**GSSM/CC 1**

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| **Part and Chapter:** | CC-20 | **Page #:** | 19 |
| **Topic:** | Volume II of Report | | |
| **Subtopic** | | | |

**Preamble (if any):**

On page 19, Evolved Energy states that:

> The planned Volume II will consist of Chapter 8. It will build on the assessment in Volume I to recommend near-term steps that reduce the risk of a capacity shortfall while keeping longer-run options open and allowing more time to develop additional analysis to support decisions around the scale and timing of capacity needs. It is separated from Volume I because parts of it rest on confidential data filed under Order 59/26 and are provided to the Board only under seal.

**Question:**

a. Given the confidentiality involved for the proposed Volume II and Chapter 8, can you please confirm or file the public portions of EER's Volume II (Chapter 8) that do not rely on the confidential data, or alternatively summarize in a non-confidential way.

b. Please specifically provide any conclusions that may depend on confidential data at a high level for consideration publicly.

**Rationale for Question:**

**Response:**

Volume II (Chapter 8) has not yet been prepared or filed. There are therefore no portions of it, public or confidential, available to confirm, file, or summarize at this time, and no conclusions that can be provided at a high level. What Volume II will address is already on the public record in Volume I: it will "build on the assessment in Volume I to recommend near-term steps that reduce the risk of a capacity shortfall while keeping longer-run options open," and parts of it are anticipated to rest on confidential data filed under Order 59/26 (Report Section 1.7, p. 18). As EER explains in response to MH/CC-3, that confidential data became available too late in the proceeding for the supporting analysis to be completed in the time available.

When Volume II is prepared, EER intends to make as much of it public as possible. To the extent any portion ultimately rests on data filed confidentially under Order 59/26, that portion will be handled within the confidentiality framework that order establishes; the remainder would be filed publicly. EER does not anticipate that any of Volume II's key findings will be redacted in full, and if that were to occur, EER would provide a public summary of the affected conclusions.

**GSSM/CC 2**

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|---|---|---|---|
| **Part and Chapter:** | CC-20 | **Page #:** | 25, 61-63 |
| **Topic:** | Capacity Planning Assumptions | | |
| **Subtopic** | | | |

**Preamble (if any):**

With respect to best practice in portfolio modelling, Evolved Energy states:

**Value modelled as well as cost.** Best practice represents not only resource cost but resource value: operational flexibility (ramp, ancillary services, multi-day reserve), diversification value (drought hedging, fuel diversity), coordination value (storage paired with renewables), and external value (export revenue where applicable). A portfolio model that represents cost but not value systematically under-values the resources whose contribution is non-cost: storage, demand response, hydro flexibility, and renewables paired with storage. LBNL 2024 BP 17 (p. 37) directs that storage be valued through its "full value stack" including ancillary services and resilience; BP 23 (p. 45) flags that island modelling that omits market revenue disadvantages zero-marginal-cost resources and storage; BP 38 (p. 66) treats chronology as essential to capturing storage value.

On page 61 it states that:

The value dimensions the model misses are concentrated in areas where alternatives to combustion turbines have the most to offer (battery storage, wind-plus-storage, and firm imports).

And page 62 that:

Cost is uniformly represented; value is not. The model's structural setup captures some value dimensions but misses others, with the misses concentrated in dimensions that would tend to favour non-combustion-turbine alternatives.

**Question:**

a. With respect to resource value, can Evolved Energy please qualitatively (or quantitively if possible) discuss the trade-offs between Manitoba Hydro's presented Resource Plans – especially for Plans 3, 5a and 7? Please provide answers with specific reference to the 2035 and longer-term 2050 plan horizons.

b. Are there any modeller-set parameters that reduce the potential resource value that is ultimately presented in Manitoba Hydro's Resource Plans – especially for Plans 3, 5a and 7 (for example restricting import capacity availability that is relied upon for Plan 7 or the inputs utilized for battery storage – again used for Plan 7)?

c. What evaluation criteria would Evolved Energy consider best practice for evaluating resource value? Does Manitoba Hydro incorporate this evaluation criteria in its IRP evaluation?

