Clean Energy and Pollution Reduction Act Senate Bill 350 Study: *Preliminary Results*

May 24, 2016

SB 350 Regional Market Study

Analysis and Preliminary Results

PRESENTED TO

Stakeholders to the SB 350 Study

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THE Brattle GROUP

Content

Scope of the SB 350 Study

Legislative Requirement:

- 359.5. (a) It is the intent of the Legislature to provide for the transformation of the Independent System Operator into a regional organization…, and that the transformation should only occur where it is in the best interests of California and its ratepayers.

- The ISO will conduct studies of the impacts of a regional market, including:
  1. Overall benefits to **California ratepayers**
  2. Emissions of **greenhouse gases** and **other air pollutants**
  3. Creation or retention of **jobs** and other **benefits to the California economy**
  4. **Environmental** impacts in California and elsewhere
  5. Impacts in **disadvantaged communities**
  6. **Reliability** and **integration of renewable energy** resources

- The modeling, including all assumptions underlying the modeling, shall be made available for public review.

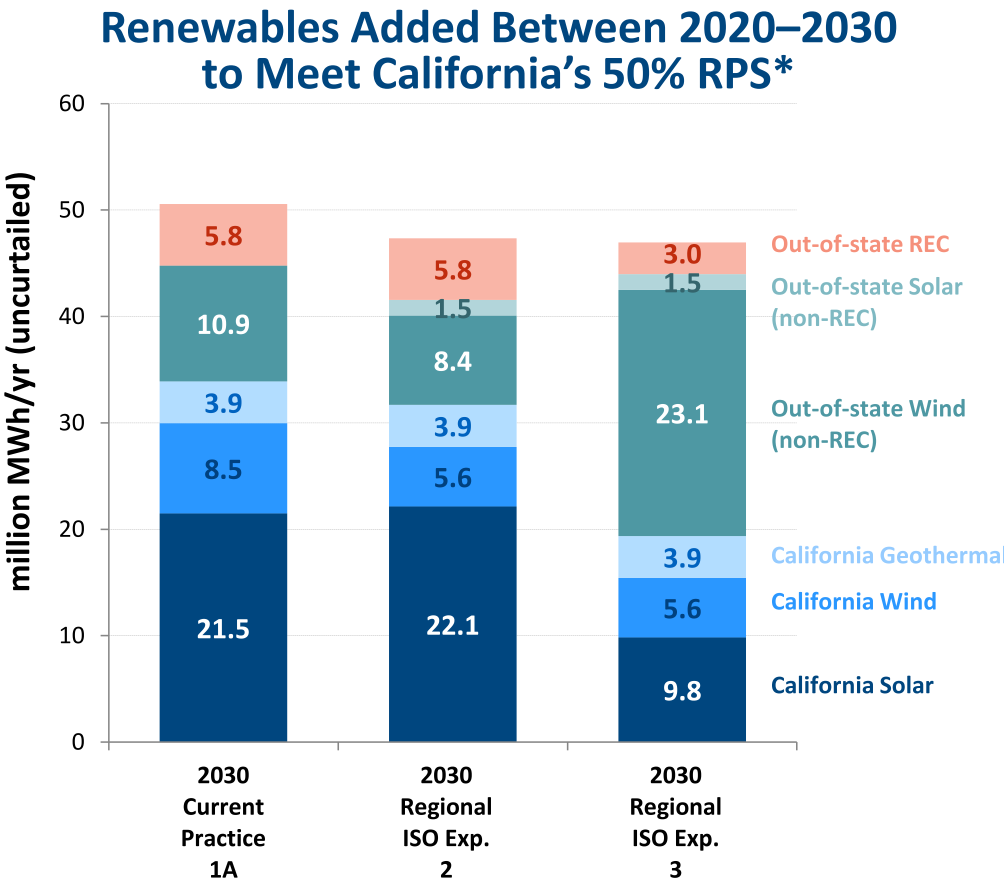
Impacts Evaluated

The Study teams have been estimating these impacts, in accordance with SB 350 requirements:

Benefits Considered	Where	Impact to be Analyzed	Metrics
1. Overall benefits to ratepayers			
Operating cost savings	CA, WECC	Production costs and wholesale market prices	Production & Net Purchase Costs (CA); Production Costs (WECC-wide)
Capital (investment) cost savings	CA, WECC	Renewable integration, resource adequacy, resource procurement	Net fixed and capital costs
2. GHG and other air pollutants	CA, WECC	Air quality and carbon intensity	Changes in emissions, including in nonattainment areas
3. Jobs and economic impact to CA	CA	Infrastructure investment, responses to changes in retail and operating costs	Employment, Gross State Product, incomes, tax revenues
4. Environmental impacts in CA and elsewhere	CA, WECC	Land use/visual resources, biological/ ecology, water supply	Impacts on environmental resources and sensitive areas
5. Impacts in disadvantaged communities	CA	Environmental and economic	Impacts in specific communities
6. Reliability and integration of renewable energy resources	CA, WECC	Ability to integrate diverse renewable resources; regional operations and control	Description of improved system monitoring and ability to integrate diverse resources

Content

Studied Three 2030 Scenarios for 50% RPS in CA



* Includes renewables added in non-CAISO entities (BANC, IID, LADWP, TIDC)

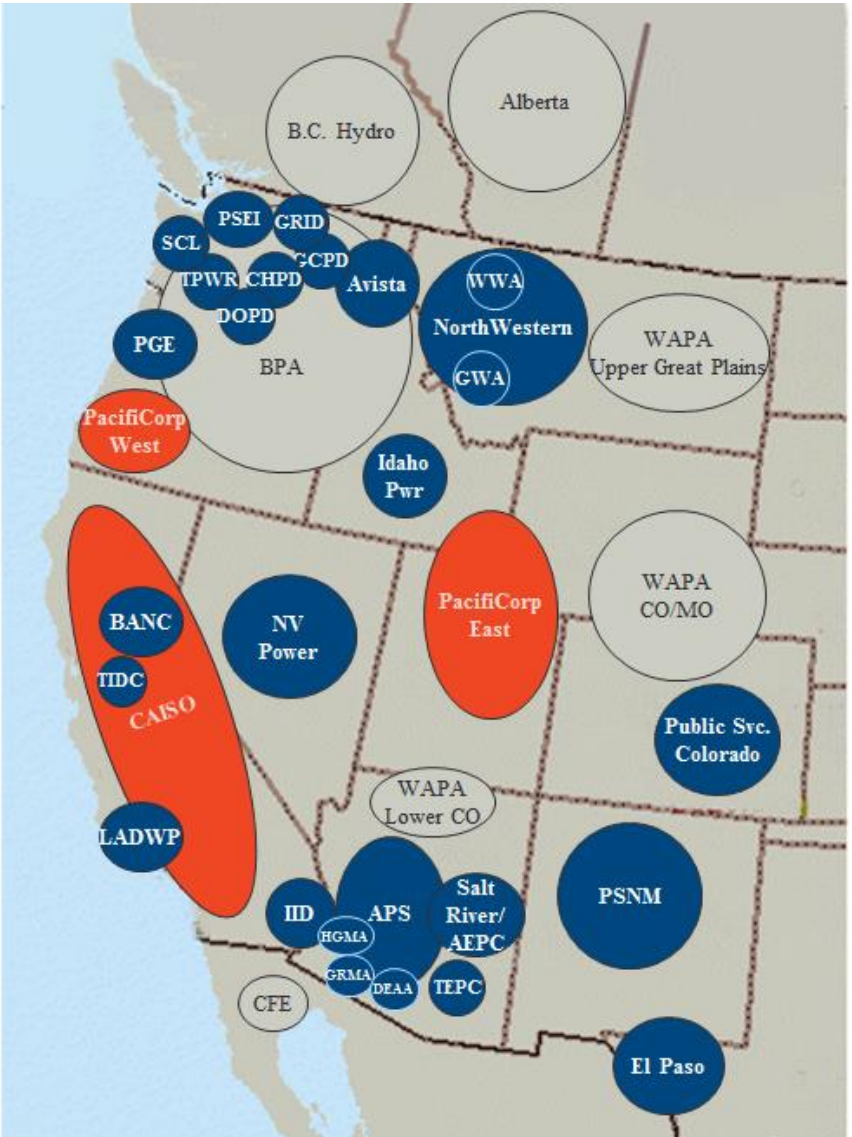
** Regional market cases were developed through consultation with stakeholders for the sole purpose of assessing the benefits of a regional market over a range of plausible renewable procurement scenarios. This study is not promoting or advocating for a particular procurement scenario.*

E3 developed three main portfolios for meeting California's RPS in 2030

- Portfolio 1A assumes no regionalization (Current Practice)
- Portfolios 2 and 3 assume regional market
  - Portfolio 2: current practice renewable generation procurement (more in-state)
  - Portfolio 3: more regional resource procurement
- Analysis updated in response to stakeholder feedback
- Further details and sensitivities will be discussed by E3

Summary of Findings

2020 and 2030 Hypothetical Regional Footprints



WECC currently consists of 38 individual Balancing Authorities

2020 Footprint: Regional ISO to consist of only CAISO and PacifiCorp: denoted as "**CAISO+PAC**"

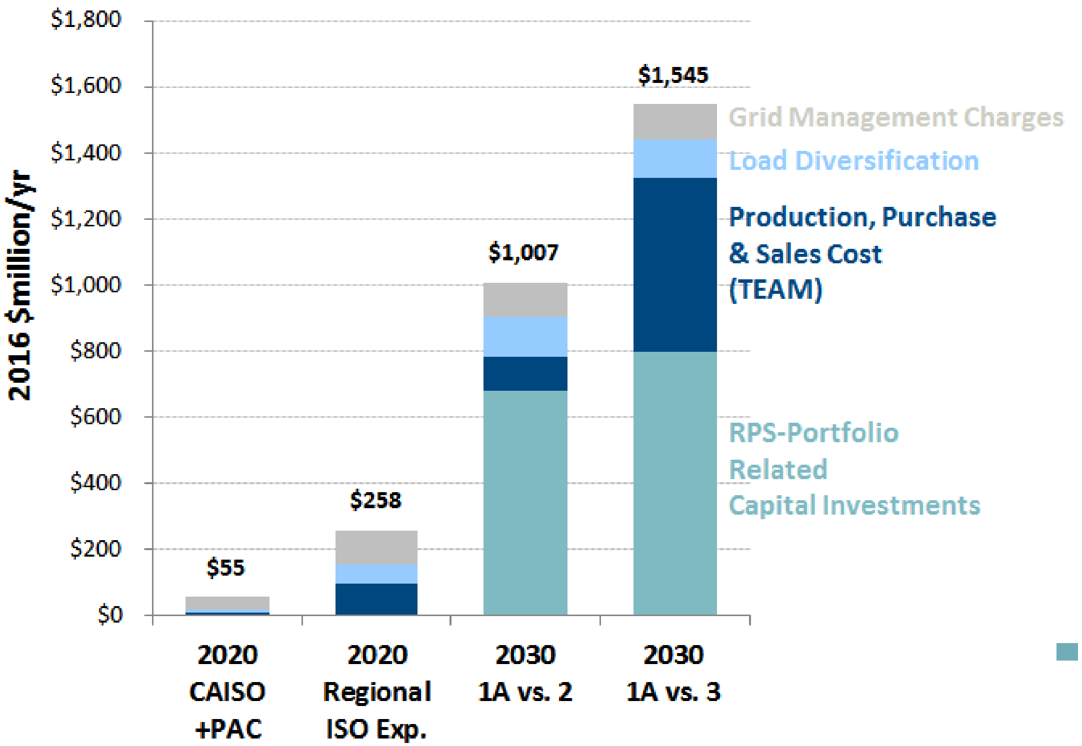
\+

2030 Footprint and 2020 Sensitivity: Expanded regional ISO to consolidate all balancing areas in the U.S. WECC except the Federal Power Marketing Agencies: denoted as "**Regional**" (U.S. WECC w/o PMAs)

PMAs shown in the graphic as BPA, WAPA Upper Great Plains, WAPA CO/MO, WAPA Lower CO

1. Overall Benefits to California Ratepayers

Annual California Ratepayer Benefits in 2020 & 2030



- California ratepayer impact analysis of an expanded regional market shows estimated savings of:
  - **$55 million/year in 2020** (0.1% of retail rates) based on limited scope of CAISO-PAC region.
    - Would be $258 million/year for expanded regional footprint (WECC without PMAs)
  - **$1 billion to $1.5 billion/year in 2030** (2–3% of retail rates) depending on renewable procurement to meet 50% RPS
- 2030 sensitivities show range from $767 million to $1.75 billion/year

Overall benefits likely larger, consistent with findings in other regional market studies (see Appendix D)

- Estimates based on conservative assumptions
- Value of additional regional market benefits was not quantified

1. Additional Ratepayer Benefits not Quantified

- **Increased system reliability** due to expanding ISO operations to a larger regional footprint that improves pricing, congestion management, generation commitment, real-time operations, and system visibility/monitoring
- **Improved use of the physical capabilities of the existing grid** both on constrained WECC transmission paths and within the existing WECC balancing areas
- **Improved regional and inter-regional system planning** to increase efficiency in transmission buildout across the West
- **Improved risk mitigation** from a more diverse resource mix and larger integrated market that can better manage the economic impacts of transmission and major generation outages and better diversify weather, hydro, and renewable generation uncertainties
- **Long-term benefits** from stronger generation efficiency incentives and better long-term investment signals across a larger regional footprint
- Consistent with findings of other regional market studies (see Appendix D)

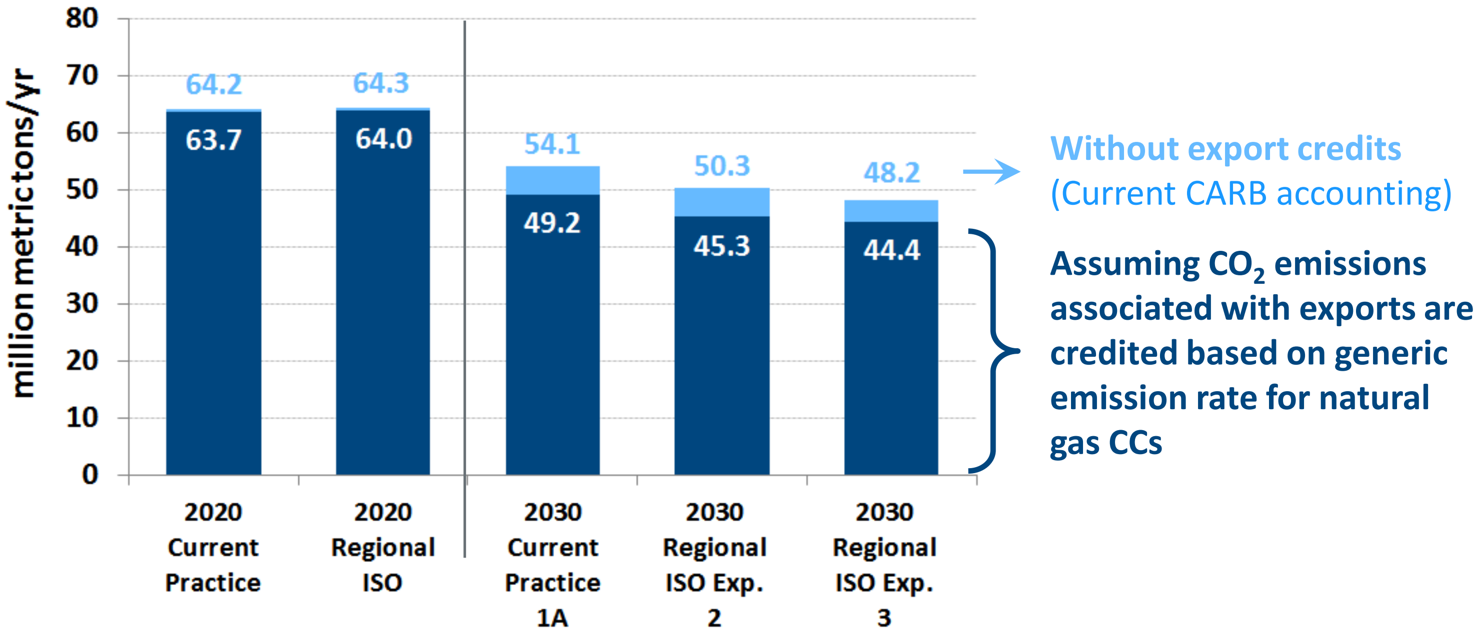
2. Emissions of GHGs and Other Air Pollutants

- Expanded regionalization (by 2030) **decreases electric sector CO_2, NO_x , SO_2, and $PM_{2.5}$ emissions** WECC-wide and within California
- Magnitude of impact of regional market **on emissions *per se* is modest**; it depends primarily on:
  - Coal plant retirements
  - Relative economics of different fuels and technologies
  - Environmental regulations in CA and rest of WECC
  - Renewable energy resource development beyond RPS (as facilitated by market)
- Limited regionalization with only PAC has a very small impact and depends on the carbon pricing and CA import hurdles faced by PacifiCorp's coal fleet
- California meets EPA's Clean Power Plan (CPP) limits in all scenarios analyzed
- With a modest WECC-wide CO_2 price ($15/tonne), WECC meets CPP, after accounting for additional coal plant retirements (announced or assumed by utilities' resource plans) and WECC RPS requirements
- Results similar to CEERT/NREL Low Carbon Grid Study
- The following slides focus on CO_2 (Aspen will provide results for NO_x, SO_2, and $PM_{2.5}$)

Summary of Findings

2. California CO_2 Emissions

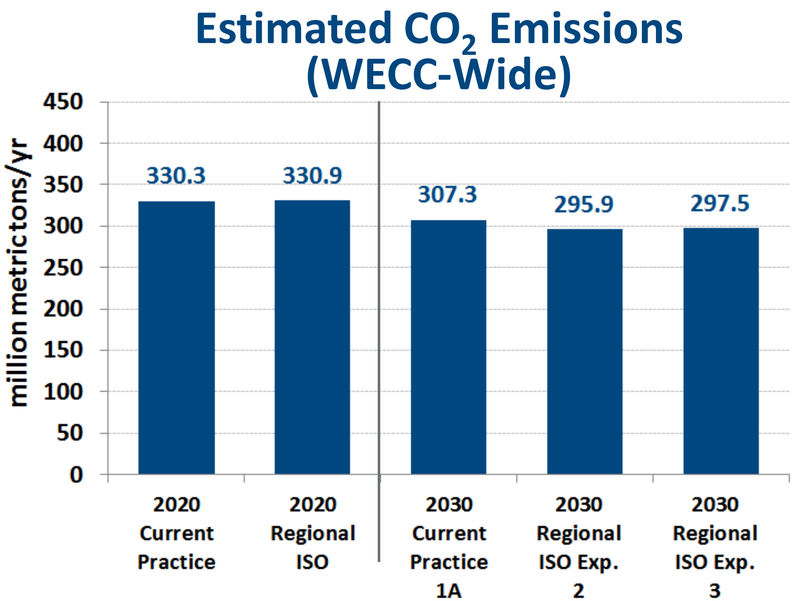
Estimated CO_2 Emissions in California

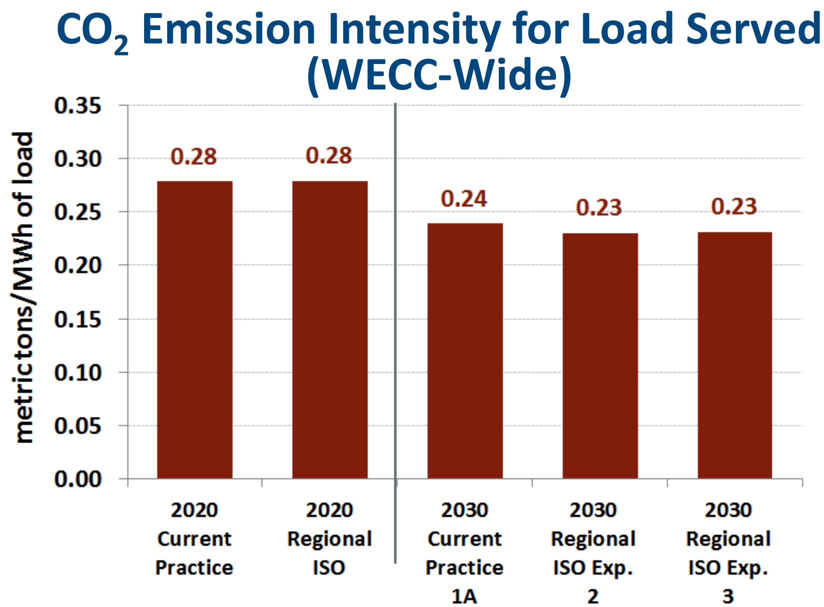


- Significant electricity sector emissions reductions between 2020 and 2030, with **2030 emissions 55–60% below 1990 levels and below EPA's CPP requirements for California**
- Regional market reduces CO_2 emissions associated with serving California load
  - Little/no change in 2020
  - **Decrease of 4–5 million tonnes (8–10% of total) of CO_2 emissions level** in 2030
- By 2030, CA exports of surplus renewable energy displaces 4-5 million tonnes of CO_2 in rest of WECC; export credits not currently considered in CARB accounting

Summary of Findings

2. WECC-Wide CO_2 Emissions





- 2020 simulations of regional market (CAISO+PAC) show almost no change in CO_2 emissions relative to Current Practice
- In 2030 (and despite load growth in rest of WECC), the expanded regional market (U.S. WECC without PMAs) is estimated to **decrease CO_2 emissions levels by about 10–11 million tonnes (3.2–3.7% of total)** depending on the Scenario
  - For load served across WECC, regional market in 2030 is expected to **reduce CO_2 emission intensity by 0.01 tonne/MWh**
- Achieving CPP compliance would require additional measures

3. Jobs and Other Benefits to the California Economy

Regionalization creates numerous and diverse jobs and delivers benefits to California households and enterprises

- Regionalization (Scenarios 2 and 3) can create 9,900–19,400 more jobs than Current Practice (Scenario 1A) in California, primarily by making electricity more affordable
  - Higher statewide household real disposable income due to more affordable energy
    - $300–$550 more disposable income per household in 2030 due to regional market
  - Higher statewide Gross State Product, real output, state revenue, and employment
- Regional market with California-focused procurement (Scenario 2) can help California balance ratepayer savings with job creation from renewable resource buildout
  - Highest impact on statewide output and employment
  - But higher environmental impacts (see next slide)
- The detailed results will be discussed by BEAR (on Day 2)

4. Environmental Impacts in California and Elsewhere

With a more efficient buildout for RPS, regional market reduces impacts on land use, biological resources, and groundwater use for construction

- Reduces acreage for new wind and solar developments by at least 42,000 acres in California
- Reduces acreage for new wind and solar outside of California for RPS by approximately 32,000 acres (Regional 2)
- Regional 3 increases land use for new out-of-state transmission
- With more renewable resource development outside of California (Regional 3), impacts on biological resources in California are reduced (and eliminated in some CREZs)
  - Tradeoff is a greater biological impact out-of-state, particularly for wind in Wyoming and New Mexico
- Both regional market scenarios decrease in-state groundwater consumption for plant operations, due to a slight decrease in generation output from California combined cycle plants
  - Similarly, consumption decreases in the rest of U.S. WECC, due to decreased output from gas and coal
- These results will be discussed in detail by Aspen (on Day 2)

Summary of Findings

5. Impacts in Disadvantaged Communities

A regional market offers benefits to disadvantaged communities:

Economic Benefits

- Increases real income and jobs in several disadvantaged communities, particularly in Inland Valley, Greater Los Angeles, and Central Valley
  - 1,300–4,600 more jobs over 2020–2030 period
  - Real income increased by $180–330 per household per year
  - These results will be discussed in detail by BEAR (on Day 2)

Environmental Benefits

- Decreases community-scale construction-related environmental impacts from decreasing renewable resource development in California, particularly in Westlands where a significant amount of new solar would be built in the Current Practice Scenario
- Lower output from natural gas-fired generators in California decreases the amount of water used during power production and decreases power plant emissions in the San Joaquin Valley and South Coast air basins
- These results will be discussed in detail by Aspen (on Day 2)

6. Reliability and Integration of Renewable Energy

A regional market reduces the cost of maintaining system reliability

- Reduced operating reserves needed to meet reliability requirements
- Better real-time visibility of system conditions in larger regional footprint
- Improved management of unscheduled power flows

A regional market improves integration of renewables to meet California's 50% RPS

- Reduces curtailments associated with bilateral trading frictions
- Regional pooling of resources to meet flexibility reserves allows smaller areas with disproportionately high renewable generation to use region's resources to balance the intermittent output
- Improved utilization of the existing grid and better regional transmission planning will lower the transmission-related integration cost

Regional markets facilitate low-cost renewable generation developments beyond those needed for RPS

Content

Refinements to Study Approach Based on Stakeholder Input

In response to stakeholder comments, we:

- Refined renewable portfolio optimization (see E3's presentation)
- Revised hypothetical regional footprint for 2020 and 2030 (see next slide)
- Estimated ratepayer impacts for the State of California as a whole
  - Impacts not attributed to specific parties (other than disadvantaged communities)
- Measured WECC-wide impacts from a societal perspective
- Conducted various sensitivities as suggested by various stakeholders
- Ensured compliance with RPS in the rest of U.S. WECC, including Oregon's new 50% by 2040 RPS
- Incorporated additional announced coal retirements, and renewable and conventional plant additions from utility integrated resource plans (IRPs)
- Estimated the regional market's ability to attract additional renewables development beyond meeting RPS
- Evaluated California and the rest of U.S. WECC's ability to meet CPP's mass-based targets (also simulated a CPP compliance sensitivity)

Other Refinements to Study Approach Since February 2016

Other study refinements include:

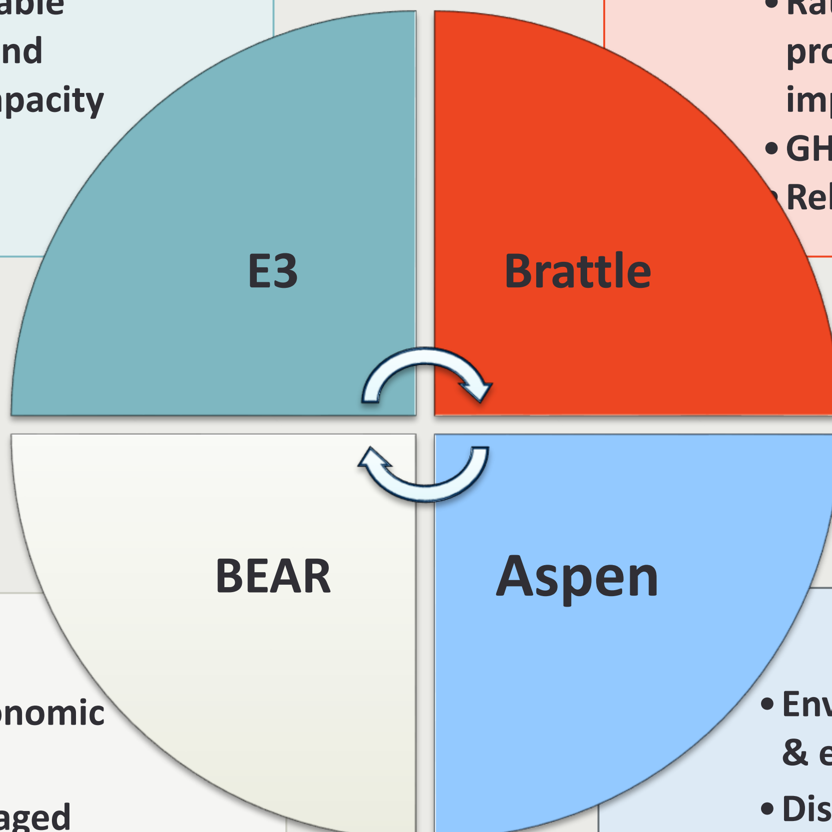
- Improved reserve requirement estimates:
  - Load-following and regulation requirements were estimated for 2020 and 2030 to be consistent with level and type of renewable generation in each Balancing Area
  - Brattle modeled those load following and regulation requirements in the production cost simulations
- Included California municipal utilities' renewable portfolio of 50% by 2030 based on estimates
- Updated input assumptions:
  - Data from 2015 Integrated Energy Policy Report (IEPR)
  - 2016 Long Term Procurement Plan (LTPP)
  - Recent extension of federal tax incentives (production and investment tax credits)
- Additional sensitivity analyses

Content

Analytical Framework

Roles of Consultants

The Brattle Group coordinates and aggregates the analyses



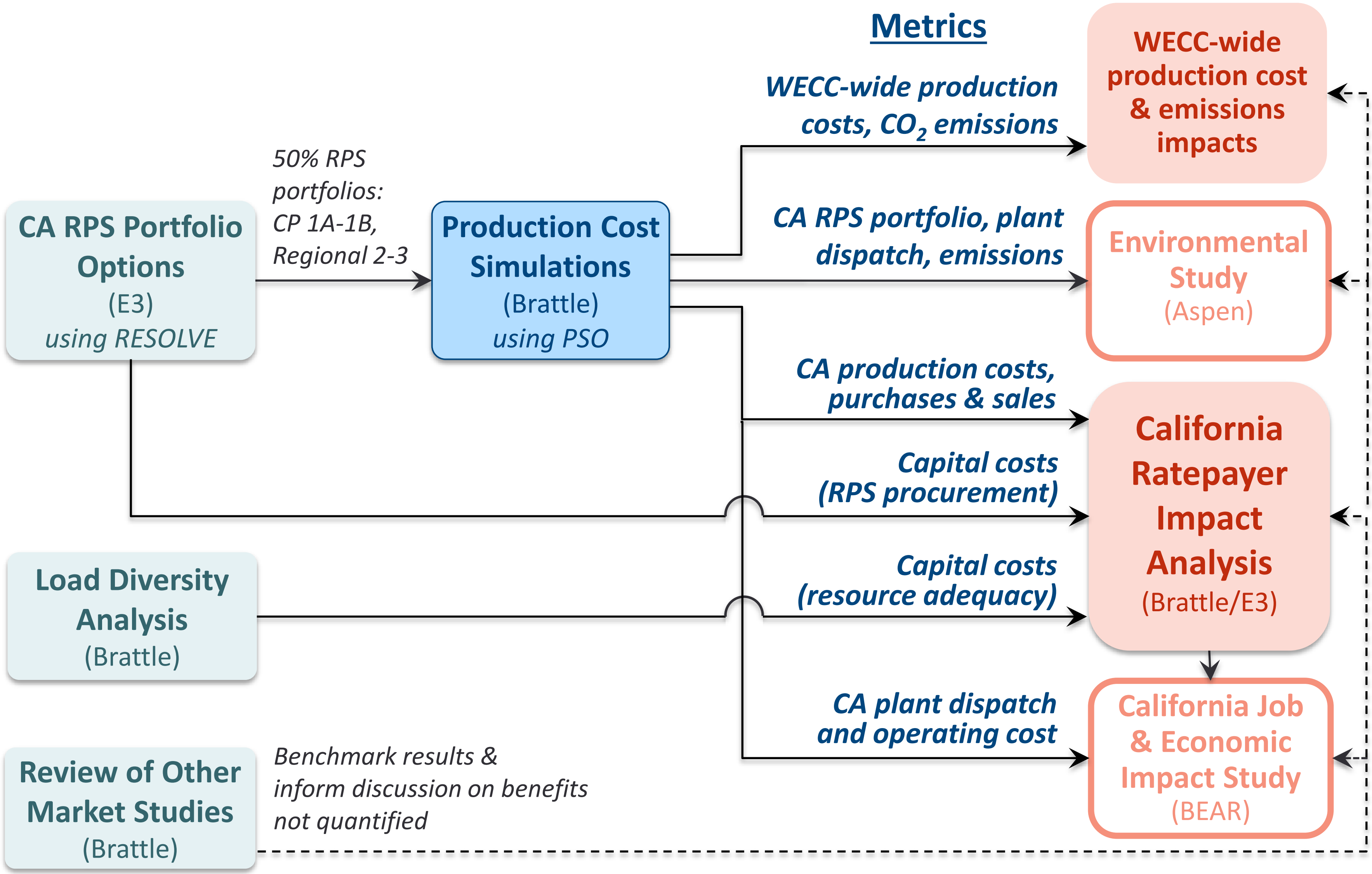
E3
- CA Renewable Portfolio and thermal capacity expansion

Brattle
- Ratepayer and production cost impacts
- GHG Emissions
- Reliability

BEAR
- Jobs & economic Impacts
- Disadvantaged communities

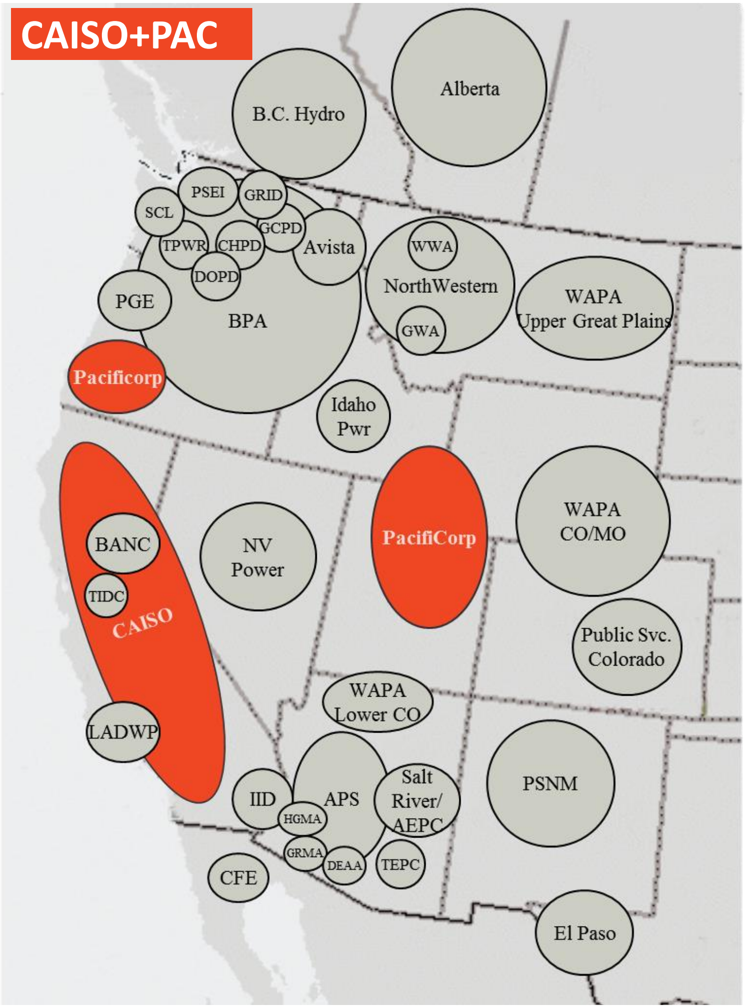
Aspen
- Environmental & emissions
- Disadvantaged communities

SB 350 Analytical Framework

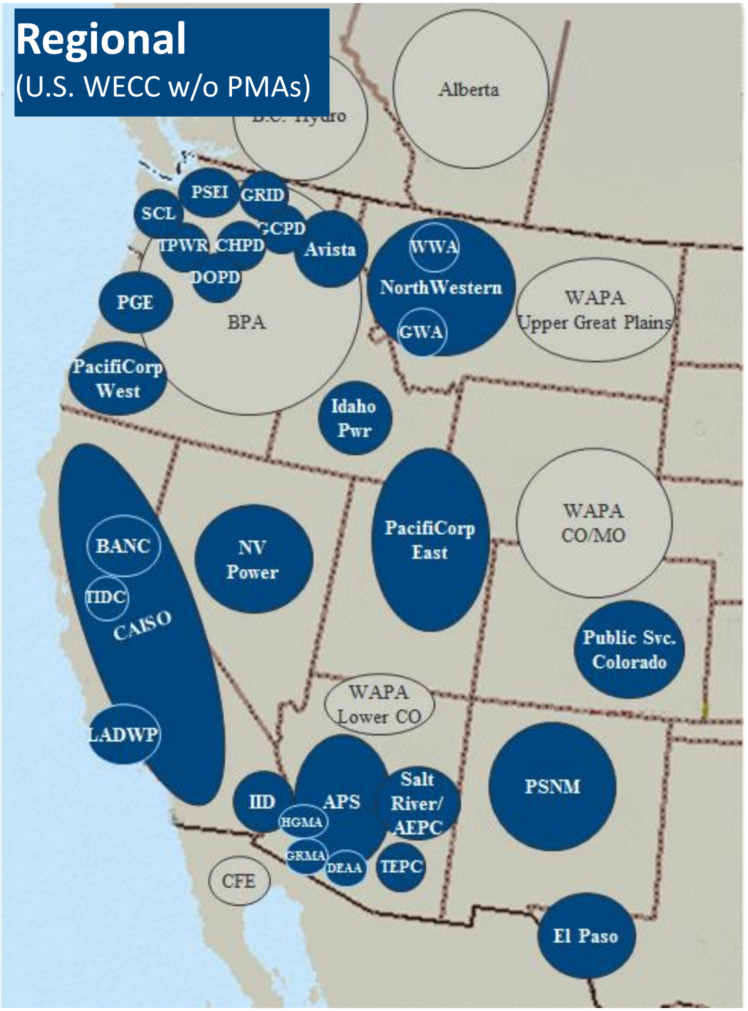


Two Regional Market Footprints Simulated

2020 Scenario



2030 Scenarios & 2020 Sensitivity



Renewable Portfolios and Scenarios Analyzed

	2020 Current Practice	2020 Regional ISO CAISO+PAC	2030 Current Practice		2030 Expanded Regional ISO U.S. WECC Minus PMAs	
Renewable Portfolio	Already contracted	Already contracted	**1A**	**1B Sensitivity**	**2**	**3**
CAISO Export Limits	0 MW net export limit	776 MW between CAISO & PAC	2,000 MW bilat. export trading limit	8,000 MW bilat. export trading limit	8,000 MW physical net export limit	8,000 MW physical net export limit
Focus of Analysis	Impact of limited near-term regional market with CAISO+PAC only		Impact of bilateral ability to re-export all existing imports (3,000–4,000 MW) plus an add'l. 2,000–8,000 MW		Impact of regional market under current renewable procurement practices	Impact of greater regional renewable procurement

Sensitivities Analyzed

Renewable Portfolio Sensitivities Analyzed by E3:

A. High coordination under bilateral markets (Current Practices 1B with low bilateral re-export hurdles)

B. High energy efficiency

C. High flexible loads

D. Low portfolio diversity

E. High rooftop PV

F. High out-of-state resource availability

G. Low cost solar

H. 55% RPS

Production Cost Sensitivities Analyzed by Brattle:

- High coordination under bilateral markets (Current Practices 1B with low bilateral re-export hurdles)
- Expanded Regional ISO for near-term (2020) market conditions
- 2030 Regional ISO Scenario for 1A Current Practice renewable portfolio (to isolate portfolio-related impacts)
- 2030 Regional ISO without renewables beyond RPS
- 2030 Scenarios with CO_2 price for rest of U.S. WECC (as proxy for possible CPP compliance)

Estimating Ratepayer Impacts of a Regional Market

Cost Savings / Source of Benefits	Captured by Expanding CAISO into a Regional RTO?	Modeling Approach to Quantify Benefit
Operating Cost Savings		
De-Pancaking – Partial	EIM	[already captured by EIM]
De-Pancaking – Full	✓	Production Cost Model
RT Imbalance Market – Partial	EIM	[already captured by EIM]
RT Imbalance Market – Full	✓	Other studies/qualitatively
DA Market and Unit Commitment	✓	Production Cost Model
Integrated Ancillary Services Market	✓	Production Cost Model
Investment Cost Savings		
Regional Resource Adequacy	✓	Load Diversity Estimation
Flexible Resource Procurement	✓	Other studies/qualitatively
Reduced Renewables Overbuild	✓	RESOLVE Model
Lower-Cost Renewable Resources	✓	RESOLVE Model

Energy+Environmental Economics

Renewable Portfolios for CAISO SB 350 Study

CAISO Public Workshop
May 24-25, 2016

Arne Olson, Partner

Contents

Energy+Environmental Economics

EXECUTIVE SUMMARY

Scope of E3 analysis

+ **E3 analysis uses the RESOLVE model to estimate the impacts of a regional market on the cost of procuring renewable resources to meet California's 50% RPS**
  - E3 analysis calculates the investment cost only; differences in operating costs are captured in PSO
  - Brattle Group has developed additional information about renewables outside of California

Cost Savings / Source of Benefits	Captured by Expanding CAISO into a Regional RTO?	Modeling Approach to Quantify Benefit
Operating Cost Savings		
De-Pancaking – Partial	EIM	[already captured by EIM]
De-Pancaking – Full	✓	Production Cost Model
RT Imbalance Market – Partial	EIM	[already captured by EIM]
RT Imbalance Market – Full	✓	Other studies/qualitatively
DA Market and Unit Commitment	✓	Production Cost Model
Integrated Ancillary Services Market	✓	Production Cost Model
Investment Cost Savings		
Regional Resource Adequacy	✓	Load Diversity Estimation
Flexible Resource Procurement	✓	Other studies/qualitatively
Reduced Renewables Overbuild	✓	RESOLVE Model
Lower-Cost Renewable Resources	✓	RESOLVE Model

