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Market Design for the 21st Century: Recommendations for Alberta's Power Market

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POLICY RECOMMENDATIONS:

- Alberta's power market needs to adapt to a changing resource mix to ensure affordability and reliability while decarbonizing.
- We recommend adding a mandatory forward energy-contracting mechanism set at the shape of system load to ensure reliability and average price stability while maintaining proper incentives at the margin.
- We recommend modernizing Alberta's energy-only market with (1) locational pricing; (2) multi-settlement markets; (3) new co-optimized ancillary service markets, such as fast frequency response; and (4) deployment of interval meters capable of reading consumption at the sub-hourly level to encourage flexible demand in the market.

EXECUTIVE SUMMARY

Alberta's electricity system is in transition. From a system dominated by coal generation less than a decade ago, Alberta's electricity is now largely supplied by natural gas generation with an increasing share of variable wind and solar energy. Falling clean technology costs, federal clean electricity regulations and a rising carbon price will further shift Alberta's supply mix away from unabated fossil fuels into one more reliant on a mix of renewables and new technologies, such as carbon-captured natural gas, small modular nuclear reactors and hydrogen generation.

In this report, we consider future market designs fit for purpose for this changing electricity mix. We assess market design options based on the criteria of reliability, affordability, investor confidence and complexity. At the heart of the matter is the question of which approach is best able to deliver reliable and low emission supply at low cost to Alberta consumers.

Importantly, we consider market designs suitable for the changing nature of 21st century grids with more variability on the supply side and more flexibility on the demand side. If the grid of the past involved forecasting demand and dispatching supply, increasingly grids of the future will flip this upside down by forecasting supply and dispatching demand. Alberta's market design needs to both reflect and enable this new reality.

One might ask why electricity markets require a regulatory intervention to ensure reliability. Consumers want to be able to withdraw electricity from the network when they need it, just like other goods and services. But it is unclear why electricity is so fundamentally different from other products that it requires paying suppliers for production capacity to exist. For example, consumers want cars, but they do not pay for automobile assembly plants. They want point-to-point air travel, but they do not pay for airplanes. They want a loaf of bread, but they do not pay

for the existence of a bakery. All of these industries are high fixed-cost, relatively low marginal-cost production processes, similar to electricity supply. Nevertheless, all of these firms earn their return on capital invested by selling the good that consumers want at a price above the variable cost of producing it. Clearly, cars, air travel and bread are in many ways essential commodities, yet there is no regulatory invention that ensures there is sufficient production capacity for these products to meet demand.

So what is different about electricity markets that necessitates a long-term resource adequacy mechanism, such as a capacity mechanism? The answer lies in how short-term markets for these products operate relative to that for wholesale electricity. This difference is the result of the regulatory history of the electricity supply industry and the technology of electricity metering, resulting in a reliability externality.

This reliability externality exists for two reasons. The first is due to a cap on the short-term market-clearing price for electricity in Alberta. Price caps limit the potential downside to electricity consumers from purchasing wholesale energy from the short-term market, leading to under-procurement in forward markets. The second reason is that in the event of insufficient supply, curtailments — also known as rolling blackouts — are applied randomly. Consumers who have purchased sufficient supply in the forward market to meet their real-time energy demand are equally likely to be randomly curtailed as those who have not procured adequate amounts of energy in the forward market. For this reason, consumers have an incentive to under-procure their expected energy needs in the forward market.

This reliability externality can be resolved in several ways. First, a capacity mechanism can be applied. This involves imposing capacity procurement obligations on load-serving entities and providing capacity payments to suppliers. Second, price caps in the energy market can be raised to a sufficiently high level that does not offer the same level of price protection in periods of scarcity and are likely to result in voluntary reductions in demand based on consumers' willingness to pay, rather than rationed electricity. And third, standardized forward contracts for energy purchased are mandated to ensure that all electricity consumers procure sufficient levels of supply in forward markets far enough ahead of delivery for suppliers to ensure that supply equals demand under all possible variable renewable supply conditions.

For long-run resource adequacy, we recommend neither a capacity market nor the existing energy-only market with only slight modifications. Neither delivers a suitable trade-off between reliability and affordability, neither offers attractive conditions for investment, and in the case of capacity markets there is a significant increase in complexity. Instead, we recommend a standardized forward energy-contracting approach, which combines the energy-only market with mandated forward contracting (Wolak 2022). This solution most directly resolves the reliability externality, doing so at low cost and with minimal complexity and regulatory intervention.

To be clear, the standardized forward energy contract should not be confused with contracting directly with power plants, i.e., power purchase agreements. Nor is it a full requirements contract for individual load-serving entities. A key feature that distinguishes our approach is contracts that settle on average system load shapes. By separating contract settlement from actual deliveries from generators and draws from individual loads, the proper incentives at the margin are maintained (Shu and Mays 2023). It also ensures technology neutrality and avoids placing the onus on the market operator to compare contract costs across resources with vastly different production and value profiles.

In addition to long-term resource adequacy concerns, Alberta's changing electricity mix requires changes to short-term markets to ensure reliability and security of supply during operations. We recommend changes to Alberta's energy and ancillary service markets to reflect the greater prominence of variability on the supply side and more involvement from the demand side. Specific recommendations include:

- Locational pricing to better align marginal prices with true system conditions and transmission constraints, and to encourage better siting decisions for new facilities;
- A multi-settlement market with the introduction of a day-ahead market to better co-ordinate dispatchable generation resources with an increasing share of variable generation resources;
- New ancillary service products, such as fast frequency response, to provide the services Alberta's system requires as the resource mix evolves; and
- We encourage the widespread deployment of interval meters capable of recording customers' consumption at the hourly or sub-hourly level so that final demand can respond to real-time price signals from the short-term energy market.

There is no perfect market design. There are only better market designs that are specifically adapted for, and evolve with, changing electricity systems. With Alberta's growing share of variable renewable energy and rapid shift towards lower emissions generation, the standardized forward energy-contracting approach coupled with changes to short-term operations, including more involvement from the demand side, can improve reliability at lower cost than the alternatives.

1. GOALS OF THIS REPORT

This report is intended to provide advice on the question of the future variable renewable-dominated market design for wholesale electricity generation in the province of Alberta. We consider this question based on three criteria — investor confidence, reliability and affordability, as well as a fourth criterion — complexity, in the context of a rapidly decarbonizing electricity system.

- **Investor confidence.** We assess the criterion of investor confidence based on two metrics: (i) the volatility of revenues and (ii) the ability to smooth revenues through the use of hedging instruments or other contract measures. One of the motivations for a capacity market is to shift some generator revenue from the volatile energy market into fixed capacity payments with, at a minimum, annual tenure. We discuss in section 5 to what degree the capacity market and the energy-only market provide a conducive environment for investment.
- **Reliability.** Reliability comes in two forms. The first is security of short-run supply. This includes the ability to withstand short-term supply events (sudden loss of a generator) or extreme demand spikes. The second is long-term resource adequacy. This is the market's ability to attract sufficient timely investment to ensure adequate supply to meet demand in the future. Again, we consider how a capacity market addresses the issue of reliability, and the potential risks and implications of remaining on an energy-only market.
- **Affordability.** As an essential service, one whose usage does not rise at the same rate as household incomes (lower income households spend a larger share of their budget on electricity than higher income households), affordability is understandably a key criterion for electricity market design. In theory, a capacity market does not necessarily create a purely additional cost. It is intended to shift revenue from periods of scarcity in energy-only markets to fixed capacity payments. However, the risk of over-procuring capacity, or procuring less valuable capacity, can create an upward bias in total costs with a capacity market as compared to energy-only. We discuss this in further detail in the sections that follow.
- **Complexity.** We have added this criterion as it is an important consideration when designing an electricity market. The market needs to be complex enough to reflect the physical limitations of the electric system to ensure efficient dispatch and location decisions; however, a challenge with a capacity market is the degree to which many decisions are set by an administrator (e.g., capacity eligibility, firm capacity values, capacity demand curve parameters, etc.). This leaves scope for complexity in design, frequent updating and persistent regulatory uncertainty, as has been the case in Eastern U.S. capacity markets.

2. BACKGROUND AND CONTEXT

The electricity landscape in Alberta is changing rapidly. A shift in its supply mix — from coal to gas dominated by a growing share of variable renewables — and policy changes can only be described as transformative to Alberta's long fossil-dominated system.

These changes raise questions as to the viability of the existing market design to deliver on the goal of reliable, affordable and increasingly clean electricity. Here, we recap recent policy and system changes to provide context to our recommendations that follow.

In 2015, the Alberta government under then-premier Rachel Notley announced several policies as part of its Climate Leadership Plan that would have material effects on Alberta's electricity market. The notable policy actions included: (i) phasing out all coal generation by 2030; (ii) increasing the stringency of carbon pricing on large emitters; and (iii) a target of 30 per cent

renewable generation as a share of total generation by 2030 with an accompanying renewable procurement auction to achieve this goal.

2.1 COAL PHASE-OUT

The Notley government set a hard deadline of 2030 by which either all coal generation would be phased out, or carbon capture and sequestration technology would be used to eliminate emissions. This policy directly affected six of Alberta's 18 coal power plants, as 12 were already scheduled to retire prior to 2030 based on the federal government's 50-year life policy.

The Alberta government compensated the owners of the six affected power plants with payments totalling approximately C\$94 million per year over 13 years. This amount was meant to reflect the truncated book value of the assets, less any remaining residual value.

Though Jason Kenney's government discussed during the campaign the possibility of rescinding the coal phase-out, no legislative action was taken to undo this policy. Further, the federal government set in place a 2030 phase-out rule which would likely be imposed in the lack of, or with later-dated, provincial legislation. As of late 2023, there were only two coal generating units left in Alberta, with both expected to be converted to natural gas by early 2024.

2.2 CARBON PRICING

The Notley government made several changes to Alberta's carbon pricing system, all of which increased its stringency as it applies to coal generation. First, the government increased the carbon price and coverage ratio in the existing Specified Gas Emitters Regulation (SGER). This increased the effective carbon price paid by a typical coal power plant from roughly \$1.80 per MWh to \$6 per MWh. Second, and more significantly, the government changed the way in which benchmarks were set for large emitters. Rather than facility-specific benchmarks, the Carbon Competitiveness Incentive Regulation (CCIR) set out sector-wide performance benchmarks for emissions. For the electricity sector, this was set as "good-as-best-gas," or roughly 0.37 tonnes of CO₂ equivalents per MWh. Generators emitting above this threshold were exposed on the difference between their actual emissions intensity and the common 0.37 t/MWh benchmark, and those below would receive emissions performance credits based on their difference to the benchmark as well.

