# 12. Alberta's Quiet but Resilient Electricity Transition

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**Highlights**

- Alberta's phase-out of coal-fired electricity has been an underreported climate policy success, expected to result in a 40 $MtCO_{2e}$/yr reduction in GHG emissions by 2030.
- Mutually reinforcing regulatory and pricing policies at the provincial and federal levels have helped ensure the durability of the phaseout through major political transitions.
- Natural gas-fired generation now dominates Alberta's electricity sector; the pathway to future decarbonization of the sector remains uncertain.
- While the rapid electricity transition has enabled provincewide emissions reductions in recent years, continued expansion of oil sands emissions threatens Alberta's progress.

**Key Resources**

- Alberta Climate Leadership Panel, Climate Leadership: Report to Minister (2015). https://open.alberta.ca/publications/climate-leadership-2015
- AESO Annual Market Statistics Reports (2021). https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/
- AESO 2021 Long-term Outlook (2021). https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf
- AESO 2019 Long-term Outlook (2019). https://www.aeso.ca/assets/Uploads/AESO-2019-LTO-updated-10-17-19.pdf

## Alberta’s quiet but resilient electricity transition

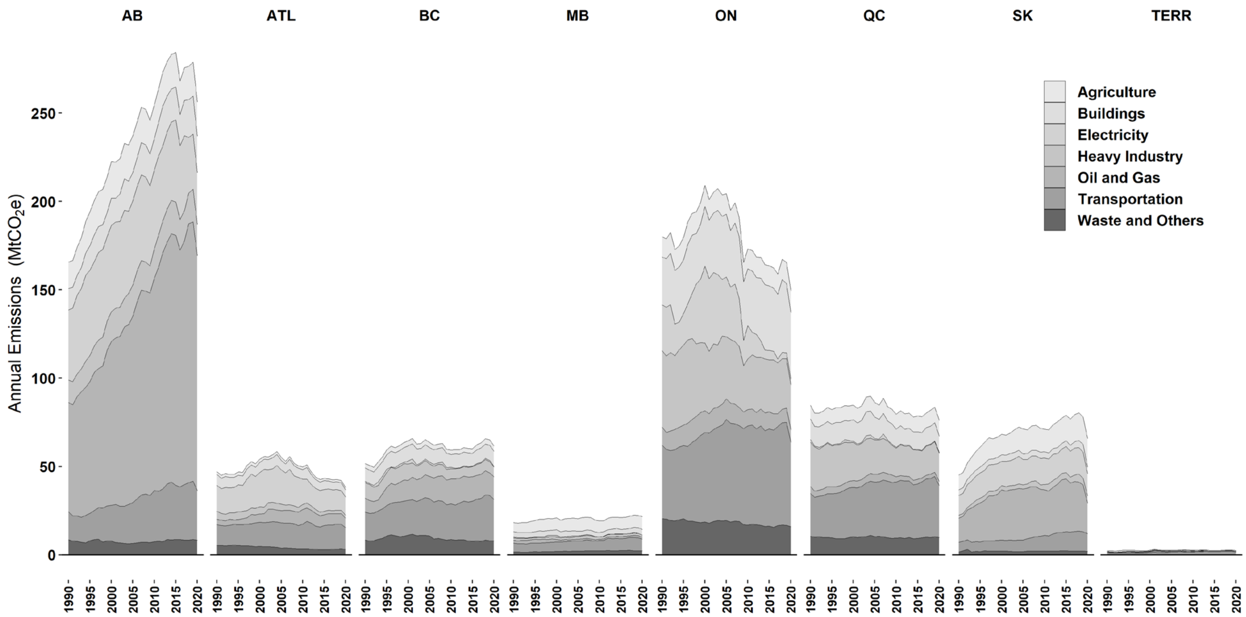
One of the biggest climate change stories in Canada is happening in Alberta, but it is not what you might think. Alberta, as home to one of the largest oil deposits in the world, has been at the center of contentious climate change battles for nearly three decades. Increasing oil sands production and related economic growth have led to increasing emissions in the province, drawing national and international attention. Although the fourth largest province by population, Alberta has by far the highest greenhouse gas (GHG) emissions and among the highest per-capita emissions globally. While most Canadian provinces have seen emissions fall for over a decade, Alberta’s emissions continued to rise quickly through the first half of the 2010s.

Since 2015 however, Alberta’s emissions have fallen, thanks to a rapid phase-out of coal-fired electricity generation. Alberta’s electricity emissions are projected to continue on a downward trajectory in coming years as natural gas displaces coal in the supply mix and renewable electricity generation grows. While oil and gas emissions have been a major focus of environmental scrutiny, the decarbonization of Alberta’s electricity sector has been quietly successful and resilient. A confluence of low natural gas prices, renewable energy cost declines, and a layering of government policy initiatives resulted in the rapid abandonment of a domestically-produced and readily available fossil fuel (thermal coal), and permanent changes to the province’s electricity system. The case both illustrates the risks of lock-in to lower-emission but still carbon-intensive transitional technologies in the decarbonization process – from coal to natural gas in this instance – emphasized by Meadowcroft and Rosebloom in Chapter 2, but also highlights some potential strategies for managing those risks.

### The *two* big emitting sectors within Alberta’s climate conundrum

Much of Alberta’s natural resource wealth is underpinned by the Athabasca oil sands, which are among the largest crude oil deposits in the world. Alberta boasts substantial conventional oil and natural gas reserves, but the oil sands have been the key economic story in the province for much of the last three decades. Once oil prices rose sufficiently to make new investments in the oil sands viable in the late 1990s, a five-fold increase in production occurred between 1995 to 2015. The same period saw a quadrupling of oil sands emissions.[1] Production has continued to rise since 2015, albeit more slowly, reaching 3.3 million barrels per day in the Summer of 2022.[2]

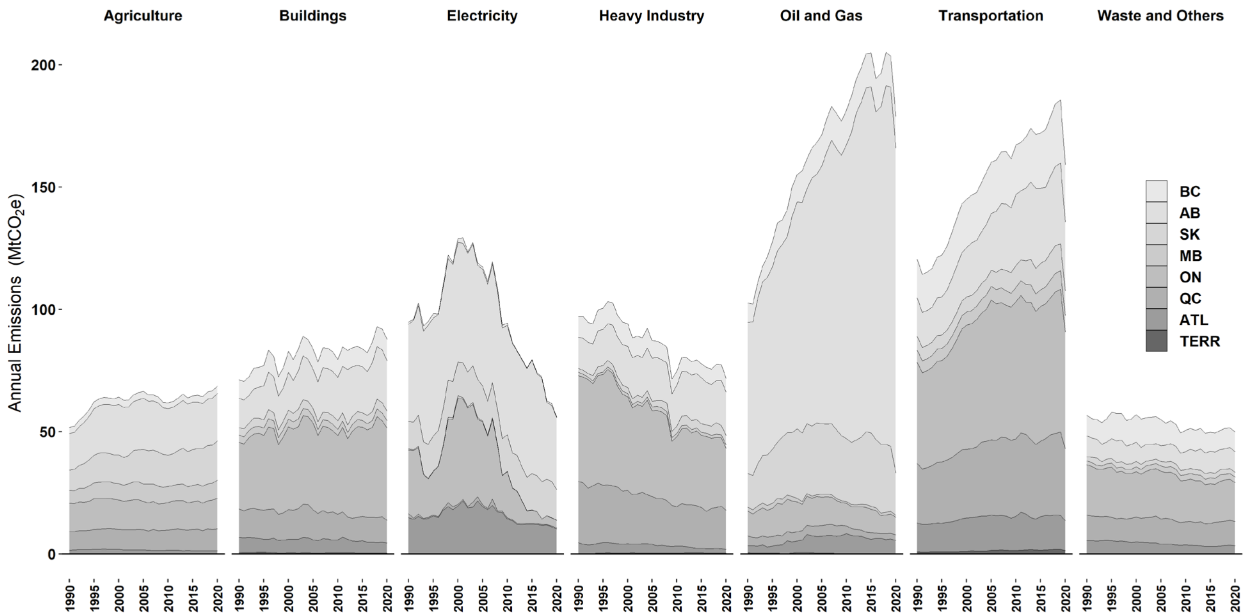
**Figure 12.1: 1990-2012 Provincial GHG emissions.** Source: Environment and Climate Change Canada, National Inventory Report (2022).




