ALBERTA'S ELECTRICITY REGIME OVERHAUL: IMPLICATIONS OF THE CURRENT AND EVOLVING REGULATORY ENVIRONMENT FOR POWER GENERATION

JESSICA KENNEDY,* JACKIE GOW,** SCOTT POITRAS,***
BRANDON LEITCH,**** VINCENT LIGHT,***** LARISSA LEES****** & NATHAN GREEN*******

Alberta is implementing its most significant electricity regulatory overhaul since 1996, responding to decarbonization, reliability, affordability, and rapid changes in the generation mix. This article explores the reforms in stringent land use, visual impact, and reclamation requirements for renewables, an overhaul of market design via the Restructured Energy Market, and new transmission planning and cost allocation frameworks. These changes generate investment uncertainty, particularly for renewables and power purchase agreements, but also create opportunities for data centres and storage developers. The transition from zero-congestion to optimal transmission planning, new market power mitigation, and cost causation principles have substantial commercial impacts. Uncertainty is expected to persist until the regulatory framework stabilizes.

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* Partner, Bennett Jones LLP.
** Manager, Strategy, Alberta Electric System Operator.
*** Legal Counsel, Alberta Electric System Operator.
**** Senior Legal Counsel, ATCO Group.
***** Senior Legal Counsel, Regulatory, TransAlta Corporation.
****** Associate, Bennett Jones LLP.
******* Associate, Norton Rose Fulbright Canada LLP.

The authors gratefully acknowledge the contributions of Nathan Murray, Associate, Bennett Jones LLP.

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INTRODUCTION

Alberta's electricity framework is undergoing the largest overhaul since deregulation in 1996. The provincial government has directed three core areas of change: (1) stricter requirements for new generation development in Alberta; (2) the significant restructuring of Alberta's electricity market; and (3) major changes to Alberta's transmission system planning and cost recovery policies.

This article examines these power sector policy changes and discusses certain resulting regulatory and commercial implications for generators.[1]

I. BACKGROUND

A. CURRENT ELECTRICITY FRAMEWORK

Alberta's electricity framework consists of deregulated generation and retail markets with regulated transmission and distribution. It is regulated by three key regulators: (1) an independent system operator (ISO) operating as the Alberta Electric System Operator (AESO); (2) the Alberta Utilities Commission (AUC or Commission); and (3) the Market Surveillance Administrator (MSA). The AESO is responsible for ensuring the safe, reliable, and economic operation of Alberta's electrical grid, establishing ISO rules and reliability standards, and promoting a fair, efficient, and openly competitive market for electricity.[2] The AUC is an independent tribunal that regulates Alberta's electric utilities[3] and is responsible for approving and overseeing the construction and operation of generation, transmission and energy storage facilities.[4] The MSA is Alberta's market watchdog, ensuring a fair, efficient, and openly competitive electricity market and compliance with regulatory standards.[5]

Alberta's current electricity market and transmission policies frameworks are predicated on robust competition in an energy-only market enabled by access to an unconstrained transmission system to drive reliability, efficiency, and affordability. Alberta maintains three transmission interconnections (interties) with neighbouring jurisdictions, over which power can be imported or exported, including the Alberta-British Columbia intertie (800-megawatt

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1 The information in this article is current to 15 July 2025.
2 *Electric Utilities Act*, SA 2003, c E-5.1, ss 7–41 [*EUA*].
3 The AUC also regulates natural gas and water utility services.
4 *Alberta Utilities Commission Act*, SA 2007, c A-37.2, ss 32–62 [*AUCA*].
5 *Ibid*.

(MW) capacity), the Montana Alberta Tie Line (300 MW capacity), and the Alberta-Saskatchewan intertie (150 MW capacity).

In the current energy-only market, generators compete to deliver energy to serve load and earn the single wholesale market price. Offers from generators are submitted each hour from lowest to highest priced (merit order), with the wholesale market price being set by the generator whose offer intersects supply and demand in each minute, which is then averaged over the hour. The wholesale market price is paid to generators when they produce and deliver energy, measured in megawatt-hours (MWh), to load customers.[6] Wholesale market revenue has traditionally functioned as the key pricing signal to attract generation investment to the province to ensure a reliable supply of energy in both the short- and long-term. As demand for electricity (load) grows in the province, the wholesale market price rises and signals new generation to enter the market. When new supply in the form of generation enters the market, wholesale prices decrease. More load growth starts the price signal cycle again.

Generation and load customers may enter into power purchase agreements (PPAs) in Alberta to hedge against the fluctuating wholesale price (discussed further below).

Until recently, the AESO was required to plan and develop the transmission system to accommodate the transmission of anticipated in-merit energy (zero-congestion).[7] This ensured that the transmission system — as the "highway" between electricity producers and consumers — could enable the physical exchange of electricity between market participants and was not a barrier to the functioning of the competitive energy-only market. Under zero-congestion, investments in transmission infrastructure were made to: (1) keep pace with load and generation growth; (2) enable market access for generators; and (3) ensure load can be served reliably and economically.[8] There are no transmission rights for market participants under this policy.[9]

A transmission-connected generator is afforded a "reasonable opportunity" to connect to the transmission system to get their energy to market.[10] The generator must obtain from the AUC: (1) a transmission system interconnection order; and (2) a permit and licence to construct and operate the generating facility.[11]

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[6] Alberta Electric System Operator, "Alberta's Restructured Energy Market, AESO Recommendation to the Minister of Affordability and Utilities" (31 January 2024) at 12, online (pdf): [perma.cc/PDB9-BE4Q] [AESO Recommendation].

[7] *Transmission Regulation*, Alta Reg 86/2007, ss 15(1)(e)–(f) [*T-Reg*]. See also *EUA*, *supra* note 2, s 33(1); *Transmission Amendment Regulation*, OC 249/2025 (not published in Alberta Gazette at time of writing) [*T-Reg Amendment*], repealing ss 15(1)(e)–(f) of the *T-Reg*, thereby eliminating zero-congestion.

[8] See *T-Reg*, *supra* note 7, s 15(1)(e). See also Alberta Energy, *Transmission Development: the Right Path for Alberta* (Policy Paper), (Edmonton: Alberta Energy, 2003) at 2, online: [perma.cc/BZP8-6GEM] [2003 Paper].

[9] *Re Alberta Electric System Operator Objections to ISO Rule 9.4 Transmission Constraints Management* (9 April 2009), 2009-042 at paras 150–58, online: Alberta Utilities Commission [perma.cc/4QWH-3RTC].

[10] *EUA*, *supra* note 2, s 29.

[11] *Hydro and Electric Energy Act*, RSA 2000, c H-16, ss 11, 14, 15, 18 [*HEEA*].

In exchange for accessing the transmission system, a generator must pay: (1) the local interconnection costs associated with connecting the generating facility to the transmission system; (2) a refundable generating unit owner's contribution (GUOC) based on generating capacity and location, which is intended to send an economic signal to site generation near load and mitigate the risk of stranded transmission assets;[12] and (3) line losses, which are intended to provide a locational signal for new generation seeking to connect.[13] All other transmission costs are allocated to load customers, who are seen as the primary beneficiaries of the transmission system.

B. DRIVERS FOR POLICY CHANGE

The current framework has supported reliability, affordability, and efficient grid integration over the past 30 years since market deregulation in the mid-1990s. However, the compounding effect of the following trends, as described by the AESO's Market Pathways Primer, is challenging the ability of the current framework to continue to deliver on those objectives:

1. CHANGING SUPPLY MIX

The shift from large, centralized, and dispatchable carbon-emitting generation to smaller, time-variable renewable sources has introduced operational and reliability challenges. As conventional generators, which provided key supply attributes that help stabilize the physics of the grid, decrease in proportion, there is a growing need to incentivize these reliability attributes through new market mechanisms.

External factors, such as carbon emission offsets and credits, tax credits, and other incentives that support renewables development outside the electricity market are also influencing the functioning of long-term investment signals in dispatchable generation. This is compounded by market price volatility, which can lead to supply imbalances. As Alberta's electricity system decarbonizes, ensuring effective price signals to manage reliability and encourage investment in necessary technologies is crucial.

2. PACE OF SUPPLY INTEGRATION AND TRANSMISSION IMPACTS

The expansion of Alberta's transmission system is increasingly driven by the growing penetration of wind and solar generation resources, particularly in southern Alberta. This shift is challenging the premise of the cost recovery framework, as new transmission is increasingly required to integrate the influx of renewable generation, rather than serve load. New generation resources are outpacing traditional transmission planning processes. This has led to rising congestion (that is, events where the transmission lines cannot accommodate all electricity flow) and more frequent use of real-time constraint management protocols by the AESO, which have associated costs and adverse market impacts. For example, in 2024, over

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12 *T-Reg*, *supra* note 7, s 29; 2003 Paper, *supra* note 8 at 6.
13 2003 Paper, *supra* note 8 at 6–7, 17–19.

508 gigawatt-hours of intermittent (mostly wind) generation was curtailed in Alberta due to transmission constraints, representing a 178 percent increase from 2023.[14]

Building transmission to alleviate congestion is a costly endeavor. Additionally, renewable penetration has shifted peak flows to the windiest and sunniest hours, which often do not align with traditional peak demand periods. These shifted peak flows complicate cost recovery and allocation under the ISO tariff because the current rate design is largely based on incenting load to reduce consumption during peak demand. This cost allocation approach does not address congestion costs driven by generation. These challenges are further highlighted in the context of the AUC's oversight of new generation projects, which does not extend to examining the need for new generation or its impacts on the regional transmission system.[15]

3. DECARBONIZATION POLICY

Decarbonization policies, including the federal *Clean Electricity Regulations*,[16] may restrict the operation of gas-fired generation in the future. Given existing barriers to the rapid deployment of carbon-free baseload generation (such as nuclear or gas-fired generation with carbon capture and sequestration), these policies are impacting the pipeline of projects necessary to provide essential reliability attributes, address load growth, and complement the growing prominence of variable renewable energy sources on the system.

II. SUMMARY OF POLICY CHANGES

Alberta's electricity framework overhaul began in mid-2023 with a series of provincial directions, regulations, orders, and consultations. This article addresses three key initiatives, each of which are at various stages of advancement.

First, the AUC's inquiry into renewable generation in Alberta has led to stricter regulatory measures affecting the development of generation, such as new visual impact assessments (VIA), land use restrictions, and reclamation security requirements. Second, the Restructured Energy Market (REM) introduces fundamental shifts in Alberta's market design to better incentivize the generation attributes required for reliable system operation. Third, Alberta has now changed its transmission policy, moving away from the zero-congestion planning framework and adjusting how certain transmission costs are recovered.[17] This article discusses the REM and transmission policy changes together, considering their interdependencies.

The table in Appendix A summarizes the key events associated with the new policy direction for each of the three core areas.

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14 See Market Surveillance Administrator, *Quarterly Report for Q4 2024* (Calgary: MSA, 2025) at 4, 57, online (pdf): [perma.cc/W7C3-CK7C].

15 *HEEA*, *supra* note 11, s 3(1)(c). The factors the AUC must consider in evaluating a new power plant proposal are stated in the *AUCA*, *supra* note 4, s 17(1).

16 SOR/2024-263.

17 *T-Reg Amendment*, *supra* note 7.

III. ALBERTA UTILITIES COMMISSION RENEWABLES INQUIRY AND REGULATORY CHANGES FOR GENERATORS

A. APPROVALS PAUSE AND INQUIRY PROCESS

On 3 August 2023, the Alberta Minister of Affordability and Utilities (Minister) announced the *Generation Approvals Pause Regulation*,[18] directing the AUC to pause facilities approvals for new renewable electricity projects until 29 February 2024.[19] The pause was implemented to facilitate a review of the policies and procedures for the development of renewable electricity generation.

The Government of Alberta directed the AUC to conduct an inquiry into the ongoing economic, orderly, and efficient development and operation of electricity generation in Alberta (the Inquiry) during the pause.[20] The scope of the Inquiry included five issues:

1. Development of power plants on specific types or classes of agricultural or environmental land;
2. The impact of power plant development on Alberta's pristine viewscapes;
3. Implementing mandatory reclamation security requirements for power plants;
4. Development of power plants on lands held by the Crown in Right of Alberta; and
5. The impact the increasing growth of renewables has to both generation supply mix and electricity system reliability.[21]

The AUC established bespoke participation processes to conduct its Inquiry, consisting of published expert reports from AUC-retained consultants and the opportunity for stakeholders to provide feedback over the course of approximately three months. The AUC bifurcated the scope into two modules: Module A, covering issues one through four; and Module B, covering issue five.[22]

The AUC submitted its reports for Modules A and B to the Minister on 31 January 2024, and 28 March 2024, respectively.[23] The reports included: a summary of information received; commitments in respect of AUC process matters; observations arising from the evidence and

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[18] Alta Reg 108/2023 [*GAPR*].

