Methodology, Risks and Drivers

Policy and Regulatory Drivers

AESO 2024 Long-Term Outlook

MAY 2024

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Carbon Pricing

In 2018, the Government of Canada passed the *Greenhouse Gas Pollution Pricing Act* (GGPPA),[1] which established a minimum national price on carbon emissions. The GGPPA requires all provincial and territorial governments maintain pollution pricing schemes that meet the national minimum carbon price or otherwise comply with the *Output-Based Pricing System Regulations*.[2] In August 2021, the Government of Canada published the *Minimum National Carbon Pollution Price Schedule*,[3] which increases the carbon price by $15 per tonne per year from $50 per tonne in 2022 to $170 per tonne in 2030. For all scenarios, the carbon price assumption in the 2024 LTO follows the federal trajectory until 2030 and applies an inflationary escalation of two per cent per annum in subsequent years.

Alberta's Technology Innovation and Emissions Reduction (TIER) Regulation

The *Technology Innovation and Emissions* (TIER) *Regulation*[4] is Alberta's framework for industrial carbon pricing and meets the national benchmark criteria established by the GGPPA. TIER applies to any facility that emits 100,000 tonnes or more of carbon dioxide equivalent (CO2e) per year, or imports more than 10,000 tonnes of hydrogen, while facilities that fall below these thresholds may be eligible to opt-in. Regulated facilities are subject to performance benchmarks that dictate their allowable emissions each year. With respect to the electricity sector, all facilities, excluding cogeneration, are subject to TIER's high-performance benchmark (HPB) for electricity. Cogeneration facilities are subject to a facility-specific benchmark (FSB) determined by their historical production-weighted average emissions. Facilities can meet their compliance obligations by reducing their on-site emissions, using Alberta-based emissions offsets, using emissions performance credits (EPCs), which are generated by facilities that exceed their emission reduction obligations or purchasing TIER fund credits. Importantly, emissions offsets and EPCs are subject to a credit-use limit and, thus, cannot be used to meet the entirety of a facility's compliance obligations. In response to the escalating national carbon pricing benchmark, the Government of Alberta amended TIER in December 2022 to ensure compliance with the GGPPA. These changes include increases to the TIER fund price and credit-use limits, tightening of FSBs and HPBs, updating emissions offsets generated by renewable electricity facilities, creating credits for carbon sequestration projects, and enabling a facility to receive negative allowable emissions, a change that primarily affects facilities that import hydrogen.

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[1] https://laws-lois.justice.gc.ca/eng/acts/g-11.55/.

[2] https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/index.html.

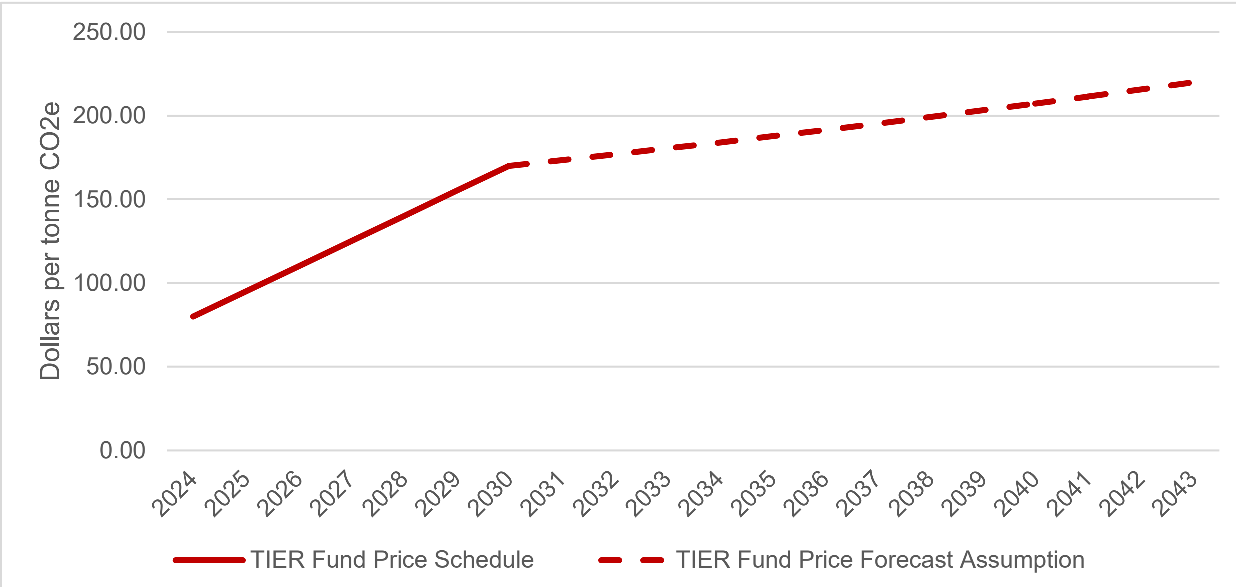
[3] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html#toc3.