Summary of renewable portfolios and investment cost results

+ **E3 developed optimal 50% RPS portfolios under three scenarios**
  1. Current practice in procurement and operations
  2. Current practice in procurement with a regional market
  3. Regional procurement and regional market
+ **Regional markets result in lower renewable procurement costs for California across all scenarios and sensitivities**
  - Savings are **$680 million/year** in 2030 under regional markets with current practices in renewable procurement
  - Savings are **$799 million/year** in 2030 under regional markets with regional renewable procurement

Renewable procurement savings are one component of several ratepayer benefits that are evaluated in the overall study

Summary of sensitivity analysis results: renewable investment cost

+ **Annual investment savings from regional integration range from $391 million to $1 billion per year under 50% RPS**
  - High flexible loads and high energy efficiency reduce savings
  - Low Portfolio diversity, high rooftop PV, and higher RPS increase savings
  - High out-of-state availability has limited effect on savings

Renewable portfolio cost savings from regional market ($MM)	Scenario 2 vs. 1a	Scenario 3 vs. 1a
Base assumptions	$680	$799
A. High coordination under bilateral markets	$391	$511
B. High energy efficiency	$576	$692
C. High flexible loads	$495	$616
D. Low portfolio diversity	$895	$1,004
E. High rooftop PV	$838	$944
F. High out-of-state resource availability	$578	$661
G. Low cost solar	$510	$647
H. 55% RPS	$1,164	$1,341

Renewable procurement savings are one component of several ratepayer benefits that are evaluated in the overall study

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MODELING OVERVIEW AND KEY INPUTS

Overview of the RESOLVE model

+ **RESOLVE is an E3 model that selects least-cost portfolios of renewable resources and integration solutions within the CAISO region between 2015 – 2030**
  - Selects portfolio of solar, wind, geothermal, biomass, and small hydro
  - Adds cost-effective integration solutions such as energy storage and flexible conventional resources, in combination with the renewable portfolio, to minimize total cost over the analysis period
+ **Resources are added to meet RPS target, overbuilding renewable portfolio if necessary**
  - Renewables are curtailed if the output cannot be consumed in California or exported to neighboring systems due to oversupply or insufficient power system flexibility
  - Renewable contracts are treated as sunk costs and fully compensated for curtailed output
  - Resources added to portfolio if necessary to replace curtailed output; renewable curtailment implicitly valued at replacement cost, which increases geometrically with curtailment

Study assesses the effect of regional markets on renewable procurement

Two major effects are tested:

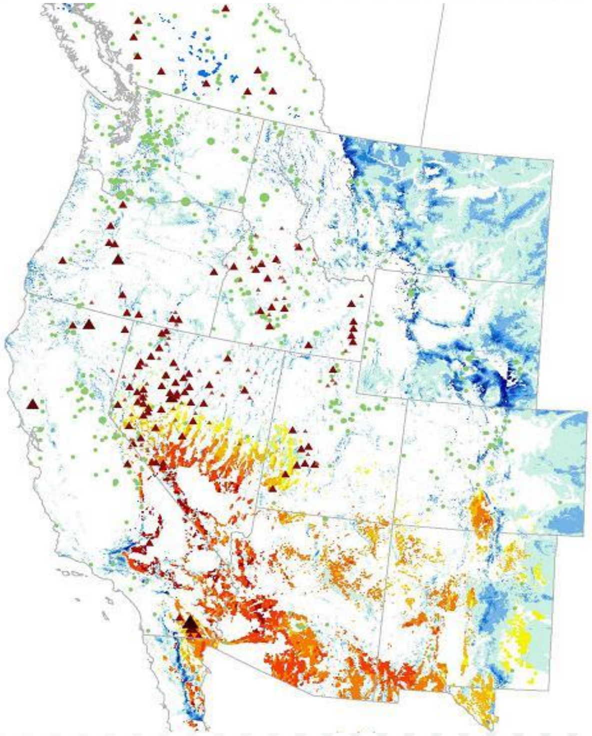
1. Effect of regional operations

- Increased access to latent flexible capacity across a broad, diverse region
- Increased ability to export surplus energy
- Could result in changes to least-cost portfolio

2. Effect of regional transmission tariff

- Reduces wheeling costs across the region
- Provides a mechanism for needed new transmission infrastructure to be studied and approved for inclusion in rates
- Provides access to high-quality wind in the Rockies and solar in the Southwest

Renewable Resource Potential in the West



Source: NREL

Three scenarios studied

1. **Current Practice Scenario**
   - Renewable energy procurement is largely from in-state resources, with 5,000 MW of out-of-state resources available over existing transmission
   - No regional market to help reduce curtailment
2. **Regional market operations with 'Current Practice' renewable energy procurement policies**
   - Assumes no increase in availability of out-of-state resources, but transmission wheeling charges are de-pancaked
   - Curtailment of renewables is reduced through better integration
3. **Regional market and renewable energy procurement**
   - Like Scenario 2, but with additional high-quality wind resources made available, requiring new transmission facilitated by the regional entity

Exports of surplus null power vary by scenario

- **Under current system of bilateral trading, the ability of other Balancing Authorities to absorb surplus null power from California during periods of high renewable output is limited**
  - Balancing authorities maintain obligation to balance their systems subject to NERC performance standards
  - Other "friction" in bilateral system may prevent some California renewable energy from finding a market
- **Exports under the Current Practice Scenario are limited to 2,000 MW**
  - Significant reduction from 4,000 MW of imports today
- **8,000 MW of exports allowed under regional markets**
  - Also tested as a sensitivity to Current Practice scenario

Out-of-state resource availability varies by scenario

- **Three categories of out of state resources are made available for selection by RESOLVE: RECs, Existing Transmission, New Transmission**
  - Selection based on least portfolio cost; not all out-of-state resources are picked
- **Pancaked wheeling and loss charges apply in Scenario 1 only**
- **Regional transmission organization facilitates new transmission development for highest-quality WY and NM wind in Scenario 3**

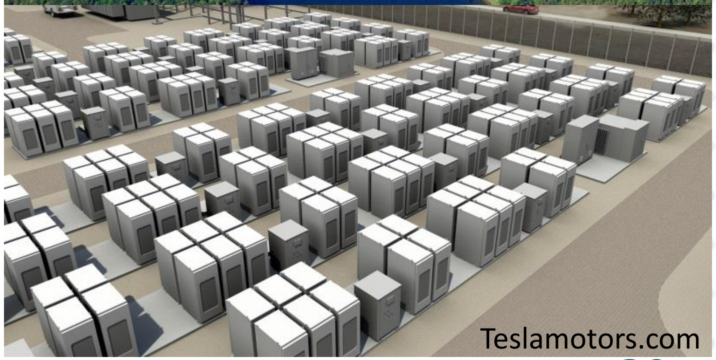
Renewable resource potential (MW) (not all resources are selected)	Scenarios 1 and 2	Scenario 3
NW Wind RECs	1,000	1,000
NW Wind, Existing Transmission	1,000	500
WY Wind, Existing Transmission	500	1,000
WY Wind, New Transmission	-	3,000
SW Solar RECs	1,000	1,000
SW Solar, Existing Transmission	500	500
NM Wind, Existing Transmission	1,000	1,000
NM Wind, New Transmission	-	3,000
Total Out of State Resources for IOUs	*5,000*	*11,000*

Many renewable integration solutions assumed in all scenarios

- Time-of-use rates that encourage daytime use
- 5 million electric vehicles by 2030 with near-universal access to workplace charging*
- 500 MW of pump storage manually added
- 500 MW of geothermal manually added
- 5,000 MW of out-of-state renewable resources available to be selected on a least-cost basis
- Unlimited storage available to be selected on a least-cost basis
- Renewables provide operating reserves
- Storage and hydro provide operating reserves and frequency response*

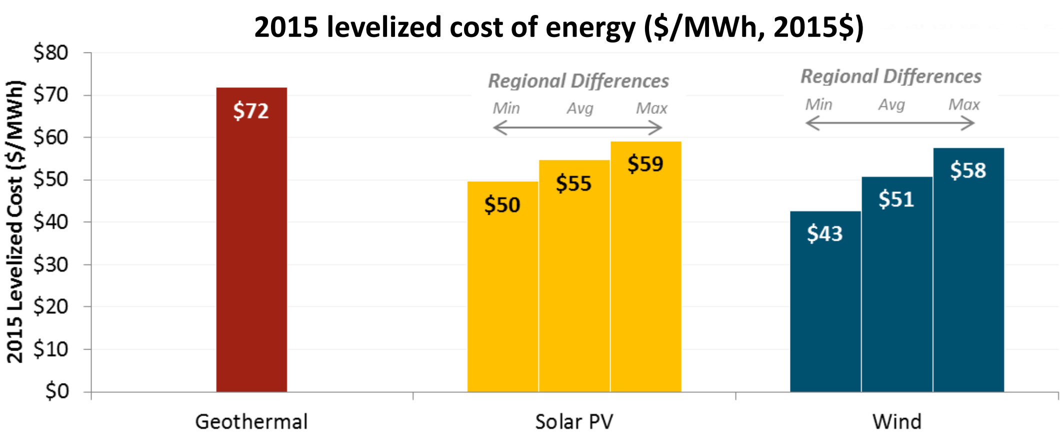
** Change since February results*

https://www.linkedin.com



Key input assumptions were updated based on stakeholder feedback

+ **Updated load forecast to CEC 2015 IEPR mid-AAEE**
    - Load and EVs are lower, Rooftop PV is higher compared to Feb. results
+ **Statewide analysis rather than exclusive focus on CAISO area**
    - Assumed renewable procurement for non-ISO areas (LADWP, BANC, TID, IID)
+ **Reduced battery storage costs**
    - Reduced capital cost, added inverter replacement, increased balance-of-systems costs, reduced fixed O&M, adjusted lifetime
+ **Reduced cost of solar, wind and geothermal resources**
+ **Other**
    - Hydro and storage can provide frequency response



* Costs include current levels of investment tax credit

33% base portfolio for CAISO area

- **All scenarios start with renewable resources under contract to meet a 33% RPS**
  - Base portfolio is drawn from CPUC RPS Calculator v6.1
- **Base portfolio assumes CPUC storage mandate plus existing pumped storage**
- **Base portfolio assumes 16,649 MW of behind-the-meter PV by 2030**
  - Based on IEPR forecast
  - Reduces sales but does qualify for RPS

CAISO Base Portfolio (MW)	
Renewables to meet 33% RPS in 2030	
	Scenarios 1 - 3
CAISO Solar	9,890
CAISO Wind	5,259
CAISO Geothermal	1,117
CAISO Small Hydro	429
CAISO Biomass	794
Northwest Wind	2,186
Northwest Biomass	1
Northwest Geothermal	32
Southwest Solar	197
Imperial Geothermal	449
Total CAISO Resources	17,489
Total Out-of-State Resources	2,417
Total Renewable Resources	20,354
Other Resources	
Energy Storage	3,157
Behind-the-meter Rooftop PV	16,649

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PORTFOLIO RESULTS

Portfolios shown are for 2030, incremental to resources needed for 33% RPS in 2020

Portfolios for non-CAISO Balancing Areas

- Hand-picked portfolios representative of plausible renewable procurement activities under each scenario
- Results also included in detailed tables on following pages

- Portfolios shown are for 2030, incremental from 33% RPS in 2020

MW

Type	Zone	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
Solar PV	In-state	2,375	2,375	2,375	1,304
Wind	NW	447	447	447	318
Wind	UT	604	604	604	420
Wind	NM	-	-	-	462
Wind	WY	-	-	-	495
Total		**3,426**	**3,426**	**3,426**	**2,998**

GWh

Type	Zone	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
Solar PV	In-state	6,592	6,592	6,592	3,616
Wind	NW	1,253	1,253	1,253	891
Wind	UT	1,693	1,693	1,693	1,177
Wind	NM	-	-	-	1,861
Wind	WY	-	-	-	1,993
Total		**9,538**	**9,538**	**9,538**	**9,538**

Total incremental resources for California (in MW)

- Model selects a diverse portfolio of in-state solar and out-of-state wind across all cases

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	7,601	8,279	7,804	3,440
California Wind	3,000	3,000	1,900	1,900
California Geothermal	500	500	500	500
Northwest Wind, Existing Transmission	1,447	447	562	318
Northwest Wind RECs	1,000	0	1,000	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	1,995
Southwest Solar, Existing Transmission	0	272	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	11,101	11,779	10,204	5,840
Total Out-of-State Resources	5,551	3,823	5,166	7,694
Total Renewable Resources	**16,652**	**15,602**	**15,370**	**13,534**
Energy Storage (MW)	972	500	500	500

- Portfolios shown are for California in 2030, incremental from 33% RPS in 2020; they include the handpicked muni portfolios

Total incremental resources for California (in GWh)

- Model selects a diverse portfolio of in-state solar and out-of-state wind across all cases

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (GWh)				
California Solar	21,482	23,483	22,147	9,827
California Wind	8,480	8,480	5,596	5,596
California Geothermal	3,942	3,942	3,942	3,942
Northwest Wind, Existing Transmission	4,056	1,253	1,574	891
Northwest Wind RECs	2,803	0	2,803	0
Utah Wind, Existing Transmission	1,693	1,693	1,693	1,177
Wyoming Wind, Existing Transmission	1,708	1,708	1,708	1,708
Wyoming Wind, New Transmission	0	0	0	8,037
Southwest Solar, Existing Transmission	0	809	1,489	1,489
Southwest Solar RECs	2,978	2,978	2,978	2,978
New Mexico Wind, Existing Transmission	3,416	3,416	3,416	3,416
New Mexico Wind, New Transmission	0	0	0	7,905
Total CA Resources	33,904	35,905	31,685	19,365
Total Out-of-State Resources	16,654	11,857	15,661	27,601
Total Renewable Resources	**50,558**	**47,762**	**47,346**	**46,966**
Curtailment (IOUs only, GWh)	4,818	2,022	1,606	1,226
Curtailment (% of available RPS energy)	4.5%	2.0%	1.6%	1.2%

- Curtailment is significantly reduced under regional operations

Scenario 1: Incremental Renewable Resource Portfolio Composition

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	**7,601**	**8,279**	7,804	3,440
California Wind	**3,000**	**3,000**	1,000	1,000
California Geothermal	**500**	**500**	[illegible]	[illegible]
Northwest Wind, Existing Transmission	**1,447**	**447**	[illegible]	[illegible]
Northwest Wind RECs	**1,000**	**0**	[illegible]	[illegible]
Utah Wind, Existing Transmission	**604**	**604**	[illegible]	[illegible]
Wyoming Wind, Existing Transmission	**500**	**500**	[illegible]	[illegible]
Wyoming Wind, New Transmission	**0**	**0**	0	1,995
Southwest Solar, Existing Transmission	0	272	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	11,101	11,779	10,204	5,840
Total Out-of-State Resources	5,551	3,823	5,166	7,694
Total Renewable Resources	**16,652**	**15,602**	**15,370**	**13,534**
Energy Storage (MW)	**972**	**500**	500	500

- Under higher export capability, in-state solar displaces out-of-state wind due to reduced curtailment

- Additional battery storage selected in Scenario 1a

Scenario 2: Incremental Renewable Resource Portfolio Composition

- **Ability to export reduces curtailment; procurement of both in-state and out-of-state wind is avoided**

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	**7,601**	8,279	**7,804**	3,440
California Wind	**3,000**	3,000	**1,900**	1,900
California Geothermal	**500**	500	**500**	500
Northwest Wind, Existing Transmission	**1,447**	447	**562**	318
Northwest Wind RECs	**1,000**	0	**1,000**	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	1,995
Southwest Solar, Existing Transmission	0	272	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	11,101	11,779	10,204	5,840
Total Out-of-State Resources	5,551	3,823	5,166	7,694
Total Renewable Resources	16,652	15,602	15,370	13,534
Energy Storage (MW)	972	500	500	500

Scenario 3: Incremental Renewable Resource Portfolio Composition

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	**7,601**	8,279	7,804	**3,440**
California Wind	**3,000**	3,000	1,900	**1,900**
California Geothermal	**500**	[illegible]	[illegible]	**500**
Northwest Wind, Existing Transmission	**1,447**	[illegible]	[illegible]	**318**
Northwest Wind RECs	**1,000**	[illegible]	[illegible]	**0**
Utah Wind, Existing Transmission	**604**	[illegible]	[illegible]	**420**
Wyoming Wind, Existing Transmission	**500**	[illegible]	[illegible]	**500**
Wyoming Wind, New Transmission	**0**	0	0	**1,995**
Southwest Solar, Existing Transmission	**0**	272	500	**500**
Southwest Solar RECs	**1,000**	1,000	1,000	**1,000**
New Mexico Wind, Existing Transmission	**1,000**	1,000	1,000	**1,000**
New Mexico Wind, New Transmission	**0**	0	0	**1,962**
Total CA Resources	11,101	11,779	10,204	5,840
Total Out-of-State Resources	5,551	3,823	5,166	7,694
Total Renewable Resources	16,652	15,602	15,370	13,534
Energy Storage (MW)	972	500	500	500

WY and NM wind displace California solar and lower-quality NW wind

Incremental renewable procurement by CREZ (MW)

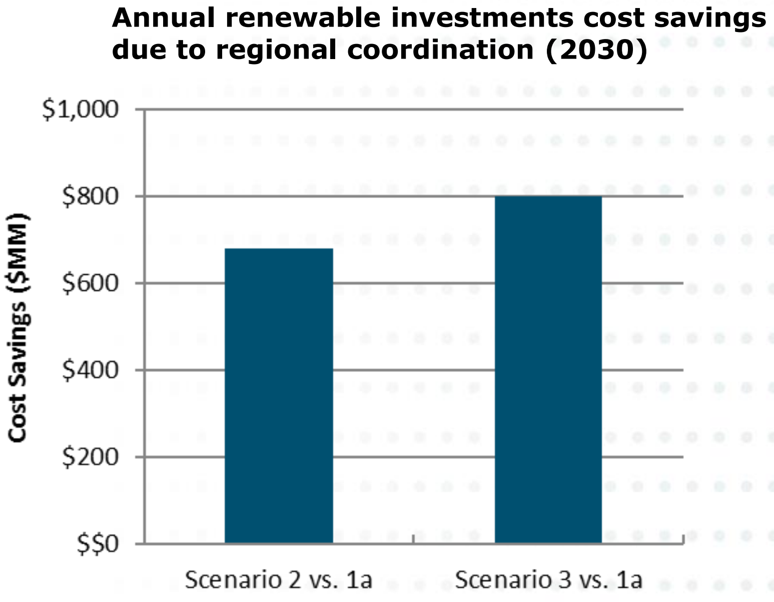
Resource (CREZ)	Technology	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
Greater_Imperial_Geothermal	Geothermal	500	500	500	500
Greater_Carrizo_Solar	Solar	570	570	570	-
Kramer_Inyokern_Solar	Solar	375	375	375	375
Mountain_Pass_El_Dorado_Solar	Solar	-	-	-	-
Riverside_East_Palm_Springs_Solar	Solar	331	2,459	1,984	-
Tehachapi_Solar	Solar	2,500	2,500	2,500	1,761
Westlands_Solar	Solar	2,323	873	873	486
Central_Valley_North_Los_Banos_Wind	Wind	150	150	150	150
Greater_Carrizo_Wind	Wind	500	500	500	500
Greater_Imperial_Wind	Wind	400	400	400	400
Riverside_East_Palm_Springs_Wind	Wind	500	500	-	-
Solano_Wind	Wind	600	600	-	-
Tehachapi_Wind	Wind	850	850	850	850
Owens_Valley_Solar	Solar	578	578	578	305
Greater_Imperial_Solar	Solar	923	923	923	512
Sonoma_Geothermal	Geothermal	-	-	-	-
Out-of-state					
OR_Wind_ExistingTx	Wind	1,447	447	562	318
OR_Wind_REC	Wind	1,000	-	1,000	-
WY_Wind_ExistingTx	Wind	500	500	500	500
WY_Wind_NewTx_1	Wind	-	-	-	1,995
AZ_Solar_ExistingTx	Solar	-	273	502	502
AZ_Solar_REC	Solar	1,000	1,000	1,000	1,000
NM_Wind_ExistingTx	Wind	1,000	1,000	1,000	1,000
NM_Wind_NewTx_1	Wind	-	-	-	1,962
UT_Wind_ExistingTx	Wind	604	604	604	420
Grand Total		**16,652**	**15,603**	**15,371**	**13,536**

Table includes handpicked muni resources

Renewable procurement cost results

+ Annual renewable procurement cost savings in 2030: $680-$799 million

- Fixed costs only; variable cost differences accounted for in PSO analysis
- Modest savings assumed for non-CAISO BAs
- Renewable procurement savings are only one component of ratepayer savings



Renewable Procurement Costs ($MM)	Scenario 1a	Scenario 2	Scenario 3
Fixed Costs - CAISO	$2,578	$1,934	$1,840
Fixed Costs– non-CAISO BAs	$714	$678	$652
Total California Fixed Costs ($MM)	**$3,291**	**$2,612**	**$2,492**
Fixed Costs Relative to Scenario 1a		**-$680**	**-$799**

Out-of-state resources by scenario

+ **Full accounting of procurement cost and potential by Portfolio Content Category is beyond the scope of this analysis**

+ **The following table shows % out-of-state resources (including Munis) for each scenario**

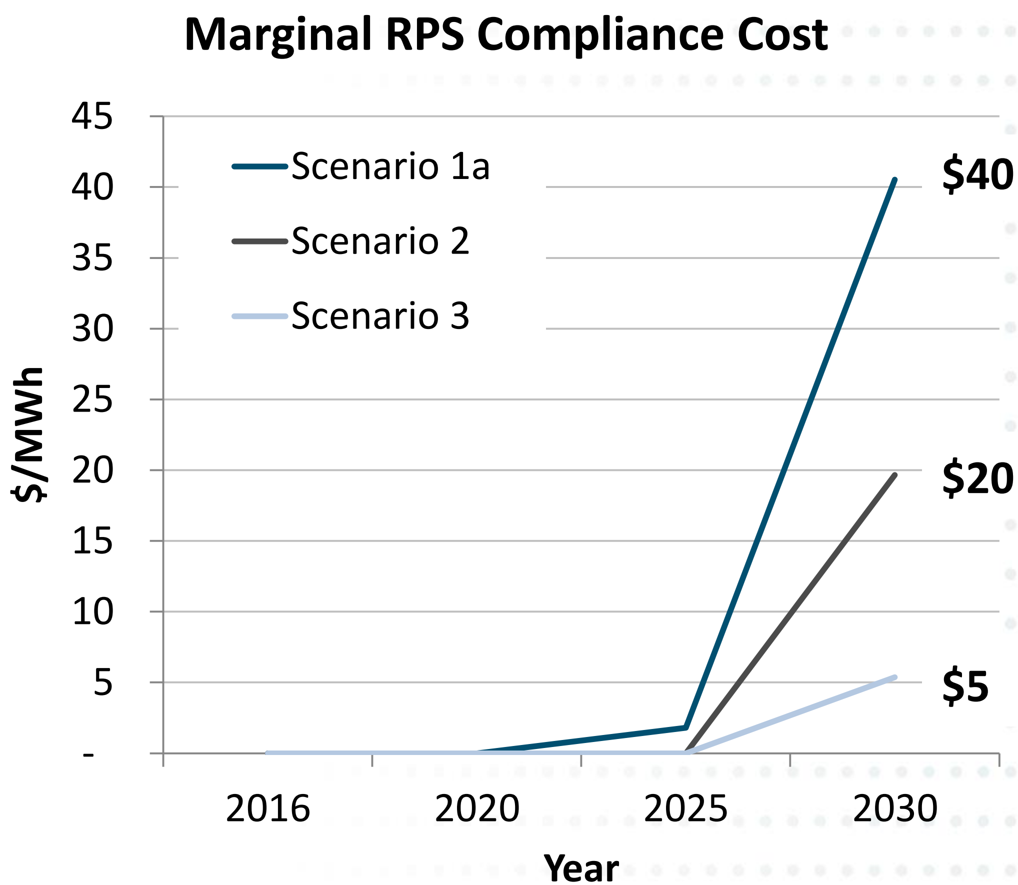
  - Due to potential for dynamic transfer under PCC1, scenarios modeled here may not require a change in PCC rules

  - ***No scenario selects <u>all</u> out-of-state resources***

		50% RPS Portfolio in 2030			
	33% Base Portfolio	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
% Out-of-State	19%	24%	21%	24%	33%
% In-State	81%	76%	79%	76%	67%

Negative market prices during curtailment hours

- **During curtailment hours, California LSEs should be willing to pay others to take their renewable energy output in order to generate the REC for RPS compliance**
  - Regional markets could benefit CA ratepayers by reducing payments to out of state loads
- **Electricity market price should clear at REC replacement cost**
  - Base assumption does not include this benefit, i.e. there is no negative pricing ($0/MWh)
  - Market price of -$40 MWh modeled as a sensitivity



SENSITIVITY ANALYSIS

Sensitivity analyses were performed in RESOLVE and capture changes in procurement cost only

Description of sensitivity cases

Eight additional sensitivity cases were run:

A. High coordination under bilateral markets ("Sensitivity 1b")

B. High energy efficiency (doubling of EE by 2030)

C. High flexible load deployment

D. Low portfolio diversity (remove 500 MW each of geothermal and pumped storage)

E. High rooftop PV

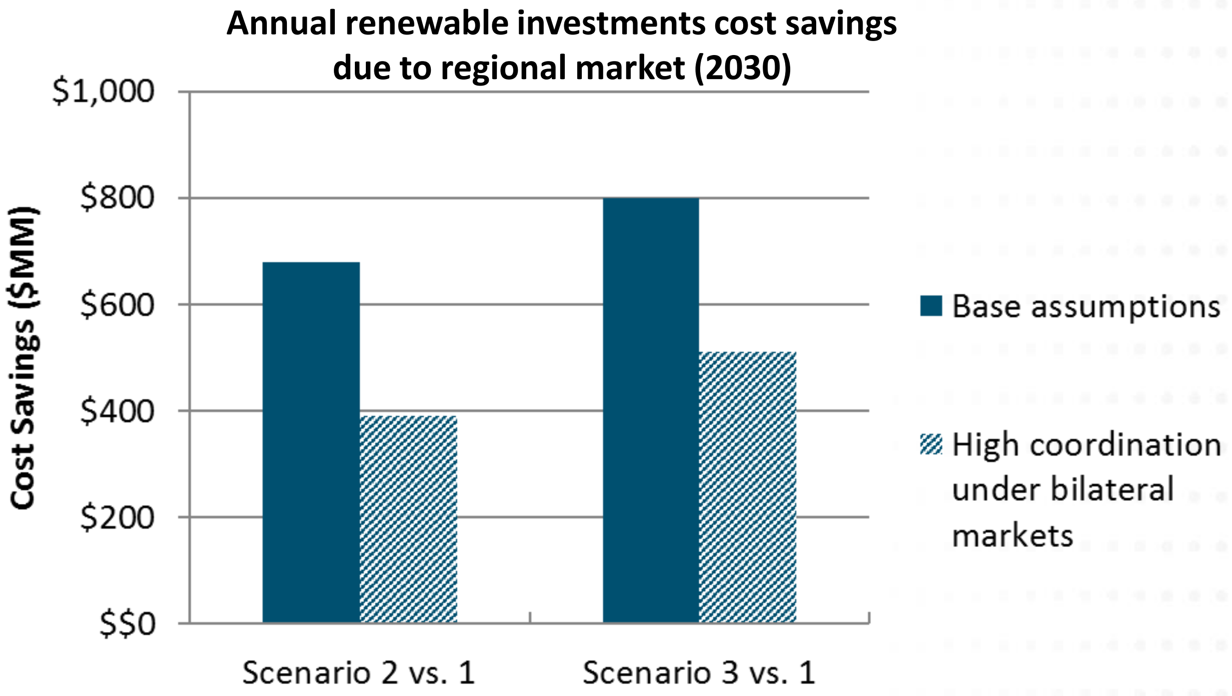
F. High out-of-state resource availability

G. Low cost solar

H. 55% RPS

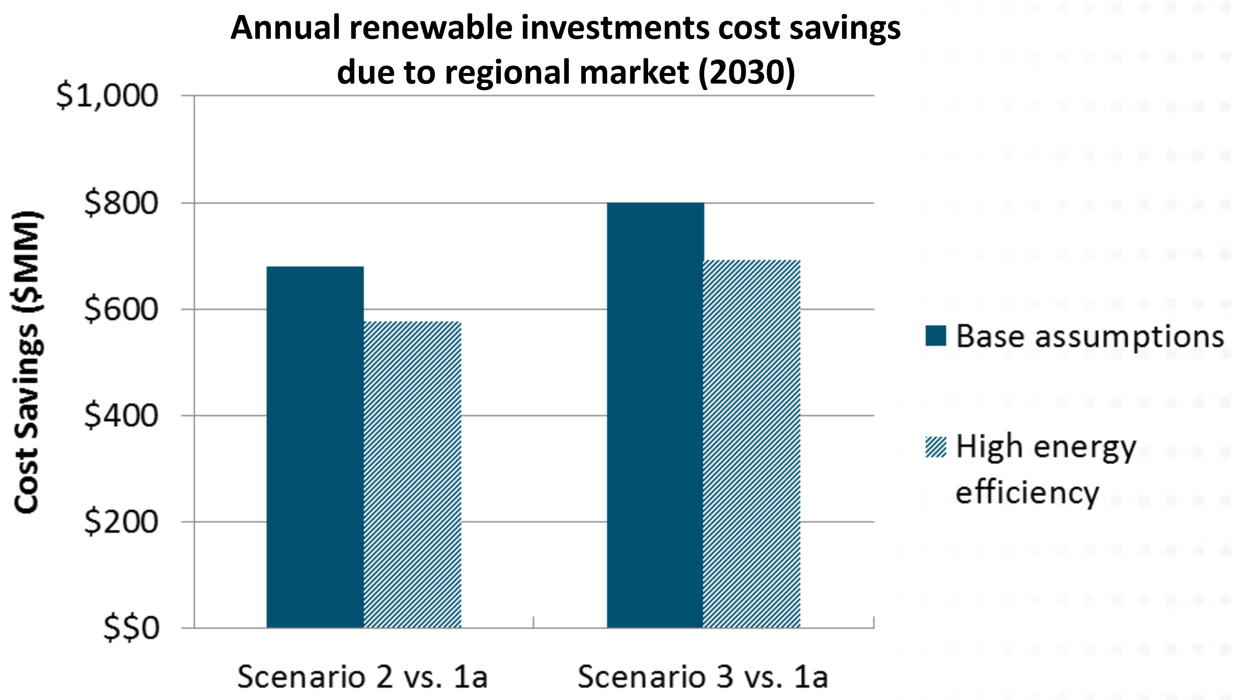
A. High coordination under bilateral markets (Sensitivity 1b)

- Increase export capability in Current Practice scenario from 2,000 MW to 8,000 MW
- Increased exports reduce benefits of regional market



B: High energy efficiency

- **Reduce loads consistent with goal of doubling energy efficiency by 2030**
  - Input data from California energy agencies
- **Lower loads reduce benefits of regional coordination**



B: High energy efficiency

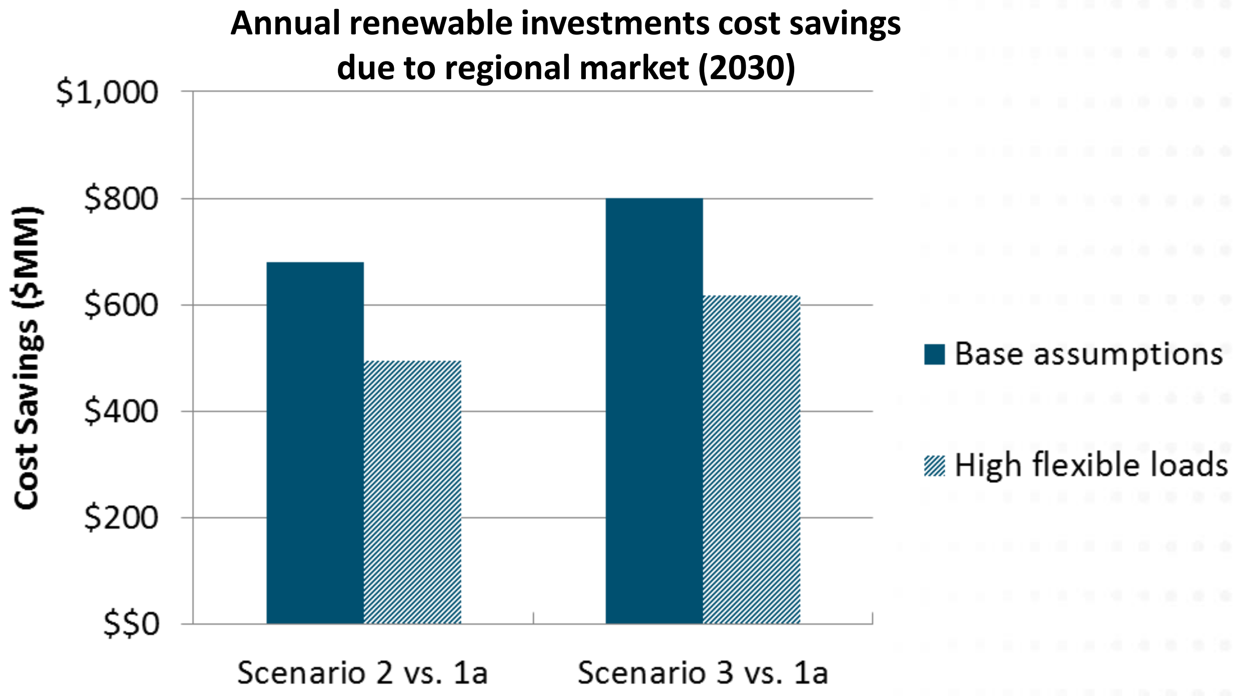
Reduction in California solar procurement

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	5,250	6,446	5,955	1,304
California Wind	3,000	2,400	1,900	1,480
California Geothermal	500	500	500	500
Northwest Wind, Existing Transmission	1,144	447	447	318
Northwest Wind RECs	1,000	0	364	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	1,995
Southwest Solar, Existing Transmission	0	0	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	8,750	9,346	8,355	3,284
Total Out-of-State Resources	5,248	3,551	4,415	7,694
Total Renewable Resources	**13,998**	**12,897**	**12,770**	**10,978**
Energy Storage (MW)	888	500	500	500

Fewer central station resources needed, modest changes to portfolio composition

C. High flexible load deployment

- Add 3,000 MW of flexible loads in all cases (modeled as free 4-hour batteries)
- Makes CA solar more economic in Scenario 1 and reduces the need for battery storage
- Reduction in benefits relative to Current Practice



C. High flexible load deployment

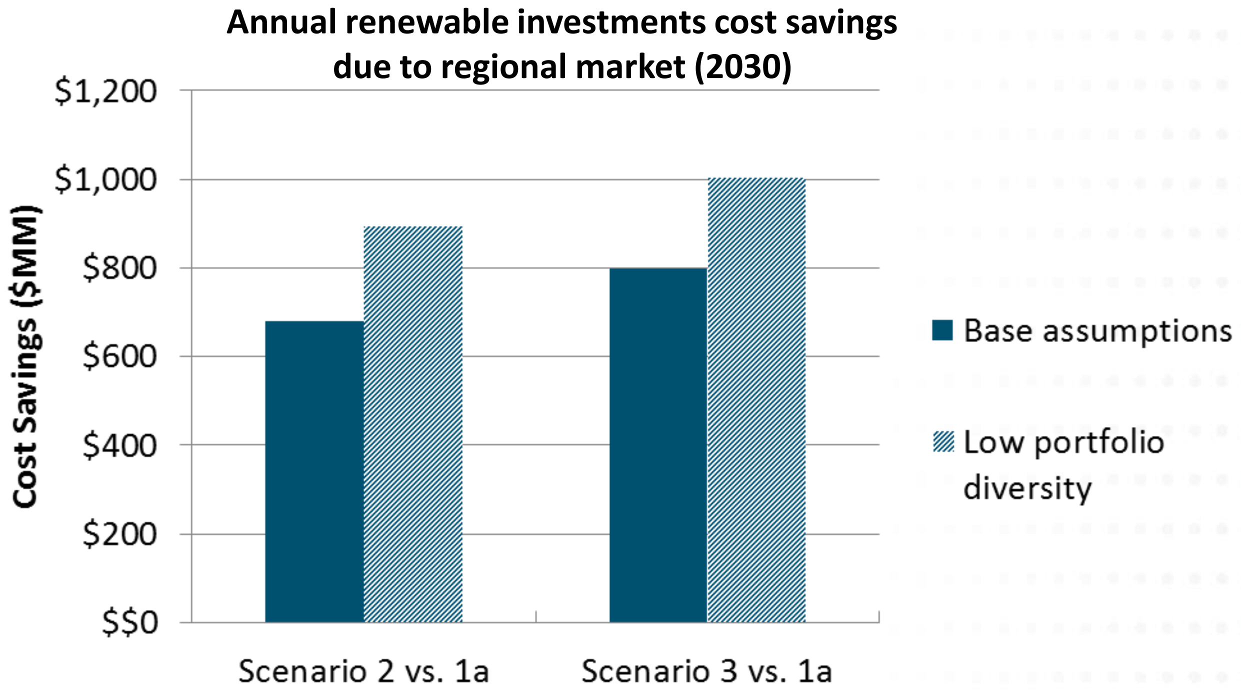
Slight increase in California solar procurement

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	8,501	8,895	8,593	3,630
California Wind	3,000	2,400	1,900	1,900
California Geothermal	500	500	500	500
Northwest Wind, Existing Transmission	447	447	447	318
Northwest Wind RECs	1,000	0	455	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	1,995
Southwest Solar, Existing Transmission	0	236	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	12,001	11,795	10,993	6,030
Total Out-of-State Resources	4,551	3,787	4,506	7,694
Total Renewable Resources	**16,552**	**15,582**	**15,499**	**13,724**
Energy Storage (MW)	587	500	500	500

Very little battery storage selected

D. Low portfolio diversity

- Remove hand-picked pumped storage and geothermal
- RESOLVE reduces cost in all scenarios by picking more in-state solar PV; batteries selected in Scenario 1
- Cost reductions are greater in Scenarios 2 and 3



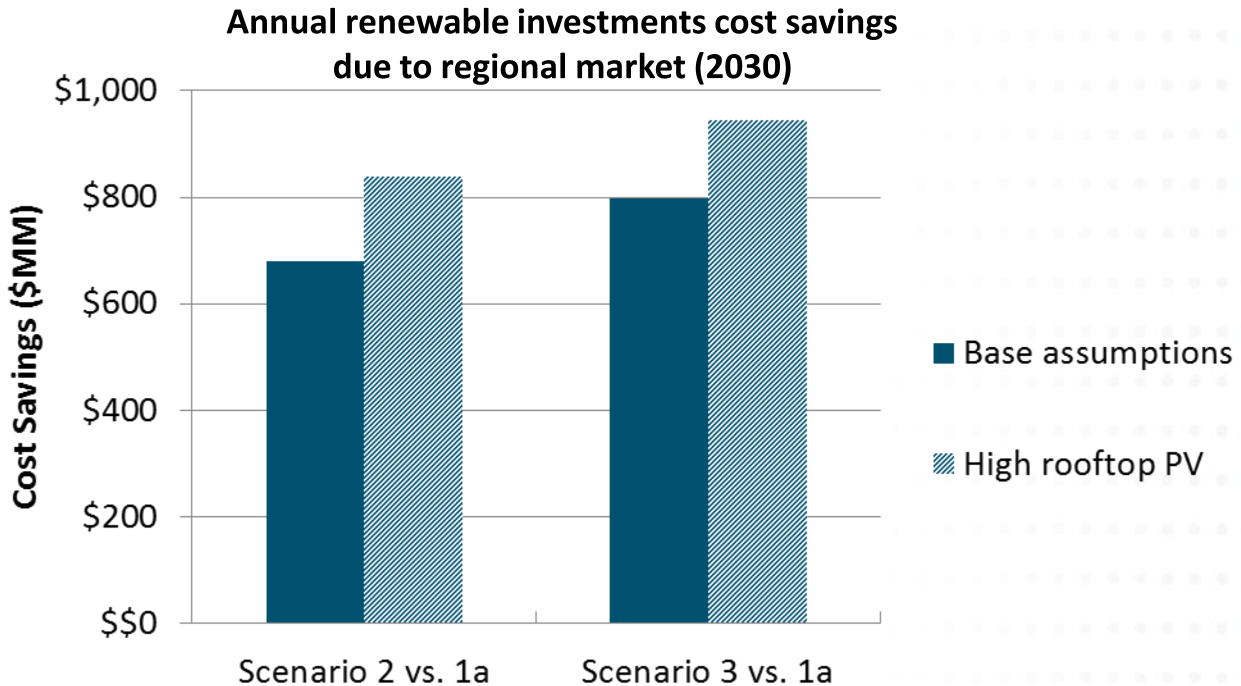
D. Low portfolio diversity

Significant increase in California solar procurement

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	9,924	10,052	8,181	5,209
California Wind	2,000	2,000	2,000	1,500
California Geothermal	0	0	0	0
Northwest Wind, Existing Transmission	1,447	600	1,447	318
Northwest Wind RECs	1,000	290	1,000	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	1,995
Southwest Solar, Existing Transmission	500	500	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	11,924	12,052	10,181	6,709
Total Out-of-State Resources	6,051	4,494	6,051	7,694
Total Renewable Resources	**17,975**	**16,546**	**16,232**	**14,403**
Energy Storage (MW)	1,070	183	0	0

E. High rooftop PV

- Increase CAISO rooftop PV from 16 GW to 21 GW by 2030
- Reduces load and RPS procurement need, but increases solar-driven curtailment
- Benefits are higher than under base assumptions – regional market has a significant benefit in integrating rooftop solar!



