REPORT ON BEST PRACTICES IN WHOLESALE ELECTRICITY MARKET DESIGN

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INTRODUCTION AND SUMMARY

Potomac Economics has been engaged by the Market Surveillance Administrator of Alberta (MSA) to provide an independent expert report on electricity market design considerations for integrating capacity, energy, and ancillary services markets in Alberta. The Alberta electricity sector is on the verge of significant change that is largely due to government policy meant to reduce carbon emissions. These policies stand to introduce rapid change in the resource mix and, consequently, affect the short-run and long-run economic relationships in the industry.

The policies include a rapid increase in the amount of renewable resources, a significant amount to be under contract within the next year. The plan also calls for retiring (or converting to a different fuel) all coal-fired generators by 2030. This will significantly change the Alberta resource mix and should significantly affect the outcomes in the existing wholesale market. In anticipation of these policies, the Alberta's Electric System Operator (AESO) has proposed the implementation of a capacity market. According to the AESO, this market is necessary in order to strengthen incentives to maintain and invest in generation capacity.[1] It is critical to recognize that the capacity market is a complement to the energy and ancillary services markets, which are the foundation of the markets in Alberta. Therefore, it is very important to consider the future development of the energy and ancillary services markets as Alberta develops a capacity market and undertakes this transition.

The wholesale electricity market in Alberta is currently organized around an energy-only real-time spot market. There is a single clearing price for each hour of the day for all units based on the highest offer accepted to serve load. Any transmission congestion is managed by out-of-merit dispatch in real time including transmission "must run" contracts. This real-time energy-only market will be limited in ability to adapt to and efficiently facilitate the imminent changes in Alberta's resource mix and market structure. This raises concerns because energy and ancillary services markets are the foundational elements of any wholesale electricity market.

Well-functioning energy and ancillary services markets commit and dispatch existing resources in an efficient, least-cost manner. Properly designed, these spot markets ensure that effective competition among suppliers and buyers produces efficient short-term prices. Such prices reflect the short-run marginal cost of supplying electricity, which not only facilitate efficient use of existing resources to satisfy the system's needs in the short term, but also provide economic signals that can be relied on by participants to engage in longer-term contracts and capital investments. Therefore, we recommend that Alberta reform its energy and ancillary services markets in conjunction with the development of a capacity market.

1 Wholesale Electricity Market Transition Recommendation issued by the AESO on October 3, 2016.

To that end, our report examines a variety of market design issues that should be considered at this critical juncture. Given the rapid influx of intermittent, low-variable cost resources and the potential retirement of coal-fired resources, Alberta should expect significant changes in:

- Network flows and potential transmission congestion;
- Ramp demands;
- Resource commitment issues; and
- Operating reserve shortages.

These operating challenges will not be addressed by the development of a capacity market, but can be efficiently and reliably addressed through well-considered reforms to Alberta's energy and ancillary services markets. Accordingly, we have identified central features of efficient and reliable energy and ancillary services markets that would integrate with a well-designed capacity market.

Our report summarizes a wide array of best practices in the design of energy and ancillary services markets, discussing the benefits of introducing each in the context of the Alberta wholesale electricity market. Additionally, we explain how these best practices would complement the capacity market and provide strong incentives for efficient investment in existing and new generating units.

Finally, even with the introduction of efficient energy and capacity markets, uncertainty can prevent market participants from responding to the economic signals to invest in the resources Alberta will need to operate reliably. Government policies that threaten to create sustained capacity surpluses will create economic risks for existing suppliers and investors in new resources that will hinder suppliers' response to the economic signals. Therefore, we discuss the value in coordinating the entry and exit of resources to avoid sustained capacity surpluses. Additionally, in order to reduce uncertainty and inform participants' expectations regarding future design changes, we discuss the value in establishing a clear market development plan. Reducing such uncertainty is a critical component of designing markets that will facilitate effective and efficient long-term decisions by market participants.

Our report is organized in four main sections. In Section I, we discuss the relationship between the energy and ancillary services markets and the capacity market, as well as how the process for developing these markets can impact their effectiveness in facilitating long-term decisions by market participants. In Section II, we discuss the core best practices for designing energy and ancillary services markets. In Section III, we discuss certain specific aspects of the proposed capacity market in Alberta. Finally, in Section IV we describe Potomac Economics' experience in market design and market monitoring.

Summary of Recommendations

The focus of our report is best practices in energy and ancillary services markets and, accordingly, our recommendations focus on those markets. However, given that reform efforts are underway to introduce a new capacity market, we also address some of the proposed capacity market elements.

Moreover, because of the strong relationship between the energy and ancillary services markets and the capacity market, we have specific recommendations regarding the reform process itself. In particular, with regard to the reform process, we recommend:

- The schedule for implementing the capacity market take into account the risk that critical market design features may be left undeveloped and that the current schedule may sacrifice a unified design of all market aspects. This favors a longer implementation timeframe; and
- Alberta establish a clear plan for the development of energy and ancillary services markets to complement the emerging capacity market. Such a plan should implement the most critical and foundational changes first. Accordingly, our recommendations regarding the energy and ancillary services market are sequential, with each one building on the previous.

With regard to the energy and ancillary services markets, we recommend that Alberta:

- Begin by developing a real-time dispatch model that jointly optimizes energy and ancillary services products;
  - Such a model is the foundation for efficient energy and ancillary services markets; and
  - This will likely require Alberta to upgrade its core modeling infrastructure, including developing a state-estimator model and constraint analysis model.
- Establish demand curves for each ancillary services product that reflects the reliability value of the product. These values will be reflected in the prices for energy and reserves when Alberta cannot satisfy all of its requirements with the available resources. Hence, this allows the markets to price shortages efficiently and create good performance incentives;
- Develop market monitoring and market power mitigation measures to ensure the competitive performance of the energy, ancillary services, and capacity markets;
- Use the tools described above together with the necessary settlement systems to implement improved real-time energy and ancillary services markets that settle with participants on a 5- to 15-minute basis in alignment with the dispatch interval;
- Allow prices to vary locationally, at least for generation and external interfaces;
  - The dispatch model described above will naturally produce prices that vary locationally to reflect transmission constraints and marginal transmission losses.

The simplest means to implement efficient energy and ancillary services markets is to use these nodal prices to settle with all generators and loads;

- If congestion is minimal and transmission losses are small, these prices will be nearly identical across the system;
- Alberta could choose to average these locational prices to create a single system-wide price, but this would be more complicated and create poor incentives if congestion arises in the future as the resource mix and locations change; and
- Alberta could also choose a hybrid approach of averaging these prices to settle with loads at a single price (or a small number of zonal prices), while settling with generators at their nodes. This would preserve the beneficial locational incentives for generators and avoid uplift payments in the future.

- Develop and implement day-ahead energy and ancillary services markets to:
  - Improve the stability of Alberta's prices and settlements;
  - Reduce costs by coordinating the commitment of resources; and
  - Improve the competitive performance of Alberta's energy and ancillary services markets by reducing opportunities to exercise market power.
- Once efficient day-ahead and real-time markets are implemented, Alberta can improve its prices by expanding its pricing model to include the ability of, demand response, emergency and other operator actions by AESO to set real-time prices.

With regard to the capacity market, we recommend that Alberta:

- Adopt a capacity market with a prompt auction rather than the currently-proposed three-year forward auction to avoid adverse investment and retirement incentives;
- Not pursue performance penalties or, in the alternative, link them to real-time prices in order to allow the energy and ancillary services markets to provide efficient performance incentives;
- Develop a process to avoid artificial policy-induced supply surpluses that could be caused by the significant out-of-market capacity procurements that are planned. Such a process could protect the integrity of the market outcomes by coordinating entry and exit to avoid sustained surpluses; and
- We recommend procuring capacity on a seasonal basis to better align revenues with the value of capacity and to provide incentives for efficient outage scheduling and retirements.

I. Relationship of Energy and Ancillary Services Markets to the Capacity Market

Alberta is proposing a capacity market at least in part to address the substantial impending changes to the resource mix in Alberta. However, a capacity market is always a complement to the energy and ancillary services markets, which are the foundation of competitive wholesale electricity markets. Therefore, it is critical to understand the linkage between each of these markets and to consider the design of the energy and ancillary services markets as Alberta moves to implement a capacity market.

The capacity market is a market that procures physical generation resources (and demand response resources) that are committed to be in service during a planning period (usually a planning year) to meet the system's planning requirements. These requirements specify the quantity of resources needed to reliably serve the load in Alberta. Most of the centrally-organized markets in the U.S. have established a capacity market to augment the energy and ancillary services markets and thereby provide the economic signals necessary to efficiently satisfy the planning requirements. Together, these markets provide market revenues that inform long-term resource investment and retirement decisions. Additionally, a capacity market can produce benefits by:

- Coordinating efficient capacity (firm) imports and preventing inefficient exports; and
- Supporting a vibrant forward bilateral contract market for capacity.

All of these benefits are contingent on coordinating the design of the energy market and the capacity market. In this section, we discuss the importance of this coordination and some of the specific relationships between these markets.

A. The Relationship of Energy and Capacity Markets

The capacity market is closely linked to the energy and ancillary services markets because a long-run equilibrium in wholesale electricity markets is achieved when energy, ancillary services, and capacity revenues in these markets allow a marginal new resource to cover its entry costs. "Energy-only" markets (no capacity market) will achieve a long-run equilibrium level of capacity that is generally well below the planning requirements of most systems unless frequent shortage prices prevail or market power is exercised. Hence, capacity markets must generate additional revenues (beyond energy and ancillary services markets) to prompt the higher level of investment (and slower retirements) needed in order to satisfy planning reserve requirements.

The incentives to invest in new resources and retire existing resources are driven by the combination of net revenues from the energy, ancillary services, and capacity market. It is therefore important that this relationship be recognized in the design of the markets in a number of ways. Most importantly, the demand for capacity must recognize the expected net revenues from the energy and ancillary service markets. Any well-functioning capacity market must specify sloped demand curves that reflect the marginal reliability value of capacity. The curve is sloped because this marginal reliability value falls as capacity levels rise. In other words, each additional unit provides a diminishing incremental benefit for improving reliability. In general, such a curve must be constructed to ensure that the marginal new resource could recover its investment costs. However, because the capacity market is simply a supplement to the energy and ancillary service markets, it is important to shift the capacity demand curve to deduct the expected revenues from these markets.

