Mountain West Transmission Group – Southwest Power Pool DC Intertie Value Study

The Glarus Group, Inc.

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1 Introduction

Mountain West Transmission Group[1] (MWTG) and the Southwest Power Pool[2] (SPP) retained The Glarus Group (TGG) to evaluate the benefits of using four DC interties that separate MWTG and SPP to schedule power as a part of the SPP market. The four DC interties are Rapid City, Stegall, Sidney and Lamar and the combined transfer capability is 720 MW. The table below shows the transfer capability of the four DC ties.

Table 1: DC Tie Transfer Capability

DC Interties	
Name	**Transfer Capability (MW)**
Rapid City	200
Stegall	110
Sidney	200
Lamar	210
Total	**720**

[1] The Mountain West Transmission Group is comprised of nine transmission owners including Basin Electric Power Cooperative, Black Hills Colorado Electric Utility Company, LP, Black Hills Power, Inc., Cheyenne Light Fuel & Power Company, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission, and Western Area Power Administration (Loveland Area Projects and Colorado River Storage Projects).

[2] The Southwest Power Pool is a regional transmission organization (RTO) that manages transmission in fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. Its membership is comprised of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers and independent transmission companies and a Federal Power Marketing Administration.

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As MWTG considers entry into an organized electricity market, the benefits of scheduling the DC ties in the market are determined by comparing the net production cost of MWTG and SPP under two potential uses of the DC ties:

- DC ties are not scheduled in the market (base case) – DC ties are not part of the market and are assumed to retain a scheduling process similar to the current scheduling process with similar impediments to efficiency.
- DC ties are scheduled by the market (alternative case) – DC tie flows are optimized by the market in hourly clearing intervals to maximize efficiency for the overall system. (Study only focused on day-ahead hourly clearing)

In addition to evaluating the benefits under the conditions described above, additional scenarios were evaluated to examine benefits of DC tie usage under a range of specified operating conditions. The six additional scenarios are the following: low and high gas prices; low and high loads; and, low and high DC tie availability.

The benefits were estimated using the AURORAxmp[3] wholesale electric market price forecasting and generation planning tool (also called AURORA in this report) and the benefit measure is savings in net production costs, defined in this study as generation costs plus market purchases less market sales. Like other electric market price and generation planning tools, AURORA models electric prices based upon the marginal cost of production at generation or other supply facilities, after accounting for transmission transfer capability and wheeling (or hurdle) rates, generation supply limitations, customer demand, and fuel prices. AURORA assumes a competitive electric market where prices are determined from the clearing price of marginal resources in AURORA[4]. The market clearing price is the marginal cost of an additional kilowatt-hour of generation, determined after the dispatch of all of the resources in the system necessary to meet total load in a least cost manner, subject to transmission and generation constraints. This process occurs for each hour that resources are dispatched in this study. In other words, prices will equal the variable cost of the last generating unit needed to meet demand. Reported monthly or annual hourly prices are derived from that hourly dispatch.

[3] AURORAxmp is one of the leading electric market price, generation planning tools in the works for electric utilities. It is used by public and private utilities, state regulatory commissions, consulting firms, investment banks, and research organizations. For more information, see: http://epis.com/aurora_xmp/

[4] The prices are determined for each area or zone defined in the model setup. The detailed area or zone setup of AURORA will be discussed later in this report.

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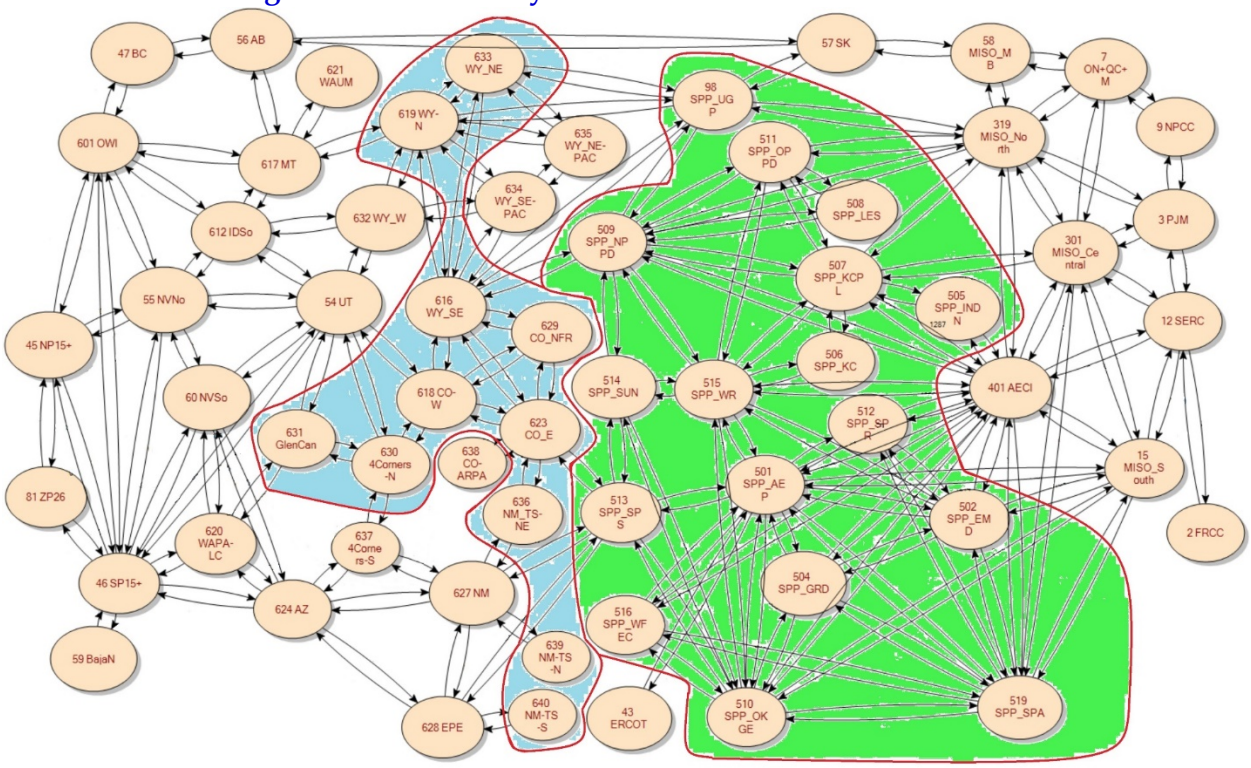
The study analyzes the four DC ties hourly for one calendar year based on data for 2016. The study uses hourly intervals in 2016 and organizes generation, load, and transmission data based on the zones shown in Figure 1, where MWTG is the blue-shaded area and SPP is the green-shaded area. Because hourly intervals and zonal representation of location have been selected for this study, this analysis does not include sub-zone (e.g., nodal) and sub-hourly (e.g., 5-minute) features of electric system operations. These are important factors as to how the results should be reviewed. The zonal results show clear benefits of the DC ties to the broader market, but also show directional values (East vs. West). The directional values are driven by the accounting methodology within the AURORA software, which assigns the entire margin, based on zonal price differences (less transmission fees) from a transaction to the selling entity. Given the zonal modeling and the accounting methodology for transactions used by AURORA, the directional benefits assigned by the model should be considered indicative and not representative of how much each side may actually benefit.

