**	**4,755**	**11,258**	**13,318**	**13,514**	**14,718**	**16,340**	**18,105**	**26,693**	**39,951**	**54,143**
Total Resources (Renewables + Storage + DR)	MW	**7,577**	**13,224**	**21,277**	**27,997**	**28,383**	**33,671**	**45,780**	**55,505**	**77,620**	**122,051**	**178,951**

- Through 2032 the increased load is mostly served by additional solar PV and battery resources
- By 2040 and 2045, the model selects more diversity and additional firm generation (shown in the selection of new gas and biomass resources) in addition to the increased solar PV and batteries

38 MMT Core vs. High Electrification (Managed Charging)

- High electrification scenarios lead to more resources, including OSW, solar, batteries, and new "gas"*

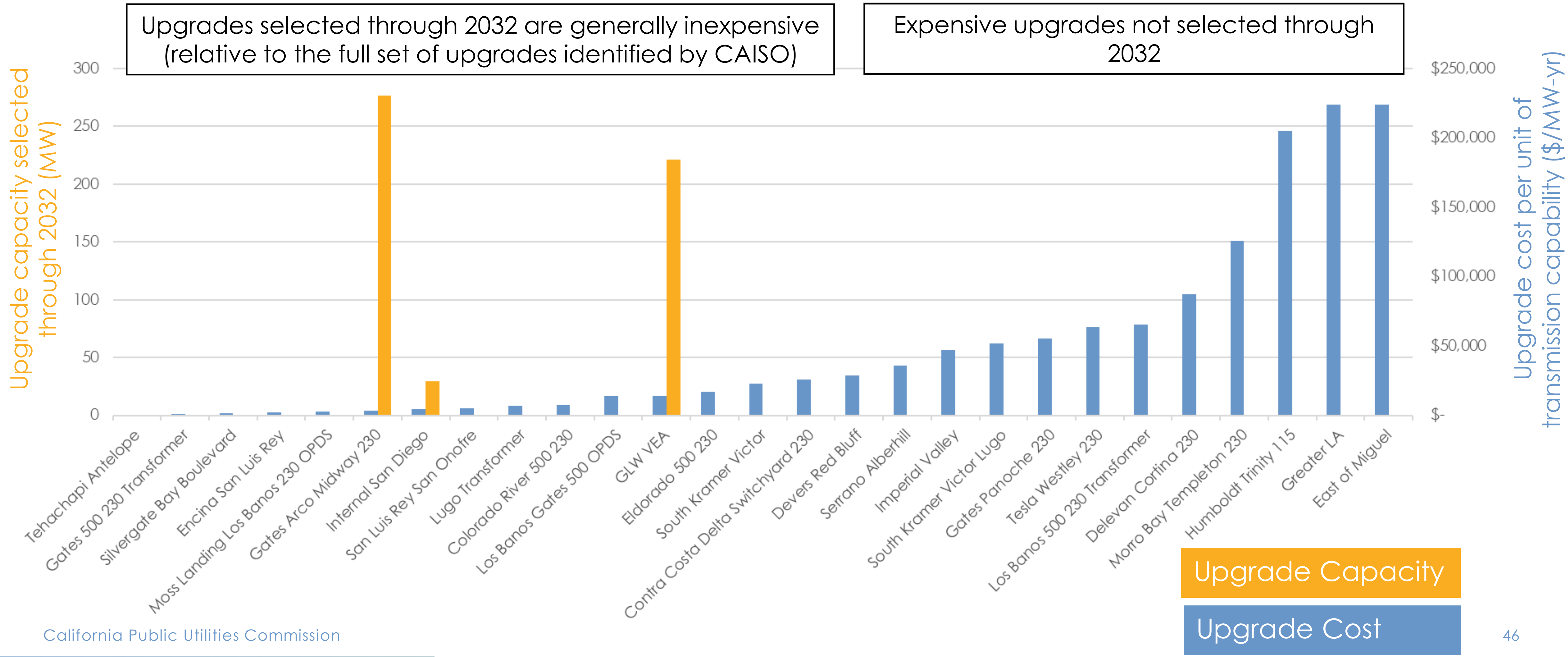


* In theory new "gas" built by RESOLVE could be non-emitting (e.g. H2 CTs), but is modeled with natural gas fuel

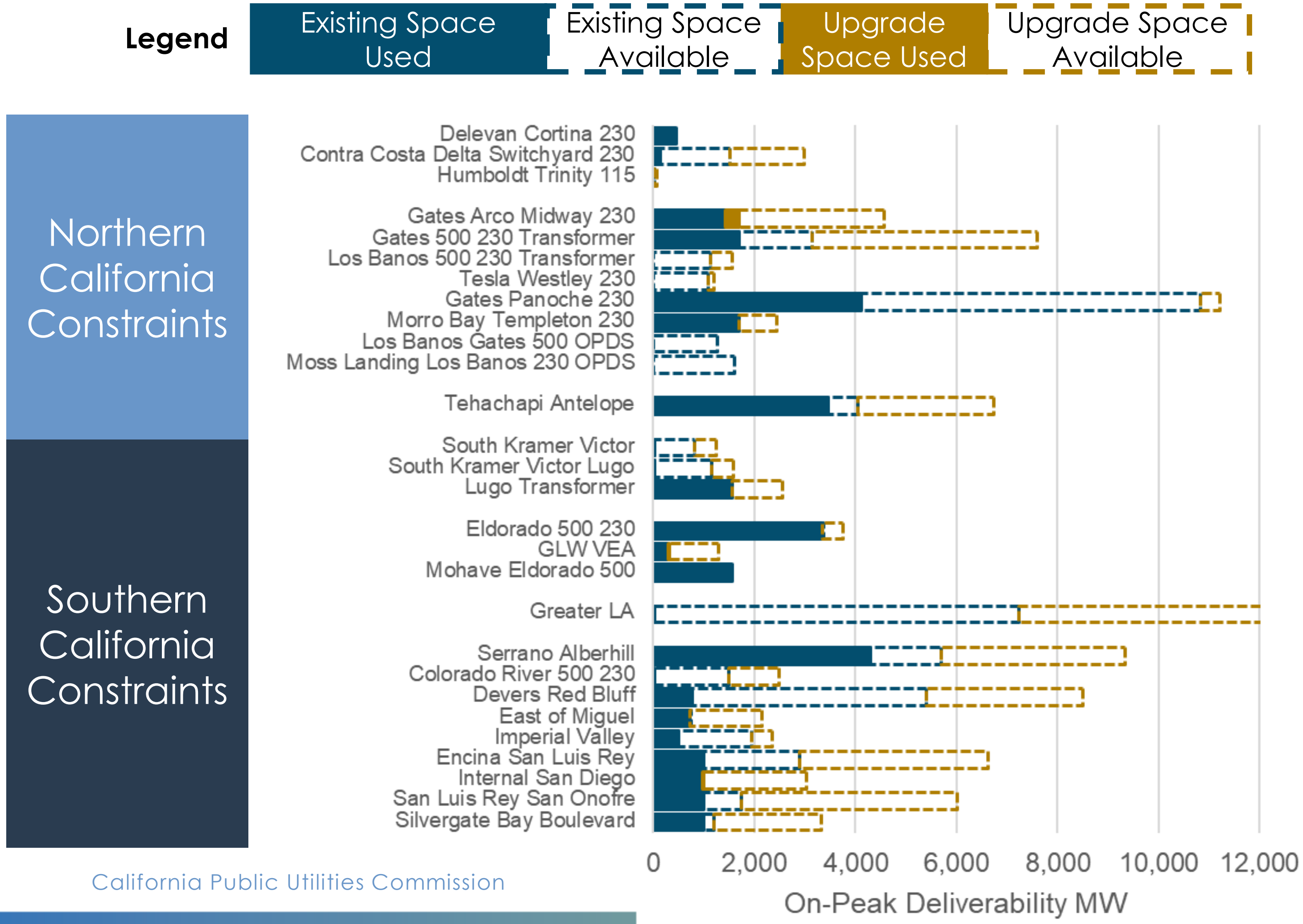
38 MMT w/ High Electrification (Managed Charging) – Transmission and Resource Interactions

- CAISO's transmission limits set an upper bound on the amount of solar + storage that could be deployed in the CAISO grid
  - Transmission upgrades create additional, but not infinite, space on the transmission system
- The 38 MMT high electrification case requires a substantial buildout of GHG-free resources, especially solar and batteries, above the core 38 MMT case
- It becomes increasingly difficult for RESOLVE to place solar and batteries in the 2040-2045 timeframe, resulting in many transmission upgrades
- It becomes particularly hard to deploy solar in this timeframe because solar becomes very limited by off-peak deliverability constraints
- As a modeling tool to explore high electrification scenarios, E3 has expanded the resource potential of Distributed PV, which in the current version of RESOLVE does not take up space in CAISO's transmission constraints
  - In the 38 MMT high electrification case, 34 GW of Distributed PV is selected in 2045; none is selected in earlier years. Further analysis would be necessary to determine interactions with CAISO's transmission constraints.
- E3 has also included a very high-cost transmission upgrade in the Greater LA area – this is for modeling purposes and is not an upgrade identified by CAISO.
  - RESOLVE will only select this upgrade as a last resort to locate additional batteries
  - However even under the high electrification case, RESOLVE does not select this upgrade
- *The amount of transmission needed for solar and batteries in the 2045 timeframe is uncertain*

Transmission upgrades 2032 – 38 MMT w/ High Electrification (Managed Charging)

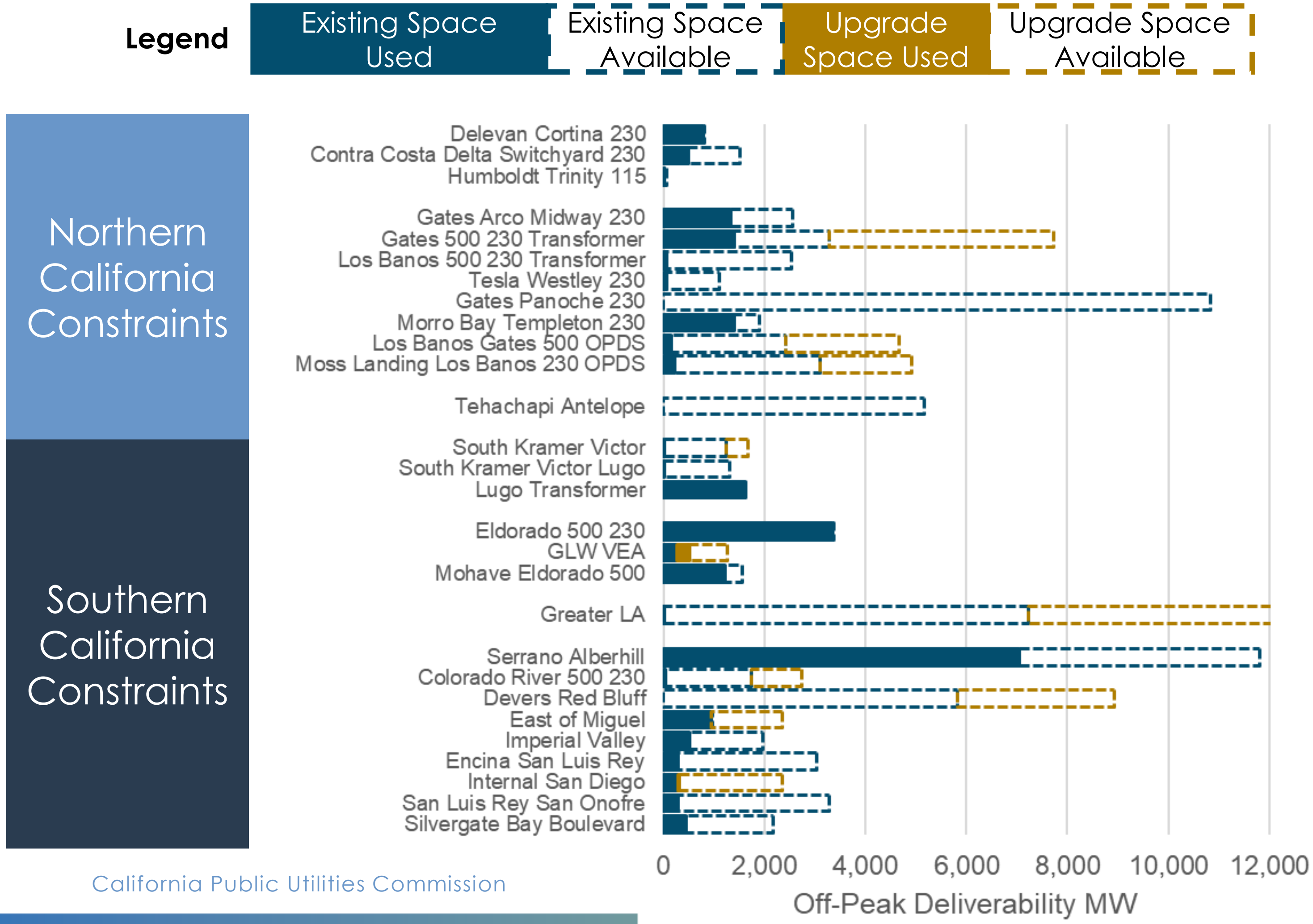


On-Peak Transmission utilization and upgrades: 2032 – 38 MMT w/ High Electrification (Managed Charging)



- Under the high electrification scenario transmission build in the 2032 timeframe is very similar because the effects of the electrification are greater beyond 2032
  - There are small increases in on-peak deliverability need in the Tehachapi antelope, Mohave Eldorado, and San Diego constraint areas
  - There is a slight decrease in on-peak deliverability need in the GLW VEA constraint area

Off-Peak Transmission utilization and upgrades: 2032 – 38 MMT w/ High Electrification (Managed Charging)



- Off peak generally less limiting than on-peak in 2032 timeframe
  - Battery deployment expands off-peak transmission capability (via charging)

Transmission upgrades (MW) annual summary – 38 MMT w/ High Electrification (Managed Charging)

Transmission Constraint	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Silvergate Bay Boulevard	-	-	-	-	-	-	-	-	-	1,833	1,833
San Luis Rey San Onofre	-	-	-	-	-	-	-	-	-	1,287	1,287
Internal San Diego	-	-	-	-	-	29	29	29	29	2,067	2,067
Encina San Luis Rey	-	-	-	-	-	-	-	-	-	134	134
Imperial Valley	-	-	-	-	-	-	-	-	-	-	-
East of Miguel	-	-	-	-	-	-	-	-	-	-	503
Devers Red Bluff	-	-	-	-	-	-	-	-	-	-	-
Colorado River 500 230	-	-	-	-	-	-	-	-	-	-	-
Serrano Alberhill	-	-	-	-	-	-	-	-	-	2,807	3,648
Greater LA	-	-	-	-	-	-	-	-	-	-	-
Mohave Eldorado 500	-	-	-	-	-	-	-	-	-	-	-
GLW VEA	-	-	-	-	-	221	221	221	221	221	221
Eldorado 500 230	-	-	-	-	-	-	-	-	-	400	400
Lugo Transformer							-	0	0	980	980
South Kramer Victor Lugo							-	-	-	-	-
South Kramer Victor							-	-	-	-	-
Tehachapi Antelope							0	0	0	2,700	2,700
Moss Landing Los Banos 230 OPDS							-	-	-	-	-
Los Banos Gates 500 OPDS							-	-	-	-	-
Morro Bay Templeton 230	-	-	-	-	-	-	-	-	-	-	-
Gates Panoche 230	-	-	-	-	-	-	-	-	-	-	378
Tesla Westley 230	-	-	-	-	-	-	-	-	-	-	-
Los Banos 500 230 Transformer	-	-	-	-	-	-	-	-	-	-	-
Gates 500 230 Transformer	-	-	-	-	-	-	-	-	-	-	-
Gates Arco Midway 230	-	-	-	-	-	-	-	277	277	277	277
Humboldt Trinity 115	-	-	-	-	-	-	-	-	-	-	21
Contra Costa Delta Switchyard 230	-	-	-	-	-	-	-	-	-	-	-
Delevan Cortina 230	-	-	-	-	-	-	-	-	41	41	2,838

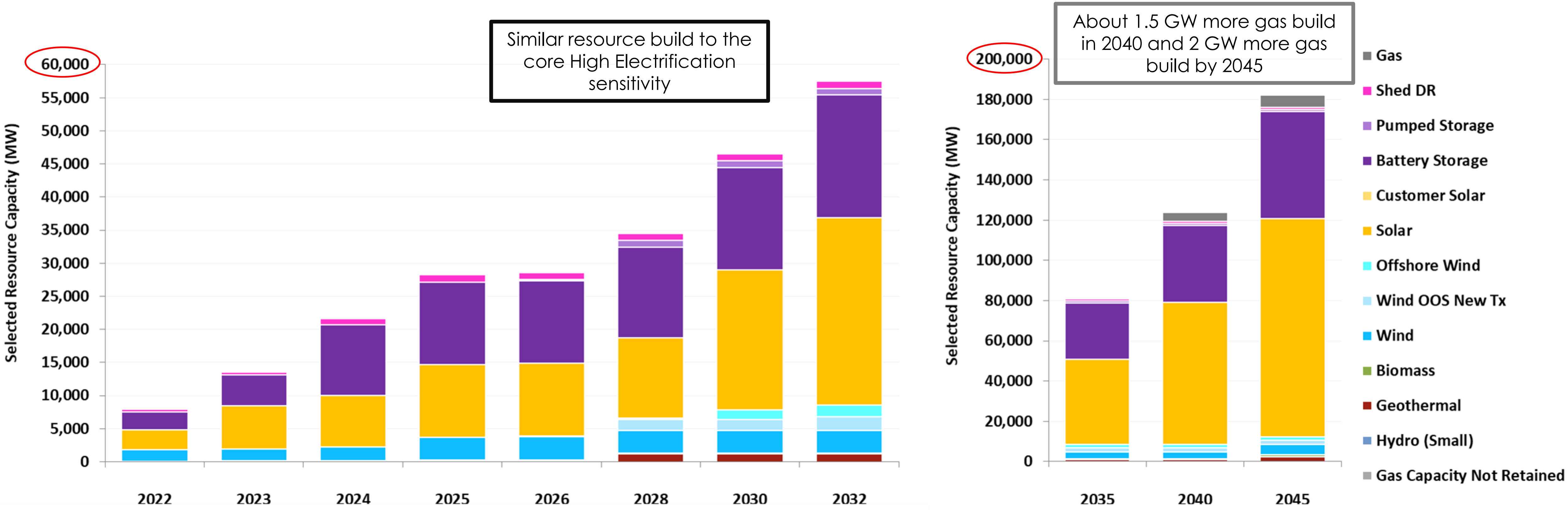
There are still few upgrades through 2032 even under the high electrification scenario

By 2040-5 most upgrades are selected, albeit with large uncertainty on transmission needs for incremental solar and batteries

38 MMT with High Electrification (Unmanaged Charging EV Profile)

With LSE Plans

Selected resources – 38 MMT with High Electrification (Unmanaged Charging)



Selected resources – 38 MMT with High Electrification (Unmanaged Charging)

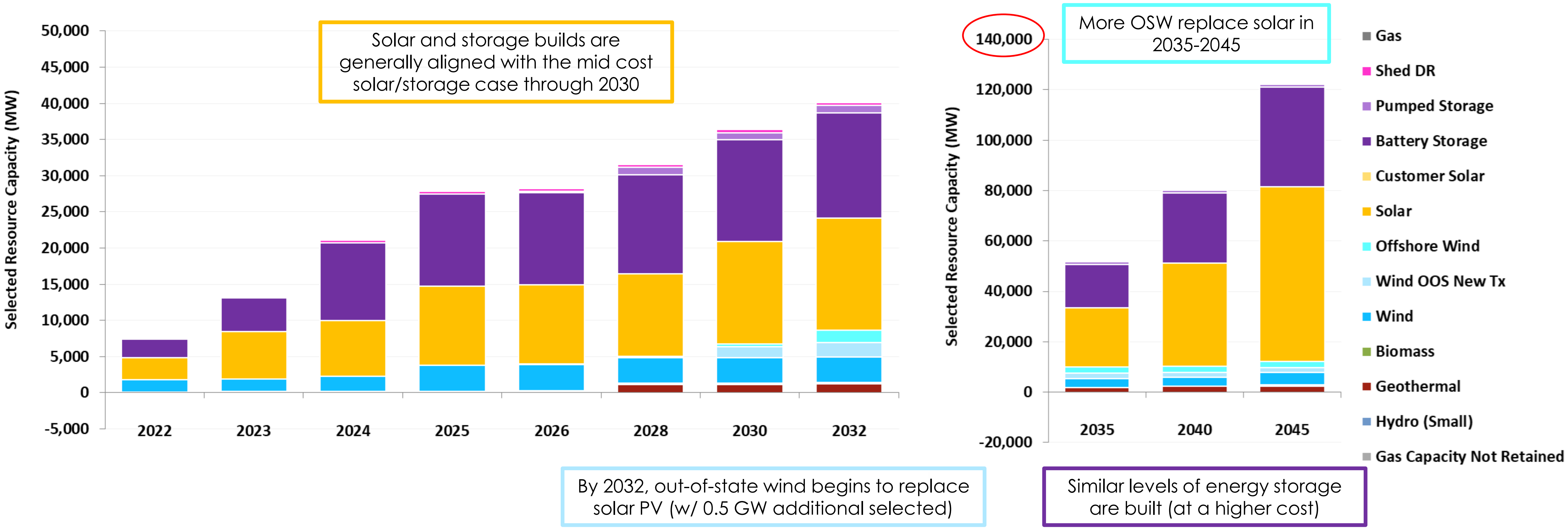
	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	*MW*	-	-	-	-	-	3	3	3	267	4,443	6,071
Biomass	*MW*	34	65	83	107	107	134	134	134	134	134	1,147
Geothermal	*MW*	14	114	114	114	184	1,162	1,162	1,162	1,162	1,162	2,332
Hydro (Small)	*MW*	-	-	-	-	-	-	-	-	-	-	-
Wind	*MW*	1,719	1,741	2,071	3,458	3,458	3,458	3,458	3,458	3,458	3,458	5,006
Wind OOS New Tx	*MW*	-	-	-	-	0	1,595	1,595	2,066	2,066	2,066	2,066
Offshore Wind	*MW*	-	-	-	-	120	195	1,431	1,708	1,728	1,728	1,749
Solar	*MW*	3,094	6,549	7,750	11,000	11,000	12,202	21,238	28,322	42,372	70,605	108,558
Customer Solar	*MW*	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	*MW*	2,630	4,604	10,687	12,436	12,436	13,675	15,410	18,543	27,744	38,225	52,961
Pumped Storage	*MW*	-	-	-	-	196	1,000	1,001	1,001	1,001	1,001	1,001
Shed DR	*MW*	444	444	889	1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111
Gas Capacity Not Retained	*MW*	-	-	-	-	-	-	-	-	-	-	-
Storage + DR	*MW*	**3,075**	**5,048**	**11,576**	**13,547**	**13,743**	**15,786**	**17,522**	**20,655**	**29,856**	**40,337**	**55,073**
Total Resources (Renewables + Storage + DR)	*MW*	**7,936**	**13,517**	**21,595**	**28,227**	**28,613**	**34,536**	**46,544**	**57,508**	**81,044**	**123,933**	**182,002**

- By 2032, the lack of managed charging results in about 2 GW more battery storage in this sensitivity relative to the High Electrification (core) sensitivity
  - New gas capacity additions of the order of 5 MW are within the margins of error for PSP RESOLVE model runs.
- In the 2040-2045 period, 1.5 GW – 2 GW more gas resources are also added relative to the High Electrification (core) sensitivity, likely due to an increased peak impact from the EV loads in 2045 without any managed charging.

38 MMT High Solar + Storage Costs

With LSE Plans

Selected resources – 38 MMT w/ high solar PV and battery storage costs

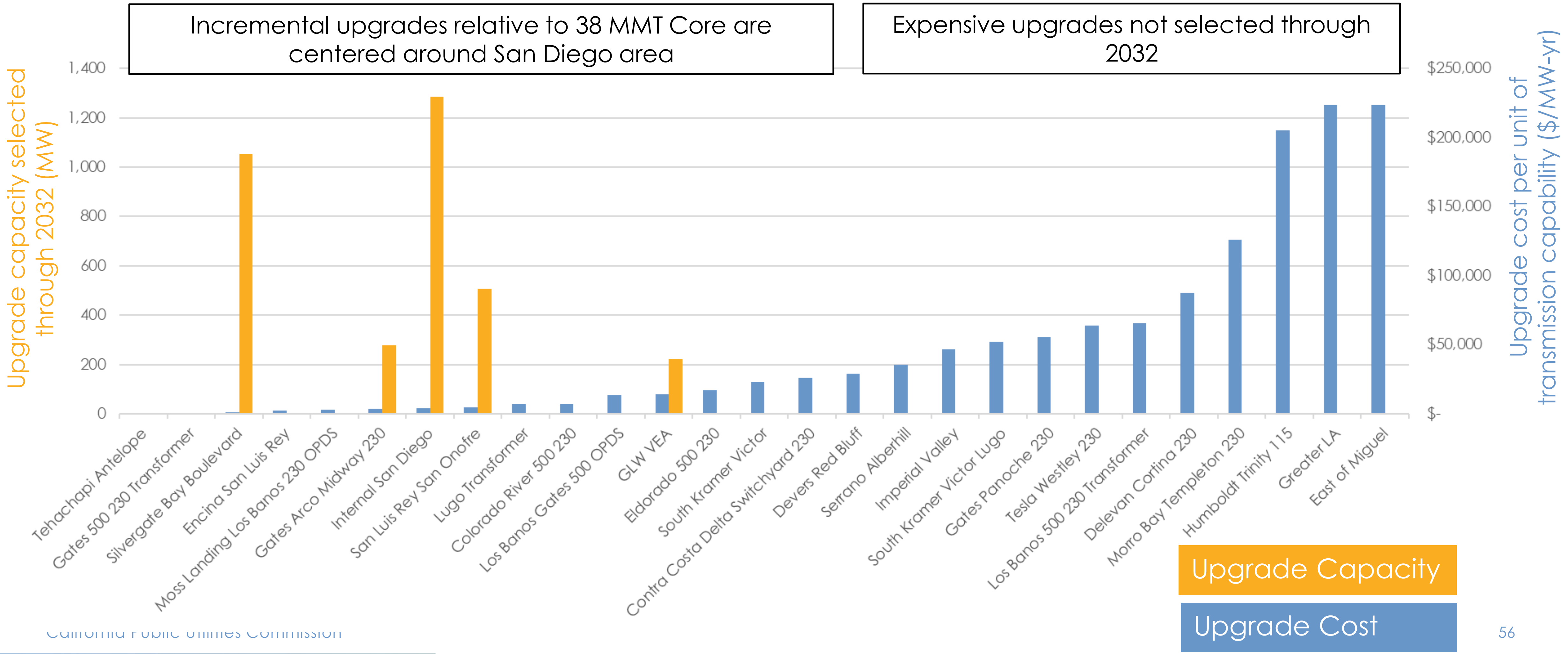


Selected resources – 38 MMT with high solar PV and battery storage costs

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	1	1	1	1	1	1
Biomass	MW	34	65	83	107	107	134	134	134	134	134	462
Geothermal	MW	14	114	114	114	184	1,160	1,160	1,238	1,805	2,298	2,332
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553	3,553	3,553	5,053
Wind OOS New Tx	MW	-	-	-	-	0	0	1,500	1,970	1,970	1,970	1,970
Offshore Wind	MW	-	-	-	-	120	195	358	1,708	2,441	2,441	2,441
Solar	MW	3,094	6,549	7,750	11,000	11,000	11,397	14,171	15,543	23,463	40,727	69,186
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,565	4,603	10,699	12,652	12,652	13,708	14,056	14,562	17,276	27,926	39,628
Pumped Storage	MW	-	-	-	-	196	1,000	1,001	1,001	1,001	1,001	1,001
Shed DR	MW	151	151	353	441	441	441	441	441	441	441	441
Gas Capacity Not Retained	MW	-	-	-	-	-	-	-	(0)	(152)	(393)	(393)
Storage + DR	MW	**2,716**	**4,755**	**11,051**	**13,093**	**13,289**	**15,149**	**15,497**	**16,003**	**18,718**	**29,368**	**41,069**
Total Resources (Renewables + Storage + DR)	MW	**7,577**	**13,224**	**21,070**	**27,867**	**28,254**	**31,589**	**36,374**	**40,150**	**51,932**	**80,099**	**122,121**

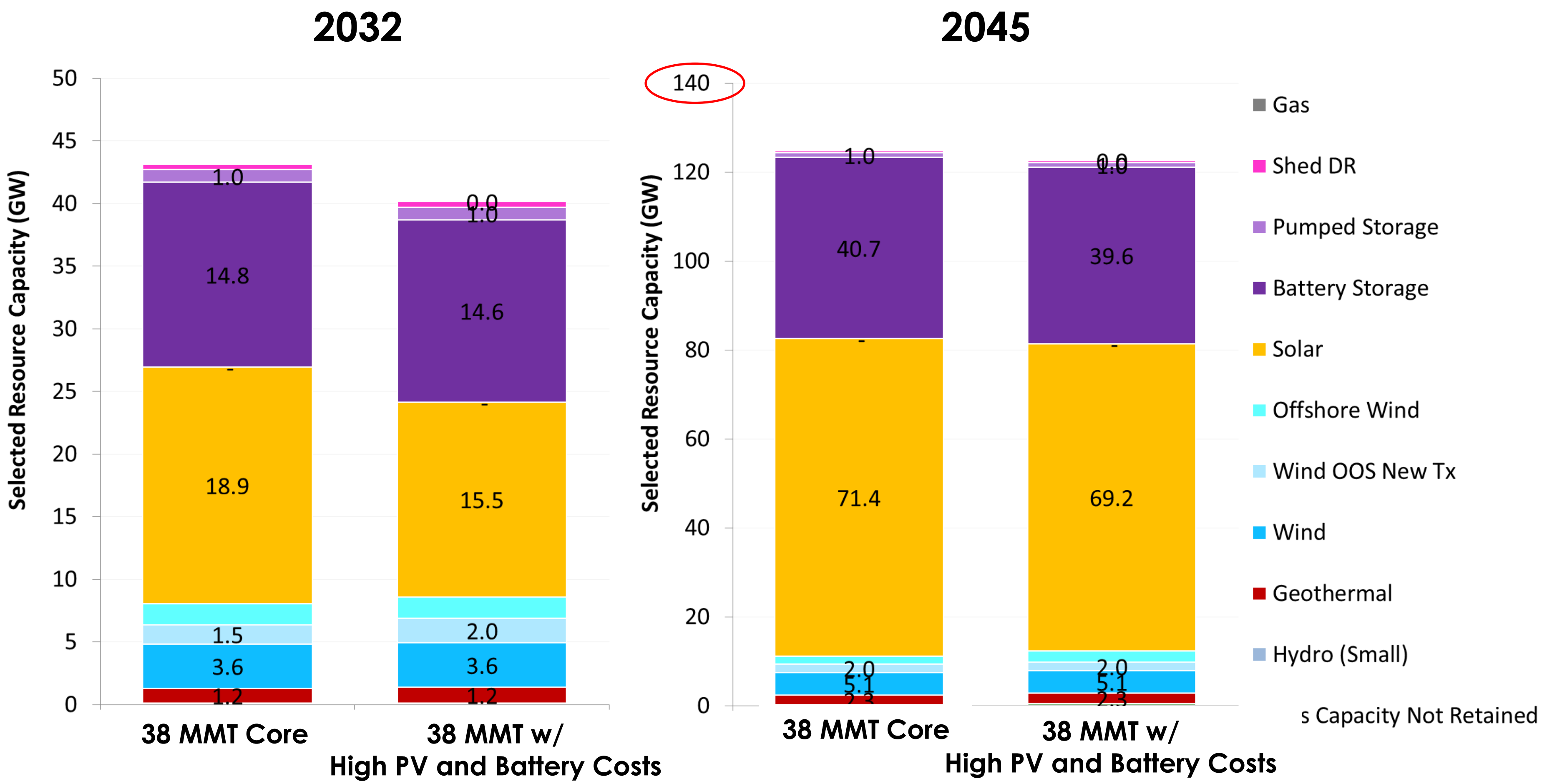
- High solar and battery buildout is relatively insensitive to solar and battery storage costs until 2032 – 2040, when additional out-of-state wind and offshore wind is selected in place of solar and battery storage
  - New gas capacity additions of the order of 5 MW are within the margins of error for PSP RESOLVE model runs. Transmission upgrades are triggered largely to accommodate more OOS wind and to offset the reduced expansion of the off-peak transmission capability due to reduced battery storage selection
- Larger upgrades in the Internal San Diego constraint, and two new upgrades at the Silvergate Bay Boulevard constraint and the San Luis Rey San Onofre constraint

Transmission upgrades 2032
38 MMT with high solar PV and battery storage costs



38 MMT Core vs. High solar PV and battery costs

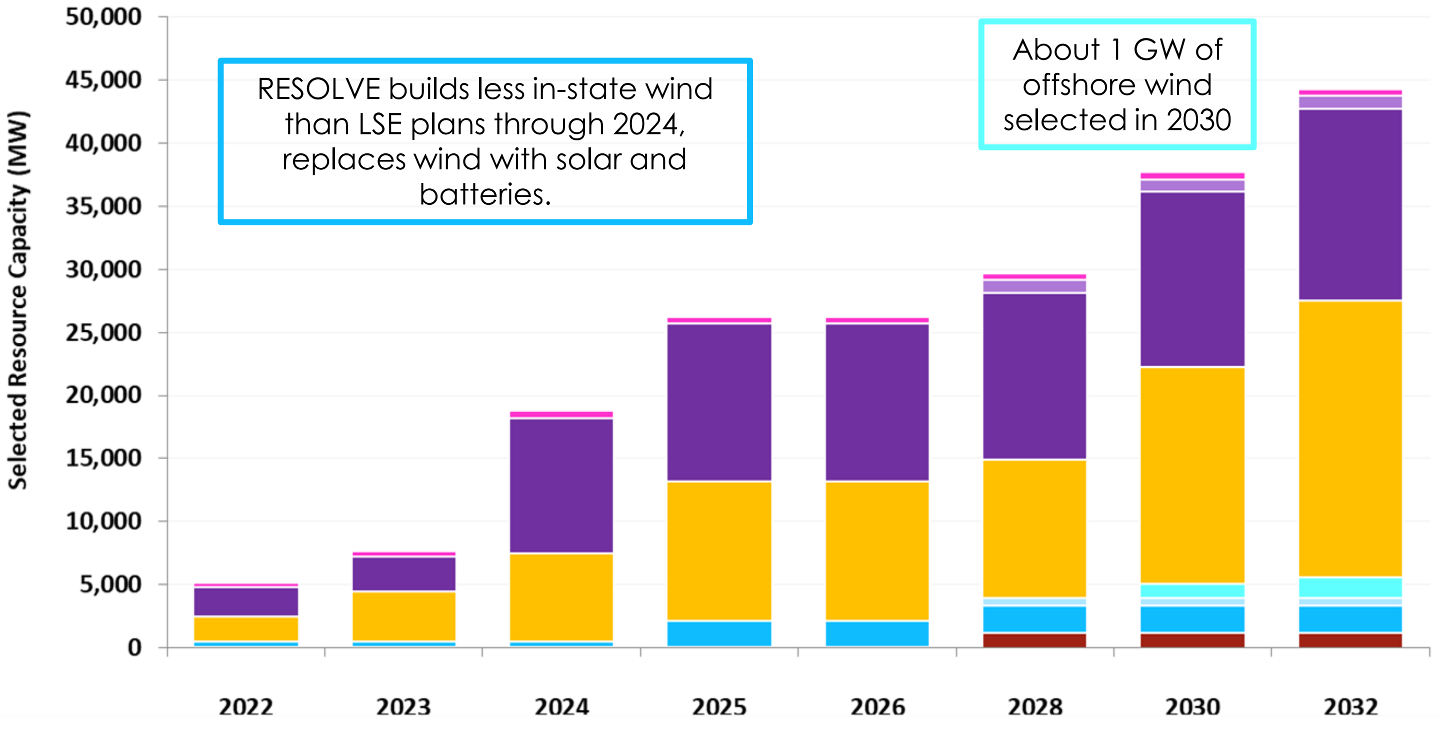
- High solar PV and battery storage costs leads to similar resource builds with less solar and a little more resource diversity

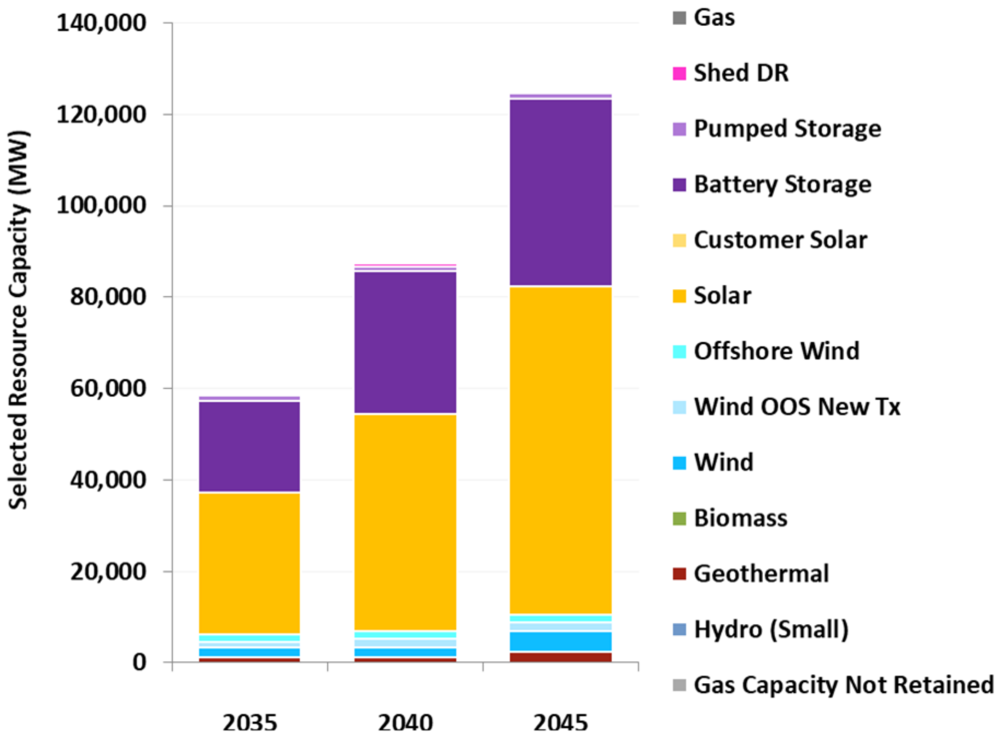


38 MMT No LSE Plans

Without any LSE Plans

Selected resources – 38 MMT without LSE Plans





Out-of-state wind on new transmission not selected in large amounts until ~2040. 605 MW selected in 2028

