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Preliminary RESOLVE Modeling Results for Integrated Resource Planning at the CPUC

CPUC Energy Division

July 19, 2017

Contents

NOTE: These results do not reflect changes made in response to party comments submitted on 6/28 and 7/12; staff may further revise the modeling prior to release of the Proposed Reference System Plan.

I. PURPOSE OF THIS PRESENTATION

Purpose of this Presentation

1. To provide parties and the general public with information about modeling the CPUC is conducting for its Integrated Resource Planning (IRP) process
2. To provide decision-makers with analytical groundwork to consider as the CPUC prepares to develop and select a Reference System Plan and an optimal 2030 resource mix

The analytical groundwork includes:

- Comparison of several potential Greenhouse Gas (GHG) Planning Targets for the electric sector
- Initial analysis of how different resource portfolios impact disadvantaged communities
- GHG Planning Prices associated with different GHG Planning Targets to enable consistent resource valuation across CPUC programs
- Sensitivities that explore the value and risk of early investment in certain resources

II. BACKGROUND

Integrated Resource Planning (IRP) in California

- Integrated Resource Planning (IRP) in the past was typically the domain of a single vertically integrated utility
- In California, it is much more complicated
  - Multiple Load Serving Entities (LSEs) including utilities, community choice aggregators (CCAs) and competitive retail service providers
  - Multiple state agencies (CPUC, Energy Commission, Air Resources Board) and California Independent System Operator (CAISO)
  - Partially deregulated market
- The value proposition of <u>integrated</u> resource planning is to reduce the cost of achieving statewide policy goals, particularly with respect to GHG abatement, by looking across individual LSE boundaries and resource types and identifying solutions that might not otherwise be found
- Goal of IRP 2017-18 cycle at CPUC is to ensure that the electric sector is on track to help California reduce economy-wide GHG emissions 40% from 1990 levels by 2030

Statutory Basis of IRP at CPUC

The commission shall…

454.51

Identify a diverse and balanced portfolio of resources…

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…

IRP Goals in 454.52 (a)(1)

The Commission will ensure that load-serving entities do the following:

- Meet GHG emissions reduction targets established by California Air Resources Board (CARB) in coordination with CPUC and CEC that reflect the electricity sector's percentage in achieving the economy-wide GHG emissions reductions of 40 percent from 1990 levels by 2030
- Achieve 50% RPS by 2030
- Enable electric corporations to serve their customers at just and reasonable rates
- Minimize impact on ratepayer bills
- Ensure system and local reliability
- Strengthen the diversity, sustainability, and resilience of bulk transmission system and distribution system, and local communities
- Enhance distribution systems and demand-side energy management
- Minimize localized air pollution and other GHG emissions, with early priority on disadvantaged communities

Overview of IRP Staff Work Products

- Three primary IRP staff work products in 2017:
  - IRP Staff Proposal Circulated for Comment (May 2017)
    - High-level components of the proposed IRP process
    - Specific recommendations for first cycle of IRP (2017-18)
    - Available at: http://www.cpuc.ca.gov/irp_proposal/
  - Release of Preliminary Modeling Results (July 2017)
    - Based on Staff Proposal, which included inputs, assumptions, and scenarios to model
    - Released to public to advance discussion
  - Proposed Reference System Plan (Sept. 2017)
    - Modeling approach revised in response to party comments on Staff Proposal; new modeling results provided
    - **Recommends GHG target, resource portfolio, and action plan to meet SB 350 goals**
    - **Parties will have a formal opportunity to comment on the Proposed Reference System Plan, which will include the full modeling results, as revised by staff in response to previous comments on the record of the proceeding**
- All 3 work products will inform a proposed decision in late 2017 adopting an IRP process and Reference System Plan

Schedule of Activities

Activity	Expected Timing
IRP Staff Proposal issued via Ruling	May 16, 2017
Comments due on Staff Proposal	June 28, 2017
Reply comments due on Staff Proposal	July 12, 2017
Informal release of preliminary RESOLVE results based on scenarios from 5/16/17 Staff Proposal	July 19, 2017
Workshop on preliminary RESOLVE results	July 27, 2017
Ruling issuing Proposed Reference System Plan, along with revised RESOLVE results	September 12, 2017
Two-day workshop to discuss Proposed Reference System Plan	Week of September 25, 2017
Comments on Proposed Reference System Plan	October 26, 2017
All-party meeting with Commissioners	November 2, 2017

Schedule of Activities

Activity	Expected Timing
Reply comments on Proposed Reference System Plan	November 9, 2017
Proposed Decision issued adopting IRP filing guidance and Reference System Plan	End of 2017
IRP filings by individual LSEs	Q2 of 2018
LSE IRPs adopted or modified by Commission	End of 2018
IRP guidance transmitted to CAISO and CEC for TPP and IEPR purposes	Early 2019

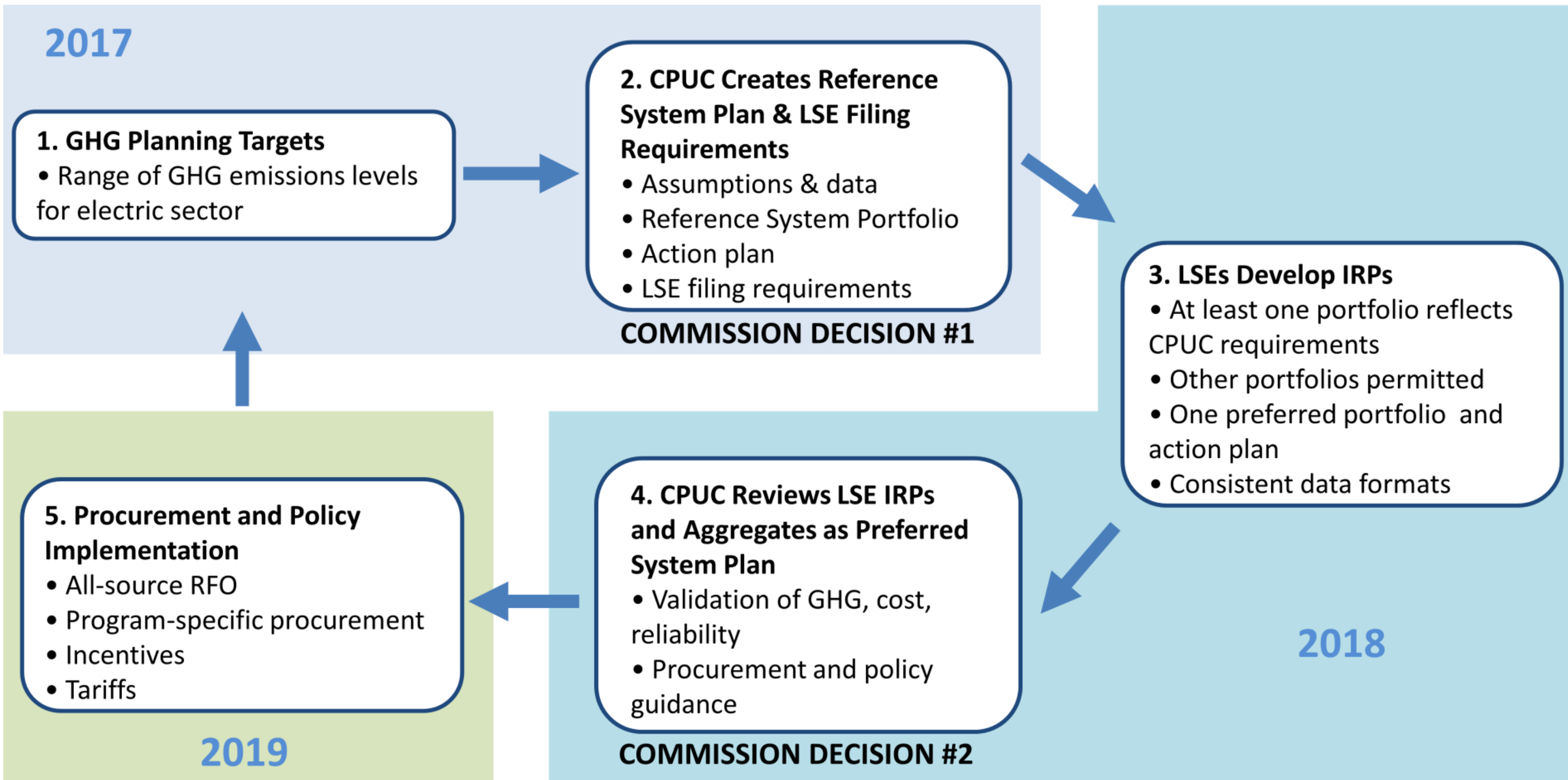
Proposed Two Year IRP Process

- Balances need to identify solutions that benefit the entire system with ability to consider load-serving entity (LSE)-specific constraints and opportunities
- Identify **short-term actions** needed to meet **long-term goals**

Key Steps Include:

- CPUC Develops and Adopts **Reference System Plan** with
  - Optimal portfolio for CAISO area that meets GHG targets and reliability at least cost
  - Action plan: actions required in next 1-3 years
  - Guidance for LSEs
- Based on Reference System Plan, LSEs Develop **LSE Plans**
  - Optimal portfolio for LSE load
  - Action plan: actions proposed for next 1-3 years
  - Procurement authorization requests
- CPUC Reviews and Aggregates LSE Plans and Adopts **Preferred System Plan**
  - Aggregation of LSEs' preferred portfolios to compare with Reference System Plan
  - Action Plan: actions ordered for next 1-3 years
  - Authorizations for procurement, tariff changes, program changes, etc.

Proposed Two Year IRP Process



GHG Target Setting for the IRP Process

- CARB, CPUC, and California Energy Commission (CEC) are coordinating to establish GHG planning targets for the electric sector and individual LSEs and POUs, per SB 350
  - Step 1: Define an electric sector GHG target
  - Step 2: Determine a methodology to divide the target between CPUC's and CEC's IRP processes
  - Step 3: Define a methodology for setting LSE- and POU-specific GHG planning targets
- CARB's proposed 2017 Scoping Plan projects emissions by economic sector to reach 40% GHG reductions from 1990 levels by 2030
  - Projections are based on existing programs and policies

CARB's Sectoral GHG Emissions Estimates

Table II-3. Estimated Change in GHG Emissions by Sector

Estimated GHGs by Sector [$MMTCO_2e$]			
	1990	2030 Proposed Plan Ranges	% change from 1990
Agriculture	26	24–25	-4 to -8
Residential and Commercial	44	38–40	-9 to -14
Electric Power	108	42–62	-43 to -61
High GWP	3	8–11	167 to 267
Industrial	98	77–87	-11 to -21
Recycling and Waste	7	8–9	14 to 29
Transportation (including TCU)	152	103–111	-27 to -32
Net Sink*	-7	TBD	TBD
Sub Total	**431**	**300–345**	**-20 to -30**
Cap-and-Trade Program	n/a	40–85	n/a
Total	**431**	**260**	**-40**

SOURCE: CARB 2017 Proposed Scoping Plan, www.arb.ca.gov/cc/scopingplan/scopingplan.htm

"The sector ranges may change in response to how the sectors respond to the Cap-and-Trade Program" (Proposed Scoping Plan, p. 43)

Staff Proposal for Modeling GHG Targets

- CPUC staff proposed (May 2017) to model three GHG-reduction targets within the Scoping Plan's 42-62 MMT range by 2030, in addition to a 30 MMT target from the "Alternative 1" scenario
  - Modeling 42, 52, and 62 MMT targets will reflect the range of effects of existing policies
  - Modeling an additional 30 MMT target can capture the uncertainty of interactions between sectors, as more cost-effective GHG reductions may be available in the electric sector (CA has not yet conducted a multi-sector optimization to identify the least-cost GHG reduction opportunities)
  - For perspective, electric sector emissions were ~84 MMT in 2015 based on CARB's GHG emissions inventory
- Modeling within a very wide range (30-62 MMT) provides deeper insights into how the optimal portfolio and system costs may change under even more stringent GHG planning targets

Four Core Cases Originally Proposed

- **62 MMT Case (Original Default Case)**
  - High end of CARB Proposed Scoping Plan estimate for electric sector
  - Storage mandate: 1,325 MW + additional cost-effective storage
  - Energy efficiency: Mid AAEE + AB802 Efficiency (roughly 1.5x gain in EE by 2030)
- **52 MMT Case**
  - Midpoint of CARB Proposed Scoping Plan estimate for electric sector
  - Includes all constraints and assumptions from Default scenario
  - Imposes a GHG constraint on the portfolio
- **42 MMT Case**
  - Low end of CARB Proposed Scoping Plan estimate for electric sector
  - Includes all constraints and assumptions from Default scenario
  - Imposes a GHG constraint on the portfolio
- **30 MMT Case**
  - CARB Proposed Scoping Plan Alternative 1 scenario (assumes Cap and Trade program is not extended beyond 2020, instead relying on other policy measures to reduce GHG)
  - Includes all constraints and assumptions from Default scenario
  - Imposes a more stringent GHG constraint on portfolio

Adjustments to Proposed Core Cases

- Initial modeling results and follow-up analysis indicated:
  - The 62 MMT Case is roughly consistent with a 33% RPS, implying a failure to achieve current RPS policy
  - A 50% RPS by 2030 achieves an emissions level consistent with a statewide target of ~51 MMT (even after accounting for RECs banked by IOUs), which is similar to the 52 MMT case originally proposed
- To better highlight what incremental investment might be needed for IRP, staff has redefined the Default Case to reflect a 50% RPS by 2030 policy rather than a statewide GHG target of 62 MMT
- Staff has removed 62 MMT from the list of core cases

Relationship Between Proposed Scoping Plan and IRP

- Proposed Scoping Plan analysis takes a higher-level (economy-wide) view than the sector specific analysis
- Proposed Scoping Plan does not reflect optimization across the CA economy; it attempts to model the effects of existing policies and a limited number of proposed policies
- High end of electric sector range (62 MMT) is roughly consistent with a 33% RPS in the Scoping Plan analysis
- 42 to 62 MMT range is from Proposed Scoping Plan, not the Final Scoping Plan, so results could change prior to approval by CARB (expected after Summer 2017)
- IRP results can help inform future Scoping Plan modeling, ensuring that its representation of the electric sector is reflective of the CPUC's optimized long-term planning

Revised Core Cases

- **Default Case (Reflects 50% RPS Compliance)**
  - Achieves approximate midpoint of CARB Scoping Plan range for electric sector (51 MMT), a 39% decrease in electric sector GHG emissions from 2015, and 53% from 1990
  - Storage mandate: 1,325 MW + additional cost-effective storage
  - Energy efficiency: CEC 2016 IEPR Mid AAEE + AB802 Efficiency*
  - Imposes a 50% RPS constraint on the portfolio
- **42 MMT Case**
  - Represents the low end of CARB Proposed Scoping Plan range for electric sector, a 50% decrease in electric sector GHG emissions from 2015 levels, and 61% from 1990 levels
  - Includes all constraints and assumptions from Default Case
  - Imposes a GHG constraint on the portfolio
- **30 MMT Case**
  - Represents CARB Proposed Scoping Plan “Alternative 1” scenario, a 64% decrease in electric sector GHG emissions from 2015 levels, and 72% from 1990 levels
  - Includes all constraints and assumptions from Default Case
  - Imposes a more stringent GHG constraint on portfolio

*AB802 analysis available at www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11189.

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 CO2 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 the split in expected emissions from CAISO-jurisdictional LSEs and non-CAISO-jurisdictional LSEs reflected in CARB's proposed Cap and Trade allowance allocation methodology for 2021-2030
  - Modeling assumes CAISO emissions are ~81% of statewide electric sector total in 2030

2030 Statewide Target	2030 CAISO Target
50% RPS	50% RPS
42.0 MMT	34.0 MMT
30.0 MMT	24.3 MMT

III. MODELING METHODOLOGY & ASSUMPTIONS

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 2017-18:
  - Covers the CAISO balancing area including POU load within the CAISO
  - POU resources outside the CAISO balancing area represented as "fixed" quantities that are not subjected to the optimization exercise
  - Does not optimize demand-side resources
  - Optimizes dispatch but not investment outside of the CAISO
- All the following inputs and assumptions were made public in May 2017; see the revised *RESOLVE Inputs and Assumptions* (July 2017) document for details, available at: www.cpuc.ca.gov/irp/prelimresults2017
  - Revisions to the May 2017 version are provided for consistency in interpreting the results, and for correcting errata. A redline version is available online.
- The complete RESOLVE model is being made public concurrent with the release of these results in July 2017

Relationship to CAISO SB350 Regionalization Study

- The analysis conducted herein builds upon the version of RESOLVE that was developed during CAISO's SB350 study of regionalization
  - Available at: www.caiso.com/Documents/SB350Study_AggregatedReport.pdf
- New functionality and updated data incorporated into RESOLVE to adapt for use in IRP:
  - Portfolio greenhouse gas constraint for CAISO
  - Planning Reserve Margin (PRM) constraint with Effective Load Carrying Capacity logic for renewables
  - Optionality for Full Deliverability or Energy Only transmission status
  - Addition of Advanced Demand Response resources identified by LBNL
  - Updated renewable supply curves based on Black & Veatch analysis

IRP Modeling Examines Some Aspects of Regionalization But Not All

- The two biggest sources of value for California that were identified in CAISO's SB350 regionalization study were
  - Access to high capacity factor out-of-state (OOS) wind
  - Improved efficiency of inter-state energy trading
- IRP modeling **does** include a detailed examination of the value of OOS wind (see Resource Studies section of this slide deck)
- IRP modeling **does not** reflect reduced costs associated with improved inter-state energy trading efficiencies that could result from regionalization

Defining "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)
  - Future resources that are deemed sufficiently likely to be constructed, usually because of prior CPUC approval
    - e.g. CPUC-approved renewable power purchase agreements, CPUC-approved gas plants
  - Projected achievement of demand-side programs under current policy
    - e.g. forecast of EE achievement, BTM PV adoption under NEM tariff
- In external zones (e.g., LADWP, BANC), where RESOLVE does not optimize the portfolios, the baseline resources also include projections of resources added to meet policy and reliability goals
- RESOLVE optimizes the selection of additional resources needed to meet policy goals, such as RPS, a GHG target, or a planning reserve margin; these resources that are selected by RESOLVE are *not* baseline resources.
- The same quantity of baseline resources are assumed in the Default, 42 MMT, and 30 MMT Core Cases

Baseline Resource Assumptions

Demand-Side

- **EE:** CEC 2016 IEPR Mid AAEE + AB802 Efficiency (roughly 1.5x gain in EE by 2030)
- **BTM PV:** CEC 2016 IEPR Mid (16 GW by 2030)
- **DR:** Existing DR programs remain in place
- **EVs:** CEC 2016 IEPR Mid
- **Building Electrification:** CEC 2016 IEPR Mid

Supply Side

- **Diablo Canyon Power Plant:** retired in 2024/25
- **Once-Through Cooling (OTC) Plants:** retired according to State Water Board schedule
- **Other Thermal Plants:** remain online throughout modeling
- **Existing Hydro & Pumped Storage:** remain online throughout modeling
- **Storage Mandate:** full storage mandate of 1,325 MW achieved
- **RPS Resources:** existing and contracted resources remain online

Existing Demand Response Programs in IRP Modeling

- RESOLVE treats the IOUs' existing demand response programs as Baseline Resources; all contribute to meeting the procurement reserve margin of 115%
- Conventional shed DR resources
  - Economically dispatched DR: bid into CAISO market as an economic product (e.g., Capacity Bidding Program)
  - Reliability dispatched DR: bid into CAISO day-ahead and real-time markets as an emergency product (e.g., Base Interruptible Program)
- Time-Varying Rates
  - Included in IEPR demand forecast as a load modifier (e.g., Critical Peak Pricing); peak impact based on 2016 Load Impact Reports*
  - Time-of-Use Rates: default peak impact based on MRW Scenario 4 X 1.5*

*See *RESOLVE Inputs and Assumptions* document for details, available at: http://www.cpuc.ca.gov/irp/prelimresults2017

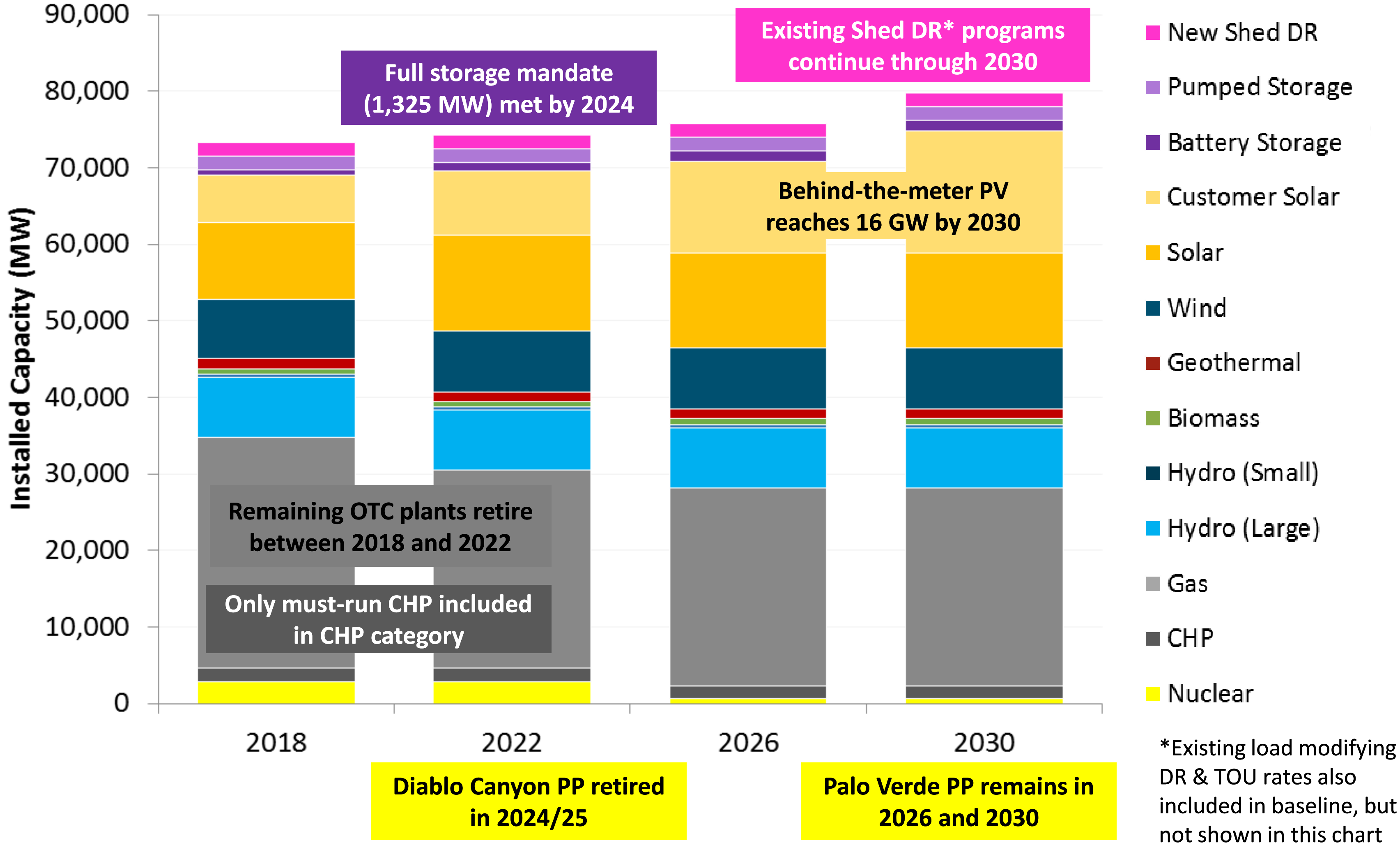
Demand Response Programs as Described in DR Potential Study

DR resources identified in LBNL's final report on the 2025 California DR Potential Study are included in some analyses, with cost, performance, and potential data based on the findings in that report.*

- New "Shed" DR:
  - DR loads that can occasionally be curtailed to provide peak capacity and support the system in emergency or contingency events
  - Treated as a candidate resource by RESOLVE in all cases; when selected by the model, the impact of the new shed is incremental to the baseline shed DR from existing programs
- "Shift" DR:
  - DR that encourages the diurnal movement of energy consumption from hours of high demand to hours with surplus renewable generation
  - Not included in RESOLVE core cases due to lack of certainty on viability of resource, but is made available as a candidate resource in the "Shift DR" sensitivity
- "Shimmy" DR
  - DR that provides load-following and regulation type of ancillary services
  - Not included in RESOLVE modeling, but recognized as possible substitute for short-duration storage resources
- "Shape" DR
  - DR that reflects "load-modifying" resources like time-of-use (TOU) and critical peak pricing (CPP) rates, and behavioral DR programs that do not have direct automation tie-ins to load control equipment
  - TOU and existing load-modifying DR (e.g., CPP) included as part of baseline assumptions in RESOLVE modeling, including sensitivities; no addition shape DR was included

*See *RESOLVE Inputs and Assumptions* document for details, available at: http://www.cpuc.ca.gov/irp/prelimresults2017

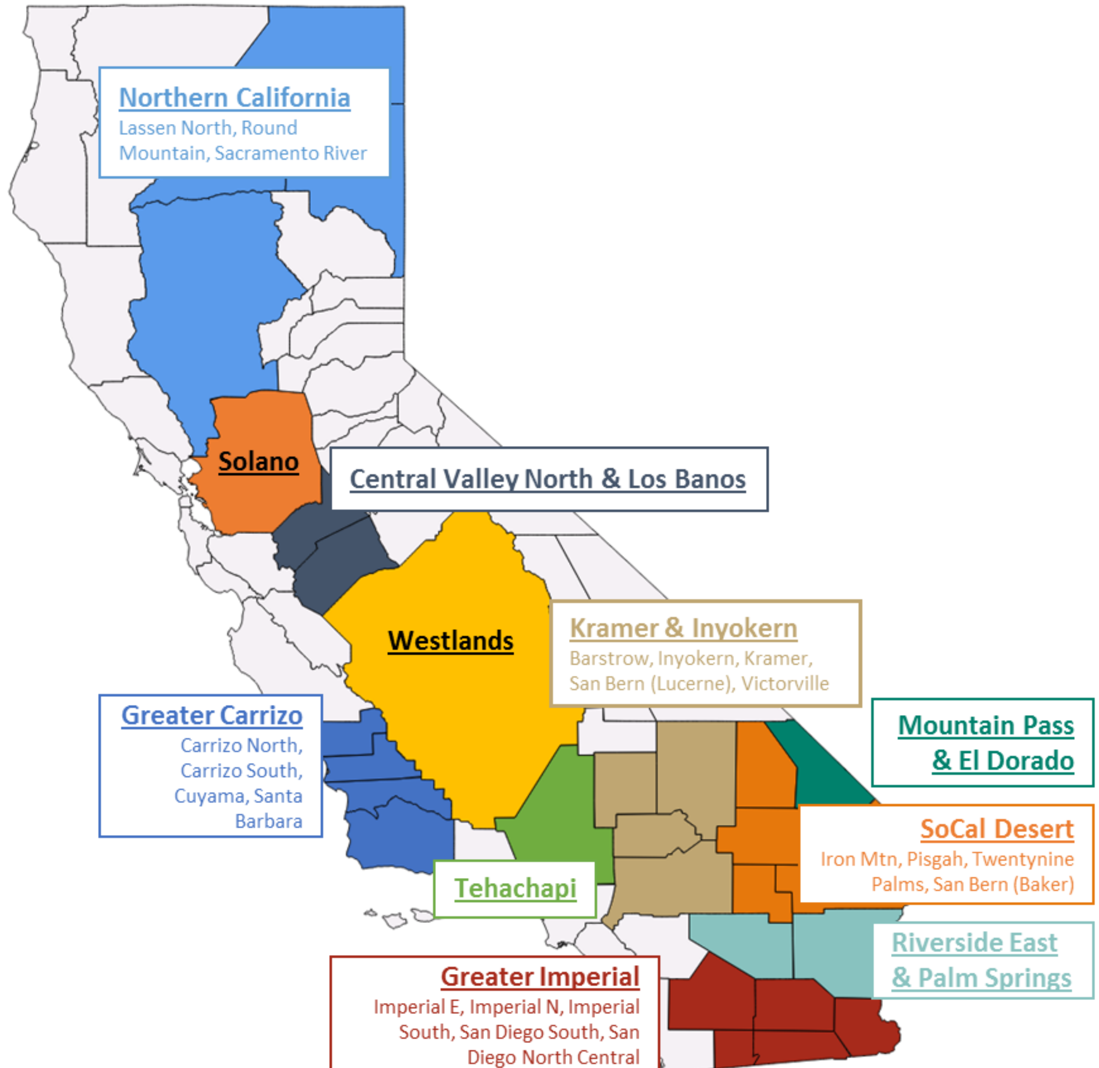
Baseline Resources Included in All Cases



*Existing load modifying DR & TOU rates also included in baseline, but not shown in this chart

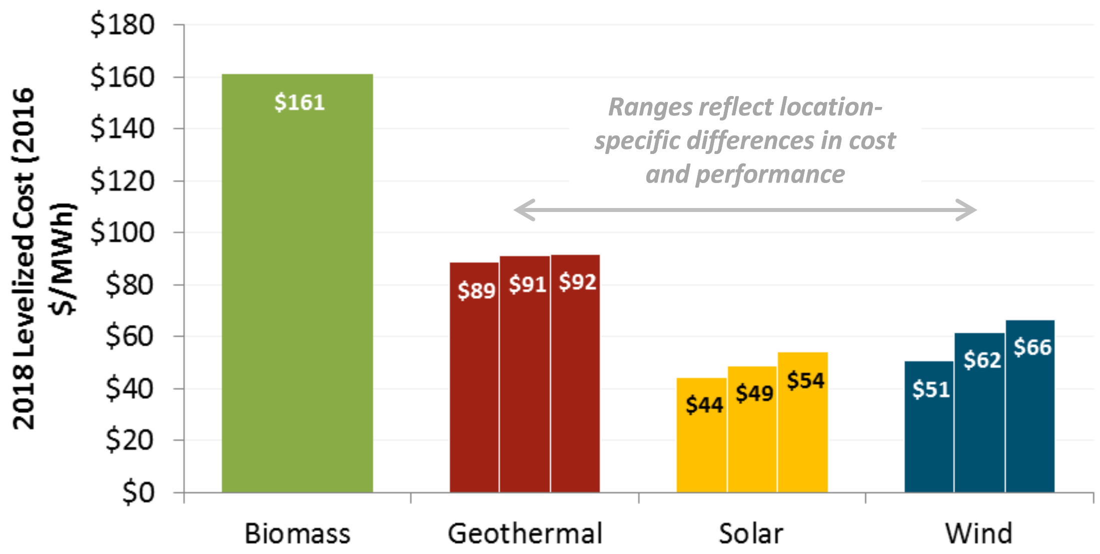
Overview of Renewable Resource Potential

- In-state resource supply curves developed by Black & Veatch for RPS Calculator v.6.3:
  - Biomass: 1,106 MW
  - Geothermal: 1,700 MW
  - Solar PV: 74,145 MW
  - Wind: 2,001 MW
- Out-of-state resources are constrained in portfolios:
  - 2,000 MW of wind on existing transmission
  - No new transmission built to accommodate new wind



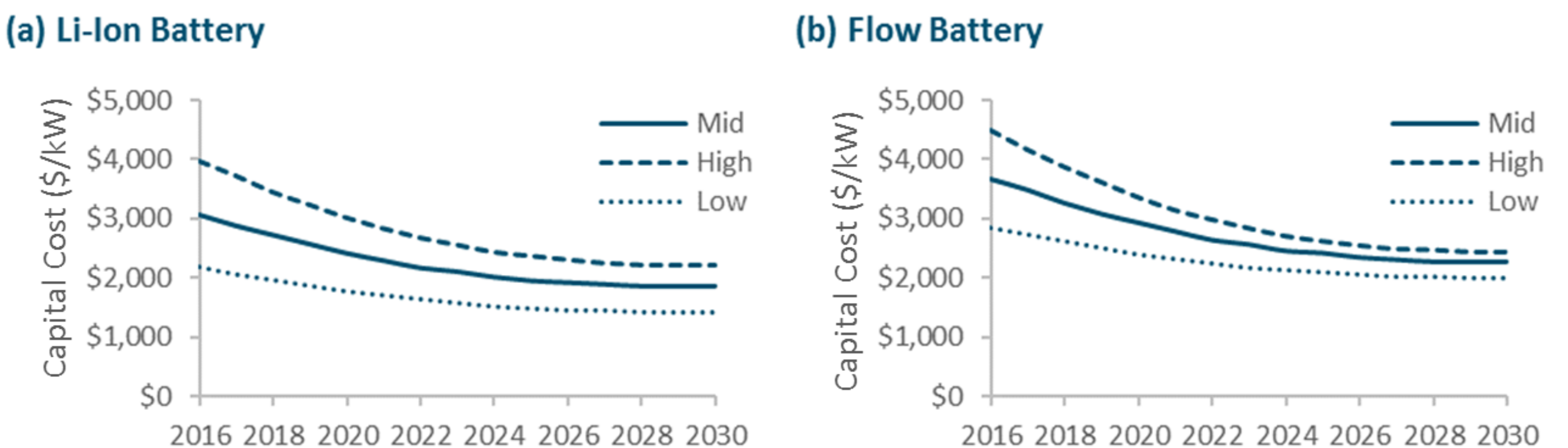
Cost Assumptions: Renewable Resource

- Renewable resource cost & performance assumptions developed by Black & Veatch in early 2016
  - Solar PV costs updated to reflect latest observed cost declines, based on E3's WECC Cost & Performance study



Cost Assumptions: Battery Storage

- Battery storage cost assumptions developed based on Lazard's *Levelized Cost of Energy Storage 2.0*, available at: www.lazard.com/perspective/levelized-cost-of-storage-analysis-20/
- Capital cost assumptions for 4-hr duration batteries shown below



Cost Assumptions: Distributed Energy Resources (DERs)

- While RESOLVE does not optimize all DERs in its portfolio development, estimated costs for assumed DER deployment are included in model results
- Estimated costs for DERs include customer costs, consistent with the Total Resource Cost (TRC) perspective usually considered to be the primary test of cost-effectiveness for DERs
- These cost estimates come from a variety of sources:
  - **EE:** costs based on 2015 compliance filing data from IOUs
  - **DR:** based on utility-proposed DR programs for 2018-2022 program cycle
  - **BTM PV:** customer costs based on projected residential and commercial rooftop PV costs developed by E3

Other Assumptions

- Cogeneration: 1,600 MW of existing CHP modeled as inflexible and must run
- Exports: CAISO net export limit of 5,000 MW in 2030 imposed
- Renewables & reserves: renewables can provide entire downward load-following requirement
- Limited OOS wind availability
  - Assumed 2,000 MW on existing transmission
  - Assumed no new transmission built to accommodate new wind (to be addressed through direct study)
- See the revised *RESOLVE Inputs and Assumptions* document for details, available at: www.cpuc.ca.gov/irp/prelimresults2017

Summary of Outputs

- RESOLVE was used to produce a number of outputs that will inform the development of the Reference System Plan:
  - Composition of optimal portfolios (MW)
  - CAISO RPS (%) and greenhouse gas emissions (MMTCO2)
  - GHG constraint shadow price (used to develop GHG Planning Price)
  - Incremental total resource cost ($, see next slide for description)

Incremental Total Resource Cost Metric

- The **"incremental total resource cost"** (or incremental TRC) for each scenario is calculated relative to the Default Case
  - Represents an **annualized incremental cost ($MM/yr)** over the course of the analysis (2018-2030)
- "Incremental TRC" metric captures the sum of costs directly considered in development of Reference System Plan:
  - 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
  - These costs also affect rates

IV. PRELIMINARY RESULTS

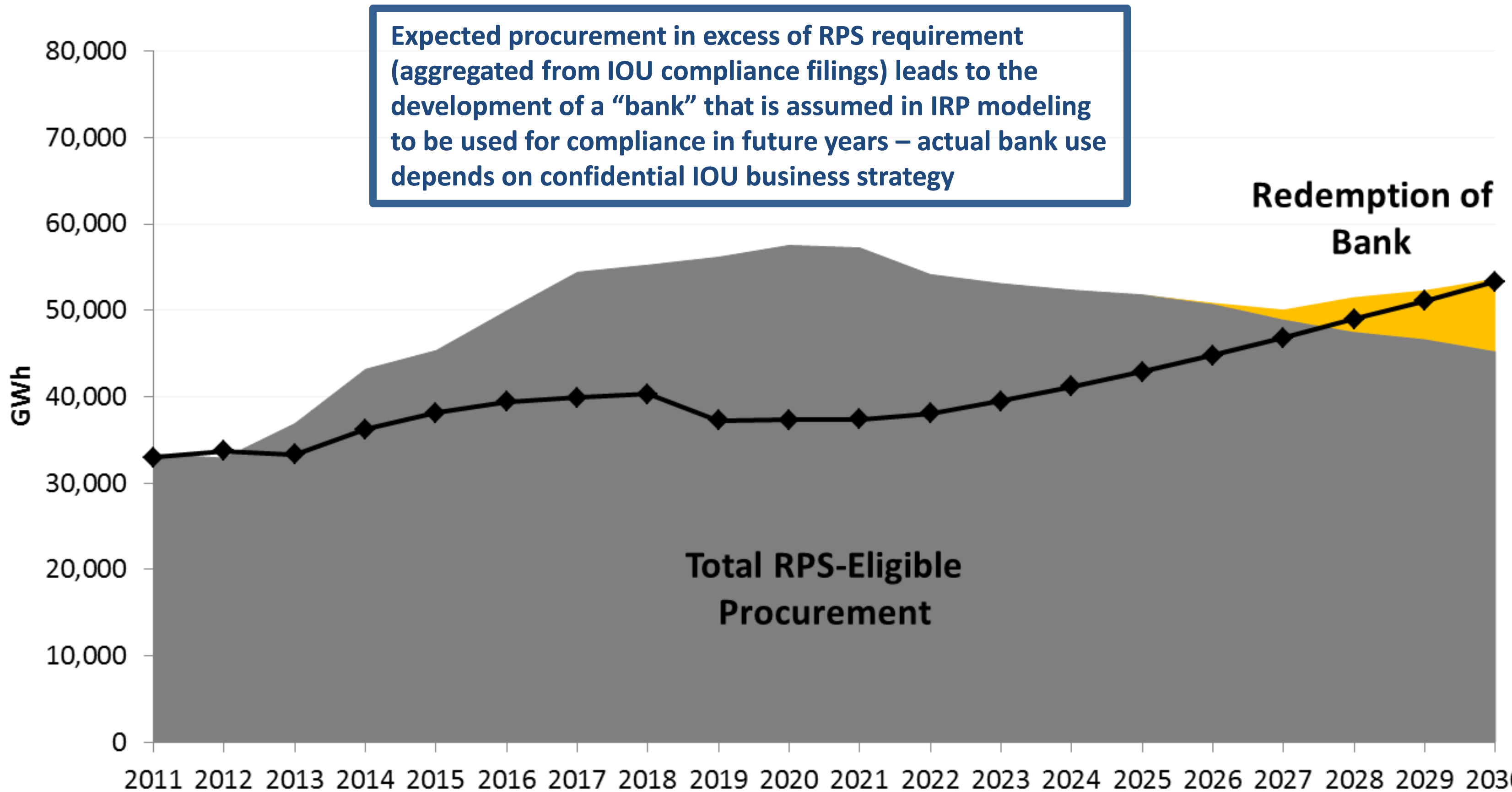
Selected Resources

- "Selected resources" are marginal resources added to system during a modeling run (i.e., incremental to the "baseline resources")
- The next series of slides presents the resources selected by RESOLVE to achieve the various policy goals and constraints defined for each model run for three primary cases:
  - Default Case: (50% RPS by 2030, resulting in 51 MMT statewide electric sector GHG emissions)
  - 42 MMT Case: a 42 MMT Statewide Electric Sector GHG Target
  - 30 MMT Case: a 30 MMT Statewide Electric Sector GHG Target