[19] Government of Alberta, "Backgrounder: AUC Pause and Inquiry" (3 August 2023), online (pdf): [perma.cc/5GNG-LLWK].

[20] OC 171/2023 (not published in Alberta Gazette at time of writing).

[21] *Ibid*.

[22] Alberta Utilities Commission, *AUC Inquiry into the Ongoing Economic, Orderly and Efficient Development of Electricity Generation in Alberta*, Module A (Calgary: AUC, 2024), online (pdf): [perma.cc/884F-MKVV] [Module A Report]; Alberta Utilities Commission, *AUC Inquiry into the Ongoing Economic, Orderly and Efficient Development of Electricity Generation in Alberta*, Module B (Calgary: AUC, 2024), online (pdf): [perma.cc/UCP9-C5YT] [Module B Report].

[23] *Ibid*.

submissions reviewed; and policy options to address the issues explored. They did not include policy recommendations to the Government of Alberta.

B. RESULTING POLICY AND REGULATORY DEVELOPMENTS

Following the Inquiry, the Government of Alberta announced its intention to advance policy, legislative, and regulatory changes before the end of 2024, including, among other matters:

- Implementing an "[a]griculture [f]irst" approach to land use, including prohibiting renewable generation development on lands with specific soil classifications unless a proponent can demonstrate that both crops or livestock and renewable generation can coexist;

- Implementing policy to ensure developers are responsible for reclamation costs via bond or other form of security;

- Implementing policy to establish a minimum 35 km buffer zone around protected areas and other "pristine viewscapes" where VIAs may be required, and new wind projects would no longer be permitted;

- Implementing policy to enable the development of renewable generation on Crown lands on a case-by-case basis with legislative changes coming into force in late 2025; and

- Requiring the AUC to conduct processes to consider the appropriate setbacks of renewable development from neighboring residences and other infrastructure, and mandatory site visits for proposed renewable generation projects.[24]

Initial policies related to the "agriculture first" land use approach, reclamation security, and viewscapes have been implemented, as summarized below. As of the date of writing, the remaining two initiatives have not resulted in regulatory changes.

1. ELECTRIC ENERGY LAND USE AND VISUAL ASSESSMENT REGULATION

On 6 December 2024, the *Electric Energy Land Use and Visual Assessment Regulation* was enacted under the *Alberta Utilities Commission Act*.[25] The *Land Use Regulation* implements the government's "agriculture first" land use approach and requirements related to viewscapes. The *Land Use Regulation* requirements apply to all generation projects, apart

[24] Letter from the Minister of Affordability and Utilities to Bob Heggie, Chief Executive Office of the Alberta Utilities Commission (28 February 2024) Re: Policy Guidance to the Alberta Utilities Commission, AR7571, online: [perma.cc/9B55-NEU2].

[25] *Electric Energy Land Use and Visual Assessment Regulation*, Alta Reg 203/2024 [*Land Use Regulation*], enacted under the *AUCA*, *supra* note 4.

from: small power plants with total capacity under 1 MW;[26] isolated generating units;[27] micro-generation units;[28] power plants situated on a reserve as defined in the *Indian Act*;[29] and any alteration to an existing power plant approval.[30]

On 7 July 2025, the Government of Alberta published guidelines relating to the implementation of agricultural requirements under the *Land Use Regulation.*[31] The guidelines provide information on requirements for siting solar and wind power plants in a manner that considers agricultural land productivity and provides other considerations relating to the coexistence of agricultural land and renewable energy projects. Notably, the requirements indicate that "[w]hether cropped or grazed activities occur on high-quality agricultural land, AGI [(Agriculture and Irrigation)] considers coexistence achieved if the agricultural output aims at a goal of 80 per cent of potential yield productivity based on five-year averages."[32]

2. "AGRICULTURE FIRST" LAND USE POLICY

The *Land Use Regulation* requires applications for wind and solar generation projects on "high-quality agricultural land" to include an agricultural impact assessment.[33] "High-quality agricultural land" is defined as specific soil classes under the Land Suitability Rating System.[34] The assessment must include anticipated effects of the proposed plant on agricultural productivity and measures demonstrating that the power plant is designed to achieve coexistence with agricultural land use.[35] Additionally, operators are required to report to the Commission within three years of starting project operations confirming agricultural productivity of the land.[36]

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26 *Land Use Regulation*, *supra* note 25, s 2(2)(a)(i), which incorporates the definition of small power plants as defined in section 3(1)(b) of the *Hydro and Electric Energy Regulation*, Alta Reg 32/2024 [*HEEA Reg*].

27 *Land Use Regulation*, *supra* note 25, s 2(2)(a)(ii), which incorporates the definition of isolated generating units as provided in the *Isolated Generating Units and Customer Choice Regulation*, Alta Reg 165/2003.

28 *Land Use Regulation*, *supra* note 25, s 2(2)(a)(iii), which incorporates the definition of micro-generation generating units as defined in the *Micro-generation Regulation*, Alta Reg 27/2008.

29 *Land Use Regulation*, *supra* note 25, s 2(2)(b), which incorporates the definition of reserve as defined in the *Indian Act*, RSC 1985, c I-5.

30 *Land Use Regulation*, *supra* note 25, s 2(2)(c), which incorporates the definition of alteration as defined in section 2(2) of the *HEEA Reg*, *supra* note 26.

31 Government of Alberta, *Guidelines to Evaluate Agricultural Land for Renewable Generation* (Edmonton: Ministry of Agriculture and Immigration, 2025), online (pdf): [perma.cc/A7JW-ZZV4].

32 *Ibid* at 5 [footnote omitted].

33 *Supra* note 25, s 4(1).

34 *Ibid*, s 1(f). The requirements apply to Class 1 or 2 lands, or Class 3 lands in the case of municipalities without any Class 1 or 2 lands, as specified in a schedule to the regulation. Section 1(h) defines the Land Suitability Rating System as "the system for evaluating land suitability based on soil, landscape and climate factors, as described in *Land Suitability Rating System for Agricultural Crops: 1. Spring-seeded small grains*, published by Agriculture and Agri-Food Canada in 1995 and amended from time to time."

35 *Ibid*, s 4(2).

36 *Ibid*, s 5(1).

Additionally, the *Land Use Regulation* grants the Commission the discretion to require proponents of wind or solar generation projects located in the "White Area" of the province[37] to submit an irrigability assessment as part of their applications for project approval, which must assess the suitability of the land for irrigation and may include certain specified information, including the opinions of the relevant irrigation district, if applicable. AUC Bulletin 2024-25, discussed below, indicates that the Commission will be deciding on a case-by-case basis whether to require a full irrigability assessment from project proponents.

3. VIEWSCAPES

The *Land Use Regulation* also sets out the requirements for pristine viewscapes, including the prohibition of new wind generation projects within certain "buffer zones" as well as the new requirements for VIAs.

The *Land Use Regulation* sets out specific areas of land designated as buffer zones and VIA zones.[38] The buffer zone is located around the Rocky Mountains and their eastern slopes, and VIA zones are in the eastern slopes, around certain parks in southern Alberta and around Wood Buffalo National Park in northern Alberta.[39]

New wind generation projects are prohibited within the buffer zone.[40] Applications for new renewable and non-renewable generation projects not prohibited in a buffer zone or VIA zone must include a VIA. A VIA is defined as "an assessment to determine changes to the scenic attributes of a landscape brought about by the introduction of visual contrasts and the associated changes in the visual experience of the landscape."[41] The VIA must include certain specified information, including visual simulations and proposed mitigation measures for adverse visual effects.[42]

4. RECLAMATION SECURITY

Alberta's *Conservation and Reclamation Regulation*,[43] enacted under the *Environmental Protection and Enhancement Act*,[44] establishes the regime for reclaiming lands disturbed by certain specified activities (including many forms of energy and mining developments). Section 17 of the *C&R Regulation* requires operators of certain projects to provide security for the reclamation of their projects (Reclamation Security). The Reclamation Security applies to projects that (1) require approval or registration, or (2) are identified by the Minister

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37 The White Area is the largely unforested portion of Alberta with predominantly human settlement and agricultural uses, as opposed to the "Green Area" of primarily Crown land that is heavily forested: see Government of Alberta, "Pristine Viewscapes and Visual Impact Assessment Zones (Map)" (December 2024), online: [perma.cc/7LAF-2YFJ] [Viewscapes Map].

38 *Supra* note 25, s 1(c) defines Buffer Zone with reference to Schedule 2; *ibid*, s 7(2) defines Visual Impact Assessment Zone with reference to Schedule 3.

39 Viewscapes Map, *supra* note 37.

40 *Land Use Regulation*, *supra* note 25, s 8(3).

41 *Ibid*, s 1(k).

42 *Ibid*, s 8(2).

43 Alta Reg 115/1993 [*C&R Regulation*].

44 RSA 2000, c E-12 [*EPEA*].

as requiring Reclamation Security.[45] The Reclamation Security is due (a) before the approval or registration for the *EPEA*-regulated activity is issued, or (b) before the activity is commenced or within 30 days of written notice from the Minister.[46] Unless an exemption applies, the Reclamation Security must be paid to the Government of Alberta, who holds it in the Environmental Protection Security Fund until proper reclamation of the land is complete.[47]

The *C&R Regulation* provides examples of acceptable forms of security. These include cash, cheque, government guaranteed bonds, irrevocable letters of credit or guarantee, or environmental trust.[48] Section 21(e) of the *C&R Regulation* provides that security can also be in "any other form that is acceptable to the Director."

Following the Inquiry, two amending regulations were passed in December 2024 that set out the Reclamation Security requirements for wind and solar projects:

1. The *Activities Designation Amendment Regulation* added the construction, operation and reclamation of wind and solar projects to the schedule of activities in the *Activities Designation Regulation* requiring registration under the *EPEA*.[49]

2. The *Conservation and Reclamation Amendment Regulation* added a provision to the *C&R Regulation* that exempts operators of renewable generation projects from paying the Reclamation Security to the Minister where the operator "provides security to a registered owner of the land under a surface lease."[50] The amendments also provide for the establishment of a *Code of Practice for Solar and Wind Energy Operations*, which the Government of Alberta published on 31 May 2025[51] and which now forms part of the *C&R Regulation*.

The effect of the above amendments is that wind and solar projects require a registration under *EPEA* and must therefore satisfy the Renewables Code and the Reclamation Security requirement under the *C&R Regulation* (or the necessary declaration to rely on the lease exemption). Existing projects — that is, those approved by the AUC before 1 January 2025 — have until 1 January 2027 to satisfy these requirements.[52]

The Renewables Code provides that existing projects must post 15 percent of the estimated liability upfront and 60 percent by year 15; new projects must post 30 percent upfront with the same top-up.[53] Alternatively, under AUC Bulletin 2025-06, landowner agreements for new projects must include 40 percent security upfront and 70 percent by year

45 *C&R Regulation*, *supra* note 43, ss 17(1)(a), 17(2).
46 *Ibid*, s 17(1).
47 *EPEA*, *supra* note 44, s 32.
48 *Ibid*.
49 *Activities Designation Regulation*, Alta Reg 276/2003 [*Activities Designation Reg*].
50 *Conservation and Reclamation Amendment Regulation*, OIC 369/2024 (not published in the Alberta Gazette at time of writing); *C&R Regulation*, *supra* note 43, s 17.1(ii).
51 Alberta, *Code of Practice for Solar and Wind Energy Operations* (Edmonton: King's Printer, 2025), online: [perma.cc/6XXH-G8JA] [Renewables Code], made under the *C&R Regulation*, *supra* note 43.
52 *Activities Designation Reg*, *supra* note 49, s 11.1; Renewables Code, *supra* note 51, ss 1(2)(g), 2(3).
53 Renewables Code, *supra* note 51, ss 5(4)–(5).

15 to satisfy the AUC.[54] Existing projects can rely on "any form of financial assurance or guarantee" provided to the landowner that ensures reclamation will occur.[55] Schedule 1 of the Renewables Code sets out required cost components for security estimates and does not allow for deductions for anticipated scrap or salvage value.[56]

C. AUC IMPLEMENTATION

Following the Inquiry, the Commission issued bulletins specifying information requirements for power plant applications supplemental to those in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*.[57]

On 18 December 2024, the Commission issued Bulletin 2024-25 confirming how the *Land Use Regulation* will be applied to renewable power plant applications before the Commission.[58] Bulletin 2024-25 also revises the Rule 007 interim information requirements established in prior bulletins.[59]

These new information requirements apply to all types of new power plant applications (not only renewable power plants) and energy storage facility applications.[60] They address agricultural capability; agricultural impact assessments; irrigation infrastructure and/or siting within an irrigation district; compliance with municipal land use planning documents[61] and municipal engagement; a description of the reclamation security program; and VIAs.

