REFERENCE:

Appendix 7.7 page 6, l. 1 - 21.

PREAMBLE TO IR (IF ANY):

Portage Area Capacity Enhancement

QUESTION:

a) Does the $156M total project cost cover both Stage 1 and Stage 2? If not, please provide the total project cost for both stages.
b) Would MH be undertaking the investment if there was no federal funding available? In other words, is the full project cost justified by the extent of the need being addressed?
c) Is the proposed Stage 2 work primarily intended to reinforce the 230 kV network in SW Manitoba?
   i. Please provide the technical studies undertaken to determine the Stage 2 need.
   ii. What is the annual duration of exposure to the load conditions that drive the Stage 2 need? Please provide the load duration curve for the affected part of the system.

RESPONSE:

a) Yes, the estimate of $156 M covers both Stages 1 and 2.

b) Yes, even without federal funding, the project is still justified. The southwest area is one of the most stressed areas due to above average load growth, new industrial customers, and deferral of the planned transmission projects. The PACE project is therefore justified to address these issues and enhance the load serving reliability of the system in the area. The PACE project not only fulfills Manitoba Hydro's duty to serve Manitoba customers but also has a positive value in the Corporate Value Framework Assessment without considering the federal funding.

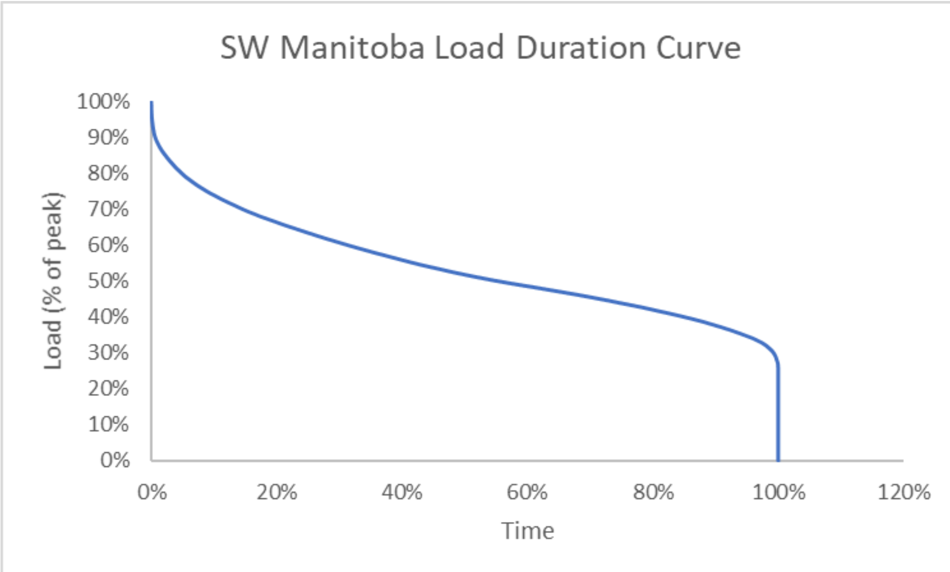
c) Stage 2 provides a new 230 kV transmission line from the Dorsey Converter Station near Winnipeg to the new Temp-Portage West Station. Completion of Stage 2 will eliminate 230kV and 115kV voltage constraints in SW region of Manitoba.

i. The technical studies are presented in the following two planning reports:

- SPD 2019-01
- GIP 2021/01

Please refer to Attachment 1 and 2 of this response for a copy of the SPD 2019-01 and GIP 2021/01 reports, respectfully. Some information contained in the Attachments has been highlighted and redacted from the public record. Public disclosure of the redacted information in this IR would result in the release of information considered to be confidential and commercially sensitive.

ii. There are several variables in addition to the load that impact the system performance driving Stage 2. Planning studies were performed to analyze a wide range of system conditions to evaluate a range of options for system enhancements, including the need for Stage 2. As load is one of the most influencing parameters, variation in load is considered in the assessment. An annual load duration curve for the area used in the study is provided below. The study found that under certain stressed conditions, stage 2 is needed in 2027 when load exceeds 94% of peak, which is one of the main drivers for Stage 2. Technical and economic assessment also found that Stage 2 is the best option. The “SW Load Duration Curve” shown below shows the percentage of time that the SW Load is operating at. For example, ~5% of the time, the system is operating over ~85% peak load.


SW Manitoba Load Duration Curve
Load (% of peak)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0%
20%
40%
60%
80%
100%
120%
Time

TRANSMISSION PLANNING & DESIGN DIVISION

SYSTEM PLANNING DEPARTMENT

REPORT ON

Brandon/Portage Area Network Reliability Evaluation Study SPD 2019/01

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REVISIONS

No.	Prepared By	Reviewed By	Date	Comment
1.0	K. Toews	B. Bagen	Jan 9, 2019	Initial Draft
2.0	K. Toews	System Planning, System Performance, Transmission Asset Management	Jan. 30, 2019	Incorporated Reviewers' Comments
3.0	K. Toews	B. Bagen	March 19, 2019	Included Section 7.5 Longevity Analysis

Executive Summary

The Brandon/ Portage area is one of the most stressed areas due to various current and/or potential developments in south western Manitoba. These developments mainly include above average load growth, new industrial customers, increasing exports to Saskatchewan and deferral of the planned transmission projects. The reliability of the transmission system in the area is deteriorating and therefore a comprehensive network reliability evaluation study (NRES) is performed to identify potential issues and propose alternatives to enhance the transmission system in the area. The studies described in this report focus on the steady state performance of the Brandon/Portage area transmission system. The NRES includes the identification of system issues, evaluation of the performance of potential transmission enhancement alternatives and comparison of the viable alternatives in terms of technical performance, planning level cost, impacts on transmission system reliability and timeline of implementation.

The NRES study examines three major transmission issues in Brandon/ Portage area including insufficient 230/66 kV transformation capacity at Portage South station, near term low voltages at several 115 kV and 230 kV stations and longer term low voltages and high thermal loading issues. The insufficient 230/66 kV transformation capacity in the Portage area requires immediate enhancement to prevent single contingency overloads. Six different mitigation options are evaluated and compared. These options include the addition of a third transformer bank at Portage South station, upgrade of the existing two transformer banks at Portage South station, transfer of load from Portage South station to Stanley station and establishment of a new station at three different locations (Elm Creek, Portage West and Portage East) with load transfer from Portage South station. The low voltages at several 115 kV and 230 kV stations require system improvement in a near term planning horizon (approximately 5-10 years). If no improvements are implemented, then violations of NERC transmission planning criteria are expected before 2027. A number of different mitigation options are evaluated and compared. These options include addition of a transmission line, establishment of a new station at different locations, addition of reactive support in the form of capacitor banks and SVC, breaker replacement, enhancement of transmission capacity by adding series capacitor compensation to several 230 kV lines, transmission line sectionalization and the supply of the area load from remote or local generation. The low voltages and high thermal loading issues require significant transmission enhancements including new transmission stations and lines in a longer-term planning horizon (approximately 10 years). Considering the immediate, near term and longer term need of transmission system five alternative transmission development plans as described in Section 6 for the Brandon/ Portage area are proposed for Corporate Value Framework (CVF) evaluation to select the preferred proposal. A comparison of the proposed transmission plans are presented in Table ES-1.

A network reliability facility study (NRFS) for the preferred plan will be conducted and results of additional technical studies, detailed cost estimate and time schedule of construction will be provided in the NRFS report.

Table ES-1: Comparison of Development Plans

Dev. Plan	Capital Investment: Expected ISD	Planning Level Cost (Millions)	Other Factors
Do Nothing	N/A	$0	NERC violations expected before 2027.
1	Bank Addition at Portage South: 2022	$26.4	New control building may be required.
	D83P: 2025	$64.0	
		$90.4	
2	Bank Upgrades at Portage South: 2021	$27.8	Extended transformer bank outages required.
	D83P: 2025	$64.0	
		$91.8	
3	Portage to Stanley Load Transfer: 2021	$21.6	Limited or no room for additional load growth (Section 7.1) and does not support salvage of aged assets (Section 7.4)
	D83P: 2025	$64.0	
		$85.6	
4	New Station near Elm Creek: 2024	$53.4	Limited or no room for additional load growth (Section 7.1) and does not support salvage of aged assets (Section 7.4)
	New Line from Elm Creek to Portage South: 2025	$62.9	
		$116.3	Longevity not on par with other Plans (Section 7.5)
5	New Station west of Portage: 2024	$53.4	
	New Line from Dorsey to the new Station: 2025	$82.4	High level of uncertainty in the estimate for the transmission line length.
		$135.8	

Table of Contents

1. Introduction

The Portage/Brandon area is one of the most stressed areas due to various current and/or potential developments in south western Manitoba. These developments mainly include above average load growth, new industrial customers, increasing exports to Saskatchewan and deferral of the planned transmission projects. The reliability of the transmission system in the area is deteriorating and therefore a comprehensive network reliability evaluation study (NRES) is proposed to address various reliability issues associated with the Brandon/Portage area. The transmission reliability concerns in the Brandon/Portage area can, generally be, categorized into the following:

1. Insufficient 230/66 kV transformation capacity in the Portage area, which requires immediate enhancement (approximately 2 years).
2. Low voltages at several 115 kV and 230 kV stations particularly in winter loading conditions, which requires system improvement in a near term planning horizon (approximately 5 years).
3. Low voltages and high thermal loading issues which requires significant transmission enhancements including new transmission stations and lines in a longer-term planning horizon (approximately 10 years).

The studies described in this report focus on the steady state performance of the Brandon/Portage area transmission system. The studies include the identification of system issues, evaluation of the performance of potential transmission enhancement alternatives and comparison of the viable alternatives in terms of technical performance, planning level cost, impacts on transmission reliability and timeline of implementation. Based on the results obtained from this NRES transmission system development plans for the Brandon/Portage area are proposed. These plans will go through the evaluation process in Corporate Value Framework (CVF) to select the preferred proposal. A network reliability facility study (NRFS) on the preferred plan will be conducted and results of additional technical studies, detailed cost estimate and time schedule of construction will be provided in a NRFS report.

2. Study Objective, Scope and Deliverables

2.1. Study Objective

The main purpose of the NRES described in this report is to assess the reliability of the transmission system in the Portage/Brandon area and to propose, evaluate and compare alternatives for system improvements in the near term and evaluate how those improvements will impact the longer term performance of the Portage/Brandon area system.

2.2. Study Scope

The study scope includes three major parts. First, steady-state analysis is performed on the base cases to identify existing issues. Second, steady-state analysis is performed for the mitigation options to evaluate the impacts of these options. Finally, steady state analysis is performed on several transmission development plans, which may include a combination of several mitigation options, to select the preferred development plans for the area.

2.2.1. Transmission Mitigation Options

Steady state contingency analysis is conducted to evaluate and compare the system performance considering the following options for mitigating voltage and/or capacity issues in the Portage/Brandon area.

A. **Options to provide additional 230/66 kV transformation capacity (2022-2025)**

Portage South Third Bank– Install a third 95 MVA 230/66 kV transformer bank. This option is considered to relieve single contingency overloads on the existing transformer banks at Portage South station due to load growth.

Portage South Bank Upgrade– Salvage the two existing 230/66 kV transformer banks at Portage South station and replace them with two new 140 MVA 230/66 kV transformer banks. This option is considered to relieve single contingency overloads of the existing transformer banks due to load growth.

New 230/66 kV Transformer Bank near Elm Creek– Install a new 230/66 kV transformer bank at a new substation near the town of Elm Creek. Terminate the new transformer bank with a new 230 kV breaker. Install a 3 breaker 66 kV ring bus to allow for two outlet 66 kV lines and one transformer bank termination. Transfer load from Portage South station to the new station to relieve high loading at Portage South.

New 230/66 kV Transformer Bank at Portage West Station– Install a new 230/66 kV transformer bank at a new substation west of Portage la Prairie. Terminate the new transformer bank with a new 230 kV breaker. Install a 3 breaker 66 kV ring bus to allow for two outlet 66 kV lines and one transformer bank termination. Transfer load from Portage South station to the new station to relieve high loading at Portage South.

New 230/66 kV Transformer Bank at Portage East Station– Install a new 230/66 kV transformer bank at a new substation east of Portage la Prairie.

Terminate the new transformer bank with a new 230 kV breaker. Install a 3 breaker 66 kV ring bus to allow for two outlet 66 kV lines and one transformer bank termination. Transfer load from Portage South station to the new station to relieve high loading at Portage South.

Transfer Load from Portage South Station to Stanley Station– Develop 66 kV infrastructure in Stanley area as required to transfer load from Portage South station to Stanley station to relieve loading on the Portage South 230/66 kV banks. A third bank has been recently installed at Stanley station which provides additional transformation capacity to accommodate the proposed load transfer.

B. **Options to mitigate voltage/overload issues (beyond 2025)**

D83P- Construct approximately 70 km of transmission line from Dorsey station to Portage South station. Terminate the new line with one additional 230 kV breaker at Dorsey station and one additional 230 kV breaker at Portage South station. A study was completed in 2001 which recommended the line be built in 2007 [1] but it has since been deferred to 2025. This option would impact the 230 kV line loading and bus voltages but it would not impact the 230/66 kV transformation capacity. Manitoba Hydro has an environmental license for this line and it is a well understood concept so it is considered as one of the mitigation options.

New Station near Elm Creek- Build a new station near Elm Creek Manitoba. Sectionalize Dorsey to St. Leon 230 kV line D14S into the new station. Build approximately 30 km of new 230 kV line from the new station to Portage South station. A new 230 kV breaker is required at Portage South station and three new breakers are required at the new station. This option is considered as an alternative to D83P because it would impact the 230 kV line loading and bus voltages. It would not directly impact the 230/66 kV bank loading.

Capacitor Banks- Provide reactive support in the Brandon area by installing capacitor banks. Simulations were performed with one 50 MVAR capacitor bank at the Cornwallis 230 kV bus or with 50 MVARs distributed in the Brandon area. This option would have an impact on 230 kV bus voltages but has no impact on the 230 kV line or 230/66 kV transformer bank loading issues.

Cornwallis SVC– Provide reactive power support in the Brandon area by installing a Static Var Compensator (SVC). The option for a Cornwallis SVC has been studied in the past [2]. Simulations were performed with an SVC at multiple sites in the Brandon area and it was found that an SVC at several stations for example Brandon Generating station, Brandon Victoria 115 kV, Souris 230 kV, Neepawa 230 kV and Cornwallis 230 kV is able to eliminate voltage violations in the 2027 winter peak without running the Brandon combustion turbines. A 225 MVAR SVC was modeled on the Cornwallis 230 kV bus for this option to provide comparable reliability performance to D83P. This option would have an impact on 230 kV bus voltages but has no impact on the 230 kV line or 230/66 kV transformer bank loading issues.

Brandon 115 kV Breaker Replacement– An operating limitation exists at the Brandon GS 115 kV bus due to the voltage rating of eleven 115 kV breakers. This option considers upgrade of the eleven existing breakers to a minimum continuous voltage rating of 127 kV so that operator adjustments can be made to raise the pre-contingency 115 kV bus voltage. This option was proposed in a previous planning study to improve 115 kV bus voltages in the area [3].

Kettle Generation Transfer– Transfer Kettle Units 1 & 2 from the Northern Collector System to the Northern AC System as required during the periods of high MH-SPC exports and winter peak loading. This has been explored in the past [4]. This option would impact the 230 kV line loading and bus voltages in the area by relieving line loading on the potentially heavily loaded lines D12P, D54N and G37C.

Vermillion to Neepawa Line– Construct a 130 km 230 kV line from Vermillion station to Neepawa 230 kV station. Terminate the new line with one additional 230 kV breaker at Vermillion station and one additional 230 kV breaker at Neepawa 230 kV station. This line was considered in the past as an alternative to increase generation capacity from the northern AC system [4]. This option would have an impact on 230 kV bus voltages and a marginal impact on the 230 kV line loading but no impact on 230/66 kV transformer bank loading issues.

Raven Lake to Neepawa 230 kV Line- Construct a 100 km 230 kV line from Raven Lake station to Neepawa 230 kV station. Terminate the new line with one additional 230 kV breaker at Raven Lake station and one additional 230 kV breaker at Neepawa 230 kV station. This line is considered because it could provide an additional path for westward powerflow during periods of high Manitoba to Saskatchewan transfers.

Dorsey to Cornwallis Line– Construct a 210 km 230 kV line from Dorsey to Cornwallis station. Terminate the new line with one additional 230 kV breaker at Dorsey station and one additional 230 kV breaker at Cornwallis station. This option was studied with and without series capacitor compensation on the proposed line.

Sectionalize D54N– Sectionalize 230 kV line D54N north of Portage la Prairie. Build two 30 km 230 kV lines from the line D54N sectionalization to Portage South station and terminate both lines onto the Portage South bus with two new 230 kV breakers. This alternative is considered because it provides an additional feed into Portage South station which would impact the 230 kV line loading and bus voltages.

230 kV Line Upgrades– This option considers upgrades of several 230 kV transmission lines. The total length of upgrade is approximately 365 km including lines D12P, P81C, and D54N. In order to effectively reduce the inductance of a transmission line, double bundled conductor is proposed. This option would impact the 230 kV line loading and bus voltages but would not impact the 230/66 kV bank overloads.

Portage West Station– Build a new station near the proposed Roquette site west of Portage la Prairie. Build a new 75 km 230 kV line from Dorsey to the new station. Terminate the new line, P81C, and a radial 230 kV line to the Roquette site with a new 3 breaker 230 kV ring. Terminate the new line at Dorsey station with one breaker. This option is considered as an alternative to D83P because it would impact the 230 kV line loading and bus voltages.

Portage East Station– Build a new station east of Portage la Prairie. Build a new 68 km 230 kV line from Dorsey to the new station. Build another 14 km 230 kV line from the new station to Portage South station. Terminate the two new lines and new transformer bank with a new 3 breaker 230 kV ring. Terminate the new line at Dorsey station with one 230 kV breaker and terminate the other new line at Portage South station with one 230 kV breaker. This option is considered as an alternative to D83P because it would impact the 230 kV line loading and bus voltages.

2.2.2. Transmission Development Plans

Viable alternatives for transmission development in the Portage/Brandon area are identified based on the results of performance assessment of mitigation options for the potential issues. A transmission development plan could consist of two or more of the transmission mitigation options as discussed in Section 2.2.1.

2.3. Deliverables

1. Develop a number of power flow cases that can be used in this study and other studies.
2. Develop a number of IDV or Python files for adding the proposed facilities of the alternatives in the related power flow cases.

3. Develop a number of conceptual SLDs for CRT to review and comment. Competing alternatives will be selected for CRT review during the later stages of the study.
4. Develop a planning report to document the assumptions, methodologies, results and recommendations.

3. Model Development and Assumptions

The studies described in this report cover approximately a 10 year planning horizon from 2018 to 2027. Planning cases representing 2018, 2022 and 2027 loading conditions are developed using the 2017 Midwest Reliability Organization (MRO)/Multiregional Modeling Working Group (MMWG) series planning models. The MRO/MMWG planning models include a detailed representation of the BES within the province of Manitoba and the adjacent Planning Coordinators and Transmission Planners. The major assumptions related to the Portage/Brandon areas modeled in this NRES are as follows:

- Three different forecast loading conditions of winter peak, summer peak and summer off-peak.
- [redacted] 1b
- A total of 3 MVA is added to Stanley in 2020 [6].
- A total of 34 MVA is added to St Leon in 2020 [6].
- The Manitoba-Minnesota Transmission Project (MMTP) is in service in 2020. 3058 MW (South)/1475 MW (North) and 2175 MW (South)/775 MW (North) flow including a reliability margin (RM) of 75 MW are on Manitoba–US (MH-US) interface representing cases with and without the MMTP respectively [7].
- G82P phase shifter angle is set such that base case flow is 0 MW. However, Settings were adjusted ranging from 0 MW to 250 MW northflow on a case-by-case basis to mitigate system issues as necessary.
- A 100 MW additional transmission service to Saskatchewan associated with the Birtle Transmission Project (BTP) is in place in 2021 [8]. For the base case, 325 MW west flow on the Manitoba-Saskatchewan (MH-SPC) 230 kV interface including existing transmission services and a RM of 75 MW was considered. For the high stress MH-SPC interface case, 365 MW west flow on the Manitoba-Saskatchewan (MH-SPC) 230 kV interface was modeled to represent an additional 40 MW transfer [9].

- For the base case, 70 MW east flow on the MH-SPC 115 kV interface including a 60 MW existing transmission service and a 10 MW of RM was considered. For the high stress MH-SPC interface case, 60 MW east flow on the MH-SPC 115 kV interface was considered.
- 25 MW (West) and 125 MW (East) flow including a RM of 25 MW are on Manitoba–Ontario (MH-ONT) interface.
- Brandon Unit 5 is operating as a synchronous condenser and Brandon Unit 6 is on for winter peak cases.
- Keeyask generating station of 630 MW is in service in 2022.

