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# **Attachment A: 2019-20 IRP: Proposed Reference System Plan**



**CPUC Energy Division  
November 6, 2019**

# Purpose of this Presentation

- Provide the 2019 IRP Proposed Reference System Plan (RSP) to IRP stakeholders for formal comment.
- Describe the steps taken in development of the 2019 IRP Reference System Portfolio.
- Provide stakeholders with supporting information regarding 2019 IRP Reference System Plan modeling:
  - Comparison of portfolios under three Greenhouse Gas (GHG) Planning Targets for the electric sector.
  - Presentation of sensitivities that explore the impact of certain assumptions changes on the optimal portfolio of resources.
  - Explanation of modeling and resource assumptions and updates.
  - Exploration of how California can make progress towards deep GHG emissions reductions in the electric sector in 2045.

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# Acronyms & Abbreviations

<b>AAEE</b>	Additional Achievable Energy Efficiency
<b>AB</b>	Assembly Bill
<b>BANC</b>	Balancing Area of Northern California
<b>BTM</b>	Behind-the-Meter
<b>Btu</b>	British thermal unit
<b>CAISO</b>	California Independent System Operator
<b>CARB</b>	California Air Resources Board
<b>CCA</b>	Community Choice Aggregator
<b>CCGT</b>	Combined Cycle Gas Turbine
<b>CEC</b>	California Energy Commission
<b>CHP</b>	Combined Heat and Power
<b>CPUC</b>	California Public Utilities Commission
<b>CREZ</b>	Competitive Renewable Energy Zone
<b>CRVM</b>	Common Resource Valuation Methodology
<b>DAC</b>	Disadvantaged Community
<b>DER</b>	Distributed Energy Resources
<b>DR</b>	Demand Response
<b>DRP</b>	Distributed Resources Plan
<b>EE</b>	Energy Efficiency
<b>EV</b>	Electric Vehicle
<b>GHG</b>	Greenhouse Gas
<b>IC</b>	Internal Combustion
<b>IDER</b>	Integrated Distributed Energy Resource
<b>IEPR</b>	Integrated Energy Policy Report
<b>IOU</b>	Investor Owned Utility
<b>IRP</b>	Integrated Resource Plan (or) Planning
<b>IRP 2017-18</b>	The first cycle the CPUC's new IRP process
<b>ITC</b>	Investment Tax Credit
<b>GW</b>	Gigawatt
<b>LBL</b>	Lawrence Berkeley National Laboratory

<b>LNBA</b>	Locational Net Benefit Analysis
<b>LSE</b>	Load Serving Entity
<b>\$MM</b>	Millions of Dollars
<b>MMBtu</b>	Millions of British thermal units
<b>MMT</b>	Million Metric Tons of Carbon Dioxide
<b>MW</b>	Megawatt
<b>MWh</b>	Megawatt hour
<b>NEM</b>	Net Energy Metering
<b>NOx</b>	Nitrogen Oxide
<b>NQC</b>	Net Qualifying Capacity
<b>OOS</b>	Out-of-state
<b>OTC</b>	Once Through Cooling
<b>PCC</b>	Portfolio Content Category
<b>PM 2.5</b>	Particulate Matter, 2.5 microns
<b>POU</b>	Publicly-owned utility
<b>PRM</b>	Planning Reserve Margin
<b>PTC</b>	Production Tax Credit
<b>PV</b>	Photovoltaic
<b>REC</b>	Renewable Energy Credit
<b>RETI</b>	Renewable Energy Transmission Initiative
<b>RPS</b>	Renewables Portfolio Standard
<b>SB</b>	Senate Bill
<b>ST</b>	Steam Turbine
<b>TOU</b>	Time-of-Use
<b>TPP</b>	Transmission Planning Process
<b>TRC</b>	Total Resource Cost
<b>TWh</b>	Terrawatt hours
<b>WECC</b>	Western Electricity Coordinating Council
<b>ZEV</b>	Zero Emissions Vehicle
<b>ZNE</b>	Zero Net Energy



# EXECUTIVE SUMMARY

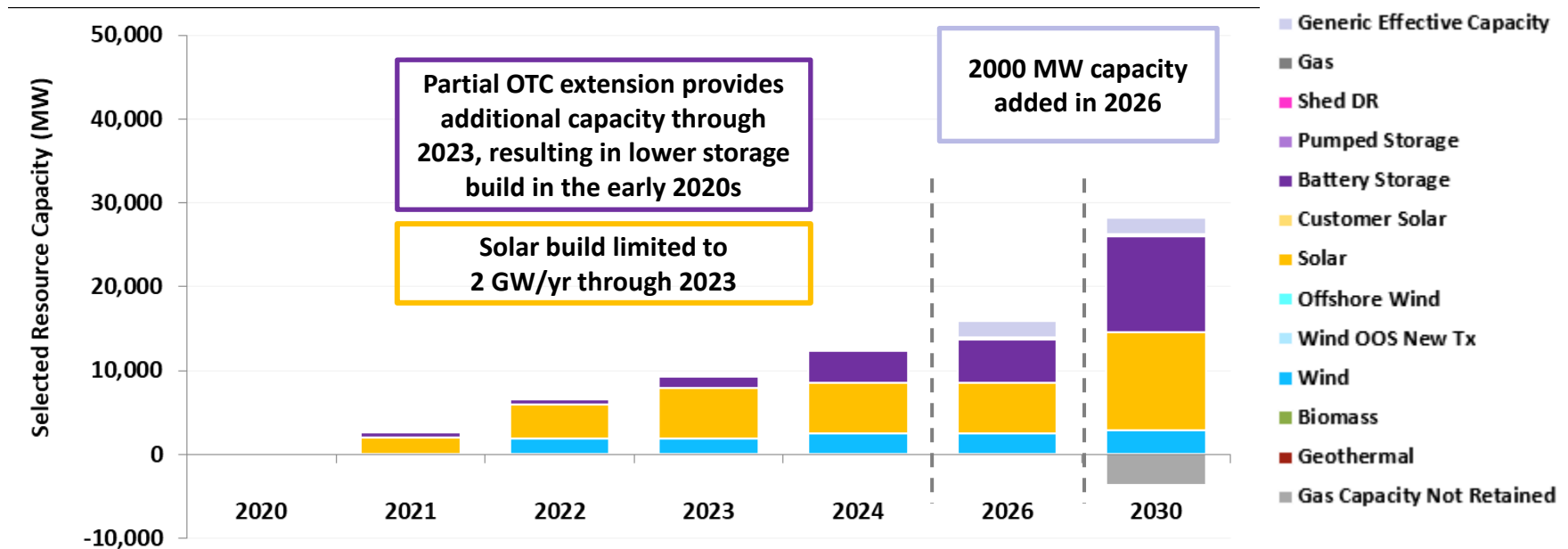
# Contents of Reference System Plan

- The Reference System Plan includes four key recommendations:
  - A GHG Planning Target of 46 million metric tons (MMT) to use for the electric sector in IRP that is consistent with 40% statewide reductions below 1990 levels by 2030.
  - A Reference System Portfolio – a single portfolio of resources that represents a least-cost, least-risk pathway to achieving the recommended GHG planning target and other SB 350 requirements.
  - A GHG Planning Price that represents the marginal cost of GHG abatement associated with the Reference System Portfolio and that will enable the CPUC and load-serving entities to consistently value both demand and supply-side resources.
  - Near-term Commission policy actions to ensure that the results from IRP modeling inform other CPUC proceedings and lead to the development or procurement of adequate resources.

# Summary of Steps Taken to Reach 2019 IRP Proposed Reference System Portfolio

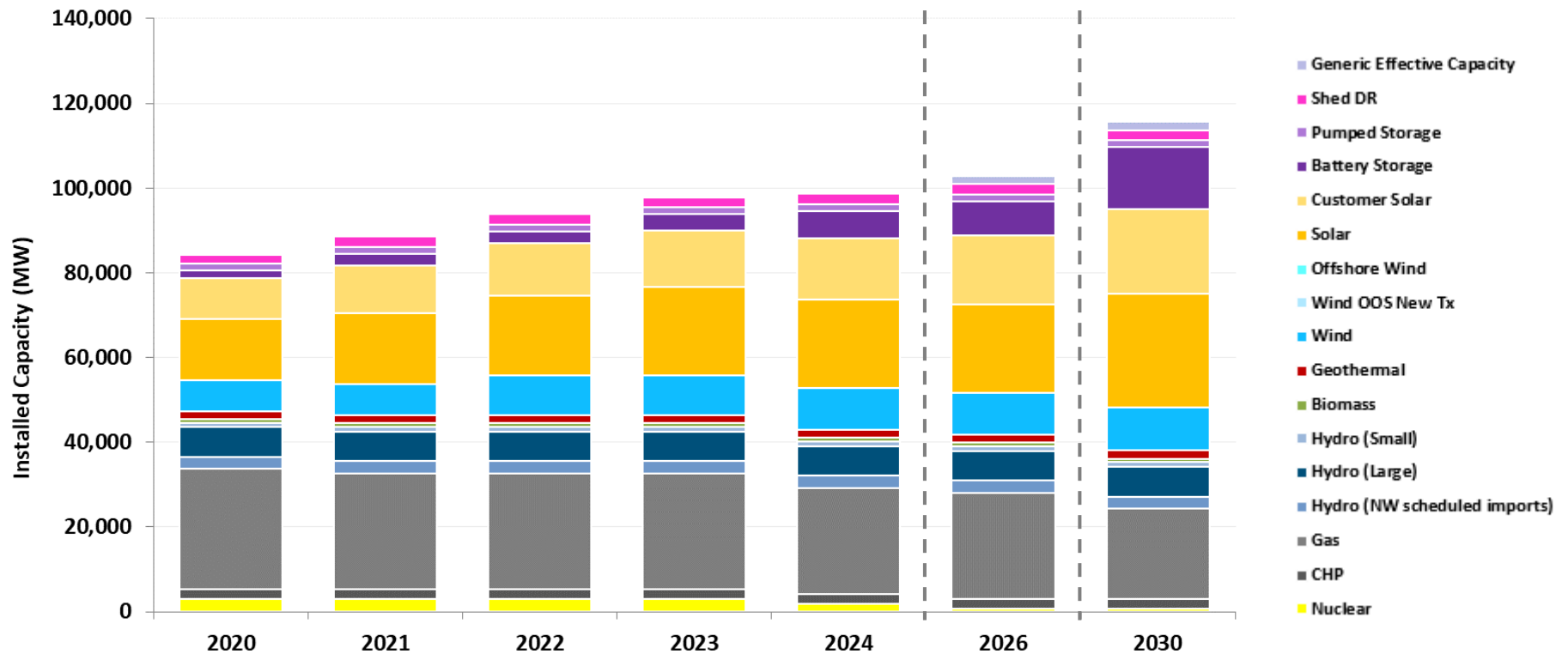
- The 46 MMT GHG Planning Target is analogous to the 42 MMT GHG Planning Target adopted in 2017-18 IRP cycle and keeps the electric sector on track to meet its 2030 GHG goals.
  - An IRP GHG accounting difference from 2017-18 IRP cycle has been rectified and accounts for the 4 MMT difference between 2017-18 IRP and 2019-20 IRP GHG target names, further described on slide 16 of this presentation.
- Core Policy Case Results for 46 MMT, 38 MMT, and 30 MMT GHG targets, as well as sensitivities on those cases, were included as part of the 2019 IRP Preliminary Results released on 10/5/19. These cases were updated as part of this 2019 IRP Reference System Plan presentation.
  - Results are contained in Section 3 of this presentation.
- The 2019 IRP Proposed Reference System Portfolio is derived from the "46 MMT limited near-term solar and partial OTC extension" sensitivity.
  - Further described on slide 125 of this presentation.
- An adjustment to the 2019 IRP Proposed Reference System Portfolio (termed the "46 MMT "Alternate" case in Ruling) was necessary in order for SERVVM analysis to demonstrate adequate system reliability. Stacked bar charts depicting that portfolio are on the next two slides.
  - Please see the Proposed Reference System Portfolio Validation with SERVVM presentation for further description of SERVVM modeling.

# 2019 IRP Proposed Reference System Portfolio, Selected Resources, with 2 GW Generic Effective Capacity Added in 2026, aka "46 MMT Alternate"





# 2019 IRP Proposed Reference System Portfolio, Total Resources, with 2 GW Generic Effective Capacity Added in 2026, aka "46 MMT Alternate"





# 1. BACKGROUND

# Integrated Resource Planning (IRP) in California Today

- The value proposition of integrated resource planning is to reduce the cost of achieving GHG reductions and other policy goals by looking across individual LSE boundaries and resource types to identify solutions to reliability, cost, or other concerns that might not otherwise be found.
- Goal of 2019-20 IRP cycle is to ensure that the electric sector is on track to help California reduce economy-wide GHG emissions 40% from 1990 levels by 2030, and to explore how achievement of SB 100 2045 goals could inform IRP resource planning in the 2020 to 2030 timeframe.
- California today is a complex landscape for resource planning:
  - Multiple LSEs including utilities, CCAs, and ESPs.
  - Multiple state agencies (CPUC, CEC, Air Resources Board) and CAISO.
  - Partially deregulated market.

# Statutory Basis of IRP

The Commission shall...

PU Code Section 454.51

**Identify a diverse and balanced portfolio of resources... that provides optimal integration of renewable energy in a cost-effective manner**

PU Code Section 454.52

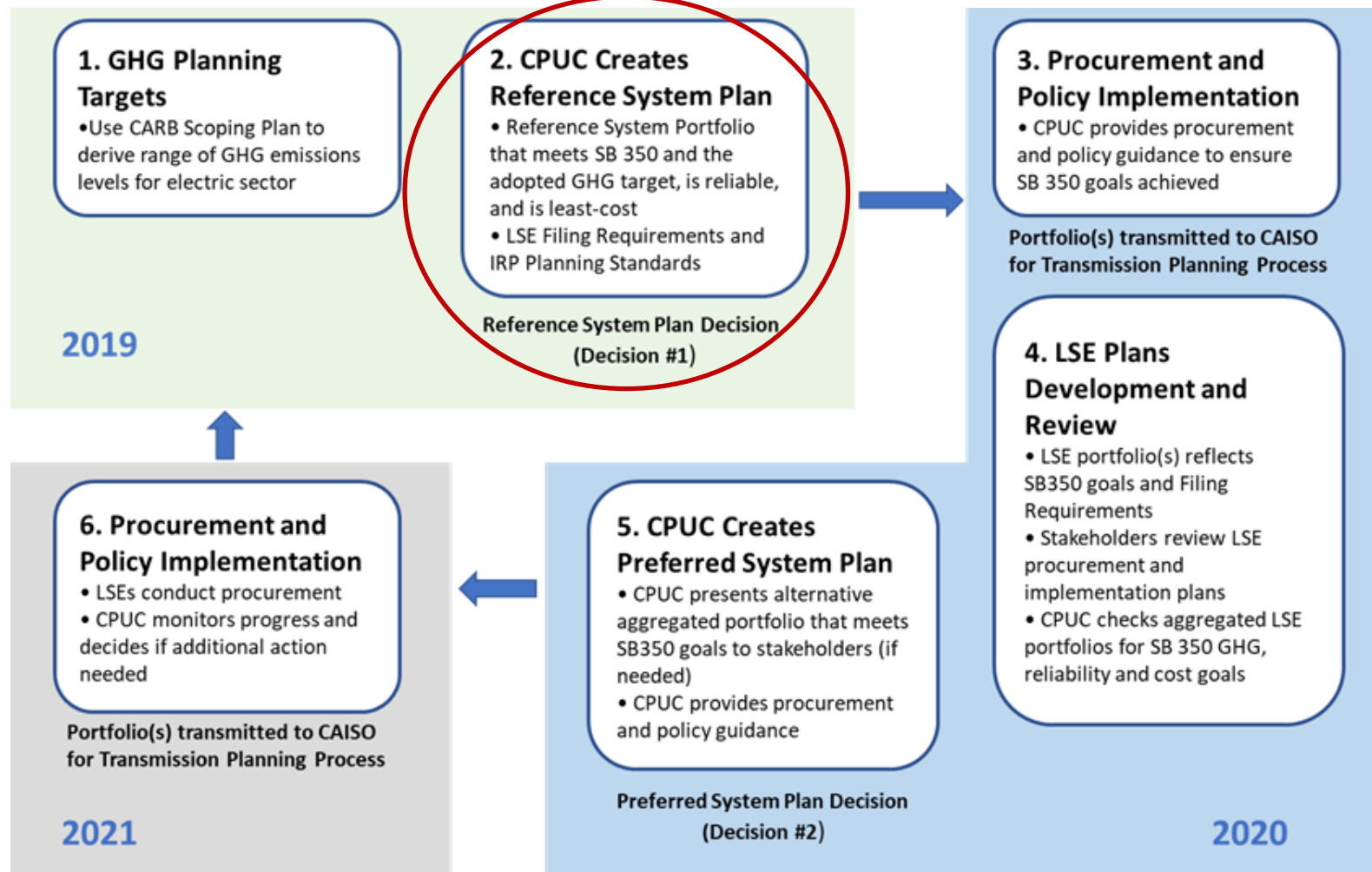
**...adopt a process for each load-serving entity...to file an integrated resource plan...to ensure that load-serving entities do the following...**

- Meet statewide GHG emission reduction targets
- Comply with state RPS target
- Ensure just and reasonable rates for customers of electrical corporations
- Minimize impacts on ratepayer bills
- Ensure system and local reliability
- Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities
- Enhance distribution system and demand-side energy management
- Minimize air pollutants with early priority on disadvantaged communities

# Background on the CPUC IRP Process

- Commission Decision (D.18-02-018) established IRP as a two-year planning cycle designed to ensure LSEs are on track to achieve GHG reductions and maintain electric grid reliability at least cost while meeting the state's other policy goals.
- Year One is focused on:
  - Generating and evaluating optimal resource portfolios at the CAISO system-level using a capacity expansion model (RESOLVE) and production cost model (SERVM) in parallel.
  - Adopting one portfolio as the Reference System Portfolio to be used in statewide planning, including the CAISO transmission planning process.
  - Identifying actions needed to implement the selected portfolio, such as new procurement authorization.
  - Developing filing requirements for LSEs to submit individual IRPs.
- Year 2 is focused on:
  - LSE development of individual IRPs.
  - Staff evaluation of LSE IRPs both individually and in aggregate.
  - Commission adoption of a Preferred System Portfolio to be used in statewide planning, as well as actions needed to implement the portfolio (Preferred System Plan).

# Overview of the IRP 2019-20 Process



# IRP GHG Target Setting

- Reduce statewide GHG emissions 40% below 1990 levels by 2030.
- In 2018, CARB, in coordination with CPUC and CEC, established a GHG planning target range for the electric sector of 30 – 53 MMT by 2030.\*
- CARB also defined a methodology for setting LSE- and POU-specific GHG planning targets in IRP based on that range.
- CPUC D.18-02-018 adopted an electric sector GHG target of 42 MMT as part of the 2017-18 IRP Reference System Plan.

\*For perspective, electric sector emissions were ~62 MMT in 2017 (SOURCE: CARB's GHG emissions inventory)

# Differences in GHG Target Naming Convention and Accounting

- RESOLVE GHG accounting in 2017-18 IRP did not consider approximately 4 MMT of annual emissions from behind-the-meter CHP facilities as part of electric sector emissions.
- In 2019-20 IRP, those emissions are now counted as part of electric sector emissions, meaning that a 42 MMT electric sector GHG target in 2017-18 IRP is analogous to a 46 MMT GHG target in 2019-20 IRP.
- Thus, a 46 MMT electric sector GHG target in 2019-20 IRP is meant to represent adopted policy and does not constitute a less stringent GHG target than the 42 MMT target used in 2017-18 IRP, but simply a change in accounting for GHG emissions.



# 2019 Core GHG Cases

- **46 MMT Case (Default\*)**
  - Achieves the Commission-established electric sector planning target
  - CEC 2018 IEPR “Mid case” assumptions for demand and various demand modifiers
  - Baseline resources assumed to be online as defined in Section 2.3 of this presentation
  - Considered "Default" case in 2019 IRP modeling as it most closely resembles adopted policy from the 2018 IRP Preferred System Plan (PSP)
- **38 MMT Case**
  - Represents the midpoint between 46 MMT and the low end of CARB's established range for the electric sector
  - Includes all constraints and assumptions from Default Case
- **30 MMT Case**
  - Represents the low end of CARB's established range
  - Includes all constraints and assumptions from Default Case

\*All cost and sensitivity cases in this presentation are characterized as incremental to the 46 MMT "default" case

# Translating Statewide GHG Targets to CAISO Targets

- Staff expresses the core modeling cases throughout this analysis in terms of the statewide electric sector GHG targets.
- However, the CPUC's IRP modeling covers only the CAISO balancing authority area; the RESOLVE model allows specification of a GHG planning target in tons of CO<sub>2</sub> equivalent to constrain the portfolio at the CAISO system level on an annual basis.
- For IRP modeling, statewide electric sector GHG targets are translated to CAISO targets based on CARB's proposed Cap and Trade allowance allocation methodology for 2021-2030 (~81% in 2030).

2030 Statewide Target	2030 CAISO Target
46.0 MMT	37.3 MMT
38.0 MMT	30.8 MMT
30.0 MMT	24.3 MMT

# Reference System Portfolio: Relationship to 2045 Analysis

- CPUC staff and consultants performed analysis to explore how SB 100's 2045 goal could affect the outlook for electricity sector GHG emissions and resource planning in the 2030 timeframe.
- This analysis is primarily informational and directional, intended to inform Commission decision-making regarding the appropriate 2030 GHG planning target for CPUC-jurisdictional LSEs, the Reference System Portfolio to meet that target, and associated least-regrets investments needed by 2030.

# Summary of Materials Released in Support of Proposed Reference System Development

- IRP 2019 Proposed Reference System Plan slide deck
  - Proposed RSP modeling results associated under multiple potential GHG targets and assumptions
  - 2045 Framing Study
- Updated IRP 2019-20 Inputs & Assumptions document
- Updated RESOLVE model and accompanying documentation
  - The RESOLVE model used to generate the Proposed Reference System Portfolio is available for use by parties, along with upstream inputs and assumptions spreadsheets and related information
- Updated SERVM model input datasets
  - Incremental to data presented at the 6/17 MAG on baseline model inputs development

# Contents of Reference System Plan

- The Reference System Plan includes four key recommendations:
  - A GHG Planning Target to use for the electric sector in IRP that is consistent with 40% statewide reductions below 1990 levels by 2030.
  - A Reference System Portfolio – a single portfolio of resources that represents a least-cost, least-risk pathway to achieving the recommended GHG planning target and other SB 350 requirements.
  - A GHG Planning Price that represents the marginal cost of GHG abatement associated with the Reference System Portfolio and that will enable the CPUC and load-serving entities to consistently value both demand and supply-side resources.
  - Near-term Commission policy actions to ensure that the results from IRP modeling inform other CPUC proceedings and lead to the development or procurement of adequate resources.

# Process for 2019 IRP Reference System Portfolio Development

Step #	Activity	Estimated Date
1	Data Development	March-June 2019
2	Informal release: core model inputs + MAG presentation	June 2019
2a	Informal party comment on Step 2 content	July 2019
3	Input validation for RESOLVE & SERVUM models	July 2019
4	Develop calibrated modeling results	July-Sept 2019
5	Informal release of complete RESOLVE model and draft results	October 2019
<u>6</u>	<u>Formal release of Proposed 2019 IRP Reference System Plan</u>	<u>November 2019</u>
7	Formal party comment on Proposed 2019 Reference System Plan	November 2019
8	Formal release of 2019 Reference System Plan Proposed Decision	January 2020
9	Formal party comment on 2019 Reference System Plan PD	January 2020
10	Commission Decision on 2019 Reference System Plan	February 2020
11	Transmittal of 2019 IRP portfolios to 2020-21 CAISO TPP	February 2020



## 2. MODELING APPROACH



## 2.1. MODELS USED



# RESOLVE Model Overview

- RESOLVE is a capacity expansion model designed to inform long-term planning questions around renewables integration.
- RESOLVE co-optimizes investment and dispatch for a selected set of days over a multi-year horizon in order to identify least-cost portfolios for meeting specified GHG targets and other policy goals.
- Scope of RESOLVE optimization in IRP 2019-20:
  - Covers the CAISO balancing area including POU load within the CAISO
  - Optimizes dispatch but not investment outside of the CAISO
    - Resource capacity outside of CAISO cannot be changed by the optimization
- The RESOLVE model used to develop the Proposed Reference System Plan results, along with accompanying documentation of inputs and assumptions, model operation, and results is available for download from the CPUC's website at:  
<https://www.cpuc.ca.gov/General.aspx?id=6442459770>

# SERVM Model Overview

- The Strategic Energy Risk Valuation Model (SERVM)\* is a probabilistic system-reliability planning and production cost model – primary objective is to reduce risk of insufficient generation to an acceptable level (e.g. security-constrained planning)
- Configured to assess a given portfolio in a target study year under a range of future weather (20 weather years), economic output (5 weighted levels), and unit performance (30+ random outage draws)
- Hourly economic unit commitment and dispatch
  - Reserve targets to reflect provision of sub-hourly balancing and ancillary services
  - Multiple day look-ahead informs unit commitment
  - Individual generating units and all 8,760 hours of year are simulated
  - Unit operating costs and constraints
- Pipe and bubble representation of transmission system
  - 8 CA regions, 16 rest-of-WECC regions
  - Includes region to region flow limits and hurdle rates as well as simultaneous flow limits

\*Commercially licensed through Astrape Consulting: <http://www.astrape.com/servm/>

# Why Two Models are Used in IRP Analysis

Objective of IRP modeling: To develop an optimal portfolio of new resources to add to the existing fleet in the CAISO area to plan for:

- Achievement of long-term GHG reduction targets and other policy goals
  - Maintaining reliability
  - Keeping costs reasonable
  - Accounting for uncertainty and expected energy market conditions (i.e., “real world” conditions)
- The role of the RESOLVE model in IRP is to select portfolios of new resources that are expected to meet our policy goals at least cost while ensuring reliability.
  - The role of the SERVVM model in IRP is to validate the reliability, operability, and emissions of resource portfolios generated by RESOLVE.



## **2.2. OVERVIEW OF MODELING ASSUMPTIONS**

# General Assumptions Components Used in 2019 IRP Modeling

- IRP seeks to use standardized modeling inputs in both capacity expansion (RESOLVE) and production cost modeling (SERVM).
- Generally, these assumptions pertain to use of demand forecasts and the definition of what baseline resources to consider in both models.
- An overview of core modeling inputs for 2019 modeling is included in this section.
  - Contains descriptions of demand forecast and baseline resource inputs.

# Core Modeling Input: Demand Forecast

- Per the 2013 joint agency leadership agreement to use a single forecast set\*, current IRP modeling uses the Energy Commission's 2018 IEPR Update Forecast as a core input.
- Uncertainty in future electricity demand considered:
  - 1998-2017 weather scenarios and 5 weighted levels of load forecast uncertainty in SERVIM
  - Sensitivity and scenario modeling (e.g. high load, high electrification) in RESOLVE
- IEPR forecast annual projections of electricity consumption and demand modifiers are used to scale corresponding hourly shapes in RESOLVE and SERVIM
  - See 6/17 MAG presentation for further background on hourly shapes used by RESOLVE and SERVIM; both models' shapes have been updated since the previous IRP cycle

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

# Core Modeling Input: Baseline Resources

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

## Core Modeling Input: Baseline Resources (continued)

- In external zones (e.g., BANC), where RESOLVE does not optimize the resources, the baseline resources are derived from the WECC Anchor Data Set, which includes each external balancing authority's plans to add/retire resources to meet assumed policy and reliability goals.
  - Future resources needed for RPS compliance by non-CAISO balancing areas are based on existing integrated resource plans where available; where such information is unavailable, utility-scale solar resources fill the gap.
- RESOLVE optimizes the selection of additional resources in the CAISO area needed to meet policy goals, including RPS targets, GHG targets, or a planning reserve margin; these incremental resources selected by RESOLVE are *not* baseline resources.
- The same baseline resources are assumed in the 46, 38, and 30 MMT Core Policy Cases.
- The baseline developed for 2019 IRP modeling includes data collected up to the spring of 2019 and differs from the baseline used in the IRP's 2018 Preferred System Plan Decision (D.19-04-040).



# Baseline Resource Assumptions: Retirements, Repowering, Risk Adjustments

- Retirements
  - Power plants with announced retirements are modeled as retired. Compliance with Once-Thru-Cooled (OTC) Water Board policy is assumed by default and Diablo Canyon Power Plant is retired in 2024/2025 in all model runs.
    - Extension of some OTC capacity through 2023 is explored via sensitivity analysis
  - Of the remaining existing plants, RESOLVE uses new economic retention functionality to examine what portion of the existing gas-fired generation fleet may need to be retained or allowed to retire within the IRP planning horizon.
- Repowering
  - Staff is aware that a significant fraction of California's wind capacity may need to be repowered to remain online through 2030.
  - Further data gathering and RESOLVE development will be needed to explicitly consider repowering in modeling.
  - In the interim Staff will estimate the capacity of wind that would need to be repowered to maintain baseline wind power production through 2030, with reference to stakeholder input already provided in this proceeding.
- Risk Adjustment for LSE-owned or contracted resources not yet online: 5% discount applied to affected capacity



## **2.3. CANDIDATE RESOURCES IN RESOLVE**

# Candidate Resource Assumptions

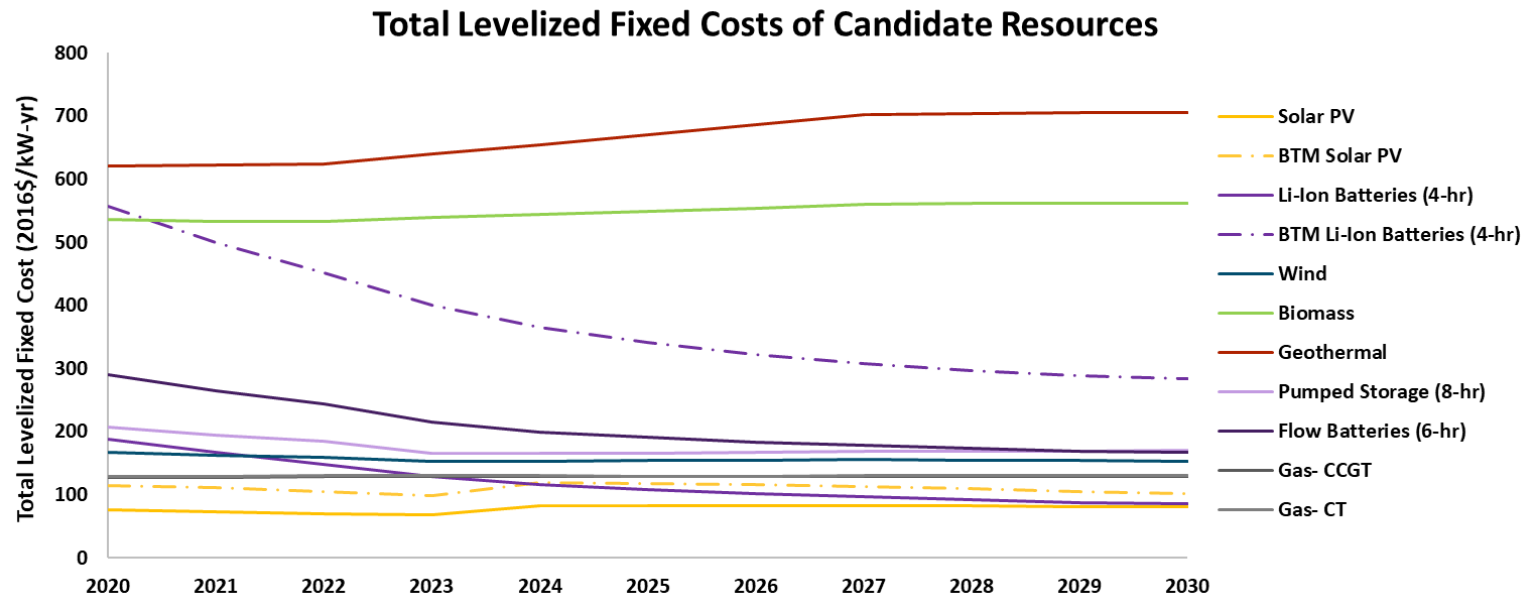
- “Candidate” resources represent the menu of options from which RESOLVE can select to create an optimal portfolio.
- Publicly-available data on cost, potential, and operations are used to the greatest extent possible to develop candidate resource assumptions.
- Both supply- and demand-side resources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

# Portfolio Selection: Costs and Benefits

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

# Levelized Fixed Resource Costs

- Renewable resource capital and fixed O&M cost forecasts based on 2018 National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB).
- Storage resource capital and fixed O&M cost forecasts based on Lazard Levelized Cost of Storage 4.0 and NREL Solar + Storage study.
- Financing costs based on NREL Annual Technology Baseline (ATB).
- Shed DR costs are not shown on plot but are included in RESOLVE modeling as a supply curve based on the LBNL California Demand Response Potential Study.

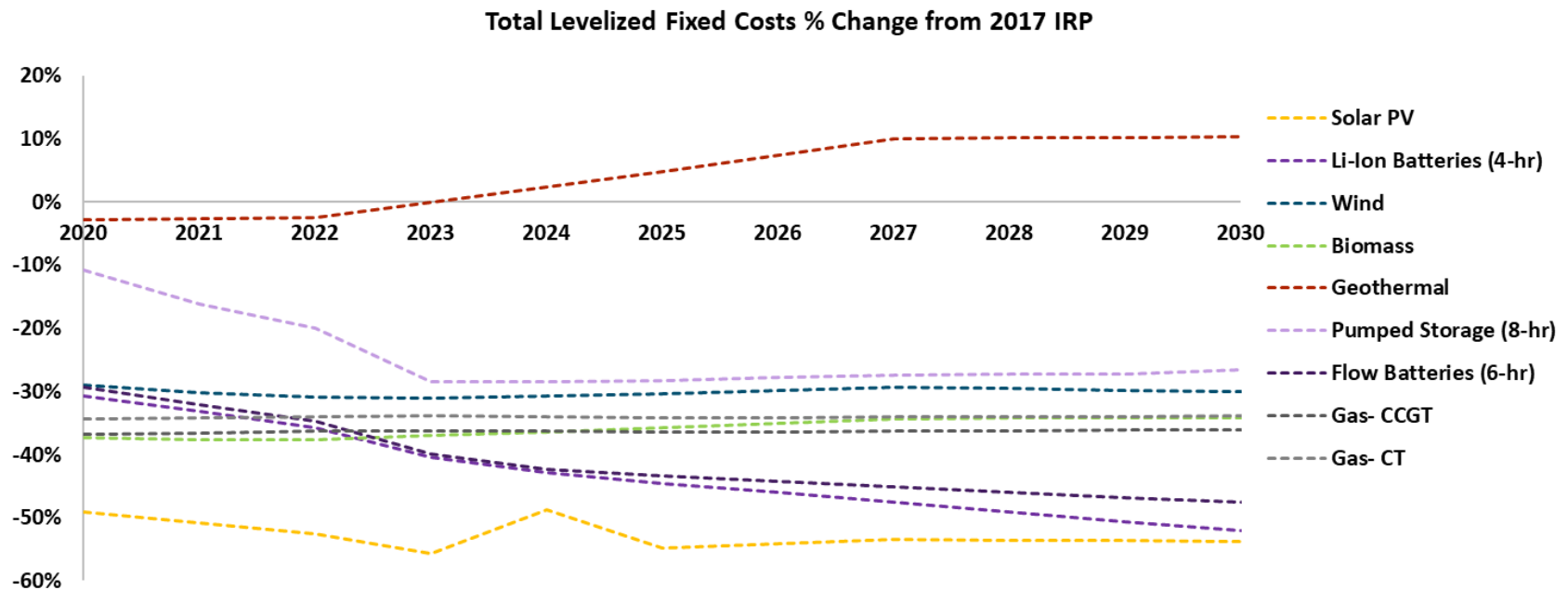


\*Costs shown are US-wide and do not include regional multipliers applied to all technologies or project-specific multipliers applied to renewable projects in the supply curve.

\*\*The chart above capture the total fixed costs of resources only. Does not include variable costs (e.g. fuel) which are modeled in RESOLVE.

