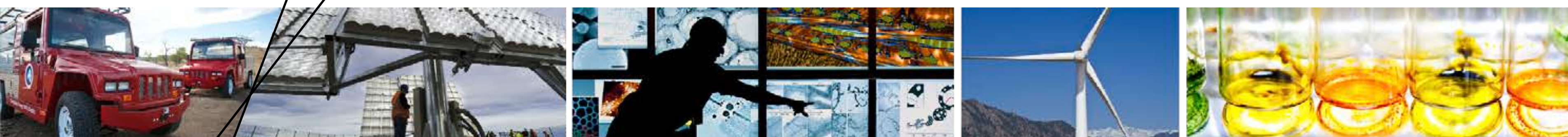
Operational Benefits of Meeting California's Energy Storage Targets



Summary Slides

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Contents

Study Objectives

1. Provide an overview of the CPUC storage mandate
2. Discuss the various applications or “use cases” of energy storage and how the value of these applications can be assessed
3. Review previous work relevant to California storage valuation
4. Analyze the potential operational value of energy storage using several modeling approaches and considering a range of sensitivities
5. Suggest next steps for model development and research

Notes to the Reader

- Unless otherwise noted, all references to the storage portfolio or storage operations refer to the “new” storage located in California (and not to the impact of existing pumped storage)

- **This study includes**
  - Valuation of storage using the 2014 LTPP model
  - Wide range of sensitivities
  - Revenue comparisons

- **This study does not include**
  - Specific storage technologies
  - New Publically owned utility storage plans
  - Power flow analysis
  - Transmission and distribution upgrade deferral
  - Local transmission congestion
  - Other services (e.g., voltage support, black start, explicit representation of ramping products, flexible capacity).

1. Background on California storage policy and related policies and programs

California storage policy

- AB 2514 in 2011 establishes requirement for LSEs to evaluate storage procurement
- California Public Utilities Commission (CPUC) 2013 decision (D.13-10-040) on storage procurement for its jurisdictional LSEs
  - Investor-owned utilities (evaluated in this study)
  - Community-choice aggregators (CCAs) and competitive retail suppliers (not evaluated in this study)
- Publicly-owned utilities compliance and reporting to California Energy Commission (not evaluated in this study)

CPUC storage policy: IOU targets

- **Energy Storage Capacity Procurements targets for California (MW) as established in CPUC D.13-10-040**

Storage Grid Domain Point of Interconnection	2014	2016	2018	2020	Total by 2024
Southern California Edison					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Cumulative Subtotal SCE	90	120	160	210	580
Pacific Gas & Electric					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Cumulative Subtotal PG&E	90	120	160	210	580
San Diego Gas & Electric					
Transmission	10	15	22	33	80
Distribution	7	10	15	23	55
Customer	3	5	8	14	30
Cumulative Subtotal SDG&E	20	30	45	70	165
Total – all 3 utilities	**200**	**270**	**365**	**490**	**1,325**

Related California policies and programs

- **Renewable Portfolio Standard**
  - Currently requires 33% renewable energy by 2020; 50% by 2030
- **Long-term resource planning**
  - CPUC’s Long-term Procurement Planning (LTPP) proceeding authorizes operational needs for the jurisdictional utilities using a 10-year ahead power system simulation (the 2014 proceeding evaluated 2024)
  - Provides assumptions and data developed through a biennial stakeholder process, including a storage portfolio
  - Further description in subsequent slides

2. Study Methodology

Overview of Methodology

- Study utilizes the 2014 LTPP model data and assumptions for California and the WECC in 2024 as well as PLEXOS production cost model software
- Additional “price-taker” model used to evaluate revenue from historical and simulated future market prices
- Study modifies some aspects of the storage resource portfolio and undertakes analysis of different applications not done in the LTPP

Two types of benefit calculations

1. Change in production costs for energy and reserves (production cost model)
   - Avoided fuel costs (2024)
   - Avoided generator start-up and variable O&M costs (2024)
2. Market revenue for energy and reserves (production cost model and price-taker model)
   - Historical CAISO market prices (2013, 2014)
   - “Shadow” prices from the production cost model (2024)

Type of Storage Value	Model Used	Where Prices Come From	Description
Reduction in production cost	Power system model	N/A	Establishes the value of storage measured by reduction in operating costs between two model runs: with and without storage. Storage dispatch is optimized to minimize production costs.
Market revenue	Power system model, “system optimized”	Power system model	Revenue to storage plant(s) when storage is optimized in a power system model. Storage revenue is calculated by multiplying storage dispatch by marginal prices for the services provided.
	Price-taker model, “self-scheduled”	Actual historical markets or power system model	Incremental storage resource is optimized to maximize revenues against either historical marginal prices OR prices generated from power system models for each service provided.

Storage benefits evaluated in the study

- Avoided generator start-up costs/variable O&M costs (production cost) for energy and ancillary services by use-case (2024)
- Avoided generator fuel costs for energy and ancillary services by use-case (2024)
- Energy market revenues (2013, 2014, 2024)
- Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve market revenues (2013, 2014)
- For more information see Appendix

Storage benefits not evaluated in the study

- Value of system, local and flexible capacity, as defined by the CPUC and CAISO
- Transmission and distribution upgrade deferral
- Local transmission congestion
- Other current and future operational services (e.g., voltage support, frequency response, explicit representation of ramping products)

Methodology

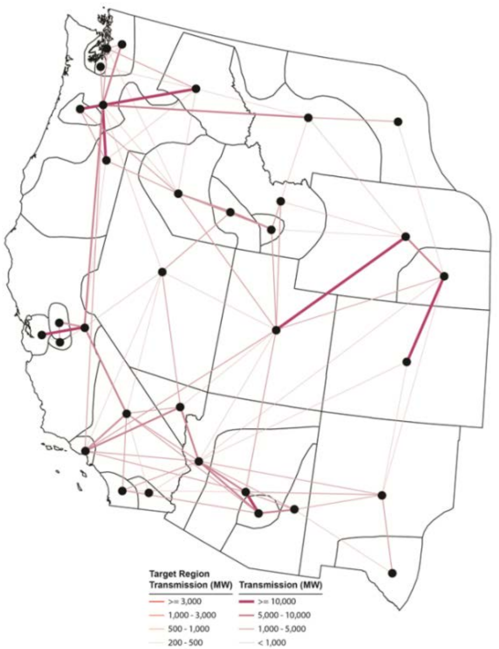
- **Long-term Procurement Planning (LTPP) Production Cost Model (PCM)**
  - Uses 2014 database developed for CPUC's LTPP proceeding
  - 33% and 40% annual renewable energy for California in 2024
  - Simulates unit commitment, energy dispatch and reserves
  - Hourly time-step
  - Renewable energy is curtailable at -$300/MWh cost
  - Enforces zonal transmission constraints and Net zero export limit from California
  - Carbon cost adder on California fossil generation and imports into California
  - Calculates production costs, shadow prices, emissions, changes to resource operations, imports/exports, etc.
- **Exogenous Fixed Price Model ("Price-Taker Model")**
  - Calculate market revenues using historical market prices for 2013-14, or simulated prices for 2024

Methodology: Production Cost Model (PLEXOS)

Performs co-optimization of energy and ancillary service products to minimize system production cost

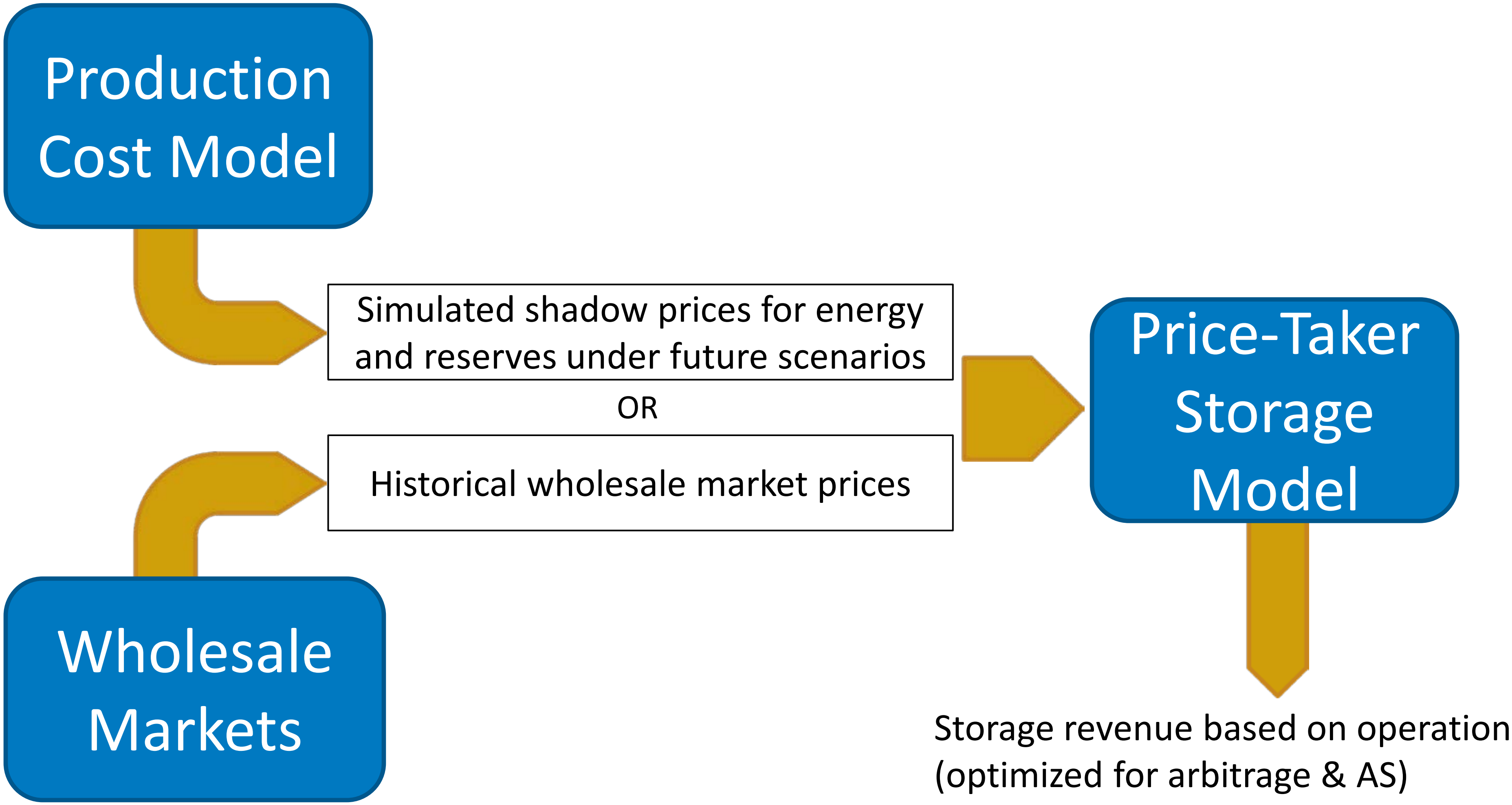
- Transmission Network (electric and gas)
- Generator properties
  (coal, gas, nuclear, renewable, etc.)
- Load requirements
- Reliability requirements
- Other System Constraints

Production Cost Model



- Generator operation
- Storage operation
- Production cost
- Fuel use
- Emissions
- Imports & Exports
- Load served
- Energy Prices
- Ancillary Service Prices

Methodology: Price-taker Model



IOU renewable portfolios in 2024

- Study modeled two 33% and 40% renewable energy portfolios from the 2014 LTPP database

	Biomass	Geothermal	Small Hydro	Large Solar PV	Small Solar PV	Solar Thermal	Wind	Total
Trajectory 33% Renewable Energy Scenario								
Capacity (MW)	1,623	2,999	3,017	9,087	3,564	1,802	11,146	**33,239**
Energy (GWh)	10,096	15,003	5,334	21,091	7,312	4,322	24,899	**88,056**
In-state energy	9,534	13,645	5,294	17,787	7,312	4,322	15,701	**73,595**
Out-state energy	562	1,358	40	3,304	0	0	9,198	**14,461**
40% Renewable Energy in 2024 Scenario								
Capacity (MW)	1,626	2,999	3,017	11,195	9,115	1,802	12,189	**41,943**
Energy (GWh)	10,117	15,003	5,334	25,597	18,518	4,322	27,844	**106,734**
In-state energy	9,555	13,645	5,294	22,293	18,518	4,322	18,646	**92,273**
Out-state energy	562	1,358	40	3,304	0	0	9,198	**14,461**

LTPP base-case storage attributes in 2024

- 2014 LTPP made initial assumptions on storage attributes, subject to updating as actual portfolios evolve

Values are MW in 2024	Transmission-connected	Distribution-connected	Customer-sited
Total Installed Capacity	700	425	200
Amount providing capacity and flexibility	700	212.5	0
Amount with 2 hours of storage	280	170	100
Amount with 4 hours of storage	280	170	100
Amount with 6 hours of storage	140	85	0

Notes:

- ~42% of portfolio has 2 hours, ~42% has 4 hours, and ~17% has 6 hours
- 412.5 MW (~31%) of distribution and customer sited storage restricted to only conducting energy time-shift/arbitrage (but no reserves)

LTPP base-case storage applications

- Distribution of modeled duration and applications by capacity and utility

	PG&E Capacity (MW)			SCE Capacity (MW)			SDG&E Capacity (MW)			Total
Storage type	2 hrs	4 hrs	6 hrs	2 hrs	4 hrs	6 hrs	2 hrs	4 hrs	6 hrs	
All services (energy + reserves)	161	161	80.5	161	161	80.5	43	19	5.5	872.5
Energy (load shifting) only	79.5	79.5	18.5	79.5	79.5	18.5	26	26	5.5	412.5
Total	240.5	240.5	99	240.5	240.5	99	69	45	11	1,285*

* Full profile includes additional 40MW from the planned Lake Hodges pumped hydro plant (modeled with 3.1 hours of duration)

Other California storage resources in the model

Plant Name	Location	Capacity (MW)	Reserve Services Provided
Castaic	LADWP	1,271	All (but assigned to LADWP)
Eastwood	SCE	199	None
Helms	PG&E Valley	1,218	All
Iowa Hill	SMUD (planned)	390	All (but assigned to SMUD)
Lake Hodges	SDG&E	40	Load following, nonspinning
SN LS PP 8 (William R. Gianelli hydroelectric plant)	PG&E Valley	374	Nonspinning
Total		3,492 (3,102 currently installed)	

Scenarios – Base cases (33% and 40%)

Scenario Name	Storage Capacity (MW) By Service Provided		
	Energy Only	All Reserves	Energy and Reserves
LTPP no storage "No Storage"	None	None	None
Base (Energy+ Reserves) "ene&res"	412.5		912.5
Energy only "ene only"	1,325		
Eligible reserves "eligible res"	412.5	912.5	
Reserves only "res only"		1,325	

Notes on scenario definition and naming

LTPP base-case scenario for storage application:

- **Energy + reserves** – “ene&res” – All storage is co-optimized for energy and reserves under LTPP application assumptions.

The remaining application scenarios are used examine what drives benefits:

- **Energy only** – “ene only” – All storage resources are used for energy arbitrage only
- **Eligible reserves** – “eligible res” – All storage eligible to provide reserves under LTPP application assumptions
- **Reserves only** – “res only” – All storage resources are used for reserves only (i.e., no energy arbitrage)

Scenarios – Sensitivities (33% and 40%)

Scenario Name	Storage Capacity (MW) By Service Provided		
	Energy Only	Regulation Only	Energy and Reserves
Regulation only	412.5	912.5	
+1 hour storage	412.5		912.5
+4 hours storage	412.5		912.5
-$150/MWh bid floor	412.5		912.5
$0/MWh bid floor	412.5		912.5
Disaggregated Portfolio	1325		
No export limit	412.5		912.5
½ capacity	206.3		456.3
¼ capacity	103.1		228.1

Notes on scenario definition and naming

- **Regulation only** – same as "eligible reserves" but storage resources limited to Regulation only
- **Other sensitivities** – see further explanation in Section 5 of this deck.

3. Brief Overview of Key Results

Base case results (1)

- WECC-wide production costs are reduced by
  - $78 million per year in the 33% scenario
  - $144 million per year in the 40% scenario
- These values are equivalent to
  - $59/kW-year for the 33% scenario
  - $109/kW-year for the 40% scenario
- Avoided generator start-up costs comprise between 29%-67% of storage value, depending on the use-case/scenario

Base case results (2)

- Ancillary services alone could provide about 90% of the value derived from jointly optimizing energy and ancillary services, but the ancillary service markets are vulnerable to saturation
- Storage decreases renewable curtailment (under the no net export assumption) by
  - 35% in the 33% scenario
  - 19% in the 40% scenario
- Storage reduces California in-state carbon emissions, and has a small, mixed effect on total WECC emissions due to increase in coal operations in the model (under current assumptions)

Sensitivity case results (1)

- There is declining value of incremental storage as more power capacity is added to the 2024 scenarios. This is partially offset by the increased value of storage in the 40% scenario
    - $70.6/kW for ¼ portfolio to $58.5/kW for full for portfolio 33% scenario
    - $146/kW for ¼ portfolio to $108/kW for full portfolio for 40% scenario
- Increased storage duration (additional 1 and 4 hours) does not greatly increase storage value (assuming fixed power capacity)
    - $2.9M increase for additional 4hrs across 33% portfolio
    - $14M increase for additional 4hrs across 40% portfolio

Sensitivity case results (2)

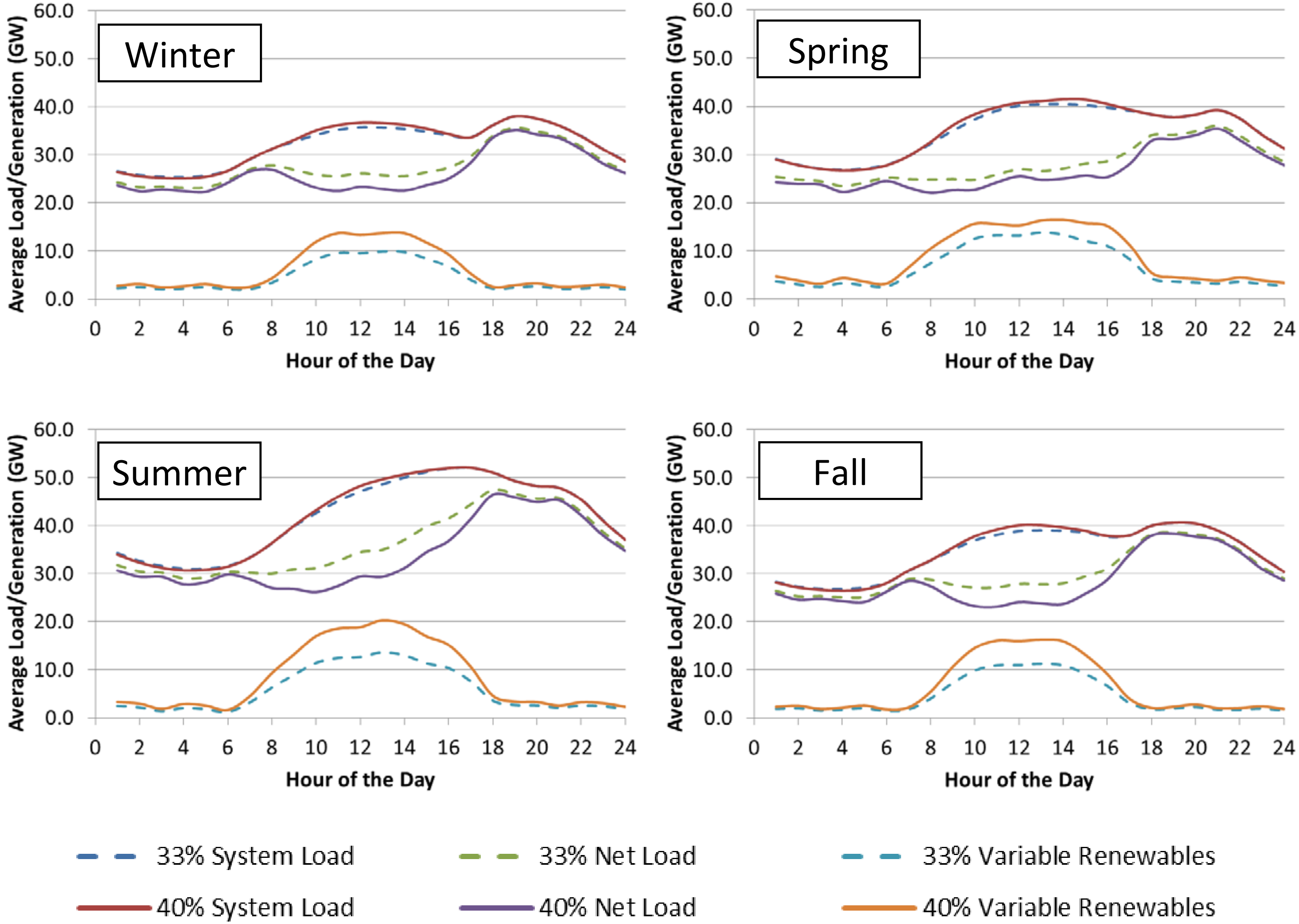
- If the storage portfolio mainly provides Regulation, the value of Regulation is reduced (causes zero marginal prices in the model)
- Allowing unrestricted exports from California diminishes the reduction in production costs due to storage
  - $5.1 million in the 33% scenario
  - $52 million in the 40% scenario
- Even if exports aren't allowed, reducing the (negative) cost of renewable curtailment from -$300/MWh to $0/MWh significantly reduces storage energy value