How Excess Procurement Banking Is Counted

- RESOLVE accounts for Renewable Energy Credits (RECs) banked by IOUs that may be available for use in complying with the RPS program
- In confidential compliance filings, IOUs document how much RPS-eligible energy they expect to generate in excess of their compliance obligations in each year through 2030 based on assumptions about future load and procurement
- These values are aggregated across IOUs and used as an input in RESOLVE to reduce the renewable net short that must be met by the model

Use of Excess RPS Procurement Under 50% RPS



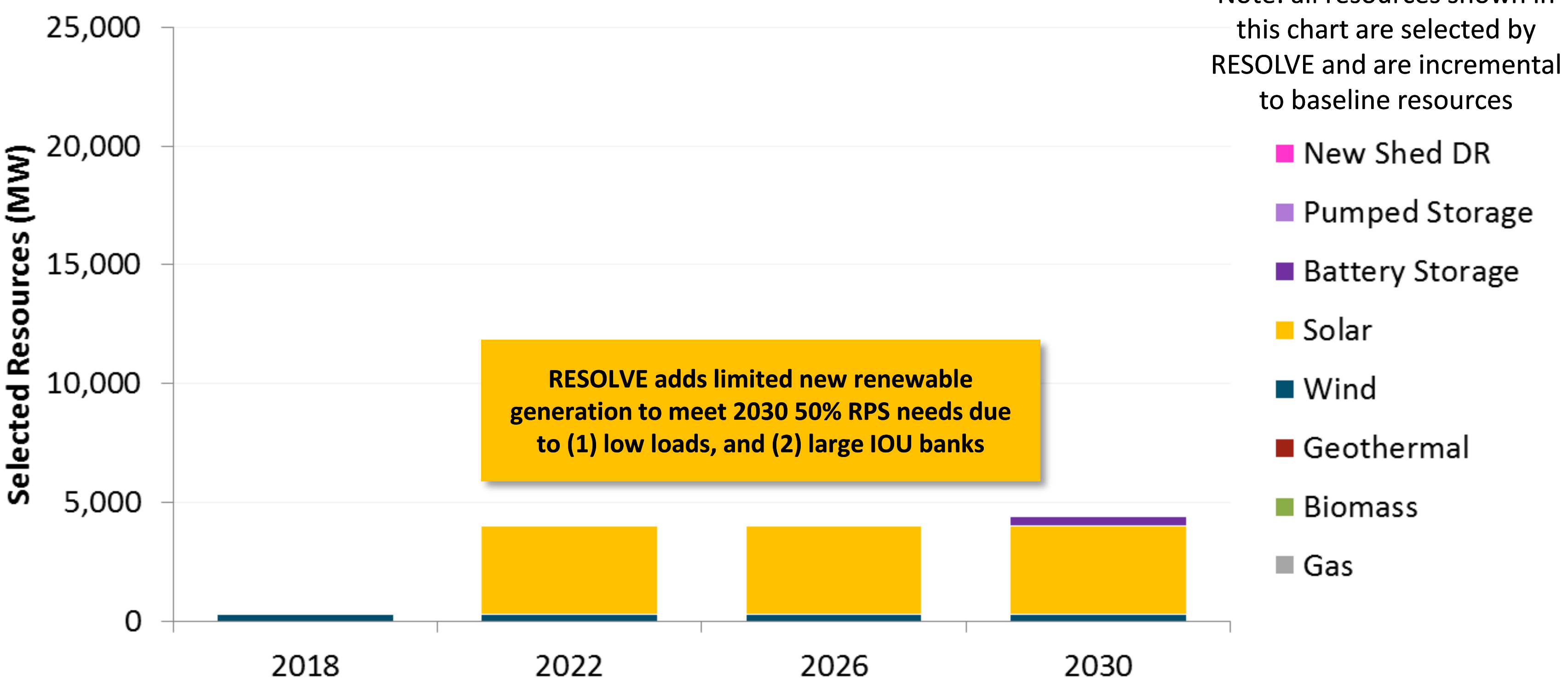
Effects of RPS Procurement Bank Are Uncertain

- Factors that would lead to **more** RPS-related procurement by 2030 than modeled in IRP:
  - IOUs do not deploy banks to defer investment as far into the future as possible
  - Short RPS positions held by a subset of IOUs are masked by the long position held by the aggregated IOUs
  - LSEs voluntarily procure new RPS-eligible resources in excess of the RPS requirement
- Factors that would lead to **less** RPS-driven procurement by 2030 than modeled in IRP:
  - Load departure does not occur at pace estimated by IOUs
  - IOUs sell excess future energy and RECs to LSEs in short positions
  - IOUs meet RPS compliance obligations with maximum allowed quantities of Portfolio Content Category (PCC) 2 or PCC 3 RECs

Resources Selected by RESOLVE: Default Case (50% RPS by 2030)

- By 2030, portfolio reaches an RPS of **50%**
  - Physical RPS in 2030 accounts for **46%** of RPS requirement
  - Banked RECs applied in 2030 account for **4%** of RPS requirement

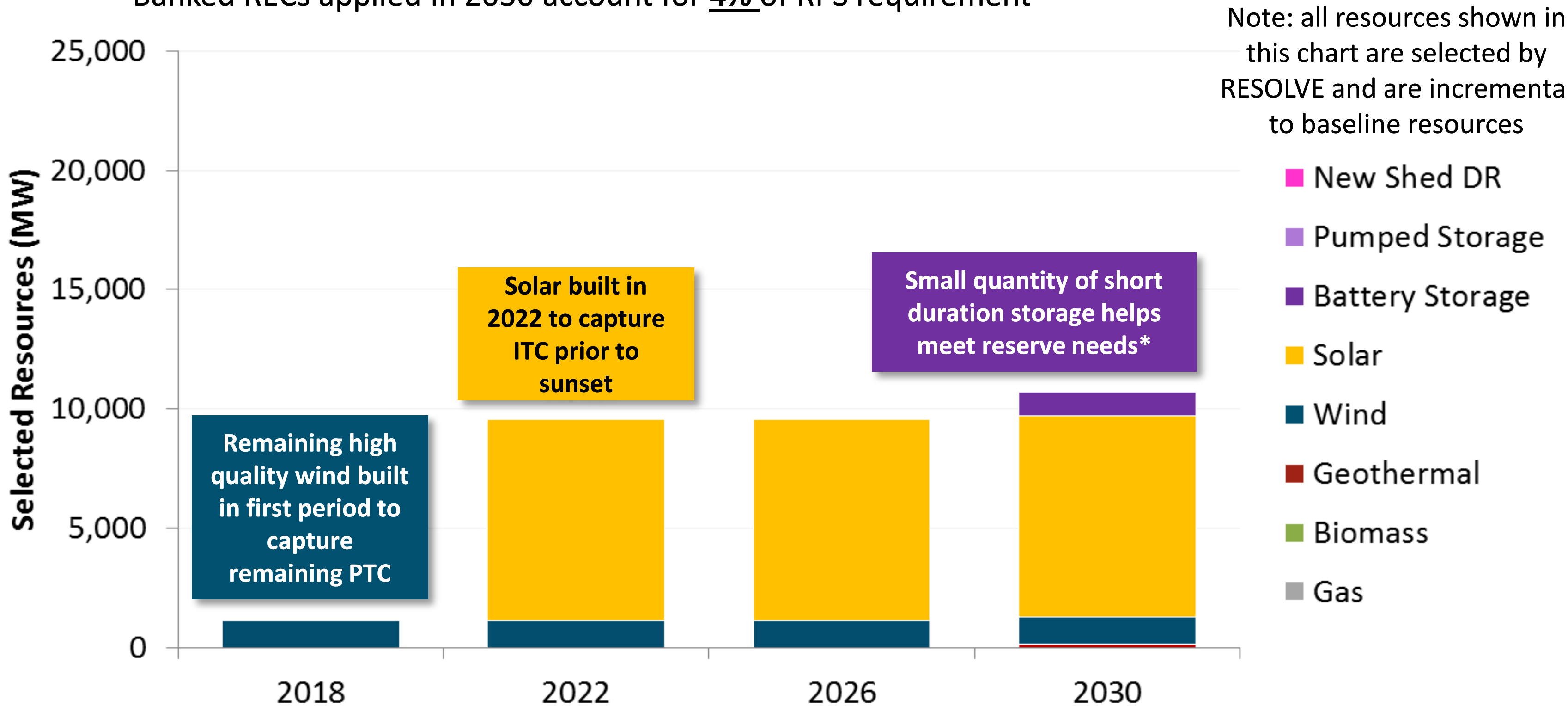
Note: all resources shown in this chart are selected by RESOLVE and are incremental to baseline resources



Each bar represents the cumulative capacity selected by the model as of the year shown, not the additional capacity added in that year.

Resources Selected by RESOLVE: 42 MMT Statewide Target

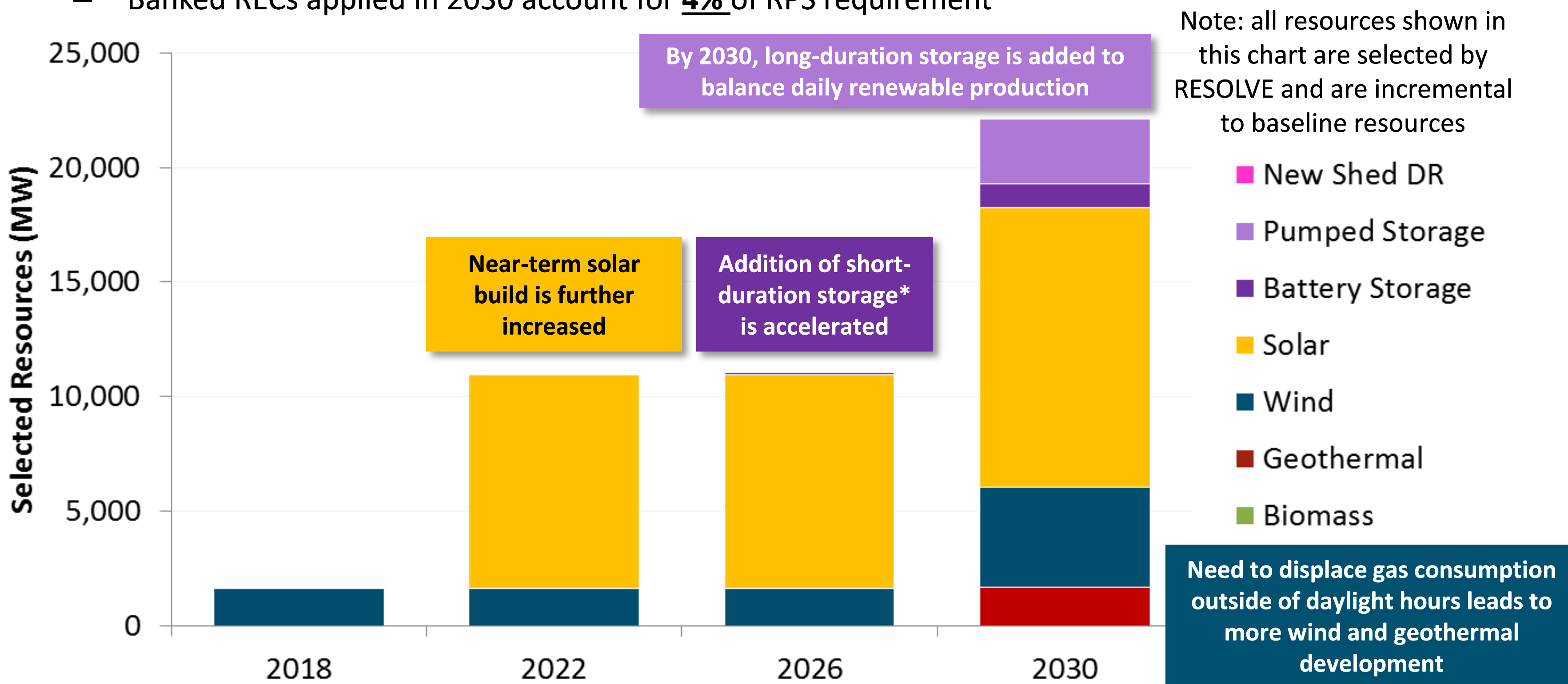
- By 2030, portfolio reaches an RPS of **57%**
  - Physical RPS in 2030 accounts for **53%** of RPS requirement
  - Banked RECs applied in 2030 account for **4%** of RPS requirement



* A portion of this need for short-duration services could be met by "Shimmy DR" resources, which were not modeled explicitly here but may have resource potential up to 300 MW. The timing of the need for short duration services is based on a calculation of load-following reserve requirements outside of RESOLVE. There may be cost benefits to earlier procurement than shown here.

Resources Selected by RESOLVE: 30 MMT Statewide Target

- By 2030, portfolio reaches an RPS of **72%**
  - Physical RPS in 2030 accounts for **67%** of RPS requirement
  - Banked RECs applied in 2030 account for **4%** of RPS requirement



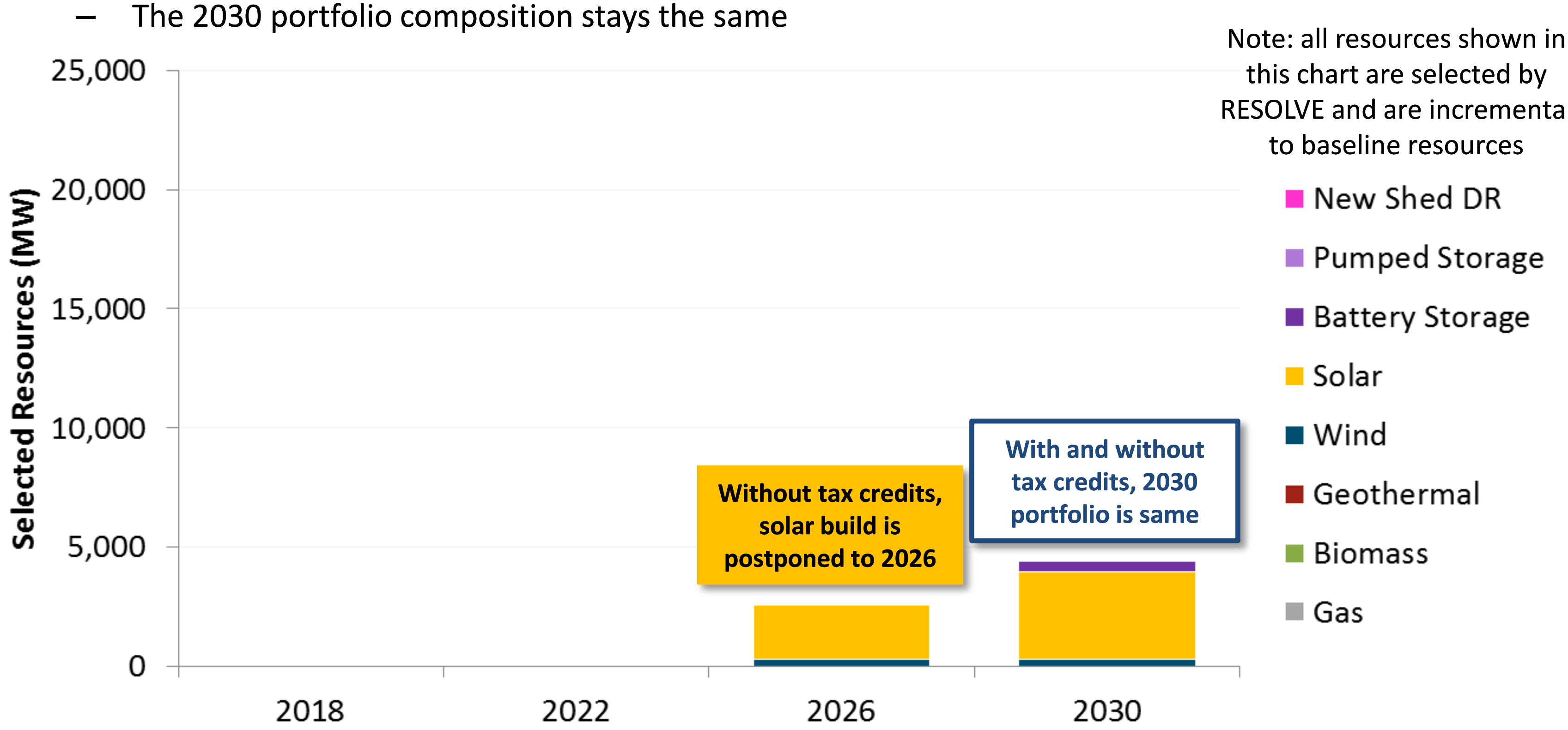
* A portion of this need for short-duration services could be met by "Shimmy DR" resources, which were not modeled explicitly here but may have resource potential up to 300 MW. The timing of the need for short duration services is based on a calculation of load-following reserve requirements outside of RESOLVE. There may be cost benefits to earlier procurement than shown here.

Federal Tax Credits Drive Early Procurement of Renewables

- Per current law, federal tax credits for utility-scale renewable energy projects decline sharply or are eliminated by 2030
  - Investment Tax Credit (ITC) for solar: 30% through 2019 stepping down to 10% in 2021 and thereafter
  - Production Tax Credit (PTC) for wind: 2.3¢/kWh through 2016 stepping down to 0 in 2020 and thereafter
- This decline leads RESOLVE to select resources relatively early in the study period, but does not change the types of resources that are selected
- The following slides show how the timing of resource selection would change if
  - federal tax credits were not available at all (hypothetical example)
  - renewable projects are were not approved and developed in time due to practical challenges

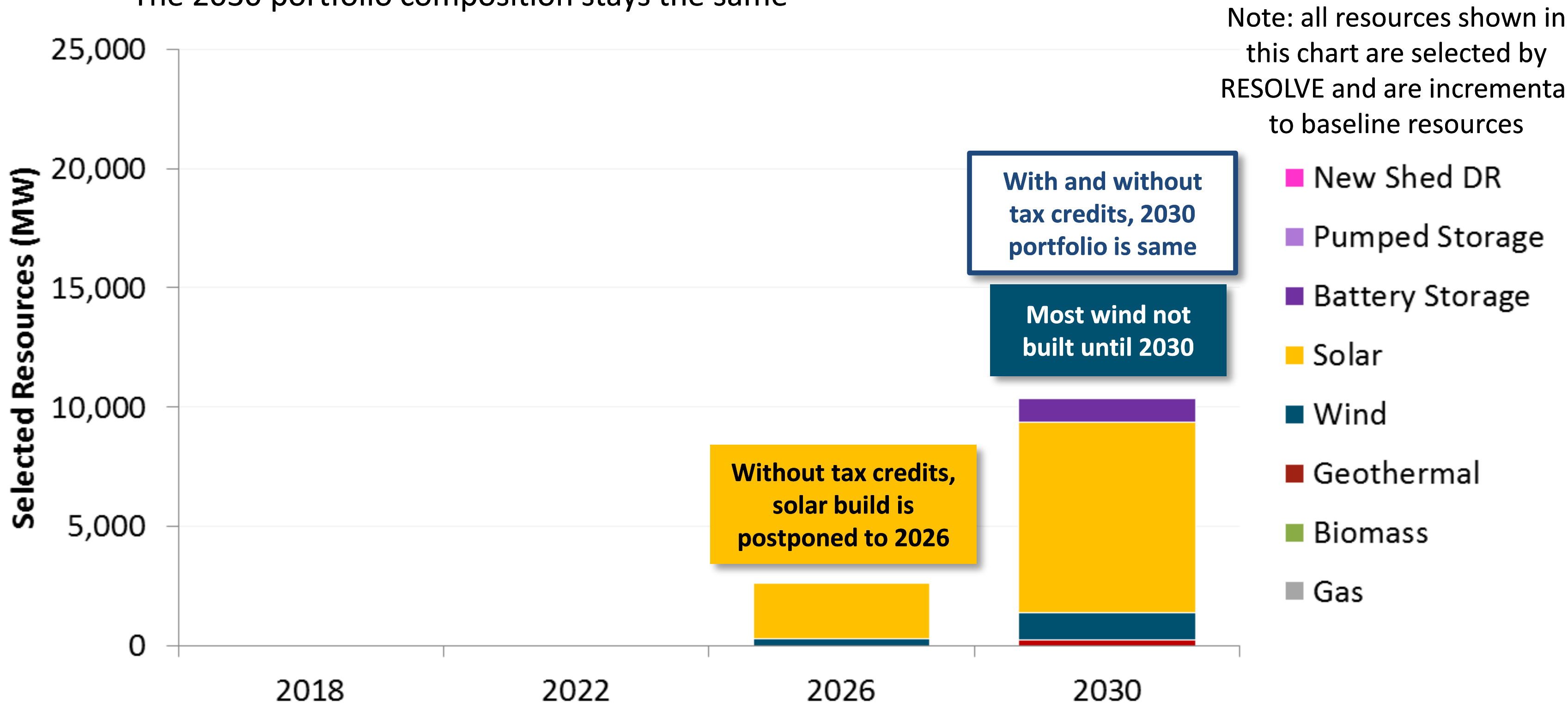
Resources Selected by RESOLVE: Default Case (50% RPS by 2030), No Fed Tax Credits

- If no federal tax credits are available:
  - Start of renewable build is postponed from 2018 to 2026
  - The 2030 portfolio composition stays the same



Resources Selected by RESOLVE: 42 MMT Statewide Target, No Fed Tax Credits

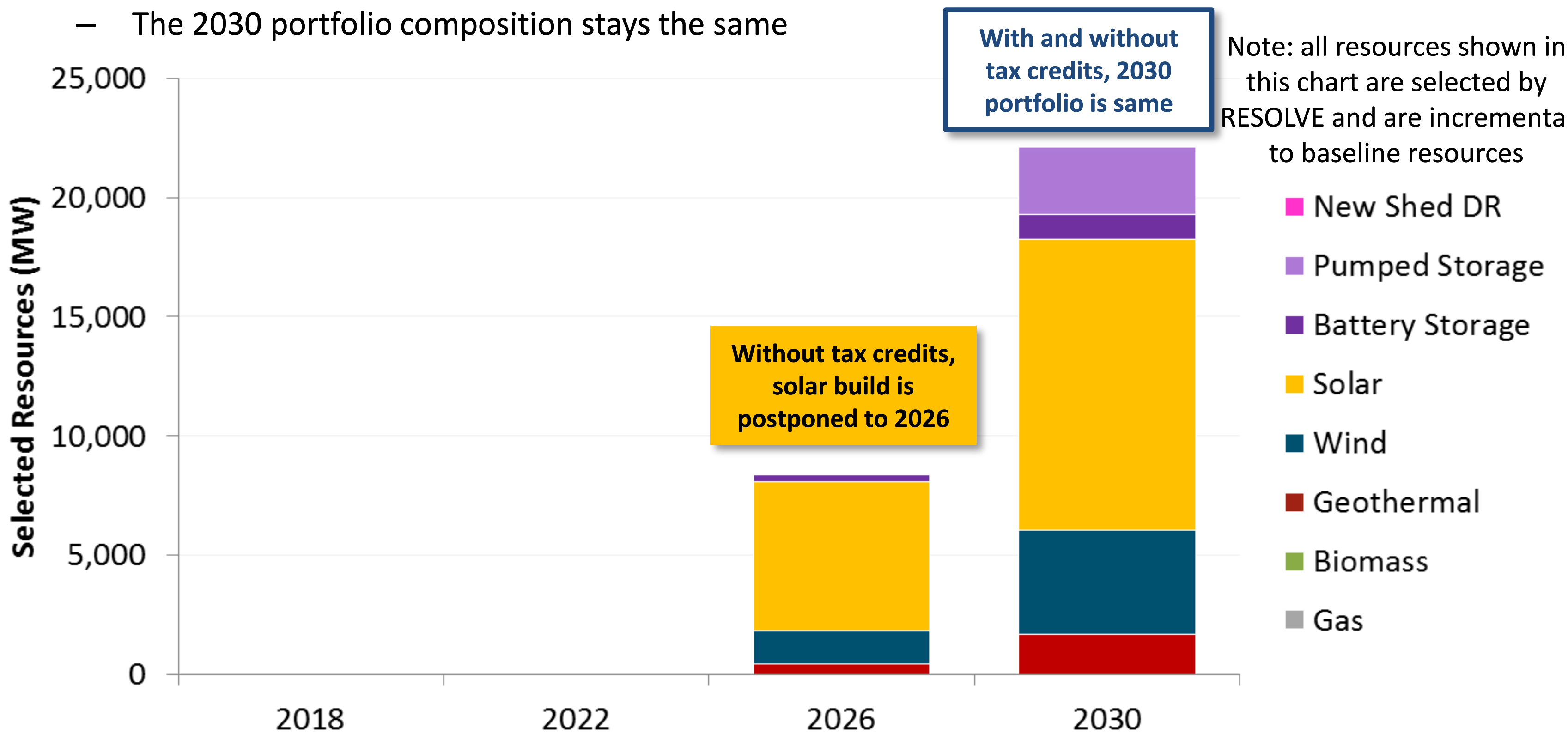
- If no federal tax credits are available:
  - Start of renewable build is postponed from 2018 to 2026
  - The 2030 portfolio composition stays the same



* A portion of this need for short-duration services could be met by “Shimmy DR” resources, which were not modeled explicitly here but may have resource potential up to 300 MW

Resources Selected by RESOLVE: 30 MMT Statewide Target, No Fed Tax Credits

- If no federal tax credits are available:
  - Start of renewable build is postponed from 2018 to 2026
  - The 2030 portfolio composition stays the same



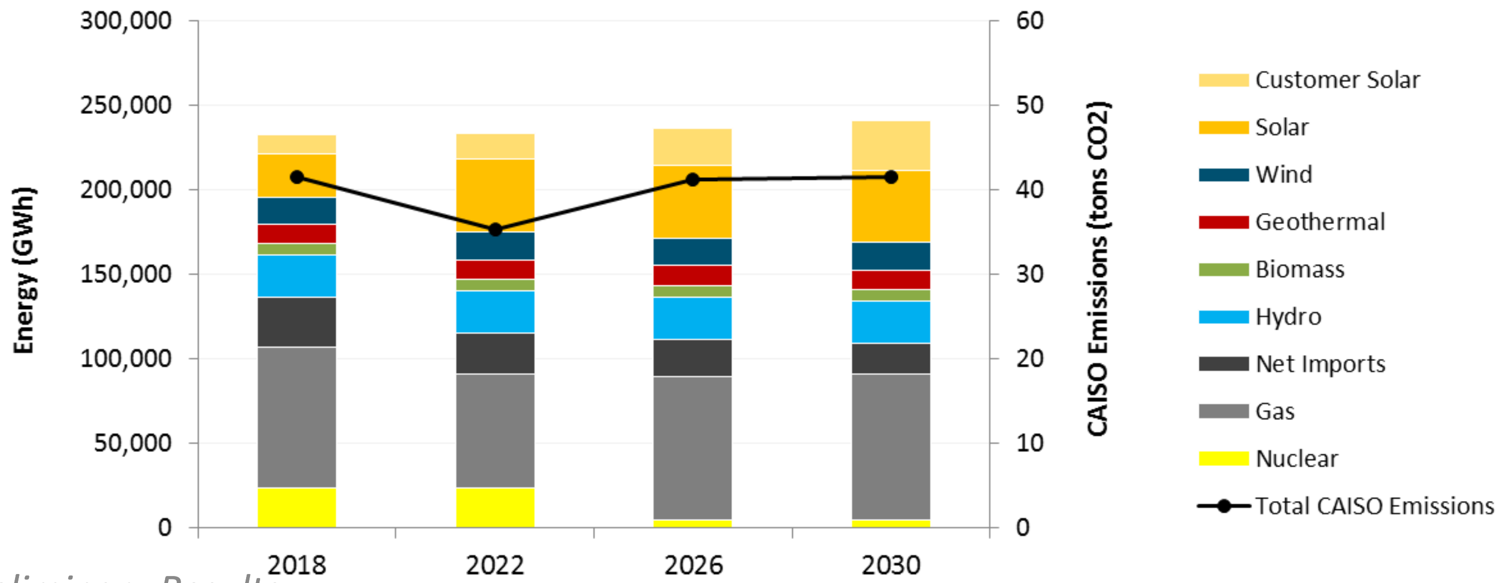
* A portion of this need for short-duration services could be met by "Shimmy DR" resources, which were not modeled explicitly here but may have resource potential up to 300 MW

Effect of New Resources on Energy Balance

- The previous slides showed the resources selected by the RESOLVE model to achieve the least cost portfolio that satisfies the specified policy, reliability, and other constraints.
- The following slides show how the electrical energy generated from different resources in CAISO changes in response to the new resources added to the system

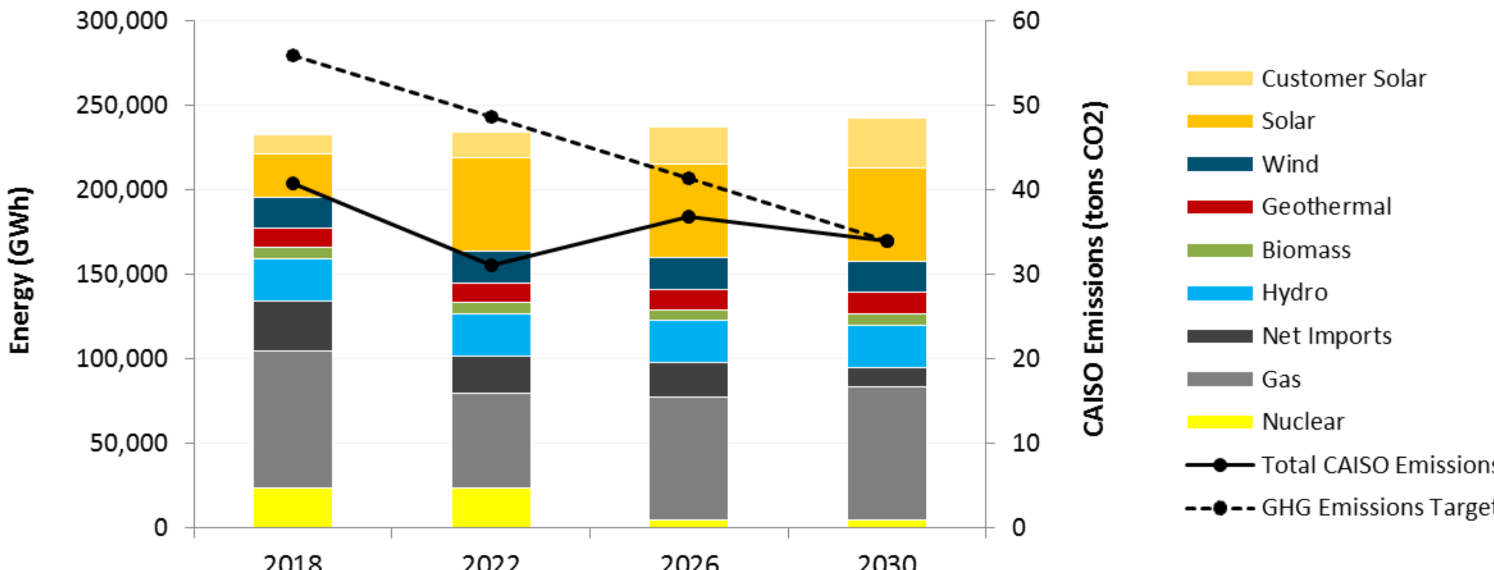
CAISO Energy Balance
Default Case (50% RPS by 2030; 51 MMT)

- Near term solar PV build displaces energy from gas 2018-2022
- Energy from gas rebounds 2026-2030 as Diablo Canyon closes
- Total CAISO emissions are 42 MMT CO2 in 2030 (equivalent to 51 MMT statewide)



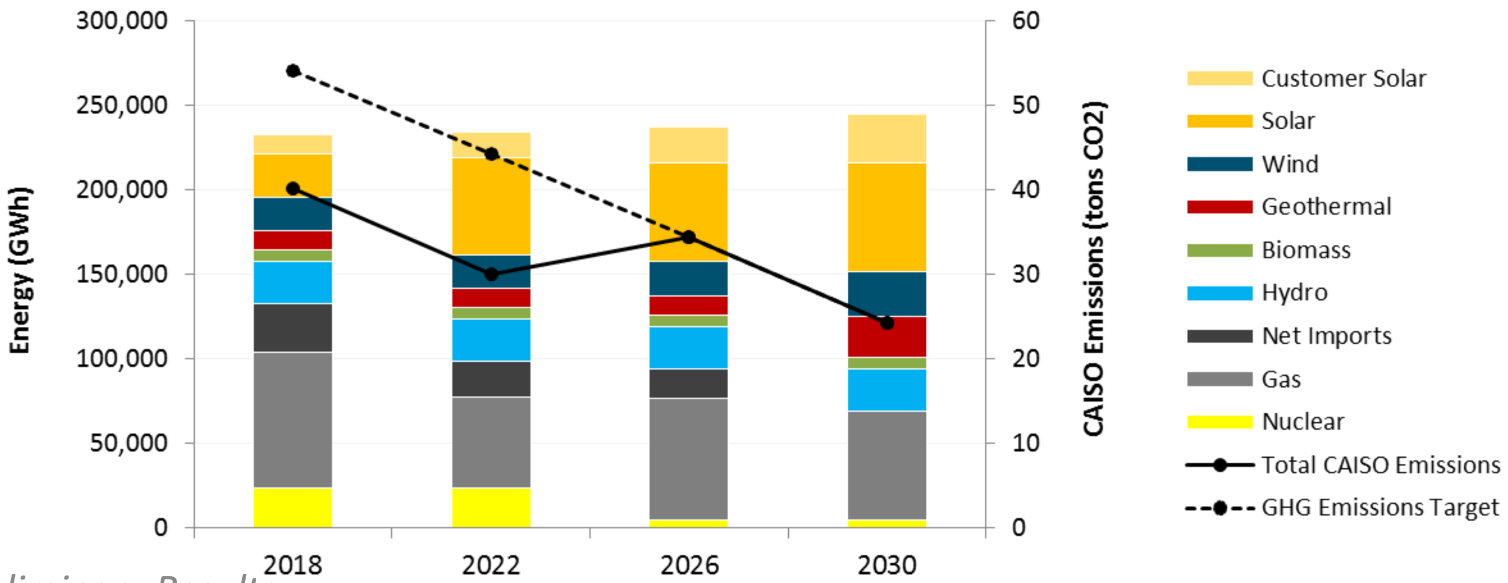
CAISO Energy Balance
42 MMT Statewide Target

- Near term solar PV build displaces energy from gas and reduces GHG emissions below GHG target over 2018-2022
- Energy from gas rebounds by 2026 with Diablo Canyon closure, but imports decrease to meet GHG target by 2030



CAISO Energy Balance
30 MMT Statewide Target

- Near term solar PV build displaces energy from gas and reduces GHG emissions below target in 2018 & 2022
- Energy from gas rebounds in 2026 with Diablo Canyon closure, but drop again by 2030
- Net imports are also eliminated to meet GHG target