A summary of the power flow base cases examined in the analysis described in this report is provided in Appendix A. Planning cases representing 2018, 2022 and 2027 summer peak and winter peak loading conditions from the MMWG/MRO 2017 series models were updated to reflect the latest topology and ratings of equipment within Manitoba and neighbouring systems.

Planning level cost estimates for the mitigation options and the proposed development plans are also presented and compared in this report. The planning level estimate provided in this NRES is unit pricing from past projects based on assumptions for required station apparatus and transmission line length only. No geographical specifics, site ground structures, actual line routing and detailed protection/communication designs are considered in such a planning level estimate. Typically the acceptable error for the planning level cost estimate based on the unit cost approach is ±50%.

4. Study Criteria and Methodology

The following criteria and methodologies are used in the studies described in this report.

4.1. Study Criteria

MH TPL-001-04 standard [10], the MH transmission system interconnection requirements (TSIR) [11] and other applicable MH criteria [12] were applied in this NRES. Steady-state pre- and post-contingency bus voltages must be maintained within limits. Bus voltages were monitored for voltages above 110% or below 90 % of the rated voltage for the first 30 minutes following a contingency (contingency voltage criterion). Bus voltages were monitored for voltages above 105% or below 95% for both system intact conditions and 30 minutes after a contingency (steady-state voltage criterion). All generating units cannot exceed their reactive power limits and acceptable reactive power reserve should be kept at Dorsey, Grand Rapids and Seven Sisters [11].

4.2. Study Methodology

Steady-state power flow studies were conducted using the criteria described in Section 4.1. The steady-state power flow analysis was performed using the PTI PSS/E Power Flow Program (Version 33) [13]. The steady-state power flow assessment includes evaluation of voltage performance and transmission facility loadings in pre-contingency and post-contingency analyses. The steady-state analysis evaluates normal operating system conditions and system operation under contingencies that conform to the MH TPL-001-4 standard. Monitoring is done for transmission elements of 100 kV and above within Manitoba. In order to represent the time period immediately following a contingency, load flow is solved with all controls, transformer taps, switched shunts and phase shifter adjustments disabled. In order to represent the system post-contingency steady state (30 minutes after a contingency), load flow is solved with all controls, transformer taps, switched shunts, and phase shifter adjustments enabled. Brandon generation was dispatched as required and plant voltage set-points were adjusted to respond to contingencies. G82P phase shifter was also adjusted up to 250 MW north flow to alleviate some of the issues that were found in the steady state power flow simulations. It is assumed that Brandon CT is dispatched before the use of G82P phase shifter. The following procedure is followed in the steady state analysis:

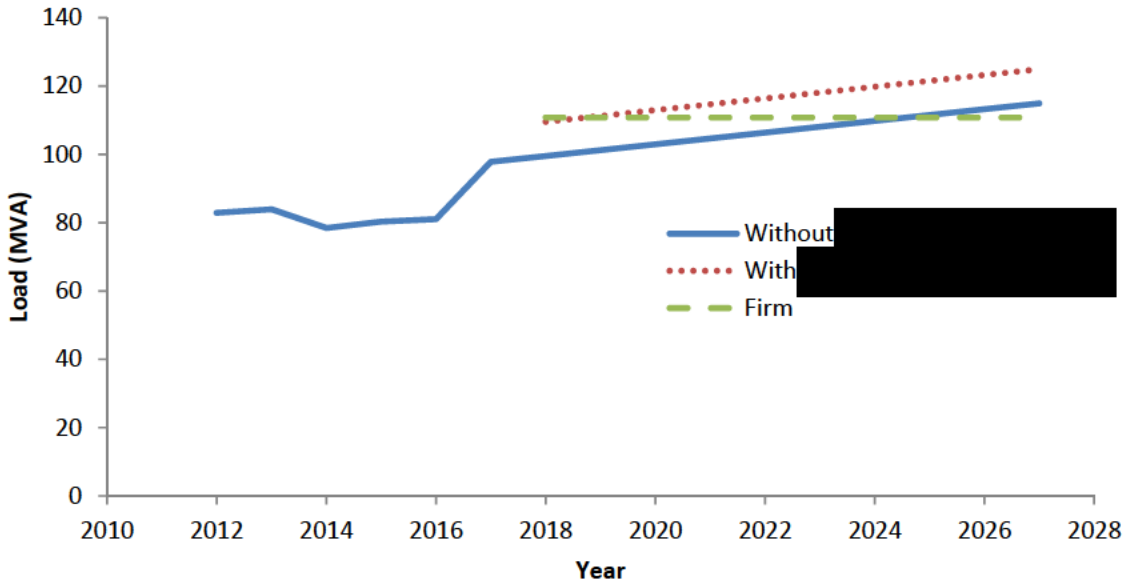
1. The base cases as summarized in Appendix A are first simulated to identify overloads and/or voltage violations in the Portage/Brandon area.
2. For the base cases with performance issues, the impacts of those mitigation options as described in Section 2.2.1 are evaluated and compared.
3. Several viable transmission system development plans are developed based on the results obtained from base case and mitigation option simulations. The proposed transmission development plans for Portage/Brandon area are compared in terms of technical performance and planning level cost. The planning level cost estimates are provided by Transmission Project upon the request of System Planning.

5. Results and Analysis

Steady-state power flow analysis was performed using the methodology described in Section 4.2.

5.1. Base Case Analysis

Figure 1 shows the historical bank loading and projections at Portage South station. It can be seen from Figure 1 that load will exceed firm capacity as early as in the winter of 2019 with addition of the new [redacted] 1b



1b

Figure 1: Portage South Transformer Loading and Forecast
(Winter Peak, with and without [redacted] 1b

Steady state power flow simulation was performed using the 2018, 2022 and 2027 base cases. The power flow simulation found a number of issues as presented in Table 1. It can be seen from Table 1 that some of the voltage violations and thermal overloads can be eliminated by running the Brandon CTs as proposed in [14] but some violations cannot be mitigated by running Brandon CTs. Additional mitigation options are, therefore, considered and evaluated.

Table 1: Summary of Simulation Results (MH-SPC High Stress Case)

Case	Thermal Overloads	Bus Voltage Violations
2018 Summer and Winter Peak, Brandon CTs Off	None	None
2022 Winter Peak, Brandon CTs Off	D12P, BP6, CN9, Portage South 230/66 kV Banks 1 & 2	Voltage collapse following a D12P contingency. Low voltage at various busses following D54N, G37C, and P81C contingencies.
2027 Winter Peak, Brandon CTs Off	D12P, BP6, CN9, Portage South 230/66 kV Banks 1 & 2	Voltage collapse following a D12P contingency. Low voltage at various busses following D54N, G37C, and P81C contingencies.
2022 Winter Peak, Brandon Unit 6=133 MW	Portage South 230/66 kV Banks 1 & 2	None
2027 Winter Peak, Brandon Unit 6=133 MW	Portage South 230/66 kV Banks 1 & 2	Low voltage at various busses following a D12P contingency

5.2. Evaluation of Options to Improve 230/66 kV Bank Loading

A number of mitigation options for Portage South transformation capacity enhancement as described in Section 2.2.1 are modeled and evaluated. The results obtained from steady state simulations of these mitigation options are summarized in Table 2 and briefly described in the following sections.

Table 2: Summary of Simulation Results
(Mitigation Options, Transformation Capacity)

Option	Thermal Overloads	Voltage Violations	Planning Level Cost	Other Factors	Estimated Construction Time (months)
Portage South Third Bank	None	None	$26.4M	New control building required.	24 - 48
Portage South Bank Upgrade	None	None	$27.8M	Extended outages required	18 - 24
New 230/66 kV Transformer Bank near Elm Creek	None	None	$21M	Limited or no room for additional load growth (Section 7.1) and does not support salvage of aged assets (Section 7.4)	18 - 24
Transfer Load from Portage South Station to Stanley Station	None	New Voltage Violations at Stanley station.	$7.5M	Limited or no room for additional load growth (Section 7.1) and does not support salvage of aged assets (Section 7.4)	18-24
Install Transformer Bank at Portage West Station	None	None	$21M	Environmental license required	18 - 24

The planning level cost estimate for each of the mitigation options presented in Table 2 is provided in Appendix B. It can be seen from Table 2 that all five alternatives effectively eliminate 230/66 kV bank overloads. However, a voltage violation will appear at Stanley station as a result of the load transfer. A 60 MVAR reactive support device at Stanley station can eliminate the voltage violation, which is included as part of one of the development plans proposed in Section 6.

5.3. Evaluation of Mitigation Options for Voltage/Overload Issues

A number of mitigation options for voltage and overload issues as described in Section 2.2.1 are modeled and evaluated. The results obtained from steady state simulations of these mitigation options are summarized in Table 3 and briefly described in the following sections. The planning level cost estimate for each of the mitigation options presented in Table 3 is provided in Appendix B.

Table 3: Summary of Simulation Results
(Mitigation Options, Voltage and Overload, MH-SPC High Stress Case)

Option	Thermal Overloads	Voltage Violations	Planning Level Cost (M)	Other Factors	Estimated Construction Time (months)
D83P	None*	Brandon CT must run at minimum generation during winter peak	$64.0	Low – environmental license has been obtained	18
New Station Near Elm Creek	None	Brandon CT must run at minimum generation during winter peak	$74.8		60
Capacitor Banks	None	Brandon CTs cannot eliminate violations	Depends on the size and location	Not Recommended. See Section 7.3.	Depends on the size and location
Cornwallis SVC (225 MVAR capacitive)	CN9, BP6, & D12P	Brandon CT must run at minimum generation during winter peak	>$50	Estimate assumes SVC with 110 MVAR capacitive rating and does not include Cornwallis termination	54
Brandon 115 kV Breaker Replacement	CN9, BP6, & D12P	Brandon CTs cannot eliminate violations	$13.2		
Kettle Generation Transfer	D12P	Brandon CTs cannot eliminate violations	Unknown	It may not be an operationally functional solution	Unknown
Vermillion to Neepawa Line	D12P	Brandon CTs cannot eliminate violations	$144.9		60
Raven Lake to Neepawa Line	D12P overloads	Brandon CTs cannot eliminate	$114.7		60

	increase	violations			
Dorsey to Cornwallis Line	C28R (only if the new line is series compensated)	Brandon CTs must be on at minimum generation to eliminate voltage violations	$228.7		60
Sectionalize D54N	D12P overloads increase	Brandon CTs must be on at 20 MW pre-contingency to eliminate voltage violations	$69.3		60
230 kV Line Upgrades	None	Brandon CTs must be on at 30 MW pre-contingency to eliminate voltage violations	>$75		
Portage West Station	None	None	$114.8	High level of uncertainty in the estimate for the transmission line length.	60
Portage East station	None	Brandon CTs must be on at minimum generation to eliminate voltage violations	$122.9		60

**Note: The existing concept for D83P is to terminate the line at Dorsey station sharing a breaker with line D54N. In the event of a fault plus a stuck breaker, lines D83P and D54N will trip and line overloads will occur. For this reason, it is assumed that the concept is revised to move the Dorsey termination to another bay on the Dorsey 230 kV bus.*

Based on the results presented in Table 3, the following options are eliminated from further consideration:

- Brandon 115 kV Breaker Replacement: This option is unable to eliminate any of the potential violations.
- Kettle Generation Transfer: Transfer of two Kettle units has a minimal positive impact on reliability performance of the Brandon/Portage area transmission system. However, this may be a low cost option that can be used to reduce the operating burden on the Brandon CTs.
- Vermillion to Neepawa Line: This mitigation option does not provide a significant improvement in transmission system reliability and the cost is high.
- Raven Lake to Neepawa Line: This mitigation option does not provide a significant improvement in transmission system reliability and the cost is high.
- Dorsey to Cornwallis Line: This mitigation option does not provide a significant improvement in transmission system reliability and the cost is high as compared to D83P.

- D54N Sectionalization: The estimated cost of this option is higher than D83P and it has a negative effect on the contingency overloads on line D12P.
- 230 kV Line Upgrades: This option involves reconductoring of several 230 kV lines in the area. The cost of upgrading these lines is expected to be higher than D83P and the reliability performance of such upgrades is poor as compared to D83P.
- Portage East station: The cost of this option is close to the cost of Portage West station but it does not effectively eliminate the need to operate combustion turbines as indicated in the simulation results of 2027 winter peak case.
- Cornwallis SVC: Study results show that an SVC with 225 MVAR capacitive reactive power capability combined with a D12P reconductor project will provide comparable performance in terms of steady state voltages and thermal loading to the D83P project. Table 4 compares D83P with a 225 MVAR SVC and shows that D83P is preferred. Based on this information and discussions presented in Section 7.3, an SVC option is eliminated from consideration.

Table 4: D83P vs 225 MVAR SVC Installation Plus D12P Reconductor

	D83P	225 MVAR SVC and D12P Reconductor
Cost	$64M	$70.5M for a 110 MVAR SVC and D12P re-conductor not including termination at Cornwallis station. A 225 MVAR SVC is needed to provide reactive support
P-V curve (Section 7.3)	No issues	No issues
Q-V curve (Section 7.3)	No issues	Lower security margin as compared to D83P

6. Proposed Transmission Development Plans

Several transmission enhancement plans are developed based on the study results presented in Section 5. Five viable development plans as detailed in Appendix C are selected for further evaluations. The in-service-dates for the bank capacity options are based on the required-by date of 2019 and the estimated schedule requirements listed in Appendix B. The in-service-date for the 230 kV voltage/overload options is assumed to be 2025 to be consistent with the current planned in service date for D83P. Studies are performed to evaluate and compare the performance of those transmission development plans. Economic analysis is also performed and presented in this report. Quantitative reliability assessment is also performed to evaluate the impact of each development plan on the Manitoba Hydro bulk electric system (BES) in terms of change in expected unserved energy (ΔEUE). The detailed information on the ΔEUE assessment will be provided in a separate report. The proposed development plans are:

1. **Development Plan 1**: New Dorsey to Portage 230 kV line (D83P) in 2025 and Portage South Bank Addition in 2022.
2. **Development Plan 2**: New Dorsey to Portage 230 kV line (D83P) in 2025 and Portage South Bank Upgrades in 2021.
3. **Development Plan 3**: New Dorsey to Portage 230 kV line (D83P) in 2025, Portage to Stanley load Transfer and Stanley Capacitor Bank in 2021.
4. **Development Plan 4**: Sectionalize D14S to create a new station near Elm Creek in 2024. Install a 230/66 kV transformer and a three breaker 66 kV ring bus at the new station. Build a 30 km 230 kV line from the new station to Portage South station and reconductor line D12P in 2025.
5. **Development Plan 5**: Build a new station west of Portage. Install a 230/66 kV transformer and a three breaker 66 kV ring bus at the new station in 2024. Sectionalize P81C into the new station and build a new 75 km line from Dorsey to the new station in 2025.

The steady state performance of each of the above development plans is evaluated using 2027 summer peak and winter peak cases. Contingency analysis was performed with G82P phase shifter flow set to 0 MW and with Brandon CTs offline (without system adjustment). If thermal overloads or voltage violations were identified, then G82P phase shifter was adjusted up to 250 MW north flow to alleviate some of the issues that were found in the steady state power flow simulations. The purpose of this analysis is to determine the minimum amount of Brandon generation required to eliminate thermal and voltage issues for comparison purpose. Appendix D shows the results of steady state analysis for each development plan with and without system adjustments. Table 5 summarizes and compares the steady state performance of these proposed development plans. It can be seen from Table 5 that all alternatives considered effectively eliminate voltage violations beyond the 2027 study year. However, the Portage West station development is the only option that will eliminate the need to operate Brandon CTs pre-contingency.

Table 5: Summary of Simulation Results (Development Plans, Voltage and Overload)

Development Plan	Thermal Overloads	Voltage Violations	Brandon Generation Required for Base Case (MW)	Brandon Generation Required for High MH-SP Case (MW)
1 and 2	None	None	0	Minimum
3	None	None	0	Minimum
4	None	None	Minimum	Minimum
5	None	None	0	0

7. Additional Considerations

In order to evaluate viable transmission development alternatives for Brandon/Portage area additional studies are performed to examine the impacts of higher load growth, series compensation of transmission lines, options of reactive support in the area and the opportunity of salvaging aged asset.

7.1. Extra Load

An industrial load addition was simulated at Portage South Station for each development plan considered. Additional 10 MVA and 20 MVA loads were modeled to examined the impact of different sizes of load interconnections on the 230/66 kV bank capacity at Portage South station. For the purpose of this analysis, it is assumed that Elm Creek station is unable to serve a major load addition in the Portage la Prairie area due to the long length of 66 kV lines required. It is also assumed that 66 kV load transfers are available in the event of a Portage West 230/66 kV bank outage. Table 5 shows the available capacity at Portage South station in 2027 winter peak case. It can be seen from Table 5 that the system is unable to support a 20 MVA load addition in 2027 for the Elm Creek station (Development Plan 3) or the Stanley Load transfer development plans (Development Plan 4). The Portage South Upgrade (Development Plans 1 and 2) and the Portage West Development (Development Plan 5) will put Manitoba Hydro in a much stronger position to serve additional load in the area.

Table 5: Available Firm 230/66 kV Transformation Capacity at Portage South Station (2027 Winter Peak Loading)

Development Plan	Base Case	10 MVA Load Addition	20 MVA Load Addition
1	96 MVA	86 MVA	76 MVA
2	39 MVA	29 MVA	19 MVA
3	11 MVA	1 MVA	-9 MVA
4	20 MVA	10 MVA	0 MVA
5	96 MVA	86 MVA	76 MVA

Table 6 shows the estimated required-by-date for the next 230/66 kV capacity enhancement for each development plan. It can be seen from Table 6 that if there is a 20 MVA load addition, then Development Plan 3 (Elm Creek Station) will require an enhancement in 2027 and the Stanley Load Transfer (Development Plan 4) will require an enhancement in 2020. All remaining alternatives provide substantial transformation capacity for the Portage la Prairie area.

Table 6: Estimated Required-By-Date of the next 230/66 kV Transformation Capacity Enhancement (Winter Peak Loading)

Development Plan	Base Case	10 MVA Extra Load	20 MVA Extra Load
1 and 2	Beyond 2038	Beyond 2038	Beyond 2038
3	2035	2027	2020
4	Beyond 2038	2035	2027
5	Beyond 2038	Beyond 2038	Beyond 2038

7.2. Series Capacitor

The impacts of series capacitor compensation on several 230 kV lines are examined using the 2027 winter peak case. Lines D54N, D12P, P81C and G37C were modeled with 70% compensation in the studies. The study results are presented in Table 7. It can be seen from Table 7 that series compensation on those 230 kV lines does not eliminate the voltage violations. In addition, the only situation that reduces contingency loading on line D12P is G37C compensation. Series capacitor compensation is, therefore, not considered as a viable mitigation option for transmission enhancement in the area.

Table 7: Summary of Simulation Results
(Impact of Series Capacitor Compensation, Voltage and Overload)

Compensated Lines	Voltage Violations	Overloads
D12P	Multiple voltage violations, Running of Brandon CTs cannot eliminate these violations	D12P contingency loading increases
P81C	Multiple voltage violations, Running of Brandon CTs cannot eliminate these violations	D12P contingency loading increases
D54N	Multiple voltage violations, Running of Brandon CTs cannot eliminate these violations	No impact on D12P contingency loading
G37C	Multiple voltage violations, Running of Brandon CTs cannot eliminate these violations	D12P contingency loading decreases
P81C & D54N	Multiple voltage violations, Running of Brandon CTs cannot eliminate these violations	D12P contingency loading increases
P81C & D54N & G37C	Multiple voltage violations, Running of Brandon CTs cannot eliminate these violations	D12P contingency loading increases

7.3. Reactive Support

One of the major issues in Brandon area is the low voltages at several 115 kV and 230 kV stations in winter loading conditions. Several options for reactive support in the area are, therefore, considered. These reactive support options include capacitor banks, SVC, transmission lines and the use of Brandon CTs. The reactive support options of shunt capacitors and an SVC are discussed in this section using P-V and Q-V curve analysis. NERC Reliability Guideline [15] discusses the use of P-V curve analysis and states that typically a 5% voltage security margin is used for single contingencies but extensive studies are required to determine an appropriate margin based on engineering judgment, operational experience, and extensive testing. The voltage security margin represents the distance from the operating point to the nose of the P-V curve. Manitoba Hydro does not have an established minimum voltage security margin, therefore the NERC suggested 5% margin is used in this analysis. In the studies described in this section, the following assumptions are used:

- 365 MW exports to Saskatchewan on the MH-SPC 230 kV interface, 70MW import from Saskatchewan on the MH-SPC 115 kV interface.
- Brandon Unit 5 is in synchronous condenser mode
- Brandon Unit 6 and Unit 7 are offline
- G82P flow is 250 MW north.