4. Detailed Results from Pre-storage Scenario

Load and net load shapes by season

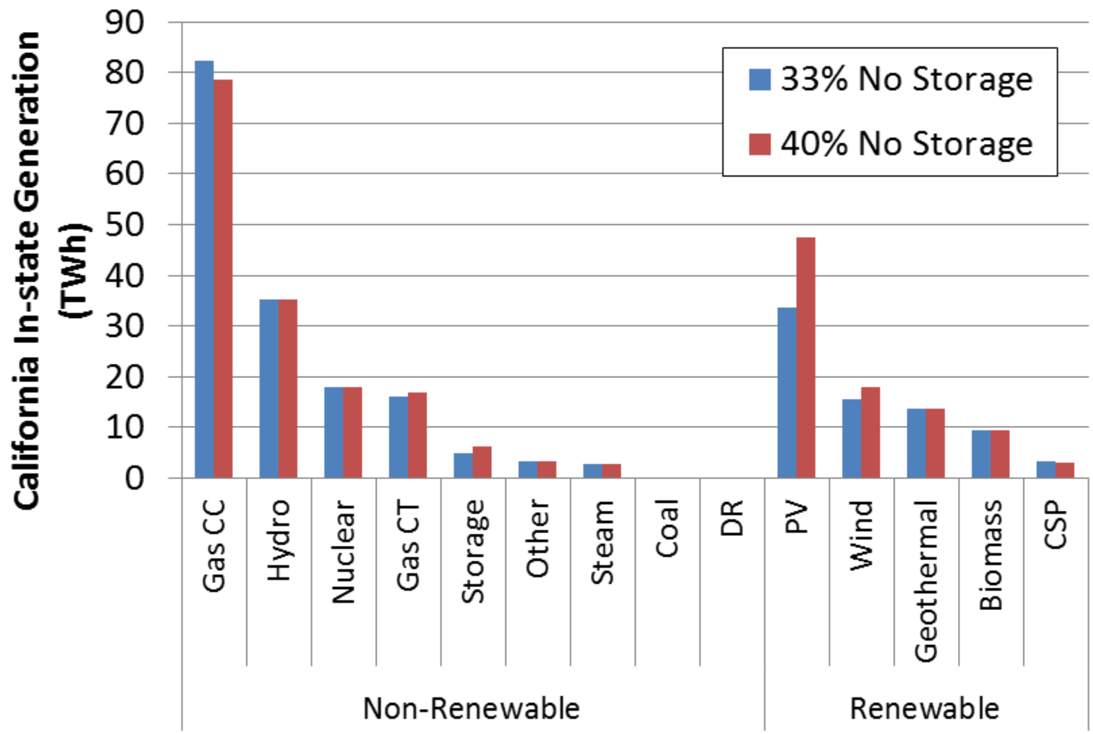
- Storage value is significantly affected by the changes in the net load shapes due to renewable penetration in California, particularly solar
- "Off-peak" shifts to the middle of the day, while "peak" is the late afternoon, early evening net load
- *Note* - load and net load shapes shown in next slide do not include the new storage portfolio

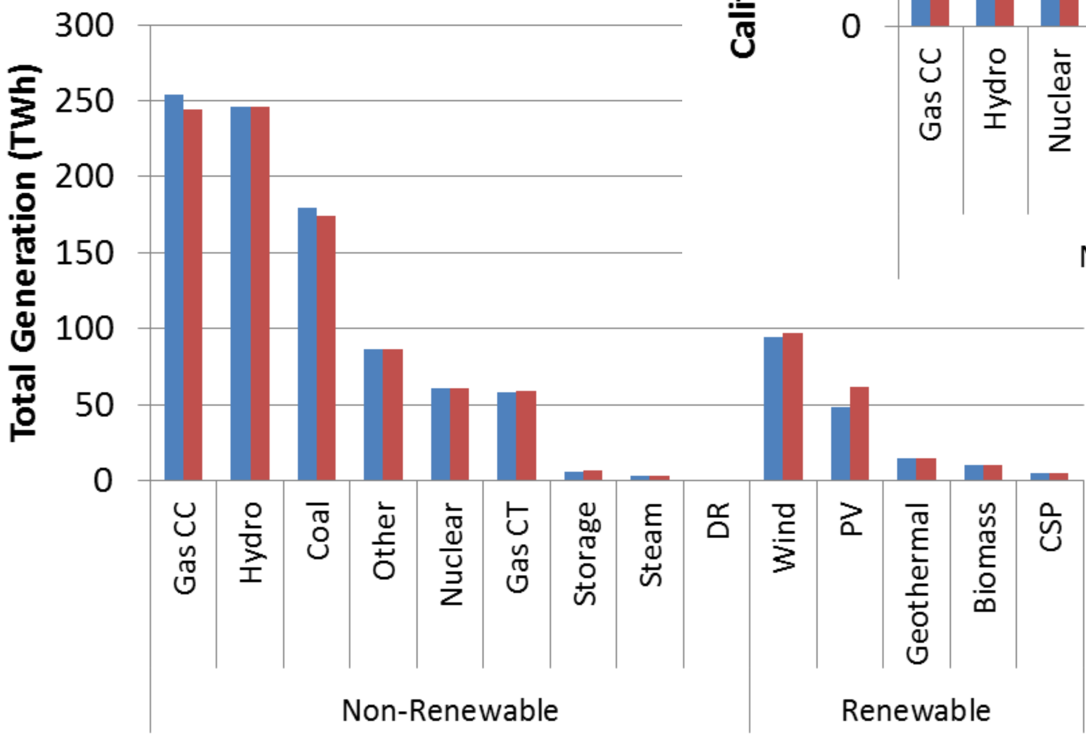
Load and net load shapes by season (2)



Base Case Results

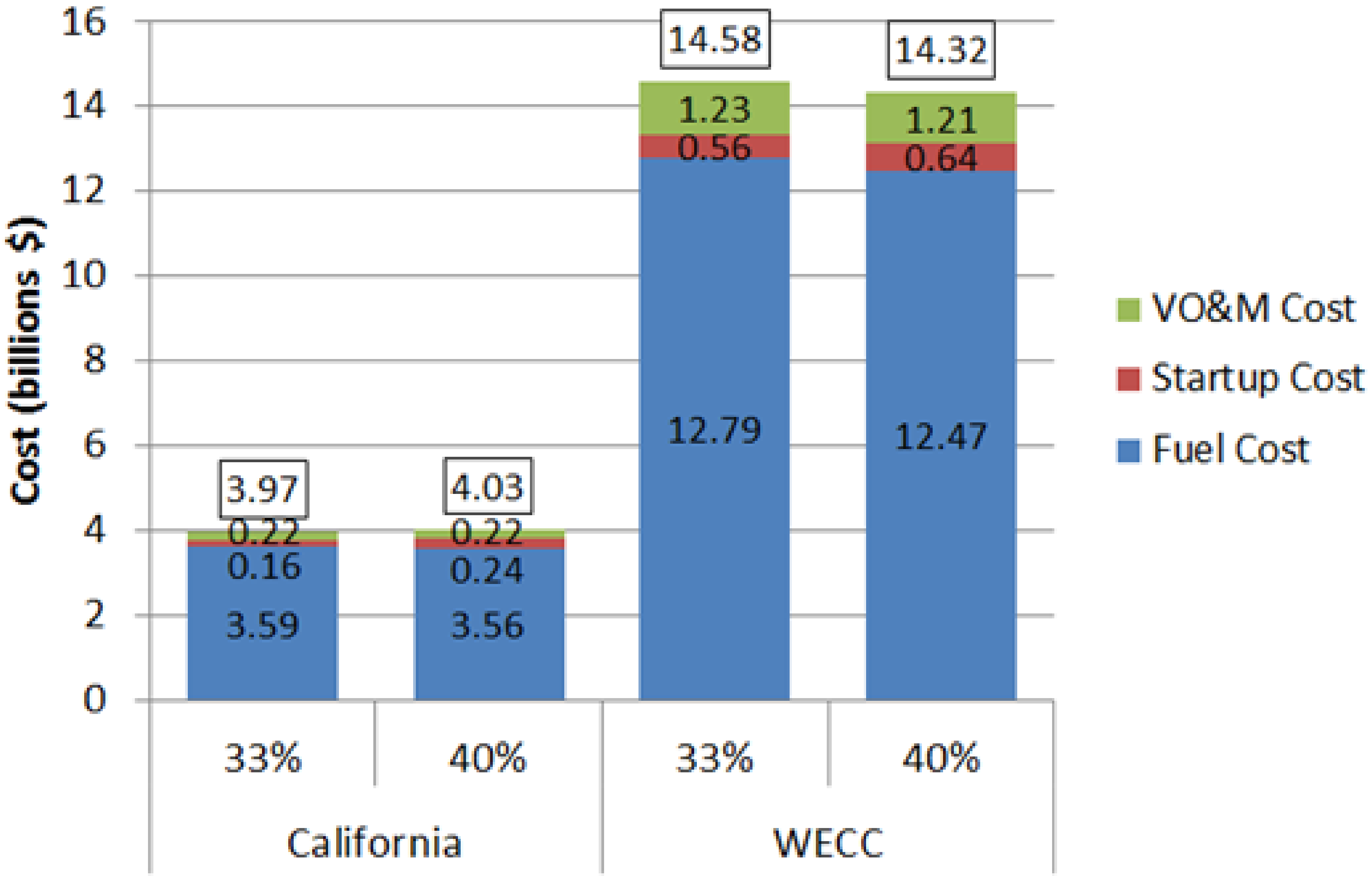
- Total modeled generation for California and across the Western Interconnect





Base Case Results

- Pre-storage Production Cost



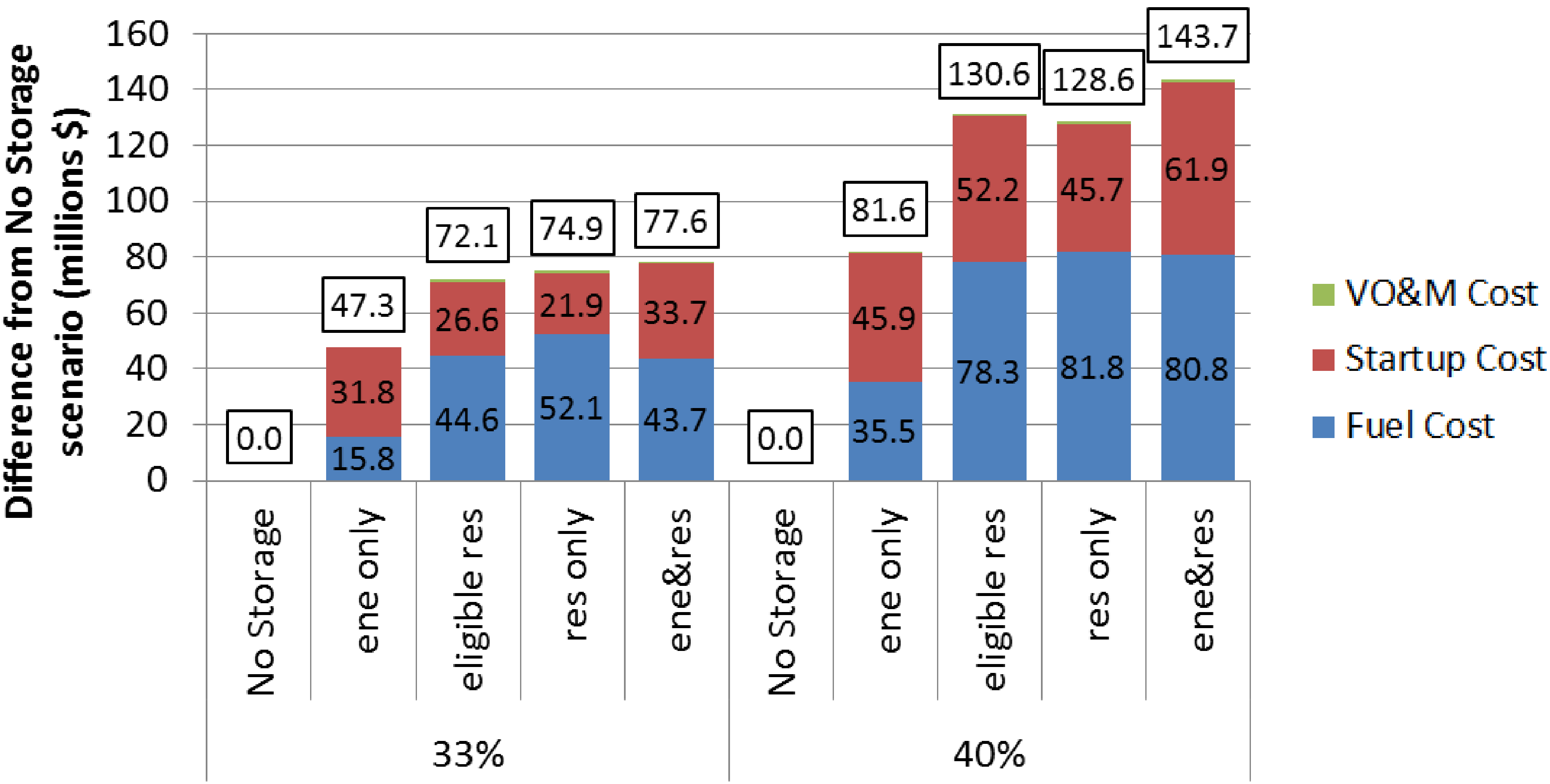
Notes on pre-storage results

- Start-up costs and variable O&M are a small part of total production costs
- As shown in the previous slide, California production costs are based on in-state generation; imports are not factored into this result (hence actual California costs are higher)
- Slight increase in production costs in the California footprint between 33% and 40% RPS scenarios due to increased generator start up in California in 40% case

5. Detailed Results from Base-Case Scenarios

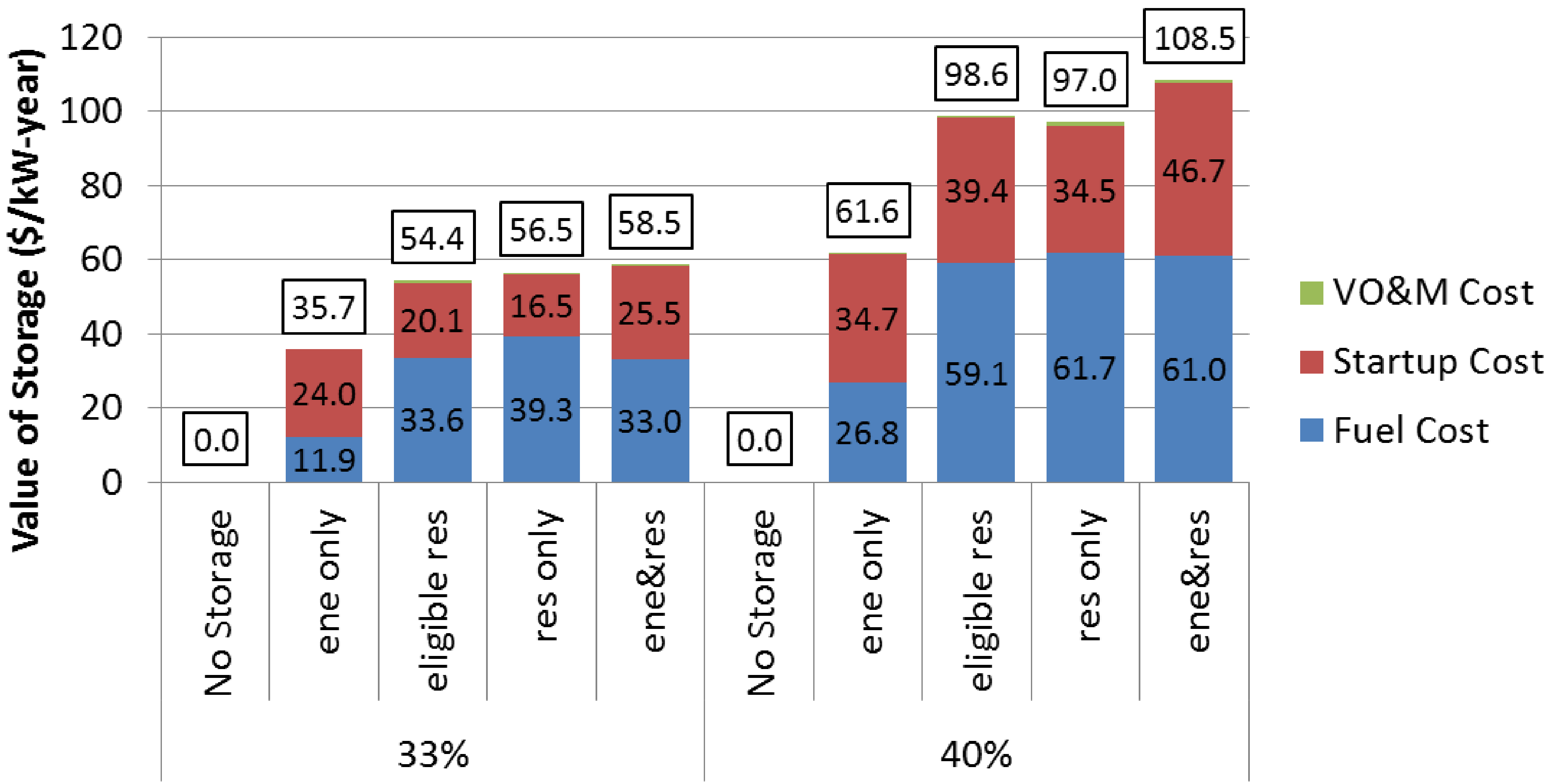
Base Case valuation results

- Reduction in annual production cost ($ million)



Base Case valuation results

- Production cost reduction divided by installed capacity ($/kW-year)



Key findings

- Increase in renewable penetration has a major impact on storage value
- High value of avoided generator start-up costs in each case modeled
- Provision of ancillary services significantly increases storage value