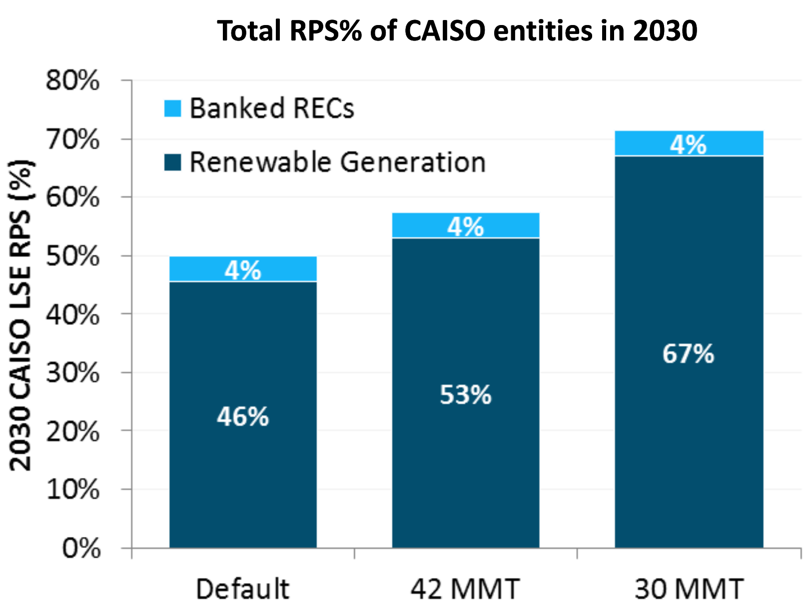


Solar PV and Energy Efficiency Replaces Energy from Diablo Canyon Power Plant

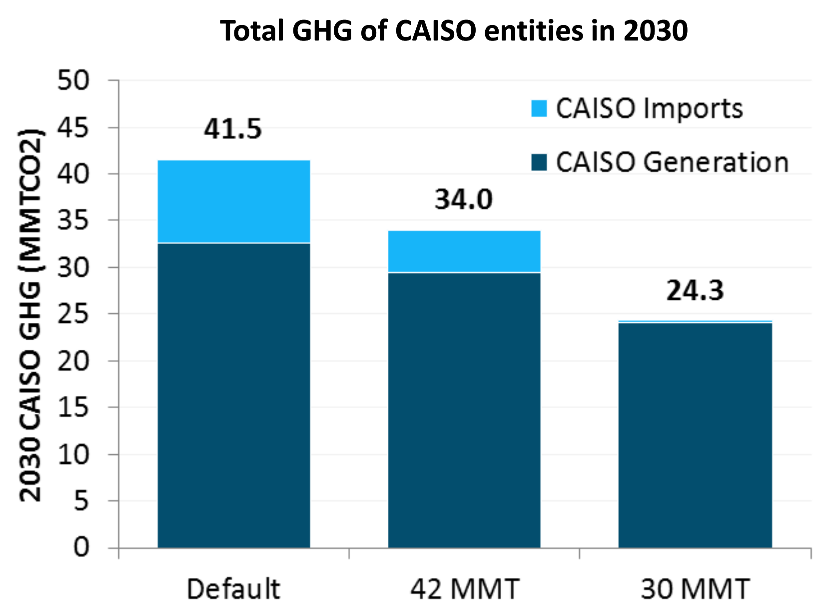
- According to these modeling results, a wide range of CAISO-wide GHG emissions targets (42-30) as well as a 50% RPS target can be met after Diablo Canyon Power Plant is retired

2030 CAISO RPS & Emissions

- GHG constraints, in combination with banked RECs, drive RPS compliance in 2030 above the 50% currently required by statute



CPUC analysis suggests IOUs' banks may allow them to meet 4% of load with banked RECs



In GHG-constrained scenarios, imports are reduced significantly due to deemed emissions rate for unspecified imports, which is higher than in-state gas generation

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

- Incremental cost of the optimal portfolios ranges from **$219 to $1,164 million per year** for the 42 MMT and 30 MMT GHG targets, respectively
- Primary driver of incremental costs is **new investment in renewables**, whose zero-carbon generation displaces emissions from thermal generation and imports

		Incremental TRC ($MM/yr)	
		42 MMT	**30 MMT**
Incremental Fixed Costs	*Renewables*	+$726	+$2,056
	Storage	+$24	+$420
	Thermal	—	—
	DR	—	—
	Transmission	—	+$39
Incremental Variable Costs		-$532	-$1,354
Incremental DSM Program Costs		—	—
Incremental Customer Costs		—	—
Incremental Total Resource Cost		**+$219**	**+$1,164**

Increased investment in zero-carbon renewables is primary driver of incremental costs

No additional thermal or DR resources added to meet GHG goals

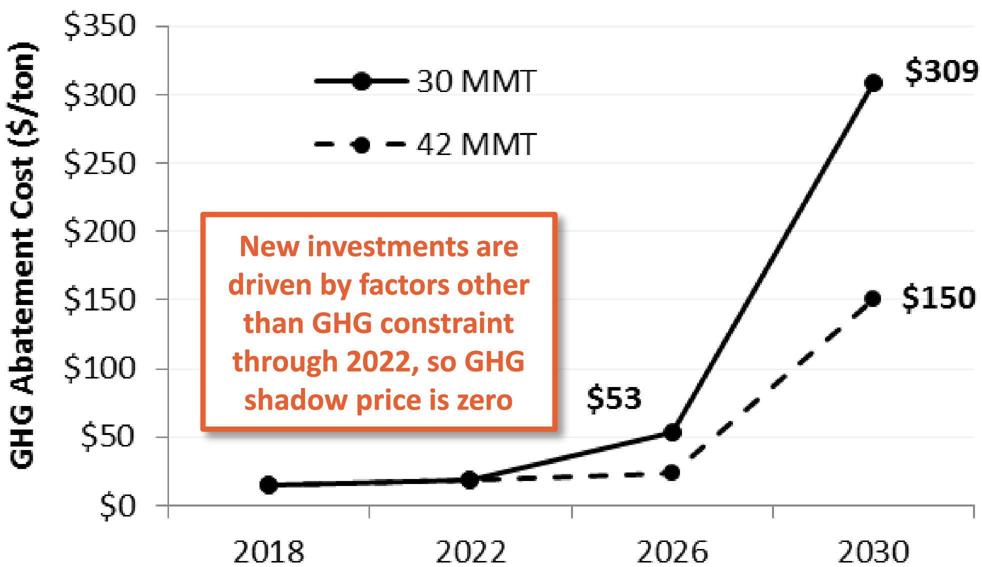
Addition of renewables displaces generation from thermal resources, reducing operating costs

Because demand-side assumptions are constant between scenarios, incremental costs are zero

RESOLVE Output: GHG Shadow Price

- The "shadow price" of a constraint is the difference between the optimized value of the objective function and the value of the objective function, if not for that constraint
- RESOLVE produces a "GHG shadow price"
  - The GHG shadow price represents the marginal cost of GHG abatement in the electric sector above GHG allowance costs
  - All scenarios include GHG allowance costs consistent with the price floor for CARB's Cap-and-Trade Program (estimated at **$29/tonne by 2030**); this allowance cost is held constant from 2018 to 2030
  - The inclusion of GHG allowance costs in RESOLVE's objective function reduces the GHG shadow price by approximately the same amount
  - Increases in allowance costs make GHG emissions appear more expensive in RESOLVE, which in turn reduces the marginal cost of GHG emissions reductions in RESOLVE
- Staff defines the "GHG Planning Price" in the IRP Staff Proposal as…
  - The system-wide marginal GHG abatement cost associated with achieving the electric sector 2030 GHG planning target (i.e., equal to the sum of the GHG shadow price and the assumed allowance price for 2030)

RESOLVE Output: Marginal GHG Abatement Cost 42 MMT & 30 MMT Cases



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

In 42 MMT scenario, GHG constraint does not become the main driver of new investments until 2030

* Note: shadow price does not include modeled GHG allowance price (see previous slide)

- Exponential shape of shadow price curve reflects 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: $279 + $29 = **$309/tonne** **(rounded up)**
  - 2030 marginal abatement cost in 42 MMT scenario: $121 + $29 = **$150/tonne**

Need to Decarbonize Other Sectors Could Increase Electric System Costs After 2030

- IRP's RESOLVE model includes straight-line projections of different load assumptions through 2050 (load, EE, etc.)
- If electrification of transportation or buildings increases significantly above a straight-line projection after 2030, additional energy will be required
- Any fixed statewide 2030 GHG target (e.g., 42 MMT or 30 MMT) will become increasingly costly to maintain the more load increases

V. SENSITIVITY ANALYSIS

Sensitivity Analysis

- Each portfolio is based on assumptions about future conditions (load levels, resource costs, etc.)
- Sensitivity analysis provides a useful framework to investigate how these assumptions impact results
- Sensitivities are defined by identifying key assumptions with a wide range of uncertainty (or significant impact on the optimal portfolio) and developing bounding values for analysis
- Sensitivities can provide insight into financial risks associated with different policies
  - If varying the value of an assumption changes the sign or significantly changes magnitude of the costs of that policy, that indicates risk

Sensitivity Analysis

- The following slides show a series of sensitivities that present the incremental cost impacts of different assumptions about
  - the achievement level for different resource goals and programs (such as adoption of energy efficiency);
  - the costs of different resources (such as battery storage); and
  - other future conditions (such as lower than expected grid flexibility)
- The sensitivities are intended to help decisionmakers evaluate
  - the potential costs of pursuing different resource policies;
  - how costs change depending on the GHG emissions target; and
  - how costs change depending on different future conditions that may be outside of CPUC control.

Interpreting Results of Cross-Sectoral Sensitivities

- Two of the sensitivities designed in this study examine how measures undertaken in other sectors of the economy to meet GHG goals could impact the electric sector:
  - High Building Electrification
  - Hydrogen Loads
- The results of these sensitivities provide a useful measure of how the electric sector might respond to such changes, but do not provide a complete picture of the impacts of such changes
  - Analysis does not evaluate costs and/or benefits outside the electric sector (e.g. avoided gasoline or natural gas purchases)
  - Analysis does not consider greenhouse gas benefits associated with electrification of end uses
- Accordingly, these sensitivities should be interpreted as “what-if?” analyses of potential cross-sectoral impacts, but cannot be used alone as justification for policy decisions on these types of measures

Overview of Sensitivities

Sensitivity	Description
Reference	**Reference Case**
High EE	Increased adoption of EE, consistent with **SB350 EE doubling goal**
Low EE	Decreased adoption of efficiency, consistent with **CEC 2016 IEPR Mid AAEE projection**
High BTM PV	Increased adoption of BTM, corresponding to cumulative adoptions of **21 GW by 2030**
Low BTM PV	Decreased adoption of BTM, corresponding to cumulative adoptions of **9 GW by 2030**
Flexible EVs	All new electric vehicle loads treated as flexible within the day (load can be shifted between hours subject to constraints on vehicle availability)
High PV Cost	High projections of future solar PV cost
Low PV Cost	Low projections of future solar PV cost
High Battery Cost	High projections of current & future battery storage costs
Low Battery Cost	Low projections of current & future battery storage costs
No Tax Credits	All new renewables assumed to be developed assuming no **long-term federal tax credits** (no PTC; 10% ITC for solar PV)
Gas Retirements	An additional **12.7 GW of gas generation assumed retire by 2030**, reducing gas fleet to 13 GW

Overview of Sensitivities

Sensitivity	Description
Reference	**Reference Case**
CHP Retirement	All existing non-dispatchable CHP **(1,600 MW)** assumed to retire by 2030
Flex Challenged	Combines a low net export constraint **(2,000 MW)** with a minimum gas generation requirement **(2,000 MW)**
High Load	Combines Low BTM PV, Low EE, High Building Electrification, and High EV sensitivities
High Local Need	Assumes hypothetical local LCR needs of **1,500 MW** by 2026
Low DR	Assumes discontinuation of existing economically dispatched DR programs after 2022
Low TOU	Low level of TOU rate impacts (based on Christensen Scenario 3)
Mid TOU	Mid level of TOU rate impacts (based on MRW Scenario 4)
Rate Mix 1	Captures a load impact consistent with rate designs modeled in LBNL Rate Mix 1 **(1-2% load reduction)**
Zero Curtailment	Prohibits renewable curtailment in day-to-day operations of the grid as an integration solution
High DER	Assumes high levels of all DERs, including BTM PV, ZEVs, EE, and DR

Sensitivity Analysis: Impact on Incremental Cost

Sensitivity	Incremental TRC ($MM/yr)			Change from Reference ($MM/yr)		
	Default	42 MMT	30 MMT	Default	42 MMT	30 MMT
Reference	**$0**	**$219**	**$1,164**			
High EE	$67	$205	$1,001	**+$67**	**-$14**	**-$162**
Low EE	-$60	$290	$1,417	**-$60**	**+$71**	**+$254**
High BTM PV	$456	$645	$1,576	**+$456**	**+$426**	**+$413**
Low BTM PV	-$715	-$430	$556	**-$715**	**-$648**	**-$608**
Flexible EVs	-$69	$112	$946	**-$69**	**-$107**	**-$217**
High PV Cost	$193	$436	$1,404	**+$193**	**+$217**	**+$240**
Low PV Cost	-$261	-$119	$773	**-$261**	**-$338**	**-$391**
High Battery Cost	$159	$383	$1,328	**+$159**	**+$164**	**+$164**
Low Battery Cost	-$159	$52	$987	**-$159**	**-$167**	**-$176**
No Tax Credits	$633	$897	$1,945	**+$633**	**+$678**	**+$781**
Gas Retirements	$460	$589	$1,282	**+$460**	**+$370**	**+$119**

"Incremental TRC" calculated relative to "Default Reference" case (highlighted in orange

"Change from Reference" calculated relative to corresponding "Reference" case

Sensitivity Analysis: Observations

Sensitivities	Observations
Energy Efficiency	Value of incremental energy efficiency increases significantly under increasingly stringent carbon constraints; under less stringent carbon constraints, the value of the additional EE is less than the cost based on the assumed program costs.
Behind-the-Meter PV	Increases in BTM PV result in increased costs (including customer costs) in all scenarios; reductions in BTM PV result in reduced costs.
Flexible EVs	Allowing flexible EV charging reduces renewable curtailment, providing grid integration benefits; those benefits increase with higher renewable penetrations or under increased GHG targets.
PV Cost	Larger-than-expected reductions in PV cost reduce overall portfolio costs; smaller reductions result in higher cost portfolios and shift portfolios away from solar PV resources.
Battery Cost	Reductions in battery cost lower overall portfolio costs. The impact is modest in comparison to other sensitivities.
Tax Credits	If procurement is deferred until after tax credits expire, 2030 costs to ratepayers may increase significantly; in other words, accelerated procurement of renewables (in spite of current surplus) could result in significant savings if tax credits are not extended.
Gas Retirements	Accelerated retirement of gas resources drives significant increase in the total cost metric, mainly a result of the need to invest in new resources that can replace system resource adequacy provided by the retired gas capacity.

Additional Sensitivity Analysis: Impact on Incremental Cost

All costs shown relative to Default Reference case

Sensitivity	Incremental Cost ($MM/yr)			Change from Reference ($MM/yr)		
	Default	42 MMT	30 MMT	Default	42 MMT	30 MMT
Reference	**$0**	**$219**	**$1,164**			
CHP Retirement	-$91	$57	$778	-$91	-$161	-$385
Flex Challenged	$79	$372	$1,488	+$79	+$154	+$325
High Load	-$337	$387	$2,019	-$337	+$168	+$855
High Local Need	$33	$251	$1,194	+$33	+$33	+$30
Low DR	-$35	$184	$1,129	-$35	-$35	-$35
Low TOU	$7	$226	$1,171	+$7	+$7	+$7
Mid TOU	$3	$222	$1,167	+$3	+$4	+$3
Rate Mix 1	-$208	-$33	$832	-$208	-$252	-$332
Zero Curtailment	$777	$1,232	$3,087	+$777	+$1,013	+$1,923
High DER	$545	$656	$1,360	+$545	+$437	+$196

"Incremental TRC" calculated relative to "Default Reference" case (highlighted in orange

"Change from Reference" calculated relative to corresponding "Reference" case

Additional Sensitivity Analysis: Observations

Sensitivities	Observations
CHP Retirements	Retirement of baseload CHP—an inflexible resource—increases operational flexibility and reduces the challenge of renewable integration. This impact results in reduced costs, as fewer investments in renewables and storage are added to meet policy goals.
Flexibility Challenged	Constraints that limit operational flexibility of the system (minimum generation, low net exports) exacerbate renewable curtailment, increasing the cost of meeting policy goals and requiring additional investment.
High Load	Sensitivity combines low BTM PV, low EE, high EVs, and high building electrification; multiple moving pieces make it difficult to isolate specific impacts in this sensitivity.
High Local Need	Hypothetical local need is met primarily by DR resources, which result in a modest increase in cost.
Low DR	The elimination of existing economically dispatched DR programs from the set of baseline resources results in a reduction in cost, as these programs have little value in today's system due to the existing capacity surplus. This finding changes if significant quantities of gas retire earlier than expected.
TOU Rates	Reductions in the load impact associated with default residential TOU rates (Low TOU/Mid TOU) cause a very slight increase in total costs. Rate Mix 1, which predicts a larger reduction in loads due to TOU pricing, leads to cost savings due to the assumed reduction in annual load (1-2%).
Zero Curtailment	Preventing curtailment shifts all portfolios towards energy storage and away from solar, as all oversupply must be stored rather than curtailed; this portfolio criterion results in a significant increase in costs

VI. FOSSIL FLEET IN IRP

Focus of IRP is Long-term Evolution of Fossil Fleet, Not Real-Time Dispatch

- Focus of IRP is identifying the short term actions (1-3 years) required to meet long-term policy goals (10-20 years), including GHG reductions, RPS, and reliability needs
- Focus of IRP is not real-time market dispatch dynamics, which determine actual plant performance
- Individual gas plant costs, efficiency, and bidding behavior are difficult to capture in a long-term simulation
- Classes of gas plants tend to exhibit similar market behavior and are therefore aggregated together for the IRP analysis

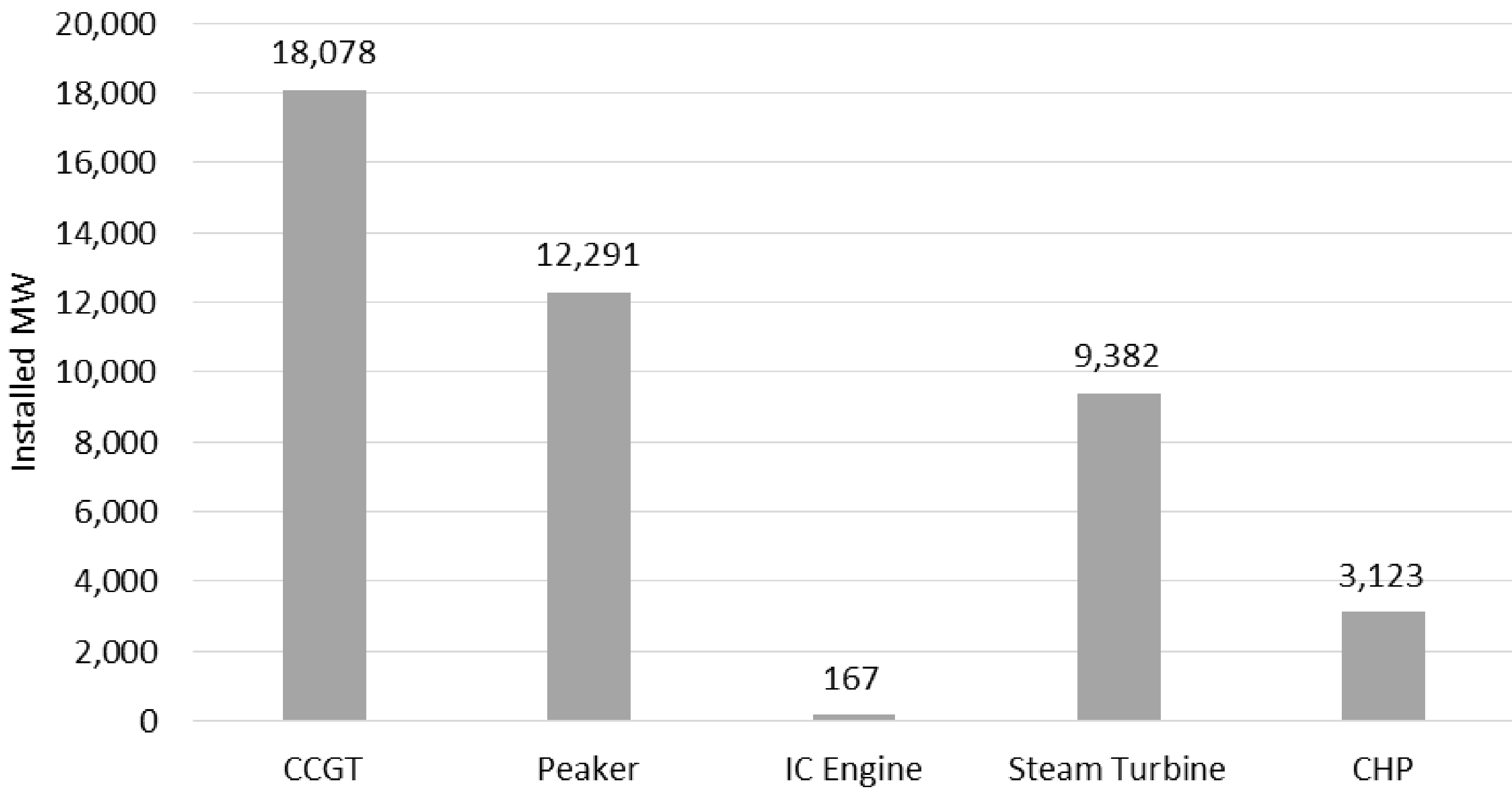
GHG Goals May Reduce Utilization of Fossil Plants

- Gas plants earn revenue by being used (dispatched) to serve load
- GHG targets (42 MMT and 30 MMT) could result in lower utilization rates of certain gas plants relative to the 50% RPS Default Case in favor of zero-carbon sources of generation
- The utilization of gas fleet within California will also be affected by the relative GHG intensity of fossil plants outside of California and the deemed rate used by CARB to allocate GHG emissions to imports (0.432 MT/MWh)
  - For example, GHG target could lead to decreased utilization of out-of-state coal, but increased dispatch of in-state gas

Evolution of California's Natural Gas Fleet as Grid Decarbonizes

- Only the widespread early retirement of gas resources sensitivity leads RESOLVE model to select new gas (it is the **<u>only</u>** future condition that leads to new gas being selected)
  - 50% RPS: ~1,600 MW of new gas resources are selected
  - 42 MMT GHG target : ~400 MW of new gas resources are selected
  - 30 MMT GHG target: new gas not selected
- It might be preferable to selectively retain a subset of existing gas plants rather than building new plants
- This raises the question of which gas plants, or plant attributes, provide value in 2030:
  - Low minimum generation level?
  - Fast ramping ability?
  - Location-specific benefits?
- Determining which gas plants, or plant attributes, offer the most value in future fleet is complex task and will require additional detailed study

Natural Gas Fleet Plant Types in California



Steam Turbine Retirement Assumptions in IRP Modeling

Plant	Steam Turbine NQC (MW)	Planned Retirement
Alamitos	2,010	2020
Encina	950	2017
Huntington Beach	452	2020
Mandalay	430	2020
Moss Landing	1,509	2017
Ormond	1,516	2020
Pittsburg	1,159	2017
Redondo	1,356	2020
Total	**9,382**	

VII. DISADVANTAGED COMMUNITIES ANALYSIS

Organization

1. Air Pollution Impacts on DACs
2. Economic Development Impacts on DACs

1. LOCALIZED AIR POLLUTANTS

Portfolio Impacts on Localized Air Pollutants

IRP statute includes the following goal:

"Minimize localized air pollution and other GHG emissions, with early priority on disadvantaged communities"

Approach to Analyzing IRP Impact on Localized Air Pollutants

Step 1: Characterize the distribution of power plant classes inside and outside DACs

Step 2: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: Default (50% RPS), 42 MMT, and 30 MMT

Step 3: Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

Characteristic Features of Power Plant Types in IRP Modeling

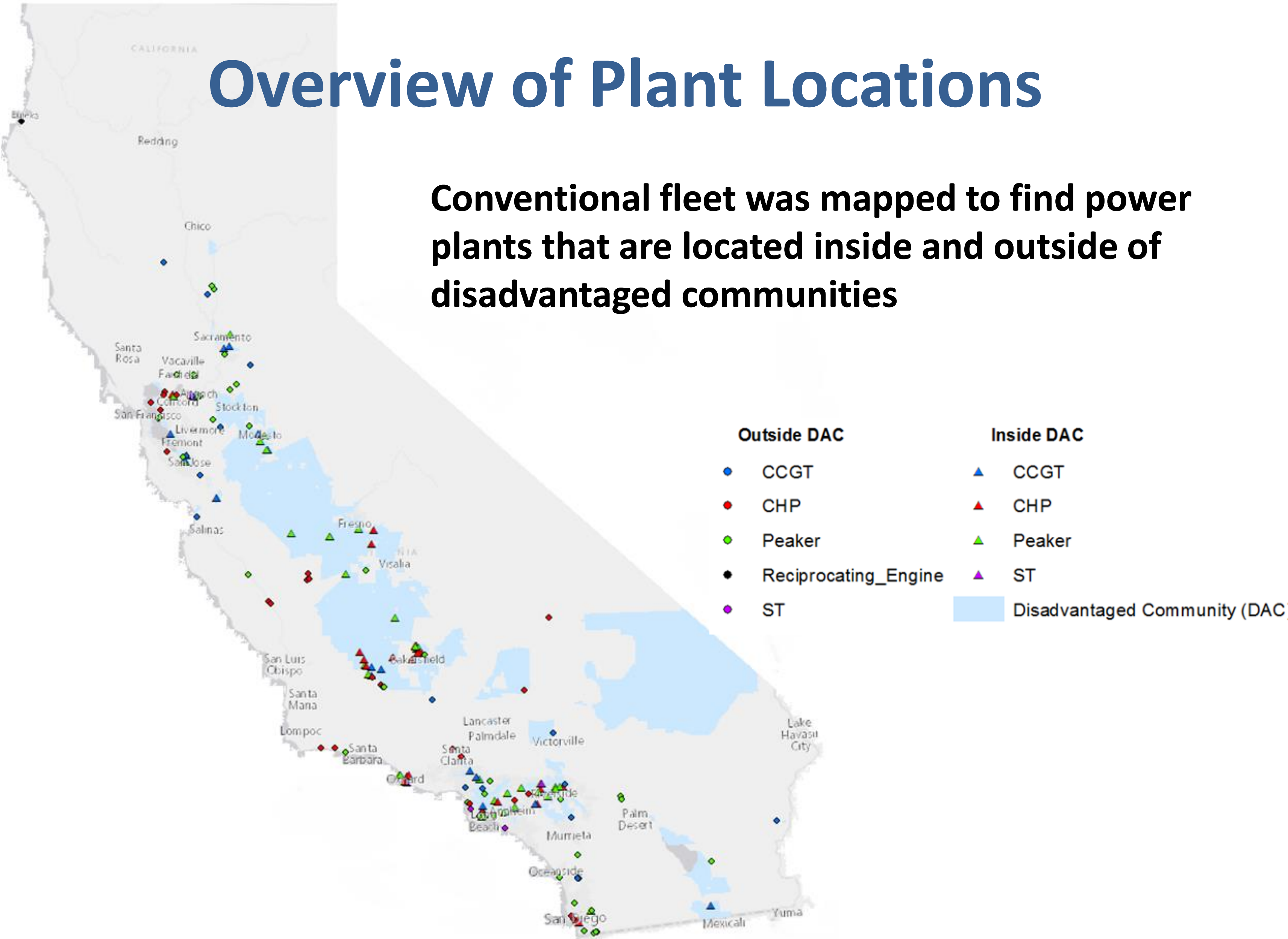
RESOLVE groups plants with similar operating characteristics into different classes:

Plant Class	Description	Representative Heat Rate at Pmax (Btu/MWh)	Examples
CCGT	Combined Cycle Gas Turbine	7-8	Otay Mesa, Colusa, La Paloma
Peaker	Single Cycle Gas Turbine	9-12	Sentinel, Long Beach, Panoche Peaker
IC Engine	Internal Combustion Engine or Reciprocating Engine	9.1	Humboldt bay
ST	Steam Turbine	9.7	Etiwanda, Alamitos
CHP	Combined Heat and Power	7.6	Crockett, Algonquin Sanger, Watson, Sycamore

See the revised *RESOLVE Inputs and Assumptions* document for details, available at:
www.cpuc.ca.gov/irp/prelimresults2017

Overview of Plant Locations

Conventional fleet was mapped to find power plants that are located inside and outside of disadvantaged communities



Power Plant Capacity in Current Fleet Is Disproportionately Located in Disadvantaged Communities

- DACs defined in IRP as CalEnviroScreen 3.0 results for top 25% scoring areas by census tract
- If capacity from natural gas power plants was distributed throughout the CA population randomly, one would expect to find about 25% of it in DACs
- In fact, 37% is in DACs, a disproportionate share

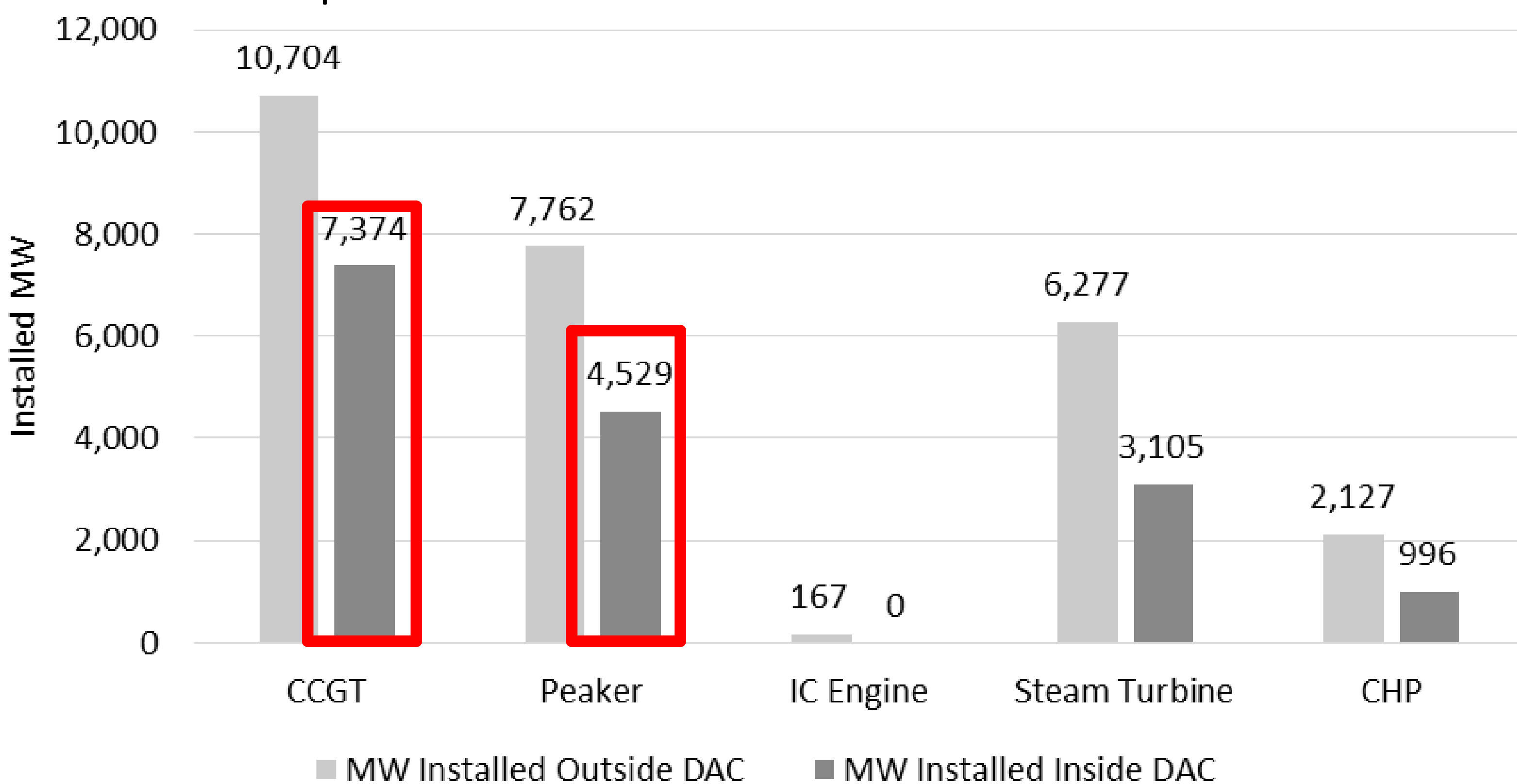
Statewide, from CalEnviroScreen 3.0	Statewide Total	Outside DAC	Inside DAC	Outside DAC (%)	Inside DAC (%)
Population	37,253,956	27,916,231	9,337,725	75%	25%
Number of Census Tracts	8,035	6,052	1,983	75%	25%
Conventional Power Plants (Installed MW)	43,041	27,037	16,004	63%	37%

Two Ways to Prioritize Plants Affecting DACs

- **Absolute**: the plants with the highest absolute amount of capacity in DACs
  - Reduction in emissions from these plants might have the greatest absolute benefits for DACs, but would benefit non-DACs even more
- **Relative**: the plants that occur disproportionately in DACs relative to non-DACs
  - Reduction in emissions from these plants would have the greatest relative impact on DACs compared to non-DACs

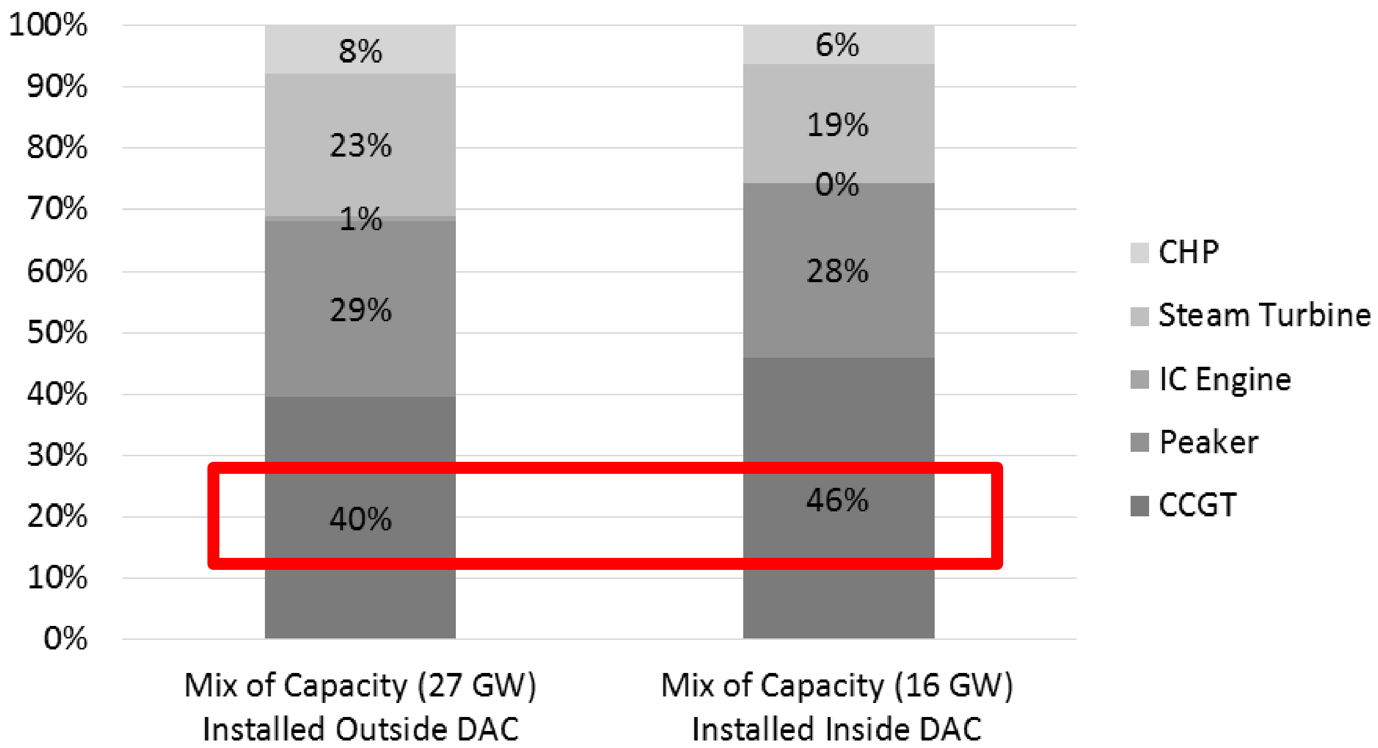
Absolute Frequency Distribution of Capacity in California By Power Plant Type

- The most common plants in DACs by capacity are CCGTs and Peakers
- Reductions from these plants may have the greatest absolute impacts on localized air pollutants from the electric sector



Relative Frequency Distribution of Capacity in California by Power Plant Type

- There are disproportionately more MW of CCGTs in DACs
- For every unit reduction of emissions in CCGTs, DACs benefit disproportionately relative to non-DACs



Step 1 Conclusions

Step 1: Characterize the distribution of power plant classes inside and outside DACs

- The largest amount of capacity in DACs is from CCGTs and Peakers
- The most disproportionate amount of capacity in DACs is from CCGTs

