Mountain West Transmission Group

"Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint"

Production Cost Savings Report

As one component of evaluating the benefits and costs of regional market participation, the Mountain West participants commissioned a study of the potential production cost savings under a regional market or common transmission tariff. The report, titled "*Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint,*" is attached.

Mountain West Notice/Caveats Regarding this Report

The report was prepared by the Brattle Group at the direction of the Mountain West participants as an initial preliminary analysis of partial gross production cost benefits under a regional market or common transmission tariff.

The study was based on certain assumptions and is not exhaustive in its evaluation of potential benefits; including for example but not limited to the following:

- The study does not evaluate a consolidated market footprint with the Southwest Power Pool.
- The study does not evaluate any of the cost-related issues associated with participation in a regional market or common transmission tariff, including the implications of alternative governance structures, implementation and administrative costs, resource adequacy and reliability benefits of regional market operations, or the cost impacts of regional transmission planning and alternative allocations of existing and future transmission investments.
- The study does not address any of the regulatory and rate recovery issues that would be associated with the potential undertaking of the Mountain West Transmission Group participants.
- The Mountain West participants will each evaluate these and other factors as part of any determination to proceed, which should be kept in mind while reviewing the Brattle Study.

Additional analysis is being conducted by the individual members as necessary. As such, the results of this report should be considered as one part of the analysis.

Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint

PREPARED FOR

Basin Electric Power Cooperative

Black Hills Corporation

Colorado Springs Utilities

Platte River Power Authority

Public Service Company of Colorado

Tri-State Generation and Transmission Cooperative

Western Area Power Administration

PREPARED BY

Judy W. Chang

Johannes P. Pfeifenberger

John Tsoukalis

DECEMBER 1, 2016

THE Brattle GROUP

This report was prepared for the Mountain West Transmission Group entities. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

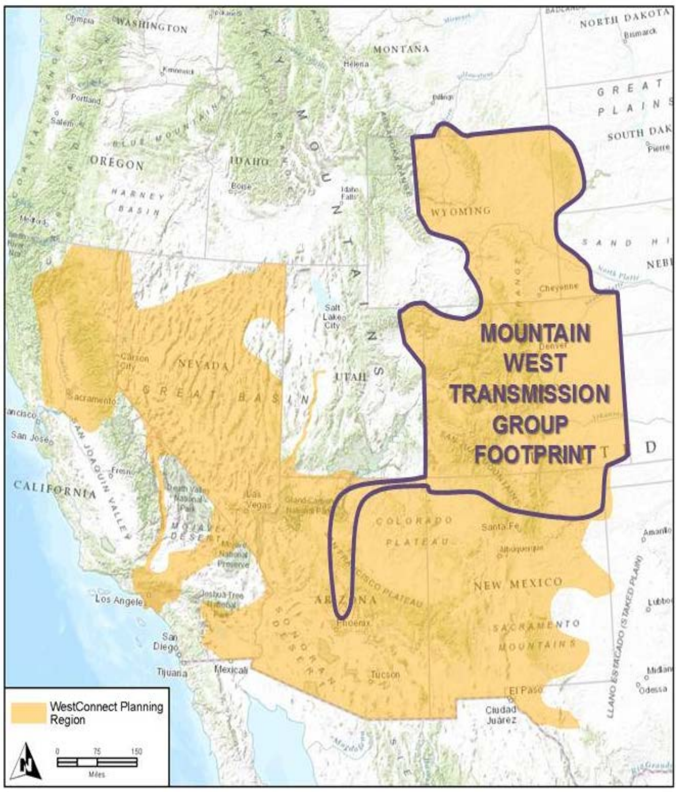
Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including members of the Mountain West Transmission Group for providing the necessary input data and members of The Brattle Group for peer review.

Table of Contents

I. Scope of Study

The Brattle Group was retained by the Mountain West Transmission Group ("MWTG" or "Mountain West") entities[1] to analyze how different market structures could alter production costs in the combined service area of the Mountain West entities.

Figure 1: The Mountain West Transmission Group Footprint



Specifically, this study analyzes the potential generation-related variable costs ("production costs") of serving electricity customers in the Mountain West region under three different market structures for the region:

[1] The Mountain West participants are Basin Electric Power Cooperative ("Basin"), Black Hills Corporation ("Black Hills"), Colorado Springs Utilities ("CSU"), Platte River Power Authority ("PRPA"), Public Service Company of Colorado ("PSCO"), Tri-State Generation and Transmission Cooperative ("Tri-State"), and Western Area Power Administration's ("WAPA") Loveland Area Projects and Colorado River Storage Project.

a. **Bilateral Market**: a representation of the status quo in the Mountain West footprint and the entire WECC region
b. **Joint Transmission Tariff**: a single transmission tariff for the Mountain West footprint (with the status quo remaining in the rest of the WECC region)
c. **Regional Market**: a centralized regional wholesale power market covering the service areas of the Mountain West entities (with the status quo remaining in the rest of the WECC region)

This report provides a comparison of the production cost simulation results across these market structures. The comparison shows the likely changes in production costs that would result from the implementation of these market structure changes.

To conduct the analysis, we used a state-of-the-art production cost simulation tool, Power System Optimizer ("PSO"), to simulate the entire Western Electricity Coordinating Council, ("WECC"), which includes the Mountain West study region. As do most production cost simulation tools, PSO simulates the economic unit commitment and dispatch of generating plants that would be conducted in a centralized regional wholesale market operated by a regional transmission organization ("RTO"). To simulate other market structure cases where a market operator does not yet conduct centralized dispatch, such as the existing bilateral market or a bilateral market with a joint regional tariff (but without a centralized regional wholesale market), we impose specific restrictions and limitations on the simulations to derive a dispatch of the generating units within the Mountain West and other areas in WECC that reflects the actual market structure. This approach is widely used in these types of analyses.

The key metric discussed in this report, Adjusted Production Cost ("APC"), is a high-level approximation of the production costs, including purchase costs net of sales revenues, incurred by the Mountain West entities to serve their customers. The APC metric uses the simulation outputs to estimate production costs for all units in the Mountain West as well as the off-system purchase expenses and sales revenues for all participants in the group. These three components are aggregated across the Mountain West region to determine a group-wide estimate of production costs incurred to serve customers. In this report, we compare the resulting APC metric across various market structures to estimate the likely range of production cost benefits that the Mountain West entities would derive as a result of moving from (1) today's bilateral market toward (2) a structure where transmission charges are de-pancaked across the Mountain

West footprint, and then toward (3) a full “Day-2” wholesale market, similar to an RTO market, with unified Security Constrained Unit Commitment (“SCUC”) and Security Constrained Economic Dispatch (“SCED”) across the entire Mountain West footprint. SCUC and SCED are optimization processes designed to meet an area’s electricity demand at the lowest cost possible, given the operational constraints of the area’s generation fleet and transmission system.

The production cost model simulates the wholesale electricity market on an hourly basis, with every generation, transmission, and load represented in the entire Western Interconnection, including the Mountain West region. Thus, the model provides as output simulated generation dispatch and hourly locational market prices at every generator location and for every load zone, consistent with optimized unit commitment and dispatch based on the marginal production cost of every generator and taking into account transmission constraints in the region. From the resulting generator dispatch and locational price data, we estimated the total variable costs of generation owned or contracted by the participants, payments made for purchasing power from others, and revenues that entities receive for selling power in excess of what is needed to serve their own load. Adjusted Production Cost is a simplified metric intended to provide an indication of the changes in entities’ production costs under different market structures. This report provides a summary of the findings associated with the adjusted production cost analysis.

Production cost impacts are only one element of evaluating participation in a RTO-operated regional wholesale market. The study does not estimate any production-cost-related impacts beyond those captured in the simulations and the APC metric, such as discrepancies between congestion charges and congestion revenue rights, marginal loss refunds, and the likely significant additional benefits related to the lower-cost balancing of uncertain loads and renewable generation achieved in a regional market during real-time operations. This report does not address other considerations related to the formation of, or the participation in, a regional market such as the implications of alternative RTO governance structures, RTO implementation and administrative costs, resource adequacy and reliability benefits of regional market operations, or the cost impacts of regional transmission planning and alternative allocations of existing and future transmission investments.

II. Summary of Results

The scope of this study included simulations of different market structures in the Mountain West region. The Mountain West participants requested simulations that reflect existing market conditions in the WECC for 2016. In addition, the MWTG asked us to simulate a future year (2024) to estimate how the benefits of a regional market would change under the currently foreseen planning assumptions ("Current Trends") as well as two sensitivities for fuel prices, load, and hydro generation.

For 2016 we analyzed four different cases, which simulate different market structures within the Mountain West footprint (while leaving the rest of the WECC region unchanged). The four different 2016 cases are:

- Status Quo ("2016 Case A")
- Joint Transmission Tariff ("2016 Case B")
- Regional Market ("2016 Case C")
- Regional Market while maintaining some Must Run generation ("2016 Case CMR")

A summary of the estimated production cost savings results from the 2016 simulation is presented below in Figure 2. These results indicate that the Mountain West participants would collectively experience a reduction in annual production costs of about $88 million/year by moving from the status quo (2016 Case A) to a regional market without must-run generation (2016 Case C). This compares with a $14 million/year production cost savings estimate from implementing only a joint transmission tariff in the Mountain West footprint (2016 Case B). The production cost reduction from a regional market would be less if the baseload units within the Mountain West maintained their current level of must-run operations. In that case the annual production cost savings from a regional market are estimated to be $53 million/year (2016 Case CMR). More detailed descriptions and discussion of the 2016 cases and simulation results are presented in Sections III and IV.

Figure 2: 2016 Simulations Production Cost Savings Results (2014 $ million/year)

Case		Production Cost	Savings vs. Status Quo
2016 Case A	Status Quo	$932	
2016 Case B	Joint Transmission Tariff	$918	$14
2016 Case C	Regional Market	$845	$88
2016 Case CMR	Regional Market with Must Run	$879	$53

For 2024, we simulated two different market structures in the Mountain West footprint based on current planning assumptions (and, again, retaining the existing market structures for the rest of the WECC region in all cases):

- Status Quo ("2024 Current Trends Case A")
- Regional Market ("2024 Current Trends Case C")

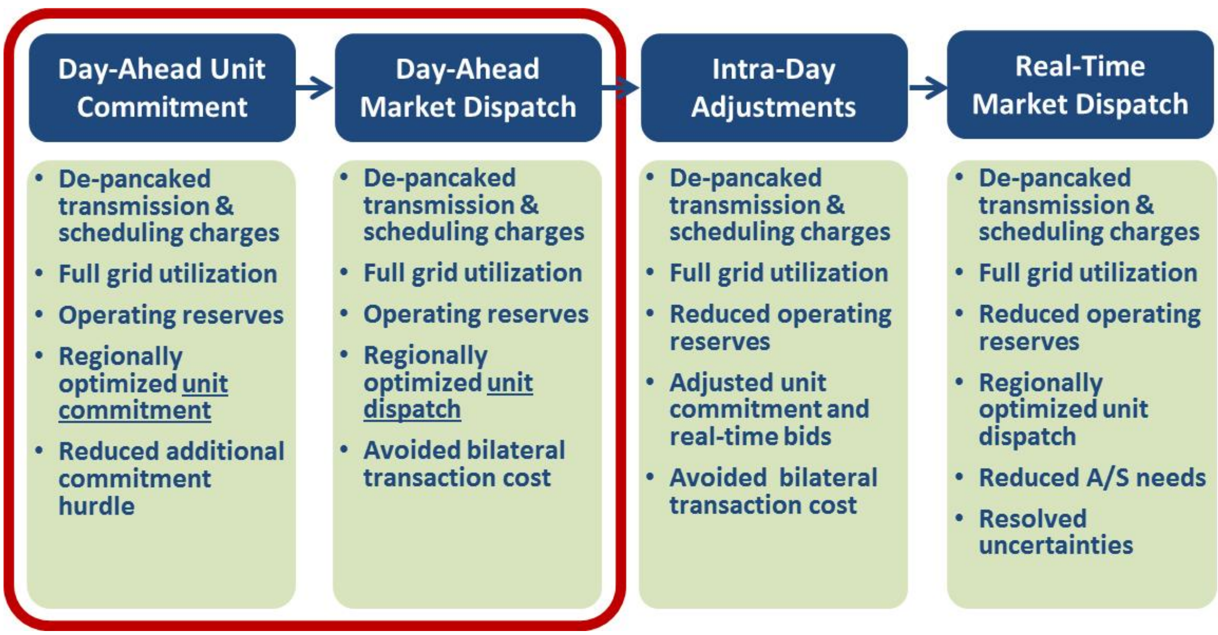
As requested by the Mountain West study participants, we simulated 2024 sensitivities of alternative fuel price, load, and hydro generation assumptions. Given that the natural gas price forecast under current-trends planning assumptions remains relatively low, the study participants requested a sensitivity analysis to test how the estimated benefits of a regional market would differ at higher natural gas prices in the region. Therefore we simulated the Status Quo and Regional Market cases for a 2024 High Natural Gas Price sensitivity. In addition, a 2024 Market Stress sensitivity (also simulated for the Status Quo and Regional Market cases) was undertaken with a combination of an elevated natural gas price, higher load across the WECC, and reduced generation from hydro plants in the Mountain West footprint. The production cost savings offered by a regional market as estimated in these 2024 simulations are presented in Figure 3.

