Draft 2023 Inputs and Assumptions (2023 I&A)

Energy Division

June 7, 2023

California Public
Utilities Commission

1. Introduction

Logistics & Scope

- 2023 Inputs and Assumptions (2023 I&A) document and supporting materials, and webinar slides are available at 2022-2023 IRP Cycle Events and Materials.
- The webinar will be recorded, with the recording posted to the same webpage
- The objectives of this webinar are to:
  - Provide an overview of the 2023 I&A document
  - Present some specific topics from the I&A document focusing on new and updated assumptions compared to the previous cycle
  - Provide an update on the overall process and timeline for finalizing the I&A document
  - Request stakeholders' informal written feedback to be incorporated in the final I&A document

Questions

- We invite clarifying questions using the “Q&A” feature of this Webex
- If time allows, we invite verbal clarifying questions at regular intervals throughout this webinar.
  - All attendees have been muted. To ask questions:
    - In Webex:
      - Please “raise your hand”
      - Webex host will unmute your microphone and you can proceed to ask your question
      - Please “lower your hand” afterwards
    - For those with phone access only:
      - Dial *3 to “raise your hand”. Once you have raised your hand, you'll hear the prompt, "You have raised your hand to ask a question. Please wait to speak until the host calls on you“
      - WebEx host will unmute your microphone and you can proceed to ask your question
      - Dial *3 to “lower your hand”
- Should time not permit attention to every question please email your questions to IRPDataRequest@cpuc.ca.gov
- The discussion in this webinar will be recorded and posted online, as well as the written portion of the Q&A transcript. Stakeholders will have two weeks from the date of this webinar to submit their informal comments on the draft 2023 I&A to Staff, per instructions to be provided later. These comments, though will be informal and not part of the IRP proceeding record.

Agenda

Topic	Timing	Presenter(s)
1. Introduction	10min	Nathan Barcic
2. Context, Process, and Timeline	10 min	Ali Eshraghi
3. Resources & Cost Assumptions		
3.1. Baseline and In-Development Resources	10 min	Sam Schreiber
3.2. Resources & Cost Assumptions	15 min	Sam Schreiber, Ali Eshraghi
3.3. Shed DR and Shift DR	5 min	Michaela Levine
3.4. Emerging Low- and Zero-Carbon Technologies	10 min	Roderick Go, Sam Schreiber
3.5. Vehicle-Grid Integration Analysis	10 min	Sumin Wang
3.6. Renewable Characterization Methodology - Resource Potential and Land-Use Constraints	5 min	Jared Ferguson
4. Operating Assumptions		
4.1. Hourly Load, Solar Generation, and Wind Generation Profiles	5 min	Patrick Young, Roderick Go
4.2. Transmission Constraint Implementation	15 min	Jared Ferguson, Sam Schreiber
4.3. Transmission Topology	5 min	Sam Schreiber
4.4. Fuel Price Update	5 min	Angineh Zohrabian
4.5. RPS and SB 100	5 min	Angineh Zohrabian
4.6. GHG Trajectory	5 min	Femi Sawyerr

Agenda (Cont.)

Topic	Timing	Presenter(s)
5. Reliability		
5.1. Approach and Inputs	10 min	Neil Raffan, Patrick Young
5.2. PRM and Reliability Need	10 min	Neil Raffan
5.3. MTR Requirement Implementation	5 min	Joshua Spooner
5.4. ELCC Surface and Curves	15 min	Charles Gulian
6. Loads	15 min	Angineh Zohrabian
7. Next Steps	10 min	Nathan Barcic, Ali Eshraghi

2. Context, Process, and Timing

California Public
Utilities Commission

Inputs and Assumptions (I&A)

- The Inputs and Assumptions (I&A) document describes the key data elements, assumptions, and methodologies for CPUC IRP modeling within a given cycle
- The I&A document for the 2022-23 IRP cycle (2023 I&A) will be used for developing the 2023 Preferred System Plan (PSP) and 2024-25 Transmission Planning Process (TPP) portfolios for the CAISO electric system that reflect different assumptions regarding load growth, technology costs and potential, fuel costs, and policy constraints
- Draft 2023 I&A document and supporting materials are available at 2022-2023 IRP Cycle Events and Materials.

2023 I&A Document Content

The document has eight sections:

- **(Section 1) Introduction**
  - Provides an overview of the RESOLVE and SERVM models and key data and model updates described in the document.
- **(Section 2) Load Forecast**
  - Documents the assumptions and corresponding sources used to derive the forecast of load in CAISO and the WECC, including the impacts of demand-side programs, load modifiers, and the impacts of electrification.
- **(Section 3) Baseline Resources**
  - Summarizes assumptions on baseline resources. Baseline resources are existing or in development resources that are assumed to be operational in the year being modeled.
- **(Section 4) Resource Cost Methodology:**
  - Describes the financial model used to calculate levelized fixed costs of candidate resources in RESOLVE.

2023 I&A Document Content (Cont.)

- **(Section 5) Optimized Resources**
  - Discusses assumptions used to characterize the potential new resources that can be selected for inclusion in the optimized, least-cost portfolio.
- **(Section 6) Generators Operating Assumptions**
  - Presents the assumptions used to characterize hourly electricity demand and the operations of each of the resources represented in RESOLVE's internal hourly production simulation model.
- **(Section 7) Resource Adequacy Requirements**
  - Discusses the constraints imposed on the RESOLVE portfolio to ensure system and local reliability needs are met, as well as assumptions regarding the contribution of each resource towards these requirements.
- **(Section 8) Greenhouse Gas Emissions and Renewables Portfolio Standard**
  - Discusses assumptions and accounting used to characterize constraints on portfolio greenhouse gas emissions and renewables portfolio standard targets.

2023 I&A Document Content (Cont.)

There are two general categories of topics:

1. Updates to the inputs and assumptions as more recent data vintages are available.
    - Load Forecast, Resource cost updates, Resource potential and land-use constraints, Generation profile creation, Transmission constraint implementation, Fuel price update
2. Introducing some new items in the 2022-23 IRP cycle.
    - Proposed updates to reflect Inflation Reduction Act (IRA), Emerging Technologies, Vehicle-Grid Integration (VGI), Reliability modeling, etc.

Overall Process & Timing for 2022 I&A

Item	Schedule
2023 I&A MAG Webinar	September 22, 2022
Stakeholders' informal comments to be submitted to Staff	October 6, 2022
Draft 2023 I&A Document	June 5, 2023
Draft 2023 I&A Webinar	June 7, 2023
Stakeholders' informal comments on the draft 2023 I&A document to be submitted to Staff	June 21, 2023
Final 2023 I&A document	August/September 2023

Stakeholders' Informal Comments Process

- Staff Invite stakeholders to submit written feedback on the draft 2023 I&A document to be incorporated in the final document
- Stakeholders will have two weeks from the date of this webinar to submit their informal comments to Staff.
- Please submit comments to IRPDataRequest@cpuc.ca.gov by June 21, 2023.
  - Stakeholders are encouraged to include the IRP service list as well.
  - Please categorize your comments based on sections and topics in the draft 2023 I&A document
- Stakeholders should support their input with data and/or explanations.
  - If referring to specific data, please provide the link(s) to those data.

3. Resources & Cost Assumptions

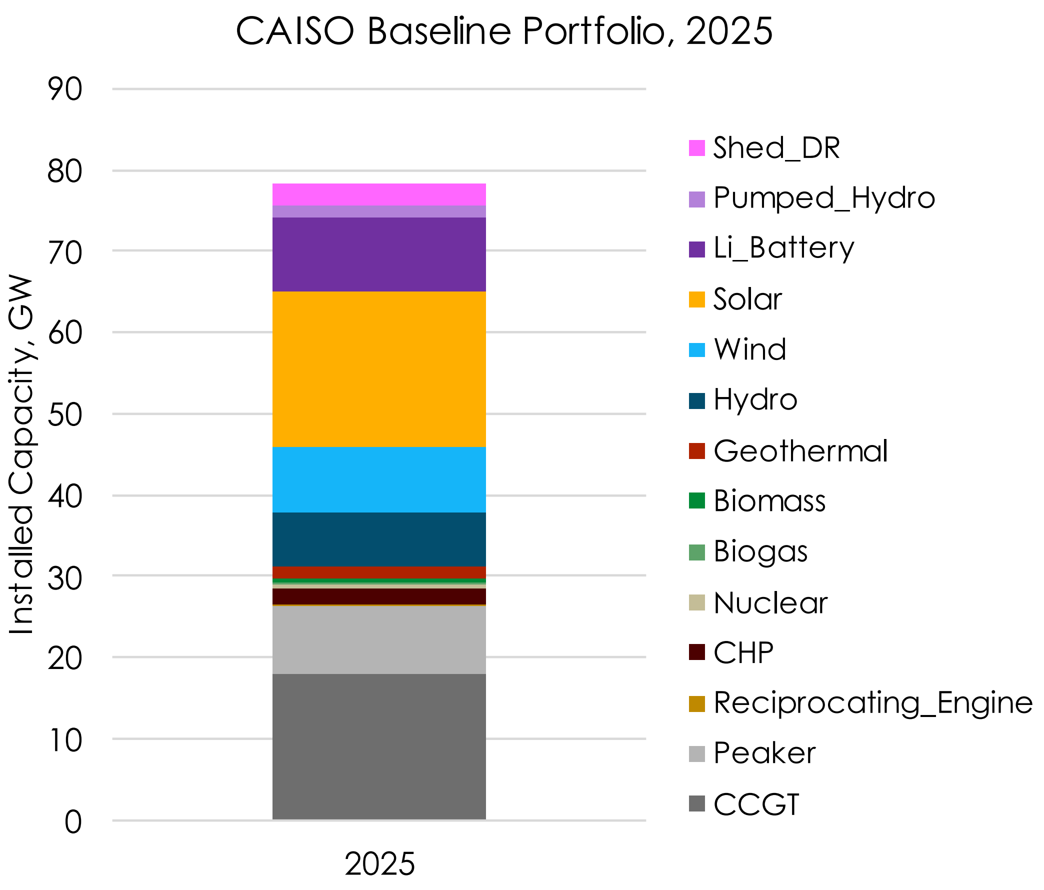
3.1. Baseline and In-Development Resources

Defining the Baseline

- The resource baseline includes both online and in-development resources, and is an input to both the RESOLVE and SERVM models
  - Online: Resources that are already built and operating, net of expected retirements
  - In-development: Resources with approved contracts, or resources already under construction, which have made sufficient progress towards an expected online date
- The resource baseline does not include candidate resources, which can be selected by the model as new resource additions
  - It also does not include any generic planned new resources reported in LSE filings, which instead are interpreted as minimum build thresholds for corresponding candidate resources
- Data sources:
  - CAISO Master File & CAISO Master Generating Capability List (Online)[1]
  - CAISO Mothball/Retirement List (Online)[2]
  - November 2022 LSE IRP Filings (In-Development)[3]
  - POU filings processed by the CEC (Online & In-Development)[4]
  - WECC Anchor Data Set (ADS) (Non-CA Online & In-Development)[5]

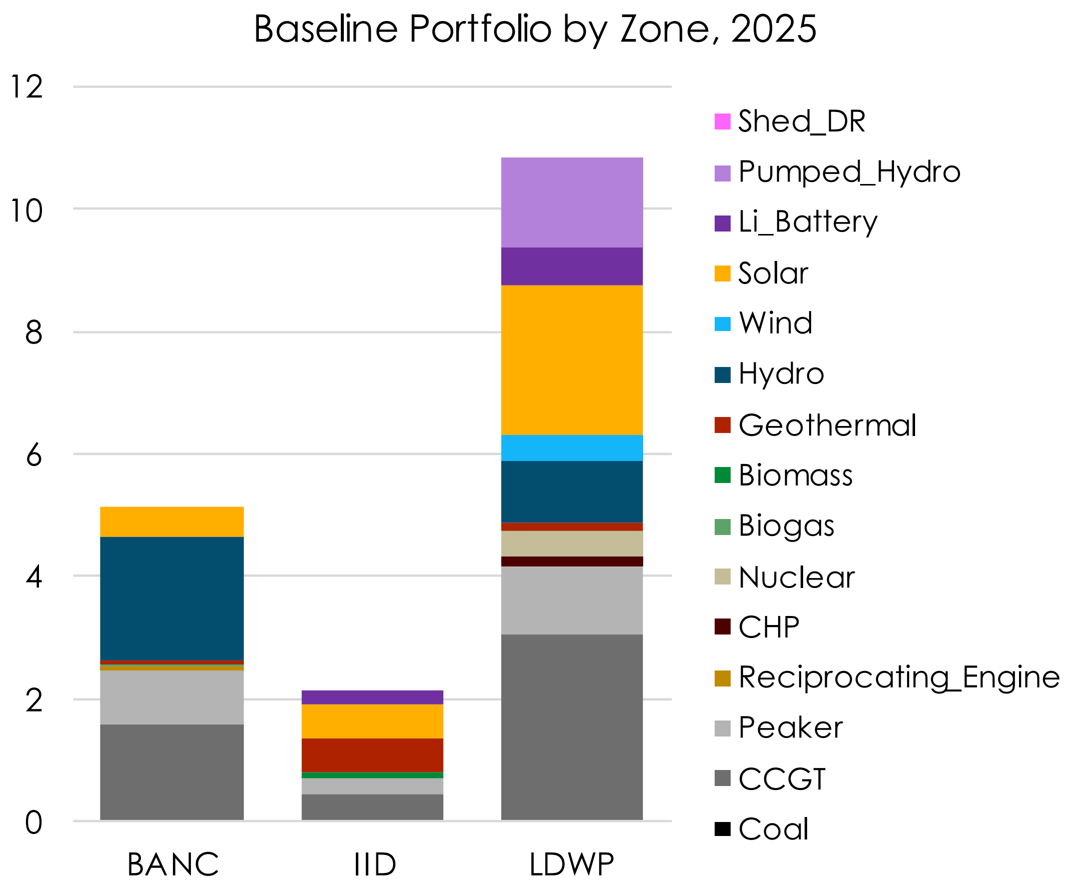
1 http://oasis.caiso.com/mrioasis/logon.do
2 Announced Resource Retirement and Mothball List Posted (caiso.com)
3 LSE 2022 Integrated Resource Plans (ca.gov)
4 https://efiling.energy.ca.gov/getdocument.aspx?tn=230474 ; LA100: The Los Angeles 100% Renewable Energy Study and Equity Strategies ; SMUD 2030 Zero Carbon Plan TechnicalReport ; https://www.energy.ca.gov/filebrowser/download/1905
5 Reliability Modeling Anchor Data Set (ADS) (wecc.org)

CAISO Baseline Resources



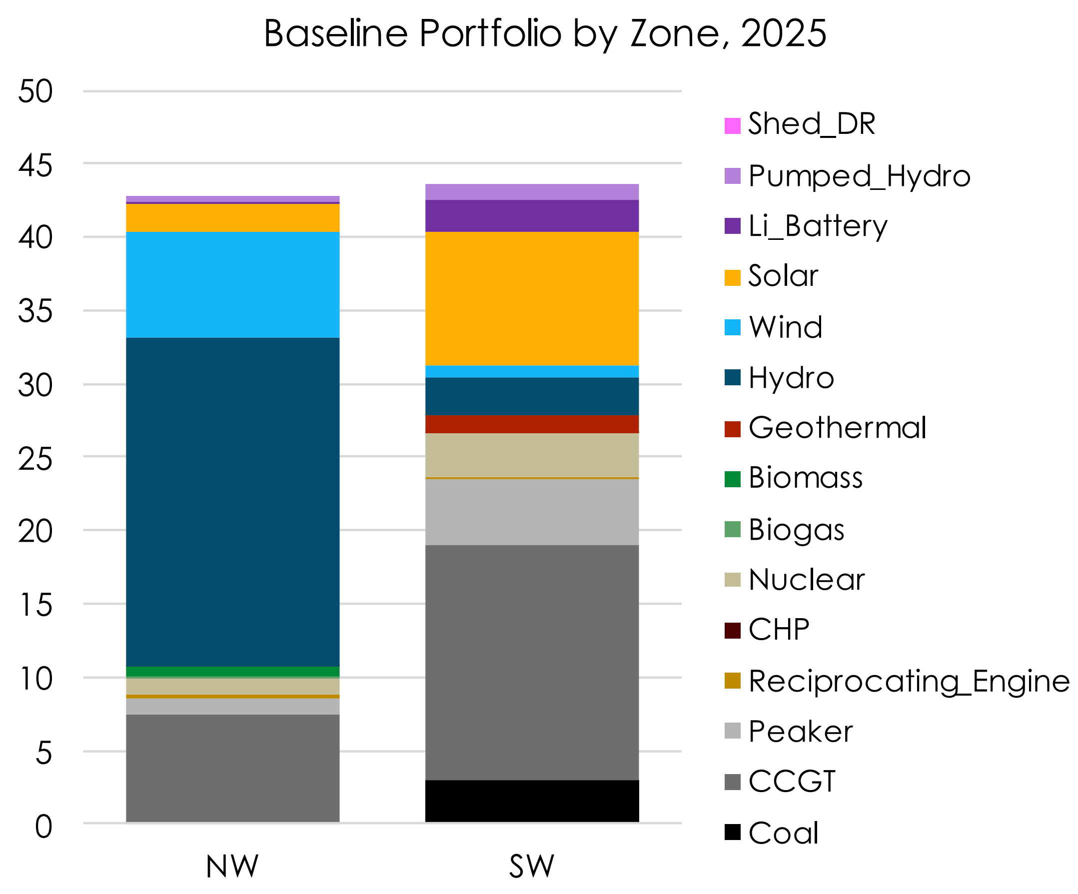
- Data from CAISO Master File and November 2022 LSE Filings
- The CAISO baseline resource portfolio totals 78.4 GW of installed capacity in 2025, including:
  - 28.5 GW of thermal gas units
  - 8.1 GW of onshore wind
  - 19.1 GW of solar
  - 9.1 GW of Li-ion batteries
- For a detailed breakdown of CAISO installed baseline capacity by modeling year, refer to Section 3 of the I&A document

Baseline Resources in non-CAISO LSEs



- Baseline resources for the non-CAISO LSEs within California (BANC, IID, LDWP) are sourced from POU filings processed by the CEC
- 2025 Baseline resource portfolio totals in non-CAISO LSEs:
  - BANC: 5.1 GW
  - IID: 2.2 GW
  - LDWP: 10.9 GW
- For a detailed breakdown of installed baseline capacity by modeling year, refer to Section 3 of the I&A document

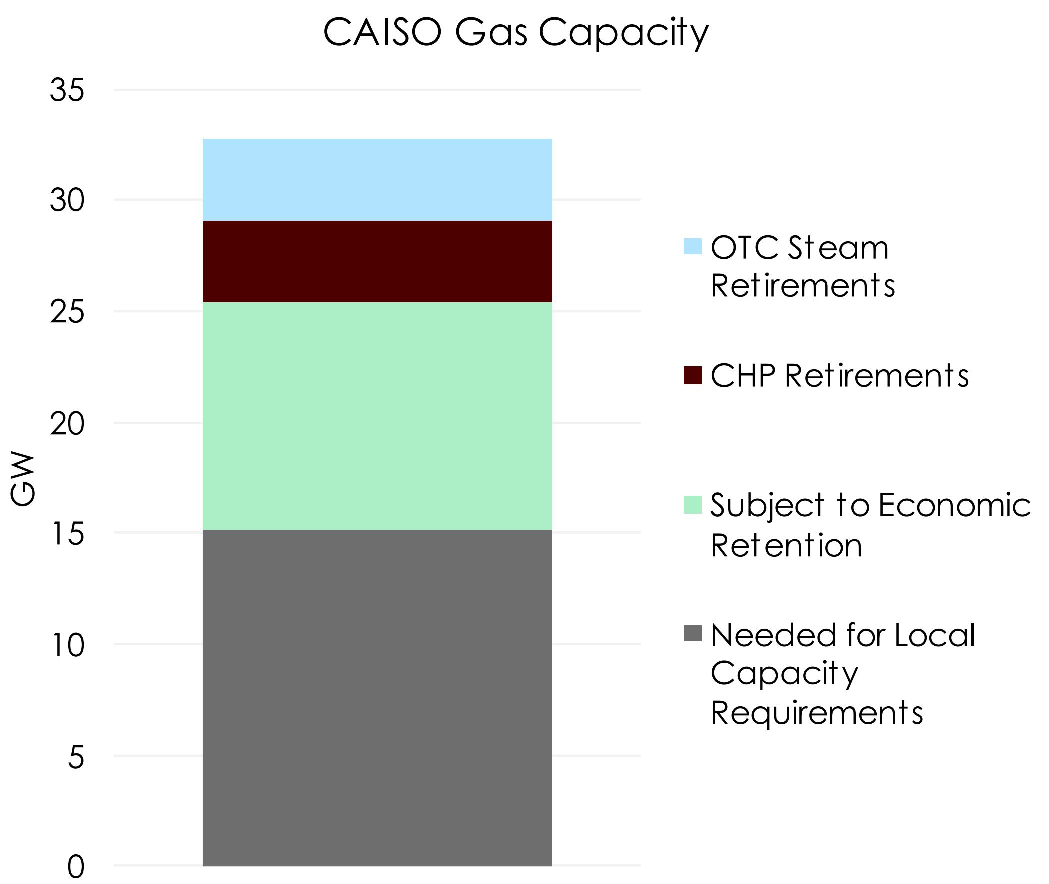
Baseline Resources in External Zones



- Baseline resources in external zones (NW, SW) are sourced from the WECC Anchor Data Set (ADS)
- 2025 Baseline resource portfolio totals in external zones:
  - NW: 42.9 GW
  - SW: 44.3 GW
- For a detailed breakdown of installed baseline capacity by modeling year, refer to Section 3 of the I&A document

Retention of Aging Thermal Units

- CAISO's remaining Steam Turbines (ST) are currently scheduled to retire for compliance with Once-Through-Cooling (OTC) regulations prior to 2025
- Combined Heat and Power (CHP/Cogen) units are assumed to retire over 2031-2040 (linear stepdown)
- CCGT, Peaker, and Reciprocating Engines are subject to economic retention decisions:
  - RESOLVE considers reliability needs and FO&M costs to determine whether it is cost-effective to retain a thermal generator
  - 19 GW of gas-fired capacity is serving local capacity requirements (LCR); 4 GW can be replaced with local 4-hr Li-ion batteries, but the remainder must be retained
  - Decision is whether to retain on the CAISO system, not to retire (generators can serve non-CAISO load)



Hydro Resources

- In previous IRP cycles, hydro generators in CAISO were grouped into Small Hydro (primarily run-of-river units) and Large Hydro resources
  - All in-state hydro resources provide resource adequacy and GHG-free energy to CAISO, but only small hydro units provide RECs
- In RESOLVE, these generators are now combined into a single "CAISO_Hydro" resource, with an energy budget and REC production determined by the historical energy production of these generators
- Additionally, firm hydro imports from the Northwest provide GHG-free energy to CAISO
  - 8.31% of the NW_Hydro resource, as determined by GWh totals from historical asset controller supplier imports, is earmarked as "NW_Hydro_for_CAISO" for this purpose

Resource Name	Average Historical Annual Production (GWh)	RPS Eligible	GHG-Free Energy	Resource Adequacy
CAISO_Hydro	17,323	Yes (11.35%)	Yes	Yes
NW_Hydro_for_CAISO	10,173	No	Yes	No

3.2. Resource Cost Update

Optimized vs. Non-Optimized Resource Additions

- **Optimized** resources are represented as decision variables in RESOLVE's capacity expansion optimization and include the following sub-categories:
  - <u>Default Candidate Resources</u> (included in all cases): established, commercially viable technologies
    - Solar, wind, geothermal, Li-ion batteries, pumped hydro storage, shed demand response, and candidate thermal resources
    - Subject to minimum build limits, as reported in LSE filings for planned/new additions that fall outside the resource Baseline (Section 3.1)
  - <u>Non-Default Candidate Resources</u> (included in sensitivities): technologies that are experimental and/or not yet commercially mature
    - Shift Demand Response (Section 3.3), Emerging Technologies (Section 3.4), Vehicle-Grid-Integration (Section 3.5)
- **Non-Optimized** resources are modeled in RESOLVE, but have prescribed adoption over time and are not represented as decision variables in the optimization model
  - Customer_PV
  - BTM Li-ion battery storage
  - Energy efficiency

Default Candidate Resource - Guiding Principles

- The 2023 I&A document defines guiding principles for a resource to become a default candidate resource in IRP modeling.
  - _Viable:_ This resource is a commercialized technology.
  - _Scalable:_ This resource could be realistically selected at sufficient volume to meaningfully impact California's electric portfolio.
  - _Economic:_ This resource is projected to be cost competitive within the timeframe of IRP analysis with sufficient publicly available market data to validate those projections.
  - _Actionable:_ Mechanisms exist, or could be reasonably expected to be put in place, to enable the CPUC to guide procurement of this resource.
  - _Timely:_ This resource can reasonably be expected to come online within the timeframe of IRP analysis.
- During each IRP portfolio development, staff evaluates the non-default candidate resources based on these guiding principles and determines if a resource meets the criteria to be a default candidate resource.

Solar Resources in IRP Modeling

- **Utility-scale solar (e.g. Tehachapi_Solar)**
  - Represents large, single-axis tracking ground-mount solar projects in California
  - <u>Optimized</u> resource in RESOLVE
- **Distributed_Solar**
  - Represents in-front-of-meter commercial rooftop solar, and solar projects developed on available urban infill land area
  - <u>Optimized</u> resource in RESOLVE
- **Customer_PV**
  - Represents distributed behind-the-meter (BTM) solar
  - <u>Non-optimized</u> resource in RESOLVE

Not Modeling Hybrid/Paired Solar-Storage as a Candidate Resource in RESOLVE

- At the September 2022 MAG Webinar, Staff sought stakeholder feedback on modeling of hybrid solar + storage resources for the I&A
- Under the Inflation Reduction Act (IRA), standalone energy storage resources can now receive investment tax credits (ITC), without any constraints on charging or co-location with renewable generation
- Given these updates, staff does not believe that hybrid storage resources need to be modeled in this IRP cycle
- Staff welcomes feedback from stakeholders on this update

Summary of Resource Cost Updates

Additional updates following the September 2022 MAG Webinar

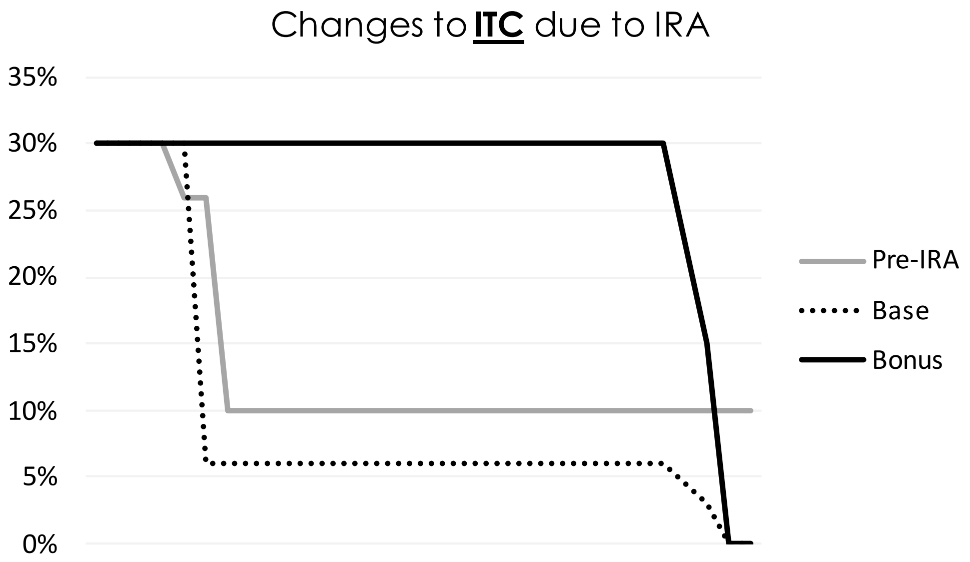
- **Updates to incorporate Inflation Reduction Act (IRA)**
  - Extensions of existing tax incentives to all zero-carbon technologies **through 2048**[1]
  - IRA "Bonus" incentives assumed for all technologies, where applicable
  - Production Tax Credit (PTC) is available to candidate solar resources and assumed to be selected in lieu of the Investment Tax Credit (ITC)
  - ITC is available to all storage technologies (Li-ion Batteries, Pumped Hydro Storage, and emerging technologies)
  - PTC credits available for CCS, direct air capture (DAC), and hydrogen production (CCGT w/ CCS, Synthetic Natural Gas, Hydrogen) for projects beginning construction by 2032

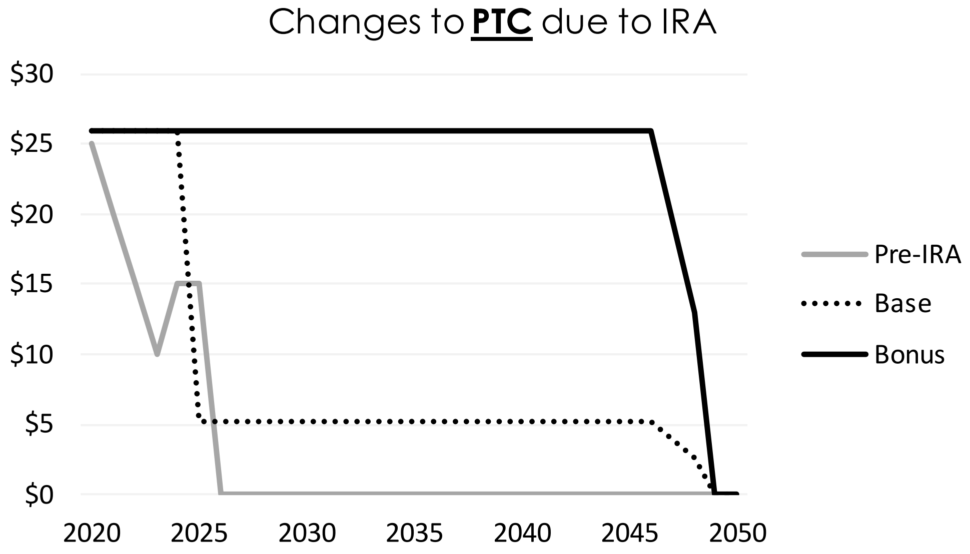
- **Additional cost modifications for solar PV, onshore wind, and Li-ion batteries**
  - These technologies have been disproportionately affected by commodity price increases, supply chain disruptions, and surging demand
  - Data source for Li-ion batteries has been updated to NREL 2022 ATB
  - Modifications to the overnight capital cost trajectories for all three technologies to either **slow or delay** the cost decline over time

[1] *Pursuant to IRA guidelines, 100% of the tax credit value can be monetized by eligible projects until the U.S. achieves 75% reduction in GHG emissions, relative to 2022 levels. This is assumed to occur in 2045, which then triggers a 3-year stepdown of incentives.*

Tax Credit Schedules Pre- vs. Post-IRA

- Solar now can choose to receive either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC)
  - PTC is assumed for utility-scale solar due to superior project economics (Appendix B)
- Standalone storage is eligible to receive ITC
- Wind continues to receive PTC, but at a higher rate per IRA
- Offshore wind can access the IRA ITC, which is technology-neutral
- The IRA "Bonus" case assumes projects meet prevailing wage and apprenticeship requirements
  - Additional adders exist if certain criteria are met for (1) domestic content requirements and (2) energy community siting; these adders are not modeled (Appendix B)



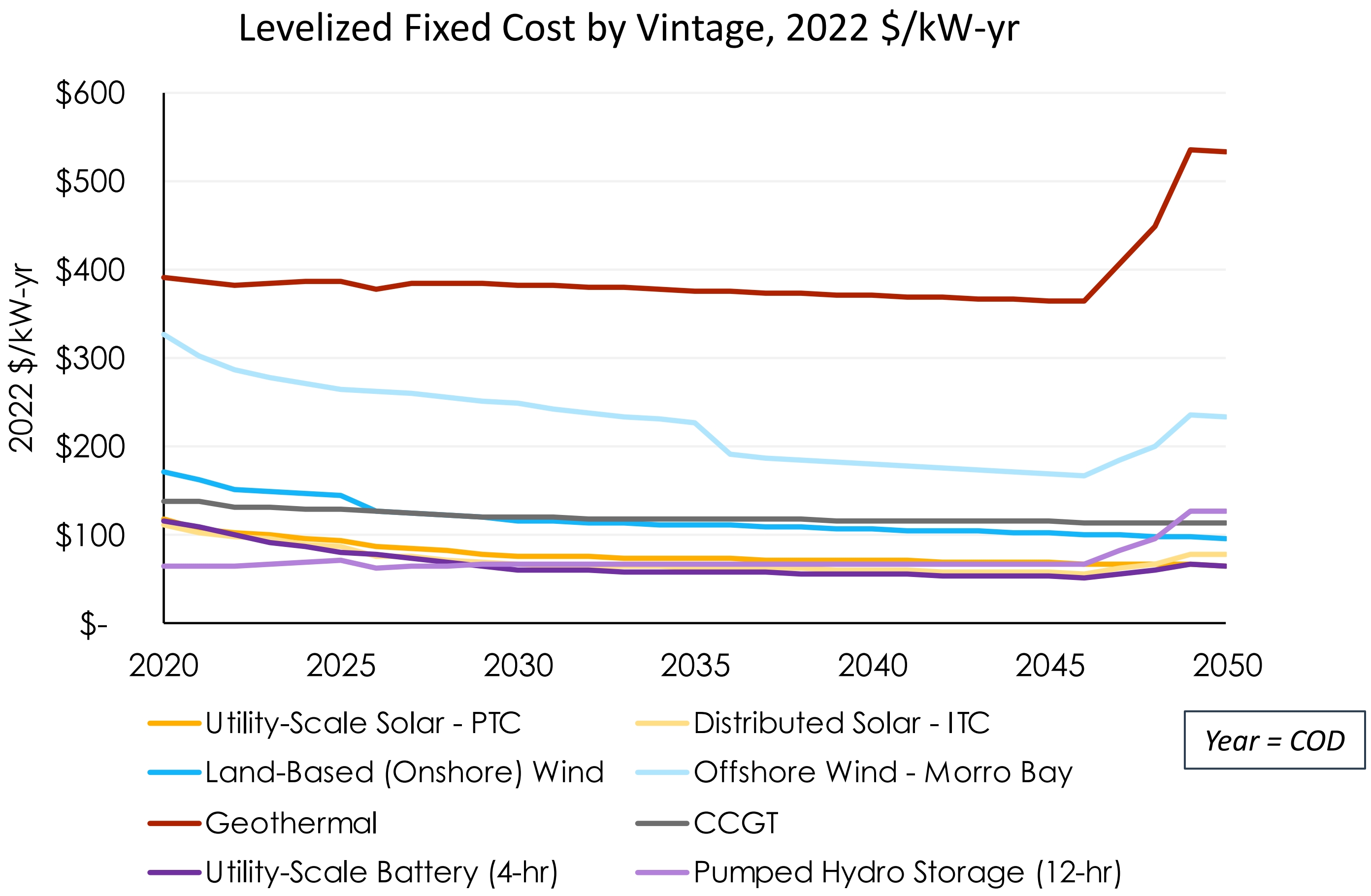


*Note: Assumes carbon emissions reduction targets are met in **2045** (75% reduction below 2022 levels for power sector per IRA), followed by a 3-year incentive step-down.*

Summary of Total Levelized Fixed Costs

Updated with IRA Tax Incentives

- Data source is the **2022 NREL ATB** for all technologies, including Li-ion batteries, and excluding Offshore Wind, which uses the location-specific 2020 NREL Cost of Floating Offshore Wind report[1]
- Total levelized fixed costs (LFC) represent the cost to construct new candidate resources and impact resource build decisions
  - Includes overnight capital cost, construction financing costs, fixed O&M costs, and any capital-based tax credits
- Relative to the Sept. 2022 MAG, LFCs are **reduced through 2045** for all zero-carbon technologies that select the ITC, due to the IRA



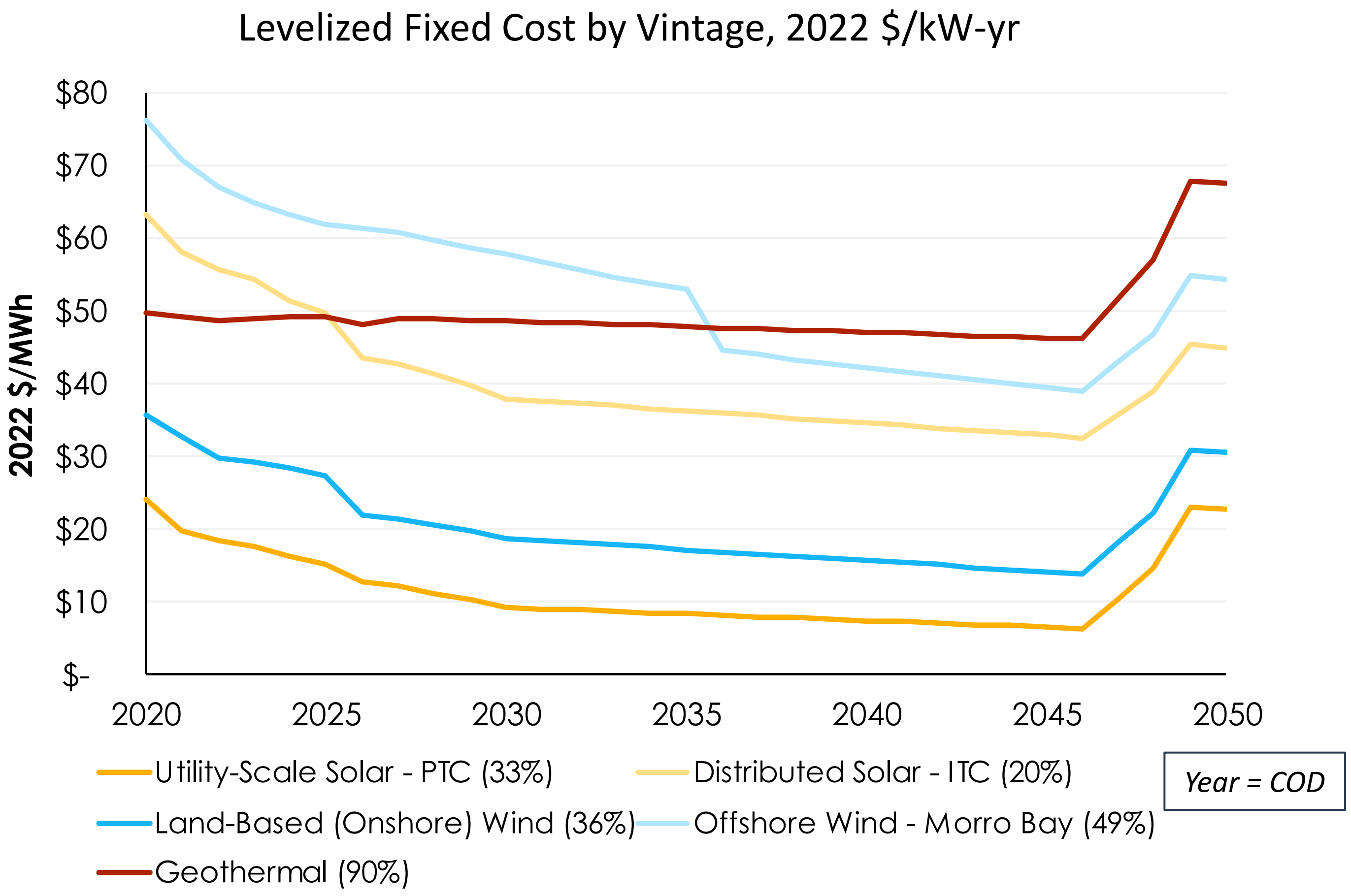
Note: Levelized cost estimates shown here do not reflect PTC, nor additional cost modifications to solar, wind, and battery resources (see following slides).

[1] https://www.nrel.gov/docs/fy21osti/77384.pdf, *Appendix A*

Summary of Total Levelized Cost of Energy

Updated with IRA Tax Incentives

- **LCOE data is indicative only and does not get used in RESOLVE**
- **The capacity factors reported here are indicative only and do not reflect the actual values used in RESOLVE.**
- The 75% reduction of power-sector carbon emissions is not assumed to be reached until 2045, resulting in a cost increase at the end of the modeling horizon (2046-2048)
- Geothermal resources benefit from the 30% ITC and become cost-competitive with offshore wind



<u>Note</u>: Capacity factors are indicative and do not represent the actual values used for candidate renewable resources. Levelized cost estimates shown here <u>do not</u> reflect additional cost modifications to solar, wind, and battery resources (see following slides).