[4] https://kings-printer.alberta.ca/1266.cfm?page=2019_133.cfm&leg_type=Regs&isbncln=9780779843916&display=html.

TIER Fund Price and Credit-use Limits

The TIER fund price is scheduled to increase in alignment with the federal carbon price starting from $65 per tonne CO_2e in 2023 to $170 per tonne CO_2e in 2030.[5] As with the federal carbon price assumptions, the 2024 LTO assumes that the TIER fund price will follow the stated trajectory until 2030, after which it escalates by two per cent per year.

Figure 1: TIER Fund Price Schedule and Forecast



Additionally, the credit-use limit, which applies to emissions offsets, EPCs and sequestration credits, is scheduled to increase 10 percentage points per year from 60 per cent of facility's compliance obligations in 2023 to 90 per cent from 2026 onwards. In the 2024 LTO, any combination of emissions offsets and EPCs used to meet compliance obligations were valued at the prevailing TIER fund price. That is, the cost for an unabated facility to meet its compliance obligations was calculated as the difference between its total emissions and its allowable emissions, multiplied by the TIER fund price. Similarly, emissions offsets or EPCs generated and used by the same facility were valued at the prevailing TIER fund price. To account for transaction costs, facilities that generate and sell emissions offsets or EPCs received a value equal to a 25 per cent discount to the TIER fund price. However, emissions offsets and EPCs are marketable commodities and, thus, may trade at any price. While the escalating TIER price may increase the relative value of emissions offsets and EPCs, it may also result in a surplus of credits generated, decreasing their marketable price. Valuing emissions offsets and EPCs at the TIER fund price may overestimate the costs to unabated facilities and benefits to abated or non-emitting facilities.

[5] https://kings-printer.alberta.ca/Documents/MinOrders/2022/Environment_and_Protected_Areas/2022_062_Environment_and_Protected_Areas.pdf.

Electricity High-Performance Benchmarks and Electricity Grid Displacement Factor (EGDF)