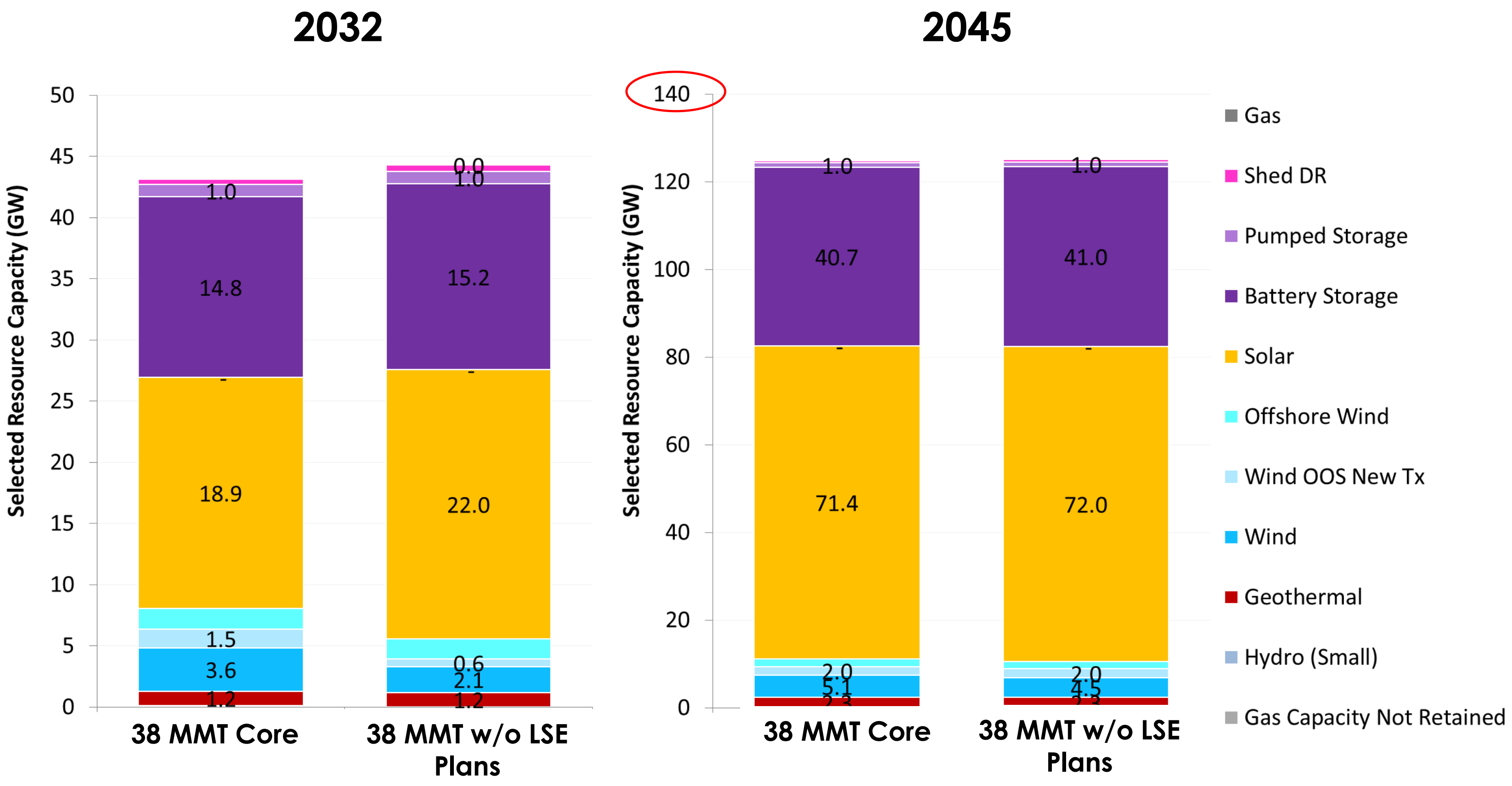
Selected resources – 38 MMT without LSE Plans

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	*MW*	-	-	-	-	-	0	0	0	0	0	0
Biomass	*MW*	15	15	15	15	15	15	15	15	15	15	15
Geothermal	*MW*	14	14	14	14	14	1,175	1,175	1,175	1,175	1,175	2,332
Hydro (Small)	*MW*	-	-	-	-	-	-	-	-	-	-	-
Wind	*MW*	431	431	431	2,118	2,118	2,118	2,118	2,118	2,118	2,118	4,519
Wind OOS New Tx	*MW*	-	-	-	-	-	605	605	605	1,191	1,970	1,970
Offshore Wind	*MW*	-	-	-	-	-	-	1,177	1,662	1,662	1,662	1,662
Solar	*MW*	2,000	4,000	7,000	11,000	11,000	11,000	17,165	21,995	31,111	47,533	71,958
Customer Solar	*MW*	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	*MW*	2,315	2,781	10,761	12,575	12,575	13,256	13,907	15,184	20,119	31,277	41,045
Pumped Storage	*MW*	-	-	-	-	0	1,000	1,000	1,000	1,000	1,000	1,000
Shed DR	*MW*	362	450	538	538	538	538	538	538	538	538	538
Gas Capacity Not Retained	*MW*	-	-	-	-	-	-	-	-	-	-	-
Storage + DR	*MW*	**2,676**	**3,231**	**11,299**	**13,113**	**13,113**	**14,794**	**15,445**	**16,722**	**21,657**	**32,815**	**42,583**
Total Resources (Renewables + Storage + DR)	*MW*	**5,136**	**7,691**	**18,759**	**26,260**	**26,260**	**29,708**	**37,701**	**44,293**	**58,930**	**87,289**	**125,040**

- Without the LSE plans about 2.6 GW of total wind is selected by 2032, compared to 5.1 GW with the LSE plans in the 38 MMT Core scenario

38 MMT Core vs. Without LSE Plans

- Less wind and OOS wind are selected by 2032
  - Replaced largely by solar PV, causing an a slightly larger total selected resource relative to the 38 MMT Core
- By 2045 the selected portfolios are largely similar with a little less wind and a little more solar PV



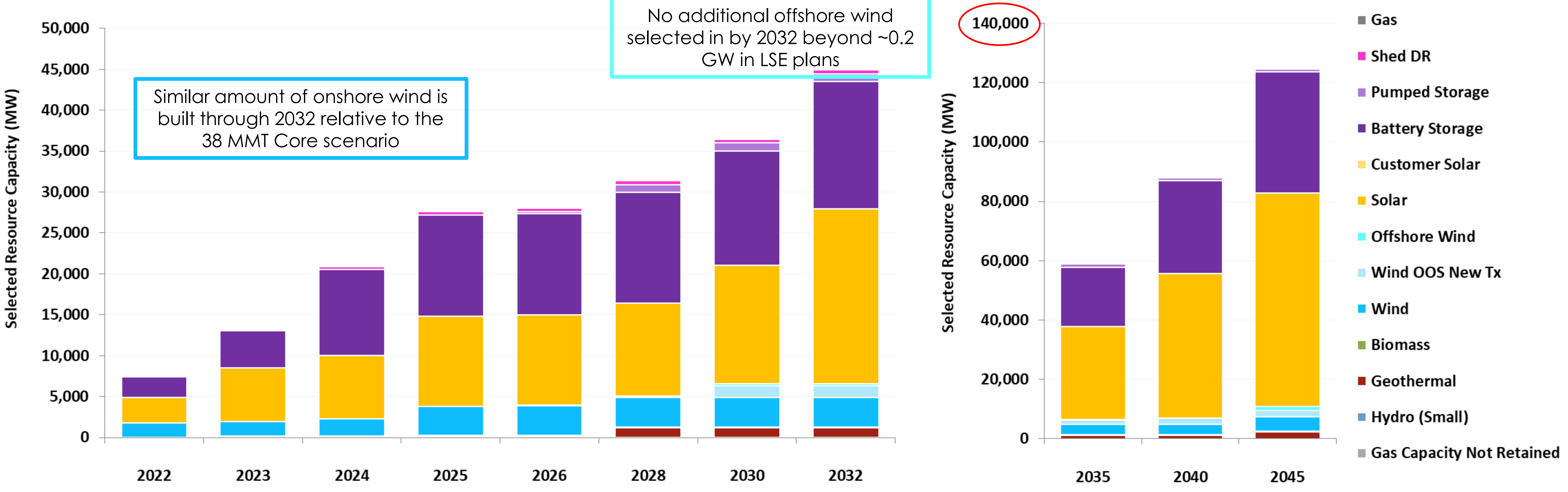
38 MMT with No Offshore Wind ITC Extension

With LSE Plans

Selected resources – 38 MMT with No Offshore Wind ITC Extension

No additional offshore wind selected in by 2032 beyond ~0.2 GW in LSE plans

Similar amount of onshore wind is built through 2032 relative to the 38 MMT Core scenario



Similar amounts of out-of-state wind on new transmission selected as in the 38 MMT Core scenario through 2045; maxes out at ~2 GW

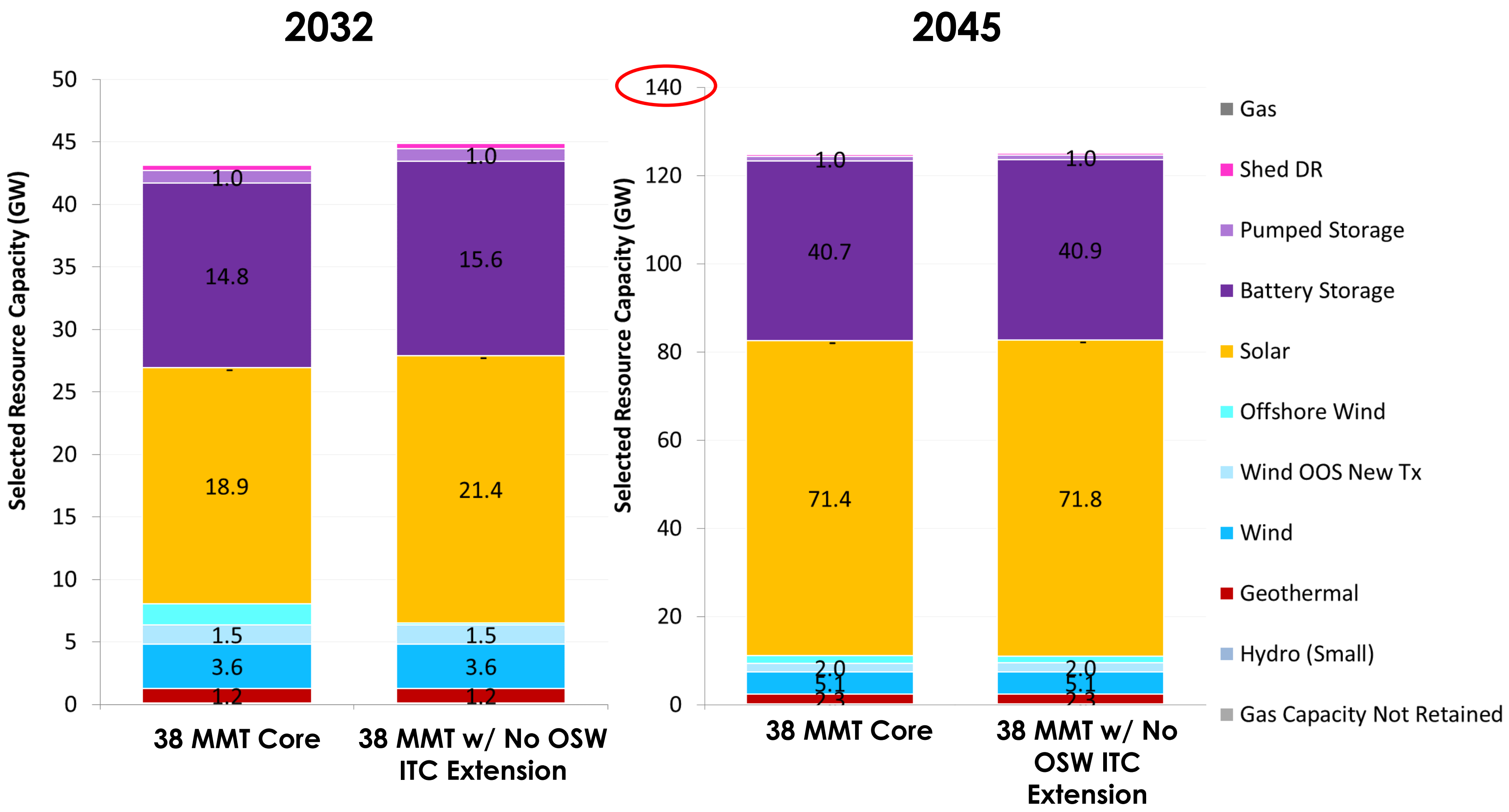
Selected resources – 38 MMT with No Offshore Wind ITC Extension

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	0	0	0	0	0	30
Biomass	MW	34	65	83	107	107	134	134	134	134	134	134
Geothermal	MW	14	114	114	114	184	1,160	1,160	1,160	1,160	1,160	2,273
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553	3,553	3,553	5,053
Wind OOS New Tx	MW	-	-	-	-	0	0	1,500	1,500	1,500	1,970	1,970
Offshore Wind	MW	-	-	-	-	120	195	195	195	195	195	1,539
Solar	MW	3,094	6,549	7,750	11,000	11,000	11,397	14,491	21,363	31,217	48,654	71,754
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,565	4,604	10,505	12,415	12,415	13,472	13,966	15,551	20,065	31,296	40,893
Pumped Storage	MW	-	-	-	-	196	1,000	1,000	1,000	1,000	1,000	1,000
Shed DR	MW	151	151	353	441	441	441	441	441	441	441	441
Gas Capacity Not Retained	MW	-	-	-	-	-	-	*(0)*	(0)	(0)	(0)	(0)
Storage + DR	MW	**2,716**	**4,755**	**10,858**	**12,856**	**13,052**	**14,913**	**15,407**	**16,992**	**21,506**	**32,737**	**42,334**
Total Resources (Renewables + Storage + DR)	MW	**7,577**	**13,224**	**20,876**	**27,631**	**28,017**	**31,353**	**36,441**	**44,898**	**59,265**	**88,404**	**125,087**

- Without access to the offshore wind ITC extension via safe harbor, offshore wind is only selected in 2045 (beyond the LSE plans amount)
- The amount of out-of-state wind is similar to the 38 MMT Core scenario, further underscoring the deduction that this resource is likely maxed out at 2 GW due to transmission constraints

38 MMT Core vs. with No Offshore Wind ITC Extension

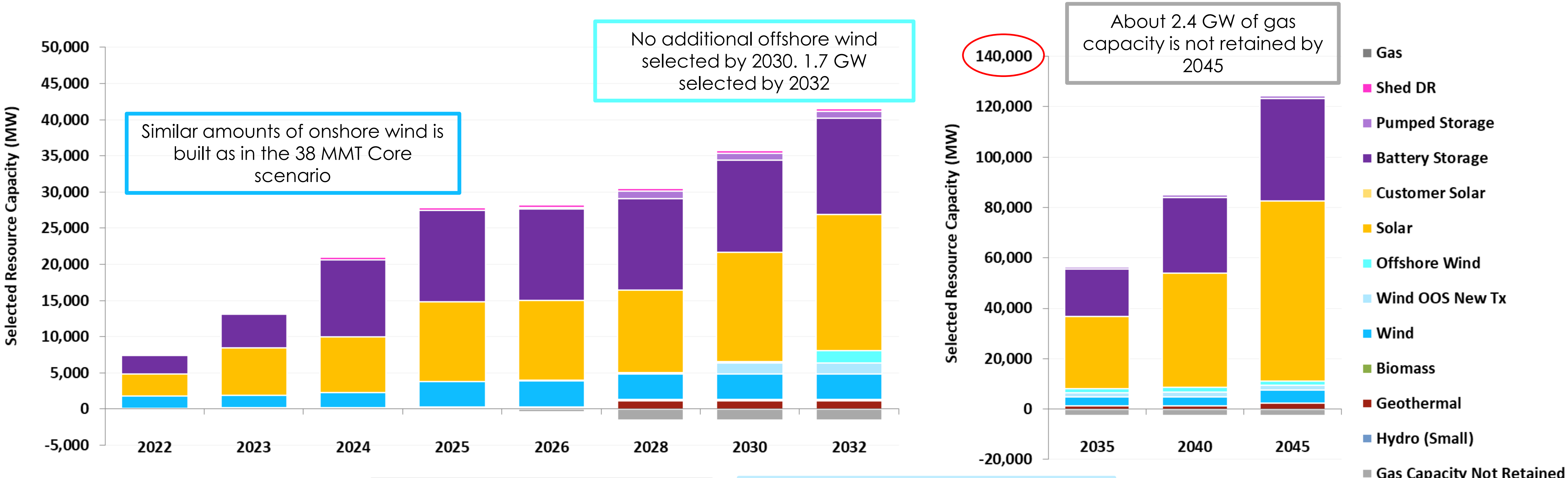
- Significantly less offshore wind is selected by 2032
  - Replaced largely by solar PV and batteries
- By 2045 the selected portfolios are largely similar



38 MMT with MTR Non-Persistence

With LSE Plans

Selected resources – 38 MMT with MTR Non-Persistence



~300 MW of gas capacity is not retained starting in 2026; 1.5 GW by 2032

Similar amounts of out-of-state wind on new transmission selected as in the 38 MMT core scenario

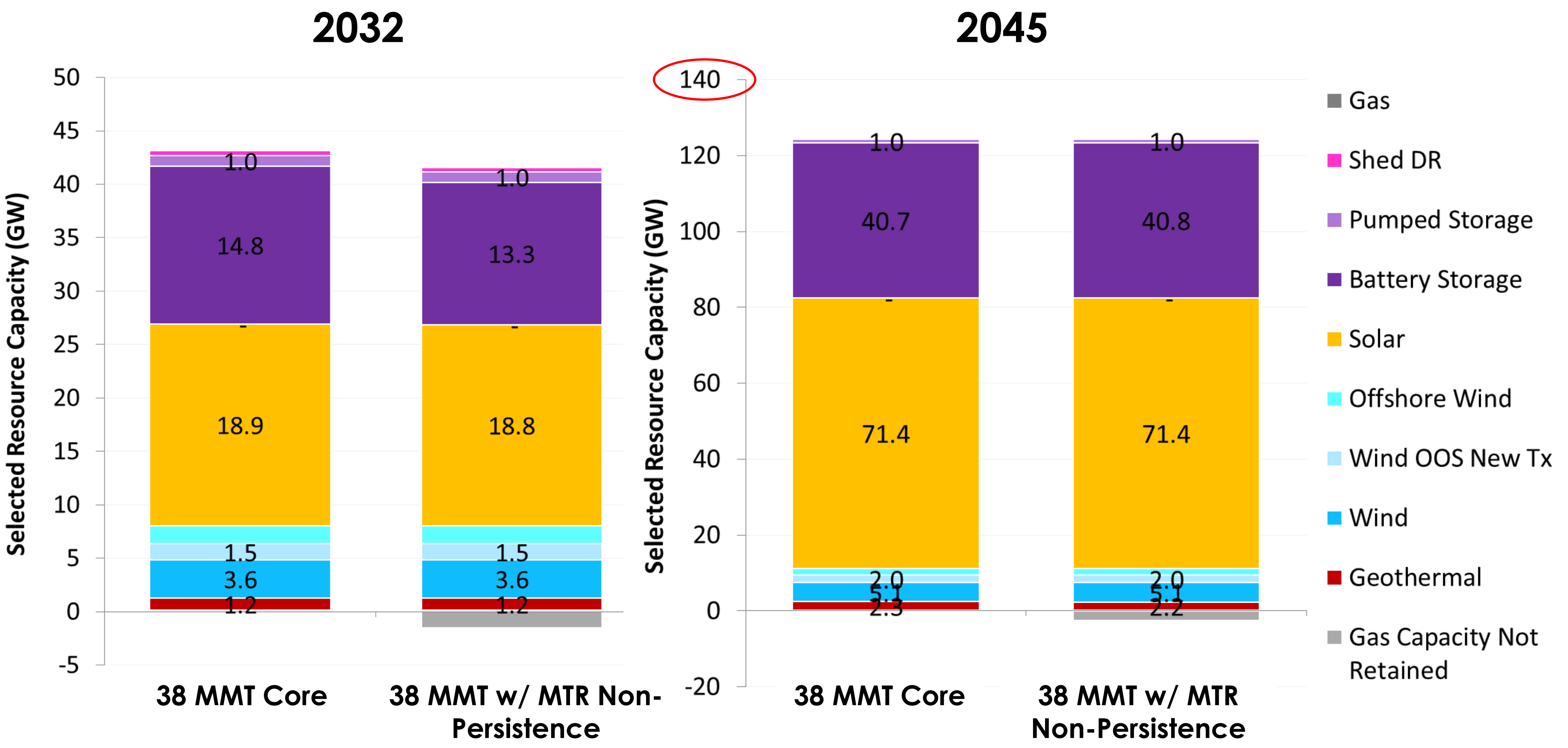
Selected resources – 38 MMT with MTR Non-Persistence

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	0	0	0	0	0	0
Biomass	MW	34	65	83	134	134	134	134	134	134	134	134
Geothermal	MW	14	114	114	114	184	1,160	1,160	1,160	1,160	1,160	2,244
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553	3,553	3,553	5,053
Wind OOS New Tx	MW	-	-	-	-	0	0	1,500	1,500	1,500	1,970	1,970
Offshore Wind	MW	-	-	-	-	120	195	195	1,708	1,728	1,728	1,728
Solar	MW	3,094	6,549	7,750	11,000	11,000	11,397	15,162	18,809	28,675	45,319	71,430
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,565	4,604	10,629	12,677	12,677	12,677	12,677	13,323	18,718	30,076	40,783
Pumped Storage	MW	-	-	-	-	196	1,000	1,000	1,000	1,000	1,000	1,000
Shed DR	MW	151	151	353	353	353	353	353	353	353	353	353
Gas Capacity Not Retained	MW	-	-	-	-	*(341)*	*(1,487)*	*(1,487)*	(1,539)	(2,447)	(2,447)	(2,447)
Storage + DR	MW	**2,716**	**4,755**	**10,982**	**13,029**	**13,225**	**14,029**	**14,030**	**14,676**	**20,071**	**31,429**	**42,136**
Total Resources (Renewables + Storage + DR)	MW	**7,577**	**13,224**	**21,000**	**27,831**	**27,876**	**28,982**	**34,247**	**40,001**	**54,375**	**82,847**	**122,249**

- Without the continuation of the D.21-06-035 requirements beyond 2026, about 1.5 GW of gas capacity is not retained starting in 2028 and growing to 2.4 GW by 2045
  - Other portfolio selections are similar to the 38 MMT Core scenario

38 MMT Core vs. MTR Non-Persistence

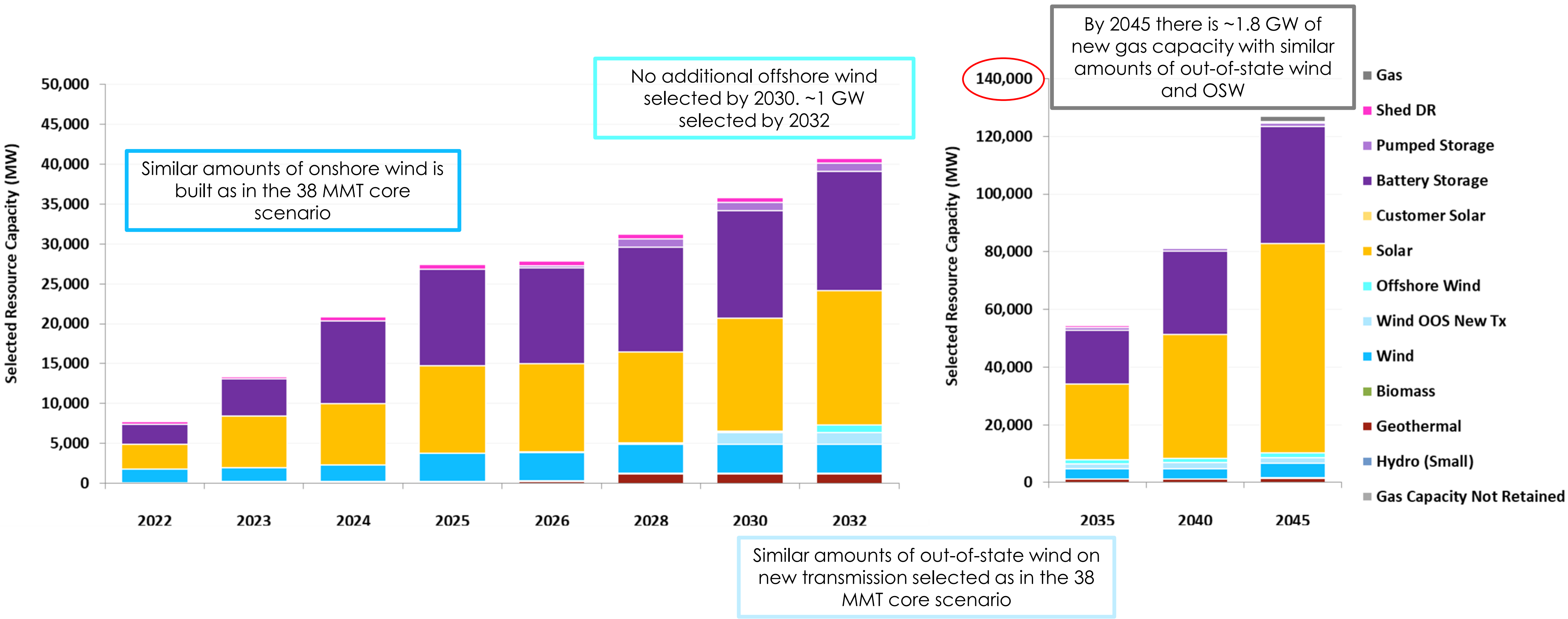
- The selected portfolio is very similar between the two scenarios
- Discontinuing the D.21-06-035 requirements allows for not retaining some gas capacity



38 MMT with 2020 IEPR

With LSE Plans

Selected resources – 38 MMT with 2020 IEPR



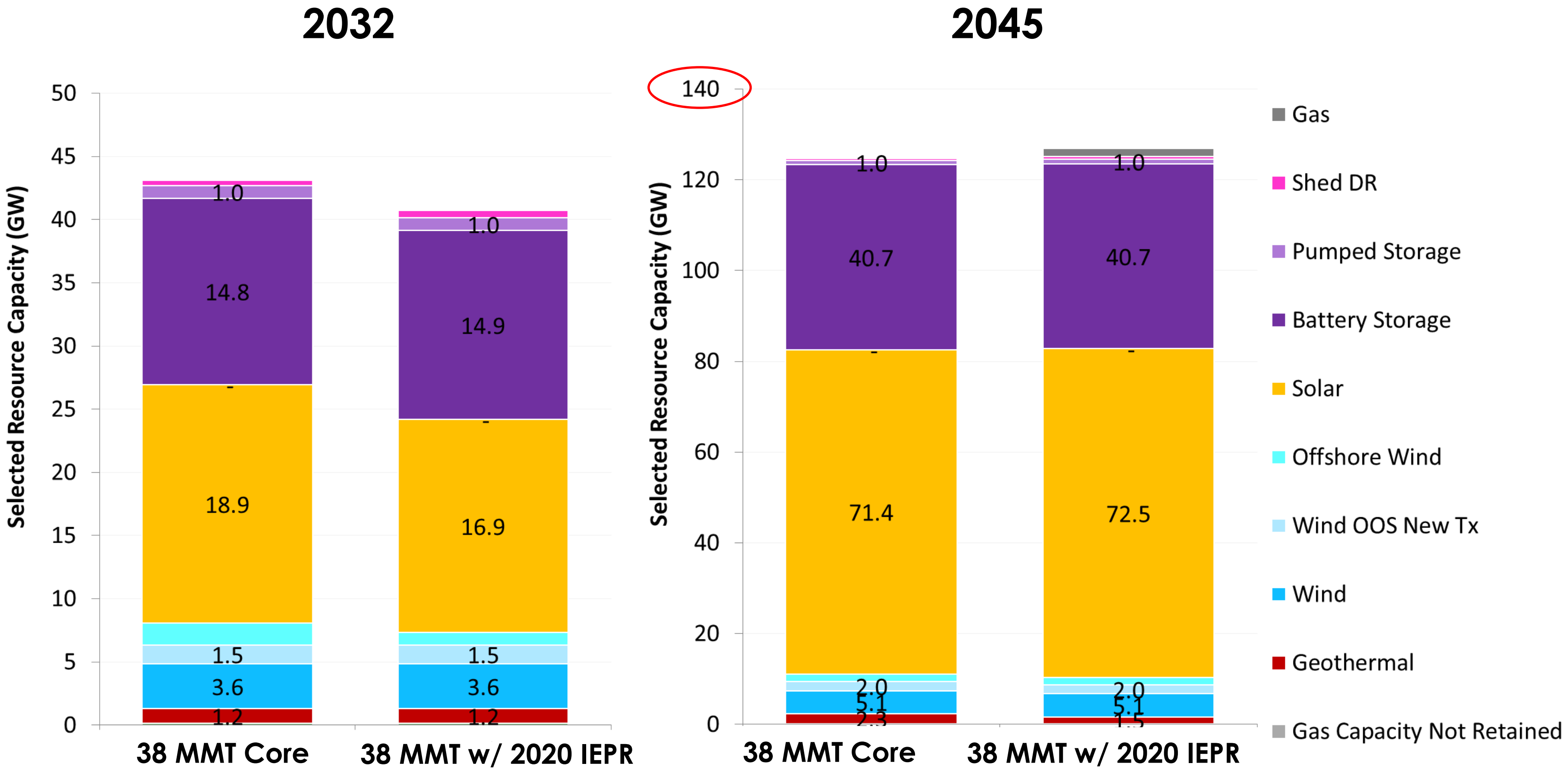
Selected resources – 38 MMT with 2020 IEPR

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	*MW*	-	-	-	-	-	1	1	1	1	1	1,801
Biomass	*MW*	34	65	83	107	107	134	134	134	134	134	134
Geothermal	*MW*	14	114	114	114	184	1,160	1,160	1,160	1,160	1,160	1,521
Hydro (Small)	*MW*	-	-	-	-	-	-	-	-	-	-	-
Wind	*MW*	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553	3,553	3,553	5,053
Wind OOS New Tx	*MW*	-	-	-	-	0	0	1,500	1,500	1,500	1,970	1,970
Offshore Wind	*MW*	-	-	-	-	120	195	195	964	1,613	1,613	1,613
Solar	*MW*	3,094	6,549	7,750	11,000	11,000	11,397	14,171	16,873	26,177	42,939	72,482
Customer Solar	*MW*	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	*MW*	2,571	4,604	10,349	12,082	12,082	13,202	13,466	14,944	18,626	28,724	40,749
Pumped Storage	*MW*	-	-	-	-	196	1,000	1,001	1,001	1,001	1,001	1,001
Shed DR	*MW*	299	299	529	617	617	617	617	617	617	617	617
Gas Capacity Not Retained	*MW*	-	-	-	-	-	-	-	-	-	-	-
Storage + DR	*MW*	**2,870**	**4,903**	**10,878**	**12,699**	**12,895**	**14,819**	**15,084**	**16,561**	**20,244**	**30,342**	**42,366**
Total Resources (Renewables + Storage + DR)	*MW*	**7,730**	**13,372**	**20,896**	**27,474**	**27,860**	**31,259**	**35,798**	**40,746**	**54,382**	**81,712**	**126,942**

- By 2032 there is about 1 GW less solar PV resources and about 700 MW less of offshore wind resources relative to the 38 MMT Core scenario
- By 2045 there's about 1.8 GW more new gas resources in this sensitivity and 700 MW less of geothermal relative to the 38 MMT Core scenario

38 MMT Core vs. 38 MMT with 2020 IEPR

- The selected portfolio is very similar between the two scenarios
  - ~2 GW less solar is selected in the 2020 IEPR sensitivity by 2032
  - ~1 GW of new gas capacity is added by 2045 in the 2020 IEPR sensitivity



38 MMT with 2020 IEPR + 2020 IEPR High EV (Managed Charging EV Profile)

With LSE Plans

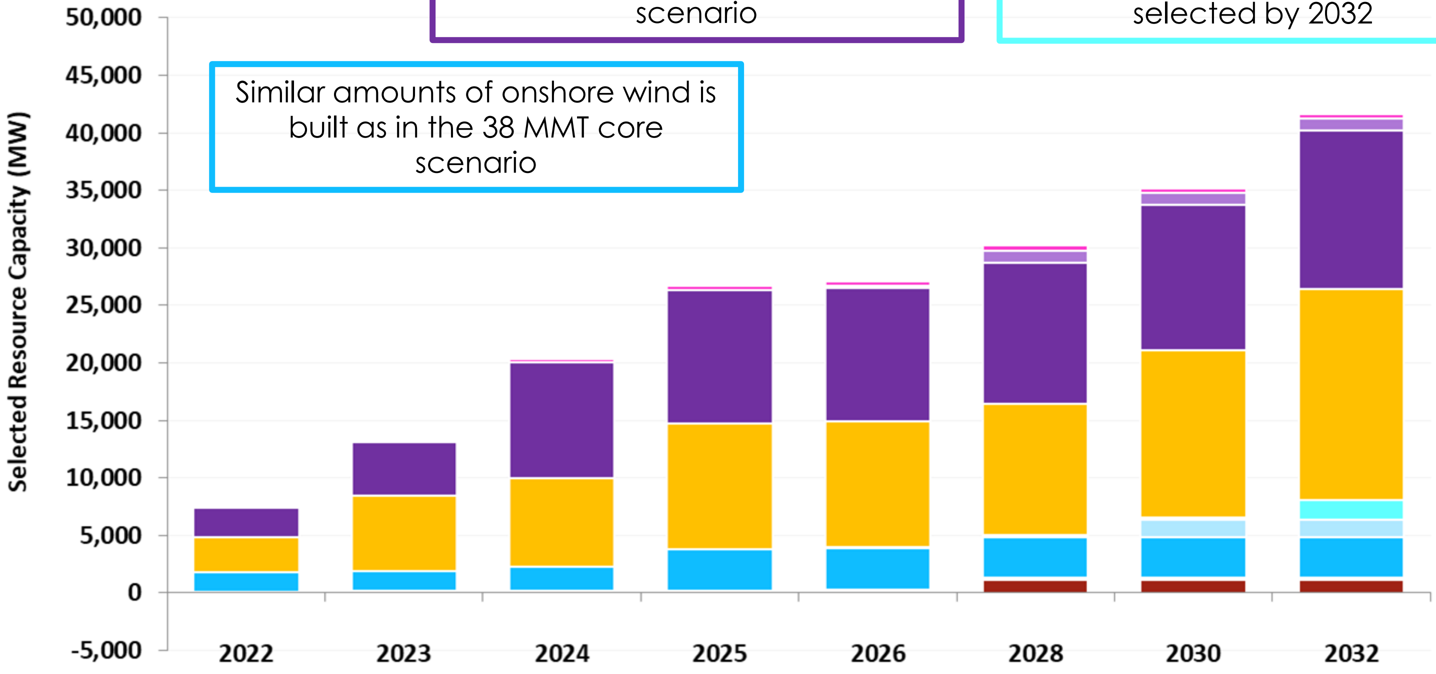
Selected resources – 38 MMT with 2020 IEPR + 2020 IEPR High EV (Managed Charging)

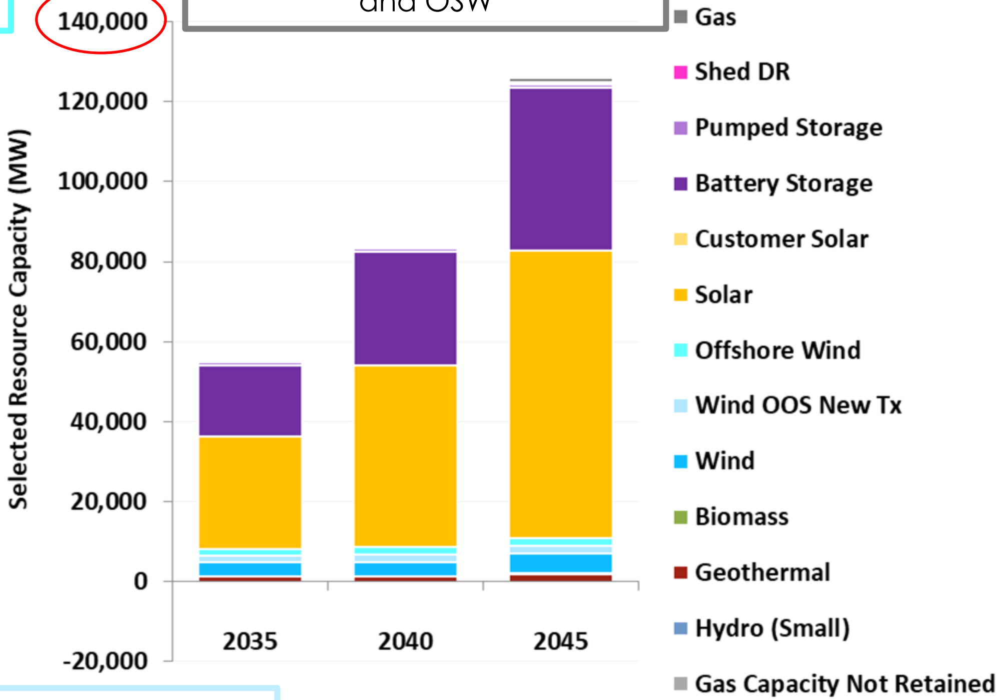
Similar amounts of batteries by 2032 is built as in the 38 MMT core scenario

No additional offshore wind selected by 2030. 1.7 GW selected by 2032

By 2045 there is ~1 GW of new gas capacity with similar amounts of out-of-state wind and OSW

Similar amounts of onshore wind is built as in the 38 MMT core scenario





Similar amounts of solar by 2032 is built as in the 38 MMT core scenario

Similar amounts of out-of-state wind on new transmission selected as in the 38 MMT core scenario

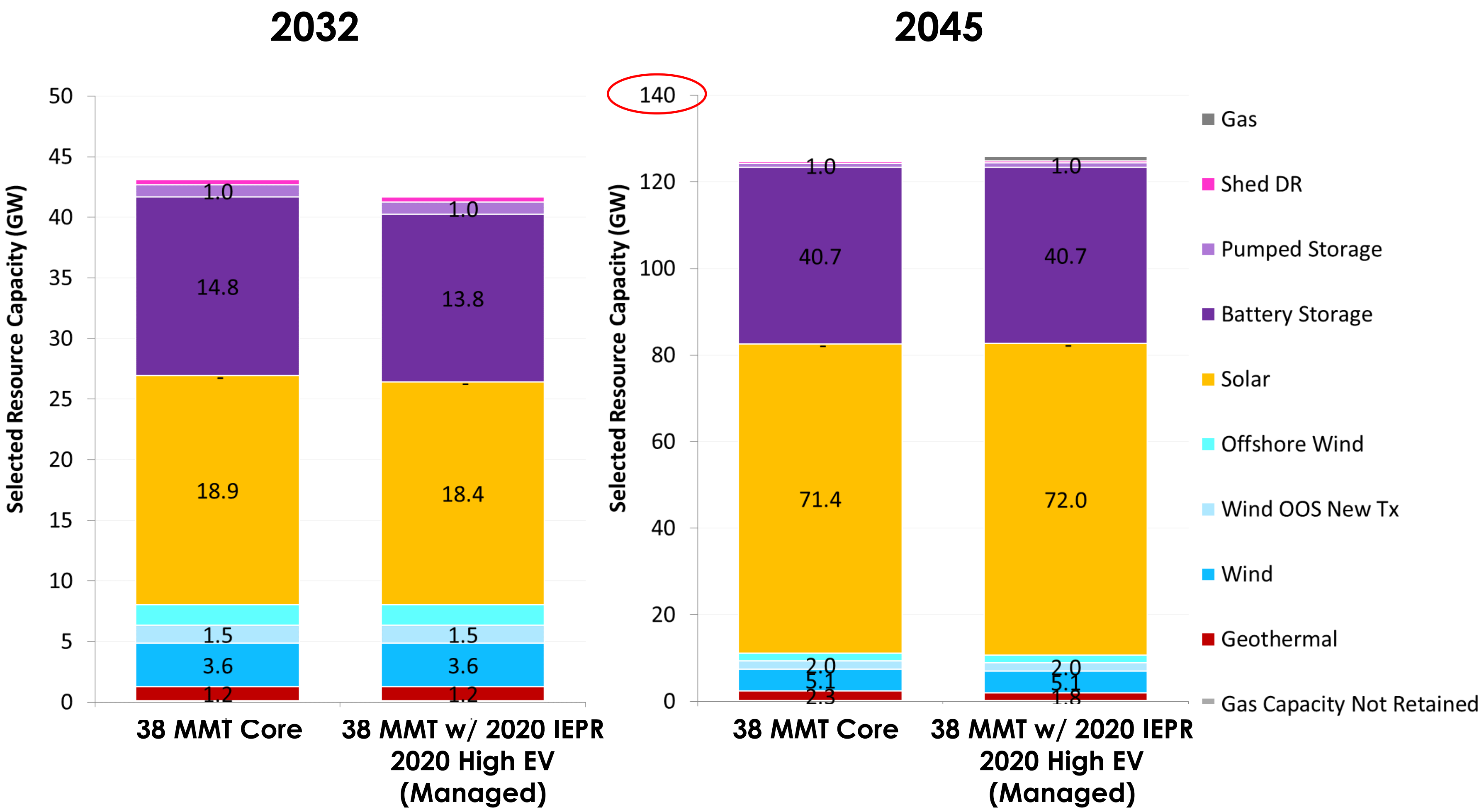
Selected resources – 38 MMT with 2020 IEPR + 2020 IEPR High EV (Managed Charging)