On 24 March 2025, the AUC published a draft blackline of Rule 007,[62] which will be finalized in mid-2025 following a public comment process.[63] In addition, Bulletin 2024-25 indicates that the AUC will be working with stakeholders to develop requirements with

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54 Alberta Utilities Commission, Bulletin 2025-06, "Reclamation Security Guidelines for Wind and Solar Power Plants" (6 June 2025), online: [perma.cc/2MGK-MTCX].

55 Renewables Code, *supra* note 51, Schedule 2 – Declaration, s (6).

56 *Ibid*, Schedule 1 – Security.

57 Alberta Utilities Commission, Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Development and Gas Utility Pipelines* (Calgary: AUC), online: [perma.cc/3KAT-HN9T]. The initial "Interim Rule 007 information requirements" following the Inquiry were published in Alberta Utilities Commission, Bulletin 2023-05 (6 September 2023), online (pdf): [perma.cc/6TU5-SCLW], and additional information requirements for reclamation security were established in Alberta Utilities Commission, Bulletin 2024-08, "AUC Consultation on Rule 007 and Enhanced Interim Information Requirements" (2 May 2024), online: [perma.cc/PG2P-H7AN].

58 Alberta Utilities Commission, Bulletin 2024-25, "Changes to Interim Information Requirements for Power Plant Applications" (18 December 2024), online (pdf): [perma.cc/ZRA4-AY8Q] [Bulletin 2024-25].

59 *Ibid*; Alberta Utilities Commission, *Rule 007 Interim Information Requirements* (Calgary: AUC, 2024), online: [perma.cc/RVG5-LZ99].

60 Bulletin 2024-25, *supra* note 58.

61 *Ibid* at 6, which defines "municipal planning documents" as including municipal development plans, area structure plans, land use bylaws, and other municipal bylaws.

62 Alberta Utilities Commission, *Rule 007 Facility Applications* (Draft) (Calgary: AUC, 2025), online (pdf): [perma.cc/L7ET-83JV] [Rule 007 Blackline].

63 Alberta Utilities Commission, Bulletin 2025-02, "Changes Proposed to Rule 007: Facility Applications – Available for Written Feedback Until May 23, 2025" (24 March 2025), online (pdf): [perma.cc/MP2W-B4WH] [Bulletin 2025-02].

respect to agricultural productivity reporting, required by the *Land Use Regulation*, to be included in AUC Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*.[64]

The new application requirements imposed by the *Land Use Regulation* and Bulletin 2024-25 do not apply to projects approved by the AUC prior to 6 December 2024 or to proponents seeking certain types of changes to their existing AUC approvals.

While the Commission does not consider the requirements in the *Land Use Regulation* to be applicable for applications filed (but not approved) prior to the issuance of the regulation, it has been considering whether to require further information to satisfy the "intent" of the regulation on a case-by-case basis.[65] In some cases, the Commission issued Information Requests seeking VIAs to meet the intent of the new requirements.[66]

Notable Commission findings related to these regulatory developments are summarized below:

Agricultural Lands: The Commission has considered agrivoltaic plans (that is, combining solar photovoltaic facilities with agricultural production) with varying results:

- The Commission accepted that some agricultural lands will be lost during the life of a project but was satisfied that the agrivoltaics plan involving a sheep grazing and cropping system yielding the same net revenue as the pre-installation farming system sufficiently reduces the project's impact on agricultural value.[67]

- The Commission did not accept the siting of one project on highly productive agricultural land.[68] The Commission found that the best land use in that case was growing annual crops and the agrivoltaics plan involving grazing represented a 40 percent reduction in gross agricultural revenue. The Commission found the proponent did not meaningfully pursue an agrivoltaics plan that incorporated some type of crop production, largely due to the solar panel layout not accommodating the equipment required for crop production.[69]

- The Commission accepted that a proposed agrivoltaics plan was sufficiently detailed,[70] even though contractual arrangements with farmers or operators were not finalized at the application stage. The Commission indicated proponents would

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64 Bulletin 2024-25, *supra* note 58 at 1–2.

65 *Re Killam (Old Bear) Solar Farm* (20 February 2025), Decision 28643-D01-2025 at para 14, online: Alberta Utilities Commission [perma.cc/M84C-YN2L] [*Re Killam (Old Bear) Solar*].

66 This is the case in Information Requests recently issued with respect to the proposed Sweetgrass Solar and Energy Storage Project: *Sweetgrass Solar and Energy Storage Project* (5 September 2025), Decision 29372-D01-2025, online: Alberta Utilities Commission [perma.cc/UU9Z-8TUY].

67 *Re Peter Lougheed Solar Project* (15 November 2024), Decision 29082-D01-2024 at para 24, online: Alberta Utilities Commission [perma.cc/Q9UH-G56M].

68 *Re Westlock Solar Project* (11 October 2024), Decision 28587-D01-2024, online: Alberta Utilities Commission [perma.cc/RC7P-M4Y7] [*Re Westlock Solar*].

69 *Ibid* at paras 28–36.

70 *Re Eastervale Solar + Energy Storage Project* (19 February 2025), Decision 28847-D01-2025 at para 63, online: Alberta Utilities Commission [perma.cc/CL96-6JN8] [*Re Eastervale Solar + Energy*].

have to provide an update to identify final equipment, project layouts, and the operator prior to construction.[71]

Visual Impacts: The Commission approved a wind project within a VIA zone based on a VIA demonstrating that, although the project would be visible from a World Heritage Site, the visual impact would be "minor" in the context of other wind turbines already present.[72]

Setbacks: The Commission imposed a 40-metre setback to impacted residences from a solar project.[73] In another decision, the Commission acknowledged the implicit setbacks under its noise rules and upheld a municipality's larger (1.6 km) residential setback for one wind turbine, ultimately denying that turbine location.[74]

Reclamation Security: Prior to the issuance of the Renewables Code, the Commission consistently held that 50 percent of estimated salvage value can be used to reduce the reclamation cost estimate, but that 100 percent of the net liability had to be secured.[75] As of 6 June 2025, the AUC requires only 70 percent of the estimated liability to be secured, but is aligning its review with the Renewables Code,[76] which does not permit reductions based on estimated salvage value. Similarly, while the Commission accepted reclamation security in the form of letters of credit or bonds to be posted before the tenth[77] and fifteenth year of operations,[78] it will likely require 40 percent upfront in future decisions, per Bulletin 2025-06, discussed above.

IV. MARKET AND TRANSMISSION POLICY CHANGES

A. RESTRUCTURED ENERGY MARKET

The REM is an AESO initiative, acting under the direction of the Minister, to develop changes to the technical design of Alberta's electricity market. The REM design process has advanced in a series of ministerial directions, intensive AESO consultation "sprints," and

[71] *Ibid* at para 61; *Re Killam (Old Bear) Solar*, *supra* note 65 at para 23.

[72] *Re Willow Ridge Wind Project* (5 May 2025), Decision 27837-D01-2025 at paras 137–38, online: Alberta Utilities Commission [perma.cc/69ZV-8NJR].

[73] *Re Caroline Solar Farm* (28 February 2025), Decision 28295-D01-2025, online: Alberta Utilities Commission [perma.cc/YRF4-U3MG].

[74] *Re Fox Meadows Wind Project* (20 June 2025), Decision 29226-D01-2025, online: Alberta Utilities Commission [perma.cc/VZ8C-N98E].

[75] *Ibid*. See also *Re Killam (Old Bear) Solar*, *supra* note 65.

[76] Following the issuance of the Renewables Code, the Commission issued information requests to wind and solar applicants asking them to justify any deviations in the proposed reclamation security program from the government's Reclamation Security requirements given the government's "expertise in the subject matter"; see e.g. *Enerfin Energy Company of Canada Inc, Big Rock Solar Project*, Proceeding 29895 (Information Request, Round 2, Request 5) (27 June 2025), online: [perma.cc/2HYJ-9H9V].

[77] *Re Lethbridge 2 and Lethbridge 3 Solar Projects* (3 December 2024), Decision 28866-D01-2024, online: Alberta Utilities Commission [perma.cc/MS25-JR2V].

[78] *Re Blue Bridge Solar Park* (12 February 2025) Decision 29044-D01-2025, online: Alberta Utilities Commission [perma.cc/VU7W-L5L3].

input from stakeholders. The REM is progressing toward detailed design and rule changes by early 2026, with phased implementation to follow.

The REM timeline is aggressive relative to other significant market initiatives in other jurisdictions,[79] with the intention being to reduce the period of uncertainty for investors. The legislature passed Bill 52, the *Energy and Utilities Statutes Amendment Act, 2025*, on 8 May 2025, which will enable the implementation of the REM.[80]

1. PROPOSED MARKET DESIGN AND INDUSTRY FEEDBACK

The REM originally contemplated six major areas of redesign for the electricity market in Alberta: (a) a mandatory day-ahead market; (b) the pricing and reserve market; (c) market power mitigation; (d) market clearing; (e) shorter settlement intervals; and (f) intertie participation. This section provides a summary of the key details under consideration and the current direction for each element of the REM design.

a. Day-Ahead Market

A day-ahead energy market (DAM) could be either a physical or financial day-ahead commitment mechanism to match supply and demand for electricity, settled one day in advance. This mechanism would aim to align forecasted demand with sufficient supply, increasing visibility and certainty for operations, efficient use of resources, and enabling price discovery and risk management for generators. In response to concerns from market participants about the large scope of proposed changes in the REM and speed of implementation, the AESO announced in April 2025 that it would not move forward with a DAM for energy, but would retain and expand on the day-ahead market for reliability products, described further below.[81] Bill 52 expressly permits the introduction of a DAM for energy, leaving open the possibility that a DAM could be implemented at a later date.[82]

b. Pricing and Reserve Market Changes

The pricing and reserve market element of the REM encompasses a range of proposed changes. First, the REM contemplates options to raise prices above an offer cap under certain circumstances to attract energy bids during periods of scarcity. The current market includes an offer cap of $999.99/MWh and a price cap of $1,000/MWh, which are the highest price to offer and to be paid for electric energy, respectively.[83]

Second, the AESO is considering options to allow prices to fall below the current floor of zero dollars ($0/MWh) and plans to implement a price floor of –$100/MWh in 2032. The

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79 For example, Ontario's electricity Market Renewal Program was announced in 2016 and just recently went live, approximately nine years later, in May 2025: see Independent Electric System Operator, "Market Renewal", online: [perma.cc/3X7U-33HE].

80 Bill 52, *Energy and Utilities Statutes Amendment Act, 2025*, 1st Sess, 31st Leg, Alberta, 2025 (assented to 15 May 2025), SA 2025, c 8 [Bill 52].

81 Alberta Electric System Operator, "Stakeholder Update" (4 April 2025), online: [perma.cc/VYJ8-2L6C].

82 Bill 52, *supra* note 80, s 1(1)(h.1).

83 Alberta Electric System Operator, *Complete Set of ISO Rules* (Calgary: AESO, 2025), s 203.1, online: [perma.cc/G8XU-QX6A] [ISO Rules].

objective of negative pricing is to increase opportunities for a market-based approach to curtailing generation when the cost of the marginal energy producer is zero (in other words, the most negatively priced assets would be last in the curtailment order under conditions of congestion or oversupply). The AESO indicated it expects that this situation will become more common as zero marginal cost generation assets (such as wind and solar generation) become more prevalent.[84] Among other effects, negative pricing is a tool to create price signals to compensate load and energy storage to consume energy during periods of oversupply and to disincentivize excess generation during those periods.[85]

The current direction of the REM is to raise the offer cap to $1,500/MWh (with a further increase to $2,000/MWh in 2032) and to raise the price cap to $3,000/MWh.[86] If these changes are implemented, a market participant's ability to receive increased value in times of scarcity (in other words, above their offer cap) would be determined through scarcity pricing curves established by the AESO. This design element intends to balance the risks of high prices caused by excessive market power against over-mitigation that reduces prices, investment, and reliability.[87]

During consultation sessions in fall 2024, generation participants generally advocated for an increased price cap. Many stakeholders raised concerns about the effect of negative pricing, including on current PPAs. Implications of the REM on PPAs are discussed in Part V.C, below.[88]

Finally, the pricing and reserve market element of the REM includes consideration of additional market-based reserve products, namely, a subset of ancillary services (AS), to enhance reliability. In the current market, the AESO procures operating reserves in a day-ahead operating reserve market, and reserved capacity is then made available in real-time to respond to potential contingency or operational events. The AESO has decided to advance a 30-minute uncertainty and ramping reserve in the REM design (R30) to account for real-time needs, including reliability, uncertainty and ramping,[89] and a new Reliability Unit Commitment mechanism to commit additional supply when there are foreseeable shortfalls in the real-time market.[90]

With respect to these products, some stakeholders raised concerns about the potential for over-procurement of AS, while others advocated primarily for broad participation rights (for example, interties, energy storage, and so on) with respect to the reserve product market.