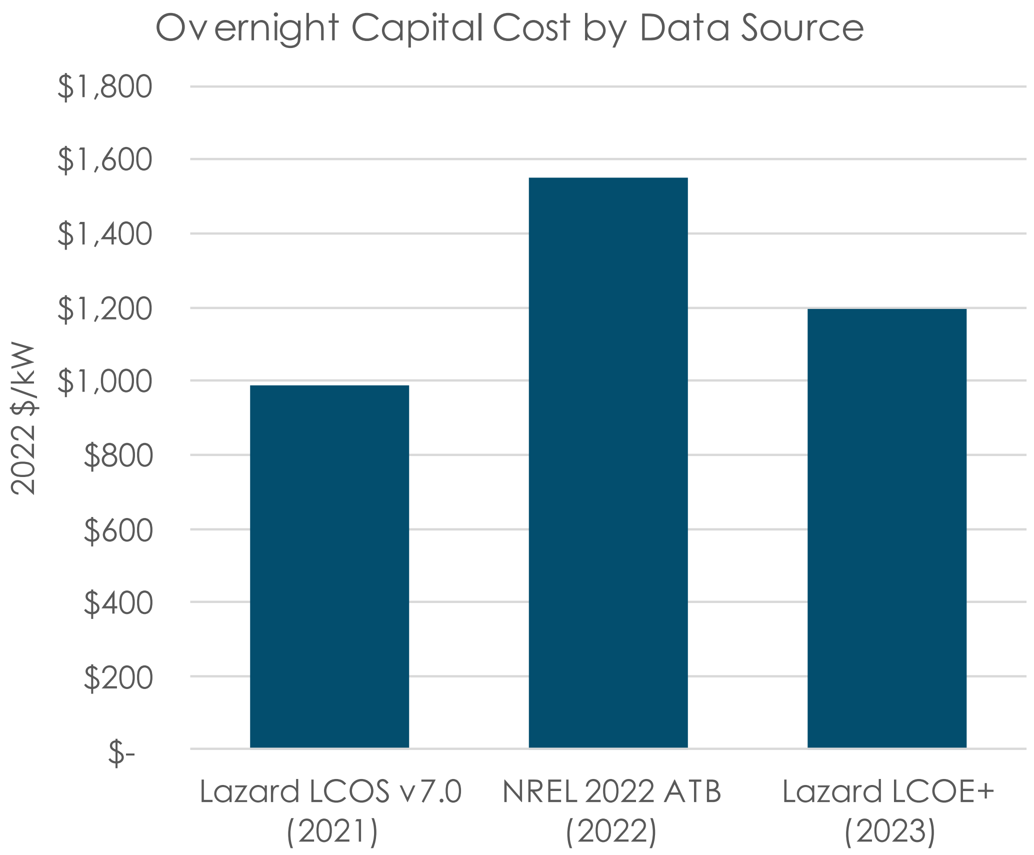
Adjustments to Resource Capital Cost due to High Commodity Prices

- At the September 2022 I&A MAG, Parties raised concerns about commodity prices and their potential impacts on resource costs
- Recent data suggests that **utility-scale solar, storage, and onshore wind** overnight capital costs have been disproportionately impacted by current market conditions (see Appendix C):
  - Continued supply chain disruptions following the COVID-19 pandemic
  - Sustained increase in demand for materials required to construct these resources, including minerals critical to the production of lithium-ion batteries
- Staff proposes that modifications are made to the 2022 NREL ATB capital cost trajectories for these technologies to respond to these concerns

Utility-Scale Li-ion Battery Capex

Lazard LCOS v7.0 vs. NREL 2022 ATB vs. Lazard LCOE+

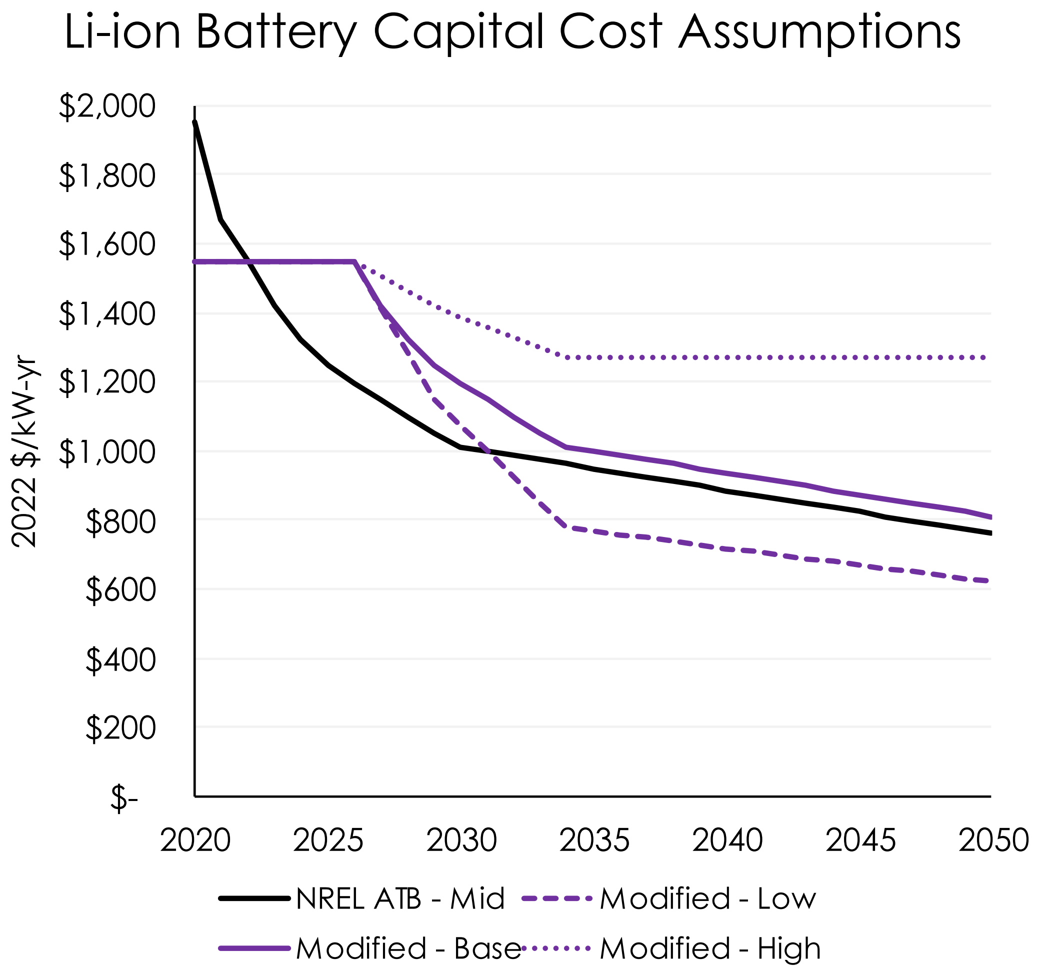
- Due to the delayed release of Lazard LCOE+ (April 2023), Staff decided to update its cost assumption data source for Li-ion Batteries from Lazard to NREL ATB
  - NREL 2022 ATB lacks financing assumptions for battery storage, and we continue to rely on Lazard for these inputs
- NREL ATB storage costs have historically been high, relative to observed market prices; with recent supply chain constraints, this gap has narrowed (Appendix C)
- Lazard assumptions tend to be more optimistic on upfront capital costs, but this is partially compensated by higher fixed O&M costs
  - Higher fixed O&M due to warranty extension, augmentation, and periodic replacement



https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/

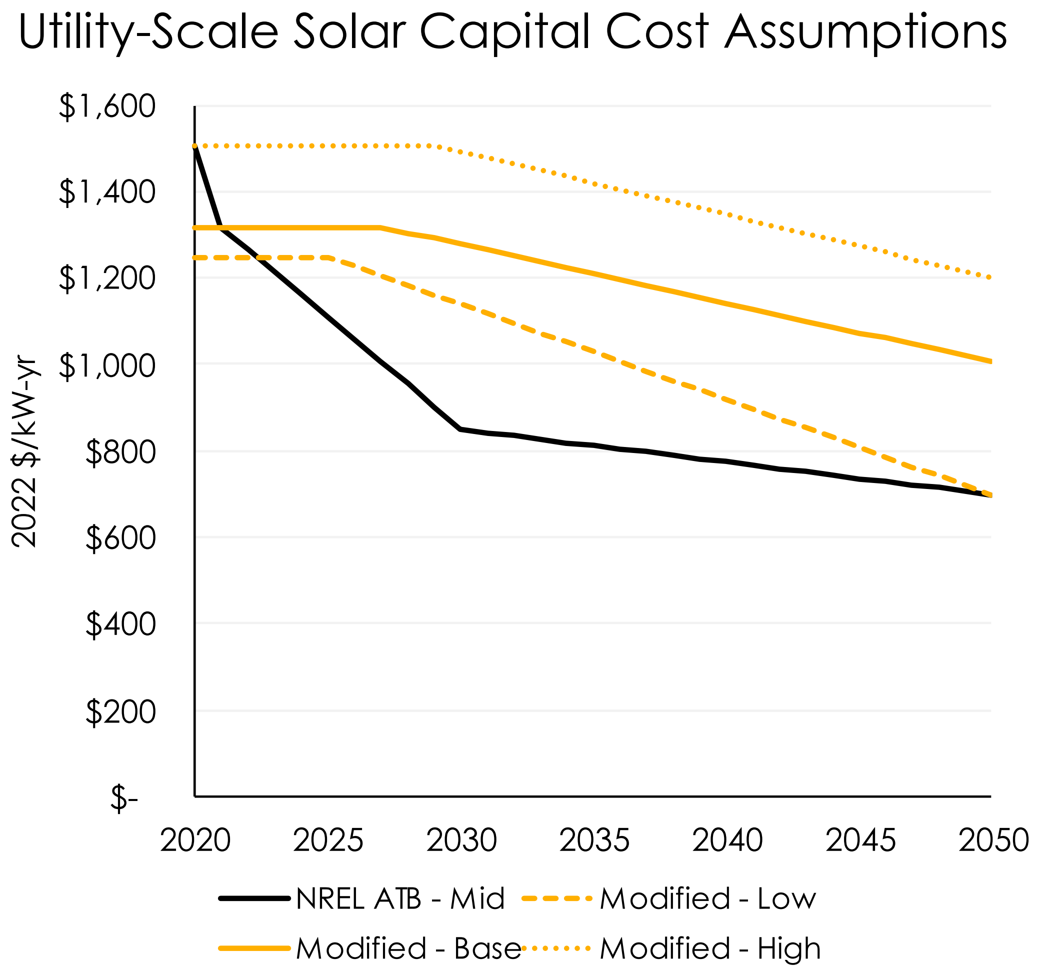
Proposed Capital Cost Modifications to Battery Storage

- Set initial value equal to the publicly reported 2022 value from the 2022 NREL ATB **($1,550/kW)**
  - Reflects the recent price shock due to sustained growth in demand promoted by new policy (IRA, etc.), supply chain issues, and coincident increases in commodity prices
- Flat trajectory extends through 2026
  - Allow several years for the commodity markets to adjust to sustained high demand
- Beginning in 2027, the trajectories follow NREL ATB with a four-year lag



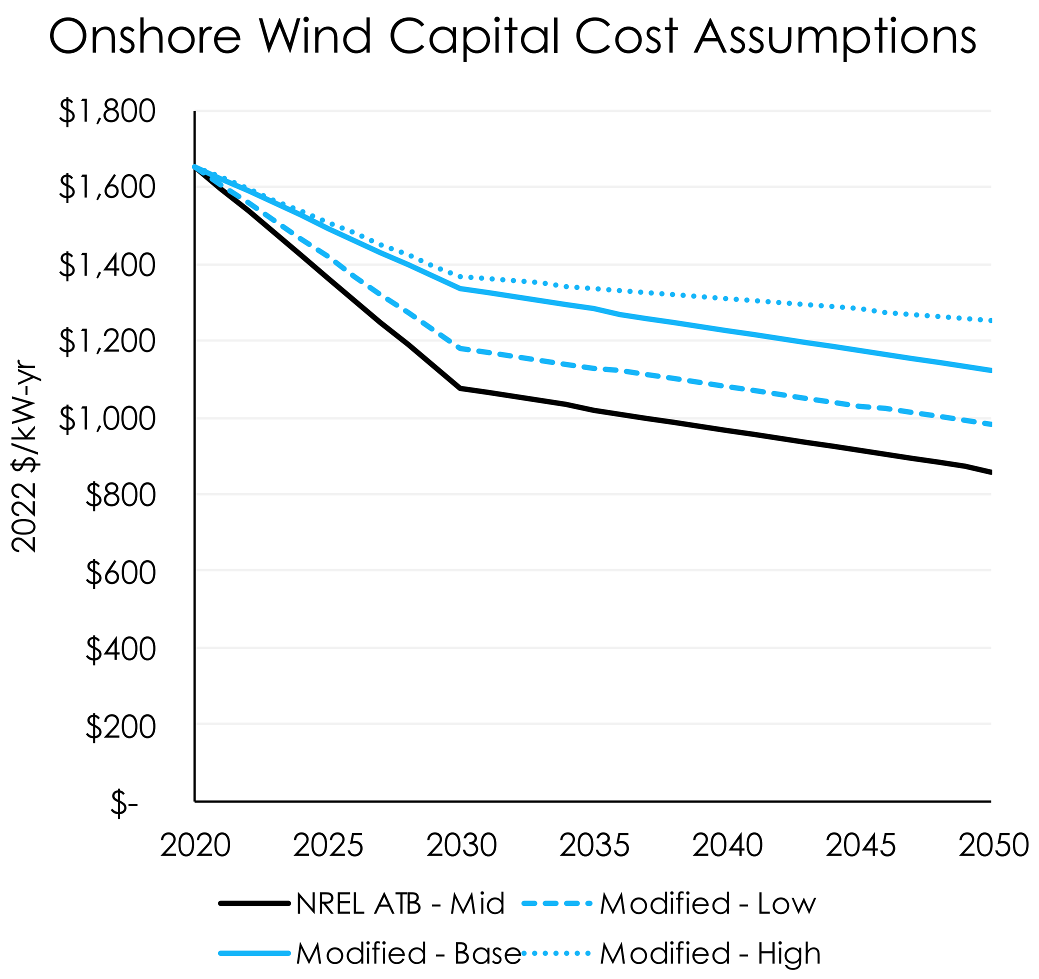
Proposed Capital Cost Modifications to Utility-Scale Solar

- Initial values indexed to the publicly reported values for 2020-2022 from the 2022 NREL ATB **($1,318/kW for “Mid”)**
  - Reflects stagnation in the cost decline for solar development since 2021
- Flat trajectory extends through 2027 (Mid)
  - Stagnation projected to continue for the next several years as the markets adjust to projected demand increases
- Beginning in 2028 (Mid), the trajectory follows a linear cost decline curve



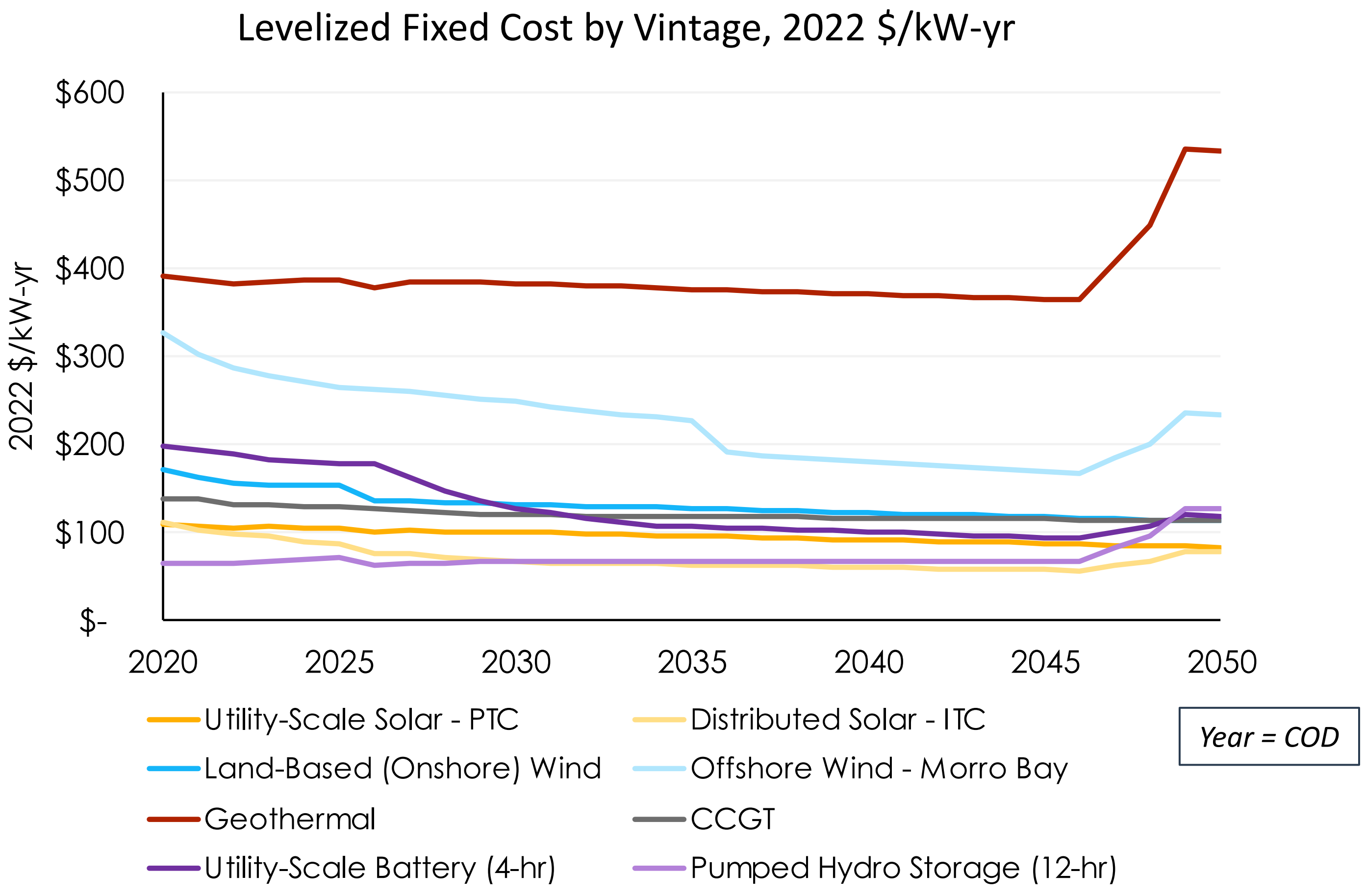
Proposed Capital Cost Modifications to Onshore Wind

- Initial value equal to the publicly reported 2020 value from the 2022 NREL ATB **($1,653/kW in $2022)**
  - Onshore wind construction costs have not been observed to suffer from recent price shocks
- Rate of cost decline halved through 2030
  - More conservative assumption than NREL ATB to allow for markets to adjust to sustained high demand
- Beginning in 2030, the trajectories follow a linear cost decline curve matching NREL ATB



Summary of Total Levelized Fixed Costs
Updated with IRA Tax Incentives and Capital Cost Modifications

- **Inclusive of proposed capital cost modifications from previous slides**
- **These LFCs are the final cost inputs into RESOLVE** for candidate resources and impact resource build decisions
  - Includes overnight capital cost, construction financing costs, fixed O&M costs, and any capital-based tax credits
- The modifications to Li-ion battery capital cost would make this technology's LFC higher than pumped hydro storage throughout the planning horizon
- Staff welcomes feedback on the capital cost modifications proposed in this Section

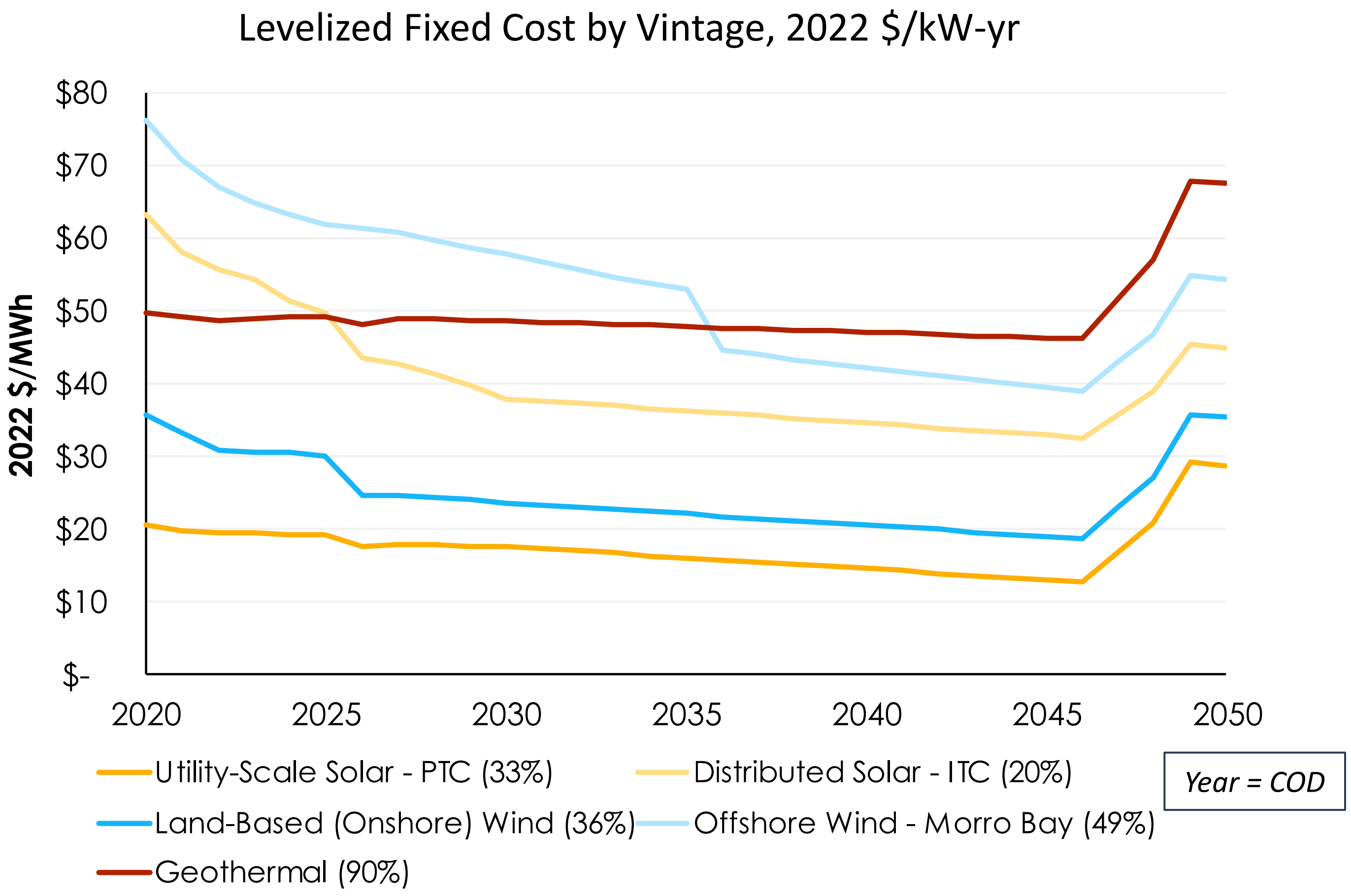


Note: Levelized cost estimates shown here do not reflect PTC.

Summary of Total Levelized Cost of Energy

Updated with IRA Tax Incentives and Capital Cost Modifications

- **LCOE data is indicative only and does not get used in RESOLVE**
- **The capacity factors reported here are indicative only and do not reflect the actual values used in RESOLVE.**
- Only slight changes to solar and onshore wind LCOE due to the capital cost modifications

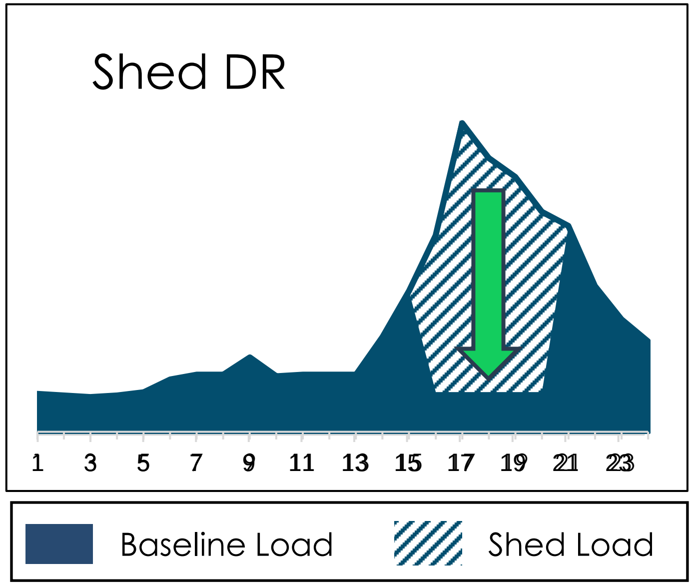


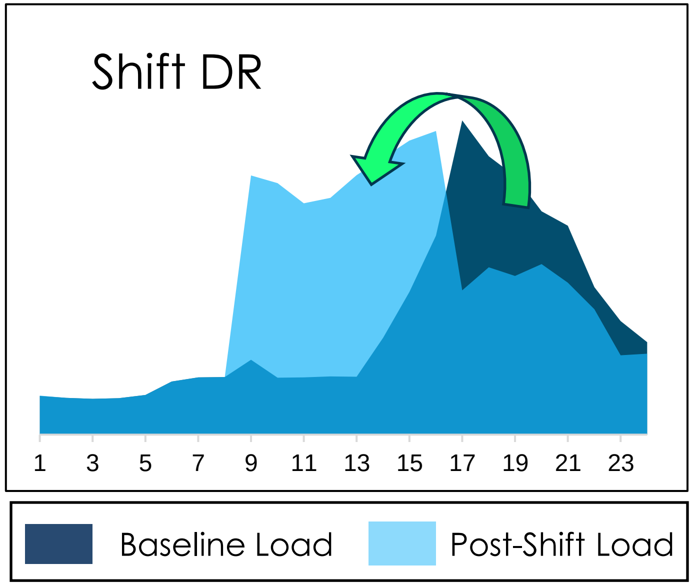
Note: Capacity factors are indicative and do not represent the actual values used for candidate renewable resources.

3.3. Shed DR and Shift DR

Shed DR and Shift DR

- **Shed (or "conventional") Demand Response (DR)** – Loads that can be curtailed to provide capacity reductions
- **Shift DR** – Loads that can be shifted between hours
- Lawrence Berkeley National Lab (LBNL) has created detailed load profiles and cost curves with achievable potential for both resources





Timeline of Shed DR and Shift DR in IRP

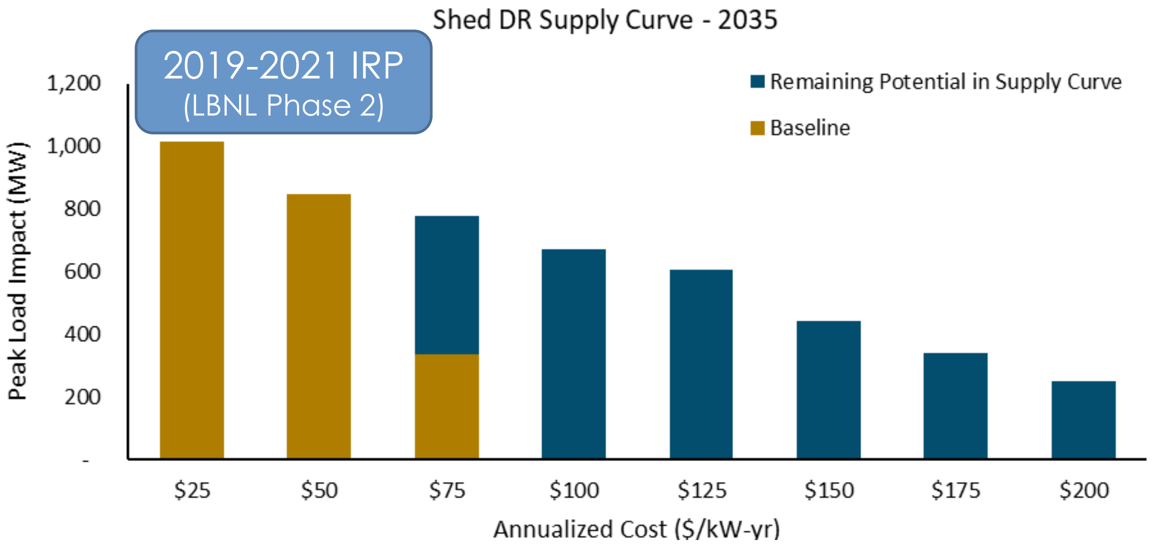
- IRP sources this data from LBNL's DR-Path model*
- Since last IRP cycle, E3 and LBNL collaborated on modeling and data updates to more accurately model load shifting resources in RESOLVE

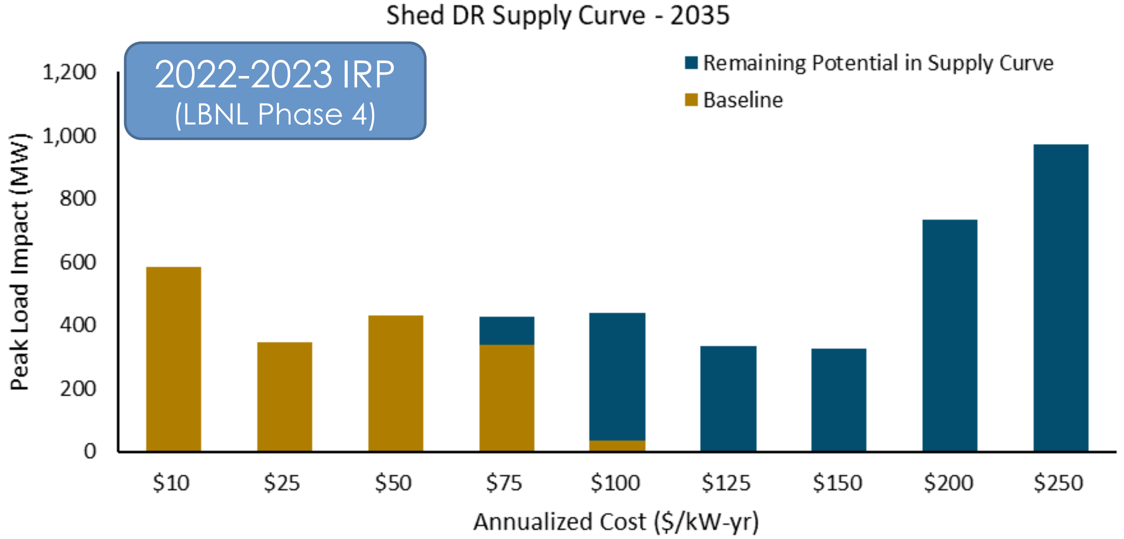
	2017-2018 IRP Cycle	2019-2021 IRP Cycle	2020 Modeling and Functionality Improvements	2022-2023 IRP Cycle
Shed DR	Candidate resource in Reference System Plan	Candidate resource in Reference System Plan		Candidate resource
Shift DR	Candidate resource in sensitivity case	Not included in any sensitivity	RESOLVE Code updated for more accurate modeling	Available as candidate resource in sensitivity case
Data Source	<u>Shed Baseline</u>: Statewide DR Load Impact Report <u>Remaining supply curves</u>: LBNL's DRPATH model with data from 2025 California Demand Response Potential Study (Phase 2 Results)[1]		LBNL's California Demand Response Potential Study, Phase 3[2]	<u>Shed Baseline</u>: Final Load Impact Protocol reports submitted by the IOUs to the CPUC[3] <u>Remaining supply curves</u>: LBNL's California Demand Response Potential Study, Phase 4[4]

*DR-Path is a model developed by LBNL to produce supply curves for variety of demand response technologies, based on assumed costs and technical potential

1) Alstone et al, 2017 https://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf
2) Gerke et al, 2020 https://eta-publications.lbl.gov/sites/default/files/ca_dr_potential_study_-_phase_3_-_shift_-_final_report.pdf\
3) Guide to CPUC's Load Impact Protocols (LIPs) Process v3.1 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/lip-filing-guide-and-related-materials/lip-filing-guide-v31.pdf
4) Gerke et al, 2022 https://emp.lbl.gov/publications/overview-phase-4-california-demand

Shed DR Updates for 2022 I&A



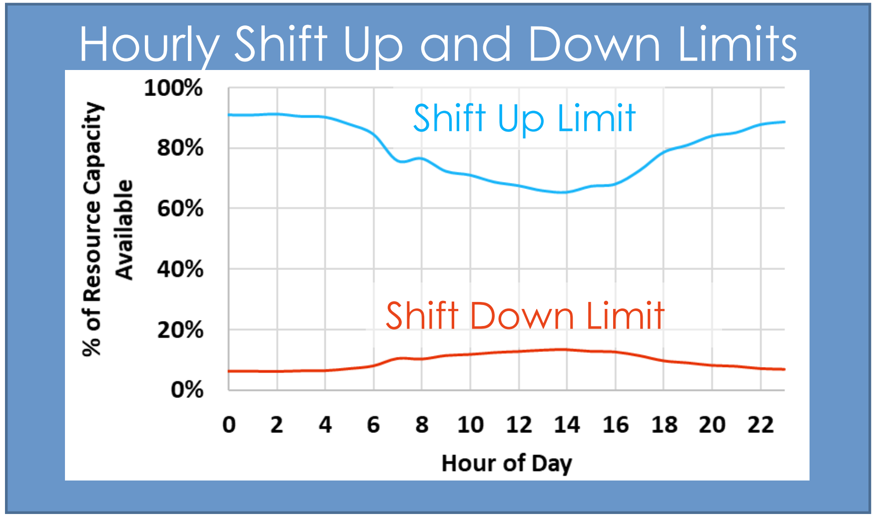


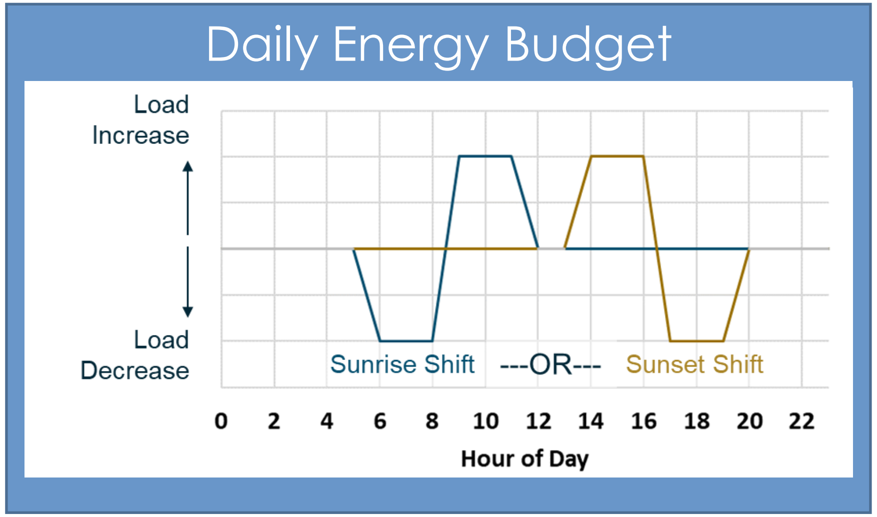
- Assumed Baseline Shed DR has decreased from 2,195 MW to 1,740 MW in 2035.[1]
- Changes in LBNL supply curve:
  - $10/kW-yr cost tranche
  - Supply curves evolve over time (2025, 2030, 2040, 2050)
  - LBNL's supply curve disaggregates potential by end-uses (ex. commercial space cooling, industrial processes).
  - Light Duty Electric Vehicles (LDEV) potential will be considered in VGI workstream.

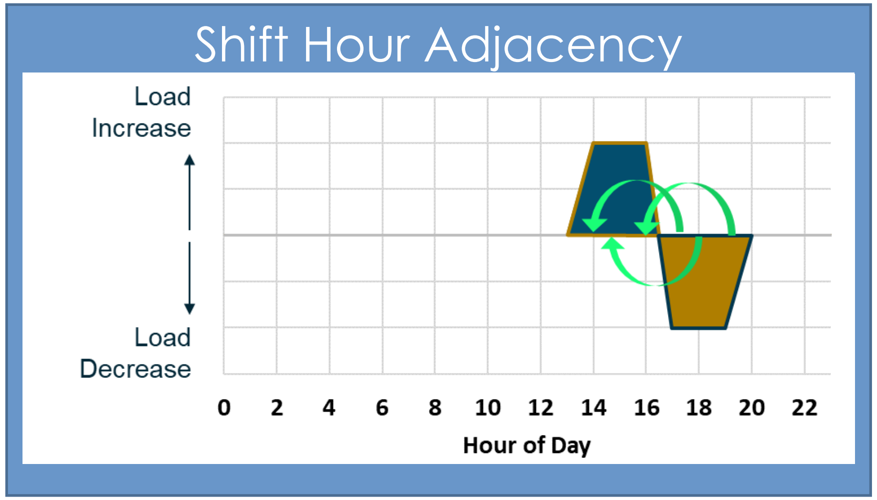
1 *2019-2021 Baseline Shed DR of 2,195MW based on 443 MW of interruptible pumping loads and 1,752MW of IOU-procured DR from 2017 Statewide Demand Response Load Impact Report (April 2018). 2022-2023 Baseline Shed DR of 1,740 MW based on 582 MW of interruptible pumping loads and 1,158 MW of IOU-procured DR is based on Final Load Impact Protocol reports submitted by the IOUs to the CPUC.*

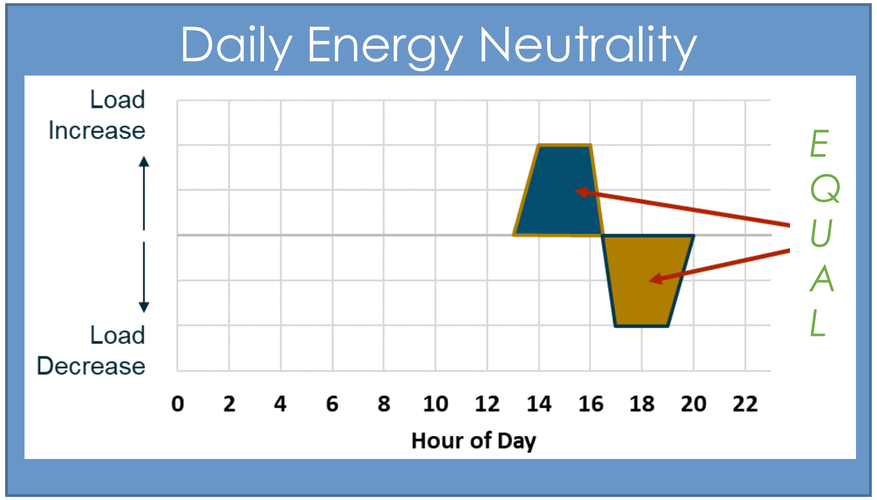
Shift DR Modeling Updates – RESOLVE Constraints

- New Shift RESOLVE Resource includes data inputs for hourly availability, based on underlying load profiles
- Model updates create more realistic bounds on load shifts
- LBNL dataset includes inputs for all of these fields, by technology









Illustrative Example: 2030 HVAC Shift DR RESOLVE Dispatch

Hour of Day

0	10.4	0	0	12.6	9.11	15.8	21.1	21	0	17.3	0	0	0	15.3	39.1	0	0	0	5.19	0	0	19.3	0	0	0	0	0	0	8.59	9.41	3.32	0	0	16.2
1	0	24.2	0	0	0	0	0	0	27.9	0	22.8	23.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31.2	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	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	0	0	57.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	63.6
8	0	0	0	0	36.9	0	0	20.1	80	0	0	67.4	0	0	57.4	0	0	0	0	59.9	144	91.7	24.5	0	0	0	0	0	0	37.2	0	0	40.1	43.7
9	0	14.8	0	37.8	150	145	81.5	87	39.9	91.1	39.3	43.4	98.2	95.6	46.9	137	48.6	0	48.6	106	107	48.7	112	116	164	0	0	0	57.8	115	113	48.9	41.9	22.7
10	96.7	90.2	143	93.8	104	102	41.6	45.7	0	50	0	0	52.5	51.4	6.83	75.2	91.5	83.4	3.36	55.1	55.3	0	58.6	61.3	75.7	115	100	0	65.8	0	0	43.2	0	0
11	16.8	48.9	99.6	50.8	55.5	55.3	0	0	0	0	0	0	0	0	6.83	52.4	53.9	58	58.8	0	0	0	0	0	58.8	60.1	59.4	73.7	0	0	0	0	0	0
12	66	62	49.9	0	0	0	0	0	0	0	0	0	0	0	6.83	35.4	51.2	0	0	0	0	0	0	23.2	92.7	92.8	0	0	0	0	0	0	0	0
13	126	120	55.4	65.2	0	79.6	36.5	73.5	0	38.5	0	0	82.4	0	69.6	0	125	102	96.7	0	13.2	0	0	110	71.1	205	102	68.3	0	98	121	0	0	0
14	50.7	0	35.1	126	0	34.3	90.7	138	54.1	106	54.9	65.4	105	71.3	6.29	63.8	10.7	0	14.3	91.1	15.9	86.6	0	0	0	68.8	0	0	189	153	127	72.9	65.3	0
15	0	41.5	0	56	105	57.1	141	105	105	109	106	122	47.9	132	40.8	0	74.2	0	224	65.8	70.2	157	77.8	0	0	0	48.1	0	161	68.1	87.2	62.4	123	0
16	0	0	0	0	44.8	0	0	0	121	0	153	101	0	26.4	6.31	0	0	15.8	0	0	0	45.8	0	0	0	0	0	0	0	0	0	0	177	0
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16.8	0	0	0	0	0	0	0	0	0
22	0	0	18.7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19.1	0	0	0	0	0	0	0	0
23	0	0	0	1.91	0	0	0	0	0	0	0	0	11.2	0	0	0	0	0	0	9.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Load **increased** during daytime hours to absorb solar

RESOLVE sample day (not ordered)

Hour of Day

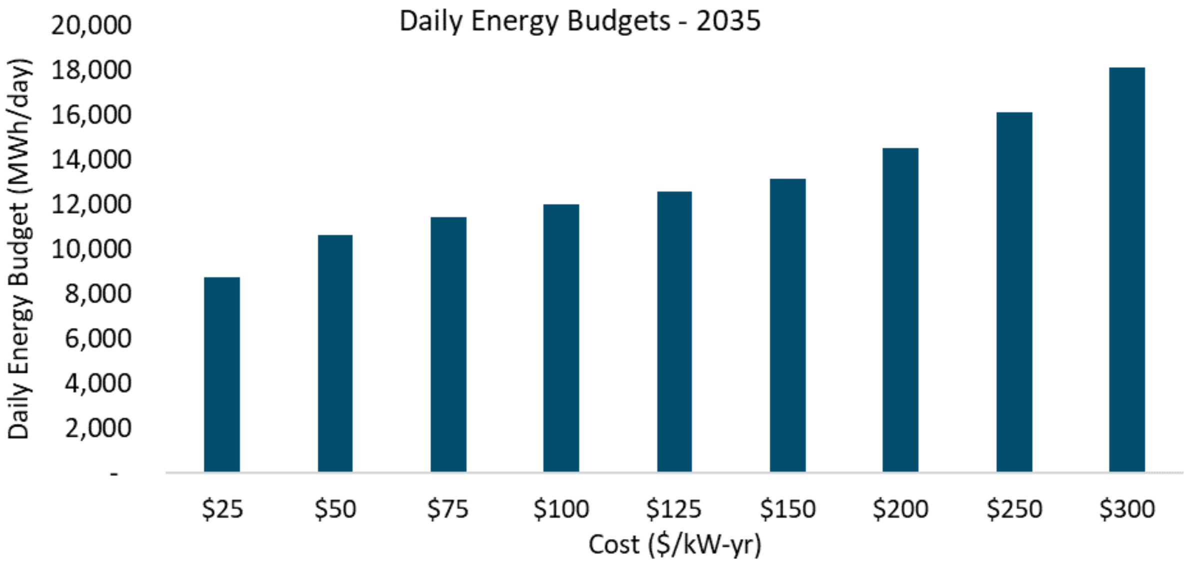
0	10.4	0	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	16.2
1	10.4	0	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	16.2
2	10.4	0	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	0	19.1	0	0	8.59	9.41	3.32	0	31.2	16.2
3	10.4	0	0	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	0	0	0	0	8.59	9.41	3.32	0	31.2	19.9
4	10.4	0	0	12.6	46	15.8	21.1	41.1	40.1	17.3	22.8	42	0	15.3	10.5	0	0	0	5.19	42.5	43	41.1	0	0	0	0	0	0	8.59	46.6	3.32	0	41.3	21
5	0	39.1	0	37.8	46.1	43	39.9	41.3	39.9	41.1	39.3	43.4	45.7	44.2	40.1	37.4	48.6	0	48.6	51.2	51.5	50.7	53.1	55.2	51.2	0	0	0	57.8	52.5	51.6	48.9	41.9	22.7
6	42	41.3	43.2	43	48.7	46.9	41.6	45.7	0	50	0	0	52.5	51.4	0	47.6	48.8	51.9	51.9	55.1	55.3	0	58.6	61.3	54.2	54.5	52	0	65.8	62.2	61.7	43.2	0	0
7	54.7	45.6	49.7	50.8	55.5	55.3	0	0	0	0	0	0	0	0	0	52.4	53.9	58	58.8	0	0	0	0	0	58.8	60.1	59.4	73.7	0	0	0	0	0	0
8	0	0	49.9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	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	0	0	6.83	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	0	3.3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	66	58.7	0	0	0	0	0	0	0	0	0	0	0	0	0	99.2	51.2	0	0	0	0	0	0	84.5	92.7	106	0	0	0	0	0	0	0	0
17	59.5	58.1	55.4	65.2	71	79.6	36.5	73.5	0	38.5	0	0	82.4	0	62.7	63.8	93.5	102	96.7	0	99.3	0	5.24	110	87.9	99.2	102	68.3	111	98	121	0	0	0
18	50.7	41.5	53.8	61	63.2	65.1	54.2	64	54.1	67.8	54.9	65.4	67.6	71.3	53.4	63.8	84.9	15.8	82.2	91.1	86.1	86.6	77.8	0	16.8	87.9	48.1	0	91.3	78	100	72.9	65.3	0
19	0	41.5	18.7	57.9	57.5	57.1	50.8	56.9	50.5	59.6	51	56.9	59.1	60.3	47.1	0	74.2	15.8	66.5	74.9	70.2	70.2	77.8	0	16.8	19.1	48.1	0	78.8	68.1	87.2	62.4	58	0
20	10.4	0	18.7	14.5	53.9	15.8	21.1	21	48.1	17.3	47.9	53.5	11.2	41.7	45.4	0	0	15.8	5.19	9.05	0	65.1	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	53.8	0
21	10.4	24.2	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	39.1	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	0
22	10.4	24.2	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	39.1	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	0
23	10.4	24.2	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	0

Load **decreased** during sunrise and sunset hours to mitigate ramps.

Note: example dispatch is based on data from previous cycle and may not reflect current data.

Shift DR Data Inputs for 2022 I&A

- Supply curve and hourly shift potential vary by technology
  - Ex. Residential space cooling has different underlying load profiles and technical constraints compared to industrial processes
- Light duty electric vehicles (LDEV) potential will be considered in VGI workstream. Medium and heavy duty electric vehicles (MHDEV) are note included in the IRP analysis.
- Technology types will be aggregated. Aggregated portfolios will be presented in I&A document



**Daily energy budget is the maximum amount of energy that can be shifted during the day. Shiftable load in a given hour depends on the underlying load profiles and technical constraints for each technology. Chart shows cumulative energy budget across price tranches.*

3.4. Emerging Low- and Zero-Carbon Technologies

What was the Emerging Zero-Carbon Technology Assessment Report?

