MIPUG/CC I-1

Part and Chapter:	Evolved Energy Research Report (CC-20); MIPUG/MH II-11	**Page #:**	63
Topic:	Wind Export Revenue Credit		
Subtopic:	Treatment of Wind Exports in Modelling		

Preamble (if any):

Evolved Energy states that wind is not credited for export value in Manitoba Hydro's modelling, noting:

> *"A resource that can sell into MISO, back a capacity swap, or run at price spikes earns value beyond serving Manitoba load… The alternatives that could serve those same markets (storage and surplus wind) receive neither narrative description nor quantified surplus-sale benefit."*

In MIPUG/MH II-11, Manitoba Hydro reports that between 50% and 73% of wind output results in "Increased Exports" in 2035, depending on the load projection.

Question:

a) Please reconcile the statement that wind is not credited for export-related value with the information provided in MIPUG/MH II-11, which indicates that Manitoba Hydro's modelling does give wind an export revenue credit, and that more than half of the wind output is ultimately only of value because it is sold on the export market.

Rationale for Question:

To clarify whether wind generation is assigned export-related value in the IRP modelling.

Response:

The two statements concern different products. Wind's export energy is credited in Manitoba Hydro's modelling — the production-cost model prices export energy at forecast market prices for all resources, wind included (PUB/MH II-24(a)), and MIPUG/MH II-11 is that accounting. EER does not dispute those figures.

The report's finding (Report §4.3.2, "Export value as a portfolio benefit," p. 63) concerns a different stream — the surplus-capacity-sale benefit, not the export-energy dispatch. Because the model "does not include a representation of a short-term capacity market," surplus-capacity value can enter only as "a predetermined surplus capacity sale benefit entered as an investment cost input," and "Conawapa was therefore the only resource to be modeled with a surplus capacity sale benefit" (PUB/MH II-24(b)); no alternative resource, wind included, received that benefit or the narrative market-support role the Major New Facility filing gives the proposed combustion turbines. As the report states,

the finding is "the asymmetry, not the dollar size of any combustion-turbine export revenue" (Report §4.3.2, p. 63).

MIPUG/CC I-2

Part and Chapter:	Evolved Energy Research Report (CC-20)	**Page #:**	63
Topic:	Drought Hedging Value of Wind		
Subtopic:	Stochastic vs. Deterministic Modelling		

Preamble (if any):

Evolved Energy indicates that wind is not given drought-hedging value and is instead treated deterministically while hydro is modelled stochastically. It states:

> *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.*

Evolved Energy further notes that Manitoba Hydro found no statistically significant correlation between wind output and hydro inflows.

Question:

a) Please explain whether treating wind as uncorrelated with hydro inflows inherently provides wind a drought-hedging benefit, given that wind output is not assumed to decline during low-flow conditions.

b) Please explain why an uncorrelated treatment of wind would undervalue or prejudice wind in the modelling, absent evidence that wind output is counter-correlated with hydro inflows.

Rationale for Question:

To understand how deterministic modelling of wind may disadvantage it with respect to drought-hedging value.

Response:

Both questions describe the model as treating wind as "uncorrelated" with hydro inflows. That is not what the model does, and the difference matters. To capture drought risk, Manitoba Hydro runs its hydro system through 112 possible water-supply years, one for each year on record. Wind is not run that way: it enters every one of those 112 years as the same fixed monthly shape of on-peak and off-peak energy (CC/MH II-12(d)). Because wind never varies in the model, it has no correlation with inflows there, in either direction. "Uncorrelated" is instead Manitoba Hydro's separate, physical finding about the two resources: lower Nelson River flows and Manitoba wind speeds show no statistically significant correlation during the winter peak (CC/MH II-12(b)). Both answers depend on keeping those two things apart.

On the first question: yes, in effect. Because wind is entered with the same output in every water-supply year, its full average energy shows up in the dry years just as in the wet ones, and production-cost runs value that wind generation in all water conditions. Manitoba Hydro's own dependable-energy numbers work the same way: under the worst drought on record they still credit wind with 100% of its average energy, while hydro is cut back to its drought output (A6 §2.1, p. 5; §5, p. 64). So wind's drought-year energy is credited.

But it is credited by assumption, not by testing, and that is the weakness. Manitoba Hydro models the drought risk of its own hydro system, its single biggest supply risk, in full across 112 years of record. Wind, whose whole point is that it does not share that risk, is handled the opposite way: it enters as one fixed average, with its dependable-energy factor and capacity credit set from outside the model (CC/MH I-15(c); GSS-GSM/MH II-1(a)).

The one place wind's variability does enter is on the cost side. Each wind option is charged an integration cost that reflects, in Manitoba Hydro's words, "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)). So the model does capture one way wind can raise costs in a drought, through the water held back to balance it. What it has no way to capture is the other side: the value of wind's independence from drought, which narrows the gap between dry-year and wet-year outcomes. The model charges the cost of wind's variability but cannot credit the hedge, so the drought-hedging value the question asks about is left out by construction, not weighed and set aside.