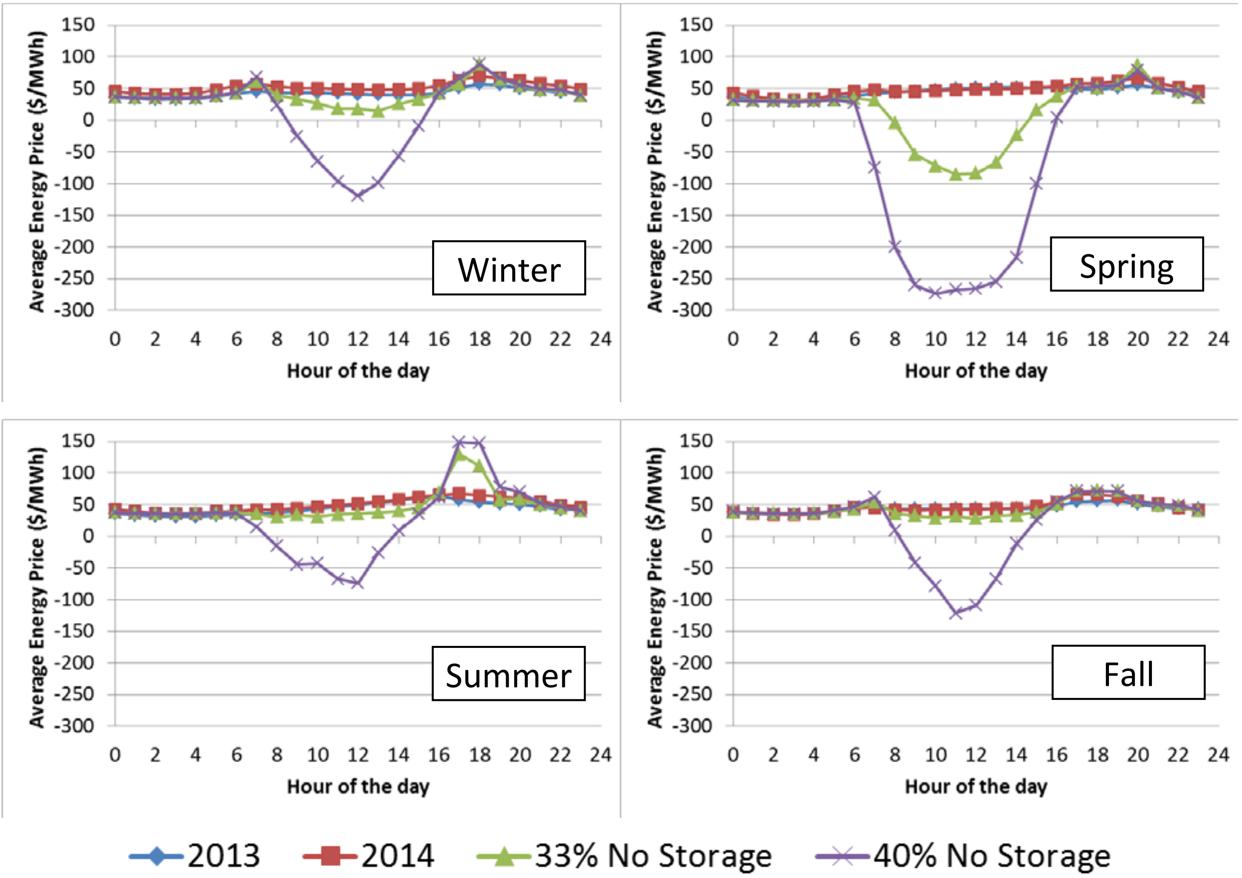
- *These results will be discussed in more detail in later slides*

Notes on base-case results

- Both 33% and 40% scenario results include certain assumptions/modeling methods which increase storage value:
  - -$300/MWh renewable curtailment costs exaggerate arbitrage opportunity
  - Storage can dump energy at high negative curtailment costs and still improve production costs due to round-trip efficiency loss
  - Maintaining no net California exports does not allow for economic regional dispatch to relieve overgeneration
- These assumptions are examined further in sensitivity analyses

Base Case Results

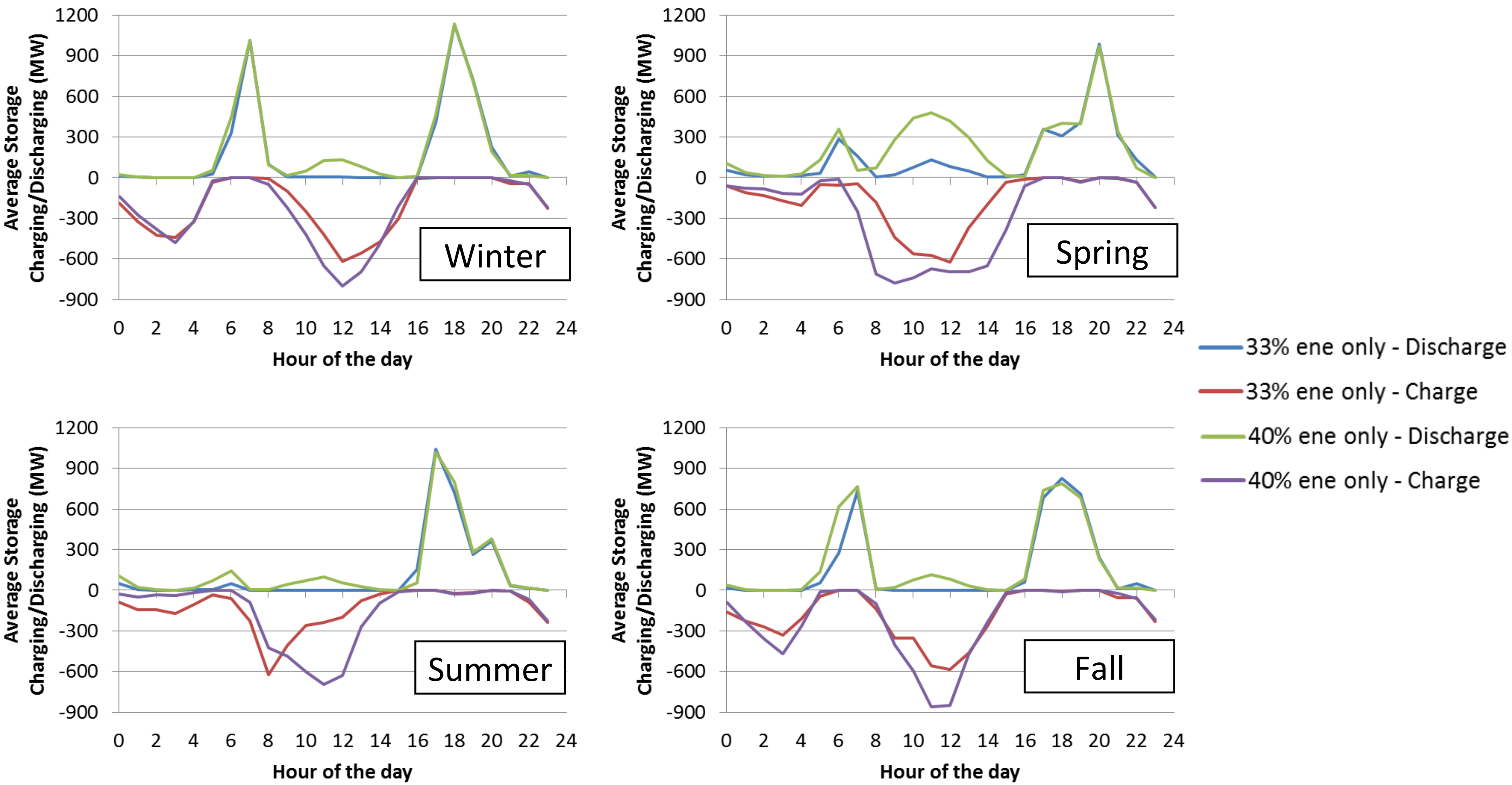
- Day-ahead energy prices with bid cost of -$300/MWh for renewables and table with alternative bid values



Energy Price Statistics ($/MWh)		Max	Min	Average	Hours ≤0
2013		187.9	14.7	43.6	0
2014		175.5	14.8	48.5	0
33% No storage	$0/MWh	2,000	0	43.9	215
	-$150/MWh	2,000	-150	40.4	197
	-$300/MWh	2,000	-300	37.1	198
40% No storage	$0/MWh	2,000	0	40.5	1,334
	-$150/MWh	2,000	-150	21.6	1,198
	-$300/MWh	2,000	-300	2.7	1,184
33% ene&res	$0/MWh	2,000	0	43.1	139
	-$150/MWh	2,000	-150	40.3	148
	-$300/MWh	2,000	-300	38.1	146
40% ene&res	$0/MWh	2,000	0	39.1	1,058
	-$150/MWh	2,000	-150	22.8	1,036
	-$300/MWh	2,000	-300	7.0	1,019

Base case results: Storage operations

- Storage operates to support a variety of grid needs (e.g., generator startups, reserves, reduce curtailment)



6. Results from Selected Sensitivity Cases and Additional Interpretation

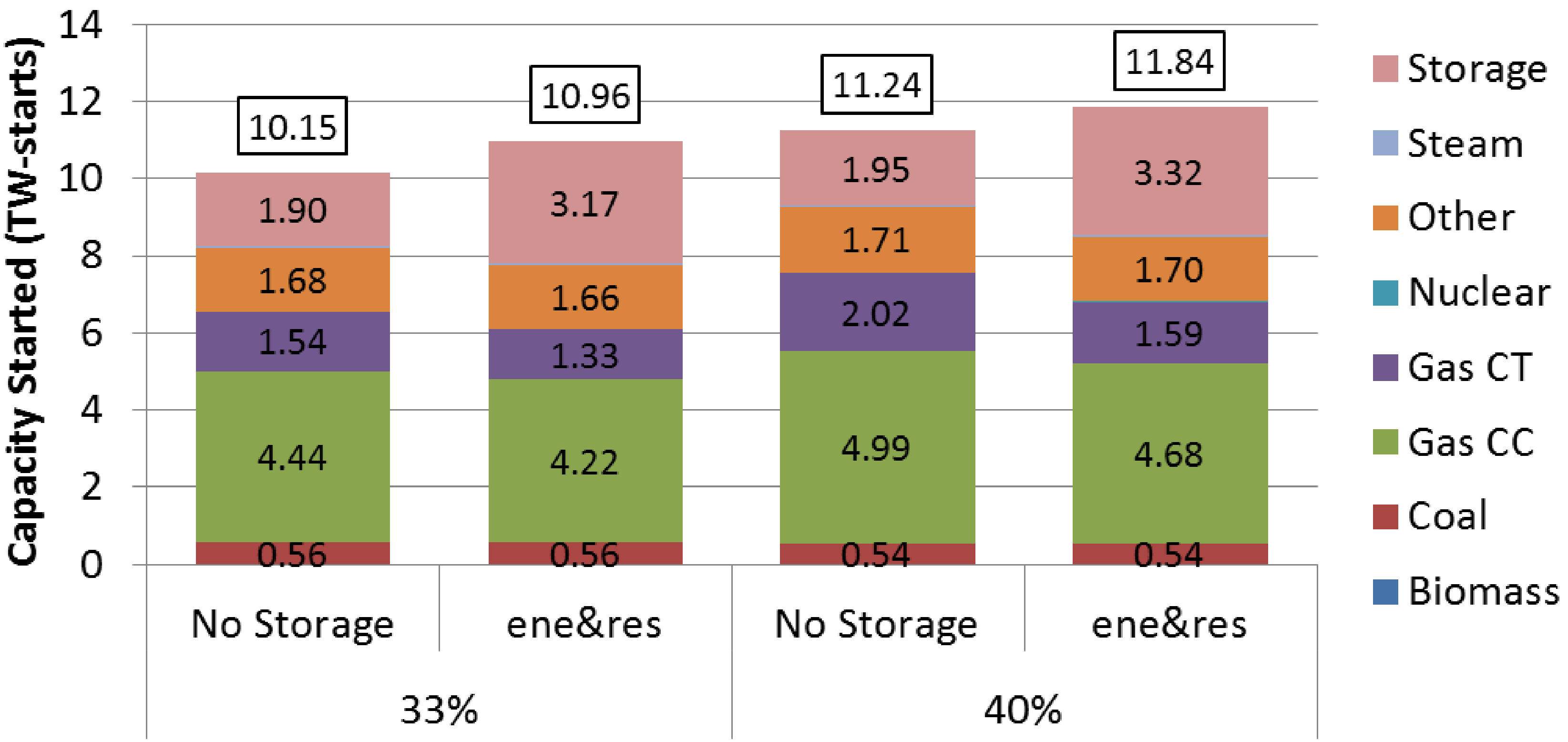
(a) Effect of storage operations on avoided generator start-up costs

Results and interpretation

- **Large effect of storage operations on avoided generator start-up costs across all cases**
  - In base-cases, ranges from ~29% - ~67% of storage value
  - Higher when storage is conducting energy arbitrage
  - Absolute value is proportional to size of storage portfolio; that is, the more storage capacity, the greater the impact on generator start-up costs
- **Drivers of this result include:**
  - Very high flexibility of new storage technologies (no inter-temporal constraints)
  - Start-up costs in model of ~$56,000/start for coal, ~$26,000/start for combined cycle (CC), and ~$3,000/start for combustion turbines (CT)

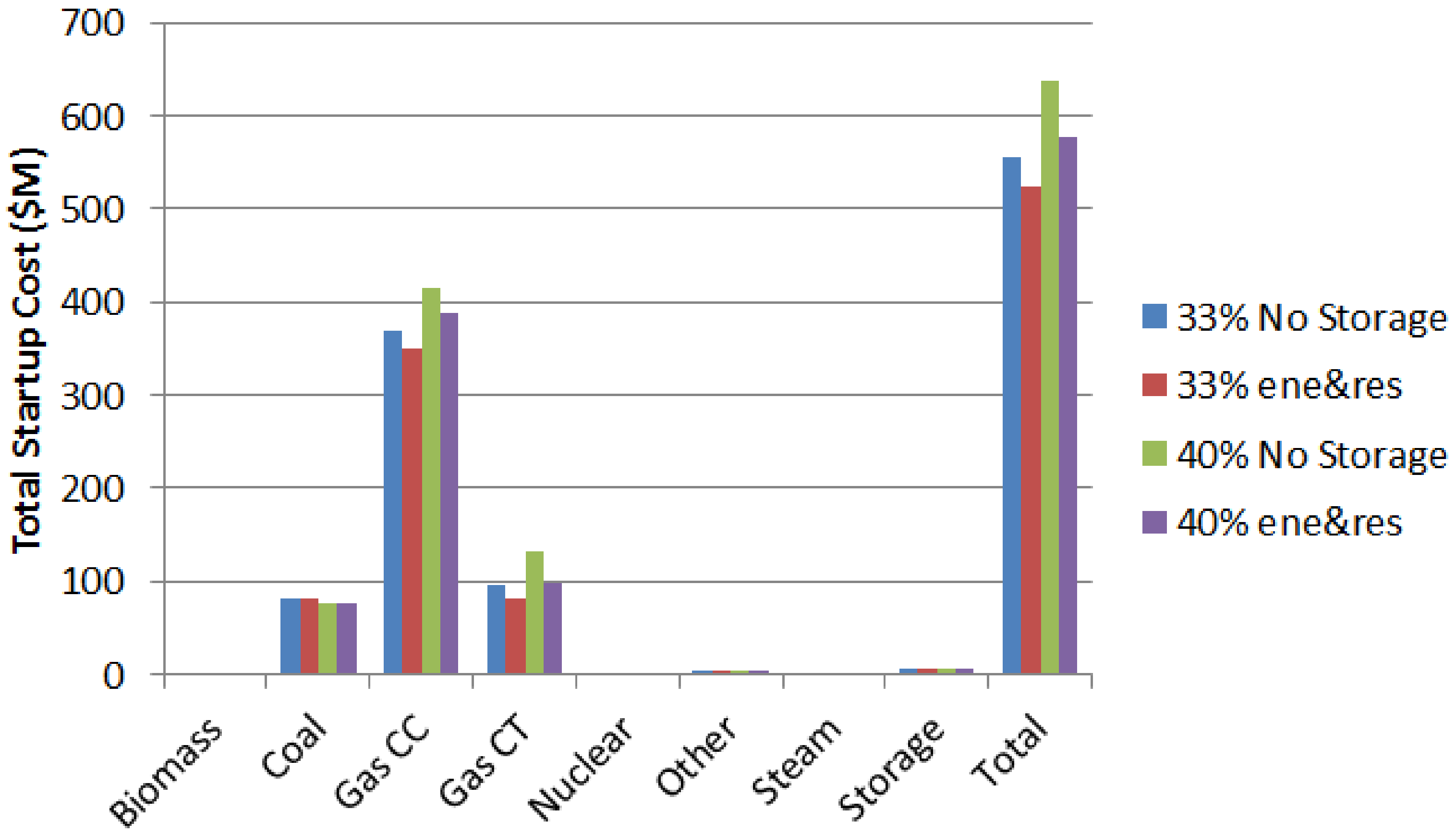
Startup Capacity

- **Total number of capacity-weighted unit starts for the Western Interconnect**
  - capacity-weighted starts =
    (number of starts per unit) * (installed unit capacity)
  - Method used so the startup values are not biased towards small units



Startup Costs

- **When optimizing the entire system, storage helps to avoid startup costs, which is not compensated for in California markets**



(b) Effect of storage operations on renewable curtailment and interaction with regional market expansion

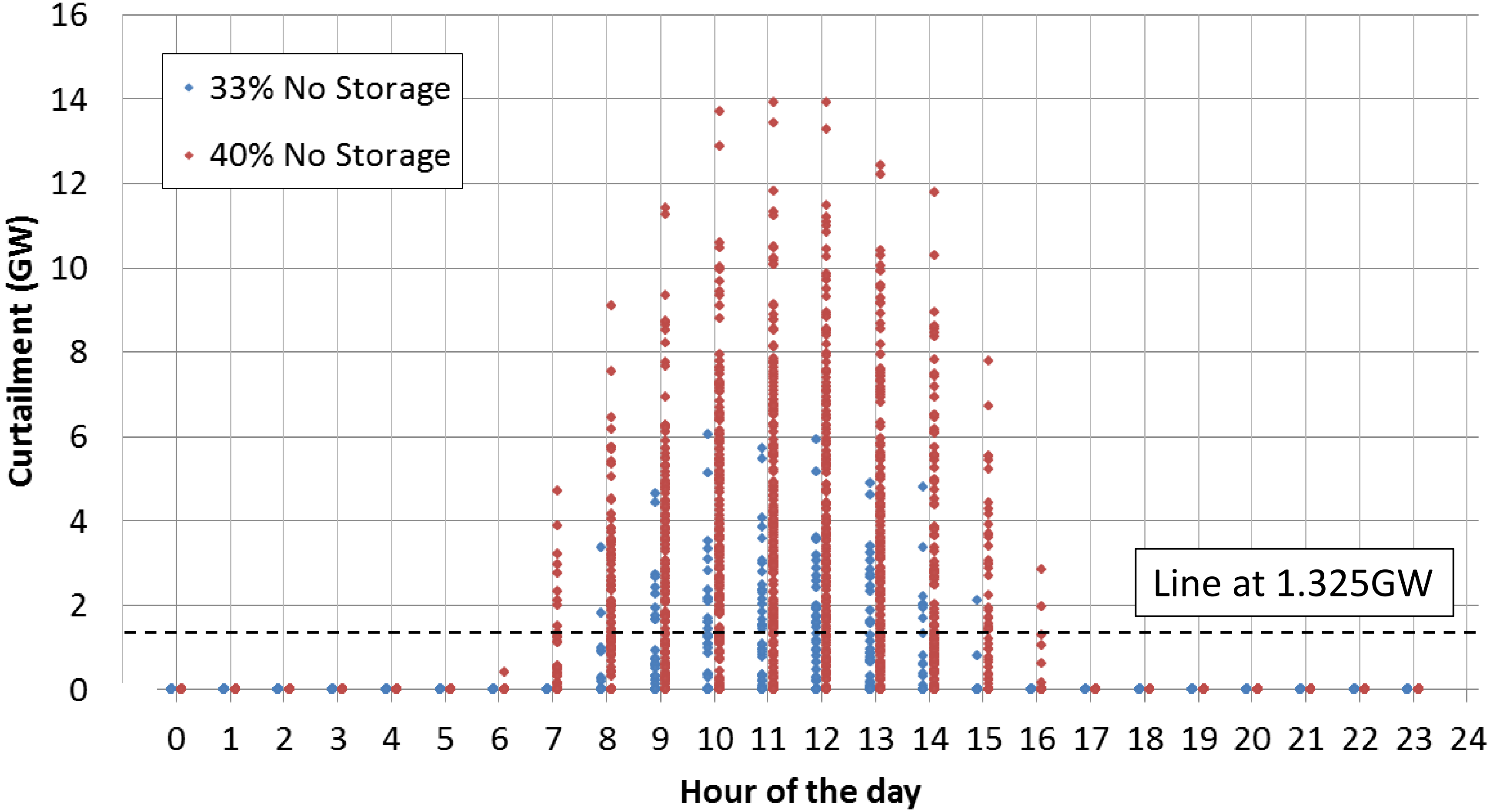
Renewable curtailment

- LTPP models have identified the potential for curtailment of about 5% of renewable energy in the 40% renewable energy scenario
- Several other studies have identified similar or greater levels of potential curtailment at high renewable penetration