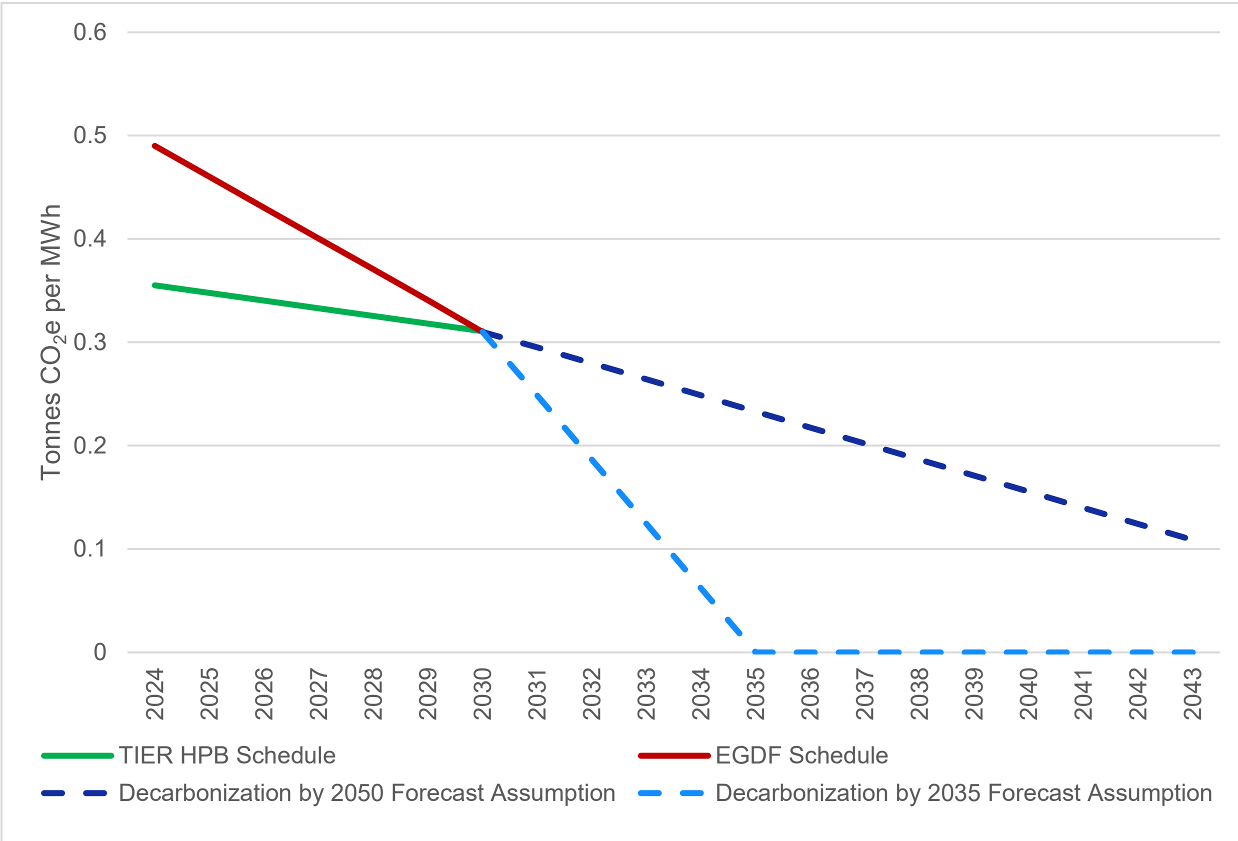
Beginning in 2023, the HPB for electricity is scheduled to decrease by two per cent annually until 2030.[6] Additionally, the Electricity Grid Displacement Factor (EGDF), which estimates the emission intensity of the grid and is used to quantify emissions offsets from renewable electricity projects, is scheduled to tighten until it converges with the prevailing HPB for electricity in 2030.[7] For cogeneration at oil sands mining, upgrading and in situ facilities, the FSB tightens by two per cent per year beginning in 2023, increasing to four per cent in 2029 and 2030.[8] After 2030, the FSBs are assumed to decline by four per cent annually. In the 2024 LTO, the HPB and EGDF were assumed to decline linearly from the 2030 threshold to zero by 2035 or 2050, depending on the scenario. In the Decarbonization by 2035 scenario, the HPB and EGDF reach zero in 2035 based on the assumption that the federal *Clean Electricity Regulations* (CER) will set the performance standards beginning in 2035. In the Decarbonization by 2050, High Electrification and Alternative Decarbonization scenarios, the HPB and EGDF reach zero in 2050, aligning with the Government of Alberta's plan to achieve net-zero electricity by 2050, rather than 2035.

[6] See TIER Schedule 2

[7] Carbon Offset Emission Factors Handbook, version 3.1. (2023). Section 1. https://open.alberta.ca/dataset/f2109d83-2153-4481-a8b8-b00178e53999/resource/99973308-0b0f-402e-acea-e1dc339f2e64/download/epa-carbon-offset-emission-factors-handbook-v3-1-2023-01.pdf.

[8] Standard for Developing Benchmarks, version 2.2. (2023), Section 8.5. https://open.alberta.ca/dataset/0cba733c-5038-4503-a2ef-33edb14abae3/resource/bf8d67ff-d925-4a75-a6c1-2dce1dfe42f1/download/epa-tier-standard-developing-benchmarks-version-2-2.pdf.

Figure 2: TIER High-Performance Benchmark Schedule and Forecast



Carbon Sequestration Credits and Capture Recognition Tonnes

The December 2022 amendments to TIER included the creation of sequestration credits and capture recognition tonnes. With this change, emissions offset projects that involve a net geological sequestration of carbon can be converted into sequestration credits that can be banked, traded, or used to meet compliance obligations. Like emissions offsets and EPCs, sequestration credits are subject to the credit-use limit for a given year. If a sequestration credit is transferred to the facility that originally captured the carbon, that facility can convert it into capture recognition tonnes. Capture recognition tonnes must be used in the year that the capture occurred and cannot be traded. However, capture recognition tonnes are deducted directly from the facility's total regulated emissions and, therefore, are not subject to the credit usage limit. For the purposes of the 2024 LTO, these credits were treated in the same manner as emissions offsets and EPCs.

