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Electricity Market Design with Increasing Renewable Generation: Lessons From Alberta

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Abstract

The electricity sector is going through a period of rapid transition with increasing decarbonization through the growth of renewable energy. In this paper, we consider the case of Alberta which has observed considerable growth in wind and solar generation capacity. We summarize the attributes of Alberta's energy-only market design and how it interacts with increasing renewable output. We highlight emerging challenges that need to be addressed through careful market redesign and provide a summary of key market design changes that can help more cost-effectively and reliably integrate the growing renewable resources. We discuss ongoing policy developments related to Alberta's market design. The experiences in Alberta can serve to inform market design in other jurisdictions as regulators work to enact policies to facilitate a higher renewable energy future.

Keywords: Electricity Markets, Regulatory Policy, Renewables, Reliability

JEL Codes: L51, L94, Q28, Q48

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1 Introduction

The electricity sector is undergoing a rapid transition worldwide. An increasing reliance on renewable generation and the electrification of more end-uses, such as transportation and heating, are changing electricity systems on both the supply and demand sides. Renewable energy is expected to reach a third of total generation globally by 2025 (IEA, 2024), with numerous jurisdictions setting ambitious net zero targets in the coming decades.[1] At the same time, peak electricity demand is expected to increase with rising temperatures and increasing electrification (Auffhammer et al., 2017; Mai et al., 2018; Rivers and Shaffer, 2020).

These changes have put increasing pressure on the electricity sector with the requirements to ensure there is an affordable and reliable supply of electricity. Historically, electricity markets were designed to operate with predictable demand with stable growth rates and centralized dispatchable fossil-fuel resources. As conditions change, electricity market design needs to evolve.

In this paper, we provide the context of Alberta's electricity market, one of the few remaining "energy-only" restructured electricity markets in the world. In recent years, Alberta has experienced considerable growth of renewable resources and evolving environmental regulations. Between 2015 and 2023, renewable output has increased from 5% to 14% of total supply, with thousands of MWs of renewable capacity under construction and/or in the interconnection queue. Over the same period, there has been a rapid decline of coal generation from 50% of output to only 8%, with coal completely leaving the market in the summer of 2024. Natural gas generation has also expanded, making up 74% of generation in 2023.[2] These market changes have come with significant reductions in emissions.[3]

As a relatively isolated northern climate, Alberta faces several key challenges with integrating renewable resources. In particular, Alberta has limited interties with neighboring Canadian provinces and the United States, extreme temperatures, and periods of low renewable output when demand is often highest (e.g., on extremely cold, windless, and dark winter days). Existing market design features make renewable resource integration more challenging and are increasingly divergent from approaches taken in other jurisdictions with growing renewable capacity. Examples include the

[1] Canada has an economy-wide net zero emissions target by 2050, with ongoing policies to accelerate the electricity sector towards net zero by 2035 (ECCC, 2023). More broadly, as of 2022, 68 countries and the European Union have pledged to various net zero targets (IEA, 2022).

[2] Data source: Alberta Utilities Commission Annual Electricity Data available at auc.ab.ca/annual-electricity-data/.

[3] For example, the average estimated emissions intensity has fallen from 0.75tCO2e/MWh in the fourth quarter of 2017 to 0.43tCO2e/MWh in the fourth quarter of 2023 (MSA, 2023b).

lack of a day-ahead market, a single price with no short-run congestion pricing signals, an intra-provincial transmission policy that requires infrastructure build-out to ensure there is no congestion in the long-run, and the reliance on unilateral market power to facilitate resource adequacy in the presence of a $999.99/MWh offer price cap.[4] We will describe how these market design features have interacted with the evolving generation mix and have led to ongoing operational challenges, questions over the viability of the existing transmission policy, and long-running concerns over investment incentives in the market.

We highlight relevant market design features that merit consideration and lessons from both the academic literature and ongoing experiences in other jurisdictions. These include the development of a financially binding day-ahead market to better coordinate resources and provide hedging opportunities, the use of a centralized dispatch algorithm that accounts for system and generation resource constraints, improvements to short-run pricing signals that enhance temporal prices via shorter settlement intervals and spatial signals via location-based pricing, policies to leverage demand-side resources that are currently lacking in the province, and a broader revisiting of the approach to long-run resource adequacy which currently relies on short-run market power to drive investment. While we discuss many of these reforms one at a time, we view this as a broader holistic package of reforms with important interactions.

We end by noting that Alberta is currently reforming numerous features of its market design to address growing challenges. As of the writing of this paper (August 2024), we summarize the announced interim market reforms that have been put in place in 2024 and describe longer-term high-level market re-design features that have been announced. We discuss how these market design elements fit within the broader suite of potential reforms that could be adopted. While the precise details are forthcoming, it is important that policymakers and regulators take this opportunity to make considerable updates to the existing market design and learn from the more sophisticated market design elements in other jurisdictions. The current market reforms serve as an opportunity to make large-scale holistic market design changes rather than piecemeal add-ons that remain anchored in historical market design decisions. The latter approach has the potential to fall short of the objectives to ensure an efficient, cost-effective, and reliable electricity market with increasing renewable generation.

The paper proceeds as follows. Section 2 provides a background on the con-

[4] All currency references in this paper are to Canadian dollars, unless otherwise noted. At time of writing (August 2024), $1 CAD ≈ $0.73 USD.

figuration and operation of Alberta's electricity market. Section 3 illustrates the considerable growth of renewable resources and summarizes key drivers. Section 4 describes the operational and market design challenges that have arisen together with the growth in renewables. We present several key market reforms that can help integrate the increasing renewable generation in Section 5. Section 6 summarizes a recent package of market reforms announced in 2024. Section 7 provides conclusions.

2 Alberta's Electricity Market: Background

Alberta's electricity market has operated as a competitive "energy-only" wholesale market design since 2001. In this market, generators only receive payments for providing electricity. This contrasts with many restructured markets that also provide capacity payments for making generation capacity available.[5]

In Alberta's wholesale electricity market, generators compete in a single hourly real-time uniform-priced auction. For each hour, firms submit up to seven price-quantity blocks for each generation unit that reflects the price at which they are willing to supply electricity. Offer prices must fall between $0/MWh and $999.99/MWh.

The Alberta Electric System Operator (AESO) – the organization that manages and operates Alberta's electricity market – stacks the wholesale market offers in order of least cost until there is sufficient supply to meet demand, setting the System Marginal Price (SMP). The pool price paid to generators that supply output throughout the hour represents the time-weighted SMP. Important for our subsequent discussions, there is no day-ahead market. Further, there is no security-constrained economic dispatch (SCED) that accounts for system and unit constraints when the AESO calls upon units and determines the prices paid to generators. Units are simply dispatched based on their bids in the real-time market.

