# Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration

## Technical Appendix

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Energy+Environmental Economics

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# 1 Introduction and Overview

This technical appendix documents the inputs and assumptions used to calculate quantitative benefit estimates, incremental to the EIM, reported in the study *Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration.*

The appendix is organized around the four incremental benefit categories quantified in the report: (1) more efficient unit commitment and dispatch, (2) lower peak capacity needs, (3) more efficient overgeneration management, and (4) renewable procurement savings. Each of these sections provides a brief description of the benefits, describes methods and approach, and provides a brief summary of results.

In addition to these sections focused on quantified incremental benefits, an initial section documents the assumptions on transmission transfer capability and renewable procurements savings that are common throughout the analysis. The two final sections describe interpolation assumptions that we use to calculate 20-year present value benefits reported in the study, and greenhouse gas emissions impacts.

# 2 Methods and Approach

## 2.1 General Assumptions

### 2.1.1 TRANSMISSION TRANSFER CAPABILITY

This study assumes transfer capability between the two systems of 982 MW in the PacifiCorp to California Independent System Operator (ISO) direction, and 776 MW in the ISO to PacifiCorp direction. Transfer capability assumptions are based on the amount of transmission rights currently held by PacifiCorp. However, it is possible that additional transfer capability may be available in an integrated PacifiCorp-ISO system. For instance, coordinated transmission planning could significantly increase the transfer capability between an integrated PacifiCorp-ISO system, which could increase the level of incremental benefits in this report.

### 2.1.2 RENEWABLE PROCUREMENT TARGETS

We assume that California load serving entities' (LSEs') procurement of renewable energy increases from 33% of total energy procurement in 2020 to 50% in 2030, as recently passed by the California legislature. We assume that the renewable procurement by California LSE's increases linearly between 2020 and 2024, resulting in a 40% RPS target in 2024. Renewable targets and goals for the other five states where PacifiCorp operates are assumed to remain at current levels.[1]

## 2.2 More Efficient Unit Commitment and Dispatch

### 2.2.1 OVERVIEW

Integration of the PacifiCorp and ISO systems is expected to bring operational efficiencies, incremental to the EIM, from optimized day-ahead unit commitment and co-optimized energy and ancillary services markets. These savings also result from having a larger pool of loads and resources that can reduce the lumpiness of unit commitment issues, as a percentage of total generation needed to serve load. This results in lower excess committed generation and higher efficiency in energy dispatch relative to the current two separate systems with business-as-usual operational practices.

### 2.2.2 ASSUMPTIONS AND APPROACH

As an alternative to statistical analysis or more detailed production simulation modeling, at this time, we draw on a review of the literature of savings estimates in other regions making similar market transitions.[2] We focus on studies of three transitions: (1) the Southwest Power Pool's (SPP's) creation of a day-ahead market; (2) the Midcontinent Independent System Operator's

[1] PacifiCorp serves retail customers in six states (CA, ID, OR, UT, WA, and WY). California, Oregon, and Washington have state renewable portfolio standards. Utah's Energy Resource and Carbon Emission Reduction Initiative also establishes renewable resource targets beginning 2025.

[2] PacifiCorp and the ISO will consider if additional analysis is necessary as policy and costs are further developed.

(MISO's) transition from a bilateral market to a centralized market; and (3) Entergy's proposal to join MISO.

The first study, performed by Ventyx in 2009, projected the benefits of existing SPP members implementing a full day-ahead market with centralized unit commitment and cooptimized ancillary services.[3] The SPP BAU case already included the benchmarked impact of efficiency gains from SPP's Energy Imbalance Service (EIS), implemented in 2007 with features similar to the ISO's current EIM.

SPP's scenario, which included a day-ahead market with centralized unit commitment as well as co-optimized energy and ancillary services markets, was projected to create $132 to $171 million in annual savings over the 2011 to 2016 period. Baseline production costs were projected to grow from $4.9 to $9.1 billion over this period due to increasing loads and fuel cost. Across this six-year period, the incremental benefits from the day-ahead market thus produced a range of 1.6% to 3.5% in cost saving when compared to baseline costs, and an average annual savings of 2.2%.

SPP's situation is similar to that of PacifiCorp and the ISO, in that the baseline already included the existence of a real-time market, so the benefits identified were incremental to savings from SPP's EIS (or, for PacifiCorp and ISO, the EIM) implementation. There are, however, important differences. SPP's total load and number of members were larger than that for the PacifiCorp and the ISO. Additionally, because the current ISO already includes a day-ahead market, the

[3] See Ventyx (2009).

SPP savings may be more representative of production cost savings in PacifiCorp rather than over the entire PacifiCorp-ISO footprint.

A separate 2009 study by The Brattle Group used historical data to evaluate the benefits of MISO's transition from a "Day 1" (bilateral plus open access) market design to a fully centralized "Day 2" market in 2005.[4] The study estimated a 1.1% improvement in fuel use efficiency and a 2.6% reduction in generator production cost, which represented $172 million in total annual savings for the MISO region. This savings was in addition to 1.4% savings that Brattle identified as resulting from MISO's implementation of a Day 1 market in 2002.

The Brattle study provides an additional example of the transition to centralized dispatch in a different, larger region, and is based on actual historical experience instead of projections. MISO's situation also differs from PacifiCorp and the ISO. Similar to SPP, MISO was comprised of a larger number of balancing authority areas than PacifiCorp and the ISO. Additionally, the Day 1 market design for MISO included a streamlined regional transmission tariff and coordinated regional transmission usage, but did not include an energy imbalance market.

The third study is based on Charles River Associates' (CRA's) analysis of expected savings from Entergy joining MISO, which was presented to the Arkansas Public Service Commission.[5] CRA used production simulation modeling for the analysis, projecting annual savings to Entergy ranging from $127 to $156 million from 2013 through 2022, compared to baseline Entergy production costs of $3.8 billion in 2013 and $6.7 billion in 2022. Savings represented an average 2.7%

[4] See Reitzes, J. P Fox-Penner, A. Schumacher, and D. Gaynor (2009).
[5] See CRA (2011) and Entergy (2011).

reduction in Entergy's production costs. Additionally, Entergy projected an additional $100 million in cost savings related to peak capacity, regulation reserve, and contingency reserve savings.

Entergy's situation is similar to PacifiCorp's in that it is a large utility that was integrating into an existing market. There are also important differences. MISO and Entergy are larger than the ISO and PacifiCorp, respectively, but the size of Entergy relative to rest of MISO is similar the size of PacifiCorp relative to the current ISO. Entergy did not already participate in a real-time imbalance market before joining MISO. Entergy recently announced that integration of its system with MISO in the first calendar year of operations produced larger than projected savings,[6] totaling over $250 million in savings for Entergy customers in Arkansas, Louisiana, Mississippi, and Texas. These savings were "largely driven by efficient commitment and dispatch of power plants" and by allowing Entergy utilities "to reduce their required generation capacity reserves."[7]

The table below provides a summary overview of these three studies and their savings ranges.

**Table 1. Comparison of other regional studies**

| Study region | Study type | Base case includes | Savings Range |
|---|---|---|---|
| SPP | Projection | EIS | 1.6% to 3.5% |
| MISO | Historical | Day 1 market | 2.6% |
| Entergy-MISO | Projection | No regional markets | 2.0% to 3.6% |

[6] AP newswire, May 2015, http://newsok.com/entergy-says-grid-manager-savings-exceed-projections/article/feed/839708.
[7] Entergy, May 2015, http://www.entergynewsroom.com/latest-news/miso-membership-produces-millions-savings-entergylouisiana-customers/.

Drawing on these three studies, we use an incremental savings range equal to 2% of baseline production costs in the low scenario and 3% in the high scenario, applied to forecasted PacifiCorp production costs. Neither scenario includes savings from more efficient unit commitment and dispatch for ISO customers, though they will likely realize at least some incremental cost savings.

Based on information developed for its integrated resource plan (IRP), PacifiCorp's estimated 2015 production cost, including fuel costs and variable O&M, is $1.2 billion. This cost is projected to increase in real terms by 2.8% per year, due to increases in load, rising fuel costs, and a changing generation mix. This results in a baseline production cost for PacifiCorp of $1.5 billion in 2024 and $1.8 billion in 2030 (2015$), against which the 2% to 3% production cost savings assumption is applied. PacifiCorp and the ISO will consider if additional analysis of this benefit category is necessary as policy and costs are further developed.

