CLEAN PROSPERITY

A Nuclear Grand Bargain

How to grow an affordable and low-emitting electricity grid in Saskatchewan

SEPTEMBER 2026

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Contents

About Clean Prosperity

Clean Prosperity is a Canadian climate policy organization that advocates for pragmatic solutions to grow the low-carbon economy. Learn more at CleanProsperity.ca. Get in touch with us here: info@CleanProsperity.ca. Our thanks to those who provided feedback on early drafts of this report.

Abbreviations

BWR	Boiling water reactor	
CCR	Concurrent cost recovery	
CCUS	Carbon capture, utilization and storage	
CfD	Contract for difference	
CGN	China General Nuclear Power Group	
CNSC	Canadian Nuclear Safety Commission	
CWIP	Construction Work in Progress	
DNNP	Darlington New Nuclear Project	
DOE	Department of Energy (U.S.)	
EDF	Électricité de France	
ENTSO-E	European Network of Transmission System Operators for Electricity	
EPC	engineering, procurement, and construction	
EPR	European pressurized reactor	
FID	Final investment decision	
FOAK	First of a kind	
GPSC	Georgia Public Service Commission	
IAAC	Impact Assessment Agency of Canada	
ITC	Investment tax credit	
KEPCO	Korea Electric Power Corporation	
KHNP	Korea Hydro & Nuclear Power	
MAC	Marginal abatement cost	
NOAK	nth of a kind	
OBPS	Saskatchewan's Output-Based Performance Standards (program)	
OPG	Ontario Power Generation	
RAB	Regulated asset base	
SMR	Small modular reactor	
W	Watt	1 W = 1 joule per second
kW	Kilowatt	1,000 watts
MW	Megawatt	1,000,000 watts
GW	Gigawatt	1,000,000,000 watts
TW	Terawatt	1,000,000,000,000 watts
Wh	Watt-hour	1 Wh = 3600 joules (1 hour = 3600 seconds)
kWh	Kilowatt-hour	1,000 watt-hours
MWh	Megawatt-hour	1,000,000 watt-hours
GWh	Gigawatt-hour	1,000,000,000 watt-hours
TWh	Terawatt-hour	1,000,000,000,000 watt-hours

Executive summary

Saskatchewan is racing to power a $62-billion wave of major projects — mines, data centres, advanced manufacturing, infrastructure, agriculture, and more. Electricity is more than an input for these projects; it is economic leverage and a draw for investment.

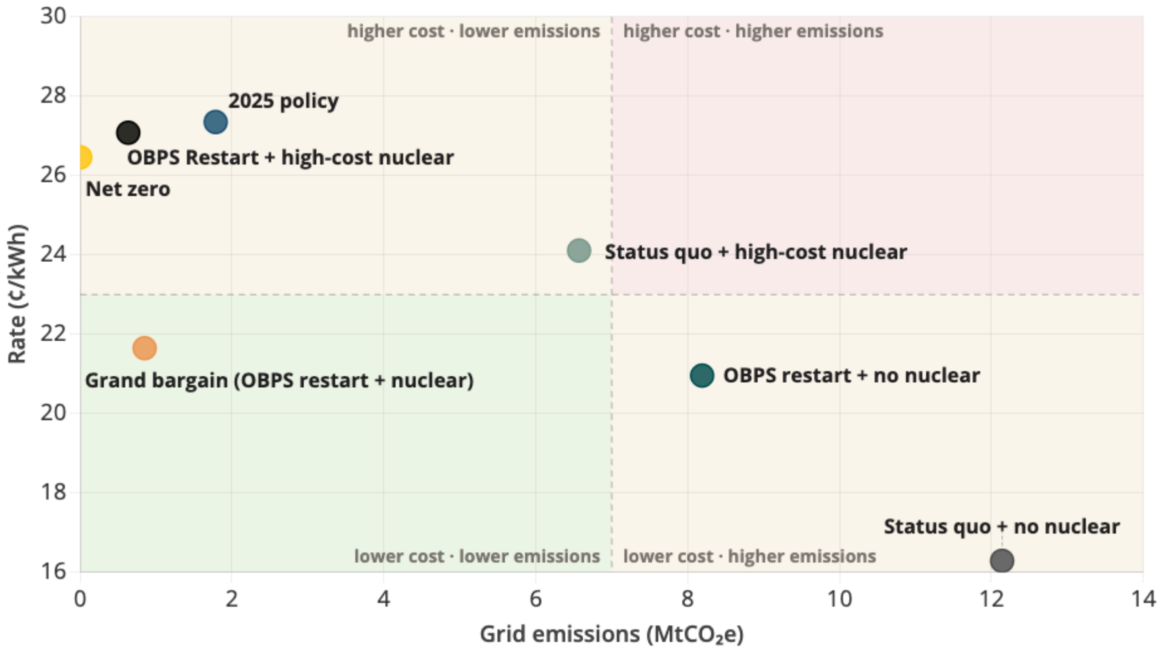
Saskatchewan is already making major investments to expand its grid's capabilities. The province's forecasts suggest electricity demand will increase by 40 to 100% by 2050.

Electricity generation in Saskatchewan remains the most emissions-intensive in Canada, a structural disadvantage that the province and federal government can work together to rectify. Securing new large-scale, non-emitting power is critical to achieving the province's goal of a carbon-neutral grid by 2050.

The federal government is resetting its relationships with the provinces on climate policy and striking deals to advance major projects across the country. There is room for a win-win deal in Saskatchewan. With Open Insights, we modelled several electricity policy scenarios for the province, including a "grand bargain" scenario where Saskatchewan restarts its output-based performance standards (OBPS) carbon market and builds 2,600 megawatts of nuclear power by 2050. Our modelling (see Figure) shows that a grand bargain:

- **Achieves nearly double the annual emissions reductions (11 Mt) of the Pathways carbon capture project (6 Mt)** versus the status quo.
- Significantly outperforms Canada's previous stack of climate policies (**2025 policy** scenario) on both cost and emissions reductions.
- Significantly outperforms a "go it alone" approach to nuclear buildout (**status quo + high-cost nuclear** scenario) on both cost and emissions reductions.
- Is comparable to an **OBPS restart** scenario (without nuclear) on cost and significantly outperforms it on emissions reductions.
- Significantly outperforms a forced **net-zero** scenario on cost, and is comparable on emissions reductions.

Figure: Modelled residential electricity prices and grid emissions in 2050



The federal government wants a reactor operating or under construction outside of Ontario by 2035. Saskatchewan is already a nuclear province. It produces nearly one quarter of the world's uranium and has a growing foothold in nuclear research. Commercial nuclear reactors are a natural solution. There is an opportunity for the federal and provincial governments to strike a deal that will bring a commercial reactor online in Saskatchewan for 2035 and help launch a vertically integrated nuclear power industry in the province.

RECOMMENDATION #1

The federal and Saskatchewan governments should work together on a "grand bargain" to build Saskatchewan's first nuclear reactor.

Achieving a carbon-neutral Saskatchewan power grid that can meet rising demand for electricity will require investment by both orders of government. Saskatchewan cannot shoulder a multi-billion-dollar nuclear project on its own without pushing substantial costs on to ratepayers and taxpayers.

The federal government and Saskatchewan can strike a "grand bargain" on energy infrastructure and climate policy that incorporates financing support for the construction of a nuclear reactor, modelled after the federal-Alberta memorandum of understanding (MOU) implementation agreement.

The objective of a joint financing package should be to build not just a single reactor, but a workforce and supply chain ecosystem capable of drawing in private capital to fund the construction of subsequent reactors.

We recommend that the federal and Saskatchewan governments develop a financing package for one reactor that contains the following elements:

- Federal co-financing via a concessional loan, loan guarantee, or similar instrument to cover a substantial share of project costs, with key milestones and deliverables set as terms of the loan. Cutting borrowing costs is even more important than the federal investment tax credits (ITCs) that support nuclear power.
- Federal ITC coverage across the full duration of the project, past the current end date of 2034 if necessary. It will take until the 2040s to build multiple gigawatts of nuclear power. Access to ITCs can help significantly with not just project capex but across the broader supply chain.
- A direct provincial equity contribution roughly equivalent to 5% of project costs, akin to the Building Ontario Fund's $1-billion stake in the Darlington New Nuclear Project (DNNP).
- A joint Indigenous loan guarantee modelled after the DNNP, to allow Saskatchewan First Nations to acquire equity in the new reactor.

The structure should ensure "skin in the game" for both orders of government, all proponents, and major contractors. This is the lesson from the extraordinary cost overruns at Plant Vogtle in the U.S. The federal government can supply significant project capital while putting guardrails around its exposure to overruns.

The bargain should create specific opportunities to expand Saskatchewan's role in Canada's nuclear supply chain. Outside of uranium production, Canada's nuclear power ecosystem is largely concentrated in Ontario. Expanding commercial nuclear generation into Saskatchewan should come with specific opportunities for the province to participate in the supply chain and innovation ecosystem, and expand the province's skilled workforce.

We recommend the bargain contain specific oversight and public reporting requirements for any nuclear project receiving federal support. Our case studies of reactor projects in other jurisdictions illustrate some of the ways that political interference and perverse institutional incentives can add to construction risk for nuclear projects. Saskatchewan requires a process that can insulate any nuclear project from some of these risks. Options range from a fully independent watchdog regulatory agency akin to the Ontario Energy Board, to amending the Saskatchewan Rate Review Panel's mandate to include oversight and public reporting responsibilities specific to nuclear construction projects. Transparency and accountability can help ensure incentives remain aligned across the life of the project.

RECOMMENDATION #2

The federal and Saskatchewan governments should work together to restart the Saskatchewan OBPS, inspired by Alberta MOU rules.

Since 2019, every Canadian province has used industrial carbon pricing for large emitters. Saskatchewan's carbon market, an output-based performance standard (OBPS), covered coal and gas-fired power plants alongside other industries like oil and gas, mining, and various types of heavy manufacturing.

Saskatchewan's OBPS has not been operating since April 2025. It will not pass equivalency under the federal 2026 carbon pricing review and requires a restart. Our modelling shows that restarting the OBPS, using the same headline price and market rules in the federal-Alberta MOU implementation agreement, is part of a one-two punch that can enable Saskatchewan to cut electricity emissions 90% by 2050. The other punch is adding significant non-emitting baseload power to the grid — 2.6 gigawatts of nuclear generating capacity in our analysis.

A restarted OBPS can help steer the investment choices of SaskPower and its vendors and partners, with modest impacts on electricity prices. There are options to fully offset costs for ratepayers. One option is for SaskPower to directly rebate OBPS revenues to ratepayers on a $/kWh basis. Saskatchewan has previously recycled revenues from its OBPS to address affordability.

RECOMMENDATION #3

Saskatchewan and SaskPower should embrace fleet-based planning with larger jurisdictions and act as a "fast follower."

Saskatchewan should follow the lead of experienced nuclear jurisdictions. Ensuring that its reactors are part of a larger fleet buildout can reduce project risk. Saskatchewan has options for reactor technology, including the BWRX-300, the AP1000, and the CANDU Monark. Focusing on models that another jurisdiction has built or is building can help the province avoid first-of-a-kind costs, and benefit from construction and operational track records, and the development of a cost curve.

To further enable fast following, Saskatchewan should accelerate its site selection and regulatory submissions to the Canadian Nuclear Safety Commission to ensure that regulatory timelines do not become a bottleneck.

RECOMMENDATION #4

Saskatchewan and SaskPower should competitively procure electricity projects once the OBPS restart has been finalized.

Saskatchewan's electricity needs are growing too fast to place non-market constraints on any generation source. Wind and solar capacity have grown rapidly in recent years and now represent approximately 15% of Saskatchewan's total generating capacity, with more projects on the way. Renewable expansion and energy efficiency are the most effective short-term levers to meet growing electricity demand without undermining the province's energy independence. Nuclear power is not deployable until the 2030s; natural gas power generation requires importing fuel and increases Saskatchewan's exposure to price volatility. With careful planning, there is room for significant expansion of wind, solar, and storage capacity to meet fast-growing demand and buy time before nuclear power deployment.

Our modelling shows that expanding solar and wind's share of total grid capacity aids affordability, particularly if the OBPS is restarted. Increasing renewable capacity to between 30% and 39% of total generating capacity has a negligible effect on electricity rates when factoring in total system costs.

Introduction: Saskatchewan's electric opportunity. Why now?

This paper analyzes the costs, benefits, and trade-offs of different approaches to significantly growing electricity generation in Saskatchewan over the next 25 years. We use electricity system modelling from Open Insights to contrast the outcomes of different policy approaches to growing Saskatchewan's grid, looking closely at the potential role of nuclear power generation. We use project finance modelling and case studies of Canadian and international nuclear projects to extract lessons for Saskatchewan in planning nuclear power deployment. We make policy recommendations to help Saskatchewan realize its ambitions to electrify its economy by developing a nuclear power industry.

Saskatchewan is reinventing its economy for a new geopolitical era. Bold energy policy can support the province's race to capture increased market share for key exports and grow its economy. Building new homes, infrastructure, and industries as fast as possible while growing existing sectors will lead to a significant increase in electricity demand. Key policy actions today can prepare for this future, protect ratepayers, and expand Saskatchewan's long-term economic potential.

Electrification — expanding the use of and access to electricity at scale — **offers economic leverage** and can serve multiple policy goals: affordability, energy security, economic growth, trade diversification. The province can and should balance these objectives with its goal of achieving a carbon-neutral grid by 2050, described in the Saskatchewan First Energy Security Strategy and Supply Plan.

Every corner of Saskatchewan's economy needs more electricity. The province has 60 projects valued at over $62 billion in development across a range of industries,[1] including the Bell Canada data centre in Regina, multiple new critical mineral and uranium mines, and

[1] All currency amounts in this paper are in Canadian dollars unless noted otherwise.

BHP's Jansen Potash expansion, the largest investment in provincial history. The agriculture sector — long reliant on natural gas and diesel — can make greater use of electricity for irrigation infrastructure and electric pumping stations, heat pumps for grain drying, climate control for animal husbandry, and precision agriculture (e.g. sensors, GPS systems, and drones for pesticide application and precision fertilization).

Compared to other provinces, expanding Saskatchewan's electricity supply poses distinct challenges. Saskatchewan has a comparable number of ratepayers to Nova Scotia but is 12 times the size, with a large number of remote and Indigenous communities, a bifurcated north-south grid, and as a result, elevated transmission costs. SaskPower, the province's Crown electric utility, serves an average of three customers per circuit kilometre of power lines, compared to the Canadian average of 12.

Even with these challenges, electrification can create durable payoffs. Saskatchewan has begun to embrace electrification with record investments in the capability and connectivity of its grid (see Figure 1).[2] These fundamentally sound long-term investments will place upward pressure on electricity prices. SaskPower is seeking 3.9% rate increases in 2026 and 2027 from the Saskatchewan Rate Review Panel[3] to cover record capital expenditures in generation and distribution, which have nearly doubling since 2021. Electricity's superior efficiency makes the tradeoff worthwhile and can lower overall energy costs even if electricity itself gets more expensive.

Provincial officials and SaskPower are proceeding on two tracks: optimizing and refurbishing existing assets, and building new assets. Over the next five years, the province will develop a mix of faster-to-build electricity generation projects like natural gas and cogeneration plants, as well as wind and solar power. In the longer term, the province has ambitions to construct commercial nuclear reactors.

Planning, developing and building a commercial nuclear power plant in Saskatchewan will take at least a decade. In the meantime, several policy decisions will set the overall direction of travel and pace of electrification.

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[2] Two recent documents outline Saskatchewan's electricity goals: Saskatchewan First Energy Security Strategy and Supply Plan and Strengthening Saskatchewan's Grid: Transmission to Power Communities and Growth.