- E3 performed an analysis of long-duration storage and generation technologies that can provide firm generation capacity with low- or zero-emissions
  - These technologies could help maintain low costs in a zero-carbon grid during longer periods of low renewable production and high load
  - The report is available here released in September 2022
- The assessment focuses on relatively mature technologies with the idea that they would be closer to commercial deployment, and potentially could be deployed at scale in California in the late 2030s and beyond
- The analysis considered various, representative technologies but is not exhaustive of all new technologies being developed for this purpose
  - This was done to ensure reasonable modeling scope during future IRP work
  - In some cases, the alternative technologies not presented here did not have enough positive attributes (e.g. low cost, high round-trip efficiency) relative to those detailed here to merit inclusion

Technologies Considered in Assessment

- **These technologies will be implemented in RESOLVE:**
  - **Generation Technologies**
    - Carbon capture and storage (CCS)
      - Gas with CCS (99% capture)
      - Allam Cycle (~100% capture)
    - Zero-carbon firm
      - Advanced nuclear, enhanced geothermal systems (EGS)
  - **Storage Technologies**
    - Zero-carbon "electrofuels"
      - Hydrogen from electrolysis, synthetic methane from electrolysis and direct air capture of carbon dioxide (DAC)
      - Turning fuels back to electricity: CTs and CCGTs (purpose built for hydrogen)
    - Long-duration mechanical and battery storage
      - Adiabatic compressed air energy storage (A-CAES), iron-air batteries

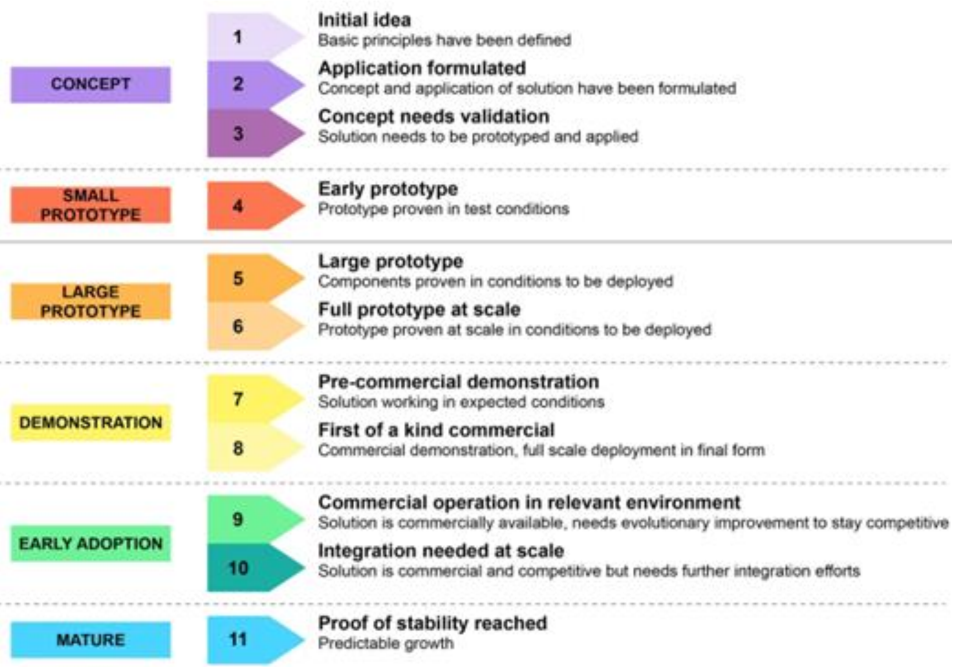
Key technology characteristics and policy challenges were considered, creating RESOLVE-type inputs

- **Initial known estimates of cost and/or potential**
  - Capital cost, fixed and variable operating costs
  - Cost trajectories or forecasts through 2050
  - Existing deployment
  - Technical potential
  - Siting and land use constraints
  - Technology Readiness Level
- **Technology and operating characteristics**
  - Ramping constraints, efficiency (thermal, roundtrip)
- **Policy and planning challenges**
  - Policy and planning considerations
  - Qualitative assessment of criteria pollutant emissions
  - Qualitative assessment of Infrastructure needs (e.g., hydrogen and CCS pipelines and storage)
  - Research, Design, and Development (RD&D) needs

Summary of Current Technology Readiness Levels and Global Deployment

- Hydrogen, A-CAES and CCGTs + CCS are reasonably mature technologies
- Iron-Air and EGS are least mature

International Energy Agency Technology Readiness Level Guide

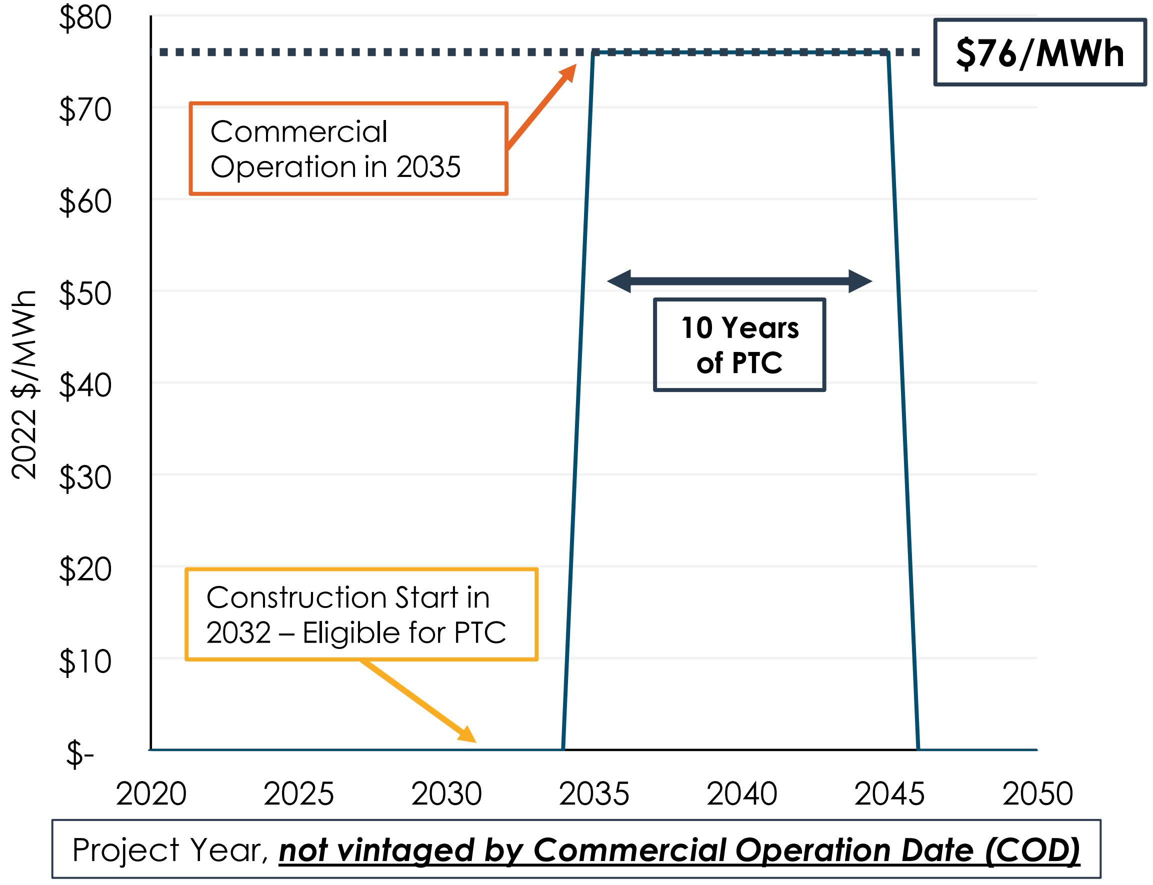


Technology Category	Technology	Tech. Readiness Level	Global Deployment
Generation	CCGT + >99% CCS	8	38 million metric tons (MMT) CO_2/yr large-scale CCS proj.
	Allam Cycle CCS	7	~25 MW Allam Cycle
	Small Modular Nuclear Reactor (SMR)	7	n/a
	Enhanced Geothermal Systems (EGS)	5	n/a
Storage	Hydrogen	9	168 MW
	Synthetic Natural Gas (SNG)	7	12 MW SNG, >0.01 MMT/yr DAC
	Adiabatic Compressed-Air Energy Storage (A-CAES)	8	1.75 MW
	Iron-Air Battery	5-6	n/a

PTCs for CCS, DAC, and Hydrogen

- PTCs under Sections 45Q and 45V are available to energy projects that sequester carbon oxides or produce clean hydrogen
  - 45Q (CCS, DAC): Credits are available for the first 12 years of project operations
  - 45V (Hydrogen): Credits are available for the first 10 years of hydrogen production, providing that the emissions factor of the facility is less than 0.45 kg CO_2 / kg H_2
- CCS: $85/ton of carbon sequestered
- DAC: $130/ton of carbon captured for use as feedstock (e.g. synthetic natural gas production)
- Hydrogen: $3/kg of hydrogen produced[1]
- **Facility must begin construction no later than 2032 to be eligible for these incentives. Three-year construction window assumed.**

Representative PTC Schedule for Hydrogen Facility



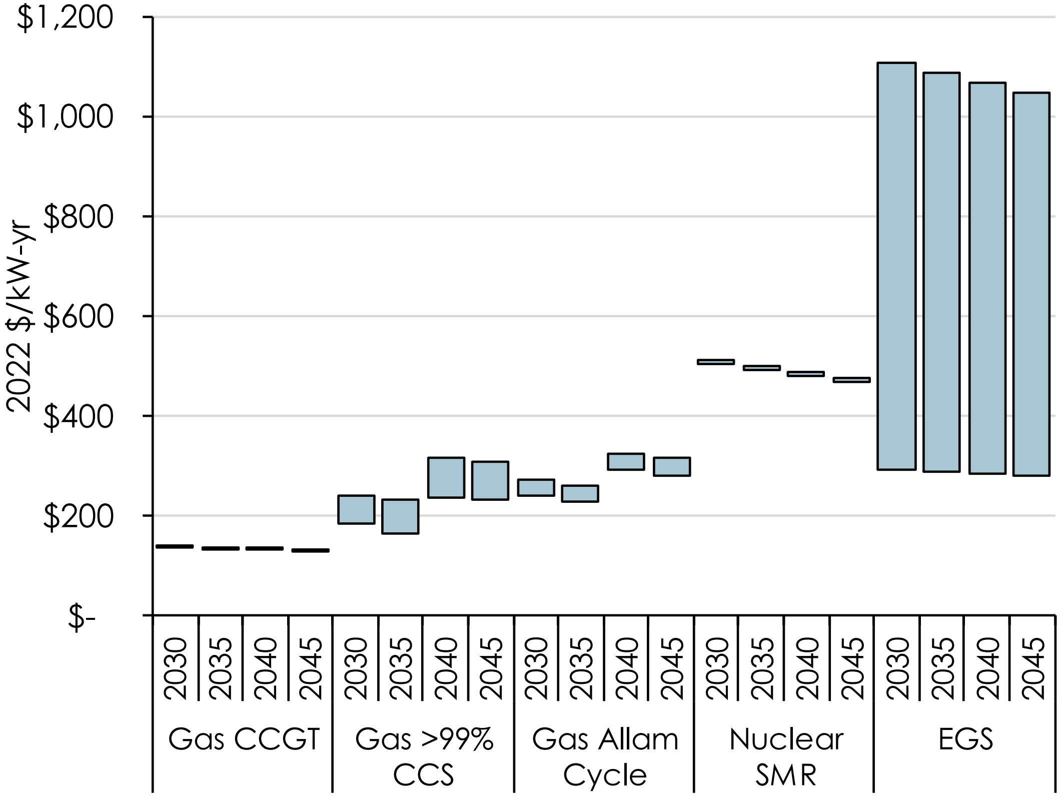
[1] *Full credit value, assuming zero-carbon emission factor*

Impacts of PTCs for CCS, DAC, and Hydrogen on resource costs are discussed in the Emerging Tech section.

Cost Comparison – Generation Technologies

- All emerging generation technologies under consideration have higher costs than conventional combined cycle gas turbines (CCGT), but provide low- or zero-carbon generation
- Enhanced Geothermal Systems (EGS) have the highest cost projections of the generation technologies analyzed
- Cost data include extended tax credits under the IRA, including the 30% tech-neutral ITC for nuclear and EGS, and $85/ton PTC for CCS

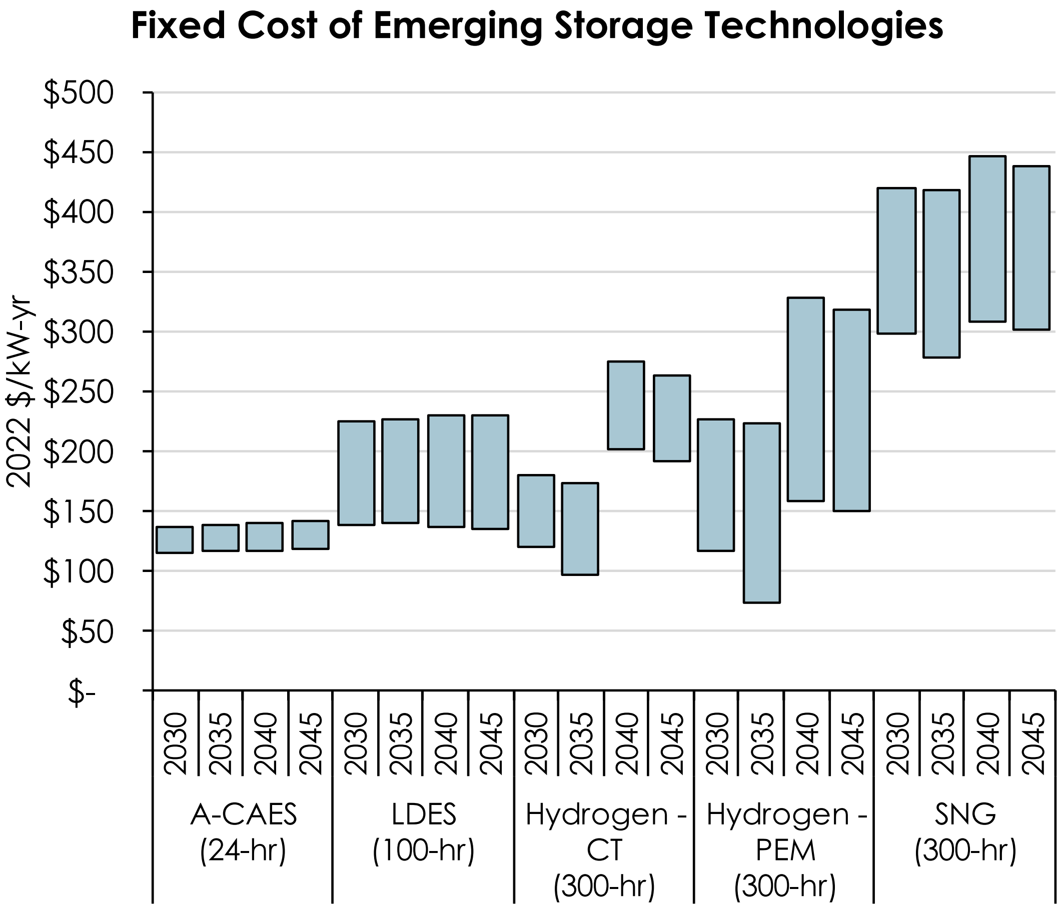
Fixed Cost of Emerging Generation Technologies (1)



(1) Includes pro-rated PTCs under the IRA, where applicable

Cost Comparison – Storage Technologies

- All emerging storage technologies under consideration have higher costs than conventional Li-ion batteries, but provide firm, long-duration capacity
- Long-duration energy storage and hydrogen may exhibit significant cost reductions under a low-cost scenario, but large uncertainty remains
- Hydrogen costs include new pipeline costs, as well as the cost of new Aero CT and underground storage
- Synthetic Natural Gas (SNG) costs include underground storage and new Aero CT, plus carbon-neutral methane-generating equipment
- Cost data include extended tax credits under the IRA, including the 30% ITC for energy storage (including fuel reservoirs), $3/kg Hydrogen PTC, and $130/ton PTC for DAC of feedstock carbon



3.5. Vehicle-Grid Integration (VGI) Analysis

Scope of the CPUC VGI Analysis

- Vehicle Grid Integration (VGI): any method that optimizes plug-in EV interaction with the grid and provides net benefits to ratepayers (D. 20-12-029)
- VGI is categorized into two main types in the 2022-2023 IRP:
  - What has been done in IRP: VGI included in the IEPR forecast in response to Time-Of-Use (TOU) rates
  - **What's new in this I&A**: VGI beyond the IEPR forecast with direct management or in response to dynamic grid signals, and capable of discharging back to the grid (V2G)
- Newly-added VGI resources will **focus only on light duty vehicles (LDV)** and are modeled as a statewide aggregated resource with four types:

Resource Types	Definition
V1G Residential	Shifting EV charging load beyond TOU rates
V1G Workplace	
V2G Residential	Shifting EV charging load beyond TOU rates + Capable of charging and discharging back to the grid
V2G Workplace	

Goal of the CPUC VGI Analysis

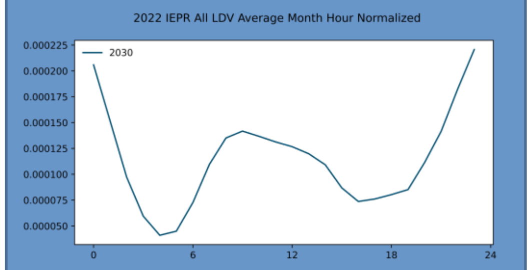
- Goals of the CPUC IRP VGI Analysis
  - Develop a methodology to model VGI as a resource in IRP
  - Gather stakeholder feedback on inputs
  - Determine the value of VGI
- **The analysis is designed to quantify the value of VGI, especially VGI as a resource, in the context of system planning and the impact of VGI on resource portfolio**
- **The modeling approach does *not* indicate any CPUC endorsed program design for VGI**

VGI as a Resource Methodology

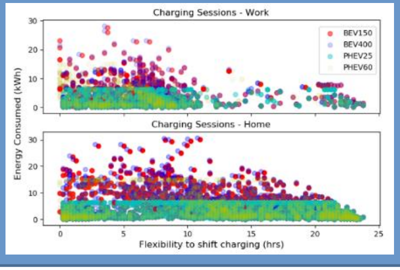
- 2022 IEPR load shapes used in IRP will serve as the baseline shapes for this analysis
- To model VGI as a resource, E3 simulates charging behaviors in EV Load Shape Tool, benchmarked with IEPR shape in 2030 (around 80% managed), to generate corresponding flexibility parameters to shape VGI dispatch

Baseline Shapes

IEPR Load Shapes

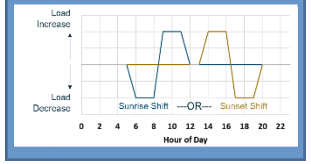


E3 Simulated Charging Session Data

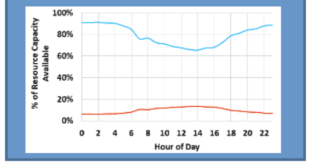


RESOLVE Flexibility Inputs

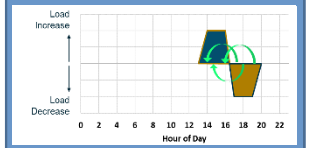
Daily Energy Budget



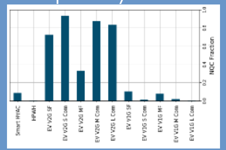
Hourly Shift Limits



Shift Window

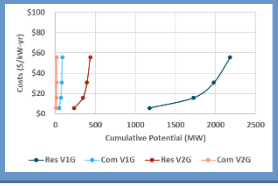


Capacity Value



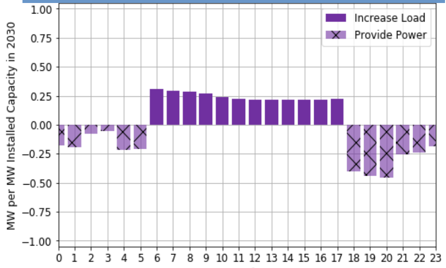
RESOLVE VGI Supply Curve (LBNL)

Costs & Potential

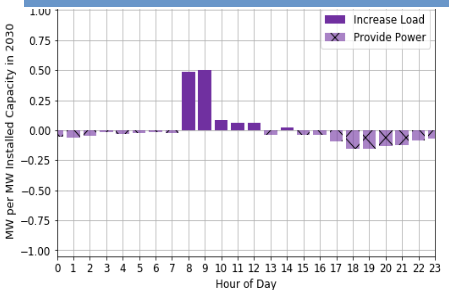


RESOLVE Dispatch Outputs

V2G



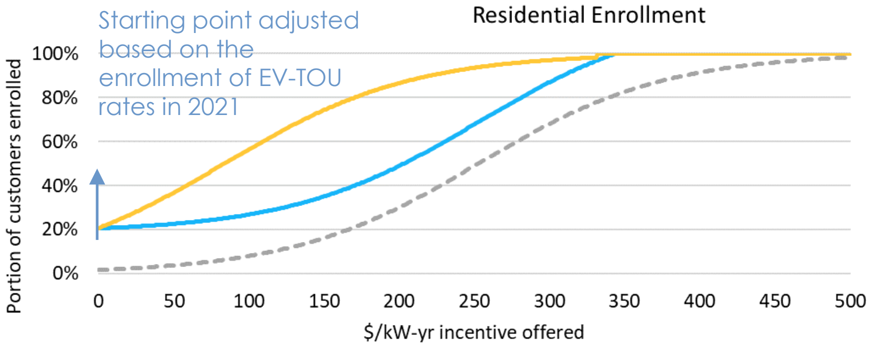
V1G

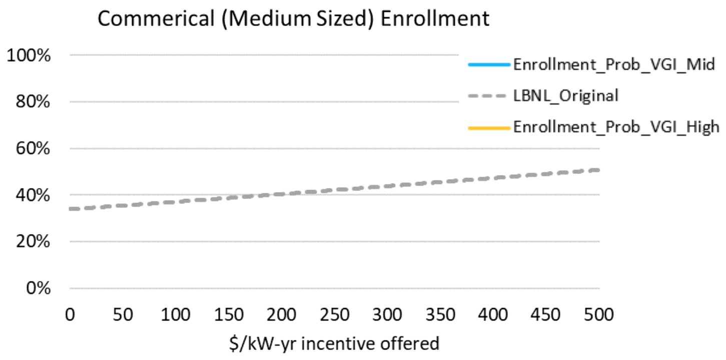


Supply Curve – VGI Technical Potential (%)

% with access to L2 charger	Value
Home (Res)	42%
Workplace (Com)	26%

- V1G potential is estimated using propensity curve from LBNL Phase 4 Study (updated)

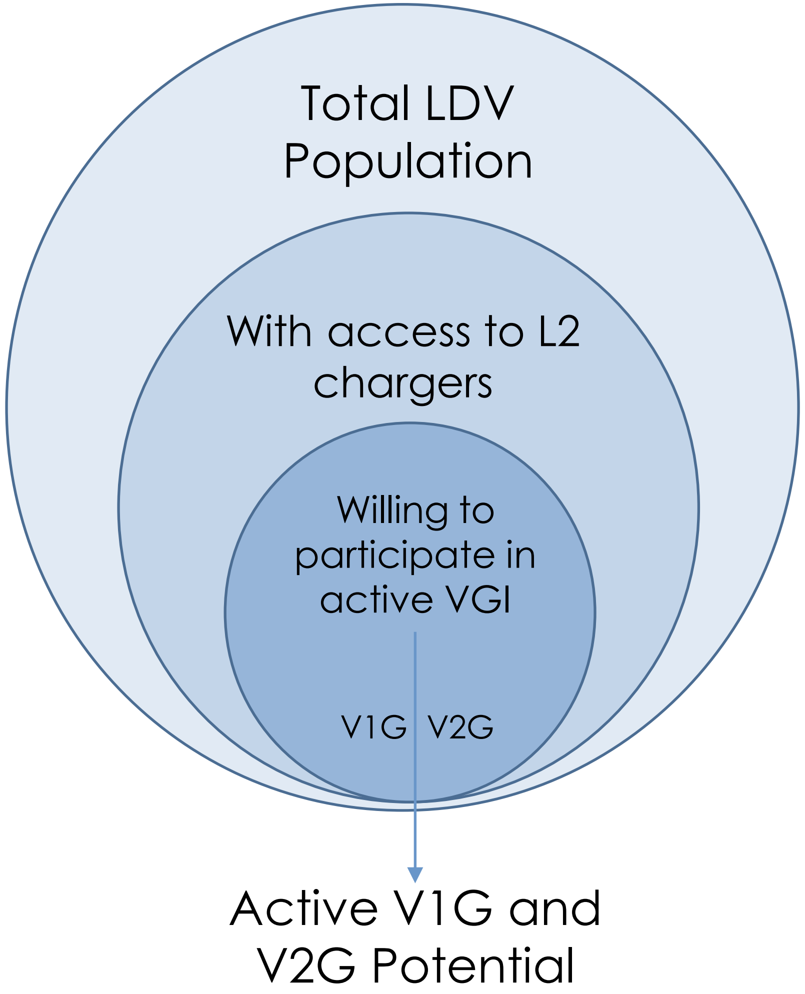




- The analysis will model different "tranches" of VGI participation as resources, which represents incremental participation at different price points

Incentive Tranches	V1G ($/kW-yr)	V2G ($/kW-yr)
T1	$0	$50
T2	$10	$60
T3	$30	$80
T4	$50	$100

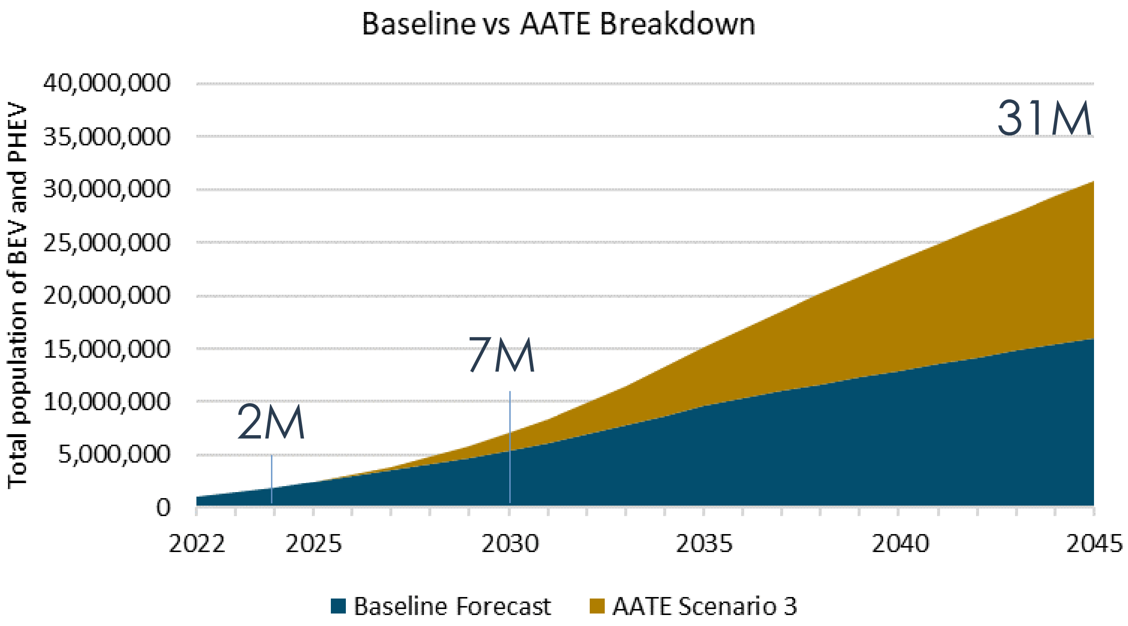
- Propensity score for V2G is further multiplied by a percentage (%) to reflect the V2G potential that can be available each year
  - Linearly grow from 0% in 2025 to 50% in 2050
- % VGI potential = % access to L2 charger * % enrollment * % V2G multiplier

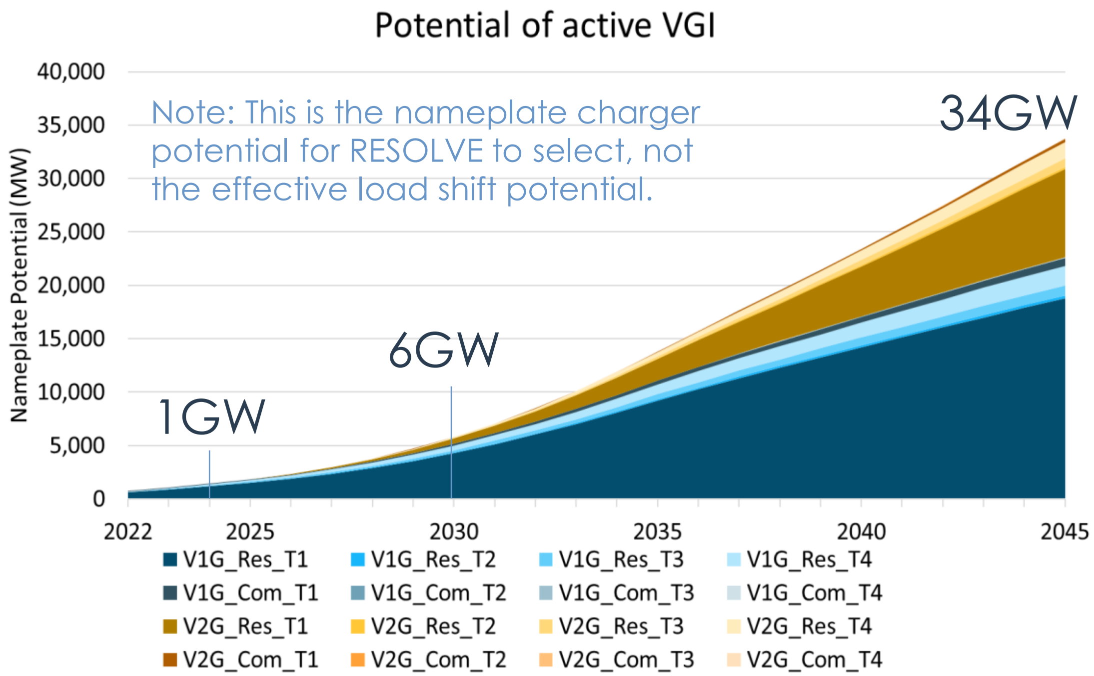


VGI Technical Potential (MW)
- 2022 IEPR, Mid Enrollment Scenario

- VGI technical potential (MW) is derived using 2022 IEPR EV adoption forecast
  - $VXG\ Technical\ Potential\ = \%\ VXG\ Potential * \boldsymbol{LDV\ stock} * \frac{\boldsymbol{Charger}}{\boldsymbol{EV}}\boldsymbol{ratio} * \boldsymbol{charger\ capacity}$
- RESOLVE will determine the final economic potential (MW) for the grid

	Value
Res EV/Charger Ratio	1
Com EV/Charger Ratio [1]	27
Weighted Average L2 charging capability (kW) [2]	7





[1] & [2] Estimated based on CEC AB2127 report. More details in the Inputs and Assumptions Document

VGI Costs

- Fixed O&M costs reflect the cost of incentivizing participation in VGI programs

Category	Fixed O&M Costs ($2022/kW-yr) [1]
Administration Costs	$20/yr for each enrolled customer (~$2.8/kW-yr)
Marketing Costs	$1-4/yr for each enrolled customer (~$0.1-0.6/kW-yr)
Incentive Costs	V1G: $0/kW-yr - $50/kW-yr V2G: $50/kW-yr - $100/kW-yr

* The incentives are *not* CPUC endorsed/approved incentives, and *not* utility payments to VGI customers as a subsidy

- Variable O&M costs reflect the battery degradation costs of cycling V2G resources

	2022	2030	2040	2050
EV Pack & Cell Price ($2022/kWh) [2]	151	98	86	74
Cycles [3]	3500	3500	3500	3500
Cost per cycle ($2022/kWh)	0.04	0.03	0.02	0.02

[1] Source: LBNL. More details in I&A Document
[2] Source: BNEF and IRP storage cost trajectory. More details in I&A Document
[3] More details in I&A Document

3.6. Renewable Characterization Methodology -Resource Potential and Land-Use Constraints

Process for Developing Resource Potential

Raw Resource Potential

Solar based on insolation

Wind based on wind speed

Geothermal from existing studies

Techno-Economic Screen

Minimum capacity factor thresholds

Slope

Population density

Feasibility screens (e.g. setbacks from roads)

Environmental Screen

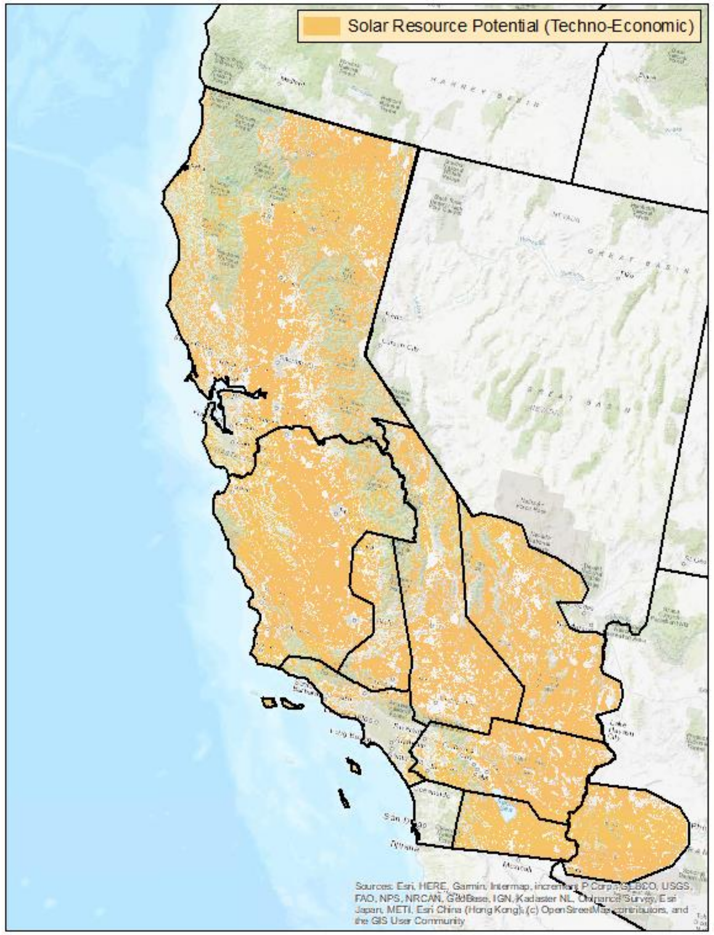
Environmental land use criteria under development by the CEC

The combination of the techno-economic land use screen (CPUC) and environmental land use screen (CEC) results in the total resource potential available to RESOLVE

Updates to the Techno-Economic Land Use Screen

Criterion [1]	Solar	Wind
Slope	> 10°	> 10°
Population Density	> 100/km²	> 100/km²
Capacity Factor	< 16% (DC)	< 28% [2]
Urban Areas	< 500 m	< 1,000 m
Water Bodies	< 250 m	< 250 m
Railways	< 30 m	< 250 m
Major Highways	< 125 m	< 125 m
Airports	< 1,000 m	< 5,000 m
Active Mines	< 1,000 m	< 1,000 m
Military Lands	< 1,000 m	< 3,000 m
Existing Project Footprints	Excluded	Excluded

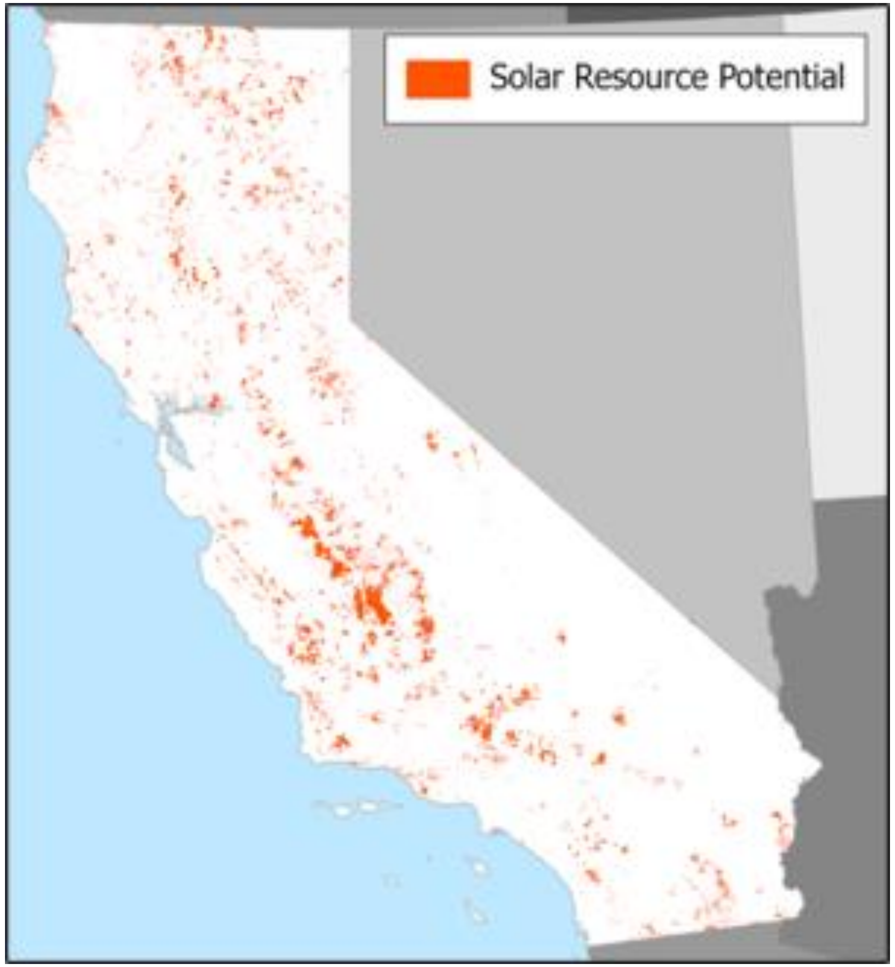
(1) *Geothermal and pumped hydro resource potentials are characterized from published results that have factored in relevant criteria and are not duplicated in this analysis.*
(2) *Assumption varies for out-of-state regions; see following slide.*



Updates to the Environmental Land Use Screen

- Environmental land use screens under development by the CEC:
  - Protected Areas
  - Cropland Index Model
  - Terrestrial Intactness Model
  - Biological Planning Priorities
    - ACE Biodiversity
    - ACE Connectivity
    - ACE Irreplaceability
    - Wetlands
    - USFWS Critical Habitat
- Implemented the current draft CEC "Core" scenario land use screen[1]
  - Final screens are pending energy commission approval
  - Will update screens if final versions are changed significantly.

CEC "Core" Draft Screen - Solar



[1] *https://www.energy.ca.gov/event/workshop/2023-03/commissioner-workshop-land-use-screens*

Minimum Capacity Factor Thresholds for Candidate Wind Resources

- Staff proposes the following capacity factor thresholds for commercial viability:

GW by Region	20%	25%	28%	30%
Central Valley North Los Banos	10.91	5.59	1.26	0.04
Greater Imperial	1.53	0.21	0.06	0.06
Greater Kramer	0.49	0.02	-	-
Humboldt	0.41	0.15	-	-
Kern Greater Carrizo	0.42	0.09	-	-
Northern California	6.97	3.66	1.34	0.62
Riverside	0.04	0.04	0.04	0.04
Solano	1.21	0.40	0.22	0.13
Tehachapi	1.23	1.09	0.76	0.60
Total, In-state	23.20	11.25	3.67	1.48

GW by Region	28%	30%	35%	40%
Southern NV Eldorado Desert	2.19	1.63	0.98	0.15
Idaho	38.55	26.76	3.36	0.26
New Mexico	234.21	194.52	124.24	72.94
Utah	36.90	23.47	8.24	1.62
Wyoming	73.68	69.11	50.81	29.35
Baja California [1]	2.47	2.47	2.47	2.47
Total, Out-of-state	388.00	317.97	190.10	106.78

[1] Resource potential for Baja California determined by totaling the MWs from the CAISO interconnection queue.

The technology configuration modeling assumptions for solar, wind, and geothermal are provided in Appendix G.

Available In-State Resource Potential

Solar Resource Totals [1]	GW [2]
Greater Kramer	31.73
Greater LA	15.35
Greater Imperial	10.55
Northern California	222.39
Riverside	16.94
Southern PGAE	155.10
Tehachapi	33.29
Total	485.37

[1] Totals are inclusive of an 80% discount factor reflecting commercial feasibility limits
[2] Assumes a land use factor of 30 MW/km^2

Wind Resource Totals	GW [3]
Central Valley North Los Banos	1.26
Greater Imperial	0.06
Greater Kramer	-
Humboldt	-
Kern Greater Carrizo	-
Northern California	1.45
Riverside	-
Solano	0.11
Tehachapi	0.76
Total	3.63

[3] Assumes a land use factor of 2.7 MW/km^2

Geothermal Resource Totals	GW
Greater Imperial	2.47
Inyokern North Kramer	0.04
Northern California	0.85
Total	3.36

Available Out-of-State Resource Potential

Solar Resource [1]	GW [2]
Southern NV Eldorado [3]	80.24
Arizona [3]	84.73
Total	164.97

[1] Totals are inclusive of an 80% discount factor reflecting commercial feasibility limits
[2] Assumes a land use factor of 30 MW/km^2
[3] Includes resources that can interconnect directly to the existing CAISO system only

Wind Resource	GW [4]
Southern NV Eldorado [3]	2.19
Baja California Wind [3]	2.47
Idaho Wind	3.36
New Mexico Wind	72.94
Utah Wind	8.24
Wyoming Wind	29.35
Total	118.55

[4] Assumes a land use factor of 2.7 MW/km^2

Geothermal Resource	GW
Central Nevada Geothermal	0.60
Northern Nevada Geothermal	0.85
Pacific Northwest Geothermal	0.52
Utah Geothermal	0.18
Total	2.15

Offshore Wind Resource Potential

- The offshore wind resource potential was calculated using the site areas and recommended area density factors from the June 2022 AB 525 NREL presentation[1]
- Previously used the "Low" potential values, and staff are seeking input on increasing to the "High" potential values

Site	Area (km^2)	Density Factor (MW/km^2)		Resource Potential (MW)	
		Low	High	Low	High
Diablo Canyon [(2)]	1,441	0	0	-	-
Morro Bay	975	3	5	2,925	4,875
Humboldt	536	3	5	1,608	2,680
Cape Mendocino	2,072	3	5	6,216	10,360
Del Norte	2,202	3	5	6,606	11,010
Total	7,226			17,355	28,925

(1) CEC Docket 17-MISC-01. https://efiling.energy.ca.gov/GetDocument.aspx?tn=243707&DocumentContentId=77539
(2) Diablo Canyon is a Dormant Call Area and is assumed to be unavailable.

Annual Build-Out Limits

- In previous RESOLVE analyses, additional near-term annual build-out limits have been applied to solar resources to constrain the model from overbuilding solar resources to capture the expiring ITC.
  - A cumulative build limit of 11 GW through 2025 was assumed in the 2021 PSP and the 2022 LSE Filing Requirements
- The annual build limits were determined based on consideration of different parameters, including:
  - In-development and planned resource additions from LSE filings
  - CAISO Interconnection (IC) Queue estimates
  - Historical annual resource build totals
- With the extension of the ITC due to the Inflation Reduction Act (IRA), this approach will need to be updated
  - Unlikely to see a rush to build solar resources in the near-term
  - Annual build limits should better reflect feasible annual development

2023 PSP Proposed Annual Build Limits for Solar PV and Li-ion Batteries

Year	Annual Build Limit (MW)
2024	3,000
2025	3,000
2026	3,000

Category	Max Annual Solar Additions (1)
Historical	2,600 MW
LSE Filings	3,032 MW
CAISO IC Queue	20,985 MW

(1) The single highest annual total of new capacity additions reported by each data source, forward projections through 2026.

First Available Online Year for Long-Lead Time Resources

- Assumptions are based on resource development timelines and the development time for transmission associated with some technology types (out-of-state resources, offshore wind)
- Availability of emerging technologies discussed in Section 3.4

Technology	Resource	First Available Online Year
Pumped Hydro Storage	Tehachapi	2026
	Riverside East	2027
	Riverside West	2029
	San Diego	2030
Geothermal	In-State: Greater Imperial, Inyokern North Kramer, Northern California	2026
	Nevada: Central Nevada, Northern Nevada	2026
	Utah	2026
	Pacific Northwest	2028
Offshore Wind	Humboldt Bay, Morro Bay	2030
	Cape Mendocino, Del Norte	2035
Out-of-State Wind	Idaho, New Mexico, Utah, Wyoming	2026

4. Operating Assumptions

4.1. Hourly Load, Solar Generation, and Wind Generation Profiles

Weather-based Hourly Profiles

- SERVM uses 23 weather years (1998-2020) to model a wide range of variability in hourly electric demand (load), solar generation, and wind generation
- Normalized electric demand, solar radiation, and wind speed profiles used in SERVM are based off the 23 weather year dataset. Historical correlations in weather variables across time and space are preserved in the resulting normalized demand and production profiles.
- 2021 and 2022 cannot be incorporated yet because of lack of necessary demand data

Load Hourly Profiles

- The 23 weather year hourly load profiles used in SERVM were developed as follows:
  1. Gather CAISO Energy Management System (EMS) electric sales data and add back simulated BTM PV production and actual Demand Response events for the most recent years (2018-2020) to reconstitute electric consumption. Use of most recent years preserves recency bias.
  2. Train a regression model using these three years of consumption and weather to forecast electric consumption demand
  3. Use the model with trained parameters to build out 23 weather years of synthetic hourly load profiles
  4. Scale the normalized load profiles to match the annual peak and energy forecasted by the CEC's IEPR demand forecast
  5. Follow a similar process for non-CAISO regions using data from FERC Form 714 and the WECC Anchor DataSet (2032)

Solar Generation Hourly Profiles

- Solar profiles are created using NREL's PVWATTSv5 calculator trained on three years of CAISO settlement data along with 23 weather years of data from the National Solar Radiation Database (NSRDB)
- Profiles were created for fixed-tilt, single and double axis tracking, and BTM PV
- Utility-scale solar uses a default inverter loading ratio of 1.3 and BTM PV uses 1.13
- Profiles were developed to cover more than two dozen locations across the WECC

Wind Generation Hourly Profiles

- Wind speed data comes from the WRF-ERA5 downscale model provided as part of CEC Cal-Adapt
- Wind model has 3 parts:
  - In-State: Wind profiles are based on NREL's System Advisor Model WIND toolkit using wind speeds from WRF-ERA5 and trained on 3 recent years of CAISO settlement data.
  - Out-Of-State: Based on EIA data and NREL's System Advisor Model WIND toolkit
  - Offshore: Offshore wind production curves lack real production data for training, so staff used a response curve provided directly by NREL with added system losses based on research prepared for the Bureau of Ocean Energy Management. Wind speeds from WRF-ERA5.