### 2.2.3 RESULTS

The table below summarizes the range of annual benefits, incremental to the EIM, to PacifiCorp in 2024 and 2030 from more efficient unit commitment and dispatch. Incremental benefits increase from $31 to $46 million per year in 2024 to $36 to $54 million per year in 2030, as a result of increased baseline total production cost expected by PacifiCorp due to growing load and rising fuel costs over this time period.

**Table 2. Annual incremental savings (million 2015$) to PacifiCorp from more efficient unit commitment and dispatch**

| Benefit Scenario | 2024 | 2030 |
|---|---|---|
| Low Scenario | $31 | $36 |
| High Scenario | $46 | $54 |

## 2.3 Lower Peak Capacity Needs

### 2.3.1 OVERVIEW

Integrating systems with different load profiles provides a "diversity benefit" because the total coincident peak for the combined system will be lower than the non-coincident peaks for the individual standalone systems. This reduction in peak load for the combined system, relative to the standalone systems, allows load serving entities to build or procure less generation capacity to meet resource adequacy obligations. PacifiCorp and the ISO have significantly different load profiles, with PacifiCorp's peak demand often occurring at an earlier hour on a different day or even in a different month than the ISO's.

### 2.3.2 ASSUMPTIONS AND APPROACH

#### *2.3.2.1 Quantity of Capacity Savings*

The quantity of capacity savings from peak load diversity depends on three factors: (1) peak load diversity between PacifiCorp and the ISO; (2) transfer limits between ISO and PacifiCorp that constrain the maximum amount of capacity savings; and (3) for PacifiCorp, the timing of new resource additions currently planned that could be deferred or avoided as a result of peak load diversity.

For different entities, peak load diversity can be quantified using a coincidence factor (Equation 1) — the ratio of each entity's coincident peak demand under the combined system to its non-coincident peak demand as a standalone entity.

$$CF_i = \frac{CP_i}{NCP_i} \tag{1}$$

$CF_i$ is entity i's coincidence factor, $CP_i$ is entity i's peak load coincident with the combined system peak, and $NCP_i$ is entity i's non-coincident peak load as a standalone system.

A lower coincidence factor indicates more diversity and higher capacity savings, whereas a higher coincidence factor indicates less diversity and lower savings. For instance, a coincidence factor of 1 means that an entity's peak load as a standalone system occurs at exactly the same time as, or, is perfectly coincident with, the peak load of the combined system.

Coincidence factors can be estimated using historical hourly load data. For this analysis, we had a limited number of years for which hourly load data is available for the ISO and PacifiCorp systems (2006-2012). To better capture the effects of weather conditions on coincidence factors over time, we use historical weather data and regression analysis to simulate annual hourly load profiles for PacifiCorp and the ISO over the period 1980-2012.[8] We then scale these hourly

[8] Specifically, we regress daily energy consumption on maximum and minimum temperature, lag and lead temperature variables, solar azimuth, a day number index, and a workday dummy variable, using load and

load profiles to forecasted 2024 energy and peak load levels in the TEPPC 2024 Common Case.[9] We calculate coincidence factors for each of these 33 years of hourly load profiles.

Resource adequacy planning in California, and capacity planning in the West more generally, typically use 1-in-2 weather conditions to forecast system peak demand. Consistent with this approach, we calculate coincidence factors for PacifiCorp and the ISO using the median of the 33 hourly load profiles. For PacifiCorp, this results in a coincidence factor of 0.92, which implies that PacifiCorp's contribution to the combined system peak is 8% lower than its peak as a standalone system. Our estimated coincidence factor for the ISO, 0.995, is much higher, indicating that the ISO's contribution to the combined system peak is much closer to its standalone non-coincident peak.

As a final step, we calculate peak capacity savings for each entity by multiplying the coincidence factor by forecasted standalone peak load, and scaled by its planning reserve margin (Equation 2).

$$PCS_i = NCP_i \times (1 - CF_i) \times (1 + PRM_i) \tag{2}$$

weather data from 2006-2012. We use the regression coefficients to estimate daily energy use from 1980-2012. We then convert daily energy estimates to hourly loads by multiplying them by normalized hourly load shapes for 2006-2012, based on a matching algorithm that identifies the closest match of daily energy within a 15 calendar day band. These 33 hourly load shapes are then scaled to WECC forecasted energy and peak load for 2024, so that the median peak of the 33 shapes is equal to the peak load forecast.

[9] The "TEPPC 2024 Common Case" is a production simulation database released by the Transmission Expansion Planning Policy Committee (TEPPC) at WECC. See WECC (2015a).

$PCS_i$ is entity i's peak capacity savings, $NCP_i$ is entity i's forecasted non-coincident peak load as a standalone system, $CF_i$ is entity i's forecasted coincidence factor, and $PRM_i$ is entity i's planning reserve margin.

For PacifiCorp's forecasted non-coincident peak ($NCP_i$), we use values supplied by PacifiCorp; for the ISO's, we use TEPPC data. We assume that planning reserve margins for PacifiCorp and the ISO remain unchanged throughout the study period, at 13% and 15%, respectively.

For PacifiCorp, multiplying its forecasted non-coincident peak by 1 minus its forecasted coincidence factor (0.08 = 1 – 0.92) and 1 plus its planning reserve margin (1.13 = 1 + 0.13) leads to a peak capacity savings of almost 900 MW in 2024 and 2030. Because we assume a maximum transfer capability of 776 MW, PacifiCorp's peak capacity savings are limited to 776 MW in 2024 and 2030. For the ISO, multiplying forecasted non-coincident peak (51 GW) by 1 minus its forecasted coincidence factor (0.005 = 1 – 0.995) and 1 plus its planning reserve margin (1.15 = 1 + 0.15) leads to a peak capacity savings of 284 MW in 2024 and 302 MW in 2030.

For the ISO, we assume that peak capacity savings begin the first year of the integration of the PacifiCorp-ISO balancing authority areas, as a result of reduced resource adequacy needs for California LSEs. For PacifiCorp, peak capacity savings depend on the expected amount of capacity that would be required in a business as usual scenario but could be displaced. In the low scenario, this avoided capacity cost is assumed to occur beginning in 2028, the first day of new thermal plant additions in the preferred portfolio of PacifiCorp's 2015 IRP. In the high scenario, PacifiCorp's first thermal plant additions are assumed to be required in 2024, consistent with a number of alternative scenario portfolios in the PacifiCorp 2015 IRP.

#### *2.3.2.2 Valuation of Capacity Savings*

The value of peak capacity reductions depends on the generation options that would be available to each entity to meet that peak capacity need in a business as usual case without full participation.

For the ISO, current capacity values are determined through the California Public Utility Commission's (CPUC's) resource adequacy (RA) process, and are lower than the net cost of new entry (CONE) because California currently has adequate generating resources. For LSEs within the ISO, the CPUC reports a weighted average RA contract price of $34.80/kW-yr ($2.90/kW-mo) for a sampling of contracts covering the 2012-2016 compliance years.[10] As the ISO system approaches load-resource balance, which we assume it reaches in 2024, the capacity value will increase to net CONE. For new capacity, we use the net CONE value from the ISO 2013-14 Transmission Plan ($215/kw-yr in 2015$),[11] which assumes that the marginal generating resource for RA compliance within the ISO will be an aero-derivative natural gas combustion turbine (CT) with independent power producer (IPP) financing. This capacity cost reflects capacity at $230/kw-yr, which covers capital and financing costs, insurance, and taxes, plus $36/kw-yr in fixed operations and maintenance costs (O&M), less $62/kw-yr in market net revenues, and a 5% summer peak-hour derate. We assume

[10] See CPUC (2014).
[11] See CAISO (2014a).

that capacity values increase linearly between 2012 and 2024, and remain at net CONE after that.