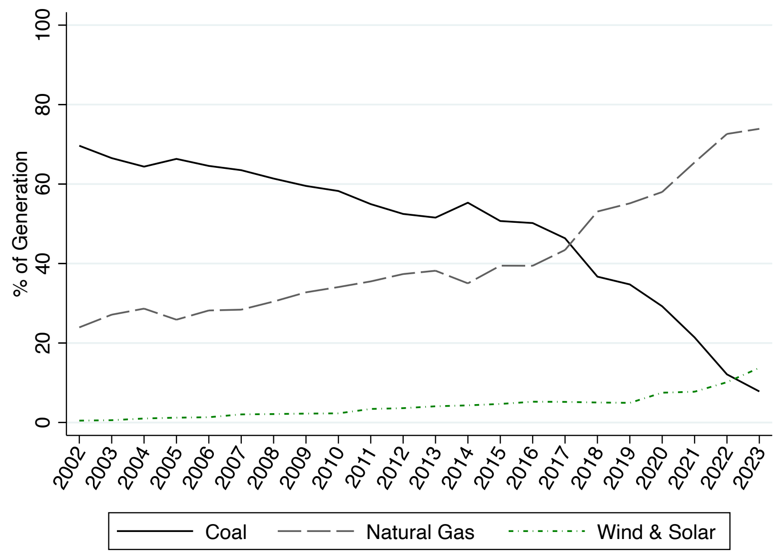
The pool price is the single market-clearing wholesale price for each hour. There is no locational marginal pricing (LMP) on the transmission network. Further, Alberta has a "no congestion" policy where in the long run sufficient transmission capacity is to be constructed such that there is no congestion (Government of Alberta, 2023). When congestion arises in the short run, the single pool price is calculated as though congestion did not occur.[6]

In addition to the wholesale energy market, the AESO procures several ancillary services products in a day-ahead market. These markets are cleared independently

[5] For a detailed review of capacity mechanisms, see Holmberg and Tangerås (2023). Alberta began to pursue implementing a capacity market design in 2017. However, the market reforms were terminated in 2019.

[6] Congestion management will be discussed in more detail in Section 4.2.

Figure 1. Annual Generation - Coal, Natural Gas, Wind & Solar



Source: Alberta Utilities Commission Annual Electricity Data available at auc.ab.ca/annual-electricity-data/.

of the wholesale market (i.e., the AS market is not co-optimized with the wholesale market). Ancillary service products are used to balance supply and demand, accounting for typical real-time variability (e.g., variability in supply and demand) and unexpected events (e.g., unit outages).

Alberta's market is relatively small and isolated from neighboring jurisdictions. For example, in 2022 the average wholesale demand was 9,883 MWhs with a peak of 12,193 MWhs that occurred in the winter. Alberta has approximately 1,100 MWs of transmission import capability with neighboring jurisdictions British Columbia, Saskatchewan, and Montana.[7] Net imports only satisfy approximately 5% of Alberta's demand (AESO, 2022).

The generation mix consists largely of fossil-fueled generation. Figure 1 presents the percentage of annual generation supplied by coal, natural gas, and wind and solar generators from 2002 - 2023. Over this period, we observe a rapid decline in coal output and an increase in natural gas generation. Between 2015 and 2023, coal generation fell from approximately 50% of total generation to 8%, while gas increased from 40% to 74%. Over the same period, wind and solar output increased from approximately 5% to 14% of total generation, with the vast majority of this output being supplied from wind facilities.

Another unique aspect of Alberta's market design is its treatment of market power.

[7]Based on the average system import capability for 2023 using data from the AESO's ATC Public Report.

Alberta's market has undergone periods of moderate market concentration. For example, in 2022 four firms had offer control over 56% of installed capacity.[8] Unilateral market power in the form of economic withholding – the bidding of generation units in excess of marginal cost – is permitted in Alberta's wholesale market (MSA, 2011, 2020).[9] Market power that is viewed to impede competition or result from coordinated behavior is not permitted. The primary motivation for this regulatory framework is to facilitate fixed cost recovery of generation units in the absence of capacity payments. The market design relies on entry and market competition to discipline the market. This contrasts with the majority of restructured markets where administrative bid mitigation mechanisms are used to limit market power execution (Graf et al., 2021). Brown and Olmstead (2017) and Brown et al. (2023) show that there have been periods of elevated economic withholding leading to a trade-off between short-run inefficiencies and the promotion of long-run investment. While firms can employ economic withholding, generators are not permitted to physically withhold generation capacity from the wholesale market.

3 Growth of Renewable Generation

While renewable output remains a relatively modest percentage of total electricity generation in Alberta, as seen in Figure 1, the construction of renewable generation capacity has been increasing rapidly in recent years. Figure 2 presents installed utility-scale wind and solar capacity (in MWs) over 2002 - 2023. There has been a sizable increase in the rate of wind and solar capacity additions starting in 2020. As of 2023, there were 5,280 MWs of wind and solar capacity installed. This reflects approximately 28% of installed capacity, increasing from just 1,491 MWs (9%) in 2015.[10]

In addition to the renewables deployed in recent years, there is a large amount of capacity under construction, adding over 1,750 MWs and 1,200 MWs of additional solar and wind capacity, respectively.[11] In August 2023, the Government of Alberta announced a moratorium on renewable projects exceeding 1 MW and directed the Alberta Utilities Commission to review the policies around renewable development. In February 2024, the Government announced new policies with restrictions on the de-

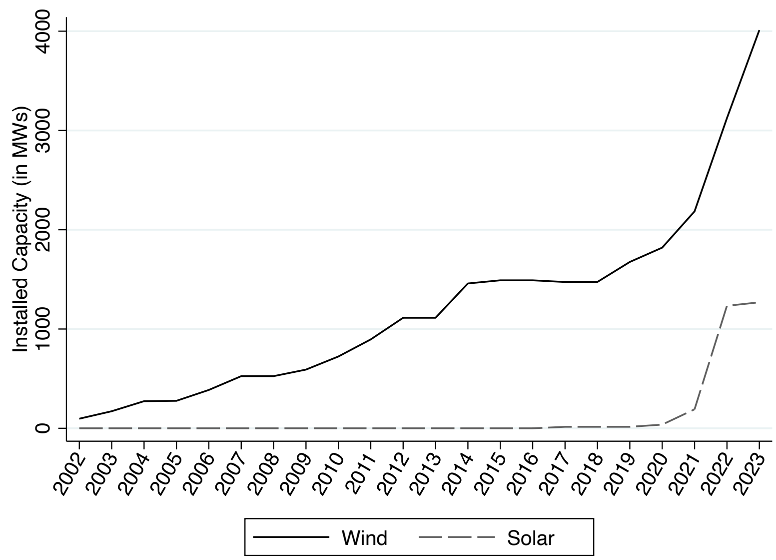
[8] Source: Alberta MSA's Market Share Offer Control report available at albertamsa.ca/documents/reports/msoc/.

[9] Alberta's Market Surveillance Administrator (MSA) is the independent market monitor of Alberta's electricity market that is tasked with ensuring market participants comply with legislation and the AESO's rules.