- *Note* – LTTP production cost models may underestimate actual curtailment, because of the level of aggregation of transmission and operational constraints

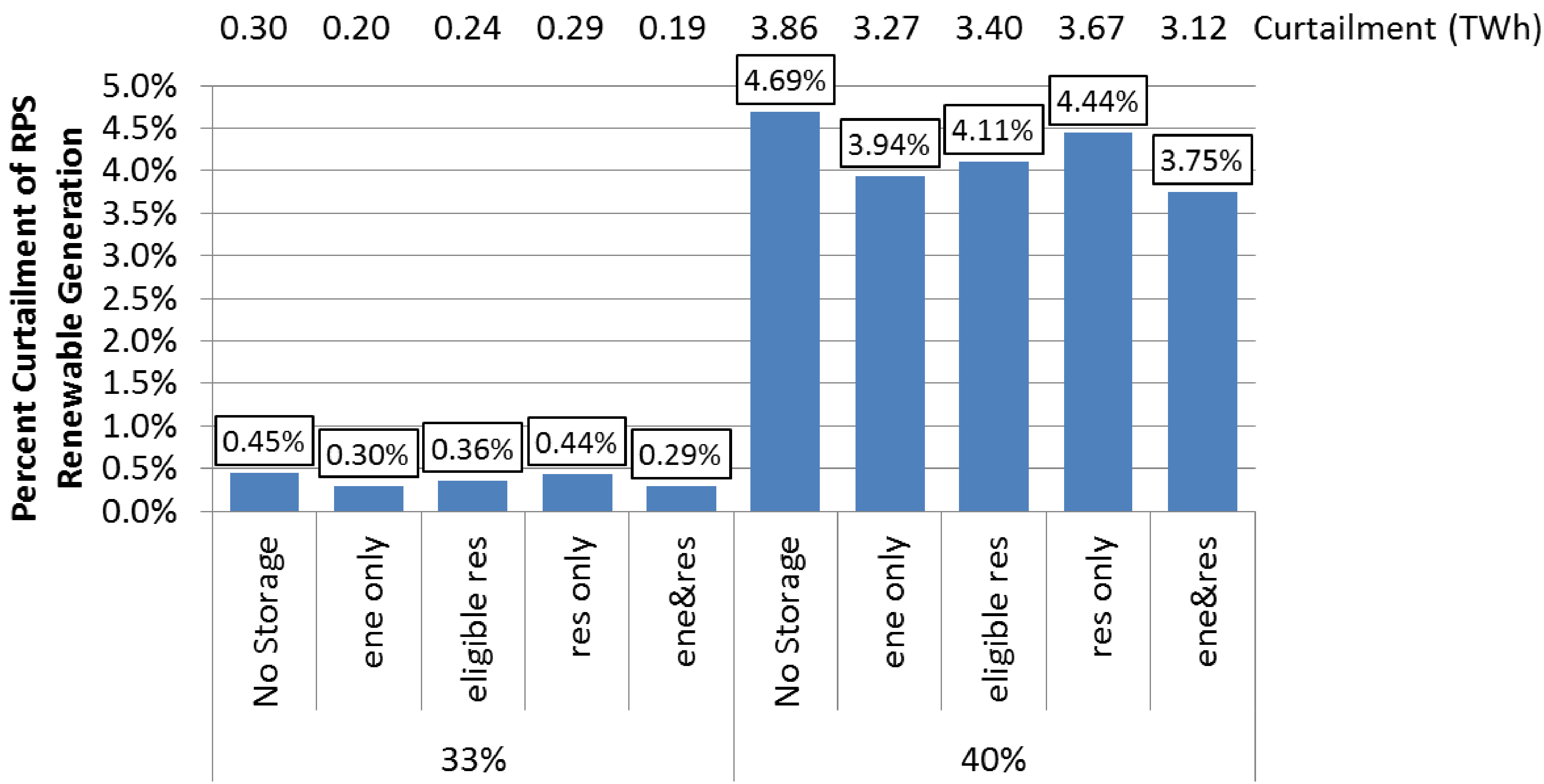
Renewable curtailment before storage operations

- Curtailment (GW) by hour of day, LTPP base-cases (before storage operations)



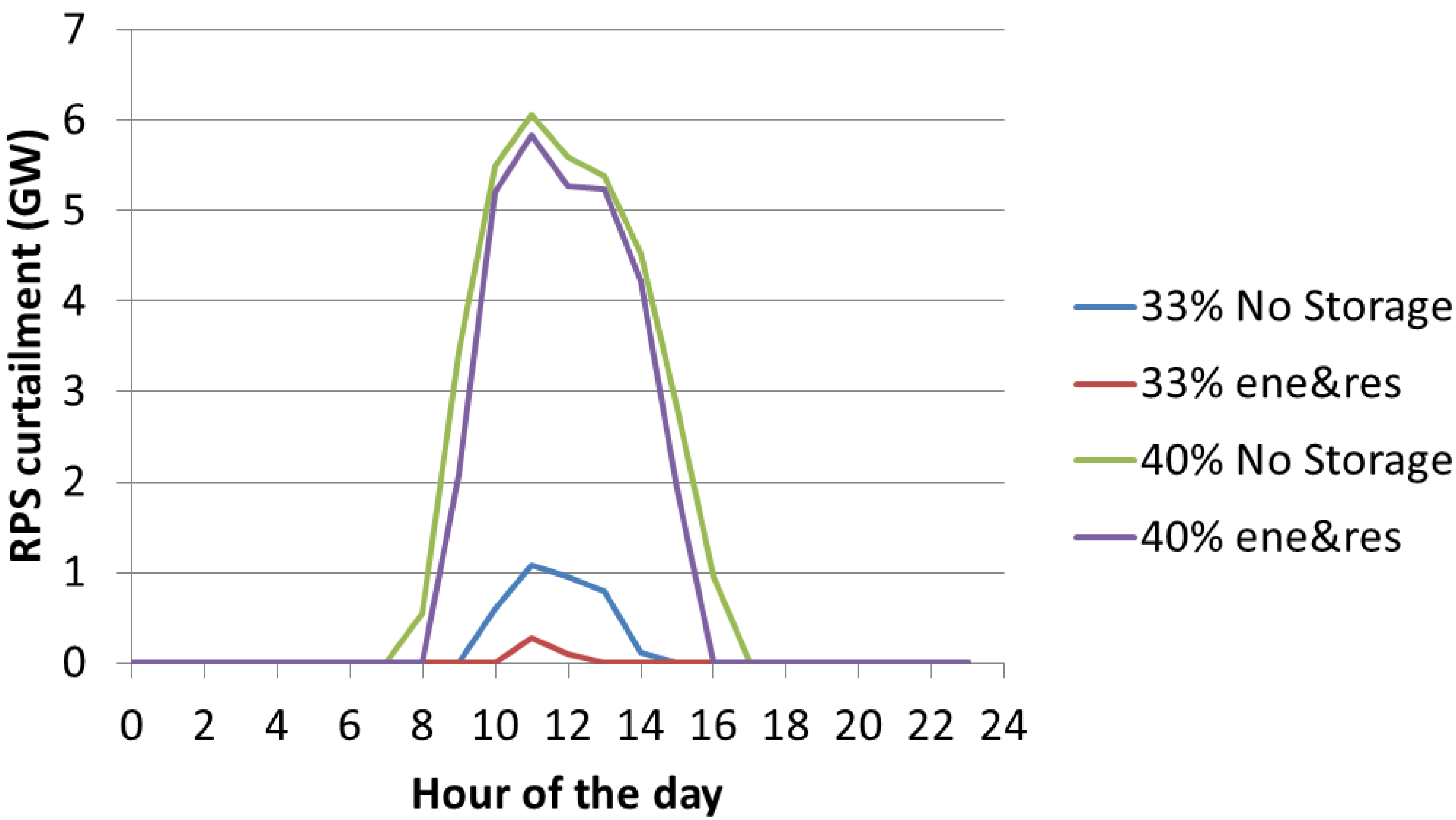
Renewable curtailment – effect of storage

- Storage reduces renewable curtailment in all cases (shown below under base case assumption that curtailment costs $300/kWh)



Renewable curtailment – example day

- Curtailment of RPS eligible wind and solar on "March 23, 2024"
- Curtailment significantly exceeds storage capacity in the 40% scenario.



Relaxation of export constraints

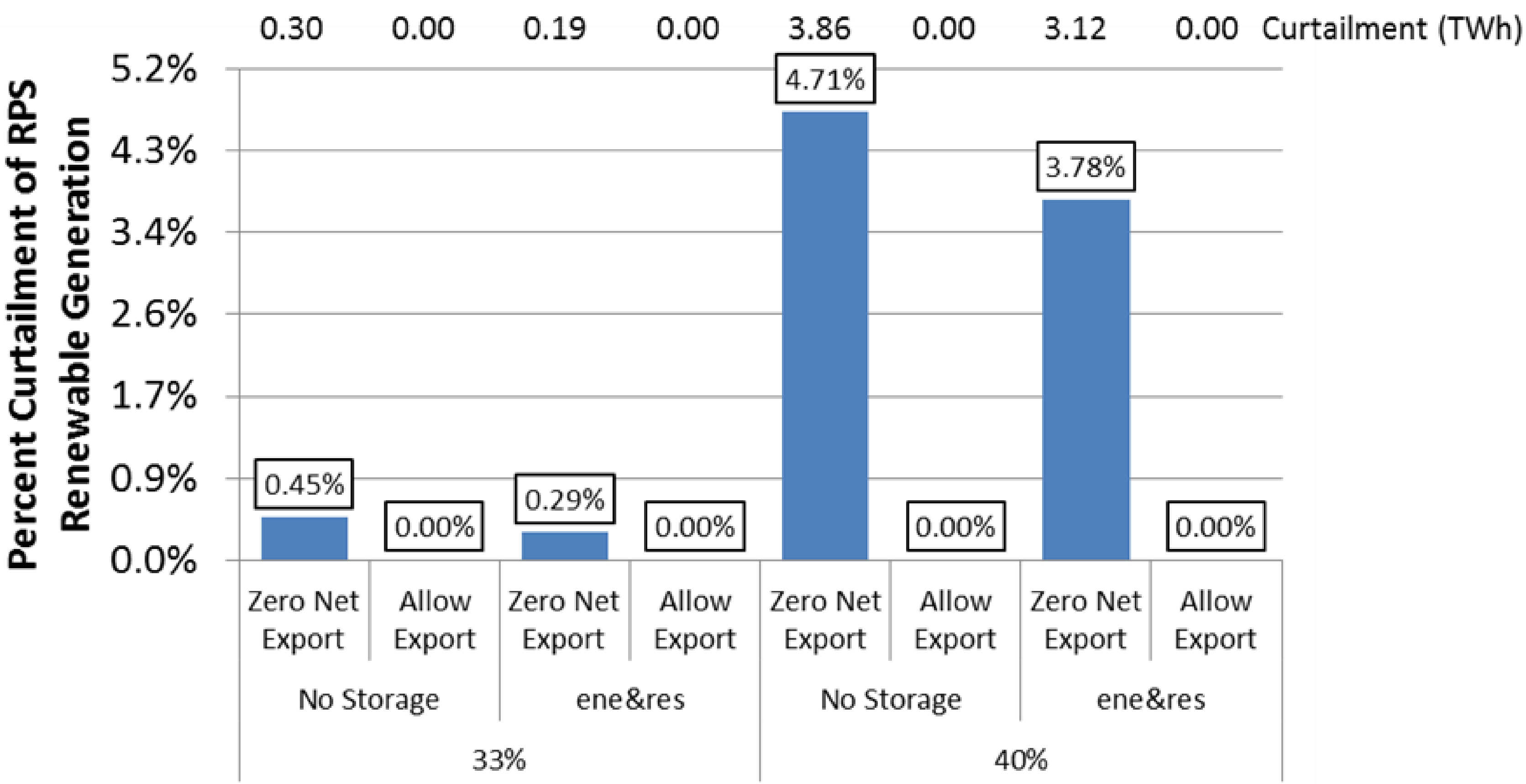
- LTPP model includes a “no net export” constraint from California, a conservative assumption based on historical considerations:
  - the CAISO has always been a net importer
  - the Energy Imbalance Market (EIM) is currently restricted to real-time energy transactions
- Other studies have shown that removing this constraint eliminates curtailment in the 33%-40% scenarios by allowing WECC-wide redispatch
- Suggests that future regional market expansion will help relieve curtailment, but scope of actual regional redispatch and effect on storage value remained to be explored

Relaxation of export constraints (2)

- Sensitivity case removes the “no net export” constraint for the 33% and 40% base-cases (ene&res)
- Two cases need to be compared to measure change in storage benefits: (1) with the constraint and (2) without the constraint
- Full WECC can be redispatched, hence this case is an upper bound on curtailment relief
- Reduced benefits of storage due to increase in “off-peak” prices

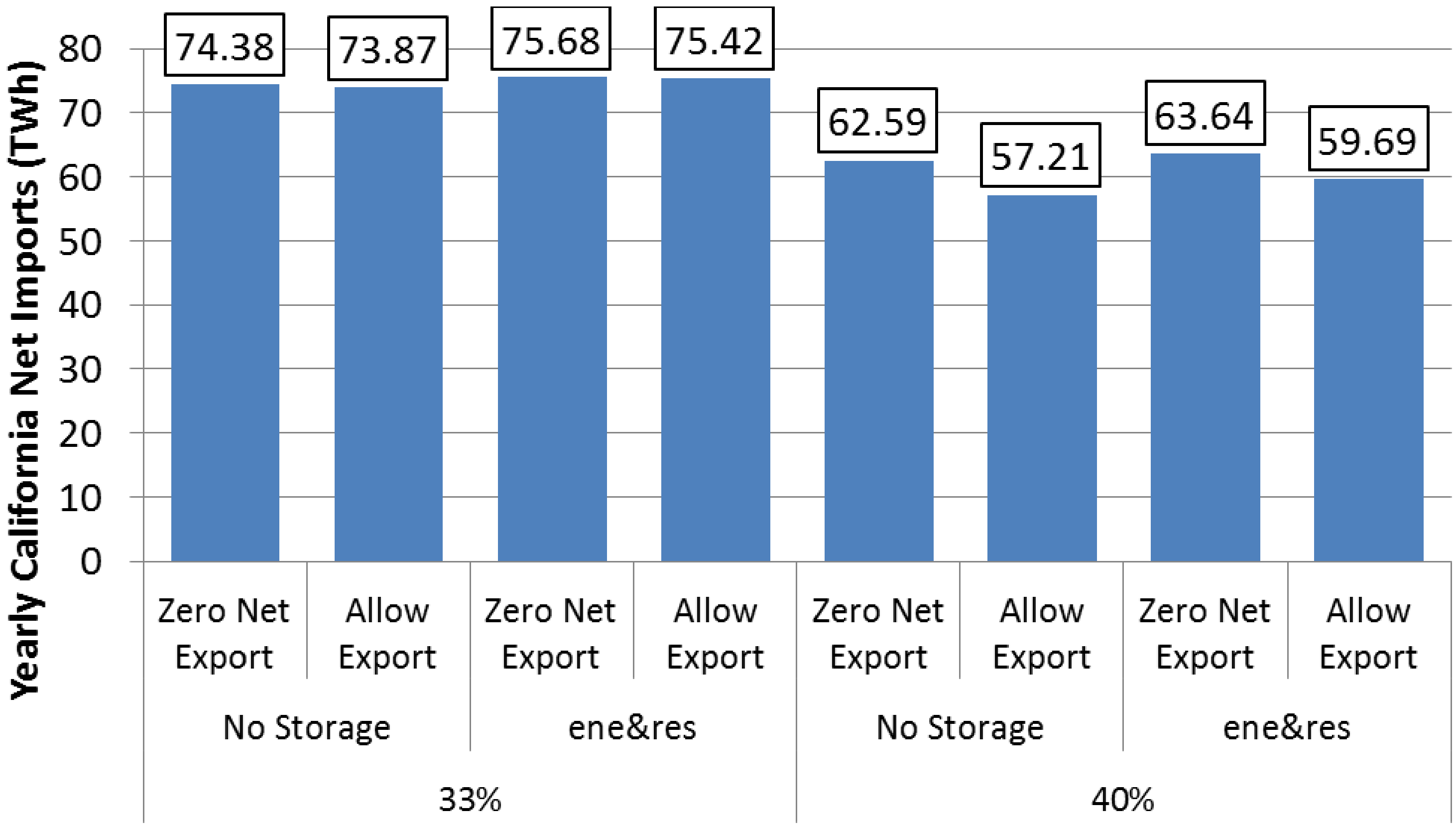
Effect of increased exports on curtailment

- Curtailment before and after relaxing California export limitations



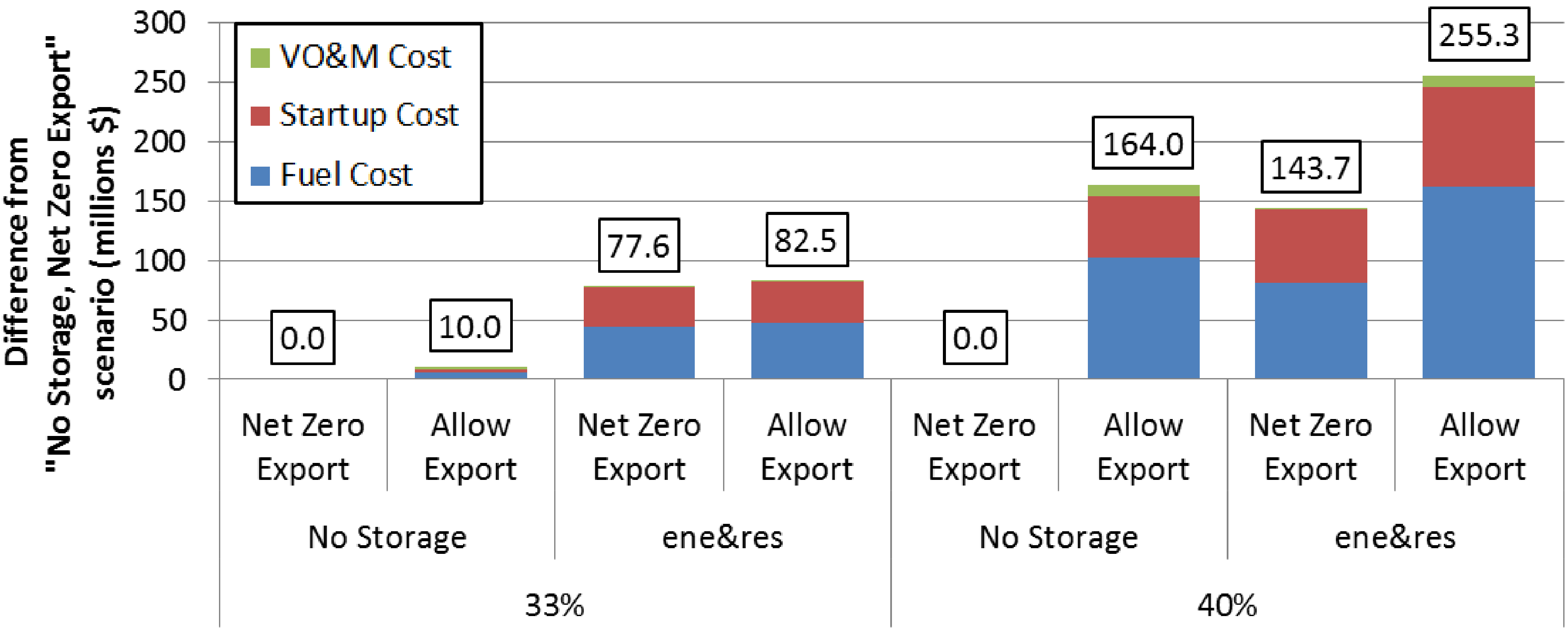
Impact on annual net imports

- California remains a net importer on an annual basis in the cases modeled



Changes in production costs

- Production cost reduction ($ million)/year when relaxing export constraints



Changes in production costs (2)