Figure 3: 2024 Simulations Production Cost Savings Results (2014 $ million/year)

Case		Production Cost	Savings vs. Status Quo
2024 Current Trends Case A	Status Quo	$942	
2024 Current Trends Case C	Regional Market	$871	$71
2024 High Natural Gas Price Case A	Status Quo	$1,133	
2024 High Natural Gas Price Case C	Regional Market	$1,007	$126
2024 Market Stress Case A	Status Quo	$1,621	
2024 Market Stress Case C	Regional Market	$1,493	$128

The simulations conducted in this study consistently show that the Mountain West group would experience significant production cost savings from implementing a RTO-operated regional wholesale market. However, it is important to recognize that the savings shown in Figures Figure 2 and Figure 3 are a conservative estimate of the overall benefits offered by a regional market. The savings summarized above represent only the production cost reductions due to the increased efficiency of system dispatch in a regional market simulations based on perfect foresight of hourly system conditions, which are akin to day-ahead market operations. This study thus only simulated day-ahead unit commitment and market dispatch as indicated by the red circle in Figure 4. It does not simulate the intra-day and real-time operations of a regional market. Therefore, this study does not estimate the likely significant additional benefits related to the lower-cost balancing of uncertain renewable generation achieved in a regional market during real-time operations. A more detailed discussion of regional market impacts not addressed in this analysis is provided in Section V below.

Figure 4: Scope of Production Cost Modeling



III. Analytical Approach

The Mountain West entities requested that the analysis incorporates a simulation of a near-term year and a future year. The near-term year analysis is intended to illustrate how a change in market structure, if it were to happen today, would impact the operations and costs for the

Mountain West entities. For the near-term analysis, we simulated the Mountain West system (and the rest of WECC) in 2016, by using assumptions that represent the most up-to-date operating costs, load, and system topologies. For the future-year analysis we conducted a "scenario-based" planning process to gather the study participants' views about plausible future scenarios that are most relevant for analyzing the impact of market structure changes. While several possible future scenarios were discussed, the group decided to focus the analysis around a "Current Trends" scenario for 2024, reflecting a trajectory of how the relevant power sector policies and resources would evolve based on what is known today and projected out to 2024.

A. 2016 Analysis

For the 2016 analysis, we simulated the Mountain West region (and the rest of WECC) under three market structures for the Mountain West footprint. We started with the foundational system data contained in the 2024 WECC Transmission Expansion Planning Policy Committee ("TEPPC") Common Case database, which is publicly available. The TEPPC database was then supplemented with unit-specific operational data, load, fuel cost, and transmission-related data provided by the study participants for the Mountain West footprint.[2] We simulated a case for each of the three Mountain West market structures discussed above and an additional one that simulates a regional wholesale market in the Mountain West region while keeping the current operations of some baseload units as must-run generation, as requested by the group.[3] The four cases simulated for 2016 are:

- Status Quo ("2016 Case A")
- Joint Transmission Tariff ("2016 Case B")
- Regional Market ("2016 Case C")
- Regional Market while maintaining some Must Run Generation ("2016 Case CMR")

---

2 The data were provided to the Brattle team on a confidential basis and the data are not shared across the Mountain West participants. All data provided to Brattle and the individual participant level results of the simulations are confidential and protected by multi-lateral non-disclosure agreements ("NDA").

3 The must-run restriction applied in the simulation forces the model to keep the unit on at least at minimum generation levels unless the unit is on forced outage.

The remaining portions of the WECC were modeled identically in all cases, reflecting today's market structure.

B. 2024 Analysis

For the 2024 Current Trends analysis, we used the most up to date 2024 planning assumptions that each Mountain West entity provided for their system. Based on discussions with the study participants, we implemented changes from the 2016 simulations in three key areas: fuel prices, load, and generation resource mix.

The only fuel price altered between the 2016 and 2024 simulations was the price of natural gas. The 2024 simulations used the natural gas price forecast provided to us by the participants. The same gas price forecast is currently used in the resource planning assumptions of Colorado utilities. Given the current and foreseeable conditions in the coal markets, we assumed that coal prices would remain unchanged, in real dollar terms, between 2016 and 2024.

We assumed relatively modest load growth across the WECC between 2016 and 2024, using the "low load growth" forecast from each participant's resource plan,[4] with an average annual load growth from 2016 to 2024 for the Mountain West that ranges from 0% to 1.5%, across the different participants' service territories.

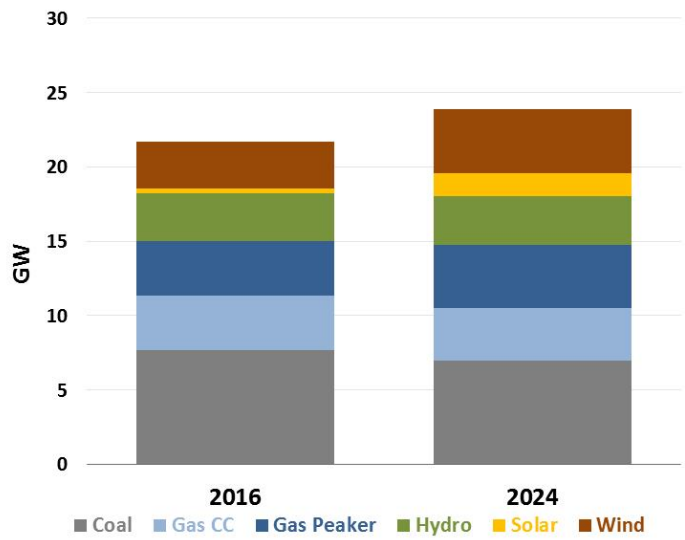
The 2024 simulations reflect planned unit retirements and additions provided by the participating entities. Figure 5 below shows how total generation capacity by fuel type changed between the 2016 and 2024 simulations. The 2024 resource mix accounts for about 700 MW of coal generation retirements currently planned to be implemented in the Mountain West region prior to 2024. Of the 700 MW of retiring coal capacity, about half is expected to be converted to natural gas-fired generation. The other resource changes currently planned within the Mountain West footprint involve the addition of new wind and solar resources, as well as gas peakers. Consistent with the current resource plans of the Mountain West entities, we add about 1,100 MW of new wind generation and about 1,200 MW of new solar generation to the Mountain West system by 2024. These renewable generation additions are mostly driven by the expected compliance with the existing renewable portfolio standard in Colorado. As a result, all

---

[4] Certain entities that do not have recent resource plans provided us with their load growth forecasts.

but 30 MW of the new wind and all but 20 MW of the new solar resources are added in Colorado.

Figure 5: Generation Capacity in the Mountain West: 2016 vs. 2024 Simulations (GW)



In addition to simulating the 2024 Current Trends scenario, we conducted two sets of sensitivities cases around the 2024 Current Trends scenario. The first sensitivity analysis ("2024 High Natural Gas Price") assumes that natural gas prices roughly double relative to the 2024 Current Trends scenario. The second sensitivity analysis ("2024 Market Stress") used the same higher natural gas prices, along with a significantly higher load across the Mountain West region, and a roughly 30% reduction in energy production from WAPA's hydro generation. The purpose of the sensitivity analyses is to test how the potential impact of market structure would change if market conditions were temporarily, significantly different from those under Current Trends. For instance, the High Gas Price Sensitivity analysis represents a situation where natural gas prices are significantly higher in 2024 than expected under Current Trends scenario. It does not assume a trajectory of a higher or increasing natural gas prices trend through 2024.

The distinction we draw in the sensitivity analysis and other long-term scenarios is that the sensitivity analysis is not a sustained market condition. For example, under a hypothetical high natural gas price future analysis, one would expect a significant amount of increase in renewable investment because a trajectory of higher gas prices would increase the market prices of power in the region and attract more renewable resource generation investment to the region. Instead, the 2024 High Natural Gas Price sensitivity reflects only a one-off change of one variable—the gas price in 2024—around the Current Trends scenario. Similarly, the 2024 Market Stress sensitivity reflects a simulated situation where several conditions coincide to create a stress in the marketplace in a particular year (2024). This stress case is not a simulated longer-term trajectory of a combination of significant draught, high load growth, and high gas price. If those conditions were projected to exist over a long-term, a significant amount of renewable resources would enter into the marketplace.

For the Current Trend scenario and the two sensitivities we simulated two different Mountain West market structures: the Status Quo case ("2024 Cases A") and the Regional Market case ("2024 Cases C"). The resulting six 2024 cases simulated in this analysis consequently include:

- Current Trends—Status Quo ("2024 Current Trends (Case A)");
- Current Trends—Regional Market ("2024 Current Trends (Case C)");
- High Natural Gas Price Sensitivity—Status Quo ("2024 High Natural Gas Price (Case A)");
- High Natural Gas Price Sensitivity—Regional Market ("2024 High Natural Gas Price (Case C)");
- Market Stress—Status Quo ("2024 Market Stress (Case A)"); and
- Market Stress—Regional Market ("2024 Market Stress (Case C)").

The 2024 planning assumptions and market structure in the rest of the WECC region are based on the TEPPC 2024 Common Case database (reflecting the region's current market structure) with updates for planned generation retirements and plant additions of major western utilities based on their recent resource planning information.[5]

---

5 The public information of these updates to planning assumptions was collected by The Brattle Group in a study for the CAISO, as posted here: https://www.caiso.com/Documents/SB350Study-Volume5ProductionCostAnalysis.pdf

C. SIMULATIONS OF 2016 AND 2024 "STATUS QUO" BILATERAL MARKET CASES

For all of the "Status Quo" cases,[6] we simulated the existing bilateral market structure by means of a transaction cost adder that included four layers of "hurdles." These transaction costs are associated with buying, selling, or transporting power across utilities. They include the sum of:

1. Wheeling charges (for moving power from one utility to the next) as specified in the transmission owners' Open Access Transmission Tariffs (OATTs)
2. Administrative charges for transmission services as specified in the OATTs (assumed at $1/MWh)
3. Trading margins in the form of bid-ask spreads to simulate the fact that bilateral trades occur only if and when the sellers can earn a reasonable margin; and the buyer would only purchase power from a third-party when the power is cheaper by some margin below its own cost of production. These bid-ask spreads are assumed to be $1.50/MWh for buyers and another $1.50/MWh for sellers.
4. An additional hurdle rate applicable only for unit commitment decisions, assumed to be $4/MWh based on industry experience from other regions.