Approach

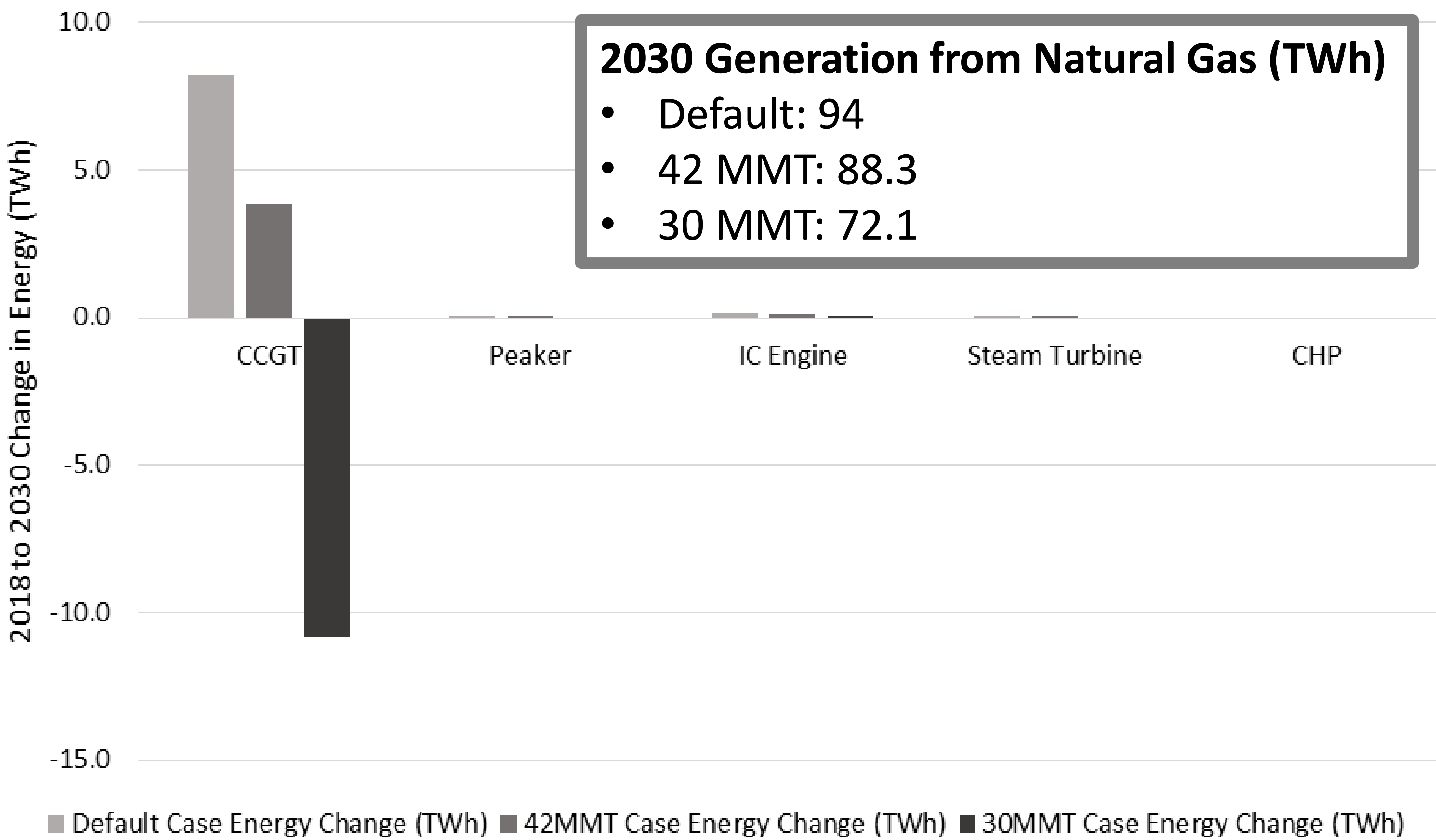
Step 1: Characterize the distribution of power plant classes inside and outside DACs

Step 2: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: default (50% RPS), 42 MMT, and 30 MMT

Step 3: Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

Change in Electricity Generation from Natural Gas Plants in California From 2018 to 2030

- Production changes most at CCGT plants
- The deemed GHG emissions factor for imported electricity is larger than California CCGT emission factors , which can lead to more in-state generation as imports decline



2030 Generation from Natural Gas (TWh)
- Default: 94
- 42 MMT: 88.3
- 30 MMT: 72.1

Estimating Localized Air Pollutants

- NOx and PM2.5 are the localized air pollutants of primary concern from California's conventional, natural gas-fired fleet
- Statewide emissions estimates can be made by post-processing the results provided by RESOLVE
  - Annual production (MWh) and fuel consumption (MMBtu) provided by RESOLVE for each natural gas plant type category
  - Apply an appropriate emission factor (lb/MWh or lb/MMBtu)
  - Numbers of unit startups are not forecasted by RESOLVE
- Because of wide changes in fuel use and energy production by CCGTs, under different GHG planning targets, emissions change the most from this power plant type

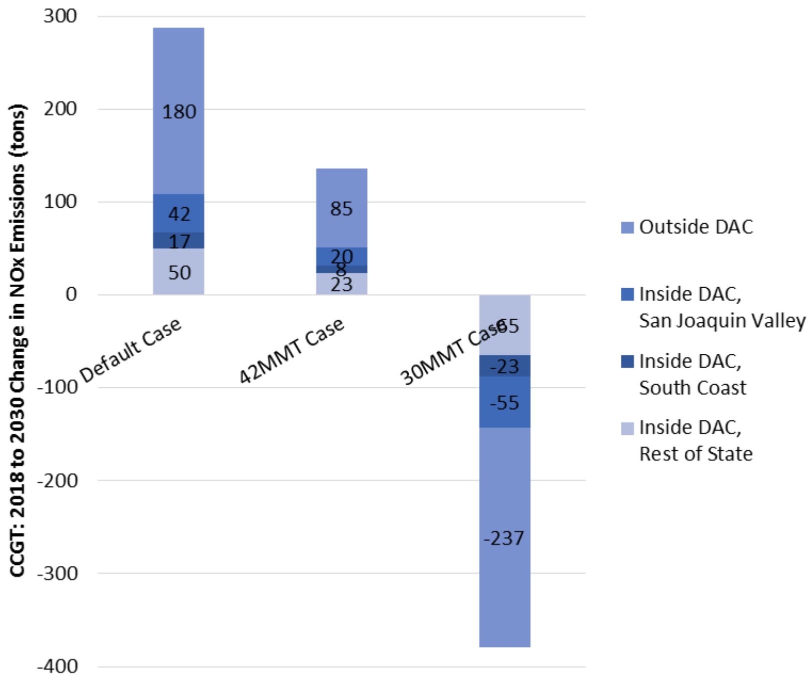
Criteria Air Pollutant Emissions Factors

- Statewide emissions estimates use the following emission factors for these broad technology types
  - CCGT NOx: 0.07 lb/MWh; PM2.5: 0.0066 lb/MMBtu
  - Peaker NOx: 0.099-0.279 lb/MWh; PM2.5: 0.0066 lb/MMBtu
    - CCGT and Peaker factors: *CEC Cost of Generation (2015) & USEPA AP-42*
    - Economy-wide emissions inventory projections for 2030: *ARB CEPAM*
    - Motor vehicle fleet and average emissions for 2030: *ARB EMFAC2014*
- Location of emissions were approximated based on distribution of installed MW for each technology
- Two air basins have 25% or more of their population in disadvantaged communities
  - San Joaquin Valley air basin
  - South Coast air basin

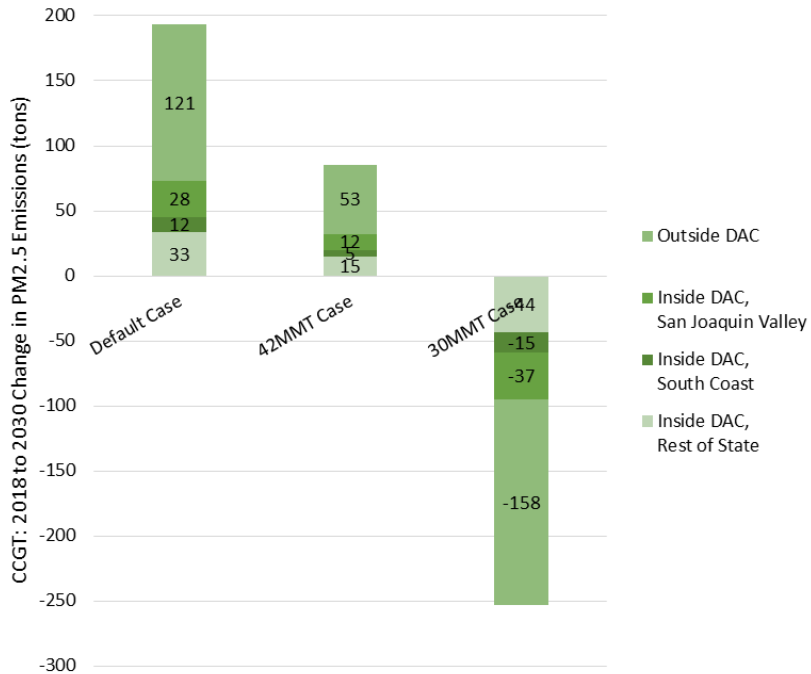
CCGT: NOx and PM2.5 Emission Changes

Statewide between 2018 and 2030

- Cycling CCGTs will increase NOx during unit-startups (not included)
- PM2.5 is not notably influenced by numbers of startups
- Changes in emissions at CCGTs disproportionately affect DACs on average



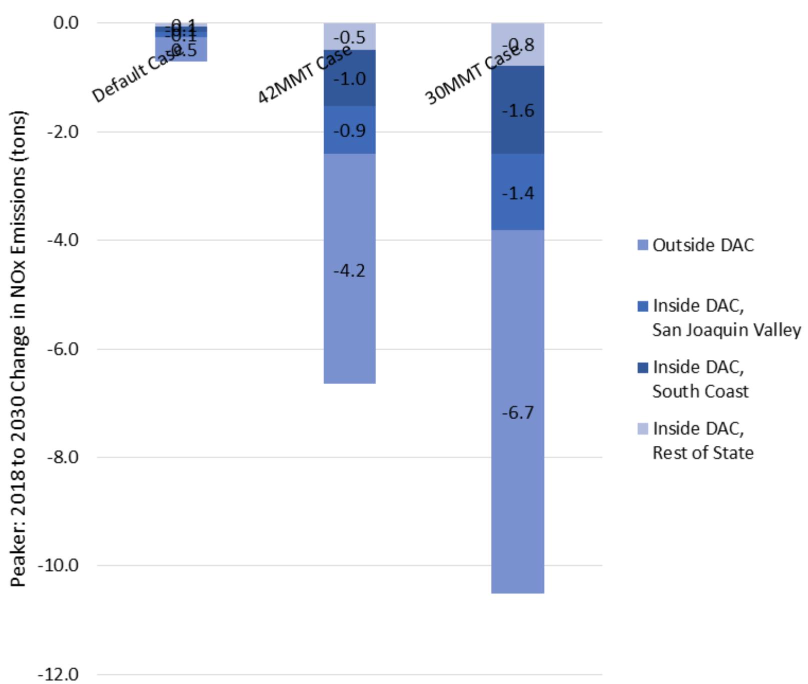
NOx



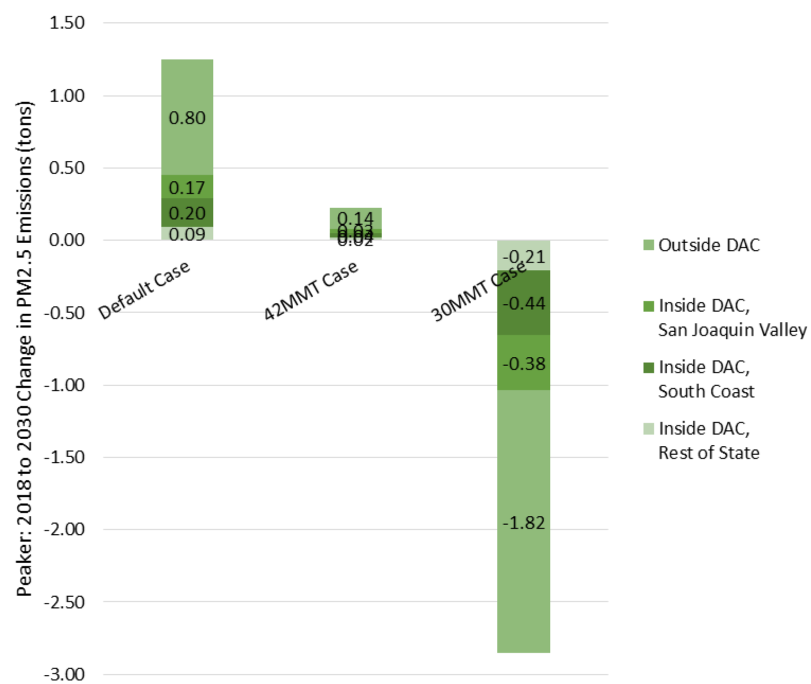
PM2.5

Peaker: NOx and PM2.5 Emission Changes
Statewide between 2018 and 2030

- Potential emissions changes within the Peaker class of power plants are much smaller than those for CCGT class
- Changes in emissions at Peakers do not disproportionately affect DACs on average



NOx



PM2.5

Step 2 Conclusions

Step 2: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: Default (50% RPS), 42 MMT, and 30 MMT

- Fuel consumption and emissions changes within the CCGT class of power plants greatly outweigh those from the Peaker class

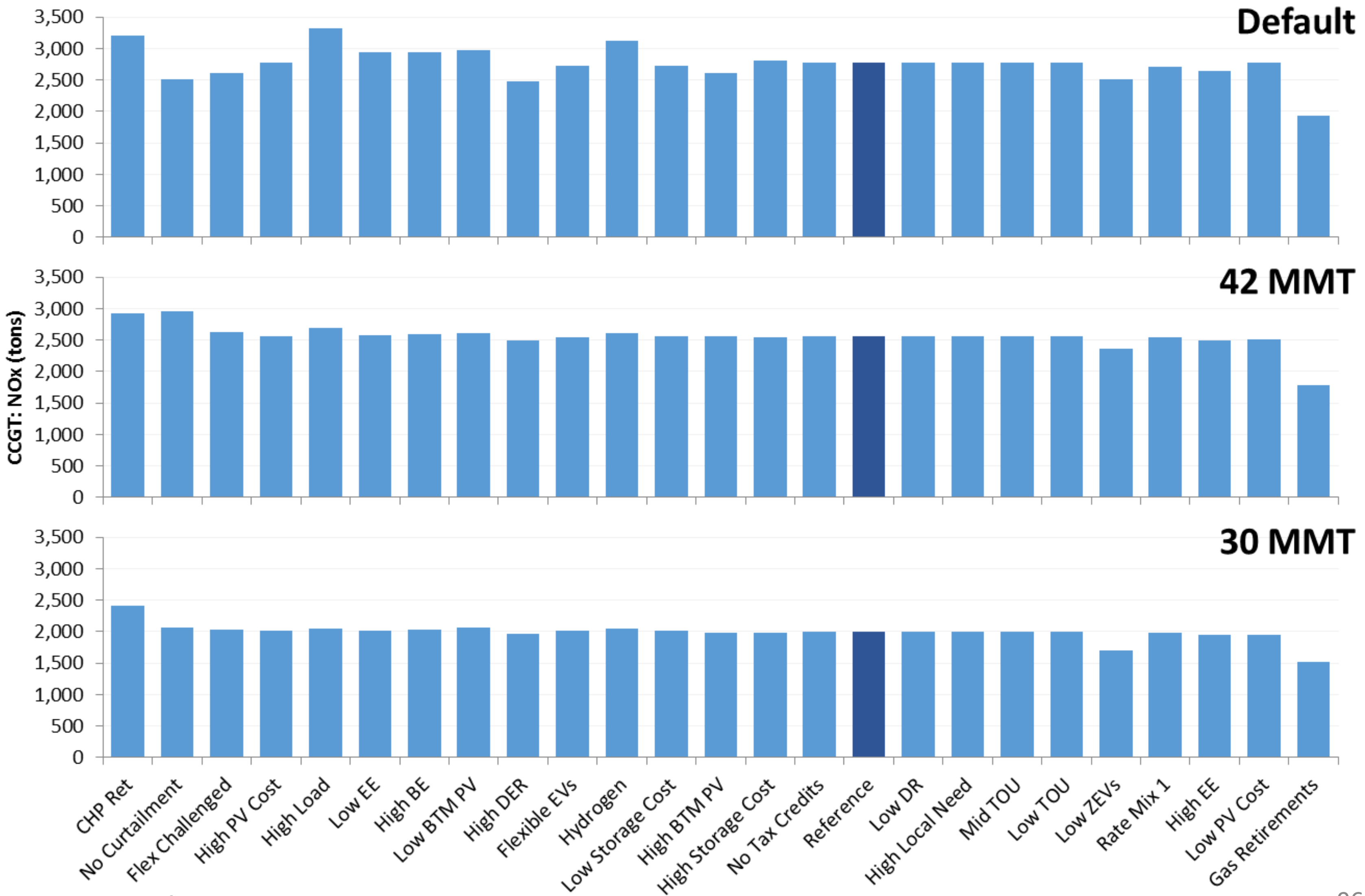
Approach

Step 1: Characterize the distribution of power plant class inside and outside DACs

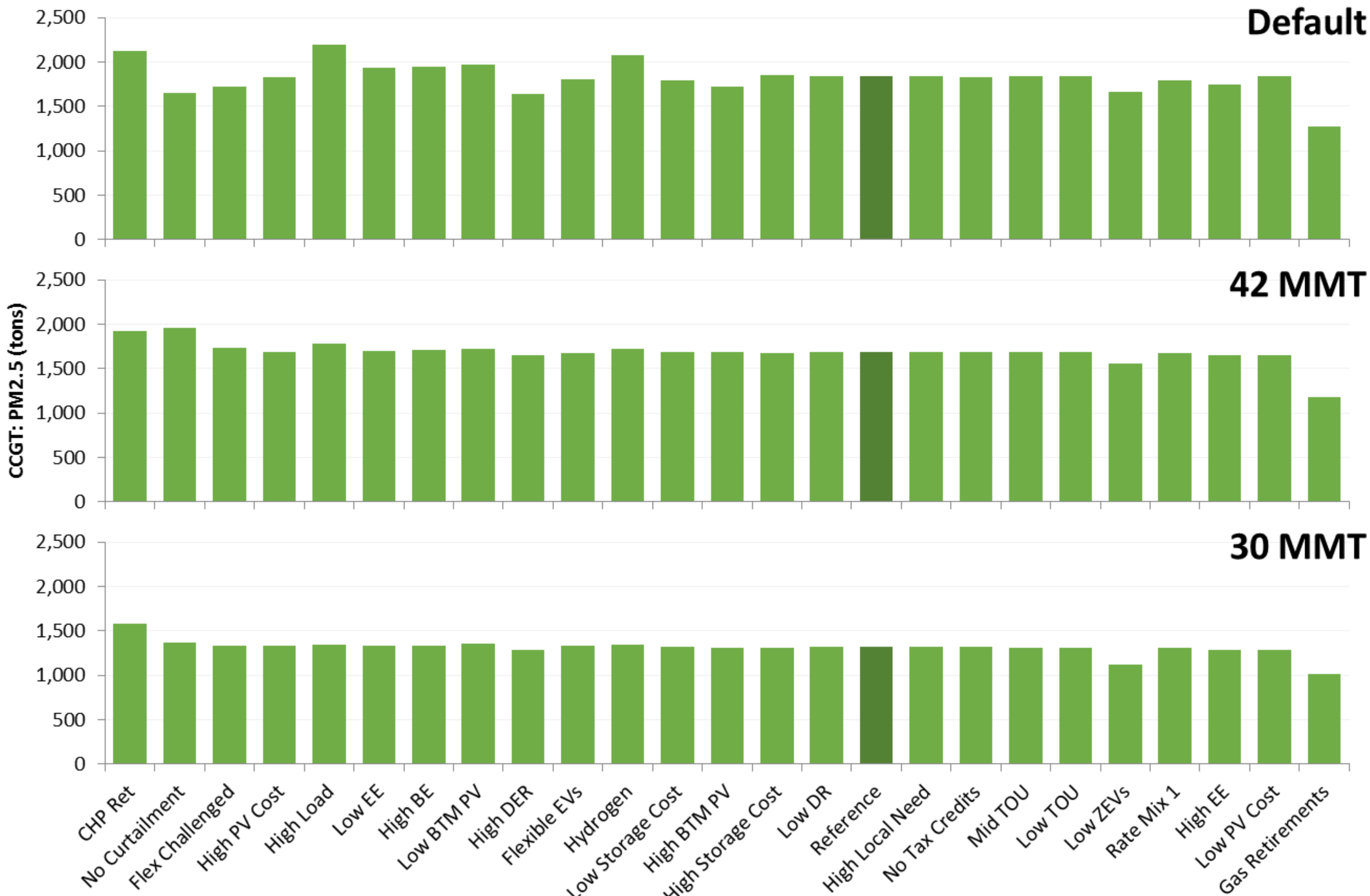
Step 2: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: Default (50% RPS), 42 MMT, and 30 MMT

Step 3: Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

NOx Emissions Statewide (tons)
CCGT Power Plants in Optimal Portfolios in 2030

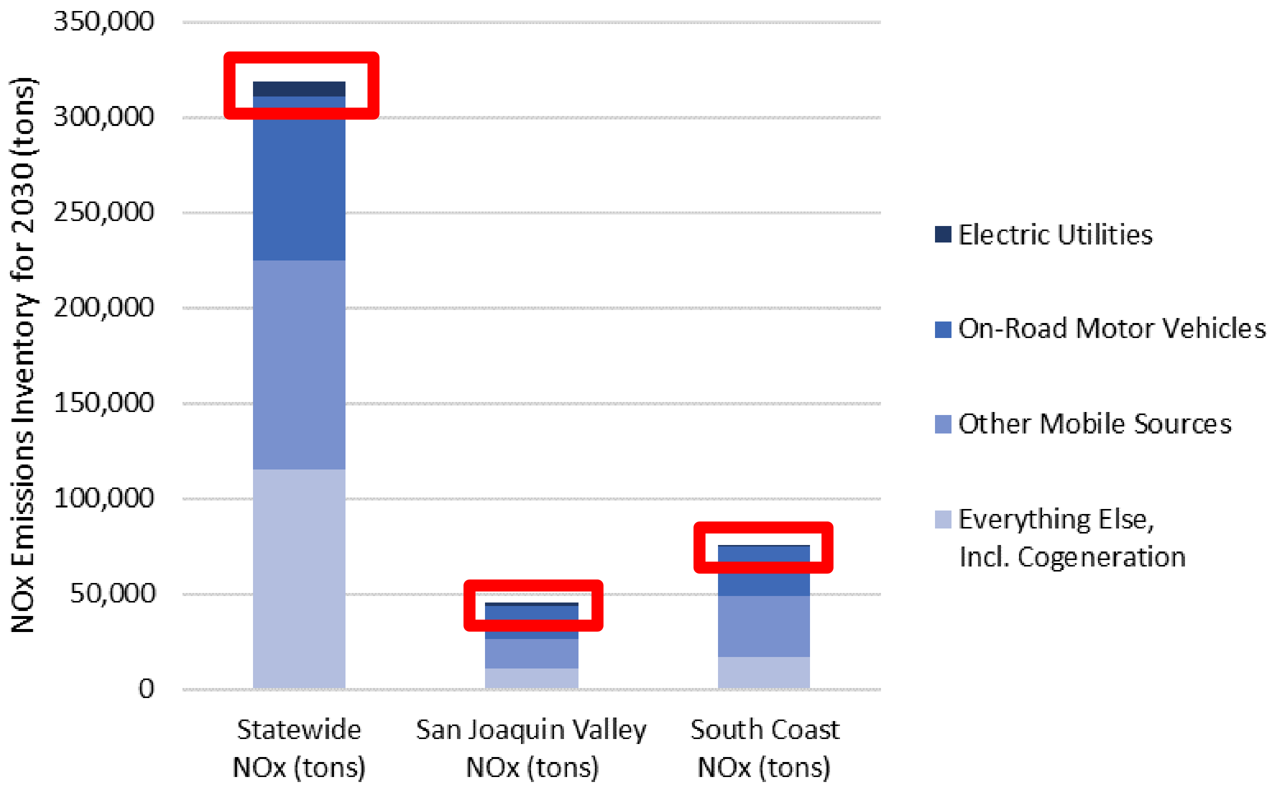


PM2.5 Emissions Statewide (tons)
CCGT Power Plants in Optimal Portfolios in 2030



Electricity Generation Compared with Mobile Source Emissions

- Motor vehicles and other mobile sources create between 60-75% of the overall NOx emissions, depending on location
- Electric utilities represent 2-4% of 2030 NOx emissions



"California Emissions Projection Analysis Model" which is an online tool at:
https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php

Step 3 Conclusions

Step 3: Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

- The overall GHG target generally has a larger impact than individual sensitivities on the level of localized air pollutants
- Factors that increase load tend to increase localized air pollutant emissions from power plants and vice versa

Overall Conclusion

- In general, reducing CCGT use achieves the greatest quantities of reductions in localized air pollutants, including in DACs.

2. ECONOMIC DEVELOPMENT

Strengthening Local Communities

IRP statute includes the following goal:

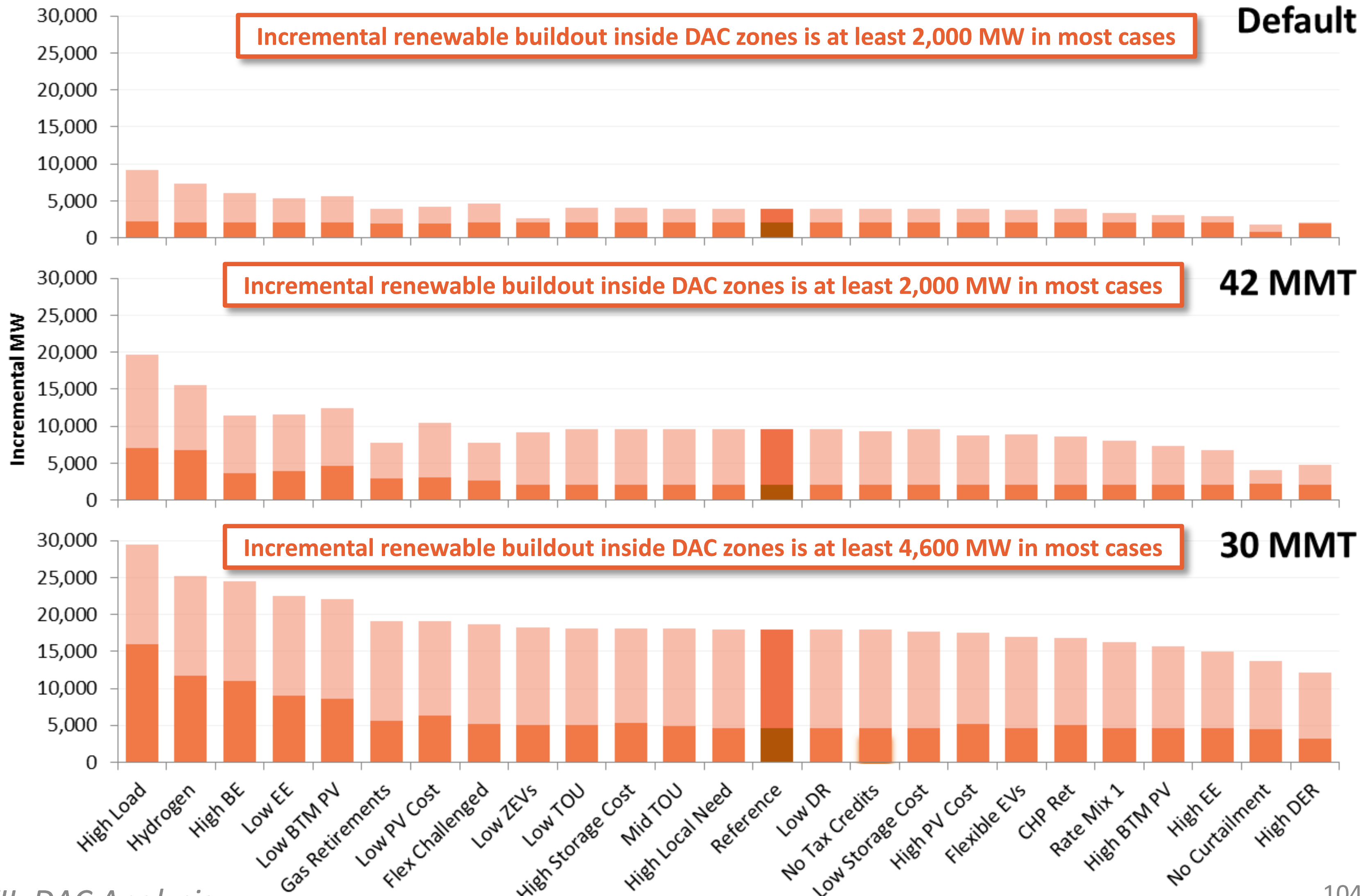
“Strengthen the diversity, sustainability, and resilience … of local communities”

Incremental Renewable Resource Buildout relative to Disadvantaged Communities

- To characterize the relative amount of new renewable resource buildout for the likelihood that disadvantaged communities will see or otherwise be aware of new construction
- Renewable resources zones as used in RESOLVE are geographic zones that can span multiple counties or substantial portions of counties
- Resource zones originally evolved from Competitive Renewable Energy Zone (CREZ) boundaries
  - **Four** renewable resource zones in RESOLVE have 25% or more of their population in disadvantaged communities:
    - Central Valley North & Los Banos
    - Westlands
    - Kramer & Inyokern
    - Greater Imperial

Incremental Renewable Resource Build

in Four Resource Zones characterized by Disadvantaged Communities



Conclusions

- The more stringent the GHG target, the more renewable energy development in DACs
- Greater ZEV adoption and greater building electrification increases load, leading to more utility-scale renewable energy development in DACs
- Greater adoption of BTM PV and EE decreases load, leading to less utility-scale renewable energy development in DACs

VIII. RESOURCE STUDIES

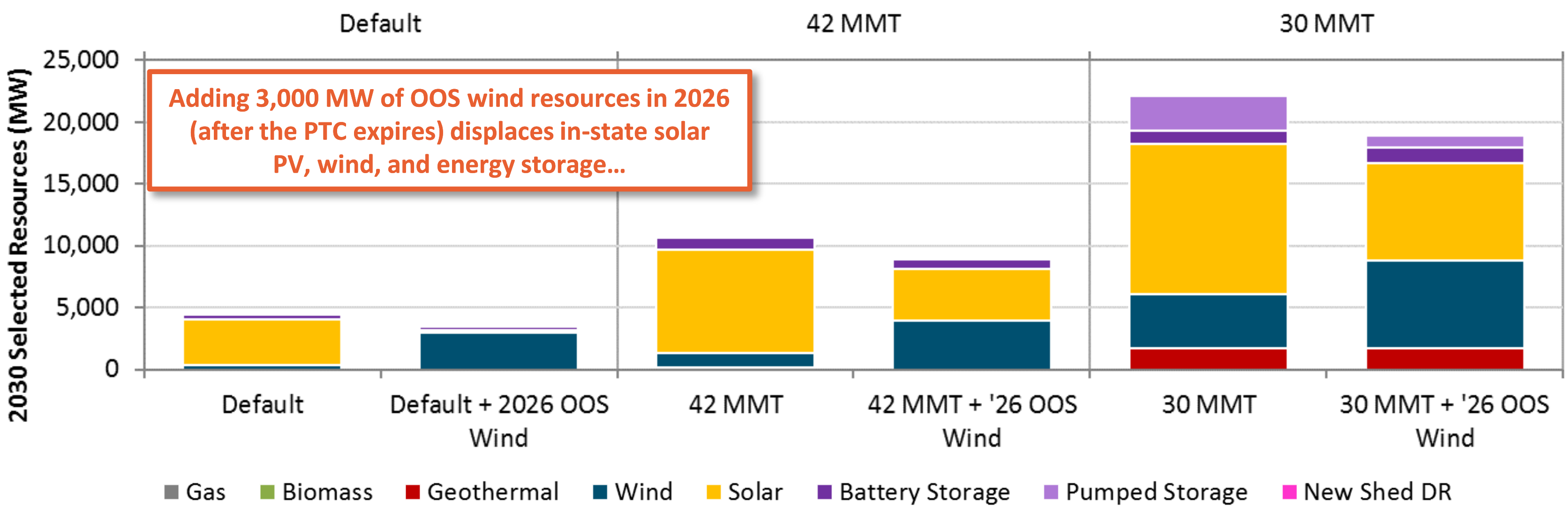
Resources Selected for Detailed Study

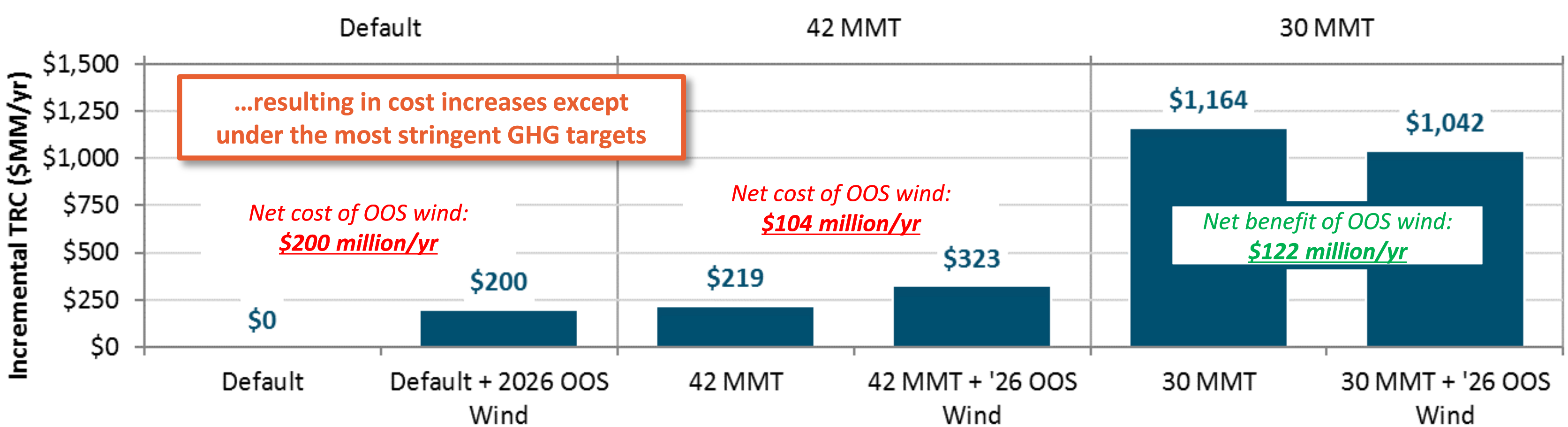
- CPUC staff selected certain resources to study in greater detail:
  - Pumped storage
  - Geothermal
  - OOS wind
- Pumped storage and geothermal resources were available for selection and chosen by the model in some cases (e.g., see 30 MMT case), but typically not until 2030
- OOS wind on new transmission was not available for selection in the core cases and sensitivities due to uncertainty in the cost and feasibility of the required transmission
- These detailed studies are designed to provide information to decision makers about the value and risk of procuring these resources **in the near term**
- In each case, the resource is manually added to the portfolio in the **earliest possible year** that it could be available based on estimated lead times for each resource type

OOS Wind Study: Overview

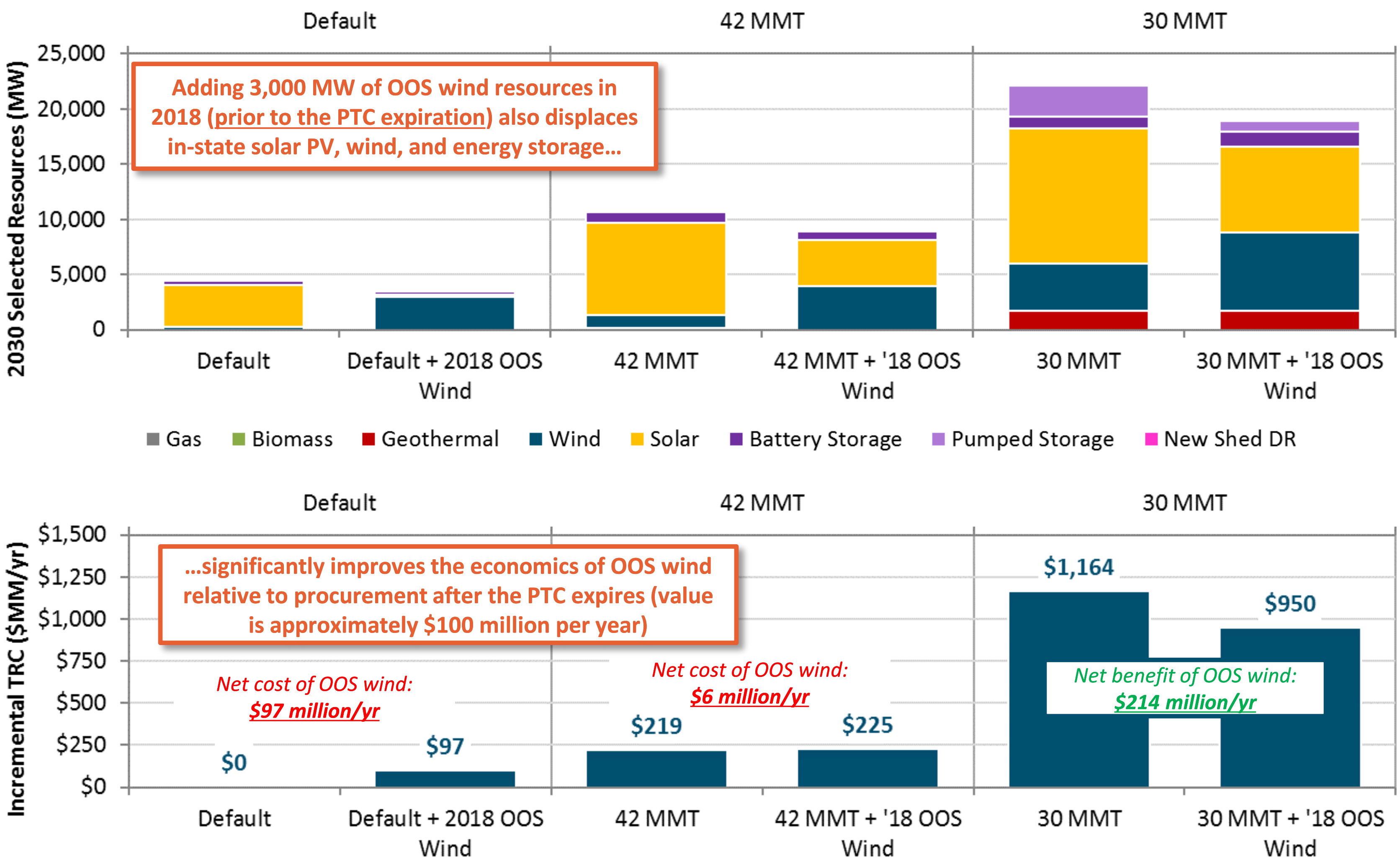
- **Study Question:**
  - Does procuring OOS wind **in the near-term** reduce risk and/or cost across a broad range of sensitivities?
- **Study Design**
  - Manually add 3,000 MW of WY & NM wind (along with associated transmission to CA) to the portfolio in 2026 to assess its impact
  - Test with three core cases (Default, 42 MMT, 30 MMT) and all main sensitivities
- **Key Assumptions**
  - Assume development of two new 500kV transmission lines to deliver wind to California

