Potential Implications of the AUC TCM Decision (2013-135) on the Alberta Electricity Market's Economic Efficiency

May 2013

Judy Chang
Johannes Pfeifenberger
Michael DeLucia

Prepared for

About the Authors

Judy W. Chang and Johannes P. Pfeifenberger are Principals and Michael DeLucia is a Research Analyst of *The Brattle Group*. The authors have analyzed the Alberta electricity market in a number of prior engagements and have been co-authors of *The Brattle Group*'s presentations and reports analyzing investment decisions in the Alberta electricity market, including Pfeifenberger, *et al.* (2011) and (2013) as listed in the report's bibliography. They can be reached at www.brattle.com, which also provides postings of the authors' prior work.

Acknowledgements and Disclaimer

The authors would like to thank the AESO staff for their cooperation and responsiveness to our many questions and requests. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone. Nothing herein is intended to provide a legal opinion.

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EXECUTIVE SUMMARY

We have prepared this report to aid the Alberta Electric System Operator (AESO) in its efforts to analyze the Principles set out by the Alberta Utilities Commission (AUC) in Decision 2013-135 regarding changes to the Transmission Constraint Management (TCM) Rule. The scope of this report is limited to assessing the efficiency implications of implementing the AUC's newly defined Principles, relative to maintaining the existing TCM framework within Alberta's energy-only market design. Due to time limitations, we have not examined alternative market design options for the purpose of compliance.

Based on our analysis of the AUC's Principles in the context of the structure of the Alberta electric system and market fundamentals, we find that implementing design changes according to the Principles would reduce the efficiency and fidelity of Alberta pool prices and likely create uneconomic barriers for future generation and transmission investments. We believe that the Commission has not accurately interpreted all of the information provided in the record of the proceeding and that additional evidence shows that the decision would likely harm Alberta's electricity market. Our findings are summarized as follows:

- Managing transmission constraints by implementing the new Principles would not send more economically-efficient price signals to generators and load in the Alberta market than the existing TCM Rule. The new Principles ignore the fact that transmission constraints in Alberta are typically small generation pockets with export constraints, and not load pockets with import constraints. The existing TCM Rule is the more effective and efficient way to manage transmission constraints that primarily reflect conditions during which the large majority of load and generation are downstream from the constraints. Allowing generation and load to compete and pool prices to accurately reflect market conditions in this downstream portion of the market will be important for the continued efficient operation of the Alberta electricity market. Implementing a market design according to the Principles would send a wrong and inefficient price signal to the majority of the generators and load in Alberta, and thereby decrease overall efficiency, suppress downstream market clearing prices below competitive levels, and suppress incentives for future investments in generation and transmission. Table 1 shows that, with the exception of constraints already managed with Transmission Must Run (TMR), the constraints in the Alberta Interconnected Electric System (AIES) are small export constrained areas, which means that most of the generators compete for market share downstream.

Table 1
Summary of Transmission Constraints in the AIES

	Frequency of Constraints (Hours)					Percent Located Downstream	
	2008	2009	2010	2011	2012	Generation	Load
Generation-Pocket Export Constraints *(Pool Price Set at Downstream Price with TCM)*							
Fort McMurray	24	245	454	519	632	86%	89%
Southwest Wind	478	927	1,480	933	286	93%	97%
KEG (Keephills/Ellerslie/Genesse)	1,002	151	1,093	306	207	78%	100%
2010 Southeast Storm-Related	0	0	1,034	0	0	NA	NA
Other Export Constraints	0	18	48	174	75	> 97%	> 97%
Load-Pocket Import Constraints *(Pool Price Already Set at Unconstrained Price Through Existing TMR/DDS)*							
Northwest Area	8,717	8,745	8,728	8,723	4,255	4%	8%
Other Import Constraints	863	2,051	221	214	154	small pockets	small pockets
Large Constraints							
SOK (South of KEG)	0	0	58	0	0	35%	40%

– Market design changes that comply with the Principles, if implemented, would strip a portion of the generation costs out of individual constrained hours and place them into annual transmission charges. Instead of allowing energy prices to rise when required to by system conditions, moving the cost of re-dispatch to annual transmission charges would reduce the fidelity and efficiency of the existing hourly pool prices that send correct price signals to the large majority of the market. Such a new market design would distort the electricity prices that are necessary to incentivize generator performance and load response. Instead, the incremental dispatch cost during constraints would be placed on all transmission customers without regard to the time of energy usage. Even if the hourly re-dispatch charges could be made visible in transmission bills based on hourly customers' usage, that information would only become available long after the fact, providing little valuable information to load and generators. Implementing design changes according to the Principles would thus reduce price fidelity because neither downstream generators nor load, representing the majority of the market, would be able to see or react to correct real-time market price changes associated with system constraints.

– Increasing the use of TMR contracts to manage transmission constraints would be setting policies counter to the direction toward which most other electric systems in North America are moving. Increased usage of TMR would: (1) be ineffective and inefficient in resolving small export-constrained situations; (2) increase the dependence of generators on long-term contracts for energy production; (3) reduce the competitiveness of the energy market; and (4) ultimately discourage transmission development when it is needed and new generation investment without TMR contracts. Attempting to use TMR contracts to resolve small export-constrained situations could ultimately require a large portion of Alberta's generation fleet to have TMR contracts because the pool of generators that can help manage the constraints would be large. Many TMR contracts would likely need to be put into place, unnecessarily eroding the existing competitive energy market.

- The Alberta pool likely does not experience a substantially higher frequency of high prices under the TCM Rule than it would under a new market design in accordance with the Principles. Data on the frequency of price spikes in the Alberta market do not show that managing transmission constraints using the TCM Rule has a significant impact on the frequency or duration of price spikes in the Alberta market. Price spikes occur with nearly the same frequency during hours with and without transmission constraints. Instead, the data show that the amount of remaining supply is the main driver of price spikes. Remaining supply accounts for generator outages, wind power output, supplies from neighboring markets, and load levels, but does not account for internal transmission constraints. Further, our prior study shows that bidding behaviors also have a strong impact on the frequency and duration of price spikes and therefore overall price levels in the Alberta electricity market.

- The forward market is not being negatively affected by the TCM Rule. There is no evidence that the TCM Rule increases price volatility; but even if it does, an increase in price volatility alone does not increase the cost of hedging. If any effect could be noticeable, implementing a market design that relies more heavily on TMR could reduce the amount of generation being hedged using the forward market and thereby reduce liquidity and increase the cost of hedging.

- The AUC appears to have accepted the claim that market clearing prices and total customer costs under the TCM Rule are significantly higher than under a market design implemented according to the Principles. If that were consistent with generators' expectations, generators might adjust their bidding behavior to "put back" into the market the "missing money" that they might lose from the change in market rules. Not allowing generators to maintain these revenues could undermine resource adequacy and the generation investment needed over the next decade, particularly in downstream market areas where new generation investment is needed the most. When the large majority of the market is downstream from a constraint and most of the downstream generators expect to receive less under the new market design, those generators might increase the occasions of trying to match their bids to guesses of the last-dispatched supplier's offer prices to ensure dispatch while maintaining their revenues. Such guessing could result in dispatching inefficient generators before efficient ones, reducing market efficiency, and increasing emissions.

I. INTRODUCTION AND BACKGROUND

On April 5, 2013, the Alberta Utilities Commission (AUC) directed the Alberta Electric System Operator (AESO) to revise its management of transmission constraints by implementing several significant changes to the current Transmission Constraint Management (TCM) Rule.[1] Specifically, the Commission ordered the AESO to revise the TCM Rule in accordance with the following four principles:

1) The single clearing price for energy in Alberta shall be established by the intersection of the unconstrained supply curve and the demand curve so as to prevent transmission congestion from setting the energy price;
2) The costs of any generation re-dispatch necessary to ensure that the transmission system operating limits are respected shall be determined based on generators' offers in the competitive energy market unless other arrangements, such as Transmission Must-Run (TMR) contracts, are in place;
3) The AESO shall recover the costs of generation re-dispatch necessary for transmission reasons through the transmission tariff; and
4) The AESO shall make available, as near to real time as possible, information on the location of transmission constraints and the cost of resolving them.

In addition, the Commission ordered the ISO to increase the use of TMR in conjunction with Dispatch Down Service (DDS).

For the purpose of our analysis, we refer to the combination of these four principles, along with the increased use of TMR and DDS, as the "AUC's Principles," "New Principals," or "Principles." Together, the Principles represent the Commission's mandate for the AESO in the development of a new transmission congestion management pricing mechanism.

The AESO asked us to assist them in evaluating the potential impacts of the AUC's Principles compared to the existing market design, and their potential impact on market efficiency, price fidelity, and investment signals. In this report, we examine the potential impact of implementing the Principles, with a focus on the economic efficiency of a market design that conforms to the Principles relative to the current TCM Rule.[2] Specifically, we review data about the types of transmission congestion that occur in Alberta, discuss the relative pricing efficiencies of the congestion management systems under TCM versus the new Principles, and review and analyze the potential impact of the Principles on the overall design of the Alberta wholesale energy market.

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1 See AUC (2013), pp. 36-37.

2 Our scope in this report is limited to examining the implications of implementing the New Principles relative to the existing TCM rule. Due to time limitations, we have not examined alternative market design options for the purpose of compliance.