B. The Tradeoff Between Shortage Pricing and Capacity Market Revenues

The most significant potential trade-off between these markets likely relates to the shortage pricing in the energy and ancillary services market. This report identifies establishing efficient operating reserve demand curves that will set prices during shortages as a best practice. These curves establish efficient shortage pricing when the system cannot satisfy the energy and operating reserve demands with the available resources. Good shortage pricing will provide a substantial share of the expected revenues a new resource would require. Hence, it will shift the demand curve for capacity and reduce reliance on the capacity market to motivate efficient long-term investment and retirement decisions.

Additionally, relying heavily on shortage pricing for delivering long-term revenues is beneficial in many ways. Good shortage pricing:

- Provides strong performance incentives for resources to be available and respond to dispatch instructions;
- Delivers more revenues to flexible resources that can respond quickly when conditions are tight or in shortage; and
- Provides incentives for fuel and technology diversity by delivering substantial revenues to resources that remain available after a fuel supply contingency.

Therefore, we recommend that Alberta jointly develop the reforms to its energy and ancillary services in conjunction with the capacity market. This should include planning for the development of efficient shortage pricing, which will substantially increase energy and reserve market revenue and reduce Alberta's reliance on capacity market revenue. Coordinating these market developments is necessary in order to develop a capacity market that will efficiently complement the energy and ancillary services markets.

Given the benefits of efficient shortage pricing described above, we recommend that Alberta rely to the maximum justifiable extent on revenues from efficient shortage pricing. When shortages occur and resources are most valuable from a reliability perspective, efficient shortage pricing provides substantially higher revenues to units that are flexible and available during the shortage.

In addition to improving the performance of existing generators, these revenues will promote investment in flexible resources – those that can start quickly and ramp up and down rapidly. These units will be increasingly valuable as Alberta transitions its generation portfolio to include a large quantity of intermittent renewable energy resources.

In contrast, capacity markets do not substantially reward units that are most flexible and available. Therefore, it is preferable to rely on capacity markets to only provide the residual revenue in excess of the energy and ancillary service revenues needed to satisfy Alberta's planning requirements.

II. Core Elements of Efficient Energy And Ancillary Services Markets

Efficiently designed and operated spot markets are those that result in offers that correspond to the underlying marginal cost of dispatch. This is important because both short-term efficiency (static efficiency) and long-term efficiency (dynamic efficiency) depends on prices reflecting the cost of production in the short run and providing revenues to support the cost of investment in the long run.

The energy and ancillary services spot markets are the cornerstone of any wholesale electricity market. Therefore, short-run market outcomes that are formed from cost-based offers are important because they will provide the signal to resources and load concerning the immediate value of energy in meeting real-time needs and securing system reliability. An efficiently-designed spot market will reveal the underlying variable cost of supplying energy and operating reserves under the various real-time conditions. Properly designed and operated, the spot markets provide investors with price signals to inform longer-term decisions about building new resources or upgrading or retiring existing ones. The spot market will also reveal the type of resource that may be needed at certain times and in certain locations. For example, a shortage of flexible units on the system will be reflected in higher prices at times when the operator is deploying expensive resources to meet reserve requirements, thus providing price signals to investors to build flexible resources. Similarly, congestion management payments to units that are dispatched out of merit provide investment signals to locate units in specific areas.

From this discussion, it becomes apparent that prices in the spot market must exceed the marginal costs of units for significant durations in order to ensure sufficient margins to support long-term fixed investment costs. This is accomplished by allowing lower-cost units to be paid the marginal cost of the highest-cost unit dispatched in each interval. For units that are frequently marginal and, therefore, cannot cover their fixed costs based on marginal clearing prices in most normal hours alone, sufficient additional revenues can be provided through a combination of shortage pricing and capacity market revenue. This is one motivation for the capacity market that is under development in Alberta.

The central feature of Alberta's electricity sector is the energy-only market that has been in operation since 2001. Since then, there has been no major redesign and, despite the lack of separate payments for capacity, capacity margins have met or exceeded the reliability requirements. As a result, without determining the exact reason for the sustained investment in Alberta under the current energy-only market, we infer there has been sufficiently frequent instances of energy prices exceeding variable costs to allow resources to cover fixed capital costs.

Now that Alberta has begun a process to increase the amount of renewable capacity on the system to replace fossil-fuel-fired capacity (specifically coal-fired capacity), the circumstances that have allowed an energy-only market to meet both dispatch needs in the operating horizon as well as longer-term capacity needs are likely to change. One of the significant changes that can be anticipated is a reduction in overall energy prices due to larger amounts of low-variable-cost energy.

A capacity market could be one answer. However, the on-going efforts to design the capacity market must take into account the current structure of the energy and ancillary services markets and consider how those spot markets might need to be changed as the conditions in Alberta change.

In this section, we discuss various approaches to establishing core elements and best practices in efficient design and operation of energy and ancillary services markets in light of the specific challenges facing Alberta. The first part of this discussion addresses the over-arching design principles that should guide electricity market design. We then identify the best practices that are key for building efficient and effective energy and ancillary services markets. In general, the market design and related processes should reflect the reliability needs of the system, allowing the market to set prices that establish efficient incentives for market participants.

A. Market Design Principles

The central goal of wholesale electricity market design is to deliver electricity to customers in a reliable and efficient manner at the lowest cost possible. This involves ensuring that the physical assets are in place and functioning and that various rules and procedures are deployed to efficiently operate the system. Accordingly, there are two main design principles. The first principle is that products (such as energy, reserves, and capacity) should be defined to correspond with the actual system requirements and that market mechanisms should procure these products at least cost. The second principle is that procedures that support the market should be designed so that affected participants have the incentive to act efficiently.

Design Principle 1: Defining Products and Market Requirements

Because of the immutable physical characteristics and limitations related to producing and transmitting electricity, electricity markets must recognize a relatively restrictive set of reliability requirements. For example, production must match consumption on a minute-to-minute or even second-to-second basis to maintain the frequency of the system. Additionally, production must account for transmission line losses and limitations related to how electricity flows over the network (i.e., transmission congestion), as well as how quickly generators must have the ability to increase or decrease output in order to accommodate changes in load, intermittent generation output, imports and exports, or potential generation forced outages.

Fortunately, system operators are well aware of the wide array of reliability needs and operating restrictions. The most important market design principle that should be employed to evaluate all potential design choices is that *a wholesale electricity market should offer products (energy, reserves, capacity) that correspond to the operating and planning needs of the system to the maximum extent possible.*

For example, operating reserve markets exist to reflect the operating needs of the system, including having sufficient resources online or with the ability to start quickly to keep the lights on after the largest system contingency occurs (e.g., largest generator tripping off or a tie-line going out of service). When the market requirements do not match the reliability needs of the system, the system operator will be compelled to take actions outside of the market to satisfy the system's needs (e.g., start generators, manually dispatch a generator, curtail load or exports, etc.). Properly designed, energy and ancillary services markets will coordinate the commitment and dispatch of the resources the system operator needs to meet the system requirements at the lowest cost and provide long-term incentives that improve generator's performance and facilitate efficient investment and retirement decisions.

Design Principle 2: Allocating Costs and Settlements to Create Efficient Incentives

Properly designed products procured on a market basis will result in efficient outcomes and prices in the wholesale electricity market. However, even in the best-designed markets, there are typically out-of-market or other costs that must be allocated to market participants. The allocation of these costs can significantly affect incentives for market participants to take short-term and long-term actions in these markets.

One category of these costs is known as "uplift" costs that arise when operators must engage in certain actions or procedures outside of the market that require make-whole payments to generators. This second market design principle would apply in developing an approach to allocate these costs. There is sometimes a clear cause for these uplift costs and it would be efficient to allocate them to participants in accordance with their responsibility for causing them. Other costs may not have a clear cause and should be allocated in a manner that is equitable and minimizes the effects on participants' incentives. Such costs include fixed transmission costs and associated transmission rates.

The second key design principle addresses how these costs should be allocated. This design principle is that *the allocation of costs should provide efficient incentives for market participants.*

This design principle is important because poorly allocated costs or revenues can create inefficient incentives for market participants. In such cases, even the best-designed markets will produce inefficient results because the conduct of the market participants will not be efficient.

In the sections that follow, the various best practices adhere to these two design principles. In addition, the specific attributes of Alberta are taken into account in assessing the relevance of each of the best practices.

B. Key Market Design Elements

1. Optimal Dispatch and Marginal Cost Pricing

Well-functioning energy and ancillary services spot markets commit and dispatch existing resources in an efficient, least-cost manner. Properly designed, these spot markets ensure that effective competition among suppliers and buyers produces efficient short-term prices that are the centerpiece of a rational and effective market-based system for the entire electricity system. Efficient short-term prices that reflect the short-run marginal cost of supplying electricity, not only help ensure efficient use of existing resources to meet real-time requirements, but also provides signals that can be relied on by participants to engage in longer-term contracts and capital investments.

The fundamental feature of modern, centrally-organized energy and ancillary services markets is a multi-lateral auction-based clearing system that accepts offers to supply energy from individual generators and bids to buy from load-serving entities. When individual generators do not have market power (or market power is mitigated through effective market monitoring), units are offered at their marginal cost of production, and the market clears at the cost of supplying the next MW of load.

The auction design for clearing energy and ancillary services markets optimizes the dispatch to utilize the lowest-cost offers to satisfy demand in each interval without overloading any constraint. In the absence of transmission constraints (and ignoring losses), the highest-cost offer needed to meet demand will set the price for all offers in that period. This means units with lower costs (i.e., infra-marginal ones) are paid more than they cost to operate, allowing them to earn revenue to cover fixed costs. The virtue of this auction is that it provides an incentive for suppliers to offer at their short-run marginal cost of production when the market is competitive.

Achieving an optimal dispatch and efficient marginal cost pricing in Alberta requires improvements in the energy and ancillary services market design, as well as the dispatch and market models and IT infrastructure, which are discussed later in this section.

Finally, there is currently no requirement in Alberta that suppliers' offers be submitted at marginal cost. As we discuss in more detail in the market monitoring section below, most centrally-organized markets in North America have market power mitigation measures that prevent suppliers from exercising market power. The main characteristic of market power mitigation approaches in North America is ensuring that suppliers' offers are competitive (reflect short-run marginal-costs) at times when they may have market power.

2. Ancillary Services Products

In Alberta, like in most centrally-organized markets, the main ancillary services include regulation, spinning and supplemental reserves, and black start service.[2] These main ancillary services are electricity products supplied from generating resources that are bought by the system operator to satisfy operating requirements.[3] Aside from black start service, the main ancillary services are operating reserves, which are supplied from unloaded capacity on online units or capacity on fast-starting offline units.