- 2027 winter peak cases are used.
- In order to achieve a variety of Manitoba Load levels, a transfer analysis is performed where the Northern Collector System acts as the source system and Manitoba load (Area 667) acts as the sink.

Reactive support in the form of capacitor banks is considered first as an option to support voltage and the performance of capacitor banks are compared for the following three cases using P-V curves:

- Base Case: It is represented by 2027 winter peak case without any additional capacitor bank.
- Lumped Capacitor Case: It is represented by 2027 winter peak case with an additional 50 MVAR capacitor bank at the Cornwallis 230 kV bus.
- Distributed Capacitor Case: It is represented by 2027 winter peak case with additional capacitor banks of 20 MVARs at Portage South, 10 MVARs at Portage Saskatchewan, and 20 MVARs at Neepawa 230 kV station.

The P-V curves are developed by increasing Manitoba load (Area 667) in variable steps (most often in an approximate 40 MW steps) under the worst contingency and corresponding changes in voltage at Portage South 230 kV station are observed. Figure 2 shows the P-V curves for the base, the lumped and the distributed capacitor cases. It is assumed that the nose of the P-V curve is reached if the case does not solve for a particular load level under the worst contingency (D12P contingency). The step size was reduced to 1 MW steps at load levels close to the nose of the P-V curve to achieve a high precision for the estimated value of the nose of the curve. It can be seen from Figure 2 that both lumped and the distributed capacitor cases help in extending the nose of P-V curve. From the nose of the P-V curve, load serving capability can be estimated. The load serving capability is defined in this section as the maximum load without a violation of voltage criteria and with a voltage security margin of more than 5% (MW value of load at the nose of the P-V curve multiplied by 0.95). Table 8 shows maximum amount of Manitoba load that can be served without voltage violations and with a security margin greater than 5% for each of the three study cases considered. For example load serving capability for the base case can be calculated by multiplying the MW value of the load at the nose of the P-V curve by 0.95 (4401*0.95 = 4181 MW). It can be seen from Table 8 that the limiting factor for all cases is the security margins. It can also be seen from Table 8 that 50 MVARs of capacitor banks will only allow for a maximum increase of 1.6% in load serving capability (66 MW of Manitoba load, 20 MW of Brandon area load).

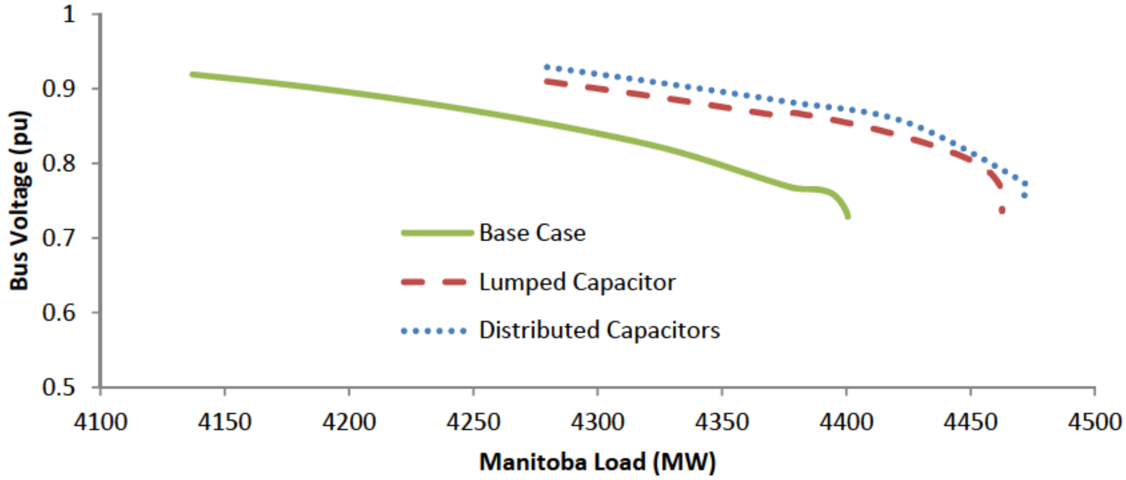


Figure 2: P-V Curve at Portage South 230 kV Bus
(D12P contingency, 2027 winter peak)

Table 8: Comparison of Load Serving Capability (Capacitor Options)

	Manitoba Load at the nose	Load Serving Capability (area 667)	Limiting Factor
Base Case	4401 MW	4181 MW	Security Margin
50 MVAR Lumped Capacitor	4462 MW	4239 MW	Security Margin
50 MVAR Distributed Capacitor	4471 MW	4247 MW	Security Margin

Based on the P-V curve analysis it can be concluded that shunt capacitor compensation helps to improve the voltage performance of the system in the area but will not provide sufficient load serving capability. The option of providing reactive support by shunt capacitor is, therefore, not an ideal option.

Reactive support in the form of an SVC is also considered as an option to improve the voltage performance in the area. An SVC was considered at multiple sites and study results show that the performance of an SVC at Cornwallis is superior to other sites for example Portage South. For the purpose of this analysis, an SVC was modeled at Cornwallis station because it has been considered in past transmission planning studies [2] and it provides better reliability performance. In this analysis P-V curves were obtained to compare the performance of D83P with different sizes of SVCs at Cornwallis 230 kV station. Figure 3 shows the P-V curves for D83P, a 200 MVAR SVC and a 225 MVAR SVC. It can be seen from Figure 3 that both options of SVC and D83P could provide sufficient voltage security margin.

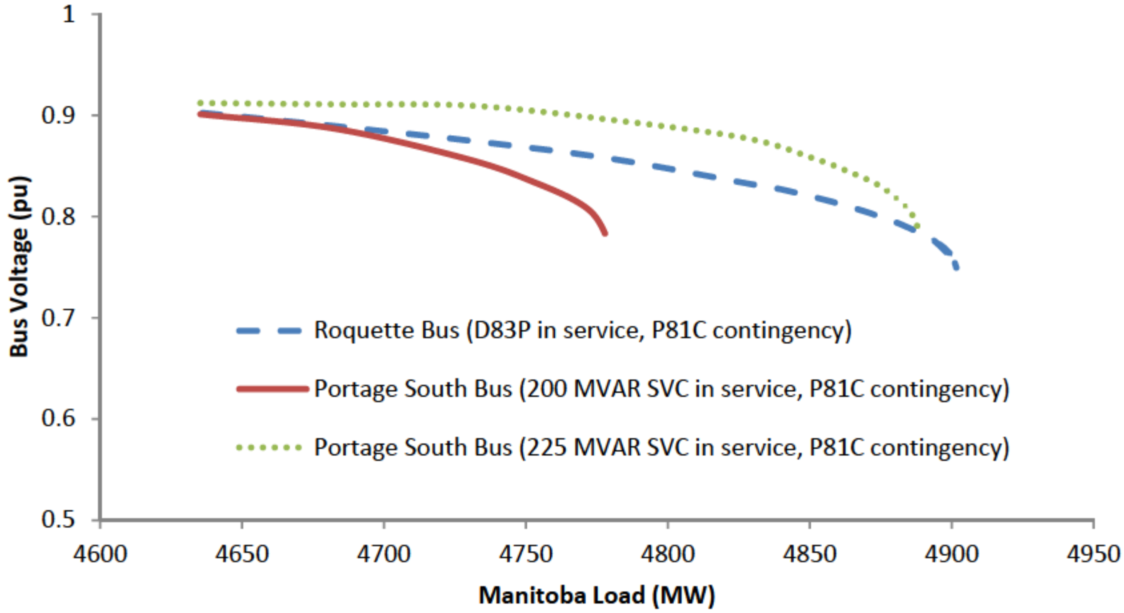


Figure 3: P-V Curve at Critical Buses (2027 winter peak)

Table 9 compares the load serving capability of D83P and two different sizes of SVC options. It can be seen from Table 9 that 225 MVAR SVC is required to provide comparable load serving capability to D83P.

Table 9: Comparison of Load Serving Capability (D83P and SVC Options)

	Manitoba Load at the nose	Load Serving Capability (area 667)	Security margin	Limiting Factor
D83P	4902 MW	4636 MW	5.4%	Voltage at Roquette 230 kV Bus
200 MVAR SVC	4778 MW	4539 MW	5.0%	Security Margin
225 MVAR SVC	4888 MW	4643 MW	5.0%	Security Margin

Additional studies are performed using Q-V curves to compare the performance of a 225 MVAR SVC with the five proposed development plans. Figure 4 shows the Q-V curve at critical 230 kV buses with Manitoba load at 4636 MW. It can be seen from Figure 4 that a 225 MVAR SVC responds poorly to changes in reactive power in the area as compared to the five proposed development plans. Based on this analysis and other considerations, an SVC is not a competitive option for Brandon/Portage area transmission enhancement in terms of technical performance and cost, which is discussed in Section 5.3.

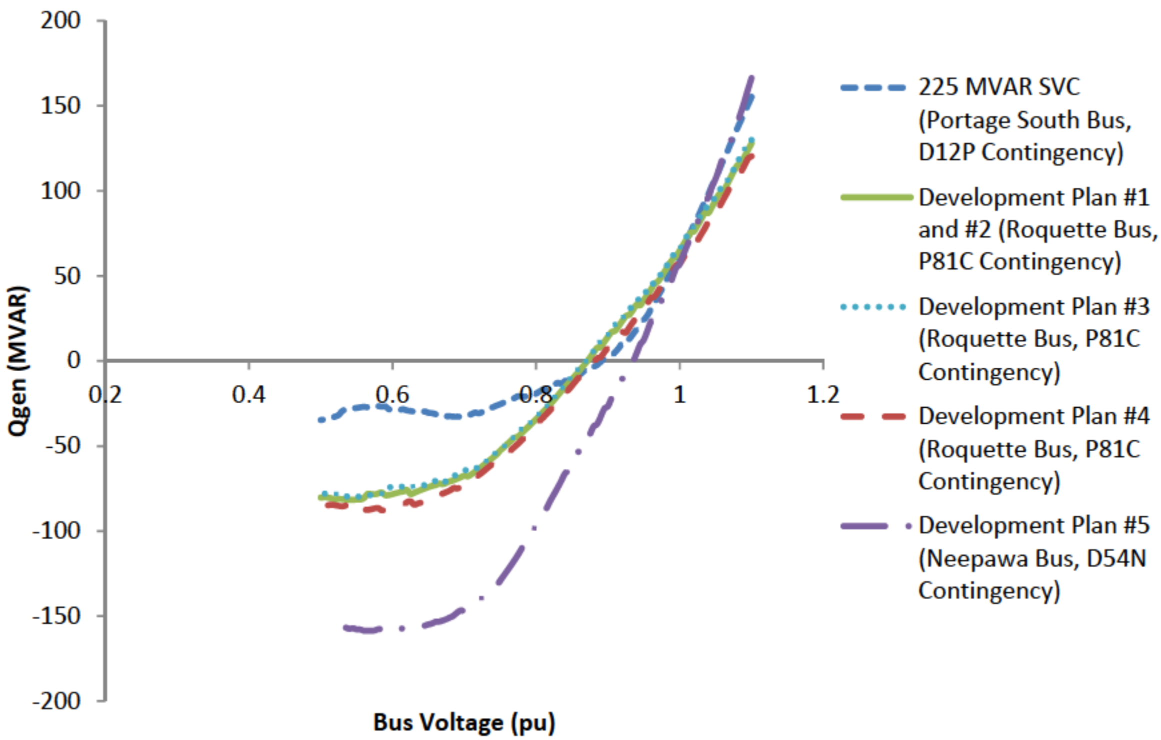


Figure 4: Q-V Curve at Critical 230 kV Buses in the Area (2027 winter peak)

7.4. Station Salvage

An opportunity has been identified to transfer load from Portage Saskatchewan station to Portage South station to allow for the salvage of aging assets at Portage Saskatchewan station. This is not expected to be a viable option with Elm Creek station (Development Plan 3) or a Stanley load transfer (Development Plan 4) due to the 66 kV limitations to supply Portage area load from Elm Creek or from Stanley station. However, a Portage South capacity enhancement (Development Plans 1 and 2) or a Portage West station development (Development Plan 5) will position the system well to salvage Portage Saskatchewan 115/66 kV banks.

A sensitivity analysis was performed to determine the impact of a Portage Saskatchewan Station Salvage on Development Plans 1, 2 and 5. The 2027 winter peak cases were analyzed with a high stress scenario on the Manitoba to Saskatchewan interface. Table 10 compares the impacted bus voltages resulting from the worst contingency. It can be seen from Table 10 that the Portage Saskatchewan station salvage will have a small positive impact on the worst case 230 kV bus voltage.

Table 10: Impact of Portage Saskatchewan Station Salvage on Voltage

Development Plan	Worst Contingency	Impacted Bus	Voltage Before Salvage (pu)	Voltage After Salvage (pu)
1 and 2	P81C Open at Portage South	Roquette 230 kV bus	0.924	0.929
5	P81C	Neepawa 230 kV bus	0.917	0.923

Table 11 compares the impacted line loading resulting from the worst contingencies. It can be seen from Table 11 that Portage Saskatchewan station salvage will have a small negative impact in terms of 230 kV line loading. Based on these results, it is expected that the Portage Saskatchewan station salvage would advance the reconductoring of line D12P but would have a negligible impact on the voltage mitigation in the Brandon area.

Table 11: Impact of Portage Saskatchewan Station Salvage on Line Loading

Development Plan	Worst Contingency	Impacted Line	Line Loading Before Salvage (% of rating)	Line Loading After Salvage (% of rating)
1 and 2	D83P	D12P	85.0	90.5
5	Dorsey to Portage West Line	D12P	87.0	92.0

7.5. Longevity Analysis

A transfer analysis was performed to determine the impact of Manitoba Load growth on each development plan. In the transfer analysis, the source was Northern Collector System (NCS) generation and the sink was area 667 Manitoba Domestic load. The purpose of the transfer analysis is to estimate the time frame of next required system upgrades for each development plan. The following assumptions were used.

- 2027 summer peak and winter peak cases were considered.
- For summer peak cases, Manitoba to US export is reduced to leave room for dispatching the NCS generation. Power transfer was increased in 25 MW increments in the transfer analysis for both the summer and winter peak cases. . The 2016 Corporate Electric Load Forecast [16] was used to estimate the Manitoba domestic load level for each year beyond 2027.
- The high stress MH-SPC interface cases were used in this analysis.
- Brandon Unit 6 was on generating 133 MW output to mitigate transmission constraints.

- The contingencies used for this analysis are limited to the area west of Winnipeg, North of the MH-US Border, East of the MH-SP border, and south of Dauphin Vermillion.

Table 12 summarizes the results of the transfer analysis. It can be seen from Table 12 that the expected longevity of Development Plans 1, 2 and 3 is around 2033. The expected longevities of Development Plans 4 and 5 are 2030 and 2035 respectively. The expected longevity of Development Plan 4 can, however be extended to 2033 at the expense of approximately 6 million dollars as indicated in Table 12.

Table 12: Summary of Transfer Analysis Results

Development Plan	Limitation	Comments
1	P81C Overload in 2033/34 winter peak. Voltage violations in 2034/35 winter peak.	
2	P81C Overload in 2033/34 winter peak. Voltage violations in 2034/35 winter peak.	
3	P81C Overload in 2033/34 winter peak. Voltage violations in 2034/35 winter peak.	
4	D14S Overload in 2030/31 winter peak	Estimate for D14S re-sag is $6M. The next limitation is a voltage violation in the winter of 2033/34.
5	P81C overload and Neepawa low voltage in 2035/36 winter peak	

8. Summary and Conclusions

A NRES is performed for Brandon/Portage area to identify potential issues and propose alternatives to enhance the transmission system in the area. The NRES focuses on the steady state performance of the Brandon/Portage area transmission system including the evaluation of base cases (do-nothing), evaluation of six different mitigation options for transformation capacity augmentation and thirteen different mitigation alternatives for transmission system enhancements. Considering the immediate, near term and longer term need of transmission system in the Brandon/Portage area alternative transmission development plans are proposed and compared. Based on the study results the following conclusions can be made:

1. All five development plans proposed for transmission enhancement of Brandon Portage area are recommended for CVF evaluation. The necessary information for CVF evaluation is summarized in the Executive Summary of this report.

2. It is the opinion of the study engineer that there is a high probability of either industrial load growth or the salvage of aging assets at Portage Saskatchewan station. Section 7.1 shows that this will drive the need for additional future 230/66 kV capacity enhancements if Development Plans 3 or 4 are chosen. Development Plans 1, 2, and 5 are, therefore, preferred to reduce the risk of additional capital investment in 230/66 kV capacity within the next ten years.

3. If Development Plan 1 is chosen, there may be a risk of additional costs due to the requirement of a new control building needed for the Portage South Bank 3 addition. It is recommended that CVF analysis be performed to determine the critical cost of the Portage South Bank Addition that may cause the preferred Development Plan to change.

4. Development Plan 5 carries a risk of additional costs due to the high level of uncertainty in transmission line length. It is recommended that these additional factors be addressed with further study before a NRFS is performed for Development Plan 5.

References

[1] System Planning Report SPD 2001/09, "Winnipeg to Brandon Transmission Improvements", August 2001.
[2] System Planning Report "Group System Impact Study Manitoba Hydro Export Power Marketing (MHEM) 185 MW Firm Point to Point Transmission Service Requests", December 2015.
[3] System Planning Report SPD 2015/09, "Portage Saskatchewan Area 115 kV Improvements", March 2016.
[4] System Planning Report "Northern AC Group Study for Kelsey, Wuskwatim and Jenpeg", May, 2012.
[5] System Planning Report SPD 2016/09, "Enbridge Souris West Project R Load Interconnection Facilities Study", April 2017.
[6] Distribution Asset Management Draft Memorandum "Carman and St Leon Cryptocurrency Mining Facility Supply Options", December 2018.
[7] System Planning Report SPD 2014/17, "Group Facilities Study Manitoba Hydro Export Marketing (MHEM) 883 MW Export/Import Firm Point to Point Transmission Service Requests", June 2015.
[8] System Planning Report SPD 2016/13 "Group Facilities Study Manitoba Hydro Export Power Marketing (MHEM) 100 MW Firm Point to Point Transmission Service Requests", January 2017.
[9] System Planning Report SPD 2008/04, "System Impact Study For Manitoba Hydro Wholesale Power & Operations Division Evaluation of Transmission Service Request #84952034", April 2018.
[10] NERC Standard MH-TPL-001-04, "Transmission Planning Performance Requirements", July 2017.
[11] MH Document, "Transmission System Interconnection Requirements", Version 4, July 2016, available on Manitoba Hydro OASIS Website: http://www.oasis.oati.com/woa/docs /MHEB/MHEBdocs/MH_transmission_interconnection_requirements_July2016-final.pdf.
[12] Manitoba Hydro Transfer Capability Methodology for the Planning Horizon, Version 2, December 14, 2016.
[13] PSS®E Product Support Website, http://www.energy.siemens.com/hq/en/services/power-transmission-distribution/power-technologies-international/software-solutions/pss-e.htm
[14] K. Toews, S. Kovnats, R. Arruda, J. Snell, M. Shaw, B. Johnson and J. Westmacott , "Integrated Resource Planning Study-Brandon Combustion Turbine", a report endorsed by 183rd Technical Review Committee Meeting, April 2018.
[15] NERC Reliability Guideline Reactive Power Planning, December 2016.
[16] Manitoba Hydro 2016 Electric Load Forecast, June 2016.