E. High rooftop PV

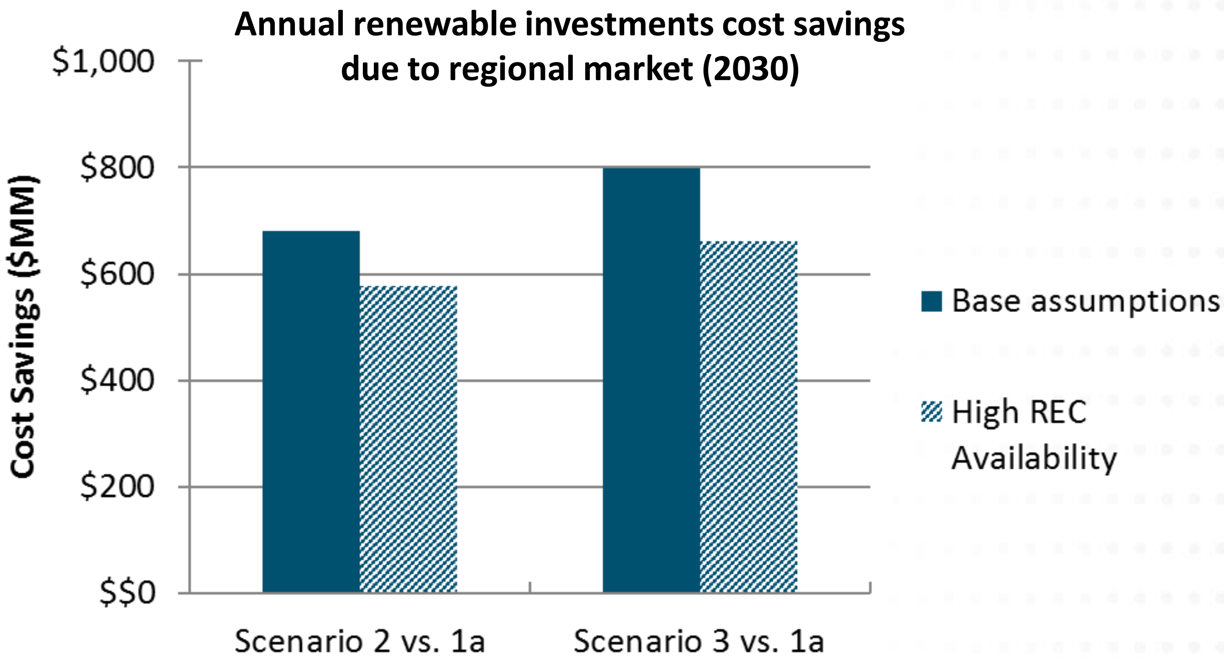
	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	7,146	7,679	5,778	2,296
California Wind	3,000	3,000	1,900	1,900
California Geothermal	500	500	500	500
Northwest Wind, Existing Transmission	1,447	447	1,447	318
Northwest Wind RECs	1,000	0	1,000	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	1,995
Southwest Solar, Existing Transmission	0	0	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	10,646	11,179	8,178	4,696
Total Out-of-State Resources	5,551	3,551	6,051	7,694
Total Renewable Resources	**16,197**	**14,730**	**14,229**	**12,390**
Energy Storage (MW)	1,547	517	500	500

Additional battery storage selected

Fewer central station resources needed, modest changes to portfolio composition

F. High out of state resource availability

- **Increase available SW Solar and NW Wind RECs to 25% of the 50% RPS goal (IOUs only)**
  - 4,526 MW of NW Wind RECs and 4,279 MW of SW Solar RECs available
- **Benefits are lower because lower cost solar RECs displace marginal California solar and out-of-state wind in Scenario 1**
  - Higher benefits from reduction in wheeling costs



F. High Out of State Resource Availability

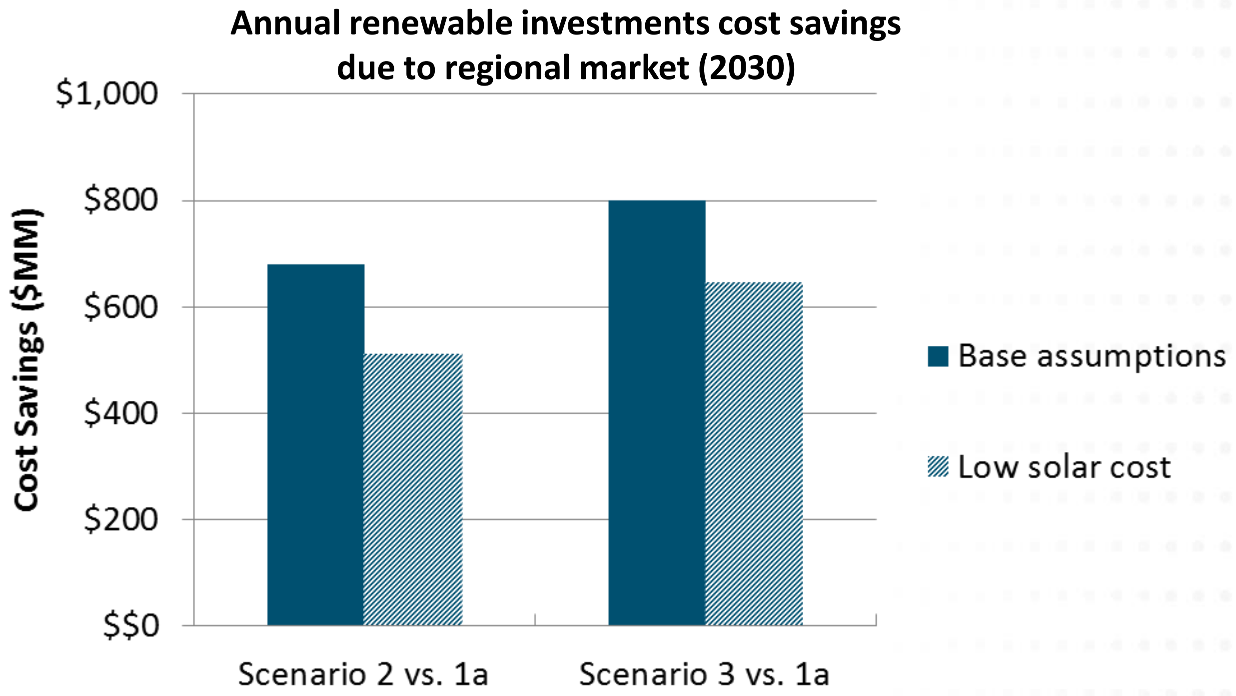
Reduction in California solar procurement

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	5,724	6,986	5,337	1,304
California Wind	3,000	2,106	1,900	1,750
California Geothermal	500	500	500	500
Northwest Wind, Existing Transmission	447	447	447	318
Northwest Wind RECs	0	0	0	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	1,995
Southwest Solar, Existing Transmission	0	0	500	500
Southwest Solar RECs	4,279	3,118	4,279	3,188
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	9,224	9,592	7,737	3,554
Total Out-of-State Resources	6,830	5,669	7,330	9,882
Total Renewable Resources	**16,054**	**15,261**	**15,067**	**13,436**
Energy Storage (MW)	598	500	500	500

SW solar RECs selected but NW wind RECs are not

G. Low Cost Solar

+ Reduce solar cost to $1/W by 2025
+ Benefits are lower because lower cost California solar displaces out-of-state wind in Scenario 1
+ Still significant curtailment reduction benefits in Scenario 2, NM and WY wind still selected in Scenario 3



G. Low Cost Solar

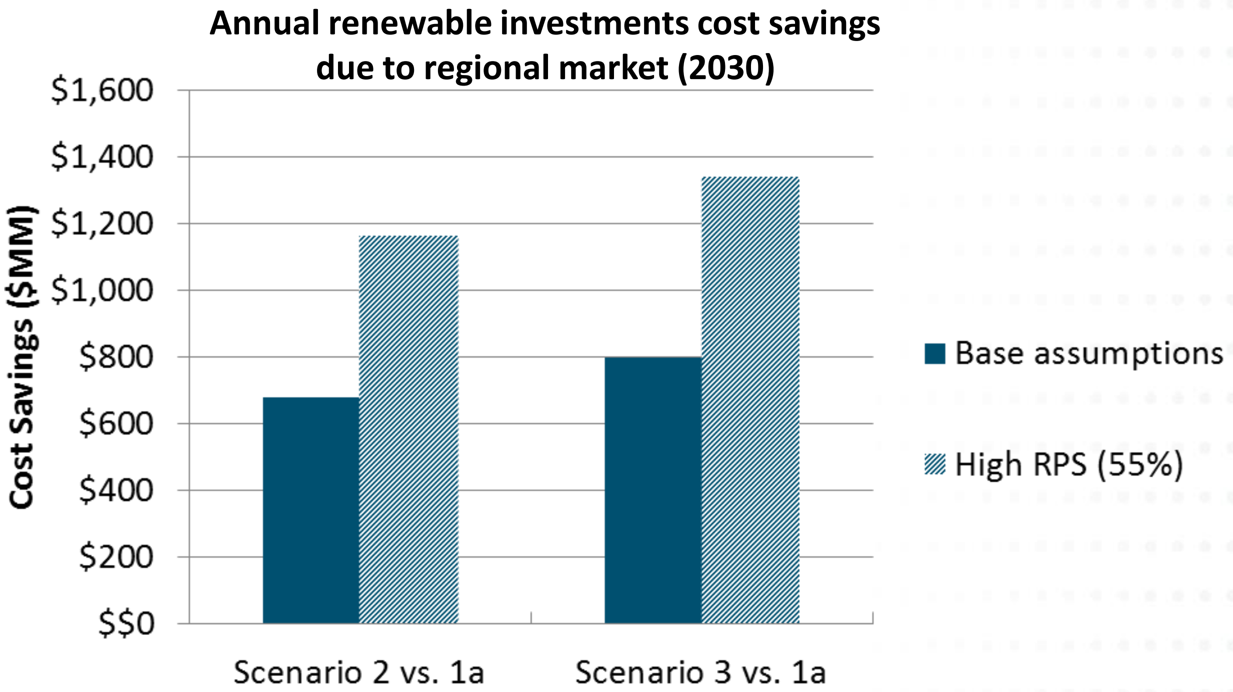
Significant increase in California solar procurement

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	9,729	9,684	9,016	4,056
California Wind	3,000	1,900	1,900	1,250
California Geothermal	500	500	500	500
Northwest Wind, Existing Transmission	447	447	447	318
Northwest Wind RECs	344	0	0	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	1,995
Southwest Solar, Existing Transmission	0	0	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	13,229	12,084	11,416	5,806
Total Out-of-State Resources	3,895	3,551	4,051	7,694
Total Renewable Resources	**17,124**	**15,635**	**15,467**	**13,500**
Energy Storage (MW)	1,127	500	500	500

Significant reduction in NW wind procurement

H. 55% RPS

- Increase California RPS to 55% in all scenarios, which may be more consistent with Governor Brown's goal of 40% GHG reduction by 2030
- Benefits are significantly higher because it is much more costly to meet higher RPS in Current Practice (Scenario 1a)



H. 55% RPS

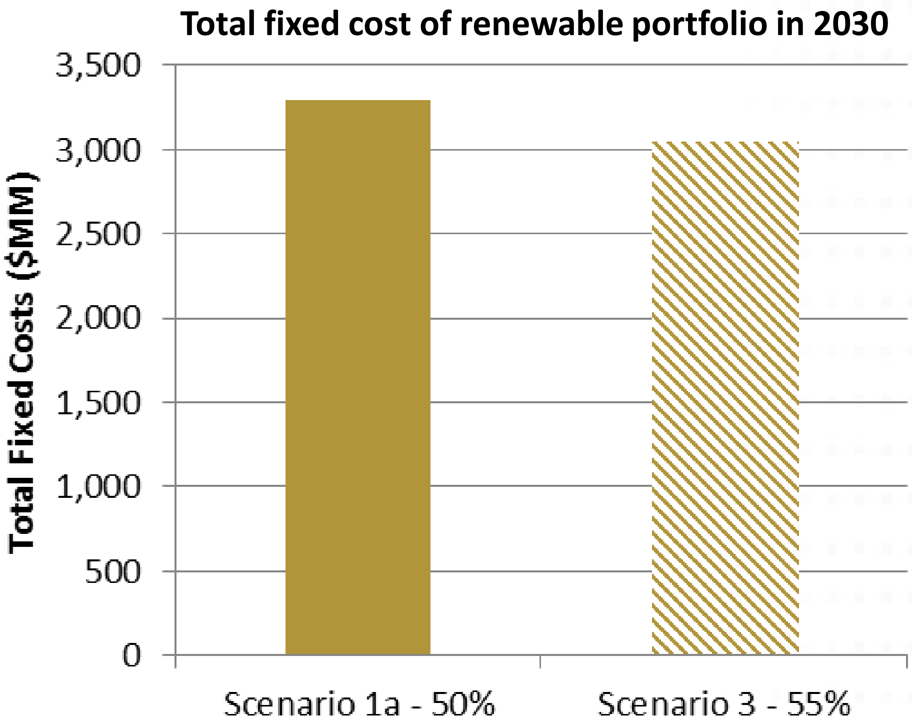
Significant increase in California solar procurement

	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
CAISO simultaneous export limit	2,000	8,000	8,000	8,000
Procurement	Current practice	Current practice	Current practice	WECC-wide
Operations	CAISO	CAISO	WECC-wide	WECC-wide
Portfolio Composition (MW)				
California Solar	12,214	9,952	9,701	5,616
California Wind	3,000	3,000	3,000	1,900
California Geothermal	500	500	500	500
Northwest Wind, Existing Transmission	1,447	1,447	1,447	318
Northwest Wind RECs	1,000	1,000	1,000	0
Utah Wind, Existing Transmission	604	604	604	420
Wyoming Wind, Existing Transmission	500	500	500	500
Wyoming Wind, New Transmission	0	0	0	3,123
Southwest Solar, Existing Transmission	500	500	500	500
Southwest Solar RECs	1,000	1,000	1,000	1,000
New Mexico Wind, Existing Transmission	1,000	1,000	1,000	1,000
New Mexico Wind, New Transmission	0	0	0	1,962
Total CA Resources	15,714	13,452	13,201	8,016
Total Out-of-State Resources	6,051	6,051	6,051	8,823
Total Renewable Resources	**21,765**	**19,503**	**19,252**	**16,839**
Energy Storage (MW)	1,809	503	500	500

Additional increment of WY wind procured

H. 55% RPS

+ **Procurement cost of meeting a 55% RPS under regional coordination is lower than procurement cost of meeting 50% RPS under current practice**
  - This is before considering fuel cost savings due to more renewables



Summary of results with sensitivity analysis

+ **Annual savings from regional integration range from $391 million to $1.004 billion per year under 50% RPS**
  - High flexible loads and high energy efficiency reduce savings
  - Low Portfolio diversity, high rooftop PV, and higher RPS increase savings
  - High out-of-state availability has limited effect on savings

Renewable Portfolio cost savings from regional market ($MM)	Scenario 2 vs. 1a	Scenario 3 vs. 1a
Base assumptions	$680	$799
A. High coordination under bilateral markets	$391	$511
B. High energy efficiency	$576	$692
C. High flexible loads	$495	$616
D. Low portfolio diversity	$895	$1,004
E. High rooftop PV	$838	$944
F. High out-of-state resource availability	$578	$661
G. Low cost solar	$510	$647
H. 55% RPS	$1,164	$1,341

Energy+Environmental Economics

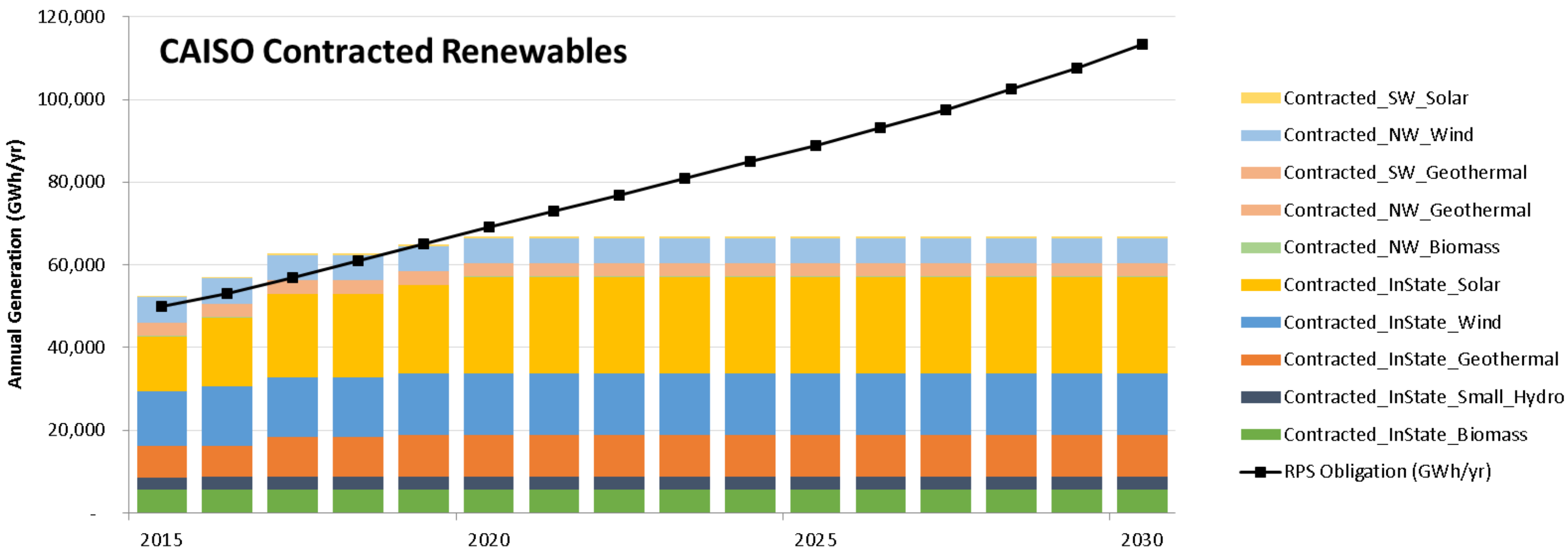
APPENDIX

Portfolio and Resource Cost Assumptions

Existing & Contracted Renewable Resources

+ **Existing and contracted renewables for IOUs are from the RPS Calculator v6.1, Municipal utility existing and contracted renewables are from TEPCC 2024 data**

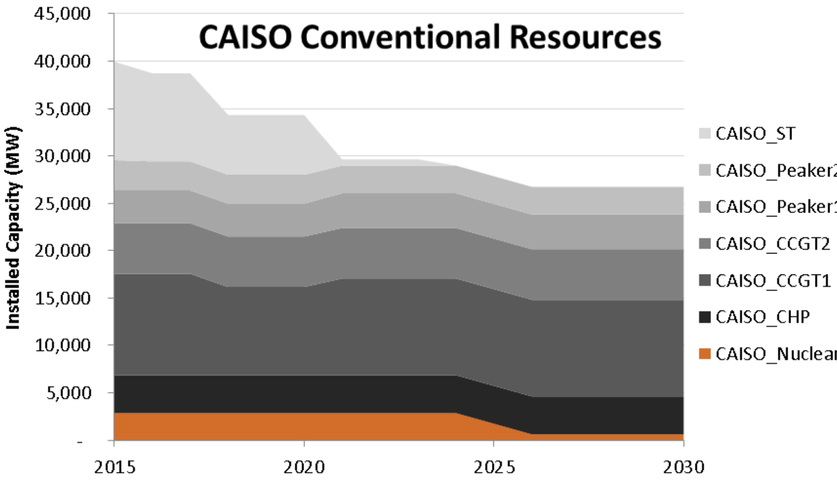
+ **18 GW of rooftop PV statewide (16.6 GW in CAISO) by 2030 based on extrapolation of CEC 2015 IEPR "mid" forecast**



Conventional Generator Additions and Retirements

+ Retirements

- Nuclear: Assumes retirement of Diablo Canyon in 2025
- California Once-through-cooling (OTC) units are retired per 2014 LTPP thermal stack assumptions



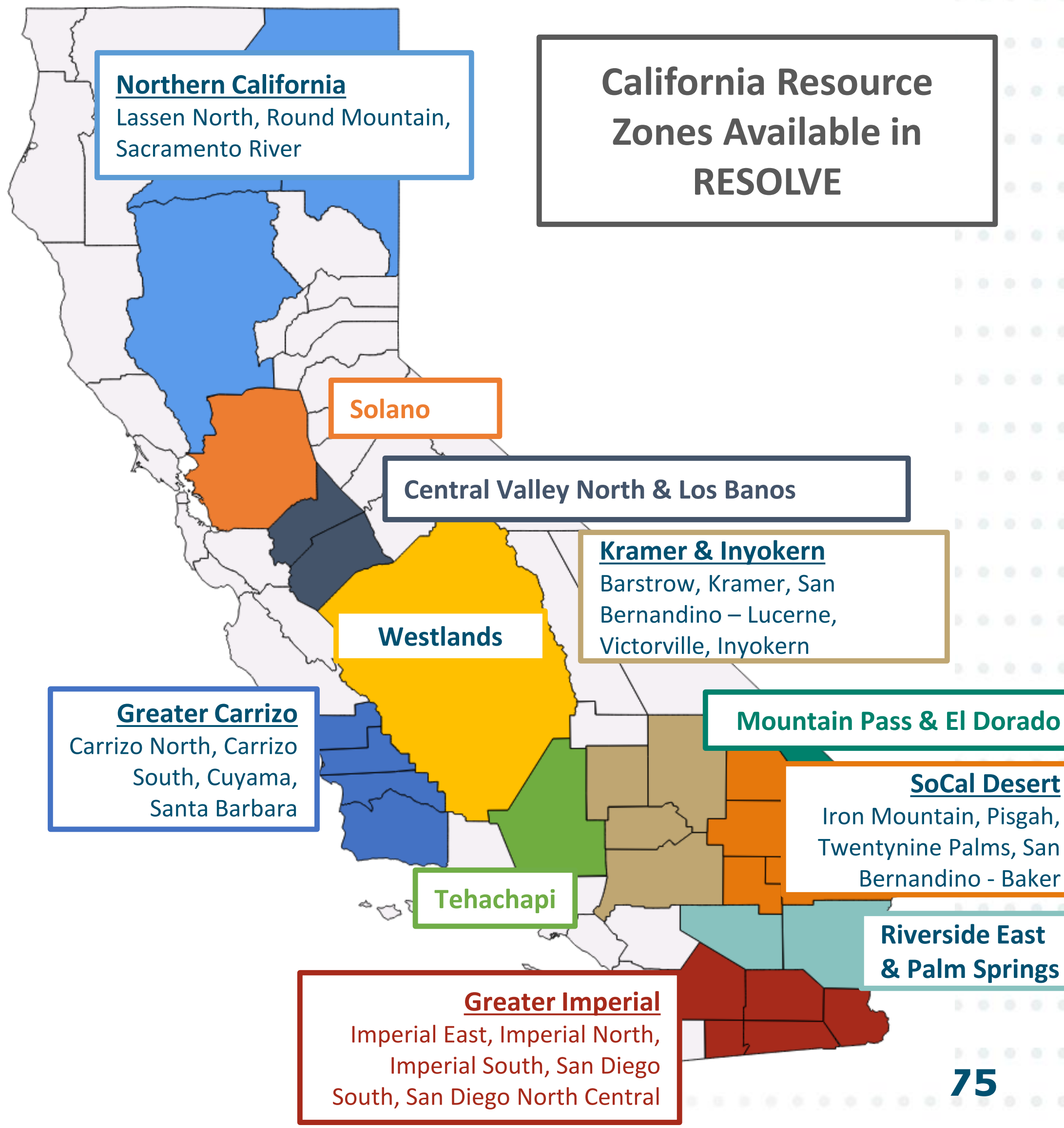
- Out of state coal retirements are based on announced retirements (including retirements assumed in PacifiCorp IRP)

+ Additions

- RESOLVE adds new capacity if resource adequacy needs are not met with preferred resources
  - No new capacity additions are triggered

Overview of In-State Resource Potential

+ **Initial renewable resource supply curve developed based on RPS Calculator 6.1, adjustments made based on stakeholder feedback**
  - Model includes extensive data on renewable resource potential and performance in California, as well as transmission cost and availability provided by CAISO
  - Renewable cost assumptions adjusted from Black & Veatch assumptions based on stakeholder feedback



Renewable Resource Costs

- **Renewable resource cost assumptions are based on the CPUC's RPS Calculator v.6.1, then modified based on stakeholder feedback to reflect current renewable market**
- **Pro-forma cash flow model translates costs into estimated PPA prices**
- **Costs are location-specific and incorporate differences in local costs of materials and labor**

Category	Geothermal	Solar PV*	Wind
Capital Cost ($/kW)	$4,759	$2,174	$2,031
Interconnection Cost ($/kW)	$260	$200	$136
Fixed O&M ($/kW-yr)	$313	$32	$33

Notes: Costs represent an average plant installed in California in 2015; costs are expressed in 2015 $; solar PV costs are expressed with respect to AC capacity

* Solar PV costs on a $/kW AC basis (modeled as single-axis tracking with an inverter loading ratio of 1.30)

Renewable cost assumptions change over time

+ **Power purchase agreement prices are projected through 2030 based on long-term industry trends:**
  - **Capital cost reductions:** technological improvement expected to reduce renewable resource costs
  - **Long run financing:** financing costs expected to increase over time due to rising interest rates
  - **Property tax exemption:** the exemption of solar facilities from California property tax is not available to facilities installed after 2024
  - **Federal tax credit sunsets:** Federal PTC and ITC phase out by 2019 for wind and by 2021 for solar and geothermal
    - Solar PV & geothermal eligible for 10% ITC after 2021

Renewable resource cost and performance assumptions

Resource	Geography		Capacity Factor (%)	Capital Cost (2015 $/kW) 2015	Capital Cost (2015 $/kW) 2030	LCOE (2015 $/MWh) 2015	LCOE (2015 $/MWh) 2030
California Geothermal	Imperial		90%	$ 5,142	$ 5,142	$ 76	$ 96
	Northern California		80%	$ 3,510	$ 3,510	$ 59	$ 81
California Solar PV	Central Valley & Los Banos		30%	$ 2,174	$ 1,826	$ 58	$ 76
	Greater Carrizo		33%	$ 2,174	$ 1,826	$ 53	$ 69
	Greater Imperial		31%	$ 2,174	$ 1,826	$ 56	$ 73
	Kramer & Inyokern		34%	$ 2,174	$ 1,826	$ 50	$ 66
	Mountain Pass & El Dorado		34%	$ 2,174	$ 1,826	$ 50	$ 65
	Northern California		29%	$ 2,174	$ 1,826	$ 59	$ 78
	Riverside East & Palm Springs		32%	$ 2,174	$ 1,826	$ 53	$ 70
	Solano		29%	$ 2,174	$ 1,826	$ 59	$ 78
	Southern California Desert		34%	$ 2,174	$ 1,826	$ 51	$ 67
	Tehachapi		33%	$ 2,174	$ 1,826	$ 52	$ 68
	Westlands		31%	$ 2,174	$ 1,826	$ 55	$ 72
OOS Solar PV	Arizona		34%	$ 2,001	$ 1,711	$ 45	$ 56
California Wind	Central Valley & Los Banos		30%	$ 2,069	$ 2,008	$ 51	$ 76
	Greater Carrizo		31%	$ 1,914	$ 1,857	$ 49	$ 74
	Greater Imperial		35%	$ 2,083	$ 2,022	$ 43	$ 68
	Riverside East & Palm Springs		33%	$ 2,047	$ 1,987	$ 57	$ 82
	Solano		27%	$ 1,992	$ 1,933	$ 58	$ 82
	Tehachapi		35%	$ 2,087	$ 2,025	$ 47	$ 72
OOS Wind	New Mexico	1	46%	$ 1,738	$ 1,687	$ 21	$ 46
		2	42%	$ 1,738	$ 1,687	$ 26	$ 51
		3	39%	$ 1,738	$ 1,687	$ 30	$ 55
	Oregon		32%	$ 1,943	$ 1,885	$ 49	$ 74
	Wyoming	1	46%	$ 1,738	$ 1,687	$ 21	$ 46
		2	42%	$ 1,738	$ 1,687	$ 26	$ 51
		3	39%	$ 1,738	$ 1,687	$ 30	$ 55

* OOS = out-of-state, LCOE = levelized cost of energy. Impacts of declining federal tax credits are included.

Energy Storage Cost Assumptions

+ **Battery cost estimates are based on literature review and quotes from manufacturers, updated based on stakeholder feedback**
    - Installed cost of Li-ion is lower even at long durations, but flow battery has longer lifetime and requires fewer/no replacements
+ **Capital investment and O&M costs are annualized using E3's WECC Pro Forma tool**

Technology	Charging & Discharging Efficiency	Financing Lifetime (yr)	Replac-ement (yr)	Minimum duration (hrs)	Resource Potential (MW)
Lithium Ion Battery	92%	16	8	0	N/A
Flow Battery	84%	20	N/A	0	N/A
Pumped Hydro	87%	40	N/A	12	4,000

Type	Cost Metric	2015	2030
Lithium Ion Battery	Storage Cost ($/kWh)	375	183
	Power Conversion System Cost ($/kW)	300	204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	7.5	3.7
	Fixed O&M PCS ($/kW-yr)	6.0	4.1
Flow Battery	Storage Cost ($/kWh)	700	315
	Power Conversion System Cost ($/kW)	300	204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	14.0	6.3
	Fixed O&M PCS ($/kW-yr)	6.0	4.1
Pumped Hydro	Storage Cost ($/kWh)	117	117
	Power Conversion System Cost ($/kW)	1,400	1,400
	Fixed O&M Battery/Reservoir ($/kWh-yr)	-	-
	Fixed O&M PCS ($/kW-yr)	15	15

Technology	2015 Annualized Cost Components ($/kW-yr; $/kWh-yr)	2030 Annualized Cost Components ($/kW-yr; $/kWh-yr)
Lithium Ion Battery	69; 85	46; 40
Flow Battery	58; 118	39; 53
Pumped Hydro	146; 12	146; 12

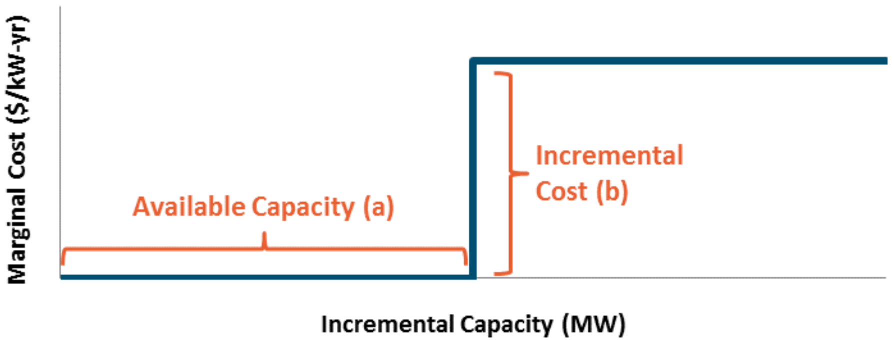
Note: The first number indicates the annualized cost of the power conversion system ($/kW-yr) of the device and the second number indicates the annualized cost of the energy storage capacity or reservoir size ($/kWh-yr). Both numbers are additive.

California in-state renewable transmission cost assumptions

+ **California transmission cost assumptions are based on CAISO's 50 Percent Renewable Energy Special Study conducted as part of the 2015-2016 Transmission Plan**
  - https://www.caiso.com/Documents/Draft2015-2016TransmissionPlan.pdf

+ **'Available Capacity (a)' represents the limit of a system to accommodate new renewables at no cost; and 'Incremental Cost (b)' reflects the cost of new transmission upgrades once the available capacity has been exhausted.**

Illustrative two-step transmission costing model for a renewable resource zone in California



Availability of energy only capacity and cost of transmission upgrades in California renewable resource zones

Zone	Available Capability (MW)	Incremental Cost ($/kW-yr)
Central Valley & Los Banos	2,000	$ 29
Greater Carrizo	1,140	$ 114
Greater Imperial	2,633	$ 68
Kramer & Inyokern	750	$ 52
Mountain Pass & El Dorado	2,982	$ 65
Northern California	3,404	$ 95
Riverside East & Palm Springs	4,917	$ 85
Solano	1,101	$ 13
Southern California Desert	-	$ 64
Tehachapi	5,000	$ 21
Westlands	2,900	$ 58

Out of state renewable transmission cost assumptions

+ Out of state transmission cost assumptions vary by region and scenario

Resource		Quantity (MW)	Costs ($/kW-year)			Basis for Assumption
			Scen. 1	Scen. 2	Scen. 3	
Southwest Solar PV		1500	$39	$0	$0	Wheeling & losses on APS system
New Mexico Wind	1	1000	$72	$0	$0	Wheeling & losses on PNM & APS systems
	2	1500	N/A	N/A	$50	Assumed project capital cost ($567 million for 1,500 MW of new transmission) based on RPS Calculator transmission costs, scaled for distance for delivery to Four Corners
	3	1500	N/A	N/A	$129	Sum of public SunZia costs ($2 billion for 3,000 MW) and assumed upgrade costs from Pinal Central to Palo Verde based on RPS Calculator
Northwest Wind		2000	$34	$0	$0	Wheeling & losses on BPA system (system + southern intertie rates)
Wyoming Wind	1	500	$66	$0	$0	Wheeling & losses on Pacificorp East & NV Energy systems
	2	3000	N/A	N/A	$88	Costs of Gateway project reported ($252 million per year for 2,875 MW) reported in *Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration* (Technical Appendix)

Content

Production Cost Simulations: Methodology

We conducted nodal market simulations to estimate:

- Production cost impacts associated with de-pancaking transmission charges , joint unit commitment and dispatch used in ratepayer impact analysis and economic impact analysis
- Changes in generation output and emissions of GHG and other air pollutants used in environmental impact analysis

Modeling Framework:

- Simulating WECC with and without regional market for near-term and longer-term
  - 2020 to demonstrate near-term impacts prior to larger regional expansion and ramp-up of California's renewable generation needs
  - 2030 to highlight impacts of an expanded regional market with a higher level of renewable resources procured to meet the 50% RPS in California
- Key results include:
  - Production cost impact for across the WECC
  - GHG emissions, unit starts, and changes in generation output (incl. NO_x , SO_2)
  - Impact on California's net production, purchase and sales cost

Production Cost Simulations: Methodology

Day-Ahead Unit Commitment

- De-pancaked transmission & scheduling charges
- Full grid utilization
- Reduced operating reserves

- Regionally optimized unit commitment
- Reduced additional commitment hurdle

Day-Ahead Market Dispatch

- De-pancaked transmission & scheduling charges
- Full grid utilization
- Reduced operating reserves

- Regionally optimized unit dispatch
- Avoided bilateral transaction cost

Intra-Day Adjustments

- De-pancaked transmission & scheduling charges
- Full grid utilization
- Reduced operating reserves

- Adjusted unit commitment and real-time bids
- Avoided bilateral transaction cost

Real-Time Market Dispatch

- De-pancaked transmission & scheduling charges
- Full grid utilization
- Reduced operating reserves

- Regionally optimized unit dispatch
- Reduced A/S needs
- Resolved uncertainties

Scope of Production Cost Simulations

(without forecast errors, renewable uncertainty, real-time outages, etc.)

EIM

Modeling Assumptions: 2020 Scenarios

- Started with CAISO's 2020 Gridview model used in 2015/16 Transmission Planning Process (TPP)
- Updated key assumptions based on CEC's 2015 IEPR data
  - California loads, distributed solar, natural gas prices, and GHG prices
- Wheeling and hurdle rates reflect economic barriers between Balancing Authorities
- Refined representation of future WECC transmission projects
- Refined modeling of pumped storage hydro, and gas CC–CT unit commitment

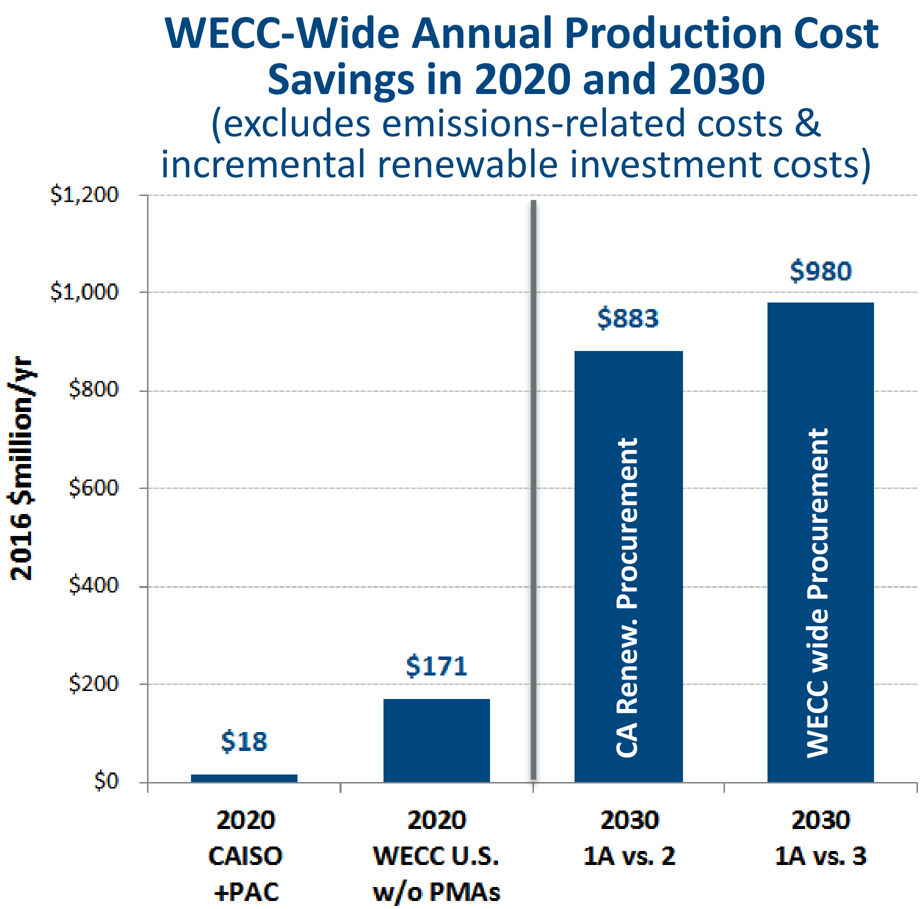
Inputs	2020 Current Practice (CAISO)	2020 CAISO+PAC Regional Market
Renewable portfolio	CAISO's Gridview model	*Same as CP*
Transmission	CAISO's Gridview model (removed post-2020 projects)	*Same as CP*
Load	2015 IEPR	*Same as CP*
Gas price	2015 IEPR	*Same as CP*
GHG price	2015 IEPR $25/tonne in CA, $0 outside of CA	*Same as CP*
Reserve requirements	Updated frequency response, LF, and regulation	Allow sharing in CAISO+PAC
CAISO net export limit	0 MW	776 MW (based on ISO-PAC contract path)
Hurdle rate	Wheeling based on recent tariff (off-peak); + admin. charges & friction	*Same as CP*
Contract path	CAISO-PAC with wheeling based on recent tariff (off-peak); $1/MWh admin charges & $1/MWh trading margin $4/MWh for unit commitment	CAISO-PAC and PACE-PACW paths not subject to any hurdle rates

Modeling Assumptions: 2030 Scenarios

- Growth in loads, distributed solar, natural gas, and GHG prices based on CEC and WECC data
- Conventional generation additions and retirements, and new regional transmission based on TEPPC 2024 Common Case
  - Additional coal retirements and natural gas additions based on company announcements and IRP plans
- Renewable generation additions to meet current 2030 RPS needs plus added low-cost WY and NM wind (beyond RPS) facilitated by regional market
- Assumed no carbon price for outside of California in base-case scenarios, but separately analyzed a sensitivity with a $15/tonne CO_2 price in rest of U.S. WECC (outside of CA)

Inputs	2030 Current Practice (CAISO)	2030 Regional ISO (US WECC–PMAs)
Renewable portfolio	Portfolios for Scenarios 1A and 1A from E3	Portfolios for Scen. 2 and 3 from E3 plus renewables facilitated beyond RPS
Transmission	CAISO's Gridview model (removed Gateway D & F)	CAISO's Gridview model (added WY & NM transmission in Scenario 3)
Load	2015 IEPR, WECC Load & Resources forecast	*Same as CP*
Gas price	2015 IEPR	*Same as CP*
GHG price	2015 IEPR $46/tonne in CA, $0 outside of CA	*Same as CP*
Reserve requirements	Updated frequency response, load-following, and regulation	Reduced requirements and allowed sharing in WECC minus PMAs
CAISO net export limit	2,000 MW (1a) 8,000 MW (1b)	8,000 MW
Hurdle rate	Wheeling based on recent tariff (off-peak); $1/MWh admin charges & $1/MWh trading margin $4/MWh for unit-commitment	Removed hurdles within regional footprint

Results: WECC-Wide Production Costs Savings



* Based on fuel, start-up, and variable O&M costs only

Does not include: societal benefits of emission reductions or incremental investment costs associated with the additional renewable resources facilitated by the regional market in 2030 Scenarios 2 and 3.