For PacifiCorp, there are no contracted capacity prices, so we value peak capacity savings based on the expected cost of new thermal capacity additions that could be displaced. Before 2028 (in the low scenario) and 2024 (in the high scenario), PacifiCorp may also realize cost savings from selling capacity freed up by peak load diversity into California's RA market. The amount of incremental capacity that would be available for sale in California is uncertain at this time, as are the RA contract prices that would result. These potential nearer-term benefits are not quantified in this analysis.

PacifiCorp provided details for the cost of planned plant additions consistent with the data used in its 2015 IRP: one 380 MW J-Class combined cycle natural gas plant with 43 MW of duct firing in 2028 added at a brownfield Wyoming site in the low scenario (or 2024 in the high scenario); and one 265 MW F-Class combined cycle natural gas plant with 48 MW of duct firing added in 2030 in the low scenario (or 2026 in the high scenario).

In total, these units represent 736 MW of total planned capacity additions to defer, which is lower than the 776 MW of peak capacity savings identified above. Due to the lumpiness of generator additions, we assume that no additional capacity beyond these two units (i.e., 736 MW) can be deferred. We use plant-specific characteristics to calculate the value of peak capacity savings for these units. Heat rate, fixed cost and variable O&M costs for the two plants are identified in Tables 6.1 through 6.3 of PacifiCorp's 2015 IRP. PacifiCorp estimates that these plants would receive net energy margins of $9-10/MWh, or annual net energy revenues of $54-61/kW-yr, depending on the year of analysis. Based on fixed cost estimates for these plants, this margin yields a remaining net cost of $34-41/kW-yr for their capacity.

For the ISO, we calculate annual savings for 2024 and 2030 as the product of the capacity value of ($215/kw-yr) based on net CONE, multiplied by the peak capacity savings quantity identified in section 2.3.2.1 (284 MW in 2024 and 302 MW in 2030).

For PacifiCorp, we calculate annual savings for 2024 in the high scenario as the product of $40/kw-yr net cost of capacity, multiplied by the 423 MW of displaced gas-fired capacity as a result of integration. PacifiCorp annual savings for 2030 are calculated for both scenarios by multiplying the annual net capacity cost of $34/kw-yr by 736 MW of total thermal capacity need displaced through integration.

### 2.3.3 RESULTS

In total, these lower peak capacity needs result in savings, incremental to the EIM, of $61 million to the ISO in 2024, rising to $65 million in 2030. Total savings, incremental to the EIM, to PacifiCorp, which are based on displacement of planned generation for 2024, are $0 in the low scenario, which assumes no deferral occurs until 2028, and $17 million in the high scenario. These savings rise to $25 million in 2030 in both scenarios.

## 2.4 More Efficient Overgeneration Management

### 2.4.1 OVERVIEW

Under business-as-usual operations, overgeneration in the ISO is expected to be prevalent when renewable penetration levels exceed 33%, resulting in significant incremental costs to meet renewable goals. The ISO's modeling for the 2014 Long Term Procurement Plan (LTPP) shows 3.4% of renewables curtailed under a 40% RPS in 2024, and E3's modeling shows overgeneration nearly 10% of renewables in the ISO, SMUD and LADWP under a 50% RPS in 2030.[12] A principal source of overgeneration is the Western interconnection's lack of coordinated resource dispatch and commitment affecting imports and exports prior to real-time operations. PacifiCorp's and ISO integration produces a coordinated commitment and dispatch plan in both the day-ahead and real-time markets, providing incremental import/export flexibility that reduces the frequency and magnitude of overgeneration.

### 2.4.2 ASSUMPTIONS AND APPROACH

We estimate the benefit of more efficient overgeneration management, driven by the California RPS target rising to 40% in 2024 and 50% by 2030, as the sum of two components:

+ **Avoided renewable procurement costs**. At high renewable penetrations, the frequency of overgeneration results in increased renewable procurement costs. This is because, without other renewable

[12] The marginal overgeneration of solar PV resources is estimated to be 65% under a 50% RPS Large Solar Scenario. See p.45 of CAISO (2014b) and Table 26 on p.107 of E3 (2014).

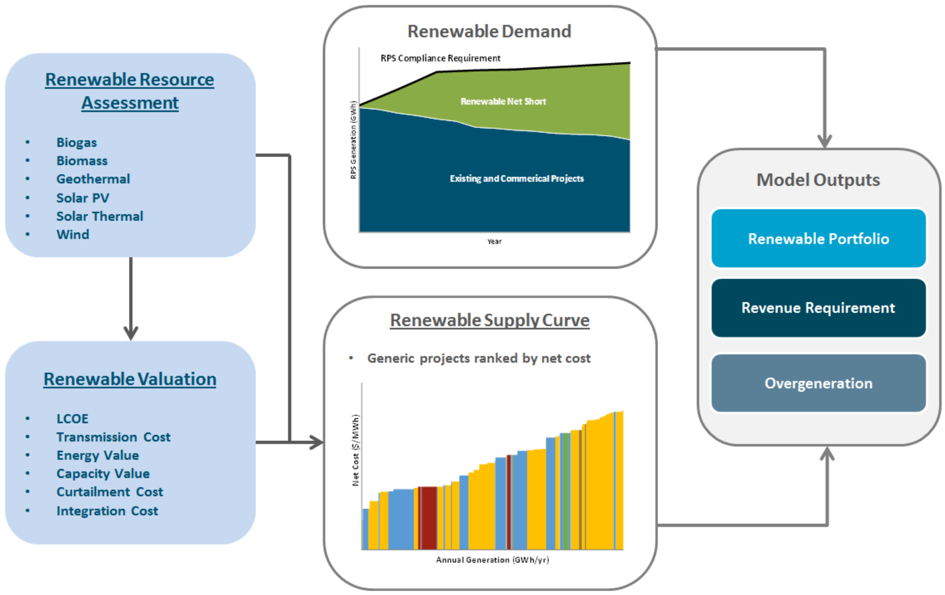
integration solutions, overgeneration is assumed to be mitigated with renewable curtailment. This results in a need to overbuild renewable generation above what would otherwise be needed to ensure that a given RPS target is met even after taking curtailment into account. Incremental exports avoid the need to procure renewables above and beyond what would otherwise be required to meet the RPS target.

+ **Avoided production costs**. Exports from the ISO allow PacifiCorp to decrease its thermal generation and/or the need to purchase from the market, resulting in production cost savings and reduced air emissions.[13]

To estimate avoided renewable procurement costs and the quantity of exports from the ISO to PacifiCorp, we use the *RPS Calculator*, a tool developed by E3 for the CPUC to provide renewable portfolios to the ISO in its annual Transmission Planning Process (TPP).[14] The RPS Calculator develops renewable resource portfolios by selecting generic resources based on their net cost to ratepayers — resource and transmission cost minus energy and capacity value. This framework is illustrated in Figure 1 below, where generic renewable resources are ranked by their net cost to California electricity consumers and added to the portfolio to meet RPS compliance. The RPS Calculator outputs include the procurement costs to meet a user-selected RPS target and the transmission necessary to deliver those resources.

[13] Reducing overgeneration with an assumed displacement of natural gas generation, as limited by assumed transfer limits from the ISO to PacifiCorp, could also reduce $CO_2$ emissions by 0.2 million metric tonnes in 2024 and by 0.6 million metric tonnes by 2030. In later years, with joint planning and increased transfer capability, emission reductions could increase. Emission reductions will be greater if overgeneration displaces coal-fired generation. For further discussion, see section 2.7.
[14] For additional information on assumptions, methodology and implementation, see CPUC (2015).

**Figure 1. RPS Calculator framework**




We based our analysis on RPS Calculator v.6.0, and made the following updates for the purposes of this study:

+ Reduced present-day, utility-scale solar PV (tracking) capital costs from \$3,540/kW-ac to \$2,600/kW-ac (2013\$), a 26.6% reduction.
+ Corrected treatment of transmission capital cost inputs, which were expressed in million dollars, but inadvertently used as \$/kW.
+ Added functionality to model exports from the ISO by increasing load, which effectively provides a “flexible load” to absorb overgeneration.

The renewable generation selected by the RPS Calculator to meet a 50% RPS target for the ISO by 2030 (without integration) resulted in a diverse technology mix that includes 20% geothermal, 29% wind, 39% solar PV, 4% solar thermal, 3% small hydro, and 6% biomass and biogas. In addition, 8,400 GWh of behind-the-meter solar PV was also included in the scenario.