[3] The Saskatchewan Rate Review Panel is an advisory body appointed by the Government of Saskatchewan with a mandate to review rate applications from SaskPower, SaskEnergy, and the SGI Auto Fund. It provides independent advice to Cabinet on these rate applications but does not have formal decision-making authority to approve applications, which ultimately rests with Cabinet.

Overview: Why electrify? Why nuclear?

Why electrify?

Switching from technologies powered by combustion to technologies powered by electricity, in most cases and most places, increases productivity and saves money. The upside of electrification is significant: These savings can accrue across the entire economy, aiding affordability, attracting investment, increasing export competitiveness, and reducing emissions.

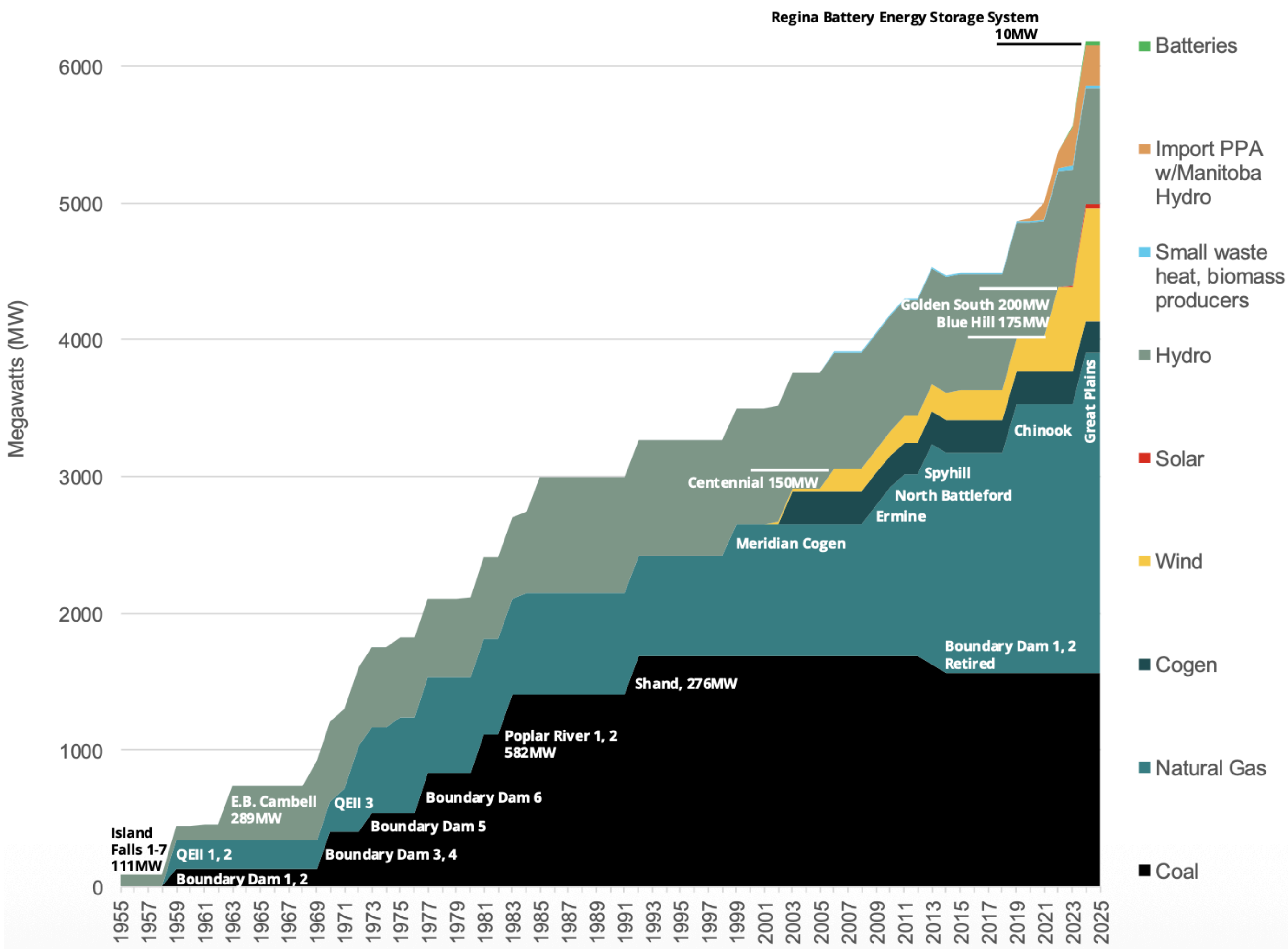
As Saskatchewan grows the size and capabilities of its grid, expanding non-emitting electricity generation will help the province attract investment. Over 90% of executives in RBC's 2026 annual Business Survey said their organizations have emissions-reduction strategies, up from 73% in 2025. Energy efficiency (82%) and electrification (48%) are among the more popular options.

Electrification will mostly run through the Crown utility, SaskPower, and its parent company, the Saskatchewan Crown Investments Corporation. SaskPower is overseeing the transformation of the province's grid, with major projects underway across a range of assets. The province currently has about 6,000 MW of generating capacity.

Saskatchewan's grid mix is diversifying but has long been dominated by coal, hydro, and natural gas generation (Figure 1). SaskPower operates about 74% of the grid's generating assets, with significant expansion and refurbishment underway. There is 1,300 MW of new generating capacity planned or under construction[4] including 416 MW of natural gas power, with additional large-scale gas facilities under consideration near Swift Current, Belle Plaine, and Rowatt. There are 400 MW of wind, 300 MW of solar, and about 200 MW of industrial cogeneration and waste-to-power projects in development. The province is also planning to refurbish its three coal-fired power plants, Poplar River Units 1 and 2 (582 MW), Boundary Dam Units 4–6 (416 MW), and Shand Unit 1 (276 MW), extending their useful lives to as late as 2050. Cost estimates for the refurbishments have ranged from $2.6 billion to $11.4 billion to $30 billion, exclusive of transmission and operating costs.

[4] SaskPower project map.

Figure 1: Saskatchewan's past and present power generation profile[5]



[5] Data taken from SaskPower's system map and project map (as of March 2026).

Why would Saskatchewan want to build a nuclear power plant?

The federal government is resetting its relationships with the provinces on energy and climate policy and striking deals to advance major projects across the country, most recently up to $10 billion in federal support for 7,200MW of hydro and wind capacity in Quebec and Newfoundland and Labrador. As articulated in the new Nuclear Energy Strategy for Canada, the federal government's stated goal is a reactor operational or under construction outside of Ontario by 2035. The strategy promised a nuclear financing plan in 2027 to help willing provinces get projects off the ground.

Saskatchewan is already a nuclear province. It produces nearly one quarter of the world's uranium, with a growing foothold in nuclear research. The province's own forecasts suggest electricity demand will increase by 40 to 100% by 2050 and it has committed to a carbon-neutral grid by 2050. Commercial nuclear reactors are a natural solution. But as a province of 1.2 million, Saskatchewan cannot shoulder the costs of this capital-intensive project on its own without pushing substantial new costs on to ratepayers and taxpayers. Both orders of government need the other's help. There is ample room for a "grand bargain" to bring a commercial reactor online in Saskatchewan for 2035.

Nuclear has important advantages relative to other power generation sources, including:

- **Geoeconomic value:** Industrial and institutional relationships, strengthened energy independence, new supply chains, and large investment flows.
- **Long operational lifespan:** A reactor that comes online in Saskatchewan in 2035 could operate into the next century, with refurbishments.
- **Large scale:** Saskatchewan is considering reactors ranging from 300 to 1,200 MW of capacity. A single 300 MW reactor would satisfy about 10% of Saskatchewan's current electricity demand.
- **High capacity:** Reactors typically operate at higher capacity factors (usually 80 to 90% when accounting for maintenance and refuelling) relative to alternatives like natural gas (typically 50–80%), wind (40%), and solar (20%).
- **Zero emissions:** An important comparative advantage over other forms of baseload power; no greenhouse gas emissions or adverse effects on air quality.
- **Density:** Nuclear is the most land-dense energy source on a lifecycle basis.

Saskatchewan is considering building both large and small nuclear reactors (see Box 1). **Even one small reactor would be one of the largest and most expensive infrastructure projects in provincial history.** High federal regulatory hurdles, the province's lack of construction and operational experience, and adapting to the nuclear industry's distinct safety culture further complicate the challenge.

Box 1: Reactor sizes and costs

Reactors differ by generation (Gen) and size. About three-quarters of the 439 reactors operating globally are large, ranging from 700 to 1,750 MW of capacity. They are a mix of Gen II reactors from the 1970s and 1980s, and Gen III reactors from the 1990s onward. Gen III+ and Gen IV are "advanced reactors" and make greater use of safety features, such as passive cooling. Gen IV reactors also use exotic coolants to achieve higher thermal efficiencies.

Gen II and Gen III nuclear reactors encountered more frequent and severe timeline and cost overruns than other types of large infrastructure projects. This arose from factors such as project complexity, capital requirements, long timelines, and workforce inexperience. Cost overruns are not universal. India, South Korea, Japan, and China build large reactors for under $5 million per MW by repeating builds of single-reactor designs on a limited number of sites and with minimal greenfield development. The U.S.'s newest reactors, two AP1000s completed at the Vogtle power plant in Georgia in 2023 and 2024, came in closer to $24 million per MW. Even with high costs, many governments have been willing to stomach the premium in exchange for long-lived assets with distinct energy and economic profiles.

Though few have been built to date, small modular reactors (SMRs — Gen III+ and Gen IV reactors under 500 MW) and microreactors (under 20 MW) have lower capital requirements and therefore promise less financial risk. The trade-off is thermodynamic and economic efficiency, which are lower than those of large reactors.

Standardized design and construction processes are projected to reduce the costs of these reactors from one project to the next. BloombergNEF and CIBC Capital Markets have estimated 50% cost reductions from first-of-a-kind (FOAK) to nth-of-a-kind (NOAK) for SMRs. The Canada Energy Regulator more conservatively estimated 10% to 30% reductions from FOAK to NOAK by 2050 in Canada. Colterjohn et al. (2024) estimated advanced reactors could experience 5% to 10% cost reductions for every doubling of global capacity. However, cost curves are not inevitable. Some reactors have experienced negative cost curves and become more expensive across successive builds (see case studies below).

Cost curves are possible for large reactors, with best-in-class 25–30% reductions for successive reactors on a single site following FOAK completions. The U.S. Department of Energy Liftoff Report for Advanced Reactors (2023) estimates that over 80% of possible cost reductions will be driven by consistent application of best practices and learning by doing.

How electrification can reduce emissions from Saskatchewan industry

Electrification can offer benefits across the economy. In Saskatchewan, heavy industry is dominated by oil and gas and mining, with a handful of facilities in other sectors. For these sectors, electrification can improve process efficiency, reduce maintenance costs, and provide more predictable energy costs. Electrification can also reduce industrial emissions.

Table 1: Economics and emissions in key industrial sectors in Saskatchewan[6]

Sector *(# of facilities)*	Percentage of provincial GDP	Average annual regulated emissions (2022-2024 Mt)
Oil and gas extraction *(80)*	8.4%	6.6
Mining *(22)*	6.8%	2.4
Utilities *(14)*	3.0%	13.5
Pipeline transportation *(4)*	1.7%	1.9
Petroleum and coal product manufacturing *(5)*	1.4%	2.0
Food manufacturing *(6)*	1.2%	0.3
Chemical manufacturing *(5)*	0.9%	0.7
Wood product manufacturing *(1)*	0.4%	0.01
Primary metal manufacturing *(1)*	0.2%	0.2
Paper manufacturing *(1)*	0.1%	0.01
Non-metallic mineral product manufacturing *(1)*	0.1%	0.1

[6] Emissions and facility totals from the Greenhouse Gas Reporting Program (GHGRP). GDP derived from sectoral 2024 GDP figures as a percentage of Saskatchewan's total 2024 real GDP of $83.6 billion. Pipeline transportation GDP is based on 2022 data, the most recent year data are available.

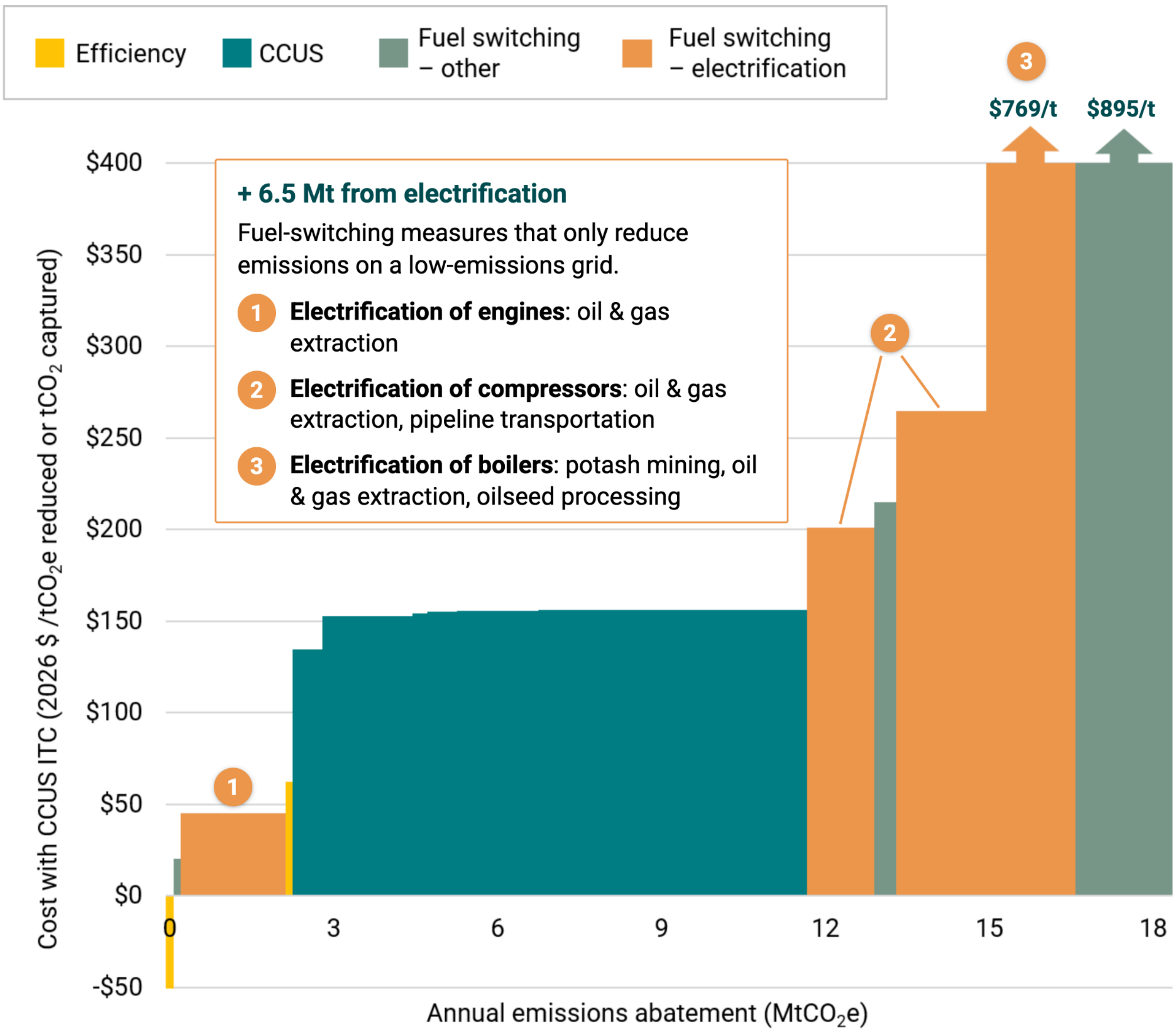
Electrification won't reduce industrial emissions unless Saskatchewan reduces the emissions intensity of its grid

Saskatchewan's grid is emissions-intensive enough that electrification (i.e. swapping fossil fuel-powered equipment for electricity at industrial facilities) **would actually increase emissions if done today.** As our analysis in the next section shows, pairing a restart of Saskatchewan's output-based performance standards (OBPS) program with the addition of 2.6 GW worth of non-emitting firm power — like the nuclear reactor deployment we model for the province below — offers a clear pathway to a carbon-neutral grid by 2050. We use a marginal abatement cost (MAC) curve with project finance modelling to identify how the reduction in grid emissions intensity would create new emissions reductions pathways for large low-carbon projects in Saskatchewan. Our analysis covers five key industrial sectors in Saskatchewan: oil and gas extraction, potash mining, petroleum refining, pipeline transportation, and oilseed processing.