Representative Sampling of Hourly Profiles

- RESOLVE uses all the hourly profile data discussed on previous slides, leveraging the same 23 weather year dataset as SERVM

- RESOLVE uses a flexible, medoids-based clustering algorithm to select representative days to reduce problem size for capacity expansion
  - Selected days are based on statistical representation of gross load, net load, solar, onshore wind, offshore wind, and hydro profiles

- Updated sampling algorithm allows RESOLVE to retain chronological information about how days link to each other
  - Allows inter- and multi-day energy shifting and long-start dynamics to be better captured in operational modeling

4.2. Transmission Constraint Implementation

Contents

Transmission Build Constraint Modeling in RESOLVE

- The modeling of transmission constraints in RESOLVE is tied to the CAISO's representation of the transmission system in its Transmission Planning Process modeling and the associated Transmission Deliverability Whitepaper[1]
- For each constraint examined, the CAISO provides data on existing transmission capability, incremental capability and corresponding upgrade costs, and construction lead time
  - Data is provided for both full-capacity deliverable status (FCDS), derived from on-peak assessments, and energy-only (EODS), derived from off-peak assessments
- Transmission constraint diagrams[2] are used to determine the constraint(s) that candidate resources in RESOLVE contribute towards when built
- Staff plan to incorporate updated transmission deliverability whitepaper data from the CAISO into RESOLVE, pursuant to the methods outlined on the following slides

(1) http://www.caiso.com/Documents/WhitePaper-2021TransmissionCapabilityEstimates-CPUCResourcePlanningProcess.pdf
(2) Confidential

Existing Transmission Capability and Incremental Baseline Generators

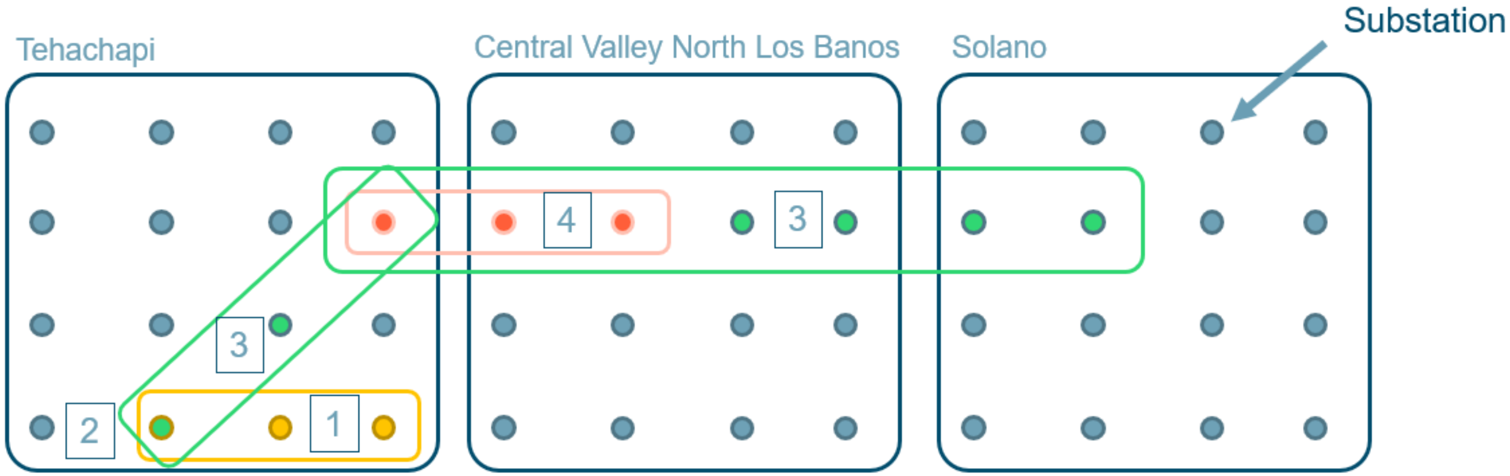
- Transmission capability estimates provided by the CAISO in the Transmission Deliverability Whitepaper were evaluated using nodal generation based on the existing generator capability as of 1/1/2022
- Online and in-development (baseline) generators with online dates after this cutoff date must occupy the available transmission capacity as defined by CAISO.
- Using the substation as the basis for assignment, the capabilities of incremental baseline generators are subtracted from the FCDS and EODS capability totals prior to input into RESOLVE

Role of Build and Dispatch Constraints in RESOLVE

- CAISO's transmission capability estimates are used to constrain the buildout of resources in RESOLVE, but are <u>not</u> enforced in RESOLVE's simplified dispatch algorithm
- As an update to RESOLVE to enable better representation of CAISO transmission constraints, in-state wind and solar candidate resources have been split into **build resources**, which obey the transmission build constraints, and **dispatch resources**, which carry the operational requirements for dispatching in RESOLVE
- <u>Build resources</u> allow for greater granularity than could be offered by the 10-15 regional solar/wind resources from previous IRP cycles. These resources:
  - Ensure that RESOLVE's resource builds fit within all CAISO-defined transmission constraints
  - More closely mimic the representation of the transmission system used in bus-bar mapping
- For each candidate resource, build resources and their capacities are combined into <u>dispatch resources</u> that are used in RESOLVE's dispatch algorithm. Dispatch resources:
  - Avoid false precision around resource quality in localized areas
  - Reduce the number of dispatch variables in RESOLVE's optimization to manage runtime

Build Resources Provide Additional Granularity to the RESOLVE Model

- With the goal of modeling the transmission system with more fidelity, RESOLVE's representation of CAISO's transmission constraints have evolved to include more overlapping transmission limits that are simultaneously applied to resource buildouts
- Depending on the point of interconnection, resource potential may be included under different sets of transmission constraints

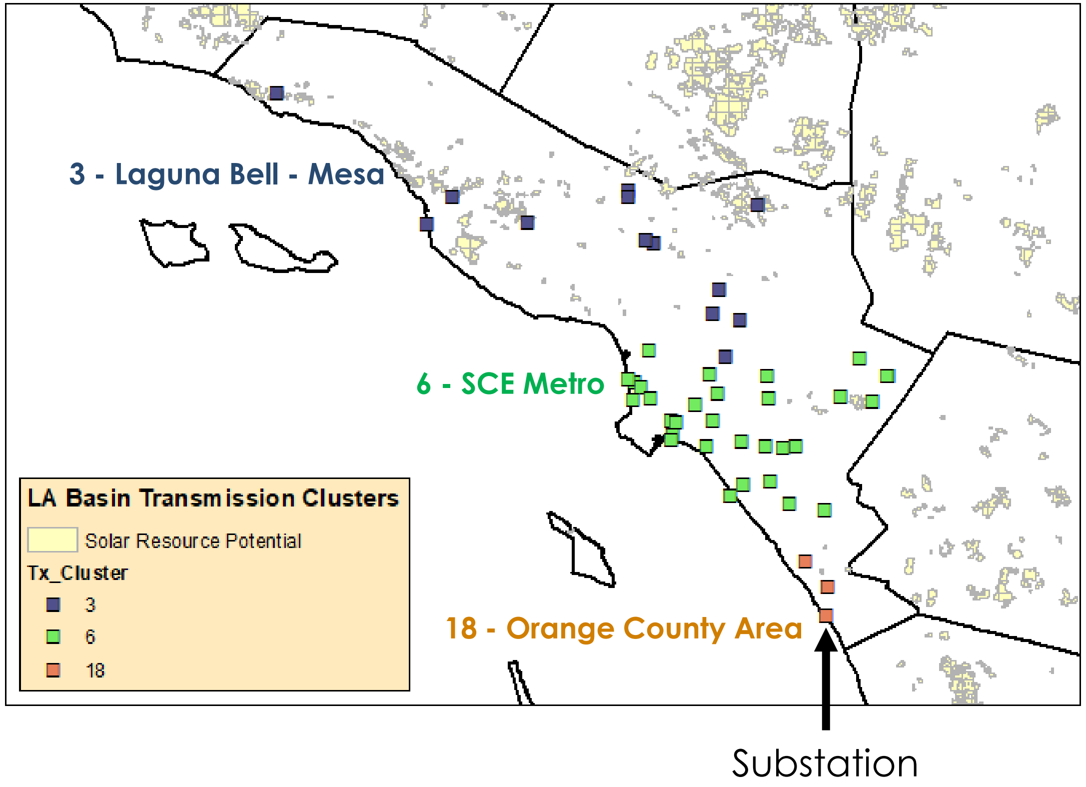


Illustrative example for visualization purposes only

Creating Build Variables from Substations and Transmission Clusters

- Resource potentials from the land use analysis are mapped to the substations from the CAISO constraint boundary diagrams
- Substations are grouped into clusters based on common memberships in transmission constraints
- Each transmission cluster represents a unique build variable in RESOLVE with its own resource potential and constraint memberships

Example: Transmission Clusters in LA Basin



Implementation of Build and Dispatch Resources in RESOLVE

Tehachapi_Solar_1

RESOLVE resource region

Technology

Transmission Cluster

- Each build resource is given a unique name comprised of its RESOLVE resource region, technology type, and transmission cluster
- Build resources are associated with a build cost, resource potential, and transmission capabilities, but do not dispatch to meet load
- All build resources belonging to the same RESOLVE resource region and technology (e.g. Tehachapi_Solar_X) are assigned to a single dispatch variable (Tehachapi_Solar) with a corresponding renewable profile via custom constraints
- All energy storage build resources across all regions (e.g. Tehachapi_Li_Battery_4hr_1) are assigned to a single battery dispatch resource (CAISO_Li_Battery_4hr_Dispatch) to reduce the number of storage variables in the dispatch model

Other Resource Interactions with Transmission Constraints in RESOLVE

- For each candidate solar build resource, a corresponding 4-hr and 8-hr Li-ion battery candidate build resource is created
- Out-of-state resources belong to transmission constraints corresponding to their likely point of tie-in to the existing CAISO transmission system
- Constraints for offshore wind resources are included in the CAISO transmission capability model
- Candidate thermal resources and emerging technologies are not modeled on the transmission network and are excluded from this framework

Generic Transmission Upgrade Zones

- The known transmission constraints and available upgrades as reported by the CAISO may be insufficient to permit enough resource additions to meet system needs through the planning horizon (2045)
- Eight "Generic Transmission Upgrade Zones" will be modeled to permit additional resource builds once all existing and incremental capability on the CAISO transmission constraints are exhausted
- 500 MW per year of incremental capability is made available starting in 2037
- Upgrade costs are adapted from large regional 500 kV upgrade costs from the 2023 Draft Transmission Capability Whitepaper, and are uniformly greater than the costliest CAISO upgrade within each zone

4.3. Transmission Topology

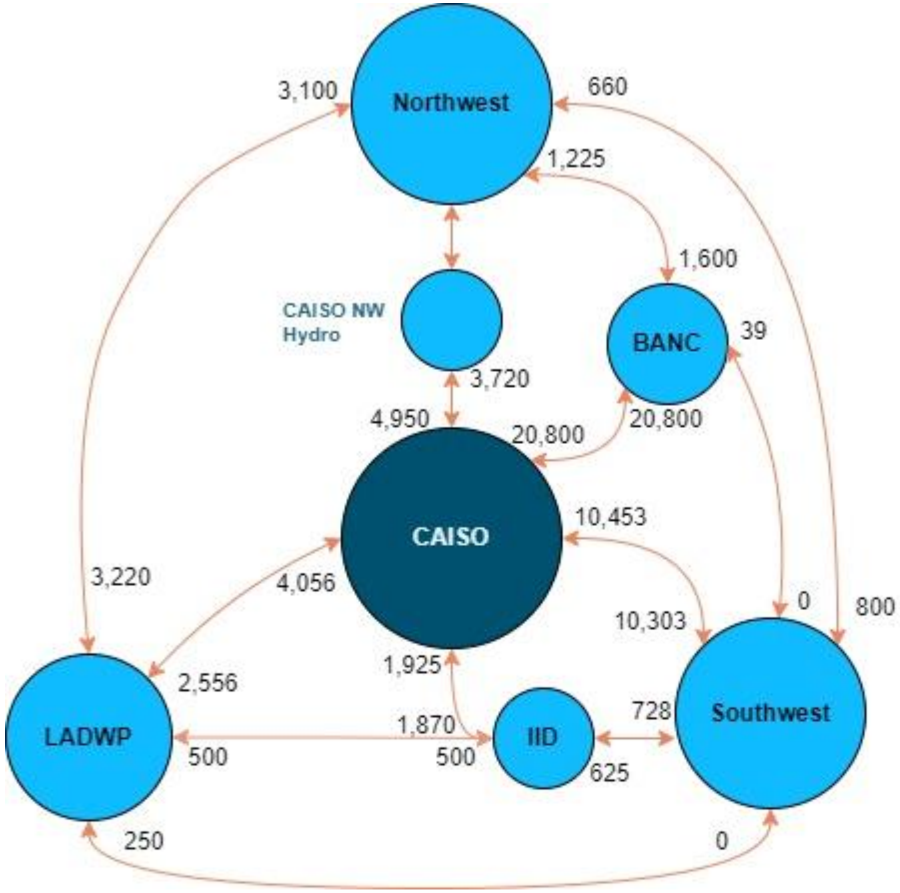
Transmission Topology in RESOLVE

- This section discusses interzonal transmission dispatch limits in RESOLVE
- RESOLVE uses a zonal transmission topology to simulate flows among the various regions of the Western Interconnection
- Six zones are modeled: four to represent the California balancing authorities, and two zones that represent regional aggregations of the out-of-state balancing authorities
- Additionally, imports of NW Hydro energy are modeled in a seventh zone, "CAISO NW Hydro"

RESOLVE Zone	Balancing Authorities
CAISO	CAISO
BANC	Balancing Authority of Northern California (BANC) Turlock Irrigation District (TID)
LADWP	Los Angeles Department of Water and Power
IID	Imperial Irrigation District
NW	Avista Corporation (AVA) Bonneville Power Administration (BPA) Chelan County Public Utility District (CHPD) Douglas County Public Utility District (DOPD) Grant County Public Utility District (GCPD) Pacificorp West (PACW) Portland General Electric Company (PGE)
SW	Arizona Public Service Company (APS) Nevada Power Company (NEVP) Salt River Project (SRP) WAPA – Lower Colorado (WALC)

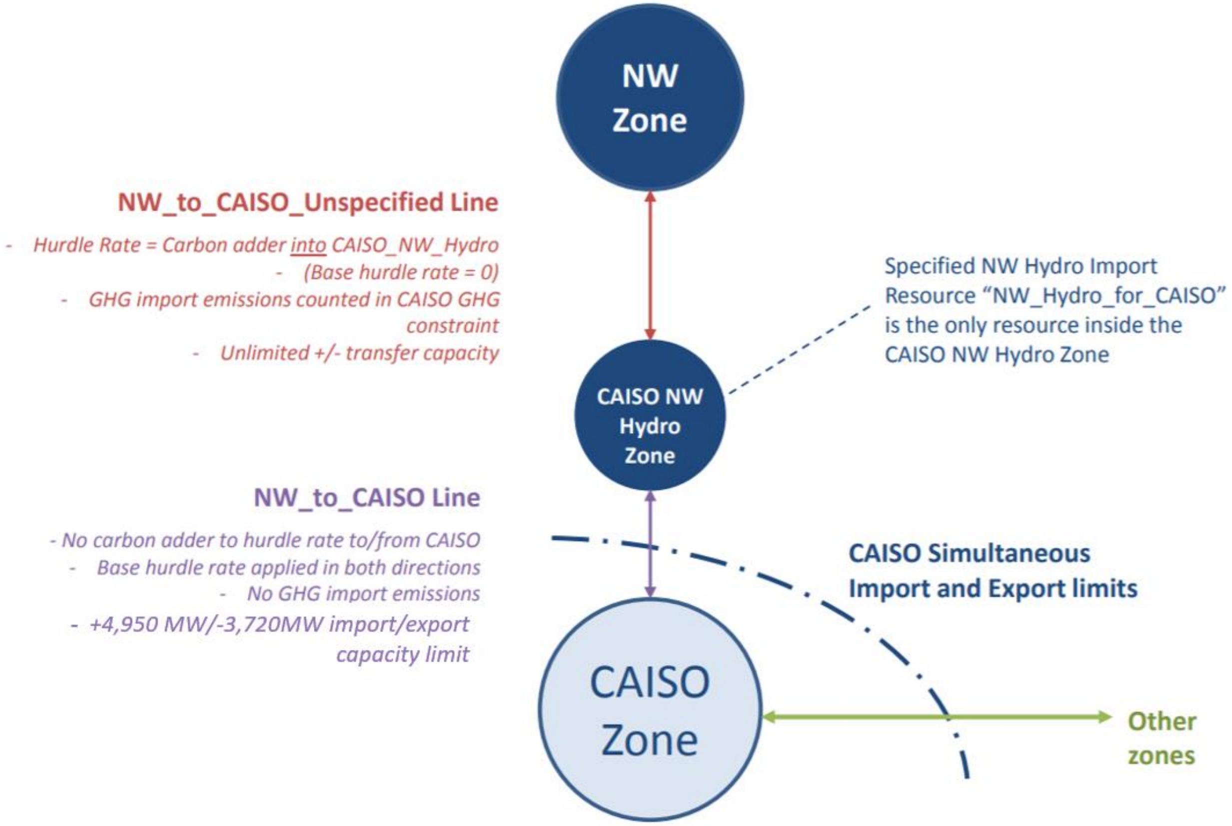
RESOLVE Zonal Topology Diagram

- Transmission flow limits between RESOLVE zones are the sum of flow limits between individual BAAs in the CPUC SERVM model, which were derived from nodal flow ratings from the WECC 2032 ADS 2.0 dataset
- Bidirectional flow values defined between each zone



Specified Imports of NW Hydro

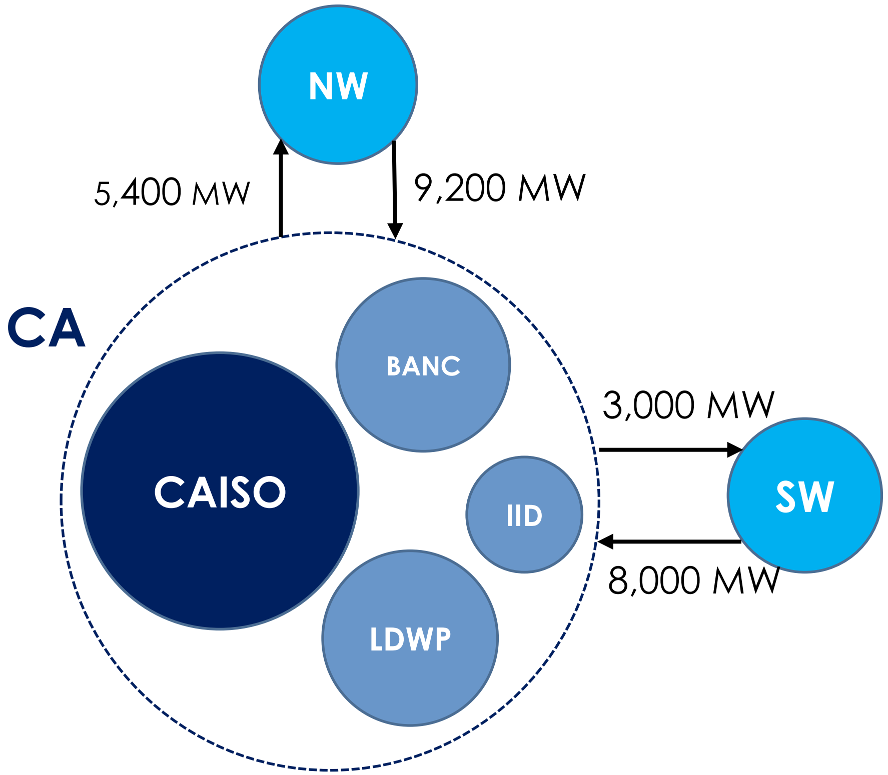
- As discussed in 3.1, 8.31% of the energy generated by NW Hydro is designated as specified imports to CAISO
- The resource "NW_Hydro_for_CAISO" exists in the CAISO NW Hydro zone
- In addition to NW Hydro imports, all unspecified imports/exports between CAISO and NW must pass through this zone
- Emissions from unspecified imports from the NW are counted towards CAISO's GHG limit and incur CARB cap and trade emission permit costs



CAISO and California Simultaneous Flow Constraints

- In addition to transmission limits between modeled zones, simultaneous imports and exports constraints restrict electricity flows to and from CA and CAISO
  - CAISO total imports limited to 11,041 MW
  - CAISO total exports limited to 5,000 MW
- The above limits apply to RESOLVE's hourly dispatch but do not apply to the planning reserve margin. For system reliability accounting, CAISO imports are restricted to 4,000 MW

CA Simultaneous Import and Export Limits from SW and NW



Simultaneous Import/Export Constraints

- The CAISO maximum resource adequacy import capability[2] sets the hourly simultaneous import constraint limit into CAISO (11,041 MW)
- Specified imports from Hoover, Sutter, Intermountain Power Plant (IPP), and Palo Verde, as well as imports from firm remote generators contracted to deliver energy to CAISO, must count against this limit

Resource [(1)]	2022	2023	2024	2025
CAISO RA Import Capability [(2)]	11,041	11,041	11,041	11,041
Sutter	275	275	275	275
IPP	480	480	480	0
Palo Verde	635	635	635	635
CCGT Imports	1,213	1,213	1,213	1,213
Geothermal Imports	209	209	209	209
Simultaneous Import Constraint	8,229	8,229	8,229	8,709

[(1)] Only imports from specified and unspecified firm resources are counted against the simultaneous import constraint; Hoover excluded.
[(2)] http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

4.4. Fuel Price Update

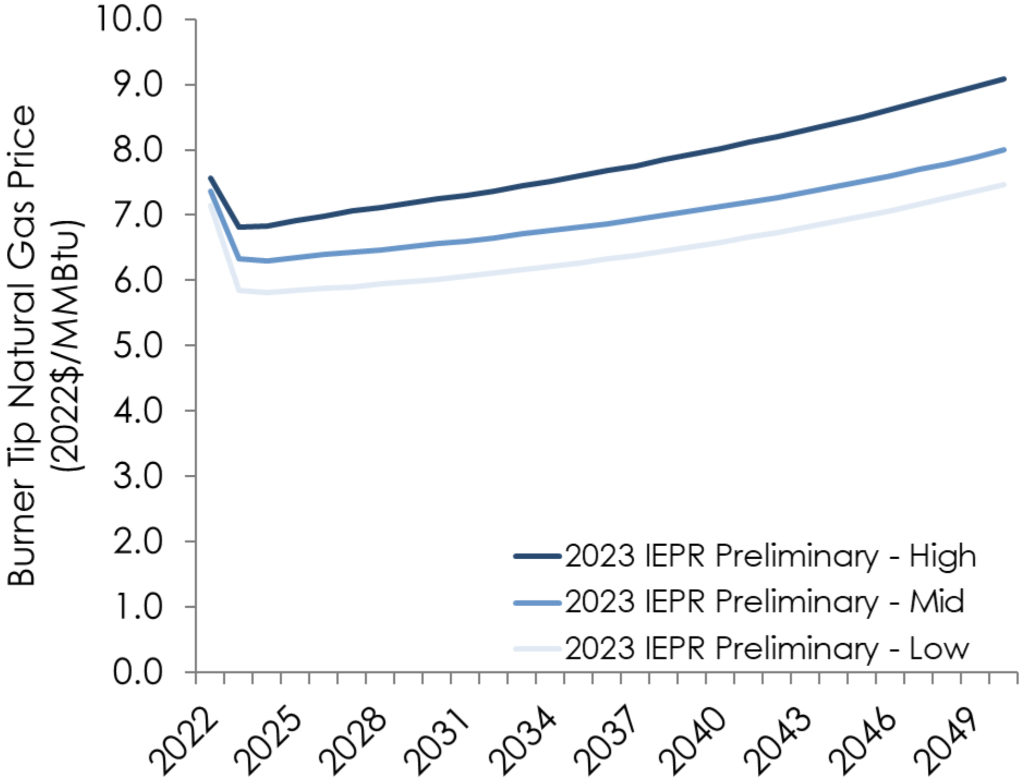
Background on natural gas price in RESOLVE

- Gas price inputs are based on WECC burner tip price estimates from the CEC's North American Market Gas-trade (NAMGas) model runs
- Gas price inputs are updated using the preliminary burner tip price estimates of March 2023[1]
  - Forecasts available from 2023 to 2050, covering the entire 2022-23 IRP cycle planning horizon
  - Seasonal price variability is captured by monthly multipliers
- The Mid Demand Price forecast will be used as the default for PSP analysis
- Gas prices will be updated if the final 2023 IEPR burner tip prices differ from the preliminary forecasts

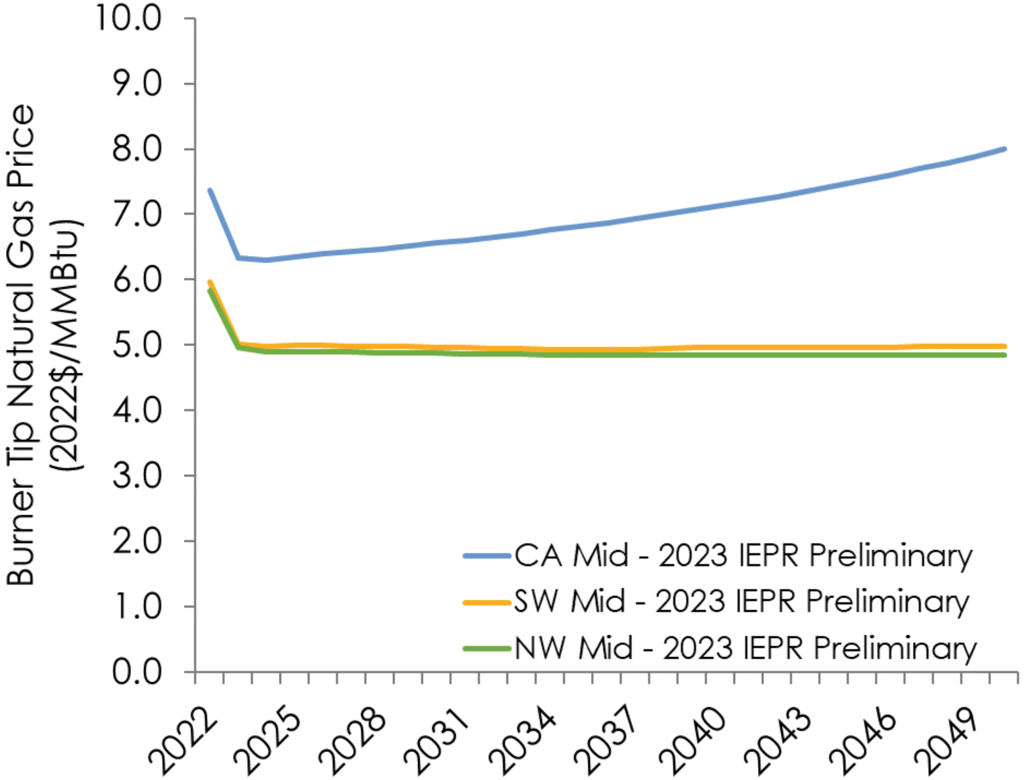
[1] *Natural Gas Electric Generation Prices for California and the Western United States*
https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-electric-generation-prices-california-and

Annual average natural gas fuel price forecast
2023 IEPR Preliminary

“Low,” “Mid,” and “High” Burner Tip Price



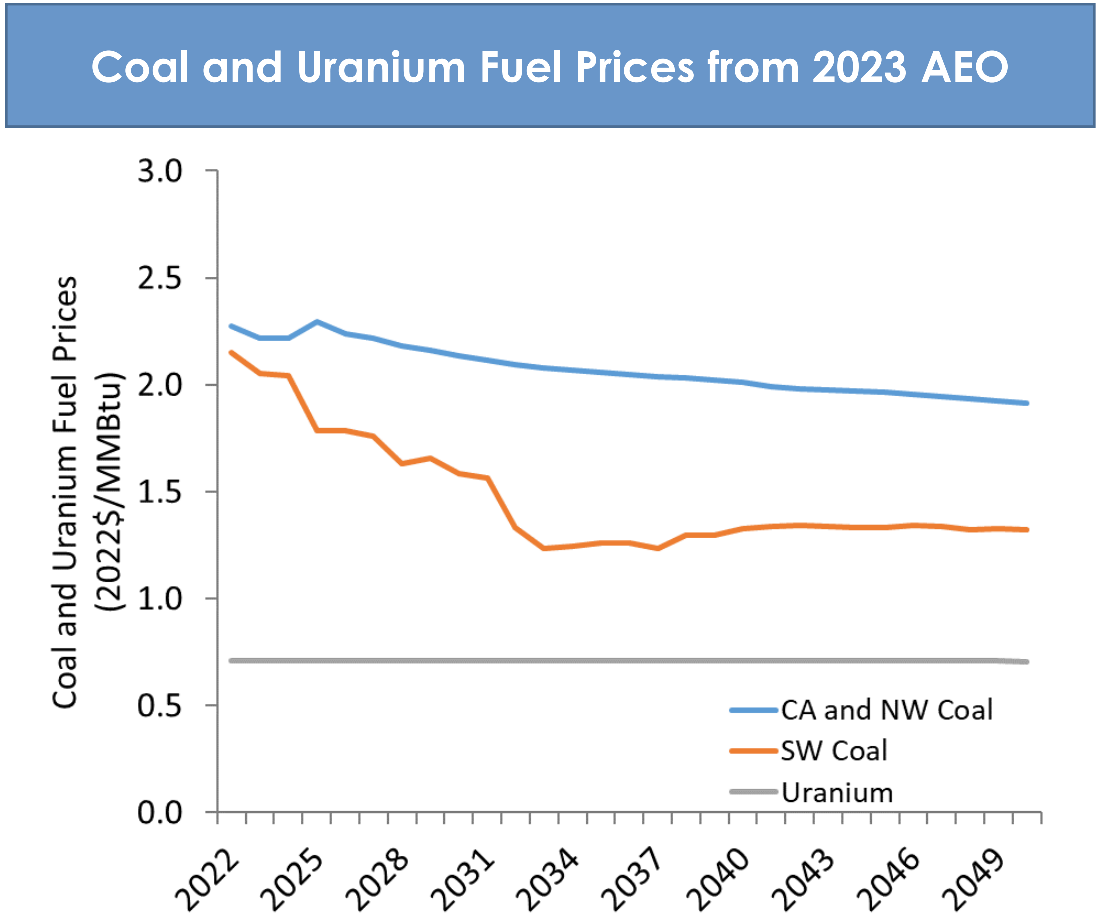
CA, SW and NW Burner Tip Price Comparison



Note: 2023 IEPR covers the entire PSP planning period; thus, no further extrapolation is applied.

Coal, uranium, and biomass fuel prices

- Fuel prices for these technologies are typically less volatile and are only modeled with annual average prices
- Coal and uranium fuel prices are sourced from 2023 Annual Energy Outlook (AEO)[1] for regional fuel prices delivered to the power sector
- Biomass fuel prices of flat $15/MMBtu is used[2]
- For biogas, fuel price data are limited, thus, the same biomass fuel price will be applied unless better data becomes available
- Biomass, biogas and nuclear resources are modeled as must-run resources; thus, the prices have little impact on portfolio selection



[1] *2023 Annual Energy Outlook:* https://www.eia.gov/outlooks/aeo/tables_ref.php
[2] https://www.energy.gov/sites/default/files/2018/11/f57/robi-biomass.pdf

4.5. RPS and SB 100

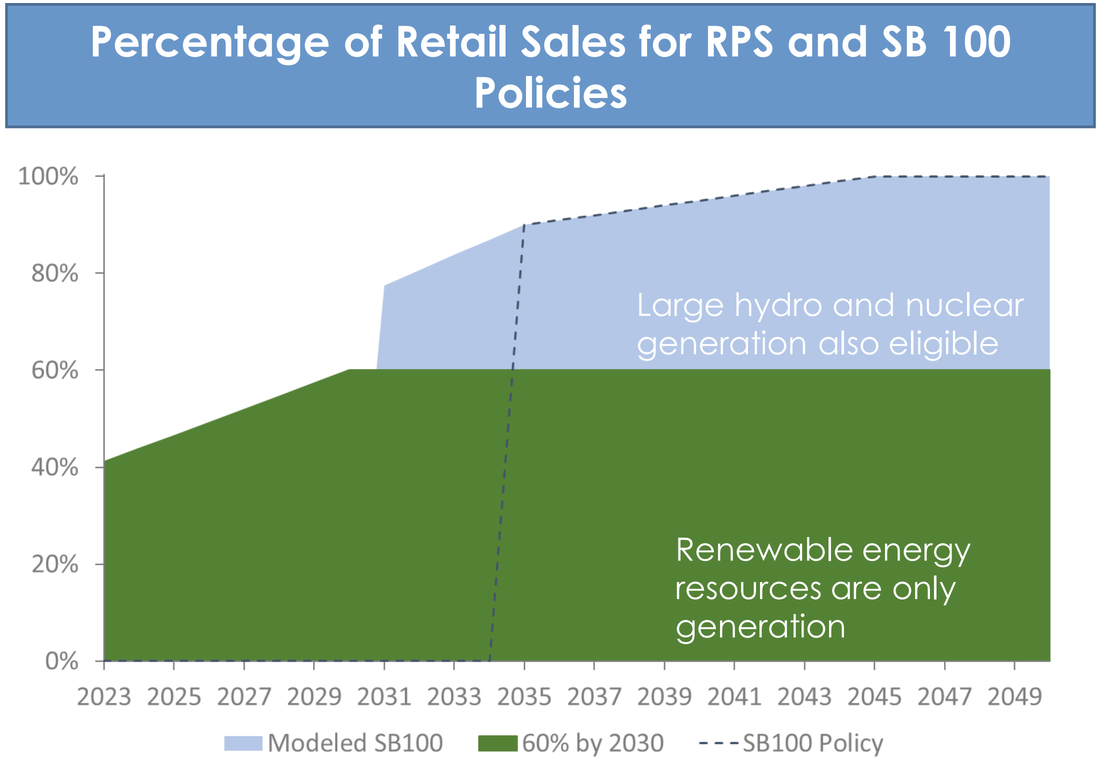
SB100 clean retail sales trajectory is updated with the SB1020 targets for 2035 and 2040

- In past IRP analysis, the 60% RPS target by 2030 was typically not binding meaning that least cost portfolios already had a higher RPS eligible generation than the target
  - RPS eligible resources include biomass, biogas, wind, solar, geothermal, and small hydro
- With SB 1020,[1] the IRP portfolios must now achieve a higher clean retail sales target of 90% by 2035, 95% by 2040 and 100% by 2045
  - In addition to RPS eligible resources, large hydro and nuclear are also eligible
- Retail sales exclude the electricity generated due to transmission and distribution energy losses. BTM resources change the system load and retail sales.

[1] *SB 1020:* Bill Text - SB-1020 Clean Energy, Jobs, and Affordability Act of 2022. (ca.gov)

RPS and SB100 are modeled as two separate clean retail sales policies

- All IRP portfolios must at least have enough RPS eligible renewables to meet 60% of retail sales by 2030
- Beyond 2030, all IRP portfolios must have enough clean generation to meet the *modeled SB100* trajectory to meet 100% of CAISO retail sales by 2045
  - There is no target before 2035, however, the modeled SB100 assumes an earlier target to allow for a much smoother compliance



4.6. GHG Trajectory

2035 GHG emissions targets of 25 MMT and 30 MMT are the main scenarios considered in the PSP analysis

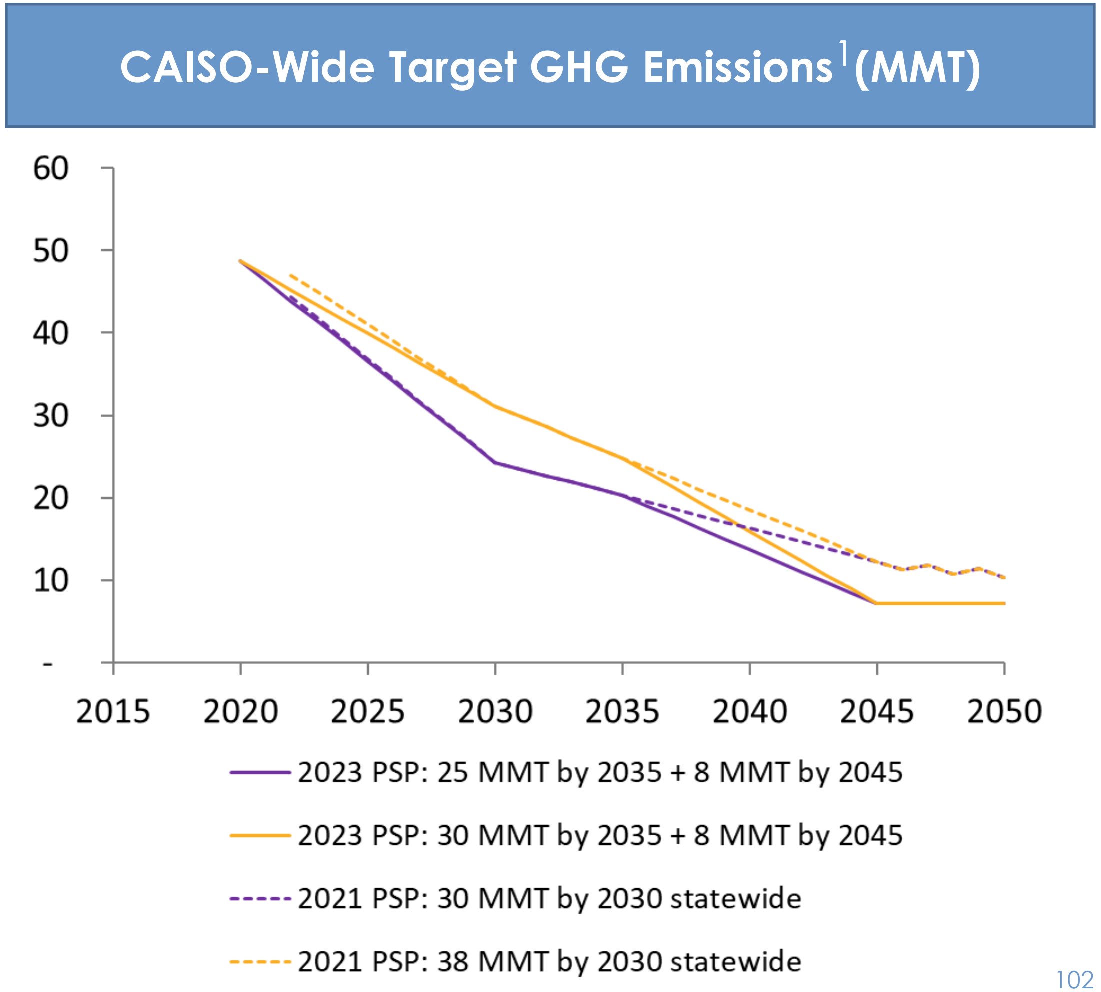
- There are no changes to the 2030 and 2035 emissions targets; however, the trajectories are renamed:
    - Previously, 30 MMT by 2030 target is now 25 MMT by 2035
    - Previously, 38 MMT by 2030 target is now 30 MMT by 2035
- There are two main changes in the GHG emissions reduction trajectories:
    1. The target for 2045 emissions is reduced to the 2022 CARB Scoping Plan statewide power sector target emissions of 8 MMT[1]
    - The baseline historical emissions for the power sector are updated using 59.5 MMT in the year 2020 based on the 2022 California's Greenhouse Gas Inventory[2]
        - A load share of 82% is applied to statewide targets to estimate CAISO-wide targets
- Lower targets than 8 MMT by 2045 might be considered for sensitivity cases

[1] *2022 CARB Scoping Plan:* https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx

[2] https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/ghg_inventory_by_scopingplan_00-20.xlsx

The updated GHG emissions targets

- **2022-2029:** GHG emissions in the power sector have reached lower levels than previously assumed; thus, in the near-term the emissions are now slightly lower than previously modeled
- **2030-2035:** No changes in the emissions targets in these years
- **2036-2045:** Emissions are linearly interpolated between 2035 and the new lower 2045 target of statewide 8 MMT
- **2046-2050:** Although outside the modeling period, emissions are assumed to be fixed at the 2045 level



1 The CAISO-Wide target includes emissions from BTM CHP which is about 4-5 MMT per year

5. Reliability

5.1. Reliability Modeling - Approach and Inputs

Use Cases for Reliability Modeling in 2022-23 IRP Cycle

- A broad set of reliability updates are being conducted this IRP cycle, for use as follows:
- **Recent use case**: **LSE plan filing requirements**[1] released in June and July, 2022
  - Reliability planning requirement, including the planning reserve margin
  - Final Resource Data Template (RDT) with resource accreditation metrics, including effective load carrying capabilities (ELCC), by resource type
- **Near-term use case (in progress): Updates to RESOLVE and SERVM**, and IRP planning track more broadly, including for 2023 Preferred System Plan (PSP) development
- **Upcoming use case**: **Mid-to long-term procurement program**, including reliability procurement need determination for 2025 and beyond
- **Approach**
  - Where possible, use consistent methodologies and inputs across all use cases

1. Filing requirements plus related material from April and July 2022 MAG webinars are available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

Other Reliability Modeling Use Cases

Energy Division is using the LOLE reliability modeling framework in a variety of Commission proceedings in addition to IRP.

- Assessing impact of gas supply reliability on electric system reliability
- Calculating avoided costs in the Integrated Demand Energy Resource proceeding
- Supporting the Slice of Day framework in the Resource Adequacy (RA) proceeding

These diverse applications of LOLE modeling all rely on the same IRP baseline dataset.

- Baseline dataset includes electric demand, baseline resources, generation profiles for non-firm resources, fuel prices, etc.
- Maintaining consistency and stability in datasets is critical for enabling modeling work across these proceedings to be relatable and consistent with each other.
- Modeling input data from 2022 work was posted to the CPUC website (Unified RA+IRP Dataset page). Data from in-progress 2023 work will be posted soon to a new webpage for parties to review and comment.

Opportunities to Improve IRP Reliability Planning

- **2017-18 IRP Cycle**
  - "Proof of concept" cycle and optimistic import assumptions meant reliability planning was secondary
- **2019-21 IRP Cycle**
  - Changing assumptions led to two large procurement orders for new resources
    - Orders were not directly tied to loss of load probability (LOLP) modeling of reliability need
  - PRM assumed in RESOLVE to reflect Mid-Term Reliability (MTR) High Need scenario has led to portfolio that exceeds the reliability standard, per 2021 Preferred System Plan (PSP) analysis
- **2022-23 IRP Cycle**
  - I&A and LSE plan filing requirements present opportunity to refresh reliability planning inputs
  - Planning track PRM update for IRP modeling broadly
  - PRM for mid-to long-term procurement program

Topic	Past IRP Method	Improvement
PRM	Shifting PRMs not tied to LOLP fundamentals → RESOLVE outputs not always matched to reliability results from loss of load modeling	SERVM-based PRM to meet reliability standard
Thermal resource accounting	NQC-based (installed capacity) → can tip the scales in favor of gas plants vs. clean energy	ELCC-based to create a level playing field
ELCCs for RESOLVE	Solar + wind surface (RECAP) Storage ELCC curve (SERVM)	Solar + storage surface (SERVM) Wind ELCC curves (SERVM)
ELCCs for LSE Plans	Interpolation from RESOLVE outputs	SERVM-based ELCC forecast

Summary of 2022-23 Approach

- **Reliability Modeling Approach**
  - Use the CPUC's SERVM model, with any appropriate updates, as the basis for need determination and resource accreditation
- **Need Determination**
  - Calculate total system need via a perfect capacity (PCAP) based total reliability need MW (TRN), then translate into a PCAP planning reserve margin (PRM) above median gross peak
  - A PCAP-based approach means removing from the reserve margin an allowance for forced outages of firm resources, and accrediting all resource types at their respective ELCC i.e., their perfect capacity equivalent, based on simulations that consider their risk of outages, resource availability, and their interaction with load and other resource types
  - Calculate marginal reliability need (MRN) relative to total reliability need (TRN) using a marginal ELCC study
  - Base LSE-specific need on share of marginal reliability need using new multi-year CEC LSE-specific managed peak share forecast
- **LSE Plan Resource Accreditation**
  - All resources will use marginal ELCCs
- **RESOLVE Updates**
  - Align PRM and ELCCs with LSE plan inputs (i.e. use same PCAP PRM and ELCCs from same SERVM model)
  - Change solar + wind ELCC surface to a solar + storage ELCC surface, include demand response (DR) on the storage dimension
  - Develop separate wind ELCC curves
  - All other resources will also use ELCC (firm resources, hydro, etc.)

Key SERVM Input Updates

Completed 12/2022 and first applied to studies of the base portfolio for the CAISO's 23-24 TPP:

- Hourly electric demand profiles adjusted to align with the summer peak hours profile found in CEC's IEPR
- Made hydro years independent of weather years in model stochastic inputs
- Imports and exports modeled with 7 regions external to California

Completed 4/2023 and will apply to the 2023 PSP:

- Major baseline resource update
    - CAISO Master Generating Capability (MGC) List as of 1/2023
    - 11/1/2022 LSE IRP compliance filings
    - 1/2023 NQC List
- 2022 IEPR vintage data
    - Planning case managed electric demand forecast
    - GHG price forecast
    - Burner-tip fuel prices from CEC's draft 2023 NAMGas model

Next Steps

- Consider RESOLVE reliability updates (next 3 sections)
- Staff expects there to be more process around vetting of reliability inputs and approaches later this cycle, for IRP planning track and mid- to long-term procurement program, including reliability procurement need determination for 2025 and beyond
- Additionally, staff and E3 are in the process of developing a new, experimental local capacity module of RESOLVE
  - Simulate the CAISO's deterministic local reliability planning standard
  - Optimize a least-cost portfolio that meets local capacity requirements considering local resource additions, retirements, and transmission upgrades
  - Staff expect to host a MAG webinar focused on this new tool later in 2023

5.2. PRM and Reliability Need

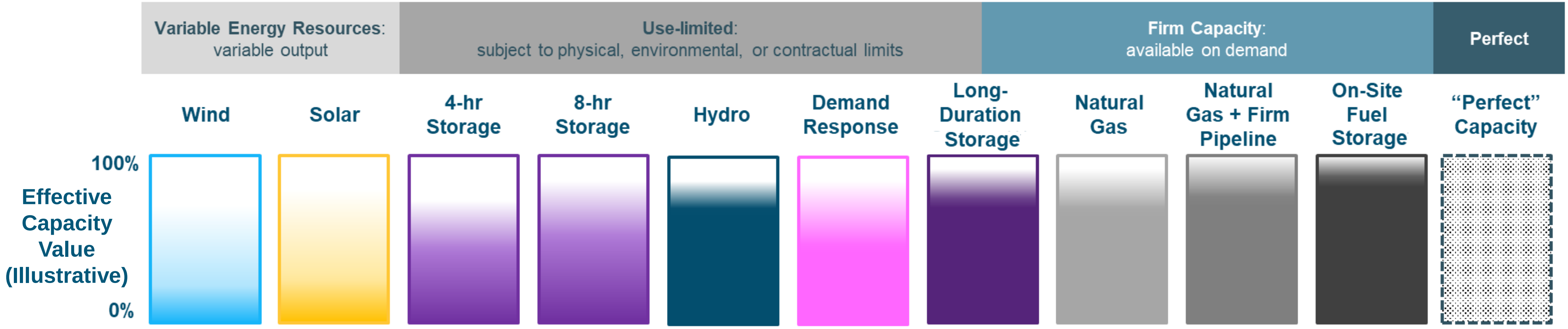
California Public
Utilities Commission

Overview of Reliability Updates in RESOLVE

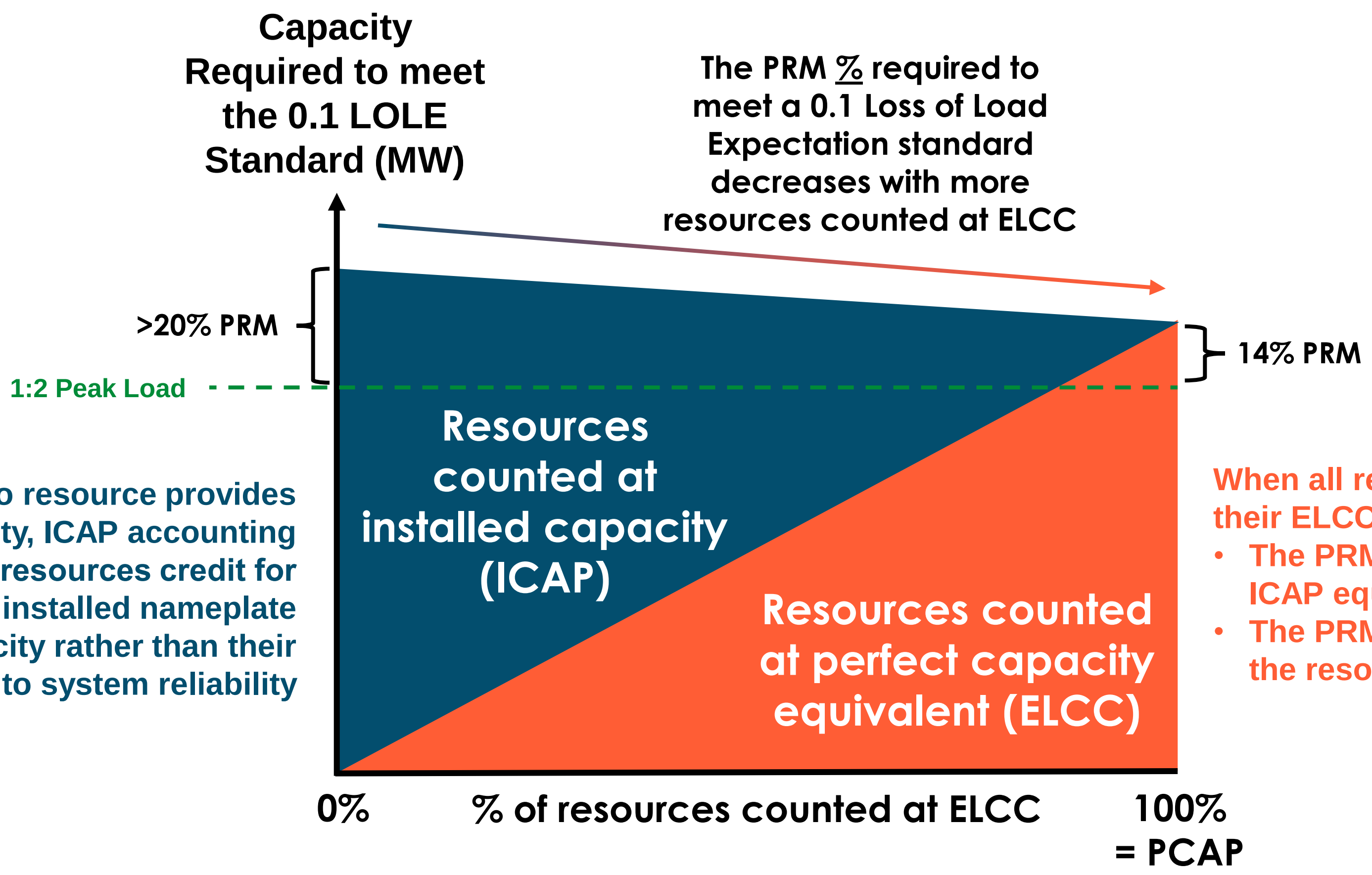
1. **Updating RESOLVE's total reliability need (Planning Reserve Margin, PRM)**
   - Switch from ICAP (Installed capacity) to PCAP (Perfect capacity) PRM
   - Update PRM based on SERVM analysis
   - Switch basis of PRM percentage from managed peak to gross peak
2. **Updating resource contributions to resource adequacy in RESOLVE**
   - Count all resources at their perfect capacity equivalent (Effective Load Carrying Capability, or ELCC) to be consistent with the PCAP PRM
   - Update resource ELCCs based on SERVM analysis
   - Move to a solar + storage ELCC surface to capture strong diversity benefits

These updates better align RESOLVE + SERVM
to better ensure RESOLVE develops sufficiently reliable portfolios

No Resource Provides Perfect Capacity



PCAP PRM provides a more durable definition of total reliability need



Even though no resource provides perfect capacity, ICAP accounting gives “firm” resources credit for their full installed nameplate capacity rather than their contribution to system reliability

When all resources are counted at their ELCC value:

- The PRM % is lower than its ICAP equivalent
- The PRM % does not change as the resource portfolio evolves*

* Since the PCAP PRM % is a function of operating reserves, and load variability, the % may change over time if these inputs change but the percentage won’t be dependent on the resource portfolio.