Operating reserve requirements are exogenous constraints established to enable the system to continue to serve load when contingencies occur, such as a generator or transmission line going out of service. Operating reserves are typically divided between regulation (frequency control), 10-minute spinning reserves, and 10-minute total reserves (including supplemental reserves). The 10-minute reserves are intended to allow operators to respond immediately to contingencies. Some systems also have 30-minute reserves that can be deployed after a contingency to replenish the 10-minute reserves to prepare for additional contingencies.

The fundamental principle underlying the design of operating reserve products and markets is that products should be defined to be as consistent as possible with operational requirements and practices of the system operator. Applying this principle has caused some systems to define locational requirements for their operating reserves. This is valuable when transmission constraints prevent operators from recovering from a large contingency in a local area. In these cases, the operator can meet the system's needs by procuring operating reserves in the local area. When reserves are needed in a local area, it is very important to define a local product to allow the market to secure the reserves needed and to provide incentives for suppliers to invest resources in the local area. Local reserve requirements are discussed further below in subsection 10.

In designing a market-based approach to operating reserves, resources must first be qualified to supply the relevant product by having the appropriate quality of resource, e.g., automatic generation control (AGC) equipment for regulation or fast enough ramp rates for spinning reserves. Qualified resources make offers for supplying the relevant service. For regulation service, offers can be submitted independently for "up regulation" and "down regulation." For spinning reserves, the unit submits an offer in $ per MW for the amount the unit is able to ramp

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2 Alberta also includes transmission-must-run service as an ancillary service, which is a manual redispatch to manage congestion given that prices are settled based on a single, system-wide price. Alberta also has an additional service called "load shed service for imports," which is used to manage the intertie.

3 Black start service is used in all transmission networks and is typically a cost-based regulated service uplifted to all users. It is not important for our discussion as it is essentially regulated and, while technically important, it is not important for market discussions and does not involve significant expense.

up in 10 minutes. As explained in the next section, market-based provision of operating reserves should be optimized with the energy product.

Alberta generally follows these product market definitions. The products are selected from available generators on a day-ahead basis. While selecting ancillary services in the day-ahead market is a good practice, these procurements should be jointly optimized with energy procurements in both the day-ahead and real-time markets, as we explain below. We also explain below that the economic value of operating reserves should be well defined by developing operating reserve demand curves that govern the maximum price the ISO should pay for reserves, and the price that should be set when the system is short of the operating reserve requirement.

3. Co-optimization of Energy and Operating Reserves

To meets its reliability standards, Alberta procures operating reserves in a day-ahead market from providers who have been qualified to provide specific products. In real time, the scheduled reserves are held out of the energy markets, and there is no explicit means to share the on-line flexibility between energy and reserves. For example, if a resource scheduled for reserves would be more economic to produce energy (while shifting the reserves to a different unit), the savings of such tradeoffs will not be captured in Alberta.

Wholesale electricity markets are more efficient if generation resources are allocated efficiently between the energy market and ancillary services markets. This allows resources to be fully utilized and results in tradeoffs being efficiently reflected in the market prices for each product. The idea is that resources are scheduled to meet both energy and ancillary services requirements, with reserves held on the higher-cost units (or higher-cost output segments on online units), allowing lower-cost units to provide the energy. However, when it is optimal for a lower-priced unit to be dispatched down to supply spinning reserves, the opportunity cost of this trade-off will be included in the spinning reserve price. Therefore, resources qualified for reserves will not be harmed by being scheduled for reserves.

Moving the energy and ancillary services markets from Alberta's current relatively manual dispatch process and separate procurement mechanisms to a jointly-optimized dispatch promises substantial savings by allowing Alberta to minimize its costs and fully utilize its generating resources. This is likely to become increasingly important as the portfolio of generating resources changes substantially. These changes will lead to a portfolio that is less controllable due to the shift toward intermittent renewable energy resources. Therefore, optimizing the commitment and dispatch of Alberta's controllable resources will likely become much more valuable.

A jointly-optimized market dispatch is particularly important in times of reserve shortages or in cases when costly measures are taken to avoid shortages. Because a unit of available capacity could be dispatched to satisfy energy demand or held to provide reserves, the price of energy will always include the marginal cost of supplying reserves. Likewise, because higher-quality reserves (e.g., 10-minute spinning reserves) can always be utilized to satisfy lower-quality reserve requirements (e.g., 10-minute total reserve requirement or a 30-minute reserve requirement) the operating reserve prices will always "cascade" – the price for the higher-value reserve and energy will always be greater than or equal to the price of the lower-value reserve. This outcome is not guaranteed in Alberta's current market design.

Finally, applying the same operating reserve requirements in the day-ahead market as in the real-time market promotes consistency between the day-ahead and real-time markets. In doing so, it will allow a day-ahead market to coordinate the commitment of resources needed to satisfy the system's needs the following day. Not only will this lower costs for consumers in Alberta, but such coordination may become necessary as the portfolio of resources changes over the next decade. A fuller discussion of the benefits of the day-ahead market to Alberta is provided in the next subsection.

4. Day-Ahead Markets and a Multi-Settlement System

Alberta currently only operates a real-time energy market. Hence, suppliers make the decision to commit resources independently and the system operator then dispatches the committed resources to serve the load in real time. Hence, all settlements occur through the real-time market at the prevailing single real-time price.

This process creates a number of economic issues:

- The decentralized commitment process is not efficient because it is not coordinated. Hence, units that are economic to commit may often not be committed while uneconomic units (or excessive quantities) may often be committed. These types of inefficiencies raise costs to customers and lower profits to Alberta's generators.
- The loads are subject to much higher price volatility in the real-time market than in other centralized electricity markets.
- Market power is easier to exercise because suppliers can effectively withhold resources by simply not committing the resources, particularly if they have relatively long start-up times.

To address these types of issues, electricity market operators have implemented day-ahead energy and ancillary services markets that are settled in a "multi-settlement" system, which is a best practice for competitive electricity markets. The multi-settlement system consists of a financially-binding day-ahead market that schedules load and generation, coupled with real-time energy and ancillary services markets that are settled based on the load and generation deviations from the day-ahead schedules. For example, if a load serving entity purchases 500 MW of energy in the day-ahead market, then consumes 480 MW of energy in real time, it will be charged for 500 MW at the day-ahead price and receive a payment for 20 MW at the real-time price. Day-ahead markets can function well even without active load-serving entities trading in the day-ahead market. In this case, the system operator can procure the forecasted load on behalf of the load, and rely on virtual trading and suppliers to allow the day-ahead prices to converge with real-time prices.

The day-ahead market allows participants to make forward purchases and sales of power for delivery in real time. It delivers benefits in a variety of ways. Day-ahead markets:

- Substantially improve the stability of participants' settlements as real-time markets are typically more than four times more volatile than day-ahead markets.
- Provide a means for participants to hedge risks associated with the real-time price volatility and congestion.
- Reduce costs by coordinating the overall commitment of resources to satisfy the next day's energy and ancillary services demands at the least cost. This day-ahead coordination generates substantial savings for customers and eliminates uneconomic generator commitments for suppliers.
- Can facilitate greater competition and reduce opportunities to exercise market power since the day-ahead market will naturally commit other resources if a supplier attempts to withhold its supply to raise prices. This supply response is not generally available in the real-time market.
- Ensure that resources are committed in a manner that can accommodate the uncertainties regarding large-scale reliance on intermittent renewable energy resources.

Virtual Trading. One of the key aspects of the day-ahead market that facilitates good market performance and allows participants to hedge risks efficiently is virtual trading. Virtual trading involves buying or selling energy in the day-ahead market financially, which results in the energy being sold or bought back in the real-time market. Virtual demand and supply transactions allow participants to arbitrage differences between the day-ahead and real-time prices. Some markets have resisted including virtual transactions because they are concerned about potential gaming or manipulation. We have not found this to be a significant concern in practice, and these bids and offers play an important role in achieving efficient day-ahead outcomes. The efficiencies described above are achieved when the day-ahead market outcomes converge with the expected outcomes in the real-time market. Virtual transactions play an important role in allowing participants in the day-ahead market to respond to significant price differences. Convergence is achieved as participants arbitrage these differences.

Three-Part Bidding. As described above, a primary role of the day-ahead market is to coordinate the commitment of resources for the following day. This is done by suppliers making offers that reflect not only the marginal energy costs, but also the start-up and other commitment costs as well as other commitment constraints, such as minimum run-times and minimum down times, that can only be considered and optimized in an advanced commitment process. The day-ahead market minimizes the total cost of meeting load for the entire evaluation period rather than each hour discretely, considering both energy and commitment costs. Participants may self-commit, subject to reliability evaluations, but resources committed through the market are guaranteed full cost-recovery, including commitment costs, through market revenues and additional guarantee payments if necessary. Self-committed resources, typically long-lead time baseload resources, are not guaranteed cost-recovery.

Expected Changes in Settlement Patterns. Based on the considerable history in multi-settlement market designs, implementing a day-ahead market will result in the vast majority of all market settlements for both loads and resources occurring through the day-ahead market at prices that are much less volatile than the real-time market. Prices are less volatile because the day-ahead market is far more flexible – with access to virtual transactions and the full array of resources that may be committed. The system is far more constrained in the 5- to 15-minute timeframe in which the real-time market operates.

5. Shortage Pricing – Energy and Ancillary Services Shortages

Virtually all shortages in any centrally-organized market are shortages of operating reserves (i.e., operators will hold less reserves than required rather than not serving the energy demand). When a system is short of its required operating reserves, the value of the foregone reserves should set the price for the reserves and be embedded in all higher-valued products, including energy. This value is established in the operating reserve demand curve (ORDC) for each reserve product.

Well-designed shortage pricing is a critical component of efficient energy and ancillary services markets. Energy prices that prevail during shortage conditions play a fundamental role in sending efficient price signals in the short run and long run. In the short run, efficient shortage pricing sends appropriate price signals to suppliers in other markets to export energy to the region in shortage and for participants with existing capability to supply additional energy or reduce consumption. In the long run, efficient shortage pricing is an important component of the economic signal governing new investment and provides incentives for existing units to remain in operation. As we explain in Section I, shortage pricing is also critical in establishing an efficient capacity market design.

A shortage occurs in real time when demand is high enough that available resources are not sufficient to meet the demand for both energy and operating reserves. In such a case, reserve shortages occur and prices must reflect the cost of degraded reliability. These shortage prices should occur even for very short-duration shortages. They are real regardless of their duration. Typically, these transitory shortages occur when the system is ramp-constrained (i.e., output is increasing as rapidly as possible). These are true shortages because if a large contingency occurs during this period (e.g., a generator tripping offline), the transmission operator will not have the ability to replace the capacity because its other generators are already ramping as quickly as possible.