Our MAC curve (Figure 2) ranks emissions-reducing technologies by cost-effectiveness. We rank the cost per tonne of carbon dioxide equivalent (CO_2e) reduced or captured (y-axis) against the total emissions reduction potential (x-axis). Each bar represents a specific technology for a specific sector and project (see Appendix A for methodology). The bar's width shows the total possible annual emissions reductions; the height shows cost per tonne.[7]

[7] Some technologies are mutually exclusive (e.g. electrification and biomass) or eat into the abatement potential of other technologies (e.g. CCUS would abate less if equipment was electrified first). All costs are expressed in 2026 CAD, with project lifetimes over a 20-year period.

Figure 2: Marginal abatement cost curve for five of Saskatchewan's heavy industries with 2.6 gigawatts of nuclear power added to the provincial power grid



Many of these abatement opportunities sit higher on the cost curve (i.e. above the revised long-term headline carbon price of $130/tonne by 2035). That does not mean they are uneconomic investments. Electricity's superior efficiency can make switching to electric equipment economic on its own as part of standard capital stock turnover, independent of any emissions abatement benefits. As shown on the orange parts of the curve, we calculate that $5.2 billion worth of capital investment would also reduce annual emissions by 6.5 Mt if Saskatchewan's grid were to reduce its grid emissions below 1 Mt, consistent with our nuclear "grand bargain" modelling scenario in the next section.[8]

[8] $5.2 billion is based on aggregate project capex per tonne reduced for electrification investments, conditional on the emissions intensity of Saskatchewan's grid declining consistent with the low-emissions scenario in Figure 2. These are electrification retrofit costs for existing facilities.

Roles for nuclear power in Saskatchewan

Nuclear power projects can take a decade or more to complete, and often take longer than scheduled. The federal nuclear strategy's aim — to have a reactor operational or under construction outside of Ontario by 2035 — presents an ambitious timeline for Saskatchewan. The payoff would come in the 2040s, when a nuclear buildout could enable the province to drive coal and gas out of Saskatchewan's grid mix.

This section uses modelling commissioned from Open Insights to analyze pathways for Saskatchewan's grid between 2026 and 2050. **We model a range of scenarios**[9] to understand how Saskatchewan's grid mix, costs, and emissions might evolve under alternate political realities:

1. **Status quo:** Saskatchewan's OBPS remains non-operational; no new climate policies are introduced.
2. **OBPS restart:** The federal and Saskatchewan governments reach a "grand bargain" on climate and energy policy. Saskatchewan's OBPS resumes, using the headline price path set out in the federal benchmark following the federal-Alberta MOU implementation agreement. The carbon price floor is set at $60 by 2030. Ottawa commits to supporting the development of Saskatchewan's first nuclear reactor. **We find that this scenario points at the optimal path to achieving Saskatchewan's goal of a secure, reliable, affordable, and low-emitting grid.**
3. For comparison, we model a **net-zero by 2050** scenario that finds the economically optimal path to remove all emissions from the economy by mid-century.
4. For additional comparison, we also model a **2025 policy** scenario that includes the previous OBPS design ($170 headline price by 2030) and federal policies as of January 2025.

We ran the **status quo** and **OBPS restart** scenarios with and without nuclear power. All nuclear power scenarios model the deployment of 2,600 MW of generating capacity in Saskatchewan by 2050, beginning in 2035 and using both small and large reactors.[10] We also ran a cost sensitivity with relatively cheaper and more expensive nuclear generation.[11] The nuclear scenarios represent a long-term commitment by Saskatchewan to making nuclear power a significant part of its overall grid mix.

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[9] With the exception of the 2025 policy scenario, all scenarios assume the Clean Electricity Regulations are not enforced and refurbishments proceed at the Shand, Poplar River, and Boundary Dam coal-fired power generating stations. Coal power is not forced offline prior to 2050.

[10] The model adds a 300 MW reactor in 2035 and another in 2040, then a 1,000 MW reactor in 2045 and another in 2050 for a total of 2,600 MW by 2050. Electricity-system and energy-economy models that optimize on cost generally do not deploy nuclear power without forcing assumptions. In our scenarios that add nuclear power, the model "forces" these reactors on the grid at a specified price.

[11] Our low-cost scenarios assume $13 to $14/W for large and small reactors, respectively. We assume some combination of learning curves, construction performance, and financing instruments that keep capital costs low. Our high-cost scenarios assume $25/W for both reactor sizes, in line with the most expensive nuclear projects. See Appendix B for description of modelling and costs.

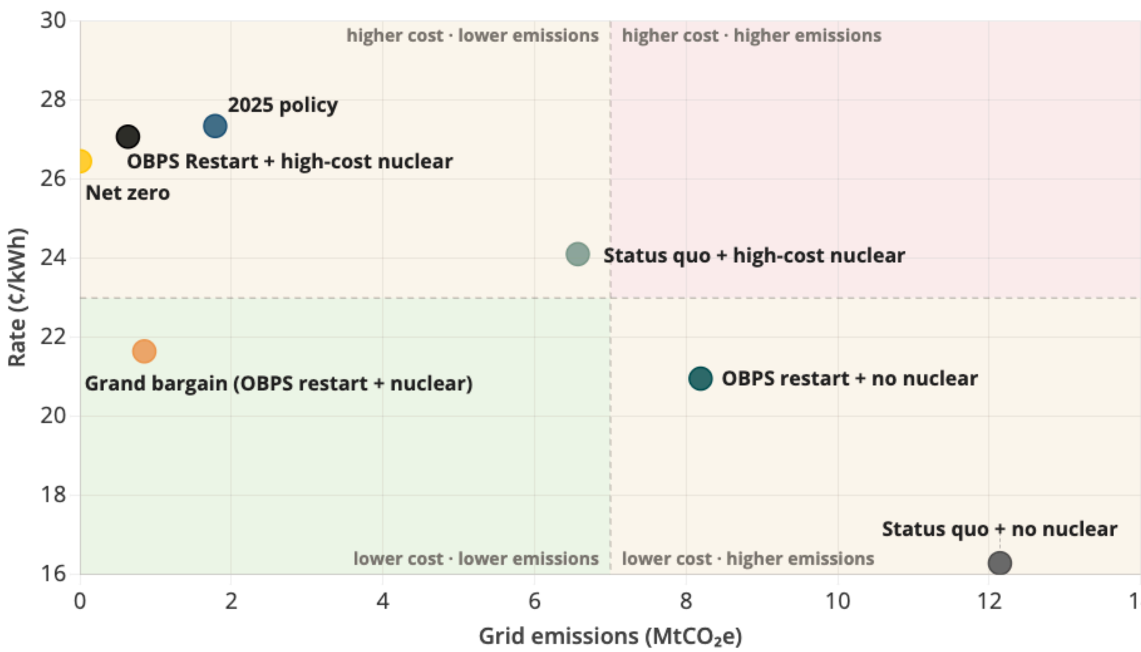
Wind and solar power represent about 15% of Saskatchewan's generating capacity. Wind, solar, and storage are already an important part of the province's generating mix today and will remain so into the future, with or without nuclear power. The growth of wind and solar energy will need to respect the concerns of local communities. We model the impact of constraining wind and solar at 15%, 30%, and 40% of total grid capacity, to understand how these policy choices could affect the grid mix, affordability, and emissions.

A grand bargain balances affordability and carbon neutrality

As shown in Figure 3, our cooperative "grand bargain" scenario strikes a more effective balance between affordability and carbon neutrality than any other modelled scenario. Modelling shows that a grand bargain:

- **Achieves nearly double the annual emissions reductions (11 Mt) of the Pathways carbon capture project (6 Mt)**, relative to the status quo.
- **Significantly outperforms Canada's previous stack of climate policies** (2025 policy scenario) on cost and outperforms it on emissions reductions.
- Significantly outperforms a "go it alone" approach to nuclear buildout (status quo + high-cost nuclear scenario) on both cost and emissions reductions.
- Is comparable to the OBPS restart scenario (without nuclear) on cost and significantly outperforms it on emissions reductions.
- Significantly outperforms the net-zero scenario on cost and is comparable on emissions reductions.

Figure 3: Modelling residential electricity prices and grid emissions in 2050



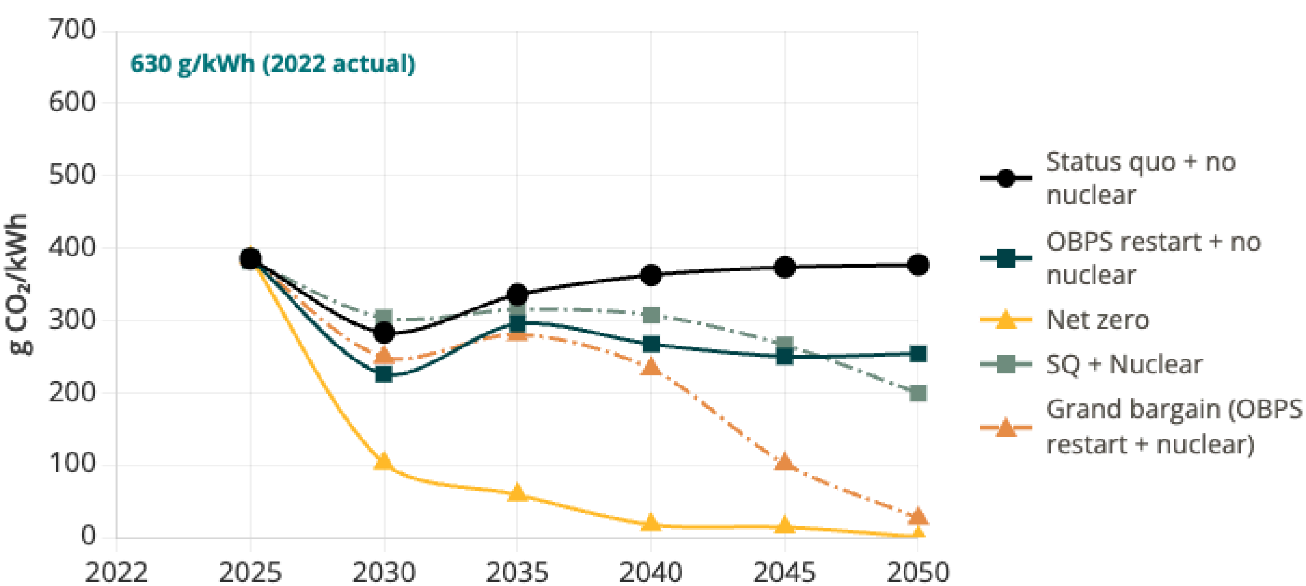
Our cost-sensitivity modelling illustrates the stakes of a financing package that can reduce upfront capital costs and efficiently executing a nuclear reactor buildout. The difference between building relatively low-cost nuclear ($13/W to $14/W) and high-cost nuclear ($25/W) for electricity prices is substantial — 4 cents/kWh by 2050. To avoid cost overruns that have hampered modern nuclear projects, Saskatchewan must tap into the experience and expertise of other jurisdictions, develop a capable workforce, and organize around the goal of developing a cost curve. The right project finance structure can help align incentives around these outcomes (see next section).

A grand bargain can fully and affordably decarbonize Saskatchewan's grid

Saskatchewan needs more power sooner than nuclear power can provide it. The rest of this section outlines policies and decisions that are needed in the short term to support a nuclear buildout and achieve a carbon-neutral grid by 2050.

Restarting Saskatchewan's OBPS in combination with the buildout of large-scale, non-emitting, firm power generation — e.g. nuclear power — can work in tandem to drive grid emissions intensity close to zero (see Figure 4 below). Our modelling shows that OBPS drives reductions in emissions intensity by 2030 by adjusting which generating assets are dispatched on an hourly basis, and by levelling the playing field for new-build capital deployment decisions across gas, solar, and wind generation.

Figure 4: OBPS plus nuclear power sustains reductions in emissions intensity through 2050



Neither OBPS on its own nor 2,600 MW of firm power without the OBPS can deliver this outcome. In tandem, they sustain progress on emissions intensity reductions through the 2040s, leading to a nearly carbon-neutral grid in 2050.

Rebates issued directly to ratepayers can further ease affordability concerns

Affordability is top of mind for both policymakers and ratepayers. Restarting the OBPS would add modest additional costs to electricity prices, but can be offset by rebating OBPS revenues directly to ratepayers via SaskPower as a line item on ratepayer bills, issued on a $/kWh basis. The Government of Saskatchewan initiated a version of this program in its 2025–26 budget through the Clean Electricity Transition Grant, which recycled $175 million in OBPS revenues to support SaskPower's non-emitting power purchase agreements and consumer-focused efficiency and demand management programs. A $/kWh rebate could be delivered in combination with revenue recycling approaches like the Clean Electricity Transition Grant or the Small Modular Reactor Investment Fund, or the rebate could be offered on its own.

In Table 2 (below) we show what a $/kWh rebate would be worth for an average SaskPower residential customer using 7,500 kWh/year, assuming all electricity revenues are rebated. OBPS applies different performance benchmarks to different sources of electricity, so only a fraction of total carbon costs are passed through to consumers (roughly 18% to 27%). By our calculations, full cost passthrough would add a maximum of 5 to 6 cents per kWh and decline over time with improvements in grid intensity.