II. PRICE SIGNALS IN THE PRESENCE OF TRANSMISSION CONGESTION

A. UNCONSTRAINED, UPSTREAM, AND DOWNSTREAM PRICES

In the presence of transmission congestion, market fundamentals deviate from the conditions of an unconstrained market. In general, during transmission constraints: (1) the marginal cost of serving load in the downstream side of the constraint would be above the unconstrained price; and (2) the marginal cost of serving load in the upstream side of the constraint would be below the unconstrained price.

An illustrative example of unconstrained, upstream, and downstream prices is shown in Figure 1. In the absence of a transmission constraint between the two regions, Generator A2 would set the system price at $30/MWh. By definition, the $30/MWh is the "unconstrained price." If the transfer limit between Region A and Region B is reached and Generator A2 is constrained off such that additional output from Generator A2 cannot reach the market, Generator B2 (located downstream from the constraint) would need to be dispatched to make up for the portion of generation that the system has constrained off from Generator A2. In a simplified form, the marginal cost upstream from the constraint is $20/MWh as set by Generator A1, and the marginal cost downstream from the constraint is $40/MWh as set by Generator B2.

Figure 1
Illustrative Example of Unconstrained, Upstream, and Downstream Marginal Costs

Region A: Upstream

Load: 100 MW

Generator	Dispatch Cost	Capacity	Generation
A1	$20/MWh	130 MW	120 MW
A2	$30/MWh	100 MW	0 MW

20 MW Transfer Limit →

Region B: Downstream

Load: 100 MW

Generator	Dispatch Cost	Capacity	Generation
B1	$20/MWh	50 MW	50 MW
B2	$40/MWh	100 MW	30 MW

Unconstrained Marginal Cost: $30/MWh (Generator A2)
Upstream Marginal Cost: $20/MWh (Generator A1)
Downstream Marginal Cost: $40/MWh (Generator B2)

Using this example, one can see that setting the pool price equal to the unconstrained $30/MWh price would suppress the price to load and generators downstream of the constraint below the $40/MWh level that reflects market fundamentals in that region, while setting a $30/MWh price that is still higher than the $20/MWh marginal costs of serving load upstream of the constraint. Fundamentally, the resulting price signal would not be economically efficient on either side of the constraint. Whether the price signal sent under the AUC's Principles would improve overall economic efficiency and price fidelity relative to the existing TCM pricing mechanism is consequently a function of which side of the constraint contains the larger portion of the total market. In other words, when a system is constrained, using a single pool price does not capture the difference in the marginal cost of serving load on either side of the constraint. How inefficient such a single price is consequently depends on how much of the load and generation it affects. Under a single-pool-price energy market design, if most of the generation and load is downstream from the constraint, a market design based on using the higher downstream price to set the price for the entire pool during constrained hours would still send the proper price signal for the majority portion of the market. On the other hand, if a majority of the pool is downstream from the constraints, setting pool-wide prices based on the unconstrained price would send price signals that are too low for the large downstream market while still setting prices that are too high for the small upstream market. On balance, the unconstrained price would send a price signal that is less efficient from the perspective of the entire pool.

B. Price Signals for Generation Investment

In deregulated electricity markets, pricing that reflects market fundamentals is needed to ensure that economically efficient price and investment signals are sent to both loads and generation to attract investment in new generation, along with demand response, to ensure that supply adequacy is maintained over time. In an energy-only market like Alberta, regulatory mechanisms are not used to enforce reserve margin requirements and investors in generating plants must recover their investment costs solely through revenues earned in the energy market. This means that when reserve margins are tight and new generation is needed, energy price levels must be high enough to retain existing supply and attract new construction. The amount of capacity in the system is determined by the aggregate effect of market-based private investment decisions made in response to the prices and revenues available from the energy market.[3] Thus, efficient price signals are particularly critical for attracting generation investment in an energy-only market like Alberta.

Pricing that reflects market fundamentals will also be a consideration for locational investment decisions—in concert with other factors such as fuel cost and availability, siting, and steam needs—to guide where new generation is built. If the majority of load and existing generation is located downstream from the constraints and that is also where future generation is most needed, then developing a market design that sends the proper price signal for the downstream majority of the market will be critical in ensuring efficient investment decisions going forward.

We recommend that the AESO carefully consider the potential impact of changing the pricing mechanism on investment decisions to ensure that resource adequacy can be sustained in Alberta through a competitive market.

C. Price Signals for Short-term Generation and Load Response

Price signals that reflect market fundamentals are needed to ensure short-term load response and generator performance during system scarcity. Energy-only markets are usually characterized by moderate levels of energy prices that are punctuated by occasional price spikes during scarcity conditions. This is because sufficient resources are available most of the time and competitive market forces yield prices close to the marginal production cost of the most expensive unit dispatched. However, there are occasions when supplies are scarce and high energy prices are realized. Such scarcity conditions are often caused by high load, generation outages, or the

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[3] For additional discussion of energy-only markets and other market designs to address resource adequacy, see Pfeifenberger and Spees (2011), Section II.A.

combination of these two factors. High prices during such scarcity conditions are needed to provide adequate incentives for price-responsive loads to reduce consumption and for generators to perform reliably.[4]

If implemented according to the Principles mandated by the Commission, the new market design and pricing mechanisms will artificially strip out the necessary downstream price signals during transmission constraints by setting the pool price at the unconstrained level. This, in turn, would suppress market prices and mute the incentive for load and generation to respond to scarcity conditions downstream of a constraint. This issue is particularly consequential from an overall market efficiency perspective when the majority of load and generation in the system is downstream from the constraint. Further, using transmission charges to recover the hourly dispatch costs for downstream generators who are re-dispatched to maintain system operating limits would only compensate at efficient price levels the small subset of generators who receive their high offer prices when they are dispatched out of the economic merit order in response to the constraint. The other downstream generators and all of the downstream loads would not see price signals that provide correct incentives to respond to the scarcity conditions in that part of the system.

III. FACTS ABOUT CONSTRAINTS IN THE ALBERTA TRANSMISSION SYSTEM

In this section, we describe the specific types of transmission constraints that cause congestion in the Alberta Interconnected Electric System (AIES) and show that the majority are export constraints with only small pockets of generation located upstream of the constraint. Under TCM, the pool prices set when these constraints are binding accurately reflect market fundamentals for the majority of generation and load in the pool, which is located downstream from the constraints. This also means that managing these constraints with a market design that reflects the AUC's Principles would send the wrong price signal to the majority of generation and load.

A. SUMMARY OF TRANSMISSION CONSTRAINTS MANAGED BY THE AESO

Table 2 summarizes the number of constrained hours per year for specific constraints in the AIES from 2008 to 2012. It also shows the proportion of the system's total generation and load that is located on the downstream side of each constraint. We categorized the types of constraints into three groups:

1) *Generation-pocket export constraints.* This is an area where a small "pocket" of generating resources is located upstream of a transmission constraint. The amount of generation capability in the relevant area can exceed the amount of load in the same area. Efficient flow of the excess power generation automatically occurs up to the point where the transmission capability used to export the excess generation capability to the rest of the pool is reached. After that point, some of the power generated in the area cannot be

4 For additional discussion of scarcity pricing in energy-only markets, see Pfeifenberger and Spees (2011), Section II.A.

exported, thereby creating what is called a "generation-pocket" or export-constrained area.

2) *Load-pocket import constraints.* This is an area where the economically-dispatched power imported from outside of the area is not always sufficient to meet the local load such that some amount of out-of-merit local generation is needed when the transmission import limit is reached.

3) *Large constraints.* These have a substantial quantity of load and generation on both the upstream and downstream sides of the constraint.

Table 2
Summary of Transmission Constraints in the AIES

	Frequency of Constraints (Hours)					**Percent Located Downstream**	
	2008	2009	2010	2011	2012	Generation	Load
Generation-Pocket Export Constraints							
(Pool Price Set at Downstream Price with TCM)							
Fort McMurray	24	245	454	519	632	86%	89%
Southwest Wind	478	927	1,480	933	286	93%	97%
KEG (Keephills/Ellerslie/Genesse)	1,002	151	1,093	306	207	78%	100%
2010 Southeast Storm-Related	0	0	1,034	0	0	NA	NA
Other Export Constraints	0	18	48	174	75	> 97%	> 97%
Load-Pocket Import Constraints							
(Pool Price Already Set at Unconstrained Price Through Existing TMR/DDS)							
Northwest Area	8,717	8,745	8,728	8,723	4,255	4%	8%
Other Import Constraints	863	2,051	221	214	154	small pockets	small pockets
Large Constraints							
SOK (South of KEG)	0	0	58	0	0	35%	40%

Sources and Notes:

Constraint information is recorded manually by controllers on a best effort basis and does not always contain precise information.

The load breakdown is approximate and representative, and is calculated based on 2012 average hourly Internal Load (AIL).

The generation breakdown is approximate and representative, and is calculated based on the average available capacity in 2012, with the exception of the Southwest Wind constraint, where it is defined as the maximum generation. See the below discussion of individual constraints for more detail.

The generation and load breakdowns for the 2010 Southeast Storm-Related constraints are unknown due to the complexity and variability of those system constraints.