Operating Reserve Demand Curves. Operating reserve demand curves establish an economic value for reserves that will be reflected in energy prices if the energy market must bid scarce resources away from the reserve markets. When this condition occurs, the reserve market effectively becomes the marginal source of supply to the energy market, and therefore appropriately influences energy prices.

The typical reserve demand is “tiered” so that a small reserve shortage will cause energy prices to increase by a relatively small amount. For example, in MISO, an operating reserve shortage up to 100 MW will result in energy prices rising by roughly $200 per MWh; larger shortages can cause prices to rise by more than $3,000 per MWh. This increasing shortage pricing reflects the increasing risk of shedding load as operating reserve levels fall, and therefore reflects the true value to the system of incremental energy and reserves.

Without reserve demand curves to set the price during shortages, the price will be set at the marginal cost of the last segment of supply dispatched from the online resources, which will generally be less than $200 per MWh. System operators will take actions during shortages with marginal costs well above this level (such as starting a high-cost peaking resource) in order to reduce the shortage and improve reliability. Under these shortage conditions, an energy price of less than $200 per MWh is inconsistent with the value of energy or the costs of restoring reserves on the system. The inconsistency results because the economic value of reserves and the associated trade-offs with energy are not reflected in the market prices. Establishing demand curves for reserves is the best practice for setting efficient shortage prices in the energy market.

Demand curves should be based on the value of lost load (VOLL). VOLL is the estimated cost to consumers of involuntarily losing their supply of electricity. In MISO, these are based on estimates from a variety of studies. At the low ends of the demand curves, the curves are set at a level that would generally cause all available offers to be accepted when the system is in a shortage. This is consistent with the mandatory nature of the reliability requirements. An efficient ORDC should abide by three principles:

- Reflect the marginal reliability value of reserves at each shortage level;
- Consider all significant supply-side contingencies, including the risk of multiple contingencies occurring simultaneously; and
- Have no discontinuities that can lead to excessively volatile outcomes.

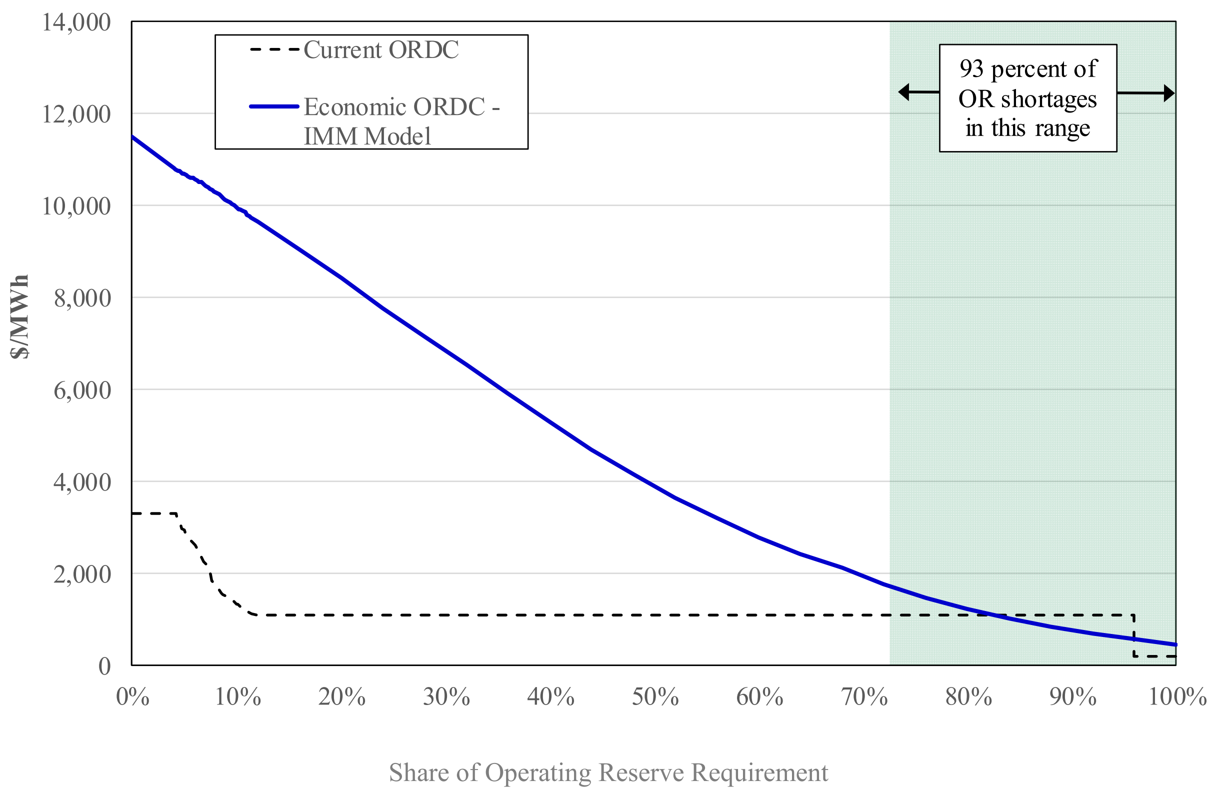
The marginal reliability value of reserves at any shortage level is equal to the expected value of the load that may not be served. This is equal to the following product at each reserve level:

VOLL* the probability of losing load

We have been proposing that MISO improve its ORDC, which steps up to $1,100 and remains constant as reserve levels fall. In reality, the probability of losing load rises as reserve levels fall and the shortage increases. We developed a Monte Carlo model to estimate this relationship, accounting for volatility of wind output, imports and exports, and energy demand. This model allowed us to estimate the probability of losing load and to trace out an "economic ORDC" based on an assumed VOLL of $12,000.

The figure below illustrates our proposed curve and MISO's current ORDC. As this figure shows, although MISO has an ORDC and uses it for shortage pricing, it does not qualify as a best practice because the value of the reserves does not increase as reserve levels drop over most of the range of the curve. This implies that the reliability value of the remaining reserves does not grow as the shortage becomes more severe, which is simply not true and is why the shape of the current ORDC does not match the economic ORDC that we have estimated.

Figure 1: An Illustration of an Economic ORDC



Allowing prices to increase during shortages would provide efficient compensation for flexible, fast-ramping resources in Alberta. These are the resources that can respond quickly to help resolve shortages. Such pricing rules will provide incentives for resources to invest in and provide flexibility in the operating timeframe, including:

- Offering faster resource ramp rates;
- Offering wider dispatch ranges; and
- Offering shorter start-up times.

Additionally, these incentives have important long-term implications. They provide efficient incentives for participants to build more flexible, fast-ramping generating resources and to make maintenance decisions on existing resources to increase their flexibility. Hence, this is a critical component of an efficient energy and ancillary services market design.

Finally, all of the markets that we monitor (ISO-NE, NYISO, MISO, and ERCOT) are designed to price all shortages, regardless of duration. The design causes the operating reserve demand curves to set price in any five-minute interval in which the operating reserve requirements cannot be fully satisfied. This is important in periods when the system is ramp constrained – when slow-ramping units are moving as rapidly as possible, causing the system to be short of operating reserves because other units must provide energy that would otherwise be providing reserves.

Alberta has an energy offer cap at $999.99 and no shortage pricing when reserves are compromised. We recommend that Alberta develop a reserve demand curve based on the VOLL. While a VOLL study may not be currently available, MISO studies would provide a comparable value.

Shortage pricing in the real-time market will provide a higher-level of revenues and would reduce the need for capacity market revenues. Generating revenues through shortage pricing is preferable to generating through the capacity market because the energy and ancillary services prices provide much greater incentives for operating availability and flexibility as described above. Resources are most valuable from a reliability perspective when tight supplies or unexpectedly high loads lead to operating reserve shortages market-wide or in a local reserves zone. Fully revealing this value through efficient shortage pricing provides substantially higher revenues to units that are flexible and available during the shortage. In contrast, capacity revenues do not substantially reward units that are most flexible and available.

6. Nodal Dispatch and Pricing

Alberta currently operates a real-time market that establishes one system-wide price for the system and many of the innovations described above could be implemented in such a system. However, the most effective and best-performing energy and ancillary services markets establish prices that vary locationally to reflect transmission congestion and transmission losses as we recommend in this section.

An optimal auction design for clearing energy and ancillary services markets will utilize the lowest-cost offers to satisfy demand in each interval without overloading any constraint. Ignoring transmission constraints and losses, the highest-cost offer needed to meet demand will set the price for all offers in that period. This means units with lower cost (inframarginal ones) are paid more than their cost to operate, allowing them to earn revenue to cover fixed costs. The virtue of this auction is that it provides an incentive for suppliers to offer at their short-run marginal cost of production. When the market is competitive, the supplier cannot earn more profits by raising or lowering its offer price from its marginal cost.

Because transmission and other operating constraints and losses are important features of electricity systems, a single price paid to all producers is rarely efficient (nor feasible). This is because out-of-merit dispatch may be necessary to manage the transmission flows so that they do not overload any constraints. Therefore, the cost to serve load in certain locations may be higher than the single system-wide price. Hence, the best practice in energy and ancillary services market design is a “nodal market” where the price can vary by node to reflect the three cost components of serving load:

- The market-wide system marginal price;
- A congestion component; and
- A marginal loss component.

These three components of the nodal price or “locational marginal price” are very important because they allow the price to reflect the true value of energy (i.e., the cost of serving load) at every location. These prices are used to settle with loads and generation in the day-ahead and real-time markets.

An important economic virtue of a nodal market is that the congestion component of the price at each location will reflect all transmission constraints. When transmission constraints are binding (the flow is equal to or greater than the limit), generation in different locations relative to the constraint will be dispatched up or down to manage the network flows. The differences in prices throughout the network will cause the amount collected from load to exceed the amount paid to generators, which is referred to as “congestion revenue.” Congestion revenue plays an important role in paying for the costs of building the network. Typically, this revenue is allocated to holders of financial transmission rights (FTRs), which can be purchased by market participants as a hedge against congestion costs. FTRs entitle the holder to the difference in the congestion component of the nodal price between two locations.

Without nodal pricing and dispatch, managing this congestion would require the operator to manually re-dispatch generators. The cost of this re-dispatch would be allocated in some fashion, usually uplifted to consumers. This can result in higher costs to consumers as generators that increase flows over the constraint must be paid to reduce their output (they would otherwise have the incentive to keep producing). In a nodal market, the nodal price would fall at these locations and rise at others to ensure that all generators have incentives to follow the operator's dispatch instructions.

