MANITOBA HYDRO
INTEGRATED RESOURCE PLAN AND MAJOR NEW FACILITIES REVIEWS

POWER TEAM CONSULTING (PTC) RESPONSES TO PUB ROUND 1 INFORMATION REQUESTS

July 09, 2026

The abbreviations/acronyms appearing in these responses are identified in the PTC report dated June 10, 2026.

Site and Equipment Suitability

PUB/PTC I-1

Part and Chapter:	Power Team Report	**Page #:**	13, 15-17, 28, 74
Topic:	MNF Process – Equipment Suitability		
Subtopic	Combustion Turbine Generator Performance Guarantee		

Preamble (if any):

On pages 15 to 16 and 74 of its report, Power Team recommends [redacted] 7a

On page 17 of its report, Power Team also describes GE's simple cycle startup time guarantee, namely:

> […] 11 minutes from ready to start to GT full speed full load, which is subject to prerequisite conditions and excludes synchronization time.

Per page 28 of Power Team's report, Manitoba Hydro currently assumes that at least two of its new combustion turbine generators will be operated in synchronous condenser mode (i.e., generators decoupled from their gas turbine) for 4,400 hours per year, which is approximately 50% of the 8,760 available hours in a year (not accounting for actual unit availability factors).

Question:

a) Please explain whether the recommended [redacted] are an accepted industry standard for units such as GE's 7F combustion turbine generators. If not an accepted industry standard, please explain how Power Team determined [redacted] 7a

b) Please confirm whether [redacted] will be assessed during final unit commissioning activities. 7a

c) Please explain how the 11-minute startup guarantee would be affected (or not) by the processes required to "clutch-in" the generator to the mating combustion turbine when that unit was initially running in synchronous condenser mode prior to the combustion turbine start-up command being initiated.

Rationale for Question:

To better understand the rationale and technical requirements supporting Power Team's performance guarantee comments and recommendations.

Response:

a.) It is an industry norm, and consistent with PTC's experience in dealing with different gas turbine manufacturers, that there is a guaranteed heat rate and output range specified in the contract. If the manufacturer fails to meet the minimum performance limits, this is abnormal and indicative of other problems. In such cases, the manufacturer is obligated to improve performance to within the minimum guaranteed levels, rather than pay LDs. Between the guarantee of [redacted] net power output and 100% net power output and between [redacted] guaranteed heat rate and 100%, it is the norm to negotiate liquidated damages rates in the form of $/kW in output and $/kJ/kWh for heat rate. 7a

PTC recommends that the guarantees be applied for each turbine separately and for each of the fuels, natural gas and diesel. [redacted] 1b

It is also our experience that the guaranteed output and heat rate values are offered by the manufacturers with a margin of conservatism applied. Therefore, it is our experience that the guaranteed values are likely to be achieved without applying liquidated damages.

b.) Yes, the industry standard performance test code for gas turbine generators is ASME PTC-22. GE uses this test code as the basis for performance testing, as do other manufacturers.

c.) The startup guarantee is specified from being ready to start to achieving GT full speed, full load. This is the time from the initial start command to the achievement of base load and has prerequisite conditions that the GTG must be ready to start, on turning gear and with site utilities available. Synchronization time is excluded from the guarantee figure.

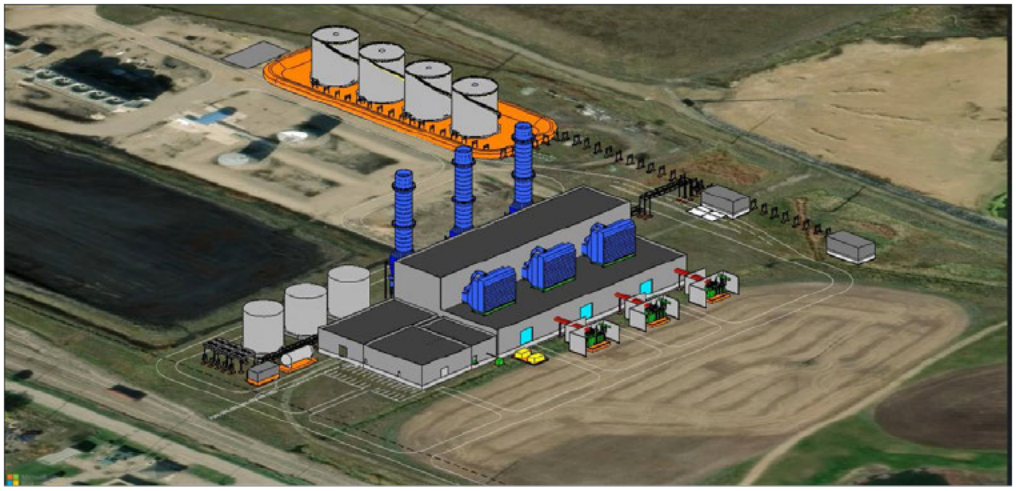
In the information made available to PTC, the startup time guarantee does not describe the time to start and ramp to base load when the initial condition is synchronous condenser operation. This will need to be explored with GE, if it has not already been done.

PUB/PTC I-2

Part and Chapter:	Power Team Report PUB/MH III-20	**Page #:**	18,20,22-23,32
Topic:	MNF Process		
Subtopic	Siting of Generation Facilities		

Preamble (if any):

On page 18 of its report, Power Team describes a Manitoba Hydro project to address the remains of a former coal pile on the existing Brandon Generating Station property in order to allow for an adequate staging/laydown project area without compromising future site rehabilitation. This former coal pile is illustrated on the right side of the figure shown below (from page 20 of Power Team's report). At page 22 of its report, Power Team further specifies that Manitoba Hydro site personnel identified potential problems with fugitive emissions from the former coal pile.



In PUB/MH III-20, Manitoba Hydro states:

> Manitoba Hydro is not planning to rehabilitate the remaining coal pile as part of the Dispatchable Capacity Project. […] If the coal pile is used for staging / laydown, then Manitoba Hydro would do sampling and design a cap to allow safe use of the area, without compromising future rehabilitation.

Gas turbine industrial experience suggests that loose dirt and dust, as well as various airborne contamination near combustion turbine units can contribute to performance degradation over time and increase turbine maintenance efforts[1].

[1] See the following industry papers as examples: https://img1.wsimg.com/blobby/go/dc8e1533-2f6f-4663-b92a-e18753e7617d/downloads/21c77d4e-d2ac-4e5b-9857-ae0dabd6950d/301_final_paper.pdf?ver=1779718594172 or https://img1.wsimg.com/blobby/go/dc8e1533-2f6f-4663-b92a-e18753e7617d/downloads/dfa34008-0a29-44ff-9c49-298ac5f48558/11-IAGT-304_paper.pdf?ver=1779718594316

At page 20 of its report, Power Team identifies that Manitoba Hydro currently plans to raise flow protection dikes for the Brandon Generating Station to above the 333-year flow level.

At pages 23 and 32 of its report, Power Team mentions new diesel storage tanks are planned for the north side of the site and that a dual fuel combustion turbine solution was chosen "considering the uncertainty of reliable natural gas supply".

At page 23 of its report, Power Team also states the following regarding the current river water pumphouse equipment:

> The equipment in the pumphouse is near end of life and would need to be replaced.
>
> The current desired course of action is to secure water supply from the city of Brandon Wastewater Treatment facility. This is being pursued, but nothing has been concluded. If river water is to be used, the equipment will either be replaced within the current pumphouse or a new one constructed.

At page 32, Power Team identifies that Hatch's preliminary site design allowed for sufficient space around the new CT plant to allow a potential conversion of the new simple cycle combustion turbine generator units to a combined cycle configuration in the future.

Question:

a) Please explain Power Team's understanding of Manitoba Hydro's coal pile remediation plans within the current project schedule and comment on the potential risk of coal dust contamination affecting the new combustion turbine's operation once in service (e.g., excessive air inlet filtration loading or compressor fouling during operation, including during windy periods).

b) Please explain whether Power Team deems Manitoba Hydro's preliminary flood protection plans to be adequate for the expected life of the existing and new equipment planned for the Brandon Generating Station site.

c) Please explain whether the new diesel tanks are expected to also support the operation of the existing G6 and G7 combustion turbine generators and whether they appear be sufficiently sized for the expected operation of the new CT units being proposed by Manitoba Hydro.

d) Further to c) please further explain Power Team's understanding of the "uncertainty of reliable natural gas supply" referenced at page 32 of its report and explain the potential scenarios where this risk may be realized, which would then support Manitoba Hydro's specification for dual-fuel (i.e., natural gas or diesel) units.

e) Please further explain Power Team's understanding of the current concept for the Generating Station water supply work scope. For example, please confirm whether Manitoba Hydro is currently planning to:

i) Replace the existing water intake and pumphouse structures with new equipment located either at the Assiniboine River or at the nearby wastewater plant;

ii) Replace the existing demineralization plant equipment (currently used for Units 6&7) with the new equipment used to supply all CT units on site (i.e., existing Units 6&7 and new Units 8-10).

f) Further to e.ii), please explain whether the new demineralization equipment will be sited in both the existing G6-G7 facility and the new G8-G10 facilities, or whether a new, centralized demineralization plant will be constructed. Which approach does Power Team recommend (separate facilities or a common demineralization plant)?.

g) Please explain whether the current Manitoba Hydro Stage III concept siting of the new diesel storage tanks may need to be moved in the future if Manitoba Hydro chooses to convert the units to a combined cycle configuration.

