POWER PROJECT PRE-FEASIBILITY: TOWN OF FOX CREEK · LSD 04-33-062-19W5

PURPOSE

A gas-fired plant at a site, with its gas, grid, permits and economics. The plant type, size and run hours are those of the sizing section.

Town of Fox Creek (54.4000, -116.8000)

KEY NUMBERS

Reciprocating engines, Alberta (Bitdeer Fox Creek) (default for 100 MW)
Plant

100 MW
Load

19.4 MMcf/d
Plant gas at full load, sales-gas basis

67–108 C$/MWh
All-in cost of on-site power, levelized, range across gas scenarios and capital costs (grid-connected at the default tie)

C$188.2M
Class 5: C$94.1M to C$376.5M
Capital outlay

Gas price, levelized over the life · swing 37.5 C$/MWh
Largest cost driver, one input at a time

92%
availability 92.0%, ambient output 100%
Capacity factor

743.2 MMcf/d
Gas reported within the radius

138/144 kV · a T-tap onto line 7L199, 0.8 km (nearest substation Fox Creek 741S, 3.4 km)
Substation the sizing ties to

3.4 km
Fox Creek 741S
Nearest 138/144 kV substation

173 within 500 m
519 within 800 m · 941 within 1.5 km
Buildings within 500 m · 800 m · 1.5 km

Each figure is quoted from a block in this report, with that block's date and source.

DATA AS OF
2026-11-19
Newest data among the blocks. Older inputs: crown or freehold surface as of 2021-11-16; climate and carbon reporting year 2024; prices and carbon as of 2025-07-31. Each block shows its own date.

GENERATED
2026-11-19

OPEN ITEMS
24
Listed at the end: what public data does not settle, and who can.

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DRAFT, NOT ISSUED · REVISION 1

SCOPE AND LIMITATIONS

This review relies on public data as published and was not independently verified; PatchWatt cannot guarantee its accuracy or completeness. It describes evidence. It is not engineering, utility or operator confirmation, advice, a permit or a land opinion, and it does not rank sites or operators. Figures were frozen when each block was saved, on the dates shown; later changes appear as logged corrections, not retyped figures.

LOCATION AND SITE

Coordinates	54.4000, -116.8000
Municipality	Town of Fox Creek
Buildings within 500 m · 800 m · 1.5 km	173 within 500 m · 519 within 800 m · 941 within 1.5 km

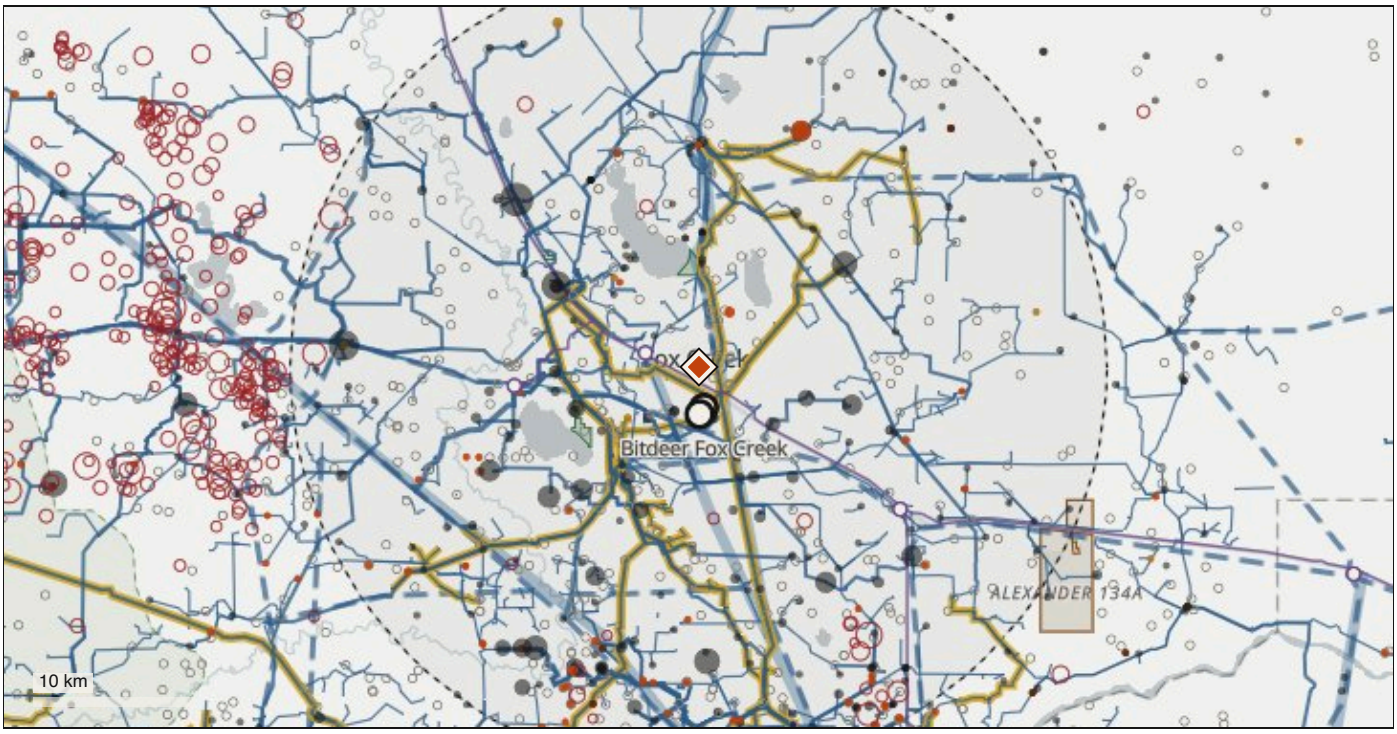
941 buildings within 1.5 km, of which 12 tagged as dwellings, 0 tagged as non-dwellings (farm, industrial, commercial or outbuildings), the rest (929) untagged or not settled by their tag; untagged buildings are treated as possible dwellings, as the noise impact assessment Rule 007 asks for (TP31, under Rule 012) surveys receptors on the ground; 662 of them are OpenStreetMap buildings, which can carry a use tag, and 279 Microsoft footprints of about 2019, which carry none.

The AUC refused a gas plant at Olds in 2026 (Decision 30732-D01-2026) citing over 700 residences within 800 m. Buildings of 40 m^2 and larger from Overture Maps release 2026-10-21.0 (about two thirds from OpenStreetMap, the rest Microsoft footprints from imagery of about 2019), counted in cells of about 280 m. Buildings OpenStreetMap tags as farm, industrial, commercial or outbuildings are counted apart from those it tags as dwellings; most rural buildings carry no tag and are counted as possible dwellings, sheds and barns included; dwellings filed in a project's noise study may differ. © OpenStreetMap contributors, Microsoft, Overture Maps Foundation (ODbL).

Buildings within 2 km · 5 km	1,005 · 1,018
Nearest building	about 190 m

Measured to the centre of the nearest building-grid cell: buildings are counted in cells of about 280 m, not mapped one by one, so the nearest building may be up to about 200 m nearer or farther.

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◆ site point ◌ 25 km radius ● gas facility, sized by latest gas (orange: stopped; ochre: down 75% or more) ○ suspended gas well
— gas pipeline ● substation (larger: 240 kV and up) ◯ data-centre project
Also drawn: screening grid; closed water basins and flood zones; earthquakes since 2010; caribou ranges and protected areas; reserves, métis settlements, municipalities; streets map.

LEGAL LAND LOCATION

SITE POINT	LSD 04-33-062-19W5 · SW quarter of section 33 · township 62, range 19, west of the 5th meridian
TOWNSHIP	062-19W5, about 95 km^2 with road allowances (36 sections of about 259 ha)
NEARBY	063-19W5 · 061-19W5 · 062-20W5 · 064-19W5 · 063-20W5 · 063-18W5 · 061-20W5 · 062-18W5

Computed from an Alberta Township System model with road allowances and correction lines, fitted to the Government of Alberta ATS v4.1 grid: section and LSD lines typically within 100 m, rarely 0.3 km. Confirm the legal description on the land title before relying on it.

GROUND COVER WITHIN 2 KM

62%	Forest
34%	Urban, developed, greenhouses
2%	Water
1%	Shrubland

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Method: note 1, Notes on method.

DATA-CENTRE PROJECTS WITHIN 25 KM

Project	Developer	Size	Stage	Gas	km
Bitdeer Fox Creek	Bitdeer Technologies Group (approval holder BitDeer Energy Inc.)	~100 MW	Under construction	Gas supply unknown	2.5
Teton Digital Northern Forge	Teton Digital	200 MW behind-the-meter gas (Teton Digital)	Proposed	Gas supply unknown	≈3

Distances marked ≈ are to projects placed by hand at town or municipality level, approximate to several kilometres; the others use the legal location, coordinates or site map in a public filing.

Municipal boundaries: Government of Alberta (Alberta Environment and Protected Areas) Municipal Boundaries, Communities and Metis Settlement services, official names from Alberta Municipal Affairs; data-centre status from council records, bylaws, AUC decisions and court files (each entry cites its record) (2026-10-05); Overture Maps buildings, release 2026-10-21.0: OpenStreetMap and Microsoft footprints (release 2026-10-21.0); Data-centre project inventory: Government of Alberta Major Projects and the AESO Connection Project List, with a hand-kept overlay of AUC, IAAC and municipal filings and company releases (2026-11-16); Power plants: NACEI North American power plants (NRCan/DOE/SENER, free with acknowledgement) (NACEI 2017); Alberta Township System arithmetic; AAFC Annual Crop Inventory (OGL-Canada), queried live · as of 2026-11-19 · saved 2026-11-19

SIZING AND COST

PROJECT SIZING AND COST

ASSUMPTIONS FOR SIZING AND COST: THE DEFAULTS

Load: **100 MW** Run hours: **8,760** Duty: **Auto (from run hours)** Availability: **92 %**

Method: note 2, Notes on method.

Full load, 8,760 run hours a year, at least half the year (4,380): the heat rate is the plant's design full-load figure.

Plant: **Reciprocating engines, Alberta (Bitdeer Fox Creek) (default for 100 MW)**

Method: note 3, Notes on method.

Method: note 4, Notes on method.

Efficiency: **42.2 %** Energy basis: **HHV**

Capital at 100 MW installed, before construction interest (the median of 5 published figures; type yours to replace it): **1,788 2025 C$/kW**

Build: **1.5 years** Scale exponent: **0.6** Spare capacity: **0 % of rated** Fixed O&M: **58.36 2025 C$/kW-yr**

Variable O&M: **5.31 2025 C$/MWh**

Method: note 5, Notes on method.

Method: note 6, Notes on method.

Method: note 7, Notes on method.

Figure	Type	MW	Struck	As published, /kW	2025 C$ by index	Post-2022 step	Today, own size	At 100 MW, before interest during construction
Reciprocating engines, Alberta (Bitdeer Fox Creek) · a company filing or release; interest during construction excluded	Engines	101	2022	C$1,543	1,780	× 0.82	1,451	1,457

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Figure	Type	MW	Struck	As published, /kW	2025 C$ by index	Post-2022 step	Today, own size	At 100 MW, before interest during construction
Bitdeer Fox Creek engine plant, 2025 figures reconciled to an all-in plant, AB, 2025 figure · a company filing or release; interest during construction excluded	Engines	101	2025	C$1,451	1,451	—	1,451	1,458
Nova Scotia Power 2022 IRP engine supply option, 2022 figure · a government agency's cost table; interest during construction included	Engines	20	2022	C$2,008	2,317	× 0.82	1,889	1,788
Nova Scotia Power 2020 IRP engine supply option, 2019 figure · a government agency's cost table; interest during construction included	Engines	50	2019	C$1,823	2,502	× 0.82	2,040	1,931
AESO 2024 Long-Term Outlook reciprocating engines, 2024 figure · a government agency's cost table; interest during construction excluded	Engines	111	2024	C$1,948	2,248	—	2,248	2,344

Method: note 8, Notes on method.

PUBLIC FIGURES NOT IN THE SET

- **AESO CONE 2018 engine screen** (AB, 2018): C$1,450–1,900/kW, 30–110 MW. A screening range, not a costed plant: the study calls its table "high-level estimates intended for screening purposes only" and states no dollar year or scope. AESO (Brattle Group and Sargent & Lundy), AESO Cost of New Entry study 2018, Table 1: Candidate Reference Technologies Screening Considerations, p. 6 (PDF p. 14). https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf
- **AESO 2026 Long-Term Outlook draft inputs, reciprocating engine (NREL ATB 2024b)** (AB, 184 MW, 2024): $2,024/kW overnight, $2,446/kW with financing (currency not stated). The table states $/kW without a currency or dollar year, and its sources (NREL ATB, US EIA) publish in US dollars: about 40% apart in Canadian dollars. The AESO calls the inputs preliminary. AESO, 2026 LTO Inputs Assumptions Scenarios, Comment Matrix and Appendix (posted 23 June 2026), Technology Costs and Assumptions table, Appendix table (an image in the document). https://aesoengage.aeso.ca/52801
- **Yukon Energy Whitehorse LNG engines** (YT, 9 MW, 2014): C$41.9M as built (C$4,765/kW). Includes an LNG receiving and storage terminal and is an 8.8 MW remote plant: not a pipeline-gas plant. Yukon Energy Corporation, Yukon Energy Corporation 2017-2018 General Rate Application, Tab 5 Capital Projects (as-built cost), PDF p. 194 (printed p. 5-23). https://yukonenergy.ca/media/site_documents/2017-2018_General_Rate_Application.pdf

> Plant capital cost is not settled by public data: published figures for reciprocating engines span C$1,457 to C$2,344/kW at this size, and the median of them misses a plant's own cost by 23% on average. It is the largest part of the cost of power; a budgetary quote from equipment vendors or an EPC contractor settles it.

> No Canadian public O&M figure for engine plants: fixed and variable O&M are the AESO CONE 2018 aeroderivative figures (C$50.6/kW-yr, C$4.6/MWh, 2021 dollars), a labelled stand-in until the AESO's new Cost of New Entry study, which adds a reciprocating engine reference (due early 2027), publishes.

> Meter station not costed as developer capital: the AESO CONE 2018 assumes NGTL builds it (p. 23), and no Canadian public cost for a meter or custody-transfer station, or for what the carrier charges the shipper for it, was found.

Method: note 9, Notes on method.

Inside this plant's fixed O&M (AESO CONE 2018 Table 10): insurance C$993k a year (0.6% of overnight capital); property tax C$993k; firm NGTL gas transport C$1,490k. Insurance, property tax and firm gas are under Assumptions (Plant).

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GAS AT FULL LOAD, SALES-GAS BASIS

19.4 MMCF/D

Method: note 10, Notes on method.

SITE CLIMATE AND OUTPUT

STATION-BASED · MAKER'S CURVE FOR THIS PLANT TYPE

July 2.5% / 1% dry-bulb	27.4 / 29.2 °C
January 1% / 2.5%	-32.9 / -29.4 °C
Mean station pressure · annual mean	92.0 kPa · 3.0 °C
Output at July design vs ISO rating	100% → 100 MW from 100 MW rated; 100 MW rated for 100 MW net (costed only when the plant is sized up for July heat)
Output at the annual mean	100%; energy uses 100% (capped at the load)

Output loss per °C above 40 °C: **0.4 %**

Method: note 11, Notes on method.

REPORTED RAW GAS NEAR THE SITE, BY OPERATOR NAME

Operator	MMcf/d, raw
CANADIAN NATURAL RESOURCES LIMITED	233.0

Method: note 12, Notes on method.

CONNECTION

Lateral to: **nearest sales-gas line: NGTL System, about 1 km** Diameter: **4 in** Cost: **224,785 C$/inch-km**

Meter station: **0 C$**

Method: note 13, Notes on method.

Grid-connected: tie to 138/144 kV, a T-tap onto line 7L199, 0.8 km (nearest substation Fox Creek 741S, 3.4 km)

Tie voltage: **138/144 kV: Fox Creek 741S, 3.4 km** Direct connection: **83.47 C$/kW** Extra line: **426,173 C$/km**

Extra substation: **0 C$**

Method: note 14, Notes on method.

Method: note 15, Notes on method.

Pipeline lateral	1.2 km route (1.1 km straight line × 1.12 measured routing factor; the straight line is approximate, measured to a CER route generalized to a few km) × NPS 4 × 224,785 C$/inch-km = C$1.1M
Meter station	C$0
Grid tie (138/144 kV, a T-tap onto line 7L199, 0.8 km (nearest substation Fox Creek 741S, 3.4 km))	C$8.3M

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CARBON (TIER)

Method: note 16, Notes on method.

Benchmark: **0.3374 t/MWh** Emission factor: **0.0503 t/GJ (HHV)** Price year: **2029 · C$100/t**

Carbon charge in single years, nominal dollars. The cost of power uses one levelized figure over the life, in constant 2025 C$: 11.5 C$/MWh. The row in use follows the schedule: each year's own benchmark (2029 0.3374, 2035 0.3165, 2040 0.2991 t/MWh).

If the benchmark is	Charged t/MWh	C$/MWh 2029, nominal	C$/MWh 2035, nominal	C$/MWh 2040, nominal
0.3374 t/MWh in 2029, falling by the schedule (in use)	**0.091 in 2029**	**9.1**	**14.6**	**18.1**
0.30 t/MWh	0.129	12.9	16.7	18.0
0.20 t/MWh	0.229	22.9	29.7	32.0
0.00 t/MWh (no free allocation)	0.429	42.9	55.7	60.0

Method: note 17, Notes on method.

COST OF POWER

The load is the plant's rated size, the basis of quoted capital costs per kW; energy takes the annual-mean output and on a July design day the plant delivers about 100 MW.

Gas: **1.78 C$/GJ** WACC, after tax, nominal: **9.7 %** Life: **20 yrs** First year of operation: **2029**

Method: note 18, Notes on method.

ALL-IN COST OF ON-SITE POWER, LEVELIZED OVER 20 YEARS FROM 2029 · CONSTANT 2025 C$, REAL DISCOUNT RATE 7.55%

67–108 C$/MWH

Method: note 19, Notes on method.

The levelized cost is the constant price of power, in 2025 dollars, at which this plant recovers its costs at the 7.55% real rate over 20 years: power bought for less over the life costs less than the plant, for more costs more.

BREAKDOWN AT TODAY'S GAS PRICE HELD FLAT (BELOW THE RANGE ABOVE, WHICH USES THE PUBLISHED OUTLOOKS), C$/MWH · CONSTANT 2025 C$, REAL DISCOUNT RATE 7.55%



Capital	24.2 C$/MWh
Fixed O&M	7.2 C$/MWh
Fuel	15.2 C$/MWh
Variable O&M	5.3 C$/MWh
Carbon (TIER), levelized	11.5 C$/MWh
Installed capacity	100 MW
Capital outlay incl. connection	C$188.2M

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Class 5 range on that outlay (–50% / +100%)	C$94.1M to C$376.5M
Interest during construction	C$10.1M
Capital at first power	C$198.4M

Method: note 20, Notes on method.

BASIS OF ESTIMATE (AACE 34R-05)

Class and method	AACE Class 5, concept screening; the median of the 5 published capital figures for reciprocating engines, each scaled to 100 MW
Dollar basis	constant 2025 C$, real discount rate 7.55%
Included	Plant capital as its sources define it (Appendix A); gas lateral and meter station (C$1.1M); grid tie (C$8.3M); interest during construction (C$10.1M)
Excluded	Land, owner's and development costs and contingency (not included unless you enter them): Kiwetinohk's installed-cost estimate "excludes costs to finance projects"; it does not say whether land, owner's or development costs are in it; transmission system upgrades and the AESO owner's contribution (no planning region found); escalation past 2025 dollars; long-lead equipment premiums
Accuracy on the cost of power	Capital is 24.2 C$/MWh of the case; at the Class 5 band's ends it moves the cost of power by –12.1 to +24.2 C$/MWh
Benchmarks	5 published capital figures for reciprocating engines at this size, C$1,457 to C$2,344/kW before interest during construction (listed above); the median rule misses a plant's own cost by 21% on average in a back-test on 15 Canadian plants

PLANT TYPES AT THIS SITE, AT THE DEFAULTS · CONSTANT 2025 C$, REAL DISCOUNT RATE 7.55%

Plant (preset order)	Heat rate GJ/MWh	Capital C$/kW	Cost of power C$/MWh
Combined cycle, Alberta (Cascade, 2020 cost)	7.03	5,989	71–167
Combined cycle, Alberta (Greenlight)	7.03	5,989	71–167
Reciprocating engines, Alberta (Bitdeer Fox Creek) (this case)	**8.52**	**1,788**	**67–108**
Combined cycle, AESO reference plant (CONE 2018, 1x1 SGT6-8000H)	7.03	5,989	71–167
Aeroderivative turbines, AESO reference plant (CONE 2018, 2× LM6000)	9.68	3,164	78–140
Industrial frame turbine, AESO reference plant (CONE 2018, SGT6-5000F)	10.06	1,682	70–116
Combined cycle, CER agency assumption (Canada's Energy Future 2026, Alberta)	7.03	5,989	74–170
Simple-cycle gas turbine, CER agency assumption (Canada's Energy Future 2026, Alberta)	9.68	3,164	81–143
Combined cycle, AESO 2024 Long-Term Outlook reference (MSA net revenue, 418 MW)	7.11	5,989	69–165
Simple cycle, AESO 2024 Long-Term Outlook reference (MSA net revenue, 47 MW)	10.37	3,164	81–145

Method: note 21, Notes on method.

WHAT MOVES THE COST OF POWER

ONE INPUT AT A TIME, LEVELIZED C$/MWH · CONSTANT 2025 C$, REAL DISCOUNT RATE 7.55%

Method: note 22, Notes on method.

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INPUT · LOW TO HIGH · RANGE BASIS	57.4 — 63.4 — 101.0	C$/MWH LOW / HIGH
Gas price, levelized over the life [1] C$1.78/GJ to C$6.19/GJ		63.4 / 101.0
Heat rate (HHV) [2] 7.65 GJ/MWh to 12.42 GJ/MWh		57.4 / 90.4
Plant capital [3] C$1,457/kW to C$2,344/kW		59.2 / 70.6
Cost of capital (WACC), after tax, nominal [4] 8.1% to 11.7%		60.7 / 67.0
Economic life [5] 15 years to 25 years		67.1 / 61.3
Variable O&M [6] C$5.31/MWh to C$10.83/MWh		63.4 / 68.9
Fixed O&M [7] C$29.26/kW-yr to C$70.03/kW-yr		59.8 / 64.9
Availability [8] 86.5% to 97.5%		65.4 / 61.7
Grid connection cost [9] C$5.9M to C$31.9M		63.1 / 66.3
Carbon price path (TIER) [10] C$95/t held from 2026 to the published TIER path, C$140/t in 2040, held to 2048		60.5 / 63.4
Lateral length (route) [11] 1.1 km to 3.7 km		63.4 / 63.7
Restatement to 2025 C$ [12] construction index only to equipment index only		59.0 / 59.2
Lateral cost per inch-km [13] C$158,246/inch-km to C$393,732/inch-km		63.4 / 63.5

Method: note 23, Notes on method.

Method: note 24, Notes on method.

Compare with: **TC Energy Cal-2027 flat forward, indicative as of 2026-11-03 · 49.75 C$/MWh**

Method: note 25, Notes on method.

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OVER THE PROJECT LIFE: PUBLISHED CANADIAN GAS PRICE SCENARIOS

Scenario	Gas 2029, 2025 C$/GJ	Levelized gas, 2025 C$/GJ	All-in, 2025 C$/MWh
CER EF2026 Canada Net-zero	3.87	3.82	81
CER EF2026 Current Measures	4.04	4.44	86
CER EF2026 Higher	5.44	6.19	101
CER EF2026 Lower	2.62	2.67	71
Sensitivity: gas at the Oct 2025–Sep 2026 mean (as of 2026-09), held flat	1.78	1.78	63
PARTIAL COVERAGE · NOT COMPARABLE			
AER ST98-2026 AECO-C · 2029–2035 only (7 of 20 y)	3.10	3.18	74

Method: note 26, Notes on method.

PERMIT PATH

Grid-connected

Grid-connected, air cooling; Data-centre load assumed equal to plant size. The grid setting is the one the regulatory path uses.

Step at 100 MW plant	Typical duration
AUC power plant approval 10 MW or more: full application. Notify within 2,000 m and consult in person within 800 m of the project boundary; the municipal engagement form goes to the municipality at least 30 days before filing.	Performance targets after a complete application: about 120 days with no objections (90 + 30 days) to about 295 days with a full hearing (205 + 90 days)
Approval life Construction must finish within the period the approval sets, at most seven years from the initial approval; after that, a new application. Smaller plants get the period they propose.	7 years maximum
EPEA approval (Alberta Environment and Protected Areas) A thermal power plant over 1 MW needs an approval; there is no code-of-practice route. Emergency-only backup units not connected to the distribution system, up to 50 MW, are excluded.	No published service standard
Environmental impact assessment · does not apply Not on the mandatory list for gas-fired plants (mandatory only for thermal plants on non-gaseous fuel at 100 MW or more). The Director can still require further assessment of an activity that is not mandatory, weighing its location, size, nature, technology, public concerns and similar activities nearby, and then order a full report; the Minister can order one regardless. The EPEA approval cannot issue until Division 1 has been complied with where it applies.	Not published; 30 days for statements of concern after notice of a further-assessment decision
Federal impact assessment (IAAC) · does not apply Fossil-fuel power plants are no longer designated projects: SOR/2026-185, in force 2026-09-03, repealed the 200 MW item and the expansion item of the Physical Activities Regulations, and the federal government says these plants are assessed under provincial processes. Greenlight (1,864 MW) and Beacon Heartland (920 MW) were screened before the repeal; the Agency decided no further assessment was required for either.	—

First 5 of 13 rows. The full table is Appendix A1.

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Time to power. About 3.1 years (behind-the-fence) to 4.2 years (connection project): the AESO's average durations for Stages 0–2 and Stage 3/4 (April 2026) added end to end; the 1.5-year plant build runs within them. A sum of published averages, not a schedule: steps overlap, and the EPEA approval, municipal permit and long-lead equipment have no published durations.

Published durations run from a complete application; steps can overlap. Municipal development permits and Crown land dispositions are not listed.

Forward scenarios: CER EF2026 (OGL–Canada), EIA AEO2026 (public domain), AER ST98-2026, AESO project list 2026-11-03, Canada–Alberta TIER agreement (manual table) (2026-11-03); ECCC CWEEDS 2020 hourly engineering weather, Alberta, station records 1998–2017 (OGL–Canada) (2022-07-13); Alberta Municipal Affairs, municipal financial and statistical data: 2026 tax rates (MR) and equalized assessment (EA) (2026-11-05); AESO CONE 2018 and Alberta project filings, constant 2025 C$; the analyst's inputs · as of 2026-11-19 · saved 2026-11-19

FUEL GAS ON AN ENERGY BASIS · TOWN OF FOX CREEK 54.4000,-116.8000

Plant	100 MW at 42.2% HHV; heat rate 8.52 GJ/MWh HHV; 20-year life
Energy basis for the year and life	806 GWh a year, the sizing section's energy: 100 MW × 8,760 run hours × 92.0% availability × 100% ambient output
Local heating value	44.1 GJ/10^3m^3 at PGI Kaybob Amalgamated, 7.2 km (Petrinex energy over volume, Sep 2026); raw-gas heating value can exceed sales-gas heating value.

Fuel gas	At 1,055 GJ/MMcf (37.26 GJ/10^3m^3)	At local 44.1 GJ/10^3m^3
Peak at full load, GJ/h	852	852
Peak day at full load, GJ/d	20,453	20,453
Peak at full load, Sm^3/h	22,874	19,324
Peak day at full load, $10^3m^3/d$	549.0	463.8
Peak day at full load, MMcf/d	19.39	16.38
A year at the sizing energy, GJ	6,868,050	6,868,050
Life of project at the sizing energy (20 y), Bcf	130.2	110.0
Life of project at the sizing energy (20 y), 10^6m^3	3,687	3,115
Ceiling: a year at full load (8,760 h, no outages), GJ	7,465,272	7,465,272

η(HHV) = η(LHV) ÷ r when the efficiency is LHV. Peak GJ/h = MW × 3.6 ÷ η(HHV); GJ/d = 24 × GJ/h; GJ/yr = MWh a year × 3.6 ÷ η(HHV), the same energy as the sizing section (MW × run hours × availability × ambient output); at full load, GJ/yr = GJ/h × 8,760. 10^3 m^3/d = GJ/d ÷ HV; Sm^3/h = GJ/h ÷ HV × 1,000; MMcf/d = 10^3 m^3/d ÷ 28.3168 (at the convention, GJ/d ÷ 1,055). Life Bcf = GJ/yr × years ÷ 1,055 ÷ 10^6 × 1,000 at the convention; 10^6 m^3 = GJ/yr × years ÷ HV ÷ 1,000. r is the HHV/LHV ratio (1.108 by default; methane 1.109). Sm^3 at 15 °C and 101.325 kPa. Peak rows are full load before any ambient derate; the yearly and life rows use the sizing section's energy (availability and ambient output applied), so they match the fuel cost and emissions there; the ceiling row is full load all 8,760 hours. Worked example: the Cascade Power Project, Project Description, IAAC 80166, January 2019 describes a 900 MW combined cycle at "over 58%" net efficiency using "up to 150,000 GJ/day"; read as LHV, 900 × 24 × 3.6 ÷ (0.58 ÷ 1.108) = 148,548 GJ/d, 1.0% under the filing; read as HHV it gives 134,069 GJ/d, 10.6% under.

AER ST50A gas processing plants (licensed capacity) with Petrinex plant receipts (capacity 2026-11-10; receipts 2026-09); heating value from Petrinex reported energy over volume; Cascade Power Project description (IAAC 80166, 2019); the analyst's sizing inputs. · as of capacity 2026-11-10; receipts 2026-09 · saved 2026-11-19

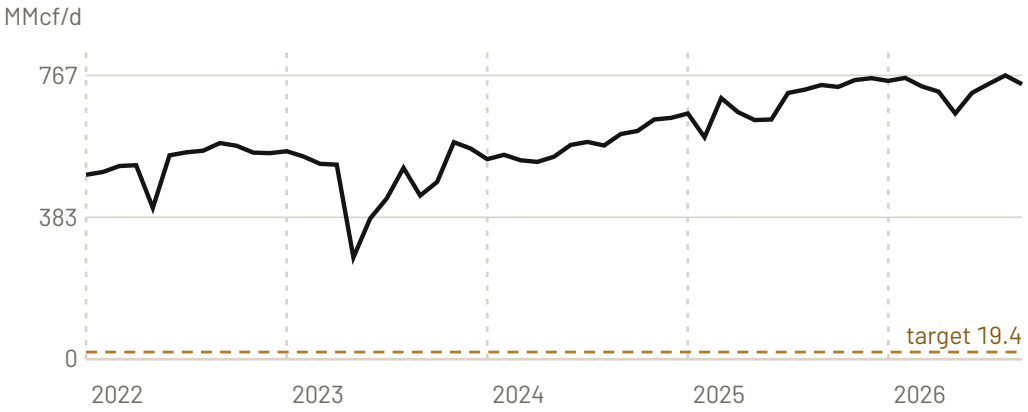
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GAS SUPPLY

Gas reported within 25 km, Sep 2026	743.2 MMcf/d
Facilities reporting gas · stopped since Jun 2024	201 · 62
Gas at the stopped facilities in Jun 2024	50.6 MMcf/d
Suspended gas wells	383

GAS OVER TIME

Monthly raw gas reported by facilities within 25 km, Jan 2022 to Sep 2026.