Table 2: Full $/kWh rebates under modelled OBPS scenarios

Scenario	2030		2035	
	Rebate (¢/kWh)	Household rebate total ($/year)	Rebate (¢/kWh)	Household rebate total ($/year)
OBPS restart	0.65	48	1.25	94
Grand bargain (nuclear $14/W)	0.69	**52**	1.10	83

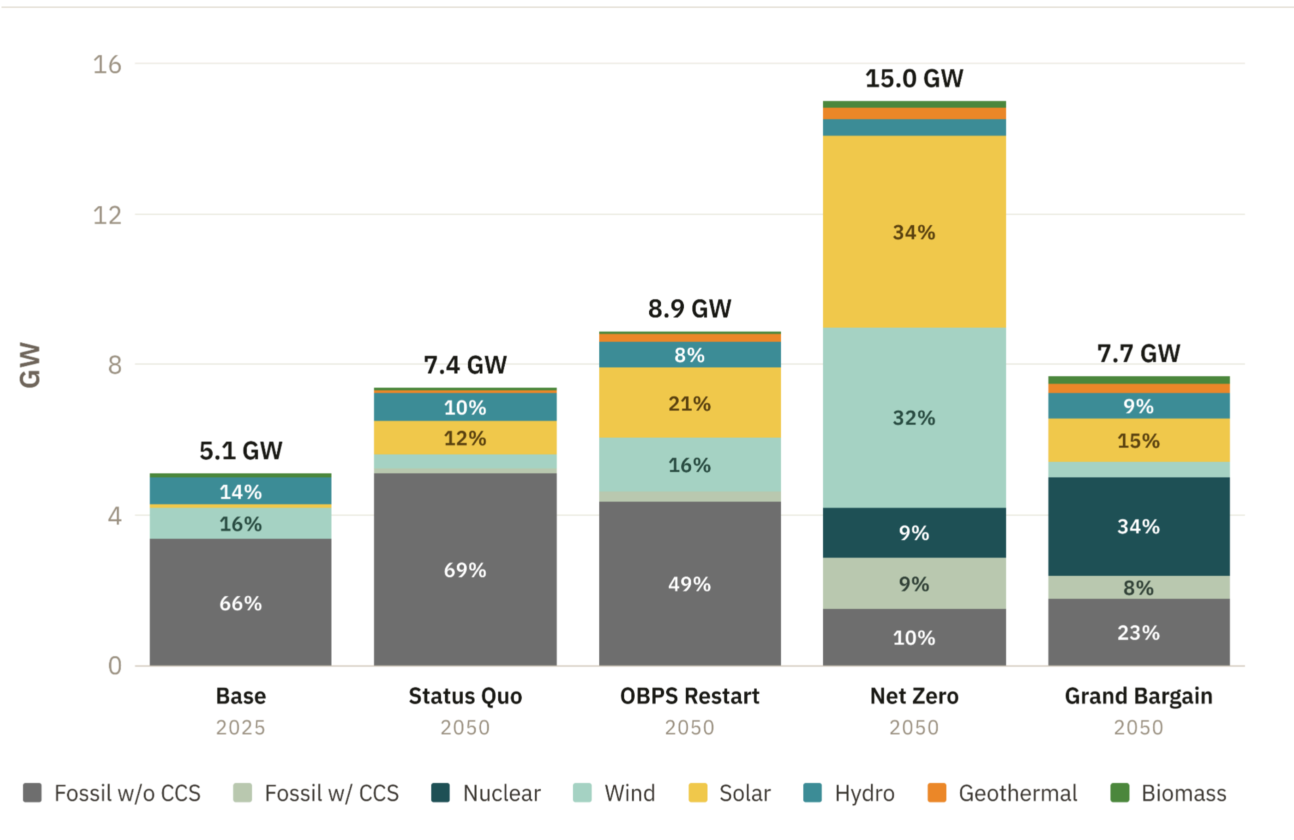
The $/kWh rebate design has the added benefit of phasing itself out over time. A rising carbon price increases carbon costs and therefore rebate sizes; grid decarbonization reduces carbon costs and rebate sizes. The grid mix ultimately determines carbon costs. Nuclear would accelerate this phase by displacing carbon-intensive generation today and shrinking the base of carbon costs that the OBPS would need to charge in future.

The rebate would not undermine the price signal provided by the OBPS, provided the province's electricity system operator factors in carbon costs when selecting the hourly dispatch mix and procuring new electricity generation projects.

Saskatchewan needs more power no matter what

In every scenario, Saskatchewan is using more electricity in 25 years in the industrial, commercial, and residential sectors. **Relative to our 2025 baseline, supply increases between 43% and 68% by 2050** (Figure 5). This is consistent with SaskPower's 40–100% growth forecasts but offers a narrower range. Unabated gas generation plays a role on the grid in all scenarios, but the grid mix varies. Only three generating technologies provide non-emitting, baseload power by 2050: nuclear, geothermal, and natural gas with carbon capture, utilization, and storage (CCUS).

Figure 5: Generation capacity in Saskatchewan by 2050 under various scenarios[12]

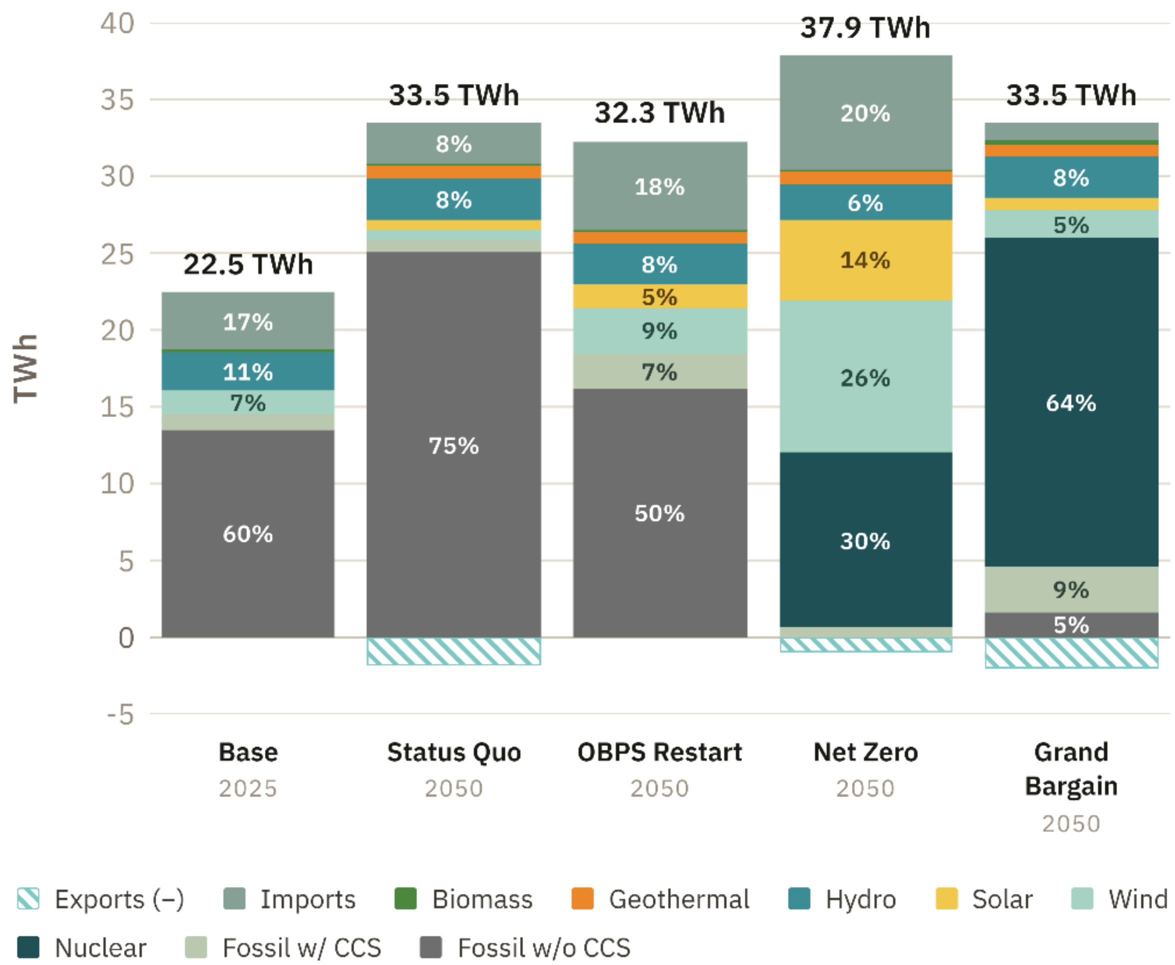


[12] There is a discrepancy between the 2025 base year supply and generation values we report for 2025 and values in SaskPower's actual reported capacity in its 2025-26 annual report. There are several causes for this. First, SaskPower reports its power purchase agreement as capacity. It is not reported in our results but is factored in on reserve margin calculations. The results also exempt the 370 MW Great Plains Power Station, which came online in December 2024.

OBPS changes how electricity is produced, not how much

The total amount of electricity demand does not vary much across our scenarios. Total electricity production in 2050 rests within a very narrow range, 32 to 34 TWh. The supply share of unabated coal and natural gas varies widely across scenarios (Figure 6).

Figure 6: Electricity supply in Saskatchewan by 2050 under four scenarios



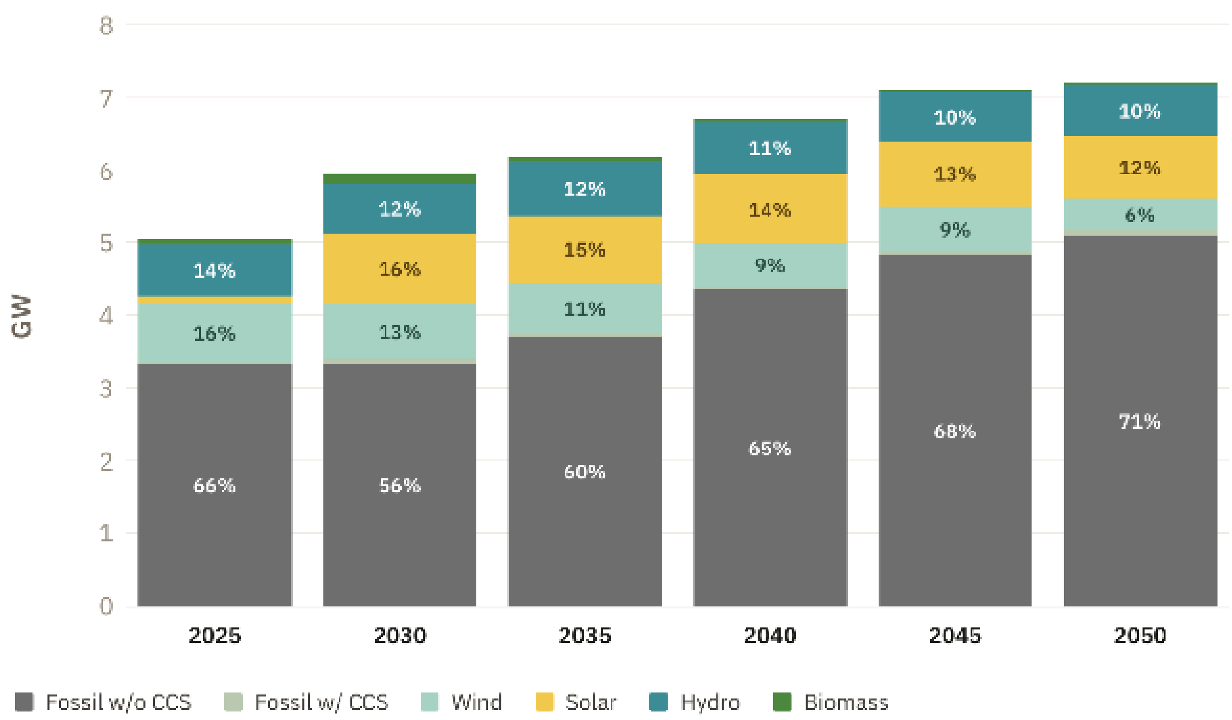
Under the status quo scenario, just 29% of Saskatchewan's electricity supply comes from non-emitting sources in 2050. Under a restarted OBPS alone, 50% of Saskatchewan's electricity supply comes from non-emitting sources by 2050. Under the grand bargain scenario that combines an OBPS restart with a major federally-supported nuclear buildout, 76% of Saskatchewan's electricity supply comes from non-emitting sources.

Constraining solar and wind could increase costs and undermine energy independence

If the OBPS restarts, wind, solar, batteries, and other non-emitting forms of electricity generation and storage become much more valuable assets on the grid — particularly in the short run as the nuclear buildout gets underway. Under a grand bargain with Ottawa, there could be considerable economic costs to constraining renewable power development.

The economics of wind, solar, and battery generation are now favourable enough in Saskatchewan that our modelling shows rapid uptake between 2025 and 2030, even in our status quo scenario (Figure 7).

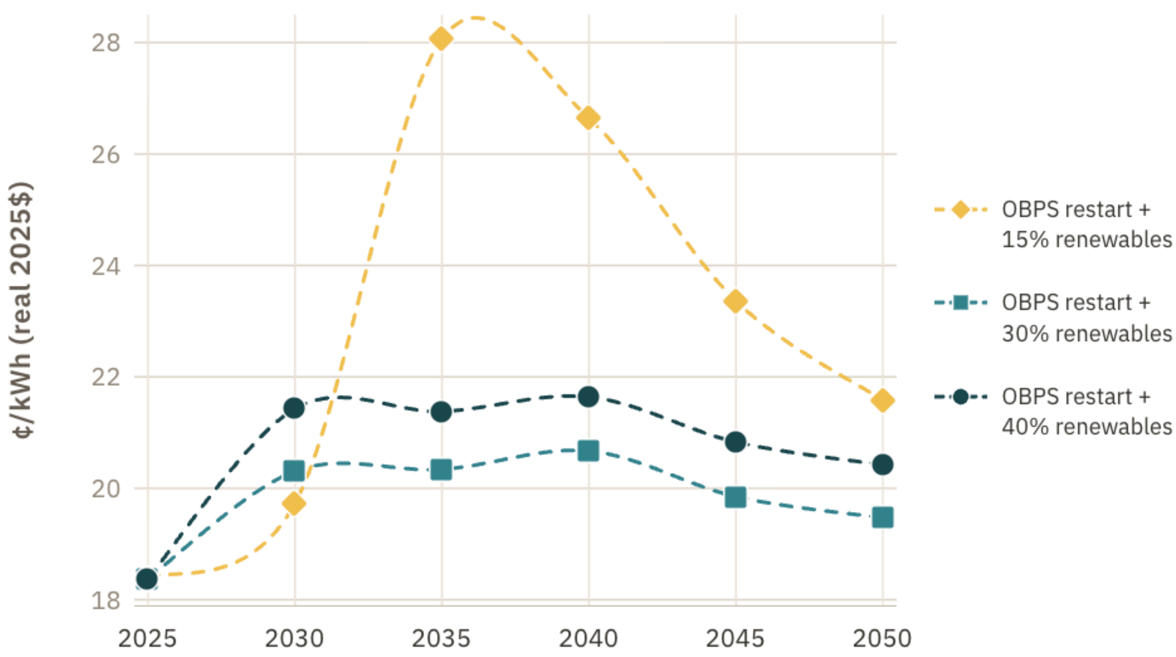
Figure 7: Generation mix under status quo conditions; solar grows quickly to 16% of total grid capacity by 2030 and stabilizes afterward



One of the sunniest and windiest jurisdictions in Canada, Saskatchewan has adopted solar and wind more cautiously than other provinces. Affordability, land and visual impacts, and avoiding costly transmission buildout are among the reasons cited for constraining solar and wind buildout. Grid reliability is also a concern, with many pointing to the 2025 Iberian Peninsula blackout as a cautionary tale.[13]

To test the impacts of limiting the buildout of solar and wind over time, we ran scenarios that constrain wind and solar power to 15%, 30%, and 40% of total grid capacity when the OBPS restarts.[14] We observe a big spike in electricity prices through the 2030s if renewables are capped near current levels (Figure 8). Constraining wind and solar necessarily increases reliance on gas and leaves Saskatchewan more vulnerable in the long-run to global fluctuations in energy prices.

Figure 8: A 15% constraint on renewables could cause electricity prices to spike



Cost, not reliability, is the real constraint. Several comparable peer jurisdictions have been able to effectively integrate high levels of renewable capacity without sacrificing reliability. For instance, the state grids of Iowa (64% wind and solar generation share in 2025) and South Dakota (58% wind and

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[13] The European Network of Transmission System Operators for Electricity's (ENTSO-E) 2026 final report identified a cascading series of failures that led to the blackout, and recommended increased investment in grid infrastructure. "The problem is not renewable energy, but voltage control, regardless of the type of generation," explained the ENTSO-E Board Chair.