[10] There is also an increasing amount of behind-the-meter microgeneration in the form of solar PV. As of December 2023, there is 207 MWs of solar at over 17,500 customer sites in the province (AESO, 2024b).

[11] Numbers calculated by the authors using the AESO's May 2024 Connection Projects List, focusing on assets under construction.

Figure 2. Installed Generation Capacity by Year - Wind and Solar



Source: Alberta Utilities Commission Annual Electricity Data available at auc.ab.ca/annual-electricity-data/.

velopment of agricultural land, requirements around the end-of-life reclamation costs, among other factors related to the review and approval of future projects (Government of Alberta, 2024b). The impact of these policy changes is out of the scope of the current discussion but is expected to impact renewable development going forward.

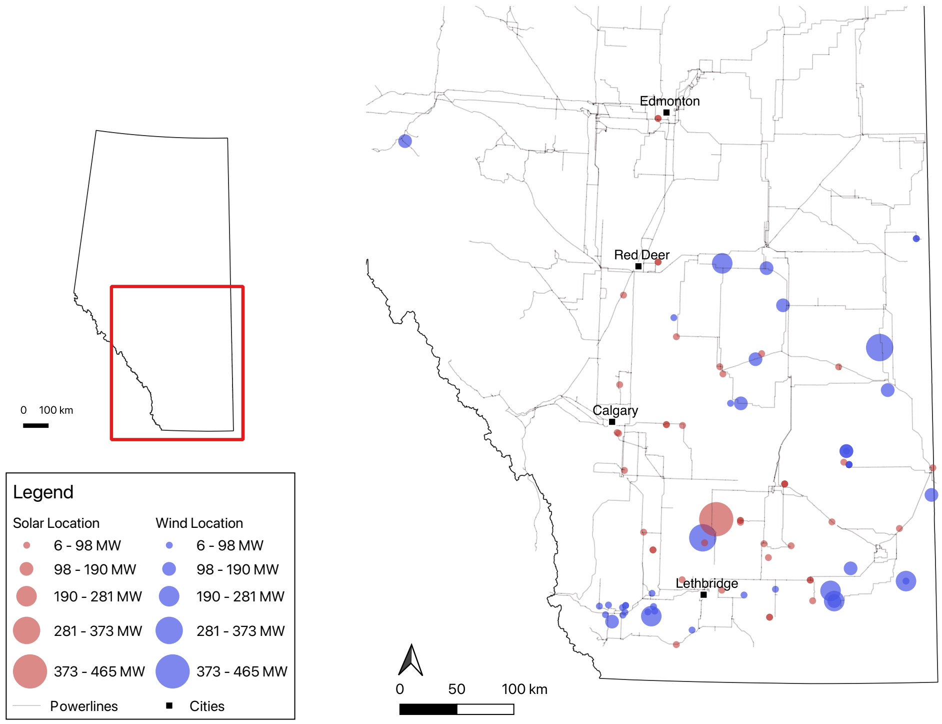
Figure 3 presents a map of the wind and solar generation resources installed and operating in the province, along with the four largest cities.[12] The largest load centers in the province are in Calgary and Edmonton with populations of approximately 1.3 and 1.1 million, respectively, followed by Red Deer and Lethbridge with populations of approximately 100,000 and 90,000. Wind and solar facilities are concentrated in the southern and eastern regions of the province away from the two largest cities. For both technologies, the resource endowments are highest in these regions. As will be discussed in Section 4, this geographical concentration creates challenges due to the temporal and spatial correlation of renewable output, combined with the costs of building transmission lines to connect these generators to the load centers.

It is informative to summarize the key economic drivers that have led to the rapid increase in renewable generation investment, the collapse of coal generation, and the increase in natural gas production documented above. Alberta has had a policy to price carbon emissions since 2007.[13] The original policy, the *Specified Gas Emitters*

[12]Generator locations collected by Authors. Transmission lines are available at Open Infrastructure Map https://openinframap.org/.

[13]For a more detailed discussion of carbon pricing in Alberta, see Leach (2012) and Olmstead and Yatchew (2022).

Figure 3. Location of Installed Wind and Solar Facilities



Source: Alberta Market Surveillance Administrator.

Regulation (SGER), applied to large generation facilities. Under SGER, generators had a facility-specific benchmark starting at 88% of the facility's historic emissions level. If a generation facility produces in excess of this benchmark, it would have to purchase offset credits or pay a carbon price of \$15 per tCO2e for these excess emissions. In 2016 and 2017, the stringency of both the facility-specific benchmark and fee per tCO2e ratcheted upwards. However, the design of and parameters for the facility-specific benchmark resulted in relatively modest costs of compliance in 2017, with a cost of \$6/MWh for coal generators and even lower costs for gas-fired units.

In 2018, Alberta changed its carbon pricing policy through a broader carbon pricing mechanism initially named the Carbon Competitiveness Incentive Regulation (CCIR), but it was replaced by the Technology Innovation and Emissions Reduction Regulation (TIER) in 2020. For the electricity sector, the policy moved away from facility-specific benchmarks, establishing a sector-wide best-in-class emissions intensity standard based on a combined cycle natural gas generator with an emissions intensity of 0.37 tCO2e/MWh. Generators above this benchmark must pay the carbon price for the difference between their emissions intensity and the benchmark. The carbon price was set by the Government of Canada to be \$30/tCO2e for 2018, 2019, and 2020, and \$40/tCO2e in 2021, \$50/tCO2e in 2022, and then increase by \$15 each year until hitting \$170/tCO2e in 2030.

The change to the CCIR/TIER framework in 2018 led to a sizable escalation in the cost of environmental compliance for coal generation, increasing from \$6/MWh in 2017 to \$18.90/MWh in 2018, with further escalating costs as the carbon price increases. Natural gas generators that are closer to the emissions intensity benchmark had considerably smaller costs of compliance (e.g., in the range of \$5/MWh for a simple cycle unit). The change in the nature of the carbon pricing policy led to a reordering of coal and natural gas units, with gas units often offering lower prices in the wholesale market. Corresponding with this change in 2018, as can be seen in Figure 1, there has been a substantial reduction in both coal generation and capacity and increasing use of natural gas (Olmstead and Yatchew, 2022). In fact, in the summer of 2024, the final coal units were converted to gas-fired facilities, 6 years ahead of the government's target to phase out coal by 2030 (Scace, 2024).

The carbon pricing regime has implications for the economics of renewable generation. Renewable generators receive revenues under the carbon pricing policy.[14] For example, in 2021, with a carbon price \$40/tCO2e, renewable resources received revenues of \$21.20/MWh. These revenues are expected to increase as the carbon price increases (e.g., to \$170/tCO2e in 2030). It is important to recognize that these revenues for the zero-emissions attributes of renewables are in addition to the revenues obtained by supplying power in the wholesale market.