**Rationale for Question:**

**Response:**

(a) EER offers a qualitative account rather than a quantitative one. Manitoba Hydro ran no sensitivity on the import or other value parameters (CC/MH II-36(b)), and EER has not re-run Manitoba Hydro's plan comparison under corrected parameters, so no quantitative re-ranking of Plans 3, 5A, and 7 exists on this record. What EER can offer is where each plan's resource mix sits relative to the value dimensions the model does and does not capture (Report Section 4.3.2, pp. 62–63).

The three plans differ mainly in how much of the capacity requirement they meet with natural-gas combustion turbines as against the alternatives. On accredited winter capacity in 2035, the combustion-turbine spectrum runs from Plan 3 at 840 MW, to Plan 5A, the recommended plan, at 744 MW, to Plan 7 at 344 MW — roughly half the combustion-turbine capacity of the other shortlisted plans (Appendix A7-2, Table A7.2.23, p. 153). Plan 7 makes up the difference with an alternative-heavy mix: 216 MW of accredited battery, 103 MW of hydro upgrades, 200 MW of additional energy efficiency, and the highest level of market interaction in the shortlisted set (Appendix A7-2 §5.5, p. 162).

That plan composition maps directly onto the value dimensions EER's report finds the model misses or captures unevenly (Report Section 4.3.2, pp. 62–63), and the 2035 comparison is best read as a two-sided trade-off rather than a ranking. On Manitoba Hydro's own cost metric, the plans sit close together: the range of differences in incremental cumulative present value of net system costs across the five shortlisted plans is only about $260M in 2035 (Appendix A7-2 §5.9, p. 167), so the choice among them turns less on modelled cost than on the value dimensions the model weighs unevenly. Plans 3 and 5A meet most of the requirement with combustion turbines, a resource whose value the model captures cleanly as block-level dispatchable capacity, so their modelled standing rests on comparatively reliable footing.

Plan 7 depends most on the dimensions the model misses: diversification, flexibility, coordination, and export value of batteries. The modelling understates the resource value Plan 7 offers. Plan 7 does carry one distortion the other way: the flat 100% battery capacity credit likely overstates the battery contribution, on Manitoba Hydro's own concession (CC/MH II-14(a)), and it is the one distortion Manitoba Hydro indicates it plans to correct (Report Section 4.3.2, p. 64). The specific modeller-set parameters that produce these gaps are itemized at part (b).

At the 2050 horizon a plan-by-plan comparison becomes difficult for two reasons. First, the shortlisted plans are defined only to the end of 2035; additions beyond that are selected by the same model configuration (Appendix A7-2 §5, p. 153), so what distinguishes the plans at 2050 reflects the model's own choices as much as any difference in plan design. Second, results that far out depend heavily on the load projection, and EER's report finds the load projection range unanchored. The projections are described rather than analytically defended, with no case tested near the observed load trend at any point through 2050 (Report Section 3.7). The differences among the plans at 2050 turn on that untested assumption as much as on the resources each plan carries. The configuration gaps identified above do not wash out over this period; the 50 MW firm-import cap, for one, is held flat to roughly 2050 even as Manitoba Hydro's own evidence puts firm net import capability at 400–500 MW opening past 2035 when existing MISO export contracts end (CC/MH II-44; Report Section 5.6.1, p. 76).

EER does not conclude that any plan is or would prove lower-cost, or that any plan should be preferred. The comparison ran on a model that represents cost uniformly but value unevenly, so the plans' relative standing is not established on this record (Report Section 7.6, p. 104).