The rapid expansion in oil production in Alberta, and the economic growth that accompanied it, is the key reason why the province's emissions stand out from the other provinces in **Figure 12.1**. Adjusted for population, the contrast is even more stark. In 2019, for example, Alberta accounted for 11.6 percent of Canada's population,[3] but 37.8 percent of emissions. The next highest-emitting province, Ontario, has over three times Alberta's population but accounted for 22.3 percent of national emissions.[4]

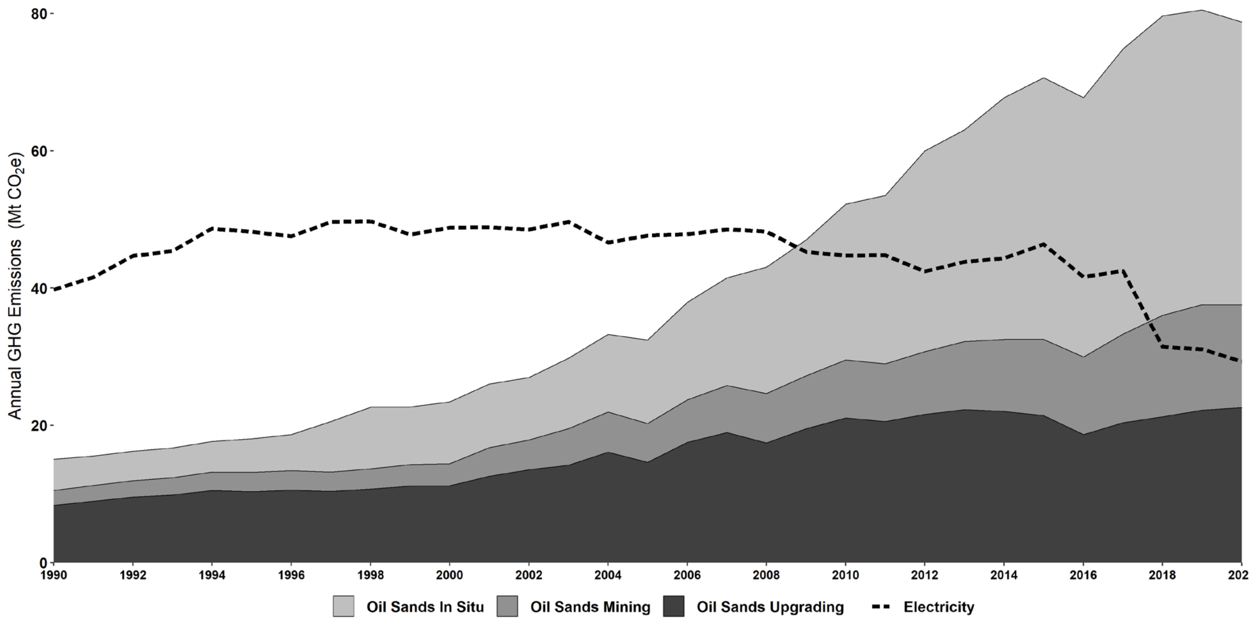
The continuing expansion of the oil sands puts substantial pressure on Canada's past and present emissions reduction goals. In 2014, Canada's target of reducing emissions by 17 percent below 2005 levels by 2020 required roughly 140 Mt of reductions. Oil sands emissions were projected to grow by 66 Mt, from 34 Mt in 2005 to over 100 Mt by 2020 (**Figure 12.2** shows the dramatic rise in oil and gas emissions relative to economic sectors across all provinces).[5] The situation presented a major technical and political challenge. Current projections now expect far less oil sands expansion in the coming decade, but the oil sands' greenhouse gas emissions are still expected to grow to 93 Mt by 2030, from estimated 2020 levels of 82 Mt.[6]

**Figure 12.2: GHG emissions by sector and province in Canada.** Source: Environment and Climate Change Canada, National Inventory Report (2022).




While domestic and international climate attention focused on oil sands extraction, Alberta's second largest-emitting sector, its coal-heavy electricity supply, attracted little notice outside of the province.[7] Until 2014, Alberta's electricity sector emissions exceeded emissions from oil sands extraction (see **Figure 12.3**). In that year, the 41.4 $Mt_{CO2e}$/yr, emissions from coal-fired power alone surpassed emissions from either type of oil sands extraction (mining and upgrading or *in situ* extraction) considered alone.[8] During this time, some domestic environmental organizations saw Alberta's runner-up climate problem as a readily-accessible source of emissions reductions in light of the low-cost of domestic natural gas, combined with ongoing cost reductions for wind and solar energy, which are abundantly available in Alberta.[9,10] These suggestions were met with scepticism. It would take years and a change in government for the seeds of coal's decline to begin to bear fruit in Alberta.

**Figure 12.3: Emissions from electricity compared to the oil sands sector in Alberta.** Source: Environment and Climate Change Canada, National Inventory Report (2022).




## Alberta's electricity emissions: Challenge & opportunity

Alberta's electricity system poses unique challenges and opportunities for emissions reductions. It employs a competitive, energy-only wholesale market in a winter-peaking system with a substantial share of both load and generation from large industrial facilities, primarily in the oil sands region. It is also a relatively isolated market, with import capacity equivalent to approximately 10% of installed internal generation capacity. The competitive market structure presents both barriers and opportunities for expedited, transformational change. The market itself is open to technological and operational innovations and can accommodate relatively quick change, by electricity system standards, in response to economic or policy conditions. At the same time, the intense competition among a relatively small set of incumbents can pose risks to any sweeping policy changes. When an electricity system relies on the ongoing participation and investment of a few incumbents, arguments around merchant risk and investment expectations ring loudly in the ears of system operators and policy-makers.