# Total Levelized Fixed Cost Comparison: 2017 to 2019 IRP

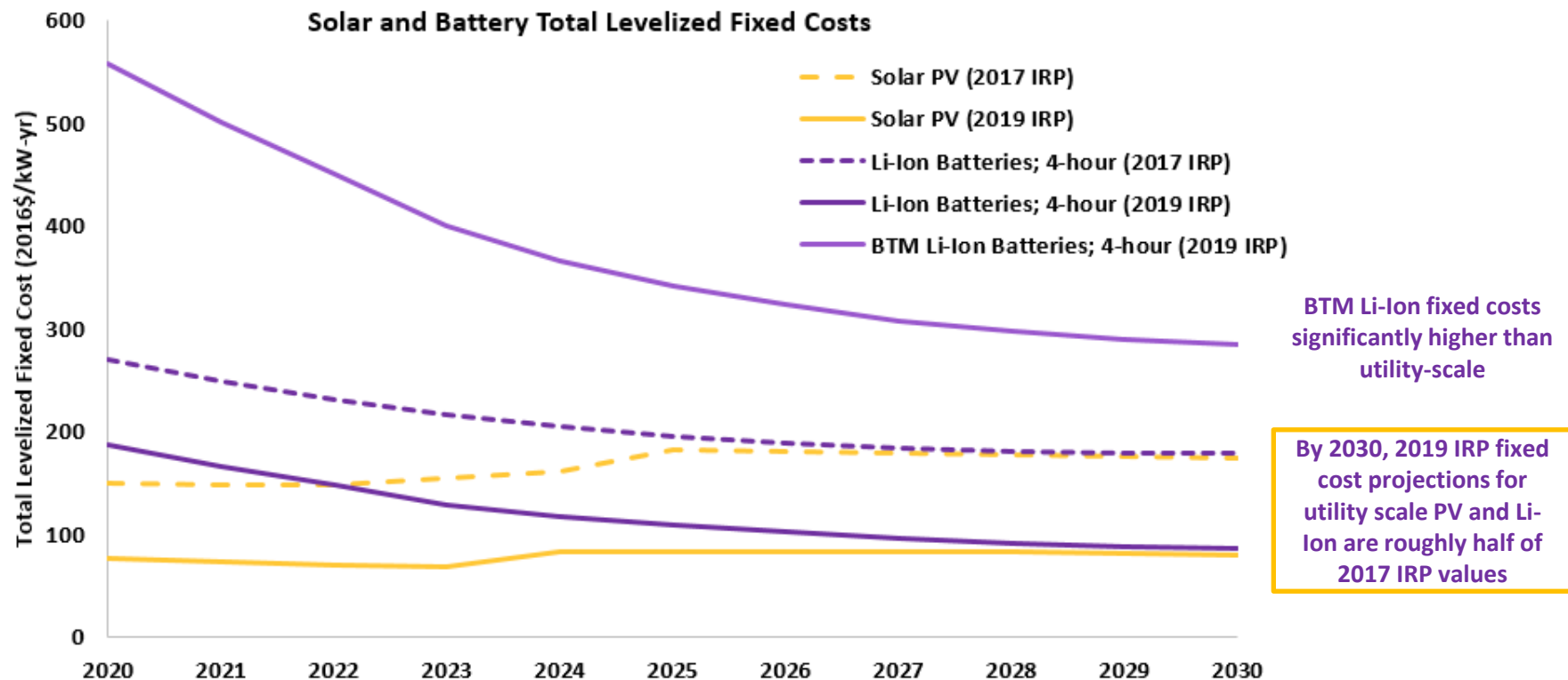
- Sustained cost declines have outpaced expectations for solar and lithium-ion technologies.
- Continued wind technology innovations (e.g., taller hub heights and longer blades that increase power capacity per turbine) result in lower installed costs per kW than assumed in 2017 IRP.
- Financing (debt/equity ratio) and tax rate updates since last IRP cycle drive changes in levelized costs assumptions for natural gas technologies.



Based on the total levelized fixed costs of technologies before the application of any regional-specific cost multipliers. Does not include variable costs (e.g. fuel) which are modeled in RESOLVE.

# Solar PV and Li-Ion Batteries

## Total Fixed Cost Comparison: 2017 to 2019



Costs shown are US-wide and do not include regional multipliers applied to all technologies or project-specific multipliers applied to renewable projects in the supply curve.

# Limitations Applied to Resource Availability in Certain Cases

- Many “real-world” factors make it challenging to ramp up resource deployment quickly.
  - Logistics of training and re-locating staff, upstream supply chain limitations, siting and permitting lead times, etc.
- Near-term limits on resource buildout will limit the capacity of resources available to be procured by LSEs, and should be represented in IRP modeling when possible. However, it can be analytically challenging to predict a feasible level of near-term deployment, particularly considering the unprecedented magnitude of resource buildout.
- Near-term resource availability changes and sensitivities explored include:
  - Shed DR limit (default):
    - To reflect lead time required to ramp up shed DR availability, total potential is phased in linearly between 2020 and 2025.
    - Shed DR potential limitation is default assumption, but sensitivity analysis explores the impact of having all shed DR potential available in 2020.
  - Solar resource limit (sensitivity only):
    - To reflect real-world constraints on solar buildout, an annual deployment limit of 2 GW/yr is enforced in certain cases on candidate solar resources through 2023.

Near-Term Resource availability further explored in Section 3.9.



# Supply Curve Validation: Cost & Potential

- Updated RESOLVE "supply curve" of candidate resources based on stakeholder feedback on supply curve used for 2017-18 IRP.
- Northern California geothermal: interconnection cost increased to reflect longer distance to interconnect with bulk transmission system.
- Wind resource potential updated to reflect contracting activity, land use changes and technology development since supply curve was refreshed by Black & Veatch in 2016; considered wind industry's feedback, including reference to commercial interest as indicated by interconnection queues.
  - Greater Carrizo: reduced potential due to interconnection and land use challenges
  - Northern California: renewable potential for Northern California wind was set to zero across all screens in 2017 IRP due to both the unproven nature of the resource and expected obstacles in resource permitting. For 2019 cycle, ~900 MW of Northern California wind resource potential was re-instated based on stakeholder input and interconnection queue review that commercial activity has increased.
- In 2017 IRP, candidate solar capacity as calculated from Black and Veatch geospatial analysis was discounted by 95% to reflect land use constraints and preference for geographic diversity. Value updated to 80% in 2019 IRP; geographic diversity largely enforced by transmission limits.

# First Available Online Date

- "First Available Year" of some resource types updated to reflect feasible timeline to bring resources online, considering current interconnection queues and typical development processes.

Resource Type	First Available Year
Solar PV	2020
Wind (CA onshore)	2022-2023*
Wind (OOS onshore)	2026
Wind (CA offshore, sensitivity only)	2030
Geothermal	2024-2026*
Biomass	2020
Pumped Storage	2026
Battery Storage	2020

\*First Available Year is an assumption applied on a resource-by-resource basis in RESOLVE; accordingly range of years applies when summarizing by resource type.

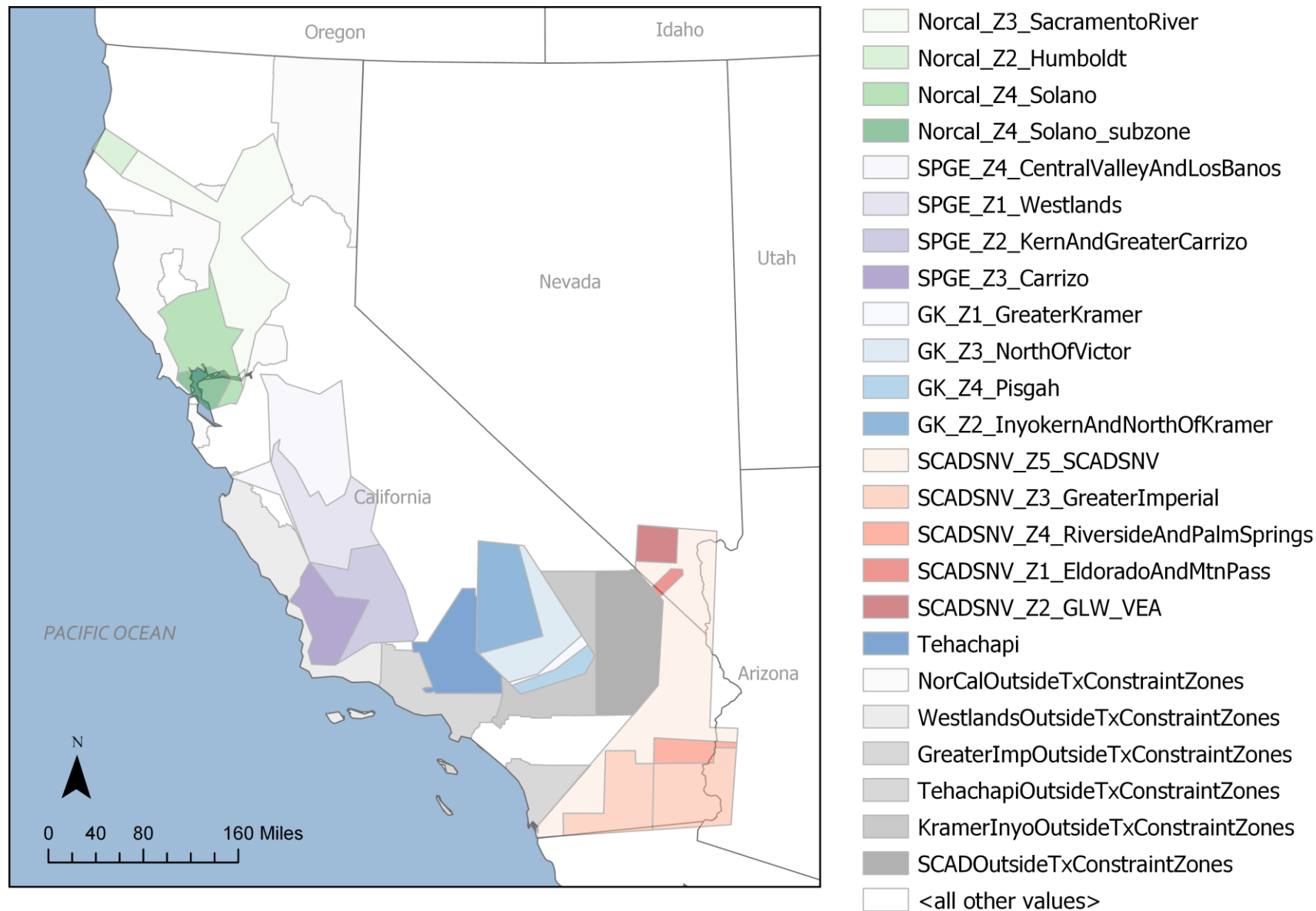
# Transmission Cost & Availability

- The CAISO published its latest capability estimates for each transmission zone, as well as cost estimates for upgrades to increase capability, in its May 20, 2019 white paper.
- RESOLVE has been updated per "Option 1" described in the June 17, 2019 Modeling Advisory Group (MAG) presentation\*:
  - Assigned candidate resources to updated transmission zone definitions.
  - Where candidate resources do not fall within any transmission zone, these were assigned to adjacent zones where possible, or to new zones for which. capability limits were assumed to equal the capacity in the interconnection queue.
  - Identified delivery points to CAISO zones for out-of-state and offshore resources.
  - Capability and upgrade cost values per the CAISO's estimates, with deductions to capability to allow for baseline resources with online dates of 2019 or later.
  - Transmission capability of all zones and subzones are represented concurrently such that both subzone and outer zone transmission limits are not exceeded.

\*See MAG slides 82-92 available at:

[https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP\\_MAG\\_20190617\\_CoreInputs.pdf](https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_MAG_20190617_CoreInputs.pdf)

# 2019 Transmission Zones





## **2.4. CORE IRP MODELING FUNCTIONALITY AND ASSUMPTIONS UPDATES**

# New RESOLVE Functionality: Economic Retention of Existing Thermal Generation

- In the 2017-18 IRP Reference System Plan, existing thermal resources were assumed to be available indefinitely unless retirement had been announced.
- In the 2019-20 IRP Proposed RSP, the RESOLVE model has been updated to determine the level of dispatchable gas resources that should be retained by CAISO ratepayers to minimize overall CAISO system costs.
  - Retention decisions are made for CCGTs, Peakers, and Reciprocating Engines.
  - All combined heat and power (CHP) facilities are retained through 2030 due to the presence of a thermal host.
  - OTC plants already scheduled for retirement are retired on schedule (retention decisions not made by RESOLVE). Some cases explore different levels of OTC retention.
  - Note: RESOLVE's economic thermal retention functionality assesses whether it is economic to retain gas capacity for CAISO ratepayers, but does not assess whether gas capacity should retire. Other offtakers may contract with gas plants balanced by CAISO, even if CAISO ratepayers do not. In addition, gas plant operators may choose to keep plants online without a long-term contract.
- To retain existing gas assets in RESOLVE, CAISO ratepayers must pay a fixed O&M cost to maintain the resource.
  - CCGT: \$11/kW-yr; Peaker and Reciprocating Engines: \$14/kW-yr (\$2016)

# Retention When Needed for Local Capacity Requirements (LCR)

- Gas plants located in LCR zones are retained indefinitely.
  - Only the retention of dispatchable gas resources *outside of* LCR zones is decided by RESOLVE.
  - Further study required to determine replacement resources that meet local reliability requirements.

RESOLVE Resource	2030 Baseline Capacity (MW)	LCR capacity - retained indefinitely (MW)	Retention decided by RESOLVE (MW)
CAISO_CCGT1	13,333	8,412	4,921
CAISO_CCGT2	2,928	1,885	1,043
Peaker1	4,914	3,163	1,751
Peaker2	3,683	1,309	2,374
CAISO_Reciprocating_Engine	255	184	71

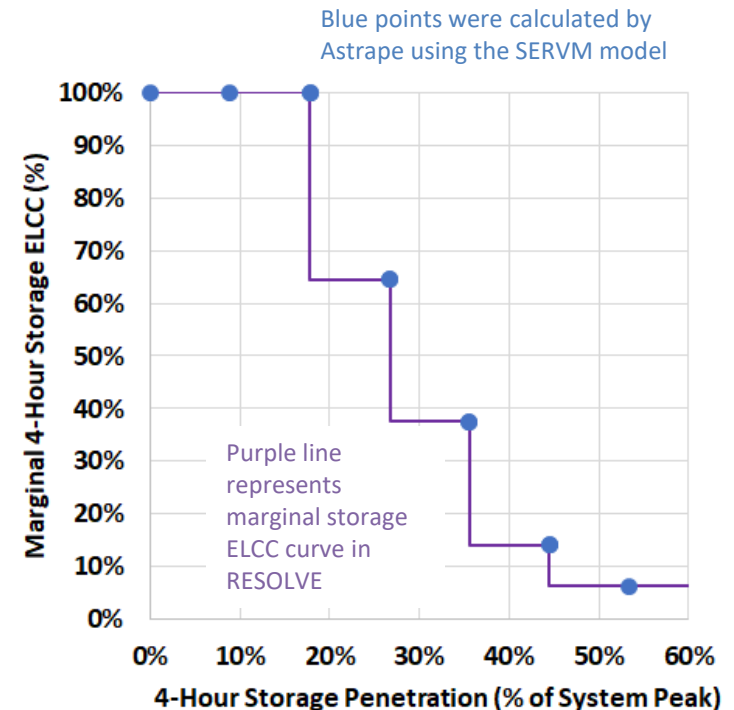
# Changes to Battery Storage Capacity Value

- Battery storage provides resource adequacy value.
  - Current CPUC RA rules count a battery with 4 hours of duration as having 100% ELCC.
- In the 2017 IRP, battery storage capacity value was a function of the duration of the battery, with batteries reaching full capacity value at 4 hours of duration.
  - Capacity value = Power Capacity \* Min(1, Duration/4)
- In the 2019 IRP, the battery storage capacity value has been modified to decline with storage penetration.
  - 2017 IRP power-duration relationship retained.



# Battery Storage ELCC Curve

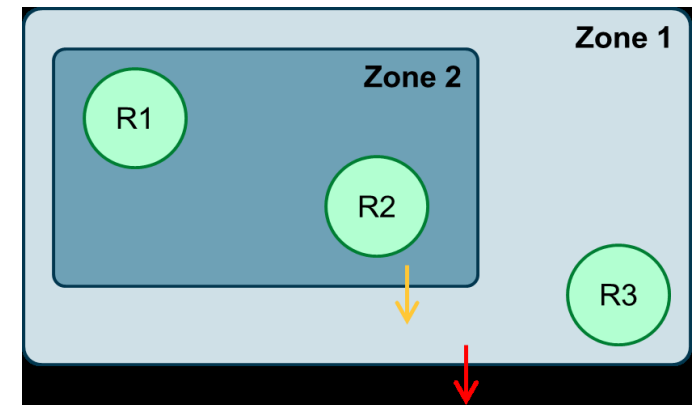
- Battery storage does not provide equivalent capacity to dispatchable thermal resources at higher battery storage penetrations because:
  - Storage flattens the net peak, requiring longer duration and/or higher stored energy volumes.
  - Increasing penetrations face the challenge of having enough energy to charge to support peak demand
- Astrapé Consulting used the SERVIM model and the CPUC's SERVIM database populated with a preliminary RESOLVE 46 MMT portfolio to calculate the capacity contribution of storage in 2030 across a wide range of storage capacities
  - A description of Astrapé's methodology and discussion of relation to previous studies can be found: <https://www.cpuc.ca.gov/General.aspx?id=6442459770>
  - Case includes significant BTM and utility-scale solar capacity that changes the shape of the net load curve and can be used to charge batteries
- RESOLVE includes a declining storage ELCC curve for utility-scale Li-Ion and Flow batteries



ELCC curve was developed for a 2030 system with high levels of solar generation and may overstate battery capacity value in the early 2020s when solar capacity is lower

# Nested Transmission Constraint Update

- CAISO has identified multiple layers of transmission constraints for many transmission zones. These “nested” constraints represent multiple concurrent limitations to delivering energy from renewable resource zones to load centers.
  - See: <http://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf>
- While only one limit may be binding at a time, all limits must be modeled simultaneously to ensure that no limits are exceeded.
- After the Preliminary Results released October 5, 2019, the RESOLVE model was updated to more fully represent nested constraint limits and associated transmission costs. In the current results:
  - Nested constraints are modeled by allowing candidate resources to be assigned to multiple (nested) transmission zones. By allowing multiple assignments, a candidate resource counts towards the FCDS and EO limits in all of the zones and subzones to which it is assigned.
  - Transmission costs for subzones represent the incremental cost to build transmission to the next level of transmission constraint. For example, building transmission along the **yellow** path in the figure above allows a resource to be delivered from Zone 2 to Zone 1; if Zone 1 does not have any available transmission capacity then transmission along the **red** path would also need to be built to deliver capacity from Zone 2 to CAISO load centers.





## 2.5. CASES MODELED

# Types of Cases Modeled

- **Core Policy Cases:** Three cases that reflect different potential GHG trajectories for the electric sector.
  - Purpose: Compare the impacts of different GHG goals on portfolio composition, costs, and emissions.
- **Core Policy Sensitivities:** Variations on the core policy cases that reflect changes to one or more of the default assumptions about the future (e.g., load, resource costs).
  - Purpose: Determine how different future conditions could affect portfolio composition, costs, and emissions.
- **Near-term Resource Availability Study:** Variations on the 46 MMT core policy case that apply limitations to near-term solar availability.
  - Purpose: Explore effects “real-world” limitations on near-term resource buildout.
- **SB100 2045 Framing Study:** Three cases that reflect different potential GHG and load trajectories for the electric sector based on different economy-wide decarbonization pathways.
  - Purpose: Explore how 2045 goal under SB100 and economy-wide decarbonization targets could affect outlook for electricity sector GHG emissions and resource planning in 2030 timeframe.

# List of Sensitivities

**Cases that reflect variations in assumptions about the future against which the core policy cases were tested.**

Sensitivities	Near-Term Resource Availability Study	2045 Framing Studies
Reference	Limited Annual Solar Build	High Electrification
Low Cost New Transmission	Limited Annual Solar Build + Partial OTC Extension	High Electrification with Full New OOS Transmission
High Cost New Transmission	Limited Annual Solar Build + Partial OTC Extension + Low RA Imports	High Electrification with No New OOS Transmission
Full New OOS Transmission		High Electrification with Offshore Wind
No New OOS Transmission		High Biofuels
Offshore Wind Available		High Hydrogen
Offshore Wind Available with no new OOS Tx		High Biofuels
High Solar PV Cost		
ITC Extension		
High Battery Cost		
Paired Battery Cost		
Low RA Imports		
High RA Imports		
2045 End Year		
High Load Baseline		
OTC Extension		
Partial OTC Extension		
Early Shed DR Availability		
No New DER		

# List of Modeling Changes Implemented Since Preliminary Results Analysis

- Added more modeling years to RESOLVE analysis, including 2020, 2021, 2023, and 2024.
- RESOLVE model was updated to more fully represent "nested" transmission constraint limits and associated transmission costs.
- Added constraints on availability for some candidate resources in RESOLVE:
  - Shed DR limit (default): Total shed DER potential phased in linearly from 2020 to 2025.
  - Utility-scale solar resource limit (sensitivity only): To reflect real-world constraints on solar buildout, an annual deployment limit of 2 GW/yr is enforced in certain cases on candidate solar resources through 2023.
- Allowed RESOLVE to build new transmission for 3 GW of out-of-state (OOS) wind resources as a default assumption.
- Implemented import capacity constraint in SERVIM to match RESOLVE assumptions. More detail is contained on Slide 11 of Validation with SERVIM presentation.



## 2.6. PORTFOLIO METRICS

# Metrics Used to Characterize Modeling Results

- **Selected Resources**, in MW: new resources that the model selects as part of the optimal, least-cost portfolio
  - Selected resources are incremental to any resources included in the baseline
- **Gas Capacity not Retained**, in MW: capacity of existing gas power plants that the model did not retain as a part of the optimal, least cost portfolio.
  - Values do not include planned retirements of OTC gas power plants.
- **Costs**
  - Incremental Total Resource Cost: fixed and operating costs, including program costs and customer costs; calculated as difference from Default Case
  - Revenue Requirements: fixed and operating costs, including program costs, but not customer costs
  - Average Rate: revenue requirements divided by retail sales



# Incremental Total Resource Cost Metric

- The **“incremental total resource cost”** (or incremental TRC) for each scenario is calculated relative to the 46 MMT Reference Case.
  - Represents an **annualized incremental cost (\$MM/yr)** expressed in 2016 dollars over the course of the analysis (2020-2030).
- “Incremental TRC” metric captures the sum of costs directly considered in development of Reference System Portfolio:
  - RESOLVE objective function
    - Fixed costs of new electric sector investments (generation & transmission)
    - CAISO portion of WECC operating costs (including net purchases & sales)
  - Other costs modeled externally to RESOLVE associated with assumptions
    - Utility & customer demand-side program costs
- “Incremental TRC” does not reflect previously authorized costs; e.g., distribution infrastructure replacement.

# Sources for Calculating Revenue Requirements

- Revenue requirements calculated based on:
  - RESOLVE outputs.
  - IOU IEPR filings: forecasts of annual IOU revenue requirement (2017-2030) submitted to CEC IEPR docket.
  - IOU AB67 filings: historical revenue requirement data (2003-2017) submitted by IOUs to CPUC.
  - Padilla report: report published by CPUC summarizing cost of renewable procurement for 2018.
  - Data from demand-side programs: assumed program costs provided by EE, DR groups in Energy Division (from 2017 IRP).

# Revenue Requirement Components

Category	Component	Source
<b>Distribution</b>	Existing Distribution Revenue Requirement (RR)	IEPR
<b>Transmission</b>	Existing Transmission RR	IEPR
	New Renewables-Driven Transmission	RESOLVE
<b>Generation</b>	Existing Utility Owned Generation (UOG) RR	IEPR
	Existing Bilateral Contracts	AB67
	Existing Renewables Contract Cost	Padilla
	New Renewables Contract Cost	RESOLVE
	New Storage Cost	RESOLVE
	Variable Generation Costs	RESOLVE
	Allowance Allocation Revenue	RESOLVE
<b>Demand-Side Programs</b>	Energy Efficiency Program Costs	Other
	Existing DR Program Costs	Other
	New DR Program Costs	RESOLVE
<b>Other</b>	DWR Bond Charges	IEPR
	Nuclear Decommissioning Cost	IEPR
	Public Purpose ( <i>excluding energy efficiency</i> )	IEPR
	Other Miscellaneous	IEPR



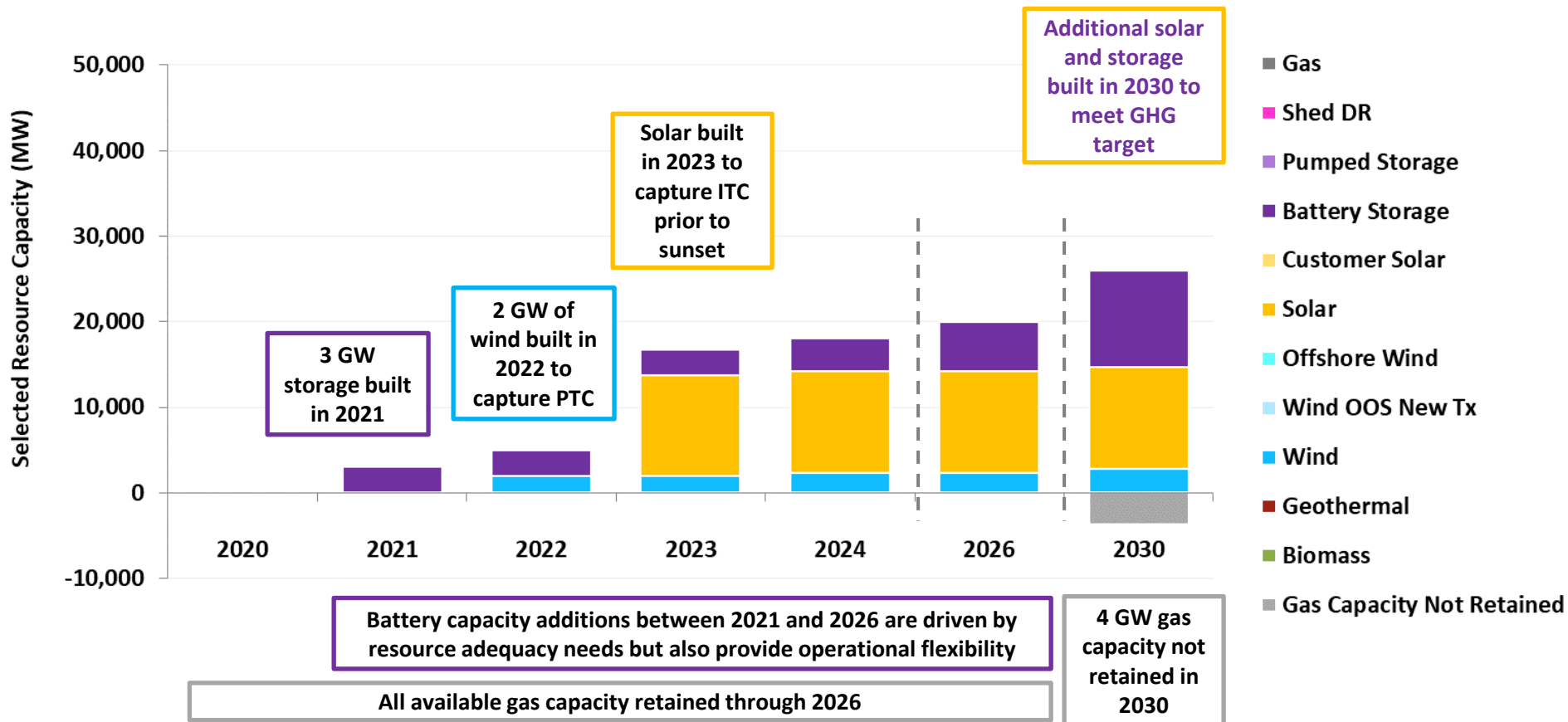
### 3. MODELING RESULTS



## **3.1. SELECTED RESOURCES IN THE CORE POLICY CASES**

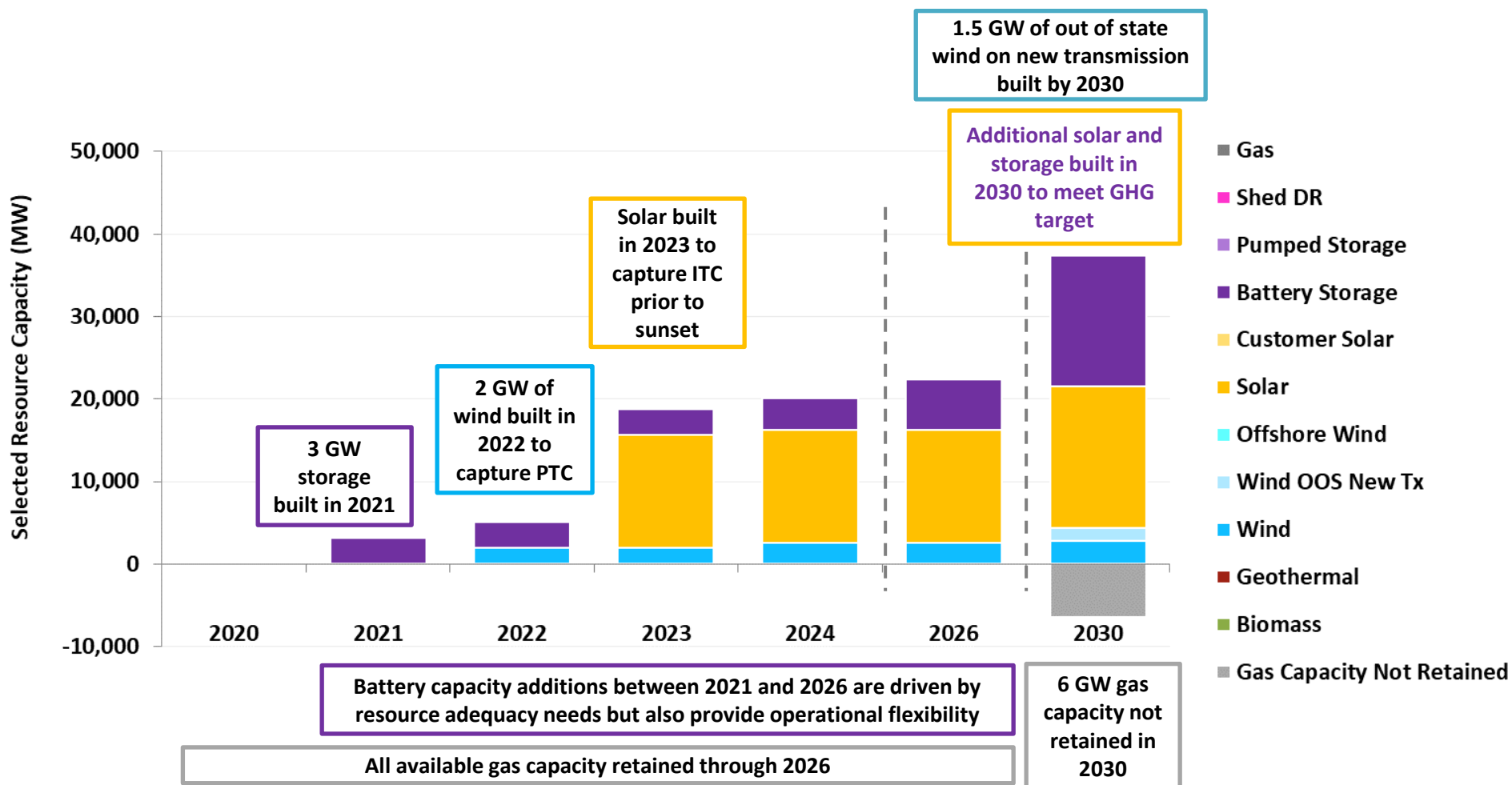
# RESOLVE Output: Resources Selected in 46 MMT Case

Note: resources shown in this chart are selected by RESOLVE and are in addition to baseline resources



# RESOLVE Output: Resources Selected in 38 MMT Case

Note: resources shown in this chart are selected by RESOLVE and are in addition to baseline resources

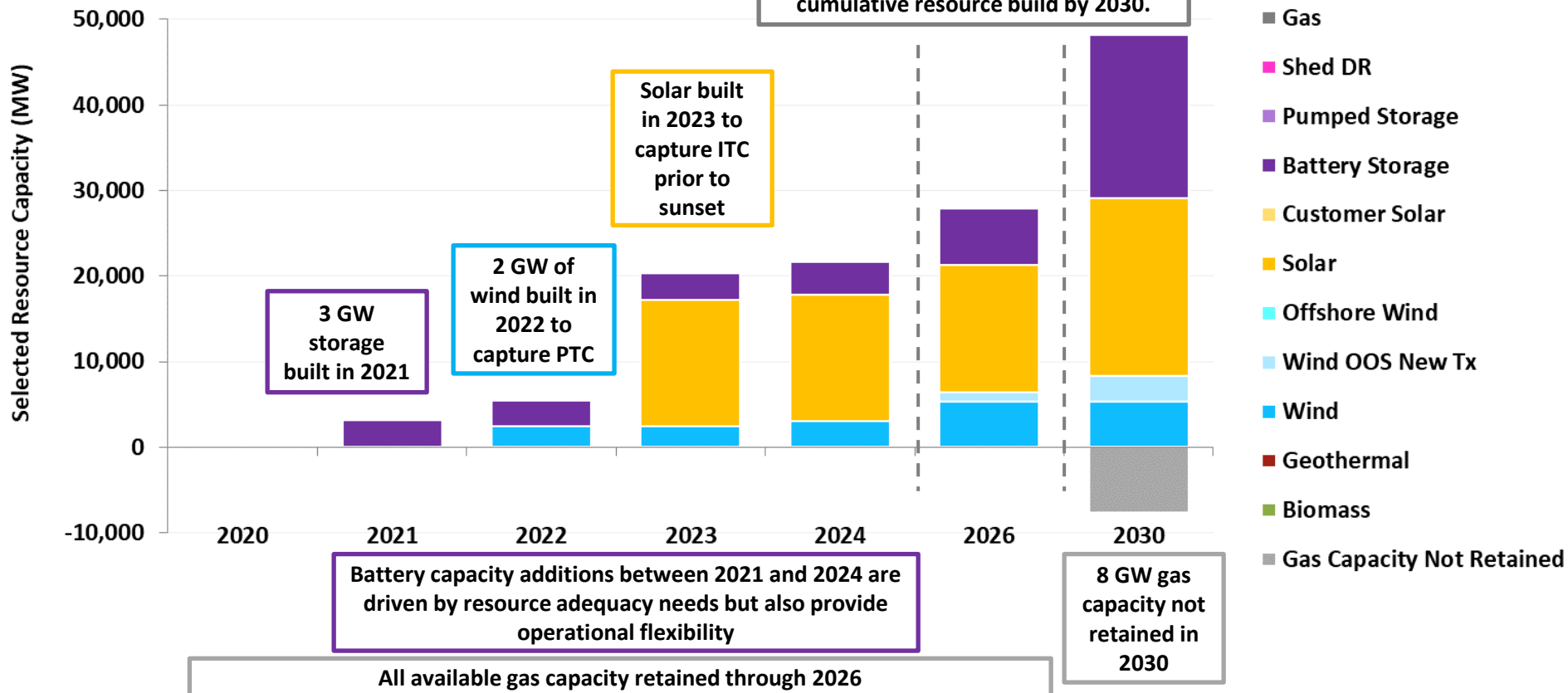


# RESOLVE Output: Resources Selected in 30 MMT Case

Note: resources shown in this chart are selected by RESOLVE and are in addition to baseline resources

8 GW of wind by 2030 provides portfolio diversity, including 3 GW on new transmission from NM and WY

GHG target drives procurement in 2026 and 2030, resulting in almost 50 GW of cumulative resource build by 2030.





# Observations Regarding Selected Resources in Core Policy Cases

- Core policy case observations:
  - New battery storage resources are first selected in 2021.
    - RESOLVE investment decisions reflect online date for resources – , which might be at odds with significant lead-time required for contracting, permitting, and construction.
  - 2023 buildout of utility-scale solar PV capacity reflects ITC cost reductions available in the near-term.
  - Utility-scale solar PV, battery storage, and wind dominate the selected resources through 2030.
  - Pumped storage (85 MW) built in 2026 under the most stringent GHG target.
  - New gas generation is not part of the least-cost solution.
  - Gas capacity retention:
    - Reflecting a near-term capacity need, all existing gas capacity (except for OTC retirements) retained through at least 2026 under all GHG targets.
    - Range of gas capacity not retained in 2030 is 4 GW (46 MMT) to 8 GW (30 MMT).
  - Shed DR is selected in early 2020s (~100-200 MW) to address near-term capacity shortfall.

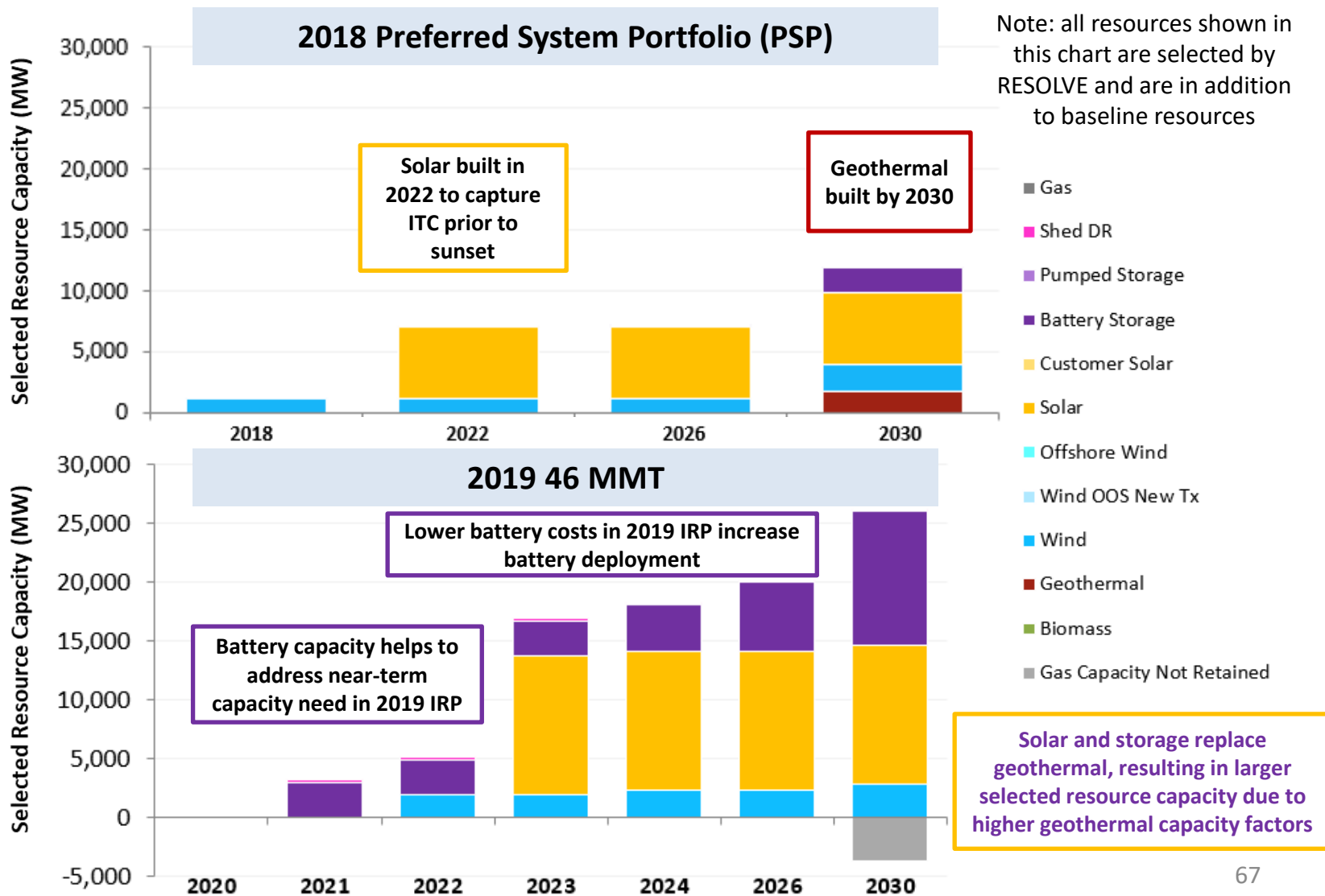
## Core Policy Case Results in 2045 Context

- The Core Policy Cases show portfolio results with a planning horizon of 2030.
- The 2045 Framing Study (Appendix A) reflects analysis performed on different decarbonization strategies in the CEC Deep Decarbonization report\* and focuses on three potential pathways: High Electrification, High Biofuels, and High Hydrogen.
- The 2045 studies generally retain more gas capacity than in the 2030 Core Policy Cases, particularly the 38 and 30 MMT cases.
- An additional sensitivity (slide 117) demonstrates more gas capacity retained in each of the 2030 Core Policy Cases if a 2045 planning year is added to the analysis.
- This suggests that context outside of the 2030 Core Planning Cases should be used to inform any decision-making regarding the optimal portfolio of resources for 2030.

