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Manitoba Hydro NFAT IEC Transmission Line Construction and Management Report – Confidential Version

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REVISION HISTORY			
DATE	**REVISED BY**	**REVISION**	**DESCRIPTION**
1-8-2014	MG, BF, PA, GD, RB	0	Check Document
1-13-2014	MG, BF, PA, GD, RB	1	General Revision
1-17-2014	MG, RB	2	Added line numbers to body, updated references to NFAT and Appendices to be more precise, revised the references and expanded the Appendices with regard to the cost estimate scope sections.

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TRANSMISSION LINE CONSTRUCTION AND MANAGEMENT

Note: *Throughout this report information in parenthesis is a reference to the location in the NFAT filing. Information in brackets is a reference to information in either external reference publications or information in the appendices of this report.*

Scope Item 1

<u>Review and assess the completeness and reasonableness of Manitoba Hydro's AC Transmission line capital cost and O & M estimates including the adequacy of the management reserve for the project.</u>

POWER Engineers construction cost estimating procedure

In order to perform our review of MH's estimates, POWER Engineers (POWER) used the physical data provided by MH and prepared estimates using POWER's proprietary estimating procedures and tools. These procedures have been used to estimate the construction cost of transmission projects throughout the U. S. and internationally. We continually update the package with information received in bids from recent or most current projects. We take into account the market price for materials, the availability and cost of labor, ground and weather conditions, and seasonal construction adjustments. POWER is one of the largest providers of transmission line design in the northern hemisphere, with experience in the development, design, routing, and construction of lines in all parts of the hemisphere. We use this experience to factor costs into the preparation and evaluation of the estimates we prepare. A procedure in itself often leaves out specific information so we use our experience to make adjustments where required. Where MH provided sufficient data it was used. For other required input data, we used our judgment and experience.

Where sufficient data was not available because lines have not yet been designed, we have used our historic cost information, adjusted for the conditions of this project based on the descriptions in the NFAT Filing. These estimates are typically made in the industry by using per mile or per km costs.

Manitoba Hydro cost estimating procedure

Manitoba Hydro (MH) uses a capital cost estimating system that includes allowances for contingencies, management reserve, interest, and escalation. (2.1.5, pg 35, fig 2.5). Present day costs are based on unit pricing received from recent tenders for similar work adjusted for inflation [D, pg 60 & 61]. The cost impacts of environmental protection, ground conditions, and construction timing are embedded in the unit rates bid by contractors for similar work. The lines are primarily on Crown Land. Where the lines are on private property in the south, Manitoba Hydro indicates that the ROW costs are offset by the reduction in difficulty of construction [B, pg 55]. Environmental costs are not broken out as a separate item [B, pg 55].

Keeyask Transmission Project

The information about the project is provided in Chapter 2 of the NFAT filing. Capital cost information is provided in NFAT filing Appendix 11.1 page 10. The capital cost of the Keeyask transmission line was revised to $80 million in [A, pg 47].

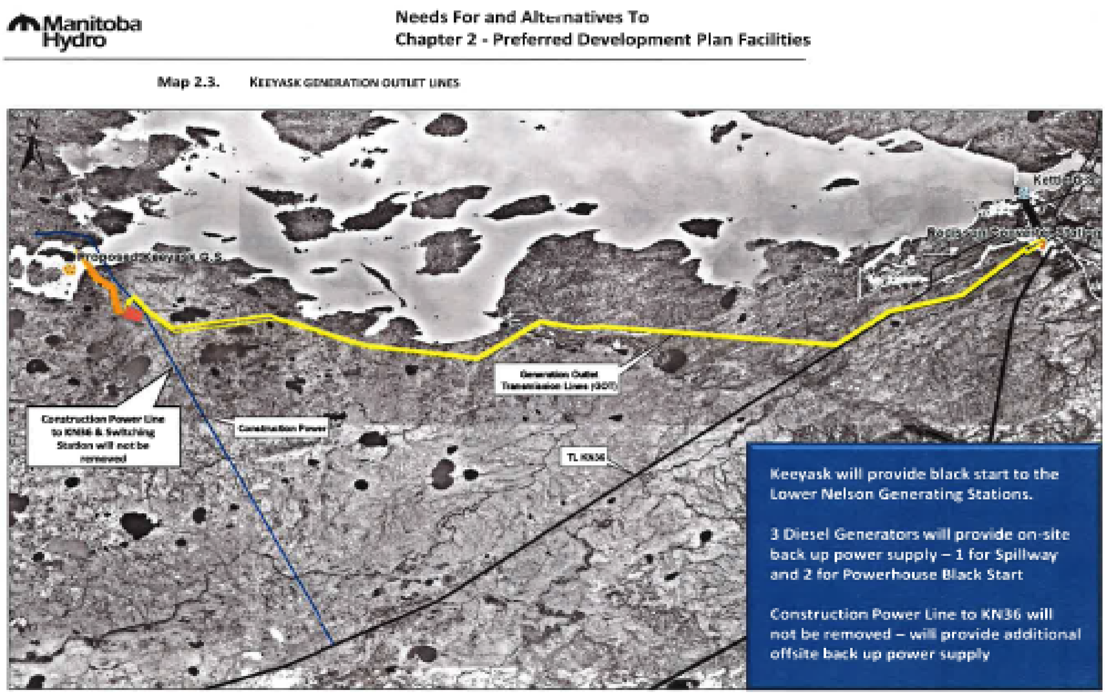

Figure 1: Keeyask Transmission Project

Information Provided in the NFAT Filing

Information in Parenthesis is the NFAT reference. Bracket numbers refer to references listed at the end of this report.

1. The transmission line project will begin in 2014 (2.1, pg 4, line 2)
2. Keeyask power production will occur in the 2019-2020 time period (2.1, pg 4, line 5)
3. The rated plant output is 695 MW (2.1, pg 1, line 7)

Facilities included in the project

1. KR1 Extension
   The KR1 extension line is a 5 km long 138 kV H-Frame line from the Keeyask Switching Station to the Keeyask Construction Power Station. It includes a 1 km long aerial crossing of the Nelson River that requires stroboscopic aerial warning lighting. It will be removed after completion of construction (2.1.2.1, pg 10, line7) [A, pg 47].

2. Unit Lines (2.1.2.3, pg 14, line 11)
   There will be four-3.4 km long single circuit lattice steel tower lines on a common ROW with 65 m center to center spacing. The lines will run from the generators across the Nelson River to the Keeyask Switching Station [A, 47]

3. Generator Outlet Lines KR-1, KR-2, KR-3 Lines (2.1.2.3, pg 14, line 12)
   Three-35 km long 138 kV single circuit guyed lattice tower lines from the Keeyask Switching Station to Radisson Converter Station [A, pg 47].

4. KN-36 Tap (2.1.2.3, pg 14, line 6)
   The KN-36 tap is a 22 km long 138 kV line on a new right-of-way (ROW). It will begin at the existing KN-36 line and proceed northward to provide construction power to the project. There will be three switches at the tap point. It will be a guyed tubular steel pole line [A, pg 48]. The KN-36 line is not included in Keeyask Transmission [A, pg 48]. <u>We have not included it in our analysis.</u>

Manitoba Hydro cost estimate in NFAT filing (<u>Based on the information in [A, pg 34], we have not considered the NFAT cost estimate</u>)

Generation Outlet Transmission (Appendix 11.1, pg 10)	$ Millions++
o Base Estimate (2012)	$ 157
o Escalation (11.46%)	$ 18
o Interest	$ 27
o TOTAL in-service-cost	$ 203

++ There is no breakdown of cost components provided in the NFAT Filing

Supplemental estimate provided in [A, pg 47] (POWER has used this information in our analysis.) POWER understands that this is an update to the NFAT documents.

Generator Outlet transmission [A, pg 47]	
o KR1, KR2, KR3 (2012)	$ 80
o Unit lines (2012)	$ 6
o Subtotal (2012)	$ 86
o Escalation (11.46%)	$ 10
o Interest	$ 15
o TOTAL in-service-cost	$ 111

POWER Engineers assessment of the completeness and reasonableness of Manitoba Hydro's estimate

In 2012 Dollars, the estimate for the Generator outlet lines and Unit lines (KR1, KR2, & KR3) totaling 110 km in length amounts to $727,272/km. We questioned this amount as being excessively high, even taking into account winter construction. A telephone conversation [C, pg 58] on December 11, 2013 with Joel Wortley provided answers that we can accept.

a. The project is very short and efficiencies of longer lines cannot be obtained.
b. The project requires 2 mobilizations because it is constructed in two different years.
c. The river crossing is difficult and expensive.

These are valid reasons for increasing estimated costs. Without these mitigating factors POWER would estimate the cost of a similar 138 kV line at about $639,000/km [E, pg 66]. The area, climatologic conditions and the multiple mobilizations all contribute to costs that can be much higher than a line without these constraints. Allowing a 15% added cost for short projects, an extra $250,000 for the second mobilization in 2019, and a river crossing cost adder of $100,000 per line, produces an estimate of about $97,018,000 for the project in 2012 Dollars, (738,000/km). Our estimate and MH's estimate fall within 5%, which we consider to be an acceptable range.

Conawapa Transmission Project

The information about the project is provided in Chapter 2 of the NFAT filing. Capital cost information is provided in NFAT filing Appendix 11.1.

Map 2.4. CONAWAPA OUTLET TRANSMISSION

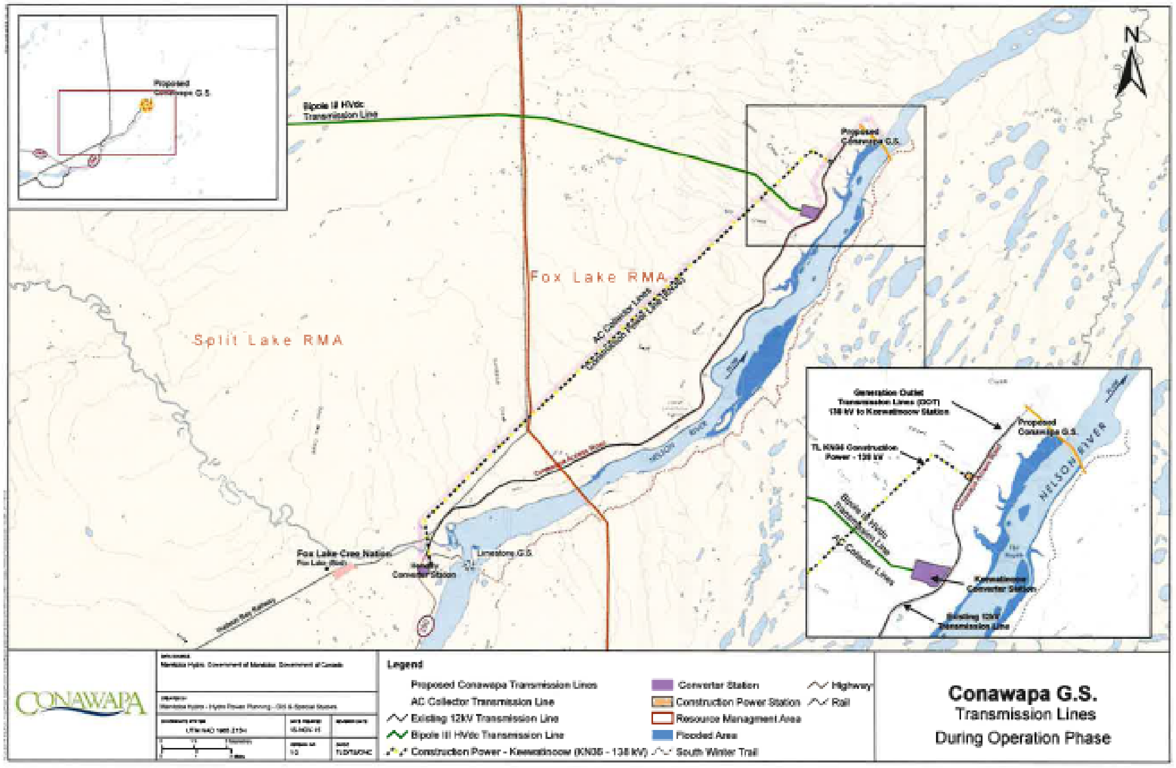

Figure 2: Conawapa Transmission Project

Information Provided in the NFAT Filing

Information in Parenthesis is the NFAT. Bracket numbers refer to references listed at the end of this report.

1. The transmission line project construction period is 2017 – 2028
2. The rated plant output is 1485 MW (2.2, pg 38, Table 2.3)

Facilities included in the project

1. Construction Power line
   A 3 km long 230 kV line from Keewatinoow Station and a new 230/12 kV transformer will be used for construction power. This line will be salvaged after construction in 2028. (2.2.2.2, pg 43, line 6)
2. Generator Outlet Lines
   Five-7 km long 230 kV lines on a common ROW from Conawapa to Keewatinoow Converter Station (2.2.2.2, page 43, line 10)

Manitoba Hydro cost estimate in NFAT filing

Generation Outlet Transmission (Appendix 11.1, pg 14)	$ Millions[++]
o Base Estimate (2012)	$ 10
o Escalation	$ 3
o Interest	$ 1
o TOTAL in-service-cost	$ 14

[++] There is no breakdown of cost components provided in the NFAT Filing

The MH per-km cost estimate for the 230 kV lines in 2012 Dollars is $286,000/km. ($10 million/35 km)

POWER Engineers assessment of the completeness and reasonableness of Manitoba Hydro's estimate

POWER Engineers prepared an estimate for a similar 230 kV line in similar ground conditions and made adjustments for winter construction [E, pg 70]. We included the structure information provided by MH, and made adjustments based on the ground conditions. Our estimate in 2013 Dollars is $344,000/km with an expected accuracy of ±20%). The estimates provided in the NFAT filing fall at the very low range of our expected cost for 230 kV line construction in similar terrain.

North-South Transmission System Upgrade Project

The project description is given in Chapter 2 of the NFAT filing. There is no capital cost breakdown in Appendix 11.1.

Information Provided in the NFAT Filing

Information in Parenthesis is the NFAT reference. Bracket numbers refer to references listed at the end of this report.

Facilities included in the project

1. HVDC Collector system upgrades (2.3.1, pg 53, line 17)
   a. Splitting the northern HVDC collector system in two
   b. Adding a 300 MVAR filter at Radisson Converter Station
   c. Addition of a synchronous condenser, CB replacements and a 230 kV AC line sectionalization at Riel
   d. Kettle Ring Bus connection

2. AC System Upgrades (2.3.1, pg 54, line 5)
   a. 80 km 230 kV line, Kelsey Generating Station to Birchtree Station (Thompson)
   b. 42 km 230 kV line, Birchtree Station to Wuskwatim Generating Station
   c. 210 km 230 kV line, Herblet Lake Station (Snow Lake) to Overflowing River Station (The Pas)
   d. 130 km 230 kV line, Vermillion Station (Dauphin) to Neepawa Station
      i. May have some ROW costs [B. pg 55]

Manitoba Hydro cost estimating process

MH indicated that since these lines have not been designed, their costs are based on using per-km costs from similar recent projects in similar terrain, escalated to the year of construction [D, pg 59]. The per-km cost used is $300,000/km. Appendix [A, pg 53] provided several historic costs. The two projects from 2011 averaged $298,000/km for 230 kV single circuit tower lines in northern Manitoba. Appendix [A, pg 36] provides the following cost breakdown:

		(2013) millions
o	4-230 kV transmission lines totaling 462 km in length	$139
o	HVDC system upgrades	$143
o	Equipment upgrades	$ 58
	TOTAL 2012 cost	$340
o	Escalation to in-service-date	$158
o	TOTAL in-service-date cost (2025-2026)	$498

Section (2.3.5, pg 55. Line 21) of the NFAT Filing gives a cost estimate of $498 million, including both AC and HVDC upgrades.

POWER Engineers assessment of the completeness and reasonableness of Manitoba Hydro's 230 kV line construction cost estimate

POWER Engineers prepared an estimate for a similar 230 kV line in similar ground conditions and made adjustments for winter construction. Our estimate in 2013 Dollars is $344,000/km [E, pg 69] with an expected accuracy of ±20%). We included the structure information provided by MH, and made adjustments based on the ground conditions. The estimates provided in the NFAT filing fall within the range of our expected cost for 230 kV line construction in similar terrain.

Using per-km costs for completed projects that are similar in scope and geographic region is a generally recognized technique for estimating the construction costs of lines that have not yet been designed. Care must be taken in using historic cost data to take into account any changed conditions such as ground condition, terrain, line length, and variations in the availability of labor and material. Based on our estimates and MH's use of recent transmission line project costs in similar regions and with similar construction, we find the transmission line construction cost estimates to be reasonable.

POWER Engineers assessment of the completeness and reasonableness of Manitoba Hydro's estimate of the HVDC system upgrades and equipment upgrade.

There is no breakdown of the HVDC system upgrades and equipment upgrades. POWER has used recent information on a thyristor based converter project, and made a judgment about the associated equipment and controls costs.

Manitoba Hydro's preferred option, identified as 2A in their "Integrated Transmission Plan for Keeyask and Conawapa Generation," SPD 2011/11 [7] requires that Bipole III rating increase from the originally planned rating of 2000 MW to 2300 MW. Manitoba Hydro has stated that this increase will use the inherent overload capability that is available in the design of the Bipole III converters. It would be anticipated that the cost of the enhanced Bipole III converters would need to address control changes, possible cooling system modifications, and the additional vars required for an increase in power levels of the dc converters. This document estimated the cost for this enhancement to be $38 million, out of a total budgeted cost of $1,828.5 million for the converter stations. The market price for increasing the rating of a conventional ±500 kV, 2000 MW converter by 300 MW would be approximately $54 million dollars based on a recent market survey POWER/TGS provided to a current client. This estimate however does not address the increased complexity and cost for Bipole

III's incorporation of the valve sparing capability which could increase the cost of this enhancement by a multiplier in the range of 2 to 3 to account for the multiple quadra valves required to meet this requirement.

Because a detailed list of improvements needed to enhance Bipole III rating by 300 MW was not included for the $143 million stated above it is not clear what additional equipment would need to be included in the estimate and due to the valve sparing requirements for Bipole III the estimated cost for the enhancement would need to be requested from HVDC converter manufacturers.

Manitoba – Minnesota Transmission Project (MMTP)

The information about the project is provided in Chapter 2 of the NFAT filing. Capital cost information is provided in Appendix 11.1. The projected In-service-date is 2026 (2.4, pg 56, line 8).

Information Provided in the NFAT Filing

Information in Parenthesis is the NFAT reference or information obtained through informal contacts with Manitoba Hydro. Bracket numbers refer to references listed at the end of this report.

Facilities included in the project (2.4.1, pg 56, line 11)

1. 68.7 km long 500 kV, 750 MW single circuit 500 kV transmission line on self-supporting steel lattice towers from Dorsey to Riel [A, pg 50]]
2. 166 km long 500 kV guyed Lattice Tower line from Riel to U. S. Border [A, pg 50]
3. 300 MVAR Shunt reactor at Dorsey [A, [g 37]
4. 75 MVAR shunt capacitor at Dorsey [A, pg 37]
5. 150 MVAR shunt capacitor at Riel [A, pg 37]
6. Three phase 300 MVA 230 kV Phase Shifting transformer at Glenboro Station [A, pg 37]
   Manitoba Hydro cost estimate in NFAT filing

MH provided an estimate of $350 million (2.4.5, pg 58, line 22). No details were given. There is no capital cost detail for the MMTP given in Appendix 11.1. MH provided a scope and construction cost estimate [A, pg 50 & 51]. This is the estimate we have used in our analysis.

Transmission line costs	$ Millions
o Environmental Assessment	$ 7.6
o Engineering	$ 10.0
o Property Acquisition	$ 5.8
o Material	$ 65.9
o Construction	$ 63.1
o Contingency	$ 21.1
o Total (2012)	$173.6

On a per km basis, the $173.6 million divided by the 234.7 km produces an estimated cost of $739,668/km in 2012 Dollars. Adding escalation and interest produces an in-service-year estimate of about $925,000/km.

Station upgrades	$ Millions
o Dorsey Station	$ 23.2
o Riel Station	$ 54.3
o Glenboro Station	$ 16.5
o TOTAL (2012)	$ 94.0

Escalating the sum of these two parts of the estimate to the in-service-year totals $350 million.

POWER Engineers assessment of the completeness and reasonableness of Manitoba Hydro's estimate

In order to perform our review of MH's 500 kV AC transmission line estimates, POWER used a recently completed 500 kV AC transmission line project estimate and modified it with the physical data provided by MH.

Our estimate for the two sections of the 500 kV line in Manitoba is $663,500/km in 2012 Dollars [E, pg 74]. The total cost for the 234.7 km of 500 kV AC line is $155.2 million in 2012 Dollars. Escalating this 2012 cost to the construction year cost produces a cost of $831,000/km, or a total in-service year cost of $195 million.

MH provided a line construction cost estimate [A, pg 50 & 51] that shows an estimated 2012 cost of $173 million. The estimate prepared by MH is about 11% lower than POWER's estimate, but within the estimate tolerance.

Scope item 2

Review and assess the completeness and reasonableness of Manitoba Hydro's AC Transmission line construction indirect costs, including access roads, campsites, and off-site mitigation costs.

Manitoba Hydro has not broken out the construction indirect costs of the projects in the NFAT filing. MH has indicated that the costs they use are contractor's unit costs that include all the indirect costs. POWER Engineers considers the costs of access roads and other indirect costs in our estimating procedure. MH's estimates and our estimates are in reasonable agreement and we can conclude that the indirect costs have been adequately included in the MH estimate.

Scope Item 3

Review and assess Manitoba Hydro's construction management, schedule, and contracting plans for the design, engineering, procurement, construction, start up, commissioning, testing, and commercial operation of the AC transmission system.