Pricing Transmission Losses. In addition to reflecting transmission constraints, nodal prices also reflect marginal transmission losses. Transmission losses are the loss of power that results from transmitting power from the location of a resource to the location of the load. Losses are lower on high-voltage facilities, so the use of lower voltage facilities can result in higher losses, all else being equal. Marginal losses, are the additional losses that are contributed by an individual resource relative to the rest of the grid. Some locations, because they are located near the load, can have negative marginal losses so they are paid more than other resources even when no constraints are binding. It is important to recognize marginal losses in the dispatch to minimize the costs of serving load. In other words, lower-cost resources that are distant from the load and result in higher levels of losses can ultimately be more costly to dispatch than generators closer to the load.

Congestion Management in Alberta. Alberta currently manages congestion through manual redispatch and must-run service, which are not optimized in the dispatch. Congestion has not been a significant issue because substantial investment has been made in the transmission network to minimize congestion. However, network flows are likely to change and significant congestion may arise as the system prepares for a large influx of renewable energy resources. Alberta plans to retire or convert its coal-fired generation and build enough renewable energy resources to supply 30 percent of the Alberta load over the next 12 years. Because these resources are likely to be in very different locations, the network flows will change and Alberta may experience congestion that has historically not been present. If Alberta continues to manage congestion manually as congestion increases, overall efficiency will be diminished because prices will not reflect the true value of energy at all locations. Revealing this locational value in Alberta's prices will provide strong incentives for generators to follow the dispatch instruction. This is particularly important if wind resources are built in areas where their output overloads nearby transmission constraints, a problem that has arisen in every U.S. electricity market that has experienced large-scale investment in wind resources.

Interchange. Locational pricing will also provide a basis for efficient interchange of power between Alberta and its neighboring control areas. The locational prices in Alberta will serve as a basis for an efficient interface price. Such a price will reflect the energy and congestion benefits from interchange with the neighboring systems. In most hours, it will reflect the marginal cost of supplying power (in the case of exports) or the cost avoided from not consuming power (in the case of buying). In some hours, the exchange could create congestion or relieve congestion. As such, a price that reflects the energy cost as well as the congestion caused or congestion relieved, will reflect the total cost or benefit to Alberta. In times of scarcity, the interface price will reflect reserve shortages and the high interface price will attract imports and discourage exports.

Long-Term Benefits of Nodal Pricing. Although the short-term benefits of nodal pricing are substantial, the long-term benefits may ultimately be larger. Efficient commitment and dispatch under a nodal market design will lead to better locational price signals to facilitate efficient investment in new resources and retirement decisions for existing resources. Although some of these long-term decisions are being guided by public policy in Alberta, efficient locational prices would efficiently influence the decisions. For example, renewable resource developers that are contracting with Alberta will choose to site differently under a nodal pricing market. Under such a market, siting in areas that are likely to be congested will be much less profitable. Avoiding such locations is good for the developer and for consumers in Alberta.

7. Real Time Pricing of Peaking Units and Emergency Actions

Prices during peak demand hours are critical for the economic efficiency of a market. During peak times, quick-starting peaking units (generally gas turbines) are started and dispatched. The cost of starting and operating these units in any instance reflects the real incremental cost of supplying load and should be reflected in marginal prices. Most real-time market dispatch models can only set prices based on the offers of online units. Historically, most markets did not have pricing rules that allow the costs of starting and dispatching high-cost peaking resources to be reflected in real-time energy prices. As a result, such units often require guarantee payments to cover their costs that are uplifted to loads.

Well-designed fast-start pricing models allow real-time prices to include the cost of committing and running peaking units when they are the incremental source of energy. Such models have been implemented by NYISO, MISO, and ISO-NE. This helps ensure that the marginal prices reflect the full cost of serving load. Such pricing rules help improve key incentives for efficient long-term and short-term efficiency. They reduce reliance on uplift payments and send more efficient economic signals to guide commitment decisions.

Real-Time Pricing for Gas Turbines. Such pricing models are needed when gas turbines are utilized because gas turbines constitute most of the resources at the high-priced end of the supply curve. When they do not set prices, the prices are often set by a much lower-cost unit. If the portfolio of higher-cost resources in the real-time market included a mixture of flexible and inflexible units, this price-setting issue would not be as large a concern because one could expect high-cost flexible units to set prices when the inflexible units could not.

Real-Time Pricing for Other Types of Resources. We have not seen evidence of significant price formation problems associated with other types of lower-cost base-load or intermediate resources. These resources are not generally subject to the issues that justify applying this pricing methodology to gas turbines, nor can their commitment be considered a marginal action in the dispatch timeframe. Therefore, we have not recommended expanding the application of this pricing logic to other classes of resources.

Real-Time Pricing of Demand Response and Emergency Actions. This approach can be adapted for pricing demand response and other out-of-market operator actions taken during emergencies. These factors alter the supply and demand balance outside real-time market dispatch, so their effects are very similar to an operator deciding to start a gas turbine. As capacity margins fall in most centrally-organized markets, the frequency with which the markets rely on demand response or other operator actions should rise and increase the importance of pricing these actions efficiently. Operators often avoid shortages by taking actions that may be as costly as the value of the shortage. Therefore, if these actions are not priced, it can significantly reduce the shortage (or near-shortage revenue) produced by the energy and ancillary services markets.

8. Price Floors in the Energy Market

Alberta currently does not allow for negative offer prices. Hence, it has a market price floor that is enforced at zero. For a variety of reasons, it is a better practice to allow prices to become negative. It is efficient to have negative prices when:

- The market is over-supplied by baseload resources that are costly to cycle (i.e., to turn off and start up again later) and/or by wind resources that may have negative marginal costs when production subsidies exist (e.g., such as production tax credits in the U.S.);
- There are resource locations that cause increased flows over a binding transmission constraint; and
- There are locations that contribute to increased transmission losses when overall energy prices are very low.

In such cases, it can be more economic for the resource to remain on line and pay to produce in accordance with the negative price than to shut down, and thereby helping to resolve the system issue efficiently by providing incentives for suppliers to respond.

Negative prices are generally infrequent, but provide important incentives. Negative prices in some areas will cause day-ahead prices to fall and alter the commitment of resources in a manner that reduces the system's exposure to these conditions. These commitment changes are efficient and improve the reliability of the system. Additionally, units that are more flexible receive more revenue in markets that allow negative prices. This is desirable in Alberta because it will incent investment in resources that will be more valuable in managing the fluctuations in intermittent renewable generation in the future.

Therefore, we do not recommend retaining a price floor at zero, but instead lowering the price floor to a level that will allow suppliers to represent their competitive costs. For example, a baseload resource that seeks to avoid cycling the resource may rationally be willing to run when real-time prices clear at -$100 or even less, so such offers and prices should not be precluded. Establishing an offer floor between -$500 and -$1,000 per MWh would generally be low enough to avoid interfering with efficient and competitive market performance.

9. Shortage Pricing – Transmission Shortages

We initially introduce shortage pricing above related to operating reserves. Shortage pricing also applies to transmission shortages. A transmission shortage occurs when the flows on a transmission line or facility exceeds the facility's operating limit – sometimes referred to as constraint violations. This generally occurs when the real-time dispatch lacks the resources or ramp capability in the right locations to reduce the flow below the transmission facility's limit. This is a shortage that is analogous to an operating reserve shortage. In both cases, the system's requirements cannot be satisfied for some period of time.

In Alberta, the transmission constraints are not incorporated into the market clearing mechanism, so the market price cannot reflect transmission shortages. As we discuss above, the changing resource mix is likely to create additional congestion which cannot be efficiently managed by current manual redispatch and must run services. If these changes result in constraint violations in Alberta, they cannot be priced in the real-time market unless Alberta implements nodal pricing.

In order to determine the value of a violation, centrally-organized markets have employed a modeling parameter to specify how valuable it is to keep the flow over a transmission facility below its limit. The modeling parameter has various names, such as marginal value limits, constraint penalty factors, and transmission constraint demand curves. For ease of discussion here, we will refer to these generally as "transmission constraint demand curves" (TCDCs).

When the cost of re-dispatch to maintain the flow under the transmission limit exceeds the TCDC value, the dispatch model allows transmission to be used above its operating limit; that is, it allows the system to be short transmission. In this way, the modeling parameter represents the cost of the transmission shortage. This is analogous to the reserve demand curves that indicate the cost of being short of reserves.

The TCDCs play a pivotal role in dispatch and prices. When a constraint is violated in the dispatch, the "shadow cost" of the constraints (the basis for the nodal congestion prices) should equal the TCDC value. Hence, these parameters can substantially affect prices and dispatch patterns. Additionally, because TCDCs directly affect real-time prices, they will also affect the day-ahead market outcomes. Higher shortage pricing for transmission shortages will generally result in more generators being scheduled in the day-ahead market that can help manage the constraint.

Some systems do not allow the TCDC to set the shadow price of a constraint when it is in violation, but instead "relax" the constraint by raising its limit. This is not a best practice because it results in inefficiently muted congestion pricing. Hence, in a nodal market context, the best practices for managing and pricing transmission shortages are to:

- Establish TCDCs that reflect the reliability value of managing the constraints (which may vary by type of constraint);
- Specify the procedures and authority for operators to modify the parameters; and
- Prohibit the practice of relaxing the pricing of violated transmission constraints and, instead, set LMPs that are consistent with the filed TCDCs for those constraints.

10. Local Reserve Requirements

Local reserve zones allow the market to reflect reliability requirements that would otherwise require out-of-market actions to satisfy. We believe that local reserve zones should be created whenever the ISO has capacity requirements in a specific area in order to respond to certain system contingencies. Such requirements exist in every market that we monitor. While Alberta has relatively strong internal transmission interconnections, transmission must-run units are still deployed on the Alberta system to support local operating requirements.

Such requirements often exist in local areas that have limited quick-start capacity. In such an area, a first contingency that results in deploying reserves will subsequently require those reserves to be replaced, generally by committing other resources in the area. Without capacity that can start in 30 minutes, operators must have units already online to replace the reserves that would be deployed for the first contingency. In other words, the operators are committing the system for the first and second contingency (N-1-1).

By establishing a reserve zone in this circumstance and procuring 30-minute reserves, the market can select the least expensive units to be committed for such reserves and provide valuable incentives for investment in quick-start capacity. Additionally, it would allow for shortage pricing in these areas when the resources are insufficient to satisfy the N-1-1 need. Thus, both short-term and long-term incentives are improved by establishing the reserve zone.