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84 Alberta Electric System Operator, "Pricing and Reserve Market Options Paper" (Calgary: AESO, 2024) at 6–7, online: [perma.cc/JW6P-SEH3].

85 Alberta Electric System Operator, *Restructured Energy Market High-Level Design Update* (Calgary, AESO: 22 May 2025) at 5, online (pdf): [perma.cc/892W-LJTR] [*High-Level Design Update*].

86 *Ibid*.

87 Alberta Electric System Operator, *Alberta's Restructured Energy Market* (Calgary: AESO, 2025), online: [perma.cc/8NFC-GLXJ].

88 Alberta Electric System Operator, *REM Design Options Stakeholder Feedback Aug. 16 – Sept. 6, 2024*, online: [perma.cc/AJW3-YEV9] [*REM Design Options Feedback*].

89 *High-Level Design Update*, *supra* note 85.

90 *Ibid* at 17–20.

c. Market Power Mitigation

The Government of Alberta, on the advice of the MSA,[91] prioritized the development of market power mitigation measures with the intent to limit the exercise economic withholding (that is, intentionally bidding generation out of merit during supply scarcity events to increase the market price). The current market power mitigation measures were introduced as interim solutions in March 2024 by regulation and are set to expire on 30 November 2027 after the REM is implemented.[92] The measures set a secondary, lower offer cap for non-renewable generating units held by entities holding offer control of 5 percent or more of the electricity market once certain market conditions have been met. Stakeholders indicated a preference for the MSA to have significant input in the market power mitigation design for the REM.[93]

The REM considers options to permanently limit economic withholding, by adopting the secondary offer cap under the interim measures with potential changes, including: a secondary offer cap that could consider energy revenues over a one-year (versus monthly) period; mandatory requirements for all eligible suppliers to offer into the day-ahead, real-time, and operating reserves, a lower offer cap in the energy market, new offer caps on all of the operating reserves, and administratively set scarcity pricing curves for energy and products with higher price caps; co-optimization between energy and products; and possible changes to applicability, changes to the evaluation period, and exemptions for certain assets.[94]

Among the market power mitigation options under consideration, market participants generally favoured the secondary offer cap but expressed concern about over-mitigation and impacts on the competitive operation of the energy market.[95] The MSA expressed concern that the proposed measures are based on the interim measures designed for the existing market, which were not intended to guide market power in the REM.[96] The current direction of the REM, which includes administrative price-setting above the offer cap (discussed above), is intended to mitigate market power while addressing some of these stakeholder concerns.[97]

d. Market Clearing

Alberta's current wholesale electricity market involves clearing the energy and operating reserve markets sequentially, and issuing energy and reserve dispatch instructions requires active AESO management. Transmission congestion is also currently managed by manual intervention of the AESO.[98] A uniform pool price is currently set equal to the average of one-

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91 Advice from Market Surveillance Administrator to the Executive Council and the Minister of Affordability and Utilities (21 December 2023), "Advice to support more effective competition in the electricity market: Interim action and an Enhanced Energy Market for Alberta", online (pdf): [perma.cc/P4RY-4RAR].

92 *Market Power Mitigation Regulation*, Alta Reg 43/2024, s 7.

93 Alberta Electric System Operator, *Consolidated Written Feedback: REM High-Level Design, (Dec. 13, 2024 - Jan. 17, 2025)* at 37, online (pdf): [perma.cc/9UAT-ZU63] [*REM High-Level Design Combined Stakeholder Feedback*].

94 *High-Level Design Update*, *supra* note 85 at 20–33.

95 *REM Design Options Feedback*, *supra* note 88.

96 Market Surveillance Administrator, "AESO's Initial Approach to the Restructured Energy Market Technical Design" (6 September 2024) online (pdf): [perma.cc/K9XR-MH5S].

97 *Ibid*.

98 ISO Rules, *supra* note 83, s 302.1.

minute System Marginal Prices (SMP) over an hour,[99] and when congestion occurs, the SMP is set by the highest pricing operating block that received a dispatch.[100] Uniform pricing means that all electric energy exchanged through the power pool is priced the same during any specific interval.

As currently contemplated, market clearing under the REM will enable a security-constrained (that is, physically constrained) economic dispatch (SCED) and will co-optimize the clearing price as between energy and ramping reserve markets (namely, buying energy and ramping services at the same time to meet demands, as opposed to sequential clearing). SCED will rely on an algorithmic optimization engine that accounts for multiple grid reliability and operational constraints (for example, reserve requirements, transmission constraints, and asset ramping constraints) in the dispatch solution that simultaneously seeks to minimize energy and costs.[101]

A separate direction from the Minister, also related to market clearing, is for the REM to maintain a uniform province-wide price for energy.[102] The AESO has noted that, under congestion conditions, the uniform price "may create incentives for generators to behave in a manner that is privately beneficial but reduces system-wide efficiency … because of the difference between the uniform province-wide price and the local value of energy" if the transmission system cannot accommodate all in-merit energy.[103] This is an ongoing consideration in the market clearing and market power mitigation elements of the REM.

e. Shorter Settlement Intervals

Currently, the energy and operating reserve markets require blocked offers at one-hour intervals. A single price is settled and paid to all energy dispatched during that interval based on the average of SMP in that hour.

Initially, the AESO advanced four options for shortened settlement intervals to capture changing system conditions with more granularity and better incentivize generators to respond to changes in price between hourly dispatches. Proposals for the shortened settlement period ranged from five to 15 minutes, applicable to all generators, intertie transactions, and loads.[104]

During consultation sessions in the fall of 2024, feedback from stakeholders indicated a preference for a new combined option that features a long-term goal of a five-minute

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99 *Ibid*, s 206.1.

100 The SMP does not consider any operating block downstream of a transmission constraint that is dispatched specifically to relieve the constraint and is given supplemental payment under section 302.1 of the ISO Rules (transmission constraint rebalancing) (*ibid*).

101 *High-Level Design Update*, *supra* note 85 at 30.

102 Letter from the Minister of Affordability and Utilities to Mike Law, President and CEO of the AESO (3 July 2023), Direction re REM, Cost Allocation, and Optimal Transmission Planning, AR8420, online (pdf): [perma.cc/D9RL-57DJ] [July 2024 Letter].

103 Alberta Electric System Operator, *Market Clearing Options Paper* (Calgary: AESO, 2024) at 15, online (pdf): [perma.cc/7UWV-Z6HS].

104 Alberta Electric System Operator, *Shorter Settlement Options Paper* (Calgary: AESO, 2024), online (pdf): [perma.cc/6HE2-GBUJ].

settlement interval, despite reservations from some stakeholders about the overall cost of doing so. There is general acknowledgement that an interim option that limits implementation risk for small customers will be needed (for example, a five-minute settlement interval for generators, interties, and transmission-connected load, and a one-hour settlement interval for distribution-connected load).[105]

In a December 2024 letter from the Minister, the Government of Alberta directed the AESO to "collaborate in an [AUC]-led initiative to implement 5-minute settlement for transmission-connected loads, generators, and interties by 2032 and for all loads by 2040."[106] The AESO confirmed that this is the current direction of the REM, with various additional technical amendments that are necessary to accommodate shortened settlement intervals.[107]

f. Intertie Participation

The REM is reviewing how interties might participate differently in the new market structure to increase flexibility. Additionally, the REM contemplates maintaining the current tariff rates for imports and exports.[108]

Under current market rules, the price of exports is set at $999.99/MWh, and the price for imports is set at $0/MWh.[109] Uneconomic trades (in other words, when power flows from high to low priced markets) can occur when there is a change in price between when the trade is scheduled (two hours before delivery) and when it is delivered.[110] Re-evaluating the existing intertie participation rules has potential to minimize uneconomic trades by aligning Alberta's price signals closer to other jurisdictions. Other benefits can include greater competition in the generation market and enhanced forecast transparency. However, existing constraints on intertie flows and seams issues across jurisdictions present challenges for intertie optimization.[111]

At this time, a current direction on intertie participation has not been communicated.

2. REM IMPLEMENTATION AND TIMING

The REM design will be implemented through ISO Rules, which all market participants must abide by.[112] Bill 52 provides the mechanism for implementation of the REM though the creation of new regulation-making authority for the Minister to implement the REM's new

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105 *Ibid*.
106 Letter from the Minister of Affordability and Utilities to Aaron Engen, President and CEO of the AESO (10 December 2024), REM and Transmission Policy Update at 2, online (pdf): [perma.cc/2PB3-EDF7] [December Letter].
107 Alberta Electric System Operator, "Restructured Energy Market High-Level Design" (13 December 2024) at 11, 47–48 online (pdf): [perma.cc/T2KR-L6Y3] [High-Level Design]. See e.g. the amendments to the current power ramp management framework set out in the ISO Rules Section 304.3, Wind and Solar Power Ramp Up Management, to ensure dispatch of renewable assets based on physical capabilities of the grid (*ibid* at 47).
108 Alberta Electric System Operator, *Intertie Participation Options Paper* (Calgary: AESO, 2024) at 3, online (pdf): [perma.cc/3KHU-D35L] [Intertie Participation Options Paper].
109 ISO Rules, *supra* note 98, s 203.1, subsections 3(3), 7(2).
110 Intertie Participation Options Paper, *supra* note 108.
111 *Ibid* at 5.
112 *EUA*, *supra* note 2, s 20.8.

ISO Rules through regulation, instead of the typical AUC review and positive approval process.[113]

The AUC's typical approval process for ISO Rules provides a transparent and inclusive hearing process to adjudicate ISO Rule applications, and an opportunity for the AUC to issue public comprehensive written decisions. A number of stakeholders have raised concerns with the Minister's decision to remove the AUC process due to the AUC's important role in safeguarding the public interest as a regulator tasked with adding a layer of rigorous, independent oversight over the AESO.[114]

Pursuant to the December Letter, the AESO is to "continue consulting with industry on the ISO Rules to ensure they align with the AESO's finalized REM design," and the AESO anticipates that consultation on the ISO Rules to implement the REM will begin around September 2025.[115] Acknowledging that the REM ISO Rules will not go through an AUC proceeding (including an opportunity to request funding), the AESO committed to providing limited funding to market participants (maximum of $50,000 per market participant) to enable participation in the REM consultation process, including development of the REM ISO Rules.[116]

The AESO anticipates that ISO Rules for the REM will be enacted sometime in early 2026, followed by a transition period to adjust and correct for potential technical deficiencies in the REM.[117]

B. MARKET MECHANISM TO AVOID CONGESTION

The December Letter directed the AESO to "develop a market-based congestion management mechanism that recognizes incumbency, provides impacted generators with a means of managing the dispatch risk arising from congestion constraints, and considers the participation of controllable load and energy storage."[118]

The design of the congestion management mechanism is within the REM technical design process. However, it is also related to the move away from zero-congestion to an "optimal transmission planning" (OTP) framework, which will inform the amount of congestion on the transmission system (discussed in greater detail below).

An overview of the existing mechanisms in place for addressing congestion is provided below, followed by a brief discussion of the AESO's original market proposal (the congestion avoidance market) and the current direction favouring locational marginal pricing (LMP) combined with financial transmission rights (FTR). In respect of implementation, Bill 52

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113 *Ibid*, ss 20(1)(1.1), 20.6(4).

114 *REM High-Level Design Combined Stakeholder Feedback*, *supra* note 93 at 209 (Kineticor), 220 (Maxim Power Corp), 273–74 (Suncor Energy Marketing Inc), 282 (TransCanada Energy Limited).