This benchmark change had two large impacts. First, renewables and other zero-emission technology would be eligible to receive emissions performance credits, which could be bilaterally traded to companies with compliance obligations. At a \$30-per-tonne carbon price, the notional value of these credits was roughly \$11 per MWh on all zero-emission generation. Second, the change in carbon pricing had a large effect on carbon costs for coal plants, increasing the effective price per MWh from roughly \$6 in the last stage of SGER, to \$18 per MWh with a \$30-per-tonne carbon price. The result was a significant reduction in coal generation in 2018, the year CCIR was implemented (Figure 1). This is due to coal plants operating less frequently due to their higher costs, as well as several coal plants being suspended (or mothballed) at the start of 2018.

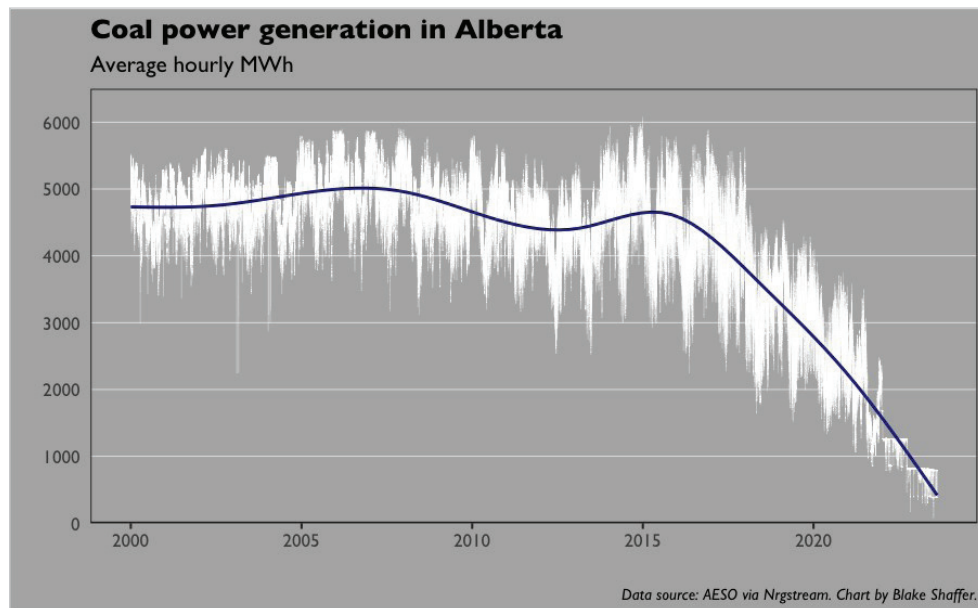
In 2020, the Kenney government replaced CCIR with a new system called the Technology Incentive Emission Reduction (TIER) fund. For large emitters outside of the electricity sector, the preliminary design significantly weakens the stringency of carbon pricing, replacing sector-wide benchmarks with individual facility-level benchmarks. However, for electricity, TIER follows the structure of CCIR in using a good-as-best-gas sector-wide benchmark. The main difference between the systems is where revenue from carbon pricing will be directed. As of October 2023, the TIER price had followed the federal carbon price and was \$65 per tonne.

2.3 RENEWABLES TARGET

The Notley government set a target of 30 per cent of total generation from renewable sources by 2030. To achieve this target, the government directed the Alberta Electric System Operator (AESO) to design the Renewable Electricity Program (REP), an auction-based mechanism for long-term competitively selected supply contracts with renewable generation developers.

The REP ran for three rounds, with AESO procuring just over 1,300 MW of wind capacity at an average price of roughly \$38 per MWh (3.8 cents per kWh). For a summary of the Renewable Electricity Program details and performance, see Hastings-Simon et al. (2022).

Figure 1: Declining Coal Power Generation in Alberta



While the Kenney government cancelled future rounds of the REP, renewables development has continued rapidly in the province driven by (a) low costs of supply, (b) high power prices and (c) a corporate market for risk-reducing long-term power purchase agreements. As of October 2023, there was a total of 5,145 MW of combined wind and solar capacity in Alberta, up from only 1,888 in 2020 (Figure 2).

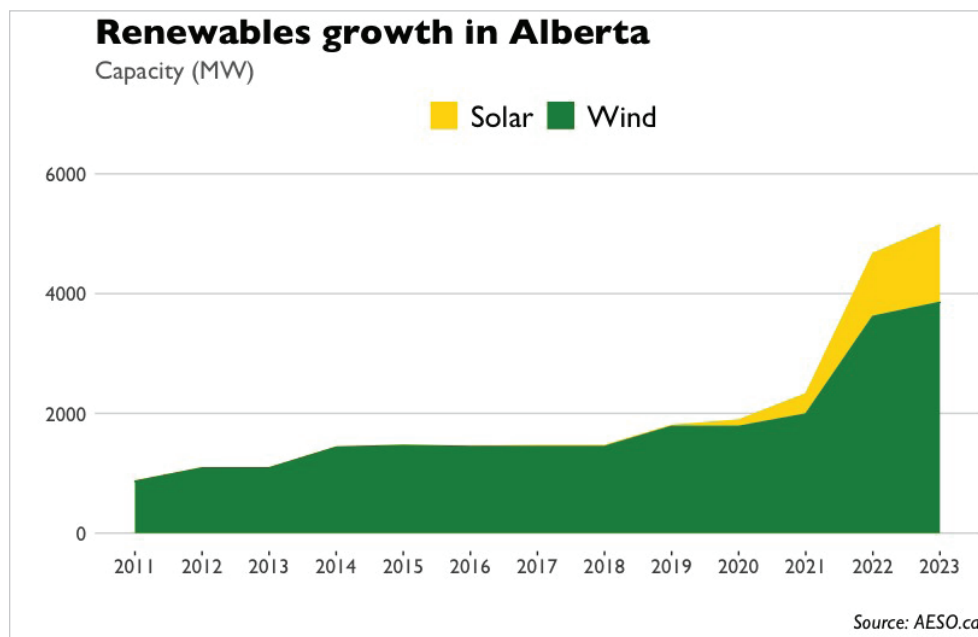
More recently, Danielle Smith's government announced a seven-month moratorium on renewable project approvals by the Alberta Utilities Commission (AUC). The pause was predicated on concerns over reclamation liabilities, land use and electric reliability. Absent an extension of the moratorium, or onerous costs imposed on renewables in response to the AUC investigation, we expect continued large growth of wind and solar in Alberta.

These policies partly motivated AESO's decision to recommend the addition of a capacity market, which the Notley government accepted in November 2016. In its report, AESO cited the changing supply mix — the elimination of coal and increase in variable renewable energy — as part of the reason to recommend a capacity market (AESO 2016). AESO favoured a capacity market to ensure system reliability and provide existing and new generation with revenue sufficiency and stability. The capacity market was preferred over other options which would have been significant departures from the market-based system currently used in Alberta. In 2019, the Kenney

government held a 90-day market design review that ultimately chose to rescind the capacity market development and revert to the status quo energy market.

The question today is whether the required investments to replace the declining coal share and manage increased intermittency can be achieved under the energy-based paradigm while maintaining a desired level of reliability, or if changes to the market design are required. This question is not unique to Alberta. In 2013, the Electric Reliability Council of Texas (ERCOT) faced a similar decision as Alberta faces today. At the time, reserve margins were expected to be low, and concerns were raised as to the electric system's reliability. Ultimately, ERCOT chose to remain energy-based, but with a significant increase in its offer price cap (to \$9,000 per MWh) and an administratively set operating reserve demand curve that is triggered under system-wide scarcity conditions.

Figure 2: Increasing Wind and Solar Capacity in Alberta



Market operators in other parts of the U.S., particularly in the northeast — in PJM Interconnection, ISO New England (NE-ISO) and the New York Independent System Operator (NYISO) — continue to operate centralized capacity markets. It is important to emphasize that these markets have significantly less variable renewable generation capacity shares than ERCOT or the California ISO.

A recent policy development in Canada adds further urgency to market design considerations. The federal government has proposed the Clean Electricity Regulations (CER), which place stringent physical performance standards on emitting generation after 2035 with limited exemptions for newer plants (20-year end-of-prescribed-life), behind-the-fence co-generation and infrequently run (fewer than 450 hours per year) peaker plants. While we avoid a detailed discussion of the CER here, we note changes are likely needed to enhance the flexibility of the draft regulations to accommodate Alberta's challenge (Leach and Shaffer 2023).

3. TYPICAL MARKET STRUCTURES TO PROVIDE LONG-TERM RESOURCE ADEQUACY

We start our discussion of long-term resource adequacy by providing an overview of three main options, the first two (capacity markets and energy-only markets) being the dominant paradigms in restructured electricity markets. We discuss each of these options in turn and our rationale for our preferred third approach in the sections that follow.

3.1 CAPACITY MARKETS

With a capacity market, the system operator can, at least notionally, procure an explicit amount of capacity to supply the system. However, there are several challenges in doing so. First, the system operator must determine what is and is not eligible capacity, and its rated amount. This can involve seasonal factors, as well as historical and expected performance factors of individual units, and is not guaranteed to reflect actual available capacity during times of need. Second, the system operator must determine how much capacity to procure, i.e., the demand curve for capacity is administratively determined, and in doing so the system operator may be biased towards over-procurement.

Defining the firm capacity of a dispatchable thermal generation unit is relatively straightforward. A first step is to use the nameplate capacity of the generation unit multiplied by that unit's availability factor.¹ Variable wind and solar resources are not dispatchable and can only produce when the underlying renewable resource is available up to the maximum amount of wind or solar energy that these generation units can harvest. Different from dispatchable thermal generation units, there is a high degree of contemporaneous correlation in the amount of wind and solar energy available in a given geographic market.² This makes it extremely challenging to define credible firm capacity values for wind and solar generation resources in the case of California (Wolak 2022).

Moreover, procuring capacity to achieve higher reserve margin levels in the system depresses energy prices, leading to more dependence on revenues from the capacity market. In the long run, generators may become ever more dependent on capacity revenue, while the energy market sets lower and less variable prices and loses its ability to reward generation units for supplying more energy and for consumers to reduce their demand during stressed system conditions.