We estimate avoided renewable procurement costs and the quantity of exports from the ISO to PacifiCorp by simulating two cases in the RPS Calculator: (1) a "No Exports Case", which assumes 0 MW of export capability; and (2) an "Exports Case", including 776 MW of maximum export capability from the ISO to PacifiCorp. Outputs from the simulations include: (1) the reduction in renewable procurement costs enabled through export capability to maintain the same RPS target; and (2) average expected level of exports by month-hour.

For each MWh of exports, we assume avoided production costs in PacifiCorp are $34.13/MWh in 2024 and $37.58/MWh in 2030.[15] Beyond the 776 MW transmission capability, we did not apply any additional constraints that limit PacifiCorp's ability to absorb overgeneration from the ISO. The more efficient overgeneration management benefits are assumed to be captured in the day-ahead market, consistent with the hourly load and resource profiles in the RPS Calculator, and are thus incremental to overgeneration avoided in the real-time through the EIM.

We assume that the total incremental benefits of more efficient overgeneration management — avoided renewable procurement costs and avoided production costs — are split evenly between PacifiCorp and ISO. This is intended to be a middle-of-the-road assumption, rather than a rigorous estimate of how the ISO

[15] Marginal operating cost assumptions provided by PacifiCorp. Assumes a natural gas plant heat rate of 7100 Btu/kWh and a delivered natural gas price of $4.78 and $5.27 per MMBtu in 2024 and 2030, respectively (in 2015$).

markets will allocate these cost savings. It implies that markets allocate some avoided renewable costs to PacifiCorp, through negative day-ahead prices.

### 2.4.3 RESULTS

Figure 2 shows exports from the ISO to PacifiCorp by month-hour for 2024 and 2030. Due to solar PV's share of the renewable portfolio, exports are concentrated in daylight hours in the spring months. Annual exports increase from 467 GWh in 2024 to 1,449 GWh in 2030 due to California's RPS increasing from 40% to 50% RPS. Due to the magnitude of overgeneration, the 776 MW transfer capacity frequently limits the amount of overgeneration that can be managed through exports from the ISO to PacifiCorp. It is important to note that the export quantities shown are based on an RPS Calculator scenario that uses a diverse mix of in-state solar, wind and geothermal additions to reach a 40% and 50% RPS California. Other recent studies[16] have indicated that a portfolio with a higher share of solar additions used to reach those RPS targets would produce larger, more frequent overgeneration conditions, and more opportunity for exports from ISO to PacifiCorp, than the levels modeled in this diverse renewable resource case.

[16] See for example E3 (2014), page 17, which indicated that 50% RPS scenario with a heavily solar portfolio resulted in more than double the level of overgeneration identified in a case with a diverse renewable resource mix. For analysis of overgeneration at 40% RPS, see also CAISO (2014c), page 39.

## Figure 2. Exports from the ISO to PacifiCorp by month-hour

**(a) 2024**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | | | | | | | | | | | | |
| **2** | | | | | | | | | | | | |
| **3** | | | | | | | | | | | | |
| **4** | | | | | | | | | | | | |
| **5** | | | | | | | | | | | | |
| **6** | | | | | | | | | | | | |
| **7** | | | | | | | | | | | | |
| **8** | | | | | | | | | | | | |
| **9** | | | | 776 | 458 | | | | | | | |
| **10** | | | 450 | 776 | 776 | | | | | | | |
| **11** | | | 776 | 776 | 776 | | | | | | | |
| **12** | | | 776 | 776 | 776 | | | | | | | |
| **13** | | | 776 | 776 | 776 | | | | | | | |
| **14** | | | 776 | 776 | 776 | | | | | | | |
| **15** | | | 776 | 776 | 776 | | | | | | | |
| **16** | | | | 373 | | | | | | | | |
| **17** | | | | | | | | | | | | |
| **18** | | | | | | | | | | | | |
| **19** | | | | | | | | | | | | |
| **20** | | | | | | | | | | | | |
| **21** | | | | | | | | | | | | |
| **22** | | | | | | | | | | | | |
| **23** | | | | | | | | | | | | |
| **24** | | | | | | | | | | | | |

| Exports (MW) |
|---|
| 0 |
| 200 |
| 400 |
| 600 |
| 776 |

**(b) 2030**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | | | | | | | | | | | | |
| **2** | | | | | | | | | | | | |
| **3** | | | | | | | | | | | | |
| **4** | | | | | | | | | | | | |
| **5** | | | | | | | | | | | | |
| **6** | | | | | | | | | | | | |
| **7** | | | | | | | | | | | | |
| **8** | | | | 776 | 776 | 128 | | | | | | |
| **9** | | | 776 | 776 | 776 | 776 | | | | | | |
| **10** | 387 | 487 | 776 | 776 | 776 | 776 | | | | 776 | 776 | |
| **11** | 776 | 776 | 776 | 776 | 776 | 776 | | | | 776 | 776 | 695 |
| **12** | 776 | 776 | 776 | 776 | 776 | 776 | | | | 776 | 776 | 776 |
| **13** | 776 | 776 | 776 | 776 | 776 | 776 | | | | 776 | 776 | 776 |
| **14** | 776 | 776 | 776 | 776 | 776 | 776 | | | | 329 | 776 | 776 |
| **15** | 776 | 776 | 776 | 776 | 776 | 776 | | | | | 270 | |
| **16** | | | 776 | 776 | 776 | 776 | | | | | | |
| **17** | | | 459 | 776 | 776 | | | | | | | |
| **18** | | | | | | | | | | | | |
| **19** | | | | | | | | | | | | |
| **20** | | | | | | | | | | | | |
| **21** | | | | | | | | | | | | |
| **22** | | | | | | | | | | | | |
| **23** | | | | | | | | | | | | |
| **24** | | | | | | | | | | | | |

Table 3 summarizes the annual benefit, incremental to the EIM, of more efficient overgeneration management for 2024 and 2030, and the contribution from avoided production costs and avoided renewable procurement costs are shown separately. Incremental benefits increase from $61.5 million per year in 2024 to $276.0 million per year in 2030 due to California's increasing RPS target. As the RPS target increases from 40% to 50%, the frequency and magnitude of overgeneration increases in the Reference Case, and the marginal cost of renewables to satisfy procurement targets increases in tandem.

**Table 3. Annual incremental benefits from more efficient overgeneration management (million 2015$)**

| Benefit Sub-Category[17] | 2024 | 2030 |
|---|---|---|
| Avoided Production Costs | 15.9 | 54.5 |
| Avoided Renewable Procurement Costs | 46.5 | 221.5 |
| **Total** | **61.5** | **276.0** |

**Note**: Individual results rounded independently.

[17] Avoided renewable procurement costs result from avoided the need to overbuild renewable generation to ensure that a given RPS target is met even after taking curtailment into account. Avoided production costs are the result of California exports allowing PacifiCorp to decrease thermal generation dispatch.

## 2.5 Renewable Procurement Savings

### 2.5.1 OVERVIEW

To quantify renewable procurement savings, this study uses low-cost wind resource potential in Wyoming to measure the benefits of a procurement strategy that benefits from joint planning, recognizing alternative transmission and supply options may exist that may yield different incremental benefit scenarios. Wyoming has very high quality wind resources, but cost-effectively accessing these resources requires a large-scale transmission build to achieve the economies of scale that reduce per-unit transmission costs. PacifiCorp's renewable energy demand may not be large enough on its own to justify a sufficiently large transmission build, in which case the total delivered cost (resource plus transmission) of Wyoming wind resources to PacifiCorp would be high relative to wind and solar resources in Oregon, Utah, and Washington.

Integration of the PacifiCorp and ISO balancing authority areas will facilitate the coordinated transmission planning needed to access low-cost renewable resources such as wind from Wyoming. Joint planning enables the economies of scale in transmission necessary to ensure that PacifiCorp and California retail customers benefit from procuring resources in this region at low cost and allows for local participation by customers in states where transmission must be permitted and constructed. Moreover, taking advantage of economies of scale for transmission costs will lower the total cost of new renewable resources, thereby increasing the competitive advantage of renewable resources relative to other alternatives, particularly when the demand for renewable resources is bolstered by known and prospective state and federal policies.