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	1	1	1	1	1	980
Biomass	MW	34	65	83	107	107	134	134	134	134	134	134
Geothermal	MW	14	114	114	114	184	1,160	1,160	1,160	1,160	1,160	1,823
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553	3,553	3,553	5,053
Wind OOS New Tx	MW	-	-	-	-	0	0	1,500	1,500	1,500	1,970	1,970
Offshore Wind	MW	-	-	-	-	120	195	195	1,708	1,728	1,728	1,728
Solar	MW	3,094	6,549	7,750	11,000	11,000	11,397	14,589	18,373	28,259	45,349	71,976
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,565	4,604	10,012	11,528	11,528	12,303	12,621	13,814	17,610	28,459	40,737
Pumped Storage	MW	-	-	-	-	196	1,000	1,000	1,000	1,000	1,000	1,000
Shed DR	MW	151	151	353	436	436	436	436	436	436	436	436
Gas Capacity Not Retained	MW	-	-	-	-	-	-	-	-	(0)	(0)	(0)
Storage + DR	MW	**2,716**	**4,755**	**10,365**	**11,964**	**12,160**	**13,739**	**14,057**	**15,251**	**19,046**	**29,896**	**42,174**
Total Resources (Renewables + Storage + DR)	MW	**7,577**	**13,224**	**20,383**	**26,739**	**27,125**	**30,179**	**35,190**	**41,679**	**55,381**	**83,791**	**125,839**

- By 2032 there is about 500 MW less solar PV resources and about 1 GW less of battery storage resources relative to the 38 MMT Core scenario
- By 2045 there's about 950 MW more new gas resources in this sensitivity and 430 MW less of geothermal relative to the 38 MMT Core scenario

38 MMT Core vs. 38 MMT with 2020 IEPR + 2020 IEPR High EV (Managed Charging)

- The selected portfolio is very similar between the two scenarios
  - ~500 MW less solar is selected in the 2020 IEPR + 2020 IEPR High EV sensitivity by 2032
  - ~1 GW of new gas capacity is added by 2045 in the 2020 IEPR + 2020 IEPR High EV sensitivity



38 MMT with 2020 IEPR + 2020 IEPR High EV (Unmanaged Charging EV Profile)

With LSE Plans

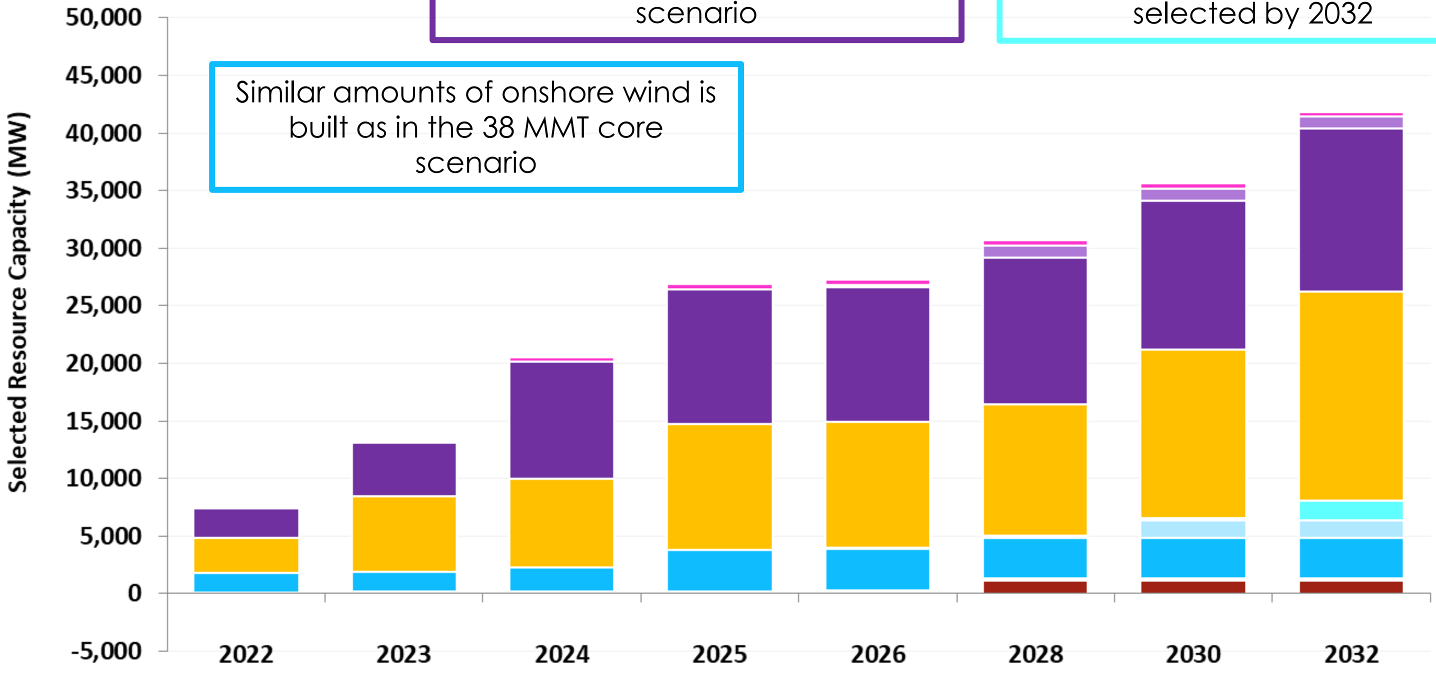
Selected resources – 38 MMT with 2020 IEPR + 2020 IEPR High EV (Unmanaged Charging)

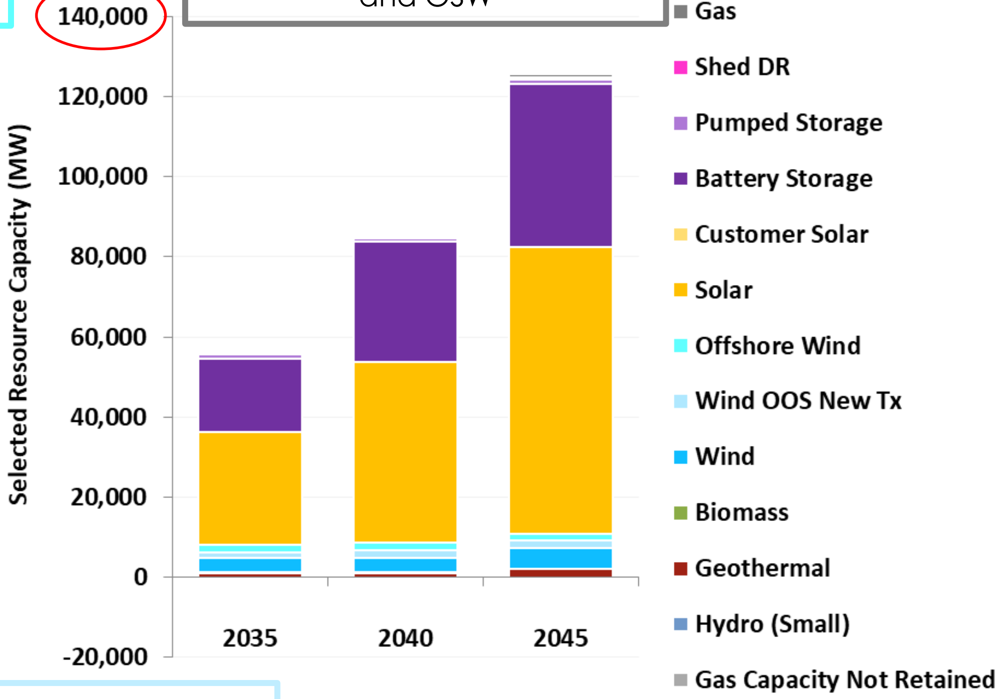
Similar amounts of batteries by 2032 is built as in the 38 MMT core scenario

No additional offshore wind selected by 2030. 1.7 GW selected by 2032

By 2045 there is ~ 1GW of new gas capacity with similar amounts of out-of-state wind and OSW

Similar amounts of onshore wind is built as in the 38 MMT core scenario





Similar amounts of solar by 2032 is built as in the 38 MMT core scenario

Similar amounts of out-of-state wind on new transmission selected as in the 38 MMT core scenario

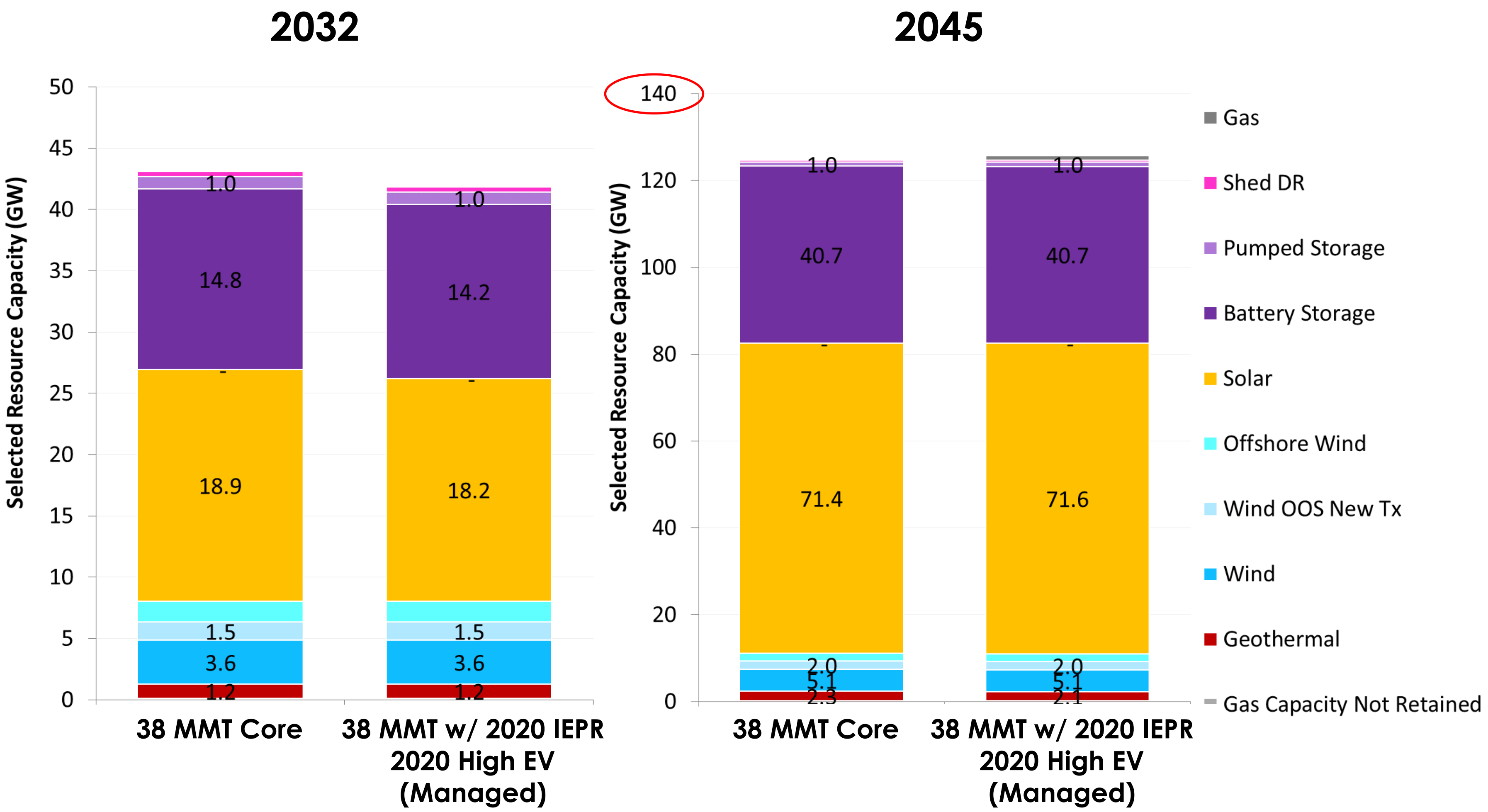
Selected resources – 38 MMT with 2020 IEPR + 2020 IEPR High EV (Unmanaged Charging)

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	1	1	1	1	1	1,009
Biomass	MW	34	65	83	107	107	134	134	134	134	134	134
Geothermal	MW	14	114	114	114	184	1,160	1,160	1,160	1,160	1,160	2,109
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553	3,553	3,553	5,053
Wind OOS New Tx	MW	-	-	-	-	0	0	1,500	1,500	1,500	1,970	1,970
Offshore Wind	MW	-	-	-	-	120	195	195	1,708	1,728	1,728	1,728
Solar	MW	3,094	6,549	7,750	11,000	11,000	11,397	14,678	18,160	28,157	45,194	71,563
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,571	4,604	10,147	11,661	11,661	12,780	12,948	14,204	18,386	29,940	40,705
Pumped Storage	MW	-	-	-	-	196	1,000	1,001	1,001	1,001	1,001	1,001
Shed DR	MW	151	151	353	441	441	441	441	441	441	441	441
Gas Capacity Not Retained	MW	-	-	-	-	-	-	-	-	-	(0)	(0)
Storage + DR	MW	**2,722**	**4,755**	**10,499**	**12,101**	**12,297**	**14,221**	**14,389**	**15,645**	**19,827**	**31,381**	**42,146**
Total Resources (Renewables + Storage + DR)	MW	**7,583**	**13,224**	**20,518**	**26,876**	**27,262**	**30,662**	**35,610**	**41,862**	**56,060**	**85,122**	**125,713**

- By 2032 there is about 700 MW less solar PV resources and about 550 MW less of battery storage resources relative to the 38 MMT Core scenario
  - About 50 MW less solar and 450 MW more batteries selected relative to the Managed Charging sensitivity
- By 2045 there's about 980 MW more new gas resources in this sensitivity and 140 MW less of geothermal relative to the 38 MMT Core scenario
  - About 300 MW more geothermal relative to the Managed Charging sensitivity

38 MMT Core vs. 38 MMT with 2020 IEPR + 2020 IEPR High EV (Unmanaged Charging)

- The selected portfolio is very similar between the two scenarios
  - ~500 MW less solar is selected in the 2020 IEPR + 2020 IEPR High EV sensitivity by 2032
  - ~1 GW of new gas capacity is added by 2045 in the 2020 IEPR + 2020 IEPR High EV sensitivity



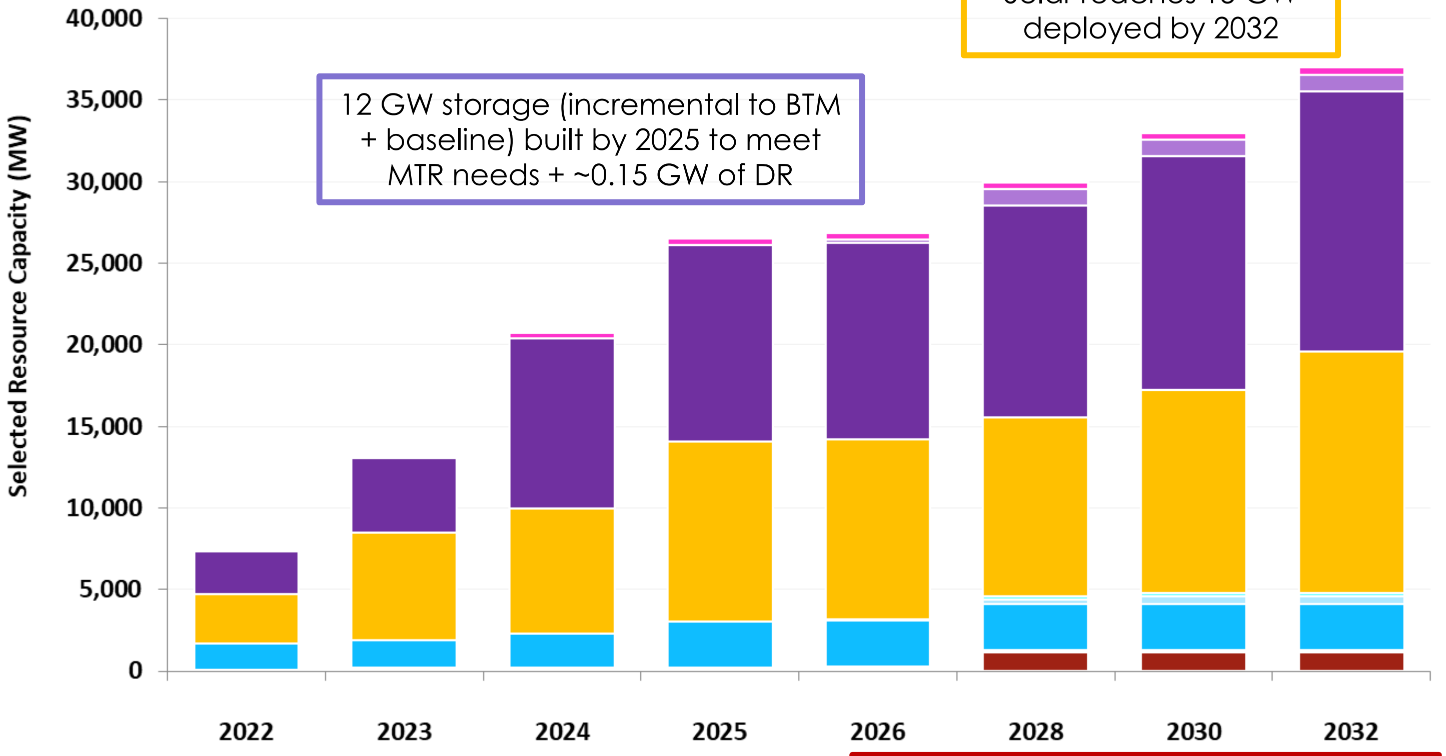
46 MMT Core

With 46 MMT LSE Plans

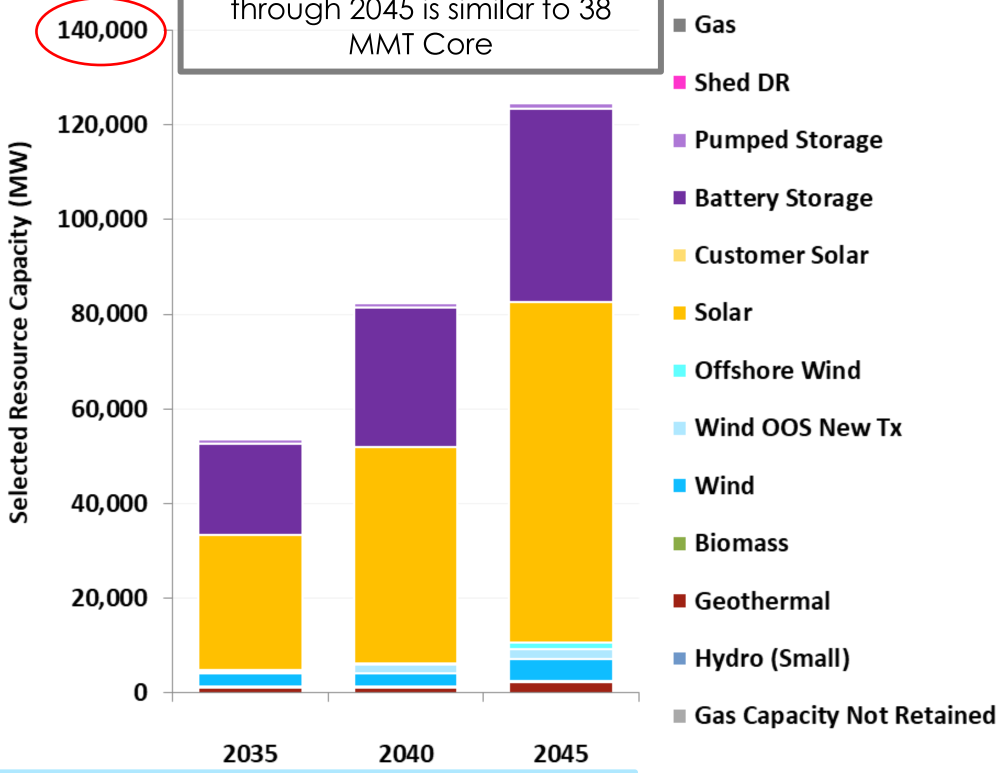
Selected resources: 46 MMT Core

Solar reaches 15 GW deployed by 2032

12 GW storage (incremental to BTM + baseline) built by 2025 to meet MTR needs + ~0.15 GW of DR



Resource selection 2040 through 2045 is similar to 38 MMT Core



Similar capacity additions for geothermal and long-duration energy storage through 2032

RESOLVE selects ~500 MW of out-of-state wind by 2032 to meet the LSE plans wind build requirement.

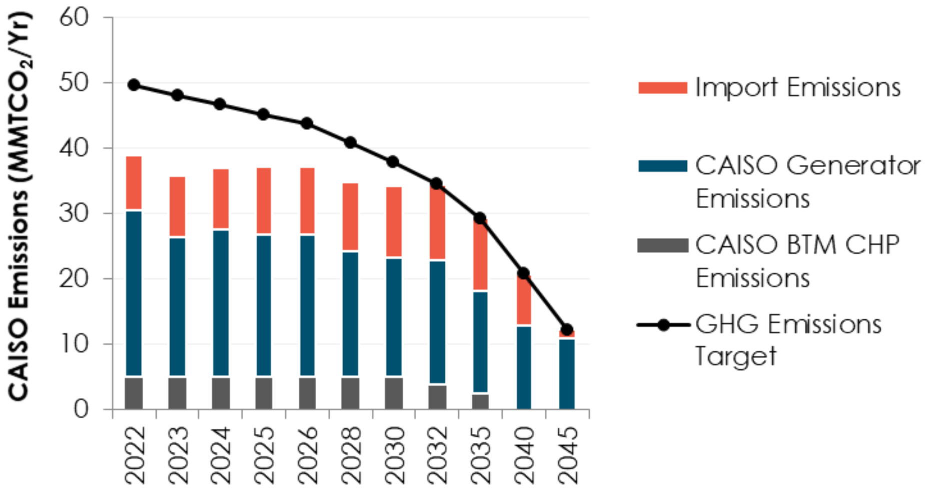
Selected resources – 46 MMT Core

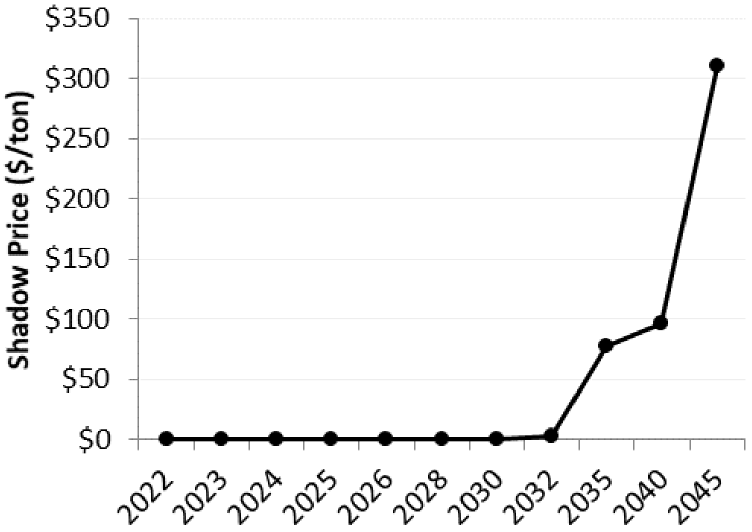
	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	*MW*	-	-	-	-	-	0	0	0	0	0	0
Biomass	*MW*	34	65	83	107	107	129	129	129	129	129	129
Geothermal	*MW*	14	114	114	114	149	1,173	1,173	1,173	1,173	1,173	2,332
Hydro (Small)	*MW*	-	-	-	-	-	-	-	-	-	-	-
Wind	*MW*	1,640	1,704	2,070	2,819	2,819	2,819	2,819	2,819	2,839	2,839	4,784
Wind OOS New Tx	*MW*	-	-	-	-	0	254	492	492	492	1,970	1,970
Offshore Wind	*MW*	-	-	-	-	120	195	195	195	195	195	1,382
Solar	*MW*	3,058	6,593	7,689	11,000	11,000	11,000	12,412	14,789	28,506	45,695	71,976
Customer Solar	*MW*	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	*MW*	2,565	4,573	10,409	12,060	12,060	12,951	14,333	15,950	19,217	29,422	40,879
Pumped Storage	*MW*	-	-	-	-	185	1,000	1,000	1,000	1,000	1,000	1,000
Shed DR	*MW*	151	151	353	441	441	441	441	441	441	441	441
Gas Capacity Not Retained	*MW*	-	-	-	-	-	-	-	-	(0)	(83)	(83)
Storage + DR	*MW*	**2,716**	**4,725**	**10,762**	**12,501**	**12,686**	**14,392**	**15,774**	**17,391**	**20,657**	**30,863**	**42,320**
Total Resources (Renewables + Storage + DR)	*MW*	**7,462**	**13,201**	**20,718**	**26,541**	**26,881**	**29,963**	**32,996**	**36,990**	**53,994**	**82,782**	**124,811**

- The reduced GHG emissions target by 2032 causes RESOLVE to select about 6 GW less resources than in the 38 MMT Core scenario

GHG constraint: 46 MMT Core

GHG constraint is binding starting only in 2032 – a few years later than the 38 MMT which is binding in 2026



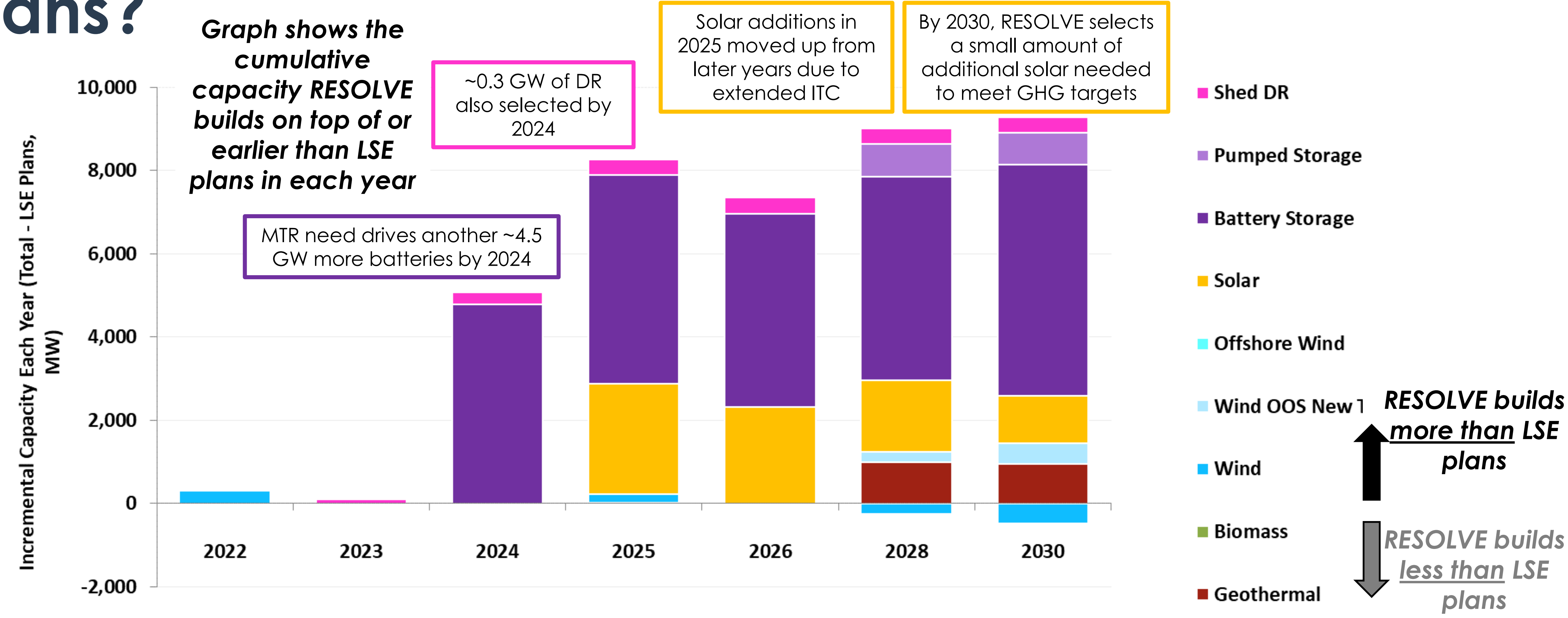


What Does RESOLVE pick on top of 46 MMT LSE Plans?

Incremental Capacity Addition On Top of LSE Planned Resources

Technology Class	Unit	2022	2023	2024	2025	2026	2028	2030
Battery Storage	MW	-	-	4,771	4,998	4,648	4,898	5,561
Pumped Storage	MW	-	-	-	-	-	783	751
Biomass	MW	-	-	-	12	-	-	-
Shed DR	MW	-	89	288	375	375	376	376
Geothermal	MW	-	-	-	-	-	988	952
Solar	MW	-	-	-	2,662	2,317	1,711	1,143
Wind	MW	308	2	2	210	2	(252)	(490)
Offshore Wind	MW	-	-	-	-	-	-	-
Wind OOS New Tx	MW	-	-	-	-	-	254	492

What Does RESOLVE pick on top of 46 MMT LSE Plans?



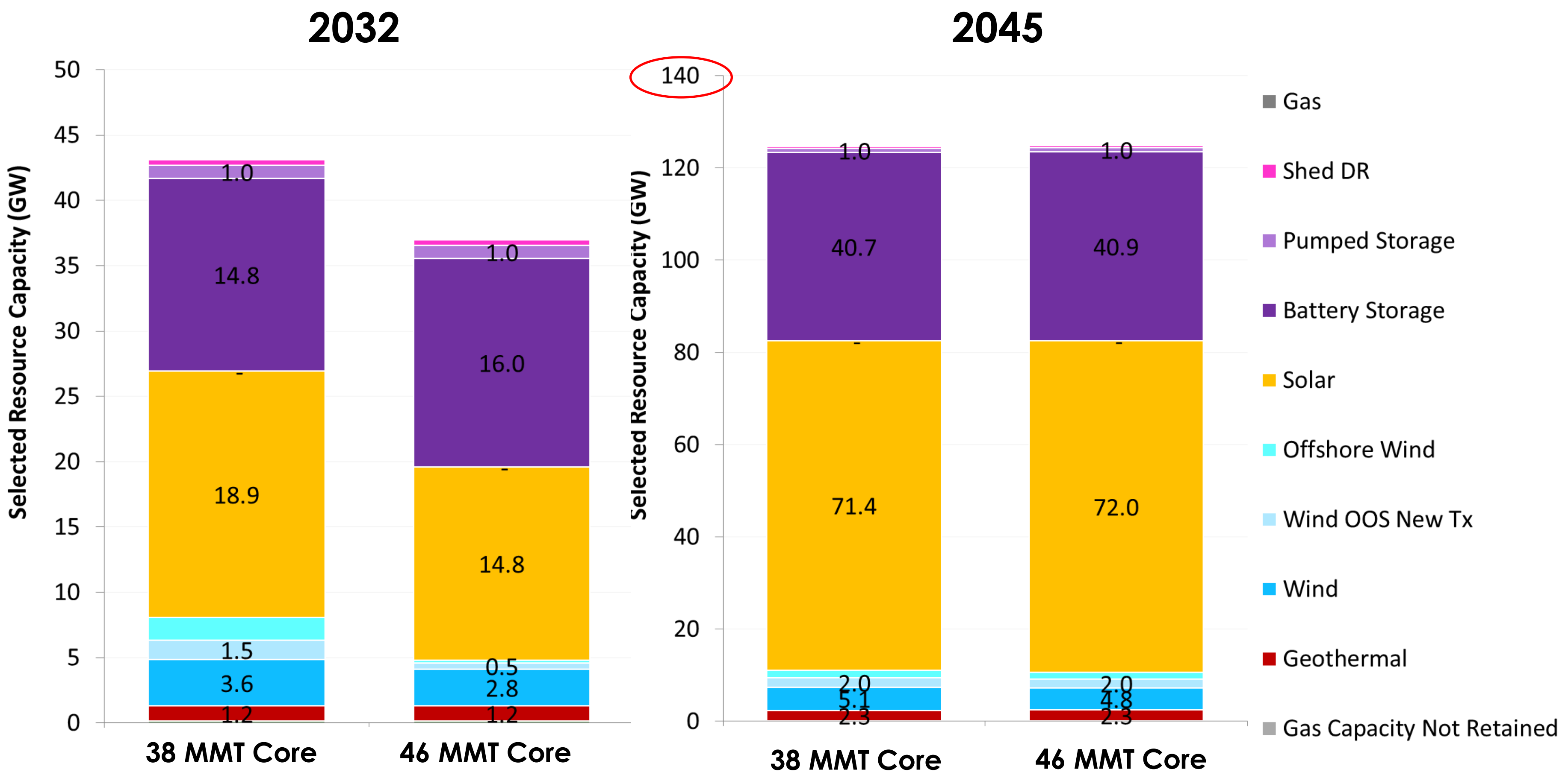
A small amount of in-CAISO wind is moved up to 2025 to meet MTR, but no incremental wind selected by 2030

Geothermal and long duration storage for MTR built on top of ~0.3 GW of each of these resources in LSE plans

490 MW of out-of-state wind on new transmission is selected in place of an equivalent amount of of in-CAISO wind and out-of-state wind on existing transmission.

38 MMT Core vs. 46 MMT Core

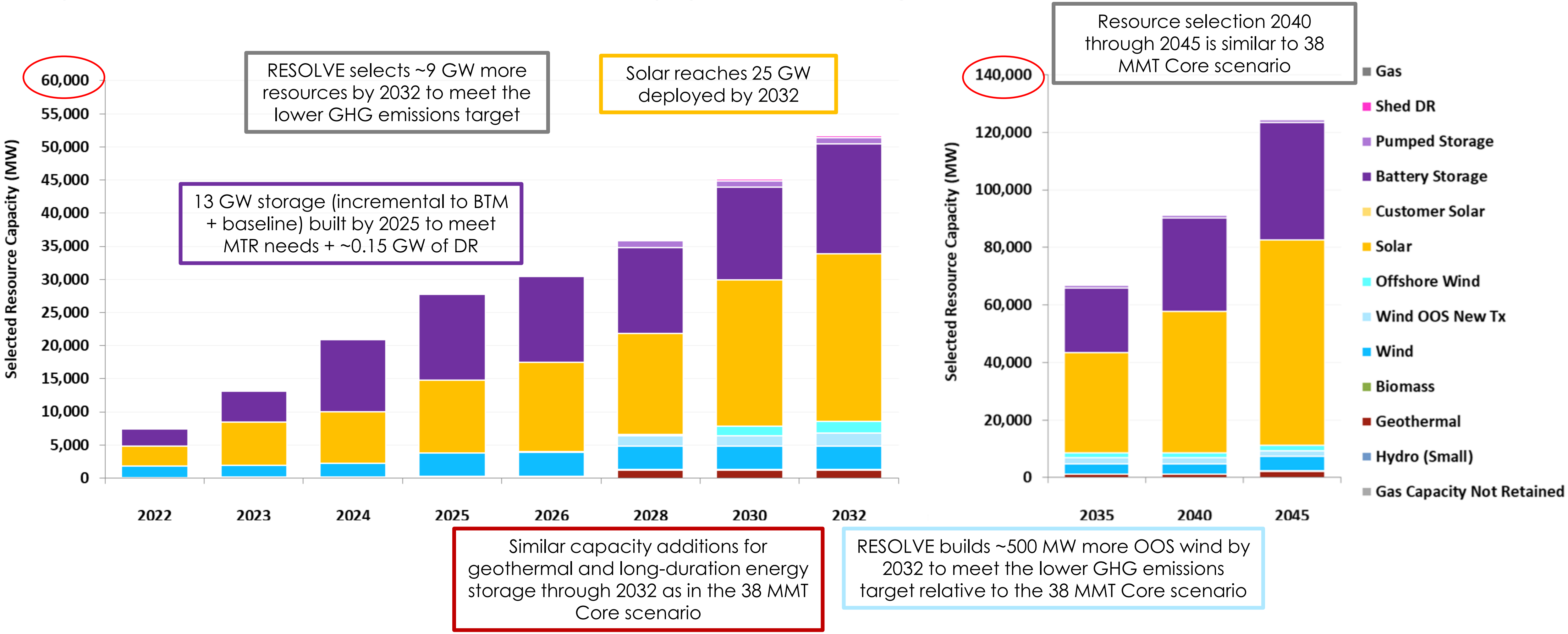
- The combination of the higher GHG limit and smaller LSE plans causes a significantly lower quantity of resources to be selected by 2032



30 MMT Core

With 38 MMT LSE Plans

Selected resources: 30 MMT Core



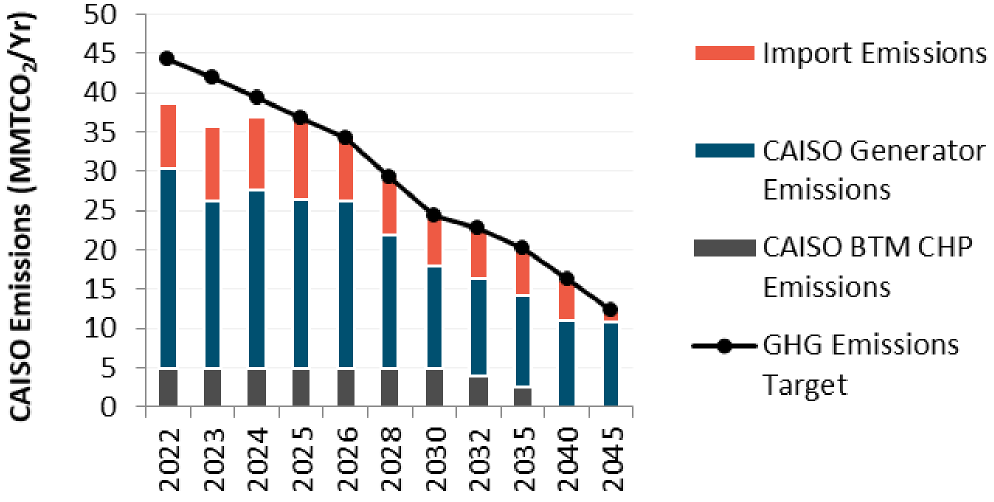
Selected resources – 30 MMT Core

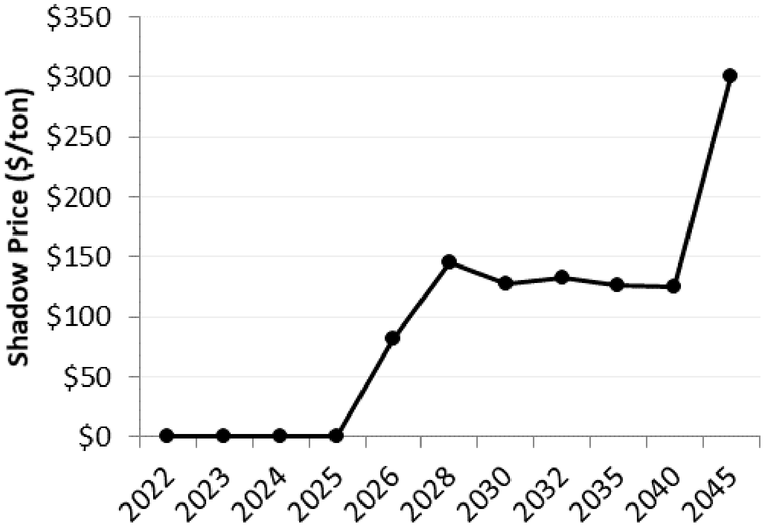
	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	0	0	0	0	0	279
Biomass	MW	34	65	83	107	107	134	134	134	134	134	134
Geothermal	MW	14	114	114	114	184	1,158	1,158	1,158	1,158	1,158	2,222
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,553	3,553	3,553	3,553	3,553	3,553	3,553	5,053
Wind OOS New Tx	MW	-	-	-	-	0	1,500	1,500	1,970	1,970	1,970	1,970
Offshore Wind	MW	-	-	-	-	120	195	1,452	1,728	1,728	1,728	1,728
Solar	MW	3,094	6,549	7,750	11,000	13,537	15,266	22,076	25,270	34,854	49,317	71,433
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,565	4,603	10,840	12,960	12,960	12,993	14,003	16,624	22,517	32,296	40,784
Pumped Storage	MW	-	-	-	-	196	1,000	1,000	1,000	1,000	1,000	1,000
Shed DR	MW	151	151	244	244	244	244	244	244	244	244	244
Gas Capacity Not Retained	MW	-	-	-	-	-	-	-	-	-	-	-
Storage + DR	MW	**2,716**	**4,755**	**11,084**	**13,204**	**13,400**	**14,237**	**15,247**	**17,868**	**23,761**	**33,540**	**42,028**
Total Resources (Renewables + Storage + DR)	MW	**7,577**	**13,224**	**21,102**	**27,979**	**30,901**	**36,044**	**45,121**	**51,682**	**67,158**	**91,401**	**124,849**

- To achieve the reduced GHG targets through 2032, additional solar, battery storage resources, and a little out-of-state wind are added relative to the 38 MMT Core
  - 9 GW more resources in total are added by 2032.