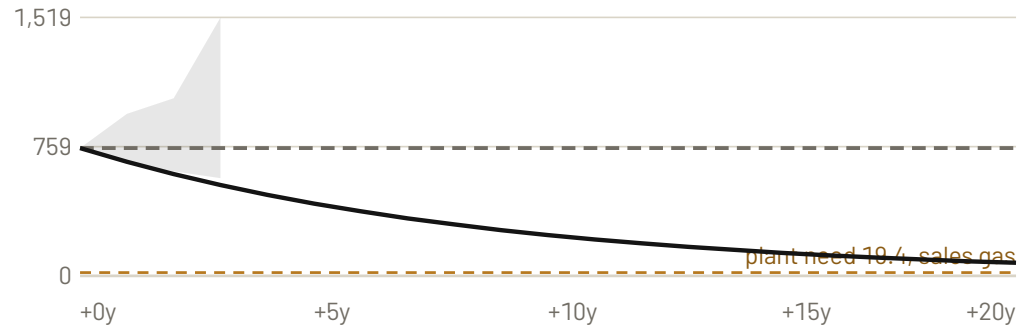
Last 3 months, average	751.3 MMcf/d
Change on a year earlier	+3%
Fitted trend, last 24 months	10% a year growth
Facilities up / flat / down over 12 months	64 / 44 / 120

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PLANT NEED AGAINST LOCAL PRODUCTION

Method: note 27, Notes on method.

MMcf/d · solid: existing base · dashed: recent trend · band: back-tested trend range, to 3 y



Existing-base decline	11% a year measured on facilities producing since Jan 2022 (53% of today's volume), recent wells tied into them included
Recent trend, all facilities	growing; held flat
Plant need as share of local gas, base path: today / +5 / +10 / +20 y	2.6% / 4.6% / 8.1% / 25%
Plant need as share of local gas, trend path: today / +5 / +10 / +20 y	2.6% / 2.6% / 2.6% / 2.6%
Base path: first year need reaches 25% of local gas	+20 y

Year	Trend path, MMcf/d	Back-tested range	Base path	Back-tested range
+1	751.3	657.1–951.4	670.3	602.1–917.5
+2	751.3	614.5–1,044.2	598.0	530.6–1,015.8
+3	751.3	573.8–1,518.7	533.5	469.1–1,284.7

In back-tests over 90 Alberta areas, the trend path's 3-year forecast fell between –51% and +31% of actual 8 times in 10. In back-tests over 61 Alberta areas, the base path's 3-year forecast fell between –58% and +14% of actual 8 times in 10. The range columns apply each method's 10th and 90th percentile miss at 1, 2 and 3 years to the figure beside them. Back-test: 97 areas of 25 km (circles about 50 km apart, each reporting at least 5 MMcf/d at the start), forecasts from 6 start months (2023-06 to 2025-09) on data to that month only, compared with the three months ending 1, 2 and 3 years later (Petrinex, 2022-01 to 2026-09). The public window is the current year plus four, so nothing past 3 years is back-tested and later years carry no stated range.

This area's own record, by the same test: the trend path fitted at each past start date on data to that date only, against what these facilities reported 1 to 3 years later. Its forecasts missed by –63% to –3% (12 forecasts from 6 start dates). That is too few forecasts for a range of its own; the range above pools every tested area of the province.

Start	+1 year	+2 years	+3 years
2023-06	–38%	–54%	–63%
2023-09	–30%	–50%	–57%
2024-03	–19%	–31%	–

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Start	+1 year	+2 years	+3 years
2024-09	−19%	−21%	—
2025-03	−12%	—	—
2025-09	−3%	—	—

Miss = forecast ÷ what was reported − 1 (negative: the forecast was low).

Arithmetic on reported volumes, not a reserves estimate. The base path assumes no new wells anywhere in the radius; wells tied into existing batteries are counted as existing, which understates base decline. Producers dedicate supply by contract, not by share of an area.

The trend line is an extrapolation of reported volumes, not a reserves or production forecast. New wells can reverse an area decline within months.

GAS THE CATCHMENT OF PGI KAYBOB AMALGAMATED WOULD SEND IT

Method: note 28, Notes on method.

Year	Central path, MMcf/d	Back-tested range	No new wells	Back-tested range
0 (Sep 2026)	187.9	fitted start, no range	186.5	fitted start, no range
+1	191.7	164.9–234.2	138.1	117.3–169.9
+3	198.6	144.1–350.4	93.7	61.3–161.2
+5	201.6	not back-tested	69.9	not back-tested
+10	204.9	not back-tested	39.0	not back-tested
+20	207.8	not back-tested	14.0	not back-tested

First year the central path falls below the plant need (19.4 MMcf/d of sales gas)	not within 20 years

Plant need: 19.4 MMcf/d of sales gas: a 100 MW plant (Reciprocating engines, Alberta (Bitdeer Fox Creek)) at 42.2% efficiency, higher heating value (HHV), at full load, converted at 1,055 GJ/MMcf (a sales-gas heating value; raw gas at the wellhead is larger by the processing shrink).

In back-tests over 90 Alberta areas, the central path's 3-year forecast fell between −43% and +38% of actual 8 times in 10. In back-tests over 90 Alberta areas, the no-new-wells path's 3-year forecast fell between −42% and +53% of what the base and the wells already producing at the start then reported 8 times in 10. The range columns apply each method's 10th and 90th percentile miss at 1, 2 and 3 years to the figure beside them. Back-test: 97 areas of 25 km (circles about 50 km apart, each reporting at least 5 MMcf/d at the start), forecasts from 6 start months (2023-06 to 2025-09) on data to that month only, compared with the three months ending 1, 2 and 3 years later (Petrinex, 2022-01 to 2026-09). The public window is the current year plus four, so nothing past 3 years is back-tested and later years carry no stated range.

Raw gas at the batteries, not sales gas.

WELLS BY STATUS WITHIN 25 KM

Wells within 25 km	3,321 wells · 3,865 well events, as of 2026-11-10

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Suspended, all fluids	663
Drilled, no production reported	152
Abandoned now · Petrinex Well Infrastructure, current status as of 2026-11-10 · within 25 km · within 1 km of the point	671 · 1
Flagged orphan	10

WELLS BY STATUS

Status	Wells	Latest status date
Flowing, pumping or on gas lift	1,578	2026-11-08
Suspended	663	2026-11-01
Drilled and cased, not completed	100	2026-10-24
Testing, completing or closed	34	2026-10-24
Injection, disposal, thermal, observation and other service wells	47	2026-07-13
Zone abandoned (other zones may produce)	142	2026-01-20
Abandoned	671	2026-08-12
No status yet (licensed or spudded, or a leg)	86	2026-11-06

One count per well: a well with several events (legs, re-entries, zones) counts once, under its most active event. Zone abandoned means one zone was sealed off; the well may produce from another. This count: Petrinex Well Infrastructure current status as of 2026-11-10, one count per well, abandoned only when no event of the well is left open (a whipstocked leg under a suspended sidetrack is a suspended well), placed at the legal subdivision centre of the well id (bottom hole for a horizontal). Abandoned wells under Ground and land use: the AER abandoned-well map, wells abandoned by its date under their licence status then (reclaimed and re-entered wells included, later abandonments missing), at the AER's own locations; the Directive 079 block: Well Infrastructure abandoned status under the same one-per-well rule, placed at the AER ST37 surveyed surface hole. The counts differ by source and date, which statuses count, and where each well is placed (a well near 1 km can fall either side).

EVERY PRODUCING WELL WITHIN 25 KM, ANY AGE

Wells reporting production since Jan 2022	1,690
Producing in the last three months to Sep 2026 · quiet for over a year	1,424 · 183
Share of the latest full year's gas from wells already producing in 2022	42%

Year	Gas, MMcf/d average	Oil and condensate, bbl/d average
2022	504.8	8,647

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Year	Gas, MMcf/d average	Oil and condensate, bbl/d average
2023	451.1	7,728
2024	532.5	13,815
2025	654.6	11,561
2026 (to Sep 2026)	690.0	8,944

OPERATORS OF THE BATTERIES THESE WELLS REPORTED TO SINCE JAN 2022, GAS OR OIL

25 operators of every battery these wells reported to, within 25 km or not, gas or oil, in any month. The count of operators reporting gas (evidence matrix, map inspector) takes only batteries within 25 km that reported gas in the latest month.

Operator	Wells
ALPHABOW ENERGY LTD.	6
ATHABASCA OIL CORPORATION	3
BENCH CREEK RESOURCES LTD.	1
CANADIAN NATURAL RESOURCES LIMITED	315
CHEVRON CANADA LIMITED	3

First 5 of 20 rows. The full table is Appendix A2.

5 more operators, alphabetically after these.

Petrinex well production rows, Jan 2022 to Sep 2026 (the public record starts in January 2022). A well is placed at its well id's legal subdivision, which for a horizontal well is the bottom hole. Operators are those of the reporting battery. Volumes as reported; recent months can still be amended.

Petrinex public volumetric data (Alberta); locations from AER ST102 (2026-09); Petrinex Well Infrastructure (Alberta) (2026-11-10); Petrinex public Well Infrastructure (Alberta) (2026-11-10); Petrinex public volumetric data: every producing well since 2022 (2026-09) · as of 2026-09 · saved 2026-11-19

GAS TRANSPORT

NEAREST GAS PIPELINES

Size class	Licensee	Diameter mm	MAOP kPa	Licensed	H2S mol/kmol	km
406 mm and up	PGI Processing ULC Licence line 45728-1	406.4	8,960	1996	0	7.5
219 to 406 mm	Paramount Resources Ltd. (sour) Licence line 52198-7	323.9	9,930	2011	60	1.1
114 to 218 mm	Paramount Resources Ltd. Licence line 9285-11	114.3	6,890	2007	0	1.2

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Operating natural gas lines only. Licensed: the year the AER first licensed the segment, kept when the licence is transferred. H2S: the H2S content of the gas the AER records for the segment; the AER calls natural gas sour above 10 mol/kmol (Enhanced Pipeline Graphics File layout, June 2025).

Nearest federally regulated gas line: Alliance Pipeline 1.1 km (Alliance Pipeline Ltd.); CER system map, route generalized to a few km. Gas for the cost under Sizing and cost: nearest sales-gas line (NGTL System), about 1 km, to a CER route generalized to a few km; Alliance carries liquids-rich gas, not sales-spec gas, so it is not used. Line size and pressure are public; available capacity at a tie-in is not.

GAS PLANTS WITHIN 50 KM

Method: note 29, Notes on method.

Plant	km	Licensed	Received	Used
PGI Kaybob Amalgamated also listed as ABGP0001120 under licence F13874 · Pembina Gas Infrastructure Inc. · Gas plant, sulphur recovery · licensed H2S 7.3% · 44.1 GJ/e3m3	7	395	185	47%
DUVERNAY SWEETENING PLANT Pembina Gas Infrastructure Inc. · Gas plant, acid gas flaring (under 1 t/d sulphur) · licensed H2S 0.01%	9	299	286	96%
DUVERNAY KAYBOB COMPLEX Pembina Gas Infrastructure Inc. · Gas plant, sweet · no licensed sulphur · 44.0 GJ/e3m3	9	358	329	92%
TRILOGY KAYBOB Paramount Resources Ltd. · Gas plant, acid gas flaring (over 1 t/d sulphur) · licensed H2S 0.62% · 42.6 GJ/e3m3	14	211	71	34%
ARCHEAN KAYBOB SOUTH Sinopec Canada Energy Ltd. · Gas plant, sweet · no licensed sulphur	14	8	—	—
KAYBOB 7-32-63-20w5 Canadian Natural Resources Limited · Gas plant, sweet · no licensed sulphur	16	6	—	—
00/05-36-061-18W5 Fox Creek Sinopec Canada Energy Ltd. · Gas plant, AER subtype sweet; the facility licence states H2S 0.2%	17	12	—	—
PGI West Fox Creek 11-22 Pembina Gas Infrastructure Inc. · Gas plant, sweet · no licensed sulphur	21	16	—	—
PCC Simonette 15-31-62-21w5 GP Petrochina Duvernay Gas Partnership · Gas plant, sweet · no licensed sulphur · 43.1 GJ/e3m3	22	110	79	72%
KAYBOB S. 11-19-60-19w5 Canadian Natural Resources Limited · Gas plant, sweet · no licensed sulphur · 41.6 GJ/e3m3	22	6	2	30%
DEVON CLOVER 9-34 PLANT #1 Paramount Resources Ltd. · Gas plant, sweet · no licensed sulphur	22	8	—	—
TRILOGY CLOVER 9-34 PLANT #2 Paramount Resources Ltd. · Gas plant, sweet · no licensed sulphur · 42.3 GJ/e3m3	22	18	3	19%

Showing the nearest 12 of 31.

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LICENSED DESIGN OF THESE PLANTS · AER ST50A, AS OF OCT 30, 2026

Plant	Raw gas	Sales gas · shrink	Liquids, m^3/d	Processing
PGI Kaybob Amalgamated	394.8	320.0 · implied shrink 19%	C3 307 · C4 207 · LPG mix 2,300 · C5+ 3,324	propane-plus liquids recovery, no ethane (shallower cut, typically refrigeration); sour, sulphur recovery (Claus, Sulfreen) and acid gas injected regenerative sweetening; acid gas injected underground; acid gas to sulphur recovery; acid gas flared or incinerated; Claus sulphur recovery process; Sulfreen sulphur recovery process · 1,090 of 1,107.70 t/d inlet recovered; approved recovery efficiency 98.5%
DUVERNAY SWEETENING PLANT	299.0	293.5 · implied shrink 2%	C5+ 7,950	condensate (C5+) recovery only; sour, acid gas flared regenerative sweetening; acid gas flared or incinerated
DUVERNAY KAYBOB COMPLEX	358.2	340.7 · implied shrink 5%	C2 mix 2,922	deep-cut liquids extraction (ethane licensed)
TRILOGY KAYBOB	211.2	203.2 · implied shrink 4%	C2 mix 1,823 · LPG mix 749 · C5+ 1,275	deep-cut liquids extraction (ethane licensed); sour, acid gas injected regenerative sweetening; acid gas injected underground; acid gas flared or incinerated · approved recovery efficiency 95.9%
ARCHEAN KAYBOB SOUTH	8.0	not stated	not stated	liquids not stated
KAYBOB 7-32-63-20w5	6.1	not stated	not stated	liquids not stated
00/05-36-061-18W5 Fox Creek	12.0	12.0 · implied shrink 0%	C3 0.1 · C4 0.2 · C5+ 4.5	condensate (C5+) recovery only; sour, acid gas flared regenerative sweetening; acid gas flared or incinerated
PGI West Fox Creek 11-22	15.7	not stated	not stated	liquids not stated
PCC Simonette 15-31-62-21w5 GP	110.0	96.6 · implied shrink 12%	LPG mix 712 · C5+ 2,118	propane-plus liquids recovery, no ethane (shallower cut, typically refrigeration)
KAYBOB S. 11-19-60-19w5	6.4	5.7 · implied shrink 11%	LPG mix 33	propane-plus liquids recovery, no ethane (shallower cut, typically refrigeration) 0 t/d recovered
DEVON CLOVER 9-34 PLANT #1	8.0	7.5 · implied shrink 5%	C5+ 42	condensate (C5+) recovery only
TRILOGY CLOVER 9-34 PLANT #2	17.7	17.6 · implied shrink 0%	C5+ 54	condensate (C5+) recovery only

Method: note 30, Notes on method.

Method: note 31, Notes on method.

AER Enhanced Pipeline data (provincially licensed lines) (2026-11-10); NRCan CanVec 1:250k pipelines (Open Government Licence - Canada) (mapped 1974-1994); Canada Energy Regulator pipeline systems (federally regulated gas lines: NGTL, Alliance, Foothills, TC Mainline, Enbridge BC) (CER service data edited 2024-11-12; downloaded 2026-11-10); AER ST50A gas processing plants (licensed capacity) with Petrinex plant receipts (capacity 2026-11-10; receipts 2026-09); Canada Energy Regulator pipeline throughput and capacity (NGTL, Alliance, Foothills), Open Government Licence - Canada (2026-06) · as of 2026-11-10 · saved 2026-11-19

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POWER AND GRID

Nearest 240 kV and up substation	65.6 km · Little Smoky 813S
Nearest 138/144 kV substation	3.4 km · Fox Creek 741S
Nearest 240 kV line · 138/144 kV line	34.0 km · 0.8 km
Substation the sizing ties to (100 MW plant)	138/144 kV · a T-tap onto line 7L199, 0.8 km (nearest substation Fox Creek 741S, 3.4 km) Screening assumption, an input: a plant under 200 MW is tied to the nearest 138/144 kV substation, 200 MW and up to the nearest 240 kV and up. Basis: the nearest public precedent, Kiwetinohk's Opal power plant near Fox Creek (101 MW of gas engines), connects through a new 1.3 km 144 kV line from its Gemini 1008S substation to ATCO line 7L199 (AUC Decision 28658-D01-2024, 2024-02-23; plant approved in Decision 27293-D01-2022). The tie runs to the band's nearest substation, or taps the band's nearest line where that is more than 0.1 km nearer, as Opal does. The 200 MW split is PatchWatt's screening assumption, not an AESO rule; the voltage, substation and route are set in the AESO's connection studies.
Connection capacity at these points	▨ Not public

GRID CONNECTION QUEUE: FOX CREEK PLANNING AREA

AESO planning area 24 (Fox Creek, Northwest region): 5 projects asking for 121.8 MW of supply (121.8 MW gas or cogeneration) and 12.4 MW of demand (0 MW data-centre load).

Not in these totals: one project the list codes to another planning area but the AESO maps inside Fox Creek: P3304 Ohm Phi MPC Gas (Gas, 400 MW supply, 1 MW demand; coded Valleyview).

Project	Status	Stage	Supply MW	Demand MW
P3290 Benbow 397S DER Gas Gas · Cluster · NW-03 · in service 2029-01-01	Cluster 3	1	23.3	0
P3140 Chevron Kaybob 551S Contract Change Salvage/Decommission · Contract · in service 2026-09-30	Recently Energized	6	0	0
P3141 Opal Data Load Data Load · BTF · in service 2027-08-06	Active	1	0	0
P2456 Opal Gas Gas · Connection · in service 2027-07-30	Active	5	98.5	0.4
P3200 South Kaybob Industrial Load Industrial Load · BTF · in service 2026-10-14	Recently Energized	6	0	12

`Method: note 32, Notes on method.`

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POWER PLANTS WITHIN 50 KM

None listed by NACEI in this radius. The AESO generator list has 1 gas-fired asset within 50 km, 33 MW of maximum capability. Nearest gas-fired unit in the AESO generator list: Kaybob 3 Cogen South, 35 km, 33 MW maximum capability.

The two lists are separate records (gas-fired: none in NACEI; 1 in the AESO list, 33 MW). NACEI carries nameplate capacity as of 2012 to 2017 and lacks later builds and conversions; the AESO figure is each grid-connected asset's maximum capability.

`Method: note 33, Notes on method.`

AESO TRANSMISSION SYSTEM NEAR THE SITE

The AESO's own map of the transmission system, as of 2026-09-16: every substation carries its voltages and planning area.

NEAREST AESO SUBSTATIONS

Substation	kV	Planning area	km
Fox Creek 741S Township 62-19-W5	144	Fox Creek Northwest region	3.4
Muir 2018S Township 62-20-W5	144	Fox Creek Northwest region	11.3
Fox Creek 347S Township 61-18-W5	138	Fox Creek Northwest region	15.1
Goose River 725S Township 66-18-W5	144	Valleyview Northwest region	34.2
Benbow 397S Township 59-18-W5	138	Fox Creek Northwest region	35.2
Chevron Kaybob 551S Township 59-18-W5	138	Fox Creek Northwest region	35.3

Nearest first. Where a substation lists several voltages (for example 69/240), it transforms between them; the highest is the transmission side. Land location is township-range-meridian as the AESO writes it.

AESO LINES WITHIN 25 KM

Voltage	Lines	Nearest line	km
138/144 kV	6	7L199 Fox Creek 347S to Fox Creek 741S · 18.9 km long	0.8

Distance to the nearest point of each line's mapped route (simplified to about 40 m). A line passing near a site says nothing about whether it can take a new connection; that needs an AESO connection study.

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GENERATING UNITS WITHIN 25 KM

None in the AESO list within 25 km; the nearest is Kaybob 3 Cogen South (Cogeneration, 33 MW), 35 km away.

HOW HARD THE NEAREST UNITS RAN

No AESO generating unit is within 25 km of the site. The nearest 3 assets with a metered record in the AESO file: Kaybob 3 Cogen South (35 km), NRGreen (42 km) and Valley View 1 (65 km).

Metered energy as a share of what each asset would make running every hour at its maximum capability, from AESO hourly metering, 2001 to Oct 2026.

Asset	MC MW	2023	2024	2025	2026 Jan–Oct	GWh 2025	km
Kaybob 3 Cogen South KAS1 · Cogeneration (metered net to the grid) · metered from Feb 2026	33	—	—	—	35%	—	35
NRGreen NRG3 · Biomass and Other · metered from Feb 2014	16	5.8%	11%	56%	55%	77.8	42
Valley View 1 VVW1 · Simple Cycle · metered from Nov 2001	50	2.9%	2.6%	4.7%	12%	20.8	65

One row per AESO asset ID, nearest first; an asset with several units on the map is one row. Capacity factor is metered MWh divided by maximum capability times the hours counted. * marks a year the asset metered only part of (its first year, or a long gap). A dash means no metered hours that year.

YEAR BY YEAR: Kaybob 3 Cogen South (KAS1)

Kaybob 3 Cogen South has no metered hours in 2025; maximum capability 33 MW (AESO, 2026-09-16).

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026		0.1%	3.4%	34%	36%	36%	33%	55%	56%	48%		

Monthly capacity factor, Nov 2023 to Oct 2026. Blank cells fall outside those months.

Year	GWh	Metered hours	Capability MW	Capacity factor
2026 (to Oct)	72.8	6,326	33	35%

Read with care. The series runs to Oct 2026: the AESO data-request files to Jul 2025 (the AESO says April to July 2025 were not final there), then the ETS Metered Volumes (All) report month by month; its recent months are initial metering and can be revised until final settlement. Maximum capability is today's value, so an older year can read high or low if a unit was uprated, derated or rebuilt since; where a year's highest metered hour is more than 10% above today's figure, or a figure would otherwise pass 100%, that hour is taken as the year's capability (†). Industrial cogeneration is metered net to the grid: the plant's own use is not in the figure, so its capacity factor understates what it generates. Hours are counted from each asset's first metered hour; an asset ID that was renamed, split or replaced can break or merge histories.

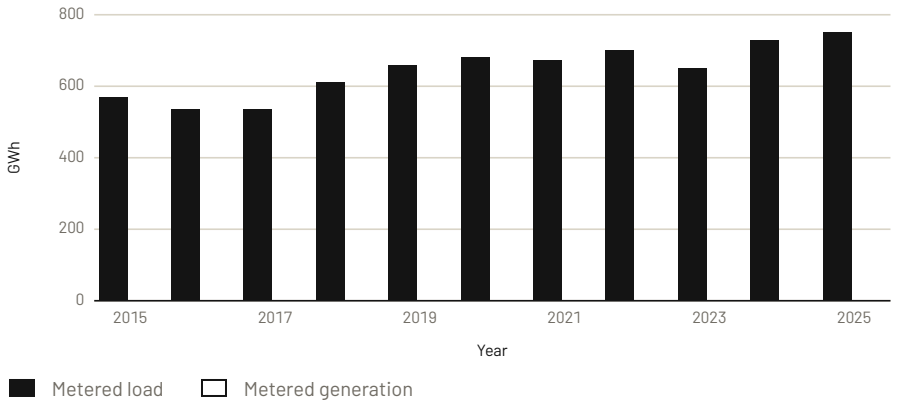
AESO hourly metered volumes by generating asset: data request 2001 to July 2025, then the ETS Metered Volumes (All) report, hourly to 2026-10-31; maximum capability from the AESO transmission system GIS as of 2026-09-16.

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PLANNING AREA 24, FOX CREEK (NORTHWEST REGION)

Metered load and generation in the planning area by calendar year, summed from AESO hourly data, and the hours in which a transmission constraint held generation in the area back (the AESO publishes constraints from 2020).

FOX CREEK PLANNING AREA: LOAD AND GENERATION BY YEAR



Year	Load GWh	Generation GWh	Actual load GWh	Peak hour MW	Constrained MWh	Hours constrained
2015	568	—	568	77	—	—
2016	537	—	537	76	—	—
2017	536	—	536	77	—	—
2018	610	—	610	80	—	—
2019	660	—	660	93	—	—
2020	681	—	681	94	0	0
2021	673	—	673	91	0	0
2022	701	—	701	99	0	0
2023	650	—	650	96	0	0
2024	729	—	729	99	0	0
2025	751	0.0	751	106	0	0

Load is metered load on the grid; generation is metered generation into the grid; actual load adds behind-the-fence generation (the AIL definition). A dash under generation means the AESO file gives no generation value for the area that year (no metered generator in it). Peak hour is the highest hour of actual load. Constrained MWh is energy the AESO held back from units in the area because of transmission limits; supply-surplus curtailment is not included, and a dash means the constraint file does not cover that year. History runs on the 2020 planning-area boundaries.

`Method: note 34, Notes on method.`

Power plants: NACEI North American power plants (NRCan/DOE/SENER, free with acknowledgement) (NACEI 2017); AESO Connection Project List and planning area boundaries (project list 2026-11-03); AESO transmission system GIS: substations (2026-09-16); AESO planning-area hourly load and generation, and constrained MW by planning area and fuel (2025-12-31) · as of 2026-09-16 · saved 2026-11-19

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QUEUE AT THE SUBSTATIONS

What else is asking to connect at the three nearest AESO substations of 138 kV and up, from the AESO list of 2026-11-03. A project is placed at a substation when the point the AESO maps it at lies within 1 km of it.

FOX CREEK 741S, 144 KV, 3.4 KM

Planning area Fox Creek · Northwest region · township 62-19-W5

No live project on the AESO list is attributed here.

MUIR 2018S, 144 KV, 11.3 KM

Planning area Fox Creek · Northwest region · township 62-20-W5

No live project on the AESO list is attributed here.

FOX CREEK 347S, 138 KV, 15.1 KM

Planning area Fox Creek · Northwest region · township 61-18-W5

1 live project: 400 MW of supply (STS) (gas and cogeneration 400) and 1 MW of demand (DTS), of which 0 MW data-centre load; 400 MW gas or cogeneration supply. By stage: 1 at stage 1.

Project	Status	Stage	Supply MW	Demand MW	Months at stage	First listed
P3304 Ohm Phi MPC Gas Gas · Cluster · in service 2029-01-01	Cluster 3	1	400	1	1 since 2026-10	2026-10 2 lists

WITHIN 10 KM OF THE SITE, NOT AT THESE SUBSTATIONS

2 live projects: 98.5 MW of supply (STS) (gas and cogeneration 98.5) and 0.4 MW of demand (DTS), of which 0 MW data-centre load; 98.5 MW gas or cogeneration supply. By stage: 1 at stage 1, 1 at stage 5.

Project	Status	Stage	Supply MW	Demand MW	Months at stage	First listed	km
P2456 Opal Gas Gas · Connection · in service 2027-07-30 · nearest substation 5.3 km, not attributed	Active	5	98.5	0.4	31 since 2024-04	2023-01 or earlier 45 lists	2.5
P3141 Opal Data Load Data Load · BTF · in service 2027-08-06 · nearest substation 5.2 km, not attributed	Active	1	0	0	12 since 2025-11	2025-11 13 lists	2.7

Method. Of the 324 projects on the list of 2026-11, 98 lie within 0.5 km, 122 lie within 1 km, 159 lie within 2 km of an AESO substation; a project is attributed to the nearest substation within 1 km, and a point farther than that from every substation is listed only by its distance to the site. Live means not marked cancelled or withdrawn; cancelled projects are shown in grey and left out of every sum. A project with both supply (STS) and demand (DTS), marked BTF, counts in both columns. Months at stage run from the first monthly list

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showing the project's current stage; "≥" and "or earlier" mark records that reach back to the first list in the history (2023-01). Stages run 0 to 6. These are connection requests, not approvals, and say nothing about capacity left at a substation, which the AESO does not publish.

AESO Connection Project List, 2026-11-03 (project points, list of 2026-11); AESO transmission system GIS (lines, substations, generators), substations as of 2026-09-16; AESO Connection Project List, monthly lists since January 2023 · as of 2026-11-03 · saved 2026-11-19

GAS-FIRED UNITS WITHIN 50 KM

1 gas-fired AESO asset within 50 km, 33 MW of maximum capability counted once each, with how hard each ran in 2023–2025. Listed by name.

Asset	MC MW	CF 2023	CF 2024	CF 2025	Years metered	km
Kaybob 3 Cogen South KAS1 · Cogeneration · PGI Processing ULC	33	–	–	–	1 from Feb 2026	35.5

MC is the AESO maximum capability, counted once per asset: the whole asset when every unit is within 50 km. CF (capacity factor) is metered MWh over capability times the hours counted, from AESO hourly metering. * marks a year metered only in part (a first year or a long gap); † a year whose capability was taken as its highest metered hour, today's figure being lower. A dash means no metered hours that year; years metered counts calendar years with any metered hour, and a dash there means the asset has no record in the AESO file. Cogeneration is metered net to the grid, so its figure leaves out the host's own use. The year-by-year and month-by-month record for each asset is in the transmission-system section above.

AESO transmission system GIS (lines, substations, generators), generators as of 2026-09-16; AESO hourly metered volumes by generating asset: data request 2001 to July 2025, then the ETS Metered Volumes (All) report, hourly to 2026-10-31; maximum capability as of 2026-09-16.

AESO transmission system GIS (lines, substations, generators), generators as of 2026-09-16; AESO hourly metered volumes by generating asset: data request 2001 to July 2025, then the ETS Metered Volumes (All) report, hourly to 2026-10-31 · as of 2026-10-31 · saved 2026-11-19

WATER

Basin	Upper Little Smoky (Smoky)
Licensing status	open

Upper Little Smoky (Smoky). Not a closed basin; new licences go through ordinary Water Act review, first in time, first in right.

> Groundwater yield at this point and municipal supply volumes are not in the public data used here; a licence shows what is allocated, not what a new well or intake would get.

NRCan National Hydro Network work units; SSRB closure under Alberta's 2006 water management plan (2021-03-25); Alberta Environment and Protected Areas, Water Act licences (active authorisations) (2026-11-02) · as of 2026-11-02 · saved 2026-11-19

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GROUND AND LAND USE

GROUND AND CONSTRAINTS

The basis is each line's H2S release level as the AER publishes it and the Directive 056 Table 6 distance it carries (Sour lines and setbacks, below).