Rationale for Question:

To better understand some of the technical details referenced in Power Team's report.

Response:

a.) Coal pile remediation plans and fugitive dust emissions risks: The following reflects PTC's understanding from discussions with MH personnel. The former coal pile did create dust that blew around the site and collected in the inlet air filters of Units 6 and 7. This was understood to be the case when the coal was in a pile rather than the current situation where coal has been removed to grade level. Some coal dust emissions may still arise from the current remains of the pile.

To clarify, the remainder of the coal pile is the black rectangular area on the left side of the illustration above, west of the three smaller tanks and not on the right-hand side.

The current plan that was described is to apply a clay cap over the remaining material in the former coal pile such that the land can be used for laydown and staging of materials and equipment during construction. This is the desired plan but has not yet been confirmed and would be subject to further evaluation, presumably to confirm the practicality and integrity of the new surface. If the clay cap remains in place into commissioning and operations, this would prevent coal dust emissions. It is understood that there are plans, outside of the scope of the generation project, to remove the remaining coal and contaminated soil and to remediate the coal pile land. Therefore, PTC does not anticipate ongoing operations with the coal pile exposed.

The comments raised are correct that high levels of dust emissions can lead to compressor fouling and degrade turbine performance, which would increase cleaning scope during major overhauls and potentially the frequency of on-line

water washes. This could also foul the inlet filters at a higher rate, necessitating more frequent replacement.

b.) Flood risk: As long as the dikes sufficiently circle the property, PTC's civil engineer considers increasing the dike height to meet the one-in-333-year flood level to be a reasonable plan that can be expected to protect the new Brandon Generating Station equipment. This is subject to acceptable design and construction of the dike.

c.) Diesel Storage Tank Volume: The Stage III Concept Summary Report defines "Existing infrastructure that will remain" to include the diesel storage tanks that serve Units 6 & 7. PTC had a follow up clarification with MH that established there will be an interconnection between the new diesel storage tanks and the existing diesel storage tanks for Units 6 & 7. The new diesel storage tanks that are to be sized for the gas turbines to be able to operate for 12 hours per day for 14 days. Considering the low capacity factor forecast from the new Brandon generating units and the fact that diesel is the back-up fuel, this storage capacity is considered sufficient. Furthermore, should the unlikely circumstance arise that natural gas is unavailable for an extended period and significant ongoing operation is required, having 14 days' capacity provides sufficient time to secure diesel to replenish the tanks.

d.) Uncertainty of Natural Gas Supply: PTC does not have details regarding the anticipated supply of natural gas and is relying upon discussions with MH personnel. The scope of our assessment was on the physical assets, including the diesel back-up for gas, but did not include the contracting of gas supply and security of that supply.

Our understanding from MH is that secure supply of natural gas is anticipated for the generating station and that the diesel back-up is to address unlikely and infrequent situations where the supply may be interrupted for commodity supply or equipment maintenance reasons. Our experience with gas supply agreements for Canadian power generation projects is that gas is reliably available.

e.) Water Supply: PTC understands that the MH preferred and anticipated plan for water supply is to secure it from the City of Brandon Water Reclamation Facility. There are no current plans to refurbish or replace equipment at the Assiniboine River water pumphouse.

It is also understood that the water treatment plant will be sized to meet the needs of Brandon Units 6 & 7 as well as the new Units 8, 9 and 10.

f.) Demineralization Water Treatment Plant Siting: PTC understands that the new demineralized water treatment plant will be sited at the south end of the new turbine hall and this will serve Units 6 & 7 along with Units 8, 9 and 10. PTC recommends this arrangement as most economical, rather than two smaller water treatment plants.

g.) Provisions for Combined Cycle Conversion: PTC has confirmed there is sufficient space at the west side of the turbine hall to accommodate heat recovery steam generators should combined cycle conversion be desired. The steam turbine would be placed south of the existing turbine hall. With the diesel storage tanks located to the north (see the area with the orange spill containment in the illustration above), this placement will not interfere with potential future combined cycle conversion.

PUB/PTC I-3

Part and Chapter:	Power Team Report PUB/MH III-21a	**Page #:**	7, 27, 32, Appendix C p.2
Topic:	MNF Process		
Subtopic	Brandon Generating Station Concepts		

Preamble (if any):

Throughout its report, Power Team identifies and comments on changes made by Manitoba Hydro to the assumed generation, transmission, and gas pipeline equipment, costs, and schedule assumptions initially described in Manitoba Hydro's major new facility submission of April 29, 2026 (primarily in Attachments 2.5a to 2.5c of that filing).

In PUB/MH III-21a, dated June 12, 2026, Manitoba Hydro states:

> Manitoba Hydro has advanced the project definition since May 2025. Hatch is progressing with Front End Engineering Design ("FEED"). Manitoba Hydro is targeting to have a class 3 estimate in the fall of 2026.

On pages 27 and 32, as well as in Appendix C (page 2 of 4), Power Team's report references Manitoba Hydro's Stage III Report and Supplemental Documents (e.g., "2026 01 14 Stage III Concept Summary Report – Brandon Combustion Turbine Project" and "2025-04 Stage III Planning – Combustion Turbines – Brandon GS Transmission Interconnection Routing"). These documents have so far not been made available to the Board and the hearing schedule approved in Orders 39/26 and 68/26 does not immediately provide an opportunity to obtain this information from Manitoba Hydro before the oral hearing commences on July 27, 2026.

Question:

Please file Manitoba Hydro's Stage III Concept Summary Report materials, drawings, and other documents listed below, which were provided by Manitoba Hydro in support of Power Team's review in this proceeding (and listed in Appendix C of Power Team's report). Alternatively, Power Team can request that Manitoba Hydro file these documents concurrently with Power Team's information request responses.

i. 2026 01 14 Stage III Concept Summary Report – Brandon Combustion Turbine Project;

ii. 2025-04 Stage III Planning – Combustion Turbines – Brandon GS Transmission Interconnection Routing;

iii. 2025-03-27 Stage III – Brandon Combustion Turbines – Brandon Pipeline Estimate;

iv. 2026-04 Layout isometric view – Preliminary;

v. 2026-04 Transmission layout – 3D view – preliminary;

vi. 2026-04 Unit isometric view – preliminary;

vii. PWC Contracting Strategy – Final Report Submission – Manitoba Hydro Dispatchable Capacity_RPT;

viii. Specification for Combustion Turbine and Generator – 043387 Technical -CTG

Rationale for Question:

To better understand Manitoba Hydro's revised equipment, cost, and schedule assumptions at the time of Power Team's review compared to the descriptions included in Manitoba Hydro's April 29, 2026 major new facility filing. The Board understands the requested materials were provided to Power Team by Manitoba Hydro but the hearing schedule approved in Orders 39/26 and 68/26 does not immediately provide an opportunity to obtain this information from Manitoba Hydro before the oral hearing commences on July 27, 2026.

Response:

PTC agrees that the PUB should have access to the documents requested above, but as the documents are the property of MH, this request will be put to MH to respond. PTC has communicated to MH regarding this IR that it is PTC's position that MH should file the documents and deal with any redaction issues. It is PTC's understanding that Manitoba Hydro will be providing the requested documents to the PUB directly.

Cost Estimates and Basis of Estimates

PUB/PTC I-4

Part and Chapter:	Power Team Report	**Page #:**	32-33
Topic:	MNF Process		
Subtopic	Generation Station Basis of Estimate		

Preamble (if any):

On page 32 of its report, Power Team recommends Manitoba Hydro to obtain an overhaul laydown map from GE to assess the spacing requirements needed during equipment maintenance activities.

On page 33 of its report, Power Team states:

> PTC highlights that NERC EOP-12 only states that a "Cold Weather Preparedness Plan" needs to be developed and does not require the gas turbine-generators to be housed in a building enclosure. PTC finds that new plant designs, even in colder climates, are typically housing the gas turbine-generators in their OEM heated enclosures rather than in a standalone building. Considering that these units are to be used for peaking ("1% capacity factor on average over all flow conditions and up to 20% capacity factor for the worst drought on record"), this provides added opportunities for maintenance. Therefore, locating the GTGs outside is an option. For reference, the GE 7F gas turbines at the Brighton Beach Power station (Atura Power) in Windsor, Ontario has the GTGs outdoors. **PTC recommends that MH consider the cost saving option of having the gas turbine and generators located outdoors in their OEM winterized enclosures**.

Question:

a) Please explain whether a peaking combustion turbine generator unit located outdoors (in a winterized enclosure) would still require an enclosed building structure near the units to complete any required maintenance or overhaul activities.

b) If the proposed units were located outdoors in their OEM winterized enclosures, please explain the type of weather-related protective measures that would need to added in order for the proposed GE 7F combustion turbine generators to remain available throughout the expected outdoor temperature operating range described in Manitoba Hydro's Stage III conceptual documentation. If possible, supplement the response with examples from other cold-weather installations of simple cycle combustion turbine generators used as peaking units in similar extreme weather operating conditions.

c) If the turbines were shipped incomplete with certain parts to follow, please confirm whether it would be feasible to install these missing components if the turbines were not enclosed in a building and instead were in their winterized enclosures, considering the possibility of winter weather.

Rationale for Question:

To better understand the pros and cons of Power Team's recommendation for Manitoba Hydro to consider the option of locating the proposed combustion turbine generators outdoors in their OEM winterized enclosures as opposed to housing them in a building enclosure.