In an effort to accelerate renewable deployment in the province, the Government of Alberta held a series of auctions in 2017 under the Renewable Electricity Program (REP). These competitive auctions led to the procurement of 1,360 MWs of new wind generation capacity. Wind resources constructed as a result of these government-backed contracts secured a guaranteed fixed price per MWh for 20 years.[15] Combined with a decline in the cost of renewable generation worldwide, these economic forces and government policy initiatives contributed to the increase in renewable generation investment in the province.

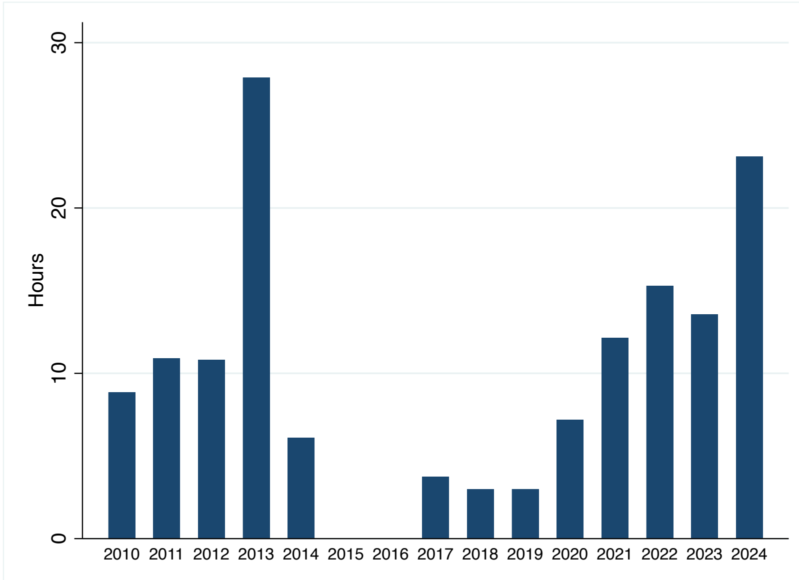
4 Impacts on the Market

In this section, we describe the key market challenges that have arisen or been magnified as renewable generation has grown in the province. This ranges from short-run

[14] For a detailed discussion of how renewable resources earn revenues under the prevailing carbon pricing policy, see MSA (2021).

[15] Hastings-Simon et al. (2022) provide a comprehensive discussion of Alberta's REP.

Figure 4. Energy Emergency Alert Events, hours per year (only first half of 2024)



Source: Market Surveillance Administrator.

operational and reliability challenges, increasing transmission congestion, and continued debates over long-run resource adequacy. We will highlight several key market design features that have amplified the difficulties of integrating renewable resources.

4.1 Short-Run Operational and Reliability Challenges

Energy Emergency Alert (EEA) events are issued when the power system is approaching supply shortfall conditions and are a measure of when the power system is at greatest risk of involuntary load shedding, i.e., brownouts. Figure 4 presents the duration of EEA events from 2010 to June 2024. From 2010 to 2014, EEA events were largely related to forced outages of thermal generators during periods of high demand. From 2017 onward, EEA events have occurred when the power system was stressed due to combinations of high demand, low wind generation, over-forecasting of wind and solar generation, thermal generation outages, and reduced import capability.

Alberta's current market design employs a self-commitment model: firms decide if and when to startup and shut down the generators they control. There is currently no centralized reliability unit commitment process in advance of the real-time wholesale market. While there is sufficient natural gas-fired generation capacity (assuming there are sufficiently few outages) to meet demand without wind or solar generation, some of this capacity has a high marginal cost and can take up to a full day to startup. These assets are referred to as long lead time (LLT) assets in Alberta. Cost characteristics mean that it is generally not profitable or economically efficient for this capacity to be kept online all of the time – especially when wind or solar generation levels are high or, perhaps more importantly, expected to be high.[16]

As a practical matter, because the exercise of unilateral market power is generally permitted in Alberta, it is difficult to distinguish instances in which firms do not startup generation capacity because it would be not profitable to generate from when they are exercising market power in the form of physical withholding. This has raised concerns that market power execution in the form of physical withholding could potentially lead to short-term reliability challenges (MSA, 2023a).

Looking forward, to ensure short-term reliability, a key issue will be to ensure that there is sufficient dispatchable generation capacity committed to be able to supply power when it is needed (e.g., when renewable output is low and/or demand is high). This becomes increasingly important the more variable renewable resources are deployed in the province.

4.2 Transmission Congestion

There has been a considerable increase in transmission congestion in recent years driven primarily by an increase in outflow constraints where there is insufficient transmission capacity to deliver wind and solar output to load centers. In 2023, 286 GWhs of wind and solar generation was curtailed. This represents a 445% increase from 2022, which had only 53 GWhs of wind and solar curtailment (MSA, 2023b). The rapid increase corresponds with the considerable growth in wind and solar resources. As shown in Figure 3, wind and solar generation capacity is geographically concentrated in the southern part of the province where renewable resource endowment is highest.

It is important to emphasize that congestion is not considered when setting the pool price that is applied uniformly across the province. When constraints are binding, the in-merit resources behind the constraint are curtailed and resources that can operate unconstrained are dispatched-on according to the next lowest-cost bids in the merit order. The associated rebalancing costs paid to the constrained-on resources are recovered outside of the pool price (MSA, 2019).[17] The increase in congestion magnifies the divergence between the short-run location-specific value of energy and

[16] In 2023, for the first time, there were times when wind and solar generation exceeded 50 percent of system demand, i.e., total electricity consumption less production by on-site generation capacity (MSA, 2023b).

[17] See Footnote 4 in Olmstead and Yatchew (2022) for additional discussion of how Alberta manages short-run congestion by dispatching down/up generation units.

the pool price. The lack of a location-specific signal has the potential to distort the location choices of generators, including renewable resources that can have the incentive to locate to maximize total output.[18]

In addition to impacting the short-run operation of the market, geographically concentrated renewable capacity interacts with the prevailing transmission planning policy. As noted in Section 2, transmission investment is planned by the AESO to meet the "no congestion" standard. This requires sufficient capacity to provide "reasonable access" to all in-merit generation when no transmission is out-of-service.

Transmission expansion will be needed to satisfy the prevailing transmission policy in regions with currently congested wind and solar resources. However, this has raised increasing concerns over the relative cost and benefits of such transmission capacity expansion because of the significant cost of transmission expansion, the relatively low capacity factor of wind and solar resources, and the geographical concentration of renewable resources resulting in a reduced wholesale market value of this energy.

4.3 Resource Adequacy

Resource adequacy – ensuring that there is sufficient supply to meet demand at (nearly) all points in time – is a fundamental regulatory objective. This brings concerns over long-run resource adequacy to the forefront of ongoing market design discussions. Historically, Alberta's energy-only market has been successful in attracting generation capacity investment, which until recently was largely in the form of coal and gas generation. The wholesale market has undergone several boom and bust cycles with elevated prices and market power, followed by investment and a subsequent decline in prices (Brown and Olmstead, 2017; Brown et al., 2023).

