MANITOBA HYDRO
2025 INTEGRATED RESOURCE PLAN
AND MAJOR NEW FACILITIES REVIEW

PUB/CC
INFORMATION REQUESTS

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Room 400 – 330 Portage Avenue
Winnipeg, MB R3C 0C4
www.pubmanitoba.ca

330, avenue Portage, pièce 400
Winnipeg (Manitoba) Canada R3C 0C4
www.pubmanitoba.ca

PUB/CC-1

Part and Chapter:	CC-20 EER Report	**Page #:**	24
Topic:	Best Practices in Portfolio Modelling		
Subtopic	Study Period and Terminal Value		

Preamble (if any):

On page 24 of its report, EER states:

> Appropriate study period. Best practice uses a study period long enough that capital-intensive resources can be compared on equal terms with alternatives that have different cost trajectories and build timelines. Resources with multi-decade economic lives (e.g., large hydro, long-distance transmission) recover their costs over time horizons that short study periods truncate; a horizon that ends before the cost-recovery profile of the candidate resources stabilizes biases the comparison toward resources whose costs fall within the window. Typically, twenty years is the floor; longer is appropriate where the resource set or policy context demands it. LBNL 2024 BP 33 (p. 61) names the practice directly: "Use a study period that is long enough to allow meaningful comparison between capital-intensive resources and others that might be considered and built in the future."

On page 57 of its report, EER states:

> **A study period long enough to compare capital-intensive resources**. Manitoba Hydro applies the yardstick's end-effects remedy of annualizing resource costs over each resource's useful life within a multi-decade horizon, so capital-intensive options compare against shorter-lived alternatives without end-effect distortion. As the filing states the rule: "only the annual costs incurred from the project's in-service date until the end of the study horizon are considered when calculating net system costs"…The annualization, not the horizon length, is what earns the credit.

Question:

Please confirm whether Manitoba Hydro's and the model's approach of annualizing the capital costs and truncating any of the annual costs beyond the study period is aligned with the best practice described on page 24 of EER's report.

Rationale for Question:

To understand whether Manitoba Hydro's approach aligns with best practices.

Response:

Confirmed. As stated at Section 4.1.2 (p. 57) of the EER report, Manitoba Hydro's approach of annualizing resource capital costs over each resource's useful life, and counting only the annual costs incurred from the project's in-service date to the end of the study horizon, is aligned with the best practice described at Section 2.3 (p. 24). The best practice concern is end-effect distortion: a study horizon that ends before the cost-recovery profile of candidate resources stabilizes biases the comparison toward resources whose costs fall within the window. Annualization is the accepted remedy for

that distortion, because it allows capital-intensive options to be compared against shorter-lived alternatives on the basis of each resource's per-year cost rather than its total cost within the window. As the report puts it, "the annualization, not the horizon length, is what earns the credit": a 30-year resource entering service in 2030 outlasts the 2050 horizon, but its costs and benefits enter the comparison on the annualized basis the yardstick calls for. This is one of the three elements of Manitoba Hydro's modelling setup that the report identifies as meeting the Section 2.3 yardstick (Section 4.1.2).

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Part and Chapter:	CC-20 EER Report	**Page #:**	29
Topic:	Best Practices in Portfolio Evaluation		
Subtopic	Customer Bill Impacts		

Preamble (if any):

On page 29 of its report, EER states:

> **Customer bill impacts evaluated by class.** Best practice evaluates the bill impacts of candidate plans as a scorecard metric, broken down by customer class (residential, commercial, industrial) at a minimum, rather than expressed only as a system-average rate path. A plan's total cost translates into bill impacts that fall on different classes differently depending on rate structure, and a system-average rate forecast does not show how those impacts are distributed. Where bill impacts are not assessed by class, the evaluation cannot speak to which customers carry the build-out's cost burden — information the Board and stakeholders require to weigh a plan in the public interest. LBNL 2024 BP 48 (p. 80) names the practice directly: "Evaluate bill impacts by customer class as part of the IRP process."

Manitoba Hydro establishes rates for individual customer classes by undertaking a cost allocation study and assessing whether individual class rates need to be adjusted to achieve class revenue targets.

Question:

Please confirm or otherwise explain whether EER envisions an IRP process where a cost allocation study is undertaken to inform the rate changes and bill impacts for individual customer classes. If a cost allocation study is not performed, please explain the basis for class-specific rate changes and bill impacts.

Rationale for Question:

To understand the evaluation necessary to align with best practices.

Response:

Not confirmed as stated, and a clarification of the mechanics of this best practice follows. The practice described at page 29 of the report (Section 2.5, "Customer bill impacts evaluated by class") is an evaluation practice within the IRP, not a rate-setting exercise. Best practice is for the plan evaluation to include, as a scorecard metric, an indicative estimate of how each candidate plan's costs would translate into bill impacts by customer class (residential, commercial, and industrial at a minimum) rather than expressing cost impacts only as a system-average rate path. EER does not envision the IRP process undertaking a new cost allocation study, whether for the IRP as a whole or for each candidate plan. Class revenue allocation and rate design remain matters for the rate-setting process.

Generally, the basis for class-specific bill-impact estimates is the utility's existing cost-allocation framework extrapolated into the future. For Manitoba Hydro specifically, the class cost allocation from its most recent cost allocation study provides a reasonable basis for translating each candidate plan's incremental revenue requirement into indicative class-level bill impacts, at the planning-level precision a scorecard metric requires. The purpose of the metric is comparative and distributional: to show how the cost consequences of the candidate plans differ and how each plan's costs would be distributed across customer classes, so that the evaluation can speak to which customers carry the build-out's cost burden (Section 2.5, p. 29). An indicative estimate prepared on that basis does not require, and would not substitute for, the more granular cost-of-service analysis Manitoba Hydro performs for rate-setting.

PUB/CC-3

Part and Chapter:	CC-20 EER Report	**Page #:**	33
Topic:	Load Projections		
Subtopic	Economic Growth and impact of rate path		

Preamble (if any):

On page 33 of its report, EER states:

> The economic assumptions rest on an undisclosed electricity-rate path that itself varies by projection, and Manitoba Hydro's positions on the path are in tension. Prices run "relatively lower" in 1-Baseline and "progressively higher" in 2-Medium and 3-High (Appendix A5 §5.2.2), yet the path itself is withheld as "commercially sensitive" (Appendix A5 §5.2.2).

Figures 49 through 60 of Attachment 1.3 show the rate path for electricity and natural gas rates for development plans P3, P5, P5A, P5B, and P7.

Appendix 4.1 of the Fiscal 2026 to 2028 General Rate Application is the 2024 Electric Load Forecast.

https://www.hydro.mb.ca/docs/regulatory_affairs/pdf/electric/gra_2026_2028/04-1_appendix_4-1_2024_electric_load_forecast.pdf

On page 38 (pdf 46), the 2024 ELF states:

> The electricity price forecast is based on the Consumer Price Index (CPI) and rate increase projections contained in the Integrated Financial Forecast. The nominal electricity price is forecast to increase annually on average by 1.0% in 2024/25 and 3.5% from 2025/26 to 2030/31, and then reduce to a 2% for the remaining years of the forecast.

Question:

Please explain whether and how EER’s findings, conclusions, and recommendations change based on the disclosed rate paths in Attachment 1.3 and 2024 ELF.

Rationale for Question:

Manitoba Hydro redacts the electricity export prices. The domestic electricity rates are disclosed in Manitoba Hydro’s financial forecasts.

Response:

The disclosed rate paths add useful information to the record, but they do not change EER's findings, conclusions, or recommendations. Attachment 1.3 discloses the rate increases assumed in Manitoba Hydro's financial projections: Figures 49 through 58 apply one path — 3.50% a year from 2025/26 through 2040/41, then 2.00% a year from 2041/42 — identically to all five development plans (P3, P5, P5A, P5B, P7) and under

both load cases shown, the 2024 Electric Load Forecast and the 2-Medium projection. The preamble separately quotes the 2024 Electric Load Forecast (Appendix 4.1 to the General Rate Application), under which the electricity price forecast that underlies that load forecast rises 1.0% in 2024/25, 3.5% from 2025/26 to 2030/31, and 2% a year thereafter.

These disclosures do not supply the input the report identified as withheld (Section 3.2.2, p. 33). That finding concerns the electricity price forecasts used as inputs to the three IRP load projections — the paths that run "relatively lower" in 1-Baseline and "progressively higher" in 2-Medium and 3-High, which Appendix A5 §5.2.2 withholds as "commercially sensitive." These are domestic price inputs to the load forecast, not the export prices the question's rationale refers to. Attachment 1.3 does not disclose them: it applies a single rate-increase assumption to every plan — the same path under both the 2024 Electric Load Forecast and the 2-Medium cases — and shows no path for the 1-Baseline or 3-High projections. The projection-specific paths that differentiate the load forecasts stay off the public record. The 2024 Electric Load Forecast passage describes the price basis of the load forecast prepared for the General Rate Application, which is not one of the three IRP projections.