### Market and supply legacy

Unlike most provinces, the Alberta government has never owned a utility.[11] For the majority of Alberta's history, all aspects of electricity supply (generation; delivery (transmission and distribution); and retail) were subject to cost-of-service "natural monopoly" regulation in a standard, vertically-integrated utility construct. The age of the vertically-integrated utility ended when Alberta joined the wave of electricity market reforms in the late 1990s, and introduced competitive generation and retail markets in the early 2000s.[12]

For electricity generation, restructuring was accomplished with the creation of an "energy-only" market, using a marginal price derived from generator offers of power on an hourly basis, with the least-cost offers dispatched to meet demand.[13] This market structure only pays generators for the energy (megawatt-hours (MWh)) that they produce. They are not compensated for capacity directly. Generators must recover both capital and operating costs from the wholesale energy market and cannot earn revenue for availability alone, apart from a small ancillary services market.[14] As such, higher-cost producers in Alberta's market cannot simply pass through those costs to consumers. Rather, producers with higher costs than other facilities will endure some combination of lower capacity factors and lower margins.

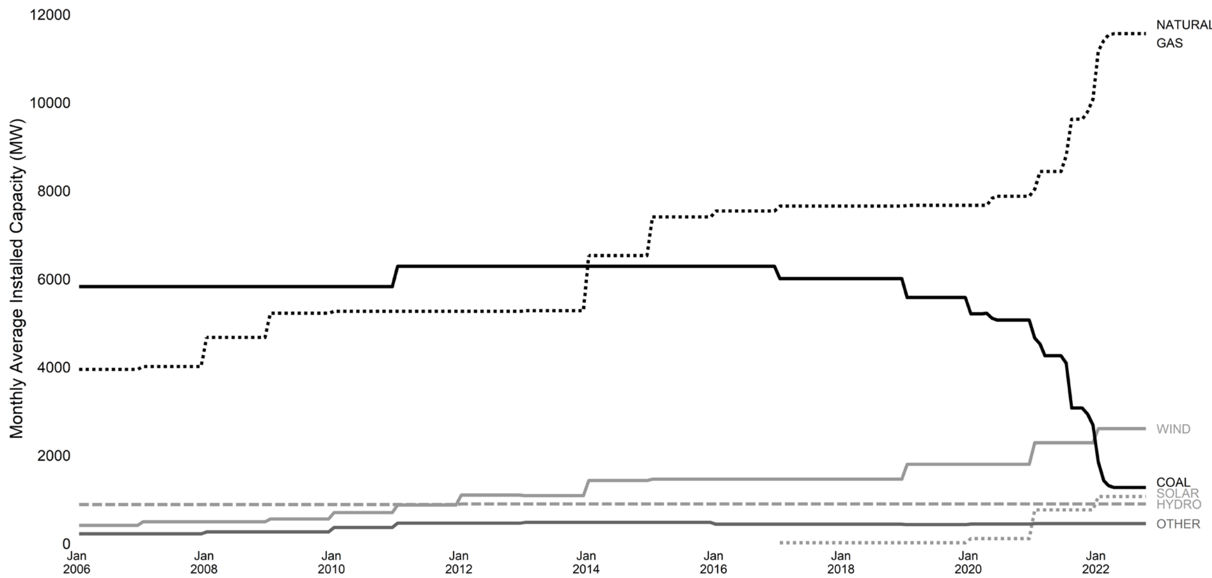
At the time of deregulation, coal dominated Alberta's electricity supply with seven power plants (each with between one and six units) providing three quarters of electricity generated in Alberta.[15] The balance was predominantly from natural-gas-fired plants, while only 3.5 percent of Alberta's electricity in 2000 came from renewable energy, most of which was run-of-river or small-reservoir hydro. Since these generating facilities had been built under a cost-of-service regulatory model that guaranteed cost recovery for their investors, complex regulatory instruments (e.g., power purchase arrangements or PPAs) were deployed as transitional mechanisms.[16]

What emerged was a generation market open to competition from new entrants, but with a very significant complement of generation remaining under quasi-regulatory transitional mechanisms. The ability for independent power producers (IPPs) to access Alberta's market opened the door for more renewable energy. Alberta added renewable generation, mostly wind, but also small amounts of hydro or biomass, in almost every year between 2001 and 2015. However, by 2015, renewable energy still supplied less than 10% of the electricity generated in the province. While renewable energy had grown in Alberta, non-renewable sources were growing faster, including coal. At a time when there was a political consensus in Ontario to phase out its coal fleet (see Chapter 11), Alberta power producers commissioned two new coal units, each accounting for over 400 MW of new installed capacity, in 2005 and 2011. The approval for another 500 MW unit was expedited by the Alberta Utilities Commission in 2011,[17] although the project was ultimately shelved.[18]

Gas-fired generation also expanded much faster than renewables. In particular, the rapidly expanding oil sands sector developed on-site cogeneration facilities to serve its steam requirements while producing electricity for its own operations and to offer excess supply to the grid. Other gas-fired generation initially declined after fuel price spikes in the mid-2000s, but the “shale gas revolution” of the early 2010s brought renewed interest in new combined cycle and simple cycle power plants. In 2011, the largest power plant ever built in the province, the 800 MW combined cycle Shepard Energy Centre, began construction on the basis of forecast electricity demand growth and expected coal unit retirements.

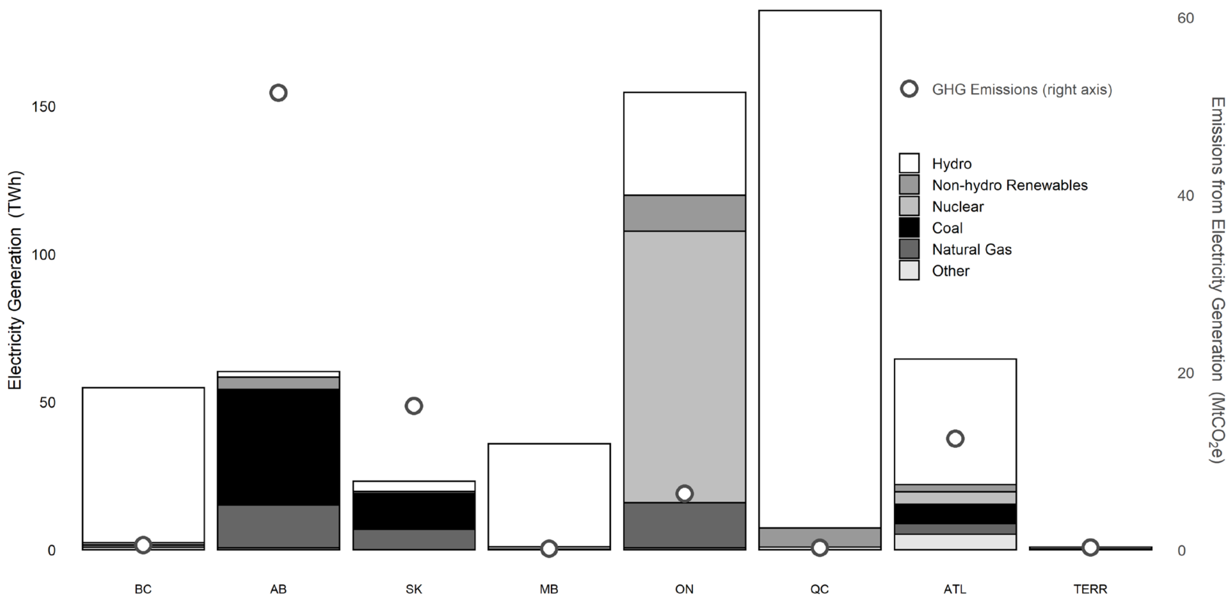
As a result, from 2005-2015, growth in generating capacity fueled by non-renewable sources quadrupled renewable capacity growth. Coal power lost some of its relative market share to the new gas-fired supply installed during this period, falling from three-quarters of installed capacity in 2000 to around two-thirds of installed capacity by 2014. However, at around 6,300 MW, installed coal-fired capacity was higher in 2014 and 2015 than it had ever been, shown in **Figure 12.4**,[19] and absolute generation from coal remained around 40 TWh annually through to 2015, topping $3B in annual energy market revenues.[20,21]