The growth in renewables has spurred a growing discussion of whether resource adequacy will continue to be achieved with the prevailing market design. The primary concerns are twofold. First, what happens when the wind does not blow and/or the sun does not shine? Will the market framework promote investment in dispatchable technologies to fill the gaps in renewable generation? The importance of flexible dispatchable technologies can be particularly acute in Alberta winters which can experience periods of extreme cold, limited sunlight, and low wind output.

Renewable generation, with its zero-marginal cost, is expected to reduce the average wholesale price via the merit-order effect. The reduced average wholesale price,

[18] Alberta currently has a static location signal via its Generating Unit Owner's Contribution (GUOC). The GUOC requires generators to pay a price per MW of capacity (e.g., $30,000/MW) for locating at different regions of the province, with the amount refunded over a 10-year period as the unit generates electricity (Government of Alberta, 2023). While this provides some location signals, it is a fairly modest incentive as designed and lacks any time-varying element.

combined with the $999.99/MWh offer price cap that limits revenues when market conditions are tight, has raised questions about whether there will be sufficient wholesale market revenues to promote continued investment in dispatchable technologies. This reflects elements of the well-known "missing money" problem (Joskow, 2008).

Second, generators are subject to an array of risks, including uncertainty over market design policies, environmental regulations, the amount of investment in renewables and other competing technologies, among others.[19] The anticipated heightened uncertainty is combined with a relatively illiquid long-term contracting market, with financial forward contracts typically ranging from 1 - 3 years. The limited avenues for longer-term contracting create concerns over generators' abilities to hedge risk when making large long-run capital investments (Newbery, 2016; Wolak, 2022).

5 Path Forward: Key Market Reforms

In this section, we discuss key market reforms that can help alleviate the challenges created by the growth in renewable generation in Alberta. Many of the market design elements leverage experience from other jurisdictions and acknowledge trade-offs associated with the various possible avenues, including the increasing complexity of the market design. Further, while we discuss the various design elements one at a time, we emphasize the value of a holistic package of market reforms as they have important interactions and synergies.

5.1 Day-Ahead Market

The vast majority of restructured electricity markets have transitioned to having a day-ahead market (DAM).[20] While there are many variants of DAMs, there has been a convergence in several high-level principles. On the day prior to delivery, resources submit forward-looking bids for all time periods of the next day. These bids often include multiple components, such as variable components for energy and emissions and fixed components for start-up costs. These bids are used alongside a security-constrained economic dispatch (SCED) algorithm to determine which units receive a DAM commitment, accounting for the important interlinkages across the hours in the DAM horizon. This algorithm aims to minimize the cost of meeting a measure of

[19] The federal government of Canada is also currently developing the Clean Electricity Regulation (CER) with the objective of achieving net-zero electricity generation by 2035 (ECCC, 2023). The CER is expected to impact the configuration of investment in the province going forward. While important for future market design and regulatory policy, the implications of the CER are out of the scope of the current paper.

[20] For a detailed review of DAM operations worldwide, see Ahlqvist et al. (2022).

forecasted demand for the next day, accounting for important operational constraints (e.g., start-up costs, ramp constraints) and transmission constraints.[21]

Resources that clear the DAM are subject to financially binding price and quantity commitments a day before the operation of the resources. The DAM price is typically used to settle financial futures contracts and set retail prices. Real-time markets follow DAMs and settle deviations between the day-ahead and real-time operations (due to unexpected changes in supply and demand). This results in location-specific DAM prices that consider economic costs, engineering constraints, and transmission constraints.

DAMs serve several key objectives, including providing supply and demand-side resources the opportunity to secure financial and operational certainty, as well as providing the system operator the opportunity to pre-schedule supply in advance. The heightened ability to coordinate resources in advance can better manage uncertainty arising from increased renewable resources. Further, scheduling based on a SCED algorithm facilitates the optimization of the system and, when coupled with effective market power mitigation, can move the market closer to the short-run cost-minimizing system-wide outcome. Important for the Alberta context, the DAM will better coordinate the start-up decisions of long-lead time (LLT) units which, as discussed in Section 4.1, has raised concerns over both short-run reliability and the potential use of physical withholding in recent years in Alberta. The move to a DAM will require a sizable deviation from the current operation of the market. While this will require the integration of more sophisticated software, there is vast experience with these programs in other jurisdictions.

The DAM described above is superior to a more targeted mechanism that only uses the DAM to schedule a subset of resources, such as inflexible LLT units. For example, one that only periodically schedules resources on a forward-looking, hour-by-hour basis, that is only triggered when a potential reliability concern arises.[22] This approach does not achieve the broader objectives of a DAM. In particular, this is not an optimization process that uses bids to minimize system costs, accounting for engineering and system constraints and linkages in outcomes across hours. Further, this does not provide a DAM price that is core to the goals of providing a financial signal on the value of energy in advance of market-clearing.

[21] In contrast, many European markets have decentralized commitment processes, where the producer chooses how best to meet its DAM quantity commitments. There is a long-standing debate over centralized versus decentralized market designs. Ahlqvist et al. (2022) provide a detailed review of these market designs and note that the prevailing literature finds centralized commitment is more efficient in facilitating short-run operations.

[22] As will be discussed in Section 6 below, this is similar to the approach that has been taken in Alberta starting in 2024 on an interim basis. Further, this approach has been noted as a possible option in the AESO's ongoing market design discussions (AESO, 2024c).

5.2 Efficient Pricing and Dispatch: Congestion and Settlement Interval

Sending efficient pricing signals is increasingly important with variability in both supply and demand and growing transmission congestion. Alberta's wholesale market currently compensates generators based on the hourly pool price, which represents the average of the 60 one-minute marginal prices. As a result, the settlement price can deviate from the value of energy provided within the hour.

Jurisdictions worldwide have transitioned towards more granular settlement periods, moving from hourly to 15 and even 5-minute settlement intervals (IRENA, 2019). Empirical evidence indicates that this can improve price signals to better reflect the value of energy, create stronger incentives for fast-start resources to better integrate renewable resources, and reduce overall wholesale prices (AESO, 2018; Märkle-Huß et al., 2018; Newbery et al., 2018).

In addition to improving the time granularity of pricing, there are considerable benefits to improving locational price signals. The operation of Alberta as a single zone with a uniform price results in short-run congestion costs not being reflected in market prices. Jurisdictions worldwide implement location-based congestion pricing either in the form of zonal or nodal pricing. Different forms of zonal pricing are commonly adopted in Europe and Australia, while nodal/locational marginal pricing (LMP) has been widely deployed in the United States (Newbery et al., 2018).

The seminal work of Schweppe et al. (1988) demonstrates the value of nodal pricing over less granular pricing. While zonal pricing incorporates congestion signals to a certain extent, there is a large literature documenting the short-run and long-run distortions that arise under zonal pricing (Katzen and Leslie, 2019; Eicke and Schittekatte, 2022). There is also an empirical literature quantifying the wholesale price and operational benefits of moving from a zonal to a nodal pricing structure (Zarnikau et al., 2014; Triolo and Wolak, 2022).