[14] Open Insights' M3 Platform (CIMS-COPPER-SILVER configuration) accounts for optimal transmission planning for wind and solar expansion and chooses build sites to minimize combined capital expenditures, spur line costs, and production costs. The model directly captures location-specific costs of wind and solar spur lines and factors in line length.

solar generation share in 2025) are more reliable than the U.S. national average, backed by strong transmission interties. Saskatchewan's low population density and vast service area create a lower ceiling for how much wind and solar capacity can be added to its grid before the required transmission buildout becomes cost-ineffective. But artificially constraining any specific source of electricity through policy will lead to higher costs.

Transmission constraints will undermine grid flexibility, electrification, and the buildout of new power plants

Transmission capacity is another potential bottleneck for electrification in Saskatchewan that could lead to higher costs as Saskatchewan adds generating assets. Open Insights' SILVER spatial analysis shows significant load shedding across our modelled scenarios without additional transmission buildout by 2050. We observe significant congestion in Saskatchewan's north, in the southwest near Swift Current, and in the southeast near Estevan. Congestion appears in similar areas of the grid regardless of the policy mix, which points to the need to prioritize transmission investment in these regions.

Alleviating grid congestion is crucial for maximizing grid flexibility, which is in turn crucial for keeping electricity costs low. There are many ways to build flexibility into the grid. Different modelling runs we have conducted with Open Insights and Navius Research over the past two years illustrate the different ways grids can build in flexibility. Net-zero modelling runs from the two groups show very similar electricity supply requirements by 2050 (see Appendix C). Navius's gTech model builds significant storage capacity (1 GW by 2035, 2.6 GW by 2050) to soak up its relatively higher renewable share and discharges this power during times of high demand. In this scenario, Saskatchewan's imports are much more modest, bringing in just 3% of supply from out of the province by 2050. Open Insights' open-source M3 Platform (CIMS-COPPER configuration) opts instead to satisfy excess demand through interprovincial trade. Here, Saskatchewan's imports are much more significant, satisfying 20% of total supply needs by 2050.

Either path — storage, interties, or a mix of both — can help alleviate pressure on the grid before large-scale non-emitting generating sources like nuclear come online.

How to finance a nuclear power project in Saskatchewan

Saskatchewan's rate base would be among the smallest to ever shoulder the cost of a commercial nuclear power project (see Table 3). Without federal support, financing these costs on provincial balance sheets would have significant impacts on electricity prices.

Table 3: Smallest North American jurisdictions with a commercial nuclear sector

Jurisdiction	**Nuclear generating station**	**Population** Year 1 of construction	**Project cost** (nominal)	**Project cost as % of GDP** Year 1 of construction
New Brunswick	Point Lepreau 1 reactor: 660 MW	**670,000** (1975)	$1.4 billion CAD	18%[15]
Saskatchewan	First 2 reactors: 600 MW total	**1.3 million** (2030)	$12.1 billion CAD[16]	13%[17]
Arkansas	Arkansas Nuclear One 2 reactors: 1800 MW total	**1.9 million** (1968)	$823 million USD	14%[18]
Kansas	Wolf Creek 1 reactor: 1200 MW	**2.3 million** (1977)	$3 billion USD	15%

Upfront capital costs account for up to 80% of lifetime expenditures for most nuclear projects. Public policy instruments can reduce borrowing costs and upfront capital requirements.

[15] To account for unprecedented inflation during the 1974-1983 construction period we measure against provincial GDP at completion.

[16] Assuming the same costs as the DNNP ($7.7 billion for the first reactor including shared infrastructure, $4.4 billion for the second reactor).

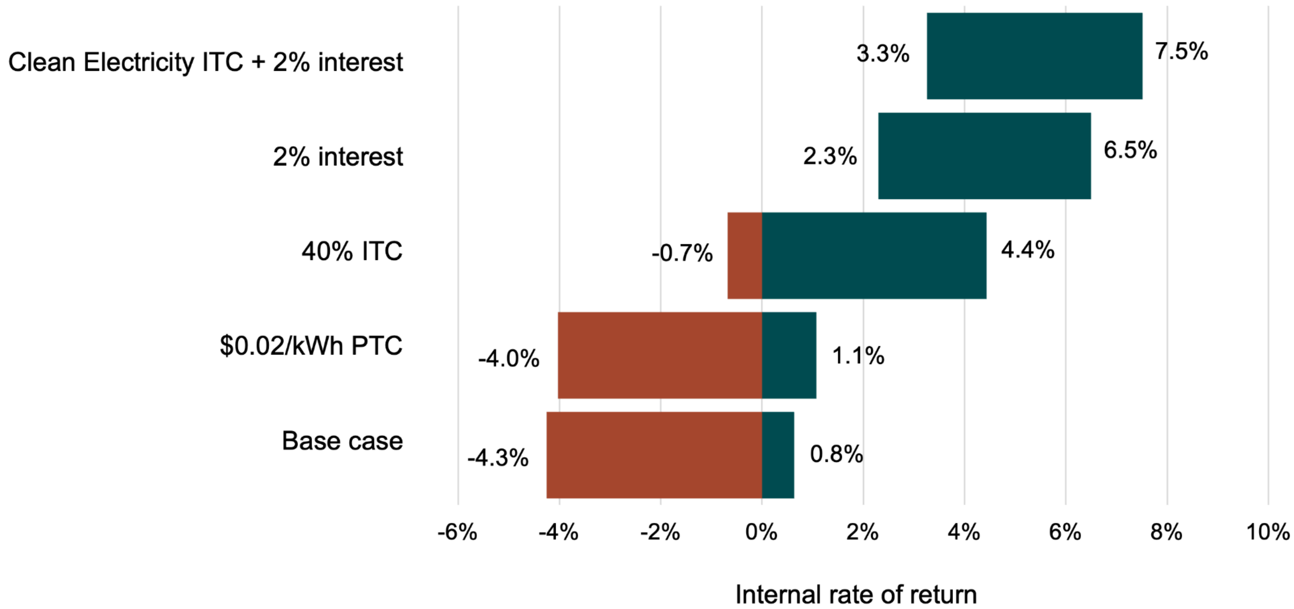
[17] Assuming provincial GDP increases 2.5% annually to reach $96 billion (nominal) by 2030.

[18] Arkansas and Kansas do not have readily publicly available GDP data dating back to the 1970s. Estimates are rough and backed out using state income and census data.

Canada is offering several investment tax credits (ITCs) for nuclear investments. Crown corporations such as SaskPower and Indigenous communities are eligible for a 15% refund on eligible energy property through the Clean Electricity ITC, including nuclear property. Private firms can also access a 30% Clean Technology Manufacturing ITC (in the case of nuclear power development, for fuel reprocessing and heavy water recycling) and the 30% Clean Technology ITC (for zero-emissions electricity technologies, including small modular reactors). Canada only offers ITCs; the U.S. offers a choice between ITCs and production tax credits for nuclear projects, and has brokered significant nuclear investments backed by bespoke public financing, including up to US$80 billion in federal support to build a fleet of AP1000 reactors. The federal government adjusted the phaseout timelines for its CCUS ITC to accommodate its grand bargain with Alberta. Making the ITCs that support investment in nuclear power available to Saskatchewan past 2034 would be consistent.

Instruments that reduce borrowing costs or upfront capital requirements are far more effective at improving the internal rate of return for nuclear projects than investment tax credits and production tax credits. This holds even for ITCs that are more generous than those currently on offer (e.g., 40%, see Figure 9). The most effective instruments to bring down borrowing costs for Saskatchewan and improve a nuclear project's financial viability is a concessional loan, loan guarantee, or similar instrument.

Figure 9: Effect of different financial supports on profitability for a single 300 MW reactor project (price range $5 billion to $10 billion per reactor)[19]



[19] Based on in-house financial modelling. Standard assumptions: Seven-year construction period, operations begin in 2033, 90% capacity factor, 75% debt financing, 8% weighted average cost of capital unless otherwise specified, $400 million of upfront planning costs, price of electricity $0.15/kWh, 30-year project life.

Saskatchewan has requested substantial federal support for the construction of the province's first nuclear reactor. Any well-structured financing package can avoid impairing Saskatchewan and SaskPower's balance sheets while ensuring all parties have long-term incentives to deliver on their commitments on the first reactor, and build the workforce, the supply chain, and the ecosystem necessary to build additional reactors.

For a nuclear grand bargain to work, incentive alignment is crucial. Federal obligations that unlock financial and other forms of support are near-term decisions that are impractical to reverse. Saskatchewan's obligations require sustained commitment over at least a decade. A provincial equity stake is therefore appropriate. We can use the Building Ontario Fund's contribution to the Darlington New Nuclear Project (DNNP) — $1 billion or roughly 5% of project costs — as a reference. This would ensure adequate financial "skin in the game" for the provincial government.

Saskatchewan can replicate the DNNP's approach to Indigenous participation directly as well. The $700-million investment in the DNNP by the Williams Treaties First Nations was structured as a loan-to-equity conversion, backed by a 50-50 federal-provincial loan guarantee between the Canada Indigenous Loan Guarantee Program and Ontario's Indigenous Opportunities Financing Program. This structure insulates First Nations investors from construction risk. Saskatchewan already has the provincial half of this structure in place: the Saskatchewan Indigenous Investment Finance Corporation currently backs Indigenous equity investments in the province's resource and energy sectors.

To minimize construction risk, the financing package must address perverse incentives (see case studies in the next section) by appropriately distributing that risk across utility, provincial, federal, and private balance sheets.

Summary of nuclear financing case studies

Through six case studies of nuclear construction projects, we analyze how other jurisdictions have structured nuclear financing packages and summarize lessons for Saskatchewan. We focus on three key evaluative criteria:

1. **Incentive alignment:** how did the financing structure address perverse incentives that could lead to cost overruns or delays?
2. **Strength of oversight**: were there accountabilities and off-ramps (i.e. opportunities to pause or halt construction if cost overruns are substantial enough to justify it) along the project's critical path?
3. **Construction performance**: was the project on time and on budget?

Table 4: Evaluation of recent nuclear projects

	Incentive alignment	Oversight strength	Construction performance
Hinkley Point C (HPC), England	**Poor:** concentrating risk in state-owned lead proponent EDF did not incentivize project discipline. EDF was too big to fail.	**Poor:** no independent oversight of schedule or construction costs in place before final investment decision (FID).	**Poor:** 94% cost overrun to date, with full construction risk placed on project lead.
Sizewell C, England	**Adequate:** builders, equity, operators, government have "skin in the game".	**Strong** relative to HPC, with more defined milestones.	**TBD**: cost estimates assume a learning curve from HPC.
Vogtle, Georgia, U.S.	**Perverse**: financing structure made cost overruns profitable for the lead proponent.	**Poor:** regulator lacked independence and binding authority to compel cost discipline.	**Poor:** 150% cost overrun, financing model at the root of the failure.
KEPCO and KHNP, South Korea	**Strong**: Because the project was based on repeat builds, vendors needed to be disciplined to win future work.	**Adequate** to ensure discipline across the supply chain. The government's majority stake in national utility and project proponent KEPCO offered implicit state backing and political insulation.	**Strong:** consistently on time and on budget with evidence of a learning curve.
Darlington New Nuclear Project, Ontario	**Adequate:** project lead exposed to overruns, offset by use of early rate recovery.	**Adequate:** Integrated Project Delivery model offers mutually reinforcing accountabilities, but project lacks off-ramps.	**TBD:** first reactor tracking for completion in 2030.
Point Lepreau, New Brunswick (refurbishment)	**Poor:** Crown corporations AECL and NB Power were not exposed to financial liability for cost overruns.	**Poor:** New Brunswick government acted as backstop with no proponent directly responsible for overruns.	**Poor:** 71% cost overrun. Root cause was unanticipated FOAK issues.

We identify two cross-cutting themes across all six case studies. First, incentive structure is a stronger predictor of construction performance than technology choice or sticker price. In each case where severe cost overruns occurred (70% or more), at least one key party was shielded from construction risk:

- The lead proponent of Hinkley Point C, Électricité de France (EDF), was "too big to fail".
- Vogtle's cost-recovery model made overruns profitable for the utility.
- As a Crown corporation, Atomic Energy of Canada Limited (AECL) was insulated from cost overruns and could not be compelled to absorb extra costs incurred by NB Power.

Projects that distribute risk across key parties with clear lines of accountability, on the other hand, fared better or are faring better:

- South Korea's fleet-based deployment model created a cost curve based on standardization, carrying the same design, supply chain, and workforce across consecutive builds.
- Sizewell C's pre-defined thresholds for cost- and benefit-sharing between investors and the U.K. government ensures investors are exposed in the event of cost overruns.
- The Darlington New Nuclear Project's (DNNP) multi-party Integrated Project Delivery model ensures "skin in the game" for key parties.

The second cross-cutting theme we observe across our case studies is that oversight requires teeth. In the cases of Vogtle and Point Lepreau, the reactors had oversight bodies that could not say no to imprudent costs. The Ontario Energy Board (OEB) and Britain's Ofgem, by contrast, have standing authority to reject cost recovery if necessary.

Key lessons for Saskatchewan emerge from our analysis. The two most salient come from the DNNP and Sizewell C. First, many of the technical lessons from the DNNP will be transferrable to Saskatchewan, but differences in the provinces' institutional setup may limit transferability in some cases. Ratepayer cost-recovery decisions, for example, as well as oversight of spending would fall to Cabinet without an independent check like the Ontario Energy Board (OEB). Second, Sizewell C shows that government equity can both enforce discipline and help crowd in private co-investors. Full write-ups of all case studies, including reactor specifications, project financing structures, and detailed lessons for Saskatchewan, are detailed in Appendix D.

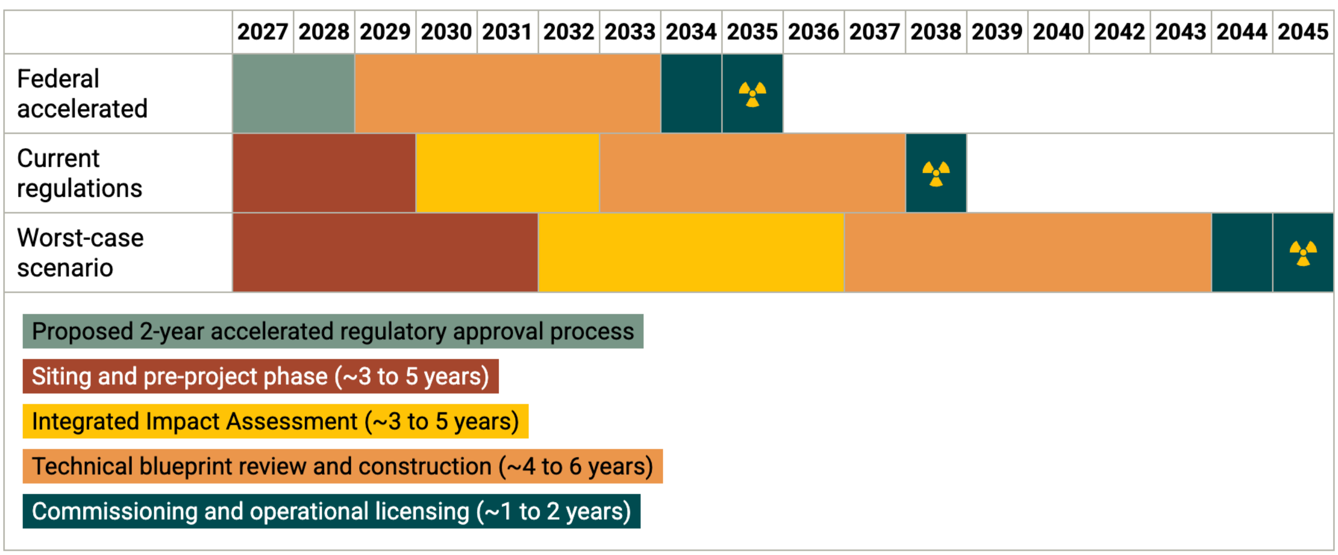
Three big unanswered questions for Saskatchewan

This section covers other areas of nuclear policy that Saskatchewan policymakers must address prior to Saskatchewan establishing a vertically integrated nuclear sector — regulatory timelines, technology choice and fuel supply, and waste and lifecycle management.