Figure 1: DC Tie Study Model Areas and Interconnections



The study area consists of all of the utilities in the lower 48 states of the United States, Canada, and Mexico's North Baja region, which are comprised of the Western Electricity Coordinating Council (WECC) where MWTG resides, and the Eastern Interconnect where SPP resides, the Electric Reliability Council of Texas (ERCOT), and Quebec. WECC and the Eastern Interconnect are electrically separated by eight DC interties, four of which

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are the subject of this study. When running a model such as AURORA, a standard approach is to include all the load, resources and transmission data for the interconnection where the utility or analysis is located. For example, a utility member of MWTG that uses AURORA would normally use all of the WECC region because power flows between all zones in WECC, and the exclusion of some WECC zones may result in higher reported production costs by failing to recognize the opportunity for lower cost power purchases or higher priced sales with the excluded areas. Similarly, a SPP utility would use most of the entire Eastern Interconnect for the same reasons. To study the impact of the DC ties between WECC and the Eastern Interconnect, all areas in WECC, the Eastern Interconnect, ERCOT and Quebec are included in the modeling.

While it is considered important to include all areas within WECC, the Eastern Interconnect, ERCOT, and Quebec, those areas more remote from MWTG and SPP are collapsed into more broadly defined zones. For example, the PJM market area was modeled as a single zone rather than multiple zones that would be used for a study focusing on the PJM market. In this example, all PJM loads and resources are included, but internal transmission constraints are dropped from consideration in determining PJM's impact on SPP and use of the DC ties.

2 Summary of Results

This analysis measures the benefits of the use of the identified four DC ties. MWTG participants requested that the analysis reflect existing market conditions for WECC and the Eastern Interconnect for calendar year 2016 to maintain consistency with other studies prepared for MWTG. Table 2 below presents the estimated savings in net production costs between the base case and the alternative case, along with the 6 additional scenarios for low and high natural gas prices, loads, and DC tie availability. Benefits in net production cost savings for MWTG and SPP range from $11.7 million to $28.8 million. The analysis demonstrates that MWTG and SPP can expect a significant reduction in net production costs once the combined MWTG/SPP area becomes a single integrated electric market and the four DC ties are dispatched by the market clearing process[5]. The additional scenarios are defined such that the relative costs and depth of supply curves of different regions change non-uniformly, so the resulting benefits are not expected to uniformly increase or decrease moving from low to medium to high conditions across

[5] AURORA does not precisely replicate SPP market rules in determining prices. AURORA does not determine day-ahead or five-minute real-time pricing, nor does AURORA determine nodal prices. However, AURORA simulates this market by aggregating clusters of nodes into areas/zones, and by simulating prices for all modeled areas/zones on an hourly basis.

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the scenarios. The results do not reflect real-time market optimization, ancillary services nor any regional through and out transmission revenues that may be available due to the better optimization of the DC ties.

Table 2: Scenario Results Summary

MWTG and SPP Scenario Savings Savings bewteen Base and Alternative Cases Net Production Cost Savings ($ Million)			
Input Parameter	**Low**	**Medium**	**High**
Natural Gas Price	13.6		28.8
DC Tie Availability	11.7	12.9	12.6
Weather-base Load	14.2		13.2

3 AURORA Overview, Setup and Data

The goal of the study is to determine MWTG and SPP production cost differences for the scenarios in which the DC ties are not scheduled by the market compared to when the DC ties are scheduled by the market. The first step in the study is to identify the production costing tool and setup the study model.

MWTG selected the single calendar year 2016 as the target year for this analysis. The base case models for generation resources, loads, and transmission are built reflecting an average state of the system in 2016:

- Resources are modeled with the average characteristics, e.g., the forced outages of individual generators are not included and fuel prices are modeled on a monthly basis
- Load levels are based on reported 2016 data and load shapes are based on multi-year historic averages
- The modeled transmission system capabilities are entered at their typical operating levels, e.g., specific outages which occurred in 2016 are not included

The results of this modeling approach are expected to provide indicative information that can be applied to typical years in the near future. Differences between the 2016 actual operations and the modeled base case are expected.

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The software and database for AURORA were selected as the production costing tool for this study. The AURORA software provides hourly power system simulation capability for the calculation of production cost changes. The AURORA North America database provides generation characteristics, transmission flow limits and hurdle rates, and load forecasts based on publicly available data sources.

AURORA is used widely in the electricity industry for integrated resource planning studies, emissions analysis, utility rate analysis, renewable integration studies, construction project valuation, merger acquisition analysis, power market studies, etc. AURORA can perform multi-year studies and supports input data variations to investigate sensitivity of results.

The following sections describe the AURORA simulation capability and the process of preparing input data for the model.

3.1 Simulation Capabilities

The AURORA analysis determines generation commitment and dispatch schedules to meet the input load forecasts, subject to the transmission limitations and costs.

In modeling generation, AURORA uses detailed operating characteristics of conventional generators (minimum and maximum seasonal operating limits, heat rates, startup costs, minimum run times, minimum down time, outages, etc.), renewable generation, hydro modeling, storage, and energy efficiency/demand response. For flexible resources, AURORA determines a commitment and dispatch schedule.

Purchases and sales are included in the analysis. When power transactions between zones is economic, including the impact of the applicable hurdle rates, AURORA will schedule the transaction. The revenues from sales for resale and the costs of purchased power are included in the net production cost for a region. AURORA optimizes globally over all zones in the model, which means that energy is transferred between zones when it benefits the overall system; the decisions are not made based on the impact to individual zones. AURORA accounts for sales and purchases in post-processing so that the benefits can be assigned to the net production cost of the various regions. In the post-processing accounting, the flow on each transmission link connecting MWTG or SPP to another region is considered a sale or purchase depending on the direction of flow. The product of the transmission link flow and the incremental price of the receiving zone is applied as sale revenue to the region sending the power and as purchase costs to the region receiving the power.

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The transmission system is modeled using interchange limits between areas with $/MWh hurdle rates and losses applied to each interchange point. The hurdle rates supplied with the AURORA database represent the transmission service charges for use of that path. Adjustments to the hurdle rates are made where more information is known to help align simulation results with observed barriers to economic opportunities for market transactions. As part of AURORA scheduling, energy in a high-cost zone will not be dispatched in favor of energy from less expensive generation in another zone, after accounting for hurdle rates and transmission losses. This accomplishes the most efficient dispatch while respecting the specified transmission link limits between zones. A transmission link is normally defined between two zones when there is one or more transmission lines connecting the zones. When the flow on a transmission link is reached, no further exchange of energy is allowed on this path, but other paths may be used to exchange energy if use of an alternative path is economical.