Nor does the finding turn on disclosure alone. Manitoba Hydro confirmed that "higher prices restrain electric demand growth" (PUB/MH I-15(d)), yet it ran no sensitivity on how the load forecast would change under a higher or lower rate path (Section 3.2.2). Because the rate path and the load projection each depend on the other, the effect of one on the other can only be stated qualitatively without that test (Section 7.5.3.1). A disclosed rate assumption is not a substitute for it: in Attachment 1.3 the rate increases enter as a uniform assumption applied to every plan, not as an input tested against demand. The two documents use different rate paths — the financial projections filed under the 2024 Electric Load Forecast hold 3.50% increases through 2040/41, while the price forecast underlying that same load forecast steps down to 2% after 2030/31 (as quoted in the preamble) — and the record does not explain the difference. The disclosed paths therefore illustrate the tension the report identified rather than resolve it. EER's conclusions are unchanged, and so is Recommendation 4 (Section 7.7): designate a reference case in the load forecast and apply symmetric sensitivity testing with rate-responsive load-shape assumptions.

PUB/CC-4

Part and Chapter:	CC-20 EER Report MIPUG-14 Bowman Report	**Page #:**	63 74
Topic:	Valuing Resources		
Subtopic	Wind		

Preamble (if any):

On page 63 of its report, EER states:

> **Drought hedging value of a diversified portfolio.** Hydro is the only resource modelled stochastically; the model captures hydro's drought exposure but does not capture the diversification value of resources that do not share hydro's drought correlation. A wind-and-storage portfolio mostly uncorrelated with low-flow years could add drought-hedging value that the model under-represents, because the non-hydro resources are deterministic.

On page 74 of Exhibit MIPUG-14, Mr. Bowman states:

> As is evident from the above table, the addition of wind to the system makes the financial consequence of every low flow case worse than without wind. The effects tend to be in the range of $20 million to $30 million each year (over a $100 million increase in the costs for a 5-year drought, all else being equal). In the extreme worst case, the addition of 600 MW of wind makes the financial consequences of the worst drought year almost $350 million worse than without the turbines (an increase from a $1.0 billion adverse event, to more than $1.3 billion in adverse impacts, in a single year).

Question:

Please provide EER's views as to whether there is in fact drought hedging value associated with the addition of wind resources, considering the conclusions drawn by Mr. Bowman on page 74 of this report.

Rationale for Question:

To test EER's conclusions with respect to the value of wind.

Response:

Yes, in a specific sense, and EER's report says so in careful terms: a wind-and-storage portfolio mostly uncorrelated with low-flow years "could add drought-hedging value that the model under-represents, because the non-hydro resources are deterministic" (Report Section 4.3.2, pp. 62-63). The basis for that value is Manitoba Hydro's own record. Manitoba Hydro found "no statistically significant correlation" between lower Nelson River inflows and Manitoba wind speeds during the peak winter period (CC/MH II-12(b)). Because wind does not fall when hydro inflows fall, it diversifies the drought risk that dominates planning for a system built on hydro. That is the sense in which the value is real: as physical diversification of supply, resting on Manitoba Hydro's own data.

Its size, though, has not been established, because the modelling as built cannot measure it. Hydro is the only resource run across the full range of water years, 112 of them (Appendix A7-1 §3.1); wind enters the production-cost model as a single fixed shape of monthly on- and off-peak energy (CC/MH II-12(d)), the same in every one of those years (Report Section 4.3.1, pp. 61-62). The value of a hedge lies in how it narrows the range of outcomes, so a model in which wind never varies, and in which only hydro's inflows carry risk, cannot put a number on wind's drought-hedging value in either direction. EER has not offered its own estimate, and does not do so here.

The dollar figures on page 74 of Exhibit MIPUG-14 measure a different thing. Mr. Bowman's table reports how much a financial line item swings from year to year: extra provincial revenue net of fuel, purchased power, and water rentals (Appendix A9-1), measured as the gap between each water year and the scenario's own average across the 112 years, comparing the no-wind case (S2B) with a 600 MW wind case (S2C) in 2035/36 (MIPUG-14 §6.2, pp. 73-74, drawing on MIPUG/MH I-9(a)-(d)(U)). That is the swing in financial results under one contracting assumption: a fixed-price power purchase agreement on the full wind output in every scenario (MIPUG/MH I-27(d)), for a resource whose energy the model sends mostly to export sales (MIPUG/MH II-11).

That swing is largely a product of the contract Manitoba Hydro assumed. In every scenario it "purchases the output of the wind facilities at a fixed price" (MIPUG/MH I-27(d)), so it pays for wind's full output regardless of conditions, and its modeling manages wind's week-to-week variability with the hydro system, "maintaining greater volumes of water in storage, to protect against the risk of low-flow conditions where additional water is required to manage week to week uncertainty in wind generation," with a resulting "reduction in export opportunity sales" (GSS-GSM/MH II-1(b)). Those forgone export sales are largest in a drought, when water is scarcest and so most valuable.

And Manitoba Hydro tested no other way of contracting for wind: it "did not model wind sensitivities for alternative contract forms such as market based PPA pricing" (MIPUG/MH I-27(f)). So the low-flow penalty rests on a single, untested contracting assumption, not on any physical property of wind. Mr. Bowman reads it the same way: he frames the result "in financial terms," calls it "not an indictment of wind for causing the flow related variability," and in his Section 6.4.2 puts the remedy in the form of the contract, not in the resource.

The comparison is confounded in a second way. The no-wind and wind cases are separately optimized plans that differ in more than wind: the no-wind case (S2B) carries extra combustion turbines and a small bioenergy-with-carbon-capture unit (MIPUG-14, p. 74), so a difference in results cannot be pinned on wind alone, a difficulty Manitoba Hydro itself flagged for its own tables (MIPUG/MH I-27(g)(ii)).

The runs behind the table cannot measure the drought hedge in any case, because they use the same setup EER's report examines. Wind is identical in all 112 water years, so the S2B/S2C comparison cannot show how wind's own weather years line up against the drought years, which is what a drought-hedging valuation needs. And while the setup charges wind's variability as a cost, through the integration cost above, it has no way to credit the other side: the value of wind's independence from drought, which narrows the

gap between dry and wet years. A framework that prices risk over hydro's inflows alone credits that hedge to no resource.

Mr. Bowman's finding about financial exposure under that contract form and EER's point about what the model can and cannot measure are therefore not in conflict.

PUB/CC-5

Part and Chapter:	CC-20 EER Report	**Page #:**	75
Topic:	Resource Options		
Subtopic	Battery Capacity Accreditation		

Preamble (if any):

On page 75 of its report, EER 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.

Question:

Considering Manitoba Hydro has no track record with battery storage systems on its system, please explain how it should derive the capacity accreditation for batteries

Rationale for Question:

To understand how accreditation of resources without a track record should be undertaken.

Response:

Manitoba Hydro does not need a track record. A battery's capacity accreditation comes from a study of the system it will serve, not from the battery's operating history, and the structure of that study is well established.

The study starts by representing the system in chronological, hourly detail: load, wind, and solar profiles spanning several decades of historical weather, built so that each year reflects what today's demand would have looked like under that year's weather. Running the full weather history keeps load and renewable output correlated the way they really are, and it lets rare cold snaps appear at their true frequency. That system is then simulated, hour by hour, over a thousand or more years. The historical weather years are run through repeatedly, and on each pass the model draws a different random pattern of generator outages from the units' forced-outage rates. Good practice varies those rates with the weather, since in severe cold units tend to fail together, and a fixed average rate misses that. The modelled system is calibrated until it just meets the reliability standard, typically a loss-of-load expectation of one day in ten years, which establishes when the system is genuinely at risk. Finally the battery is added, defined by its power rating, storage duration, and efficiency, and dispatched within those limits, ideally without assuming perfect foresight. Its effective load carrying capability (ELCC) is the amount of perfectly firm capacity the battery can replace while the system still meets the standard. The study needs no operating history from a Manitoba battery. Its inputs are the battery's

specification and data Manitoba Hydro already holds: hourly loads, inflow records, generator outage records, and the transfer limits of its ties to neighbouring systems.

A battery's credit depends on how much storage the system already has and on how long the battery can discharge, so the study repeats the measurement across storage levels and durations. The result is a schedule of credits: one curve for a five-hour battery, another for an eight-hour battery, each declining as storage is added. Utilities across North America commission these studies routinely, and the method is the same everywhere. Only the data change.

Manitoba Hydro is already headed in this direction. It says it is building the capability for "chronologic, probabilistic simulations of short duration storage resources like batteries to estimate their Equivalent Load Carrying Capacity," with results expected in future IRPs (CC/MH I-4(a)), and it has contracted for the SERVM resource-adequacy model to support that work (CC/MH II-28(a)). That is the study described above.

Until that study is complete, 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). The 47% figure Manitoba Hydro cites is an example: it is BC Hydro's modelled credit for the first 450 MW of four-hour batteries on BC Hydro's system, and any Manitoba use of it would need adjustment for duration, storage level, and the differences between the two systems (CC/MH II-14(a)).

PUB/CC-6

Part and Chapter:	CC-20 EER Report PUB/MH I-27	**Page #:**	78
Topic:	Resource Options		
Subtopic	Demand-side resource modelling		

Preamble (if any):

On page 78 of its report, EER states:

> EER's best practice is to put a demand-side resource on an equal footing with supply when the plan is built, giving it the same chance to be chosen, and so to displace new supply, that a supply resource has to be built. There are two ways to do that, and best practice is neutral between them: make the resource selectable, so the model may choose it, or carry it as a load modifier whose level comes from a maximum-achievable potential study and varies across the scenarios. What equal footing rules out is the path Manitoba Hydro took, fixing the resource at a single level, set outside the model and tied to the supply plan's own need.