\*Deep Decarbonization in a High Renewables Future. Available at:

<https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf>

# Comparison of 2019 46 MMT Core Policy to 2018 PSP: Resource Build

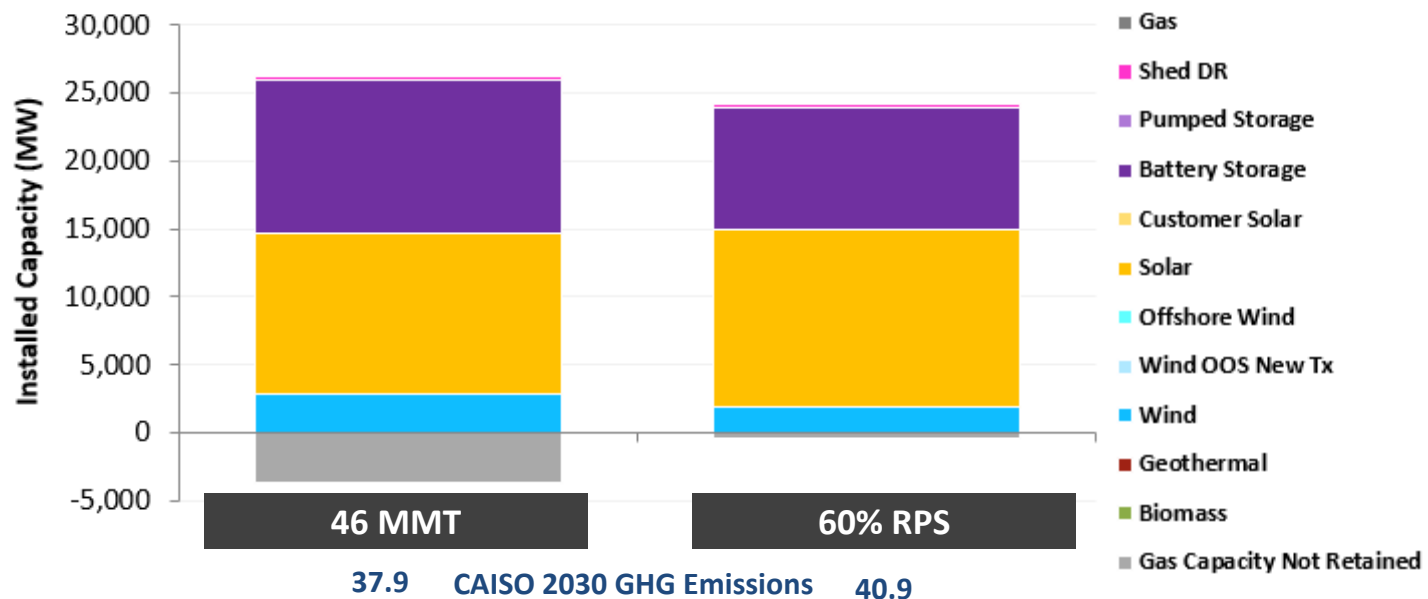


# Observations Regarding Comparison of 2019 46 MMT Core Policy Case and 2018 PSP

- Similarities:
  - Utility-scale solar PV, battery storage, and wind represent most of the selected resource capacity through 2030.
  - Solar PV selected in the early 2020s to capture value of ITC.
  - New gas plants not part of the least-cost solution.
- Differences:
  - Economic thermal retention functionality has been implemented, with approximately 4 GW of gas capacity not retained in 2030 in the 2019 IRP.
  - Capacity shortfall in the early 2020s (further described on slide 83) drives much earlier procurement of battery storage in the 2019 IRP, as well as selection of Shed DR.
  - No geothermal resources selected in 2019 46 MMT.
  - More total nameplate capacity is selected by in 2019 46 MMT, likely driven by decreased battery and solar PV cost assumptions in 2019 IRP modeling.
  - Wind potential updated to reflect feasible timeline to bring resources online, given current interconnection queue and typical development processes.

# 60% RPS vs 46 MMT Comparison

- To explore an RPS-driven portfolio, a case was run without a GHG target. In this case, the 60% RPS requirement by 2030 is a major driver of investments.
- While not identical, the 46 MMT case and the 60% RPS case produce similar portfolios in 2030 (shown below).
  - Portfolio costs are very similar, with the levelized TRC of 60% RPS case ~\$100 million/yr lower than 46 MMT case
- The 46 MMT portfolio results in 3 MMT/yr lower emissions than the 60% RPS portfolio, because renewable exports count toward RPS requirements, they do not count towards state GHG goals.
- An additional ~3 GW of additional storage build in 46 MMT is accompanied by an additional ~3 GW of gas capacity that is not retained.

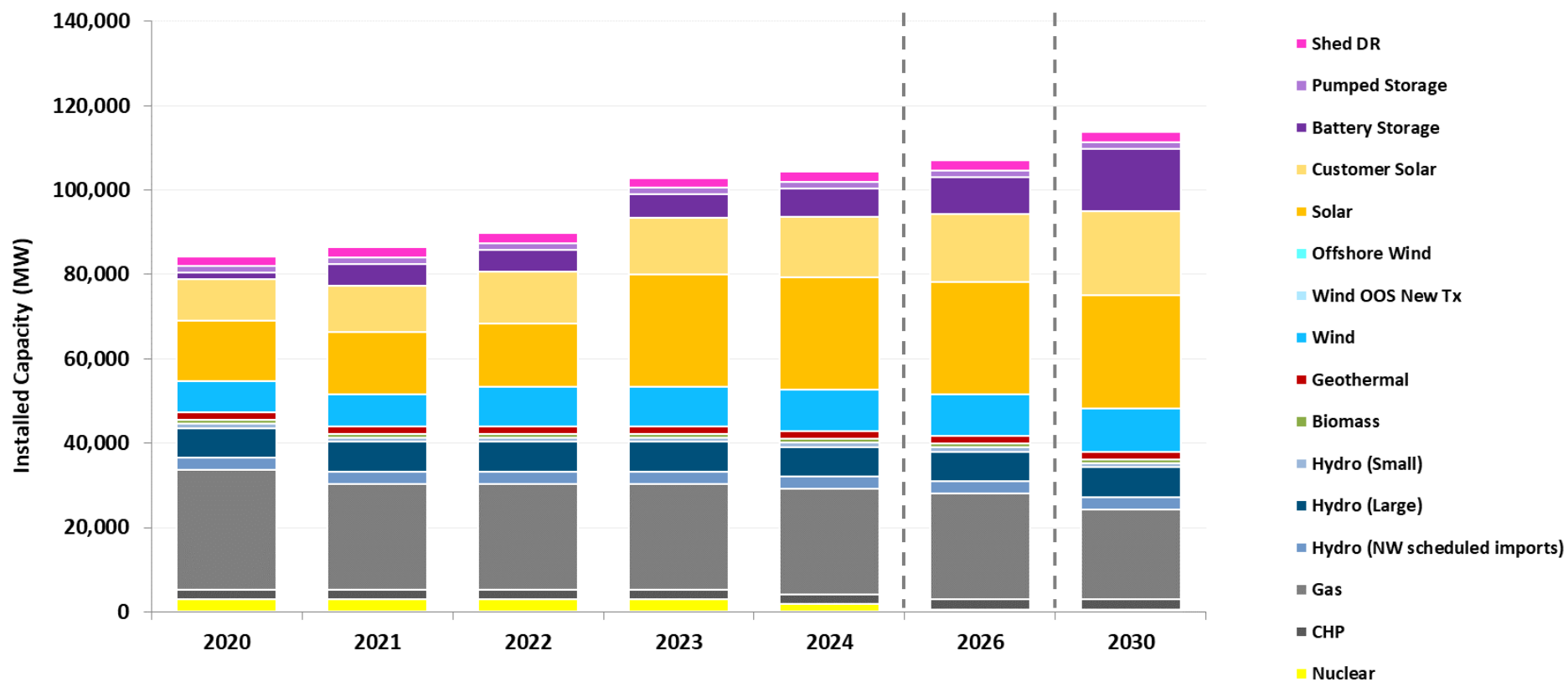


## Total Resource Stack Plots

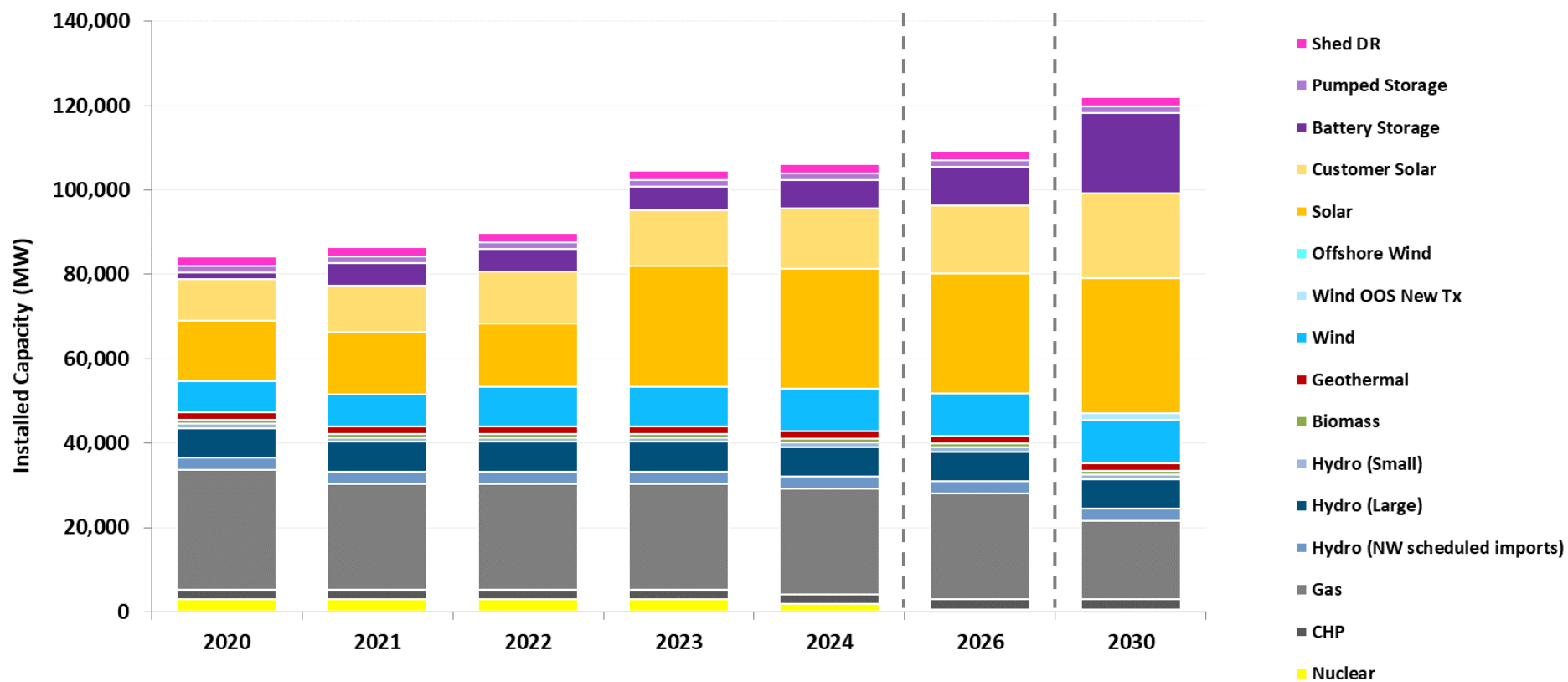
- The previous slides focused on the resource capacity selected by the RESOLVE optimization.
- The subsequent slides add baseline resource capacity to the selected capacity to show the total CAISO resource portfolio.
- Gas capacity not retained, shown as a negative value on the previous plots, is depicted as a reduction in gas capacity on the subsequent slides.
- When the Commission adopts a Reference System Portfolio, it will constitute the total resource stack – not just the capacity selected by RESOLVE articulated in previous slides.

Note: the resource capacity of “NW Scheduled Imports” was developed to be consistent with an expected amount of energy delivered to CAISO from Northwest hydroelectric resources. The resource capacity on the subsequent slides is not meant to imply a specific level of resource adequacy contracting with NW hydro resources.

# Total Resource Stack: 46 MMT Case

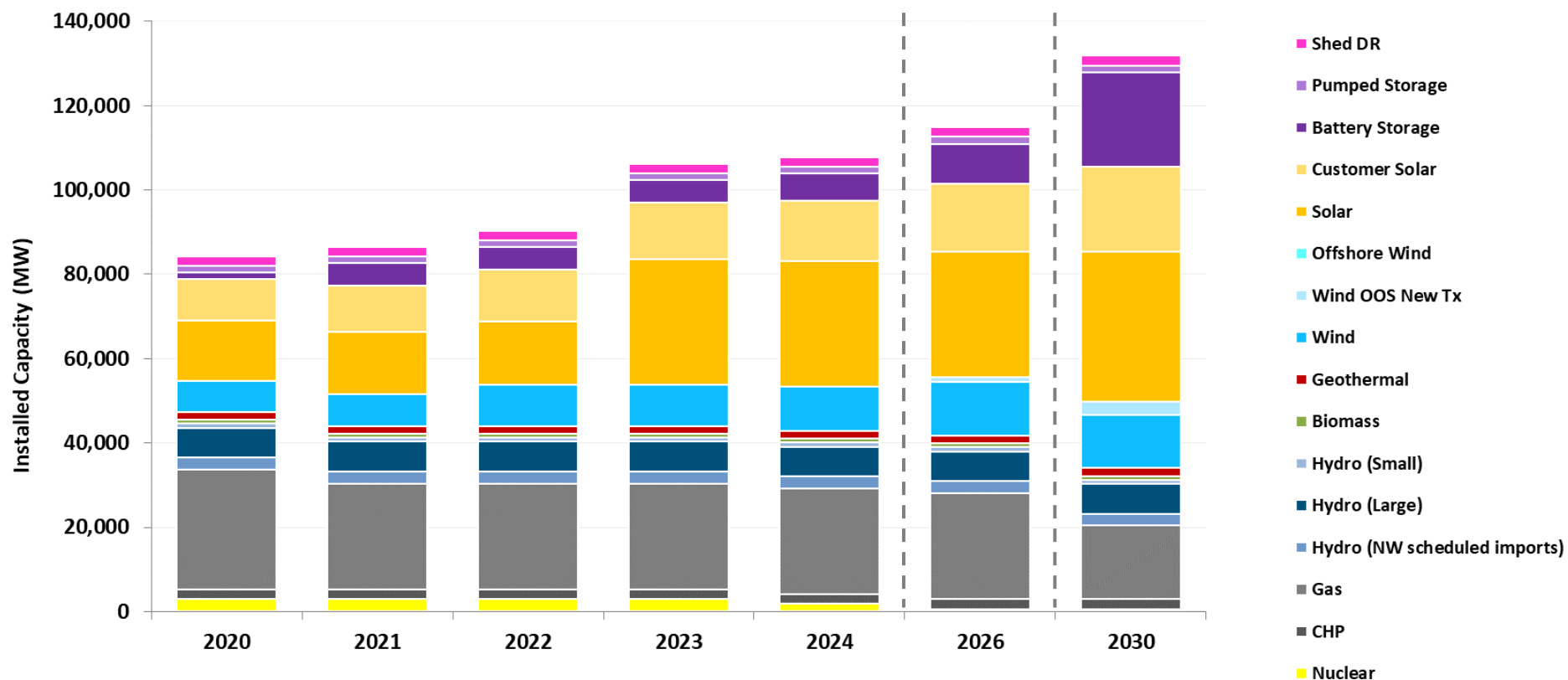


# Total Resource Stack: 38 MMT Case





# Total Resource Stack: 30 MMT Case

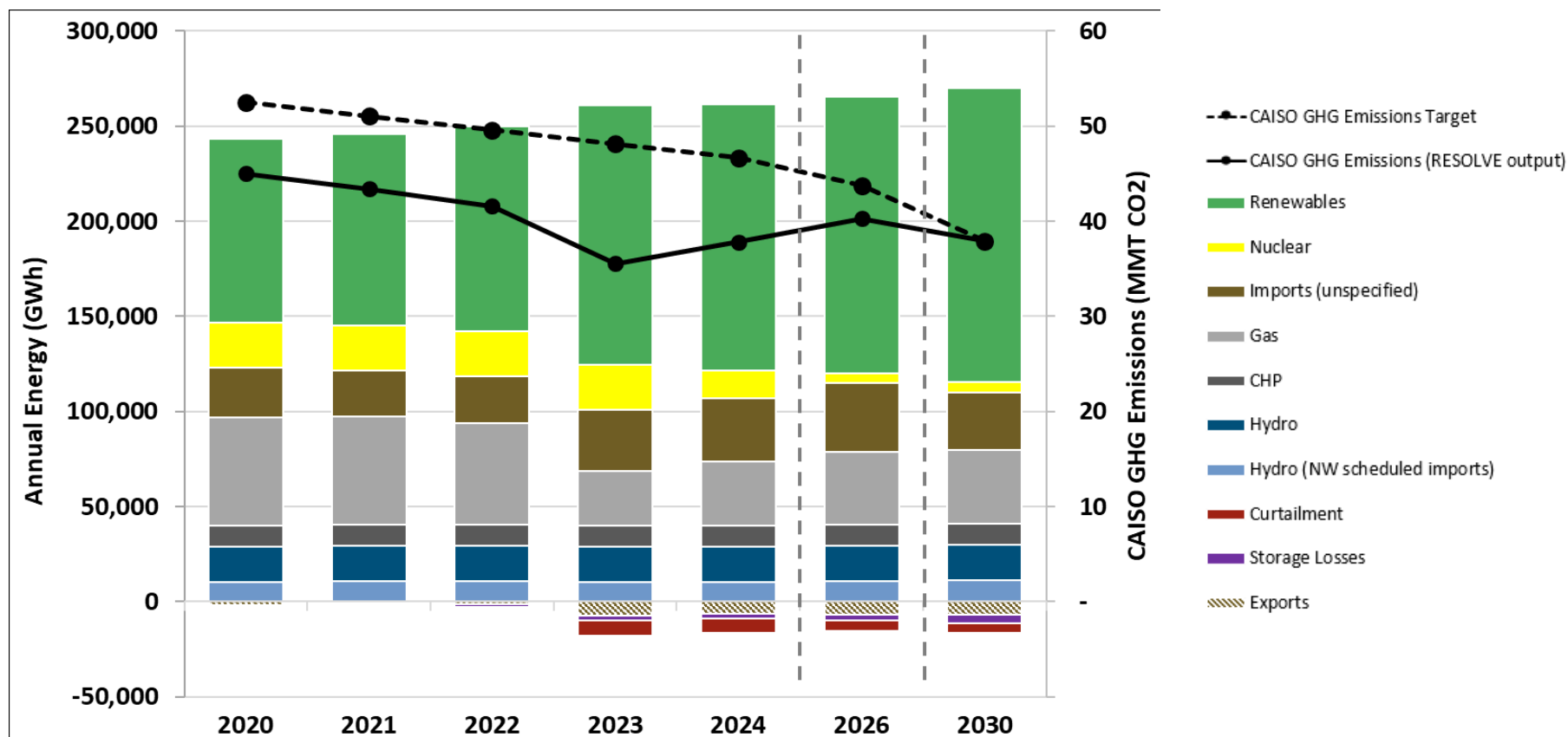


# Total Resource Stack in Core Policy Cases

- The previous slides showed installed capacity of both baseline resources and resources selected by RESOLVE.
- RESOLVE's dispatch module uses resource performance information and demand profiles to develop hourly dispatch schedules, resulting in energy production from each resource.
- The following slides show how annual average energy production from different resources to serve CAISO load for the three core policy constraints.
- The GHG target (a RESOLVE *input*), and portfolio GHG emissions (a RESOLVE *output*) are shown for reference.

# CAISO Energy Balance

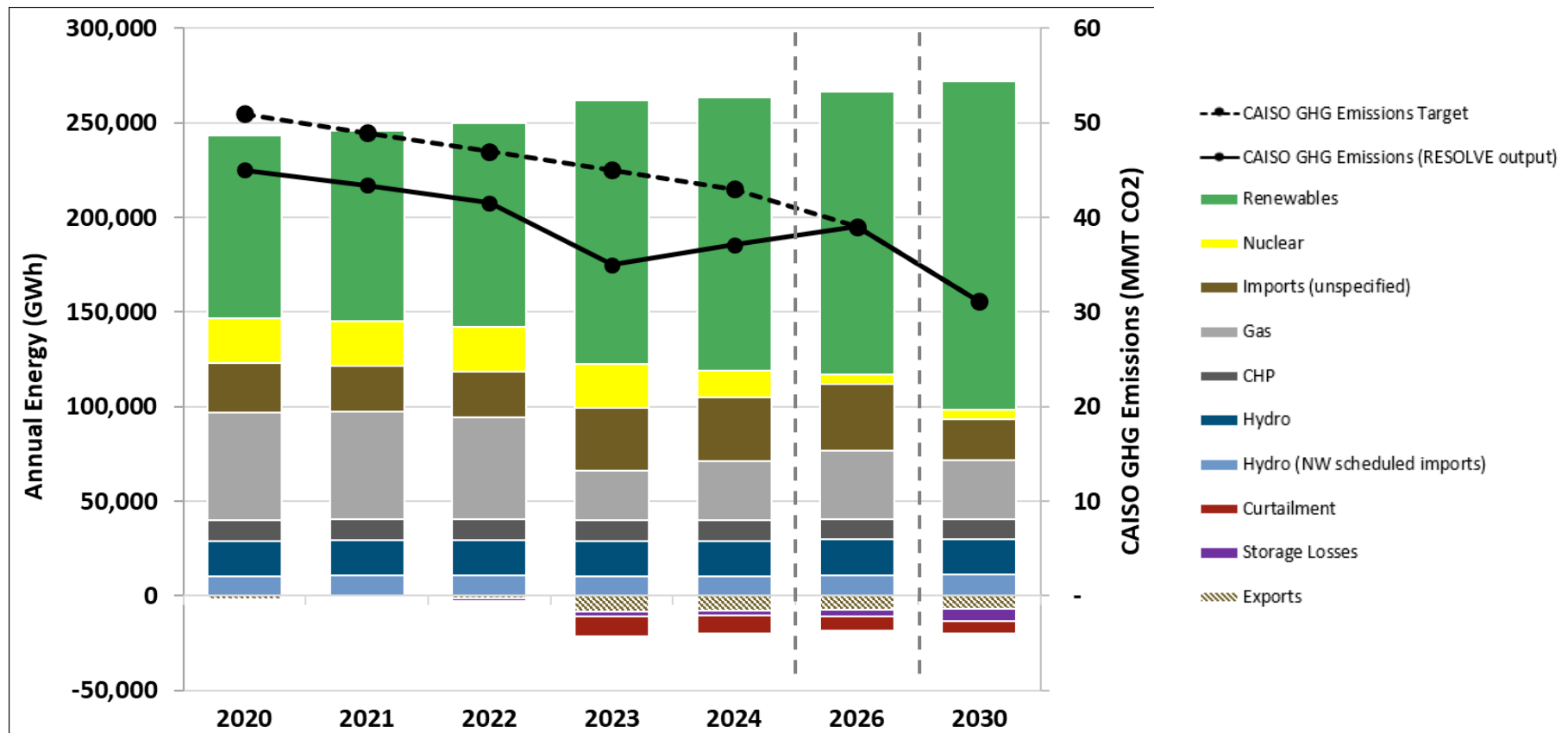
## 46 MMT Statewide Target



Renewable generation (green) is net of curtailment. Curtailment is shown separately on the graph to demonstrate its magnitude.

# CAISO Energy Balance

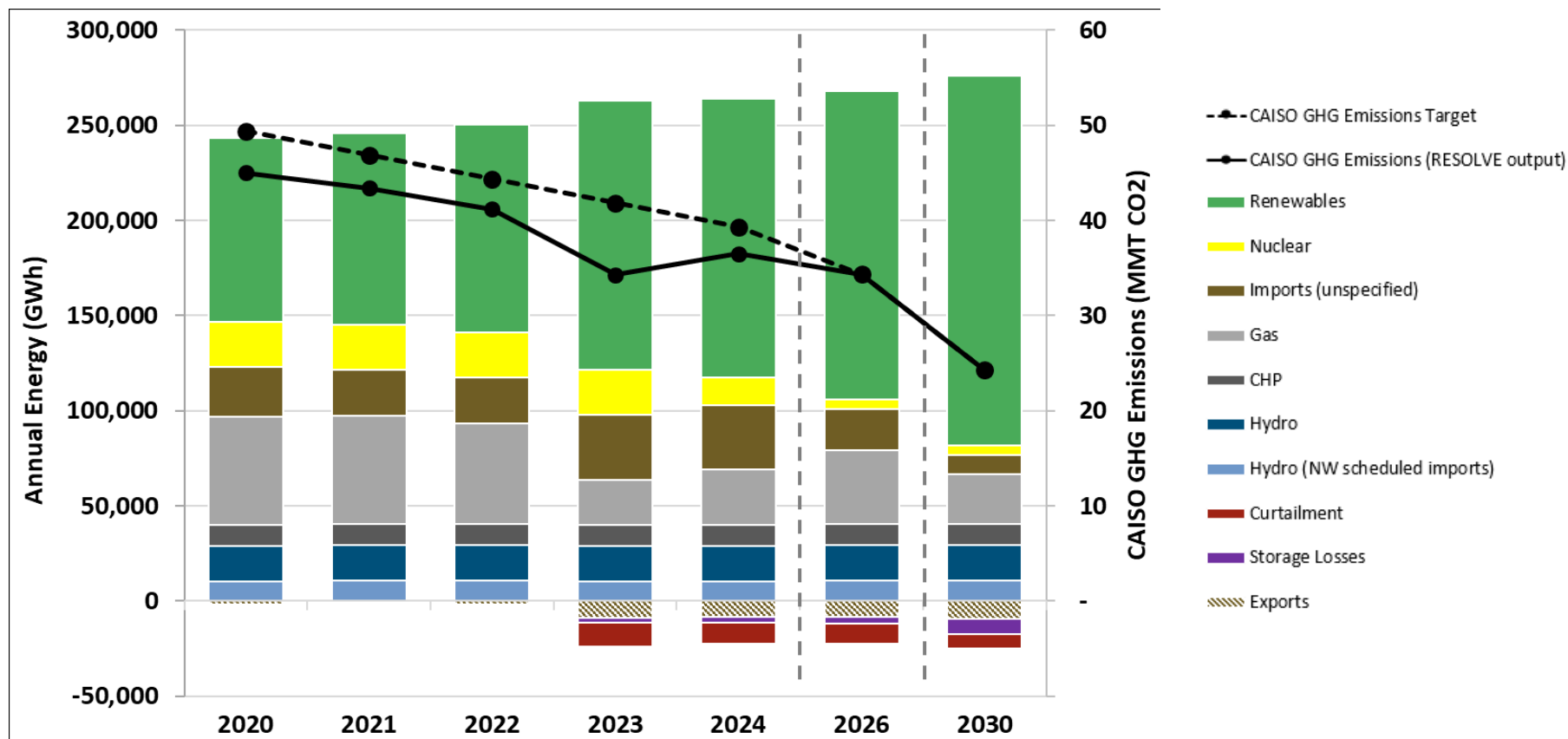
## 38 MMT Statewide Target



Renewable generation (green) is net of curtailment. Curtailment is shown separately on the graph to demonstrate its magnitude.

# CAISO Energy Balance

## 30 MMT Statewide Target



Renewable generation (green) is net of curtailment. Curtailment is shown separately on the graph to demonstrate its magnitude.

# Energy Balance Observations

- From 2020 to 2024, emissions are lower than the GHG target in all three cases (46, 38, and 30 MMT).
  - Baseline resources in 2020 are sufficient to reduce emissions below the 2020 constraint.
  - Resource additions beginning in 2021, especially solar PV in 2023, reduce emissions below 2020 levels, and significantly below the 2023 GHG constraint.
  - Battery storage additions in the early 2020s, driven by resource adequacy needs, provide operational flexibility that helps to integrate variable renewable resources.
- GHG emissions are higher in 2024 relative to 2023, in large part due to the retirement of Diablo Canyon Power Plant (DCPP) Unit 1.
  - Solar deployment in 2023 increases GHG-free energy available to the system before DCPP retirement, largely due to other factors such as capturing the value of expiring ITC for those solar resources.\*
- More stringent GHG constraints in 2030 (relative to 2026) drive investment in zero-GHG generation and storage, reducing production from GHG-intensive resources (in-CAISO gas resources and unspecified imports).

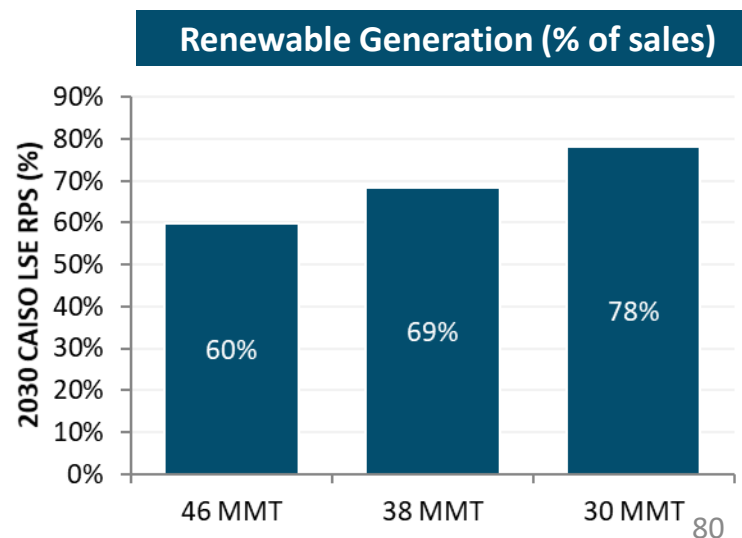
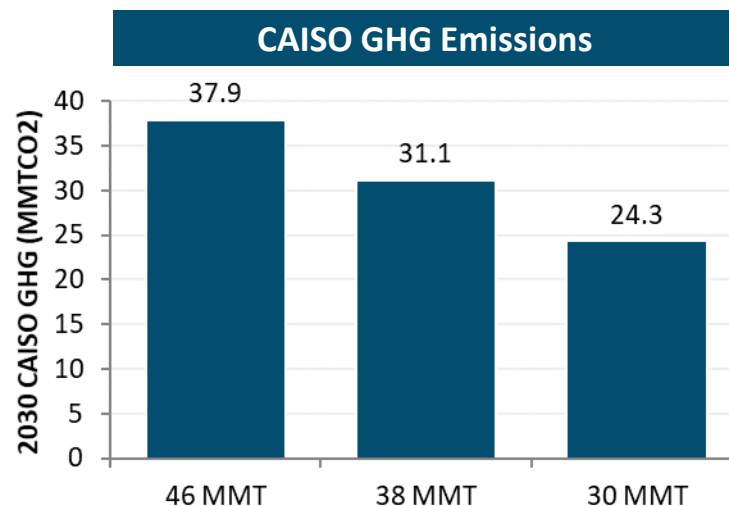
\*CPUC Decision (D.)19-04-040, Section 6.3, addresses this topic and the relationship between IRP modeling results, Diablo Canyon retirement, and the adopted 2018 Preferred System Plan in more detail: <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF>

# GHG Goals Are Expected to Lead to Reduced Utilization of Fossil Plants

- Expansion of renewable and storage resources in response to GHG planning targets results in lower energy production on a fleet-wide basis from dispatchable gas resources.
- Total gas plant capacity is relatively independent from gas plant usage.
- Dispatchable gas plants can provide power during times when energy-limited resources (solar and storage for example) are not able to produce.
- Under more stringent GHG targets, gas plants are increasingly retained for capacity rather than energy and are dispatched less frequently. Related content in other portions of this presentation:
  - Slide 46, explanation of economic retention functionality in RESOLVE
  - Slide 66, discussion of context of Core Policy Case gas retention in broader context, including 2045
  - Slide 86, description of existing gas generation in the context of 2022 capacity shortfall and increased battery storage penetration

# 2030 CAISO Renewables & Emissions

- GHG target assumptions are one of the largest drivers of RESOLVE investments, especially in 2030.
- All three core GHG cases (46, 38, and 30 MMT) also include a 60% RPS constraint in 2030 and interim RPS targets, per SB100.
  - Each core policy case meets SB100 RPS target.
- The 46 MMT case results in 60% RPS energy, but the RPS target is very close to binding.
- In the 38 and 30 MMT cases, the GHG target drives resource portfolio selection – more than 60% renewables are selected in 2030 as a result of the GHG target.
  - For example, an RPS of ~69% is a byproduct of achieving the 38 MMT carbon goal.