**Figure 12.4: Alberta's Installed Electricity Capacity 2004-2022.** Source: AESO data via NRGStream.




The emissions intensity of electricity in Alberta remained stagnant in the decade leading up to deregulation at around 940-950 t/GWh, approaching the intensity of one of the more efficient subcritical coal units. By 2014, the average had dropped to around 800 t/GWh, still over four times the Canadian average[22] and amongst the highest in North America.[23] While industry touted improved emissions intensity performance (with the lower relative contribution from coal), they also projected increasing absolute emissions from power generation in Alberta through 2050.[24] Any improvement in emissions intensity was swamped by increases in total generation, and electricity GHG emissions reached 51.5 Mt in 2015.[25] Alberta was responsible for well over half (59 percent) of all of Canada's electricity GHG emissions in that year, while supplying only 10 percent of all electricity generated in Canada (see **Figure 12.5**).

**Figure 12.5: Provincial GHG Emissions and Electricity by Energy Source (2015).** Source: Environment and Climate Change Canada, National Inventory Report (2022).[26]




## Early climate policy efforts related to electricity

This growth of emissions under Alberta's open and competitive market did not take place in the absence of climate policy — but the policies in place were insufficient to drive material emissions reductions in the sector.

### Early carbon pricing

Recognizing the mounting pressure on the province to curb the growth of GHG emissions, as well as the threat that federal regulation might occupy the field, Premier Ed Stelmach introduced Canada's first industrial carbon pricing scheme in 2007. The *Specified Gas Emitters Regulation* (*SGER*) notionally required the province's largest GHG emitters to reduce emissions intensity by 12 percent from a 2003-2005 baseline.

In reality, *SGER* imposed no firm requirement. Rather, the regulation was akin to a carbon tax with an output-based allocation of tax credits, with facilities receiving free credits at a rate equal to 88 percent of their 2003-2005 emissions intensity. Facilities could then exercise one of three compliance options to meet their requirements under the regulation if their emissions exceeded their allocated credits: they could purchase *emissions performance credits* (EPCs) from facilities with leftover allocations; they could purchase *offsets* from activities certified under protocols as reducing emissions outside of the price coverage, including renewable power plants;

or they could pay \$15/$t_{CO2e}$ into a *technology fund*, which was reinvested in activities to reduce emissions in Alberta. This last financial compliance option effectively set a ceiling price on the value of emissions reductions and the trading price of EPCs or offsets.

With a \$15/$t_{CO2e}$ ceiling, and a regulatory regime which effectively allocated emissions credits at a rate equal to 88% of a facility's historic emissions intensity, the impact of the SGER on operating costs was minimal. A typical 1.0 $t_{CO2e}$/MWh coal plant would only incur costs of \$1.80/MWh (\$15/$t_{CO2e}$ for uncredited emissions of 0.12 $t_{CO2e}$/MWh) while annual average market prices at the time were consistently above \$50/MWh.[27] The policy increased costs for coal generators, but these costs were insufficient to advance retirement schedules for coal units or to significantly alter their market position. Nevertheless, the system established a framework for industrial carbon pricing, including annual carbon emissions monitoring and reporting. It also established a resilient offset regime which created a secondary product that new renewable energy facilities could use as a small (in the range of \$10/MWh),[28] but relatively secure revenue source to supplement uncertain market revenues.

However, by the end of 2014, despite public musings of significant increases by Premier Redford in early 2013,[29] the financial compliance price and the implied credit allocation rates remained unchanged from the original policy set almost 8 years earlier.[30] With the newest coal unit abandoning its plans for carbon capture and storage,[31] and a newly proposed unmitigated coal unit racing through regulatory approval in 2011, there is no evidence that *SGER* impacted construction, operating, or retirement decisions for coal plants.

**Renewable energy supports**

The plains of southern Alberta are particularly windy, making them the natural home for Canada's first commercial wind farm in 1993. Between 2002 and 2011, the Canadian government implemented a series of production incentives for new wind power projects,[32] as well as an accelerated capital cost policy for renewable energy.[33] Combined with the availability of offsets in Alberta, wind energy grew from a few small projects at the time of deregulation to almost 5% of the electricity market by 2013.

Early wind projects were developed in close proximity due to the particularly strong winds near the community of Pincher Creek. Given that wind energy is a price-taker in the power pool, and that early wind production was highly correlated across the geographically concentrated plants, the average revenues earned by wind power facilities were consistently lower than the average market price, falling between 25 and 41 percent below the annual average market price over the first half of the 2010s.[34] With the price discount increasingly apparent, the carbon price for offsets not increasing as planned, and the last of the federal production incentive agreements ending in 2011, developers creatively pursued opportunities for financial support for new projects, but these were short-lived or one-off opportunities.[35] The development of new wind projects largely stagnated by 2015, a situation that was forecast to continue indefinitely.[36]

Renewable energy developers and environmental organizations initiated efforts around this time to advance renewable energy policy in Alberta.[37] These groups developed policy proposals congruent with Alberta's electricity market, settling on a "clean electricity standard": similar to the renewable portfolio standards which are commonplace in the United States, but with an obligation for retailers to meet a portfolio emissions-intensity standard rather than a prescribed renewable proportion. In spite of the market-based and technology neutral, outcome-based approach, the proposal nevertheless met opposition, particularly but not exclusively from incumbent generators, who argued that it was incompatible with market principles. The concept was reviewed and considered by government officials, and even gained enough traction that the government participated in dialogue sessions.[38] Renewable electricity soon fell off the priority list, however, the victim of an era of frequent leadership churn. Alberta had four different Progressive Conservative (PC) premiers in the three years between September 2011 and September 2014.