In the response to PUB/MH I-27a, Manitoba Hydro states:

> The demand response is assumed to be 280 MW in 2032 representing the assumed reliably achievable peak demand reduction from the combined effect of the existing Curtailable Rates Program and additional demand response programs assessed in the IRP. This assumption is based on an independent demand response market potential study conducted by Dunsky, as discussed in Appendix 5, Section 5.8.

Question:

Please confirm or otherwise explain whether Manitoba Hydro’s approach to demand response follows EER’s best practice as described on page 78 of EER’s report.

Rationale for Question:

To understand whether Manitoba Hydro’s approach aligns with best practices.

Response:

Not confirmed. Manitoba Hydro's approach to demand response does not follow the best practice described on page 78 of EER's report, for the reasons set out in Section 5.7.1 (pp. 78-79).

The standard quoted in the preamble offers two routes to equal footing. The first is to make the resource selectable, so the capacity-expansion model may choose it on the same terms as supply. The second is to carry it as a load modifier whose level comes from a maximum-achievable potential study and varies across the scenarios (EER Report, Section 5.7, p. 78). Manitoba Hydro's approach took neither route on the terms equal footing requires.

Manitoba Hydro did not make demand response selectable, and best practice does not require that it be. The model "is technically capable" of treating demand response and the Curtailable Rates Program as selectable resources, but "no modelling run was performed with DR and CRP represented as selectable resource options" (CC/MH II-32), and Manitoba Hydro's reason that the programs "are assumed to be maximized" (PUB/MH I-27(d)) defends that choice. Because best practice is neutral between the two routes, the objection is not that Manitoba Hydro declined to make demand response selectable. It is whether the route Manitoba Hydro did take, the load modifier, was carried on equal-footing terms.

It was not. Its quantity was fixed at a single level rather than varying with the scenarios, and its timing was set by the supply plan itself. The increment that brings demand response to 280 MW in 2032 was scheduled and "aligned with the first need for new capacity resources in each scenario" (Appendix A5, Section 5.8). A quantity defined by the need date cannot be what moves that date (EER Report, Section 5.7.1, p. 78).

EER acknowledges, as the preamble notes, that the 280 MW assumption draws on an independent market potential study conducted by Dunsky (PUB/MH I-27(a)). A potential study addresses one element of the load-modifier route, but not the two features that take Manitoba Hydro's approach outside it. The level does not vary across the scenarios, and the schedule is tied to the supply plan's own need (EER Report, Section 5.7.1, p. 79).

PUB/CC-7

Part and Chapter:	CC-20 EER Report	**Page #:**	78, 80
Topic:	Resource Options		
Subtopic	Evaluating cost effectiveness of resources		

Preamble (if any):

On page 78 of its report, EER states:

> A measure's cost-effectiveness is tested against the system's avoided costs, by a recognized test or by genuine model selection, never against the cost of the supply resource it would displace.

On page 80 of its report, EER states:

> But selection by the optimization is not a cost-effectiveness screen. It shows the model chose a resource at the costs and limits it was given, not that the resource's benefits were tested against the system's avoided costs.

Question:

Please explain the pitfalls or downsides of measuring cost effectiveness against the cost of other resources, and why it is a best practice to measure cost effectiveness against the system’s avoided costs.

Rationale for Question:

To understand the evaluation approach that aligns with best practices.

Response:

The two passages quoted in the preamble state a single standard. The cost-effectiveness of a demand-side measure is a question about how it impacts the whole system. It asks whether the measure's cost is lower than the system costs it lets Manitoba Hydro avoid (EER Report, Section 5.7, p. 78). Those avoided costs are the full value the measure provides, and they include: the energy value in the hours the savings occur, the capacity value at the time of the system's need, the avoided line losses valued at the marginal rate, and the deferred transmission and distribution investment, each reflecting the timing and duration of the savings. The cost of a single competing supply resource captures at most a portion of the value, usually the carrying cost of capacity, at a single point in time.

Benchmarking a measure against the cost of the resource it would displace has two main pitfalls, and both are forms of mis-valuation. The first is understatement. The cost of a single competing supply resource is at most the capacity component of avoided cost, valued at one point in time. It can be a fair estimate of that component. But it leaves out the rest of the stream. That includes the energy value in the hours the savings occur, the avoided line losses, and the deferred transmission and distribution investment. Judged

against that partial figure, a measure that also delivers those services is worth less than it appears. The second is overstatement. Where the competing resource would not in fact have been built when assumed, the system never stood to incur that cost, so crediting the measure with displacing it counts a saving the system was never going to make.

The one explicit benchmark in the record illustrates the understatement. The Curtailable Rates Program incentive rate of $4.39 per kilowatt-month "is based on an estimate of the annual carrying cost of a combustion turbine along with applying a 42% qualifying factor" (PUB/MH I-27(c)). The 42% factor scales the combustion turbine's carrying cost to the firm capacity the program reliably provides, so the rate is a fair estimate of the capacity component of the program's avoided cost. It is not the whole of that avoided cost. It stops at capacity and leaves the program's energy, loss, and deferral value uncounted, yet it is offered as the measure of whether the program is worth running (EER Report, Section 5.7.2, p. 79).

Testing against the system's avoided costs addresses both pitfalls. Benchmarking against avoided costs covers every service the measure provides, in every hour, over the full life of the savings. It is also plan-neutral: it measures what the system would otherwise spend, not the cost of a pre-selected alternative, so the same yardstick applies even-handedly to demand-side and supply-side options. This is what places demand-side resources on an equal footing with supply.

EER notes that the cost of a marginal supply resource can legitimately inform the capacity part of an avoided-cost estimate; the pitfall arises only when a single resource's cost substitutes for the full avoided-cost stream. There are two ways to make this comparison. The first is a recognized cost-effectiveness test, such as the Total Resource Cost, Rate Impact Measure, or Participant Cost test referenced in MIPUG/MH I-14(b). The second is genuine model selection, where the measure is offered to the capacity-expansion model at its actual cost, on the same terms as any supply resource. Offered that way, the model performs the avoided-cost comparison itself, selecting the measure only where it lowers total system cost (see EER's response to MH/CC-4). This standard reflects EER's planning experience (EER Report, Section 5.7, p. 78) and is corroborated by LBNL 2024 BP 22 (p. 53), which holds that modeling demand-side resources in a capacity-expansion model captures only avoided energy and generation capacity and must be supplemented to reflect their full system benefits, including avoided transmission and distribution and risk management.

The second passage quoted (EER Report, Section 5.7.2, p. 80) makes the same point from the other side. A model that selects a resource has performed the avoided-cost test only if the measure was genuinely offered to compete, at its actual cost and free to be chosen or rejected. If the measure was instead fixed into the plan, left out of the selection set, or confined to a sensitivity not carried into the base analysis, the model's choice reflects how the run was set up, not whether the measure's benefits beat the system's avoided costs.

PUB/CC-8

Part and Chapter:	CC-20 EER Report Appendix 7.2 GSSM/MH I-5U	**Page #:**	89 5-7
Topic:	Portfolio Evaluation		
Subtopic	Testing decarbonization policy assumptions		

Preamble (if any):

On page 89 of its report, EER states:

> Building a policy assumption into the model is appropriate, but where it drives the outcome, the evaluation cannot be relied on unless the assumption's effect on the result is tested[6].
>
> …
>
> And the model "consistently selected combustion turbines … despite both high cost biomethane and a net-zero grid modelling constraint being assumed in most scenarios" (CC/MH I-21(c)). A binding net-zero constraint that still yields new gas build is the outcome that most called for testing the constraint's effect, the test Manitoba Hydro never ran.
>
> Footnote 6: By "testing" a binding assumption EER means re-running the model with that assumption varied or relaxed — a sensitivity that shows how much the assumption drove the result. It does not mean removing the policy or modelling outcomes contrary to it. The cost delta is the difference between the two portfolios' total costs: roughly $44 billion for Strategy D against roughly $34.5 billion to serve the 3-High projection (Appendix A7-2).

In Manitoba Hydro's modelling, resource option strategy "A" is technology-agnostic. Resource option strategy "B" requires a net-zero grid by 2035. In Appendix 7.2, Manitoba Hydro provides the capacity optimization results for scenarios S1A, S1B, S2B, and S3B. In GSSM/MH I-5U, Manitoba Hydro provides the optimization results for scenarios S2A and S3A. Under load projection 1-Baseline, the model selects the same resources under resource option strategies A and B. Under load projections 2-Medium and 3-High, the model selects the same combustion turbine resources under resource option strategies A and B, but adds bioenergy with carbon capture resources in order to meet the net-zero grid requirement.

Question:

Please confirm or otherwise explain whether Manitoba Hydro's additional modelling shown in GSSM/MH I-5U addresses EER's concern with respect to the policy assumption and the need to test it.

Rationale for Question:

To understand whether Manitoba Hydro's modelling aligns with best practices.

Response:

In part. The S2A and S3A runs are the kind of comparison Section 6.5 of the report called for, but they do not fully address EER's concern.