Response:

a.) Implications of Outdoor Weather Protected Turbine / Generator Enclosure: Many turbines without turbine halls are maintained without a heated building. The vast majority of routine turbine maintenance can be performed inside the turbine, generator and auxiliaries' enclosures. In the case of hot gas path inspections and major overhauls, the enclosure roof must be removed, along with other components (fans, ductwork, casings, etc.), or partially removed, to facilitate maintenance. Considering the very low capacity factor, it should not be difficult to plan these major maintenance events during spring through fall to avoid winter conditions. Some scaffolding and hoarding are likely required to protect some portions of the work from rain, no different from the majority of turbine / generators in the US that are installed outdoors.

The time when a turbine hall building would be desired is if there is a significant problem, arising during the winter, that necessitates an unplanned forced outage requiring turbine overhaul activities that may include work equivalent to a hot gas path inspection or major overhaul. GE frame 7F gas turbines are very well proven and amongst the most reliable in the world. Therefore, such events can be considered very unlikely, especially considering the low capacity factor. However, in the unlikely event that such work may be required in the winter, scaffolding, hoarding and heaters can be installed to facilitate the work. Rental of a local temporary structure may be required near the engines for the storing and staging of components (similar to temporary event structures / tents).

Note that there are other considerations that MH must run to ground to help make the decision between an indoor and outdoor installation, including the weather specification, where they have specified -45°C design conditions. If this specification remains, this triggers an upgrade to the structural steel grade which can impact cost and influence the decision on indoor vs outdoor unit placement.

b.) Weather-Related Protective Measures: If the turbine enclosures are installed outdoors, the specification would reflect this and GE will need to provide an enclosure with appropriate insulation, heat tracing and heaters suitable for the service conditions.

The Brighton Beach 7F power station in Windsor, Ontario (as referenced in the PTC report) is an example of an outdoor installation with cold weather exposure, although likely not as cold as the extremes faced in Brandon. Other examples include GE LM6000 peaking plants in Alberta: Valleyview 1&2, Poplar Hill, Rainbow Lake 4&5, and Crossfield (3 units). The Capital Power Genessee

Mitsubishi 501JAC turbines near Edmonton are also located outdoors in their heated enclosures.

c.) If turbine components are shipped later and require significant overhaul activities to install them, it would be undesirable if the project schedule requires this work during the winter. It could still be done based upon the provisions outlined above, but work will be less efficient. Staging of turbine work will help minimize critical path impacts, however if the hardware is not available until near the end of construction and arrives at the same time for all 3 units, there may be critical path impacts and consequential EPC contractor costs. The details as to how this may play out and the opportunities to mitigate impacts will need to be managed once details of any applicable circumstances come to light. This is all speculative, but if this proves necessary during cold winter conditions, there will be some impacts. Assumptions can be made and costs quantified to include with the indoor vs outdoor cost benefit calculations and assessment, including the structural steel implications noted above.

PUB/PTC I-5

Part and Chapter:	Manitoba Hydro MNF Attachment 2.5 Manitoba Hydro MNF Attachment 2.5a Power Team Report	**Page #:**	4, 6 PDF 61 of 68 33, 34, 36, 41-45
Topic:	MNF Process		
Subtopic	Generation Station Basis of Estimate		

Preamble (if any):

On page 4 of Attachment 2.5 of its major new facilities filing, Manitoba Hydro provides the Base Cost estimate shown below for the Generating Station, Transmission, and Pipeline portions of the Dispatchable Capacity Project.

Figure 1: Base Cost (Direct and Indirect), In-Service Cost, and Estimate Confidence Level

Estimate (Billions $) Year 2024/2025 Dollars		P50	P80	P90	Estimate Class
Generating Station	Direct Cost	$1.14	$1.14	$1.14	Class 4
	Indirect (Owner's) Cost	$0.12	$0.12	$0.12	
	Contingency	$0.19	$0.49	$0.68	
	Base Cost	$1.44	$1.75	$1.94	
Transmission	Direct Cost	$0.06	$0.06	$0.06	Class 5
	Indirect (Owner's) Cost	$0.01	$0.01	$0.01	
	Contingency	$0.01	$0.03	$0.04	
	Base Cost	$0.07	$0.09	$0.10	
Pipeline	Direct Cost	$0.09	$0.09	$0.09	Class 5
	Indirect (Owner's) Cost	$0.01	$0.01	$0.01	
	Contingency	$0.01	$0.04	$0.06	
	Base Cost	$0.11	$0.14	$0.15	
	Total Base Cost	$1.63	$1.98	$2.20	
	Scope Development Cost	$0.01	$0.01	$0.01	
Interest & Esclation	Interest & Escalation	$0.26	$0.34	$0.38	
	Schedule Contingency	$0.06	$0.14	$0.20	
In-Service Cost		**$1.96**	**$2.46**	**$2.79**	

** Note that the estimate excludes pre-planning costs.*

*** Note that the values may not add up due to rounding.*

PDF page 61 of the public version of Attachment 2.5a (shown below) provides a summary for the various AACE (Association for the Advancement of Cost Engineering) estimate classes. At page 6 of Attachment 2.5, Manitoba Hydro characterizes the Generating Station cost estimate as class 4, while the estimates for the Transmission and Pipeline portions of the project are deemed class 5.

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges at an 80% confidence interval
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Table 1 – Cost Estimate Classification Matrix for Process Industries

Throughout its report, Power Team identifies some of the changes that have occurred in the Brandon project that are expected to affect the cost estimate, including but not limited to: the cost of the turbines in the reservation agreement, transmission and pipeline routing, transmission equipment, pipeline size, and EPC contracting approach.

Question:

Given the changes made to the generating station, transmission line, and pipeline projects since Manitoba Hydro developed the estimates shown in Figure 1, please provide Power Team's view as to whether the new estimates will be within the accuracy ranges identified in Table 1 for Class 4 and 5 estimates.

Rationale for Question:

To help reconcile Manitoba Hydro's project cost estimates in Attachment 2.5 of the April 29, 2026 MNF filing with the significant scope and cost changes (or potential changes) identified in Power Team's report. This also appears consistent with OIC 88/2026 Schedule A item #5, which requires the Board to assess the impacts of the proposed facility on electric rates over the short and long-term and what contingencies and mitigating actions can be taken to reduce the rate impacts.

Response:

PTC has gained information on the ongoing advancement of the scope and design for the generation, transmission and gas supply projects and some limited cost inputs. Our understanding is that the design, cost and schedule for all three projects are being advanced as part of the Stage IV development FEED study and that this will yield an AACE Class III CAPEX estimate, a Level 3 Project Execution Schedule and the package of technical deliverables that support these outcomes. PTC raised a follow up question to MH on July 2, 2026 to confirm the timing of the FEED deliverables for each of the three projects. Manitoba Hydro provided the following reply:

“The FEED deliverables for the generation component are targeted to be complete by end of July 2026. The transmission component class 3 estimate is targeted to be complete by end of August 2026. The gas component class 3 estimate is targeted to be complete by end of November 2026.”

This will support the November 2026 Order in Council approval and the February 2027 Capital Expenditure Justification and Manitoba Hydro Board Approval.

PUB/PTC I-6

Part and Chapter:	Manitoba Hydro MNF Attachment 2.5 Power Team Report	**Page #:**	4 12-13, 42-45
Topic:	MNF Process		
Subtopic	Generation Station Basis of Estimate		

Preamble (if any):

At page 4 of Attachment 2.5 of its major new facilities filing, Manitoba Hydro provides the following Generating Station Base Cost estimates: P50 - $1.44 billion, P80 - $1.75 billion, and P90 - $1.94 billion.

On pages 12 to 13 of its report, Power Team describes how the ThermoFlow software was used by Hatch to assess the performance of available combustion turbine generator providers and to prepare cost estimates (along with Hatch's in-house database information).

On pages 42 to 45 of its report, Power Team describes how it sought to validate Manitoba Hydro's Generating Station cost estimate by using its own ThermoFlow modelling capabilities.

Per pages 43 to 44 of the report, Power Team reported the following regarding its two cost estimate comparisons for the Generating Station portion of the project:

> **[1-PTC modelling based on a previous SGT6-5000F Simple Cycle Estimate]** Brandon CAPEX with P50 Contingency ($1,440M) closely matches PTC CAPEX ($1,457M). Brandon P50 Contingency is $190M which closely matches PTC Contingency of $198M.
>
> **[2- PTC Thermoflow™7F.05 Plant Estimate]** This estimate suggests that Brandon's CAPEX may be underestimated

Item No.	Description	Dispatchable Capacity Project Brandon Generating	Cost / kW(net)	Thermoflow - PTC Estimate AACE Class IV	Cost / kW(net)
		Amount	GE7F.05 / kW	Amount	GE7F.05 / kW
1	POWER PLANT	[redacted]			
2	MISC DIRECT				
	TOTAL ESTIMATE INDIRECT (OWNERS COSTS)	122,578,000	$177 / kW	107,900,000	$159 / kW
	Subtotal	1,258,795,000	$1,814 / kW	1,542,300,000	$2,273 / kW
	CONTINGENCY (P80)	489,671,000	$706 / kW	396,800,000	$585 / kW
		39%		20%	
	TOTAL	1,748,466,000	$2,520 / kW	1,939,100,000	$2,858 / kW

The Table shows:

> • Project TOTAL Costs are: o Brandon: $1,750M vs Thermoflow™: $1,939M. (~-22%)
>
> • Power Plant Direct and Misc. Direct costs are relatively comparable: o Brandon: $1,136M vs Thermoflow™: $1,4344M. (~26%)

• Power Plant Indirect costs are comparable: o Brandon: $123M vs Thermoflow™: $108M. (~-12%)

• PTC estimate Total Power Plant costs, without Contingency, are substantially higher: o Brandon: $1,259M vs Thermoflow™: $1,542M. (~23%)

• Comparing the Contingencies: o Brandon: 39% ($490M) vs Thermoflow™: 26% ($397M).