Last, while a capacity market does shift some volatile energy market revenue to annual fixed-capacity payments, it is unlikely to boost investor confidence and resulting investment for several reasons. First, as mentioned above, at higher reserve margins revenues from the energy market are likely to fall, leading to more reliance on revenue from annual capacity auctions, with the added single-event risk of missing a contract award. Second, the capacity contract terms are short relative to the lifespan of a generator and likely insufficient for financing new investment. Third, capacity markets raise the prospects of continued regulatory intervention in the markets as rules are tweaked, increasing uncertainty for investors as to future cash flows and thus raising required returns to invest capital.

¹ The availability factor of a generation unit is the number of hours it is able to produce electricity over a certain period, divided by the number of hours in that time period.

² There is an extremely high degree of contemporaneous correlation between the energy produced each hour at solar and wind locations in California (Wolak 2016).

3.2 ENERGY-ONLY MARKETS

A price-capped energy-only market maintains the fundamental problem of reliability.³ Given the price cap, consumers will under-procure in forward markets, knowing energy will be provided at or below the price cap in short-term markets or random curtailment will occur during stressed system conditions that they can fully or partially avoid. Because the physics of electricity delivery in most distribution grids requires all customers in a portion of the grid to receive electricity if one customer receives service, without additional technology it is impossible to curtail the consumption of specific customers to the amount of energy they purchased in the forward market during that hour.

Paradoxically, the effort to minimize high-priced hours through an offer cap can increase average costs to consumers because firms under-invest in generation, which increases both the hours when higher cost units must operate and the opportunities for large suppliers to exercise unilateral market power. The volatility of market revenue ensures that firms will require higher expected returns to enter the market.

3.3 MANDATED LONG-TERM ENERGY CONTRACTING

The energy-contracting approach retains the energy-only market but with the added requirement of mandated levels of forward contracting for energy. Load-serving entities would be required to procure a certain percentage of their expected energy demand in advance on a rolling basis, with the percentage of final demand covered increasing closer to the delivery date of the contract. Generators, as well as financial intermediaries, would offer into the standardized market for forward contracts for blocks of energy on an ongoing basis. This approach has several advantages.

First, forward contracts provide more cost certainty for consumers for the bulk of their demand while maintaining the fidelity of the short-term energy market price to signal the need for marginal increases and decreases in production from specific generation resources. Consumers would maintain the incentive to respond to short-term price signals, optimizing their consumption away from high-priced to low-priced hours as they see fit or collectively through demand-response aggregators.

Second, forward contracts offer more revenue certainty for generators over longer tenures than annual capacity contracts. This reduces risk to new investment, lowering hurdle rates for new generation and encouraging entry at appropriate price levels. A higher level of forward contracting also reduces the incentive for suppliers to exercise market power in the short-term market (Wolak 2000).

Third, energy contracting involves far less complexity than a capacity market as a resource adequacy mechanism. Rather than a regulator determining eligible capacity and setting the amount of firm capacity purchased, generators determine the mix of generation capacity needed to meet their energy supply obligations given the forward contracts they have sold and bear the risk of doing so. Far fewer administrative interventions are required under this approach, leading to less regulatory uncertainty for investors.

Finally, a mandated, standardized-forward-contract-for-energy approach to long-term resource adequacy eliminates the need to set firm capacity values for wind and solar resources. This mechanism encourages cross-hedging between variable renewable resources and dispatchable thermal resources to ensure that the appropriate mix of dispatchable resources exists in a market with significant wind and solar resources (Wolak 2021b).

³ As the experience of ERCOT's market during February 2021 demonstrated, a higher price cap does not eliminate the reliability externality. The ERCOT market had a price cap of \$9,000 per MWh during this time. A higher offer cap only makes random curtailments less likely to occur, but when they do, the economic and health costs can be enormous.

4. WHY IS A LONG-TERM RESOURCE ADEQUACY MECHANISM NECESSARY?

One might ask why electricity markets require a regulatory intervention to ensure reliability. Consumers want to be able to withdraw electricity from the network when they need it, just like other goods and services. But it is unclear why electricity is so fundamentally different from other products that it requires paying suppliers for production capacity to exist. For example, consumers want cars, but they do not pay for automobile assembly plants. They want point-to-point air travel, but they do not pay for airplanes to exist to provide this service. They want a loaf of bread, but they do not pay for the existence of a bakery. All of these industries are high fixed-cost, relatively low marginal-cost production processes, similar to electricity supply. Nevertheless, all of these firms earn their return on capital invested by selling the good that consumers want at a price above the variable cost of producing it. Clearly, cars, air travel and bread are in many ways essential commodities, yet there is no regulatory intervention that ensures there is sufficient production capacity for these products to meet demand.

So what is different about electricity markets that necessitates a long-term resource adequacy mechanism? The answer lies in how short-term markets for these products operate relative to that for wholesale electricity. This difference is the result of the regulatory history of the electricity supply industry and the technology of electricity metering. The limitation on the level of short-term prices and the way that supply shortfalls are dealt with in wholesale electricity markets creates what has been termed a reliability externality that requires a regulatory intervention to internalize (Wolak 2013).

In the market for automobiles, air travel and even bread, there is no explicit prohibition on the short-term price of the good rising to the level necessary to clear the market. Take the example of air travel. Airlines adjust seat prices on a flight over time to try to ensure that the number of customers travelling on that flight equals the number of seats flying. This can result in very different prices for a seat on the same flight, depending on when the customer purchases the seat. A customer who waits too long to purchase a seat faces the risk of an infinite price in the sense that all of the seats on the flight are sold out. This ability to use price to allocate the available seats also allows the airline the flexibility to recover its total production costs. Airlines can set low prices to fill flights with low demand and extremely high prices on other flights, or at other times for the same flight, when demand is high.

The ability to use the short-term price to manage the supply-and-demand balance in the electricity supply industry is limited first by the fact that all North American wholesale electricity markets have offer caps that limit a supplier's offer price into the wholesale market and/or a price cap that limits the magnitude of the eventual market-clearing price. In addition, historically, virtually all electricity supply industries did not have interval meters that can record a customer's 15-minute or hourly consumption throughout the month. Even today, most regions only have mechanical meters that compute the customer's consumption for the entire month as the difference between two consecutive meter readings. With monthly or bimonthly reading of mechanical meters, it is impossible for the utility to know how much electricity a customer consumed in a given hour of the month.⁴

⁴ Many regions have eliminated or are eliminating this technological barrier to allowing price to manage the real-time supply-and-demand balance by installing interval meters for all customers and offering real-time meter reading as a regulated service.

Although these offer caps and price caps can limit suppliers' ability to exercise unilateral market power in the short-term energy market, they also reduce the revenues suppliers can receive during scarcity conditions. This is often referred to as the missing-money problem for generation unit owners (Joskow 2013). However, this missing-money problem is a symptom of the existence of the reliability externality.

Any finite price cap limits the potential downside to electricity retailers and large consumers (able to purchase from the short-term market) delaying their purchases of electricity until real-time operation. Specifically, if the retailer or large consumer knows the price cap on the short-term market is \$250/MWh, then it is unlikely to be willing to pay more than that for electricity in any earlier forward market. This creates the possibility that real-time system conditions can occur where the amount of electricity demanded at or below the offer cap is less than the amount suppliers are willing to offer at or below the offer cap. This outcome implies that the system operator must be forced to either abandon the market mechanism or curtail load until the available supply offered at or below the offer cap equals the reduced level of demand, as was the case a number of times during the period January 2001 and March 2001 and most recently in August of 2020 in California and February 2021 in ERCOT (Wolak 2022).

Because random curtailments of supply — also known as rolling blackouts — are used to make demand equal to the available supply at or below the bid cap under these system conditions, this mechanism creates a reliability externality. This is because no retailer or large consumer bears the full cost of failing to procure adequate amounts of energy in advance of delivery. A retailer that has purchased sufficient supply in the forward market to meet its real-time energy demand is equally likely to be randomly curtailed as the same size retailer that has not procured adequate amounts of energy in the forward market. For this reason, all retailers and large loads have an incentive to under-procure their expected energy needs in the forward market.

Particularly for markets with very low offer caps, retailers have little incentive to engage in sufficient fixed-price forward contracts with generation unit owners to ensure a reliable supply of electricity for all possible realizations of real-time demand. For example, a 200 MW generation unit owner that expects to run 100 hours during the year with a variable cost of \$80/MWh would be willing to sign a fixed-price forward contract to provide up to 200 MWh of energy for up to 100 hours of the year to a retailer. Because this generation unit owner is essentially selling its expected annual output to the retailer, it would want a \$/MWh price that at least exceeds its average total cost of supplying energy during that year. This price can be significantly above the average price in the short-term wholesale market during the hours that this generation unit operates because of the offer cap on the short-term market and other market power mitigation mechanisms. This fact implies that the retailer would find it profit-maximizing not to sign the forward contract that allows the generation unit owner full cost recovery but instead wait until the short-term market to purchase the necessary energy at prices that are limited by the offer cap.

Although this incentive for retailers to rely on a price-capped short-term market is most likely to impact generation units that run infrequently, if the level of demand relative to the amount of available supply is sufficiently large, it can even impact intermediate and baseload units. Because of the expectation of very low prices in the short-term market and the limited prospect of very high prices because of offer caps, retailers may decide not to sign fixed-price forward contracts with these generation unit owners and purchase their energy in the short-term market. By this logic, a short-term energy market with an offer cap always creates an incentive for retailers to delay purchasing some of their energy needs until real-time, when these caps can be used to obtain this energy at a lower price than the supplier would be willing to sell it in the forward market.

The lower the offer cap, the greater the likelihood that the retailer will delay its electricity purchases in the short-term market. Delaying more purchases in the short-term market increases the likelihood that insufficient supply will offer into the short-term market at or below the offer cap to meet demand. If a retailer knows that part of the cost of its failure to purchase sufficient fixed-price forward contracts will be borne by other retailers and large consumers because of random curtailment, then it has an incentive to engage in fewer fixed-price forward contracts than it would if all customers had hourly meters. Then, all customers could be charged hourly prices high enough to cause them to reduce their demand to equal the amount of supply available at that price.