(b) Yes. The record identifies several modeller-set parameters that suppress the resource value presented in the plans, and they fall on the resources the question names:

- **Import parameters.** The 50 MW cap on firm capacity imports, the pricing of the firm import product off the costlier aeroderivative turbine benchmark before a 20% adder, and the fixed five-year contract term were each set within the model rather than derived from market data or technical system constraints (CC/MH I-30(a), I-30(b), I-30(d), I-40(a); Report Section 5.6, pp. 75–78). The basis and effect of each are set out in EER's response to GSSM/CC-4.
- **Battery parameters.** Deployment is capped at 350 MW on a single-daily-cycle representation rather than a system-specific analysis, and that same representation excludes energy arbitrage, time-shifting, transmission and distribution deferral, and ancillary services, which Manitoba Hydro states "are not represented at this time" (A6 §2.13, p. 43). The battery is also costed at the 15% utility investment-tax-credit rate while wind is modelled as a third-party purchase at the 30% private rate (Report Section 5.5, pp. 74–75).
- **Deterministic wind and solar profiles.** Wind and solar are represented by single deterministic profiles, so the diversification value of resources uncorrelated with hydro drought goes unassessed. That configuration choice suppresses the value of wind and of wind-plus-storage (Report Section 4.3.1, pp. 61–62).

Plan 7 is the shortlisted plan that relies most on batteries, and the one that leans most on energy imports in low-water years (Appendix A7-2 §5.5). These parameters therefore bear most directly on the resource value shown for Plan 7, and each operates to understate it, except the flat 100% battery capacity credit, which runs the other way. How much these parameters shift the plans' relative cost, however, cannot be quantified on this record: Manitoba Hydro ran no sensitivity on them (CC/MH II-36(b)), and EER has not performed its own modelling to re-run the comparison.

(c) EER's report sets out the evaluation criteria it considers best practice in Chapter 2, on EER's expert judgment from resource-planning practice. For valuing resources, the core criteria are to represent resource value (operational flexibility, diversification, coordination, and external value) as well as cost, with hourly chronological resolution where multi-day stress and storage value matter, symmetric stochastic treatment across resource types, and probabilistic resource adequacy underneath the capacity requirement (Report Section 2.3, pp. 23–26); to derive capacity accreditation and import parameters from the system and market being studied, and where a cap is placed on a resource, to state it transparently, limit its timeframe, and run scenarios without it (Report Section 2.4, pp. 26–27); and to evaluate portfolios on commensurate metrics with documented selection criteria (Report Section 2.5, pp. 27–29).

Manitoba Hydro's IRP evaluation does not adequately incorporate these criteria. The model represents cost uniformly but misses or unevenly captures the value dimensions listed above, with the misses concentrated in dimensions that would tend to favour non-combustion-turbine alternatives (Report Section 4.3.2, pp. 62–64); the battery accreditation was assumed rather than derived and the import parameters were set within the model rather than from market data (Report Sections 5.5–5.6, pp. 74–78); and the caps were never tested without the cap (CC/MH II-36(b)).

The point is underscored by a diagnostic Manitoba Hydro's own modelling suite produces: OptGen generates reduced costs (the model's implied marginal value for each resource) that would have revealed how the configuration valued the alternatives. Manitoba Hydro states it "does not use marginal cost outputs provided by the model (either OptGen or SDDP), and therefore, it has not validated the appropriateness of these outputs and is not familiar with their calculation or interpretation" (CC/MH II-29; Report Section 4.3.2, p. 62). In EER's view those outputs are a routine diagnostic in resource-planning practice, and a built-in check on whether the plan comparison under-valued the alternatives went unrun.

**GSSM/CC 3**

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| **Part and Chapter:** | CC-20 | **Page #:** | 75 |
| **Topic:** | Utility-Scale Battery | | |
| **Subtopic** | | | |

**Preamble (if any):**

Page 75 states:

Best practice derives a resource's capacity accreditation from the system being studied (Section 2.4); Manitoba Hydro credited storage at a flat 100% it concedes overstates, rather than deriving it from the system-specific accreditation it applies to its own wind.