EARTHQUAKES	20 recorded within 25 km since 2010, 11 of magnitude 2.5 or more; largest M3.9 on 2019-06-27. 30% are labelled industry-related by NRCan; 6 in the last five years. The AER applies induced-seismicity orders in parts of the Duvernay, including around Fox Creek; check whether one covers this area.
SOUR GAS	Nearest sour pipeline is 52198-7 (Paramount Resources Ltd., sour natural gas, H2S 60 mol/kmol), 1.11 km away; the AER publishes no release level for it. 8 sour segments (H2S above 0) within 2 km, 5 above 10 mol/kmol, the level at which the AER calls gas sour and Table 6 applies, listed with their levels under Sour lines and setbacks. Nearest sour gas plant is PGI Kaybob Amalgamated, 7.2 km.
FLOOD	No flood mapping within 10 km. Only 57 river reaches are mapped, so this is not a finding of no flood risk.

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NOISE

ASSUMED: BUILDINGS ≈ HOMES

941 buildings within 1.5 km, of which 12 tagged as dwellings, 0 tagged as non-dwellings (farm, industrial, commercial or outbuildings), the rest (929) untagged or not settled by their tag; untagged buildings are treated as possible dwellings, as the noise impact assessment Rule 007 asks for (TP31, under Rule 012) surveys receptors on the ground; 662 of them are OpenStreetMap buildings, which can carry a use tag, and 279 Microsoft footprints of about 2019, which carry none. Nearest building-grid cell about 190 m away, measured to the centre of the nearest building-grid cell: buildings are counted in cells of about 280 m, not mapped one by one, so the nearest building may be up to about 200 m nearer or farther. Nighttime permissible sound level 45 dBA, daytime 55 dBA, assumed ambient 40 dBA, set by the possible dwellings about 1,240 m away (a building-grid cell), with 6 possible dwellings within 451 m of them: Table 1 column 1 to 8 dwellings, category 2; Table 1 takes each dwelling's own density, and the strictest receptor within 1.5 km sets the limit (AUC Rule 012 Table 1, **30–500 m from one**). Category 2: dwellings more than 30 m but less than 500 m from heavily travelled roads or rail lines and not subject to frequent aircraft flyovers: 173 buildings within 451 m of the point (a quarter section), above the 160 per quarter section where Rule 012 Table 1's denser columns start, so category 2 is used, taking town dwellings to be within 500 m of a heavily travelled road; no traffic map is in the data. The limit itself takes each dwelling's own density (451 m around it, Table 1 note 4), so a dwelling at the edge of town can set a lower one. Buildings tagged as non-dwellings are left out of the receptors and the density; every other building stands in for a dwelling, which overcounts them; measured from the site point, not a plant boundary. Buildings of 40 m^2 and larger from Overture Maps release 2026-10-21.0 (about two thirds from OpenStreetMap, the rest Microsoft footprints from imagery of about 2019), counted in cells of about 280 m. Buildings OpenStreetMap tags as farm, industrial, commercial or outbuildings are counted apart from those it tags as dwellings; most rural buildings carry no tag and are counted as possible dwellings, sheds and barns included; dwellings filed in a project's noise study may differ. © OpenStreetMap contributors, Microsoft, Overture Maps Foundation (ODbL).

WETLANDS

LIVE QUERY · RESTRICTED LICENCE

The site point is not in a mapped wetland. Within about 1 km: Swamp 23, Open Water 4, Fen 3 polygons. Disturbing a wetland needs a Water Act approval under the Alberta Wetland Policy: avoid, minimize, then replace, with replacement set by wetland value class. Alberta Merged Wetland Inventory, queried live; Government of Alberta copyright, not for commercial reuse without permission.

FIBRE

PROXY, NOT A ROUTE

No ISED hex within 25 km reports high-capacity transport; nearest about 78 km (Shaw). Presence proxy from ISP-reported hexes of about 25 km^2 (ISED National Broadband Data, 2026-05-05); no public fibre route map exists for Alberta, so this is not a distance to a cable.

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ABANDONED WELLS DATA TO JAN 2025	554 within 25 km on the AER abandoned-well map, 1 within 1 km; nearest about 760 m (RecExempt). Abandoned 265, RecCertified 167, RecExempt 110, other statuses 12. Directive 079 forbids structures within 5 m of an abandoned well (wells under 150 m deep exempt) and asks for an access route. This count: the AER abandoned-well map to 2025-01-30, locations revised 2026-11-03, wells abandoned by its date under their licence status then (reclaimed and re-entered wells included, later abandonments missing), at the AER's own locations. Wells by status under Gas supply: Petrinex Well Infrastructure current status, one count per well, abandoned only when no event of the well is left open (a whipstocked leg under a suspended sidetrack is a suspended well), placed at the legal subdivision centre of the well id (bottom hole for a horizontal); the Directive 079 block: Well Infrastructure abandoned status under the same one-per-well rule, placed at the AER ST37 surveyed surface hole. The counts differ by source and date, which statuses count, and where each well is placed (a well near 1 km can fall either side).
HISTORIC RESOURCES	The site point is not in a listed land unit. HRV 3: 6 · HRV 4: 288 · HRV 5: 306 listed units within 25 km. Nearest HRV 3 about 13.0 km away. Projects that need AUC approval always file a Historical Resources Act application, listed or not (Listing instructions, 2023-09). Listing of Historic Resources, Fall 2026.
WILDLIFE	Not inside a caribou range; nearest is Little Smoky, about 35 km away.
PROTECTED	Not inside a protected area; nearest is Iosegun Lake Provincial Recreation Area (Provincial Recreation Area, IUCN category not reported; designated by OC 603/2006 of 2006-11-22), about 6 km away. 3 within 25 km of the point: Provincial Recreation Area 3. Designation, IUCN management category and Order in Council as the Government of Alberta records them (Parks and Protected Areas of Alberta, OGL-Alberta). Provincial parks, wildland parks and recreation areas are designated under the Provincial Parks Act; ecological reserves, natural areas, wilderness areas and heritage rangelands under the Wilderness Areas, Ecological Reserves, Natural Areas and Heritage Rangelands Act.
INDIGENOUS	Treaty 8 (1899) territory. Not inside a reserve or Métis settlement; nearest is Alexander 134A (Alexander First Nation), about 23 km away. Consultation duties are not limited to these lands.

SLOPE AND RELIEF

Elevation at the point	841 m
Relief over 1.4 km square	34 m (812 to 846 m)
Slope, mean · 90th percentile · steepest	3% · 5.2% · 6.1%
Share of the square under 2% · under 5% slope	32.8% · 87.5%

64 cells at 150 m spacing. SRTM 1-arc-second (NASA/USGS, public domain) via the OpenTopoData public API. SRTM includes part of the forest canopy, so slopes under trees read high; a grading survey sets pad earthworks.

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ABANDONED WELLS WITHIN 1 KM (AER DIRECTIVE 079)

1 abandoned well within 1 km by Petrinex Well Infrastructure status, placed at the ST37 surveyed surface hole; nearest 760 m from the point. 1 carries the 5 m setback radius.

Well	Abandoned	Licensee	Total depth	Setback under D079	From point
11-28-062-19W5 100/11-28-062-19W5/00	1970-07-11 N/A · ABAN · reclamation exempt	CHEVRON CANADA LIMITED	2,063 m	5 m radius	760 m

Directive 079 (September 2022): no surface structure may sit on an abandoned well, and a minimum 5 m setback radius around it must be kept; wells drilled and abandoned to less than 150 m need no setback. A municipality may require more, and the directive asks developers to locate each well on the ground, test it, and show its setback on the subdivision or development plan. Wells with only a zone abandoned, or with an abandoned leg beside a suspended or producing one, are not counted here; the setback applies whether or not the site has since been reclaimed. “Orphan” is the orphan-well flag Petrinex carries on the well. This count: Well Infrastructure abandoned status as of 2026-11-10 under the same one-per-well rule, placed at the AER ST37 surveyed surface hole. Wells by status under Gas supply: Petrinex Well Infrastructure current status, one count per well, abandoned only when no event of the well is left open (a whipstocked leg under a suspended sidetrack is a suspended well), placed at the legal subdivision centre of the well id (bottom hole for a horizontal); Abandoned wells under Ground and land use: the AER abandoned-well map, wells abandoned by its date under their licence status then (reclaimed and re-entered wells included, later abandonments missing), at the AER's own locations. The counts differ by source and date, which statuses count, and where each well is placed (a well near 1 km can fall either side).

Status: Petrinex Well Infrastructure. Surface hole and total depth: AER ST37 List of Wells in Alberta, 2026-11-03. Rule: AER Directive 079.

Alberta Flood Hazard Identification Program mapping, Open Government Licence - Alberta (2026-10-09); Earthquakes Canada (NRCan) event catalogue, Open Government Licence - Canada (2026-11-10); Alberta wildlife sensitivity maps: caribou ranges (Government of Alberta; free use, maps not to be redistributed commercially) (2015-06-11); Parks and Protected Areas of Alberta, Alberta Environment and Protected Areas (Open Government Licence - Alberta) (2026-09-21); Alberta First Nations reserves, Métis settlements and treaty areas (Government of Alberta boundary services, Open Government Licence - Alberta) (2026-08-11); AER Abandoned Well spatial data with Revised Abandoned Well Locations (2025-01-30); Alberta Listing of Historic Resources, Fall 2026 (OGL-Alberta) (2026-09-29); Alberta Merged Wetland Inventory, queried live (GoA copyright, all rights reserved) (live); Green/White Area, Alberta Environment and Protected Areas (Open Government Licence - Alberta) (2021-11-16); SRTM terrain · as of 2026-11-19 · saved 2026-11-19

SOUR LINES AND SETBACKS · TOWN OF FOX CREEK 54.4000,-116.8000

8 pipeline segments licensed as sour (H2S above 0) within 2 km of the point, 5 above 10 mol/kmol, the level at which the AER calls gas sour and Table 6 applies: 4 with the H2S release level the AER publishes, 0 with a level read from the published release volume, 4 with neither published. 3 are discontinued; Table 6 still applies to discontinued lines.

Licence-line · operator	Substance · status	H2S mol/kmol	Release m³	Level	Site, km	Permanent dwellings	Unrestricted country development	Urban centre or public facility
52198-7 Paramount Resources Ltd. · 323.9 mm · 13-15-062-19W5 to 02-10-063-19W5	Sour Natural Gas Operating	60 6%	—	not published	1.11	level not published		
63754-3 Whitecap Resources Inc. · 168.3 mm · 08-29-062-19W5 to 03-31-062-19W5	Natural Gas Operating	7 0.7%	—	not published	1.23	H2S 7 mol/kmol, not above the 10 mol/kmol at which the AER calls gas sour and Table 6 applies		
63543-3 Athabasca Oil Corporation · 168.3 mm · 08-29-062-19W5 to 03-31-062-19W5	Oil-Well Effluent Discontinued	30 3%	3	1 AER	1.24	right-of-way	right-of-way	right-of-way

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Licence-line · operator	Substance · status	H2S mol/kmol	Release m^3	Level	Site, km	Permanent dwellings	Unrestricted country development	Urban centre or public facility
63976-2 Whitecap Resources Inc. · 273.1 mm · 15-35-062-19W5 to 02-35-062-20W5	Sour Natural Gas Operating	15 1.5%	239	1 AER	1.27	right-of-way	right-of-way	right-of-way
63754-2 Whitecap Resources Inc. · 168.3 mm · 01-28-062-19W5 to 08-29-062-19W5	Natural Gas Operating	7 0.7%	—	not published	1.27	H2S 7 mol/kmol, not above the 10 mol/kmol at which the AER calls gas sour and Table 6 applies		
63543-2 Athabasca Oil Corporation · 168.3 mm · 01-28-062-19W5 to 08-29-062-19W5	Oil-Well Effluent Discontinued	30 3%	3	1 AER	1.28	right-of-way	right-of-way	right-of-way
63754-1 Whitecap Resources Inc. · 168.3 mm · 07-34-062-19W5 to 01-28-062-19W5	Natural Gas Operating	7 0.7%	—	not published	1.37	H2S 7 mol/kmol, not above the 10 mol/kmol at which the AER calls gas sour and Table 6 applies		
63543-1 Athabasca Oil Corporation · 168.3 mm · 07-34-062-19W5 to 01-28-062-19W5	Oil-Well Effluent Discontinued	30 3%	3	1 AER	1.38	right-of-way	right-of-way	right-of-way

Permanent dwellings	The site point is beyond the level distance of every segment listed with a level.
Unrestricted country development	The site point is beyond the level distance of every segment listed with a level.
Urban centre or public facility	The site point is beyond the level distance of every segment listed with a level.

LICENSED SOUR FACILITIES WITHIN 2 KM

No gas plant with a licensed design H2S and no facility licensed for a sulphur inlet within 2 km.

Gas plants: AER ST50A licensed capacity and design H2S. Other facilities: Petrinex facility licences with a sulphur inlet above 0 t/d, one row per licence (its rate is shared by the facilities under it; the distance is the nearest one's), placed by AER ST102 (licences as of 2026-11-10, locations 2026-11-02). Design H2S % = sulphur t/d × 737.5 m^3 H2S per t ÷ (licensed raw gas $10^3 m^3$/d × 1,000) × 100, a licensed ceiling, not a gas analysis. Directive 056 Table 5 sets facility setbacks by the release volume of the associated pipelines, which is not published per facility, so no level is given here.

AER Enhanced Pipeline data: H2S content, H2S release volume and Directive 056 release level per segment (2026-11-10); Petrinex public Facility Licence and Facility Infrastructure files (Alberta) (2026-11-10); AER ST102 Facility List (shapefile) (2026-11-02); AER ST50A gas processing plants (licensed capacity) with Petrinex plant receipts (capacity 2026-11-10; receipts 2026-09); AER Directive 056: Energy Development Applications and Schedules, edition released and effective 2026-10-01 (replaces 2026-03-31), s. 6.5.2, requirement 5 and Table 6 (p. 81); read 2026-11-11 · as of 2026-11-10 · saved 2026-11-19

CROWN OR FREEHOLD SURFACE

GREEN AND WHITE AREA · TOWN OF FOX CREEK 54.4000,-116.8000

For administration the Government of Alberta divides the province into the Green Area, the forested north, mountains and foothills, and the White Area, the settled centre, south and Peace River country. The split tells who most likely holds the surface; it is not the land title.

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Site point	In the Green Area
Distance to the White Area	26 km

The forested part of the province, about 61% of Alberta, which the Government of Alberta describes as nearly all publicly owned. Surface at a point here is likely public (Crown) land; industrial use of public land is held under a disposition issued under the Public Lands Act, such as a mineral surface lease (MSL), a miscellaneous lease (MLL) or a licence of occupation (LOC), rather than bought from a landowner.

Ownership shares: Government of Alberta, Understanding Land Use in Alberta (Land-use Framework, April 2007), Table 1, p. 11 (document). Dispositions: Government of Alberta, Dispositions under the Public Lands Act. The area line is an administrative boundary, generalised here to about 100 m; a point within a few hundred metres of it can fall on either side. Whether the surface at this point is titled or public, and who holds it, is on the Alberta land title or in the public land disposition records, neither of which is in the data used here.

Green/White Area, Alberta Environment and Protected Areas (Open Government Licence - Alberta), boundary as last revised 2021-11-16; Government of Alberta, Understanding Land Use in Alberta (Land-use Framework, April 2007), Table 1, p. 11 · as of 2021-11-16 · saved 2026-11-19

REGULATORY PATH

Municipal stance on data centres	no record found, which is not the same as no rule

Zoning at the site	Not in the public data used here; check the municipal land-use bylaw map.
Air quality before the project	Not in the public data used here; the EPEA approval rests on dispersion modelling against the Alberta Ambient Air Quality Objectives.

APPROVALS THAT APPLY TO A 100 MW GAS-FIRED PLANT

Data-centre load assumed equal to plant size.

Step	Applies	What it involves	Published duration
AUC power plant approval AUC Rule 007 (2025-11-06) s. 4.2, Table 4.7, Appendix A1 s. 6.3, Table 3.1; Hydro and Electric Energy Act s. 11	Yes	10 MW or more: full application. Notify within 2,000 m and consult in person within 800 m of the project boundary; the municipal engagement form goes to the municipality at least 30 days before filing.	Performance targets after a complete application: about 120 days with no objections (90 + 30 days) to about 295 days with a full hearing (205 + 90 days)
Approval life AUC Bulletin 2025-14; AUC Rule 007 s. 5.1	Yes	Construction must finish within the period the approval sets, at most seven years from the initial approval; after that, a new application. Smaller plants get the period they propose.	7 years maximum
EPEA approval (Alberta Environment and Protected Areas) Activities Designation Regulation, Alta Reg 276/2003, s. 5(1), s. 2(2)(vv), Sch. 1 Div. 2 Part 9	Yes	A thermal power plant over 1 MW needs an approval; there is no code-of-practice route. Emergency-only backup units not connected to the distribution system, up to 50 MW, are excluded.	No published service standard

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Step	Applies	What it involves	Published duration
Environmental impact assessment Environmental Assessment (Mandatory and Exempted Activities) Regulation, Alta Reg 111/93, s. 1, Sch. 1 cl. (k); EPEA, RSA 2000 c E-12, ss. 43, 44(1)(b), 44(3), 44(6), 45(4), 47, 63	No	Not on the mandatory list for gas-fired plants (mandatory only for thermal plants on non-gaseous fuel at 100 MW or more). The Director can still require further assessment of an activity that is not mandatory, weighing its location, size, nature, technology, public concerns and similar activities nearby, and then order a full report; the Minister can order one regardless. The EPEA approval cannot issue until Division 1 has been complied with where it applies.	Not published; 30 days for statements of concern after notice of a further-assessment decision
Federal impact assessment (IAAC) SOR/2026-185 s. 3; Physical Activities Regulations SOR/2019-285 (former Sch. s. 30); IAAC registry 89790 and 90123	No	Fossil-fuel power plants are no longer designated projects: SOR/2026-185, in force 2026-09-03, repealed the 200 MW item and the expansion item of the Physical Activities Regulations, and the federal government says these plants are assessed under provincial processes. Greenlight (1,864 MW) and Beacon Heartland (920 MW) were screened before the repeal; the Agency decided no further assessment was required for either.	—

First 5 of 13 rows. The full table is Appendix A3.

Grid-connected and air-cooled. Lists what applies under the published rules, not how an application would go.

Municipal boundaries: Government of Alberta (Alberta Environment and Protected Areas) Municipal Boundaries, Communities and Metis Settlement services, official names from Alberta Municipal Affairs; data-centre status from council records, bylaws, AUC decisions and court files (each entry cites its record) (2026-10-05); Alberta Utilities Commission featured proceedings (public web pages) (retrieved 2026-11-10; newest page change 2026-10-23); AUC Rule 007, AR 276/2003, AESO connection process as cited per step. AUC content curated from its public web pages, no open licence · as of retrieved 2026-11-10; newest page change 2026-10-23 · saved 2026-11-19

FINANCE AND SUPPLY COUNTERPARTIES

PROJECT FINANCE: HYPOTHETICAL MERCHANT CASE

ASSUMPTIONS FOR PROJECT FINANCE: THE DEFAULTS

`Method: note 35, Notes on method.`

> Financing terms not settled by public data: the 20-year loan tenor and the 1.35× minimum coverage on contracted cash flow are judgement, not an agency rule; no Canadian public source gives them for a gas plant. Merchant borrowing has no coverage test: it is sized by the 50% gearing cap of the regulation's reference merchant plant, and lenders set coverage case by case.

> Carbon compliance price not settled by public data: the 85% credit share is judgement following the MSA, and the credit price is the MSA-reported market average held in real terms, never below the 2030 minimum.

Revenue: **Merchant: sell energy into the pool**

Carbon: **Credit market: 85% at the MSA-reported credit price (held in real terms, never below the 2030 floor), 15% at the fund price**

Operating reserves: **On: sell the products the plant qualifies for**

Repayment: **Level annuity (sized to the lowest year's coverage)**

Debt on merchant cash flow: **Yes, at the merchant coverage ratio** All: **No: half-year rule in year one**

Reserve offered: **50 % of output** Share of AESO volume: **10 %**

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Escalation: **2 %** Tax: **23 %** Debt rate: **6.5 %** on merchant cash flow: **7 %** Tenor: **20 y** contracted: **1.35**
Max gearing: **65 %** on merchant cash flow: **50 %** Equity hurdle: **15.5 %** Financing fees: **4 % of debt**
Debt service reserve: **0 months** Interest cap (EIFEL): **On: the federal 30% cap (s. 18.2)** Receivables: **0 days**

Gearing at most 50% of capital on this uncontracted cash flow: the cap on merchant cash flow (50%), below the 65% maximum gearing, which does not bind here.

PROJECT IRR AFTER TAX · FORWARD CASE AND RECENT YEARS, WITH THE HISTORY

14.4%

FORWARD CASE, CAL-27-30 (LOW 8.3%, HIGH 19.3%); A THIN MARKET: CAL 29 TRADED ONCE IN AUGUST 2026 (MSA Q3 2026, P. 80)

3.3% · −1.1%

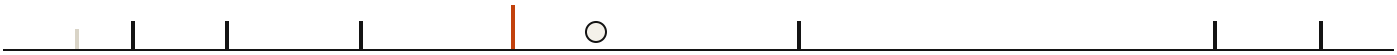
2025 HELD OVER THE LIFE; 2026 TO DATE, ANNUALISED FROM 10.5 MONTHS, HELD

8.1% – 17.4%

HISTORY: P10–P90 OVER 400 20-YEAR LIVES OF PAST YEARS (P50 12.4%); MEDIAN YEAR 11.9%

Method: note 36, Notes on method.

Method: note 37, Notes on method.



−1.1% median 11.9% 36.1%

| a dispatch year · ○ forward case · grey: 2026 to date

Dispatch year	Run hours	Captured, C$/MWh	Reserves, C$/kW-yr	Project IRR	Equity IRR
2019	6,108	64.1	1.5	7.4%	8.8%
2020	2,855	80.8	4.6	0.5%	−7.0%
2021	6,343	123.8	1.0	20.5%	32.1%
2022	6,810	190.9	0.2	36.1%	61.0%
2023	7,025	156.8	0.4	32.9%	55.0%
2024 · median	4,589	102.4	2.0	11.9%	16.9%
2025	2,577	106.1	2.2	3.3%	0.6%
2026 to date, annualised from 10.5 months (not in the median)	1,512	109.3	6.3	−1.1%	−12.9%
Forward case, Cal-27-30 then held	4,516	122.5	1.8	14.4%	21.3%
Forward low: Cal-27-30, then 2031 at the P25 of the year spread, held	2,318	156.8	3.0	8.3%	10.9%
Forward high: Cal-27-30, then 2031 at the P75 of the year spread, held	7,036	134.8	0.4	19.3%	28.8%

Method: note 38, Notes on method.

Method: note 39, Notes on method.

Method: note 40, Notes on method.

> Operating reserve offer and market shares are judgement: half of the plant's available output offered, at most 10% of each product's procured MW won in an hour. The AESO qualifies each plant's reserve MW itself (ISO rule 205.6).

> In the 2020 and 2025 dispatch years held over the life, the debt costs more than the project earns, so equity IRR is below project IRR there. Project IRR is the headline figure.

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ONE INPUT AT A TIME, PROJECT NPV AT WACC, C$ · CENTRAL CASE THE MEDIAN YEAR (2024)

Power price moves project NPV at WACC most: –C$39.9M to C$106.7M over its range.

INPUT · LOW TO HIGH · RANGE BASIS	–C$39.9M	C$35.0M	C$106.7M	LOW / HIGH
Power price [1] –20% to +20%				–C$39.9M / C$106.7M
Capital cost [2] lowest (–19%) to highest (+31%)				C$70.9M / –C$25.4M
Discount rate (WACC) [3] 8.1% to 11.7%				C$66.3M / C$3.0M
Heat rate [4] P10 (-8% on the case) to P90 (+8%)				C$46.7M / C$23.8M
Gas price [5] –20% to +20%				C$45.4M / C$25.5M
Carbon price case [6] headline fund price to credit market				C$22.7M / C$35.0M
Insurance (inside CONE fixed O&M) [7] –20% to +20%				C$36.6M / C$33.3M
Property tax (inside CONE fixed O&M) [8] –20% to +20%				C$36.6M / C$33.3M
Operating reserve price [9] 2020 level (–39%) to 2022 level (+110%)				C$34.3M / C$36.9M
Availability [10] — to —				— / —

Method: note 41, Notes on method.

Method: note 42, Notes on method.

PROJECT IRR OVER LIVES OF PAST YEARS

Project IRR: 8.1 to 17.4 (central 12.4) %.

Scenario	Inputs	%
Low (P10)	Lives: one in ten returns less	8.1
Central (P50)	Lives: half return less	12.4
High (P90)	Lives: one in ten returns more	17.4

Method: note 43, Notes on method.

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Scenario row, the same lives	Project IRR P10 / P50 / P90	Equity IRR P50	Basis
Economic life 30 years	10.2% / 13.4% / 17.6%	18.5%	The regulation's reference merchant plant's 30-year useful life (Market Power Mitigation Regulation, Alta Reg 43/2024, Schedule (reference generating unit), item 11), against AESO CONE 2018's 20 years; the same draws, each life 30 years
Gearing 40%	8.1% / 12.4% / 17.4%	16.0%	40% debt, the lenders' cap on merchant revenue in a financing (Norton Rose Fulbright, Cost of Capital: 2026 Outlook, a secondary source); moves equity IRR, not project IRR
Gearing 65%	8.1% / 12.4% / 17.4%	21.4%	65% debt, AESO CONE 2018's levered case (Table 11), between Pembina's ~60% for Greenlight and the AESO's 75% for contracted renewables; moves equity IRR, not project IRR. Default merchant gearing 50% (Alta Reg 43/2024, item 7)

FORWARD CASE: WHAT IT DOES NOT MODEL

- Restructured Energy Market: the switch from one pool price to locational marginal prices is scheduled for 2028. A plant's own node price can then differ from the pool prices this case is built on. MSA Wholesale Market Report Q2 2026 (https://www.albertamsa.ca/assets/Documents/Wholesale-Market-Report-Q2-2026.pdf)
- Operating reserves under REM (2028): reserves are bought hour by hour in a day-ahead reliability market that co-clears regulating, spinning and supplemental, with new indexed offer caps (+C$25/MW for supplemental) and a 1 MW minimum, and a new real-time 30-minute reserve (R30) co-optimised with energy. The forward case's reserve line keeps each historical year's index to the pool price; under REM that relation, the volumes bought and an entrant's share may all change. AESO, Restructured Energy Market Final Design, August 2025, pp. 6, 11, 13, 31 (https://www.aeso.ca/assets/REM/Restructured-Energy-Market-Final-Design.pdf); REM ISO rules 212.1–212.10, approved 2026-03-12 (https://www.aeso.ca/rules-standards-and-tariff/rem-iso-rules/); MSA Wholesale Market Report Q3 2026, p. 80, REM "on schedule in 2028" (https://www.albertamsa.ca/assets/Documents/Wholesale-Market-Report-Q3-2026.pdf)
- Market power mitigation since 2024-07-01 (ISO rule 206.1): a secondary offer cap of the greater of C$125/MWh or 25× the day-ahead gas price once a month's net revenue passes a threshold. It caps scarcity revenue; it was not triggered in 2025. MSA Wholesale Market Report Q4 2025, market power mitigation and supply cushion regulations (https://www.albertamsa.ca/assets/Documents/Wholesale-Market-Report-Q4-2025.pdf)
- Federal Clean Electricity Regulations: from 2035 each unit's yearly limit is 65 t of CO2 per GWh of its capacity over the year (capacity × 8,760 hours), plus up to 35 t per GWh more covered by offset credits. An unabated gas unit emits 350–400 t per GWh generated, so it could run only about a sixth to a quarter of the year. Held in abeyance in Alberta while the Alberta Court of Appeal hears the province's reference; not modelled either way. Clean Electricity Regulations, SOR/2024-263, ss. 12 and 28, Canada Gazette Part II vol. 158 no. 26, 2024-12-18 (https://gazette.gc.ca/rp-pr/p2/2024/2024-12-18/html/sor-dors263-eng.html); abeyance: Implementation Agreement for the Canada–Alberta Memorandum of Understanding (2026-05-15), s. 2.1 (https://open.alberta.ca/dataset/f49d6e65-5f8b-48c7-9ab2-1180c6e455e7/resource/d4fc724a-5a8f-465c-9e54-67b5af61aa84/download/implementation-agreement-mou-goc-goa-energy-collaboration.pdf)
- New entry lowers prices: 2025's lower prices "were driven by increased gas capacity and more intermittent generation" (available thermal capacity 9,217 MW in 2023, 10,415 MW in 2025). More new plants would push the forward shape down again. MSA Wholesale Market Report Q4 2025 (https://www.albertamsa.ca/assets/Documents/Wholesale-Market-Report-Q4-2025.pdf)
- 2025–26 prices reflect a supply surplus and the mitigation rules above (the supply cushion directives lowered October 2025 prices by an estimated 47%); a forward built on them carries that surplus forward. MSA Wholesale Market Reports Q4 2025 (https://www.albertamsa.ca/assets/Documents/Wholesale-Market-Report-Q4-2025.pdf) and Q2 2026 (https://www.albertamsa.ca/assets/Documents/Wholesale-Market-Report-Q2-2026.pdf)

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BASIS

Debt	C$107.4M · 50% of capital in the median year, set by the 50% cap on merchant cash flow (the 65% maximum gearing does not bind)
Minimum coverage	No minimum coverage on merchant cash flow (pool sales): debt sized by the gearing cap, DSCR reported (lenders set coverage case by case)
Tenor	20 years, judgement, not an agency rule
DSCR, median year, min / average	2.81 / 3.03 (an output: no coverage test on merchant debt; lenders set coverage case by case)
Debt rate	7.00% on merchant cash flow (Alta Reg 43/2024 Schedule, item 6)
Carbon	Credit market: 85% at the MSA-reported credit price (held in real terms, never below the 2030 floor), 15% at the fund price
Plant dispatched	Reciprocating engines, Alberta (Bitdeer Fox Creek): dispatched like simple cycle on its own heat rate (the MSA has no engine reference); 8.52 GJ/MWh; Output × 0.92: the plant's availability, 92% (PatchWatt's sizing default unless entered)
Delivered gas	CONE fixed O&M already includes firm gas transport (AESO CONE 2018, Table 10: the firm gas contract is 26% of the fixed O&M), so no NGTL delivery toll is added on top; choose the NGTL tolls under Firm gas transport to replace it
Financing fees, reserve and interest cap (equity only)	C$4.3M fees (4% of debt; 4% of the debt (AESO CONE 2018)), no debt service reserve (not included unless you enter it); interest capped at 30% of tax EBITDA, the rest carried forward (EIFEL, Income Tax Act s. 18.2); all-in cost of debt 7.5%

Method: note 44, Notes on method.
Method: note 45, Notes on method.
Method: note 46, Notes on method.

PRODUCTION COVERAGE SCENARIO

Method: note 47, Notes on method.