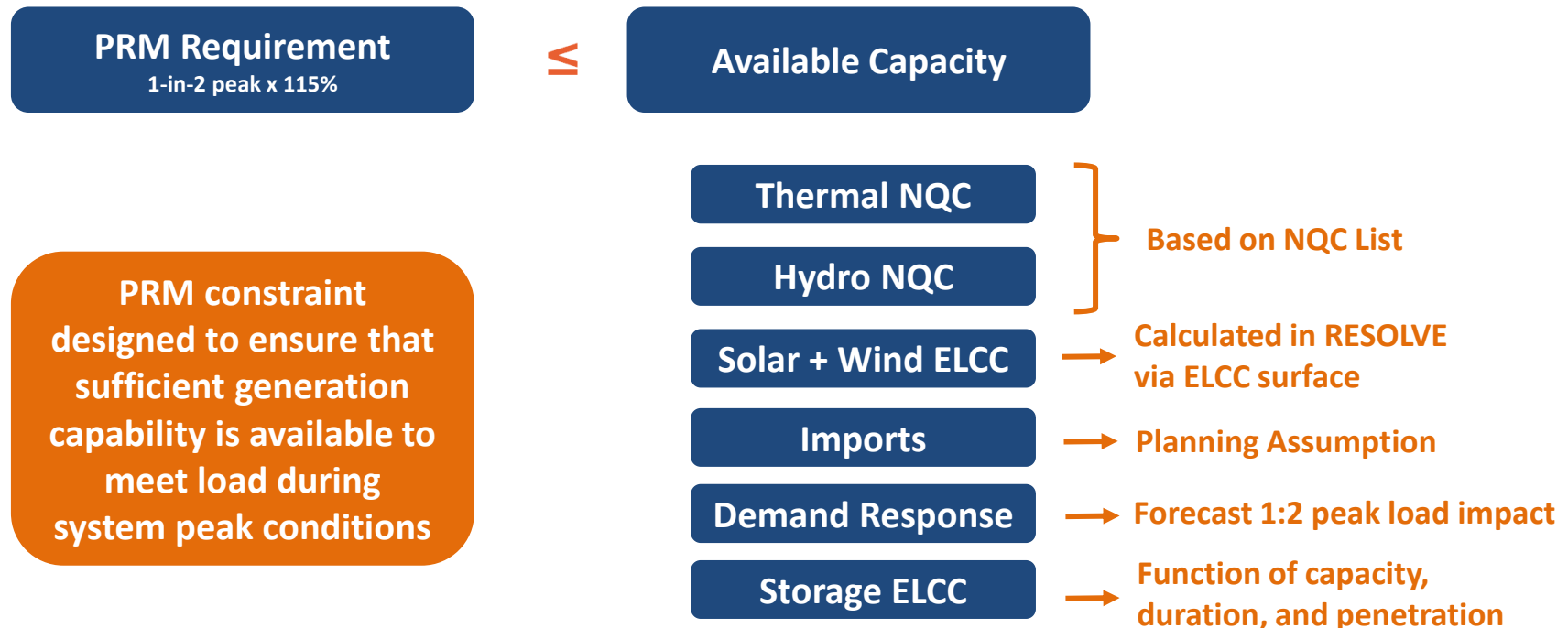




## **3.2. RELATIONSHIP TO CAPACITY NEEDS**

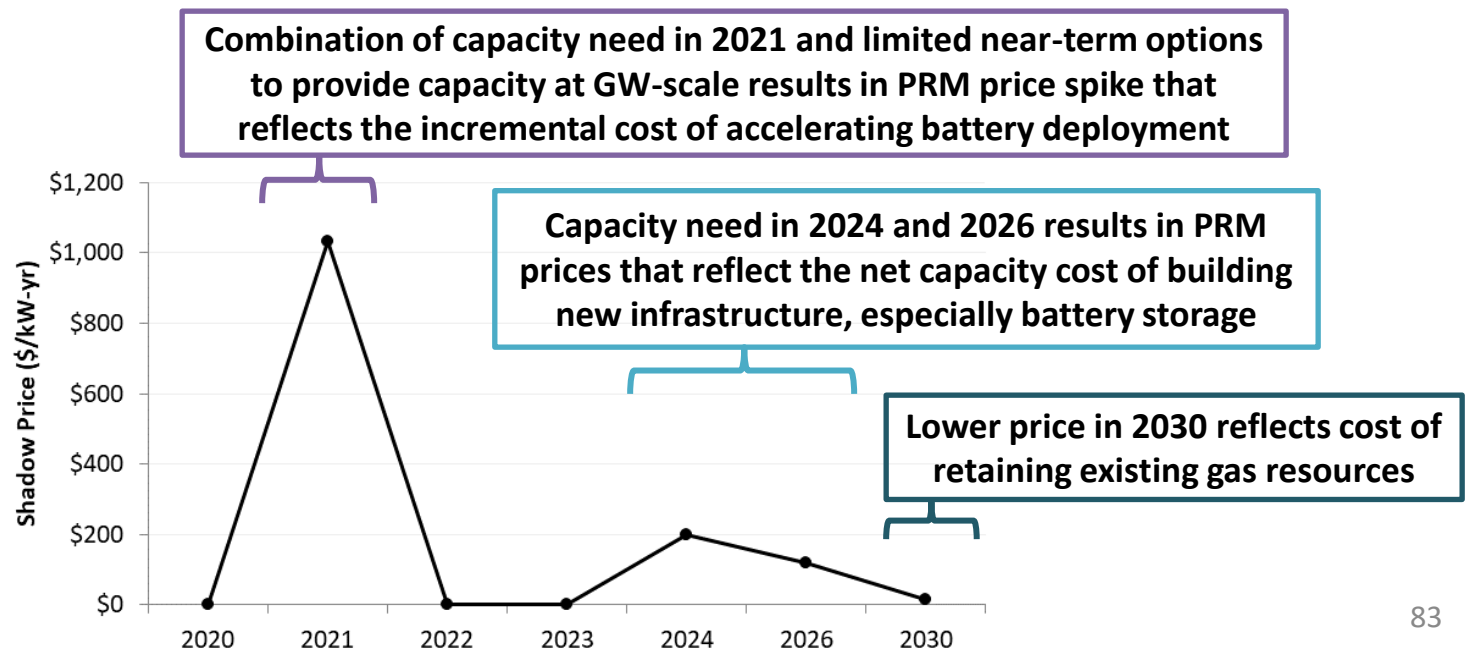
# RESOLVE Planning Reserve Margin Constraint

- In each year modeled, RESOLVE imposes a Planning Reserve Margin (PRM) constraint on the total CAISO generation fleet
- Contribution of each resource to the PRM requirement depends on the capabilities of the resource



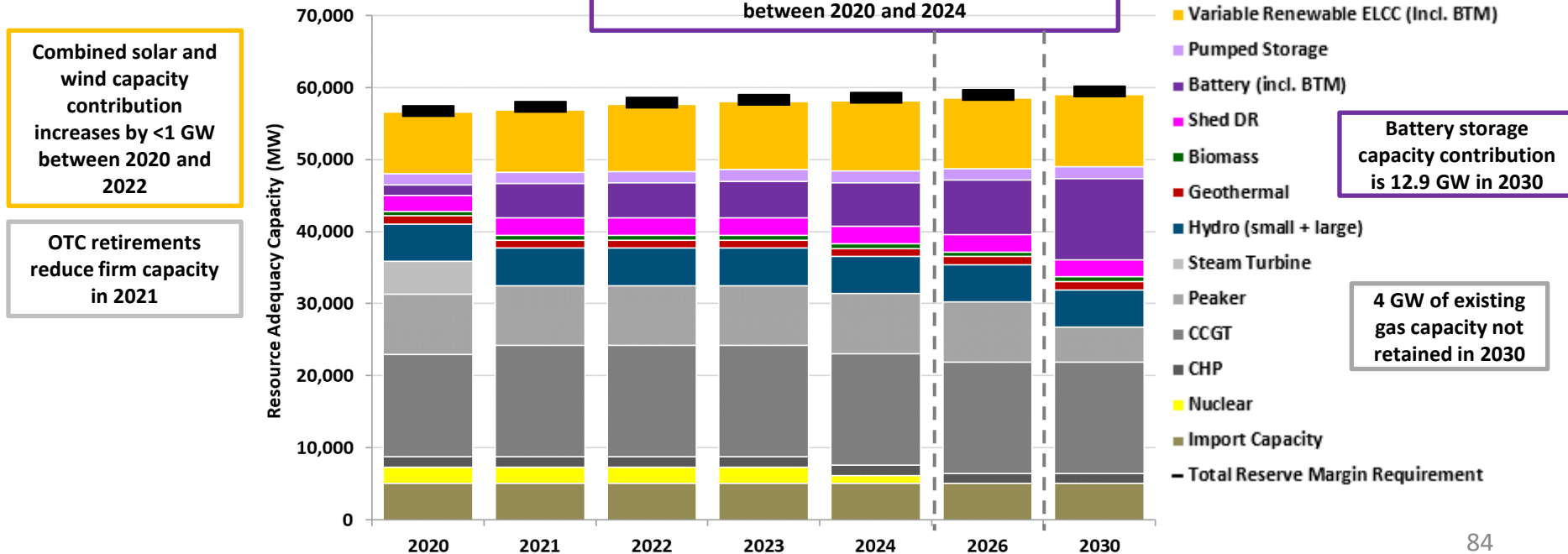
# Capacity Need and Price: 46 MMT Case

- RESOLVE's Planning Reserve Margin (PRM) constraint ensures that system resource adequacy needs are met in each period.
- If the baseline resource capacity does not meet the 15% PRM target, RESOLVE will build additional resources until the target is met.
- The marginal cost of meeting the PRM constraint (the "shadow price") reflects the difficulty of meeting the constraint.



# Resources to Address Capacity Needs: 46 MMT Case

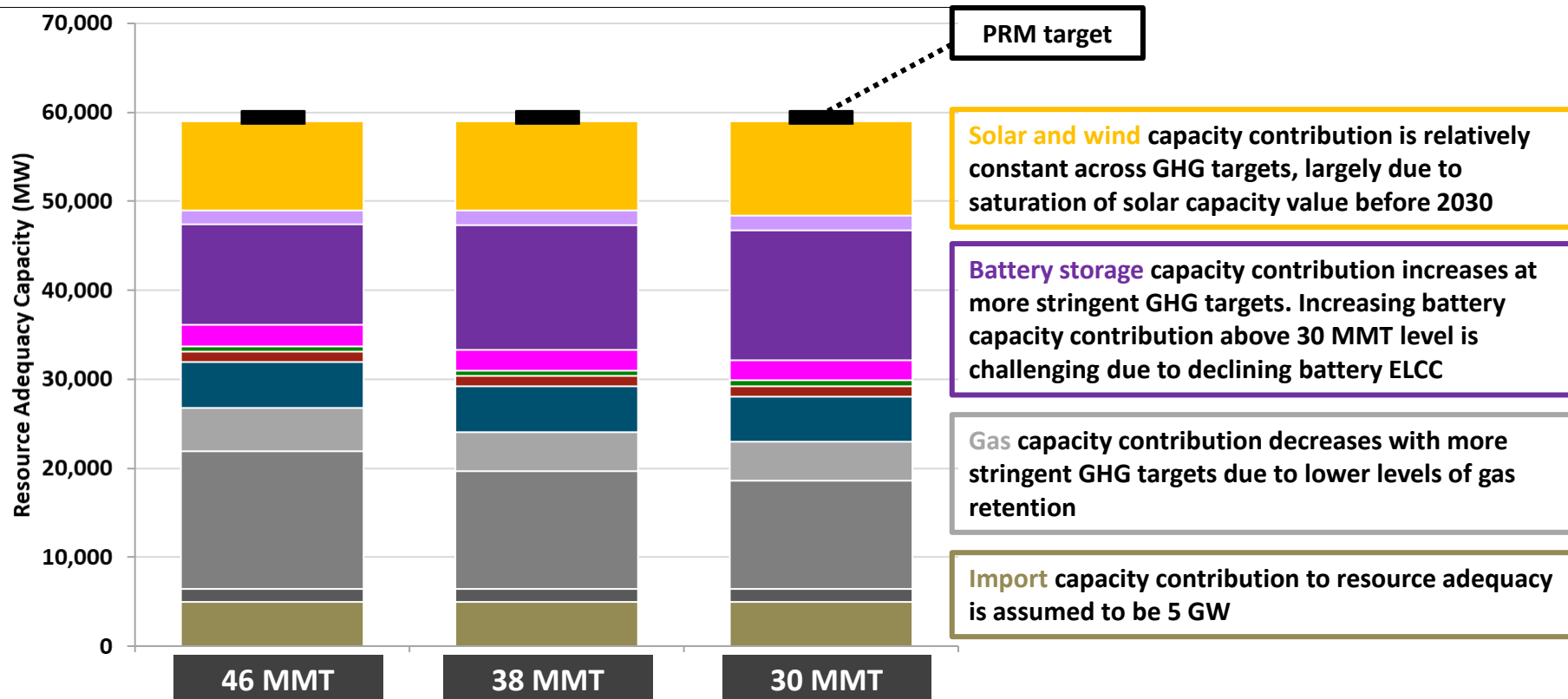
- Even after retaining all baseline gas resources, additional resources are necessary to meet capacity needs until 2030.
- 2021 capacity shortfall met with predominantly by growth battery storage capacity (both baseline and selected).
- Marginal solar capacity value is minimal due to resource saturation after the early 2020s.
- Battery capacity represents large source of new capacity by 2030, with 14.6 GW of batteries (baseline + selected) providing 12.9 GW of RA capacity.
  - Marginal ELCC of 4-hour Li-Ion batteries in 2030 is 65%
- Plot below depicts the resource adequacy contribution of resource types, which is always less than or equal to the installed capacity of the resource type.



Note: BTM PV and Storage modeled on supply side, with Reserve Margin requirement adjusted upwards accordingly

# Resource Types That Fill 2030 Core Policy Case Resource Adequacy Requirements

- Plot depicts the resource adequacy capacity value of various resource types in 2030. The planning reserve margin target is shown for reference.



Note: BTM PV and Storage modeled on supply side, with Reserve Margin requirement adjusted upwards accordingly

## Existing Gas Not Retained

- A capacity shortfall in 2021, followed by retirement of 2 GW of capacity from Diablo Canyon Power Plant in 2024-5, results in all available gas power plants being retained for CAISO ratepayers through 2026 in all core policy cases.
  - All remaining OTC plants are retired at the end of 2020 by default and retention decisions for these plants are not made in RESOLVE.
- By 2030, RESOLVE selects ~11 – 19 GW of battery storage for the main purpose of shifting solar generation into the nighttime. The total (baseline + selected) battery storage RA capacity contribution is ~13 – 16 GW.
  - 4 - 8 GW of gas is surplus to CAISO ratepayers as a result.
  - Gas generation dispatch decreases from 2026 to 2030.
  - Level of gas retention is dependent on the capacity value of battery storage in a grid with relatively abundant solar generation.
    - Batteries + solar is an untested reliability paradigm and the combined capacity contribution of these resources has significant uncertainty.
- RESOLVE does not select new gas in any core policy case.



## **3.3. SUMMARY OF CORE POLICY CASE METRICS**

# RESOLVE Output: Incremental Total Resource Cost (TRC) to Meet GHG Targets

- Relative to the 46 MMT case, the incremental cost of meeting a 38 or 30 MMT GHG target is **\$0.5 to \$1.2 billion per year** respectively
- Primary driver of incremental costs is **new investment in renewables and storage** which displace emissions from thermal generation and unspecified imports

		Incremental TRC (\$MM/yr)	
		38 MMT	30 MMT
Incremental Fixed Costs	<i>Renewables</i>	+505	+1,332
	<i>Storage</i>	+366	+661
	<i>Thermal</i>	-18	-26
	<i>DR</i>	-13	-13
	<i>CAISO Transmission</i>	-	+15
Incremental Variable Costs		-368	-728
Incremental DSM Program Costs		—	—
Incremental Customer Costs		—	—
<b>Incremental Total Resource Cost</b>		<b>+473</b>	<b>+1,242</b>

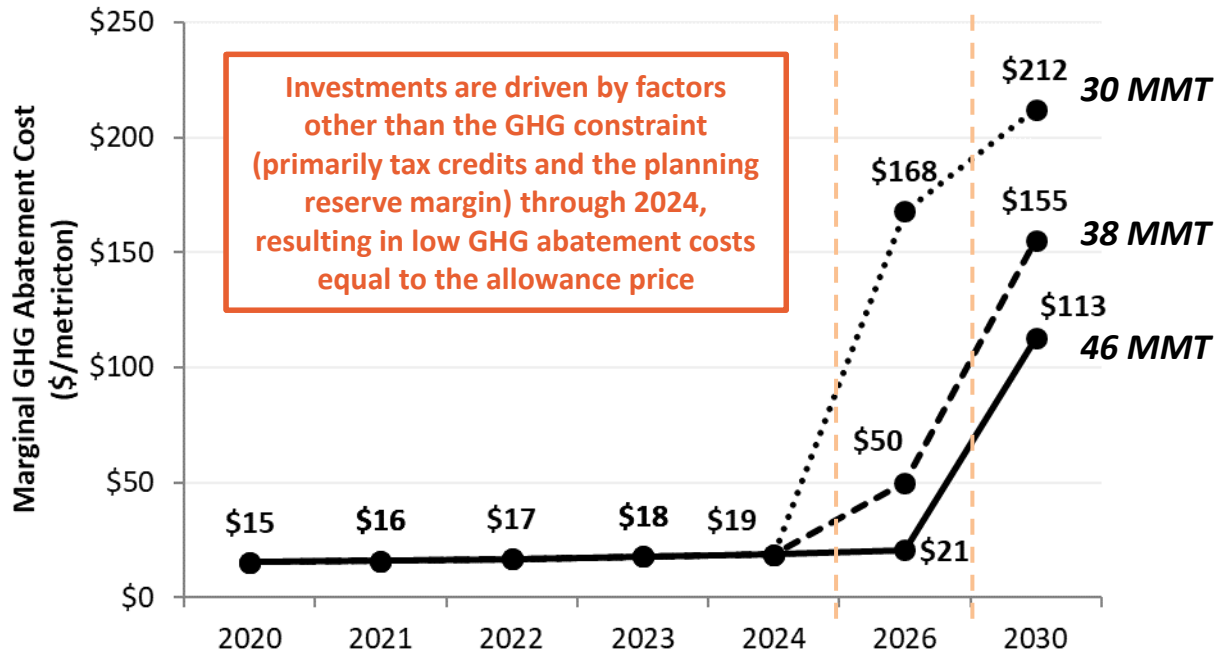
- Increased investments in zero-carbon renewables and storage are primary driver of incremental costs
- No additional thermal resources added to meet GHG goals (retirement amounts vary)
- Lower GHG targets select less Shed DR
- Little new transmission construction within CAISO
- Addition of renewables displaces generation from thermal resources, reducing operating costs
- Because demand-side assumptions are constant between scenarios, incremental costs are zero



## GHG Planning Price

- Staff defines the “GHG Planning Price” as the system-wide marginal GHG abatement cost associated with achieving the electric sector GHG emissions targets.
- To determine the GHG Planning Price, Staff relies on the “shadow price” of the GHG constraint in RESOLVE.
  - Within optimization modeling, the “shadow price” of a constraint is the change in the objective function if that constraint is relaxed by one unit and is frequently interpreted as the marginal cost to meet that constraint.
- Because RESOLVE captures the financial cost of allowances under the cap & trade in its objective function, the shadow price alone does not reflect the full marginal cost of GHG abatement.
  - The assumed allowance cost increases the cost to combust fossil fuels, reducing the apparent cost premium of carbon-free resources (and, by extension, the shadow price).
- Therefore, Staff calculates the GHG Planning Price as the sum of RESOLVE’s GHG shadow price and the assumed cost of allowances under cap & trade.
- In 2017-18 IRP, the GHG Adder adopted in D.18-02-18 and currently used in the IDER proceeding was derived partially from the GHG Planning Price.

# RESOLVE Output: Marginal GHG Abatement Cost in Core Policy Cases



Investments are driven by factors other than the GHG constraint (primarily tax credits and the planning reserve margin) through 2024, resulting in low GHG abatement costs equal to the allowance price

In 38 MMT and 30 MMT case, the GHG constraint first becomes a main driver of new investments in 2026, and marginal cost of carbon abatement increases quickly thereafter as marginal GHG reductions become more expensive

In 46 MMT case, the GHG abatement cost only becomes large in 2030

- GHG abatement cost curves reflect the selection of increasingly higher-cost resources to reduce increasingly more GHG emissions.
- The total marginal cost of GHG abatement (or “GHG Planning Price”) is estimated by adding the assumed allowance cost to the GHG shadow price.
  - 2030 marginal abatement cost in 30 MMT scenario:  $\$187 + \$25 = \underline{\$212/\text{metric ton}}$
  - 2030 marginal abatement cost in 46 MMT scenario:  $\$87 + \$25 = \underline{\$113/\text{metric ton}}$

# Summary Metrics for 46 MMT, 38 MMT and 30 MMT Portfolios in 2030

Metric	46 MMT Case	38 MMT Case	30 MMT Case
CAISO GHGs	37.9	31.1	24.3
Selected Resources (by 2030)	<ul style="list-style-type: none"> <li>2.8 GW wind (in-state)</li> <li>0.0 GW wind (OOS)</li> <li>11.8 GW solar</li> <li>11.4 GW battery storage</li> <li>0.0 GW pumped storage</li> <li>0.2 GW shed DR</li> </ul>	<ul style="list-style-type: none"> <li>2.8 GW wind (in-state)</li> <li>1.5 GW wind (OOS)</li> <li>17.2 GW solar</li> <li>15.8 GW battery storage</li> <li>0.0 GW pumped storage</li> <li>0.1 GW shed DR</li> </ul>	<ul style="list-style-type: none"> <li>5.3 GW wind (in-state)</li> <li>3.0 GW wind (OOS)</li> <li>20.8 GW solar</li> <li>19.1 GW battery storage</li> <li>0.1 GW pumped storage</li> <li>0.1 GW shed DR</li> </ul>
Gas Capacity Not Retained	3.7 GW	6.5 GW	7.7 GW
Selected Renewables (In-state)*	14.6 GW	19.8 GW	26.1 GW
Levelized Total Resource Cost (TRC)	\$45.4 billion/yr	\$45.9 billion/yr	\$46.7 billion/yr
Incremental TRC (relative to 46 MMT Case)**	-	\$473 million/yr*	\$1.2 billion/year*
Marginal GHG Abatement Cost	\$113/metric ton	\$155/metric ton	\$212/metric ton
Planning Reserve Margin Achieved	15%	15%	15%

\*Includes Southern Nevada and Baja resources that directly interconnect to the CAISO system

\*\*The incremental TRC results are calculated relative to the Default Case. All other results are total, not incremental.

# Comparison of 2019 46 MMT Core Policy Case to 2018 PSP: 2030 Summary Metrics

Metric	2018 Preferred System Plan	2019 46 MMT Core Policy Case
CAISO GHGs (BTM CHP GHGs excluded)	34 MMT	32.4 MMT
Selected Resources (by 2030)	<ul style="list-style-type: none"> <li>2.2 GW wind</li> <li>5.9 GW solar PV</li> <li>2.1 GW battery storage</li> <li>1.7 GW geothermal</li> <li>0.0 GW shed DR</li> </ul>	<ul style="list-style-type: none"> <li>2.8 GW wind (in-state)</li> <li>11.8 GW solar PV</li> <li>11.4 GW battery storage</li> <li>0.0 GW geothermal</li> <li>0.2 GW shed DR</li> </ul>
Selected Renewables <i>(in-state)*</i>	5.7 GW	14.6 GW
Levelized Total Resource Cost (TRC)	\$44.5 billion/yr	\$45.4 billion/yr
Marginal GHG Abatement Cost	\$219/metric ton	\$113/metric ton
Planning Reserve Margin Achieved	22%	15%

- 2019 IRP results do not exceed 15% planning reserve margin target. 2018 PSP did not include economic gas retention (retained all available gas through 2030) and assumed ~2x the RA import capacity relative to 2019 assumptions, resulting in a 22% reserve margin.
- Cost projections of solar PV and batteries are roughly half of 2017 IRP assumptions
- Two cases include different load and baseline resource assumptions
- Updated BTM CHP assumptions result in a slightly more stringent GHG target



## 3.4. SENSITIVITY CASE RESULTS

# Sensitivity Definitions

Sensitivity	Description
Reference	Core Policy Case
Low Cost New Transmission	Limited NM/WY wind resources on new transmission available with 25% lower out of state transmission costs than default
High Cost New Transmission	Limited NM/WY wind resources on new transmission available with 25% higher out of state transmission costs than default
Full New OOS Transmission	Out-of-state resources on new transmission available; full potential for NM/WY wind
No New OOS Transmission	No out-of-state resources on new transmission available
Offshore Wind	Offshore wind available
Offshore Wind no new OOS Tx	Offshore wind available with no out-of-state resources on new transmission
High Solar PV Cost	Higher projections of future solar PV cost
ITC Extension	30% Investment Tax Credit (ITC) for solar PV is maintained indefinitely
High Battery Cost	Higher projections of future battery cost
Paired Battery Cost	Li-Ion battery costs are reduced due to ITC benefits and shared infrastructure from co-locating
Low RA Imports	2 GW of RA import capacity assumed
High RA Imports	Maximum (10.2 GW) RA import capacity assumed
2045 End Year	Core Policy Cases are run with 2045 as end year
High Load Baseline	High IEPR baseline load trajectory assumed
OTC Extension	All the once-through-cooling capacity available in 2020 is kept online through 2023
Partial OTC Extension	~2.3 MW once-through-cooling capacity is kept online through 2023
Early Shed DR Availability	Full shed DR potential is available beginning in 2020
No New DER	Zero incremental DER resources including energy efficiency, BTM solar and battery, and DR

# RESOLVE Output:

## Impact of Sensitivities on Incremental Cost

	"Incremental TRC" calculated relative to 46MMT Reference case (highlighted in orange)			"Change from Reference" calculated relative to corresponding "Reference" case		
	Incremental Cost (\$MM/yr)			Change from Reference (\$MM/yr)		
Sensitivity	46 MMT	38 MMT	30 MMT	46 MMT	38 MMT	30 MMT
Reference	\$0	\$589	\$1,621			
Low Cost Tx for 3 GW OOS Wind	-\$9	\$399	\$1,169	-\$9	-\$73	-\$72
High Cost Tx for 3 GW OOS Wind	\$0	\$488	\$1,318	-\$0	+\$15	+\$76
Full New OOS Tx	\$0	\$446	\$1,182	-\$0	-\$26	-\$59
No New OOS Tx	-\$1	\$487	\$1,358	-\$1	+\$15	+\$116
Offshore Wind	-\$1	\$473	\$1,241	-\$1	-\$0	-\$1
Offshore Wind no new OOS Tx	-\$2	\$487	\$1,334	-\$2	+\$14	+\$92
High Solar PV Cost	\$556	\$1,119	\$1,964	+\$556	+\$647	+\$723
ITC Extension	-\$250	\$164	\$925	-\$250	-\$309	-\$317
High Battery Cost	\$586	\$1,196	\$2,169	+\$586	+\$724	+\$927
Paired Battery Cost	-\$475	-\$73	\$626	-\$475	-\$546	-\$616
Low RA Imports	\$259	\$728	\$1,436	+\$259	+\$255	+\$195
High RA Imports	-\$389	\$168	\$970	-\$389	-\$305	-\$271
High Load Baseline	\$745	\$1,306	\$2,212	+\$745	+\$834	+\$971
OTC Extension	-\$173	\$299	\$1,068	-\$173	-\$173	-\$173
Partial OTC Extension	-\$132	\$341	\$1,109	-\$132	-\$132	-\$132
Early Shed DR Availability	-\$18	\$465	\$1,234	-\$18	-\$8	-\$7



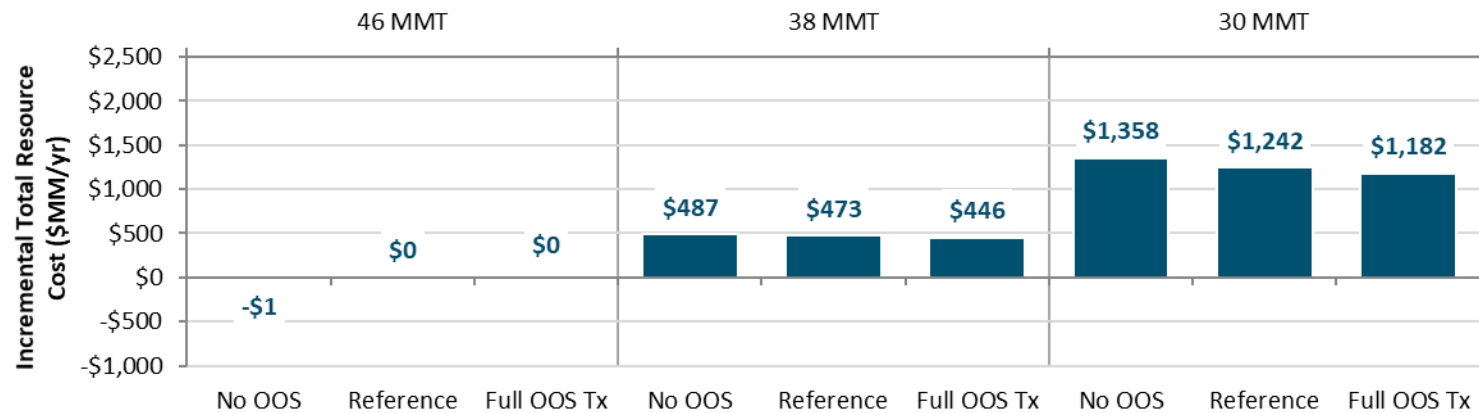
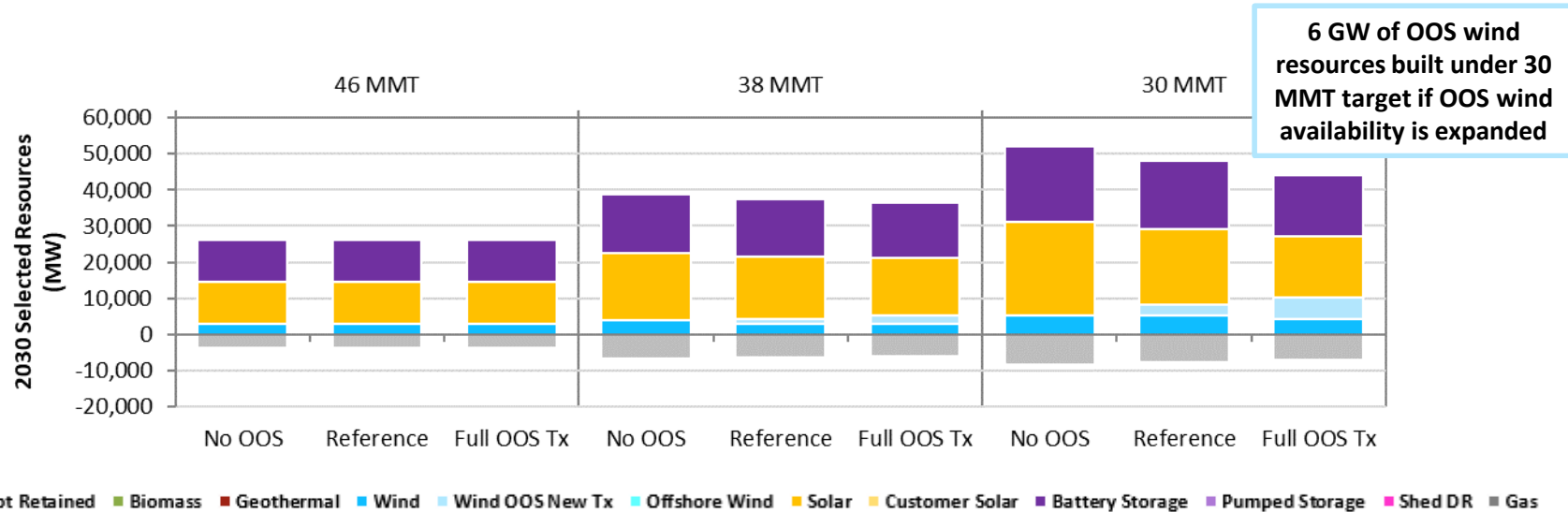
## 3.5. TRANSMISSION SENSITIVITIES



# Out-of-State Transmission Sensitivities

- New out of state transmission sensitivities:
  - **Reference** case assumes a maximum availability of 1.5 GW of WY wind and 1.5 GW of NM wind on new transmission is assumed by default.
  - **No out-of-state (OOS)** transmission sensitivity removes ability to procure 3 GW of out of state wind that is assumed in the reference case.
  - **Full out-of-state** transmission sensitivity allows access to full potential of out of state resources (wind and solar) that require new transmission, i.e., not constrained by the maximum 3 GW default assumption.
  - High and low-cost sensitivities are explored around the cost of out of state resources on new transmission. A 25% increase and decrease in the cost of new transmission is applied to the default out of state assumption that allows for a combined 3 GW of NM and WY wind.

# New Out of State Transmission Sensitivity

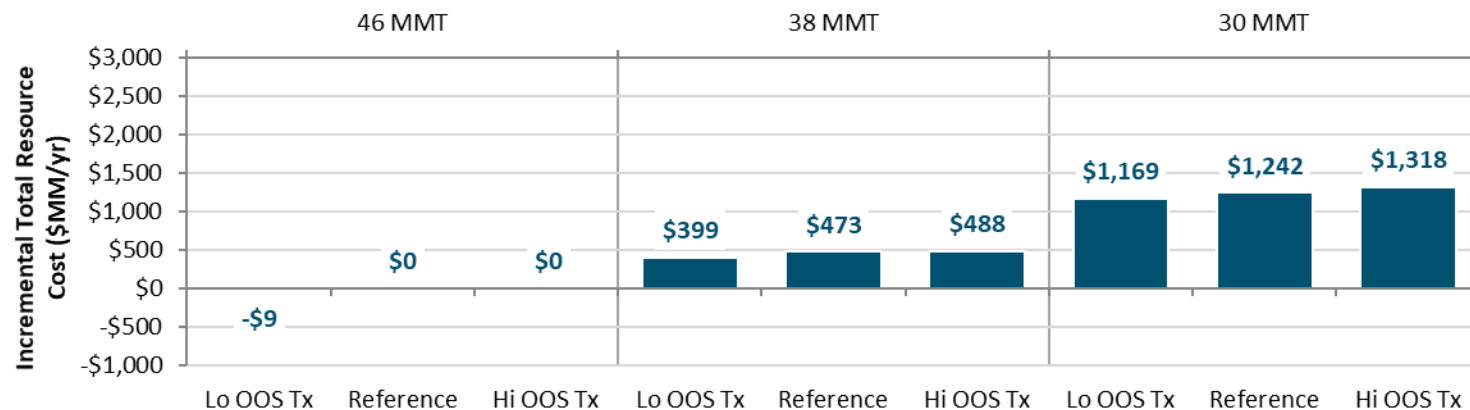
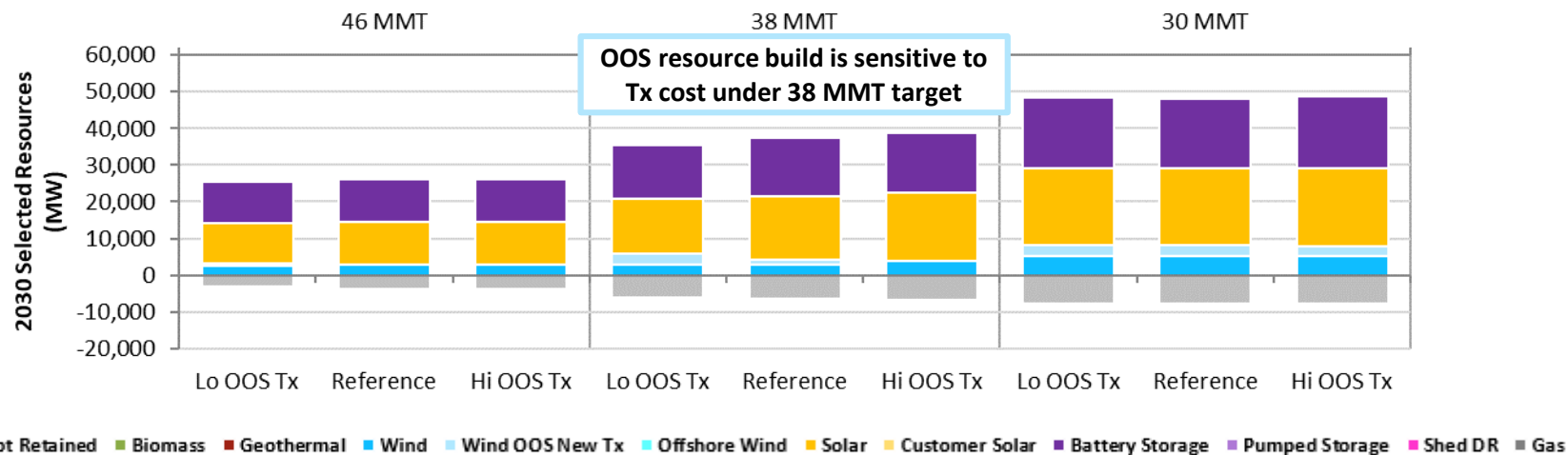


OOS wind is not selected at 46 MMT. The three cases do not have material cost differences

Under 38 MMT target, different levels of OOS resource availability result in modest cost differences

Availability of WY and NM wind at more stringent GHG targets result in significant cost savings

# New Out of State Transmission Cost Sensitivities



600 MW of OOS wind selected under a 46 MMT target and lower Tx cost assumptions, but system cost savings are minimal (\$9 MM/yr)

OOS wind resources are cost-effective under 30 MMT target, even under higher Tx cost assumptions. Higher Tx costs lead to higher costs overall.

# New Out of State Transmission Conclusions

- By default, a maximum of 3 GW of out of state wind resources on new transmission are available for selection.
  - 1.5 GW from NM and 1.5 GW from WY.
- Selected capacity of OOS resources on new transmission is sensitive to the GHG target.
  - Under the 46 MMT target, OOS wind resources are not cost-effective unless transmission costs are less than the default assumptions.
  - Under the 38 MMT target, different levels of OOS Tx resource availability result in modest cost differences and the selected capacity of OOS wind on new transmission is sensitive to transmission cost assumptions.
  - Under the 30 MMT target, OOS wind resources are cost-effective even under higher transmission cost assumptions. 6 GW of OOS wind resources are selected by 2030 under default transmission cost assumptions if OOS wind availability is expanded.
- Both NM and WY wind are selected under the 30 MMT target. The location of OOS wind resources on new transmission (NM or WY) is sensitive to transmission cost assumptions under a 38 MMT target.