All of the wholesale markets in Latin America recognize this incentive to purchase energy in the short-term wholesale market when it is subject to offer caps or other market power mitigation mechanisms (Wolak 2003a). These countries address this incentive to under-contract by mandating forward contract coverage ratios for retailers and large consumers that have the option to purchase from the short-term market. For example, in the Brazilian market all retailers and large consumers are required to have 100 per cent of their final demand covered in a forward contract. Similar forward energy-contracting mandates exist in Chile and Peru (Wolak 2021a).

Without these forward contracting requirements on retailers and large consumers, a wholesale market with offer caps and stringent market power mitigation mechanisms, and final consumers without hourly meters, faces significant reliability challenges in both the short and long terms. In the short-term market, the lower the bid caps and more stringent the market power mitigation mechanism the greater the likelihood there will be insufficient supply offered into the short-term market at or below the offer cap. Because of the mitigated short-term market and inadequate fixed-price forward contracting by retailers, it is also likely that new generation entrants will be unable to obtain the future revenue commitments necessary to construct new generation units to manage load growth or plant retirements, which increases the possibility of future supply shortfalls.

Because externalities are typically the result of a missing market, the Latin American response to this problem suggests another way of characterizing this reliability externality as a missing market (Newbery 2016). In this case, retailers do not bear the full cost of failing to procure sufficient energy to meet their real-time needs in the future. Thus, there is a missing market for long-term contracts for long enough delivery horizons to allow new generation units to be financed and constructed to serve demand under all possible future conditions in the short-term market.

The above discussion implies that unless the regulator is willing to eliminate or substantially increase the offer cap on the short-term market so that the short-term price can be used to equate available supply to demand under all possible future short-term market conditions, some form of regulatory intervention is necessary to internalize the resulting reliability externality. However, if customers do not have interval meters that can record their hourly consumption, they have a limited ability to benefit from shifting their consumption away from high-priced hours, so raising or having no offer cap on the short-term market would not be advisable.⁵

As the above discussion makes clear, relying on a capped short-term energy market price to ensure long-term resource adequacy does not address the reliability externality and leaves both a missing-money and missing-market problem. Capacity payment mechanisms are one approach

⁵ Recall that only a customer's total monthly or bimonthly consumption, not the amount consumed in any hour of the month, can be measured with mechanical meters and monthly or bimonthly meter reading. This means that reducing consumption by one kilowatt-hour at any time in the monthly or bimonthly billing cycle has the same impact on the customer's bill. Consequently, the customer is likely to reduce demand when it is easiest, rather than when the system is stressed or the hourly price is highest.

to addressing this reliability externality designed primarily for thermal generation-dominated markets, where the major concern is insufficient generation capacity to meet future demand peaks. In variable renewable-dominated markets, the major reliability concern is more likely to be insufficient renewable energy (i.e., wind and sunshine) to meet a sustained demand, which implies other approaches to addressing the reliability externality may dominate a capacity-based approach for these electricity markets.

As the share of variable renewable generation in a wholesale electricity market increases, the magnitude of the reliability externality is also likely to increase. The uncertain availability of wind and solar resources increases the magnitude and duration of potential future energy supply shortfalls that must be managed. This implies many more instances when a capped short-term energy market may not yield a sufficient energy supply increase or demand decrease to maintain real-time supply-and-demand balance.

In the sections that follow, we first describe how capacity markets address the reliability externality. We then explain why they may not be the most cost-effective approach, particularly in a market with a significant amount of variable renewable generation capacity.⁶ We then discuss an alternative mechanism that involves limited regulatory intervention better suited to the reliability challenges of such a market.

5. CAPACITY PAYMENT MECHANISMS AND MARKETS

A major rationale for capacity markets in the U.S. appears to be a holdover from the vertically integrated, regulated monopoly regime when capacity payments compensated generation units for their capital costs, because the regulatory process typically reimbursed unit owners for their variable operating costs through generation unit pooling arrangements.

All of the Eastern U.S. wholesale markets with formal capacity markets — PJM, ISO-New England and the New York ISO — started as power pools where groups of vertically integrated utilities agreed to dispatch their generation units centrally in order to reduce the variable cost of serving their respective loads. The state-level regulatory process would compensate each utility for the variable cost of serving its load either from its own units or from the units owned by other utilities. The capacity costs of each utility's generation units would be recovered through a dollar-per-installed-kilowatt capacity payment set by each utility's state regulator.

It is important to emphasize that in a wholesale market regime all generation unit owners can earn the market-clearing price which is typically above the generation unit's average variable cost when the unit is operating. In this way, the generation unit earns a return to capital during each hour it produces electricity. This paradigm for earning a return on capital from the difference between the market price and the firm's average variable cost of production provides the appropriate signal for investment in new productive capacity in all workably competitive industries. There is little reason to expect that it could not work in the wholesale electricity industry with an active demand side.

All U.S. regional capacity markets have the following characteristics: All retailers in the region are assigned firm capacity obligations equal to some multiple of their annual peak demand — typically in the range of 110 to 120 per cent, depending on the region. The capacity procurement obligations for retailers often also entail sub-regional or local requirements.

⁶ Alberta has a growing amount of intermittent generation capacity. And as our previous discussion notes, this share is likely to grow in the near future as more coal units retire.

All generation units in the region are then assigned a firm capacity quantity equal to the amount of energy the unit can produce under all possible system conditions. In the case of a thermal generation unit, this magnitude is typically equal to the nameplate capacity of the unit multiplied by the unit's availability factor. For hydroelectric resources, this figure is typically equal to the amount of energy the unit could produce under the historically worst hydrological conditions. For solar and wind resources, determining a defensible firm capacity figure is extremely challenging (Wolak 2022).

All U.S. regional capacity markets run annual and higher frequency auctions for firm capacity where retailers can purchase their system-wide and local capacity obligations at a uniform price. Because of concerns about suppliers exercising unilateral market power, capacity auctions often have rules that require existing generation units to act as price-takers and the aggregate demand curve for firm capacity to be set through a regulator-determined administrative process. The regulator first sets the maximum willingness to pay for firm capacity to meet the market-wide requirement and a rate at which it is willing to purchase more firm capacity at lower market-clearing prices. The market-clearing price and quantity are set by the intersection of the aggregate offer curve for firm capacity with this regulator-determined demand curve. The resulting capacity price is equal to dollar-per-kilowatt-year (\$/kW-year) payment to firm capacity, which is the same for all MWs of firm capacity sold in the auction.

The sale of firm capacity from a generation unit typically requires that the owner offer that capacity into the energy market whenever the unit is available. In some markets, this is called a must-offer obligation. More recently, capacity market designers have attempted to strengthen the incentive for providers of firm capacity to offer into the energy market under stressed system conditions with mixed success (McRae and Wolak 2019).

6. WHY A CAPACITY MARKET IS UNLIKELY TO MEET THE GOVERNMENT'S DESIRED CRITERIA

This section assesses the extent to which a capacity market meets the four criteria described earlier for a long-term resource adequacy process, under both the current and likely future mix of generation capacity in Alberta.

6.1 INVESTOR CONFIDENCE

There is very little empirical evidence that the existence of a capacity market provides investors with a greater degree of confidence that they will earn an adequate return on their investment in new generation capacity. Capacity payments typically only provide a fraction of the revenues needed to support an investment in new generation capacity and these payments are typically only for one year, although more recently some markets are procuring longer term capacity commitments.

A fixed-price commitment to purchase a pre-specified quantity of energy from an electricity retailer or large load for a number of years is usually the primary source of finance for an investment in new generation capacity. This certain revenue stream for the facility allows the investor to obtain the financing to construct the plant. Because of the magnitude and duration of capacity payments, they are extremely unlikely to be pivotal in an investor's ability or incentive to construct new generation capacity.

Capacity markets can also create a missing-money problem because of the bias towards a region setting a high aggregate firm capacity requirement or obtaining an inefficient mix of generation capacity investments to meet a given aggregate firm capacity requirement. Both of these

outcomes depress wholesale energy prices, which can lead to revenue shortfalls for generation units, which reduces investor confidence in achieving cost recovery for new capacity.

Uncertainty in the regulatory rules governing the operation of the short-term wholesale market and long-term resource adequacy process has a significant impact on investor confidence. Market participants crave stable market rules and long-term contracts that they can count on not to be invalidated by the regulatory process. In contrast, capacity market rules are subject to frequent change in every region of the U.S. where they exist, which undermines investor confidence.

Finally, capacity mechanisms may dull the incentive of suppliers and load-serving entities to sign fixed-price forward contracts for energy. Consequently, the capacity payment a supplier might receive typically does little to limit the incentive of suppliers to exercise unilateral market power in the short-term energy market. In contrast, a mandated standardized fixed-price forward contract approach to long-term resource adequacy limits the incentive of suppliers to exercise unilateral market power in the short-term energy market (Thurber et al. 2022).

6.2 RELIABILITY

There is also little, if any, empirical evidence that regions with capacity markets have greater levels of grid reliability than regions without them. An energy market with a low price cap and a capacity market provides relatively weak incentives for suppliers to make their capacity available during stressed system conditions. A generation unit that is not available during stressed system conditions loses out on a short-term energy price that can only be as high as the price cap. Alternatively, a generation unit that fails to produce the amount of energy sold in the day-ahead market or in a long-term contract faces a price to replace this energy that is only as high as the price cap.

Consequently, although a capacity market may result in more installed generation capacity in a wholesale market, the owners of this generation capacity have less incentive to ensure this capacity is available during stressed system conditions because of the relatively low cost of replacing this energy enabled by the lower price cap.

The sale of firm capacity typically does not alter a supplier's ability or incentive to exercise unilateral market power in the short-term energy market, an activity that can reduce system reliability. A generation unit that has sold firm capacity must only offer this capacity into the wholesale market at or below the offer cap. Consequently, during system conditions when one or more suppliers has the ability and incentive to exercise unilateral market power in the energy market, the fact that a supplier has sold firm capacity does not change this ability or incentive. In contrast, a fixed-price forward contract obligation to supply energy significantly limits the incentive of a generation unit owner to exercise unilateral market power in the energy market (Wolak 2000).

As the California electricity crisis demonstrated, the existence of adequate generation capacity to serve demand does not ensure that this capacity will sell in the short-term market at a price that does not reflect the exercise of substantial unilateral market power (Wolak 2003b). Graphic illustration of this point is provided by the fact that peak hourly demands in California of over 44,000 MWh were met during the summers of 2000 and 2001 without reliability incidents, and all of the rolling blackouts in California occurred during the winter and early spring when the daily peak demand was less than 34,000 MWh.