GHG constraint: 30 MMT Core

GHG constraint is binding starting in 2026 – a few years earlier than cases with higher GHG targets. Target is close to binding in 2025.



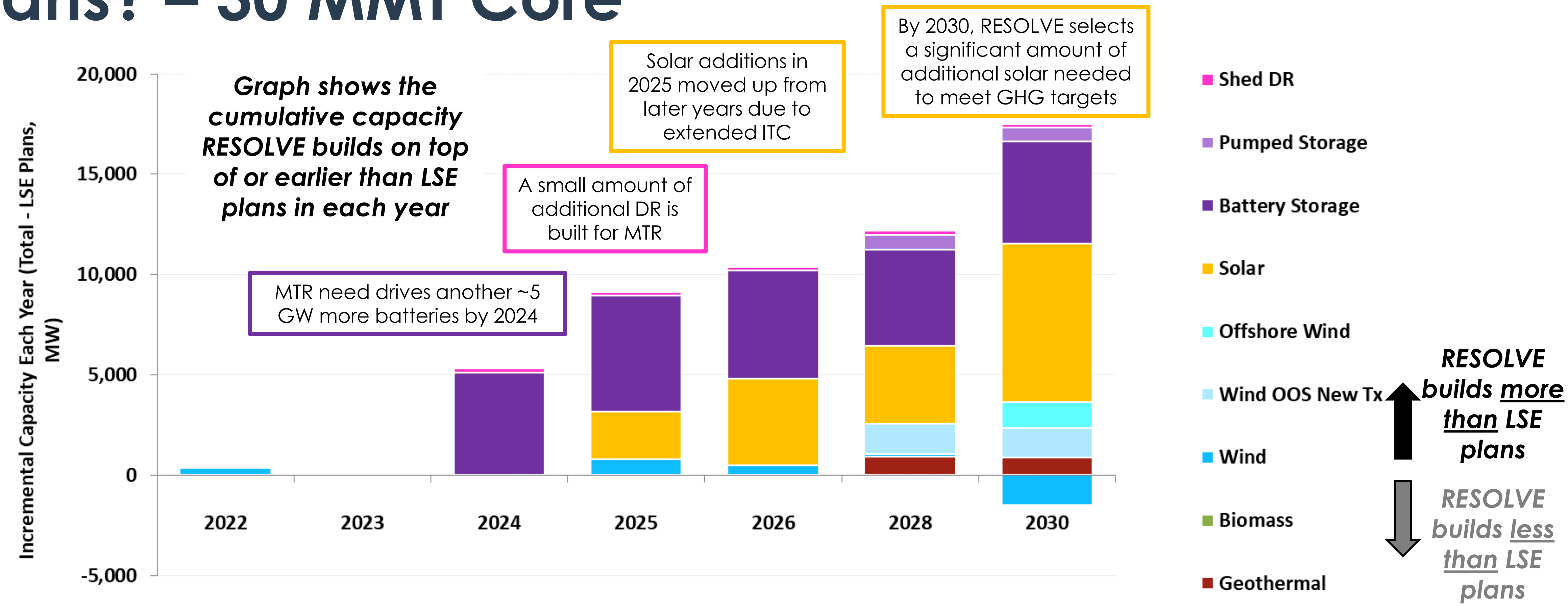


What Does RESOLVE pick on top of 38 MMT LSE Plans? – 30 MMT Core

Incremental Capacity Addition On Top of LSE Planned Resources

Technology Class	Unit	2022	2023	2024	2025	2026	2028	2030
Battery Storage	MW	-	-	5,105	5,784	5,417	4,791	5,101
Pumped Storage	MW	-	-	-	-	-	764	692
Biomass	MW	-	-	-	12	-	-	-
Shed DR	MW	-	89	180	178	178	179	179
Geothermal	MW	-	-	-	-	-	938	867
Solar	MW	-	-	-	2,344	4,330	3,869	7,905
Wind	MW	365	22	22	796	475	134	(1,478)
Offshore Wind	MW	-	-	-	-	-	-	1,257
Wind OOS New Tx	MW	-	-	-	-	-	1,500	1,500

What Does RESOLVE pick on top of 38 MMT LSE Plans? – 30 MMT Core



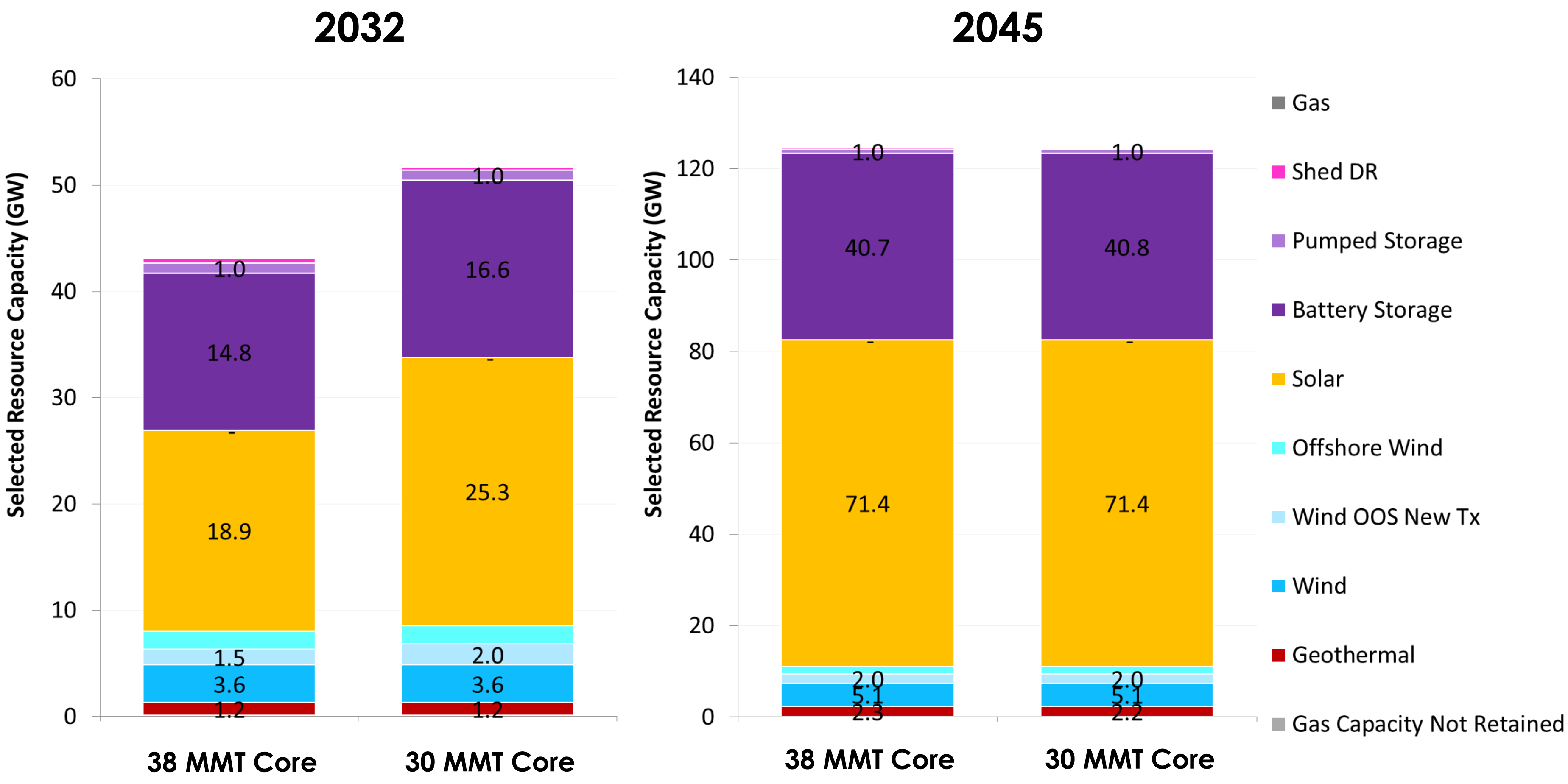
A small amount of in-CAISO wind is moved up to 2025 to meet MTR but no incremental wind selected by 2030

Like in the 38 MMT core, geothermal and long duration storage for MTR are built on top of ~0.3 GW of each of these resources in LSE plans

1.5 GW of out-of-state wind on new transmission is selected in 2028, earlier than the LSE plans for new wind in 2030; this OOS wind still replaces about 1.7 GW of in-CAISO wind and out-of-state wind on existing transmission

38 MMT Core vs. 30 MMT Core

- The lower GHG target by 2032 largely leads to additional solar and battery storage builds, also additional out-of-state wind
  - 8.7 GW of additional resources relative to the 38 MMT Core

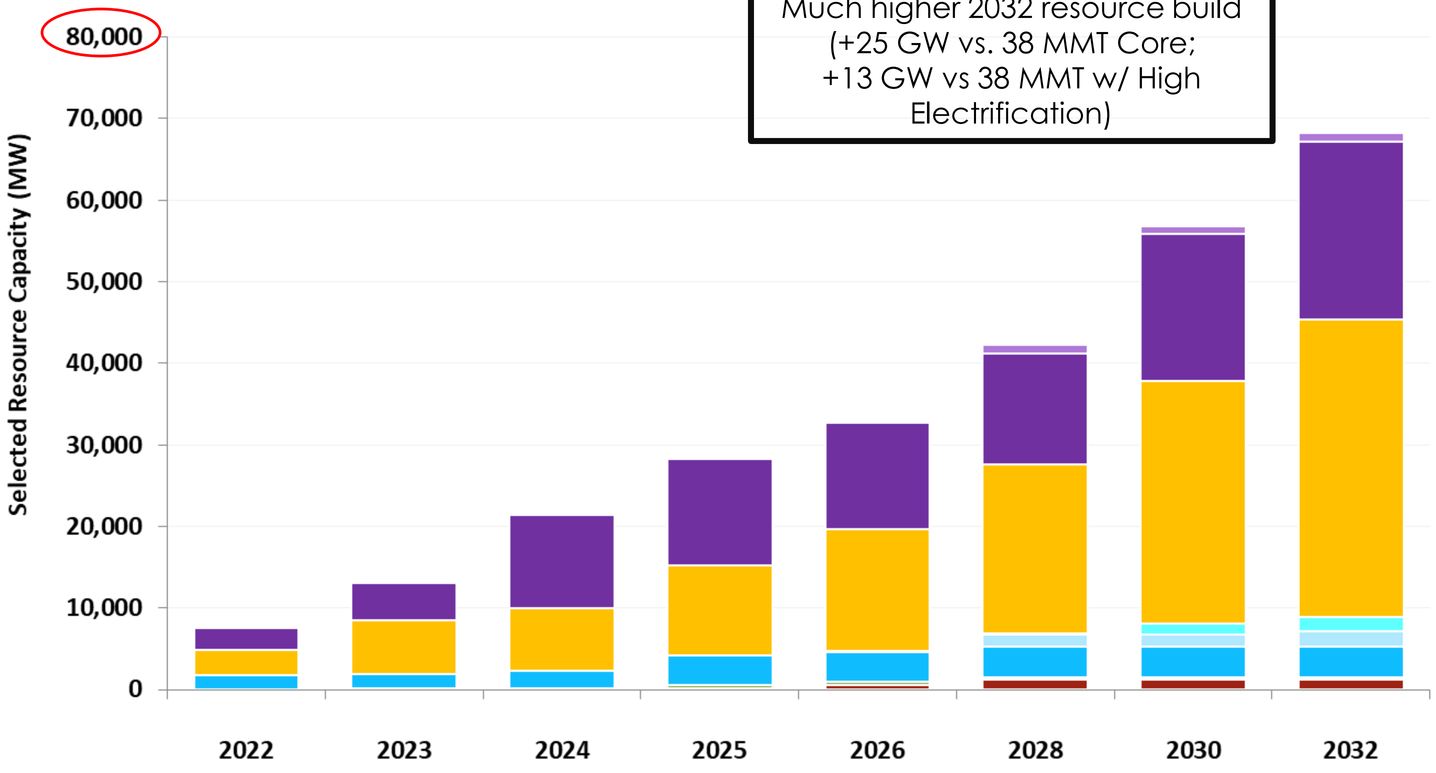


30 MMT High Electrification (Managed EV Profile)

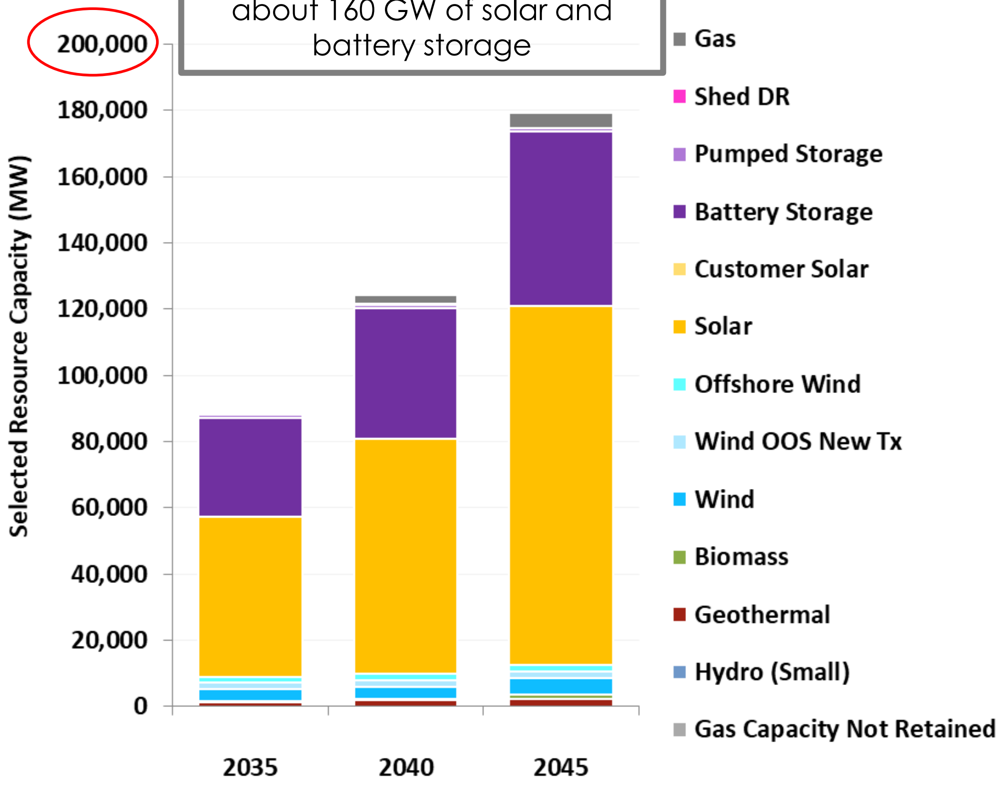
With 38 MMT LSE Plans

Selected resources – 30 MMT w/ High Electrification (Managed)

Much higher 2032 resource build (+25 GW vs. 38 MMT Core; +13 GW vs 38 MMT w/ High Electrification)



4.4 GW of new gas + 1.1 GW of biomass built by 2045 and about 160 GW of solar and battery storage



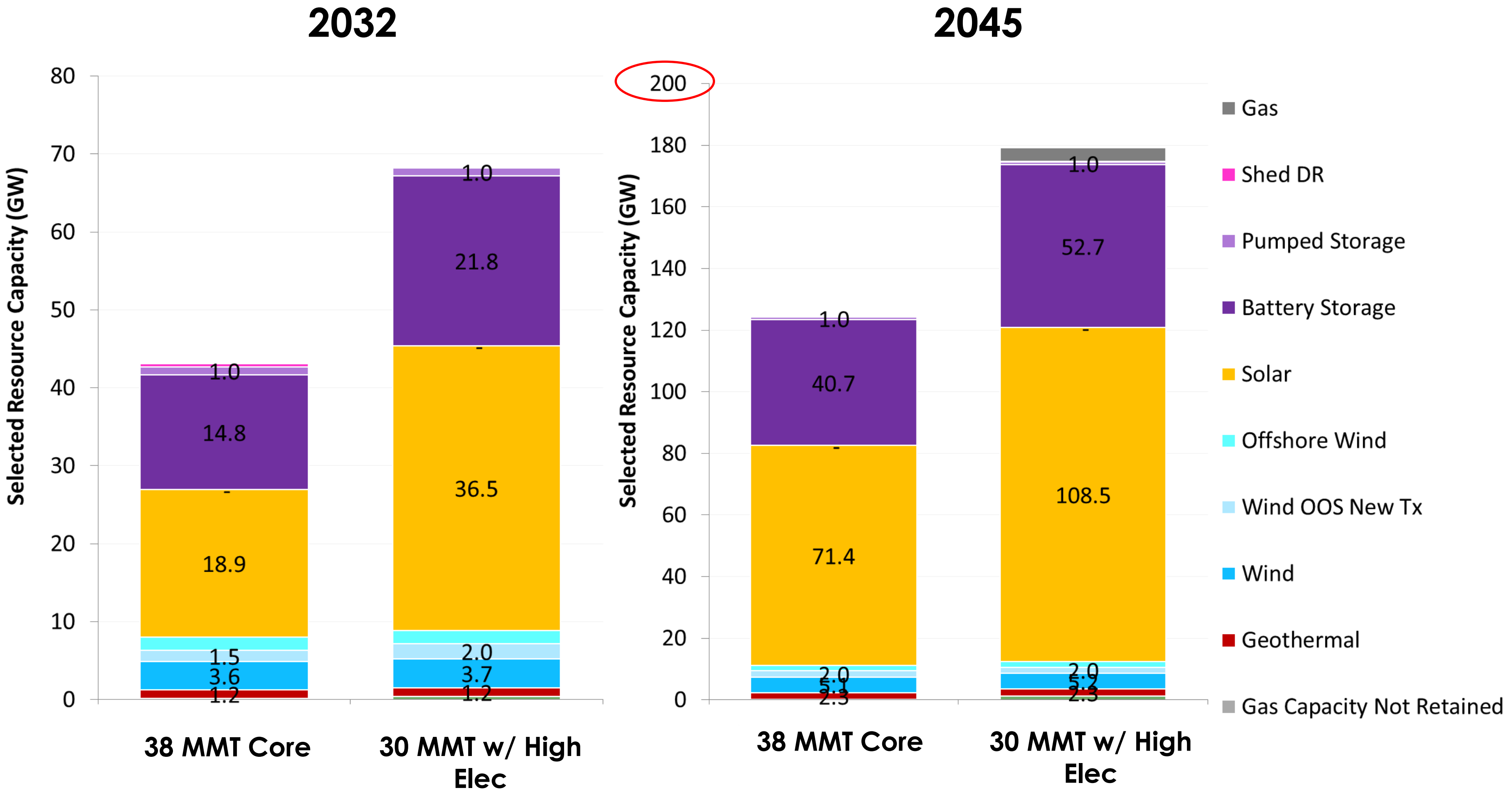
Selected resources – 30 MMT PSP w/ High Electrification

	Unit	2022	2023	2024	2025	2026	2028	2030	2032	2035	2040	2045
Gas	MW	-	-	-	-	-	0	0	0	0	2,677	4,497
Biomass	MW	34	65	83	373	373	373	373	373	373	373	1,147
Geothermal	MW	14	114	114	114	527	1,156	1,156	1,156	1,156	1,995	2,332
Hydro (Small)	MW	-	-	-	-	-	-	-	-	-	-	-
Wind	MW	1,719	1,741	2,071	3,687	3,687	3,687	3,687	3,687	3,687	3,687	5,187
Wind OOS New Tx	MW	-	-	-	-	0	1,500	1,500	1,970	1,970	1,970	1,970
Offshore Wind	MW	-	-	-	-	120	195	1,431	1,708	1,728	1,728	1,749
Solar	MW	3,094	6,549	7,750	11,000	14,963	20,726	29,736	36,522	48,405	71,064	108,472
Customer Solar	MW	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	MW	2,626	4,604	11,345	13,085	13,085	13,584	17,938	21,775	29,679	39,615	52,744
Pumped Storage	MW	-	-	-	-	196	1,000	1,000	1,001	1,001	1,001	1,001
Shed DR	MW	176	176	176	176	176	176	176	176	176	176	176
Gas Capacity Not Retained	MW	-	-	-	-	-	-	-	-	-	-	(0)
Storage + DR	MW	**2,803**	**4,780**	**11,521**	**13,262**	**13,458**	**14,761**	**19,115**	**22,952**	**30,856**	**40,791**	**53,921**
Total Resources (Renewables + Storage + DR)	MW	**7,663**	**13,249**	**21,540**	**28,436**	**33,128**	**42,398**	**56,999**	**68,368**	**88,176**	**124,286**	**179,274**

- Through 2032 the increased load is mostly served by additional solar PV and battery resources
  - About 100 MW of additional onshore wind is selected in 2025 through 2040.
- By 2040 and 2045, the model selects more diversity and additional firm generation (shown in the selection of additional geothermal, new gas, biomass resources) in addition to the increased solar PV and batteries

38 MMT Core vs. 30 MMT w/ High Electrification

- The combination of lower GHG targets and higher loads due to electrification lead to significant additional solar and battery storage builds, and firm resources
  - About 25 GW more by 2032 and 55 GW more by 2045



Appendix A: Overview of RESOLVE

RESOLVE Model Overview

- RESOLVE is a capacity expansion model designed to inform long-term planning questions around renewables integration
- RESOLVE co-optimizes investment and dispatch for a selected set of days over a multi-year horizon in order to identify least-cost portfolios for meeting specified GHG targets and other policy goals
- Scope of RESOLVE optimization in the 2021 PSP and 2022-2023 TPP:
  - Covers the CAISO balancing area including POU load within the CAISO
  - Optimizes dispatch but not investment outside of the CAISO
    - Resource capacity outside of CAISO cannot be changed by the optimization
- The RESOLVE model used to develop the Preferred System Plan results, along with accompanying documentation of inputs and assumptions, model operation, and results will be available for download from the CPUC's website.
- The role of the RESOLVE model in IRP is to select portfolios of new resources that are expected to meet policy goals at least cost while ensuring reliability

General Assumptions Components Used in 2021 PSP Modeling

- IRP seeks to use standardized modeling inputs in both capacity expansion (RESOLVE) and production cost modeling (SERVM)
- Generally, these assumptions pertain to use of demand forecasts and the definition of what baseline resources to consider in both models
- An overview of core modeling inputs for 2021 modeling is included in this section
  - Descriptions of demand forecast and baseline resource inputs
- Additional updates for resource costs and transmission model are covered in Appendix B and Appendix C respectively

Core Modeling Input: Demand Forecast

- Per the 2013 joint agency leadership agreement to use a single forecast set*, current IRP modeling uses the Energy Commission's 2019 IEPR Update Forecast as a core input
- Uncertainty in future electricity demand considered:
  - 1998-2017 weather scenarios and 5 weighted levels of load forecast uncertainty in SERVM
  - Sensitivity and scenario modeling (e.g. high EV load, high electrification) in RESOLVE
- IEPR forecast annual projections of electricity consumption and demand modifiers are used to scale corresponding hourly shapes in RESOLVE and SERVM

* See February 25, 2013 CPUC-CEC-CAISO Letter to Senators Padilla and Fuller and more information available on CPUC's webpage; Also see Final 2018 Integrated Energy Policy Report Update, Volume II- Clean Version

Core Modeling Input: Baseline Resources

- **Baseline resources** are resources that are included in a model run as an assumption rather than being selected by the model as part of an optimal solution
- Within CAISO, the baseline resources are intended to capture:
  - Existing resources, net of planned retirements (e.g. once-through-cooling plants)
  - "Steel-in-the-ground" new resources that are deemed sufficiently likely to be constructed, usually because of being LSE-owned or contracted, with CPUC and/or LSE governing board approval
    - e.g. CPUC- or LSE governing board-approved renewable power purchase agreements, CPUC-approved gas plants, CPUC storage procurement target (i.e., AB 2514)
  - Projected achievement of demand-side programs under current policy
    - e.g. forecast of EE achievement, BTM PV adoption under NEM tariff

Core Modeling Input: Baseline Resources (continued)

- In external zones (e.g., BANC), where RESOLVE does not optimize the portfolios, the baseline resources are derived from the WECC Anchor Data Set, which includes each external BA's plans to add/retire resources to meet assumed policy and reliability goals
- RESOLVE optimizes the selection of additional resources in the CAISO area needed to meet policy goals, such as RPS, a GHG target, or a planning reserve margin; these resources that are selected by RESOLVE are *not* baseline resources
- The same baseline resources are assumed in the 46, 38, and 30 MMT Core and sensitivity scenarios
- Baseline resources for the 2021 PSP analysis include previously proposed ground truthing updates and have been updated to align with LSE plan data and MTR baseline with the NQC percentages matching the 2021 CPUC NQC List

Baseline Resource Assumptions: Retirements, Repowering, Risk Adjustments

- Retirements
  - Power plants with announced retirements are modeled as retired. Compliance with Once-Thru-Cooled Water Board policy is assumed and Diablo Canyon Power Plant is retired in 2024/2025
  - Of the remaining existing plants, RESOLVE uses economic retention functionality to examine what portion of the existing gas-fired generation fleet may need to be retained or allowed to retire within the IRP planning horizon
- Repowering
  - Staff is aware that a significant fraction of California's wind capacity may need to be repowered to remain online through 2032
  - Further data gathering and RESOLVE development will be needed to explicitly consider repowering in modeling

Candidate Resource Assumptions

- "Candidate" resources represent the menu of options from which RESOLVE can select to create an optimal portfolio
- Publicly-available data on cost, potential, and operations are used to the maximum extent possible to develop candidate resource assumptions
- Both supply and demand-side resources are included as candidate resources
- Supply-side Candidate Resources:
  - Natural gas: CCGT, CT
  - Renewables: Solar PV, Wind, Geothermal, Biomass
  - Utility-Scale battery storage: Li-ion, Flow
  - Pumped storage
- Demand-side Candidate Resources:
  - Behind-the-meter PV (Distributed Solar PV)
  - Behind-the-meter Li-ion Storage
  - Shed Demand Response

Portfolio Selection: Costs and Benefits

- The optimal mix of candidate resources in RESOLVE is a function of the costs and characteristics of the candidate resources and the constraints that the portfolio must meet.
- When choosing a resource, RESOLVE weighs:
  - Costs of building and operating each resource
    - Fixed costs: capital, fixed O&M, transmission upgrades
    - Variable costs: fuel, variable O&M, start
  - The system benefits of adding each resource to the portfolio
    - Hourly energy and reserve value
    - Contribution to GHG and RPS policy goals
    - Contribution to system resource adequacy (planning reserve margin)
    - Contribution to local capacity requirements (if any - none modeled in 2019 IRP)
- Capital costs are typically the largest cost category for renewable resources.

Appendix B: Resource Cost and Build Updates

Summary of cost and build updates

- **Update to NREL 2020 ATB as data source for most technology costs**
  - Exceptions are batteries (Lazard) and offshore wind (NREL OCS study) – see below
- **Battery costs**
  - Update to Lazard v6.0
  - Including capex, fixed O&M, annual warranty and augmentation costs (% of capex)
- **Offshore wind costs**
  - Update to incorporate final numbers from NREL OCS Study BOEM 2020-048
- **ITC/PTC schedules**
  - Update to reflect statute and IRS guidance as of Dec 2020
  - Solar (PV, thermal), wind (onshore, offshore), battery with ITC (hybrid with solar PV)
- **Updated solar annual build constraints to reflect updated ITC schedule**
  - 2021 – 3.1 GW; 2022 – 3.5 GW; 2023 – 1.2 GW, 2025 – 3.2 GW
- **Financing lifetimes**
  - Update to align with latest E3 assumptions based on recent LBNL studies
  - Utility and commercial solar PV, onshore wind, and gas
- **Solar PV inverter loading ratios**
  - Align with latest E3 assumptions based on recent LBNL research
  - Specifically, utility solar PV changed from 1.35 to 1.3 to align with assumption used for solar profile simulation
- **Interconnection cost for storage**
  - Utility-scale Li-ion, flow batteries, pumped hydro

ITC/PTC schedules

- **Solar (commercial PV, utility PV, solar thermal)**
  - ITC extends for projects coming online through 2025 (ITC drops to 10% afterward – same as previous)
- **Residential solar**
  - ITC drops to 0% after 2025
- **Onshore wind**
  - PTC extends through 2025; values adjusted for inflation
- **Offshore wind**
  - ITC extends through 2035 (to reflect assumption that developers will access 10-year safe harbor by end 2025 for projects on federal land / waters)
- **Battery with ITC (hybrid with solar PV) - not used for PSP model runs**
  - ITC extends through 2025 (to be consistent with solar PV)

Financing lifetimes

Technology	Before	After	Source of E3 proforma
Solar - Commercial	35	30	LBNL, 2020, Benchmarking Utility-Scale PV Operational Expenses and Project Lifetimes: Results from a Survey of U.S. Solar Industry Professionals
Solar - Utility Tracking	35	30	LBNL, 2020, Benchmarking Utility-Scale PV Operational Expenses and Project Lifetimes: Results from a Survey of U.S. Solar Industry Professionals
Wind - Onshore	25	30	LBNL, 2019, Benchmarking Anticipated Wind Project Lifetimes: Results from a Survey of U.S. Wind Industry Professionals
Gas CC/CT	20	25	E3

Solar PV inverter loading ratio

Technology	Before	After	Source of E3 proforma
Solar - Residential	1.35	1.15	LBNL, 2019, Tracking the Sun
Solar - Commercial	1.35	1.15	LBNL, 2019, Tracking the Sun
Solar - Utility Tracking	1.35	1.3	E3 assumptions for profile simulation

Storage interconnection costs

- **Apply $100/kW interconnection cost to utility-scale Li-ion batteries, flow batteries, and pumped hydro storage**
  - Rationale for including interconnection cost: Previously assumed zero interconnection cost for storage. Given the low and aggressive storage cost estimates in Lazard v6.0, interconnection costs were included to be conservative.
  - Rationale for $100/kW: A lot of storage will be connected at low costs at existing solar or gas points of interconnection. The interconnection cost for solar in the Resource Costs & Build workbook is $200/kW based on the Black & Veatch study. The $200/kW for storage is currently considered to be rather high and could mean that solar + storage is effectively double paying for interconnection. Therefore, the interconnection cost of new gas resources was adopted as a proxy, which is $100/kW in the Resource Costs & Build workbook.
  - Same interconnection cost applied to pumped hydro for consistency
- **$100/kW interconnection cost ~ $10/kW-yr cost increase on a levelized basis**
  - For utility-scale Li-ion batteries, $10/kW-yr in 2020 → $8/kW-yr in 2029 and onward

Overview of resource cost comparison

<u>High-level takeaways:</u> Resource cost vintage (e.g., NREL 2020 vs. 2018 ATB, Lazard v6.0 vs. v5.0) has the highest impacts on costs. Most of the recent ("2022-23 TPP") updates only affect levelized costs and have relatively small impacts.

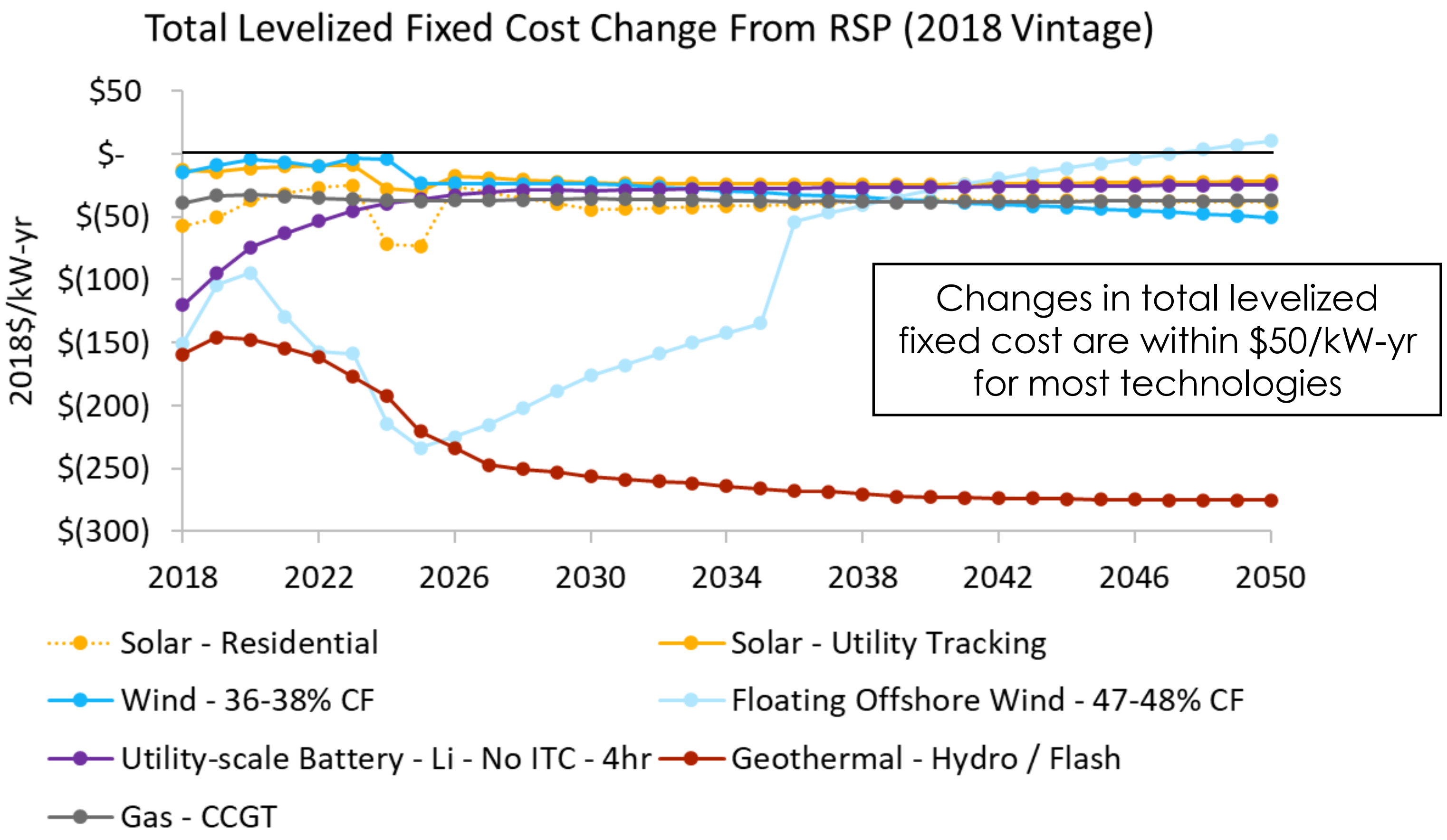
Three sets of resource costs are compared:

- **"2018"**
  - Resource costs prior to summer 2020 updates
  - 2018 vintage (NREL 2018 ATB, Lazard 4.0)
- **"2020"**
  - Resource costs updated (and presented to CPUC) in summer 2020
  - 2020 vintage (NREL 2020 ATB, Lazard 5.0)
- **"2021 PSP / 2022-23 TPP"**
  - Updates for TPP and PSP runs, summer 2021
  - Changes described in previous section (slides 11-14) are relative to "2020" costs

Note: LCOEs shown here are illustrative. All-in levelized costs are the primary cost inputs for new resources in RESOLVE. LCOEs are inferred from dispatch results.