115 December Letter, *supra* note 106 at 2.

116 Alberta Electric System Operation, "Funding for Participation in REM Engagements", online: [perma.cc/UC3U-YUFV].

117 December Letter, *supra* note 106 at 2.

118 *Ibid*.

amends the AESO's duties under section 17 of the *EUA* to permit the AESO to reconstitute the price or dispatch of electricity instead of the current requirement to strictly dispatch according to relative economic merit order, with express ability to do so to account for transmission constraints.[119] This includes the ability to establish prices that may vary by location, instead of the current province-wide uniform price for electricity, allowing for the introduction of an LMP.[120]

1. EXISTING PROCESS

Section 302.1 of the ISO Rules, *Real-Time Transmission Constraint Management*, provides the existing process for addressing congestion on the transmission system. Import and export transactions contributing to system congestion are curtailed first,[121] and then generation assets upstream of the system constraint location or locations are curtailed in reverse merit order (in other words, from higher to lower offer prices), with pro rata curtailments for equally priced offers into the power pool.[122] Curtailed generation results in lost revenue for generators when the pool price is above $0/MWh. Under this current practice, disorderly bidding practices often occur when conditions indicate congestion and curtailments are likely to occur, resulting in a "race to the floor" for offers into the power pool from assets likely to be curtailed in attempt to maximize dispatch.[123]

2. INITIAL PROPOSAL: CONGESTION AVOIDANCE MARKET

The Congestion Avoidance Market (CAM) proposal would have enabled generation owners expecting to be subject to a system constraint to submit "congestion avoidance bids" in $/MWh demonstrating their willingness to pay for system access.[124]

To date, the CAM has been viewed by stakeholders as overly complex and unmanageable if the amount of congestion on the system is unknown.[125] Many stakeholders supported more discussion on some form of transmission rights to achieve the objective of recognizing incumbency,[126] echoing statements made in the Government of Alberta's 2003 transmission

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119 Bill 52, *supra* note 80, would amend the *EUA*, *supra* note 2, s 17(c), to facilitate this change.

120 See Bill 52, *supra* note 80, s 1(7) replacing the current section 18 of the *EUA*, *supra* note 2 and providing under the new subsection 18(6) that "Any prices established under subsection (5) may vary by location, subject to the regulations, if any."

121 ISO Rules, *supra* note 83. This aspect of the rule is currently the subject of a complaint before the AUC: *BHE Canada Limited Notice of Complaint* (15 February 2024), Proceeding 28829.

122 ISO Rules, *supra* note 83, s 302.1, subsection 2(1). This is a simplification as there are other measures that occur, if needed, to ensure supply and demand are balanced downstream of the system constraint.

123 See Alberta Electric System Operator, *Restructured Energy Market (REM) – Market Clearing Overview* (Calgary: AESO, 2025) at 4, online: [perma.cc/S4KM-QSZ3].

124 High-Level Design, *supra* note 107 at 31.

125 *REM High-Level Design Combined Stakeholder Feedback*, *supra* note 93. The Renewable Generators Alliance expressed concerns that the CAM would create "LMP outcomes for generators behind a transmission constraint" (*ibid* at 263). See also, e.g. ATCO EnPower's, Capital Power's and TransAlta's comments, expressing a concern that the CAM will create unhedgeable risk for new investment (*ibid* at 31, 38–39, 80–81, 87–88, 306–08).

126 *Ibid* at 210, 214–16 (Kineticor), 264–66 (Renewable Generators Alliance), 272, 276–77 (Suncor Energy Marketing Inc).

policy paper regarding the existence of implicit injection and withdrawal rights in a zero-congestion model.[127]

3. CURRENT DIRECTION: LMP AND FTRS

In response to these concerns, the AESO explored introducing an LMP, financial transmission rights, or congestion revenue rights based model for the market-based congestion management mechanism, or FTRs in addition to the CAM model.[128] Under this model, generators would receive different prices in different parts of Alberta when congestion is present, but load would still pay a uniform price based on the achieved price downstream of all system constraints.[129] Transmission-connected load could elect, however, to pay the applicable LMP instead of the uniform price.[130] FTRs would consist of a right to compensation for rights holders upstream of a system constraint. This compensation would be based on the difference between the marginal price of generation upstream of a transmission constraint and the downstream marginal price.[131] Since all loads (unless they elect otherwise) would pay the (higher) downstream marginal price, FTRs would be financed through the higher energy price paid by load upstream of the system constraint than what would have otherwise been paid if the upstream marginal price set the province-wide price.[132]

The AESO is considering how it might potentially assign FTRs to respect incumbency, being one of the goals identified in the Minister's December Letter for the congestion management mechanism.[133] While this proposal is in ongoing development and discussion, the AESO stated in June 2025 that its preferred option for congestion pricing was for LMP paired with FTRs, and the Minister confirmed support for this approach in a 15 July 2025 direction letter to the AESO.[134]

C. TRANSMISSION POLICY CHANGES IMPACTING GENERATION

1. THE GREEN PAPER

Transmission policy development is within the purview of the Minister.[135] The *T-Reg*, which is the primary legal mechanism by which the Government of Alberta implements transmission policy, has remained largely unchanged since its introduction in 2004.[136] As

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127 2003 Paper, *supra* note 8 at 8.

128 See Alberta Electric System Operator, *REM Design Finalization – Week 1 Presentation* (Calgary: AESO, 2025) at 13–14, 25, 29, online (pdf): [perma.cc/5QUK-SRKY] [AESO Feb 2025 Presentation].

129 *Ibid*.

130 *High-Level Design Update*, *supra* note 85 at 5. See also Letter from the Alberta Minister of Affordability and Utilities to Aaron Engen, President and CEO of the AESO (15 July 2025), online (pdf): [perma.cc/FEQ8-EBF8] [July 2025 Letter].

131 Alberta Electric System Operator, "Optimal Transmission Planning (OTP) & Transmission Reinforcement Payment (TRP) Sprint 1" (2025) at 113–29, online (pdf): [perma.cc/GE3T-HURF].

132 *Ibid.*

133 *REM High-Level Design Combined Stakeholder Feedback*, *supra* note 93 at 47; December Letter, *supra* note 106 at 2.

134 July 2025 Letter, *supra* note 130.

135 *Designation and Transfer of Responsibility Regulation*, Alta Reg 11/2023, s 3(1).

136 *T-Reg*, *supra* note 7. The *T-Reg* initially implemented the transmission policies discussed in the 2003 Paper, *supra* note 8.

discussed in the background section, significant changes to Alberta's generation supply mix, decarbonization policies, and increased transmission infrastructure costs underpin the changes to Alberta's transmission policy.

The *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act, 2022*, which was developed between 2021 and 2022 and took effect in 2024, addressed narrow aspects of Alberta's transmission policy, including by allowing for an expanded use of non-wires transmission solutions (other than new line builds), including energy storage.[137]

In 2023, the Minister initiated a broader review of transmission policy to consider policy changes for improving reliability and affordability in response to the changes occurring on the system. The Government of Alberta released a "Green Paper" discussing its preferred policy direction and inviting stakeholder feedback on key policy areas including the GUOC, line loss calculations, the zero-congestion planning standard, cost allocation for wires and ancillary services costs, and intertie restoration and development. The Green Paper clarified that policy developments would adhere to the core principles of: (1) maintaining the transmission system as a regulated monopoly service, and (2) maximizing efficiency of the system through optimized use of existing infrastructure and ensuring new wires are built only when necessary to help control costs.[138]

2. Resulting Policy Developments

Following the Green Paper consultation, the Government of Alberta announced forthcoming changes to transmission system planning and cost allocation policies to increase the affordability of utilities for Albertans.[139] Specifically, the Minister has directed five areas of transmission policy change:

1. Move away from the zero-congestion policy to an OTP framework to ensure that new transmission infrastructure is only built when necessary to serve load, to meet reliability requirements or when the benefit of the build outweighs the cost.

2. Replace the current refundable GUOC payments with a non-refundable Transmission Reinforcement Payment (TRP) to optimize the use of the existing transmission system infrastructure and ensure generators are fairly contributing to transmission system costs they cause and impose a greater degree of financial discipline on siting decisions.

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137 SA 2022, c 8 [Bill 22]; see e.g. *ibid*, s 2(2)(i) amending the definition of "transmission facility" in the *EUA*, *supra* note 2.

138 Alberta Ministry of Affordability and Utilities, *Transmission Policy Review: Delivering the Electricity of Tomorrow* (Edmonton: Government of Alberta, 2023), online (pdf): [perma.cc/JR4N-B9D5] [Green Paper].

139 *Ibid*; July 2024 Letter, *supra* note 102. See also December Letter, *supra* note 106; Letter from the Minister of Affordability and Utilities to Mike Law, President and CEO of the AESO (11 March 2024), AR7506, online: [perma.cc/CJ94-PCX2] [March Letter]; Mandate Letter from the Office of the Premier of Alberta to the Minister of Affordability and Utilities (19 July 2024), online: [perma.cc/7A99-H3SP]. The Premier of Alberta specifically identified the reduction of customers' utility bills, including transmission costs, as a key initiative in this mandate letter.

3. Allocate AS costs based on cost causation to ensure costs are internalized by the market participants that cause them.

4. Recover line losses through a system-wide average to reduce the complexity of the calculation and the variability in the charge.

5. Require the AESO to apply to the AUC for approval to increase the capacity of the Alberta-British Columbia intertie 950 MW by 31 December 2026.[140]

The AESO has launched several initiatives to engage with stakeholders on the implementation of this policy,[141] and regulatory amendments are underway.[142] The first of those expected amendments became law on 9 July 2025, including amendments to the *EUA* clarifying that the AESO is not required to plan for a congestion-free transmission system and associated amendments to the *T-Reg*, laying the groundwork for OTP.[143] The remainder of this section provides a summary of the key details under consideration and the status of each of the AESO's implementation engagements.

3. OPTIMAL TRANSMISSION PLANNING

The AESO has commenced its stakeholder engagement process about the OTP to replace the zero-congestion policy and posted an options paper to facilitate stakeholder discussion.[144] Specific proposals for implementation are likely to come later in 2025.

OTP is a new transmission system planning framework to maximize the economic efficiency of new investments by employing a more robust cost-benefit analysis methodology.[145] New transmission investments will be categorized by three underlying drivers: reliability (required to serve load), economic efficiency, and "other," including intertie projects.[146] The OTP will apply to the economic efficiency category of transmission investments while the other two categories will continue to apply the pre-existing "least-cost" criteria used by the AESO.[147] The core principles of the OTP will be: (1) transparency; (2)

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140 December Letter, *supra* note 106; July 2024 Letter, *supra* note 102. See also *EUA*, *supra* note 2, s 1(1)(b), defining AS as "those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency."

141 See Alberta Electric System Operator, "AESO Engage – Join Us in Shaping the Future of Electricity", online: [perma.cc/PZ9Y-LWJW].

142 See *T-Reg Amendment*, *supra* note 7; see also *Proclamation*, OC 248/2025, (2025) A Gaz I.

143 Bill 52, *supra* note 80, s 1(15) providing a new proposed section 33(1); see also s 1(12), amending s 29 of the *EUA* to clarify that the AESO's duty to provide a reasonable opportunity to electricity market participants to exchange electric energy and AS does not require the removal of transmission constraints or the planning of a congestion-free transmission system.

144 AESO Feb 2025 Presentation, *supra* note 128. See also Alberta Electric System Operator, *Optimal Transmission Planning (OTP) Framework Options Paper* (Calgary: AESO, 2025), online (pdf): [perma.cc/77T2-ASHY] [OTP Framework Options Paper].

145 *Ibid* at 2.

146 *Ibid*.

147 *Ibid*.

predictability; (3) balancing of multiple perspectives on economics and reliability; and (4) ensuring the framework is implementable.[148]

The AESO is considering other jurisdictions' approaches to transmission planning as part of this process, including jurisdictions with an OTP such as the Australian Energy Market Operator's integrated system plan methodology or the California Independent System Operator's transmission economic assessment methodology.[149] The OTP options paper sets out a series of nine key decisions with prescribed "options" to facilitate the OTP design and stakeholder engagement process.[150] The first three key decisions involve issues related to the planning process, such as what constitutes "optimal" and what is the appropriate planning horizon. The other six key decisions relate primarily to how costs and benefits should be weighed when planning new transmission investments, such as whether total electricity system costs or ratepayer impacts alone should inform a cost-benefit analysis, how to capture a realistic level of congestion cost, and what criteria should be used to evaluate and select solutions, among other things. The current implementation schedule forecasts draft ISO Rules (separate from the REM implementation) later in 2025 and an AUC application and hearing process in 2026, leading to implementation in Q4 2026 or Q1 2027.[151]

4. NON-REFUNDABLE TRPS

The current GUOC payment was intended to be a signal for generators to choose a location on the transmission system closer to load.[152] However, the $50,000/MW cap on the GUOC in the *T-Reg,* and the fact that the GUOC is refundable, have reduced the effectiveness of the locational signal over time.[153] The recent *T-Reg* changes now provide for the recovery of TRPs, including transitional provisions providing that the GUOC continues to apply until TRPs are included in the ISO tariff.[154]

The TRP will be a non-refundable fee that generators will be required to pay during the AESO Connection Process. The Minister has directed that this calculation be informed by factors such as the: (1) generator's proximity to transmission capacity; (2) generator's technical attributes and characteristics; and (3) costs of reinforcing the transmission system to accommodate the generator's output.[155]

The Minister's direction also specified that TRP shall have no upper limit, a floor of $0/MW, and apply to both transmission-connected and distribution-connected generators.[156]

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148 *Ibid*.
149 See Alberta Electric System Operator, *OTP Practice in Other Jurisdictions* (Calgary: AESO, 2025), online: [perma.cc/9UFT-YK84] which provides links to a number of system operators' policy guidance for transmission planning in the United States, Australia and Europe.
150 OTP Framework Options Paper, *supra* note 144 at 6.
151 *Ibid*.
152 Green Paper, *supra* note 138 at 7–8; see also 2003 Paper, *supra* note 8 at 5–6.
153 *T-Reg*, *supra* note 7, s 29; Green Paper, *supra* note 138 at 8.
154 See *T-Reg Amendment*, *supra* note 7, ss 11–12, amending s 29 of the *T-Reg*, *supra* note 7 (adding ss 29.1, 29.2).
155 December Letter, *supra* note 106.
156 *Ibid*.

