MANITOBA PUBLIC UTILITIES BOARD · INTERVENER FILING · AUGUST 2026

Heat that works twice

NEWPCC Clean Hybrid Portfolio vs the Brandon gas expansion

Manitoba doesn’t need another gas plant.
It needs heat that works twice — and a Board that tests both plans
to the same arithmetic before the concrete is poured.

413–788 MW ELECTRIC | $1.95B GROSS | DUAL LEDGER | SIX ORDERS

One document for the public and the Board. Same voice. Math in the back.

Executive brief

One page · August 2026

Manitoba doesn't need another gas plant. It needs heat that works twice.

Hydro seeks ~$3 billion for new Brandon gas turbines while its existing units failed or derated in **3 of 10** peak winter events, including 22–23 January 2024 at **5,096 MW** [PD]. Winnipeg is rebuilding NEWPCC for another $3 billion-plus — and will waste usable sewage heat unless recovery taps are designed in now. A clean hybrid of batteries, demand response, interties, and an effluent-stage NEWPCC heat hub delivers **413–788 MW electric** for **$1.95B** gross (**$1.50B** if ITC confirmed), with non-overlapping twenty-year costs vs gas — with zero compute credit in any scenario. The summer add-on (~120 MW: ≈50 PDRC + 70 BTES) is a residual benefit — not winter firm.

Decision	Brandon gas	Clean hybrid
Capital	$3.0B	$1.95B / $1.50B net
Firm electric	750 MW nameplate; 525 MW **scenario**	413 / 688 / 788 MW
20-year all-in	$4.5–6.9B	$1.5–1.8B · save $2.7–5.4B

Six orders — the ask

1. **Head-to-head** hybrid (incl. sewage heat) vs gas — LOLE / ELCC / $/kW-year — before any capital certificate.
2. **Independent cold-weather audit** at ≤ −30 °C; identical ELCC rules for both plans.
3. **Machine-readable** cost models from both parties.
4. **Disclose** interconnection headroom near screened anchors + extreme-event logs.
5. **Preserve** NEWPCC trench / effluent heat-recovery option while contracts are open.
6. **Authorize** a measured pilot (effluent hub + 10–20 kW public compute) with Hydro SCADA and public metering.

> **Same arithmetic, before the concrete.** The Board need not adopt our numbers — only insist both plans face the same test in public. What follows is one paper in one voice for citizens and regulators; the mathematical appendix at the end is for advisors who must check every substitution.

Evidence tags used throughout: O official · C computed & tested · E engineering estimate · A needs confirmation · PD public disclosure (verify on docket). Registry: assumptions.yaml.

1. Manitoba doesn't need another gas plant. It needs heat that works twice.

On the mornings that matter, furnaces do not wait. **Winnipeg Free Press** reporting by Malak Abas put in public view what Public Utilities Board testimony had already shown: Manitoba Hydro's Brandon gas turbines failed or had to reduce output during **three of the ten** busiest winter periods in the last five years — including **22–23 January 2024**, when demand reached **5,096 MW** [PD]. That morning is the exam a Manitoba energy plan is not allowed to fail.

Despite that record, Hydro still seeks on the order of **$3 billion** for new Brandon turbines. CEO Allan Danroth told the Board the turbines are "necessary." Finance Minister Adrien Sala referred the project to the PUB. The sales pitch is near-perfect reliability. The operating history is not.

New machines can be more modern. They cannot repeal physics: **gas supply chains freeze when the cold arrives**. They also miss the real shape of Manitoba's crunch. Our highest demand is **heating**. Electrify homes without care at –35 °C and air-source heat pumps fall back on resistance coils — creating the shortage Hydro proposes to solve by burning more gas.

Manitoba already owns the multi-day answer: northern reservoirs, roughly **4,800 MW** firm even in drought conditions [PD/A] — the 2024 peak already ran ~300 MW above that firm-hydro floor, covered by imports and non-hydro resources, which is exactly the slack the 2030 shortfall consumes. What the system lacks is not weeks of energy but a few hundred megawatts of **power** on the coldest mornings and evenings. Hydro's projected **~600 MW** drought-year shortfall by 2030 is real [PD]. The dispute is not whether to act. It is what to buy.

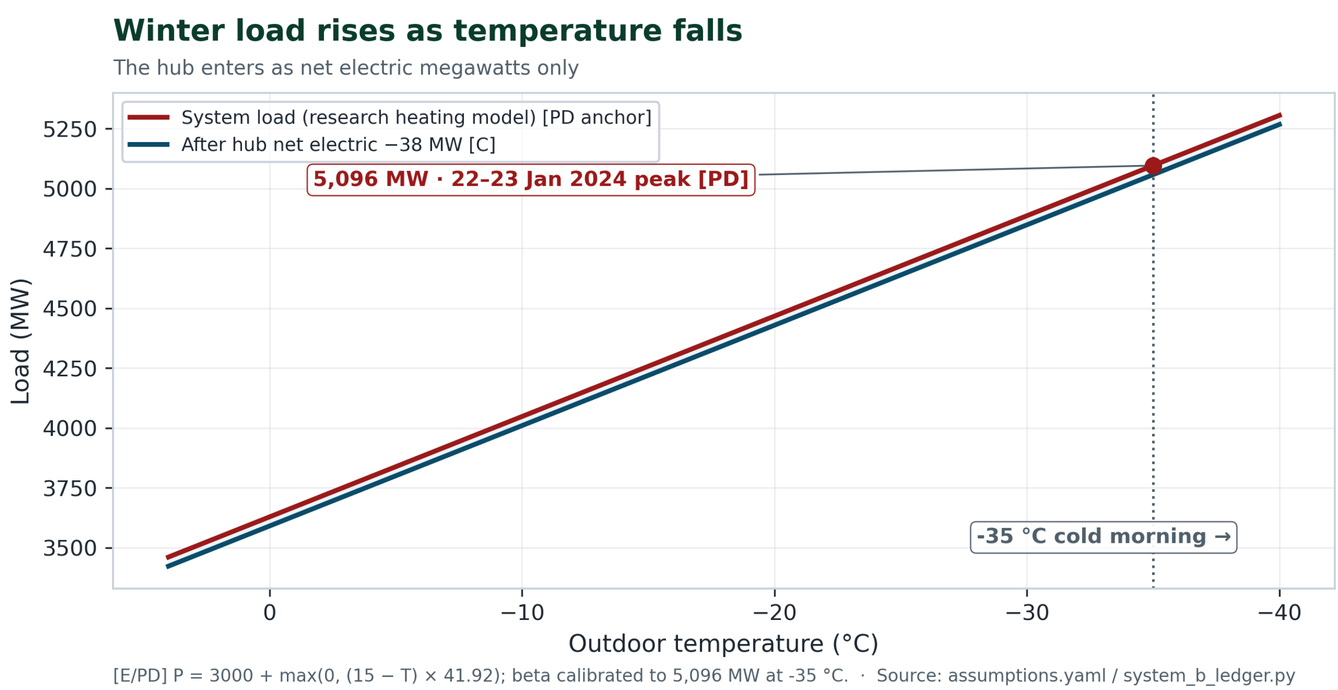

Figure 1 — Winter load rises as temperature falls. Peak anchor 5,096 MW [PD]. Hub enters only as net electric MW.

2. Two $3-billion choices, one wastes heat forever

Here is the absurdity hiding in plain sight.

The province debates a **$3-billion** gas plant in Brandon. At the same time, Winnipeg spends **$3 billion-plus** modernizing the North End Water Pollution Control Centre — the largest capital project in the city's history. NEWPCC already treats about **70%** of Winnipeg's wastewater. Sewage carries low-grade heat **every hour of every season**. Vancouver's False Creek has used that kind of heat for buildings for more than a decade. On a –35 °C morning, every megawatt of that heat that reaches a radiator is one less megawatt Hydro must generate for electric heating. **Same energy, twice.**

If we miss the window, Winnipeg will have a plant that treats water well and **wastes heat forever**. If we act while contracts are open, the North End can host a low-carbon heating system for a generation — without asking ratepayers to fund another fossil plant.