A lower level of grid reliability with a capacity market is increasingly likely in a wholesale market with a significant share of variable renewable generation. This outcome can occur because it is

extremely difficult to determine a credible value for the firm capacity of a variable renewable generation unit. McRae and Wolak (2019) provide an example of this challenge for the case of hydroelectric generation units in Colombia, a market dominated by hydroelectric capacity that is subject to sustained periods of water shortfalls caused by the El Niño phenomenon.

The problem of determining a credible value for the firm capacity of wind or solar generation units is even more difficult. If extreme system conditions occur when it is cloudy outside or when there is no sunlight, then it is difficult to assign a very large value for the firm capacity of a solar generation unit. However, it is also very difficult politically to assign a very small value for it. Similar arguments hold for wind units if extreme system conditions occur on days when the wind is not blowing. Consequently, as the share of variable renewables in a region increases, the amount of firm capacity that can actually provide what it claims to be able to provide during extreme system conditions declines, which implies a lower level of supply reliability.

6.3 AFFORDABILITY

There is also no empirical evidence that capacity markets deliver lower average total capacity, energy and ancillary services costs to electricity consumers. Paying a market-clearing price for capacity and a market-clearing price for energy and each ancillary service implies that suppliers are receiving inframarginal rents for capacity, energy and ancillary services. This makes it more difficult for regions with both capacity and energy markets to supply consumers at a lower cost.

Market-clearing prices are set by the highest offer necessary to serve demand which implies that all suppliers with offers below the market-clearing price are receiving revenues above their as-offered cost. This per-unit price versus variable cost difference goes to fixed-cost recovery. Moreover, generation unit owners with some ability to exercise unilateral market power in the energy market are likely to submit offer prices above their marginal cost of production, which implies an additional source of revenues for fixed-cost recovery when the unit is accepted to supply energy.

Firm capacity obligations do little to alter the ability or incentive of suppliers to exercise unilateral market power in this energy market. Thus, more such power is likely to be exercised in the short-term energy market in a wholesale market, with a capacity market with limited fixed-price contract coverage of final demand, versus a wholesale market without a capacity market and significant fixed-price forward contract coverage of final demand, but with the same mix of generation capacity.

Capacity markets are typically accompanied by offer caps and market power mitigation mechanisms that significantly limit the incentive for final consumers to become active participants in the short-term wholesale market. For example, if the maximum wholesale price in an hour is \$400/MWh because of an offer cap at this level, then a 1 KWh reduction in demand for a residential customer (a very large demand reduction) during an hour only saves the customer 40 cents, which seems unlikely to be sufficiently attractive to cause that consumer to reduce its demand. This lack of an active demand side of the wholesale market impacts how generation unit owners offer their units into the wholesale market.

Active participation by final demand substantially increases the competitiveness of the short-term wholesale market because all suppliers know that higher offer prices will result in less of their generation capacity being called upon to produce, since the offers of final consumers to reduce their demand are accepted instead. Without an active demand side of the wholesale market, suppliers know they can submit offers that are farther above their variable cost of supplying electricity and not have these offers rejected because of a lower system demand at that offer price.

The administrative process used to set overall firm capacity obligation is likely to raise costs to consumers. The regulator, generation unit owners and incumbent electricity retailers all have an incentive to set a high value for the aggregate firm capacity obligation. The regulator faces less risk of high prices that may attract attention from politicians and the public. The generation unit owners would clearly prefer more firm capacity to be sold rather than less. Incumbent retailers would also like larger firm capacity requirement because this reduces wholesale price volatility, which reduces the incentive for new entrants into electricity retailing.

This bias toward large values for the capacity obligation also limits the incentive for investments in storage and other load-shifting technologies that are financed by exploiting price differences over time. The financial viability of an investment in storage is much greater in a market with an average price difference between peak and off-peak hours of \$30/MWh versus a market with \$10/MWh average difference.

6.4 COMPLEXITY

Capacity markets are significantly more complex than energy markets and are becoming increasingly so as more and more changes are being made to their design. As noted earlier, determining the firm capacity of generation for variable renewable generation is an extremely complex task that is fraught with untestable technical assumptions and political hurdles. There is no generally agreed-upon approach to computing the firm capacity of a solar or wind generation unit.

There is a considerable amount of debate over how to set the administrative demand curve for firm capacity, particularly over the height of the highest step of the demand curve and its slope. There has also been significant legal wrangling in a number of regional markets over whether there should be a floor on the prices that suppliers can offer into capacity auctions, the so-called minimum offer price rule (MOPR).

More recently, capacity obligations have had to be defined both locationally and in terms of the technological capability of generation units. For example, there are typically local capacity obligations near major load centres. In regions with significant amounts of variable renewable energy, there are fast-ramping capacity requirements.

All of these features of a capacity market design are continually under scrutiny and often subject to change, significantly increasing the market's complexity, creating persistent regulatory uncertainty and potentially risking unintended consequences from changes in market design.

7. WHY AN ENERGY MARKET COMBINED WITH MANDATED LONG-TERM ENERGY CONTRACTING IS THE PREFERRED APPROACH

AESO has been operating the wholesale electricity market since 2003 without a capacity market. While Alberta does at times see periods of sustained market power (see, e.g., Brown et al. 2023), market outcomes appear to reflect effective competition between market participants for the vast majority of hours. Significant new investment in transmission and generation capacity has also taken place to serve a growing demand for electricity in Alberta over this time, with over 8,000 MW in new generation capacity installed since restructuring to a competitive generation market in 2001.⁷

As noted earlier, a major argument for a capacity market was the anticipated retirement of significant amounts of coal-fired generation capacity and its replacement with an increasing amount of wind and solar generation capacity. In a regime with significant variable renewable generation capacity, the major reliability challenge is adequate energy to meet electricity demand all hours of the year, rather than sufficient installed capacity to serve system demand peaks, as is the case in a thermal-dominated system.

In a variable generation capacity-dominated system, supply shortfalls can occur at almost any hour of the year. Because it is difficult, if not impossible, to set credible values for the firm capacity of variable renewable generation units, having adequate firm capacity from variable renewables does not necessarily mean that these resources can supply energy demand during all hours of the year.

This section proposes an alternative approach to ensuring a reliable supply of energy at a reasonable price to consumers.⁸ This approach requires purchases of standardized forward financial contracts for energy by all loads in Alberta at various horizons to delivery. Generation unit owners are free to engage in incremental cross-hedging arrangements to re-insure their renewable energy risk, input fossil fuel availability and outage risks within and across technologies using bilateral contracts. A critical feature of this approach is the separation between individual generators' and retailers' profiles and the settlement profile of the contracts, which is based on average load shapes. This ensures both generators and loads have incentives at the margin to improve upon their profiles to provide (and invest in) higher valued generation profiles and lower cost load profiles.

The ultimate goal of this reliability mechanism is to develop a liquid forward market for energy at long time horizons to delivery to achieve both long-term generation adequacy and ensure that when real-time system operation arrives, the forward market positions of suppliers are closely aligned with their production of electricity under a least-cost dispatch.

Fixed-price forward contracts are the standard approach used to ensure a real-time supply-and-demand balance in markets for products with high fixed costs of production. The prospect of a high real-time price for the product provides incentives for customers to hedge this real-time price risk through a fixed-price forward contract. A supplier benefits from signing such a contract because it has greater quantity and revenue certainty. The airline industry is a familiar example of this phenomenon. There is a substantial fixed cost associated with operating a flight between a given origin and destination pair. Regardless of how many passengers board the flight, the airplane, pilot and co-pilot, flight attendants and fuel must be paid for. Moreover, there are a finite

⁷ Of this total, roughly 3,000 MW was co-generation capacity, largely in the oil sands (AUC 2022).

⁸ For an in-depth description of the standardized forward energy-contracting approach, see Wolak (2022).

number of seats on the flight, so passengers wanting to travel face the risk that if they show up at the airport one hour before the flight and attempt to purchase a ticket, they may find that it is sold out or tickets are extremely expensive because of a high real-time demand for seats. Customers hedge this short-term price risk by purchasing their tickets in advance, which is a fixed-price, fixed-quantity (one seat) forward contract for travel on the flight. These forward market purchases allow the airline to better plan the types of aircraft and flight staff it will use to serve each route and how much fuel is needed for each flight.

Similar arguments apply to wholesale electricity markets to the extent that the regulator allows short-term prices to rise to very high levels. The potential for very high short-term prices provides strong incentives for electricity retailers and large customers to purchase their electricity through fixed-price forward contracts, rather than face the risk of these extreme short-term prices. Purchasing these fixed-price and fixed-quantity forward financial contracts far enough in advance of delivery for new entrants to compete to provide this energy ensures that retailers will receive a competitive forward market price for their purchase. These forward market purchases far in advance of delivery also ensure that the seller of the contract has sufficient time to construct the new generation capacity needed to meet this demand. Consequently, in the same sense that fixed-price forward contracts for air travel allow an airline to better match airplanes and flight staff to routes, fixed-price forward contracts for electricity allow electricity suppliers to match the mix of generation capacity to the pattern of demand that has purchased fixed-price forward contracts for energy.

Key to the success of a strategy for obtaining sufficient generation capacity to meet future demand without regulatory intervention is the threat of very high short-term prices which provide the incentive for load-serving entities to sign fixed-price forward contracts for their expected future demands far enough in advance of delivery to allow new entrants to compete with existing suppliers in providing these contracts. Allowing short-term prices to rise to the level necessary to achieve sufficient hedging of short-term price risk far enough in advance of delivery to obtain competitive prices for these contracts requires a liquid forward market for energy and the political will to allow prices to rise to the level needed to clear the market under all possible system conditions. Neither of these circumstances exists in virtually all wholesale electricity markets around the world. The political process in virtually all countries finds it extremely challenging to pre-commit to allowing wholesale electricity prices to rise to whatever level is necessary to clear the market under all possible future system conditions.