As such, a TRP could exceed the current legislated cap of $50,000/MW maximum GUOC payments currently applicable under section 29(2) of the *T-Reg.*

The detailed calculation of the TRP will be determined as part of the "TRP & Supply SAS" stream of the ISO Tariff Redesign engagement. Bill 52 did not amend the legal test for the ISO tariff, which continues to be "just and reasonable" and "not unduly preferential, arbitrarily or unjustly discriminatory."[157]

5. LINE LOSS COST RECOVERY

Generators are currently responsible for the cost of electricity that is lost as heat during its transmission along a line. These "line loss" costs are recovered by the AESO based on a generator's location and contribution to transmission losses.[158]

The current line loss methodology was intended to provide a locational signal for generators to locate closer to load and was based on cost causation principles. However, the cost associated with line losses has not been high enough or predictable enough to incentivize generators to consider transmission impacts in choosing their location.[159] Further, stakeholders had ongoing concerns regarding the annual variability that can occur in loss factors, especially in areas where significant new generation is coming online and causing rapid and unpredictable changes to the loss factors of incumbents.

Given the variability and extremely complicated methodology, the government considered replacing the existing line loss methodology with a system average line loss methodology. Under a system wide average approach, the AESO would calculate a line loss percentage for each calendar year and that percentage would apply equally to all generators, regardless of location. However, instead, the government recently confirmed that costs associated with line losses will be recovered through established locational prices, which is a common practice in jurisdictions that have implemented an LMP framework.[160]

6. INTERTIE RESTORATION AND EXPANSION

The *T-Reg* has required the AESO to prepare a plan and make arrangements to restore both the interties to, or near to, their path ratings since 2007.[161] The Commission had previously interpreted this obligation to be subject to the AESO's discretion as to the form and timing of the restoration.[162] The recent *T-Reg* amendments now impose a deadline of 31 December 2026, for the AESO to file an application with the Commission to advance this restoration work for the Alberta-British Columbia intertie.[163] For Alberta generators,

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157 *EUA*, *supra* note 2, s 121(2)(a)–(b).
158 *T-Reg*, *supra* note 7, s 36.
159 Green Paper, *supra* note 138.
160 July 2025 Letter, *supra* note 130.
161 *Supra* note 7, s 16.
162 See *Re AESO - Objections to ISO rules Section 203.6 Available Transfer Capability and Transfer Path Management* (1 February 2013), Decision 2013-025, online: Alberta Utilities Commission [perma.cc/KTV5-ZD5V].
163 *T-Reg Amendment*, *supra* note 7, s 6 adding new ss 16–16.3. See also December Letter, *supra* note 106.

increased intertie capacity may present both an opportunity and a risk, expanding the opportunity to export when prices are low, while increasing competition through imports in high-priced periods. The *T-Reg* amendments also direct the AESO to procure AS to support intertie inflows on the Alberta-British Columbia intertie and Montana Alberta Tie Line as well as to increase the path rating of the Alberta-Saskatchewan intertie as part of equipment end-of-life replacement.[164]

7. AS COST ALLOCATION

AS are services required to support the physics of the grid — namely, flexibility, frequency, and voltage — to deliver energy from where it is produced to where it is consumed.[165] Currently, the AESO procures four main categories of AS either through commercial contract or a specific market mechanism:

1. Operating reserves — procured across three product types: regulating reserve, spinning reserve, and supplemental reserves. These products comprise the majority of AS costs and are used to balance demand and supply in real-time and recover the frequency of the system in the event of sudden disruptions (such as loss of a generator, load, or intertie).

2. Transmission must-run service — procured or conscripted to direct a generator to operate at a specific level for a specific time to meet local area demand in the province when system constraints arise that cannot be solved through normal dispatches of generation.

3. Fast frequency response — procured through Load Shed Service for imports and certain qualifying generating units to stabilize frequency decay caused by sudden changes on the grid (for instance, the loss of an import tie-line).

4. Blackstart service — procured from generators that are able to "self-start" and re-energize the grid after a blackout.

The AESO may recover the cost of these AS from load either through the ISO tariff or ISO fees.[166] The need for new or refined AS to support the safe and reliable operation of the grid is consistently under evaluation by the AESO.[167] For example, the new proposed R30 product is an examples of new AS to support generator ramping introduced as part of the REM design.

Like wires, the need for and use of AS was historically considered for the benefit of load customers and all costs were charged to this group of market participants. However, the need

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164 December Letter, *supra* note 106.
165 *EUA*, *supra* note 2, s 1(1)(b).
166 *Ibid*, s 30(4).
167 See Alberta Electric System Operator, *AESO 2023 Reliability Requirements Roadmap* (Calgary: AESO, 2023), online (pdf): [perma.cc/3E5G-TTPL] [Reliability Requirements Roadmap].

to lean on AS to operationally manage the variability of intermittent resources and their inability to provide certain attributes (such as, frequency and voltage) pushed this principle.[168]

The Minister directed that, going forward, "all ancillary services costs" will be allocated based on cost causation.[169] This is now reflected in section 48.1 of the recently amended *T-Reg*, which will apply once related ISO tariff changes are made.[170] Cost causation is a well-established principle in utility ratemaking. It provides that the party that causes certain utility costs should pay for those costs and should not be allowed to have those costs defrayed by other ratepayers. This principle is derived from James Bonbright's *Principles of Public Utility Rates*[171] — which has been repeatedly cited and relied upon in utilities ratemaking proceedings. The AUC and its predecessor have historically affirmed that cost causation is the primary consideration in ratemaking:

> The second and third [Bonbright] principles will be satisfied by rates which recover costs in the manner in which they are caused. That is, rates based on cost causation should provide appropriate price signals, should be fair, objective, and equitable, and should minimize or eliminate inter-customer subsidies.… [C]ost causation therefore remains the primary consideration when evaluating a rate design proposal.[172]

The current policy shift is supported by the most recent Commission decision on the ISO tariff, where it noted that increases in transmission system costs were increasingly caused by the integration of new generation and therefore not caused by load consumers.[173] The Commission found it was unable to allocate those transmission costs caused by integration of generation to those participants due to the "load pays" and the "postage stamp"[174] principles embedded in the legislation. As a result, the Commission concluded that, for transmission rate design, the cost causation principle must itself be "constrained to those aspects of consumer behaviour that affect system costs independent of location."[175]

Despite the longstanding nature of the cost causation principle, applying it in practice to fairly allocate AS costs as between load and generation may present challenges. To illustrate this, we can consider an example from the 2018 ISO tariff application. In that case, the Commission approved a change to the way distribution-connected generation (DCG) was metered for the purposes of properly allocating costs to both distribution-connected load

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168 Green Paper, *supra* note 138 at 19–20.

169 July 2024 Letter, *supra* note 102.

170 *T-Reg Amendment*, *supra* note 7, s 15 adding s 48.1 to the *T-Reg*, *supra* note 7.

171 James C Bonbright, Albert L Danielsen & David R Kamerschen, *Principles of Public Utility Rates*, 2nd ed (Arlington, VA: Public Utilities Reports, Inc, 1988) at 383–84.

172 *Re Alberta Electric System Operator: 2007 General Tariff Application* (21 December 2007), Decision 2007-106 at 14, online: Alberta Energy and Utilities Board [perma.cc/BPU5-GZL9].

173 See *Re Alberta Electric System Operator: Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application* (10 Nov 2022), Decision 26911-D01-2022 at paras 45, 47, online: Alberta Utilities Commission [perma.cc/3TA6-W4P8] [*AESO Rate Application*].

174 The postage stamp principle is that customer rates should not differ based on location. Section 30(3)(a) of the *EUA*, *supra* note 2 incorporates this principle as follows: "The rates set out in the tariff … shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system."

175 *AESO Rate Application*, *supra* note 173 at para 59.

(DCL) and DCG.[176] This change provided that DCG power flows into and DCL power flows out of a transmission substation would be measured on a gross and not a net basis as had been happening. This was motivated by a concern that DCL customers were cross-subsidizing the costs of DCG access to the transmission system contrary to the cost causation principle because the net metering effectively eliminated DCG responsibility to contribute to system upgrade costs.[177]

The Commission later varied this decision finding that this change could result in the allocation of some transmission system costs to DCG customers for substation upgrades when the need for those upgrades was not clearly caused by DCG.[178] The Commission accepted an interim proposal of attributing all connection related costs for DCG and DCL to DCL customers, effectively applying the "load pays" principle.[179] The Commission also articulated the following principles for the AESO to consider related to cost causation and DCG-related costs in future tariff design:

- Providing a level playing field in support of fair competition between [transmission-connected generation] and DCG, when evaluating the allocation of transmission system costs to DCG.

- Costs should not be allocated to a DCG after the DCG has energized if the DCG does not directly cause those costs.[180]

These decisions illustrate: (1) the traditional approach of applying a "benefactor test" to assigning transmission wires costs based on cost causation; and (2) the difficulty of assigning benefits between generation and load.

Instead of who is the ultimate beneficiary, cost allocation principles for certain AS are likely to place greater emphasis on the purpose of each product and what necessitated its need. However, determining allocation ratios between load and generation — if relevant to the product — is still likely to present challenges. For example, the new AS ramping product introduced by the REM (R30) is intended to address increasing net demand variability,[181] largely driven by the growth of renewable generation on the system. The AESO confirmed that some portion will be allocated to renewables, but methodology is still under discussion.[182]

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176 *Re Alberta Electric System Operator: 2018 Independent System Operator Tariff* (22 September 2019), Decision 22942-D02-2019, online: Alberta Utilities Commission [perma.cc/9YB3-SU8N] [*Re 2018 ISO tariff*]; see also Alberta Electric System Operator, *Information Document: Determination of Rate STS, Rate DTS and Metering Levels for a Distribution Facility Owner*, No 2018-019T (Calgary: AESO, 2018), online (pdf): [perma.cc/X8GG-G8V6].

177 *Re 2018 ISO tariff*, *supra* note 176 at paras 624–25, 641–42.

178 *Re Alberta Electric System Operator: Stage 2 Review and Variance of Decision 22942-D02-2019 Adjusted Metering Practice and Substation Fraction Methodology* (23 December 2020), Decision 25848-D01-2020 at para 25, online: Alberta Utilities Commission [perma.cc/DM2T-PYHQ].

179 *Ibid* at para 26.

180 *Ibid* at para 39.

181 The AESO calculates net demand variability as the difference of Alberta Internal Load, less variable generation: see Alberta Electric System Operator, *Flexibility and Price Fidelity* (Calgary: AESO, 2015), online: [perma.cc/Q7KJ-7YST].

182 Alberta Electric System Operator, *REM Design Finalization Week 2* (Calgary: AESO, 2025), online: [perma.cc/2SLW-2PR4].