Section 6.5 (p. 89) identifies the net-zero-2035 grid constraint as a binding input whose effect on the result Manitoba Hydro never tested, and it describes the test best practice calls for: re-run the model with the constraint relaxed and report that build alongside the build with it binding, so the evaluation's dependence on the constraint is visible (Section 6.5, footnote 6). The S2A and S3A runs are that comparison — Strategy A carries no net-zero constraint, Strategy B requires a net-zero grid by 2035, so the two differ in the one input at issue. Manitoba Hydro reports the difference as the incremental cost of the constraint, measured as incremental cumulative present value of net system costs: $16 million in 2035 rising to $436 million by 2050 under 2-Medium, and $98 million rising to $816 million under 3-High (PUB/MH II-20(b), Tables 3 and 4). To that extent the additional modelling is the test the report described, and it usefully informs the record.

Three limits keep it from fully addressing the concern.

First, the test came after the plan was selected, not before. Best practice tests a binding policy assumption's effect while the evaluation is still live, before the plan relies on it (Section 2.5, p. 27). Manitoba Hydro initially declined to run S2A and S3A (GSS-GSM/MH I-5(a), (b)) and produced them only after the Board directed a response in Order 59/26 (PUB/MH II-21). By then the Least Regret Analysis, the shortlisting, and the scorecard evaluation were complete and the Recommended Development Plan chosen, and the Strategy A results were never carried through that framework. The comparison assists the Board's review now; it does not change how the plan was evaluated.

Second, the comparison cannot isolate the constraint's effect on the decision at the centre of the near-term plan — the 2030 combustion-turbine build. Manitoba Hydro optimizes in sequential sub-horizons, and the window containing the 2030 decision runs only to 2034 (CC/MH II-38(a)); "long-term system needs beyond a sub-horizon are not considered during optimization of that sub-horizon" (CC/MH I-13(c)). The 2035 constraint is therefore out of view when the 2030 build is optimized, under Strategy A or B alike, so the near-term builds match by construction rather than because the constraint made no difference there. That the near-term build is sensitive to what the model can see past 2034 is clear from Manitoba Hydro's own full-period run: with the whole study period optimized at once — so the 2030 decision can see the 2035 net-zero constraint — the model builds about 496 MW of natural-gas combustion turbines by 2035 instead of 840 MW, building less natural gas and more biodiesel, wind, and storage in its place (Report Section 4.2.4, p. 60; PUB/MH II-44(a)).

Third, Section 6.5's concern reaches past the net-zero constraint. It names two further binding choices whose effects Manitoba Hydro likewise did not test: the sub-horizon structure discussed above, and its assignment of all incremental non-ethanol biofuel to the electricity sector, made as a "modelling simplification" that Manitoba Hydro concedes "should not be interpreted as an assessment of the most economic use case" (CC/MH I-21(a)). The S2A and S3A runs address neither.

PUB/CC-9

Part and Chapter:	CC-21 (Dr. Fitzpatrick report)	**Page #:**	21
Topic:	Gas-Fired Turbines		
Subtopic	Public Expectations Basis		

Preamble (if any):

At lines 500-503, the report indicates that the plan to build a gas-fired turbine may not align with the expectations expressed by "many Manitobans". Table 4 provides four quotations from Public Survey 2 respondents on the topic of gas-fired turbines or fossil fuels.

Question:

Please provide additional information explaining the basis for the conclusion that gas-fired turbines may not align with the expectations of "many Manitobans" and the "frequency" of comments, including the number of engagement participants who expressed views on gas-fired turbines, specifically.

Rationale for Question:

To better understand Manitobans' views on gas-fired turbines as distinct from their more general viewpoints on fossil fuels.

Response:

The quotation in the report is drawn from the analysis of the qualitative responses to Manitoba Hydro's Public Survey 2. It is important to note that this survey **did not** ask Manitobans whether they endorsed the Integrated Resource Plan, and/or the decision to construct gas-fired turbines. Instead, the survey asked—at a general level—whether respondents had questions or feedback on the roadmap, which parts of the roadmap they were interested in learning more about, and whether they had any additional comments.

The two open-ended questions ("feedback" and "additional comments") provided meaningful qualitative information. While enumerating qualitative data can occur, it is methodologically controversial outside of specific approaches such as discourse analysis[1]. Tallying or counting unstructured responses can distort the purpose and

[1] Discourse analysis studies how language constructs meaning, power, and social reality.
Because it often examines patterns of language use, it can legitimately include counts, frequencies, or distributions of linguistic features, whereas thematic and grounded analysis avoid quantification because they focus on interpretive meaning, not measurable linguistic patterns.

integrity of qualitative research, as qualitative data are intended to capture meaning, depth, and context**,** rather than frequency**.**[2]

However, it is fair to note that, within these unstructured responses, the most common thematic focus related to renewable energy options, including comments emphasizing "no fossil fuels", interest in solar energy and interest in nuclear energy. The quotations included in Table 4 are representative of the sentiments coded within these thematic areas.

Higher frequency codes included between 120 and 550 entries (with the parent code of "energy sources" being an anomaly at 1928). I can confirm that data supporting solar energy and opposing fossil fuels were in the top three entries for higher frequency responses (excluding "energy sources"). Middle frequency responses ranged from 55 to 119 entries. Lower frequency responses had between 45 and 54 entries. Unique or very low frequency responses were put in the "parking lot."

For quantitative evidence of Manitobans' views on energy sources, one can refer to the two previous public opinion polls commissioned by CAC Manitoba, included in Appendix 2 and reproduced in full in response to PUB/CC-11(c). In both 2020 and 2022, only 14% of Manitobans indicated that the province should use more energy from natural gas. These results provide a statistically grounded complement to the qualitative findings from Manitoba Hydro's Public Survey 2.

[2] Because these responses are qualitative, assigning numeric rankings would imply a level of precision that the data does not support. Instead, I can categorize themes, highlight patterns, and identify relative strengths without converting them into numbers.

PUB/CC-10

Part and Chapter:	CC-21 (Dr. Fitzpatrick report)	**Page #:**	6; 22
Topic:	Engagement Gaps		
Subtopic	Consequence of Perspective Voids		

Preamble (if any):

The Report identifies that there were substantial voids in the perspectives captured through the engagement process and says that "further work is needed to engage Rights Holders, smaller municipalities, northern communities, and other underrepresented groups."

Question:

What, Dr. Fitzpatrick's opinion, are the implications of the substantial voids identified in the perspectives captured on the IRP's approaches, resource options, and outcomes?

Rationale for Question:

To better understand the precise ways in which a greater range of engagement perspectives could have resulted in a different IRP.

Response:

There is a long and well documented history of the harms and benefits of major projects being unevenly distributed. Historically disadvantaged groups have tended to carry a disproportionate share of the harms. Analysis infused by *Charter* values is necessary to assist in better understanding the consequences of development projects for communities and individuals who are often ignored in decision-making processes.[3]

For too long, public engagement has been shaped by a "one-size-fits-all" approach that assumes equal treatment naturally produces equal access. Traditional methods- such as an open house in a regional centre, an online survey circulated broadly—presume that if no one is explicitly excluded, everyone has an equal opportunity to participate. But lived experiences across Manitoba tell a different story.

Small municipalities with limited administrative capacity, northern communities located far from decision-making hubs, and customers who are hard to reach because of geography, connectivity, or historical marginalization all face structural barriers that make participation uneven. These communities hold essential knowledge about energy use, local infrastructure, and the impacts of development—especially in the North, where much

[3] Dilay, K., Pastora Sala, J., & P. Fitzpatrick (accepted) *Infusing Charter Values in Impact Assessment* in Intersectionality and Impact Assessment (ed. D. Hoogeveen & P. Fitzpatrick) Edwin Elgar.

of Manitoba's electricity is generated, yet where residents have often been least heard in shaping the province's energy future.

Purposeful engagement design must therefore move beyond universal methods and actively work to reduce systemic barriers, ensuring that underrepresented groups can meaningfully share their expertise. Without these perspectives, we cannot form a complete or accurate understanding of Manitoba's energy needs or the futures people envision.

If methods based on universal design result in under-represented populations, increased efforts should be made to engage those groups. If responses continue to be underrepresented, alternative methods to seek information from under-represented groups should be employed.

For example, in the CRCT hearing examining retail sale practices of Canada's large telecommunication carriers, the Commission engaged an Ipsos Public Affairs to improve representative input into the hearing. Methods included a survey with a representative panel of over 1,600 Canadians; a voluntary public survey that reached over 7,000 Canadians; 10 in-depth interviews with individuals with a disability; and 10 focus groups with seniors, residents of rural communities, Canadians who use a language other than French or English at home, and residents of official language minority communities.

PUB/CC-11

Part and Chapter:	CC-21 (Dr. Fitzpatrick report), Appendix 3	**Page #:**	3, 22-23 12
Topic:	Demographics		
Subtopic	Contribution to IRP Outcomes		

Preamble (if any):

The Report includes demographic observations at page 12. Appendix 3 states that this information "can support more informed decision-making, planning, engagement, and communication related to Manitoba's energy future."

Dr. Fitzpatrick also identifies "a striking disconnect between the volume of information collected through the engagement program and the extent to which it appears to have shaped the Integrated Resource Plan…"

Dr. Fitzpatrick's three recommendations in section 5.2 of her report pertain to Manitoba Hydro's public engagement practices but do not address how engagement results did or did not inform Manitoba Hydro's 2025 IRP.

Dr. Fitzpatrick also explains:

> As the public surveys were not intended to be representative and in light of the challenges identified Manitoba Hydro's data analysis, it may be necessary to rely on other data to understand Manitobans for purposes of this IRP. CAC Manitoba paid for two opinion polls (2020, 2022) which sought information on these matters. Appendix 2 includes findings from these polls, as they relate to source of energy, and factors that should inform energy selection.