- Regional production cost savings of $18 million in 2020 is low due to limited scope of regionalization (CAISO+PAC) and conservative modeling assumptions
- For expanded region (U.S. WECC w/o PMAs), 2020 savings would be $171 million
- 2030 annual production cost savings range from **$883 million to $980 million (4.5–5% of total production costs)** under the regional market (U.S. WECC w/o PMAs)
- Results depend on:
  - Ability to manage excess generation in a bilateral, non-market environment
  - Extent to which CA renewable procurement is focused on in-state vs. regional resources (Scenario 2 vs. 3)

WECC-Wide Production Costs Savings

- Production cost savings are an overall societal benefit accrued across the entire WECC due to the efficiency of a larger regional ISO footprint
- These savings are the estimated cost reductions in fuel, variable O&M, and start-up costs (excluding carbon costs). They are driven by:
  - **Optimized joint unit commitment and dispatch** across a larger, consolidated balancing area with de-pancaked transmission charges
  - **Reducing/removing hurdles** faced by bilateral trades allows the commitment and dispatch of lower-cost renewable resources across a larger footprint
  - **Sharing (and joint dispatch of) resources** used as operating reserves
  - **Higher ability to (re)export excess renewable generation** from California to the rest of WECC
- Results are conservatively low because of simplified simulations
- The magnitude of the estimated savings are within the range of savings found in other market studies (see review of other studies in Appendix D)

Impact of Generation Unit Starts on Costs and Emissions

- A regional market **reduces the number of unit starts**
- **Production cost and emissions also decrease** with the number of times generators shut down and start up.
- Regional market scenarios reduce cycling of the California natural gas generators significantly compared to Current Practice scenarios to less challenging over-generation conditions
  - Thus, less startup costs (as reflected in production cost savings) and emissions
  - Starting a combined cycle unit emits as much NO_x as approximately 7 hours or full-load, steady state operation

Number of Starts in 2030
California State Natural Gas-Fired Generators

Unit Type	Avg. MW Started	Number of Starts: 2030 Current Practice 1A	Number of Starts: 2030 Regional ISO Exp. 3	Number of Starts: 3 minus 1A
CC-Industrial	429	5,404	3,460	(1,944)
CT-Aero	41	5,033	3,148	(1,885)
ICE	8	11,477	10,896	(581)
CC-Single Shaft	281	1,767	1,318	(449)
CC-Aero	172	1,018	744	(274)
ST	45	232	108	(124)
CT-Industrial	93	347	355	8

Production Cost Savings Not Quantified

Actual regional market operations will likely offer production cost and emissions benefits beyond those quantified because of the conservative nature and scope of our analyses:

1. Limitations of production cost simulations mean that results do not capture the full production cost benefits of regional market operations
   - Example: No improved regional optimization of hydro resources
   - See slide 37
2. Simulations do not fully capture under-utilization of the existing grid under current practices
3. Long-term benefits of improved regional and inter-regional transmission planning and improved long-term price signals for generation investments is not yet included
4. Reduction in counterparties' transactions costs associated with bilateral trading activities is not accounted for (recognizing that there will be some cost to ISO participation)

Not Quantified: Improved Utilization of Existing Grid

The simulations over-optimize the utilization of the existing grid under current practices, thus understating regional market benefits

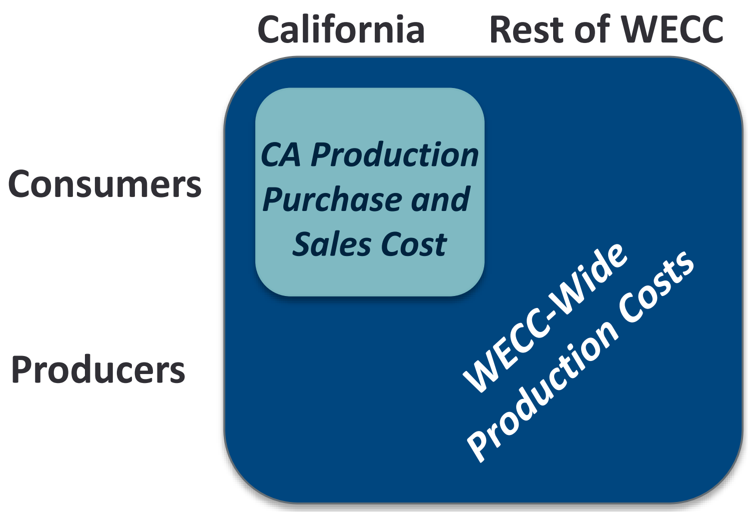
- Simulations "optimize away" many of the congestion-related challenges encountered under the current bilateral market model. For example:
  - Congestion on the California-Oregon border (COI and NOB) have ranged from \$60–150 million/year for 2012–14; yet there is almost no congestion in our simulated "Current Practices" (consistent with less than \$1 million congestion in the CAISO 2020 and 2025 simulations used for transmission planning studies)
  - BPA announced an RFP to "relieve a major summertime bottleneck in the Northwest" on Path 71; yet there is no congestion on that path in the simulations
  - Flow data shows the existing grid capability is not fully utilized (see end of Appendix A)
- Simulations conservatively assume perfectly optimized, security-constrained unit commitment and dispatch both (a) within each WECC Balancing Area and (b) perfectly optimized coordination across BAs (subject only to the hurdle rates).
  - These two points do not reflect reality
  - Wolak (2011) found that even moving from a zonal market design (previous CAISO market design) to a security-constrained nodal market design offers benefits approximately equal to 2.1% of production cost savings (see Appendix D)

Limitations of Production Cost Simulations

The production cost simulations are limited in capturing some benefits of regional market operations (which yields a conservative estimate of benefits)

1. Simulated only "normal" weather, hydro, and loads for entire WECC
2. No transmission outages or operational de-rates; no extended generation outages
3. No unusual/challenging market conditions (such as Aliso Canyon impacts)
4. No improved regional optimization of hydro resources (almost identical hydro dispatch in "Current Practice" and "Regional" simulations)
5. Assumed perfectly competitive bidding behavior (does not capture competitive benefits)
6. Did not simulate benefit of regional market operations in addressing uncertainties in real-time load and renewable generation (which are only partly addressed through EIM)
7. Used only "generic" TEPPC and CEC plant and fuel cost assumptions, which understate the true variance in plant efficiencies and fuel costs (and thus the benefit of optimized regional dispatch)
8. Assumed all BAs in WECC already utilize an ISO-like optimized security-constrained economic unit commitment and dispatch even in the Current Practice Scenarios
9. Did not simulate less efficient utilization of existing grid in bilateral market (which shows flowgate capacity underutilized by 5–25%; see end of Appendix A)
10. Simulations do not capture inefficiency of bilateral trading blocks (25 MW 6x16 HLH vs. LLH), contract path scheduling, and unscheduled flows

California Operating Cost Impacts: Framework



California's net cost of production, purchases and sales =

+ Production cost of utility/customer owned & contracted generation

+ Costs of market purchases

− Revenues from market sales

- California operating cost impact metric consistent with CAISO's Transmission Economic Assessment Methodology (TEAM)
- Assumed no change in recovery of existing transmission costs (i.e., Assume that changes in TAC and existing wheeling revenues and costs would offset each other)
- Market sales during excess generation conditions can be costly due to combination of: (a) renewable generation curtailment and (b) sales at negative market prices
- Overall California (and WECC-wide) results <u>do not</u> represent impacts to specific individual parties, utilities, generators, or customer classes

CA Cost of Production, Purchases & Sales

Regional market operations reduces California costs associated with the production, purchase, and sale of wholesale power

- 2020: $10 million in annual savings ($97 million w/ expanded region)
- 2030: **$104 million to $523 million in annual savings** depending on the Scenario

Estimated Savings for California Annual Power Production, Purchase and Sales Costs

(Statewide/ 2016 $MM)

	2020 CAISO +PAC	2020 Regional ISO Exp.	2030 1A vs. 2	2030 1A vs. 3
Production costs savings from owned and contracted gen	$19	$125	$193	$244
Reduction in market purchase cost from merchant gen and imports	($10)	($49)	($290)	$52
Increase in market sales revenues	$2	$21	$202	$227
Savings to CA Ratepayers	**$10**	**$97**	**$104**	**$523**

Less wind increases volume of market purchases during off-peak hours

Fewer REC purchases; more wind decreases costs when purchasing off-peak

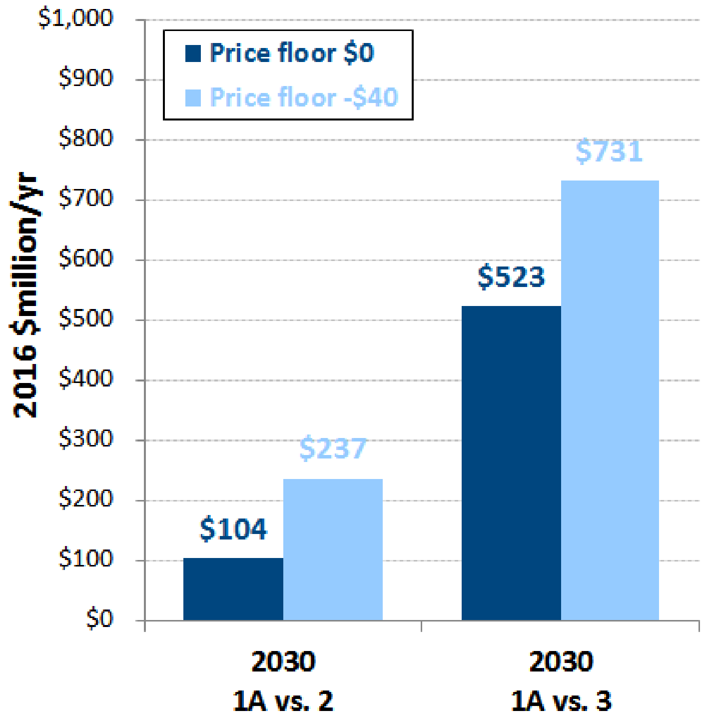
The main drivers of the savings are from:
(a) lower production costs from owned and contracted generation to meet load; **(b)** reduced power purchase costs when load exceed owned and contracted generation (higher in scenarios with more REC purchases); and **(c)** higher revenues when selling into the wholesale market during hours with excess owned and contracted generation (we assume power is sold at no less than $0/MWh)

Negative Pricing During Over-Supply

- In the Current Practice Scenario bilateral trading hurdles limit exports of California renewable generation portfolios in hours with low load and high wind/solar output
  - Results in renewable curtailments and low or negative prices when CAISO entities cannot bilaterally sell enough power during over-supply conditions
- Negative prices represent a significant additional cost to California associated with selling power during over-supply conditions
  - Example: negative prices at Mid-C trading hub during excess hydro conditions
- Simulations of a regional market (and experience in other regions) show the mitigating effects on over-supply, reduction in renewable curtailments and frequency of negatively priced trading periods
- Our baseline estimates of California production, purchase and sales costs conservatively assumes settlement prices do not drop below zero during over-generation (give power away for free but not pay more)
  - Conservatively excludes the additional cost to California imposed by negative prices
  - Sensitivity results (on next slide) provide estimated costs with prices at negative $40/MWh, reflecting marginal REC cost

Impact of Negative Bilateral Settlement Prices

Comparison of 2030 Savings for CA Cost of Production, Purchases & Sales
(Zero vs. *negative* $ 40/MWh price floor)



- Regional market benefits depend significantly on energy price during over-supply and renewable curtailment conditions
- At a zero price (give power away for free, but wheeling rate paid for by outside counterparty), sales do not impose additional costs on California
- At negative prices (consistent with experience during over-supply in other markets, including at Mid-C), California would have to pay counterparties to take the power exported
- E3's analysis: regional market will likely reduce negative prices to -$5/MWh (Scenario 3) from -$40/MWh (Scenario 1A)

Compared to $0/MWh, a negative $40/MWh price during excess generation and renewable curtailment periods, increases annual regional market savings by $133–209 million.

Content

Load Diversity Savings: Methodology

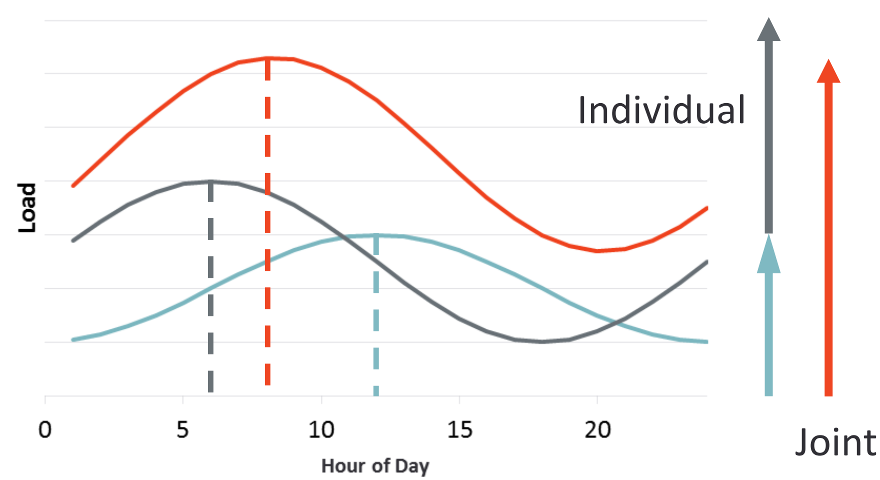
Load diversity creates the opportunity for capacity savings

- BAs within WECC peak during different times and seasons
- Less generating capacity is required to meet the coincident peak load of multiple BAs than to meet the peak load of each BA separately
- Less generating capacity is needed to meet the regional reserve margin

Coincidence factors capture diversity

- Coincidence factors calculated using hourly FERC 714 data for 9 historical years: 2006–2014
- Annual coincidence factors calculated based on 4-CP peaks
- We apply median of historical coincidence factors to forecast peak loads for 2020 and 2030

Reduction in Capacity Requirement Due to Load Diversity



Load Diversity Savings: 2020 Results (CAISO+PAC)

In California:

- Only the current CAISO is assumed to participate in the regional market in 2020
- $35/kW-year avoided capacity cost, reflecting average Resource Adequacy Requirement contract price for 2012–2016
- Regionalization will reduce capacity requirement for the CAISO by 184 MW, saving $6 million/year (with current transmission)

In the rest of the region:

- Only PacifiCorp is assumed to participate in 2020
- $0–$39/kW-year avoided capacity cost (higher value reflects average net new unit cost in PacifiCorp region)
- Reduces capacity requirement by 776 MW, saving up to $30 million/year (with current transmission)

2020 Load Diversity Benefit and Annual Capacity Cost Savings

	CAISO	PacifiCorp
Capacity Benefit of Load Diversity with Current Transmission	**184 MW** (0.39%)	**776 MW** (5.86%)
Additional Capacity Savings with Transmission Upgrades	-	392 MW (2.96%)
Value of Capacity Benefit with Current Transmission ($ millions/year)	**$6MM**	**$0–30MM**
Additional Value of Capacity Benefit with Transmission Upgrades ($ millions/year)	-	$0–15MM

Note: In 2016 dollars; savings with current transmission used as base study results.

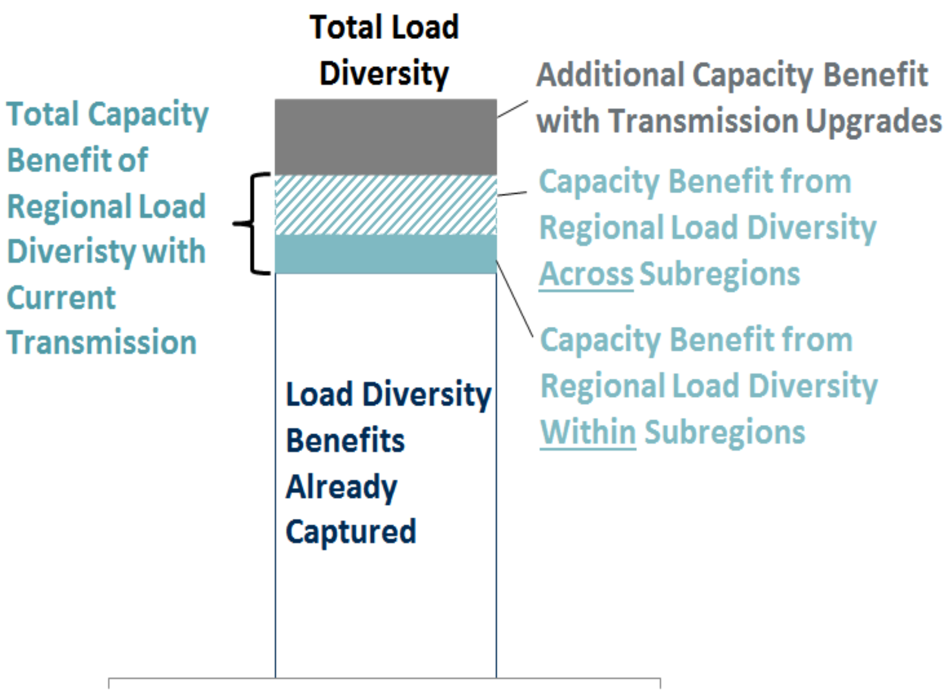
Load Diversity Analysis

2030 Approach for an Expanded Regional ISO

Savings depend regional load diversity not already captured

- ***Current Practice: Some Sharing within Sub-Regions*** (BA-internal reserve margins lower to reflect benefits of some imports)
  - Estimate of sub-regional load diversity already captured today
- ***Full sharing within Sub-Regions*** (BAs share capacity within each Sub-Region subject to intra-regional transmission constraints)
- ***Sharing Across Sub-Regions*** (Capacity sharing across full integrated market footprint subject to inter-regional transmission constraints)
- Additional benefits available with **future transmission upgrades**

Total Load Diversity and Additional Capacity Savings from a Regional Market



2030 Results for an Expanded Regional ISO

In California:

- All California BAs are assumed to participate in the regional market in 2030
- Capacity savings of $75/kW-year, reflecting California approaching resource balance
  - Low: $35/kW-year (average of 2012–16 Resource Adequacy contract prices) for 2012–2016
  - High: $150/kW-year (based full net cost of new entry in California)
- Regionalization will reduce California capacity requirement by 1,594 MW, saving $120 million (with current transmission)

In the rest of the region:

- Region = U.S. WECC w/o PMAs
- Assumed avoided cost of capacity savings of $100/kW-year to reflect net cost of new entry, ranging from:
  - Low: $39/kW-year (current new brownfield CC cost in PacifiCorp)
  - High: $120/kW-year (net cost of new entry based on Lazard 2015)
- Regionalization will reduce capacity requirement by 2,665 MW, saving $266 million (with current transmission)

2030 Load Diversity Benefit and Annual Capacity Cost Savings

	California	Rest of Region
Load Diversity Benefits Already Captured	0 MW	4,481 MW
Capacity Benefit from Regional Load Diversity with Current Transmission	**1,594 MW** (2.79%)	**2,665 MW** (3.12%)
Additional Capacity Benefit with Transmission Upgrades	145 MW (0.25%)	1,942 MW (2.28%)
Capacity Cost Savings with Current Transmission ($ millions/year)	**$120MM** ($56–239MM)	**$266MM** ($104–320MM)
Additional Capacity Cost Savings with Transmission Upgrades ($ millions/yr)	$11MM ($5–22MM)	$194MM ($76–233MM)

Note: in 2016 dollars; savings with current transmission used as base results.

Content

CA Ratepayer Impacts Methodology

CA Revenue Requirement (2016 EIA)

+

Fixed Portion of CA Revenue Requirement

Portions of revenue requirement that vary by scenario

Scenario 1A	Scenario 2	Scenario 3

1. Incremental Portfolio-Related Annualized Investment Costs (Renewable PPAs and Transmission, Storage)

+

2. California Production, Purchase and Sale Costs (TEAM)

3. Capacity Savings of Load Diversification Benefit

=

Total Revenue Requirement ($MM)

***82% of revenue requirement is fixed**, i.e. independent of scenarios (existing T&D, existing generation and planned generation, DSM, & other fees)*

- *E3 estimate; Fixed part is assumed to have a **real escalation rate of 1%***

We estimate **state-wide California ratepayer impact** by analyzing the extent to which **regional market participation** will affect annual retail revenue requirements.

- Analysis limited to quantified monetary impacts
- Conservative nature of analyses will understate overall California ratepayer benefits of regional market expansion

Ratepayer Impact Categories

The impacts of expanding regional market operations on California ratepayers come from three main categories of costs as previously discussed:

1. The mostly investment-related **fixed annual costs related to** expanding California's portfolio of **renewable resources**
   - Includes storage and (out of state) transmission related to incremental renewable buildout
   - E3 estimates **annual savings of $680 million to $800 million** in reduced fixed renewable procurement costs, depending on California's ability to rely on lower-cost renewable resources in Wyoming and New Mexico (Regional Scenarios 2 and 3)
   - Savings also depend on extent of renewable curtailments, need for overbuild, and ability to export excess generation in bilateral markets (e.g., Current Practice 1A vs. enhanced-flexibility sensitivity in Scenario 1B)

Ratepayer Impact Categories (cont'd)

2. California's **net costs associated with production, purchases, and sales** (estimated consistent with TEAM approach)
   - Impact of regional market expansion estimated to result in **annual savings of $104 million to $731 million** depending on:
     - Ability to re-export (and sell bilaterally) current imports and additional renewable imports in "Current Practice" Scenarios without a regional market
     - Access to out-of-state renewables that reduce balancing costs in CA
     - Extent of zero or negative LMPs in California during over-generation and renewable curtailment conditions
       - $104–523 million at zero; $237–731 million at negative $40/MWh (discussed before)
3. California's **capacity cost savings from regional load diversity**
   - Impact of regional market expansion estimated to be **annual savings of $56–261 million** depending on:
     - Market price and need for resource adequacy capacity in California
     - Extent to which transmission capabilities will be upgraded in the future

Ratepayer Impact Categories (cont'd)

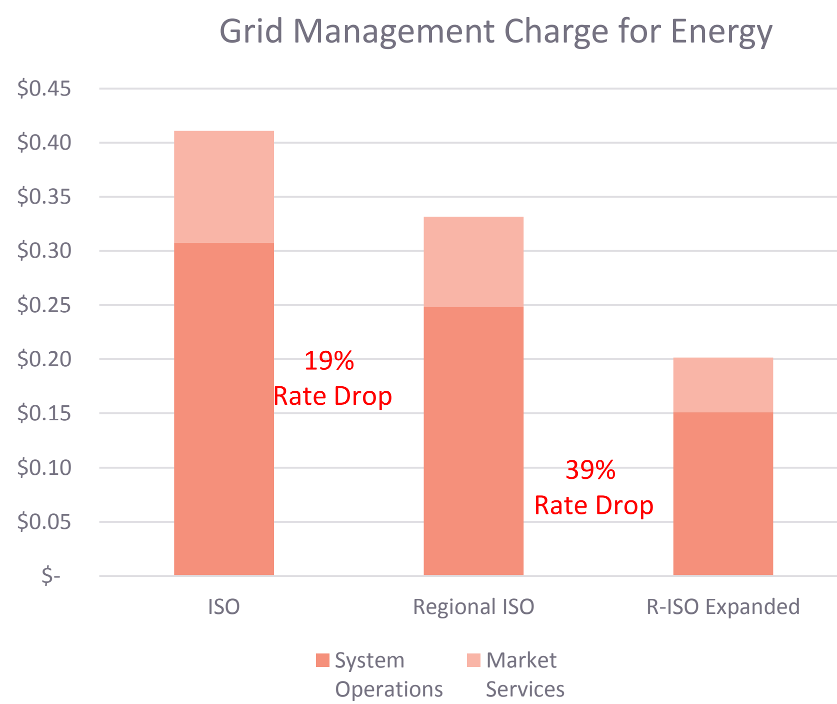
4. Reduction in Grid Management Charges (GMC) to California ratepayers

CAISO + PAC

- Direct and indirect cost increase by $5 million/year
- Revenue cap increase to $212 million/year
- Transition would not have a material impact to revenue requirement
- **19% decrease to existing GMC rate payers**

Regional ISO Expansion

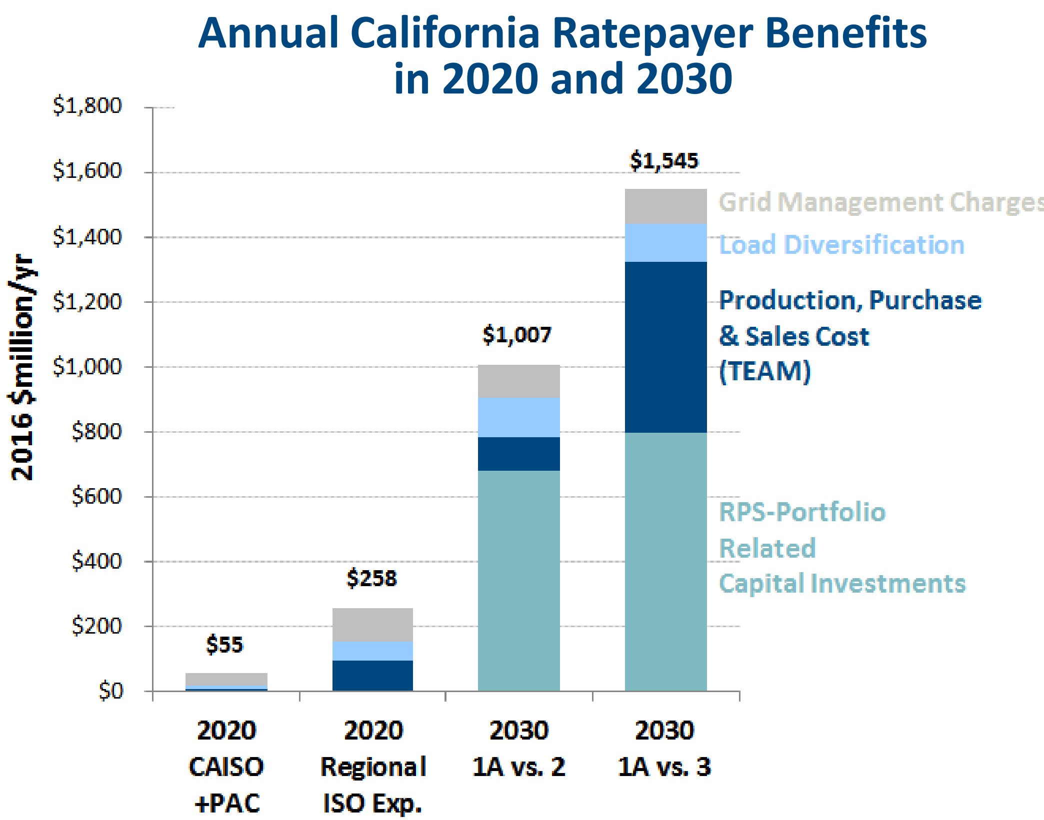
- Assume 160 additional employees and some additional physical infrastructure
- Revenue cap increase to $282 million/year
- **39% decrease to existing GMC rate payers**



Source: CAISO estimate (see Appendix F)

California Ratepayer Impact Analysis

Summary of CA Ratepayer Impacts: $ Million/year



- California ratepayer impact analysis of an expanded regional market result in estimated <u>annual</u> savings ranging from at least **$1 billion to $1.5 billion** (2–3% of retail rates) by 2030
- Magnitude of ratepayer savings depends on:
  - Ability to access lower-cost and more diverse renewable resources
  - Ability of selling (re-exporting) excess California resources in a bilateral market environment
  - Prices for resource adequacy

Overall benefits likely are significantly larger due to: (1) conservative nature of these estimates; and (2) regional-market benefits not quantified

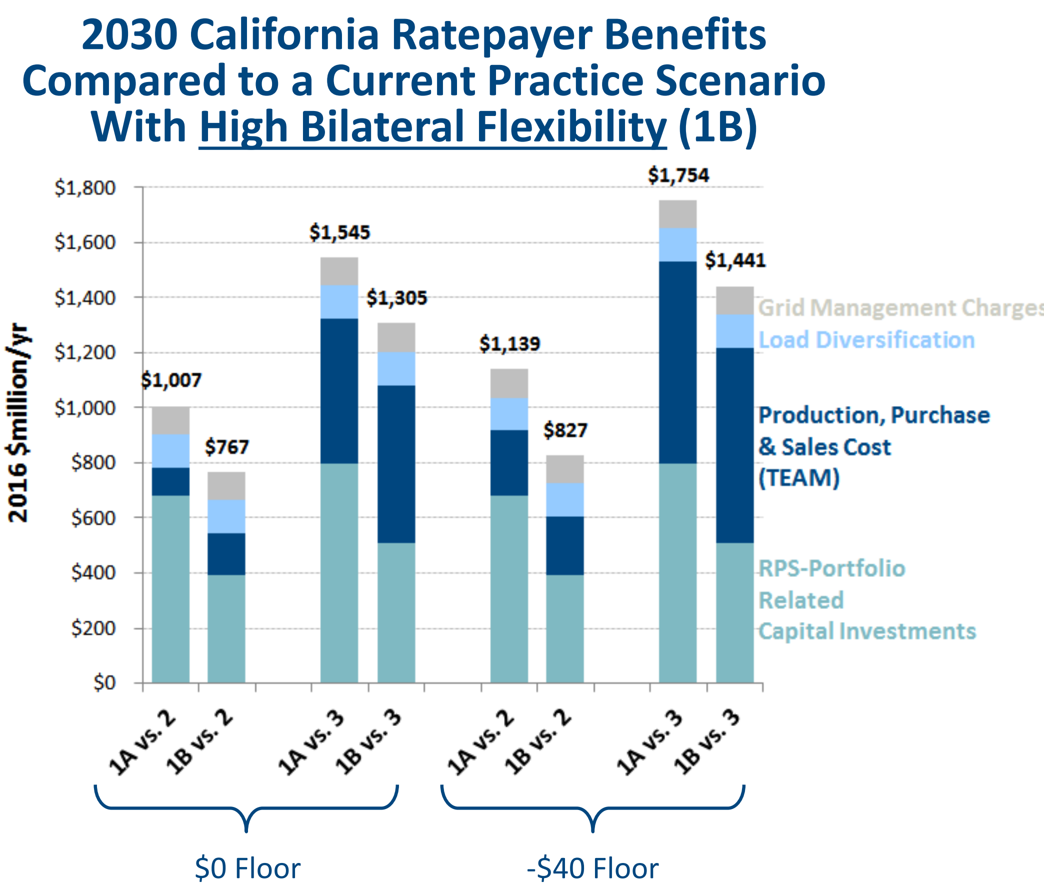
Achieving the identified savings will require setting the stage for a regional organization that can achieve a sufficiently large regional footprint over the next decade

Summary of CA Ratepayer Impacts: ¢/kWh

The identified potential impacts from an expanded regional ISO market, are conservatively estimated to **decrease 2030 California total retail rates by at least 0.4–0.6 ¢/kWh or by 2.0%–3.1%**

		2020 Current Practice	2020 Regional ISO	2030 Current Practice 1A	2030 Regional ISO Exp. 2	2030 Regional ISO Exp. 3
RPS-Portfolio Related Capital Investment	($MM)	$0	$0	$3,292	$2,612	$2,492
Production, Purchase & Sales Cost (TEAM)	($MM)	$7,752	$7,742	$8,066	$7,962	$7,544
Load Diversification Benefit	($MM)	$0	($6)	$0	($120)	($120)
Grid Management Charges Savings	($MM)	$0	($39)	$0	($103)	($103)
Total Retail Revenue Requirements	**($MM)**	**$43,316**	**$43,262**	**$50,643**	**$49,636**	**$49,098**
Total Retail Sales	(GWh)	260,028	260,028	256,404	256,404	256,404
Average Retail Rate	**(cent/kWh)**	**16.7**	**16.6**	**19.8**	**19.4**	**19.1**
Impact of Regionalization Relative to CP 1A	(cent/kWh)		(0.0)		(0.4)	(0.6)
	(%)		(0.1%)		(2.0%)	(3.1%)

Sensitivity: High Flexibility in Bilateral Markets



Even with much higher bilateral flexibility a regional market offers $767 million to $1.4 billion in annual ratepayer benefits

- Current Practice 1B assumes higher flexibility in bilateral markets
  - Increased net bilateral export capability from 2,000 MW to 8,000 MW
- Even if over-generation conditions can be managed more flexibly without a regional market as simulated in CP 1B sensitivity, the annual benefits of a regional market would still be a significant **$767 million to $1.4 billion**, depending on the scenario considered
- The incremental value of high flexibility assumed in CP 1B is estimated to be $240–313 million

Summary of CA Ratepayer Impacts

Estimated Annual California Ratepayer Benefits in Base Scenarios and Sensitivities

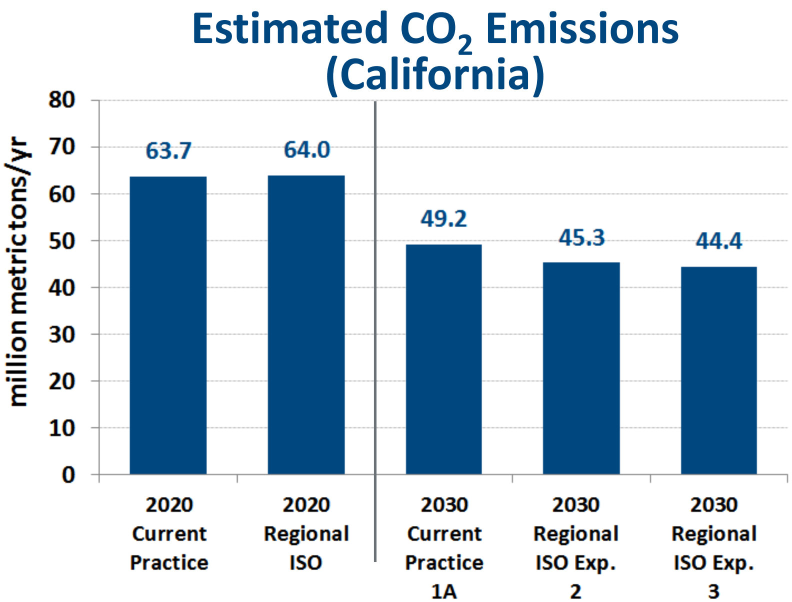
		2020 CAISO +PAC	2020 Regional ISO	2030 1A vs. 2	2030 1A vs. 3	2030 1B vs. 2	2030 1B vs. 3	2030 1A vs. 2 -$40 floor	2030 1A vs. 3 -$40 floor	2030 1B vs. 2 -$40 floor	2030 1B vs. 3 -$40 floor
RPS-Portfolio Related Capital Investment	($MM)	$0	$0	$680	$799	$391	$511	$680	$799	$391	$511
Production, Purchase & Sales Cost (TEAM)	($MM)	$10	$97	$104	$523	$153	$572	$237	$731	$212	$707
Load Diversification Benefit	($MM)	$6	$58	$120	$120	$120	$120	$120	$120	$120	$120
Grid Management Charges Savings	($MM)	$39	$103	$103	$103	$103	$103	$103	$103	$103	$103
Total Estimated California Ratepayer Savings	**($MM)**	**$55**	**$258**	**$1,007**	**$1,545**	**$767**	**$1,305**	**$1,139**	**$1,754**	**$827**	**$1,441**

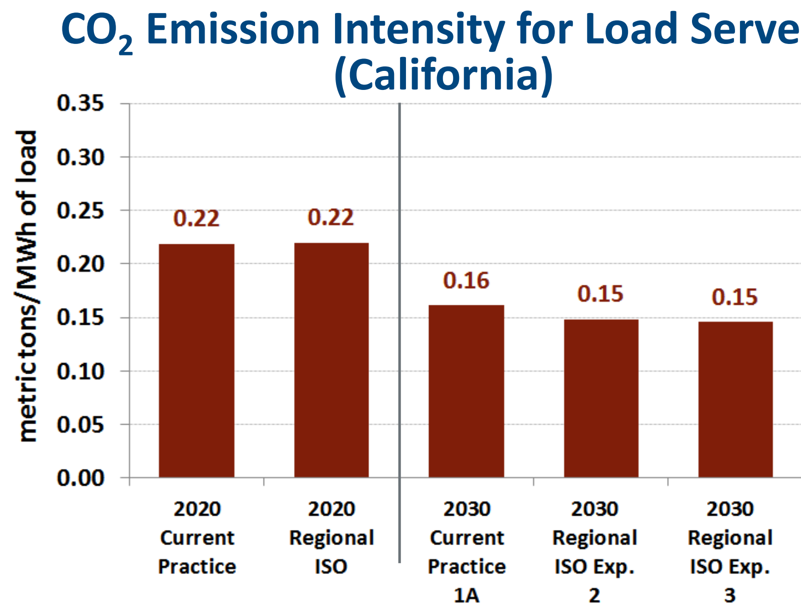
Base Scenarios

Sensitivity Analyses

Content

California CO_2 Emissions



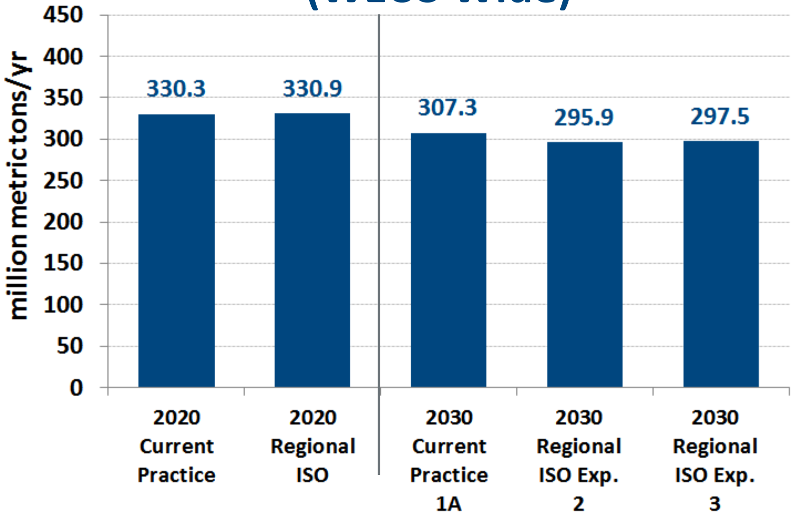


- Significant electricity sector emissions reductions between 2020 and 2030, with **2030 emissions 55-60% below 1990 levels and below EPA's CPP requirements for California**
- Regional market reduces CO_2 emissions associated with serving California load
  - Little/no change in 2020
  - **Decrease of 4–5 million tonnes (8–10% of total) of CO_2 emissions level** in 2030
- For California load served, regional market in 2030 is expected to **reduce CO_2 emission intensity by 0.01 tonne per MWh**
  - Calculations assume CO_2 emissions associated with imports are charged (and exports are credited) based on a generic emission rate for natural gas CCs
- State-wide emissions from all sources may remain at AB32 emissions cap

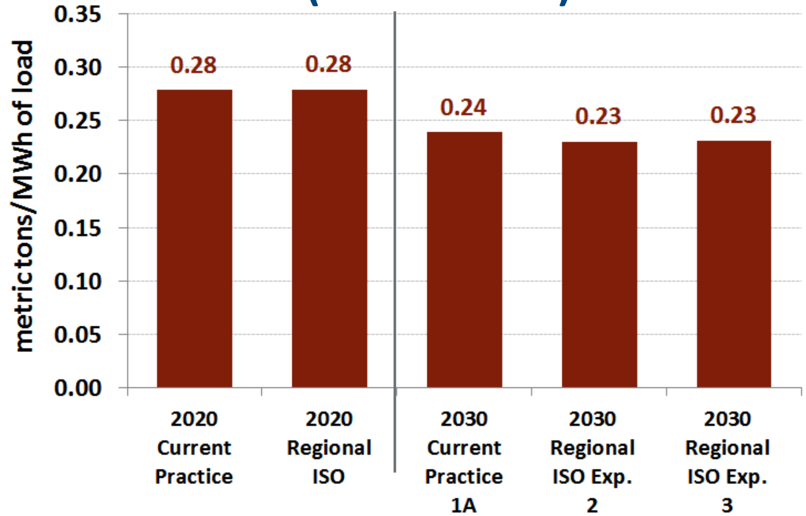
Impact on GHG Emissions

WECC-Wide CO_2 Emissions

Estimated CO_2 Emissions (WECC-Wide)



CO_2 Emission Intensity for Load Served (WECC-Wide)