POWER reviewed a summary schedule for the project lines [F, pg 78]. The schedule showed time periods for engineering design, procurement, and construction. These periods appear to be reasonable for projects of the magnitudes of the project lines. The calendar periods are reasonable. The schedule shows the northern construction occurring in the winter. The initial work at Keeyask; the first generation outlet line and the construction power line are shown in the same the period. The major project, MMTP, has a 5 ½ year schedule with 2 ½ years allotted for construction. The construction period is reasonable for a project this size. Achieving this completion rate will require an average of about 250 workers. This is not an unusual crew complement for a project this size. The MMTP project will wind down with a gradual reduction in the number of workers required in the first half of 2019 during the period when the Keeyask lines will be in construction. This means that the Keeyask projects will, at least initially, face a tight labor market. MH indicated that their estimates for the Keeyask projects have considered the potential tight labor market.

Manitoba Hydro typically uses the Design-Bid- Build contracting method. This will be used for this project. MH performs the design work necessary to specify the requirements of the project to the contractor. MH procures the material. This is a well trusted contracting method. It allows MH to control the quality of both the design and the material purchased, and prepare construction specifications that govern the quality of the workmanship. MH provides Construction Management and Inspection services using their staff. By providing material, construction specifications, and inspecting the quality of the workmanship, MH will obtain a quality product. AC Transmission lines do not require start up, commissioning, and testing. Substations associated with the lines require these services. These services typically require manufacturer specified tests on equipment prior to energization. Relay circuits must be tested for accuracy in terminations, and continuity. Relay settings must be input and verified to assure proper protection of the equipment, and control wiring to equipment must be checked for proper size and terminations. This work is routinely performed as part of substation commissioning and start-up. MH specifications for construction cover these functions.

The schedule is dependent on winter construction conditions. The ground is marshy for a lot of the line length. Winter conditions provide benefits in frozen ground that can be traversed by equipment to reach the work sites. It also provides hazards in inclement weather that can slow or halt construction. The schedule has made allowances for inclement weather.

Scope Item 4

<u>Review and assess Manitoba Hydro's cost estimating risks and risk management practices, sensitivity analysis in construction cost estimates, contingencies, and construction cost indices for the AC Transmission system.</u>

The NFAT filing has extensive descriptions of MH's cost estimating and risk management practices, sensitivity analysis in construction cost estimates, contingencies, and construction cost indices. The descriptions and discussions given in Chapter 10 relate to the generation projects, and overall plan, rather than to the transmission lines. The approach is very thorough. The "tornado diagram" in (10.1.1.1, Figure 10.1) shows that major cost variations in transmission line costs have a very minor cost risk to the overall project. This is to be expected in a major generation project. The transmission line cost risk is mitigated, to a great extent, by the fact that the lines are predominantly on Crown Lands. The risks of line routing and rerouting during the course of the project are minimized compared to lines on private property. Only the Dauphin – Neepawa line has some private right of way. The major risk to the transmission cost estimate is inclement winter weather. This is reflected in the Tornado diagram.

MH has used historical costs for transmission lines constructed in similar locations and with similar types of construction. These costs have been appropriately escalated to in-service-year dollars. This is a methodology commonly used by utilities and consultants. POWER often uses the same approach for lines that have not yet been designed. The availability of contractor labor and the associated price has also been considered. The availability of labor is an important risk factor. When labor is in high demand, contractors face higher costs and demand higher payment for their work. The estimate for the transmission line work in the 2014 to 2017 time period is adjusted for the large Bipole III project which is likely to have an effect on labor availability and cost.

Scope Item 5

Provide comparable estimates of costs for each of the forgoing new transmission projects, including Bipole III as suggested by Manitoba Hydro.

POWER's approach to assessing the MH cost estimates for the various projects was to prepare an independent cost estimate or adjust estimates that we have recently prepared for similar lines. The adjustments are for escalation and differing conditions. For the project lines that are not designed, we used previous cost estimates for lines of the same voltage and adjusted them to account for the terrain and climatology of Manitoba. We expressed these costs on a per km basis, which is the approach used by Manitoba Hydro based on their recent project experience. We agree with this approach. Comparable cost estimates for 138 kV, 230 kV, and 500 kV lines are provided in Appendix E.

Bipole III is not part of the NFAT filing. Based on past experience with some of the estimates we have prepared, we developed costs that are typical of costs that would be associated with the 500 kV HVDC Bipole III project. Our estimate is $959,000/km in 2012 Dollars. The summary page of the estimate is given on Appendix E, pg xx. For the 1485 km of Bipole III this would produce a line construction cost of $1.42 billion. Escalated to 2016 this would amount to $1.54 billion for the line.

Scope item 6

Review and assess Manitoba Hydro's estimate for the cost of construction of U.S. transmission infrastructure to facilitate sales into MISO.

Manitoba Hydro did not develop cost estimates for the U.S. facilities. These costs were developed by Minnesota Power and provided to MH. POWER has compared these cost estimates to similar 500 kV lines in similar terrain and finds them to be reasonable.

MANITOBA HYDRO TRANSMISSION RELIABILITY

Scope Item 7

Review and assess the completeness and reasonableness of the technical aspects of Manitoba Hydro's existing and proposed AC & DC transmission system.

POWER reviewed Manitoba Hydro's 2012 System Performance Assessment[1] that included the existing system and proposed long term additions out to the year 2022, including Bipole III and Keeyask. This document addresses system performance and compliance with NERC Transmission Planning Standards TPL-001-0 through TPL-004-0, MRO and Manitoba Hydro operating criteria. The scope and time frame of that assessment and proposed plan did not include the integration of the Conawapa generation station and the NFAT Preferred Plan. An updated system assessment is conducted annually by MH to determine any changes needed to continually meet the NERC planning standards. MH should conduct another System Performance Assessment, similar to the 2012 effort, once the NFAT Preferred Plan is confirmed and approved.

POWER reviewed several characteristics of the existing and proposed system including HVDC valve group on-line sparing practices, firm and non-firm transmission capability, and reliability. POWER developed several tables to illustrate these characteristics. POWER's assessment is also based on

[1] Manitoba Hydro's 2012 System Performance Assessment: NERC Planning Standards TPL-001-0 through TPL-004-0 CONFIDENTIAL

information contained in the Integrated Transmission Plan for Keeyask and Conawapa Generation", SPD2011/11, July 17, 2012. In the Executive Summary of that report, MH explains that

> *'In order to qualify as a Designated Network Resource, firm transmission is required. In the context of HVdc transmission, the capacity is considered firm when a spare valve group over generation is provided to cover for the most frequent outages. The non-firm transmission will result in portions of the proposed Keeyask and Conawapa generation being treated as Energy Resource (i.e. potential bottled generation). This report identifies the firm and non-firm transmission plans for Keeyask and Conawapa generation'.*

Outage data provided by MH confirms that valve group outages are the most frequent type of outage. The largest valve group outage determines firm transmission capacity.

POWER developed Table 1 below. It shows that before Bipole III comes on line, the existing two-Bipole system does not have enough capability to deliver all of the Northern Collector System (NCS) generation to southern MH load over firm transmission. At present, the total generation on NCS is 3554 MW and total HVDC firm transmission, accounting for a 500 MW valve group (VG) outage, is 3354 MW. Thus, there is a shortage of about 200 MW when considering that the largest valve group is 500 MW. POWER made an assumption here that the largest valve group outage for the combined system drives the determination of firm transmission capacity and not the individual HVDC Bipoles. For example, on an individual basis, Bipole I is rated at 1854 MW, with six valve groups each at 309 MW, and has a firm transmission capacity of 1545MW, considering a valve group outage. Bipole 2 is rated at 2000 MW, with 4 valve groups - each at 500 MW - and has a firm transmission capacity of 1500 MW, considering a valve group outage. The combined Bipole I and Bipole II system has a transmission capability of 3854 MW, with a firm transmission capability of 3354 MW, considering the largest valve group outage of 500 MW. The total generation connected to the two Bipole system is 3554 MW, creating a shortage of firm transmission of about 200 MW. Table1 shows the progression of transmission development and resulting non-firm transmission over time before implementing the preferred plan, option 2A.

Table 1: Before Implementing the Preferred Plan and Splitting the Northern Collector System

Facility/ Rating	Timeline	Combined HVDC Capacity MW	Largest VG MW	Total HVDC Firm MW	Generation @ NCS	Non-Firm Transmission
BP I/1854	Existing	1854	309	1545	3554 MW	N/A
BP II/2000	Existing	3854	500	3354	3554 MW	200 MW
Bipole III/2000	2017	5854 [redacted] [2]	500	[redacted]	3554 MW	Zero
Keeyask/630[3]	2019/2020	5854 [redacted]	500	[redacted]	4184 MW	Zero
Conawapa/1395[4]	2026	5854 [redacted]	500	[redacted]	[redacted]	[redacted] MW

After Bipole III goes in service, all NCS generation and Keeyask generation comes on line, all NCS generation can be delivered over firm transmission. The total HVDC capacity after Bipole III will be 5854 MW, with BP III rated at 2000 MW. However, based on transient stability studies, MH has determined that the maximum HVDC system reliability loading limit is [redacted] MW, based on the response of the HVDC system to a simulated three-phase fault near the NCS bus with normal

[2] Manitoba Hydro's Integrated Transmission Plan for Keeyask and Conawapa Generation, Section 3.2.1, pg 3939
[3] Net generation value
[4] Net generation value

clearing. [redacted] The HVDC limit will be reviewed when a better model becomes available for Bipole III in 2014. This is explained further in section 3.2.1, page 39 of MH report. After Keeyask generation comes on line, the three Bipole HVDC system reliability limit is [redacted] MW. The three Bipole system can still deliver [redacted] MW with the largest valve group outage, and total generation connected at the NCS is 4184 MW with Keeyask. Therefore there is no shortage of on-line valve group sparing and thus all transmission capability is considered firm.

After Conawapa goes in service, and prior to splitting the NCS bus, total generation at NCS will be 5579 MW. The three-Bipole HVDC system reliability limit remains at [redacted] MW. This leaves a transmission capacity shortage of [redacted] MW. The NFAT Preferred Plan, Option 2A of the NFAT filing, proposes upgrading Bipole III to 2300 MW, splitting the NCS system into two busses, adding 100 MW of new N-S AC transmission, and permanently connecting one Kettle generating unit on the AC transmission. It also proposes switching[5] of up to three Kettle generating units to optimize the on-line valve group sparing and reliance on non-firm transmission. Table 2 below shows the impact of splitting the NCS bus, with Bipole 1 connected to NCS 1, which connects Kettle Generating Station and Keeyask. Bipole II and Bipole III are connected to Limestone, Long Spruce, and the new Conawapa generation. The table assumes that all but one Kettle generating unit are connected to NCS1 and Bipole I. Each Kettle unit has a rating of 102 MW.

Table 2: Option 2A: Splitting the Northern Collector System, BP III@ 2300 MW, 1 Kettle Unit on AC, No Kettle Unit Switching

Facility/ Rating Split NCS[6]	Timeline	Combined HVDC Capacity MW	Largest VG MW	Total HVDC Firm MW	Generation @ NCS	Non-firm Transmission @ NCS
BP I/NCS 1	2026	1854	309	[redacted][7]	[redacted]	207 MW
Bipole II & III(2300)/ NCS 2	2026	4300	575	[redacted]		Zero
Total		6154	575	[redacted]		207MW

Table 2 shows that NSC1 is not capable of delivering all connected generation over Bipole I on a firm basis without additional AC transmission. The shortage is about 207 MW. This shortage could be mitigated by upgrading the AC Transmission by approximately 300 MW and permanently connecting three Kettle generating units to the new AC transmission. This would require an AC transmission upgrade of approximately 300 MW. This is essentially Option 2. However, MH made a case for

[5] Operator may restrict switching of equipment below -30C.

[6] NCS split occurs when Conawapa comes on line

[7] After splitting the NCS, non-firm transmission would increase to 300 MW, not including switching of Kettle generation between NCS1 and NCS2. This potentially reduces non-firm transmission to 20 – 120 MW.

Option 2A in the Integrated Transmission Plan for Keeyask and Conawapa Generation report (see Table 11, page 29) that the lack of on-line valve group sparing and associated non-firm transmission could be partially mitigated by switching Kettle generating units between NCS1 and NCS2. The 100 MW AC Transmission upgrade also increases the firm transmission for Kelsey and Wuskwatim generation by 85 MW. Table 3 below is an abbreviated version of Table 11 in the NFAT report. Notice that adequate sparing and thus firm transmission cannot be provided simultaneously for both NCS1 and NCS2. However, from a system perspective, the system equivalent non-firm transmission is reduced to a range of 20 – 120 MW. This appears to be as good as or better than the 200 MW of non-firm transmission on today's system without Bipole III.

Table 3 below shows the non-firm transmission resulting from switching of up to three Kettle generating units between NCS1 and NCS2. On-line valve group sparing and the choice to utilize non-firm transmission capacity do not impact reliability. The choice does however influence how large the AC transmission upgrade should be to guarantee that firm transmission is available for all generation.

Table 3: Non-Firm Transmission with Kettle Generation Switching

	Required Spare valve group	Option 1: Shortage without Kettle Switching	Option 2: Shortage with 2 Kettle unit on NCS2	Option 3 Preferred: Shortage with 2 units on NCS1 and 1 on NCS2
NCS 1	309	207	Zero	105
NCS 2	575	Zero	204	102
Net with 85 MW firm		122	119 MW	20 MW

Reliability for Southern System AC Faults

Sections 4.1 and 4.2 in the MH Integrated Transmission Plan for Keeyask and Conawapa Generation report discuss system stability for three-phase faults with normal clearing near the Inverter busses at Riel or Dorsey. As shown in figure 30; page 60 of the MH report, with the HVDC loading above 5200 MW, system frequency can dip below the Underfrequency load shedding threshold. However, in discussions with MH, the frequency recovers and does not stay below 59.3 Hz for the 65 ms required to trigger Underfrequency load shedding. MH explained that studies examined loading levels from [redacted] MW up to [redacted] MW in 100 MW increments without a NERC violation due to Underfrequency load shedding. POWER would suggest that any crossing of the 59.3 Hz threshold should be carefully reviewed to determine if there is sufficient margin in the studies to avoid Underfrequency load shedding.

In Option 2A, the HVDC loading is [redacted] MW. MH considers this to provide some margin, since the highest loading studied without a NERC violation was [redacted] MW. MH has indicated that higher HVDC loadings tend to put the system at higher risk of failing to recover from a three-phase fault and possible blocking of a single Bipole. The ultimate risk is the simultaneous loss of the three-Bipole system. Such an event would be catastrophic, possibly leading to a cascading transmission system outage and blackout. A safe operating limit for the combined HVDC system that minimizes the risk of a total HVDC system loss is crucial to providing overall system reliability and also influences the amount of new AC Transmission required to off-load the HVDC system.

In follow up discussions, MH indicated that that a more detailed Bipole III model is under development and will be used in studies to confirm its performance during and after clearing a three-phase AC fault. MH also indicated that a coordinated Bipole restart control system will be developed to avoid possible tripping of the three-Bipole system. For now, it appears that, using current information and models, that the HVDC loading level is safe and reliable at [redacted] MW, after splitting the NCS bus. However, POWER is concerned that MH may not have provided sufficient margin to the three-Bipole system that would ensure avoidance of Underfrequency load shedding and avoidance of a complete loss of one or more Bipoles for Southern AC System faults. Future studies by MH should include developing a rationale, similar to that provided for NCS faults, to assure that sufficient margin is provided for Southern AC System faults. For example, if subsequent investigations reveal that the safe operating limit is [redacted] MW, including a 200 MW margin, then this would tend to support moving towards Option 2 with provisions for a 300 MW AC Transmission upgrade, where three Kettle generating units are permanently transferred from the HVDC to the AC system. This option allows adequate on-line valve group sparing over generation; and all generation can be transmitted over firm transmission. Table 4 shows the impact of Option 2 of on-line valve group sparing and non-firm Transmission. Note that under Option 2, the total HVDC firm capacity is [redacted] MW, which is very close to the total generation connected to the HVDC transmission system. Therefore, almost all generation can be delivered over firm transmission. Furthermore, a 5200 MW loading level for the HVDC system would provide a reliability margin over 300 MW below the maximum study value of [redacted] MW.

Table 4: Option 2 with 300 MW of Kettle Generation on AC Transmission

Facility/ Rating Split NCS[8]	Combined HVDC Capacity MW	Largest VG MW	Total HVDC Firm MW	Generation @ NCS	Non-firm Transmission @ NCS
BP I/NCS 1	1854	309	[redacted]	[redacted]	Near Zero
Bipole II & III(2300)/ NCS 2	4300	575	[redacted]		Zero
Total	6154	575	[redacted] [9]		Zero

POWER's overall assessment is that Manitoba Hydro has conducted a thorough analysis of system reliability for the existing transmission system through its 2012 MH System Performance Assessment. This study looks at NERC standards TPL -001 through TPL-004.

MH reviewed critical outages on the proposed transmission system in developing the Preferred Plan. Due to the unique three-Bipole HVdc scheme of Manitoba Hydro system, ac system faults in the southern and northern systems are more severe in comparison to a dc contingency such as a pole or Bipole loss, as they simultaneously affect the power delivery on all three Bipoles. MH should conduct another System Performance Assessment, similar to the 2012 effort once the NFAT Preferred Plan is confirmed and approved.

An effort is underway by MH to alleviate the reliability concerns raised in this report. [redacted]

[8] NCS split occurs when Conawapa comes on line

[9] This is near the HVDC loading represented in Option 2. Reliable HVDC operating limit requires further analysis.

[redacted] Bipole III uses a generic model. MH has indicated that a new detailed Bipole III model will be available by the end of the year 2014 and additional studies will be conducted by the end of 2014.

MH is still investigating requirements and consequences for on-line valve group sparing for the split northern collector system. POWER concurs with the MH view that on-line valve group sparing over generation is mostly an economic choice, and not reliability issue. The economic decision will no doubt include consideration of impacts of future energy transactions and facility component reliability. In this case, the selected firm operating limit of the three Bipole HVDC system will also determine how much additional AC transmission is required to off-load DC facilities. This will, in turn, firm-up the HVDC transmission system and connected generation.

TRANSMISSION LOSSES– WITHIN MANITOBA

Scope Item 8

Define the average energy flow and transmission losses from Keeyask and Conawapa G.S. to Southern Manitoba for domestic load during peak and off-peak times with a) BP I and II only and b) BP I, II, and III

Background

Manitoba Hydro's (MH) proposed development stages of northern Manitoba generation were reviewed with respect to energy flow and loss impacts of the planned generation, with ac system and dc lines at points in time when the proposed facilities are in service. There are a number of options being considered for delivering northern generation to the Winnipeg load area with different possible levels of export to the US. This analysis used the Manitoba Hydro Preferred Option 2A and a consistent set of parameters to reduce other variables from having an influence on both the load flow and resulting losses.

Today the primary transmission that transports energy from a single Northern Collector System (NCS) to the southern part of Manitoba in the Winnipeg area is comprised of two HVDC transmission lines, Bipole I and Bipole II. The current system has a north to south transfer capability of 3,854 MW, which is the combined total rating of Bipole I & II, individually rated 1854 MW and 2000 MW respectively. The current generation level connected to the NCS is 3554 MW.

Generation on the Nelson River that feeds into the collector system for delivery to load on Bipole I and Bipole II includes the following generation stations:

1. Kelsey
2. Long Spruce
3. Kettle Rapids
4. Limestone

Proposed additional generating stations on the Nelson River and new transmission facilities are planned as follows:

1. Keeyask with a net capacity of 630 MW and planned in service date of 2019 - 2020
2. Conawapa with a net capacity of 1395 MW and planned in service date of 2025-2026 [1]
3. Bipole III has already been approved in a separate process to improve reliability and has a planned in service date of 2017. While not part of this NFAT review, the addition of Bipole III will increase the HVDC transmission capacity to enable delivery of the new Keeyask and Conawapa generation station power to loads in southern Manitoba. The NCS currently collects approximately 70% of northern Manitoba Hydro generation and funnels that generation over the existing two Bipole system. After the addition of Keeyask and Conawapa, Bipole III will provide necessary transmission capacity to serve load and fulfill anticipated export contracts.
4. New contracts have been approved with Minnesota Power (250 MW + 133 MW contract pending) and additional contracts that are under pending negotiations. The MH – US interconnection will be upgraded by 750MW to enable those contracts.
5. After the integration of Conawapa, the HVDC system will approach its safe and reliable operating limit. Manitoba Hydro is planning to split the existing NCS bus into two busses. Generation will be rerouted to these busses in a manner that will keep the HVDC system loading within its safe operating limit. Some additional AC transmission must also be provided to offload the three Bipole HVDC system and firm up transmission from northern system generation.

Manitoba Hydro, "Need For and Alternatives To," Alternatives, August 2013.

Manitoba Hydro's NFAT addresses a number of alternatives for improving the ability of the AC and HVDC transmission systems to transmit power from Keeyask and Conawapa generation stations to the load in the Winnipeg area. The recommended alternative or Preferred Plan in the NFAT is Option 2A.

The Preferred Option 2A implements the following transmission system changes:

1. Bipole III upgraded from the planned 2000 MW to a rating of 2,300 MW.
2. The existing Northern Collector System (NCS) is split into two separate collector systems - NCS1 and NCS2 - at Radisson Station.
3. Keeyask generation and eight units of Kettle generation will be placed on the Bipole I transmission line. Limestone, Long Spruce and Conawapa generation will be placed on Bipole II & III transmission lines.
4. One Kettle generating unit will be placed on the 230 kV system and the AC firm capacity increased 100 MW under this option by constructing additional 230 kV ac transmission facilities.
5. Up to three Kettle generating units will be switchable between NCS1 and NCS2.

Transmission Losses

The transmission losses from Keeyask and Conawapa G.S. to southern Manitoba for domestic seasonal load during peak and off-peak times were determined by examining approximately 21 power flow diagrams, supplied by Manitoba Hydro at POWER's request. A summary of results from those power flow cases are listed in Table A1 in Appendix D. Data from Table A1 includes Total AC + DC system losses and export losses for various Summer Off-Peak, Summer On-Peak, and Winter Peak loads under a range of export levels. POWER derived additional values including incremental generation to support US exports, total Manitoba load and US exports, and export losses resulting from US exports.

Descriptions of the system parameters and conditions modeled in the power flow cases are provided in Appendix D, Tables A2, A3 & A4. These conditions include system generation, system Load, Bipole loading for Bipole I & II in service, Bipole loading for Bipole I, II, & III in service, and the new 500 kV tie line in and out of service.