### 2.5.2 ASSUMPTIONS AND APPROACH

#### *2.5.2.1 Methodology*

We estimate the benefits of procuring Wyoming wind resources by measuring the difference in renewable resource and transmission costs for two cases: (1) a "No Wyoming Wind Case," in which incremental renewable demand is met with local renewable resources; and (2) a "Wyoming Wind Case," where PacifiCorp and ISO integration facilitates the development of Wyoming wind to jointly satisfy renewable demand from PacifiCorp and LSEs in the ISO.

In the "No Wyoming Case," we assume that LSEs in the ISO limit their renewable procurement to resources in California and PacifiCorp limits renewable procurement to Utah, Oregon, and Washington. This assumption is based on our assessment of recent trends in California and information included in PacifiCorp's 2015 IRP.[18, 19]

In the "Wyoming Wind Case," we assume different levels of Wyoming wind for 2024 and 2030, based on discussions with PacifiCorp and summarized in Table

[18] For California, approximately 90% of the renewable energy contracted from new commercial projects is located within California, with the remaining 10% from individual renewable projects located at the border (Arizona, Nevada and Baja Mexico) that are physically connected to the ISO, rather than delivered from new transmission projects. See the "Active_Portfolio" sheet in the RPS Calculator v.6.0 (available at: http://www.cpuc.ca.gov/NR/rdonlyres/591C8524-5838-47CA-94C3-5333CD3AC343/0/CPUC_RPSCalculator_v60.xlsm).

[19] For PacifiCorp, its 2015 IRP includes multiple scenarios where it is assumed environmental policies require incremental renewable resources. Without incremental transmission investment, these wind and solar resources are sited in Utah, Oregon, and Washington.

4. In 2024, the development of Energy Gateway Segments D and F is assumed to provide 2,875 MW of incremental wind capacity to the expanded PacifiCorp-ISO footprint. By 2030, we assume that the four Dave Johnston units in Wyoming, totaling 762 MW, will be retired (consistent with PacifiCorp's 2015 IRP) and that, due to peak load diversity (described in section 2.3), new resources at the site can be avoided. This provides an additional 762 MW of export capability from Wyoming, resulting in 3,637 MW of deliverable wind capacity in 2030.

**Table 4. Wyoming wind scenarios**

| Transmission Options | 2024 | 2030 |
|---|---|---|
| Energy Gateway Segment D | ☑ | ☑ |
| Energy Gateway Segment F | ☑ | ☑ |
| No Dave Johnston Replacement | ☒ | ☑ |
| **Total WY Wind (MW)** | **2,875** | **3,637** |

We assume that current ISO PTOs procure 70% of the available Wyoming wind capacity and energy, and PacifiCorp procures the remaining 30%. The allocation of Wyoming wind capacity and energy for each scenario is summarized in Table 5 below.

**Table 5. Allocation of Wyoming wind capacity and energy**

| Participants | | 2024 | 2030 |
|---|---|---|---|
| **PacifiCorp** | Installed Capacity (MW) | 863 | 1,091 |
| | Annual Generation (GWh) | 3,249 | 4,110 |
| **Current ISO PTOs** | Installed Capacity (MW) | 2,012 | 2,546 |
| | Annual Generation (GWh) | 7,581 | 9,590 |
| **Total** | Installed Capacity (MW) | **2,875** | **3,637** |
| | Annual Generation (GWh) | **10,830** | **13,700** |

**Note**: Wyoming wind capacity factor assumed to be 43%, consistent with the performance assumptions in PacifiCorp's 2015 IRP.

To estimate the renewable resources and transmission in California avoided by procuring Wyoming wind, we ran two cases in the RPS Calculator: (1) a "No Wyoming Wind Case," where we limit procurement to California; and (2) a "Wyoming Wind Case," where we added the ISO's share of Wyoming wind described in Table 5 above. The "No Wyoming Wind Case" is equivalent to the "Exports Case" described in the Section 2.4.2. This allows us to only measure the incremental impact of Wyoming wind and exclude the efficiencies gained from day-ahead export capability already quantified above.

For PacifiCorp, we assume that the amount of Wyoming wind procured displaces an equivalent amount of renewable energy from resources in Oregon, Utah, and Washington. Table 6 summarizes the location, type and share of renewables avoided by procuring Wyoming wind in 2024 and 2030. These assumptions were provided by PacifiCorp, and are meant to represent potential new renewable resource needs driven by known or prospective state and federal policies.[20] For instance, Cases C04-1 and C07-1 in PacifiCorp's 2015 IRP reflect a policy construct in which new renewable resources are required to achieve compliance with different alternatives to EPA's draft Clean Power Plan. The resource portfolios for these cases include between 629 MW and 1,382 MW of new renewable resources by 2024, rising to between approximately 1,197 MW and 2,161 MW by the 2030/2031 timeframe.

[20] Examples of state and federal polices include EPA's Clean Power Plan (CPP), future regulations that might transition the U.S. power fleet to lower or zero emitting resources beyond the CPP, and policies that might implemented to achieve state GHG reduction goals. For example, Washington has a GHG goal to reduce carbon emissions to 1990 levels by 2020 and Oregon has a GHG goal to reduce carbon emissions to 10% below 1990 levels by 2020.

**Table 6. PacifiCorp renewable energy avoided by Wyoming wind**

| Item | Units | OR Solar PV | OR Wind | UT Solar PV | WA Wind |
|---|---|---|---|---|---|
| **2024** | | | | | |
| Nameplate Capacity | MW | 111 | 400 | 154 | 600 |
| Capacity Factor | % | 29.2 | 29.0 | 31.6 | 29.0 |
| Annual Energy | GWh/yr | 284 | 1,016 | 426 | 1,524 |
| Share of total | % | 8.7 | 31.3 | 13.1 | 46.9 |
| **2030** | | | | | |
| Nameplate Capacity | MW | 447 | 400 | 154 | 600 |
| Capacity Factor | % | 29.2 | 29.0 | 31.6 | 29.0 |
| Annual Energy | GWh/yr | 1,143 | 1,016 | 426 | 1,524 |
| Share of total | % | 27.8 | 24.7 | 10.4 | 37.1 |

**Note**: The renewable resources in this table do not include Wyoming wind resources when it is assumed Dave Johnston is retired at the end of 2027. This is because without integration, lower peak capacity benefits would not be realized and brownfield replacement combined cycle resources at the Dave Johnston site would not be displaced.

#### *2.5.2.2 Transmission Costs and Allocation Assumptions*

For the purposes of this study, PacifiCorp provided transmission cost and availability assumptions for the Energy Gateway segments required to export wind from Eastern Wyoming to load. The costs assumptions are consistent with those studied in PacifiCorp's 2015 IRP. As shown in Table 7 below, Energy Gateway Segments D and F support 2,875 MW of Wyoming wind at a real levelized cost of $252 million per year. The 762 MW of incremental capacity enabled by not replacing Dave Johnston with resource on its site is assumed to be available at zero incremental cost.

**Table 7. Transmission cost and availability assumptions**

| Transmission Options | Export Capability (MW) | Real Levelized Cost (2015 $mil/yr) |
|---|---|---|
| Energy Gateway Segment D and F | 2,875 | 252 |
| No Dave Johnston Replacement | 762 | 0 |

We assume that the incremental transmission costs presented here are shared by current ISO customers and PacifiCorp according to their share of the combined system load.[21] This approach results in existing ISO customers incurring 80% of the incremental transmission cost and PacifiCorp incurring 20% of the costs.[22] ISO customers incur an incremental transmission cost of $202 million per year, and PacifiCorp retail customers incur an incremental transmission cost of $50 million per year.

#### *2.5.2.3 Renewable Resource Cost and Value Assumptions*

The renewable resource cost, transmission cost and energy value assumptions assumed for PacifiCorp's renewable resources are summarized in Table 8 below.

[21] This is consistent with the ISO's current approach to allocating transmission project costs.
[22] Based on a net energy for load forecast in 2024 of 61,647 GWh for PacifiCorp and 241,078 for the ISO.