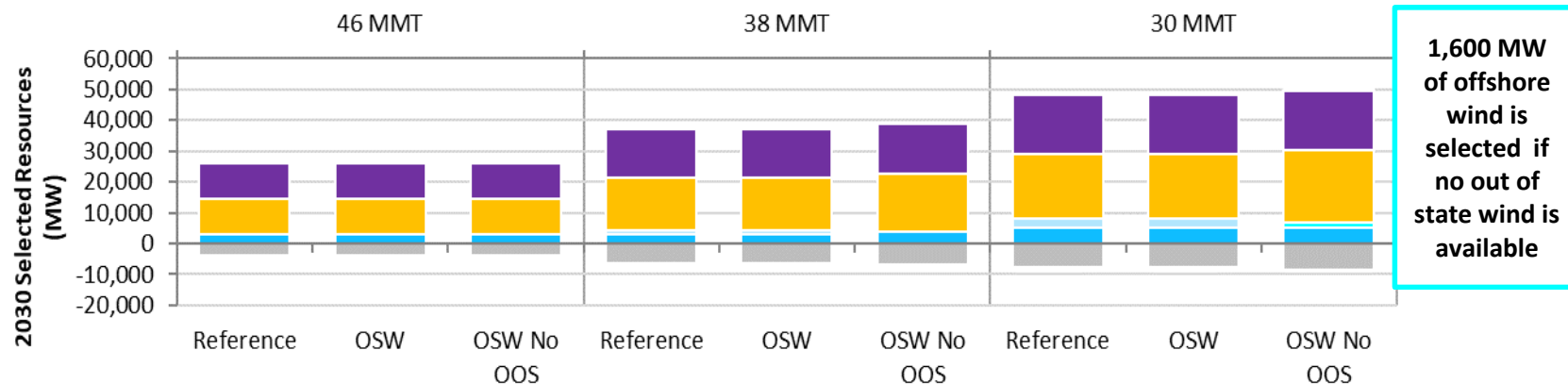


## 3.6. OFFSHORE WIND SENSITIVITIES

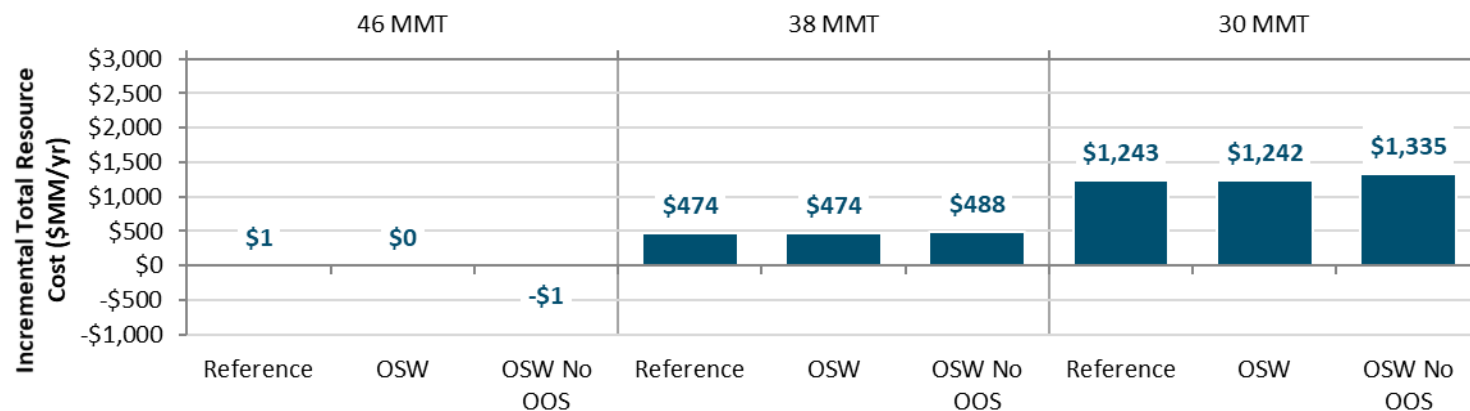
# Offshore Wind Sensitivities

- Offshore wind is not included as a candidate resource by default. As assumptions get further developed with stakeholder vetting, it should become appropriate to include as a default resource available for selection in IRP modeling.
- In sensitivities, offshore wind is added as a candidate resource.
  - The **OSW** sensitivity adds offshore wind as a candidate resource but retains all other default assumptions. Importantly, this sensitivity includes the default level of out-of-state wind resources on new transmission: 3 GW of NM and WY wind are available for selection.
  - The **OSW No OOS** sensitivity explores the selection of OSW resources under the assumption that OOS wind resources on new transmission are not available. The OSW No OOS sensitivity does not include any candidate OOS wind resources on new transmission (0 GW of OOS new transmission resources are available for selection).

# Offshore Wind Sensitivities



■ Gas ■ Biomass ■ Geothermal ■ Wind ■ Wind OOS New Tx ■ Offshore Wind ■ Solar ■ Battery Storage ■ Pumped Storage ■ Shed DR ■ Gas Capacity Not Retained



Costs for the "OSW no OOS" cases reflect the net cost of deploying additional offshore wind and *not* deploying out of state wind on new transmission. The 30 MMT OSW no OOS sensitivity reduces incremental TRC by ~\$25MM/yr relative to the "No OOS" sensitivity (earlier slide).

# Offshore Wind Conclusions

- Offshore wind, when available for selection by RESOLVE, is included in the least-cost 2030 resource portfolio under the most stringent GHG target (30 MMT).
  - Model builds 1.6 GW of offshore wind (primarily Morro Bay) if no out-of-state wind on new transmission is available and a very small amount (6 MW) if 3 GW of WY/NM wind is available.
    - RESOLVE is a linear optimization model and therefore cannot enforce a minimum project size for offshore wind resources. The selection of 6 MW of offshore wind resources indicates that a relatively small amount of offshore wind capacity is cost-effective in 2030 under default assumptions.
- The availability of out-of-state wind - a resource that can provide similar value streams to the CAISO system - is a key driver of offshore wind selection. Wind resources (both onshore and offshore) provide resource diversity to the CAISO system, resulting in more wind capacity getting selected as the incremental cost of serving the next MWh of load with solar and battery storage increases.
- Site selection for offshore wind will impact offshore transmission costs and resource production profiles. RESOLVE selects Morro Bay offshore wind over Diablo Canyon offshore wind, likely due to the higher capacity factor of the Morro Bay resource. More detailed studies would be necessary to pinpoint the most viable location(s) for offshore wind, and to assess the tradeoff between transmission costs (both onshore and offshore) and capacity factor.
- The results presented here are a preliminary investigation of the offshore wind resource in California. Offshore wind deployment is expected to be sensitive to additional factors not explored in this study, especially the cost of floating offshore wind turbines.



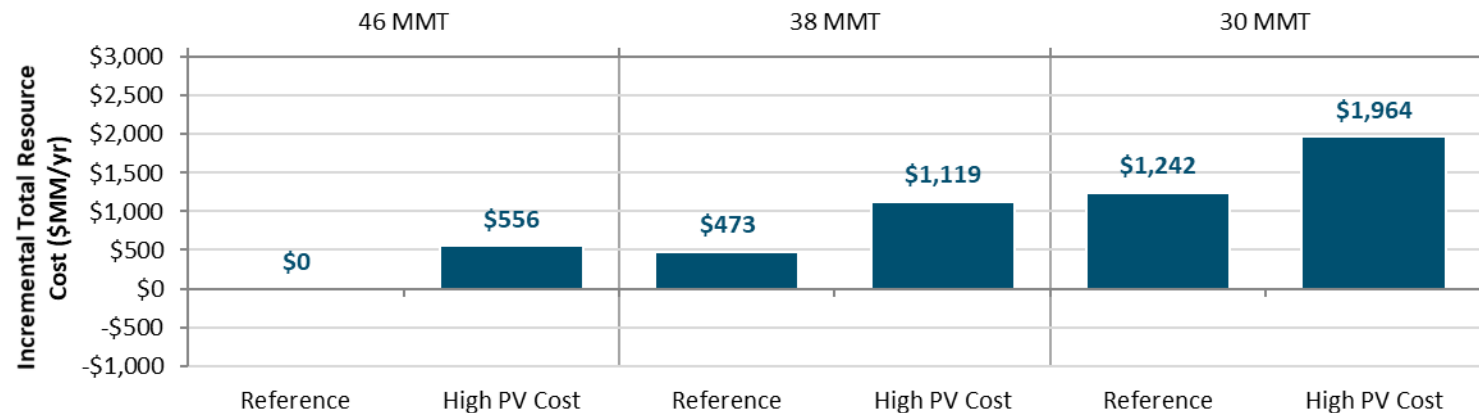
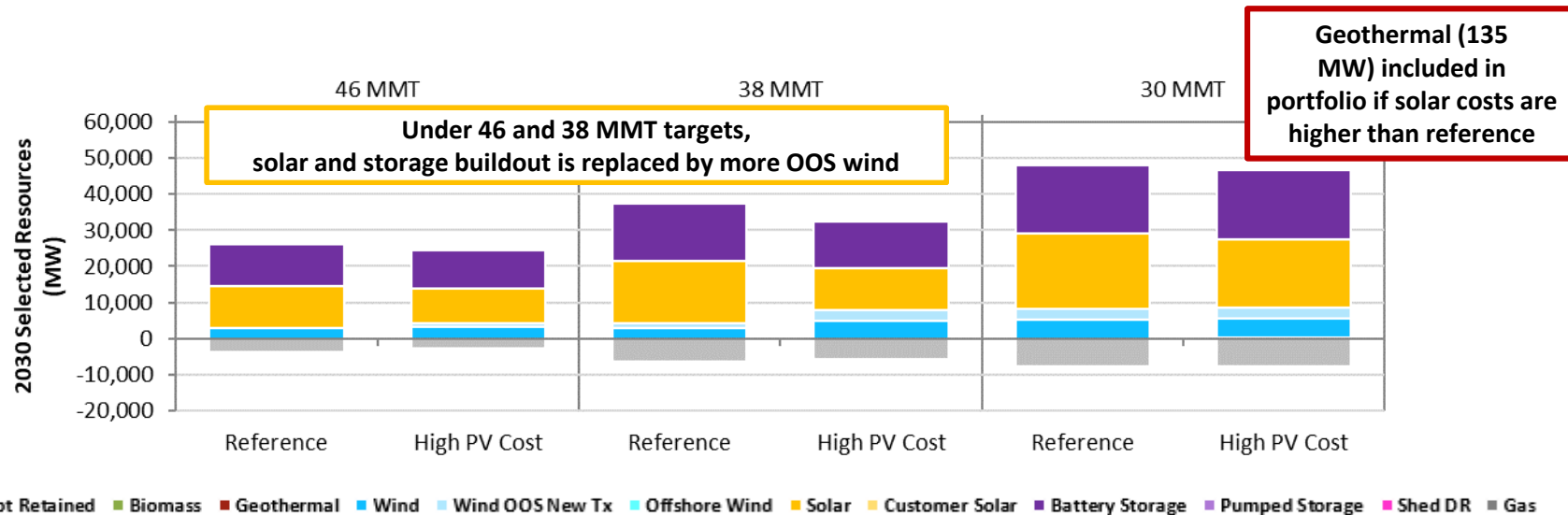


## 3.7. COST SENSITIVITIES

# Cost Sensitivities

- Solar cost sensitivities:
  - **High PV Cost:** NREL ATB high solar PV costs are used in place of NREL ATB mid costs
  - **ITC Extension:** 30% Investment Tax Credit (ITC) for solar PV is maintained indefinitely
    - By default, per the current law, solar ITC drops from 30% to 10% for utility scale PV in the early 2020s
- Battery cost sensitivities:
  - **High Cost:** High costs from Lazard 4.0 and NREL Solar + Storage Study for both Li-Ion and Flow batteries
  - **Paired Battery Costs:** Li-Ion battery costs are reduced due to shared infrastructure from co-locating with other resources (likely solar) and are eligible for the solar ITC tax credit through the early 2020s (e.g., “hybrid” battery resources).
    - Note: additional operational constraints are not imposed on battery charging and discharging in this sensitivity. Including ITC charging requirements and operational constraints resulting from pairing would reduce the value of pairing relative to what is depicted herein.

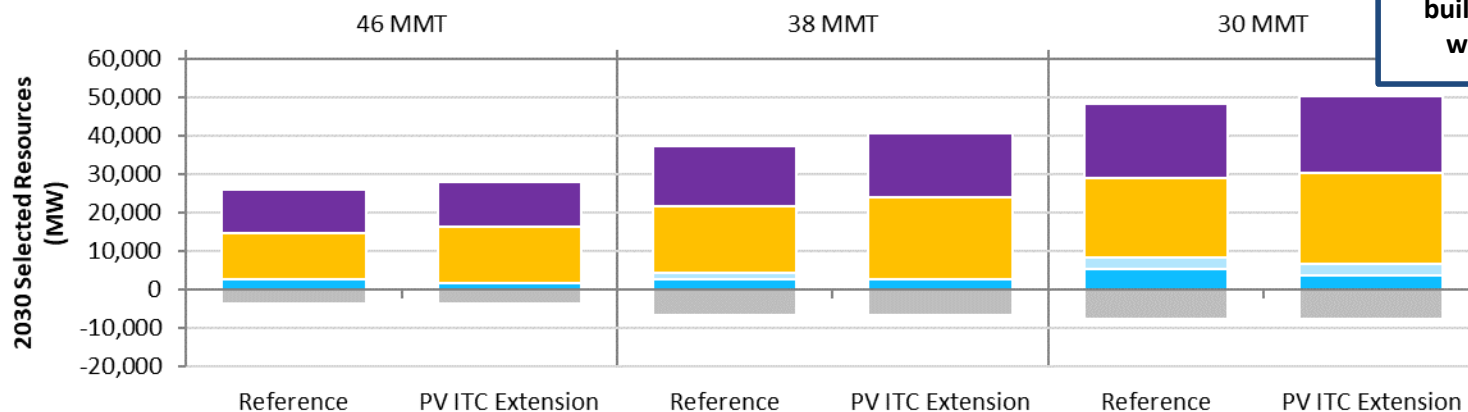
# Solar Cost Sensitivities: High PV Cost



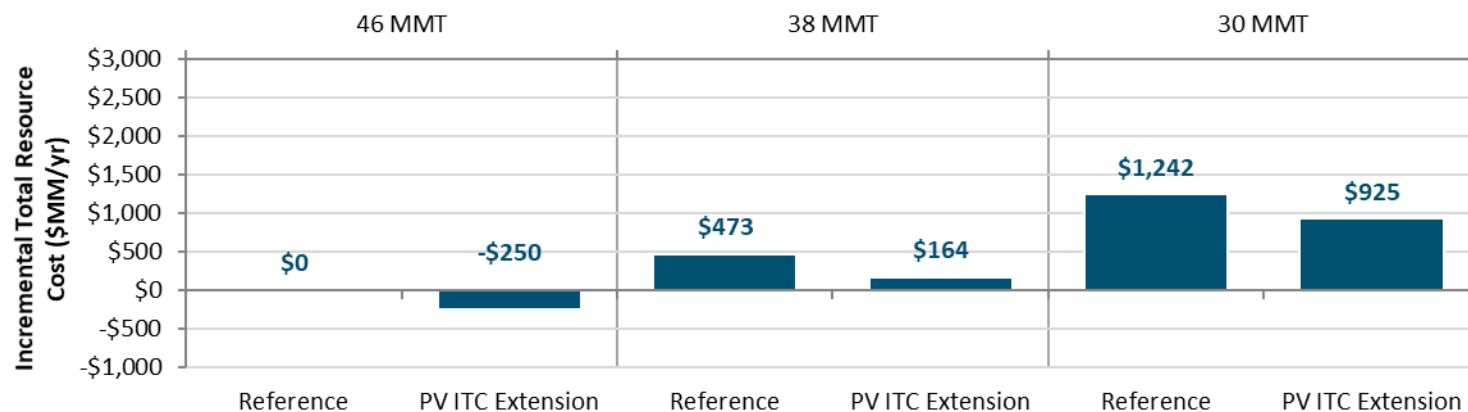
**Increasing the cost of solar resources results in large cost increases relative to the Reference**

# Solar Cost Sensitivities: PV ITC Extension

Solar ITC extension leads to more solar buildout and less wind by 2030

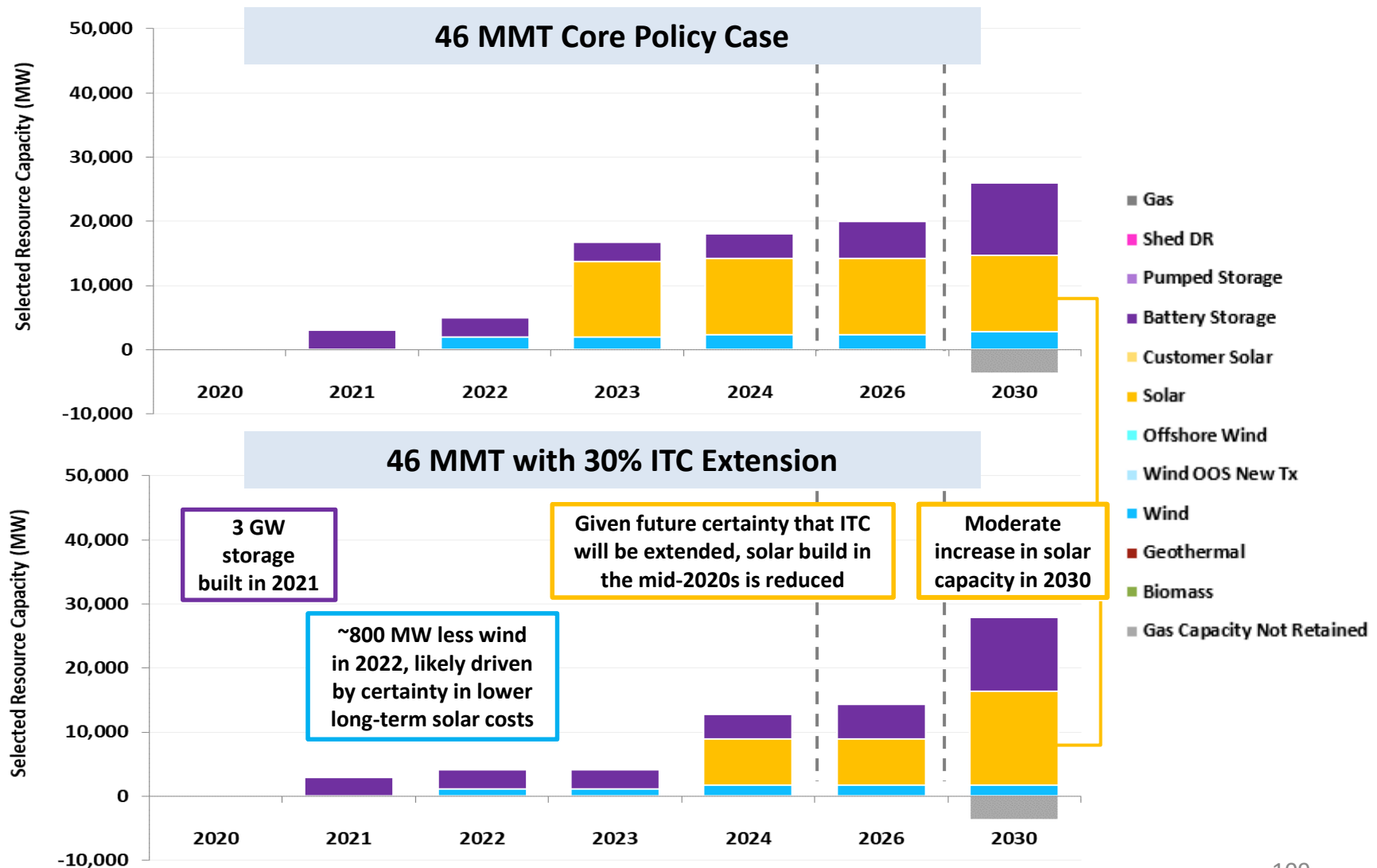


■ Gas Capacity Not Retained ■ Biomass ■ Geothermal ■ Wind ■ Wind OOS New Tx ■ Offshore Wind ■ Solar ■ Customer Solar ■ Battery Storage ■ Pumped Storage ■ Shed DR ■ Gas



Costs decrease with ITC extension because lower cost solar is available through 2030

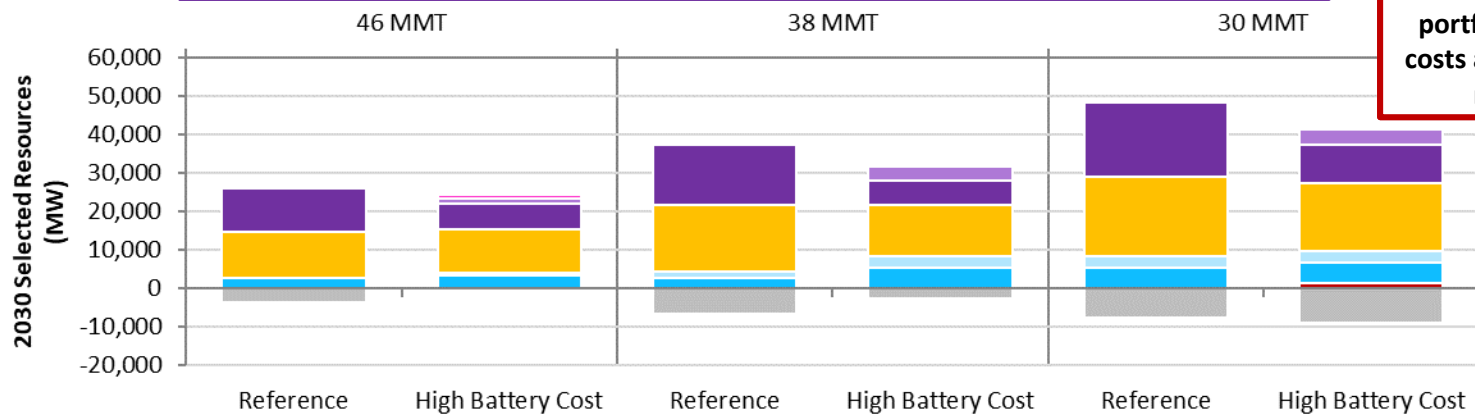
# Solar Cost Sensitivities: PV ITC Extension, Comparison with 46 MMT Core Policy Case



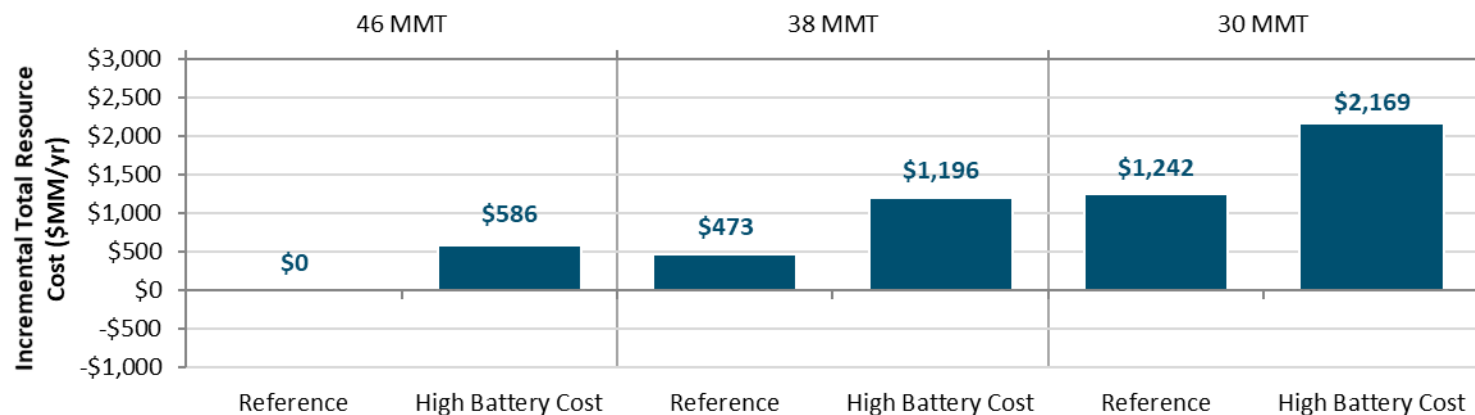
# Battery Cost Sensitivities: High Cost

Higher cost batteries result in partial replacement of batteries with pumped storage and a more diverse resource portfolio

Geothermal (1.3 GW) included in portfolio if battery costs are higher than reference



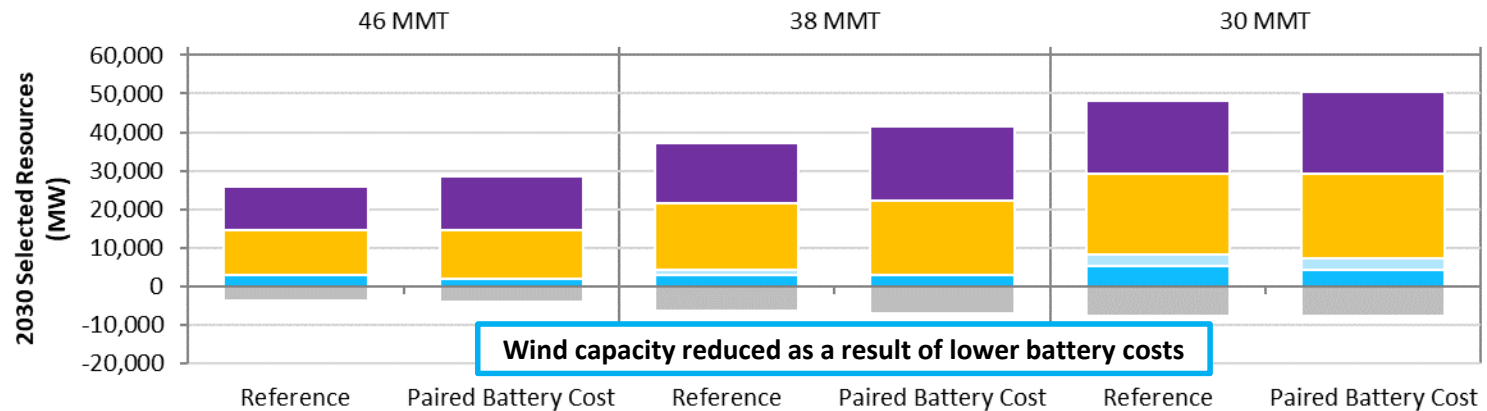
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More expensive batteries result in higher system costs

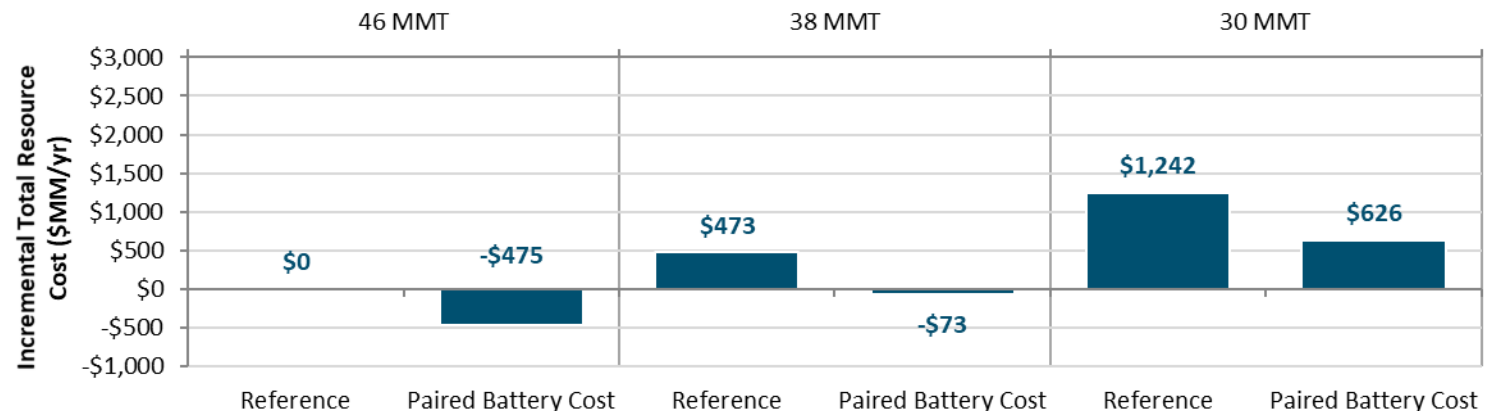
# Battery Cost Sensitivities: Paired Battery Costs

Reduced battery costs from pairing results in modest increases in 2030 battery capacity



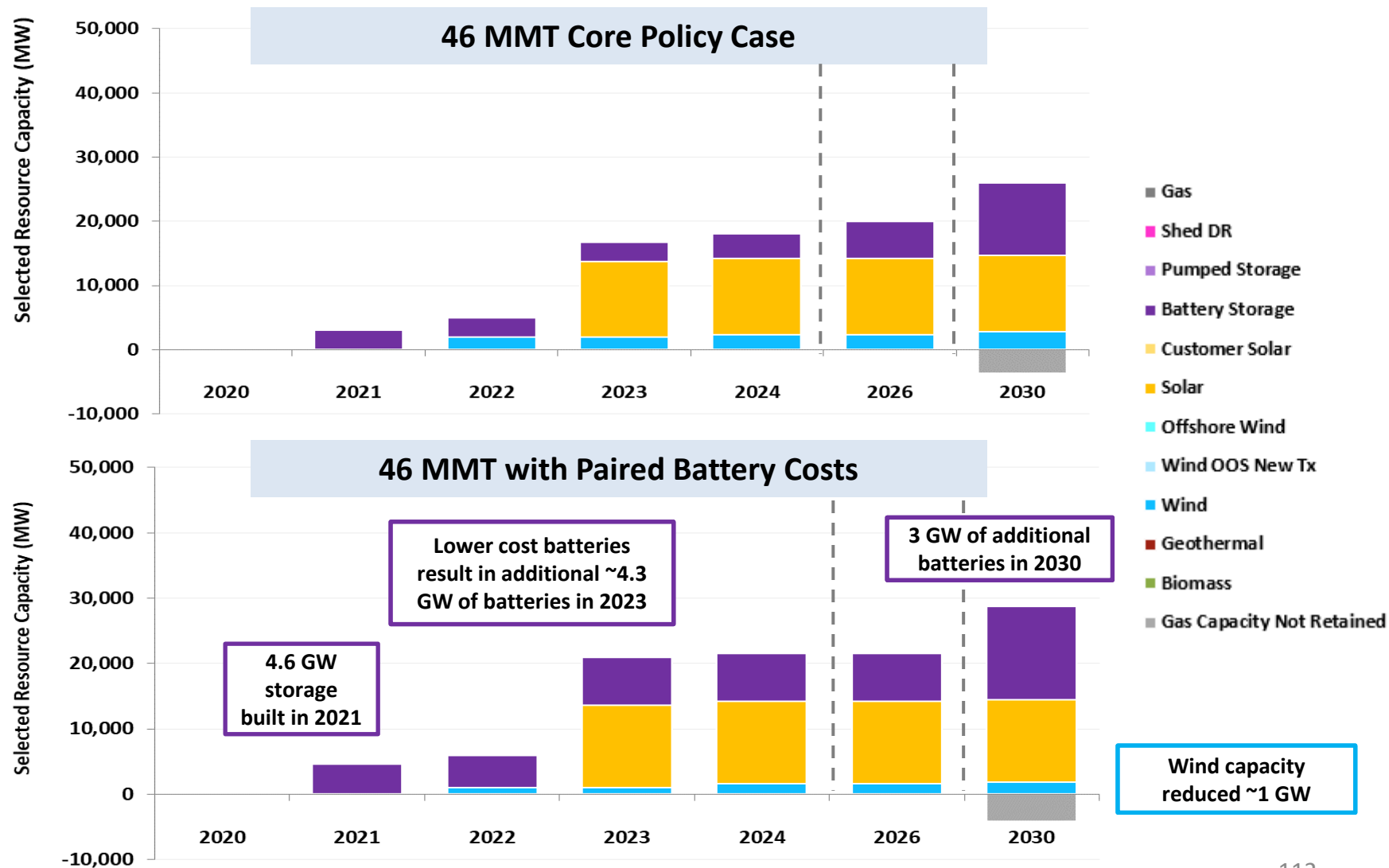
Wind capacity reduced as a result of lower battery costs

■ Gas Capacity Not Retained ■ Biomass ■ Geothermal ■ Wind ■ Wind OOS New Tx ■ Offshore Wind ■ Solar ■ Customer Solar ■ Battery Storage ■ Pumped Storage ■ Shed DR ■ Gas



Costs decrease with paired battery costs, especially for near-term battery installations. As shown on next slide, near-term ITC cost reductions drive earlier installation of batteries. ITC-driven cost reductions may be an upper bound due to the lack of charging constraints.

# Battery Cost Sensitivities: Paired Battery Costs, Comparison with 46 MMT Core Policy Case





## Cost Sensitivities Conclusions

- Under more ambitious GHG targets, higher solar or battery costs result in a more diverse portfolio of resources.
  - Geothermal is included in the 30 MMT portfolio if either solar or battery costs are higher than expected.
  - Higher cost batteries replace some battery capacity with pumped storage and result in a more diverse resource portfolio.
- Extension of the Investment Tax Credit delays solar build relative to default case, but results in broadly similar 2030 portfolios.
- Lower battery costs result in higher near-term buildout of batteries to capture ITC savings from pairing.



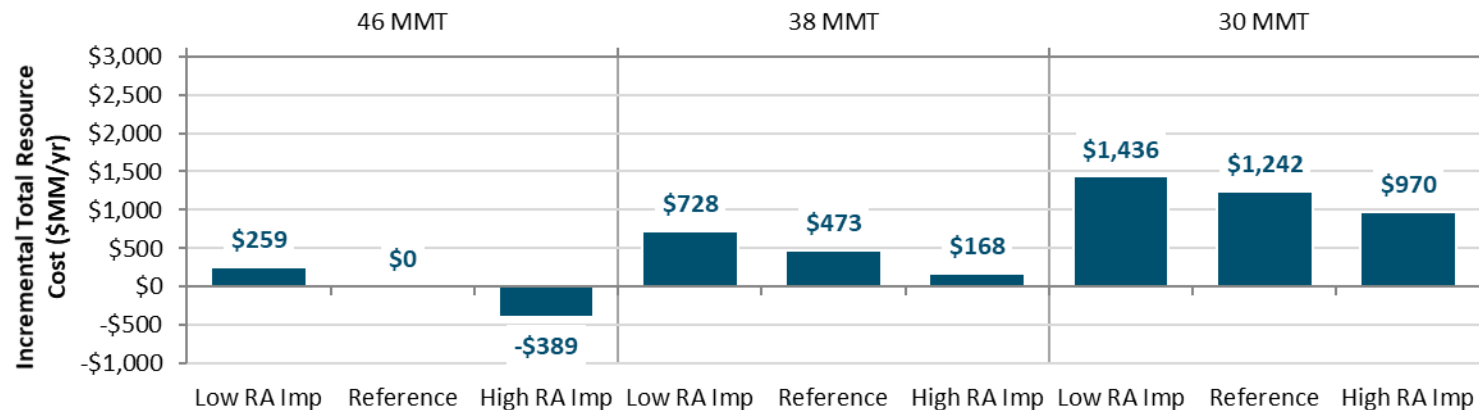
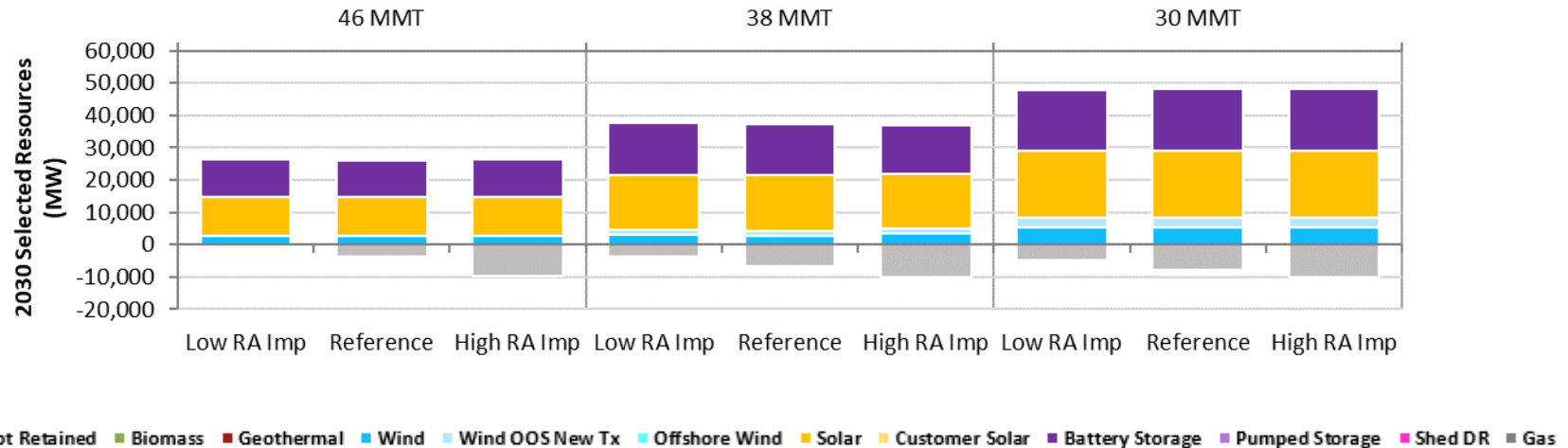
## **3.8. RESOURCE ADEQUACY AND LOAD SENSITIVITIES**

# Resource Adequacy and Load Sensitivities

- Sensitivities in this section are grouped together due to their potential impact on the planning reserve margin
- **RA Imports Sensitivities:**
  - Resource adequacy contribution of imports is assumed to be 5 GW by default but the changing load and resource balance outside CAISO make this value uncertain.
  - In sensitivities, import RA contribution is increased or decreased:
    - Low RA import – 5 GW in 2020, 3.5 GW in 2021, 2 GW after 2021
    - High RA import – 11.7 GW across the entire modeling horizon (2020 – 2030)
- **2045 End Year Sensitivity:**
  - Cases run through 2030 – but not further – may result in sub-optimal resource portfolios if the magnitude and timing of electricity demand changes drastically after 2030.
  - The 2045 end year sensitivity adds a single 2045 period onto the core policy cases. Electricity demand and GHG targets in 2045 are consistent with the CEC Deep Decarbonization High Biofuels case.
- **No Shed DR Limit**
  - Core policy cases assume ramp up of shed DR limit between 2020 and 2025.
  - The no shed DR limit sensitivity assumes full shed DR potential is available starting in 2020.
- **High Load Baseline**
  - Core policy cases use the IEPR Mid load forecast. Faster economic and/or demographic growth may result in higher baseline load than is found in the IEPR Mid forecast.
  - The High Load Baseline sensitivity use the IEPR High baseline load forecast through 2030, but does not vary other components of the load forecast (e.g.; energy efficiency, electric vehicles, etc.)