- Table shows that storage benefits decline by $5.1 million in the 33% scenario (about 7%) and $52.4 million in the 40% scenario (about 36%)

Case	Storage benefit ($ million)	Reduction in storage benefits due to export of curtailed energy
33% case – no net export	$77.6 - $0 = $77.6	$77.6 - $72.5 = $5.1
33% case – allow export	$82.5 - $10 = $72.5	
40% case – no net export	$143.7 - $0 = $143.7	$143.7 - $91.3 = $52.4
40% case – allow export	$255.3 - $164 = $91.3	

(c) Effect of negative renewable curtailment cost and negative prices on storage value

Cost of curtailment/negative prices

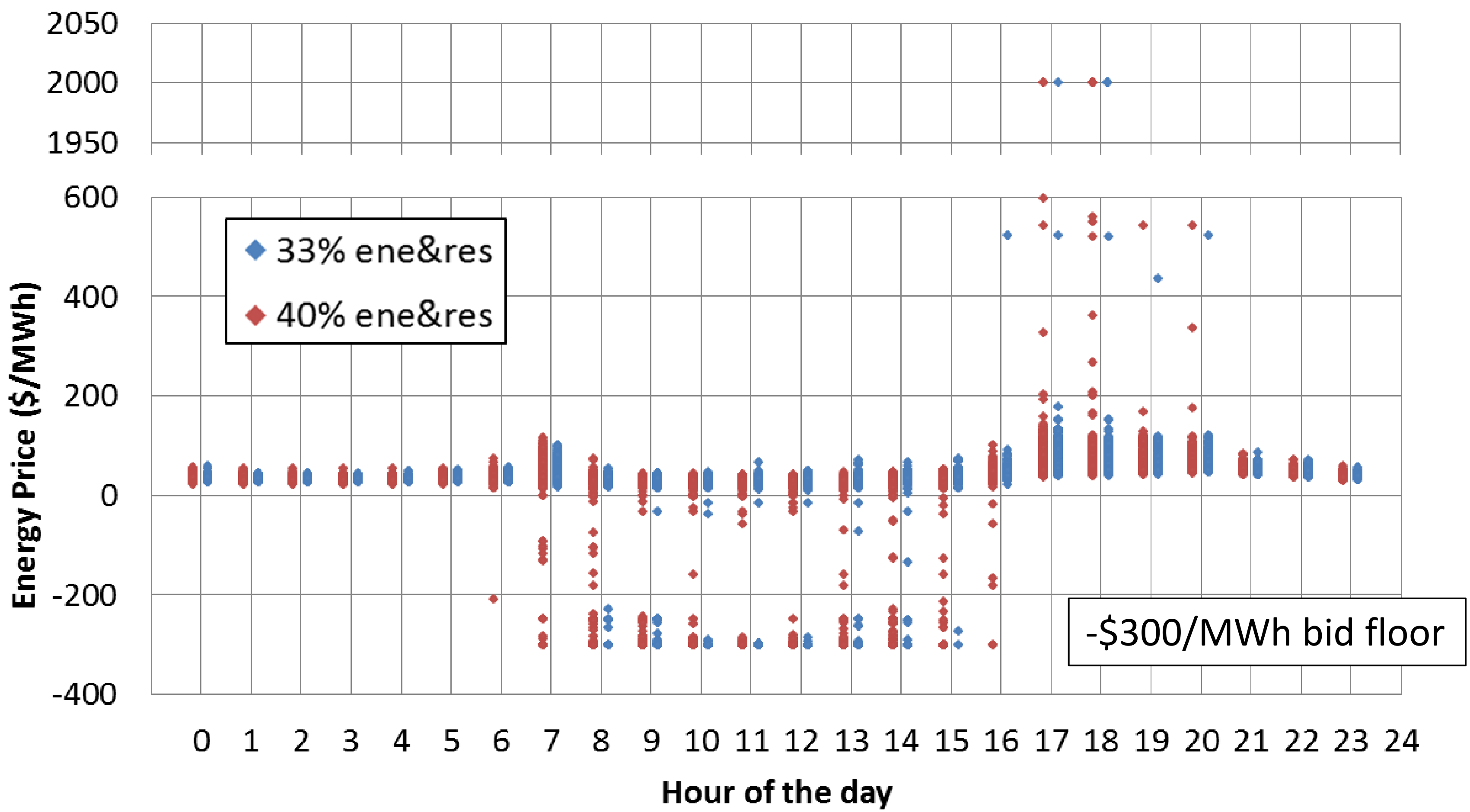
- LTPP model uses a -$300/MWh variable O&M cost on renewable generation to reduce curtailment
  - This cost is the maximum allowed negative bid (i.e., "bid floor") in the CAISO market by 2024; otherwise arbitrary
- When renewable energy is curtailed, the energy shadow price is set by the negative cost – i.e., a negative market price
- Negative prices occur during the middle of the day and are caused by a combination of renewable generation and inflexibility of the system to accommodate the renewables (e.g., demand shape, generator min gen, renewables do not provide reserves, no net export rule and other system constraints)
- Increases storage value, but also creates opportunities for inefficient storage cycling

Cost of curtailment/negative prices (2)

- To evaluate effect of negative curtailment cost assumptions on storage value, study conducts sensitivity analysis on curtailment cost: -\$300/MWh (base-case), -\$150/MWh, \$0/MWh
  - In production cost model, a more negative curtailment cost increases overall production costs, reduces curtailment, and increases storage value
  - Making the curtailment cost less negative changed the resulting negative energy prices but had a minimal impact on the rest of the prices

Energy prices in modeled scenarios

- *Note* – prices are after storage operations, but there was little difference before and after

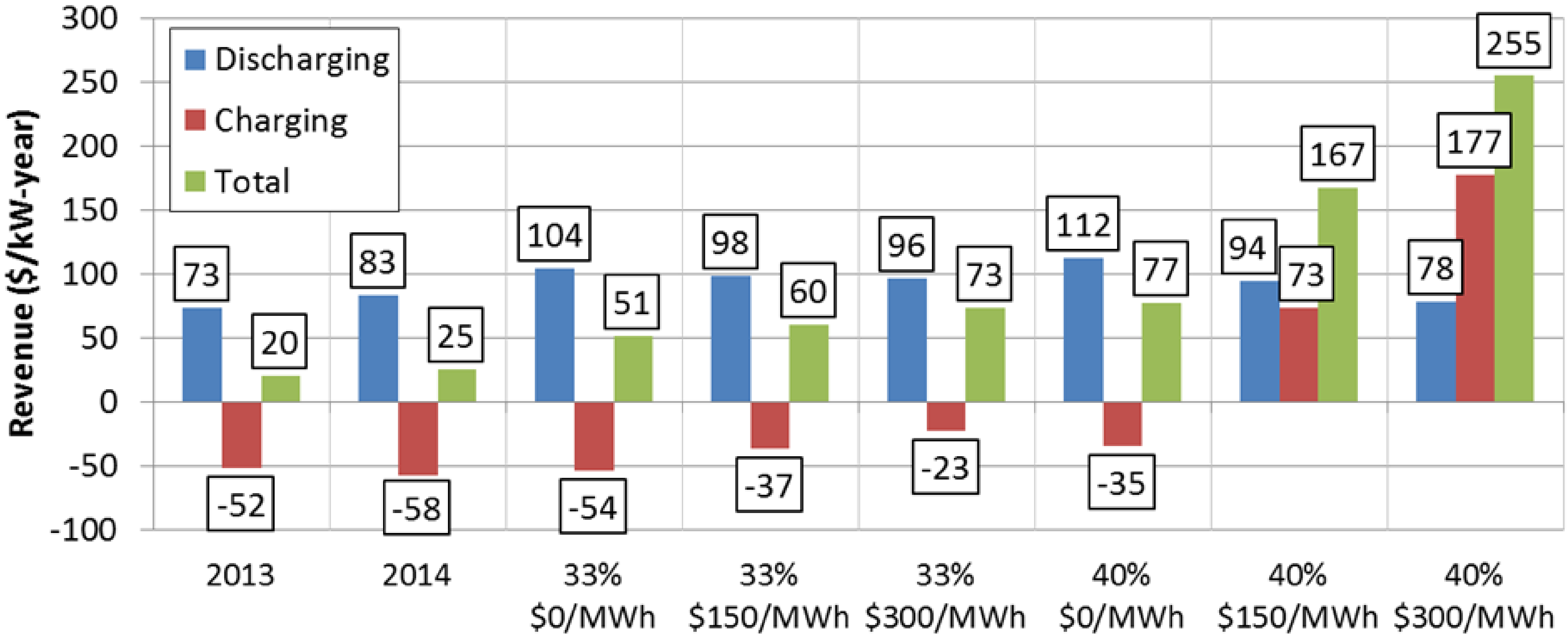


Energy price statistics from different scenarios

Energy Price Statistics ($/MWh)		Max	Min	Average	Hours ≤0
2013		187.9	14.7	43.6	0
2014		175.5	14.8	48.5	0
33% No storage	$0/MWh	2,000	0	43.9	215
	-$150/MWh	2,000	-150	40.4	197
	-$300/MWh	2,000	-300	37.1	198
40% No storage	$0/MWh	2,000	0	40.5	1,334
	-$150/MWh	2,000	-150	21.6	1,198
	-$300/MWh	2,000	-300	2.7	1,184
33% ene&res	$0/MWh	2,000	0	43.1	139
	-$150/MWh	2,000	-150	40.3	148
	-$300/MWh	2,000	-300	38.1	146
40% ene&res	$0/MWh	2,000	0	39.1	1,058
	-$150/MWh	2,000	-150	22.8	1,036
	-$300/MWh	2,000	-300	7.0	1,019

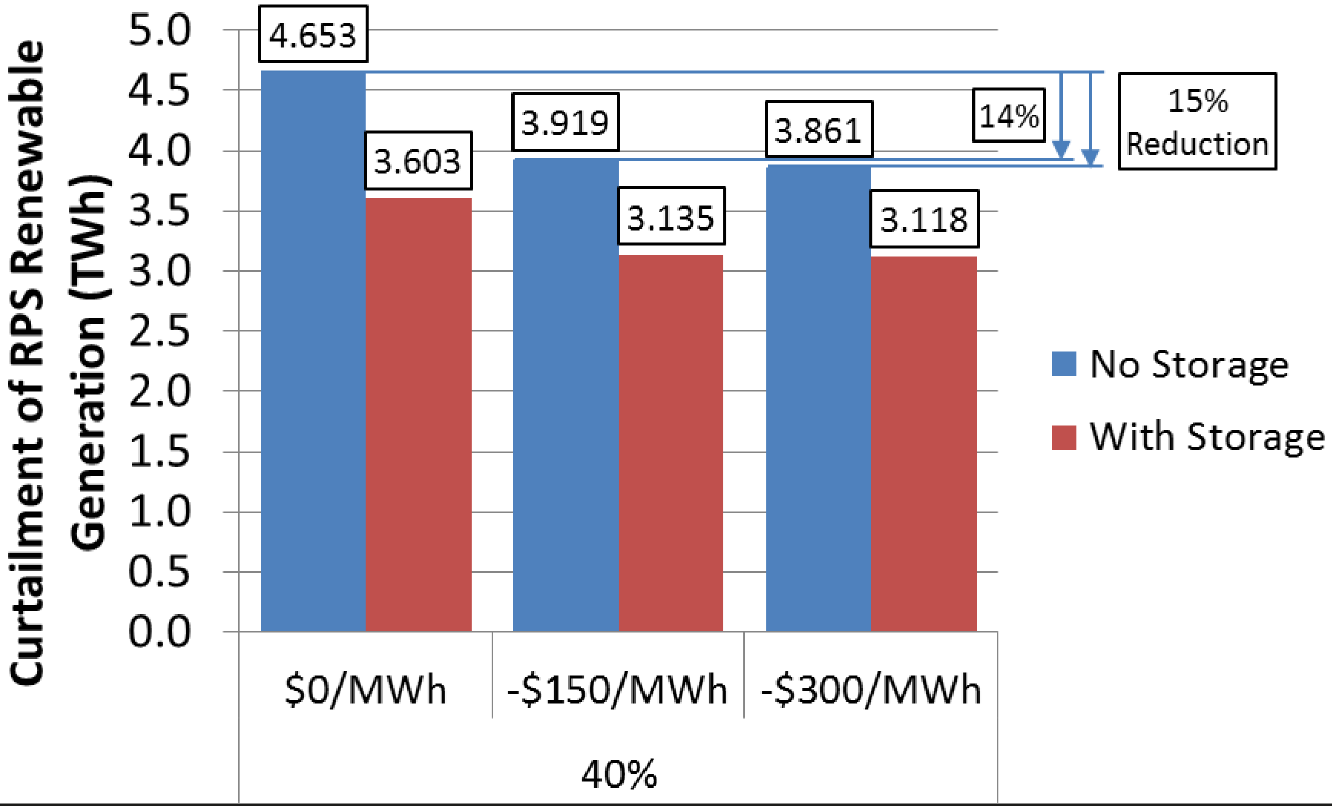
Energy arbitrage value using historical and future prices

- Price-taker model allows for comparison of energy arbitrage value using historical and future prices, under negative price sensitivities
  - Negative prices provide positive revenues for storage charging



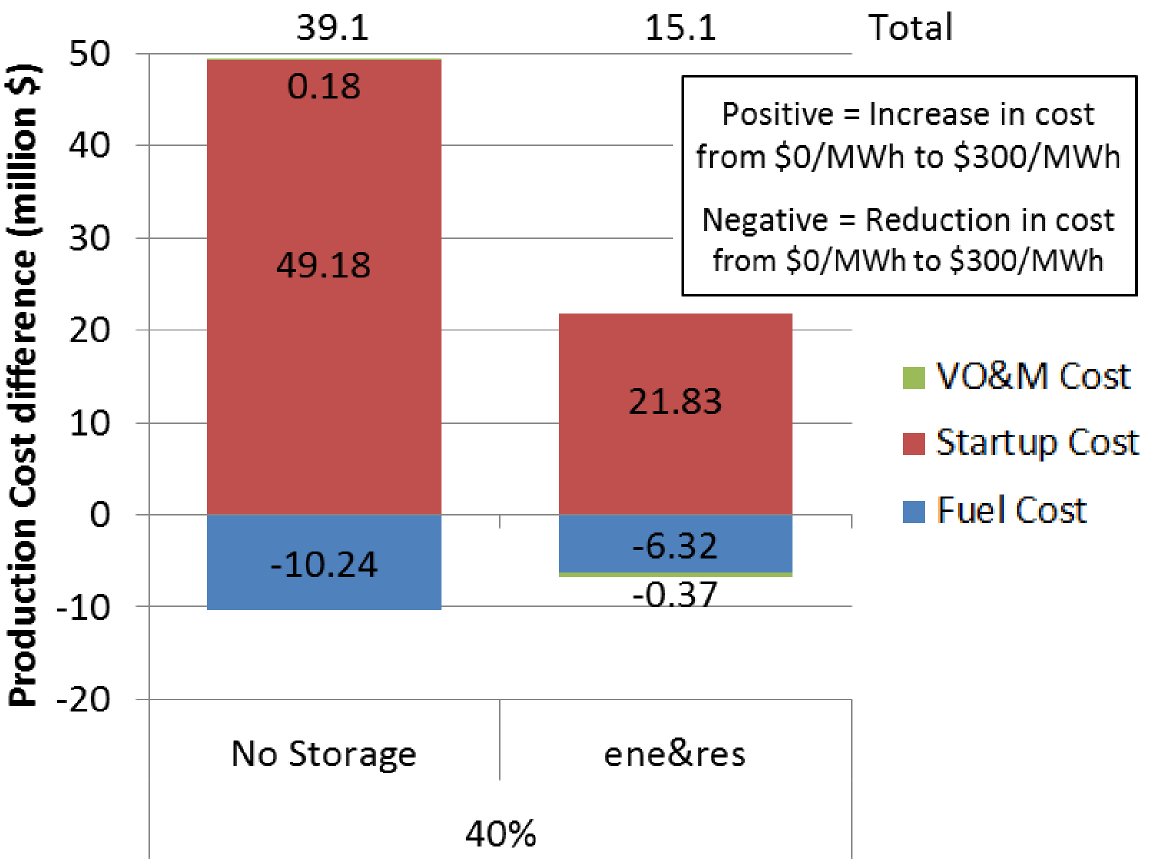
Effect of changing negative curtailment costs on simulated curtailment

- Adjusting the assumed negative cost for renewable curtailment has a significant impact from \$0/MWh to -\$150/MWh but the impact from -\$150/MWh to -\$300/MWh is much smaller



Effect of changing negative curtailment costs on production costs

- Production cost reduction differences from $0/MWh to -$300/MWh renewable bid cost
  - Fuel costs are reduced due to reduction in curtailment but startup costs increase
  - The net result is a slight increase in production cost



Negative Bid Price: Cost of curtailment

- By combining the curtailment values with the change in production cost from the previous two figures we can construct a measure for the cost of curtailment
- Going from \$0/MWh curtailment cost to \$300/MWh results in…
  - Curtailment reduction of 792 GWh (w/o storage) and 485 GWh (w/ storage)
  - Production cost increase of \$39.1M (w/o storage) and \$15.1M (w/ storage)
- The resulting cost of curtailment is
  - \$49/MWh without storage
  - \$31/MWh with storage

(d) Ancillary Service Benefits

Historical and forecast CAISO reserve procurement

- Model assumes increase in ancillary service procurement by 2024. Table shows:
  - Historical CAISO system procurement of Regulation and Operating Reserves (2013 and 2014)
  - LTPP model includes CAISO forecast of Regulation, Operating Reserves and load-following reserves for 2024
  - *Note*: CAISO has recently (2016) increased Regulation procurement to higher levels than forecast for 2024

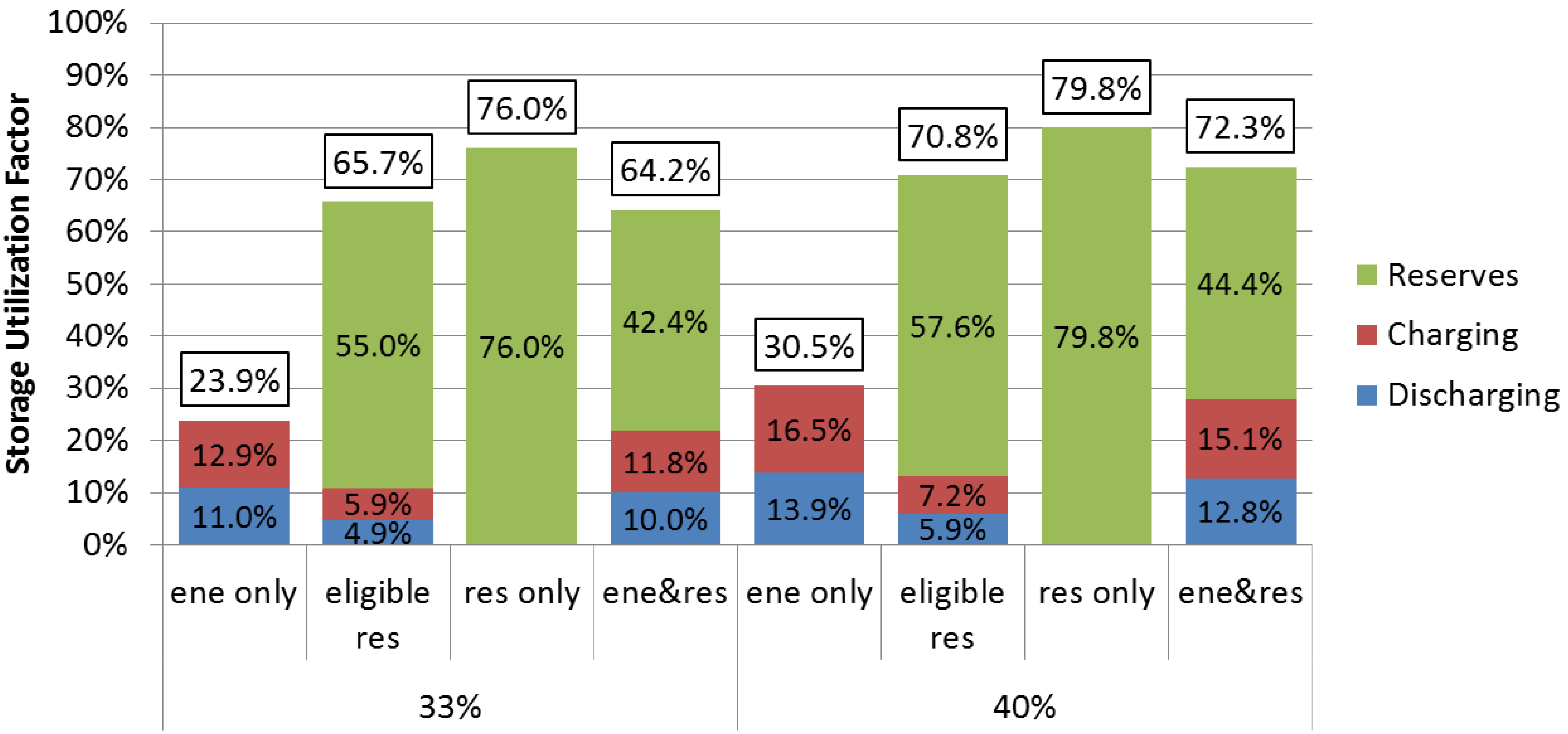
	2013 Avg.	2014 Avg.	2024 – 33% Scenario			2024 – 40% Scenario		
			Avg.	Max.	Min.	Avg.	Max.	Min.
Current ancillary services								
Regulation up	338	341	385	803	0	397	1026	0
Regulation down	325	326	401	1109	62	422	1412	0
Spinning reserve	~871	~849	850	1588	559	850	1588	559
Non-spinning reserve	~846	~853	850	1588	559	850	1588	559
Load-following reserve (LTPP model only)								
Load-following up	N/A	N/A	1279	2573	471	1412	3532	467
Load-following down	N/A	N/A	1256	2669	520	1373	3529	491