Term: 10 y From: 2029 Set aside: 50 % of each Decline if unmeasured: 28 %/y
AECO: 1.78 C$/GJ NGTL delivery group: Group 2 Load factor: 100 %

First year this scenario falls short	Not within 10 years
Supply-deal band: the producer's hub netback (AECO less FT-R receipt and NGTL fuel) to the buyer's delivered cost (AECO plus FT-D delivery and the abandonment surcharge)	1.51 – 2.10 C$/GJ

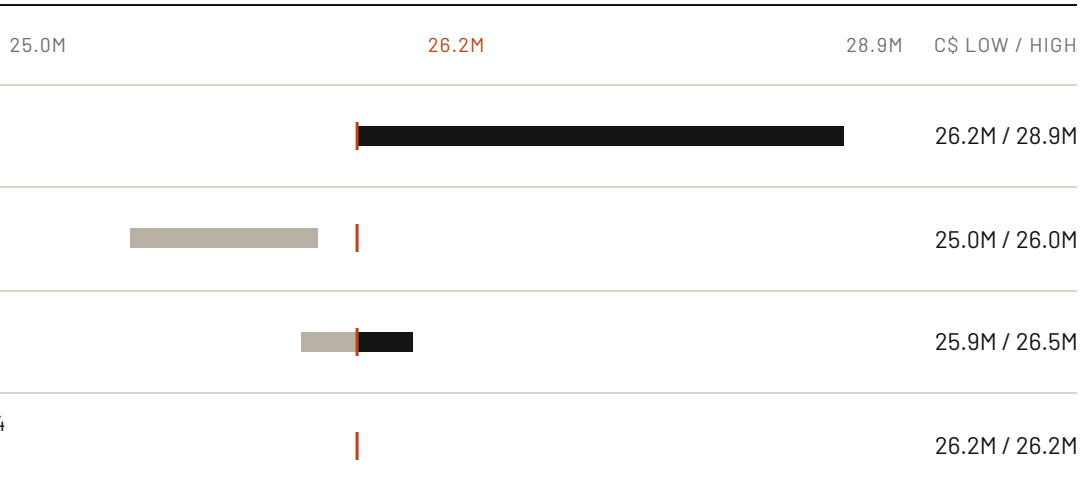
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Tailgate siting avoids	C$0.60/GJ of tolls and fuel, which buyer and seller can splitreceipt 0.239 · fuel 0.035 · delivery 0.310 · surcharge 0.013 C$/GJ
Henry Hub-linked price (US reference, not used in any cost): the producer's upside case	3.09 C$/GJAECO plus US$1.00/MMBtu at 1.38 C$/US$ (CER Canada's Energy Future 2026, Current Measures: Henry Hub minus NIT basis and exchange rate for 2026 (2025 US$; fetched); https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2026/). Priced as in Pine Cliff Energy, 2025-01-17: 25-year supply priced off "a rolling 12-month average of NYMEX price" (company release, https://www.pinecliffenergy.com/news/pine-cliff-energy-ltd-announces-natural-gas-supply-agreement-for-an-alberta-data-centre-development). Not a default and not used in any cost.

Method: note 48, Notes on method.

ONE INPUT AT A TIME, BUYER'S SAVING OVER THE TERM, C$ · GAS PRICED AT THE BAND'S MIDPOINT, SO THE AVOIDED TOLLS ARE SPLIT EVENLY

NGTL delivery group moves buyer's saving over the term most: 26.2M to 28.9M C$ over its range.



Method: note 49, Notes on method.

Method: note 50, Notes on method.

Producer	Today		Decline	Yr 1	Yr 10
CANADIAN NATURAL RESOURCES LIMITED	233.0	growing, held flat		116.5	116.5

The scenario takes producers from the largest reported volume down until their set-aside volume in year 10 covers the need: 1 of 19 producers. Listed by name, not by volume.

Year	Set-aside volume, MMcf/d	Need covered
2029	116.5	100%
2031	116.5	100%
2033	116.5	100%
2038	116.5	100%

Method: note 51, Notes on method.

Petrinex public volumetric data (Alberta); locations from AER ST102 (2026-09); Petrinex Well Infrastructure (Alberta) (2026-11-10); Petrinex Well

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Infrastructure: well licences by licensee and licence status (2026-11-10). Not the AER's Licensee Capability Assessment or LMR, which are not published per licensee · as of 2026-11-10 · saved 2026-11-19

CLIMATE AND CARBON

July 2.5% design dry bulb · 1%	27.4 °C · 29.2 °C
January 1% · 2.5% design	-32.9 °C · -29.4 °C
Mean station pressure	92.0 kPa
Stations used	Whitecourt A (72 km), Valleyview Agdm (82 km), Edson Climate (94 km)

FACILITIES REPORTING GREENHOUSE GAS WITHIN 25 KM

Airshed: 1 reporting facility within 5 km of the point, the distance an EPEA approval application describes ambient air over.

15 facilities reported 755 kt CO2e in 2024 (13 reported 537 kt in 2019). By sector in 2024: oil and gas extraction (except oil sands) 755 kt.

Facility	kt CO2e 2019	kt CO2e latest	km
Fox Creek Division Millar Western Forest Products Ltd. · Sawmills (except Shingle and Shake Mills) · last reported 2021	8.6	8.4	1
Kaybob Amalgamated Sour Gas Plant PGI Processing ULC · Oil and gas extraction (except oil sands)	206	171	8
Kaybob 15-28 PGI Processing ULC · Oil and gas extraction (except oil sands)	17.7	11.0	9
Kaybob West 07-14 Athabasca Oil Corporation · Oil and gas extraction (except oil sands)	49.1	46.5	9
Duvernay Sweetening Plant Pembina Pipeline Corporation · Oil and gas extraction (except oil sands)	—	61.6	9
Duvernay Kaybob Complex Pembina Pipeline Corporation · Oil and gas extraction (except oil sands)	16.9	38.2	9
RBR KAYB 15-30-063-18W5 MWOB Saturn Oil & Gas Inc. · Oil and gas extraction (except oil sands)	11.1	22.4	11
XTO 07-20-061-19W5 XTO Energy Canada ULC · Oil and gas extraction (except oil sands) · last reported 2019	0.0	0.0	12
Kaybob Gas Plant Paramount Resources Ltd. · Oil and gas extraction (except oil sands)	47.9	51.9	14
PARA KAYBOB 12-10-064-19W5 Paramount Resources Ltd. · Oil and gas extraction (except oil sands)	—	42.5	14

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Facility	kt CO2e 2019	kt CO2e latest	km
Kaybob 05-33 Gas Battery Veren Inc. · Oil and gas extraction (except oil sands)	35.8	69.4	18
Kaybob 05-33 Gathering Station Veren Inc. · Oil and gas extraction (except oil sands)	—	41.8	18

Showing the first 12 of 19.

Reporting year	2017	2018	2019	2020	2021	2022	2023	2024
Facilities reporting	7	10	13	12	13	13	14	15
kt CO2e	467	513	537	628	634	678	637	755

Method: note 52, Notes on method.

ECCC CWEEDS 2020 hourly engineering weather, Alberta, station records 1998–2017 (OGL-Canada) (2022-07-13); ECCC Greenhouse Gas Reporting Program facility data, Open Government Licence - Canada (reporting years 2004-2024); Canada–Alberta TIER implementation agreement (2026-05-15) · as of reporting years 2004-2024 · saved 2026-11-19

PRICES AND CARBON

REALISED GAS AND POWER PRICES, TO 2026-10

What gas and power actually averaged in the last full year and this year so far, before the forecasts below. AER ST98-2026 AECO-C forecast for 2026: 2.73 C$/GJ; realised Jan–Sep 2026: 1.66 (AECO/NIT same-day gas price); Jan–Aug 2026: 1.56 (Alberta natural gas reference price).

Price	Period	Value	Unit	Method and source
AECO-C monthly index (NGX), as AER reports it	2025	1.74	C$/GJ	Annual actual as published. AER ST98-2026 prices data file, Table S1.2 · static.aer.ca
AECO/NIT same-day gas price	2025	1.61	C$/GJ	Mean of 12 monthly averages. Market Surveillance Administrator (MSA), Quarterly wholesale market reports Q1 2019 to Q3 2026, monthly AB-NIT (2A) table · www.albertamsa.ca
AECO/NIT same-day gas price	Jan–Sep 2026 (year to date)	1.66	C$/GJ	Mean of 9 monthly averages. Market Surveillance Administrator (MSA), Quarterly wholesale market reports Q1 2019 to Q3 2026, monthly AB-NIT (2A) table · www.albertamsa.ca
Alberta natural gas reference price	2025	1.43	C$/GJ	Mean of 12 monthly averages. Alberta Energy and Minerals, Alberta natural gas reference price, monthly table (also the Alberta Economic Dashboard series NaturalGasPrices) · www.alberta.ca
Alberta natural gas reference price	Jan–Aug 2026 (year to date)	1.56	C$/GJ	Mean of 8 monthly averages. Alberta Energy and Minerals, Alberta natural gas reference price, monthly table (also the Alberta Economic Dashboard series NaturalGasPrices) · www.alberta.ca
Alberta pool price	2025	43.68	C$/MWh	Hours-weighted mean of the 12 complete monthly means of the AESO pool price, the same as the mean of the hourly prices. AESO pool price, annual average of 8,760 hourly prices (ETS Historical Pool Price report) · www.aeso.ca

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Price	Period	Value	Unit	Method and source
Alberta pool price	Jan–Oct 2026 (year to date)	34.32	C$/MWh	Hours-weighted mean of the 10 complete monthly means of the AESO pool price, the same as the mean of the hourly prices. AESO pool price, Jan–Oct 2026 average of 7,295 hourly prices (ETS Historical Pool Price report) · www.aeso.ca

EACH FORECAST FOR THIS YEAR BESIDE THE REALISED PRICES

Gas, C$/GJ. Difference is realised minus forecast. The forecasts publish a whole-year figure, so a part-year average is only a guide to where the year is running. CER and EIA rows are in 2025 dollars, the realised prices and ST98 are nominal.

Forecast	2026 forecast	Realised Jan–Sep 2026 AECO/NIT same-day gas price	Realised Jan–Aug 2026 Alberta natural gas reference price	Difference vs Jan–Sep 2026	Difference vs Jan–Aug 2026
CER EF2026: Current Measures, Higher, Lower, Canada Net-zero 2025 C$	3.92	1.66	1.56	−2.26	−2.36
AER ST98 (AECO-C) nominal C$	2.73	1.66	1.56	−1.07	−1.17
EIA Baseline (US reference, not used in any cost) 2025 C$	3.77	1.66	1.56	−2.11	−2.21
EIA High supply (US reference, not used in any cost) 2025 C$	2.88	1.66	1.56	−1.22	−1.32
EIA Low supply (US reference, not used in any cost) 2025 C$	4.33	1.66	1.56	−2.67	−2.77

Method: note 53, Notes on method.

Market Surveillance Administrator (MSA), quarterly wholesale market reports; Alberta Energy and Minerals, Alberta natural gas reference price; AER ST98-2026 prices data file; AESO pool price · as of 2026-10 · saved 2026-11-19

GAS PRICE AND CARBON SCENARIOS · 2026, 2030, 2035, 2040, 2050

Gas, $/GJ, each row in its own dollar basis. By source.

Scenario	2026	2030	2035	2040	2050
CER EF2026 Current Measures 2025 C$ · OGL-Canada · CER Canada's Energy Future 2026, NIT benchmark converted at CER FX	3.92	4.08	4.34	4.67	5.32
CER EF2026 Higher 2025 C$ · OGL-Canada · CER Canada's Energy Future 2026, NIT benchmark converted at CER FX	3.92	5.94	6.12	6.39	7.03
CER EF2026 Lower 2025 C$ · OGL-Canada · CER Canada's Energy Future 2026, NIT benchmark converted at CER FX	3.92	2.20	2.54	2.90	3.60
CER EF2026 Canada Net-zero 2025 C$ · OGL-Canada · CER Canada's Energy Future 2026, NIT benchmark converted at CER FX	3.92	3.84	3.81	3.81	3.81

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Scenario	2026	2030	2035	2040	2050
AER ST98-2026 AECO-C nominal C$ · AER	2.73	3.46	3.99	—	—
EIA AEO2026 Baseline, less US$1.00 basis (US reference, not used in any cost) 2025 C$ · Public domain · EIA AEO2026 Henry Hub, minus CER's US$1.00/MMBtu NIT basis, at CER Current Measures FX (our arithmetic)	3.77	4.42	5.07	5.45	4.55
EIA AEO2026 High supply, less US$1.00 basis (US reference, not used in any cost) 2025 C$ · Public domain · EIA AEO2026 Henry Hub, minus CER's US$1.00/MMBtu NIT basis, at CER Current Measures FX (our arithmetic)	2.88	2.49	3.03	2.88	2.19
EIA AEO2026 Low supply, less US$1.00 basis (US reference, not used in any cost) 2025 C$ · Public domain · EIA AEO2026 Henry Hub, minus CER's US$1.00/MMBtu NIT basis, at CER Current Measures FX (our arithmetic)	4.33	7.51	9.53	11.74	15.85

8 scenarios, all listed.

TIER CARBON PRICE, $/T CO2E, NOMINAL

Schedule	2026	2030	2035	2040	2050
TIER	95	115	130	140	140 (held)

After the last published year the TIER price is held at its last value, as the cost of power carries it ("held").

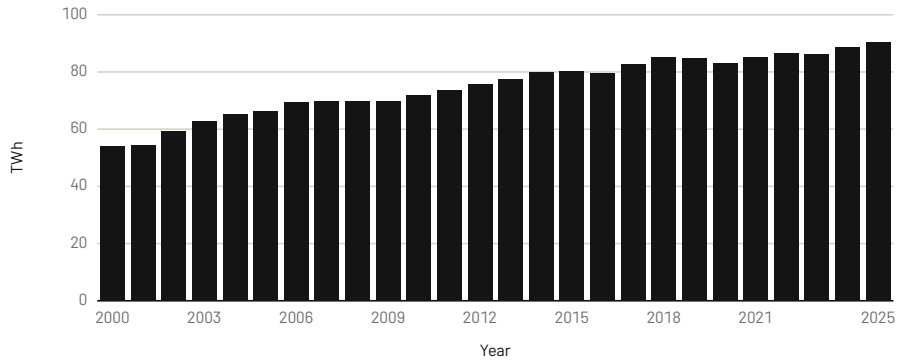
CER Canada's Energy Future, latest edition (Open Government Licence – Canada); EIA Annual Energy Outlook, latest edition (US public domain; a US reference, not used in any cost); AER ST98, latest edition; Canada–Alberta TIER Implementation Agreement · as of 2026-11-03 · saved 2026-11-19

ALBERTA INTERNAL LOAD, 2000 TO 2026-11-16

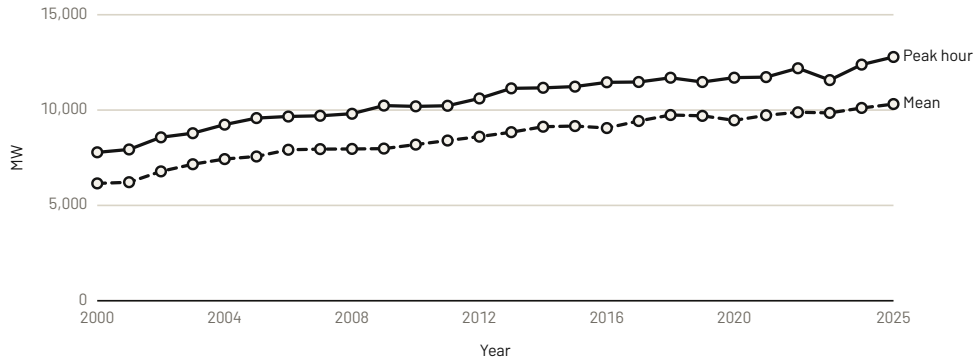
Method: note 54, Notes on method.

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ALBERTA INTERNAL LOAD, ENERGY BY CALENDAR YEAR

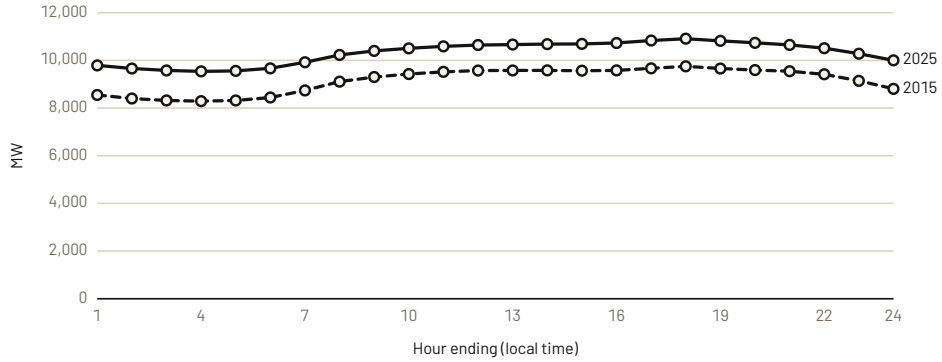


PEAK HOUR AND MEAN LOAD BY CALENDAR YEAR



Peak hour Mean

MEAN LOAD BY HOUR OF DAY, 2025 AND 2015



2025 2015

Year	Energy TWh	Mean MW	Peak MW	Peak hour	Load factor	Energy on year before
2026 (to 2026-11-16)	80.33	10,461	12,404	17 Feb 2026, hour ending 19	84.3%	–
2025	90.37	10,316	12,785	11 Dec 2025, hour ending 18	80.7%	+1.7%
2024	88.83	10,112	12,384	11 Jan 2024, hour ending 18	81.7%	+2.9%
2023	86.29	9,851	11,572	22 Feb 2023, hour ending 19	85.1%	–0.3%
2022	86.57	9,883	12,193	21 Dec 2022, hour ending 18	81.1%	+1.6%

First 5 of 27 rows. The full table is Appendix A4.

Newest year first. AIL is Alberta Internal Load, the province's demand including behind-the-fence load, as the AESO reports it hour by hour (MW; one hour's figure is its MWh). Energy is the sum of the year's hours; load factor is the mean hour over the peak hour. The change on the year before compares full years only, so leap years carry 24 more hours; the year in progress is compared month for

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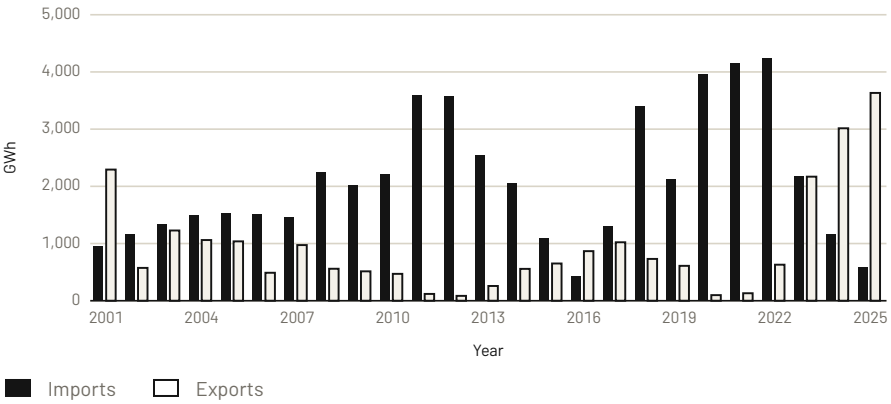
month in the sentence above. Hour of day is local time, hour ending.

AESO Alberta Internal Load, hourly, ETS Historical Pool Price report, hourly Jan 2000 to 2026-11-16 · as of 2026-11-16 · saved 2026-11-19

INTERTIE IMPORTS AND EXPORTS, 2001 TO 2026-10-31

Method: note 55, Notes on method.

IMPORTS AND EXPORTS BY CALENDAR YEAR



Year	Imports GWh	Exports GWh	Net import GWh	Hours importing	Hours exporting	BC net GWh	MT net GWh	SK net GWh	Tie not named GWh
2026 (10 months)	1,113	1,537	−425	41%	51%	249	−50	55	−679
2025	582	3,633	−3,051	21%	75%	−2,063	−231	22	−778
2024	1,160	3,015	−1,856	33%	65%	−2,226	186	184	—
2023	2,177	2,169	8	60%	40%	−1,232	658	582	—
2022	4,243	630	3,613	89%	11%	1,996	1,122	495	—

First 5 of 26 rows. The full table is Appendix A5.

26 years, all listed.

Newest year first. Net import is imports less exports (negative: net export). An hour counts as importing when its net flow over all three ties is into Alberta, and exporting when it is out. Montana opened in 2013; the 2001–2009 file has no Montana columns. From 2025-08-01 the AESO ETS report does not name the tie in a field: it is read from each importer and exporter asset ID (ending BC, MT or SK; XB, XM or XS). Rows whose ID names no tie are under "Tie not named" (2025 and 2026), so totals and net are complete while the per-tie figures for those months are a lower bound.

NET IMPORT BY TIME OF DAY

Mean net import over all ties, MW, by four-hour block of local hour ending. Negative is net export.

Year	HE 1–4	HE 5–8	HE 9–12	HE 13–16	HE 17–20	HE 21–24
2025	−511	−431	−338	−356	−168	−286
2024	−380	−302	−184	−205	−53	−144
2023	−151	−69	54	22	130	21

HOURS EACH TIE IMPORTED OR EXPORTED

Share of the hours with a value in the data-request files, which name the tie (to 2025-07-31). A tie neither importing nor exporting in an hour counts in neither.

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Year	British Columbia: importing, exporting		Montana: importing, exporting		Saskatchewan: importing, exporting	
2025 (5,087 h)	16%	73%	28%	63%	0%	0%
2024	23%	64%	50%	39%	40%	11%
2023	38%	50%	81%	12%	72%	10%
2022	78%	15%	86%	6%	73%	3%
2021	85%	3%	88%	4%	74%	2%
2020	86%	3%	85%	3%	48%	3%
2019	49%	22%	71%	6%	39%	5%
2018	68%	17%	64%	6%	31%	16%
2017	34%	30%	20%	32%	6%	17%
2016	20%	28%	23%	16%	3%	21%

MONTH BY MONTH, LAST 24 MONTHS

Month	Imports GWh	Exports GWh	Net import GWh	Hours importing	Hours exporting	BC net GWh	MT net GWh	SK net GWh	Tie not named GWh	Source
Oct 2026	77	222	−145	27%	72%	−42	1	2	−106	ETS
Sep 2026	35	233	−199	10%	88%	−73	−33	−3	−90	ETS
Aug 2026	91	222	−131	20%	65%	−87	−50	26	−21	ETS
Jul 2026	154	161	−7	44%	55%	71	−58	−3	−18	ETS
Jun 2026	161	36	125	69%	26%	101	7	18	0	ETS

First 5 of 24 rows. The full table is Appendix A6.

24 months, all listed.

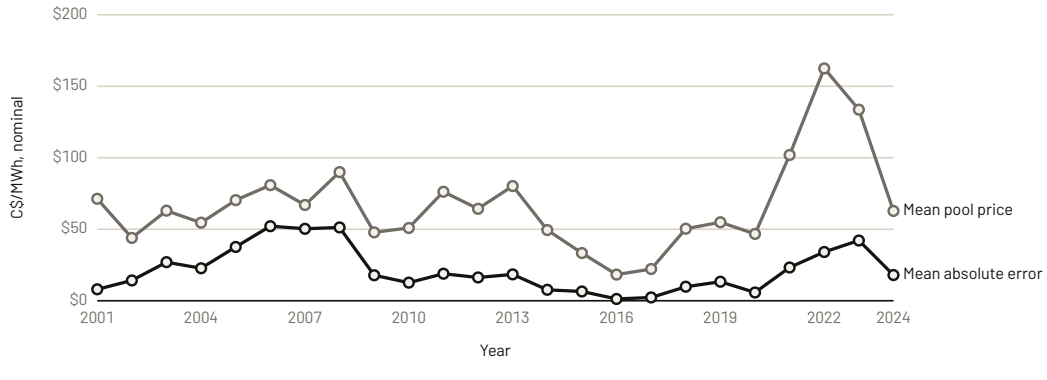
AESO hourly metered volumes, intertie import and export columns (data request 2001 to July 2025), then the ETS Metered Volumes (All) report's importer and exporter rows, hourly Jan 2001 to 2026-10-31 (data request to 2025-07-31, ETS 2025-08-01 to 2026-10-31) · as of 2026-10-31 · saved 2026-11-19

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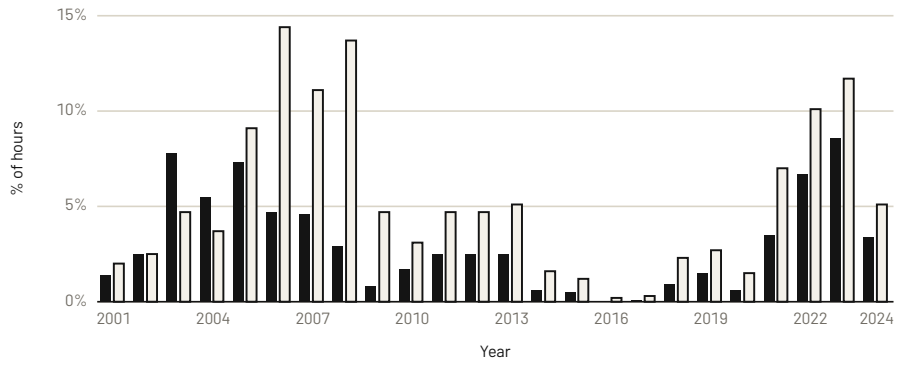
HOUR-AHEAD POOL PRICE FORECAST AGAINST THE SETTLED PRICE, 2001 TO 2025-07-31

Method: note 56, Notes on method.

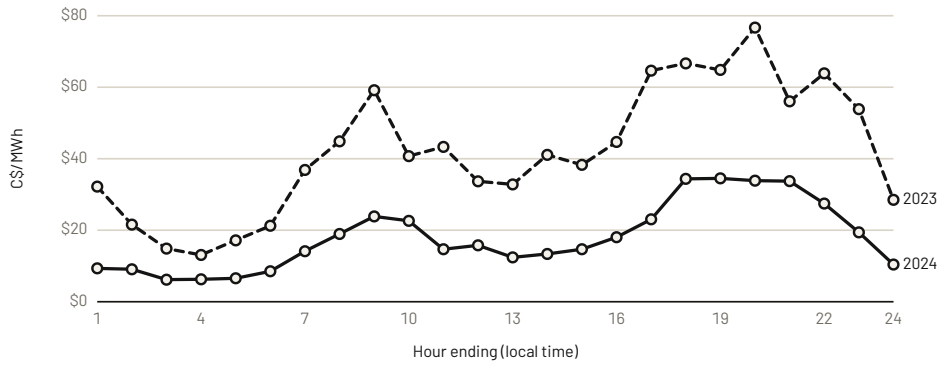
MEAN ABSOLUTE FORECAST ERROR AND MEAN POOL PRICE BY CALENDAR YEAR



SHARE OF HOURS THE PRICE SETTLED MORE THAN C$50/MWH FROM ITS FORECAST



MEAN ABSOLUTE ERROR BY HOUR OF DAY, 2024 AND 2023



Year	Mean pool price	Mean absolute error	Mean error	RMS error	Hours off by over C$50	of which above	of which below	Hours off by over C$100	Hours
2025 (7 months)	C$38.83	C$12.46	−C$3.39	C$54.59	4.0%	1.2%	2.8%	2.2%	5,087
2024	C$62.78	C$17.97	−C$3.56	C$56.42	8.5%	3.4%	5.1%	4.5%	8,784
2023	C$133.63	C$42.11	−C$7.59	C$98.71	20.2%	8.6%	11.7%	13.5%	8,760
2022	C$162.46	C$34.08	−C$8.25	C$85.02	16.8%	6.7%	10.1%	10.3%	8,760

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Year	Mean pool price	Mean absolute error	Mean error	RMS error	Hours off by over C$50	of which above	of which below	Hours off by over C$100	Hours
2021	C$101.93	C$23.24	−C$8.29	C$70.04	10.5%	3.5%	7.0%	6.8%	8,760

First 5 of 25 rows. The full table is Appendix A7.

25 years, all listed.

Newest year first. Error is the settled pool price less the hour-ahead forecast, C$/MWh, nominal; a positive mean error means prices settled above the forecast on average. Mean absolute error and the shares count every hour with both figures; RMS (root mean square) error weighs the large misses more. This is the uncertainty in price between the hour-ahead forecast and settlement that a plant selling at the pool price carries; contracts and hedges are not in it. Left out as file errors (a price or forecast outside the pool floor of C$0 and cap of C$999.99): 2 hours in 2001. The AESO says April to July 2025 were not final in the data-request files.

AESO hour-ahead pool price forecast and actual pool price, hourly (data request 2001 to July 2025), Jan 2001 to 2025-07-31 · as of 2025-07-31 · saved 2026-11-19

EVIDENCE MATRIX

EVIDENCE MATRIX AND OPEN ITEMS · TOWN OF FOX CREEK 54.4000,-116.8000

Item	Evidence	What the public data shows
Gas volumes near the site Petrinex volumetrics	■ Sourced	743.2 MMcf/d raw gas reported by all batteries within 25 km, from 19 operators reporting gas (Sep 2026); 50.6 MMcf/d stopped since the comparison month.
Gas quality (H2S, heating value) AER ST50A; Petrinex	◧ Partial	Plant design H2S and area heating value only; no analysis of a specific supply.
Pipeline tie-in route and distance AER pipelines; CER pipeline systems; CanVec	◧ Partial	Sales-gas tie-in used in sizing: NGTL System, about 1 km, to a CER route generalized to a few km (the nearest sales-gas line: a CER system other than Alliance, or a sweet transmission or utility line). The CER publishes its routes generalized to within a few km, so the tie-in route and distance are a screening estimate. The nearest 219 mm+ line of any service, Paramount Resources Ltd. at 1.1 km, may be a producer's gathering line and is not the fuel tie-in.
Pipeline capacity at the tie-in —	▨ Not public	Line size and maximum pressure are public; available capacity and tolls at a point are not.
Nearest substations AESO transmission system GIS (not shown where AESO data is withheld)	■ Sourced	Nearest 138/144 kV substation 3.4 km (Fox Creek 741S); 240 kV and up 65.6 km (Little Smoky 813S), straight-line.
Grid connection capacity —	▨ Not public	The sizing ties a plant under 200 MW at 138/144 kV, larger at 240 kV and up; a grid-connected case costs the direct connection at the AESO CONE 2018 figure per kW (restated) plus any line and substation cost entered, an off-grid case none. Capacity at the substation, queue position and upgrade cost are not public.
Land ownership and access —	▨ Not public	Titles and surface rights are not in the public data used here.
Municipal stance on data centres Council records, bylaws, AUC decisions and court files	◧ Partial	Town of Fox Creek: no record found, which is not the same as no rule.
Water for cooling NRCan NHN; Water Act	◧ Partial	Basin Upper Little Smoky: open.