Question:

a) Please identify decisions and/or assumptions made in Manitoba Hydro's 2025 IRP which were or could have been informed by public engagement results. Examples may include but are not limited to load forecasts, EV adoption assumptions, household fuel switching assumptions, uptake of energy efficiency programs, interests in or preferences between resource options, etc.

b) For each decision or assumption identified in a), please provide a summary of Manitobans' relevant views on the issue as presented in Dr. Fitzpatrick's and Dr. Hinds' analysis of Manitoba Hydro's engagement results. The response may also draw on the information presented in Appendix 2 to Dr. Fitzpatrick's report if necessary, as long as any references to Appendix 2 are identified as such.

c) Please confirm whether the 2020 and 2022 opinion polls have previously been filed with the Public Utilities Board. If not, please file the questions and results from these polls as attachments to this response.

Note: It may be appropriate for both Evolved Energy Research and Dr. Fitzpatrick to contribute to the response to part a) of this information request.

Rationale for Question:

To inform assessment of the 2025 IRP in light of responses to public engagement.

Response:

a) The following response was prepared by both Evolved Energy Research and Dr. Fitzpatrick.

Decisions and assumptions that were, or could have been, informed by public engagement results:

i) **The evaluation framework — the factors scored and their weighting**. Manitoba Hydro scored candidate development plans across four themes — Reliability, Cost, Environment, and Socio-economic — and gave the four themes equal consideration with no numerical weighting (PUB/MH I-68(a); Appendix A8 to Manitoba Hydro's 2025 IRP). Qualitative factors such as social acceptability and technology readiness were treated outside the optimization model rather than as scored resource characteristics (Appendix A6, §4; Appendix A7-1, §5), and Manitoba Hydro did not test an alternative weighting against the priorities expressed through engagement (CC/MH II-41). A clear, quantified statement of public priorities existed and could have informed the choice of metrics or the weighting applied to them.

ii) **Public acceptance of the resource mix.** The recommended plan adds 750 MW of natural gas by 2030 (2025 IRP Final Report, §3.2.2), and Manitoba Hydro weighs social acceptability outside the cost-optimization model (Appendix A6, §4). The socio-economic evaluation theme contains only two metrics — Indigenous economic participation and province-wide economic benefit (Appendix A8) — so the evaluation carries no metric for public acceptance of the resource mix itself. Manitobans hold clear preferences among resource types, which could have informed an acceptance dimension the evaluation currently lacks.

iii) **The electric-vehicle adoption assumption in the load forecast.** Manitoba Hydro built its EV adoption from federal zero-emission-vehicle targets, registration data, and general literature, not from Manitoba-specific data on customer intent (Appendix A5, §5.3). Engagement captured Manitobans' interest in EVs and the barriers they perceive, either of which could have informed the adoption assumption and its uncertainty range.

iv) **The household fuel-switching / heat-pump assumption in the load forecast**. The gas-to-electric switching and heat-pump-uptake assumptions were set from Manitoba Hydro's 2023 Residential Energy Use Survey and external roadmap studies, not from engagement (Appendix A5, §5.4.1). The same Manitoba-specific interest-and-barrier data could have helped to inform them.

v) **The regional resolution of the load forecast.** The load forecast is reported for the province as a whole. Its three projections differ in how much and how fast demand grows — a baseline plus two higher pathways tied to a net-zero economy — not by region, so the forecast never distinguishes northern Manitoba, where electric-heating dependence and load shapes differ from the south (Appendix A5, §3.1 and §4.1). Matching the forecast to the spatial diversity of load is a recognized modelling practice, and engagement raised the north/south distinction directly.

vi) **The plan's reliance on customer uptake of efficiency and demand-response programs.** About half the capacity the plan adds by 2035 is on the customer side — roughly 860 MW of 1,760 MW, split between energy efficiency and 310 MW of demand response (Final Report, §6.1.1). Manitoba Hydro set these amounts from Efficiency Manitoba's savings plan and Dunsky market-potential studies, adopting the maximized potential those studies identified. It acknowledges, though, that participation is voluntary and that low uptake could significantly reduce the capacity these programs deliver (Final Report, §6.1.1; Appendix A6, Table A6.15). What Manitobans said about their interest in these measures, and the barriers they see, bears directly on whether that assumed uptake is realistic.

b) Manitobans' relevant views on each item.

i) **Evaluation framework.** In Public Survey 1 reliability (minimizing the frequency and length of outages) drew the highest importance rating (95.6%), ahead of protecting the environment (91.8%) and minimizing rate impacts (91.2%), with reducing greenhouse gas emissions lowest (77.6%). But when respondents were required to trade these priorities off against one another, the order reversed — protecting the environment ranked first, minimizing rate impacts ranked above reducing emissions, and reliability fell to fourth (Dr. Hinds' analysis of Public Survey 1, CC-21 Appendix 3, §§4.1–4.2). The points allocated also varied significantly by age and region. Technical Advisory Committee (TAC) members repeatedly asked Manitoba Hydro to broaden the scored characteristics beyond cost and emissions to include social acceptability and technology readiness, cautioning that weighing qualitative factors outside the model "allows for significant bias" (CC-MH I-61-a-b (U) - Attachment 4, pp. 70-71 and 80-81). The CAC opinion polls at Appendix 2 to Dr. Fitzpatrick's report show the same unequal ranking of these priorities (2022: reliable system 59%, environment 54%, cost 49%, emissions 42%, economy 27%; 2020: impact on water / land / animals 72%, cost 63%, climate 55%, emissions 47%).

ii) **Public acceptance of the resource mix.** Open comments in Public Survey 2, run after the plan was released, objected to the new gas build (e.g. "Who thought it was a good idea to lean more into GHGs? Combustion turbines? Really? In 2025?") and repeatedly asked why solar is so limited, and a Technical Advisory Committee member observed that "Climate Action supports wind, solar, and battery storage, yet these are underutilized in the plan" (Dr. Fitzpatrick's report, Table 4, p. 21; CC-MH I-61-a-b (U) - Attachment 4, p. 99). Dr. Hinds' analysis of Public Survey 1 found strong interest in adding solar panels (43.9%) and that 74.4% of respondents believe Manitoba Hydro should be a leader in the energy transition. The CAC polls show a stable preference for non-emitting generation and against new gas (2022: 75% want more solar, 65% more wind, 60% more geothermal, but only 14% more natural gas while 42% want less; 2020: solar 69%, wind 58%, gas 14% more / 34% less) (Appendix 2).

iii) **Electric-vehicle adoption.** Public Survey 1 found substantial interest in buying an electric vehicle (43.8%) and in adding home charging capacity (39.5%), while also showing that a substantial share of respondents was not yet considering adoption and that larger investments were contemplated over the medium-to-longer term rather than the next two years (Dr. Hinds' analysis of Public Survey 1). Technical Advisory Committee members asked why the vehicle forecast assumed no behavioural or mode shift (CC-MH I-61-a-b (U) - Attachment 4, pp. 18 and 67). The CAC polls show the same mix of intent and constraint (2020: 40% would switch to an electric vehicle; 2022: only about 4-5% currently own a hybrid or electric vehicle, with upfront cost (53%) and too few charging stations (40%) the leading barriers) (Appendix 2).

iv) **Household fuel switching / heat pumps**. In Public Survey 1, 23.7% of respondents had already switched gas heating to electric (Dr. Hinds' analysis of Public Survey 1); a Technical Advisory Committee member noted the need for care in how a heat pump's coefficient of performance is represented (CC-MH I-61-a-b (U) - Attachment 4, p. 57). The CAC polls show interest tempered by cost (2020: 15% would switch heating fuel; 2022: only 6% had switched fuel, with cost the barrier) (Appendix 2).

v) **Regional resolution of the load forecast.** Technical Advisory Committee members asked directly, "Do the projections consider northern Manitoba end users?" and observed that Winnipeg and rural areas have different load profiles that are "not visible in the IRP" (CC-MH I-61-a-b (U) - Attachment 4, pp. 10 and 54). Dr. Hinds' analysis of Public Survey 1 likewise found significant Winnipeg / non-Winnipeg differences in energy priorities, and a Public Survey 2 comment noted that "rural residents in the south need reliable power too, not just Winnipeg, not just the north" (Dr. Fitzpatrick's report, Table 3, p. 17).

vi) **Reliance on customer participation in demand-side resources.** Manitoba Hydro's own engagement synthesis records that efficiency is seen as "a desirable solution to manage increased energy demand, but additional incentives, policy and regulation are likely needed to encourage equitable

uptake of these solutions" (Final Report, §6.1.1). A Technical Advisory Committee member challenged the reliance on customer action directly: "50% of total capacity comes from consumer actions. What would be the risk mitigation so that these targets are achieved?" (CC-MH I-61-a-b (U) - Attachment 4, p. 91). Public Survey 1 found that while most respondents report frequently acting to reduce their everyday energy use (81.3%), adoption of specific household measures remains limited (Dr. Hinds' analysis of Public Survey 1). The CAC 2022 poll indicates the participation reality on the residential side: only 15% report participating in an energy-efficiency program in the past five years, and the same poll finds upfront cost the leading barrier to reducing home energy use (56%) (Appendix 2).

c) To the best of Dr. Fitzpatrick's knowledge, the opinion polls have not been previously filed with the Public Utilities Board. The reports are appended here as Attachments A and B.