- 2020 simulations of regional market (CAISO+PAC) show close to no change in CO_2 emissions relative to Current Practices; 2030 WECC-wide emissions from electricity sector reduced by 23–35 million tonnes relative to 2020 (and despite load growth in Rest of WECC)
- In 2030, the expanded regional market (WECC without PMAs) is estimated to **decrease CO_2 emissions in WECC by 10–11 million tonnes (~3.5 % of total)** relative to the 2030 Current Practices Scenario
  - For load served across WECC, the regional market in 2030 is expected to **reduce CO_2 emission intensity by 0.01 tonne/MWh(~4%)** relative to the 2030 Current Practice Scenario
- Achieving CPP compliance would require modest additional measures (see Sensitivities)

Factors Affecting CO_2 Emissions Impact

- The Impact of regional market on electric sector CO_2 emissions in California and the rest of U.S. WECC depends on:
  - The magnitude of future coal retirements throughout U.S. WECC
  - Mechanisms for complying with the Clean Power Plan, and interactions with California's GHG cap-and-trade
  - The degree of renewable development beyond RPS due to regional market
- Sensitivity analyses estimate some of these impacts:
  - <u>WECC Carbon Pricing</u>: Scenarios 1A and 3 with $15/tonne for rest of WECC, recognizing that carbon cost under CPP is likely to be lower than under AB32
  - <u>Scenario 1A Regional</u>: Regional market with the 1A renewable portfolio to isolate the impact of emissions by avoiding curtailments of CA renewables during over-generation conditions
  - <u>Scenario 3 Regional without Beyond-RPS renewable development</u>: To isolate the potential impact of CO_2 emissions when no renewables beyond RPS are developed

Sensitivities on CO_2 Emissions: Summary of Results

Several sensitivities focus on how regional market may affect CO_2 emissions under different assumptions about the future

- **WECC Carbon Pricing:** Using $15/tonne for rest of WECC for both Scenarios 1A and 3 as a proxy for CPP compliance revealed that, considering significant future coal plant retirements already announced, even a modest carbon price is sufficient to meet or exceed CPP emission targets
- **Scenario 1A Regional:** Simulating a regional market with the 1A renewable portfolio showed that most of the renewable curtailments experienced in the Current Practices 1A Scenario would be avoided, reducing California CO_2 emissions by 5% or 2.5 million tonnes
- **Without Renewables Development Beyond-RPS:** Simulating the regional market Scenario 3 without any assumed facilitation of renewables development beyond-RPS show that a regional market would only slightly decrease CO_2 emissions WECC wide and associated with CA loads

Sensitivity Analysis: Carbon Price in Rest of WECC

Simulated 2030 scenarios with a carbon price in rest of WECC as proxy of CPP compliance:

- In 2030 Scenario 1A (without CO_2 pricing), CO_2 emissions are **23 million tonnes/year below 2020 emissions**
- CO_2 pricing in 2030 for the rest of WECC reduces WECC-wide emissions by an additional **5% or 16 million tonnes/year**
- Creation of an ISO-operated regional market further magnifies this CO_2 emission reduction by **10 million tonnes/year (or 3.6%)** WECC-wide
- Additional renewables in WECC assumed to be facilitated by the regional market contribute to this reduction of CO_2 emissions
- CO_2 emissions for serving CA load reduces by **4.7 million tonnes/year** (similar results as with no carbon price in rest of WECC)

Annual CO_2 Emissions
With $15/Tonne in Rest of WECC
(million tonne/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 3
WECC TOTAL	**291.2**	**280.6**
Impact of Regionalization		(10.6) (3.6%)
CA In-State	46.7	44.9
CA Imports Contracted	6.2	3.7
CA Imports Generic	1.4	1.2
CA Export Generic	(5.2)	(5.5)
CA Emissions for Load	**49.1**	**44.4**
Impact of Regionalization		(4.7) (9.6%)

Sensitivity Analysis: Scenario 1A Portfolio with Regional Market

Simulated the regional market scenarios with Portfolio 1A

- This sensitivity assumes same renewable portfolio as in Scenario 1A Current Practice and no additional renewables beyond RPS
- Regional market offers significant emissions reductions (particularly in California) by lowering renewable curtailments when Scenario 1A portfolio remains unchanged
- WECC-wide annual CO_2 emissions decrease by **2.9 million tonnes**, most of which is associated with resources needed to serve California's load

Annual CO_2 Emissions Holding Scenario 1A Portfolio Constant

(million tonne/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 1A
WECC TOTAL	**307.3**	**304.4**
Impact of Regionalization		(2.9) (0.9%)
CA In-State	46.2	46.4
CA Imports Contracted	6.2	5.1
CA Imports Generic	1.7	2.8
CA Exports Generic	(4.8)	(7.5)
CA Emissions for Load	**49.2**	**46.9**
Impact of Regionalization		(2.4) (4.8%)

Sensitivity Analysis: Impact of Additional Renewables Beyond RPS

- Without the 5,000 MW of beyond-RPS wind assumed to be enabled by the regional market, CO_2 emissions are still estimated to be lower than under Current Practice
  - WECC-wide CO_2 emissions drop by 1.3 million tons (0.4%)
  - CO_2 emissions associated with serving California load decrease by 2.2 million tons (4.5%)
    - Slight increase of CO_2 emissions from in-state resources is more than offset by reduced emissions from contracted resources and credits for net exports

Annual CO_2 Emissions
(million tonne/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 3	2030 Regional ISO Exp. 3
WECC TOTAL	**307.3**	**297.5**	**306.0**
Impact of Regionalization		(9.8) (3.2%)	(1.3) (0.4%)
CA In-State	46.2	43.3	46.5
CA Imports Contracted	6.2	3.3	4.5
CA Imports Generic	1.7	1.5	2.3
CA Exports Generic	(4.8)	(8.7)	(6.3)
CA Emissions for Load	**49.2**	**39.5**	**47.0**
Impact of Regionalization		(9.7) (19.8%)	(2.2) (4.5%)
		with 5 GW wind beyond RPS	without 5 GW wind beyond RPS

For a discussion of the how regional markets facilitate renewable developments and the reasonableness of the assumed 5,000 MW of additional wind, see Section 9 and Appendix B

Impact on GHG Emissions

Clean Power Plan (CPP) Compliance

- CPP only covers coal, natural gas CCs (existing or existing *plus* new), and some cogen facilities larger than 25 MW
- **California easily complies with CPP in all scenarios examined**
- Rest of WECC does not comply with no simulated CO_2 price despite significant coal retirements through 2030
- At a CO_2 price of $15/tonne, the emissions from rest of U.S. WECC would drop below CPP mass-based standards (for both existing only and existing *plus* new CC)
- Compliance with $15/tonne CO_2 price is greater with regional market, signifying **CPP compliance can be achieved at a lower cost with regional market**

Mass-Based CPP Standard

With and Without Covering New CC Units (million tonne/yr)

	2030 Mass-based Target	2030 CP1A	2030 CP1A $15 CO2	2030 Reg.3 $15 CO2
Existing Units				
California	**43.9**	**27.2**	**27.6**	**26.2**
Target –Simulated		*16.7*	*16.3*	*17.8*
Rest of WECC U.S.	**179.3**	**183.8**	**164.4**	**156.6**
Target –Simulated		*(4.5)*	*14.9*	*22.7*
Existing + New Units				
California	**47.9**	**27.6**	**28.0**	**26.6**
Target –Simulated		*20.4*	*19.9*	*21.3*
Rest of WECC U.S.	**191.3**	**201.8**	**185.6**	**179.1**
Target –Simulated		*(10.5)*	*5.8*	*12.2*

Content

Reliability Impacts Quantified

Our quantitative analyses focus on maintaining the same level of reliability in a more cost-effective way

- The estimated ratepayer impacts include only the following cost savings associated with meeting applicable planning and operational reliability standards :
  - Lower generation investment costs from load diversity based on estimated market price for capacity
    - Does not include the additional reliability value of higher effective reserve margins
  - Production cost savings associated with:
    - Lower operating, regulation, and load-following reserve requirements
    - Reduced cost of providing these operating reserves due to reserve sharing and net load diversity
- Did not analyze the value of achieving more reliable region-wide system operations (see next slides)

Reliability Impacts Not Quantified

Expanding CAISO operations to a larger regional footprint offers significant reliability benefits to both California and the larger regional market area:

- Regional ISO operations and practices will offer various reliability benefits over the standard operational practices of Balancing Authorities in the WECC footprint
- The WECC is a single interconnected system, which means reliability events in neighboring regions affect California as well
  - Examples: October 6, 2014 Northwest RAS Event; September 8, 2011 Arizona – Southern California Outage; August 10, 1996 Western Interconnection (WSCC) System Disturbance
- Reliability-related benefits would be higher during stressed system conditions, such as extreme weather, drought, and unexpected outages
- Expanding CAISO operational practices consequently offer reliability benefits to (a) the expanded regional footprint which, in turn, (b) also increases reliability in the ISO's current California footprint

Reliability Benefits of Regional System Operations

- Improved **real-time awareness** of system conditions
- More timely, more efficient, and lower-cost **congestion management** and adjustments for **unscheduled flows**
- Regionally-optimized, multi-stage **unit commitment**
- **Enhanced systems and software** for monitoring system stability and security; enhanced system backup
- Coordinated **operator training** that exceeds NERC requirements
- Frequent review of **operator performance and procedures**
- Consolidated **standards development and NERC standards compliance**
- More unified **regional system planning**, supported by FERC Order 1000
- Broader **fuel diversity** to more effectively respond to changes in fuel availability or costs and hydro/wind/solar conditions
- Better **price signals for investment** in new resources of the right type and in the right place

(See Appendix E for more detail)

Renewable Resource Integration

Regional operations and planning more cost effectively and more reliably integrate and balance intermittent renewable resources

- A single intra-hourly energy markets for selling intermittent output
- Coordinated and centralized forecasting of renewable output to reduce balancing costs, improve congestion management, and avoid curtailments
- Reduced system-wide operating and load following reserve requirements in a regional market because of larger-regional diversification of renewable generation variances and more cost-effective combination of renewable resources and transmission
- Lower-cost provision of regional operating and load following reserves through optimized security-constrained unit commitment and dispatch
- Lower integration-related investment needs through improved region-wide generation interconnection and transmission planning processes

Facilitation of Renewable Development Beyond RPS

Regional markets also facilitate the development and integration of low-cost renewable resources <u>beyond RPS requirements</u> through:

- Better integration into system commitment and dispatch:
  - 5-minute real-time pricing for all energy generated by intermittent resources
  - Availability of ancillary service markets with lower-cost balancing options
  - Coordination of dispatch over a broader region with a more diverse set of resources
  - Fewer curtailments through improved utilization of transmission infrastructure
- Streamlined access to existing and new transmission to deliver low-cost renewables:
  - One-stop shopping for interconnection and transmission service requests
  - Improved regional transmission planning to provide access to low-cost regions
  - Easier contracting for load-serving entities (including coops/munis) and commercial/industrial customers who do not have transmission access to the low-cost renewable generation areas within the region
- Better financial and hedging options:
  - Day-ahead markets, congestion management, and financial hedging mechanisms
  - More transparent pricing and more competitive access to a larger regional market
  - Improved access to more liquid trading hubs offering financial hedges and forward contracting for full or partial merchant entry (e.g., prior to signing PPAs)

(See Appendix B for experience and magnitude in other markets)

Assumptions on Renewable Development Beyond RPS

To realistically capture the impact of a regional market in terms of renewable development we:

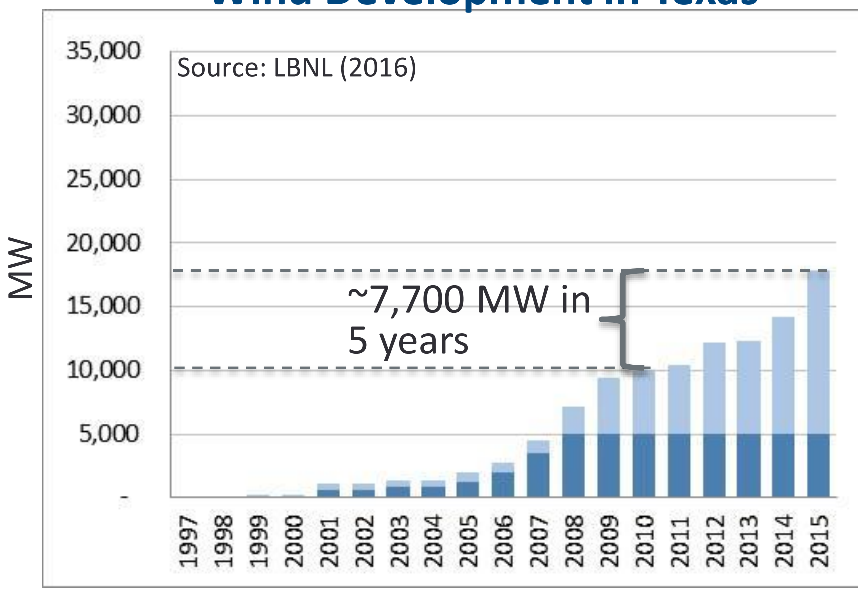
- Added a combined 5,000 MW of wind distributed in WY and NM as conservative proxy for renewable development beyond RPS facilitated by regional market between 2020 and 2030 (see next slide and Appendix B for support)
- Development of renewable resources facilitated by a regional market most likely in Wyoming and New Mexico due to availability of low-cost wind resources
  - Low-cost of wind resources can earn revenues in day-ahead and intra-hour real-time energy market without the need for significant REC payments
- Renewable development enabled and supported by regional market attract investors who can use market-based products to hedge the financial uncertainties due to the market providing:
  - Sub-hourly energy market for intermittent generation
  - Efficient balancing of intermittent resources
  - Ready access to more liquid regional trading hubs in WECC
  - Market-based congestion management and balancing of intermittent output at lower cost

We also present a sensitivity case without market-based renewable development

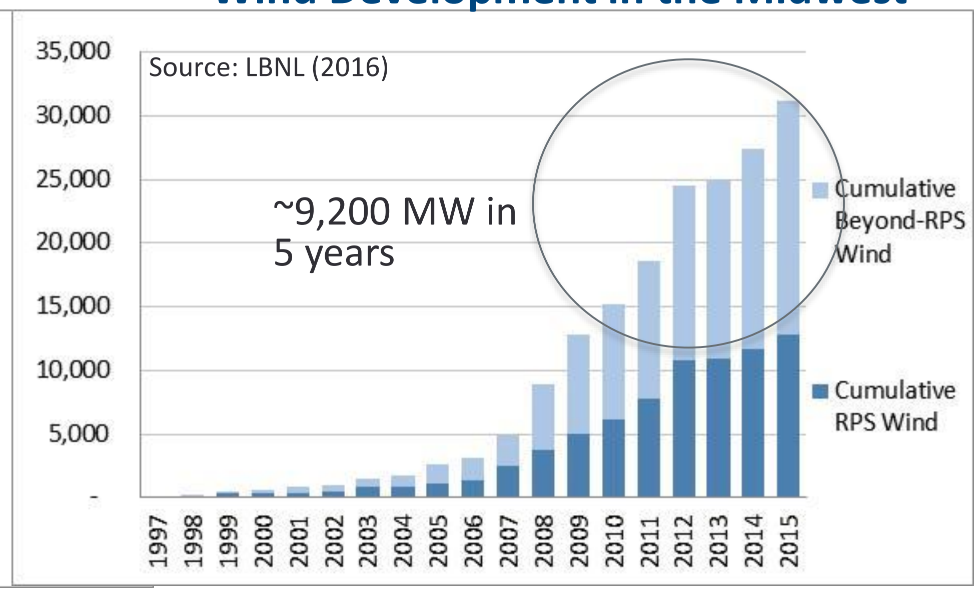
Renewable Development Beyond RPS

- Wind development trend across regional markets in the Great Plains show that resources are built beyond the RPS needs of the region
- In the past 5 years, Texas built 7,700 MW and the Midwest built 9,200 MW of wind beyond those needed for RPS

Wind Development in Texas

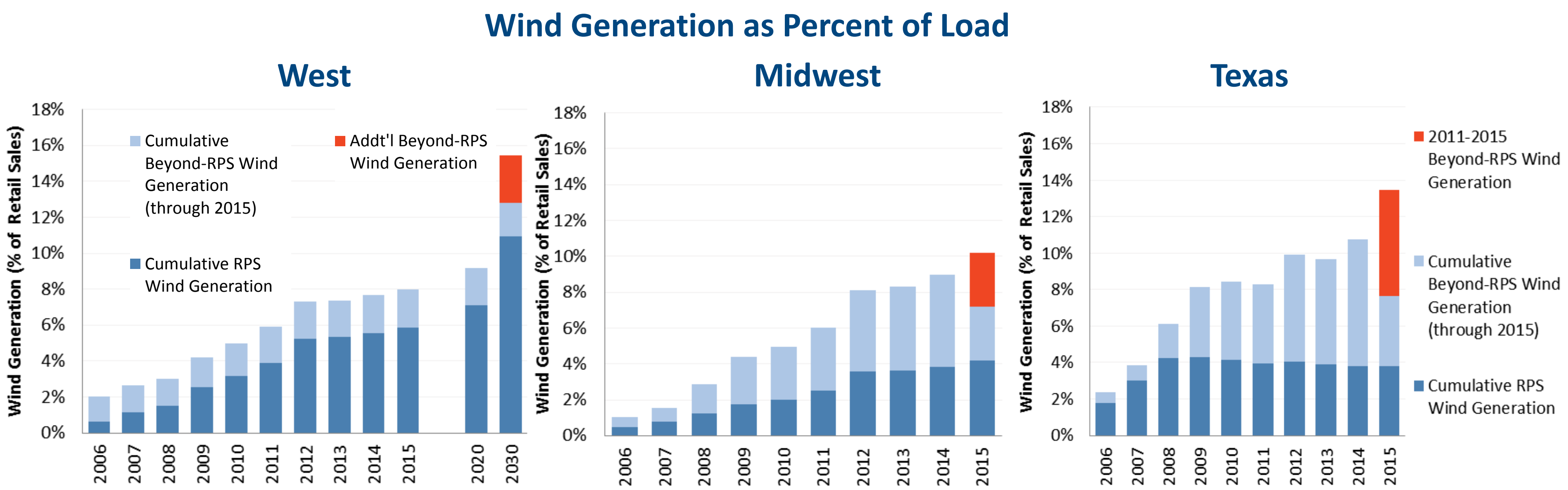


Wind Development in the Midwest



For our analysis, we assumed a regional ISO would attract additional 5,000 MW of wind located on the western side of the Great Plains.

Renewable Development Beyond RPS

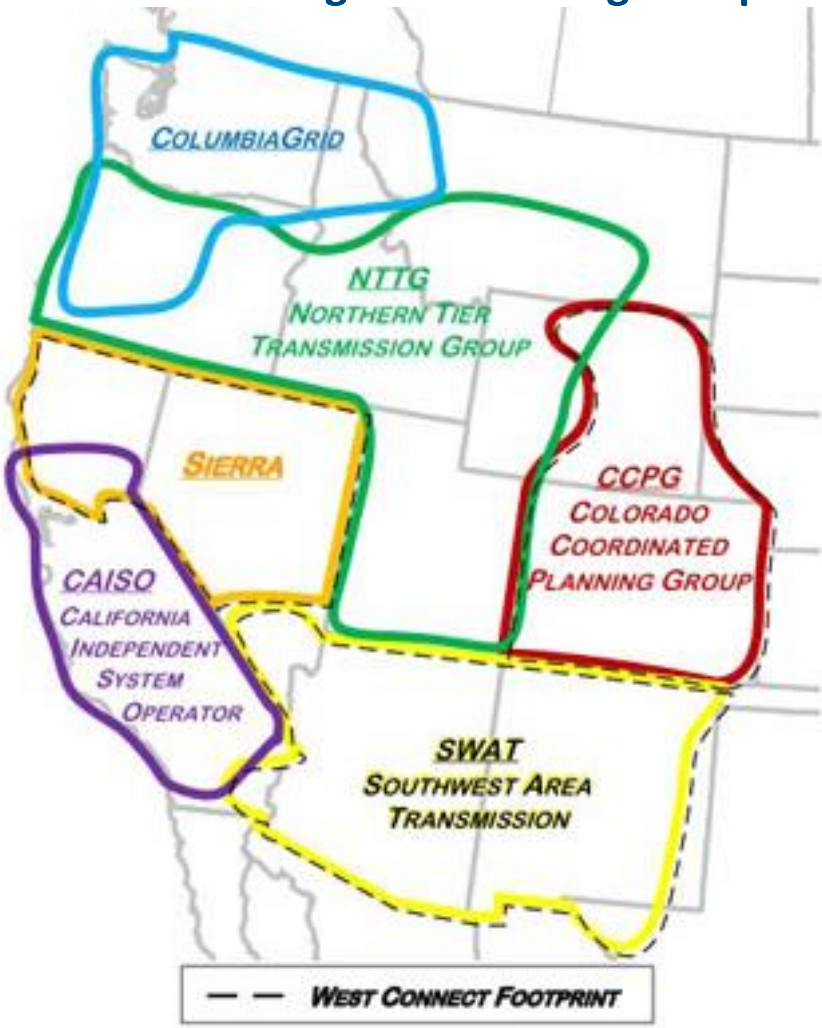


- Renewable development beyond RPS is pronounced in areas where low-cost resources have access to regional operations and markets (in Texas and the Midwest)
  - Between 2011 and 2015 (5 years), these areas added new wind generation to meet 4-5% of retail sales
  - Assuming that regional market in U.S. WECC would attract additional 5,000 MW of beyond-RPS renewables by 2030 is only approximately 2.6% of retail sales compared to ~3% added in the Midwest and ~6% added in Texas between 2011 and 2015

Source of historical data: EIA and LBNL (2016)

Transmission Planning: Current Practice

Western Sub-Regional Planning Groups



Source: http://www.westerngrid.net/western-sub-regional-planning/

Transmission planning is currently a undertaken by the CAISO and each of the many utilities in the West

- Sub-regional planning requires coordination of utility planning efforts through four transmission planning groups
  - CAISO, WestConnect (and its three subregions), Northern Tier Transmission Group, and Columbia Grid
- Interregional planning requires coordination across the four regional transmission planning groups
- Coordination is time consuming, imperfect, and focused primarily on reliability-related transmission projects (not as much on economically-driven or public policy projects) even with FERC Order No. 1000
- Challenging cost allocation for valuable interregional transmission projects

Improved Regional Transmission Planning

A more unified interregional transmission planning process of an expanded regional ISO offers significant long-term value

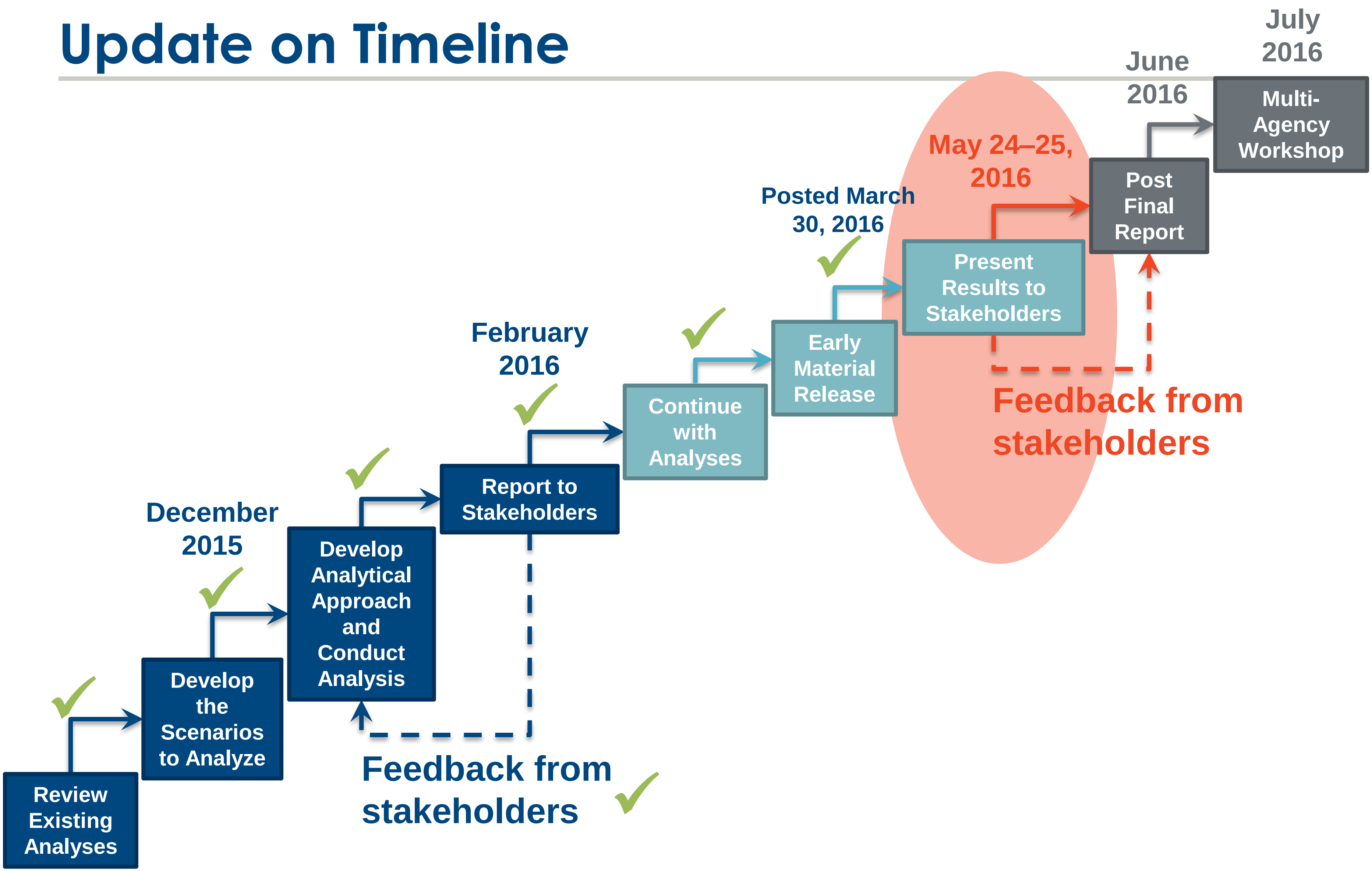
- Unified planning process and criteria will apply to a larger regional footprint
- Enhanced focus on identifying valuable economic and public policy transmission projects (while maintaining reliability) that reduce overall system costs
- Facilitate regional access to and integration of renewable resources
- Simplification of generator interconnection and repowering process due to fewer affected systems
- More effective and integrated regional planning through a larger regional perspective (across greater number of transmission owners)
- Fewer planning coordination challenges and more consistent and unified regional planning tools
- Streamlined cost allocation processes facilitates development of valuable regional transmission projects
- Fewer planning challenges related to “market seams” between small, individual planning areas

Content

Day 2 Agenda

Time	Duration	Topic / Title	Lead Presenter
9:00 AM	15 min	Recap from previous day	Keith Casey
9:15 AM	60 min	BEAR Economics explains the analytical approach used for the employment and economic impact analysis.	Dr. David Roland-Holst
10:15 AM	15 min	Break	
10:30 AM	90 min	Aspen describes the analytical approach used for environmental impact analyses and assumptions.	Susan Lee / Brewster Birdsall
12:00 PM	60 min	Lunch	
1:00 PM	90 min	Stakeholder Comments	Stakeholders
2:30 PM	15 min	Next Steps and Wrap-up	Deb Le Vine / Judy Chang
2:45 PM		Adjourn	

Update on Timeline



Wrap-Up: Next Steps

Milestone	Date
Comments due on presentation materials and meeting discussion – Please use comments template available at http://www.caiso.com/Documents/CommentsTemplate-SB350CleanEnergy-PollutionReductionAct-Presentation-Discussion.doc	June 8
Review stakeholder feedback and refine analytics, where reasonable and feasible	
Post final report	Target – Mid-June
Joint agency workshop	Target – July

Additional questions or comments can be directed to:
regionalintegration@caiso.com

Appendices

Appendix A: Production Cost Simulations

Appendix B: Renewable Generation Development Stimulated by Regional Markets

Appendix C: Load Diversity Benefits

Appendix D: Review of Other Market Integration Studies

Appendix E: Reliability Impacts

Appendix F: Grid Management Charge

SB350 Study Reference Material

Today's meeting is being recorded in its entirety. The recording will be available to stakeholders on the regional energy markets webpage at http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx.

This is a service to stakeholders who couldn't join us, or would like to review the proceedings. Materials related to the SB350 study and other regional integration efforts are also available at the link provided above.

Additional reference materials:
Senate Bill No. 350 - Clean Energy and Pollution Reduction Act of 2015
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350
Fast Facts – Benefits of a regional energy market
http://www.caiso.com/Documents/2015RegionalBenefitsFactSheet.pdf
Early release material
http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

SB 350 Regional Market Study

Appendices to Brattle Group Presentation: Additional Information and Detailed Study Results

PREPARED BY

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May 24–25, 2016

THE Brattle GROUP

Appendices

Appendix A: Production Cost Simulations

Appendix B: Renewable Generation Development Stimulated by Regional Markets

Appendix C: Load Diversity Benefits

Appendix D: Review of Other Market Integration Studies

Appendix E: Reliability Impacts

Appendix F: Grid Management Charge

Appendix A

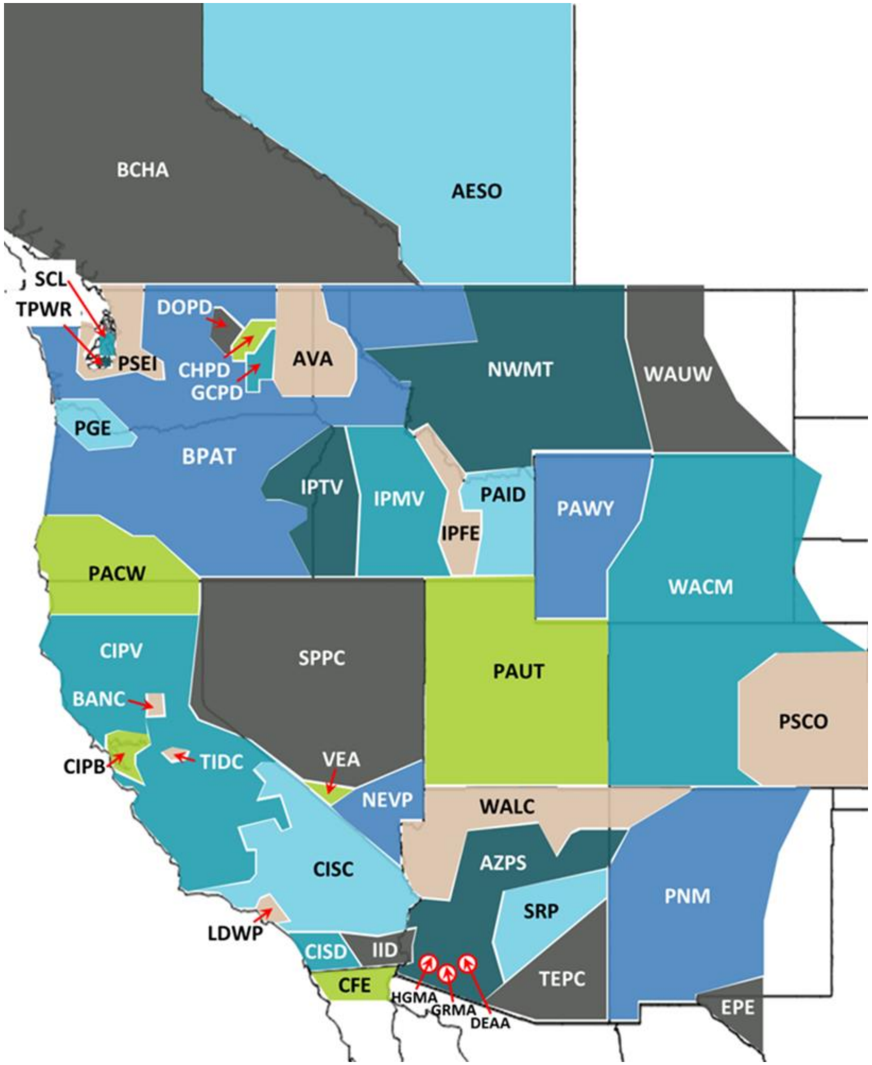
Production Cost Simulations

Simulation Assumptions:
Power Systems Optimizer (PSO) Model

Production cost analysis utilized PSO model to simulate least-cost security-constrained unit commitment and economic dispatch in WECC footprint

- Started with inputs from CAISO's 2020 Gridview model used in 2015/16 Transmission Planning Process (TPP)
- Included same WECC areas in CAISO Gridview model
- Updated key modeling assumptions based on more recent data available and stakeholder feedback

See slides 5, 16-18, 22-23, and 29-31 of main presentation for summary of study assumptions



Simulation Assumptions:

Incremental Generation Retirements and Additions

Generation retirements and additions in the Rest of U.S. WECC beyond the TEPPC 2024 Common Case assumptions (as reflected in CAISO Gridview Model) further include:

- Coal plant retirements and natural gas plant additions based on utility integrated resource plans (IRPs)
- RPS-related renewable generation additions in the rest of U.S. WECC, based on: (a) utility IRPs, and (b) additional renewables needed to meet 2030 requirements of current RPS standards in rest of U.S. WECC
- Renewable additions facilitated by regional market beyond RPS requirements, based on analysis of non-RPS additions in ERCOT, SPP, and MISO (see main slides and **Appendix B**)

Incremental Generation Updates to TEPPC 2024 Common Case for Rest of U.S. WECC

	Coal (MW)	Gas (MW)	Renewables RPS (MW)	Renewables non-RPS (MW)
Northwest	(3,469)	5,249	1,250	0
Southwest	(923)	4,306	1,500	2,000
Rocky Mt	262	0	500	3,000
Total	**(4,130)**	**9,555**	**3,250**	**5,000**

Notes:

[1] Updates to coal and gas generation capacity reflect additional retirements and additions based on utility IRPs. The increase of 262 MW coal capacity in Rocky Mountain reflects the change of retirement date for Hayden 2 unit to after 2030.

[2] Approximately 6,250 MW of the increase in gas capacity is from CC units and the remaining 3,300 MW is from peakers (mostly CT units).

[3] Renewable additions for RPS are estimated based on the incremental amount needed to meet RPS in rest of WECC. The values do not include the renewables added to meet California's RPS.

[4] The non-RPS renewable additions facilitated by the regional market are included only in scenarios 2–3.

Simulation Assumptions:
Hurdle Rates

Hurdle rates reflect economic barriers between Balancing Authorities

- Wheeling rate for CAISO reflects recent TAC projections
- Wheeling rates for other BAs are based on Schedule 8 of OATTs and other publicly posted transmission rates (as of February 2016)
  - Non-firm point-to-point off-peak hourly rates
- Hurdle rates also include:
  - \$1/MWh administrative charge
  - \$1/MWh trading margin
  - \$4/MWh hurdle adder for unit commitment
  - CO_2 hurdle for imports into California set based on emission rate of gas CCs at 0.435 metric tonnes per MWh
    - BPA is allowed to sell its hydro surplus at lower rates under a 2-tier structure (parameters based on TEPPC 2024 Common Case)

Balancing Authority	Wheeling Charge	Dispatch Hurdle	Commitment Hurdle
AESO	\$5.2	\$7.2	\$11.3
AZPS	\$4.1	\$6.2	\$10.3
AVA	\$5.8	\$7.8	\$11.9
BANC	\$2.1	\$4.1	\$8.2
BPA	\$4.3	\$6.3	\$10.4
BCHA	\$5.4	\$7.5	\$11.6
CAISO	\$11.5	\$13.5	\$17.6
CFE	\$12.2	\$14.2	\$18.3
CHPD	\$4.3	\$6.3	\$10.4
DOPD	\$4.3	\$6.3	\$10.4
GCPD	\$4.3	\$6.3	\$10.4
EPE	\$3.2	\$5.2	\$9.3
IPCO	\$2.7	\$4.7	\$8.8
IID	\$1.0	\$3.0	\$7.1
LDWP	\$5.1	\$7.2	\$11.3
NEVP	\$3.8	\$5.8	\$9.9
NWMT	\$4.3	\$6.4	\$10.5
PACE	\$3.3	\$5.3	\$9.4
PACW	\$3.3	\$5.3	\$9.4
PGE	\$0.7	\$2.8	\$6.9
PSCO	\$4.6	\$6.7	\$10.8
PNM	\$6.0	\$8.1	\$12.2
PSEI	\$2.5	\$4.5	\$8.6
SCL	\$1.1	\$3.2	\$7.3
SRP	\$2.2	\$4.3	\$8.4
SPPC	\$3.8	\$5.8	\$9.9
TPWR	\$3.0	\$5.0	\$9.1
TEPC	\$3.1	\$5.2	\$9.2
TIDC	\$2.5	\$4.6	\$8.7
WACM	\$5.4	\$7.5	\$11.6
WALC	\$2.2	\$4.3	\$8.4
WAUW	\$4.0	\$6.0	\$10.1

Simulation Assumptions:
Considerations Regarding Hurdle Rate Assumptions

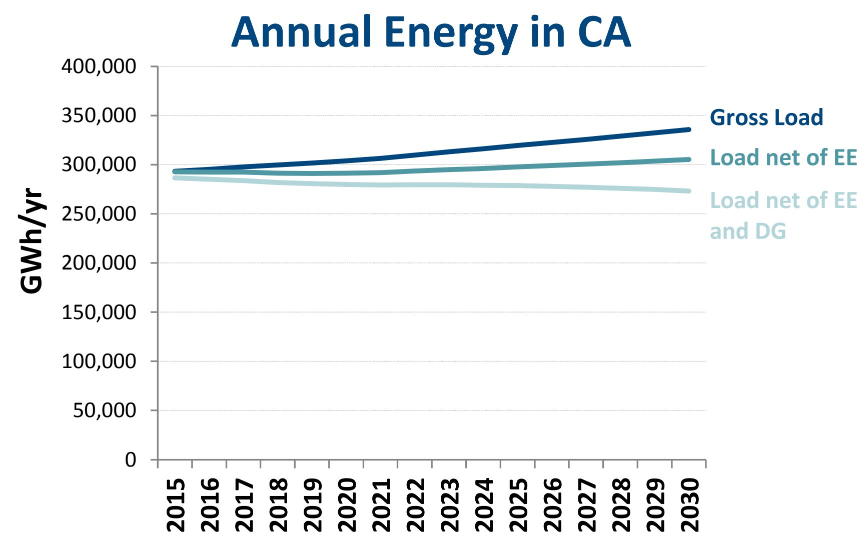
The simulations do not explicitly model long-term transmission rights. However:

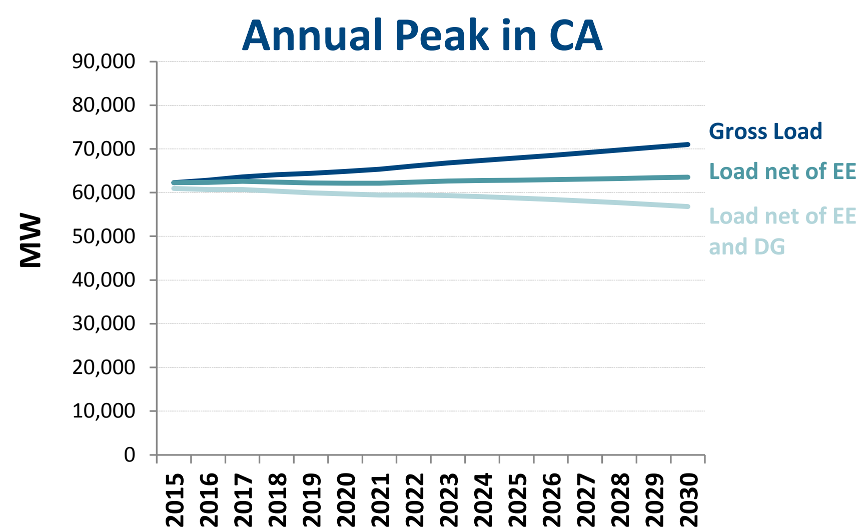
1. Total hurdles are conservative: OATT charges (off-peak), \$1/MWh administrative charges, \$1/MWh trading margin (split by bilateral counterparties), CC-based CO_2 hurdle for CA imports, and a \$4/MWh added hurdle for unit commitment.
2. OATT charges for point-to-point reservations are only a portion of the overall hurdles
   - Conservatively used off-peak rates, which in some cases are \$0.5–5.5/MWh below on-peak rates
   - California export hurdles are MWh-based charges for all exports
   - California CO_2 import hurdles also are variable charges on 100% of all generic imports
   - Administrative charges, trading margins, and unit commitment hurdles are variable costs even for those with long-term transmission reservations
3. Unit dispatch is affected most strongly by the marginal import and export transactions, which primarily rely on hourly services. Impacts are mostly determined by those variable charges.
4. Parties with long-term reservations who trade actively will not "give away" 100% of their variable cost advantage. More realistically, they will be able to achieve higher trading margins than competitors who buy hourly transmission service. In fact, <u>they will need to make higher margins to pay for their long-term reservations</u>.
5. Market simulations assume perfectly competitive behavior of all generators and holders of long-term point-to-point transmission reservations (bidding only variable costs).