Decision	Brandon gas	NEWPCC clean hybrid
Capital	$3.0B	$1.95B gross ($1.50B if ITC confirmed)
What counts as firm	750 MW nameplate; 525 MW only as **scenario**	413 / 688 / 788 MW **electric** by accreditation
Heat	—	50 MWth effluent hub (+95 MWth gated); +38 MW net electric
20-year all-in	$4.5–6.9B	$1.5–1.8B · savings $2.7–5.4B

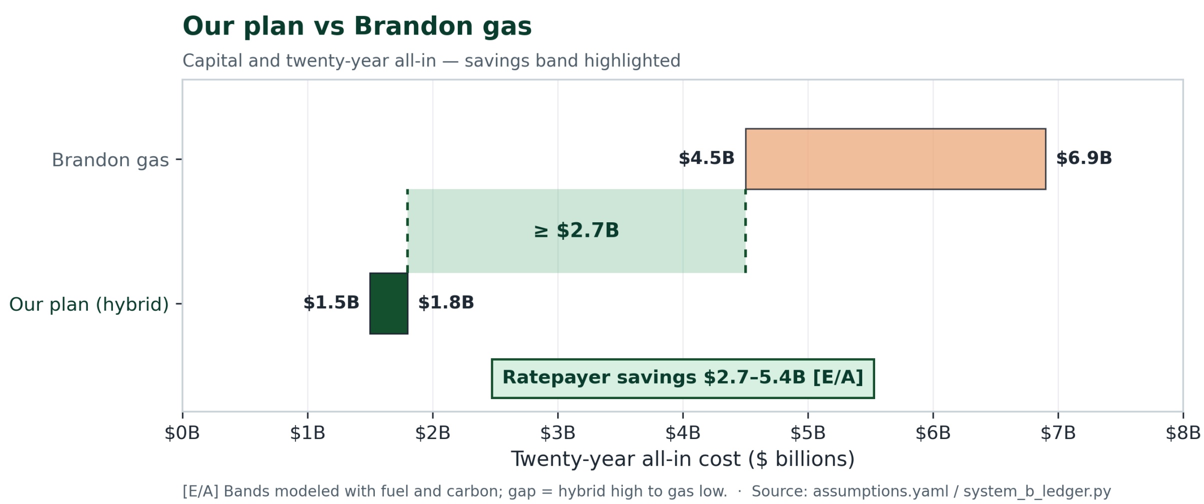

Figure 2 — Our plan vs Brandon gas: twenty-year all-in bands with the ratepayer savings gap highlighted [E/A].

That is a **heat-pump answer to a heat problem** — not a gas-plant answer to a spreadsheet problem.

3. Our plan: sewage heat, batteries, demand response, interties

Think of four tools and one optional upside working together — not one giant machine replacing Brandon.

1. **Sewage heat at NEWPCC (the base).** Treated effluent stays warm in January — with or without compute. Heat pumps lift it into a district loop. This is the civic heart of the case. MWTH
2. **300 MW batteries (4 h).** Cover the 7–9 a.m. and 5–7 p.m. spikes. Reservoirs already hold the multi-day energy.
3. **150 MW demand response.** Pay willing customers — especially baseboard stock — to shed the worst hours.
4. **Interties up to 300 MW.** Counted cautiously; zero in the conservative case until deliverability is proven [A].
5. **Small public compute, optional upside.** Not a private hyperscale warehouse — clean, publicly accountable nodes (10–20 kW), heat-first, and **curtailable in the top load hours** with reject heat banked in the seasonal ground store (BTES): load off at peak, heat still flowing at peak. Its winter value is demand response, never firm supply, and it carries **zero credit** in every scenario above. Eligible **today: 0 MW** [C]. Effluent heat does not depend on them.

DUAL-LEDGER RULE

Heat megawatts are not electricity megawatts. We never add them — and compute reject heat is never booked as firm supply, because the load that makes it must be netted first. The honest winter electric range is **413 / 688 / 788 MW**, built on the effluent-stage hub only. Summer's **~120 MW** PDRC/BTES shave is a residual benefit — never padded into winter firm. Substitutions are in the mathematical appendix.

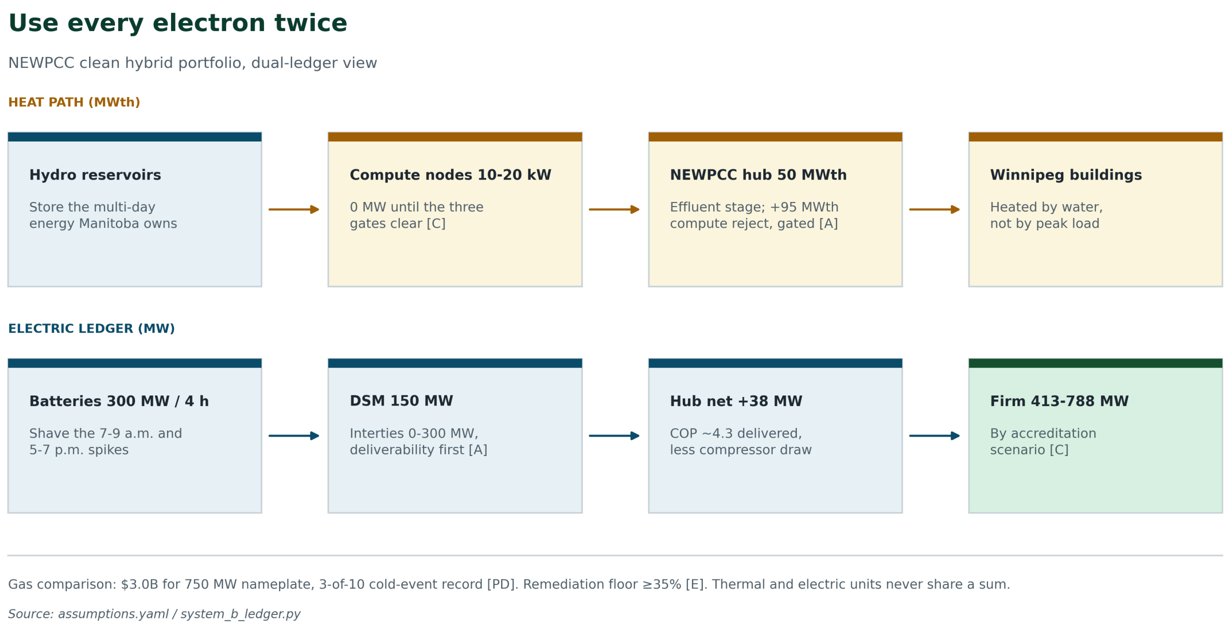

Figure 3 — Heat path above; electric firm capability below.

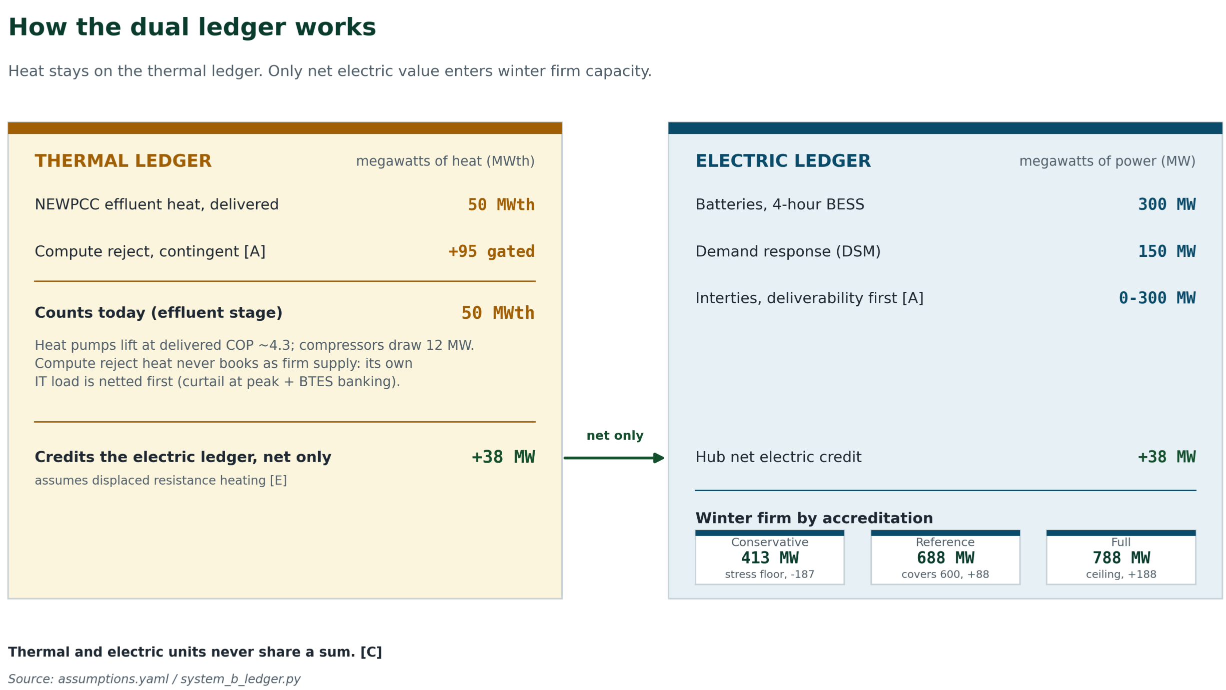

Figure 4 — How the dual ledger works: the 50 MWth effluent stage credits +38 MW electric net; compute reject stays gated; winter firm is 413 / 688 / 788 MW [C].