OOS Wind Built in 2026: Portfolio Summary





OOS Wind Built in 2018: Portfolio Summary



OOS Wind Built in 2026: Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($MM/yr)		
	Base Case	+ 2026 OOS Wind	Change	Base Case	+ 2026 OOS Wind	Change	Base Case	+ 2026 OOS Wind	Change
Reference	**$0**	**$200**	**+$200**	**$219**	**$323**	**+$105**	**$1,164**	**$1,042**	**-$122**
High EE	$67	$283	**+$216**	$205	$343	**+$138**	$1,001	$926	**-$76**
Low EE	-$60	$123	**+$183**	$290	$340	**+$51**	$1,417	$1,242	**-$176**
High BTM PV	$456	$664	**+$208**	$645	$752	**+$107**	$1,576	$1,470	**-$107**
Low BTM PV	-$715	-$506	**+$209**	-$430	-$348	**+$82**	$556	$409	**-$147**
Flexible EVs	-$69	$146	**+$215**	$112	$245	**+$133**	$946	$848	**-$99**
High PV Cost	$193	$374	**+$182**	$436	$520	**+$83**	$1,404	$1,255	**-$149**
Low PV Cost	-$261	-$20	**+$241**	-$119	$35	**+$154**	$773	$707	**-$66**
High Battery Cost	$159	$359	**+$201**	$383	$487	**+$103**	$1,328	$1,209	**-$118**
Low Battery Cost	-$159	$43	**+$202**	$52	$160	**+$108**	$987	$866	**-$121**
No Tax Credits	$633	$748	**+$115**	$897	$937	**+$41**	$1,945	$1,753	**-$192**
Gas Retirements	$460	$581	**+$121**	$589	$625	**+$36**	$1,282	$1,148	**-$134**

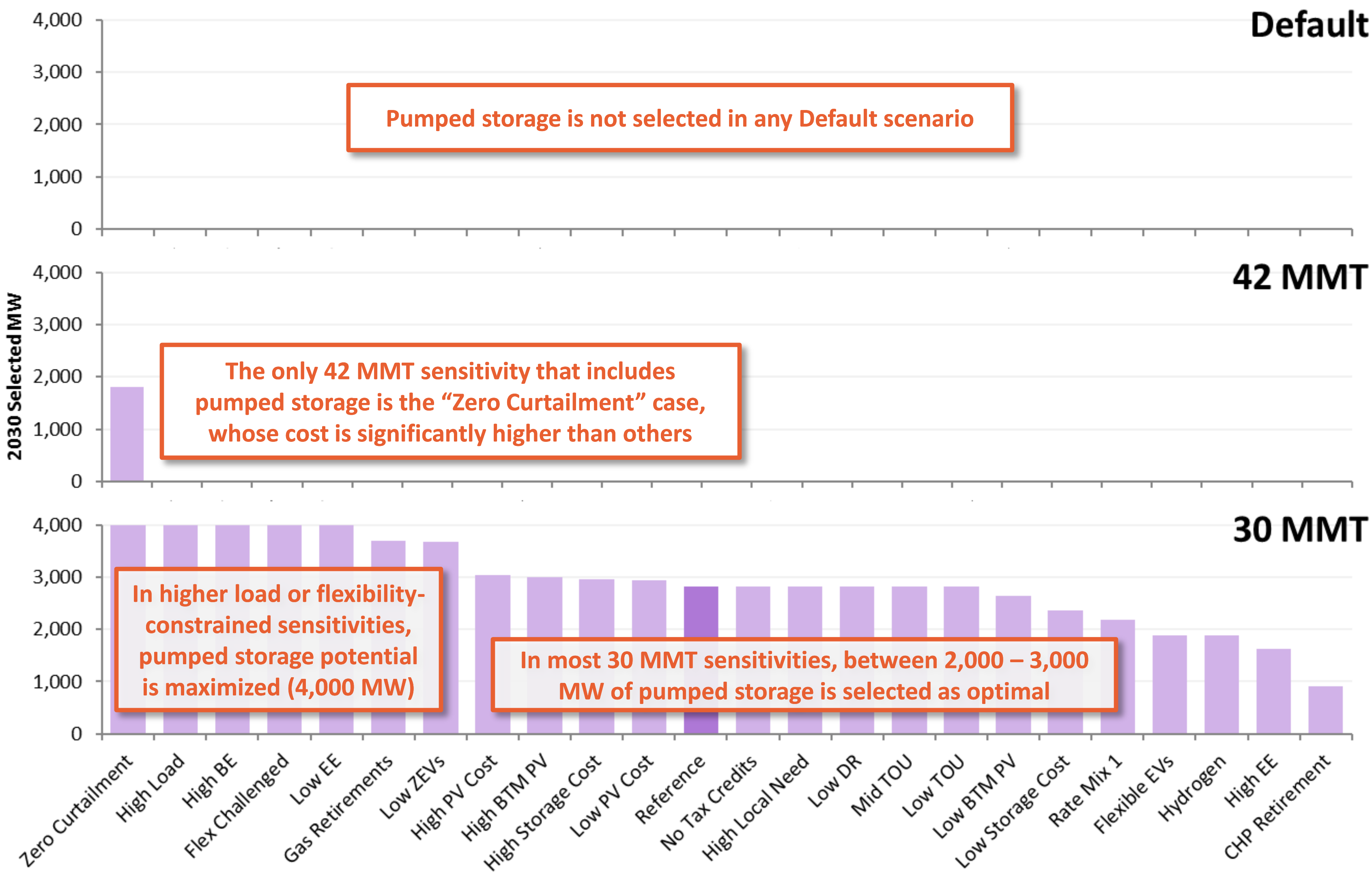
Near-Term OOS Wind: Conclusions

- The relative economic attractiveness of OOS wind resources increases under increasingly stringent RPS and/or GHG targets
  - In the 30 MMT Case a large, near-term OOS wind project will provide significant benefits to ratepayers across a broad range of sensitivities
- The ability to procure OOS wind resources prior to the expiration of the PTC significantly improves the economics under all RPS and GHG targets
  - 3,000 MW wind procured in 2018 (with the PTC) is approximately $100 MM/yr cheaper than the same resource procured in 2026 (without the PTC) *on a levelized basis*
  - The timing of procurement, and a project's ability to capture the PTC, could be a major factor in the competitiveness of OOS wind projects
- **Caveat**: Because this analysis assumes OOS wind requires major new multi-state transmission investment to deliver directly to California, it may understate the potential benefits to ratepayers
  - Additional follow-up analysis based on RETI 2.0 transmission analysis will explore potential lower cost transmission solutions

Pumped Storage Study: Overview

- **Study Questions**
  - Is there a minimum amount of pumped storage that is selected across a road range of sensitivities?
  - Does procuring pumped storage **in the near-term** reduce risk and/or cost across a broad range of sensitivities?
- **Study Design**
  - Examine the quantity of pumped storage that appears in the 2030 optimal portfolio across all main sensitivities under each core case (Default, 42 MMT, 30 MMT)
  - Examine the impact of manually adding **1,000 MW of pumped storage** into the portfolio **in 2022** to assess the cost impact of procuring pumped storage in the near term ("Near-Term Pumped Storage Portfolios")

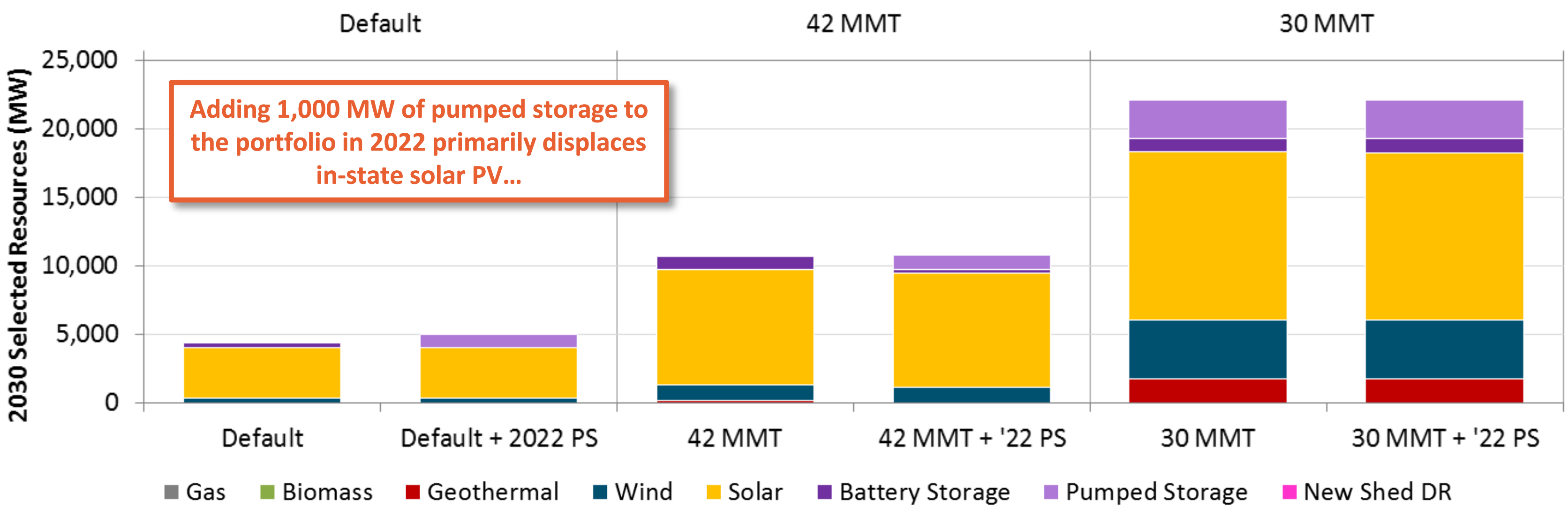
Pumped Storage in 2030: Optimal Portfolios

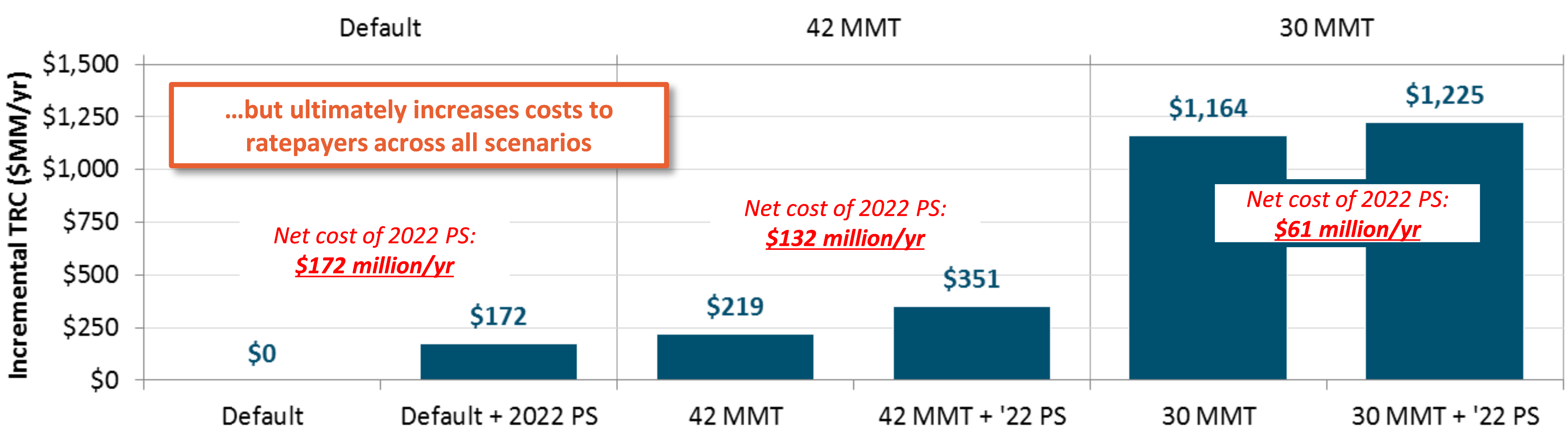


Pumped Storage in 2030: Explanation of Results

- Main driver of pumped storage in the portfolio is the benefit of capturing GHG-free energy produced in-state
- Under Default and 42 MMT Cases, renewable integration challenges are not significant enough to justify addition of long-duration storage
  - At lower penetrations, renewable curtailment offers a lower cost solution to manage oversupply
  - Exception: 1,000 MW of pumped storage added in "Zero Curtailment" sensitivity with 42 MMT carbon target
- Some amount of pumped storage is selected in all 30 MMT sensitivities, and most include at least 2,000 MW
- Factors that increase the amount of more pumped storage additions in 30 MMT Case:
  - Increased capacity needed to meet planning reserve margin (PRM) (e.g. under "Gas Retirements" sensitivity)
  - Higher loads, which must be met by incremental solar + long-duration storage (e.g. under "Low EE," "High Building Electrification," and "High Load" sensitivities)
  - Limitations on operational flexibility (e.g. under "Flexibility Challenged" sensitivity)

Pumped Storage Built in 2022: Portfolio Summary





Pumped Storage Built in 2022: Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($B)		
	Base Case	+ 2022 PS	Change	Base Case	+ 2022 PS	Change	Base Case	+ 2022 PS	Change
Reference	$0	$172	+$172	$219	$351	+$132	$1,164	$1,225	+$61
High EE	$67	$242	+$175	$205	$358	+$154	$1,001	$1,065	+$64
Low EE	-$60	$109	+$169	$290	$404	+$115	$1,417	$1,477	+$60
High BTM PV	$456	$625	+$169	$645	$774	+$130	$1,576	$1,638	+$62
Low BTM PV	-$715	-$533	+$182	-$430	-$296	+$133	$556	$616	+$60
Flexible EVs	-$69	$110	+$179	$112	$265	+$153	$946	$1,010	+$64
High PV Cost	$193	$365	+$172	$436	$567	+$131	$1,404	$1,463	+$59
Low PV Cost	-$261	-$88	+$174	-$119	$12	+$131	$773	$834	+$61
High Battery Cost	$159	$330	+$172	$383	$510	+$127	$1,328	$1,388	+$61
Low Battery Cost	-$159	$19	+$178	$52	$194	+$142	$987	$1,051	+$64
No Tax Credits	$633	$811	+$178	$897	$1,041	+$145	$1,945	$2,021	+$76
Gas Retirements	$460	$574	+$114	$589	$678	+$89	$1,282	$1,342	+$60

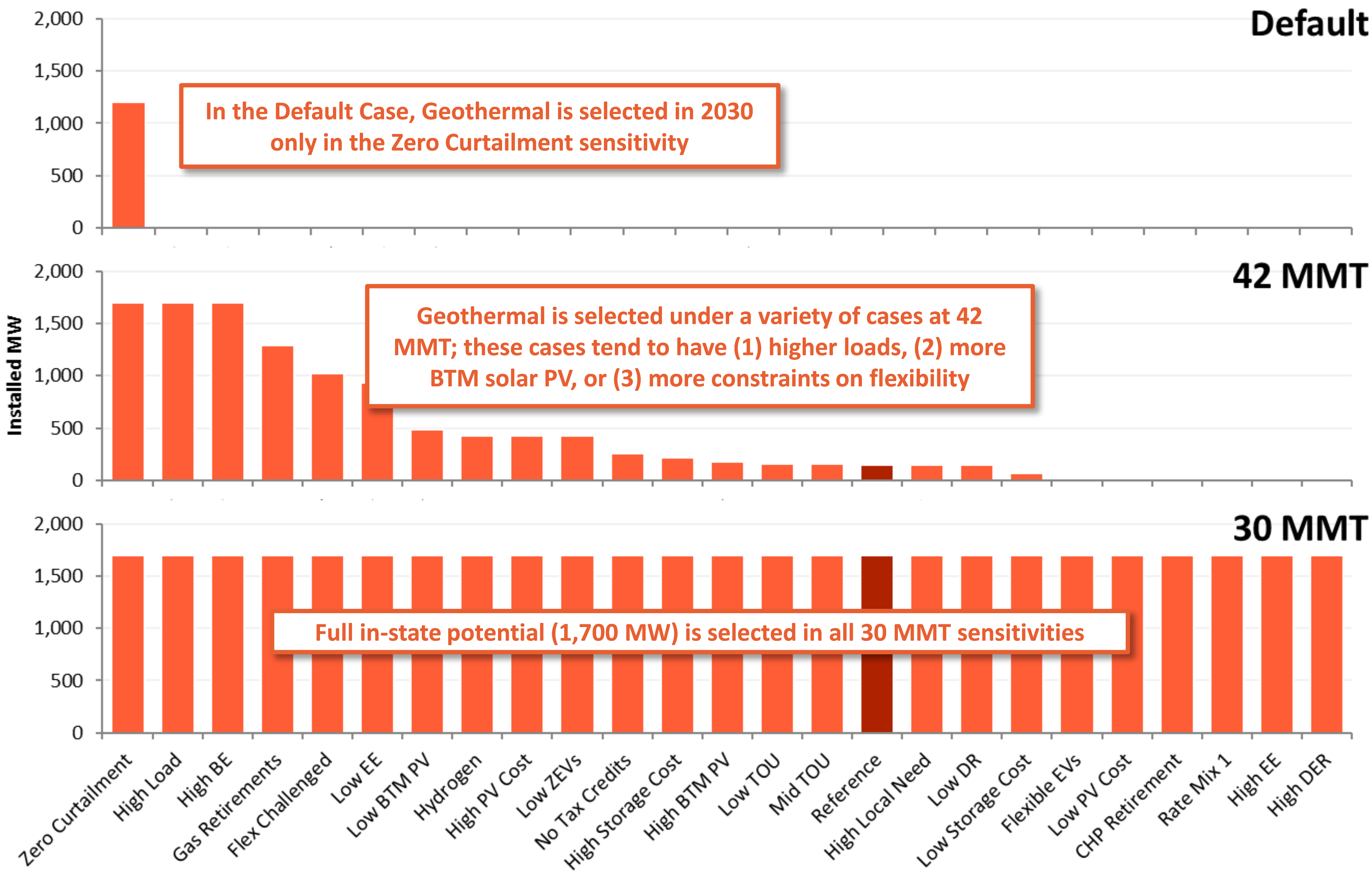
Pumped Storage: Conclusions

- **Relative benefit of pumped storage in 2030 is directly tied to selection of GHG target**
  - Pumped storage not selected in optimal portfolio or most sensitivities under the Default and 42 MMT Cases
  - Adding pumped storage may become cost-effective between the 42 MMT and 30 MMT Cases
  - All sensitivities in the 30 MMT Case include some pumped storage
- **Addition of pumped storage in the near-term results in some cost increases across all scenarios**
  - Under Default Case, pumped storage results in cost increases across all sensitivities
  - In 30 MMT Case, adding pumped storage in 2022 has a limited impact on long term system costs
    - Since pumped storage is part of the optimal 2030 portfolio, the cost premium in these cases reflects the cost of early action

Geothermal Energy Study: Overview

- **Study Questions**
  - Is there a minimum amount of geothermal resources that are selected across a broad range of sensitivities?
  - Does procuring geothermal resources **in the near-term** reduce risk and/or cost across a broad range of sensitivities?
- **Study Design**
  - Examine the quantity of geothermal resources that appear in the 2030 optimal portfolio across a broad range of sensitivities
  - Examine the impact of manually adding **1,000 MW of geothermal** into the portfolio **in 2022** to assess the cost impact of procuring geothermal resources in the near term

Geothermal in 2030: Optimal Portfolios



Geothermal in 2030: Explanation of Results

Default Case

- Geothermal is only selected in the "Zero Curtailment" sensitivity, as few renewable resources must be added to comply with RPS target

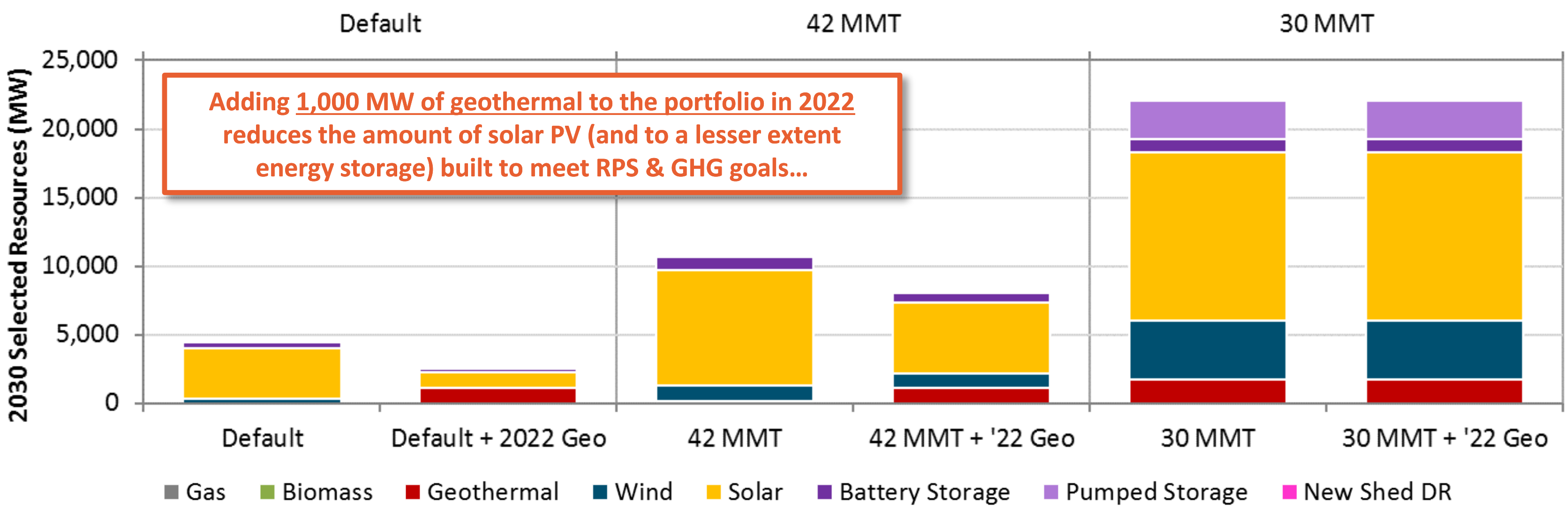
42 MMT Case

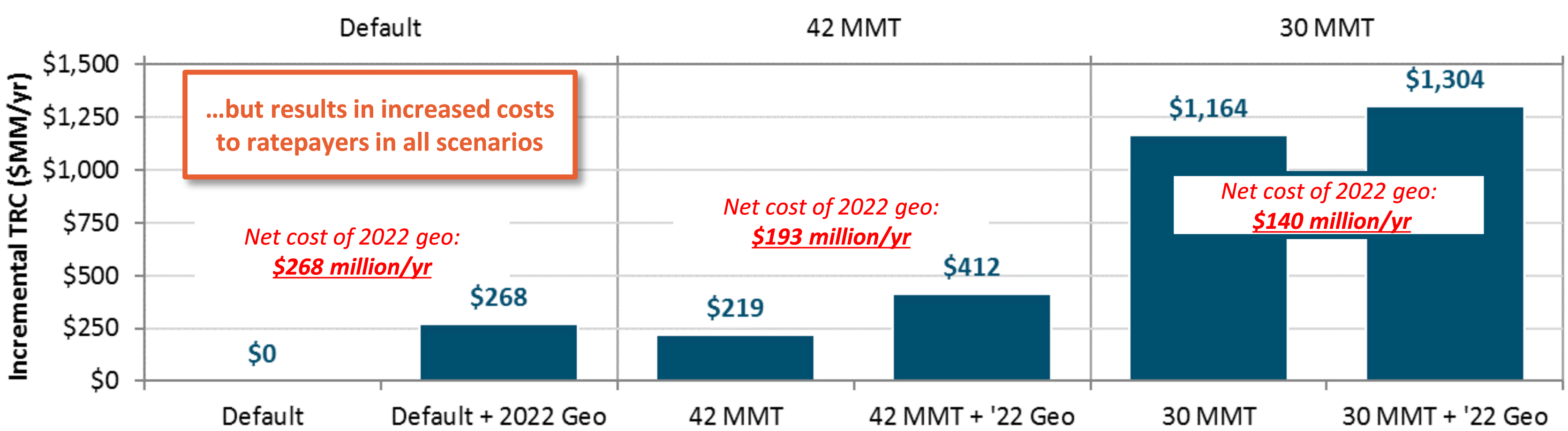
- Geothermal resources are selected under a select set of sensitivities:
  - When capacity is needed to meet planning reserve margin (e.g. under "Gas Retirements" sensitivity)
  - When higher loads exist and incremental need for renewables creates more value for diversity (e.g. under "Low EE," "High Building Electrification," and "High Load" sensitivities)
  - When there are limitations on operational flexibility (e.g. under "Flexibility Challenged" sensitivity)

30 MMT Case

- Maximum in-state geothermal potential is selected across all sensitivities

Geothermal Built in 2022: Portfolio Summary





Geothermal Built in 2022:
Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($MM/yr)		
	Base Case	+ 2022 Geo	Change	Base Case	+ 2022 Geo	Change	Base Case	+ 2022 Geo	Change
Reference	$0	$268	**+$268**	$219	$412	**+$193**	$1,164	$1,304	**+$140**
High EE	$67	$345	**+$279**	$205	$429	**+$224**	$1,001	$1,149	**+$147**
Low EE	-$60	$195	**+$255**	$290	$443	**+$153**	$1,417	$1,548	**+$131**
High BTM PV	$456	$724	**+$268**	$645	$836	**+$192**	$1,576	$1,720	**+$144**
Low BTM PV	-$715	-$442	**+$274**	-$430	-$251	**+$179**	$556	$689	**+$133**
Flexible EVs	-$69	$211	**+$280**	$112	$331	**+$219**	$946	$1,087	**+$141**
High PV Cost	$193	$446	**+$254**	$436	$614	**+$178**	$1,404	$1,552	**+$148**
Low PV Cost	-$261	$42	**+$303**	-$119	$114	**+$233**	$773	$913	**+$140**
High Battery Cost	$159	$427	**+$269**	$383	$575	**+$192**	$1,328	$1,467	**+$139**
Low Battery Cost	-$159	$110	**+$269**	$52	$249	**+$197**	$987	$1,127	**+$140**
No Tax Credits	$633	$830	**+$197**	$897	$1,031	**+$134**	$1,945	$2,025	**+$80**
Gas Retirements	$460	$665	**+$204**	$589	$730	**+$141**	$1,282	$1,422	**+$139**

Geothermal Energy: Conclusions

- **Relative benefits of geothermal in 2030 is directly tied to selection of GHG target**
  - Default Case: Geothermal not included in any optimal portfolios
  - 42 MMT Case: In some sensitivities, geothermal is cost-effective
  - 30 MMT Case: Maximum in-state geothermal potential is selected in all sensitivities by 2030
- **Near-term procurement of geothermal increases cost across all scenarios**
  - In Default and 42 MMT Cases, geothermal displaces less costly resources from portfolios
  - In 30 MMT Case, cost increase is mainly driven by having to procure a costly resource before it is needed

IX. DETAILED RESULTS

Organization

1. DISTRIBUTED ENERGY RESOURCE RESULTS

DER Study: Overview

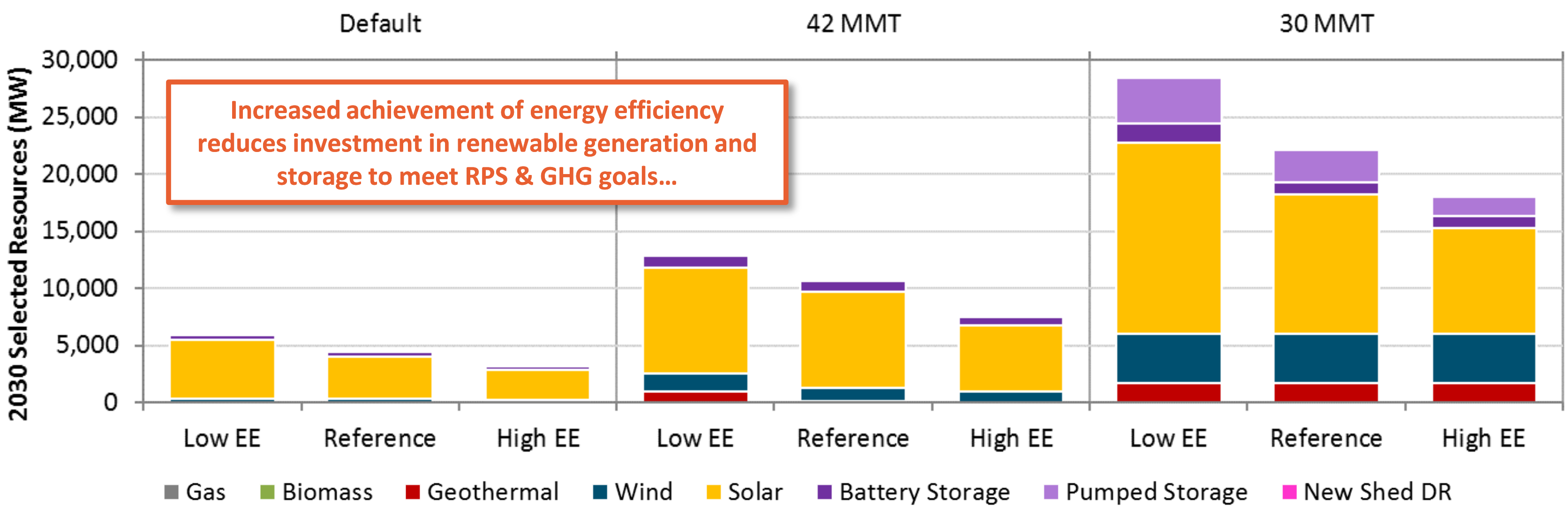
- Some results related to demand energy resources (DERs) were provided earlier as sensitivities
- The following slides present more detailed results regarding key demand-side resource areas that are the subject of previous, current, and/or future Commission proceedings (EE, BTM PV, DR, Battery Storage, and ZEVs)
- With exception of DR, DER resources were not optimized within the RESOLVE model due to technical, data, and resource limitations
  - Future iterations of IRP are anticipated to optimize more and more DERs directly
- Instead of optimizing DERs directly, different levels of DER adoption were tested against the core cases (Default, 42 MMT, 30 MMT)

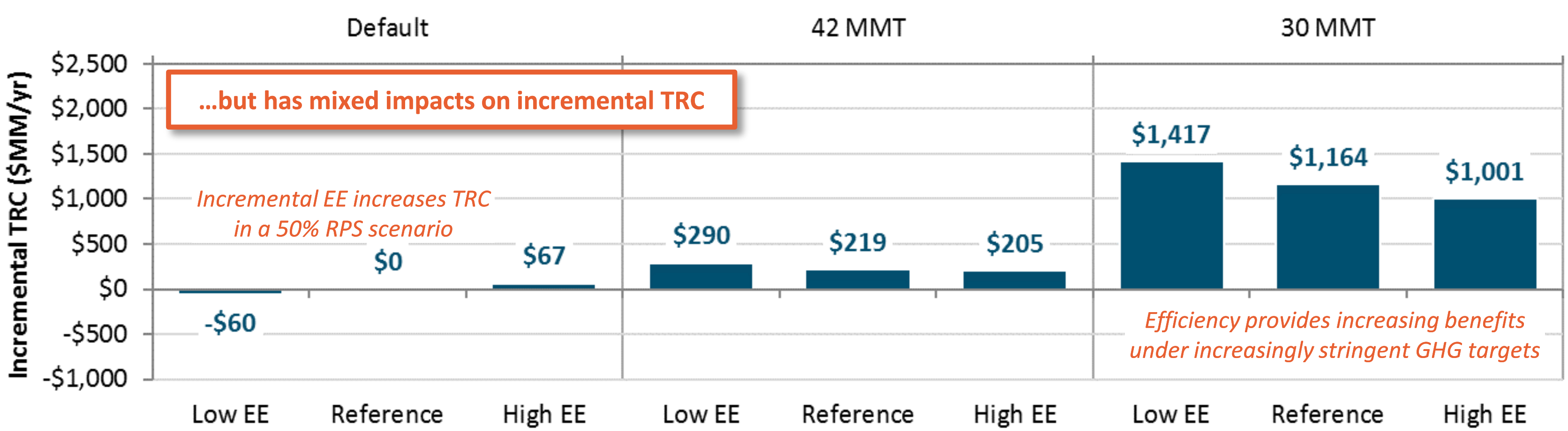
2. ENERGY EFFICIENCY RESULTS

Energy Efficiency Study: Overview

- **Study Question**
  - What is the impact of the EE adoption level on portfolio composition and cost?
- **Study Design**
  - Examine the impacts of three different amounts of EE under the three core cases (Default, 42 MMT, 30 MMT)
- **Key Assumptions**
  - Low EE Sensitivity assumes EE savings in 2030 equivalent to the 2016 IEPR Mid AAEE forecast
  - High EE Sensitivity assumes EE savings in 2030 equivalent to a doubling of the 2015 IEPR Mid AAEE, consistent with SB350 goals
  - The doubling of the 2015 IEPR Mid AAEE case assumes incremental efficiency savings can be achieved at unit costs comparable to current utility programs

Energy Efficiency Sensitivities: Summary Results





Energy Efficiency: Explanation of Results

The value of energy efficiency depends on the avoided costs of the resources it displaces. EE costs considered in RESOLVE include customer costs.

Default Case

- Each MWh of incremental efficiency displaces 0.5 MWh of renewables (by reducing retail sales) and 0.5 MWh of low-cost gas/imports
  - Because (1) the price of gas is relatively low, and (2) renewable integration challenges have not become significant in the Default scenario, the avoided cost is relatively low
  - Relatively low value is not enough to entirely offset assumed cost of EE, so total cost increases with higher levels of EE

42 MMT Case

- Each MWh of incremental efficiency displaces 1 MWh of renewables, as efficiency and renewables are directly substitutable in a GHG-constrained world
  - In this case, the avoided cost increases, both because (1) renewables are more expensive than low-cost natural gas generation, and (2) renewable integration challenges become more significant as penetration increases
  - Increase in avoided cost results in benefits that slightly outweigh costs

30 MMT Case

- The dynamic is similar to the 42 MMT Case, but to increased effect: due to increasing integration renewable challenges at higher penetrations, the net benefit of incremental efficiency increases
  - Significant increase in avoided costs of renewables lead to EE benefits that significantly outweigh costs

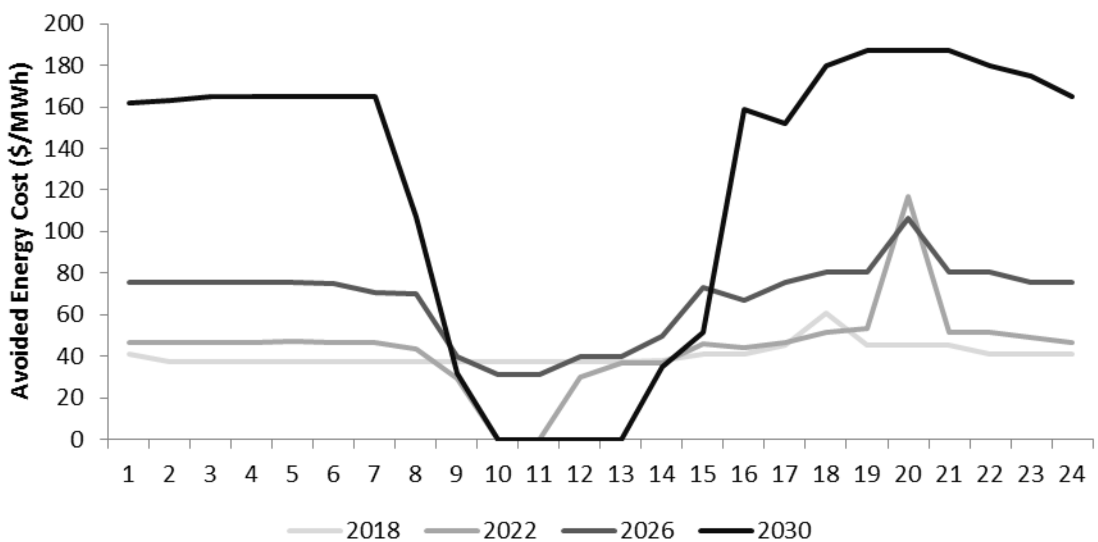
Energy Efficiency: Explanation of Results

Future value of incremental energy efficiency depends on the magnitude of the GHG Planning Target

- Without a GHG constraint (e.g. the Default Case), additional EE may increase total portfolio costs
- Under stringent GHG targets (e.g. the 30 MMT Case), additional EE reduces total costs
- Analysis may understate EE costs and overstate benefits
  - It assumes incremental efficiency savings can be achieved at unit costs comparable to current utility programs

Avoided Energy Cost

- Shape and magnitude of avoided costs change dramatically in a carbon-constrained world:
  - Surplus solar generation in the middle of the day drives prices to zero
  - High shadow price associated with GHG constraint (particularly in 30 MMT Case) drives very high energy avoided costs in other periods of the day
  - The avoided energy cost below reflects a GHG policy rather than an RPS policy



SOURCE: RESOLVE output

3. BEHIND-THE-METER SOLAR PV RESULTS

BTM PV Study: Overview

Study Question:

- What is the impact of the BTM PV adoption level on portfolio composition and cost?