APPENDIX A

Steady State Powerflow Case Summary

Summary Created On : Fri Dec 28 14:56:55 2018

Tie Line Flow (MW)

Case Name	MH->US	MH->SPC 230kV	MH->SPC 115kV	MH->SPC Net	MH->ONT	B10T (S)	S. Ont->US	F3M(S)	E-W Ties West	MWSI	MWEX	NDEX	L20D	R50M	M602F	D604I	G82R/G82P
2018SUM	1462	224	-68	156	-3	163	-10	153	45	760	180	1940	120	107	1367	0	-131
2018WIN	-781	229	-68	160	-1	-163	85	-99	-132	-27	304	-624	-85	57	-443	0	-310
2022SUM-SPHigh	1599	366	60	426	0	164	-5	150	7	794	194	2228	-65	76	1017	571	0
2022SUM-SPLow	1761	328	-67	260	0	165	-5	149	7	828	192	2223	-38	82	1091	625	0
2022WIN-SPHigh	-1476	369	60	428	4	-163	92	-100	-150	-73	342	-621	-264	51	-754	-513	4
2022WIN-SPLow	-1471	323	-67	256	-6	-169	82	-98	-138	-71	340	-627	-258	50	-750	-509	-3
2027SUM-SPHigh	1607	366	60	426	0	164	-5	150	-6	834	212	2216	-70	80	1022	575	0
2027SUM-SPLow	1764	324	-58	266	0	166	-5	150	-6	868	210	2212	-43	86	1094	628	0
2027WIN-SPHigh	-1479	368	60	428	0	-165	47	-101	-109	-188	355	-675	-254	57	-775	-508	1
2027WIN-SPLow	-1474	326	-67	259	-1	-165	47	-101	-108	-187	356	-676	-252	57	-772	-507	1

PGEN (MW)

Case Name	Kelsey	Wuskwatim	Jenpeg	Grand Rapids	Selkirk	Brandon	Pine Falls	Great Falls	McArthur Falls	Seven Sisters	Slave Falls	Pointe du bois	ST Leon	ST Joseph	Winnipeg River
2018SUM	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2018WIN	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2022SUM-SPHigh	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2022SUM-SPLow	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2022WIN-SPHigh	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2022WIN-SPLow	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2027SUM-SPHigh	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027SUM-SPLow	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027WIN-SPHigh	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2027WIN-SPLow	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528

MVar	Reserve							QGen						
Case Name	Dorsey	Riel	Grand Rapids	Seven Sisters	Ponton	Birchtree	Brandon U5	Dorsey	Riel	Grand Rapids	Seven Sisters	Ponton	Birchtree	Brandon U5
2018SUM	1533	931	169	168	150	89	0	167	69	-3	-2	0	6	0
2018WIN	1740	994	191	142	150	96	86	-40	6	-26	24	0	-1	6
2022SUM-SPHigh	1353	987	184	192	150	93	0	347	13	-19	-26	0	2	0
2022SUM-SPLow	1329	945	150	191	150	94	0	371	55	15	-25	0	1	0
2022WIN-SPHigh	1401	917	164	150	150	89	52	299	83	1	16	0	6	40
2022WIN-SPLow	1578	961	180	151	150	95	52	122	39	-15	15	0	0	40
2027SUM-SPHigh	1275	1010	179	180	150	95	0	425	-10	-14	-14	0	0	0
2027SUM-SPLow	1256	968	150	179	151	96	0	444	32	15	-13	-1	-1	0
2027WIN-SPHigh	1447	972	142	148	150	90	52	253	28	23	18	0	5	40
2027WIN-SPLow	1617	997	158	148	148	94	52	83	3	7	18	2	1	40

Load (MW)	Area	Zones					Buses	MHDC (Inverter Side) and NCS PGEN (MW)					
Case Name	667	1646	1647	1648	1649	1650	667206	MHDC (MW)	Lime Stone	Long Spruce	Kettle	Keeyask	Conawapa
2018SUM	3237	835	1255	398	63	687	125	3350	1330	965	1206	0	0
2018WIN	4520	888	2114	444	211	863	146	2377	932	676	845	0	0
2022SUM-SPHigh	3393	813	1273	440	65	803	89	3925	1348	979	1222	595	0
2022SUM-SPLow	3393	813	1273	440	65	803	89	3925	1348	979	1222	595	0
2022WIN-SPHigh	4621	790	2312	457	213	849	89	2136	700	508	635	360	0
2022WIN-SPLow	4621	790	2312	457	213	849	89	1930	631	458	572	325	0
2027SUM-SPHigh	3472	815	1322	467	64	804	89	4016	1350	980	1224	695	0
2027SUM-SPLow	3472	815	1322	467	64	804	89	4016	1350	980	1224	695	0
2027WIN-SPHigh	4778	801	2427	485	215	850	89	2305	757	549	686	390	0
2027WIN-SPLow	4778	801	2427	485	215	850	89	2111	691	502	627	356	0

APPENDIX B

Detailed Cost Estimate Information

B1 - Estimate from Transmission Projects

A. **Options to mitigate voltage/overload issues**

D83P- Build approximately 70 km of transmission line from Dorsey station to Portage South station. Terminate the new line with one additional 230 kV breaker at Dorsey station and one additional 230 kV breaker at Portage South station. A study was completed in 2001 which recommended the line be built in 2007 but it has since been deferred to 2025. Manitoba Hydro has an environmental license for this line and it is a well understood concept so it is considered as one of the mitigation options.

Costs: **(49.6M + 1.85M + 1.85M + 10.6M) = $63.96M**

- $49.6M = 70KMs of 230kV line and assumes OPGW is required, based on current market condition.
- $1.85M = Additional Breaker at Dorsey and any associated switches, arrestors, buswork, controls etc.
- $1.85M = Additional Breaker at Portage South and any associated switches, arrestors, buswork, controls etc.
- $10.6M = Contingency at this stage of development is usually 50% however, the TLine calculation above does include some contingency (15%) and the environmental license and routing is already known so I would recommend reducing the contingency to 20% of the total base cost for this case as there is still a chance that market conditions could increase by the time this line is in service. (53.3 x 20% = $10.6M)

Schedule: 18 Months

- A Transmission Line project of this size would likely require two winter seasons to complete the work. Given that the license is already acquired work could begin December and span two winters completing in the spring.
- Breakers installs would not be on the critical path.

New Station near Elm Creek - Build a new station near Elm Creek Manitoba. Sectionalize Dorsey to St. Leon 230 kV line D14S into the new station. Build approximately 30 km of new 230 kV line from the new station to Portage South station. A new 230 kV breaker is required at Portage South station and a new three breaker 230 kV ring bus is required at the new station.

Costs: **(19.6M + 2M + 26.4M + 1.85M + 24.9M) = $74.8M**

- $19.6M = New Station near Elm Creek, 3x 230kV breakers, brand new station and control building and communication equipment.
- $2M = Sectionalization of 230kV line D14S into station (the line length was not provided so I am assuming less than 1km of total new line is required.
- $26.4M = 30KM of 230kV line from Portage South to New Station

- $1.85M = Additional Breaker at Portage South and any associated switches, arrestors, buswork, controls etc.
- $24.93M = Contingency at this stage of development is usually 50%, given that this new line and station would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.
- Property acquisition and Design would happened concurrently and construction would still require two winters to complete the transmission line work, which wouldn't be able to start until the license is in hand.

Cornwallis SVC– Provide reactive power support in the Brandon area by installing a Static Var Compensator (SVC) at Cornwallis station. Terminate the SVC with a new 230 kV breaker on the Cornwallis 230 kV ring bus. There is a high level of uncertainty regarding the optimal location of the SVC and potential unforeseen costs. For example, it may not be feasible to expand Cornwallis station due to the space or environmental limitations as it is in close proximity to the Assiniboine River, a rail line, natural gas line, and Brandon Generation Station.

Costs: ($33.3M + $16.7M) = $50M

- Costs are based on limited understanding of scope and previous costs. Only example we have of this type of project is the Birchtree station, which was a combination of an Engineering and Procurement contract and internal costs for building the station and installing the SVC.
- $33.3M = Costs of Birchtree SVC (P:06853) are escalated using Policy G911 from when they were installed ($29.5M in 2012 = $M x1.13 = $33.3M)
- Original cost was 51M however there was a new station build as well as the SVC, costs associated with the new station were removed and other construction costs were halved as no detail was recorded to determine the breakdown. Some costs were specifically for the SVC in construction those were accounted for.
- $16.7M = Contingency at this stage of development is usually 50%, given the background information used for the estimate I would think this is still a safe assumption

Schedule: 54 Months

- This is based on the time the Birchtree station took however there may be opportunity to optimize these timelines.

Brandon 115 kV Breaker Replacement– An operating limitation exists at the Brandon GS 115 kV bus due to the non-standard voltage rating of eleven 115 kV breakers. This option considers upgrade of the eleven existing breakers to a minimum continuous voltage rating of 127 kV. This option was also analyzed as part of report SPD 2015/09 to improve 115 kV bus voltages in the area.

Costs: ($11M + 2.2M) = $13.2M

- $11M = Recent Breaker Replacement projects include MchPhillips (2x 115kv = $1M) and Dorsey (15 x 230kV = $11M), purchasing and installing 11 new breakers in an existing station is estimated at $13.8M but includes other station equipment such as batteries or switches, if the breakers are going on existing pads and require no new equipment then the price would be $6M.
- $2.2M = Contingency is normally 50% for estimates at this stage, however given the recent data available and the simplicity of this type of work a 20% contingency is adequate.

Schedule: 36 Months

- Lead times for the breakers and station design is approximately 1 year, allowing two years for installation. Outages will dictate the schedule, if more than one breaker can be taken out at a time the schedule could be compressed.

Vermillion to Neepawa Line– Install a 130 km 230 kV line from Vermillion station to Neepawa 230 kV station. Terminate the new line with one additional 230 kV breaker at Vermillion station and one additional 230 kV breaker at Neepawa 230 kV station.

Costs: ($92.9M + 1.85M + 1.85M + 48.3M) = $144.9M

- $92.9M = 130KM of 230kV line from Vermillion to Neepawa
- $1.85M = Additional Breaker at Vermillion and any associated switches, arrestors, buswork, controls etc.
- $1.85M = Additional Breaker at Neepawa and any associated switches, arrestors, buswork, controls etc.
- $48.3M = Contingency at this stage of development is usually 50%, given that this new line would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two to three years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.
- Property acquisition and Design would happen concurrently and construction would still require two winters to complete the transmission line work, which wouldn't be able to start until the license is in hand.

Raven Lake to Neepawa 230 kV Line- Install a 100 km 230 kV line from Raven Lake station to Neepawa 230 kV station. Terminate the new line with two additional 230 kV breakers at Raven Lake station and one additional 230 kV breaker at Neepawa 230 kV station.

Costs: **($70.8M + 3.8M + 1.85M + 38.2M) = $114.7M**

- $70.8M = 100KM of 230kV line from Raven Lake to Neepawa
- $3.8M = Two Additional Breaker at Raven Lake and any associated switches, arrestors, buswork, controls etc.
- $1.85M = Additional Breaker at Neepawa and any associated switches, arrestors, buswork, controls etc.
- $38.2M = Contingency at this stage of development is usually 50%, given that this new line would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two to three years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.
- Property acquisition and Design would happen concurrently and construction would still require two winters to complete the transmission line work, which wouldn't be able to start until the license is in hand.

D83P and Portage to Cornwallis Line– Install the 70 km 230 kV line from Dorsey to Portage South station D83P. Terminate the new line with one additional 230 kV breaker at Dorsey station and one additional 230 kV breaker at Portage South station. In addition, install another 130 km 230 kV line from Portage South station to Cornwallis station. Terminate the new line with one additional 230 kV breaker at Dorsey station and one additional 230 kV breaker at Portage South station.

Costs: ($49.6M + 1.85M + 1.85M + 92.9M + 1.85M +1.85M + 75M) = $224.9M

- $49.6M = 70KMs of 230kV line and assumes OPGW is required, based on current market condition.
- $1.85M = Additional Breaker at Dorsey and any associated switches, arrestors, buswork, controls etc.
- $1.85M = Additional Breaker at Portage South and any associated switches, arrestors, buswork, controls etc.
- $92.9M = 130KM of 230kV line from Portage South to Cornwallis
- $1.85M = Additional Breaker at Cornmallis and any associated switches, arrestors, buswork, controls etc.
- $1.85M = Additional Breaker at Portage South and any associated switches, arrestors, buswork, controls etc.
- $75M = Contingency at this stage of development is usually 50%, given that this new line would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two to three years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.
- Property acquisition and Design would happen concurrently and construction would still require two winters to complete the transmission line work, which wouldn't be able to start until the license is in hand.

Dorsey to Cornwallis Line– Install a 210 km 230 kV line from Dorsey to Cornwallis station. Terminate the new line with one additional 230 kV breaker at Dorsey station and one additional 230 kV breaker at Cornwallis station.

Costs: ($149M + 1.85M + 1.85M + 76M) = $228.7M

- $149M = 210KMs of 230kV line and assumes OPGW is required, based on current market condition.
- $1.85M = Additional Breaker at Cornmallis and any associated switches, arrestors, buswork, controls etc.
- $1.85M = Additional Breaker at Dorsey and any associated switches, arrestors, buswork, controls etc.
- $76M = Contingency at this stage of development is usually 50%, given that this new line would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two to three years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.
- Property acquisition and Design would happen concurrently and construction would still require two winters to complete the transmission line work, which wouldn't be able to start until the license is in hand.

D83P and Portage to Neepawa Line– Install a 70 km 230 kV line from Dorsey to Portage South station (D83P). Terminate the new line with one additional 230 kV breaker at Dorsey station and one additional 230 kV breaker at Portage South station. In addition, install another 111 km 230 kV line from Portage South station to Neepawa station. Terminate the new line with one additional 230 kV breaker at Dorsey station and one additional 230 kV breaker at Portage South station.

Costs: ($49.6M + 1.85M + 1.85M + 78.6M + 1.85M + 1.85M + 67.8M) = $203.4M

- \$49.6M = 70KMs of 230kV line and assumes OPGW is required, based on current market condition.
- \$1.85M = Additional Breaker at Dorsey and any associated switches, arrestors, buswork, controls etc.
- \$1.85M = Additional Breaker at Portage South and any associated switches, arrestors, buswork, controls etc.
- \$78.6M = 11KMs of 230kV line and assumes OPGW is required, based on current market condition.
- \$1.85M = Additional Breaker at Dorsey and any associated switches, arrestors, buswork, controls etc.
- \$1.85M = Additional Breaker at Neepawa and any associated switches, arrestors, buswork, controls etc.
- \$67.8M = Contingency at this stage of development is usually 50%, given that this new line would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two to three years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.

- Property acquisition and Design would happen concurrently and construction would still require two winters to complete the transmission line work, which wouldn't be able to start until the license is in hand.

Sectionalize D54N– Sectionalize 230 kV line D54N north of Portage la Prairie. Build two 30 km 230 kV lines from line D54N sectionalization to Portage South station and terminate both lines onto the Portage South bus with two new 230 kV breakers.

Costs: (\$42.5M + 3.7M + 23.1M) = \$69.3M

- \$42.5M = 60KMs of 230kV line and assumes OPGW is required, based on current market condition.
- \$3.7M = Two additional Breakers at Portage South and any associated switches, arrestors, buswork, controls etc.
- \$23.1M = Contingency at this stage of development is usually 50%, given that this new line would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two to three years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.

~~**230 kV Line Upgrades–**~~This option is removed as a result of discussions between System Planning and Transmission & Civil Design Department.

Reconductor Line D12P– String line D12P (66 km) with a new conductor (expected to be 795 ACSS) to increase the capacity.

Costs: (\$16.4M + \$4.1M) = \$20.5M

- \$16.4M = 66KMs of 230kV reconductoring is expected to be 35% of new line costs.
- \$4.1M = Contingency at this stage of development is usually 50%, however given the simplicity of the project I think a 25% contingency would be sufficient. It should be noted that it is assumed that existing towers would not need to be replaced to handle a the new conductor, if they did the project costs would essentially be that of a new transmission line (\$47M).

Schedule: 18-24 Months

Assumption would be that no environmental license would be required as the work would be happening on an existing ROW such as the case with the South West Winnipeg Project. The timeline would be for design, procurement and construction which would likely be capable in one winter season, but we be safer to plan in two.

Reconductor Line D14S– String 64 km of line D14S with a new conductor (expected to be 795 ACSS) to increase the capacity.

Costs: ($15.9 + $4.0M) = $19.9M

- $15.9M = 64KMs of 230kV reconductoring is expected to be 35% of new line costs.
- $4.0M = Contingency at this stage of development is usually 50%, however given the simplicity of the project I think a 25% contingency would be sufficient. It should be noted that it is assumed that existing towers would not need to be replaced to handle a the new conductor, if they did the project costs would essentially be that of a new transmission line ($47M).

Schedule: 18-24 Months

Assumption would be that no environmental license would be required as the work would be happening on an existing ROW such as the case with the South West Winnipeg Project. The timeline would be for design, procurement and construction which would likely be capable in one winter season, but we be safer to plan in two.

Rerate Line D12P– Re-rate the operating temperature of line D12P (66 km) from 75 deg C to 100 deg C.

Costs: ($3M + $3.0M) = $6M

- $3M = 66KMs of 230kV retensioning which is expected to be $38K/km.
- $3M = Contingency at this stage of development is usually 50%, however there could be a risk of additional efforts such as tower replacements for additional height or reconductoring, this project has potential to increase in cost drastically as the scope is developed, I would recommend 100% contingency in this case.

Schedule: 18-24 Months

Assumption would be that no environmental license would be required as the work would be happening on an existing ROW such as the case with the South West Winnipeg Project. The timeline would be for design, procurement and construction which would likely be capable in one winter season, but we be safer to plan in two.

Rerate Line D14S– Re-rate the operating temperature of 64 km of line D14S from 75 deg C to 100 deg C.

Costs: ($3M + $3.0M) = $6M

- $3M = 64KMs of 230kV retensioning which is expected to be $38K/km.
- $3M = Contingency at this stage of development is usually 50%, however there could be a risk of additional efforts such as tower replacements for additional height or reconductoring, this project has potential to increase in cost drastically as the scope is developed, I would recommend 100% contingency in this case.

Schedule: 18-24 Months
Assumption would be that no environmental license would be required as the work would be happening on an existing ROW such as the case with the South West Winnipeg Project. The timeline would be for design, procurement and construction which would likely be capable in one winter season, but we be safer to plan in two.

Stanley Capacitor Bank – Install three steps of 20 MVAR capacitor banks on the Stanley 66 kV bus (60 MVAR total). Terminate the capacitor bank on the 66 kV bus with one 66 kV breakers. Three circuit switchers will also be required (one for each step).

Costs: ($9.4M + $4.7M) = $14.1M

- $9.4M = 3 Capacitor Banks and one 66kV breaker, plus necessary switches.
- $4.7M = Contingency at this stage of development is usually 50% as there are a lot of unknowns about the scope and what might be required at site with regards to grounding, station layout and availability.

Schedule: 18-24 Months
Capacitor Banks lead times would dictate the critical path of the project, it would be a safe assumption that design and material would take approximately one year, with construction ranging from 6- 12 months.

Portage West Station– Build a new station west of Portage la Prairie. Build a new 75 km 230 kV line from Dorsey to the new station. Terminate the new line, P81C and a radial 230 kV line to the Roquette site with a new 3 breaker 230 kV ring. Terminate the new line at Dorsey station with one breaker.

Costs: (19.6M + 2M + 53.1M + 1.85M + 5.6M + 41M) = $123.2M

- $19.6M = New Station Portage West, 3x 230kV breakers, brand new station and control building and communication equipment.

- $2M = Radial Line to Roquette (the line length was not provided so I am assuming less than 1km of total new line is required).
- $53.1M = 75KM of 230kV line from Portage South to New Station
- $5.6M = 3 Breaker Ring at Roquette
- $1.85M = Additional Breaker at Dorsey and any associated switches, arrestors, buswork, controls etc.
- $41M = Contingency at this stage of development is usually 50%, given that this new line and station would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two to three years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.
- Property acquisition and Design would happened concurrently and construction would still require two winters to complete the transmission line work, which wouldn't be able to start until the license is in hand.

Portage East Station– Build a new station east of Portage la Prairie. Build a new 68 km 230 kV line from Dorsey to the new station. Build another 14 km 230 kV line from the new station to Portage South station. Terminate the two new lines with a new 2 breaker 230 kV ring. Terminate the new line at Dorsey station with one 230 kV breaker and terminate the other new line at Portage South station with one 230 kV breaker.

Costs: (17.7M + 12.3M + 48.2M + 1.85M + 1.85M + 41M) = $122.9M

- $17.7M = New Station Portage West, 2x 230kV breakers, brand new station and control building and communication equipment.
- $12.3M = 14KM line from New Station to Portage South Station
- $48.2M = 68KM of 230kV line from Dorsey to New Station
- $1.85M = Additional Breaker at Dorsey and any associated switches, arrestors, buswork, controls etc.
- $1.85M = Additional Breaker at Portage South and any associated switches, arrestors, buswork, controls etc.
- $41M = Contingency at this stage of development is usually 50%, given that this new line and station would require an environmental licenses and property, the route would not be known and that market conditions for construction and material could go up in the future I would recommend 50%.

Schedule: 60 Months

- Licensing requirements for this project would be on the critical path and would take approximately two to three years to acquire. This is based on typical Licensing estimated timelines, some projects of late (MMTP) have taken much longer, but others such as Poplar Bluff, was less than a year.
- Property acquisition and Design would happened concurrently and construction would still require two winters to complete the transmission line work, which wouldn't be able to start until the license is in hand.