Page 36 of Exhibit GSSM-10, Evidence of M. Davies, compares the credited storage for utility scale battery assumptions used for NC Hydro and Nova Scotia battery in their resource planning:

- BC Hydro: descending ELCC with first 50 MW at 100% ELCC, next 400 MW at 40% ELCC (effectively 47% for first 450 MW)
- Nova Scotia Power: descending ELCC with first 100 MW at 72% ELCC, next 50 MW at 48% ELCC and next 150 MW thereafter at 33% ELCC

**Question:**

a. Directionally, in Evolved Energy's opinion, does it make sense that if Manitoba Hydro were to limit battery installation to 50 – 100 MW the accredited capacity would likely be quite high, similar to BC Hydro and Nova Scotia Power's assumptions? Please explain your rationale.
b. Are BC Hydro and Nova Scotia Power appropriate comparators for comparing battery storage planning assumptions, or is it only reasonable to use Manitoba Hydro system specific metrics?
c. Can Evolved Energy provide any other jurisdictional comparisons on utility scale battery planning assumptions that may be useful to consider Manitoba Hydro's resource plans that include battery, in light of the 100% ELCC credited storage level being an overstatement.

**Rationale for Question:**

**Response:**

(a) Yes on the direction. A battery's capacity credit declines as storage is added, which Manitoba Hydro accepts (PUB/MH I-28(a)), so a battery held to 50–100 MW would earn more credit than any battery added after it.

Whether it would earn a high credit, near the BC Hydro or Nova Scotia Power numbers, is a different question, and no study of Manitoba's system exists to answer it. BC Hydro credits its first 50 MW at 100%; Nova Scotia Power credits its first 100 MW at 72%. The numbers differ because the credit depends on the system itself: its load shape, its generation mix, its interconnections, and how long its worst reliability events run, among other factors (Report Section 2.4). Manitoba's worst events are winter cold snaps that run for days, and Manitoba Hydro concedes its accreditation work "does not specifically address" those sustained multi-day conditions (CC/MH II-11(b)).

(b) BC Hydro is an appropriate comparator, Nova Scotia Power is not, and neither replaces a study of Manitoba's own system. That study is where the credit should ultimately come from. EER describes the study in its response to PUB/CC-5, and Manitoba Hydro says it is building the capability to run it (CC/MH I-4(a)). Until it exists, best practice allows interim use of values from comparable systems, with well-justified and documented adjustments (Report Section 2.4, p. 26, citing LBNL 2024 BP 4).

BC Hydro and Manitoba Hydro run the same kind of system, winter-peaking and hydro-dominated, so a battery study done for BC Hydro measures the right kind of thing for Manitoba, and the remaining differences can be adjusted for. Manitoba Hydro has already made a first comparison of its own: BC Hydro's peak, about 11,100 MW, is more than twice Manitoba's roughly 5,000 MW, and on that comparison it expected an ELCC below 47% for a 200 MW Manitoba battery, not the flat 100% in the plan (CC/MH II-14(a)). Nova Scotia Power runs a different kind of system altogether — smaller, more wind generation, not hydro-dominated — and what a battery does for Nova Scotia says little about what one would do for Manitoba.

(c) EER does not offer further jurisdictions, because the ones already filed show the point that matters, and it is a shared practice rather than any single value. Every system on this record that has studied battery accreditation — BC Hydro, Nova Scotia Power, and the Pacific Northwest study Manitoba Hydro cites (CC/MH II-14(a)) — sets a declining schedule tied to its own system and to battery duration. The Pacific Northwest study also shows how sensitive the values are to the system in which they are measured. Within that one study, the first tranche of four-hour batteries is credited anywhere from 6% in 2030 to 79% in 2045 as the modelled system evolves. That is why a borrowed value needs the careful adjustment described in (b), and why the "6% winter ELCC" cannot be lifted from that system and applied to Manitoba.