Transmission losses that include delivery of generation from Keeyask and Conawapa Generating Stations to Southern Manitoba for domestic seasonal loading levels during peak and off-peak times with Bipole I & II only, and with Bipole I, II, & III in service, and incremental transmission losses for exports to the US border are shown in Tables 5 and 6, respectively.

Table 5 Total AC + DC Transmission losses from Keeyask and Conawapa G.S. to Southern Manitoba for the existing system with Bipoles I & II (no Bipole III) for domestic peak and off-peak load with no US tie line.

Table 5: Existing System (No Bipole III, No New US Tie Line)

Season	Summer Off-Peak		Summer On-Peak		Winter Peak	
US Exports	0	2175	0	2175	0	878
System Losses – Generation to Load, MW	101	343	170	374	308	378
Export Losses to border, MW	0	242	0	204	0	70
Total System Load + Exports, MW	2435	4610	3577	5752	4910	5788

Table 6 Total AC + DC Transmission losses from Keeyask and Conawapa G.S. to Southern Manitoba Preferred Option 2A, included Bipoles I, II and III, includes the US tie lines for domestic peak and off-peak load levels.

Table 6: Preferred Option 2A (Bipole III, New US Tie Line)

Season	Summer Off-Peak		Summer On-Peak			Winter Peak		
US Exports	0	2175	0	2175	2975	0	2175	2784
System Losses – Generation to Load, MW	112	239	177	329	423	267	529	566
Export Losses to border, MW	0	127	0	152	246	0	262	299
Total System Load + Exports, MW	2425	4610	3577	5752	6502	4910	7085	7694

A few observations can be made from Tables 5 and 6.

Losses are lower for Preferred Option 2A than the existing system as shown in Table 7, when the loading is above 3,577 MW. The difference in losses between these two operating scenarios will be more pronounced at higher load and export levels.

Table 7: System Loss Comparison between Preferred Option 2A and Existing System

Season	Summer Off-Peak		Summer On-Peak			Winter Peak		
US Exports	0	2175	0	2175	2975	0	2175	2784
Preferred Option 2A System Losses, MW	112	239	177	329	423	267	NA	NA
Existing System Losses, MW	101	343	170	374	Not Run	308	NA	NA
Total System Load + Exports, MW	2425	4610	3577	5752	6502	4910	Load mis-match	Load mis-match

Tables 6 and 7 also show the export losses to the US for different export levels and seasonal loadings.

What is not as obvious from these tables is that the increased Bipole capacity with the addition of Bipole III reduces losses on the DC transmission system – Bipoles I, II and III. The addition of Bipole III reduces losses by allowing the northern generation to be shared between the three Bipoles.

Average Energy

Manitoba Hydro estimates the Bipole loss reduction in [4] System Firm Winter Peak Demand and Capacity Resources (MW) @ generation, K19/C25/250MW, August 16, 2013 to be 90 MW in 2020/21, which is treated as a capacity addition to the Manitoba Hydro system. This loss saving reduces over time as the loading increases on the dc Bipole system, with this table showing the Bipole loss saving decreasing to 18 MW in 2026/27 when Conawapa is brought on line and remaining at this level for future years.

The companion table for [4] System Firm Energy Demand and Dependable Resources (GWh)@generation indicates that Manitoba Net Load is 27,762 GWh for 2020/21. This is equivalent to 3,163 average MW of load. Expected exports for this same year are estimated at 2012 GWh or 230 average MW. The average MW level represents the power that would be flowing to the load or being exported every hour of the day throughout the year.

LOSSES ASSOCIATED WITH EXPORTS INTO THE UNITED STATES

Scope Item 9

Define the average energy flow and incremental transmission losses for exports into MISO during peak and off peak time with a) Bipoles I and II plus AC to the US Border; and b) Bipoles I, II, and III plus AC to the US border.

This analysis extracts data from Table 8 to address the losses associated with the Bipoles and the incremental export losses from the AC transmission lines to the US Border.

The incremental losses in the Bipoles and AC transmission [Table A1, G, pg 80] to the US border for the existing system are tabulated in Table 8. The existing system does not include Bipole III, the new US Tie Line or Keeyask or Conawapa generation.

Table 8: Incremental Transmission for US Export - Existing System (No Bipole III, No New US Tie Line)

Season	Summer Off-Peak		Summer On-Peak		Winter Peak	
US Exports to MISO	0	2175	0	2175	0	878
Incremental Export Losses, MW	0	242	0	204	0	70
Incremental Bipole Losses, MW	0	155	0	155	0	50.6
Total System Load + Exports, MW	2435	4610	3577	5752	4910	5788

The incremental losses in the Bipoles and AC transmission to the US for Manitoba Hydro's Preferred Option 2A are tabulated in Table 9. The Preferred Option 2A includes Bipole III, the US Tie Line, Keeyask and Conawapa generation, and splits the NCS bus.

Table 9: Incremental Transmission for US Export - Preferred Option 2A (Added Bipole III, New US Tie Line)

Season	Summer Off-Peak		Summer On-Peak			Winter Peak		
US Exports to MISO	0	2175	0	2175	2975	0	2175	2784
Incremental Export Losses, MW	0	127	0	152	246	0	262	299
Incremental Bipole Losses, MW	0	54	0	94	167	0	207	235
Total System Load + Exports, MW	2425	4610	3577	5752	6502	4910	7085	7694

Comparing Tables 8 & 9 shows that incremental export losses are reduced in the Preferred Option 2A, when making comparisons between the seasonal loading period and export levels for these two tables. POWER believes the reduction in export losses is due to the addition of the new 500 kV tie line. Incremental Bipole losses are also reduced and are attributed to the addition of Bipole III. These results are subject to change and can be higher or lower, depending on operation of the AC and HVDC transmission systems.

Average Energy

The companion table for [4] System Firm Energy Demand and Dependable Resources (GWh)@generation reference in Scope Item 8 also applies for this section. The Manitoba Net Energy to Load over the calendar year is 27,762 GWh for 2020/21, which is equivalent to an hourly average load of 3,163 MW.

Expected exports for this same year are estimated at 2012 GWh or 230 average MW. Manitoba Hydro has also published monthly gross firm energy expressed in GWh in [38], and data from that reference for 2020/21 is presented in Table 10.

Table 10: Monthly Gross Firm Energy Demand (GWh) [3]

2020/21	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Energy, GWh	2126	2043	1966	2048	2003	1940	2276	2594	2953	3028	2672	2751
Ave MW	243	233	224	234	229	222	260	296	337	346	305	314

MANITOBA HYDRO TRANSMISSION PLANS – MANITOBA – US

Scope Item 10

Provide an assessment of MISO transmission constraints that require new interconnections and/or require Manitoba Hydro's financial participation in US transmission project(s).

MISO Transmission Constraints that contribute to the need for new interconnections

POWER reviewed the following documents in order to determine which MISO transmission constraints are driving the need for new interconnections to increase existing transfer capability:

- NFAT Business Case [1]
- Manitoba Hydro responses to Power Engineers Oct 24 2013 [5]
- NFAT Confidential - Group Facility Study MHEM 1100/750/250 MW Export/Import Firm Point to Point Transmission Service Requests, dated October 2, 2013 [6]
- Minnesota Power filings MPUC Docket No. E-015/CN-12-1163, application for Certificate of Need for the Great Northern Transmission Line [7]
- MP Dorsey - Iron Range 500 kV Report.pdf from MAPCON docket 12-1133, Appendix N [8]

The existing Manitoba – United States (MH-US) Interconnection consists of three 230 kV transmission lines and one 500 kV transmission line. The current maximum power transfer capability from Manitoba to the US is 2175 MW. This limit depends on the successful operation of the Dorsey – Forbes 500 kV line SPS (Special Protection Scheme) that rapidly reduces the MH-US HVDC power level following loss of any portion of the interconnection. The existing import total transfer capability into Manitoba from the US is 700 MW.

The NFAT Business Case, Chapter 5, Table 5.7 identifies the firm export schedule limit of 1950 MW. There is also a 75 MW TRM and a 150 MW MISO Contingency Reserve obligation, bringing the total transfer capability of the interconnection to 2175 MW. The existing MH–US interconnection consists of the following lines showing their individual facility ratings.

Letellier to Drayton 230 kV (L20D)	467.7 MVA
Glenboro to Rugby 230 kV (G82R)	335.0 MVA
Richer to Moranville 230 kV (R50M)	229.9 MVA
Dorsey to Forbes 500 kV (D602F)	1732.0 MVA

The existing Riel-Forbes 500 kV line rating of 1732 MW is based on the Roseau series capacitor current rating of 2000 A. This limit can be reached during steady state (pre-contingency) loading caused by loop flow during heavy North Dakota exports into MISO. Loss of the Dorsey to Forbes 500 kV line triggers the HVDC reduction Special Protection Scheme (SPS) and represents the largest single contingency for MISO.

Manitoba Hydro provided the following response to Power Engineers, dated October 24 2013 [5]:

[redacted]

[redacted]

[redacted]

[redacted]

In [6], Manitoba Hydro studied transmission options and upgrades that were necessary to allow increasing the total transfer capability in order to meet new TSRs (Transmission Service Requests). [redacted]

The preferred plan is to execute a 750 MW upgrade to the existing MH – US tie line, with the capability to expand to 1100 MW. The additional 350 MW capability is achieved by expanding the 345 kV transmission systems in Minnesota.

In [6], MH also describes the impact on existing facilities and required system upgrades. [redacted]

[redacted]

[redacted]

[redacted]

The Minnesota CON filing [7, pg 74] for the Great Northern Transmission Line[10] describes the impact of possibly upgrading the existing Dorsey to Forbes[11] 500 kV line facility rating in lieu of developing a new 500 kV line.

'When any of the four Manitoba – United States tie lines trips, the existing Manitoba Hydro HVDC Reduction Scheme Special Protection System (SPS) initiates a power order reduction on the high voltage direct current (HVDC) lines connecting Winnipeg to hydroelectric generation in Northern Manitoba. This HVDC power order reduction is equal to 100 percent of the flow on the line or lines that are being tripped. If a 100 percent HVDC reduction level is maintained in the SPS, the flow limit on D602F could not be increased beyond 1732 MW, even if all the limiting equipment was upgraded. This is because MISO will not allow an increase in the amount of HVDC or generation runback on an existing SPS beyond its current maximum level. Simply put, for an existing SPS, transmission or generation additions cannot make the worst runback scenario (in terms of generation loss) worse. This requirement would limit the maximum HVDC reduction and potentially the rating of D602F to 1732 MW. It would be possible to modify the SPS to limit HVDC reduction to 1732 MW, allowing flow on D602F to be increased to 2165 MW. However, the impact of this SPS modification on system transient stability, dynamic reactive power requirements, and the underlying transmission system would almost certainly increase the cost and complexity of the Project as well as the overall risk to the reliability of the system'.

'Finally, loss of D602F and the associated HVDC reduction is currently the largest single contingency in MISO. In the current system, the maximum reduction in Manitoba – United States transfers is 1500 MW. This is calculated as the difference between the system intact transfer limit of the interface (2175 MW) and steady-state transfer limit of the interface after loss of D602F (675 MW), which is often referred to as the prior outage limit. Increasing the rating of D602F in order to increase the total system intact transfer limit on the Manitoba – United States interface would therefore require a corresponding increase in the prior outage transfer limit of the interface for loss of D602F in order to avoid increasing the size of the largest single contingency in the MISO

[10] This project consists of adding a Dorsey to Blackberry 500 kV line and associated facilities.
[11] Note: The Riel Station Reliability Project (ISD late 2014) will sectionalize the Dorsey to Forbes line into the Dorsey to Riel and the Riel to Forbes 500 kV lines. Riel is also the termination point for the new Bipole III HVDC line.

footprint. Depending on the level of increased firm capability required, it may not be possible to increase the prior outage transfer limit without building a new Manitoba – United States tie line.'

'Aside from the reasons given above, Minnesota Power believes that upgrading existing facilities is not a feasible long-term solution given the likelihood of significant increases in hydroelectric power imports from Manitoba including and exceeding Minnesota Power's power purchase and Renewable Optimization Agreements representing 383 MW. Appropriate long-term capacity for the interface between Manitoba and the United States can be achieved more efficiently, economically, and reliably with a single new transmission line build large enough to facilitate Minnesota Power's 383 MW and additional transfer capability up to 750 MW to meet future needs in the region.'

POWER agrees that new facilities will be needed to increase the MH – US transfer capability by 750 MW, and to mitigate constraints on the MISO system. The following table shows required network upgrades under increased Export and Import conditions [redacted]

[redacted]

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

MISO Transmission Constraints that require Manitoba Hydro's financial participation in US transmission projects

POWER reviewed the NFAT Executive Summary and Chapter 6, and also discussed financial participation in US transmission with MH. Cost sharing for required transmission in the US to mitigate MISO transmission constraints is being spread among committed participants. MH has indicated that several agreements are underway. To date, only Minnesota Power has committed to a 250 MW participation level, based on a commission approved contract. A pending 300 MW WPS sales agreement is being developed, but WPS has indicated that they will not invest in the line at this time. POWER also reviewed the Minnesota Power filing for the Great Northern Transmission Line[12], which references two agreements with MH. One is the approved 250 MW power sales agreement and the other is a pending 133 MW Renewable Optimization Agreement, bringing the transmission contract total to 388 MW. This amounts to 51% of the proposed 750 MW transmission capacity and would limit MH ownership to 49%. MH indicated in our discussions that it is actively marketing surplus capacity and energy to the US, and that the likelihood of establishing those sales contracts is very high because price for energy delivered from Manitoba to US delivery points is substantially

[12] MPUC Docket No. E-015/CN-12-1163

lower than US prices. Any new participation in the line would reduce MH ownership by requiring participant funding on a pro-rata basis. The following excerpt from the NFAT Executive Summary, page 7/42, provides explanation as to why MH has agreed to fund any of the US transmission.

This proposed project consists of a 750 MW, 500 kV AC transmission line in southeastern Manitoba, connecting at the border with MP's proposed Great Northern Transmission Line[13] with an ISD of 2020. The project would enable power to be exported to the U.S. based on current sales agreements, improve reliability and import capacity in emergency and drought situations, and increase access to markets in the U.S.

This project is still in the study and negotiation phase. Manitoba Hydro will be responsible for the Manitoba portion of the interconnection, which is estimated to cost $350 million. Manitoba Hydro will also be responsible for some portion of the capital and ongoing operating costs associated with the U.S. portion of the facilities. For the Preferred Development Plan, it is assumed that Manitoba Hydro will be responsible for 40% of the capital and ongoing operating costs associated with the U.S. portion of the 750 MW interconnection facilities, with the remainder of the transmission costs to be borne by MP and WPS. The total cost of the U.S. portion of the 750 MW interconnection is in the order of $700 M (2020 base dollars, not including interest).

However, WPS recently advised that an investment in the 750 MW Interconnection Transmission does not match their current business objectives and that they will not invest in the line. They also advised that they will continue to negotiate the 300 MW Power Purchase Agreement; as of this writing that negotiation is proceeding under the auspices of the term sheet agreed to previously. In order to avoid becoming a majority owner in a U.S. transmission line, Manitoba Hydro will only enter into an arrangement where it will not own more than 49% of the interconnection facilities in the U.S. In return for investing in the U.S. portion of the transmission interconnection, Manitoba Hydro will benefit by having the right to use and/or sell its proportionate share of the U.S. transmission service associated with the new interconnection. Manitoba Hydro will also have the right to sell its share in the future. In the development plans without the WPS sale but with a 750 MW interconnection, a conservative assumption has been used whereby Manitoba Hydro will be responsible for approximately two-thirds of the capital.

MANITOBA HYDRO TRANSMISSION PLANS – WITHIN MANITOBA

Scope Item 11

<u>Provide an analysis and justification of Manitoba Hydro's need for additional North-South AC transmission when Conawapa comes on-line.</u>

The additional N-S AC transmission referred to here is within Manitoba. This additional N-S AC transmission is needed after Conawapa to accomplish three goals:

1. Provide the required level of firm transmission for Conawapa
2. Provide the required level of HVDC on-line sparing capability, and
3. Limit the combined three-Bipole HVDC loading within the reliability operating limit for Southern System faults.

[13] The US portion of the new 750 MW line is referred to as the Great Northern Transmission Line

These issues are also discussed in Scope Item 7. The following is POWER’s assessment of the need for additional AC transmission.

MH indicated in discussions with POWER that the required level of firm transmission for Conawapa is still under consideration. The NFAT Preferred Plan, Option 2A adds 100 MW of new AC Transmission, permanently connects one Kettle generation unit to the AC system, and provides the capability to switch up to three Kettle generation units between Northern Collector Systems (NCS), NCS1 and NCS2, to minimize the overall use of non-firm transmission to deliver northern system generation.

POWER reviewed several characteristics of the existing and proposed system including valve group on-line sparing, firm and non-firm transmission capability, and reliability. Reliability was more specifically addressed in our discussion of Scope Item 7. POWER developed several tables to illustrate these characteristics. POWER’s assessment is based on information contained in the Integrated Transmission Plan for Keeyask and Conawapa Generation”, SPD2011/11, July 17, 2012. In the Executive Summary of the report, where MH explains that

> ‘In order to qualify as a Designated Network Resource, firm transmission is required. In the context of HVdc transmission, the capacity is considered firm when a spare valve group over generation is provided to cover for the most frequent outages. The non-firm transmission will result in portions of the proposed Keeyask and Conawapa generation being treated as Energy Resource (i.e. potential bottled generation). This section of the report identifies the firm and non-firm transmission plans for Keeyask and Conawapa generation’.

POWER conducted a high level review of the MH Transmission Tariff available on the MH webpage to determine the significance of including Conawapa as a Designated Network Resource. The term ‘Energy Resource’ was not found in the MH tariff. However, the term Designated Network Resource is found in Section 28.3 of the MH transmission tariff which provides guidance on requiring firm transmission service from designated Network Resources to serve Network Loads. Section 28.4 suggests that energy from non-designated Network Resources can be delivered on an as available basis. Those definitions are included here:

> *28.3 Network Integration Transmission Service: The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider’s use of the Transmission System to reliably serve its Native Load Customers.*

> *28.4 Secondary Service: The Network Customer may use the Transmission Provider’s Transmission System to deliver energy to its Network Loads from Generation resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff but instead shall be requested in accordance with the procedures set forth in Section 18 of the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other*

than Network Resources will have a higher priority than any Non-Firm Point-to-Point Transmission Service under Part II of the Tariff.

The MH tariff provides the basis for providing firm transmission for a Designated Network Resource. MH provides a definition for firm transmission in the context of HVDC transmission as providing a spare valve group over generation to cover for the most frequent outages, the most frequent outages being a valve group. MH provided information regarding the frequency of planned valve group outages compared to pole outages. For Bipole I, planned outages average 10.5 days per year for all valve groups and 1 day per year for a pole outage. For Bipole II, planned outages average 7 days per year average for all valve group outages and 1 day per year for a pole outage. Forced pole outages tend to average about 9 hours per year. The outage data, supplied by MH, confirms that valve group outages are by far the most frequent outage experienced on the HVDC transmission system.

An excerpt from the NFAT Overview pg. 9 states that Pathway 5 *'Keeyask 2019, 750 MW Interconnection, Large Export Pathway 'This is a choice to rely on Keeyask to meet domestic load requirements and to proceed with a new 750 MW interconnection, along with the 250 MW MP sale, the 300 MW WPS sale and the 125 MW NSP expansion. The choice for next generation after Keeyask most likely would be Conawapa for an ISD in or around 2026, in which case this pathway results in the Preferred Development Plan. During the capital intensive period involving both Keeyask and Conawapa, projected net debt and cumulative rate increases are generally higher than other alternatives, but are lower in the long-term. Development plans that include Keeyask and Conawapa have the strongest projected balance sheets, with high levels of fixed assets and retained earnings, and provide the most robust ability to absorb adverse financial impacts over the entire study period. The choice of next plant after Keeyask would depend on the situation at that time and, as previously noted, could include deferral of Conawapa (if load growth were slower than expected or a much higher DSM level were achieved) or could instead involve cancellation of Conawapa and the development of gas generation. Commitment to construct Conawapa for a 2026 ISD is not required until 2018, which is after the 2017 scheduled approvals and construction start of the 750 MW interconnection'*

The Preferred Development Plan confirms that the order of development is as shown in Table 1 from Scope Item 7. It is repeated here:

Table 12: Before Splitting the Northern Collector System

Facility/ Rating	Timeline	Combined HVDC Capacity MW	Largest VG MW	Total HVDC Firm MW	Generation @ NCS	Non-Firm Transmission
BP I/1854	Existing	1854	309		3554 MW	N/A
BP II/2000	Existing	3854	500	3354	3554 MW	200 MW
Bipole III/2000	2017	5854/4750	500	[redacted]	3554 MW	Zero
Keeyask/630	2019/2020	5854/4750	500	[redacted]	4184 MW	Zero
Conawapa/1395	2026	5854/4750	500	[redacted]	[redacted] MW	[redacted] MW

Non-firm transmission totaling 200 MW exists today with Bipole I and Bipole II able to carry only 3354 MW of firm. This is a direct result of Bipole II having a deficit of 200 MW of spare valve group capacity over generation. An additional 200 MW of transmission would be required to meet the MH definition of firm transmission. POWER has not been able to find documentation that attributes this amount of non-firm transmission to a specific generation resource. However, by definition, some of the generation connected to the NCS would not be a Designated Network Resource.

NFAT Chapter 2, section 2.3 discusses the North-South Transmission System Upgrade Project, indicating that the majority of Conawapa power can be transmitted over the HVDC transmission system after Bipole III with the remainder requiring an upgrade to the existing AC transmission system. Splitting the HVDC collector system in to two busses is essential when adding Conawapa to avoid loading the HVDC system above its stability limit.