On the second question: no. Treating wind as uncorrelated does not undervalue or penalize it, and the report does not say it does. Wind does not need to move opposite to hydro to help: as long as it does not fall when water is short, it spreads out a hydro-heavy system's drought risk, and a resource that moved opposite to hydro would only spread it out further. The point is not that the integration cost charged to wind is wrong; it is that the framework counts that cost while leaving the offsetting hedge uncredited (Report Section 4.3).

MIPUG/CC I-3

Part and Chapter:	Evolved Energy Research Report (CC-20); MNF Review (Volume 2)	**Page #:**	71
Topic:	Combustion Turbine Cost Assumptions		
Subtopic:	Impact of MNF Cost Updates on Resource Advantages		

Preamble (if any):

Evolved Energy states that Manitoba Hydro advantaged combustion turbines through "*screening and accreditation*" rather than cost.

In the Major New Facilities filing, Manitoba Hydro updated combustion turbine capital costs, increasing the P50 estimate from $1.19 billion (2025 IRP) to $1.63 billion, with a P80 estimate of $1.98 billion.

Question:

a) Please confirm whether Evolved Energy Research has reviewed the updated combustion turbine cost estimates in the MNF filing.

b) If confirmed, please indicate whether Evolved Energy Research considers that the 2025 IRP analysis *also* advantaged combustion turbines over alternatives through cost (i.e., by relying on the outdated, lower capital cost assumptions in the IRP capacity expansion modelling), in addition to the advantages provided through screening and accreditation.

Rationale for Question:

To assess whether updated cost information affects Evolved Energy's conclusions regarding the treatment of combustion turbines.

Response:

(a) Confirmed. EER has reviewed the updated estimates, including the Updated Economic Evaluation (MNF Review, Volume 2, Attachment 2.7). Spread over the 750 MW of combustion turbines the estimate covers, the updated $1.63 billion P50 implies roughly $2,170/kW.

(b) Yes. An understated capital cost for one resource favours its selection in a capacity-expansion optimization, and the updated estimates indicate the turbine cost the 2025 IRP modelling relied on was materially below Manitoba Hydro's current estimate for the same units. The update supports the report's findings rather than revising them: the report found Manitoba Hydro's fossil-resource cost basis "cannot be audited from the public record," and recorded that the one disclosed test of an updated turbine cost shifted the model toward battery storage and away from gas — a result Manitoba Hydro did not carry into the Recommended Plan (Report Section 5.3, pp. 72–73). EER cannot quantify the effect

of the updated costs on resource selection: the sensitivity's detailed results are confidential, and the Updated Economic Evaluation re-prices the five shortlisted plans as defined rather than re-running the near-term resource selection that chose the turbines (Attachment 2.7 §§1–2).

MIPUG/CC I-4

Part and Chapter:	Evolved Energy Research Report (CC-20)	**Page #:**	
Topic:	Battery Storage Investment Drivers		
Subtopic:	Modelling Assumptions and Value Exclusions		

Preamble (if any):

The Evolved Energy report identifies several modelling choices and assumptions in Manitoba Hydro's 2025 IRP that affect the selection and valuation of battery storage.

Question:

a) Please provide a comprehensive list of factors identified by Evolved Energy Research that may cause battery storage investment to be overestimated or underestimated in the IRP modelling.

   In your response, please address the directional impact (upward or downward) of the following factors, if relevant or expected to be material:

   i. Battery capital cost assumptions (too high or too low?).

   ii. Combustion Turbine capital cost assumptions.

   iii. The assumption that battery storage is owned by Manitoba Hydro versus the private sector.

   iv. The application of a 15% Investment Tax Credit versus a 30% Investment Tax Credit.

   v. Battery Effective Load Carrying Capability (ELCC) capacity assumptions.

   vi. The exclusion of battery ancillary services and arbitrage value.

   vii. The use of a 21-block temporal analysis rather than hourly chronological modelling.

   viii. The use of rolling horizons for optimization rather than modelling the full scenario to 2050.

Rationale for Question:

To understand how modelling assumptions collectively influence the selection and valuation of grid-scale battery storage either upward or downward in the IRP results.

Response:

Each factor named in the question is addressed in order, followed by one additional factor the report identifies. "Upward" means the factor tends to overestimate battery storage investment in the IRP results; "downward," that it tends to underestimate it.

i) Battery capital cost assumptions — downward; the record evidence indicates the assumed cost is too high. The IRP assumes $3,028/kW for a 100 MW, five-hour battery, roughly 1.9 times the $1,622/kW it assumes for a natural-gas combustion turbine (A6, Figures A6.21 and A6.10). The most current market evidence on the record is the NRStor affidavit (Order 100/26), which prices a 100 MW battery from recent bids at $1,450/kW for a four-hour system and $2,300/kW for an eight-hour system. The IRP therefore prices a five-hour battery above what the market now charges for an eight-hour one, and the comparison is conservative: the affidavit's prices include construction financing, which Manitoba Hydro's overnight figures exclude. Market pricing also changes the battery's standing against the turbine: at $1,450/kW, a four-hour battery costs less per kilowatt than the IRP's own turbine assumption, and remains well below the roughly $2,170/kW that the turbines' updated $1.63 billion P50 estimate implies (see EER's response to MIPUG/CC I-3). Manitoba Hydro defends its battery figure by comparison to the Oneida project (MEED/MH II-12(c)), whose pricing predates the roughly 50% cost decline the affidavit documents. EER has not independently verified NRStor's figures.