Items Nos. 1, 2, and 3 above mean the hurdle rates during the generation dispatch phase of the simulations are the sum of the wheeling charges and $4/MWh in administrative charges and trading margins. During the unit commitment phase of the simulations, an additional $4/MWh hurdle applies such that the total hurdle is the sum of the wheeling charges and $8/MWh. These hurdle rates are then varied across the market structure cases as shown in Figure 6 below.

The other assumptions used to simulate the Status Quo cases include:

- Less efficient use of transmission facilities under purely bilateral trading by de-rating the path limits on major transmission paths in the Mountain West region to approximate the maximum and minimum path flows experienced in the region based on information provided by the participants;
- Some baseload generation units are operated as must-run generation based on existing practices; and

6 The status quo cases include: 2016 Status Quo ("2016 Case A"), 2024 Current Trends–Status Quo ("2024 Current Trends (Case A)"), 2024 High Natural Gas Price Sensitivity–Status Quo ("2024 High Natural Gas Price (Case A)"), and Market Stress–Status Quo ("2024 Market Stress (Case A)")

- Each Mountain West entity is required to provide a certain amount of operating reserves from its own resources.

D. Simulations of the 2016 "Joint Tariff" Bilateral Market Case

In the 2016 Joint Transmission Tariff case ("2016 Case B"), we simulated the Mountain West footprint without region-internal transmission charges and without the internal transmission administrative charge (of $1/MWh). We maintained the rest of the bilateral market structure and assumed transactions costs (i.e., trading margins). We assumed a uniform wheeling-out charge to move power out of the Mountain West region to neighboring regions. This rate was calculated as the transmission-revenue-requirement-weighted average of the Mountain West entities' existing transmission rates. For the Joint Transmission Tariff market structure ("2016 Case B") we also partially relaxed the de-rating assumption applied to transmission facilities under the Status Quo. This change was made to approximate the likely increase in efficiency of region-wide transmission scheduling by a single entity under a jointly-administered transmission tariff. We continued to apply a partial de-rate to the Mountain West transmission capabilities to capture the less-than-fully efficient use of these facilities in a bilateral market.

E. Simulations of the 2016 and 2024 Regional Market Cases

Figure 6 summarizes the levels of transactions costs (hurdle rates) for each of the three different market structures. In the regional market cases, all four hurdles used to simulate transactions costs in a bilateral market were removed within the Mountain West region. This allows the model to simulate an optimal centralized unit commitment and dispatch across the entire Mountain West footprint, as would be the case if the region were operated as a RTO market. The Regional Market cases also completely removed the de-rating of transmission capabilities and, additionally, allow for operating reserves procured economically by a single market operator for the entire Mountain West footprint from the entire pool of resources in the region.

Figure 6: Transaction Cost Assumptions for Simulating Different Market Structures

Case	Wheeling Rate	Combined Administrative, Trading, and Commitment Hurdle	Area Connections
Status Quo	Average of on- and off-peak export transmission wheeling charges for each entity	\$8/MWh commitment adder, \$4/MWh dispatch adder	Existing connections without transmission charges as provided by Mountain West entities
Joint Tariff	**Export From Mountain West**: Average of each entity's on- and off-peak transmission wheeling charge, weighted by the area's transmission revenue requirement **Intra-Mountain West Connections:** No hurdle	**Export From Mountain West**: \$8/MWh commitment adder, \$4/MWh dispatch adder **Intra-Mountain West Connections:** \$7/MWh commitment adder, \$3/MWh dispatch adder	No transmission charges for trading between areas within Mountain West Any external area that connected to at least one area in Status Quo now connects to all Mountain West entities
Regional Market	Same as Joint Tariff	**Export From Mountain West**: Same as Joint Tariff **Intra-Mountain West Connections:** No adders	Same as Joint Tariff

IV. Summary of Findings

In this report, we focus on several key simulation results and computed metrics to illustrate the impact of different market structures on Mountain West. Specifically, we highlight four key results or metrics:

- The Adjusted Production Cost ("APC") metric
- Average annual power prices produced by the model
- Aggregate shifts in generation by fuel type for the Mountain West region
- Simulated power flows across major transmission paths in the Mountain West region

We focus on these metrics as they provide the most relevant description of the impacts of changes in market structure as captured by the production cost simulations. We qualitatively discuss other potential impacts associated with operating in a regional market in Section V.

We first present the results and metrics for the 2016 simulations and then summarize the 2024 simulations.

A. 2016 SIMULATION RESULTS

This section presents the results for the 2016 simulations. We explain the key takeaways and intuition from these results and how to interpret them when considering participating in a regional market.

1. Adjusted Production Cost Metric

The Adjusted Production Cost metric is a simplified metric widely used in the industry to estimate the production costs of individual entities represented in these types of market simulations. The metric allows us to estimate the production cost savings that the Mountain West entities would experience under the different simulated market structures. The adjusted production cost reflects the **net costs associated with production, purchases, and sales of wholesale power**. For the Mountain West entities, adjusted production costs are calculated as:

(+) Generator costs (fuel, start-up, and variable operation and maintenance ("O&M")) for generation owned or contracted by the Mountain West entities;

(+) Costs of market purchases by the Mountain West entities from other generators and imports from neighboring regions; and

(–) Revenues from market sales and exports by the Mountain West entities.

In Figure 7 below, the left hand side of the table (Columns 1-4) displays the different components of the APC metric for each of the four 2016 simulation cases. The first row (labeled "Production") calculates the total cost of producing power in the Mountain West region for each of the simulated cases. The second row (labeled "Purchases") shows the total cost of all off-system purchases made by Mountain West entities. These values include the cost associated with power purchases from other entities in the Mountain West region and from systems outside the Mountain West footprint. The third row (labeled "Sales") shows the estimated revenues that Mountain West entities receive from selling power to others. The estimated sales revenues include sales to other Mountain West entities as well as to others outside the Mountain West footprint. The last row (labeled "Total") is calculated as Production Costs *plus* Purchases Costs *minus* Sales Revenues. This "total" amount represents the overall cost for the Mountain West entities to produce or procure the power needed to serve load less any revenues generated from selling off-system.

The grey-shaded area (columns 5-7) on the right hand side of Figure 7 compares the adjusted production cost components of the alternative market structures (Cases B, Case CMR, and Case C) to the Status Quo case (Case A). These columns show the monetary benefits achieved in each alternative market structure compared to the Status Quo (2016 Case A). Column 5 of Figure 7 labeled "B–A Difference" shows the difference in this APC component between the Status Quo (2016 Case A) and the Joint Tariff (2016 Case B) simulations. It shows our estimate that adjusted production costs in the Mountain West region decreases by $14 million/year when the region implements a joint transmission tariff. The components of such a $14 million/year decrease include a $9 million/year reduction in the cost of producing power in the Mountain West region, a $5 million/year increase in the cost of purchasing power, and a $10 million/year increase in total off-system sales revenue by the Mountain West group.

Following the same logic, column 7 of Figure 7 shows that, if the Mountain West region were to implement a RTO-operated regional market, the overall adjusted production cost savings are estimated at $88 million/year for the simulated 2016 market conditions. Since there are some uncertainties around how the existing must-run generators would operate in a regional market, we also simulated a regional market in which some of the baseload generators maintain their must-run operating approach. As one would anticipate, maintaining the must-run status decreases the adjusted production cost savings by about $35 million/year, resulting in an estimated savings of $53 million/year (shown in column 6 of Figure 7).

Figure 7: APC Comparison for 2016 Simulations: Total Production Cost (2014 $million/yr)

	Total ($m/yr)						
					B-A	CMR-A	C-A
	Case A	Case B	Case CMR	Case C	*Difference*	*Difference*	*Difference*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Production	$1,033	$1,024	$1,090	$992	($9)	$57	($41)
Purchases	$99	$104	$132	$208	$5	$34	$109
Sales	$199	$209	$343	$355	$10	$144	$156
Total	$932	$918	$879	$845	($14)	($53)	($88)

Figure 8 displays the average cost of production and average price paid for off-system purchases and sales for the 2016 cases simulated. The figure shows the estimated average prices under the different market structures. Column 7 (labeled "C–A Difference") indicates that the weighted average cost of production in the Mountain West region is reduced by $0.64/MWh under a regional market, the weighted-average price paid for purchased power decreased by $2.04/MWh, and the weighted-average price received for off-system sales increased by $1.84/MWh. These changes in average prices show that more efficient market transactions will occur under a regional market.

Figure 8: Comparison of Cost and Price Changes (2014 $/MWh) for the 2016 Simulations

	$/MWh						
	Case A	Case B	Case CMR	Case C	B-A *Difference*	CMR-A *Difference*	C-A *Difference*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Production	$13.34	$13.29	$13.29	$12.70	($0.05)	($0.05)	($0.64)
Purchases	$21.00	$19.29	$17.77	$18.96	($1.71)	($3.23)	($2.04)
Sales	$17.59	$18.01	$18.39	$19.43	$0.41	$0.80	$1.84
Total	$13.17	$12.98	$12.42	$11.94	($0.20)	($0.75)	($1.24)

Figure 9 shows the magnitude of energy that the Mountain West group of entities produces and trades under the different market structures. Column 7 of the figure shows the changes experienced by the Mountain West group as it operates in a regional market. As shown, the group produces approximately 1% (0.7 TWh) more power under a regional market than under the status quo bilateral market, which is exported to neighboring systems. As the table shows, the group also trades more, both with each other and with neighboring systems, under a regional market than under the status quo case for 2016.

Figure 9: Comparison of Production and Trading Changes (TWh) for the 2016 Simulations

	TWh						
	Case A	Case B	Case CMR	Case C	B-A *Difference*	CMR-A *Difference*	C-A *Difference*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Production	77.4	77.0	82.0	78.1	(0.4)	4.6	0.7
Purchases	4.7	5.4	7.5	11.0	0.7	2.8	6.3
Sales	11.3	11.6	18.7	18.3	0.3	7.4	7.0
Total	70.8	70.8	70.8	70.8	0	0	0

In summary, Figure 7–Figure 9 above show that, based on our 2016 simulations, a RTO-operated regional market in the Mountain West region would generate production cost savings of approximately $88 million/year compared to the existing bilateral market. As the group produces power more efficiently and trades more cost-effectively with each other and with neighbors, the Mountain West entities would capture these efficiency gains.

2. Price Shifts Caused by Transition to a Regional Market

The simulations we conducted produce hourly locational marginal prices at every generator and load bus across the entire WECC region. This allows us to compare market prices across the Mountain West system and observe how changes in the market structure affect prices across locations. Figure 10 presents the 2016 simulation results of average annual market prices at different locations across the WECC. The table shows five key pricing points within the Mountain West region: Ault, Laramie River, Dave Johnston, Craig, and Midway; and two points in the WECC outside Mountain West: Palo Verde and Four Corners. The table also shows the load-weighted average price for the Mountain West footprint in 2016.