Hydrogen

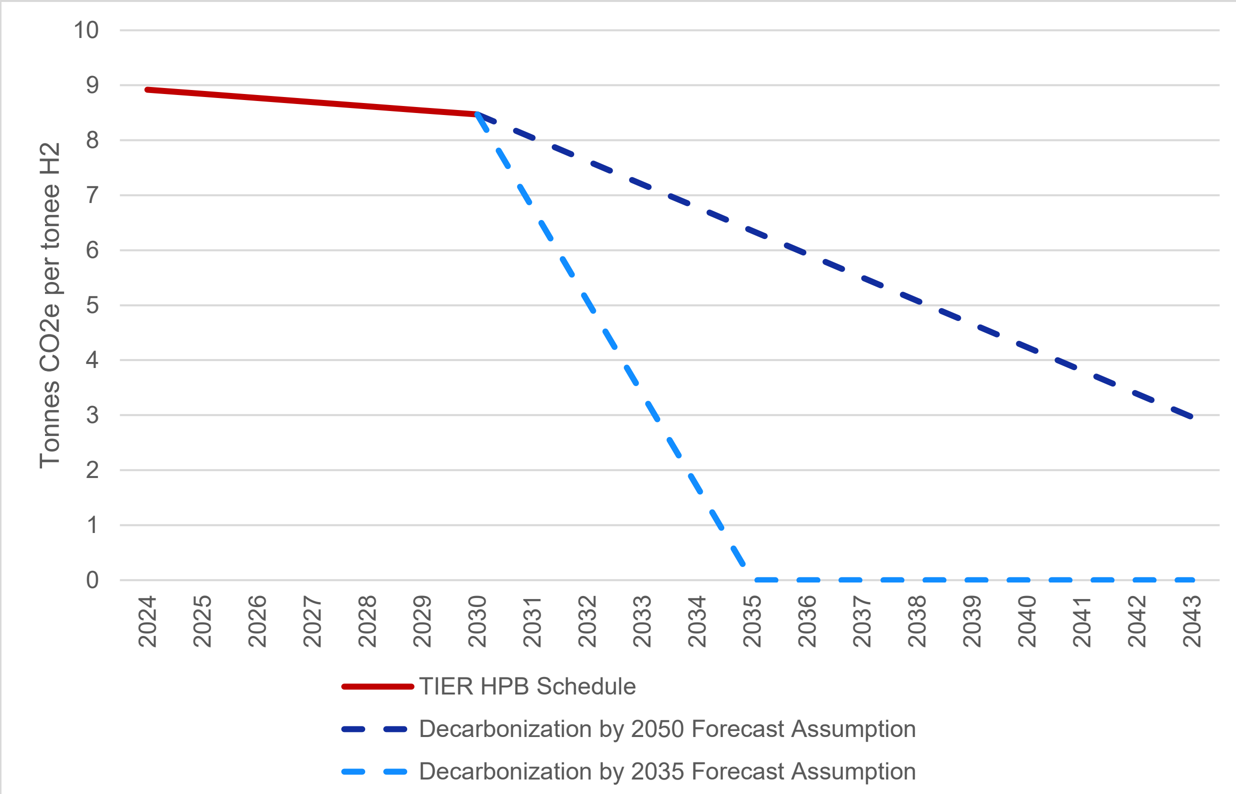
Prior to the December 2022 amendments, a facility could not be allocated allowable emissions less than zero. This lower bound was repealed, allowing facilities to receive negative allowable emissions. This primarily impacts hydrogen-fired generation facilities that import hydrogen, as they would effectively receive no credits for the generation of zero-emissions electricity. Instead, facilities could generate credits during hydrogen production (e.g., sequestration credits generated during blue hydrogen production), but importing hydrogen would not enable the creation of a secondary credit for the combustion of the fuel. As a result, an integrated hydrogen production, CO2 sequestration and hydrogen-fired generation facility would be treated similarly to three facilities with separate ownership. Using the AESO's method of hydrogen production cost estimation, the reduction in credits available to hydrogen-fired generation increases the cost of hydrogen compared to the results in the previous *AESO's Net-Zero Emissions Pathways Report.* This "true up" creates a higher cost of fuel for hydrogen-fired generation and limits investment in hydrogen-fired generation facilities until later in the forecast as compared with previous AESO analysis.

The production of blue hydrogen from steam-methane reforming or autothermal reforming with carbon capture and sequestration are expected to create sequestration credits, which may ultimately reduce both the full cost of hydrogen production and the unit cost of hydrogen that may be sold in an arms-length transaction. Similarly, the production of hydrogen via low-carbon electrolysis (i.e., green hydrogen) could produce EPCs, thereby reducing the net-cost of hydrogen production via such methods.

The HPB for hydrogen[9] was assumed to decline along a similar trajectory as the HPB for electricity, post-2030, in the Reference Case and most scenarios. In the Decarbonization by 2035 scenario; however, the HPB for hydrogen declines linearly from its 2030 value to zero by 2035. In the Decarbonization by 2050, High Electrification and Alternative Decarbonization scenarios, the HPB for hydrogen declines linearly from its 2030 value to zero in 2050.