ii) Combustion turbine capital cost assumptions — downward. The battery competes with the combustion turbine for the same capacity need, so a turbine priced below market tilts the comparison against the battery. Daymark, the Board's independent consultant, found Manitoba Hydro's "reference CT costs appeared to be significantly below market prices," and when Manitoba Hydro re-ran the model with updated turbine costs it "selected less natural gas capacity and more battery storage capacity." Manitoba Hydro did not carry that result into the recommended plan, and it designated the updated cost and the detailed results confidential (Report Section 5.3, pp. 72–73). It has since raised the turbine cost estimate from the $1.19 billion used in the IRP to a $1.63 billion P50, an increase of roughly 37% (MNF Review, Volume 2, Attachment 2.7; see EER's response to MIPUG/CC I-3).

iii) Factors iii) and iv) handled together below.

iv) The ownership assumption and the Investment Tax Credit (ITC) rate — downward. Ownership enters the report's analysis through its tax consequence: by Manitoba Hydro's own definition, the federal ITC rate "depends on the ownership structure, with private entities eligible for 30% and government entities eligible for 15%" (PUB/MH I-29(a)). The IRP costs the battery as utility-owned, at the 15% rate, while modelling wind as a third-party purchase at the 30% rate (A7-1 §§7.2, 7.13). The difference is worth up to roughly 15% of the battery's qualifying capital cost (Report Section 5.5, p. 75).

The report makes no finding on the other cost consequences of private versus Crown ownership; EER's response to MIPUG/CC I-5 addresses those.

v) The battery ELCC assumption — upward. Manitoba Hydro did not derive an effective load carrying capability (ELCC) for battery storage: it assumed 100%, applied to the full 350 MW the model could build (A7-1 §7.13). It concedes that assumption "is overstating the capacity value of the batteries" (CC/MH II-14(a)). The difficulty with assuming any single number is that an ELCC is not a property of the battery alone: it depends on the system the battery serves, on the storage duration, and on how much storage is already installed, and it declines as more is added. Manitoba Hydro acknowledges that decline for wind, solar, and battery alike (PUB/MH I-28(a)). Those same properties limit the one comparator Manitoba Hydro offers, BC Hydro's 47% credit (CC/MH II-14(a)). The figure shows a derived battery ELCC can sit far below 100%, but it is a single value from a different system at a different scale; it says nothing about where Manitoba's accreditation would start or how quickly it would decline. Only a derivation from the Manitoba system can supply that, and the IRP contains none.

vi) The exclusion of ancillary services and arbitrage value — downward. In the model, the battery cycles once a day, charging in low-demand hours and discharging into the daily peak, and that cycle and the firm capacity credited to it are the whole of the battery's modelled value (CC/MH II-14(c); A6 §2.13, p. 43). Manitoba Hydro's own resource description lists the other services storage can provide — energy arbitrage, transmission and distribution deferral, and ancillary services — and states that these benefits "are not represented at this time" (A6 §2.13, p. 43). Energy arbitrage and transmission and distribution deferral are properties of batteries, not of combustion turbines, so excluding them disadvantages only the battery.

vii) The 21-block temporal representation — effects in both directions. Manitoba Hydro's production-cost model does not operate in hours: within each month, every hour is assigned to one of 21 blocks based on similar demand level, and the model dispatches against the blocks (Report Section 4.2.2, pp. 58–59). That costs the model two things at once. It loses resolution, because a month of hourly load, wind, and market-price data collapses into 21 demand levels that average away the hour-to-hour variation; and it loses chronology, because hours grouped by demand level are no longer in calendar order. A battery is exposed to both losses: it earns value from the variation, and its physical operation depends on the sequence. In the upward direction, the lost chronology relaxes the battery's physical limit: Manitoba Hydro concedes the block representation "may allow charging or discharging at maximum power for longer than the intended 5-hour energy capacity" (CC/MH II-14(b)), overstating what a five-hour battery could contribute to a sustained cold snap (Report Section 4.2.2). In the downward direction, a representation with neither hourly variation nor sequence cannot model what a battery actually does — when it charges, when it discharges, and against what swings — so its operation is assumed instead: the fixed daily cycle at factor 6, from which the value-stream

exclusions above and the 350 MW cap below both follow (Report Sections 4.3.2 and 5.5). Manitoba Hydro's own resource description notes that "in some instances, battery storage may be paired with variable resources, such as wind and solar, in order to assist in integrating the resources into the electrical system" (A6 §2.13, p. 43). The pairing runs into the same limit: assisting integration means responding to the paired resource's fluctuations in the order they arrive, and the block structure discards that order.

viii) Rolling horizons — no directional finding for batteries. The report's rolling-horizon finding concerns the near-term combustion-turbine selection, not batteries (Report Section 4.2.4). In the one disclosed comparison, battery selection by 2035 moves only from zero to 13 and 23 MW, in a run that stopped short of Manitoba Hydro's own convergence target (PUB/MH II-44(a), Table 1). EER draws no directional conclusion for storage from it.