In Alberta, a move to LMP would likely result in lower prices in regions with higher renewable penetration where congestion occurs most often, resulting in reduced entry incentives for generators in these regions. In contrast, this can elevate incentives for large loads (e.g., data centers) or other technologies that can arbitrage off of the low-priced hours (e.g., battery storage) to locate in regions with high renewable resources. These incentives are fundamental to causing an efficient allocation of resources in the long run. A move to LMP (or even zonal pricing) should be coupled with adjustments to the Transmission Regulation away from the prevailing "no congestion" policy. Transmission planning should assess both reliability implications, as well as an economic evaluation of the cost and benefits of transmission investments.

A transition to more granular time and location-based pricing will require more sophisticated software to dispatch resources. While costly, as noted above in Section 5.1, this market reform can be coupled with the introduction of a DAM and SCED algorithm. These joint market reforms can lead to better price fidelity in the market and can leverage well-established software developed in other jurisdictions.

5.3 Demand Response and Distributed Energy Resources

Demand-side resources have the potential to provide flexibility and contribute to the increasingly difficult challenge of instantaneously balancing supply and demand. The potential for demand response is enhanced by the deployment of customer-sited distributed energy resources (DERs) such as battery storage, electric vehicles, and smart home appliances.

The configuration of Alberta's electricity demand is unique in that approximately 80% is non-residential, with 47% coming from industrial customers (AUC, 2024). This compares to the United States in which 64% is non-residential and 26% is industrial (EIA, 2024). Consequently, there is considerable potential to leverage industrial demand response.

Large industrial loads are often exposed to wholesale prices. Further, industrial customers provide supplementary reserves, frequency regulation services to manage the intertie with British Columbia, and voluntary load curtailment program (VLCP) during supply shortfalls (Pfeifenberger and Hajos, 2011).

Despite this participation, the demand response provided by industrial customers is fairly modest given its considerable potential. Alberta could consider expanding its demand response programs. For example, the refinement and expansion of the VLCP to provide demand-side flexibility during scarcity conditions, possibly taking lessons from ERCOT's Emergency Response Service program (King et al., 2021). Further, in addition to better signaling the value of energy under scarcity conditions, industrial demand response to wholesale prices could be further facilitated by increasing the wholesale price cap which is currently limited to approximately $1,000/MWh.

There are currently no incentives to motivate residential demand-side flexibility in the province. Alberta has a competitive retail market where retailers offer customers fixed and variable price contracts. However, even the variable-priced contracts vary at most monthly. In addition, customers are settled based on total monthly consumption with service-territory-wide hourly load shapes applied for settlement (i.e., customers are not billed based on their actual hourly profiles). The ability for hourly metering is limited in certain parts of the province by a lack of advanced metering infrastructure

(AMI). However, AMI is currently being rolled out in various jurisdictions across the province.[23]

Residential demand response can be facilitated by the continued deployment of AMI and a transition to billing based on a customer's hourly interval data. This will set the stage for exposing retail customers to time-varying pricing. Empirical estimates suggest a modest degree of residential price responsiveness to time-varying pricing (Harding and Sexton, 2017). Recent literature finds that barriers to demand response can be overcome by leveraging automation, resulting in a considerable increase in the price-responsiveness of residential customers (Blonz et al., 2021; Bailey et al., 2024a). Further, customers with emerging DERs such as electric vehicles have been shown to exhibit considerable potential for responding to time-varying pricing (Bailey et al., 2024b). Programs that can leverage automation and emerging DER technologies have the potential to enhance residential demand response programs.

One possible business model that could be deployed in Alberta is to leverage the presence of competitive retailers. Retailers would be exposed to the costs of providing services to their retail customers based on hourly-metered volumes. Currently, this would reflect the time-varying costs of wholesale energy.[24] Retailers would offer customers a diverse array of plans, including both fixed-price and time-varying plans to capture the heterogeneous preferences of customers. Retailers could further target customers with programs to unlock additional flexibility. For example, through the use of automation of smart appliances and DERs in the household. This can help avoid the cognitive burden of responding to price signals, provide customers with compensation for providing these services, and reduce the retailer's cost of its retail load obligations. These types of programs are deployed by retailers Octopus Energy and David Energy in ERCOT as part of their "virtual power plant" offerings (Spector, 2023). An important caveat to this market design is that regulators would need to carefully monitor the extent of retail competition. This can be of particular concern in jurisdictions where the market is concentrated among a handful of retailers, as is the case in Alberta.[25]

[23]For example, AMI is currently widely available in Edmonton, and ENMAX recently announced a rolling out of AMI in Calgary (ENMAX, 2024).

[24]The efficiency of this market framework would be enhanced by exposing retailers to spatially and temporally granular costs of transmission and distribution services (Wolak and Hardman, 2021). This is particularly valuable in the presence of emerging DERs that can place particular pressure on local distribution networks, e.g., in the form of large electric vehicle loads (Bailey et al., 2024c).

[25]For example, in December 2023, three (four) retailers had a market share of 79% (91%) of residential customers on competitive retail products (by customer counts). Approximately 74% of residential customers were on competitive products, with the remaining being on the default regulated product (MSA, 2024b).

5.4 Market Power Mitigation

A unique element of Alberta's market design has been permitting the exercise of market power via economic withholding as a mechanism to promote resource adequacy (Olmstead and Ayres, 2014). In recent years, there has been an escalation in the extent of market power corresponding with an increase in market concentration (Brown et al., 2023). This has led to elevated wholesale prices that increased the retail price paid by consumers, and has resulted in growing criticisms of the market leading to calls for market reforms (MSA, 2023a).

While there has been considerable investment that is coming online in 2024 by non-incumbent generators, particularly in renewable capacity, market power is expected to be an ongoing factor. Dispatchable (flexible) supply is expected to remain concentrated leading to opportunities for firms to exercise market power in hours when renewable output is low. These concerns are enhanced by the fact that TransAlta, the largest firm in the market by generation capacity, has plans to acquire Heartland Generation, the third largest firm (TransAlta, 2023; MSA, 2024a).

Explicitly permitting market power execution has been an Alberta-specific design element. Typical models of market design do not include the use of market power to facilitate resource adequacy. Other market features, discussed in more detail in Section 5.5, are implemented to achieve this objective. If market power continues to be permitted, regulators are accepting the trade-off of short-run productive inefficiencies that result from market power to facilitate investment. Going forward, generator investments will need to be made based on potentially increasingly uncertain market power rents as renewable capacity expands.