Figure 10: 2016 Average Annual Prices in the 2016 Simulations (2014 $/MWh)

	Case A	Case B	Case CMR	Case C	Case B - Case A	Case CMR - Case A	Case C - Case A
Ault	20.22	19.44	18.35	19.48	(0.78)	(1.88)	(0.75)
Laramie River	19.20	19.42	18.12	19.23	0.21	(1.08)	0.02
Dave Johnston	20.60	21.19	20.48	21.16	0.59	(0.12)	0.56
Craig	20.09	19.87	19.72	18.53	(0.22)	(0.37)	(1.57)
Midway	17.06	17.27	19.68	18.55	0.21	2.62	1.50
Palo Verde	24.88	24.74	24.53	25.03	(0.15)	(0.35)	0.15
Four Corners	22.35	21.91	21.59	22.35	(0.44)	(0.77)	(0.01)
MWTG Load-Weighted	18.62	18.29	18.52	19.63	(0.33)	(0.10)	1.01

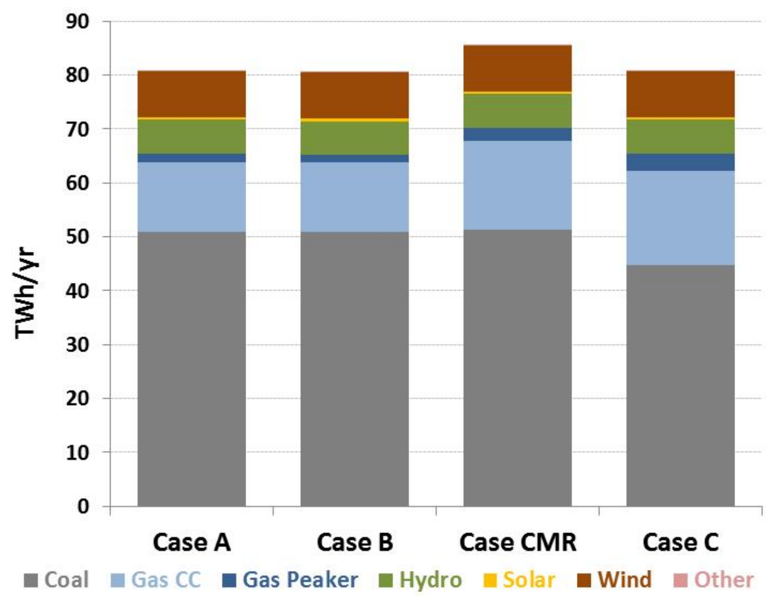
As Figure 10 shows, the average price spreads between points across the Mountain West generally decrease under a regional market. For example, the estimated average annual market prices at Ault and the Mountain West region's load-weighted price for the 2016 Status Quo case (Case A) were $20.22/MWh and $18.62/MWh respectively—a price spread of over $1.50/MWh. Under the 2016 Regional Market case (Case C) we see that spread collapses to $0.15/MWh (the difference between $19.48 and $19.63). Similar patterns can be observed when considering the prices at Laramie River, Craig, and Midway, compared to the load-weighted price for the Mountain West region. This price convergence is anticipated since trades can occur more efficiently within a regional market. These efficiency gains come from more effective use of existing transmission facilities, the removal of trading barriers between regions, and the increased efficiency of dispatch, all of which allows more power to flow from low-priced areas to higher-priced areas, which allows prices to converge.

3. Generation Shifts between Resource Types

The implementation of a regional market will increase efficiency in generation commitment and dispatch, resulting in more generation output from resources with lower costs, including the costs associated with start-ups and operating subject to minimum generation. At the low natural gas prices currently witnessed in the marketplace (and replicated in the model assumptions), moving from the Status Quo (2016 Case A) to a Regional Market (2016 Case C), the Mountain West region would produce less power from the region's coal plants and more from gas-fired generation. This effect of low natural gas prices is compounded as must-run operating practices at some of the region's coal plants would no longer be necessary, and the regional market allows for more efficient commitment and dispatch of all plants in the region to minimize the cost of producing energy and providing operating reserves.

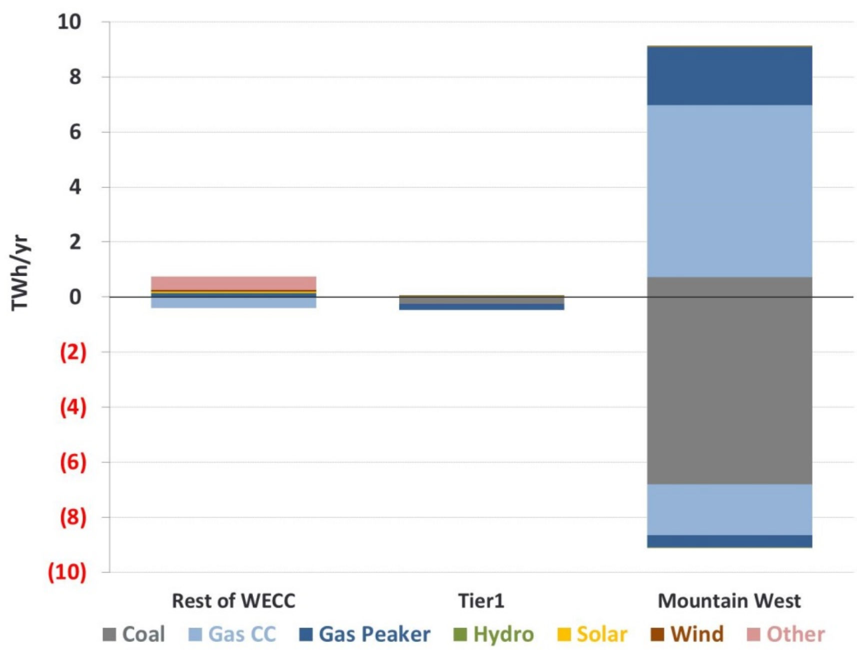
Figure 11 shows the shift of generation output across the four cases simulated for 2016. As shown, the shift in generation between the Status Quo case (2016 Case A) and the Joint Tariff case (2016 Case B) is small, which is consistent with the limited production cost benefits achieved with only a joint transmission tariff. In the Regional Market (2016 Case C), we observe an increase of over 6 TWh of gas-fired generation and an equally sized decrease in coal generation.

Figure 11: Mountain West Generation Levels in 2016 Simulations (TWh)



This shift from coal to gas within the Mountain West region under the 2016 Regional Market case (Case C) is apparent in Figure 12 below, which shows the impact of the Mountain West regional market on both the generation output of the Mountain West and other generation owners across the WECC. We defined "Tier 1" as the balancing areas that have direct interconnection with at least one of the Mountain West participants.[7] Figure 12 shows that the implementation of a regional market in the Mountain West region will have very little impact on generation output outside of the Mountain West region. Within the Mountain West region, the regional market will drive a net reduction of approximately 7 TWh/year from coal generation, a net increase of close to 6 TWh/year of generation from gas combined-cycle plants ("CCs"), and another 2 TWh/year net increase in generation from gas combustion turbines ("CTs").

Figure 12: Generation Level Changes 2016 Regional Market vs. Status Quo (TWh)



While the low natural gas prices currently seen in the market, which are reflected in the simulations, provide for significant benefits from fuel switching between coal and gas when the must-run operation for some of the coal plants in the region ceases, this is only a part of what drives the benefit of a regional market. The regional market provides benefits by increasing

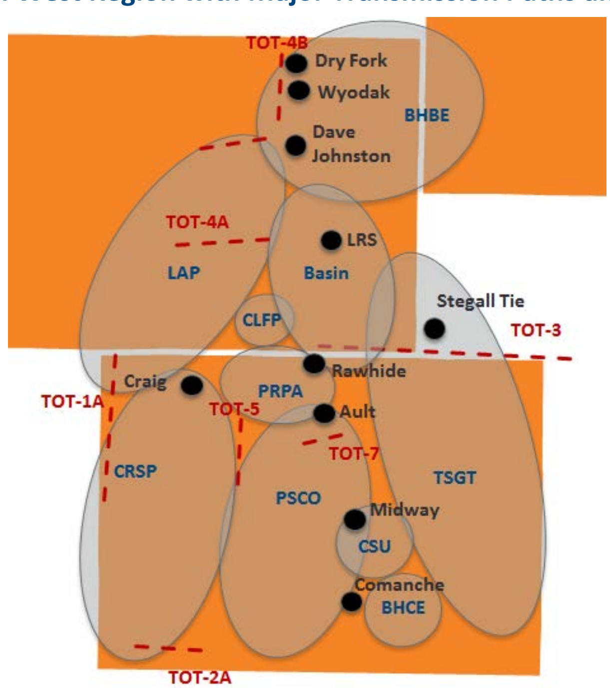
[7] The Tier 1 connections consist of the following balancing areas: Arizona Public Service Electric Company, PacifiCorp (eastern balancing area), El Paso Electric Company, NorthWestern Energy Corp., Public Service Company of New Mexico, Salt River Project, Tucson Electric Power, WAPA Lower Colorado Region, and WAPA Upper Great Plains.

production from the most efficient coal units and decreasing production from the least efficient coal units. This is illustrated by the data presented in Figure 12. The small grey bar that appears above the zero-axis in the Mountain West column indicates that some coal units in the region actually produce more under a regional market even while a significant number of coal units experience a decrease in production (shown as the grey bar below the zero-axis). The same effect can be seen for gas-fired units. These effects show that the regional market achieves a more efficient dispatch not only by switching to lower cost fuels, but also by switching to more efficient units within the same fuel.

4. Changes in Power Flows on the Mountain West System

Through the simulations, we report the hourly power flows across the most relevant transmission paths. We report the hourly power flow data for the major WECC paths within the Mountain West region. These paths are TOT1A, TOT2A, TOT3, TOT4A, TOT4B, TOT5, and TOT7. Below in Figure 13 is a diagram showing the locations of the WECC paths and large generating units (and trading locations) in the Mountain West region relative to the service areas of the Mountain West Transmission Group entities.

Figure 13: Mountain West Region with Major Transmission Paths and Generating Plants



For each of these transmission paths, the model includes a limit on how much power can flow across the path in each hour. For the transmission paths in Mountain West region, we used path limitations provided by the Mountain West entities. The limits used in the 2016 Status Quo case (2016 Case A) are based on the actual trading experiences of the Mountain West entities. Based on these input assumptions provided by the Mountain West entities, we limited the power flows across the paths within the Mountain West under the Status Quo case (2016 Case A) and Joint Transmission Tariff case (2016 Case B) to levels lower than under the Regional Market case (2016 Case C). The limits placed across certain paths under the Status Quo (2016 Case A) and Joint Transmission Tariff (2016 Case B) are summarized in Figure 14. The flow limits used in the Regional Market (2016 Case C) reflect the limits defined in the WECC path rating catalog for the relevant transmission paths and are higher than those imposed under the Status Quo case (2016 Case A) and the Joint Transmission Tariff case (2016 Case B). We have *not* altered the physical characteristics of the transmission lines.

Figure 14: Path Limits in the 2016 Status Quo (Case A), Joint Transmission Tariff (Case B), and Regional Market (Case C) Simulations

		Status Quo		Joint Tariff		Regional Market	
Path	Flow Direction	Min	Max	Min	Max	Min	Max
TOT 1A	West to East	-400	400	-550	550	-650	650
TOT 2A	South to North	-350	350	-540	540	-690	690
TOT 3	South to North	-1,100	1,100	-1,450	1,450	-1,680	1,680
TOT 4A	Southwest to Northeast	-750	750	-810	810	-810	No limit
TOT 4B	Northwest to Southeast	-750	750	-880	880	-880	No limit
TOT 5	West to East	-1,400	1,200	-1,500	1,200	-1,680	No limit
TOT 7	South to North	-550	550	-700	890	-890	890

Figure 15 shows the simulated hourly flows across TOT3 under Status Quo (2016 Case A), Joint Transmission Tariff (2016 Case B), and Regional Market (2016 Case C). As shown earlier in Figure 13, TOT3 consists of the transmission system that stretches between southern Wyoming and northern Colorado. The red line in Figure 15 shows the flows across TOT3 for the Status Quo (2016 Case A) simulation. The light-red horizontal lines show the 1,100 MW limit imposed on the path under the Status Quo (2016 Case A). The light-blue line in Figure 15 shows the simulated flows across TOT3 in the Joint Transmission Tariff case (2016 Case B), and the dark-blue line shows the simulated flows in the Regional Market case (2016 Case C). The ability to increase flows across TOT3 under the Regional Market (2016 Case C) is intended to simulate the more efficient use of transmission scheduling possible in RTO markets relative to regions where transmission is scheduled bilaterally.

Figure 16 below shows a summary of the simulated hourly flows across all the paths in the Mountain West region for the Status Quo case (2016 Case A), the Joint Transmission Tariff case (2016 Case B), and the Regional Market case (2016 Case C).