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Item	Evidence	What the public data shows
Wetlands AMWI	Partial	Checked in the app against the Alberta Merged Wetland Inventory (queried live, restricted licence); no field delineation.
Flood hazard Alberta FHIP	Partial	Not inside a mapped flood hazard area. Unmapped streams are not assessed.
Indigenous lands and consultation Alberta open data	Partial	nearest reserve or settlement Alexander 134A (Alexander First Nation), 23.2 km; treaty area Treaty 8 (1899).
Species and protected areas Alberta wildlife maps; Parks and Protected Areas of Alberta	Partial	Caribou: nearest range Little Smoky, 35.3 km. Protected areas: nearest area Iosegun Lake Provincial Recreation Area, 5.7 km.
Historic resources Listing of Historic Resources; Historical Resources Act	Partial	Listing of Historic Resources checked in the site report; projects that need AUC approval always file a Historical Resources Act application (Listing instructions, 2023-09).
Homes near the point (AUC precedent) AUC Decision 30732-D01-2026 ¶28, ¶36; Overture Maps buildings release 2026-10-21.0 (OpenStreetMap, gaps filled with Microsoft footprints of about 2019), © OpenStreetMap contributors, Microsoft, Overture Maps Foundation (ODbL)	Partial	The AUC refused a gas plant at Olds in 2026 (AUC Decision 30732-D01-2026) citing over 700 residences within 800 m; this point has 519 buildings within 800 m (173 within 500 m, 941 within 1.5 km). Buildings stand in for homes and include sheds and barns.
Noise (AUC Rule 012) Overture Maps buildings release 2026-10-21.0 (OpenStreetMap and Microsoft footprints), © OpenStreetMap contributors, Microsoft, Overture Maps Foundation (ODbL)	Partial	1005 buildings within 2 km; nearest 190 m. Building counts (Overture Maps: OpenStreetMap, gaps filled with Microsoft footprints of about 2019) stand in for dwellings; a filed noise study may count differently.
Seismicity Earthquakes Canada	Sourced	20 events since 2010 within 25 km, 11 at M2.5 or more, largest M3.9.
Sour gas setback AER Enhanced Pipeline data (H2S release volume and level); AER Directive 056 (2026-10-01) Table 6; ST50A	Partial	8 sour pipeline segments within 2 km: release level published by the AER on 4, read from the published release volume on 0, not published on 4. Nearest 52198-7, 1.11 km, level not published. Nearest sour-gas plant 7.2 km. Directive 056 Table 6 distances by level are in the sour lines section.
Air emissions approval —	Not public	An EPEA approval is needed for a thermal plant over 1 MW (Alta Reg 276/2003); dispersion modelling is engineering work outside this screen.
Climate and output derate ECCC CWEEDS	Sourced	July design temperature and pressure from the three nearest CWEEDS stations; output with heat and altitude from the makers' published curves for the plant type (turbines lose output with heat and thin air; large gas engines hold rated output to 40 °C and about 1,500 m), unless you enter your own loss.
Capital and operating cost AESO CONE 2018; company filings and releases	Partial	Alberta project filings and the AESO's 2018 Cost of New Entry reference plants, restated to constant 2025 C$, and the analyst's assumptions; not a quote. Engine O&M has no Canadian public figure.

Evidence register built from the sections above; status words describe the public evidence, not the place · as of 2026-11-19 · saved 2026-11-19

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ASSUMPTIONS, SITE BY SITE

ASSUMPTIONS BEHIND THE FIGURES · TOWN OF FOX CREEK 54.4000,-116.8000

Assumption	Value	Basis
Load	100 MW, 8,760 run hours	Analyst input
Availability	92% of run hours	Default assumption, 92%, allowing for planned maintenance on top of forced outages: AESO CONE 2018 assumes a 2.5% forced outage rate and publishes no planned-outage figure (Tables 3–5); Alberta's combined-cycle plants produced in a median 96% of hours in 2019–2024 (10th percentile 88%), from AESO metered output
Data-centre load (permit path)	100 MW	Assumed equal to plant size
Plant	Reciprocating engines, Alberta (Bitdeer Fox Creek): 1,787.769 2025 C$/kW, efficiency 42.2% (HHV)	Alberta plant: the 101 MW gas-engine power plant at Fox Creek (nine 11.237 MW engines, 101.133 MW; AUC Power Plant Approval 29785-D02-2025), now Bitdeer's, first developed by Kiwetinohk Energy as Opal. Capital is the plant's all-in installed cost: Kiwetinohk's "Total estimated installed capital cost" of C$156M, an AACE Class 3 estimate that "excludes costs to finance projects" (and carbon capture), for the whole plant, first stated in Kiwetinohk's MD&A of March 23, 2022 ("increased its installed cost estimate by $11 million to $156 million", PDF p. 8, https://kiwetinohk.com/Financial/Dec_31_2021_MDA.pdf) and repeated unchanged to the Q3 2023 MD&A (p. 6, https://kiwetinohk.com/Financial/2023_Q3_MDA.pdf), so 2022 dollars, moved by the engine post-2022 step: C$156M ÷ 101,133 kW = C$1,543/kW. The estimate does not itemize the plant's electrical equipment or the gas and grid connections; ATCO's C$14.5M transmission connection is a separate project (AUC Decision 28658-D01-2024). Kiwetinohk withdrew the estimate in its 2023 Annual Information Form (March 2024) pending power-policy clarity, while it prepared a current one. The engine step is measured on this plant: Bitdeer's 2025 figures (Form 6-K exhibit 99.1, 2025-02-04, estimated costs table, https://www.sec.gov/Archives/edgar/data/1899123/000114036125003778/ef_ex99-1.htm: "Gas-fired power plant ~$90 million", "Electrical & datacenter infrastructure" US$300K per MW or about US$30M, the site US$21.7M) reconciled to Kiwetinohk's scope are the plant line plus the plant's share of the electrical line (not split by the filing: US$0–30M, the midpoint taken, a judgement), the site purchase and financing left out: US$90–120M, central US$105M, C$1,451/kW at the Bank of Canada 2025 rate (C$1,244–1,659). Over Kiwetinohk's C$1,780/kW (2025 C$ by the engine index) that is 0.82× (0.70–0.93): by this pair the plant's cost rose less than the price indices carry. No Canadian public O&M figure for engine plants: fixed and variable O&M are the AESO CONE 2018 aeroderivative figures (C$50.6/kW-yr, C$4.6/MWh, 2021 dollars), a labelled stand-in until the AESO's new Cost of New Entry study, which adds a reciprocating engine reference (due early 2027), publishes. Heat rate: heat rate 8.52 GJ/MWh HHV, derived from Beacon AI Centers – Heartland Project, Initial Project Description (IAAC registry 90123, document 164422E, 2025-12-14), §23 Table 23.1.1, p. 102, https://iaac-aeic.gc.ca/050/documents/p90123/164422E.pdf: 3,004 kt CO2 a year from 200 INNIO Jenbacher J624 engines at 800 MWe × 8,760 h = 7,008 GWh is 0.4287 t CO2/MWh, ÷ 0.0503 t CO2/GJ HHV (the emission factor this model applies, so its emissions reproduce the filing) = 8.52 GJ/MWh (8.57 at the CONE study's 0.050 t/GJ); CO2 only, not the CO2e figure, which carries methane slip. In constant 2025 C$ (Statistics Canada price indexes): capital 1,543 (2022 dollars) × 1.1538 (equipment 0.40 × 1.1660 + construction 0.60 × 1.1456) = 1,780 C$/kW; fixed O&M 50.60 (2021 dollars) × 1.1534 (Alberta CPI 1.1534) = 58.36 C$/kW-yr; variable O&M 4.60 (2021 dollars) × 1.1534 (Alberta CPI 1.1534) = 5.31 C$/MWh. Capital costed in 2022: lowered 0.82× for the post-2022 change in plant costs the price indices miss: by this pair the plant's cost rose less than the indices carry (median of 1 matched engine pair: Fox Creek gas engine plant (Kiwetinohk 'Opal' Firm Renewable; now Bitdeer Fox Creek) 2022 to Bitdeer Fox Creek engine plant, 2025 figures reconciled to an all-in plant 2025, 0.82×), C$1,451/kW.

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Assumption	Value	Basis
Plant O&M	58.36 C$/kW-yr fixed, 5.31 C$/MWh variable (2025 C$)	Assumption: No Canadian public O&M figure for engine plants: fixed and variable O&M are the AESO CONE 2018 aeroderivative figures (C$50.6/kW-yr, C$4.6/MWh, 2021 dollars), a labelled stand-in until the AESO's new Cost of New Entry study, which adds a reciprocating engine reference (due early 2027), publishes

First 5 of 26 rows. The full table is Appendix A8.

PatchWatt assumptions register · as of 2026-11-19 · saved 2026-11-19

AUC RULE 007 CROSS-REFERENCE

AUC Rule 007, effective 2025-11-06, §4.5.2 thermal power plant applications, items TP1–TP42: 24 groups, 2 covered here, 17 partly, 5 needing site or applicant work.

Item	Rule 007 asks for	Here	Where, or what is missing
TP1	Units, make, model and MW	partly	Plant type and size screened (Sizing and cost); make and model are not chosen
TP2	Existing approvals affected	partly	An existing power plant at the point is checked (Location and site)
TP3–TP4	Ownership; municipal ownership	site work	Not in public data
TP5	Legal description and component locations	partly	LSD of the site point (title and Location and site); a plant boundary and .kml come with a layout
TP6	Maps: residences, reserves, sensitive areas	partly	Site map; buildings at the Rule 007 radii, those OpenStreetMap tags as dwellings or non-dwellings counted apart and untagged ones treated as possible residences (Location and site); reserves and settlements (Ground and land use). Here: 941 buildings within 1.5 km, of which 12 tagged as dwellings, 0 tagged as non-dwellings (farm, industrial, commercial or outbuildings), the rest (929) untagged or not settled by their tag; untagged buildings are treated as possible dwellings, as the noise impact assessment Rule 007 asks for (TP31, under Rule 012) surveys receptors on the ground; 662 of them are OpenStreetMap buildings, which can carry a use tag, and 279 Microsoft footprints of about 2019, which carry none.

First 5 of 24 rows. The full table is Appendix A9.

AUC Rule 007 (effective 2025-11-06) §4.5.2; PatchWatt sections · as of 2025-11-06 · saved 2026-11-19

WHAT THIS DOES NOT DETERMINE

Whether gas can be contracted, at what price or for how long

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Pipeline or grid capacity at a tie-in, or connection cost and timing

Land availability, ownership or access

Whether the AUC, AEPA or the municipality will approve a project

Air dispersion, noise, geotechnical or hydraulic results (stamped engineering)

Equipment selection or vendor performance

Reserves or deliverability of any well or pool

Whether a project belongs at this site: this lists evidence and does not rank sites

Transmission and distribution charges a grid-supplied data centre would pay, which the grid price comparison leaves out

Delivery times for long-lead equipment (generator step-up transformers, turbines, engines)

PatchWatt scope statement and assumptions register · as of 2026-11-19 · saved 2026-11-19

OPEN ITEMS

Items the public data used here does not settle. Each stays open until the named party answers in writing.

Every item applies to the site in this report.

Could it change the reading: Yes where the answer feeds a figure, a screen or a cost in this report; No where no figure here uses it (it can still bear on an approval or an agreement, as stated).

Item	Who closes it	How	Could it change the reading?
Plant capital cost	Equipment vendors; an EPC contractor	Get budgetary quotes for the chosen machines at this size and site. Public figures for one plant type differ by more than the Class 5 range, and capital is the largest part of the cost of power.	Yes: The answer replaces the "Plant capital at the plant size costed, before interest during construction" assumption, which feeds capital charge in the cost of power.

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Item	Who closes it	How	Could it change the reading?
Engine plant O&M	Engine vendor (long-term service agreement); the plant operator	Get a long-term service agreement quote and an operating budget for the engines chosen; they replace the stand-in fixed and variable O&M (the AESO's aeroderivative reference figures).	Yes: The answer replaces the "Fixed O&M" assumption, which feeds fixed O&M in the cost of power and the finance model.
Meter station cost and who pays for it	NGTL (TC Energy) or the gas carrier	Ask the carrier for its facilities estimate for the meter station and any contribution it would require from the shipper; enter it as the meter station cost.	Yes: The answer replaces the "Meter station" assumption, which feeds connection capital where a tie-in is found.
Financing terms (loan tenor and minimum coverage)	Lenders; a financial adviser	A term sheet for this project replaces the assumed tenor and minimum coverage ratio.	Yes: The answer replaces the "Debt tenor" assumption, which feeds debt service and sizing.
Carbon compliance price (credit share and price)	The facility's TIER compliance adviser; a carbon credit broker	A compliance plan or a credit purchase quote replaces the assumed 85% credit share and the held credit price; enter them as the credit share and carbon case.	Yes: The answer replaces the "Carbon price case" assumption, which feeds the C$/t applied to tonnes above (and credits below) the benchmark in the finance model and the dispatch engine.
Operating reserve qualification, offer share and market share	The plant's owner or the AESO's ancillary services team	Enter the MW the AESO has qualified the plant for (its supplemental reserve qualification) and the share of procured volume it expects to win; whether the plant qualifies at all depends on its start time and the ISO's qualification test (ISO rule 205.6).	Yes: The answer replaces the "Operating reserves (ancillary services)" assumption, which feeds a separate revenue line.

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Item	Who closes it	How	Could it change the reading?
Financial statements, debt and hedges	The company	Obtain audited financial statements and the latest reserves report (NI 51-101 for a reporting issuer).	No: Not in the figures, which are gross Alberta volumes and public licence data.
Gas quality (H2S, heating value)	Supplier gas analysis	Public data covers part (AER ST50A; Petrinex); confirm the rest	Yes: A supplier's analysis replaces the area heating value that turns the plant's energy need into a gas volume (Sizing and cost), and the H2S decides whether the gas needs treating.
Pipeline tie-in route and distance	Line operator; route survey	Public data covers part (AER pipelines; CER pipeline systems; CanVec); confirm the rest	Yes: The tie-in distance sets the gas lateral's length and cost in Sizing and cost.
Pipeline capacity at the tie-in	Line operator (NGTL for federal lines)	Not in public data: ask directly and record the answer	No: Not in the figures: they assume gas service at the tie-in. The answer decides whether there is any.
Grid connection capacity	AESO connection process; transmission facility owner	Not in public data: ask directly and record the answer	Yes: An upgrade cost, entered as line and substation cost, adds to the cost of power in Sizing and cost.
Land ownership and access	Land agent; Alberta Land Titles	Not in public data: ask directly and record the answer	No: Not in the figures; it bears on land agreements (AUC Rule 007 TP5).
Municipal stance on data centres	Municipal planning department; land-use bylaw	Public data covers part (Council records, bylaws, AUC decisions and court files); confirm the rest	Yes: The screen can leave out municipalities that paused or refused data centres; a stance on record moves this site in or out.

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Item	Who closes it	How	Could it change the reading?
Water for cooling	Alberta Environment and Protected Areas (Water Act)	Public data covers part (NRCan NHN; Water Act); confirm the rest	Yes: The screen can leave out closed basins, and wet cooling adds a Water Act licence to the regulatory path.
Wetlands	Qualified wetland assessment	Public data covers part (AMWI); confirm the rest	No: Not in the figures; it bears on a Water Act approval (AUC Rule 007 TP26).
Flood hazard	Alberta flood hazard mapping; site hydrology	Public data covers part (Alberta FHIP); confirm the rest	Yes: The screen can leave out mapped flood hazard areas.
Indigenous lands and consultation	Aboriginal Consultation Office; affected Nations	Public data covers part (Alberta open data); confirm the rest	No: Not in the figures; it bears on consultation (AUC Rule 007 TP35).
Species and protected areas	Wildlife survey; AEPA	Public data covers part (Alberta wildlife maps; Parks and Protected Areas of Alberta); confirm the rest	Yes: The screen can leave out caribou ranges and protected areas.
Historic resources	Alberta Historic Resources Management Branch	Public data covers part (Listing of Historic Resources; Historical Resources Act); confirm the rest	No: Not in the figures; it bears on the Historical Resources Act application (AUC Rule 007 TP34).
Homes near the point (AUC precedent)	Applicant's participant involvement program (residences within 800 m and 2 km) and noise impact assessment	Public data covers part (AUC Decision 30732-D01-2026 ¶28, ¶36; Overture Maps buildings release 2026-10-21.0 (OpenStreetMap, gaps filled with Microsoft footprints of about 2019), © OpenStreetMap contributors, Microsoft, Overture Maps Foundation (ODbL)); confirm the rest	Yes: The screen's building limit counts building footprints; a count of residences from a filing replaces them.
Noise (AUC Rule 012)	Acoustic consultant: noise impact assessment	Public data covers part (Overture Maps buildings release 2026-10-21.0 (OpenStreetMap and Microsoft footprints), © OpenStreetMap contributors, Microsoft, Overture Maps Foundation (ODbL)); confirm the rest	Yes: The screen's building limit reads the building count this row reports; a noise study replaces it.

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Item	Who closes it	How	Could it change the reading?
Sour gas setback	Licensee's Directive 056 H2S release volume calculation and emergency planning zone	Public data covers part (AER Enhanced Pipeline data (H2S release volume and level); AER Directive 056 (2026-10-01) Table 6; ST50A); confirm the rest	Yes: The setback in Ground and land use, and the screen's sour-line level limit, read the line's release level.
Air emissions approval	Air quality consultant; AEPA	Not in public data: ask directly and record the answer	No: Not in the figures; dispersion modelling bears on the EPEA approval.
Capital and operating cost	EPC estimate; vendor quotes	Public data covers part (AESO CONE 2018; company filings and releases); confirm the rest	Yes: Quotes replace the reference capital and O&M; the cost of power moves.

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APPENDIX: FULL TABLES

APPENDIX A1 · SIZING AND COST · PERMIT PATH (13 rows)

Step at 100 MW plant	Typical duration
AUC power plant approval 10 MW or more: full application. Notify within 2,000 m and consult in person within 800 m of the project boundary; the municipal engagement form goes to the municipality at least 30 days before filing.	Performance targets after a complete application: about 120 days with no objections (90 + 30 days) to about 295 days with a full hearing (205 + 90 days)
Approval life Construction must finish within the period the approval sets, at most seven years from the initial approval; after that, a new application. Smaller plants get the period they propose.	7 years maximum
EPEA approval (Alberta Environment and Protected Areas) A thermal power plant over 1 MW needs an approval; there is no code-of-practice route. Emergency-only backup units not connected to the distribution system, up to 50 MW, are excluded.	No published service standard
Environmental impact assessment · does not apply Not on the mandatory list for gas-fired plants (mandatory only for thermal plants on non-gaseous fuel at 100 MW or more). The Director can still require further assessment of an activity that is not mandatory, weighing its location, size, nature, technology, public concerns and similar activities nearby, and then order a full report; the Minister can order one regardless. The EPEA approval cannot issue until Division 1 has been complied with where it applies.	Not published; 30 days for statements of concern after notice of a further-assessment decision
Federal impact assessment (IAAC) · does not apply Fossil-fuel power plants are no longer designated projects: SOR/2026-185, in force 2026-09-03, repealed the 200 MW item and the expansion item of the Physical Activities Regulations, and the federal government says these plants are assessed under provincial processes. Greenlight (1,864 MW) and Beacon Heartland (920 MW) were screened before the repeal; the Agency decided no further assessment was required for either.	—
Federal Clean Electricity Regulations · does not apply SOR/2024-263 sets an annual limit of 65 t CO2/GWh from 2035 on gas units of 25 MW and more on a NERC grid. In Alberta the regulations are held in abeyance while the CER Reference is before the Alberta Court of Appeal and any appeal to the Supreme Court proceeds; if upheld, Canada and Alberta negotiate an equivalency agreement to stand them down in Alberta, and if struck down, Canada repeals them. Carbon here is priced under TIER (see Carbon).	—
Historical Resources Act application Projects that need AUC approval always file a Historical Resources Act application, whether or not the land is on the Listing of Historic Resources; the Minister may order a historic resources impact assessment.	Not published
Water Act licence · does not apply Air cooling avoids a diversion licence.	Not published
AESO connection Behind-the-fence or connection project through the AESO stages, to the AESO's connection requirements for transmission-connected data centres. Off-grid designs avoid this step but not the AUC or EPEA.	Stages 0–2 average 75 weeks (behind-the-fence) to 86 weeks (connection); Stage 3/4 average 89 weeks (behind-the-fence), Stage 3 134 weeks (connection); April 2026

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Step at 100 MW plant	Typical duration
Reclamation cost estimate and security Recent thermal approvals set it by condition. Greenlight ($30.54 million estimate, 2025 dollars): letters of credit from the 5th anniversary of commercial operation, every five years, reaching the full updated estimate by year 20. Beacon Heartland: 5% of the estimate by the end of year one, rising each year to the full amount by year 20.	—
Municipal development permit Under the municipality's land use bylaw: a permitted use that conforms gets a permit; a discretionary use is decided case by case. The plant's AUC approval prevails over the municipal plan, bylaw and permit decisions, and the municipality must approve a consistent application to the extent it complies with that approval; a plan or bylaw amendment of that kind is due within 90 days. The AUC does not regulate data centres themselves, so the data-centre building rests on the bylaw alone. The zoning district at the site is not in the public data used here; check the municipal bylaw map.	Set by the municipality; 90 days for a plan or bylaw amendment consistent with an AUC approval
Data Centre Regulation Grid-connected: the test is maximum demand directly from the transmission system of 75 MW or more (s. 2(1)), where demand is the rate the data centre may draw from it (s. 1(2)(c)); shown here on the data-centre load, 100 MW (taken as equal to the plant size). With a plant behind the fence the draw the connection allows can be smaller than the load; the regulation does not say how on-site generation counts toward demand, so the AESO's reading of the connection governs. The AESO may set a lower threshold (s. 2(2)) and treat integrated data centres on the same or adjacent parcels as one (s. 3). It must process tethered data centres (tied to new generation or storage at least equal to their maximum demand) before other large data centres (s. 6); a bridged data centre is a tethered one served before its generation, for up to 3 years (s. 9(5)). The AESO may set criteria on site control, zoning, financing and permits or water licences (s. 7(1)). Its bring-your-own-generation process was not final at the 2026-09-08 update.	Bridged service up to 3 years
Data centre levy Yearly levy on the computing equipment of a data centre whose electricity capacity is 75 MW or more at any time in the year, from 2026 (s. 92.3(3)); shown here on the data-centre load, 100 MW (taken as equal to the plant size). Part 9.1 does not define electricity capacity. Levy = (E + F) × R, where E is 45% of the cost of equipment under 4 years old and F 15% of older equipment. R is 2% on the share of electricity received from the power grid and 1% on the grid share delivered under a new power capacity agreement or self-generation arrangement; electricity from other sources, including the operator's own generation, counts in the total but carries no rate (s. 92.3(7)). Grid-connected: R runs from 2% when all electricity comes from the grid unmatched toward 0% as more comes from other sources; the split is not known here, and whether a behind-the-fence supply is received from the power grid turns on its definition (s. 92.2(1)(p)).	Return and payment within 14 months after each calendar year

APPENDIX A2 · GAS SUPPLY · OPERATORS OF THE BATTERIES THESE WELLS REPORTED TO SINCE JAN 2022, GAS OR OIL (20 rows)

Operator	Wells
ALPHABOW ENERGY LTD.	6
ATHABASCA OIL CORPORATION	3
BENCH CREEK RESOURCES LTD.	1
CANADIAN NATURAL RESOURCES LIMITED	315
CHEVRON CANADA LIMITED	3
DOAG ENERGY LTD.	4
GRAN TIERRA CANADA LTD.	12
HWN ENERGY LTD.	113
MURPHY OIL COMPANY LTD.	52

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Operator	Wells
NVP EXPLORATION INC.	1
ORLEN UPSTREAM CANADA LTD.	18
PARAMOUNT RESOURCES LTD.	384
PETROCHINA DUVERNAY GAS PARTNERSHIP	92
PEYTO EXPLORATION & DEVELOPMENT CORP.	39
RIDGEBACK RESOURCES INC.	1
ROCKY MOUNTAINS ENERGY LTD.	23
ROK RESOURCES INC.	32
SATURN OIL & GAS INC.	40
SINOPEC CANADA ENERGY LTD.	23
SINOPEC DAYLIGHT ENERGY LTD.	1

APPENDIX A3 · REGULATORY PATH · APPROVALS THAT APPLY TO A 100 MW GAS-FIRED PLANT (13 rows)

Step	Applies	What it involves	Published duration
AUC power plant approval AUC Rule 007 (2025-11-06) s. 4.2, Table 4.7, Appendix A1 s. 6.3, Table 3.1; Hydro and Electric Energy Act s. 11	Yes	10 MW or more: full application. Notify within 2,000 m and consult in person within 800 m of the project boundary; the municipal engagement form goes to the municipality at least 30 days before filing.	Performance targets after a complete application: about 120 days with no objections (90 + 30 days) to about 295 days with a full hearing (205 + 90 days)
Approval life AUC Bulletin 2025-14; AUC Rule 007 s. 5.1	Yes	Construction must finish within the period the approval sets, at most seven years from the initial approval; after that, a new application. Smaller plants get the period they propose.	7 years maximum
EPEA approval (Alberta Environment and Protected Areas) Activities Designation Regulation, Alta Reg 276/2003, s. 5(1), s. 2(2)(vv), Sch. 1 Div. 2 Part 9	Yes	A thermal power plant over 1 MW needs an approval; there is no code-of-practice route. Emergency-only backup units not connected to the distribution system, up to 50 MW, are excluded.	No published service standard
Environmental impact assessment Environmental Assessment (Mandatory and Exempted Activities) Regulation, Alta Reg 111/93, s. 1, Sch. 1 cl. (k); EPEA, RSA 2000 c E-12, ss. 43, 44(1)(b), 44(3), 44(6), 45(4), 47, 63	No	Not on the mandatory list for gas-fired plants (mandatory only for thermal plants on non-gaseous fuel at 100 MW or more). The Director can still require further assessment of an activity that is not mandatory, weighing its location, size, nature, technology, public concerns and similar activities nearby, and then order a full report; the Minister can order one regardless. The EPEA approval cannot issue until Division 1 has been complied with where it applies.	Not published; 30 days for statements of concern after notice of a further-assessment decision

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Step	Applies	What it involves	Published duration
Federal impact assessment (IAAC) SOR/2026-185 s. 3; Physical Activities Regulations SOR/2019-285 (former Sch. s. 30); IAAC registry 89790 and 90123	No	Fossil-fuel power plants are no longer designated projects: SOR/2026-185, in force 2026-09-03, repealed the 200 MW item and the expansion item of the Physical Activities Regulations, and the federal government says these plants are assessed under provincial processes. Greenlight (1,864 MW) and Beacon Heartland (920 MW) were screened before the repeal; the Agency decided no further assessment was required for either.	—
Federal Clean Electricity Regulations Clean Electricity Regulations, SOR/2024-263, ss. 2(1), 5(1), 9(1)(a), 10(2)(a); Implementation Agreement for the Canada–Alberta Memorandum of Understanding, 2026-05-15, §2.1.1–2.1.3	No	SOR/2024-263 sets an annual limit of 65 t CO2/GWh from 2035 on gas units of 25 MW and more on a NERC grid. In Alberta the regulations are held in abeyance while the CER Reference is before the Alberta Court of Appeal and any appeal to the Supreme Court proceeds; if upheld, Canada and Alberta negotiate an equivalency agreement to stand them down in Alberta, and if struck down, Canada repeals them. Carbon here is priced under TIER (see Carbon).	—
Historical Resources Act application Listing of Historic Resources, Instructions for Use (2023-09), p. 2; Historical Resources Act s. 37(2)	Yes	Projects that need AUC approval always file a Historical Resources Act application, whether or not the land is on the Listing of Historic Resources; the Minister may order a historic resources impact assessment.	Not published
Water Act licence Water Act s. 49(1)	No	Air cooling avoids a diversion licence.	Not published
AESO connection AESO Connection Process Performance Update, April 2026 (latest at 2026-11-10); AESO data centre connection guide (2026-06-12)	Yes	Behind-the-fence or connection project through the AESO stages, to the AESO's connection requirements for transmission-connected data centres. Off-grid designs avoid this step but not the AUC or EPEA.	Stages 0–2 average 75 weeks (behind-the-fence) to 86 weeks (connection); Stage 3/4 average 89 weeks (behind-the-fence), Stage 3 134 weeks (connection); April 2026
Reclamation cost estimate and security AUC Decision 30261-D02-2026 ¶48, ¶56 conditions k–l; AUC Decision 30518-D01-2026 ¶123 conditions g–h	Yes	Recent thermal approvals set it by condition. Greenlight ($30.54 million estimate, 2025 dollars): letters of credit from the 5th anniversary of commercial operation, every five years, reaching the full updated estimate by year 20. Beacon Heartland: 5% of the estimate by the end of year one, rising each year to the full amount by year 20.	—
Municipal development permit Municipal Government Act ss. 619(1)–(3), 640(1), 642(1); AUC data centre fact sheet; municipal land use bylaws	Yes	Under the municipality's land use bylaw: a permitted use that conforms gets a permit; a discretionary use is decided case by case. The plant's AUC approval prevails over the municipal plan, bylaw and permit decisions, and the municipality must approve a consistent application to the extent it complies with that approval; a plan or bylaw amendment of that kind is due within 90 days. The AUC does not regulate data centres themselves, so the data-centre building rests on the bylaw alone. The zoning district at the site is not in the public data used here; check the municipal bylaw map.	Set by the municipality; 90 days for a plan or bylaw amendment consistent with an AUC approval

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Step	Applies	What it involves	Published duration
Data Centre Regulation Data Centre Regulation, Alta Reg 117/2026 (in force 2026-06-09), ss. 1(2)(c), 2, 3, 6, 7, 9; AESO Phase 2A update, 2026-09-08	Yes	Grid-connected: the test is maximum demand directly from the transmission system of 75 MW or more (s. 2(1)), where demand is the rate the data centre may draw from it (s. 1(2)(c)); shown here on the data-centre load, 100 MW (taken as equal to the plant size). With a plant behind the fence the draw the connection allows can be smaller than the load; the regulation does not say how on-site generation counts toward demand, so the AESO's reading of the connection governs. The AESO may set a lower threshold (s. 2(2)) and treat integrated data centres on the same or adjacent parcels as one (s. 3). It must process tethered data centres (tied to new generation or storage at least equal to their maximum demand) before other large data centres (s. 6); a bridged data centre is a tethered one served before its generation, for up to 3 years (s. 9(5)). The AESO may set criteria on site control, zoning, financing and permits or water licences (s. 7(1)). Its bring-your-own-generation process was not final at the 2026-09-08 update.	Bridged service up to 3 years
Data centre levy Alberta Corporate Tax Act, RSA 2000 c A-15, Part 9.1, ss. 92.2(1)(p), 92.3(3), 92.3(7), 92.5 (added by SA 2025 c 20)	Yes	Yearly levy on the computing equipment of a data centre whose electricity capacity is 75 MW or more at any time in the year, from 2026 (s. 92.3(3)); shown here on the data-centre load, 100 MW (taken as equal to the plant size). Part 9.1 does not define electricity capacity. Levy = (E + F) × R, where E is 45% of the cost of equipment under 4 years old and F 15% of older equipment. R is 2% on the share of electricity received from the power grid and 1% on the grid share delivered under a new power capacity agreement or self-generation arrangement; electricity from other sources, including the operator's own generation, counts in the total but carries no rate (s. 92.3(7)). Grid-connected: R runs from 2% when all electricity comes from the grid unmatched toward 0% as more comes from other sources; the split is not known here, and whether a behind-the-fence supply is received from the power grid turns on its definition (s. 92.2(1)(p)).	Return and payment within 14 months after each calendar year

APPENDIX A4 · PRICES AND CARBON · ALBERTA INTERNAL LOAD SINCE 2000 (27 rows)