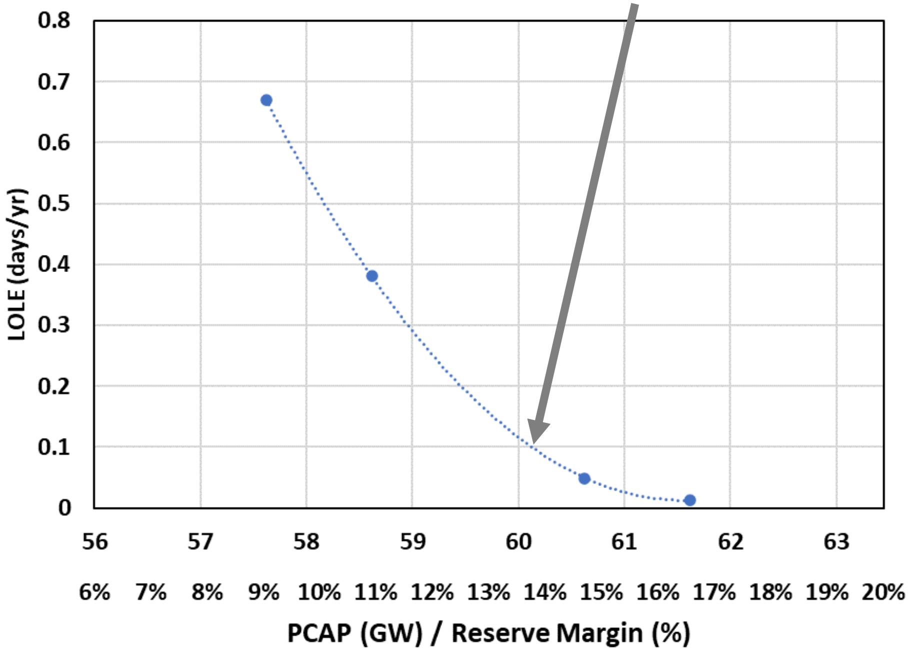
PCAP PRM Results
(from July 2022 Filing Requirements MAG Webinar)

- A Perfect Capacity (PCAP) PRM analysis varies PCAP MW until 0.1 LOLE is achieved
- PCAP PRM is driven by
    - A. Inter-annual load variability in historical weather dataset
    - B. SERVM's load forecast error
    - C. 6% operating reserves
- PCAP PRM was calculated for 2024, 2026, 2030, and 2035
- PRM is measured relative to median gross peak (i.e. BTM PV counted as a supply-side resource at ELCC)

Staff propose RESOLVE to use a 14% PCAP PRM applied to the IEPR gross peak

SERVM's CAISO PCAP PRM Simulations (2024)

*LOLP simulations indicate an **13.8%** reserve margin needed to meet 0.1 days/year LOLE*

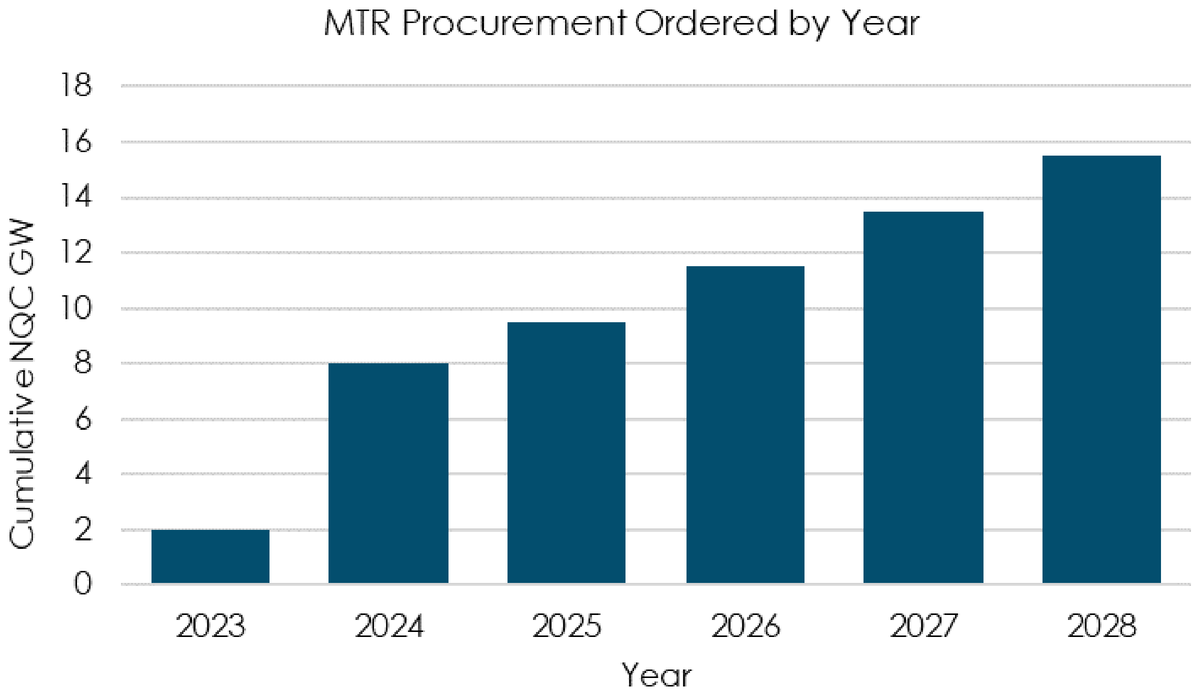


- *PCAP PRM simulations for years 2024, 2026, 2030 and 2035 ranged between ~13.5-14.0%*
- *Equivalent 2030 ICAP PRM over gross peak is ~18-21.5%, depending on the share of resources counted at ELCC vs. installed capacity*
- *All PRMs calculated relative to CAISO median gross peak*

5.3. MTR Requirement Implementation

Reflecting the Mid-Term Reliability (MTR) Procurement Orders

- In June 2021 and February 2023, the CPUC ordered its jurisdictional in-CAISO LSEs to procure 15.5 GW NQC of new zero-emission resources from 2023 through 2028[1]
- MTR procurement ordered in each year is included as a requirement that RESOLVE must meet in addition to the 14% PRM requirement. Consistent with the MTR order, only new, zero-emission resources can contribute to RESOLVE's MTR requirement
  - Includes requirements for 1 GW each of geothermal and long-duration (>8-hr) storage



[1] D.21-06-035 and D.23-02-040

Counting Resources Toward MTR Procurement

- Wind, solar, and storage resources are counted toward the 15.5 GW NQC requirement using ELCCs determined in the MTR ELCC Study[1]
- MTR Study ELCCs will only be used to meet the procurement requirement and do not apply to other RESOLVE decisions
- For geothermal and biomass, RESOLVE uses NQC values from the RA program

Incremental ELCCs for MTR Procurement, as of January 2023

	From prior study, for reference only		Updated values from this study		Additional Proposed MTR Tranches[7]	
	Tranche 1 2,000 MW 2023	Tranche 2 6,000 MW 2024	Tranche 3 1,500 MW 2025	Tranche 4 2,000 MW 2026	Tranche 5 2,000 MW 2027	Tranche 6 2,000 MW 2028
4-Hour Battery	96.3%	90.7%	75.1%	76.6%	74.0%	76.5%
6-Hour Battery	98.0%	93.4%	79.6%	80.3%	80.5%	83.3%
8-Hour Battery	98.2%	94.3%	84.0%	84.0%	87.1%	90.1%
8-Hour PSH	N/A	76.8%	82.6%	82.6%	85.7%	88.7%
12-Hour PSH	N/A	80.8%	86.6%	86.6%	89.7%	92.7%
Solar - Utility and BTM PV	7.8%	6.6%	6.6%	7.0%	7.5%	8.8%
Wind CA	13.9%	16.5%	12.0%	13.2%	14.0%	14.7%
Wind WY	28.9%	28.1%	31.0%	33.0%	31.7%	30.9%
Wind NM	31.1%	31.0%	30.0%	35.0%	33.7%	31.9%
Wind Offshore	N/A	N/A	48.0%	46.0%	44.0%	44.7%

[1] Incremental ELCC Study for Mid-Term Reliability Procurement (January 2023 Update)

5.4. ELCC Surface and Curves

New ELCC Runs since September 2022 MAG Webinar

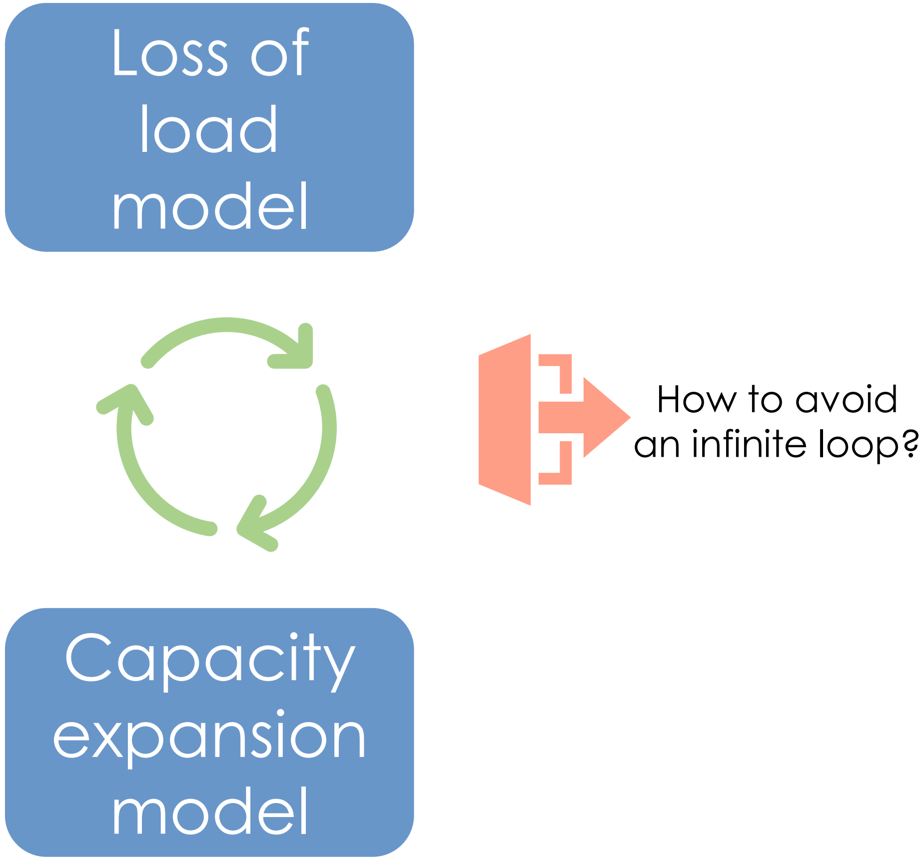
- Staff has conducted new SERVM runs to update key ELCC inputs to RESOLVE for the 2023 IRP, including for:

1. In-state wind and out-of-state wind ELCC curves
2. Solar + storage ELCC surface
3. Long-duration storage (LDES) ELCCs

- Primary updates to SERVM model inputs included
    - New load shape
    - New out-of-state wind profiles
    - Updated starting portfolio for solar + storage surface

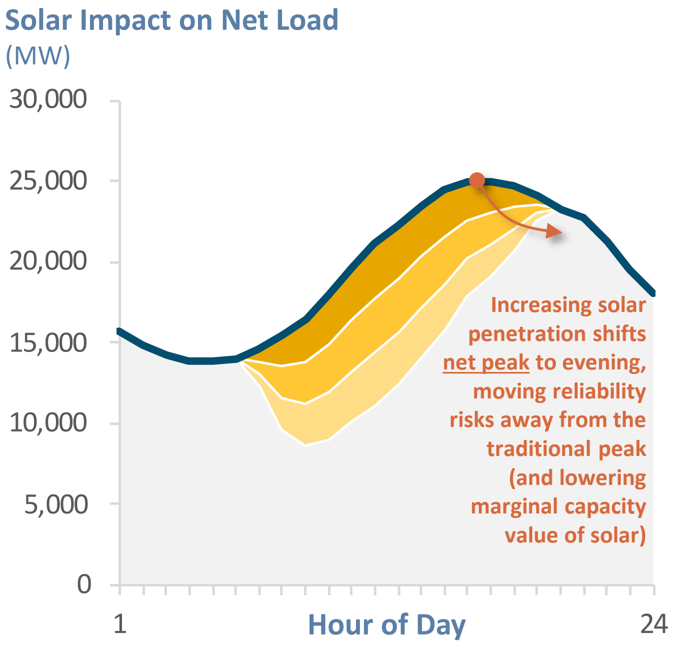
Planning models need estimates of resource adequacy contributions

- Capacity expansion models enforce resource adequacy constraints (e.g. PRM)
- To ensure reliability at minimum cost, the marginal *and* total resource adequacy contribution of energy-limited resources needs to be accurately reflected
  - But declining marginal capacity values and interactive effects between resources require <u>constant re-calibration</u> of energy-limited resource adequacy contributions
- It's not feasible to embed a detailed loss-of-load model within a capacity expansion model

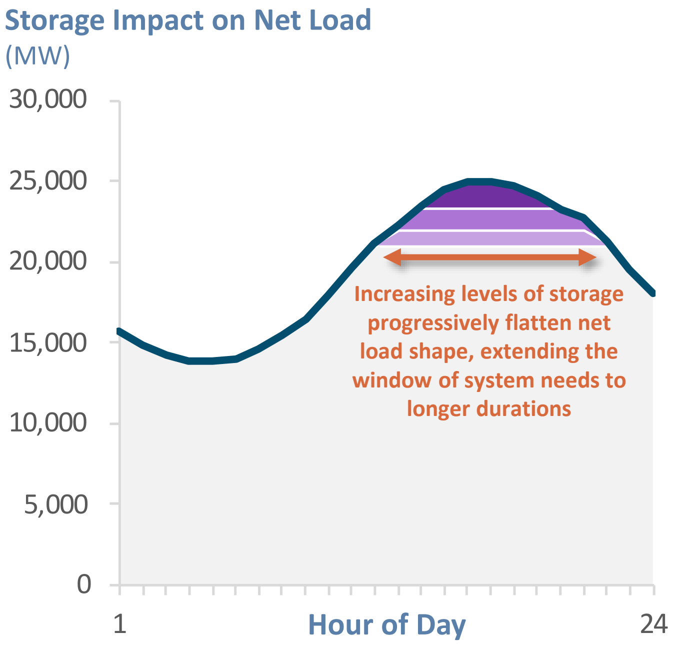


ELCC captures complex dynamics resulting from increasing penetrations of variable & energy limited resources

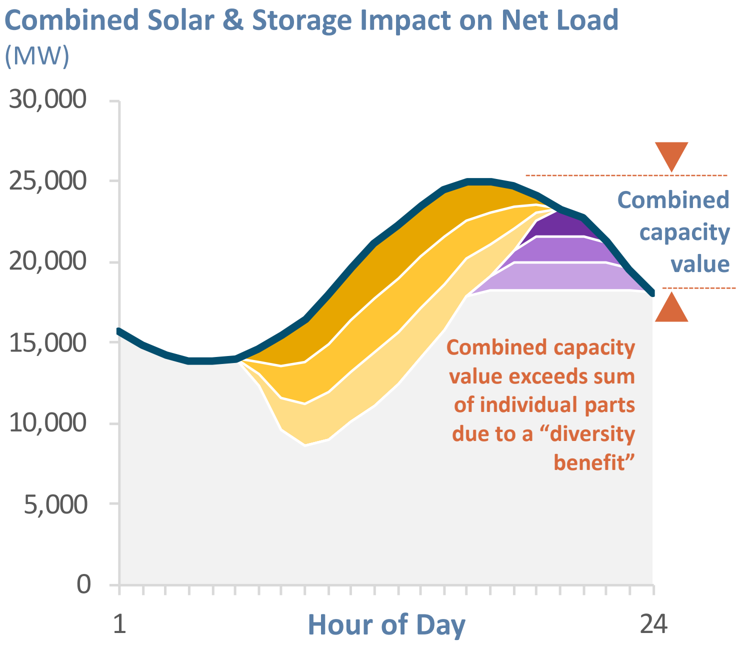
"Variable" resources shift reliability risks to different times of day



"Energy-limited" resources spread reliability risks across longer periods



A portfolio of resources exhibit complex interactive effects, where the whole may exceed the sum of its parts



The ELCC approach inherently captures both **capacity** & **energy** adequacy

Proposed RESOLVE Approach

	Prior Approach: 2021 Preferred System Plan (PSP)	Proposed Approach: 2022-23 IRP Cycle and beyond
Planning Reserve Margin	**22.5% installed capacity based (ICAP)** PRM above managed peak	**14% perfect capacity based (PCAP)** PRM above gross peak
Wind	ELCC (solar/wind ELCC surface)	ELCC (in-state, OOS, offshore wind curves)
Solar PV		ELCC (solar/storage surface)
BTM PV	ELCC (solar/wind ELCC surface), after increasing need by IEPR peak shift	
Battery Storage	ELCC curve (Battery only)	
Demand Response (Load Shed)	DR program capacity (NQC) for new + existing	ELCC (model new DR on storage dimension of solar/storage surface)
Pumped Storage	Installed capacity (NQC) for new + existing	ELCC (model new pumped hydro storage on storage dimension of solar/storage surface)
Hydro	Installed capacity (NQC)	ELCC (static)
Bio/Geo/Nuclear		
Fossil (CT/peaker, CCGT, CHP, coal)		
BTM Storage	Load modifier via IEPR assumptions	Load modifier via IEPR assumptions

RESOLVE will now rely on SERVM runs to represent resource ELCCs, driving further consistency between the two models

- ELCC calculations in SERVM use 2030 loads from the 2021 IEPR and the 2030 38MMT portfolio from the LSE filing requirement runs.
- To avoid double counting interactive effects, ELCC calculations in SERVM were sequenced: firm resources first, hydro second, existing pumped storage third, existing demand response fourth, then candidate resource options.
- Bio/GeoCHP values ELCC values are proposed to rely on NQC values from the RA program

ELCC curves and surfaces address challenging issues for capacity expansion models

- Saturation impacts are addressed because marginal ELCC declines endogenously with resource penetration
- Creating ELCC curve equations using the results of a LOLE model implicitly includes energy limitations on different timescales
  - For wind and solar, production profiles across many years in the LOLE model allow for consideration of low renewable output periods
  - For storage, ELCC simulations have charging and discharging constraints
    - Portfolio ELCC captures charging energy sufficiency and flattening of the net peak via the LOLE model
- ELCC curve with a single resource class does *not* include synergistic or antagonistic impacts with other resource classes
  - ELCC "surface" with two resource classes can include interdependent effects between two resource classes

Workflow for using ELCC curve or surface in planning

1. LOLE model (SERVM)

Calculate ELCC of combinations of energy-limited resources over a wide range of installed capacities

→

2. Linear equations

Convert portfolio ELCC values at a range of penetrations into linear equations for marginal and total ELCC

→

3. Capacity Expansion

Implement curve or surface equations in capacity expansion model, create least-cost portfolios

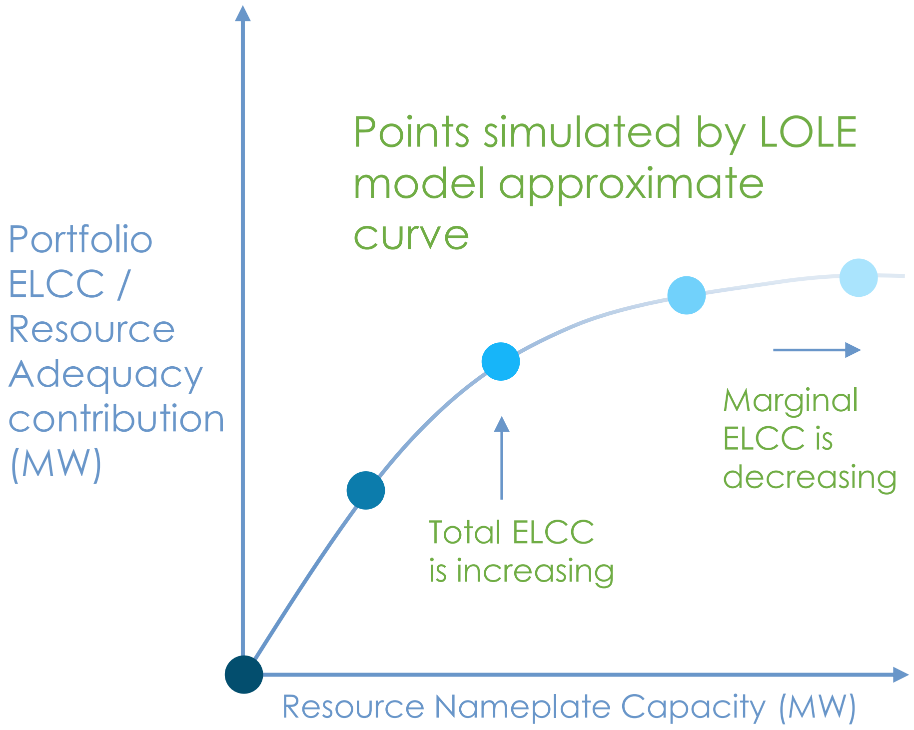
→

4. Reliability Check

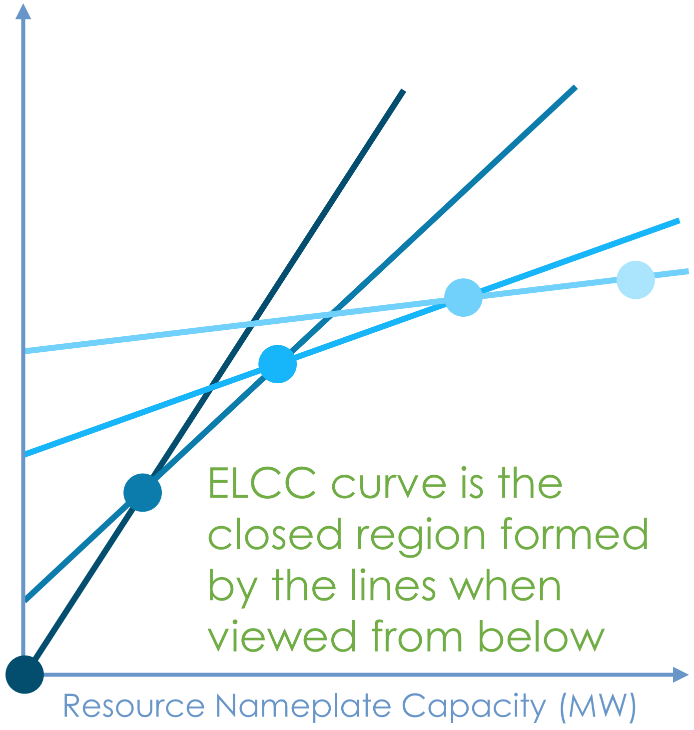
Check reliability using LOLE model, adjusting if any issues are found

Building an ELCC curve in one dimension

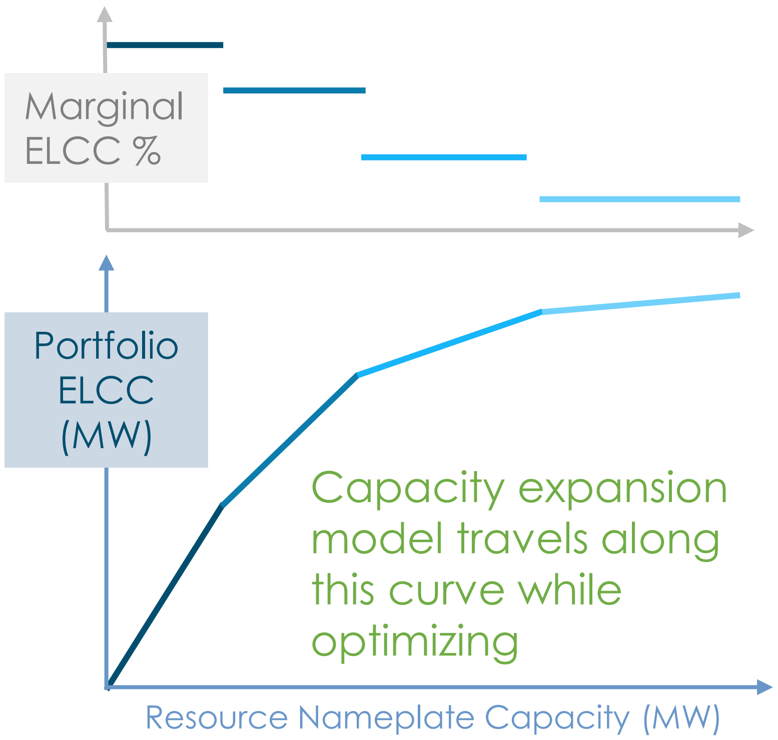
1 Calculate ELCC at Different Levels of Penetration



2 Linear equations approximate "true" ELCC curve

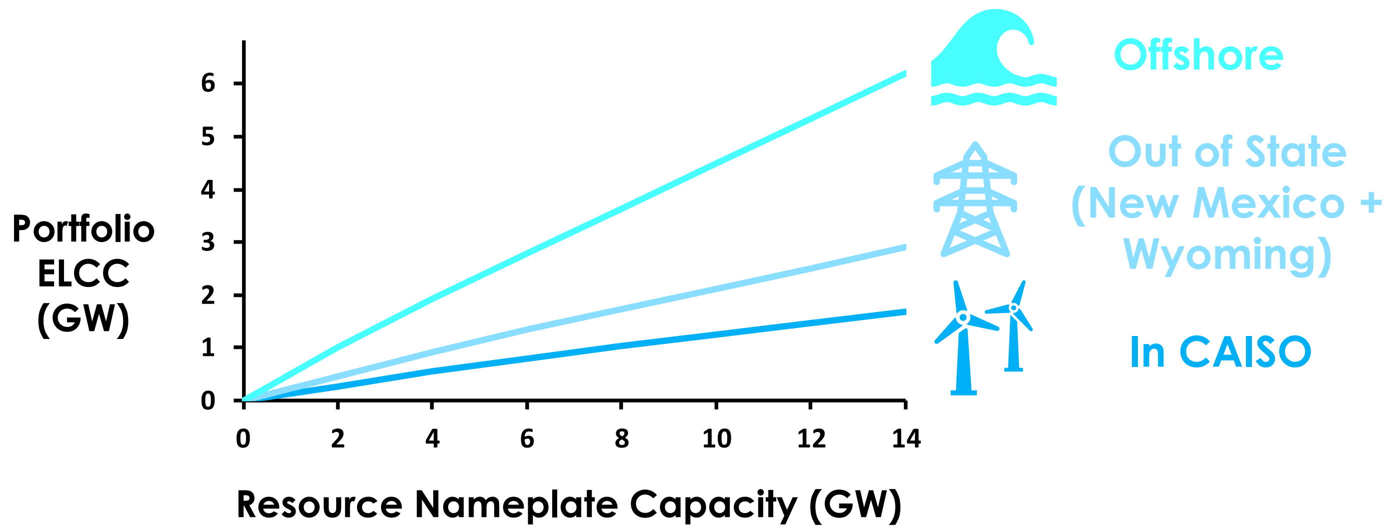


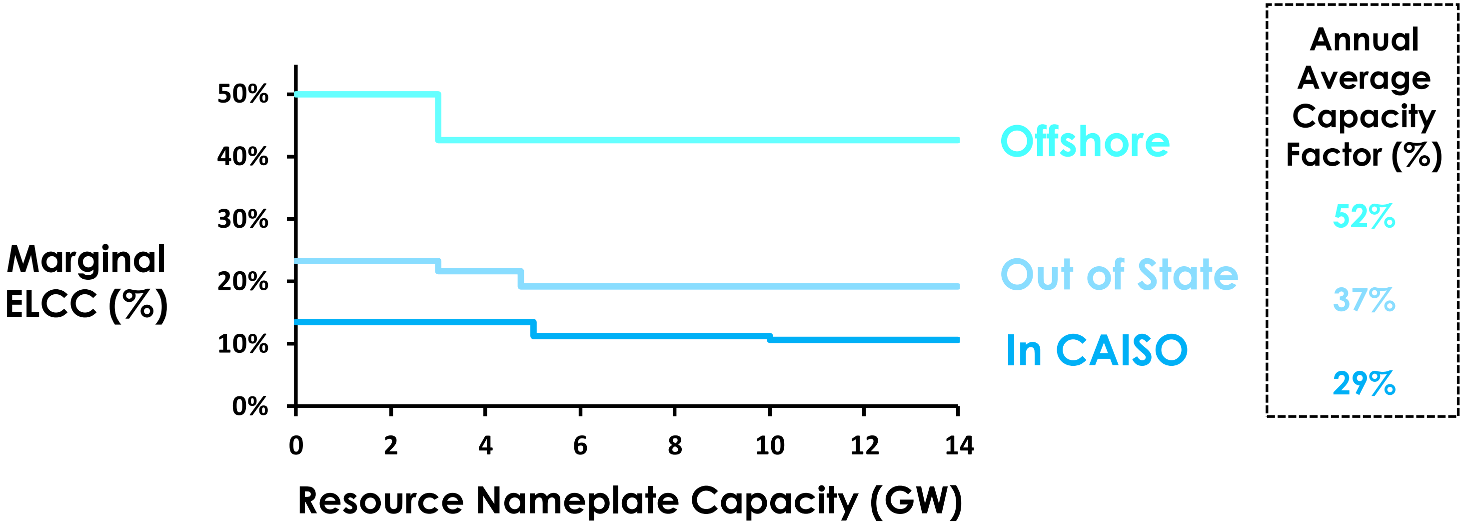
3 Implement in capacity expansion model



Wind ELCC Curves

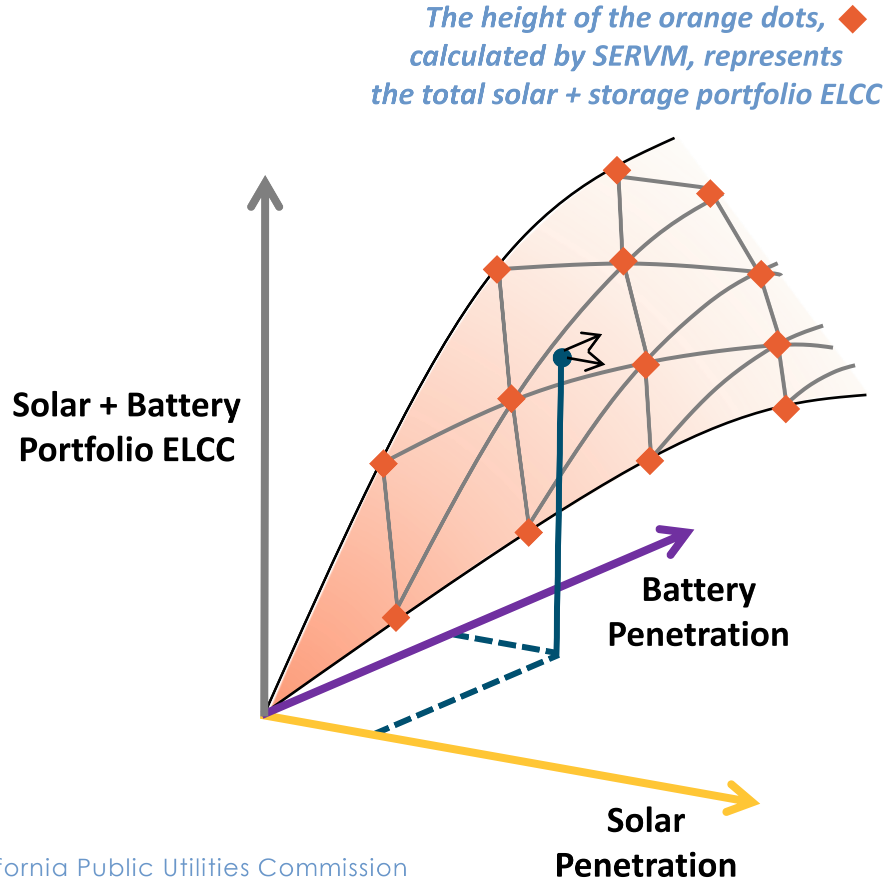
- Proposed update is to model three wind types (in-CAISO, out of state, and offshore) on separate ELCC curves
  - SERVM runs with different combinations of the three wind types demonstrated that separate ELCC curves are more accurate than combining into a single wind ELCC curve
- Marginal ELCC is relatively stable over range of wind capacity and is largely proportional to annual average capacity factor



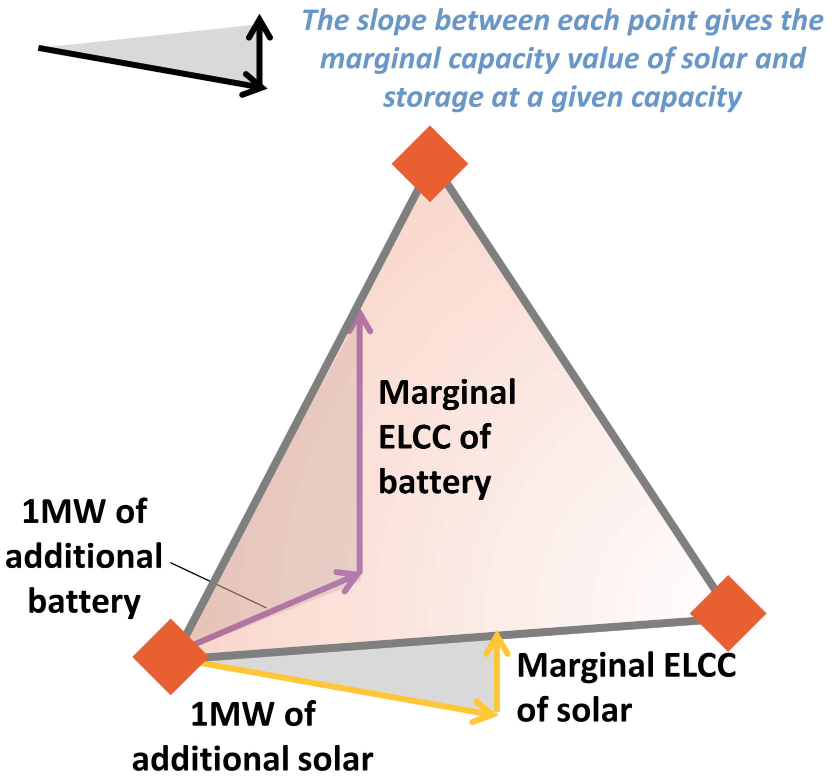


Now add a dimension….

- An ELCC surface with two resource classes can capture both diminishing returns and diversity benefits between resources



For any plane on the surface:



Solar + Battery Surface Marginal ELCCs

At lower levels of battery capacity, battery marginal ELCC is supported by solar because A) solar can charge batteries, and B) solar production can delay battery discharge

Marginal Battery ELCC (%)

Battery marginal ELCC increases for a given battery penetration as solar is added

4-Hour Battery Nameplate Capacity (GW) (rows) / Solar Nameplate Capacity (GW) (columns)

	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
0	90%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
5	90%	92%	92%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%	95%	95%
10	90%	90%	92%	92%	92%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%
15	70%	79%	79%	87%	90%	90%	91%	92%	92%	92%	92%	95%	95%	95%	95%
20	33%	33%	33%	65%	70%	75%	81%	84%	84%	84%	90%	90%	92%	92%	95%
25	33%	33%	33%	33%	37%	44%	45%	52%	52%	52%	52%	52%	52%	52%	52%
30	27%	27%	27%	27%	27%	27%	28%	30%	32%	36%	36%	36%	36%	36%	36%
35	17%	17%	17%	17%	17%	17%	17%	17%	28%	32%	36%	36%	36%	36%	36%
40	9%	9%	9%	9%	9%	9%	9%	11%	11%	12%	12%	32%	36%	36%	36%
45	9%	9%	9%	9%	9%	9%	9%	9%	11%	11%	11%	11%	12%	36%	36%
50	9%	9%	9%	9%	9%	9%	9%	9%	9%	11%	11%	11%	11%	11%	12%

Battery marginal ELCC saturates without supporting solar capacity

Marginal Solar ELCC (%)

Solar marginal ELCC increases for a given solar penetration as batteries are added

4-Hour Battery Nameplate Capacity (GW) (rows) / Solar Nameplate Capacity (GW) (columns)

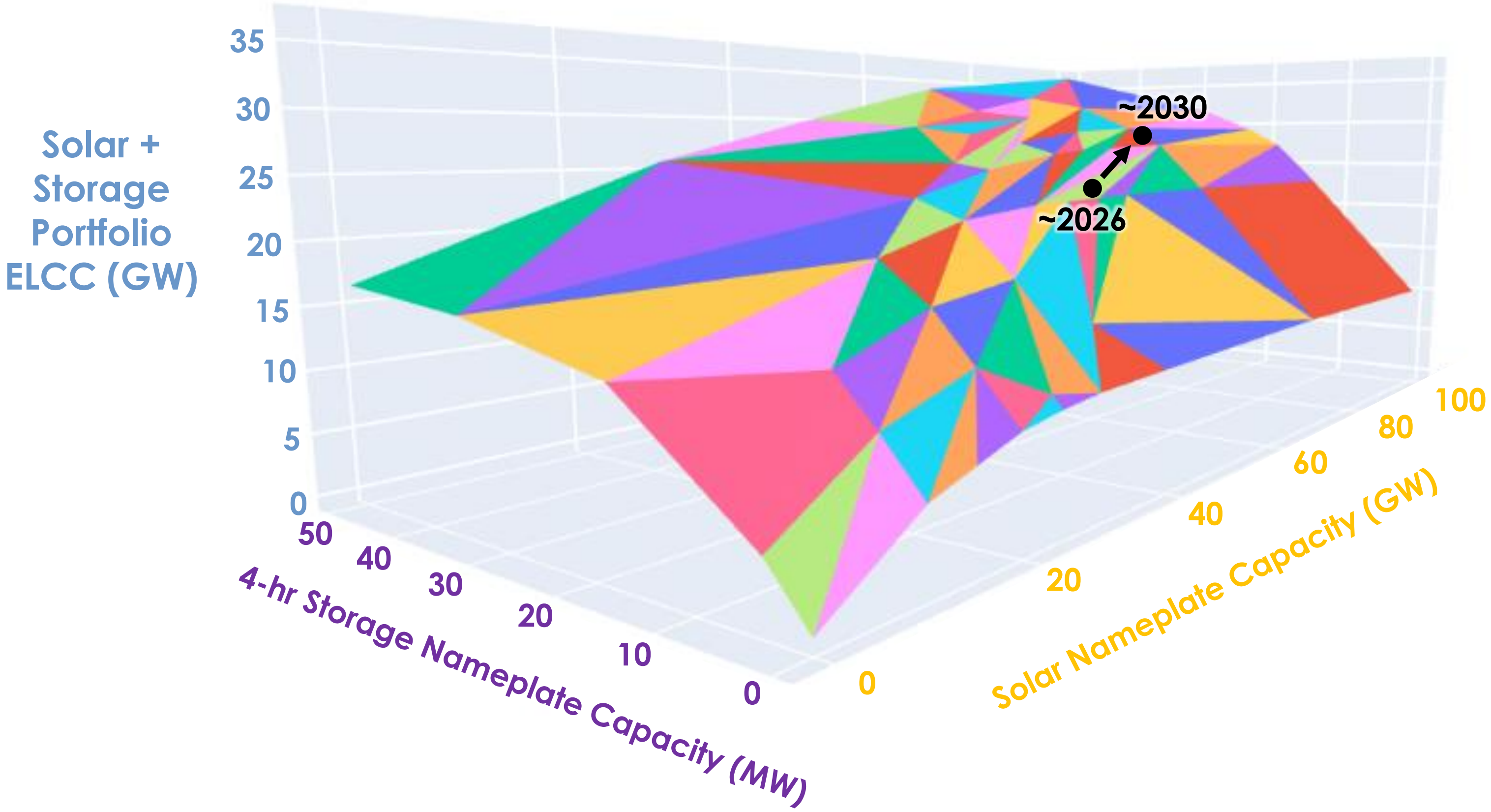
	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
0	5%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%			
5	6%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%			
10	6%	5%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%			
15	13%	8%	8%	4%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%
20	25%	25%	21%	9%	6%	4%	4%	4%	4%	4%	3%	3%	3%	3%	2%
25	25%	21%	21%	21%	16%	9%	8%	4%	4%	4%	4%	4%	1%	1%	1%
30	25%	21%	21%	21%	19%	19%	10%	9%	4%	1%	1%	1%	1%	1%	1%
35	25%	21%	21%	21%	19%	19%	17%	14%	10%	4%	1%	1%	1%	1%	1%
40	25%	21%	21%	21%	19%	19%	17%	14%	14%	14%	14%	4%	1%	1%	1%
45	25%	21%	21%	21%	19%	19%	17%	17%	14%	14%	14%	14%	14%	1%	1%
50	25%	21%	21%	21%	19%	19%	17%	17%	17%	14%	14%	14%	14%	14%	14%

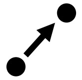
Solar marginal ELCCs saturate without supporting storage capacity

Batteries support solar marginal ELCC by shifting solar generation to hours when it is needed most

Solar + storage surface in 3D

Each colored area represents a different combination of marginal solar and marginal storage ELCC

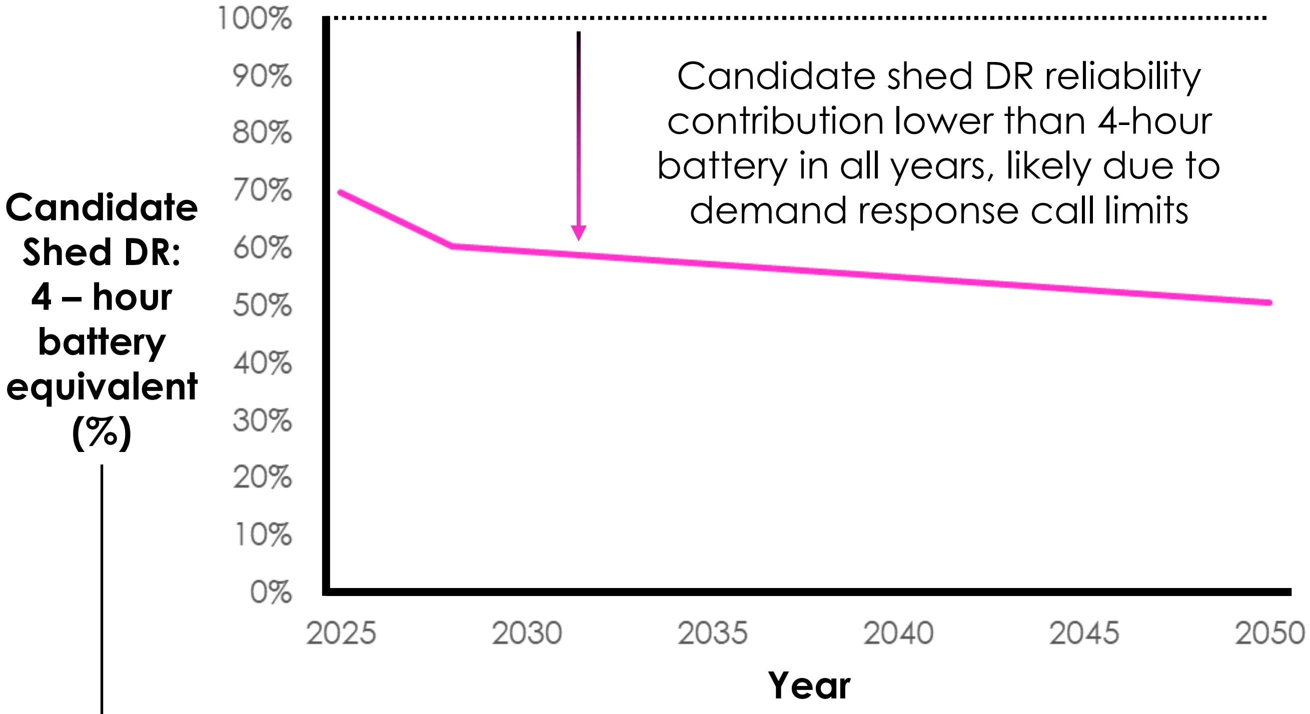




As RESOLVE adds solar and storage resources:
(1) the portfolio ELCC increases and (2) the marginal solar and storage values may change if enough capacity is added to move to a different plane (each colored area is a plane)