**GSSM/CC 4**

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| **Part and Chapter:** | CC-20 | **Page #:** | 75 - 78 |
| **Topic:** | Imports as a resource option | | |
| **Subtopic** | | | |

**Preamble (if any):**

At page 75, Evolved Energy states:

> Imports are held out of Manitoba Hydro's resource mix not by a finding that capacity is unavailable, but by a set of planning assumptions and modelling parameters: a 50 MW cap on firm capacity imports, a 20% cost adder, and limits on contract terms. Several of these Manitoba Hydro concedes are not derived from market data.

**Question:**

a. In Evolved Energy's opinion, is Manitoba Hydro's 50 MW import cap, 20% cost adder, and use of a costlier aeroderivative CT unit to price imports as opposed to MISO or other pricing forecasts impacting the cost-competitiveness of Plan alternatives, including Plan 7, compared to Manitoba Hydro's recommended Plan 5a? Please explain.

**Rationale for Question:**

**Response:**

Yes. In EER's opinion the three parameters the question identifies (the 50 MW cap on firm capacity imports, the 20% cost adder, and the aeroderivative combustion turbine used as the pricing benchmark) do affect the cost-competitiveness of the plan alternatives relative to the recommended Plan 5A. The effect runs in one direction: against the plans that lean less on Manitoba-built combustion turbines and more on the market (Report Section 5.6, pp. 75–78).

Manitoba Hydro applies the 50 MW cap without empirical benchmarking (CC/MH I-30(a)) and states that it is "not based on technical system constraints" (CC/MH I-40(a)). It holds the cap flat through roughly 2050, even though its own evidence puts firm net import capability at 400–500 MW, opening past 2035 when existing MISO export contracts end (CC/MH II-44; Report Section 5.6.1, p. 76).

The pricing is set the same way. The firm import product is benchmarked to the costlier of Manitoba Hydro's two turbine options, an aeroderivative unit it describes as "nearly double the cost per MW of the Natural Gas CT" it proposes to build (A6 §2.4). A 20% adder is then applied on top, which Manitoba Hydro concedes "was applied as a modeling assumption rather than being derived from empirical market data," with the stated purpose of "encourag[ing] the model to select Manitoba based solutions" (CC/MH I-30(b); Report Section 5.6.2, pp. 76–77).

One clarification on the question's premise: these parameters constrain the firm, capacity-backed winter import product only. They are not a limit on import energy. The model already assumes

access to the full 1,400 MW interface for non-firm energy imports in roughly 20 of every 24 hours (CC/MH II-44; CC/MH II-36(a); Report Section 5.6, p. 75). What they govern is how much firm winter capacity a plan may draw from the market, and at what modelled cost.

The effect on the plan comparison operates at two levels. The first is pricing: any firm import a plan carries enters the cost comparison at the inflated benchmark. Daymark, the Board's independent consultant, described the premium as intended "not to reflect potential import costs, but instead to model a resource that is only used as a last resort" (MIPUG/Daymark I-15(b); Report Section 5.6.2, p. 77).

The second level, and the more consequential one, is plan construction. The 50 MW cap bounded every candidate plan, so no alternative, Plan 7 included, could substitute the several hundred megawatts of firm import headroom Manitoba Hydro's own evidence identifies for near-term combustion-turbine capacity. No genuinely import-reliant alternative to Plan 5A was ever constructed and carried through the evaluation on the same terms as the combustion-turbine-led plans (Report Sections 6.1–6.3 and 6.7, pp. 85–91). Plan 7 sits closest to that boundary. With 344 MW of accredited winter combustion-turbine capacity in 2035 against 744 MW in Plan 5A (Appendix A7-2, Table A7.2.23), it meets the largest share of its winter capacity need from resources other than Manitoba-built gas. In theory, it is the plan that would most have drawn on firm import capacity, and the one the 50 MW cap most constrains.