The additional factor identified in the report:

ix) The 350 MW deployment cap — downward where it binds. The cap is not derived from a study of the Manitoba system; it is the arithmetic of the assumed daily cycle, half of the roughly 700 MW winter day-night swing (A6 §2.13, p. 43). In most of the filed runs it never binds: batteries are selected at zero to 20 MW by 2032 "in the vast majority of scenarios and sensitivities" (A7-2 §4.2), so it is the factors above, not the cap, that limit battery selection there. The cap binds where new gas is restricted — the least-regret run built without new natural-gas turbines selects the full 350 MW (LR7; A7-2, Table A7.2.21) — and no run could test whether more than 350 MW would be economic (Report Section 5.5, p. 74). The remedy is not simply to lift the cap. The cap and the flat 100% credit are two halves of the same simplification: the full credit is plausible only for the quantity a single daily cycle can serve, so the cap must be corrected together with the accreditation at factor 5.

Manitoba Hydro never tested what battery storage is worth to the Manitoba system (Report Section 5.5, p. 74). The battery selection in the filed results therefore reflects the modelling choices described above as much as the value of the resource itself. EER does not conclude from these factors that a corrected treatment would select more battery storage, or less.

MIPUG/CC I-5

Part and Chapter:	Evolved Energy Research Report (CC-20)	**Page #:**	75
Topic:	Battery Storage Ownership and Cost Assumptions		
Subtopic:	Private Sector vs. Manitoba Hydro Ownership Costs		

Preamble (if any):

Evolved Energy states that storage is penalized by being modelled as utility-owned rather than privately owned:

> *… storage's cost basis is set at the 15% utility tax-credit rate, where a third-party owner would qualify for 30%... it models wind as a third-party power-purchase agreement at the 30% private rate*

Question:

a) Please confirm whether a private-sector owner of battery storage would be subject to corporate income taxes and potentially other tax costs from which Manitoba Hydro, as a Crown corporation, is exempt.

b) Please confirm whether a private-sector option would necessitate a required rate of return on the owner's investment or equity, which would need to be recovered through the costs passed on to Manitoba Hydro.

c) Please indicate whether, in Evolved Energy Research's view, the benefit of the incremental 15% ITC for private-sector ownership definitively outweighs the additional costs associated with private sector ownership compared to a Manitoba Hydro-owned asset.

Rationale for Question:

To assess whether private ownership provides a net cost advantage once all financial factors are considered.

Response:

(a) Yes. A private owner of battery storage would pay corporate income tax, and potentially other taxes, that Manitoba Hydro as a Crown corporation does not.

(b) Yes. It would also need a return on the capital it invests, recovered through the price it charges Manitoba Hydro for the resource's capacity or output.

Neither cost is specific to storage. The same tax and return attach to any third-party-owned resource and come back through the contract price the same way — including the wind Manitoba Hydro itself modelled as a third-party power purchase agreement at the

30% private Investment Tax Credit (ITC) rate (Appendix A7-1 §7.2; Report Section 5.5, pp. 74–75). Nothing in the record puts a number on either one for a battery in Manitoba.

(c) No. EER does not say the extra 15 percentage points of ITC under private ownership definitively outweigh those added costs, and the report makes no such claim. The report says the differential "is worth up to roughly 15% of the battery's qualifying capital" (Report Section 5.5, pp. 74–75). That figure is the tax credit alone, not the net cost of one ownership structure against the other. Whether a Manitoba battery comes out cheaper utility-owned or privately owned, once the taxes, the required return, and the ITC are all counted, is a question the record does not answer: the per-resource ITC values are themselves confidential (PUB/MH I-29 Attachment 1). EER offers no such determination.

The report's finding does not depend on any of this. Its point is not that private ownership is cheaper, but that Manitoba Hydro applied the utility 15% rate to the battery and the private 30% rate to wind in the same comparison, without weighing what that does to how they compete (PUB/MH I-45; Appendix A7-1 §§7.2, 7.13; Report Section 5.5, pp. 74–75). See also EER's response to MIPUG/CC I-4.

MIPUG/CC I-6

Part and Chapter:	Evolved Energy Research Report (CC-20); PUB/MH II-33b Attachment 1	**Page #:**	8
Topic:	Justification for 750 MW Combustion Turbines		
Subtopic:	Supply/Demand Monte Carlo Risk Analysis		

Preamble (if any):

Evolved Energy states that Manitoba Hydro has not established the need date or the scale for the proposed 750 MW combustion turbines.

Manitoba Hydro subsequently filed a "Supply/Demand Monte Carlo Risk Analysis," stating that it provides a more rigorous assessment of winter capacity risk and concluding that the 750 MW build-out is "*essential to materially reduce risk*".