# RA Imports Sensitivities

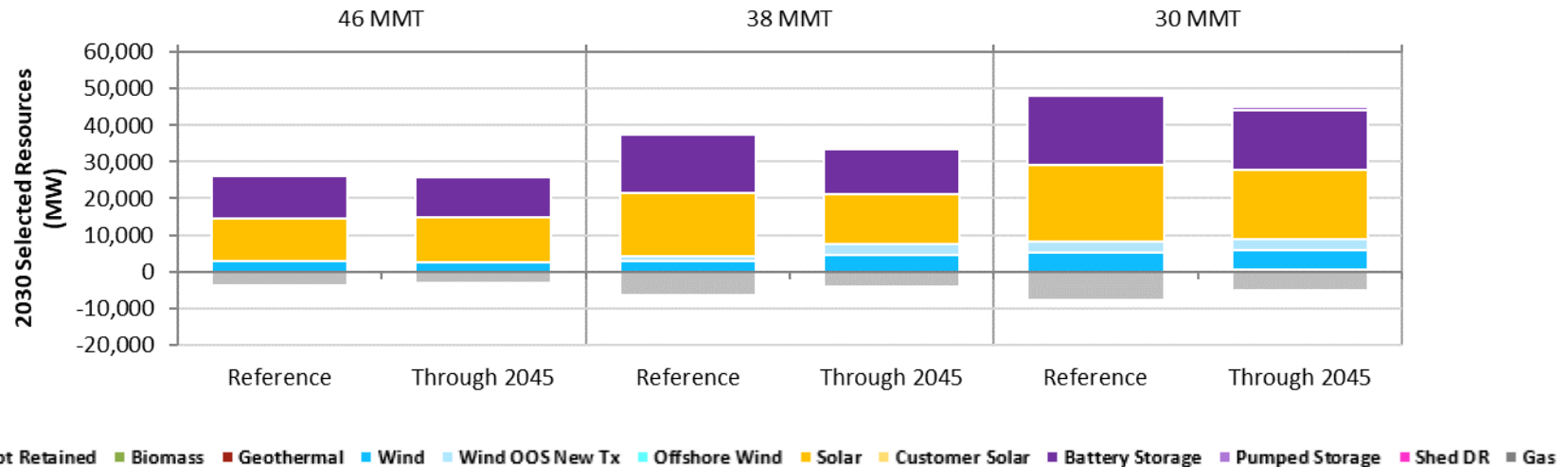
Lower available RA import capacity results in higher levels of gas retention in 2030



Lower levels of available RA import capacity can increase costs to CAISO ratepayers because additional and/or more expensive resources, especially in the early 2020s, must be selected to meet resource adequacy requirements. Note: cost of contracting with OOS resources for resource adequacy not included in optimization. As a result, the cost differences shown here represent an upper bound.

# 2045 End Year Sensitivity

An additional ~1 - 2.5 GW of gas retained if simulation horizon is extended through 2045

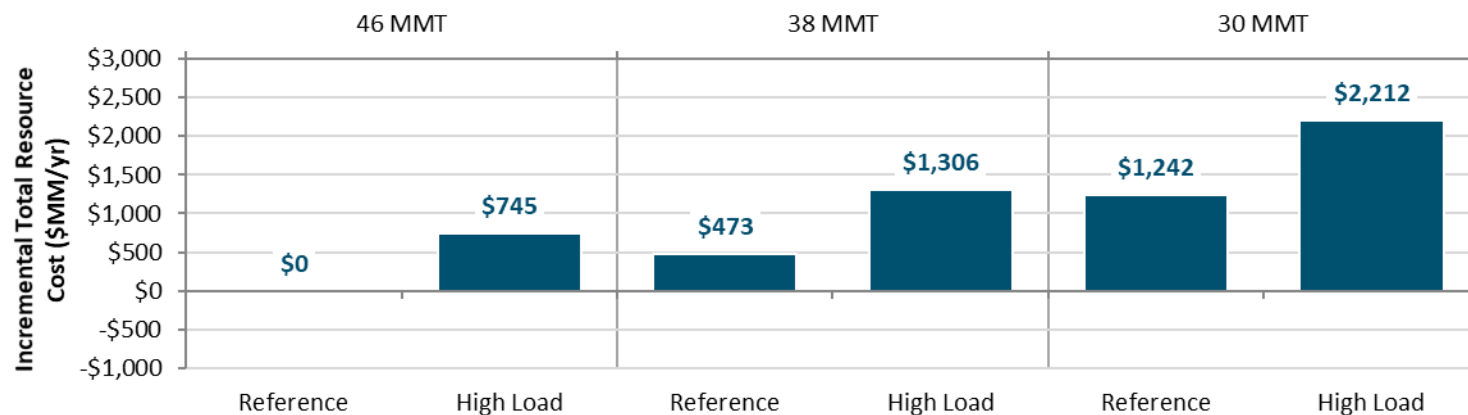
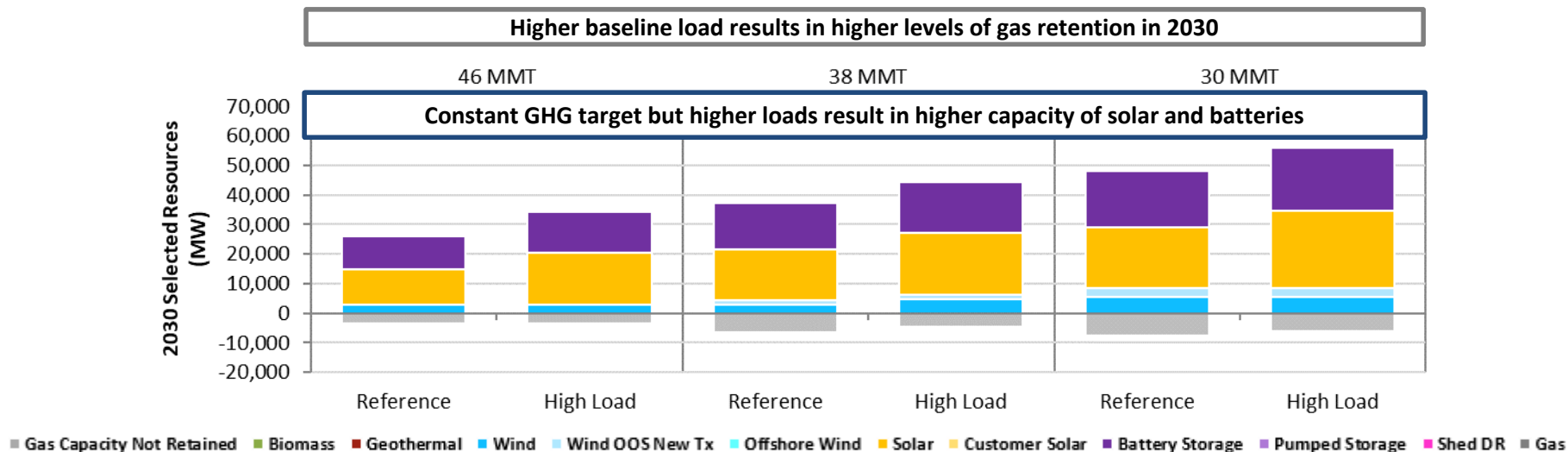


Post-2030 load and GHG targets can significantly impact the 2030 portfolio.

The 2045 End Year Sensitivity includes loads that are broadly consistent with the 2045 High Biofuels Framing Study. Loads in the High Biofuels scenario are lower than the other two framing study scenarios. It is likely that more gas capacity would be retained under higher load levels, which would increase the difference in gas retention between the 2030 core policy cases and cases that include a 2045 end year.

Simulating past 2030 results in a more diverse resource portfolio under more stringent GHG targets, with 500 MW of **Geothermal** and 1 GW of **Pumped Storage** selected under a 30 MMT 2030 target (limited visibility on chart due to scale of build-out)

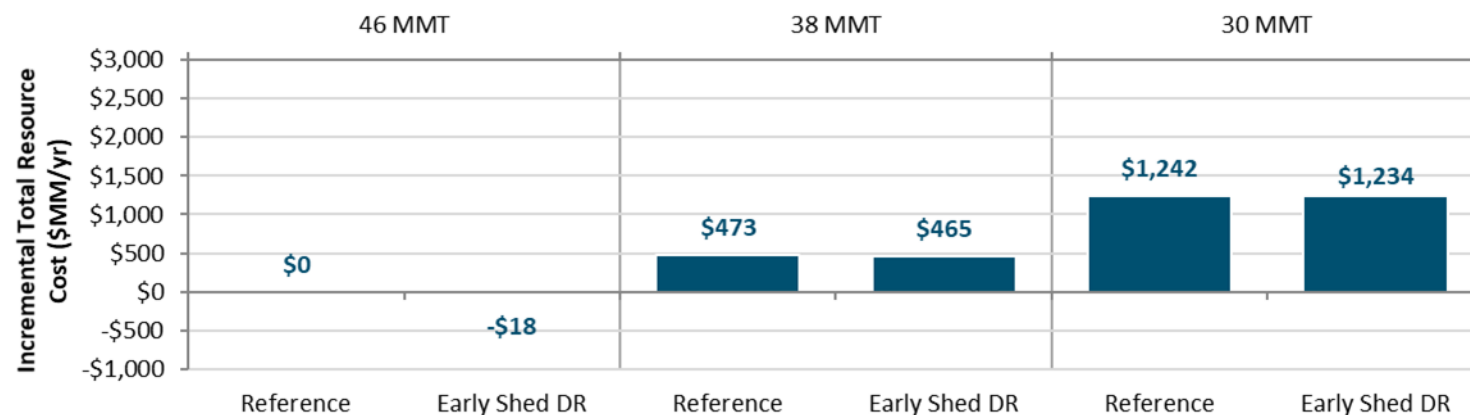
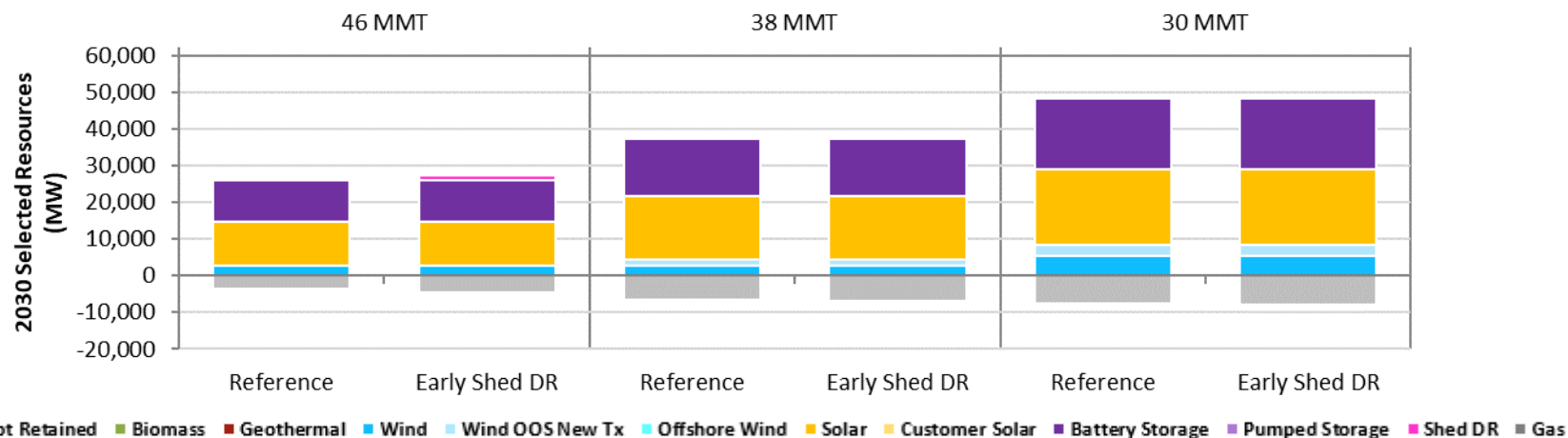
# High Load Baseline



**Higher load projections result in higher total resource cost because more load must be served while meeting the same GHG target.**

# Early Shed DR Availability

Lower GHG targets result in higher operational value for batteries, reducing the net capacity cost of batteries and thereby decreasing the opportunity for Shed DR to provide cost-effective capacity



Differences in cost resulting from additional near-term Shed DR availability is minimal

# Resource Adequacy and Load Sensitivities

## Conclusions

- Sensitivities demonstrate conditions under which additional gas capacity would be retained relative to core policy case assumptions.
  - Lower available RA import capacity results in higher levels of gas retention and selection of additional and/or more expensive resources to meet reliability requirements.
  - A higher load baseline results in more solar and battery capacity under the 46 MMT and 38 MMT GHG targets, as well as incremental gas retention.
  - Extending the analysis timeframe past 2030 results in higher levels of gas plant retention.
- Higher load projections result in higher total resource cost because more load must be served while meeting the same GHG target.
- Higher availability of shed DR in the early 2020s has a minimal impact on the portfolio cost, and results in a moderate increase in shed DR procurement under the least stringent GHG target.





## **3.9 NEAR-TERM RESOURCE AVAILABILITY SENSITIVITIES**

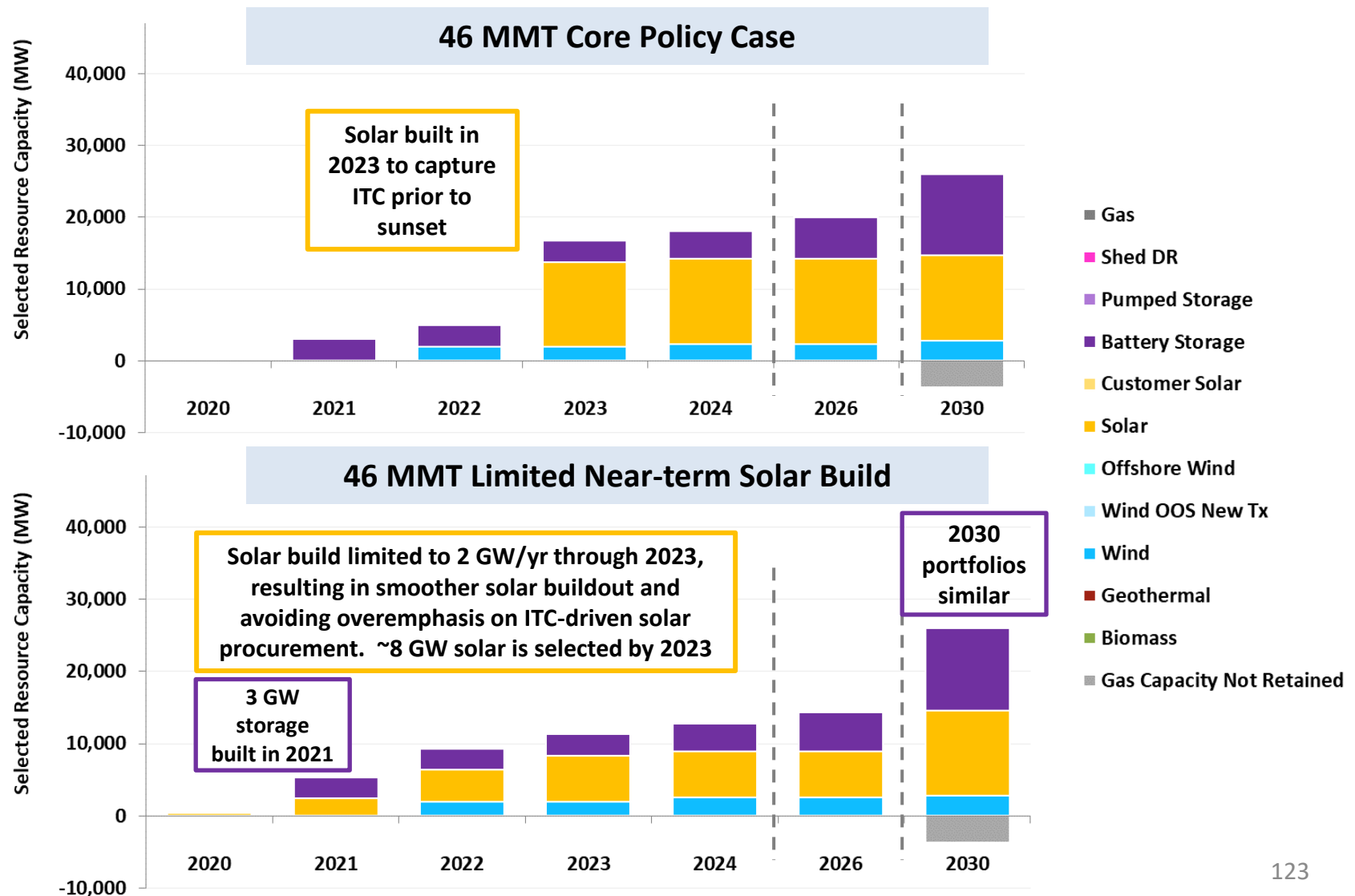
# Motivation for Near-Term Resource Availability Study

- Many “real-world” factors make it challenging to ramp up resource deployment quickly.
  - Logistics of training and re-locating staff, upstream supply chain limitations, siting and permitting lead times, etc.
- Near-term limits on resource buildout will limit the capacity of resources available to be procured by LSEs, and should be represented in IRP modeling when possible.
- However, it can be analytically challenging to predict a feasible level of near-term deployment.

In all cases in this section, a **solar deployment limit** is applied:

- The steep increase in solar deployment in 2023 in the core policy cases, driven by the economic incentive to capture the Investment Tax Credit, would likely need to be spread out over the preceding years.
  - There may be competition at a national level to deploy solar before ITC expiration.
- To reflect real-world constraints on solar buildout, an annual deployment limit of 2 GW/yr is enforced on candidate solar resources through 2023.
  - 2 GW/yr reflects recent utility-scale solar deployment rates in CAISO.
  - No constraint is imposed after 2023 – adequate lead time allows higher rates of deployment after 2023.
  - Growth in BTM PV from the IEPR is incremental to the 2 GW/yr limit – baseline BTM PV buildout is not impacted by the annual deployment limit.
  - Candidate distributed solar is included under the annual deployment limit.

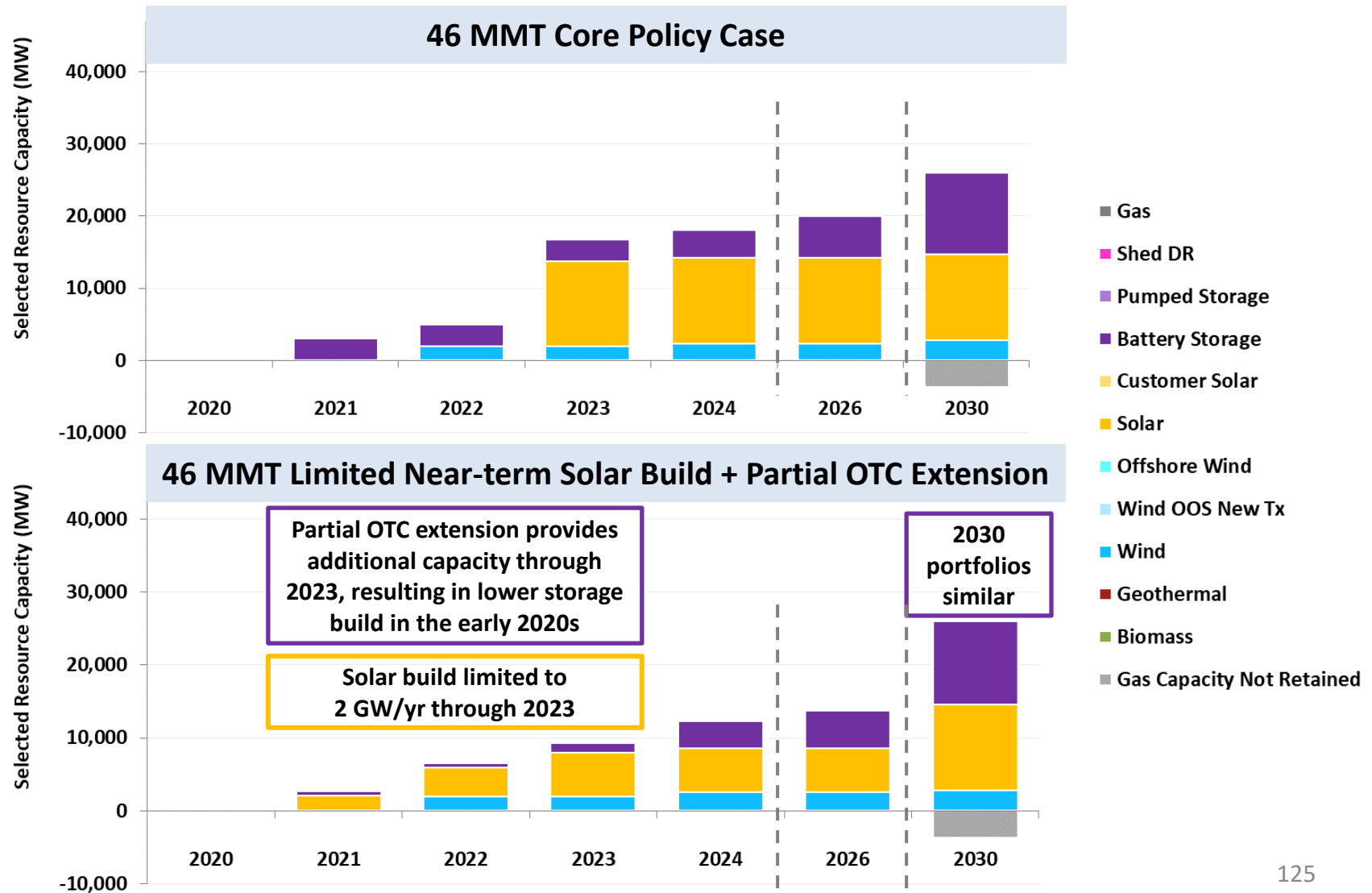
# 46 MMT Limited Near-term Solar Build: Resource Build Comparison



# OTC Extension, Import Capacity, and Battery Deployment

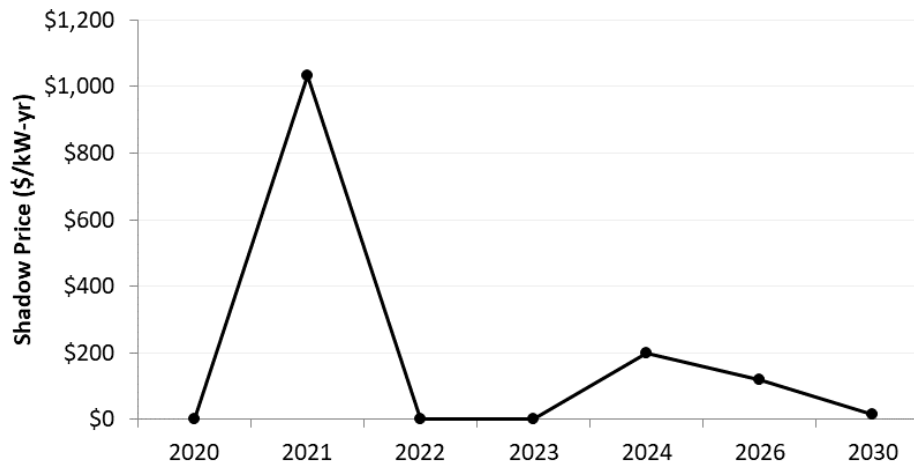
- Options to meet near-term capacity needs include significant implementation risk
  - OTC extension is a “stopgap” measure that can provide additional capacity for limited time.
  - Relying on out-of-state imports for resource adequacy will become increasingly challenging as remote resources retire and are not replaced with an equivalent amount of firm capacity. Many large coal-fired generators in other parts of the West have announced accelerated retirement schedules.
  - Significantly increasing Shed DR capacity could take several years, thereby limiting the ability of this resource to meet near-term capacity needs.
  - Battery storage has not yet been deployed at a multi-gigawatt scale to provide resource adequacy.
- An additional sensitivity is explored that combines limitations on near-term buildout:
  - 46 MMT Limited Solar and Partial OTC Extension:
    - Enforces the 2 GW / yr solar deployment limit
    - Includes partial extension of OTC capacity - 2,289 MW through 2023 and none thereafter

# 46 MMT Limited Near-term Solar and Partial OTC Extension Resource Build Comparison

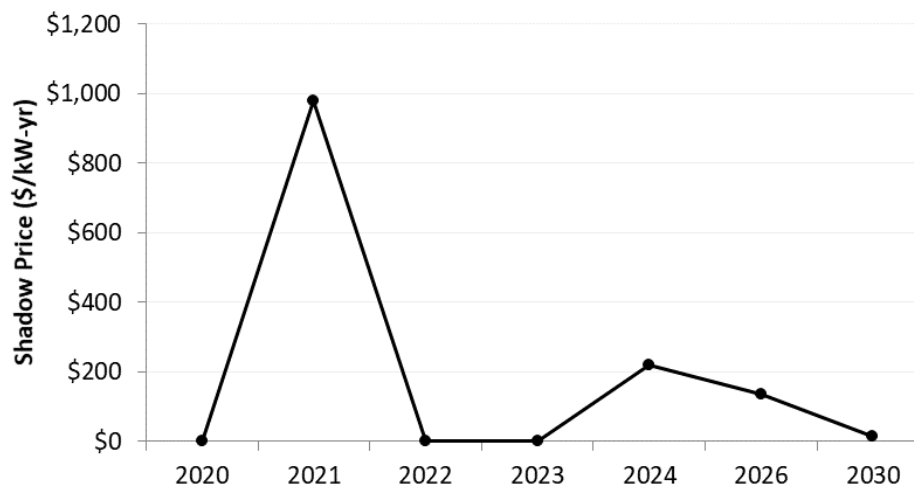


# 46 MMT Limited Solar and Partial OTC Extension Marginal PRM Price Comparison

## 46 MMT Core Policy Case



## 46 MMT Limited Near-term Solar Build + Partial OTC Extension



Partial OTC extension provides additional capacity through 2023 but does not fully eliminate a capacity shortfall in 2021, resulting in similar capacity prices in RESOLVE.

## Near-Term Resource Availability Conclusions

- Slowing solar buildout to a constant annual rate results in steady deployment over time through 2023.
  - Without an annual build rate constraint, modest ITC savings drive steep deployment of ~10 GW of solar in a single year.
- OTC extension pushes out most battery build until 2024 if 5 GW of RA imports are available.
  - Risk of near-term battery deployment decreased.
  - However, industry may not be prepared to deploy ~3 GW of batteries in 2024 (the build observed seen in Limited solar + Partial OTC extension case) without incremental installations over time.

# Summary Metrics for Near-Term Resource Availability Study Portfolios in 2030

Metric	46 MMT Case	46 MMT Limited Solar	46 MMT Limited Solar + Partial OTC Extension
CAISO GHGs	37.9	37.9	37.9
Selected Resources (by 2030)	<ul style="list-style-type: none"> <li>2.8 GW wind (in-state)</li> <li>0.0 GW wind (OOS)</li> <li>11.8 GW solar</li> <li>11.4 GW battery storage</li> <li>0.0 GW pumped storage</li> <li>0.2 GW shed DR</li> </ul>	<ul style="list-style-type: none"> <li>2.8 GW wind (in-state)</li> <li>0.0 GW wind (OOS)</li> <li>11.8 GW solar</li> <li>11.4 GW battery storage</li> <li>0.0 GW pumped storage</li> <li>0.2 GW shed DR</li> </ul>	2030 portfolio is identical for 46 MMT Limited Solar case
Gas Capacity Not Retained	3.7 GW	3.7 GW	3.7 GW
Selected Renewables (In-state)*	14.6 GW	14.6 GW	14.6 GW
Levelized Total Resource Cost (TRC)	\$45.4 billion/yr	\$45.5 billion/yr	\$45.3 billion/yr
Incremental TRC (relative to 46 MMT Case)**	-	+42 million/yr	(85 million/yr)
Marginal GHG Abatement Cost	\$113/metric ton	\$114/metric ton	\$114/metric ton
Planning Reserve Margin Achieved	15%	15%	15%





## 4. RECOMMENDATIONS



## **4.1. RECOMMENDED GHG PLANNING TARGET**

## 46 MMT GHG Planning Target is Consistent With Adopted Policy

- The 46 MMT GHG Planning Target is analogous to the 42 MMT GHG Planning Target adopted in 2017-18 IRP cycle and keeps the electric sector on track to meet its 2030 GHG goals.
- Resource buildouts in the 46 MMT Core Policy Case and related sensitivities are generally more aggressive than the buildout adopted in the 42 MMT Preferred System Plan adopted in 2017-18 IRP.
- A deeper electric sector GHG target by 2030 may be too aggressive in the near term:
  - More cost-effective GHG reduction opportunities may be available in other sectors.
  - Electrification of other sectors may increase electric sector loads.
  - An aggressive GHG target, together with load departure and CCA renewable goals, could over-stimulate the market in short term.
  - It exposes ratepayers to unnecessarily high costs.
- In future IRP cycles it may be useful to study more stringent GHG targets to help the electric sector prepare for greater reductions that will likely be needed after 2030 to achieve 2050 goals.
- The 46 MMT GHG Planning Target would apply to CPUC-jurisdictional LSEs.



## **4.2. RECOMMENDED REFERENCE SYSTEM PORTFOLIO**

# IRP-Related Statutory Requirements

(All references are to the Public Utilities Code)

- Identify a diverse and balanced portfolio (454.51)
- Meet state GHG targets (454.52(a)(1)(A))
- Comply with state RPS (454.52(a)(1)(B))
- Ensure just and reasonable rates for customers of electrical corporations (454.52(a)(1)(C))
- Minimize impacts on ratepayer bills (454.52(a)(1)(D))
- Ensure system and local reliability (454.52(a)(1)(E))
- Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities (454.52(a)(1)(F))
- Enhance distribution system and demand-side energy management (454.52(a)(1)(G))
- Minimize air pollutants with early priority on disadvantaged communities (454.52(a)(1)(H))

# Steps Taken Since Preliminary Results Workshop to Determine RSP

- Core Policy Case Results for 46 MMT, 38 MMT, and 30 MMT GHG targets, as well as sensitivities on those cases, were included as part of the 2019 IRP Preliminary Results. These cases were updated as part of this 2019 IRP Reference System Plan presentation.
  - New sensitivities, including those focusing on near-term resource availability and offshore wind, are now also included.
- Multiple key updates in RESOLVE cases have occurred since the 10/8 workshop that informed which portfolios should be validated for reliability, operability, and emissions using SERVIM:
  - RESOLVE implementation of nested transmission constraints and small corrections to inputs
  - Near-term resource availability assumptions changes in RESOLVE
- In addition, staff revised SERVIM's modeling of import constraints to approximate a future where firm imports that can be counted upon for resource adequacy are limited, consistent with RESOLVE's PRM constraint.
  - As further described on Slide 11 of Validation with SERVIM presentation.

## Need for Additional Capacity to Maintain System Reliability

- Analysis of the latest 46 MMT Core Policy Case suggested that assumptions regarding the availability of resources to meet capacity needs in the short- and medium-term may have been optimistic.
- To address this issue, CPUC staff ran additional sensitivities – described in Section 3.9 above – that reflected new assumptions regarding the short- and medium-term availability of certain resources.
- Analysis of these sensitivities compared to other sensitivities and the core policy cases, particularly the 46 MMT core policy case (now referred to as 46 MMT "Default"), informed staff's decision-making regarding which cases to model in SERVVM for production cost modeling.

# Description of Analysis of 46 MMT Default and Alternate Cases

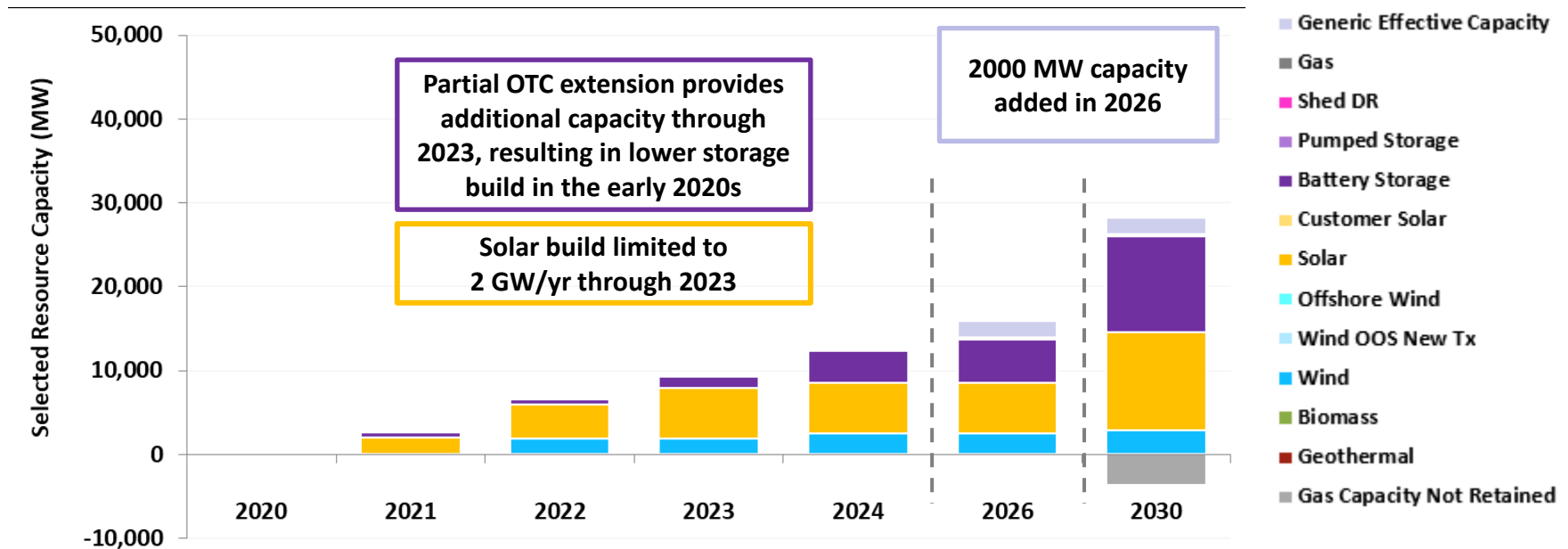
- Two updated RESOLVE cases were selected for validation with SERVM, the 46 MMT Default, and the 46 MMT "Alternate", which differs from the 46 MMT Default in two ways and is included on slide 125 as the "Limited Near-term Solar and Partial OTC Extension" case:
  - Adjustment of candidate resource solar resource potential to implement a deployment limit of 2 GW/yr for utility-scale solar resources through 2023.
  - Inclusion of a partial extension of OTC generation capacity of 2,289 MW through 2023 and none thereafter.
- 46 MMT Default case was studied in SERVM without the new import constraint. Consistent with earlier studies presented in the 10/8 workshop, this portfolio was found to have sufficient reliability (LOLE was below 0.1).
- When the 5,000 MW import constraint was added to the SERVM analysis of the 46 MMT Default case, LOLE was above 0.1.
- Given similarity in RESOLVE selected resources between the 46 MMT Default and 46 MMT Alternate cases, staff expected a SERVM study with the 46 Alternate case as-is from RESOLVE would also result in  $LOLE > 0.1$ .
- Staff determined that an adjustment to the portfolio would likely be necessary for it to have sufficient reliability.
  - Please see Validation with SERVM presentation for further description of SERVM modeling for these cases.



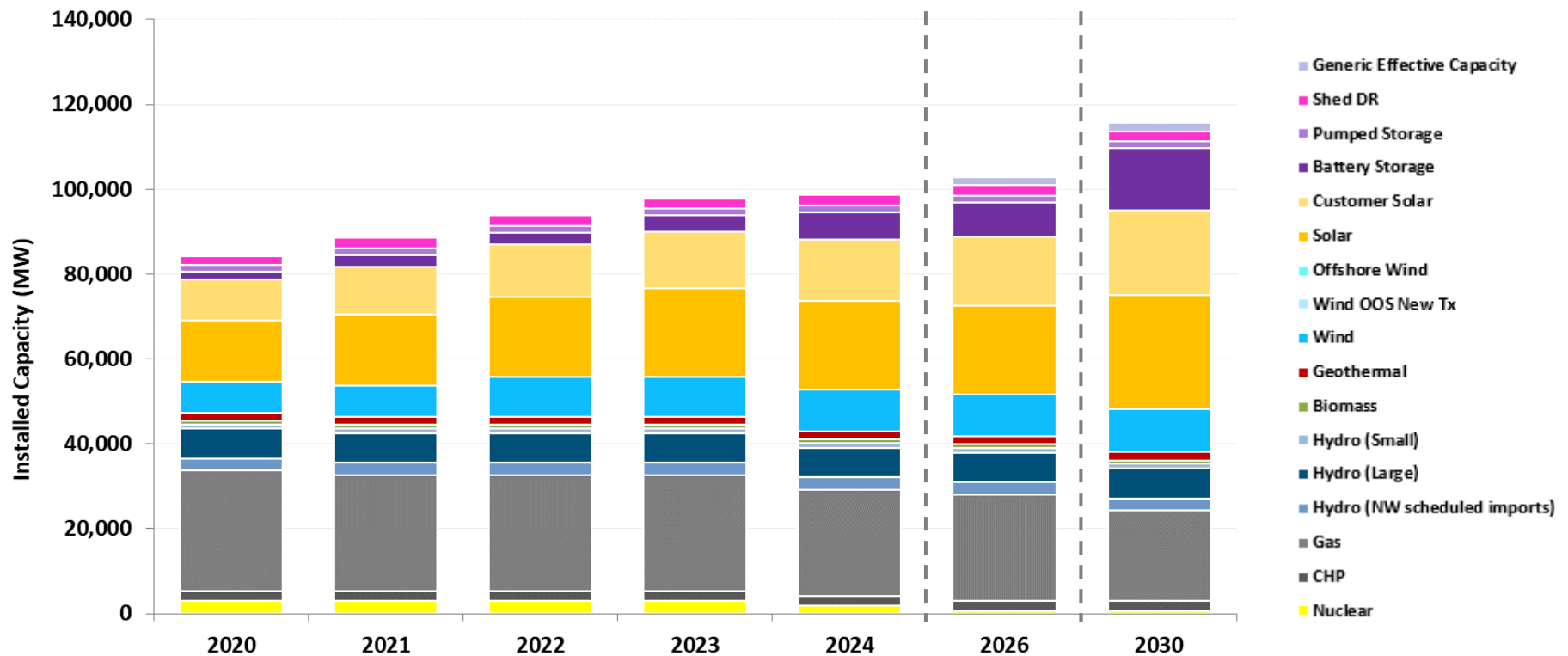
# Description of Adjustments to 46 MMT Alternate Case

- Rather than study the 46 MMT Alternate case as-is from RESOLVE, staff added 2,000 MW of "generic effective capacity" only to SERVVM, for the purposes of validating reliability.
  - "Generic effective capacity" was modeled in SERVVM as a perfectly dispatchable peaker with zero-emissions. In reality, the additional capacity could be realized through firm imports, batteries paired with solar, geothermal, more economic retention of existing thermal generation, demand response, or other.
- The addition of 2,000 MW of generic effective capacity in 2026 and 2030 to the 46 MMT Alternate case decreased LOLE to below 0.1 for each year, meeting the threshold for sufficient reliability.
- The 46 MMT Alternate case with the addition of 2,000 MW of generic effective capacity is the 2019 Proposed Reference System Portfolio, and corresponds to the 46 MMT Alternate scenario referenced in the 2019 Proposed RSP Ruling.
- Stacked bar charts depicting the 2019 IRP Proposed Reference System Portfolio are included on the next two slides.