Our proposed reliability mechanism limits the amount of regulatory intervention necessary to ensure long-term resource adequacy and a reliable supply of electricity at reasonable prices. Rather than designating a required amount of firm capacity that each retailer must purchase, this reliability mechanism mandates fixed-price forward contract purchases by all electricity retailers and large consumers at various horizons to delivery. This mechanism would require all electricity retailers and large consumers to purchase a standardized fixed-price forward contract for energy equal to various fractions of their expected demand at various horizons to delivery. For example, a retailer or large consumer could be required to purchase 95 per cent of its actual annual demand in a fixed-price forward contract one year in advance of delivery, 90 per cent of its actual annual demand two years in advance of delivery, 85 per cent three years in advance of delivery and 80 per cent four years in advance, and all of these contracts clear against the hourly short-term price during the delivery period. Retailers would be subject to financial penalties for under-procurement of forward contracts relative to their actual demand.

For example, if the retailer's realized demand is 100 gigawatt-hours (GWh) and it purchased 96 GWh in the standardized forward contract one year in advance, 89 GWh two years in advance, 86 GWh three years and 81 GWh four years in advance, the retailer would only be subject to penalties for under-procurement two years in advance of delivery. These forward financial market energy purchases would provide retailers and large consumers with wholesale price certainty for the vast majority of their electricity demand. To the extent the regulator feels that these mandated financial contracting levels are insufficient to ensure a reliable supply of electricity at a reasonable price, higher levels of contract coverage can be mandated; say 98 per cent one year in advance, 93 per cent two years in advance, 90 per cent three years and 85 per cent four years in advance.

It is important to emphasize that mandating these contracting levels is unlikely to impose a financial hardship on retailers that lose customers to competing retailers. If a retailer purchased more fixed-price forward contract coverage than it ultimately needs because it lost customers to a competitor, it can sell this obligation in the secondary market. Unless the aggregate demand for energy in the future is unexpectedly low, this retailer is just as likely to make a profit on this sale as it is to make a loss, because one of the retailers that gained customers is going to need a standardized forward contract to meet its regulatory requirements for coverage of its final demand. Only in the very unlikely case that the aggregate amount of forward contracts purchased is greater than the realized final demand for the system, will there be a potential for stranded forward contracts held by retailers that lose customers.

As discussed earlier, fixed-price forward contract obligations also significantly limit the incentive of suppliers to exercise unilateral market power in the short-term market. The closer a supplier's fixed-price forward contract quantity is to its actual output level, the less incentive the supplier has to exercise unilateral market power (Wolak 2000). The standardized forward contract holdings of retailers and large consumers ensure that in a stressed system these entities are protected against high short-term prices and the counterparties to these contracts — renewable resource owners and thermal generation units — are producing the maximum amount of energy they are able to provide.

Under this regime of mandated standardized forward contracts for energy resource adequacy, thermal resource owners would sell significantly more energy in the standardized fixed-price forward contract than they expect to produce and the renewable resource owners would sell significantly less than they expect to produce. When there are significant amounts of available renewable energy, the thermal resource owners will find it profitable not to produce electricity, but instead purchase from the short-term market to meet their forward financial contract obligations. In contrast, when little renewable energy is available, the thermal resource owners will produce the difference between the market demand and renewable generation production. Because the renewable resource owners have sold less of the standardized fixed-price forward contract than their expected output, they are likely to have only a modest net short position in energy that they must cover through purchases from the short-term market.

Under this mechanism, the renewable supplier produces whenever the wind or solar resource is available and the thermal resource owner only produces when the wind and solar resources are unavailable. The thermal resources make the efficient "make versus buy" decision by submitting an offer to supply energy in the short-term market at their variable cost. This offer price ensures that when it's cheaper for the thermal resource owner to meet its standardized forward financial contract obligation from its generation unit, it will be accepted to supply energy in the short-term market and when it is cheaper to purchase this energy from the short-term market, its unit will not operate.

The precise form of the standardized forward contract sold is an important aspect of this reliability mechanism. The most straightforward approach would be to make the contracts system-load-weighted. The values of $Q_{hk}(Contract)$, the forward contract obligation of supplier k during hour h , would be computed as follows. Let QD_{hd} equal the system demand in hour h of day d . Define:

$$w_{hd} = \frac{QD_{hd}}{\sum_{d=1}^D \sum_{h=1}^{24} QD_{hd}}$$

Suppose that the standardized forward contracts are for an entire quarter, so that D is the number of days in that quarter. Suppose that supplier k sells $Q_k(Contract)$ MWh of energy for the quarter. The contract's hourly value for both the buyer and seller is $Q_{hdk} = w_{hd} \times Q_k(Contract)$. Specifically, the quarterly total amount of energy sold is allocated to hours in the quarter according to the actual load shape during that quarter. The values of the w_{hd} would be higher during the hours of the day when the value of the system load is higher, which would make Q_{hdk} higher during those hours. Alternatively, the market operator could specify values of the w_{hd} in advance based on historical values. The basic idea of this approach is to adjust the hourly values of the total amount of energy sold in a quarter to match the hourly load shape in order to limit the deviations between $Q(Contract)$ and the efficient level of hourly output for each supplier.

This standardized product could be traded through AESO or some other entity, but the most important aspect of this mechanism is that all retailers and large consumers are required to purchase at least the mandated percentage of their realized load at various horizons to delivery or face financial penalties. This will create the demand for these standardized forward contracts. Prices paid for these contracts will be determined through market mechanisms. Suppliers and loads are free to re-trade these obligations. The only requirement is that once a retailer makes its forward contracting compliance filing with the regulator, it is no longer allowed to sell the contracts it has used for compliance. These must be held to the clearing date of the contract.

For the regulated retail customers, the purchase prices of these forward contracts can also be used to set the wholesale price implicit in the regulated retail price over the time horizon that the forward contract clears. Specifically, the average price paid for standardized contracts that deliver during a given quarter by an electricity retailer can be used to set the average wholesale price of power during that quarter implicit in the quarterly regulated retail price. Consequently, one benefit of this reliability mechanism is that it provides a transparent market price to set the wholesale price component of a retailer's regulated retail price.

A final point to emphasize about this reliability mechanism is that there is no prohibition on generation unit owners or retailers engaging in other hedging arrangements outside of this mechanism. Specifically, a generation unit owner could enter into a bilateral contract for energy with another generation unit owner or a retailer. Because it mandates purchases of standardized contracts out to four years into the future, this reliability mechanism should stimulate the development of an active forward market for individually designed products to hedge the residual risks that suppliers, retailers and free consumers face that cannot be hedged with the standardized forward contract at these time horizons to delivery.

7.1 ADVANTAGES OF PROPOSED APPROACH FOR ENHANCING LONG-TERM RESOURCE ADEQUACY

This mechanism has a number of advantages relative to a capacity payment mechanism. There is no up-front payment made to a generation unit. AESO could operate the standardized forward contract market and manage the counterparty risk of financial default of all buyers and sellers of the contracts through its existing margin requirements process in a manner consistent with how any standardized forward financial market operates.

AESO can tailor the margin requirement process to the financial health of individual market participants, if necessary. If a supplier has sold energy forward at a substantially lower price than the short-term price that it is likely to clear against, AESO can require this market participant to post additional funds to ensure that the supplier will follow through with its forward market commitment. AESO can manage a clearinghouse function among buyers and sellers of this standardized forward financial contract as part of its existing settlements system.

It is not unusual for standardized forward financial markets for energy to have outstanding volume trading at horizons to delivery up to four years in the future. The New York Mercantile Exchange (NYMEX) offers standardized forward contracts that clear up to 10 years in the future for natural gas and oil. There is typically significant outstanding volume in these contracts at delivery horizons at least four years into the future. Over the past 10 years, oil and natural gas markets have shown significant price volatility yet these standardized futures markets have continued to operate. Based on this evidence, it appears feasible to manage the margin requirements on standardized electricity contracts in Alberta with delivery horizons up to four years in the future.

Our proposed reliability mechanism does not require the regulator to set a capacity reserve margin. Generation unit owners collectively make this decision based on their standardized forward contract sales to retailers and large consumers. Specifically, if a retailer or large consumer is able to limit its demand during certain hours of the year, it can avoid purchasing as much energy in the forward market, which can reduce the amount of generation capacity necessary to serve demand on an annual basis.

This mechanism focuses on ensuring that adequate energy is available to meet system demand at a reasonable price all hours of the year, whether it be from generation units providing energy or a final consumer reducing its demand in response to a higher short-term price.

This mechanism significantly limits the incentive suppliers have to exercise unilateral market power in the short term, because all suppliers have substantial fixed-price forward contract obligations to supply energy during all hours of the year and the hourly magnitude of these obligations follows the shape of system demand.

Before each compliance period for the standardized forward-contract reliability mechanism, the following sequence of events would occur. Each retailer and free consumer would show the regulator the quantity of contracts it has purchased at various horizons to delivery. Specifically, each retailer would show the total energy purchased in each quarterly standardized forward contract for each quarter over the next four years. AESO could validate this showing. These contracts would then be placed in that retailer's compliance account and held until the clearing date. The retailer would not be allowed to sell these contracts until their delivery or clearing period.

We now discuss why we believe this mechanism will achieve long-term resource adequacy in Alberta in a more cost-effective manner than a capacity market.

7.1.1 Investor confidence

The sale of fixed-price forward contracts for energy in three to four years, starting delivery two years in the future, provides a revenue stream that will significantly increase investor confidence in recovering the cost of any investment in new generation capacity.

To the extent that the regulator would like to provide potential new investors with revenue certainty for a longer time, the terms of these standardized forward contracts, and the fraction of realized demand that must be purchased in advance, could be increased.

7.1.2 Reliability

This mechanism will provide strong incentives for demand to be served under all possible system conditions. Each generation unit owner will have fixed-price forward contract obligations by hour of the day that match the pattern of system demand throughout the quarter of the year. Moreover, the final demand of all retailers and large loads are hedged against short-term prices through these standardized fixed-price forward financial contracts. Therefore, generation unit owners bear all of the short-term price risk associated with supply shortfalls. However, this does not mean that final consumers cannot become active participants in the short-term market to help maintain the real-time supply-and-demand balance.

Since these standardized forward contracts protect retailers and loads from high short-term prices, the offer cap on the short-term market can be increased, which will increase the incentive for suppliers to produce during stressed system conditions. The higher price cap and potentially greater short-term price volatility will support investments in storage and load-shifting technologies, thereby further enhancing system reliability.