Question:

a) Please summarize Evolved Energy Research's understanding of the methodology and inputs used in the Supply/Demand Monte Carlo Risk Analysis (PUB/MH II-33b Attachment 1).

b) Based on Evolved Energy's review, please assess whether the Monte Carlo analysis is a reasonable and robust approach to determining the need (from an Integrated Resource Planning perspective) for the 750 MW of combustion turbines. Please explain why or why not and specify whether this supplemental analysis resolves Evolved Energy's conclusion that the scale and need date of the turbines have not been established.

Rationale for Question:

To evaluate whether the supplemental probabilistic analysis resolves concerns regarding the justification for the proposed combustion turbines.

Response:

(a) EER's understanding is based on the narrative and summary exhibits in PUB/MH II-33b Attachment 1 (May 22, 2026). The analysis is a probabilistic version of Manitoba Hydro's conventional winter-peak supply/demand tables: a "dynamic winter peak supply/demand model (based on Manitoba Hydro's traditional supply and demand tables)" run in Excel with the @RISK Monte Carlo add-in (Attachment 1, Sections 2-3). Its baseline inputs are those of the deterministic Winter Peak Capacity Supply and Demand tables for the Recommended Development Plan, including the 750 MW of combustion turbines in service by 2030 (Section 3). Each simulation draws a defined set of risk variables: HVDC failures and outage timing; incremental generation forced-outage rates; a two-year delay of the first wind phases; the load projection; reductions in accredited capacity; energy-efficiency underperformance; and regulatory restrictions on

hydro capacity (Figure 1). It computes the winter-peak surplus or deficit, thousands of times. The P50 result is appended to the conventional tables as a "risk adjustment": with the turbines in service the median position runs from +2 MW to +110 MW across 2030/31–2035/36, with a 32%–53% probability of falling below the 12% reserve margin depending on the year; without them, the distribution shifts left by 750 MW and that probability exceeds 95% (Section 5).

(b) As a general matter, probabilistic treatment of winter capacity risk is the direction best practice points, and this analysis is an improvement in kind over the deterministic risk treatment in the filing. This is a point Manitoba Hydro's attachment itself makes ("deterministic supply/demand tables alone are not sufficient to understand emerging capacity risk," Sections 1.2, 6.1) and one EER's report shares (Section 6.4, p. 88; Recommendation 10, Section 7.7).

It is not, however, a robust basis for determining the need, neither the date nor the scale, for the 750 MW project. That follows directly from how Manitoba Hydro designed it. The combustion-turbine in-service date "was outside the scope of the simulation" (Attachment 1, Section 1.2), so the analysis cannot speak to the need date. And the only alternative it tests is the same portfolio with all 750 MW removed: as the attachment explains, the without-turbines case is simply the with-turbines distribution shifted left by 750 MW (Section 5). No intermediate scale, alternative resource, or alternative timing was simulated. The comparison of with and without combustion turbines simply measures the contribution of 750 MW of accredited capacity. The conclusion that the turbines are "essential to materially reduce risk" within this design is simply arithmetic.

The analysis also states no reliability target, and it is unclear how its results are meant to be read against the reserve margin. A reserve margin derived from a probabilistic resource adequacy study is set to hold the risk of shortfall to a stated target, so it already accounts for the outage, availability, and load risks this analysis varies. Manitoba Hydro's 12% margin was not derived that way: Manitoba Hydro "has not conducted a probabilistic resource adequacy study for the 2025 IRP system" (CC/MH II-15(b)). As a result, the analysis reports the probability of falling below a reserve margin that was not itself calibrated to any risk standard, and offers no basis for judging whether a 32%–53% probability is acceptable. The analysis holds the plan Manitoba Hydro has already chosen as fixed and varies the risks around it; it does not test whether that plan is the right scale and timing to meet the need.

The supplemental analysis therefore does not resolve EER's conclusion. It shows the range of winter capacity surpluses and shortfalls for the plan Manitoba Hydro has already selected, across the risks it models; it does not establish the need date, which was outside its scope, or the scale, which it did not test. EER's finding is not that no capacity need exists; it is that Manitoba Hydro's analysis, including this supplement, has not established the date or the scale of that need. EER's conclusion at Section 7.5 (pp. 95-104) stands.

MIPUG/CC I-7

Part and Chapter:	Evolved Energy Research Report (CC-20); Efficiency Manitoba Act; Efficiency Manitoba Regulations	**Page #:**	
Topic:	Selectable Energy Efficiency		
Subtopic:			

Preamble (if any):

Efficiency Manitoba Act – Mandate

4(1) The mandate of Efficiency Manitoba is to

(b) achieve additional reductions in the consumption of electrical energy or natural gas — including resulting reductions in the demand for electrical power — if the reductions can be achieved in a cost-effective manner;

Efficiency Manitoba Act – Regulations

39 The Lieutenant Governor in Council may make regulations

(i) prescribing rules for determining if the initiatives included in a proposed efficiency plan are adequate, cost-effective or both;

Efficiency Manitoba Regulations – Determining Cost-Effectiveness

12(1) For the purpose of clause 11(d), the cost-effectiveness of the portfolio of electrical energy demand-side management initiatives included or under consideration to be included in an efficiency plan must be determined by comparing

(a) the levelized cost to Efficiency Manitoba of the electrical energy net savings resulting from those initiatives;

with

(b) the levelized marginal value to Manitoba Hydro of the net savings resulting from those initiatives, as determined by Manitoba Hydro based on a methodology consistent with its resource planning process, taking into account the timing and duration of the savings.