This estimate suggests that Brandon's CAPEX maybe underestimated.

Question:

a) Please confirm whether use of the ThermoFlow software is deemed standard practice for power plant planning purposes, that the software is commercially available, and that it is not directly produced by original equipment manufacturers of combustion turbines or generators.

b) Please explain whether Power Team's Generating Station benchmark cost estimates outlined at pages 43 to 44 of its report are deemed to be P50, P80, or other confidence level.

c) Please confirm whether Power Team's modelling suggests that, given the project assumptions initially used by Hatch or Manitoba Hydro, the P80 Generating Station base estimate should be $1.939 billion instead of $1.75 billion as shown in Figure 1 of Manitoba Hydro MNF filing Attachment 2.5 (p.4 of 6).

d) In the comparison between Manitoba Hydro's estimate and PTC's Thermoflow estimate, please explain why the 26% difference in direct costs is considered "relatively comparable", while a 23% difference in total power plant costs is "substantially higher".

e) Please confirm whether the Hatch project costs assume turbine pricing at the mid-point of the reservation agreement. If not confirmed, where does the Hatch estimate lie within the range in the reservation agreement? Is the same turbine pricing used for both Manitoba Hydro's estimate and Power Team's estimate in the above table?

f) Please confirm whether the project costs shown in the table on page 44 are based on the turbine price from the reservation agreement and the updated EPC contracting approach. If not confirmed, please explain how the costs in the table for both Manitoba Hydro's estimate and Power Team's estimate will change.

Rationale for Question:

To better understand Power Team's cost estimate modelling results and to obtain a revised Generating Station base cost estimate that's based the revised planning assumptions identified in Power Team's report compared to those described in Manitoba Hydro's MNF filing. This is also consistent with the requirements of OIC 88/2026 Schedule A item #5.

Response:

a.) ThermoFlow Software: The ThermoFlow software package is provided by ThermoFlow Inc. from Jacksonville, Florida. This software was first introduced in 1988 and was developed by Massachusetts Institute of Technology professors. On their website, they state, "All our engineers who do any programming on our models hold Ph.D. degrees in Mechanical Engineering, many from MIT." The software is currently in Version 31 and annual licences are available for purchase by anyone.

ThermoFlow software has about three thousand users in 80 countries and ThermoFlow claims to have the largest share of the world market. All turbine manufacturers, along with EPC contractors, are familiar with this software. It is a respected tool that is well known and used amongst those developing power generation projects.

ThermoFlow is independent of the turbine manufacturers. Manufacturers have their own internal proprietary equipment design and performance models and often provide project- and site-specific performance runs to clients and EPC contractors to support the refinement of ThermoFlow models built by those parties.

b.) Confidence Level of Power Team Consulting Estimates: The Siemens SGT6-5000F based estimate, referenced at pages 43 and 44 of the PTC report, reflects a project that was in advanced development (FEED phase) and supported ThermoFlow model refinements that support an AACE Class III estimate. The GE 7F.05 based estimate, at page 44 of the PTC report, was created new for our analysis of this project and can be deemed to be at an AACE Class IV level due to the input of major equipment costs from MH.

PTC did not undertake a risk and contingency Monte Carlo assessment for this project. There is a description in the AACE standard which states, "Table 1 illustrates typical ranges of accuracy ranges that are associated with the process industries. The +/- value, represents typical percentage variation at an 80% confidence interval of actual costs from the cost estimate after application of appropriate contingency (typically to achieve a 50% probability of project cost overrun versus underrun) for given scope. Depending on the technical and project deliverables (and other variables) and risks associated with each estimate, the accuracy range for any particular estimate is expected to fall into the ranges identified. However, this does not preclude a specific actual project result from falling outside of the indicated range of ranges identified in Table 1."[2]

Based upon the AACE description and associated PTC class of estimates, it is reasonable to assume that the AACE estimate range should be generally

[2] AACE International Recommended Practice No. 18R-97, COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES, TCM Framework: 7.3 – Cost Estimating and Budgeting, August 7, 2020

comparable to a P80 confidence level. However, without a Monte Carlo assessment, this should be taken as a reasonable expectation only.

The PTC estimates are meant to provide rough cost benchmarking for this project with costs indicative of F-frame simple cycle power stations. These estimates should therefore be considered as approximate benchmarks and do not reflect detailed refinements to align with specific characteristics of the Brandon project.

c.) Initial Hatch / MH Estimate Comments: The initial assumptions from Hatch and MH that form the basis of the $1.75B project estimate have changed since that estimate was prepared. The Hatch / MH development that produced their estimate was much more refined and project-specific than the PTC ThermoFlow-based benchmark. As the PTC modelling produced a higher value in this case, it is our opinion that the Hatch / MH estimate may be low. However, without a more refined exercise, we cannot state that the original estimate should be replaced by the PTC value of $1.939B, but rather that there is risk that the cost will be greater than the MH / Hatch value.

As discussed in the PTC report, there have been many changes since the original estimate was produced, including the contracting approach change to EPC, and major equipment pricing is now known. Risks have been defined further as well, and risk and contingency should be reappraised in the context of project execution circumstances. We anticipate that the upcoming Class III estimate will be higher.

d.) PTC Cost Comparison Comments: Your identification of an inconsistency in PTC's cost comparisons is correct. The comment raised on the Direct Costs at 26% higher in the PTC estimate deemed as "relatively comparable" was a carryover from our initial draft of the comparison, which produced a smaller difference. We missed changing the comment on this comparison when the difference was refined and established to be 26% higher.

The correct appraisal would be for both the Direct Cost comparison (26% higher) and the Total Project Cost (23% higher) to be deemed as substantially higher than the MH / Hatch estimates.

e.) Turbine Generator Estimates: The Hatch estimate for the turbine generator equipment was developed prior to obtaining the Reservation Agreement pricing. PTC used the same value for the turbine generator pricing (from Hatch) as was used in the MH estimate.

[redacted]

7a

[redacted]

7a

[redacted]

[redacted]

f.) Turbine Price References for Estimates: The price used by PTC in the estimate on page 44 was the MH assumed price and not the price provided by GE in the Reservation Agreement. An EPCM contracting approach was assumed in PTC's estimate, consistent with the basis of the MH estimate.

[redacted]

7a

[redacted]

It should be noted that these are just two factors that influence the project CAPEX. There have been a number of changes to the design and the project risk register, and further price inputs are being gained, which will result in further changes.

PUB/PTC I-7

Part and Chapter:	Manitoba Hydro MNF Attachment 2.5 Power Team Report Manitoba Hydro MNF Attachment 2.5c	**Page #:**	4 7, 47-48, Appendix B p.3 2-3 (PDF p. 8-9 of 45)
Topic:	MNF Process		
Subtopic	Transmission Line Basis of Estimate		

Preamble (if any):

At page 4 of Attachment 2.5 of its major new facilities filing, Manitoba Hydro provides the Transmission Station direct cost estimate as $0.6 billion.

On page 7 of its report, Power Team states:

> The Transmission interconnection design has evolved since the Major New Facility (MNF) application Attachment 2.5c – Basis of Estimate Transmission was issued. The design now reflects changed routing for the third unit's 230 kV lines to the substation and the addition of an autotransformer on the 115 kV to 230 kV interface.

On pages 47 to 48 and Appendix B (p.3 of 10) of its report, Power Team describes various design changes for the transmission line portion of the proposed project.

At pages 2 to 3 of the public version of Attachment 2.5c (PDF p.8-9 of 45), Manitoba Hydro describes its scope assumptions for the Transmission line portion of the Dispatchable Capacity Project. This includes 1.2 km transmission lines to connect the new generators and the Cornwallis station. However, page 47 of Power Team's report states the length of the three lines is now estimated at 3.2 km in total.

Question:

a) Please explain Power Team's understanding of why the existing transmission lines for units 6 and 7 must be re-routed as part of the proposed Transmission line portion of the project.

b) Please confirm whether the new transmission configuration and equipment sizing supports the possible future conversion of the units to combined cycle operation, or whether rework and upsizing of equipment will be required.

c) Please update the Transmission project direct costs based on Manitoba Hydro's recent changes in the Transmission line scope and basis of estimate compared to the planning assumptions described in Manitoba Hydro's April 29, 2026 MNF filing.

Rationale for Question:

To better understand the Transmission line project changes described in Power Team's report compared to the descriptions included in Manitoba Hydro's MNF filing for April 29,

2026. The request also addresses potential updates to the project cost estimates, which is consistent with OIC 88/2026 Schedule A item #5.