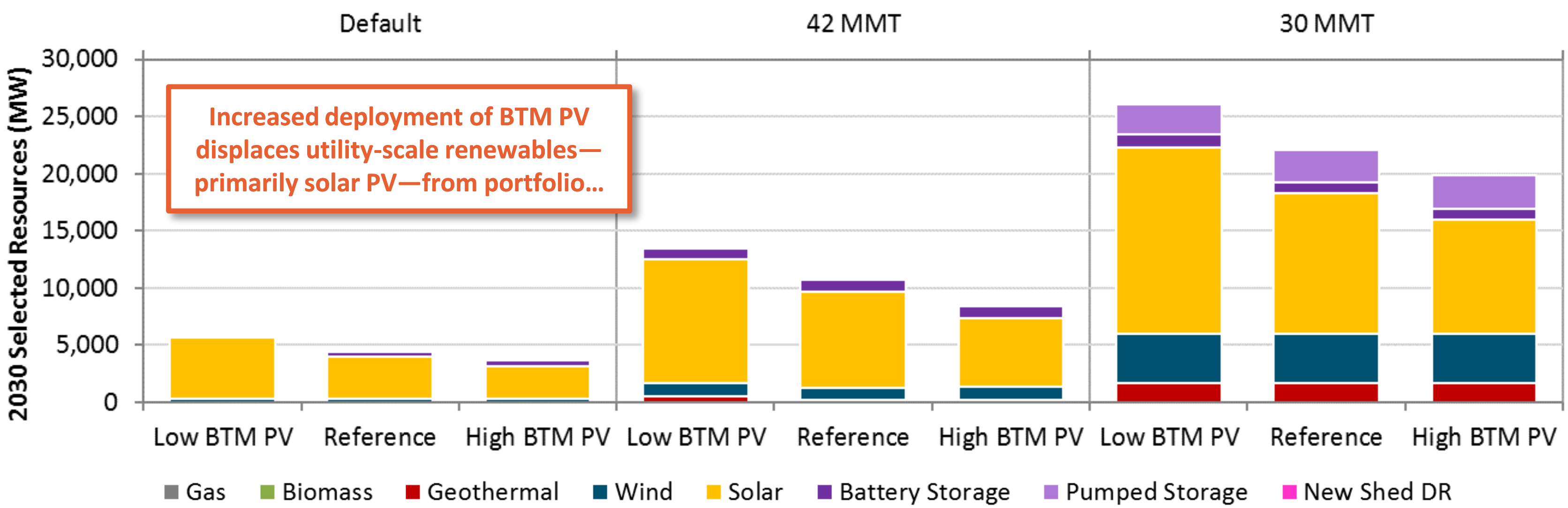
Study Design:

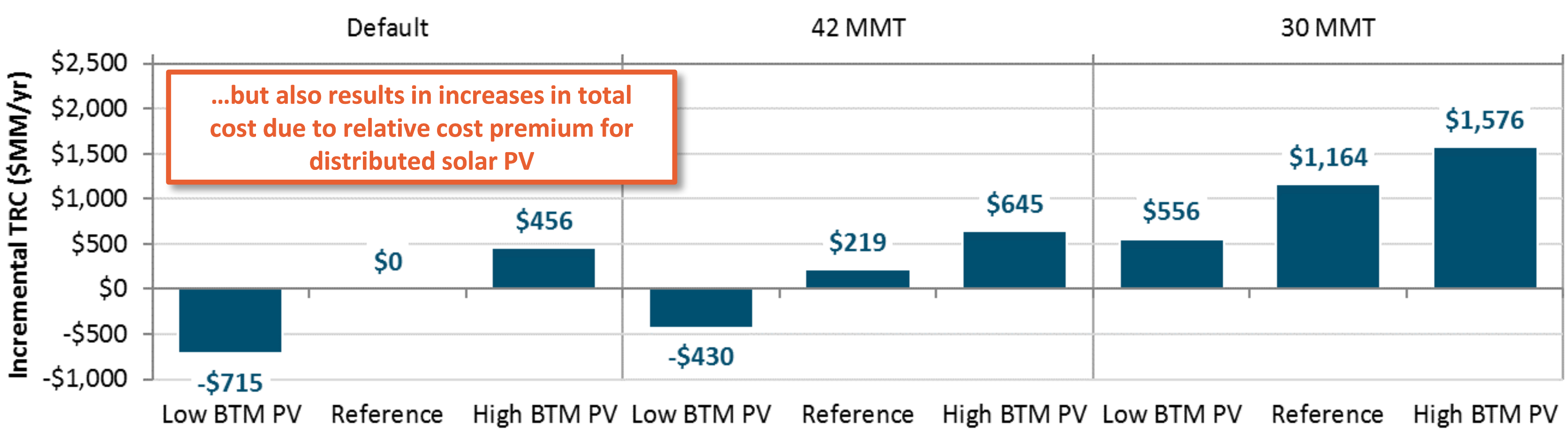
- Examine the impacts of three different amounts of BTM under the three core cases (Default, 42 MMT, 30 MMT)

Key Assumptions

- **Low BTM PV Sensitivity**: 9 GW of customer PV adopted by 2030 (CEC 2016 IEPR High Demand Forecast)
- **Reference BTM PV level:** 16 GW of customer PV adopted y 2030 (CEC 2016 IEPR Mid Demand Forecast, which assumes continuation of current NEM policy and compensation structure)
- **High BTM PV Sensitivity**: 21 GW of customer PV adopted by 2030 (CEC 2016 IEPR Low Demand Forecast)

BTM PV Sensitivities: Summary Results





BTM PV: Explanation of Results

- BTM PV displaces utility-scale renewable generation
  - The marginal RPS resource displaced is primarily utility-scale solar PV
- In 42 MMT and 30 MMT Cases, increasing amounts of BTM PV also increases amount of energy storage
- Increasing quantities of BTM PV increase total cost across all scenarios
- While rooftop solar and utility-scale solar have a similar operational impact on GHG emissions, the cost of rooftop solar is significantly higher than utility-scale solar (or other utility-scale renewables) due to:
  - Economies of scale
  - Coastal areas where BTM PV is most frequently installed generally provides lower quality solar resource than further inland
- Location-specific distribution and certain transmission deferral benefits not considered (to be taken from DRP in future)
- Potential cost-shifting from NEM participants to non-participants is also not considered here

4. DEMAND RESPONSE RESULTS

Demand Response Studies: Overview

Study Question:

- Under what conditions do existing economic DR programs, new shed DR resources, and new shift DR shift (flexible loads), provide value?

Study Design:

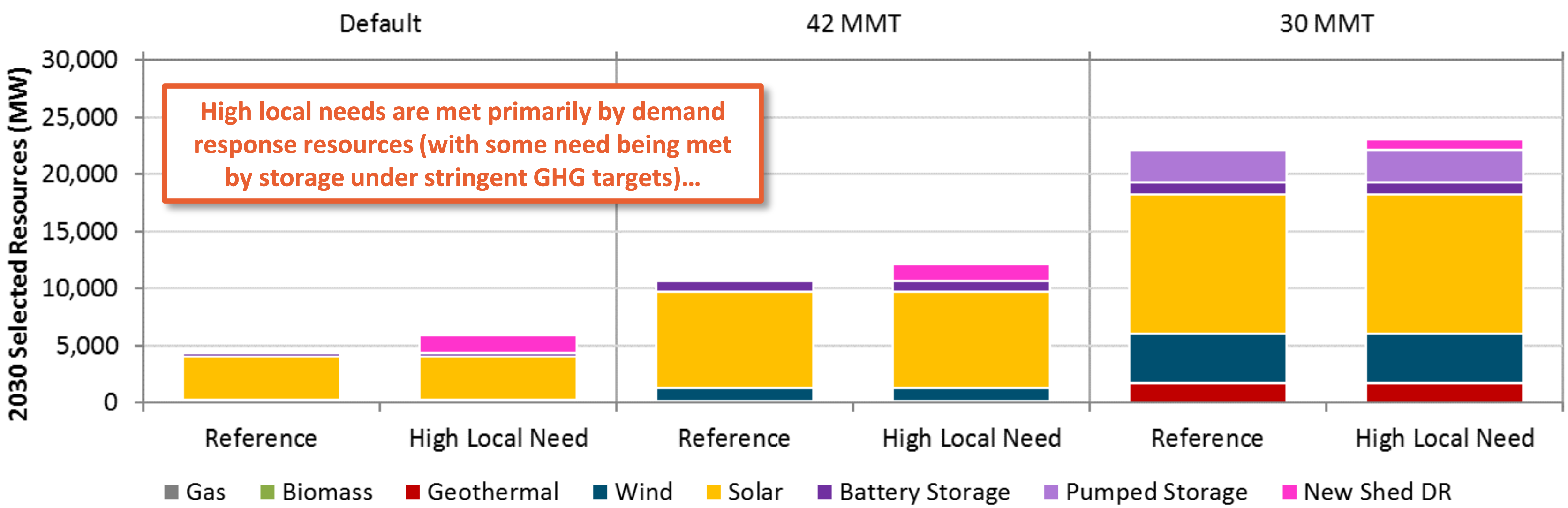
- For new shed DR and new shift DR, make the resources available for optimization by the model, and test against the core cases (Default, 42 MMT, 30 MMT) and multiple sensitivities
- For existing economic DR programs, remove the cost and load impact of non-reliability DR programs and test against the core cases (Default, 42 MMT, 30 MMT)

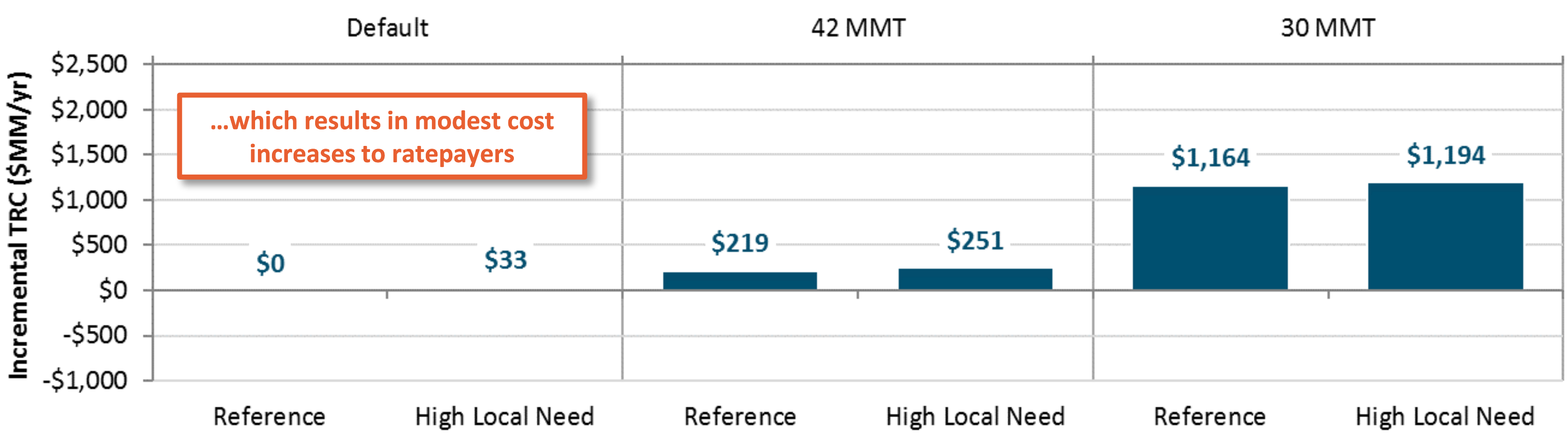
Demand Response Studies: Overview

Key Assumptions

- **High Local Needs Sensitivity:** assumes 1,500 MW of local need
- **Gas Retirements Sensitivity:** assumes economic retirement of 12,000 MW of natural gas resources by 2030, triggering new capacity needs for resource adequacy
- **Low DR Sensitivity:** eliminates both cost and MW associated with existing economically dispatched DR programs (non-reliability programs) from utility portfolios beyond 2022
- **Shift DR Sensitivity:** allows selection of "shift" resources identified in LBNL's Advanced Demand Response study as part of portfolio

High Local Needs Sensitivity: Summary Results

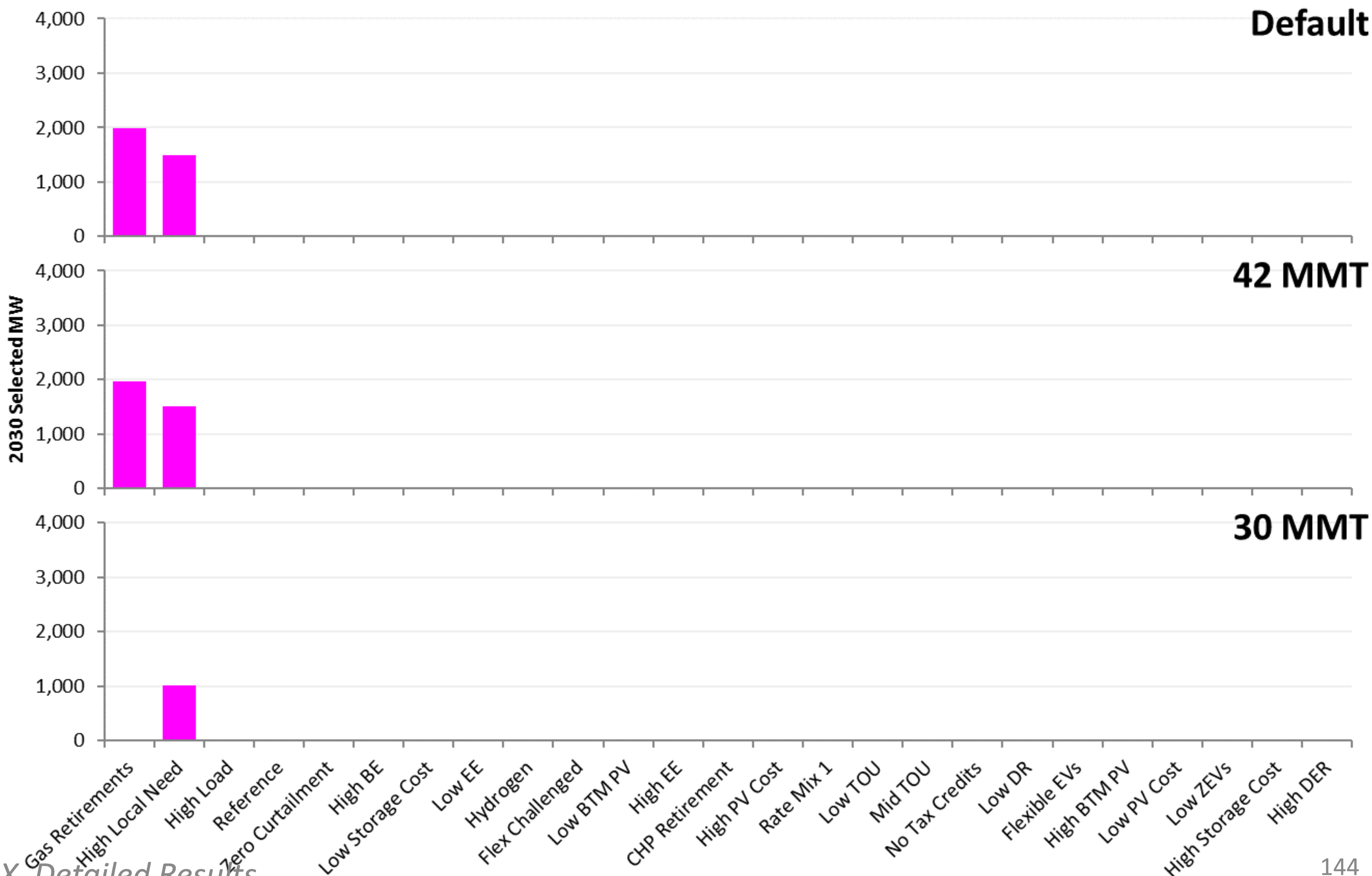




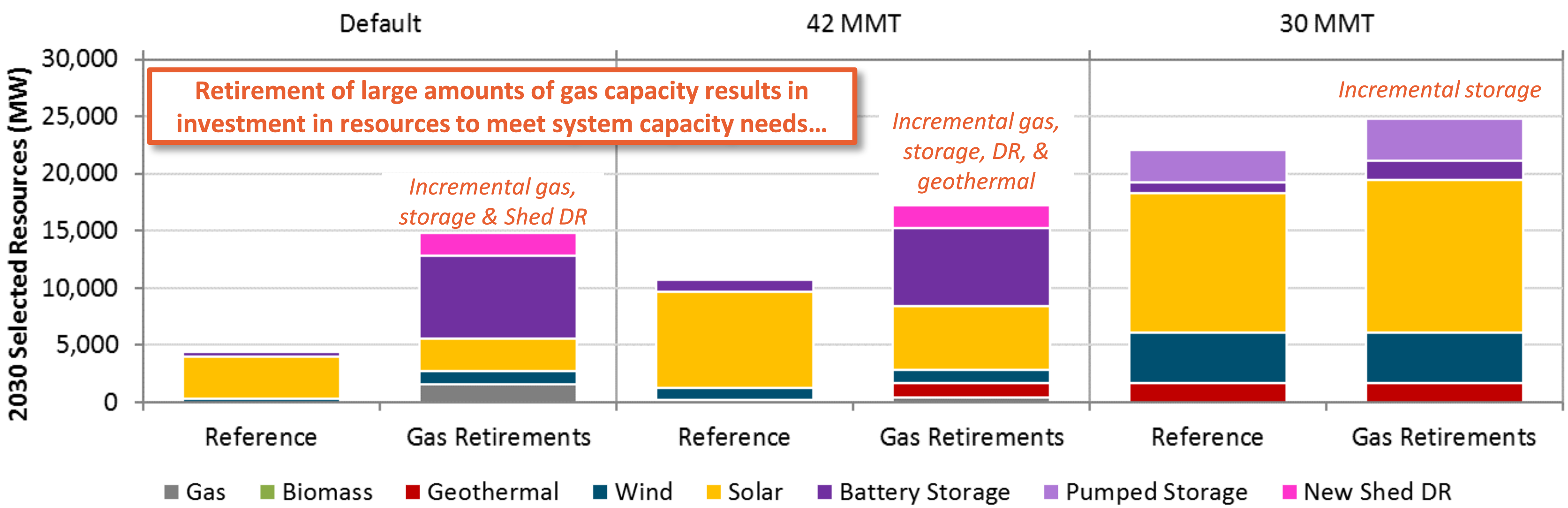
High Local Needs Sensitivity: Explanation of Results

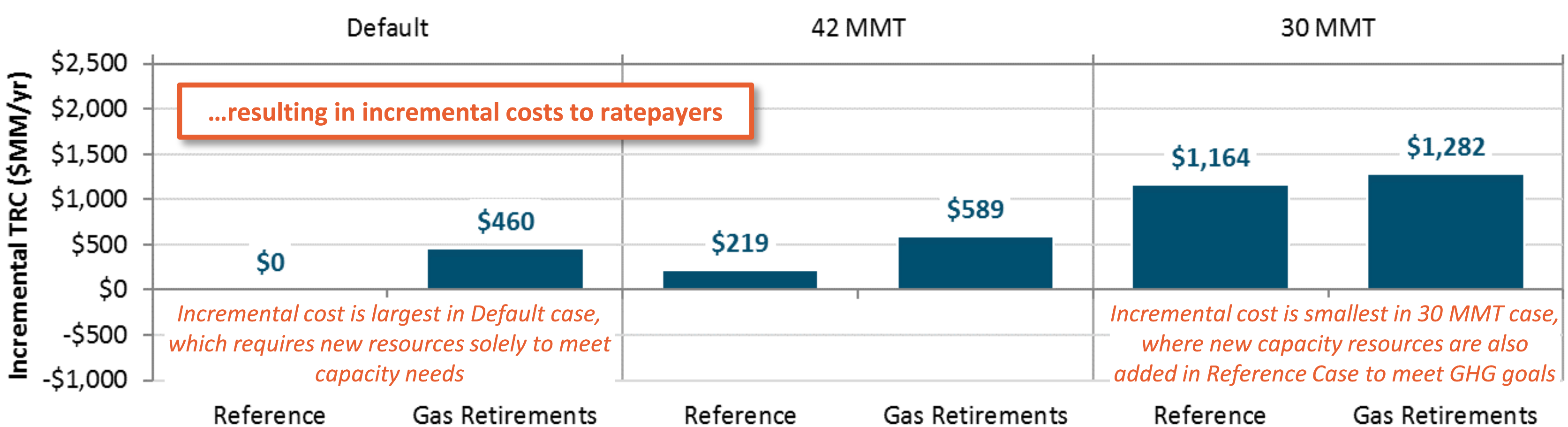
- Addition of generic local need (1,500 MW) introduces need for new capacity resources that can be sited in local areas
- Under Default & 42 MMT cases, RESOLVE selected New Shed DR to meet local needs
  - Incremental cost of DR selected to meet local needs: $33 MM/yr
- Under 30 MMT case, RESOLVE selected a combination of New Shed DR and local pumped storage to meet needs
  - Up to 500 MW of pumped storage is assumed to be located in areas that could contribute to meeting local needs
  - Remainder of local need is satisfied by New Shed DR

New Shed DR Selected Across all Sensitivities

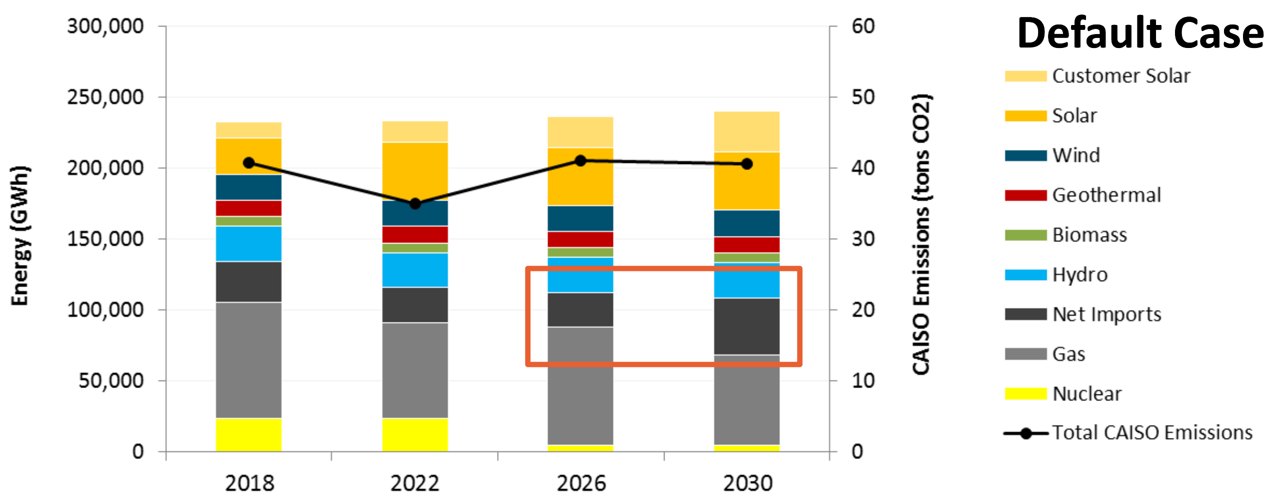


Gas Retirements Sensitivity: Summary Results

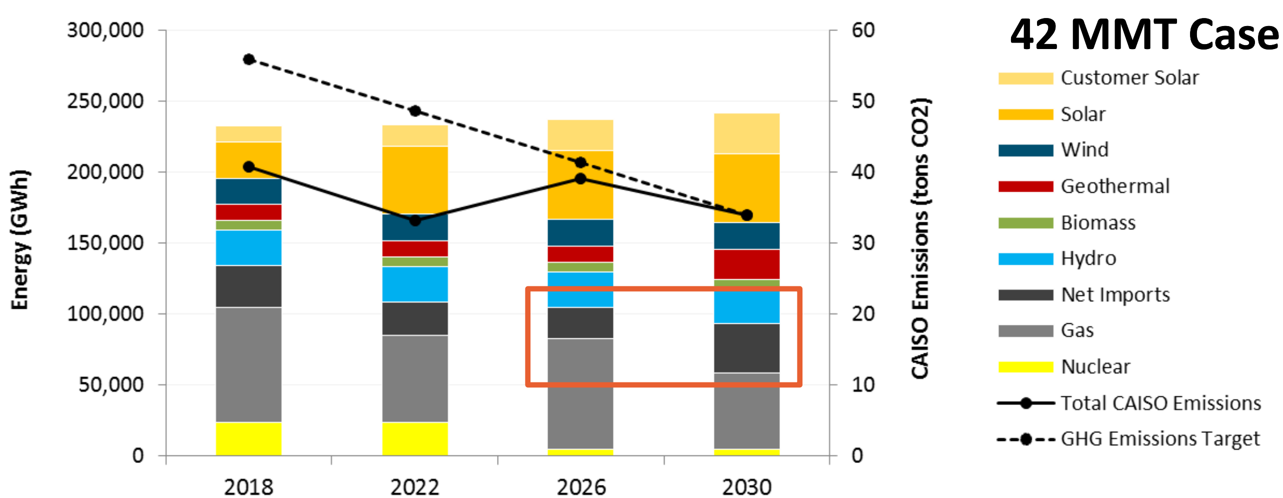




Gas Retirements Sensitivity: Energy Balance Results



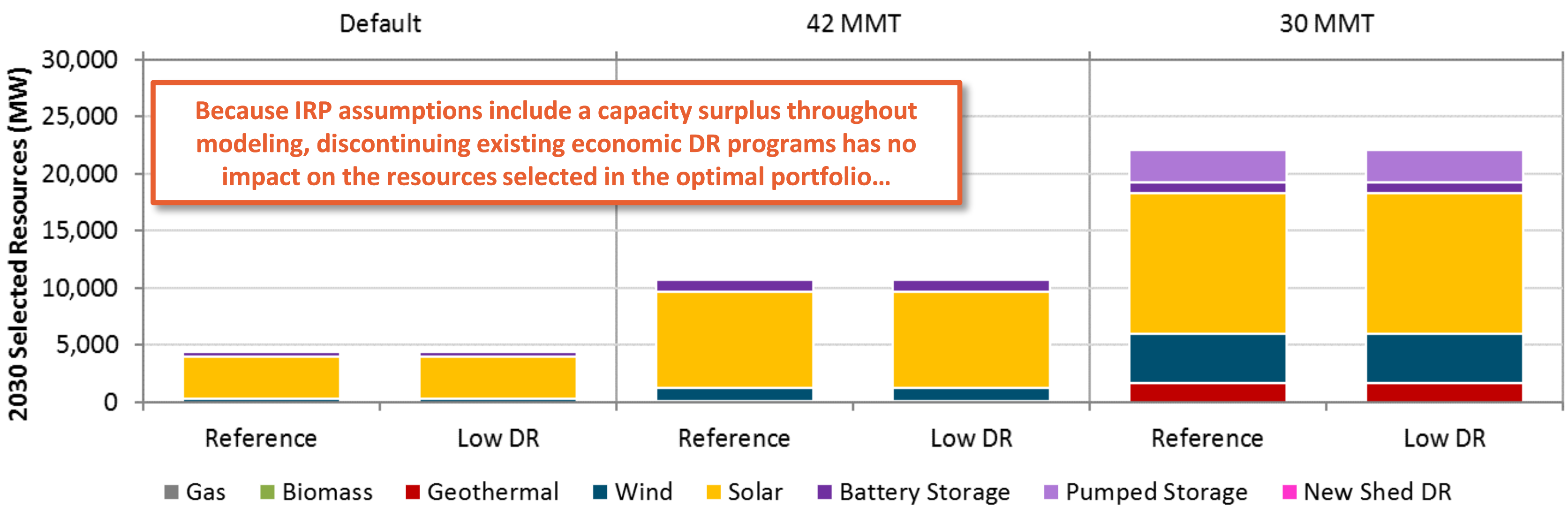
Retirement of large amounts of gas capacity results in increased imports under Default and 42 MMT Cases

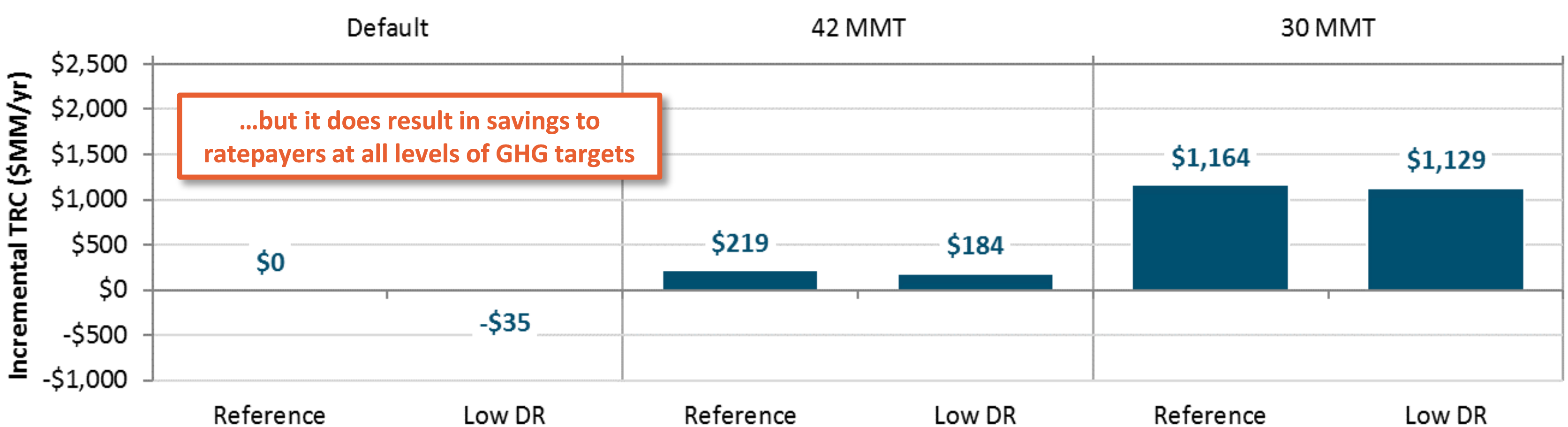


Gas Retirements: Explanation of Results

- Large-scale retirement of existing gas generators requires addition of capacity resources to meet PRM, increasing total costs across all scenarios
- Type of capacity resources added to meet PRM need depends on the GHG Planning Target
  - New Shed DR selected in Default and 42 MMT cases as part of least-cost, optimal solution (along with new gas and battery storage)
  - In 30 MMT Cases, additional renewables and storage needed to meet GHG constraint also provide capacity
    - New Shed DR not selected
    - New gas not selected
    - Battery storage quantities greatly reduced

Low DR Sensitivity: Summary Results

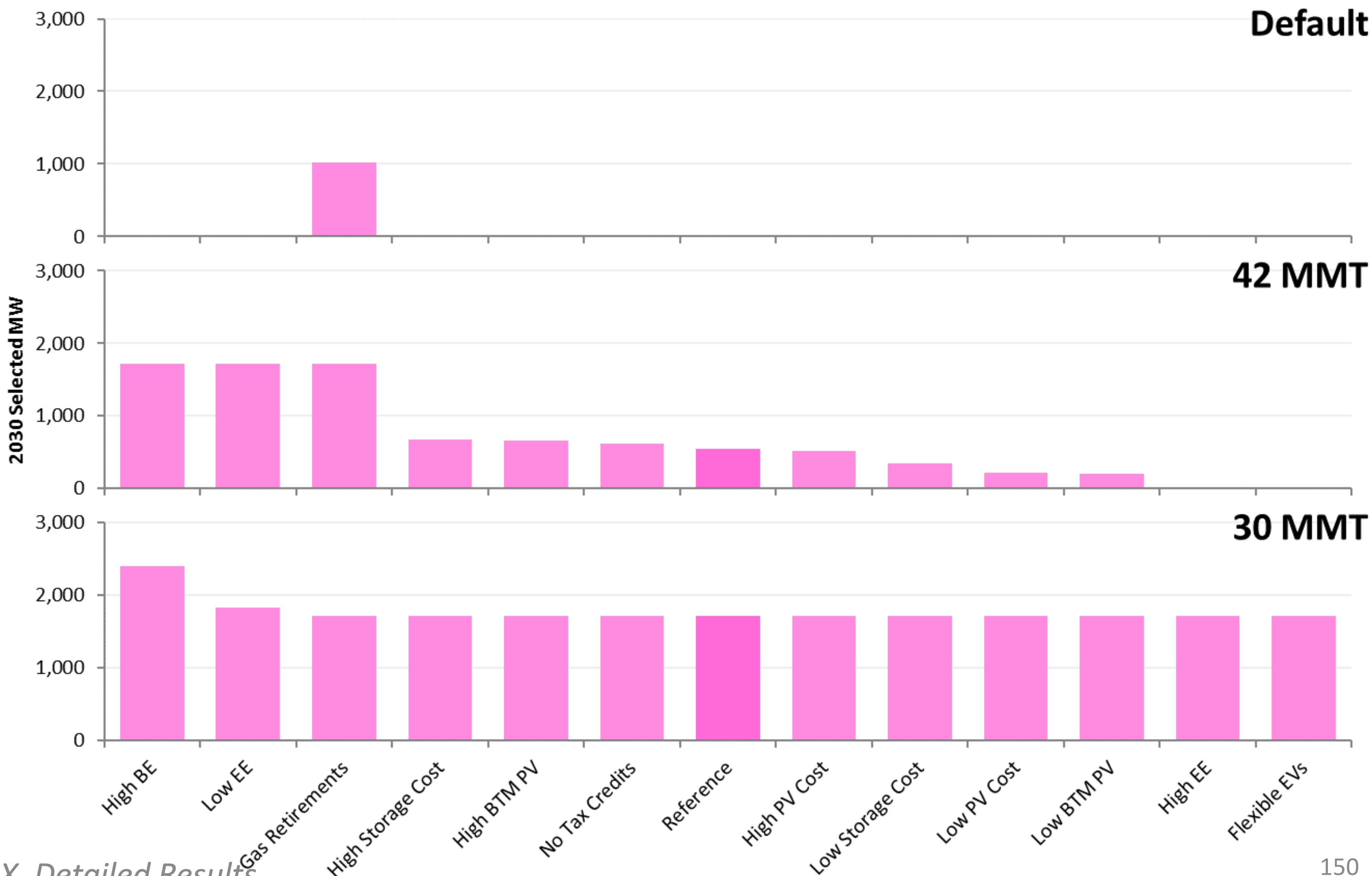




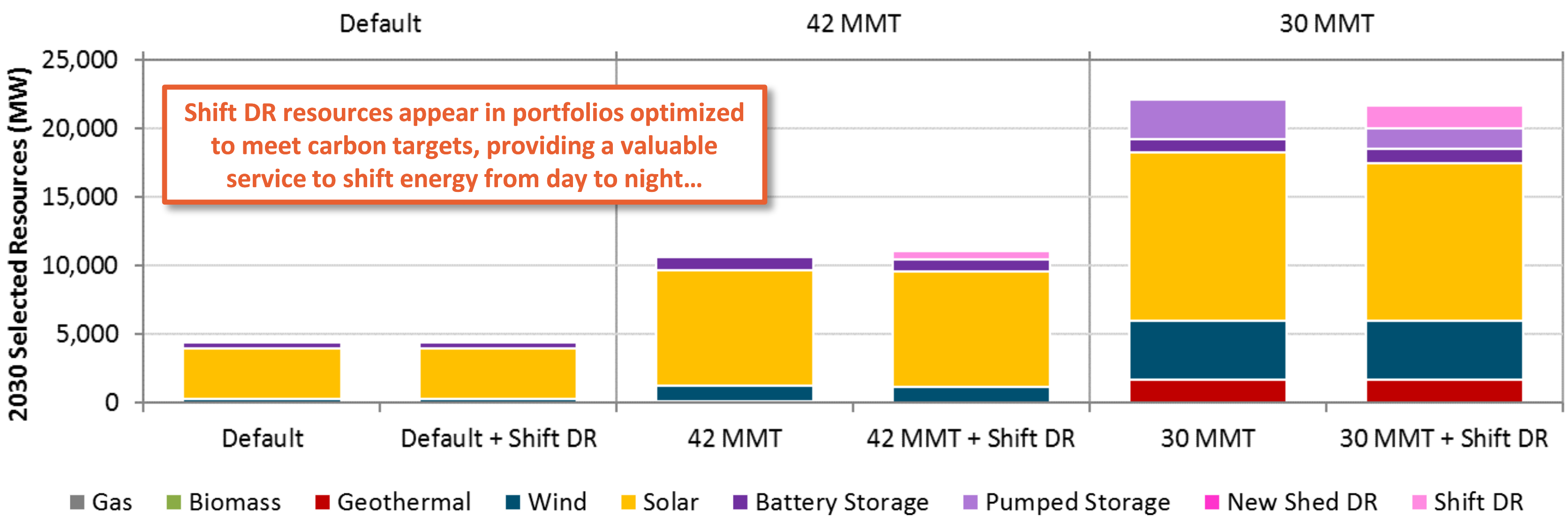
Low DR Sensitivity: Explanation of Results

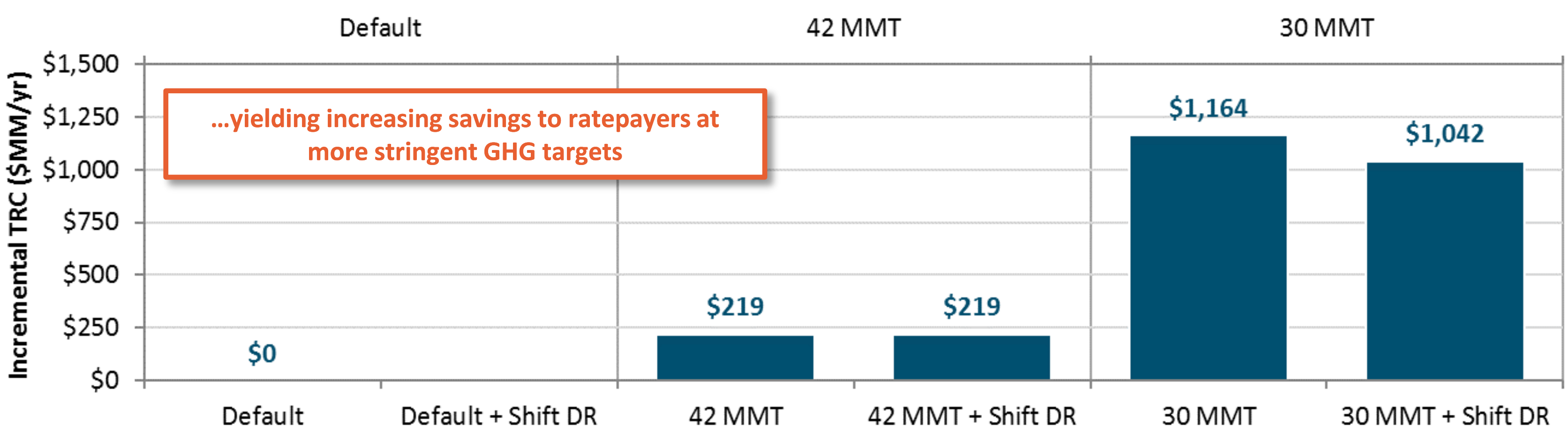
- Low DR sensitivity assumes discontinuation of existing economic DR programs
- Because all cases have a capacity surplus above the PRM requirement, eliminating existing economic DR programs does not trigger any new investment
- As a result, elimination of existing economic DR programs reduces ratepayer costs under all cases by the assumed cost of those programs

Shift DR Selected Across Sensitivities



Shift DR Sensitivity: Summary Results





Shift DR Portfolio:
Sensitivity Analysis on Incremental Cost

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($MM/yr)		
	Base Case	+ Shift DR	Change	Base Case	+ Shift DR	Change	Base Case	+ Shift DR	Change
Reference	$0	$0	—	$219	$219	—	$1,164	$1,042	-$122
High EE	$67	$67	—	$205	$205	—	$1,001	$896	-$106
Low EE	-$60	-$60	—	$290	$280	-$10	$1,417	$1,277	-$140
High BTM PV	$456	$456	—	$645	$640	-$5	$1,576	$1,450	-$126
Low BTM PV	-$715	-$715	—	-$430	-$429	—	$556	$437	-$119
Flexible EVs	-$69	-$69	—	$112	$112	—	$946	$844	-$102
High PV Cost	$193	$193	—	$436	$436	—	$1,404	$1,275	-$129
Low PV Cost	-$261	-$261	—	-$119	-$120	—	$773	$658	-$115
High Battery Cost	$159	$159	—	$383	$383	—	$1,328	$1,208	-$120
Low Battery Cost	-$159	-$159	—	$52	$51	-$1	$987	$869	-$118
No Tax Credits	$633	$633	—	$897	$896	-$1	$1,945	$1,823	-$122
Gas Retirements	$460	$458	-$2	$589	$561	-$27	$1,282	$1,173	-$109

Shift DR is selected in all cases that show savings

Shift DR Sensitivity: Explanation of Results

- At less stringent GHG targets, renewable balancing challenges are not significant enough to justify payments to flexible loads
  - Limited renewable integration challenges
- At more stringent targets, balancing challenges become significant enough to incent addition of flexible loads to the system
  - More frequent renewable curtailment creates more value to incent shifting of loads

Demand Response: Summary of Results

- Future value of traditional new shed DR programs depends on the future of the gas fleet
  - If existing capacity surplus remains, new shed DR programs will have little future value
  - If changing market economics triggers economic retirement of large quantities of existing gas generation, new shed DR resources may offer a low-cost source of resource adequacy capacity
- At higher levels of GHG constraints, advanced “shift” demand response offers a cost-effective option to increase flexibility of the electric system
- “Shimmy” DR resources could meet some portion (up to 300 MW) of the need for short-duration storage services provided by battery storage, at lower cost
- Additional research is needed to understand the mechanisms needed to enable advanced “shift” DR programs:
  - What sorts of wholesale or retail compensation schemes are needed to induce customer participation?
  - How can actual performance of “shift” DR be measured?