[9] See TIER Schedule 2 for the high-performance benchmark for hydrogen.

Figure 3: TIER High-Performance Benchmark for Hydrogen Schedule and Forecast



Federal Investment Tax Credits

The Government of Canada announced several investment tax credits (ITCs) intended to accelerate decarbonization. These include ITCs for carbon capture, utilization, and storage (CCUS), non-emitting and abated electricity generation, electricity storage projects, and clean hydrogen production. These ITCs will impact the net capital cost of renewable generation assets, abated and low-carbon thermal generation assets, energy storage assets, and emissions control technologies.

The ITC for CCUS was announced in Budget 2022[10] and provides significant incentives for carbon mitigation infrastructure. From 2022 through 2030, this ITC provides a refundable tax credit equal to 60 per cent of capital costs for direct air capture projects, 50 per cent of capital costs for other CCUS projects, and 37.5 per cent of capital costs for transportation, storage, and use. To incentivize early adoption, these rates will be reduced by 50 per cent from 2031 through 2040. This ITC is expected to provide meaningful incentives for combined-cycle natural gas facilities and hydrogen production facilities to pursue CCUS projects throughout the 2024 LTO forecast horizon. This ITC may also incentivize CCUS projects more broadly in other industrial sectors.

[10] Budget 2022, p. 97. https://www.budget.canada.ca/2022/home-accueil-en.html.

The ITC for Clean Technologies was announced in the 2022 Fall Economic Statement[11] and provides refundable tax credits equal to 30 per cent of the capital cost of non-emitting electricity generation, including solar, wind, small modular reactors, and certain hydro-electric projects, and electricity storage projects that do not use fossil fuels in their operation. This includes batteries, compressed air storage, and pumped hydro. Budget 2023 extended the Clean Technologies ITC to the end of 2034.[12]

Budget 2023 bolstered electricity sector subsidies by introducing the ITC for Clean Electricity.[13] This ITC provides a 15 per cent refundable tax credit for capital costs relating to non-emitting electricity generation systems, including large-scale nuclear and hydro, abated natural gas-fired generation, stationary electricity storage systems that do not use fossil fuels, and interprovincial transmission. Notably, both taxable and non-taxable entities, such as Crown corporations, publicly owned utilities, and corporations owned by Indigenous communities, are eligible for the ITC. The Clean Electricity ITC is scheduled to end after 2034.

Lastly, the ITC for Clean Hydrogen was announced in the 2022 Fall Economic Statement,[14] with further details released in Budget 2023.[15] This ITC provides a refundable tax credit for between 15 and 40 per cent of capital costs related to hydrogen production, where production with a lower carbon intensity will receive a higher tax credit rate. Blue hydrogen produced via steam-methane reforming or autothermal reforming is expected to receive a rate of 15 per cent, whereas green hydrogen production is expected to receive a rate of 40 per cent.

[11] 2022 Fall Economic Statement, p. 30. https://www.budget.canada.ca/fes-eea/2022/home-accueil-en.html.