After Bipole III, but prior to adding Conawapa and splitting the NCS, there is sufficient firm transmission to transmit all of the Northern Collector System generation, including Keeyask. If Conawapa is added without splitting the NCS, there is a shortage of [redacted] MW of firm transmission, in addition to the problem of loading above the safe operating limit of the combined three-Bipole HVDC limit. Splitting the collector system and reconnecting generation to each bus as specified in the Preferred Development Plan results in a reduced amount, 207 MW of non-firm transmission as shown in Table 12. From the perspective of Table 12, with most of Keeyask connected to NCS1, there is not enough firm transmission to transmit all of Keeyask on a firm basis. Conawapa generation can be transmitted over firm transmission because Bipole II and Bipole III will have enough on-line valve group sparing to cover the outage of the largest valve group.

Table 13: Option 2A: Splitting the Northern Collector System, BP III @ 2300 MW, 1 Kettle Unit on AC, No Kettle Unit Switching

Facility/ Rating Split NCS[14]	Timeline	Combined HVDC Capacity MW	Largest VG MW	Total HVDC Firm MW	Generation @ NCS	Non-firm Transmission @ NCS
BP I/NCS 1	2026	1854	309	[redacted]	[redacted]	207 MW
Bipole II & III(2300)/ NCS 2	2026	4300	575	[redacted]	[redacted]	Zero
Total		6154	575	[redacted]	[redacted]	207 MW

As discussed in Scope Item 7, the Preferred Development Plan proposes to permanently place one Keeyask unit on the new AC transmission and provide capability at Keeyask to switch up to three generating units from NCS 1 to NCS 2. Table 13 below is a simplified version of Table 11 in the Integrated Transmission Plan for Keeyask and Conawapa Generation report, section 2.3.1, Pg 29. It shows the impact of switching Kettle generation units on the effective total non-firm generation for the MH system. Note that even though the total effective non-firm for the MH system is minimized, the preferred operating plan never totally eliminates non-firm transmission for connected generation for both NCS 1 and NCS 2 simultaneously. On an individual basis, there is a 105 MW shortage for NCS1 and a 102 MW shortage for NCS2. POWER is not aware of any specific protocol for assigning non-firm transmission to specific generation, however, the last generator on NCS1 is Keeyask, and the last generator on NCS2 is Conawapa. Depending on the options selected for switching Kettle generation units, a portion of either Keeyask or Conawapa, or both could be delivered over firm non-firm transmission.

The Executive Summary page 3 of the Integrated Transmission Plan for Keeyask and Conawapa Generation report, states the following:

'The inadequate HVdc spare capacity (300MW spare vs. 500MW valve group size) of the existing HVdc system has resulted in frequent reliance on the reserve sharing pool, to make up the shortfall of capacity due to HVdc outages, particularly the numerous valve group outages. In view of minimizing such reliance a System Planning report, endorsed by the HVdc Task Force, recommended that a minimum spare capacity over generation equal to the nominal rating of the largest valve group be provided and maintained for future north-south transmission expansion for new generation assuming a single northern collector system. This report recommends a similar level of spare capacity for the split northern collector systems.'

POWER interprets the recommendation by the HVdc Task Force to mean that maintaining valve group sparing over generation on an individual collector system basis could provide an increased economic benefit over the preferred plan by reducing reliance on the reserve sharing pool for individual valve group outages. Additional benefits might also accrue from the ability to operate all collector system generation as a Designated Network Resource. If adequate spare capacity over generation is to be maintained on each collector system, it does not appear necessary to switch Kettle units to NCS2. However, there may be other benefits for switching Kettle generation during generator outages or reduced capacity at Limestone, Long Spruce, or Conawapa, or during times of reduced capacity on Bipole I. However, the most straight forward means of maintaining adequate sparing on the HVDC systems is to increase the new AC Transmission capacity by approximately 300 MW and permanently switch three Kettle units to the new AC transmission. This is Option 2 in the Preferred Development Plan.

Table 14: Non-Firm Transmission with Kettle Generation Switching

	Required Spare	Option 1 Shortage without Kettle Switching	Option 2 Shortage with 2 Kettle unit on NCS2	Option 3 Preferred Shortage with 2 units on NCS1 and 1 on NCS2
NCS 1	[redacted]	[redacted]	[redacted]	[redacted]
NCS 2	[redacted]	[redacted]	[redacted]	[redacted]
85 MW additional firm[15]		[redacted]	[redacted]	[redacted]

In Scope Item 7, POWER discusses the reliability aspects of the proposed plan and the need to validate the HVDC limit on the three-Bipole HVDC system for close in Southern AC System faults. While splitting the NCS bus reduces HVDC loading below the limit imposed by NCS faults ([redacted] MW), it does nothing to eliminate the problem for Southern System AC faults. With the split NCS bus configuration, the maximum loading limit studied for the combined three-Bipole HVDC system is [redacted] MW. This loading produced stable results. However, as explained in Scope Item 7, the safe HVDC loading limit needs further review. The Preferred Development Plan, Option 2A produces a maximum HVDC loading of [redacted] MW. Option 2 will provide a wider reliability margin for close in Southern System AC faults by limiting the maximum HVDC loading to [redacted] MW. Option 2A only works if the safe operating limit is determined to have sufficient margin at [redacted] MW. Additional studies may be needed to determine the economic value of providing complete on-line sparing capability and the maximum safe operating limit for the combined three-Bipole HVDC system.

[15] New AC Transmission firms up an additional 85 MW for Kelsey and Wuskwatim generation

MANITOBA HYDRO TRANSMISSION PLANS TO FACILITATE EXPORTS

Scope Item 12

<u>Review and assess Manitoba Hydro's technical need for the cost of construction of U.S. transmission infrastructure to facilitate sales into MISO.</u>

POWER's assessment in Scope Item10 confirms the technical need for US transmission infrastructure to support the planned 750 MW increase in the MH - US interconnection. In our view, it is not feasible to increase the rating of the existing interconnection by 750 MW without the new proposed Dorsey-Blackberry 500 kV line and associated facilities. The primary reason is that the existing 500 kV transmission line would need to be upgraded, i.e., an increase to the Roseau series capacitor ratings from 2000A to 2500 A. This approach would increase the largest single contingency to MISO. As noted in its MCON Filing[16], Minnesota Power (MP) claims that there would be complications resulting from upgrading existing facilities. The most persuasive argument is that an increase in the amount of power reduction needed by the HVDC reduction scheme (a Special Protection Scheme) for loss of the upgraded 500 kV line would need to be increased beyond the current 1500 MW level. This SPS is initiated for loss of the existing 500 kV tie line, which is currently the largest single contingency in the MISO area.

POWER also provided an assessment in workscope item 10 of US transmission infrastructure required to facilitate all existing Transmission Service Requests. Technical details are discussed in the NFAT Confidential Preliminary Report in GROUP FACILITY STUDY (MHEM 1100/750/250 MW Export/Import Firm Point to Point Group Transmission Service Requests) SPD 2013/05[17]. In this report, Option Y500 from Pg 7, MH states:

> '*The following Network Upgrades in addition to the proposed facilities are needed for <u>granting the group import/export Transmission Service Requests of 750 MW:</u>* [redacted]

A diagram of the proposed 750 MW project without the additional network upgrades is shown below. This is taken from Figure A4, Appendix A of the MH report. Proposed 750 MW project facilities include:

- Winnipeg (Dorsey) to Iron Range (Blackberry) 500 kV line with 60% series compensation,
- second Riel 500/230 kV 1200 MVA transformer, and
- one 500/230 kV 900 MVA transformer at Blackberry.

The targeted import/export transfer increase for this option is 750 MW.

[16] MPUC Docket No. E-015/CN-12-1163 Application For A Certificate Of Need--October 21, 2013, pgs 73-74

[17] Table ES 1 Upgrade Summary on pg 5 of the report shows network upgrades needed for each transmission studied for both import and export conditions. MH indicated that an update to this report is due in January 2014.

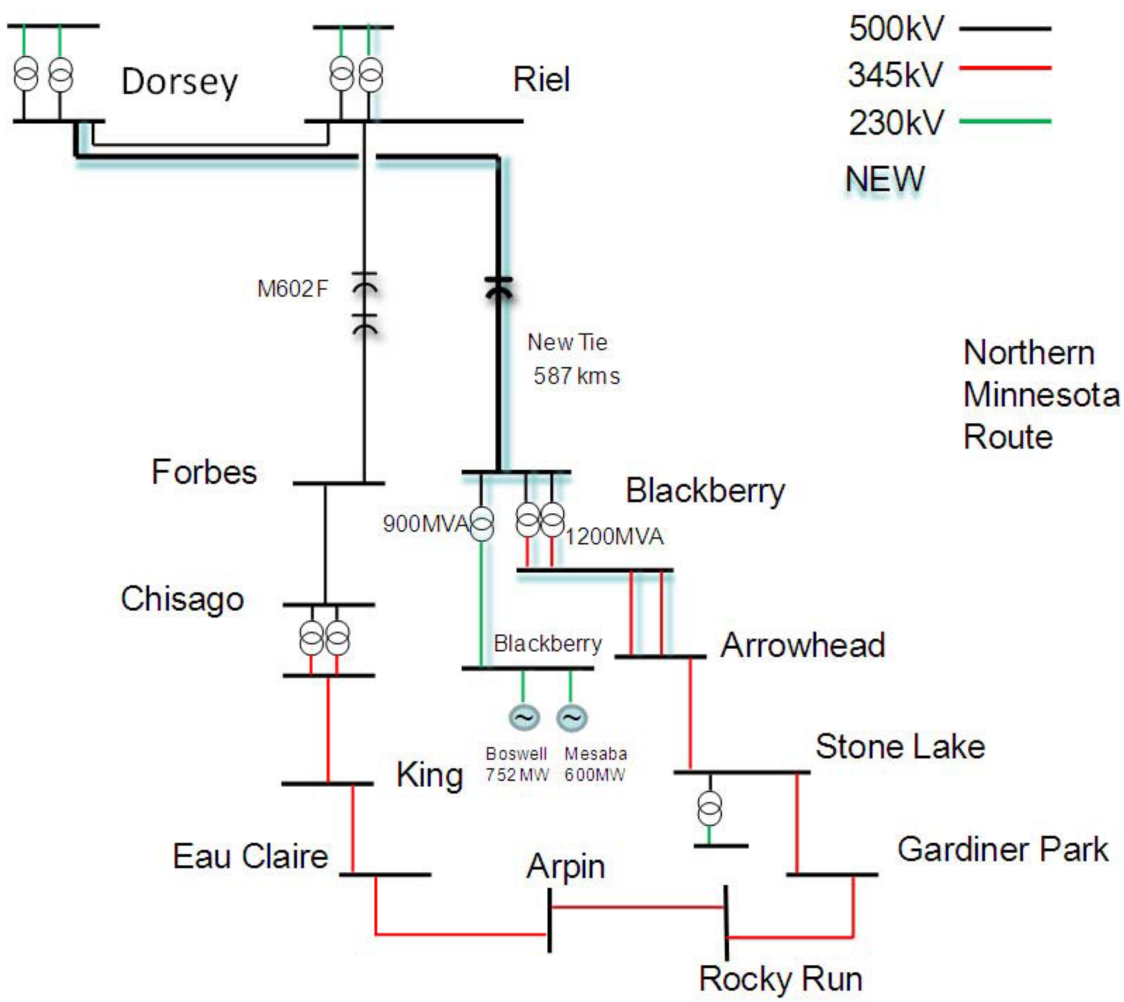

Figure 3: Diagram of the 750 MW System Without Network Upgrades

The need for MH financial participation in US transmission is based not only on technical reasons, but on approved contracts and pending contract negotiations. The only approved contract in place today is the MP 250 MW power sales agreement. As pending agreements come to fruition, MH ownership and costs can be transferred to new project participants.

The MCON filing Section 3[18], further elaborates on project ownership and contractual arrangements between MH and MP. Information from the filing is included below to highlight the contractual sharing arrangements, as interpreted by POWER, for the project:

- Minnesota Power will have majority ownership (51%) of the Project.
- The balance of the Project (49%) will be owned by a subsidiary of Manitoba Hydro.

[18] MPUC Docket No. E-015/CN-12-1163 Application For A Certificate Of Need--October 21, 2013, pg 16

- While Minnesota Power will own 51% of the Project, Minnesota Power's customers will be financially responsible for only 33.3% of the Project's revenue requirements.
- Minnesota Power will receive an amount equal to the balance of the revenue requirements associated with its ownership percentage (17.7%) from Manitoba Hydro by way of a scheduling fee arrangement included in the proposed 133 MW Renewable Optimization Agreements.
- While the Project will have a transfer capability of approximately 750 MW, Minnesota Power and its customers will be responsible for the revenue requirements associated with 250 MW of that total capability.
- An Operation and Maintenance agreement will invoice MH monthly for its 49% pro rata share of Operation and Maintenance expenses associated with the Project.
- Facilities on the Canadian side of the border will be owned and operated by Manitoba Hydro
- Minnesota Power has signed the Commission-approved 250 MW Agreements and the 133 MW Renewable Optimization Agreements.

POWER's analysis associated with this scope item focused on technical aspects of proposed facilities, and did not include assessment of project economics. However, it should be clear that there will be an economic benefit to Manitoba resulting from marketing portions of the proposed Keeyask and Conawapa generation. Sales revenue will offset a portion of the financing and operating costs associated with planned hydro facilities and MH-US transmission. MH appears to be uniquely positioned at this time to develop generating capacity beyond that required for Manitoba power supply at the scheduled energization dates for the proposed facilities. Additional economic assessment can identify benefits of MH transactions.

The additional MH-US transmission facilities will increase reliability of that interconnection, can facilitate reserve sharing, and will allow additional capacity for additional transactions in both directions.

In conclusion, POWER believes that MH has demonstrated a technical need for US transmission, namely the new 500 kV line and network upgrades in support of incrementing the existing 2175MW interconnection to 2925MW. Pending contract negotiations and the ongoing activity to finalize transmission studies to determine final network upgrades will ultimately determine project financing and cost sharing. In the interim, capital and O&M cost sharing is based primarily on terms of the latest Power Purchase Agreement between Minnesota Power and Manitoba Hydro.

REFERENCES

1. Manitoba Hydro, "Need For and Alternatives To," August 2013.

2. Manitoba Hydro, Transmission Planning and Design Division, System Planning Department Report on "Integrated Transmission Plan for Keeyask and Conawapa Generation," SPD 2011/11.

3. Manitoba Hydro 2012 Electric Load Forecast (For External Use, Market Forecast May 2012, Approved July 2012.

4. Manitoba Hydro, "Need For and Alternatives To," August 2013, Manitoba Hydro Supply and Demand Tables – NFAT 2012 Reference, Pg 1668 of 6543, System Firm Energy Demand and Dependable Resources (GWh)@generation, K19/C25/250MW, August 16, 2013.

5. Manitoba Hydro responses to Power Engineers Oct 24 2013.

6. NFAT Confidential - Group Facility Study MHEM 1100/750/250 MW Export/Import Firm Point to Point Transmission Service Requests, dated October 2, 2013.

7. Minnesota Power filings MPUC Docket No. E-015/CN-12-1163, application for Certificate of Need for the Great Northern Transmission Line.

8. MP Dorsey - Iron Range 500 kV Report.pdf from MAPCON docket 12-1133, Appendix N.

APPENDIX A

Glenn Davidson 8969

From:	Mazur, Ron [rwmazur@hydro.mb.ca]
Sent:	Wednesday, December 11, 2013 6:20 AM
To:	Mark Graham 1-303-915-4906; Glenn Davidson 8969
Cc:	Wortley, Joel; Wang, Pei; Jacobson, David
Subject:	FW: Revised Questions
Attachments:	Tower Drawings - Type F Angle.pdf; Tower Drawings - Type A-211-0 Suspension.pdf; Keeyask Transmission and MMTP Scope and Cost Summaries.pdf; Past project cost summary.pdf

Joel Wortley has prepared material related to your line design questions PE-015 and PE-016 a –j. If you have specific questions on the material, please contact Joel. Joel's contact info is:
Joel Wortley
TRANSMISSION & CIVIL DESIGN DEPT MGR
Phone: 204-360-4570
jwortley@hydro.mb.ca
Sincerely,

Ron W. Mazur

Ronald W. Mazur, P.Eng., M.Sc.E.E.
Manager
System Planning Department,Transmission Planning & Design Division;,Transmission BU
Manitoba Hydro, P.O. Box 7950, 820 Taylor Avenue, Winnipeg, Manitoba, R3C 0J1
Email: rwmazur@hydro.mb.ca
Work Telephone: 1-204-360-3113, Cell Phone: 1-204-781-4433, FAX:1-204-360-6177

From: Wortley, Joel
Sent: Tuesday, December 10, 2013 3:23 PM
To: Mazur, Ron
Subject: RE: Revised Questions

Ron,

Further to our conference call with POWER Engineers I am providing:

1) Updated scope and cost estimate documents for the Keeyask Transmission and Manitoba-Minnesota Transmission Projects (Keeyask Transmission and MMTP Scope and Cost Summaries.pdf).
   Please disregard the original scope and cost documents provided (dated 2013 10 17) as:
   i. The scope of Keeyask Transmission incorrectly included the construction power line (KN36 tap);
   ii. Unit lines were incorrectly excluded; and
   iii. The cost estimates provided were not consistent with costing provided elsewhere in the NFAT submission.

   These issues have now been resolved.
   Route maps for both projects have also been provided in the documents.
   It should be noted that the Construction Power Line (KN36 Tap) is <u>not included in Keeyask Transmission</u>, however is included here for completeness.

2) Typical tower and foundation drawings for 230 and 138 kV projects in the north, as requested in the conference call (Tower Drawings – Type A-211-0 Suspension.pdf) and (Tower Drawings – Type F Angle.pdf).

3) A summary of recent transmission project costs, as requested in the conference call (Past project cost summary.pdf).

Regards,
Joel

Joel Wortley, P. Eng.
Manager - Transmission & Civil Design Department

Manitoba Hydro
Transmission & Civil Design Department
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P.O. Box 7950
Winnipeg, Manitoba R3C 0J1

ph: 204-360-4570
jwortley@hydro.mb.ca

From: Mazur, Ron
Sent: Friday, December 06, 2013 9:37 AM
To: 'Glenn Davidson'
Cc: Wang, Pei; Jacobson, David; Wortley, Joel
Subject: RE: Revised Questions

Glenn

See below.

Ron W. Mazur

Ronald W. Mazur, P.Eng., M.Sc.E.E.
Manager
System Planning Department,Transmission Planning & Design Division;,Transmission BU
Manitoba Hydro, P.O. Box 7950, 820 Taylor Avenue, Winnipeg, Manitoba, R3C 0J1
Email: rwmazur@hydro.mb.ca
Work Telephone: 1-204-360-3113, Cell Phone: 1-204-781-4433, FAX:1-204-360-6177

From: Glenn Davidson [mailto:gdavidson@powereng.com]
Sent: Thursday, December 05, 2013 2:12 PM
To: Mazur, Ron
Subject: Revised Questions

2

Ron,

I got two projects mixed together in my previous email. Here is a corrected request. I apologize for any confusion. I resolved my question about Conawapa.

Can you clear up a couple of questions:

1. North-South Transmission

NFAT Filing article 2.3.5 gives an estimate of $498 million for the North South Transmission System Upgrade, which includes both AC and HVDC upgrades.
I could not find any net capital cost table for it in Appendix 11.1. Is it included within the budget of Keeyask or Conawapa?
I believe that the 230 kV lines were estimated on the basis of $300,000/km based on your experience with recent similar projects, and that this is an all-inclusive cost. 462 km of 230 kV lines at $300,000/km gives $139 million. That leaves $359 million for the other project components. Can you provide cost breakdowns and brief descriptions of the various components of the project?

A detailed summary of the North-South Upgrade Project cost is included in the following table.

Item	Cost ($2012)
HVdc system upgrades (including splitting northern HVDC collector systems, addition of a new 300 MVar filter at the Radisson Converter Station, addition of a new synchronous condenser, circuit breaker replacements and a 230 kV line Sectionalization, Kettle ring bus connection)	$143M
Four 230kV new transmission lines with a total length of 462km (include license and communications	**$139M**
Equipment Upgrades at various stations (riser, CTs and SVC) and line retentions	$58M
Total	$340M (in 2012 dollars)

This breakdown has been posted on the website under a LaCapra question LCA-0154.
The $340 M 2012 dollars translates to $498M in-service dollars.
Joel Wortley will be providing design details next Tuesday for the line design, as discussed at last week's conference call.

MMTU Project
NFAT filing article 2.4.1 describes the components of the project. I cannot find any net capital cost table for it in Appendix 11.1. Is it included within the budget of Keeyask or Conawapa?

3

NFAT filing article 2.4.5 gives an estimate of $350 million. You provided us with a detailed estimate for the MMTU 500 kV line in Manitoba that totals $134 million. I assume the remaining $216 million is for the substation modifications/additions in Manitoba.
Can you provide cost breakdowns and brief descriptions for the other components of the project?

A detailed summary of the 750 MW Manitoba-Minnesota Transmission Project (**MMTP**) costs in Canada is included in the following table.