Response:

a.) Rerouting of Existing Transmission Lines for Units 6 & 7: With the revised design for the south units 240 kV interconnection now routed along the south of the property entering the Cornwallis substation from the south, the existing Units 6 & 7 115 kV interconnection must be rerouted further north and various breakers replaced due to the increased fault levels associated with the new project. The fault level threshold is 40 kA. The need for rerouting the 115 kV line was not part of the Stage III concept but will be addressed in Stage IV. In the Stage IV Deliverables summary, MH states that, "a new 115 kV single-circuit line, approximately 0.5 km long, will also be constructed to facilitate the re-termination of units G6 and G7 to Cornwallis Station."

b.) Transmission Accommodations for Future Combined Cycle Conversion: If the plant is converted to combined cycle, PTC assumed and MH has confirmed (on July 8, 2026), that the configuration for combined cycle conversion is 3x1. With this configuration, one steam turbine is associated with combined steam output from all three combustion turbine generator/HRSGs. The combustion turbine generator outputs will remain the same, but the transmission line loading of the 230 kV circuit to which the steam turbine generator connection is made will be increased by the additional steam turbine generation added to the associated combustion turbine transmission circuit.

It may also be possible to add another separate 230 kV transmission circuit for the steam turbine addition. This will require an additional generator step-up transformer at the power station for the steam turbine/generator, additional 230 kV transmission interconnection equipment at the power station (breakers, disconnects, sensing, metering, protection, control, etc.) as well as modifications to the receiving end substation settings and equipment.

The transmission line being added for the combustion turbine, to which the steam turbine generator will be added in future, will need to be initially sized for the combined generation of the connected combustion turbine generation and the steam turbine generation, or upgraded as part of the future combined cycle steam turbine generation addition. The details and location of the steam turbine interconnection at the power station end do not appear to have been defined in the design to date, but PTC assumes it may be added to the transmission area at the power station end. If the proposed transmission lines, rights of way or 230 kV system cannot accommodate the additional steam turbine-related transmission circuit or generation, then combined cycle conversion viability becomes questionable.

PTC has not been provided with design details that identify the loading capacity of the transmission interconnections or system studies including combined cycle

generation capacity, and it is our understanding that this level of design was not undertaken at the time of our review (at a Class V level).

PTC notes our recommendation on pages 50 and 51 of the PTC report that it may be possible to increase the line loading of the north transmission interconnections negating the need for the south interconnection. The same comment would apply to the potential future steam turbine generator transmission requirement – it may be possible to address the need through increased line loading rather than additional circuit(s). PTC recommends that MH consider this as part of their design finalization.

Beyond the power station and Cornwallis substation, it is understood that the external existing power grid transmission infrastructure can accommodate up to about 750 MW of new generation with minimal upgrades; however, studies are being undertaken by MH as part of the grid interconnection process to establish and address any implications. A similar study would need to be conducted to establish any implications to the transmission grid to accommodate the additional generation arising from combined cycle conversion.

c.) Updated Transmission Project Direct Costs: PTC has discussed and clarified the revised plans from MH for the transmission interconnection and has questioned the cost of some components, but we do not have design details and the costs required to produce an updated direct cost estimate. It is understood that MH is undertaking this work as part of the Stage IV FEED development, with results available in Q3 2026.

Schedule and Basis of Schedule

PUB/PTC I-8

Part and Chapter:	Manitoba Hydro MNF Attachment 2.5a Power Team Report PUB/MH `-13e	**Page #:**	10 (PDF p.16 of 68) 8-9, 29, 58-64, 66-67
Topic:	MNF Process		
Subtopic	Project Construction Schedule		

Preamble (if any):

On page 10 (PDF p.16 of 68) of the Brandon Generating Station Basis of Estimate document filed as Attachment 2.5a (public version) of the MNF filing, which is dated February 18, 2026, Manitoba Hydro provides Figure 2 shown below. Appendix E of the confidential version of Attachment 2.5a also provides a Level 2 construction schedule for the generating station that's dated February 1, 2025.

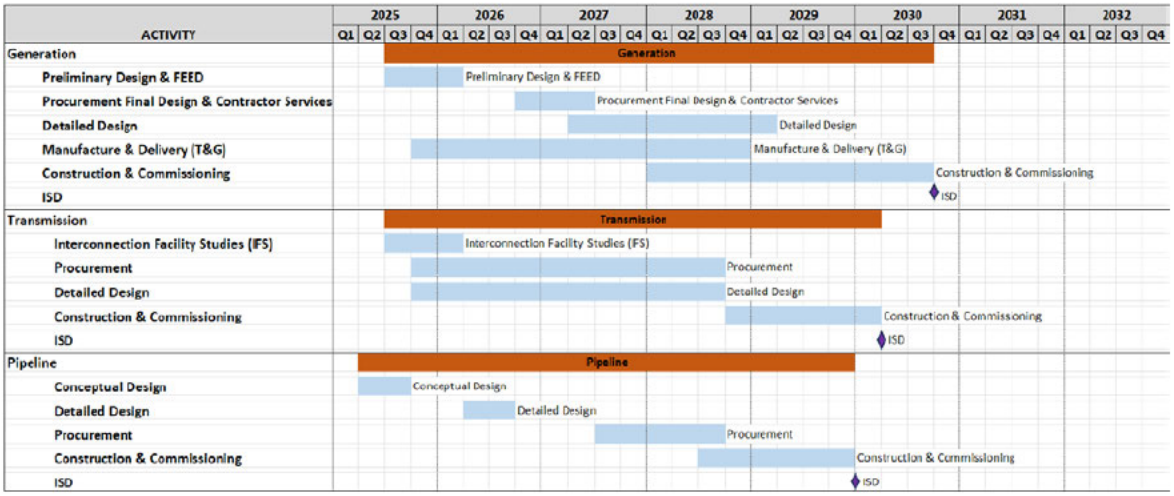


Figure 2: Project Summary Schedule

In response to PUB/MH III-13e, Manitoba Hydro provides a high-level update on the above project summary schedule.

On pages 8 to 9 of its report, Power Team states:

> The basis of schedule and the schedule included in the generation basis of estimate document has changed so drastically that PTC spent little time reviewing those documents. There is a brief transmission and gas schedule in their basis of estimate documents, but those differ from the current schedule. The schedules for all three projects have been replaced by a new complete project schedule for generation, transmission and gas that is being maintained at present by MH. As an AACE Level 1 schedule it portrays just the highest-level tasks and milestone events. All PTC comments pertain to this latest MH Level 1 schedule.

At pages 60 and 66 to 67 of its report, Power Team identifies the risk of combustion turbine generators shipping without some components (e.g., turbine blades) due to OEM supply chain challenges. As a result, Power Team points out that this could necessitate overhaul activities prior to unit operation and delay Manitoba Hydro's project schedule.

At page 29 of its report, Power Team specifies that the building enclosure for the new combustion turbine generator units is being designed with a single overhead bridge crane, which Power Teams appears to deem adequate given the infrequent overhauls expected for the proposed peaking units.

Question:

a) Please provide a copy of the revised Level 1 project schedule used to support Power Team's comments in section 10 of its report. Alternatively, Power Team can request that Manitoba Hydro file the revised Level 1 project schedule concurrently with Power Team's information request responses.

b) Please provide Power Team's view of realistic in-service dates for each turbine generator based on Power Team's understanding of the updated equipment delivery timelines and project planning assumptions.

c) Please explain whether the single overhead bridge crane currently assumed for the Generating Station design could cause site commissioning delays should more than one of the new combustion turbine engines or generators be delivered to site with missing components.

d) Further to c), please explain whether the currently planned staggering of the commissioning of the G8, G9, and G10 combustion turbine generators in Manitoba Hydro's revised Level 1 project schedule would allow for sufficient time to install missing components on all three units with only one overhead crane available while meeting the updated Level 1 schedule.

Rationale for Question:

To help reconcile Manitoba Hydro's project schedule submissions in its April 29, 2026 MNF filing with Power Team's project schedule comments in its report dated June 5, 2026. The Board understands updated Level 1 project schedule requested above was provided to Power Team by Manitoba Hydro. However, this updated document has so far not been filed with the Board and the hearing schedule approved in Orders 39/26 and 68/26 does not immediately provide an opportunity to obtain this information from Manitoba Hydro before the oral hearing commences on July 27, 2026.

Response:

a.) Revised Level 1 Project Schedule: Similar to the request for documents in PUB/PTC I-3, PTC has requested that MH issue the updated Level 1 project schedule to the PUB.

b.) Realistic In-Service Dates for Each Turbine Generator: PTC's assumptions for each generator based upon the committed dates in the Reservation Agreement are:

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

7a

The above dates assume 2 months for delivery to site plus 15 months for installation and commissioning.

c.) Bridge Crane Implications on Commissioning If Components Delayed: The risk to commissioning timing if more than one of the new combustion turbine engines or generators are delivered to site with missing components will be dependent upon the nature of the missing components and the timing of the work.

Risk of generator, gearbox, clutch and auxiliary compartment components shipping late is very low as these are anticipated to be complete assemblies with fewer long lead time parts. Gas turbine compressor hardware is unlikely to be shipped late as the components are less exotic than those in the hot gas path. Combustion hardware components have some potential to be shipped late, but these are more easily managed and may be able to be installed using internal turbine compartment lifting beams and rigging and may not need roof removal and overhead crane use.

The greatest risk for components shipped late to site pertains to third party fabricated hot gas path parts. Specifically, exotic alloy turbine blades are anticipated to be at greatest risk, and these are fabricated by third party specialist fabricators. Due to the extremely high demands from all suppliers, these are most at risk of late shipment to site and PTC is aware of this happening in recent times with other manufacturers.