The "Other Export Constraints" category includes but is not limited to the Joffre, Crossfield, and Cold Lake constraints.

There are a total of 92 additional constraint-hours from 2008-2012 that were not categorized due to data limitations and are not shown in the table.

The Frequency of Constraint data were categorized specifically for this report and counted at each individual constraint. As such they will not match the previously published constraint data presented in the 24- Month Reliability Outlook published by the AESO.

The primary generation-pocket export constraints on the AIES system are the Southwest Wind, Fort McMurray, and KEG (Keephills/Ellerslie/Genesee) constraints. The constraints triggered by the storm in spring 2010 were also generation-pocket export constraints. There are also several small generation-pocket constraints that occur infrequently, which we have summarized as Other Export Constraints.[5] For these constraints, the vast majority of generation and load is located downstream of the constraints, as shown in the final two columns of Table 2. Therefore, for these situations, setting the price to reflect downstream market fundamentals ensures that the pool price sends the efficient price signal to the vast majority of the pool's generation and load. Under TCM, these export constraints are managed by constraining off upstream generation with Reverse Merit Order (RMO)/Pro-rata curtailments, dispatching downstream generation according to the Energy Market Merit Order (EMMO), and setting the pool price at the marginal cost of the downstream generator dispatched according to the EMMO. This approach sets a pool price that is consistent with the market fundamentals on the downstream side of the constraint.

When examining how efficient the pricing under TCM is from an overall market perspective, we examined the frequency of those constraints and estimated the amount of generation and load located downstream that receives the appropriate pricing. Based on the weighted average amount of load and generation reported in Table 2, approximately 87% of generation and 94% of load was located downstream on average across hours when generation pocket-export constraints were binding in 2011 and 2012. Recognizing the fact that this type of constraint occurred during 16% of all hours in 2011 and 2012 implies that the efficient price signal was applied to approximately 98% of the total generation and 99% of the total load over this period.[6] Setting the pool price equal to the unconstrained price in these situations would result in less, not more, pricing fidelity and efficiency.

The primary load-pocket import constraint on the AIES system is located in the Northwest Area of the Province. While this constraint was binding in almost all hours from 2008 through 2011, the frequency of the constraint declined substantially in 2012 due to the completion of transmission upgrades in the area between 2008 and 2012.[7] In addition to the Northwest Area constraint, there are several other small import constraints near Calgary and Edmonton that have occurred only infrequently. Under TCM, the Northwest Area constraint and the other small import constraints are managed by constraining on certain downstream generators under existing TMR contracts and constraining off upstream generation using DDS. The resulting system-wide pool price is set at the intersection of the unconstrained supply and demand curves which sends the correct price signal to the majority of the market. The management of this type of constraint would be fundamentally unchanged under the new Principles.

The South of KEG (SOK) constraint is neither a generation pocket nor load pocket, as it separates the pool roughly into two halves when the constraint is binding. No KEG constraints have occurred since 2010, and the AESO does not expect constraints to occur in the future as the North-to-South transmission corridor is being reinforced with two new High Voltage Direct

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5 These constraints include but are not limited to the Joffre, Crossfield, and Cold Lake constraints.

6 For 16% of the hours, 13% of the generation is located upstream from the constraints. Multiplying 16% by 13%, approximately 2% of generation might have received a higher price than the marginal cost of serving the upstream load. Multiplying 16% by the 6% of load located upstream is equal to less than 1% of load is paying more than the marginal cost of serving upstream load.

7 See AESO (2012a), p.14 for further discussion of transmission upgrades in this region.

Current (HVDC) lines, which the AESO anticipates will be placed in service during 2014 and 2015.[8]

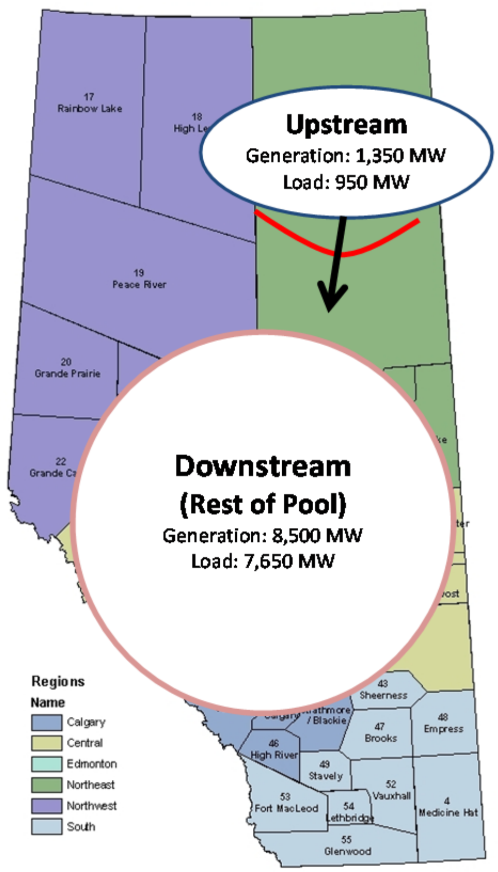
We discuss each of these constraints in more detail below.

1. Generation-Pocket Export Constraints

a) Fort McMurray

Figure 2 shows the approximate location of the Fort McMurray constraint and summarizes the amount of generation and load upstream and downstream of the constraint.

Figure 2
Map of Fort McMurray Constraint
With 2012 Average Load and Average Available Generation Capacity



Sources and Notes:
The load breakdown is representative, and is calculated based on average hourly AIL in 2012. The generation breakdown is representative, and is calculated based on the average hourly available capacity in 2012.

8 Current expectations for the in-service dates of the HVDC projects are listed in recent project updates. See ATCO (2013), and AltaLink (2013).

The constraint is located in the Northeast corner of the Province. It is an export-constraint from the Fort McMurray region to the rest of the pool. The export capability from the Fort McMurray region to the rest of the pool is 630 MW during normal system operation (defined as no system contingencies occurring).[9] In fact, the constraint has occurred only during abnormal conditions, when transmission facilities in the region are out of service and the export capability out of the region is reduced below the normal level.[10] Going forward, transfer capabilities in the region will be increased with the installation of additional voltage support devices, and longer-term plans include the construction of 500kV lines into the region.[11]

The region upstream of the constraint is primarily composed of baseload cogeneration facilities and large industrial loads. The transmission constraint binds when the output of baseload cogeneration exceeds industrial loads in the region by more than the export capacity to the rest of the pool. Over the course of the last two years, 2011 and 2012, the export constraint out of the Fort McMurray area was binding for 1,151 hours, as shown above in Table 2. This translates into approximately 7% of all hours over this period. Under the existing TCM Rule, this constraint is managed by constraining off upstream generation with RMO/Pro-rata curtailments and allowing the rest of the generators in the pool (which are all located downstream from the constraint) to compete in the market.[12] The dispatch of the rest of the system is based on EMMO and pool prices are set at the marginal downstream supplier's offer price.

Figure 2 shows that the average 2012 load upstream of the constraint was approximately 950 MW, or 11% of the total system load, while the rest of system load is located downstream of the constraint. Similarly, in 2012, the average available generation capacity upstream of the constraint was approximately 1,350 MW, or 14% of the system's total available generation, while the rest of the generation in the pool is located downstream.

If this constraint were managed in accordance with the new Principles and pool prices were set at the unconstrained system-wide price, the pool price would not reflect competitive market fundamentals facing approximately 89% of load and 86% of generation in Alberta during those constrained hours. In contrast, the existing TCM Rule sets the pool price at the level that correctly reflects downstream market fundamentals and would therefore send the economically efficient price signal for the majority of Alberta's generation and load. Under the existing TCM Rule, the generators and load located upstream from the constraint may witness a higher price than the marginal cost of serving the load in Fort McMurray area, but this inefficient price signal would prevail for only 11% of load and 14% of generation during hours when the constraint is binding, which would translate to inefficient prices for less than 1% of total load and generation across all hours in 2011 and 2012. In contrast, managing this constraint in accordance with the new Principles would send an inefficient price signal to 86% of generation and 89% of load in the pool during constrained hours.

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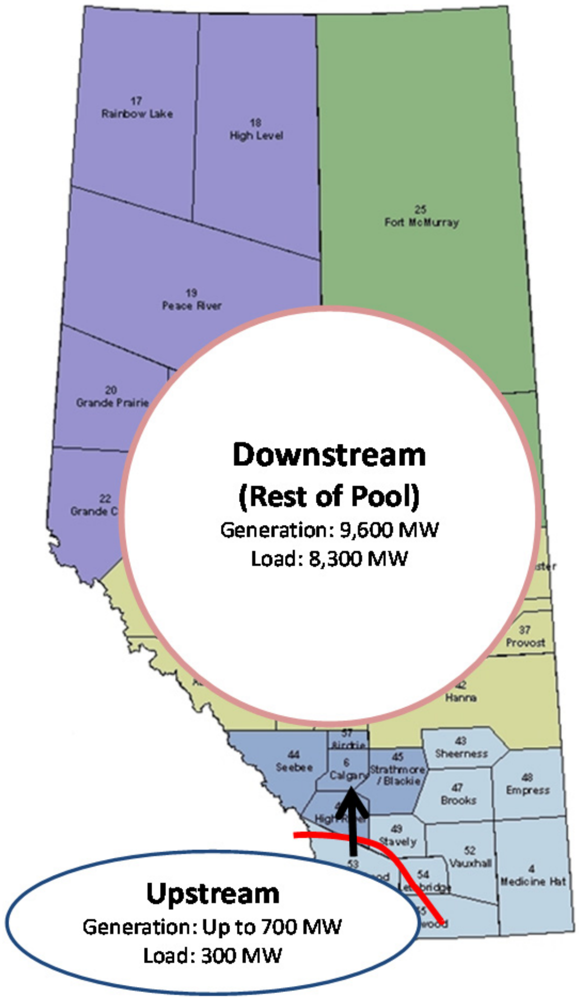
[9] See AESO (2012b), p. 16.
[10] Per communication with AESO staff, May 2013.
[11] See AESO (2012a), p.15.
[12] See AESO (2012b) p. 5.

b) Southwest Wind

Figure 3 shows the approximate location of the Southwest Wind constraint and summarizes the amount of generation and load upstream and downstream of the constraint.