The direction of the effect of the import constraints is clear, but its magnitude is not. Manitoba Hydro confirms it "did not conduct any sensitivity analysis on the import contract price or cap size" (CC/MH II-36(b)), and EER has not re-run the plan comparison under market-derived parameters, so EER can offer no re-ranked comparison of Plan 7 against Plan 5A. Nor can EER conclude that Plan 7 is, or would prove to be, lower-cost than Plan 5A. The narrower conclusion EER can identify is that the cost comparison ran on import parameters that were set to steer the optimization away from imports and were never tested, and that untested narrowing of the field is among the reasons Manitoba Hydro's analysis has not demonstrated that the recommended plan is the least-cost option for ratepayers (Report Section 7.6, p. 104).

**GSSM/CC 5**

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| **Part and Chapter:** | GSSM/MH I-1c & GSSM-10, pages 10 & 14<br>CC-20 | **Page #:** | Pg. 97 - 102 |
| **Topic:** | CRP & DR | | |
| **Subtopic** | | | |

**Preamble (if any):**

GSSM-10, Evidence of M. Davies, page 14, with respect to load forecast asymmetry notes that:

> There is also a short-term asymmetry in the load projections, where Manitoba Hydro includes load growth of under 40 MW for a new Top Consumer; but on the basis of materiality, Manitoba Hydro did not remove the load of a Top Consumer that recently permanently shut down - even though it has a similar, offsetting magnitude of impact on peak demand, at least in the short-term. That amount of load is material to the near-term planning period to 2035, as there are supply-side resources selected of a similar magnitude (for example 40 MW of wind installation included 2039 for all resource plans).

Manitoba Hydro in response to GSSM/MH I-1c cited immateriality for not incorporating the recent loss of a large industrial customer with demand at a similar level to the Top consumer growth that was included, between 30 – 40 MW.

At page 10 of GSSM-10, Ms. Davies evidence notes:

> With respect specifically to the Manitoba context, recent government decisions to turn away potential customers in these emerging sectors out of caution for impacts on electricity rates could slow or delay anticipated growth relative to other jurisdictions, some of which have inversely provided strong incentives to these sectors to attract load. Other jurisdictions, such as BC, are actively managing load growth due to data centres and AI, ensuring growth in this emerging sector is paced, provides economic value, tests the willingness to pay a premium to contribute to marginal cost of supply (to minimize cost impacts on existing customers), and ensure the electricity system is not overwhelmed.
>
> Additionally, Manitoba policy changes to interconnection process and cost responsibility for potential customers above 5 MW could reduce or delay larger customer growth – as it adds potential upfront capital barriers and lack of transparency, which in turn puts pressure on project economics**.**

At page 97, Evolved Energy states that, “Manitoba Hydro's burden is to establish the need behind the 750 MW build, both the date and the scale.”

**Question:**

a. With respect to Evolved Energy's analysis that Manitoba Hydro does not establish the need for 750 MW of new gas by 2030, does permanently dropped demand of 30 – 40 MW from the loss of a long-term industrial customer register as material or pertinent for inclusion when assessing short-term need for either the scale, the date, or both? Please explain your rationale.

b. With respect to Evolved Energy's analysis that Manitoba Hydro does not establish the need for 750 MW of new gas by 2030, should the ability to manage economic and electrification load growth in the near-term through policy be a consideration for either the date, the scale or both? Please explain.

**Rationale for Question:**

**Response:**

(a) Yes. The lost customer is a long-term industrial load of roughly 30–40 MW that has now shut down for good (GSSM-10, p. 14), and Manitoba Hydro confirms it did not take that load out of its forecast (GSS-GSM/MH I-1(c)). A permanent drop of that size matters to the near-term need, because it is large next to the numbers Manitoba Hydro's own near-term case turns on. EER's report did not examine this customer, but it can be weighed with the same near-term figures the report already uses for the 2030 need date.