If the regulator is concerned that adequate new generation capacity is being built to meet future demand, milestones could be set for completing the proposed generation project that is the basis for a forward contract energy sale. For example, if energy was sold four years in advance based on a proposed generation unit, then construction of the new unit must begin within a pre-specified number of months after the signing date of the contract, or the contracted quantity of energy would be automatically liquidated. This means the supplier would have to buy back the energy that it sold based on the expected energy output of the proposed unit. Other completion milestones would also have to be met at future dates to ensure the unit will be ready to provide energy on its original initial operating date, and if any of these milestones were not met, the contract would be liquidated. On this point, it is important to emphasize that in order for a supplier to liquidate contracted energy, the supplier must find a willing seller of the energy that it previously sold in a standardized forward contract. Because the retailers and free consumers that purchased these contracts must use them to meet their compliance obligations, buying back this energy is likely to require the supplier to pay an extremely high price, which provides the supplier with a strong incentive to deliver the forward energy sold from a proposed generation unit. Because of these incentives, our proposed mechanism is unlikely to leave nearly as many, if any, proposed projects sold as standardized contract energy to be cancelled or completed far behind schedule.

One question likely to be raised about this approach is whether sufficient generation resources will be built to meet demand if consumers only purchase standardized forward financial contracts that clear against the short-term price. Bear in mind the incentives faced by a seller of the forward financial contract once this contract has been sold. The supplier is obligated to ensure that the forward contract quantity of energy can be purchased in the short-term market at the lowest possible short-term price. The seller of the contract bears all of the risk associated with higher

short-term prices. In order to prudently hedge this risk, the seller has a very strong incentive to ensure that sufficient energy is available from its generation units, or generation units owned by other market participants, to set the lowest possible price in the short-term market for the quantity of energy it sold in the fixed-price forward contract.

This logic implies that if a supplier signs a forward contract guaranteeing the price for 500 MWh of energy for 24 hours a day and seven days per week, it will construct or contract for more than 500 MW of generation capacity to hedge this short-term price risk. Building only a 500 MW facility to hedge this risk would be extremely imprudent and expose the supplier to significant risk, because if this 500 MW facility is unavailable to provide electricity, the supplier must purchase the energy from the short-term market at the price that prevails at the time. Moreover, if this generation unit is unavailable, then the short-term price is likely to be extremely high.

As the above discussion makes clear, the sale of a fixed-price forward contract for energy provides a strong incentive for the seller of this contract to ensure that this energy is supplied to the buyer of the contract. If all of final demand is covered by these contracts, then suppliers have a strong incentive to supply the real-time demand under all possible future system conditions.

7.1.3 Affordability

The standardized energy-contracting approach to long-term resource adequacy has a number of features that likely make it significantly more affordable than a capacity-based approach. First, the procurement process focuses precisely and only on what consumers want — energy. Second, the precise mix of generation capacity and active demand-side participation required to achieve this goal is left up to market participants rather than a regulatory mandate. Third, the potential to raise the offer cap on the short-term market creates greater opportunities for active demand-side participation, storage and load-shifting technologies to eliminate the need to build new generation capacity because of the lower load factor enabled by active demand-side participation.⁹

The purchase of fixed-price forward contracts far enough in advance of delivery to allow new generation units to compete to supply this energy ensures that consumers pay the most competitive price for these contracts. The fact that the hourly quantities of energy sold in these contracts are tailored to the aggregate load shape of the system significantly limits the ability of the suppliers that sold these contracts to exercise unilateral market power in the short-term market, even during hours of the quarter when the demand for electricity is high.

Because the mix of generation capacity needed to serve demand is no longer mandated by a firm capacity obligation, market participants have the strongest possible incentive to find the least-cost mix of generation capacity, active demand-side participation and storage and load-shifting investments to serve demand during all hours of the year.

Because consumers are protected from high short-term prices by their fixed-price forward financial contract holdings, raising the offer cap on the short-term energy market could unlock more active demand-side participation and stimulate investments in storage. Moreover, if this active demand-side participation successfully increases the aggregate load factor for the system, the average cost of serving demand can be reduced because the market can get by with less installed capacity and serve the same amount of demand annually.

⁹ The annual load factor of an electricity supply industry is the ratio of the annual average hourly demand divided by the annual peak hourly demand.

Finally, as long as the aggregate demand for electricity in Alberta does not decline — an unlikely outcome given current trends in electrification of the transportation sector — there is little risk that any of the standardized contracts purchased by a retailer or large-load consumer will become stranded in the sense that there will be no active secondary market for these contracts.

All of these factors support the argument that our energy-contracting approach to long-term resource adequacy is the most affordable option for ensuring a reliable supply of energy.

7.1.4 Complexity

The energy-contracting approach is substantially less complex to administer than a capacity-based approach. There is no need to define the firm capacity of a generation unit. There is no need to set an aggregate firm capacity requirement. There is no need to set the parameters of an administrative demand curve for firm capacity.

Many markets currently trade standardized forward financial contracts for commodities, including energy. Any of these market designs could be adapted to serve this function for the proposed long-term resource adequacy mechanism.

The only aspect that does involve some level of complexity is the verifying compliance of retailers and large loads with the contracting requirement. However, this administrative and regulatory burden is likely to be no greater than that necessary to verify compliance with the capacity obligations associated with administering a capacity market.

8. ADDITIONAL CONSIDERATIONS

In this section we discuss a few additional market design changes that are likely to improve the efficiency of Alberta's wholesale electricity market. The following is largely excerpted from Wolak (2019).

8.1 LOCATIONAL MARGINAL PRICING

A key determinant of wholesale market performance, particularly in regions with a significant amount of variable renewable generation capacity, is the extent to which the market mechanism used to dispatch and operate generation units is consistent with how the grid is actually operated. In the early stages of electricity restructuring, many regions attempted to operate wholesale markets that used simplified versions of the transmission network. These markets either assumed infinite transmission capacity between locations in the transmission grid or only recognized transmission constraints across large geographic regions. These simplifications of the transmission network configuration and other relevant operating constraints created opportunities for market participants to increase their profits by taking advantage of the fact that, in real-time, the actual configuration of the transmission network and other operating constraints would need to be respected to serve demand at all locations in the transmission network.

Market mechanisms that used simplified versions of the transmission network would often produce prices and dispatch levels for generation units that were not feasible given the network's configuration or other constraints in how the system was operated. Between the close of the wholesale market and real-time system operation, the system operator would need to decrease the dispatch levels of some units and increase the output of others to create a physically feasible configuration of operating levels for all generation units.

The final outcome of this process would be generation units with offer prices below the market-clearing price not producing electricity and units with offer prices above the market-clearing price producing electricity. Generation units operating “out of merit order” occurs because of the location of demand and available generation units within the region. The transmission network’s configuration prevents some of these low-offer price units from producing electricity and requires some of the high-offer price units to supply electricity instead. The former units are typically called “constrained-off” units and the latter are called “constrained-on” or “must-run” units.

Constrained-on suppliers with offer prices above the market-clearing price would typically be paid their offer price or a regulator-determined price for this energy. Suppliers constrained off would typically sell their energy back to the system operator at their offer price or at a regulated determined price. These markets differ in terms of the sophistication of the mechanism the system operator uses to determine which generation units are constrained on and off.

How frequently generation units are constrained on or off will impact the offer prices they submit into the short-term wholesale energy market. For example, if generation units are paid their offer price for electricity when they are constrained on and the unit’s owner knows that it will be constrained on, a profit-maximizing unit owner will submit an offer price far higher than the variable cost of operating the unit and raise the total cost of electricity supplied to final consumers. This action increases the cost of serving demand because the constrained-on unit may not be accepted in the formal market, which raises the market-clearing price.

A similar set of circumstances can arise for constrained-off generation units. Constrained-off suppliers are usually paid the difference between the market-clearing price and their offer price for not supplying electricity that would have been supplied if not for the configuration of the transmission network. This market rule creates an incentive for a profit-maximizing supplier that knows its unit will be constrained off to submit the lowest possible offer price in order to receive the highest possible payment for being constrained off and raise the total cost of electricity supplied to final consumers. Bushnell, Hobbs and Wolak (2008) discuss this problem and the market efficiency consequences in the context of the California zonal market. Similar problems occurred in the zonal markets that initially existed in other parts of the United States, such as New England and Texas. This problem is not unique to industrialized country markets. Wolak (2009) discusses these same issues in the context of the Colombian single-price market.

All markets in the United States now employ a market mechanism used to set prices across locations and hours of the day that matches as closely as possible how the transmission network is operated. This eliminates the need for payments to constrained-on and constrained-off units because the market mechanism sets potentially different prices at all locations in the transmission network. Constrained-on and constrained-off units will receive unique prices that reflect the cost of withdrawing an additional MWh of energy at that location in the transmission network during that pricing interval.

All wholesale markets in Europe continue to ignore the configuration of the transmission network or assume a simplified version of the transmission network in setting prices and dispatch levels. Because of the increased number and magnitude of reliability constraints that must be respected as the share of variable renewable energy in these markets has increased, the cost of making the dispatch levels that emerge from the short-term energy market physically feasible has increased.

Alberta operates under a single-price model for its current energy-only market. Where transmission constraints occur, resolution occurs outside of the market-clearing process, resulting in additional out-of-market costs. Moving to nodal, or at least zonal, pricing would ensure efficient dispatch and incentivize efficient siting decisions for new investment.

One complaint often levelled against locational marginal-price (LMP) markets is that they increase the likelihood of political backlash from consumers because prices paid for wholesale electricity can differ significantly across locations within the same geographic region. For example, customers in urban areas that primarily import electricity over congested transmission lines will pay more than customers located in generation-rich rural regions that export electricity to these regions. Because more customers live in the urban areas than in the rural regions, charging final consumers in the urban areas a higher retail price to recover the LMP at their location may be politically challenging for the regulator to implement.

Many regions with LMP pricing have overcome this potential problem by charging all customers in a given state or utility service territory a weighted average of the LMPs in the region, where the weight assigned to each price is the share of system load that is withdrawn at that location. Under this scheme, generation units continue to be paid the LMP at their location. For example, in Singapore all generation units are paid the LMP at their location, but all loads are charged the Uniform Singapore Electricity Price (USEP), which is the quantity-weighted average of the half-hourly LMPs in Singapore. This approach to pricing captures the reliability and operating efficiency benefits of an LMP market while addressing the equity concerns regulators often face with charging customers at different locations prices that reflect the configuration of the transmission network.