Question:

a) Please confirm whether Evolved Energy Research supports Manitoba Hydro's NPV levelized cost determinations as a primary indicator of cost-effectiveness for ratepayers when evaluating selectable energy efficiency measures.

i) If “Yes”, please explain how this approach supports or compromises the criteria pertaining to cost-effectiveness within the Efficiency Manitoba Act and its Regulations.

ii) If “No”, please indicate the approach that EER would recommend for determining the cost-effectiveness of DSM measures for ratepayers within an IRP.

b) Please detail how the use of annual marginal value (or avoided cost) projections may be used when determining the cost-effectiveness of selectable DSM within an IRP, including considerations for scalability (ability to adjust savings to match variability in load growth) and timing of implementation (ability to respond to marginal value price signals).

Rationale for Question:

Consideration for annual marginal values as an important ingredient for the transparent determination of cost effectiveness.

Response:

EER does not support that approach as a primary indicator. Two clarifications frame the answer. First, the record of the 2025 IRP does not contain an explicit "NPV levelized cost determination" of cost-effectiveness for selectable energy efficiency. Manitoba Hydro "did not explicitly perform a TRC test, RIM test or Participant Cost test to evaluate the cost effectiveness of energy efficiency measures for either the EM forecast or the Additional EE" (MIPUG/MH I-14(b)). Its position is that, by carrying the Additional Energy Efficiency options at program administration cost assuming 100% incentives, it "effectively conducted a dynamic evaluation with a similar effect of the TRC test through its capacity expansion planning modelling" (MIPUG/MH I-14(b)). The levelized comparators that do appear on the record are the 30-year levelized marginal values from Manitoba Hydro's 2020-21 marginal value analysis (PUB/MH I-34(a)), and Manitoba Hydro itself cautions that comparing the levelized cost of the Additional Energy Efficiency options to those values "does not provide a full indication of cost effectiveness" (PUB/MH I-34(c)). EER agrees with that caution. A single levelized measure cost set against a single levelized marginal value, fixed years in advance and invariant to the load outlook, is not a sufficient primary indicator of cost-effectiveness for ratepayers. Second, EER's review is of the 2025 IRP. EER has not reviewed Efficiency Manitoba's cost-effectiveness determinations under the Efficiency Manitoba Act and its Regulations and offers no view on them.

The approach EER recommends within an IRP is the avoided-cost standard set out in Section 5.7 of its report and carried into Recommendation 5 (EER Report, Section 5.7, p. 78; Section 7.7, p. 105). A demand-side measure is cost-effective for ratepayers when its cost is lower than the system costs it lets Manitoba Hydro avoid, since ratepayers ultimately bear those costs. The benchmark is the full stream of avoided-cost value the measure provides, not the cost of a single supply resource in its place, and the comparison can be made by a recognized test or by genuine model selection (see EER's response to PUB/CC-7 for the full standard). In the filed analysis the selection route was

not available to additional energy efficiency, which "is not eligible for selection in all scenarios or sensitivities, other than the Additional Energy Efficiency sensitivity" (PUB/MH I-47(a)).

This bears on the standard the preamble raises. The comparison prescribed by section 12(1) of the Efficiency Manitoba Regulations, quoted in the preamble, sets a levelized cost of net savings against a levelized marginal value determined "taking into account the timing and duration of the savings." That has the structure of an avoided-cost test. Whether it functions as one depends on whether the marginal value in fact reflects the timing and duration of the savings, which a dated, load-invariant levelized average does not.

Annual marginal value, or avoided cost, projections are the transparent form of that benchmark. Properly constructed, they are broken down by component (generation energy, generation capacity, transmission, distribution, and losses), by season and pricing period, and by year, and they are consistent with the load projection being planned for. That makes avoided costs particularly useful for three purposes in an IRP.

The first is valuation matched to the savings profile. A measure's savings are valued in the years and periods in which they occur, over the full life of the measure, which is what gives effect to timing and duration. A single 30-year levelized average cannot tell apart a measure that delivers savings in the years approaching the system's first capacity need from one that delivers the same levelized savings after it.

The second is scalability. Annual marginal values respond to the load-resource balance, rising when load growth tightens the system and falling as demand-side depth or new supply is added. Comparing demand-side supply curves against them shows the cost-effective depth of the portfolio in each year and under each load projection, and lets acquisition scale with load growth rather than being fixed in advance.

The third is timing of implementation. A capacity component that steps up as the system approaches a need signals when ramping program acquisition carries the most deferral value, and when it can relax. Where a measure is instead made genuinely selectable, the model applies these same signals itself, and publishing the annual streams makes the comparison transparent and auditable outside the model.