Figure 3
Map of Southwest Wind Constraint
With 2012 Generation Capacity and Average Load



Sources and Notes:
The load breakdown is representative, and is calculated based on average hourly AIL in 2012. The generation breakdown is representative, and is calculated based on the average hourly available capacity in 2012 for the downstream region, and maximum available capacity in the upstream region.

The Southwest Wind constraint is located in the southwestern corner of the province, where the majority of wind resources are located. It is an export constraint from this region to the rest of the pool. The constraint occurs during windy periods when the wind power output exceeds the amount of local load by more than the export capability to the rest of the pool. Sometimes the constraint affects only a few local generators while at other times the constraint affects all of the generators in the Southwest region. In 2011 and 2012 combined, the Southwest Wind constraint was binding in 1,219 hours, as shown above in Table 2. This translates to 7% of all hours during this period. Several upgrades to enhance transmission capability in this region will be implemented by 2016 under the Southern Alberta Transmission Reinforcement (SATR) project.[13]

Figure 3 shows that there was up to 700 MW of generation located upstream of the constraint in 2012. This level of generation capability represents the maximum generation output currently available from this region, and would only be reached when wind generation was at maximum output. Therefore, the maximum amount of generation that could be upstream of the constraint (if the constraint were binding at the same time as wind's maximum output) is approximately 7% of the system's total generation capability. In 2012, the average load upstream of the constraint was approximately 300 MW, or 3% of the total system load, while the rest of system load is located downstream of the constraint.

If this constraint were managed according to the new Principles and the pool prices were set to the unconstrained system-wide price, this price would *fail* to reflect the market fundamentals facing at least 93% of generation and approximately 97% loads in the pool. In contrast, TCM sets the pool price at the level that correctly reflects downstream market fundamentals and would therefore send economically-efficient prices signal for all that downstream generation and load.

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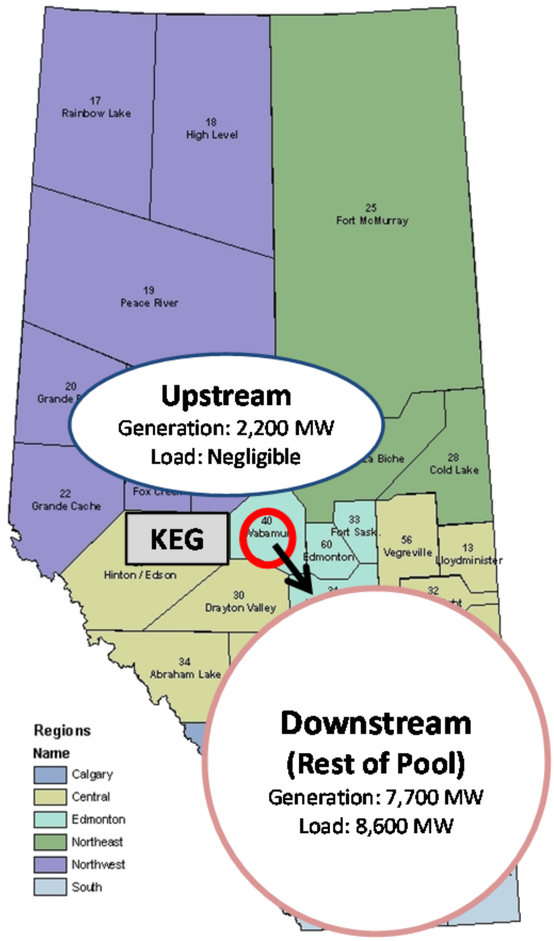
13 See AESO (2012a), p. 22.

c) KEG (Keephills/Ellerslie/Genesee)

Figure 4 shows the approximate location of the KEG area constraint and summarizes the amount of generation and load upstream and downstream of the constraint.

Figure 4
Map of KEG Constraint
With 2012 Average Load and Average Available Generation Capacity



Sources and Notes:
The load breakdown is representative, and is calculated based on average hourly AIL in 2012. The generation breakdown is representative, and is calculated based on the average hourly available capacity in 2012.

The KEG constraint is located in the Lake Wabamun area to the west of Edmonton. It is an export constraint from the Keephills and Genesee generating stations to the rest of the pool. The constraint occurs when the power output from the Keephills and Genesee stations exceeds the export capability from that region to the rest of the pool. This constraint has typically occurred when there is a reduction in export capability due to transmission outages (including while conducting maintenance or system upgrades). For example, outages associated with a major transmission upgrade in 2010 triggered a number of the observed constraints.[14] In 2011 and 2012 combined, there were 513 constrained hours associated with this constraint, as shown earlier in Table 2. This means that the constraint was binding in 3% of all hours over this period.

Figure 4 shows that, in 2012, the average available generation capacity upstream of the constraint (*i.e.*, the Keephills and Genesee stations) was approximately 2,200 MW or 22% of the system total available generation, while the rest of the generation in the pool is located downstream. The amount of load located upstream of the constraint is negligible.

If this constraint were managed according to the new Principles and pool prices were set to the unconstrained system-wide price, this price would not reflect the correct market fundamentals facing approximately 78% of generation and 100% loads in the pool. In contrast, TCM sets the pool price at the level that correctly reflects downstream market fundamentals and would therefore send the economically-efficient price signal for all downstream generation and load, again representing the majority of the Alberta system's generation and all of its load. Under the TCM Rule, the generators upstream from the constraint may witness a higher price than the marginal cost of exporting power from their region, but this inefficient price signal would prevail during the small number of constrained hours for only 22% of generation in the pool and none of Alberta's load.

d) 2010 Southeast Storm-Related

On April 14, 2010, a spring storm caused several line outages in southeastern Alberta. Repairs to the affected lines were completed June 1, 2010. During that period, the outages constrained the output levels of the two coal-fired generators in that area, Sheerness and Battle River.

While the constraints caused by the storm can be broadly characterized as export constraints which constrained the production of generators in southeastern Alberta, the specific breakdown of upstream and downstream generation and load is unknown due to the complexity and variability of the constraints. The transmission outages caused by the storm created multiple potential line overloads that were managed by system operators in real time, and the specific procedures used to maintain reliable operation of the system varied across the affected period.

e) Other Export Constraints

In addition to the constraints described above, there are several other small generation pockets that bind infrequently. This group of constraints includes but is not limited to the Joffre, Crossfield, and Cold Lake constraints. A summary of the upstream and downstream generation and load for these three constraints is shown in Table 3. Upstream generation and load are less than 3% of the system total for each of the three constraints, with the rest of generation and load located downstream.

[14] See AESO (2012a), p.18 for a description of the KEG-area debottlenecking project which began in the spring of 2010.

Table 3
Approximate Generation and Load for Other Export Constraints

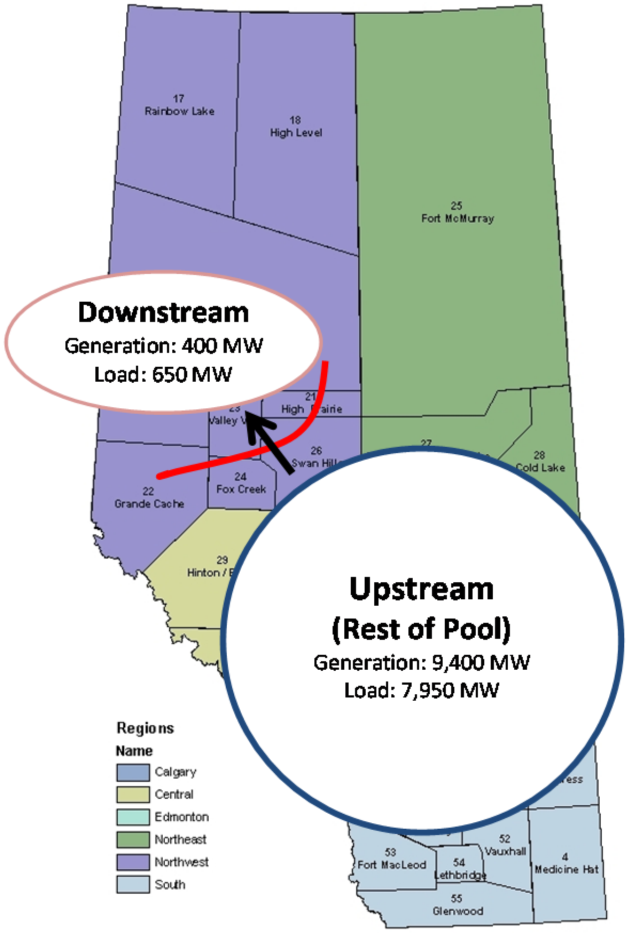
	Joffre	Crossfield	Cold Lake
Generation			
Upstream	200	200	300
Downstream	9,600	9,600	9,500
Percent Upstream	2%	2%	3%
Load			
Upstream	50	negligible	250
Downstream	8,550	8,600	8,350
Percent Upstream	1%	-	3%

Sources and Notes:
The load breakdown is representative, and is calculated based on average hourly AIL in 2012. The generation breakdown is representative, and is calculated based on the average hourly available capacity in 2012. We note that the average available capacity at Joffre is less than the maximum capacity.