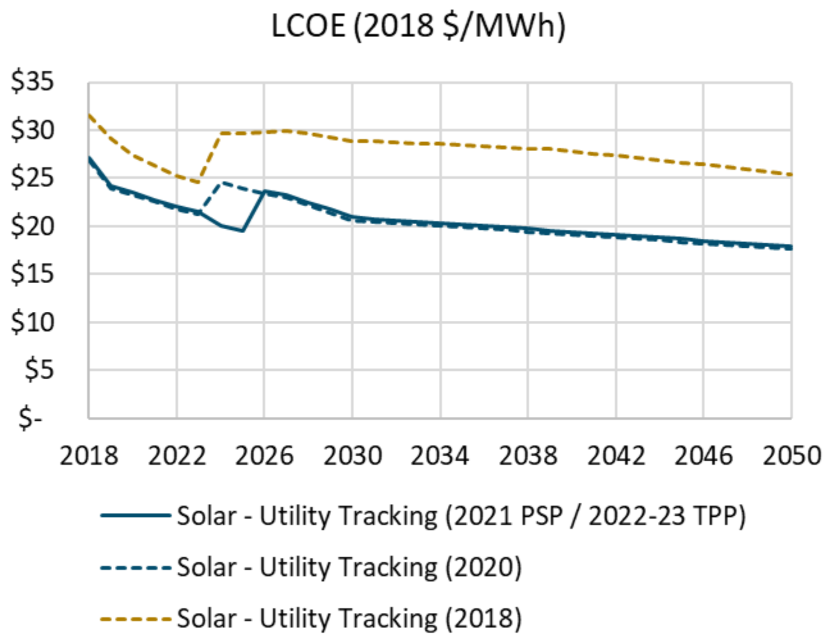
Changes in total levelized fixed cost

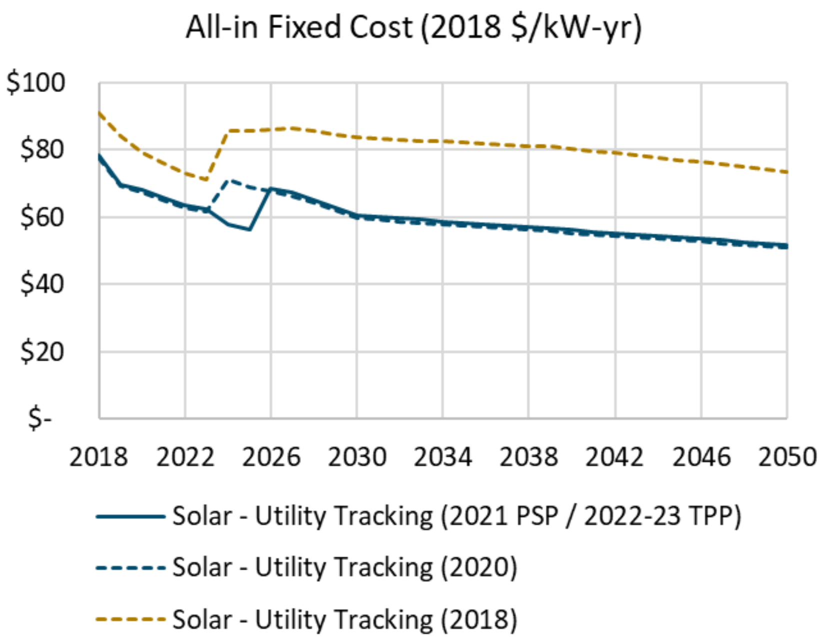
2021 PSP / 2022-23 TPP vs. RSP (2018 vintage)



Utility-scale solar PV

- Biggest differences due to resource cost vintage (2020 vs. 2018 NREL ATB)
- Among the other updates, ITC schedule had the biggest impact

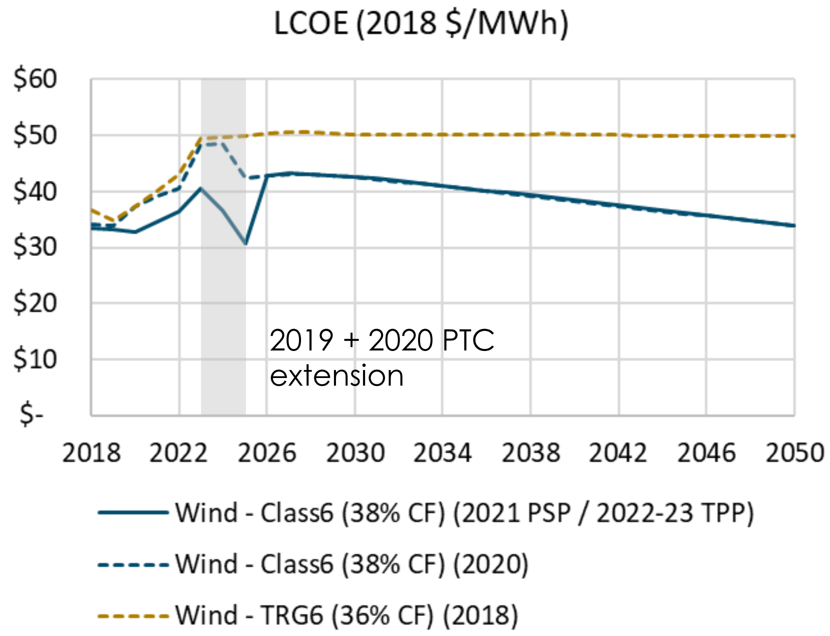




Onshore wind, Class 6 (36-38% capacity factor)

- Biggest differences due to resource cost vintage (2020 vs. 2018 NREL ATB)
- Among the other updates, PTC schedule had the biggest impact

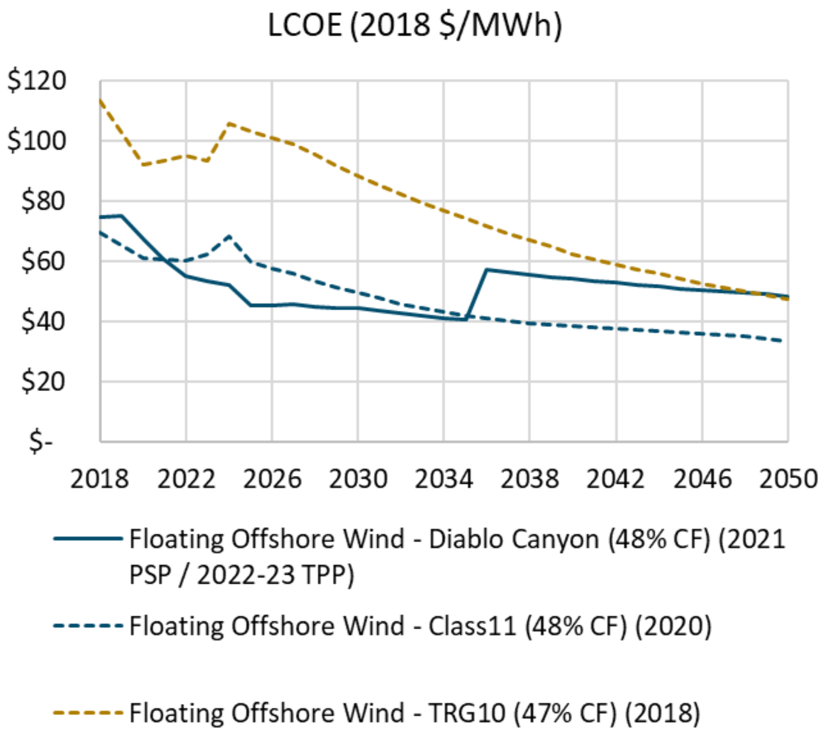
PTC timeline:
- Previous legislation: PTC decreases to **40%** by the end of **2023** (online date)
- Dec 2019: PTC extension at **60%** to the end of **2024** (online date)
- Dec 2020: PTC extension at **60%** to the end of **2025** (online date)

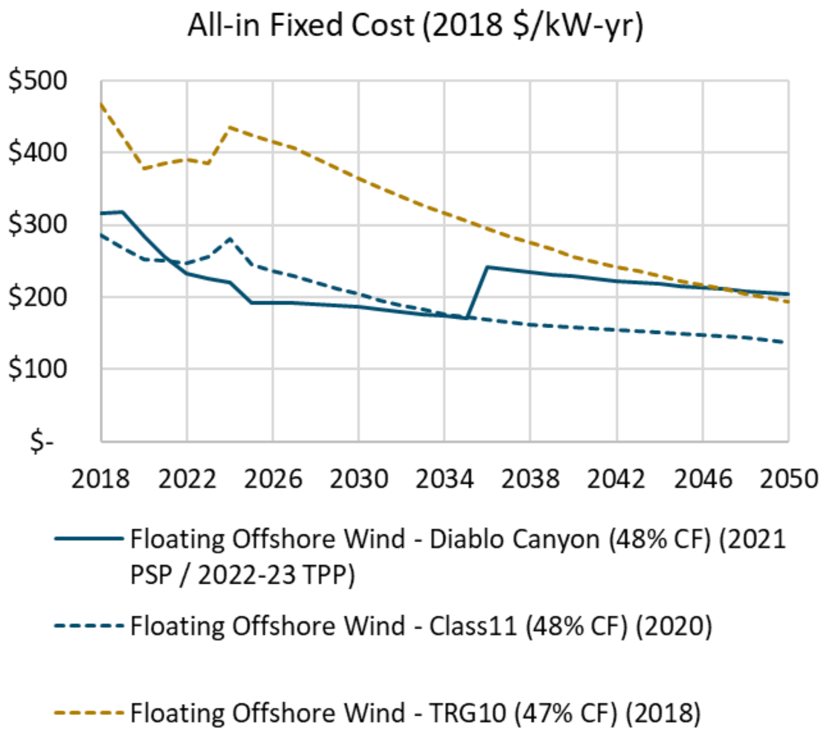


Note: wind bins (Techno-Resource Groups or Classes) changed between 2019 and 2020 ATB, resulting in small differences in capacity factor.

Floating offshore wind, 47-48% capacity factor

- Biggest differences due to resource cost data source (NREL OCS Study vs. NREL ATB/E3)
- Among the other updates, ITC schedule had the biggest impact

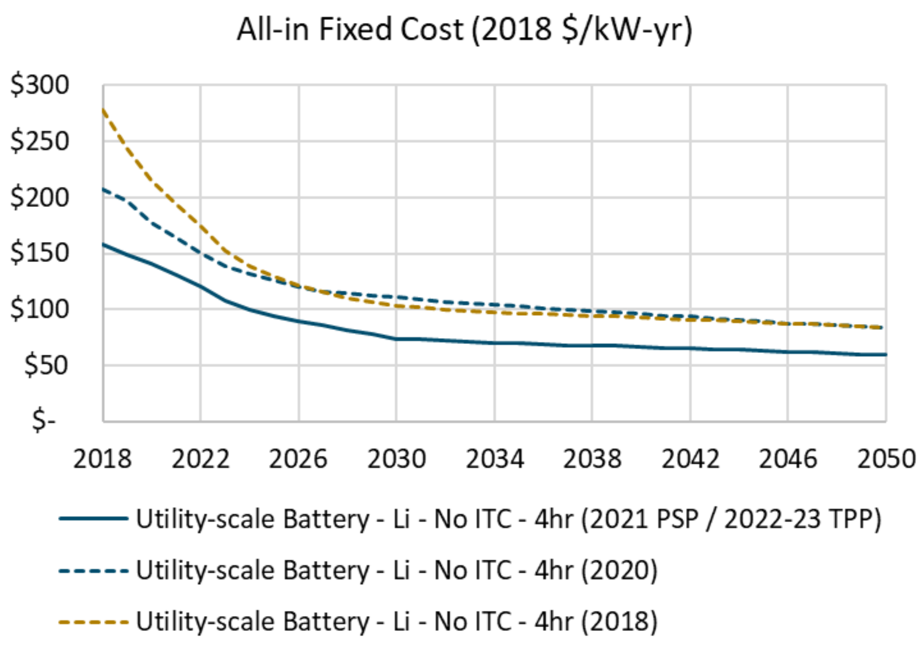




Note: wind bins (Techno-Resource Groups or Classes) changed between 2019 and 2020 ATB, resulting in small differences in capacity factor.

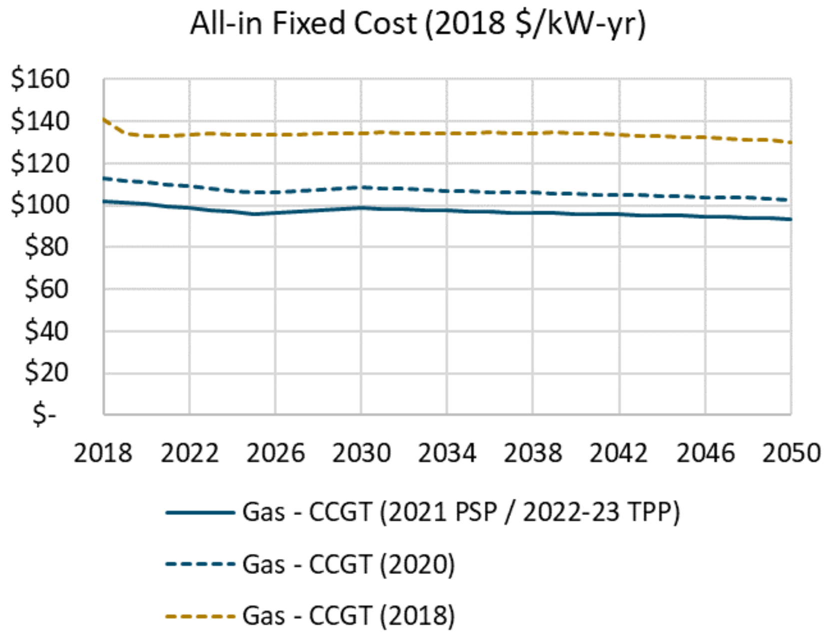
Utility-scale standalone Li-ion battery

- Biggest differences come from resource cost vintage
  - Lazard 6.0 assumed substantial cost reductions



Gas CCGT

- Biggest differences due to resource cost vintage (2020 vs. 2018 NREL ATB)
- Assumption for financing lifetime had relatively small impacts



Note: LCOE not shown because the capacity factor of gas resources is a RESOLVE output.
The capacity factor can change over time and cannot be predicted prior to each model run.

Appendix C: Transmission Updates

Objective of RESOLVE Transmission Updates

- E3 updated RESOLVE to incorporate additional technology-specific and location-specific transmission deliverability information in order to refine location information of resources selected in RESOLVE portfolios
- The RESOLVE updates use new and updated data described in CAISO's white paper, which includes:
  - More detail on how generation and storage resources and transmission constraints interact via resource output factors
  - Additional detail on the timing of peak needs via highest and secondary on-peak transmission constraints
  - An expanded set of transmission constraints
  - Details of how transmission upgrades impact on-peak and off-peak capability
  - Estimates of time to construct transmission upgrades

White paper available at http://www.caiso.com/Documents/WhitePaper-2021TransmissionCapabilityEstimates-CPUCResourcePlanningProcess.pdf

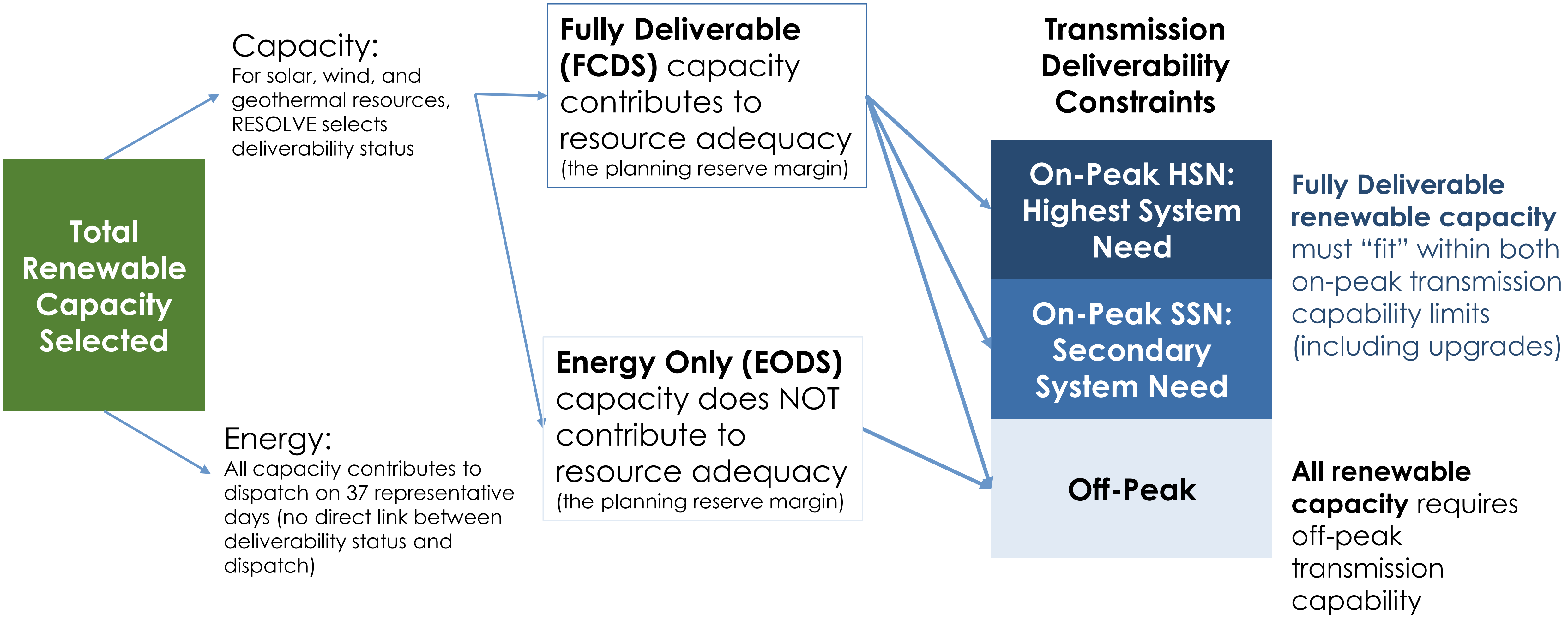
Transmission Capability Update Approach

1. Create transmission capability constraint equations
2. Input new transmission capability data
   - Existing transmission capabilities
   - Upgrade cost and first available year
   - Upgrade effectiveness at increasing on-peak and off-peak deliverability
3. Assign RESOLVE resources to each constraint
   - Use CAISO's resource output factors for deliverability
     - Offshore and out of state wind data not provided by CAISO; E3 scaled land-based CAISO wind resource output factors by capacity factor

- Implementation of all three approaches relies on RESOLVE's new "custom constraint" functionality, enabled by an updated code base

EODS = Energy Only Deliverability Status
FCDS = Full Capacity Deliverability Status

Fully Deliverable vs. Energy Only



Transmission Constraint – On-Peak HSN Example

Constraint Type	Existing Transmission System Capability Estimate (MW)	Transmission Upgrade Capacity (MW)		Non-Storage Resource (r) Capability Required (MW)	Storage Resource (sr) Capability Required (MW)
On-Peak HSN: Highest System Need	Fully Deliverable (FCDS)	Upgrade FCDS MW	$\geq$	$\sum_r \left(\begin{array}{l} \text{Fully Deliverable Capacity}_r \ * \\ \text{Resource HSN Output Factor}_r \end{array} \right)$	$+ \sum_{sr} (\text{Installed Capacity}_{sr})$

There are three different limits for each transmission constraint; HSN limit used as example here

CAISO estimates of existing network capability and how upgrade would increase capability

Each resource has an output factor ranging from 0 to 1, representing capacity factor during periods when the constraint is limiting

Storage discharge (On-Peak) requires transmission capability; Storage charging (Off-Peak) increases transmission capability

Generalized Constraint Equations

On-Peak HSN: Highest System Need	Fully Deliverable (FCDS)	Upgrade FCDS MW	$\geq$	$\sum_r \left(\begin{array}{c} \text{Fully Deliverable Capacity}_r \ * \\ \text{Resource HSN Output Factor}_r \end{array} \right)$	$+\sum_{sr} (\text{Installed Capacity}_{sr})$
On-Peak SSN: Secondary System Need	Fully Deliverable (FCDS)	Upgrade FCDS MW	$\geq$	$\sum_r \left(\begin{array}{c} \text{Fully Deliverable Capacity}_r \ * \\ \text{Resource SSN Output Factor}_r \end{array} \right)$	$+\sum_{sr} (\text{Installed Capacity}_{sr})$
Off-Peak	Energy Only (EODS)	Upgrade EODS MW	$\geq$	$\sum_r \left(\begin{array}{c} \text{Installed Capacity}_r \ * \\ \text{Resource Off–Peak Output Factor}_r \end{array} \right)$	$-\sum_{sr} (\text{Installed Capacity}_{sr})$

EODS = Energy Only Deliverability Status
FCDS = Full Capacity Deliverability Status

Transmission Upgrades

- CAISO provided 44 constraints of which 28 were modelled in RESOLVE
  - Upgrades without a RESOLVE candidate resource weren't modeled
  - Some RESOLVE Constraint names may differ from names in CAISO white paper
- Transmission upgrades are not made available for selection until the First Available Year
  - Ensures that upgrades can be built on a feasible development timeline

RESOLVE Transmission Constraint Name	Resource Constraint Area	First Available Year	Upgrade size - On-peak (MW)	Upgrade size - Offpeak (MW)	Levelized Cost ($2020/MW-yr)
Delevan Cortina 230	Northern California	2034	2,838	N/A	87,364
Contra Costa Delta Switchyard 230	Northern California	2030	1,476	N/A	26,009
Humboldt Trinity 115	Northern California	2031	57	N/A	205,153
Gates Arco Midway 230	Southern PGAE	2031	3,137	332	3,374
Gates 500 230 Transformer	Southern PGAE	2026	4,453	1,603	732
Los Banos 500 230 Transformer	Southern PGAE	2028	446	N/A	65,595
Tesla Westley 230	Southern PGAE	2027	114	N/A	63,617
Gates Panoche 230	Southern PGAE	2027	378	6,723	55,275
Morro Bay Templeton 230	Southern PGAE	2031	739	123	125,914
Los Banos Gates 500 OPDS	Southern PGAE	2031	N/A	2,246	2,250
Moss Landing Los Banos 230 OPDS	Southern PGAE	2031	N/A	1,822	2,773
Tehachapi Antelope	Tehachapi	2024	2,700	N/A	476
South Kramer Victor	Greater Kramer	2029	430	480	22,883
South Kramer Victor Lugo	Greater Kramer	2025	430	N/A	51,832
Lugo Transformer	Greater Kramer	2026	980	N/A	6,906
Eldorado 500 230	El Dorado SNV	2026	400	N/A	16,920
GLW VEA	El Dorado SNV	2027	1,000	1,110	14,118
Mohave Eldorado 500	El Dorado SNV	No upgrade identified			
Serrano Alberhill	SCE Eastern/SDGE	2031	3,648	N/A	35,528
Colorado River 500 230	SCE Eastern/SDGE	2026	1,000	1,000	7,155
Devers Red Bluff	SCE Eastern/SDGE	2031	3,100	1,876	28,870
East of Miguel	SCE Eastern/SDGE	2032	1,412	943	223,754
Imperial Valley	SCE Eastern/SDGE	2031	400	N/A	46,850
Encina San Luis Rey	SCE Eastern/SDGE	2032	3,718	N/A	2,355
Internal San Diego	SCE Eastern/SDGE	2024	2,067	274	4,331
San Luis Rey San Onofre	SCE Eastern SDGE	2032	4,269	N/A	4,766
Silvergate Bay Boulevard	SCE Eastern SDGE	2028	2,119	N/A	1,360
Greater LA	Greater LA	No upgrade identified *			

* Upgrade modeled in RESOLVE with an extremely high cost to act as an "overflow" zone for long-run (~2040+ timeframe) planning

Input Data: Resource Output Factors for Transmission Capability Estimates

- Transmission capability varies with:
  - Resource type
  - Time of delivery
    - Highest System Need
    - Secondary System Need
    - Offpeak
  - Location
- CAISO provided **resource output factors** to reflect this:
  - The fraction of installed resource capacity that requires transmission space under different constraint scenarios
- Storage resources expand EODS limits via charging off-peak (negative 100% in EODS table)

Resource output factors – Full Capacity Deliverability Status (FCDS) Capability Estimates

On Peak Scenario	Highest System Need (HSN)			Secondary System Need (SSN)		
Load Serving Entity	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	3.0%	10.6%	10.0%	40.2%	42.7%	55.6%
Wind	33.7%	55.7%	66.5%	11.2%	20.8%	16.3%
Pumped Hydro	100%					
Li Battery	100%*					
Geothermal	100%					

Resource output factors – Energy Only Deliverability Status (EODS) Capability Estimates

Constraint Area Type	"Wind" Area			"Solar" Area		
Load Serving Entity	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	68.0%	68.0%	68.0%	79.0%	77.0%	79.0%
Wind	69.0%	64.0%	64.0%	44.0%	44.0%	44.0%
Pumped Hydro	-100%					
Li Battery	-100% *					
Geothermal	100% **					

* Discharge power capacity used for Li storage regardless of duration

**100% of Geothermal nameplate capacity assumed to need off-peak deliverability

Data Source: CAISO Whitepaper - Transmission Deliverability Study

Resource Constraint Assignment Northern California

Resources

Transmission Constraints	Northern California Wind	Solano Wind	Humboldt Wind	Humboldt Bay Offshore Wind	Solano Geothermal	Northern California Geothermal	Northern California Solar	Northern California Li Battery	Northwest Wind on Existing Transmission
Delevan Cortina 230	1	1	1	1	1	1	1	1	1
Contra Costa Delta Switchyard 230	0	1	0	0	1	0	0	0	1
Humboldt Trinity 115	0	0	1	1	0	0	0	0	0

1 indicates that the resource is included in the constraint;
0 indicates that it is not

Resource Constraint Assignment Southern PG&E

	Kern Greater Carrizo Wind	Carrizo Wind	Central Valley North Los Banos Wind	Diablo Canyon Offshore Wind	Morro Bay Offshore Wind	Southern PGAE Solar	Southern PGAE Li Battery
Gates Arco Midway 230	1	1	0	0	1	0	0
Gates 500 230 Transformer	1	1	1	0	1	0	0
Los Banos 500 230 Transformer	0	0	1	0	0	0	0
Tesla Westley 230	0	0	1	0	0	0	0
Gates Panoche 230	0	1	0	1	1	1	1
Morro Bay Templeton 230	1	1	1	0	1	0	0
Los Banos Gates 500 OPDS	1	1	0	0	0	0	0
Moss Landing Los Banos 230 OPDS	1	1	1	0	0	0	0

Resource Constraint Assignment Tehachapi, Greater Kramer, & El Dorado

El Dorado

	Southern NV Eldorado Solar	Southern NV Eldorado Li Battery	Southern Nevada Wind	Southern Nevada Geothermal	Wyoming Wind
Eldorado 500 230	1	1	1	1	0
GLW VEA	0	0	1	1	0
Mohave Eldorado 500	0	0	0	0	1

Tehachapi

	Tehachapi Wind	Tehachapi Solar	Tehachapi Li Battery	Tehachapi Pumped Storage
Tehachapi Antelope	1	1	1	1

Greater Kramer

	Greater Kramer Solar	Greater Kramer Li Battery	Inyokern North Kramer Geothermal
South Kramer Victor	0	0	1
South Kramer Victor Lugo	0	0	1
Lugo Transformer	1	1	1

Resource Constraint Assignment SCE + Eastern SDG&E

	Riverside Solar	Riverside Li Battery	Riverside Palm Springs Geothermal	Riverside Palm Springs Wind	Arizona Solar	Arizona Li Battery	New Mexico Wind	SW Ext Tx Wind	Imperial Solar	Imperial Li Battery	Greater Imperial Geothermal	Riverside East Pumped Storage	San Diego Pumped Storage	Baja California Wind	San Diego Li Battery
Serrano Alberhill	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
Colorado River 500 230	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
Devers Red Bluff	0	0	0	1	1	1	1	1	0	0	0	1	0	0	0
East of Miguel	0	0	0	0	1	1	1	1	1	1	1	0	0	1	0
Imperial Valley	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0
Encina San Luis Rey	0	0	0	0	0	0	0	0	1	1	1	0	1	1	1
Internal San Diego	0	0	0	0	0	0	0	0	1	1	1	0	1	1	1
San Luis Rey San Onofre	0	0	0	0	0	0	0	0	1	1	1	0	1	1	1
Silvergate Bay Boulevard	0	0	0	0	0	0	0	0	1	1	1	0	0	1	1

Resource Constraint Assignment Greater LA Constraint

- CAISO identified additional transmission capability near the Los Angeles area that is not included in other transmission constraints
  - The Greater LA constraint was created to include this transmission capability in RESOLVE.
- The Greater LA constraint combines the existing system capability for the following CAISO-identified constraints:
  - Orange County Area
  - Laguna Bell – Mesa Flow Limit
  - SCE Metro Area
- The Greater LA solar resource was limited to 3,000 MW based on interconnection queue activity

	Riverside West Pumped Storage	Greater LA Solar	Greater LA Li Battery
Greater LA	1	1	1

Serrano – Alberhill Transmission Constraint Example

- The following section provides an example of how resources, transmission limits, and transmission upgrades interact in RESOLVE
  - One of the largest transmission constraints is used as an example: the Serrano – Alberhill constraint in the Southern SCE area.

Serrano – Alberhill Tx Constraint Example Transmission Constraint Data

Constraint Attributes	
Full Capacity Deliverability	5,700 MW
Energy Only Deliverability	11,800 MW
Upgrade type	Adds peak deliverability
Upgrade size	3,648 MW
Upgrade cost	$1.48 Bn
Construction time	105 Months (+ 12 months for approval process)
Area constraint type (for off-peak deliverbality factors)	Solar

- Existing transmission lines provide:
  - 5.7 GW on-peak space
  - 11.8 GW off-peak space
- RESOLVE can build up to 3,648 MW of new **on peak** transmission capability
  - The upgrade creates 0 MW of off-peak capability
- Levelized cost of **35,528 $/MW-year** (2020 $)
  - This includes AFUDC* costs
- New transmission capability available from **2031** at the earliest

*Allowance for Funds Used During Construction (AFUDC)

Serrano – Alberhill Example: Resources

Resource Name	LSE Zone	Resource Type	HSN	SSN	Offpeak
	Used to look up resource output factors		Resource Output Factors		
Riverside Palm Springs Geothermal	N/A	Geothermal	100%	100%	100%
Greater Imperial Geothermal	N/A	Geothermal	100%	100%	100%
Riverside Li Battery	N/A	Li Battery	100%	100%	-100%
Arizona Li Battery	N/A	Li Battery	100%	100%	-100%
Imperial Li Battery	N/A	Li Battery	100%	100%	-100%
San Diego Li Battery	N/A	Li Battery	100%	100%	-100%
Riverside East Pumped Storage	N/A	PSH	100%	100%	-100%
San Diego Pumped Storage	N/A	PSH	100%	100%	-100%
Riverside Solar	SCE	Solar	11%	43%	77%
Arizona Solar	SCE	Solar	11%	43%	77%
Imperial Solar	SCE	Solar	11%	43%	77%
Baja California Wind	SDG&E	Wind	34%	11%	44%
New Mexico Wind	SCE	Wind	79%	29%	62%
Riverside Palm Springs Wind	SCE	Wind	61%	23%	48%
SW Ext Tx Wind	SCE	Wind	65%	24%	51%

The Serrano – Alberhill constraint has 15 associated resources in the SCE Eastern + SDG&E region

The constraint is in a solar constrained area and therefore the corresponding offpeak resource output factors are used

Serrano – Alberhill Example: On-Peak HSN

On-Peak HSN: Highest System Need	5,700 MW (constant)	+ Transmission Upgrade FCDS MW (RESOLVE decision variable)	≥	$0.106 * (FCDS\_Capacity_{Riverside\_Solar}$ $+ FCDS\_Capacity_{Imperial\_Solar}$ $+ FCDS\_Capacity_{Arizona\_Solar})$ + $1 * (FCDS\_Capacity_{Riverside\_Palm\_Springs\_Geothermal}$ $+FCDS\_Capacity_{Greater\_Imperial\_Geothermal})$ + $0.607 * FCDS\_Capacity_{Riverside\_Palm\_Springs\_Wind}$ + $0.788 * FCDS\_Capacity_{New\_Mexico\_Wind}$ + $0.647 * FCDS\_Capacity_{SW\_Ext\_Tx\_Wind}$	+ $Installed\_Capacity_{Riverside\_Li\_Battery}$ + $Installed\_Capacity_{Riverside\_East\_Pumped\_Storage}$ + $Installed\_Capacity_{Imperial\_Li\_Battery}$ + $Installed\_Capacity_{Arizona\_Li\_Battery}$

Only Fully Deliverable (FCDS) renewable capacity included in On-Peak constraints.

Serrano – Alberhill Example: On-Peak SSN

On-Peak SSN: Secondary System Need	5,700 MW (constant)	+ Transmission Upgrade FCDS MW (RESOLVE decision variable)	≥	0.427 * ($\text{FCDS\_Capacity}_{\text{Riverside\_Solar}}$ + $\text{FCDS\_Capacity}_{\text{Imperial\_Solar}}$ + $\text{FCDS\_Capacity}_{\text{Arizona\_Solar}}$) + 1 * ($\text{FCDS\_Capacity}_{\text{Riverside\_Palm\_Springs\_Geothermal}}$ +$\text{FCDS\_Capacity}_{\text{Greater\_Imperial\_Geothermal}}$) + 0.227 * $\text{FCDS\_Capacity}_{\text{Riverside\_Palm\_Springs\_Wind}}$ + 0.294 * $\text{FCDS\_Capacity}_{\text{New\_Mexico\_Wind}}$ + 0.242 * $\text{FCDS\_Capacity}_{\text{SW\_Ext\_Tx\_Wind}}$	+ $\text{Installed\_Capacity}_{\text{Riverside\_Li\_Battery}}$ + $\text{Installed\_Capacity}_{\text{Riverside\_East\_Pumped\_Storage}}$ + $\text{Installed\_Capacity}_{\text{Imperial\_Li\_Battery}}$ + $\text{Installed\_Capacity}_{\text{Arizona\_Li\_Battery}}$

Note that the coefficients change between HSN and SSN. Solar resources here require more on-peak space in the SSN constraint than the HSN

Serrano – Alberhill Example: Off-Peak

Off-Peak	11,800 MW (constant)	+ 0 MW (The Serrano – Alberhill upgrade provides no additional off-peak deliverability)	≥	0.77 * (Installed_Capacity$_{Riverside_Solar}$ + Installed_Capacity$_{Imperial_Solar}$ + Installed_Capacity$_{Arizona_Solar}$) + 1*(Installed_Capacity$_{Riverside_Palm_Springs_Geothermal}$ + Installed_Capacity$_{Greater_Imperial_Geothermal}$) + 0.480 * Installed_Capacity$_{Riverside_Palm_Springs_Wind}$ + 0.643 * Installed_Capacity$_{New_Mexico_Wind}$ + 0.511 * Installed_Capacity$_{SW_Ext_Tx_Wind}$	- Installed_Capacity$_{Riverside_Li_Battery}$ - Installed_Capacity$_{Riverside_East_Pumped_Storage}$ - Installed_Capacity$_{Imperial_Li_Battery}$ - Installed_Capacity$_{Arizona_Li_Battery}$

Note: Many of the CAISO-identified upgrades do increase off-peak deliverability

-1 coefficient for storage resources represents charging off-peak. Storage charging decreases available energy in the constraint zone off-peak.

END ATTACHMENT A

ATTACHMENT B

Reliability and GHG Modeling Results
Aggregated LSE Plans
38 MMT Core Portfolio

August 17, 2021
Energy Resource Modeling Team
Energy Division

California Public
Utilities Commission

Outline of this Presentation

- Summary of Results
- Background/Definitions – Loss of Load and Production Cost Modeling
- Study Definitions - LOLE studies conducted on Aggregated System Plan
  - 46 MMT Aggregated LSE Plans
  - 38 MMT Aggregated LSE Plans
- Study Definitions - 38 MMT Core portfolio
  - 2026 38 MMT Core Results
  - 2030 38 MMT Core Results
- Study Definitions - sensitivities
  - 2026 38 MMT Sensitivity – Geothermal moved to 2026
  - 2026 38 MMT Sensitivity – PSH moved to 2026
  - 2026 38 MMT Sensitivity – 1000 MW batteries moved to 2026
- Conclusion and next steps

Summary of results

Aggregated LSE Plans

- LSE IRP plans - Aggregated 46 MMT and 38 MMT Portfolios are not reliable.
  - LOLE are greater than 0.1 in all studies and all years.
- GHG targets met in 46 MMT case, but not met in 38 MMT cases.
- More renewable and reliability capacity is needed in order to make the LSE plans meet state objectives.

38 MMT Core Portfolio and Sensitivities

- The 38 MMT Core portfolio is reliable – LOLE is below 0.1 - and modeling confirms GHG emissions are significantly lower than the Aggregated LSE Plans.
- The 2026 sensitivity, enforcing 2026 rather than 2028 delivery dates on a portion of the MTR resources, demonstrates significantly lower GHG emissions and reduced reliability risk.
  - LOLE of 0.065 is below 0.1 but there is some uncertainty as to operational constraints and resource viability.
- Additional operational and LOLE results data will be made available to stakeholders for their review.

Background

- LSEs submitted IRP plans in September 2020
  - Reached Aggregated LSE Portfolios for both 46 MMT and 38 MMT GHG scenarios after several rounds of corrections and resubmittals.
- CPUC's IRP process:
  - Staff used aggregated LSE IRP portfolios to design portfolios of new resources expected to meet electric system planning goals at least cost.
  - Staff used the SERVM probabilistic reliability and production cost model (PCM) to validate the reliability, operability, and emissions of resource portfolios generated by RESOLVE. Staff modeled 38 MMT and 46 MMT portfolios for both 2026 and 2030 study years.

Overall PCM Framework

- Probabilistic reliability planning approach – primary goal: reduce risk of insufficient generation to an acceptable level.
- Uses the Strategic Energy Risk Valuation Model (SERVM), a probabilistic system-reliability planning and production cost model – Configured to assess a given portfolio in a target study year under a range of future weather (20 weather years), economic output (5 weighted levels), and unit performance (outages) assumptions
- Simulate hourly economic unit commitment and dispatch
- Multiple day look-ahead informs unit commitment
- Individual generating units and all 8,760 hours of year are simulated – hourly results
- 8 CA regions, 16 rest-of-WECC regions - pipe and bubble representation of regions

Probabilistic Reliability Model Definitions

- **Expected Unserved Energy (EUE):** expected magnitude of unserved energy, expressed in total MWh of firm electric demand or reserves unserved per year
- **Loss of loss hours per loss of load event (LOLH/LOLE):** expected average duration of each LOLE event expressed as hours/event
- **Normalized EUE:** EUE normalized by the average annual load level for the target study year
- **0.1 loss of load expectation (LOLE) per year target:** value for LOLE that corresponds to the "1 day in 10 year" industry standard for probabilistic system reliability, where > 0.1 LOLE indicates a less reliable system and < 0.1 LOLE indicates a more reliable system. There are no commonly accepted standards for the other forms of reliability metrics.
- **EUE Intra-Hour:** Expected unserved energy due to ramping constraints not identified 1 hour prior to the hour being simulated.
- **EUE Multi-Hour:** Expected unserved energy due to ramping constraints identified >1 hour prior to the hour being simulated
- **EUE Capacity:** Expected unserved energy due to capacity shortage

PCM results – Aggregated LSE 38 MMT and 46 MMT Portfolios

Study Definitions

- **Aggregated LSE Plans 46 MMT for 2026 and 2030**

  - Staff began with the PCM baseline and electric demand inputs used to produce the Transmission Planning Process (TPP) portfolios sent to the California Independent System Operator (CAISO) for their 2021-2022 TPP process. These portfolios are described in a CPUC ruling from October 2020. Staff updated the baseline resource fleet with new units online in CAISO information, then replaced RESOLVE planned capacity with capacity included in aggregated LSE 46 MMT portfolios to generate Aggregated 46 MMT LSE Plans.

- **Aggregated LSE Plans 38 MMT for 2026 and 2030**

  - The Aggregated LSE Plans 38 MMT Portfolio is also based on the TPP portfolios sent to the CAISO, adjusted for new baseline units and RESOLVE planned capacity replaced by aggregated LSE 38 MMT portfolios. The resulting Aggregated 38 MMT LSE Plans were also tested in PCM model.