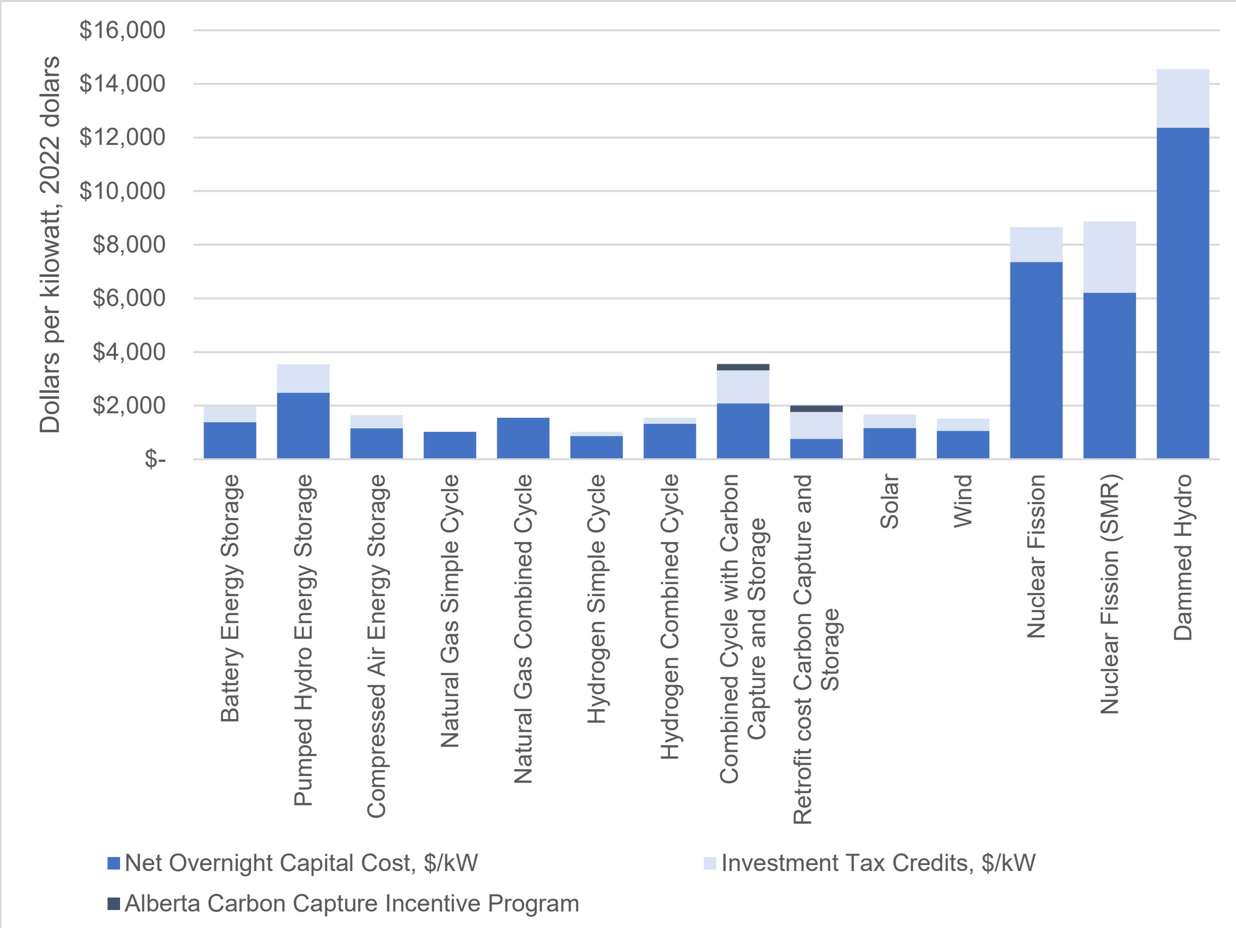
[12] Budget 2023, p. 91. https://www.budget.canada.ca/2023/home-accueil-en.html.

[13] Budget 2023, p. 79.

[14] 2022 Fall Economic Statement, p. 31.

[15] Budget 2023, p. 88.

Figure 4: 2024 LTO Overnight Capital Costs



Importantly, these ITCs are all refundable credits, meaning they are credited in their entirety regardless of how much tax is owed. As such, the AESO has accounted for these ITCs by discounting the capital costs of each technology by the ITC rate for the 2024 LTO.

Provincial Alberta Carbon Capture Incentive Program (ACCIP)

In late 2023, the Government of Alberta announced an Alberta Carbon Capture Incentive Program (ACCIP).[16] The program will provide a grant of 12 per cent for new eligible CCUS capital costs. This grant is expected to be additional to the federal ITCs, creating subsidization of up to 62 per cent of capital costs for new CCUS projects. Within the 2024 LTO, both the applicable ITCs and ACCIP were applied to hydrogen production components, retrofits, and applicable new post-combustion carbon capture equipment. More details on the ACCIP are expected to be released in 2024.

[16] https://www.alberta.ca/alberta-carbon-capture-incentive-program.

Clean Electricity Regulations

In August 2023, the federal government published its draft CER.[17] As outlined in Part I of the Canada Gazette, the CER would impose an emission performance standard of 30 tonnes of carbon dioxide per gigawatt-hour of electricity produced (30 t CO_2e/GWh) on any unit that uses any amount of fossil fuels, has a capacity of 25 MW or greater, and operates for more than 450 hours per year. The 30 t CO_2e/GWh performance standard would apply beginning January 1, 2035, for all units commissioned after January 1, 2025. Existing natural gas-fired units would be assigned a 20-year end of prescribed life, after which they would be subject to the performance standard. Significantly modified units (i.e., coal-to-gas conversions) would be assigned an end of prescribed life depending on their emission intensity before modifications. By 2039, the performance standard would apply to all significantly modified units.