General findings on ancillary service value

- Storage provides significant additional reductions in production costs when providing ancillary services
- Factors to consider which increase ancillary service value in the LTTP model:
  - LTPP model allows for calculation of avoided generator start-up costs when storage provides ancillary services (not currently reflected in CAISO market prices)
  - LTPP model carries a load-following reserve which is not a current CAISO ancillary service
- Note: LTPP model does not generate useful ancillary service “shadow prices” due to a number of factors; not able to reasonably analyze future market revenues (modifications could improve this result)

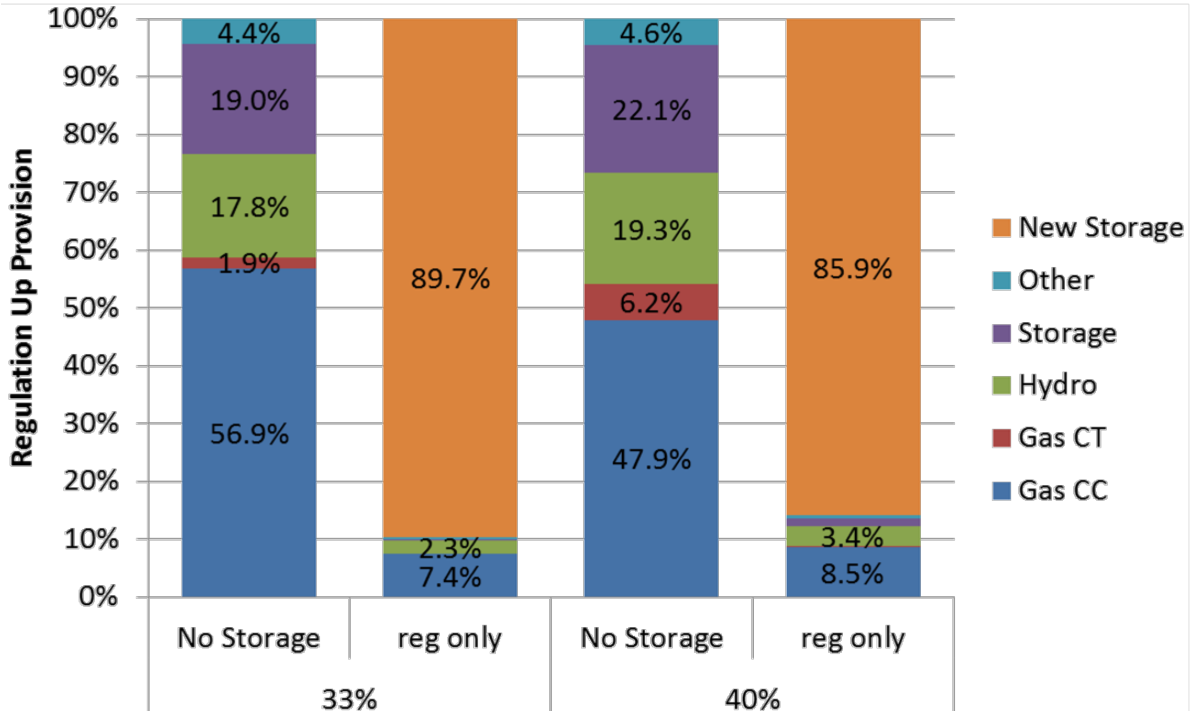
Storage Portfolio Utilization Factor

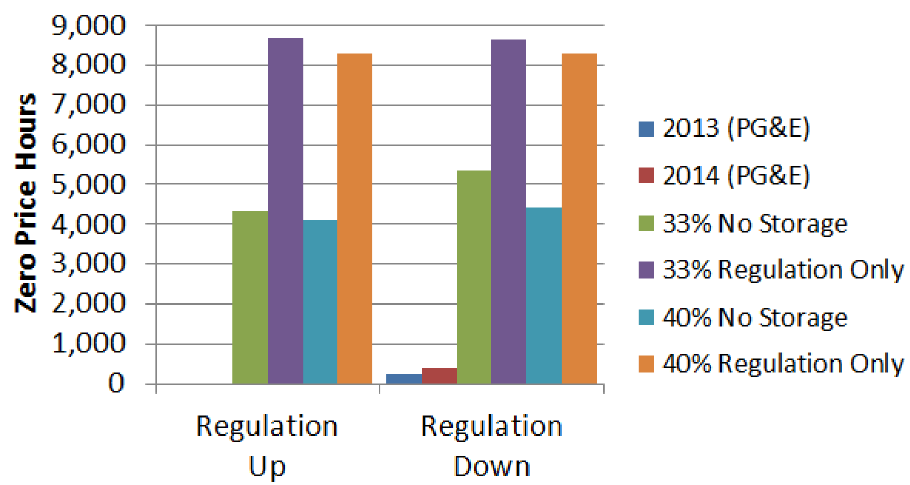
- **Majority of storage utilization comes from providing reserves (if allowed)**



Regulation Only

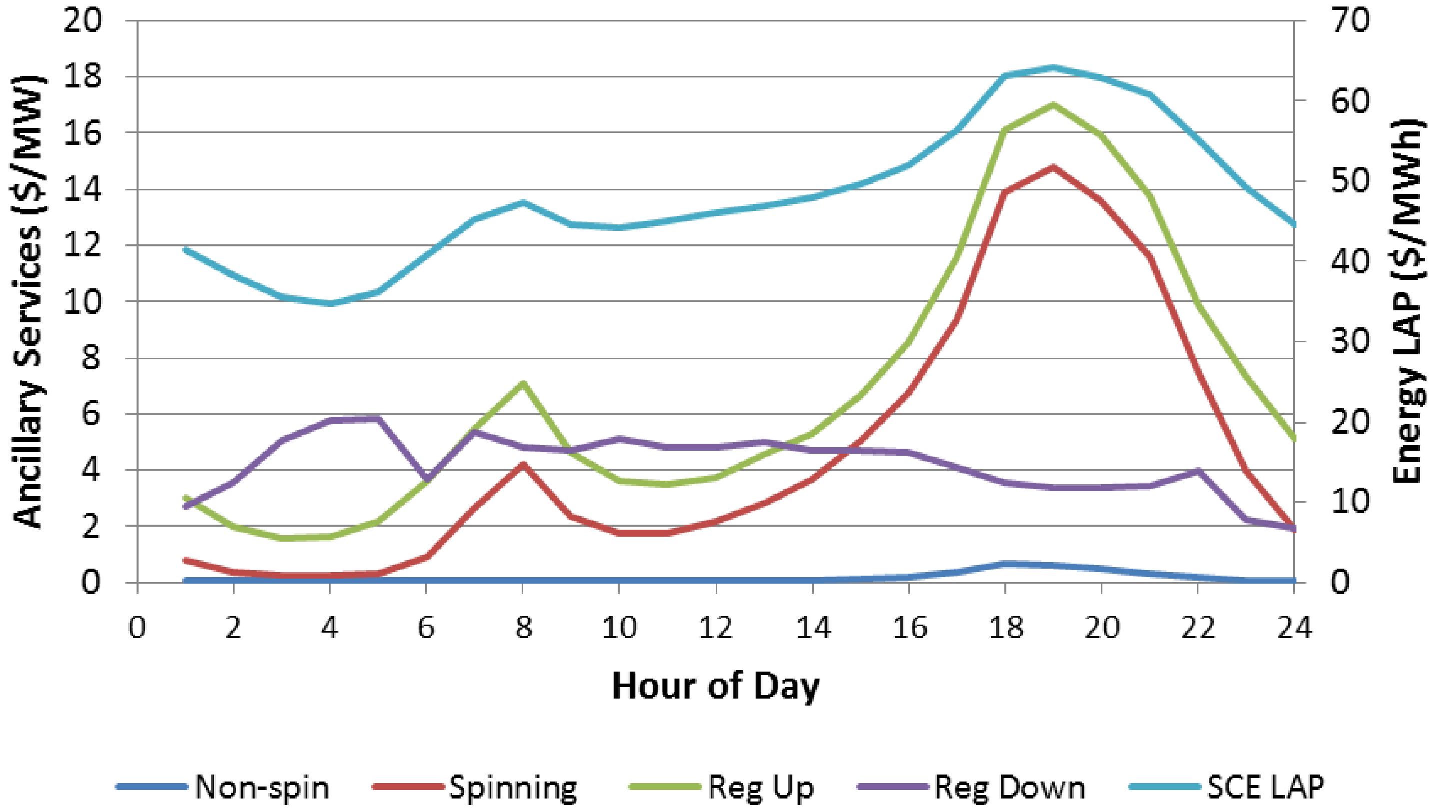
- Eligible storage (912.5MW) providing only regulation dominates the regulation market
- The prices are also heavily depressed
- This also creates concerns for the depth of the regulation market





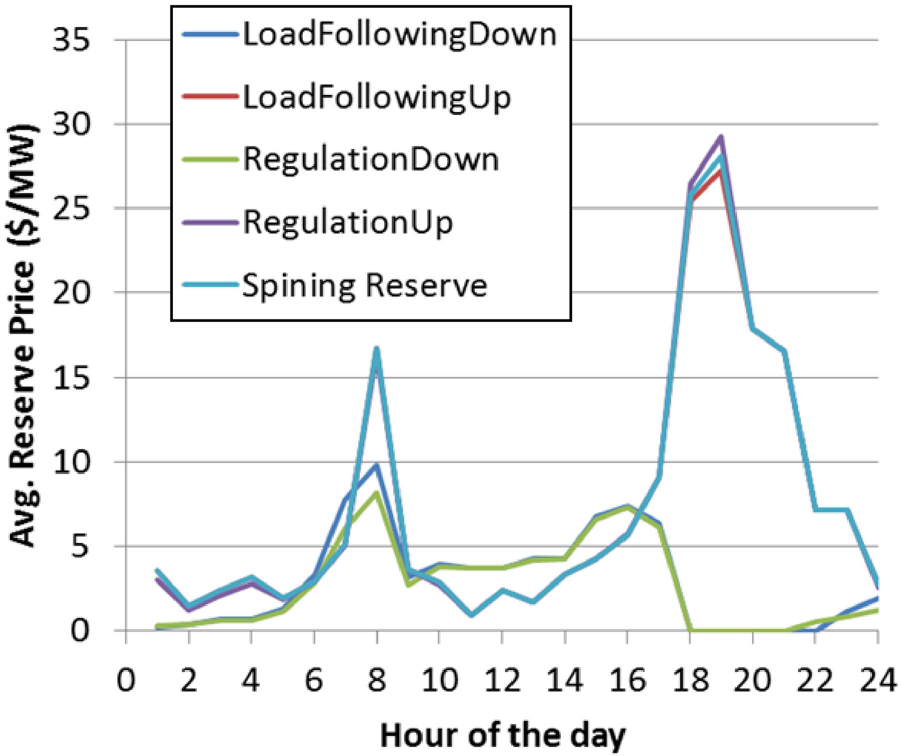
Revenue Comparison

- **Average CAISO 2014 day-ahead energy and ancillary service prices for SCE.**



Revenue Comparison

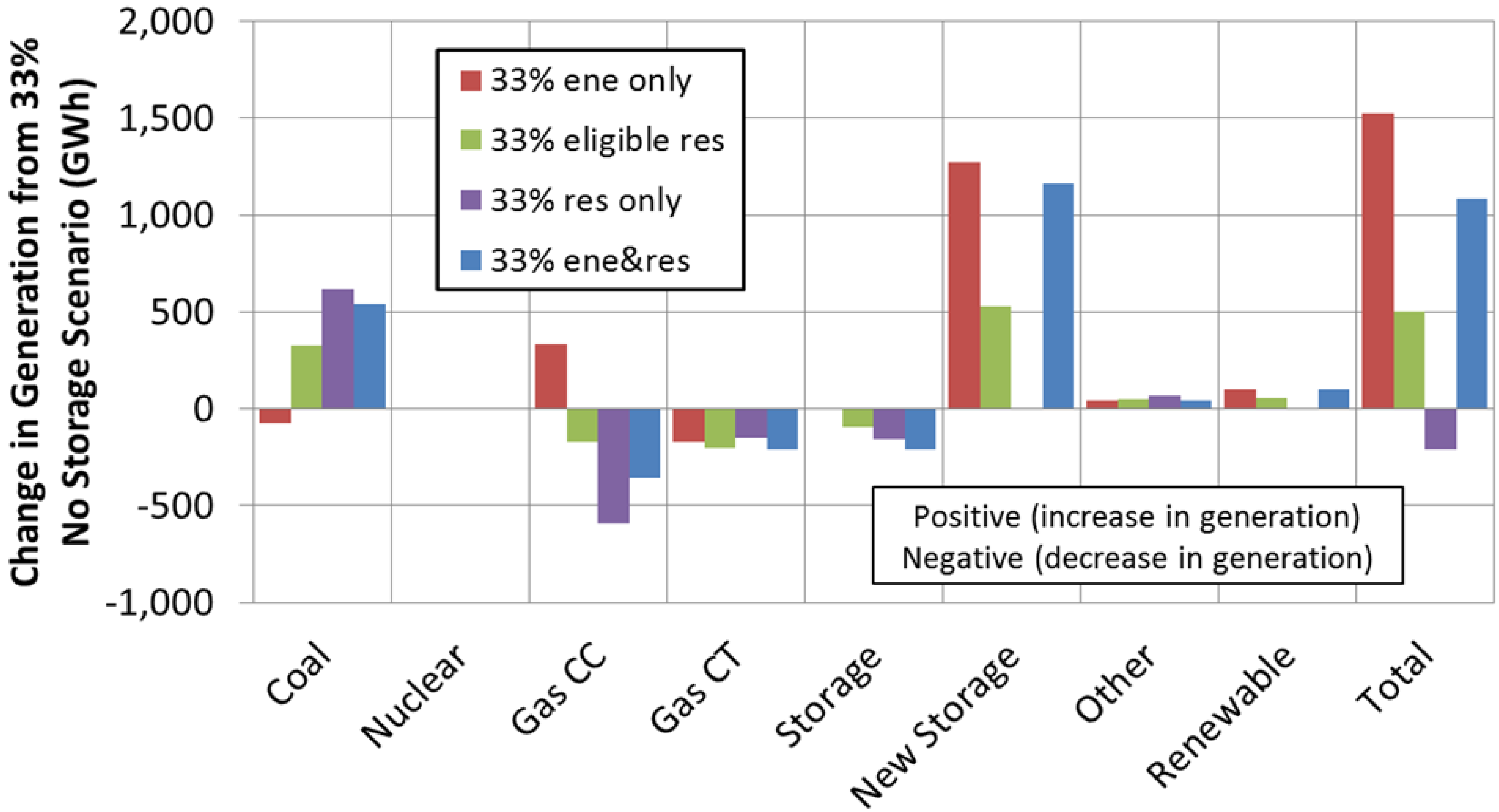
- **Average modelled ancillary service prices (33% scenario, no storage)**
  - Limited differentiation of reserve types in model
  - Upward and downward services have identical prices
  - Regulation bid costs are not included
  - No energy usage for ancillary services, particularly regulation



(e) Effect on resource operations and emissions

Change in generation by fuel type (33% base-case)

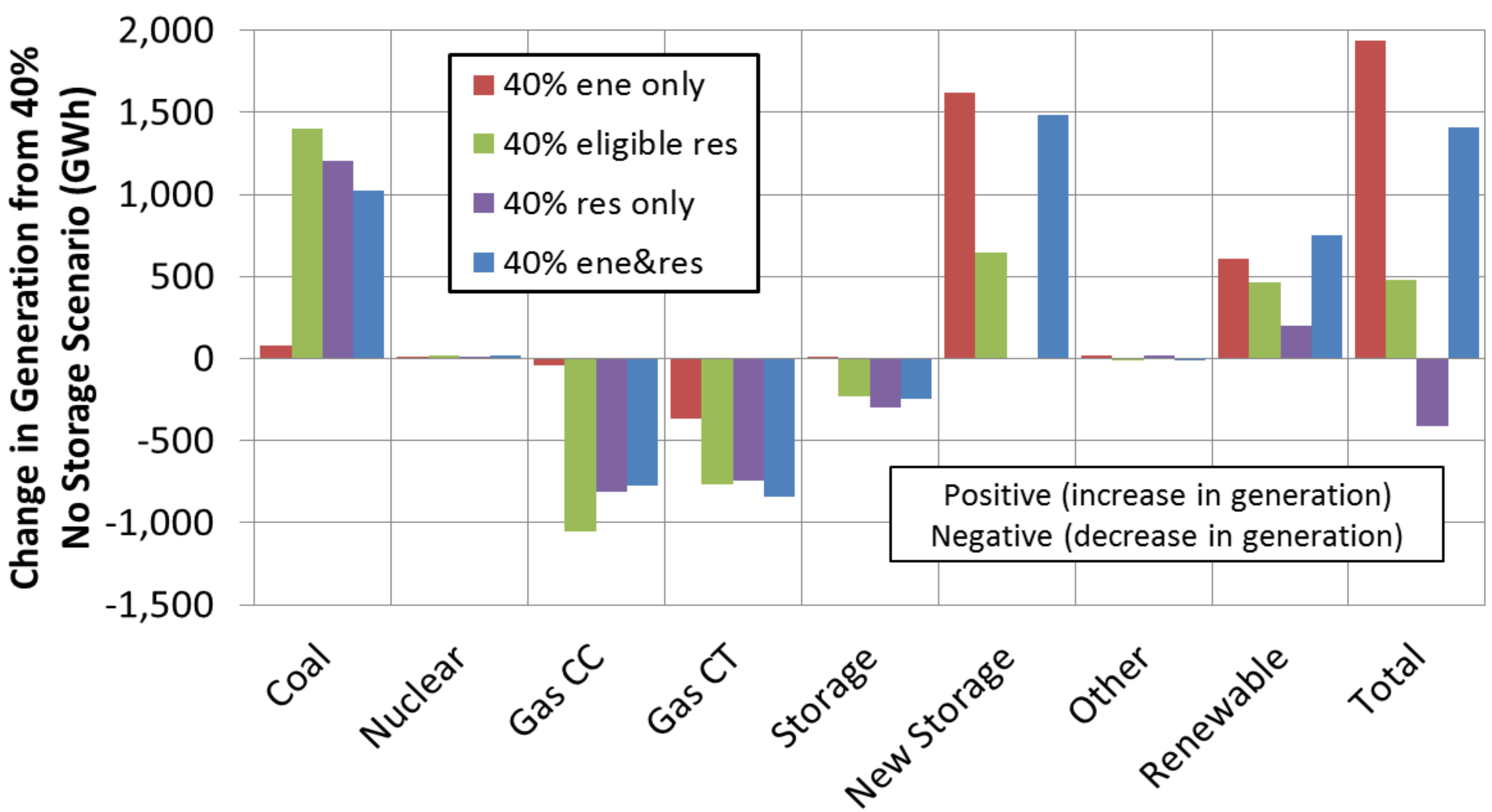
- Storage reduces curtailment of renewable generation (hence increase in renewable energy)
- Storage reduces gas generation
- On a WECC basis, an increase in coal production
- “New” higher efficiency storage can displace existing pumped storage