Regulatory timelines

Saskatchewan is contemplating the long and complex federally-regulated process of building a nuclear reactor. Current SaskPower plans envision the first reactor coming online in the mid-2030s. The federal discussion paper [Getting Major Projects Built in Canada]() proposes several reforms that could shorten critical paths.

Table 5: Estimated timelines for nuclear reactor construction



There are several safe regulatory changes that could shorten Saskatchewan's construction timelines without sacrificing safety or rigour. Previously, a project would have had to completely finish its multi-year Impact Assessment, managed by the Impact Assessment Agency of Canada (IAAC), before the Canadian Nuclear Safety Commission (CNSC) would begin its 24-month Licence to Prepare Site process. By conducting these processes in parallel, there are three to five years of possible time savings. The current bottleneck for Saskatchewan is site selection. Adequate environmental baseline monitoring at the site cannot be bypassed and the sooner monitoring starts, the sooner a full impact assessment can be completed.

Other options are available to shorten regulatory timelines. For instance, the IAAC process has a so-called two-threshold rule used to determine whether a new Class 1A nuclear facility project requires a federal impact assessment. It is a dual-trigger framework. The first holds that a proposed Class 1A reactor with a capacity of at least 200 megawatts thermal (MWth) on a new site automatically triggers a federal impact assessment. The second threshold applies to utilities that want to build a new reactor on an existing nuclear site. So long as the proposed reactor is under 900 MWth and on an existing nuclear site, it bypasses the federal impact assessment process. The BWRX-300 has a capacity of 870 MWth.[20]

Saskatchewan has no existing nuclear sites so any reactor is by definition a greenfield project and would trigger a full federal impact assessment. As part of the revisions to the federal IAA framework under consideration, the federal government could consider a regulatory amendment that changes the thresholds on a greenfield reactor project being designated under the IAAC from 200 MWth to 900 MWth if a design has obtained approval elsewhere by the CNSC. If Saskatchewan uses the same BWRX-300 reactor design as Ontario, reproving the basic safety of the reactor design from scratch is duplicative. All small modular reactor (SMR) projects, not just those at pre-existing sites, could benefit from this change and enable a pan-Canadian fleet-based approach to deployment of smaller reactors.

Technology choice and fuel supply

Saskatchewan has not made any definitive technology choices and is keeping both large and small reactors on the table. The BWRX-300 was selected by SaskPower in 2022 for potential deployment and is currently the leading candidate. This reactor is "right sized" for Saskatchewan's grid infrastructure and transmission capabilities. At 300 MW, its generating capacity is comparable to Shand Power Station (276 MW), or one of the two 291 MW units at the Poplar River

[20] A nuclear fission reactor's capacity to generate heat, expressed as MWth (megawatts thermal), is always greater than its capacity to generate electricity, expressed as MWe (megawatts electric). Throughout this paper, we use MW on its own to refer to a reactor's electric capacity.

Power Station. Larger reactor builds could require billions in transmission upgrades to accommodate higher voltages, depending on siting. Building the BWRX-300 does not preclude Saskatchewan from building larger reactors in the future.

The BWRX-300 under construction at the Darlington New Nuclear Project (DNNP) will be the first nuclear reactor in Canada to require low-enriched uranium fuel, with a 3–5% concentration of fissile uranium-235. Ontario's existing fleet of CANDU reactors use natural, unenriched uranium, with a uranium-235 concentration of 0.7%, sidestepping the need for enrichment. Most commercial nuclear reactors run on low-enriched uranium.

Canada has no enriched fuel manufacturing capabilities. The DNNP fuel procurement plan involves an international partnership between Canadian, French, and American companies. Under the plan, uranium ore mined by Cameco in Saskatchewan and converted into uranium hexafluoride (UF_6), at Cameco's Port Hope, Ontario, conversion plant will be sent to either Urenco USA or Orano in France for enrichment. The enriched uranium will then be sent to Wilmington, North Carolina for fuel fabrication and assembly, before final use at Darlington.

Waste and lifecycle management

Nuclear power generation in Saskatchewan will produce spent nuclear fuel and long-term environmental obligations. Western Canada will ultimately need nuclear waste management solutions, and likely its own deep geological repository.

Both the long-term safety and overall global volume of nuclear waste are manageable. Canada's long-term approach to nuclear waste storage is ongoing and consistent with other advanced democracies.[21] Long-term geological storage for high-level nuclear waste in Canada is managed by the Nuclear Waste Management Organization (NWMO). In 2010, NWMO initiated a community-driven site selection process for long-term geological storage. Potential host sites voluntarily expressed their interest, engaged with NWMO, and conducted independent site and environmental reviews. Three northern Saskatchewan communities — Creighton, English River First Nation, and Pinehouse — participated in the first selection process but were not chosen. Following a 14-year search, the NWMO officially selected Wabigoon Lake Ojibway Nation, near the Township of Ignace in Ontario. The area features a deep, geologically stable rock formation suitable for long-term storage.

The NWMO announced that it will begin the site selection process for a second repository in 2028.

[21] Canada's Policy for Radioactive Waste Management and Decommissioning, administered by Natural Resources Canada, describes roles and responsibilities and detailed protocols for managing high-level, intermediate-level, and low-level radioactive waste.

Conclusion and recommendations

Our analysis finds a clear need for large-scale, non-emitting power in Saskatchewan over the next 25 years. There is a strong case for nuclear power to fill that gap as part of a broader electrification strategy. But achieving the province's goal of a carbon-neutral grid requires more than just a large-scale nuclear buildout.

Our recommendations follow from three key findings in our analysis. The first finding is the **massive financial scale** of any potential investment in nuclear power for Saskatchewan. Even a single reactor is an outsized undertaking for a province of 1.2 million people. Assuming no serious cost overruns, a four-pack of SMRs or a single large reactor would cost in the range of 15% to 25% of Saskatchewan's GDP. Saskatchewan cannot afford to go it alone.

Second, **structure matters more than sticker price.** Whether a nuclear power project stays on budget depends less on the reactor technology than on the distribution of risk and management of cost overruns. Third, **time is of the essence.** Less cooperation and financial support from the federal government will inevitably slow the project.

Renewed federal-provincial partnerships and national unity remain atop the national political agenda. The federal government has begun to reset its energy and climate policies with the provinces and collaboratively advance major infrastructure projects.

The federal government's new ambition is to build a reactor outside of Ontario by 2035. Saskatchewan should secure its spot at the front of the line.

RECOMMENDATION #1

The federal and Saskatchewan governments should work together on a "grand bargain" to build Saskatchewan's first nuclear reactor.

Affordably achieving a carbon-neutral Saskatchewan power grid that will meet rising demand for electricity will require investment by both orders of government. As a province of 1.2 million people, Saskatchewan cannot shoulder the costs of a capital-intensive, multi-billion-dollar nuclear project on its own without pushing substantial new costs on to ratepayers and taxpayers, worsening stubborn affordability challenges. Getting a reactor online in Saskatchewan before the 2040s will require federal involvement. The federal government and Saskatchewan can strike a "grand bargain" on energy infrastructure and climate policy that incorporates financing support for the construction of a nuclear reactor, modelled after the federal-Alberta memorandum of understanding (MOU) implementation agreement signed in May 2026.

If Saskatchewan wants to build a commercial nuclear power sector over the long term, the objective of a joint financing package should therefore be to build not just a single reactor, but a workforce and supply chain ecosystem capable of drawing in private capital to fund the construction of subsequent reactors.

We recommend that the federal and Saskatchewan governments develop a financing package for one reactor that contains the following elements:

- Federal support for co-financing via a concessional loan, loan guarantee, or similar instrument to cover a substantial share of project costs, with key milestones and deliverables set as terms of the loan. Cutting borrowing costs is even more important than the federal ITCs that support nuclear power.
- Federal ITC coverage across the full duration of the project, i.e., past the current end date of 2034 if necessary. The realistic timeline for multiple gigawatts of large-scale, non-emitting power is the 2040s. Access to ITCs can help significantly with not just project capex but across the broader supply chain.
- A direct provincial equity contribution roughly equivalent to 5% of project costs, akin to the Building Ontario Fund's $1-billion stake in the DNNP.
- A joint Indigenous loan guarantee modelled after the DNNP, to allow Saskatchewan First Nations to acquire equity in the new reactor.

The structure should ensure "skin in the game" for both orders of government, all proponents, and major contractors. The need for key players to all have meaningful stakes in project outcomes is the generalized lesson from the extraordinary cost overruns at Plant Vogtle in the U.S. The federal government can supply significant project capital while putting guardrails around its exposure to overruns. The federal government is often the funder of last resort on megaprojects and has previously been forced to go over the cap for projects that are too big to fail. Saskatchewan, the technology provider, and the engineering and construction vendors all need risk exposure to ensure alignment of interests.

We recommend the bargain create specific opportunities to expand Saskatchewan's role in Canada's nuclear supply chain. Outside of uranium production, Canada's nuclear power ecosystem is largely concentrated in Ontario. Expanding commercial nuclear generation into Saskatchewan should come with specific opportunities for the province to participate in the supply chain and innovation ecosystem and expand the province's skilled workforce. This would include long-term flagship research infrastructure as articulated in the federal Nuclear Strategy for Canada.

We recommend the bargain contain specific oversight and public reporting requirements for any nuclear project receiving federal support. Our case studies illustrated some of the ways that political interference and perverse institutional incentives can add to construction risk for nuclear projects. Saskatchewan requires a process that can insulate any nuclear project from some of these risks. There are options, ranging from a fully independent watchdog regulatory agency akin to the Ontario Energy Board, to amending the Saskatchewan Rate Review Panel's mandate to include oversight and public reporting responsibilities specific to nuclear construction projects. Transparency and accountability can help ensure incentives remain aligned across the life of the project.

RECOMMENDATION #2

The federal and Saskatchewan governments should work together to restart the Saskatchewan OBPS, inspired by Alberta MOU rules.

Since 2019, every Canadian province has used industrial carbon pricing for large emitters. Saskatchewan's carbon market, an output-based performance standard (OBPS), covered coal- and gas-fired power plants alongside other industries such as oil and gas, mining, and various types of heavy manufacturing.

Saskatchewan's OBPS has not been operating since April 2025. It will not pass equivalency under the federal 2026 carbon pricing review and requires a restart. Our modelling shows that restarting the OBPS, under the same revised headline price and market rules found in the federal-Alberta MOU implementation agreement, is part of a one-two punch that can enable Saskatchewan to cut electricity emissions 90% by 2050. The other punch is adding a significant amount of non-emitting baseload power to Saskatchewan's grid — 2.6 GW of nuclear generating capacity in our analysis.

There are two levers to reduce the emissions intensity of Saskatchewan's grid: 1) adding non-emitting or low-emitting assets (solar, wind, storage, nuclear, geothermal, interties) and 2) retiring high-emitting facilities. A restarted OBPS can help steer the investment choices of SaskPower and its vendors and partners, with modest impacts on electricity prices. There are options to fully offset these affordability impacts for ratepayers. One option is for SaskPower to directly rebate the revenues collected under the OBPS to ratepayers on a fixed $/kWh basis. Saskatchewan has previously recycled revenues from its OBPS to several affordability initiatives, as well as into the Small Modular Reactor Investment Fund.

RECOMMENDATION #3

Saskatchewan and SaskPower should embrace fleet-based planning with larger jurisdictions and act as a "fast follower."

Following the lead of experienced nuclear jurisdictions should be a key plank of Saskatchewan's approach to nuclear deployment. Ensuring Saskatchewan's reactors are part of a larger fleet buildout across other jurisdictions, rather than one-off technology choices, can reduce project risk. Saskatchewan has options for reactor technology, including the BWRX-300, the AP1000, and the CANDU Monark. The province should focus on models that another jurisdiction has already built or is building, thereby absorbing the first-of-a-kind costs, establishing a construction and operational track record, and initiating the development of a cost curve.

To further enable fast following, Saskatchewan should accelerate its site selection and regulatory submissions to the CNSC to ensure that regulatory timelines do not become a bottleneck.

RECOMMENDATION #4

Saskatchewan and SaskPower should competitively procure electricity projects once the OBPS restart has been finalized.

Saskatchewan's electricity needs are growing too fast to place non-market constraints on any generation source. Wind and solar capacity have grown rapidly in recent years and now represent approximately 15% of Saskatchewan's total generating capacity, with more projects on the way. Renewable expansion and energy efficiency are the most effective short-term levers to meet growing electricity demand without undermining the province's energy independence. Nuclear power is not deployable until the 2030s; natural gas power generation requires importing fuel and increases Saskatchewan's exposure to price volatility. With careful planning, there is room for significant expansion of wind, solar, and storage capacity to meet fast-growing demand and buy time before nuclear power deployment.

Our modelling shows that expanding solar and wind's share of total grid capacity aids affordability, particularly if the OBPS is restarted. Increasing renewable capacity to between 30% and 39% of total generating capacity has a negligible effect on electricity rates when factoring in total system costs.

Appendix A: MAC curve methodology

- **Financing:** 10% weighted average cost of capital over the project life. We assume debt financing on 50% of capital costs. Annual inflation is 2%.
- **Project life:** 20 years.
- **Costs:** All costs are expressed in 2026 Canadian dollars, unless otherwise specified.
- **Tax credits:** The CCUS ITC application assumes 75% of capital expenses are eligible and claim maximum tax credit rates, meeting labour and apprenticeship requirements.
- **Carbon credits:** All costs are exclusive of any potential revenue from carbon credit generation in voluntary or compliance carbon markets.
- **Emissions baselines:** Average annual regulated emissions from 2022 to 2024 (the most recent year of reporting at time of publication) are used for each sector's emissions reduction potential. For a typical facility, we use average annual facility emissions and assume standard operations.
- **Current electricity grid:** The baseline carbon intensity of the current electricity grid in 2026 is 631 gCO_2e/kWh electricity consumed.
- **Low-emissions electricity grid:** Assumes a carbon intensity of the electricity grid is 26 gCO_2e/kWh electricity consumed, aligned with 2.6 gigawatts of nuclear power added to the provincial power grid.

Appendix B: Description and cost assumptions for Open Insights modelling

Open Insights' open-source M3 Platform (CIMS-COPPER-SILVER configuration) is an integrated energy-economy-emissions model designed to simulate the interaction of energy supply-demand and estimate the effects of policy and market dynamics on Canada's energy system. CIMS represents detailed energy-related technologies and the realistic preferences of consumers and firms across supply sectors such as oil and gas, as well as key energy demand end-uses in residential, commercial/institutional, transportation, and various industrial sectors. It optimizes for cost when faced with specific policies.

Because of this optimization, model outputs can underrepresent costs relative to the real world, which has physical and institutional frictions that the model cannot represent. First, the model minimizes total system cost and has no preference for energy independence or in-province generation. The model enforces an 11% in-province planning reserve margin with technology-specific capacity values, but treats imports as low-cost and without the same rate-base or policy costs as domestic build. The model can in theory meet most energy needs through imports while holding a relatively small domestic fleet (e.g. existing or peaking capacity) to satisfy reserve requirements. Because it operates with foresight over the full 25-year timeframe, the model tends to front-load investment, which leads to more aggressive rate increases over 2030 and 2035 fewer rate increases in the 2040s as assets amortize. There are several reasons SaskPower's planning could prioritize other objectives. The model also does not represent regulatory lag or project delays and overruns. The trajectory is an efficient-build cost path, not necessarily a forecast of how SaskPower would actually set rates or smooth them. Lastly, restarting the OBPS pushes the model away from coal and gas (high fuel and carbon costs) toward wind, solar, and imports (low operating cost, very few carbon costs). Under these conditions, the model may overstate how much reliance on imports is acceptable in practice.