2. Load-Pocket Import Constraints

The only import constraint in the AESO system that could be observed consistently is the Northwest Area load pocket. The approximate location of the constraint and the amount of generation and load located upstream and downstream of the constraint is shown in Figure 5. In contrast to the export constraints described above, only a small portion of system load and generation is located downstream of the constraint, while the majority of Alberta's generation and load in the pool is located upstream.

Figure 5
Map of Northwest Area Constraint
With 2012 Average Load and Average Available Generation Capacity



Sources and Notes:
The load breakdown is representative, and is calculated based on average hourly AIL in 2012. The generation breakdown is representative, and is calculated based on the average hourly available capacity in 2012.

The Northwest Area load-pocket constraint is located in the Northwest corner of the province, where the local generating capacity is substantially less than the area's load, such that the load is served by imports of energy from the rest of the pool under normal operation.[15] Because the Northwest area had a relatively weak transmission system (consisting of long 144 kV and 240 kV bulk-power transmission lines) and a low degree of redundancy, constraints necessitate the out-of-merit dispatch of internal generators to meet the system operating limits and dynamic reactive reserve requirements. While this constraint occurred during almost all hours from 2008 through 2011, the frequency of the constraint declined substantially in 2012, as shown previously in Table 2, due to the completion of transmission upgrades in the area between 2008 and 2012.[16]

[15] See AESO (2013a), p. 1.
[16] See AESO (2012a), p.14 for further discussion of transmission upgrades in this region.

To manage the constraint, the AESO dispatches downstream generation with existing TMR contracts to provide reliability support for the load pocket. The AESO also constrains down upstream generation using DDS. The pool price is therefore set at the intersection of the unconstrained supply and demand curves for all generation and load located upstream, representing the large majority of the market. Because this constraint is already managed with TMR and DDS, the management of this constraint would remain fundamentally unchanged in a market design that reflected the new Principles.[17]

In addition to the Northwest Area constraint, TMR dispatch also is used infrequently to manage contingency-related line overloads in less robust system configurations near other load pockets (Edmonton Area & Calgary Area) on an irregular basis. In 2011 and 2012, such constraints occurred during a total of 368 hours or 2% of all hours, as previously shown in Table 2. The management of these constraints would also be fundamentally unchanged under the new Principles.

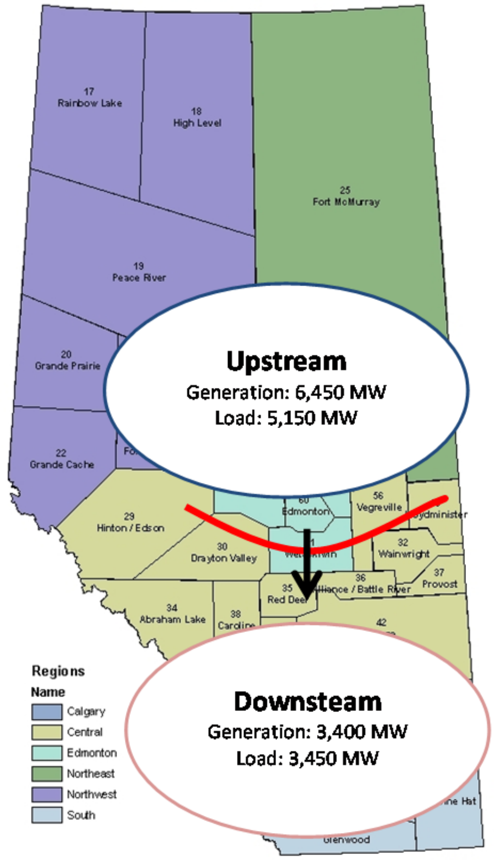
3. Large Constraints

The South of KEG (SOK) constraint divides the province into two relatively large sections, each with a significant amount of generation and load, as shown in Figure 6. The constraint occurred when the north-to-south power flows exceeded the capability of the major north-to-south transmission paths between Edmonton and Calgary. The constraint did not occur in 2011 or 2012, as shown above in Table 2. Going forward, the completion of two 500 kV HVDC transmission lines between Edmonton and Calgary is expected to substantially increase transfer capability between the two areas to avoid this constraint. The AESO anticipates that these lines will be completed in the 2014–2015 time frame.[18]

[17] As noted earlier, however, the same is not true for generation-pocket export constraints, where a market design in accordance with these Principles would impose significant changes that would reduce market efficiency and price fidelity.

[18] Current expectations for the in-service dates of the HVDC projects are listed in recent project updates. See ATCO (2013), and AltaLink (2013).

Figure 6
Map of South of KEG (SOK) Constraint
With 2012 Average Load and Average Available Generation Capacity



Sources and Notes:
The load breakdown is representative, and is calculated based on average hourly AIL in 2012. The generation breakdown is representative, and is calculated based on the average hourly available capacity in 2012.

B. TRANSMISSION CONSTRAINTS AND PRICE SPIKES

Data on the frequency of price spikes in the Alberta market do not show that managing transmission constraints using the TCM Rule has a significant impact on the frequency or magnitude of price spikes. For the purposes of our analysis, we conservatively define a price spike as any hour with an average pool price greater than or equal to $200/MWh. Price and transmission constraint data show that, historically, price spikes occurred with nearly the same frequency during hours with and without transmission constraints. Below, we present two summary statistics that indicate that managing transmission constraints with the TCM rule has not been a major cause of price spikes in the AESO pool.

First, we show that the majority of price spikes occurred in hours when there were no transmission constraints that would have prevented a portion of generation from being dispatched.[19] Specifically, Table 4 summarizes the percent of prices spikes that occurred during hours when there was constrained down generation (CDG), or generation that was unavailable for dispatch due to transmission constraints. With the exception of 2010, the majority of price spikes occurred in hours when there was no constrained-down generation. For example, there were 609 total price spike hours in 2012 and there was constrained down generation during only 100 of these hours, which is 16% of all hours. The remaining 84% of price spikes occurred when there was no constrained-down generation.

Table 4
Percent of Price Spike Hours With Constrained-Down Generation (CDG)
(Price spike defined as hourly pool price ≥ $200/MWh)

	2008	2009	2010	2011	2012
Number of CDG Hours with Price Spikes	175	18	180	111	100
Total Number of Price Spike Hours	630	176	277	652	609
Percent of Price Spike Hours with CDG	28%	10%	65%	17%	16%

Source: Hourly CDG and pool price data provided by the AESO.

Next, we show that transmission constraints were not associated with an increase in the frequency of price spikes in 2011 and 2012. Table 5 below compares the frequency of price spikes in hours with CDG to the frequency of price spikes in hours without CDG. As the table shows, the frequency of price spikes in 2011 and 2012 was approximately the same, irrespective of whether there was constrained-down generation under the existing TCM Rule. If transmission constraints or the use of the TCM Rule were causing price spikes, one would expect to observe a higher frequency of price spikes during periods with transmission constraints—particularly during 2011 and 2012 when the TCM Rule was first in place. While these summary statistics do not directly document the absence of a causal relationship between transmission constraints and price spikes, the fact that transmission constraints were not associated with an increase in the frequency of price spikes in 2011 or 2012 strongly indicates that they are not a significant cause of the observed price spikes.

Table 5
Frequency of Price Spikes With vs. Without Constrained Down Generation (CDG)
(Price spike defined as hourly pool price ≥ $200/MWh)

	2008	2009	2010	2011	2012
Percent of CDG Hours with Price Spikes	12%	1%	5%	7%	8%
Percent of non-CDG Hours with Price Spikes	6%	2%	2%	8%	7%

Source: Hourly CDG and pool price data provided by the AESO.

[19] Import constraints that are managed with TMR (such as the Northwest Area constraint) do not prevent generation from being dispatched and do not cause pool prices to increase.

Furthermore, data from the same period indicates that low overall levels of remaining supply (regardless of whether transmission constraints existed) and changes in generators' offer behavior are the major drivers of price spikes and volatility.