# Proposed Reference System Portfolio, Selected Resources with 2 GW Generic Effective Capacity Added in 2026, aka "46 MMT Alternate"



# Proposed Reference System Portfolio, Total Resources, with 2 GW Generic Effective Capacity Added in 2026, aka "46 MMT Alternate"



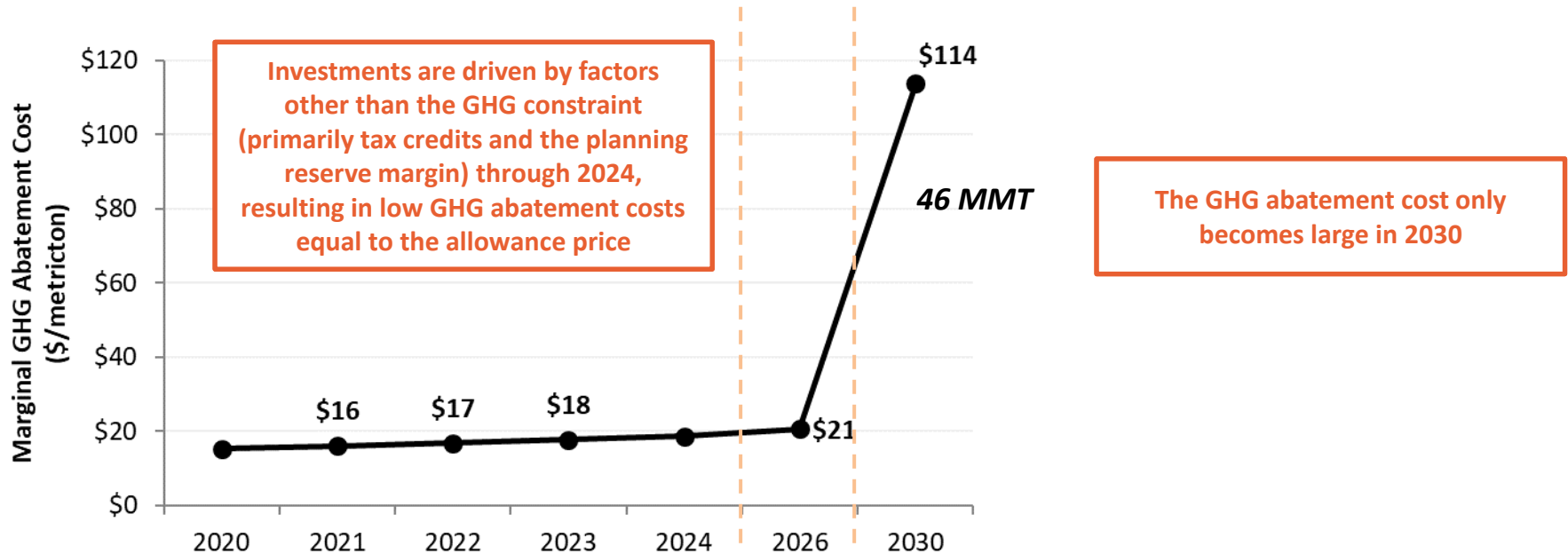
# Summary of Annual Resource Buildouts from 46 MMT "Default" and the 2019 Proposed Reference System Portfolio

Case	2020	2021	2022	2023	2024	2026	2030	
<b>46 MMT "Default"</b>	-	34	1,950	1,950	2,372	2,372	2,837	Wind (in-state)
		-	-	-	-	-	-	Wind (out of state)
		-	-	11,807	11,807	11,807	11,807	Solar PV
		2,960	2,960	2,960	3,878	5,796	11,376	Battery storage
		-	-	-	-	-	-	Pumped Storage
		222	222	222	222	222	222	Shed DR
		-	-	-	-	-	-	<i>Generic Effective Capacity</i>
<b>2019 Proposed Reference System Portfolio (46 MMT "Alternate")</b>	6	34	1,950	1,950	2,550	2,550	2,837	Wind (in-state)
	-	-	-	-	-	-	-	Wind (out of state)
	-	2,006	4,006	6,006	6,006	6,006	11,774	Solar PV
	-	624	624	1,336	3,759	5,193	11,384	Battery storage
	-	-	-	-	-	-	-	Pumped Storage
	-	222	222	222	222	222	222	Shed DR
	-	-	-	-	-	2,000	2,000	<i>Generic Effective Capacity</i>



## **4.3. RECOMMENDED GHG PLANNING PRICE**

# RESOLVE Output: Marginal GHG Abatement Cost in 46 MMT Limited Solar and Partial OTC Extension



- GHG abatement cost curves reflect the selection of increasingly higher-cost resources to reduce increasingly more GHG emissions.
- The total marginal cost of GHG abatement (or “GHG Planning Price”) is estimated by adding the assumed allowance cost to the GHG shadow price.
  - 2030 marginal abatement cost in 46 MMT scenario:  $\$89 + \$25 = \underline{\$114/\text{metric ton}}$



## **4.4. RECOMMENDED LSE-SPECIFIC GHG BENCHMARKS**

# Determining LSE-Specific GHG Emissions Benchmarks (1 of 2)

- Staff is proposing no changes to how the Commission assigns a “GHG Emissions Benchmark” to each LSE required to file a Plan.
- The GHG Benchmark is calculated in two steps:
  - Divide the 2030 GHG Planning Target for the electric sector among CPUC-jurisdictional electric distribution utilities (EDUs) based on CARB’s draft methodology for the 2021-2030 allowance allocation under the Cap-and-Trade program.
  - Further divide that value proportionally among the host EDU and non-EDUs (CCAs and ESPs) within the host EDU’s territory based on their projected 2030 load share.



# Determining LSE-Specific GHG Emissions Benchmarks (2 of 2)

- The hypothetical example below reflects the recommended 46 MMT GHG Planning Target for 2030

LSE	Proportion of 2030 Allowance Allocation Under CARB's Cap-and-Trade Program	Proportion of 2030 Load Share Within the EDU Service Territory	2030 GHG Emissions Benchmark
EDU	30%	60%	7.56 MMT
CCA within EDU	N/A	35%	4.41 MMT
ESP within EDU	N/A	5%	0.63 MMT



## **4.5. SUMMARY OF RECOMMENDED GUIDANCE FOR LSE IRPS**

## Summary of Recommended Guidance for LSEs

- The CPUC issued a Ruling in September 2019 seeking comment on a staff proposal for LSE filing requirements for their 2020 IRPs.
- The staff proposal recommends several modifications and clarifications to last year's requirements to ensure that the CPUC has enough information in a useful form to assess and approve individual IRPs, and to aggregate the LSE portfolios to develop a proposed Preferred System Portfolio.
  - Proposed changes seek to standardize reporting across LSEs, better align LSE plans with the RSP, and improve the functionality of the tools and templates available to the LSEs.
- Staff is reviewing comments and reply comments and will seek to release draft filing templates in late 2019.



# **APPENDIX A: 2045 FRAMING STUDY**

# Purpose of SB100 2045 Framing Study

- Explore how 2045 goal under SB100 could affect the outlook for electricity sector GHG emissions and resource planning in the 2030 timeframe.
- Provide analysis that includes context from other sectors.
- Inform Commission decision-making around the appropriate 2030 GHG planning target for CPUC-jurisdictional LSEs, as the Reference System Portfolio to meet that target.
- Primarily informational and directional regarding least-regrets investments needed by 2030.

# SB100 2045 Framing Study Scenarios

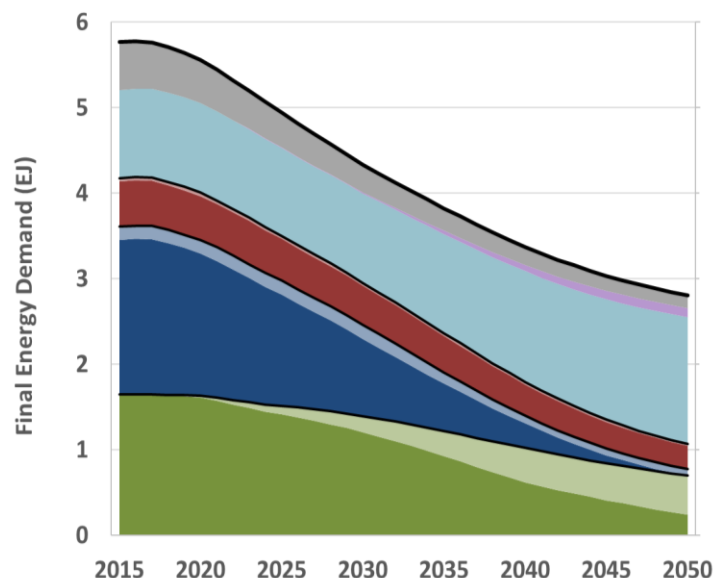
- While the CPUC IRP focuses on infrastructure decisions between present day and 2030, some near-term decisions may depend on changes to the electricity sector that result from post-2030 economy-wide decarbonization.
- Three scenarios are explored in the 2045 Framing Studies that reflect different decarbonization strategies in the CEC Deep Decarbonization report:\*
  - High Electrification
  - High Biofuels
  - High Hydrogen
- The three scenarios have the same economy-wide GHG constraint of 86 MMT by 2050 (80% below 1990).
- The electric sector GHG emissions target and electricity loads vary by scenario and are a product of complex cross-sectoral interactions within each scenario. Electricity-sector GHG emissions and electric loads by sector are outputs of the PATHWAYS model.

\*CEC, 2018, *Deep Decarbonization in a High Renewables Future*.

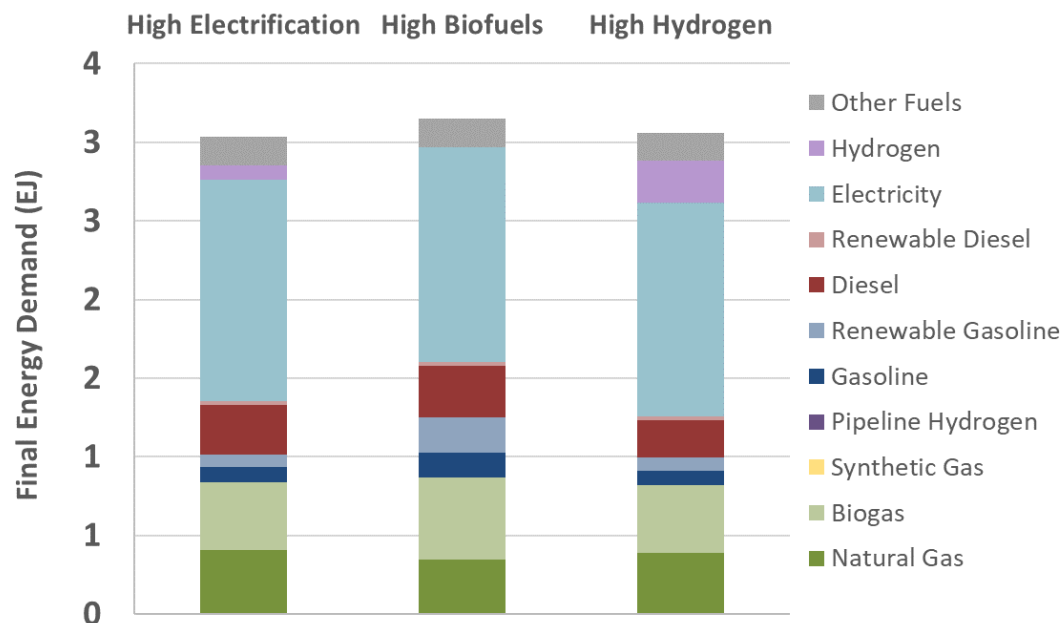
[https://www.ethree.com/wp-content/uploads/2018/06/Deep\\_Decarbonization\\_in\\_a\\_High\\_Renewables\\_Future\\_CEC-500-2018-012-1.pdf](https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf)

# Final Energy Demand by Fuel, Statewide

## High Electrification



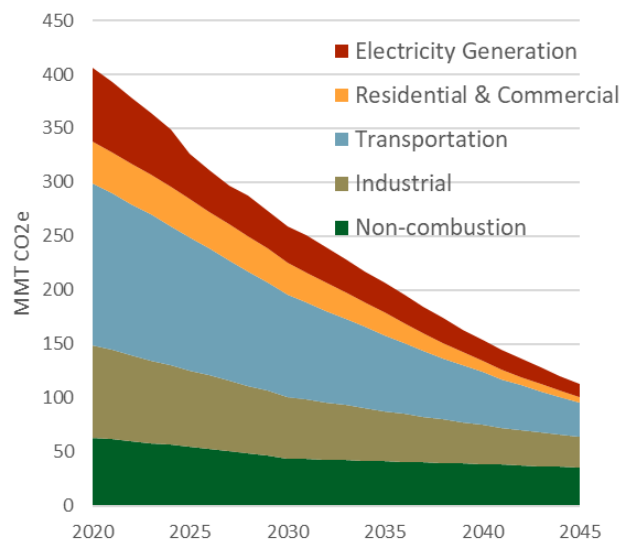
## 2045 – Comparison Between Scenarios



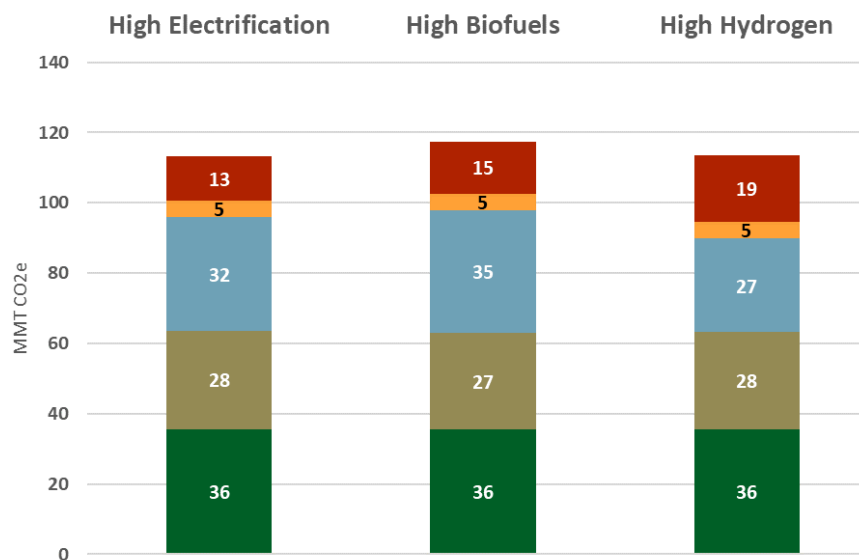
- Demand for electricity, hydrogen and biofuels varies by scenario

# GHG Emissions by Sector, Statewide

## High Electrification



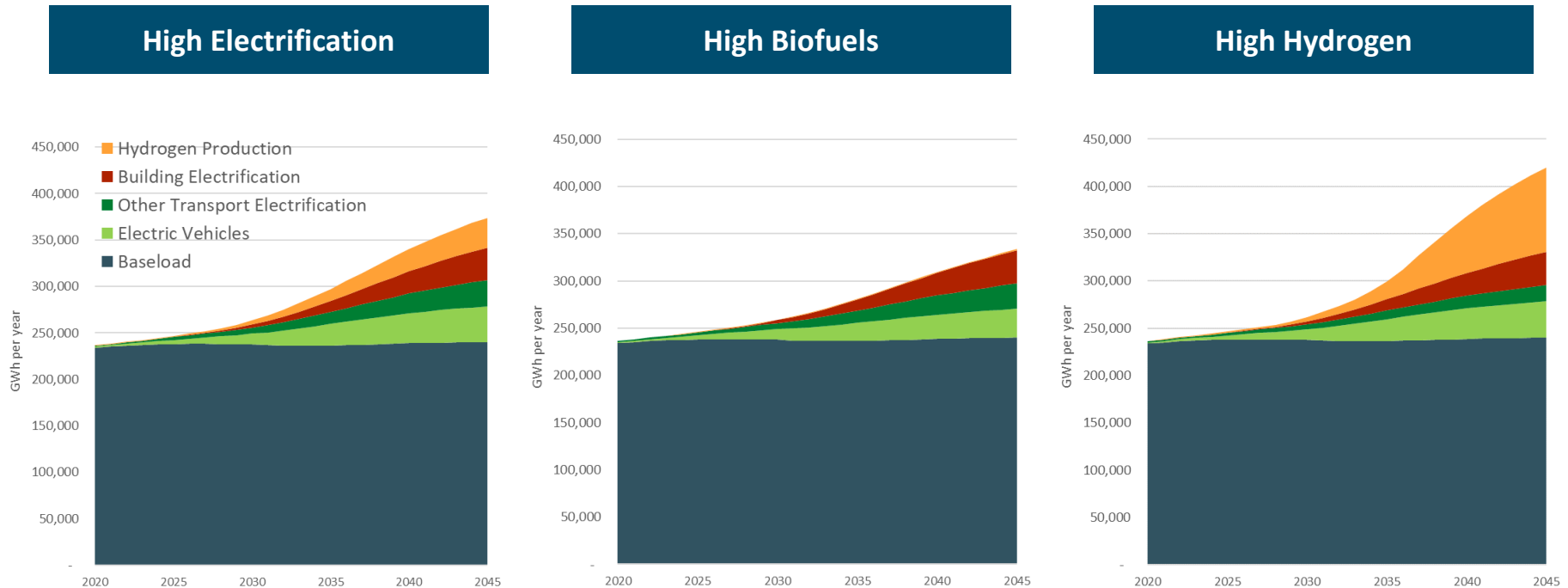
## 2045 – Comparison Between Scenarios



- All scenarios meet the same economy-wide 2050 GHG target, but result in different energy systems

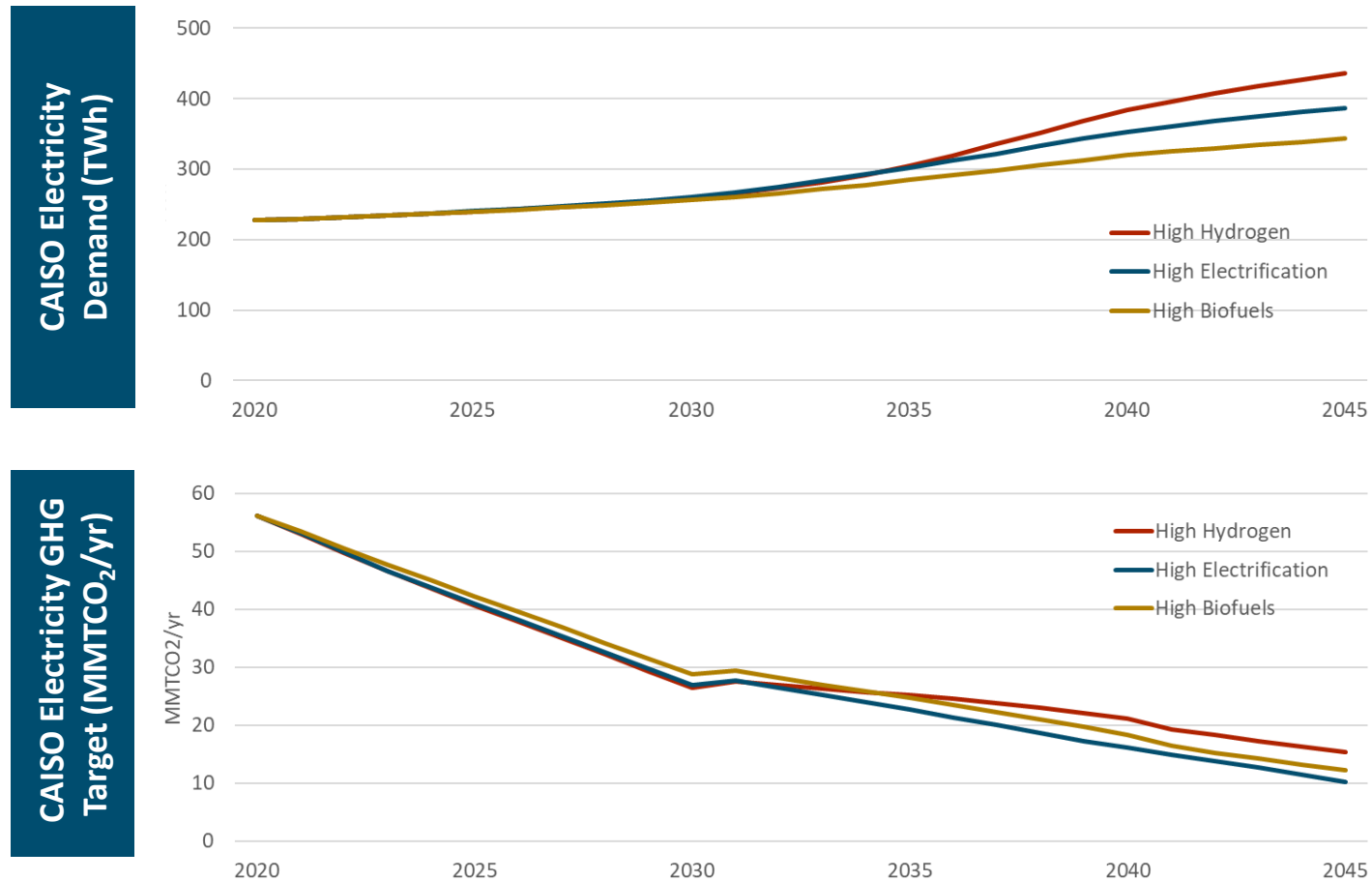


# CAISO Electricity Loads

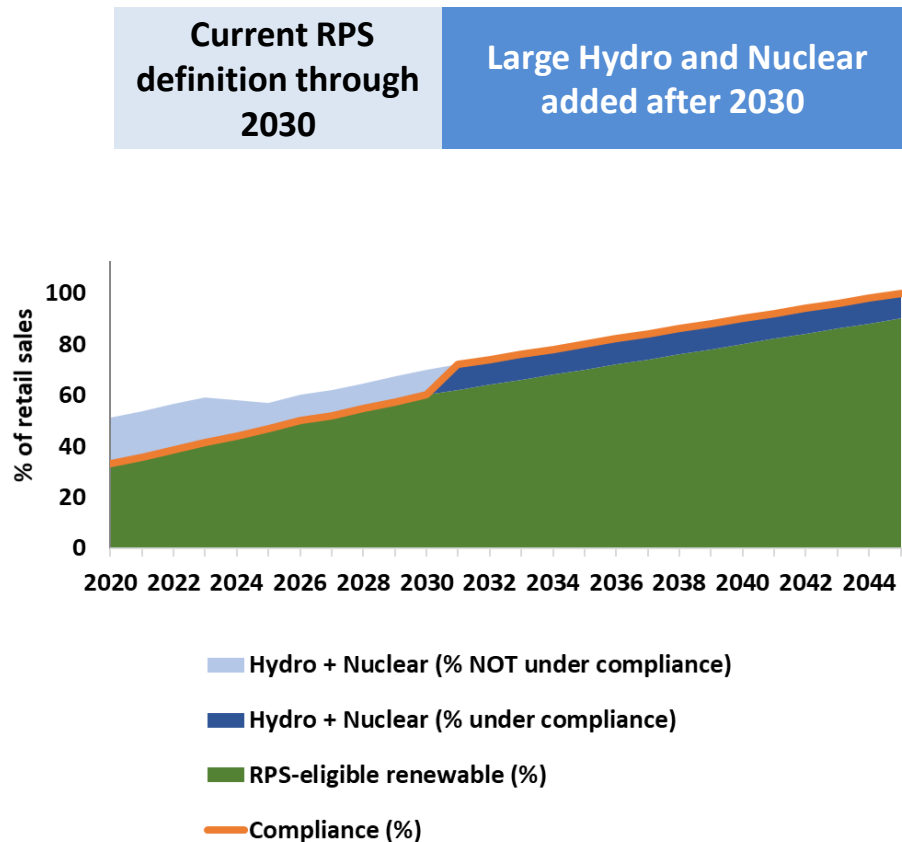


- Electricity loads vary by scenario and are a product of complex cross-sectoral interactions within each scenario
- Electrifying buildings, transportation and industry, and hydrogen electrolysis are key drivers of higher electric sector loads

# Pathways Inputs into RESOLVE



# Modeling SB 100 in RESOLVE



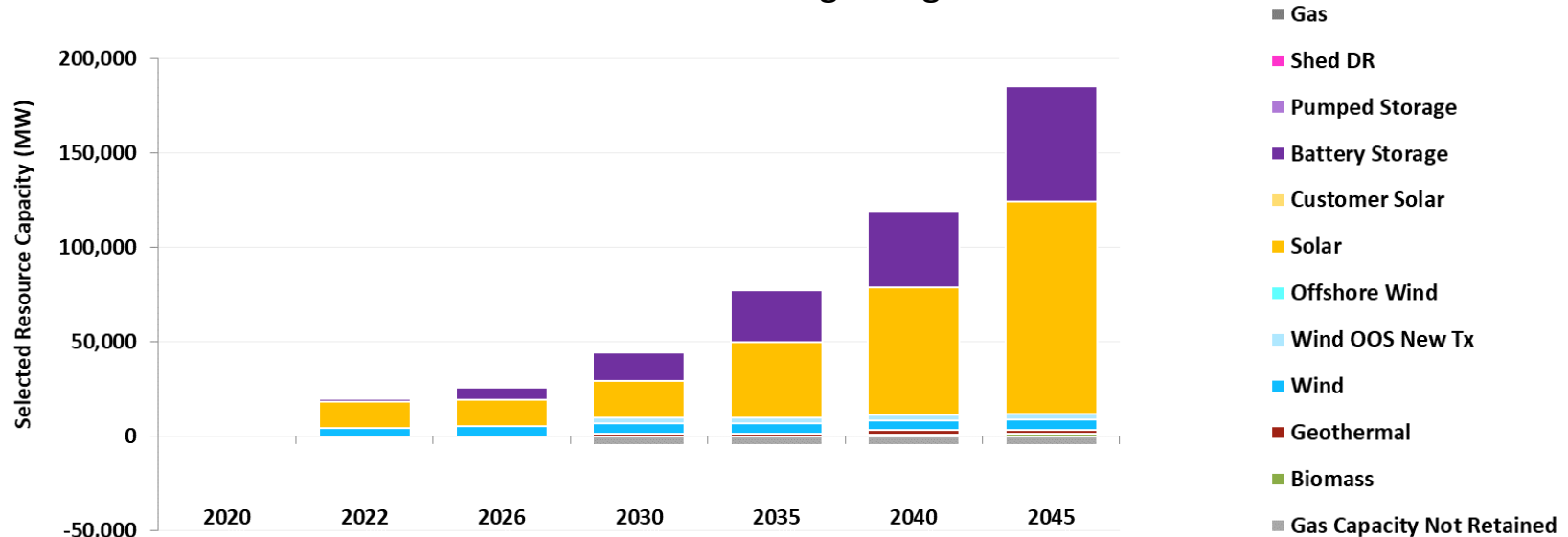
\*Total retail sales includes pumping loads after 2030 (not shown)

- Will inform SB100 joint agency report process\*\*
- SB100 does not define “zero carbon resources”
  - Renewables, nuclear and hydro are assumed to be eligible resources under SB100 post-2030
- SB100 interpreted as a percent of retail sales
  - Through 2030: current RPS definition retained
  - After 2030: nuclear and large hydro are added to eligible resources
- SB100 requires GHG-free generation to equal electricity retail sales in 2045 and, as modeled in RESOLVE, gas generation is not prohibited for the following reasons:
  - Exported GHG-free power counts towards the SB100 requirement, leaving room for some internal load to be met with GHG-emitting resources
  - Transmission and distribution losses (~8% of demand) are not counted as retail sales, and may be met with GHG-emitting resources
- All of the 2045 framing studies include some natural gas power plants
  - The model makes economic decisions on how much existing gas capacity to retain, but must retain some gas plants for local reliability
  - All natural gas combined heat and power capacity is ramped down between 2030 and 2040

\*\* More on joint agency report: <https://www.energy.ca.gov/sb100>

# Resource Build: High Electrification

- Resources in chart are selected by RESOLVE and are in addition to baseline resources
- RESOLVE does not retain some thermal resources beginning in 2030



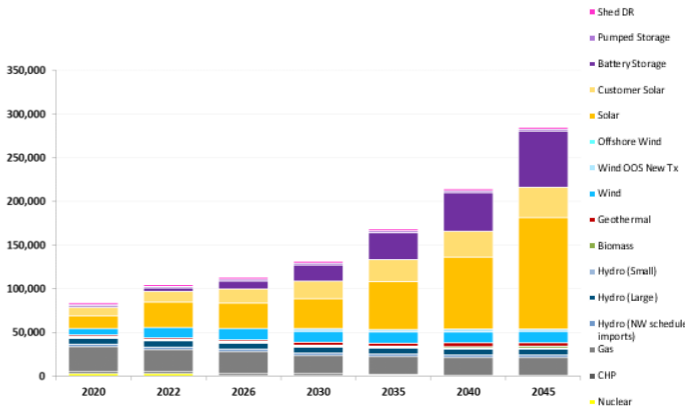
- Solar and batteries dominate
  - Li-Ion batteries have 6-8 hours of duration from 2030 through 2045
- Around 700 MW of long duration (12-hr) pumped storage is selected in 2026
- Wind:
  - Maximum resource potential built for onshore wind
  - The option to build offshore wind is allowed in a 2045 sensitivity
- Biomass and geothermal provide resource diversity and firm capacity, but are a small portion of the portfolio

# Comparison to Previous Studies

- Resource mix in the High Electrification scenario predominantly consists of solar, wind, and battery storage after 2030 through 2045. Wind resource potential limited to in-state onshore, but sensitivities increase wind generation options.
- Results are broadly consistent with recent studies examining long-term electric sector decarbonization portfolios.

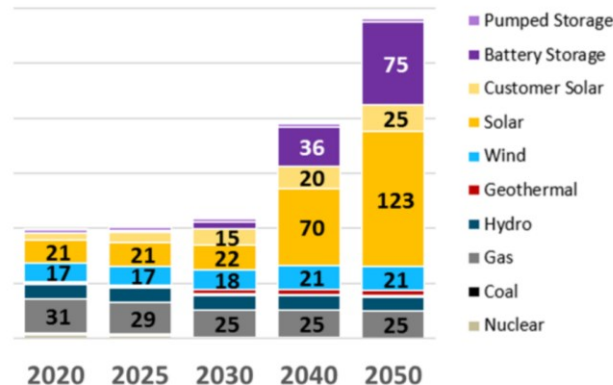
*CAISO-only*

## 2019 IRP High Electrification

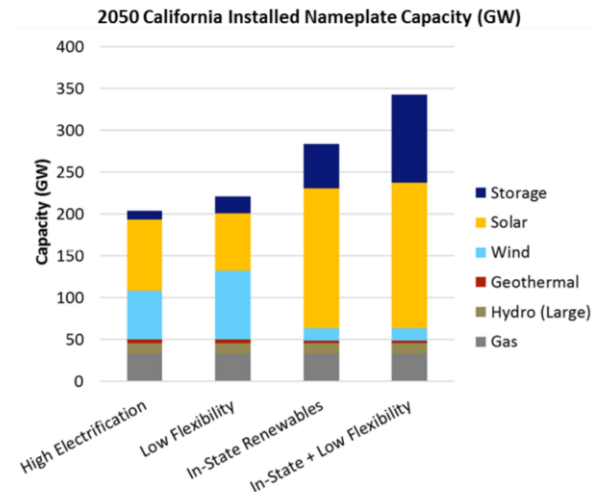


*California Statewide*

## Long-Run Resource Adequacy (a): High Electrification



## CEC Deep Decarbonization (b)



(a) [https://www.ethree.com/wp-content/uploads/2018/06/Deep\\_Decarbonization\\_in\\_a\\_High\\_Renewables\\_Future\\_CEC-500-2018-012-1.pdf](https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf), Figure 10

(b) [https://www.ethree.com/wp-content/uploads/2019/06/E3\\_Long\\_Run\\_Resource\\_Adequacy\\_CA\\_Deep-Decarbonization\\_Final.pdf](https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf), Figure 16

*"Flexibility" = demand flexibility*

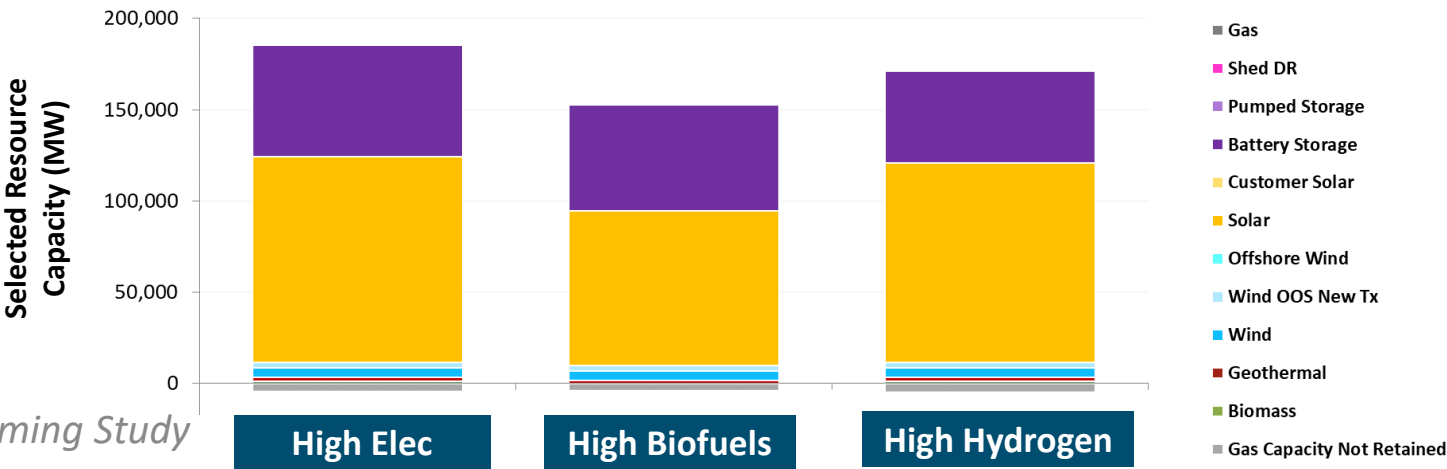
# Key Scenario Metrics in 2045

Metric	High Electrification	High Biofuels	High Hydrogen
CAISO load in 2045	425 TWh	383 TWh	459 TWh
CAISO GHG Target in 2045	10.3 MMTCO <sub>2</sub> /yr	12.3 MMTCO <sub>2</sub> /yr	15.5 MMTCO <sub>2</sub> /yr
Marginal GHG Abatement Cost	\$587/tCO <sub>2</sub>	\$458/tCO <sub>2</sub>	\$493/tCO <sub>2</sub>
Effective SB100 % <small>Note: 100% CES target enforced</small>	109%	106%	104%
Gas capacity not retained <small>Note: Does not include OTC retirements</small>	4.5 GW	4.1 GW	4.8 GW
Reserve Margin Requirement	71 GW	69 GW	69 GW
Curtailment + storage losses	24%	20%	18%
Levelized Total Resource Cost (TRC) <small>Note: Electrolysis capital cost not included</small>	\$55.5 bn/yr	\$53.5 bn/yr	\$55.2 bn/yr
Incremental TRC <small>(relative to High Electrification)</small>	-	(\$2 bn/yr)	(\$0.3 bn/yr)