Manitoba Hydro's own figures show why. In its 2-Medium forecast, the winter peak grows by 417 MW in total between now and the 2030/31 need date (Section 7.5.3.1; MEED/MH I-1(d) Attachment 2), so a permanent 30–40 MW loss is a meaningful share of the growth that gives Manitoba Hydro its need date. The loss is larger still next to the gaps between Manitoba Hydro's own plans. Those plans are judged against two tests, one for capacity and one for energy: the closest plan Manitoba Hydro rejected, P6, fell short on the capacity test in 2030 by only 8 MW, and a plan with a single combustion turbine, P7, passed both tests (Section 7.5.4, pp. 102–104).

Manitoba Hydro left the loss out for a different reason. It said that at this scale, 30–40 MW, putting the customer back in "would not materially change" the charts in that response (GSS-GSM/MH I-1(c)). But those charts cover the whole system year by year, and a change that small is hard to see on them. The question behind a 750 MW decision is narrower: how much new capacity the system needs at the 2030 winter peak. At that scale, a permanent 30–40 MW drop in demand is not small; it is a real part of the near-term need the build is meant to meet.

This mainly affects the timing of the need, not its size. A customer closing is a one-time drop that carries forward, and its impact is on the near-term balance of supply and demand. The size of the proposed build is driven by the longer-run growth (Section 7.5.3.2). EER does not put this forward as proof of a later need date. The point, consistent with the report, is that Manitoba Hydro committed to the build without testing items like this or assessing the extent to which it might change the answer, and that is why the need date and the scale are not established (Section 7.5.4).

(b) Yes, as a matter of good planning, with a caveat noted below. How fast near-term demand grows is not entirely outside the province's hands. Manitoba Hydro agrees that higher electricity rates would "restrain electric demand growth" (PUB/MH I-15(d)), and it accepts that industrial customers who electrify but keep a fuel-based backup "could potentially represent an ideal

interruptible load," a load the system could call on at the peak, though "[n]o specific analysis was undertaken" to measure how much (CC/MH II-22(a); Section 7.5.3.2). When the assumptions that drive the forecast depend on policy choices that have not been made yet, good planning states them openly and tests a range of them, instead of building on a single fixed assumption. Manitoba Hydro ran no case that varied any of these near-term demand assumptions (Section 7.5.3), the gap EER's Recommendation 4 is meant to close (Section 7.7, p. 105).

Whether Manitoba should attract new large loads, take them on more slowly, or turn them away is a government policy question, and EER takes no position on it. EER's point is only about planning. Where choices like these have a large effect on the forecast, the IRP should follow written government policy where it exists, and where it does not, should treat the answer as uncertain and test a range of outcomes rather than settle on one built-in assumption (Section 7.4, pp. 94–95). As with the first question, none of this proves a different date or size on its own. It widens the range of outcomes Manitoba Hydro never tested, and it is that missing test of the range that leaves the date and the scale not established.

**MANITOBA HYDRO**
**Major New Facilities Application**

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**INFORMATION REQUESTS**

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**July 16, 2026**



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| **Part and Chapter:** | CC-25 Rainkie Report | **Page #:** | 16, 48, 49. |
| **Topic:** | Effect of Potential Capital Cost Increases from MNF | | |
| **Subtopic** | | | |

**Preamble (if any):**

At p. 16, Mr. Rainkie comments on the limitations to his evidence from deficiencies in Manitoba Hydro's filings, including the numerous assumptions embedded in their evidence.

One factor is the capital cost of natural gas turbines, which have seen significant cost increases from Manitoba Hydro's initial filing. GSSM notes that recent public documents indicate even higher prices for natural gas generation than Manitoba Hydro projects on a per MW basis.[1]

At p. 48, Mr. Rainkie provides Graphs 18 and 19 showing the effect on Retained Earnings from an extended DSM amortization period. At p. 49 Mr. Rainkie provides the implications for rate paths from those changes.