3.2 Input Data Preparation

Because AURORA relies on publicly available generic data, a significant amount of review, analysis and 'cleaning' of the data is required. Additionally, changes are needed to configure the desired scenarios for the study. The AURORA data comes from numerous sources such as the Energy Information Agency, North American Reliability Council, and Federal and state agencies. The primary focus of the data cleaning in preparation for this study was generating resources, loads, transmission limits, and fuel prices. The focus on generating resources was required due to the large number of generating resources and generating resource characteristics. Special generator types have inputs specific for that type of generator. For example, wind generation has an hourly maximum output profile that is applied in all cases run in this study. The maximum output profile for each wind generator or group of wind generators is based on three years of National Renewable Energy Lab's synthetic data, reported at 10-minute intervals, then averaged to come up with a representative 168-hour profile by month for each month of the year. Pumped storage generation plants model minimum and maximum storage levels.

During the data cleaning process, TGG added about 200 resources, primarily in MWTG and WECC. In addition, about 800 resources were revised or updated based on EIA reports; some resources simply required changing the name of the owner. However, in the supplied AURORA database, some 85 retired resources were shown as operating, about 184 were in the wrong zone, 86 changed the primary fuel type (either oil to gas, or vice versa), generating capacity was changed for 44 resources and 10 resources were duplicates. The resulting available generation capacity by fuel type for MWTG and SPP are summarized in Figures 2 and 3.

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Figure 2: Modeled 2016 MWTG Resource Mix by Fuel Type

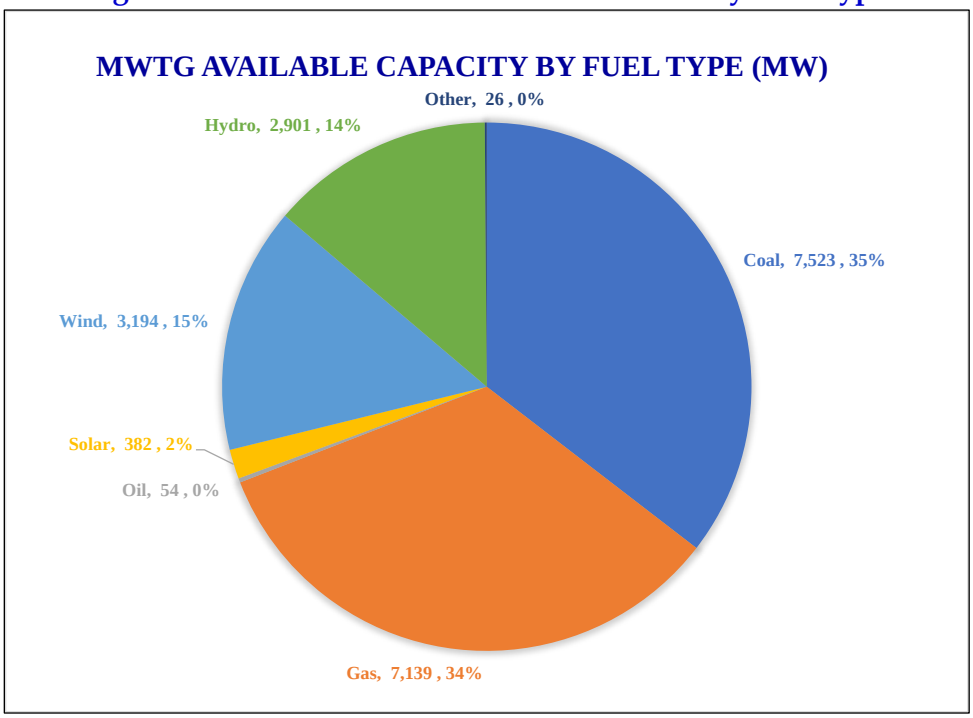
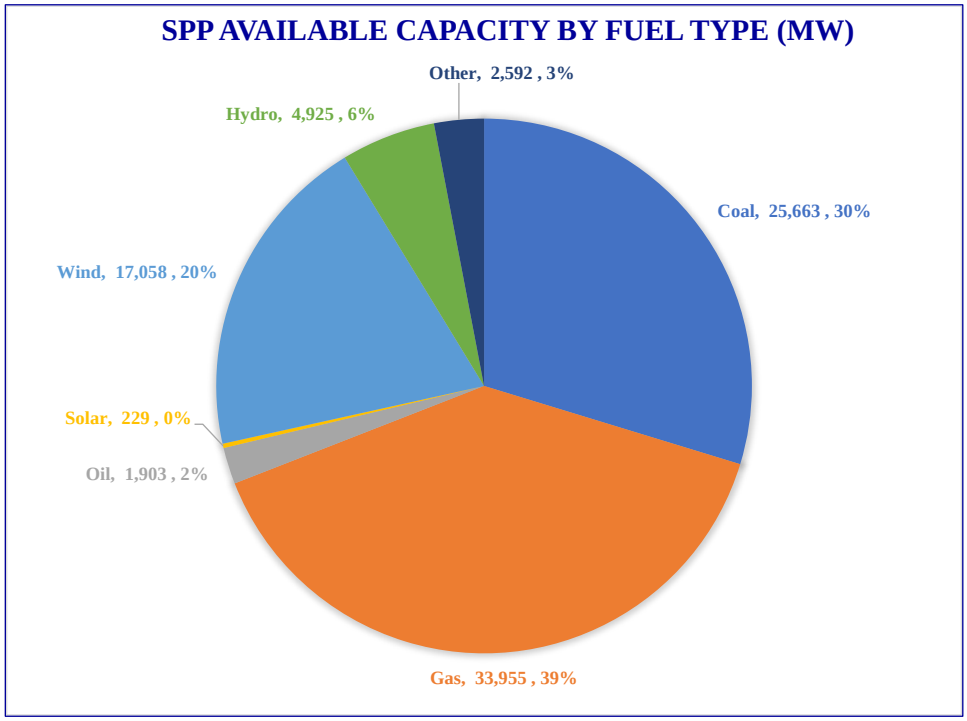


Figure 3: Modeled 2016 SPP Resource Mix by Fuel Type



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To enable the flexibility to reconfigure the AURORA-supplied zones to model transmission and precision in zonal loads, this study uses more granular 2016 EIA-reported retail sales, grossed up to total generation, instead of the load data supplied with AURORA. The hourly load shapes were determined by averaging multiple years (2006-2015) of hourly load data to develop a normalized load shape for each zone.

TGG also reviewed and verified transmission links and capacities with MWTG and SPP transmission representatives, and adjustments were made in the MWTG and SPP footprints, as described in the following sections.

To provide a more realistic regional diversification of natural gas prices (e.g., more than one natural gas price in Colorado), monthly pipeline gas prices were used from Natural Gas Intelligence, a supplier of natural gas market information.

3.2.1 Zone Definitions and Transmission Parameters

To analyze the benefits of using the DC ties between MWTG and SPP, TGG used all area/zones within WECC, the Eastern Interconnect, ERCOT, and Quebec. This large study was required because MWTG is within WECC and SPP is within the Eastern Interconnect. SPP is directly interconnected with ERCOT by two DC ties.