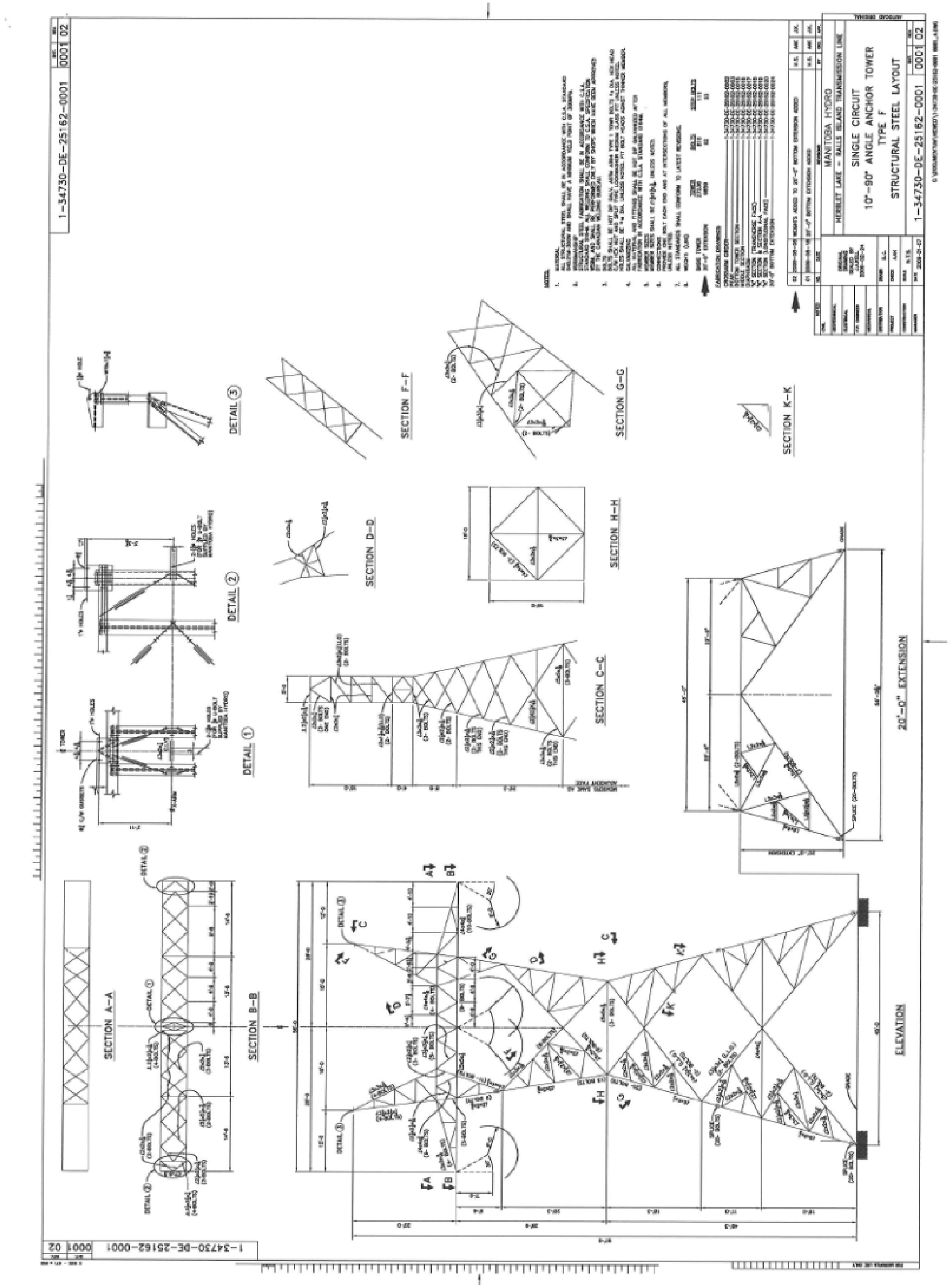
Item	Cost ($2012)
235-km 500-kV line (includes communication and licensing)	$173.6 million
Dorsey station upgrades (includes circuit breakers, current transformers, 300 MVAr shunt reactor, 74 MVAr shunt capacitor)	$23.2 million
Riel Station upgrades (includes circuit breakers, current transformers, 1200 MVA 230/500 kV transformer, 2-74 MVAr shunt capacitors)	$54.3 million
Glenboro Station (1-300 MVA phase shifting transformers, circuit breakers)	$16.5 million
Total	$267.6 million ($2012)

This breakdown has been posted on the website under a LaCapra question LCA-0155
The $268M 2012 dollars translates to $350M in-service dollars.
Joel Wortley will be providing design details next Tuesday for the line design, as discussed at last week's conference call.

I am unable to find a reference for the $134M.

Glenn

4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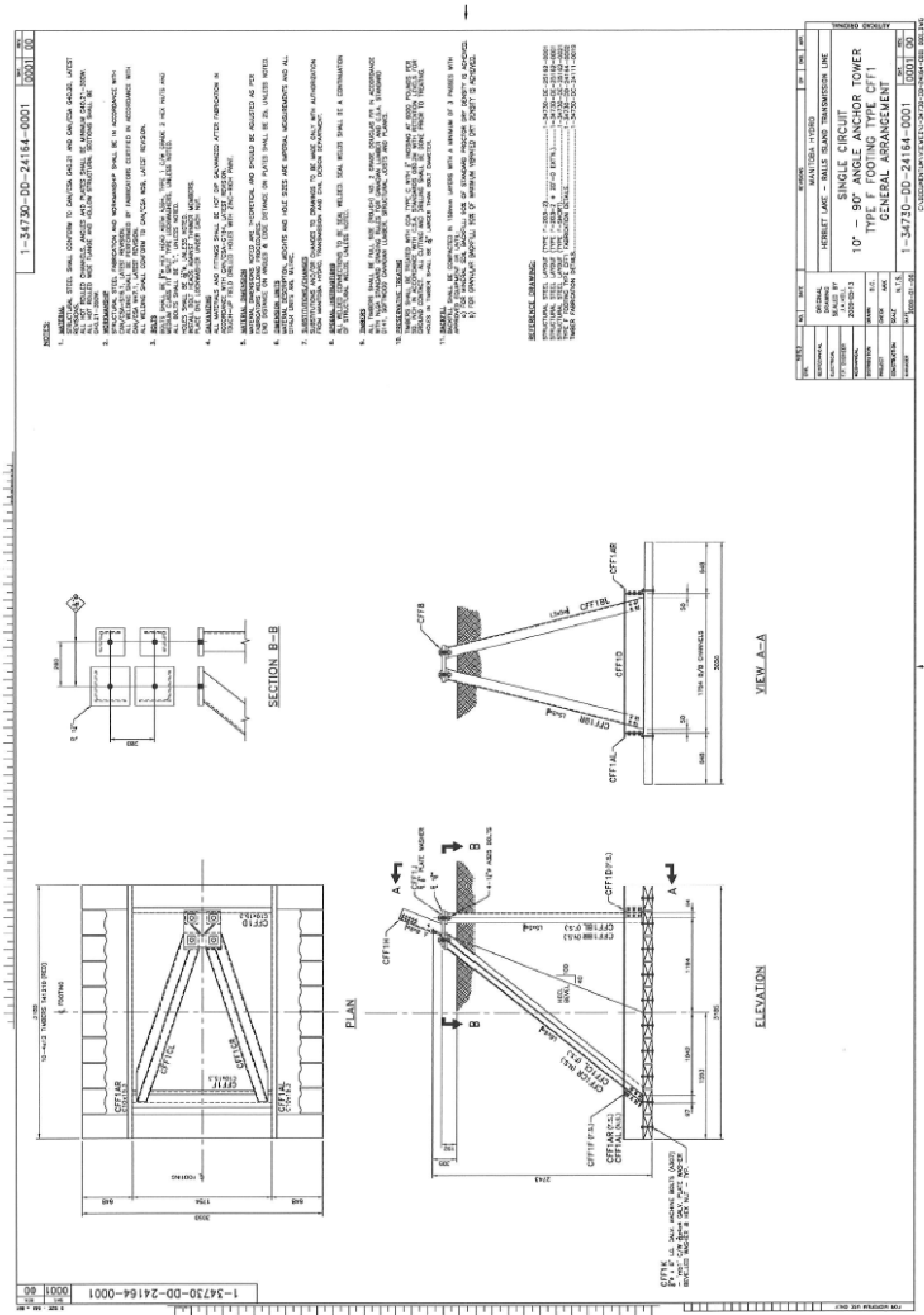
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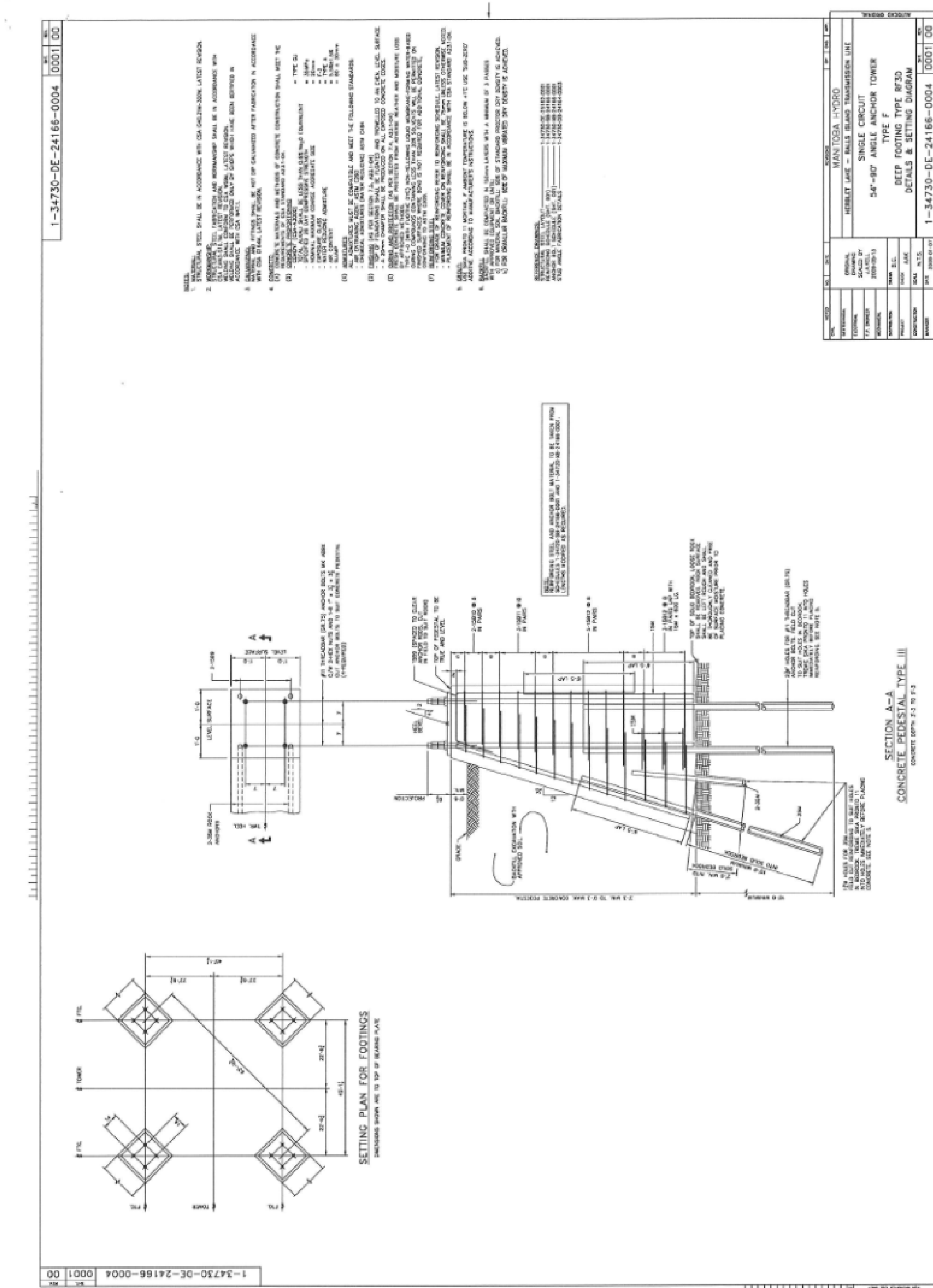
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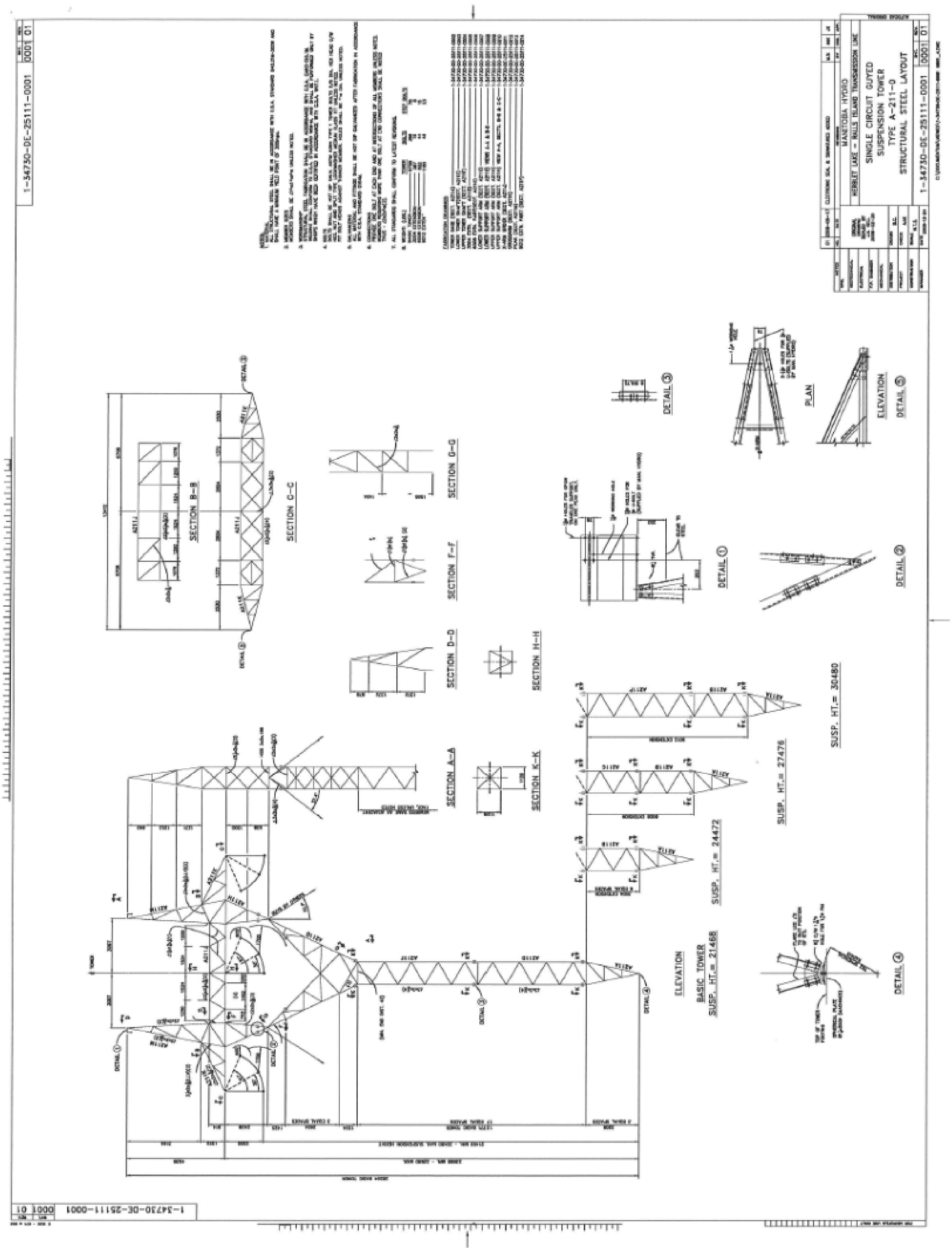
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SECTION H-H
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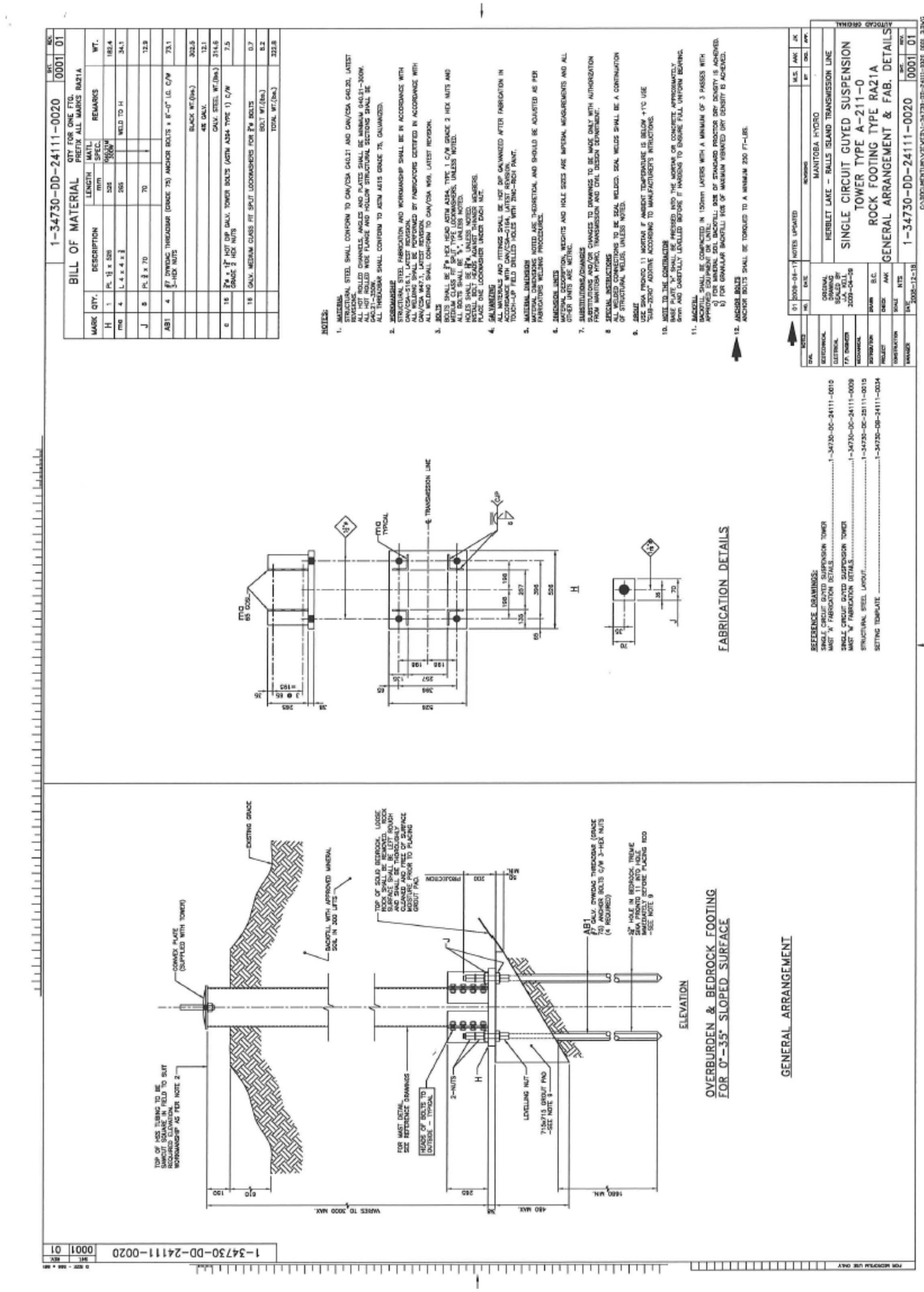
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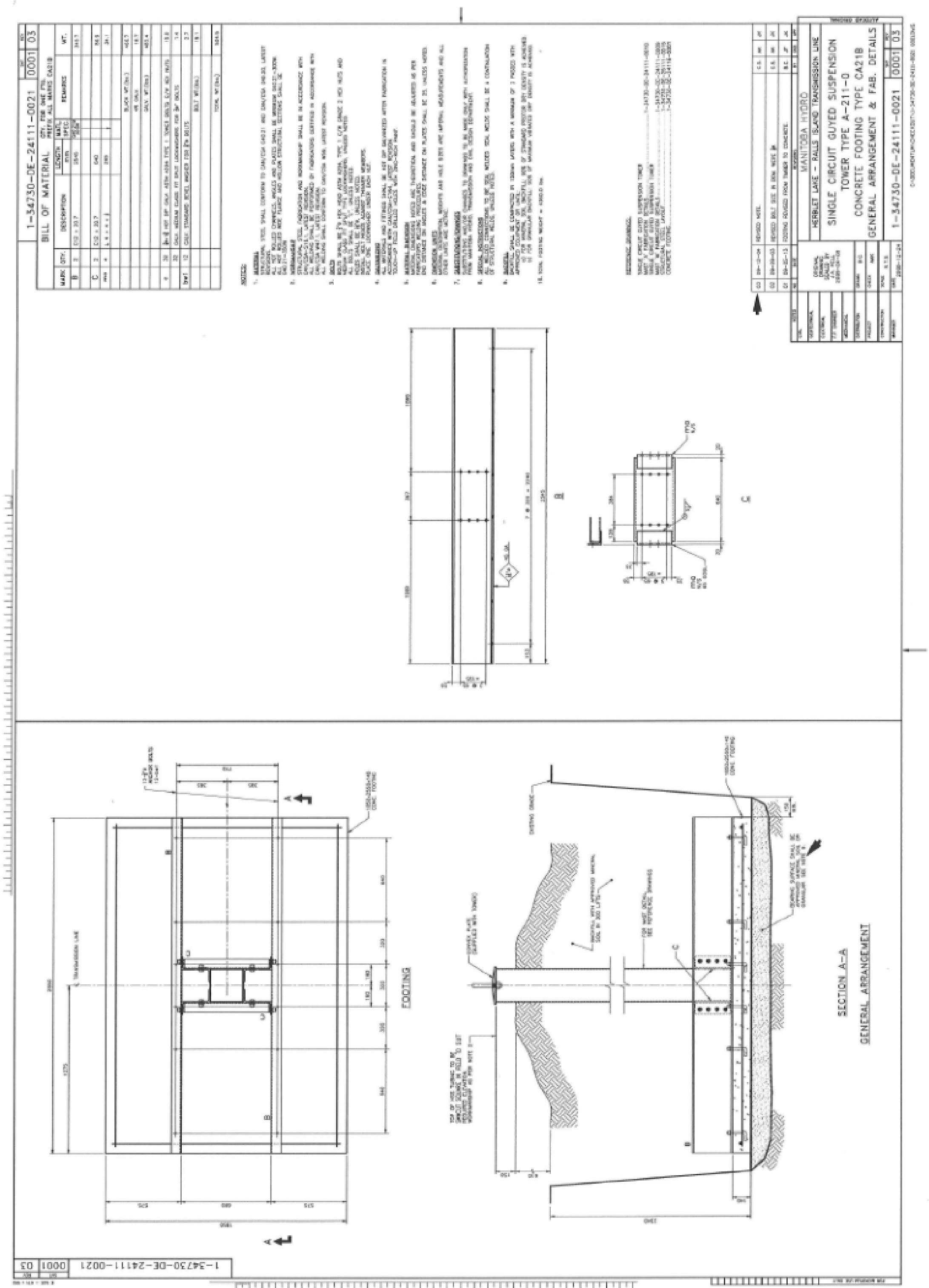
GENERAL ARRANGEMENT & FAB. DETAILS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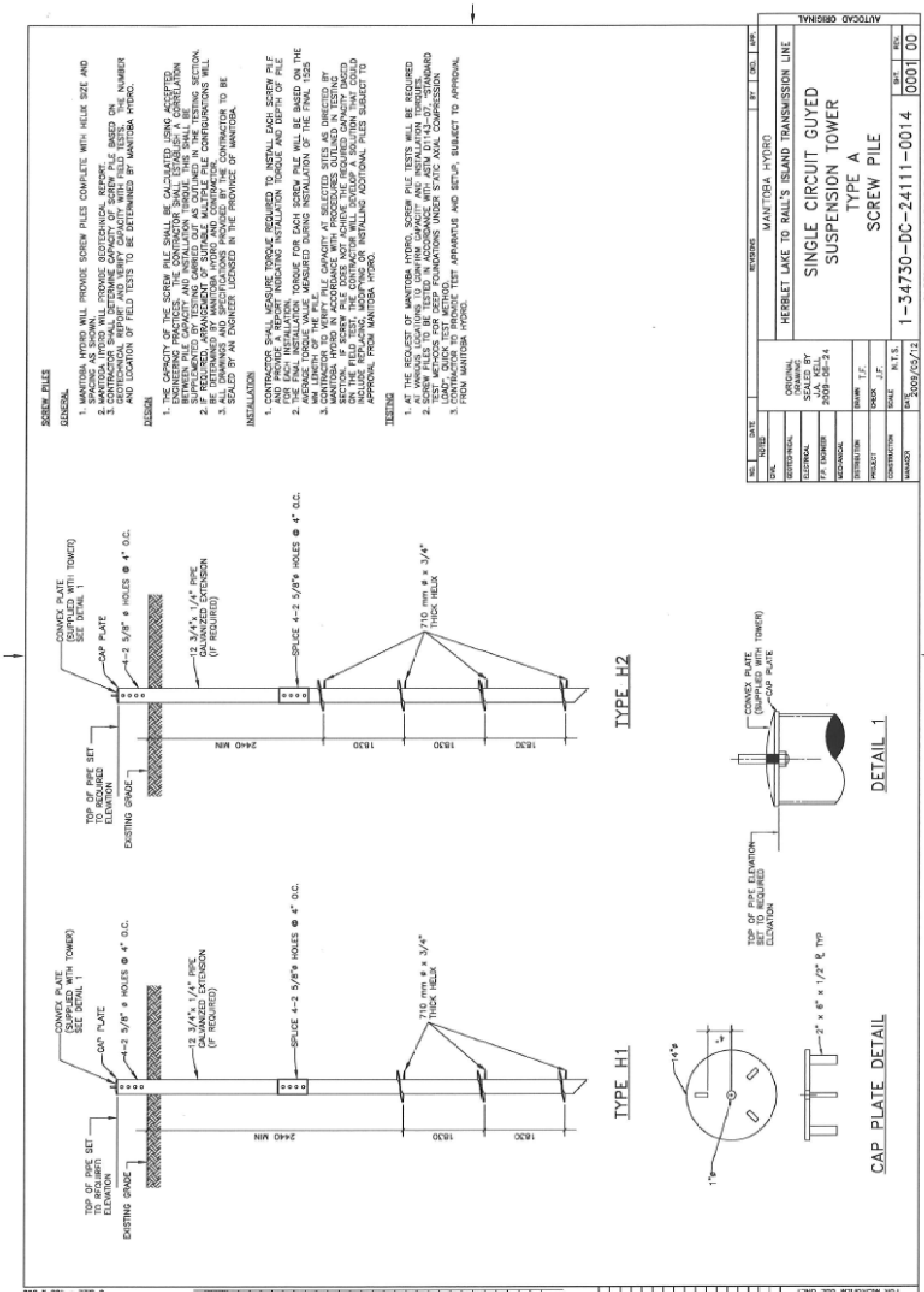
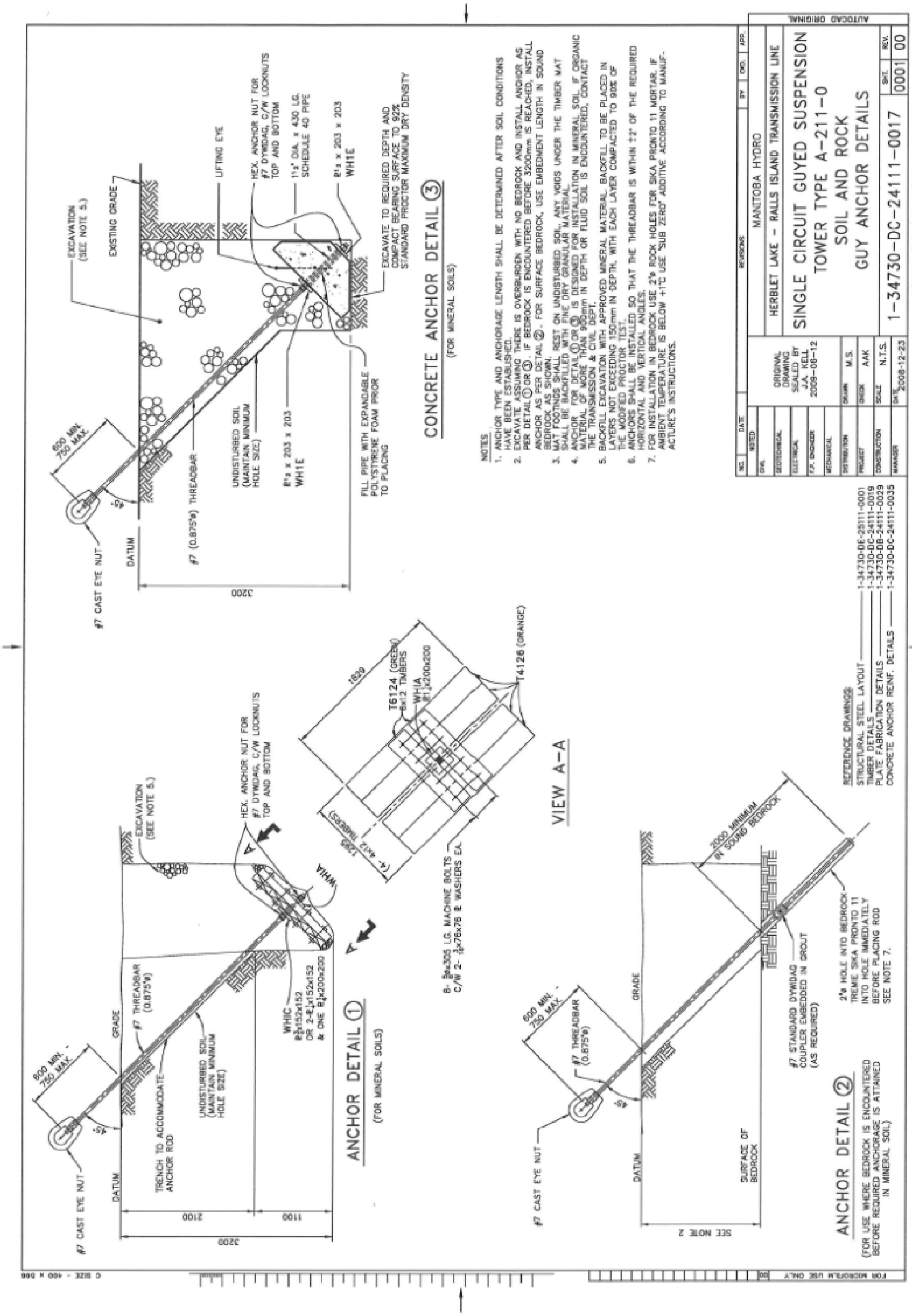
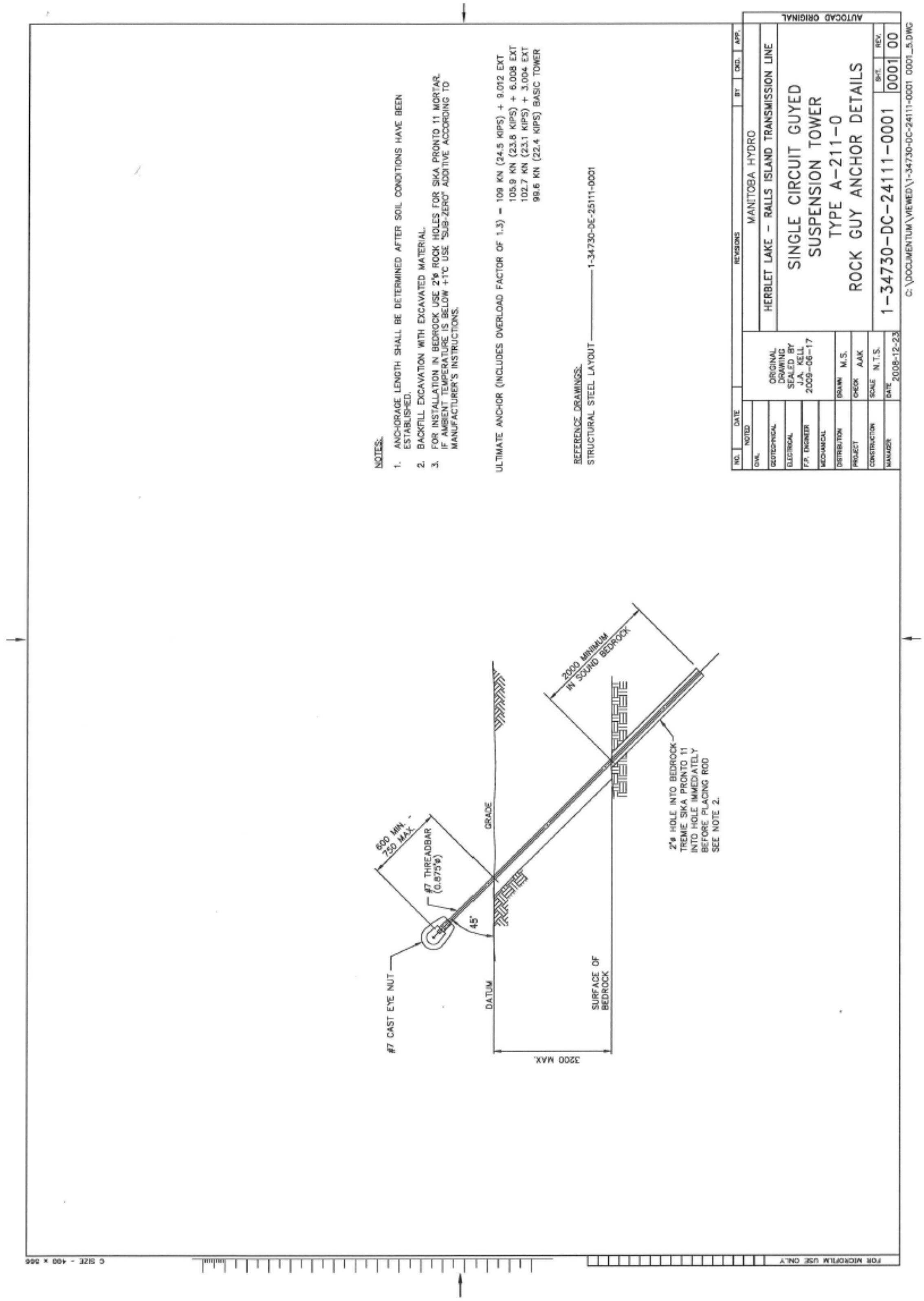