Most centrally-organized markets have recognized that this element of market design is necessary to reflect their reliability needs. ISO-NE, NYISO, and MISO have all either implemented 30-minute reserve zones to address these types of reliability requirements, or are in the process of doing so.

C. Dispatch, Settlement and Infrastructure

In the previous section, we discussed best practices in energy and ancillary services market design. In this section, we address a number of best practices for operating a market. It is not always practical to design products that correspond to all aspects of electric supply. During the operating horizon, operators make many decisions to manage changing system conditions including, for example, turning on resources. Regulators rely on procedures to determine and guide operator actions, so it is important that these and other procedures be designed to ensure proper incentives for market participants. Many actions taken by the operator involve adding costs to the system and these costs must be classified and allocated. In this section, we examine some of the issues relating to operating the system and how to make these attributes efficient.

1. Dispatch and Settlement Timing

The timing of dispatch and when the resources are settled raises important issues. The dispatch interval represents the time between dispatch signals sent to resources in real time and forms the basis of contract quantities in the day-ahead market. The settlement interval determines the frequency with which a resource settlement price is calculated. Alberta adjusts dispatch continually in real time and settles at an hourly-integrated price, (i.e., the 60-minute weighted average of one-minute dispatch price). For comparison, US markets that are dispatched and settled in intervals ranging from every 15 minutes (e.g., PJM and ISO-NE) to every 5 minutes (e.g., MISO, ERCOT, SPP, and NYISO).

Alberta should consider a more frequent settlement interval (e.g., 5-minute) because aligning dispatch and settlement intervals allow for better control of the system and recognition of transitory shortages. The energy and ancillary services market settlements should coincide with the dispatch interval. By doing this, suppliers will always be paid for the output they provide based on the value of the energy or reserves in the interval they are provided. This produces better incentives for flexible resources to be online and to follow dispatch. Together with the 5-minute dispatch, 5-minute settlements would allow controllable resources to be fully-compensated for their flexibility and ability to follow dispatch instructions. Fast-ramping, flexible resources earn substantially more revenues when markets settle on a 5-minute basis because they can respond and benefit much more as prices fluctuate. In the long-run, these improvements would induce a greater flexibility from new and existing resources and, consequently, lower dispatch costs and improve reliability.

In a multi-settlement market setting, day-ahead settlement intervals that match the real-time settlement intervals can avoid some inefficiencies associated with day-ahead and real-time price convergence. Hourly scheduling in the day-ahead market causes large schedule changes for load, generation, and net imports because schedules begin at the top of the hour. In general, unit commitments and decommitments are timed to meet these schedules. This creates ramping issues in real time because many participants operate in real time consistent with their day-ahead schedules. Additionally, the day-ahead market could select a lower-cost mix of resources if it recognized more accurately the intra-hour changes in system demands.

It may be very difficult to implement a 5-minute day-ahead market because the day-ahead market would have to clear 288 separate intervals (compared to 24 hourly schedules in the current U.S. day-ahead markets). Alberta could avoid some of the issues described above related to the hourly day-ahead markets in the U.S. by implementing a 15-minute day-ahead market. This market would:

- Allow the ramping of the day-ahead market supplies to be much more consistent with the real-time system demands; and
- Reduce the frequency of transitory shortages and associated reliability issues.

2. Look-Ahead Commitment and Multi-Interval Dispatch

A real-time "look-ahead" capability in economic commitment and dispatch software can produce significant benefits by utilizing resources more efficiently. A look-ahead system is used to make an intra-day forecast of load to optimize the commitment and decommitment of peaking resources. In general, such models implemented by centrally-organized markets in the U.S. run every 15 minutes for the upcoming one to three hours. Optimizing the commitment of these resources can produce substantial savings in a system that frequently utilizes peaking resources.

A multi-interval real-time dispatch model can also produce sizeable benefits by optimizing each 5-minute interval for the upcoming 15 minutes to an hour (rather than simply the next 5 minutes). This provides a greater ability to efficiently utilize slow-ramping units. The NYISO has implemented such a dispatch model for its real-time market.

3. Offer Guarantee and Opportunity Cost Payments

Ideally, providing energy and ancillary services through day-ahead and real-time market would satisfy all reliability needs in the operating horizon. However, there are practical limits to the extent to which the markets can satisfy operating needs during all unforeseen events and circumstances. This has generally created the need for "uplift" payments that allow the operator to use resources to meet operating requirements and pay the units "out of market." There are two main types of uplift payments associated with operations: guarantee payments and opportunity cost payments.

Guarantee payments. Guarantee payments should be made in both the day-ahead and real-time markets when a unit committed by the market operator is unable to recover its as-offered production cost through market payments alone. In other words, if the market revenues for a committed unit are not sufficient to cover the unit's as-offered start-up and running cost, then a guarantee payment should be made at settlement. Otherwise, participants would risk economic losses by following the market and operator commitment instructions. For example, operators in centrally-organized markets often commit certain generators to be online for the next-day even if the unit did not clear the day-ahead market. This is usually done as a result of the operator's assessment that reliability issues may arise due to insufficient capacity. In such an instance, it is reasonable and fair to compensate the unit if it ends up making losses in the real-time market.

Opportunity costs. Similar to offer guarantee payments that ensure suppliers do not make financial losses by following dispatch instructions, there should also be payments that compensate suppliers for lost opportunities. These opportunity costs arise when a unit may be instructed to produce at a level below their day-ahead schedule and, as a result, lose the opportunity to earn the margins that were settled in the day-ahead market. In other words, by being dispatch down, the unit is liable for real-time energy purchases for the amount it under produces its day-ahead schedule. By ensuring these margins are paid, the unit can follow the dispatch instructions without the risk of financial loss, thereby allowing the operator the flexibility required to ensure reliable operations.

4. Uplift Allocation

Uplift allocation rules are the rules which determine who pays for uplift costs. For example, should uplift be paid by all load in proportion to energy consumption, or should it be allocated to generators, or a combination of load and generation? The rules for allocation can create incentives (both good and bad) and so should be carefully considered. For most markets in the U.S., uplift is incurred when generators must be started in real time to satisfy the system's needs. Alberta also has a class of uplift that must be paid when generators must ramp up or ramp down to manage transmission congestion (because these costs are not priced in Alberta's real-time market). In this section, we examine best practices associated with uplift allocation.

While uplift costs should be avoided as much as possible by incorporating reliability requirements and other operator actions into market-based products, any uplift remaining should be allocated based on the actions that cause the uplift. By allocating it to those that cause it or benefit from it, there is an incentive for these participants to act to minimize it. MISO's allocation approach is the best practice in the industry and has produced substantial efficiency savings. It is the best practice because it recognizes why the uplift is incurred (i.e., to satisfy local reliability needs, to satisfy system-wide capacity needs, to manage congestion on a particular constraint, etc.), and allocates these costs to the scheduling actions that cause them. For example, loads that under-schedule in the day-ahead market or generators that fail to start can cause commitment of peaking units that receive guarantee payments. The associated uplift costs should be allocated to these participants because they caused these units to be committed.

Most centrally-organized markets still do not allocate uplift costs consistent with cost causation principles, allocating most uplift to load or to all deviations from the day-ahead market. As Alberta moves forward with market reforms, policy makers should remain attentive to the underlying causes of uplift costs and allocate them to the participants that cause them. Currently, most uplift costs in Alberta are the result of operating reserves. These are currently allocated to load based on energy consumption, which is efficient because the reserves are procured on a system-wide basis. In multi-settlement systems and in locational markets, some of the uplift can be linked to specific participants and subsets of customers and costs should be allocated accordingly.

In the longer-term, operating the system in a manner that requires frequent out-of-market actions to meet the system's reliability needs (which generates uplift) can mute investment signals. By improving the consistency between the markets, costs are shifted out of uplift and into prices where they provide better long-term signals.

5. Foundational Modeling Infrastructure

To facilitate efficient energy and ancillary services markets, the ISO must develop key capabilities that we briefly describe in this section. These are:

- State Estimator Model;
- Constraint Analysis Model; and
- Security Constrained Commitment and Dispatch Model.

State Estimator Model

State-Estimator (SE) Models are a primary tool used in reliability coordination of bulk power systems. The core of the SE model is a power flow model, which solves the power-flow equations using the latest topological network status (operating status of lines, transformers, breakers, etc.) as well as the latest data on line currents and bus voltages. The "estimation" includes current flow and voltages where no telemetry (real-time measurements) are available, as well as verification of other telemetry and topology. The SE model allows reliability coordinators to have confidence in both their topological model and real-time data, as well as produce the modeling inputs needed to optimally dispatch the system and manage congestion in the real-time market.

Operators that lack such a model will often not recognize as quickly that a transmission facility is overloaded or that a security violation is occurring. Additionally, it would be difficult to implement a nodal real-time market without first developing a SE model.

Constraint Analysis Model

Most centrally-organized markets also operate a Real-Time Contingency Analysis (RTCA) Model. The RTCA evaluates all single (N-1) contingencies and other pre-defined credible contingencies. The RTCA determines the post-contingency flows (i.e., the network flows that will occur after the most significant contingency). These post-contingency flows are then compared to the applicable ratings (e.g., Short-Term Emergency Ratings) to determine if the post-contingency flows are within or approaching their limits. This tool allows the ISO to establish limits for use in its real-time dispatch software.

Security Constrained Commitment and Dispatch Model

Market models perform numerous functions, but most critical are the commitment and scheduling decisions made prior to real time, and the real-time dispatch. For example, the MISO's Security-Constrained Commitment and Dispatch Model is normally executed the day before the operating day and is the basis for the day-ahead energy and ancillary services markets. The commitment and dispatch optimization secures all transmission constraints that are activated based on the results of a contingency analysis.

Many markets also have shorter-term security-constrained commitment and dispatch models that are executed within the operating day, typically optimizing over the next one to three hours, as discussed above in Section C.2. In real time, the dispatch models (Unit Dispatch Software or UDS) solve the least-cost dispatch (minimization of production costs) subject to operating constraints every 5 to 15 minutes.

D. Administrative and Other Attributes

1. Market Monitoring

Market monitoring and market power mitigation measures are essential to efficient and effective energy and ancillary services markets because they mitigate residual problems in market structure that have not been or cannot be mitigated through market design. Centralized wholesale markets, although highly competitive in many circumstances, can face transitory conditions that allow market power to emerge. This is especially true in systems with a dominant supplier or in systems where localized market power can arise due to congestion or local reserve requirements. But market monitoring is not limited to monitoring for market power. Market monitoring also involves reporting on market outcomes as well as identifying and proposing solutions to market design problems.