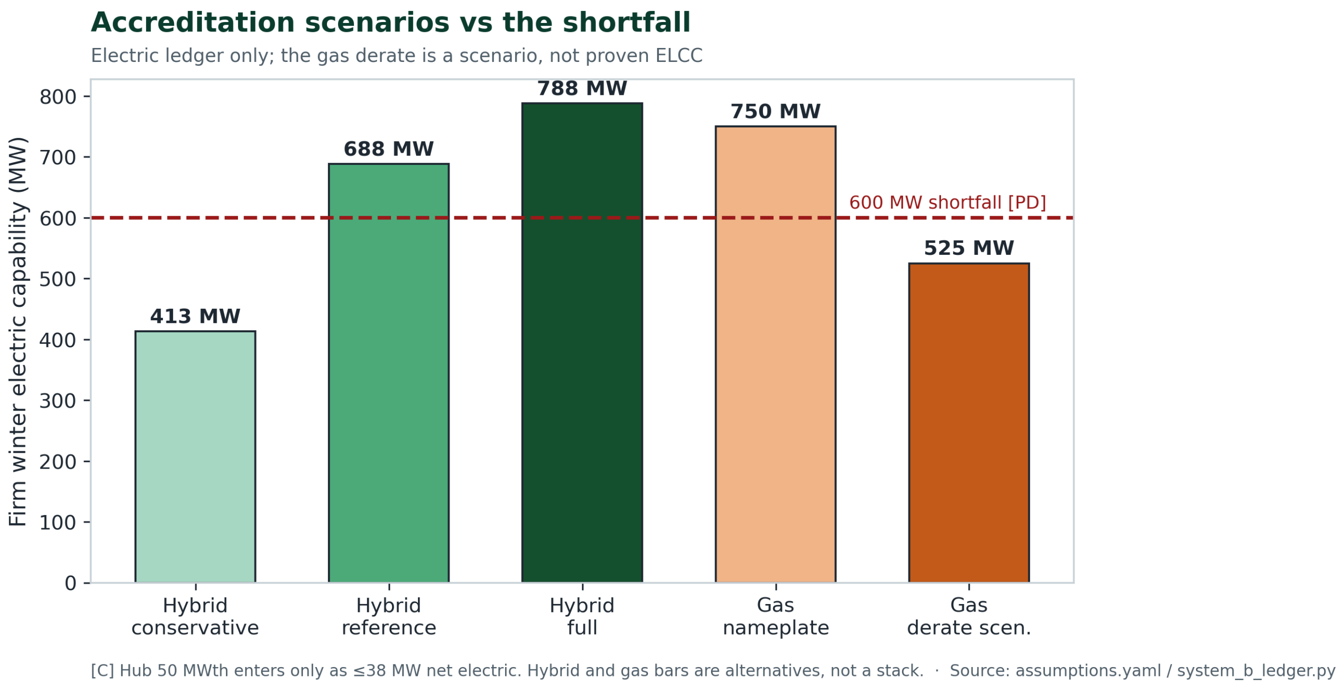

Figure 5 — Accreditation scenarios vs 600 MW shortfall and gas. Electric ledger only [C].

Conservative (**413 MW**) is the **stress floor** — interties at zero, DSM at half — so the Board can see what fails if optimism is stripped out. It is **not** the recommended build. Reference (**688 MW**) is the planning case and covers the shortfall by **+88 MW** — a margin carried by interties counted at 200 of 300 MW [A], a dependency we disclose rather than hide. Full (**788 MW**) covers it by **+188 MW**. Under an illustrative ELCC haircut on our own resources (BESS at 85%, DSM at 80%), reference still clears the shortfall at **613 MW**. Modular batteries and demand response can close gaps without pouring a single-station foundation.

4. Winter modelling: reference covers the shortfall, +88 MW

Manitoba is winter-peaking. Load climbs as the thermometer falls. Unmanaged heat-pump rollout steepens that curve; the hybrid flattens it by moving heat off the electric peak and covering the two daily spikes. The 2024–2035 peak-path exhibit is in the mathematical appendix.

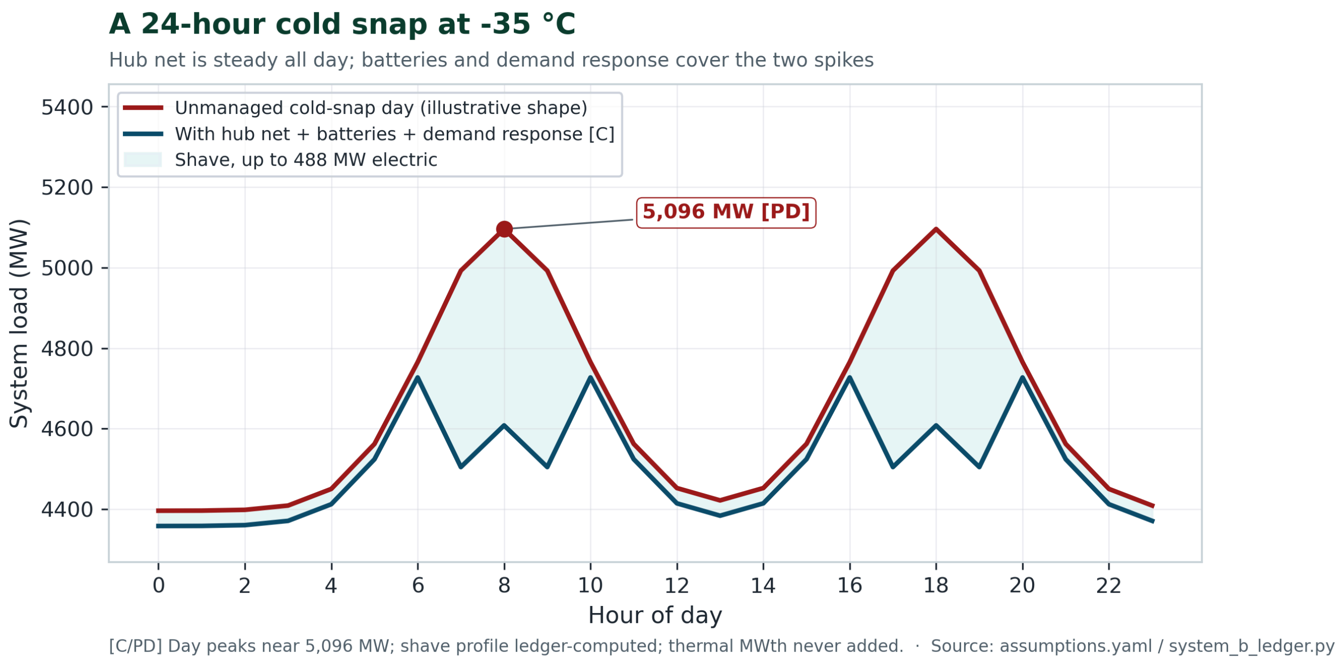

Figure 6 — 24-hour cold-snap day at −35 °C: hub net steady; batteries and demand response cover the dual spikes [C/PD].

Claimed: reference covers the shortfall; full widens the margin; conservative shows what fails if optimism is stripped out. **Not claimed:** summer cooling megawatts as winter firm; flat 30% gas derate as proven ELCC; “>98%” hybrid availability.

5. Money: $1.5–1.8B beats $4.5–6.9B before any credit

Capital: gas **$3.0B** vs hybrid **$1.95B** gross. If the federal Clean Technology ITC is confirmed, hybrid net is **$1.50B** [A]. We show **both** because credits are a fact to prove.