B. Options to provide additional 230/66 kV transformation capacity

Portage South Third Bank– Install a third 95 MVA 230/66 kV transformer bank. There is a high level of uncertainty for the station layout because the current location of the control building limits a typical station expansion. For the purpose of this analysis, the following assumptions will be made:

- Acquire land and expand the station to allow for an additional 230 kV bay to the north.
- Install a new control building at the north end of the station with new protection and control equipment.
- Salvage the existing control building and associated equipment.

Costs: **($17.6M + $8.8M) = $26.4M**

- $17.6M = New 95MVA transformer Bay, with site expansion and control building and communication equipment, assumed half of the site expansion costs for a new station ($3.75M as there wasn't a per sq foot cost).
- $8.8M = Contingency at this stage of development is usually 50% as there are a lot of unknowns about the scope, this would also cover the salvage costs for the building.

Schedule: 24-48 Months

Transformer lead times would be upwards of a year leaving one year for construction. The site expansion could require an environmental license which could add two years to the project timeline.

Portage South Bank Upgrade– Salvage the two existing 230/66 kV transformer banks at Portage South station and replace them with two new 140 MVA 230/66 kV transformer banks.

Costs: **($18.5M + $9.3M) = $27.8M**

- $18.5M = Two new 140MVA transformers, with no site expansion, control building or communication equipment required.

- \$9.3M = Contingency at this stage of development is usually 50% as there are a lot of unknowns about the scope and what might be required at site with regards to grounding, station layout and availability.

Schedule: 18-24 Months
Transformer lead times would be upwards of a year leaving one year for construction.

New 230/66 kV Transformer Bank near Elm Creek– Install a new 230/66 kV transformer bank at the proposed station near the town of Elm Creek Manitoba. Install a new three breaker 66 kV ring bus and terminate the new bank with one 230 kV breaker.

Costs: (\$14M + \$7M) = \$21M
- \$14M = New 95MVA transformer, with no site expansion, control building. Assumed upgraded communication equipment required to support new breakers, includes the breakers.
- \$7M = Contingency at this stage of development is usually 50% as there are a lot of unknowns about the scope and what might be required at site with regards to grounding, station layout and availability.

Schedule: 18-24 Months
Transformer lead times would be upwards of a year leaving one year for construction.

New 230/66 kV Transformer Bank near at Portage West Station– Install a new 230/66 kV transformer bank at the proposed station east of Portage la Prairie Manitoba. Install a new three breaker 66 kV ring bus and terminate the new bank with one 230 kV breaker.

Costs: (\$14M + \$7M) = \$21M
- \$14M = New 95MVA transformer, with no site expansion, control building. Assumed upgraded communication equipment required to support new breakers, includes the breakers.
- \$7M = Contingency at this stage of development is usually 50% as there are a lot of unknowns about the scope and what might be required at site with regards to grounding, station layout and availability.

Schedule: 18-24 Months
Transformer lead times would be upwards of a year leaving one year for construction.

New 230/66 kV Transformer Bank near at Portage East Station– Install a new 230/66 kV transformer bank at the proposed station west of Portage la Prairie Manitoba. Install a new three breaker 66 kV ring bus and terminate the new bank with one 230 kV breaker.

Costs: **($14M + $7M) = $21M**

- $14M = New 95MVA transformer, with no site expansion, control building. Assumed upgraded communication equipment required to support new breakers, includes the breakers.
- $7M = Contingency at this stage of development is usually 50% as there are a lot of unknowns about the scope and what might be required at site with regards to grounding, station layout and availability.

Schedule: 18-24 Months
Transformer lead times would be upwards of a year leaving one year for construction.

C. Portage Saskatchewan Station Work

An opportunity has been identified to salvage Portage Saskatchewan station and transfer the load to a new 230/66 kV development. Please provide estimates for the following work:

- Salvage the 115/66 kV transformers, Bank 6 and Bank 7
- Salvage the 115 kV ring bus including breakers R2, R3, R4, R5, R6 and R7.
- Salvage the 66 kV bus including breakers 830, 600, 700, T76, 840, 29, and 850.

Costs: **($500K)**

- In your description you talk about salvaging the entire station, which would have a considerable cost, but the broken down costs you requested below are negligible, for the Dorsey Breaker Replacement, the salvage costs were under 500K for 15 breakers so you could assume that the direct salvage cost of 6 would be less, however those costs would have been to remove wiring, zone boxes and have the breakers removed from site, and would not have included returning the site back to a natural state. A full removal of the site could cost as much as to construct the site which would be estimated at $7.5M.

Schedule: 12 months

Removal of the equipment could be done over the course of a year, assuming it's just the equipment, to completed remove the site could take as long as two, however we don't have recent experience with this to estimate the schedule accurately.

By salvaging Portage Saskatchewan station future station upgrades will no longer be required. Please provide estimates for the following work:

- Replace/refurbish the 115/66 kV transformers, Bank 6 and Bank 7 -
- Replace/refurbish the 115 kV ring bus including breakers R2, R3, R4, R5, R6 and R7.
- Replace/refurbish the 66 kV bus including breakers 830, 600, 700, T76, 840, 29, and 850
- Replace/refurbish the ground grid in the vicinity of the 115 kV and 66 kV bus.

Costs: ($4.94M + $5.695M + $0.5M + $5.5M) = $16.7M

- Refurbishment costs are impossible to estimate without knowing the status of the equipment and what repairs are required. It's safe to assume they would be less that a full replacement however its unknown to what extent. For the sake of this estimate I will provide pricing for replacement.
- $4.944M = 2 x 115kv transformers (assumed 60MVA)
- $5.695M = 6 x 115kV breakers and 7 x 66kV breakers.
- $500K = Ground grid replacements.
- $5.5M = 50% Contingency which given the unknowns associated with the project at this time would be the recommended allocation of contingency

Schedule: 30 months

The lead times for the transformers and breakers would drive the schedule assuming there would be no environmental licensing required because this work would take place within an existing station. Design would take place during the procurement timelines allowing for approximately 12 months for construction.

B2 – Estimate from Distribution Asset Management

Toews, Kurtis

From:	Verch, Graham
Sent:	Wednesday, September 12, 2018 2:22 PM
To:	Toews, Kurtis
Cc:	Gillson, Trevor; Bagen, Bagen
Subject:	RE: Portage Area Study Request
Follow Up Flag:	Follow up
Flag Status:	Completed
Categories:	Red Category

Options 1 & 2 would have the same impact on the 66 kV system since capacity is in the same location. There would be no major 66 kV line additions required. This option would probably allow the future salvage of Treherene if a new Line is built south towards St. Claude Station (roughly 22 km or $3.3 million). There would be no major 66 kV line additions required.

Option 3 would have limits as to how much capacity it could offload the Portage area. Because of the line distances, we would only have the ability to transfer Elm Creek, TCPL, Oakville & Poplar Point which is 41 MVA. The line distances are likely too great to transfer additional load. This would require no major 66 kV line additions. This option could allow the future salvage of Treherne Station without any major 66 kV line additions.

Option 4 has limited capacity as well. At best we could transfer TCPL and Elm Creek to Stanley which is around 24MVA but it would require 50 km line at a cost of $7.5 million. I would likely need to run loadflows to confirm this as a later time but for now I will assume that this could technically work.

Have I missed any other issues or concerns we discussed?

From: Toews, Kurtis
Sent: Wednesday, August 29, 2018 8:39 AM
To: Verch, Graham
Cc: Bagen, Bagen; Gillson, Trevor
Subject: Portage Area Study Request

Hi Graham,

As you are aware, we are working on a study to address the 230/66 kV bank capacity limitations at Portage South station (among other transmission related issues). Please provide high level estimates for the 66 kV line upgrades required to implement the four options listed below. Please provide any other comments or concerns you have with the options considered.

The options listed below do not include an option to salvage equipment at Portage Saskatchewan station. We are not prepared to do a proper evaluation of a Portage Saskatchewan station salvage at this time but we expect that it may come at a later date. The results from the Portage Saskatchewan station salvage analysis will likely still be needed to complete the comparison of development plans using the corporate value framework.

1. Portage South Third Bank– Install a third 95 MVA 230/66 kV transformer bank.
2. Portage South Bank Upgrade– Salvage the two existing 230/66 kV transformer banks at Portage South station and replace them with two new 140 MVA 230/66 kV transformer banks.

3. New 230/66 kV Station near Elm Creek– Install a new 230/66 kV transformer bank at a proposed new terminal station near the town of Elm Creek Manitoba. Transfer load from Portage South station to the new station to relieve high loading at Portage South.
4. Transfer Load from Portage South Station to Stanley Station– Install 66 kV infrastructure in Stanley area as required to transfer load from Portage South station to Stanley station to relieve loading on the Portage South 230/66 kV banks.

I understand that we may need to meet again to discuss some of the assumptions (eg. Portage South 3rd bank station layout, location of Elm Creek station, quantity of load to be transferred to Stanley). I am particularly interested in option 4 because a load transfer will play a major role in the in service dates and the load flow results of the study.

Thanks,

Kurtis Toews, P. Eng
System Planning Dept
Manitoba Hydro
820 Taylor Ave, Winnipeg MB
(204) 360-7943

B3 – Estimate from Transmission & Civil Design Department

Toews, Kurtis

From:	Dupas, Julien
Sent:	Tuesday, September 11, 2018 11:34 AM
To:	Toews, Kurtis
Cc:	Kell, Jon; Radons, Roberta; Ducheminsky, Ken
Subject:	RE: Brandon/Portage Area Network Reliability Evaluation Study
Follow Up Flag:	Follow up
Flag Status:	Completed
Categories:	Red Category

Hey Kurtis,

I believe that the cost to restring the 350 km of identified lines (D54N, D12P, P81C) with double-bundle 685.4 MCM ACSR 'Grand Rapids' conductor would exceed the costs of building the new 70 km transmission line D83P. The following is some rough costing information I've gathered (I've rounded things for simplicity).

- $12M – Cost of conductor
- $4M – Insulator, damper, connectors, and hardware costs
- $9M – Costs to rebuild wood pole sections
- $30M – Construction costs for reconductoring only
- >$15M – Costs for materials and construction for structure change-outs and modifications
    - The first major item that put us over D83P's expected cost is the foundations for the P81C and D12P lines. These lines were built on shallow steel grillage foundations that would not support the increased load of the new conductor (increase surface area for ice accretion, increased profile area for wind pressure, increased unit weight), therefore about 470 towers would need upgraded/new foundations.
    - There is also the risk of needing select tower member upgrades and/or full tower replacements to meet the increased loading on all lines
    - Finally, it's quite likely that there are spans that would require some type of mitigation due to insufficient ground clearance or clearances to obstacles (tower height increase, intermediate tower). Although the new proposed conductor sags slightly better than the existing, design standards have changed with time (as farm equipment grows in size for example) and the landscape has likely changed (new driveways, roadways increased in elevation, new obstacles, ground classification changed).

(Assumed cost of D83P was $70M based on current SOW of 70 km on TPD's sharepoint site and Kurtis' unit cost).

Jon & Ken please let Kurtis know if you'd like to add anything.

Kurtis, please let us know if you'd like to proceed with any further comments or estimates.

Thanks,
Julien Dupas, P. Eng.

From: Toews, Kurtis
Sent: Wednesday, September 05, 2018 9:21 AM
To: Dupas, Julien

APPENDIX C

Analysis of Development Plans

Bank Capacity Option	Cost (M)	Voltage Mitigation Option	Cost (M)	Total Cost (M)	Comments
Portage South Third Bank	$26.4	D83P	$64.0	$90.4	Development Plan 1
		New Station Near Elm Creek	$74.8	$101.2	Higher cost than 1 and no clear advantages.
		Portage West Station	$123.2	$149.6	Development Plan 5 is strongly preferred to this because it puts 230/66 kV bank capacity much closer to the Portage load center.
Portage South Bank Upgrade	$27.8	D83P	$64.0	$91.8	Development Plan 2
		New Station Near Elm Creek	$74.8	$102.6	Higher cost than 2 and no clear advantages
		Portage West Station	$123.2	$151.0	Development Plan 5 is strongly preferred to this because it puts 230/66 kV bank capacity much closer to the Portage load center.
New 230/66 kV Transformer Bank near Elm Creek	$21.0	D83P	$64.0	$117.4*	Higher cost than Development Plan 2 and no clear advantages.
		New Station Near Elm Creek	$74.8	$95.8	Development Plan 3
		Portage West Station	$123.2	$176.6*	Cost prohibitive.
Transfer Load from Portage South Station to Stanley Station and Stanley Capacitor Bank	$21.6	D83P	$64.0	$85.6	Development Plan 4
		New Station Near Elm Creek	$74.8	$96.4	Higher cost than 4 and there are no clear advantages.
		Portage West Station	$123.2	$144.8	Development Plan 5 is strongly preferred to this because it puts 230/66 kV bank capacity much closer to the Portage load center.
Install Transformer Bank at Portage West Station	$21.0	D83P	$64.0	$117.4**	Higher cost than Development Plan 2 and no clear advantages.
		New Station Near Elm Creek	$74.8	$128.2**	Higher cost than Development Plan 3 and no clear advantages.
		Portage West Station	$123.2	$144.2	Development Plan 5

*$32.4M added for Elm Creek Station Construction and D14S sectionalization to supply the Elm Creek transformer.
** $32.4M added for Portage West Station construction and P81C sectionalization,

APPENDIX D

Simulation Results

Voltage Issues Using 'After System Adjustments' Cases:

Bus#	BusName	Base KV	ContVolt	Low Limit	Upp Limit	Contin. Description	Case	Comments
667053	PORTSOU4 230.	230	0.8261	0.9	1.1	P1:MH D12P	2027SUM-SPHigh-	Base case issues that are eliminated by all development plans.
800001	CUSTOMER BUS230.	230	0.8326	0.9	1.1	P1:MH D12P	2027SUM-SPHigh-	
800000	NEW CUSTOMER230.	230	0.8347	0.9	1.1	P1:MH D12P	2027SUM-SPHigh-	
668019	FORTIER7 110.	110	0.9249	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668020	CROCUSP7 110.	110	0.9282	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668028	CANEXUS7 110.	110	0.9283	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668018	HIGHLND7 110.	110	0.9285	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668026	BK41-TP7 110.	110	0.9308	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668027	MAPLELF7 110.	110	0.9333	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668021	BD52-TP7 110.	110	0.9333	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668017	BRANE 7 110.	110	0.9345	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668024	KOCHB2 7 110.	110	0.9348	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668025	KOCHB1 7 110.	110	0.9349	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
667085	G82RPHT1 230.	230	0.8953	0.9	1.1	P1:MH D12P	2027SUM-SPHigh-	
668070	CORNW1 7 110.	110	0.9354	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668072	CORNW427 110.	110	0.9354	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668071	CORNW3 7 110.	110	0.9354	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668023	BE1 TP 7 110.	110	0.9355	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668022	BRANDON7 110.	110	0.9355	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668138	CORNW4 7 110.	110	0.9355	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668045	CARBRYN7 110.	110	0.9384	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
668041	CARBB2 7 110.	110	0.9385	0.94	1.15	P1:MH D12P	2027SUM-SPHigh-	
667053	PORTSOU4 230.	230	0.8452	0.9	1.1	P1:MH D12P	2027SUM-SPLow-	
800001	CUSTOMER BUS230.	230	0.8514	0.9	1.1	P1:MH D12P	2027SUM-SPLow-	
800000	NEW CUSTOMER230.	230	0.8534	0.9	1.1	P1:MH D12P	2027SUM-SPLow-	
668019	FORTIER7 110.	110	0.931	0.94	1.15	P1:MH D12P	2027SUM-SPLow-	
668020	CROCUSP7 110.	110	0.9344	0.94	1.15	P1:MH D12P	2027SUM-SPLow-	
668028	CANEXUS7 110.	110	0.9345	0.94	1.15	P1:MH D12P	2027SUM-SPLow-	
668018	HIGHLND7 110.	110	0.9347	0.94	1.15	P1:MH D12P	2027SUM-SPLow-	
668026	BK41-TP7 110.	110	0.9369	0.94	1.15	P1:MH D12P	2027SUM-SPLow-	
668027	MAPLELF7 110.	110	0.9394	0.94	1.15	P1:MH D12P	2027SUM-SPLow-	
668021	BD52-TP7 110.	110	0.9394	0.94	1.15	P1:MH D12P	2027SUM-SPLow-	
667068	SOURENB4 230.	230	0.8982	0.9	1.1	P11:18:SPC: CHINOOK#1*	2027WIN-SPHigh-PortWest-Line-	To be explored in a separate study.
667053	PORTSOU4 230.	230	0.8358	0.9	1.1	P1:MH D12P	2027WIN-SPHigh-	Base case issues that are eliminated by all development plans.
800001	CUSTOMER BUS230.	230	0.8399	0.9	1.1	P1:MH D12P	2027WIN-SPHigh-	
800000	NEW CUSTOMER230.	230	0.842	0.9	1.1	P1:MH D12P	2027WIN-SPHigh-	
668046	AUSTIN 7 110.	110	0.9308	0.94	1.15	P1:MH D12P	2027WIN-SPHigh-	
668045	CARBRYN7 110.	110	0.9328	0.94	1.15	P1:MH D12P	2027WIN-SPHigh-	
668041	CARBB2 7 110.	110	0.9337	0.94	1.15	P1:MH D12P	2027WIN-SPHigh-	
668042	MACRGR 7 110.	110	0.9338	0.94	1.15	P1:MH D12P	2027WIN-SPHigh-	
667085	G82RPHT1 230.	230	0.8978	0.9	1.1	P1:MH D12P	2027WIN-SPHigh-	

* SPC naming convention. This is a P1 contingency.

Thermal Issues Using 'After System Adjustments' Cases:

Overloaded Facility **	From Bus **	To Bus **	CKT	Cont Flow (A)	Rating (A)	IntLd%	Contingency	Case	Comment
None*									

* No thermal issues were identified in the 'after system adjustments' base cases or in the development plan cases. The thermal issues identified throughout the study were found in the 'before system adjustments' cases and in some of the mitigation options cases as discussed in Section 5.3.

APPENDIX E

CPD and Conceptual SLDs for Development Plans

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INTEGRATED RESOURCE PLANNING DIVISION

GRID INFRASTRUCTURE PLANNING DEPARTMENT

REPORT ON

Portage Area Capacity Enhancement Network Reliability Facilities Study
GIP 2021/01

PREPARED BY:

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REVISIONS

No.	Prepared By	Reviewed By	Date	Comment
1.0	K. Toews	B. Bagen	Jan 15, 2021	Initial Draft
2.0	K. Toews	System Planning, System Performance, Distribution Asset Management	March 1, 2021	Incorporated reviewers' comments
3.0	K. Toews	B. Bagen	March 5, 2021	Final

Executive Summary

The Portage/Brandon area is one of the most stressed areas due to various current and/or potential developments in southwestern Manitoba. These developments mainly include above average load growth, new industrial customers, increasing exports to Saskatchewan and deferral of the planned transmission projects. A Network Reliability Evaluation Study (NRES) [1] has been completed which evaluated 19 transmission enhancement options and recommended 5 development plans for the Corporate Value Framework (CVF) evaluations. One development plan is selected based on the CVF analysis results. A new project called the Portage Area Capacity Enhancement (PACE) has been created to implement this plan. The development plan mainly consists of the following enhancements which will be constructed in two stages. This plan will both strengthen the grid and relieve system constraints that may preclude major load additions in the area.

<u>Stage 1 (March 2025 In Service Date):</u>

The construction of a new 230-66 kV station west of Portage la Prairie (tentatively called "Temp[1] – Portage West Station") including the addition of a new 230/66 kV transformer bank inside the station. Completion of Stage 1 will eliminate the 230/66 kV transformation capacity constraints in the Portage la Prairie and surrounding area.

<u>Stage 2 (February 2027 In Service Date):</u>

A new 230 kV transmission line from the Dorsey Converter Station near Winnipeg to the new Temp – Portage West Station. Completion of Stage 2 will eliminate 230 kV and 115 kV voltage constraints in the southwestern region of Manitoba.

A Network Reliability Facilities Study (NRFS) is performed to provide a detailed assessment of the PACE project including steady state analysis, transient stability analysis, an assessment of line conductor options, an assessment of 230/66 kV transformer size options, a cost estimate, and a detailed schedule. The total cost for PACE is estimated to be approximately $161.6 million (in 2020 overnight Canadian dollars including interest and escalation) as detailed in Table ES 1.

[1] "Temp – Portage West Station" is a name that has been temporarily assigned to station that is planned to be permanent. A permanent name will be selected during public engagement activities.