Simulation Assumptions:
Load Forecasts

Load inputs are updated based on CEC and WECC data

- California's load from "Mid-Demand Baseline Case" with mid-AAEE savings
  - Published as part of the CEC's 2015 IEPR
  - Provides net peak and energy values for 2016–2026 at BA level
  - After 2026, extrapolated at CEC's long-term growth rate
- Rest of WECC's load from WECC Load and Resources (LAR) forecasts for each BA
  - After 2025, extrapolated at 2020–2025 average growth rate





Simulation Assumptions:
Natural Gas Prices

Gas prices updated based on CEC forecast

- "Mid-Demand Case" of CEC's *WECC Gas Hub Burner Tip Price Estimates using 2015 IEPR Natural Gas Estimates*
  - Published as part of the CEC's 2015 IEPR
  - Provides monthly burnertip prices for 2016–2026 at 33 western gas hubs
  - After 2026, prices are assumed to remain constant (in real dollar terms)

Average Delivered NG Prices (2016$/MMBtu)

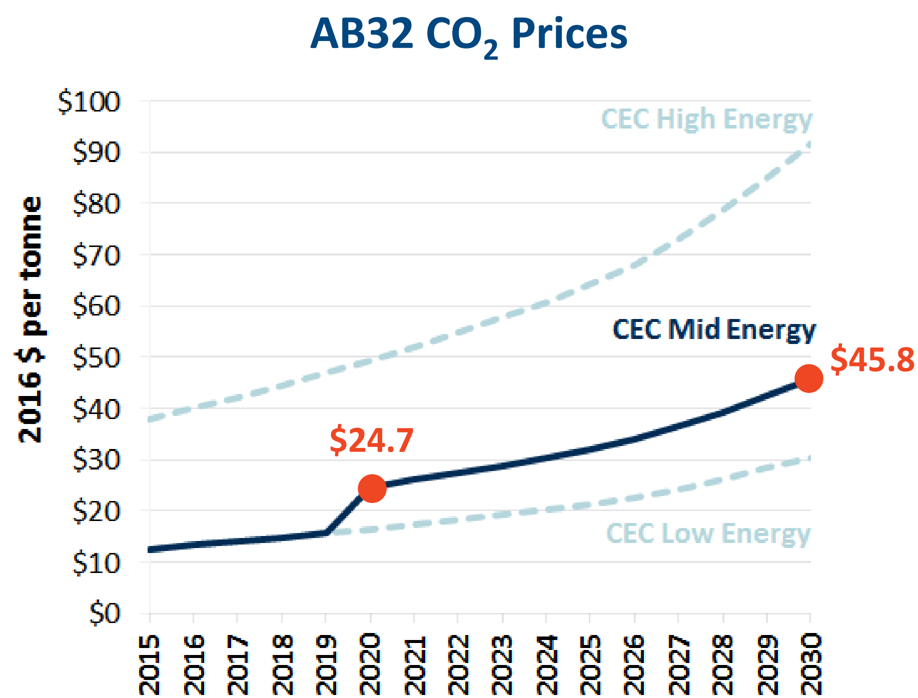
Region	2020	2030
California	$4.57	$5.13
Northwest	$4.20	$4.69
Southwest	$4.27	$4.73
Rocky Mt	$3.96	$4.44
WECC non-US	$4.15	$4.66

* Values in the table reflect the simple average of modeled hub prices within the given geographic area.

Simulation Assumptions:
CO_2 Prices

California CO_2 prices under AB32 are updated based on CEC forecast

- "Mid Energy Consumption Scenario" of CEC's *Revised GHG Price Projections*
  - Published as part of the CEC's 2015 IEPR
  - $24.7/tonne in 2020, and $45.8/tonne in 2030 (in 2016 dollars)
- Assumed no CO_2 price for outside of California in base-case scenarios, but separately analyzed a sensitivity with a $15/tonne carbon price in rest of U.S. WECC (outside of CA)



Simulation Results:
WECC-wide Production Costs (in 2016 $million/yr)

	2020 Current Practice	2020 Regional ISO CAISO+PAC	2030 Current Practice 1A	2030 Current Practice 1B	2030 Regional ISO Exp. 2	2030 Regional ISO Exp. 3
Fuel cost	$14,316	$14,312	$17,602	$17,600	$16,844	$16,809
Start-up cost	$436	$421	$769	$816	$673	$605
Variable O&M cost	$1,380	$1,382	$1,188	$1,184	$1,159	$1,164
TOTAL	**$16,133**	**$16,115**	**$19,559**	**$19,600**	**$18,676**	**$18,579**
Impact of Regionalization Relative to CP 1A		($18) (0.1%)			($883) (4.5%)	($980) (5.0%)
Impact of Regionalization Relative to CP 1B					($924) (4.7%)	($1,022) (5.2%)

* Based on fuel, start-up, and variable O&M costs only

Does not include: societal costs of emission reductions or incremental investment costs associated with the additional renewable resources facilitated by the regional market in 2030 Scenarios 2 and 3

Simulation Results:
WECC-wide CO_2 Emissions (in million tonnes/yr)

	2020 Current Practice	2020 Regional ISO CAISO+PAC	2030 Current Practice 1A	2030 Current Practice 1B	2030 Regional ISO Exp. 2	2030 Regional ISO Exp. 3
WECC TOTAL	**330.3**	**330.9**	**307.3**	**306.3**	**295.9**	**297.5**
Impact of Regionalization		0.6			(11.4)	(9.8)
Relative to CP 1A		0.2%			(3.7%)	(3.2%)
Impact of Regionalization					(10.4)	(8.8)
Relative to CP 1B					(3.4%)	(2.9%)

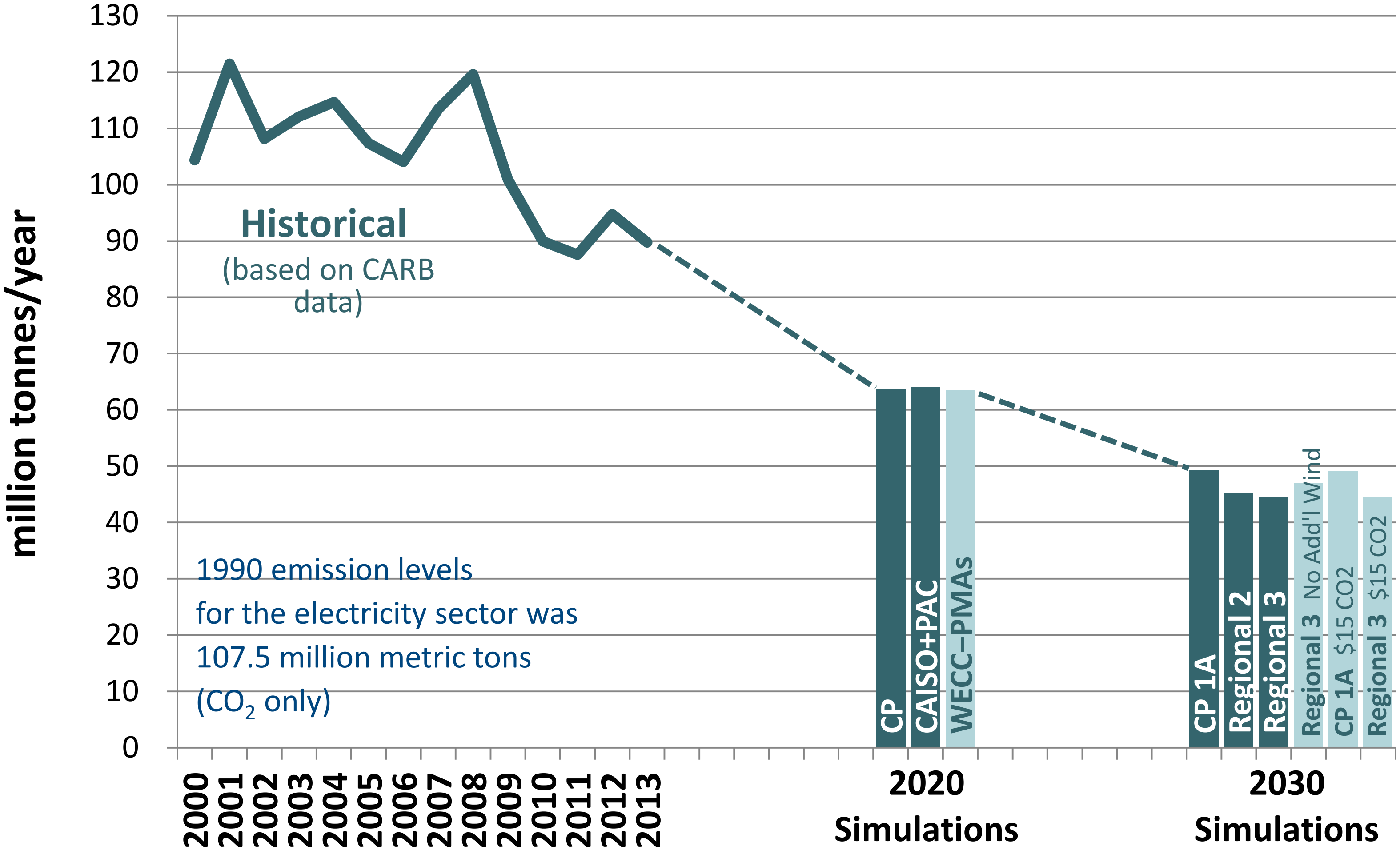
Simulation Results:
California CO_2 Emissions (in million tonnes/yr)

	2020 Current Practice	2020 Regional ISO CAISO+PAC	2030 Current Practice 1A	2030 Current Practice 1B	2030 Regional ISO Exp. 2	2030 Regional ISO Exp. 3
CA In-State	51.8	51.6	46.2	46.6	44.5	43.3
CA Imports Contracted	9.2	8.7	6.2	6.1	4.0	3.3
CA Imports Generic	3.2	4.0	1.7	1.8	1.8	1.5
CA Exports Generic	(0.4)	(0.4)	(4.8)	(7.0)	(5.0)	(3.7)
CA Emissions for Load	**63.7**	**64.0**	**49.2**	**47.4**	**45.3**	**44.4**
Impact of Regionalization		0.2			(3.9)	(4.8)
Relative to CP 1A		0.4%			(7.9%)	(9.7%)
Impact of Regionalization					(2.1)	(3.0)
Relative to CP 1B					(4.5%)	(6.3%)

* Simulation results assume CO_2 emissions associated with imports are charged and exports are credited based on a generic CO_2 emission rate for natural gas CCs

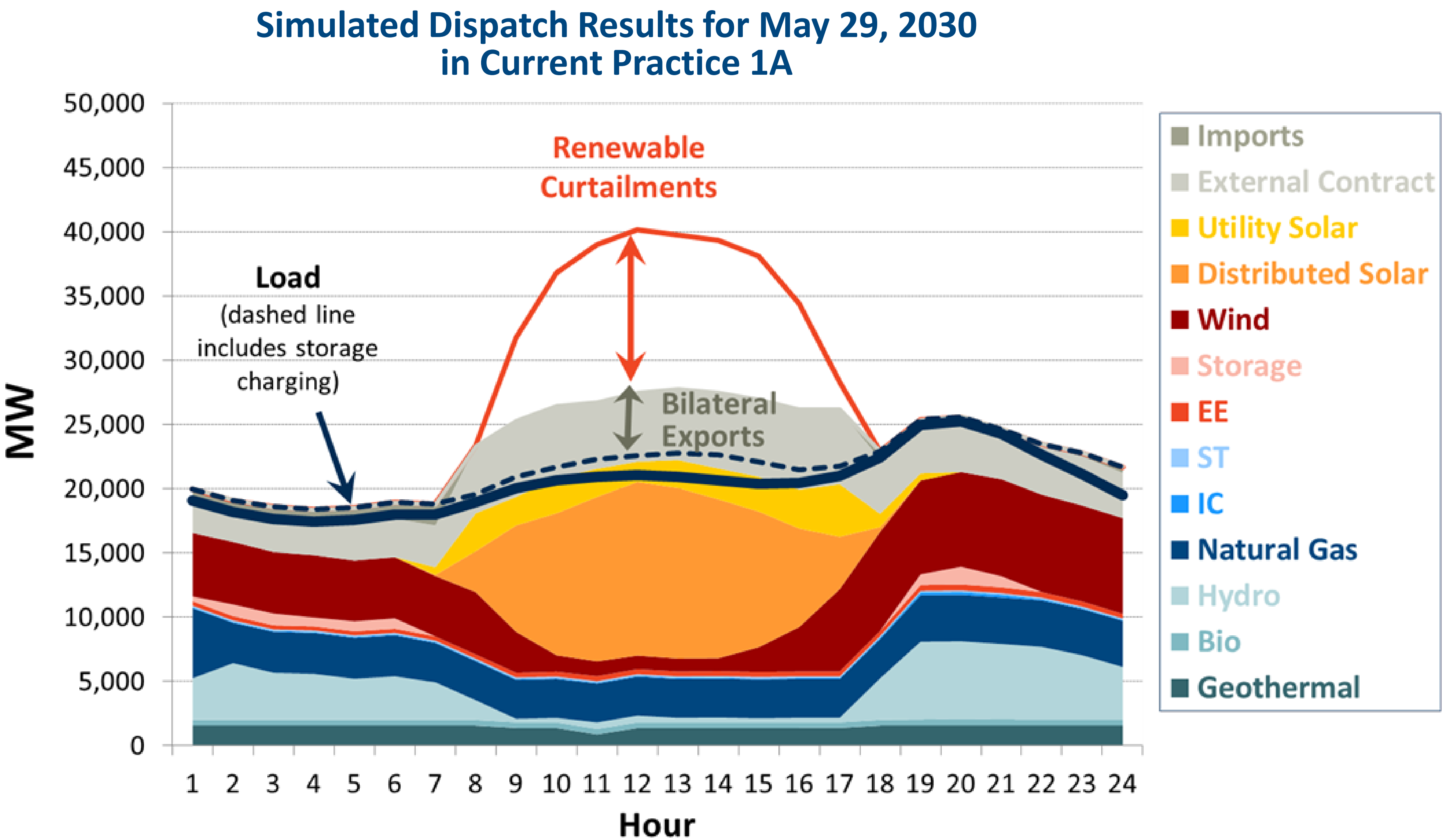
Simulation Results:

Simulated vs. Historical California CO_2 Emissions

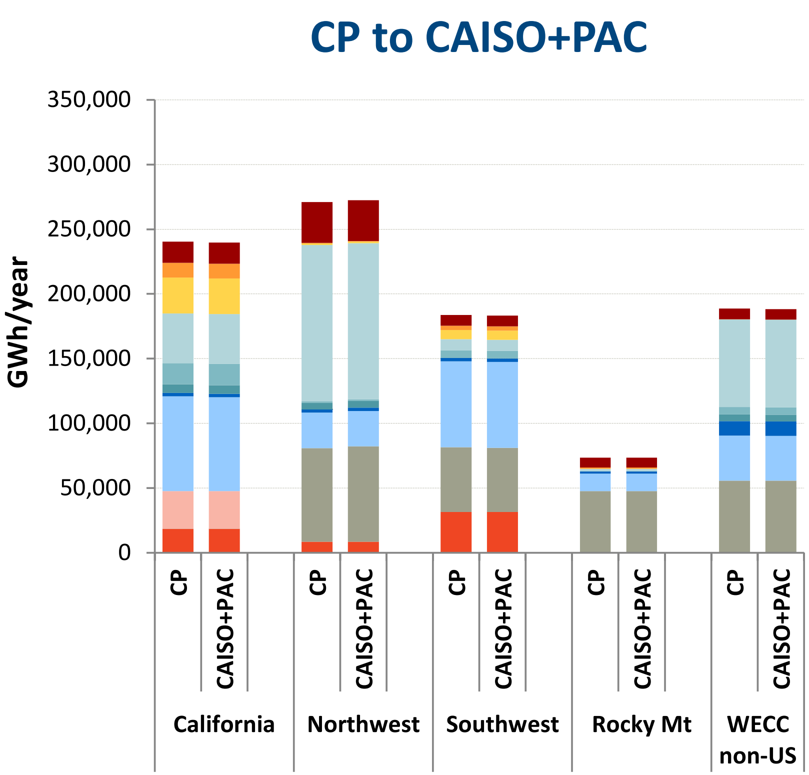


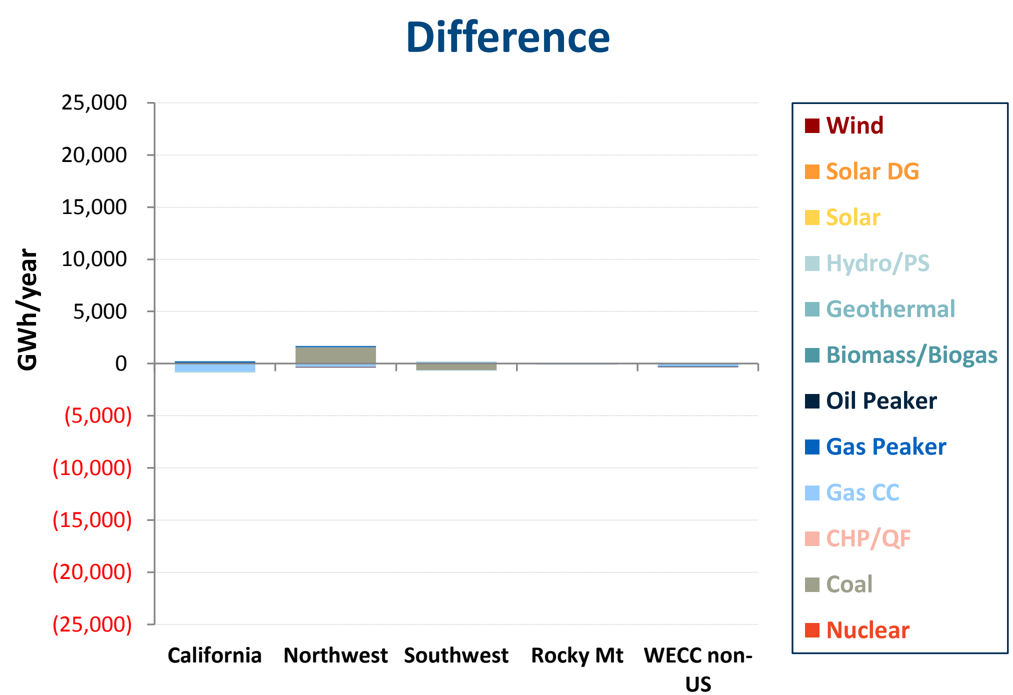
* Simulation results assume CO_2 emissions associated with imports are charged and exports are credited based on a generic CO_2 emission rate for natural gas CCs.

Simulation Results:
Example: Daily Dispatch in 2030



Simulation Results:
2020 Annual Generation by Type

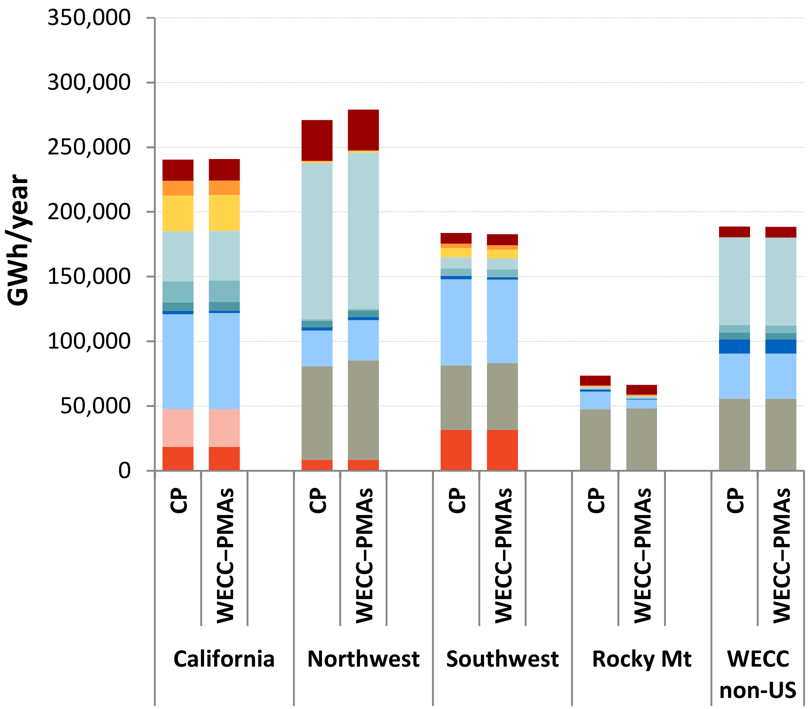




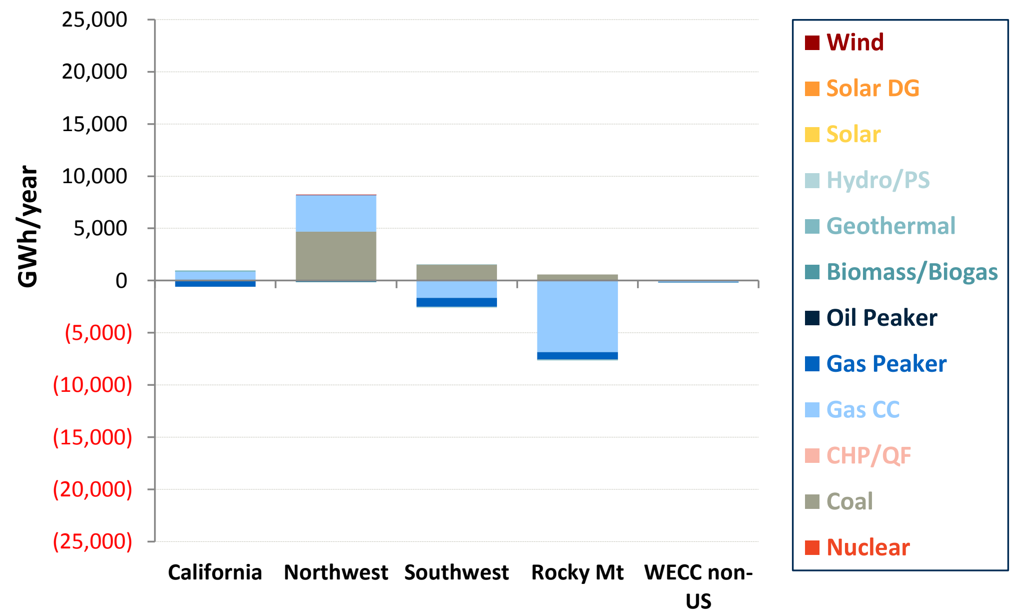
* Increase in WECC-wide coal generation is estimated to be 0.4% of total.
These simulation results likely <u>overstate</u> impact on coal dispatch due to the generic CC-based CO_2 hurdle rate applied to all imports into California. Contrary to the hurdle that would actually be imposed, this simplification artificially advantages coal in the simulations.

Simulation Results:
2020 Annual Generation by Type (cont'd)

CP to Expanded Regional



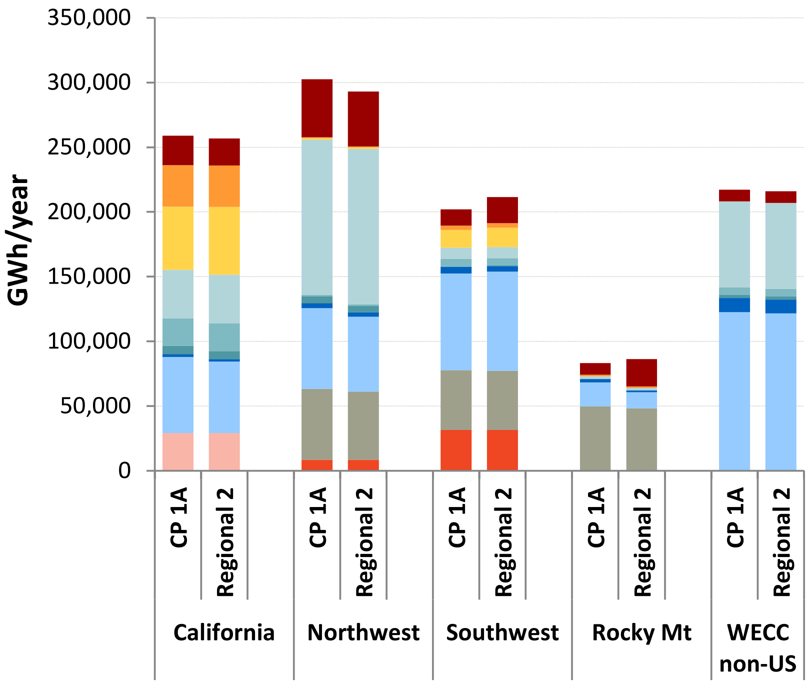
Difference



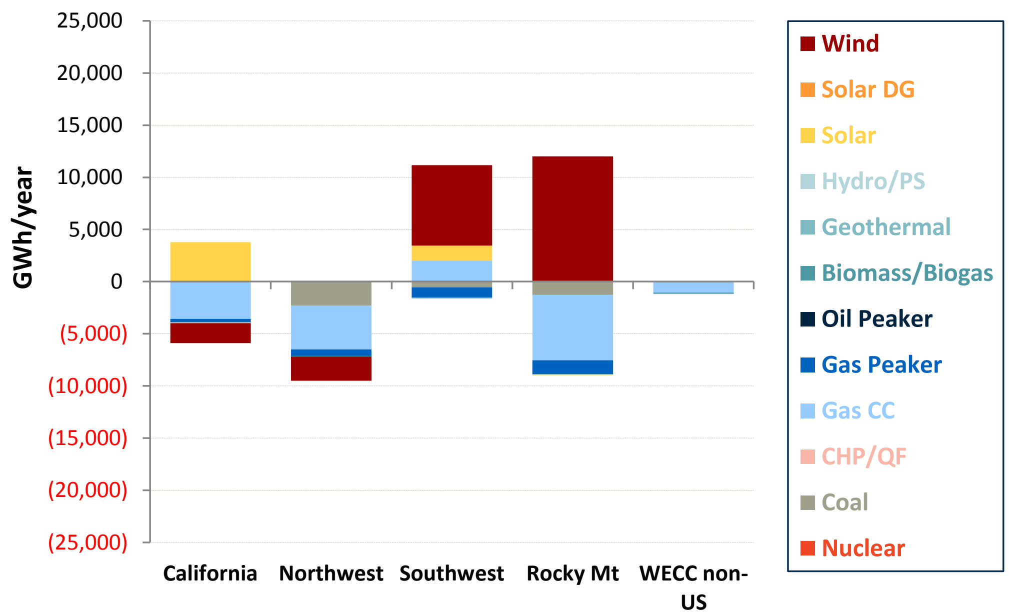
* Increase in WECC-wide coal generation is estimated to be 3% of total.
These simulation results likely <u>overstate</u> impact on coal dispatch due to the generic CC-based CO_2 hurdle rate applied to all imports into California. Contrary to the hurdle that would actually be imposed, this simplification artificially advantages coal in the simulations.

Simulation Results:
2030 Annual Generation by Type

CP 1A to Regional 2

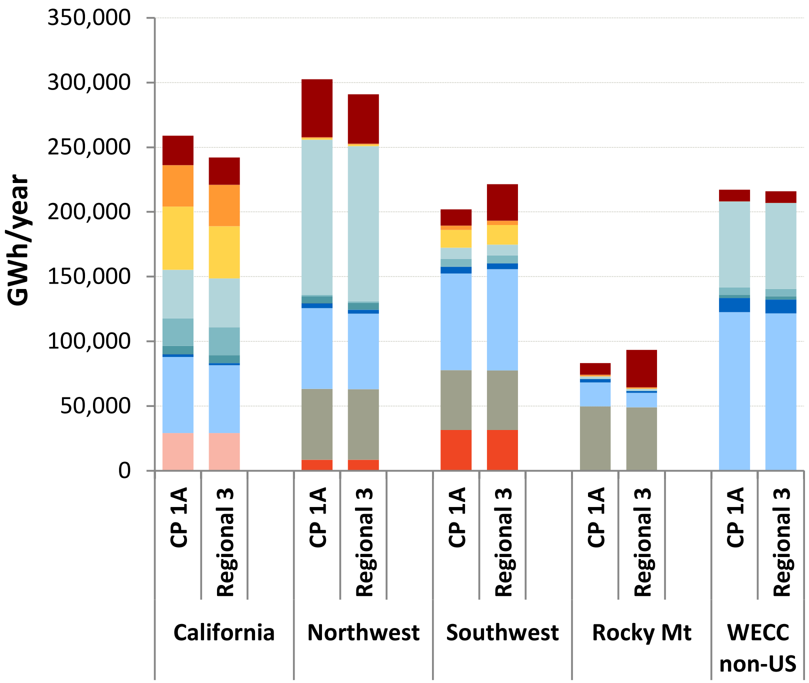


Difference

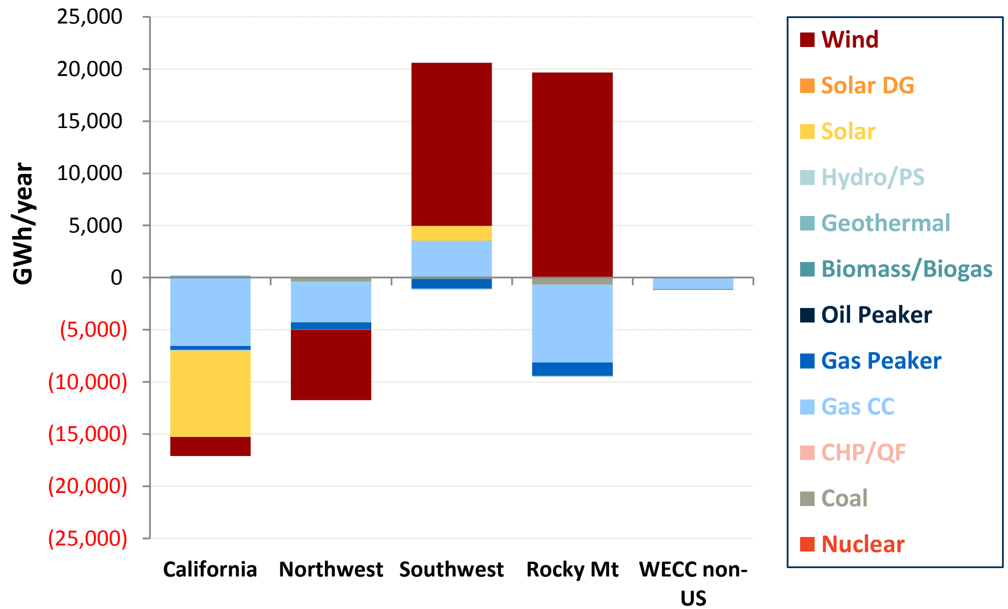


Simulation Results:
2030 Annual Generation by Type (cont'd)

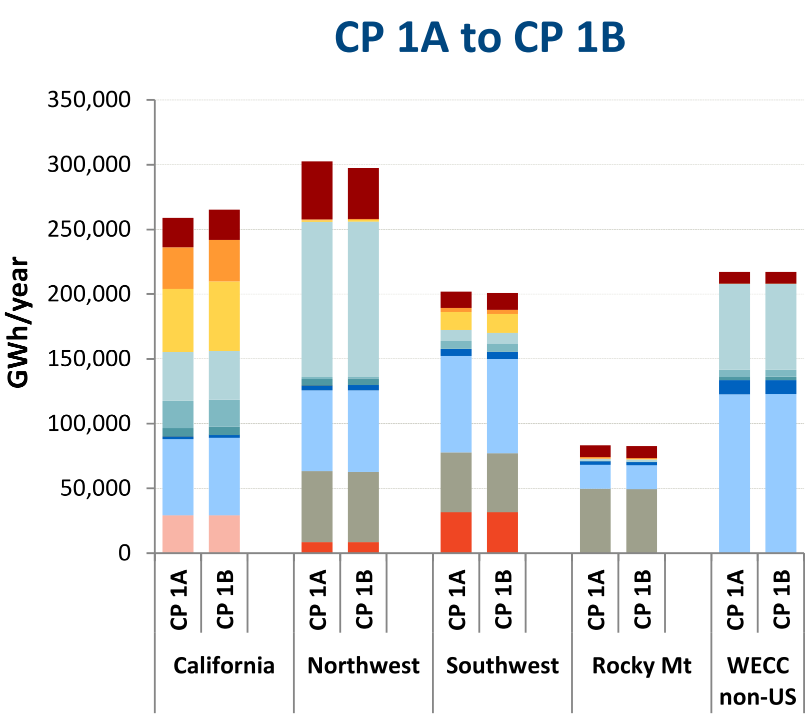
CP 1A to Regional 3

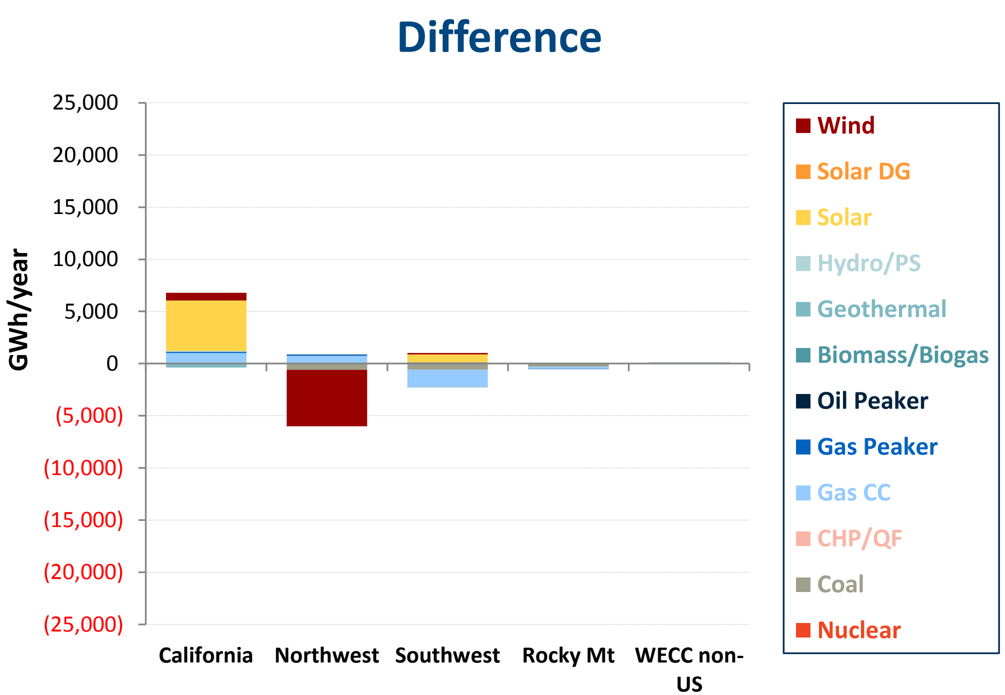


Difference

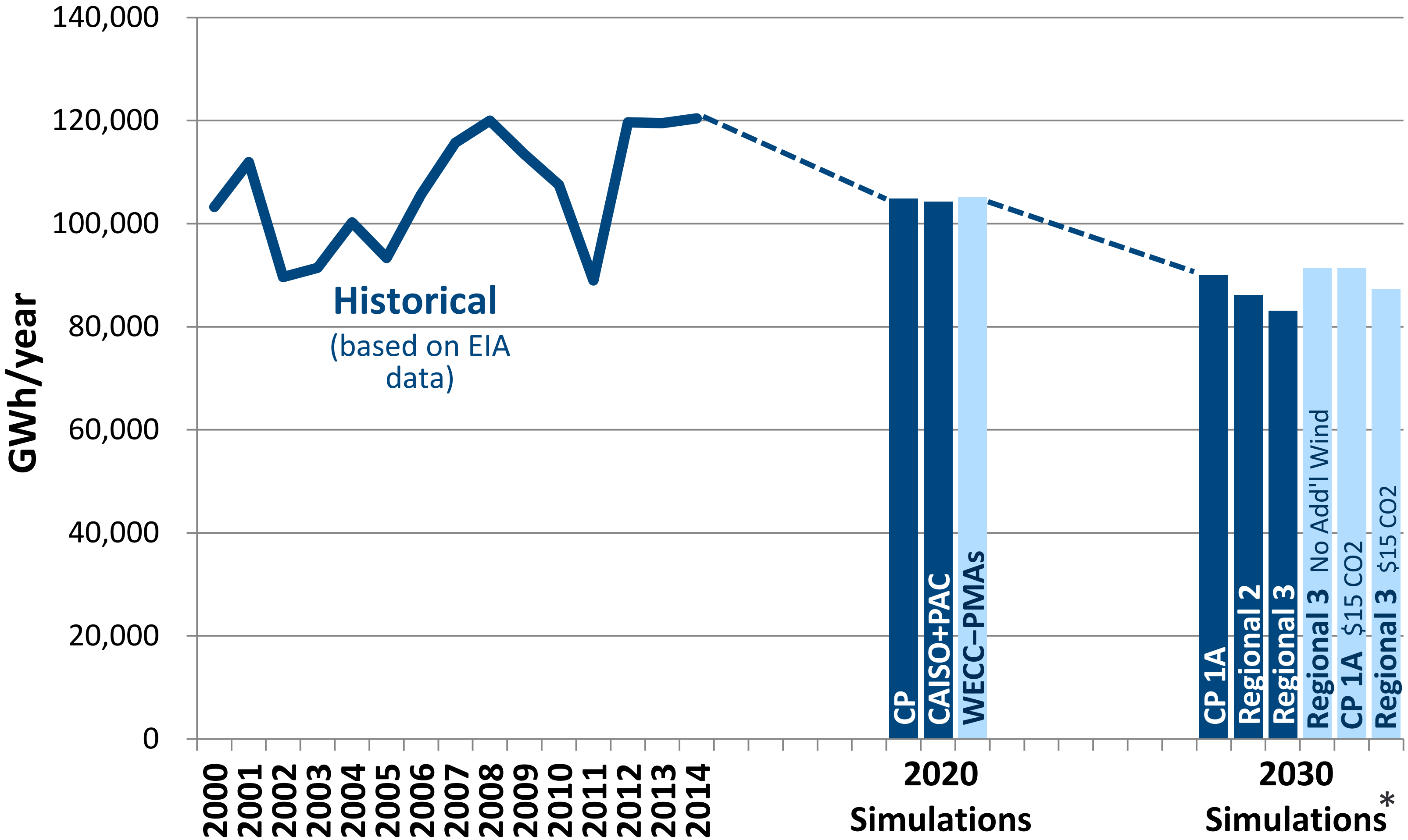


Simulation Results:
2030 Annual Generation by Type (cont'd)