For the purposes of our analysis, we calculated the hourly level of remaining supply (irrespective of transmission constraints) by subtracting dispatched offers from the total quantity of available generation capacity to calculate the remaining supply on an hourly basis. This metric, which we call "remaining supply" reflects magnitudes of load levels, wind output, flows from neighboring provinces, and generator outages, but does not account for internal transmission constraints, as it includes all of the available MWs whether or not they may be constrained by binding transmission constraints.[20]

Table 6 and Table 7 below summarize the relationship between price spikes and remaining supply in the same form used above to summarize the relationship between price spikes and constrained down generation. Table 6 shows that the vast majority of price spikes occurred in hours when there were less than 1,500 MW of remaining supply, and Table 7 shows that the frequency of price spikes is substantially higher when less than 1,500 MW of remaining supply is in the market relative to other hours.

Table 6
Percent of Price Spike Hours with Remaining Supply less than 1,500 MW
(Price spike defined as hourly pool price ≥ $200/MWh)

	2011	2012
Number of Hours with Remaining Supply Less than 1500 MW with Price Spikes	608	461
Total Number of Price Spike Hours	652	609
Percent of Price Spike Hours with Remaining Supply Less than 1500 MW	93%	76%

Source: Hourly available capacity, dispatched offers, and pool price data provided by the AESO.

20 We note that this metric is not the same as the Supply Cushion metric calculated by the Alberta Market Surveillance Administrator.

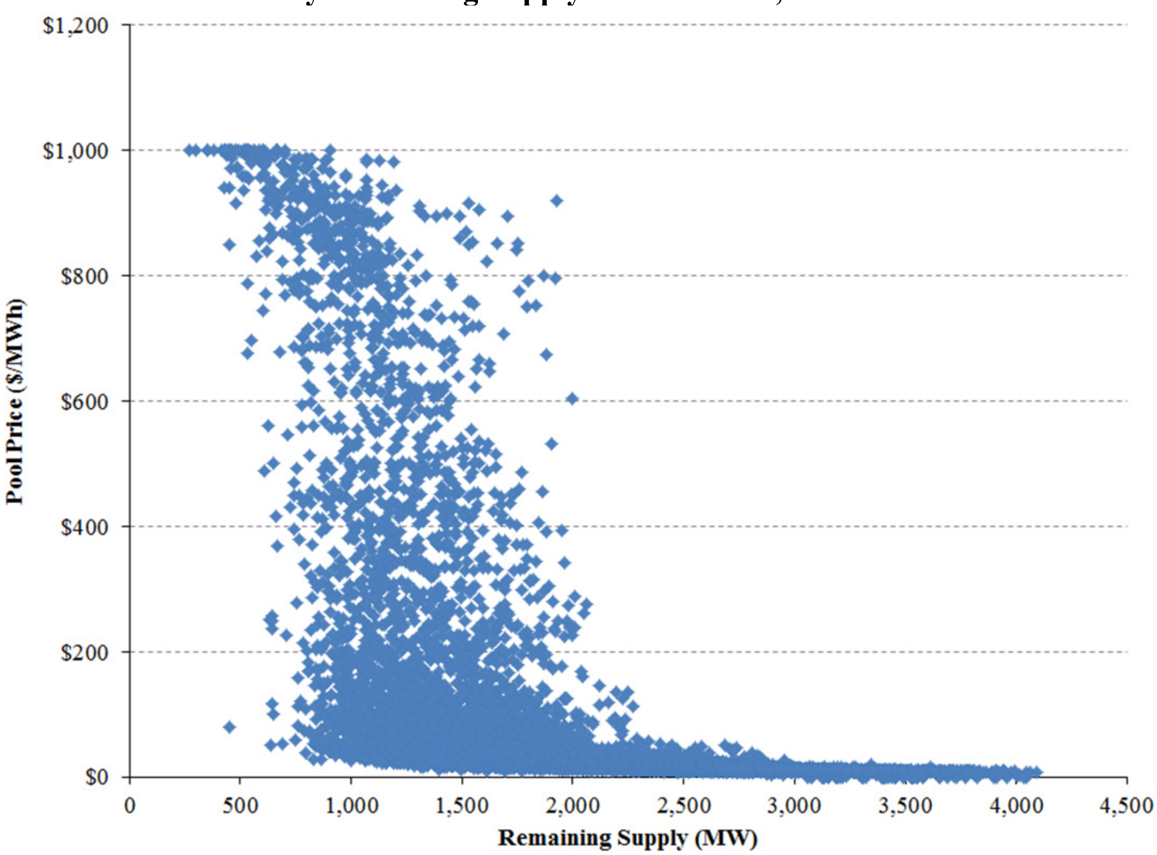
Table 7
Frequency of Price Spikes with Remaining Supply Less than vs. Greater than 1,500 MW
(Price spike defined as hourly pool price ≥ $200/MWh)

	2011	2012
Percent of Hours with Remaining Supply Less than 1500 MW with Price Spikes	25%	34%
Percent of Hours with Remaining Supply Greater than 1500 MW with Price Spikes	1%	2%

Source: Hourly available capacity, dispatched offers, and pool price data provided by the AESO.

Figure 7 below visually illustrates the relationship described in the tables above, demonstrating that high prices occur more frequently as remaining supply declines. This relationship suggests that regardless of the existence of transmission constraints, the primary drivers of price spikes in Alberta are the amount of remaining supply in the market, which accounts for the combined effects of load levels, wind power output, import and export flows from and to neighboring provinces, and generator outages.

Figure 7
Hourly Remaining Supply vs. Pool Price, 2011-2012



Source:
Hourly available capacity, dispatched offers, and pool price data provided by the AESO.

In addition to remaining supply levels, generators' offer behavior also plays a key role in contributing to price spikes. In our recent evaluation of market fundamentals and resource adequacy in the Alberta market, we found that the increase in higher-priced hours during 2011 and 2012 relative to 2009 and 2010 was likely driven by a shift in generators' offer behavior. Specifically, it appears that a change in offer behavior in early 2011 resulted in substantially higher prices being realized at otherwise similar levels of scarcity.[21]

IV. POTENTIAL IMPACT OF IMPLEMENTING THE PROPOSED PRINCIPLES ON THE ALBERTA MARKET

A. IMPACT OF THE PRINCIPLES ON PRICE SIGNALS

As discussed in Section II of this report, transmission constraints cause the marginal cost of serving load on either side of the constraints to deviate from the price set by the intersection of the unconstrained system-wide supply and demand curves. In a single-clearing-price energy market where the prices are set by the marginal cost of supply, the clearing price will rise up to the offer price of the last unit of supply that must be dispatched to meet demand. If system or operational constraints limit the use of some supply resources, they can increase the marginal cost of meeting demand. Any such constraint that limits the use of supply resources could cause an increase in market prices, regardless of the cause of the constraint. The simplest example of an operational constraint is a generator outage. When a generator is not operational to produce power, the marginal cost of meeting system-wide demand increases as the next resource on the supply stack must be utilized in the system's merit order, and the energy price increases accordingly. This is a core economic principle in wholesale electricity markets and it is also the efficient pricing mechanism that ensures that all resources used to meet demand receive the market price set by the last offer accepted and dispatched. Any amount that suppliers earn above their marginal costs contributes toward paying for their fixed and investment costs. To continue reliable operation of their plants, generators need to earn enough to cover their fixed costs going forward. To build new resources, they also need to recover their investment and earn a sufficient return on it.

As mentioned earlier in Section II, Alberta's electricity market is an energy-only market. This means that generators must earn their returns on investment solely through payments from the energy market.[22] In contrast with many other North American wholesale electricity markets, there is not a separate capacity market that helps generators recover their capital investments. This means that when reserve margins are tight and new generation is needed, energy price levels must be able to rise high enough to retain existing supply and attract new construction when needed. Based on our earlier analysis of the Alberta market, the current market design provides sufficient return for investors to attract new investments.

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21 See Pfeifenberger et al. (2013), pp. 21-24.

22 In Alberta's and other "energy-only" markets, suppliers can also earn revenues from their sale of ancillary services (such as operating reserves) when they are not producing energy. See Pfeifenberger, *et al.* (2011) and (2013).

1. Implications of Principles #1, #2, and #3

Principle #1 states that the pool price shall be set at the intersection of the unconstrained supply curve and the demand level, to prevent transmission constraints from affecting the pool price.

If implemented according to Principle #1, when transmission congestion occurs anywhere on the system, the AESO would ignore how much generation was unable to be dispatched to serve load in setting the pool price. Instead, the pool price would be reconstructed using the unconstrained supply offer curve without regard to the amount of generation that is constrained off due to transmission limitations. In other words, the pool price would always be set by the marginal generator offers, regardless of whether or not those generators could actually be dispatched to serve load. Under this Principle, the pool price during transmission constraints would no longer represent the realities of the system, and would not reflect the marginal cost of serving load in the pool. As discussed earlier, this price would be too low for the downstream portion of the market and too high for the upstream portion of the market.

For example, if a generator behind the Fort McMurray constraint could not be dispatched to serve load because of the transmission constraint, a more expensive generator downstream from the constraint would need to be dispatched to serve load. This would increase the marginal cost of serving load in the large downstream portion of the pool that accounts for most of the entire market. Under Principle #1, however, the pool price would not rise to reflect this fact.

The inefficiency of pool prices during transmission constraints under Principle #1 is particularly apparent when considered in comparison to pricing during generators' operational outages. Both generator outages and transmission constraints will cause some generation to be unavailable to serve load and require that more expensive generators be dispatched, thereby increasing the marginal cost of serving load in the pool. If a generator experiences an outage, the pool price rises to reflect that the generator outage has increased the cost of serving load in the pool. Under Principle #1, however, if the same generator becomes unavailable for dispatch because of a generation-pocket export constraint, the pool price would fail to reflect that the cost of serving load in most of the pool has increased in a similar manner.