Alternatively, every other restructured electricity market in North America has a formal *ex-ante* bid mitigation mechanism. Broadly speaking, if a generator is determined to have the ability to exercise market power and/or its bidding behavior has a sufficient impact on market outcomes, the generator's bids are limited to not exceed a multiple of its estimated marginal cost (Graf et al., 2021). While bid mitigation mechanisms differ across regions and have their ongoing challenges (Adelowo and Bohland, 2022), the objective is to limit short-run market distortions and use other mechanisms to facilitate resource adequacy. In the presence of zonal or nodal pricing, location-based bid mitigation is used to limit local market power (Graf et al., 2021).

Bid mitigation mechanisms are typically implemented in conjunction with day-ahead markets.[26] To further enhance arbitrage across day-ahead and real-time markets, virtual bidding – the participation of purely financial entities – has been used.

[26] For a detailed analysis of market power in sequential markets, see (Ito and Reguant, 2016).

The empirical literature has found that virtual bidding reduces price spreads across these markets and limits market power opportunities (Mercadal, 2022; Jha and Wolak, 2023). Even if an ex-ante market power mitigation mechanism is not broadly adopted, virtual bidding should be considered to enhance competition in the DAM.

5.5 Long-Run Resource Adequacy

Jurisdictions worldwide have introduced additional mechanisms to facilitate long-run resource adequacy. While there is a long-standing debate over the approach (Holmberg and Tangerås, 2023), one element of market reform is broadly accepted. First and foremost, strengthening energy market signals should be the first step in motivating efficient investment. This includes refinements to better reflect the spatial and temporal value of energy. Many of the reforms discussed above move in this direction. Despite these energy market reforms, there are concerns that there will be insufficient investment incentives due to inherent features of electricity markets and regulatory/political frictions (Joskow, 2008; Newbery, 2016; Wolak, 2022). This is particularly acute in Alberta if the wholesale price cap of $999.99/MWh remains.

Alberta has several possible routes that could be taken to help facilitate long-run resource adequacy. First, it could pursue what we will call an "enhanced energy-only" market. Essentially this would entail adopting reforms to strengthen the energy market signals, as noted above, and ideally elevate the wholesale price cap to magnify the potential for scarcity pricing. A number of jurisdictions have implemented an additional market mechanism called the Operating Reserve Demand Curve (ORDC) that serves as an administrative-determined pricing tool to elevate prices during periods of supply scarcity (Hogan, 2013).

In theory, an enhanced energy-only market design with a price cap equal to the Value of Lost Load (VoLL) and perfectly competitive markets could facilitate the optimal level of investment (Joskow and Tirole, 2007). However, several real-world frictions raise concerns over the ability to achieve this outcome. There has been limited appetite for an elevated price cap, particularly to levels believed necessary to motivate sufficient investment. Scarcity pricing supplemented by an ORDC mechanism has been criticized for its administrative nature and the ability of its uncertain stream of revenues to motivate large capital investments (Bajo-Buenestado, 2021).

It is possible that Alberta could continue to rely on market power in an enhanced energy-only market to facilitate long-run investment incentives. However, this approach comes with the downside of continuing to accept short-run inefficiencies and the potential for extra-normal rent transfers to firms in the short-run given the time required to make large-scale investments. The anticipated increase in market concentration, as noted in Section 5.4 above, raises additional questions about the appropriate level of market power to be permitted. This path would require firms to make generation investments based in part on potentially increasingly uncertain market power rents. More broadly, a growing critique of energy-only market designs is the considerable uncertainty in expected market revenues and the imperfections in financial markets to provide sufficient risk-hedging instruments (Mays et al., 2022). Concerns over risk of cost recovery are compounded in the case of Alberta by the ongoing uncertainty over federal environmental policies and growing renewables that put downward pressure on average wholesale prices, but increase price volatility (Mays and Jenkins, 2023).

Alternatively, many jurisdictions have moved towards capacity payment mechanisms that provide payments to generators for making their capacity available, supplementing revenues provided for energy services. While capacity mechanisms have been successful in achieving regulatory-determined capacity levels, they have been the subject of considerable critiques. This includes their considerable complexity and regulatory-determined parameters raising concerns that capacity markets lead to overinvestment (Garmlich and Goggin, 2019). In addition, capacity markets require allocating capacity values to resources. This is relatively straightforward with thermal resources. However, this is extremely challenging with renewable generation, storage technologies, and demand response (Wolak, 2022; Holmberg and Tangerås, 2023). Given these critiques, and the previous move to adopt a capacity market in Alberta that was subsequently terminated, a move to a capacity mechanism is not likely to succeed.

The growing critiques of capacity markets and the continued concerns over resource adequacy have led to the proposal of alternative instruments to promote resource adequacy. There is increasing interest in the use of an energy-contracting-based approach. Wolak (2022) develops a detailed proposal for a standardized fixed-price forward contracting approach. Load-serving entities would be required to procure a fixed amount of energy in advance using forward-contracting instruments. The forward contracts reflect the average system-wide load shapes in contrast to power purchase arrangements that are commonly employed which depend on actual generation (Shu and Mays, 2023). This approach is argued to facilitate risk-hedging for both generators and consumers while maintaining short-run pricing signals in energy markets. Two additional key advantages in the Alberta context are that it can be readily added onto an existing energy-only market framework while avoiding the complexities of capacity markets, and it mitigates firms' incentives to exercise market power via the standard pro-competitive impacts of forward contracts (Allaz and Vila, 1993).[27]

Regardless of which resource adequacy approach is taken, a key approach that has considerable risks is to employ out-of-market ad hoc long-term contracting. For example, if there is a belief that there will be resource adequacy concerns in several years, regulators may feel inclined to procure long-term capacity contract(s) outside of the existing market mechanisms to promote investments in pre-selected technologies. This is likely to impede broader investment incentives in the market. Rather, as part of the ongoing market redesign, it is preferred to develop a robust market mechanism to promote resource adequacy.

6 Recent Market Design Announcements

In this section, we summarize the ongoing market design developments in Alberta and discuss how they fit within the discussion of potential paths forward detailed above. In response to the operational issues discussed in this paper, as well as affordability concerns related to high wholesale prices in 2022 and 2023 due to elevated market power, in the summer of 2023, the Government of Alberta (Government) directed the AESO and the MSA to provide advice related to potential market changes to the electricity market design. The AESO recommended that Alberta develop a Restructured Energy Market (REM) that would include several features common to other electricity markets, including a day-ahead market and improved real-time system operation tools (AESO, 2024a). The MSA made a similar recommendation and also recommended the implementation of a market power mitigation scheme and unit commitment process on an interim basis until the REM could be implemented to address the immediate challenges in the market (MSA, 2023a).