At reference accreditation: hybrid **$2,834/kW** gross and **$2,180/kW** net of the ITC — against gas **$4,000/kW** nameplate. That is the pass gate: **gross against nameplate**, with no ITC and no derate assumed — a factor of 1.4 in the hybrid's favour. The event-informed derate (**$5,714/kW** at 525 MW) is a clearly-labelled sensitivity, never asserted as fact. On this measure at reference accreditation, every contested assumption has to resolve against the hybrid at once merely to narrow the gap.

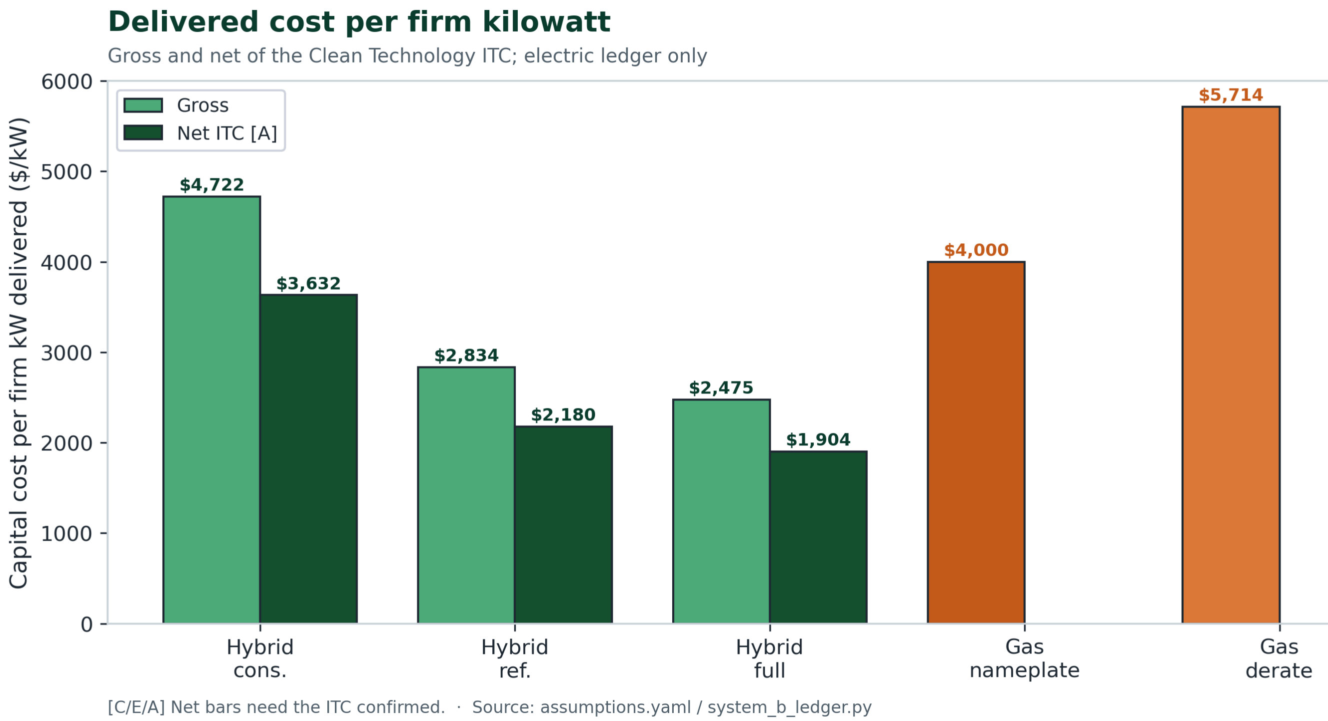

Figure 7 — Delivered capital cost per firm kilowatt [C/E/A].

Twenty-year all-in bands do not overlap: gas **$4.5–6.9B**, hybrid **$1.5–1.8B**. The cheapest defensible gas future still costs **$2.7B** more than the most expensive defensible hybrid future in this model.

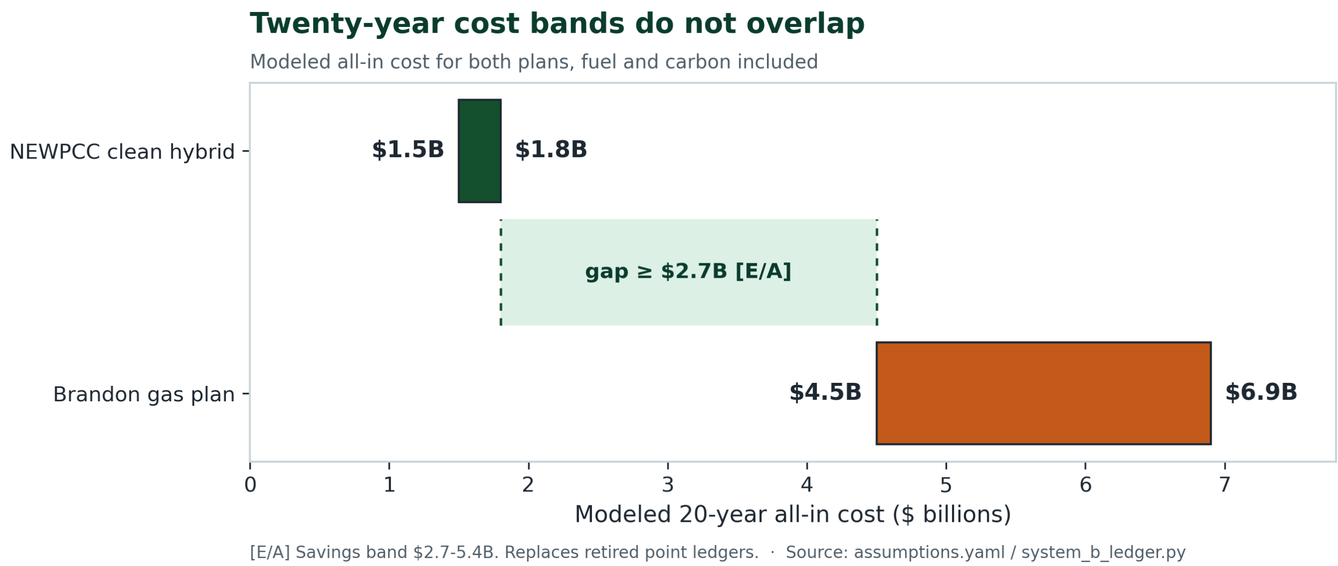

Figure 8 — Non-overlapping twenty-year cost bands. Savings $2.7–5.4B [E/A].

For ratepayers

Three billion dollars of rate-based fossil capital, plus fuel and carbon, shows up on bills. A smaller, fuel-free package — and a North End heat utility that can attract clean-energy capital a compliance sewage plant alone cannot — shows up more gently. Heat taps missed at NEWPCC are wasted for a generation.

All numbers at a glance

Quantity	Value	Role
2024 winter peak	5,096 MW	Exam anchor [PD]
2030 firm shortfall	600 MW	Hydro disclosure [PD]
Gas capital / nameplate	$3.0B / 750 MW	Brandon referral [PD]
Gas derate **scenario**	525 MW	Event-informed [A] — not ELCC
Hybrid capital	$1.95B / $1.50B net	Net needs ITC [A]
Winter firm electric	413 / 688 / 788 MW	Cons / ref / full [C]
Margins vs shortfall	−187 / +88 / +188 MW	Only ref+ cover
Hub, effluent stage	50 MWth → +38 MW	Dual ledger [C]
Hub, compute reject	95 MWth contingent	Gated; load netted first — 0 credit [A]
$/kW reference	$2,834 / $2,180	vs gas $4,000 nameplate; $5,714 sensitivity
20-year all-in	$4.5–6.9B vs $1.5–1.8B net of ITC	Savings $2.7–5.4B ($2.3–5.0B gross basis)
PDRC summer	180 MWth → ≈50 MW	**Add-on** — not winter firm [E]
BTES chiller avoid	70 MW	**Add-on** — not winter firm [E]
Summer total	≈120 MW	**Residual benefit** only

6. Reliability: audit both plans, assert neither

The **3-of-10** cold-event record is grounds to **commission an independent ELCC study** — not to assert a flat 30% derate as proven fact, and not to treat "near-perfect reliability" as settled. Hydro's **91%** start-reliability figure answers a different question: annual averages blend mild months into the average peak planning must ignore. The Board's concern is conditional availability in the top load hours.