Using another example, the pricing inefficiency associated with Principle #1 is even more apparent. When considering the generation pocket related to the Southwest Wind constraint, the requirement to set the pool price at the intersection of the unconstrained system-wide supply and demand curves would first require estimating the amount of wind power generation that *would have been produced* had the generation-pocket export constraint not been present. Setting the system-wide unconstrained pool price would then be based on the *estimate* of the amount of wind power generation that would have reached load. In such a situation, the unconstrained price is based on a hypothetical supply curve, which may not reflect reality. Furthermore, the unconstrained price set by hypothetical supply curves is inefficient from a system-wide basis since the majority of generators and load are located downstream from the constraint, where a significant amount of resources are available to compete to serve the large portion of the market. As in all of the export constrained situations when the majority of the load and generation is downstream from the transmission constraint, the Southwest Wind constraint shows that setting the pool price at the system-wide unconstrained price would yield inefficient pricing for all downstream entities. In addition, it would be impractical because the amount of unconstrained wind generation is not known and would need to be estimated.

Principle #2 states that the costs of generation re-dispatch to maintain system operating limits would need to be based on generators' offer prices unless TMR contracts can be used to dispatch around the constraint.

Principle #3 requires the AESO to distinctly separate the cost of generation re-dispatch during transmission constraints from the overall cost of energy supply, and collect the "re-dispatch cost" through the Alberta transmission tariff.

Principles #2 and #3 effectively say that, aside from the unconstrained pool price, all of the costs associated with the dispatch of out-of-merit generation, whether obtained through the competitive market or through TMR contracts, will be considered a "re-dispatch cost." This also means that all generators located downstream from a constraint would be paid the higher of the system-wide unconstrained price or their offer price when they are dispatched to replace the power that would have been produced by the upstream generators that are constrained off.

Under these Principles, dispatched generators with offer prices above the unconstrained pool price would receive payments that match their bids, and generators with offer prices lower than the unconstrained pool price would simply receive the unconstrained pool price. Under such a market payment system, the efficient existing and new generators would only receive the unconstrained pool price during transmission constrained hours, while the additional payments for re-dispatch during constraints would likely only benefit inefficient existing generators. These higher payments to inefficient, out-of-merit generators would not provide any investment signal to potential new entrants.

The existing transmission tariff, which is used to pay for the transmission costs of cost-of-service regulated transmission owners, spreads the annual cost of transmission uniformly across all system load. It also applies charges to customers without regard for the specific timing of the customers' energy consumption. The existing transmission tariff provides an efficient way of recovering transmission costs and reduces barriers to transmission investments needed to reduce system congestion. Principle #3, if implemented, would strip a portion of the cost of generating power to serve load during individual transmission-constrained hours out of the pool price and, instead, recover that cost through annual transmission charges. Moving the cost of re-dispatch incurred during individual hours into the average annual charges used to recover transmission costs would thus reduce the fidelity and efficiency of the existing hourly pool prices. Instead of allowing energy prices to rise temporarily in response to changes in system conditions, Principle #3 would place the incremental dispatch costs incurred during transmission constrained hours on transmission customers without regard to the time of their energy usage, stripping away a more efficient mechanism that provides price fidelity and transparency to the marketplace. Even if it were possible to separately account for these costs when collected through transmission charges and attribute them to the correct hours, those hourly charges would be visible to retail customers only long after-the-fact, providing almost no information to customers about when and where their load is too high relative to the available supply in the market. As such, stripping away efficient hourly price signals from the energy market would remove the incentive for customers to respond to these prices and reduce their consumption when the system would benefit from them doing so. Since most of the system constraints managed with the TCM Rule are export-constrained generation pockets, Principle #3 would remove the proper hourly price signals and incentives for the majority of customers during those constrained events. Following Principle #3 would distort the energy price signals that are necessary to provide incentives for loads to reduce consumption when the marginal cost of serving load is high. This will reduce static efficiency in the Alberta electricity markets.

In addition, recovering such re-dispatch costs through the transmission tariff would artificially dampen the price signals necessary to indicate the need for additional transmission and/or new generation. Price increases are an efficient way for the market to signal the need for new resources. Under the TCM Rule, when transmission constraints limit some upstream generation from reaching downstream markets, the associated price increases are an efficient way for the market to indicate that additional resources are needed to meet the demands of customers. Such price increases provide information to the marketplace about the need for either new generation or transmission. Stripping away that price signal also undermines the market's dynamic efficiency by reducing the incentives for new generators to locate downstream from transmission export-constrained areas. It will also reduce customers' incentives to invest in increasing their demand response capabilities and could hide the benefit of transmission investments that could increase competitive forces for the overall market.

2. Overall Implications on Price Signals in Alberta

As discussed in Section III above, most of the transmission constraints in the AIES are export constraints that affect small pockets of generation upstream of the constraints. In these situations, only a relatively minor portion of the pool's generation resources are constrained from serving the larger market. The vast majority of system load and generation are located downstream from the constraints. In fact, based on the amount of load and generation reported in Table 2 of Section III, approximately 87% of generation and 94% of load was located downstream on average across hours when generation pocket-export constraints were binding in 2011 and 2012. During these constrained hours, a market design consistent with the New Principles would pay a majority of the generators in the province a price that does not represent the cost of meeting system load during constrained periods.

For example, if 50 MW of generation located upstream of the Fort McMurray constraint were constrained off because the transmission export capability out of the Fort McMurray area is insufficient to allow all of the in-merit generation to serve load, then: (1) an incremental 50 MW of downstream generation with offers higher than the system-wide unconstrained price would be dispatched to replace the constrained-down generation and would be paid a higher price; and (2) the rest of the generation in the pool would receive the lower unconstrained price. This means that the system-wide unconstrained price would be earned by all dispatched resources downstream, consisting of approximately 8,500 MW of generation—except for the 50 MW of downstream generation with high offers that are dispatched out of merit to replace the constrained-down generation. That last 50 MW dispatched downstream would likely be composed of relatively inefficient generating units with higher dispatch costs. Thus, under the New Principles the pool price would send the wrong price signal to the majority of the generation on the system, while only the inefficient units that are used to replace the 50 MW of constrained-down generation would receive a higher price. Furthermore, the higher prices paid to the inefficient units would not be transparent to the market, but would be provided only as a side-payment through an uplift charge in the transmission tariff.

Under the Principles, only the downstream generator that is dispatched out of merit would be paid a higher price. All *other* downstream generators would receive the lower unconstrained clearing price. This result does not reflect downstream market conditions. It would reduce incentives for both short-term generator performance and long-term generation investment downstream of the constraint where future generation is needed the most. The change in pricing rules may also reduce generation investment in Alberta because it demonstrates uncertainty around transmission policies in the province that would likely be perceived to undermine the stability and integrity of the Alberta pool price.

Furthermore, under the Principles, load located downstream would not face the temporary (*e.g.*, hourly) increase in pool prices associated with the transmission constraints and, therefore, will not face the incentive to reduce consumption when market fundamentals are such that load reduction would benefit the market. While load upstream from constraints may witness a higher price than the marginal cost of serving upstream load under the existing TCM Rule, this inefficient price signal would prevail only for a very small fraction of load in the pool. Therefore, the argument that load upstream might not respond appropriately to price signals under the TCM Rule is a weak justification for inefficiently reducing the price for the rest of the pool, where the vast majority of load is located.

In summary, allowing generation and load to compete and pool prices to accurately reflect market conditions in the downstream portion of the market is critical for the continued efficient operation of the Alberta electricity market. Implementing a market design according to the Principles would send an inaccurate and inefficient price signal to a majority of the generators and load in Alberta during transmission constrained periods and, thereby, decrease overall market efficiency, suppress downstream market clearing prices below competitive levels, and suppress incentives for demand response and future generation investments.

B. IMPACT OF IMPLEMENTING THE PRINCIPLES ON OFFER BEHAVIOR

As we showed in Section III, data indicates that managing transmission constraints using the TCM Rule is not a primary cause of the observed price spikes (conservatively defined in our analysis as prices above $200/MWh). We also noted that managing transmission constraints using the new Principles would suppress prices below efficient levels for the majority of the market when export-constraints are binding. Finally, we noted that suppressing prices in this manner for the majority of the market while paying relatively inefficient existing generators a higher price when they are dispatched would reduce both the static and dynamic efficiency of the Alberta market.

As such, if the market design were implemented according to the Principles, the generators located in the large downstream portion of the market would likely try to adjust their bidding behavior from today's levels to "put back" into the market the missing contributions to investment cost recovery revenues that the change in market rules would otherwise impose on them. To do so, generators would submit offers at their estimate of the price of the out-of-merit generators dispatched, rather than at their own variable cost. During transmission constrained periods, if generators expect to receive a market clearing price that is lower than the price needed to serve all load subject to the transmission constraint, to be compensated according to market fundamentals, those generators would need to estimate how the last generator dispatched would bid and then bid slightly below that level. This would ensure they will be dispatched while maintaining a similar level of energy revenues. In other words, generators operating in a market designed according to the New Principles would have an incentive to increase their offers above the uneconomically-low, system-wide unconstrained price.