To be compliant with the CER, natural gas-fired units will require sufficient carbon capture rates or will otherwise be limited to 450 hours per year. The rate of carbon capture needed to meet the 30 tonne CO2e/GWh performance standard can be estimated using the emissions output from a facility, which can be calculated from the natural gas emission factor and the gross heat rate (higher heating value [HHV]) of a unit:

$$Natural\ Gas\ Emission\ Factor\ \left(\frac{t\ CO_2e}{GJ}\right) \times Gross\ Heat\ Rate\ \left(\frac{GJ}{GWh}\right) = Emissions\ Output\ \left(\frac{t\ CO_2e}{GWh}\right)$$

Estimates for the natural gas emission factor vary. The value used for this analysis, 0.0561 t CO_2e/GJ, is the value published and used by the Intergovernmental Panel on Climate Change.[18] Similarly, the heat rate of a unit varies depending on factors like output, temperature, fuel mix and configuration. A brand new, top-of-the-line combined-cycle facility would have a heat rate of approximately 6,900 GJ/GWh,[19] while a mid-vintage combined-cycle facility would have a heat rate of approximately 7,400 GJ/GWh;[20] these values would be representative of existing generators such as Cascade and Shepard, respectively. Given these heat rates, the capture rate needed to meet the CER compliance obligations would be 92.25 per cent and 92.77 per cent, respectively.

[17] https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html.

[18] Intergovernmental Panel on Climate Change (2014), Annex II: Metrics & Methodology. ipcc_wg3_ar5_annex-ii.pdf.

[19] Heat rate estimate derived from Alberta Utilities Commission proceeding 24081.

[20] Heat rate estimate derived from Alberta Utilities Commission proceeding 241.

Table 1: Carbon Capture Rates Required to Meet CER Compliance Obligations

Facility Type	Natural Gas Emission Factor ($t\ CO_2e/GJ$)	Gross Heat Rate (GJ/GWh)	Unabated Emissions Output ($t\ CO_2e/GWh$)	Capture Rate Needed to Meet CER Obligations
Brand new, top-of-the-line combined-cycle	0.0561	6,900	387.09	92.25%
Mid-vintage combined-cycle	0.0561	7,400	415.14	92.77%

This presents a regulatory risk, as there are still relatively few carbon capture facilities in commercial operation, most of which operate on pre-combustion emissions. Only five projects operate on post-combustion emissions, only one of which operates on emissions from natural gas. Early operational data reports a 90 per cent to 98 per cent capture rate, but there remains uncertainty surrounding the effectiveness of existing technologies when scaled up for use on large combined- or simple-cycle facilities. Given the calculation above, a natural gas-fired facility requires carbon capture to be similarly effective to meet the CER emission performance standard.

Furthermore, it is expected that the CER will fully expose emitters to the carbon price for all emissions (i.e., there will be no opportunities for facilities to use EPCs or emissions offsets to meet compliance obligations). For the 2024 LTO, the CER restrictions were included only in the Decarbonization by 2035 scenario. This informs the assumption of a TIER high-performance benchmark for electricity equal to zero from 2035 forward. Additionally, the AESO assumes that the CER will limit generation from unabated natural gas to 450 hours per year, or a five per cent capacity factor, and that generation assets will be assigned an end of prescribed life of 20 years, or, for coal-to-gas units, an end of prescribed life based on their pre-modification emissions intensity, after which they will be bound by the capacity factor constraint. Units smaller than 25 MW have been modeled as exempt from the regulation. Final details on the CER are expected to be released in 2024.

Although the CER is not expected to have an operational impact on generators until 2035, the regulation may limit investment in reliable thermal generation prior to this timeframe. The AESO believes that this regulation could present reliability challenges to the Alberta Interconnected Electric System (AIES) if suitable firm generation cannot be developed to serve increasing system demand, compounded by electrification.

Emissions Reduction Plan

Canada's 2030 *Emissions Reduction Plan* (ERP) provides a sector-by-sector guide to reach emissions reductions 40 per cent below 2005 by 2030 and net-zero emissions by 2050, which influences electrification of transportation and building heating and cooling and heavy industry. With the objective of accelerating cleaner transportation by reducing carbon dioxide emissions, the ERP defines new sales mandates of zero-emission vehicles (ZEV) adoption for light-duty vehicles (LDVs), medium-duty vehicles (MDVs), heavy-duty vehicles (HDVs) and buses which are outlined below in Table 21 These new vehicle sales mandates defined by the ERP guide the trend of EV adoption in the LTO. The 2024 LTO Reference Case considers economic and infrastructure conditions that influence EV adoption. As such, ZEV adoption is more modest in the short-term than the ERP targets; however, it follows that trend in the long run. Alternatively, the 2024 High Electrification Case features more aggressive ZEV adoption strictly in line with the ERP new sales mandates.[22]