Capital costs are entered as annualized costs ($/MW-year) for modelling runs in this report, which use Open Insights' open-source M3 Platform (CIMS-COPPER-SILVER configuration). Values in the table below are converted to overnight capital costs ($/MW) using a capital recovery factor at an 8% real discount rate, with technology lifetimes of 30 years for thermal and renewable generation, 60 years for nuclear (including SMRs), and 15 years for lithium-ion battery storage. Fixed O&M costs are reported on an annual basis ($/MW-year). These capital figures reflect COPPER's base technology cost assumptions and do not include period-specific capital cost evolution applied within the model runs.

Table 5: Cost assumptions for Open Insights modelling simulations

Generation Type	Total project capital costs ($2025/MW)	Fixed O&M costs ($2025/MW-year)	Variable O&M costs ($2025/MWh)
Unabated gas (combined cycle)	1,909,290	17,849	2.73
Unabated gas (refurbished)	693,072	17,849	2.73
Abated gas (new build, 90% capture rate)	4,985,710	40,378	8.54
Abated gas (retrofit, 95% capture rate)	2,318,355	40,378	8.54
Nuclear (conventional)	13,320,330	177,983	3.47
Nuclear (SMR)	14,285,210	138,996	4.39
Nuclear high cost (conventional)	25,000,000	177,983	3.47
Nuclear high cost (SMR)	25,000,000	138,996	4.39
Solar	2,269,770	22,308	0
Battery storage (Li-ion)	1,939,130	59,488	0
Wind (offshore)	10,775,410	160,953	0
Wind (onshore)	3,359,170	38,532	0

Appendix C: Net-zero electricity supply and capacity requirements, Open Insights and Navius Research

Figure 10: Electricity supply in 2050 under net-zero policy conditions

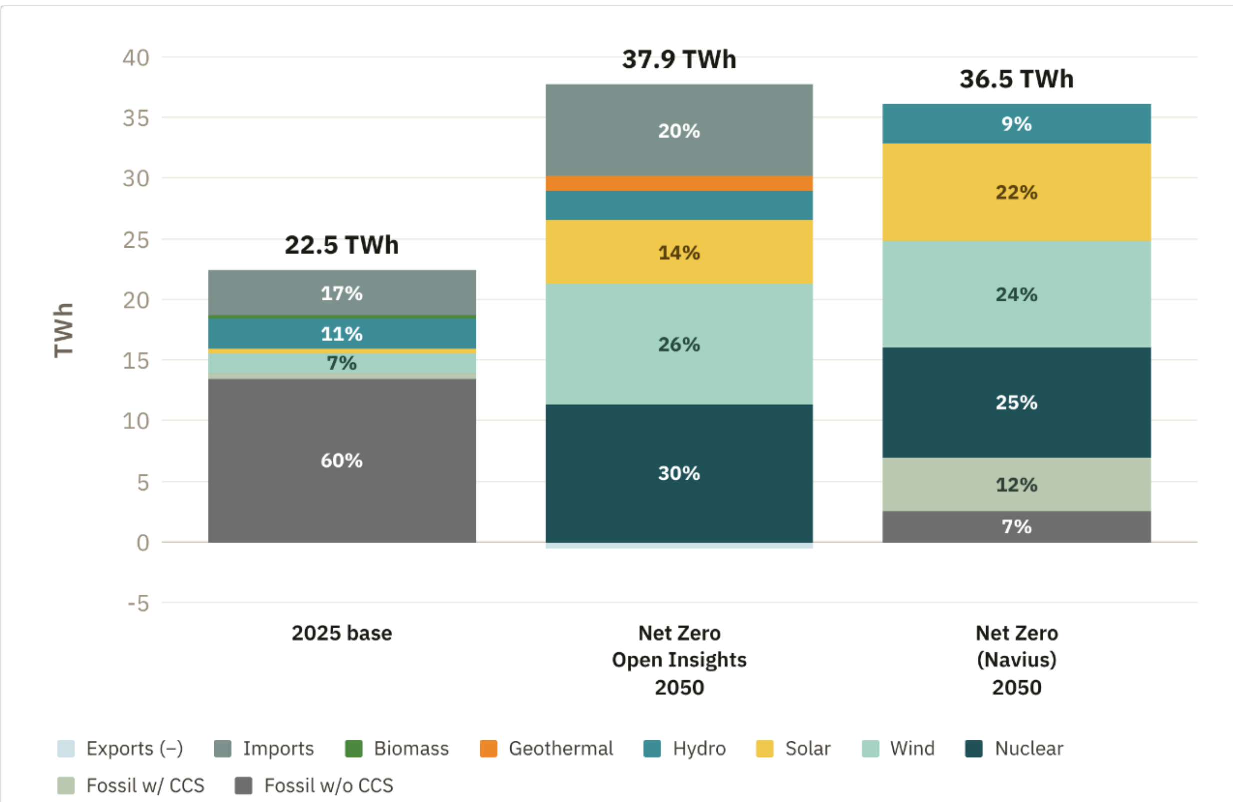
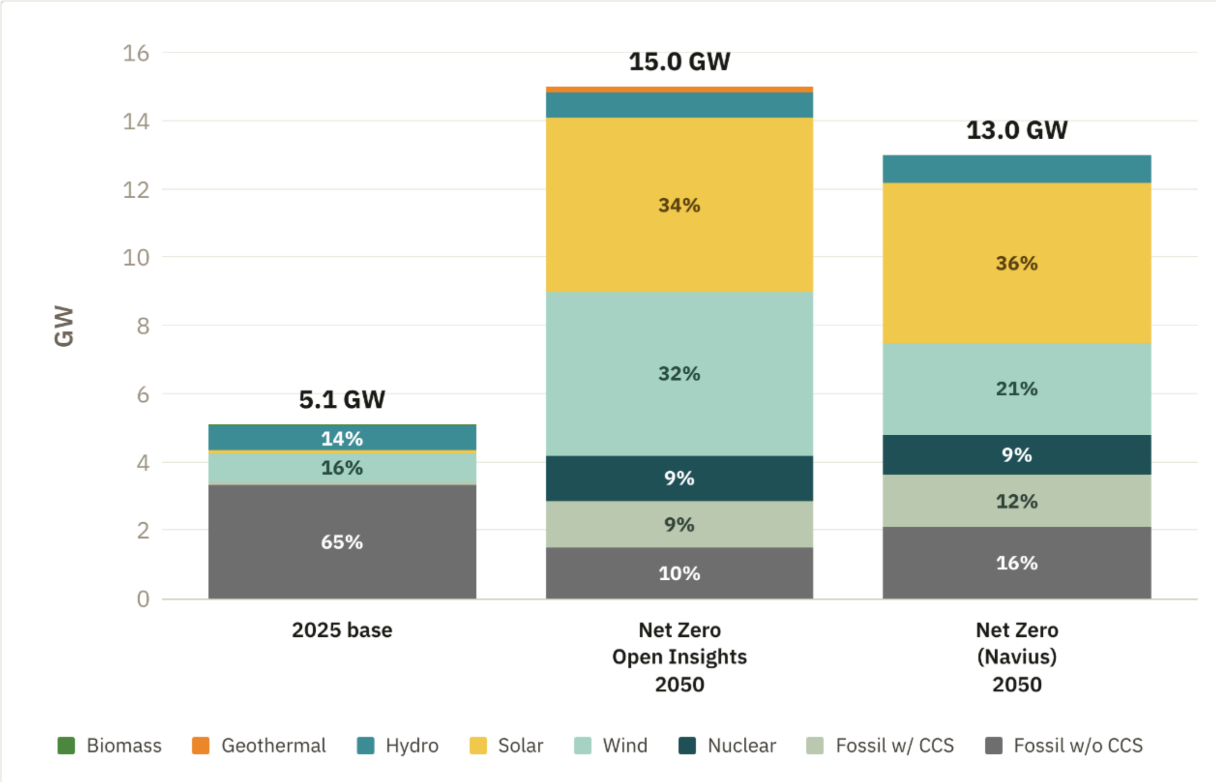


Figure 11: Electricity generating capacity in 2050 under net-zero policy conditions



Appendix D: Nuclear financing case studies

Case 1: Hinkley Point C

Project summary: A two-unit, 3,260 MW power plant in Somerset, U.K. Britain's first new nuclear build since Sizewell B entered operation in 1995. Site preparation began in 2012, civil works construction in 2017. Unit 1 is expected online in 2030.

- **Reactor type:** Generation III+ 1,630 MW European Pressurized Reactor (EPR); the fifth and sixth EPR units to begin construction globally and the first in the U.K.
- **Project proponent:** State-owned multinational French utility EDF (77% equity, initially 66.5%), and China General Nuclear Power Group (CGN; 23%). There was no government equity stake or board representation.
- **Financing structure:** The government-run Low Carbon Contracts Company (LCCC) issued EDF a contract for difference (CfD) with a guaranteed strike price (£89.50 per MWh; 2012 prices) paid once the plant is online. EDF bore 100% of construction cost risk in exchange for price certainty with the CfD. CGN's 33.5% stake at final investment decision (FID) diluted to 23% as EDF took on the overruns. EDF secured up to £4.5 billion of supplementary bond financing from U.S. asset manager Apollo Global Management in 2025.

Incentive alignment: Poor. The CfD placed full construction risk on EDF. In theory, placing construction risk with the project lead should offer the necessary discipline for on-time and on-budget delivery. In practice, placing the risk on a state-owned utility that remains "too big to fail" was inadequate. Many subcontractors operated under design-and-build arrangements with limited financial exposure to overruns.

Oversight strength: Poor. No independent oversight of construction costs or schedule were in place before the 2016 FID. EDF reported delays and cost escalations with no contractual lever to address poor performance, short of cancellation.

Construction performance: Poor, 94% cost overrun. Project delays, including delays caused by the COVID-19 pandemic, increased interest accrual during construction. EDF's original £18 billion estimate for the project has grown to £35 billion. Chinese co-investor CGN declined to fund further cost overruns and has effectively withdrawn from the project.
EPRs have experienced a negative learning curve similar to those seen in the United States' nuclear fleet. Taishan 1 and 2 in China started operations in 2018 and 2019 respectively, 10 years after

construction began. Finland's Olkiluoto 3 and France's Flamanville 3 started operations in 2023 and 2025 respectively, both 18 years after construction began. All overshot their budgets and deadlines. Hinkley Point C is the fifth EPR project, with a 13-year construction timeline consistent with peer EPR projects.

Lessons for Saskatchewan: The CfD did successfully attract a private proponent willing to bear construction risk. With this guarantee in a jurisdiction with tens of millions of ratepayers, EDF proved most willing to take on the cost and risk. But because EDF was majority owned by the French government, even a financial risk of this scale was inadequate to ensure discipline. COVID-19 exacerbated these challenges. The results at Hinkley underscore both the risk of guarantees for FOAK projects and the need to distribute risk and accountability across a larger number of actors. Single-point accountability was ineffective, even prior to COVID-19.

Case 2: Sizewell C

Project summary: A two-unit, 3,260 MW power plant under construction near Suffolk, England. Sizewell C is a near replica of Hinkley Point C, which was a key factor in derisking this project. It received a final investment decision in 2025. Construction is underway with a targeted completion in the late 2030s.

- **Reactor:** Generation III+ European Pressurized Reactor (EPR).
- **Project proponent:** EDF took a smaller role with Sizewell C. The U.K. Government (44.9%), La Caisse de dépôt et placement du Québec (20%), Centrica (15%), and Amber Infrastructure (7.6%, acting on behalf of the U.K. Nuclear Liabilities Fund and International Public Partnerships) are all equity holders. EDF holds equity (12.5%) but is the builder and member of the operating consortium rather than the sole financial risk-bearer.
- **Financing structure:** Debt plus a regulated asset base (RAB). Under a RAB model, project costs are added to the utilities' regulated rate base, i.e. the cost of capital and assets they can legally pass on to ratepayers. Households pay about £1/month during construction, converting some construction risk into an early regulated revenue stream for equityholders. The RAB licence contains two thresholds. If project costs end up below the lower regulatory threshold, the underspend is added to the RAB and accrued by investors. If project costs are between the low and high threshold, risk is shared; if project costs are above the high threshold the risk rests with the U.K. government.

  Debt financing includes £5 billion from French export credit agency Bpifrance and additional lending from the U.K. National Wealth Fund. The project's debt is rated investment grade by Moody's, S&P, and Fitch. Total financing capacity of approximately £50 billion is available against an estimated construction cost of £38 billion (2024), with headroom for cost overruns.

The estimated weighted average cost of capital for Sizewell C under the RAB model is approximately 6.7% compared to 10% for Hinkley Point C with a CfD.[22]

Incentive alignment: Adequate, far superior to Hinkley Point C. Both investors and contractors had incentives for delivery below the £38 billion target. The consortium-style equity structure includes a sophisticated institutional investor (La Caisse) alongside the government. The RAB levy also gives consumers a formal stake in cost performance through Britain's energy regulator, Ofgem. Financial incentives to avoid overruns are well aligned once the thresholds are set, but proponents or vendors gaming initial thresholds with inflated initial costs remains a risk with this model. Ofgem also does not have the ability to regularly review expenses related to the core delivery of the project.

Oversight strength: Strong. Incentives are built into the contract and Ofgem regulates the RAB economic licence, providing ongoing oversight of cost milestones and the impact on consumer bills, independent of the project's equity holders. Financial close in November 2025 required independent due diligence by all institutional investors, an oversight mechanism that was not included in Hinkley Point C.

Construction performance: Too early to assess; civil works began in late 2025. The outstanding question is whether EDF can develop a learning curve for the EPR reactor across the Hinkley Point C and Sizewell C projects. The £38 billion estimate already assumes significant savings across both projects.

Lessons for Saskatchewan: The U.K. government kept the EPR design from Hinkley to capture the benefits of fleets and learning-by-doing but switched from a private financing model backed by a CfD to a RAB model paired with a government equity stake for Sizewell C. The RAB that allows for concurrent cost recovery during construction was a global first for a nuclear reactor, even though it is a common method used by rate-regulated utilities to defray interest costs for large projects. The U.K. government's 44.9% equity stake, taken explicitly to crowd in private capital, offers a modern template for federal equity participation in a nuclear project. The 3,200-MW scale is not transferable to Saskatchewan, but aspects of the financing architecture are.

Case 3: Plant Vogtle Units 3 and 4

Project summary: The third and fourth reactors at Plant Vogtle near Waynesboro, Georgia are the most recent nuclear reactors built in North America. Construction began in 2009; Unit 3 entered commercial operation in July 2023, Unit 4 in April 2024.

- **Reactor:** Westinghouse AP1000, Generation III+ pressurized water reactor, 1,117 MW per unit; 2,234 MW total.

[22] Derived from a 10.8% allowed return on equity, 4.5% cost of debt, and 65% gearing with a 65:35 debt-to-equity ratio.

- **Project proponent:** Four utility equity holders: Georgia Power (45.7%), Oglethorpe Power (30%), Municipal Electric Authority of Georgia (22.7%), and Dalton Utilities (1.6%), with a $8.3 billion loan guarantee from the U.S. Department of Energy (DOE) Loan Programs Office.
- **Financing structure:** The Construction Work in Progress (CWIP) rate recovery model enabled Georgia Power to earn a regulated return on all construction costs from ratepayers as they were incurred. Westinghouse held fixed-price engineering, procurement, and construction (EPC) contracts intended to cap cost risk. Because of delays and overruns, this structure contributed to Westinghouse's 2017 bankruptcy.