Table ES 1: Summary of Cost Estimates for PACE
(in 2020 overnight Canadian dollars including interest and escalation)

Item	Costs
PACE Scope Development	$692k
Temp-Portage West to Dorsey 230kV Line	$69.8M (Base)
230kV Line P81C Sectionalization	$2.6M (Base)
Licensing & Environmental Assessment	$3.6M (Base)
Temp-Portage West 230-66kV Station	$26.8M (Base)
Dorsey Station 230kV Line Termination & Breaker Addition	$2.1M (Base)
Cornwallis Station Protection Changes	$93K (Base)
Portage South Station Protection Changes	$94K (Base)
Roquette Station Protection Changes	$174K (Base)
Temp-Portage West 66kV Line	$546K (Base)
Temp-Portage West 230-66kV Telecommunications	$670K (Base)
PACE Transmission Lines	$22.9M (Contingency)
PACE Transmission Stations	$8.8M (Contingency)
PACE Telecommunications	$200K (Contingency)
PACE Distribution Line	$170K (Contingency)
Base Estimate	**$107.2M**
Contingency Estimate	**$32M**
Interest & Escalation	**$22.4M**
Total Estimate	**$161.6M**

Table of Contents

1. Introduction

The Portage/Brandon area is one of the most stressed areas due to various current and/or potential developments in southwestern Manitoba. These developments mainly include above average load growth, new industrial customers, increasing exports to Saskatchewan and deferral of the planned transmission projects. A Network Reliability Evaluation Study [1] has been completed which evaluated 19 transmission enhancement options and recommended 5 development plans be evaluated and compared using the CVF. The preferred development plan selected by CVF analysis involves the construction of a new station west of Portage la Prairie (tentatively called "Temp – Portage West Station") and a line from Dorsey to the new station. This plan will relieve 230/66 kV transformer bank loading at Portage South station and will eliminate low voltage issues on various 230 kV and 115 kV buses in the western area. A new project called the Portage Area Capacity Enhancement (PACE) has been created to implement the preferred development plan. Capital Budget Single Line Diagrams have been created for the project and the most recent versions are provided in Appendix A.

The studies described in this report focus on the steady state and transient stability performance of the recommended development plan. The studies include the evaluation of the impact of the preferred development plan in terms of technical performance, detailed cost estimates, impacts on transmission reliability and timeline of implementation. The study results will be used in the Capital Investment Justification (CIJ) process.

2. Study Objective, Scope and Deliverables

2.1. Study Objective

The main purpose of the NRFS described in this report is to provide a detailed assessment of the preferred development plan [1, 2] in the Portage/Brandon area. The development plan will be assessed in terms of reliability, cost and timeline of implementation.

2.2. Study Scope

The study scope includes steady state contingency analysis with and without the preferred development plan with sensitivities to G82P phase shifter operation and variations in Manitoba to US transfer levels. The scope also includes a transient stability analysis of severe disturbances in the area with and without the preferred development plan. A detailed seven year assessment of the change in expected unserved energy (ΔEUE) as a result of the preferred development plan is provided in a separate report.

An assessment of the available options for 230 kV line conductors and the available options for the 230/66 kV transformer bank size is also provided.

2.3. Deliverables

1. Develop the Capital Budget Single Line Diagrams required to proceed with CIJ approval.
2. Provide cost estimate and timeline estimate of the construction of the PACE
3. Develop a planning report to document the assumptions, methodologies, results and recommendations.

3. Model Development and Assumptions

The studies described in this report use planning cases representing 2027 loading conditions which are developed using the 2017 Midwest Reliability Organization (MRO)/Multiregional Modeling Working Group (MMWG) series planning models. The MRO/MMWG planning models include a detailed representation of the BES within the province of Manitoba and the adjacent Planning Coordinators and Transmission Planners. The major assumptions made in this NRFS are the same as those presented in the NRES [1].

A summary of the power flow base cases examined in the analysis described in this report is provided in Appendix B and a summary of the sensitivity cases is provided in Appendix C.

4. Study Criteria and Methodology

The following criteria and methodologies are used in the studies described in this report.

4.1. Study Criteria

MH-TPL-001-4 standard [3] and the MH transmission system interconnection requirements (TSIR) [4] were applied in this NRES. Steady-state pre- and post-contingency bus voltages must be maintained within limits. Bus voltages were monitored for voltages above 110% or below 90 % of the rated voltage for the first 30 minutes following a contingency (contingency voltage criterion). Bus voltages were monitored for voltages above 105% or below 95% for system intact conditions (steady-state voltage criterion). All generating units cannot exceed their reactive power limits and acceptable reactive power reserve should be kept at Dorsey, Grand Rapids and Seven Sisters [4].

4.2. Study Methodology

Steady-state power flow studies were conducted using the criteria described in Section 4.1. The steady-state power flow analysis was performed using the PTI PSS/E Power Flow Program (Version 33) [5]. The steady-state power flow assessment includes evaluation of voltage performance and transmission facility loadings in pre-contingency and post-contingency analyses. The steady-state analysis evaluates normal operating system conditions and system operation under contingencies that conform to the MH-TPL-001-4 standard. Monitoring is done for transmission elements of 100 kV and above within Manitoba. Load flow is solved with transformer tap adjustments enabled, and switched shunts and phase shifter adjustments disabled. Brandon generation was dispatched as required

Transient stability studies were conducted using the criteria described in Section 4.1. The analysis was performed using the PTI PSS/E Power Flow Program (Version 33) [5]. Transient bus voltages within the Manitoba BES were monitored. Transient voltages must be within the MH default limits with the exception of a few specific buses that have specific requirements [4]. Out of step conditions were identified using the default out of step scanning tool within PSS/E. A default distance relay scanning tool within PSS/E (RELAY1) was used to screen for potential undesirable protection operations. All Manitoba Hydro BES branches were compared with 100% of the PSS/E Rate B (30 minute emergency rating) after the disturbance has occurred and the system has reached a new steady state.

5. Results and Analysis

Steady-state power flow analysis was performed using the methodology described in Section 4.2.

5.1. Steady State Powerflow

Without PACE

Steady state powerflow simulation was performed using the 2027 study models considering both with and without Brandon CT operation. Table 1 and Table 2 show the worst observed voltage and thermal loading issues. It can be seen from Table 1 and Table 2 that both overloads and voltage violations were observed in summer and winter cases. Sensitivity cases also showed consistent overloads and voltage violations in both the summer and winter seasons when no upgrades are modeled. Detailed simulation results are provided in Appendix D.

Table 1: Summary of Simulation Results - Voltage Issues (Base Case with High Saskatchewan Exports, without PACE)

Season	Contingency	Worst case Bus Voltage (pu)	Mitigation Options
Summer Peak	D12P	Portage South - 0.861	Run any Brandon Unit to eliminate voltage violation – not normal planning practice in summer.
Winter Peak, Brandon CTs offline	D12P	Case does not solve	Curtailment of 118 MW or running Brandon Unit 5 is not sufficient to eliminate issue.
Winter Peak, Brandon CTs online	D12P (Brandon Unit 7 Prior Outage)	Portage South – 0.770	Issue is eliminated by setting Glenboro PST to 25 deg bias and curtailing 75 MW of Brandon load.

Table 2: Summary of Simulation Results - Thermal Overloads (Base Case with High Saskatchewan Exports, without PACE)

Season	Contingency	Worst Case Overload	Mitigation Options
Summer Peak	D54N	D12P – 102.9%	Issue is eliminated by setting Glenboro PST to 25 degrees bias and turning on 20 MW of generation at Brandon GS.
Winter Peak, Brandon CTs offline	A4D/D54N	D12P – 125.5%	Curtailment of 118 MW or running and adjustments of Glenboro PST to 25 degrees bias is not sufficient to eliminate issue.
Winter Peak, Brandon CTs online	D54N (Brandon Unit 7 prior outage)	D12P – 110.3%	Issue is eliminated by setting Glenboro PST to 25 degrees bias.

With PACE

Steady state powerflow simulation was performed using the 2027 study models considering both with and without Brandon CT operation. Table 3 and Table 4 show the worst observed voltage and thermal issues. It can be seen from Table 3 and Table 4 that many of the issues were eliminated. All remaining issues identified after PACE can be eliminated by adjusting the G82P Phase Shifting Transformer (PST) to 100 MW north flow, or by turning on a CT to 4 MW output during the winter peak. Detailed simulation results are provided in Appendix D.

Table 3: Summary of Simulation Results - Voltage Issues (Base Case, With PACE)

	High Saskatchewan Export Case		Low Saskatchewan Export Case	
Season	**Contingency**	**Worst case Bus Voltage (pu)**	**Contingency**	**Worst case Bus Voltage (pu)**
Summer Peak	No Issues			
Winter Peak, Brandon CTs offline	P81C/Cornwallis Bank 4	**Neepawa – 0.899	Y51L/J89L	*Letellier – 0.886
Winter Peak, Brandon CTs online	No Issues			

* Outside study area.
** All voltage issues can be eliminated by setting the G82P phase shifter to 100 MW import.

Table 4: Summary of Simulation Results - Thermal Overloads (Base Case, With PACE)

	High Saskatchewan Export Case		Low Saskatchewan Export Case	
Season	**Contingency**	**Worst Case Overload**	**Contingency**	**Worst Case Overload**
Summer Peak	No Issues			
Winter Peak, Brandon CTs offline	A4D/D54N**	*P81C – 102.4%	No Issues	
Winter Peak, Brandon CTs online	No Issues			

* All overloads can be eliminated by setting the G82P phase shifter to 60 MW north flow.
** A4D and D54N are on a common structure for only approximately 11 km. In the future, there may be advantages to separating these lines which will eliminate this common structure contingency.

Sensitivity to G82P Phase Shifter Locked at 0 Degrees

Steady state powerflow simulation was performed on the sensitivity cases summarized in Appendix C. Sensitivity cases were developed by adjusting the angle setting on the G82P phase shifter to 0 degrees and locking the control mode. Table 5 shows the impact of this sensitivity on the High Saskatchewan Export Case (High SPC Export) with the PACE in service. It can be seen from Table 5 that there are several new issues when G82P phase shifter angle is set to 0 degrees. All issues shown in Table 5 can be eliminated by adjusting G82P between 100 MW and 250 MW north flow. Detailed simulation results are provided in Appendix D.

Simulation results show that all issues are eliminated if G82P is importing between 100 MW and 250 MW. Table 6 shows the relationship between the PST angle and G82P flow in the winter peak base case with MH-US transfer levels set to 1475 MW import and 233 MW export. It can be seen from Table 6 that issues are eliminated when the PST is set to 25 degrees in the import case or 0 degrees in the export case.

Table 5: Sensitivity to G82P Phase Shifter Operation
(High SPC Export Case, After PACE, Brandon CTs Offline)

Season	Contingency	Base Case Results	Sensitivity Results
Summer Peak	No Issues		
Winter Peak	P81C/Cornwallis Bank 4	Neepawa – low voltage – 0.899 pu	Glenboro – low voltage – 0.878 pu
	A4D/D54N	P81C – overload – 102.4%	Glenboro – low voltage – 0.889 pu
	P81C	No Issues	Glenboro – low voltage – 0.882 pu
	S53G		Stanley – low voltage – 0.881 pu
	Boundary Dam Unit 6		Glenboro – low voltage – 0.897 pu
	Chinook Unit # 1		Glenboro – low voltage – 0.896 pu
	Various		Glenboro – phase shifting transformer thermal overload

Table 6: G82P Phase Shifter Adjustments
(2027 Winter Peak, High SPC Export Case, After PACE, Brandon CTs Offline)

PST Bias (degrees)	G82P North Flow (MW)			
	MH-US 1475 MW Import	Comments	MH-US 233 MW Export	Comments
0	309.1	Overload on Glenboro PST	200	No issues
25	202.6	No issues	77.3	Post-contingency overload on P81C
50	97.6	Post-contingency low voltage at Neepawa 230 kV station	-34.7	Post-contingency Overloads and voltage violations
75	-8.5	Post-contingency overloads and voltage violations	-135.1	

Sensitivity to Variations in MH-US Exports

Steady state powerflow simulation was performed on the sensitivity cases summarized in Appendix C. Winter peak sensitivity cases were developed by setting all Manitoba Hydro hydraulic generation to maximum Designated Network Resource levels and sinking the power in the US. This resulted in a change of MH-US transfer levels from 1475 MW import to 233 MW export. Summer peak sensitivity cases were developed by changing the MH-US exports from 1600 MW to 0 MW. The source was US generation and the sink was the northern collector system. Table 7 shows the impact of this sensitivity on the High SPC Export Case with the PACE in service. It can be seen from Table 7 that adjustments in MH-US exports have a small impact on the results. All issues identified in Table 7 can be eliminated by either adjusting G82P to 100 MW north flow or by turning on a Brandon CT. Detailed simulation results are provided in Appendix D.

Table 7: Sensitivity to Variations in US Exports
(High SPC Export Case, After PACE, Brandon CTs Offline)

<table>
<tr><th>Season</th><th>Contingency</th><th>Base Case Results</th><th>Sensitivity Results</th></tr>
<tr><td>Summer Peak</td><td colspan="3">No Issues</td></tr>
<tr><td rowspan="4">Winter Peak</td><td>A4D/D54N</td><td>P81C – overload – 102.4%</td><td>P81C – overload – 104.4%</td></tr>
<tr><td>P81C/Cornwallis Bank 4</td><td>**Neepawa – low voltage – 0.899 pu</td><td>Neepawa – low voltage – 0.8942 pu</td></tr>
<tr><td>E93L</td><td rowspan="2">No Issues</td><td>Stanley – low voltage – 0.883 pu</td></tr>
<tr><td>P81C/Cornwallis Bank 4</td><td>*CN9 – Overload – 105.2%</td></tr>
</table>

*CN9 loading is limited by a relay setting. It is assumed that this overload can be eliminated at a low cost by changing the relay setting.

5.2. New Line Conductor Size

Two transmission line conductors are compared. Both 795 ACSR and 954 ACSR conductor are considered because they are commonly used in rural areas. It is recognized that there are many other conductor options available that could have benefit and further assessment may be performed to determine the optimal conductor size. Steady state powerflow simulation was performed on all base cases and sensitivity cases considering both with and without Brandon CT operation. Thermal loading on the new line from Dorsey to Temp - Portage West Station was monitored. Table 8 shows the highest observed winter and summer loading.

Table 8: Highest Observed Thermal Loading on the Proposed New Line
(After PACE, Brandon CTs Offline)

Case	Contingency	New Line Loading	Comment
Summer peak, high MH-SP stress, base case	D12P	694 A	72% of 795 ACSR rating
Winter peak, high MH-SP stress, MH-US sensitivity	D12P	1079 A	86% of 795 ACSR rating

Current flow on the new line depends on many parameters including the Manitoba load forecast and MH-SP transfer levels. In order to understand the impact of MH-SP transfer levels on line loading, the winter peak case is examined further. MH-SP transfer levels are increased by dispatching generation from the US and sinking it in Saskatchewan. The results are summarized in Figure 1. It can be seen from Figure 1 that increases in MH-SP transfer levels up to 615 MW will cause the thermal loading of the line to exceed the rating or 795 ACSR conductor operating at 100 degrees Celsius. However, if 954 ACSR conductor is used, then there is still ample margin for load growth, transfer increases, or other unforeseen circumstances.

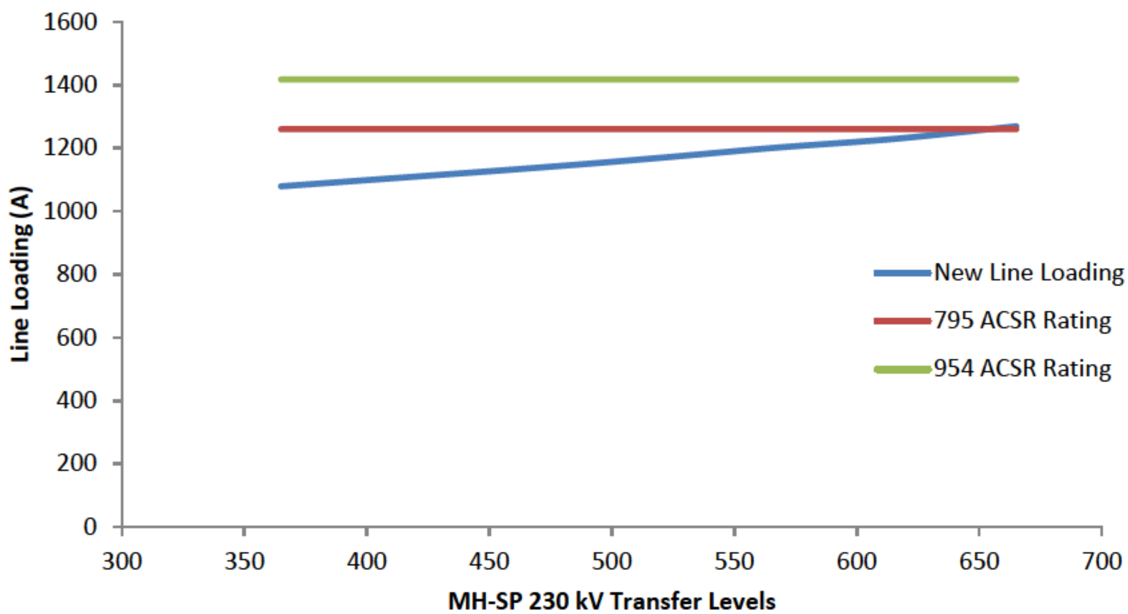

Figure 1: Impact of MH-SP 230 kV Transfer Level Increases on the Proposed New Line Thermal Loading
(Summer Peak Base Case, D12P Contingency, After Improvements, Brandon CTs Offline)

In order to understand the impact of Manitoba load levels on line loading, the winter peak case is examined further. Generation is increased in the US and the sink is Manitoba (area 667) load. The results are summarized in Figure 2. It can be seen from Figure 2 that increases in Manitoba load of 20% will cause the line to exceed the rating or 795 ACSR conductor operating at 100 degrees Celsius. However, if 954 ACSR conductor is used, then there is still ample margin for load growth, transfer increases, or other unforeseen circumstances.

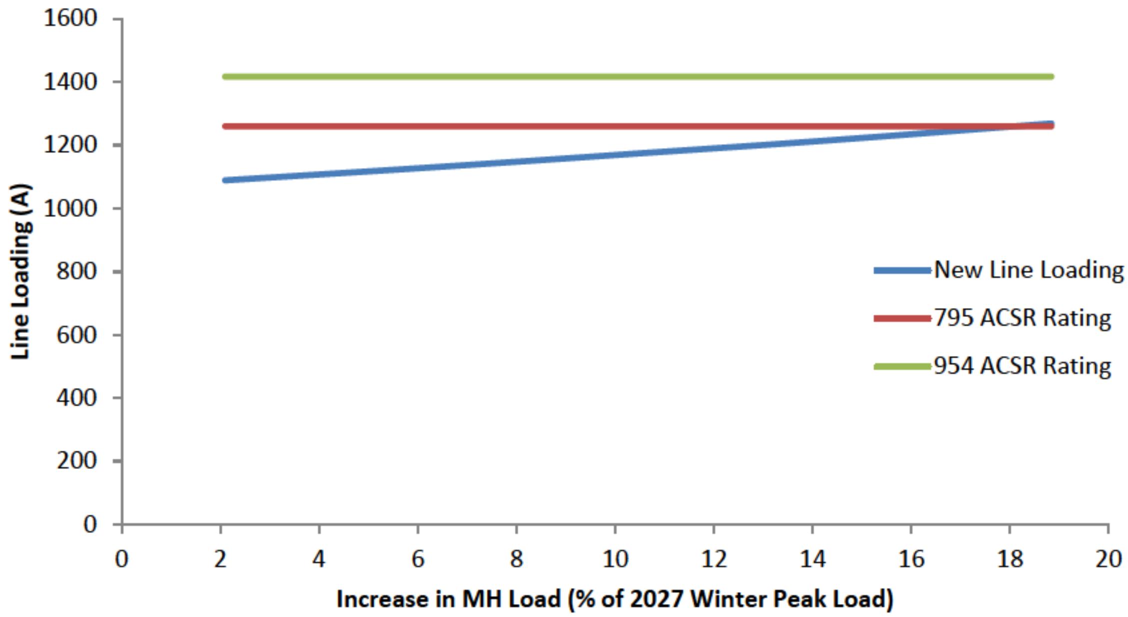

Figure 2: Impact of Manitoba Load Increases on the Proposed New Line Thermal Loading (Winter Peak Manitoba Load, After Improvements, Brandon CTs Offline)

954 ACSR is preferred because it provides margin for load growth, transfer increases and other unforeseen circumstances.

5.3. Transformer Bank Size

Manitoba Hydro typically installs 230/66 kV banks with a nameplate rating of either 95 MVA or 140 MVA. This section analyzes the impact of both a 95 MVA bank and a 140 MVA bank. Figure 3 shows the load forecast at Portage South station without the load transfer. It can be seen from Figure 3 that only 13 MVA needs to be transferred from Portage South to Temp – Portage West Station in 2030 to bring Portage South below firm capacity. This can be accomplished with either a 95 MVA and a 140 MVA bank. A 95 MVA transformer bank is a lower cost option.