5. TIME-OF-USE RATES RESULTS

TOU Study: Overview

Study Question:

- What is the impact of different TOU rates on the cost of achieving policy goals?

Study Design

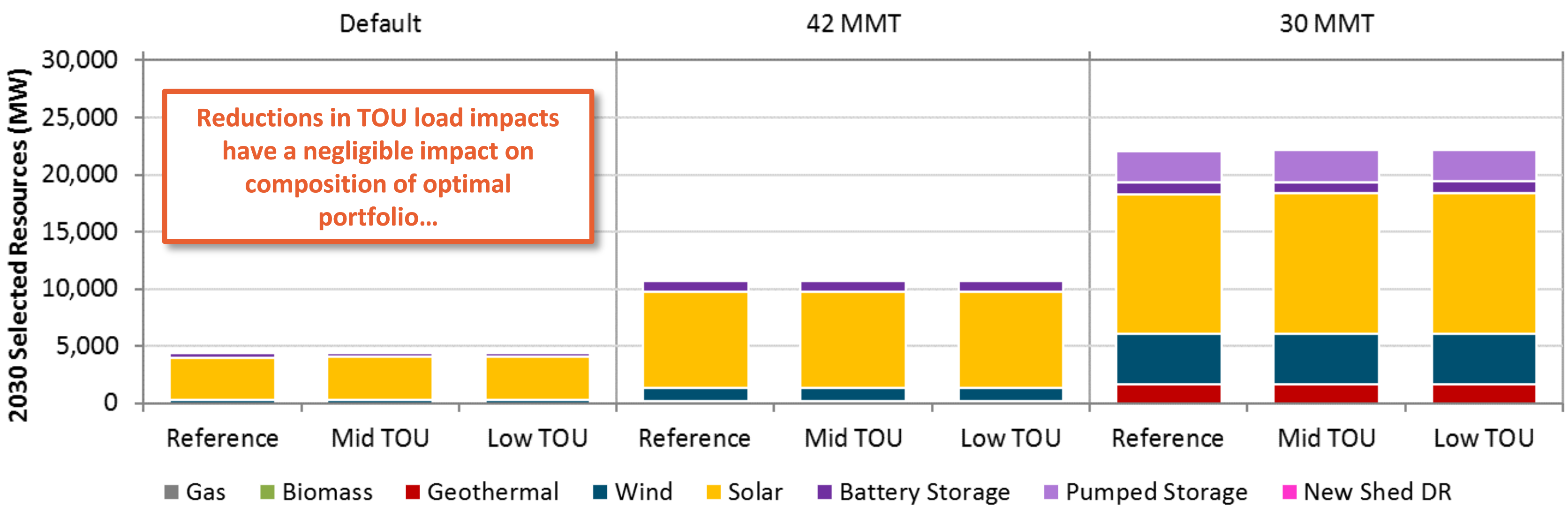
- Examine the impact of three different TOU impact levels on costs under the three core cases (Default, 42 MMT, 30 MMT).

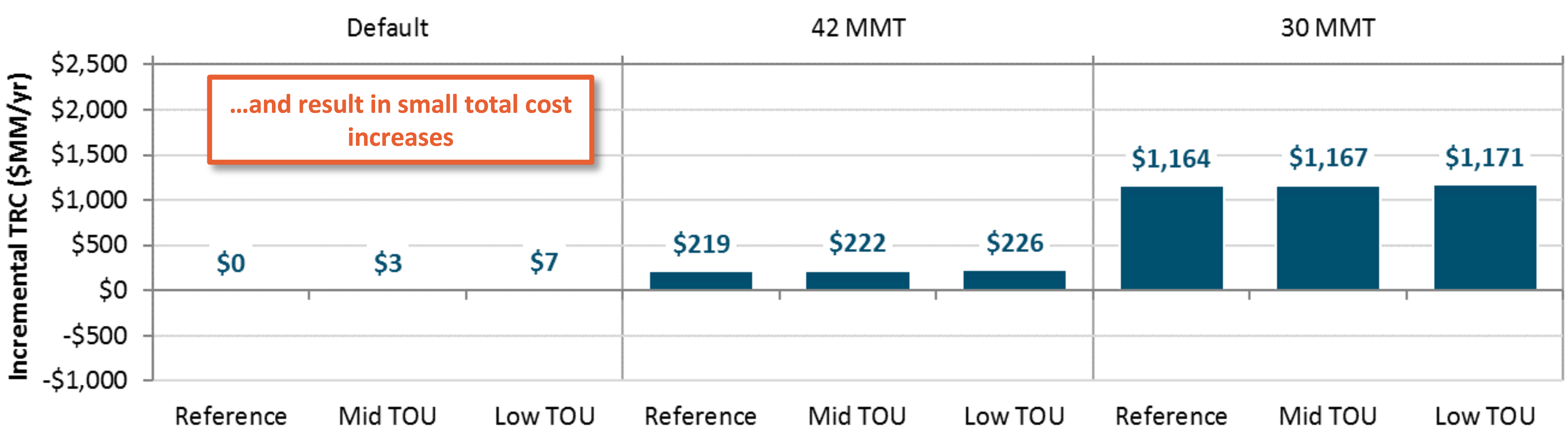
Key Assumptions

- Low TOU impacts: Christensen S3
- Mid TOU impacts: MRW S4
- High TOU impacts (default in reference): MRW S4 x 1.5
- Rate Mix 1

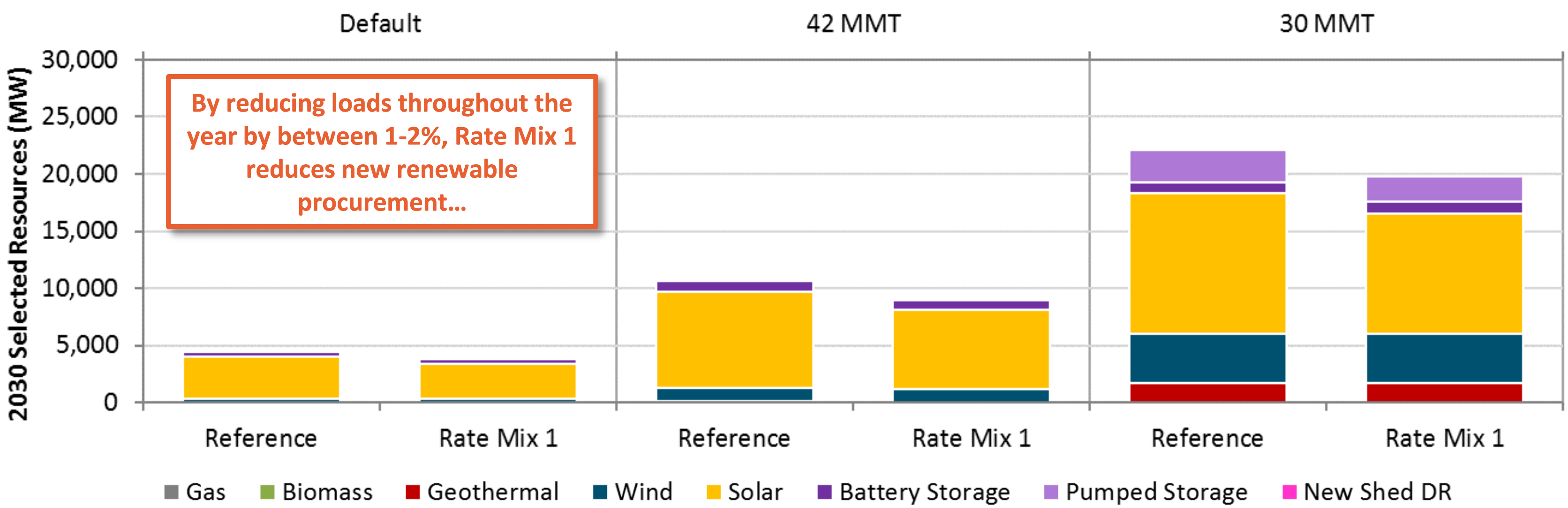
See the revised *RESOLVE Inputs and Assumptions* document for further explanation, available at: www.cpuc.ca.gov/irp/prelimresults2017

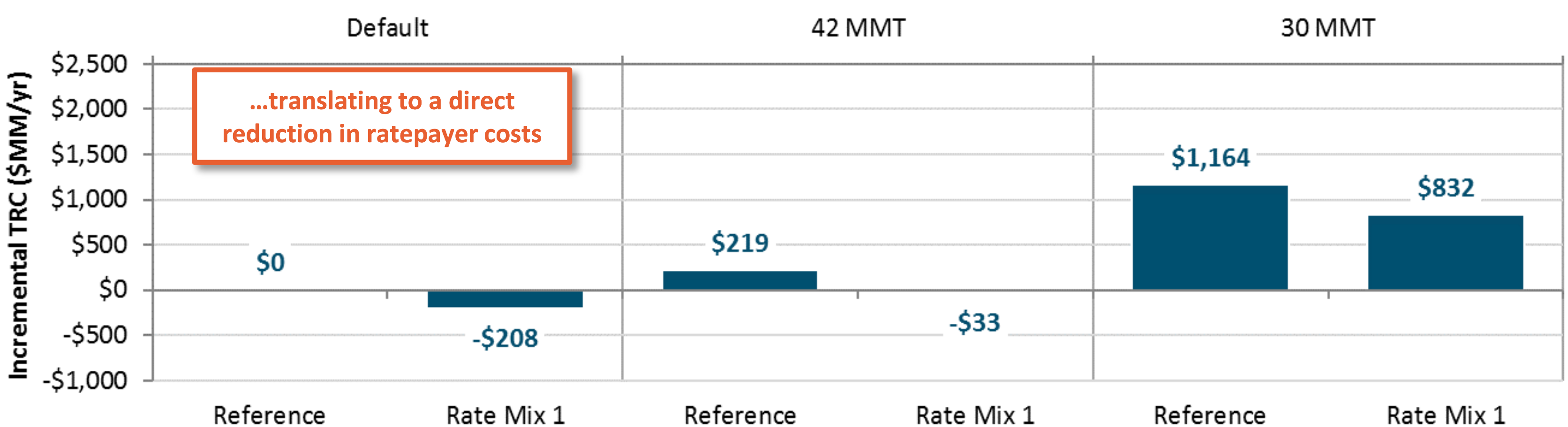
TOU Sensitivities: Summary Results





Rate Mix 1 Sensitivity: Summary Results





TOU Study: Explanation of Results

- The High (reference), Mid, and Low TOU sensitivities have very limited effect on the total load shape, resulting in very little change in the optimal portfolio between these sensitivities
  – Up to 700 MW of hourly load reduction, with a negligible effect on annual load because of shifted load rather than conservation or efficiency
- The Rate Mix 1 sensitivity has a 1-2% reduction in annual load embedded in it, which reduces the amount of renewables required to meet a certain GHG or RPS target, resulting in significant savings

6. ELECTRIC VEHICLES RESULTS

Flexible EV Study: Overview

Study Question

- To what extent does EV charging flexibility affect portfolio costs?

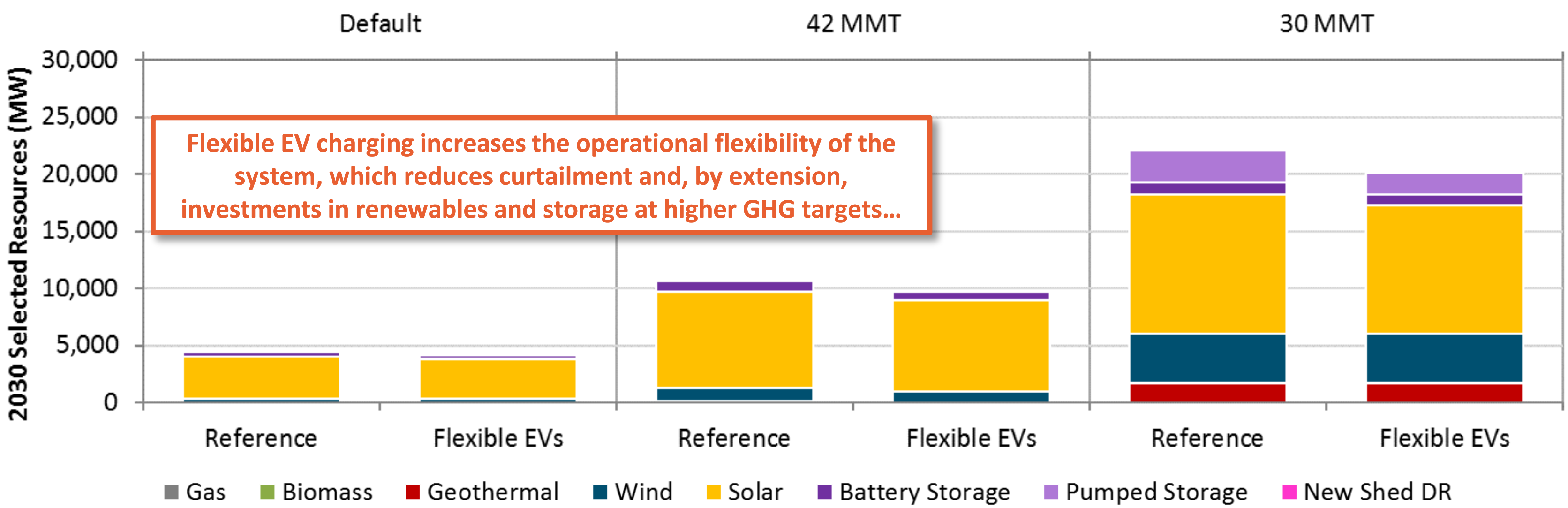
Study Design

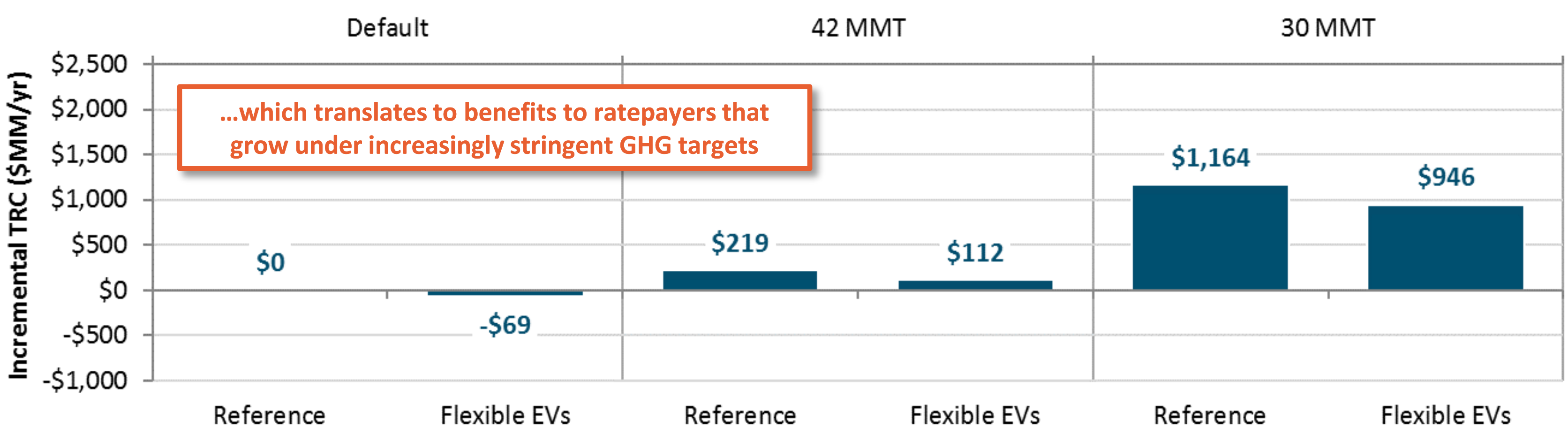
- Examine impact on portfolio composition and costs of allowing the model to treat EV loads as flexible within the day (load can be shifted between hours subject to constraints on vehicle availability).
- Test against core cases of Default, 42 MMT, and 30 MMT

Assumptions

- CEC 2016 IEPR Mid Demand forecast
- CARB's Proposed Scoping Plan scenario with 3.6M light-duty EVs by 2030
- CARB's Proposed Alternative 1 scenario with 4M light-duty EVs by 2030

Flexible EV Sensitivity: Summary Results





Flexible EV: Explanation of Results

- In the 42 MMT and 30 MMT Cases, flexible EV charging reduces the amount of renewable generation and energy storage selected to meet GHG Planning Target
  - Flexible charging mitigates renewable curtailment, reducing the need to overbuild the portfolio
  - Flexible charging also displaces some need for long-duration pumped storage by shifting load to the middle of the day
- Financial benefit of flexible charging grows with increasing penetrations of renewables (or increasingly stringent GHG targets)

7. BATTERY STORAGE RESULTS

Battery Storage Study: Overview

Study Question

- Is there a minimum level of storage that is part of the optimal solution across a broad range of sensitivities?

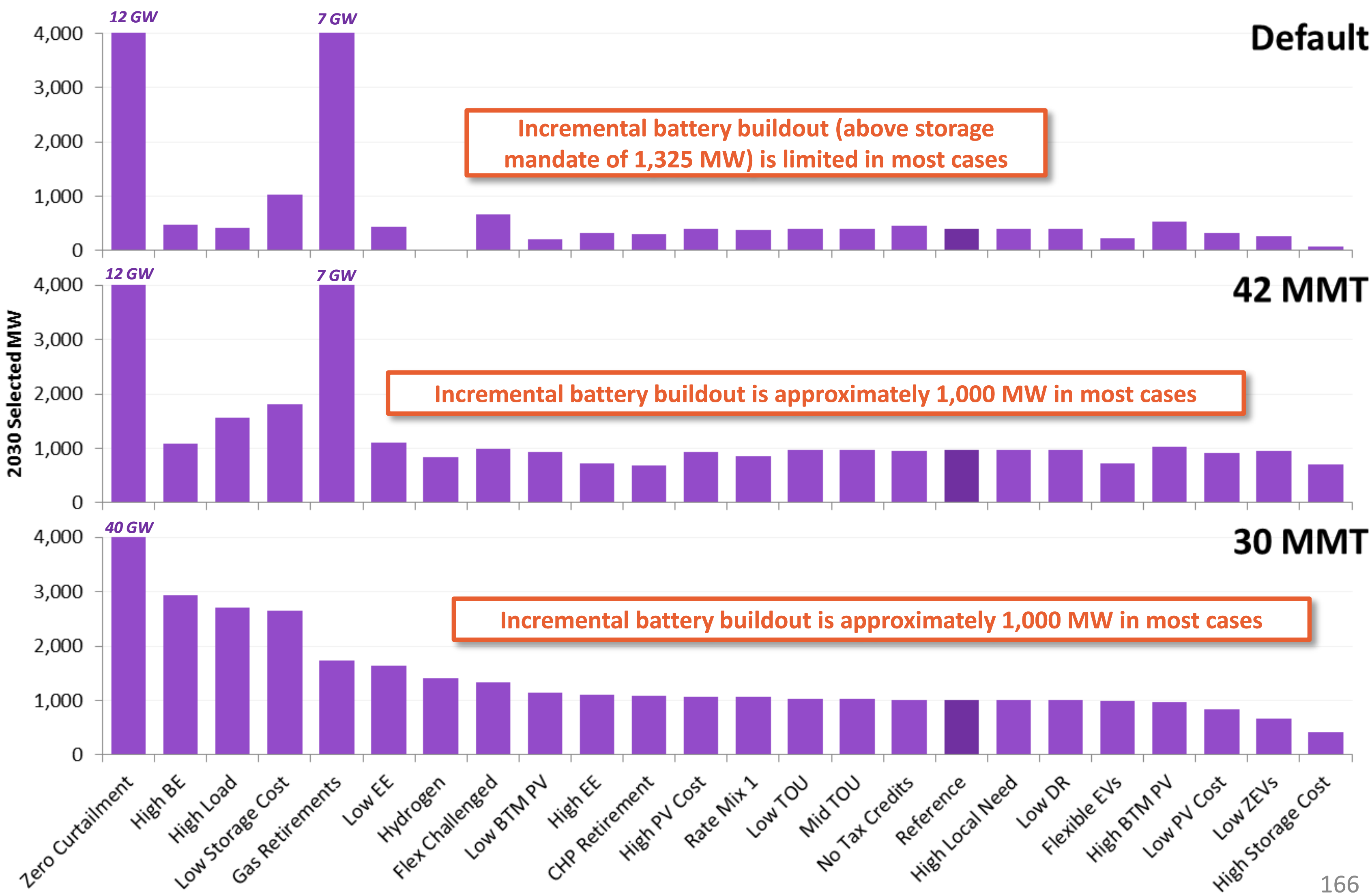
Study Design

- Examine the quantity of storage procured across multiple sensitivities.
- Test against the core policy goals of Default, 42 MMT, and 30 MMT.

Assumptions

- The mandated 1,325 MW of battery storage is assumed to be installed and operational in baseline scenarios
- Battery storage incremental to 1,325 MW is considered as a candidate resource

Battery Storage in Optimal Portfolios



Battery Storage: Explanation of Results

Default Case

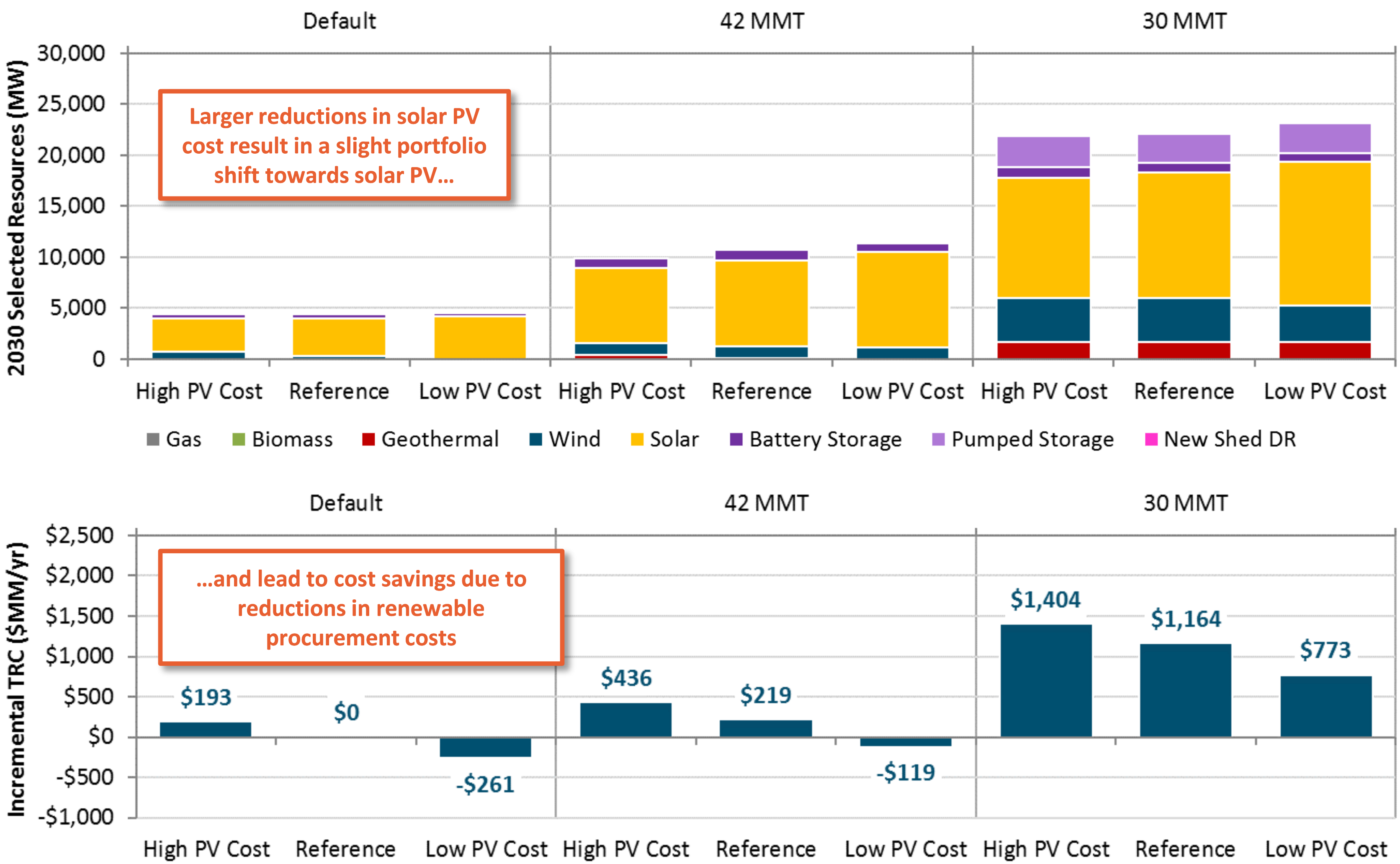
- Very little incremental storage (beyond 1,325 MW mandate) is added
  - Renewable integration challenges are not significant enough to drive new procurement
  - Exception: “Gas Retirements” and “Zero Curtailment” sensitivities

42 MMT and 30 MMT Cases

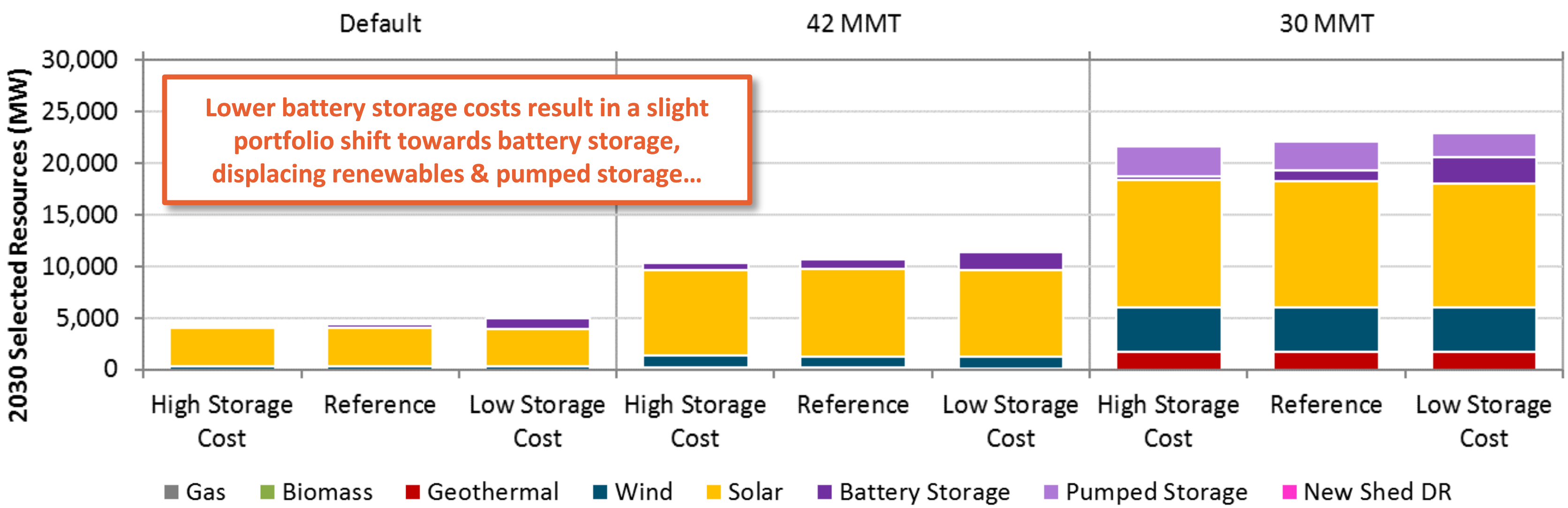
- Increased renewable penetration and need for short-duration balancing services results in 1,000 MW of additional storage in most sensitivities
  - Most storage added across sensitivities is short-duration (~1 hr)
  - Little incremental storage is added between 42 MMT and 30 MMT Cases because long-duration shifting is provided by pumped storage
- A portion of this need could be met by “shimmy” DR resources, which were not modeled explicitly but may have resource potential up to 300 MW

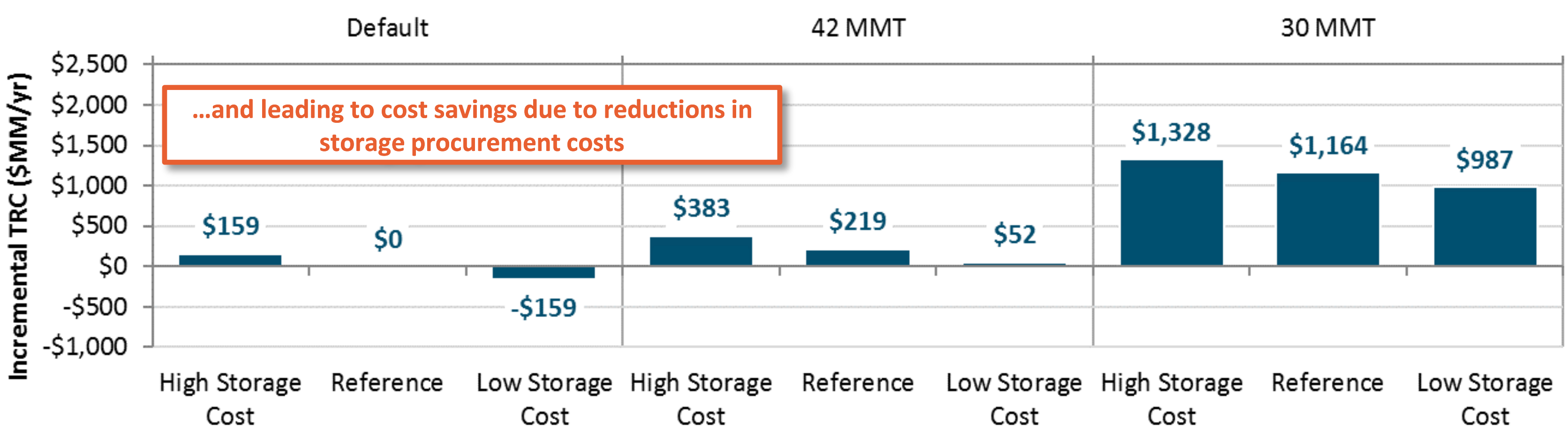
X. ADDITIONAL SENSITIVITY RESULTS

Solar PV Cost Sensitivities: Summary Results

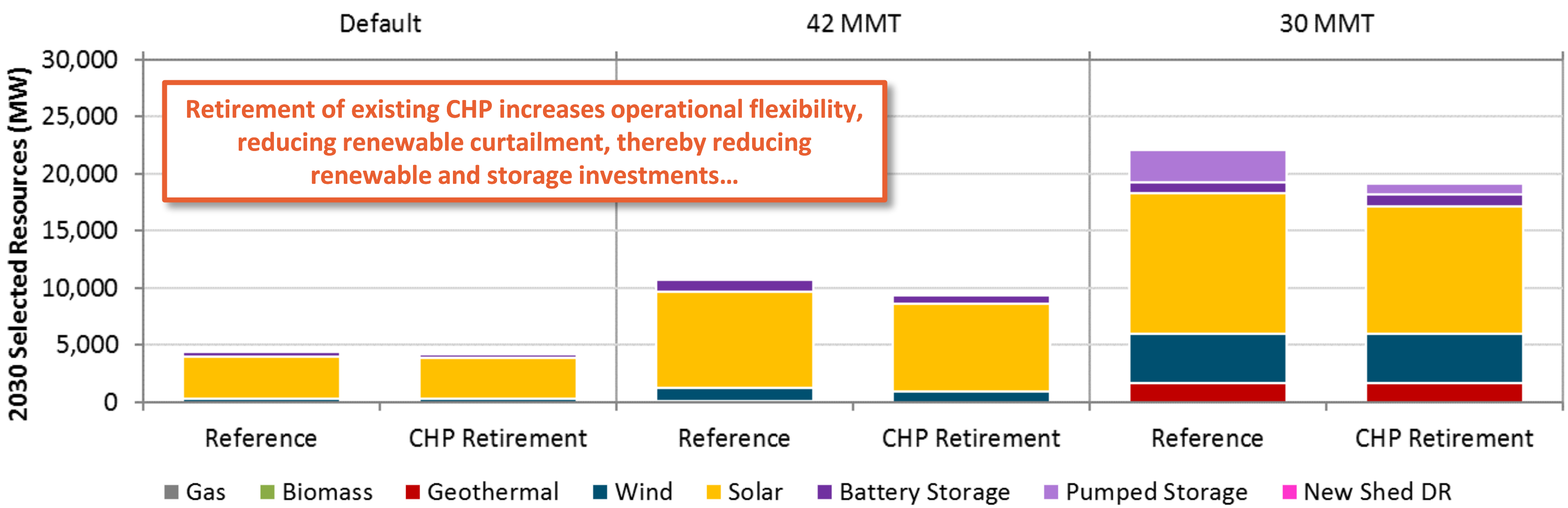


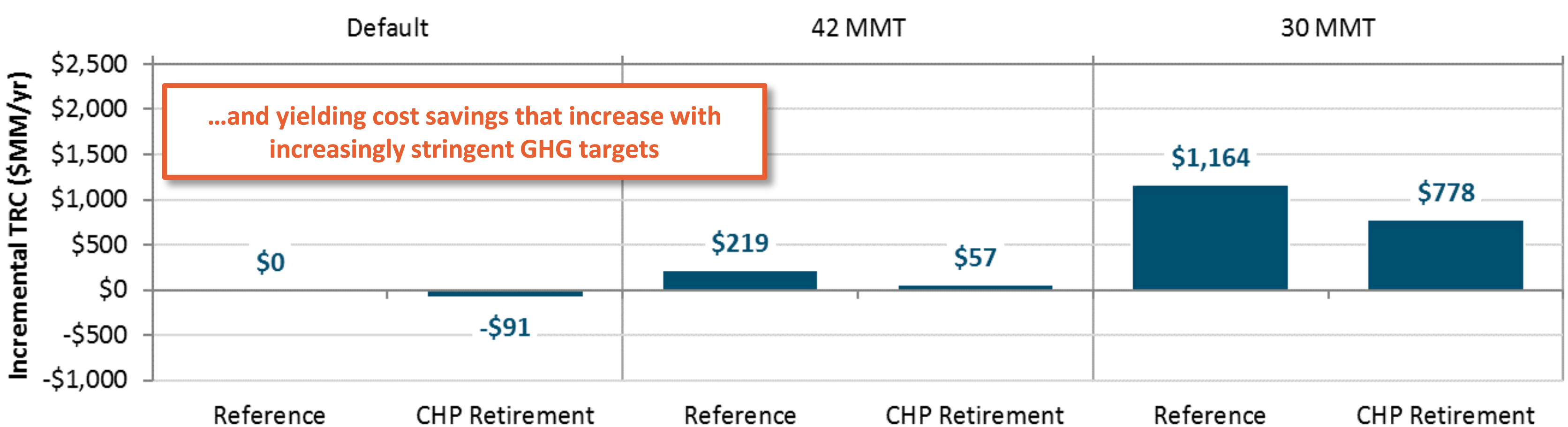
Storage Cost Sensitivities: Summary Results