CPUC ruling issuing proposed 2021-2022 TPP portfolios linked here: https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=348821790

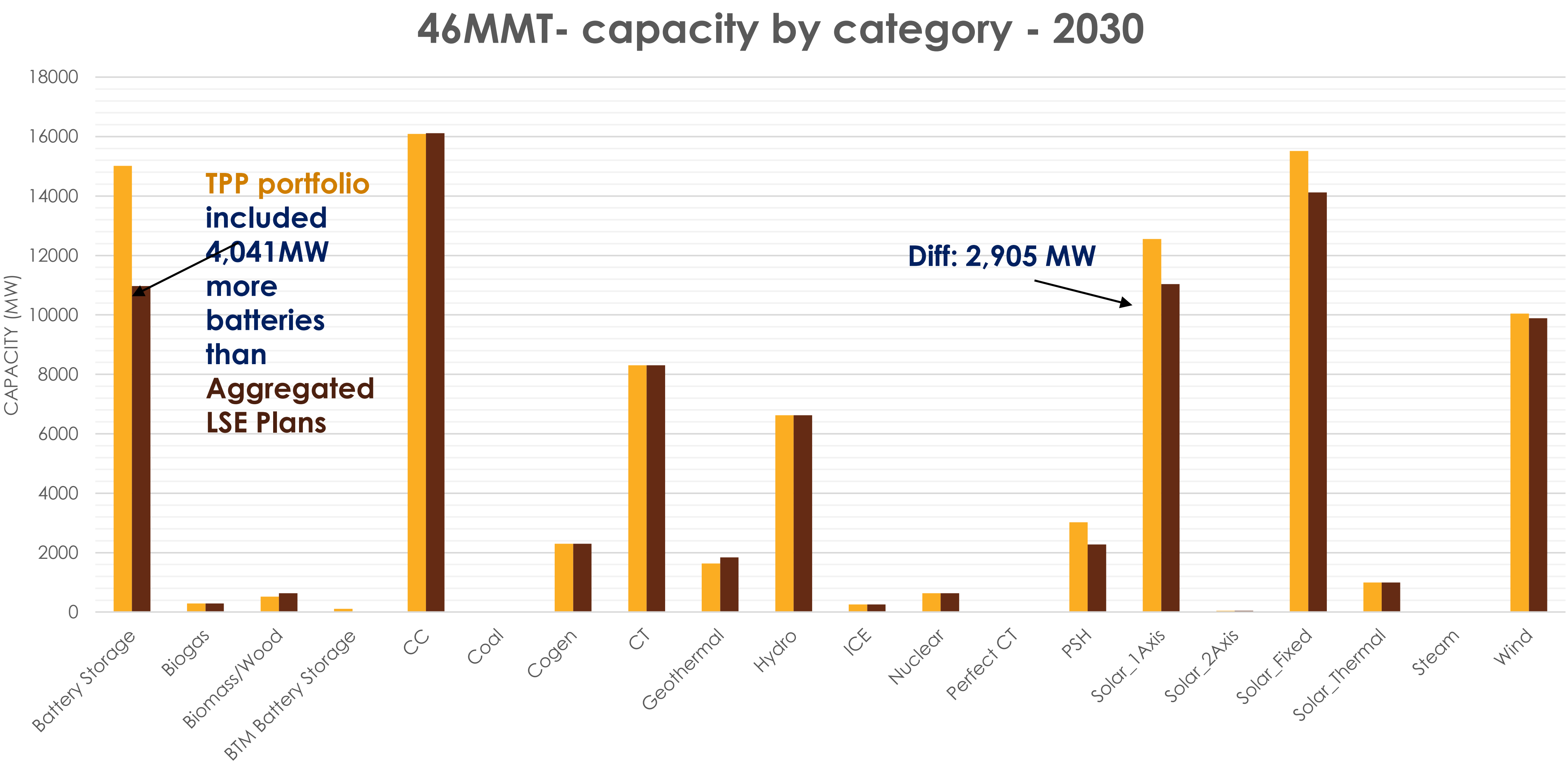
Specific updates to SERVM PCM model since TPP studies

- The LSEs Portfolio represents a combination of the existing baseline resources with the new resource build-out proposed by LSEs in their IRP plans, adjusted for assumed physical limitations.
- Steps used to build the LSEs Portfolio:
  1. Began with the PCM inputs to SERVM for the TPP portfolios. The TPP portfolios are based on updated 2019 IEPR forecasts.
  2. Replaced the "Selected Resources" (new build) from RESOLVE to reflect the LSE new build portfolio preferences as submitted in their IRP plans
- Staff updated the resource baseline in SERVM in four steps - baseline reconciliation with updated CAISO generator lists, performed ground truth adjustments for data errors particularly in the WECC Anchor Data Set, added LSE IRP filings by adding Development resources firmly under contract, then finally added Review and Planned_new resources that are not highly certain units or contracts yet

SERVM Inputs – TPP versus PSP

- Staff studied years 2026 and 2030 of the 46 MMT and 38 MMT portfolios from LSE IRP filings. As a point of comparison to previous PCM results published for parties, staff compared the Aggregated LSE PSP to the TPP portfolio staff sent to the CAISO in January 2021 for the 2021-2022 TPP. The TPP portfolio showed greater capacity added, resulting in better LOLE and GHG results relative to the Aggregated PSP portfolio.
  - Large differences are seen in Solar and Battery additions, and by 2030 there is significantly less overall capacity in LSEs' plans
  - Other resource types are similar
  - Hybrid resources in LSE plans separated into battery and solar lines for comparison to TPP

MW capacity – TPP portfolio vs. Aggregated LSE Plans



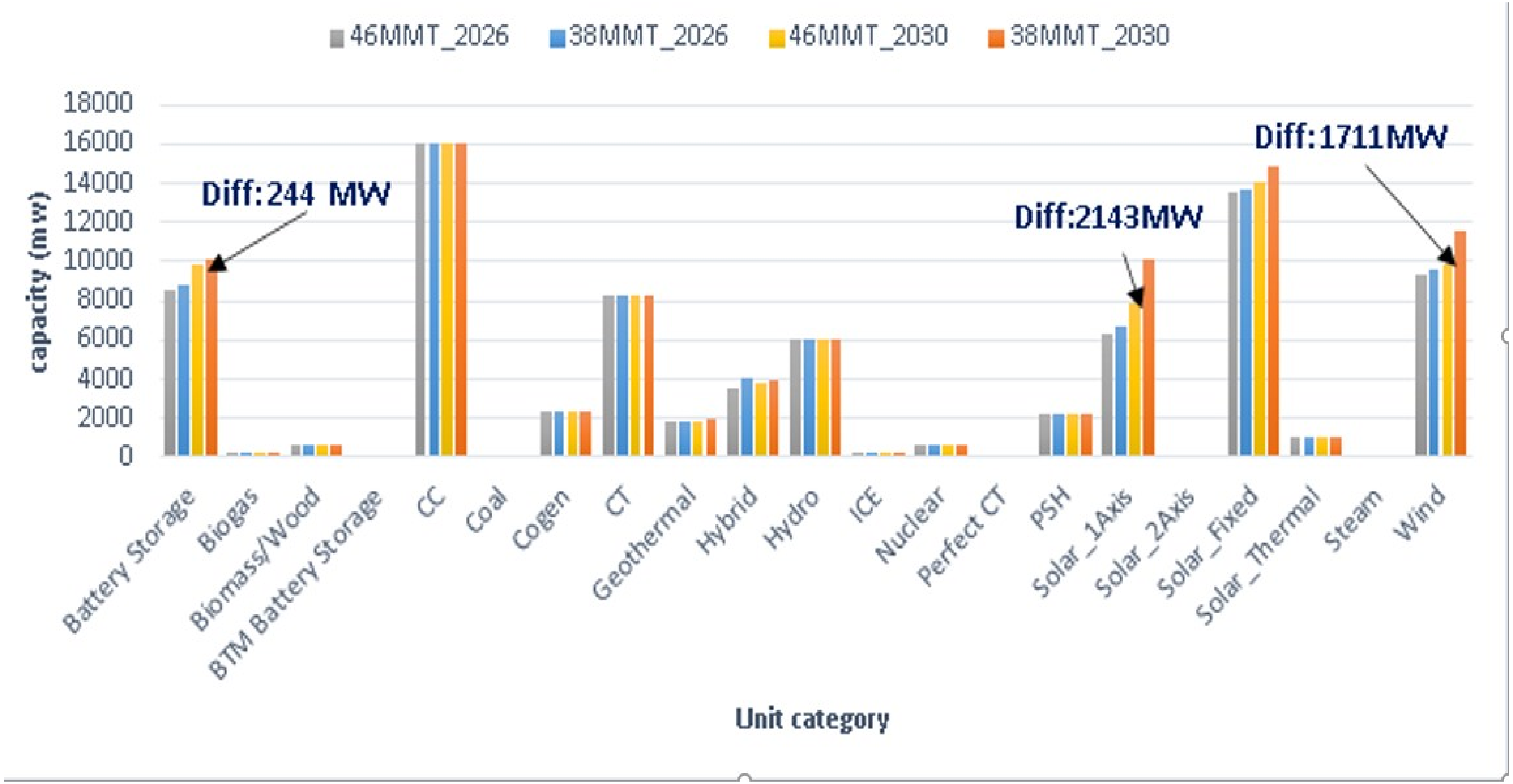
Note – For purposes of comparison, hybrids were split into battery storage and solar categories. Also batteries were restricted to only charge from the solar, not the grid.

Capacity Comparison (MW) 46 and 38 MMT Aggregated LSE Plans

- Aggregated LSE Plans were similar between the 46 and 38 MMT portfolios, with the 38 MMT plans including slightly more solar and wind resources.

	2026		2030	
Unit Category	38MMT_PSP	46MMT_PSP	38MMT_PSP	46MMT_PSP
AAEE	2,121	2,121	3,279	3,279
Battery Storage	8,745	8,549	10,064	9,820
Biogas	290	290	290	290
Biomass/Wood	609	610	638	634
BTM Battery Storage	0	0	0	0
BTMPV	18,833	18,833	22,878	22,878
CC	16,116	16,116	16,116	16,116
Coal	0	0	0	0
Cogen	2,299	2,299	2,299	2,299
CT	8,307	8,307	8,307	8,307
DR	1,726	1,726	1,704	1,704
EV	-3,120	-3,120	-4,794	-4,794
Geothermal	1,803	1,768	1,910	1,840
Hybrid	4,051	3,503	3,954	3,829
Hydro	6,004	6,004	6,004	6,004
ICE	255	255	255	255
Nuclear	635	635	635	635
Perfect CT	0	0	0	0
PSH	2,273	2,273	2,273	2,273
Solar_1Axis	6,717	6,269	10,064	7,921
Solar_2Axis	47	47	47	47
Solar_Fixed	13,720	13,571	14,836	14,122
Solar_Thermal	997	997	997	997
Steam	0	0	0	0
TOU	-2,907	-2,907	-3,003	-3,003
Wind	9,658	9,393	11,602	9,891
Total	99,178	97,537	110,355	105,343

Comparison of LSE 38MMT and 46MMT Portfolios

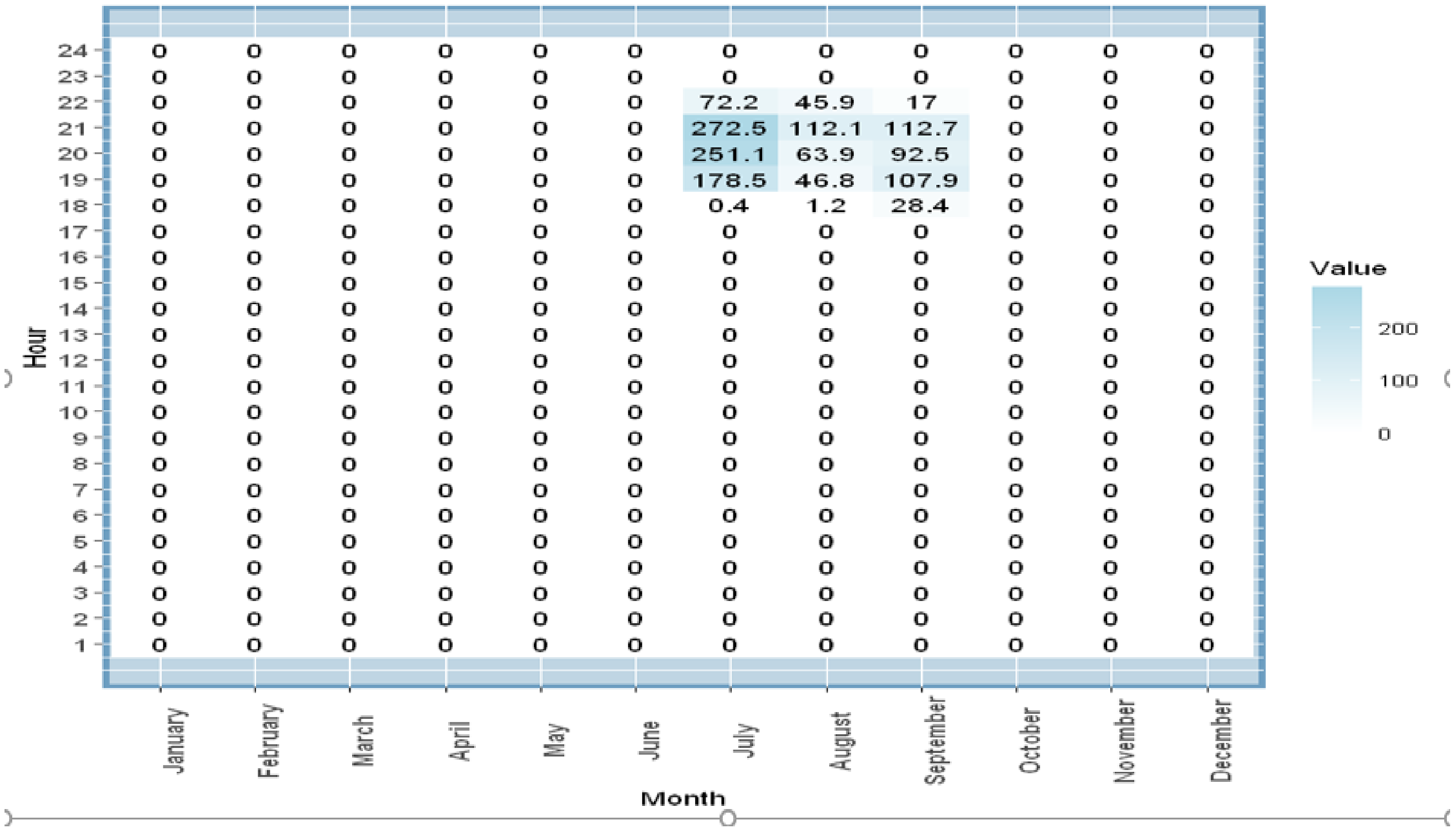


Aggregated LSE Plans – CAISO LOLE Exceeds 0.1 target in all studies

Reliability Metrics	46MMT 2026	46MMT 2030	38MMT 2026	38MMT 2030
LOLE (expected outage events/year)	0.36	0.68	0.29	0.41
Loss of Load Hours (hours/year)	0.76	1.63	0.61	0.94
LOLH/LOLE (hours/event)	2.09	2.38	2.07	2.26
Expected Unserved Energy (MWh)	1,436.66	2,468.93	1,176.91	1,364.54
Annual load (MWh)	255,116,344	265,501,285	255,094,310	258,290,192
normalized EUE (%)	5.631E-06	9.299E-06	4.614E-06	5.283E-06

Findings: LOLE is greater than 0.1 in all studies and all years, meaning the Aggregated LSE Plans portfolio is unreliable.

38 MMT study for 2030 - EUE (MWh) by Hour and Month



- Bulk of EUE occurs in July evening hours.
- the EUE hours shift later, likely due to further peak shift from solar penetration.

NOTE: The chart only shows hours with nonzero EUE in at least one month. The graded color scale shows the magnitude of the EUE in a given month-hour. Dark blue indicates the largest EUE, followed by light blue ,and white.

SERVM Annual Energy Generation Results (GWh)

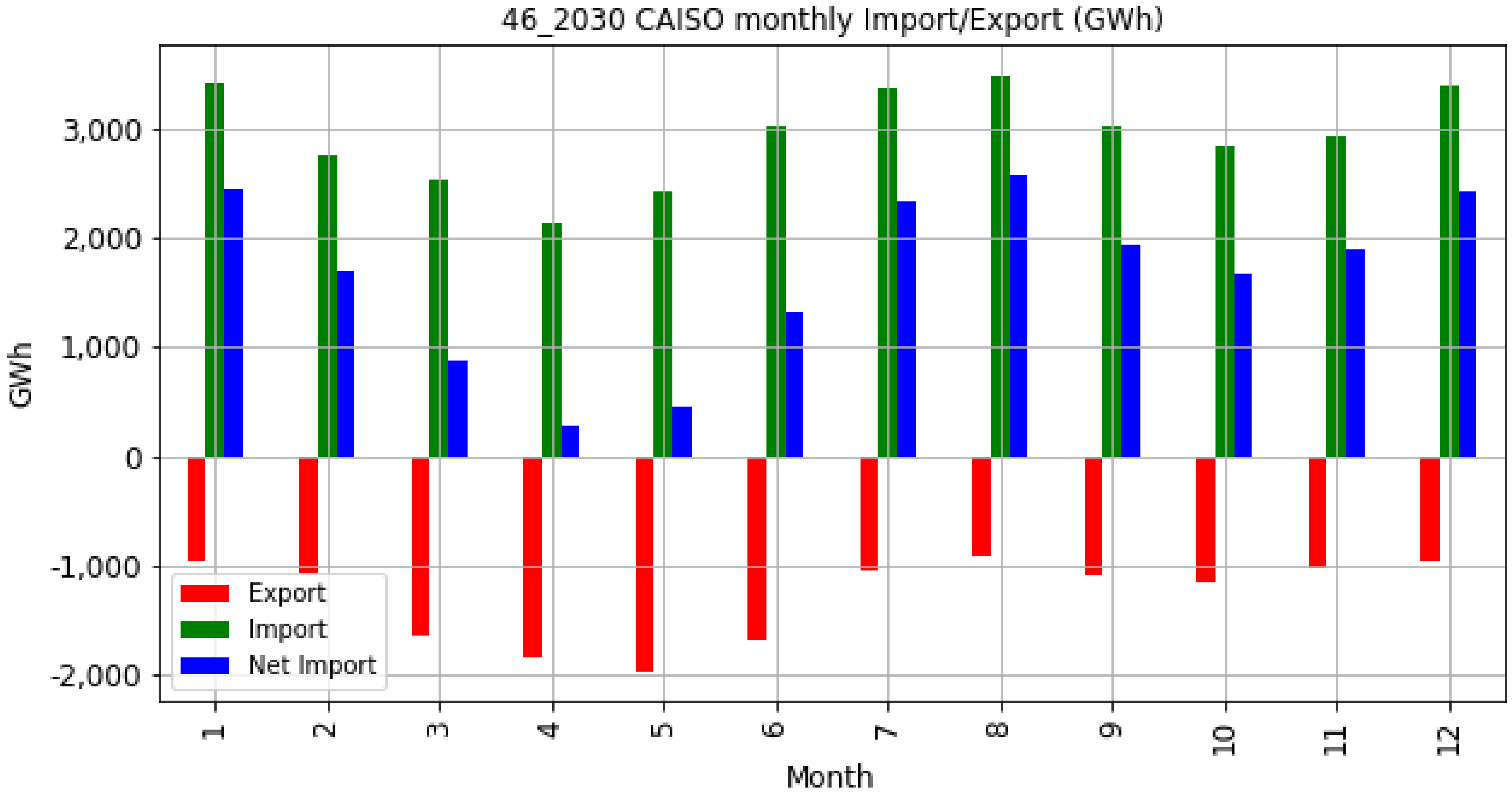
Resource type/Annual GWh	46MMT_2026	46MMT_2030	38MMT_2026	38MMT_2030
CAISO_CCGT1	44,715	46,109	43,721	41,023
CAISO_CCGT2	5,323	5,616	5,211	4,984
CAISO_Peaker1	2,795	3,138	2,852	3,002
CAISO_Peaker2	1,453	1,789	1,482	1,682
Perfect CT	0	0	0	0
Steam	0	0	0	0
Coal	0	0	0	0
Biomass	6,609	6,547	6,534	6,046
BTMPV	32,301	39,177	32,256	38,100
All Solar: fixed PV, tracking PV, solar thermal	51,436	57,487	53,075	63,541
Wind	23,534	24,730	24,570	28,056
Scheduled Hydro Plus ROR Hydro	25,122	25,394	25,392	24,735
Geothermal	14,486	14,951	14,714	14,760
Cogen	12,010	12,285	11,997	11,738
Nuclear	5,563	5,136	5,563	4,995
ICE	71	88	70	75
Generation Subtotal Before Curtailment	225,418	242,446	227,437	242,736
Non-PV Load Modifiers (net effect of AAEE, EV load, TOU)	-858	-2,698	-858	-2,623
Curtailment not included inline above	-551	-1,370	-674	-3,107
TOTAL not including Non-PV load modifiers	224,867	241,076	226,763	239,628

SERVM Annual GHG Emissions Results

CAISO Emissions accounting	46MMT_2026	46MMT_2030	38MMT_2026	38MMT_2030
In-CAISO and gross direct imports thermal generation in GWh	66,367	69,024	65,332	62,504
In-CAISO and gross direct imports CO2 emissions in MMT	27.21	28.41	26.82	25.78
In-CAISO and gross direct imports average emissions factor in MT/MWh	0.41	0.412	0.411	0.412
Unspecified imports netted hourly (no NW Hydro) in GWh	20,109	17,134	19,239	13,922
NW Hydro imports in GWh	11,000	11,000	11,000	11,000
Carbon-free imports from RPS energy, RECs contracts	0	0	0	0
Unspecified imports netted hourly (no NW Hydro) CO2 emissions in MMT	8.61	7.33	8.23	5.96
Unspecified imports netted hourly (including NW Hydro) average emissions factor in MT/MWh	0.277	0.261	0.272	0.239
Total CAISO CO2 emissions in MMT	35.8	35.7	35.1	31.7
BTM CHP emissions in MMT	5	5	5	5
Total CAISO CO2 emissions in MMT, including BTM CHP	**40.8**	**40.7**	**40.1**	**36.7**

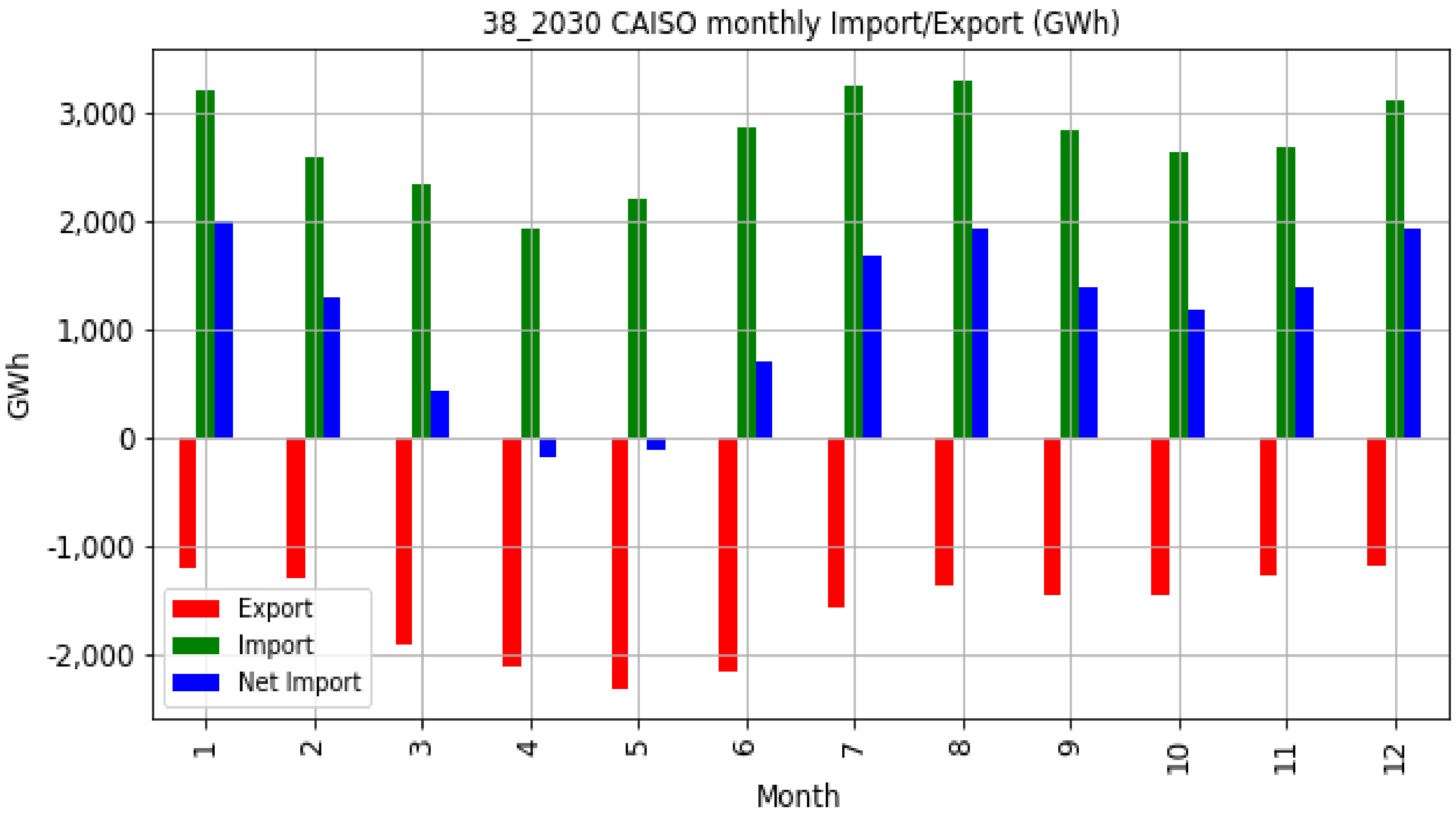
PSP portfolio GHG results close to RESOLVE in 46 MMT case **BUT about 5.5 MMT too high in the 38 MMT 2026 and 2030 cases.**

46 MMT 2030 CAISO average monthly Import/Export



With a 46 MMT buildout from LSE plans, CAISO is a net importer for all12 months

38 MMT 2030 CAISO average monthly Import/Export



In the 38 MMT portfolio from LSE Plans, CAISO is a net importer in 10 out of 12 months and LSE plans lead to less imports in summer than 46 MMT portfolio

Aggregated LSE Plans PCM Conclusions

- LSE IRP plans - 46 MMT and 38 MMT PSP Portfolios are not reliable.
  - LOLE are greater than 0.1 in all studies and all years.
- GHG targets met in 46 MMT case, but not met in 38 MMT cases.
- More renewable and reliability capacity is needed in order to augment the LSE plans to ensure meeting reliability and GHG targets.
- In developing the PSP, certain conventions were made even more conservative, meaning these results may understate LOLE resulting from the Aggregated LSE Plans would be even higher.
  - Reinforces that Aggregated LSE Plans portfolio is unreliable.

PSP 38 MMT Core Portfolio and Sensitivities

Study Definitions – 38 MMT Core Portfolio

38 MMT 2026 and 2030 Core Portfolio Definition:

Existing Baseline
+ Aggregated 38 MMT LSE plans
+ Mid Term Reliability procurement
+ RESOLVE resource additions

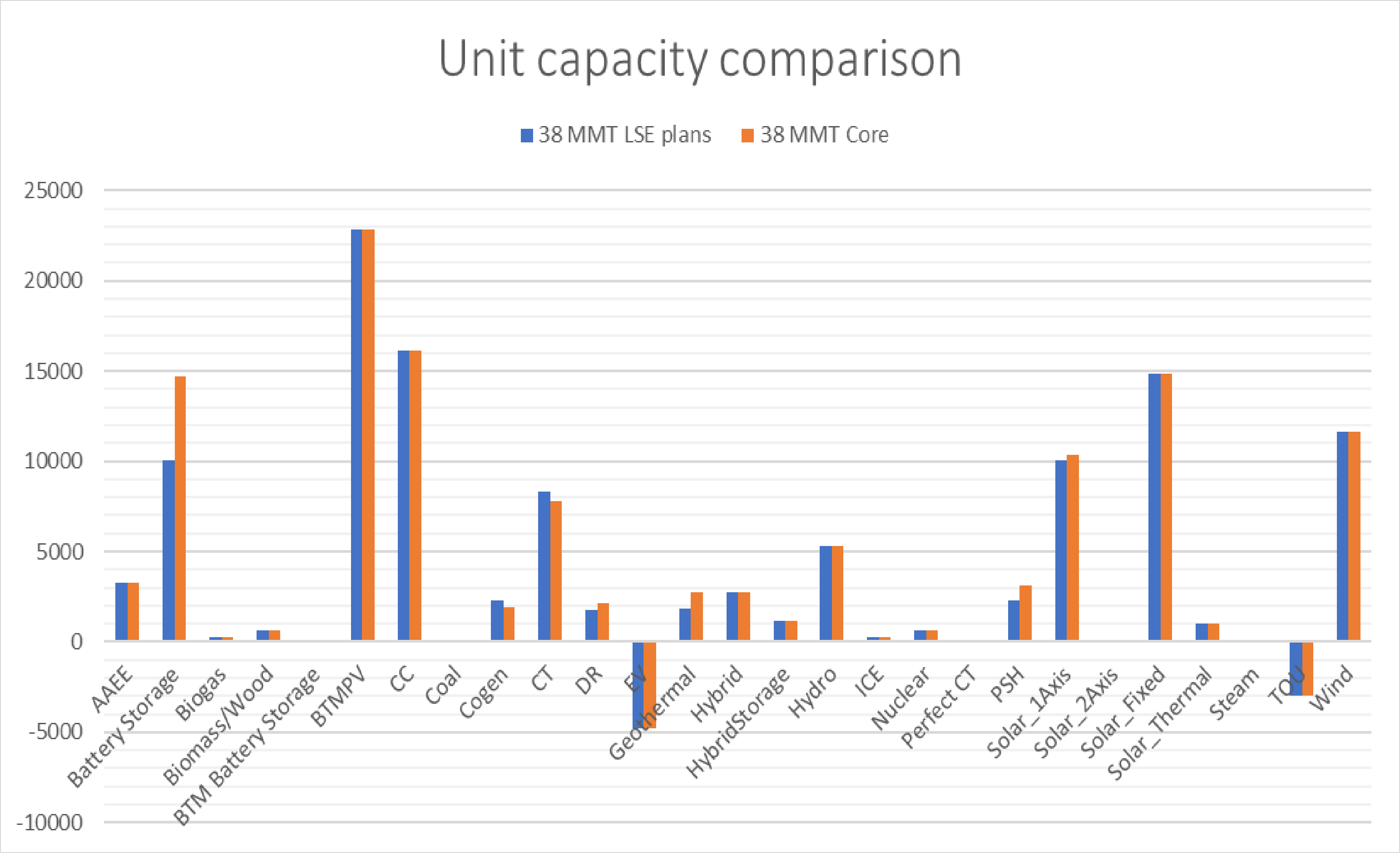
Definition of 38 MMT sensitivity cases:

2026 38 MMT Sensitivity – Geothermal moved to 2026
2026 38 MMT Sensitivity – Pumped Storage Hydro moved to 2026
2026 38 MMT Sensitivity – 1,000 MW Battery Storage moved to 2026

38 MMT Core - Modeling conventions

- 4,000 MW import restriction – imposed from HE17-HE22, Jun thru Sep (Jul thru Sep in previous studies)
- Fully implemented CAISO reserve requirements (including load following and regulation requirements) to create a LOLE event when 3% spinning reserves or 3% regulation up reserves are not met. In addition, other types of reserves (Quickstart reserves and load following reserves) were matched to CAISO requirements.
- Certain assumptions reflect historical data without projections of future climate change; for example hydro assumptions based on weather year 1998-2017, which means recent low hydro years since 2018 are not part of the analysis. Current low hydro conditions may recur in future years given climate change, particularly in California, which may exacerbate reliability conditions due to decreased overall hydro generation. Likewise, other planning assumptions may not fully represent a climate change future.

Aggregated LSE Plans vs. 38 MMT Core (2030)



38 MMT Core case:

- +47% in battery storage
- +46% in geothermal
- +36% in PSH
- +21% in DR
- Slight increase in solar and wind
- ~950 MW thermal retirement (Cogen and CT)

Generation in GWh RESOLVE vs. SERVM

Technology (GWh)	RESOLVE_2026	SERVM_2026	RESOLVE_2030	SERVM_2030
CAISO_CCGT1	46,106	47,036	32,273	41,118
CAISO_CCGT2	2	5,812	2	5,179
CAISO_Peaker1	1	4,341	1	4,431
CAISO_Peaker2	1	2,269	0	2,653
Battery Storage	-3,562	-3,555	-4,234	-3,838
PSH	-664	-1,772	-1,506	-2,274
Steam	0	0	0	0
Coal	0	0	0	0
Biomass	4,957	6,592	5,148	6,580
BTMPV	32,779	32,256	39,528	39,177
All Solar: fixed PV, tracking PV, solar thermal	70,302	68,749	78,547	74,688
Wind	27,334	25,066	32,980	28,849
Scheduled Hydro Plus	22,964	25,393	22,962	25,394
Geothermal	10,082	14,311	17,411	22,069
Cogen	8,967	10,156	8,967	9,961
Nuclear	5,108	5,563	5,108	5,136
ICE	7	75	6	62
Generation Subtotal	224,383	242,292	237,193	259,184
Imports (unspecified)	24,134	27,328	23,832	26,486
Exports	-3,877	-16,041	-7,030	-20,564
Net Import	20,257	11,287	16,803	5,923
Generation+NetImport	244,640	253,579	253,996	265,106

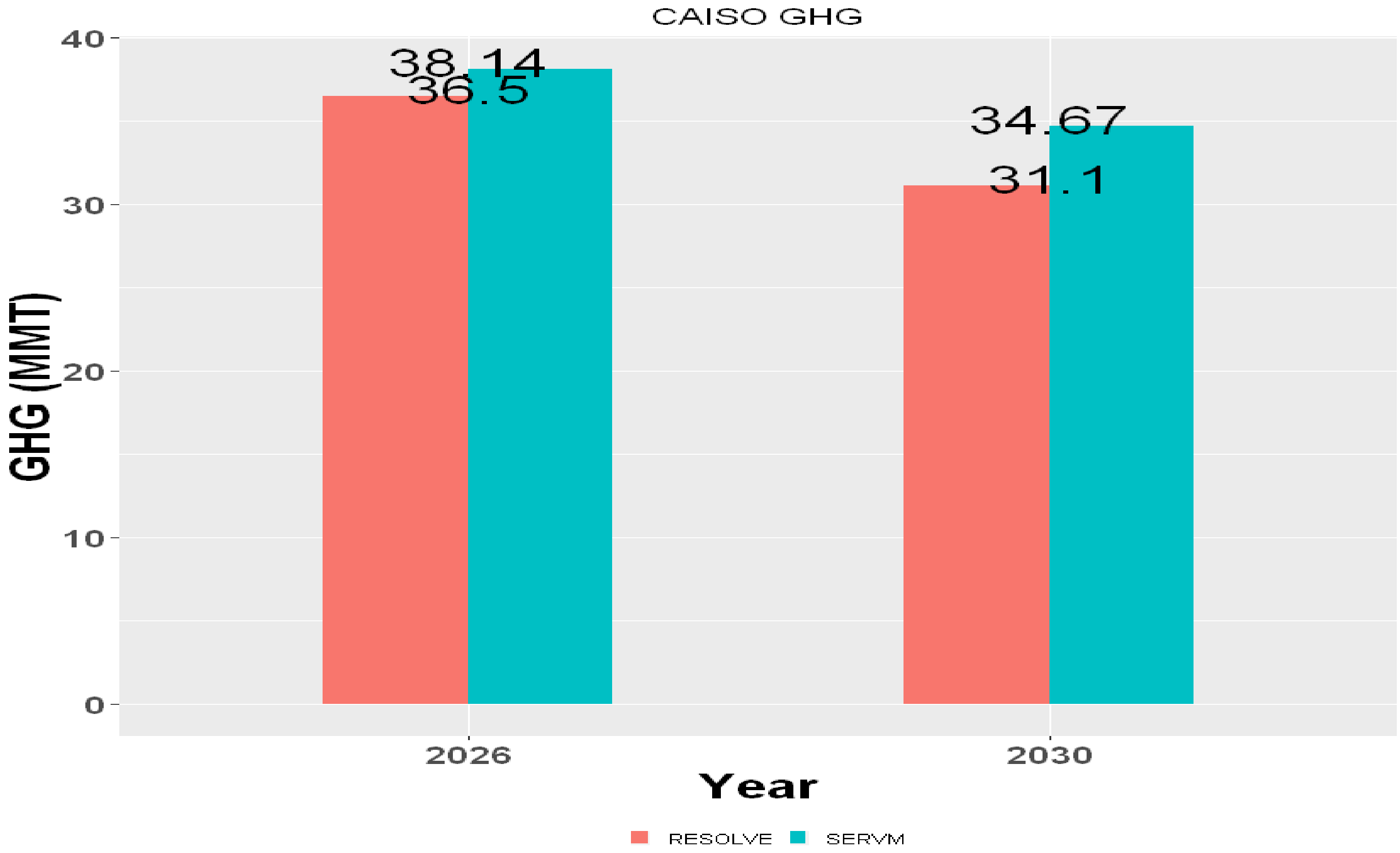
- SERVM produces similar amounts of GHG-free energy (about 201 TWh total in 2030) to RESOLVE, but more GHG emitting energy, and about 13 TWh more exports relative to RESOLVE
- SERVM produces 9% more in-CAISO generation than RESOLVE but lower net imports, totaling about 4% more total net energy for CAISO.

38 MMT Core LOLE Capacity results for the CAISO area

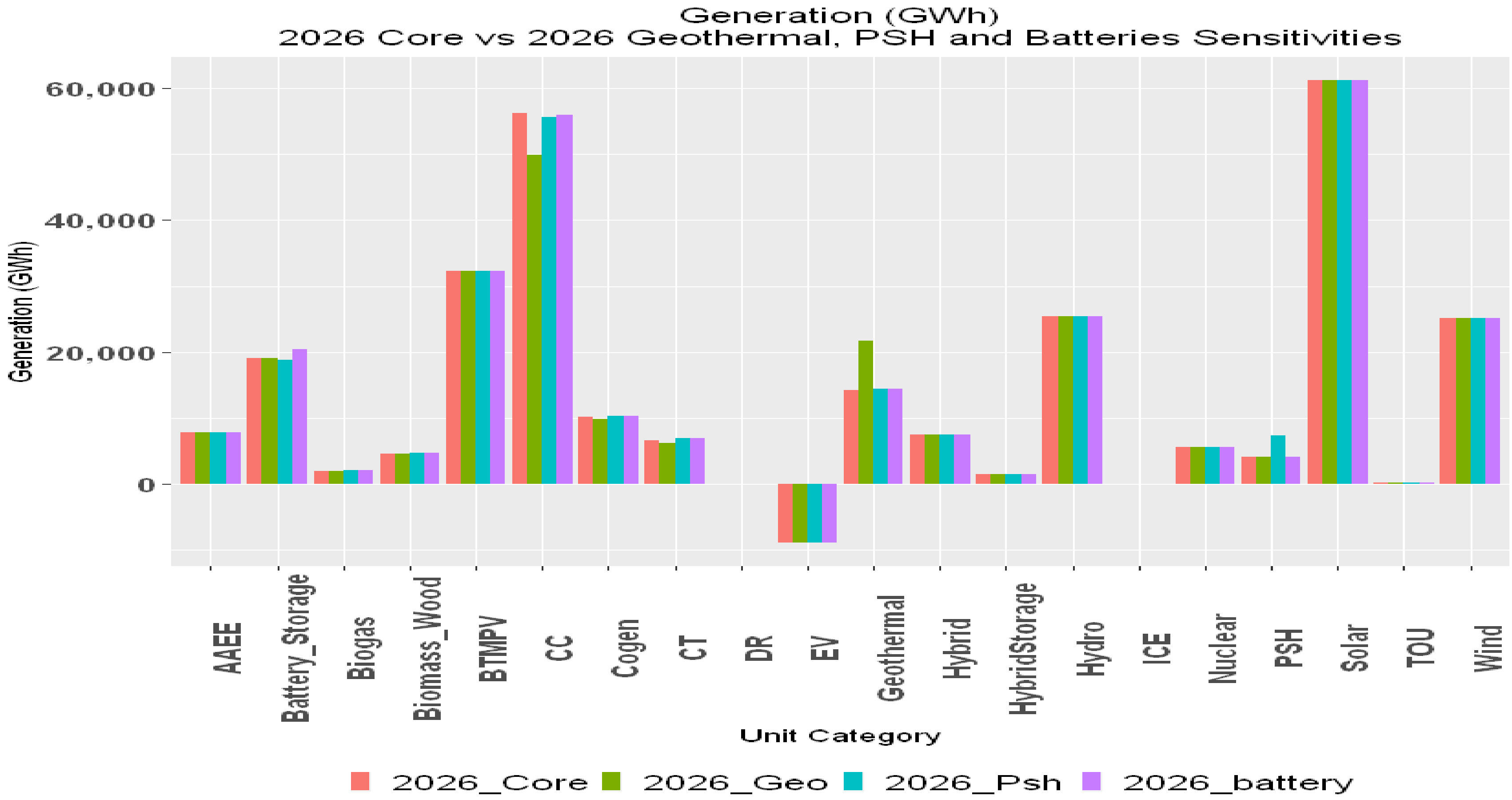
Reliability and GHG Metrics	38 MMT 2030	38MMT 2026
LOLE (expected outage events/year)	**0.054**	**0.064**
LOLH (hours/year)	0.15	0.21
LOLH/LOLE (hours/event)	1.72	1.76
EUE (MWh)	187.45	292.28
annual load (MWh)	265,753,062	255,345,985
normalized EUE (%)	7.054E-07	1.145E-06
GHG (MMT)	**34.67**	**38.14**

Findings: LOLE is less than 0.1 in both 2026 and 2030, meaning this portfolio is reliable. GHG emissions in 2026 are about 1 MMT higher than RESOLVE but GHG emissions in 2030 are about 3 MMT higher than RESOLVE.