**Federal coal GHG regulations**

By 2010, the Conservative federal government began work on new regulations to reduce GHG emissions from coal-fired power. Finalized in 2012, the regulations set a "good-as-gas" emissions intensity standard, effectively requiring the application of carbon capture and storage, although the technology remained uncompetitive in Alberta's market.[39] The standard would apply to any new plants commissioned after mid-2015 or existing plants once they hit their deemed economic end-of-life, which was the 50th year of operation for most units.[40] The regulations put a clear end date on new capital investment in unabated coal plants, but the long timeline for application to existing plants meant very slow emissions reductions, with the last unit allowed to operate without emissions abatement until 2062.[41]

## Public discourse heading into 2015

Beginning in 2009, environmental organizations began to draw attention to the climate and air pollution impacts of Alberta's heavy reliance on coal-fired power[42]. By 2014, health groups had also joined the public campaign and coalesced into an organized effort to bring public attention to the health and climate impacts of coal power.[43] Albertans were initially only scantily aware that most of Alberta's electricity was supplied by coal.[44] Polling quickly suggested growing support for transitioning away from coal and toward cleaner generating sources, particularly renewable energy.[45] By 2014, all five active provincial political parties had made statements, with varying degrees of commitment and urgency, to pursue a phase out or support a transition away from coal power.[46]

Premier Prentice, who had been the federal Minister of Environment when the coal regulations discussed above were first proposed, publicly mused about a coal phase-out in September 2014, shortly after becoming premier.[47] Recognizing the forceful public discussion on the topic, in January 2015 he initiated a multi-session roundtable discussion among coal plant owners, PPA buyers, government agencies, and Alberta environmental organizations to investigate options for coal power emissions reductions. Industry proposed alternatives to a strict phase-out that involved so-called "dial-down" options purported to reduce the dispatch of coal-fired power. Industry's proposals included demands for public compensation for lost revenue opportunities from coal power facilities. Government received the proposals and took them away for assessment, but they met with strong disapproval from consumer groups in the midst of an early election campaign called by Premier Prentice in the spring of 2015.[48]

The election of 2015 was earth-shaking in Alberta for many reasons. The leaders' debate took on unusual significance as an off-the-cuff remark that "math is hard" to NDP leader Rachel Notley by Premier Prentice proved a turning point. The same section of the debate featured a central exchange where Premier Prentice attacked the NDP's promise to phase out coal-fired electricity, pointing to the industry demand for billions of dollars in compensation. The election resulted in the first change in government in Alberta in 44 years. The new NDP government's platform included a commitment to phase-out coal power as part of a broader plan to improve the province's image and record of action on climate change.

## The 2015 Climate Leadership Plan

One of the major initiatives launched by new premier Notley's NDP government was to pursue more aggressive climate action. The looming United Nations climate summit to be held in Paris in November 2015 provided a short time frame for action. In June, Environment Minister Shannon Phillips announced stringency and price increases to the *SGER*[49] while also launching a public engagement and policy advisory process led by the Climate Leadership Panel.[50] Three of the central planks of the panel mandate involved changes which would have profound effects on the electricity sector: an updated approach to carbon pricing; an evaluation of the potential for an accelerated phase-out of coal-fired electricity; and a policy to accelerate the deployment of renewable electricity in the province.[51]

Formal input was sought throughout the panel process, including submissions from the public, industry and other stakeholders, all of which remain publicly accessible.[52] All of the major electricity companies in the province, including TransAlta, the largest owner of coal assets, put forth proposals recognizing the need to reduce coal-fired generation and increase renewable power capacity. The incumbent industry submissions mostly proposed flexible options that still enabled profitable use of their existing assets and emphasized the costs of more ambitious options, including coal facility conversions to natural gas. TransCanada (a company which owns natural gas pipeline infrastructure and electricity generating assets in the province), was the sole industrial actor to propose coal-to-gas conversions.

In November 2015, the panel recommended five major climate change measures, three of which directly implicated the electricity sector: the adoption of an economy-wide carbon tax; a phase-out of coal-fired power by 2030; and an aggressive, market-based renewable power procurement program. Over the subsequent four years, the government adhered closely to the recommendations, bringing in some of the strongest climate policy measures at the time in North America. While climate policies have increased in ambition both in Canada and the USA since, in 2015, the 15-year commitment to phase out coal alone would match the emissions reductions in Ontario's coal phase out which has been widely seen as the single largest greenhouse gas reduction in North America,[53] while the \$30/$t_{CO2e}$ carbon tax would match British Columbia, the only other broad based carbon tax in North America at the time. The Alberta government announced its intent to accept the recommendations of the panel, with the CEOs of 5 major oil companies sharing the stage with 5 environmental advocacy groups and representatives from

First Nations and organized labour. It then undertook implementation over the ensuing three-and-a-half years.

### Coal phase-out agreements

Having announced its commitment to the Climate Leadership Plan's 2030 coal phase-out, the Alberta government also made a commitment not to strand generator capital unnecessarily.[54] In March 2016, it launched a comprehensive consultation and negotiation process led by Terry Boston, the former president and CEO of the PJM Interconnection, to develop transition agreements with the three owners of coal units that would be affected by the 2030 phase out: Capital Power; TransAlta; and ATCO.[55] In November 2016, the government announced transition agreements providing for annual payments to the companies until 2030, totaling $1.1 billion.[56] The payments were explicitly not framed as "compensation" for early closure, though the net book value at 2030 (minus the value salvaged through possible conversion to natural gas, estimated at $10 billion) was a key input into the amount of the transition payments.[57] Rather, they were framed as transfers to enable investment in Alberta's electricity system that would be required en route to replacing coal power.

The secure revenue provided by the payments helped to shore up company balance sheets against difficult electricity market dynamics, as the 2014-16 collapse of global oil prices meant that expected increases in demand failed to materialize. Large new generation investments had been made to serve that growing demand, resulting in a supply glut and a prolonged period of very low energy market prices. In return, the transition agreements obligated the coal plant owners to cease emitting GHGs at any coal-fired electricity generating operations by December 31, 2030. In this way, the government implemented the phase out commitment without new legislation or regulations. The government also made commitments to support the transition of the communities that hosted the coal power facilities.

Important support for the Alberta coal phase-out process came when the newly-elected federal Liberal government announced its own regulations to phase out coal-fired electricity across the country. Building on the pre-existing federal regulations implemented by the previous government, the new policy applied the same *good-as-gas* standard, but accelerated the end date for the youngest units to the end of 2029.[58] This change effectively backstopped Alberta's phase out agreements with federal law. The federal government also promulgated new gas-fired power regulations, but included a grace period during which converted coal units would be allowed a higher emissions rate than purpose-built gas-fired units. The modification enabled extended use of existing assets through modest fuel conversion investments.[59] While converted coal-to-gas units produce more emissions in the near term than newly built gas facilities, enabling the re-use of existing facilities also creates an easier medium-term transition by avoiding the construction of new 40-year assets to fill in short-term energy demands. Capital Power, one of three major owners of the original coal fleet began converting coal units to natural gas using turbines capable of operating on hydrogen as part of their net-zero by 2050 plan.[60]

### 30% renewable energy by 2030

In addition to the coal phase out, the Notley government introduced legislation to formalize a target of 30% renewable electricity generation by 2030.[61] The legislation also enabled the government to launch procurement programs to develop the estimated 5,000 MW of renewable generation capacity required to achieve the target.[62] The Renewable Electricity Program (REP) was designed as a series of competitive procurements with proponents stipulating a strike price for contracts-for-differences (CfD), bidding on fixed-price assurance from the government that insulated developers from market price volatility.[63]

There was considerable skepticism about the cost of meeting the 30% renewable generation target. Some estimates ran as high as $8 billion.[64] However, these estimates failed to recognize recent improvements in wind energy technology, a slowdown in wind energy deployment in the United States and elsewhere in Canada, and the supply of pent-up (partially pre-developed) projects in Alberta. Most importantly, they unduly discounted the reduced cost of capital enabled by the de-risked long-term CfD price.