PUB/CC-12

Part and Chapter:	CC-21 (Dr. Fitzpatrick report), Appendix 3	**Page #:**	22-23
Topic:	Recommendations		
Subtopic			

Preamble (if any):

Dr. Fitzpatrick provides three recommendations as follows:

> That the PUB find that Manitoba Hydro's approach to public engagement did not align with its own objectives and with industry best practice.
>
> That in future IRPs, Manitoba Hydro demonstrate how it met the standard of "consult" in its engagement tools, data analysis and findings.
>
> That the Public Utilities Board develop and issue a directive on expectations re: data analysis for public engagement activities. This should include specific requirements addressing qualitative data.

Question:

a) Please confirm or otherwise explain whether Dr. Fitzpatrick endorses the "consult" standard as an appropriate standard for Manitoba Hydro to meet.

b) Please articulate the expectations that would be included in the directive that is the subject of Dr. Fitzpatrick's 3rd recommendation, including the specific requirements addressing qualitative data.

Rationale for Question:

To clarify the author's recommendations.

Response:

(a) The Spectrum of Participation by the International Association of Impact Assessment relied upon by Manitoba Hydro is not the standard I endorse for framing the process of participation. Although widely referenced, it is an international standard that does not fully account for regional, cultural, or jurisdictional differences in engagement practice. Its proprietary nature also raises concerns, as it in fact feels counter-intuitive to rely on a closed, pay-to-access model for a field grounded in openness, accessibility, and public empowerment.

The Spectrum's conceptual roots lie in Sherry Arnstein's Ladder of Citizen Participation[4] (1969), a foundational piece of scholarship that has shaped decades of work in the field. While the Spectrum draws from this lineage, it simplifies Arnstein's insights into a linear, five-step model that can obscure the complexity of real engagement processes. The Spectrum's placement of "listening" at the Consult level does not align with contemporary understandings of meaningful engagement, where listening is a baseline expectation, not a mid-level activity. The contemporary framing emerged in the late 1990s and early 2000s which saw attention change from public participation to meaningful public participation to meaningful engagement.[5]

My own work in this area has been significantly influenced by Dr. A. John Sinclair[6] of the University of Manitoba, whose contributions to public engagement and impact assessment are internationally recognized. Along with Dr. Alan Diduck, Dr. Sinclair's early work on public participation and social learning processes has shaped much of the Canadian and international and practice on public engagement programs.

At its basic level, to meaningfully engaging requires ensuring[7]

> *… that all interested persons and organizations have the opportunity to contribute their knowledge and views, and to see how their contributions are used. As a result, proponents and government decision makers receive better information — enabling them to more effectively address public concerns — and final decisions better reflect values (of the public)*[8]

A meaningful process is open to all*. It can be accessed by all who are interested*[9] *, and is accessed by representative members of the public.* [10]

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[4] Arnstein, S. (1969). Ladder of citizen participation. Journal of the American Institute of Planners, 35(4), 216–224.

[5] See discussion in Fitzpatrick, P., & Dilay, K. (2020). "Your Voice Matters" – Public Participation Literature Review. Winnipeg, MB.

[6] E.g., Sinclair, A. J., & Burdett, T. (2024). The next generation of public participation in impact assessment. In Handbook of Public Participation in Impact Assessment (pp. 408–418): Edward Elgar Publishing.; Sinclair, A. J., Diduck, A. P., & Parkins, J. R. (2022). Innovative approaches to achieving meaningful public participation in next-generation impact assessment. In Routledge Handbook of Environmental Impact Assessment (pp. 239–258): Routledge; Sinclair, A. J., Diduck, A. P., & Fitzpatrick, P. (2008). Conceptualizing learning for sustainability through environmental assessment: critical reflections on 15 years of research. Environmental Impact Assessment Review, 28(7), 415–428. doi:10.1016/j.eiar.2007.11.001

[7] Much of the section in italics is taken directly from Fitzpatrick & Dilay (2020)

[8] Canadian Environmental Assessment Agency. (2001). Strengthening environmental assessment for Canadians. Retrieved from Ottawa, Canada at p. 22 (hereafter CEA Agency)

[9] Expert Panel Review of Environmental Assessment Processes. (2017). Building common ground: A new vision for impact assessment in Canada. Retrieved from Ottawa, ON: https://www.canada.ca/content/dam/themes/environment/conservation/environmental-reviews/building-common-ground/building-common-ground.pdf at p.17 (hereafter Expert Panel)

[10] Doelle, M. (2018). Meaningful Public Participation in the Proposed Federal Impact Assessment Act (IAA). Retrieved from https://blogs.dal.ca/melaw/2018/02/23/meaningful-public-participation-in-the-proposed-canadian-impact-assessment-act-ciaa/ ; Stewart, J., & Sinclair, A. J. (2007). Meaningful public participation: Perspectives from participants, proponents and government. Journal of Environmental Assessment Policy and Management, 9(2), 1–23

Meaningful participation requires reliable data. *The record "...must be entirely based on evidence that is, and is seen to be, unbiased, accurate, accessible and complete."*[11] *It is important to note that this does not mean evidence follows one specific knowledge system, such as science; it simply means that the evidence must be reliable as per the worldview in which it is situated. The process should demonstrate that the information was heard by decision-makers, and "had a chance to influence the ultimate decisions."*[12]

Process integrity, through transparency and accountability is essential. *"[P]eople must be able to see and understand how the process is being applied …. and how decisions are being made. Without this transparency, no process will be trusted."*[13] *This includes rigor in data analysis, and clear communication about how the information informs (or cannot inform) the final decision(s).*

In theory, the three requirements outlined above can inform the "consult" standard. However, these principles are not emphasized in the Spectrum of Participation, and thus this is not the approach, nor level of the spectrum, I would "endorse."

(b) It is not uncommon for Public Utilities Boards and similar administrative tribunals to provide guidance on data analysis through various tools such as filing manuals, benchmarking standings and regulatory reporting directives. The goal of these tools is to standardize procedures and improve efficiency, among others.

The submission by Manitoba Hydro required substantial effort to understand the outcomes of engagement, and the methodology through which those outcomes were reached.

While comprehensive documentation is important, the volume of material submitted in the original application that focused on how the company solicited feedback obscured information related to data analysis. It was difficult to determine how data were analyzed (including how the key findings were identified and supported by the data) and subsequently how these findings were considered in the development of the 2025 Integrated Resource Plan.

In essence, the information provided in the original application leaned towards procedural data (i.e., here is what we asked, here is how we promoted engagement, here is a newsletter about our new IRP process), rather than focusing on the substance of what the participants said – including data analysis, deeper reflection on how that data informed the plan, and providing substantive feedback to participants to demonstrate how they were listened to.

For future hearings, issuing a directive could avoid applications which over-emphasize procedural data (i.e., the how) over evidence-based engagement (the what was said). Participants want transparency on the participatory process, in fact best practice is to

[11] Expert Panel at page 14
[12] Expert Panel at page 14; see also Stewart & Sinclair (2007)
[13] Expert Panel at page 13

involve them in designing the how, and they want to know how the data/information collected was analyzed.

Experience in this regard has proven that cherry-picking of data/information to support a particular aspect of a proposal often occurs when there is not full disclosure on what was collected and how it was analyzed. A directive on analysis could be issued to ensure that the PUB receives the level of analytical transparency necessary to fully understand the scope, methodology, and implications of engagement activities.

Such guidance would ensure that future submissions provide not only descriptive material but also the analytical depth required for effective oversight. It would identify the standard of evidence surrounding public engagement that would permit the PUB to better adjudicate this component of the application.

A directive could address:

- requirements for cross-tabulation of quantitative data across all demographic factors to identify if there are substantial differences across different demographic categories. This would also serve to ensure that no unnecessary personal information is collected by proponents;

- detailed information about qualitative analysis, including approach, the entire list of themes/codes applied to the dataset and the grounded themes that emerged, the factors that informed theme development and led to key findings, identification of how direct quotes were selected for inclusion in the report, and procedures for data validity and trustworthiness of the findings;

- directives on the role of AI in data analysis (which will likely need to be updated on a regular basis for the foreseeable future); and

- more robust documentation about if the engagement data informed the application (and how) or why it was not.

MANITOBA HYDRO
2025 INTEGRATED RESOURCE PLAN AND MAJOR NEW FACILITIES REVIEW

PUB/CC
INFORMATION REQUESTS

July 16, 2026

PUB/CC-13

Part and Chapter:	CC-25 Rainkie Report PUB/MH I-70; PUB/MH III-37	**Page #:**	28, 26
Topic:	Financial Forecasts		
Subtopic	Equal Annual Rate-Setting Approach		

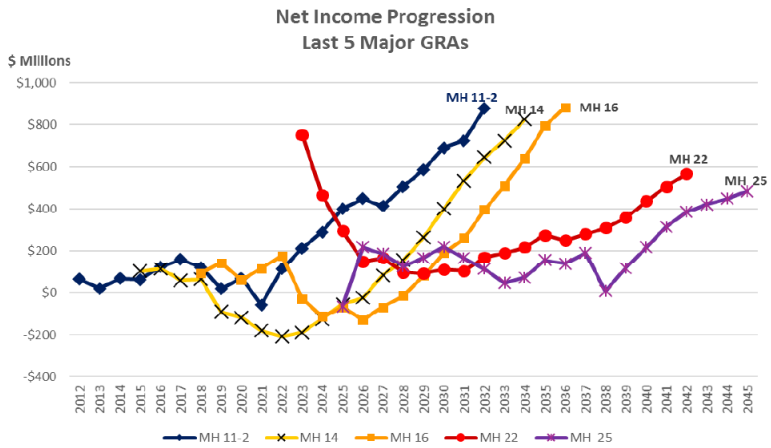
Preamble (if any):

On page 28 of his report, Mr. Rainkie states:

> MH commenced presenting 20-year financial projections for the 2013 and 2014 Test Years and has continued that practice with major GRA filings until the filing of its most recent 2026 to 2028 GRA in 2025. As part of the filing of the 20-year financial projections with GRAs, MH modified its approach to developing rate proposals for the test period such that these rate proposals were based on a long-term indicative rate path (even annual rate increases for the Test Period which continued towards the back-end of the forecast).