The U.S. Federal Energy Regulatory Commission (FERC) required broad-based market monitoring in centrally-organized markets in Order No. 2000. The Commission directed that market monitoring "should examine the structure of the market, compliance with market rules, behavior of individual market participants and the market as a whole, and market power and market power abuses" (U.S. FERC Order 2000, at 465).

We believe market monitoring is essential, particularly as new markets are implemented. Market monitoring generally involves a number of common functions across all centrally-organized markets, which include:

- Providing market design recommendations to address flaws in the market rules or improve the market's competitive performance;
- Monitoring the operation of the market to the extent it affects the performance of the market, including evaluating operator decisions that impact market outcomes;
- Reporting market information to market participants, including regular periodic reports to provide transparency and improve market confidence; and
- Identifying market conduct that may constitute market manipulation or abuses of market power.

When implementing new markets as is occurring in Alberta, it is particularly important that market outcomes and participant conduct are monitored closely. The experience in California in 2001 and other markets in the U.S. shows that market design flaws and market abuses can rapidly produce sizable costs for the market participants.

2. Market Power Mitigation

The Alberta market is concentrated and, historically, Alberta has relied to some extent on exercise of market power to raise energy prices. In absence of a capacity market, the energy prices alone needed to be high enough to sustain an adequate resource base. There are a number of drawbacks to relying on market power to provide these economic signals:

- Economic signals not based on underlying supply and demand are not as effective in motivating investment because they will disappear if entry or other factors cause suppliers to behave more competitively; and
- Market power is unlikely to produce efficient price signals – it may result in prices that understate or overstate the true value of energy in the short-run and the capital cost of generating resources in the long-run.

A well-designed market with energy, ancillary services, and capacity elements together with a mechanism to mitigate distortions associated with government intervention, is a superior means to provide these signals. Hence, as Alberta makes this transition, it should prioritize market power mitigation measures that will ensure competitive outcomes in the energy and ancillary services markets, as well as its new capacity market.

The chief goal of market power mitigation is to minimize intervention in the market while limiting suppliers who have market power to behavior that is consistent with competitive conduct. The conduct-impact approach is the best practice in applying mitigation in wholesale electricity markets. The conduct-impact test mitigation is a two-step process that uses "reference levels" to test both a participant's conduct as it relates to a competitive norm and its impact on the market. The first part of the conduct-impact test considers whether a unit's offer exceeds its reference level by some pre-established threshold. If the threshold is exceeded, then a second part of the test determines whether the conduct (i.e., the offer) has caused an impact on the market clearing price for energy or ancillary services or an impact on an uplift payment.

The conduct test is a straightforward comparison of the offer parameter to a reference level, which is an estimate of the competitive offer parameter. For example, the reference level for the energy offer parameter is an estimate of the participant's marginal energy cost, because the energy offer of a competitive supplier should be the unit's marginal cost. The reference level for an existing unit in the capacity market should reflect the costs of satisfying the capacity obligations and the going-forward costs of keeping the unit in operation that are not covered by the energy and ancillary services markets.

If the offer parameter exceeds the reference level by some threshold, e.g., $25 per MWh in the energy market, then the conduct test is failed and the impact test is performed. If the offer does not exceed the reference level by the threshold, then the impact test is not performed. The impact test compares the market outcome with the original offer and the offer replaced with the reference level. If market prices or uplift payment increase by some threshold, e.g., $25 per MWh, then the unit's offer is replaced (mitigated) by the reference level for the actual market run. The conduct-impact framework is often made more stringent (tighter thresholds) in areas where there is chronic congestion.

We use $25 per MWh as a threshold in the energy market example above. The reasonableness of a threshold will vary with the frequency of the potential market power concern. In markets that employ the conduct and impact framework, the threshold normally ranges from:

- *Roughly $5 per MWh*. Applied in chronically-constrained, highly-concentrated areas like the load pockets in New York City. Applying such a threshold elsewhere would be unreasonable because it would likely result in unjustified mitigation because it does not account for measurement errors and factors that are difficult to quantify in the reference levels.
- *The lower of $100 per MWh or 300 percent*. Applied in areas where market power is not a frequent concern, such as areas that are not chronically constrained in MISO. This threshold would likely be unreasonably high for Alberta because of the highly concentrated market structure.

Market power mitigation is also applied to the ancillary services market in the same fashion as in the energy market. The conduct-impact test is used to determine whether the offers of ancillary service products exceeds the reference value for that ancillary services product by some threshold (e.g., $10/MW) or whether any other offer parameter is modified significantly to withhold ancillary services. If the conduct test is failed for any of the offer parameters, then an impact test is performed to estimate whether the offer causes the clearing price to increase by some threshold (e.g., $10/MW).

Currently, mitigation of market power in Alberta, among other things, includes must-offer rules, information sharing prohibitions, and the use of offer caps and price floors in the energy and ancillary services markets. This will likely allow significant market power to be exercised at times. The conduct-impact framework protects the market from the exercise of market power, but at the same time prevents excessive intervention. It prevents excessive intervention because participants are only affected if they have a market impact, rather than permanent offer caps or market wide price caps. Such an approach could be automated as is the case in a number of the U.S. markets. However, it could also be implemented in a simpler, more manual process that would constrain resources to cost-based offers for a period of time once they fail the conduct test and an offline impact test.

III. Comments on Elements of the Proposed Capacity Market

The purpose of this report has been to identify best practices for energy and ancillary services market design. However, some aspects of the currently-proposed capacity market construct in Alberta can undermine effective energy market performance. The most objectionable of these design elements are the "capacity performance" rules, which create energy settlements outside of the energy market during shortage conditions. Another aspect of the proposed design is the forward auction design, which introduces unnecessary and unhelpful complexities. We discuss these two aspects of the market design below.

1. Capacity Performance Incentives Undermine Energy Market Efficiency

The proposed performance incentives are similar to ones proposed by ISO-NE and PJM. In these proposals, payments are made to or collected from resources based on their energy output during periods when the system is in shortage (typically an operating reserve shortage). A payment is made to suppliers providing energy in excess of their capacity obligation at these times. Conversely, a payment would be collected from suppliers that are producing less energy than their capacity obligation during these periods. Essentially, the performance incentives are a form of real-time shortage pricing intended to strengthen the incentive for suppliers to be available in real time when the system most needs their energy. However, this is not a sound approach because the proposal would create a shortage pricing regime for energy and reserves outside of the energy and reserves markets. This raises the following concerns.

As we introduced above, the energy and ancillary services spot markets are the most effective way to provide incentives for resources to be available and flexible during the operating horizon to meet demand at peak times efficiently. The incentive for resources to be available, provide needed flexibility, and follow dispatch instructions are all largely determined by real-time prices. If the system relies on mandated performance of capacity resources, the effective price paid to capacity resources that are supplying energy during peak times will be greater than other, non-capacity resources that are responding to the system needs. Relying on real-time prices would reward all resources that respond to the system needs.

If well-designed energy and ancillary services markets are in place, units will have a strong incentive to provide flexibility and availability at the time of system peak. This will naturally make its way into planning studies and, consequently, lead to reduced capacity requirements. This will save on overall cost of maintaining and operating the system over time. As a result, the focus on effective energy and ancillary services market design is critical.

Nonetheless, if the reform process retains performance penalties, they should be linked to real-time prices in order to allow the energy and ancillary services markets to provide efficient incentives. For example, Alberta could require that suppliers that have sold capacity be charged the shortage pricing premium (e.g., the portion of any system-wide energy price greater than $500). This would essential embed a forward energy contract for the shortage revenues within the capacity product. It is analogous to the capacity performance structures implemented in the U.S., except that it is linked directly to the shortage pricing in the energy market rather than to a shortage settlement that occurs outside of the energy market.

2. Prompt Capacity Markets are Superior to Forward Auction Markets

Capacity markets have been designed and implemented under two primary procurement timeframes:

- *Forward procurement*: The auction is conducted years ahead of the planning year (usually 3 years) to allow potential new resources to be offered. Typically, the auctions procure capacity for one planning year on behalf of all of the load. This is not a typical forward commodity market where procurement is voluntary and the prices clear best on expectations of the spot price for the commodity.
- *Prompt procurement*: The auction is conducted only a few weeks or months in advance of the planning year. The price will clear based one the actual supply and demand for the planning year and new resource participant once they have entered the market.

We have monitored and evaluated the performance of forward capacity markets and prompt capacity markets in the U.S. Based on our evaluation of these markets, we do not believe forward capacity markets are a best practice in the design of capacity markets. They can adversely affect decisions to invest in new resources and retire existing resources.

Adverse Effects on New Investments. Under a forward procurement, a competitive offer by a new resource would be close to the net cost of new entry (CONE). If they do offer competitively, then the market will clear at an efficient price when new resources are needed to satisfy the ISO's planning needs. However, new resources are not likely to make competitive offers near net CONE for at least two reasons:

- New resources clear for only one year – less than three percent of the life of most resources. This may cause some investors to inflate their offers since no revenue after the first year is guaranteed and future revenue uncertainty may be high.
- New resources face substantial risk of completing its entry within three years so many developers commit to entering prior to the capacity auction. This may cause some investors to incur a substantial fraction of its costs prior to the auction, creating the incentive to offer well below their net CONE.

The first of these two scenarios prompted some U.S. RTOs to establish revenue "lock-in" provisions to ensure that new suppliers submit offers close to net CONE. Lock-in provisions enables a new resource that clears to elect to be guaranteed the clearing price for a certain number of years. For example, ISO-NE allows a new resource to lock-in the clearing price for up to seven years. Unfortunately, these provisions are only partially efficient and generally raise costs by discriminating against existing resources. This discrimination causes new resources to inefficiently displace existing resources.

The second scenario is likely more common, in part because of the risk the new supplier faces of not completing its project by the start of the planning year. To address this risk, it is rational for the investor to begin incurring costs and securing permits well before the auction. Additionally, because the new unit's return on investment will almost entirely depend on the subsequent revenues after year one, these expectations should dominate the investor's decision (which is, therefore, likely to be made prior to the auction). Incidentally, this second scenario describes how investors make new investment decisions in prompt capacity auctions -- they form a long-term expectation (and/or sign long-term contracts) and make the decision to invest based on the expectation. To the extent investment decisions in both forward and prompt auctions are based on future expectations, the forward market does not offer any benefits over the prompt auction from the perspective of facilitating new investment.

Therefore, we do not find that procuring capacity years in advance provides any advantage to procuring capacity through a prompt capacity market. In fact, given the much greater supply and demand uncertainty that exists in the forward procurement timeframe, we believe that forward capacity markets are less likely to facilitate efficient investment and capacity prices.