Installation of turbine hot gas path rotating and stationary blades and shroud blocks requires lifting of the turbine compartment roof (and associated fans, ductwork, etc.) and the casing. This will require overhead crane use. As long as the late-shipped components arrive and are planned for installation in a sequence similar to the one-month time lag illustrated above, this should be manageable with one crane. Only if the missing components all arrive very late and at the same time for all three turbines might there be an additional delay to commissioning arising from having just one overhead crane.

d.) Potential Mitigation from Staggered Delivery and Commissioning of Units: [redacted] 7a As the "overhaul" to open the turbine and install this hardware typically takes about 18 days (with day and night shifts), the risk of overlap of this work between units and of crane use conflicts is significantly reduced.

It is the opinion of PTC that the single bridge crane presents a modest risk of impacting the commissioning schedule due to installation of potentially late-delivered components.

Risk Management and Contingencies

PUB/PTC I-9

Part and Chapter:	PUB/MH III-15a-e Attachment 1 Power Team Report	**Page #:**	36, 41, 67
Topic:	MNF Process		
Subtopic	Risk Management		

Preamble (if any):

Attachment 1 of PUB/MH III-15a provides Manitoba Hydro's current risk register (dated May 15, 2026).

On page 36 of its report, Power Team states:

> PTC endorses the choice of an EPC approach for this project for the reasons discussed elsewhere in this report; however, it is important to recognize that increased schedule and cost certainty under an EPC approach comes at a cost premium for EPC services, fees and mark-ups. […] In today's heated market, even higher EPC premiums may be sought.

On page 41 of its report, Power Team states:

> Besides the GTG price, **PTC recommends caution with regards to the EPC contractor price and anticipates cost escalation in excess of that derived from policy P911**. With extreme high demands for projects, EPCs are taking increasingly large margins and allowances in their pricing.

On page 67 of its report, Power Team identifies, among other things, risks and possible mitigation measures related to:

- EPC contractor under-performance; and
- EPC contractor and construction resource availability.

Question:

a) Given the "heated market" conditions described throughout Power Team's report, please explain whether Manitoba Hydro could also face the risk of receiving a limited number of bids (or no bids at all) from reputable and experienced EPC contractors for its Generating Station project. Further, are reputable and experienced EPC contractors in short-supply in North America given the current "heated market" conditions?

b) Please explain the steps Manitoba Hydro has taken (or plans to take) to ensure it is distributing its EPC request for proposals widely and maximizing the number of potential bidders.

c) If Power Team reviewed Manitoba Hydro's tendering strategy for the EPC contract, please provide comments on whether the strategy is appropriate.

Rationale for Question:

To better understand the possible risks faced by Manitoba Hydro regarding market availability of qualified EPC contractors.

Response:

a.) EPC Contractor Availability: Securing a reputable and experienced EPC contractor is definitely a risk for the project. Demand is exceptionally high across North America and availability to bid is a risk. PTC understands that, in conjunction with the PWC support, EPC contractors were contacted to gain their input on the project and desired contracting approach. It is anticipated that this would have provided MH with a list of short-listed EPC contractors. Ongoing engagement is recommended with a short listed contractors until a selection is made.

Some previously unheard-of circumstances exist in the current market whereby some EPC contractors are refusing to participate in competitive bids for projects and will only consider an exclusive arrangement. PTC also understands that some contractors are seeking reservation agreements to secure their support.

7a

Another point of caution relates to the team put forward to support the project. The most experienced personnel are often spoken for on other projects, so it will be important to obtain resumes of proposed EPC personnel and contractual language that secures their commitment to the project.

b.) Manitoba Hydro's EPC Contracting Steps: PTC has not seen documented plans by MH regarding the identification of EPC contenders and broad consideration of options. At the time of the PTC review, the key information shared was the PWC report that recommended an EPC approach rather than EPCM, which was considered and endorsed by MH. The new Level 1 Schedule shows EPC Tender Prep and Award scheduled from 16 March 2026 through 28 January 2027. When this was discussed, MH advised that they were at the very early stages of evaluating their approach and did not have an EPC contracting plan to share with PTC (describing the engagement of contractors). MH also had not decided upon the specifics of the EPC contracting approach (bid vs negotiated, fixed vs variable cost structure, etc.).

PTC and MH did have some informal conversations about candidate EPC companies, and PTC relayed the risks and challenges portrayed in our report.

We therefore cannot provide information on the EPC contractors being considered or the details of the approach taken, including plans to mitigate risks due to the heated market and anticipated scarcity of options.

c.) Tendering Strategy: As noted above, this was not available at the time of the PTC review.

PUB/MH I-10

Part and Chapter:	Power Team Report	**Page #:**	64, 65
Topic:	Risk Register		
Subtopic	Quantification of Schedule Risks		

Preamble (if any):

On page 64 of its report, Power Team states:

> PTC reviewed the on-going risk register, including the most recent updates and closed risks.
>
> …
>
> It was also discussed that the basis for quantifying schedule impacts was the carrying cost for project development, which produces quite modest costs. This holds true for schedule impacts that are realised during development; however, as the project enters execution, **PTC recommends that this cost basis should reflect the full carrying cost of the execution organization and, if the critical path is impacted leading to extension of the project, costs should reflect the economic impacts of delayed commercial operation of the facilities.**

On page 65 of its report, Power Team states:

> Quantifying project schedule delays based upon the internal burn rate greatly underestimates the consequences of such delays should the impact of the delays carry forward to execution critical path. **For the next risk and contingency assessment, prior to execution phase, PTC recommends the schedule impacts reflect the financial consequences of not delivering the project on schedule, including costs to secure generation capacity from other sources and the carrying cost for additional time prior to COD.**

Question:

a) Please confirm whether schedule risks due to delays in turbine generator delivery by the turbine vendor are appropriately quantified in the risk register, including costs charged by the EPC contractor if they are ready to receive the turbine generator. If not confirmed, how should the risk register be amended? What steps should Manitoba Hydro take to mitigate this risk?

b) Please confirm whether schedule risks due to delays attributed to the EPC contractor where the site is not ready to receive the turbine generators are appropriately quantified in the risk register, including costs charged by the turbine vendor if they must delay delivery of the turbine generators. If not confirmed, how should the risk register be amended? What steps should Manitoba Hydro take to mitigate this risk?

Rationale for Question:

To understand whether Manitoba Hydro has identified and quantified risks related to turbine delays and whether it has or will undertaken appropriate mitigation.

Response:

a.) Turbine Generator Delivery Risk: [redacted] 7a

PTC believes there should be a risk in the register that speaks to this circumstance. Quantification can be made based upon an assumed delay period impacting the commercial operation date (perhaps 6 months), potential EPC contractor costs arising from schedule and work execution disruption, along with extended carrying costs for a longer project.

PTC notes that the original risk register and the risk quantification reflected in the risk and contingency assessment led by Validation Estimating focused upon delay costs arising from carrying costs during the development phase. The updated current risk register correctly focuses upon execution phase risks. PTC expects that the contingency will be reassessed following the FEED development and risks will be quantified based upon execution phase consequences.

b.) Risks of EPC Not Prepared to Take GTGs on Site: Although there are various risks that speak to delay circumstances, the version of the risk register shared with PTC does not yet include a risk that speaks to not being ready to take delivery of the gas turbine generators.

PTC considers it reasonable to include this in the risk register. Due to the very long lead time for turbine manufacturing and delivery, the likelihood of this event

would be remote and the consequences minor according to the MH Risk Rating Matrix.

[redacted]

7a

[redacted]

It should be possible to mitigate this risk through the following actions:

- Timely selection and contracting of the EPC contractor
- Establishing EPC contract terms that incentivise schedule compliance with meaningful penalties for delays

- Establishing a project schedule that thoughtfully plans for major equipment delivery, including all prerequisite and preparatory activities
- Maintaining schedule contingency for the period prior to equipment delivery such that reasonable delays can be incurred without impacting the critical path and equipment delivery timing.
- Owner's supervision of EPC contractor work and schedule compliance, including requesting schedule recovery measures should the schedule slip.

Contracts and Contracting Approach

PUB/MH I-11

Part and Chapter:	Power Team Report	**Page #:**	15,16
Topic:	Turbine Contract		
Subtopic	GTG Technical Specification		

Preamble (if any):

On page 15 of its report, Power Team states:

> The following comments are based upon the MH Technical Specification issued as part of the RFP. For the most part, this specification is typical of what is used for power generation projects.

On page 16 of its report, Power Team states:

> As part of GE's bid issued on Sept 29, 2025, they have provided a GE Technical Specification. This is a very lengthy document at 1377 pages; importantly, it provides the performance values that they are prepared to guarantee as well as performance across the ambient temperature range and the numerous correction curves used to adjust performance test values to guaranteed conditions.

Question:

a) Please confirm which technical specification (Manitoba Hydro's or GE's) formed the basis of the Reservation Agreement.

b) Please confirm whether the same technical specification is expected to form part of the equipment supply contract. If GE's specification is expected to form part of the equipment supply contract, please explain whether and how that affects the costs, schedule, or risks to Manitoba Hydro.

c) If Power Team reviewed the technical specifications, please comment on any material differences that would negatively affect Manitoba Hydro if the GE technical specification forms part of the equipment supply contract.

Rationale for Question:

To understand how finalization of the technical specification may affect costs, schedule, or risks to Manitoba Hydro.

Response:

a.) Technical Specification as the Basis of the Reservation Agreement: GE issued their technical specification, guarantee sheets and a variety of technical submittals as the basis for the Reservation Agreement.

b.) Technical Specification as Part of the Equipment Supply Contract: Yes, GE's technical specification is part of their equipment supply contract. This is tabled by GE as the basis for negotiations, so PTC considers that changes may be possible.