For example, if an efficient downstream generator with a $40/MWh variable cost anticipated that the system-wide unconstrained pool price would be $60/MWh during transmission constraints, but that a less efficient generator with an $80/MWh offer would be the last-dispatched supplier in their large downstream portion of the market, they would have an incentive to increase their offer to slightly below the $80/MWh to ensure that they would receive revenue close to the $80/MWh price that reflects market fundamentals in their downstream region, rather than $60/MWh (the unconstrained pool price).[23]

The inaccuracy inherent to such guessing behavior could result in dispatching inefficient generators before efficient ones. If, in the example described above, the efficient generator inaccurately estimated that the last-dispatched supplier would have a $90/MWh offer price and therefore submitted its own offer at $89/MWh, but the last-dispatched supplier actually had an $80/MWh offer, the efficient generator may not be dispatched at all despite having an incremental cost of only $40/MWh. This type of outcome would result in inefficient generators being dispatched instead of efficient ones, thereby increasing costs, increasing emissions, and reducing efficiency in the Alberta market. While some amount of strategic bidding behavior already exists, the New Principles likely increase the incentives for such behaviors.

Because generators cannot always perfectly anticipate when transmission constraints will occur, these effects would carry into hours without constraints, and further erode market efficiency. In contrast, under the current TCM Rule, relatively efficient generators can maximize their revenues simply by submitting offers at their actual dispatch costs because they can rely on the market to yield the efficient downstream pool price of $80/MWh and all dispatched generators in the large downstream portion of the market receive that price.

C. IMPACT OF INCREASING THE USE OF TMR

The Commission also ordered the AESO to increase the use of TMR in conjunction with Dispatch Down Service (DDS). This is problematic for several reasons.

First and foremost, the use of TMR is not suited for a market where most of the transmission constraints are export-constraints with upstream generation pockets where only a small amount of load and generation is located. If TMR contracts are to be used to manage those export-constraints, the AESO would need to either enter into TMR contracts with many of the downstream generators because almost all downstream resources can help relieve those constraints, or design a method to select which TMR generator to dispatch in real time based on their offer prices. The first approach of entering into TMR contracts with many downstream generators would seem to defeat the intent of entering into TMR contracts with a select few resources in the first place. If many resources can provide the same service, then the AESO should be able to rely on market-based dispatch and there should be no need for TMR contracts. The second approach would rely on the energy market merit order to determine the optimal

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23 In this example we assume that generators dispatched with offers above the pool price would be paid their offer price.

dispatch for the downstream market. But allowing downstream resources to compete and set the pool price at the necessary downstream premium to the system-wide unconstrained price would bring that price to exactly the same level as managing the constraints with the TCM Rule.

Second, the Commission's order to increase the use of TMR is counter to the direction toward which most other electricity markets in North America are moving. In most other power markets, system operators and regulators strive to reduce their reliance on must-run generation because must-run payments distort prices for the competitive portion of the market. In addition, most must-run resources are old and inefficient generators suited only to provide temporary solutions to the system's reliability needs. These must-run generators are usually uneconomic due to their high ongoing capital and operating costs relative to other generators in the fleet. To keep them from retiring, system operators enter into contracts with them at prices that are sufficient to cover their going-forward operating costs. At the same time, many grid operators develop transmission plans to limit the reliance on must-run generation.

In those situations, must-run generators are supported by out-of-market payments that keep them operating until new and more permanent generation or transmission solutions are implemented. Since out-of-market payments are generally not transparent to the rest of the market, increasing those payments would only support the continued operation of inefficient units, while decreasing the incentives for new generation or transmission investments.

Third, the use of more TMR contracts would seem to bring Alberta back to a market design where more of the generation, particularly inefficient older plants, will operate outside the competitive market framework and are ensured continued cost recovery. The AUC's order to increase the use of TMR in Alberta is the direct opposite of the effort of most system operators and regulators in competitive electricity markets, and would be a step back toward the structure of regulated cost recovery for generation, spreading the cost of these contracts across all load without regard to the time periods when the transmission constraints occur.

Finally, the combined effect of implementing Principles #1, #2, #3, and the directive to increase the use of TMR would give the AESO the option to contract more must-run generation and pay the inefficient generators contract prices that are partially recovered through the annual transmission tariff. Such a market design would discourage new suppliers from entering the Alberta market without long-term contracts for their power output, in the same way that incumbent (and often inefficient) generators receive payments through TMR contracts. These effects together would further undermine the competitive nature of the Alberta market and decrease its dynamic efficiency. Rather than choosing to invest in the Alberta market when efficient price signals provide the proper incentives for new entry, suppliers would be demanding contracts to support their investments.

In sum, increasing the use of TMR contracts to manage transmission constraints would be counter to the direction toward which most other electric systems in North America are moving, and would: (1) be ineffective and inefficient in resolving small export-constrained situations; (2) increase the dependence of generators on long-term contracts; (3) reduce the competitiveness of the Alberta wholesale electricity market; and (4) ultimately discourage transmission development and new generation investment without TMR contracts.

D. PRICE VOLATILITY AND THE FORWARD MARKET

In its Order, the Commission seems to have accepted the claim that the TCM Rule increases price volatility and that such volatility would increase the risk premium for generators and load.

As we have shown in Section III, however, transmission constraints and the use of the TCM Rule to manage these constraints are not a primary cause of price spikes. We observed that overall levels of remaining supply and bidding behavior are the primary drivers of price spikes. Thus, counter to the arguments presented to the Commission, the data does not support the claim that the use of the TCM Rule increases price volatility.

Furthermore, even if the use of the TCM Rule did increase price volatility, such an increase would not increase the cost of hedging in the forward market as long as market liquidity is not decreased. Implementing a market design that relies more heavily on TMRs, however, would reduce the volume of generators participating in the forward market. This would reduce the liquidity in the forward market. As a result, reliance on more TMR generation would likely increase the cost of hedging relative to the current TCM-based market design.

V. SUMMARY OF FINDINGS

Based on our analysis of the structure of the Alberta electric system and market fundamentals, we find that implementing design changes according to the AUC's Principles would reduce the static and dynamic efficiency of the Alberta wholesale electricity market, reduce the fidelity of Alberta pool prices, and likely create uneconomic incentives for demand response and future generation investments. We believe that the Commission's proposed Principles create material risks of undermining the current structure of the Alberta market; and the additional evidence provided in this report shows that the decision would likely harm Alberta's electricity market. We summarize our findings as follows:

- The existing TCM Rule is more effective and efficient than a market design that would implement the New Principles for managing transmission constraints. This is the case because constraints in the Alberta market are mostly export constraints during which the large majority of load and generation are downstream from the constraint. When these constraints are binding, the TCM Rule sets the correct price signals for this large majority of the market. Implementing a market design that sets prices based on system-wide unconstrained conditions would suppress pool prices below efficient levels for the large majority of Alberta's loads and generators that are located in the downstream portion of the constraint.

- Instead of allowing energy prices to rise temporarily when the system conditions require it, moving the cost of re-dispatch to annual transmission charges would reduce the fidelity and efficiency of the existing hourly pool prices that send correct signals to downstream loads and generators which reflect the large majority of the market.

- Data on the frequency of price spikes in the Alberta market do not show that managing transmission constraints using the TCM Rule has a significant impact on the frequency or duration of price spikes in this market. Instead, overall levels of remaining supply and bidding behaviors have the primary drivers of the frequency and duration of price spikes.

- When the large majority of the market is downstream from a constraint and most of the downstream generators expect to receive less under a market design in accordance with the Principles, those generators might increase their bids to match their guess of the out-of-merit supplier's offer prices to ensure dispatch while maintaining their revenues and contributions to investment cost recovery. An increase in such guesses when bidding could result in dispatching inefficient generators before efficient ones, reducing market efficiency, and increasing emissions.

- Increasing the use of TMR contracts to manage transmission constraints would be counter to the direction toward which most other electric systems in North America are moving, and would: (1) be ineffective and inefficient in resolving the small generation-pocket export-constraints that account for the majority of transmission constraints in the Alberta markets; (2) increase the dependence of generators on long-term TMR contracts; (3) reduce the competitiveness of the wholesale electricity market; and (4) ultimately discourage new generation investment without TMR contracts.

- Implementing a market design that relies more heavily on TMR contracts could reduce the amount of generation being hedged using the forward market and thereby reduce liquidity and increase the cost of hedging.

We recommend that these findings be considered by the AESO in the consultation, design, and implementation of revisions to the TCM Rule.

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LIST OF ACRONYMS

AESO	Alberta Electric System Operator
AIES	Alberta Interconnected Electric System
AIL	Alberta Internal Load
AUC	Alberta Utilities Commission
CDG	Constrained Down Generation
DDS	Dispatch Down Service
EMMO	Energy Market Merit Order
HVDC	High Voltage Direct Current
KEG	Keephills/Ellerslie/Genesee
MW	Megawatt
MWh	Megawatt Hour
RMO	Reverse Merit Order
RTMR	Real-Time Transmission Must-Run
SOK	South of KEG
TCM	Transmission Constraint Management
TMR	Transmission Must-Run