SCREW PILES
GENERAL
1. MANITOBA HYDRO WILL PROVIDE SCREW PILES COMPLETE WITH HELIX SIZE AND SPACING AS SHOWN.
2. MANITOBA HYDRO WILL PROVIDE GEOTECHNICAL REPORT.
3. CONTRACTOR SHALL DETERMINE CAPACITY OF SCREW PILE BASED ON GEOTECHNICAL REPORT AND VERIFY CAPACITY WITH FIELD TESTS. THE NUMBER AND LOCATION OF FIELD TESTS TO BE DETERMINED BY MANITOBA HYDRO.
DESIGN
1. THE CAPACITY OF THE SCREW PILE SHALL BE CALCULATED USING ACCEPTED ENGINEERING PRACTICES. THE CONTRACTOR SHALL ESTABLISH A CORRELATION BETWEEN PILE CAPACITY AND INSTALLATION TORQUE. THIS SHALL BE SUPPLEMENTED BY TESTING CARRIED OUT AS OUTLINED IN THE TESTING SECTION.
2. IF REQUIRED, ARRANGEMENT OF SUITABLE MULTIPLE PILE CONFIGURATIONS WILL BE DETERMINED BY MANITOBA HYDRO AND CONTRACTOR.
3. ALL DRAWINGS AND SPECIFICATIONS PROVIDED BY THE CONTRACTOR TO BE SEALED BY AN ENGINEER LICENSED IN THE PROVINCE OF MANITOBA.
INSTALLATION
1. CONTRACTOR SHALL MEASURE TORQUE REQUIRED TO INSTALL EACH SCREW PILE AND PROVIDE A REPORT INDICATING INSTALLATION TORQUE AND DEPTH OF PILE FOR EACH INSTALLATION.
2. THE FINAL INSTALLATION TORQUE FOR EACH SCREW PILE WILL BE BASED ON THE AVERAGE TORQUE VALUE MEASURED DURING INSTALLATION OF THE FINAL 1525 MM LENGTH OF THE PILE.
3. CONTRACTOR TO VERIFY PILE CAPACITY AT SELECTED SITES AS DIRECTED BY MANITOBA HYDRO IN ACCORDANCE WITH PROCEDURES OUTLINED IN TESTING SECTION. IF SCREW PILE DOES NOT ACHIEVE THE REQUIRED CAPACITY BASED ON THE FIELD TEST, THE CONTRACTOR WILL DEVELOP A SOLUTION THAT COULD INCLUDE REPLACING, MODIFYING OR INSTALLING ADDITIONAL PILES SUBJECT TO APPROVAL FROM MANITOBA HYDRO.
TESTING
1. AT THE REQUEST OF MANITOBA HYDRO, SCREW PILE TESTS WILL BE REQUIRED AT VARIOUS LOCATIONS TO CONFIRM CAPACITY AND INSTALLATION TORQUES.
2. SCREW PILES TO BE TESTED IN ACCORDANCE WITH ASTM D1143-07, "STANDARD TEST METHODS FOR DEEP FOUNDATIONS UNDER STATIC AXIAL COMPRESSION LOAD", QUICK TEST METHOD.
3. CONTRACTOR TO PROVIDE TEST APPARATUS AND SETUP, SUBJECT TO APPROVAL FROM MANITOBA HYDRO.
CONVEX PLATE (SUPPLIED WITH TOWER) SEE DETAIL 1
TOP OF PIPE SET TO REQUIRED ELEVATION
CAP PLATE
EXISTING GRADE
4-2 5/8" ø HOLES @ 4" O.C.
12 3/4"x 1/4" PIPE GALVANIZED EXTENSION (IF REQUIRED)
2440 MIN
SPLICE 4-2 5/8"ø HOLES @ 4" O.C.
710 mm ø x 3/4" THICK HELIX
1830
1830
TYPE H1
TYPE H2
14"ø
1"ø
4"
2" x 6" x 1/2" ℞ TYP
CAP PLATE DETAIL
TOP OF PIPE ELEVATION SET TO REQUIRED ELEVATION
CONVEX PLATE (SUPPLIED WITH TOWER)
CAP PLATE
DETAIL 1
NO. DATE REVISIONS BY CKD. APP.
NOTED
CIVIL
GEOTECHNICAL
ELECTRICAL
F.P. ENGINEER
MECHANICAL
DISTRIBUTION
PROJECT
CONSTRUCTION
MANAGER
ORIGINAL DRAWING SEALED BY J.A. KELL 2009-08-24
DRAWN T.F.
CHECK J.F.
SCALE N.T.S.
DATE 2009/05/12
MANITOBA HYDRO
HERBLET LAKE TO RALL'S ISLAND TRANSMISSION LINE
SINGLE CIRCUIT GUYED SUSPENSION TOWER
TYPE A
SCREW PILE
1-34730-DC-24111-0014
SHT. 0001
REV. 00
AUTOCAD ORIGINAL
C:\DOCUMENTUM\CHECKOUT\1-34730-DC-24111-0014 0001.DWG
FOR MICROFILM USE ONLY
C SIZE - 400 x 566


CONCRETE ANCHOR DETAIL 3
(FOR MINERAL SOILS)
ANCHOR DETAIL 1
(FOR MINERAL SOILS)
VIEW A–A
ANCHOR DETAIL 2
MANITOBA HYDRO
HERBLET LAKE – RALLS ISLAND TRANSMISSION LINE
SINGLE CIRCUIT GUYED SUSPENSION
TOWER TYPE A–211–0
SOIL AND ROCK
GUY ANCHOR DETAILS
1–34730–DC–24111–0017


#7 CAST EYE NUT
600 MIN. - 750 MAX.
#7 THREADBAR (0.875"ø)
45°
DATUM
GRADE
3200 MAX.
SURFACE OF BEDROCK
2000 MINIMUM IN SOUND BEDROCK
2"ø HOLE INTO BEDROCK TREMIE SIKA PRONTO 11 INTO HOLE IMMEDIATELY BEFORE PLACING ROD SEE NOTE 2.
NOTES:
1. ANCHORAGE LENGTH SHALL BE DETERMINED AFTER SOIL CONDITIONS HAVE BEEN ESTABLISHED.
2. BACKFILL EXCAVATION WITH EXCAVATED MATERIAL.
3. FOR INSTALLATION IN BEDROCK USE 2"ø ROCK HOLES FOR SIKA PRONTO 11 MORTAR. IF AMBIENT TEMPERATURE IS BELOW +1°C USE "SUB-ZERO" ADDITIVE ACCORDING TO MANUFACTURER'S INSTRUCTIONS.
ULTIMATE ANCHOR (INCLUDES OVERLOAD FACTOR OF 1.3) = 109 KN (24.5 KIPS) + 9.012 EXT
105.9 KN (23.8 KIPS) + 6.008 EXT
102.7 KN (23.1 KIPS) + 3.004 EXT
99.6 KN (22.4 KIPS) BASIC TOWER
REFERENCE DRAWINGS:
STRUCTURAL STEEL LAYOUT — 1-34730-DE-25111-0001
NO. DATE REVISIONS BY CKD. APP.
NOTED
CIVIL
GEOTECHNICAL
ELECTRICAL
F.P. ENGINEER
MECHANICAL
DISTRIBUTION
PROJECT
CONSTRUCTION
MANAGER
ORIGINAL DRAWING SEALED BY J.A. KELL 2009-06-17
DRAWN M.S.
CHECK AAK
SCALE N.T.S.
DATE 2008-12-23
MANITOBA HYDRO
HERBLET LAKE – RALLS ISLAND TRANSMISSION LINE
SINGLE CIRCUIT GUYED
SUSPENSION TOWER
TYPE A-211-0
ROCK GUY ANCHOR DETAILS
1-34730-DC-24111-0001
SHT. 0001
REV. 00
AUTOCAD ORIGINAL
C:\DOCUMENTUM\VIEWED\1-34730-DC-24111-0001 0001_5.DWG
C SIZE - 400 x 566
FOR MICROFILM USE ONLY

KEEYASK TRANSMISSION - SCOPE and ESTIMATE - GENERATION OUTLET and UNIT LINES

GENERATION OUTLET TRANSMISSION (G.O.T.) LINES - KR1, KR2, KR3

PROJECT DESCRIPTION

KR1, KR2, KR3: three 138 kV single circuit lines from Keeyask Switching Station to Radisson station using guyed lattice steel towers, similar to recent 230kV projects in the north such as H75P.

KR1 ext: temporary 138 kV line with H - Frame wood structures from Keeyask switching station to Keeyast construction power station

	KR1, KR2, KR3	KR1 extension
Line Length	35km (each)	5km
Average Span	425m	160m

KR1 in-service date: 2015 (including extension). KR2 & KR3 in-service date: 2019 (including salvage of extension)

STRUCTURE TYPES & ESTIMATED QUANTITIES

Structure Type	Qty.	Weights (lbs.)	KR1 temp - wood pole structures	
Guyed Lattice Suspension	88	12000	1	3 Pole Termination
River Crossing Suspension	2	25000	23	H-Frame Wood Pole Suspension
Anti Cascade	12	20000	3	3 Pole Dead End Heavy Angle
Heavy Angle	11	40000	1	3 Pole Light Angle
Tie Down	2	25000		

FOUNDATION & ANCHOR TYPES

Assumed conditions:

40% mineral soil suitable for mat footings and anchors (typ. 10'x10' mat footings; 4' x 8' mat anchors for steel, direct embed wood)
40% shallow bedrock suitable for dowelled footings and anchors
20% unfavourable conditions requiring site-specific designs: helical piles, micro piles, cast in place solutions, etc

INSULATORS

KR1, KR2, KR3
120 KN Suspension - Porcelain or glass
220 KN Dead End - Porcelain or Glass
12 bells per suspension string (7')

KR1 extension
70 KN Suspension - Porcelain or glass
120 KN Dead End - Porcelain or Glass
8 bells per suspension string (5')

CONDUCTOR TYPES

	KR1, KR2, KR3	KR1 extension
Phase:	1590 MCM ACSR	336 MCM ACSR
Ground:	OPGW (One skywire of KR1) and Size 9 - 7 Strand Steel	Two Size 9 - 7 Strand Steel

RIGHT-OF-WAY: KR1, KR2, KR3: New shared corridor (width varies - typ 200m)

COST ESTIMATE ($2012)

Environmental Assessment	$3.8M
Engineering	$2.5M
Material	$20.9M
Construction	$37.2M
Contingency	$15.6M
Generation Outlet Transmission Total	**$80M**

KEEYASK UNIT LINES

Project Description:

Four 138 kV single circuit lines originating at the Keeyask Generating Station and crossing the river to the Keeyask Switching Station (approx 4km each)

In-service date: 2019

Towers, foundations, conductor, etc to be similar to Generator Outlet lines above.