The net present value of those marginal values, differentiated by capacity and energy, season, and period, is a key component of the avoided cost against which a demand-side measure's levelized cost should be compared, because it values the measure's savings in the periods in which they occur. Manitoba Hydro has not produced it. It confirms marginal values "are an output of the development plans" but "were not used for evaluation of development plans" (MIPUG/MH I-3(a)), and it declined to calculate their net present value "for any duration, season, or period" (I-3(c)). The values already exist as model outputs, so constructing and disclosing them, or collaborating with Efficiency Manitoba on the matter, would provide a transparent basis for determining the cost-effectiveness of selectable demand-side management that this question seeks.

MIPUG/CC I-8

Part and Chapter:	Dr. Patricia Fitzpatrick Evidence (CC-21)	**Page #:**	13
Topic:	Smart Home Devices		
Subtopic:	Existing Smart Device Usage		

Preamble (if any):

Dr. Fitzpatrick states:

> *Respondents reported varying levels of adoption and interest in household energy technologies. Installing smart home devices to track and manage energy use was the most common change already made (26.3%), followed by switching gas heating to electric (23.7%), while adoption of technologies such as solar panels (3.6%) and battery storage (1.8%) was low.*

Question:

a) Please describe how "smart home devices" were defined in the survey. In your response, specify whether these devices were understood to:

   i) Measure and record energy use;

   ii) Provide reporting and feedback to users;

   iii) Communicate with external systems or utilities; and/or

   iv) Actively modify or control household energy use (e.g., adjust loads); and/or

   v) Integrate with commonly used Advanced Metering Infrastructure (AMI) or Distributed Energy Resource Management Systems (DERMS).

b) Please indicate whether Dr. Fitzpatrick's survey methods investigated outcomes (i.e. energy/demand savings) achieved by respondents when using existing smart home devices.

   i) If "Yes", please provide an indication of the typical energy/demand savings reported by respondents.

c) Please explain how respondents differentiated between energy savings (i.e. reductions in overall consumption) and demand savings (i.e. reductions in consumption during peak hours) in their use of existing smart home devices.

Rationale for Question:

Understanding of how the definition for smart home devices may have influenced the survey results.

Response:

(a) Public Survey 1 refers to the General Public Round 1 Survey administered by Manitoba Hydro. The instruments (i.e., the survey, as administered by Manitoba Hydro) are available in Attachment 1.2 – Appendix A pp.6-11. The results of our analysis, quoted above, are in reference to question 5 (p. 7). For your reference, the question posed by Manitoba Hydro was as follows:

> **"**The energy related decisions our customers make now and in the future impact how we plan to meet Manitobans' energy needs. Are you considering making any of the following energy related changes? (Scale: Have already made this change, Considering this change within the next 2 years, Considering this change in the next 3-5 years, Considering this change in the next 6-10 years, Not considering this change, Not applicable)
>
> 1) Switching gas space heating to electric
>
> 2) Switching space heating to a ground or air-source heat pump
>
> 3) Purchasing an EV for your personal use
>
> 4) Upgrading capacity to add EV charging capability to your home
>
> 5) Adding solar panels to your home
>
> 6) Installing smart home devices to better track and manage your energy use
>
> 7) Adding battery storage capacity at your home.**"**

(b) For greater clarity – this survey was not administered by Dr. Fitzpatrick, but rather Manitoba Hydro. Dr. Fitzpatrick is not aware of a survey by Manitoba Hydro which "investigated outcomes (i.e. energy/demand savings) achieved by respondents when using existing smart home devices."

(c) The questions for Manitoba Hydro's Public General Public Round 1 Survey does not appear to distinguish "how respondents differentiated between energy savings (i.e. reductions in overall consumption) and demand savings (i.e. reductions in consumption during peak hours) in their use of existing smart home devices

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Part and Chapter:	Evolved Energy Report (CC-20)	**Page #:**	100
Topic:	Dual-Fuel Heating		
Subtopic:			

Preamble (if any):

Evolved Energy states:

> *The second lever, larger but also unmodelled, is converting part of the roughly 1,200 MW of existing electric resistance heating across the province to heat pumps with fuel backup. Wider adoption of dual-fuel heat pumps would have an emission impact, burning gas in the coldest hours, which is an important planning consideration. But Manitoba Hydro did not meaningfully assess the trade-off between the peak relief from dual-fuel heat pumps and the residual emissions, nor did it consider the trade-offs of assuming biofuels go to power generation rather than other hard-to-decarbonize sectors.*

Question:

a) Please explain whether EER considered the influence of constrained access to natural gas supplies (as the most cost-effective dual fuel option) in rural areas of Manitoba dominated by electric resistance heat when evaluating the costs and potential impacts for wider adoption of dual-fuel heat pumps.

b) Does EER consider dual-fuel heating to be a cost-effective option in areas with constrained access to natural gas? If so, explain with supporting evidence.

Rationale for Question:

Clarification pertaining to recommendations related to the treatment of dual-fuel heating systems.