The first round of REP saw wind energy from 600 MW of wind capacity procured at an average price of $37/MWh. The procurement cost was so low that the forecast cost of the program round was a fraction of its original budget, so the government easily added 200 MW to the originally announced 400 MW procurement.[65] Similar results were secured in two subsequent rounds, including a round that required 25% equity participation by an Indigenous community for projects to qualify. The province also followed up with a procurement of solar energy for 55% of the government's own electricity needs, using a very similar CfD approach, in this case with a special incentive for bids with 50% Indigenous equity. The solar procurement was finalized at an equally astounding $48/MWh with 50% Indigenous-owned projects. The government's cost over the 20-year horizon of the REP contracts is uncertain because its exposure under the CfDs is inversely related to electricity prices. Recent analysis has shown that, to date, the value of generated power has exceeded the contract strike price by $1.35/MWh, implying a net payment to the Government of Alberta, and thus a negative cost of emissions reductions from the REP contracts.[66]

In total between 2016 and 2018, the province contracted for around 1,360 new MW of wind generating capacity. With higher capacity factors than earlier wind projects, the REP projects, the earliest of which began production in late 2019, are expected to more than double Alberta's annual wind energy generation. A detailed plan to meet the 30% by 2030 target with future REP rounds (including Indigenous and other community participation), along with community generation and micro-generation programs, was cancelled after the Notley government was defeated in the 2019 election.

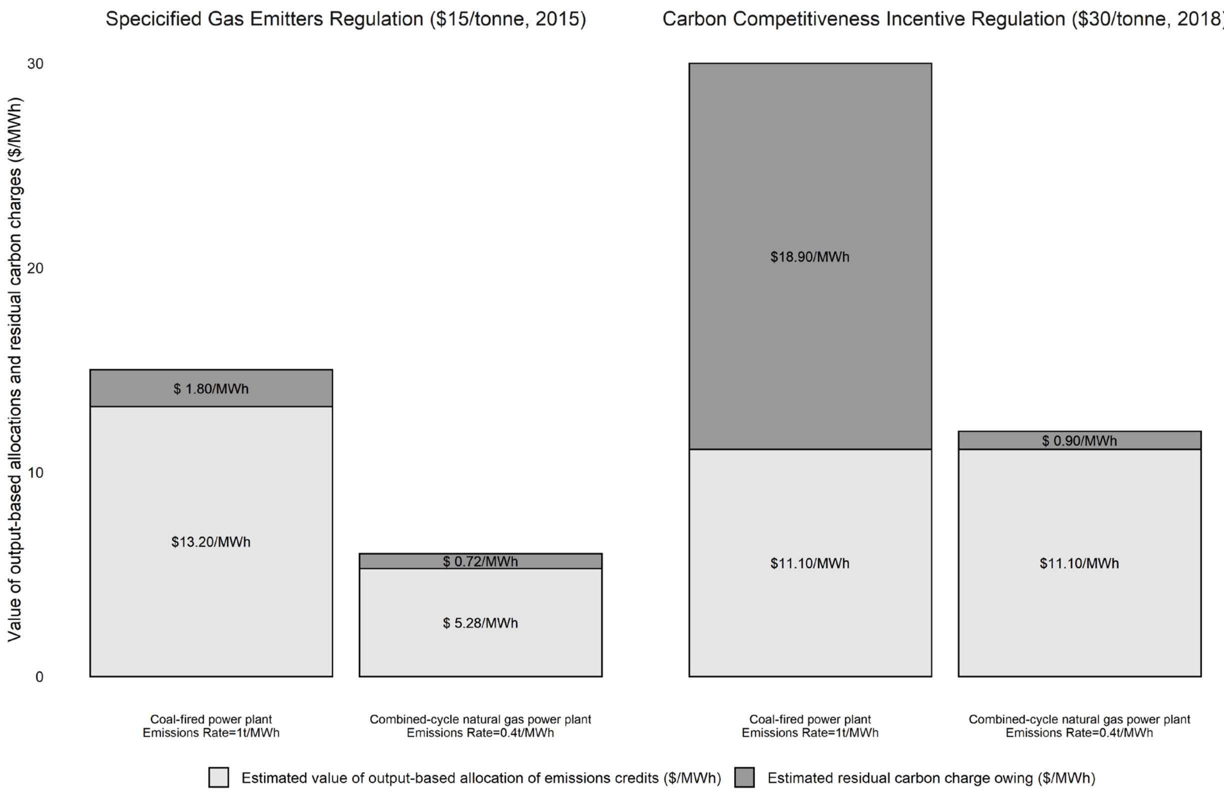
## Better industrial carbon pricing

While the coal phase-out and renewable energy procurement changed the baseline trajectory of Alberta's electricity market, the most immediate effects were realized by changes to the province's carbon pricing policy. The government's initial price, and stringency increases to *SGER* in 2016 and 2017 immediately widened the carbon pricing differential for higher-emitting coal versus lower-emitting generation and appears to have had some immediate effect: coal-fired generation fell by 5.4%, while gas-fired generation rose. The more dramatic effect, however, came when the facility-specific emissions intensity standards of *SGER* were replaced entirely by the sector-wide standards of the *Carbon Competitiveness Incentive Regulation* (*CCIR*) in 2018.

While financial compliance remained an option for firms under the *CCIR* at the same \$30/$t_{CO2e}$ rate introduced under *SGER* in 2017, the output-based allocations of emissions credits shifted from *SGER*'s facility-specific allocations based on historic emissions intensities to the *CCIR*'s uniform allocation based on the emissions intensity of a "best in class" facility. For the electricity sector, this meant *good-as-best-gas*: 0.37 $t_{CO2e}$/MWh. A typical older coal unit with emissions intensities of 1 $t_{CO2e}$/MWh would now incur costs up to \$18.90/MWh,[67] more than 10-times the compliance costs from pre-2015 levels. At the same time, a high-efficiency combined-cycle gas unit would incur almost no effective cost as its emissions would be almost entirely covered by the allocation of credits, and some plants could actually see compliance costs decrease relative to pre-2015 levels.

This difference is illustrated in Figure 12.6 with priced emissions under the SGER for a sample coal and gas units shown on the left compared to priced emissions for sample coal and gas units under the CCIR on the right. While carbon pricing might have given a hypothetical new combined-cycle plant a $1.18/MWh advantage in 2015 relative to a subcritical coal plant, that advantage grew to approximately $18/MWh by 2018. Carbon prices were now much more material to generators' offer behaviour.