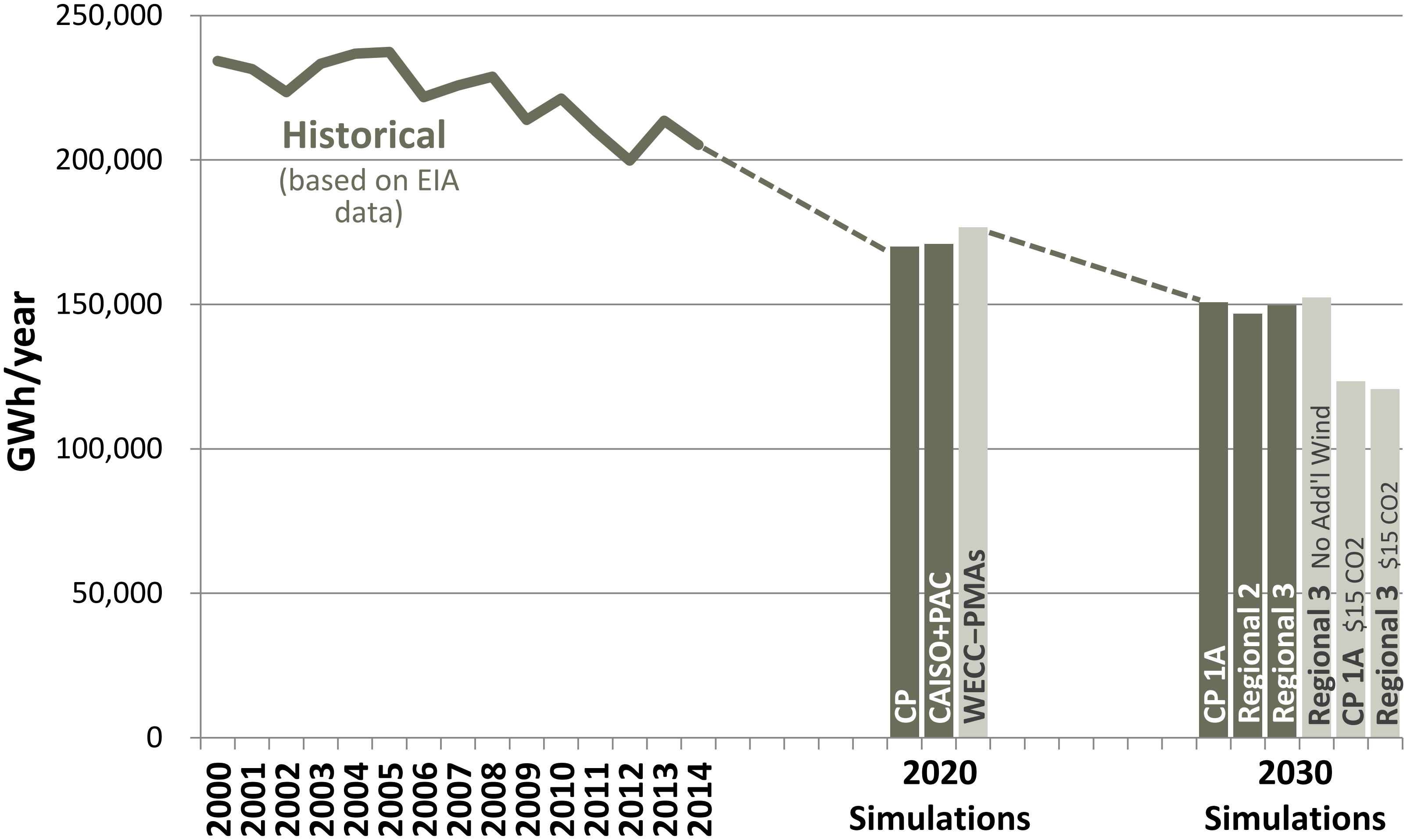


Simulation Results:
Simulated vs. Historical CA Natural Gas Generation

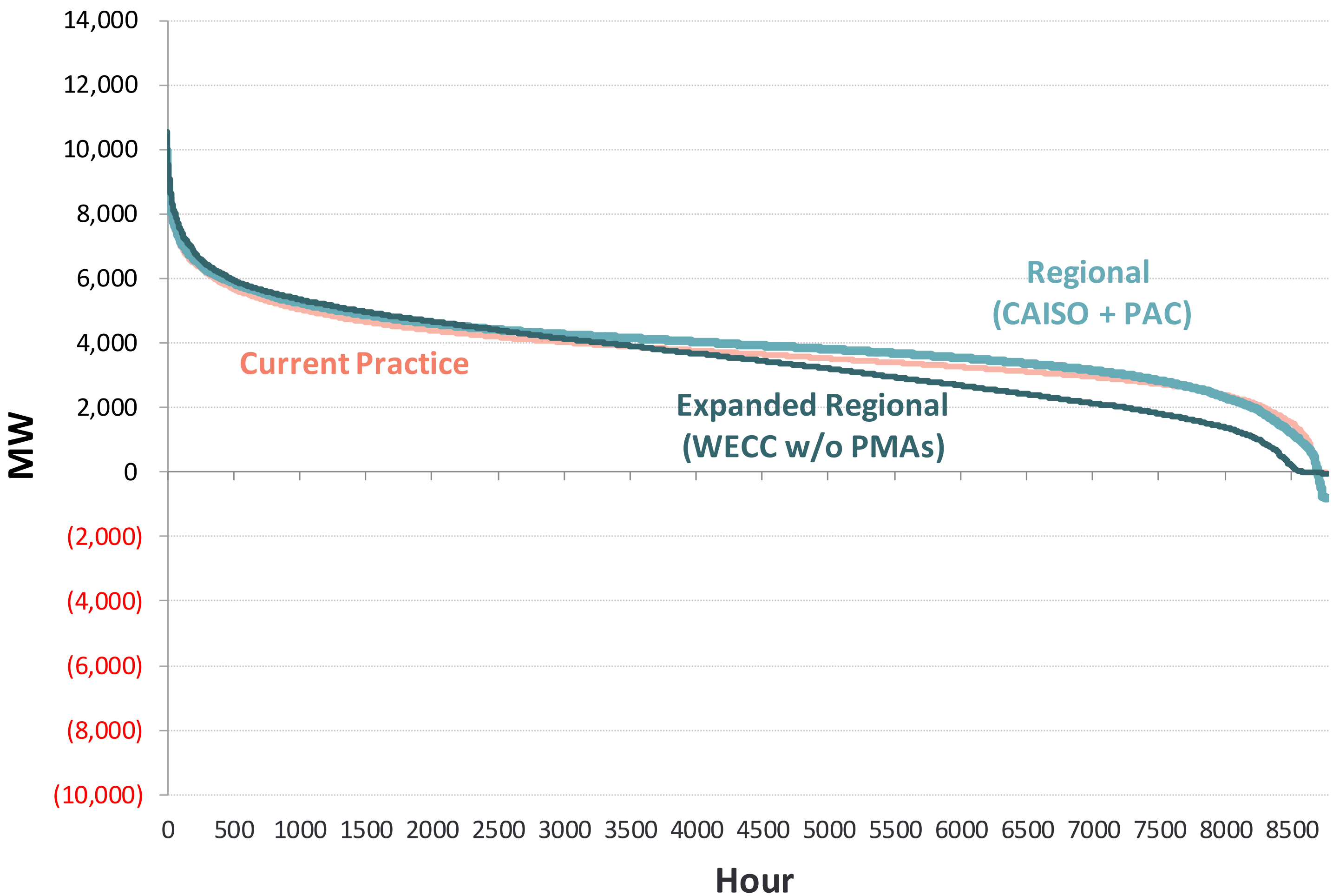


* 2030 values reflect increased natural gas use associated with assumed retirement of Diablo Canyon nuclear plant

Simulation Results:
Simulated vs. Historical U.S. WECC Coal Generation



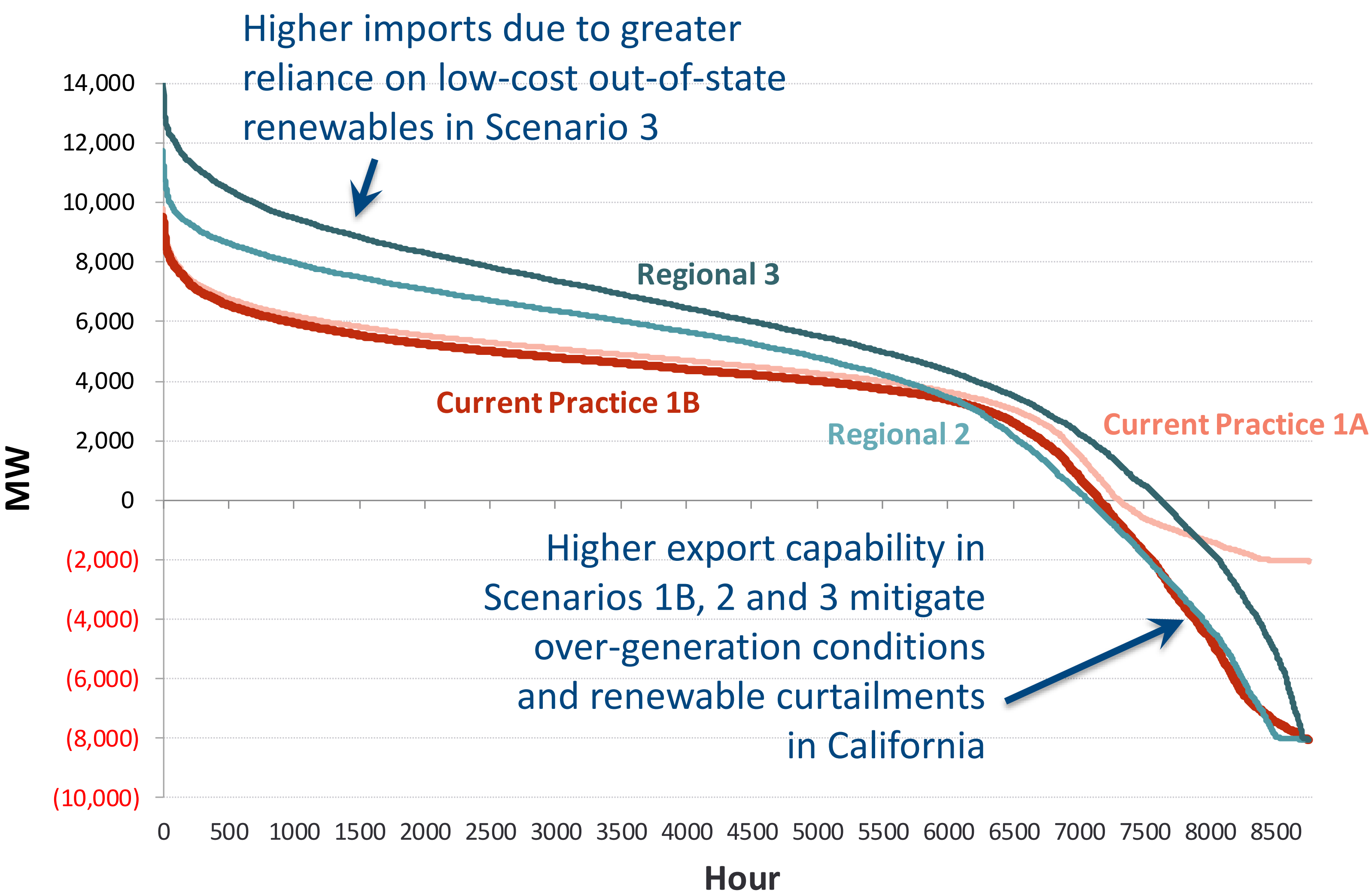
Simulation Results:
2020 CAISO Net Import Duration Curves



* Values are based on physical flows across CAISO's interties.

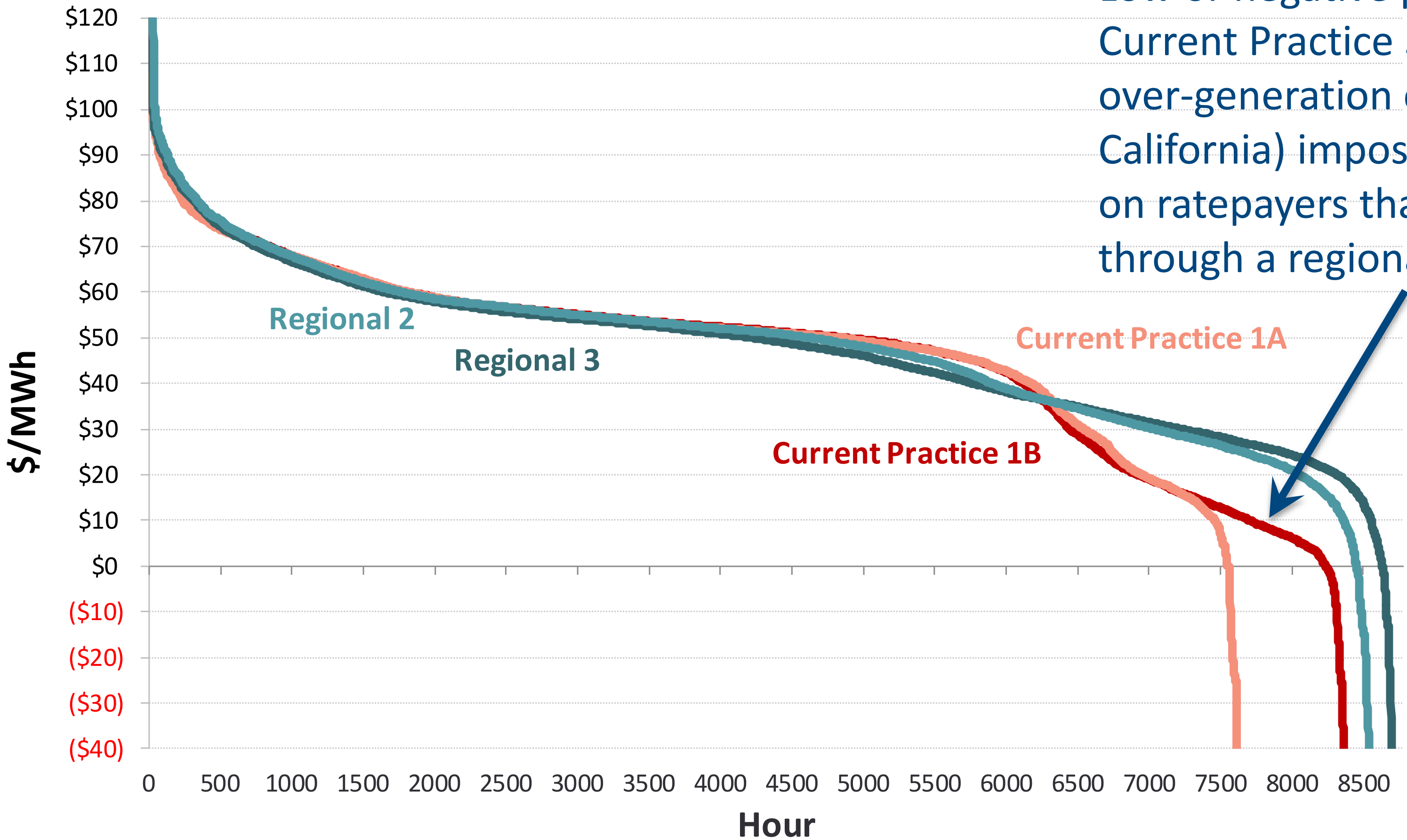
Simulation Results:

2030 CAISO Net Import Duration Curves



* Values are based on physical flows across CAISO's interties.

Simulation Results:
2030 CAISO Price Duration Curves



Low or negative prices in Current Practice Scenarios (due to over-generation conditions in California) impose significant costs on ratepayers that are mitigated through a regional market

Negative prices during curtailment hours are adjusted to be zero or -$40 in TEAM calculations

Simulation Results:
2030 Annual Renewable Curtailments (in million MWh)

	2030 Current Practice 1A	2030 Current Practice 1B	2030 Regional ISO Exp. 2	2030 Regional ISO Exp. 3
PSO	4.5	0.9	0.5	0.1
RESOLVE	4.8	2.0	1.6	1.2
Diff.	**(0.3)**	**(1.1)**	**(1.1)**	**(1.1)**

More limited bilateral (re)export ability in Scenario 1A (assuming all 3,000-4,000 MW of existing imports plus an additional 2000 MW case be sold and re-exported bilaterally) results in significant curtailments of in-state renewable generation even under the assumed optimal portfolio.

Curtailment pattern are generally similar in PSO and Resolve models.

2020 Sensitivity: "2020 Expanded Regional ISO"

Larger Regional Footprint in 2020

- Regional footprint assumed to be the same as in 2030 (U.S. WECC w/o the PMAs)
- Expanded regional market provides about 10 times larger savings (compared to $18 million for CAISO+PAC)
- CO_2 emissions would decrease in CA and increase minimally in WECC (before consideration of facilitation of renewable generation development beyond RPS)

WECC-wide Production Cost Savings (in 2016 $MM/yr)

	2020 Current Practice	2020 Regional ISO Exp.
Fuel cost	$14,316	$14,206
Start-up cost	$436	$363
Variable O&M cost	$1,380	$1,393
TOTAL	**$16,133**	**$15,961**
Impact of Regionalization		($171)
		(1.1%)

* These simulation results likely overstate impact on coal dispatch due to the generic CC-based CO_2 hurdle rate applied to all imports into California. Contrary to the hurdle that would actually be imposed, this simplification artificially advantages coal in the simulations.

Impact on Annual CO_2 Emissions (in million tonnes/yr)

	2020 Current Practice	2020 Regional ISO Exp.
WECC TOTAL	**330.3**	**333.2**
Impact of Regionalization		2.9
		0.9%
CA In-State	51.7	51.7
CA Imports Contracted	9.2	7.6
CA Imports Generic	3.2	4.6
CA Exports Generic	(0.4)	(0.4)
CA Emissions for Load	**63.6**	**63.4**
Impact of Regionalization		(0.2)
		(0.3%)

2030 Sensitivity: "Regional 1A"

Regional Market Simulations for Portfolio 1A

- Regional market case as in Scenarios 2 and 3, but with the CP 1a portfolio (same overbuild, so no capital savings)
- Regional market offers significant emissions reduction (particularly in CA) by reducing renewable curtailments if CP 1A portfolio remained unchanged

WECC-wide Production Cost Savings (in 2016 $MM/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 1A
Fuel cost	$17,602	$17,320
Start-up cost	$769	$666
Variable O&M cost	$1,188	$1,185
TOTAL	**$19,559**	**$19,171**
Impact of Regionalization		($388) (2.0%)

Impact on Annual CO_2 Emissions (in million tonnes/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 1A
WECC TOTAL	**307.3**	**304.4**
Impact of Regionalization		(2.9) (0.9%)
CA In-State	46.2	46.4
CA Imports Contracted	6.2	5.1
CA Imports Generic	1.7	2.8
CA Exports Generic	(4.8)	(7.5)
CA Emissions for Load	**49.2**	**46.9**
Impact of Regionalization		(2.4) (4.8%)

2030 Sensitivity: "CO_2 Pricing in Rest of WECC"

Simulating Carbon Prices in Rest of U.S. WECC

- Simulated Scenarios 1A and 3 with CO_2 prices of $15/tonne in Rest of U.S. WECC
- Offers additional CO_2 emission reductions that results in CPP compliance for the Rest of WECC region. Regional market results show additional emissions reductions.

WECC-wide Production Cost Savings (in 2016 $MM/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 3
Fuel cost	$17,842	$17,074
Start-up cost	$735	$558
Variable O&M cost	$1,137	$1,110
TOTAL	**$19,713**	**$18,743**
Impact of Regionalization		($971)
		(4.9%)

Impact on Annual CO_2 Emissions (in million tonnes/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 3
WECC TOTAL	**291.2**	**280.6**
Impact of Regionalization		(10.6)
		(3.6%)
CA In-State	46.7	44.9
CA Imports Contracted	6.2	3.7
CA Imports Generic	1.4	1.2
CA Exports Generic	(5.2)	(5.5)
CA Emissions for Load	**49.1**	**44.4**
Impact of Regionalization		(4.7)
		(9.6%)

2030 Sensitivity: "Without Non-RPS Wind"

Scenario 3 Regional without Wind Beyond RPS

- Sensitivity without the development of additional low-cost, non-RPS renewables in WECC (3,000 MW of wind in WY and 2,000 MW wind in NM) that is assumed to be facilitated by the regional market
- Renewables facilitated by market increases production cost savings and emission reductions (both in CA and WECC-wide)

WECC-wide Production Cost Savings (in 2016 $MM/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 3
Fuel cost	$17,602	$17,412
Start-up cost	$769	$622
Variable O&M cost	$1,188	$1,190
TOTAL	**$19,559**	**$19,224**
Impact of Regionalization		($335) (1.7%)

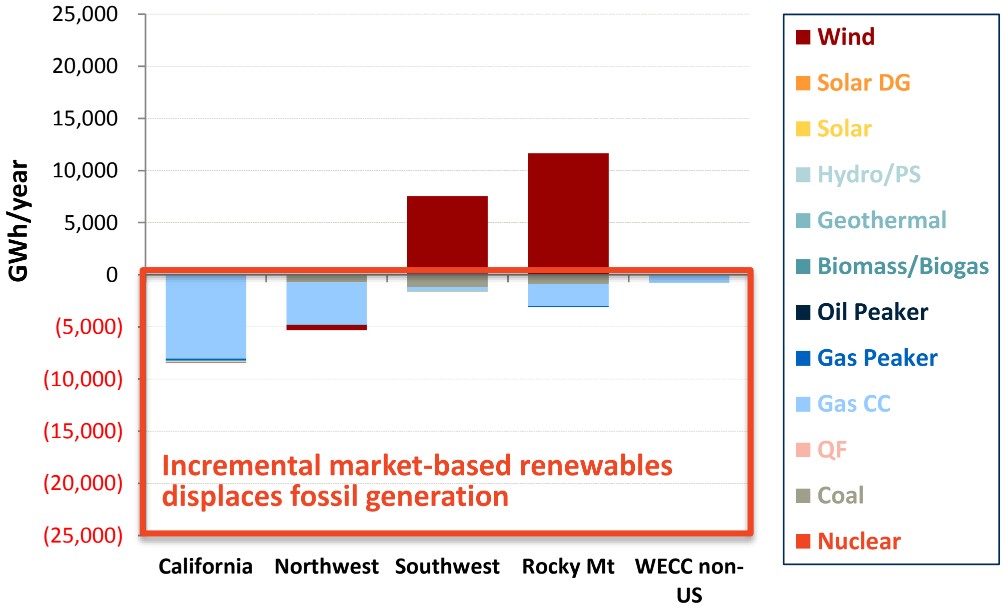
Impact on Annual CO_2 Emissions (in million tonnes/yr)

	2030 Current Practice 1A	2030 Regional ISO Exp. 3
WECC TOTAL	**307.3**	**306.0**
Impact of Regionalization		(1.3) (0.4%)
CA In-State	46.2	46.5
CA Imports Contracted	6.2	4.5
CA Imports Generic	1.7	2.3
CA Exports Generic	(4.8)	(6.3)
CA Emissions for Load	**49.2**	**47.0**
Impact of Regionalization		(2.2) (4.5%)

2030 Sensitivity: "Without Non-RPS Wind"

Scenario 3 without Wind Beyond RPS

Impact of 5,000 MW Renewable Generation Beyond RPS on Regional Scenario 3



Integrating 5,000 MW of wind generation beyond RPS displaces WECC-wide fossil-fired generation and reduces WECC-wide CO_2 emissions by about 8.5 million metric tonnes per year

A regional market in WECC is expected to offer substantial emission reductions by:

- Creating region-wide access to lower-cost renewable resources
- Facilitating the development of market-based (beyond-RPS) renewable generation in low-cost areas of the region

Simulation results show that market-based renewable generation additions:

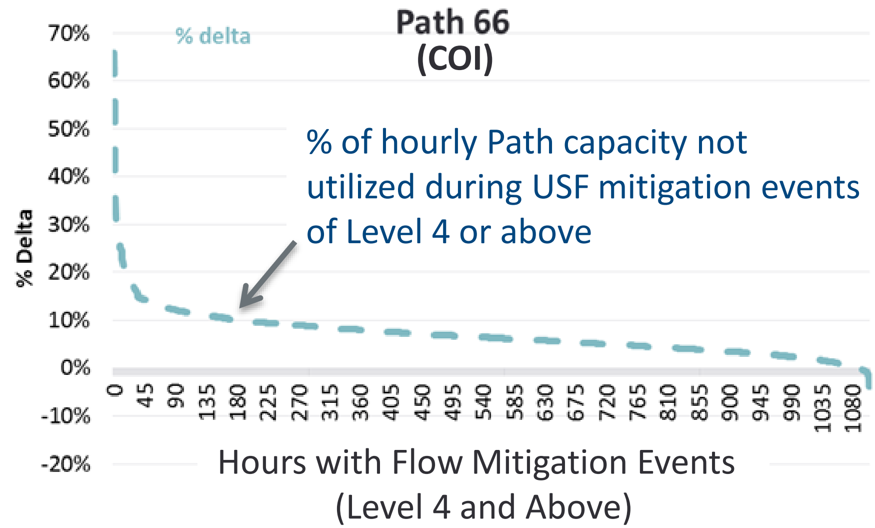
- Reduces emissions from displacement of both coal and natural gas generation
- Significantly reduces natural gas generation in California (assuming no CA carbon hurdle is imposed on imports from these sources)

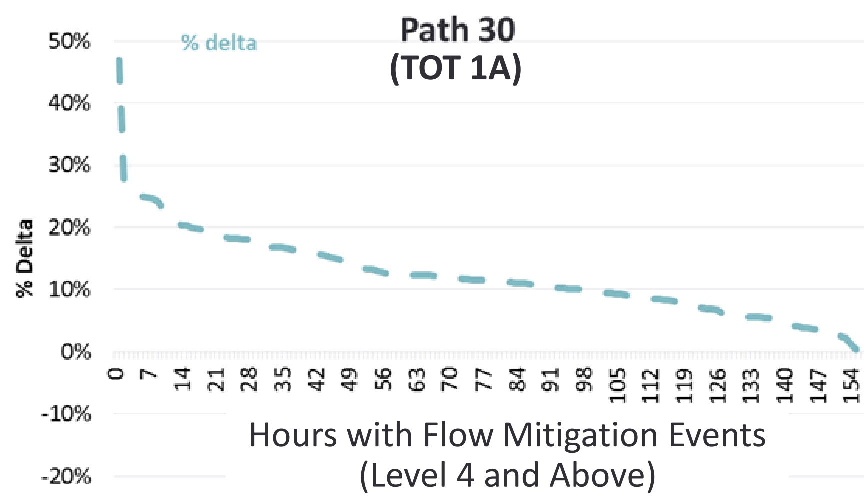
Production Cost Benefits Not Quantified:

Improved Utilization of the Existing Grid

Bilateral market and the associated contract path transmission service are not able to fully utilize the physical capabilities of the existing grid, compared to ISO-operated markets.

- A 2003 MISO study showed that its bilateral Day-1 market did not utilize between 7.7% to 16.4% of the existing grid capacity during congestion management events (compared to the flows that could have been accommodated in its regional Day-2 with regional security-constrained economic dispatch)
- Analysis of 2012 WECC path-flow data (most recent year available), showing **5–25% of grid capacity remains unutilized** during unscheduled flow (USF) mitigation
- **Not reflected in simulations**; will only be partly addressed by EIM





Appendix B

Renewable Generation Development Stimulated by Regional Markets

Development of Renewables Beyond RPS

The baseline simulations capture some emissions-related impacts of a regional markets' ability to facilitate the development and integration of renewable generation beyond RPS

The following slides summarize some of the available data documenting that organized markets have been attracting significant renewable development well beyond RPS needs

- Particularly pronounced in markets with low-cost renewables
- Expansion of the CAISO to include PacifiCorp (or a larger regional footprint) will provide direct access to such low-cost locations in Wyoming and other areas of the WECC

Our analysis shows that the additional renewable development offers substantial emission-related benefits to California

Types of Additional Renewable Development

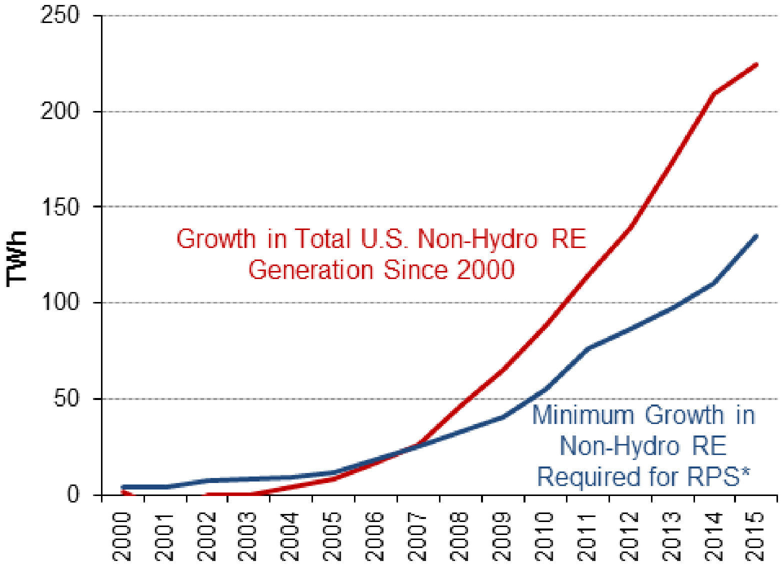
Based on the experience in other regional markets with low-cost renewable resources (ERCOT, MISO, SPP), renewable development beyond RPS comes in the form of:

1. **Voluntary utility/muni/coop purchases** due to low cost (e.g., $20–25/MWh with PTC) and fuel-cost hedge value
2. **Merchant renewable generation** developed with financial hedges
3. **Renewable PPAs with large C&I customers** that support investments beyond RPS

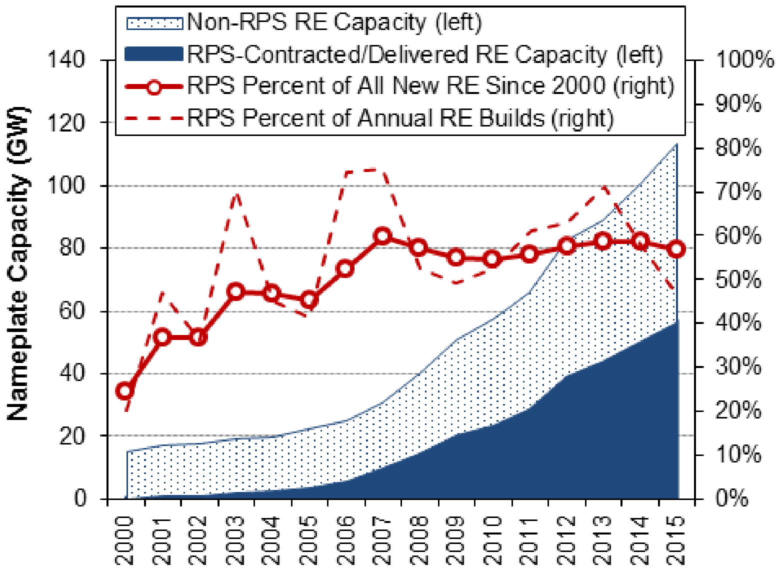
Actual Market-Based Renewable Additions beyond RPS

- Since 2006, RPS mandates account for only 50–60% of total (non-hydro) renewable generation development
  - Most of the approx. 50,000 MW of additions <u>beyond RPS</u> is wind in low-cost RTO/ISO regions
  - In MISO, SPP, and ERCOT, the incremental RPS demand is only 1,000 MW through 2030, while over 8,000 MW of renewable generation is already permitted or under construction today

RPS requirements comprised 60% of total growth in U.S. renewable electricity generation since 2000



More than half (57%) of all new renewable generation capacity is sold to entities with RPS obligations



BERKELEY LAB

Source: Barbose, Galen. 2016. "U.S. Renewables Portfolio Standards: 2016 Annual Status Report." Lawrence Berkeley National Laboratory. http://rps.lbl.gov

Actual Market-Based Renewable Additions Beyond RPS (cont'd)

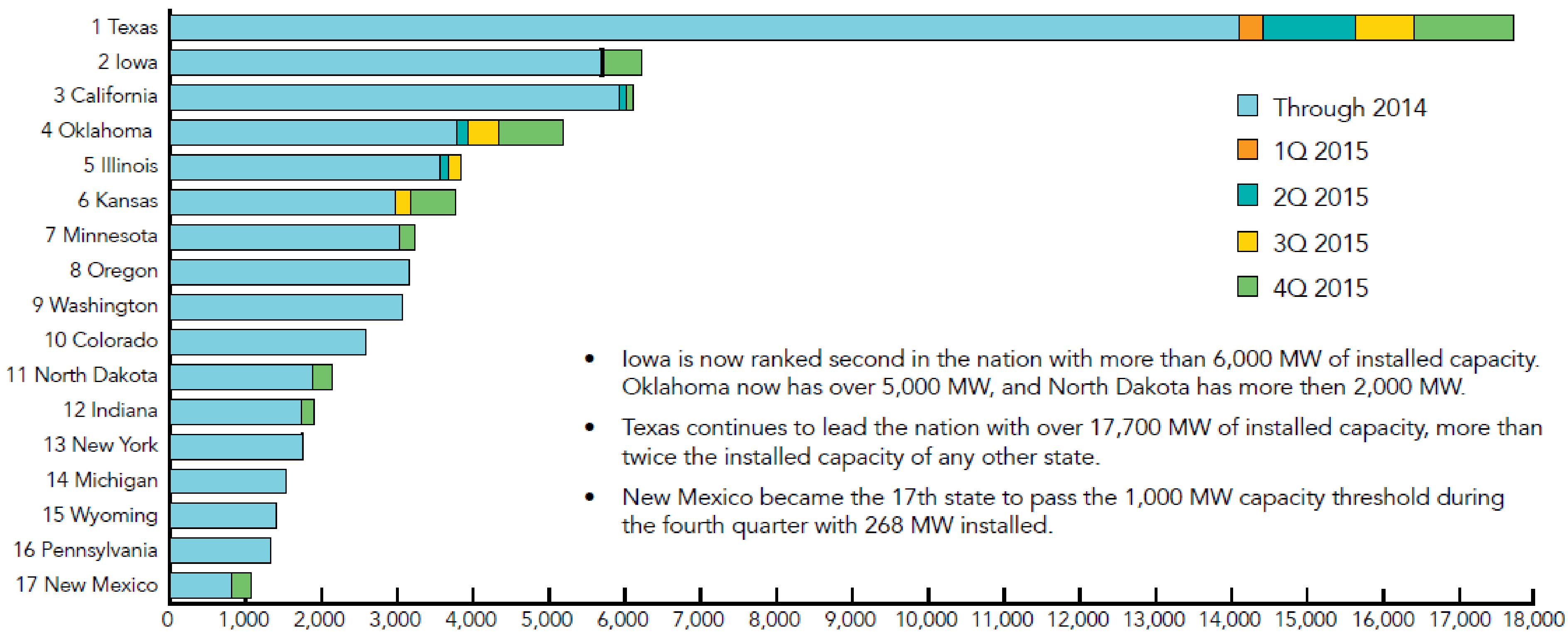
Data provided by the Lawrence Berkeley National Laboratory shows:*

- 44,000 MW of "non-RPS-related" renewable additions nationwide account for 44% of total renewable generation additions for 2000–2015 (59% in 2015)
  - 80% of these non-RPS-related renewable resource additions are wind generation
  - 77% of non-RPS-related renewable additions in 2000–2015 happened in seven states (TX, IA, OK, CA, KS, IL, IN) all of which have ISO-operated markets
  - In 2015, these seven states accounted for 88% of all non-RPS-related renewable additions
- 35,000 MW of non-RPS-related wind additions account for 49% of all wind additions in 2000–2015 (76% in 2015)
  - 80% of non-RPS-related wind additions for 2000-2015 happened in six states with ISO-operated markets (TX, IA, OK, KS, IL, IN)
  - In 2015, these six states accounted for 95% of all non-RPS-related wind additions
- Example Texas:
  - 72% of ERCOT's 17,600 MW of wind capacity installed by the end of 2015 was added <u>beyond</u> RPS mandates
  - 7,690 MW of these non-RPS-related wind plants have been added in the last 5 years
  - Transmission, improved wholesale market design, and liquid forward markets allowed ERCOT to attract over 1,400 MW of pure "merchant" wind projects in 2014**

* Source: Dr. Galen Barbose LBNL (2016). ** LBNL Wind Technology Report (2015)

States with Most Wind Additions are in ISO Markets

- The seven states with the highest total installed wind generating capacity (TX, IA, CA, OK, IL, KS, MN) are all located in areas with regional ISO markets*
- Highest 2015 additions in lowest-cost locations with ISO markets (e.g., TX, OK, KS, IA)



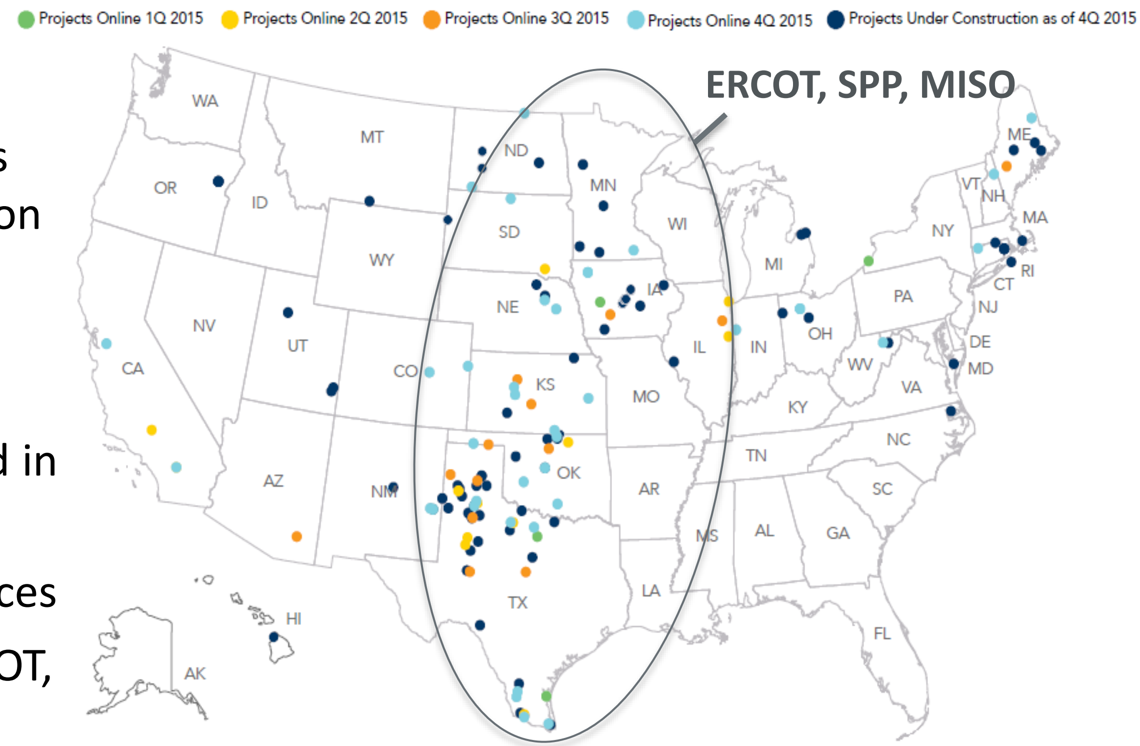
* Source: http://awea.files.cms-plus.com/FileDownloads/pdfs/4Q2015%20AWEA%20Market%20Report%20Public%20Version.pdf

2015 Wind Additions and Construction

Wind-rich areas with ISO markets show high market-based renewables development

- AWEA data shows that the majority of the 2015 additions and projects under construction (shown on this map) was not related to RPS requirements
- The map shows that <u>most</u> of these 2015 additions occurred in areas that offer <u>both</u>
  - Low-cost renewable resources
  - ISO-operated markets (ERCOT, SPP, MISO)
- Little market-based (non-RPS) development in WECC today

2015 Wind Generation Additions and Projects under Construction

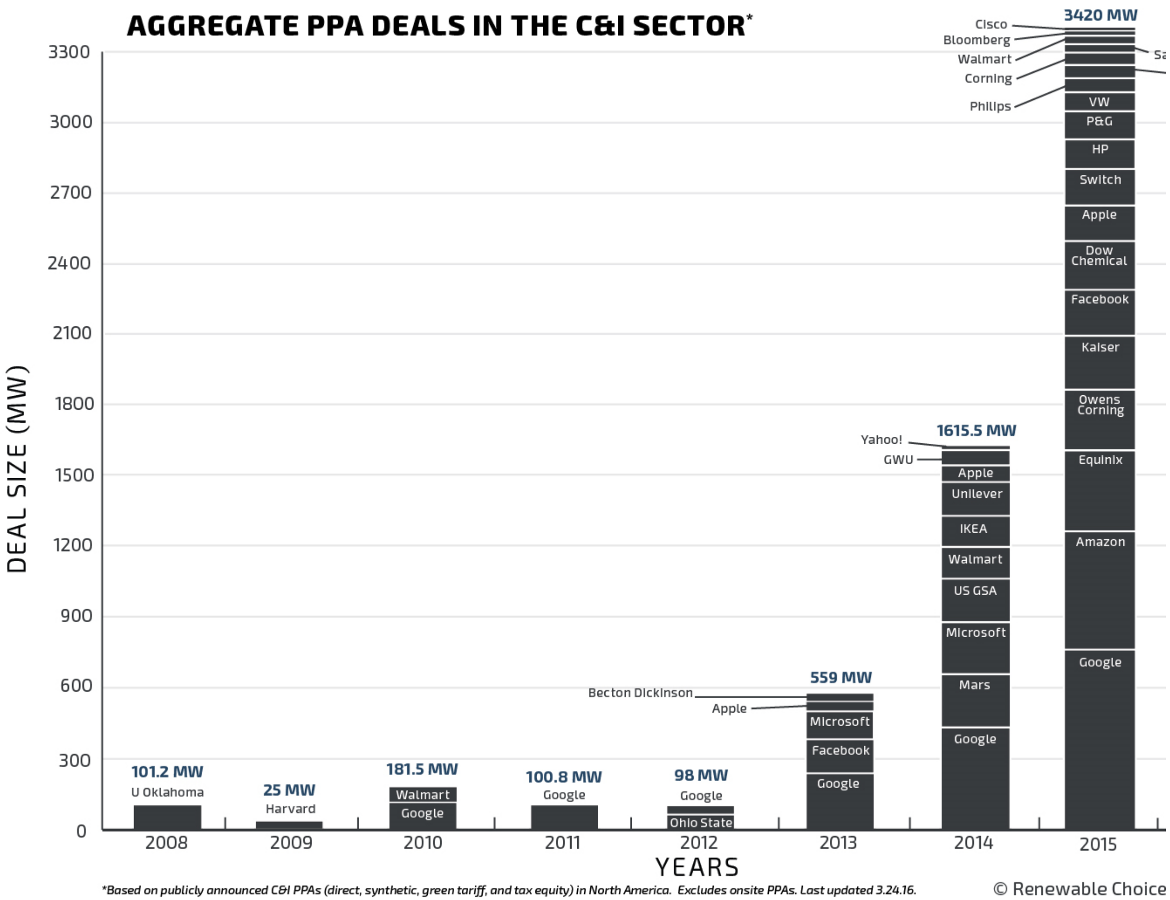


American Wind Energy Association | U.S. Wind Industry Fourth Quarter 2015 Market Report | AWEA Public Version

* Source: http://awea.files.cms-plus.com/FileDownloads/pdfs/4Q2015%20AWEA%20Market%20Report%20Public%20Version.pdf

Renewable PPAs with Commercial/Industrial Customers

- In 2015, 3,420 MW of low-cost wind resources were developed through PPAs with large C/I customers (up from 1,615 MW in 2014 and 559 MW in 2013)*
  - These C/I contracts are greatly facilitated by regional ISO-operated markets**



* Source: http://www.renewablechoice.com/blog-corporate-energy-buyer/

** For a discussion see: http://www.renewablechoice.com/blog-electricity-corporate-ppa-buyers/

Merchant Renewable Development

- Renewables-rich regions with liquid wholesale power markets support "merchant" developers to finance their renewable projects by relying on financial hedges (instead of PPAs)*
  - Merchant projects accounted for 33% of all new wind generating capacity and 23% of cumulative capacity in 2014 (compared to 25% in 2013 and approx. 20% in each of the three years from 2010–2012)
  - All of the merchant wind generation capacity built in 2014 is located in ISO-operated regional markets (mostly Texas) with:
    - Ready access to liquid trading hubs,
    - Low-cost renewable resources
    - Sufficient transmission infrastructure
    - High correlation between natural gas and electricity market prices that allows for long-term financial hedging through natural gas market

* Source: LBNL 2014 Wind Technology Report (https://emp.lbl.gov/sites/all/files/lbnl-188167.pdf)

Factors Contributing to Increased Renewables Penetrations in ISO/RTOs

Main factors lead to increased support for renewables in ISO/RTO markets

Factor	Description
Improved Market Designs	• Increased granularity in time (5-minute) and location (nodal) improves price signals and stimulates efficient transmission and generation investment • Increased granularity increases the ability of prices to reflect avoided cost and improves dispatch of low carbon resources • ISO/RTO markets provide a mechanisms for non-transmission owners (such as most renewables developers) to hedge against congestion
Larger Markets	• The larger geographic reach of ISO/RTO markets allows the development of renewable resources in lower-cost locations • Allows a larger set of low-cost resources to provide balancing services for renewables • Large footprints of ISO/RTO markets reduce balancing costs by taking advantage of the diversity of renewables output • Liquidity of RTO spot markets further reduces the cost of addressing wind's variability and uncertainty compared to illiquid markets
Transparency, Open Access, and Fairness	• Fair, transparent pricing rules give confidence to investors • Markets reduce the potential for conflicts of interest in selecting new transmission projects and allocating the costs of these projects • ISO/RTOs help promote Open Access to transmission, which is particularly important to the largely independent producers who develop renewables

Quotes from Studies of Markets Facilitating Renewable Generation Development

Brookings: Clean Economy Study (2011)

- "In addition to its role in lowering prices, the ISO/RTO model is more conducive to clean energy because the market shares generation and transmission over a larger geographic area and harbors fewer conflicts of interest in expanding capacity to accommodate new renewable generators or in allocating costs to market participants" (p. 36)

Hogan: Markets In a Low Carbon Future (2010)

- "In the US, installations of wind energy are disproportionately found in the RTO markets because of the greater ease of integration " (p. 10)

ISO/RTO Metrics Report (2015)

- "Open access to the grid and competitive wholesale electric markets have facilitated the increased development of renewable energy projects" (p. 261)

IRC: Increasing Renewables (2007)

- "Four features of these large wholesale electricity markets play an especially critical role in the development of renewable resources."