Although groupings of the input data into zones or markets are provided with the AURORA database, individual utilities or key transmission constraints determined to be important for this study were not necessarily included. Development of utility zones or other special study areas, require some level of customization by AURORA users. For this study, there were two primary objectives in defining zones:

- Zonal definitions support the modeling of key transmission constraints impacting the evaluation through transmission link limits
- Zonal resources and loads for MWTG and SPP contain only resources and loads belonging to MWTG or SPP so that purchases and sales can be represented by the flows on transmission links connecting MWTG or SPP to its non-member neighbors.

As shown in Figure 1 above, MWTG is configured as 11 zones in the blue-shaded region, and SPP as 17 zones in the green-shaded region. These zones are the smallest granularity in the model that capture major transmission constraints; thus, all generators and loads in a zone are deemed to be co-located at a common location, and all see the same price.

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The process of defining the zones began with consideration of the key transmission constraints. Because sub-zone impacts are not modeled in this study, it is important that the zonal definitions support the key transmission constraints impacting system operations. Work with the MWTG and SPP staff resulted in several iterations of zone definitions and/or transmission limits to ensure the key transmission constraints are represented in the zonal model.

- In MWTG, zone definitions ensured key WECC-defined transmission constraints were supported by one or more transmission paths between zones. When multiple transmission links represent a single rated path, the path rating is divided based on the square of the line voltages.
    - Example: TOT5 (Path 36) is rated at 1680 MW and represents nine lines connecting the Colorado West zone to Colorado East, Colorado North Front Range, and Wyoming Southeast zones. The rated limit is distributed between the three transfer links as shown in Table 3: CO-W – CO-E sums to 1007 MW; CO-W – CO-NFR sums to 466 MW, and CO-W – WY-SE sums to 207 MW.

Table 3: TOT5 Transmission Link Model Example

TOT5 Transmission Link Limit Analysis			
Line	**Voltage (kV)**	**CO-W Connected Area**	**Limit Allocation**
North Park-Terry Ranch Road	230	WT-SE	207
Craig-Ault	345	CO-NFR	466
Hayden-Gore Pass	230	CO-E	207
Hayden-Gore Pass	138	CO-E	75
Gunnison-Salida	115	CO-E	52
N. Gunnison-Salida	115	CO-E	52
Curecanti-Poncha	230	CO-E	207
Basalt-Malta	230	CO-E	207
Hopkins-Malta	230	CO-E	207
Total			**1680**

- SPP internal transmission link limits are based on an internal SPP study of significant transmission flowgates. The SPP study incorporates generation shift factors derived from power flow analysis and flowgate definitions to calculate simultaneous flowgate impacts of generation in each zone as a source to all other SPP zones in proportion to their loads. The most limiting flowgate for each source is generally pro-rated across the relevant paths. SPP

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transmission links with first-tier neighbors (those directly interconnected with SPP) were generally selected as the tie-line capacity with the first-tier zone.

Part of the zonal setup was also to develop a link-based accounting system to measure and account for power transactions between MWTG and WECC and to SPP across the DC ties. This required some additional adjustments to the modeled areas to ensure that the MWTG zones contain only generation and load belonging to MWTG participants. Similarly, SPP transactions are measured at links between MWTG over the DC ties and with other Eastern Interconnect, ERCOT and WECC zones. SPP zones contain only SPP member generation and load.

Transmission link parameters also include losses and hurdle rates.

- Losses on transmission links are included through the specification of transmission link loss rates. Losses for transmission within each zone are included in the zonal load.
- Hurdle rates represent the costs and/or inefficiencies of energy transfers. Hurdle rates normally include transmission usage charges, but can also represent other costs of interchange or barriers to efficiencies. Generally, the following describe the hurdle rates applied in the model:
    - Internal MWTG hurdle rates = $0/MWh. For this study, it is assumed in all conditions that MWTG will be organized in a market-based structure with transfers economically optimized through market clearing, and there are no costs for transferring power between MWTG zones.
    - MWTG and other WECC zones have hurdle rates representing transmission usage charges between MWTG utilities and other WECC utilities; generally using the hourly transmission rate of the exporting transmission provider. For purposes of this study, a composite MWTG export rate was developed based on the transmission costs and rates of MWTG participants.
    - Internal SPP hurdle rates = $0/MWh. Since SPP already has a market structure with transfers economically optimized, SPP specifies that there are no additional costs for transferring power between SPP zones.
    - SPP and WECC are connected by DC ties:
        - The four DC ties that are the subject of this study have hurdle rates to reflect the conditions for specific scenarios. In the final analysis, the DC ties are either unavailable in the base case (in which case the specific hurdle rates do not matter) or the hurdle rates are set to $0/MWh in the alternative case.

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- Blackwater, Eddy County, and Miles City DC tie hurdle rates are set to the values tuned to achieve a level of annual MWh flow close to 2016 actuals in the medium scenario base case.
- SPP and other non-MWTG/non-SPP zones have hurdle rates representing transmission usage charges between SPP and its neighbors, using values supplied by SPP as represented in SPP planning studies.
- All other hurdle rates (for those transmission links not connected to MWTG or SPP) use rates supplied in the AURORA dataset, generally representing the transmission usage charges.

3.2.2 DC Interties

TGG and the MWTG and SPP technical staff worked closely to ensure that the representation of the transmission interfaces in AURORA is as accurate as needed for this study. After numerous discussions, TGG and the technical representatives agreed that the best way to model the four DC ties in the base case is to assume that they were not available, that is, they have zero transfer capability. The initial approach had been to tune DC tie hurdle rates to achieve the MWh flows on DC ties similar to 2016 levels. However, this approach assumes that the DC tie use is in the most economic hours, which is not always the case. Furthermore, it was technically infeasible to re-tune the DC tie flow for each scenario to 2016 actual usage. The approach with no DC tie flow was determined to provide a more robust basis for the analysis.

In actual practice, the DC ties flows are determined through normal scheduling practices in which tags are submitted prior to the scheduling interval. However, for MWTG members, there are several impediments to the economic scheduling of the DC ties: price uncertainty, intra-hour pricing and other financial risks, scheduling overhead, the costs of transmission service, and other factors. For example, today, real-time schedules must be submitted 20 minutes prior to the start of an hour. At that time, the real-time prices used to settle the transaction in SPP are not known. To the extent that exposure to the volatile 5-minute real-time prices are unhedged, the submitted schedule may represent substantial financial risk if the schedule is not in a favorable direction for the entire operating hour. This uncertainty and risk leads to less than optimal scheduling of the DC ties and relatively light use of the DC ties, as can be seen in in Table 4. Once MWTG joins SPP and the DC tie schedules are determined as part of the market clearing process, the DC tie schedules will be determined optimally in each market interval, reducing the scheduling risk and increasing the efficiency of the DC ties.