Year	Energy TWh	Mean MW	Peak MW	Peak hour	Load factor	Energy on year before
2026 (to 2026-11-16)	80.33	10,461	12,404	17 Feb 2026, hour ending 19	84.3%	—
2025	90.37	10,316	12,785	11 Dec 2025, hour ending 18	80.7%	+1.7%
2024	88.83	10,112	12,384	11 Jan 2024, hour ending 18	81.7%	+2.9%
2023	86.29	9,851	11,572	22 Feb 2023, hour ending 19	85.1%	−0.3%
2022	86.57	9,883	12,193	21 Dec 2022, hour ending 18	81.1%	+1.6%
2021	85.21	9,728	11,729	9 Feb 2021, hour ending 19	82.9%	+2.5%
2020	83.11	9,462	11,698	14 Jan 2020, hour ending 18	80.9%	−2.1%
2019	84.93	9,695	11,471	12 Feb 2019, hour ending 19	84.5%	−0.5%
2018	85.33	9,741	11,697	11 Jan 2018, hour ending 18	83.3%	+3.3%
2017	82.57	9,426	11,473	28 Dec 2017, hour ending 18	82.2%	+3.8%
2016	79.56	9,057	11,458	16 Dec 2016, hour ending 18	79.0%	−0.9%
2015	80.26	9,162	11,229	5 Jan 2015, hour ending 18	81.6%	+0.4%
2014	79.95	9,127	11,169	29 Dec 2014, hour ending 18	81.7%	+3.2%

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Year	Energy TWh	Mean MW	Peak MW	Peak hour	Load factor	Energy on year before
2013	77.45	8,841	11,139	2 Dec 2013, hour ending 18	79.4%	+2.5%
2012	75.57	8,604	10,609	16 Jan 2012, hour ending 18	81.1%	+2.7%
2011	73.60	8,402	10,226	12 Jan 2011, hour ending 18	82.2%	+2.6%
2010	71.72	8,188	10,196	16 Dec 2010, hour ending 18	80.3%	+2.6%
2009	69.91	7,981	10,236	14 Dec 2009, hour ending 18	78.0%	0.0%
2008	69.95	7,963	9,806	15 Dec 2008, hour ending 18	81.2%	+0.4%
2007	69.66	7,952	9,701	3 Dec 2007, hour ending 18	82.0%	+0.4%
2006	69.37	7,919	9,661	28 Nov 2006, hour ending 18	82.0%	+4.7%
2005	66.27	7,565	9,580	5 Dec 2005, hour ending 18	79.0%	+1.5%
2004	65.26	7,429	9,236	22 Dec 2004, hour ending 18	80.4%	+4.1%
2003	62.71	7,159	8,786	15 Dec 2003, hour ending 18	81.5%	+5.5%
2002	59.43	6,784	8,570	3 Dec 2002, hour ending 18	79.2%	+9.1%
2001	54.46	6,217	7,934	10 Dec 2001, hour ending 18	78.4%	+0.8%
2000	54.05	6,154	7,785	12 Dec 2000, hour ending 18	79.0%	—

APPENDIX A5 · PRICES AND CARBON · INTERTIES: IMPORTS AND EXPORTS (26 rows)

Year	Imports GWh	Exports GWh	Net import GWh	Hours importing	Hours exporting	BC net GWh	MT net GWh	SK net GWh	Tie not named GWh
2026 (10 months)	1,113	1,537	−425	41%	51%	249	−50	55	−679
2025	582	3,633	−3,051	21%	75%	−2,063	−231	22	−778
2024	1,160	3,015	−1,856	33%	65%	−2,226	186	184	—
2023	2,177	2,169	8	60%	40%	−1,232	658	582	—
2022	4,243	630	3,613	89%	11%	1,996	1,122	495	—
2021	4,151	131	4,019	98%	2%	2,225	1,133	661	—
2020	3,966	98	3,868	95%	1%	2,410	1,100	358	—
2019	2,132	610	1,522	73%	20%	561	755	207	—
2018	3,394	731	2,663	73%	22%	1,642	914	107	—
2017	1,295	1,022	273	35%	50%	459	−62	−124	—
2016	435	867	−432	27%	43%	−274	29	−187	—
2015	1,091	651	441	47%	34%	273	208	−40	—
2014	2,052	557	1,495	72%	17%	926	667	−99	—
2013	2,547	258	2,289	83%	12%	1,679	124	486	—
2012	3,582	85	3,497	92%	5%	3,005	—	492	—

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Year	Imports GWh	Exports GWh	Net import GWh	Hours importing	Hours exporting	BC net GWh	MT net GWh	SK net GWh	Tie not named GWh
2011	3,591	119	3,473	96%	3%	2,976	—	496	—
2010	2,205	470	1,735	78%	20%	1,425	—	310	—
2009	2,019	514	1,505	78%	20%	856	—	649	—
2008	2,248	559	1,689	76%	22%	1,056	—	633	—
2007	1,467	973	494	61%	37%	42	—	452	—
2006	1,517	489	1,028	70%	24%	641	—	386	—
2005	1,535	1,038	497	58%	38%	83	—	413	—
2004	1,492	1,061	430	58%	39%	105	—	325	—
2003	1,332	1,228	104	54%	43%	−291	—	395	—
2002	1,161	574	588	61%	31%	454	—	134	—
2001	948	2,293	−1,344	30%	69%	−1,957	—	613	—

APPENDIX A6 · PRICES AND CARBON · MONTH BY MONTH, LAST 24 MONTHS (24 rows)

Month	Imports GWh	Exports GWh	Net import GWh	Hours importing	Hours exporting	BC net GWh	MT net GWh	SK net GWh	Tie not named GWh	Source
Oct 2026	77	222	−145	27%	72%	−42	1	2	−106	ETS
Sep 2026	35	233	−199	10%	88%	−73	−33	−3	−90	ETS
Aug 2026	91	222	−131	20%	65%	−87	−50	26	−21	ETS
Jul 2026	154	161	−7	44%	55%	71	−58	−3	−18	ETS
Jun 2026	161	36	125	69%	26%	101	7	18	0	ETS
May 2026	209	23	186	76%	15%	148	18	20	0	ETS
Apr 2026	145	18	127	60%	17%	113	13	6	−6	ETS
Mar 2026	132	115	17	54%	41%	52	46	−9	−73	ETS
Feb 2026	40	240	−200	23%	68%	−24	−7	0	−169	ETS
Jan 2026	68	266	−198	29%	68%	−11	12	−2	−197	ETS
Dec 2025	77	269	−192	32%	67%	−20	12	2	−187	ETS
Nov 2025	70	250	−180	37%	61%	−33	−13	19	−152	ETS
Oct 2025	31	378	−347	16%	81%	−72	−41	2	−236	ETS
Sep 2025	17	146	−129	15%	52%	−44	−21	0	−64	ETS
Aug 2025	41	314	−273	14%	86%	−67	−66	0	−140	ETS
Jul 2025	19	395	−376	4%	96%	−304	−72	0	—	Data request
Jun 2025	35	282	−247	16%	77%	−232	−15	0	—	Data request
May 2025	59	213	−153	28%	67%	−158	5	0	—	Data request

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Month	Imports GWh	Exports GWh	Net import GWh	Hours importing	Hours exporting	BC net GWh	MT net GWh	SK net GWh	Tie not named GWh	Source
Apr 2025	72	232	−159	37%	62%	−161	1	0	—	Data request
Mar 2025	85	331	−245	25%	74%	−258	12	0	—	Data request
Feb 2025	43	350	−306	17%	82%	−301	−5	0	—	Data request
Jan 2025	32	474	−442	10%	90%	−414	−28	0	—	Data request
Dec 2024	26	337	−310	12%	87%	−273	−37	0	—	Data request
Nov 2024	122	165	−43	50%	49%	−82	40	0	—	Data request

APPENDIX A7 · PRICES AND CARBON · HOUR-AHEAD PRICE FORECAST AGAINST THE SETTLED PRICE (25 rows)

Year	Mean pool price	Mean absolute error	Mean error	RMS error	Hours off by over C$50	of which above	of which below	Hours off by over C$100	Hours
2025 (7 months)	C$38.83	C$12.46	−C$3.39	C$54.59	4.0%	1.2%	2.8%	2.2%	5,087
2024	C$62.78	C$17.97	−C$3.56	C$56.42	8.5%	3.4%	5.1%	4.5%	8,784
2023	C$133.63	C$42.11	−C$7.59	C$98.71	20.2%	8.6%	11.7%	13.5%	8,760
2022	C$162.46	C$34.08	−C$8.25	C$85.02	16.8%	6.7%	10.1%	10.3%	8,760
2021	C$101.93	C$23.24	−C$8.29	C$70.04	10.5%	3.5%	7.0%	6.8%	8,760
2020	C$46.72	C$5.76	−C$2.67	C$37.10	2.1%	0.6%	1.5%	1.2%	8,784
2019	C$54.88	C$13.30	−C$5.20	C$65.65	4.2%	1.5%	2.7%	3.0%	8,760
2018	C$50.35	C$9.81	−C$4.51	C$55.51	3.1%	0.9%	2.3%	2.2%	8,760
2017	C$22.19	C$2.30	−C$0.97	C$25.21	0.4%	0.1%	0.3%	0.3%	8,760
2016	C$18.28	C$1.24	−C$0.54	C$13.47	0.2%	0.0%	0.2%	0.1%	8,784
2015	C$33.34	C$6.47	−C$2.90	C$46.05	1.8%	0.5%	1.2%	1.4%	8,759
2014	C$49.42	C$7.66	−C$2.55	C$42.56	2.2%	0.6%	1.6%	1.4%	8,758
2013	C$80.19	C$18.43	−C$6.80	C$67.72	7.6%	2.5%	5.1%	5.0%	8,760
2012	C$64.27	C$16.29	−C$5.58	C$61.90	7.2%	2.5%	4.7%	4.4%	8,783
2011	C$76.22	C$18.90	−C$7.23	C$74.24	7.2%	2.5%	4.7%	4.8%	8,760
2010	C$50.88	C$12.66	−C$5.06	C$56.77	4.8%	1.7%	3.1%	3.3%	8,760
2009	C$47.81	C$17.82	−C$13.11	C$72.24	5.6%	0.8%	4.7%	4.2%	8,760
2008	C$89.95	C$51.25	−C$34.87	C$135.04	16.6%	2.9%	13.7%	13.4%	8,784
2007	C$66.95	C$50.30	−C$25.54	C$139.44	15.7%	4.6%	11.1%	11.1%	8,760
2006	C$80.83	C$52.12	−C$30.79	C$132.32	19.1%	4.7%	14.4%	13.2%	8,746
2005	C$70.36	C$37.61	−C$7.49	C$87.69	16.4%	7.3%	9.1%	8.8%	8,760

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Year	Mean pool price	Mean absolute error	Mean error	RMS error	Hours off by over C$50	of which above	of which below	Hours off by over C$100	Hours
2004	C$54.59	C$22.70	C$1.04	C$53.12	9.2%	5.5%	3.7%	3.7%	8,784
2003	C$62.99	C$26.98	C$2.42	C$64.77	12.4%	7.8%	4.7%	6.5%	8,760
2002	C$43.93	C$14.18	C$0.26	C$53.57	5.0%	2.5%	2.5%	2.7%	8,760
2001	C$71.28	C$8.01	−C$1.90	C$30.75	3.4%	1.4%	2.0%	1.4%	8,758

APPENDIX A8 · ASSUMPTIONS, SITE BY SITE (26 rows)

Assumption	Value	Basis
Load	100 MW, 8,760 run hours	Analyst input
Availability	92% of run hours	Default assumption, 92%, allowing for planned maintenance on top of forced outages: AESO CONE 2018 assumes a 2.5% forced outage rate and publishes no planned-outage figure (Tables 3–5); Alberta's combined-cycle plants produced in a median 96% of hours in 2019–2024 (10th percentile 88%), from AESO metered output
Data-centre load (permit path)	100 MW	Assumed equal to plant size

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Assumption	Value	Basis
Plant	Reciprocating engines, Alberta (Bitdeer Fox Creek): 1,787.769 2025 C$/kW, efficiency 42.2% (HHV)	Alberta plant: the 101 MW gas-engine power plant at Fox Creek (nine 11.237 MW engines, 101.133 MW; AUC Power Plant Approval 29785-D02-2025), now Bitdeer's, first developed by Kiwetinohk Energy as Opal. Capital is the plant's all-in installed cost: Kiwetinohk's "Total estimated installed capital cost" of C$156M, an AACE Class 3 estimate that "excludes costs to finance projects" (and carbon capture), for the whole plant, first stated in Kiwetinohk's MD&A of March 23, 2022 ("increased its installed cost estimate by $11 million to $156 million", PDF p. 8, https://kiwetinohk.com/Financial/Dec_31_2021_MDA.pdf) and repeated unchanged to the Q3 2023 MD&A (p. 6, https://kiwetinohk.com/Financial/2023_Q3_MDA.pdf), so 2022 dollars, moved by the engine post-2022 step: C$156M ÷ 101,133 kW = C$1,543/kW. The estimate does not itemize the plant's electrical equipment or the gas and grid connections; ATCO's C$14.5M transmission connection is a separate project (AUC Decision 28658-D01-2024). Kiwetinohk withdrew the estimate in its 2023 Annual Information Form (March 2024) pending power-policy clarity, while it prepared a current one. The engine step is measured on this plant: Bitdeer's 2025 figures (Form 6-K exhibit 99.1, 2025-02-04, estimated costs table, https://www.sec.gov/Archives/edgar/data/1899123/000114036125003778/ef_ex99-1.htm: "Gas-fired power plant ~$90 million", "Electrical & datacenter infrastructure" US$300K per MW or about US$30M, the site US$21.7M) reconciled to Kiwetinohk's scope are the plant line plus the plant's share of the electrical line (not split by the filing: US$0–30M, the midpoint taken, a judgement), the site purchase and financing left out: US$90–120M, central US$105M, C$1,451/kW at the Bank of Canada 2025 rate (C$1,244–1,659). Over Kiwetinohk's C$1,780/kW (2025 C$ by the engine index) that is 0.82× (0.70–0.93): by this pair the plant's cost rose less than the price indices carry. No Canadian public O&M figure for engine plants: fixed and variable O&M are the AESO CONE 2018 aeroderivative figures (C$50.6/kW-yr, C$4.6/MWh, 2021 dollars), a labelled stand-in until the AESO's new Cost of New Entry study, which adds a reciprocating engine reference (due early 2027), publishes. Heat rate: heat rate 8.52 GJ/MWh HHV, derived from Beacon AI Centers – Heartland Project, Initial Project Description (IAAC registry 90123, document 164422E, 2025-12-14), §23 Table 23.1.1, p. 102, https://iaac-aeic.gc.ca/050/documents/p90123/164422E.pdf: 3,004 kt CO2 a year from 200 INNIO Jenbacher J624 engines at 800 MWe × 8,760 h = 7,008 GWh is 0.4287 t CO2/MWh, ÷ 0.0503 t CO2/GJ HHV (the emission factor this model applies, so its emissions reproduce the filing) = 8.52 GJ/MWh (8.57 at the CONE study's 0.050 t/GJ); CO2 only, not the CO2e figure, which carries methane slip. In constant 2025 C$ (Statistics Canada price indexes): capital 1,543 (2022 dollars) × 1.1538 (equipment 0.40 × 1.1660 + construction 0.60 × 1.1456) = 1,780 C$/kW; fixed O&M 50.60 (2021 dollars) × 1.1534 (Alberta CPI 1.1534) = 58.36 C$/kW-yr; variable O&M 4.60 (2021 dollars) × 1.1534 (Alberta CPI 1.1534) = 5.31 C$/MWh. Capital costed in 2022: lowered 0.82× for the post-2022 change in plant costs the price indices miss: by this pair the plant's cost rose less than the indices carry (median of 1 matched engine pair: Fox Creek gas engine plant (Kiwetinohk 'Opal' Firm Renewable; now Bitdeer Fox Creek) 2022 to Bitdeer Fox Creek engine plant, 2025 figures reconciled to an all-in plant 2025, 0.82×), C$1,451/kW.
Plant O&M	58.36 C$/kW-yr fixed, 5.31 C$/MWh variable (2025 C$)	Assumption: No Canadian public O&M figure for engine plants: fixed and variable O&M are the AESO CONE 2018 aeroderivative figures (C$50.6/kW-yr, C$4.6/MWh, 2021 dollars), a labelled stand-in until the AESO's new Cost of New Entry study, which adds a reciprocating engine reference (due early 2027), publishes

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Assumption	Value	Basis
Dollar basis	Constant 2025 C$; real discount rate 7.55%	The cost of power is in constant 2025 C$. It is discounted at the real rate (1 + 9.7%) ÷ (1 + 2%) − 1 = 7.55%, from the 9.7% after-tax nominal cost of capital and 2% inflation (AESO CONE 2018). Capital and O&M are restated from each source's dollar year to 2025 C$ with Statistics Canada price indexes (plant capital: turbine equipment and Alberta industrial building construction, weighted by plant type with the AESO CONE 2018 escalation weights; connections: construction; O&M: Alberta CPI; 2% a year only for a year the indexes do not cover); nominal price paths (TIER, AER ST98) are deflated to 2025 C$ at 2% a year; CER scenarios are published in 2025 C$. The flat gas price (the latest 12 published months) is taken as 2025 C$ without deflation. Restatement index: Restated to 2025 C$ with Statistics Canada price indexes (annual averages; Statistics Canada Open Licence). Plant capital: Statistics Canada table 18-10-0283-01, Machinery and equipment price index, by commodity, monthly (Turbines, turbine generators, and turbine generator sets (except aircraft turbines) · Total domestic and imported, Canada; v1567106374), published to 2026-08, https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810028301 for equipment and Statistics Canada table 18-10-0289-01, Building construction price indexes, by type of building and division, quarterly (Industrial buildings · Division composite, Alberta; v1617915564), published to 2026-07, https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810028901 for construction labour and materials, weighted by plant type with the escalation weights AESO Cost of New Entry study (Brattle Group and Sargent & Lundy for the AESO, 2018-09-04), https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf sets out for updating its cost of new entry (pp. 51–52, Table 17: turbine 15% combined cycle, 40% aeroderivative, 30% frame; engines 40%, an assumption). Gas lateral and grid connection: the construction index. O&M: Statistics Canada table 18-10-0005-01, Consumer Price Index, annual average, not seasonally adjusted (All-items, Alberta; v41694625), published to 2025, https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501. 2% a year (the AESO Cost of New Entry study (Brattle Group and Sargent & Lundy for the AESO, 2018-09-04), https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf inflation rate, p. 45), used only for a year the Statistics Canada index has no complete annual average for
Capital scaling	1,788 C$/kW at 100 MW installed: the median of the 5 published capital figures for this plant type, each scaled to that size (exponent 0.6), not a scaling of the preset's own figure	Cost-capacity rule, cost ∝ size^n with n = 0.6 (Williams, "Six-tenths factor aids in approximating costs", Chemical Engineering, 1947); applied below the preset's reference size only: no economies of scale are credited above it, since engine and turbine plants grow by adding like units. Applied over at most 3× the reference size (assumption, not a published limit): a plant smaller than that is costed at the 3× factor and flagged, since a plant that much smaller is usually a different design, not a scaled one
Interest during construction	+5.7% on plant capital: a 1.5-year build at the 7.55% real rate	Interest during construction: the plant's capital spent evenly over the build, each dollar carried to first power at the real discount rate (the after-tax WACC less inflation), factor ((1 + r)^T − 1) ÷ (T × ln(1 + r)). The real rate because the capital is in constant 2025 C$: the inflation part of nominal interest is the rise of the dollars themselves, not a cost. On the plant, not the connections; an assumption, not a published schedule. Check: Greenlight's C$4.0B over its four years from FID to service gives C$0.73B at the 8.5% nominal rate (C$0.54B in constant dollars at 6.37%) against the C$0.6B gross Pembina states. Construction period by plant type: combined cycle 3.8 years (Cascade, Alberta, 2020–2024, as built; the AESO CONE 2018 study assumed 36 months), aeroderivative and industrial frame turbines 20 months (AESO Cost of New Entry study 2018, p. 25); reciprocating engines 1.5 years (Fox Creek, Alberta, planned 1.45 years; Whitehorse 1.0 year as built)

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Assumption	Value	Basis
Plant type	Reciprocating engines, Alberta (Bitdeer Fox Creek) (default for 100 MW)	The plant defaults to the Alberta project nearest the load in size, compared as a ratio (Bitdeer Fox Creek, 101 MW; Greenlight, 932 MW). Where two projects are the same size, the more recent cost is used; the other stays in the published capital range, as do the AESO CONE 2018 reference plants (an agency estimate for a 2021 online date, never the default). Choose another plant to change it
Redundancy	None costed	Default
Efficiency basis	HHV (the presets' heat rates are HHV: AESO CONE 2018 Tables 3–5; Beacon Heartland IPD Table 23.1.1 for engines)	Default
Sized for July heat	No: the load is the plant's rated size	Default; quoted capital costs are per rated kW
First year of operation	2029	Default
Gas price	1.78 C$/GJ held flat, taken as 2025 C$ (a sensitivity; the headline range uses the published scenarios)	AB-NIT (2A) same-day gas price at the AECO hub, mean of the 12 monthly averages Oct 2025–Sep 2026 (MSA Wholesale Market Reports Q4 2025, Q1 2026, Q2 2026, Q3 2026, Table 1). Gas scenarios: the Canada Energy Regulator's Energy Futures scenarios (published in 2025 C$) and the AER's ST98 outlook (published nominal, deflated to 2025 C$ at 2% a year); the EIA's Henry Hub cases are a US outlook and are not used in any cost
Carbon (TIER) price	2026 C$95/t, 2027 C$100/t, 2028 C$100/t, 2029 C$100/t, 2030 C$115/t, 2031 C$118/t, 2032 C$121/t, 2033 C$124/t, 2034 C$127/t, 2035 C$130/t, 2036 C$131.95/t, 2037 C$133.93/t, 2038 C$135.94/t, 2039 C$137.98/t, 2040 C$140/t; held at C$140 after 2040	Canada–Alberta implementation agreement, 2026-05-15; TIER price path to 2040, held at C$140 after 2040 (nothing is published beyond it). Nominal; in the cost of power deflated to 2025 C$ at 2% a year and levelized over the life

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Assumption	Value	Basis
TIER benchmark	0.3374 t/MWh in 2029; 0.2991 in 2040, held after	Past years: 0.37 t CO2e/MWh for 2018 and 2019 (Carbon Competitiveness Incentive Regulation, Alta Reg 255/2017, Schedule 2 Table, "Electricity 0.3700"; https://faolex.fao.org/docs/pdf/al180251.pdf) and under TIER to 2022; 2022 0.3700, 2023 0.3626, 2024 0.3552, 2025 0.3478 (Technology Innovation and Emissions Reduction Amendment Regulation, Alta Reg 251/2022 (Order in Council 403/2022), s. 20(b), Schedule 2 Table, in force 2023-01-01; https://kings-printer.alberta.ca/Documents/Orders/Orders_in_Council/2022/2022_403.pdf); years before 2018 held at 0.37 (an earlier regime). From 2025: TIER electricity high-performance benchmark 0.3478 t CO2e/MWh (Technology Innovation and Emissions Reduction Regulation, Alta Reg 133/2019, Schedule 2, consolidated to Alta Reg 270/2025, current as of 2025-12-03; https://kings-printer.alberta.ca/documents/Regs/2019_133.pdf), held for 2026; from 2027 lowered by 1.0% of that value a year, the electricity stringency rate for 2027–2040 (Canada–Alberta Implementation Agreement, 2026-05-15, §1.3.2); held after 2040. Our reading, not stated in the agreement: the 1.0% is taken off the 2025 value each year, not compounded, the way the 2023–2025 steps were each 2% of 0.37. Unverified: no ministerial order setting post-2025 values (regulation s. 6(2)) was found
Cost of capital and life	9.7% WACC (after tax, nominal; 7.55% real), 20 years	9.7% after-tax cost of capital (nominal), the after-tax equivalent of the 10.5% pretax WACC of the reference merchant plant in Market Power Mitigation Regulation, Alta Reg 43/2024, Schedule (reference generating unit) (item 5; 50% debt at 7%, 23% tax), https://kings-printer.alberta.ca/documents/Regs/2024_043.pdf, and a 20-year economic life (AESO Cost of New Entry study (Brattle Group and Sargent & Lundy for the AESO, 2018-09-04), https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf, executive summary). The cost of power discounts at the real rate, 7.55% at 2% inflation
Gas lateral	To the nearest sales-gas line (NGTL System), about 1 km, to a CER route generalized to a few km; NPS 4 at 224,785 2025 C$/inch-km; meter station C$0.0M (assumption)	Diameter sized to the gas (API RP 14E erosional velocity). C$224,785 per inch of diameter per km (2025 C$): the median of 10 NGTL gas laterals in service 2016 to 2019, C$157,000 (C$111k to 275k, nominal dollars, taken as 2018 dollars), AESO Cost of New Entry study (Brattle Group and Sargent & Lundy for the AESO, 2018-09-04), https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf, Table 23, restated to 2025 C$ × 1.4318 (construction index 1.4318: Statistics Canada building construction price index, industrial buildings, Alberta). The study itself assumes C$2M/km for a developer-built 2 km lateral. Meter station: C$0 of developer capital, an assumption. The AESO CONE study assumes "NGTL will construct the meter station" (p. 23); no Canadian public cost for a meter or custody-transfer station, or for what the carrier charges the shipper for it, was found. Not included unless you enter it: enter C$ of developer capital, the carrier's quote for the station or its contribution-in-aid charge to the shipper
Grid tie	To 138/144 kV, a T-tap onto line 7L199, 0.8 km (nearest substation Fox Creek 741S, 3.4 km); direct connection at C$83.47/kW (2025 C$), plus any line or substation cost entered	Screening assumption, an input: a plant under 200 MW is tied to the nearest 138/144 kV substation, 200 MW and up to the nearest 240 kV and up. Basis: the nearest public precedent, Kiwetinohk's Opal power plant near Fox Creek (101 MW of gas engines), connects through a new 1.3 km 144 kV line from its Gemini 1008S substation to ATCO line 7L199 (AUC Decision 28658-D01-2024, 2024-02-23; plant approved in Decision 27293-D01-2022). The tie runs to the band's nearest substation, or taps the band's nearest line where that is more than 0.1 km nearer, as Opal does. The 200 MW split is PatchWatt's screening assumption, not an AESO rule; the voltage, substation and route are set in the AESO's connection studies. C$83.47/kW (2025 C$) for the direct connection facilities (line up to 12 km and substation): C$58.3/kW in 2018 dollars, the capacity-weighted average of 19 Alberta generation projects, network upgrades excluded, AESO Cost of New Entry study (Brattle Group and Sargent & Lundy for the AESO, 2018-09-04), https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf, Table 24, restated to 2025 C$ × 1.4318 (construction index 1.4318: Statistics Canada building construction price index, industrial buildings, Alberta). Line past the 12 km it covers is costed per km (Extra grid line past the 12 km the direct connection covers: C$426,173 per circuit-km (2025 C$), the median transmission-line cost per km of 13 Alberta connections with 2 km or more of line built by the transmission owner (range C$13,499–3,153,859/km), from the transmission owners' cost estimates on the AESO's project pages (https://www.aeso.ca/grid/transmission-projects/, read 2026-11-15); 138/144 kV and 240 kV pooled. The estimates cover what the transmission owner builds; a line the connecting party builds itself can cost more or less); any substation cost entered is added
Corporate tax	23%	Federal 15% + Alberta 8% general corporate rates

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Assumption	Value	Basis
Escalation	2%	AESO Cost of New Entry study (Brattle and Sargent & Lundy for the AESO, 2018), p. 45 and Table 9: long-term inflation 2.0% a year (prices and costs escalate together); the same rate restates the cost of power to constant 2025 C$
Debt rate	6.5%	Contracted cash flow (a toll, or self-supply with a contract price, and a plain case with a fixed power price): AESO Cost of New Entry study (Brattle and Sargent & Lundy for the AESO, 2018), Table 11: 6.5% cost of debt at 65% debt, priced off long-term (20-year) bond yields. Merchant cash flow takes the merchant debt rate
Debt tenor	20 years (assumption)	An assumption: no Canadian public source gives a loan tenor for merchant gas generation. 20 years follows AESO Cost of New Entry study (Brattle and Sargent & Lundy for the AESO, 2018), which prices its debt off 20-year bonds ("long-term (20-year) debt financing", executive summary) over a 20-year economic life; the study models no loan
Minimum DSCR	None (merchant debt sized by the gearing cap)	None by default: no primary public source gives a minimum debt service coverage ratio for merchant gas generation (rating-agency criteria are not public; Morningstar DBRS (2025-02-04): to reach a minimum investment-grade rating merchant renewables "may need a DSCR in the range of 1.5 times (x) to 1.7x while the merchant thermal project, in theory, will need a DSCR three times that", thermal being in "a different bucket" with "much greater cash flow variability"; a rating view, not a lender's sizing ratio, https://dbrs.morningstar.com/research/447217/morningstar-dbrs-takeaways-from-the-evolution-of-project-finance-event-our-methodologies-keep-pace-with-technologies), so merchant debt is sized by the 50% gearing cap alone (Market Power Mitigation Regulation, Alta Reg 43/2024, Schedule (reference generating unit), https://kings-printer.alberta.ca/documents/Regs/2024_043.pdf, item 7) and the DSCR is reported, minimum and average, not imposed. Lenders set coverage case by case: enter a ratio (×, on CFADS) from a term sheet to size merchant debt by it
Maximum gearing	65%	Contracted cash flow: AESO Cost of New Entry study (Brattle and Sargent & Lundy for the AESO, 2018), Table 11: 65% debt (its other case is 50%), between Pembina's Greenlight final investment decision release (2026-07-02) states about 60% asset-level debt for the tolled 932 MW combined cycle, https://www.pembina.com/media-centre/news/details/3403fb77-2257-466b-a8e2-f043f4cd4650 and the AESO models contracted renewable generation with "75 per cent debt and 25 per cent equity ... based on minimum debt service coverage guidance from credit ratings agencies" (AESO 2024 Long-Term Outlook, Generation Forecast Methodology, p. 7, https://www.aeso.ca/assets/Uploads/grid/lto/2024/2024-LTO-Generation-Forecast-Methodology.pdf)
Equity hurdle	15.5%	AESO Cost of New Entry study (Brattle and Sargent & Lundy for the AESO, 2018), Table 11: 15.5% return on equity at 65% debt and 6.5% debt, consistent with its 8.5% after-tax cost of capital

APPENDIX A9 · AUC RULE 007 CROSS-REFERENCE (24 rows)

Item	Rule 007 asks for	Here	Where, or what is missing
TP1	Units, make, model and MW	partly	Plant type and size screened (Sizing and cost); make and model are not chosen
TP2	Existing approvals affected	partly	An existing power plant at the point is checked (Location and site)
TP3–TP4	Ownership; municipal ownership	site work	Not in public data
TP5	Legal description and component locations	partly	LSD of the site point (title and Location and site); a plant boundary and .kml come with a layout