## Table 8. PacifiCorp renewable resource net cost summary

| Category | Units | Location | | | | |
|---|---|---|---|---|---|---|
| | | Oregon Solar PV | Oregon Wind | Utah Solar PV | Washington Wind | Wyoming Wind |
| **Resource Costs** | | | | | | |
| Capital Cost | $/kW | $ 2,470 | $ 2,178 | $ 2,359 | $ 2,178 | $ 2,199 |
| Fixed O&M | $/kW-yr | $ 36.2 | $ 35.1 | $ 35.6 | $ 35.1 | $ 35.1 |
| Variable O&M | $/MWh | $ - | $ - | $ - | $ - | $ 0.7 |
| Capital Recover Factor | % | 7.6% | 7.4% | 7.6% | 7.4% | 7.4% |
| Resource Cost | $/MWh | $ 88.0 | $ 77.3 | $ 78.0 | $ 77.3 | $ 53.2 |
| **Transmission Costs** | | | | | | |
| 2024 Transmission Cost | $/kW-yr | $ 9.9 | $ 11.6 | $ - | $ 15.9 | $ 58.4 |
| 2030 Transmission Cost | $/kW-yr | $ 9.9 | $ 11.6 | $ - | $ 15.9 | $ 46.2 |
| 2024 Transmission Cost | $/MWh | $ 3.9 | $ 4.6 | $ - | $ 6.2 | $ 15.5 |
| 2030 Transmission Cost | $/MWh | $ 3.9 | $ 4.6 | $ - | $ 6.2 | $ 12.3 |
| **Energy Value** | | | | | | |
| 2024 Energy Value | $/MWh | $ 55.7 | $ 56.4 | $ 56.4 | $ 59.2 | $ 51.0 |
| 2030 Energy Value | $/MWh | $ 53.9 | $ 55.9 | $ 55.9 | $ 58.1 | $ 50.1 |
| **2024 Net Cost Summary** | | | | | | |
| Resource Cost | $/MWh | $ 78.0 | $ 77.3 | $ 77.3 | $ 88.0 | $ 53.2 |
| Transmission Cost | $/MWh | $ - | $ 4.6 | $ 6.2 | $ 3.9 | $ 15.5 |
| Energy Value | $/MWh | $ (55.7) | $ (56.4) | $ (56.4) | $ (59.2) | $ (51.0) |
| **Net Cost** | $/MWh | **$ 22.3** | **$ 25.4** | **$ 27.1** | **$ 32.6** | **$ 17.7** |
| **2030 Net Cost Summary** | | | | | | |
| Resource Cost | $/MWh | $ 78.0 | $ 77.3 | $ 77.3 | $ 88.0 | $ 53.2 |
| Transmission Cost | $/MWh | $ - | $ 4.6 | $ 6.2 | $ 3.9 | $ 12.3 |
| Energy Value | $/MWh | $ (53.9) | $ (55.9) | $ (55.9) | $ (58.1) | $ (50.1) |
| **Net Cost** | $/MWh | **$ 24.1** | **$ 26.0** | **$ 27.6** | **$ 33.7** | **$ 15.4** |

**Note**: Renewable resource costs from PacifiCorp 2015 IRP. Costs escalated from 2014 to 2015 dollars assuming 2% per year inflation. Solar PV capital costs reflect 14.4% real reduction from present-day costs. Wyoming wind transmission cost decreases from 2024 to 2030 due to incremental capability assumed by Dave Johnston retirement at zero cost. Transmission cost and energy value assumptions provided by PacifiCorp.

The RPS Calculator contains a large database of generic renewable resource projects in California and across the WECC to develop plausible renewable resource portfolios. Table 9 contains average resource cost, performance and financing assumptions used to estimate the power purchase agreement (PPA) price that LSEs in California would pay to purchase renewable energy. The table below represents only a subset of technologies available in the model, and includes the PPA price we assume current ISO LSEs would pay for Wyoming wind energy. The levelized cost estimate for the PPA is assumed to increase at the assumed rate of inflation (i.e., is constant in real dollar terms).

**Table 9. Estimated PPA prices for renewable resources contracted to ISO LSEs**

| Item | Units | Resource | | | |
|---|---|---|---|---|---|
| | | CA Solar PV Tracking | CA Wind | CA Geothermal | WY Wind |
| Capacity Factor | % (ac) | 33% | 30% | 83% | 43% |
| Degradation | %/yr | 0.7% | 0.0% | 0.0% | 0.0% |
| Capital Cost | $/kW-ac | $ 2,388 | $ 2,395 | $ 5,745 | $ 2,008 |
| Fixed O&M | $/kW-yr | $ 36 | $ 36 | $ 329 | $ 42 |
| Variable O&M | $/MWh | $ - | $ 3 | $ - | $ 1 |
| Financing Lifetime | Years | 25 | 20 | 20 | 20 |
| After-tax WACC | % | 8.3% | 8.3% | 8.3% | 8.3% |
| PPA Esalation Rate | %/yr | 2.0% | 2.0% | 2.0% | 2.0% |
| **Calculated PPA Price** | **$/MWh** | **$ 83** | **$ 106** | **$ 124** | **$ 64** |

**Note**: All costs are in 2015 dollars and represent 2024 vintage resources. The California resource costs reflect an average resource, and project-specific cost multipliers and capacity factors are used to determine PPA price for individual projects in the RPS Calculator's resource selection process. Wyoming wind capacity factor is consistent with assumption in PacifiCorp 2015 IRP (i.e., 43%). No federal production tax credit assumed.

### 2.5.3 RESULTS

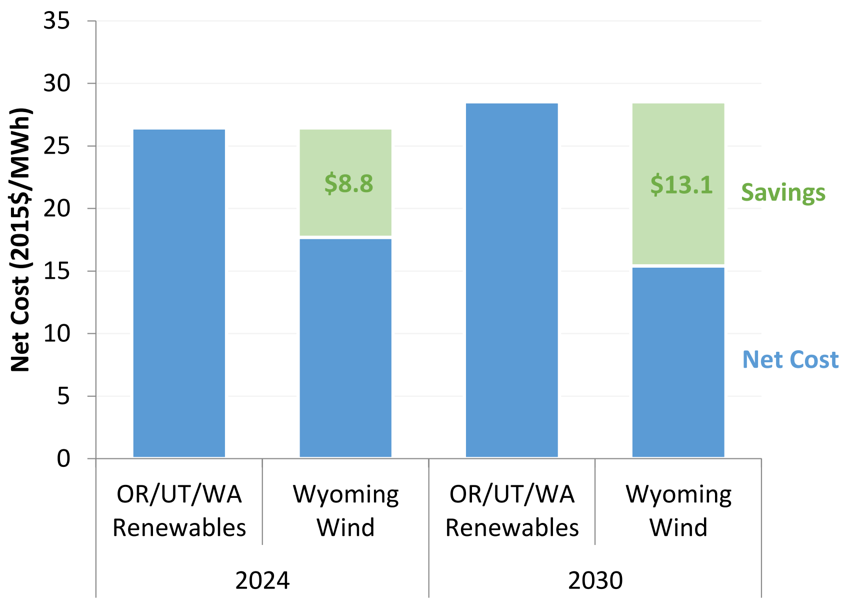
This section describes the renewable procurement savings, incremental to EIM benefits, enabled by coordinated transmission planning for the 2024 and 2030 study years. Table 10 summarizes the results, showing $28.5 million in savings for PacifiCorp in 2024 and $54.0 million in 2030. ISO benefits begin at $121.0 million in 2024 and increase to $691.2 million in 2030.

**Table 10. Renewable procurement incremental savings summary (million 2015$)**

| Entity | 2024 | 2030 |
|---|---|---|
| PacifiCorp | 28.5 | 54.0 |
| ISO customers | 121.0 | 691.2 |
| **Total** | **149.5** | **745.2** |

The net incremental benefit to PacifiCorp is primarily driven by the lower resource cost for Wyoming wind (due to its high capacity factor) less the incremental Energy Gateway transmission costs necessary to deliver generation to load. In 2024, the net cost of Wyoming wind is estimated to be $17.7/MWh and the generation-weighted average net cost of alternative renewable resources in Oregon, Utah and Washington is $26.4/MWh. Procuring Wyoming wind would save consumers $8.8 per MWh of renewable energy, resulting in $28.5 million of savings in 2024. The assumed retirement of Dave Johnston enables PacifiCorp to procure additional Wyoming wind at no incremental transmission cost by 2030, resulting in a larger dollar per MWh cost savings in 2030 than 2024 ($13.1/MWh versus $8.8/MWh). Net costs for 2024 and 2030 are shown in Figure 3, below.