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Table 4: 2016 DC Ties Usage

DC Tie Usage - 2016				
Intertie Name	**Lamar**	**Sidney**	**Stegall**	**Rapid City**
Intertie Capacity MW	**210**	**200**	**110**	**200**
Intertie Capacity Factor - Net	**1%**	**4%**	**7%**	**10%**
Intertie Capacity Factor - Gross	**3%**	**4%**	**29%**	**12%**
Total 2016 Energy (MWh) - Net	26,274	64,426	71,722	(169,182)
Total 2016 Energy (MWh) - Total Transfer	51,457	76,971	277,001	205,120
Total 2016 Energy (MWh) - Into MWTG	38,866	70,698	174,361	17,969
Total 2016 Energy (MWh) - Into SPP	12,591	6,273	102,640	187,151

In this study, the benefits of the DC ties being scheduled as part of the market are determined as the MWTG and SPP net production cost differences between two cases:

- Base case: the four DC ties are not in the market and are modeled as zero DC tie availability. The other DC ties are available for use with hurdle rates calibrated to produce total annual flows approximately equal to 2016 actual flows under medium scenario conditions.
- Alternative case: the four DC ties are in the market. The DC ties will be modeled as in service (except during outages) with zero hurdle rates, reflecting that the market can freely adjust the flow to maximize efficiency with each market dispatch solution.

While elimination of all use of the DC ties in the base case may seem unusual, it is a reasonable assumption for modeling the DC ties when they are not scheduled in the market. In today's market, there are other non-economic drivers for scheduled flows such as must offer requirements for participants with load located within the current SPP market. To the extent that anybody using the results of the study feels that the DC ties are generating value greater than zero today, they can simply reduce this study's change in value with their own estimate of today's value to achieve a revised value of the when DC ties are scheduled in the market.

DC tie outages are modeled in both the base case and the alternative case. Two weeks of planned maintenance outage is incorporated and scheduled for Blackwater, Eddy County, and Miles City for both cases, and those three plus Lamar, Sidney, Stegall, and Rapid City for alternative case. The planned outages for Lamar, Sidney, Stegall, Rapid City, and Miles City are coordinated in either the spring or fall so that no two of these ties are out of service at the same time in the medium scenarios. Two weeks of forced outage is used in the model for all ties except Stegall, for which one week of forced outages is deemed to be more appropriate by the owner. The forced outage schedule for each DC

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tie is randomly scheduled based generally on 12- and 24-hour outages outside that DC tie's scheduled maintenance period. No restriction was placed on forced outages relative to outages of other DC ties.

DC tie operating minimums were considered, but not included in the model. The results showed that few hours were scheduled with flows below the minimum MW rating, so the effect of enforcing the DC tie minimum operating limits on study results are minimal.

For the hourly intervals of this study, no restrictions were included on DC ties for minimum time limits for switching directional flows or changes in flow levels (ramp rates). Although large swings in DC tie flow are not generally expected from hour to hour, when available, the DC ties have the flexibility to switch between maximum flow in one direction and maximum flow in the opposite direction from hour to hour, if that is found to be the most economic operation.

4 Study Results

This analysis includes benefit estimates between the base case, which assumes no DC tie usage, and an alternative case, where MWTG is part of SPP and the DC ties are used to schedule power as an integral part of SPP operations. Table 5 below shows the results of the base case with no DC tie usage and the alternative case, where the DC ties are scheduled by SPP and no hurdle rates are levied on transfers across the DC ties. Estimated MWTG and SPP benefits total $12.9 million.

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Table 5: Base Case with No DC Tie usage and Alternative Case with No Hurdle Rates

Mountain West Transmission Group Analysis of Using DC Ties between MWTG and SPP Comparison of Zero Transfer Capability and Without DC Tie Hurdle Rates - MWTG Utilities									
	Base Case With Zero Transfer Capability			Base Case Without DC Tie Hurdle Rates			Difference Zero Capability/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
MWTG Generation	75,535,320	1,822,822	24.13	77,480,760	1,868,576	24.12	1,945,440	45,754	23.52
Market Purchases	2,642,407	65,568	24.81	3,923,637	97,682	24.90	1,281,230	32,114	25.06
Market Sales	(5,723,169)	(151,190)	26.42	(8,934,028)	(239,418)	26.80	(3,210,859)	(88,228)	27.48
Total MWTG	**72,241,668**	**1,737,201**	**24.05**	**72,241,670**	**1,726,841**	**23.90**	**2**	**(10,360)**	**N.M.**

Mountain West Transmission Group Analysis of Using DC Ties between MWTG and SPP Comparison of Zero Transfer Capability and Without DC Tie Hurdle Rates - SPP Utilities									
	Base Case With Zero Transfer Capability			Base Case Without DC Tie Hurdle Rates			Difference Zero Capability/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
SPP Generation	288,526,000	7,794,991	27.02	287,080,064	7,754,779	27.01	(1,445,936)	(40,212)	27.81
Market Purchases	2,619,431	75,928	28.99	5,782,280	162,696	28.14	3,162,849	86,768	27.43
Market Sales	(14,609,928)	(454,589)	31.12	(16,288,349)	(503,670)	30.92	(1,678,421)	(49,081)	29.24
Total SPP	**275,961,711**	**7,416,330**	**26.87**	**275,961,722**	**7,413,805**	**26.87**	**12**	**(2,525)**	**N.M.**

Loss adjustments included in MWH totals but not shown.

In addition to this scenario where fuel prices, loads, and DC tie availability are set at medium levels, six additional scenarios were run to estimate benefits under a variety of economic and operational conditions. The flows on the four DC ties are reported for all scenarios following the results of the six scenarios.

4.1 High and Low Natural Gas Scenarios

For natural gas, high and low gas price scenarios are performed to test the impact of varying gas prices. For the high gas price scenario, the Henry Hub price is increased by $1.50/MMBtu, so that all regions increase by the same value, and then the pipeline basis differentials between the Henry Hub price and each pipeline serving MWTG and SPP zones are modified to account for observed differentials during periods of high gas prices. For the low gas scenario, the Henry Hub price is decreased by $0.50/MMBtu, and an adjustment is made to the pipeline basis differentials to account for observed differentials during periods of low gas prices. Figure 4 shows the resulting gas prices for the low, medium, and high gas scenarios, with the low gas scenario on top, medium in the middle and high on the bottom. It is important to note that these scenarios change the relative prices between zones, which will alter the purchases and sales between those zones, and therefore, change the level of benefits.