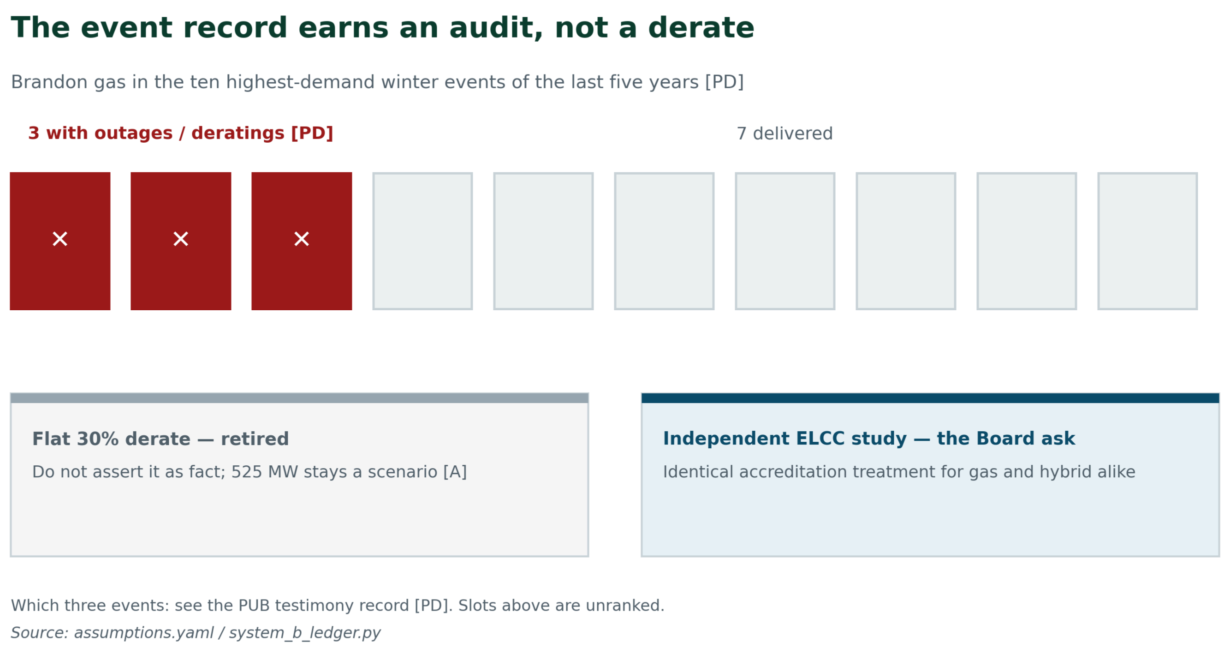

Figure 9 — Event record ⟶ Board audit ask. 525 MW is a scenario only [PD].

Against the multi-day vortex objection: reservoirs supply the days; batteries and demand response supply the hours; district heat and dual-fuel shrink the need itself. A four-technology, multi-site portfolio has no single component whose loss removes most of its capability. A single station on a single fuel line does.

7. The ask: six orders before the concrete pours

The Board need not adopt our numbers — only insist that both plans face the same arithmetic in public. Six orders make that a process, not a slogan:

1. **Head-to-head** hybrid (incl. sewage heat) vs gas — LOLE / ELCC / $/kW-year — before any capital certificate.
2. **Independent cold-weather audit** at ≤ −30 °C; identical ELCC rules for both plans.
3. **Machine-readable** cost models from both parties.
4. **Disclose** interconnection headroom near screened anchors + extreme-event logs.
5. **Preserve** NEWPCC trench / effluent heat-recovery option while contracts are open.
6. **Authorize** a measured pilot (effluent hub + 10–20 kW public compute) with Hydro SCADA and public metering.

Six Board orders

The closing ask: a fair exam for both plans, before the concrete

1	Head-to-head hybrid vs gas modelling before any capital certificate
2	Independent cold-weather reliability audit, identical ELCC treatment
3	Machine-readable economic models from both parties
4	Disclose interconnection headroom and extreme-event logs
5	Preserve the NEWPCC trench option for thermal headers
6	Authorize a measured pilot: effluent hub plus 10-20 kW nodes

From regulator paper §11 · Source: assumptions.yaml / system_b_ledger.py

Figure 10 — Six orders. Test both plans; keep the trench and the taps.

8. What would change our mind

A case that cannot say what would overturn it is advocacy.

- An ELCC finding gas tail-hour availability above ~95% **and** battery accreditation far below its four-hour rating.
- Verified capital quotes pushing the portfolio far above $1.95B gross, or gas far below $3.0B.
- A twenty-year gas scenario under $4.5B under filed fuel and carbon curves.
- District-heat uptake stuck at effluent-only — already priced in the **413 MW** case.

None of these falsifiers has occurred. Each is checkable. Symmetric candour has not, to date, been offered for the gas plan.

9. Beyond winter: summer PDRC, a ground battery, and gated compute

The Brandon referral is a **winter** capacity fight. Winning it does not require cooling roofs. The same stewardship logic has a summer chapter, and the potential is a **pair**:

- **PDRC films** reject heat to the sky even under direct sun. On an illustrative ~2.4 million m² commercial / institutional rooftop envelope at ~75 W/m² net radiative cooling, that is ≈ **180 MWth** of rejected heat — ≈ **50 MW** of avoided electric A/C load once chiller COP (~3.5) is applied — shaved from a +35 °C peak [E].
- **A ground battery** — borehole thermal energy storage (BTES) at the heat hosts — banks reject heat for winter and avoids ~**70 MW** of parasitic chillers in summer [E].
- **Together ~120 MW summer (electric)** — sky cools the roofs; ground stores the heat — registered and gated so it **never** enters 413 / 688 / 788. The winter case stands on its own.

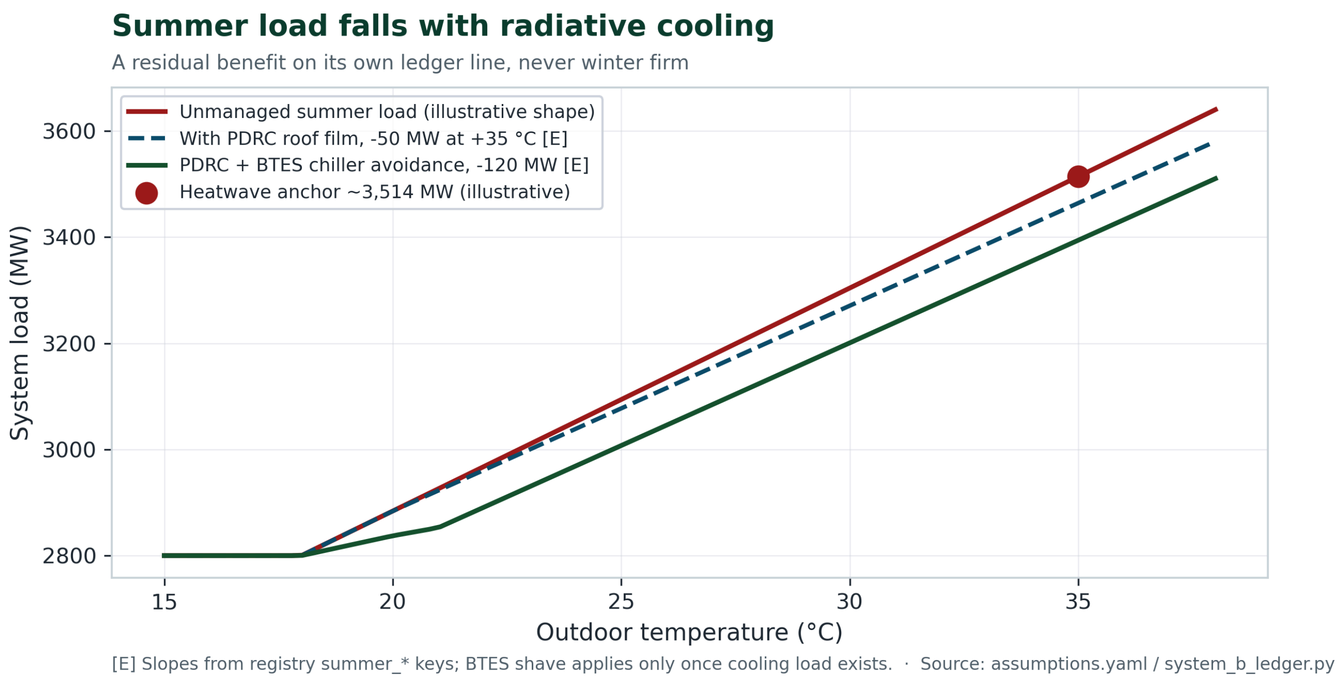

Figure 11 — Summer load vs temperature: PDRC and BTES lower the curve as an add-on [E]. Illustrative — not a filed Hydro summer peak.