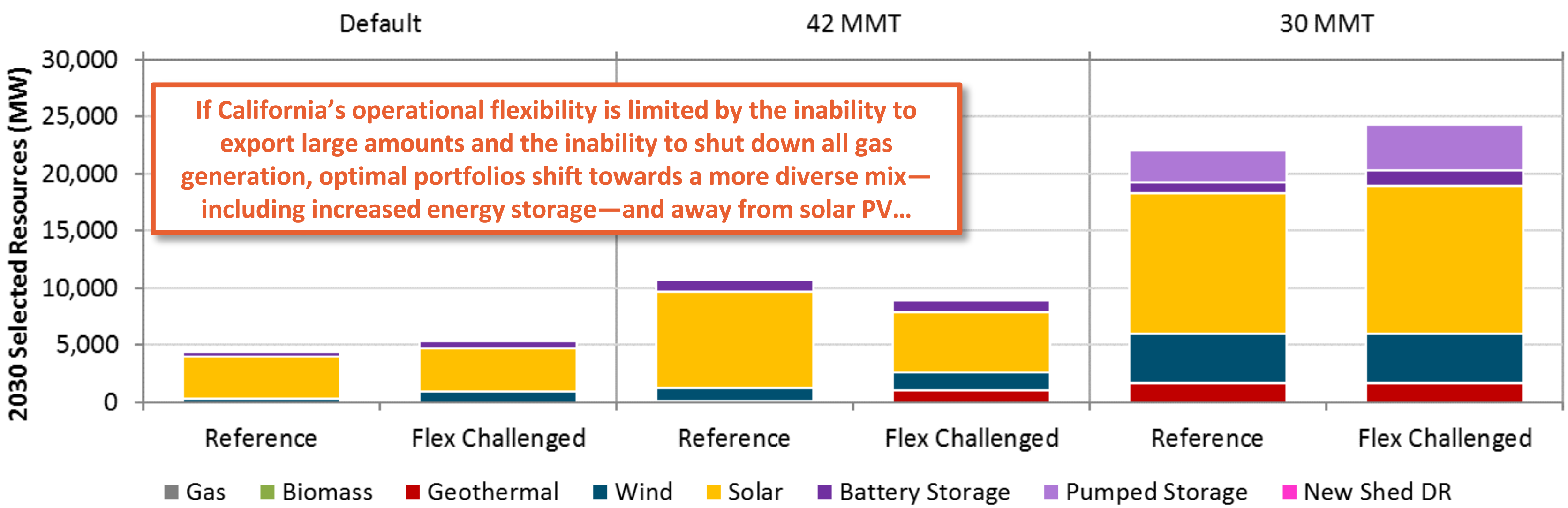


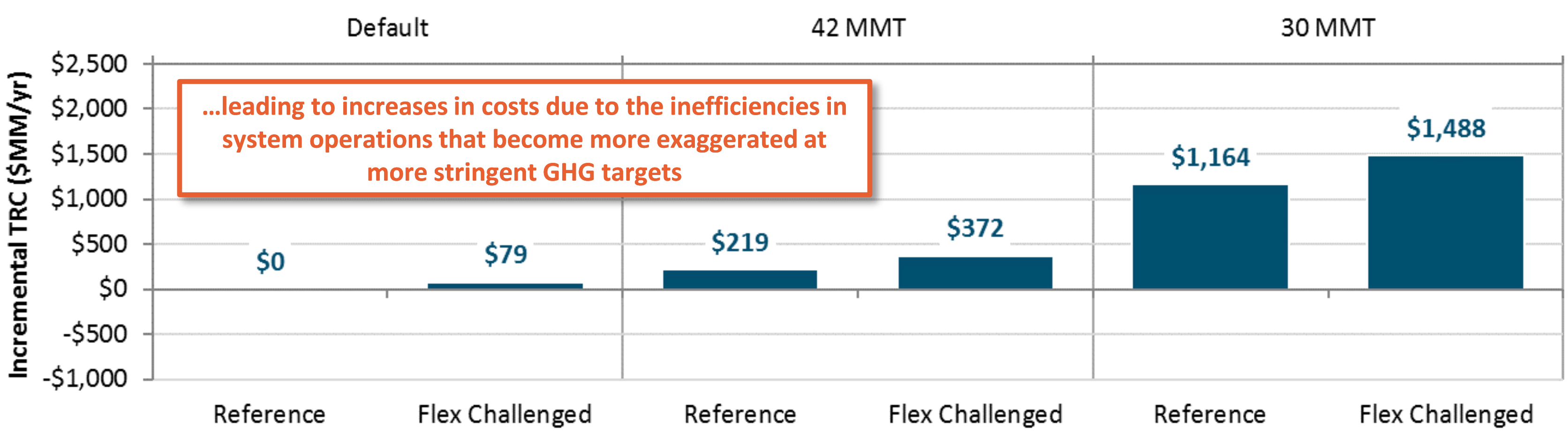
CHP Retirements Sensitivity: Summary Results



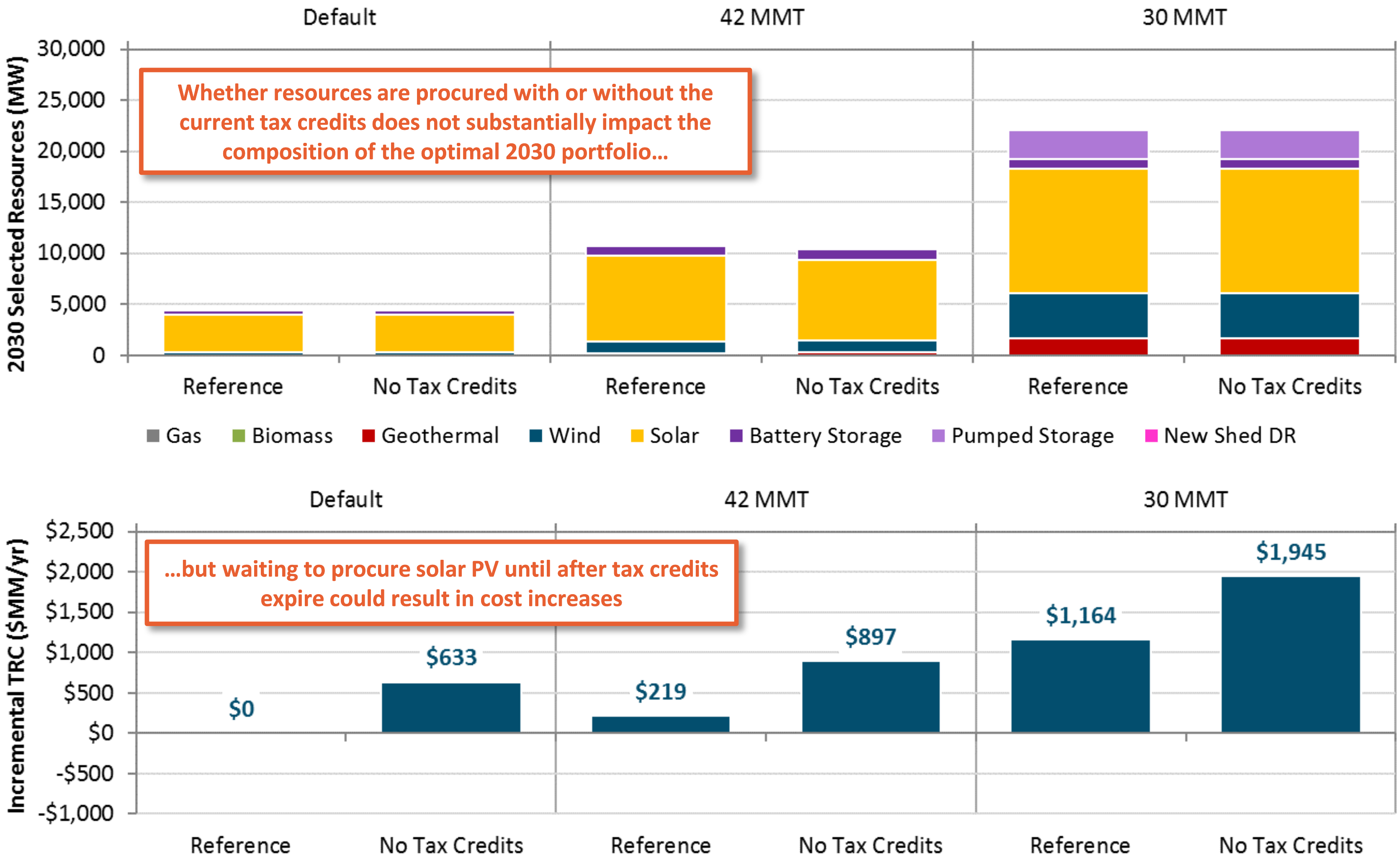


Flexibility Challenged Sensitivity: Summary Results

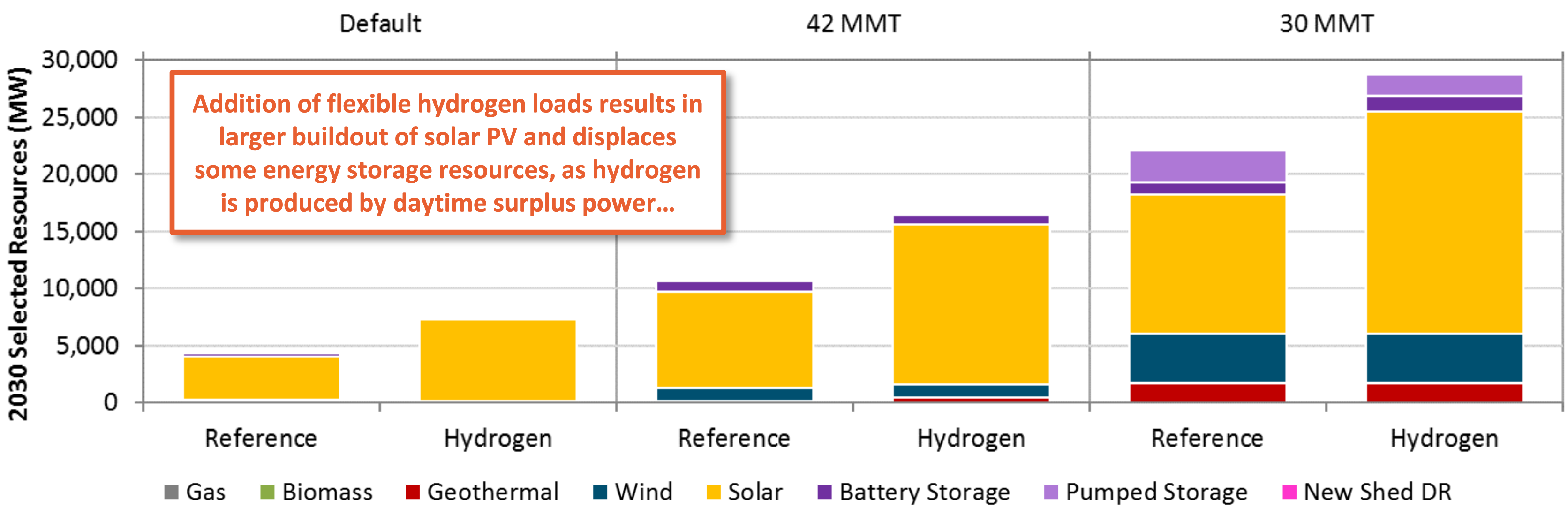


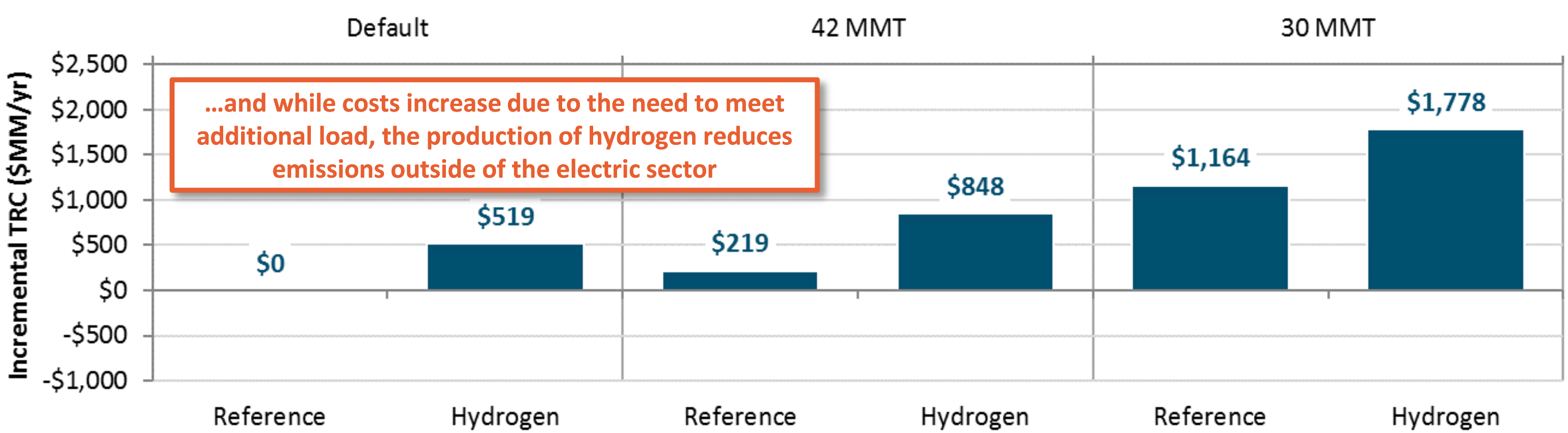


No Tax Credits Sensitivity: Summary Results

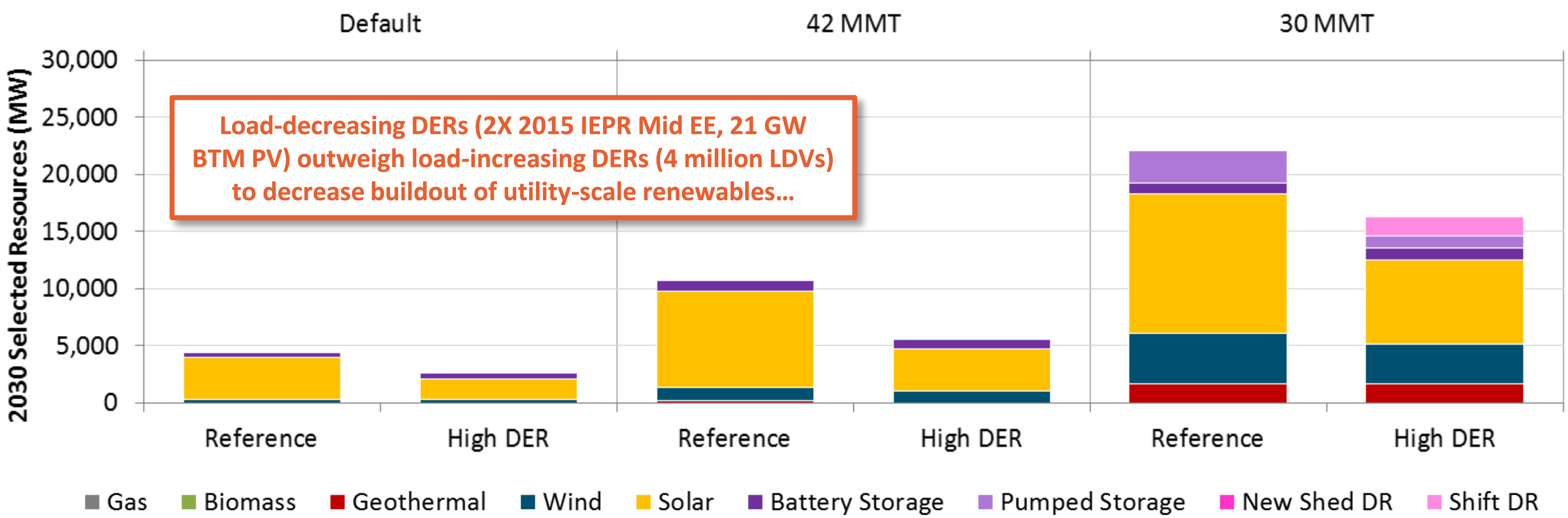


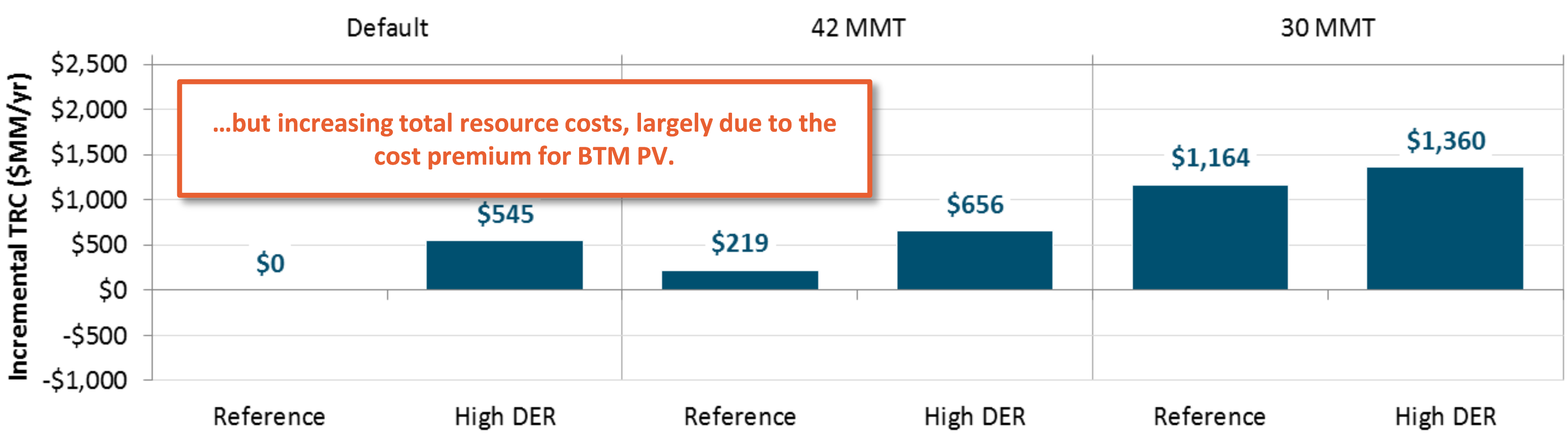
Hydrogen Sensitivity: Summary Results



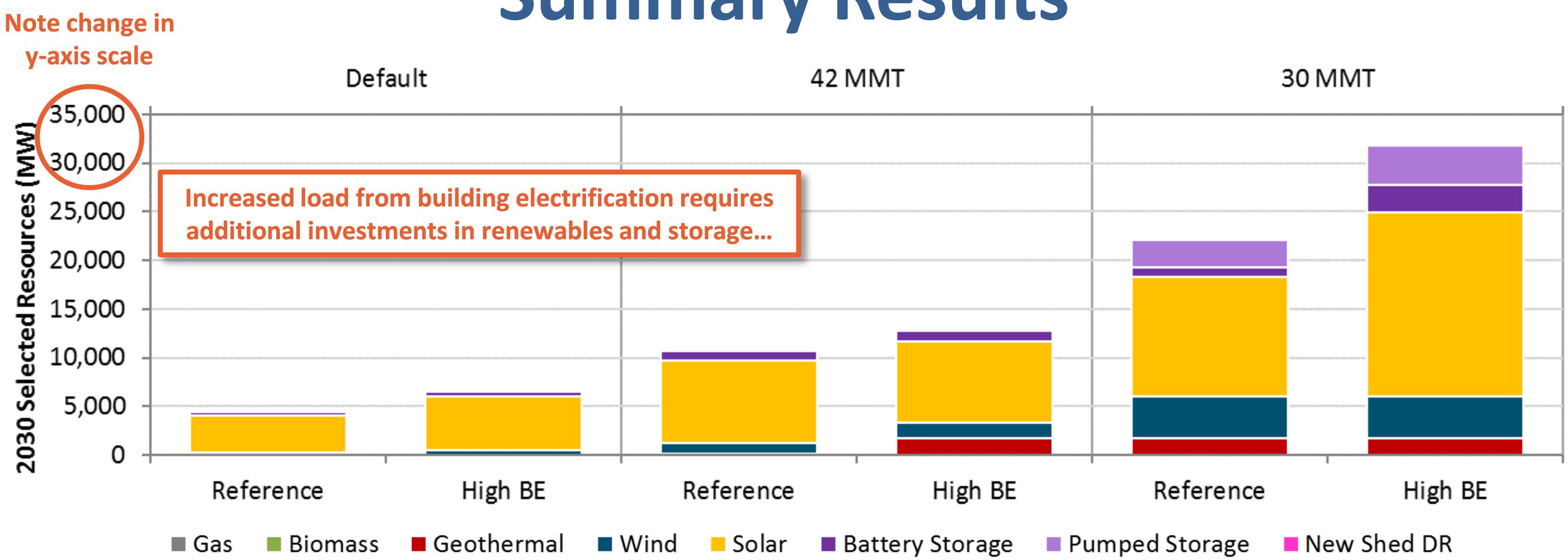


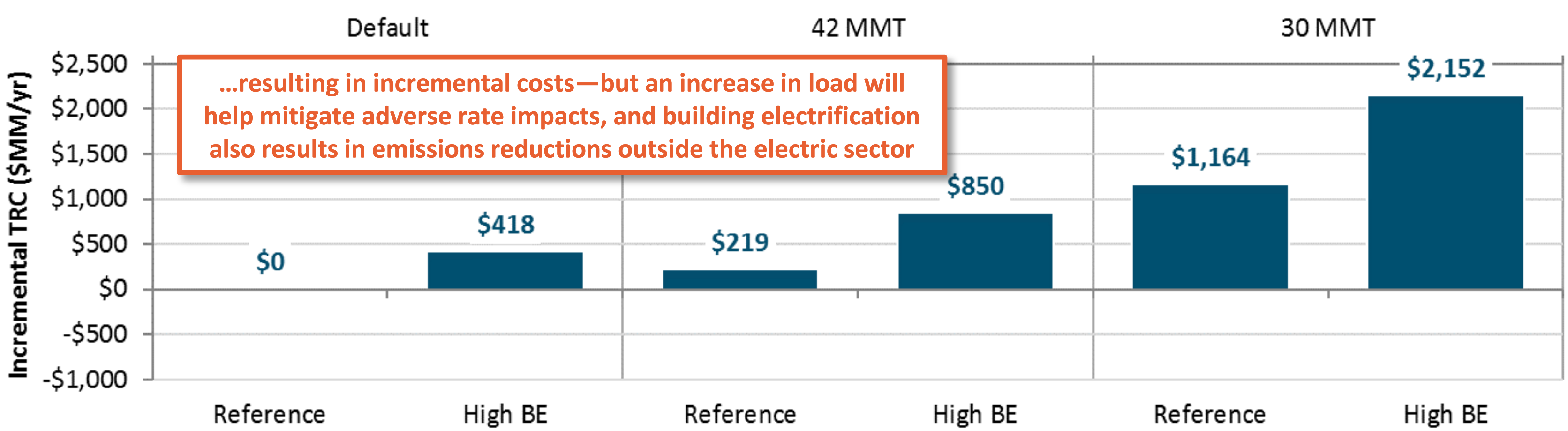
High DER:
Summary Results



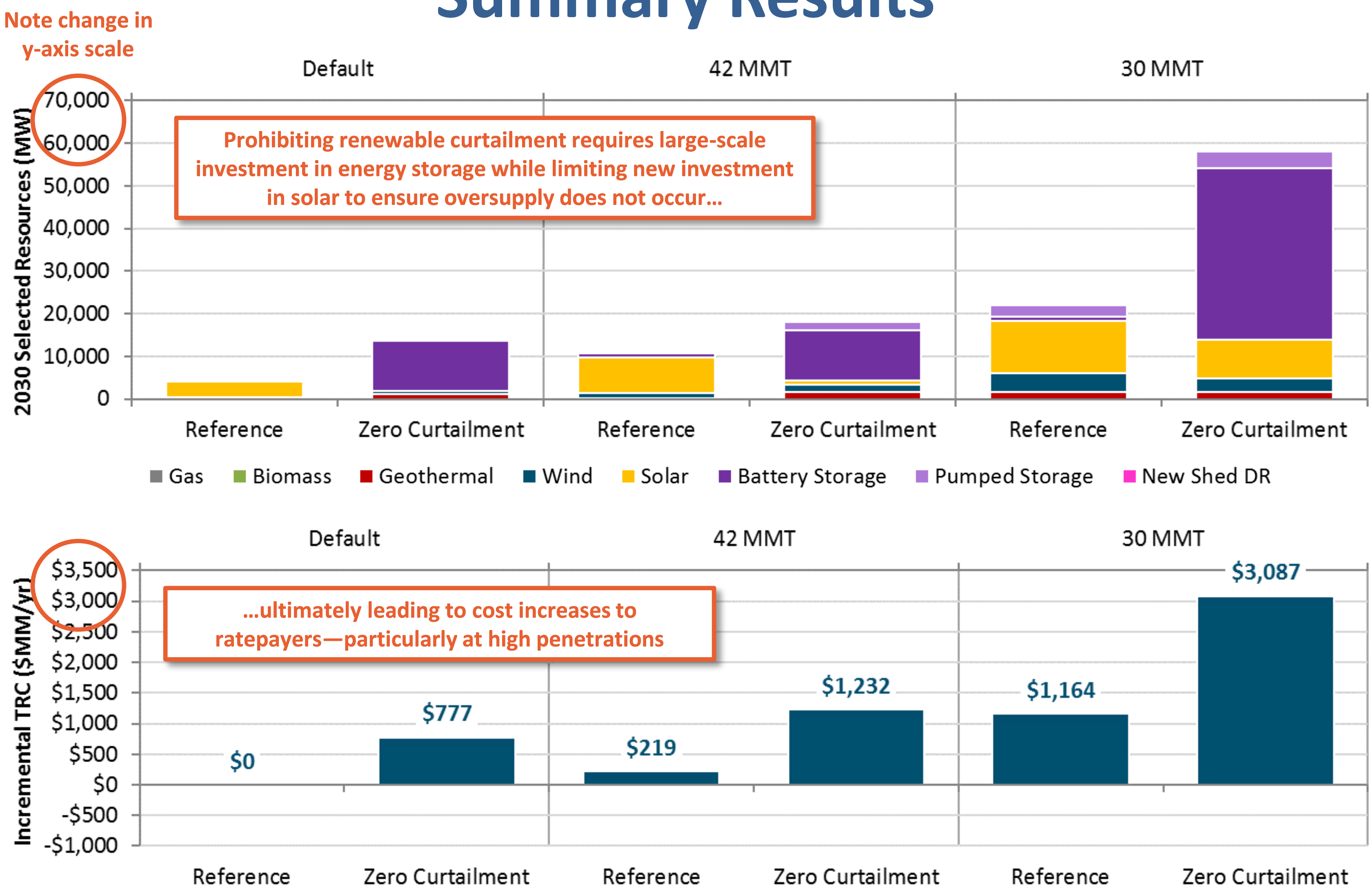


High Building Electrification Sensitivity: Summary Results

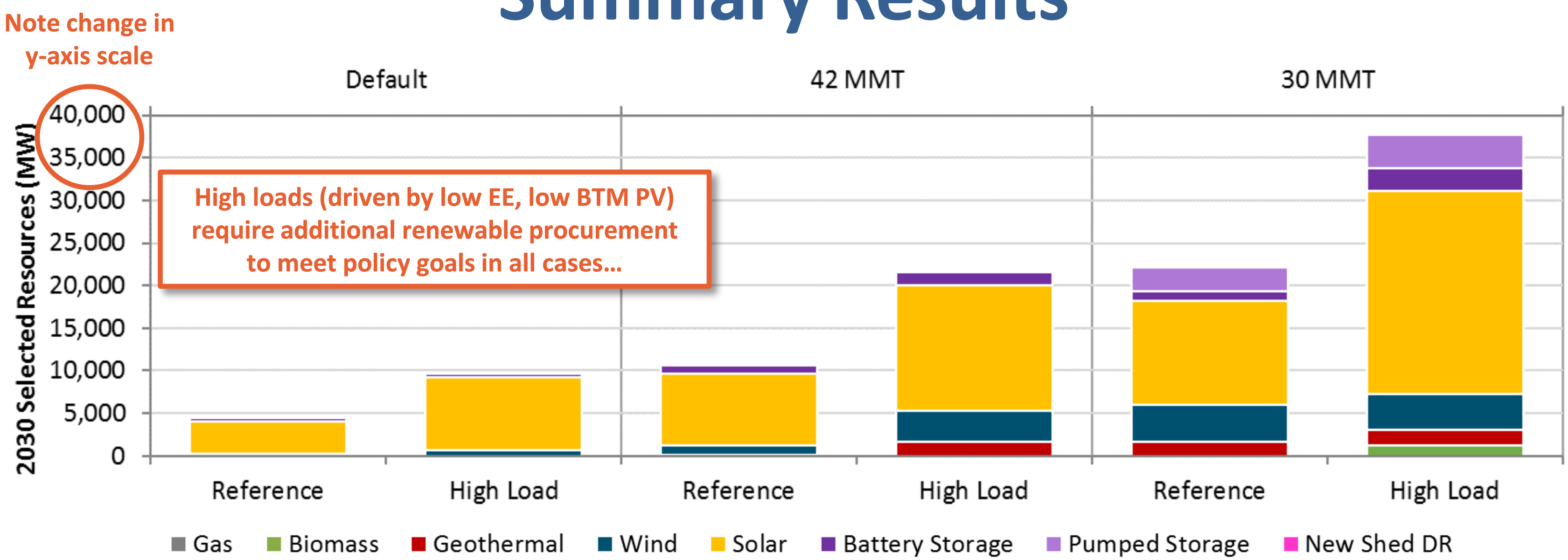


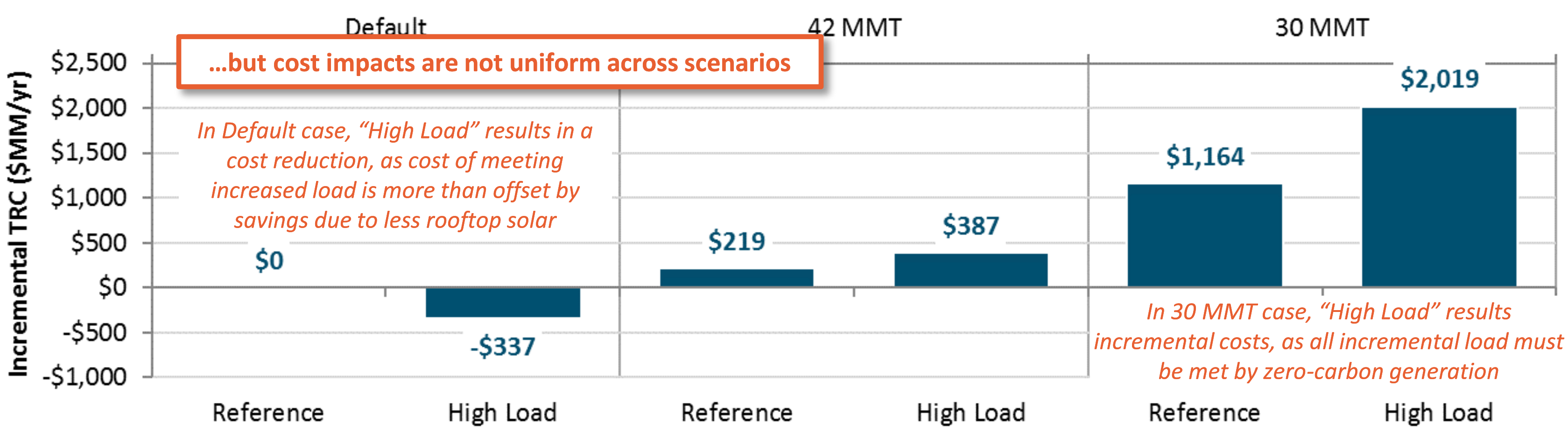


Zero Curtailment Sensitivity: Summary Results



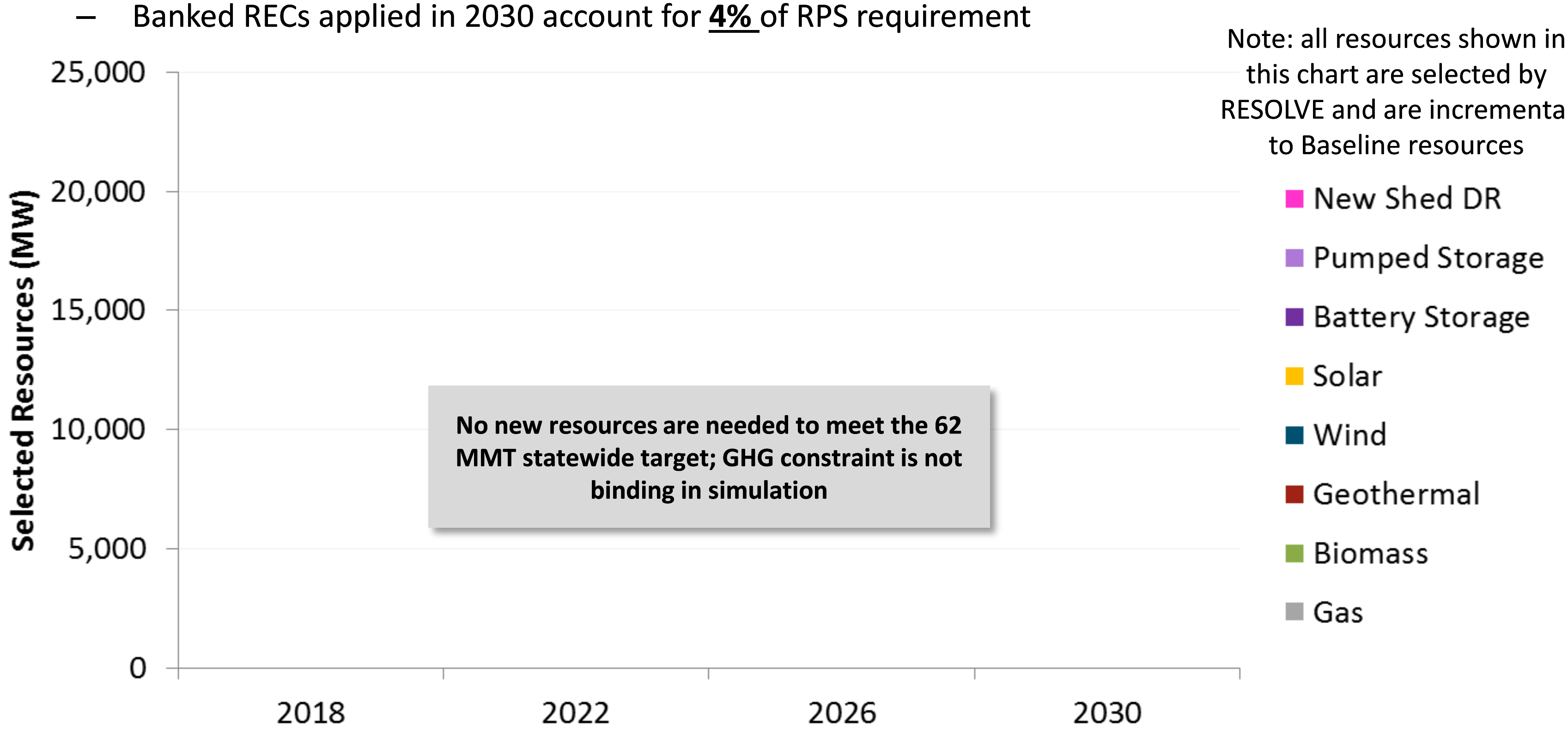
High Load Sensitivity: Summary Results





62 MMT Case: Summary Results

- By 2030, portfolio reaches an RPS of **43%**
  - Physical RPS in 2030 accounts for **39%** of RPS requirement
  - Banked RECs applied in 2030 account for **4%** of RPS requirement



XI. LIST OF ACRONYMS

List of Acronyms

AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
BANC	Balancing Authority of Northern California
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCGT	Combined Cycle Gas Turbine
CEC	California Energy Commission
CHP	Combined Heat and Power
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
DAC	Disadvantaged Community
DER	Distributed Energy Resources
DR	Demand Response
DRP	Distribution Resources Plan
EE	Energy Efficiency
EV	Electric Vehicle
GHG	Greenhouse Gas
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Plan (or) Planning
IRP 2017-18	The first cycle the CPUC's new IRP process
ITC	Investment Tax Credit

LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LSE	Load Serving Entity
MMTCO2e	Million Metric Tons of Carbon Dioxide Equivalent
MW	Megawatt
MWh	Megawatt hour
NEM	Net Energy Metering
NOx	nitrogen oxide
OOS	Out-of-state
OTC	Once Through Cooling
PCC	Portfolio Content Category
PM	particulate matter
POU	Publicly-owned utility
PRM	Planning Reserve Margin
PTC	Production Tax Credit
PV	Photovoltaic
REC	Renewable Energy Credit
RETI	Renewable Energy Transmission Initiative
RPS	Renewables Portfolio Standard
SB	Senate Bill
TOU	Time-of-Use
TPP	Transmission Planning Process
TRC	Total Resource Cost
WECC	Western Electricity Coordinating Council
ZEV	Zero Emissions Vehicle