Adverse Effects on Retirements. The other long-term decision that is facilitated by the capacity market is the retirement decision – a resource will retire if it does not expect to earn enough revenue in the capacity and energy/ancillary services markets to pay for the fixed going-forward cost of staying in service. While we do not believe mandatory forward procurement improves the new investment process, we believe it harms efficient retirement decisions. In a mandatory forward procurement, suppliers must determine whether old resources will continue to operate for an additional four years (three years plus the planning year). This is not optimal for units facing physical or regulatory uncertainty. Not surprisingly, almost all units on the brink of retirement are very old and face substantial uncertainty.

In contrast, a well-functioning prompt auction allows existing suppliers to make rational economic decisions regarding when to suspend or retire a unit. In prompt procurement markets, old units can operate until they suffer equipment failure and can make efficient decisions to mothball or retire based on the auction.

Other Benefits of Prompt Auctions vs. Forward Auctions. Given that forward capacity procurement provides few if any benefits over a prompt auction, it is useful to recognize that there are a number of benefits of prompt auctions:

- There is very little uncertainty regarding the true capacity needed since AESO would not be required to forecast the demand three years in advance.

- Prices will always reflect the actual supply and demand in the market. For example, if a resource suffers a catastrophic failure and is out of service for an extended period, the supply will be reduced in the prompt auction.
- There is very little exposure to the risks that the entry of new resources will be delayed because new resources begin selling into the auction after they become operational. Such delays have been a substantial problem in the forward markets in the U.S.

Hence, having monitored both prompt and forward capacity markets in the U.S., we conclude that prompt capacity markets are the superior alternative.

3. Out-of-Market Capacity Purchases

Alberta is developing a capacity market to provide efficient economic signals to guide market participants' investment and retirement decisions. At the same time, it is seeking to substantially change the resource mix by contracting for a large amount of renewable energy resources and retiring its coal-fired resources over the next 12 years. These changes will largely be accomplished through out-of-market contracts.

Out-of-market capacity procurement is problematic to the extent that it artificially alters the supply and demand balance, which can significantly distort prices and other market outcomes. This undermines the ability of the market to facilitate efficient long-term decisions by market participants that must rely on their expectations of market outcomes when deciding whether to invest in new resources, make capital improvements to existing resources, build new transmission facilities, or make other long-term decisions. Hence, government intervention in the market undermines these long-term decisions by increasing the uncertainty of future market outcomes and the associated risk to long-term investment.

However, we recognize that the current U.S. markets do not fully price many externalities associated with producing and consuming electricity, including emissions. Therefore, contracts that include embedded subsidies for clean energy technologies may be justified by the value of the externalities they reduce. Nonetheless, they can still create risk for market participants that own or invest in conventional resources.

While subsidized entry in itself is not necessarily problematic, it is imperative to develop processes or provisions to protect the economic signals and performance of the energy and capacity market in Alberta. For example, if subsidized entry simply displaces non-subsidized entry in similar quantities, it would not have significant adverse effects on the supply-demand balance. To develop such provisions, one must recognize that the problem is largely one of coordination and avoiding sustained disequilibrium conditions (i.e., capacity surpluses caused by the out-of-market contracts).

In evaluating alternatives for achieving its public policy goals, we recommend that Alberta consider the following objectives:

- Protecting existing and new participants' market expectations by minimizing artificial, policy-induced surpluses created by out-of-market purchases and their effects on prices;
- Preventing the inefficient entry of new conventional resources, given the entry of the subsidized resources. In other words, making sure the mechanism does not clear new resources when they are not needed given the out-of-market entry.
- Facilitating the desired entry of the renewable resources by Alberta while achieving the first two objectives; and
- Minimizing excess costs to be borne by Alberta's customers.

ISO-NE is developing a proposal to achieve these objectives that would pay suppliers to retire existing resources in quantities that would match the renewable resources that are entering the market.[4] We recommend that Alberta consider a process or market-based solution that would accomplish a similar outcome. By requiring that entry and exit be coordinated, private investors and other market participants will have more confidence in the market and, therefore, make more efficient long-term decisions regarding conventional resources. Ultimately, this will lower costs to the consumers in Alberta.

4. Seasonal Capacity Procurements

Alberta is planning to implement a capacity market that would clear on an annual basis. However, both the demands of the system and the available system supply change substantially from one season to the next. Hence, procuring capacity on a seasonal basis can be valuable and we believe that this is a best practice in the context of capacity markets. This would produce the following benefits:

- The revenues would be better aligned with the value of the capacity;
- Relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder seasons;
- Resources retiring mid-year would have more flexibility to retire mid-year without having to procure significant replacement capacity to satisfy post-retirement capacity obligations; and
- The qualification of resources with extended outages can better match their availability.

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4 The proposal is: Competitive Auctions with Sponsored Policy Resources (CASPR), a description of which can be found at: https://www.iso-ne.com/committees/key-projects/caspr.

5. *Implementation Schedule*

Alberta proposes a capacity market under an aggressive time table which may undermine the goal of improving the efficiency and effectiveness of the wholesale markets. This is because of the close link between the energy and ancillary services markets and the capacity markets. The aggressive schedule creates the risk that the critical market design features that would establish an efficient market design for Alberta will be left undeveloped or otherwise discarded for the sake of expediency. Our experience in market design in the US markets is that any significant reform in one aspect of the market should integrate necessary reforms in other markets in order to achieve a unified design that promote efficient overall outcomes.

IV. About Potomac Economics

Potomac Economics is a leading provider of economic consulting services to the electricity and natural gas industries. Our primary area of business is monitoring and evaluating the design and performance of competitive wholesale electricity markets. Our assignments involve markets in the United States, as well as clients in Canada, Europe, and South America. We have played a key role in developing the major centrally-organized wholesale electricity markets in the United States and have had strong influence in state and federal policy making in electricity markets.

Potomac Economics operates out of its primary offices in Fairfax, Virginia and offices located at the MISO in Carmel, Indiana and at ERCOT in Austin, Texas. The Company employs more than 30 professionals, consisting primarily of economists, engineers, programmers, and IT professionals. We offer services in a variety of areas, including monitoring centrally-organized wholesale markets, monitoring transmissions system access, and advising international clients on market reform.

Centralized Wholesale Market Monitoring and Market Design

Potomac Economics is the leading provider of market monitoring and evaluation services for centrally-organized electricity markets in the United States. We provide independent market monitor services for the Midcontinent ISO, New York ISO, ISO-NE, and ERCOT (Texas). Potomac Economics played a key role in designing, testing, and implementing each of these markets.

As the Independent Market Monitor for these markets, Potomac Economics is responsible for evaluating the performance of the markets, recommending design improvements, reviewing the operation of the markets, and monitoring the conduct of market participants to identify attempts to exercise market power or manipulate the market.

Market Monitoring. As the independent market monitor for four of the seven competitive electricity markets in the U.S., Potomac Economics is tasked with ensuring that they perform competitively and efficiently. This broad and unique experience has made Potomac Economics the world's leading expert in nodal electricity markets.

Potomac Economics' market monitoring expertise and capabilities include:

- A detailed and thorough understanding of nodal electricity markets and the associated market software systems used to operate the markets.
- In-depth knowledge of ISO reliability requirements and the operating procedures invoked to satisfy these requirements.

- Insight regarding the market design, trends, and operation of a broad array of ISOs that we monitor.
- Extensive expertise on transmission pricing and cost-recovery provisions employed in the ISO markets.
- A detailed understanding of settlement rules, including guarantee payments and other uplift rules, cost allocation rules, and other provisions that affect participants' incentives.
- Potomac Economics' proprietary market monitoring system, which includes software to:
  - ✓ Receive, store, screen, and analyze market data;
  - ✓ Develop screens, indices, and economic models to assess potential withholding strategies; and
  - ✓ Produce automated market monitoring reports on market outcomes and market behavior;
- The development of production-grade software to implement real-time market power mitigation measures.

Effective market monitoring requires a complete and detailed understanding of the market design, the software employed to operate the market, the operating procedures employed by the market operator, and the incentives and behavior of the market participants. Potomac Economics developed this expertise over almost 20 years as the leading market monitor in the United States.

Market Design. Since a large component of the market monitoring role involves evaluating and recommending improvements to the market design, Potomac Economics continuously addresses nodal market design issues. Although nodal markets may appear similar at a very high level, they have been implemented very differently in each of the market we monitor in the U.S.

The different detailed design choices made by the market in the U.S. play a critical role in the performance of these markets and the benefits they provide. These design differences include variations in product definitions, modeling parameters, pricing rules, operating procedures, dispatch timeframes, transmission pricing methods, cost allocations, resource commitment optimizations, day-ahead market structures, and settlement rules. Potomac Economics has extensive experience evaluating and providing advice on all of these design differences, both for markets we monitor and for other competitive wholesale market operators in the U.S. and around the world.

We also have been closely involved in the design and implementation of nodal markets as markets transitioned from pre-nodal structures. In MISO, for example, the pre-nodal market was a regional bilateral market relying on open-access transmission rules to facilitate trading. ERCOT was a zonal market, before transitioning to a nodal market. In both cases, we advised the market operators and regulators on key design issues and evaluated the benefits of transitioning to a nodal market framework.

Open-Access Transmission Tariff Monitoring

Potomac Economics provides independent monitoring services to help ensure full, nondiscriminatory access to transmission capability. We have performed independent transmission monitoring of six utilities under FERC-approved market monitoring plans.

The objective of this monitoring is to ensure full access to transmission service, which is essential for promoting competition in wholesale electricity markets. This involves evaluating posted available transmission capability, transmission reservation refusals, and the causes of transmission curtailments. In addition to monitoring for anticompetitive conduct by the transmission provider, we also seek to identify improvements in transmission provider processes and assumptions that would increase transmission availability to wholesale market participants.

International Consulting

Potomac Economics provides economic consulting services to international clients on a wide range of wholesale electricity market monitoring and market development issues.

We have provided consulting services to countries in South East Europe, the Black Sea Region, Latin America, and Canada. Our work has been far ranging, including transmission access issues, market monitoring, market monitoring software applications, and wholesale market design and market development. This work has also involved complex litigation concerning open-access transmission tariff issues in Quebec and a market price assessment project in Manitoba.

We have worked with USAID and the National Association of Regulatory Utility Commissioners on projects in South East Europe and the Black Sea Region where we assisted regulators in reforming wholesale market electricity in accordance with European Union Electricity Directives. This development work has involved cross-border transmission access, competitive energy market design, ancillary services market design, and market monitoring.