Shed Demand Response (DR)

- 2021 PSP approach: Shed DR program capacity (NQC) for existing and candidate
- 2022-23 proposed approach:
  - Existing: constant SERVM-calculated ELCC of 96% in all years
  - Candidate: Modeled on the storage dimension of solar + storage ELCC surface with multiplier that represents the 4-hour storage equivalent for DR in each future year
    - Multiplier calculated via pairs of SERVM runs in which additional batteries are compared to additional shed DR



Y-axis represents candidate shed DR reliability contribution *relative to a 4-hour battery*. 4-hour battery ELCC declines with increasing penetration via ELCC surface so candidate shed DR ELCC will also decline in the same manner

Long-duration Storage ELCCs

- Long-duration storage ELCCs are higher than short-duration storage… but how much higher may change significantly across the solar-storage surface

Factors to consider:

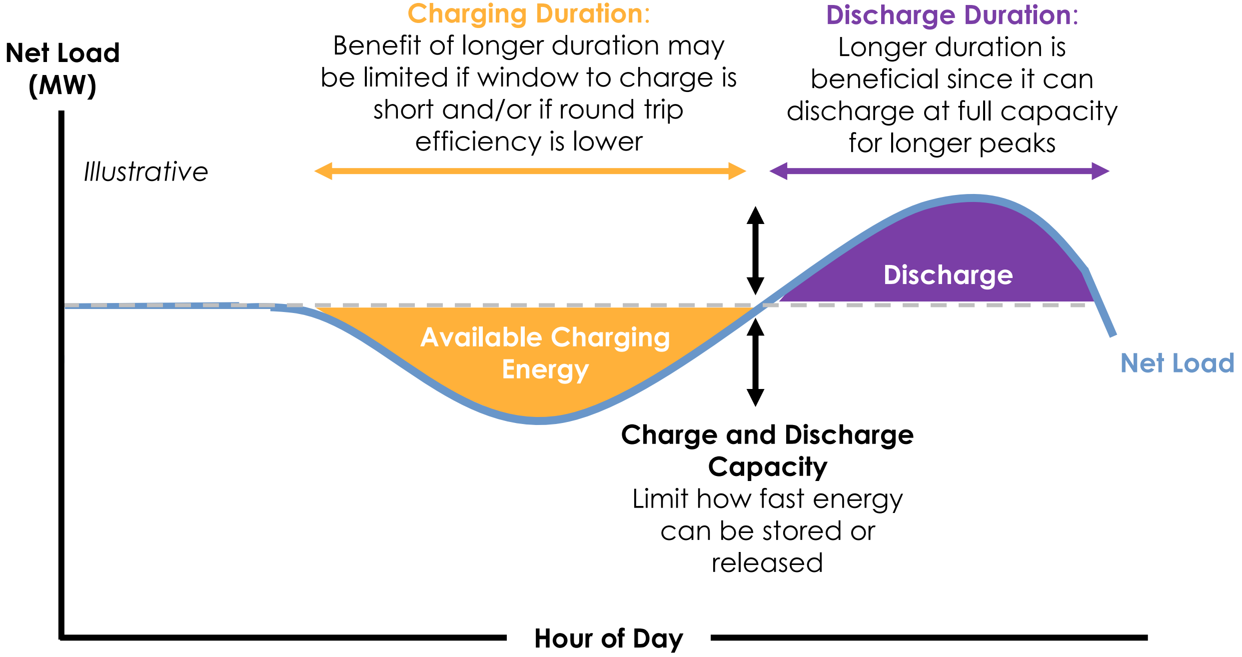
- Storage duration
- Storage round trip efficiency (incl. parasitic / idle losses)
- Charging energy availability
- Duration of charging energy availability
- Portfolio of longer and shorter duration storage already on the system
- Persistence of extreme weather events
- LOLP modeling of operations (including foresight to pre-charge long duration storage)

2022 LSE Filing Requirements Marginal ELCC (38MMT scenario)

Resource Class	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
4-hr Battery Storage	89%	90%	92%	85%	77%	76%	75%	68%	61%	54%	47%	40%
8-hr Battery Storage	89%	91%	93%	90%	87%	86%	85%	82%	79%	76%	73%	70%

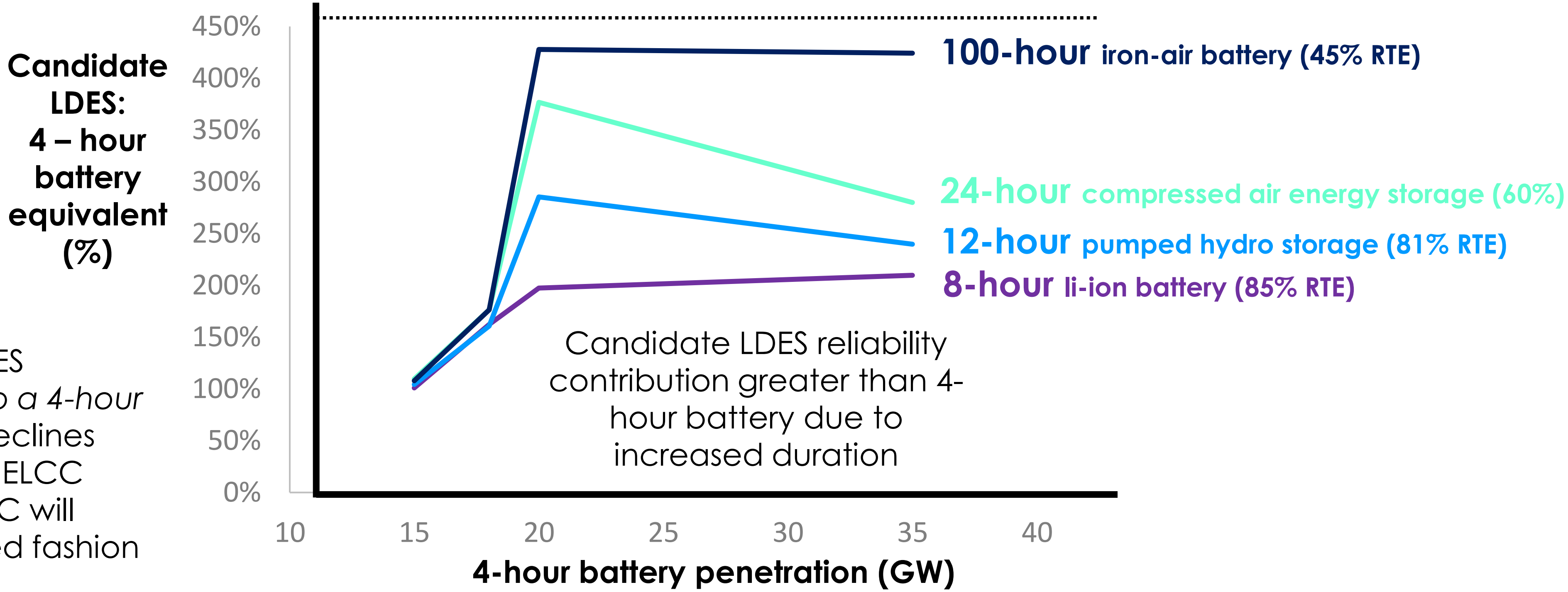
Minimal ELCC increase for longer duration

Longer duration results in large ELCC increase



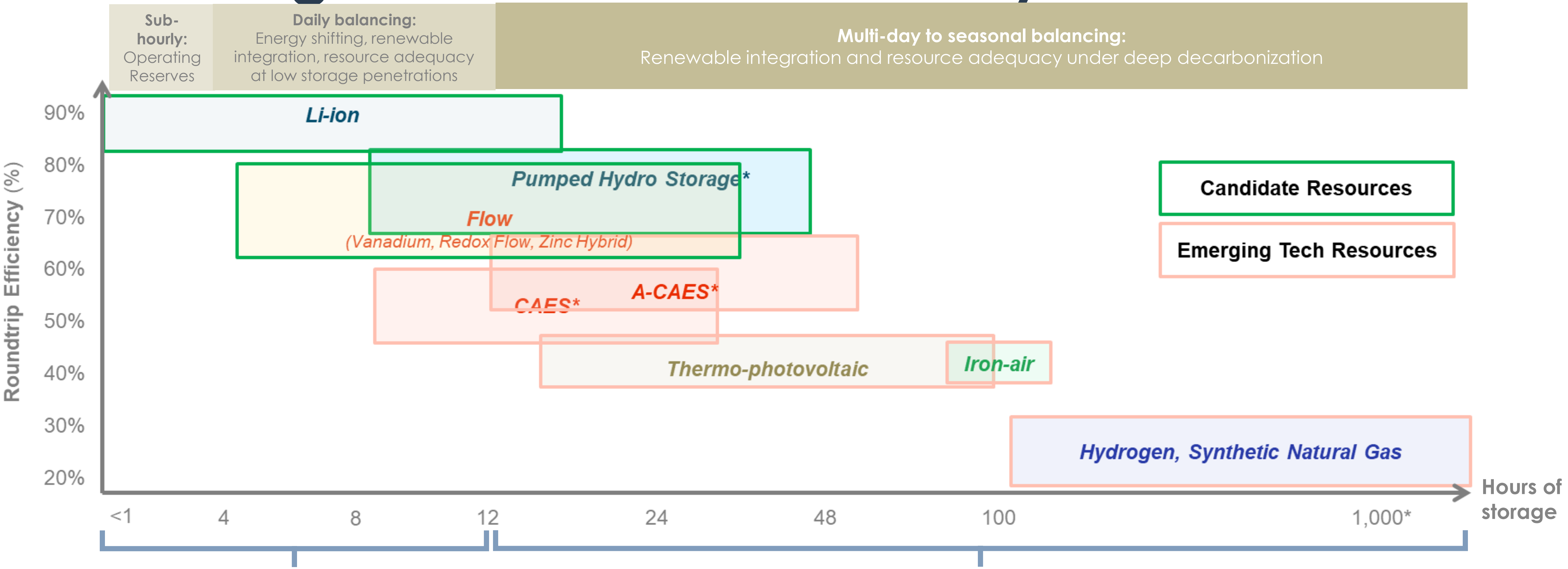
Long-duration Storage ELCCs

- Proposed approach for the 2023 PSP:
  - Candidate LDES modeled on the storage dimension of solar + storage ELCC surface with multiplier that represents the 4-hour storage equivalent for each duration / technology in each future year
    - Multiplier calculated via pairs of SERVM runs in which additional batteries are compared to additional LDES



Y-axis represents candidate LDES reliability contribution *relative to a 4-hour battery*. 4-hour battery ELCC declines with increasing penetration via ELCC surface so candidate LDES ELCC will decline similarly but in a delayed fashion

Consideration of new long-duration storage technologies in the 2022-23 IRP cycle



***Past CPUC IRP Models*: li-ion, flow, PHS**

Existing models like the 2019-2022 IRP cycle RESOLVE capture most of these operations

***Updated CPUC IRP Models*: all storage shown above**

Model updates planned as part of the 2022-23 CPUC IRP cycle will enable additional long-duration storage functionality (enabling modeling of multi-day or seasonal arbitrage, detailed modeling of hydrogen as a storage resource, consideration of ELCC reliability values)

Hydro ELCC

- 2021 PSP approach: Non-pumped hydroelectric facilities counted at their (Sept) NQC value from the CAISO NQC list
- 2023 proposed approach:
  - ELCC of the hydro portfolio (both small and large) calculated by SERVM
    - Portfolio ELCC = 3,872 MW
    - Portfolio ELCC distributed between small and large hydro based on their capacity-weighted NQC
  - Resultant values to be used in RESOLVE:
    - Large hydro = 60% ELCC, or 3,557 MW ELCC (includes Hoover dam imports)
    - Small hydro = 43% ELCC, or 315 MW ELCC
    - Large and small hydro aggregated into single resource with 58% ELCC in RESOLVE

Firm Resource ELCCs

1 Portfolio ELCC of all "firm" resources was calculated in SERVM

2 Firm resource portfolio ELCC allocated between resource classes using capacity-weighted forced outage rate (EFORd from SERVM analysis)

> Due to portfolio interactive effects, especially the dynamic that loss of load events happen more frequently during simultaneous outages, this results in a lower ELCC than the Unforced (UCAP) %

Resource Class	1-EFORd: Equivalent Forced Outage Rate demand (%)	UCAP =1-EFORd (% of nameplate)	>	ELCC for RESOLVE (% of nameplate)
Combined Cycle	5.5%	94.5%		88.3%
Combustion Turbine	6.2%	93.8%		87.0%
Reciprocating Engine	4.2%	95.8%		91.2%
Steam	7.2%	92.8%		84.8%
Nuclear	2.0%	98%		95.9%
Combined Heat and Power (CHP)	3.1%	96.9%		Equal to NQC
Biomass and Biogas	5.7% (biomass) 7.6% (biogas)	94.3% (biomass) 92.4% (biogas)		Equal to NQC
Geothermal	2.6%	97.4%		Equal to NQC

For CHP, biomass/gas, and geothermal resources, NQC MW accounts for availability derates and ELCC, so ELCC MW = NQC MW

Note: In SERVM, biomass and biogas are modeled as separate categories, while they are modeled together in RESOLVE

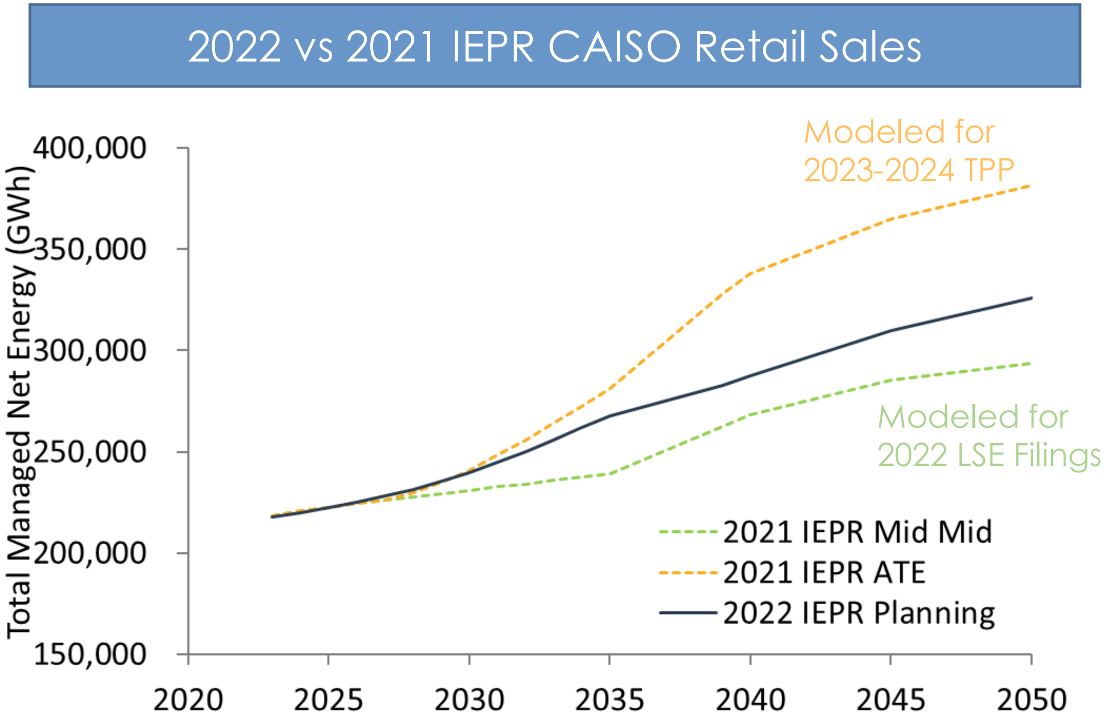
6. Loads

This IRP cycle will rely on 2022 IEPR Planning Scenario

- The PSP/TPP analysis in this current IRP cycle will use the CEC's 2022 Integrated Energy Policy Report (IEPR) Planning Scenario[1] for CAISO and non-CAISO California loads
  - The forecast is adopted through 2035
  - For some of the load modifiers, additional data were made available through 2050
- Higher electrification load scenarios could be used for sensitivity cases
- Behind-the-meter (BTM) generation data are also updated based on 2022 IEPR forecasts
- Gross system peak is calculated using hourly 2022 IEPR data
- Northwest and Southwest zones are expected to have a considerable load growth

[1] *2022 IEPR Load:* https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2

2022 IEPR Planning Scenario has more loads than 2021 IEPR Mid Mid and less loads than 2021 ATE

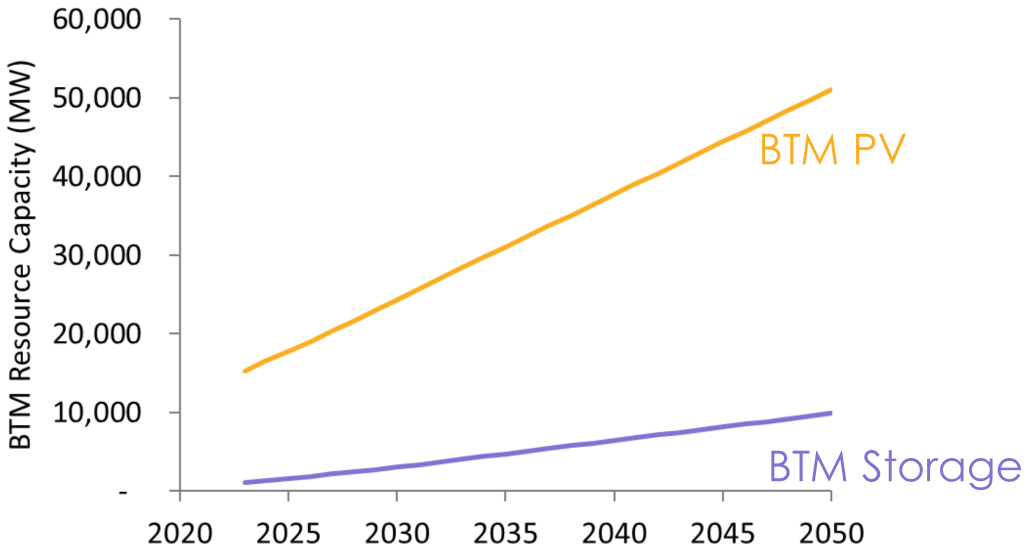


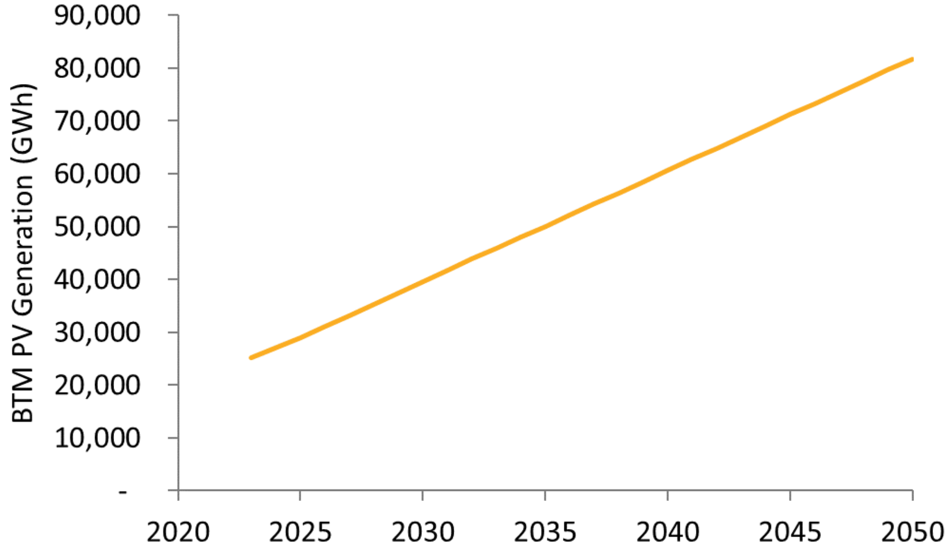
Load Component	2022 IEPR Planning Scenario
Baseline Demand	2023-2035: Mid 2036-2050: 2021 ATE
Transportation	2023-2050: Mid
Additional Achievable Energy Efficiency (AAEE)	2023-2050: Mid (scenario 3)
Additional Achievable Fuel Substitution (AAFS)	2023-2050: Mid (scenario 3)
Time-of-Use Impacts	2023-2035: 2022 IEPR Planning 2036-2050: flat at the 2035 level
BTM PV	2023-2035: 2022 IEPR 2036-2050: linearly extrapolated
BTM Batteries	2023-2035: 2022 IEPR 2036-2050: linearly extrapolated

Behind-the-meter (BTM) resources

- BTM PV and storage resources are forced into the model as planned resources with the forecasted adoption from IEPR
- BTM PV and storage have IEPR forecasts through 2035
  - For 2036-2050, the forecast is extrapolated linearly
- The 2022 IEPR has a single forecast for BTM PV adoption which will be used in this cycle of analysis
  - For sensitivity cases, lower or higher adoption rates might be used likely from 2021 IEPR forecasts.

BTM PV and Storage Capacity in 2022 IEPR



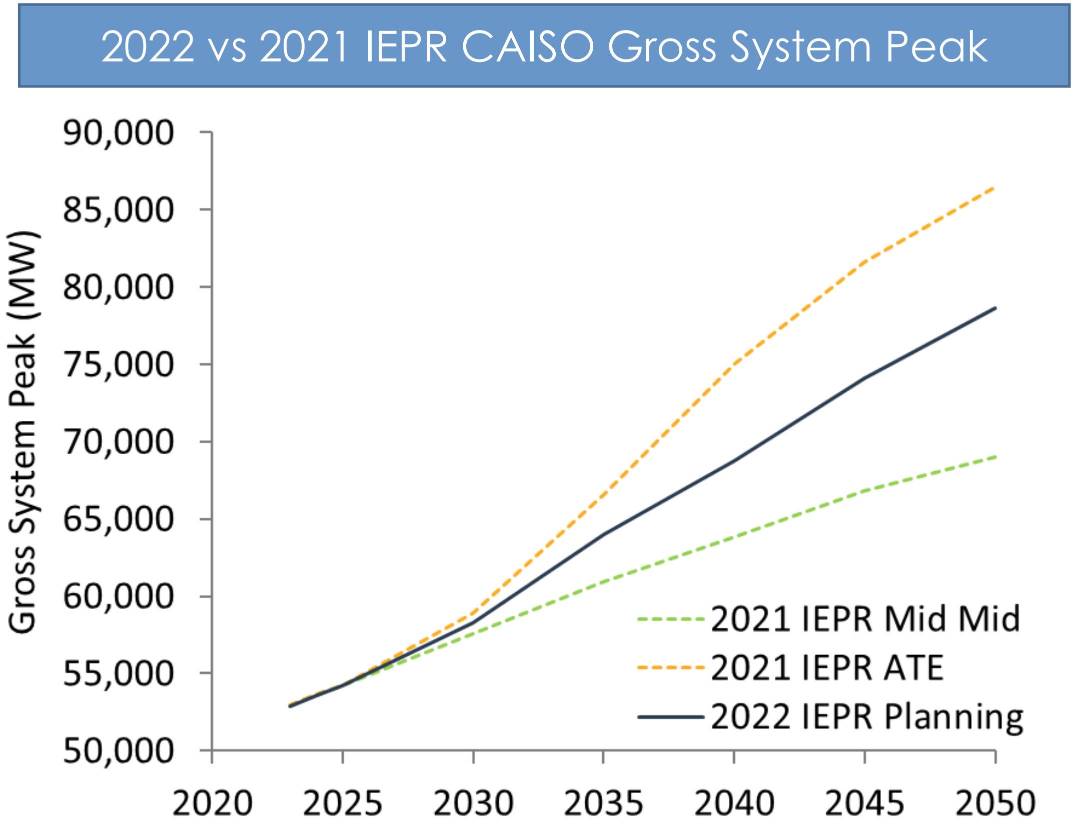


2022 IEPR CAISO Gross System Peak is higher than 2021 IEPR Mid Mid but much lower than 2021 ATE

- CAISO gross system peak is calculated for each year by finding the maximum of hourly load from the IEPR forecast as:

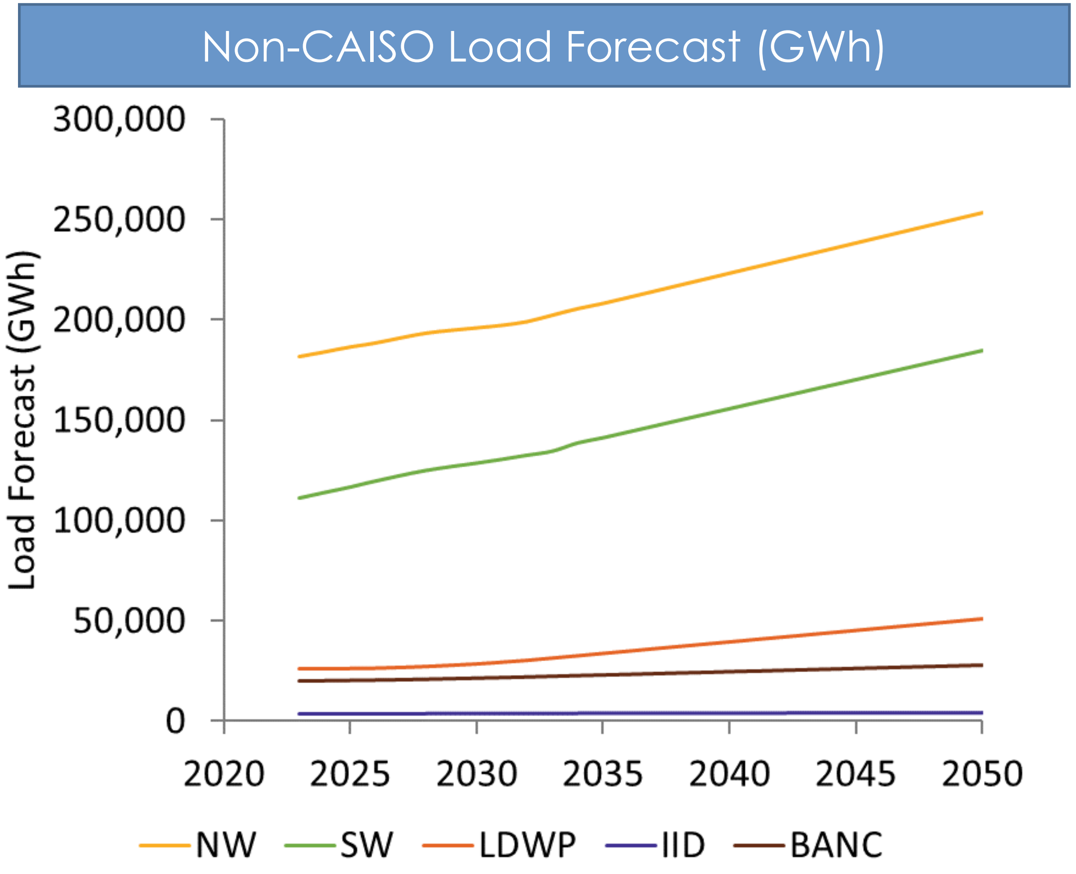
  Gross CAISO Load = Managed Net Load – BTM PV Generation

- BTM PV is modeled on the supply-side with an appropriate ELCC value
- BTM storage is treated as load modifier



Non-CAISO loads

- Non-CAISO California loads are from 2022 IEPR through 2035
  - From 2036 and beyond, the load is extrapolated linearly
- For non-CAISO non-CA zones, loads are taken from 2032 WECC Anchor Data Set (ADS) and extrapolated for future years



[1] From 2022 IEPR Form 1.5a: https://efiling.energy.ca.gov/GetDocument.aspx?tn=249499

7. Next steps

Next Steps

- Staff Invite stakeholders to submit written feedback on the draft 2023 I&A document by June 21, 2023
  - Submit your comments to IRPDataRequest@cpuc.ca.gov and use "2023 I&A" in the subject line
  - Stakeholders are encouraged to include the IRP service list as well.
  - Please categorize your comments based on sections and topics in the draft 2023 I&A document
  - Stakeholders should support their input with data and/or explanations. If referring to specific data, please provide the link(s) to those data
- Staff will review and incorporate input in the final 2023 I&A document
- Staff expects to release the final 2023 I&A document in late Q3 2023.

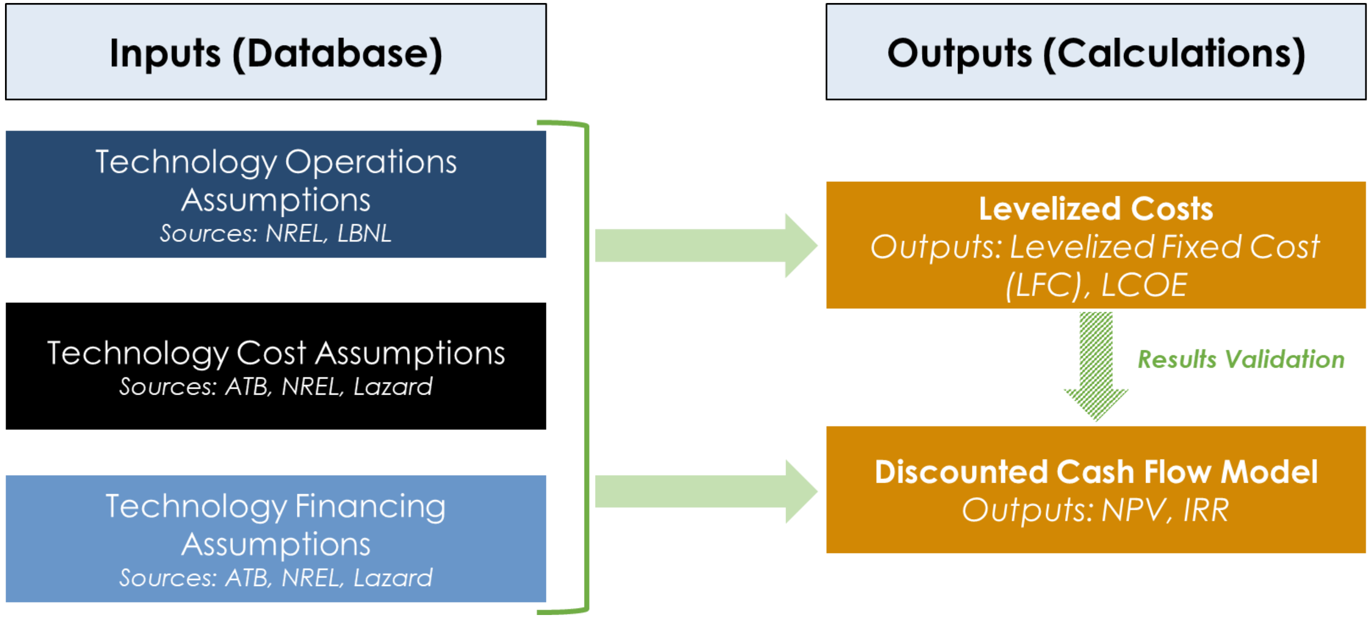
Appendix

Appendix A
Additional Resource Cost Information

Resource Cost Methodology

- Levelized fixed costs (RESOLVE inputs) are calculated in E3's pro forma financial model
  - E3's pro forma calculates levelized costs of energy ($/MWh) or capacity ($/kW-yr) under typical project financing structures, and validates these results using discounted cash flow analysis
- The pro forma model with California-specific assumptions is incorporated into the Resource Costs & Build workbook, which is published as part of the RESOLVE package
- The model and methodology are consistent with previous IRP analyses

E3's Pro Forma Model



**Note: Levelized costs for emerging technologies can be generated using the same pro forma model, with cost and performance data coming from various sources (combination of E3 analysis, and scientific and manufacturer literature, as documented in the Zero-Carbon Technology Assessment Report).*

More details: Inputs & Assumptions: 2019-2020 Integrated Resource Planning. February 27, 2020.

Terminology

- **Total ("all-in") levelized fixed costs**
  - Include overnight capital cost, construction financing costs, fixed O&M costs, and any capital-based tax credits[1]
  - Total levelized fixed costs are cost inputs into RESOLVE for candidate resources and impact resource build decisions
- **Levelized cost of energy (LCOE)**
  - LCOE is not a RESOLVE input or output but can be inferred from dispatch results
  - The LCOEs shown in this presentation are illustrative and are for generic technologies
    - The LCOE of individual resources may vary by factors such as resource location and resource availability (e.g., capacity factor)
    - The LCOE is calculated using the pre-curtailment potential production; RESOLVE can curtail wind and solar resources, potentially resulting in lower levels of renewable production than are reflected in the LCOE values[1]

[1] *Inputs & Assumptions: 2019-2020 Integrated Resource Planning. February 27, 2020.*

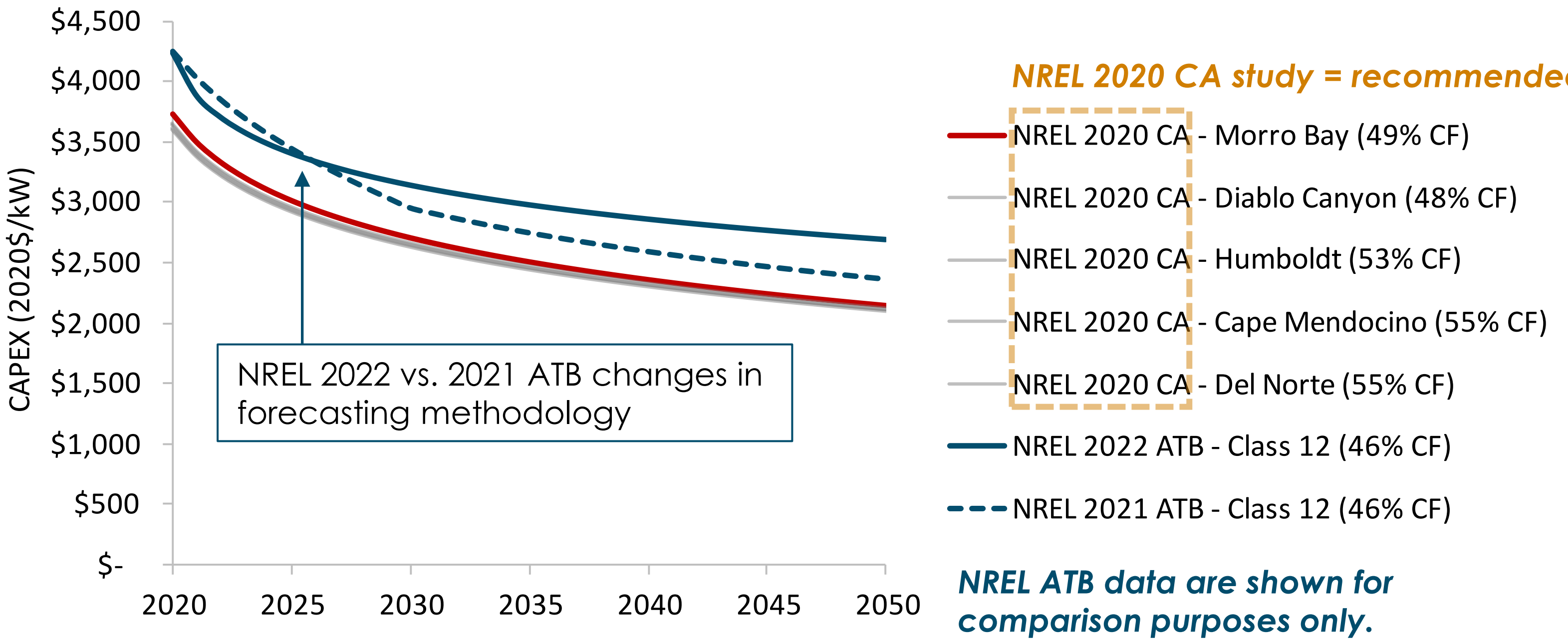
Summary of Data Sources

Technology	Data Source – 2023 I&A
Solar PV (utility-scale, distributed)	NREL **2022** ATB, with modifications
Land-Based (Onshore) Wind	NREL **2022** ATB, with modifications
Offshore Wind	NREL OCS Study BOEM 2020-048 (+ financing assumptions from NREL **2022** ATB)
Geothermal	NREL **2022** ATB
Small Hydro	NREL **2022** ATB
Biomass	NREL **2022** ATB
Gas (combined cycle, combustion turbine)	NREL **2022** ATB
Li-ion Battery	NREL **2022** ATB, with modifications
Flow Battery	Lazard LCOS **v4.0** (no updates)
Pumped Hydro Storage	NREL **2022** ATB

NREL ATB: https://atb.nrel.gov/electricity/2022/index
Lazard LCOS v4.0: https://www.lazard.com/media/sckbar5m/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

Offshore Wind Data Source

- **Recommendation:** Continue to use NREL 2020 CA offshore wind study (NREL OCS Study BOEM 2020-048) for offshore wind resource costs in RESOLVE, as this study is relatively recent and provides California-specific costs
  - Notably, ATB adopted new cost reduction methodologies in 2022 for plant upsizing and supply chain efficiencies that align with the NREL 2020 CA offshore wind study (2022 ATB)



NREL ATB data are shown for comparison purposes only.

Notes:

(a) Wind Resource Class 12 most closely represents the resource characteristics of mid-term deployment for floating technology in the NREL 2020 California study (see: 2022 ATB).

(b) Capex shown here excludes grid connection costs.

Gas Fixed O&M Costs

- In RESOLVE, fixed O&M costs can be used separately to inform investment decisions (new generators) and plant retirements (existing generators)
  - Currently, fixed O&M costs for both new and existing gas generators are based on NREL ATB, which are believed to be lower than values indicated by some asset owners
- The 2018 CEC report on Estimated Cost of New Generation[1] carries a higher estimate for fixed O&M than NREL ATB
  - Used in CPUC Gas Plant Risk of Retirement study[2]
  - These costs align with ongoing fixed O&M for the existing gas fleet based on other E3 analyses
- **Recommendation** for modeling:
  - Use **NREL 2022 ATB** fixed O&M for **new** gas generators (new investments)
  - Use **CEC** data for **existing** gas fleet (retirement decisions)

Fixed O&M, 2020 $/kW-yr	NREL 2022 ATB	CEC 2018 Report
Combustion Turbine	$ 21.00	$ 34.26
Combined Cycle	$ 28.00	$ 43.05
	New Gas Generators	Existing Gas Generators

[1] Estimated Cost of New Generation, *CEC* (2018), energy.ca.gov
[2] Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning, *CPUC* (2021), cpuc.ca.gov

Appendix B
Inflation Reduction Act Supplemental Data

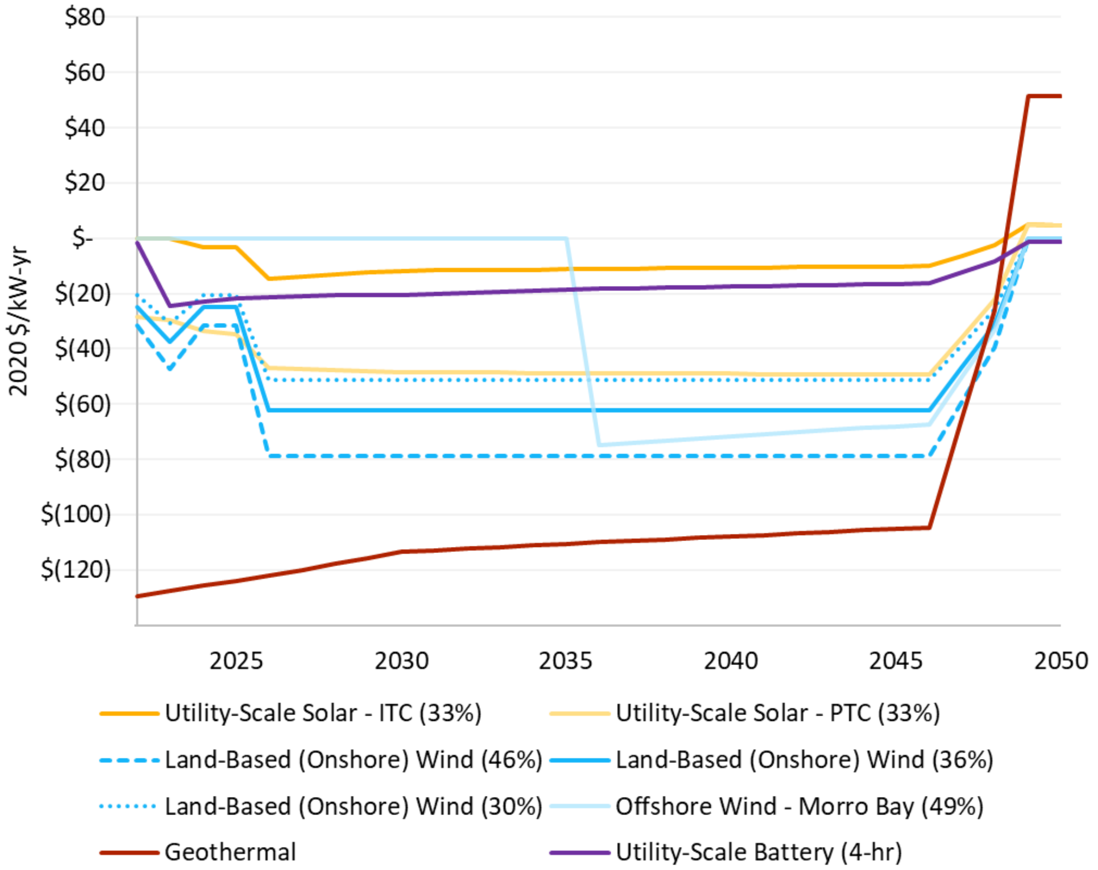
Highlights of Inflation Reduction Act (IRA)

- Extends tax credits for renewables until the **early 2030s at a minimum**
- **Production tax credits (PTC)** applied to a broad range of technologies including **solar**
- Credit can be higher depending on location and whether it uses domestic content
  - Only applicable for projects placed in service or sold in 2023 or later
- **New credits** for **standalone storage**, **clean hydrogen**, **small modular nuclear reactors** among other technologies and various end-use measures
- PTCs for renewables can be **stacked with storage and fuels production**
- **Higher credits** for **carbon capture and storage (CCS)** including new credit for direct air capture (DAC)
- These all come with conditions
  - Higher IRA incentives have prevailing wage and qualified apprentice requirements
  - Given the resulting increase in incentives, we believe most project developers will strive to meet requirements to be able to be cost-competitive

IRA Impacts on Levelized Fixed Costs

- Relative ($/kW-yr) impact on levelized fixed cost due to the IRA
- Assumes "**Bonus**" incentive level for meeting prevailing wage and apprenticeship guidelines
- IRA tax credits end date is subject to **assumption** of IRA emissions reduction target year
- Impacts on LCOE and sensitivities on different IRA tax credit options can be found in Appendix B

Total Levelized Fixed Cost Change due to IRA

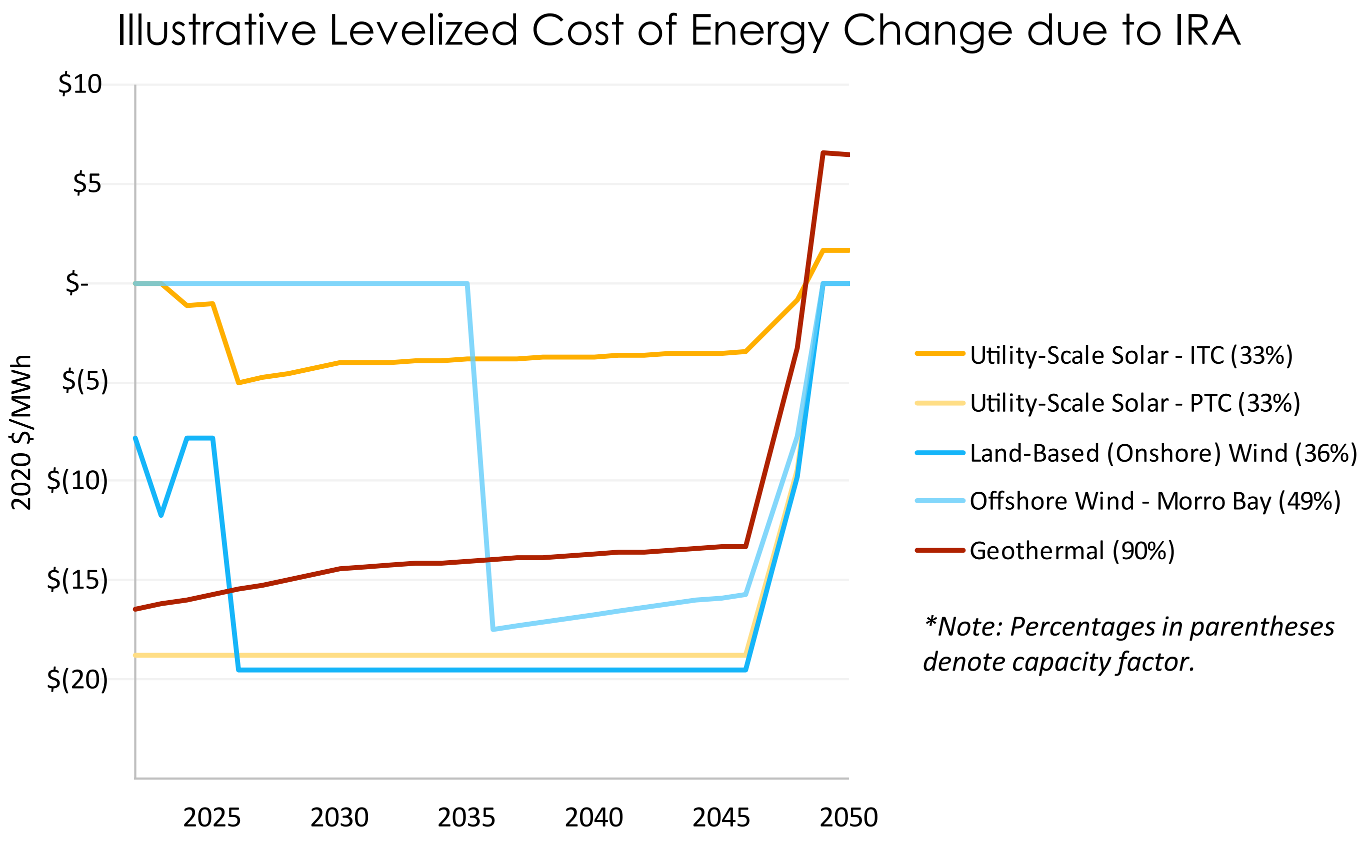


**Note: Percentages in parentheses denote capacity factor.*

*Note: Assumes carbon emissions reduction targets are met in **2045** (75% reduction below 2022 levels for power sector per IRA), followed by a 3-year incentive step-down.*