7a

c.) PTC Comments on GE Technical Specification: PTC made some brief comments and recommendations based upon the Hatch Technical Specification that was included as part of the RFP, and these are included in section 5.3 of our report. This section also includes comments on guarantees reflected in the GE Technical Specification. This is one of the most significant aspects of the Technical Specification as it should be linked to contractual guarantee obligations. The full GE package provided as part of the Technical Specifications is 1377 pages long, so PTC's review was quite limited and focused on key elements.

PTC recommends initial negotiating focus on the key performance and guarantee terms, minimum performance levels and damages, and then focusing upon additional technical aspects that relate to equipment supply contract terms highlighted by PTC in report section 12.2.2.2. Care should be taken to clearly specify Canadian and provincial codes and standards that must be complied with, including requirements for grid interconnection.

PUB/MH I-12

Part and Chapter:	Power Team Report	**Page #:**	42, 62, 67, 68
Topic:	Contracting Approach		
Subtopic	Fixed Price, Turnkey, and Cost Reimbursable Contracts		

Preamble (if any):

On page 42 of its report, Power Team states:

> It is also the experience of PTC that EPC pricing has increased at a huge rate. With very high competition for projects, EPC fees and mark-ups are very high. EPC contractors are also not willing to take on risks and build generous contingencies into both price and schedule. It is very rare to obtain a lump sum turnkey EPC price and most EPC contractors seek more reimbursable arrangements. Some EPC contractors have even sought reservation agreements for their services and have refused to participate in competitive procurement processes.

On page 62 of its report, Power Team states:

> The other consideration for the EPC contract is the nature of that contract. This could be lump sum turnkey (unlikely these days), fixed price with an incentive fee, an open book / closed book arrangement, or other EPC contracting variant.

On page 67 of its report, Power Team states:

> EPC Contractor Under-performance
>
> • If the EPC contractor under performs, then the impacts can be incurred in project cost, schedule, health and safety and reputation.
>
> o **PTC recommends careful prequalification and screening of contractors, confirming past performance and establishing the team of individuals who will be assigned to this project.**

Question:

a) Please confirm whether Manitoba Hydro explained to Power Team its past experience with a large cost reimbursable, target price contract used for the civil works of the Keeyask generating station.

b) Please confirm whether Manitoba Hydro explained to Power Team how it plans to manage the EPC contract differently, if Manitoba Hydro is forced to use a cost reimbursable structure for the EPC contract.

c) Please explain the open book-closed book contracting arrangement and give its pros and cons.

d) In Power Team's experience, are turbine generator EPC contractors typically self-performing contractors (directly employing their own personnel), or do they

subcontract the majority of the labour? Has Power Team witnessed both approaches? If so, in Power Team's view, which approach is superior from the perspective of the owner?

e) In the table on page 68, Power Team shows the expected contract model for the "detailed design, procurement, and construction" work package as being "Engineer-Procure-Construct." Is this EPC contract expected to be lump sum/fixed price, unit rate, cost reimbursable, or some other model?

f) If the EPC contract is not a lump sum/fixed price or unit price contract, please explain how the EPC approach gives Manitoba Hydro any cost certainty and risk mitigation.

g) If the EPC contract is a cost reimbursable contract (with or without a target price), please explain what oversight, project management, and controls Manitoba Hydro should have in place. If Power Team reviewed any of plans for such oversight, project management, and controls, please comment on their sufficiency.

h) If the EPC contract is a cost reimbursable contract (with or without a target price), please explain what steps Manitoba Hydro should take if the contractor's profit (as determined by the target price incentive mechanism) is completely eroded prior to completion of the project.

Rationale for Question:

Manitoba Hydro experienced challenges with the Keeyask general civil contract, a target-price, cost reimbursable contract. This information request seeks to understand whether lessons learned in that project are being applied in the current project.

Response:

a.) MH Past Experience with the Keeyask Generating Station: MH did not discuss its experience with the Keeyask Generating Station contract.

b.) How MH Intends to Manage the EPC Contract Differently than for the Keeyask Generating Station: This was not discussed.

c.) Open Book / Closed Book Contracting Arrangement: In an open book / closed book contracting arrangement, the contractor is selected and key terms, fees and mark-ups are agreed. Development then proceeds on an open book basis with full visibility to the client. This allows for funded development with open scrutiny regarding costs up to an agreed milestone (often 30% or 60% design development) at which time the open book price becomes fixed and the contract becomes a fixed price agreement, often lump sum turnkey, but it may include both fixed and variable payment terms, subject to negotiations.

Pros and cons associated with this approach include:

Pros:

- In a market when contractors are unwilling to bid a fixed price up front, this is a method to get to a fixed price following some degree of development.
- EPC fees, mark-ups and allowances are all agreed and accepted up front
- Transparency of the estimate
- The EPC contractor can allocate less contingency to cover price risk due to higher project refinement before locking in the price
- Higher scope definition in contract should reduce the risk of extra project costs for missing scope
- Owner risk is lower than with an EPCM approach
- Cost surety is greater than with an EPCM approach, once the closed book phase is reached.
- In theory, this should provide a lower project cost than a fixed price EPC without open book development

  Cons:
- Owner scrutiny of the EPC costs requires significant effort and engagement, but can be managed by an Owner's Engineer
- Price is higher than with an EPCM approach
- Some contractors may not wish to participate in this method

d.) EPC Contractor Subcontracting: PTC has experienced both situations of EPC contractors self-performing the work (other than craft labour) and cases where EPCs will partner with another contractor that is skilled with execution, but not the engineering. Both approaches can work well, and it depends upon the capabilities of the EPC contractor and their capacity to fulfill the entire role without subcontracting. Another consideration is the experience of the EPC contractor working with the subcontractor. If they are used to working together, get along, have clear divisions of responsibility and clearly define who is doing what, it should work well. If there is confusion or ambiguity, there is risk of duplication of effort (and cost) and of scope and roles being missed.

PTC recommends including questions when screening candidate EPC contractors to explore their intentions to subcontract part of their role and to gain comfort that both parties have a history of successful work together.

e.) EPC Contracting Approach: Although MH has decided to undertake the work execution on an EPC basis and has gained input from EPC contractors regarding their preferred EPC model details through the PWC contracting study, MH clarified to PTC that the specific approach has not been selected. It is therefore unknown at present whether the EPC contract is expected to be lump sum/fixed price, unit rate, cost reimbursable, or some other model. In the time that has passed since the PTC review, it is expected that MH has selected the approach.

f.) EPC Contract Approach Implications for Cost Certainty and Risk Mitigation: PTC is unable to respond to this question as we are not aware of the EPC method chosen by MH.

g.) Oversight, PM and Controls for an EPC Cost Reimbursable Contract: As clarified earlier, MH had not defined their preferred EPC contracting method and the associated plans to execute work under this method at the time of the PTC review.

Should MH choose the cost-reimbursable EPC approach, PTC recommends the following:

- A strong staffing structure to support Owner scrutiny of EPC scope, resources and costs and to ensure compliance with what has been agreed. There is potential for scope creep or less efficient methods by the EPC in a cost reimbursable arrangement, so this should be monitored. The MH role will require a higher degree of attention than under a fixed price EPC arrangement. Resourcing can utilize support from an Owner's Engineer; however, they will also need to be managed, so this will be more taxing on the MH organization than a fixed price EPC approach would. MH should consider contracting a few experienced individuals to work directly for MH as well as an Owner's Engineer.
- Negotiating a robust EPC Contract with a well-defined scope
- Project reporting details, content and frequency should be defined and agreed up front with the EPC contractor, preferably as part of the contract. This should be designed to inform MH as to project status, actual spend and forecast spend, and include sufficient details / back-up for review. MH project controls personnel should have a close working relationship with the EPC project controls staff.

h.) Steps to Take if EPC Profit is Eroded: If the EPC profit is eroded, it will become difficult to incentivise the EPC contractor. There will also be a risk that they will look to cut corners to save costs. MH will need to increase attention to EPC contract and scope conformance. When using a contract with incentives, it is important to ensure they do not work against you and act as a disincentive for the contractor to complete the job. PTC recommends considering things like step-in rights, termination provisions, etc., to protect against such circumstances.

The following is a list of steps PTC recommends:

- Confirm the erosion is real and correctly attributed
- Determine why the fee has been eroded. Is this all attributable to the EPC? Is some of this attributable to MH or external circumstances?
- Assess the remedies built into the contract (as highlighted above)
- Increase MH oversight and controls (as highlighted above)
- Assess contractor solvency. If this is at risk, that will drive remedial actions, including exploring alternate contractors to preserve the project and schedule.
- Consider negotiating a contract change that will reintroduce some incentive (only if this is in MH's best interests and done carefully)
- Protect the MH legal position by having legal support for all decisions
- Keep the Governance Committee informed and involved
- Consider expert support (if the project is far from complete and the course of action is not clear)

PUB/MH I-13

Part and Chapter:	Power Team Report	**Page #:**	70
Topic:	Contracting Approach		
Subtopic	EPC Contract		

Preamble (if any):

On page 70 of its report, Power Team states:

> Reasons to advance and finalize the GTG technical specification and contract ahead of, or in concert with, the EPC contract include:
>
> > o As the major long lead component of the plant, the cornerstone to the plant's design and the least flexible components / contract in the current heated market, securing this agreement and the associated technical terms as soon as possible and ahead of the EPC agreement allows for alignment.
> >
> > o With the GTG agreement in place, the EPC design can be established within the context of the GTG scope of supply and technical parameters.