Figure 15: TOT3 2016 Simulated Power Flows

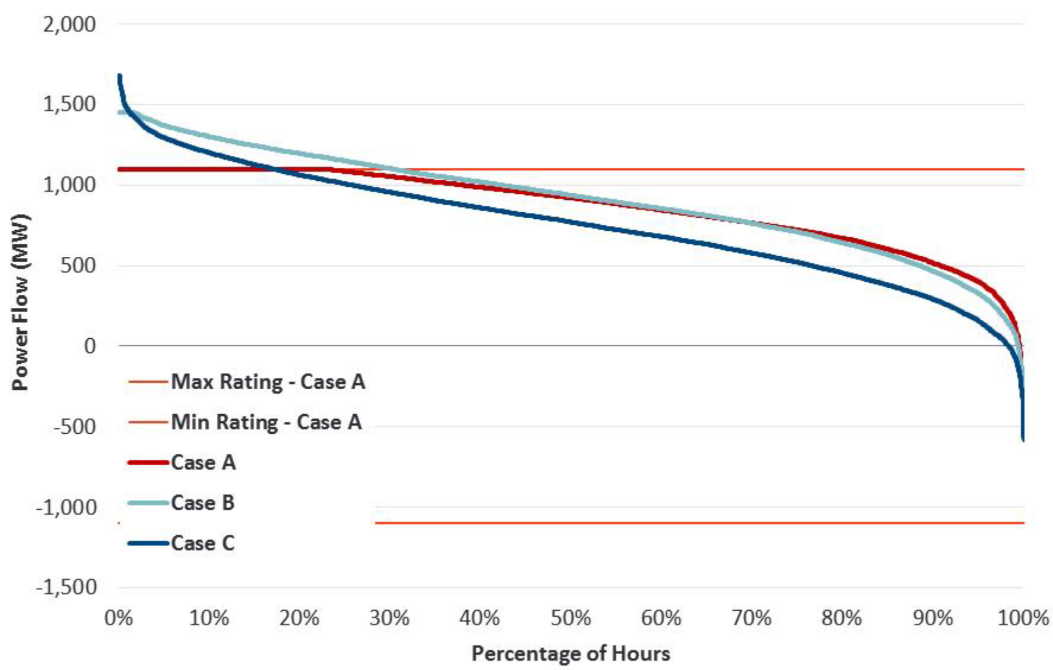


Figure 16: Simulated Flows in 2016 Status Quo (Case A), Joint Transmission Tariff (Case B), and Regional Market (Case C)

		Status Quo			Joint Tariff			Regional Market		
Path	Flow Direction	Min	Average	Max	Min	Average	Max	Min	Average	Max
TOT 1A	West to East	-359	244	400	-327	257	550	-181	330	650
TOT 2A	South to North	-350	43	350	-540	24	540	-437	142	690
TOT 3	South to North	-430	860	1,100	-432	906	1,450	-584	755	1,680
TOT 4A	Southwest to Northeast	-629	-216	299	-684	-271	163	-770	-347	76
TOT 4B	Northwest to Southeast	-750	-429	84	-786	-366	112	-814	-374	57
TOT 5	West to East	-612	365	1,200	-572	414	1,200	-469	830	2,434
TOT 7	South to North	-464	1	550	-700	-15	830	-562	215	890

Figure 17 shows how much congestion was experienced across these transmission paths in the 2016 simulations. The figure indicates the number of hours each path was congested and the total annual congestion charges. The amount of congestion indicates how much production costs increase due to congestion on each path. As seen in the figure, TOT 1A, TOT2A, and TOT3 experienced the most congestion in our 2016 simulations. In the 2016 Status Quo (Case A) congestion across all paths in the Mountain West would have caused congestion charges of over $18 million per year, while in the Regional Market (Case C) the total congestion charges were roughly $15 million per year. In the Status Quo case, the most congested path within the interior of the Mountain West region was TOT3. This congestion was almost entirely eliminated in the regional market cases.

Figure 17: Simulated Flows in the 2016 Simulations

		Number of Hours the Path is Constrained				Annual Congestion Cost ($ Millions)			
Path	Flow Direction	Case A	Case B	Case CMR	Case C	Case A	Case B	Case CMR	Case C
P30 TOT 1A	West to East	1896	693	1172	805	$9.93	$4.61	$8.11	$14.71
P31 TOT 2A	South to North	884	121	154	98	$0.30	$0.08	$0.19	$0.39
P36 TOT 3	South to North	1992	149	8	8	$7.85	$0.24	$0.01	$0.01
P37 TOT 4A	Southwest to Northeast	0	0	0	0	$0.00	$0.00	$0.00	$0.00
P38 TOT 4B	Northwest to Southeast	7	0	0	0	$0.04	$0.00	$0.00	$0.00
P39 TOT 5	West to East	20	67	0	0	$0.07	$0.37	$0.00	$0.00
P40 TOT 7	South to North	9	0	1	10	$0.06	$0.00	$0.08	$0.00
Total		4808	1030	1335	921	$18.25	$5.29	$8.39	$15.11

B. 2024 Simulation Results

1. Adjusted Production Cost Metrics

The estimated adjusted production cost savings for the 2024 simulations are presented in Figure 18 through Figure 20 below. For 2024, we simulated a baseline future scenario ("Current Trends") reflecting existing conditions and already-projected changes. We also analyzed two sensitivities of that Current Trends future: "High Natural Gas Price" and "Market Stress". For these baseline scenario and sensitivity cases, we simulated a Status Quo case (2024 Cases A) that reflects the existing bilateral market in the Mountain West region and a Regional Market case (2024 Cases C) that implements a RTO-operated wholesale power market in the Mountain West footprint. (The rest of the WECC region is simulated based on the status quo in all cases.)

Figure 18 presents the adjusted production cost metric for both the Status Quo (2024 Current Trends Case A) and the Regional Market (2024 Current Trends Case C) cases for the Current Trends baseline scenario. We estimate a benefit of $71 million/year attributable to the regional market, as shown in column 9 in Figure 18. This benefit represents an approximately 7.6% reduction of total 2024 production costs in the Mountain West region.

Figure 18: Adjusted Production Cost Comparison for *2024 Current Trends* Simulations (2014$)

	TWh			$/MWh			Total ($m/yr)		
	Case A	Case C	C-A *Difference*	Case A	Case C	C-A *Difference*	Case A	Case C	C-A *Difference*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Production	82.2	84.1	1.9	$12.41	$12.15	($0.27)	$1,020	$1,021	$1
Purchases	5.0	7.1	2.1	$25.45	$23.19	($2.26)	$128	$165	$37
Sales	9.9	13.9	4.0	$20.74	$22.67	$1.92	$206	$316	$110
Total	77.3	77.3	0	$12.19	$11.27	($0.92)	$942	$871	($71)

Figure 18 also shows the main drivers of the adjusted production cost savings in the 2024 Current Trends simulations. The figure shows that average production costs remain relatively flat, decreasing by only $0.27/MWh between the Status Quo (2024 Current Trends Case A) and the Regional Market (2024 Current Trends Case C). However, as shown in column 3 above, the Mountain West entities increase their aggregate power production by about 2 TWh (about 2.3%) and therefore export more power to neighboring regions in the Regional Market case (2024 Current Trends Case C) compared to the Status Quo case (2024 Current Trends Case A). The APC benefits in the 2024 Current Trends scenario thus are primarily derived from higher profits from sales to each other within the Mountain West group and to the neighboring areas. Even though on aggregate, the Mountain West entities would spend more on producing power and power purchases, the additional profits from their increased sales in the Regional Market (2024 Current Trends Case C) create significant benefits to the Mountain West entities and their customers. This increase in purchases and sales is shown in column 3 of Figure 18, which indicates that the Mountain West group increases its trading volumes by over 6 TWh under a regional market (sum of the 2 TWh increase in purchases and the 4 TWh increase in sales). Column 6 shows that the average price of purchased power for the Mountain West entities declines by $2.26/MWh and that the average revenue earned from off-system sales increases by $1.92/MWh. Overall, the dispatch and trading efficiencies net approximately $71 million/year benefit for the Mountain West and its customers under the Regional Market (2024 Current Trends Case C).

Figure 19 and Figure 20 show the result for the two sensitivity analyses of the 2024 Current Trends future: High Natural Gas Price and Market Stress. In both of these sensitivity analyses, the benefits of the Regional Market (2024 Cases C) are considerably larger than under the Current Trends baseline scenario described above. The higher regional market benefits in the sensitivity cases compared to the Current Trends baseline are driven primarily by the higher gas prices used in these simulations. With the significantly higher gas price assumption in the 2024 sensitivities, the overall APC benefits increase significantly. In these sensitivity cases, the simulation of a Mountain West regional market causes a larger shift from higher-cost gas-fired generation to coal-fired generation. In addition, we see a larger shift from high-cost gas generation to low-cost gas generation, which provides significant additional benefits.

Overall, the APC savings for the 2024 High Natural Gas and Market Stress sensitivities are $126 million/year and $128 million/year respectively (shown in column 9 of the two figures). These savings are equivalent to an 11.1% reduction in production costs in the High Natural Gas Price sensitivity and a 7.9% reduction in the Market Stress sensitivity.

Figure 19: APC Comparison for *2024 High Natural Gas Price Sensitivity* Simulations (in 2014$)

	TWh			$/MWh			Total ($m/yr)		
	Case A	Case C	C-A *Difference*	Case A	Case C	C-A *Difference*	Case A	Case C	C-A *Difference*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Production	80.3	79.3	(1.0)	$14.56	$13.22	($1.35)	$1,169	$1,048	($121)
Purchases	6.4	8.0	1.6	$42.66	$40.31	($2.36)	$274	$324	$49
Sales	9.4	10.0	0.6	$33.00	$36.43	$3.43	$311	$365	$54
Total	77.3	77.3	0	$14.66	$13.03	($1.63)	$1,133	$1,007	($126)

Figure 20: APC Cost Comparison for *2024 Market Stress Sensitivity* Simulations (in 2014)

	TWh			$/MWh			Total ($m/yr)		
	Case A	Case C	C-A *Difference*	Case A	Case C	C-A *Difference*	Case A	Case C	C-A *Difference*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Production	82.7	80.8	(1.9)	$16.76	$15.15	($1.60)	$1,386	$1,224	($162)
Purchases	9.5	12.0	2.5	$45.75	$42.94	($2.80)	$434	$514	$79
Sales	5.5	6.1	0.5	$36.17	$40.51	$4.34	$199	$245	$46
Total	86.7	86.7	0	$18.70	$17.22	($1.48)	$1,621	$1,493	($128)

The average production costs due to participation in a regional Market drop significantly in both sensitivity analyses. The results shown in the figures indicate that, by comparing 2024 High Gas Price Regional Market (Case C) with 2024 High Gas Price Status Quo (Case A), the cost of production decreased by $121 million/year. Production costs decreased by $162 million/year under the 2024 Market Stress Regional Market (Case C) compared to the 2024 Market Stress Status Quo (Case A). In both sensitivity analyses, the reduction in production costs is the largest driver of benefits under the regional market. The gains from more efficient trading further increases benefits as the average price of purchased power falls by over $2/MWh (while purchasing more under the regional market) and the average revenue gained by off-system sales increases by about $4/MWh in both sensitivity analyses.

2. Price Shifts Caused by Transition to a Regional Market

Figure 21 presents the average prices at different locations for the 2024 Current Trends scenario and the High Natural Gas Price and Market Stress sensitivities. The figure summarizes the 2024 annual average price at five points within Mountain West: Ault, Laramie River, Dave Johnston, Craig, and Midway. It also shows a 2024 load-weighted average price for the Mountain West area, and average prices at Palo Verde and Four Corners.