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Item	Rule 007 asks for	Here	Where, or what is missing
TP6	Maps: residences, reserves, sensitive areas	partly	Site map; buildings at the Rule 007 radii, those OpenStreetMap tags as dwellings or non-dwellings counted apart and untagged ones treated as possible residences (Location and site); reserves and settlements (Ground and land use). Here: 941 buildings within 1.5 km, of which 12 tagged as dwellings, 0 tagged as non-dwellings (farm, industrial, commercial or outbuildings), the rest (929) untagged or not settled by their tag; untagged buildings are treated as possible dwellings, as the noise impact assessment Rule 007 asks for (TP31, under Rule 012) surveys receptors on the ground; 662 of them are OpenStreetMap buildings, which can carry a use tag, and 279 Microsoft footprints of about 2019, which carry none.
TP7	Heat rate, efficiency, cooling	in this report	Sizing and cost
TP8	In-plant gas piping	partly	Tie-in line and lateral size (Sizing and cost, Connection); piping design is engineering
TP9	Approval, construction and in-service dates	partly	Time to power from published durations (Regulatory path)
TP10	Public benefits	site work	Not covered
TP11–TP13	Connection timing, AESO IDs, conceptual interconnection	partly	Nearest substations and the line a T-tap would use (Power and grid); AESO IDs follow a system access service request
TP14–TP16	Cumulative effects; land-use framework	partly	Power plants, gas plants and emitters nearby (Power and grid; Gas supply; Climate and carbon)
TP17–TP19	Emergency response plan	site work	Not covered
TP20–TP21	Municipal plans, zoning, setbacks	partly	Municipality named; zoning and bylaw setbacks are not in the data used
TP22–TP25	Emission rates, ambient air, modelling	partly	CO2 intensity and TIER (Climate and carbon); NOx, SO2 and PM rates need equipment data; dispersion modelling is engineering
TP26	Environmental evaluation	partly	Wetlands, flood, caribou, protected areas, ground cover, slope (Ground and land use); delineation is field work
TP27	Federal lands	partly	Reserves near the point (Ground and land use)
TP28	Environmental protection plan	site work	Not covered
TP29	Visual impact assessment zone	site work	The Pristine Viewscapes map is not in the data used
TP30	Reclamation cost estimate and security	partly	Conditions in recent decisions (Regulatory path); the estimate is a third-party study

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Item	Rule 007 asks for	Here	Where, or what is missing
TP31–TP32	Noise impact assessment; construction noise	partly	Rule 012 receptors and permissible sound levels (Location and site); the assessment is engineering. Here: 941 buildings within 1.5 km, of which 12 tagged as dwellings, 0 tagged as non-dwellings (farm, industrial, commercial or outbuildings), the rest (929) untagged or not settled by their tag; untagged buildings are treated as possible dwellings, as the noise impact assessment Rule 007 asks for (TP31, under Rule 012) surveys receptors on the ground; 662 of them are OpenStreetMap buildings, which can carry a use tag, and 279 Microsoft footprints of about 2019, which carry none.
TP33	Other acts and approvals	in this report	Regulatory path
TP34	Historical Resources Act approval	partly	Listing of Historic Resources (Ground and land use); the application is filed with the project
TP35	Aboriginal Consultation Office assessment	partly	Treaty, reserves and settlements (Ground and land use); consultation is the Crown's
TP36–TP42	Participant involvement program	partly	Building counts at 800 m and 2,000 m (Location and site); the program is the applicant's

NOTES ON METHOD

1. **Ground cover within 2 km**: Share of the 12.6 km^2 circle around the site point in each cover class, AAFC Annual Crop Inventory 2024 (30 m satellite classification, Open Government Licence - Canada), queried live. Cover type only: not ownership, zoning, soil capability or whether land is cultivated under a lease.
2. **Project sizing and cost**: Default assumption, 92%, allowing for planned maintenance on top of forced outages: AESO CONE 2018 assumes a 2.5% forced outage rate and publishes no planned-outage figure (Tables 3–5); Alberta's combined-cycle plants produced in a median 96% of hours in 2019–2024 (10th percentile 88%), from AESO metered output. Run hours are the dispatch profile (8,760 = baseload); availability takes planned and forced outages off them.
3. **Project sizing and cost**: Default for 100 MW: the Alberta project nearest this load in size. The plant type moves the heat rate more than any other input. Measured Alberta operating heat rates, median: combined cycle 8.09, gas engines 11.53, simple-cycle turbines (40 MW and up) 10.71 GJ/MWh HHV (2019–2024; ECCC GHGRP CO2 ÷ AESO metered output); this plant's design figure is 8.52.
4. **Project sizing and cost**: Alberta plant: the 101 MW gas-engine power plant at Fox Creek (nine 11.237 MW engines, 101.133 MW; AUC Power Plant Approval 29785-D02-2025), now Bitdeer's, first developed by Kiwetinohk Energy as Opal. Capital is the plant's all-in installed cost: Kiwetinohk's "Total estimated installed capital cost" of C$156M, an AACE Class 3 estimate that "excludes costs to finance projects" (and carbon capture), for the whole plant, first stated in Kiwetinohk's MD&A of March 23, 2022 ("increased its installed cost estimate by $11 million to $156 million", PDF p. 8, https://kiwetinohk.com/Financial/Dec_31_2021_MDA.pdf) and repeated unchanged to the Q3 2023 MD&A (p. 6, https://kiwetinohk.com/Financial/2023_Q3_MDA.pdf), so 2022 dollars, moved by the engine post-2022 step: C$156M ÷ 101,133 kW = C$1,543/kW. The estimate does not itemize the plant's electrical equipment or the gas and grid connections; ATCO's C$14.5M transmission connection is a separate project (AUC Decision 28658-D01-2024). Kiwetinohk withdrew the estimate in its 2023 Annual Information Form (March 2024) pending power-policy clarity, while it prepared a current one. The engine step is measured on this plant: Bitdeer's 2025 figures (Form 6-K exhibit 99.1, 2025-02-04, estimated costs table, https://www.sec.gov/Archives/edgar/data/1899123/000114036125003778/ef_ex99-1.htm: "Gas-fired power plant ~$90 million", "Electrical & datacenter infrastructure" US$300K per MW or about US$30M, the site US$21.7M) reconciled to Kiwetinohk's scope are the plant line plus the plant's share of the electrical line (not split by the filing: US$0–30M, the midpoint taken, a judgement), the site purchase and financing left out: US$90–120M, central US$105M, C$1,451/kW at the Bank of Canada 2025 rate (C$1,244–1,659). Over Kiwetinohk's C$1,780/kW (2025 C$ by the engine index) that is 0.82× (0.70–0.93): by this pair the plant's cost rose less than the price indices carry. No Canadian public O&M figure for engine plants: fixed and variable O&M are the AESO CONE 2018 aeroderivative figures (C$50.6/kW-yr, C$4.6/MWh, 2021 dollars), a labelled stand-in until the AESO's new Cost of New Entry study, which adds a reciprocating engine reference (due early 2027), publishes. Heat rate: heat rate 8.52 GJ/MWh HHV, derived from Beacon AI Centers – Heartland Project, Initial Project Description (IAAC registry 90123, document 164422E, 2025-12-14), §23 Table 23.1.1, p. 102, https://iaac-aeic.gc.ca/050/documents/p90123/164422E.pdf: 3,004 kt CO2 a year from 200 INNIO Jenbacher J624 engines at 800 MWe × 8,760 h = 7,008 GWh is 0.4287 t CO2/MWh, ÷ 0.0503 t CO2/GJ HHV (the emission factor this model applies, so its emissions reproduce the filing) = 8.52 GJ/MWh (8.57 at the CONE study's 0.050 t/GJ); CO2 only, not the CO2e figure, which carries methane slip. In constant 2025 C$ (Statistics Canada price indexes): capital 1,543 (2022 dollars) × 1.1538 (equipment 0.40 × 1.1660 + construction 0.60 × 1.1456) = 1,780 C$/kW; fixed O&M 50.60 (2021 dollars) × 1.1534 (Alberta CPI 1.1534) = 58.36 C$/kW-yr; variable O&M 4.60 (2021 dollars) × 1.1534 (Alberta CPI 1.1534) = 5.31 C$/MWh. Capital costed in 2022: lowered 0.82× for the post-2022 change in plant costs the price indices miss: by this pair the plant's cost rose less than the indices carry (median of 1 matched engine pair: Fox Creek gas engine plant (Kiwetinohk 'Opal' Firm Renewable; now Bitdeer Fox Creek) 2022 to Bitdeer Fox Creek engine plant, 2025 figures reconciled to an all-in plant 2025, 0.82×), C$1,451/kW. Every money figure in this section is Canadian dollars (C$), constant 2025 C$ unless marked nominal.

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5. **Project sizing and cost**: Heat-rate basis: higher heating value (HHV) throughout. The presets' heat rates are HHV (AESO CONE 2018 Tables 3–5; the engine plant's is derived from the Beacon Heartland filing), so choosing a plant sets HHV; an OEM efficiency is usually ISO LHV and is divided by the HHV/LHV ratio (1.108; methane 1.109, pipeline gas about 1.10 to 1.11) before use. Cascade Power's filed "over 58%" read as LHV is 52.3% HHV.
6. **Project sizing and cost**: Capital: C$1,788/kW, the median of the 5 published figures for reciprocating engines at 100 MW installed, each taken before interest during construction (the model adds 5.7% for it (a 1.5-year build at the 7.55% real rate)). The median rule was back-tested on 15 Canadian plants, each left out (mean absolute error 21%, against 28% for one plant's own figure); the engine set is too small to back-test on its own. Reciprocating engines, Alberta (Bitdeer Fox Creek)'s own figure is one of them. The AESO Cost of New Entry study 2018 found engines similar in cost to aeroderivative turbines: it screened engines out as a reference plant "despite its similarity in efficiency and cost to the much more prevalent Aero CT" (indicative C$1,450–1,900/kW for engines against C$1,300–2,000/kW for aeroderivatives, Table 1, p. 6, https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf). That is context here, not used to pool the two, because the measured Canadian steps since part them: aeroderivatives 1.79× (Maritime Electric CT4, 2015 to 2024), engines under 1 (the Fox Creek plant, 2022 to 2025). Spare capacity (N+1 on n equal units is 100 ÷ n %, e.g. +20% for five running units and one spare) adds to the installed size that capital and fixed O&M are charged on. Interest during construction: the plant's capital spent evenly over the build, each dollar carried to first power at the real discount rate (the after-tax WACC less inflation), factor ((1 + r)^T − 1) ÷ (T × ln(1 + r)). The real rate because the capital is in constant 2025 C$: the inflation part of nominal interest is the rise of the dollars themselves, not a cost. On the plant, not the connections; an assumption, not a published schedule. Check: Greenlight's C$4.0B over its four years from FID to service gives C$0.73B at the 8.5% nominal rate (C$0.54B in constant dollars at 6.37%) against the C$0.6B gross Pembina states. Construction period by plant type: combined cycle 3.8 years (Cascade, Alberta, 2020–2024, as built; the AESO CONE 2018 study assumed 36 months), aeroderivative and industrial frame turbines 20 months (AESO Cost of New Entry study 2018, p. 25); reciprocating engines 1.5 years (Fox Creek, Alberta, planned 1.45 years; Whitehorse 1.0 year as built).
7. **Project sizing and cost**: Published capital for reciprocating engines at 100 MW installed, each scaled by the same rule and taken before interest during construction: C$1,457/kW (Reciprocating engines, Alberta (Bitdeer Fox Creek), lowered 0.82× for the post-2022 change, a company filing or release); C$1,458/kW (Bitdeer Fox Creek engine plant, 2025 figures reconciled to an all-in plant, AB, 2025 figure, a company filing or release); C$1,788/kW (Nova Scotia Power 2022 IRP engine supply option, 2022 figure, lowered 0.82× for the post-2022 change, a government agency's cost table); C$1,931/kW (Nova Scotia Power 2020 IRP engine supply option, 2019 figure, lowered 0.82× for the post-2022 change, a government agency's cost table); C$2,344/kW (AESO 2024 Long-Term Outlook reciprocating engines, 2024 figure, a government agency's cost table). Across them the cost of power moves by –4 to +7 C$/MWh against the capital used. Canadian plants of this type with capital filed before 2023 (Fox Creek gas engine plant (Kiwetinohk 'Opal' Firm Renewable; now Bitdeer Fox Creek), AB, 2022) are in the range lowered 0.82×: by the measured pair this type's plant costs rose after 2022 by less than the price indices carry, and the gap is measured from the same owner's plants, or the same plant, of the same type and size costed before and after (Fox Creek gas engine plant (Kiwetinohk 'Opal' Firm Renewable; now Bitdeer Fox Creek) 2022 C$1,780/kW to Bitdeer Fox Creek engine plant, 2025 figures reconciled to an all-in plant 2025 C$1,451/kW, 0.82×; both in 2025 dollars).
8. **Project sizing and cost**: In use: the median, C$1,788/kW at 100 MW (figures that carry interest during construction are taken before it, as in the last column). Spread for the sensitivity: min–max, C$1,457 to C$2,344/kW; lowest and highest C$1,457 and C$2,344. Figures are as each source states them (plant only, connections a source itemizes taken out), restated to 2025 C$ by the Statistics Canada indices for the type, moved by the type's measured post-2022 step where struck before 2023, then scaled to the installed size by the same rule.
9. **Project sizing and cost**: Property tax in FOX CREEK, 2026: M&E rate 20.7548 + DIP requisition 0.0728 = 20.8276 mills (Alberta Municipal Affairs tax rates, 2026); no assessed value is entered: this plant's fixed O&M is the AESO CONE 2018 figure, which already carries property tax at Edmonton-area rates (C$993k a year, Table 10), so none is added on top. Enter the assessed value to replace it with this municipality's rate.
10. **Project sizing and cost**: Heat rate 8.52 GJ/MWh (HHV); volume at 1,055 GJ/MMcf, a sales-gas heating value. Energy 806 GWh a year = 100 MW × 8,760 h × 92.0% availability × 100% ambient output (annual-mean output, the plant rated at the load); capacity factor 92%. Fuel and emissions follow that energy; the gas figure above is the peak day.
11. **Site climate and output Station-based · maker's curve for this plant type**: From ECCC CWEEDS hourly data, Whitecourt A (72 km, 782 m, 2000–2017); Valleyview Agdm (82 km, 698 m, 2003–2017); Edson Climate (94 km, 927 m, 1998–2017), weighted by distance; no elevation adjustment to the site. Gas engines: rated output held up to 40 °C and down to 84 kPa (about 1,500 m), past which it falls about 1.6% per kPa and 0.4% per °C (Wärtsilä, Combustion engine power plants white paper, 2011, p. 5: derating only above 40 °C or 2,000 m, the chart for a 10 MW engine read; Wärtsilä: under 2% output lost at 45 °C). The pressure ratio is not applied on top. Large lean-burn engines of the Wärtsilä 34SG/50SG class; some smaller engines hold their rating to lower altitudes (Caterpillar G3520: 655–1,310 m at 25 °C). Not a vendor performance curve.
12. **Reported raw gas near the site, by operator name**: To test the plant's 19.4 MMcf/d of sales gas, reported raw gas within 25 km is added from the largest operator down until the sum reaches it: 1 of 19 operators, 233.0 MMcf/d together. Listed here by name, not by volume. Bases differ: the plant need is sales gas at 1,055 GJ/MMcf; reported volumes are raw gas before processing shrink (liquids, CO2 and H2S removed at the plant), which the public data does not give, so a raw volume overstates the sales gas it yields. Reported production is not volume available for sale.
13. **Connection**: Turbine and engine fuel is sales-spec gas taken through a meter station, not raw gas from a producer's gathering line. A tie-in is a federally regulated gas system (not Alliance, which carries liquids-rich gas) or a sweet line licensed to a gas transmission carrier (NGTL, ATCO Gas and Pipelines, TC Energy, Foothills, Westcoast). Producers' gathering lines and sour lines are left out, and so are local utility and gas co-op distribution lines (Apex Utilities, the rural gas co-ops): they are built to serve local customers, and whether one could carry a plant's gas is not public. NGTL System is mapped from the CER system map, generalized to a few km, so its distance is approximate. Diameter: NPS 4 for 19.4 MMcf/d (carries about 24 MMcf/d). Smallest standard size (NPS 2–24, standard wall) whose API RP 14E erosional velocity (C = 100, continuous service) carries the peak gas at 4,000 kPa(g), gas SG 0.6; a screening rule, not a hydraulic design. Room on any line is not public.
14. **Connection**: Tie voltage follows the plant size (100 MW): 138/144 kV. Screening assumption, an input: a plant under 200 MW is tied to the nearest 138/144 kV substation, 200 MW and up to the nearest 240 kV and up. Basis: the nearest public precedent, Kiwetinohk's Opal power plant near Fox Creek (101 MW of gas engines), connects through a new 1.3 km 144 kV line from its Gemini 1008S substation to ATCO line 7L199 (AUC Decision 28658-D01-2024, 2024-02-23; plant approved in Decision 27293-D01-2022). The tie runs to the band's nearest substation, or taps the band's nearest line where that is more than 0.1 km nearer, as Opal does. The 200 MW split is PatchWatt's screening assumption, not an AESO rule; the voltage, substation and route are set in the AESO's connection studies.

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15. **Connection**: C$224,785 per inch of diameter per km (2025 C$): the median of 10 NGTL gas laterals in service 2016 to 2019, C$157,000 (C$111k to 275k, nominal dollars, taken as 2018 dollars), AESO Cost of New Entry study (Brattle Group and Sargent & Lundy for the AESO, 2018-09-04), https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf, Table 23, restated to 2025 C$ × 1.4318 (construction index 1.4318: Statistics Canada building construction price index, industrial buildings, Alberta). The study itself assumes C$2M/km for a developer-built 2 km lateral. Meter station: C$0 of developer capital, an assumption. The AESO CONE study assumes "NGTL will construct the meter station" (p. 23); no Canadian public cost for a meter or custody-transfer station, or for what the carrier charges the shipper for it, was found. Not included unless you enter it: enter C$ of developer capital, the carrier's quote for the station or its contribution-in-aid charge to the shipper. Grid tie: C$83.47/kW (2025 C$) for the direct connection facilities (line up to 12 km and substation): C$58.3/kW in 2018 dollars, the capacity-weighted average of 19 Alberta generation projects, network upgrades excluded, AESO Cost of New Entry study (Brattle Group and Sargent & Lundy for the AESO, 2018-09-04), https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf, Table 24, restated to 2025 C$ × 1.4318 (construction index 1.4318: Statistics Canada building construction price index, industrial buildings, Alberta). Line past the 12 km it covers is costed per km (Extra grid line past the 12 km the direct connection covers: C$426,173 per circuit-km (2025 C$), the median transmission-line cost per km of 13 Alberta connections with 2 km or more of line built by the transmission owner (range C$13,499–3,153,859/km), from the transmission owners' cost estimates on the AESO's project pages (https://www.aeso.ca/grid/transmission-projects/, read 2026-11-15); 138/144 kV and 240 kV pooled. The estimates cover what the transmission owner builds; a line the connecting party builds itself can cost more or less); any substation cost entered is added. Grid-connected or off-grid is one setting, shared with the approvals list.
16. **Carbon (TIER)**: This plant emits 429 t CO2/GWh. The federal Clean Electricity Regulations (SOR/2024-263) set 65 t/GWh from 2035; in Alberta they are held in abeyance while the CER Reference is before the courts (Canada–Alberta Implementation Agreement, 2026-05-15, §2.1.1), and carbon is priced under TIER as below.
17. **Carbon (TIER)**: Benchmark for 2029 from the schedule: Past years: 0.37 t CO2e/MWh for 2018 and 2019 (Carbon Competitiveness Incentive Regulation, Alta Reg 255/2017, Schedule 2 Table, "Electricity 0.3700"; https://faolex.fao.org/docs/pdf/al180251.pdf) and under TIER to 2022; 2022 0.3700, 2023 0.3626, 2024 0.3552, 2025 0.3478 (Technology Innovation and Emissions Reduction Amendment Regulation, Alta Reg 251/2022 (Order in Council 403/2022), s. 20(b), Schedule 2 Table, in force 2023-01-01; https://kings-printer.alberta.ca/Documents/Orders/Orders_in_Council/2022/2022_403.pdf); years before 2018 held at 0.37 (an earlier regime). From 2025: TIER electricity high-performance benchmark 0.3478 t CO2e/MWh (Technology Innovation and Emissions Reduction Regulation, Alta Reg 133/2019, Schedule 2, consolidated to Alta Reg 270/2025, current as of 2025-12-03; https://kings-printer.alberta.ca/documents/Regs/2019_133.pdf), held for 2026; from 2027 lowered by 1.0% of that value a year, the electricity stringency rate for 2027–2040 (Canada–Alberta Implementation Agreement, 2026-05-15, §1.3.2); held after 2040. Our reading, not stated in the agreement: the 1.0% is taken off the 2025 value each year, not compounded, the way the 2023–2025 steps were each 2% of 0.37. Unverified: no ministerial order setting post-2025 values (regulation s. 6(2)) was found. Prices: TIER price path to 2040, held at C$140 after 2040 (nothing is published beyond it); Canada–Alberta Implementation Agreement, 2026-05-15, §1.2.1.1. Emissions 345 kt/yr (0.429 t/MWh); 74 kt/yr above the 2029 benchmark; TIER applies (over 100 kt/yr). Carbon in the cost of power is levelized over the life, each year's intensity above that year's benchmark at that year's price deflated to 2025 C$ at 2% a year: 11.5 C$/MWh (constant 2025 C$); the first year (2029) alone is 9.1 C$/MWh in nominal 2029 dollars.
18. **Cost of power**: Gas default: AB-NIT (2A) same-day gas price at the AECO hub, mean of the 12 monthly averages Oct 2025–Sep 2026 (MSA Wholesale Market Reports Q4 2025, Q1 2026, Q2 2026, Q3 2026, Table 1), C$/GJ, as of 2026-09. WACC and life: 9.7% after-tax cost of capital (nominal), the after-tax equivalent of the 10.5% pretax WACC of the reference merchant plant in Market Power Mitigation Regulation, Alta Reg 43/2024, Schedule (reference generating unit) (item 5; 50% debt at 7%, 23% tax), https://kings-printer.alberta.ca/documents/Regs/2024_043.pdf, and a 20-year economic life (AESO Cost of New Entry study (Brattle Group and Sargent & Lundy for the AESO, 2018-09-04), https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf, executive summary). The cost of power discounts at the real rate, 7.55% at 2% inflation. The cost of power is in constant 2025 C$. It is discounted at the real rate (1 + 9.7%) ÷ (1 + 2%) − 1 = 7.55%, from the 9.7% after-tax nominal cost of capital and 2% inflation (AESO CONE 2018). Capital and O&M are restated from each source's dollar year to 2025 C$ with Statistics Canada price indexes (plant capital: turbine equipment and Alberta industrial building construction, weighted by plant type with the AESO CONE 2018 escalation weights; connections: construction; O&M: Alberta CPI; 2% a year only for a year the indexes do not cover); nominal price paths (TIER, AER ST98) are deflated to 2025 C$ at 2% a year; CER scenarios are published in 2025 C$. The flat gas price (the latest 12 published months) is taken as 2025 C$ without deflation.
19. **Cost of power**: Range across the 4 published Canadian gas price scenarios that cover the life (table below) and the 5 published capital figures for reciprocating engines (above), carbon levelized. Gas scenarios alone, at 1,788 C$/kW: 71–101; capital moves it by −4 to +7. Sensitivity: gas at 1.78 C$/GJ (AB-NIT, mean of Oct 2025–Sep 2026, as of 2026-09) held flat for 20 years gives 63 C$/MWh, below that range.
20. **Cost of power**: Accuracy is AACE Class 5 (concept screening, 0–2% project definition; AACE 18R-97 range −20/−50% to +30/+100%). The widest band is shown. A Class 4 or better estimate needs an engineer's study. Part load and starts: carried by the measured operating heat rate on cycling duty (see Duty); at full load none is applied.
21. **Cost of power**: Each plant type at 100 MW at this site with every assumption at its default (your overrides other than the plant are not applied here); the range as in the headline. Listed in the order of the plant list. Capital: every combined cycle preset takes the median of the published capital figures for combined cycle (C$5,989/kW here), so they differ only by heat rate and O&M; every aeroderivative turbines preset takes the median of the published capital figures for aeroderivative turbines (C$3,164/kW here), so they differ only by heat rate and O&M.
22. **What moves the cost of power**: The cost of power is most sensitive to the gas price, the heat rate and plant capital (swings of 38, 33 and 11 C$/MWh, one input at a time from 63 C$/MWh at today's gas price held flat; the headline range uses the published outlooks); closing the open item "Plant capital cost" narrows the third-largest swing.
23. **What moves the cost of power**: Gas price, levelized over the life: Lowest and highest of the 4 Canadian gas outlooks (CER, AER ST98) covering the life, levelized over 20 years from 2029, 2025 C$ (CER EF2026 Lower; CER EF2026 Higher); the low end is the flat price, the latest 12 published months held for the life, below every outlook.Heat rate (HHV): measured: 3 Alberta gas-engine plants (engine plants named as such by an AUC decision or the owner; plants of 20 MW or less, mostly peaking, so starts and part load are included; West Cadotte burns flare gas, which carries more CO2 per GJ than pipeline gas, so its figure reads high), 4 plant-years, ECCC GHGRP CO2 ÷ AESO metered output, 2019–2024, P10–P90 10.61–12.42 GJ/MWh (median 11.53); and the filed design heat rates of Alberta projects, 8.42 to 10.00 GJ/MWh (Fox Creek engine plant (Opal, now Bitdeer) 8.42 GJ/MWh: AUC approval record: 7.6 MJ/kWh ±5%, HHV or LHV not stated, read as LHV ×1.108 (as HHV it would be 52.5% LHV, above the maker's 48.9% rating for the plant's Bergen B36:45 engines); Beacon Heartland

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8.52 GJ/MWh: IAAC 90123 IPD Table 23.1.1: 3,004 kt CO2 over 7,008 GWh at 0.0503 t CO2/GJ HHV; Beacon Heartland 10.00 GJ/MWh: IAAC 90123 IPD: 8.0 TJ/h average fuel for 800 MW, basis not stated); the manufacturer floor, 7.65 GJ/MWh HHV: Wärtsilä 20V31SG efficiency optimised genset, 10,389 kW at 60 Hz, 6,907 kJ/kWh (52.1%) at the generator terminals, 25 °C suction air, 100 kPa, ±5% tolerance (ISO 3046-1) (Wärtsilä 31SG product leaflet, 08/2023, p. 2), LHV ×1.108; the lowest heat rate the maker rates a new unit that fits this plant at, which a plant in service runs above; moves fuel, emissions and carbon together.Plant capital: Published capital figures for reciprocating engines at 100 MW installed, 5 references, cheapest to dearest (Reciprocating engines, Alberta (Bitdeer Fox Creek), lowered 0.82× for the post-2022 change; AESO 2024 Long-Term Outlook reciprocating engines, 2024 figure), each on the same construction-interest basis as the capital used. Open item: Plant capital cost.Cost of capital (WACC), after tax, nominal: 1.6 points below and 2 above, the published range around the 9.7% default (8.1% to 11.7%: Low 8.1%: the regulation's 10.5% pretax WACC read the other way, as an after-tax rate grossed up for tax (10.5 × (1 – 23%)); AESO CONE 2018's 8.5% after tax, sized for a capacity market, sits inside. High 11.7%: the MSA's "Very high" 12.5% capital-recovery WACC (Wholesale Market Report Q4 2025, Figure 35, p. 50), converted to after tax the same way as the default (50% debt at 7%)); each discounted at its real rate.Economic life: ±5 years, the step the AESO CONE 2018 sensitivity tests on its economic life (p. 49), around AESO CONE 2018's 20 years; carbon re-levelized over each life, gas held flat.Variable O&M: Published variable O&M for reciprocating engines, 2025 C$: C$5.31/MWh (Reciprocating engines, Alberta (Bitdeer Fox Creek)); C$6.50/MWh (Nova Scotia Power 2022 IRP, 2022 C$27.0/kW-yr and C$6.0/MWh (PDF p. 18)); C$10.83/MWh (Nova Scotia Power 2020 IRP, 2019 C$27/kW-yr and C$9/MWh (E3 study PDF p. 13)). Open item: Engine plant O&M.Fixed O&M: ±20%, the fixed O&M band the AESO CONE 2018 sensitivity tests (p. 49); and published fixed O&M for reciprocating engines in 2025 C$: C$29.26/kW-yr (Nova Scotia Power 2022 IRP, 2022 C$27.0/kW-yr and C$6.0/MWh (PDF p. 18)); C$32.49/kW-yr (Nova Scotia Power 2020 IRP, 2019 C$27/kW-yr and C$9/MWh (E3 study PDF p. 13)). Open item: Engine plant O&M.Availability: High: 97.5%, 1 – the 2.5% forced outage rate AESO CONE 2018 assumes for its reference plants (Tables 3–5), no planned maintenance; low: as far below the 92% default (86.5%), an assumption (no measured range: Alberta engine plants run mostly as peakers, so their running hours measure dispatch, not availability).Grid connection cost: AESO CONE 2018 Table 24, direct connection by plant size band, C$50.3 to C$68.8/kW (2018) against the C$58.3/kW average; and measured: Alberta 138/144 kV connections, 12 transmission owner estimates on the AESO's project pages (participant share, 2025 C$; circuits of 4.85 km median length): P10 C$5.9M, median C$14.5M, P90 C$31.9M per connection. The estimates cover what the transmission owner builds, not a line the connecting party builds itself.Carbon price path (TIER): Low: the published TIER path held at its 2026 price (C$95/t nominal), the benchmark schedule unchanged; high: the published TIER path itself, the case shown, so only the low side moves.Lateral length (route): measured: routing factor of 4,102 AER-licensed natural gas segments, NPS 8 and larger, ends 1–30 km apart (licensed length ÷ straight-line distance between the mapped ends, AER pipeline file of 2026-11-10), P10–P90 1.01–1.38 (median 1.12), applied to the 1.1 km straight-line distance to the tie-in; the case uses 1.12, the median; high: the nearest NGTL meter station (Iosegun Sales), 3.4 km straight-line (Petrinex; NGTL's pipe passes through it) × 1.12, where large Alberta plants have tied in rather than at a nearer utility line (Cascade a 7 km lateral to NGTL, Greenlight 7–10 km; project filings).Restatement to 2025 C$: Statistics Canada price indexes: the plant capital and the lateral and grid unit costs restated wholly at the construction index (building construction, industrial buildings, Alberta, 18-10-0289-01) and wholly at the equipment index (machinery and equipment, turbines and turbine generator sets, 18-10-0283-01), against the index used (AESO CONE 2018 Table 17 weights, the aeroderivative weight for engines, an assumption; connections construction only); O&M stays on Alberta CPI.Lateral cost per inch-km: AESO CONE 2018 Table 23, the cheapest and dearest of 10 NGTL laterals (C$111k and C$275k per inch-km, 2018 dollars, against the C$157k median), restated to 2025 C$ like the default.