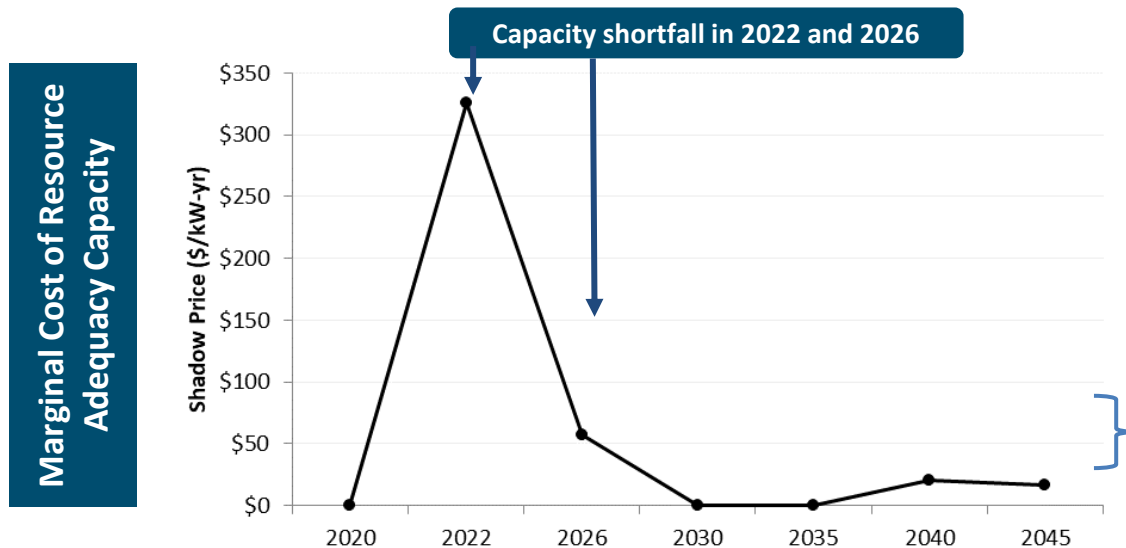
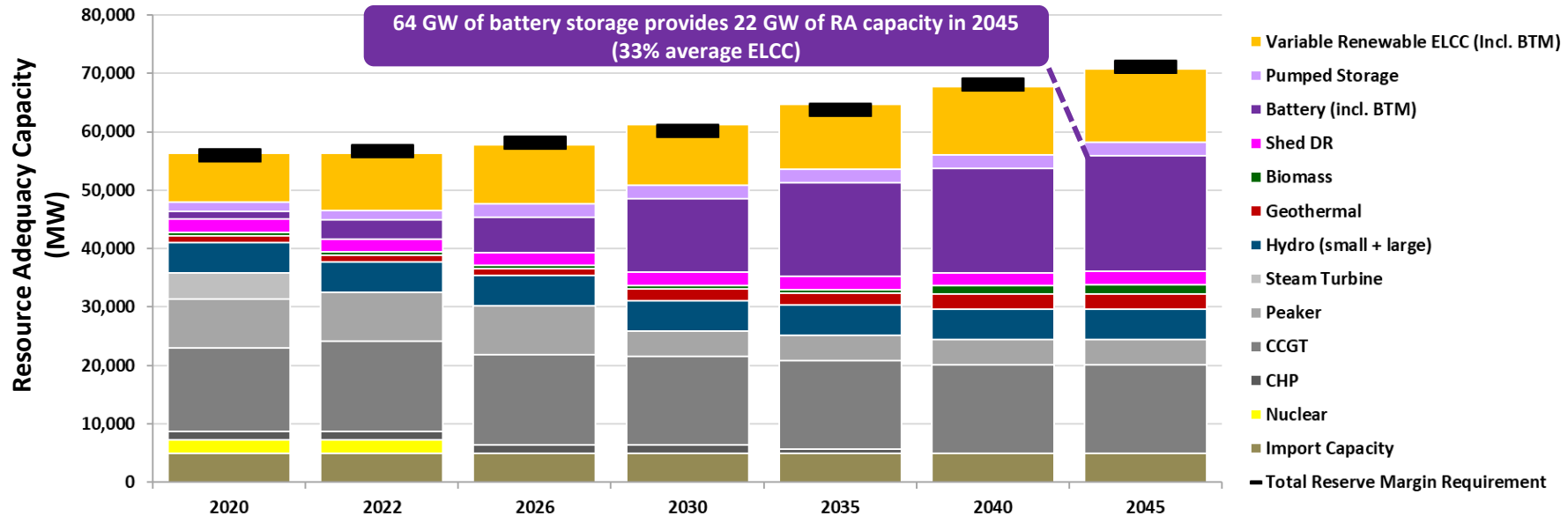
More zero-GHG generation is procured to meet GHG targets than is required to meet the RESOLVE SB100 constraint, resulting in > 100%

Almost all gas capacity retained due to high peak demand post-2030

Hydrogen load flexibility substitutes for storage and reduces curtailment relative to high electrification, but would require significant electrolyzer investment



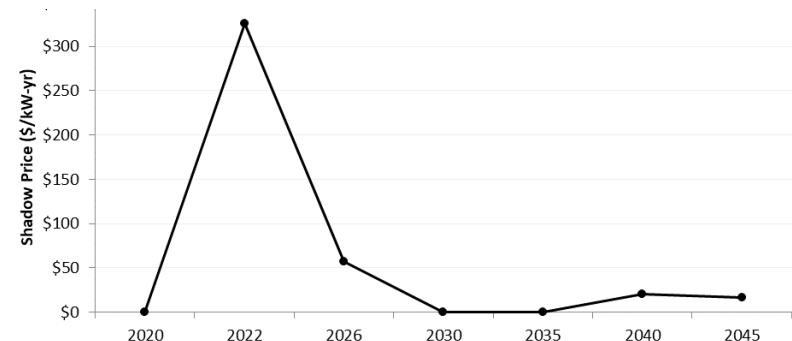
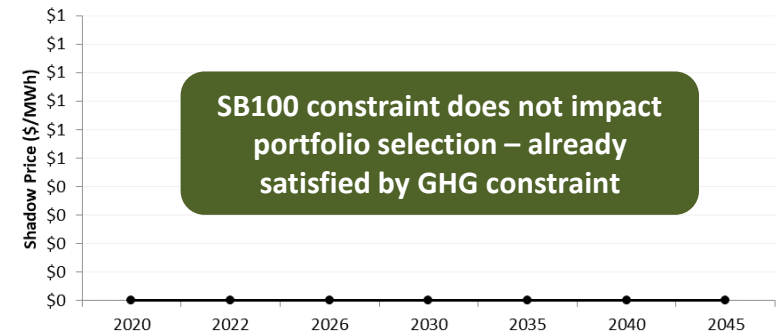
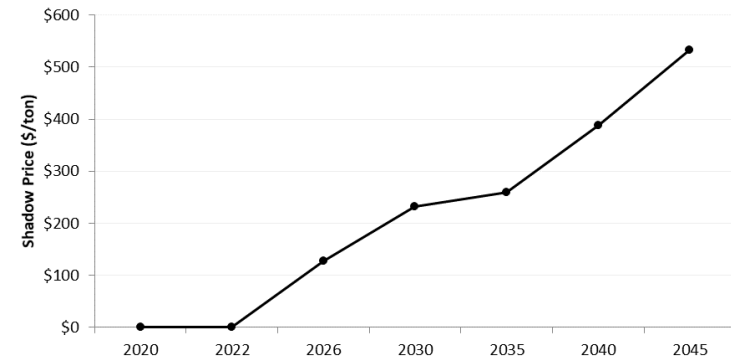
# Capacity Contribution: High Electrification



Policy targets drive capacity installation in most years. Moderate cost of retaining existing gas likely explains low but non-zero capacity cost in 2040-5

# Multiple Constraints: High Electrification

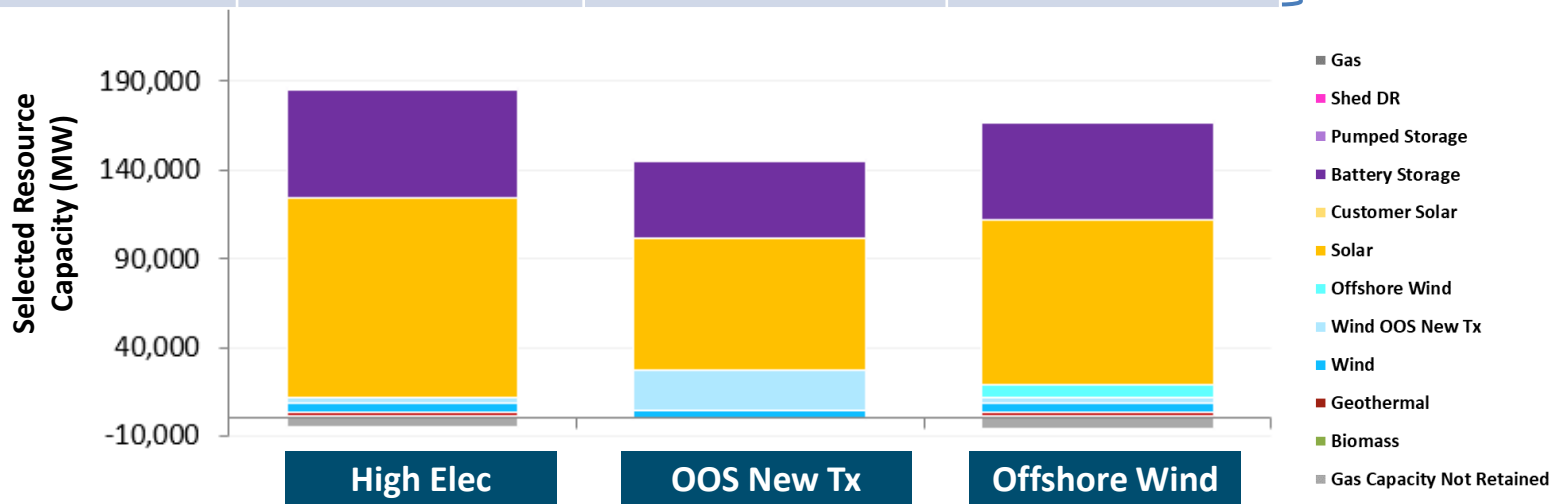
- RESOLVE portfolios are the least cost solution to meet many different requirements (“constraints”)
- Three important constraints may drive portfolio selection: GHG, RPS/SB100, and Planning Reserve Margin
- In any modeled year, one or many of the constraints could drive portfolio selection.
- Constraints that drive selection have a high “shadow price,” – a high cost to meet the constraint.
- A shadow price of zero indicates that the constraint is not impacting the solution.
  - The constraint could be removed and the optimal portfolio would not change.





## High Electrification: Wind and Tx Sensitivities

Metric	High Electrification (Base)	OOS New Transmission (mostly wind)	Offshore Wind available	
CAISO load in 2045 (TWh)	425 TWh	425	425	
CAISO GHG Target in 2045	10.3 MMTCO <sub>2</sub> /yr	10.3 MMTCO <sub>2</sub> /yr	10.3 MMTCO <sub>2</sub> /yr	
Marginal GHG Abatement Cost	\$587/tCO <sub>2</sub>	\$408/tCO <sub>2</sub>	\$539/tCO <sub>2</sub>	
Effective SB100 % Note: 100% CES target enforced	109%	107%	108%	
Gas capacity not retained (GW) Note: Does not include OTC retirements.	4.5 GW	1 GW	5.2 GW	Gas capacity necessary to maintain reliability, even with significant buildout of OOS or offshore resources
Reserve Margin Requirement	71 GW	71 GW	71 GW	
Curtailment + storage losses (%)	24%	15%	21%	
Levelized Total Resource Cost (TRC)	\$55.5 bn/yr	\$54.8 bn/yr	\$55.3 bn/yr	Availability of additional wind resources reduces curtailment and costs
Incremental TRC (relative to High Electrification)	-	(\$0.7 bn/yr)	(\$0.2 bn/yr)	

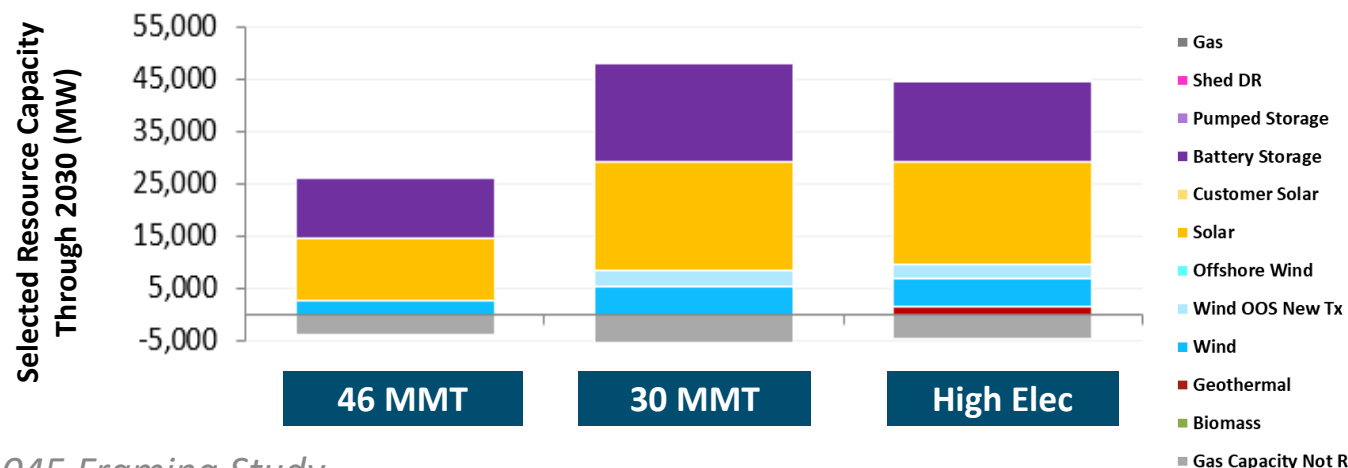


# Looking Beyond 2030 Highlights Potential Path Dependencies of 2030 Portfolios

Metric in 2030	46MMT in 2030	30MMT in 2030	High Electrification in 2030 (ends in 2045)
CAISO load in 2030 (TWh)	257	257	275
CAISO GHG Target in 2030	37.9 MMTCO <sub>2</sub> /yr	24.3 MMTCO <sub>2</sub> /yr	26.9 MMTCO <sub>2</sub> /yr
Marginal GHG Abatement Cost	\$113/tCO <sub>2</sub>	\$212/tCO <sub>2</sub>	\$258/tCO <sub>2</sub>
Effective RPS % Note: 60% target enforced	60%	78%	77%
Gas capacity not retained in 2030 (GW) Note: Does not include OTC retirements.	3.7 GW	7.7 GW	4.5 GW
Achieved RA Reserve Margin (target = 15%)	15%	15%	18%

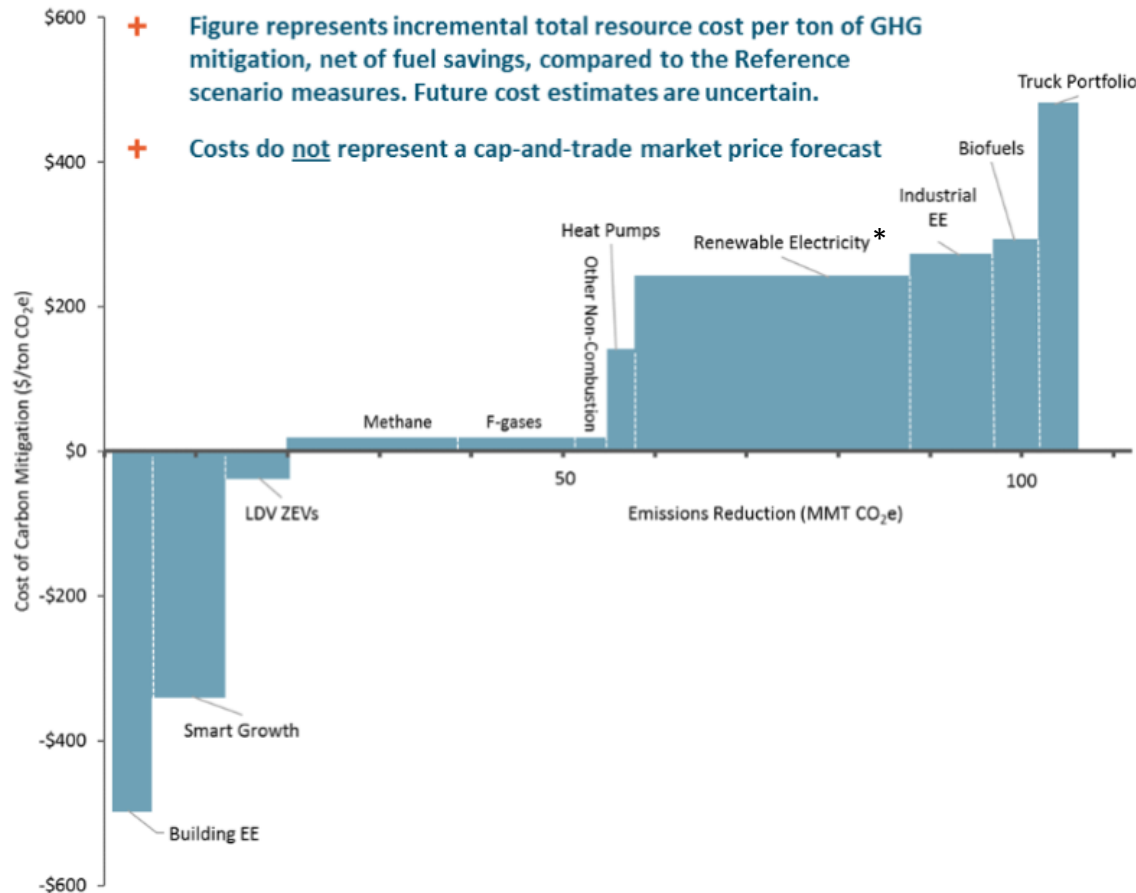
30 MMT and High Electrification runs similar in 2030

Comparing the 30 MMT and High Electrification scenarios, an increase in electrification loads post-2030 results in more gas retention in 2030



# Abatement Opportunities are Available Across Sectors, but have Greater Implementation Uncertainty

**Figure 25. 2030 Incremental Carbon Abatement Cost Curve (Total Resource Cost per Ton of GHG Reduction Measures, Net of Fuel Savings), in the High Electrification Scenario**



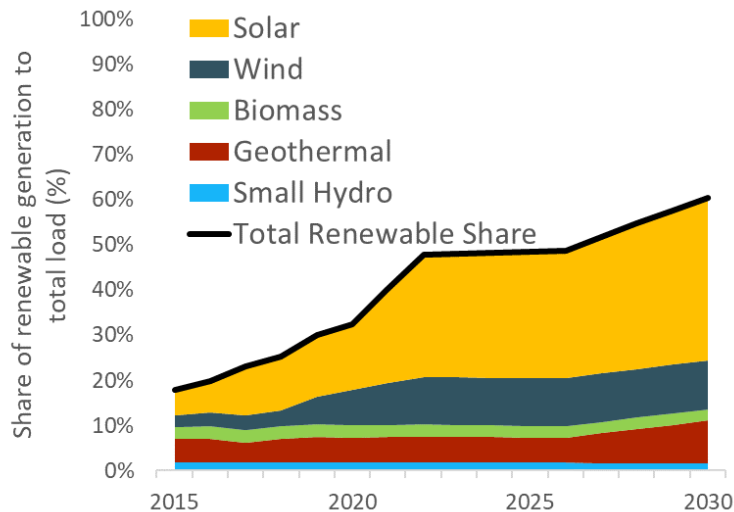
- Mitigation measures from other sectors may have lower estimated GHG abatement cost in 2030:
  - e.g., EE and VMT reduction, EVs, building electrification
- However, successful implementation of these measures is still uncertain
- The PATHWAYS electricity GHGs assume success in all other sectors, but if any of these fall short, greater reductions in electricity may be needed as a backstop

**\* Illustrative results from E3 2018 report CEC-500-2018-012.** The cost of carbon mitigation for the Renewable Electricity represents the average incremental cost of mitigating electricity emissions by 30 MMT by 2030. This is different than the marginal costs shown previous slides, which represent the cost of mitigating the last ton of carbon to reach the electricity sector GHG target. The average incremental cost of renewable electricity is higher in the E3 2018 report due to the significantly higher cost assumptions for solar and storage than those used in this analysis.

# PATHWAYS Electricity GHG Targets Assume Maximum Level of Effort in Other Sectors

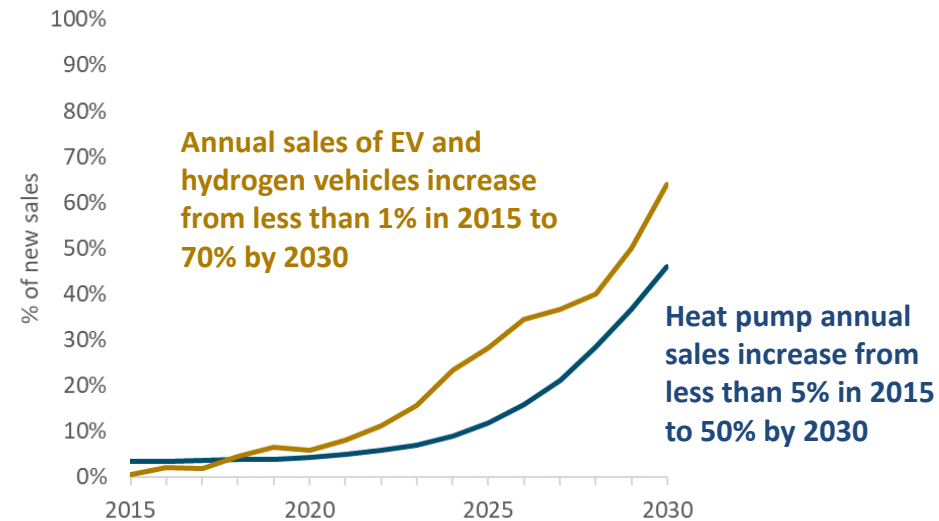
- Meeting the 2030 target requires accelerated progress in all other sectors with aggressive effort compared to the historical trajectory.

**Renewable generation share increases steadily from 18% in 2015 to 60% by 2030**



Source: RESOLVE High Electrification scenario

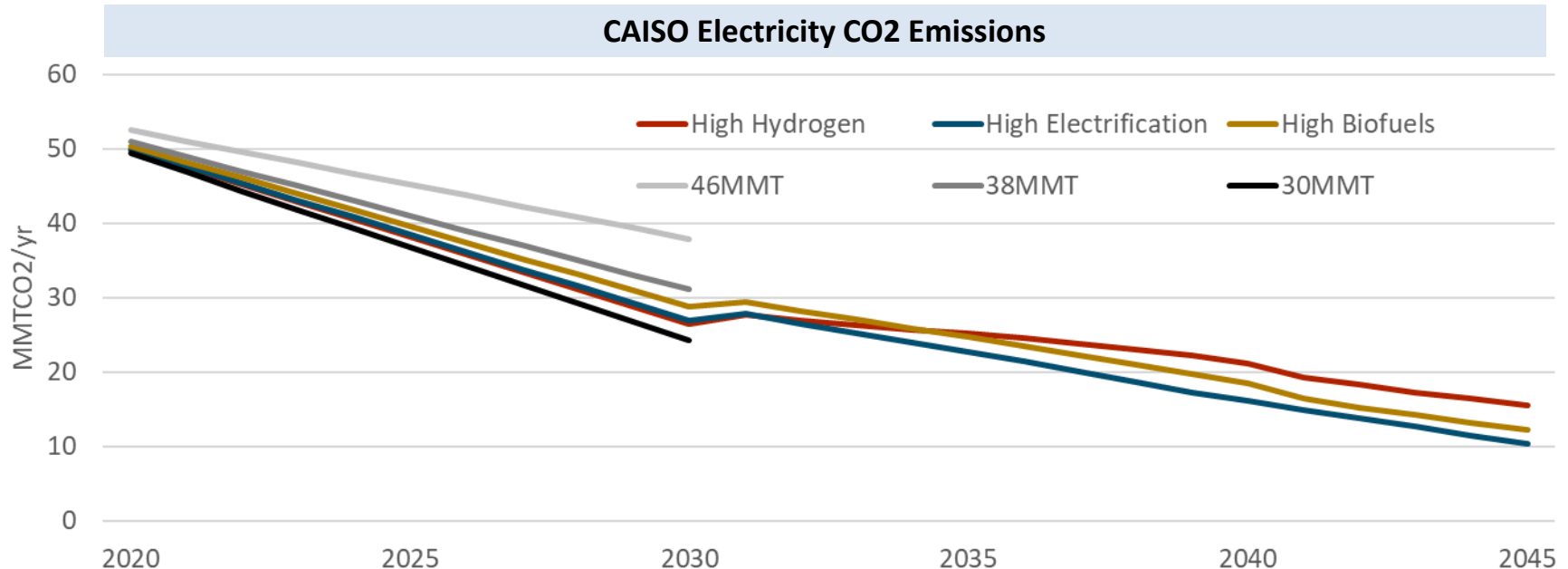
**The sales share of electric heat pumps and ZEVs need to ramp up rapidly from single digits to more than 50% by 2030**



Source: E3 2018 report CEC-500-2018-012, High Electrification Scenario

- Recent trends suggest challenges in achieving intended progress
  - Increased LDV GHG emissions in year 2017 inventory
  - Uncertainty over implementation of fuel economy standards
- How should the costs and risks of achieving GHG mitigation in the electricity sector be compared to the other sectors?

## GHG Target Comparison Shows Deeper Reductions in 2030 Under 2045 Framing Studies than 46 MMT Scenario



- 46MMT scenario includes ~60% RPS in 2030, roughly consistent 2030 requirements under SB100
- The High Hydrogen, High Electrification, and High Biofuels scenarios all exceed a 60% RPS in 2030, and have lower GHG emissions in 2030 than the 46MMT scenario. These scenarios are consistent with the statewide PATHWAYS scenarios (CEC 2018) that achieve a 40% reduction in economy-wide GHG emissions by 2030, relative to 1990 levels
- In the PATHWAYS (CEC 2018) scenarios, the electricity sector reduces GHG emissions more than other sectors, and exceeds the minimum regulatory requirements under SB100, due to lower GHG abatement costs in the electricity sector relative to other sectors, and due to the implementation challenges of achieving a 40% reduction in GHG emissions from some of the other sectors by 2030

# Key Takeaways from 2045 Framing Study

- Looking beyond 2030 helps to inform near-term thermal retention decisions.
- New resource build in 2030 under the 30 MMT core policy case is similar to that of the High Electrification scenario in 2030.
- Thermal retention in 2030 under the 46 MMT core policy case is more in line with the High Electrification scenario in 2030.
- All three 2045 Framing scenarios rely heavily on solar and batteries to meet load and GHG goals.
- Availability of out-of-state or offshore wind displaces in-state solar and batteries and lowers costs. Resource diversity lowers the cost of meeting long-run GHG goals.
- PATHWAYS electricity GHG targets assume maximum level of achievement in other sectors but it is not certain to what extent other sectors will achieve those expected reductions.



## **APPENDIX B: IDER ANALYSIS**

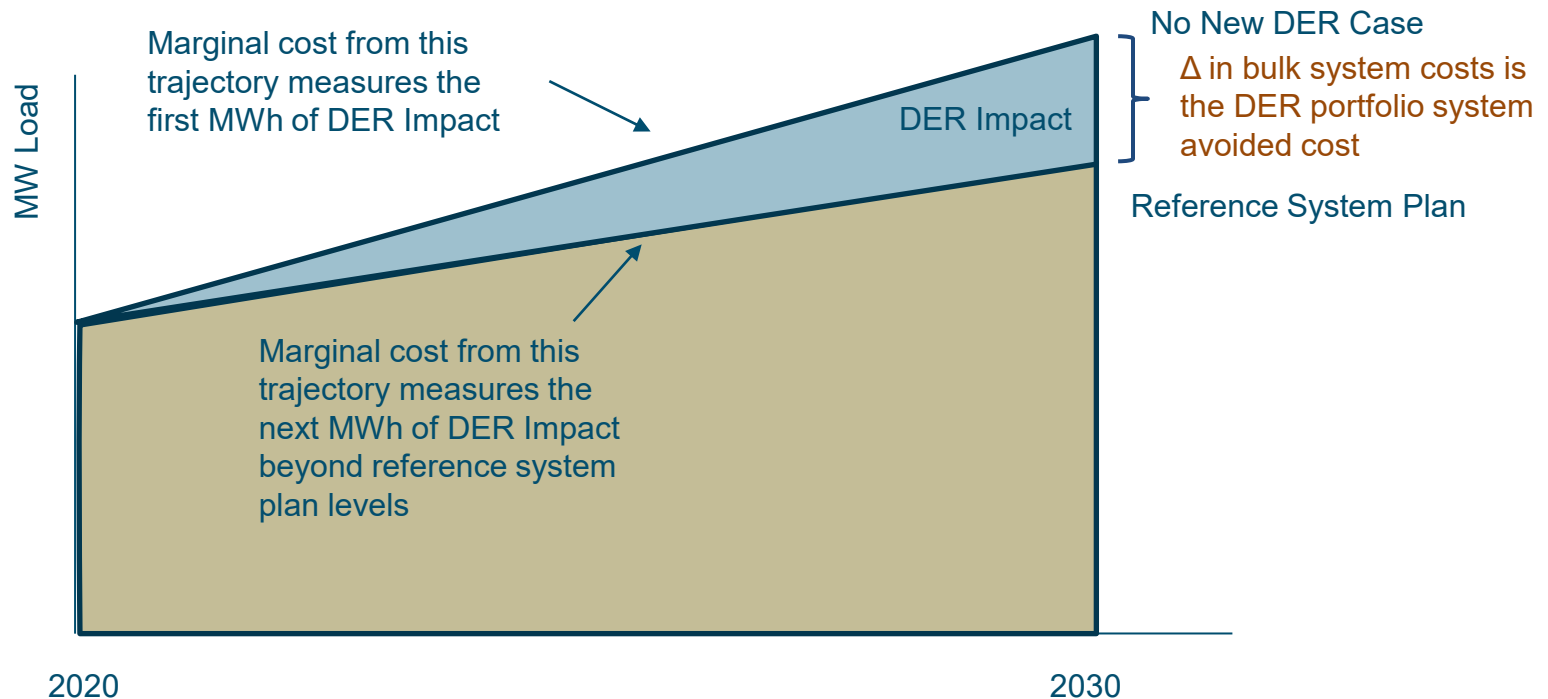
# Using IRP Reference System Portfolio for DER Avoided Costs

- 2020 IDER Avoided Cost Calculator (ACC) update proposes to use the IRP Reference System Portfolio as basis for calculating DER avoided costs.
- GHG value and system capacity (RA) avoided cost values would be based on RESOLVE shadow prices.
- Reference System Portfolio will be used in production simulation to develop hourly energy and ancillary service values for DERs.
- Objective is to align values used in supply and demand side planning for meeting SB100 zero carbon energy goals.
- Proposed 2020 ACC update seeks greater alignment and consistency between CPUC, CEC and CARB proceedings.
- DER costs will be evaluated in IDER cost-effectiveness: RESOLVE TRC results will not be used.



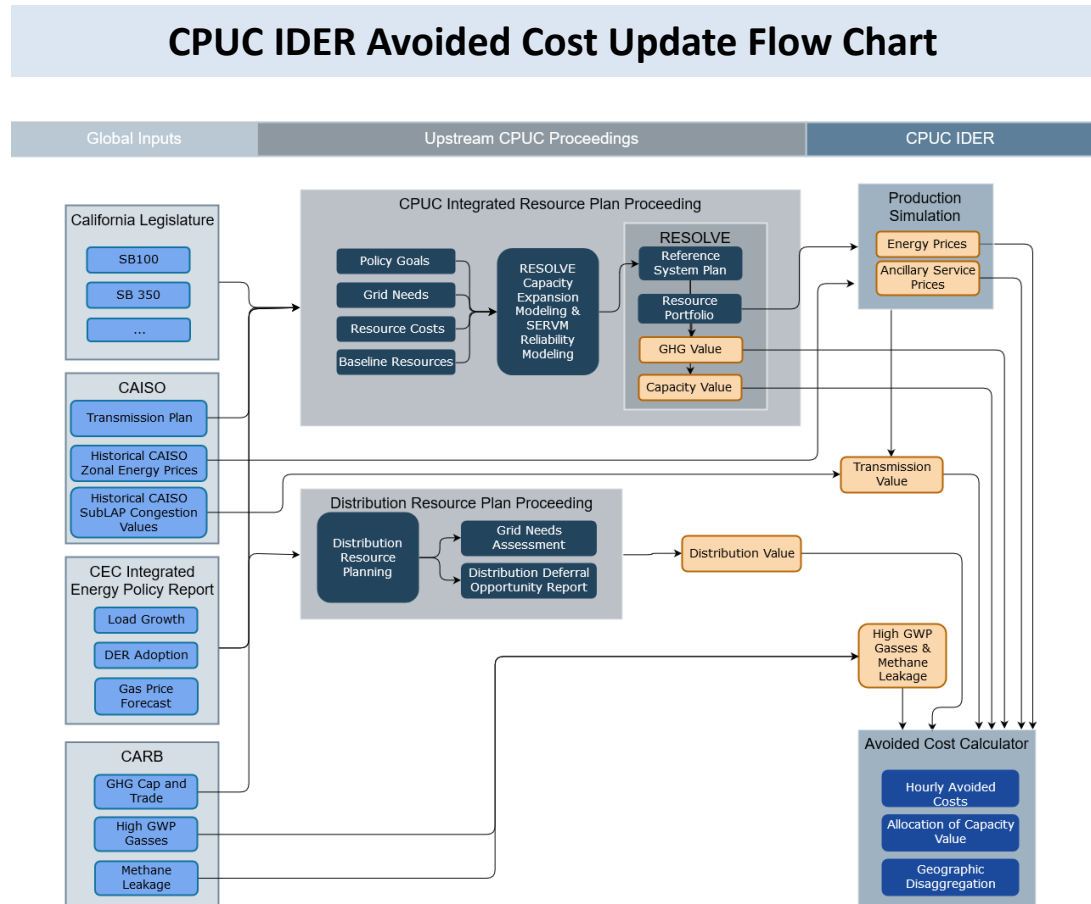
# Objective for "No New DER Case"

- Proposed Reference System Plan includes significant growth in DER in baseline forecast.
- Stakeholders in IDER will want a measure of the value of the DER that is included in the RSP.
- Removing DER from portfolio (in the No New DER case) in the provides a basis for quantifying its value.
- Change in shadow price of GHG and capacity may also be useful inputs for ACC.



# RSP Inputs for ACC

- Direct Inputs
  - GHG Value
  - Capacity value
- Resource Portfolio
  - Used in production simulation to generate energy and ancillary service values.
- Proposed RSP will be base case.
- Results from No New DER Case may be used directly or as a sensitivity case for ACC.
- $\Delta$  in bulk system costs will provide useful information, but not currently proposed as an input for the ACC.



# No New DER Resources Removed Assumptions

## Legend

CEC IEPR DER  
Adoption in RSP

Existing DER  
included in No  
New DER Case

No New DER  
Energy Resources  
Removed

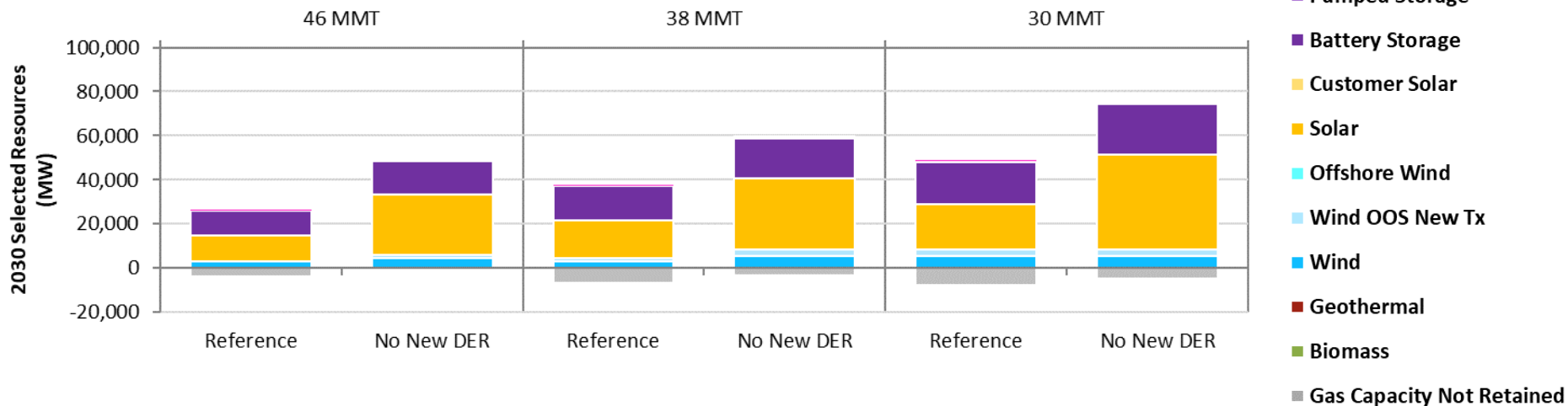
No New DER  
Capacity Resources  
Removed

CAISO Sales Forecast Buildup	2018	2020	2025	2030
<b>Energy Efficiency (GWh)</b>				
CEC 2018 IEPR - Mid Mid AAEE	1,906	5,930	17,322	27,940
No New DER Case	1,906	1,906	1,906	1,906
<b>Committed BTM PV</b>				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	12,439	16,797	25,446	32,466
No New DER Case	12,439	12,439	12,439	12,439
<b>Additional Achievable BTM PV</b>				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	-	134	1,441	2,657
No New DER Case	-	-	-	-
<b>Behind-the-Meter CHP (GWh)</b>				
CEC 2018 IEPR - Mid Demand	13,594	13,637	13,648	13,595
No New DER Case	13,594	13,594	13,594	13,594
<b>Non-PV Non-CHP Self Generation (includes storage losses) (GWh)</b>				
CEC 2018 IEPR - Mid Demand	764	751	716	681
No New DER Case	764	751	716	681

BTM PV and BTM Storage Capacity from CEC 2018 IEPR	2018	2020	2025	2030
<b>Committed BTM PV</b>				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	7,269	9,694	14,387	18,555
No New DER Case	7,269	7,269	7,269	7,269
<b>AAPV (Additional Achievable BTM PV)</b>				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	-	134	843	1,511
No New DER Case	-	-	-	-
<b>BTM Storage (MW)</b>				
CEC 2018 IEPR - BTM Storage installed capacity	92	722	1,239	1,647
CEC 2018 IEPR - BTM Storage peak impact	(81)	(641)	(1,072)	(1,390)
No New DER Case	(81)	(81)	(81)	(81)
<b>Load Modifying Demand Response</b>				
Load-Modifying Demand Response: Mid Mid AAEE	(137)	(162)	(186)	(200)
No New DER Case	-	-	-	-
<b>Capacity Contribution of BTM Resources Modeled as Supply-Side in RESOLVE</b>				
<b>BTM PV (MW peak reduction)</b>				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	3,532	4,408	5,859	5,641
No New DER Case	3,532	3,532	3,532	3,532
<b>Baseline DR 1-in-2 Peak Load Impact (MW)</b>				
<b>DR 1-in-2 Load Impact (MW)</b>				
Mid Case	1,617	1,617	1,617	1,617
No New DER Case	-	-	-	-

# "No New DER" Selected Resources

Without incremental DER resources, the selected capacity of solar, battery, and wind resources is increased substantially (note the y-axis change on the plot), and more gas capacity is retained.



# "No New DER" Total Resource Build