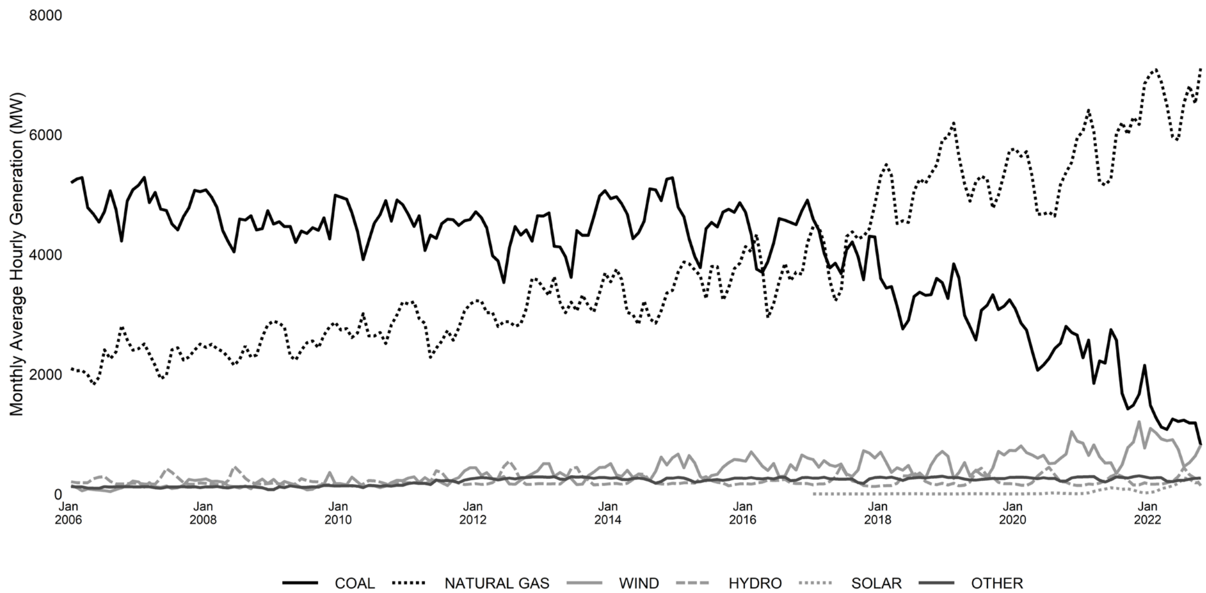
**Figure 12.6: Illustration of Priced Emissions from Sample Thermal Plants Under Alberta's 2015 and 2018 Carbon Pricing Policies.** Source: Author's calculations.




The immediate effect was to increase the market share of lower-emitting gas generation running largely at the expense of the now economically disadvantaged coal fleet. This, combined with the closures of some older, less efficient coal units would result in a 25% drop in coal-fired generation (and a consequent 41% drop in GHG emissions) from 2015 to 2018. Gas-fired generation increased to fill the difference. In 2018, natural gas plants replaced coal plants as the largest combined source of net-to-grid electricity generation, as can be seen in **Figure 12.7**.[68] Electricity generation GHG intensity has continued to fall, and was 32% below 2015 levels by 2020. Absolute emissions fell by 18.8 Mt over the same period— more than all emissions from

New Brunswick and PEI combined. In latest projections from Environment and Climate Change Canada, emissions from Alberta's electricity sector, which had hovered around 50 Mt per year for over two decades from 1994-2015,[69] will be reduced to just 9.4 megatonnes per year by 2030.[70]

**Figure 12.7: Alberta monthly average electricity generation by fuel, 2004-2022.** Source: AESO data via NRGStream.




The decline was also assisted by the allocation of $300 million in funding for energy efficiency provided through Energy Efficiency Alberta. A further $50 million was allocated annually to programming specific to Indigenous communities. These funds were for training, community energy planning, and energy efficiency improvements and retrofits. Projects included 18 solar PV projects, 125 building upgrades and support for Indigenous communities to acquire ownership stakes in renewable energy projects.[71]

## Enduring results and policy learnings

The United Conservative Party (UCP), led by Jason Kenney, swept to power in April 2019 having opposed the coal phase out, supports for renewable power and energy efficiency, and carbon pricing. A "summer of repeal" was promised to overhaul NDP policies including the Climate Leadership Plan. The first Bill introduced by the UCP government was to repeal the province's carbon levy on end-use fuel consumption.[72] However, the policy framework established by the NDP government for the electricity sector proved remarkably resilient. Its durability may hold important lessons for the design of emissions reduction policies facing political uncertainty.

**Defense in depth: the transition off coal**

The transition away from coal has been locked-in by the preservation of two mutually reinforcing CLP measures: carbon pricing; and the transition payments paid to firms to commit to the agreed-upon 2030 coal phase out. Federal backstops through both federal carbon pricing legislation and coal-fired power regulations were also critically important. Market forces, primarily the low price of natural gas and falling renewable power costs, were significant factors as well.

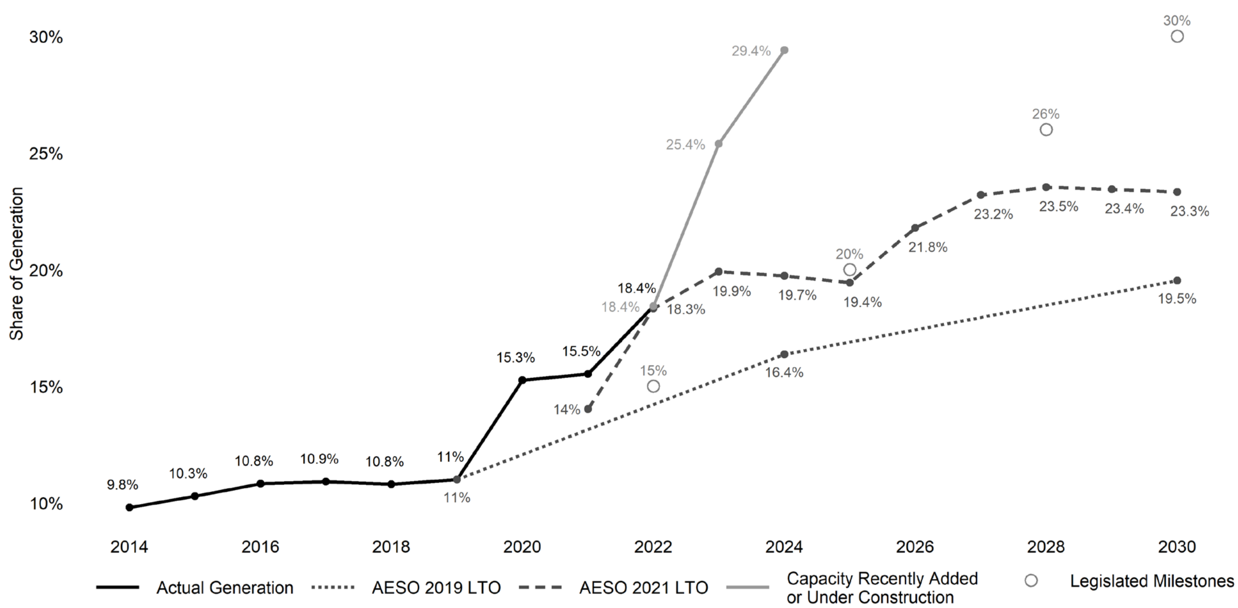
Although the UCP ran against the carbon pricing regime instituted by the NDP government, and swiftly transitioned back to a facility-specific standard for most sectors with its *Technology Innovation and Emissions Reduction* (*TIER*) *Regulation*, it preserved the previous government's sector-wide standard approach for electricity, including the substantial cost disadvantage for coal generators. Furthermore, while the UCP had vocally opposed the coal phase-out while in opposition, the UCP government has given no hint of any intent to cancel the contracted phase-out. Plant owners, who would relinquish the transition payments provided under the agreements, would have limited incentives to push for cancellation with the federal phase-out regulations remaining in place, especially since no equivalent federal transition payments would be on offer. This is particularly true given the diminished asset value of these plants resulting from the retained sector-wide carbon pricing approach, rising carbon price schedule, and their inability to compete with increasing zero-marginal-cost renewable energy and cheap natural gas seen in recent years (which has caused rapid coal plant retirements even in jurisdictions without carbon pricing or regulatory phase outs, like the United States). In fact, all the coal facility owners in Alberta have made public statements that they will accelerate their coal phase out, with the last unit to be converted to gas by 2023.[73]