8.2 MULTI-SETTLEMENT MARKETS

Multi-settlement nodal-pricing markets have been adopted by all U.S. jurisdictions with a formal short-term wholesale electricity market. A multi-settlement market has a day-ahead forward market that is run in advance of real-time system operation. This market sets firm financial schedules for all generation units and loads for all 24 hours of the following day. Suppliers submit generation unit-level offer curves for each hour of the following day and electricity retailers submit demand curves for the same. The system operator then minimizes the as-offered cost to meet these demands for all 24 hours of the following day subject to the anticipated configuration of the transmission network and other relevant operating constraints during that time. This gives rise to LMPs and firm financial commitments to buy and sell electricity each hour of the following day for all generation unit and load locations.

These day-ahead commitments require neither a generation unit to supply the amount sold in the day-ahead market nor a load to consume the amount purchased. The only requirement is that any shortfall in a day-ahead commitment to supply energy must be purchased from the real-time market at that same location or any production greater than the day-ahead commitment is sold at the real-time price at that same location. The same logic applies for loads. Additional consumption beyond the load's day-ahead purchase is paid for at the real-time price at that location and the surplus of a day-ahead purchase relative to actual consumption is sold at the real-time price at that location. In all U.S. wholesale markets, real-time LMPs are determined from the real-time offer curves from all available generation units and dispatchable loads by minimizing the as-offered cost to meet real-time demand at all locations in the control area, considering the current configuration of the transmission network and other relevant operating constraints. This process gives rise to LMPs at all locations in the transmission network and actual hourly operating levels for all generation units. Real-time imbalances relative to day-ahead schedules are cleared at these real-time prices.

To understand how a two-settlement market works, suppose that a generation unit owner sells 50 MWh in the day-ahead market at \$60/MWh. It receives a guaranteed \$3,000 in revenues from this sale. However, if the generation unit owner fails to inject 50 MWh of energy into the grid

during that hour of the following day, it must purchase the energy it fails to inject at the real-time price at that location. Suppose that the real-time price at that location is \$70/MWh and the generator only injects 40 MWh of energy during the hour in question. In this case, the unit owner must purchase the 10 MWh shortfall at \$70/MWh. Consequently, the net revenues the generation unit owner earns from selling 50 MWh in the day-ahead market and only injecting 40 MWh is \$2,300 — the \$3,000 of revenues earned in the day-ahead market less the \$700 paid for the 10 MWh real-time deviation from the unit's day-ahead schedule.

If a generation unit produces more output than its day-ahead schedule, then this incremental output is sold in the real-time market. For example, if the unit produced 55 MWh, then the additional 5 MWh beyond the unit owner's day-ahead schedule is sold at the real-time price. By the same logic, a load-serving entity that buys 100 MWh in the day-ahead market but only withdraws 90 MWh in real-time, sells the 10 MWh not consumed at the real-time price. Alternatively, if the load-serving entity consumes 110 MWh, then the additional 10 MWh not purchased in the day-ahead market must be purchased at the real-time price.

A multi-settlement LMP market design is also particularly well suited to managing a generation mix with a significant share of variable renewable resources. The additional operating constraints necessary for reliable system operation with an increased amount of renewable resources can easily be incorporated into the day-ahead and real-time market models. Therefore, the economic benefits from implementing a multi-settlement LMP market relative to market designs that do not model all transmission and other operating constraints are likely to be greater the larger the share of variable renewable resources. This is due to the increasing number of operating constraints that must be accounted for in both system and market operation.

A multi-settlement LMP market also values the dispatchability of generation units even though it pays all resources at the same location in the grid the same price in the day-ahead and real-time markets. Suppose that a wind unit sells 50 MWh and a thermal resource sells 40 MWh in the day-ahead market at \$30/MWh. If, in real-time, not as much wind energy is produced, the dispatchable thermal unit must make up the difference. Suppose that the wind unit produces only 30 MWh, so that the thermal unit must produce an additional 20 MWh. Because of this wind generation shortfall, the real-time price is now \$60/MWh. Under this scenario, the wind unit is paid an average price of \$10/MWh = $(50 \text{ MWh} \times \$30/\text{MWh} - 20 \text{ MWh} \times \$60/\text{MWh})/30 \text{ MWh}$ for the 30 MWh it produces, whereas the dispatchable thermal unit is paid an average price of \$40/MWh = $(40 \text{ MWh} \times \$30/\text{MWh} + 20 \text{ MWh} \times \$60/\text{MWh})/60 \text{ MWh}$ for the 60 MWh it produces. Similar logic applies to the case that the wind resource produces more than expected and the thermal resource reduces its output because the real-time price is lower than the day-ahead price due to the unexpectedly large amount of wind energy produced. Consequently, multi-settlement markets benefit variable resource owners that are better able to forecast, on a day-ahead basis, the real-time production of their generation units.

The experience of all U.S. wholesale electricity markets supports the argument that a multi-settlement LMP market design is the most effective mechanism for achieving economically efficient wholesale prices. All U.S. wholesale markets initially used simplified models of the grid in the dispatch of generation units and pricing of energy. These designs created significant market performance problems, particularly in regions with limited transmission capacity. As a result, all these regions ultimately adopted multi-settlement LMP market designs.

Multi-settlement markets allow the participation of purely financial participants that act as virtual generators and loads at any location in the day-ahead market. Any position won by a purely financial participant in the day-ahead market must subsequently be unwound as a price-taker in

the real-time market. Purely financial participants have been found to reduce average price differences between day-ahead and real-time, reduce the volatility in these price differences and reduce the total cost of serving demand during stressed system conditions (Jha and Wolak 2023).

Alberta currently operates only a single, real-time market. Incorporating a day-ahead market would provide the benefits described above.

8.3 NEW ANCILLARY SERVICE PRODUCTS

The growth of grid-following inverter-based resources, in the form of wind and solar generation, has led to a decrease in resources capable of providing critical fast frequency response services to maintain the reliability of Alberta's power grid (AESO 2023). This is not unique to Alberta. In Texas, for example, where wind and solar have also grown rapidly, the grid operator has also had to consider implications related to reliability services, such as fast frequency response, inertia, etc.

There are several potential solutions to this challenge. We don't take a stand on any preferable route, but rather discuss a suite of potential options.

One option is a rules-based approach; for example, requiring inverter-based resources to be grid-forming and specify a power factor that provides the headroom to respond to under-frequency events. This is now the norm in FERC jurisdictions and has also been adopted in non-FERC ERCOT.

A second option is a direct procurement approach. Here, reliability products could be treated similar to transmission grid services, where AESO conducts competitive calls for long-term procurements of resources that provide specific ancillary services. These should be open to a wide range of potential resources, including both thermal generators and power electronics solutions, including capacitors and batteries.

A third approach is to rectify missing markets for specific reliability requirements, such as fast frequency response, by creating new ancillary service products to complement Alberta's existing reserve products. This ensures technology neutrality and shifts risk awareness from load on a direct procurement and instead to the provider. Conversely, that risk shift poses potential risks to investors providing reliability resources over the long run having to rely on spot prices.

8.4 INTERVAL METERS

The widespread deployment of interval meters offers a number of potential benefits to overall market efficiency and final consumers. In most jurisdictions this has been accomplished by the regulated distribution network owner providing meter reading services at regulated prices to all electricity retailers.

This approach takes advantage of the economies of scale in the installation and operation of interval meter-reading systems. The most important reason to deploy interval meters is to provide the capability to capture and record a customer's hourly consumption for each hour of the year. Retailers can competitively provide add-on services.

Once even the most rudimentary interval meters are installed, it is then possible to expose customers to the real-time price for electricity for deviations from their typical load shape in the day (Wolak 2013). Customers can now realize the full economic benefits of reducing consumption in any hour because their consumption during that hour can be measured. Wolak (2013) notes that a cellphone-plan approach to dynamic pricing protects consumers from bill risk, but still allows them to reduce their monthly bill by reducing their consumption during high-priced hours

and increasing their consumption during low-priced hours. This would not be possible without an interval meter that can record the customer's hourly consumption. This dynamic retail pricing plan enabled by interval metering will also stimulate the deployment of distributed storage and load-shifting technologies.

With the increased share of variable resources on the supply side and increasing flexibility on the demand side (e.g., EV charging), encouraging (and valuing) the involvement of responsive demand is imperative for all future market designs.

GLOSSARY OF TERMS

Electricity is riddled with a jargon all its own. Here, we briefly describe several common terms essential to the understanding of energy-only and capacity markets.

- Capacity is the amount of electricity a power plant can produce at its maximum rated power. This is often referred to as nameplate capacity; it is what is available at optimum operating conditions. A related term, available capacity, is simply the amount of nameplate capacity available at any given time. The difference can be due to maintenance, forced outages or derates due to current conditions (e.g., hot summer temperatures derate the available capacity of thermal generators).

Generation capacity can be refined into dispatchable and non-dispatchable capacity. For example, a wind turbine may be rated at 1 megawatt (MW) capacity, giving it the ability to produce at most 1 MWh of energy in an hour under optimal wind conditions. However, this non-dispatchable capacity, in the sense that control over the instantaneous amount of energy the wind unit can produce between zero and 1 MW, is out of the hands of the dispatcher (operator). It depends on wind conditions during the hour. In contrast, thermal generators and hydroelectric facilities with reservoir storage can generate on command (when available), anywhere between its minimum safe operating level and maximum capacity and are thus considered dispatchable.

- Energy is the amount of electricity actually produced by a generation unit and either used by load (consumers) or exported. Energy is measured in units of power \times time, e.g., megawatt-hours (MWh).

The two concepts are clearly connected. Energy is what consumers want to power their devices, cool their homes, to use for lighting and to provide other services. However, there must always be at least as much generation capacity producing as the instantaneous demand for energy.

- Availability factor is the ratio of available capacity to nameplate capacity. If a power plant is unavailable due to maintenance, forced outage or natural reasons, its resulting availability factor is reduced. However, if the plant is available to be dispatched but this is not done for economic reasons, the availability factor is unaffected. For dispatchable generation units, the annual availability factor provides a summary measure of the fraction of the capacity of the generation unit that can be supplied at the discretion of the system operator. For non-dispatchable units, the availability factor has less meaning, because even if the unit is available to operate, it may be unable to do so if the wind is not blowing or the sun is not shining or blocked by clouds.
- Capacity factor is the ratio of actual generation in a given time period to the total generation that would have been produced had the power plant been operating at full capacity around the clock during that time period. The capacity factor is thus a combination of the availability of a plant, as well as the economic decision to run the plant or not.

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