In the response to PUB/MH III-37, Manitoba Hydro provides the equal annual rate increases required to reach a debt ratio of 80% for each development plan. The equal annual rate increases are for every year of the financial forecast with the exception of the three test years of the 2026 to 2028 GRA.

On page 36 of his report, Mr. Rainkie provides Graph 11 showing the net income forecasts from financial forecasts provided from the most five most recent GRAs.



Question:

a) Please confirm whether the equal annual rate increase approach has been consistently applied in each of the financial forecasts shown in Graph 11, or whether some of the financial forecasts have rate increases declining to 2% in the last four years.

b) Please confirm which equal annual rate increase approach used in the IRP and MNF filings (PUB/MH I-70, PUB/MH III-37) is consistent with the approach or approaches in the financial forecasts shown in Graph 11.

c) Please explain whether or how the different approach to the equal annual rate calculations used in the IRP and MNF affects Mr. Rainkie's conclusions and recommendations, particularly in reference to the "hockey stick" analogy.

Rationale for Question:

The approach to calculating equal annual rate increases has not been consistent between the past five GRA forecasts and the IRP/MNF financial forecasts.

Response:

Response to a, b, and c:

Mr. Rainkie's "hockey stick" analogy is the pattern of slow or stagnant growth in net income (and equity ratio) early in the projection period (the blade of the hockey stick). This is followed by a sudden and massive upward spike in net income (and equity ratio) later in the projection period (the handle of the hockey stick). The "hockey stick on wheels" analogy is if you graph the successive forecasts over time – the graph has the appearance of a hockey stick being on wheels as you move from left to right.

MH11-2, MH14 and MH25 in Graph 11 from Mr. Rainkie's evidence included 2.0% rate increases in the back-end of the projection period. These 2.0% rate increases were necessary as a means for MH to slow down the exaggerated levels of net income and corresponding year over year improvement in the equity ratio – in order to moderate the "hockey stick" pattern, which would have been even more pronounced in these projections than it already is.

The graphs of the progression of net income and equity ratio (Graph 11 and 12 on page 36 of Mr. Rainkie's evidence), clearly demonstrate the "hockey stick" pattern in of the projections from the last 5 MH GRAs, regardless of minor adjustments by MH toward the back-end of the projection to include 2% rate increases in the above noted projections to slow down the exaggerated improvement in net income and equity ratio.

For the IPR and MNF filing, the even annual rate increase scenarios (including PUB/MH I-70 and PUB/MH III -37) are for the full time-frame of each projection (2029 to 2045) after the test period from the last MH GRA (2026 to 2028). Even annual rate increases to the end of the projection period was specified in the information request itself.

None of these rate scenarios achieved the prior MH target of a 25% equity ratio by the end of the projection period in 2045, as a result of the projected deterioration in MH's financial health in the MNF filing. As such, it would not be necessary for MH to include

2.0% rate increases in the back-end of these scenarios to attempt to slow down or moderate the “hockey stick” pattern.

Mr. Rainkie’s conclusion in Section 5.0 of his evidence is that caution should be exercised by the PUB to avoid over reliance on long-term rate path projections that target a specified equity ratio at the back-end of the projection period. This conclusion is not impacted by the insertion of 2.0% rate increases in the back-end of some of the projections from the last 5 MH GRAs.

The various even annual rate increase scenarios from the IRP and MNF proceeding continue to demonstrate the “hockey stick” pattern of exaggerated net income levels and corresponding improvements in the equity ratio in the last 5 years of the projection period. This continuing pattern is shown in Graphs 14 and 15 (pages 38 to 39) and the observations related to these graphs on page 39 of Mr. Rainkie’s evidence. In summary, Graphs 14 and 15 show projected net income levels ranging from $236 million to $974 million and equity ratio improvement ranging from 11% to 18% in the last 5 years of the projection period – across the 3 representative development plans, at the ELF.

PUB/CC-14

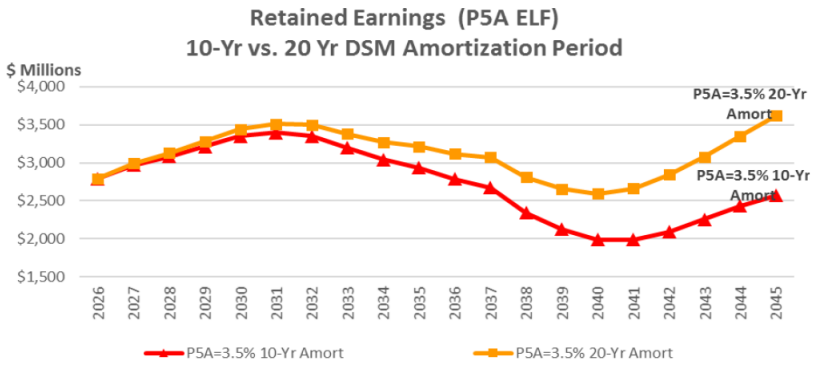
Part and Chapter:	CC-25 Rainkie Report	**Page #:**	47
Topic:	Energy Efficiency		
Subtopic	DSM Amortization Period		

Preamble (if any):

On page 47 of his report, Mr. Rainkie states:

> As part of the IRP filing, MH provided asset life estimates (number of years) of the various resource options and additional energy efficiency programs that it asserts are feasible in the timeframe of its need for new resources. The range of useful lives for additional energy efficiency programs is from 15 to 25 years, as follows:
> • Residential home insulation = 20 years;
> • Heat pumps = 20 to 25 years;
> • Electric thermal storage systems = 20 years; and
> • Customer energy solutions = 15 years

On page 48 of his report, Mr. Rainkie provides Graph 18:



The measure lives or aggregate life for the Efficiency Plan do not appear to be on the record of the IRP and MNF proceeding.

Question:

a) If available in the record of this proceeding, please provide the aggregate life of the measures included in the current Efficiency Plan.

b) If not available, please explain whether it would be more appropriate to consider changes to the amortization period for DSM expenditures once the aggregate life of all energy efficiency measures is known.

c) Please confirm or otherwise explain whether changing the DSM amortization period has any impact on Manitoba Hydro's debt ratio.

Rationale for Question:

The measure life of only a few energy efficiency measures appears to be on the record of this proceeding.

Response:

a) The aggregate life of measures include in the current Efficiency Plan does not appear to be on the record of the IRP and MNF proceeding.

b) Mr. Rainkie agrees that it would be appropriate to consider changes to the amortization period for DSM expenditures once the aggregate life of all energy efficiency measures has been calculated.

Mr. Rainkie understands that to support its request to the BCUC to increase the DSM amortization period from 10 years to 20 years, FEI provided a calculation of the expenditure-weighted average measure life of its 2019 to 2022 DSM Plan and determined that DSM savings persist on average for 20.1 years when weighted by expenditures.

Mr. Rainkie also understands that to support its request to the BCUC to increase the DSM amortization period from 10 years to 15 years, BC Hydro estimated the energy-weighted average persistence of new DSM programming to average 14.9 years between its 2012 and 2015 fiscal years. BC Hydro also noted in its application to the BCUC, that substantial DSM savings are also now provided by two other DSM tools, conservation rate structures and codes and standards with savings with persistence up to 30 years. Inclusion of these savings in the calculation would result in a considerably longer average persistence for the overall DSM savings portfolio, well in excess of 15 years.

Typically, the undertaking of this type of analysis to support an updated DSM amortization period would occur at a GRA proceeding. However, in the joint IRP and MNF proceeding, the Government of Manitoba has directed the PUB to review and make recommendations on the impacts of the MNF on MH's financial health, electricity rate impacts and mitigating actions to reduce the projected rate impacts.

The information on the record of the joint IRP and MNF proceeding indicates that there are material impacts to projections of MH's financial health and resulting indicative rate impacts of the representative development plans if the DSM amortization period were to be aligned with the useful life of the underlying energy efficiency programs (Please see the response to part c of this information request below). Alignment of amortizations periods of resource options and their useful lives ensures that the financial projections in the MNF reflect the economic substance (representational faithfulness) of alternative resource options and places all resource options on an equal footing (neutrality for decision making).

As such, this information should be considered by the PUB in making recommendations to the Government of Manitoba on financial health, rate impacts and potential rate mitigation matters in this joint IRP and MNF proceeding.

c) Yes, increasing the DSM amortization period to be aligned with the useful life of the underlying energy efficiency programs would positively impact MH's debt ratio. For example, using a 20-year DSM amortization period for P7 (at the ELF and at a 3.5% rate path), would increase retained earnings by $525 million and decrease the debt ratio by 1% (from 89% to 90%) by 2035. Retained earnings would be projected to increase by $1.7 billion and the debt ratio would be projected to decrease by 4% (from 96% to 92%) by 2045.