On March 11, 2024, the Government announced that an interim market power mitigation scheme and unit commitment process would be implemented as of July 1, 2024 (Government of Alberta, 2024a). These tools would be deployed until the market design elements decided under the REM are implemented. The interim market power mitigation will limit offers for natural gas generators to the greater of $125/MWh or 25 times the day-ahead price of natural gas in Alberta for firms with a market share in excess of 5%. The bid mitigation mechanism is only triggered once the monthly net short-run revenues (revenue in excess of operating costs) of a hypothetical combined cycle natural gas generator exceeds one-sixth of the annualized unavoidable cost of

[27]For a detailed summary of this approach in the Alberta context, see Shaffer and Wolak (2024).

the hypothetical generating unit. The logic of this approach is that firms will earn short-run market power rents to cover fixed costs, but there is a "safety valve" on the amount of market power rents, while being feasible to implement within the existing market tools in a short period of time. The unit commitment process will require the AESO to direct generators on LLT status online when forward-looking supply-demand conditions are sufficiently tight. Committed generators are eligible for cost guarantee payments under some circumstances. This somewhat ad hoc approach aims to reduce the reliability concerns of LLT units that are potentially physically withholding supply until (ideally) a more sophisticated mechanism is deployed.

In July 2024, the AESO began consulting on the core market design elements of the REM, including a mandatory day-ahead market, continued reliance on strategic offer behavior to set pool prices with market power mitigation to limit excessive exercise of market power, a province-wide uniform price for electricity, security-constrained economic dispatch, sub-hourly power pool settlement intervals, and co-optimization of energy and ancillary services (AESO, 2024c). The AESO was also directed to review the price floor and ceiling.

The consultations on the REM will continue into 2025. The REM would replace the interim measures noted above upon its implementation. Concurrent with the direction to develop the REM, the Government announced that Alberta would move away from its current zero-congestion transmission planning standard to a more actively planned transmission system. Details about these transmission policy changes are not yet decided.

The proposed elements of the REM include a number of the key market design reforms discussed above in Section 5. However, the final design and implementation details are key. The move to a DAM market will provide important benefits to facilitate unit commitment, coordination of resources, and the overall optimization of the system. This is superior to the interim measure that focuses only on the unit commitment of LLT units. It is important that the AESO takes lessons learned from other jurisdictions in the design details of the DAM and SCED algorithm that were summarized in Section 5.1. Examples include the use of financially-binding bids that are used within the SCED algorithm to optimize the system, demand-side participation, and the use of virtual bidding to facilitate financial arbitrage across the DAM and RTM. These design elements have been successfully integrated in other jurisdictions with empirically demonstrated benefits (Jha and Wolak, 2023).

While the proposed market design has a shorter settlement interval to improve the granularity of price signals, it maintains the uniform energy price (i.e., there is no move towards location-based pricing to any extent). As discussed in Section 5.2, there is a large literature documenting the benefits of LMP both in terms of the short-run operational improvements and the importance of the long-run location-specific signal of the economic value of energy. The continued reliance on uplift payments to compensate generators that are dispatched-on leads to price signals that are not contained in the wholesale market price, and require the use of redispatch mechanisms that can yield inefficiencies. This goes against what should be the core goal of market reforms, to improve and strengthen the wholesale energy price signals.

The move towards a refined transmission policy away from the zero-congestion planning standard to one that is based on both reliability and economic value is a clear improvement. However, this indicates that congestion will persist in the long run. This magnifies concerns over the lack of location-based energy pricing signals and the associated distortions.

Under the proposed design, there are discussions to increase the price-cap to \$2,000/MWh or \$3,000/MWh. This is broadly consistent with calls to enhance scarcity pricing signals to promote resource adequacy. However, it was indicated that there will be a continued reliance on market power to facilitate resource adequacy. The elevated price cap and continued concerns over market concentration, particularly in hours where renewable output is low, will require the replacement of the interim market power mitigation scheme, ideally with a mechanism that accounts for multipart bids in the DAM. Given a longer implementation timeline, a broader and more sophisticated set of market power mitigation options is feasible. Alberta regulators will face the challenging task of limiting excessive market power while simultaneously providing sufficient signals for investment. There is growing support in the academic literature, summarized in Section 5.5, highlighting concerns of insufficient liquidity in forward markets to promote risk-hedging. These challenges are magnified by the anticipated increase in wholesale price volatility with increasing renewable generation. The proposed market reforms do not address these growing concerns.

Finally, the proposed reforms only briefly make note of other initiatives to facilitate demand-side flexibility, including the role of time-varying pricing for residential customers and the continued development of demand response programs. While the focus of the REM is largely on the supply side of the market, as discussed in Section 5.3, the demand side is a critical tool that can facilitate a reliable and cost-effective electricity market, particularly with increased variability in supply from renewables. The design elements of the REM will impact demand-side decisions. For example, the potential for an elevated price cap will create stronger price signals for commercial and industrial customers on wholesale-priced contracts to respond to tight market conditions. Alternatively, the decision to maintain a uniform price will result in no financial signal for large loads to locate in certain areas of the province with excess supply and congestion. As a result, the role of the demand side in the prevailing market design should be a central element of the REM going forward.

7 Conclusions

Like many jurisdictions worldwide, Alberta's electricity market is undergoing a period of transformation with an increasing reliance on renewable generation. However, unlike other restructured markets, Alberta's market design is relatively simplistic with its lack of centralized unit commitment, no day-ahead market, no locational pricing, a zero congestion policy guiding intra-provincial transmission investment, and a reliance on market power to promote resource adequacy. We discuss ongoing challenges that have arisen due to the interaction between renewable capacity growth and existing market design features, including short-run operational challenges arising from a lack of a unit commitment mechanism, increasing transmission congestion and the divergence between locational energy value and prices, and concerns over elevated market power in recent years and the continued reliance on strategic behavior to promote resource adequacy.

In this paper, we describe approaches employed in other jurisdictions to more cost-effectively integrate renewable generation while maintaining reliability. This includes a reliance on day-ahead markets to coordinate resources under uncertainty, strengthened energy market price signals with more spatially and temporally granular pricing, alternative approaches to promoting resource adequacy, bid mitigation to limit market power, and enhanced demand response. There is a growing empirical literature demonstrating the value of these market reforms.

In ongoing discussions, the Alberta Electric System Operator has proposed several market design reforms at the direction of the Government of Alberta. These include the development of a day-ahead market and security-constrained economic dispatch to improve unit commitment, reforms to long-run transmission planning, and strengthened wholesale price signals via shorter settlement intervals and a potentially elevated price cap. While the proposed reforms tackle several immediate challenges and adopt certain elements described in this paper, key gaps remain. Examples include the continued reliance on a uniform price rather than the development of a zonal or locational pricing mechanism, and limited changes to the prevailing market design to address concerns over resource adequacy with growing renewable generation.

As renewable generation capacity expands, it will be important for jurisdictions such as Alberta to ensure they are adopting a holistic package of reforms that strengthen the wholesale market signals and develop a market and regulatory framework to promote resource adequacy and demand-side participation. There is a growing body of empirical evidence pointing to key market design reforms that can be employed to facilitate renewable integration while ensuring the electricity system remains reliable and cost-effective. While such reforms are challenging and can reflect a considerable deviation from current market operations, it is important that jurisdictions do not remain anchored in historical market design elements at the cost of overall efficiency.

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