Cost Estimate ($2012): $6M - Total Unit Lines

Transmission Construction and Line Maintenance Division 2013 12 10

KEEYASK CONSTRUCTION POWER - SCOPE and ESTIMATE (not included in Keeyask Transmission)

CONSTRUCTION POWER LINE: KN36 TAP

PROJECT DESCRIPTION

KN36: one single circuit guyed tubular steel 138 kV transmission line tapping off of KN36 to Keeyask Construction Power Station located on the north side of the Nelson River. The transmission line will be tapped near structure 285 of KN36.

Three separate switch structures will be required. One is a grounding switch on the tap portion to Keeyask CP and other two are on KN36.

Aircraft warning light (Stroboscopic light) system and power supply for that will be needed for the Nelson river crossing span which is approximately 1km long.

Line length: 21.4km   Average span: 350m

In-service date: 2015

STRUCTURE TYPES & ESTIMATED QUANTITIES

Structure Type	Qty.	Weights (lbs.)
KN36 Tap		
Guyed Tubular Steel Suspension	56	6000
Guyed River Crossing Suspension	2	15000
Guyed 0-37 Angle	2	28163
Guyed 7-25 Angle Anchor	3	7500
Guyed 25 -90 Angle	3	11000
Guyed 3 Pole Dead End	1	10500
Self Supporting Lattice Switch Structure	3	28163

FOUNDATION & ANCHOR TYPES

Assumed conditions:

40% mineral soil suitable for mat footings and anchors
40% shallow bedrock suitable for dowelled footings and anchors
20% unfavourable conditions requiring site-specific designs: helical piles, micro piles, cast in place solutions, etc

Typical mat footing and anchor sizes:

6' x 6' mat footings
2' x 4' mat anchors

INSULATORS

70 KN Suspension - Porcelain or glass
120 KN Dead End - Porcelain or Glass
8 bells per suspension string (5')

CONDUCTOR TYPES

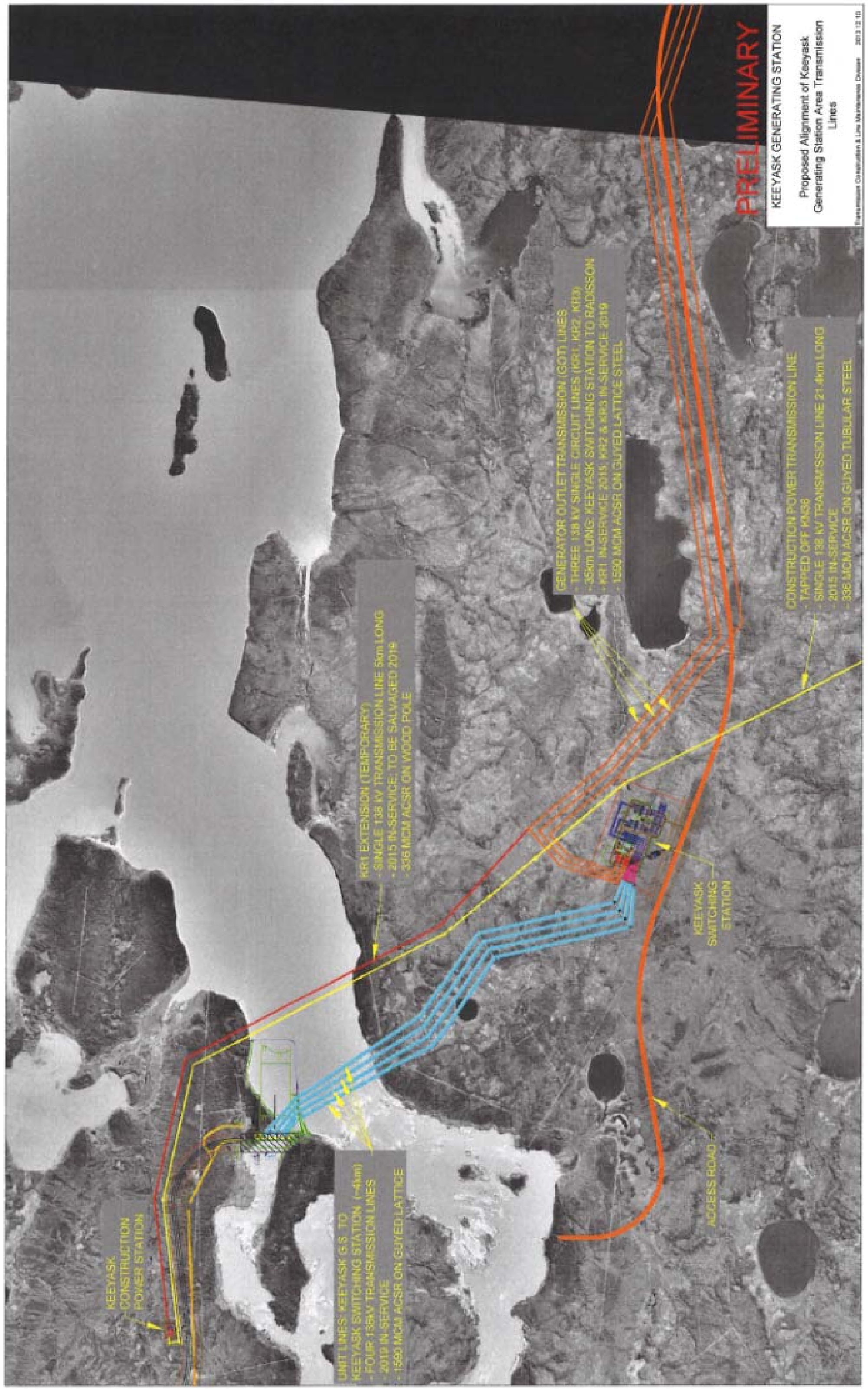
Phase: 336 MCM ACSR
Ground: Two Size 9 - 7 Strand Steel

RIGHT-OF-WAY

KN36 Tap: New Corridor (60m)

COST ESTIMATE ($2012)

Engineering	$1.6M
Material	$3.0M
Construction	$9.3M
Contingency	$4.7M
Keeyask Construction Power Total	**$18.6M**


PRELIMINARY
KEEYASK GENERATING STATION
Proposed Alignment of Keeyask Generating Station Area Transmission Lines
GENERATOR OUTLET TRANSMISSION (GOT) LINES
- THREE 138 kV SINGLE CIRCUIT LINES (KR1, KR2, KR3)
- 35km LONG: KEEYASK SWITCHING STATION TO RADISSON
- KR1 IN-SERVICE 2015, KR2 & KR3 IN-SERVICE 2019
- 1590 MCM ACSR ON GUYED LATTICE STEEL
CONSTRUCTION POWER TRANSMISSION LINE
- TAPPED OFF KN36
- SINGLE 138 kV TRANSMISSION LINE 21.4km LONG
- 2015 IN-SERVICE
- 336 MCM ACSR ON GUYED TUBULAR STEEL
KR1 EXTENSION (TEMPORARY)
- SINGLE 138 kV TRANSMISSION LINE 5km LONG
- 2015 IN-SERVICE; TO BE SALVAGED 2019
- 336 MCM ACSR ON WOOD POLE
KEEYASK SWITCHING STATION
ACCESS ROAD
UNIT LINES: KEEYASK G.S. TO KEEYASK SWITCHING STATION (~4km)
- FOUR 138kV TRANSMISSION LINES
- 2019 IN-SERVICE
- 1590 MCM ACSR ON GUYED LATTICE
KEEYASK CONSTRUCTION POWER STATION

MANITOBA MINNESOTA TRASMISSION PROJECT - SCOPE and CONSTRUCTION ESTIMATE

	Leg 1: Dorsey to Riel	Leg 2: Riel to US Border
Line Length	68.7km	166 km
Average Span	400m	450m

PROJECT DESCRIPTION

Leg 1: 68.7km of 500kV AC self supporting lattice steel transmission line from Dorsey - Riel Station. The entire route will follow Manitoba Hydro's South Loop Transmission Corridor. This portion of the transmission line will not terminate into Riel Station but pass nearby for future termination.

Leg 2: 166km of 500kV AC guyed lattice steel transmission line from Riel to Canada / US Border crossing near Piney. Majority of the transmission line traverses forested land east of Winnipeg.

STRUCTURE TYPES & ESTIMATED QUANTITIES

Leg 1: Dorsey - Riel

Structure Type + ext (m)	Qty.	Description	Weights (lbs.)
A-501-1+7.5	65	Self Supporting Suspension	28798
A-501-1+9	71	Self Supporting Suspension	29870
A-501-1+10.5	5	Self Supporting Suspension	31435
A-501-1 Special	2	Self Supporting Suspension	33813
B-501-1+6	1	Self Supporting Running Angle	39294
C-500-1	4	Self Supporting Light Angle	49118
E-500-1	9	Self Supporting Medium Angle	61397
E-500-1 Special	1	Self Supporting Medium Angle	61397
F-500	4	Self Supporting Heavy Angle	76746
P-501	20	Self Supporting Anti-Cascade	50000

Leg 2: Riel - US Border

Structure Type + ext (m)	Qty.	Description	Weights (lbs.)	Terrain
A-500-1+3	85	Guyed Suspension	16000	Marsh and forest
A-500-1+6	230	Guyed Suspension	17000	Marsh and forest
A-501-1+9	18	Self Supporting Suspension	29870	Agriculture
F-500	7	Self Supporting Heavy Angle	76746	All
P-500	30	Guyed Anti-Cascade	25000	Marsh and forest

FOUNDATION & ANCHOR TYPES

Leg 1: Dorsey - Riel

Structure Type	Qty.	Tower type	Description
A-501-1+7.5	65	Self Supporting Suspension	3'x30' CIP concrete piles
A-501-1+9	71	Self Supporting Suspension	3'x30' CIP concrete piles
A-501-1+10.5	5	Self Supporting Suspension	3'x30' CIP concrete piles
A-501-1 Special	2	Self Supporting Suspension	3'x30' CIP concrete piles
B-501-1+6	1	Self Supporting Running Angle	4'x30' CIP concrete piles
C-500-1	4	Self Supporting Light Angle	5'x30' CIP concrete piles
E-500-1	9	Self Supporting Medium Angle	5'x30' CIP concrete piles
E-500-1 Special	1	Self Supporting Medium Angle	5'x30' CIP concrete piles
F-500	4	Self Supporting Heavy Angle	5'x30' CIP concrete piles
P-501	20	Self Supporting Anti-Cascade	5'x30' CIP concrete piles

Leg 2: Riel - US Border

Structure Type	Qty.	Tower type	Description
A-500-1+3	85	Guyed Suspension	Mat footing (10' x 10') and Anchors (4' x 8')
A-500-1+6	230	Guyed Suspension	Mat footing (10' x 10') and Anchors (4' x 8')
A-501-1+9	18	Self Supporting Suspension	3'x30' CIP concrete piles
F-500	7	Self Supporting Heavy Angle	5'x30' CIP concrete piles
P-500	30	Guyed Anti-Cascade	Mat footing (12' x 12') and Anchors (double 4' x 8')

Note: 20% of foundations on Leg 2 are assumed to require site-specific designs (e.g. helical piles) due to unfavourable conditions

INSULATORS

Centre phase V-String, all other I-String
160 KN suspension - porcelain or glass
220 KN dead end - porcelain or glass
26 bells per suspension string (16')

MANITOBA MINNESOTA TRASMISSION PROJECT - SCOPE and CONSTRUCTION ESTIMATE (cont) - Page 2

CONDUCTOR TYPES

Leg 1: Dorsey - Riel
Triple Bundle 1272 MCM 54/19 ACSR Pheasant
2 - Ground conductors Size 10 (7/16") Steel - 7 Strand Grade 1300

Leg 2: Riel - US Border
Triple Bundle 1272 MCM 54/19 ACSR Pheasant
1 - Ground conductor for this section will be galvanized Size 10 (7/16") Steel - 7 Strand Grade 1300
1 - 14 mm OPGW conductor terminated at Riel Station

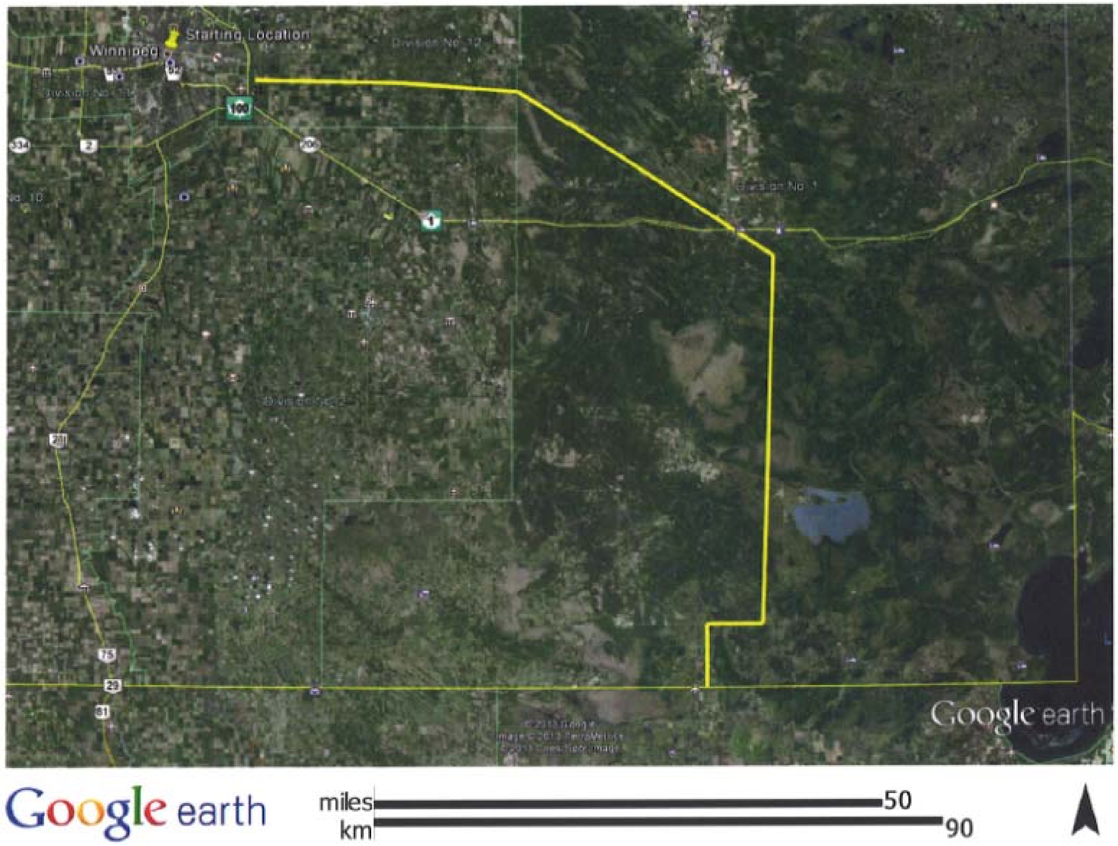
RIGHT-OF-WAY

Leg 1: Existing Right-of-Way
Leg 2: new 76.2m Right-of-Way

COST ESTIMATE ($2012)

Environmental Assessment	$7.6M
Engineering	$10M
Property Acquisition	$5.8M
Material	$65.9M
Construction	$63.1M
Contingency	$21.1M
Transmission Line Total	**$173.6M**

Trasmission Construction and Line Maintenance Division 2013 12 10



MANITOBA-MINNESOTA TRANSMISSION PROJECT
CONCEPTUAL TRANSMISSION LINE ROUTING FOR ESTIMATING PURPOSES ONLY
TRANSMISSION CONSTRUCTION & LINE MAINTENANCE DIVISION
2013 12 10

SUMMARY OF TRANSMISSION LINE COSTS – PAST PROJECTS AND FUTURE ESTIMATES
TRANSMISSION CONSTRUCTION & LINE MAINTENANCE DIVISION
2013 12 10

Project	Location	Circuit	Conductor	Length	Average Span	Construction	In-Service Year	Total Project Cost
Glenboro-Rugby	South - farm	230 kV single circuit	954 MCM ACSR single bundle	80 km	205m	Mostly wood pole gulfport	2002	$18.2M
Rosser-Silver	South - mixed	230 kV single circuit	954 MCM ACSR single bundle	109 km	254m	Wood pole gulfport, tubular steel (direct embed and concrete caisson foundations)	2007	$23M
Birchtree Wuskwatim	North	230 kV single circuit	954 MCM ACSR single bundle	45 km	409m	Guyed lattice towers with self-support lattice angles	2008	$18.3M
Wuskwatim-Herblet	North	Two single circuit 230 kV lines	954 MCM ACSR single bundle	137 km x 2 lines	365m	Guyed lattice towers with self-support lattice angles	2011	$81.2M
Herblet -Ralls	North	230 kV single circuit	954 MCM ACSR single bundle	165 km	420m	Guyed lattice towers with self-support lattice angles	2011	$49.5M
Keeyask Transmission (GOT lines KR1, KR2, KR3 and Unit Lines)	North	138 kV single circuit	1590 MCM ACSR single bundle	140.4 km	425m	Guyed lattice towers with self-support lattice angles	2015 2019	$86M (est-$2012)
Manitoba-Minnesota	South - forest	500 kV single circuit	1272 MCM triple bundle	235 km	435m	Mixture of Guyed and self-supporting lattice towers	2019	$173.6M (est-$2012)
North-South AC								$139M (est-$2012)
Dauphin – Neepawa	South - farm	230 kV single circuit	954 MCM ACSR single bundle	130 km	250m	Wood or steel H-frame	2026	
Herblet to OverFlowing R. Kelsey to Birchtree Birchtree to Wuskwatim	North North North	230 kV single circuit 230 kV single circuit 230 kV single circuit	954 MCM ACSR single bundle 954 MCM ACSR single bundle 954 MCM ACSR single bundle	210 km 80 km 42 km	425m 425m 425m	Guyed lattice towers with self-support lattice angles Guyed lattice towers with self-support lattice angles Guyed lattice towers with self-support lattice angles	2026 2026 2026	

9.

APPENDIX B

MY NOTES ON THE MH WEBEX CALL OF 11/7/13

Glenn Davidson

Question: PE 0001
We need some details on some of the information provided in the Keeyask and MMTP material provided in response to PE 0001.
Response:
We should send detailed questions to Ron Mazur who will forward them to Joel Ortley (Spelling?).

Question: PE 0002
How was the generic cost of $300,000/km for the N-S AC transmission lines derived? Can MH provide design information indicating design information on the lines used for determining the comparative cost, and how their design compares to the proposed NFAT Project lines?
Response:
MH will provide information similar to the information provided in the Keeyask scope and construction estimate provided.

Question: PE 0001 & PE 0002
Are R/W costs included in the estimates?
Response:
All lines are on Crown Lands and there are no R/W costs. Except for possibly Dauphin – Neepwa – depending on the route selected.

Question: PE 0001 & PE 0002
Are there environmental assessment costs and are they included in the estimates?
Response:
They are included but not broken out. They are blended into the "Generic" line cost of $300,000/km.

Question: PE 0001 & PE 0002
Can MH provide us with line plan & profile drawings, topo maps, or other information to allow us to understand the terrain, topography and other site specific information needed to complete our estimate review?
Response:
The land is generally all muskeg and bog requiring winter construction. MH can direct us to published information, or provide us with corridor maps that we can use. The lines are not yet designed.

Question: NOT IN PE IRs
How were the costs of lines in the US determined?
Response:
Minnesota Power prepared the estimates. The NFAT filing documents have costs for various alternatives. Information may be available in the Minnesota Power filing for Certificate of Need.

Glenn Davidson 8969

From: Wortley, Joel [jwortley@hydro.mb.ca]
Sent: Thursday, December 12, 2013 9:21 AM
To: Glenn Davidson 8969
Subject: RE: Notes of telephone call

Hi Glenn,

I would offer the following as clarification to the notes:

The Keeyask GOT lines are split into two phases: KR1 (and extension) in 2015, followed by KR2 & KR3 in 2019, thus 40km of line will be built in 2015 and 70km in 2019. The result being:

- Short projects where efficiencies of longer lines cannot be obtained.
- 2 mobilizations (2015 and 2019)

Work is required on two sides of the Nelson River (in both 2015 and 2019). Crossing the river is approximately a 175km drive using the highway river crossing at Long Spruce GS .

The transmission line construction contracting market is expected to be impacted by the Bipole III project (1485km of 500 kV HVDC from Gillam to Winnipeg being built 2014 to 2017).

Regards,
Joel

From: Glenn Davidson [mailto:gdavidson@powereng.com]
Sent: Wednesday, December 11, 2013 2:35 PM
To: Wortley, Joel
Subject: Notes of telephone call

Joel,

Please review my notes. Do you have any corrections or additions?

Glenn

1

APPENDIX C

POWER ENGINEERS

TELEPHONE RECORD

DATE:	December 11, 2013	TIME OF CALL:	11:30
TO:	G Davidson	PHONE NUMBER:	303-716-8969
FROM:	Joel Wortley/MH	C:	
TYPED BY:	G Davidson	PROJECT NUMBER:	132171
CLIENT:	Manitoba PUB		
PROJECT NAME:	Manitoba Hydro NFAT		
SUBJECT:	Clarifications on some costs		

MESSAGE

1. Why are the Keeyask Transmission line 138 kV per km costs so high? Is the switching station cost included?
Joel responded that the-per unit costs were high because of the following factors:
a. The project is very short and efficiencies of longer lines cannot be obtained.
b. The project requires 2 mobilizations because it is on two sides of the Nelson River
c. The river crossing is difficult and expensive
d. Switching station costs are not included in the transmission costs.

2. Are the costs of the 230 kV line to be constructed and then salvaged at Conawapa included in the transmission line costs?
a. This line is not included in the transmission line project. It is included in Plant costs.

PAGE 1 OF 1

APPENDIX D

Manitoba Hydro responses to Power Engineers – Transmission related questions

October 24, 2013

PE-0001

The transmission lines included in the NFAT review process are the Manitoba Minnesota Transmission Project (MMTP), Keeyask Transmission and Conawapa generator outlet transmission lines.