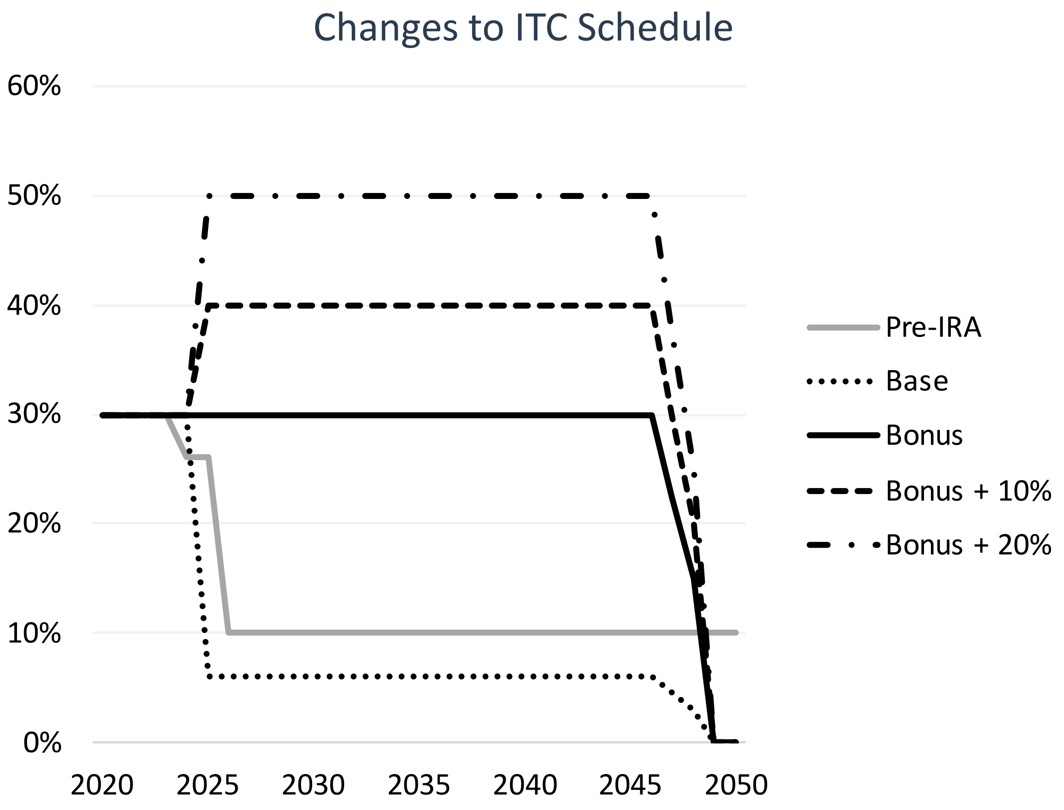
Inflation Reduction Act Impacts on Levelized Cost of Electricity (LCOE)

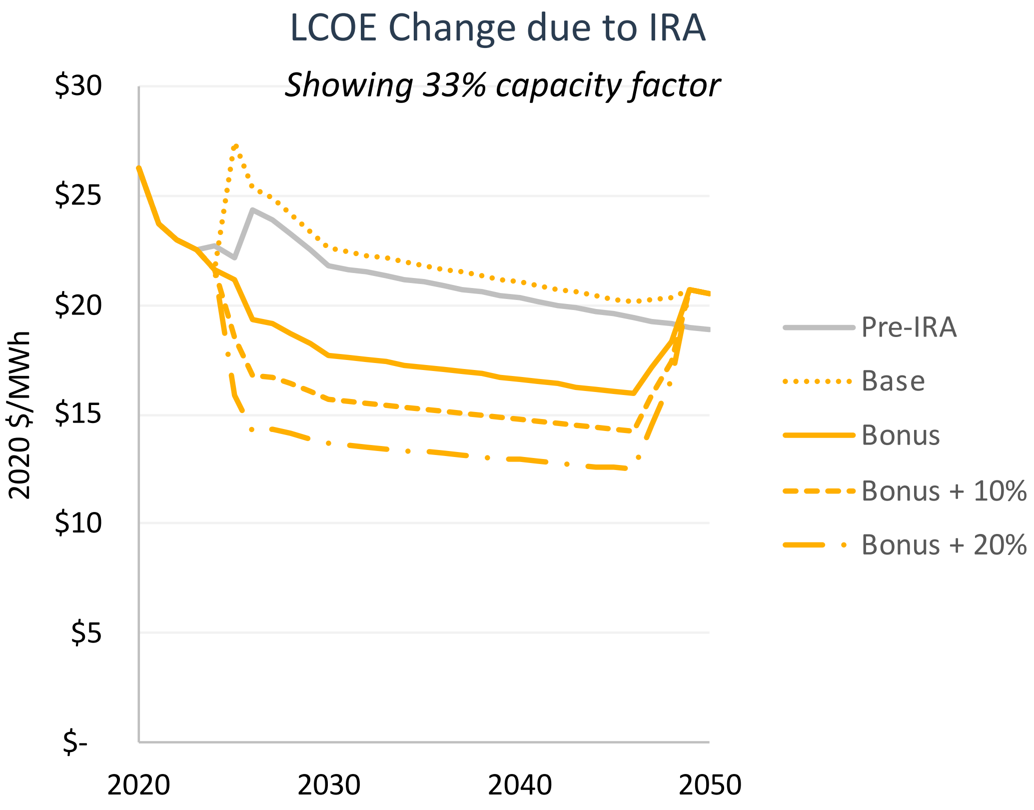
- Relative ($/MWh) impact on LCOE due to the IRA
- Assumes "**Bonus**" incentive level for meeting prevailing wage and apprenticeship rules
- IRA tax credits end date is subject to **assumption** of IRA emissions reduction target year



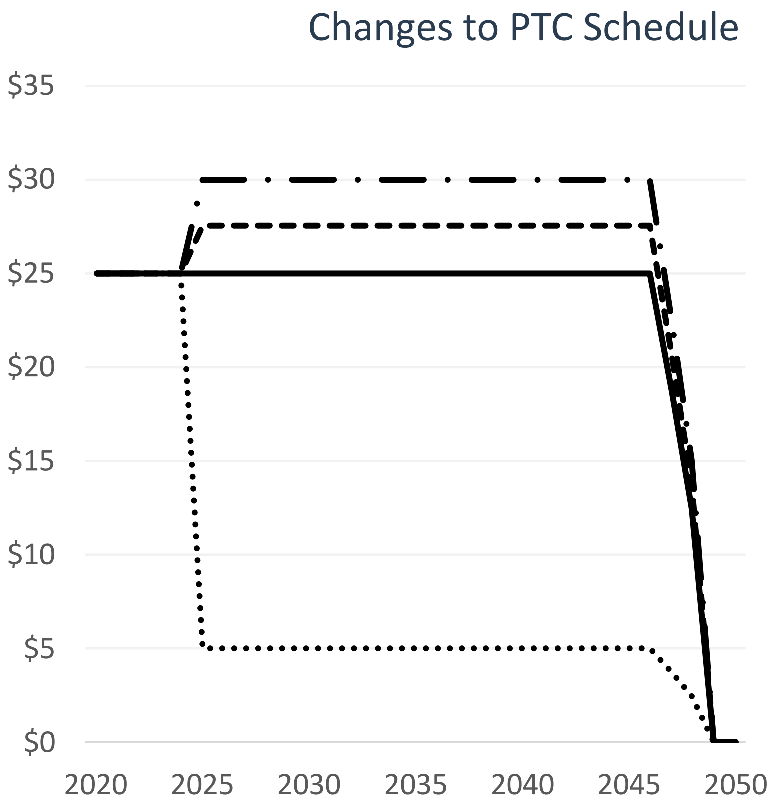
*Note: Assumes carbon emissions reduction targets are met in **2045** (75% reduction below 2022 levels for power sector per IRA), followed by a 3-year incentive step-down.*

IRA Impact on LCOE – Solar ITC

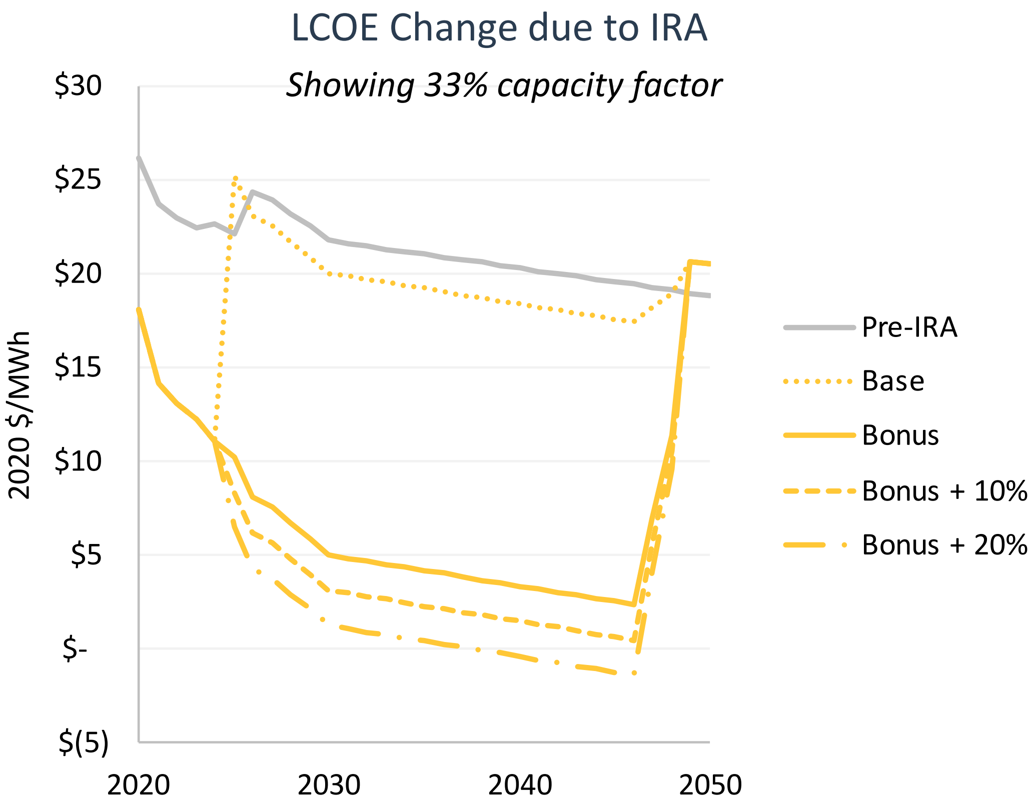




IRA Impact on LCOE – Solar PTC

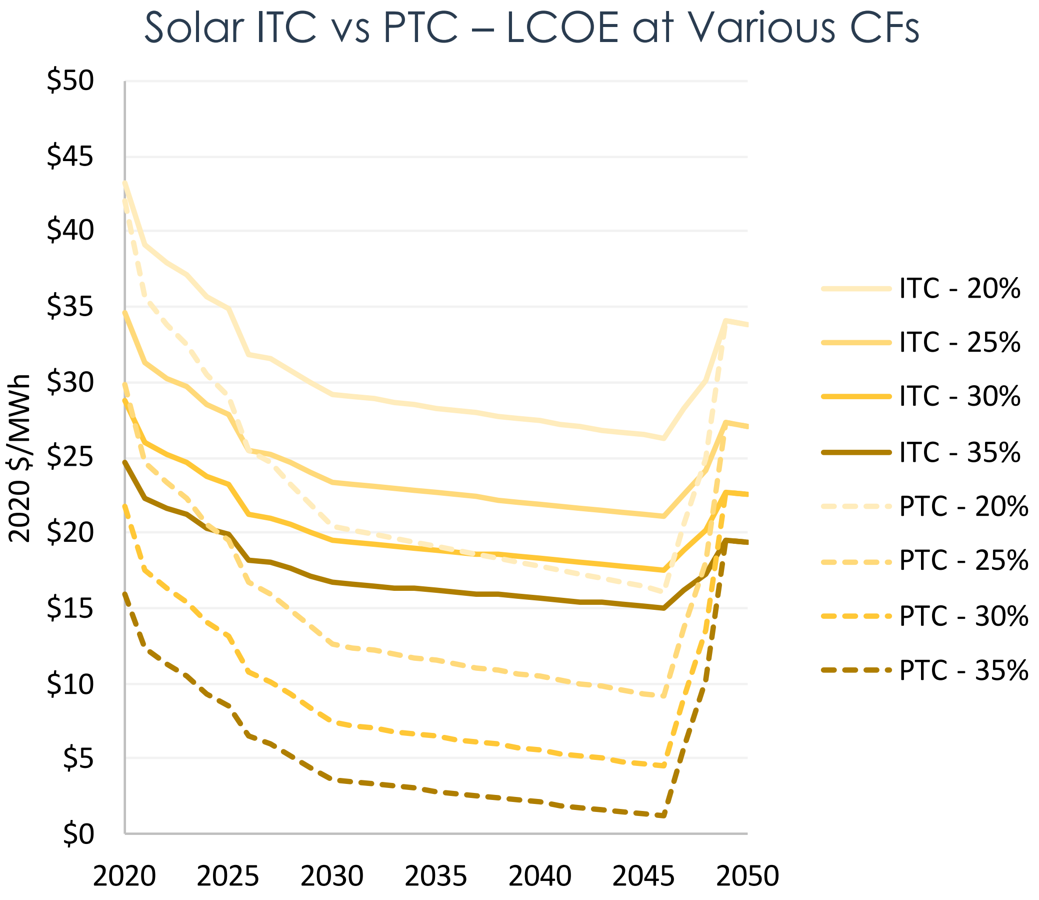


Note: Solar does not have access to PTC pre-IRA.

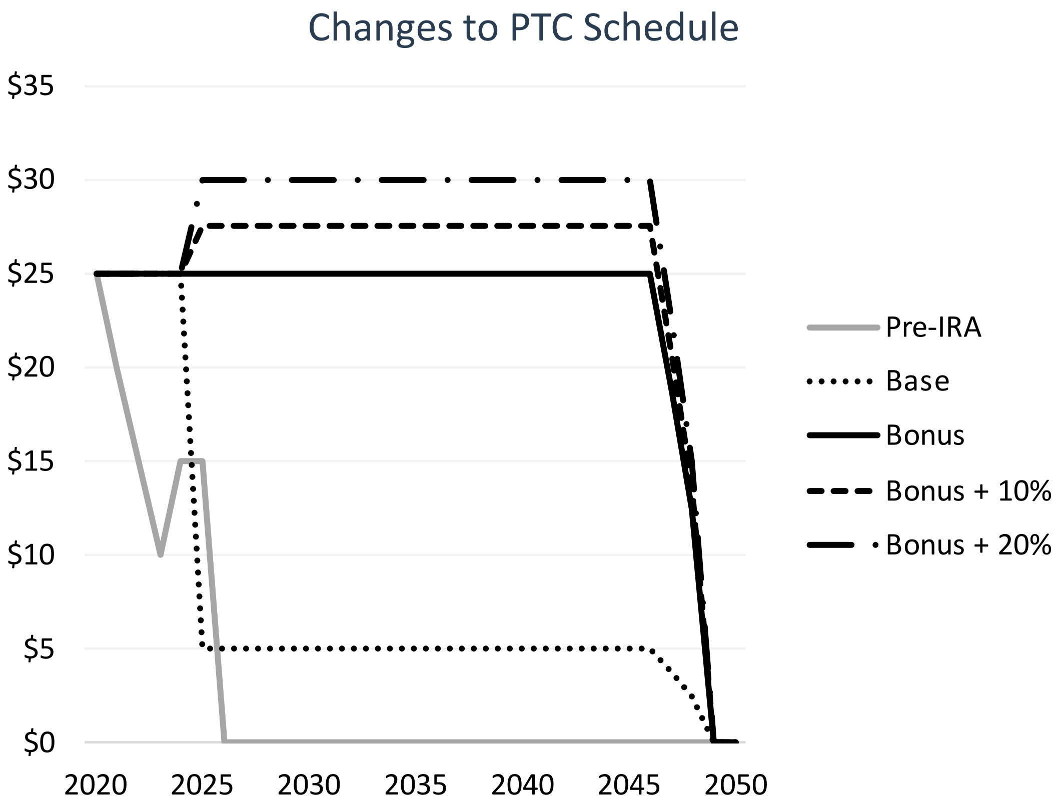


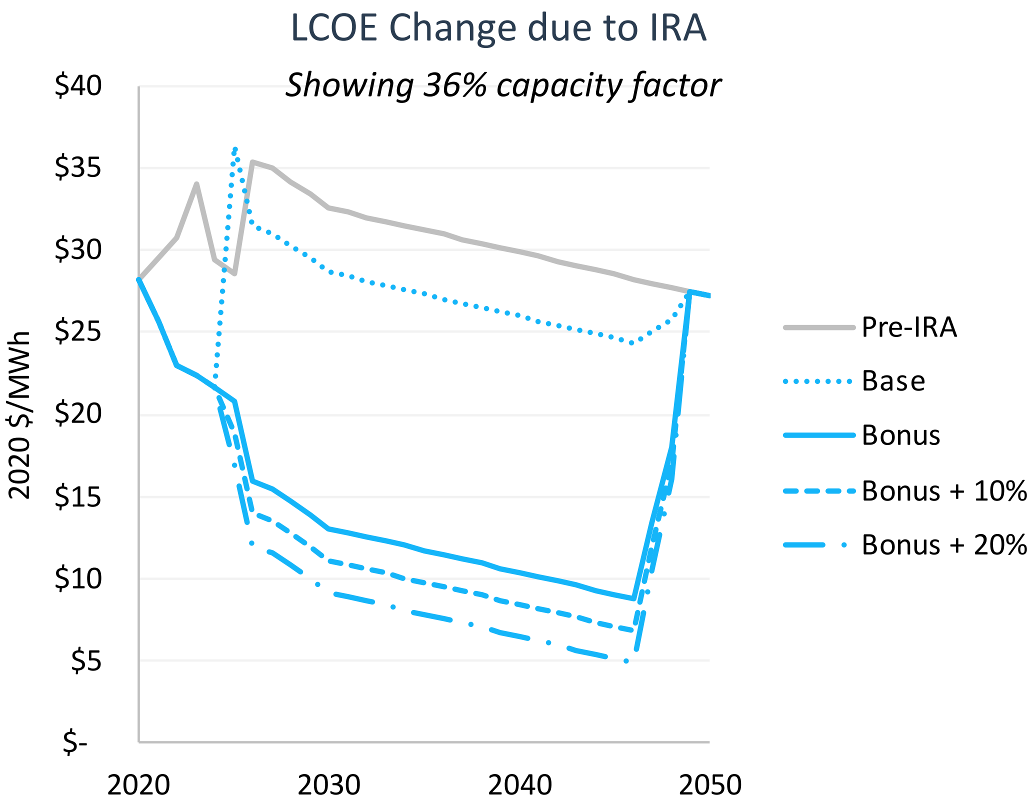
IRA Impact on LCOE – Solar ITC vs PTC

- Under the IRA, solar has the option to select either investment tax credits (ITC) or production tax credits (PTC)
- The decision to choose ITC vs PTC is primarily a function of vintage year, capacity factor (CF), and Capex
- Using NREL 2022 ATB Capex assumptions, PTC is found to outperform ITC across a wide range of CFs

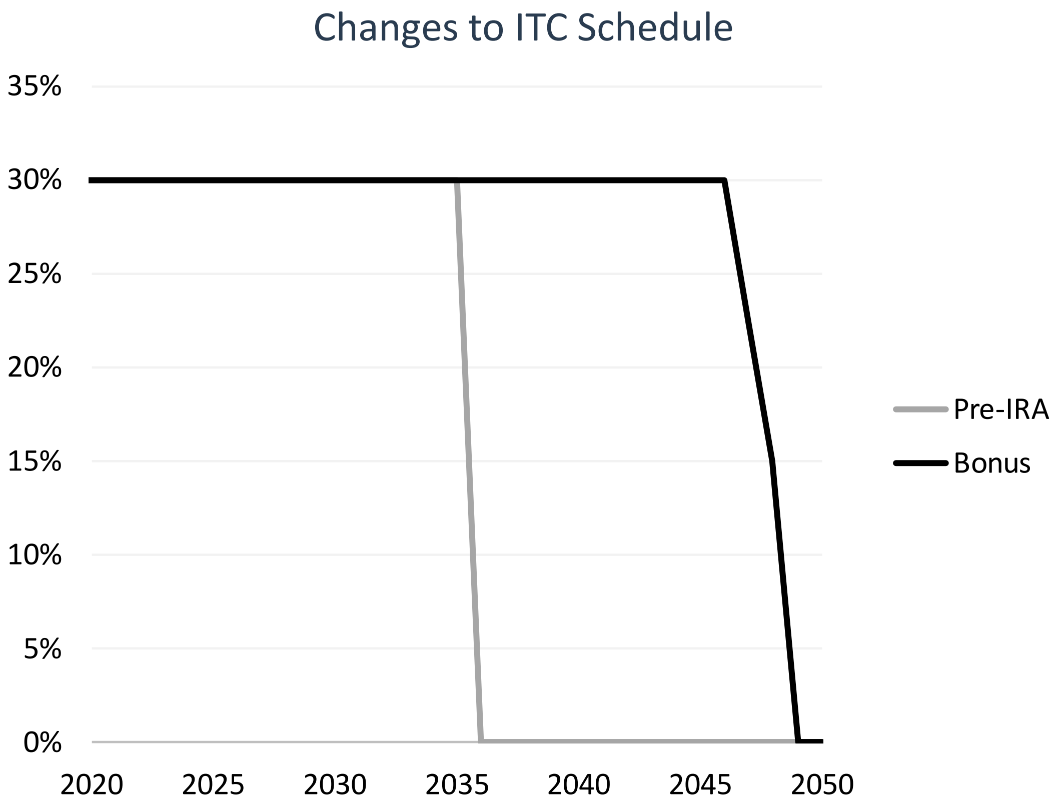


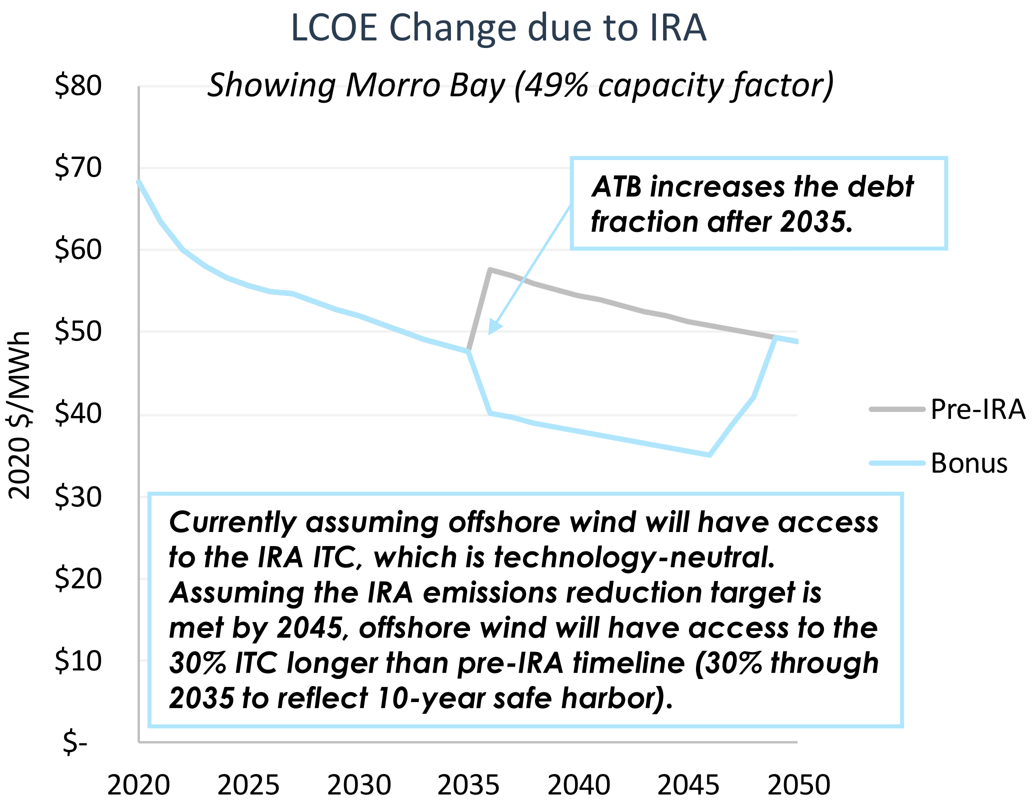
IRA Impact on LCOE – Onshore Wind





IRA Impact on LCOE – Offshore Wind



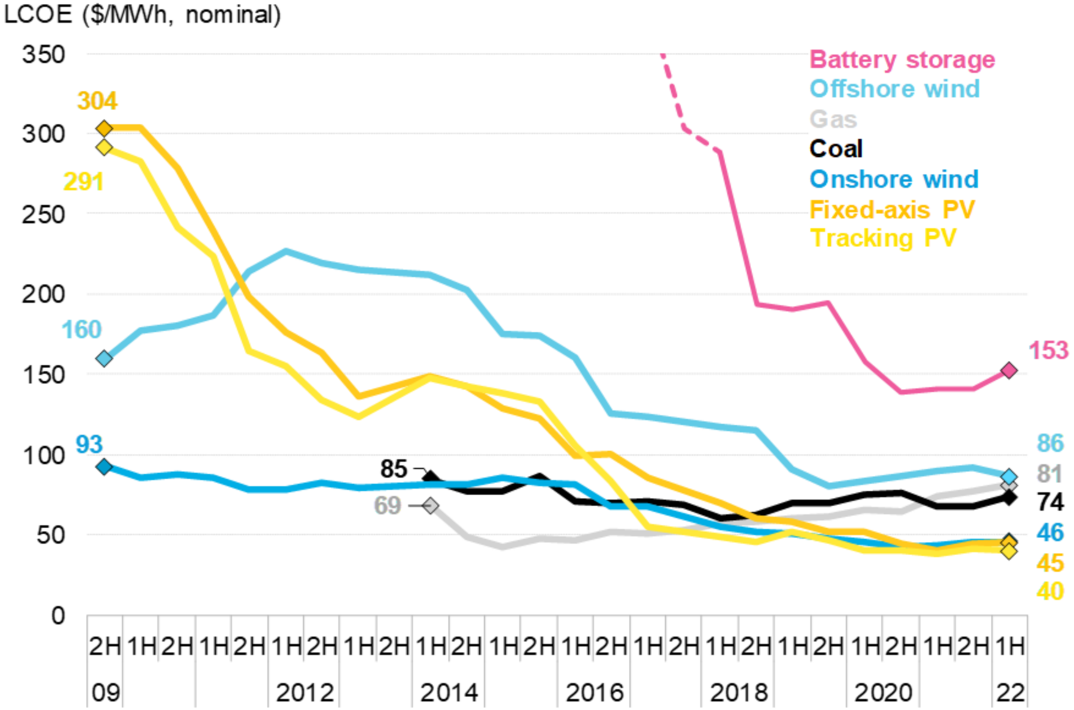


Appendix C
Modifications to Candidate Solar, Wind, and Li-ion Battery Resource Costs

Wind, Solar, and Battery Storage

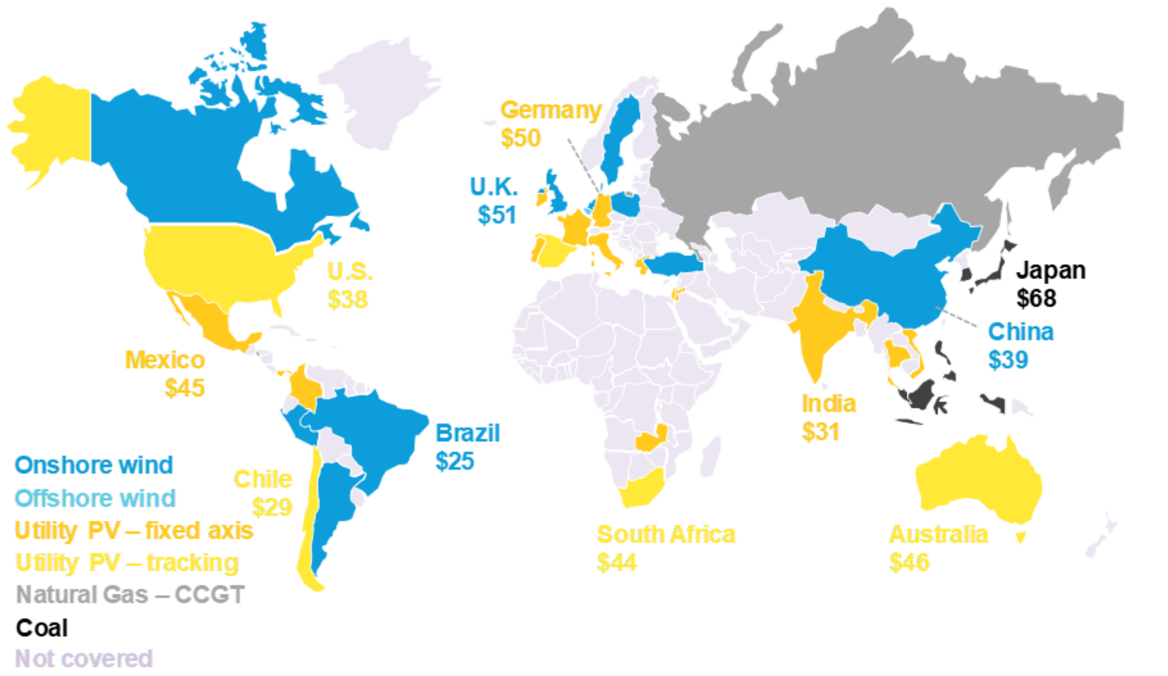
Levelized Cost of Electricity Estimates

LCOE Estimates by Technology, BNEF



Source: BloombergNEF. Note: The global benchmark for PV, wind and storage is a country-weighted average using the latest annual capacity additions. The storage LCOE is reflective of a utility-scale Li-ion battery storage system with four-hour duration running at a daily cycle and includes charging costs.

LCOE Estimates by Country, BNEF

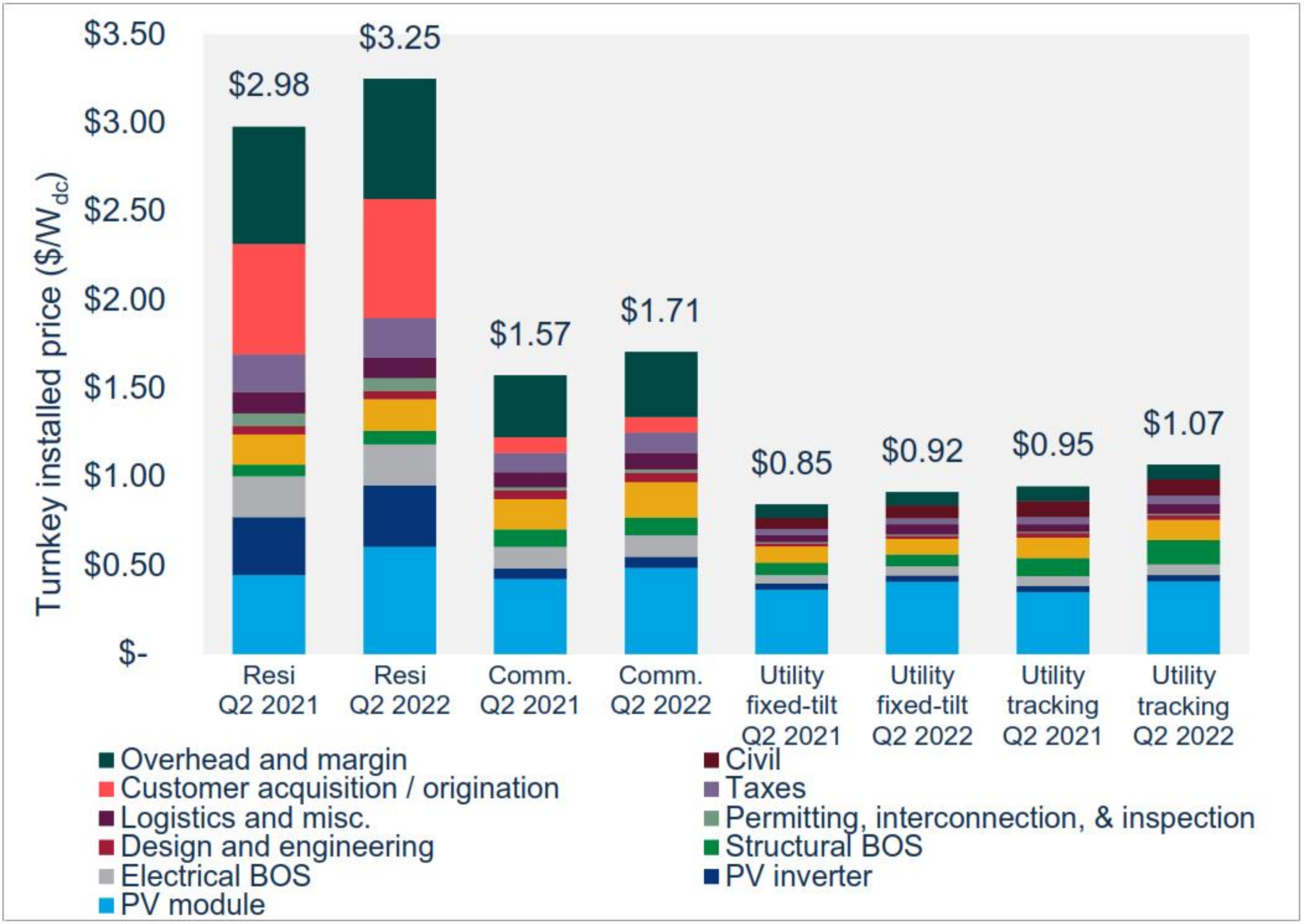


Source: BloombergNEF. Note: The map shows the technology with the lowest LCOE for new-build plants in each country where BNEF has data. The dollar numbers denote the per-MWh benchmark levelized cost of the cheapest technology. All LCOEs are in nominal terms. Calculations exclude subsidies, tax-credit or grid connection costs. CCGT is combined-cycle gas turbine.

Bloomberg New Energy Finance (https://about.bnef.com/blog/cost-of-new-renewables-temporarily-rises-as-inflation-starts-to-bite/)

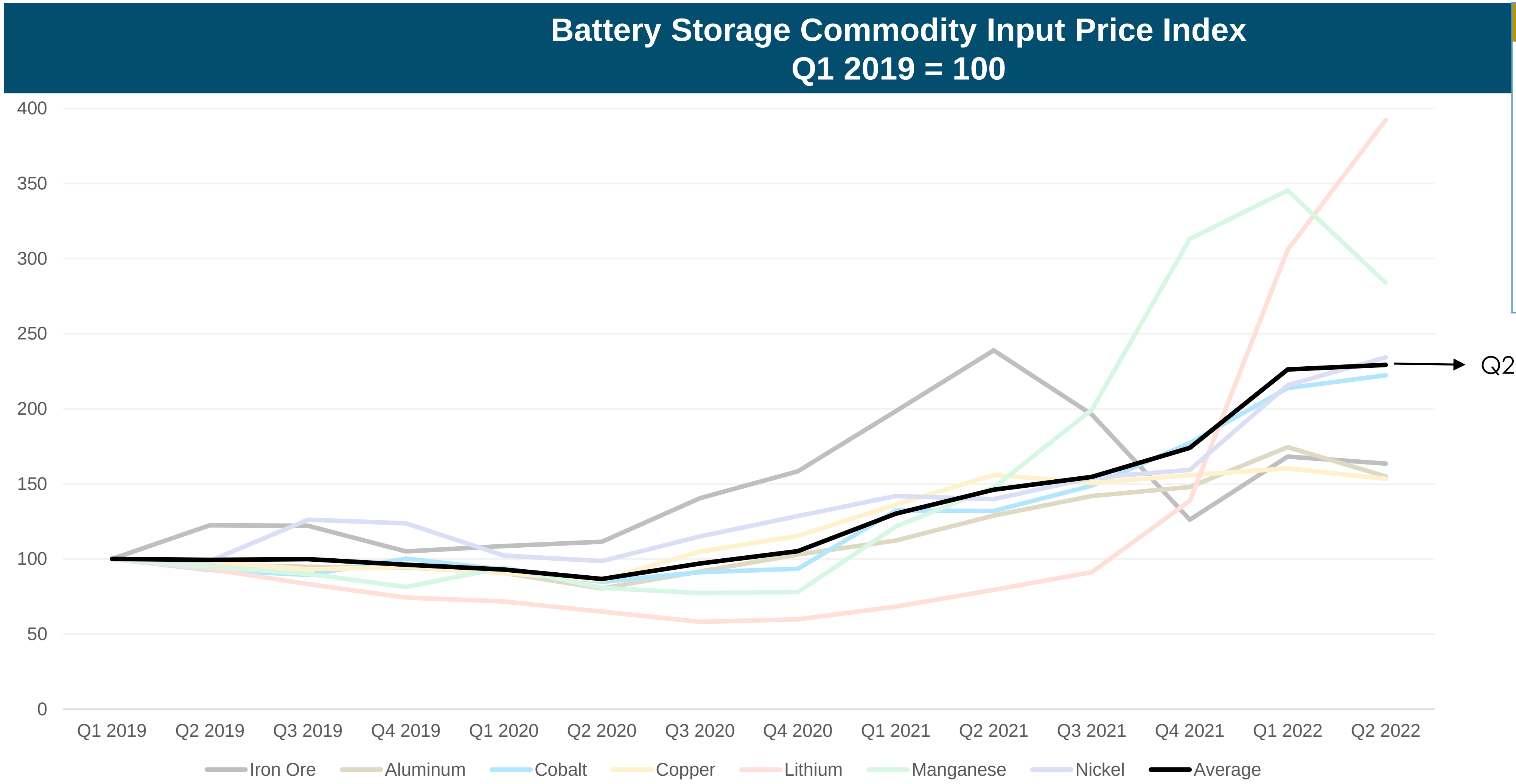
Utility-Scale Solar PV
Upfront Capex Adjustments

U.S. National Average System Prices by Market Segment, Q2 2021 and Q2 2022



Source: Wood Mackenzie

Battery Storage
Commodity Prices



Q2 2022	Price ($/MT)
Lithium	$462,298
Cobalt	$77,190
Nickel	$29,080
Copper	$9,546
Manganese	$5,886
Aluminum	$2,887
Iron Ore	$136

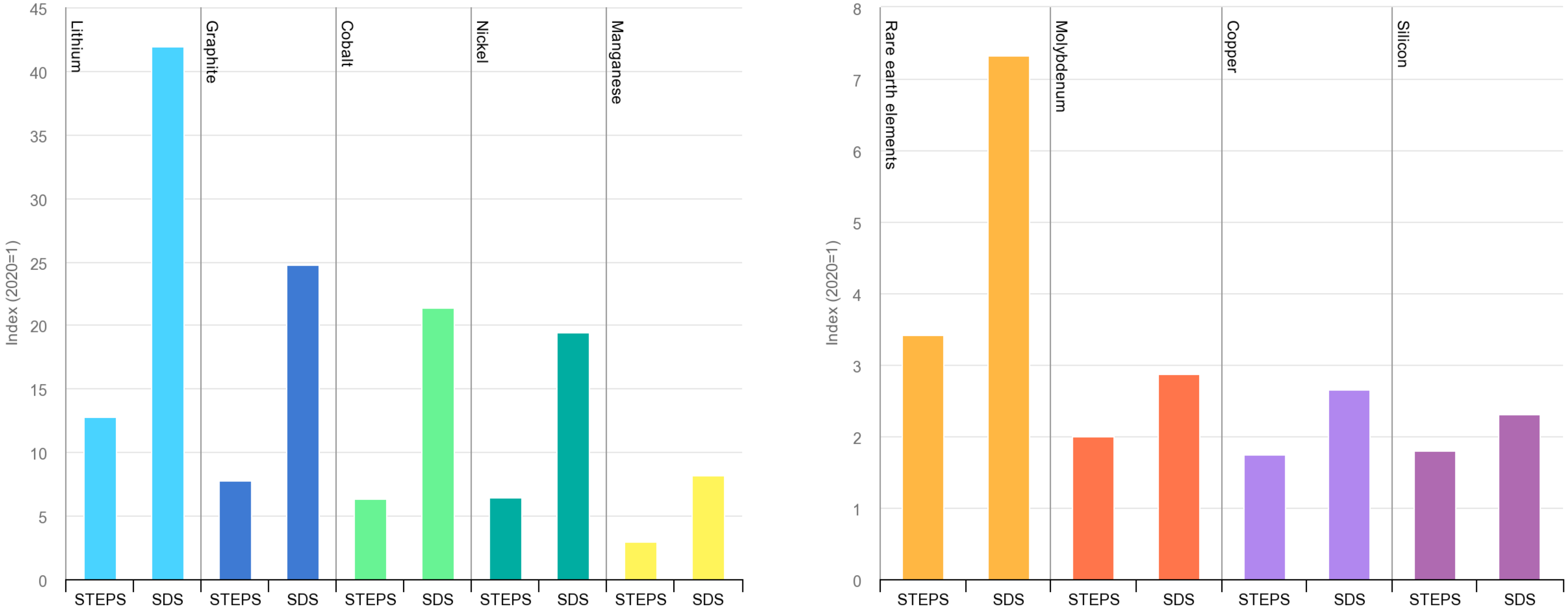
Q2 2022 = **2.3x** Q1 2019

IMF Quarterly Data as of 9/7/2022 (https://data.imf.org/?sk=471DDDF8-D8A7-499A-81BA-5B332C01F8B9&sId=1390030341854).

Battery Storage

Demand Drivers of Battery Costs

Growth in Demand for Selected Minerals from Clean Energy Technologies in 2040 Relative to 2020 Levels



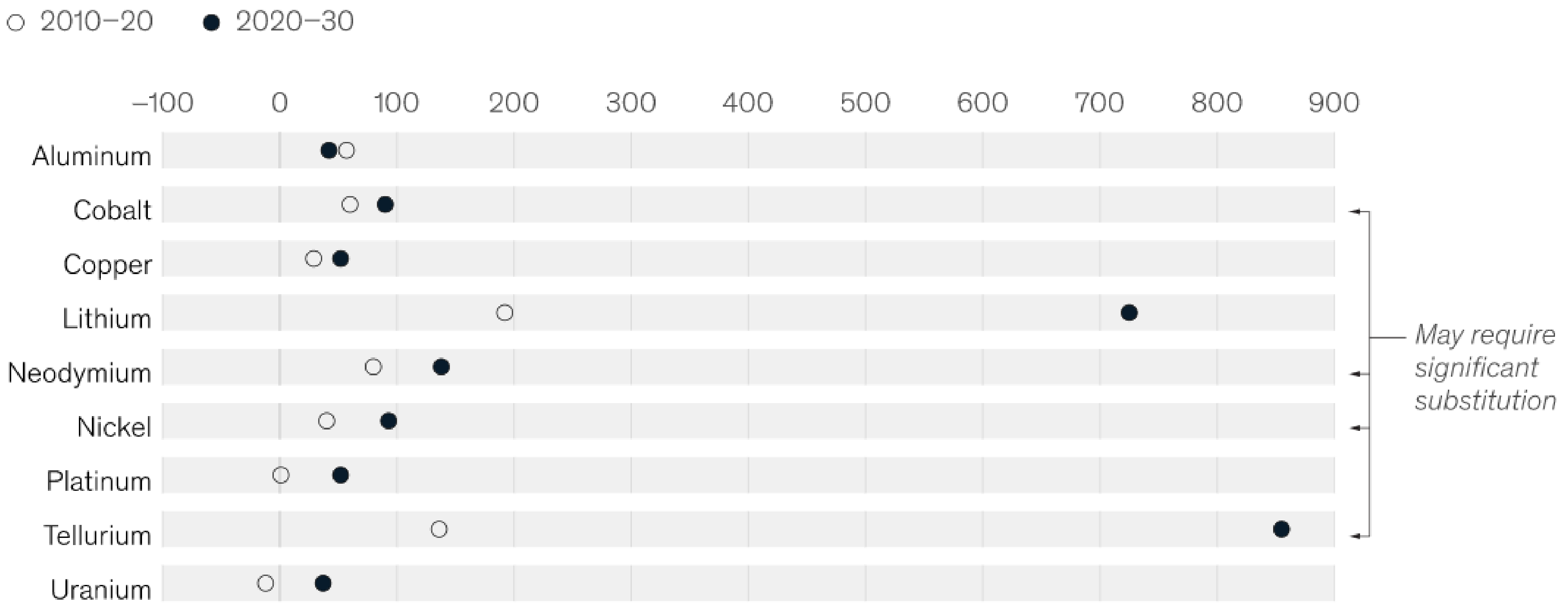
Note: STEPS refers to the "Stated Policies Scenario" and SDS refers to the "Sustainable Development Scenario"

Source: International Energy Agency (https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions/mineral-requirements-for-clean-energy-transitions).