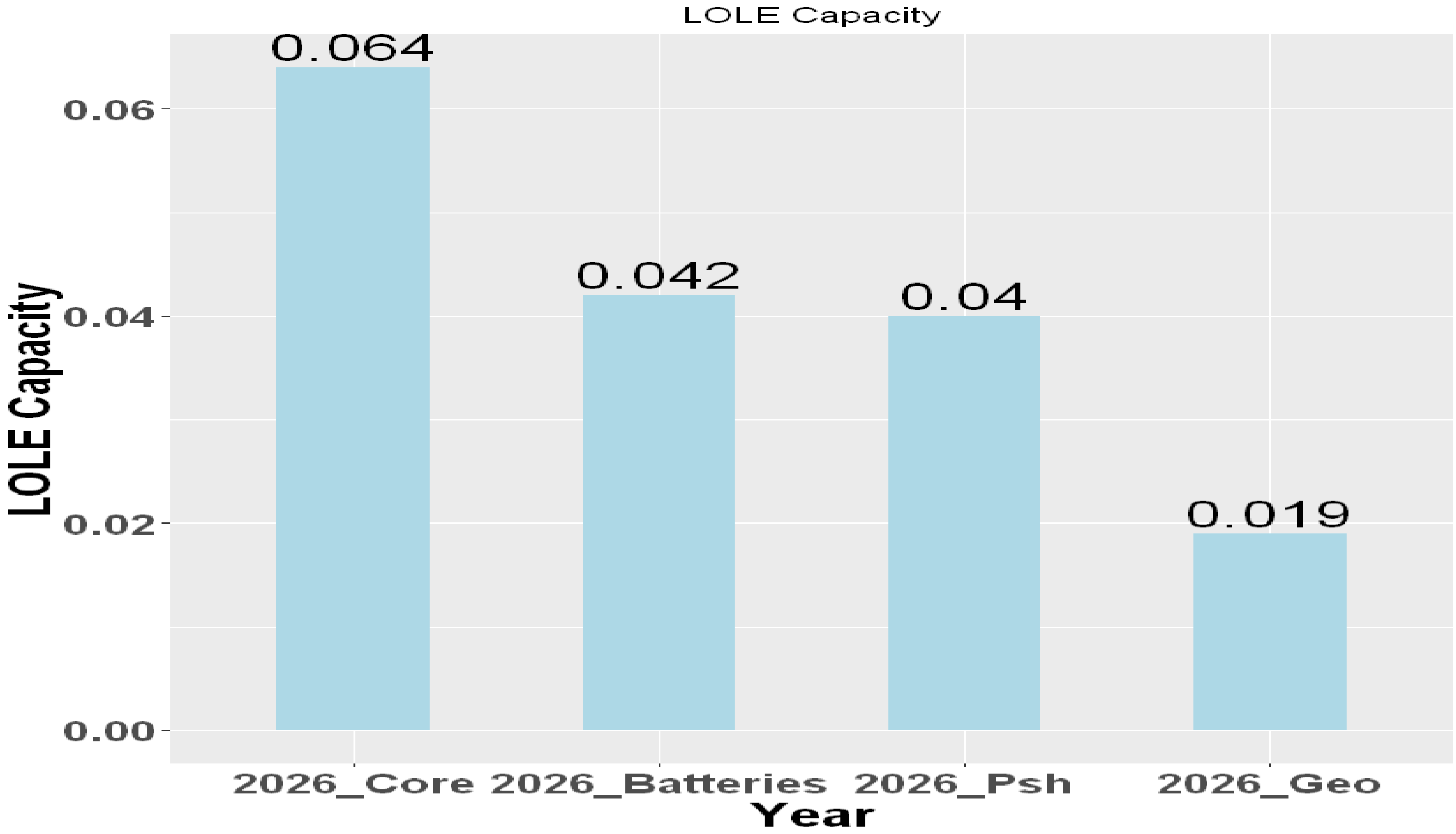
38 MMT Core Total CAISO CO2 emissions in MMT, including BTM CHP



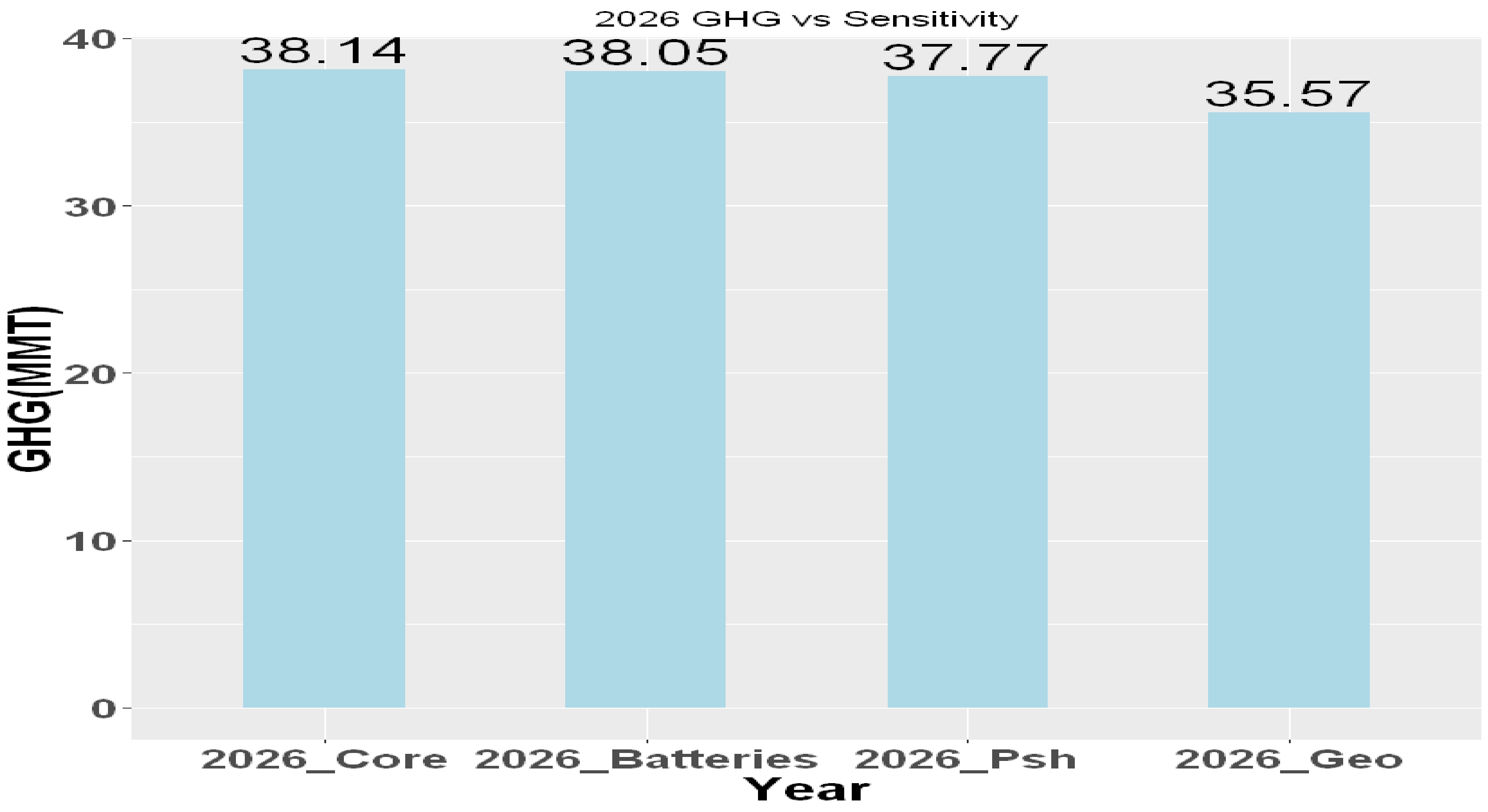
Generation by unit category for 2026: Core vs. 3 Sensitivities



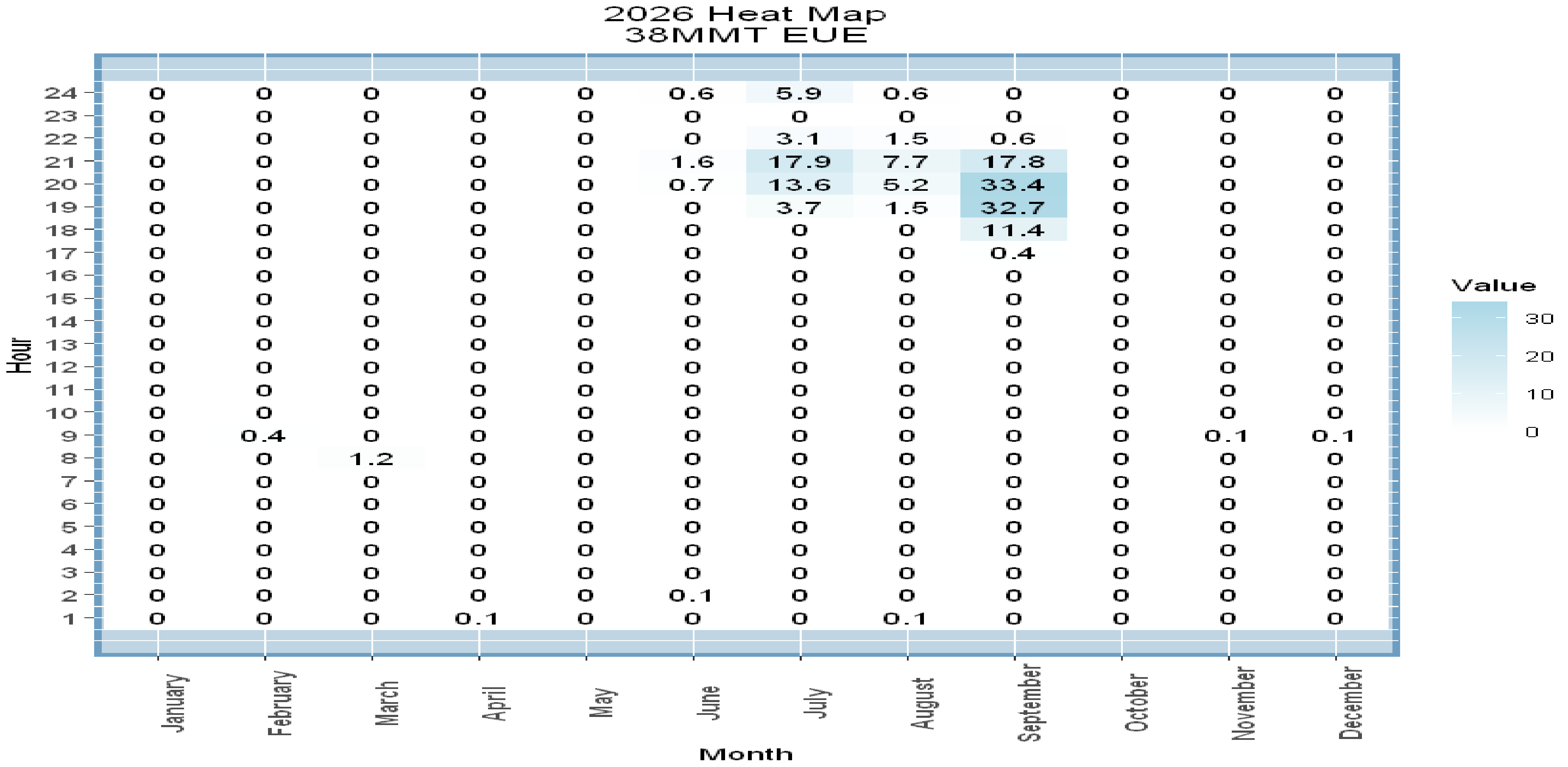
LOLE for 2026: Core case vs. Sensitivities



GHG for 2026: Core case vs. Sensitivities



38 MMT Core (2026) – EUE (MWh) by Hour and Month



38 MMT Core (2030) – EUE (MWh) by Hour and Month

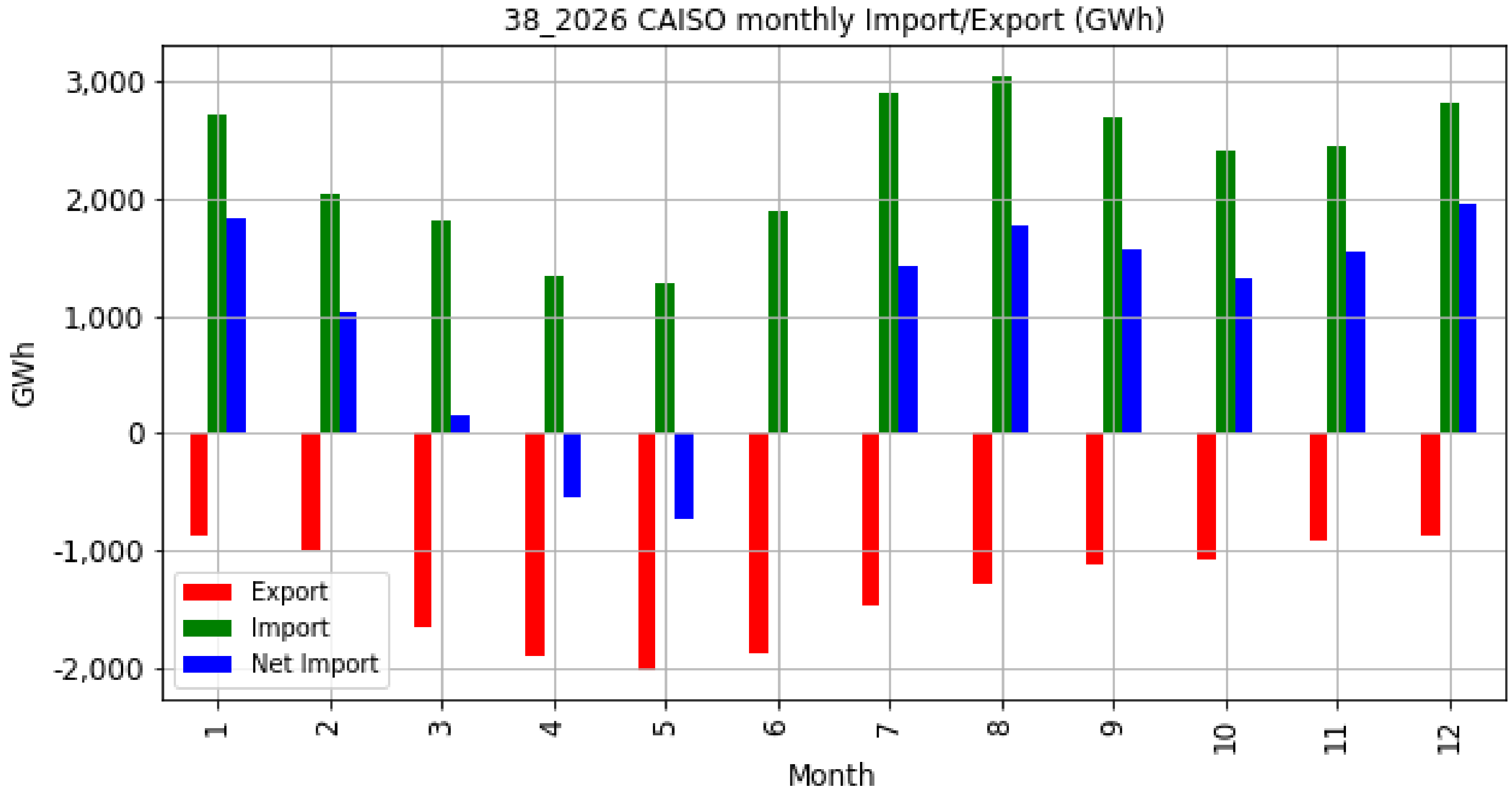
2030 Heat Map
38MMT EUE

Hour	January	February	March	April	May	June	July	August	September	October	November	December
24	0	0	0	0	0	0	0.1	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0.7	18.9	3.4	1.4	0	0	0
21	0	0	0	0	0	0.6	43.2	10.7	12.9	0	0	0
20	0	0	0	0	0	0	14.9	2.7	20	0	0	0
19	0	0	0	0	0	0	2.3	1.2	20.2	0	0	0
18	0	0	0	0	0	0	0	0	1.9	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0.2	0	0	0	0	0	0	0	0	0
9	0	0.1	6.6	0.1	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0

Month

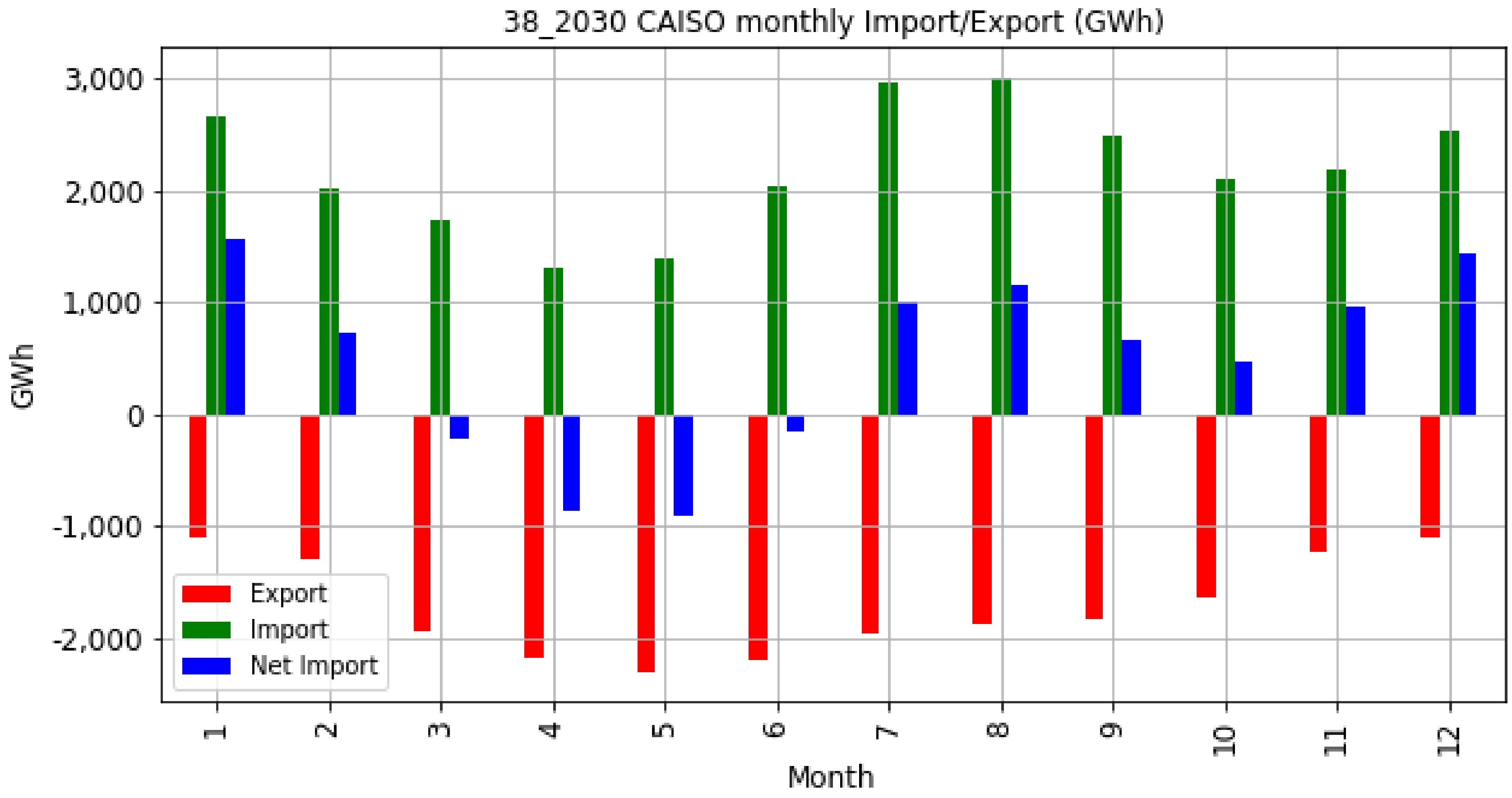
Value: 40, 30, 20, 10, 0

38 MMT Core -2026 CAISO monthly Import/Export



In 38 MMT Core case, CAISO is a net importer for 10 out of 12 months

38 MMT Core -2030 CAISO monthly Import/Export



In 38 MMT Core case, CAISO is a net importer for 8 out of 12 months

38MMT 2026 Core Criteria Pollutant metric tons

CAISO total

Unit_Category	All_NOx_Emission	Cold_Emission	Hot_Emission	Warm_Emission	NOx_Steady_Emission	PM_Emission	SO2_Emission
CC	2281.2	23.3	186.7	35.3	2035.9	1248.9	132.5
CT	1666.8	972.5	56.8	230.3	407.2	234.1	24.8
Cogen	1152.2	44.5	0.5	0.0	1107.2	231.8	24.6
ICE	19.6	0.0	5.3	0.0	14.3	2.6	0.2
Total	5119.9	1040.3	249.3	265.6	3564.7	1717.4	182.1

CAISO DAC

Unit_Category	All_NOx_Emission	Cold_Emission	Hot_Emission	Warm_Emission	NOx_Steady_Emission	PM_Emission	SO2_Emission
CC	499.6	2.8	47.3	0.7	448.9	271.0	28.7
CT	494.3	283.9	17.2	66.2	127.1	74.1	7.9
Cogen	289.5	15.3	0.1	0.0	274.1	57.4	6.1
Total	1283.5	302.0	64.6	66.9	850.0	402.5	42.7

Area_Category							
CA	6038.2	1154.0	291.8	292.2	4300.1	2085.2	220.9
OutOfCA	47122.2	731.8	182.5	37.4	46170.4	14541.2	42955.4

These totals do not include biomass emissions due to incomplete data.

38MMT 2030 Core criteria pollutant in metric tons

CAISO total

Unit_Category	All_NOx_Emission	Cold_Emission	Hot_Emission	Warm_Emission	NOx_Steady_Emission	PM_Emission	SO2_Emission
CC	2042.4	17.3	206.9	37.4	1780.7	1095.3	116.2
CT	1735.5	1032.4	48.0	208.9	446.2	252.8	26.8
Cogen	1131.2	43.8	0.5	0.0	1086.9	227.6	24.1
ICE	16.3	0.0	4.5	0.0	11.8	2.2	0.2
Total	4925.4	1093.5	260.0	246.3	3325.5	1577.8	167.3

CAISO DAC total

Unit_Category	All_NOx_Emission	Cold_Emission	Hot_Emission	Warm_Emission	NOx_Steady_Emission	PM_Emission	SO2_Emission
CC	444.2	1.9	50.4	0.6	391.3	236.0	25.0
CT	511.3	306.0	14.1	57.1	134.1	77.3	8.2
Cogen	286.7	14.6	0.1	0.0	272.0	57.0	6.0
Total	1242.2	322.5	64.6	57.7	797.4	370.3	39.3

Area_Category							
CA	5891.6	1207.4	304.2	276.2	4103.8	1964.4	208.1
OutOfCA	47576.0	605.4	169.4	36.9	46764.3	15065.4	42852.9

38MMT Core CA criteria pollutants comparison in metric tons: SERVM mix vs CARB projection

POLLUTANTS	2026 CARB	2030 CARB	2026 SERVM	2030 SERVM	2026 Difference	2030 Difference
NOX	7,341	7,567	6,038	5,891	-1303	-1675
SOX	1,356	1,409	221	208	-1135	-1201
PM	2,096	2,145	2,085	1,964	-11	-181

The SERVM results reflect a cleaner resource mix than when CARB made their projections. Some of the cleaner resource mix may be driven by CPUC/LSE actions, and some may be driven by non-CAISO resource mix change.

Source for CARB projections here: https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php

California Public Utilities Commission

Conclusions and Next Steps

- The 38 MMT Core portfolio is reliable – LOLE is below 0.1 – and modeling confirms GHG emissions are significantly lower than the Aggregated LSE Plans.
- The 2026 sensitivity, enforcing 2026 rather than 2028 delivery dates on a portion of the MTR resources, demonstrates significantly lower GHG emissions and reduced reliability risk.
  - LOLE of 0.065 in 2026 for the 38 MMT Core portfolio is below 0.1 but there is some uncertainty as to operational constraints and resource viability.
- Additional operational and LOLE results data will be made available after further internal and external review.

Questions?

- Thank you for your comments and questions.
- For additional follow up, please email staff at donald.brooks@cpuc.ca.gov

END ATTACHMENT B

ATTACHMENT C

Methodology for Resource-to-Busbar Mapping & Assumptions for The Annual TPP

CPUC Energy Division
August 2021

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1. Document Purpose

Resource-to-busbar mapping ("busbar mapping") is the process of refining the geographically coarse portfolios produced in the California Public Utilities Commission's (CPUC) Integrated Resource Plan (IRP) proceeding, into plausible network modeling locations for transmission analysis in the California Independent System Operator's (CAISO) annual Transmission Planning Process (TPP). The purpose of this methodology document is to memorialize and communicate the steps the CPUC, CAISO and California Energy Commission (CEC) will take to implement the process and provide transparency and opportunity for stakeholder comment.

The busbar mapping methodology outlined in this document is focused on achieving effective and timely busbar mapping of the utility-scale resources in IRP portfolios, which need to be adopted via a CPUC decision to be able to inform the CAISO's annual TPP.

2. Document Version History

The table below outlines the evolution of this document, listing and linking previous versions of the busbar mapping methodology. Key updates added in the current version are outlined in Section 4 below.

Version	Revision Notes
October 18, 2019[1]	Staff Proposal for the 2020-2021 TPP
February 21, 2020[2]	Improvements informed by stakeholder feedback on the Staff Proposal, and staff experience during implementation of the process for the 2020-2021 TPP
March 30, 2020[3]	Addition of methodology for battery resources for the 2020-2021 TPP
October 23, 2020[4]	Staff Proposal for the 2021-2022 TPP
January 7, 2021[5]	Final Methodology for the 2021-2022 TPP
July 1, 2021	Staff Proposed Methodology & Assumptions

[1] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_Busbar_Mapping-Methodology-2019-10-18.pdf
[2] ftp://ftp.cpuc.ca.gov/energy/modeling/Busbar_Mapping-Methodology-2020-02-21.pdf
[3] ftp://ftp.cpuc.ca.gov/energy/modeling/Busbar_Mapping-Methodology-2020-03-30.pdf
[4] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M348/K816/348816247.PDF
[5] ftp://ftp.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%202021-2022%20TPP_V.2021-01-07.pdf

3. IRP & TPP Context

Through the IRP process, the CPUC generates portfolios of electrical generation, distributed energy resources, storage, and transmission resources designed to meet the state's greenhouse gas emission reduction targets for the electric sector while minimizing cost and ensuring reliability. In order to ensure alignment between the planning and development of generation, storage, and transmission resources, where the ability to serve the grid is often interdependent, the CPUC's IRP process coordinates closely with the CAISO's TPP. The IRP process develops a resource portfolio(s) annually as a key input to the TPP base case studies, which includes a reliability base case portfolio and a policy-driven base case portfolio. The CPUC may also transmit additional resource portfolios as inputs for sensitivity studies that test the implications of various policy futures. These are collectively referred to as "IRP portfolios."

The IRP cycle can involve developing these portfolios with different approaches. RESOLVE,[6] a capacity expansion model, is used to develop portfolios for the Reference System Plan, whereas Load Serving Entities' (LSEs') IRP plans are used to develop a Preferred System Plan portfolio, and a hybrid approach may be used to supplement specific portfolio development. Upon formal CPUC adoption of the IRP portfolios, they are transmitted to the CAISO to be used as inputs to the TPP. The adopted IRP portfolios include a mix of existing resources, resources under development and scheduled to come online (or retire) in the near term, as well as generic future candidate resources. However, the locational specificity of the selected generic candidate resources is limited because of the geographically coarse planning zones used in IRP modeling.

In order to more accurately study the performance of the IRP portfolios at the high voltage system level, the CAISO needs to model the selected generic resources in representative sizes at specific transmission substation locations within each renewable planning zone identified in the IRP portfolios. Consequently, the selected generic resources need to be remapped outside of RESOLVE or LSEs' plans to specific busbars[7] in the transmission system before the portfolios can be transmitted to the CAISO and be considered as inputs to the TPP.

To disaggregate the selected zonal resource capacities and allocate to specific busbars, CPUC staff and CEC staff translate the tabular format of the portfolios into geographic map format and consider higher resolution information about transmission infrastructure and land use. This methodology identifies the guiding principles, busbar mapping steps, and the associated criteria for conducting this process.

4. Scope of Busbar Mapping

Deep decarbonization of the electric sector to meet California's climate goals is likely to require a transformation of the state's electrical infrastructure, i.e., significant investment in solar, wind geothermal and storage, including the associated transmission. In turn, the requirements placed on planning processes, including busbar mapping, are likely to be significant due to the need to co-

[6] Further information on RESOLVE is available here: https://www.cpuc.ca.gov/irp/

[7] "Busbar" and "substation" are used interchangeably in this document. A busbar, a specific connection point within a substation, is the more accurate term. The mapping process need only identify the applicable substation to connect a resource, so long as the availability of a feasible busbar there has been considered.

optimize economic, land use, transmission, and interconnection issues associated with the amount of renewables and storage needed to be online in the next decade. This will be critical for California to stay on a trajectory to achieve the state's SB 100 goal[8] of 100 percent clean electricity by 2045, as well as 80 percent below 1990 emissions by 2050.

. This busbar mapping methodology may need to be revisited in future years to ensure that the co-optimization issues identified above are fully incorporated in the busbar mapping methodology in time to inform annual TPP modeling.

Further, the methodology is focused on resources within CAISO and other Californian Balancing Authority Areas (BAA) selected to serve CPUC IRP jurisdictional LSEs. Selected resources outside CAISO and other Californian BAAs are represented at CAISO boundaries so that their in-CAISO effects can be studied in the TPP.

The methodology outlined in this document builds on what was used by the agencies for 2021-2022 TPP.[9] That methodology was informed by staff experience and stakeholder feedback during the implementation of the process for portfolios transmitted for 2020-2021 TPP in addition to the Staff Proposal for the 2020-2021 TPP,[10]. It contains details of the processes used in prior years.

This methodology for mapping resources in IRP portfolios will serve as a living document for continued use in the annual TPP. The document will be updated to incorporate changes or improvements as needed at appropriate junctures of future cycles. This methodology aims to improve on the methodology developed for the 2021-2022 TPP by:

- Utilizing new CAISO transmission deliverability data for available transmission headroom for full capacity deliverability status (FCDS) and energy only deliverability status (EODS). See Section 6.
- Incorporating new transmission constraint divisions based on the new CAISO transmission deliverability data, different from the nested-transmission zones and Ex-zones used in the previous cycle. See Section 5.
- For non-battery busbar mapping, incorporating busbar-level granularity of commercial interest rather than zonal-level of commercial interest. See Section 9.
- For all resources, incorporating expected online dates for commercial interest into the mapping criteria for allocation to busbars. See Section 9.
- Updating the battery busbar mapping steps to account for the locational information for battery resources that will be provided by RESOLVE for the first time. See Section 8.
- Removing elements no longer necessary with the implementation of the new CAISO transmission deliverability data, including the 90% transmission utilization limit used in mapping battery resources to busbars, and for co-located battery and solar PV resources, removing the transfer of FCDS status from the solar PV resources to the battery resources. See Section 7 and 8.
- Inclusion of an additional battery ranking value applied to substations in proximity of a fossil-fueled plant that has been identified in the Thermal Generator Retirement list. See Section 8.

8 Detailed at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100
9 Available at: Portfolios & Modeling Assumptions for the 2021-2022 Transmission Planning Process (ca.gov)
10 Available at Modeling Assumption for the 2020-2021 Transmission Planning Process (ca.gov)

- Updating the busbar mapping process flow chart and the battery and non-battery mapping steps and workflow between the CPUC, CEC, and CAISO. See Section 6.
- Improving the implementation process of the busbar mapping criteria to better capture mapped resources' compliance with the criteria and to incorporate latest stakeholder input and updated data sets. See Section 9.

5. Guiding Principles

The following principles are intended to guide the busbar mapping process. Later sections of this document detail how to implement these principles, and criteria with which to assess whether the implementation is effective.

- The more granular resource and transmission cost, land use, and interconnection optimization done in the busbar mapping process should align with CPUC policy requirements, maintain reliability, and minimize cost to ratepayers. To the extent practical and feasible with the aforementioned criteria, busbar allocation should be consistent with the higher-level optimization that occurs during the IRP portfolio development process
- Busbar allocations should generally represent the expected outcome of LSE procurement activity in response to policy requirements, maintaining reliability, and minimizing cost to ratepayers. This is achieved by observing to the extent practical and feasible the resource needs identified in PUC modeling and analysis, planned procurement indicated in LSEs' plans, previous planning and procurement decisions, and the level of commercial interest in the CAISO and other relevant interconnection queues.
- The allocations should strive to minimize transmission congestion by respecting transmission constraint limits[11] and identified transmission upgrades demonstrated to be cost-effective for ratepayers or necessary to achieve policy or reliability requirements. The allocations should minimize local congestion and overloads, where known, understanding that these are typically addressed through local transmission upgrades identified in the CAISO's Generation Interconnection and Deliverability Allocation Process (GIDAP) rather than the TPP.
- A successful busbar mapping process should result in IRP portfolios that minimize post processing in the CAISO's TPP.
- Consistency with prior year mapping results for equivalent TPP cases is important to the IRP and TPP processes. Staff should consider whether changes are occurring due to exogenous factors (e.g., demand or resource cost shifts) or due to modeling margin of error. Where significant changes are proposed in the resource mapping from one year to the next, these should be explicitly justified.

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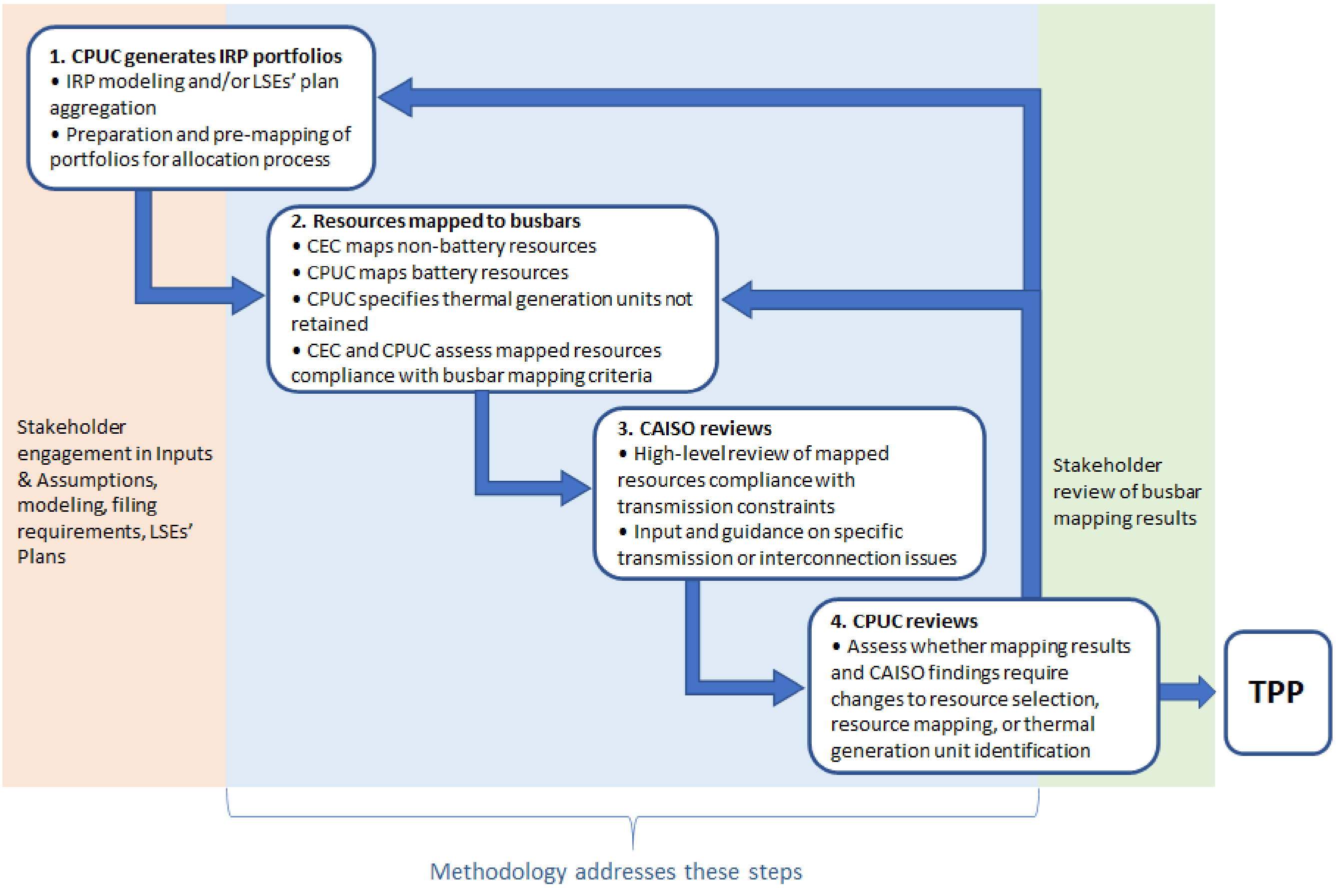
[11] Further described in the CAISO's July 2021 White Paper "Transmission Capability Estimates for use in the CPUC's Resource Planning Process" available at: http://www.caiso.com/Documents/WhitePaper-2021TransmissionCapabilityEstimates-CPUCResourcePlanningProcess.pdf
May 2019 White Paper "Transmission Capability Estimates as an input to the CPUC Integrated Resource Plan Portfolio Development" available at: http://www.caiso.com/Documents/TransmissionCapabilityEstimates-CPUC-IRP-PortfolioDevelopmentRedacted.pdf

6. High-level Busbar Mapping Steps

The busbar mapping process is completed through a sequenced transfer of information between the CPUC, CEC, and CAISO. It is an iterative process, as demonstrated by Figure 1.

Figure 1. Flowchart of the busbar mapping process



7. Non-Battery Busbar Mapping Steps

Information transfers related to non-battery resources follow this sequence:

Step 1 - Draft portfolio(s) prepared and shared with CEC for busbar mapping (CPUC)
Step 2 - Draft busbar mapping performed (CEC and CPUC)

- Note: Step 2 is further divided into two parts below delineating CEC staff centered work and CPUC staff centered work

Step 3 - Observations and recommended revisions (CAISO)
Step 4 - Review mapping results as well as observations and recommendations from CAISO staff (CPUC)

- Note: Steps 1-4 make up a "round" of busbar mapping.

Step 5 - Repeat steps 1-4 if mapping results do not conform with mapping criteria
Step 6 - Successfully mapped IRP portfolio(s) formally transmitted to the CAISO (CPUC)

The discussion of each step below centers on the mapping of non-battery resources. The detailed battery mapping steps are outlined in Section 8: Battery Storage. The mapping of batteries is conducted by CPUC staff in parallel with the mapping processes of non-battery resources outlined in Step 1 and Step 2, with the CAISO staff reviewing the combined results of mapping battery and non-battery resources in Step 3.

CPUC – Step #1

The CPUC staff will provide the following materials to the CEC and CAISO staff for the annual busbar mapping process:

- IRP portfolios generated by RESOLVE and/or resulting from the aggregation of LSEs' plans, as applicable.
  - Baseline resources: megawatts (MW), by unit, by location
    - This information will also identify new baseline resources, including their point of interconnection, that have recently come online or are in development which were not included in calculating the most recent CAISO transmission capability limits.
  - LSE planned resources: MW, by resource type, by location
  - Selected new resources: MW, by resource type, location, and applicable transmission constraints[12]
    - Where the baseline set of resources has been updated after the portfolio of selected resources was formed, CPUC staff should reconcile the two sets of resources to avoid double-counting.
    - For certain resource types selected by RESOLVE, specifically solar and battery resources, CPUC staff will conduct pre-mapping work to provide the granularity of information needed for the CEC to conduct its mapping process.
    - This pre-mapping exercise maps solar and battery resources from the few large regional areas that RESOLVE selects, to geographic specific areas to aid CEC staff in mapping solar resources to busbars and to properly assess transmission compliance with all transmission constraints once the resources are mapped to busbars by the CEC. This process also allows solar and battery resources to be mapped to busbars as co-located resources.
    - CPUC staff will incorporate commercial interest as defined from planned procurement in LSEs' plans and proposed projects in the interconnection queues when conducting this pre-mapping downscaling for RESOLVE selected resources.

[12] For example, see Excel-based results viewer, dated March 23, 2020, available at https://www.cpuc.ca.gov/General.aspx?id=6442464143. See "Portfolio Analytics" tab

- Resource potential estimates (geographic information system (GIS) data format – polygons and associated attribute tables) to give the CEC further information about the selected resources[13]

- Transmission upgrades triggered in RESOLVE (tabular format)[14]

Stakeholder participation:

- Stakeholders will be provided an opportunity to comment on the RESOLVE inputs and assumptions (including CAISO transmission capability and cost values), RESOLVE functionality, and the proposed Reference System Portfolio (year 1) and proposed Preferred System Portfolio (year 2)
- Stakeholders will be provided opportunities to comment on this busbar mapping methodology and to review the mapped resource portfolios. Further, stakeholders' feedback during TPP may demonstrate the opportunity to better fulfill the guiding principles outlined in this document. Small changes to allocations may be made during TPP at CAISO staff's discretion.

<u>CEC – Step #2 – Part A</u>

The CEC staff will provide the following materials to the CPUC and CAISO staff after each round of busbar mapping:

- Draft CEC busbar mapping results
    - See CEC Busbar Mapping Results workbooks from previous cycles for examples of prior work[15]

The CEC is using a busbar mapping methodology that is summarized as follows:

1) CEC staff will use the information described in Step #1 above from the CPUC to develop a geographic map for the renewable energy resource technologies and for each portfolio, consistent with the RESOLVE model inputs and assumptions developed by the CPUC.