**Figure 3. PacifiCorp renewables net cost comparison and resulting savings (2015$/MWh)**




**Note**: Net cost data shown in Table 8 above.

The ISO's renewable procurement savings, incremental to EIM benefits, are driven by similar factors, but the substantial increase in net benefits from 2024 to 2030 is primarily explained by the assumed increase in RPS from 40% in 2024 to 50% in 2030. The net cost of California renewables procured in the 2030 timeframe is substantially higher than 2024 because: (a) the highest quality/lowest cost resources in the state are already procured; (b) the frequency and magnitude of overgeneration increases non-linearly from 40% to 50% renewables, requiring a substantial "renewable overbuild" to meet RPS targets; and (c) opportunities to access renewables using existing and minor transmission upgrades are depleted, requiring new major transmission upgrades.

Table 11 illustrates how net benefits are calculated for current ISO customers using outputs from the RPS Calculator. Renewable procurement savings in 2030 are approximated by multiplying the change in renewable energy procurement (third column) against the average PPA price for all procurement (fourth column). Net benefits include the benefit of avoiding a combination of geothermal, solar PV and wind resource costs less the incremental cost of Wyoming wind, resulting in approximately $500 million of annual savings in 2030. The approximation in Table 11 is close to the actual benefits estimated of $535 million per year in 2030, but slightly lower due to the fact that the PPA prices for avoided generation are project specific and the resources avoided by procuring Wyoming wind are often the highest on the renewable net cost supply curve.

In addition to the renewable resource cost savings, Wyoming wind enables the ISO to avoid $358 million per year in transmission costs for accessing in-state resources that the RPS Calculator indicates would otherwise be needed, while adding $202 million per year in transmission costs from their share of Energy Gateway, resulting in a net transmission savings of $156 million in 2030. The annual benefit from Wyoming wind in 2030 is $691 million ($535 million from resource cost savings and $156 million in transmission cost savings).

**Table 11: Illustration of renewable generation cost savings in ISO for 2030**

| Technology | Quantity (Procurement) Without WY Wind GWh | Quantity (Procurement) With WY Wind GWh | Quantity Change Change in Procurement GWh | Price Average PPA* $/MWh | Price x Quantity Change Cost Change $MM/yr |
|---|---|---|---|---|---|
| Biogas | 1,954 | 1,515 | -439 | 153 | -67 |
| Biomass | 4,313 | 4,313 | 0 | 160 | 0 |
| Geothermal | 23,586 | 21,144 | -2,442 | 124 | -302 |
| Hydro | 3,099 | 3,099 | 0 | 166 | 0 |
| Solar PV | 44,793 | 39,357 | -5,436 | 83 | -451 |
| Solar Thermal | 4,143 | 4,143 | 0 | 227 | 0 |
| Wind (Non-Wyoming) | 33,184 | 30,373 | -2,811 | 106 | -299 |
| Wind (Wyoming) | 0 | 9,590 | 9,590 | 64 | 614 |
| Total | 115,072 | 113,534 | -1,538 | | -505 |

**Note**: The PPA prices in the table represent an average resource for illustration. The actual calculation of renewable procurement benefits uses the marginal PPA prices of individual projects from renewable supply curves in the RPS Calculator, which reflect project-specific costs and capacity factors and integration costs.

To show how the ISO's RPS portfolio changes with and without the incremental wind facilitated by the integration of the Pacific Corp system, Table 12 below translates the first three columns from Table 11 from energy (GWh) to capacity (MW). The table highlights several results:

1. Procuring slightly more than 2,500 MW of relatively high capacity factor wind in Wyoming reduces the quantity of solar, geothermal, biogas, and wind resources required.

2. The ISO portfolio maintains a high percentage of solar resources in both cases. With no Wyoming wind, there is more than 16,000 MW of grid connected solar in the portfolio. The RPS Calculator still selects more than 14,500 MW in the integration case. These numbers exclude the behind the meter solar.

3. The RPS Calculator also makes a small reduction in the higher cost and lower capacity factor in-state wind, which drops from slightly more than 12,000 MW to just under 11,000 MW.

4. The RPS Calculator also makes the economic choice to reduce in-state geothermal by about 350 MW from the slightly more than 2,900 MW in the “No Wyoming Wind Case”, and to reduce biogas procurement by 56 MW.

5. Incrementally, the ISO still adds more than 4,300 MW of California grid connected solar resources in moving from its 33 percent to 50 percent RPS goal for 2030, as well as over 1,000 MW of geothermal and 3,300 MW of in-state wind resources.

**Table 12: Nameplate capacity of ISO portfolio (MW) in 2030**

| Technology | Without WY Wind | With WY Wind | Delta |
|---|---|---|---|
| Biogas | 206 | 150 | -56 |
| Biomass | 669 | 669 | 0 |
| Geothermal | 2,925 | 2,576 | -349 |
| Hydro | 866 | 866 | 0 |
| Solar PV | 16,372 | 14,627 | -1,745 |
| Solar Thermal | 1,666 | 1,666 | 0 |
| Wind (Non-Wyoming) | 12,154 | 10,881 | -1,273 |
| Wind (Wyoming) | | 2,546 | 2,546 |
| **Total** | **34,858** | **33,980** | **-878** |

## 2.6 Calculation of Present Value of Benefits

We estimate benefits, incremental to the EIM, for a 20-year period, from 2020, assumed to represent the first full year of operation for the integrated system, through 2039. For the years 2020 to 2023, we estimate incremental savings from: (a) more efficient unit commitment dispatch for PacifiCorp and (b) reduced peak capacity savings for the ISO. We assume all other savings are zero.

For the years between 2024 and 2030, we interpolate between 2024 and 2030 savings estimates for incremental reduced overgeneration savings and incremental renewable procurement savings for the ISO. For PacifiCorp, we assume incremental annual renewable procurement savings between 2024 and

2030 hold constant at 2024 savings levels. We assume incremental peak capacity savings for PacifiCorp increase according to a schedule of needed capacity additions under different scenarios, 2024 and 2026 in the high scenario, and 2028 and 2030 in the low scenario. We calculate incremental savings from more efficient unit commitment and dispatch for the entire 2020 to 2039 period as a percent of projected PacifiCorp production costs. We assume all other incremental savings categories remain constant in real terms after 2030.

The figures below illustrate the 20 years of annual savings, incremental to the EIM, for PacifiCorp and the ISO under the high and low scenarios, and are the basis of our present value calculations in the report. The annual values in the figures reflect the interpolation described above.