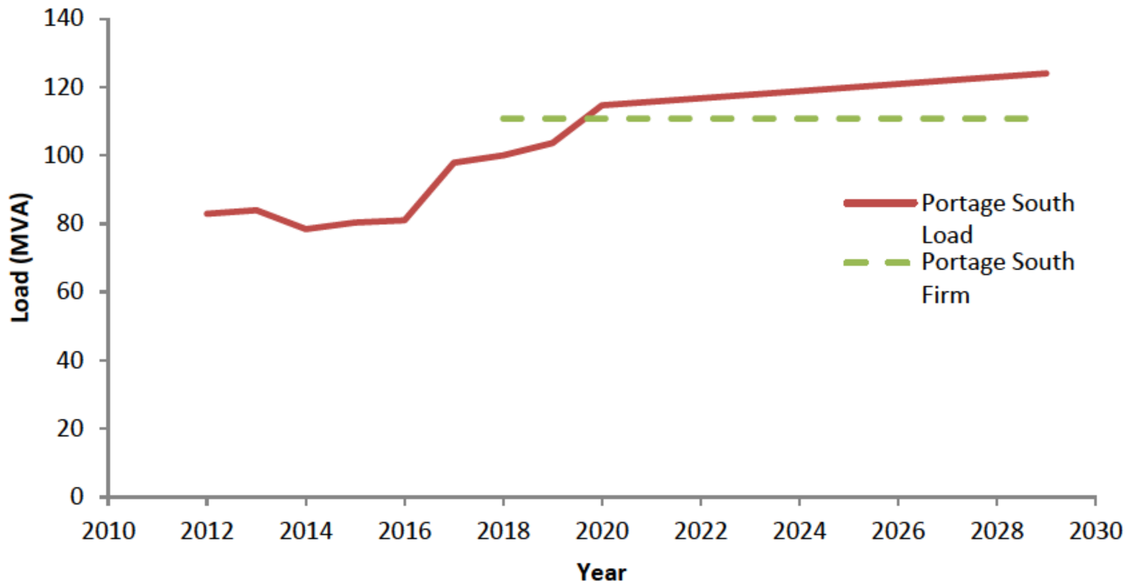

Figure 3: Portage South station load forecast without considering the load transfer to Temp – Portage West Station.

In order to assess the longevity of a 95 MVA transformer bank, a 50 year analysis is done on the base case and three sensitivities. It is important to note that this analysis involves scaling load 50 years into the future which is highly speculative and has a high level of uncertainty. The assumptions used in this analysis are only intended to provide an equal comparison of two options and test the impact of a variety of scenarios. The following sensitivities are considered for this analysis:

1. Portage Saskatchewan 115/66 kV transformer bank salvage – transfer all Portage Saskatchewan load to Temp – Portage West Station.
2. New 30 MVA industrial customer load – the impact of 30 MVA of new load is considered.
3. High load growth – due to uncertainty in the load forecast, the impact doubling the growth rate from 1% to 2% is considered.

The following assumptions are used in this longevity analysis:

- 1% load growth at Portage South and Portage Saskatchewan stations
- Real Weighted Average Cost of Capital is 4.5%.
- A 30 MVA load transfer from Portage South to Temp – Portage West Station is modeled in 2025. Additional load can be transferred from Portage South to Portage West as required to prevent Portage South from exceeding winter firm capacity (110.8 MVA).
- The in service date of the second bank at Portage West station is currently unknown because it depends on many factors including the ability to implement

66 kV load transfers from Temp – Portage West Station to Portage South in the event of a bank failure. For the purpose of this analysis, it is assumed that a second bank will be installed when Portage West load reaches 50 MVA.
- Analysis is truncated in 2069.

Table 9: Transformer Bank Size Comparison
(Base Case Scenario)

Year	Option 1: 95 MVA Bank	Option 2: 140 MVA Bank	Comments
2025	\$21M	\$24M	Install Bank 1
2059	\$21M	\$24M	Install Bank 2
2069	\$0M	\$0	Bank 3 is not required in the next 50 years
NPV	\$19.7M	\$22.6M	

Table 10: Transformer Bank Size Comparison
(Sensitivity to Portage Saskatchewan 115/66 kV Salvage)

Year	Option 1: 95 MVA Bank	Option 2: 140 MVA Bank	Comments
2025	\$21M	\$24M	Install Bank 1
2030	\$21M	\$24M	Install Bank 2
2069	\$0	\$0	Bank 3 is not required in the next 50 years
NPV	\$29.1M	\$33.2M	

Table 11: Transformer Bank Size Comparison
(Sensitivity to New 30 MVA Industrial Customer Load)

Year	Option 1: 95 MVA Bank	Option 2: 140 MVA Bank	Comments
2025	\$21M	\$24M	Install Bank 1
2030	\$21M	\$24M	Install Bank 2
2069	\$0M	\$0	Bank 3 is not required in the next 50 years
NPV	\$29.1M	\$33.22M	

Table 12: Transformer Bank Size Comparison
(Sensitivity to High Load Growth of 2%)

Year	Option 1: 95 MVA Bank	Option 2: 140 MVA Bank	Comments
2025	$21M	$24M	Install Bank 1
2038	$21M	$24M	Install Bank 2
2069	$21M	$0	Bank 3 is required for Option 1 only
NPV	$27.6M	$28.8M	

It can be seen from Tables 9, 10, 11 and 12 that in all scenarios considered, Option 1 has the lowest present value cost.

5.4. Short Circuit

A short circuit study has been completed providing fault current levels at Temp – Portage West Station [6]. The results summarized in Table 13 can be used to inform the design of the station.

Table 13: Short Circuit Study Results

Location	**When**	**Base kV**	**Thevenin Equivalent Impedance (pu) @ 100 MVA Base**			**Fault Levels**	
			Zero $R_0 + jX_0$	**Positive $R_1 + jX_1$**	**Negative $R_2 + jX_2$**	**3-Phase (kA)**	**SLG (kA)**
Temp - Portage West Station	ISD (2025)	230 kV	0.00769 + j0.04670	0.00377 + j0.03347	0.00382 + j0.03405	7.45	6.53
		66 kV	0.0000 + j0.0000	0.00895 + j0.19756	0.00900 + j0.18912	4.42	0*
	40/50 Year Horizon	230 kV	0.00324 + j0.02767	0.00347 + j0.03014	0.00352 + j0.03052	8.27	8.47
		66 kV	0.0000 + j0.0000	0.00514 + j0.08432	0.00519 + j0.08469	10.35	0*

All fault levels are calculated using per unit base values of 100 MVA and voltage bases of 230 & 66 kV.

****Note** that the 66 kV SLG fault levels are indicated as 0 due to the Delta connected secondary transformer banks, assumed 66 kV connected network and model limitations which exclude any customer owned equipment.*

5.5. Transmission Reliability Risk Assessment

A transmission reliability risk assessment has been performed to assess the impact of the proposed upgrades. Table 14 below summarizes the results of the study. Detailed information on the assumptions and methodology will be documented in a separate report.

Table 14 – Transmission Reliability Risk Assessment Study Results

Year	Annual EUE without upgrades (MWh)	Annual EUE with upgrades (MWh)	Delta EUE (MWh)
2025	20.01	0.01	20
2026	22.29	0.01	22.28
2027	8919.325	8280.995	638.33
2028	8993.635	8315.5	678.135
2029	9065.53	8359.15	706.38
2030	9245.065	8431.65	813.415
2031	9593.055	8642.685	950.37

5.6. Stability

Stability simulation is performed using the 2027 base case study models considering both with and without Brandon CT operation. Six cycle three phase faults are simulated in the following locations:

- 230 kV line P81C near Cornwallis station.
- 230 kV line D12P near Portage South station.
- Brandon Unit 6 generator bus.
- Brandon Unit 5 generator bus.
- New 230 kV line near Temp - Portage West Station.
- 230 kV line R7B near Reston.

Low voltages are observed at several 230 kV and 115 kV buses without PACE. The observed low voltages occur after the system has settled into a steady state and they are consistent with the low voltages observed in the steady state analysis in section 5.1. No transient stability issues or concerns are observed. Voltage response at many buses in the area is improved with PACE. Figure 4 shows the Portage South bus voltage following a three phase fault on D12P near Portage South station. It can be seen from Figure 4 that the transient voltage settles into a steady state below 0.9 pu without the proposed upgrades. However, the proposed upgrades significantly improve the voltage response at Portage South.

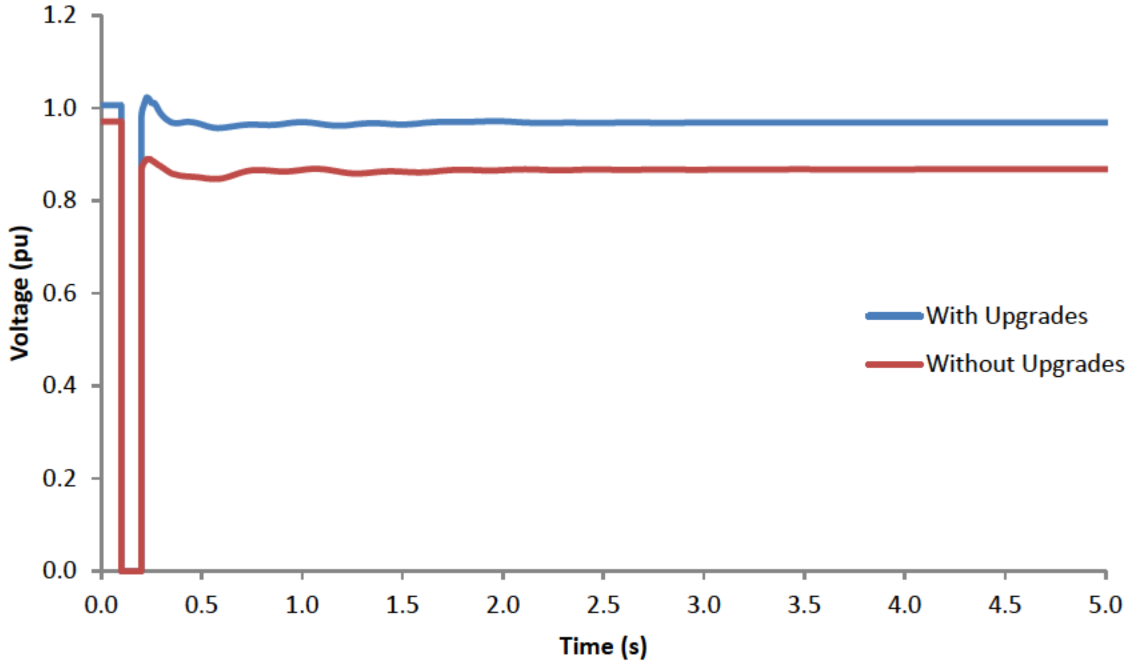

Figure 4: Impact of the Proposed Upgrades on the Dynamic Voltage Response at the Portage South 230 kV Bus (Winter Peak Base Case, D12P 3 Phase Fault, Brandon CTs Offline)

5.7. Impact on Southern Area NRES

A Grid Infrastructure Planning study is currently underway which is expected to consider the three development plans listed below to address low voltages observed in the southern 230 kV system particularly at Stanley and De Salaberry East.

- Development Plan 1: Install 30 MVAR capacitor bank at Stanley station and 60 MVAR capacitor bank at De Salaberry East station
- Development Plan 2: Install 60 MVAR capacitor bank at Stanley station and 30 MVAR capacitor bank at De Salaberry East station
- Development Plan 3: Install 30 MVAR capacitor bank at Stanley station and a new line from De Salaberry East to Richer South

A brief assessment of the worst case conditions identified in Table 3 is performed to understand the impact of the expected Southern Area NRES Development Plans on the PACE project. Thermal loading was not impacted by the development plans, so the worst case overloads (Table 4) are not repeated in this section. It can be seen from Table 15 that the southern area study development plans will have a small impact on the worst case bus voltage at Neepawa station. Development Plan #2 has the largest impact on Neepawa voltage as it improves the voltage from 0.899 pu to 0.908 pu (0.009 pu increase).

Table 15: Summary of Simulation Results - Voltage Issues (Base Case, With PACE, Brandon CTs Offline, 2027 Winter Peak)

Southern Area Study Development Plans	Contingency	Worst case Bus Voltage (pu)
Existing System	P81C/Cornwallis Bank 4	Neepawa – 0.899
Development Plan #1 (30 MVAR and Stanley and 60 MVAR at De Salaberry)	P81C/Cornwallis Bank 4	Neepawa – 0.905
Development Plan #2 (60 MVAR and Stanley and 30 MVAR at De Salaberry)	P81C/Cornwallis Bank 4	Neepawa – 0.908
Development Plan #3 (30 MVAR and Stanley and 30 MVAR at De Salaberry)	P81C/Cornwallis Bank 4	Neepawa – 0.905

6. Project Cost and Schedule

Detailed cost estimates and schedule has been developed based on a preliminary line route developed with expertise within Manitoba Hydro but without external stakeholder engagement. A summary of the cost estimate and schedule is provided in Appendix E. The in service date for Stage 1 is March 2025 and the in service date for Stage 2 is February 2027. The base estimate for the complex is $107.2M, the contingency estimate is $32M, the interest & escalation is $22.4M, and the total estimate is $161.6M.

7. Summary and Conclusions

A NRFS is performed for the PACE project to provide a detailed steady state and transient stability assessment, a cost estimate and timeline for construction. The NRFS also provides an updated transmission reliability/risk score in terms of ΔEUE, an assessment of transmission line conductor size options and an assessment of 230/66 kV transformer bank size options. The PACE project provides significant reliability benefits Manitoba Hydro customers and it eliminates constraints that may preclude large load additions in some areas of the province. Stage 1 has a planned in service date of March 2027 and Stage 2 has a planned in service date of February 2027. The total estimated cost of the project is $161.6M including contingency, interest and escalation.

References

[1] System Planning Report SPD 2019/01, "Brandon/Portage Area Network Reliability Evaluation Study", March 2019.

[2] Manitoba Hydro Interoffice Memorandum, "Proposed New Capital Project – Brandon/Portage Area Reliability Enhancement" March 2019.

[3] Manitoba Hydro Standard MH-TPL-001-4, "Transmission Planning Performance Requirements", July 2017.

[4] MH Document, "Transmission System Interconnection Requirements", Version 4, July 2016, available on Manitoba Hydro OASIS Website: http://www.oasis.oati.com/woa/docs /MHEB/MHEBdocs/MH_transmission_interconnection_requirements_July2016-final.pdf.

[5] PSS®E Product Support Website, http://www.energy.siemens.com/hq/en/services/power-transmission-distribution/power-technologies-international/software-solutions/pss-e.htm

[6] System Planning Interoffice Memorandum "Fault Analysis (Preliminary) – New 230-66 kV Portage West Station." March 2020.

APPENDIX A

Capital Budget Single Line Diagrams

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APPENDIX B

Base Case Summary

Appendix B - Base Case Summary

Summary Created On : Tue Jun 11 13:39:08 2019

Tie Line Flow (MW)

Case Name	MH->US	MH->SPC 230kV	MH->SPC 115kV	MH->SPC Net	MH->ONT	B10T (S)	S. Ont->US	F3M(S)	E-W Ties West	MWSI	MWEX	NDEX	L20D	R50M	M602F	D604I	G82R/G82P
2027SUM-SPHigh	1605	368	60	427	0	166	-5	150	-6	763	201	1952	-38	79	995	569	0
2027SUM-SPHigh-PortWest-line	1610	368	60	427	1	166	-4	150	-8	764	200	1952	-36	79	997	569	0
2027SUM-SPLow	1762	325	-58	267	1	166	-4	150	-8	796	198	1948	-12	85	1067	621	0
2027SUM-SPLow-PortWest-Line	1765	330	-58	272	-2	170	-9	151	-2	798	197	1950	-11	84	1067	620	4
2027WIN-SPHigh	-1476	365	60	425	4	-167	49	-100	-111	-81	367	-298	-298	58	-734	-499	-2
2027WIN-SPHigh-PortWest-Line	-1453	366	60	426	-1	-166	46	-100	-108	-74	366	-297	-294	59	-725	-493	-1
2027WIN-SPLow	-1469	325	-67	258	-2	-166	45	-100	-106	-80	367	-300	-294	58	-733	-499	-1
2027WIN-SPLow-PortWest-Line	-1453	323	-67	256	1	-167	48	-101	-110	-76	367	-299	-292	59	-724	-493	-2

PGEN (MW)

Case Name	Total AC	Kelsey	Wuskwatim	Jenpeg	Grand Rapids	Selkirk	Brandon	Pine Falls	Great Falls	McArthur Falls	Seven Sisters	Slave Falls	Pointe du bois	ST Leon	ST Joseph	Winnipeg River
2027SUM-SPHigh	1668	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027SUM-SPHigh-PortWest-line	1668	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027SUM-SPLow	1668	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027SUM-SPLow-PortWest-Line	1668	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027WIN-SPHigh	1678	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2027WIN-SPHigh-PortWest-Line	1678	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2027WIN-SPLow	1678	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2027WIN-SPLow-PortWest-Line	1678	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528

MVar	Reserve							QGen							In Service?	
Case Name	Dorsey	Riel	Grand Rapids	Seven Sisters	Ponton	Birchtree	Brandon U5	Dorsey	Riel	Grand Rapids	Seven Sisters	Ponton	Birchtree	Brandon U5	Ponton	Birchtree
2027SUM-SPHigh	1284	1027	179	180	150	95	0	416	-27	-14	-14	0	0	0	Yes	Yes
2027SUM-SPHigh-PortWest-line	1324	1029	182	180	150	95	0	376	-29	-17	-14	0	0	0	Yes	Yes
2027SUM-SPLow	1265	987	150	180	151	96	0	435	13	16	-14	-1	-1	0	Yes	Yes
2027SUM-SPLow-PortWest-Line	1285	986	151	179	151	96	0	415	14	15	-13	-1	-1	0	Yes	Yes
2027WIN-SPHigh	1486	1004	144	146	150	90	54	214	-4	21	20	0	5	38	Yes	Yes
2027WIN-SPHigh-PortWest-Line	1580	1017	158	147	150	91	57	120	-17	7	19	0	4	35	Yes	Yes
2027WIN-SPLow	1644	1026	159	148	148	95	53	56	-26	6	18	2	0	39	Yes	Yes
2027WIN-SPLow-PortWest-Line	1728	1042	169	149	149	95	60	-28	-42	-3	17	1	0	32	Yes	Yes

Load (MW)	Area	Zones					Buses		MHDC (Inverter Side) and NCS PGEN (MW)						
Case Name	667	1646	1647	1648	1649	1650	667206	701		MHDC (MW)	Total DC	Lime Stone	Long Spruce	Kettle	Keeyask
2027SUM-SPHigh	3472	815	1322	467	64	804	89	0		4016	4250	1350	980	1224	695
2027SUM-SPHigh-PortWest-line	3472	815	1322	467	64	804	89	0		4016	4250	1350	980	1224	695
2027SUM-SPLow	3472	815	1322	467	64	804	89	0		4016	4250	1350	980	1224	695
2027SUM-SPLow-PortWest-Line	3472	815	1322	467	64	804	89	0		4016	4250	1350	980	1224	695
2027WIN-SPHigh	4778	801	2427	485	215	850	89	0		2305	2382	757	549	686	390
2027WIN-SPHigh-PortWest-Line	4778	801	2427	485	215	850	89	0		2305	2382	757	549	686	390
2027WIN-SPLow	4778	801	2427	485	215	850	89	0		2111	2176	691	502	627	356
2027WIN-SPLow-PortWest-Line	4778	801	2427	485	215	850	89	0		2111	2176	691	502	627	356

APPENDIX C

Sensitivity Case Summary

Appendix C - Sensitivity Case Summary

Summary Created On : Tue Jan 05 14:18:07 2021

Tie Line Flow (MW)

Case Name	MH->US	MH->SPC 230kV	MH->SPC 115kV	MH->SPC Net	MH->ONT	B10T (S)	S. Ont->US	F3M(S)	E-W Ties West	MWSI	MWEX	NDEX	L20D	R50M	M602F	D604I	G82R/G82P
2027SUM-SPHigh-PST	1610	368	60	428	0	167	3	150	-6	773	197	1965	12	84	1051	613	-150
2027SUM-SPHigh-PST-PW	1617	366	60	426	0	166	3	150	-6	774	197	1963	13	84	1051	613	-144
2027SUM-SPHigh-PW-USexp	38	284	60	344	-7	84	-6	152	4	441	243	2021	-268	17	241	48	0
2027SUM-SPHigh-USexp	38	280	60	339	-7	79	-6	152	4	441	243	2018	-267	17	243	50	-5
2027WIN-SPHigh-PST	-1446	369	60	428	0	-162	49	-100	-108	-43	352	-274	-203	69	-594	-391	-327
2027WIN-SPHigh-PST-PW	-1429	366	60	426	0	-164	48	-100	-108	-39	351	-274	-202	69	-588	-388	-321
2027WIN-SPHigh-PW-USexp	254	367	60	427	0	-164	48	-100	-108	260	295	-300	-57	121	114	76	0
2027WIN-SPHigh-USexp	234	367	60	427	0	-165	48	-100	-108	255	295	-300	-64	120	106	72	0