Table 2: Summary of ZEVs Per Cent of New Sales for Each Type of Vehicle Class Based on ERP Target

Vehicle Type	ZEV Percentage of new Sales
Light duty	20 per cent by 2026 60 per cent 2030 100 per cent by 2035
Medium- and Heavy-duty	35 per cent by 2030 100 per cent by 2040
Bus	100 per cent by 2040

The ERP features the Canada Green Buildings Strategy which aims to reach net zero emissions by 2050 from residential, commercial, and industrial buildings. The Canada Green Buildings Strategy aims to reduce emissions from building heating and cooling by electrifying these processes and improving energy efficiency, among other methods. At this current stage, the government is exploring ways to accomplish the objective of net zero buildings through funding research and exploring opportunities to reduce emissions in certain communities. The Canada Green Buildings Strategy shapes assumptions regarding the adoption of electric heating and cooling in the 2024 LTO Building Electrification load forecast as the strategy strives to achieve net-zero emissions in the buildings sector by 2050.[23]

The ERP influences electricity demand in heavy industry in the High Electrification scenario as it provides guidelines on electrification of capital stock in this sector.[24] The 2024 LTO accounts for the chemical, cement and pulp and paper heavy industries, the ERP electrification targets are met in these industries. As per the ERP, from 2022, the electricity share (per cent) of equipment stock in key industrial sectors should increase linearly by two per cent in 2030. This assumption is applied to the pulp and paper, and chemical industries. For cement, the ERP outlines that starting from 2022, electricity share (per cent) should increase linearly by one per cent in 2030.[25]

[21] More details about new ZEV sales mandates can be found on p57 of factsheet-06-transportation.pdf (canada.ca)

[22] For more information on how the ERP's new vehicle mandates are applied in the 2024 LTO see the Load Forecast Methodology section.

[23] For more information on the building electrification assumptions used in the 2024 LTO see the Load Forecast Methodology section.

[24] Heavy Industry electrification guidelines in the ERP are found on page 202 in the 2030 Emissions Reduction Plan. En4-460-2022-eng.pdf (publications.gc.ca)

[25] For more information on the Heavy Industry Electrification assumptions used in the 2024 LTO see the Load Forecast Methodology section.

Alberta's Moratorium on Renewables and Announced Policy Changes

In August 2023, the Government of Alberta announced a seven-month moratorium on renewable electricity projects while the Alberta Utilities Commission (AUC) completed an inquiry on land-use and reclamation. The moratorium ended on February 29, 2024, with the announcement of several incoming policy and regulatory changes that would apply to all new renewable project approvals.[26] While the key details of many of these changes are yet to be released, they include:

- Taking an "agriculture first" approach that requires the AUC to prioritize agricultural uses when making decisions around proposed renewables projects. This includes no longer permitting renewable generation projects on Class 1 or 2 lands unless the proponent can demonstrate compatibility with crops and/or livestock.
- Requiring developers to post bonds or other security for the reclamation costs of the project, the amounts of which will be determined by the Ministry of Environment and Protected Areas in consultation with the Ministry of Affordability and Utilities by the end of 2024.
- Establishing a minimum 35-kilometre buffer around protected areas and other "pristine viewscapes" as designated by the province. On March 15, 2024, the government released a draft map to stakeholders[27] which would prohibit wind and solar developments in UNESCO world heritage sites and national parks, implement a buffer zone to the edge of the Rockies that prohibits new wind projects, but allows new solar projects, and implement zones which trigger visual impact assessments surrounding some provincial parks and UNESCO world heritage sites.
- Permit renewable generation projects on Crown land on a case-by-case basis.
- Changes in the allocation of transmission costs that will be announced with the new *Transmission Regulation* later in 2024.
- Grant municipalities the right to participate in AUC hearings, expand their eligibility for cost recovery and allow them to review rules related to municipal submission requirements.

Most of these changes will not apply retroactively to any projects that have already received AUC approval but will apply to those still in the application process. However, the reclamation cost requirements will apply to all projects approved after March 1, 2024, indicating an intention to enact retroactive legislation or regulation. While these changes have the potential to materially impact development of wind and solar projects, they were not included in the 2024 LTO.

[26] https://www.alberta.ca/system/files/au-minister-neudorf-letter-to-auc-20240228.pdf

[27] https://rmalberta.com/wp-content/uploads/2024/03/2024.03.14_Map.pdf.

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