Incentive alignment: Perverse. Under CWIP cost overruns were profitable for Georgia Power because all costs were recoverable, not just those defined in the initial project scope. The utility had no disincentive to avoid spending, though it was still exposed to regulatory risk through poor or slow decision-making. The fixed-price EPC structure ended up transferring risk to contractors that lacked the capital reserves to absorb them, and was therefore ill-suited for a FOAK project.

Oversight strength: Poor. The elected Georgia Public Service Commission (GPSC) repeatedly approved cost overruns despite its own staff's recommendations to consider cancellation. Independent construction monitors documented Georgia Power providing materially inaccurate cost estimates for at least 10 years but the Commission continued to approve CWIP-eligible spends as the project struggled. Unlike Ofgem at Sizewell C, the GPSC lacked binding authority to compel cost discipline. In December 2023, six months after the first unit entered service, the Commission passed US$7.6 billion in overrun costs directly to ratepayers and rejected US$2.6 billion in overrun cost passthrough.

Construction performance: Poor, 150% cost overrun. Vogtle's combined construction and financing costs exceeded US$35 billion, dwarfing the original certified cost estimate of US$14 billion. Georgia Power's credit was downgraded during construction and its parent company, Southern Company, was forced to sell a subsidiary to strengthen its balance sheet. Westinghouse held fixed-price engineering, procurement, and construction contracts intended to cap cost risk but delays strained Westinghouse's balance sheet and led to its 2017 bankruptcy. The U.S. DOE identified root causes for the overruns, including incomplete design at construction start, inadequate scheduling alignment, shortage of experienced labour, and supply chain failures.

Lessons for Saskatchewan: Vogtle is a cautionary tale, a failure of financing and governance. The CWIP model was at the root of the failure as it made cost overruns profitable. The combination of FOAK risks and perverse incentives continued to generate positive returns for the utility's shareholders, leaving ratepayers holding the bag on cost overruns. Any financing structure for Saskatchewan offering guaranteed returns would encounter the same problem, though the case is fundamentally different in that the proponent in this case is likely the Saskatchewan government, not a private firm.

Vogtle's governance failures are manyfold. The Georgia Public Service Commissioners overrode their own staff's findings that the project was uneconomic after Westinghouse's bankruptcy. To avoid succumbing to the sunk-cost fallacy, projects require clear milestones, where decisions to halt are based on predetermined criteria that cannot be politically overridden. The GPSC was supposed to prevent this outcome, but Commissioners faced no consequences for approving overruns and significant political consequences for cancelling a major infrastructure project. Preferably, there would be a politically insulated independent economic regulator with binding authority over preestablished cost thresholds, plus a financing structure that aligns equity holders and project proponents with the interests of ratepayers.

There was meaningful learning between units: Unit 4 was roughly 30% more efficient and 20% cheaper to build than Unit 3, with key testing milestones completed 40–80% faster. The U.S. DOE Liftoff Report points to five efficiencies that led to this outcome:

- Key testing milestones were completed approximately 38-76% faster;
- Engineering service requests dropped by about 50%;
- Modified project sequencing to accommodate work packages, staffing, and scheduling;
- Learning by doing via modular construction methods, material management plans, and electrical quality inspections; and
- Various vendor and supply chain efficiencies.

Case 4: KEPCO and KHNP's 26-reactor fleet

Project summary: Initiated in the 1980s, South Korea's 26-reactor nuclear fleet was built and operated by Korea Hydro & Nuclear Power (KHNP), a subsidiary of Korea Electric Power Corporation (KEPCO), which is 51% government-owned.

- **Reactor:** APR-1400 (Advanced Power Reactor 1,400 MW), Generation-III pressurized water reactor. The APR-1400 became the first non-U.S. design to receive U.S. Nuclear Regulatory Commission design certification in 2019.
- **Project proponent:** State-backed and majority-owned utility with no external engineering contractor. All four of South Korea's nuclear stations had KHNP as builder and operator, KEPCO E&C as engineering lead, Doosan Enerbility as primary heavy component manufacturer, and Hyundai and Samsung as construction contractors.
- **Financing structure:** Debt on KEPCO's balance sheet with sovereign backing via the Korean government's majority stake in KEPCO. KEPCO's 51% government ownership gave it access to favourable borrowing rates. Costs were recovered through regulated electricity tariffs, using a similar mechanism to a RAB or concurrent cost recovery (CCR). KEPCO's electricity rates are set politically rather than by an independent economic regulator, so in practice the true cost of the nuclear expansion has been borne more by taxpayers than ratepayers.

Incentive alignment: Strong. The critical differentiator in South Korea's case was a clear long-term plan for continuous domestic construction of reactors to eliminate stop-start FOAK costs. The buildout was characterized by vertical integration and repeat builds with the same firms (KHNP, KEPCO E&C, Doosan, Hyundai, Samsung) as part of a single program. Supply chain leads were prepared to absorb FOAK costs and perform well to earn repeat work, and poor performance could have cost firms future work.

Oversight strength: Adequate. Implicit government backstop gave the South Korean government incentives to ensure adequate oversight.

Construction performance: Strong. Consistently on time and on budget domestically, South Korea has added a new reactor approximately every 18 months since 1995. This has led to international construction opportunities, including four APR-1400 units for the Barakah Nuclear Energy Plant in the UAE and two for Czechia's Dukovany Nuclear Power Station.

Lessons for Saskatchewan: The South Korean model is the global benchmark for fleet-based planning, cost discipline, and learning-by-doing. Reactors have been delivered at costs below $5/W. South Korea's experience offers a high benchmark and several strategic lessons on replication and continuous domestic build, supply chain development, and institutional commitment. Optimizing the economics of fleets requires projects to use the same supply chain and workforce across successive builds within a specific jurisdiction. Negative learning curves occurred with the EPR at Hinkley and Sizewell C in part because the projects did not meet these criteria.

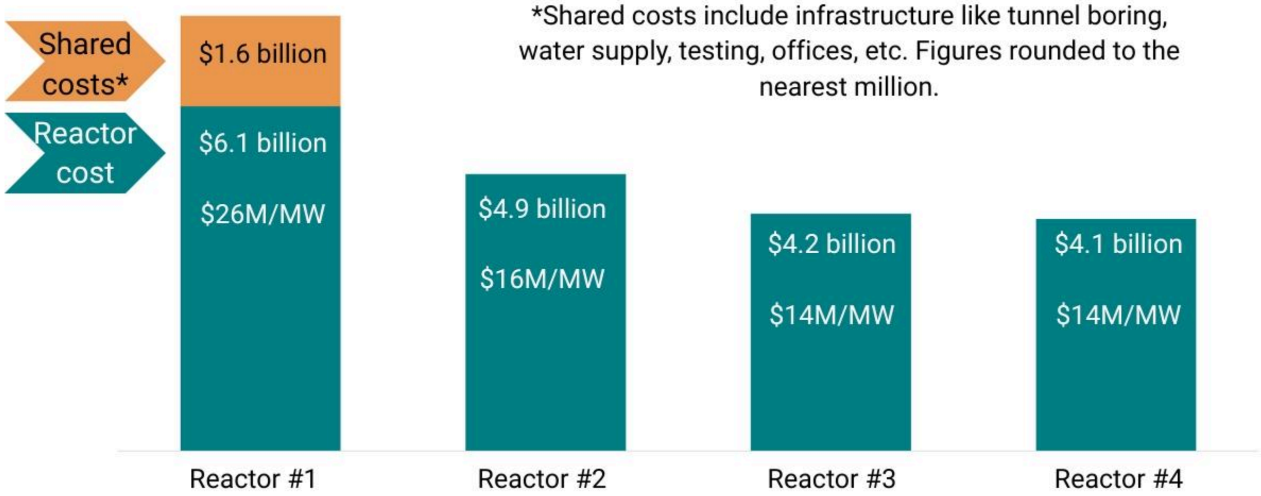
Case 5: Darlington New Nuclear Project (DNNP)

Project summary: Ontario Power Generation (OPG) is constructing the first of four 300 MW reactors at its Darlington Nuclear Generating Station, 70 km east of Toronto. It is the first commercial SMR project in the G7 and the global first-of-a-kind (FOAK) project for the BWRX-300. The CNSC issued a Licence to Construct in April 2025 and Ontario reached FID the following month. The first unit is targeting commercial operation by 2030, with all four units operating by the mid-2030s. This new build follows successful on-time and on-budget refurbishment projects at Ontario's two largest nuclear sites, Darlington and the Bruce Nuclear Generating Station.

- **Reactor:** BWRX-300, a 300 MW boiling water SMR developed by GE Vernova Hitachi Nuclear Energy. The DNNP is the global FOAK for the BWRX-300.
- **Project proponent:** Provincial utility and Crown corporation OPG is majority owner and operator, 100% owned by the Province of Ontario. Aecon is providing construction, project management, construction planning, and execution. GE-Hitachi is the technology developer responsible for major component procurement. AtkinsRéalis is the architect and engineer providing design, engineering, and procurement support.
- **Financing structure:** In October 2025 the equity structure was formalized through a limited partnership, DNNP LP. Through this partnership the Canada Growth Fund (CGF) committed up to $2 billion and the provincial Building Ontario Fund up to $1 billion in equity. OPG will fund the project through a mix of free cash flow, government equity, federal investment tax credits (15–30%), and rate-base recovery. Ontario established a Concurrent Cost Recovery (CCR) mechanism in 2026 that lets OPG recover debt interest during the construction period,

generating a reliable revenue stream prior to the production of electricity. The estimated total cost of construction for the four units is [$20.9 billion (2024 CAD)], inclusive of interest and contingency. OPG's FOAK cost estimates offer a clear benchmark ($6.1 billion), multiples higher than [GE Vernova Hitachi's original NOAK cost of $1.5 billion per reactor].

Figure 12: OPG cost estimate for DNNP, inclusive of federal ITCs



Incentive alignment: Adequate. The DNNP is using an [Integrated Project Delivery model], a multi-party agreement where OPG, GE Vernova Hitachi, AtkinsRéalis, and Aecon share in the upside and downside of project delivery. Overruns erode the margins of all the project participants and savings are also shared, and the structure promotes collaboration and consensus-building. Government equity has helped to derisk the FOAK stage and can later be sold off. The use of a CCR mechanism is distinct from the CWIP model seen at Vogtle; it covers only construction period interest rather than costs as they are incurred. The mechanism remains subject to OEB oversight and cost overruns do not need to be rubber stamped. The key challenge is OPG's Crown status, which positions the Government of Ontario as an implicit backstop.

Oversight strength: Adequate. Two regulators are presiding over different aspects of the project. The [CNSC's Licence to Construct] carries clear milestones through three stage-gated regulatory hold points that OPG must satisfy before proceeding. The first, covering the reactor building foundation, was cleared in March 2026. On cost, the OEB sets OPG's regulated nuclear payment amounts, and has shown a [willingness to reject recovery of certain costs].

The lack of a clear project off-ramp remains a problem. Neither regulator has the ability to judge whether the DNNP should continue if it encounters cost overruns.

Construction performance: Too early to assess, but with promising early indicators. As of 2026 the project has cleared early milestones on schedule: the reactor building basemat — the first major module — was set in place in May 2026, the CNSC lifted the first of three regulatory hold points in March 2026, and OPG applied for a 20-year operating licence in the same month.

Lessons for Saskatchewan: The technology, the Crown corporation proponent model, the financing architecture, and the use of an Integrated Project Delivery model are transferable to Saskatchewan. There is an opportunity for the province to be a "fast follower" and proceed quickly with the BWRX-300 should the FOAK build at Darlington successfully come in on-time and on-budget. However, transferability is limited by SaskPower's lack of experience in the commercial nuclear sector, its lack of an independent regulator analogous to the OEB, and its unique geographic challenges.

Case 6: Point Lepreau refurbishment

Project summary: Point Lepreau Nuclear Generating Station houses a single 660 MW CANDU-6 reactor located on the Bay of Fundy in New Brunswick. It's Canada's only nuclear reactor located outside Ontario after the decommissioning of Quebec's Gentilly Nuclear Generating Station in 2012. Construction at Point Lepreau ran from 1975 to 1983 at a cost of approximately $1.4 billion ($4.8 billion in 2026 dollars). After 25 years of operation, owner-operator NB Power undertook a full refurbishment starting in 2008. The initial 18-month timeline for refurbishment included a $1.4 billion fixed-price contract with AECL. The reactor was returned to service three years behind schedule in 2012 and approximately $1 billion over budget.

- **Reactor:** CANDU-6, 660 MW, a pressurized heavy water reactor designed by AECL using natural uranium fuel and heavy water as a moderator. The original reactor entered service in 1983. This case study focuses on the 2008–2012 refurbishment of that plant, not its construction.
- **Project proponent:** NB Power, a provincial Crown utility wholly owned by the Province of New Brunswick. No federal equity stake or co-investor. For the refurbishment, AECL — itself a federal Crown corporation and the original designer of the CANDU-6 — held the fixed-price EPC contract.
- **Financing structure:** NB Power financed the refurbishment through utility debt, effectively backstopped by the provincial government, recovering costs through ratepayer bills over decades. A fixed-price contract with AECL was intended to cap NB Power's cost exposure at $1.4 billion — but as a federal Crown corporation, AECL had no financial liability mechanism that NB Power could effectively enforce, so NB Power was left responsible for cost overruns.

Incentive alignment: Poor. NB Power's fixed-price contract with AECL was meant to cap its exposure to cost overruns, but the contract proved difficult to enforce against a fellow Crown corporation. AECL could not be forced to absorb losses in the event of cost overruns, leading to a long-running dispute with NB Power. That dispute never advanced past mediation and the federal government refused to compensate NB Power beyond what the contract already specified. NB Power was left holding the bag, and there was evidence that its own project management decisions were at least partly to blame. In one widely reported example, NB Power's own project team overrode expert advice to halt installation of 380 calandria tubes. All 380 tubes had to be pulled and reinstalled, at a cost of $33 million per month in delay.

Oversight strength: Poor. With the New Brunswick government operating as a backstop and no proponent directly on the hook, incentives were insufficient to avoid cost overruns. NB Power had no independent construction monitor for the refurbishment until crises emerged, and no binding mechanism or recourse against AECL. The decision to proceed with refurbishment was also explicitly political. The New Brunswick Energy and Utilities Board (EUB) conducted an independent economic review in 2004 and ruled that the refurbishment had no significant economic advantage and was not in the public interest. With political support, NB Power overrode the EUB. There was no binding mechanism by which the EUB's economic judgment could stop a politically-supported project from proceeding.

Refurbishment performance: Poor. Refurbishment ran three years over schedule and approximately 71% over budget. The root cause of the overrun was unanticipated FOAK issues, as AECL had never performed a full CANDU-6 refurbishment before.

The economics of refurbishment hinged on assumptions that the reactor would operate at 90% capacity but the reactor has had reliability issues post-refurbishment. The reactor has struggled with operational issues, achieving a 60% capacity factor in 2022. In 2024, a 98-day planned maintenance shutdown was extended to 248 days, after problems with the station's generator.

Lessons for Saskatchewan: As a FOAK nuclear project with unproven construction methods in a small province ill-equipped to absorb cost overruns, there are clear parallels between Point Lepreau and a hypothetical nuclear project in Saskatchewan. As a small Canadian nuclear jurisdiction that struggled with financing, incentive alignment, and performance, Point Lepreau's FOAK refurbishment offers a cautionary tale. Deals with entities that cannot be compelled to absorb losses, such as Crown corporations, require careful attention and consideration.

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