24. **What moves the cost of power**: Each bar is the levelized cost with one input at its low and its high value and every other input as above; the flame line is the case shown, with gas held flat (63.4 C$/MWh). Grey: below that case; black: above it. Rows run from the widest swing. Ranges are published figures or study bands where a source gives one and are marked assumed where none does; a figure you entered centres its own range. The headline range above moves gas and capital together; this chart moves one input at a time.
25. **What moves the cost of power**: TC Energy Cal-2027 flat forward, indicative as of 2026-11-03: TC Energy Power Market Update, forward prices table, Cal-2027 flat 7x24, indicative as of 2026-11-03 (as of 2026-11-03). On-site power at the flat gas price is 14 C$/MWh above it; the scenario range is 17 to 58 C$/MWh against it. Grid supply also carries transmission and distribution charges not shown here.
26. **Over the project life: published Canadian gas price scenarios**: Scenarios by name; each is discounted at the 7.55% real rate over 20 years from 2029, in constant 2025 C$. Carbon: TIER price path to 2040, held at C$140 after 2040 (nothing is published beyond it), deflated to 2025 C$, on the intensity above each year's benchmark, levelized 11.5 C$/MWh, the same in every row. Gas scenarios: the Canada Energy Regulator's Energy Futures scenarios (published in 2025 C$) and the AER's ST98 outlook (published nominal, deflated to 2025 C$ at 2% a year); the EIA's Henry Hub cases are a US outlook and are not used in any cost. A price deck of your own is read as nominal and deflated the same way. A source publishing under 75% of the life is averaged over its published years only and left out of the range; holding its last value flat would invent the rest.
27. **Plant need against local production**: Plant need 19.4 MMcf/d of sales gas (1,055 GJ/MMcf), as set in Sizing and cost, against two paths from 751.3 MMcf/d of raw gas, the average reported over the three months to Sep 2026. Raw volumes are before processing shrink, so the shares below understate the share of sales gas.
28. **Gas the catchment of PGI Kaybob Amalgamated would send it**: The batteries now feeding PGI Kaybob Amalgamated (7.2 km from the point): a central path (their reported gas at its trend, blended with each recent well's fitted decline, a fitted decline for the base and wells added at the last 12 months' count) and the same with no new wells, each with the range its method's forecasts fell in 8 times in 10 over the back-test of Alberta areas.
29. **Gas plants within 50 km**: Licensed raw-gas inlet capacity (AER ST50A) against gas received in Sep 2026 (Petrinex). Unused licensed capacity totals 1,132 MMcf/d across the 19 plants within 50 km that reported receipts that month; 12 more (250 MMcf/d licensed) reported none, so their use cannot be worked out; the table shows the 12 nearest. Licensed capacity is an approved ceiling, not room confirmed available to a new shipper.
30. **Gas plants within 50 km**: MMcf/d for gas. Licensed design, not measured: the facility licence's approved rates. Implied shrink is 1 – licensed sales gas / licensed raw gas. Plant Processes in ST50A are the AER Directive 056 Schedule 2.3 H2S fields (sweetening, acid gas disposal, sulphur recovery process); ST50A states no hydrocarbon process, so the plant type (deep cut, propane-plus, condensate only, no liquids) is PatchWatt's reading of the licensed liquids rates (judgement), not an AER class. Liquids rates under 1 m^3/d are printed but do not set the type.
31. **Gas plants within 50 km**: MMcf/d. Licensed capacity is a permit ceiling, not proof the plant can run that high. Receipts can include gas passed between plants. A plant is marked as handling storage gas when, in any of the last 12 months, half or more of its receipts trace back to withdrawals from commercial storage (AER ST98 Table S5.4 pools). Where ST50A lists one licence under several facility ids, each repeating the licence's capacity, it is one row here.

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"History" opens a plant's receipts by year since 2010 (AER ST60B) and by month since 2022 (Petrinex) against today's licence. "—" means no receipts reported that month. Licensed H2S is implied by licensed sulphur inlet over licensed raw gas (design, not measured). Heating value is reported energy over volume (2026-09, Petrinex). No public CO2 or full gas analysis exists; the AER sells them.

32. **Grid connection queue: Fox Creek planning area**: AESO Connection Project List, 2026-11-03. The list names no substation, so this table matches projects to the site by planning area (AESO boundaries of 2020-06-23); Queue at the substations, below, places each project at the nearest AESO substation within 1 km of the point the AESO maps it at. These are connection requests: most have no approval, and stages run 0 to 6. Supply is STS (generation) and demand is DTS (load), summed over the energization steps of each project.
33. **Power plants within 50 km**: Power plants from NACEI (2012-2017 (mostly 2017-08); NRCan, free use with acknowledgement); "—" means no capacity listed. NACEI lists all fuels only at 100 MW and up, so small gas units and recent builds can be missing. Coal units listed by NACEI have since been converted to gas or retired. AESO MC: the maximum capability of the AESO generating assets of the same fuel (any fuel where NACEI says "other") with a unit within 2 km of the mapped plant, each asset counted at one plant only (the nearest); "—" means none (AESO generator list, 2026-09-16).
34. **Planning area 24, Fox Creek (Northwest region)**: AESO transmission system GIS (lines, substations, generators), as of 2026-09-16; AESO data requests: planning-area hourly load and generation (2015 on); constrained volume by planning area and fuel type (2020 on), load to 2025-12-31, constraints to 2025-12-31; planning areas from the AESO Connection Project List boundaries.
35. **Project finance: hypothetical merchant case**: A hypothetical case from the analyst's inputs, not the economics of any named project. Starts from Sizing and cost: 100 MW of Reciprocating engines, Alberta (Bitdeer Fox Creek), C$198.4M capital at first power in constant 2025 C$, from 2029 for 20 years; levelized all-in 67–108 C$/MWh across the published Canadian gas scenarios, 63.4 C$/MWh at the flat gas price, both constant 2025 C$. Revenue, fuel and output come from dispatching this plant hour by hour against AESO pool prices, one run per year 2019–2025 and a forward case, and each year is financed as if its prices held over the life. The model is in nominal C$: capital and fixed O&M are carried from 2025 to 2029 dollars at the 2% escalation, each dispatch year escalates from its own dollars, and NPV discounts at the 9.7% nominal cost of capital.
36. **Project finance: hypothetical merchant case**: Forward case 14.4% (low 8.3% to high 19.3%); 2025 held over the life 3.3%; 2026 to date, annualised from 10.5 months, held over the life −1.1%. History: project IRR over 400 lives drawn from the past years P10 8.1%, P50 12.4%, P90 17.4%; across 2019–2025 dispatch years (each year's power and gas prices held over the life, a stress test of that year, not a forecast) 0.5% to 36.1% (median 11.9%). The year to date is shown apart and kept out of the median and the lives.
37. **Project finance: hypothetical merchant case**: The Market Surveillance Administrator's verdict: hypothetical combined-cycle and simple-cycle gas plants "were all uneconomic in 2025 as net revenues from the energy market were not sufficient to cover fixed and capital costs" (Wholesale Market Report Q4 2025, p. 4), below the capital charge at each of its WACCs from 6.5% to 12.5% (Figure 35, p. 50); the energy market "was unprofitable in Q1" and "in Q2" and "remained unprofitable in Q3" of 2026 (Wholesale Market Reports Q1, Q2 and Q3 2026, p. 4). A secondary offer cap has applied since July 1, 2024 (ISO rule 206.1) under the Market Power Mitigation Regulation, which "expires on November 30, 2027" (Alta Reg 43/2024, s. 7). The forward market is thin: "Liquidity in the forward market remained low in Q3" and "Cal 29 traded once" in August (Q3 2026, pp. 76 and 80).
38. **Project finance: hypothetical merchant case**: Each year's hourly prices and gas held over the 20-year life from 2029, escalated at 2.0% from that year's dollars. Carbon is not held: the finance charges each operating year's tonnes at that year's TIER price and benchmark (the dispatch year's own carbon price only sets its run hours). Run hours are per year at the plant's output; captured price is revenue per MWh, net of transmission losses. A year with no return is one whose cash never repays the capital; it is counted, never shown as 0%. Forward case: each full year 2019–2025's hourly price shape shifted by a constant so its mean matches the Cal-27 to Cal-30 flat annual power forward (TC Energy's Power Market Update for Cal-27 to Cal-29 (as of 2026-11-03); MSA Wholesale Market Report Q3 2026, Table 29 for Cal-30 (as of 2026-09-30)), gas at the same document's gas forward for the same year, carbon and the TIER benchmark of that year; the mean over the base years. Held flat in real terms (2% a year) after the last forward year; not a forecast.
39. **Project finance: hypothetical merchant case**: Forward low and high: the same forwards, then from the year after the last one a level scaled by the spread of past years (run hours and captured price shown for that year). Low · Forwards: Cal-27 to Cal-30 forwards (TC Energy's Power Market Update for Cal-27 to Cal-29 (as of 2026-11-03); MSA Wholesale Market Report Q3 2026, Table 29 for Cal-30 (as of 2026-09-30)); Low · From 2031: power C$52.42/MWh (P25 of the years, −38% on their mean), gas C$1.73/GJ (P25, −35% on their mean), nominal 2031; Low · Then: held flat in real terms (2% a year); Low · Long-term path: none published (AESO 2024 LTO, CER EF2026 and AER ST98-2026 checked). High · Forwards: Cal-27 to Cal-30 forwards (TC Energy's Power Market Update for Cal-27 to Cal-29 (as of 2026-11-03); MSA Wholesale Market Report Q3 2026, Table 29 for Cal-30 (as of 2026-09-30)); High · From 2031: power C$115.28/MWh (P75 of the years, +36% on their mean), gas C$3.12/GJ (P75, +17% on their mean), nominal 2031; High · Then: held flat in real terms (2% a year); High · Long-term path: none published (AESO 2024 LTO, CER EF2026 and AER ST98-2026 checked). Central forward case: the Cal-27 to Cal-30 forwards (TC Energy's Power Market Update for Cal-27 to Cal-29 (as of 2026-11-03); MSA Wholesale Market Report Q3 2026, Table 29 for Cal-30 (as of 2026-09-30)), then Cal-30 held flat in real terms (2% a year); not a forecast. No public long-term Alberta pool price path was found to follow past the last forward (checked 2026-11-17): the AESO 2024 Long-Term Outlook publishes capacity, generation, emissions and costs but no pool price (its data file has no price sheet); the CER's Canada's Energy Future 2026 publishes only end-use electricity prices (residential, commercial, industrial), not a wholesale price; and AER ST98-2026 forecasts AECO-C gas to 2035 but no power price. So each case holds its last level flat in real terms, and gas with it, so the spark spread stays one source's.
40. **Project finance: hypothetical merchant case**: Operating reserves: sold only in hours the plant sells no energy, at each day's AESO clearing index to the pool price (max(0, pool + index)) for active supplemental, and the premium plus the expected activation for standby; the MSA's net-revenue analysis and the AESO CONE study leave them out. The forward case keeps each base year's index to the pool price on the shifted prices. Reserves column: the year's reserve revenue per kW of nameplate, in that year's dollars. Supplemental, active and standby: an engine plant that is off can reach output within the 10 minutes ISO rule 205.6 s. 6(1) allows (gas engines start in minutes; the start time is judgement, no public Alberta figure). Not spinning (needs the unit synchronised: it is off in these hours) nor regulating (AGC within 28 s, rule 205.4). On 2025-01-01 the AESO's Operating Reserve Offer Control report shows simple-cycle gas units (e.g. VVW1, a simple-cycle unit in the AESO's metered volumes) holding 15–30 MW each of the 200–215 MW of active supplemental reserve for generation (ETS Operating Reserve Offer Control report).
41. **Project finance: hypothetical merchant case**: Power price: ±20% on revenue (every hour's pool price, contract price, capacity charge), judgement; run hours re-dispatched at the new prices.Capital cost: min–max of the 5 published capital figures for reciprocating engines at 100 MW, C$1,457 to C$2,344/kW around their median C$1,788/kW (each before interest during construction), applied to the case's capital; quartiles with eight or more figures, else the extremes, is judgement.Discount rate (WACC): 1.6 points below and 2 above the case's 9.7% on uncontracted cash, the published range around the 9.7% default: Low

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8.1%: the regulation's 10.5% pretax WACC read the other way, as an after-tax rate grossed up for tax (10.5 × (1 – 23%)); AESO CONE 2018's 8.5% after tax, sized for a capacity market, sits inside. High 11.7%: the MSA's "Very high" 12.5% capital-recovery WACC (Wholesale Market Report Q4 2025, Figure 35, p. 50), converted to after tax the same way as the default (50% debt at 7%); moves NPV, not IRR.Heat rate: measured: 3 Alberta gas-engine plants (engine plants named as such by an AUC decision or the owner; plants of 20 MW or less, mostly peaking, so starts and part load are included; West Cadotte burns flare gas, which carries more CO2 per GJ than pipeline gas, so its figure reads high), 4 plant-years, ECCC GHGRP CO2 ÷ AESO metered output, 2019–2024, P10–P90 10.61–12.42 GJ/MWh (median 11.53); fuel and tonnes scaled by P10 or P90 ÷ median, dispatch hours not re-run.Gas price: ±20% on fuel cost (every month's gas), judgement; run hours re-dispatched at the new prices; pool prices held, so this is the spark spread moving (the scenarios below move gas and power together).Carbon price case: Headline: the whole obligation at the TIER fund price; against Credit market: 85% at the MSA-reported credit price (held in real terms, never below the 2030 floor), 15% at the fund price.Insurance (inside CONE fixed O&M): ±20%: the AESO CONE 2018 study's own fixed O&M sensitivity (p. 49).Property tax (inside CONE fixed O&M): ±20%: the AESO CONE 2018 study's own fixed O&M sensitivity (p. 49).Operating reserve price: The lowest (2020) and highest (2022) full year's mean active supplemental price, max(0, pool + the day's index), over the 2019–2025 median of C$24.95/MW-h (AESO ETS daily operating reserve reports); the reserve line only, energy dispatch not re-run.Availability: No measured range: Alberta engine plants run mostly as peakers, so their running hours measure dispatch, not availability.

42. **Project finance: hypothetical merchant case**: Each bar is the project NPV at WACC with one input at its low and its high value and every other input at the central case; the flame line is the central case (C$35.0M). Grey: below it; black: above it. Rows run from the widest swing; a dash is a row with no result, listed last: an input with no measured range to move it by (its basis says why), or a case with no result (the plant does not run). Ranges are published figures or study bands where a source gives one and are marked judgement where none does.
43. **Project finance: hypothetical merchant case**: Each of 400 lives runs 20 years, each year one of 2019–2025's, drawn in runs of 3 consecutive years so a stretch of calm or tight years stays together. The market sets the level, history the swings: through 2030 each year's hourly price shape is dispatched at that year's published power and gas forward (as the forward case); after 2030, at the last forward times the drawn year's own power and gas over the 7-year mean (power –52% to +88%), so the years average to the forward held flat in real terms. capital drawn evenly from lowest (–19%) to highest (+31%) (min–max of the 5 published capital figures for reciprocating engines at 100 MW, C$1,457 to C$2,344/kW around their median C$1,788/kW (each before interest during construction), applied to the case's capital; quartiles with eight or more figures, else the extremes, is judgement). P10: one life in ten returns less; P90: one in ten returns more. The carbon case stays as chosen. A shift in the long-run level itself is the forward low and high cases above. Not included unless you enter it: land, owner's and development costs; heat-rate degradation; decommissioning; working capital; the AESO owner's contribution (off-grid, or no region). Equity returns only (not project IRR or this tornado): financing fees of 4% of debt, the 30% interest-deductibility cap (EIFEL).
44. **Basis**: Gas by dispatch year: monthly AB-NIT averages as the MSA publishes them (the reference price, labelled, where a month is missing); the sizing's flat gas price is not used here. 180,974 t CO2e a year: at or above TIER's 100,000 t threshold, so the facility is regulated; carbon is charged here as if the facility is in TIER. Capital cost allowance: Class 17; Accelerated Investment Incentive off by default (a toggle): Budget 2025 and Bill C-15 reinstated an accelerated first-year allowance, but sources conflict on its available-for-use dates (before 2030 or before 2034) and on whether it reaches Class 48 and 17 gas property; on, it claims 1.5 × the rate in year one with no half-year rule.
45. **Basis**: Engine check: with the MSA's own 2025 inputs it lands +1.8% on the combined cycle and +7.3% on the simple cycle against the MSA's published net revenue (±10% test passed); with PatchWatt's defaults and against real Alberta units, see the validation view (Land & market, gas price and carbon scenarios).
46. **Basis**: A screening model, not a lender's model. Capital is the sizing's capital at first power (interest during construction included), in 2029 dollars, spent at close. Tax is 23% (federal 15% plus Alberta 8%) on EBITDA less capital cost allowance (Class 17 at 8% declining balance), with the half-year rule in year one and losses carried forward 20 years; interest is deducted in the levered case. The gas lateral and meter station are claimed in Class 1 (4%) and the grid tie in Class 47 (8%), as the AESO CONE 2018 study classes its gas and electrical interconnections (Table 15). Buildings are not separated in the published capital: they stay in the equipment class unless you enter their share of capital (Class 1, 4%, or 6% for an eligible non-residential building). Debt is a level annual payment, the largest whose lowest DSCR within the tenor meets the target on the CFADS shown, capped by gearing, and the tenor never runs past the contract that services it. Carbon is charged by case on tonnes above the TIER benchmark and credited below it. Debt rate, gearing and hurdle default to the AESO CONE 2018 case; tenor and minimum coverage are judgement, not an agency rule.
47. **Production coverage scenario**: A what-if, not a supply assessment: if the largest producers reporting within 25 km each set aside 50% of today's local volume and nothing new were drilled, how much of the plant's 19.4 MMcf/d would that cover each year? Plant need: 19.4 MMcf/d of sales gas: a 100 MW plant (Reciprocating engines, Alberta (Bitdeer Fox Creek)) at 42.2% efficiency, higher heating value (HHV), at full load, converted at 1,055 GJ/MMcf (a sales-gas heating value; raw gas at the wellhead is larger by the processing shrink).
48. **Production coverage scenario**: NGTL system average tolls in force on 2026-11-19 (CER open data; TC Customer Express, NGTL Pricing & Tolls, final 2026 rates effective 2026-06-01 (https://www.tccustomerexpress.com/2766.html)); a given receipt point's FT-R lies between TC's floor and ceiling. Firm demand charges per GJ burned at a 100% load factor. NGTL fuel and loss 1.98% of the gas (2026-09; 1.72–2.46% over 2025-10 to 2026-09), borne by the producer shipping to the hub: Government of Alberta, Monthly reference price calculations, "Alberta Fuel Usage and Measurement Variance on NGTL": 1.98% for 2026-09, 1.72% to 2.46% over 2025-10 to 2026-09 (open.alberta.ca, OGL-Alberta). NGTL delivery group not verified for this delivery point: Group 2 used, Group 3 shown as the high end. Heat content: Measured heat content 43.9 GJ/10^{3}m^3 (the plant's Petrinex gas energy ÷ volume) × 28.3168 m^3/Mcf, receipts-weighted over 8 gas plants within 25 km of the producers' facilities. Load factor 100%: the need above is a full-load figure and a plant serving a data-centre load runs flat; firm tolls are demand charges, so a lower load factor raises the per-GJ figures.
49. **Production coverage scenario**: NGTL delivery group: Group 2 is the judgement default (the NGTL delivery group under Assumptions); Group 3 the dearer intra-Alberta group, TC's 2026 FT-D rates. Open item: NGTL delivery group of the plant's delivery point.Load factor: P10–P90 capacity factor of 8 Alberta gas-engine assets (plants of 20 MW or less named as engines by an AUC decision or the owner, mostly peaking), so the range measures how often a peaker was dispatched, not a plant serving a flat load, 2019–2024 (AESO metered output).AECO price: ±20%, judgement; it moves only NGTL fuel, which is a share of the gas.Decline where unmeasured: Peyto base (PDP) decline 27–30% in 2021–2025, 28% in 2025, Peyto 2025 reserves release (2026-02-19, https://www.peyto.com/Files/Operations/2025ReservesPressRelease.pdf); a tight-gas operator's decline.
50. **Production coverage scenario**: Each bar is the buyer's saving over the term with one input at its low and its high value and every other input at the central case; the flame line is the central case (26.2M C$). Grey: below it; black: above it. Rows run from the widest swing; a dash is a case with no result (the plant does not run), listed last. Ranges are published figures or study bands where a source gives one and are marked judgement where none does.

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51. **Production coverage scenario**: Reported production is not gas available for sale: this does not know which volumes are already contracted, which wells connect to which lines or plants, processing capacity, gas quality, firm service, reserves, credit or any producer's willingness to sell. Volumes are each producer's reported raw gas within 25 km, times the dedication share, declining at its measured 24-month rate (1 of 1 measured; the rest at 28%/y, default 28% from the Peyto base (PDP) decline 27–30% in 2021–2025, 28% in 2025, Peyto 2025 reserves release (2026-02-19, https://www.peyto.com/Files/Operations/2025ReservesPressRelease.pdf); a tight-gas operator's decline) with no new wells, including the 2.3 years from Sep 2026 to the start of 2029, so year 1 is below today's volume. Transport is the NGTL system average, not a station toll.
52. **Facilities reporting greenhouse gas within 25 km**: ECCC Greenhouse Gas Reporting Program, reporting years 2004–2024 (Open Government Licence - Canada). Totals exclude CO2 from biomass. Facilities report when they emit at or above the threshold in force: 100,000 t CO2e a year for 2004-2008, 50,000 t for 2009-2016 and 10,000 t from 2017. Totals and facility counts step up at 2009 and 2017 for that reason alone. Year totals here start in 2017, the first year under the current threshold. Neighbouring emitters can matter for a TIER benchmark, a shared airshed and a carbon capture hub; this table measures none of those.
53. **Each forecast for this year beside the realised prices**: AB-NIT: Same-day trades at NOVA Inventory Transfer (the AECO hub). The latest report read covers months to 2026-09. Reference price: A royalty valuation price from a simplified netback model, not a hub price; it usually sits below AB-NIT. No public monthly series for the NGX AECO-C index (the basis of AER's forecast) was found for 2026.
54. **Alberta Internal Load since 2000**: In 2025 Alberta Internal Load came to 90.4 TWh: a mean of 10,316 MW against a peak hour of 12,785 MW (11 Dec 2025, hour ending 18), a load factor of 80.7%. Energy was 1.7% above 2024, and grew 1.2% a year over the ten years from 2015. 2026 to the end of Oct 2026 is 2.8% above the same months of 2025; its highest hour so far is 12,404 MW (12,211 MW in those months of 2025). Load factor in the last ten full years ran from 79.0% to 85.1%.
55. **Interties: imports and exports**: In 2025 Alberta imported 582 GWh and exported 3,633 GWh over its interties with British Columbia, Montana and Saskatchewan, a net export of 3,051 GWh. The province was a net importer in 21% of its hours and a net exporter in 75%. The last full year with net imports was 2023 (8 GWh). 2026 to Oct 2026: net export of 425 GWh, importing in 41% of hours.
56. **Hour-ahead price forecast against the settled price**: An hour before each hour the AESO publishes a forecast of its pool price; the price that settles can differ. In 2024 the settled price was on average C$17.97/MWh away from the hour-ahead forecast, against a mean pool price of C$62.78/MWh, and more than C$50/MWh away in 8.5% of hours (3.4% above the forecast, 5.1% below). The widest year was 2023: C$42.11/MWh, 20.2% of hours over C$50 off. January to July 2025: C$12.46/MWh and 4.0%. The series ends on 2025-07-31 with the AESO data-request files; the files fetched after that carry no forecast.

DATA SOURCES AND LICENCES

Data licences. AER, Petrinex and AESO data are shown for non-commercial use until written consent is received. The full list of datasets with their dates is at https://patchwatt.web.app/data-updates.

1. Municipal boundaries: Government of Alberta (Alberta Environment and Protected Areas) Municipal Boundaries, Communities and Metis Settlement services, official names from Alberta Municipal Affairs; data-centre status from council records, bylaws, AUC decisions and court files (each entry cites its record) (2026-10-05); Overture Maps buildings, release 2026-10-21.0: OpenStreetMap and Microsoft footprints (release 2026-10-21.0); Data-centre project inventory: Government of Alberta Major Projects and the AESO Connection Project List, with a hand-kept overlay of AUC, IAAC and municipal filings and company releases (2026-11-16); Power plants: NACEI North American power plants (NRCan/DOE/SENER, free with acknowledgement) (NACEI 2017); Alberta Township System arithmetic; AAFC Annual Crop Inventory (OGL-Canada), queried live (as of 2026-11-19)
2. Forward scenarios: CER EF2026 (OGL-Canada), EIA AEO2026 (public domain), AER ST98-2026, AESO project list 2026-11-03, Canada–Alberta TIER agreement (manual table) (2026-11-03); ECCC CWEEDS 2020 hourly engineering weather, Alberta, station records 1998–2017 (OGL-Canada) (2022-07-13); Alberta Municipal Affairs, municipal financial and statistical data: 2026 tax rates (MR) and equalized assessment (EA) (2026-11-05); AESO CONE 2018 and Alberta project filings, constant 2025 C$; the analyst's inputs (as of 2026-11-19)
3. AER ST50A gas processing plants (licensed capacity) with Petrinex plant receipts (capacity 2026-11-10; receipts 2026-09); heating value from Petrinex reported energy over volume; Cascade Power Project description (IAAC 80166, 2019); the analyst's sizing inputs. receipts 2026-09)
4. Petrinex public volumetric data (Alberta); locations from AER ST102 (2026-09); Petrinex Well Infrastructure (Alberta) (2026-11-10); Petrinex public Well Infrastructure (Alberta) (2026-11-10); Petrinex public volumetric data: every producing well since 2022 (2026-09)
5. AER Enhanced Pipeline data (provincially licensed lines) (2026-11-10); NRCan CanVec 1:250k pipelines (Open Government Licence - Canada) (mapped 1974-1994); Canada Energy Regulator pipeline systems (federally regulated gas lines: NGTL, Alliance, Foothills, TC Mainline, Enbridge BC) (CER service data edited 2024-11-12; downloaded 2026-11-10); AER ST50A gas processing plants (licensed capacity) with Petrinex plant receipts (capacity 2026-11-10; receipts 2026-09); Canada Energy Regulator pipeline throughput and capacity (NGTL, Alliance, Foothills), Open Government Licence - Canada (2026-06)

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6. Power plants: NACEI North American power plants (NRCan/DOE/SENER, free with acknowledgement) (NACEI 2017); AESO Connection Project List and planning area boundaries (project list 2026-11-03); AESO transmission system GIS: substations (2026-09-16); AESO planning-area hourly load and generation, and constrained MW by planning area and fuel (2025-12-31)
7. AESO Connection Project List, 2026-11-03 (project points, list of 2026-11); AESO transmission system GIS (lines, substations, generators), substations as of 2026-09-16; AESO Connection Project List, monthly lists since January 2023
8. AESO transmission system GIS (lines, substations, generators), generators as of 2026-09-16; AESO hourly metered volumes by generating asset: data request 2001 to July 2025, then the ETS Metered Volumes (All) report, hourly to 2026-10-31
9. NRCan National Hydro Network work units; SSRB closure under Alberta's 2006 water management plan (2021-03-25); Alberta Environment and Protected Areas, Water Act licences (active authorisations) (2026-11-02) (as of 2026-11-02)
10. Alberta Flood Hazard Identification Program mapping, Open Government Licence - Alberta (2026-10-09); Earthquakes Canada (NRCan) event catalogue, Open Government Licence - Canada (2026-11-10); Alberta wildlife sensitivity maps: caribou ranges (Government of Alberta; free use, maps not to be redistributed commercially) (2015-06-11); Parks and Protected Areas of Alberta, Alberta Environment and Protected Areas (Open Government Licence - Alberta) (2026-09-21); Alberta First Nations reserves, Métis settlements and treaty areas (Government of Alberta boundary services, Open Government Licence - Alberta) (2026-08-11); AER Abandoned Well spatial data with Revised Abandoned Well Locations (2025-01-30); Alberta Listing of Historic Resources, Fall 2026 (OGL-Alberta) (2026-09-29); Alberta Merged Wetland Inventory, queried live (GoA copyright, all rights reserved) (live); Green/White Area, Alberta Environment and Protected Areas (Open Government Licence - Alberta) (2021-11-16); SRTM terrain (as of 2026-11-19)
11. AER Enhanced Pipeline data: H2S content, H2S release volume and Directive 056 release level per segment (2026-11-10); Petrinex public Facility Licence and Facility Infrastructure files (Alberta) (2026-11-10); AER ST102 Facility List (shapefile) (2026-11-02); AER ST50A gas processing plants (licensed capacity) with Petrinex plant receipts (capacity 2026-11-10; receipts 2026-09); AER Directive 056: Energy Development Applications and Schedules, edition released and effective 2026-10-01 (replaces 2026-03-31), s. 6.5.2, requirement 5 and Table 6 (p. 81); read 2026-11-11
12. Green/White Area, Alberta Environment and Protected Areas (Open Government Licence - Alberta), boundary as last revised 2021-11-16; Government of Alberta, Understanding Land Use in Alberta (Land-use Framework, April 2007), Table 1, p. 11 (as of 2021-11-16)
13. Municipal boundaries: Government of Alberta (Alberta Environment and Protected Areas) Municipal Boundaries, Communities and Metis Settlement services, official names from Alberta Municipal Affairs; data-centre status from council records, bylaws, AUC decisions and court files (each entry cites its record) (2026-10-05); Alberta Utilities Commission featured proceedings (public web pages) (retrieved 2026-11-10; newest page change 2026-10-23); AUC Rule 007, AR 276/2003, AESO connection process as cited per step. AUC content curated from its public web pages, no open licence (as of retrieved 2026-11-10; newest page change 2026-10-23)
14. Petrinex public volumetric data (Alberta); locations from AER ST102 (2026-09); Petrinex Well Infrastructure (Alberta) (2026-11-10); Petrinex Well Infrastructure: well licences by licensee and licence status (2026-11-10). Not the AER's Licensee Capability Assessment or LMR, which are not published per licensee (as of 2026-11-10)
15. ECCC CWEEDS 2020 hourly engineering weather, Alberta, station records 1998–2017 (OGL-Canada) (2022-07-13); ECCC Greenhouse Gas Reporting Program facility data, Open Government Licence - Canada (reporting years 2004-2024); Canada–Alberta TIER implementation agreement (2026-05-15) (as of reporting years 2004-2024)
16. Evidence register built from the sections above; status words describe the public evidence, not the place (as of 2026-11-19)
17. PatchWatt assumptions register (as of 2026-11-19)
18. AUC Rule 007 (effective 2025-11-06) §4.5.2; PatchWatt sections (as of 2025-11-06)
19. PatchWatt scope statement and assumptions register (as of 2026-11-19)
20. Market Surveillance Administrator (MSA), quarterly wholesale market reports; Alberta Energy and Minerals, Alberta natural gas reference price; AER ST98-2026 prices data file; AESO pool price (as of 2026-10)
21. CER Canada's Energy Future, latest edition (Open Government Licence – Canada); EIA Annual Energy Outlook, latest edition (US public domain; a US reference, not used in any cost); AER ST98, latest edition; Canada–Alberta TIER Implementation Agreement (as of 2026-11-03)
22. AESO Alberta Internal Load, hourly, ETS Historical Pool Price report, hourly Jan 2000 to 2026-11-16

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23. AESO hourly metered volumes, intertie import and export columns (data request 2001 to July 2025), then the ETS Metered Volumes (All) report's importer and exporter rows, hourly Jan 2001 to 2026-10-31 (data request to 2025-07-31, ETS 2025-08-01 to 2026-10-31)
24. AESO hour-ahead pool price forecast and actual pool price, hourly (data request 2001 to July 2025), Jan 2001 to 2025-07-31

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