Studies of Markets Facilitating Renewables

Study	Finding
Brookings Clean Economy Study (2011)	• ISO/RTOs facilitate renewables through geographic diversity • ISO/RTOs also reduce barriers to expanding transmission capacity to allow additional renewables
AWEA Green Power Superhighways (2009)	• Markets that incentivize flexibility minimize the cost of integrating renewables • RTOs have been more effective in administering large balancing areas, using short scheduling intervals, and operating sophisticated energy markets
Hogan Markets In a Low Carbon Future (2010)	• Wind installations are disproportionately in RTO markets • Markets facilitate integration of low-carbon technology through improved granularity of pricing and dispatch
COMPETE Markets and Environmental Challenges (2014)	• Renewables developers are attracted to ISO/RTO markets due to transparency, fairness of rules, and geographic diversity
ISO/RTO Metrics Report (2015)	• ISO/RTOs facilitate renewables by establishing simple interconnection processes for new resources, providing access to spot markets, and allowing resources to take advantage of geographic diversity
IRC Increasing Renewables (2007)	• ISO/RTO markets facilitate renewables by having transparent pricing, highly granular dispatch, and geographic diversity

Appendix C

Load Diversity Benefits

Load Diversity Savings: Transmission Constraints

Potential savings are limited by transmission

- To achieve savings, capacity must be transferred on peak
- Transmission constraints limit these transfers

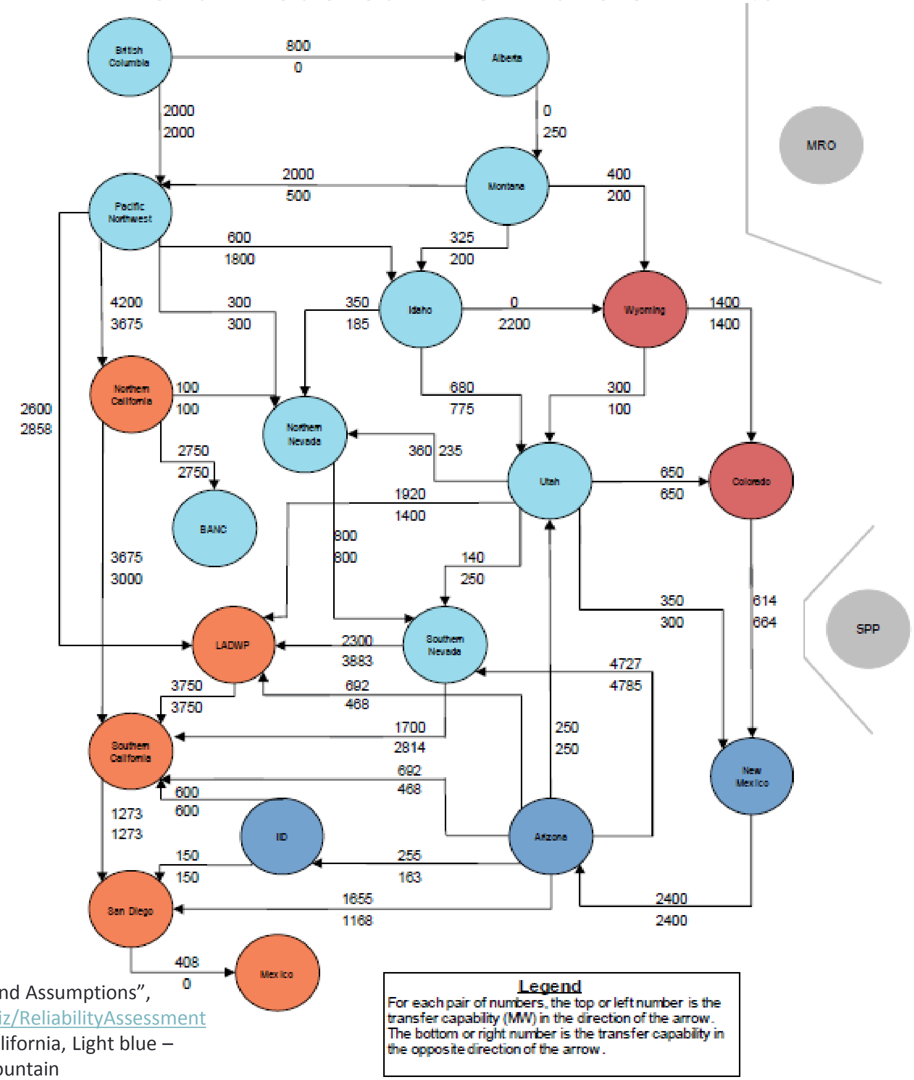
For 2020 PAC-ISO Scenario:

- ISO to PAC: 776 MW
- PAC to ISO: 982 MW

For 2030 Regional Scenarios: transfer capabilities from WECC LAR zonal model

- Provides summer and winter transfer limits between 19 zones in the WECC
  - Used the lower of the two seasonal limits, which usually occurs in the summer
- Relied on capacity of single largest intertie into each BA as very conservative proxy for simultaneous limit

LAR Zonal Model Summer Transfer Limits



Sources and Notes:
Table 4 of WECC, "Loads and Resources Methods and Assumptions", November 2015, Available at: https://www.wecc.biz/ReliabilityAssessment
Zone colors correspond to subregions: Orange – California, Light blue – Northwest, Dark blue – Southwest, Red – Rocky Mountain

2020 Load Diversity Savings: ISO-PAC

Estimated 2020 savings are consistent with those found in ISO-PAC Integration Study

- Slightly reduced savings for Current ISO are primarily due to slightly higher coincidence factor
- Slightly higher savings for PAC are primarily due to use of BAA load rather than PacifiCorp utility load

		Current ISO	PacifiCorp	ISO+PAC Total
Capacity Requirement	[1]	115.0%	113.0%	
Non-Coincident Peak (MW)	[2]	47,010	13,234	60,244
Median Coincidence Factor	[3]	99.7%	92.2%	
BA's Share of Regional Market Peak (MW)	[4]	46,849	12,201	59,050
Potential Capacity Savings (MW)	[5]	184	1,168	1,352
Maximum Transmission Import Capability (MW)	[6]	982	776	
Savings w/ Current Transmission (MW)	[7]	184 (0.39%)	776 (5.86%)	960
Savings Requiring Transmission Upgrades (MW)	[8]	- (0.00%)	392 (2.96%)	392
Avoided Cost of Capacity Savings ($/kW-yr)	[9]	$35	$0-$39	
Total $ Savings ($ million/year)	**[10]**	**$6**	**$0-$30**	**$6-$37**

Sources and Notes:
[1]: Based on PacifiCorp 2014 IRP and CAISO published Reserve Margins.
[2]: Forecast 2020 Non-Coincident Peak Loads. ISO from 2015 IEPR, equal to CEC 'Mid Baseline Case.' PacifiCorp from 2015 LAR Peak and Energy forecast, PACE + PACW coincident peak.
[3]: Median of annual coincidence factors calculated based on 4CP of hourly load profiles from 2006 to 2014.
[4]: [2] * [3]
[5]: [1] * ([2] - [4])
[6]: Contracted import capability for the ISO and PacifiCorp.
[7]: Minimum of [5] and [6]
[8]: [5] – [7]
[9]: ISO's value reflects 2012-2016 weighted-average contract prices. High end of PacifiCorp rang reflects capacity cost net of energy margins for two units as reported in the 2015 IRP. The low end reflects the fact that these units are not expected to come online before 2020.
[10]: [9] * [7]

2030 Load Diversity Savings: US WECC w/o PMAs

		California	Rest of Region
Capacity Requirement	[1]	115%-116.1%	75%-116.1%
Sum of BA Non-Coincident Peaks (MW)	[2]	57,188	85,302
Effective Coincidence Factor (Coincidentwith Subregion Peak)	[3]	99.2%	94.2%
Sum of BA Peak Loads Coincident with Subregion Peak (MW)	[4]	56,747	80,364
Potential Savings: Sharing Within Subregions (MW)	[5]	508	5,703
Savings Already Captured (Estimated) (MW)	[6]	-	4481
Incremental Savings w/ Current Transmission: Sharing Within Subregions (MW)	**[7]**	**363**	**604**
Savings Requiring Transmission Upgrades (MW)	[8]	145	618
Effective Coincidence Factor (Coincident with WECC-PMAs peak)	[9]	98.1%	96.3%
Estimated Load Coincident with WECC Peak (MW)	[10]	55,676	77,415
Potential Savings: Sharing Across Subregions (MW)	[11]	1,231	3,385
Incremental Savings w/ Current Transmission: Sharing Across Subregions (MW)	**[12]**	**1,231**	**2,060**
Savings Requiring Transmission Upgrades (MW)	[13]	-	1,324
Total Savings Requiring Transmission Upgrades (=[8] + [13]) (MW)	[14]	145 (0.25%)	1,942 (2.28%)
Total Savings w/Current Transmission (=[7] + [12]) (MW)	[15]	1,594 (2.79%)	2,665 (3.12%)
Avoided Cost of Capacity Savings ($/kW-yr)	[16]	$75	$100
Total Avoided Cost w/Current Transmission ($ million/yr)	**[17]**	**$120**	**$266**

Sources and Notes:
[1]: Range of capacity requirements based on WECC-determined reserve margin levels as reported in 2015 NERC LTRA.
[2]: Sum of forecast BA Non-Coincident Peaks in 2030.
[3]: [4] / [2]
[4]: Sum of BA loads during subregion peaks
[5]: [1] * ([2] - [4])Effective capacity requirement from [1] is an average of the BA capacity requirements, weighted by the BA contributions to capacity savings
[6]: Capacity savings already achieved by BAs based on internal reserve margins.
[7]: Savings achievable with current transmission into each BA.
[8]: Savings requiring additional transmission based on within-subregion transmission limits in WECC LAR zonal model.
[9]: [10] / [4]
[10]: Sum of BA loads during WECC peak
[11]: [1] * ([4] - [10]). Effective capacity requirement from [1] is an average of the BA capacity requirements, weighted by the BA contributions to capacity savings
[12]: Savings achievable with current transmission into each subregion.
[13]: Savings requiring additional transmission based on across-subregion transmission limits in WECC LAR.
[14]: [8] + [13] ([14] / [2])
[15]: [7] + [12] ([15] / [2])
[16]: $75/kW-yr for California reflects no new builds by 2030, $100/kW-yr for reflects estimated Balancing Authorities and $100/kW-yr for rest of region reflects net cost of new entry
[17]: [15] * [16]

Appendix D

Review of Other Market Integration Studies

Review of Market Integration Studies

We leveraged insights from relevant existing studies to inform the analysis and provide bookends to estimated impacts

Study Type	Examples of Studies
Day-2 Market Studies Evaluate benefits of moving from de-pancaked transmission and energy imbalance market to full Day-2 market	SPP IM Retrospective (2015), SPP IM Prospective (2009), Navigant Markets Study (2009), Chan Efficiency Study (2012), MISO Value Proposition (2015), MISO Retrospective Study (2009), Wolak Nodal Study (2011), NYISO Plant Efficiency Study (2009), ERCOT Nodal Study (2014)
RTO Participation Studies Evaluate benefits and costs to a utility of joining an existing RTO	E3 PAC Integration Study (2015), Basin/WAPA Study (2013), Entergy-MISO (2011), SPP/Entergy Cost-Benefit Analysis (2010), Mansur PJM Efficiency Study (2012)
Post Order 2000 Studies Benefit-cost studies of forming RTOs that followed issuance of FERC Order 2000 in late 1999	LBNL RTO Review Study (2005), RTO West Study (2002), National RTO Study (2002)
Energy Imbalance Market (EIM) Studies Evaluate the benefits of the Western EIM, or the benefits of a utility joining the EIM	WECC-Wide EIM (2011), APS-EIM (2015), PGE-EIM (2015), NV Energy-EIM (2014), Puget Sound-EIM (2014), PacifiCorp-EIM (2013)
European Market Integration Studies Evaluate the benefits of market integration in the European context	EPRG Integrating European Markets (2015), EU Single Market Study (2013)
WECC Renewable Integration Studies Studying the challenges of higher penetration of renewable resources	NREL/DOE WWSIS 2 (2013), NREL/DOE WWSIS 3 (2014), CEERT/NREL Low Carbon Grid Study (2016), CAISO/GE Stability Study (2011), WGA Least-Cost Integration (2012), SPP Renewable Integration (2016)
Markets and Merchant Renewables Studies Discussing the function of markets in facilitating renewables development	Brookings Clean Economy Study (2011), AWEA Green Power Superhighways (2009), Hogan Markets In a Low Carbon Future (2010), COMPETE Markets and Environmental Challenges (2014), ISO/RTO Metrics Report (2015), IRC Increasing Renewables Study (2007)

Relevance of Other Regional Market Studies

- While most other studies analyzed markets different from those in California and the West, they offer relevant information and helpful reference points
- They employ analytical frameworks very similar to those used in this SB350 study
- The studies show that magnitude of benefits from regionalizing markets is generally consistent across the various regions, circumstances, and time periods
- Some studies analyzed circumstances similar to those explored in this SB350 study
  - The SPP Retroactive study (2015) studied benefits of moving from energy imbalance market to full Day-2 market
    - SPP resembles WECC (on a smaller scale) with major load centers in one portion of the footprint (the southeast) and distant areas with low-cost generation (the Great Plains)
  - WAPA/Basin RTO integration study (2013) explored benefit of regional market participation to entities similar to those found in WECC
  - Entergy-MISO study (2011) analyzed benefit of an expansion of regional market
- A few of the reviewed studies specifically focused on WECC and explored benefits of improved regional market design and renewable integration

Findings from Other Regional Market Studies

Two general types of studies: Prospective and Retrospective Studies

- Most **prospective market integration studies estimated production cost savings from implementing regional energy markets at 1–3%** of total production costs (including when starting from EIM-type markets)
  - Studies generally evaluated Day-2 market features (day-ahead energy, real-time energy, and ancillary services markets) with full de-pancaking of transmission charges for all transactions (not just EIM)
  - Savings associated with unit commitment and day-ahead dispatch
- Most **prospective studies also emphasize their limitations**, which tend to not capture certain benefits and underestimate the overall benefits:
  - Studies generally analyze only normal weather, hydrology, load, and generation and do not consider the effects of transmission outages
  - Most studies do not assess benefit of improved management of uncertainties between day-ahead and real-time operations
  - Only some studies analyzed more efficient utilization of the existing grid
  - Only some studies assessed improvements in generator efficiency and availability

Findings from Other Regional Market Studies

- Most **retrospective studies of market integration benefits document higher benefits** than those estimated in prospective studies
  - Production cost savings of 2–8%
  - Higher impact confirms limitations of prospective studies
- In addition to production cost savings, **studies document that market integration can reduce investment costs** associated with:
  - Reduced need for generating capacity and associated investment costs
  - Improved access to lower-cost renewable resources and reduce the investment costs of meeting RPS goals
  - Reduced balancing resources to address variable renewable generation output

Overall Benefits Documented in Other Studies

Type of Benefit		Estimated Savings as % of Total Production Costs
Savings Captured by Real-Time Energy Imbalance Markets (similar to EIM)	[1]	0.1% – 1%
Other Production Cost Savings Estimated by Prospective Studies	[2]	0.9% – 2%
Total Production Cost Savings Estimated by Prospective Studies	**[3]**	**1% – 3%**
Plant Efficiency and Availability Improvement	[4]	2% – 3%
Additional Real-Time Savings (Considering Daily Uncertainties)	[5]	1% – 2%
Additional Operational Savings with High Renewables	[6]	0.1% – 1%
Total Additional Production Cost Savings Estimated by Some Studies	**[7]**	**3.1% – 6%**
Load Diversity Benefits (Generation Investment Cost Savings)	[8]	1% – 1.4%
Renewable Capacity Cost Savings	[9]	1% – 4%
Total Investment Cost Savings (Expressed as Equivalent to % of Production Costs)	**[10]**	**2% – 5.4%**
Total Overall Savings as Share of Total Production Costs	**[11]**	**6% – 13%**

[1]: Range from E3's utility-specific and WECC-wide EIM studies
[2] = [3] – [1] Includes benefits of Transmission Charge De-Pancaking and Day Ahead Markets in all studies, Ancillary Service Markets in some studies, and Full Real Time Benefits and Improved Transmission Utilization in some studies
[3]: Based on summary table for prospective studies (see Appendix)
[4]: Based on Chan et al. (2012)
[5]: Difference between savings in retrospective studies and sum of savings in prospective studies and efficiency and availability savings
[6]: Low end of range based on "Overgeneration Management" savings in PAC Integration study. High end based on savings of "Enhanced Flexibility" in high renewables scenario in NREL Low Carbon Grid study.
[7] = [4] + [5] + [6]
[8]: Low end of range based on the PAC Integration study. High end based on average of savings from the PAC Integration, National RTO, and Entergy/SPP MISO studies.
[9]: Based on reduced resource cost estimated in PAC Integration study.
[10] = [8] + [9]

The CEERT/NREL Low Carbon Grid Study (2016)

- NREL studied the impacts on the Western power grid and costs of California pursuing a goal of reducing 2030 CO_2 emissions from California's electric power sector by 50% relative to 2012 levels
  - Goal is reach a 2030 emission level of 48 million metric tons/year
  - The study found that a 50% CO_2 emissions reduction goal requires the development of <u>56% renewable generation</u>, increased energy efficiency, and the retirement of all California-contracted (out of state) coal plants
  - Evaluated the production costs impacts of achieving this level of renewable generation development for (1) a "conventional flexibility" case reflecting current grid operating practices; and (2) a "enhanced flexibility" case based on operation and institutional that (<u>similar to the flexibility provided by regional market</u>) eliminates the need to physically import contracted resources and provides for higher operating flexibility
- Estimated production cost savings from enhanced trading and system flexibility:
  - 2030 WECC-wide production cost savings of \$440-610 million/year (1.5-2.1% of total production costs) moving from conventional to partially/fully enhanced flexibility (see Appendix D)
  - \$550 million/yr reduction in 2030 CA power production, purchase, and sales costs
  - Savings are much higher in scenarios with high penetration of renewables

Other Regional Market Impact Studies

Production Cost Savings Estimated by Prospective Studies

Market Design Features Captured in Production Cost Savings	National RTO (2002) [1]	LBNL Review (2005) [2]	RTO West (2002) [3]	SPP Prospective (2009) [4]	Basin/ WAPA (2013) [5]	Entergy SPP/MISO (2011) [6]	E3 PAC Integration (2015) [7]
Transmission Charge De-Pancaking	✓	✓	✓	✓	✓	✓	✓
Day-Ahead Market		✓		✓	✓	✓	✓
Full Real-Time Imbalance Market	✓	Varies	✓		✓	✓	Varies
Ancillary Services Market		Varies	✓	✓			Varies
Improved Transmission Utilization	✓	Varies	✓			✓	Varies
Generator Efficiency and Availability Improvements	✓	Varies					Varies
% Reduction in Total Production Costs	**0.3%–5%**	**<1% to 8%**	**Not Reported**	**1.3%–2.0%**	**0.9%–2.1%**	**3.4%–3.8%**	**1.6%–3.6%**

[1]: The range represents savings in the "Transmission Only" scenario (de-pancaked transmission charges and increased transmission capacity) on the low end and "RTO Policy" scenario (includes 6% efficiency and 2.5% availability improvement for fossil units) on the high end. This study used a single-stage dispatch model to estimate benefits. It did not model unit commitment.

[2]: This was a study review report. Studies in the review modeled different market designs. Inter-quartile range of reported savings was 1%–3%. Some of the reviewed studies reported other savings in addition to production cost (*e.g.*, congestion revenues).

[3]: Study did not provide baseline production costs, so % savings could not be calculated.

[4]: Total production cost savings over 2009–2016 time horizon with low end of range from across case I (DA market-only) and high end from case IIB (DA + AS markets).

[5]: WAPA 'Enhanced Adjusted Production Cost" savings of joining SPP as a percentage of "Standalone" LMP-based charges. Range reflects 2013–2020 savings.

[6]: Range reflects Entergy adjusted production cost savings of joining SPP and MISO as estimated using production cost simulation. Savings do not include spinning and regulation reserve savings estimated using MISO's Value Proposition methodology.

[7]: This was a study review. Studies in the review modeled different market designs.

Other Regional Market Impact Studies

Benefits Estimated by Retrospective Studies

Study	Region	Metric	Savings
MISO Retrospective Study (2009)	MISO	Production Cost Savings	1.4% Implementing a regional, de-pancaked bilateral market + 2.6% Consolidating BAs and implementing nodal DA, RT, and AS markets = 4.0% Total
SPP IM Retrospective Study (2015)	SPP	Production Cost Savings	3.2% Implementing a de-pancaked regional imbalance energy market (EIS) + 4.8% Consolidating BAs and implementing nodal DA, RT, and AS markets Markets), = 8.0% Total
MISO Value Proposition Report (2015)	MISO	Reduced production costs, generation investment needs, wind integration cost; improved reliability; net of MISO costs	Total of $2.1–$3.0 Billion/year
Wolak Nodal Study (2011)	CAISO	Production cost savings	2.1% Moving from de-pancaked zonal Day-2 market to full nodal DA, RT, and AS markets
ERCOT Nodal Study (2014)	ERCOT	Wholesale power price reductions	2.0% Moving from de-pancaked zonal Day-2 market to full nodal DA, RT, and AS markets
Navigant Markets Study (2009)	PJM, MISO, and NYISO	Improved Availability of Nuclear Units and Heat Rates of Large Coal Units	Nuclear Unit Availability Increased from 81% to 93% and Large Coal Unit Heat Rates Improved by 9.4% from 1998 to 2007
Chan Efficiency Study (2012)	U.S.	Improved Heat Rates of Large Coal Units	2%–3% increase in restructured markets compared to non-restructured regions
NYISO Plant Efficiency Study (2009)	NYISO	Improved Heat Rates of Fossil Fueled Units	21% Improvement in market-wide heat rates from 1999 to 2008
Mansur PJM Efficiency Study (2012)	PJM	Gains from Trade (due to PJM expansion in 2004)	Gains from trade were $163 million (48%) higher in the first year of organized markets compared to a bilateral market

Load Diversity Benefits

Several other studies estimated load diversity capacity savings in the range of 0.6–8% of peak load

- MISO and Entergy confirmed 6–7% capacity savings in their retrospective analyses[1,4]
  - Confirms estimates for capacity savings made in prospective studies
- PAC Integration also accounted for transmission limitations

Load Diversity Capacity Savings in Other Studies

Study	Reported Capacity Reduction (% of Peak Load)	Note
MISO 2015 Value Proposition[1]	**6%–7%**	Capacity savings to all MISO members of participating in the RTO market
Entergy SPP/MISO (2011)[2]	**6%**	Capacity savings to Entergy of joining MISO
E3 PAC Integration (2015)[3]	**0.6% (ISO)** **8% (PAC)**	Capacity savings with an integrated market consisting of the California ISO (ISO) and PacifiCorp (PAC)

Sources and Notes:

1. MISO, "2015 Value Proposition Stakeholder Review Meeting," January 21, 2016, Available at: https://www.misoenergy.org/WhatWeDo/ValueProposition
2. Entergy, "An Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies And Support for Proposal to Join MISO," May 12, 2011, Available at: http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=bc5c1788-4ce0-4daa-9ad0-71f09ad43643
3. Energy + Environmental Economics (E3), "Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration," October 2015, Available at: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx
4. Entergy, "Estimate of MISO Savings," Presented by: Entergy Operating Companies, August 2015, Available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/ICT%20Materials/ERSC/2015/20150811/20150811%20ERSC%20Item%2006%20Benefits%20of%20MISO%20Membership.pdf

Other Regional Market Impact Studies

Production Costs in CEERT/NREL Low Carbon Grid Study

Study also analyzed WECC-wide production costs:

- "Baseline" (33%) and "Target" (56%) California renewables, with rest of WECC at 16% renewables
- Significant savings from "Enhanced" over "Conventional" operational flexibility

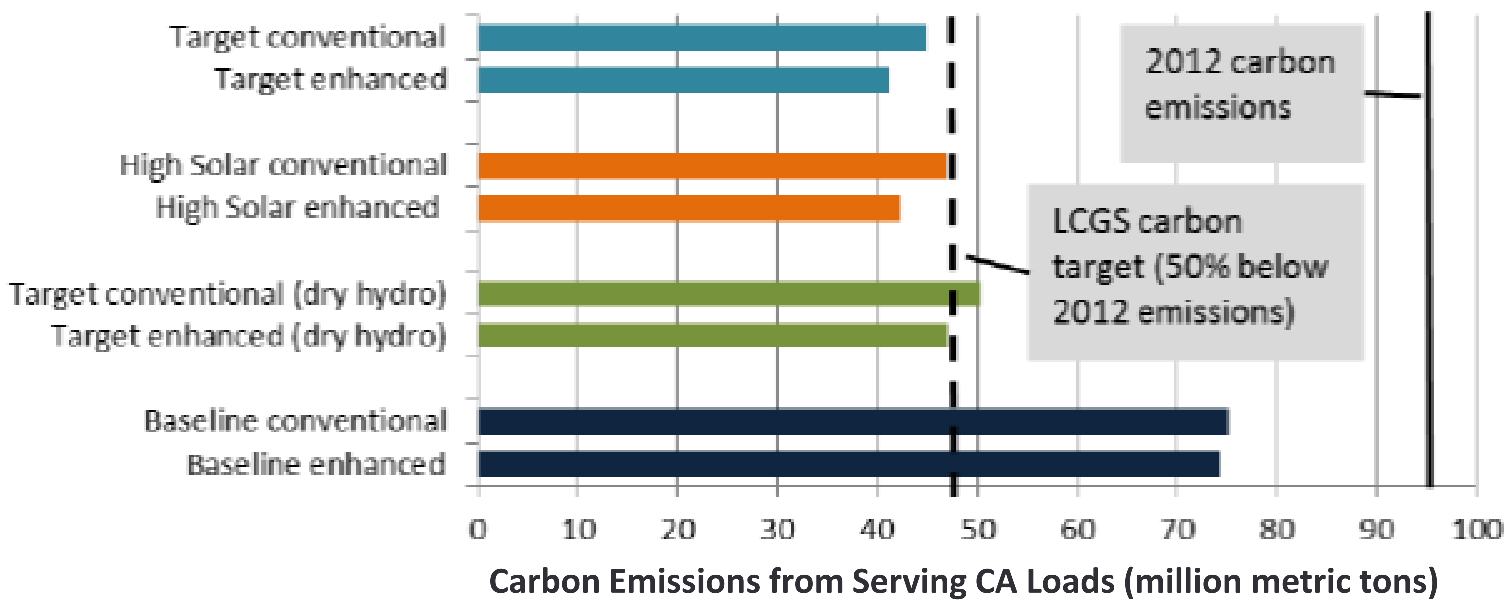
	Renewables Penetration	70% Import Requirement for CA RPS Resources	Limited AS from Hydro	Minimum 25% Energy from Local Thermal and Hydro in CA BAs	Total WECC Production Cost ($ millions)
Baseline (33% CA RPS), Conventional Flexibility [1]	33%	✓	✓	✓	$33,760
Baseline (33% CA RPS), Enhanced Flexibility [2]	33%				$33,660
Estimated Production Cost Savings of Regional Markets with 33% California Renewables as Difference between [1] Conventional Flexibility Case (as approximation of bilateral markets) and [2] Enhanced Flexibility Case (as approximation of an ISO-operated regional market)					***$100 0.3%***
Target (56% CA renewables), Conventional Flexibility [3]	56%	✓	✓	✓	$29,430
Target (56% CA renewables), Partially Enhanced Flexibility [4]	*56%*		✓	✓	*$28,990*
Target (56% CA renewables), Enhanced Flexibility [5]	56%				$28,820
Estimated Production Cost Savings of Regional Markets with 56% California Renewables as Difference between [3] Conventional Flexibility Case (as approximation of bilateral markets) and [5] Enhanced Flexibility Case (as approximation of an ISO-operated regional market)					***$610 2.1%***

Note: The Target, Enhanced Flexibility scenario [5] includes additional storage in excess of the CPUC mandate (mandated storage is included in all scenarios) in the form of a 1 GW of pumped hydro facility in California and a 1.2 GW compressed-air energy storage facility in Utah. We also reported production costs in the Target, Partially Enhanced Flexibility scenario [4] (which has only mandated storage). Production costs with full Enhanced Flexibility, but no additional storage (a scenario not examined in the study), should be no larger than this.

Emissions in CEERT/NREL Low Carbon Grid Study

The Low Carbon Grid Study also reports WECC-wide and CA GHG emissions for several study cases:

- 2030 "Baseline" cases with 33% CA RPS
- 2030 "Target" cases with 56% CA RPS (to yield a 50% emissions reduction)
- Cases with "Conventional" flexibility (as a proxy for current practices) and "Enhanced" flexibility (similar to the flexibility provided by a regional market)
- Additional sensitivity cases (Dry Hydro, High Solar, High WECC RPS)



Emissions in CEERT/NREL Low Carbon Grid Study

GHG emissions as reported in CEERT/NREL Low Carbon Grid Study

Table 10. Annual Carbon Accounting, in Million Metric Tons (MMT)

Scenario	CO_2 from CA gas generators	CO_2 assigned to imports and exports	CO_2 assigned to CA load	Change in assigned California CO_2 emissions compared to Baseline	Total* WECC CO_2 emissions	Change in WECC CO_2 emissions compared to Baseline
Baseline Enhanced	67.7	6.7	74.4	-	380.9	-
Baseline Conventional	68.9	6.3	75.2	0.8	381.0	0.2
Target Enhanced	43.7	-2.5	41.1	-33.2	345.1	-35.8
Target Conventional	48.9	-3.9	45.0	-29.4	349.3	-32.4

- Exports in this context include both net exports and specified imports that are not imported. This is zero-carbon energy that is sold out of state.
- Total WECC emissions not only include the western United States but also parts of Mexico and Canada (Alberta and British Columbia).
- Unspecified imports and exports are assumed to have a 0.432 MT/MWh carbon penalty (or credit). Unspecified imports from the Northwest have a penalty of 20% of 0.432 MT/MWh, which is consistent with the California Air Resources Board 2012 assumptions (CARB 2014) and the California ISO LTPP modeling (Liu 2014). CARB uses 0.022 MT/MWh for data year 2015.

* Coal plant retirements as reported in TEPPC 2022 Common Case plus Intermountain

Appendix E

Reliability Impacts

Detail on Reliability Impacts

	Function	Western Interconnection Operations/Standard Practice	Regional Operations/ISO Practice
1	Locational 5-Minute Real-Time (and Hourly Day-Ahead) Price Signals	Bilateral markets achieve reliability based on contractual rights and industry standards with little guidance from locational prices or focus on economic impacts	• ISO enhances reliability by informing all market participants on the state of grid conditions and market operations through locational electricity prices and the day-ahead and real-time posting of other key system information • As a reflection of actual real-time (and projected day-ahead) system conditions, market prices in the ISO energy market provides specific locational signals where more (or less) generation is needed to maintain reliability
2	Congestion Management	• Performed using WECC Unscheduled Flow Mitigation Procedure or internally developed operating procedure based on congestion management system • 30 – 60 minute response time	• Market-based congestion management that relies on a five minute security constrained economic dispatch to mitigate transmission congestion on a least-cost basis allows for more timely and efficient congestion management • Look Ahead Commitment Tool provides unit commitments, de-commitments, online extension recommendations for congestion management, and models near-real-time conditions to utilize resource capabilities • Simultaneous feasibility tests performed to capture transmission security constraints in DA market processes, while Real-time contingency analysis of Energy Management System provides real-time security constraints for real-time clearing and pricing
3	Unscheduled Flow Management	• Unscheduled flows are managed sub-optimally on a limited set of qualified paths	• A regional integration allows congestion management to more effectively manage unscheduled flows in the entire grid and also solve the related congestion
4	Regional Unit Commitment	Decentralized unit commitment decisions without region-wide perspective and differing granularity can lead to inconsitencies and unintended reliability	Regional unit commitment to address footprint-wide reliability needs: • Advisory 2-day ahead process • Multi-day residual unit commitment (RUC) • Regional Reserve Requirements Calculation • Day-Ahead RUC • Intra-Day RUC

Detail on Reliability Impacts (cont'd)

	Function	Western Interconnection Operations/Standard Practice	Regional Operations/ISO Practice
5	Sytem Monitoring and Visualization	• Real-time monitoring using SCADA on a local area basis (Some has limited Real Time Contingency Analysis) • Use of standard vendor supplied displays • Operator interface of standard monitor display screen augmented with static map board (some has digital dynamic map board) • Ad-hoc and off-line voltage security analysis review	• Regional view/monitoring of the power system including: – A State Estimator - runs every 60 seconds – Contingency analysis of over 2000 contingencies every five minutes that is scallable to higher number of contingencies – 24-hour shift engineer coverage responsible for maintaining security application performance - Advanced real-time voltage stability and security application • Extended use of custom tools and displays to allow for faster analysis and better situational awareness • Large video wallboard (80 feet) that provides operators with live data reflecting the state of the power system and real-time market results • Real-time Voltage Stability Analysis Tool (VSAT) and Transmission Security Assessment Tool (TSAT), which allow comprehensive analyses of system operating conditions for predicting and preventing voltage insecurity and transient instability
6	Backup Capabilities	• Offline and/or scaled down backup facility • Significant time to bring backup facility up in the event a failover or failback is needed • Testing of failover process performed annually	• 24 x 7 staffed back-up control center • On-line back-up facility with full coverage of power system and market applications immediately available • Less than 30 minutes required for failover or failback for critical applications • Testing of failover process is performed quarterly for critical applications
7	Operator Training	• Classroom training only (some has limited simulators) • Train to meet minimum NERC requirements • Five-person rotation (no training rotation) and some has six person rotation • Offline power system restoration procedure review	• Training methods include extensive use of full-dispatch training simulator • Training exceeds NERC requirements • Six-person rotation at key operator positions (allowing a training week during each cycle) • Annually conduct a regional "live" power system restoration drill that includes dozens of companies in the region

Detail on Reliability Impacts (cont'd)

	Function	Western Interconnection Operations/Standard Practice	Regional Operations/ISO Practice
8	Performancve Monitoring	• Performance reviewed on a "post-event" basis • Operator call review on a "post-event" basis	• Daily review of operational performance including: – Frequent near-term performance feedback to operators and support personnel – Routine review of upcoming operational events • Standardized operator call review process • Feedback provided to each operator
9	Procedure Updates	• Procedures updated on an ad-hoc, as-needed basis	• Annual procedure review conducted on all control room procedures • Routine drills including member participation conducted on capacity emergency procedures • Annual Emergency Operating Procedures training session with members, neigboring entities, and reliability coordinator
10	Standards Development	• Utilities are varied in their approach to standards engagement. • Many are "standards takers," relying on the good judgment of others in the industry to develop standards	• By collaborating and participating in the standards creation, the ISO and its members can better manage the ultimate compliance responsibilities • ISO engages in several WECC/NERC drafting teams to actively manage the scope of standards development and to limit the number of changes required to MISO and stakeholders • ISO's integrated efforts lighten the workload on all members for a given level of input and control of the process
11	NERC Compliance	• Many parties in the WECC region are responsible for managing NERC compliance • 30+ Interchange Authorities, Transmission Service Providers, Balancing Authorities (BA) • Several Planning Authorities • Individual Reserve Sharing Groups	• With ISO as a regional balancing authority, many compliance responsibilities are consolidated (and member responsibilities decreased) • Single regional Transmission Service Provider • Significantly fewer BAs and related compliance requirements • Fewer Planning Authorities • Consolidated Reserve Sharing Administrator • Centralization of some Transmission Operator Requirements • Allows members to avoid hiring compliance-dedicated staff or reduce existing compliance-driven staff to track these compliance-related issues

Detail on Reliability Impacts (cont'd)

	Function	Western Interconnection Operations/Standard Practice	Regional Operations/ISO Practice
12	Regional Planning	• Planning by many individual utilities focused on local needs • Regional and interregional planning require complex coordination among many utilities and planning groups	• Single regional view and planning can address reliability needs more accurately and consistently • Offers opportunities to find most efficient solutions across multiple transmission owners
13	Fuel Diversity	• 38 WECC Balancing Areas with limited fuel diversity within many of the areas	• Regional market can mitigiate reliability risks associated with fuel supply risks (Gas, Hydro/Drought, Renewable Intermittency)
14	Long-Term Investment Signals	Bilateral markets provide less granular price signals which can result in less efficient investment and placement of generation resources and transmission infrastructure	Price signals sent by the ISO's market provides investors in generation assets with more economic signals upon which they can anchor their forecasts for future wholesale prices and provide the basis for market driven investments

Appendix F

Grid Management Charge

2020 Grid Management Charge Calculation

Entity	Forecast Load GWH	2*GWH [1]	Market Services Billing Determinant [2] (in thousands)	Revenue Cap (in millions)	Market Service [3]	System Operations [4]	Congestion Revenue Rights [5]	Total
ISO	229,724	459,448	528	$202	$0.1032	$0.3078	$0.0132	$0.42
ISO+PAC	298,777	597,544	687	$212	$0.0833	$0.2483	$0.0106	$0.34
R-ISO Exp.	654,068	1,308,136	1,504	$282	$0.0506	$0.1509	$0.0065	$0.21

1/ GMC is charged to both supply and demand

2/ Billing determinant = 2*GWH * 115%

3/ Market Services component is 27% of GMC based on cost of service allocation and is charged to market transactions (MW and MWH). Market Services rate = Annual Revenue Requirement * 27% / Billing Determinant

4/ System Operations component is 70% of GMC based on cost of service allocation and is charged to energy flows both supply and demand. System Operations rate = Annual Revenue Requirement * 70% / 2*GWH

5/ Congestion Revenue Rights component is 3% of GMC based on cost of service allocation and is charged to energy of congestion. Congestion Revenue Rights rate = Annual Revenue Requirement * 3% / 2*GWH