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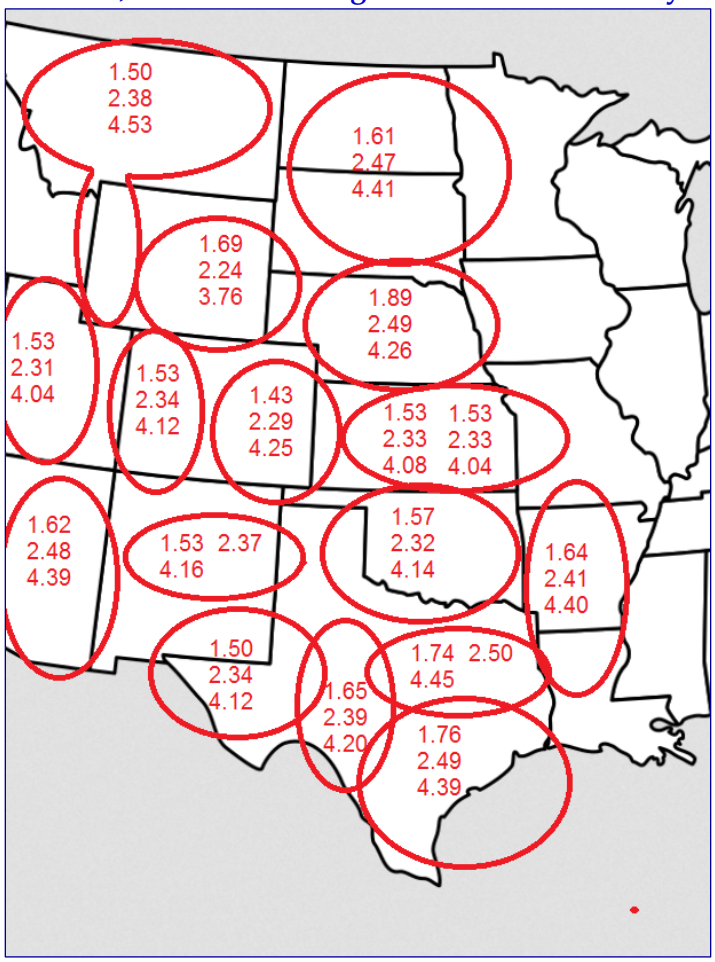
Figure 4: Low, Medium and High Natural Gas Prices by Region



For the low gas price scenario, total MWTG and SPP benefits increase slightly above the medium gas price scenario to $13.6 million. Table 6 shows the benefits of the low gas price scenario.

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Table 6: Low Gas Price Scenario

Mountain West Transmission Group Scenario Analysis
Analysis of Using DC Ties between MWTG and SPP
Comparison of Low Gas (with Low Basis) - MWTG Utilities

	Low Gas With Zero DC Tie Capability			Low Gas Without DC Tie Hurdle Rates			Difference Zero/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
MWTG Generation	76,903,120	1,771,332	23.03	78,237,080	1,801,346	23.02	1,333,960	30,014	22.50
Market Purchases	1,307,227	31,394	24.02	2,788,113	64,491	23.13	1,480,886	33,096	22.35
Market Sales	(5,768,189)	(141,556)	24.54	(8,572,648)	(213,985)	24.96	(2,804,459)	(72,429)	25.83
Total MWTG	**72,241,668**	**1,661,170**	**22.99**	**72,241,666**	**1,651,851**	**22.87**	**(2)**	**(9,319)**	**N.M.**

Mountain West Transmission Group Scenario Analysis
Analysis of Using DC Ties between MWTG and SPP
Comparison of Low Gas (with Low Basis) - SPP Utilities

	Low Gas With Zero DC Tie Capability			Low Gas Without DC Tie Hurdle Rates			Difference Zero/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
SPP Generation	292,889,184	7,445,290	25.42	292,079,360	7,420,031	25.40	(809,824)	(25,259)	31.19
Market Purchases	2,754,909	68,572	24.89	5,669,035	143,294	25.28	2,914,126	74,722	25.64
Market Sales	(19,058,473)	(572,137)	30.02	(21,117,830)	(625,895)	29.64	(2,059,357)	(53,758)	26.10
Total SPP	**275,961,705**	**6,941,725**	**25.15**	**275,961,702**	**6,937,430**	**25.14**	**(3)**	**(4,295)**	**N.M.**

Loss adjustments included in MWH totals but not shown.

The high gas price scenario is shown on Table 7. Total MWTG and SPP benefits are $28.8 million.

Table 7: High Gas Price Scenario

Mountain West Transmission Group Scenario Analysis
Analysis of Using DC Ties between MWTG and SPP
Comparison of High Gas (with High Basis) - MWTG Utilities

	High Gas With Zero DC Tie Capability			High Gas Without DC Tie Hurdle Rates			Difference Zero/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
MWTG Generation	74,235,780	2,004,870	27.01	75,289,624	2,041,123	27.11	1,053,844	36,253	34.40
Market Purchases	5,210,615	173,355	33.27	7,471,396	240,258	32.16	2,260,781	66,903	29.59
Market Sales	(6,917,694)	(254,616)	36.81	(10,170,393)	(383,719)	37.73	(3,252,699)	(129,103)	39.69
Total MWTG	**72,241,675**	**1,923,609**	**26.63**	**72,241,663**	**1,897,663**	**26.27**	**(11)**	**(25,946)**	**N.M.**

Mountain West Transmission Group Scenario Analysis
Analysis of Using DC Ties between MWTG and SPP
Comparison of High Gas (with High Basis) - SPP Utilities

	High Gas With Zero DC Tie Capability			High Gas Without DC Tie Hurdle Rates			Difference Zero/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
SPP Generation	288,709,984	8,523,472	29.52	288,097,472	8,488,929	29.47	(612,512)	(34,543)	56.40
Market Purchases	7,549,723	344,877	45.68	9,409,891	418,023	44.42	1,860,168	73,146	39.32
Market Sales	(19,671,352)	(686,325)	34.89	(20,888,414)	(727,817)	34.84	(1,217,061)	(41,492)	34.09
Total SPP	**275,961,713**	**8,182,024**	**29.65**	**275,961,717**	**8,179,135**	**29.64**	**4**	**(2,889)**	**N.M.**

Loss adjustments included in MWH totals but not shown.

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4.2 *High and Low DC Tie Availability Scenarios*

Two scenarios are performed to test the impact of DC tie availability, the low scenario reduces DC tie availability to 86% (88% for Stegall reflecting its differing maintenance outage assumption discussed earlier in this document), and in the high scenario, availability increases to 98% for all seven DC ties.

Table 8 shows DC tie outage hours under the low, medium, and high availability scenarios.

Table 8: DC Tie Outage Hours by Scenario

DC Tie Out of Service Hours			
DC Tie	**Low Avail**	**Medium Avail**	**High Avail**
Miles City	1224	672	168
Rapid City	1224	672	168
Stegall	1056	504	168
Sidney	1224	672	168
Lamar	1224	672	168
Eddy County	1224	672	168
Blackwater	1224	672	168

The low DC tie availability scenario produces results of $11.7 million. Table 9 shows the benefits of the low DC tie availability scenario.