Figure 21: 2024 Average Annual Prices in the 2024 Simulations (2014 $/MWh)

	Current Trends			High Natural Gas Price			Market Stress		
	Status Quo	Market	Market - Status Quo	Status Quo	Market	Market - Status Quo	Status Quo	Market	Market - Status Quo
Ault	24.45	23.49	(0.96)	41.60	39.19	(2.40)	45.64	42.60	(3.03)
Laramie River	23.61	23.20	(0.41)	35.37	38.65	3.28	38.95	42.20	3.25
Dave Johnston	22.91	23.10	0.19	34.15	37.03	2.88	36.21	39.88	3.67
Craig	25.13	23.84	(1.29)	41.46	39.93	(1.53)	45.47	43.17	(2.30)
Midway	22.57	23.72	1.14	40.83	39.61	(1.22)	45.22	42.92	(2.31)
Palo Verde	27.44	27.30	(0.15)	45.99	45.44	(0.55)	45.78	45.73	(0.05)
Four Corners	26.81	26.40	(0.40)	46.03	45.33	(0.70)	44.12	44.01	(0.11)
MWTG Load-Weighted	23.56	23.65	0.09	40.48	39.39	(1.09)	44.59	42.75	(1.84)

Similar to the results of the 2016 simulations, the simulated 2024 market prices presented in Figure 21 show that the price differentials between locations within the Mountain West footprint decrease with a regional market. For example, in the 2024 Current Trends simulations, the average price spread between Ault and Dave Johnston was $1.54/MWh in the Status Quo (2024 Current Trends Case A). In the 2024 Regional Market case (2024 Current Trends, Case C) that spread decreases to $0.39/MWh. In general, the 2024 prices at the Mountain West locations listed in Figure 21 range from $22.57 to $25.13 in the Status Quo (2024 Current Trends Case A). This price spread collapses to a range of $23.10 to $23.84 in the Regional Market case (2024 Current Trends Case C).

This change in prices is driven by two key factors. First, the Regional Market (2024 Cases C) simulation allows for more efficient use of transmission capacity than in the Status Quo bilateral market case (2024 Cases A). Second, in a Regional Market the pancaked transmission charges and the trading frictions that exist in the bilateral market are removed. These effects allow for more efficient dispatch and trading, causing market prices to converge.

3. Generation Shift between Resource Types

Figure 22 shows the simulated generation output within the Mountain West region by fuel type for all 2024 simulations. Moving from the bilateral market (Case A) to a regional market structure (Case C) in the Current Trends future, we see a small increase in generation from both the more efficient gas-fired and coal-fired generation in the Mountain West region. Production from gas-fired generation increases by about 1.5 TWh and generation from coal-fired units increases by about 0.5 TWh in the Regional Market case (2024 Current Trends Case C) relative to the Status Quo case (2024 Current Trends Case A). Overall production within the Mountain West increases and the region exports more power to the neighboring areas.

Conversely, in the High Natural Gas Price and the Market Stress sensitivity simulations, when 2024 natural gas prices are much higher relative to coal prices, the coal-fired generation becomes more competitive relative to gas CCs and CTs such that generation output from the coal plants slightly increases in the Regional Market case (2024 High Gas Price and Market Stress Cases C) compared to the Status Quo case (2024 High Gas Price and Market Stress Cases A). However, the total generation within the Mountain West region decreases slightly (as already shown in Figure 19 and Figure 20).

Figure 22: Mountain West Generation Levels in 2024 Simulations (TWh)

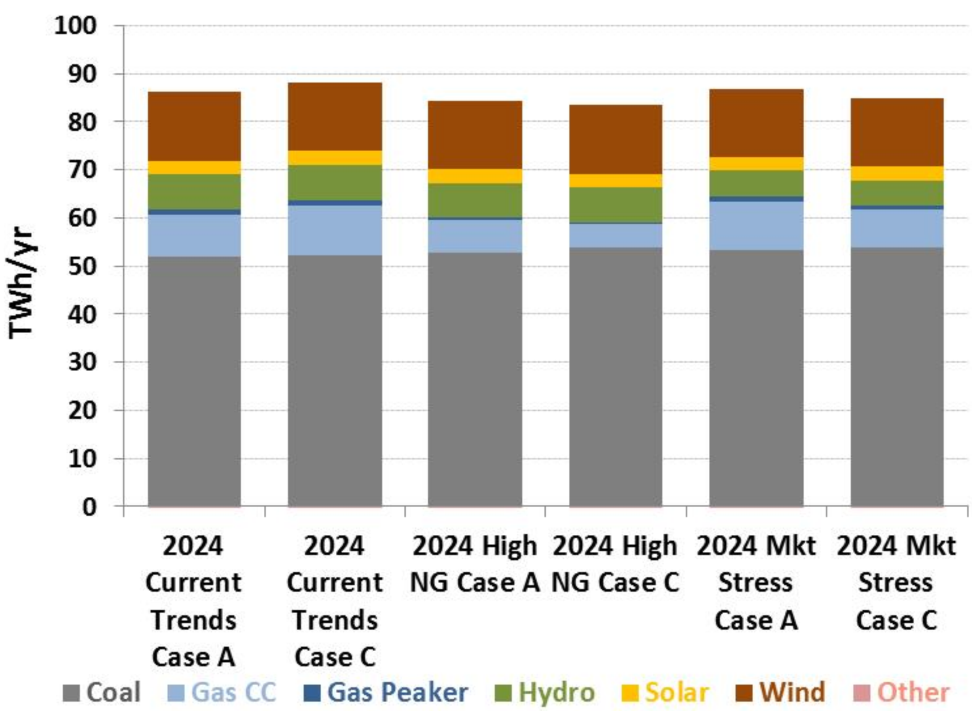
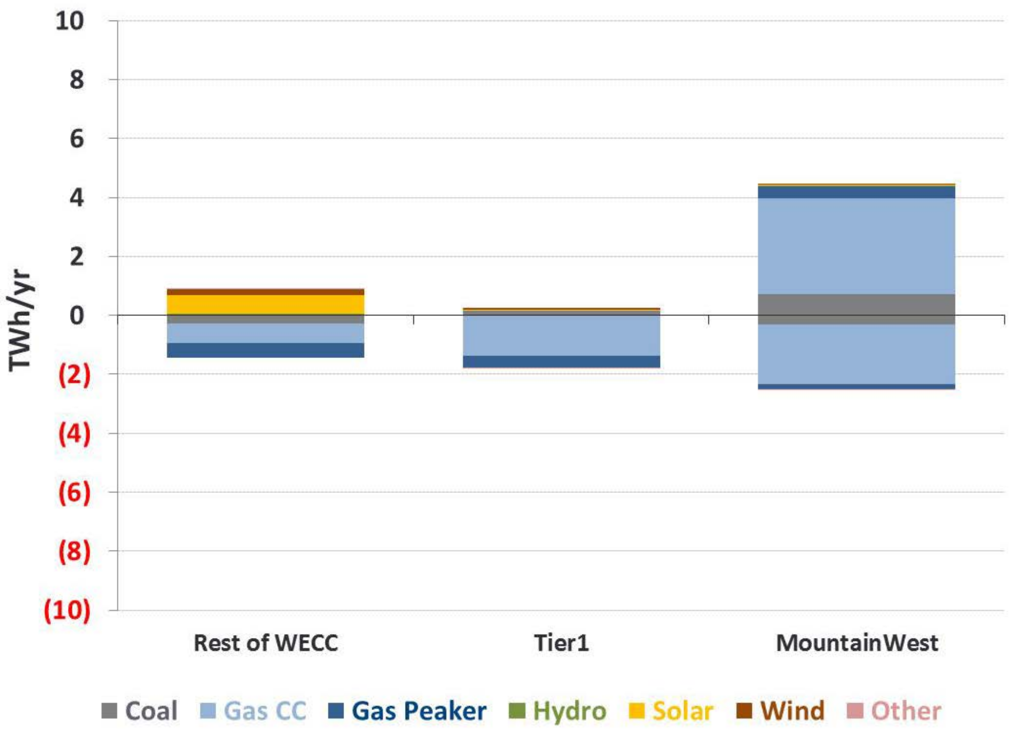


Figure 23 focuses on the Current Trends simulations, and summarizes how generation by fuel type differs between the Status Quo case (2024 Current Trends Case A) and the Regional Market case (2024 Current Trends Case C). Within the Mountain West region, output from the more efficient gas-fired CC plants increases by about 3.2 TWh in in the Regional Market case (2024 Current Case C) compared to the Status Quo case (2024 Current Trends Case A), while output from less efficient CC generation decreases by about 2 TWh. Similarly, generation from more efficient coal plants increases by about 0.7 TWh in the Mountain West region under the Regional Market case (2024 Current Trends Case C) compared to the Status Quo case (2024 Current Trend Case A), while the less efficient coal produces about 0.3 TWh less in the Regional Market case. We also observe that the gas generation in the Tier 1 balancing areas decreases slightly. This result reflects the increased exports out of the Mountain West region in the Regional Market case.

Figure 23: Generation Level Changes 2024 Current Trends Regional Market vs. Status Quo (TWh)



4. Changes in Power Flows on the Mountain West System

Based on anticipated transmission upgrades and information provided by the Mountain West participants, we updated the power flow limits on the transmission paths in the Mountain West region for the 2024 simulations. Figure 24 below presents these adjusted limits. As in the 2016 simulations, we have not modified the physical representation of the transmission system across the various cases.

Figure 24: Path Limits in the 2024 Status Quo (Cases A) and Regional Market (Cases C)

		Status Quo		Regional Market	
Path	Flow Direction	Min	Max	Min	Max
TOT 1A	West to East	-500	500	-650	650
TOT 2A	South to North	-500	500	-690	690
TOT 3	South to North	-1,300	1,300	-1,840	1,840
TOT 4A	Southwest to Northeast	-750	750	-810	No limit
TOT 4B	Northwest to Southeast	-750	750	-880	No limit
TOT 5	West to East	-1,400	1,400	-1,680	No limit
TOT 7	South to North	-550	550	-890	890

The most significant difference in the above path limits relative to those used in the 2016 simulations relates to the path rating of TOT 3. Based on information provided by the Mountain West entities about planned transmission upgrades that would likely increase the path rating of TOT 3, we increased the path limit for the 2024 Status Quo cases (2024 Cases A) to 1,300 MW from the previously-assumed 1,100 MW for the 2016 Status Quo case (2016 Case A). When simulating the Regional Market cases (2024 Cases C), we assumed a TOT 3 path rating of 1,840 MW (compared to the 1,680 MW used in the 2016 Regional Market (2016 Case C)). In addition, based on additional information received from the Mountain West entities, we implemented a simplified nomogram that limits the flows over TOT 3 depending on the output of nearby generators and flows on the Stegall and Sidney DC ties that interconnect the Western and Eastern Interconnections. The generators included as part of this nomogram are the Laramie River Station, Pawnee, the Brush CCs, and the Manchief CTs.

The hourly power flows in the Current Trends simulations over TOT 3 are shown in Figure 25 below. The upper and lower limits in the Status Quo (2024 Current Trends Case A) simulation are represented by the horizontal light-red lines. The simulated flows over TOT 3 for the Current Trends Status Quo case (2024 Current Trends, Case A) are shown as the red curve, which reaches the 1,300 MW limit in about 35% of all hours. The dark blue line shows simulated flows under the Current Trends Regional Market (2024 Current Trends Case C). At the higher path rating limit, flows over TOT 3 do not reach the 1,840 MW limit in the Regional Market case (2024 Current Trends Case C), but flows are limited by the nomogram described above. The binding nomogram limits are shown in Figure 25 for about 5% of hours with the highest flows in 2024.