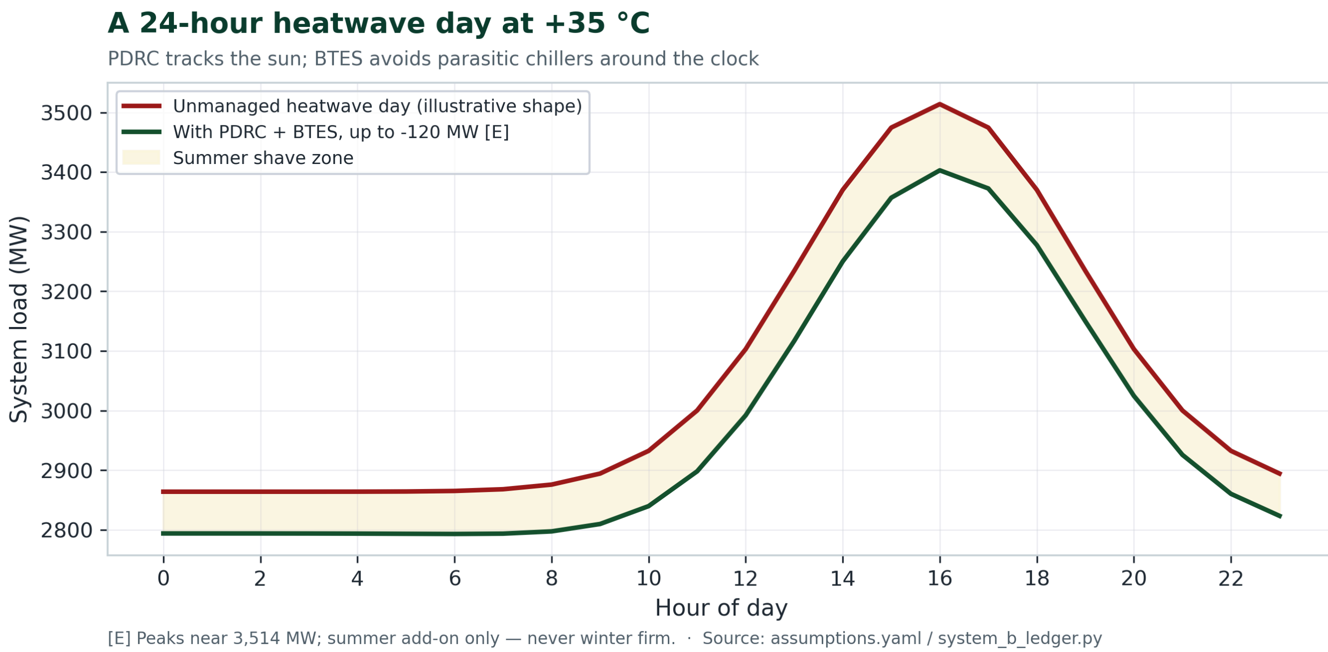

Figure 12 — A 24-hour heatwave day: PDRC tracks the sun; BTES works around the clock [E].

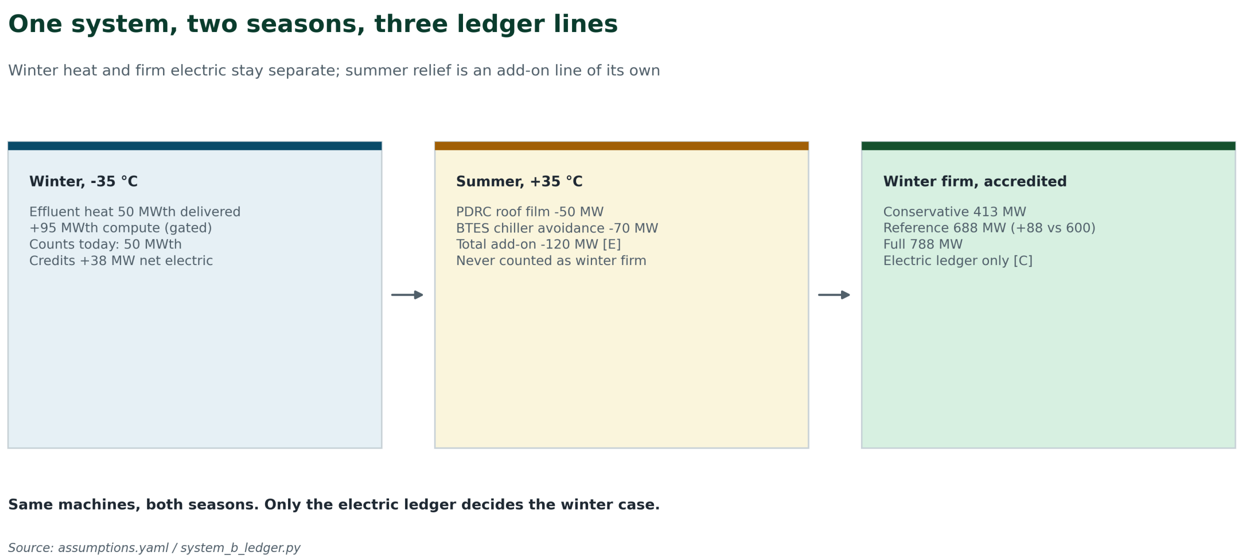

Figure 13 — One system, two seasons, three ledger lines; only the electric ledger decides the winter case [C/E].

Summer equations are in the mathematical appendix.

Clean power is not a discount coupon for big tech

Manitoba was right when Premier Wab Kinew rejected a hyperscale AI campus southeast of Winnipeg. The concern was not “technology.” It was **scale, electricity use, community impact, and whether benefits last for Manitobans**. Recent reporting also noted he did not reject data centres altogether — he distinguished ordinary and future facilities from hyperscale projects of a much larger order.

Saying no to one giant **private extraction** machine should not mean saying no to digital infrastructure. The cloud is not an idea. It is buildings, wires, substations, cooling, water, workers, land, and electricity. Health care, schools, emergency systems, research, city services, and climate modelling all need a physical place to run. The real question is whether private corporations should control almost all of those places — or whether the public should own **some** of them too.

Manitoba has a unique advantage. The Canada Energy Regulator reports Manitoba produced **33.3 TWh** of electricity in 2023, with **99.7%** from renewable sources, mostly hydro [O]. That clean power is not a coupon to hand to distant shareholders. It is something Manitobans built and passed down. If it is going to serve the digital economy, Manitobans deserve public ownership, accountability, and real public benefits — not only construction traffic and unclear promises about innovation.

A Manitoba tradition — when something becomes essential, ask who owns it

We have taken this approach before:

Public power — Manitoba Hydro: dams, lines, workers, political choices across generations.

Flood protection — the Red River Floodway (1962–68), once mocked as "Duff's Ditch," now credited with preventing tens of billions in damage.

Water — the Winnipeg Aqueduct from Shoal Lake (1915–19), still in daily use every time someone opens a tap.

Public insurance — MPI (1971), after hearings found private auto insurance expensive, inadequate, and confusing.

Communications — Manitoba Government Telephones (1908), later MTS: the province once treated networks as public enough to own.

Public housing — Manitoba Housing (1967): stable homes were not left entirely to the market.

None of those projects were perfect. Mistakes were made. That history should make us **more careful, not less ambitious**.

A data centre is power, heat, water, communications, and — increasingly — public-service infrastructure. Spirited Energy treats small, **publicly accountable** compute as climate infrastructure: heat-first into the NEWPCC district loop, locked at **10–20 kW** per node, gated to **0 MW eligible** until heat customer, Hydro headroom, and public buyer are verified [C]. That is the opposite of a hyperscale warehouse on farmland. It is the Manitoba rule applied to the cloud: when something becomes essential to daily life, ask whether the public should own a share.