Table 9: Low DC Tie Availability

Mountain West Transmission Group Scenario Analysis Analysis of Using DC Ties between MWTG and SPP Comparison of Zero Transfer Capability and Low DC Tie Availability Without Hurdles - MWTG Utilities									
	Zero Transfer Capability			Low Available Without DC Tie Hurdle Rates			Difference Zero Capability/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
MWTG Generation	75,512,990	1,822,096	24.13	77,471,480	1,868,502	24.12	1,958,490	46,406	23.69
Market Purchases	2,651,014	65,762	24.81	3,678,991	91,827	24.96	1,027,977	26,065	25.36
Market Sales	(5,709,488)	(150,576)	26.37	(8,683,838)	(233,234)	26.86	(2,974,349)	(82,658)	27.79
Total MWTG	**72,241,662**	**1,737,282**	**24.05**	**72,241,671**	**1,727,095**	**23.91**	**9**	**(10,187)**	**N.M.**

Mountain West Transmission Group Scenario Analysis Analysis of Using DC Ties between MWTG and SPP Comparison of Zero Transfer Capability and Low DC Tie Availability Without Hurdles - SPP Utilities									
	Zero Transfer Capability			Low Available Without DC Tie Hurdle Rates			Difference Zero Capability/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
SPP Generation	288,545,152	7,794,751	27.01	287,096,224	7,755,013	27.01	(1,448,928)	(39,738)	27.43
Market Purchases	2,628,673	76,638	29.15	5,556,248	156,835	28.23	2,927,575	80,198	27.39
Market Sales	(14,642,811)	(455,291)	31.09	(16,083,003)	(497,297)	30.92	(1,440,191)	(42,006)	29.17
Total SPP	**275,961,703**	**7,416,097**	**26.87**	**275,961,709**	**7,414,551**	**26.87**	**6**	**(1,546)**	**N.M.**

Loss adjustments included in MWH totals but not shown.

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The high DC tie availability scenario produces total benefits of $12.6 million. Table 10 shows the benefits of the high DC tie availability scenario.

Table 10: High DC Tie Availability

Mountain West Transmission Group Scenario Analysis Analysis of Using DC Ties between MWTG and SPP Comparison of Zero Transfer Capability and High DC Tie Availability Without Hurdles - MWTG Utilities									
	Zero Transfer Capability			High Available Without DC Tie Hurdle Rates			Difference Zero Capability/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
MWTG Generation	75,532,070	1,822,559	24.13	77,638,310	1,872,306	24.12	2,106,240	49,747	23.62
Market Purchases	2,641,892	65,460	24.78	3,895,473	97,115	24.93	1,253,582	31,654	25.25
Market Sales	(5,719,282)	(150,792)	26.37	(9,064,300)	(243,288)	26.84	(3,345,018)	(92,496)	27.65
Total MWTG	**72,241,668**	**1,737,227**	**24.05**	**72,241,668**	**1,726,133**	**23.89**	**(0)**	**(11,095)**	**N.M.**

Mountain West Transmission Group Scenario Analysis Analysis of Using DC Ties between MWTG and SPP Comparison of Zero Transfer Capability and High DC Tie Availability Without Hurdles - SPP Utilities									
	Zero Transfer Capability			High Available Without DC Tie Hurdle Rates			Difference Zero Capability/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
SPP Generation	288,516,900	7,794,797	27.02	286,742,816	7,746,502	27.02	(1,774,084)	(48,295)	27.22
Market Purchases	2,678,727	77,829	29.05	5,957,718	167,284	28.08	3,278,991	89,455	27.28
Market Sales	(14,660,516)	(456,093)	31.11	(16,122,727)	(498,711)	30.93	(1,462,211)	(42,617)	29.15
Total SPP	**275,961,730**	**7,416,532**	**26.88**	**275,961,729**	**7,415,075**	**26.87**	**(1)**	**(1,457)**	**N.M.**

Loss adjustments included in MWH totals but not shown.

4.3 High and Low Weather-Related Load Scenarios

The final two scenarios are high and low load scenarios to test the impact of weather-related load changes. To determine the variation of loads with respect to weather, the SPP total annual loads in years 2006-2013 were analyzed to find the years with the highest and lowest annual loads. Little load growth was observed within SPP during in this period, so the loads for the identified years are applied without load growth factors applied.

For the low load scenario, 2009 was identified as the source year. The 2009 SPP loads were calculated as 2.6% below the 2016 loads used in the medium scenario. Thus, the low load scenario reduces each zone's annual load by 2.6%. Additionally, the 2009 zonal load shapes are applied to ensure that the temporal correlation of loads across the modeled zones is consistent with the low load conditions in SPP as a whole. With the load changes representing weather-related changes, the load changes are applied in SPP, MWTG, New Mexico, Arizona, Utah, and Montana. Other areas retain their average load conditions.

For the high load scenario, 2011 was identified as the highest load year. The 2011 loads were applied to produce a 2.6% (equal to the low scenario strictly by happenstance)

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increase in each zone's annual load compared to the 2016 load used in the medium scenario. The 2011 load shape is applied to the modeled zones to maintain temporal correlation.

In the low load scenario, total benefits are $14.2 million. Table 11 show the results of the low load scenario.

Table 11: Low Load Scenario

Mountain West Transmission Group Scenario Analysis Analysis of Using DC Ties between MWTG and SPP Comparison of Low Load (with Low Shape) - MWTG Utilities									
	Low Load With Zero DC Tie Capability			Low Load Without DC Tie Hurdle Rates			Difference Zero/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
MWTG Generation	73,329,760	1,771,762	24.16	75,637,130	1,824,627	24.12	2,307,370	52,864	22.91
Market Purchases	3,129,178	73,980	23.64	4,185,239	100,194	23.94	1,056,061	26,215	24.82
Market Sales	(5,882,214)	(153,777)	26.14	(9,236,482)	(244,202)	26.44	(3,354,268)	(90,424)	26.96
Total MWTG	**70,363,663**	**1,691,964**	**24.05**	**70,363,660**	**1,680,619**	**23.88**	**(3)**	**(11,345)**	**N.M.**

Mountain West Transmission Group Scenario Analysis Analysis of Using DC Ties between MWTG and SPP Comparison of Low Load (with Low Shape) - SPP Utilities									
	Low Load With Zero DC Tie Capability			Low Load Without DC Tie Hurdle Rates			Difference Zero/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
SPP Generation	283,370,600	7,654,878	27.01	281,713,632	7,609,568	27.01	(1,656,968)	(45,310)	27.35
Market Purchases	2,200,959	61,157	27.79	5,559,528	151,517	27.25	3,358,568	90,360	26.90
Market Sales	(16,221,917)	(506,674)	31.23	(17,876,455)	(554,588)	31.02	(1,654,539)	(47,914)	28.96
Total SPP	**268,786,679**	**7,209,360**	**26.82**	**268,786,652**	**7,206,496**	**26.81**	**(27)**	**(2,864)**	**N.M.**

Loss adjustments included in MWH totals but not shown.

Results for the High Load scenario are $13.2 million, as shown in table 12.