Details of cost allocation for the REM products will be consulted as part of the REM technical design work. Details of cost allocation regimes for other AS to implement the Government's policy directions will be dealt with under the "Ancillary Services Cost Allocation" stream of the AESO's ISO Tariff Redesign is scheduled to begin in September 2025.[183]

V. IMPLICATIONS

A. IMPACTS ON ELECTRICITY GENERATION PROJECT DEVELOPMENT

The evolving regulatory landscape for Alberta's requirements for power generation approvals, electricity market redesign and revised transmission policy has significant implications for proponents of power generation (thermal and renewable) and storage projects. Uncertainty regarding ongoing policy change in Alberta is impacting investor confidence and the development of generation and load projects in the province.[184] Further, carbon pricing, emission caps and performance standards, incentives for carbon capture, utilization, and storage and renewable and low-emitting electricity projects, electric vehicle adoption, building codes, microgeneration, energy efficiency initiatives, and the Government of Alberta's goal of securing significant investment in data centres all play crucial roles in shaping the province's electricity consumption patterns and generation technology mixes.[185] These types of policies, in addition to applicable tax incentives, remain in flux both provincially and federally.[186]

In respect of renewable generation, market participants have cautioned that many renewable energy developers will have made decisions to build projects elsewhere by the time the details around allocating transmission and ancillary service costs to renewable projects are available.[187] Moreover, there has been a trend of increased scrutiny for renewable projects in Alberta, which aligns with growing interest and concerns expressed by various stakeholders through AUC processes. While previously the Commission has been more likely to impose mitigation measures and conditions in respect of potential impacts (including post-construction monitoring), recent decisions demonstrate less tolerance and acceptance of such measures. As a result, several applications for the construction and operation of renewable projects have been recently fully or partially denied, in addition to many proposals (including

183 Alberta Electric System Operator, "Feedback Requested, ISO Tariff Redesign" (6 March 2025), online: [perma.cc/R5S2-GHLN].

184 Alberta Electric System Operator, *Methodology, Risks and Drivers: Risks and Uncertainties, AESO 2024 Long-Term Outlook* (Calgary: AESO, 2024), online: [perma.cc/6T2B-GPF4] [AESO 2024 Long-Term Outlook]; Canadian Renewable Energy Association, "CanREA concerned about Alberta uncertainty" (11 March 2024), online: [perma.cc/99FR-QBY8].

185 AESO 2024 Long-Term Outlook, *supra* note 184 at 2.

186 See e.g. Inayat Singh, "What's at Stake as Canada's Industrial Carbon Pricing Rules Face Political Headwinds", *CBC News* (30 March 2025), online: [perma.cc/2GH3-5TEV].

187 Business Renewables Centre-Canada, Media Release, "Business Renewables Centre-Canada Disappointed by Alberta Government Electricity Market Decision" (11 December 2024), online: [perma.cc/CYZ8-UHR6].

amendment applications) being subjected to longer and more contentious hearing processes.[188]

B. IMPACTS ON EXISTING GENERATION

Changes to line loss methodology may impact existing generators that were sited in response to the current line loss methodology. On the other hand, the new system-wide average methodology will reduce the significant volatility in charges and improve investment certainty for companies considering constructing new generation in Alberta, as line losses for the duration of the generator's life would be much easier to estimate.[189]

Incumbent generators have also cautioned against policy that undermines existing investment in Alberta, advocating for legacy treatment or strategies that recognize incumbency.[190] Policymakers appear to be receptive to those concerns, as reflected in the Minister's December Letter (which expressly requires the congestion management mechanism to "recognize incumbency")[191] and the AESO's recent exploration of LMPs and FTRs.[192] On the other hand, replacing the zero-congestion approach with the OTP framework and new congestion management mechanisms could create a favourable environment for energy storage strategically located in congested areas.

C. PPA IMPLICATIONS

The evolving regulatory landscape for Alberta's energy market will also have significant implications for existing PPAs and will influence the market for PPAs going forward — particularly so for renewables. PPAs are contracts that facilitate the purchase of electricity and related renewable attributes directly from a generator. PPAs can either entail the physical exchange of energy between the generator and customer or, more commonly and for all grid-supplied power, PPAs can be financial (or "virtual") in nature. With virtual PPAs, the generator delivers the electricity that is notionally the subject of the PPA to the power pool,[193] the customer procures from the power pool, and the parties settle respective financial obligations relative to the market price, using the PPA as a hedge against price volatility. PPAs are significant commercial arrangements that generally include long-term commitments. They are commonly used to underpin capital investments in new generation, and of critical importance for financing wind and solar development since periods of high renewable generation are highly correlated with low pool prices.

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188 See e.g. *Re Westlock Solar*, *supra* note 68; *Re Eastervale Solar + Energy*, *supra* note 70; *Re Harvest Sky Solar Farm* (6 June 2025), Decision 29274-D01-2025, online: Alberta Utilities Commission [perma.cc/25SH-DY5L]; *Re Rising Sun Solar Project* (27 June 2025), Decision 29312-D01-2025, online: Alberta Utilities Commission [perma.cc/VX97-D9CN].

189 Green Paper, *supra* note 138.

190 See *REM High-Level Design Combined Stakeholder Feedback*, *supra* note 93 at 32, 38–39 (ATCO EnPower), 80–81 (Capital Power), 158, 164 (ENMAX), 309–10 (TransAlta) expressing concerns about properly addressing incumbency.

191 December Letter, *supra* note 106.

192 Alberta Electric System Operator, *REM Stakeholder Feedback: Design Finalization Session Week 1* (Calgary: AESO, 2025), online: [perma.cc/C9XW-D8GL].

193 PPAs are "direct sales agreements," which are permitted pursuant to section 19 of the *EUA*, *supra* note 2.

The recent changes to renewables regulation, the forthcoming REM, and transmission policy changes that impact generation all potentially affect the commercial basis for certain PPAs and have implications for existing PPA counterparties. The specific effects depend on each agreement (including the specific change in law provisions and associated remedies) or contemplated arrangement. Certain aspects of the evolving regulatory environment are particularly likely to materially impact existing and contemplated PPAs in Alberta. For example, the introduction of negative pricing would represent a major shift in the economic assumptions that underly most PPAs. During supply surplus conditions, negatively priced offers may result in PPA assets either (1) paying a market price to produce electricity; or (2) being dispatched down (in other words, ramping down or shutting off), respectively resulting in increased costs or reduced output, neither of which may have been contemplated under existing PPAs.

PPAs may also be impacted by the potential introduction of LMP, especially where settlement of the PPA is deemed to occur at a particular location in Alberta. Pricing at the generator's location and the consumer's location may differ, creating discrepancies that must be allocated between the parties under the contract, especially where the PPA stipulates a specific settlement point that is not the generator's connection point. Depending on local conditions and congestion, this can materially increase or decrease costs for parties under existing PPAs and create new commercial considerations for parties looking to enter into PPAs.

Ultimately, the regime overhaul underway in Alberta is likely to create winners and losers under existing PPAs, depending on who bears the associated risk, what remedies are available under the contract, and how incumbency will be recognized in the adopted congestion management mechanism. Where impacts are material, parties may seek to renegotiate or even terminate existing PPAs.

The current uncertainty with respect to the final market design and regulatory environment for generation is further impacting the ability for interested parties to negotiate new PPAs. In addition, regulatory uncertainty emanates from net-zero planning and other major policy considerations at both the provincial and federal levels. These circumstances have created conditions that may diminish the commercial demand for PPAs over the medium term. As certainty on material features of the market and regulatory regime is achieved, PPA activity may once again become very active in the Alberta market, particularly given the limited opportunity for similar agreements in other jurisdictions.

VI. OTHER TRENDS AFFECTING GENERATION DEVELOPMENT IN ALBERTA

A. DATA CENTRE DEVELOPMENT

The rapid growth of cloud computing, artificial intelligence (AI), and machine learning is driving unprecedented demand for data centres — facilities that house infrastructure for storing and processing data. These centres require vast computing power, and global electricity consumption from data centres, AI, and cryptocurrency could double by 2026, rising from an estimated 460 terawatt-hours (TWh) in 2022 to over 1,000 TWh.[194]

Both the Canadian and Albertan governments support data centre development. The Government of Canada's 2024 Fall Economic Statement introduced the Canadian Sovereign AI Compute Strategy,[195] offering financial incentives for the industry, while Alberta's AI Data Centre Strategy outlines the province's unique advantages and plans for growth.[196] According to Invest Alberta CEO Rick Christiaanse, this sector represents a potential $75 billion to $100 billion economic opportunity for Alberta.[197] At the time of writing, there are approximately 266 data centre projects listed in Canada, including 26 in Alberta, with approximately 16,000 MW in new data centre connection requests submitted to the AESO.[198]

For data centre developers, the availability of reliable electricity supply is a paramount consideration. As Canada's largest natural gas producer, Alberta has an abundant, reliable, and affordable energy supply for scalable power generation capability and has the geologic characteristics to enable carbon capture, utilization, and storage. Alberta also has abundant solar and wind resources and is a hub for renewable energy development. Access to both reliable natural gas and low-carbon solutions can meet a variety of needs for data centre developers.

The Government of Alberta and the AESO have recognized concerns that data centre development may stress the provision of reliable and affordable electricity for all consumers in Alberta.[199] As such, the provincial government has encouraged data centres to "bring their own power" or partner directly with generators.[200] However, the provincial regulatory regime applicable to both generation and load that could impact data centre developers is in a transition phase. For instance, recent legislative amendments allow commercial users such as data centres to supply their own power and export excess power to the grid.[201] However, the applicable transmission tariff regime for such arrangements has not yet been determined. Moreover, issues related to the development of transmission and distribution infrastructure for the purposes of supplying power to behind-the-fence load continue to be raised in front

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194 International Energy Agency, *Electricity 2024 Executive Summary* (Paris: IEA, 2024), online: [perma.cc/C8SA-8EYF].

195 Government of Canada, *2024 Fall Economic Statement* (Ottawa: Department of Finance, 2024) online (pdf): [perma.cc/D32U-RMHG].

196 Ministry of Technology and Innovation, Alberta's AI Data Centre Strategy, (Alberta: Ministry of Technology and Innovation, 2024), online (pdf): [perma.cc/6899-4JA5].

197 Chris Varcoe, "Alberta Sizes up $100B Data Centre Opportunity, but Says 'Bring Your Own Electricity'", *Calgary Herald* (13 July 2024), online: [perma.cc/964N-PTH4].

198 Dan Swinhoe, "Details Emerge Around Beacon AI's Planned 400MW Alberta Data Center Campuses", *Data Center Dynamics* (18 March 2025), online: [perma.cc/4YKF-ZMEQ]; Alberta Electric System Operator, Announcement, "AESO Announces Interim Approach to Large Load Connections" (4 June 2025), online: [perma.cc/LF74-NL7N].

199 Alberta Electric System Operator, *AESO Update on Data Centres* (Calgary: AESO, 2025), online: [perma.cc/QCL2-D7VC].

200 Varcoe, *supra* note 197.

201 Bill 22, *supra* note 137.

of the AUC.[202] Separately, the AESO also recently implemented a new interconnection process that applies to parties seeking to supply power to or obtain power from the grid.[203]

Growth in load presents opportunities for generators of all types and sizes. While Alberta currently has a modest surplus of generation on the system, the development of large loads like data centres will rapidly drive the need for new investment in generation and transmission. Opportunities for generators include directly supplying the data centres, supplying other load that would otherwise be underserved due to new demands on the system, and fulfilling carbon-neutral power needs of individual data centre customers (such as via virtual PPAs).

B. NOVEL GENERATION AND ENERGY STORAGE TECHNOLOGIES

The push to decarbonize and electrify the economy has led to increased research and investment in nuclear energy as a source of carbon-free baseload power not subject to the same intermittency problems inherent with wind and solar. The Government of Alberta has prioritized the development of a nuclear policy framework in a recent mandate letter to three cabinet ministers.[204] Small modular reactor (SMR) technology has been touted as a potential solution to streamline construction and regulatory compliance matters that have previously contributed to enormous costs for nuclear projects. It remains unclear the extent to which the provincial government will consider other Canadian jurisdictions' policy frameworks as a template for nuclear development or how they will cooperate with the federal government, which has jurisdiction over the development of nuclear energy.[205]

The Canadian Nuclear Safety Commission recently approved Ontario Power Generation's application for authorization to construct the BWRX-300 SMR design at the site of its existing Darlington nuclear power plant.[206] The decision on this will provide guidance to proponents seeking to develop SMRs elsewhere in Canada.[207]

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202 See e.g. *Re Coaldale Renewables GP Inc* (3 June 2025), Decision 29294-D01-2025, online: Alberta Utilities Commission [perma.cc/M8VV-VL5C], regarding a proposed behind the fence renewable generation project collocated with an industrial load facility. Both AltaLink Management Limited and FortisAlberta Inc are contesting the proponents' proposal on varying grounds of ISO Rule compliance and whether the behind the fence power gathering system constitutes an "electric distribution system" (*ibid* at 4).

203 See Alberta Electric System Operator, "Cluster Assessment Process Implementation" (24 March 2025), online: [perma.cc/PZ9Y-LWJW].

204 See Mandate Letter from the Office of the Premier to the Ministers of Affordability and Utilities, Energy and Minerals, and Environment and Protected Areas (16 October 2024), online (pdf): [perma.cc/ZU5Y-WNAP].