Change in generation by fuel type (40% base-case)

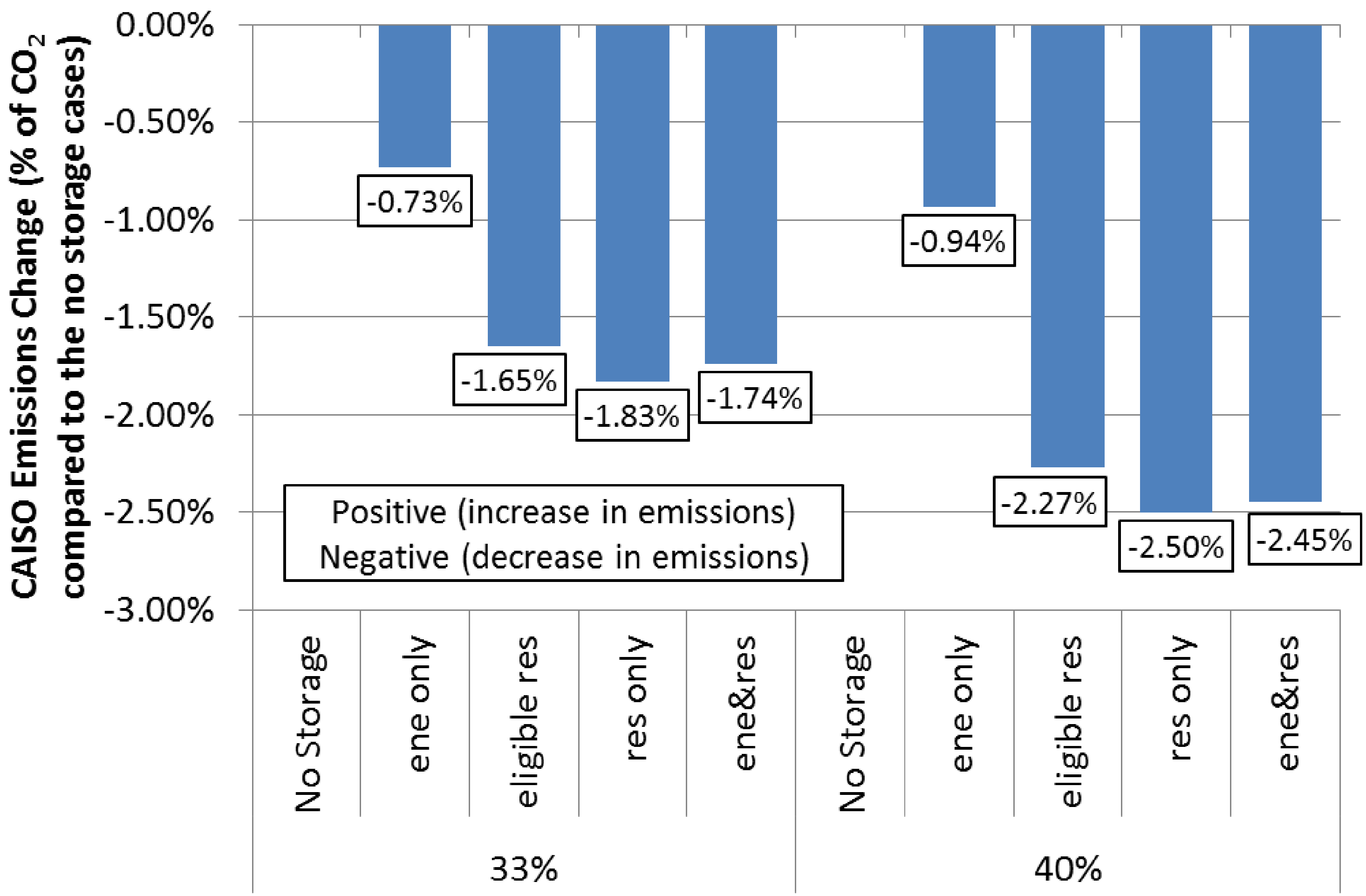
Compared to 33% case:

- Storage reduces more curtailment of renewable generation
- Greater decrease in gas generation
- Greater increase in coal production
- Slight additional displacement of pumped storage



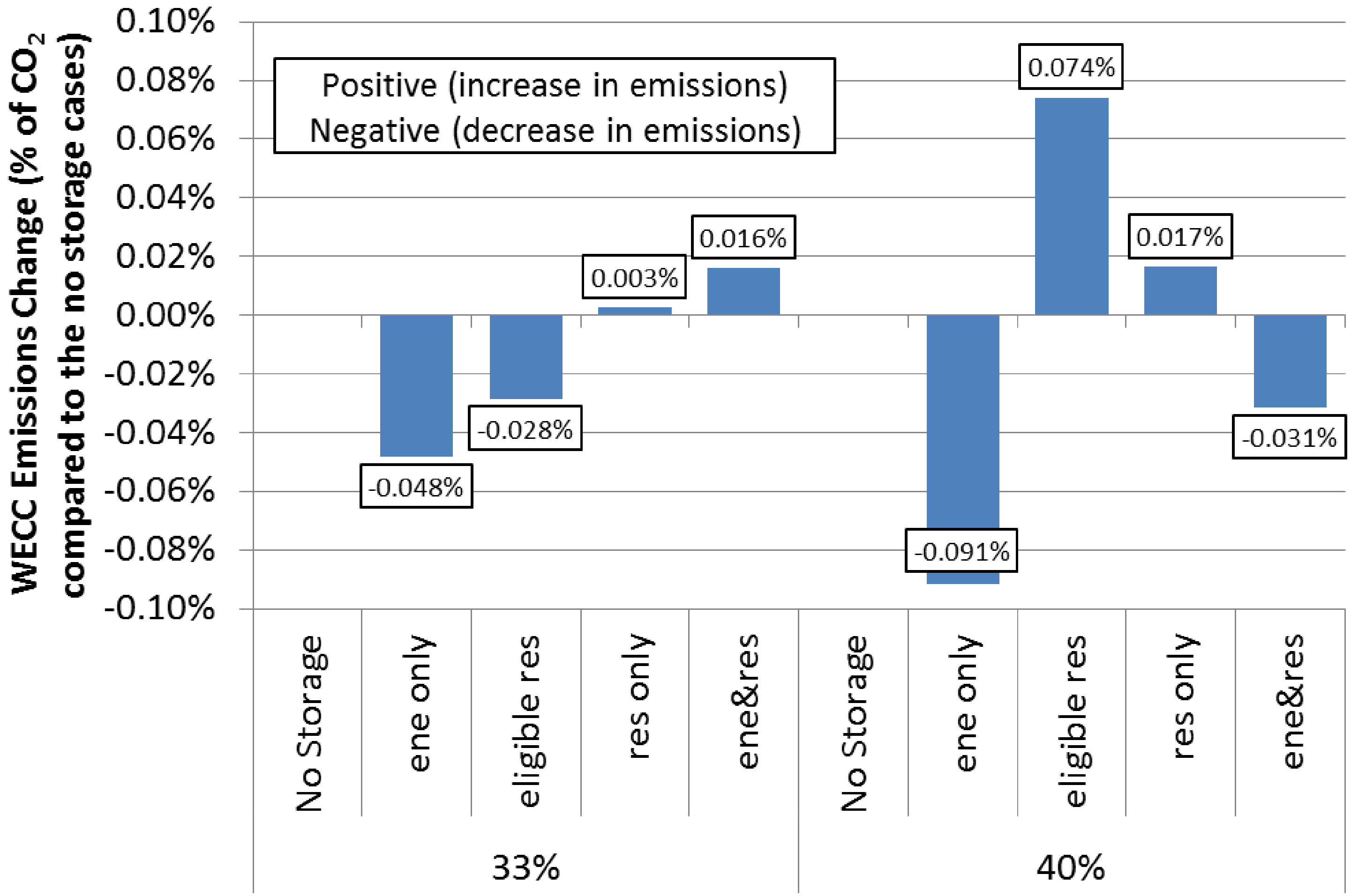
Emissions impact within California

- Storage operations result in net displacement of gas generation within California



Emissions impact across WECC

- Storage operations has a small and variable impact on WECC-wide emissions, which depends in part on the storage application



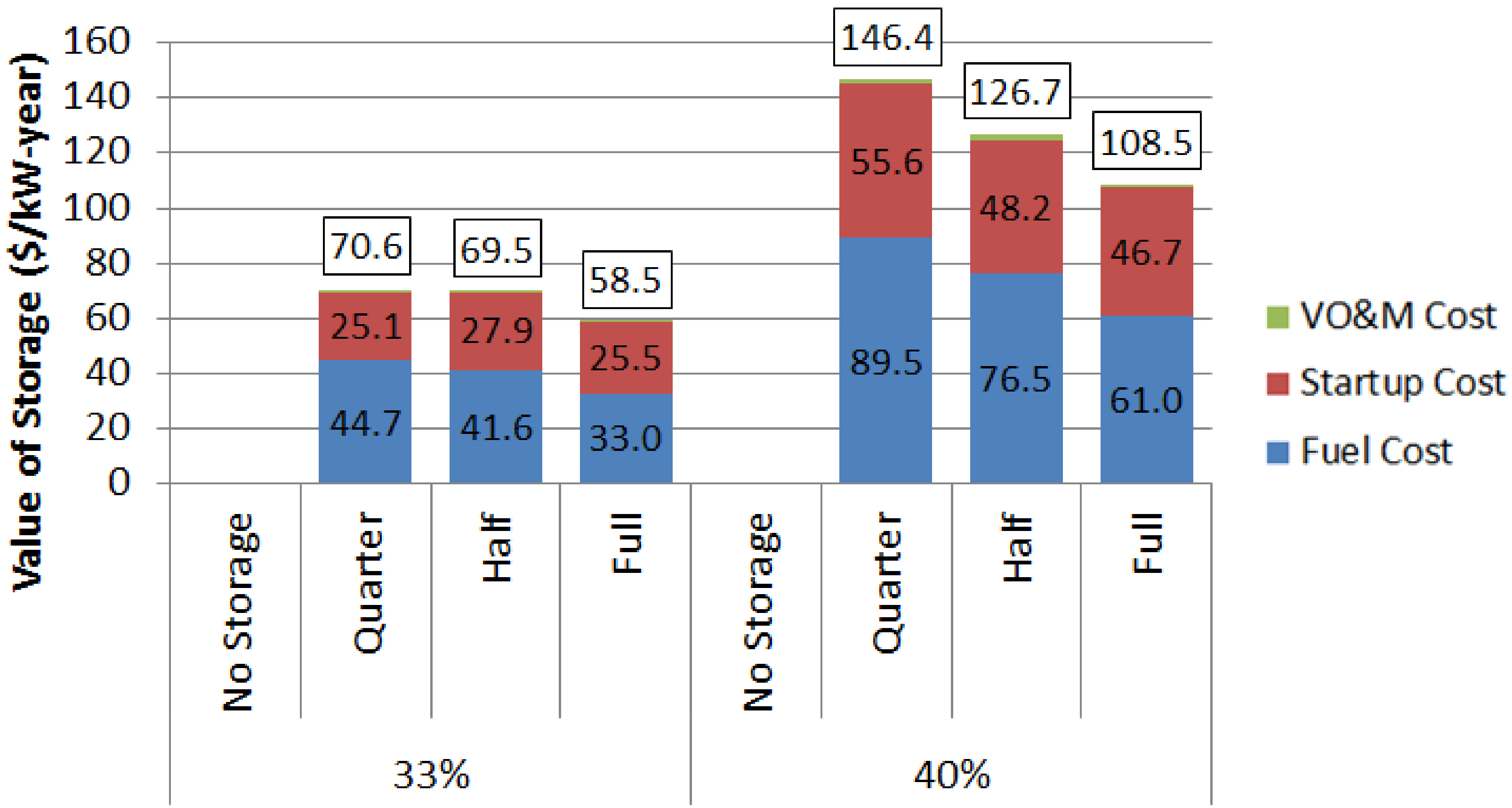
(f) Effect of Storage Penetration on Value

Three types of storage penetration modeled

- **Power capacity of storage portfolio in 2024**
  - We only examined ¼ and ½ of the CPUC storage target; did not example increases in power capacity
- **Increases in energy capacity of storage portfolio in 2024**
  - We examined entire portfolio + 1 hour and + 4 hours
- **Dedication of portfolio to particular services**
  - As noted, we examined impact of portfolio focused on ancillary services and Regulation only

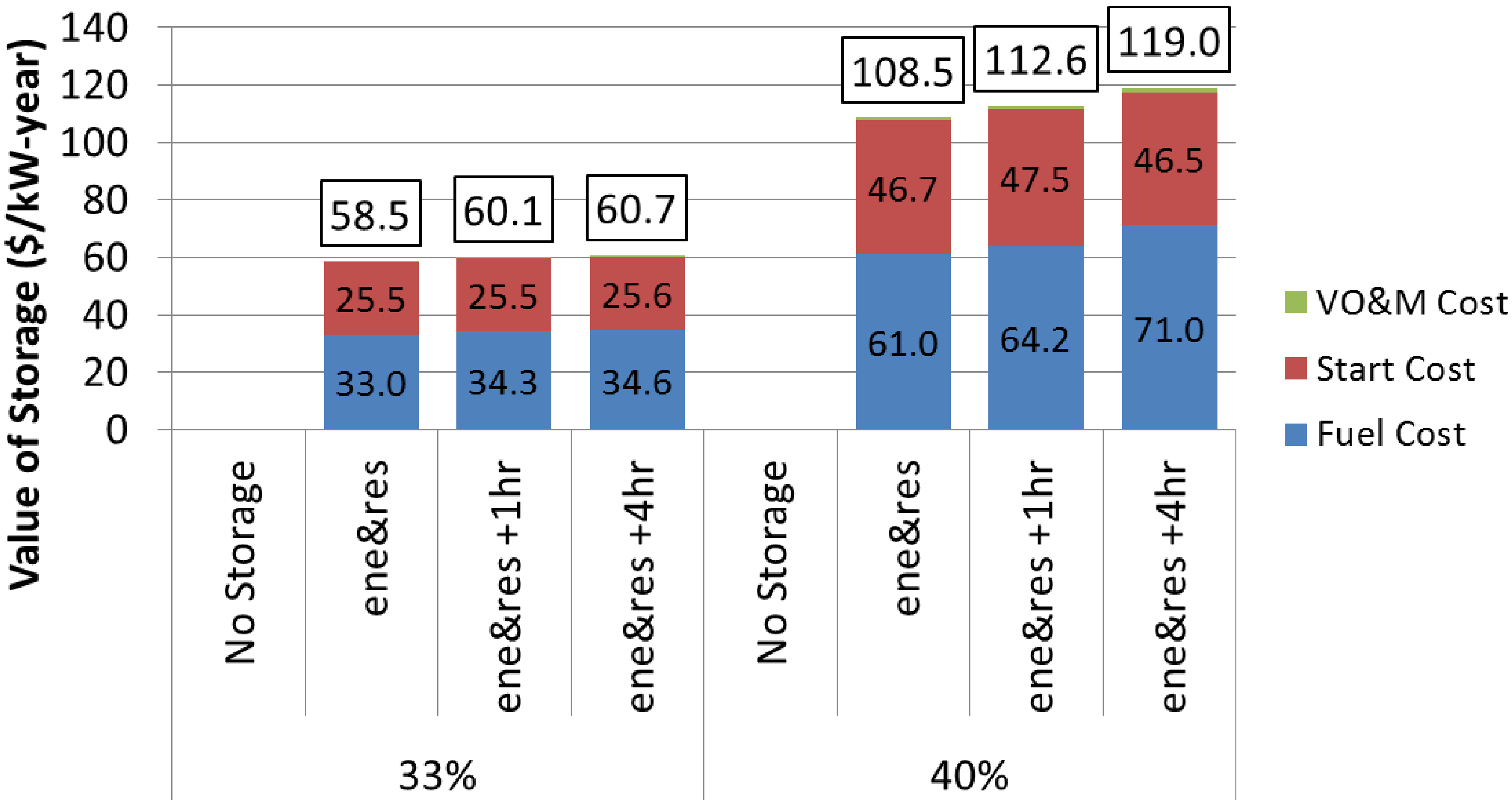
Progressive Entry of Storage

- The cost reduction of progressively more storage capacity increases, but the value of the marginal storage unit decreases



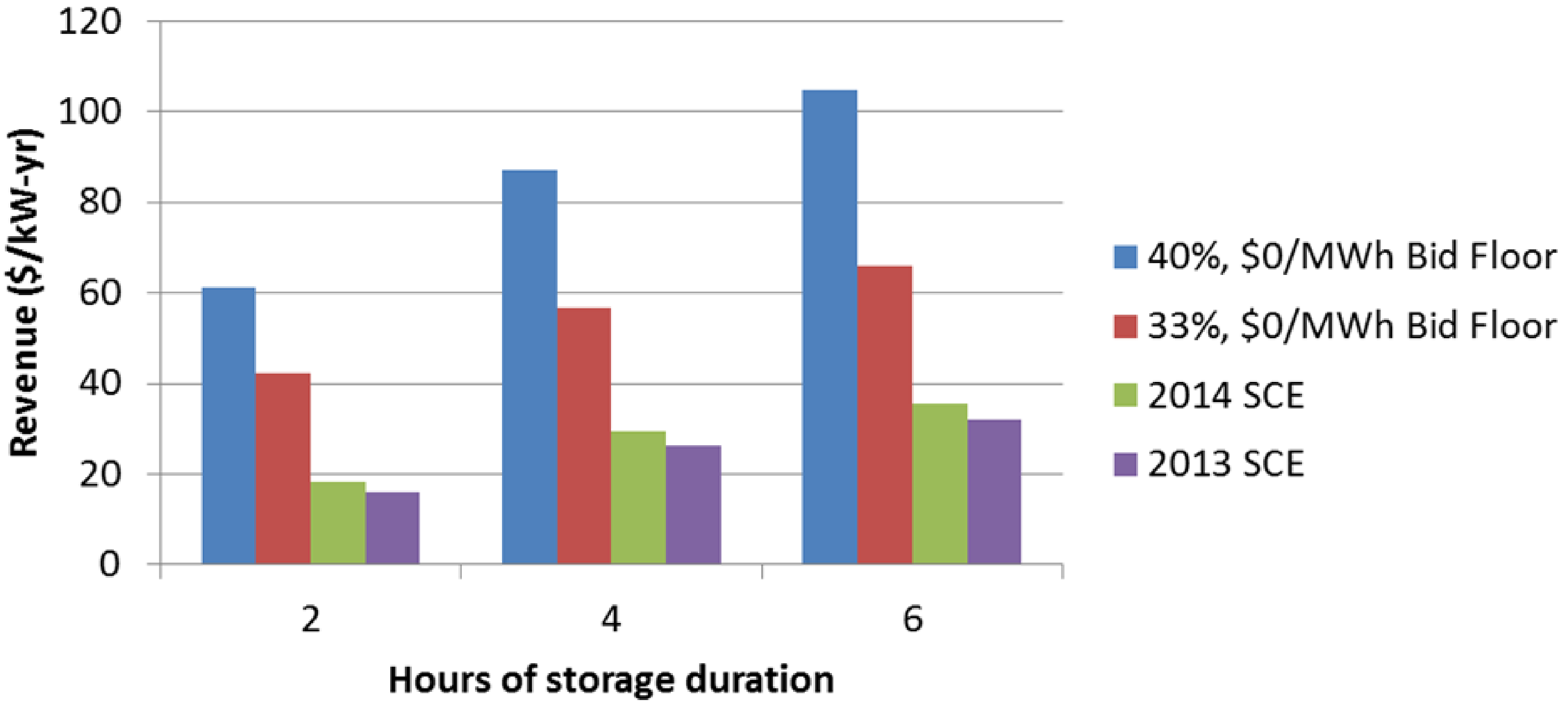
Increase in storage duration

- Additional storage duration increases the production cost reduction
- The cost reduction must help support the cost of additional duration