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Table 12: High Load Scenario

Mountain West Transmission Group Scenario Analysis Analysis of Using DC Ties between MWTG and SPP Comparison of High Load (with High Shape) - MWTG Utilities									
	High Load With Zero DC Tie Capability			High Load Without DC Tie Hurdle Rates			Difference Zero/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
MWTG Generation	76,378,216	1,844,722	24.15	78,266,140	1,889,194	24.14	1,887,924	44,472	23.56
Market Purchases	3,605,776	88,904	24.66	4,981,136	124,108	24.92	1,375,360	35,204	25.60
Market Sales	(5,643,908)	(147,799)	26.19	(8,891,053)	(238,990)	26.88	(3,247,145)	(91,190)	28.08
Total MWTG	**74,120,135**	**1,785,827**	**24.09**	**74,120,131**	**1,774,313**	**23.94**	**(4)**	**(11,514)**	**N.M.**

Mountain West Transmission Group Scenario Analysis Analysis of Using DC Ties between MWTG and SPP Comparison of High Load (with High Shape) - SPP Utilities									
	High Load With Zero DC Tie Capability			High Load Without DC Tie Hurdle Rates			Difference Zero/No Hurdle		
		Production Cost			Production Cost			Production Cost	
	MWh	($000)	$/MWh	MWh	($000)	$/MWh	MWh	($000)	$/MWh
SPP Generation	292,741,536	7,918,842	27.05	291,194,560	7,875,029	27.04	(1,546,976)	(43,813)	28.32
Market Purchases	3,181,290	98,959	31.11	6,289,251	184,146	29.28	3,107,960	85,187	27.41
Market Sales	(12,220,482)	(367,466)	30.07	(13,739,698)	(410,552)	29.88	(1,519,215)	(43,087)	28.36
Total SPP	**283,136,862**	**7,650,335**	**27.02**	**283,136,846**	**7,648,623**	**27.01**	**(15)**	**(1,712)**	**N.M.**

Loss adjustments included in MWH totals but not shown.

4.4 DC Tie Flow Use

In each scenario, two cases are considered. In the base case, the four DC ties that are the focus of this study have no availability and, therefore, have zero flows. In the alternative cases, the four DC ties are available (except for outages) with no hurdle rates. Table 13 reports the use of the four DC ties in the alternative case when the DC ties are available. The 2016 actual use of the DC ties is also reported for reference.

All scenarios show significant use of the DC ties. The DC tie use in the low and high gas scenarios have the largest differences compared to the other scenarios, indicating that the relative regional cost of generation has a significantly greater impact than the factors modeled in the other scenarios. The natural gas price variations can be seen in the magnitude and distribution of prices changes described in Section 4.1. The DC tie availability scenarios also saw notable changes in DC tie flows due to changes in the duration and timing of the DC tie outages. Also of note, is that Rapid City is used less than the other three DC ties. This is due to a variety of transmission constraints reflected in the model.

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Table 13: DC Tie Usage by Scenario

DC Tie MWh Usage by Scenario								
	2016 Actual	Medium	High Gas	Low Gas	High Load	Low Load	High Avail	Low Avail
Rapid City into SPP	187,151	662,451	514,725	707,261	665,505	696,307	653,454	595,343
Rapid City into MWTG	17,969	131,153	446,558	120,308	134,859	117,839	145,797	146,138
Stegall into SPP	102,640	536,297	229,981	582,686	525,809	549,344	534,165	495,113
Stegall into MWTG	174,361	167,885	510,913	138,035	174,057	152,223	186,731	164,314
Sidney into SPP	6,273	952,742	356,171	992,238	927,641	998,136	996,335	884,239
Sidney into MWTG	70,698	300,162	1,038,792	278,886	321,993	279,130	334,366	284,222
Lamar into SPP	12,591	1,390,037	1,592,243	813,611	1,359,113	1,419,968	1,472,289	1,289,967
Lamar into MWTG	38,866	101,809	34,950	509,940	127,252	95,979	110,289	97,747
Rapid City Total	205,120	793,604	961,283	827,569	800,364	814,146	799,251	741,481
Stegall Total	277,001	704,182	740,894	720,721	699,865	701,567	720,896	659,428
Sidney Total	76,971	1,252,905	1,394,963	1,271,124	1,249,634	1,277,266	1,330,701	1,168,461
Lamar Total	51,457	1,491,845	1,627,193	1,323,551	1,486,365	1,515,946	1,582,577	1,387,714
Rapid City Usage*	12%	45%	55%	47%	46%	46%	45%	42%
Stegall Usage*	29%	73%	77%	75%	72%	73%	75%	68%
Sidney Usage*	4%	71%	79%	72%	71%	73%	76%	67%
Lamar Usage*	3%	81%	88%	72%	81%	82%	86%	75%

* Usage is based on 100% availablity.

4.5 Benefits Not Captured

Almost all electric utility planning studies attempt, at some level, to approximate real operating conditions. This study is no different. While there is some level of hourly volatility represented in the model used in this study, several approximations used in the configuration and execution of this study lean toward model results that reflect average operating conditions. For example, the modeling utilizes monthly natural gas prices instead of individual daily day-ahead and secondary market prices and does not include reflect significant variable energy resource volatility. TGG believes that these assumptions have led to conservative study results. If AURORA would be modified to produce market prices in SPP that reflect the significant volatility that occurs in fact, TGG believes that the benefits for scheduling the DC ties into the SPP market would increase. The study does not assess the benefits of managing uncertainties with a larger pool of resources. Errors that manifest between day-ahead and real-time operations are more easily and cost-effectively managed with a larger electrical footprint. AURORA does not model uncertainty, but rather has 'perfect knowledge' of load, variable energy resources, and unit availability.

A measure of the conservative assumptions in the current AURORA setup can be seen through the volatility in the hourly electric market prices. SPP publishes hourly electric market prices, which can be compared against the SPP hourly market prices from the AURORA results in this study. For example, the modeled 2016 SPP South Hub average

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price of power from the base case was $26.54/MWh with a standard deviation of about $5.50/MWh. The day-ahead 2016 South Hub price had an average of $25/MWh and standard deviation of $9/MWh. Higher volatility indicates more opportunity for the DC ties to bring value by moving power between MWTG and SPP. With the reduced volatility in the AURORA modeled results, the benefits exclude increased value when MWTG could sell power into SPP when prices were very high, which would increase benefits for MWTG because of higher sales for resale revenue, and increase benefits at SPP, because the cost of purchase from MWTG would be lower than their cost of generation. Conversely, when SPP power prices are very low, or negative, MWTG benefits would increase because they could curtail or shut down higher cost generation to take advantage of the low cost SPP power. SPP's benefits would increase because the sales to MWTG would be higher, possibly reducing the number of negatively priced hours.

5 Conclusions

The results of this study show a significant level of benefits for MWTG and SPP from the market scheduling of the flow of the four DC ties in a combined MWTG-SPP market, ranging from $11.7 million to $28.8 million as a result of varying key input parameters.

During this project, TGG went through several iterations of the study model designs to more accurately represent the MWTG and SPP characteristics.

- Refined area models and transmission transfer limits.
- Implemented a link-based sale and purchase valuation over 45 individual transmission links to capture the impact of purchases and sales on the DC tie value.
- Switched to more granular natural gas price data source to better represent geographic diversity of natural gas prices.

TGG is confident that the AURORA setup represents the MWTG and SPP systems under the average conditions modeled, although with conservative levels of volatility. TGG believes there are significant additional DC tie benefits available in resulting from high volatility conditions that are not included in the less volatile conditions represented in this study.

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