Question:

Please explain Manitoba Hydro's options if there are delays in finalizing the equipment supply contract including the GTG technical specification, such that it causes delays with finalizing the EPC contract.

Rationale for Question:

Manitoba Hydro still has to finalize the equipment supply contract which will contain a version of the GTG technical specification, as well as the EPC contract.

Response:

If there are delays in being able to finalize the equipment supply contract, PTC recommends that MH reflect upon the GE technical specification and commercial terms and conditions tabled with the Reservation Agreement as an assumed draft, when negotiating the EPC contract and associated EPC technical specification or design basis. The key goal is to have compatible contract terms, scope / terminal points and obligations that transfer as much risk as possible to GE and the EPC contractor and minimize MH risk. As MH are purchasing the gas turbine generators and associated auxiliary scope from GE directly, there is a risk that MH will be in the middle between the two contracts and will carry risks should there be shortcomings or incompatible obligations between GE and the EPC (to the extent practical). Selecting a contractor who has completed other power projects using this model of gas turbine, would help with compatibility between the OEM and EPC.

PUB/PTC I-14

Part and Chapter:	Power Team Report	**Page #:**	15, 28-29, 72, 76-78
Topic:	MNF Process		
Subtopic	Equipment Supply Agreements		

Preamble (if any):

On page 72 of its report, Power Team makes various comments on the GE equipment supply contract, including some in relation to inspection witness point notifications.

On pages 76 to 78 of its report, Power Team makes comments regarding potential combustion turbine generator long-term service agreements or other services agreements to support maintenance needs once the new units are placed in service.

At pages 15 and 29 of its report, Power Team also highlights that there are reputable third parties who provide non-OEM support (e.g., parts and services) for GE F-Frame units.

At page 15 of its report, Power Team states:

> There have been some past areas of vulnerability that have been identified within the GE fleet and subsequently addressed. This includes compressor blade cracking vulnerabilities at the front of the compressor section (R0) and issues of combustion dynamics. Blade design modifications have resolved the compressor issues. Combustion dynamics monitoring and tuning have minimized issues with combustion dynamics; this can be monitored as part of GE's Monitoring and Diagnostic (M&D) services, if selected.

Further, Power Team recommends, on page 77 of its report, that the GE Multi-Year Maintenance Plan include the procurement of specific spare parts (i.e., a full set of power train bearings and four combustion cans with fuel nozzle assemblies). This recommendation follows Power Team's comments at page 32 of its report regarding the potential need for a set of spare parts held on site and the related storage space requirements.

On page 28 of its report, Power Team identifies that Manitoba Hydro currently plans to operate at least two of its new combustion turbine generators in synchronous condenser mode for 4,400 hours per year (approximately 50% of the 8,760 hours available in a year). This contrasts to the expected operation in normal generation mode of 0-100 hours per year per unit (maximum 2,200 hours per year per unit).

Question:

a) Please provide examples of fabrication and testing milestone witness points that are commonly associated with the supply of GE 7F combustion turbine generator units. Further explain whether Power Team expects the witness points to be within

the scope of the Owner's Engineer who will be retained by Manitoba Hydro as part of this project.

b) Please explain whether non-OEM service providers offer combustion dynamics monitoring for GE 7F units, including remote monitoring and diagnostic services.

c) Further to b) please explain, given the expected low capacity utilization factors for the three new GE 7F units, the pros and cons of combustion dynamics monitoring and whether this service agreement option would bring value commensurate with its cost.

d) Given the expected low capacity utilization factor for the three new GE 7F units, please explain whether Power Team recommends that Manitoba Hydro explore alternative service agreements options with non-OEM service providers instead of locking itself into a GE Multi-Year Maintenance Plan.

Rationale for Question:

Combustion turbine generator maintenance agreements are expected to affect Manitoba Hydro's operation and maintenance expense (or capital expenditures depending on the work scope involved) once the new units are place into service. While these costs are not understood to be included in the cost estimates included in Manitoba Hydro's MNF filing, these agreements are often negotiated and executed during the initial equipment procurement activities. As such, considerations of the available options for unit maintenance agreements appear relevant to the requirements of OIC 88/2026 Schedule A item #5, which requires the Board to assess the impacts of the proposed facility on electric rates over the short and long-term and what contingencies and mitigating actions can be taken to reduce the rate impacts.

Response:

a.) Fabrication and Testing Witness Points: PTC recommends the following fabrication witness and testing points for the project. Exact details can be agreed once GE produces their Inspection and Test Plan:

- Gas Turbine
    - Review of quality and conformance documents
        - Includes items such as material test certificates, quality assurance test results, non-conformance reports / resolution and purchase specifications for third-party sourced materials
    - Hydrostatic testing of pressure components
    - Rotor final balance
        - Three-plane low-speed balance (unless a high-speed balance machine is available for a rotor of this size)
        - Balance to achieve ISO grade 2.5 or better and vibration levels within Zone A of ISO 7919-4 and ISO 10816-4
        - Balance machine calibration certification and test
        - Confirm, prior to the test, that shaft run-out measurements are within specification

- Gas Turbine and Auxiliary Components
  - Visual inspection prior to shipment for the gas turbine and selected auxiliary packages / components
  - Gas turbine packaging for shipment
- Generator
  - Review of quality and conformance documents
    - Includes items such as material test certificates, quality assurance test results and non-conformance reports / resolution
  - Generator rotor balance to ISO grade 2.5 or better
  - Generator balance machine calibration confirmation
  - Generator rotor high-speed run to 120% of rated speed
  - Mechanical inspection
  - Measurement of cold resistance of armature and field windings
  - Measurement of insulation resistance of armature and field windings
  - Dielectric tests of armature and field
  - Generator and excitation system testing in accordance with applicable IEEE standards:
    - Insulation resistance of generation armature and excitation system
    - Dielectric tests of armature and field windings
    - AC over-potential test on generator armature and field windings, and windings of excitation system
    - No-load saturation curves of excitation system and generator
    - Test to prove that no rotor turns are shorted
    - Excitation system range of regulation, ceiling voltage, and speed of response
    - Exciter step response (5% reference voltage step change)
    - Power system stabilizer (PSS) performance test
    - Exciter voltage range test
  - Pre-shipment inspection
- Excitation System Testing
  - Mechanical inspection
  - Voltage regulator gain test
  - High potential tests on all circuits to ground
  - Mechanical balance and over-speed test of rotor
  - Rectifier voltage drop and reduced current
  - Test to ensure proper operation of all devices associated with the excitation system
- Control System Testing
  - Factory Acceptance Test (FAT) performance using a software test simulation based upon hardware options and turbine control type

MH may choose to witness the above tests for some or all of the units and may decide to receive test results, if in-person attendance at all tests is not practical or deemed required. PTC considers it to be normal scope for an Owner's Engineer to witness the tests on behalf of MH. It is recommended to confirm that the OE(s) designated to witness the tests is sufficiently knowledgeable and experienced to do so.

b.) Non-OEM Service Providers Capabilities: Many non-OEM service providers do not offer combustion dynamics monitoring of GE 7F units, including remote monitoring and diagnostic services; however, PTC is aware that Hanwha Power (formerly PSM) from Jupiter, Florida, does offer all of these services and has a 24/7 monitoring and diagnostics centre.

c.) Merits of Combustion Dynamics Monitoring: Combustion dynamics monitoring is accomplished through pressure transducers in each of the combustors or accelerometers on the combustion cans (we believe the norm is pressure transducers these days). The monitoring provides an indication of combustion dynamics to the control system and control room operator. GE offers an auto-tune feature that monitors combustion dynamics and other parameters and optimizes control parameters to avoid combustion dynamics and optimize performance and emissions. Although it should be confirmed, we believe these features may be standard supply from GE. If they are not, PTC recommends selecting them as an option, despite the anticipated low capacity factor and relatively constant fuel parameters associated with main line fuel gas supply.

Combustion dynamics can be very damaging to combustion hardware and may lead to liberation of components that can pass through the turbine, damaging the hot gas path section (i.e. turbine blades and nozzles). In the worst case, catastrophic failure of the turbine may result. The probability is very low given the low capacity factors and main line fuel gas supply, but as the consequences of damage are very high, PTC recommends this monitoring.

GE's Multi-Year Maintenance Plan proposal (long term services agreement) included GE Monitoring and Diagnostics (M&D) as part of their offering. If this is selected, it provides another layer of oversight of combustion dynamics. M&D services provide monthly reports on turbine health, condition and performance monitoring parameters. In the M&D control room, algorithms are used to detect changes from baseline conditions as well as alarm conditions. This service should provide another way to detect combustion dynamics and initiate corrective actions.

d.) Alternative Service Agreement Options with Non-OEM Service Providers: [redacted] 7a

Some non-OEM service providers cannot provide a full suite of parts and services to act as an alternative to GE. However, Hanwha Power, referenced earlier, can

provide full long term service agreements, all hardware required for 7Fs, and M&D services. If MH wishes to explore alternate market offerings, PTC recommends they be considered. Other third-party service providers that we anticipate offering similar capabilities include Wood Group, Ethos Energy and MD&A (Mechanical Dynamics and Analysis). PTC has undertaken due diligence on Hanwha Power but has not recently done due diligence on these others; however, that is not to say they may not be equally capable.