Figure 25: TOT3 2024 Current Trends Simulated Power Flows

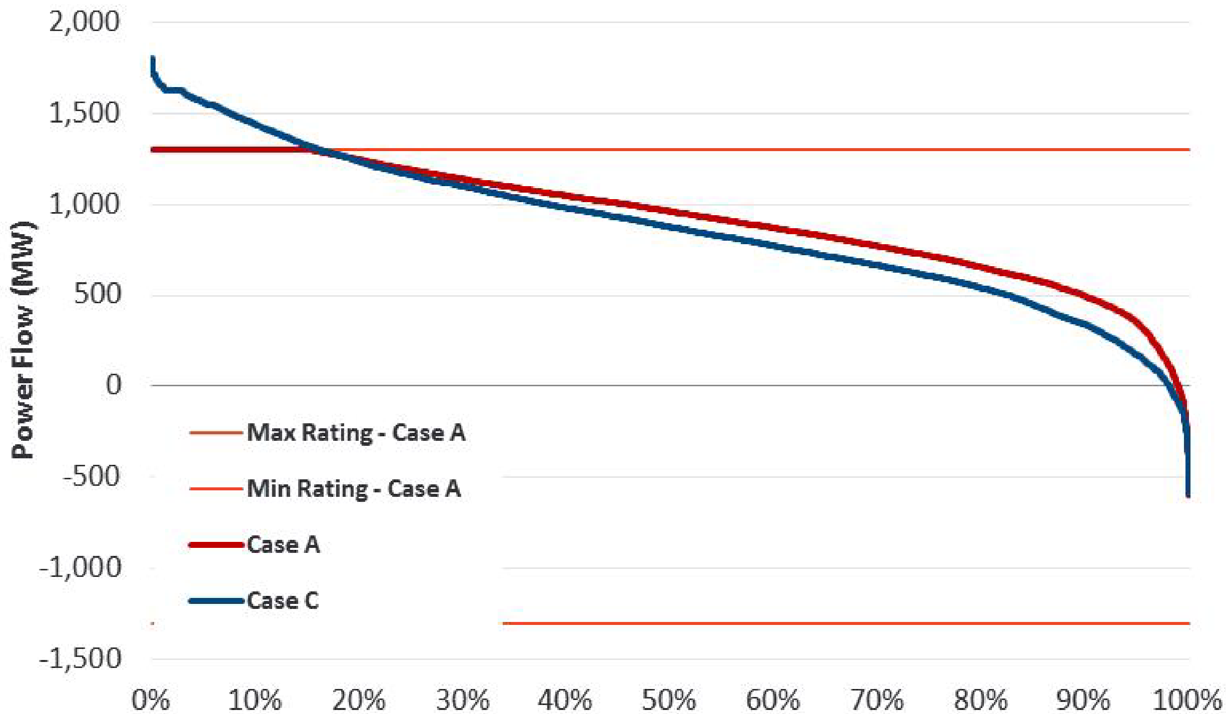


Figure 26 below summarizes simulated power flows for the two Current Trends cases, the Status Quo case (2024 Current Trends Case A) and the Regional Market case (2024 Current Trends Case C), for the transmission paths in the Mountain West region.

Figure 26: Power Flows in the *2024 Current Trends* Simulations

		Status Quo			Regional Market		
Path	Flow Direction	Min	Average	Max	Min	Average	Max
TOT 1A	West to East	-500	288	500	-636	341	650
TOT 2A	South to North	-500	129	500	-690	176	690
TOT 3	South to North	-602	918	1,300	-589	875	1,801
TOT 4A	Southwest to Northeast	-748	-170	526	-810	-247	501
TOT 4B	Northwest to Southeast	-750	-432	126	-824	-418	58
TOT 5	West to East	-1,001	247	1,400	-1,112	401	2,027
TOT 7	South to North	-550	-112	550	-736	-35	742

Figure 27 summarizes congestion for the 2024 Current Trends simulations. The figure indicates that congestion charges in the Status Quo (2024 Current Trends Case A) are over $20 million per year. In the Regional Market (2024 Current Trends Case C) total congestion charges fell to $4.45 million per year. As in the 2016 simulations, the most congestion was experienced on

TOT3 in the Status Quo case and that congestion has been eliminated entirely in the regional Market Case.

Figure 27: Simulated Flows in the *2024 Current Trends* Cases

		Number of Hours the Path is Constrained		Annual Congestion Cost ($ Millions)	
Path	Flow Direction	Current Trends Case A	Current Trends Case C	Current Trends Case A	Current Trends Case C
P30 TOT 1A	West to East	1,240	748	$3.01	$4.14
P31 TOT 2A	South to North	838	350	$0.21	$0.30
P36 TOT 3	South to North	1,330	0	$16.36	$0.00
P37 TOT 4A	Southwest to Northeast	0	4	$0.00	$0.01
P38 TOT 4B	Northwest to Southeast	80	0	$0.20	$0.00
P39 TOT 5	West to East	50	0	$0.17	$0.00
P40 TOT 7	South to North	8	0	$0.06	$0.00
Total		3,546	1,102	$20.02	$4.45

V. Potential Benefits Not Quantified in the Production Cost Savings

Production cost modeling is helpful for understanding the benefits of a regional market, but one must keep in mind its limitations. Production cost models are powerful tools: they jointly simulate generation dispatch and power flows to capture the actual physical characteristics of both generating plants and the transmission grid, including the complex dynamics between generation and transmission availability, energy production and operating, and load following requirements. These types of simulations provide valuable insights to both the operations and economics of the wholesale electric system in the entire interconnected region. For that reason production cost models are used by every ISO and RTO for transmission planning purposes. Production cost models are also used by many utilities and regulators for resource planning and to evaluate the implications of policy decisions and market uncertainties. In fact, the simulations conducted in this study provide an estimate of production cost savings that could be achieved under different market structures.

However, similar to most other production cost simulations, the simulations undertaken for this study have their limitations. This yields conservatively low estimates of the production cost savings offered by a regional market. The specific limitations include:

- The production cost simulations are based on **normal weather, typical hydrology, normal monthly energy and peak load, and normal generation outages** without considering additional benefits realized during unusually challenging market conditions. Examples of such challenging conditions not simulated include extreme weather patterns that could create large swings of power flows across a system. These types and other challenging conditions tend to increase the benefit of regional markets. The simulated "Market Stress" sensitivity cases address some but not all such challenges.

- The simulations **do not consider** the additional transmission constraints on the power grid during **transmission-related outages**. The greater flexibility provided by integrated regional market operations yields higher cost savings and improved reliability during transmission outages.[8]

- We do not assess the benefits of improved **management of uncertainties** between day-ahead and real-time operations, particularly as it relates to the **integration and balancing of increasing amounts of renewable generation** in real-time.[9] Having a regional market provides the system operator with a larger pool of resources and optimization tools to manage unexpected changes of generation and load between the day-ahead and real-time operations, thereby reducing costs, reducing the need for reserves and ramping capability, and increasing reliability, particularly when integrating large amounts of variable resources, such as wind and solar generation.

- We do not assume that the improved incentives of operating in a price-transparent and competitive regional market would improve **generator efficiency and availability**, as has been documented by the experience in other regional markets.

- Other than through trading margins and reduced path ratings, the simulations **do not fully capture inefficiencies of current trading practices** in terms of less flexible bilateral trading blocks (*e.g.*, 16 hour blocks at 25 MW increments), contract path scheduling limits, and congestion caused by unscheduled power flows.

---

8 While transmission limits are defined based on N-1 contingency constraints (and in some cases nomograms reflecting the extent to which generation availability affect transmission capabilities), the transmission limits do not reflect the additional (temporary) de-rates that occur when actually operating under N-1 conditions.

9 This study simulates unit commitment and dispatch deterministically based on perfect foresight of all loads and available generation, without considering uncertainties in loads, generation outages, or the level of wind and solar generation. The simulations thus roughly reflect a day-ahead market outcome without capturing the additional benefits gained from improved real-time energy market operations and the balancing of uncertain wind and solar generation output.

- The simulations do not capture any benefits achievable through improved regional coordination and optimization of hydro power resources. We have left hydro dispatch unchanged between the Status Quo cases and the Regional Market cases, leaving out value associated with allowing the flexible portion of hydro resources to be dispatched more optimally by the regional market (subject to their operating constraints).
- The simulations conservatively assume perfectly optimized, security-constrained unit commitment and dispatch already exists within every individual member area even under the Status Quo bilateral market (Cases A). This assumption alone may underestimate regional market benefits by approximately 2% of total production costs.[10]
- This study does not consider potential savings from retiring expensive generation assets. High-cost generation assets can more easily be retired in a regional market because individual entities are less dependent on the self-provision of energy and operating reserves. This may result in lower fixed operation and maintenance costs and avoided capital expenditures for the owners of those units.

Just as many other regional-market studies have adopted similarly conservative modeling assumptions, the magnitude of the estimated production cost savings in this study is within the range of savings found in other market studies. Most analyses of actually-achieved regional market benefits have found production cost savings in the range of 2–8% of total production costs. For example, a 2015 study by the Southwest Power Pool (SPP) analyzed the impact of moving from a region-wide energy imbalance market with de-pancaked transmission rates to a system with a centrally-operated regional market. The study estimated savings equal to 4.8% of total production costs in addition to the 3.2% savings already achieved by SPP's prior region-

10 For example, Wolak 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. (Wolak, Frank A., "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Market," American Economic Review: Papers & Proceedings 2011, 101:3, 247-252). A similar benefit has been documented for moving from a zonal to nodal market design in Texas. The extent to which a zonal market is less optimized than a nodal market likely is a reasonable proxy for the extent to which unit commitment and dispatch within individual member zones is not yet fully optimized.

wide imbalance market and elimination of pancaked transmission charges.[11] Based on this SPP experience, moving from a bilateral market to a full centrally-operated regional market in the Mountain West region should result in a similar magnitude of savings. In fact, the smaller size of individual members within the Mountain West region will likely yield higher benefits. Further, the estimated production cost impact is only one element of evaluating the potential implications of participating in an organized regional wholesale market. As noted earlier, this study does *not* estimate generation-related cost impacts beyond those captured in the simulations and the adjusted production cost metric—including discrepancies between congestion charges and the value of allocated congestion revenue rights, marginal loss refunds, and the benefits associated with using a regional market to balance variable renewable generation in real-time.

This study also does *not* address other considerations related to the formation of or participation in a RTO-operated regional market, such as:

- The implications of alternative RTO governance structures and the implementation and administrative costs associated with participating in a regional market.
- The benefits and cost impacts of different approaches to regional transmission planning and the allocation of existing and future transmission investments.
- The documented ability of regional markets to facilitate additional investments in renewable generation resources (beyond those needed to comply with regulatory requirements).
- The reliability benefits of a larger regional market footprint resulting from (1) reducing the planning reserve margins needed to meet resource adequacy requirements; and (2) increasing operational reliability through improved visibility of regional system conditions and control of system operations.

VI. Conclusion

Our market simulations find that the Mountain West Transmission Group entities would collectively experience a significant reduction in production costs by transitioning to a

11 Many aspects of SPP resemble the Mountain West region with major load centers in one portion of the footprint (the southeast), areas with low-cost renewable generation (the Great Plains), and significant reliance on coal- and natural gas-fired generation.

centralized wholesale power market. We reach this conclusion by simulating different market structures for two different years, 2016 and 2024. The production cost simulations are run on three different market structures:

1. The Status Quo Case (Case A) represents the existing bilateral market structure in the Mountain West region;
2. A Joint Transmission Tariff Case (Case B) simulates a joint transmission tariff across all Mountain West transmission owners; and
3. Regional Market Case (Case C) simulates a full regional market similar to the existing RTOs in the West and other regions.

For 2016 we simulated all three of these market structures, as well as a variation of the Regional Market case (2016 Case CMR) in which we maintain must-run operational parameters for certain baseload units as assumed in the Status Quo (Cases A) and the Joint Tariff (Cases B) cases. For 2024 we simulate only the Status Quo (2024 Case A) and the Regional Market (2024 Case C) for a Current Trends future, but include sensitivities with different assumptions about natural gas prices, hydro generation, and load in the Mountain West footprint.

The results of simulating 2016 market conditions indicate that the Mountain West participants would realize annual **production cost savings ranging from $53 million/year to $88 million/year by joining a centralized wholesale power market**. This range represents a reduction in production costs of 5.7% to 9.4%. The low end of this range assumes that specific baseload units within the Mountain West will continue to operate on a must-run basis even in a regional market environment. The high end of the range assumes that all baseload units will be fully dispatched by the market (which would likely require more flexible fuel supply arrangements). The 2016 simulations also show that the Mountain West group would experience **a reduction in production costs of $14 million/year, or 1.5% of total production costs, solely by implementing a joint transmission tariff**.