Response:

EER did not evaluate the cost or the impact of converting more homes and businesses to dual-fuel heat pumps, nor did EER study where natural gas is or is not available across the province. Section 7.5.3.2 is not EER's own assessment of that conversion; it points to an assessment Manitoba Hydro did not carry out. Manitoba Hydro "has not performed any quantitative analysis" of increasing the dual-fuel share in any of its forecasts (CC/MH II-23(c)), and it "did not meaningfully assess the trade-off between the peak relief from dual-fuel heat pumps and the residual emissions" (Report Section 7.5.3.2, p. 100).

In keeping with that, the report puts no peak-reduction number on converting the existing electric resistance heating. Figure 7.3 counts only the dual-fuel share of the new heating

fleet, and the illustrative figures in Section 7.5.3 "should not be taken as forecasts or projections" (Report Section 7.5.3, p. 97).

EER agrees that needing a backup fuel limits how much of the roughly 1,200 MW of existing electric resistance heating could realistically convert, which is why the report speaks of "converting part of" that stock, not all of it (Report Section 7.5.3.2, p. 100). The report also describes the backup as "fuel backup" generally, leaving open the possibility of delivered fuels rather than only natural gas, and Manitoba Hydro confirmed it "did not evaluate other decarbonized fuels for winter backup" (CC/MH I-19(b); Report Section 3.3.1, pp. 39–40). Sizing how much could convert, including in areas the gas network does not reach, and weighing that against the peak relief, the cost of the heating systems with fuel, and the added emissions, is the analysis the report found missing.

On the second question, EER takes no position on whether dual-fuel heating is cost-effective where natural gas access is limited. EER has not done that assessment, and the record does not allow one: Manitoba Hydro ran no quantitative analysis of wider dual-fuel adoption (CC/MH II-23(c)) and confirmed it "did not evaluate other decarbonized fuels for winter backup" (CC/MH I-19(b)). So the record holds neither a cost comparison among backup-fuel options nor any cost-effectiveness finding for areas without gas service.

What the record does show is at the province-wide level, not area by area. Efficiency Manitoba's market potential study finds, on cost-effectiveness grounds, that "[h]ybrid space heating systems … dominate all achievable savings scenarios" (EM-02, p. xi), and Manitoba Hydro's own sensitivity analysis finds that "pursuing additional dual-fuel systems … can be a more effective method of reducing electric system costs, associated net system costs, and energy rates than lowering negative GHG emissions load" (Appendix A7-2 §3.7.2, p. 87; both quoted at Report Section 3.5). Whether conversion is cost-effective for customers without gas service, and where, is part of a critical trade-off that should be assessed, and was not in this IRP.

MIPUG/CC I-1

Part and Chapter:	Mr. Rainkie Evidence, Section 6.3	**Page #:**	47
Topic:	Amortization Period for DSM Expenditures		
Subtopic:	Treatment of Renewal and/or Reinvestment Costs		

Preamble (if any):

Mr. Rainkie states in his evidence:

> *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.*
>
> *Some basic research into the DSM amortization periods used by other Canadian utilities indicates that Fortis Energy Inc. (FEI) (a large natural gas utility in British Columbia) is currently requesting BCUC approval to increase the DSM amortization period to 20-years and that BC Hydro and Hydro Quebec both use DSM amortization periods of 15 years. [PDF p. 47]*

Question:

a) Please describe the approach that Mr. Rainkie would recommend for the amortization of renewal (or re-investment) costs applicable to DSM measures that may require renewal on an annual basis (i.e. load displacement) or short-term basis (i.e. 1 to 3 years - customer behavior / strategic energy management).

b) Indicate whether the approach noted in response to a) would be similar the recommendation for amortization of reinvestment costs incurred when longer-term DSM measures reach end-of-life.

c) Did Mr. Rainkie undertake a comparison to establish how amortization for DSM expenditures applicable to shorter-life resources are addressed in other jurisdictions across Canada?

   i) If “Yes”, please provide the results of this jurisdictional comparison.

Rationale for Question:

Clarification for the recommended amortization of DSM expenditures incurred for resources with a shorter life.

Response:

Response to a, b and c:

Please refer to the responses to PUB/CC - 14 a, b and c. In those responses, Mr. Rainkie outlines that FEI and BC Hydro developed calculations of the expenditure-weighted average DSM measure life and energy-weighted average DSM measure persistence, respectively, to propose updated DSM amortization periods to the BCUC.

An approach based on an average expenditure-weighted average DSM measure life basis or an energy-weighted average DSM measure persistence basis could be used to weight MH DSM measures with both shorter and longer lives.

Alternatively, a “componentization-like approach” could be developed for MH where there was more than one DSM amortization period that varied according to the duration of the DSM measure life or the DSM measure persistence.

While the merits of each of the approaches noted above would have to be analyzed in detail at the next MH GRA to consider which approach best meets revenue-related attributes (i.e., revenue sufficiency, rate stability etc.) and cost-related attributes (cost-causation, fairness, equity etc.) of rate-making, Mr. Rainkie notes that the FEI approach appears to have merits in terms of the practical-related attributes (practicality, administrative simplicity etc.) of rate-making.