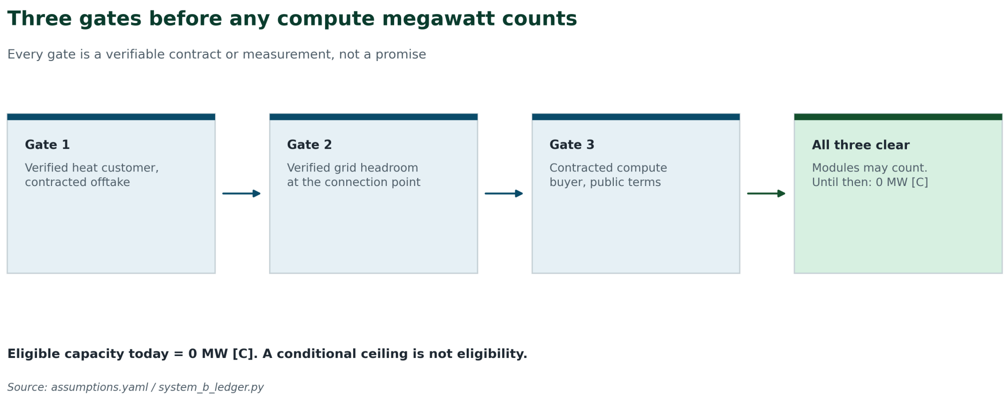

Figure 14 — Three-gate eligibility. Conditional is not eligible [C].

What we are not proposing

Not Île-des-Chênes-scale private load. Not handing hydro to big tech as a discount. Not counting speculative compute megawatts as winter firm capacity. Effluent heat is the base; public compute is optional upside behind gates — and today the verified eligible number is zero.

10. Soil & water: honest phosphorus arithmetic

Lake Winnipeg's phosphorus problem is real. Nutrient removal at NEWPCC — binding phosphorus into solids and recovering nutrient product — is how Winnipeg finally takes a point source out of the lake. In the mid-case stack that recovery is only about **130 t P/yr**, roughly **4%** of the ~**3,050 t/yr** external-load gap [E]. This energy plan does **not** close that gap alone. This filing attaches a binding surplus rule the Board can require: ≥**35%** of heat-recovery / gated-compute surplus to Lake Winnipeg phosphorus remediation as a first lien, changeable only by a **75%** supermajority governance amendment with public notice — intergenerational equity as a lock, not a press release [E]. Yield bands are in the mathematical appendix — not oversold here.

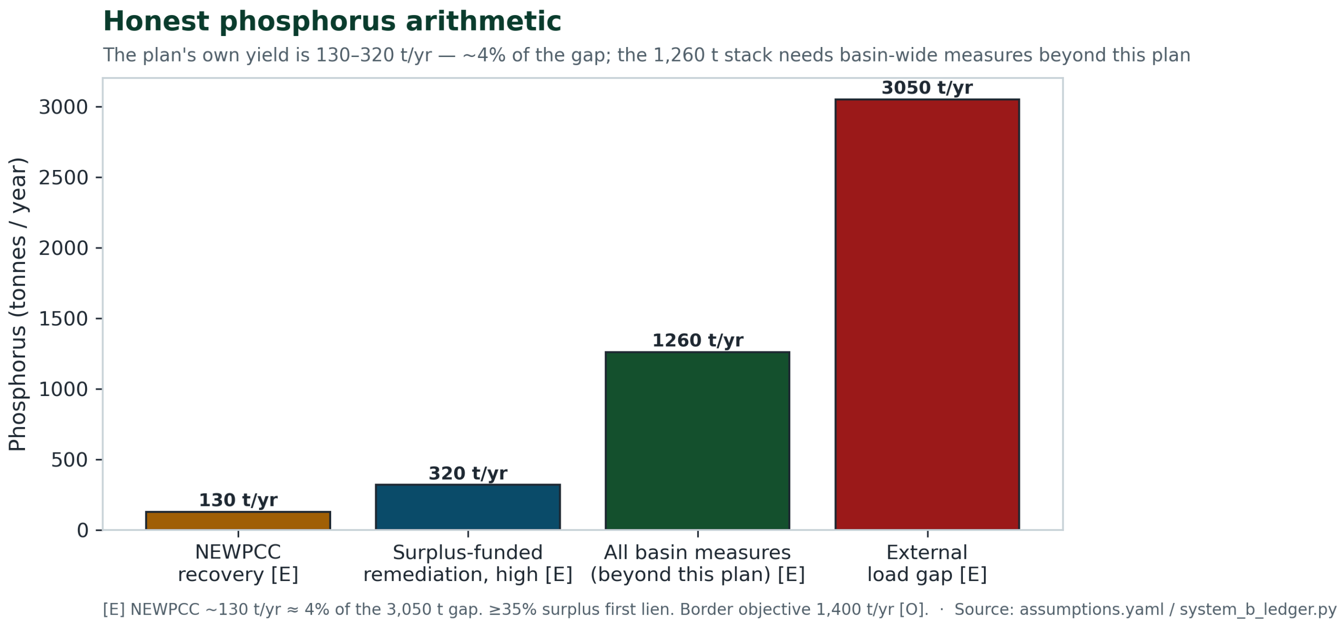

Figure 15 — Phosphorus honesty bands. Plan yield ≠ lake cure [E/O].

Objections the Board will hear — and our replies

Steelmanned objection	Reply on the record
“Batteries cannot ride a two-week vortex.”	Correct — and we never ask them to. Reservoirs hold the days; BESS holds the hours; heat shrinks the spike.
“Wastewater heat is municipal plumbing, not firm capacity.”	Sewage does not stop at −35 °C. Firmness is contractual: a 25-year Hydro–City thermal service agreement is a **condition** of treating hub displacement as firm [A]. Conservative case already prices effluent-only / low hub optimism.
“91% start reliability answers the 3-of-10 record.”	It answers a different question. Peak planning needs tail-hour ELCC, not annual averages. Order the study.
“ITC and cheap federal debt may not arrive.”	Every figure appears gross **and** net. Reference hybrid beats gas nameplate **with no credit**. Credits widen a gap they do not create.
“District piping will blow the budget.”	Phased behind anchor demand; can stop mid-build. Gas is one non-refundable pour. Share the open NEWPCC trench; HDD vs open-cut bounds in the mathematical appendix [E/A].
“Compute tenants are flighty.”	Bonds, boiler backup, municipal effluent base without them, and **0 MW eligible** until gates clear. Flight risk is real; exposure is engineered small.
“Any data centre is hyperscale extraction.”	Reject the warehouse; keep public digital infrastructure. Heat-first, 10–20 kW, publicly accountable — Hydro / Floodway / aqueduct / MPI tradition. Eligible today: **0 MW**.
“Brandon failed from deferred maintenance, not gas physics.”	Maintenance matters — and continental cold snaps show wellhead freeze-offs and valve moisture are class risks at −35 °C. ELCC settles the dispute.
“Summer PDRC pads the winter case.”	It does not. The ≈120 MW summer residual is gated out of winter accreditation. Tests enforce it.

11. Take action: same arithmetic, before the concrete

PUB process runs into early September. Cabinet has the last word. Premier Wab Kinew and Minister Sala can require Hydro to model sewage heat recovery and hybrid peak-shaving against the Brandon gas plan under independent cold-weather stress testing — and tell Winnipeg to put heat-recovery taps into NEWPCC before the last major contracts close.

> The Board need not choose our numbers.
> It need only insist that both plans face the same arithmetic — in public — before the concrete is poured.
>
> Will we use this energy once, or twice?

THE ASK — what this filing is for

Return to the six orders (section 7 and the executive brief). They are the CTA. Everything in this paper exists to make them the least-regret path under **The Public Utilities Board Act —** least-cost, safe, reliable service in the public interest. Advisors: the mathematical appendix follows.

Mathematical appendix — Board arithmetic

This appendix is part of the same filing. It states the governing relations with numbers from `assumptions.yaml` / System B. Thermal power (MWth) and electric power (MW) never share a headline sum.

Dual-ledger axiom

$$P_{\text{firm}} \neq P_{\text{elec}} + Q_{\text{th}}$$

Hub thermal and net electric:

The hub that counts today is the effluent stage: delivered heat

$$Q_{\text{hub}} = Q_{\text{src}(4^\circ\text{ C})} + P_{\text{comp}} \approx 37.6 + 12 \approx 50\ \text{MWth}$$

at delivered COP ≈ 4.3 (≈3.3 units of source heat moved per unit of work — a low-lift sewage-source machine), inside the 4 °C river-safe draw. **Stated assumption:** displaced load is electric resistance heating (COP 1) in the tail hours; if the displaced stock were air-source heat pumps at COP 1.5–2, the credit scales to 19–25 MW — disclosed, not hidden.

$$P_{\text{hub,net}} = Q_{\text{hub}} - P_{\text{comp}} = 50 - 12 = 38\ \text{MW}$$

Contingent compute reject heat ($Q_{\text{compute}} = 95\ \text{MWth}$) is **never** a firm-supply credit: netted honestly at full build it is $+95 - 22 - 95 \approx -22\ \text{MW}$ in the peak hour if run flat — the IT load that makes the heat must be counted. The design answer is curtailment with BTES banking: load off at peak, stored heat still serving the loop. Its winter value enters only through the demand-response line once contracted; today it carries $0\ \text{MW}$.