The 2024 simulations estimate similar production costs savings for the Mountain West entities as the result of operating in a regional market. The results of the 2024 Current Trends scenario indicate that the Mountain West group could achieve estimated **production cost savings of $71 million/year, or 7.6% of total production costs.** The two sensitivities of the 2024 Current Trends scenario—2024 High Natural Gas Price and 2024 Market Stress—produce higher production cost savings. The simulations of the 2024 High Natural Gas Price sensitivity suggest that the Mountain West group would **realize production cost savings of $126 million/year, or 11.1% of total production costs.** The 2024 Market Stress sensitivity shows **production cost benefits from a regional market of $128 million/year, or 7.9% of total production costs.** This increase in production cost savings is driven mostly by the higher natural gas prices assumed in these two sensitivities.

Production cost savings are not the only benefits the Mountain West participants can anticipate achieving in a regional market. The production cost simulations conducted in this study provide only a conservatively low estimate of the savings achievable by a regional market. They do not capture any impacts related to resource adequacy and operational reliability, renewable integration, regional transmission planning and cost allocation, or improved flexibility to manage extreme weather and outage events as discussed in Section V. The decision to form or join a regional market will also need to evaluate other considerations such as governance of the organization that is set up to make the necessary market design and system planning decisions.

VII. Technical Appendix

A. Overview of PSO Model and Simulation Scope

For the simulations conducted in this study, we used the Power Systems Optimizer ("PSO") software developed by Polaris Systems Optimization, Inc. PSO is a state-of-the-art production cost simulation tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual ISO operations. In that regard, PSO is similar to "Gridview," the simulation tool that WestConnect and WECC use for their regional transmission and generation resource planning analyses. A production cost model, like PSO, can be used as a tool to test system operation under varying assumptions, including but not limited to: generation and transmission additions or retirement, de-pancaked transmission and scheduling charges, changes in fuel costs, and jointly-optimized generating unit commitment and dispatch. PSO can be set up to produce hourly prices at every bus in the WECC and generation output for each unit in the WECC. These results can then be used to estimate changes in generation output, fuel use, production cost, or other metrics on a unit, state, utility, or regional level.

PSO has certain advantages over traditional production cost models, which are designed primarily to model controllable thermal generation and to focus on wholesale energy markets only. Recognizing modern system challenges, PSO has the capability to capture the effects on thermal unit commitment of the increasing variability to which systems operations are exposed due to intermittent and largely uncontrollable renewable resources (both for the current and future developments of the system), as well as the decision-making processes employed by operators to adjust other operations in order to handle that variability. PSO simultaneously optimizes energy and multiple ancillary services markets, and it can do so on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements. The model's objective function is set to minimize system-wide operating costs given a variety of assumptions on system conditions (*e.g.*, load, fuel prices, *etc.*) and various operational and transmission constraints. One of PSO's most distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which would occur at different points in time and with different amounts of information about system conditions.

PSO uses mixed-integer programming to solve for optimized system-wide commitment and dispatch of generating units. Unit commitment decisions are particularly difficult to optimize due to the non-linear nature of the problem. With mixed-integer programming, the PSO model closely mimics actual market operations software and market outcomes in jointly-optimized competitive energy and ancillary services markets.

For the purposes of this study, we have developed the model assumptions to simulate day-ahead market outcomes in three cycles as shown in Figure 28.

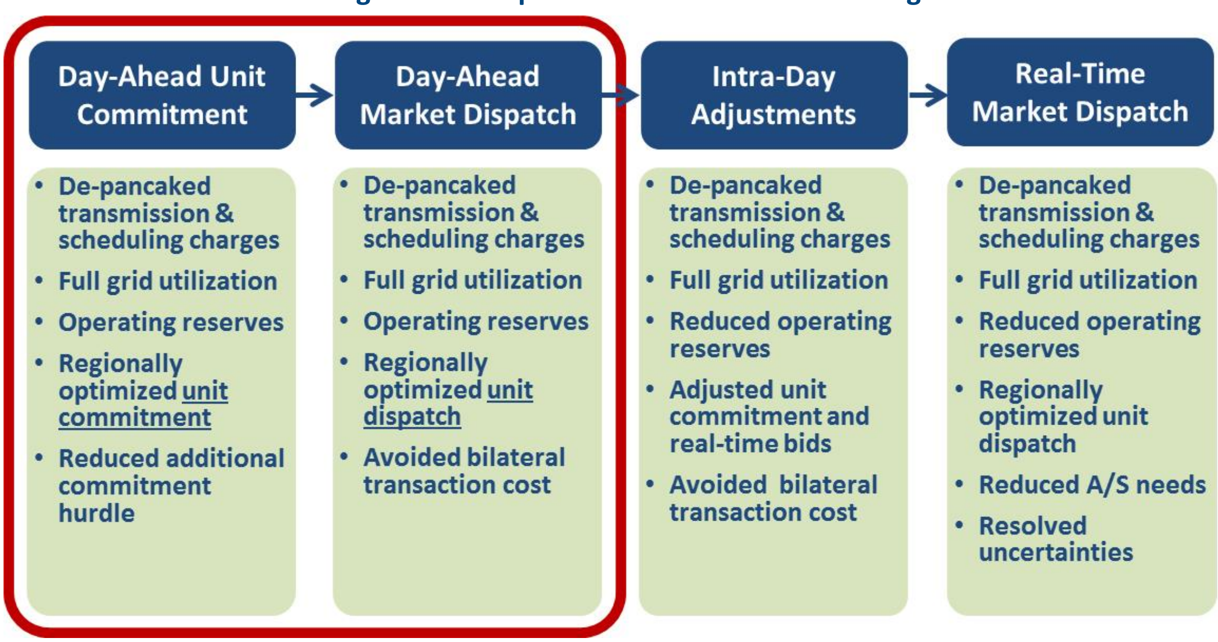
- In the first cycle, PSO calculates the marginal loss factors on the transmission system. The marginal losses affect the locational prices and the relative economics of generators.
- In the second cycle, PSO optimizes unit commitment decisions, particularly for resources with limited operational flexibility (*e.g.*, units that start up slowly or have long minimum online and offline periods). In this cycle, PSO determines which resources should start up to meet energy and operating reserve needs in each hour of the following day, while anticipating the needs one week ahead. While the model has the capability to address uncertainties between the day-ahead and real-time markets, we have not operated the model in such a mode. Thus, the entire simulation effort for this study is conducted with perfect foresight. This means that the unit commitment is always efficiently determined since no system changes (*e.g.*, changes in load or generation between the day-ahead and the real-time market) are simulated that would alter the unit commitment after the day-ahead schedule is complete.
- In the third cycle, PSO solves for economic dispatch of resources given the unit commitment decisions made in the second cycle. Explicit modeling of the commitment and dispatch cycles allows us to more accurately represent the preferences of individual utilities to commit local resources for reliability, but share the provision of energy around a given commitment. This consideration is captured through the use of a "bilateral trading adder" on the bilateral transfers between areas and we have used adders that are higher for unit commitment in the second cycle than for generation dispatch in the third cycle.

Figure 28: PSO Decision Cycles

	Cycle	Description
Cycle 1	Marginal Losses	Calculates marginal loss factors
Cycle 2	Unit Commitment	Makes commitment decisions based on the up/down time and the magnitude of minimum generation amount for different types of generation resources (longer for baseload and older gas-fired combined-cycles and shorter for peakers) and decide which resources would operate to provide energy versus reserves
Cycle 3	Unit Dispatch	Dispatches resources for energy; allows more economic sharing of resources to provide energy and reserves around a fixed commitment determined in Cycle 2

Figure 29 below illustrates the different day-ahead and real-time time horizons over which RTO markets make unit commitment and dispatch decisions. As indicated by the red box surrounding the day-ahead unit commitment and day-ahead unit dispatch steps, the market simulations undertaken in this study roughly approximate the scope of day-ahead market operations. Additional market-related benefits, such as those accrued from centrally-optimized real-time operations, are not captured in this analysis.

Figure 29: Scope of Production Cost Modeling



B. MODELING ASSUMPTIONS AND DATA

As a starting point for the simulations, we utilized the database developed by WECC's Transmission Expansion Planning Policy Committee ("TEPPC") and used to simulate their Common Case v1.5. The starting point was to convert the TEPPC Gridview database into PSO format. The TEPPC database contains the following information for all of WECC:

- Unit-level data on maximum capacity and estimated minimum dispatch, heat rate, ramping rate, minimum up and down times, as well as additional data
- Hourly load shapes for each balancing area in the WECC
- Monthly energy consumption and peak demand by balancing area
- Generic fuel costs
- Transmission topology of the entire WECC system
- Power flow case for the entire WECC system

Prior to conducting the 2016 simulations we updated the TEPPC database for the Mountain West region to reflect more accurate data provided to us by the participating entities. This includes unit-specific fuel costs, more detailed and accurate unit-level operating costs and operational data, recent load forecasts for the individual Mountain West participants, entity-specific transmission contracts and wheeling charges, and reserve requirements for each Mountain West entity.

The TEPPC model simulated the WECC on a balancing area level. Therefore, in the WECC database the Mountain West region is represented as simply the PSCO and WACM balancing authority areas. Before we could conduct the 2016 simulations we had to create an area within the model for each of the ten operating entities that constitute the Mountain West. We did this by mapping transmission, load, and generation assets to the individual entities, including partially assigning jointly-owned generation to multiple entities. We then assigned transmission buses from TEPPC's transmission topology to each entity so that the model could simulate transactions in and out of each entity's area. Lastly, we applied entity-specific load profiles to each new area in the model and assigned them an entity-specific operating reserve requirement. This process was conducted in close collaboration with the individual Mountain West entities.

After incorporating the unit- and entity-specific data provided by the participants, we adjusted the model inputs to reflect the assumptions we wanted to portray in each simulation. Figure 30 below presents the key modeling assumptions we adjusted between the 2016 and 2024 simulations, and between the 2024 Current Trends and the two sensitivities—High Natural Gas Price and Market Stress.

Figure 30: Summary of Modeling Assumptions for Mountain West Region

	2016	2024		
		Current Trends	High NG Price	Market Stress
Energy Consumption (GWh)	70,777	76,757	76,757	86,178
Peak Load (MW)	12,931	14,307	14,307	15,510
Average Gas Price (2016$/MBtu)	$2.25	$3.87	$8.36	$8.36
Hydro Production (GWh)	6,271	7,302	7,198[12]	5,292
Wind Capacity (MW)	3,146	4,281	4,281	4,281
Solar Capacity (MW)	311	1,591	1,591	1,591
Coal Capacity (MW)	7,673	6,960	6,960	6,960
Gas Capacity (MW)	7,313	7,824	7,824	7,824

The key modeling assumptions we adjusted across the simulations are load, gas prices, and the generation capacity mix.

12 Hydro production for the High Natural Gas sensitivity differs from the Current Trends baseline assumptions only due to different utilization of pumped storage plants.

List of Acronyms

APC	Adjusted Production Cost
CAISO	California Independent System Operator
CC	Combined-Cycle
CSU	Colorado Springs Utilities
CT	Combustion Turbine
GW	Gigawatt
GWh	Gigawatt Hour
ISO	Independent System Operator
MBtu	Thousand British Thermal Unit
MR	Must Run
MW	Megawatt
MWh	Megawatt Hour
MWTG	Mountain West Transmission Group
NDA	Non-disclosure agreement
NG	Natural Gas
O&M	Operation and Maintenance
PRPA	Platte River Power Authority
PSCO	Public Service Company of Colorado
PSO	Power System Optimizer
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SPP	Southwest Power Pool
TEPPC	Transmission Expansion Planning Policy Committee
TWh	Terrawatt Hour
WACM	Western Area Colorado Missouri Balancing Authority
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council