PGEN (MW)

Case Name	Total AC	Kelsey	Wuskwatim	Jenpeg	Grand Rapids	Selkirk	Brandon	Pine Falls	Great Falls	McArthur Falls	Seven Sisters	Slave Falls	Pointe du bois	ST Leon	ST Joseph	Winnipeg River
2027SUM-SPHigh-PST	1668	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027SUM-SPHigh-PST-PW	1668	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027SUM-SPHigh-PW-USexp	1668	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027SUM-SPHigh-USexp	1668	251	200	168	480	0	0	89	130	56	165	54	34	19	22	528
2027WIN-SPHigh-PST	1678	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2027WIN-SPHigh-PST-PW	1678	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2027WIN-SPHigh-PW-USexp	1678	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528
2027WIN-SPHigh-USexp	1678	251	200	168	480	0	0	89	130	56	165	54	34	23	28	528

MVar	Reserve							QGen							In Service?	
Case Name	Dorsey	Riel	Grand Rapids	Seven Sisters	Ponton	Birchtree	Brandon U5	Dorsey	Riel	Grand Rapids	Seven Sisters	Ponton	Birchtree	Brandon U5	Ponton	Birchtree
2027SUM-SPHigh-PST	1301	1004	187	180	150	98	0	399	-4	-22	-14	0	-3	0	Yes	Yes
2027SUM-SPHigh-PST-PW	1321	1006	189	180	150	95	0	379	-6	-24	-14	0	0	0	Yes	Yes
2027SUM-SPHigh-PW-USexp	1688	1076	190	180	150	95	0	12	-76	-24	-14	0	0	0	Yes	Yes
2027SUM-SPHigh-USexp	1672	1075	188	181	150	97	0	28	-75	-22	-15	0	-2	0	Yes	Yes
2027WIN-SPHigh-PST	1675	1080	172	148	150	96	53	25	-80	-6	18	0	-1	39	Yes	Yes
2027WIN-SPHigh-PST-PW	1727	1091	183	148	150	96	61	-27	-91	-17	18	0	-1	31	Yes	Yes
2027WIN-SPHigh-PW-USexp	941	1047	167	148	150	96	54	759	-47	-2	18	0	-1	38	Yes	Yes
2027WIN-SPHigh-USexp	873	1044	153	148	150	96	52	827	-44	12	18	0	-1	40	Yes	Yes

Load (MW)	Area	Zones					Buses	MHDC (Inverter Side) and NCS PGEN (MW)					
Case Name	667	1646	1647	1648	1649	1650	667206	MHDC (MW)	Total DC	Lime Stone	Long Spruce	Kettle	Keeyask
2027SUM-SPHigh-PST	3472	815	1322	467	64	804	89	4016	4250	1350	980	1224	695
2027SUM-SPHigh-PST-PW	3472	815	1322	467	64	804	89	4016	4250	1350	980	1224	695
2027SUM-SPHigh-PW-USexp	3472	815	1322	467	64	804	89	2320	2398	762	553	691	392
2027SUM-SPHigh-USexp	3472	815	1322	467	64	804	89	2320	2398	762	553	691	392
2027WIN-SPHigh-PST	4778	801	2427	485	215	850	89	2305	2382	757	549	686	390
2027WIN-SPHigh-PST-PW	4778	801	2427	485	215	850	89	2305	2382	757	549	686	390
2027WIN-SPHigh-PW-USexp	4778	801	2427	485	215	850	89	4014	4250	1351	980	1223	695
2027WIN-SPHigh-USexp	4778	801	2427	485	215	850	89	4014	4250	1351	980	1223	695

APPENDIX D

Simulation Results

Appendix D - Steady State Thermal Loading Results

Overloaded Facility	**	From Bus **	**	To Bus **	CKT	ContFlow	Rating	IntLd%	Contingency	Case	Comment
BP6	668042	MACRGR 7 110.	668044	PORTAGE7 110.	1	264.95	262.96	100.8	P1 MH D12P	BDN-2027SUM-SPHigh-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	853.85	829.88	102.9	P1 MH D54N	BDN-2027SUM-SPHigh-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	831.62	829.88	100.2	P1 MH N56C	BDN-2027SUM-SPHigh-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	830.62	829.88	100.1	P1 MH S53G	BDN-2027SUM-SPHigh-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	833.98	829.88	100.5	P4 MH N56C/D54N	BDN-2027SUM-SPHigh-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	853.85	829.88	102.9	P4 MH D83P/D54N	BDN-2027SUM-SPHigh-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	852.26	829.88	102.7	P7 MH A4D/D54N	BDN-2027SUM-SPHigh-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	839.86	829.88	101.2	P7 MH N56C/BN5	BDN-2027SUM-SPHigh-	Issue
CN9/D12P	-	-	-	-	-	-	-	-	Various	BDN-2027WIN-SPHigh-CTon-	CN9/D12P overloads following various contingencies
D12P/CN9/UP80/A6V	-	-	-	-	-	-	-	-	Various	BDN-2027WIN-SPHigh-	Various overloads following various contingencies
VC									P1 MH D12P	BDN-2027WIN-SPHigh-	Issue
G82P PST	667085	G82RPHT1 230.	667052	GLENBOR4 230.	1	314.3	300	104.8	-	BDN-2027WIN-SPHigh-PST-CTon-	G82P PST overloads following various contingencies
G82P/D12P/CN9	-	-	-	-	-	-	-	-	Various	BDN-2027WIN-SPHigh-PST-	G82P/D12P/CN9 overloads following various contingencies
VC									P1 MH D12P	BDN-2027WIN-SPHigh-PST-	Issue
D12P/CN9	-	-	-	-	-	-	-	-	-	BDN-2027WIN-SPHigh-USexp-CTon-	D12P/CN9 overloads following various contingencies
D12P/CN9/UP80/A6V	-	-	-	-	-	-	-	-	-	BDN-2027WIN-SPHigh-USexp-	D12P/CN9/UP80/A6V overloads following various contingencies
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	1109.55	1103.99	100.5	P1 MH D54N	BDN-2027WIN-SPLow-CTon-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	1109.55	1103.99	100.5	P4 MH D83P/D54N	BDN-2027WIN-SPLow-CTon-	Issue
D12P	667035	DORSEY 4 230.	667053	PORTSOU4 230.	1	1129.26	1103.99	102.3	P7 MH A4D/D54N	BDN-2027WIN-SPLow-CTon-	Issue
D12P	-	-	-	-	-	-	-	-	-	BDN-2027WIN-SPLow-	D12P Overloads following various contingencies

Appendix D - Steady State Voltage Results

Bus#	BusName	Base KV	ContVolt	LowLimit	UppLimit	Contin.Description	Case	Comments
667053	PORTSOU4 230.	230	0.8745	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-PST-	Issue
800001	CUSTOMER BUS230.	230	0.8803	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-PST-	Issue
800000	NEW CUSTOMER230.	230	0.8823	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-PST-	Issue
667053	PORTSOU4 230.	230	0.8799	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-USexp-	Issue
800001	CUSTOMER BUS230.	230	0.8856	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-USexp-	Issue
800000	NEW CUSTOMER230.	230	0.8876	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-USexp-	Issue
667053	PORTSOU4 230.	230	0.8606	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-	Issue
800001	CUSTOMER BUS230.	230	0.8665	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-	Issue
800000	NEW CUSTOMER230.	230	0.8685	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPHigh-	Issue
667053	PORTSOU4 230.	230	0.8808	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPLow-	Issue
800001	CUSTOMER BUS230.	230	0.8865	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPLow-	Issue
800000	NEW CUSTOMER230.	230	0.8884	0.9	1.1	P1:MH D12P	BDN-2027SUM-SPLow-	Issue
667053	PORTSOU4 230.	230	0.7704	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-CTon-	Issue
800001	CUSTOMER BUS230.	230	0.7748	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-CTon-	Issue
800000	NEW CUSTOMER230.	230	0.7771	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-CTon-	Issue
667071	NEEPAWA4 230.	230	0.8492	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-CTon-	Issue
667070	CORNWLS4 230.	230	0.8683	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-CTon-	Issue
667068	SOURENB4 230.	230	0.8811	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-CTon-	Issue
667069	SOURSTP4 230.	230	0.8855	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-CTon-	Issue
667052	GLENBOR4 230.	230	0.893	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-CTon-	Issue
667048	LETELER4 230.	230	0.8919	0.9	1.1	P4:MH Y51L/J89L	BDN-2027WIN-SPHigh-CTon-	Outside study area
667200	LIMESTN6 138.	138	1.0501	0.95	1.05	Pre Contingency	BDN-2027WIN-SPHigh-PST-CTon-	Issue
667053	PORTSOU4 230.	230	0.7623	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
800001	CUSTOMER BUS230.	230	0.767	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
800000	NEW CUSTOMER230.	230	0.7693	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
667085	G82RPHT1 230.	230	0.8527	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
667071	NEEPAWA4 230.	230	0.8632	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
667070	CORNWLS4 230.	230	0.8633	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
667052	GLENBOR4 230.	230	0.8711	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
667068	SOURENB4 230.	230	0.8769	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
667069	SOURSTP4 230.	230	0.8813	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPHigh-PST-CTon-	Issue
667068	SOURENB4 230.	230	0.8969	0.9	1.1	P11:18 SPC:CHINOOK#1	BDN-2027WIN-SPHigh-PST-PW-	Adjust G82P PST to eliminate issues
667085	G82RPHT1 230.	230	-	-	-	Various	BDN-2027WIN-SPHigh-PST-PW-	Various low voltages for several contingencies, adjust G82P PST to eliminate issues
667049	STANLEY4 230.	230	0.8843	0.9	1.1	P1:MH E93L	BDN-2027WIN-SPHigh-PST-PW-	Outside study area
667049	STANLEY4 230.	230	0.8842	0.9	1.1	P4:MH E93L/G79L	BDN-2027WIN-SPHigh-PST-PW-	Outside study area
-	-	-	-	-	-	-	BDN-2027WIN-SPHigh-PST-	Various low voltages for several contingencies
667049	STANLEY4 230.	230	0.8832	0.9	1.1	P1:MH E93L	BDN-2027WIN-SPHigh-PW-USexp-	Outside study area
667049	STANLEY4 230.	230	0.883	0.9	1.1	P4:MH E93L/G79L	BDN-2027WIN-SPHigh-PW-USexp-	Outside study area
667071	NEEPAWA4 230.	230	0.8968	0.9	1.1	P4:MH P81C/COR_BK1	BDN-2027WIN-SPHigh-PW-USexp-	Turn on a Brandon CT to eliminate issue
667071	NEEPAWA4 230.	230	0.8942	0.9	1.1	P4:MH P81C/COR_BK4	BDN-2027WIN-SPHigh-PW-USexp-	Turn on a Brandon CT to eliminate issue
667071	NEEPAWA4 230.	230	0.8988	0.9	1.1	P1:MH P81C	BDN-2027WIN-SPHigh-PW-	Turn on a Brandon CT to eliminate issue
667049	STANLEY4 230.	230	0.8823	0.9	1.1	P1:MH E93L	BDN-2027WIN-SPHigh-PW-	Outside study area
667071	NEEPAWA4 230.	230	0.8988	0.9	1.1	P2:MH P81C OEBRA	BDN-2027WIN-SPHigh-PW-	Turn on a Brandon CT to eliminate issue
667049	STANLEY4 230.	230	0.8829	0.9	1.1	P4:MH E93L/G79L	BDN-2027WIN-SPHigh-PW-	Outside study area
667048	LETELER4 230.	230	0.8825	0.9	1.1	P4:MH Y51L/J89L	BDN-2027WIN-SPHigh-PW-	Outside study area
667049	STANLEY4 230.	230	0.891	0.9	1.1	P4:MH Y51L/J89L	BDN-2027WIN-SPHigh-PW-	Outside study area
667071	NEEPAWA4 230.	230	0.8988	0.9	1.1	P4:MH P81C/D83P	BDN-2027WIN-SPHigh-PW-	Turn on a Brandon CT to eliminate issue
667071	NEEPAWA4 230.	230	0.8956	0.9	1.1	P4:MH P81C/COR_BK1	BDN-2027WIN-SPHigh-PW-	Turn on a Brandon CT to eliminate issue
667071	NEEPAWA4 230.	230	0.8931	0.9	1.1	P4:MH P81C/COR_BK4	BDN-2027WIN-SPHigh-PW-	Turn on a Brandon CT to eliminate issue
-	-	-	-	-	-	P1:MH D12P	BDN-2027WIN-SPHigh-USexp-CTon-	Various low voltages for D12P contingency
-	-	-	-	-	-	-	BDN-2027WIN-SPHigh-USexp-	Various low voltages for several contingencies
-	-	-	-	-	-	-	BDN-2027WIN-SPHigh-	Various low voltages for several contingencies
667053	PORTSOU4 230.	230	0.8143	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPLow-CTon-	Issue
800001	CUSTOMER BUS230.	230	0.8175	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPLow-CTon-	Issue
800000	NEW CUSTOMER230.	230	0.8196	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPLow-CTon-	Issue
667071	NEEPAWA4 230.	230	0.8812	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPLow-CTon-	Issue

Appendix D - Steady State Voltage Results

Bus#	BusName	Base KV	ContVolt	LowLimit	UppLimit	Contin.Description	Case	Comments
667070	CORNWLS4 230.	230	0.8964	0.9	1.1	P1:MH D12P	BDN-2027WIN-SPLow-CTon-	Issue
667048	LETELER4 230.	230	0.8968	0.9	1.1	P4:MH Y51L/J89L	BDN-2027WIN-SPLow-CTon-	Outside study area
667048	LETELER4 230.	230	0.8858	0.9	1.1	P4:MH Y51L/J89L	BDN-2027WIN-SPLow-PW-	Outside study area
667049	STANLEY4 230.	230	0.8991	0.9	1.1	P4:MH Y51L/J89L	BDN-2027WIN-SPLow-PW-	Outside study area
667049	STANLEY4 230.	230	0.8792	0.9	1.1	P1:MH E93L	BDN-2027WIN-SPLow-	Outside study area
667049	STANLEY4 230.	230	0.8803	0.9	1.1	P4:MH E93L/G79L	BDN-2027WIN-SPLow-	Outside study area
667048	LETELER4 230.	230	0.8716	0.9	1.1	P4:MH Y51L/J89L	BDN-2027WIN-SPLow-	Outside study area
667049	STANLEY4 230.	230	0.8829	0.9	1.1	P4:MH Y51L/J89L	BDN-2027WIN-SPLow-	Outside study area
667049	STANLEY4 230.	230	0.898	0.9	1.1	P4:MH D14S/D15Y	BDN-2027WIN-SPLow-	Outside study area
667049	STANLEY4 230.	230	0.8979	0.9	1.1	P4:MH D14S/D55Y_LAV_BK1	BDN-2027WIN-SPLow-	Outside study area
667049	STANLEY4 230.	230	0.8979	0.9	1.1	P7:MH D14S/D55Y	BDN-2027WIN-SPLow-	Outside study area
VC						P1:MH D12P	BDN-2027WIN-SPLow-	Issue

APPENDIX E

Summary of Cost Estimate and Schedule – Developed by Transmission Projects Department

Capital Investment Concept (CIC) for Portage Area Capacity Enhancement (PACE) Complex (9-Projects)

IM Node No. 2.1.30.15.02.93
Project Owner: Kurtis Toews – System Planning
Project Managers: Amna Mackin & Ty Nguyen – Transmission Projects

Developed By: Transmission Projects
Date: January 14, 2021

NOTE: This document was developed just prior to Capital Investment Justification (CIJ) submission for collaboration.

- Acquire CIJ approval of $161.6M for project execution of the PACE Complex, which will enhance capacity and reliability in the Portage la Prairie area with the addition of a new station and transmission line and station modifications.
- The Portage la Prairie area is one of the most stressed segments of the Transmission system due to above average load growth, new industrial customers, increasing exports to Saskatchewan and deferral of planned Transmission projects are causing a deterioration of reliability to customers in the area. As a result, capacity for connection of large industrial customers in the area is limited.

Proposed Scope & In-Service Date (ISD) Overview

Stage 1 Projects – Proposed ISD of March 2025

- Build a new Temp-Portage West 230-66kV Station.
  - Official station name to be determined during Round 1 Public Engagement process (after project approval).
  - Station Site B selected (out of eight (8) proposed station sites) as part of internal Conceptual Station Site Selection and Conceptual Transmission Line Routing process.
- Sectionalize existing 230kV transmission line P81C (reconfiguration of three-terminal line P81C from Portage South-Cornwallis-Roquette Stations to Portage South-Cornwallis-Temp-Portage West Stations) (proposed short line length of 200m).
- Terminate new 66kV line at new Temp-Portage West Station.
- Protection Changes at Manitoba Hydro's (MH) existing Cornwallis Station.
- Protection Changes at MH's existing Portage South Station.
- Protection Changes at Customer's existing Roquette Station.

Stage 2 Projects – Proposed ISD of February 2027

- Build a new 230kV transmission line from new Temp-Portage West Station to existing Dorsey Converter Station (proposed line length of 85kms).

- Terminate new 230kV transmission line at new Temp-Portage West Station.
- Terminate new 230kV transmission line and add a 230kV Circuit Breaker at existing Dorsey Converter Station.

Environment Act Licences (EAL) are required for the Stage 1 and Stage 2 Projects.

With the two (2) in-service dates approach, MH would address the 230-66kV transformation capacity limitation issue in the Portage la Prairie area with completion of the Stage 1 projects and would address the voltage issues in the Portage la Prairie and southwest Manitoba area with completion of the Stage 2 projects.

Proposed Budget Overview

Project Name	Network #	Plan / Cost Estimate
PACE Scope Development	Varies	$692K (Base)
PACE Project Execution		
Temp-Portage West to Dorsey 230kV Line	4402260	$69.8M (Base)
230kV Line P81C Sectionalization	4402204	$2.6M (Base)
Licensing & Environmental Assessment	4402647	$3.6M (Base)
Temp-Portage West 230-66kV Station	4402256	$26.8M (Base)
Dorsey Station 230kV Line Termination & Breaker Addition	4402255	$2.1M (Base)
Cornwallis Station Protection Changes	4402334	$93K (Base)
Portage South Station Protection Changes	4402365	$94K (Base)
Roquette Station Protection Changes	4402366	$174K (Base)
Temp-Portage West 66kV Line	4306366	$546K (Base)
Temp-Portage West 230-66kV Telecommunications	4402616	$670K (Base)
PACE Transmission Lines	4402746	$22.9M (Contingency)
PACE Transmission Stations	4402747	$8.8M (Contingency)
PACE Telecommunications	4402748	$200K (Contingency)
PACE Distribution Line	4402749	$170K (Contingency)
	Base Estimate	$107.2M
	Contingency Estimate	$32M
	Interest & Escalation	$22.4M
	Total Estimate	$161.6M

Proposed Schedule Overview

- **April 2021 – Projects Approved (via CIJ Approval)!**
- April 2021 to November 2024 – Licensing, environmental assessment, public engagement, regulatory review and property activities for station and transmission line projects.
  - **January 2022 – EAL Acquired for Stage 1 Projects!**
  - **December 2023 – EAL Acquired for Stage 2 Projects!**
- April 2021 to September 2024 – Field (survey, geotechnical drilling, etc.), engineering reports, detailed designs, construction drawings, apparatus procurement and material procurement activities for station and transmission line projects.
- October 2022 to April 2023 – Station construction tender development, tender, evaluation, negotiations and award of contract for Temp-Portage West 230-66kV Station Project.
- **April 2023 – Station construction contract awarded!**
- May 2023 to March 2025 – Construction and commissioning activities for Stage 1 projects.
- **March 2025 – Stage 1 projects placed into service!**
- November 2024 to May 2025 – Transmission line construction tender development, tender, evaluation, negotiations and award of contract for Temp-Portage West to Dorsey 230kV Line Project.
- **May 2025 – Transmission line construction contract awarded!**
- August 2025 to February 2027 – Transmission line construction and commissioning activities.
- **February 2027 – Stage 2 projects placed into service!**
- February to August 2027 – Project closeout activities.
- August 2027 – Projects completed and closed-out.