In this way, the layers of climate policies have mutually reinforced each other's political durability. Sector-wide carbon pricing that materially disadvantages coal's economics are tolerated by facility owners who have developed plans to transition to lower-emitting sources to extend assets beyond the phase-out date, and the coal phase-out is broadly accepted when pricing and competition are pushing coal out of the market in any case. The combination of market forces and policy defense-in-depth means that coal will be phased out in Alberta long before any individual policy forces this outcome.  Coal-fired power will depart with a whimper, not a roar.

**Trust the market on renewable energy**

The prospects for renewable energy in Alberta are less clear than what's to come for coal, but there are strong signs of durability here too. The current government has so far retained the 30% by 2030 target in legislation, though the AESO's reference case scenario in its latest Long-term Outlook (2021) forecasts renewable energy to reach only 23 percent of in-province generation by 2030, as shown in **Figure 12.8**.[74] However, carbon offset values (new projects receive emissions offsets under *TIER* at a rate of 0.52 t/MWh, equivalent to $33.80/MWh at the 2023 carbon price of $65/t) and corporate ESG commitments have jump-started interest in private-sector offtake deals for environmental attributes (e.g. emissions offsets or renewable energy credits) from new renewable energy projects.[75]

**Figure 12.8: Trajectories for renewable energy in Alberta.** Source: AESO and Government of Alberta data, authors' calculations**.**[76]




While private-sector interest in such deals likely goes back further (corporate vPPAs were already very common in the United States in the early 2010s), it was not until after the auction price results for wind under the three REP rounds  and for solar under the 2019 government procurement were publicized that a new era of active dealmaking kicked off in

Alberta. In both public procurements, the government served catalytic roles by shouldering the costs of running a sophisticated, open, and highly competitive procurement, and by publicly disclosing the competitive process elements, contracts and strike prices. The government's actions supplied "price discovery" for interested corporations, a public benefit that typical private-sector commercial agreements are unlikely to provide. Private procurement of renewable energy is poised to drive the next leg of renewable energy investment expansion, but public leadership paved the road.

By mid-2022, companies have announced private deals for energy production from 1,141 MW of new solar capacity and 951 MW of new wind capacity, supporting $3.75 billion of new capital investment by 2024.[77] Enough new projects are either under construction or have secured private or government offtake deals (both signals of higher likelihood of project completion) to far outstrip the AESO's 2021 forecast and even to surpass the legislated 30% target several years ahead of schedule. As shown in **Figure 12.8**, expected production from projects already under construction will likely see the legislated 2030 target met or exceeded 5-6 years before that date.

Nevertheless, how far and how fast corporate procurement takes renewable energy growth are major unknowns. It is still an open question whether the current pace of private deals can endure as more wind and solar production reduces the prices that these technologies capture in the power pool, particularly with the carbon price schedule over the next decade subject to federal political variables.

**Beware political and financial lock-in**

The coal phase-out and transition payments experiences demonstrate that stranding assets to pursue more aggressive emissions reductions can be expensive, with costs borne either by investors, taxpayers or consumers. In the coal experience in Alberta, it was primarily investors who bore the losses as coal plant asset value was reduced substantially by environmental policies and the advent of cheap natural gas. Taxpayers did cover the compensation costs, but these were smaller than the estimated erosion in asset value borne by investors. The cost to investors was mitigated considerably by the advent of coal-to-gas conversion innovations that had progressed dramatically in the United States under the Obama Clean Power Plan. These were largely unknown at the point of capital investment into Alberta's coal plants. With coal being phased out, the next climate policy stranded asset challenge may already be in the making in the form of new gas-fired power plants, which are multi-decade investments. The difference this time being that both companies and government entities are now aware of major climate policy initiatives and have begun to prepare for such transitions. In early 2022, the AESO initiated stakeholder engagement[78] around a "net-zero emissions pathway" for the electricity system on the heels of the official opposition NDP committing to such a target by 2035 if they were returned to office[79] and the federal government's policy development effort toward the same goal through its clean electricity regulation.[80] While the federal plan is still being developed and finalized, the precedent set by a rapid coal phase out has not been lost on future ambitions.

## Conclusions

Though Alberta is still in the midst of an accelerated transition away from coal and toward a stronger complement of renewable energy that was initiated with the CLP, the experience has provided some early lessons and highlighted some key issues going forward. Most importantly, Alberta's experience shows how policy layering, the public policy equivalent of defense-in-depth, can both compound outcomes and strengthen policy resilience. Another lesson is that the government can play a role not only by assuming risk but also in driving price- and technology-discovery. However, in doing so, it is also important to let the market work where it can drive costs down. Had Alberta opted for a feed-in tariff model without competitive procurement, prices for renewables would have been set far above the costs of REP and, instead of driving private sector uptake, procurement could have entrenched opposition.

It is important to recognize that circumstances also played an important role in the coal-phase-out. Low natural gas prices allowed substantial emissions reductions with limited increases in consumer costs, at least while natural gas prices remained low. Combined-cycle natural gas plants also provided a clear, understandable solution which gave comfort both to politicians and the public as they could see familiar facilities, already in successful operation, as part of the potential solution. The downside risk was something well-understood — that Alberta would replace coal with natural gas generation. The next stage toward fully decarbonizing the grid, either leapfrogging unabated gas generation altogether or phasing it out later, may be more challenging without a clear, tangible vision for such a pathway, although the success of the coal phase out suggests major transitions in short periods of time are possible and the industry continues to prepare itself for a lower-carbon future.

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https://www.energyregulationquarterly.ca/articles/one-hundred-years-of-public-utility-regulation-in-alberta#sthash.s3Mt7zyH.dpbs.

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14 Ibid.

15 2018 NIR, Part 3, p. 69.

16 The PPAs enabled owners' preexisting cost-recovery expectations from the cost-of-service regulated system, while weakening their market power for the first 20 years of the new competitive wholesale market.

17 The AUC expedited approval expressly to allow the project to complete construction by 2015 to allow it to be grandfathered against pending federal regulations. See Leach, Andrew, "The AUC and Maxim Power: No Steps Forward, 3 Steps Back", *Rescuing the Frog*, July 8, 2011, http://andrewleach.ca/canadian-climate-policy/the-auc-and-maxim-power-no-steps-forward-3-steps-back/.

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19 2018 NIR, p. 69.

20 2016 NIR

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