PUB/CC-15

Part and Chapter:	CC-25 Rainkie Report	**Page #:**	50
Topic:	Financial Targets		
Subtopic	Retained Earnings Target Based on 7-Year Drought		

Preamble (if any):

On page 50 of his report, Mr. Rainkie states:

> In the absence of a financial reserves target, retained earnings in the medium-term to 2035 and the **$2.6 billion**[46] estimated impact of a 7-year drought is used as a proxy of a financial metric/target for the analysis that is provided in the remainder of this Section of this Evidence.

Question:

Please confirm or otherwise explain whether setting the retained earnings target at $2.6 billion means these reserves can only be used to address a single risk (a 7-year drought) and not any compounding risks.

Rationale for Question:

To explore whether a retained earnings target of $2.6 billion is sufficient.

Response:

The premise of this information request appears to assume that only regulatory action is available to MH, in order to manage the impacts of a prolonged drought. However, Mr. Rainkie notes that MH management actions can mitigate a portion of the impact of a prolonged drought, and as such, a $2.6 billion proxy for a financial-reserves based target would include an allowance for other risks faced by MH. This approach is supported by prior PUB findings as further outlined below.

There is extensive policy guidance contained in the findings of the PUB in Order 59/18 (pages 64 to 66) flowing from the MH 2018 & 2019 GRA, with respect to how the key risks of MH should be considered and dealt with for rate-setting purposes. This policy guidance included that:

- Rates should not be set to increase financial reserves for all identifiable risks;
- The PUB was prepared to take regulatory action (rate increases) when emergent situations face MH;
- Retained earnings should be used to manage drought risk in combination with regulatory action by the PUB;
- Interest rate and export price risks over the long-term should be addressed with rate increases as and when those risk materialize;

- Rates should not be set to increase retained earnings to manage these longer-term risks; and
- The PUB found that there was merit to gain a better understanding of the financial reserves required for MH under various circumstances, including consideration of risk tolerances and which risks should be protected by reserves.

The following PUB findings from Order 43/26, flowing from the recent MH 2026 to 2028 GRA, outline the PUB expectations on the role of management actions to manage the financial impacts of drought:

- The PUB continued to find that MH has the discretion in its capital spending and that this is one tool that can be used to manage the financial impacts of drought, along with rate increases and the use of retained earnings (Order 43/26, page 113); and
- The PUB found that MH made no adjustments to O&A expenditures, despite a half-billion dollar degradation to its 2025/26 net income projections and had not taken sufficient steps to control O&A expenditures in response to the ongoing drought (Order 43/26, pages 138 and 139).

On page 50 of Mr. Rainkie's evidence in the joint IRP and MNF proceeding (CC-25), he indicated a preference for a financial-reserves based target using MH's Uncertainty Analysis to develop a target range of financial reserves for MH, that considers both management action and regulatory action. He also noted that to date, MH has not developed the Uncertainty Analysis to its full potential as a risk management and rate-setting tool.

In the absence of an enhanced MH Uncertainty Analysis and a corresponding refined financial reserves target, Mr. Rainkie has used the $2.6 billion impact of a 7-year drought as a "proxy" for a financial-reserves based target for the MNF proceeding. Use of this proxy is intended to (i) demonstrate the concept and implications of a financial-reserves based target to the PUB for the purposes of the MNF review and making recommendations to the Government of Manitoba and (ii) to contrast such an approach with the historic approach used by MH for the last 5 major GRAs (even annual rate increases targeting specified levels of equity ratio toward the back-end of the projection period).

PUB/CC-16

Part and Chapter:	CC-25 Rainkie Report	**Page #:**	60
Topic:	Business Strategy		
Subtopic	Strategy 2040		

Preamble (if any):

On page 60 of his report, Mr. Rainkie states:

> MH does not have an overarching MH business strategy that it can use to organize around the external structural changes that are inherent in the energy transition (decarbonization, decentralization, democratization, decreased use and digitisation) and to increase its odds of success of managing though the uncertainties associated with government energy and climate policy, customer behavior and emerging resource option maturity.
>
> MH indicated at the last GRA that it had developed six Enterprise Goals that were focused on critical projects or initiatives for the 2026 to 2028 Test period, including the HVDC Reliability Project, new energy resources and implementation of SAP. MH is using this list of operating imperatives as its "strategic framework" at present. These six Enterprise goals do not represent an overarching business strategy for MH.

In the 2023/24 & 2024/25 GRA, Manitoba Hydro presented its then-current strategy titled "Strategy 2040" in Appendices 2.1 and 2.2. Strategy 2040 had three drivers of change: decarbonization, decentralization, and digitalization.

Question:

a) Please explain whether Strategy 2040 was an overarching business strategy for Manitoba Hydro that satisfies Mr. Rainkie's recommendations.

b) Please identify and explain the specific elements that Manitoba Hydro should incorporate into its overarching business strategy that would result in Mr. Rainkie's recommendations being satisfied.

Rationale for Question:

To explore whether Manitoba Hydro has or had an appropriate business strategy to address Mr. Rainkie's concerns and recommendations.

Response:

a) No, Mr. Rainkie does not consider Strategy 2040 to be an overarching business strategy that would satisfy his recommendations.

Strategy 2040 was a "strategic" plan and not a true strategy to respond to the external transformative structural changes that are inherent in the energy transition (decarbonization, decentralisation, democratization, decreased use and digitization).

A strategy is an integrated set of choices that positions an organization to resolve its most vexing issues and provide superior value to its customers and respond to external threats. Strategy involves focus (choices of areas to focus and not to focus and how to improve customer value in the areas of focus), trade-offs (absolute and relative trade-offs recognizing that all organizations are resource constrained) and synergistic fit (choices made fit together such that the choices reinforce each other and the whole is greater than the sum of its parts).

Strategy 2040 suffered from the same deficiencies as most "strategic" plans in that it produced a long list of operating imperatives/initiatives that lacked focus, trade-offs and synergistic fit. Such lists of operating imperatives tend to represent hedging, replication of imperatives in the industry and repacking of prior initiatives to fit the new "strategic plan" pillars. The hope in this approach is that if the organization implements all of the long list of operating initiatives that it will be successful in providing ratepayer value.

Strategy 2040 was generally unwieldy for MH and costly for ratepayers and contributed to upward pressure on rates. MH informed the PUB and intervenors during the 2026 to 2028 GRA that it no longer uses Strategy 2040 as its "strategic" framework. Instead, MH indicated that it had adopted six Enterprise Goals that were focused on critical projects or initiatives for the 2026 to 2028 Test Period as its new "strategic" framework. The MH six Enterprise Goals represent a different list of operating imperatives than Strategy 2040 - and not a long-term overarching business strategy to successfully manage the transformative forces shaping the energy sector.

b) Mr. Rainkie recommends that MH organize is overarching business strategy around the external transformative forces and resulting strategic themes that are shaping the energy sector.

The external transformative forces that are shaping the energy sector include decarbonization, decentralisation, democratization, decreased use and digitization. Strategic themes tend to sit where two or more of the transformative forces converge and represent opportunities or threats that are structural shifts, with cross functional relevance and are actionable.

Organizing an overarching business strategy around a few of these strategic themes protects against the diffusion associated with conventional "strategic" plans that attempt to respond to all changes in the business environment (thus becoming unfocused, unwieldy and costly).

Mitigating the weakening financial health and increasing rate impacts that are demonstrated in the MH MNF filing, requires bold management action and transformational change that only a strategy (and not a plan) can deliver.

Mr. Rainkie also recommends that MH use the same strategy framework to create an overarching business strategy as he recommends guiding the development of a rate management strategy (Please see Section 7.4, pages 59 and 60 of Mr. Rainkie's evidence). The components of the recommended strategy framework are:

1. Customer-centric aspirations;

2. Where to focus to provide value for ratepayers;

3. How to improve value for ratepayers in the areas of focus;

4. Required organizational capabilities to execute the areas of focus and improve ratepayer value; and

5. Enabling management systems in terms of the structures, processes and metrics to ensure that the required organizational capabilities are built, maintained and measured.

PUB/CC-17

Part and Chapter:	CC-25 Rainkie Report	**Page #:**	61
Topic:	Rate Mitigating Actions		
Subtopic	Affordable Energy Plan Guiding Principles		

Preamble (if any):

On page 61 of his report, Mr. Rainkie states:

> Manitoba's Affordable Energy Plan states that "The first, most important guiding principle is that the shift to more clean energy will keep rates affordable for Manitoban's"[62].

Question:

Please explain whether Mr. Rainkie considers the government's statement in the Affordable Energy plan referenced in the preamble to be a fact, an aspirational statement, a directive to Manitoba Hydro and the Board, or something else.

Rationale for Question:

To obtain Mr. Rainkie's views on a guiding principle from the Affordable Energy Plan.

Response:

Mr. Rainkie considers the government's articulation that the first and most important guiding principle is that the shift to more clean energy will keep rates affordable for Manitoban's – as the expression of a policy imperative, an overarching goal to drive decision making within the energy ecosystem in Manitoba.

Regardless of the label placed on this statement, Mr. Rainkie interprets the policy direction as affordable energy being a critical component for the Manitoba Government to maintain public support and political legitimacy for energy and climate policy focused on the shift to more clean energy.