2) CEC staff will create a set of GIS layers to identify the potential environmental and land use implications of the RESOLVE-selected renewable resources. The layer is a combination of the following statewide data and information:

    - Terrestrial Landscape Intactness (California Energy Commission and Conservation Biology Institute, 2016)[16]

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[13] For example, see GIS Data available at http://www.cpuc.ca.gov/General.aspx?id=6442453965

[14] For example, see Excel-based results viewer, dated March 23, 2020, available at https://www.cpuc.ca.gov/General.aspx?id=6442464143 See "Portfolio Analytics" tab

[15] The 2021-2022 TPP results are available at Portfolios & Modeling Assumptions for the 2021-2022 Transmission Planning Process (ca.gov) and the 2020-2021 TPP results at https://www.cpuc.ca.gov/General.aspx?id=6442464144

[16] Available at https://databasin.org/datasets/e3ee00e8d94a4de58082fdbc91248a65

- Areas of Conservation Emphasis, version 3.0 (ACE III) (California Department of Fish and Wildlife, 2018)[17]
- Terrestrial Connectivity[18]
- California Agricultural Value (California Energy Commission and Conservation Biology Institute, 2018)[19]
- NLB (Natural Landscape Blocks)[20]
- Connectivity[21]
- Biodiversity[22]
- Rarity[23]
- Native species[24]
- Irreplaceability[25]
- Wildfire Threat26

3) The first three datasets above will be normalized and summed to create a comprehensive layer with numerical scores that represent the degree of potential environmental and land use implications if resources are utilized. The California Agricultural Value and Wildfire Threat data will either be incorporated into the model or used as separate overlays to compare different substation allocations.

4) The environmental and land use layers will be overlain with the renewable resource potential geographies to identify the environmental implications (low and high) of developing renewable resources, particularly solar resources and where necessary, wind energy resources.

5) Available transmission substations, including those that are planned and approved as well as existing, will be identified. Available substations include those in Californian BAAs, as well as CAISO. A subset of total available substations is considered when assigning the portfolios. This subset of substations is identified in the following manner:

[17] Available at https://www.wildlife.ca.gov/Data/Analysis/Ace
[18] Available at https://www.wildlife.ca.gov/Data/Analysis/Ace#523731772-connectivity
[19] Available at https://databasin.org/datasets/f55ea5085c024a96b5f17c7ddddd1147
[20] Available at https://databasin.org/datasets/e3ee00e8d94a4de58082fdbc91248a65
21 Available at https://data.cnra.ca.gov/dataset/terrestrial-connectivity-ace-ds2734
22 Available at https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=150831
23 Available at https://data.cnra.ca.gov/dataset/statewide-terrestrial-rare-species-richness-summary-ace-ds13331
24 Available at https://data.cnra.ca.gov/dataset/statewide-terrestrial-native-species-richness-summary-ace-ds1332
25 Available at https://data.cnra.ca.gov/dataset/statewide-terrestrial-irreplaceability-summary-ace-ds13341
26 Available at https://ia.cpuc.ca.gov/firemap/

i. GIS datasets for California substations are combined with the GIS data set for U.S. substations to help identify available substations for out-of-state resources.[27]

ii. The combined set of substations is queried to select substations that meet the following criteria:

1. Transmission capability and constraint information available from CAISO adjusted to account for newly added baseline resources not included in the baseline used by CAISO to establish the transmission limited[28]

2. Location information (GIS data) available from CEC or U.S. HIFLD

3. Identified as currently operational or planned

4. Identified as having both multiple buses and bus voltages of 115 kV and above; except in cases of remote resources where the only available buses are of lower voltages.

5. Identified as having commercial interest per CAISO interconnection queue

iii. Project documents for new, approved powerline projects are examined to identify the mapped locations of proposed substations and they are hand-digitized to add them to the available substation dataset.

iv. The substation data is overlain with the CPUC RESOLVE resource potential data and for substations with significant renewable resource potential in reasonable proximity, the resource potential is assigned to the relevant transmission constraint for that substation.

v. During iterative rounds of busbar mapping, individual substations from the identified data sources may be added if additional substation mappings are needed.

6) A suitable standard radius will be established around each available substation. The standard radius will be set to approximate the longest distance factoring the MW size of resources selected that economically feasible interconnection power lines (gen-ties) typically fall within. This standard radius, path viability, and busbar voltage - all key drivers of interconnection cost - will be used when mapping each resource type as follows:

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27 Available at
https://data.ca.gov/dataset/california-electric-substation2
https://hifld-geoplatform.opendata.arcgis.com/datasets/electric-substations
28 CAISO transmission capability estimates are available at:
http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=82442AF7-0A68-4BFC-86FD-AAE1B066AE5E

a. Solar – calculate the amount of renewable resources with lower environmental implications within each substation radius. Allocate the transmission planning area-level solar resources to substations based on the available lower environmental implication area within the substation radius.

b. Wind - compare the location of wind energy resources to each substation radius and allocate the transmission planning area-level wind resources to substations in closest proximity. High- and low-environmental-implication information will be identified, but options for moving the resource to a different substation will be more limited for wind, given the site-specific nature of the resource. For offshore wind, the transmission planning area-level resource is allocated to substations in closest proximity that have been identified as potential offshore winder interconnection points. For out of state wind, the area-level resources are allocated to the point of interconnection substation respecting where the resource is injected into the CAISO system.

c. Geothermal – compare the location of geothermal energy resources to each substation radius and allocate the transmission planning area-level geothermal resources to substations in closest proximity.

d. Biomass - compare the location of biomass energy resources to each substation radius and allocate the transmission planning area-level biomass resources to substations in closest proximity.

e. Location specific long duration energy storage – compare the location of long duration energy storage resources that are limited to a specific geographic area to each substation radius and allocate the transmission planning area-level long duration energy storage resources to substations in closest proximity.

f. For resources which fall outside the standard substation radius or have identified issues likely to significantly increase interconnection costs, CPUC staff will conduct further analysis outlined in Step 2B.

7) CEC staff will work with CPUC staff to review the CAISO's Transmission Capability Estimates to check that resources are not mapped in such a way that departs from the high-level allocation of the IRP portfolios, which should already be respecting capability limits - the existing system "Estimated Full Capacity Deliverability Status Capability (MW)" and the "Estimated Energy Only Deliverability Status Capability (MW)" for each transmission constraint or triggering upgrades where intended. Any triggered transmission upgrades will be highlighted and examined by the CAISO and CPUC staff in Steps #3 and #4.

8) CEC staff will develop a spreadsheet to report out the results of the megawatt allocations by substation, for each renewable energy resource It will include details of the specific methodology applied, enabling reporting against the criteria outlined in the Busbar Mapping Criteria section below, and any notes needed to interpret and understand the allocation outputs.

Stakeholder participation:

- Stakeholders will be provided opportunities to comment on this busbar mapping methodology and to review the mapped resource portfolios. Further, stakeholders' feedback during TPP may demonstrate the opportunity to better fulfill the guiding principles outlined in this document. Small changes to allocations may be made during TPP at CAISO staff's discretion.

<u>CPUC – Step #2 – Part B</u>

The CPUC staff will provide draft portfolio dashboards to the CAISO and CEC staff after each round of busbar mapping and do the following:

1. CPUC staff will utilize the information provided by CEC staff above to assess mapped resources compliance with land-use, environmental, distance to transmission, and transmission capability limits described in Section 9 Busbar Mapping Criteria and Implementation. Staff will conduct addition review on mapped resources alignment with LSEs' plans and the CAISO and other BAA interconnection queues and consistency with prior years' base case portfolios.
2. With respect to mapped resources' interconnections to substations identified by CEC staff, CPUC staff will conduct, as necessary, further interconnection analysis on mapped resources that fall beyond the standard radius or CEC staff identified possible interconnection path viability issues or a busbar voltage that may lead to additional interconnection costs. For resources that fall beyond the standard radius, staff will compare their interconnection cost assumed in the supply curve, and the gen-tie distance it allows, to the distance to the busbar identified in busbar mapping. If the distance to the substation is greater, then depending on the busbar voltage, this may mean a criterion has not been met; refer to the Busbar Mapping Criteria section below.
3. CPUC staff will complete battery mapping as outlined in Section 8: Battery Storage
4. CPUC staff will assess mapped non-battery and battery resources' compliance with existing transmission capability limits and confirm any transmission upgrades triggered alleviate transmission capability exceedances in a demonstrated cost-effective manner. Staff will incorporate the transmission related impacts of battery mapping and account for the co-location of battery storage with mapped solar resource.
5. CPUC staff using the process established in Thermal Generator Retirement Assumptions, Section #10, will identify thermal generation units not retained and should be assumed as retired for the transmission planning process
6. CPUC staff will develop draft dashboard worksheets for each portfolio to summarize the mapping results, their transmission capability limit alignment, and their compliance with the busbar mapping criteria.

Stakeholder participation:

- Stakeholders will be provided opportunities to comment on this busbar mapping methodology and to review the mapped resource portfolios. Further, stakeholders' feedback during TPP may demonstrate the opportunity to better fulfill the guiding principles outlined in this document. Small changes to allocations may be made during TPP at CAISO staff's discretion.

<u>CAISO – Step #3</u>

During each round of busbar mapping the CAISO staff will provide the CEC and CPUC staff the following:

- A high-level review of the CEC's and CPUC's draft busbar allocations and the conceptual transmission upgrades that the CPUC and CEC determined are likely to be required based on the mapping in Steps #1 and/or #2 including:
    - Input on any specific transmission issues encountered during the mapping process
    - Additional information on interconnection feasibility, including electrical suitability and physical space availability at each substation, if this information is available from the transmission owner
- If the CEC and CPUC staff map portfolio resources to substations in BAAs other than the CAISO, then the CAISO staff may consult appropriate planning entities during the resource modeling phase of TPP. These planning entities may recommend adjustments to locations and size of resources mapped in their BAAs, In such cases, the CAISO will consult the CPUC and CEC staff before incorporating any subsequent busbar allocation changes to the portfolios. Staff will engage with TPP stakeholders and/or IRP stakeholders if the changes may result in a materially different transmission outcome, in terms of constraints or upgrades. All changes will be publicly documented.
- Observations, problems encountered, recommended portfolio modifications needed.

Stakeholder participation:

- Stakeholders will be provided opportunities to comment on this busbar mapping methodology and to review the mapped resource portfolios. Further, stakeholders' feedback during TPP may demonstrate the opportunity to better fulfill the guiding principles outlined in this document. Small changes to allocations may be made during TPP at the CAISO staff's discretion.
- The CAISO's observations and any recommended modifications to identified transmission upgrades will be reported in the CEC's mapping results and/or in the CPUC's report

<u>CPUC – Step #4</u>

CPUC staff will review the draft mapping by CEC staff, as well as observations and recommendations from CAISO staff. Using the busbar mapping criteria, described in the Implementation of the Busbar Mapping Criteria section below and the resulting portfolio dashboards developed in Step #2, CPUC staff will determine whether the mapping results are ready to be transmitted to the CAISO for TPP, or require a further round of mapping.

Resource selections with multiple high priority criteria violations will be considered for adjustments or further rounds of mapping.

If a further round of mapping is required, CPUC staff may reallocate resources between transmission constraint areas. Such changes should not result in material changes to the expected cost, reliability or emissions performance of the portfolio. This can be implemented and demonstrated by using RESOLVE directly, or manually while mirroring the resource optimization criteria RESOLVE uses.

Stakeholder participation:

- Stakeholders will be provided opportunities to comment on this busbar mapping methodology and to review the mapped resource portfolios. Further, stakeholders' feedback during TPP may demonstrate the opportunity to better fulfill the guiding principles outlined in this document. Small changes to allocations may be made during TPP at CAISO staff's discretion.

8. Battery Storage Mapping Steps

Introduction

Mapping battery storage to busbars differs from the methodology for non-battery resources described earlier in this document for reasons including:

- The locational information for selected battery storage provided by RESOLVE is not as granular as that provided for resource types such as wind or geothermal;
- RESOLVE provides some flexibility in siting storage due to not directly linking the battery storage to solar, wind or other input resources;
- With charging and discharging, the interaction of batteries with the transmission grid is different than that of generation resources
- Land use considerations and environmental implications associated with siting batteries are different than for other resources; and
- Busbar mapping of battery storage provides the opportunity to consider local values not modeled in RESOLVE.

The methodology used for mapping batteries is centered around the intersection of policy objectives and commercial interest. The feedback from stakeholders and the lessons learned from the previous mapping effort highlighted a few reasons why this update to the methodology is necessary. They include:

- Busbar mapping of batteries presents an opportunity for proactive planning that helps ensure that the battery storage development contributes to achieving the range of state policy goals – like GHG reduction, reliability, and cost minimization – for which the battery resources were selected in RESOLVE;
- Busbar mapping of batteries also allows batteries to contribute to achieving additional policy goals which were not optimized for in the RESOLVE model (i.e. policy goals that require locational specification of batteries); and
- Busbar mapping of batteries can contribute to addressing issues related to operations and retirements of specific plants located in disadvantaged communities (DACs) and locations with high air quality health impacts (areas with non-attainment for ozone and PM 2.5).

The execution of the battery mapping effort to achieve the policy objectives will be completed in such a way that they are in accordance with the guiding principles outlined in Section 5: Guiding Principles above. The following sections highlight the proposed policy objectives, the issues to be addressed, and the data required to ensure the execution of the battery mapping will achieve the desired results.

Stakeholders will be provided opportunities to comment on the battery busbar mapping methodology and to review the mapped resource portfolios. Further, stakeholders' feedback during TPP may demonstrate the opportunity to better fulfill the guiding principles outlined in this document. Small changes to allocations may be made during TPP at CAISO staff's discretion.

Battery Mapping Policy Objectives

The RESOLVE model selects a least-cost optimized portfolio that meets a range of system-level policy goals. To remain consistent, it is important that the battery mapping effort is also grounded in a policy objective that ensures costs are minimized.

Policy Objective #1: Minimizing Ratepayer Costs

The first policy objective that will be achieved by this battery mapping effort is a minimization of ratepayer costs. This will be done by maximizing the value of the storage MW and durations selected by RESOLVE as needed to meet system needs, by considering additional locational benefits.

Issues Addressed:

The execution of the battery mapping effort to achieve this policy directive will address the following issues:

- Increasing the amount of co-located battery resources. Generally, co-located batteries are cheaper than stand-alone batteries.[29] The mapping exercise will be executed in such a manner that siting of co-located batteries will be maximized to the limits of available solar resource for charging and without triggering a need for new transmission development. The meaning of the term "co-located" in this busbar mapping exercise is based on the CAISO tariff definition.[30] In addition to the potential tax incentive benefits from solar, co-location of solar and battery storage can be used to prevent exceeding existing transmission capability limits when the battery resources assume the full deliverability (FD) status of the solar resource they are co-located with, and the busbar mapping of the storage is not intended to trigger transmission limits. This FD transfer is considered for two reasons, a significant amount of commercial interest in battery storage is co-located and hybrid resources,

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[29] 2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark, Ran Fu et al. NREL. November 2018. https://www.nrel.gov/docs/fy19osti/71714.pdf

[30] Available at: http://www.caiso.com/Documents/Sep16-2020-Tariff-Amendment-Hybrid-Resources-Phase-1-ER20-2890.pdf

also given the low marginal ELCC of new solar resources in the portfolios (2%), co-location with storage will preserve the FD status of the busbars.

- Reducing congestion. In the CAISO analysis of Local Capacity Requirement (LCR) areas some battery resources are proposed as solutions for allowing increased imports into constrained areas during off peak periods. An additional benefit of siting battery storage resources in LCR areas, particularly LCR areas with solar resources with which the battery resource can be co-located, is to reduce transmission congestion and curtailment. The mapping exercise will be executed in such a way that these benefits will be evaluated, to the extent possible, when assigning battery resources to LCR areas with congestion.
- Reducing opportunities for market power. For certain LCR areas, local RA price premiums exist when natural gas-fired power plants are needed to provide capacity to local areas. In LCR areas with, or approaching, tight load/resource balances, these power plants may have the opportunity to exert market power (for instance, by seeking market exit but necessitating a reliability must run agreement). The execution of the battery mapping exercise will seek to site battery storage resources in such local capacity areas, which can reduce market power and the local price premiums paid to such resources. Concerns around reliability, particularly given the August 2020 rotating outages, require that some additional consideration will need to be given to the impact of the elimination of such premiums on resource retention needed for both local and system reliability.

Policy Objective #2: Minimizing Criteria Pollutants

The second policy directive is borne out of a desire to use the battery mapping effort to achieve additional policy goals which are not necessarily yet considered explicitly in the RESOLVE modeling. The minimization of criteria pollutants is proposed to utilize the batteries, especially the stand-alone resources, to address a range of localized issues which are not represented in the RESOLVE optimization.

Issues Addressed:

The execution of the battery mapping effort to achieve this policy directive will address the following issues:

- Reduction of local emissions, particularly in areas with high air quality impacts. Siting batteries in these areas can reduce local price premiums for the criteria air pollutant emitting fossil-fuel resources, yet those resources may still be required for system RA needs. However, even if emitting plants do not retire, siting batteries in areas with acute air quality concerns has the potential to reduce local power plant emissions, especially in transmission-constrained LCR areas. Similarly, a consideration is the necessity of the emitting resources for system reliability needs.
- Reduction of emissions in Disadvantaged Communities (DACs). Siting of battery resources specifically within DACs may enable pollution reduction in these communities, as well as potential economic benefits from battery storage development. PU Code Section 454.51 requires the CPUC to "*...adopt a process for each load-serving entity…to file an integrated resource plan…to ensure that load-serving entities do the following… Minimize air pollutants with early priority on disadvantaged*

communities…" among other requirements. LSEs can procure batteries in DACs to prioritize the minimization of air pollutants in these specific communities.

The battery mapping for the 2020-2021 TPP considered LCR areas and the mapping of batteries to ameliorate the issues in those areas. However, the possibility of using batteries to reduce the air quality issues in DACs was not addressed by the methodology utilized to map resources to busbars for the 2020-2021 TPP. The methodology developed for the 21-22 TPP improved on the 2020-2021 TPP battery mapping by explicitly considering the alignment of LCR opportunities with disadvantaged communities and/or those areas facing air quality concerns and this is maintained in this version of the methodology.

Battery Mapping Steps

The battery mapping steps detailed below will holistically consider the policy directives described in the previous section. The steps represent a direction for assigning both co-located and stand-alone batteries. To complete this task, information on battery opportunities in LCR areas, local air quality, and characterization of DACs will be used. Additionally, the battery mapping effort will coordinate with the non-battery busbar mapping effort to optimize for collocation with solar resources, and to account for availability of transmission headroom, triggering transmission development where it is determined to be cost-effective The CalEnviroScreen dataset provides information on emissions, air quality, and DAC assignments. This busbar mapping exercise will consider only DACs located within California as defined by SB535[31]. Ozone and PM nonattainment areas data from the EPA Green Book also provide information on air quality burdens for areas outside of DACs. GIS level data on local emissions, DACs, and LCR areas will be needed to ensure the mapping effort is consistent with the available data being used in the non-battery mapping efforts. CAISO Local Capacity Technical studies provide information on opportunities to displace LCR resources with battery storage. The non-battery mapping exercise will provide information on the amount of solar that is mapped to a busbar and the available transmission headroom.

Outline of Battery Mapping Steps

The battery mapping in Step 1 of the process discussed in Section #6 above will be done in two phases:

- <u>First Phase:</u> Battery resources will be assigned to zones based on the zonal battery resource selections results from the RESOLVE capacity expansion analysis.
- <u>Second Phase</u>: A manual check will be carried out to identify if there is any available transmission headroom which was not reflected in the RESOLVE analysis due to the simplified approach used in interpreting the CAISO transmission deliverability data in RESOLVE. If there is any available headroom, coordination with the non-battery mapping analysis will determine whether battery resources will be assigned to these zones or not.

[31] Available at: https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30

The battery mapping analysis for Step 2 of the process discussed in Section #6 will utilize the steps described below:

1. Identify primary substation list – substations to be considered and their assigned transmission constraints
    a. This step will utilize the same substations list as the non-battery mapping.
    b. All substations located in identified transmission constraint, with voltage >= 115 kV, unless otherwise indicated in the non-battery mapping.
2. Receive zonal build results from RESOLVE capacity expansion analysis
3. Identify the transmission headroom available for the corresponding transmission constraints for the zone
    a. This step will consider the transmission headroom available for the transmission of each busbar using the most recent TPP base scenario
    b. This step will utilize the most recent CAISO transmission deliverability data

4. Identify how much FD solar and wind is assigned to the substation
    a. This step will utilize information from the non-battery busbar mapping exercise.
    b. This step will also utilize the most recent CAISO transmission deliverability methodology.

5. Identify commercial interest at that substation
    a. This step will use the CAISO Interconnection Queue data
    b. This step will also utilize information from the non-battery busbar mapping exercise
    c. This step will also utilize the planned procurement indicated in the most recent LSEs' plans
6. Identify whether the substation is in an LCR area
    a. Batteries mapped to LCR areas will be prioritized based on the CAISO's 2030 Local Capacity Technical study results[32], which show the level of 4-hour battery storage that the CAISO states can provide both system and local capacity value within each LCR area.
        i. The 4-hour battery storage limit represents the amount of 1 MW-for-1 MW replacement of resources that the battery storage resource can achieve while providing both system and local capacity value within the LCR area
        ii. Beyond these 4-hour limits, the battery mapping will also allocate system-only battery resources within the LCR areas, unless the 4-hour battery storage quantity is indicated to be a physical constraint for siting in the LCR area.
    b. Assign a value 1 if the substation is in an LCR area.
7. Identify whether the substation is in a DAC
    a. This step will utilize the CalEnviroScreen DAC status
        i. Assign a value 1 if the substation is in a DAC
8. Identify whether the substation is in an air quality standard non-attainment area
    a. This step will utilize the EPA Greenbook data
        i. Assign a value 1 for each of the non-attainment areas the substation is in
9. Identify whether the substation is in a zone that has high curtailment

[32] Available at: www.caiso.com/Documents/AppendixG-BoardApproved2020-2021TransmissionPlan.pdf

a. This step will utilize the CAISO 2020-2021 Transmission Planning Process results[33]
b. Three tiers of curtailment value are used.
    i. Greater than 10% but less than 20% - assign a value 0.25
    ii. Greater than 20% but less than 30% - assign a value 0.5
    iii. Greater than 30% - assign a value 1

10. Identify whether the substation is in the proximity of a fossil-fueled plant that has been identified by the process established in Thermal Generator Retirement Assumptions, in Section #10
    a. Four tiers of rank values are used
        i. Distance greater than or equal to 7 miles – assign a value of 0.
        ii. Distance greater than or equal to 2.5 miles but less than 7 miles – assign a value of 0.25
        iii. Distance greater than or equal to 0.25 miles but less than 2.5 miles – assign a value of 0.5
        iv. Distance less than 0.25 mile – assign a value of 1
11. Rank all substations in order of highest rank to lowest rank based on sum of all assigned values.
    a. The rank order represents the priority of a substation for consideration of allocation of battery resources.
    b. If there is no available transmission headroom to assign battery resources at this substation the allocation will move to the next highest ranked substation
12. Allocate batteries based on the rankings from step 11 using the following order and considerations.
    a. Batteries will first be assigned to substations with transmission headroom and commercial interest. Priority will first be given to resources located in LCR areas that will provide both system and local capacity value. The hierarchy followed is shown below
        i. Substations contained within LCR areas, DACs, non-attainment status areas and high curtailment areas
        ii. Followed by substations with the highest number of each of the four status categories in descending order of rank
    b. After the LCR system and local capacity value stand-alone resources are mapped, system-only stand-alone resources will then be mapped.
    c. After completing the mapping of the stand-alone batteries, batteries will be assigned to substations with FD solar resources using the order in step 12a.
        i. This step will use the updated CAISO transmission deliverability methodology
        ii. Based on the results of the non-battery mapping batteries will be assigned to substations with FD solar and wind are allocated and where commercial interest for battery storage is shown.
    d. If there are still unassigned battery resources after steps a through d have been executed, then batteries will be assigned manually based on further interaction with

[33] Available in Section 3.7 of the 2020-2021 TPP at: www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf

the non-battery busbar mapping and consistency with previous TPP busbar mapping results. The order of assignment is as follows:

i. Prioritize substations where transmission exceedances have not occurred when resources have been mapped beyond the initial stated transmission headroom values

ii. If there are no such substances, map to substations where exceedance has occurred.

iii. Both mappings will follow the steps below:

   1. Prioritize zones where non-battery busbar mapping in any of the three scenarios has triggered transmission upgrades.
   2. Prioritize substations within these zones that have available transmission headroom after accounting for the non-battery resource busbar mapping.
   3. Prioritize substations that have battery commercial interest
   4. Spread the remaining battery capacity evenly across substations that meet criteria 1. through 4.

9. Busbar Mapping Criteria and Implementation

Busbar Mapping Criteria

The busbar mapping process should result in plausible network modeling locations for the portfolios, assuming the portfolios do not violate predetermined busbar mapping criteria. If the busbar mapping results in any of the criteria not being met, then the violation(s) would require interagency discussion and potentially necessitate the remapping of the IRP portfolios. The busbar mapping criteria are as follows:

- Distance to transmission of an appropriate voltage
  - Selected candidate resources should fall within an economically viable distance to transmission; and the resource interconnection path should be viable from an environmental and land use perspective (i.e., path that does not cross high-environmental implication areas or dense urban areas) as well as a project size perspective (i.e. a longer gen-tie may be economically feasible for a larger MW amount of selected resources).
  - CEC will flag applicable resources for which the recommended busbar allocation results in an exceedance of a predetermined standard radius (explained below). As described in Section 7: Non-Battery Busbar Mapping Steps, the exceedance of the predetermined standard radius does not necessarily mean the busbar allocation is not plausible because the resources might still be economically viable with a longer/higher cost gen-tie.
- Transmission capability limits
  - Selected resource allocation to a given busbar should abide by all the estimated transmission constraints that apply to that busbar, triggering only those upgrades which are determined to be cost-effective or necessary to meet policy and reliability requirements
  - Where busbar mapping utilizes planned substations rather than existing substations, this will be highlighted because of the inherently higher uncertainty regarding the substation in-service date
  - Busbar mapping process might also identify resources that cannot interconnect to an existing or planned substation because the resource is triggering a transmission upgrade that has not been previously studied by the CAISO. Such resources will be highlighted, and CAISO staff input will be sought per Step #3, with assumptions and implications documented. During the TPP that follows, the specific assumed interconnection and transmission solutions for those resources should be tested.
- Land use and environmental constraints
  - Allocation in each area should not exceed available land area to accommodate the resources, based on environmental information applied in Step #2 above

- If available land area is insufficient to accommodate selected resources within reasonable distance to the substation, or if the resources have high environmental implications, then these issues will be flagged and addressed in a further round of mapping. Possible solutions may include increasing the gen-tie beyond the standard radius for the particular resources if their interconnection cost estimates allow or re-optimizing the IRP portfolio(s) with updated assumptions about resource potential informed by this busbar mapping process.

- Commercial interest
  - Busbar allocations should reflect the planned procurement indicated in LSEs' plans and the level of commercial interest in the CAISO and other relevant interconnection queues, as well as projects in advanced stages of development identified through working group communications.
  - In considering commercial interest, the CPUC will
    - Compare selected portfolio resources to interconnection queues and other sources, on a busbar basis
    - Take into account the stage of development as well as the expected online date of the commercial interest
    - Flag any busbars which have large portfolio selection but no commercial interest or a selected resource amount that is significantly lower or higher than the amount of commercial
      - "High-confidence" commercial interest is defined by those projects that have an interconnection agreement executed and resources identified in LSE plans
    - Busbar allocations occurring at busbars with no commercial interest or that deviate significantly from the amount of commercial interest may be adjusted in a further round of mapping
- Consistency with prior year
  - Busbar allocations for equivalent TPP cases should be relatively consistent year to year: for example, Base Cases from one year to the next; and Policy-driven Sensitivity Cases exploring the same issue from one year to the next. Where large changes are necessary, the reasons for these should be clear. Staff should consider whether changes are occurring due to exogenous factors (e.g., demand or resource cost shifts) or due to modeling margin of error. Where significant reductions are proposed in the resource mapping from one year to the next, these should be explicitly justified.

Implementation of the Busbar Mapping Criteria

Staff use a "dashboard" to identify whether busbar allocations of a particular round of mapping of a portfolio comply with the five key criteria described above. This informs whether changes to the allocation may be required. An assessment using the criteria will be implemented and reported in the dashboards as follows below. "Level 1" refers to strong compliance; "Level 2" to possible or moderate breach of a criterion; and "Level 3" to a likely or material breach, indicating that a further round of mapping is required to improve compliance. Blank cells are shown in the dashboards where there is insufficient data to assess compliance.

1. Distance to transmission of an appropriate voltage
   a. Level 3 non-compliance threshold (i.e., exceedance of this threshold results in Level 3 assessment):
      i. Resources for which the busbar allocation results in viable gen-tie lengths that exceed a 20 mi. threshold (standard radius) approximated from the 90th percentile for planned solar and wind facilities:[34,35,36]
   b. Level 2 non-compliance threshold:
      i. Resources for which the busbar allocation results in viable gen-tie lengths that exceed a 10 mi threshold (standard radius) approximated from the 75th percentile distances for planned solar and wind facilities.
   c. Consideration of busbar voltage: When assessing distance staff will check the voltage of the busbar to ensure the combination of gen-tie length and interconnection voltage broadly align with the interconnection cost allowed for in the resource's selection. Accordingly, assessment of compliance with this criterion should not be based solely on the standard radius; in general, the thresholds above apply to busbar voltages in the range of 115-230kV. Further, staff should look for opportunities to minimize expected costs for ratepayers, for example by mapping to a busbar that may be more distant yet with a lower voltage than the alternative busbar.
      i. Resources allocated to a busbar which exceeds 230kV will initially be considered Level-2 non-compliance and assessed for opportunities to re-map to lower voltage busbar.
   d. Consideration of the MW amount of selected resources mapped to substation: When assessing interconnection distance and cost staff, will also consider the MW amount of resources selected at a substation and the per MW cost of interconnection. A small MW amount of a selected resource may economically require a shorter gen-tie distance than a potential larger project of the same resource type.
   e. For out-of-state resources staff will take the following approach:
      i. For out-of-state land area availability
         1. Use the spatial wind and solar resource potential information available in the "Low-impact land use pathways to deep

[34] 90th percentile of planned facilities, per publicly available filings: EIA (last) (2019). Preliminary Monthly Electric Generator Inventory (Based on FormEIA-860M as a Supplement to Form EIA-860).[Online]. Available at: https://www.eia.gov/electricity/data/eia860m/.11

[35] Spatial analysis was performed to check the interconnection distances for existing and planned solar facilities in the U.S. Source data for existing solar facilities: USGS "National Solar Arrays" https://www.sciencebase.gov/catalog/item/57a25271e4b006cb45553efa. Source data for planned facilities: U.S. Energy Information Administration, Form 860, public filings https://www.eia.gov/electricity/data/eia860m/.11

[36] Spatial analysis was performed to check the interconnection distances for existing and planned wind facilities in the U.S. Source data for existing wind facilities: USGS national wind turbine database "USWTDB" https://doi.org/10.5066/F7TX3DN0. Source data for planned facilities: U.S. Energy Information Administration, Form 860, public filings https://www.eia.gov/electricity/data/eia860m/.11

decarbonization of electricity" study[37] to assess distance to transmission

2. Note this source identifies four levels of wind, solar, and geothermal resource potential, based on four levels of environmental screening criteria. Resource potential from any "Siting Level", from 1-4, may be used. Siting Level 1 excludes only those areas where development is legally prohibited, and Siting Level 4 excludes all important habitat, intact landscapes, wildlife corridors, and areas with conservation value. Siting Level 2 will be used for out-of-state resources. This excludes wetlands and designated endangered species habitat but does not exclude big game priority habitat or Audubon Important Bird Areas.

2. Transmission capability limits
   a. Level 3 non-compliance threshold:
      i. Selected resource exceeds transmission capability for the applicable transmission constraints (FCDS or EODS)
   b. Level 2 non-compliance threshold
      i. Selected resource exceeds transmission capability for the applicable default transmission constraint

Note: If the selected resources exceed transmission capability for the applicable transmission constraints but the exceedance is alleviated by a transmission upgrade determined to be cost-effective or necessary then the selected resources are considered compliant with the criteria.

3a. Available land area
   a. Level 3 non-compliance threshold:
      i. Exceeds 100% of candidate project area land within the standard radius
   b. Level 2 non-compliance threshold:
      ii. Resources for which the busbar allocation results in exceedance of 100% of the low-value land area estimated to be available to accommodate a resource

3b. Environmental Impact
   a. Level 3 non-compliance threshold:
      i. Exceeds 75% of high-value land (terrestrial) in the resource potential areas within the standard radius, for four or more, or 95% for two or more of the following:
         1. Intactness
         2. Biodiversity
         3. Connectivity
         4. Rarity
         5. Native species

[37] Grace C Wu, Emily Leslie, Oluwafemi Sawyerr, D Richard Cameron, Erica Brand, Brian Cohen, Douglas Allen, Marcela Ochoa and Arne Olson, "Low-impact land use pathways to deep decarbonization of electricity," Environmental Research Letters, vol. 15, no. 7, Jul. 2020. doi: https://doi.org/10.1088/1748-9326/ab87d1. [Online]. Available at: https://iopscience.iop.org/article/10.1088/1748-9326/ab87d1

6. Audubon Important Bird Areas (IBA)
7. Important habitat
8. Wildfire threat
9. Irreplaceability

b. Level 2 non-compliance threshold:
   i. Resources for which the busbar allocation results in exceedance of 50% of the low-environmental-implication land area estimated to be available to accommodate a resource
   ii. Resources for which the busbar allocation results in 75% of two or more, or 95% or more of one

Notes regarding available land area and available low-value land area criteria:

- Refer to the approaches described above for criterion 1, for out-of-state resources, which are also applicable for criteria 3a and 3b
- If based on review of the portfolios, these thresholds turn out to be too low (for example, if approximately half or more of the new resources get flagged at level 3 non-compliance, and this would trigger further rounds of mapping of a large portion of the portfolio, creating a major departure from the logic and optimization objective within RESOLVE), then staff may adjust these thresholds accordingly.

4. Commercial interest
   a. Level 3 non-compliance threshold:
      i. Selected resource (any amount) at a busbar without any commercial interest; or
      ii. Commercial interest at selected busbar is evident, yet selected resource amount is lower by more than an amount to be specified based on the queue data at the time of mapping.
   b. Level 2 non-compliance threshold:
      i. Commercial interest at selected busbar is evident, yet selected resource amount is higher or lower than the "high confidence" commercial interest by an amount to be specified based on the queue data at the time of mapping.
      ii. Commercial interest at selected busbar is evident but the expected online date is a year or more later than the portfolio's resources' online date.
      iii. No commercial interest at selected busbar, but selected resource's modeled online date is beyond expected online dates for any commercial interest.

5. Consistency with prior year's mapping
   a. Level 3 non-compliance threshold:
      i. 500 MW or greater or a 50% or greater reduction from prior year's base case portfolio (to identify material absolute changes from prior year's mapping or changes that may be smaller in absolute terms yet are still significant in percentage terms)
   b. Level 2 non-compliance threshold:
      i. Any reduction from prior year's base case portfolio

Note: If based on review of the portfolios, these thresholds turn out to be too low (for example, if approximately half or more of the new resources get flagged at level 3 non-compliance, and this would trigger further rounds of mapping of a large portion of the portfolio, creating a major departure from the logic and optimization objective within RESOLVE), then staff may adjust these thresholds accordingly.

10. Other TPP Assumptions

Thermal Generator Retirement Assumptions

RESOLVE reports the aggregate amount of thermal generation not retained by resource category. Unit-specific information is not modeled. Because the TPP studies require modeling of specific units and locations, CPUC staff will apply the following steps to RESOLVE's aggregate data on thermal generation not retained in order to specify in the transmitted portfolios which units should be assumed as retired for transmission planning purposes:

1. Rank all existing thermal generation units by age in the categories of combined cycle (CCGT), combustion turbine (Peaker), reciprocating engine (ICE) and combined heat and power (CHP). Staff recognizes there are additional economic considerations on CHP operations.
2. Model offline the oldest units, up to but not exceeding the total amount selected in RESOLVE, broken down by resource category up to the limits below. While CHP is not specifically modeled in RESOLVE and therefore cannot be one of the thermal generator types not selected for retention, CHP often operates similarly to a CCGT unit, so CPUC staff will retire CHP and CCGT up to the limit for the CCGT category in the table below.
3. CPUC staff will share the specific list of retired units with CAISO, and if necessary, through consultation, CPUC staff will assemble a list that does not create additional transmission needs. This will include in the following order:
    a. Maintaining the retirement of the thermal generation unit in the area with identified transmission needs but adequately replacing the capacity with generation and/or battery storage resources; and/or
    b. Restoring the thermal generation units in areas with identified transmission needs in reverse order of the list developed in steps 1 and 2.
4. If specific local units are turned back on in step 3.b. then an equal amount of additional system generation capacity will be modeled off-line following steps 1 and 2.

The above steps aim to minimize any post-processing work by the CAISO. Once the IRP portfolios are transmitted to the CAISO, if within the TPP it is identified that known local area requirements are not met, then CAISO staff may reallocate mapped battery storage from a general CAISO System area to a particular local area to meet the local area requirement up to known battery storage charging limits. If known local area requirements are still not met, then local thermal generation will be restored in reverse order of the list developed in steps 1 and 2.

Demand Response

This subsection provides guidance on modeling treatment of demand response (DR) programs in network reliability studies including allocating capacity from those programs to transmission substations.

The CPUC's Resource Adequacy (RA) proceeding (R. 17-09-020 or its successor) determines what resources can provide system and local resource adequacy capacity. Current RA accounting rules indicate that all existing DR programs count to the extent those program impacts are located within the relevant geographic areas being studied for system and local reliability. For its TPP studies the CAISO utilizes data from Supply-Side Resource Demand Response, which is registered in the CAISO market as either dispatchable, fast-response Reliability Demand Response Resources (RDRR) or slow-response Proxy Demand Response (PDR).

By nature, impacts from DR programs are distributed across large geographies. In order for these impacts to be applied in network reliability studies, DR program capacity must be allocated to transmission substations. To this end, CPUC staff requests the Investor-Owned Utilities (IOUs), in their capacity as Participating Transmission Owners (PTOs), to submit this information through the CAISO's annual TPP Study Plan stakeholder process. To the extent possible, this data should also allocate impacts of DR programs administered by CCAs or procured from third parties.

Separately, and coupled with the CPUC's annual Load Impact Protocols (LIP) filings,[38] IOUs are to submit a second, updated filing. Thus, the data for the TPP is first filed in mid-February, followed by the LIP final Report filing in April, which is then followed by the updated filing in August of the same year.

While we recognize that the annual TPP Study Plan that concludes in March already incorporates busbar-level details, this additional reporting will validate the results from the earlier filings.

Because the data requirements specified in both filings contain confidential information, the CPUC expects the CAISO and the IOUs to exchange data using their own non-disclosure agreements.

Contact and recipient details for these filings will be provided by the CAISO. Both the TPP and updated filings are to contain the following:

1. Portfolio aggregate ex-ante load impacts (in MW), by program, for 1-in-2 under CAISO's August system peak, for each of the full ten-year forecast period, disaggregated by Western Electricity Coordinating Council (WECC) transmission level busbar, in plain Excel format. The WECC busbar shall be identified by two columns (fields):

a. WECC busbar number as used in CAISO power flow models;
b. Substation identifier/name (for example, [22256, ESCNDIDO] for SDG&E; [24214, SANBRDNO] for SCE; and [33207, BAYSHOR2] for PG&E). This applies to all

[38] D. 08-04-060 in R. 07-01-041, "Decision Adopting Protocols for Estimating Demand Response Load Impacts" LIP Final Reports are filed annual on April 1.

dispatchable IOU DR programs and does not include non-dispatchable programs such as Time-of-Use (TOU) rates;

c. The final year of the forecast (furthest into the future), for all program operating hours (not just the Resource Adequacy [RA] operating window). Disaggregate the data into four geographic zones: PG&E Bay, PG&E Valley, SCE, and SDG&E. PG&E Bay is defined as the Greater Bay Area Local Capacity Area (LCA) and PG&E Valley is defined as everything else in PG&E. This requirement applies to all dispatchable and non-dispatchable programs.

2. The methods and assumptions for disaggregating DR impacts by WECC transmission level busbar shall be standard and uniform across each IOU and documented in a supplemental report. To the extent this data does not sufficiently mask individual customer load information, the IOUs shall provide both a public version of the data with individual customer load information masked, and a confidential version of the data with complete information. The IOUs shall make the confidential dataset known and available to the CAISO (with applicable NDAs) by the annual deadline for its request for stakeholder input on "unified planning assumptions" for the TPP.

---- DOCUMENT ENDS ----

END ATTACHMENT C