Winter accreditation [C]

Building blocks: $P_{\text{BESS}} = 300\ \text{MW}$ (4 h → 1,200 MWh); $P_{\text{DSM}} = 150\ \text{MW}$; $P^{\text{cap}}_{\text{intertie}} = 300\ \text{MW}$ [A].

$$P_{\text{cons}} = 300 + 75 + 0 + 38 = 413\ \text{MW}$$

$$P_{\text{ref}} = 300 + 150 + 200 + 38 = 688\ \text{MW}$$

$$P_{\text{full}} = 300 + 150 + 300 + 38 = 788\ \text{MW}$$

Margins vs shortfall $S = 600\ \text{MW}$: $M_{\text{cons}} = -187$, $M_{\text{ref}} = +88$, $M_{\text{full}} = +188$ (MW). Reference and full cover S; conservative does not — by design. Illustrative ELCC haircut on our own resources (BESS 85%, DSM 80%): $0.85 \cdot 300 + 0.80 \cdot 150 + 200 + 38 = 613\ \text{MW} \geq S$ — the reference case survives the treatment we ask the Board to apply to gas.

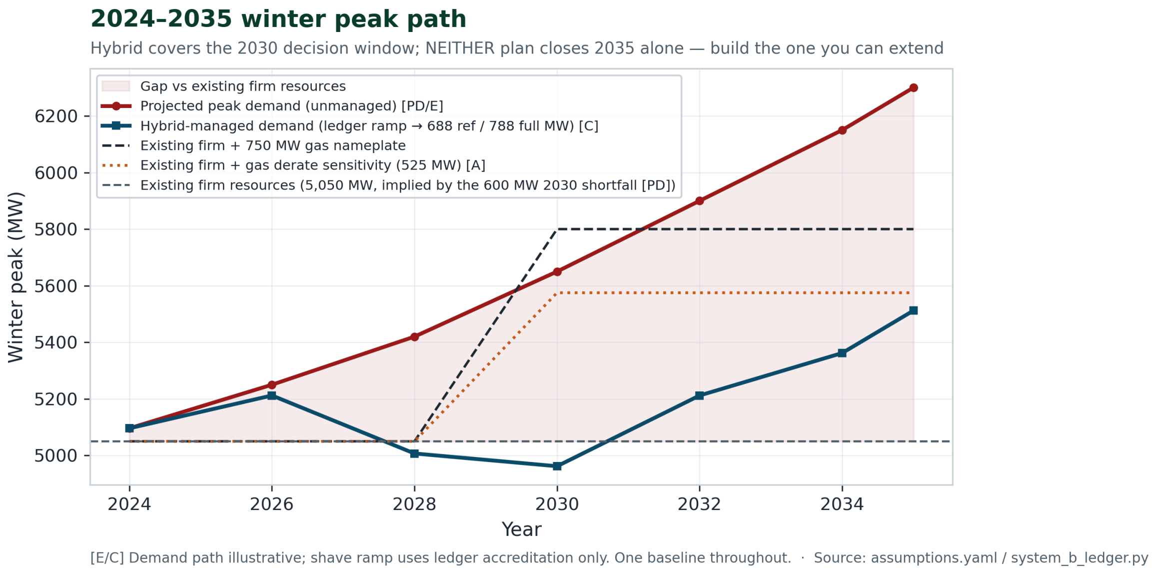

Exhibit A1 — 2024–2035 winter peak path: unmanaged demand, gas nameplate vs derate scenario, hybrid electric-ledger ramp [E/C].

Gas comparison

$P_{\text{g,name}} = 750\ \text{MW}$, $C_g = \$3.00\text{B}$. Event-informed derate **scenario** (not an ELCC finding): $P_{\text{g,derate}} = 525\ \text{MW}$ [A]. The **3-of-10** cold-event record [PD] is an ELCC study ask — not a flat 30% derate-as-fact.

Delivered capital intensity

Delivered cost per firm kilowatt, in $/kW:

$$c_{\text{kW}(P)} = \frac{C}{P \cdot 10^3}$$

Hybrid: $C_{\text{h,gross}} = \$1.95\text{B}$, $C_{\text{ITC}} = \$0.45\text{B}$ [A], $C_{\text{h,net}} = \$1.50\text{B}$.

Scenario	P (MW)	Gross $/kW	Net $/kW
Conservative	413	4,722	3,632
Reference	688	2,834	2,180
Full	788	2,475	1,904
Gas nameplate	750	4,000	—
Gas derate scen.	525	5,714	—

Pass gate: hybrid reference **gross** $/kW beats gas **nameplate** $/kW — no ITC, no derate assumed. The derate column is a sensitivity only.

Twenty-year bands [E/A]

$C_g^{(20)} \in [4.5, 6.9]\text{B}$, $C_h^{(20)} \in [1.5, 1.8]\text{B}$ **net of the ITC**. On a gross basis (ITC add-back $0.45B) the hybrid band is $[1.95, 2.25]\text{B}$ and savings become $[2.3, 5.0]\text{B}$ — the conclusion is unchanged. O&M, DSM payments, loop operation and BESS augmentation are itemised in the forensic accounting whitepaper. Non-overlap: $C_{\text{h,high}}^{(20)} < C_{\text{g,low}}^{(20)}$. Savings band $\Delta \in [2.7, 5.4]\text{B}$ (net basis).

Sewage-heat physics [E]

$Q_{\mathrm{src}(\Delta T)} \approx 9.4\ \mathrm{MWth} \cdot \Delta T$, with ΔT in °C — so 1 °C ≈ 9.4 MWth and 4 °C ≈ 37.6 MWth **source** heat. With ≈12 MW of compressor work at delivered COP ≈ 4.3, delivered hub heat is ≈50 MWth. $Q_{\mathrm{src},4°\mathrm{C}} = 37.6\ \mathrm{MWth}$ (source, thermal) and $P_{\mathrm{hub,eff}} = 38\ \mathrm{MW}$ (net electric credit) are different quantities that round alike — never interchange them.

Summer add-on — not winter firm [E]

PDRC rejects $Q_{\mathrm{PDRC}} \approx 180\ \mathrm{MWth}$ of heat (2.4M m² × 75 W/m²); the avoided **electric** A/C load is $P_{\mathrm{PDRC}} = Q_{\mathrm{PDRC}}/\mathrm{COP}_{\mathrm{chiller}} \approx 180/3.5 \approx 50\ \mathrm{MW}$. With BTES chiller avoidance ($70\ \mathrm{MW}$): $P_{\mathrm{summer}} \approx 120\ \mathrm{MW}$ — and this quantity is **excluded** from P_{cons}, P_{ref}, and P_{full}.

System B pass predicates

All currently PASS under `build_ledger().pass_report()`: dual-ledger integrity; reference and full cover shortfall; $/kW and lifecycle gates; hub net < hub thermal; summer excluded from winter firm.

Reproduction: `python3 research/recalculate_and_generate_all.py` · registry `research/assumptions.yaml`.

Appendix — Retired composites (audit trail)

Quantity	Canonical now	Do not use
Firm electric	413 / 688 / 788 MW	895 MW; 850 MW as firm; 761 / 861 MW (carried compute-derived credit)
Hub electric	+38 MW net, effluent stage	“145 MW peak displacement”; “≤111 MW net” (compute reject un-netted)
Gas cold performance	3-of-10 ⟶ ELCC ask	Flat 30% derate-as-fact; 525 MW as comparator of record
Hybrid availability	No % claimed	“>98%”
Summer PDRC/BTES	≈120 MW electric residual only	250 MW (booked thermal flux as electric); any use as winter firm pad

Glossary

Term	Plain meaning
Firm capacity	Power the planner can count on for the coldest peaks
ELCC	What a resource is worth in the hours that matter
MWth vs MW	Heat vs electricity — never add
Accreditation	How much counts toward the shortfall after reliability review
NEWPCC	North End Water Pollution Control Centre
PDRC	Passive daytime radiative cooling — summer only
BTES	Seasonal borehole/aquifer heat storage

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One filing · one voice · same arithmetic before the concrete.
Registry: assumptions.yaml