**Figure 4. PacifiCorp low scenario incremental annual savings, 2020-2039 (2015$ millions)**

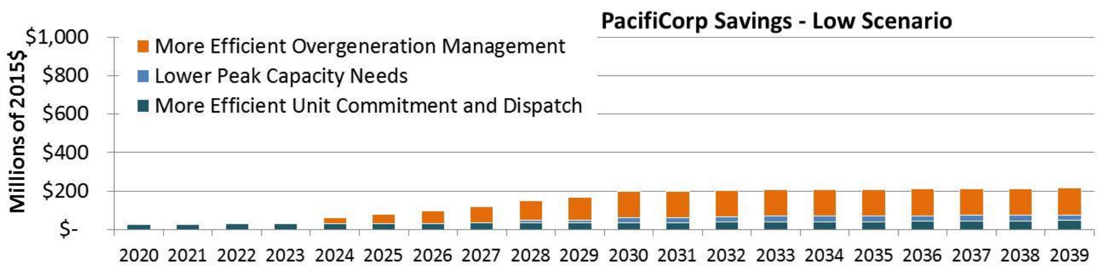


**Figure 5. PacifiCorp high scenario incremental annual savings, 2020-2039 (2015$ millions)**

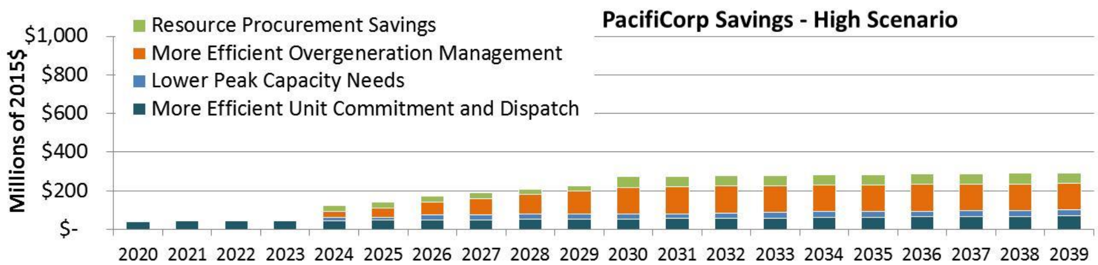
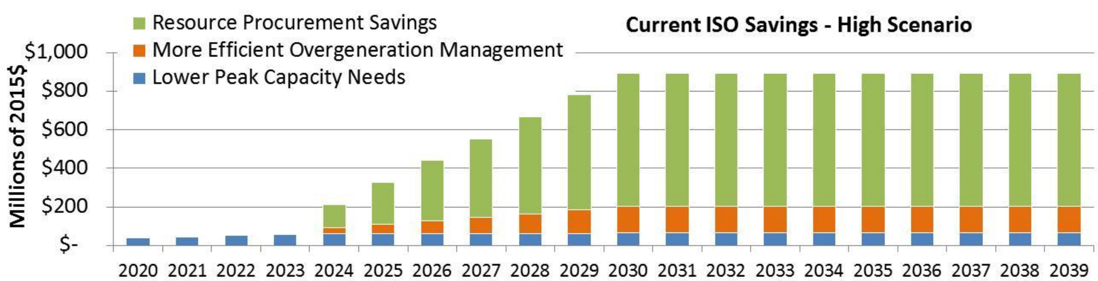



**Figure 6. ISO low scenario incremental annual savings, 2020-2039 (2015$ millions)**


**Figure 7. ISO high scenario incremental annual savings, 2020-2039 (2015$ millions)**



## 2.7 Greenhouse Gas Emissions

While comprehensive quantification of the greenhouse gas (GHG) emissions impact of PacifiCorp-ISO integration is beyond the scope of this study, this section identifies and discusses the operational factors that could affect GHG emissions. In the main report, we note that, the primary impact of PacifiCorp-ISO integration will be to facilitate ISO customers meeting their 50% RPS target with a more diversified and lower cost portfolio of renewable resources, improved cost competitiveness of renewable resources for PacifiCorp, and improved management of renewable overgeneration. Integration will therefore provide incentives for GHG reductions over time.

Net reductions in GHG emissions grow over the 2015 to 2030 time period as a result of both higher expected GHG prices as well as a general reduction in the amounts of energy produced from fossil-fueled generating units. The precise impact of PacifiCorp-ISO integration on GHG emissions will depend on the following five potential changes in operations, shown in Table 13.

**Table 13. Five operational factors that impact GHG emissions**

| Operational change | Impact on GHG emissions | Description |
|---|---|---|
| **Renewables displace gas generation** | Reduction | If renewable energy resources that would otherwise be curtailed in the ISO can instead be exported to PacifiCorp, PacifiCorp could back down thermal (most likely gas-fired) generation, reducing emissions. |
| **More efficient gas generation displacing other gas** | Reduction | Integration allows more efficient gas plants to displace less efficient ones, resulting in lower average emission factors. |
| **Optimized unit commitment** | Reduction | Integration is expected to allow the combined system to reduce the number of starts and stops |

| | | |
|---|---|---|
| | | needed for gas generators, allowing units that are committed to run more often at their most efficient output levels, reducing emissions. |
| **Gas displaces coal generation** | Reduction | If coal generation is already being dispatched and its energy is exported to California (as an unspecified market import), integration could provide an incentive to reduce coal generation and increase gas by applying a resource-specific emissions factor to the dispatch, reducing emissions if $CO_2$ prices are large. |
| **Coal displaces gas generation** | Increase | If coal generators have available capacity not already being dispatched but that becomes economic to dispatch after integration, coal generators may run more after integration, increasing emissions. The potential for this change to occur is limited. |

The emissions impact of renewable displacement of gas generation depends on the amount of overgeneration that is avoided and the emission factor of thermal units that PacifiCorp would likely displace. Using our projected renewable energy exports of 467 GWh and 1,449 GWh in 2024 and 2030, respectively, and assuming this energy could displace an efficient gas unit with a 7,100 Btu/kWh heat rate, this would result in GHG reductions of approximately 0.2 $MtCO_2$ in 2024 and 0.6 $MtCO_2$ in 2030. If the energy displaced by renewable overgeneration instead is from a less efficient gas unit or a coal unit operating as a marginal resource in certain hours, the emission reductions would be larger. Additionally, if the 2030 renewable generation mix has a higher share of solar PV than is represented in the scenario modeled, overgeneration in California would likely be higher, which would also increase the potential emissions reductions resulting from PacifiCorp-ISO integration.

More efficient use of gas resources and optimized unit commitment would also have a downward impact. For instance, a 2% improvement in average heat rate of PacifiCorp gas resource generation (through using more efficient units, dispatching those units at more efficient operating levels, and reducing gas used during unit startup) would produce an additional reduction of approximately 0.1 $MtCO_2$.

Coal displacement of gas generation, if and when it occurs, would have an upward impact on emissions due to coal's higher emission factor relative to gas. However, the potential for this to happen is limited by four factors:

+ *PacifiCorp's coal units are typically already infra-marginal*, meaning that they are run as baseload units and are not often the units that change dispatch in response to short-term changes in demand or energy market prices. PacifiCorp more often increases or reduces gas generation and market purchases as a result of changes in prices or hourly demand, and coal units run at levels approaching their maximum output when not affected by outages or operational de-rates of capacity for maintenance.
+ *California GHG allowances for imported power limit coal dispatched for export*. Currently, the California Air Resources Board's cap-and-trade program requires emission allowances for in-state generators (based on actual emissions) and for power imports to the state (based typically on a generic emission factor for unspecified purchases). Under the EIM and the integration case, however, specific emissions of PacifiCorp generators are identified by the central dispatch. If there are incremental exports to California, the optimized dispatch will identify the emissions rate of the plants being dispatched and reflect the cost of $CO_2$ allowances for those emissions in their dispatch cost. At a $20/$tCO_2$

allowance price $CO_2$ costs would add \$8.7/MWh to the cost of unspecified energy imported with a generic emission factor of 0.435 $tCO_2$/MWh. Under coordinated dispatch, however, the emissions factor for specific resources would be individually identified, raising the emissions factor applied to coal units to approximately 0.9 $tCO_2$/MWh, and increasing the $CO_2$ cost for coal imports to \$18.0/MWh. Application of plant-specific emissions rates for $CO_2$ import charges therefore reduces the incentive to dispatch coal to serve California loads. As carbon prices increase, they should increase the strength of the incentive to displace coal with gas resources.

+ *PacifiCorp plans to retire coal resources over next 15 years*. PacifiCorp's 2015 IRP already includes plans to retire many of its coal generators by 2030. As a result of these changes and additional new renewable resources, PacifiCorp's system emissions factor is expected to significantly decline by 2030. PacifiCorp has no plans to build additional new coal generators. Anticipated coal retirements, and plant conversions to natural gas, by 2030 in the IRP include Carbon 1-2, Cholla 4, Dave Johnston 1-4, Huntington 2, and Naughton 1-3. These retirement and conversion plans would be unaffected by PacifiCorp-ISO integration. This reduction to the share of coal share in PacifiCorp's fleet will reduce the overall quantity of coal generation capacity that could have potential room to increase dispatch.
+ *States are bound by federal emission regulations*. The federal Clean Power Plan is likely to present a hard cap on emissions. Regardless of the impact of integration on emissions, states in the PacifiCorp and ISO footprints would need to comply with reductions needed to meet state-level targets, and as a result will be limited to options that comply with that capped level of emissions, further limiting the risk of an increase in emission from integration.

# 3 References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