Disaggregation of storage portfolio

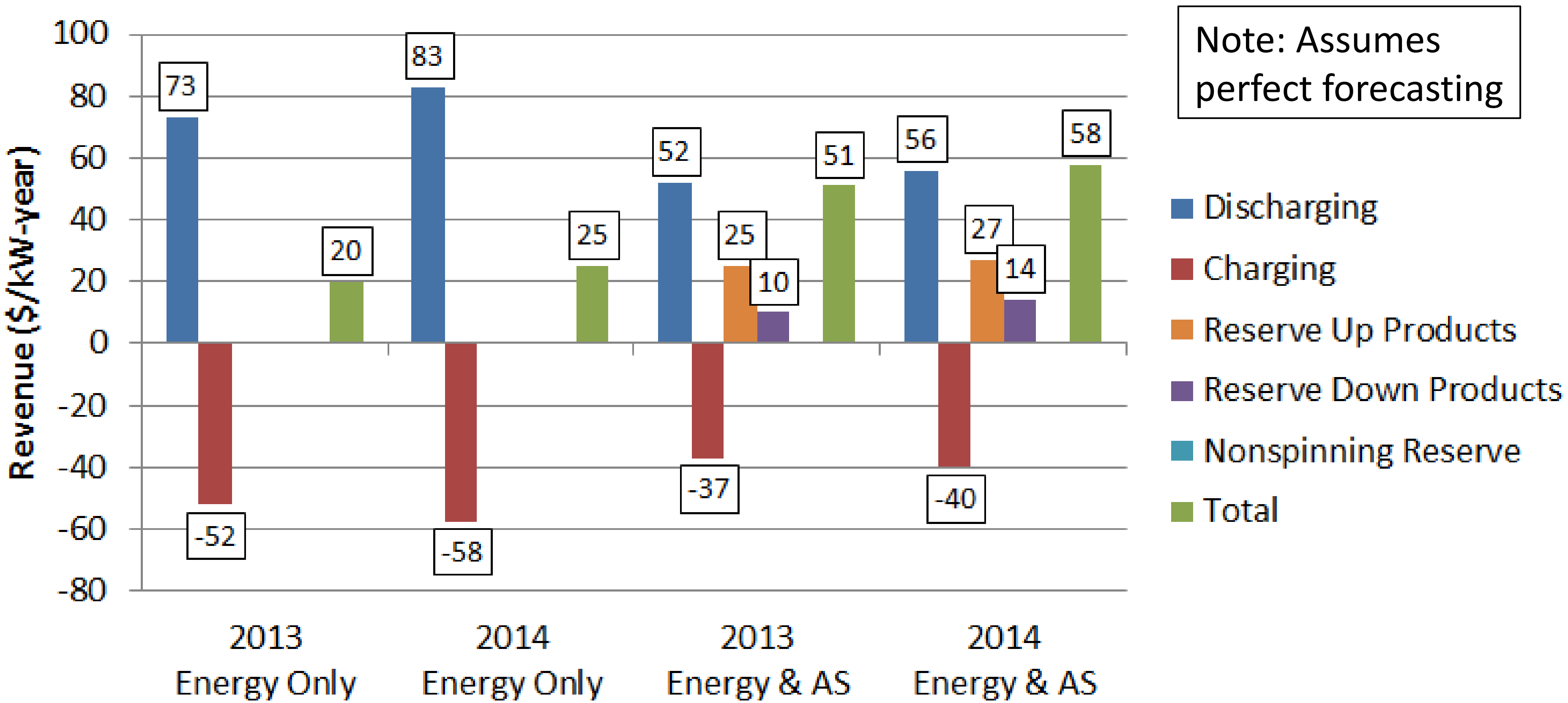
- Disaggregation of revenue by storage duration (energy arbitrage only)



(g) Additional Revenue Comparisons

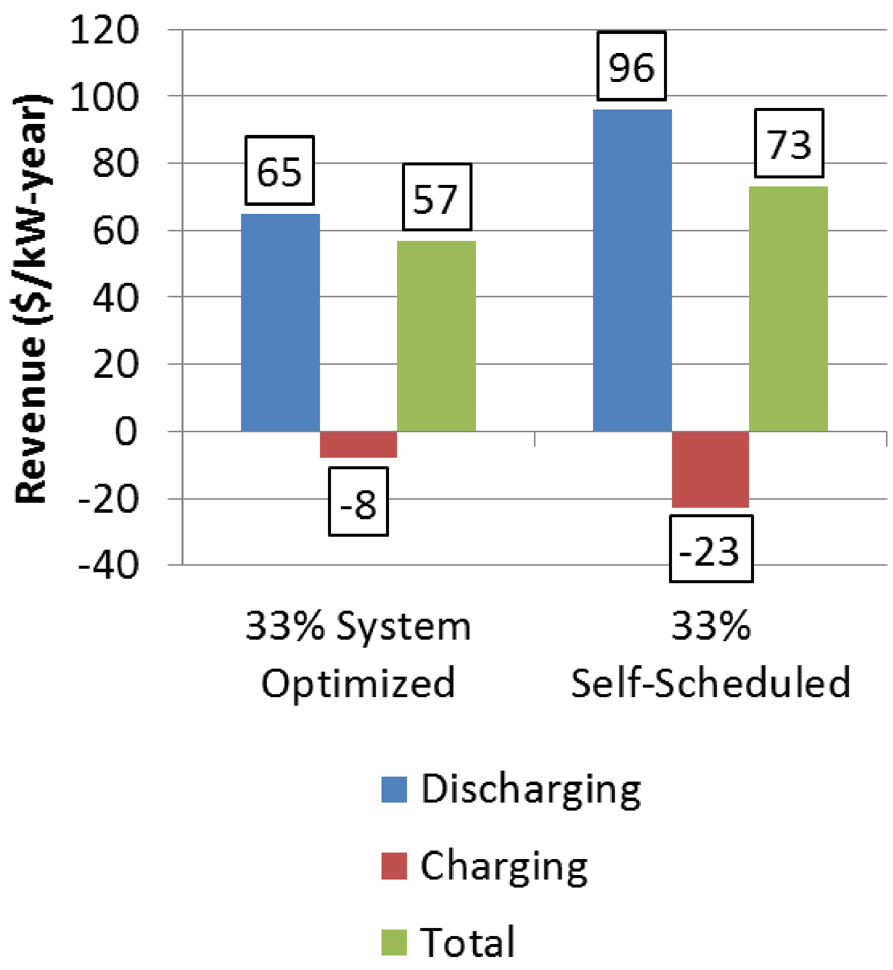
Revenue Comparison

- **Storage revenue from a price-taker model**
  - Optimal provision of energy and ancillary services greatly increases expected revenues



Revenue Comparison

- Figure shows revenue comparison for self-scheduled and system-optimized storage dispatch under -$300/MWh renewable curtailment cost
- Due to several factors
  - Dispatch schedule of system optimized resource used to minimize start-up costs
  - Less constrained operations in "self-schedule" price-taker model



(h) Qualifying storage for capacity provision and resulting value

Capacity value of storage

- **Storage capacity ratings under current CPUC rules**
  - Capacity is the maximum output sustainable for 4 hours
  - The proposed storage portfolio has a net qualifying capacity of 730MW

Values are MW in 2024	Transmission-Connected	Distribution-Connected	Customer-Sited	Total
Total installed capacity	700	425	200	1325
Amount eligible to provide capacity	700	212.5	0	912.5
Net Qualifying Capacity (NQC):				
Storage with 2-hour capacity	140 of 280	42.5 of 85	0 of 100	182.5
Storage with 4-hour capacity	280 of 280	85 of 85	0 of 100	365
Storage with 6-hour capacity	140 of 140	42.5 of 42.5	0	182.5
Total	560	170	0	730

  - Annualized cost of a new combustion turbine: $190/kW
  - Net cost of new entry: ~$160/kW

Study Available On-line

Operational Benefits of Meeting California's Energy Storage Targets

Josh Eichman, Paul Denholm, and Jennie Jorgenson
National Renewable Energy Laboratory

Udi Helman
Helman Analytics

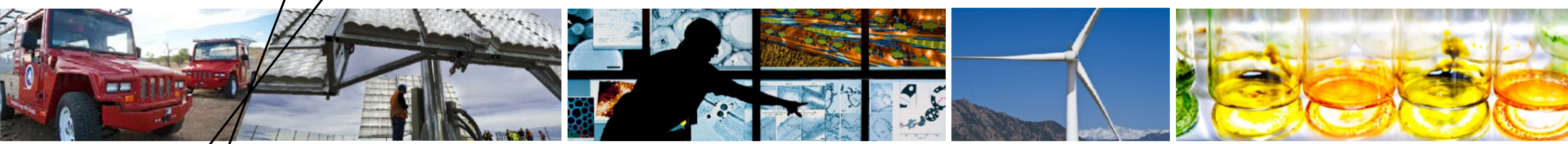
NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Technical Report
NREL/TP-5400-65061
December 2015

Contract No. DE-AC36-08GO28308

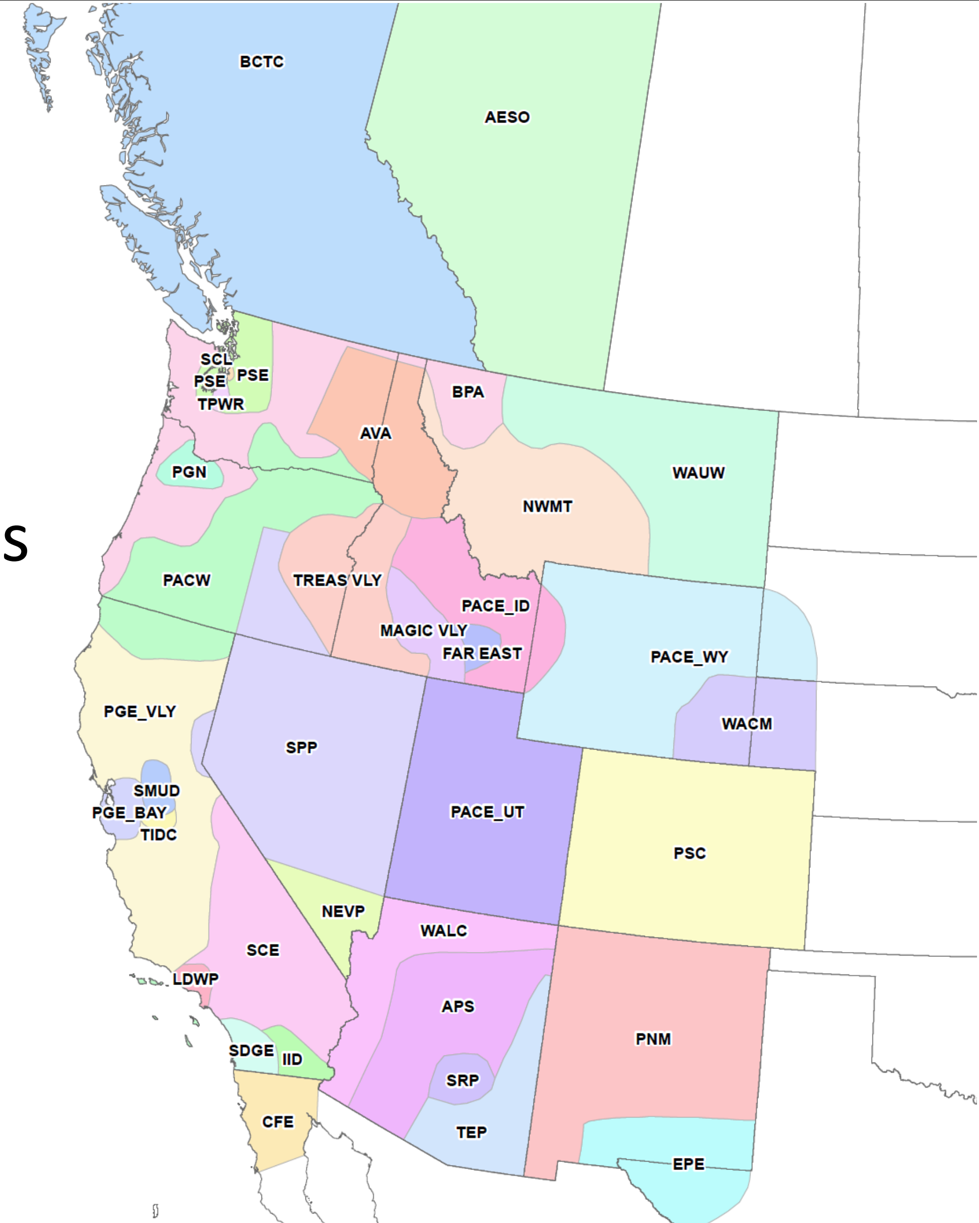
Available at
http://www.nrel.gov/docs/fy16osti/65061.pdf



Appendix – additional slides

CAISO 2014 LTPP model

- **Production cost model**
  - Zonal (43 regions)
  - >2,400 generators, storage and DR devices
  - 151 transmission lines (bundled)



Storage Services (slide 1 of 2)

- **Comparison of storage services**

Storage Operational Services and Benefits	CPUC Consistent Evaluation Protocol/Other Directives	CAISO Wholesale Market	LTPP Model
Energy and Ramping Reserves			
Avoided start-up costs	Not discussed as a component of energy or ancillary services value	Resource start-up and minimum load costs are bid into the markets and compensated separately for any residual such costs that are not recovered through market price revenues. In the CAISO markets, this is called Bid Cost Uplift or Bid Cost Recovery. These costs are reported in CAISO reports on an aggregated basis.	Calculated as component of production costs
Day-ahead energy	Requires calculation of net energy value; CPUC does not distinguish day-ahead or real-time energy value; utilities may conduct valuation of these markets separately	Hourly market with locational marginal prices	LTPP model reflects both day-ahead and real-time market attributes (load-following) using an hourly time-step. Energy value can be calculated as avoided production costs or market revenues.
Real-time energy		15-minute and 5-minute markets with locational marginal prices	
Ramping reserves	Not mentioned	Flexible ramping constraint implemented (real-time); flexible ramping product scheduled to be deployed in 2016	Load-following Up and Load-following Down capacity reservation in model reflects a combination of ramping reserves and economic dispatch. Load following value can be calculated as avoided production costs or market revenues.

Storage Services (slide 2 of 2)

- **Comparison of storage services**

<table>
<tr><th>Storage Operational Services and Benefits</th><th>CPUC Consistent Evaluation Protocol/Other Directives</th><th>CAISO Wholesale Market</th><th>LTPP Model</th></tr>
<tr><th colspan="4">Ancillary services</th></tr>
<tr><td>Regulation (up and down)</td><td rowspan="3">Requires calculation of market value</td><td rowspan="3">Hourly day-ahead and real-time markets with zonal clearing prices</td><td rowspan="3">All of these ancillary services are represented as reserve capacity, subject to resource eligibility. Ancillary service value can be calculated as avoided production costs or market revenues.</td></tr>
<tr><td>Spinning reserve</td></tr>
<tr><td>Non-spinning Reserve</td></tr>
<tr><td>Voltage support</td><td>Identified, but not required to be quantified</td><td>Tariff-based rate</td><td>Not evaluated</td></tr>
<tr><td>Blackstart</td><td>Identified, but not required to be quantified</td><td>Tariff-based rate</td><td>Not evaluated</td></tr>
</table>

Methodology: Recent Storage Studies

- **Comparison of recent California Storage Studies using production cost models (PCM)**

Study/ publication year	California LTPP scenarios or other scenarios	Types of new storage	Storage services modeled	New storage scenarios
CAISO 2014 LTPP models (2014)	All 33% and 40% LTPP scenarios (2014)	Generic electrical storage, CSP-TES	LTPP services	Storage mandate portfolio shown in Table 10 assumed within scenarios
Lawrence Livermore National Lab (LLNL) (2014) 2012 LTPP models	CPUC 33% RPS trajectory scenario (2012)	Lithium ion batteries, flow batteries, CAES, pumped hydro	LTPP services (Table 3) plus subhourly regulation dispatch	Multiple storage scenarios showing incremental additions and variations in attributes, up to 1,700 MW of new storage capacity
DNV-GL (2014) 2012 LTPP models	CPUC 33% RPS trajectory scenario (2012)	Lithium ion batteries, flow batteries, CAES	LTPP services plus subhourly regulation dispatch	Storage mandate portfolio
Argonne Natl Lab (2013)	14% and 33% renewable Western Interconnection scenarios	Pumped storage	LTPP services plus day-ahead to real-time commitment and dispatch	Planned and proposed pumped storage plants
Jorgenson et al., 2014 (NREL) 2012 LTPP models	CPUC 33% RPS trajectory scenario (2012); 40% California renewable energy scenario (developed for the study)	CSP-TES, generic electrical storage	LTPP services	Incremental CSP with thermal storage
Denholm et al., 2013 (NREL) 2012 LTPP models	CPUC 33% RPS trajectory scenario (2012)	CSP-TES	LTPP services	Incremental CSP with thermal storage

Changes to the LTPP model

1. **Removed regulation up, load following up, and spinning reserve capacity constraint for three storage units (PGE Bay_4_TC, PGE Bay_6_TC, PGE Valley_4_TC).**
2. **Added charge and discharge constraints to ensure that there is sufficient energy in storage to provide ancillary services if they are called upon.**
3. **Removed minimum stable level for all new storage resources except for Lake Hodges.**
4. **Adjusted round-trip efficiency from 80% to 83.3%, as prescribed in the CPUC testimony.**
5. **Added a constraint to the distribution-connected resources to limit the amount of load following down and regulation down that the resources can provide to half of their capacity.**

Methodology: Comparison to CAISO

- **Comparison CAISO model, NREL unaltered model (NREL – Original) and NREL altered model (NREL – Base).**

Property and Model	RPS	Month												Total
		1	2	3	4	5	6	7	8	9	10	11	12	
RPS Generation (TWh)														
CAISO - Original	33%	4.53	4.78	6.13	6.32	6.50	6.47	6.22	5.40	5.26	5.16	4.69	4.61	66.07
NREL - Original	33%	4.53	4.78	6.15	6.36	6.51	6.47	6.21	5.40	5.26	5.16	4.69	4.61	66.14
NREL - Base	33%	4.53	4.78	6.15	6.35	6.50	6.47	6.21	5.40	5.26	5.16	4.69	4.61	66.12
CAISO - Original	40%	5.54	5.83	7.16	7.17	7.72	8.05	8.06	7.08	6.75	6.48	5.80	5.58	81.20
NREL - Original	40%	5.54	5.85	7.43	7.66	8.02	8.19	8.08	7.08	6.79	6.53	5.83	5.58	82.58
NREL - Base	40%	5.54	5.85	7.40	7.62	7.98	8.17	8.08	7.08	6.78	6.52	5.82	5.58	82.43
Curtailment (GWh)														
CAISO - Original	33%	-	0.5	48.4	76.7	21.7	6.2	-	-	-	-	-	-	153.0
NREL - Original	33%	-	0.5	48.4	76.7	21.9	6.2	-	-	-	-	-	-	153.7
NREL - Base	33%	-	0.9	58.7	96.4	30.0	8.3	-	-	-	-	-	-	194.4
CAISO - Original	40%	15.0	59.0	583	1,013	594	291	47.0	2.0	70.0	88.0	48.0	17.0	2,825
NREL - Original	40%	14.6	58.5	583	1,019	591	292	46.5	1.5	70.2	87.0	47.9	16.9	2,828
NREL - Base	40%	19.3	68.9	635	1,087	655	334	53.0	3.5	82.7	98.0	61.0	20.7	3,118