205 See *Ontario Hydro v Ontario (Labour Relations Board)*, 1993 CanLII 72 (SCC), and the *Nuclear Energy Act*, RSC 1985, c A-16, s 18. Parliament has declared works and undertakings for the production of nuclear energy to be "for the general advantage of Canada," which brings them under section 92(10)(c) of the *Constitution Act, 1982*, Schedule B to the *Canada Act 1982* (UK), 1982, c 11 and therefore subject to federal jurisdiction.

206 See Canadian Nuclear Safety Commission, News Release, "Commission authorizes Ontario Power Generation Inc. to construct 1 BWRX-300 reactor at the Darlington New Nuclear Project site" (4 April 2025), online: [perma.cc/NJD5-KV5R].

207 Canadian Nuclear Safety Commission, Decision Release, "Decision by the Commission to Authorize Ontario Power Generation Inc. to Construct 1 BWRX-300 Reactor at the Darlington New Nuclear Project Site" (4 April 2020), online: [perma.cc/H63G-P6NE].

Given the significant price drop in wind and solar generation over recent years,[208] there has also been a significant focus on energy storage technology to pair with wind and solar, thereby addressing intermittency in supply and related technical issues. Much like wind and solar, the cost of lithium-ion battery technology has decreased significantly over the past decade, from approximately USD$800/kWh in 2013 to less than USD$140/kWh for battery pack and cell prices.[209] The United States now has over 20,000 MW of utility-scale battery storage generating capacity online, and Alberta currently has 190 MW online with roughly 4,500 MW in the AESO connection process at the time of writing.[210]

There is also significant interest in alternate forms of energy storage technology. One example under development in Alberta is compressed air energy storage, which typically uses underground geological formations for injecting and releasing pressurized air through a turbine.[211] Another is new battery chemistries using cheaper materials, such as iron-air batteries, since grid-scale storage does not require the same energy densities as electric vehicles.[212] In short, developers are actively working to deploy low-cost energy storage technologies to address the present and future contribution of wind and solar generation to Alberta's energy supply mix.

Alberta's energy-only market compensates solely for energy produced and dispatched onto the grid.[213] This is in contrast to some other jurisdictions that also compensate dispatchable generators for available generating capacity to ensure electricity supply adequacy at all times.[214] Under an energy-only market, generators must be prepared to manage the energy price volatility risk, which is frequently done through PPAs. For example, in Alberta the average annual power pool price in the last 20 years has varied from a low of $18.28/MWh in 2016 to a high of $162.46/MWh in 2022.[215] This volatility can present a barrier to investment in novel technologies with upfront capital costs that tend to be much higher in proportion to their operational costs.

Emissions reductions policy such as Alberta's *Technology Innovation and Emissions Reduction Regulation* (commonly known as TIER) can support low-carbon generation

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208 Lazard, *Levelized Cost of Energy* (June 2024), online: [perma.cc/Y29V-52QS].

209 See International Energy Agency, *Batteries and Energy Transitions* (Paris: IEA, 2024) at 21–22, online: [perma.cc/T5EF-EWV6].

210 See Kimberly Peterson & Mark Morey, "Today in Energy: Batteries are a fast-growing secondary electricity source for the grid", *US Energy Information Administration* (5 September 2024), online: [perma.cc/9WXY-NFZJ]; see also Alberta Electric System Operator, "Connection Project List Dashboard" (Calgary: AESO, 2025), online: [perma.cc/P2J9-LKYP].

211 See e.g. *Re Marguerite Lake Compressed Air Energy Storage Project* (5 June 2025), Decision 28132-D01-2024, online: Alberta Utilities Commission [perma.cc/D9LF-D867].

212 See Scott J Mulligan, "2024 Climate Tech Companies to Watch: Form Energy and its iron batteries", *MIT Technology Review* (1 October 2024), online: [perma.cc/W7KD-UHR9].

213 Alberta Electric System Operator, "Guide to Understanding Alberta's Electricity Market", online: [perma.cc/PA5T-UYZY]. There is also an AS market where generators and other market participants can sell services such as operating reserves, fast frequency response and blackstart services to support reliability.

214 See e.g. PJM Interconnection, "Capacity Market" (19 March 2025), online: [perma.cc/9FNP-U29D]. Alberta previously pursued the development of a capacity market, in addition to the energy market. Those plans ended in 2019.

215 See Market Surveillance Administrator, *Quarterly Report for Q4 2016* (Calgary: MSM, 2017) at 3, online: [perma.cc/33YD-TZTG]; Market Surveillance Administrator, *Quarterly Report for Q4 2022* (Calgary: MSM, 2023) at 4, online: [perma.cc/33YD-TZTG].

technology through the development of a carbon credit market and the corresponding need for higher-carbon generators to purchase credits.[216] Nevertheless, significant uncertainty regarding future policy stringency and therefore carbon credit pricing also poses investment risks for novel technologies.

VII. CONCLUSION

The Government of Alberta's recalibration of the electricity regulatory framework through the policies described in this article will have varying effects on generators. Uncertainty remains, but there are clear signals about some likely outcomes. While renewable energy generators may have more challenges to find suitable project development sites with favourable economics and uncongested grid access, the new AS market products may incent new thermal generation and energy storage with reliability attributes that are currently in need.

Generators are actively monitoring and, in some cases, pursuing opportunities presented by significant load growth from new data centres and other electrification technologies. Apart from that, the slowdown in new generation investment is likely to persist while Alberta advances toward certainty on the regulatory framework over the next two years. In the meantime, many stakeholders continue to dedicate significant resources to tracking and providing input on the many policy and regulatory initiatives underway to ensure the end result presents an investment-friendly environment that supports a reliable, affordable, and sustainable energy supply for Albertans and the economy.

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[216] Alta Reg 133/2019. Electricity generators are subject to an emissions intensity high performance benchmark per MWh that ratchets up annually to require higher emissions performance until 2030 (*ibid*, s 12(3) and Schedule 2). TIER's credit market allows regulated facilities to receive emissions performance credits for emissions less than their allowable limit and to sell those credits for other parties' compliance purposes (*ibid*, s 20).

APPENDIX: TABLE OF KEY ALBERTA ELECTRICITY POLICY DEVELOPMENTS, 2023–2025

Date	Event
19 July 2023	The Premier of Alberta provides mandate direction to the Minister of Affordability and Utilities, with direction to reduce utility bills for customers, including by addressing transmission costs.[217]
Renewable Energy Development Policy	
3 August 2023	The Minister of Affordability and Utilities announces the *Generation Approvals Pause Regulation*,[218] which directed the AUC to pause facilities approvals in respect of new renewable electricity generation projects until February 29, 2024.[219]
August 2023	The AUC invites initial industry feedback on how to implement the approvals pause.[220]
9 September 2023	The AUC establishes bespoke participation processes to conduct an inquiry into renewable generation, and bifurcated the scope into two modules: Module A in respect of various land, reclamation, and viewscape issues; and Module B in respect of the impact of renewable energy on the generation supply mix and on electricity system reliability.[221]
31 January 2024	The AUC delivers its Module A report to the Minister of Affordability and Utilities.[222]
28 March 2024	The AUC publishes its Module B report in AUC Proceeding 28542.[223]
6 December 2024	Government of Alberta passes the *Land Use Regulation*.[224]
24 March 2025	The AUC publishes a draft blackline of Rule 007[225] and commences a public comment process.[226]
Electricity Market Policy	
27 June 2022	The AESO publishes the *Net-Zero Emissions Pathways Report* containing analysis and implications of reaching a net-zero electricity system in Alberta by 2035.[227]

217 July 2024 Letter, *supra* note 102.
218 *GAPR*, *supra* note 18.
219 OIC 171/2023, *supra* note 20.
220 Alberta Utilities Commission, *Renewable Approval Pause Period – Stakeholder Comments and Responses* (Calgary: AUC, 2023), online (pdf): [perma.cc/9LY4-M3NC].
221 Alberta Utilities Commissions, Bulletin 2023-06, "AUC Inquiry into the economic, orderly and efficient development of electricity generation in Alberta" (11 September 2023), online: [perma.cc/NH6M-MKHL]. The AUC established Proceeding 28501 and Proceeding 28542 to consider Module A and Module B, respectively.
222 Module A Report, *supra* note 22.
223 Module B Report, *supra* note 22.
224 *Land Use Regulation*, *supra* note 25.
225 Rule 007 Blackline, *supra* note 62.
226 Bulletin 2025-02, *supra* note 63.
227 Alberta Electric System Operator, *AESO Net-Zero Emissions Pathways Report* (Calgary, AESO: 2022), online (pdf): [perma.cc/3PVQ-QM4B].

10 March 2023	The AESO publishes the *Reliability Requirements Roadmap* highlighting current and emerging reliability and operational challenges caused by changes in generation fleet characteristics, pace of renewables integration, and decarbonization/electrification trends.[228]
27 June 2023	The AESO initiates the *Market Pathways* engagement with stakeholders to: (1) evaluate the sustainability of the existing market design to respond to identified reliability and operational challenges; and (2) consider alternatives.[229]
31 August 2023	The Minister directs the AESO to conduct a study on the current energy market framework and provide recommendations on market incentives, design and the role of new dispatchable technologies.[230]
31 January 2024	The AESO delivers its report to the Minister recommending a REM.[231]
11 March 2024	The Minister directs the AESO to develop a draft technical design of the REM in collaboration with stakeholders.[232]
3 July 2024	The Minister instructs the AESO to move forward with specific elements of the REM: a mandatory day-ahead market, market power mitigation measures, shortened settlement intervals, market clearing design changes, and changes in the pricing and reserve market.[233]
10 December 2024	The Minister directs the AESO to develop a market-based congestion management mechanism to address dispatch risks, integrate controllable load and storage, and use generated revenue to fund transmission projects in congested areas.[234]
8 May 2025	The Government of Alberta passes Bill 52, the *Energy & Utilities Statutes Amendment Act*, enabling the Minister to implement the REM directly by regulation, amending associated definitions in the *EUA*, and modifying some of the AESO's duties.[235]
15 July 2025	The Minister instructs the AESO to move forward with specific elements of the REM: maintain uniform pricing framework for loads while adopting a locational marginal pricing framework for generators and transmission connected loads who wish to settle at the locational marginal price; recover costs associated with line losses through locational marginal prices; and allocate financial transmission rights to generators with existing projects.[236]
Transmission Policy	
23 October 2023	The Ministry of Affordability and Utilities initiates transmission policy review

228 Reliability Requirements Roadmap, *supra* note 167.
229 Alberta Electric System Operator, *AESO Stakeholder Symposium: Leadership in the Transformation* (27 June 2023) at 48–59, online (pdf): [perma.cc/ACJ7-FKMB].
230 AESO Recommendation. *supra* note 6 at 1.
231 *Ibid*.
232 March Letter, *supra* note 139.
233 July 2024 Letter, *supra* note 102.
234 December Letter, *supra* note 106 at 2.
235 Bill 52, *supra* note 80.
236 July 2025 Letter, *supra* note 130 at 1–2.

	via release of a Green Paper titled *Transmission Policy Review: Delivering the Electricity of Tomorrow*.[237]
30 November 2023	Stakeholders provide input on the Green Paper.
3 July 2024	The Minister affirms: (1) the departure from the zero-congestion transmission planning standard to an optimally planned transmission planning standard; and (2) the direction to allocate *new* transmission infrastructure costs and all AS costs based on cost causation principles.[238]
10 December 2024	The Minister directs the AESO to (1) implement a cost allocation framework for new transmission infrastructure, replacing the Generating Unit Owner's Contribution with a non-refundable Transmission Reinforcement Payment (TRP); (2) recover line losses through a system-wide average starting 1 January 2027; and (3) file a needs identification document for the Alberta Intertie Restoration project by 31 December 2026.[239]
8 May 2025	The Government of Alberta passes Bill 52, the *Energy & Utilities Statutes Amendment Act*, setting the stage for removal of the zero-congestion policy by amending certain AESO duties and rulemaking powers.[240]
9 July 2025	The Government of Alberta proclaims certain Bill 52 provisions in force and implements changes to the *T-Reg*, eliminating zero-congestion and implementing a number of policy goals from the Minister's direction letters.

[237] Green Paper, *supra* note 138. It is noteworthy that the Government of Alberta does not appear to have openly published this document in contrast with the 2003 Paper, *supra* note 8 — see comments expressing concern about this lack of availability in Nigel Bankes, "Transmission Policy in Alberta" (21 November 2023), online (blog): [perma.cc/K7RC-DUNW].

[238] July 2024 Letter, *supra* note 102.

[239] December Letter, *supra* note 106.

[240] Bill 52, *supra* note 80.