Battery Storage

Medium-Term Demand for Battery Storage Inputs

Supply Change, 2010 – 2020 Versus Required Growth in 2020 – 2030 in 1.5C Degree Pathway



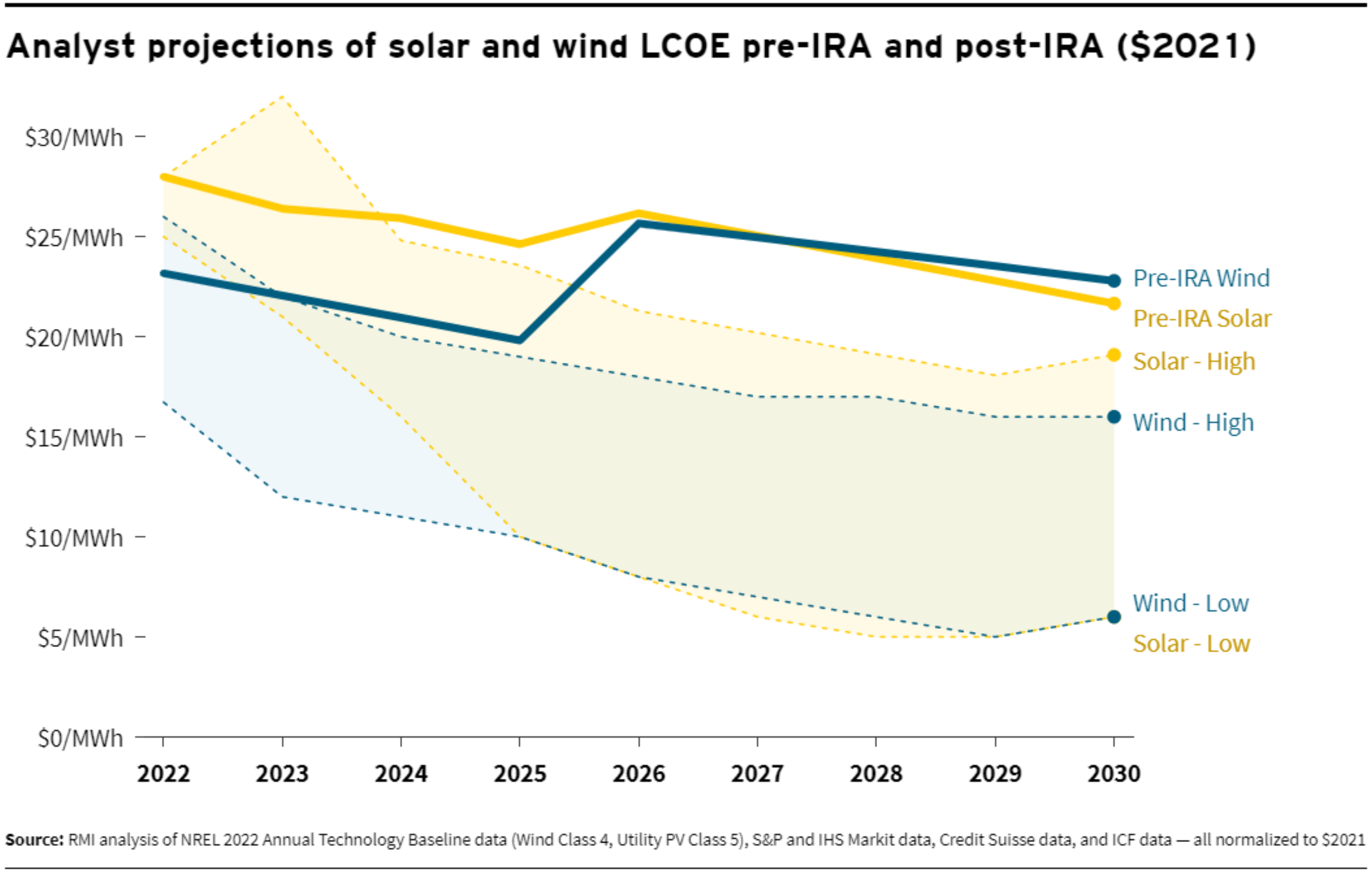
[1]One of the many possible scenarios used to illustrate the impact on raw-materials demand. Demand also includes other applications for each material.
Source: *Critical raw materials for strategic technologies and sectors in the EU*, A foresight study, European Commission, Mar 9, 2020; US Geological Survey; World Nuclear Association; MineSpans by McKinsey; McKinsey analysis

McKinsey & Company

Source: McKinsey (https://www.mckinsey.com/industries/metals-and-mining/our-insights/the-raw-materials-challenge-how-the-metals-and-mining-sector-will-be-at-the-core-of-enabling-the-energy-transition).

LCOE Estimates

Rocky Mountain Institute (RMI) Estimates of LCOE



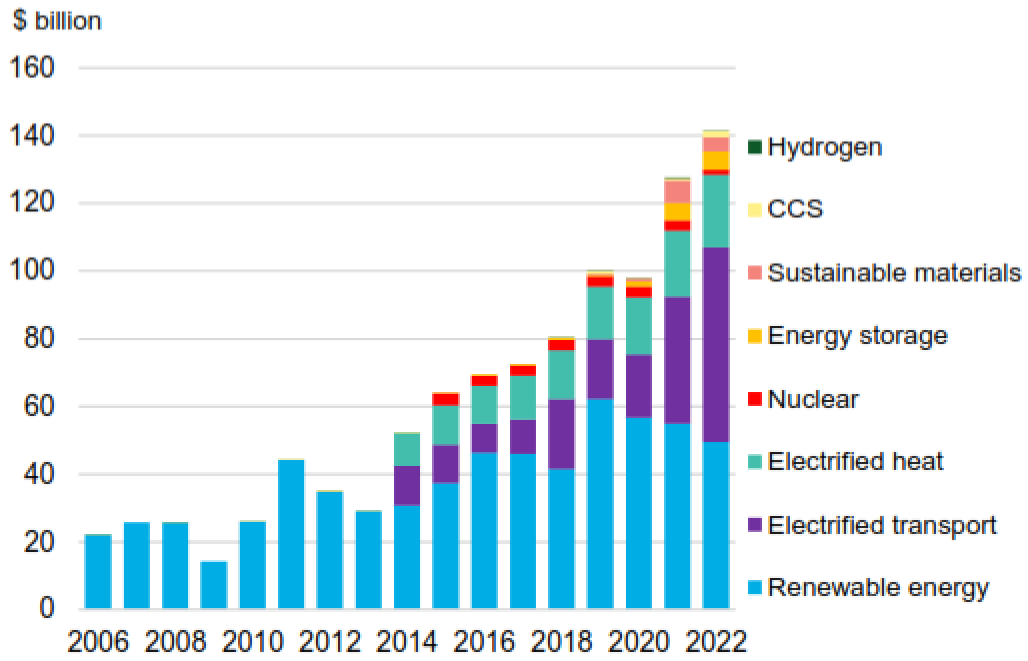
Source: RMI (https://rmi.org/business-case-for-new-gas-is-shrinking/?utm_medium=email&utm_source=spark&utm_content=spark-a&utm_campaign=2022_12_08&utm_term=button).

Key Trends

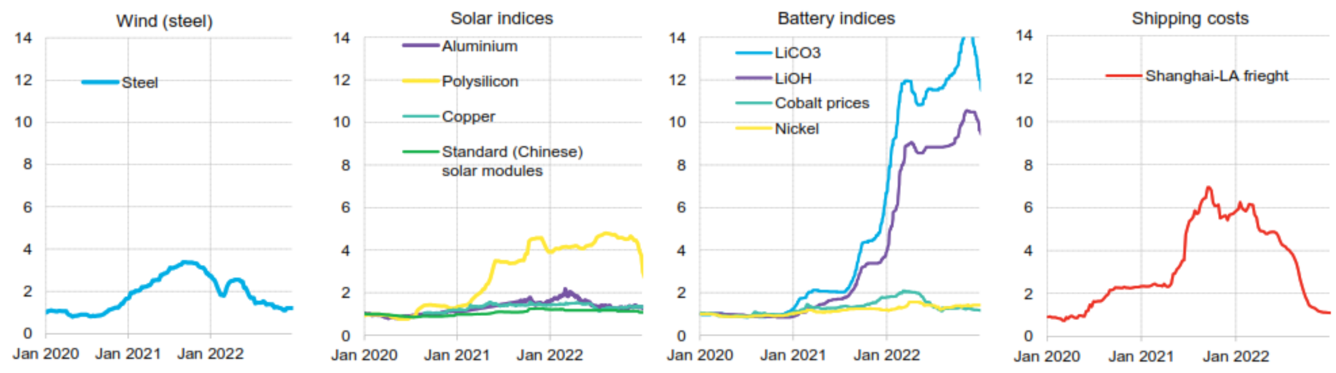
Energy Transition Investment

- Energy transition investment is a broad term, but historically has been dominated by renewable energy with electrified transport ramping up significantly in the last 3 years
- Energy storage and emerging opportunities in hydrogen and CCS may be on the horizon, pace/scale of investments will continue to be influenced by underlying commodity/shipping costs

US energy transition investment, by sector



Price movements since January 2020



Appendix D
Additional Information on Emerging Technologies

Summary of Operational Parameters

- CCGTs + >99% CCS are found to have slightly lower efficiency than Allam Cycle + CCS
- Round-trip efficiency of storage technologies tends to decline with the duration of storage

Category	Tech.	Efficiency (One-Way or RTE, HHV)	Ramp Rate Limit	Operational Lifetime
Generation	CCGT + >99% CCS	~ 30% - 45% (One-way)	Modeling suggests CCS has minimal impact on ramping	Equivalent to plant without CCS
	Allam Cycle CCS	~40-50% (One-way)	Unknown	30 years
	SMR	30% (One-way)	Unknown	30-80 years
	EGS	10-22% (One-way)	Unknown	30-80 years
Storage	Hydrogen	H_2: 70-80% (One-way), 25-45% (RTE in CT/ CCGT)	Electrolyzer: 100%/Min.	20 years for electrolyzer
	SNG	SNG: 40-50% (One-way), 15-25% (RTE in CT/CCGT)	Electrolyzer: 100%/Minute. DAC and Sabatier reaction flexibility unknown	20 years for electrolyzer; 20-40 years for DAC and Sabatier reactor
	A-CAES	60% (RTE)	Unknown	30-50 years
	Iron Air Battery	45-50% (RTE)	Unknown	Unknown

RTE = round-trip efficiency; HHV = higher heating value

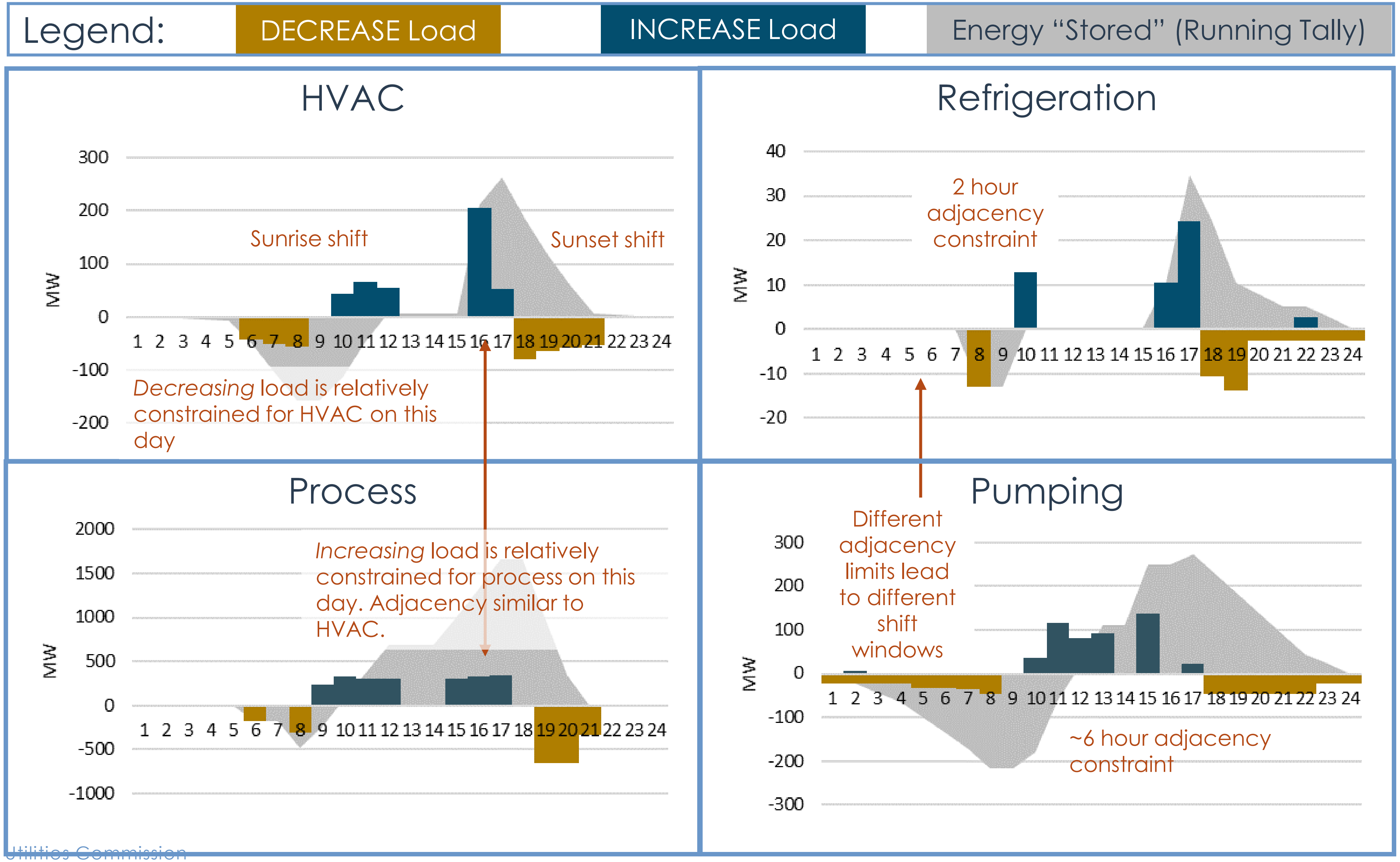
Appendix E
Shift DR and Shed DR

Technologies Included in Shed DR and Shift DR Supply Curves

- LBNL's Shed DR supply curve and Shift DR supply curve represent potential from each of these sectors and technologies
- Light Duty EV potential is removed from the Shed and Shift DR resources and included in the VGI workstream

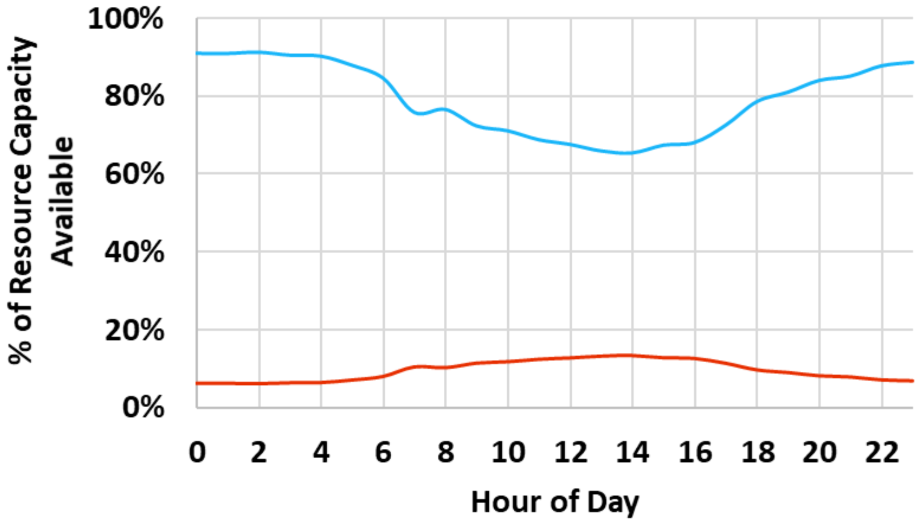
Commercial	Residential	Industrial
Space cooling	Pool pumps	Industrial heat
Space heating	Space cooling	Process
HVAC fans	Space heating	Industrial cooling
Water heating	Appliances	Industrial Pumping
Refrigeration	Water heating	Agricultural Pumping
Lighting	Refrigeration	
IT equipment	Lighting	
Office Equipment	Electronics	
	Spa heater	

Example Shift Hourly Results



Hourly Shift Up and Down limits

- Unique limit on each hour of each RESOLVE dispatch day
- Shift Up limits represent maximum "headroom" on loads, for example the number of "plugged in" devices minus the (unshifted) reference load of those devices
- Shift Down limits represent the portion of the (unshifted) reference load that could be reduced in an hour while still maintaining an acceptable amount of "service" (cool houses, pumped water, etc)



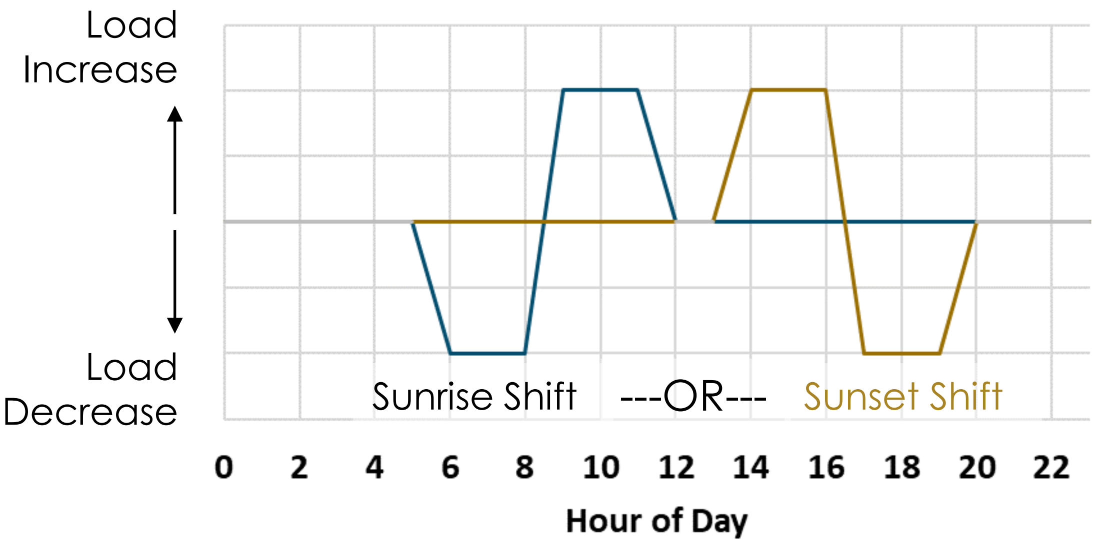
Shift Up less constrained than Shift Down

Shift Down opportunities limited

Example day for HVAC resource

Daily Mileage

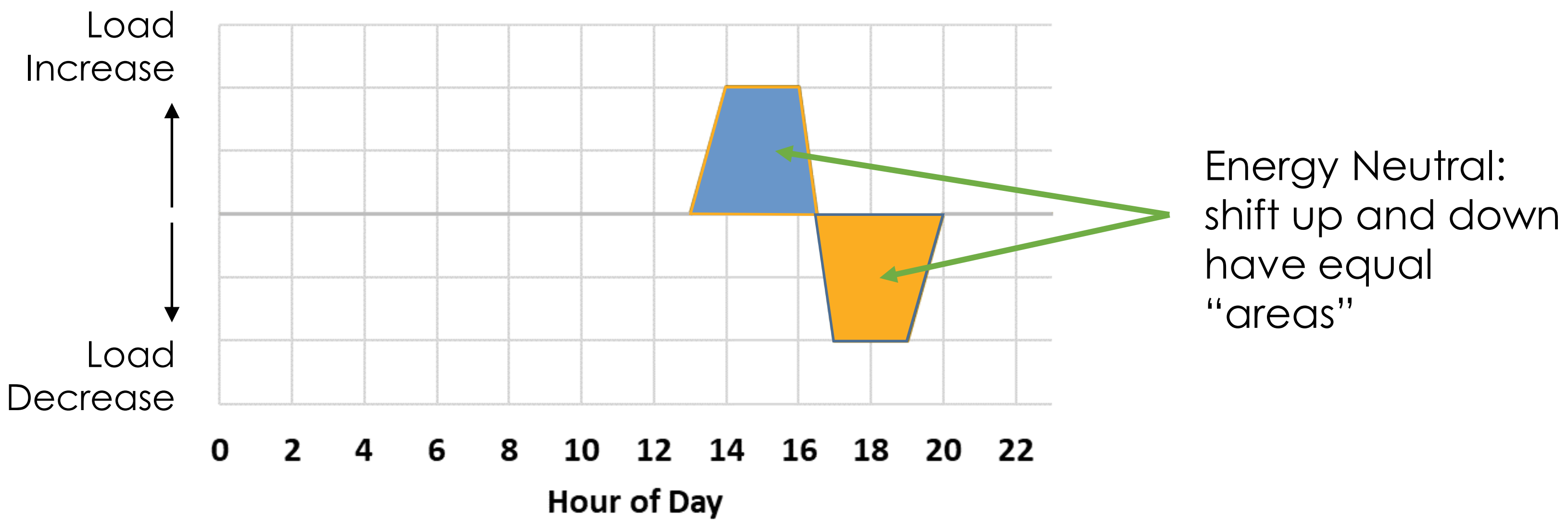
- For many loads there is significant potential to shift loads up or down each hour
- But, it's not acceptable to the end-user for the load to be increasing and decreasing frequently
- LBNL provided daily limits on the MWh of shiftable load, per MW of shiftable load capacity – these limits are enforced in RESOLVE



Example: Without mileage constraint, model would want to do both sunrise and sunset shifts. Mileage constraint forces it to pick only one.

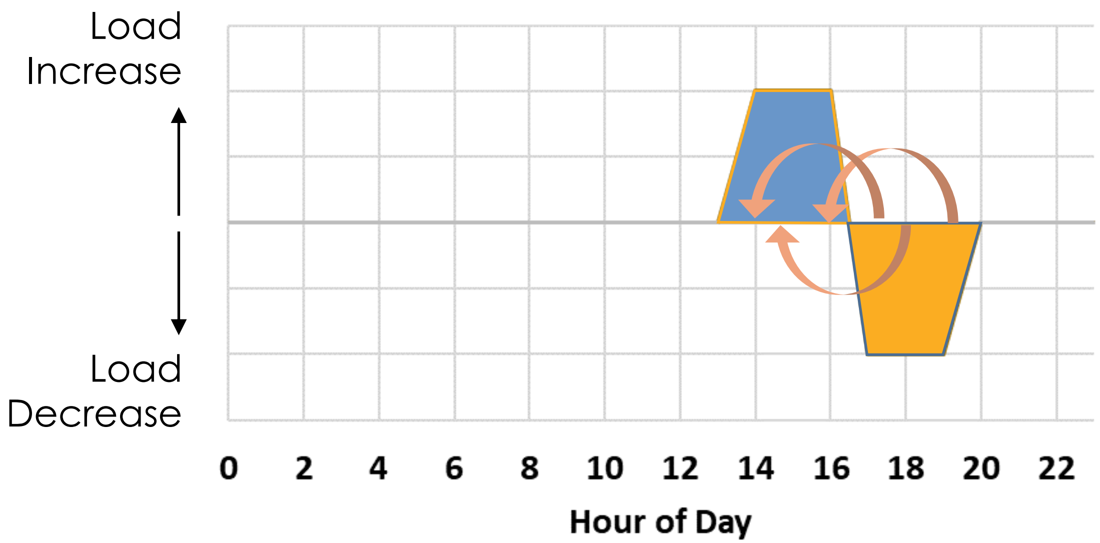
Daily Energy Neutrality

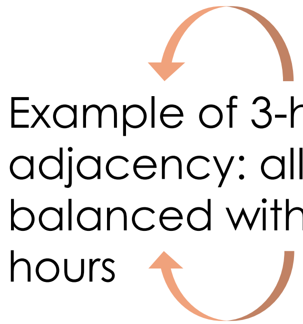
- Shift resources are assumed to be energy neutral across each day
- This is a simplification because pre-heating, pre-cooling, etc. can result in some efficiency loss (or gain)



Shift Hour Adjacency

- Shifting down and shifting up must be relatively close to each other
  - Consumers can't wait for most of a day to cool buildings, heat water, etc.
- Adjacency constraints ensure that if load is shifted down in one hour, an equivalent amount of load is shifted up at most X hours away
  - X depends on the type of load and is provided by LBNL.
  - Opposite limit is also enforced (if load is shifted *Up* in an hour, *Down* is X hours away)



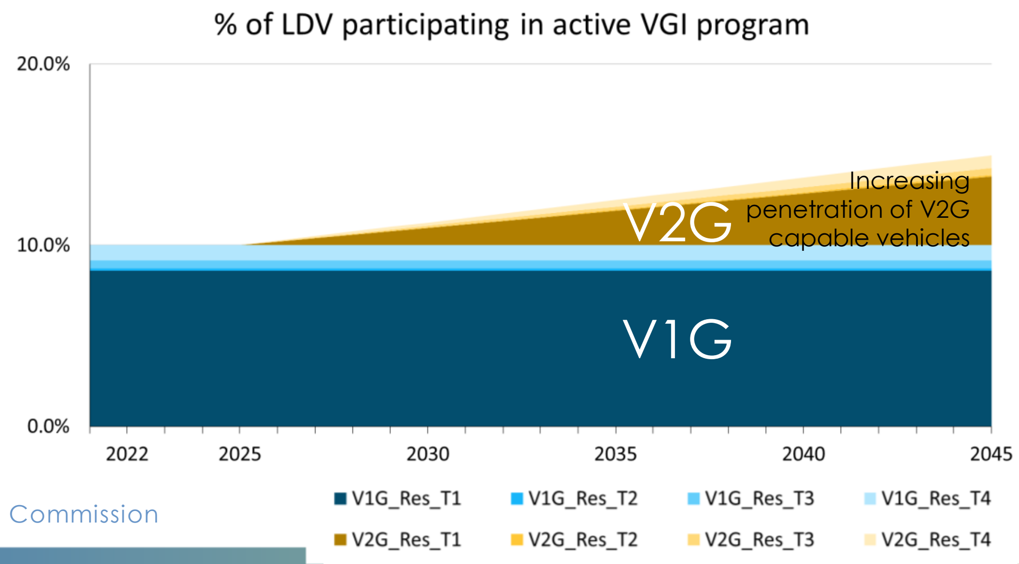


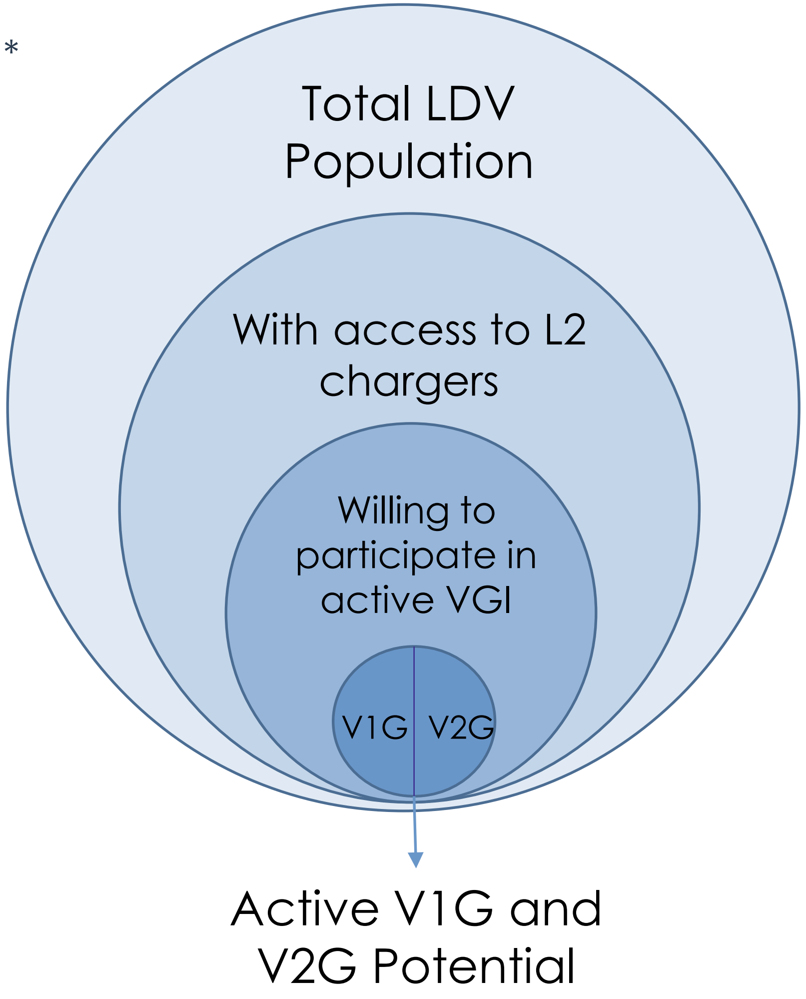
Appendix F
Vehicle-Grid Integration Analysis

Example of VGI Technical Potential (%) Calculation
- 2022 IEPR, Mid Enrollment Scenario

- VGI Potential (%)
  - $\% \, Driver \, with \, VGI \, Potential = \% \, Access \, to \, L2 \, charger * \% \, Enrollment \, by \, tranches * \% \, V2G \, as \, of \, V1G \, potential$

Example in 2030	V1G_Res_T1	V2G_Res_T1
Total LDV Population	100%	100%
% Access to VGI (L2) enabled chargers at home	42%	42%
% Willingness to enroll at cost tranche 1 (V1G: $0/kW-yr; V2G: $50/kW-yr)	21%	23%
% V2G potential as of V1G in 2030	-	10%
T1 Potential as of LDV population in 2030	**8.6%**	**0.9%**



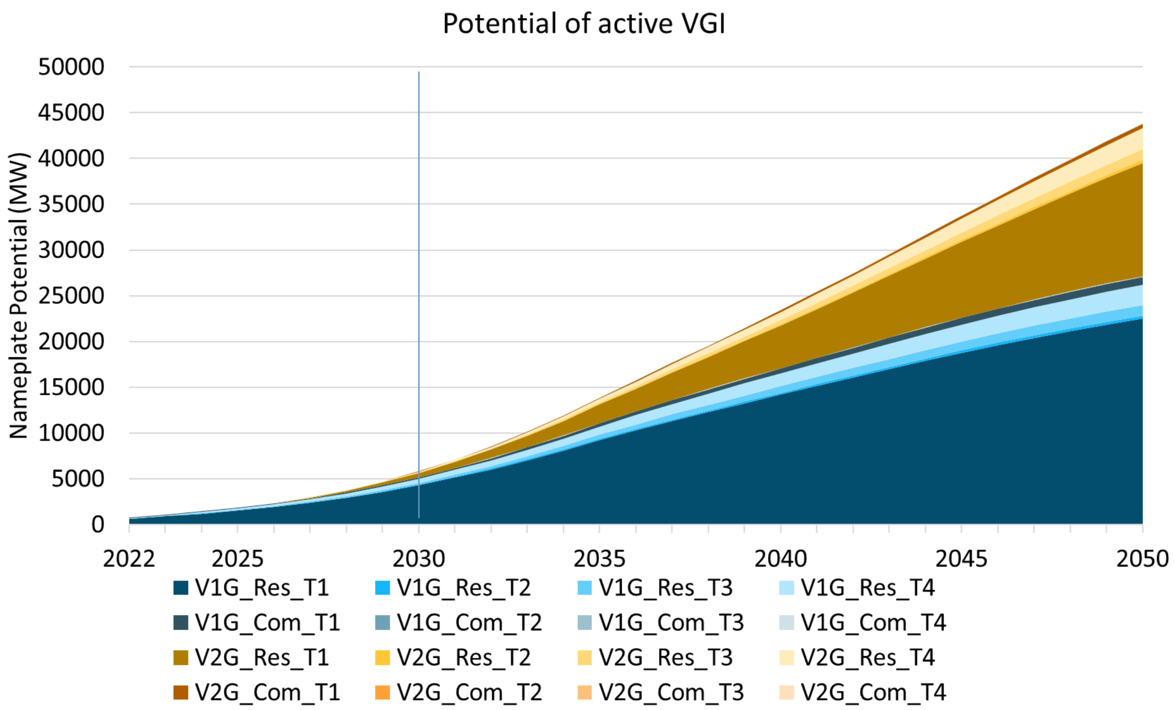


Example of VGI Potential (MW) Calculation
- 2022 IEPR, Mid Enrollment Scenario

- VGI potential (MW)
  - $V1G\ Potential\ = \%\ Access\ to\ L2\ charger * \%\ Enrollment\ by\ tranches\ * \boldsymbol{LDV\ stock} * \frac{\boldsymbol{Charger}}{\boldsymbol{EV}}\boldsymbol{ratio} * \boldsymbol{charger\ capacity}$
  - $V2G\ Potential\ = \%\ Access\ to\ L2\ charger * \%\ Enrollment\ by\ tranches\ * V2G\ potential\ \%\ as\ of\ V1G * \boldsymbol{LDV\ stock} * \frac{\boldsymbol{Charger}}{\boldsymbol{EV}}\boldsymbol{ratio} * \boldsymbol{charger\ capacity}$

Res Example in 2030	V1G_Res_T1	V2G_Res_T1
T1 Potential as of LDV population in 2030	**8.6%**	**0.9%**
LDV population in 2030	7 million	7 million
Charger/EV ratio at Res	1	1
Charger capacity (kW)	7	7
Res_T1 Potential in 2030 (MW)	**4300**	**470**

Com Example in 2030	V1G_Com_T1	V2G_Com_T1
T1 Potential as of LDV population in 2030	**8.7%**	**0.9%**
LDV population in 2030	7 million	7 million
Charger/EV ratio at Com	1/27	1/27
Charger capacity (kW)	7	7
Com_T1 Potential in 2030 (MW)	**160**	**20**

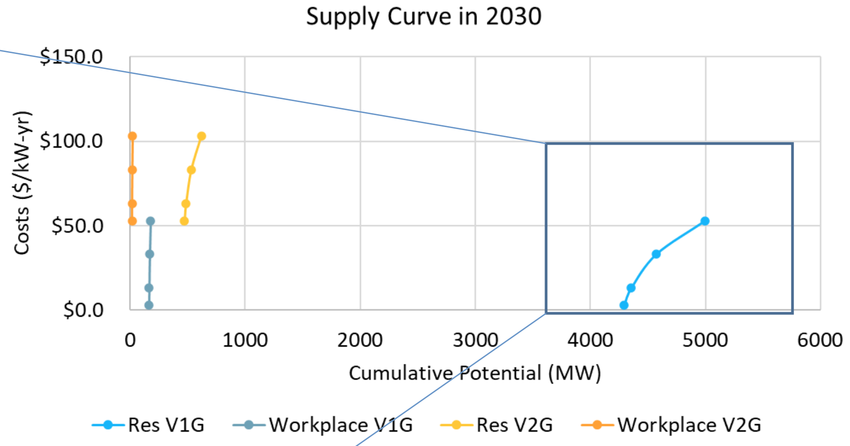


* Res and com potential are estimated using separate enrollment curves
* To avoid confusion, the V2G potential (MW) here is at charger capacity level. It's not multiplied by 2 as in the MAG workshop but it will be automatically accounted for inside the model

Example of VGI Supply Curve Results
- 2022 IEPR, Mid Enrollment Scenario

- Supply curve is a function of cost and potential

Res V1G Example in 2030	Access to L2 Charger (%)	Incremental Willingness to Participate (%)	LDV Population	Charger/EV ratio at Res	Charger Capacity (kW)	Potential (MW)	Cumulative Potential (MW)
V1G_Res_T1	42%	21%	7 million	1	7	4300	**4300**
V1G_Res_T2	42%	0.3%	7 million	1	7	60	**4360**
V1G_Res_T3	42%	1%	7 million	1	7	220	**4580**
V1G_Res_T4	42%	2%	7 million	1	7	420	**5000**



Res V1G Example in 2030	Administration ($/kW-yr)	Marketing ($/kW-yr)	Incentives ($/kW-yr)	Total Costs ($/kW-yr)
V1G_Res_T1	2.8	0.1	0	**3**
V1G_Res_T2	2.8	0.1	10	**13**
V1G_Res_T3	2.8	0.1	30	**33**
V1G_Res_T4	2.8	0.1	50	**53**

Due to the low charger to EV ratio at workplace, the magnitude of the workplace VGI potential is much smaller than residential VGI

Costs of VGI modeled are about $3-$53/kW-yr for V1G, $53-$103/kW-yr for V2G
Minimal difference on the costs of VGI between residential and workplace

Example of VGI Reliability Contribution Calculation

- Given that VGI is not as fully available as grid-scale storage to provide power at its nameplate in every single hour, a scaling factor will be applied to normalize VGI shift down capability relative to its "nameplate capacity" during the 4-hr evening net peak (e.g., 6-10pm)
- Equation
  - $VGI\ Scaling\ Factor(\%) = \sum_1^4 \frac{Shift\ Down_h}{Nameplate\ Capacity_h} = \frac{Population\ Average\ Shift\ Down\ Potential\ \ During\ Peak\ Period(kWh)}{Total\ Nameplate\ Potential\ During\ Peak\ Period\ (kWh)}$

Res Example in 2030	V1G	V2G
Population average shift down potential per charger from 6-10pm (kWh)	0.5	9
VGI nameplate capacity per charger (kW)	5	10
Peak window duration (hr)	4	4
Total nameplate potential per charger from 6-10pm (kWh)	20	40
Res VGI Scaling Factor (%) *	**2%**	**20%**

  - $Battery\ (4hr)\ Equivalent\ Capacity\ of\ VGI(kW) = VGI\ Nameplate\ Capacity\ (kW) * VGI\ Scaling\ Factor\ (\%)$

Res Example in 2030	V1G	V2G
VGI nameplate capacity per charger (kW)	**5**	**10**
VGI Scaling Factor (%)	2%	20%
Battery (4hr) Equivalent Capacity (kW)	**0.1**	**2**

* VGI scaling factor is highly dependent on the underlying load shapes and charger utilization. Workplace scaling factor is much higher than residential scaling factor due to the higher utilization of charger

Formula for Flexibility Parameters

<table>
<tr><th></th><th>V1G</th><th>V2G</th></tr>
<tr><td>Shift Window</td><td colspan="2">Shift window is calculated as the average flexible window for all charging sessions (e.g. a car is parked plugged in for 8 hours, and spends 2 hours charging, flex window = 6 hours):

$$flex\_window_s = plugin\_period_s - \frac{SOC\_kWh\_end_s - SOC\_kWh\_start_s}{charge\_power_s}$$

$$shift\_window = \frac{\sum_s^n flex\_window_s}{n}$$

plugin_period = time the EV is parked at a location with charging
SOC_kWh_start/end = state of charge of battery in kWh at the start/end of the session
charge_power = max available charging power for the session</td></tr>
<tr><td>Hourly Shift</td><td>Baseline shapes determines the hourly shift potential

$$Shift\ Down_h = Baseline\ Charging\ Load_h$$

$$Shift\ Up_h = Plugged\ in\ Capacity_h - Baseline\ Charging\ Load_h$$</td><td>IEPR shapes assume no baseline discharging load so greyed out

$$Shift\ Down_h = Plugged\ in\ Capacity_h + Baseline\ Charging\ Load_h - Baseline\ Discharging\ Load_h$$

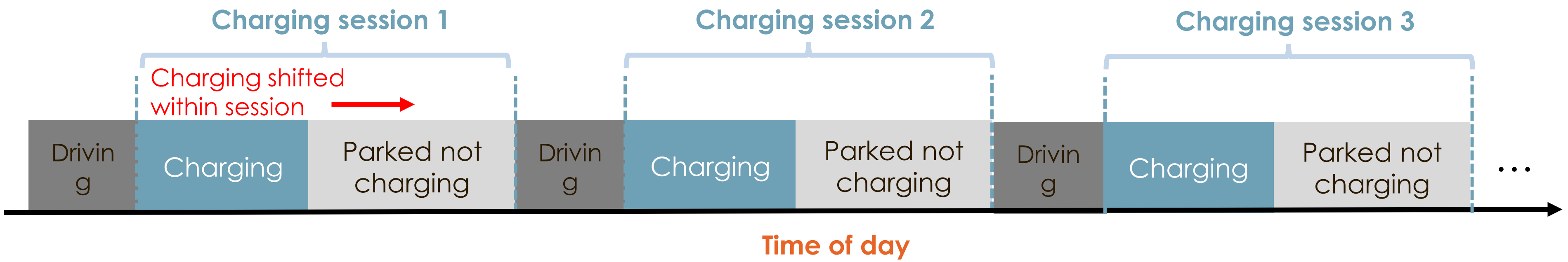
$$Shift\ Up_h = Plugged\ in\ Capacity_h - Baseline\ Charging\ Load_h + Baseline\ Discharging\ Load_h$$</td></tr>
<tr><td>Daily Energy</td><td>Daily energy is calculated as a minimum of the total shift up and shift down potential within a day:

$$Daily\_energy = \min\left\{\sum_0^{23} Shift\ Down_h, \sum_0^{23} Shift\ Up_h\right\}$$</td><td>V2G daily energy is not constrained by the total energy charged during the session, but only by total plugged in capacity. Multiplying it by ½ because V2G can technically charge during half of a day and discharge during another half:

$$Daily\_energy = \left(\sum_0^{23} Plugged\ in\ Capacity_h\right) * \frac{1}{2}$$</td></tr>
</table>

Illustrative Example to Calculate Shift Window

- Shift window is the average window when the vehicle is plugged in and able to change its charging behaviors



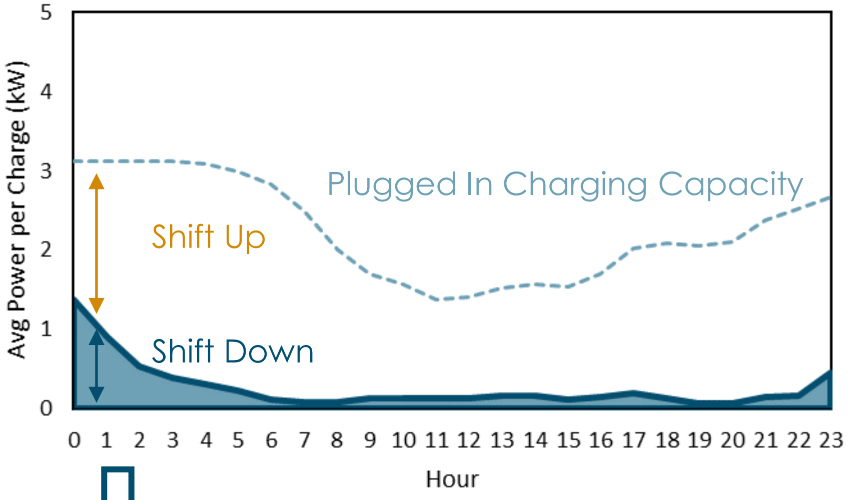
- $$\text{Shift window (h)} = \frac{\text{Parked not charging 1} + \text{Parked not charging 2} + \text{Parked not charging 3} + \dots + \text{Parked not charging n}}{\text{N, Total Number of Charging Sessions}}$$

* Modeling currently assumes intra-session charge management, which means that charging can only be shifted within each session, not between sessions

Illustrative Example to Calculate Daily Energy

- Aggregated, population-level average charging shapes per vehicle

Res V1G

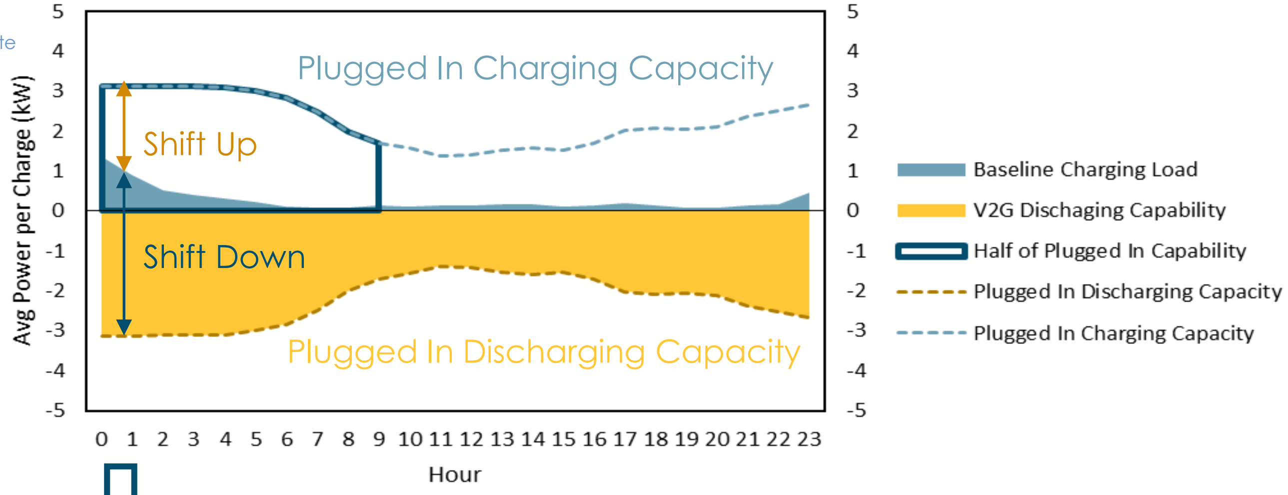


Assuming 5kW average nameplate capacity

V1G Daily Energy (kWh) =
Total shaded blue area of shift down potential

The daily baseline charging load determines the max amount of energy that an EV can shift in a day. It can't reduce more load than its baseline charging amount.

Res V2G



V2G Daily Energy (kWh) =
Half of Total Plugged In Charging (or Discharging) Capability

V2G daily energy is not constrained by the total energy charged during the session, but only by total plugged in capacity. It can technically charge half of a day and discharge another half of a day assuming the vehicle is plugged in the whole day

Appendix G
Renewable Characterization Methodology

Technology Configuration Modeling Assumptions for Candidate Resources

	Wind	Solar	Geothermal
Typical nameplate capacity (MW)	4 (turbine)	50	N/A
Land use factor (MW/km^2)	2.7	30	N/A
Mounting structure	N/A	Single-axis tracking	N/A
Hub height / Rotor diameter	110 m / 150 m	N/A	N/A
Operating losses	16.7%	14%	N/A
Azimuth	N/A	180°	N/A
Ground coverage ratio	N/A	30%	N/A
Inverter loading ratio	N/A	1.34	N/A
Maximum field depth	N/A	N/A	10 km
Enhanced geothermal (EGS)	N/A	N/A	Not included in GIS analysis