**Question:**

a. Could Mr. Rainkie please provide sensitivities for Graphs 18 and 19 assuming that the capital cost for natural gas generation increases by each of 10%, 25%, and 50%, and comment on the attendant effect on medium-term rate paths?

**Rationale for Question:**

GSSM seeks to how changes in natural gas capital costs could affect Mr. Rainkie's analysis.

**Response:**

Graphs 18 and 19 of Mr. Rainkie's evidence were based on rate scenarios that were ran by MH using its integrated financial projection model. Mr. Rainkie is not in possession of the necessary financial projection model and underlying capital cost estimates to produce the requested scenarios of increases of 10%, 25% and 50% in gas turbine capital costs and the related retained earnings impacts.

Directionally, significant increases in natural gas turbine capital cost estimates would place added pressure on retained earnings and result in higher medium-term rate paths, all other things being equal.

Additionally, Mr. Rainkie notes the following (at the ELF):

[1] For example, Pembina recently announced a new 932 MW project with an anticipated capital cost of $4 billion plus $600 million in financing charges. See here: https://www.pembina.com/media-centre/news/details/3403fb77-2257-466b-a8e2-f043f4cd4650

- The medium-term retained earnings/rate path impacts on P7 would be lower than the impacts on P5A, given that the cumulative projected MH gas turbine capital costs to 2035 are $1.5 billion for P7 as compared to $2.5 billion for P5A (Please see the response to CC/MH III - 7 d, figures 11 and 7, respectively); and

- The medium-term retained earnings/rate path impacts for P3, P5A and P7 would be all somewhat muted - given the relatively long depreciable life assumption for gas turbines of 30-years (annual 3.33% depreciation rate) in the MH financial projection model.

**GSSM**Error! Bookmark not defined.**/CC 7**

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| **Part and Chapter:** | CC-25 Rainkie Report | **Page #:** | 40, 56 |
| **Topic:** | Risk Management | | |
| **Subtopic** | | | |

**Preamble (if any):**

At p. 56, Mr. Rainkie comments on the "hockey stick on wheels" concerns with Manitoba Hydro's forecasting.

At p. 40, Mr. Rainkie comments on "how optimistic/realistic MH's financial projections are" given concerns that their approach "tends to result in projections of excessive annual net income…and retained earnings levels…at the back-end of the projection period". He notes that uncertainty is created in part by "major capital project placeholders in the MH financial projection for projects that are in early stages of development".

**Question:**

a. Please comment on whether a more "just-in-time" resourcing approach, with fewer near-term resource commitments, could help address Mr. Rainkie's concerns. Please explain your response.

**Rationale for Question:**

GSSM seeks to identify whether alternative planning options can help mitigate Mr. Rainkie's concerns.

**Response:**

Yes, more of a "just-in-time" resourcing approach, with fewer near-term resource commitments, could help to address Mr. Rainkie's concerns.

Mr. Rainkie has expressed concern that the medium-term period to 2035 is especially challenging for MH's finances and rates as a result of the concurrent capital investments in both new resources and the HVDC reliability project, which are plateauing in a similar timeframe (Please see Section 6.1, pages 43 to 45 of Mr. Rainkie's evidence).

Mr. Rainkie also noted the benefits of potential deferral of the resource development plans during this concurrent investment period as demonstrated in the "P5A CT Deferral Scenario" with the assumption of one Gas CT in 2031, one Gas CT in 2039 and one Gas CT in 2042. This scenario indicated that the incremental cumulative investment would be projected to decrease from $3.2 billion to $2.1 billion by 2035 and retained earnings in 2035 would be projected to increase from $2.9 billion to $3.5 billion.

As such, a "just-in-time" resourcing approach or deferral of resource development plans with fewer near-time resource commitments could assist in addressing Mr. Rainkie's concerns with respect to impacts on MH's financial health and rates. These approaches would have to be balanced with considerations and risks associated with load forecast uncertainty.