Detailed scopes and construction estimates for the MMTP and Keeyask Transmission are included on the non-confidential share point site [5], [6]. These construction costs were estimated based on unit pricing received from recent transmission line tenders for similar work, such as the Wuskwatim-Herblet and the Herblet-Ralls transmission lines. The unit prices were adjusted for inflation and other specific circumstances of the work and take into account winter work, requirements of the Environmental Protection Plans (i.e. working in environmentally sensitive areas), safety, etc.

Construction will be guyed lattice towers with average span length of 450m supported by mat footings and anchors. Single bundle 1113 MCM conductor is anticipated.

The five Conawapa generator outlet transmission lines are 7 km long. The north-south ac transmission in the NFAT filing consists of a 130 km Dauphin to Neepawa 230 kV line, a 210 km Herblet Lake to OverFlowing River 230 kV line, an 80 km Kelsey to Birchtree 230 kV line and a 42 km Birchtree to Wuskwatim 230 kV line. The estimate for these lines was based on a generic cost of $300,000/km.

PE-0002

The transmission lines included in the NFAT review process are the Manitoba Minnesota Transmission Project (MMTP), Keeyask Transmission and Conawapa generator outlet transmission lines. The construction cost impacts of environmental protection, ground conditions, and construction timing are embedded in the unit rates bid by contractors for similar work that used to build the project estimates [5], [6].

The majority of the lengths of these lines traverse wet terrain that can only be accessed when frozen, thus are winter-only construction. The work on these projects will be done in accordance with project-specific environmental protection plans, which include provisions for protecting sensitive areas such as riparian buffers at stream crossings. Helicopter transportation for construction purposes is not anticipated to be required, albeit the construction contractor may choose to employ such methods if expedient.

The construction cost estimates for the transmissions lines within the NFAT review process are based on unit pricing received from recent transmission line tenders for similar work, such as the Wuskwatim-Herblet and Herblet-Ralls transmission lines. The Wuskwatim-Herblet and Herblet-Ralls transmission lines were winter-only construction projects built across wet terrain with environmental protection plans. Thus the costs of access, timing and environmental protection is built into the unit prices bid for the work that were used to estimate the construction costs for the NFAT transmission lines.

PE-0003

First Nations employment on the NFAT transmission lines will be a requirement of the construction contracts, as it was on the Wuskwatim-Herblet and Herblet-Ralls transmission lines. The costs are included in the contractor's payroll and factored into the unit rates bid for the work.

The construction cost estimates for the transmissions lines within the NFAT review process are based on unit pricing received from recent transmission line tenders for similar work, such as the Wuskwatim-Herblet and Herblet-Ralls transmission lines.

PE-0004

For the Keeyask Generator outlet lines:

a) Each 138kV transmission line will use a single circuit structure (on its own line of structure).

b) The centre to centre separation of the lines is about 65 metres based on the preliminary study.

PE-0005

Based on the experience of past transmission projects, The Keeyask transmission assumed the followings cash flows (Appendix 11.1, pages 10, 12): Year 1 – 1%; Year 2 – 1%; Year 3 – 12%;Year 4 – 6%; Year 5 – 10%; Year 6 – 17%; Year 7 – 24%; Year 8 – 29% . The expected cash flows (Appendix 11.1, pages 14, 16 , 18)) of the transmission costs for Conawapa are as follows: Year 1 – 5%; Year 2 – 10%; Year 3 – 20%; Year 4 – 45%; Year 5 – 20%.

Escalation and interest are calculated for each project on a monthly basis. Constant 2012 dollar project cash flows are adjusted for inflation by applying a monthly inflation index. The inflation index is derived from the escalation rates for Canadian CPI shown in Appendix 11.2 – Projected Escalation, Interest and Exchange Rates relative to a 2012 base year. Interest during construction is calculated by applying the interest capitalization rate (see Appendix 11.2) to the actual or forecasted month-end work in progress balance (total cumulative costs incurred to that period) of each project, until such project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction.

PE-0006 (a, b, c, d, e, f, g, h, I, j, k, l, m, n, o)

The nominal converter ratings of Bipole I and Bipole II are 1668MW and 1800MW, respectively. Bipole I operates at +/- 463.5kV while Bipole II is rated at +/- 500kV. The continuous overload ratings are 1854MW for Bipole I and 2000MW for Bipole II. There is no short time overload available.

The North-South transmission capacity of the two existing bipoles (bipole I and Bipole II) is 3854MW after the recent upgrades of Bipole I smoothing reactors. Previously, the rating was limited to 3620MW when the ambient temperature exceeds 28C. There are no plans to change the rating of Bipoles I and II.

APPENDIX E

Keeyask 138 kV Lines

138 kV Keeyask Lines Estimate

summary — used provided structure weights
included typical costs for installation of towers, foundations, guys, anchors and wires
arrived at cost per km and mi that are

total project cost
$83,884,969

KN36	KR1, KR2, KR3	KR1 X	total	
$427,342	$695,759	$337,040	$638,394	<< cost p/km to install
$687,603	$1,118,754	$543,614	$1,026,744	<< cost p/mi to install

KN36	KR1, KR2, KR3	KR1 X		
21.4 km	105.0 km	5.0 km	131.4 km	<< total kilometers
13.3 mi	65.3 mi	3.1 mi	81.7 mi	<< total miles

	KN36	KR1, KR2, KR3	KR1 X	
	$7,620,936	$60,878,870	$1,123,468	
w/ 20% contingency >	$9,145,123	$73,054,644	$1,685,202	< with removal cost

	str type	weight	qty	ton	cost p/lb	material cost per pole	total pole cost	labor to haul, assemble, erect p/lb or ton	installed labor cost p/str		total installed str cost
KN36	guyed tubular susp	6,000 lb	56		$1.75	$10,500	$588,000	$1.00	$6,000		$924,000
	guyed lattice river crossing	15,000 lb	2	7.50 ton	$3.00	$45,000	$90,000	$16,000	$120,000		$330,000
	lattice guyed angle 0-37	28,163 lb	2	14.08 ton	$1.20	$33,796	$67,591	$8,000	$112,652		$292,895
	lattice guyed angle 7-25	7,500 lb	3	3.75 ton	$1.20	$9,000	$27,000	$8,000	$30,000		$117,000
	lattice guyed angle 25-90 de	11,000 lb	3	5.50 ton	$1.10	$12,100	$36,300	$8,000	$44,000		$168,300
	guyed 3 pole de	31,500 lb	1		$1.75	$55,125	$55,125	$1.00	$31,500		$86,625
	ss lattice switch de	28,163 lb	3	14.08 ton	$1.10	$30,979	$92,938	$8,000	$112,652		$430,894
											$2,349,714

	str type	weight	qty	ton	cost p/lb	material cost per pole	total pole cost	labor to haul, assemble, erect p/lb or ton	installed labor cost p/str		total installed str cost
	guyed lattice susp	12,000 lb	264	6.00 ton	$1.20	$14,400	$3,801,600	$8,000	$48,000		$16,473,600
KR1-	lattice river xing susp	25,000 lb	6	12.50 ton	$3.00	$75,000	$450,000	$16,000	$200,000		$1,650,000
KR2-	anti cascade lattice de	20,000 lb	36	10.00 ton	$1.10	$22,000	$792,000	$8,000	$80,000		$3,672,000
KR3-	heavy angle lattice de	40,000 lb	33	20.00 ton	$1.10	$44,000	$1,452,000	$8,000	$160,000		$6,732,000
	lattice tie down de	25,000 lb	6	12.50 ton	$1.10	$27,500	$165,000	$8,000	$100,000		$765,000
											$29,292,600

	str type		qty		material cost per str	hardware/ insulator cost ea		labor cost per str			total str installed cost
KR1- X	3 pole termination		1		$18,000	$4,500		7,500			$30,000
	H frame susp		23		$9,000	$800		6,000			$363,400
	3 pole light running angle		3		$12,000	$4,500		7,500			$72,000
	3 pole heavy dead end		1		$18,000	$4,500		12,000			$34,500
											$499,900

5 280

	item	length	miles	no of wires	length req'd	price p/ft	total wire cost	install cost per ft	install cost p/mi	installed labor cost	total installed cost
KN36	336 acsr conductor	75000 ft.	13.3 mi	3	225,000 ft	$1.00	$225,000	$4.00	$63,360	$842,688	$1,067,688
	2) 7/16 shield wire	75000 ft.	13.3 mi	2	150,000 ft	$0.50	$75,000	$1.75	$18,480	$245,784	$320,784
											$1,388,472

5 280

KR1-	1590 acsr conductor	350000 ft.	65.3 mi	3	1,050,000 ft	$3.00	$3,150,000	$5.00	$79,200	$5,167,800	$8,317,800
KR2-	1) opgw	350000 ft.	65.3 mi	1	350,000 ft	$2.10	$735,000	$3.00	$15,840	$1,033,560	$1,768,560
KR3-	1) 7/16 shield wire	350000 ft.	65.3 mi	1	350,000 ft	$0.50	$175,000	$1.75	$9,240	$602,910	$777,910
											$10,864,270

5280

KR1-X	1590 acsr conductor	18000 ft.	3.1 mi	3	54,000 ft	$3.00	$162,000	$5.00	$79,200	$245,520	$407,520
	1) opgw	18000 ft.	3.1 mi	1	18,000 ft	$2.10	$37,800	$3.00	$15,840	$49,104	$86,904
	1) 7/16 shield wire	18000 ft.	3.1 mi	1	18,000 ft	$0.50	$9,000	$1.75	$9,240	$28,644	$37,644
											$532,068

	structure type	hardware		labor cost per assembly		qty per str		installed cost per str	no of structures		total hardware material and labor cost
	2) I string	$275		$200		2		$950	63		$59,850
KN36	1) V string	$500		$300		1		$800	63		$50,400
	1) dead end	$350		$400		6		$4,500	7		$31,500
											$141,750

KR1-	2) I string	$275		$200		2		$950	270		$256,500
KR2-	1) V string	$500		$300		1		$800	270		$216,000
KR3-	1) dead end	$350		$400		6		$4,500	75		$337,500
											$810,000

	structure type	qty	6x6 pad for pedestal		grouted in rod for pedestal		screw in anchor for pedestal		2x4 mat anchor for guy		anchor bolt foundation		stub angle foundations-reg		stub angle foundations-lge		installed cost
			qty	cost ea	qty	cost ea	qty	cost ea	qty	cost ea	qty	cost ea	qty	cost ea	qty	cost ea	
			1	$15,000	1	$12,000	4	$3,500	4	$3,500	1	$50,000	4	$22,000	4	$36,000	
	guyed tubular susp	56	50	$750,000	16	$192,000	50	$700,000	56	$784,000							$2,426,000
	guyed lattice river crossing	2	2	$30,000			2	$28,000	2	$28,000							$86,000
	lattice guyed angle 0-37	2	2	$30,000			2	$28,000	2	$28,000							$86,000
KN36	lattice guyed angle 7-25	3	3	$45,000			3	$42,000	3	$42,000							$129,000
	lattice guyed angle 25-90 de	3													3	$432,000	$432,000
	guyed 3 pole de	1									3	$150,000					$150,000
	ss lattice switch de	3													3	$432,000	$432,000
																	$3,741,000

	guyed lattice susp	264	200	$3,000,000	64	$768,000	200	$2,800,000	264	$3,696,000							$10,264,000
KR1-	lattice river xing susp	6													6	$864,000	$864,000
KR2-	anti cascade lattice de	36											36	$3,168,000			$3,168,000
KR3-	heavy angle lattice de	33													33	$4,752,000	$4,752,000
	lattice tie down de	6													6	$864,000	$864,000
																	$19,912,000

			dig holes for wood pole direct embed														
			qty	cost ea													
			1	$1,500													
	3 pole termination	1	3	$4,500													$4,500
KR1-X	H frame susp	23	46	$69,000													$69,000
	3 pole light running angle	3	9	$13,500													$13,500
	3 pole heavy dead end	1	3	$4,500													$4,500
																	$91,500

Keeyask Transmission Analysis

2012 estimated costs

KR1 KR2 KR3 cost	$KR123 := 7305464$	2012 $	In-service-year
KR1 is 1/3 total	$KR1 := \frac{KR123}{3}$	$KR1 = 24351548$	2015
KR2 &3 are 2/3 total	$KR23 := KR123 \cdot \frac{2}{3}$	$KR23 = 48703096$	2019
$costperkm := \frac{KR1 + KR23}{110}$	$costperkm = 664133$	2012 $	

Escalating to in-service-year at 2%

$KR1 := KR1 \cdot (1.02)^3$	$KR1 = 24351548$	2015 $
$KR23 := KR23 \cdot (1.02)^7$	$KR23 = 55944548$	2019 $
	In-service-year $	
$Total := KR1 + KR23$	$Total = 80296096$	
$costperkm := \frac{Total}{110}$	$costperkm = 729965$	

230 kV Transmission Line Comparable Estimate

summary

used provided tangent structure weights for guyed and self supporting lattice structures- and increased weights incrementaly to come up with a conservative weight for additional angles and dead ends.
included typical costs for installation of towers, foundations, guys, anchors and wires
allowed for percentage of tower types for all structure types

guyed tangent lattice	50%
ss tangent lattice	40%
ss running angle lattice	5%
ss dead end lattice	5%

arrived at cost per km and mi that are

$550,382	<< cost p/mi to install
$343 989	<< cost p/km to install

str type	cost ea	str percentage	line length		structures per km	structures per mi	total required		str count	total str costs		
guyed tangent lattice	$55,520	50%	461 km	288 mi	2 2	3 6	1,031	1,031	515	$28,618,960		
ss tangent lattice	$156,150	40%							412	$64,392,661		
ss running angle lattice	$234,225	5%							52	$12,073,624		
ss dead end lattice	$390 375	5%							52	$20 122 706		
										total wire costs		
wire					$72,270	$115,632	461 km	288 mi		$33,302,016		
								288 mi		$158,509,967	$550,382	<< cost p/mi to install
							461 km			$158,509,967	$343,989	<< cost p/km to install

str type	average weight	cost per pound for material	average ton		cost per ton to haul, assemble and erect				installed cost
self supporting lattice	35,000	$1.10	17.5		$6,000				$143,500

foundation type	average weight	cost per pound for material	average ton		cost per site to install	installed cost	qty per str		installed cost
10x10 pad	750	$1.10	0.375		$6 000	$3 075	4		$12 300

tangent str cost	angle str cost	dead end str cost
$156 150	$234 225	$390 375

hardware		cost per assembly			cost haul, assemble and install		qty per str		installed cost
2) I string		$400			$100		2		$200
1) V string		$700			$150		1		$150

str type	average weight	cost per pound for material	average ton		cost per ton to haul, assemble and erect				installed cost
guyed lattice	7,600	$1.20	3.8		$6,000				$31,920

foundation type		Material Cost			cost per site to install		qty per str		installed cost
10x10 pad for pedestal		$4,000			$6,000		1		$10,000
grouted in rod for pedestal		$2,500			$3,500		1		$6,000
screw in anchor for pedestal		$1,000			$2,500		3		$5,500
anchor for guy		$1,250			$1,500		4		$7,250

total str cost
$55,520

hardware		cost per assembly			cost haul, assemble and install		qty per str		installed cost
2) I string		$400			$100		2		$200
1) V string		$700			$150		1		$150

span length - meter	span length - feet			str per km	str per mi
450	1475			2.2	3 6

				3300	5280
conductor material cost	**no of conductors**	**cost per ft**		**cost per km**	**cost per ft**
1113 acsr	3	$1.75		$17,325	$27,720
7/16 ehs	1	$0 50		$1 650	$2 640
opgw	1	$2.15		$7,095	$11,352
				$26 070	$41 712

total wire cost per km	total wire cost per mi
$72,270	$115,632

conductor labor cost	no of conductors	cost per ft		cost per km	cost per ft
1113 acsr	3	$3 25		$32,175	$51,480
7/16 ehs	1	$2.75		$9,075	$14,520
opgw	1	$1 50		$4,950	$7,920
				$46,200	$73,920

Comparable 500 kV AC Transmission Line Estimate

COMPARABLE 500kV TRANSMISSION LINE ESTIMATE		Project Costs	
Manitoba PUB	146.2 Miles		
Date: 12/30/2013 Rev: A	Itemized Project Costs	Contractor Expense	Owner Expense
Hardware & Insulator: Material	$5,321,388		x
Steel Structure: Material	$13,165,940		x
Steel Structure: Labor	$26,331,880	x	
Foundation: Material	$2,623,230		x
Foundation: Labor	$8,161,160	x	
Guy: Material	$1,600,200		x
Anchorage/Helical Pedestal and Cap: Guyed V Material	$4,693,500		x
Anchorage/Helical Pedestal and Cap: Guyed V Labor	$1,339,538	x	
Helical Pedestal and Stub Angle Cap: SS Lattice Material	$9,610,800		x
Helical Pedestal and Stub Angle Cap: SS Lattice Labor	$5,230,575	x	
Conductor: Material	$18,516,446		x
Conductor: Labor	$15,627,938	x	
Guard Structures for Installing Wires: Labor	$202,500	x	
OHGW: Material	$432,952		x
OHGW: Labor	$1,543,500	x	
OPGW Cable: Material	$1,795,126		x
OPGW Cable: Labor	$2,315,250	x	
Fiber Optic Splicing: Labor	$152,011	x	
OPGW Splice: Material	$142,267		x
Flight Diverters / Aerial Marker Balls: Labor	$267,805	x	
Flight Diverters / Aerial Marker Balls: Material	$173,305		x
Grounding: Material	$51,285		x
Grounding: Labor	$238,572	x	
BMP measures: Labor and Materials	$369,338	x	
Restoration: Labor and Materials	$1,084,949	x	
Receive, Unload and Yard Owner Materials	$1,434,375	x	

Material Storage Yards	$210,000	x	
Project Field Office and Support: Labor	$792,000	x	
Access Road Construction: Labor	$1,543,500	x	
ROW Clearing: Labor	$3,213,600	x	
OPGW Regeneration Site: Material	$450,000		x
OPGW Regeneration Site: Labor	$350,000	x	
Mobilization	$504,000	x	
SUBTOTAL A - COST PER SEGMENT >>>> (does not include major material items (other than foundation material))	**$70,912,490**		
Contractor Engineering and Support (includes Lidar)	$4,963,874	x	
Contractor Geotech Activities	$828,000	x	
Owner provided Construction / Structure Survey	$394,645		x
Owner Furnished Line Material	$58,576,438		x
Contractor - Construction Management	$2,836,500	x	
Contractor Insurance / bonding	$2,481,937	x	
Contingency	$14,182,498	x	
SUBTOTAL B - COST PER SEGMENT >>>>	**$84,263,892**		
TOTAL COST PER SEGMENT >>	**$155,176,382**		
COST PER KILOMETER >>>>>	$663,534		

Comparable 500 kV HVDC Cost Estimate

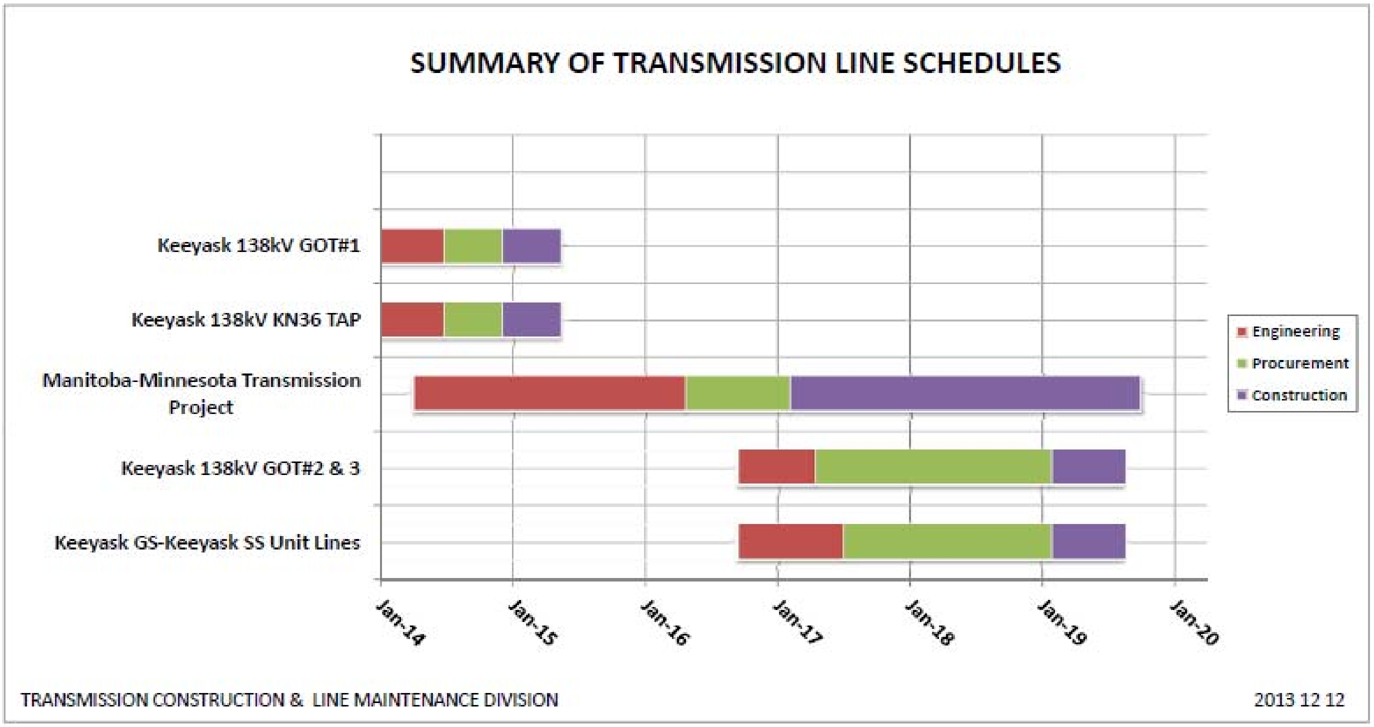
TYPICAL 500 kV HVDC LINE PROJECT

Triple Bundle Conductor		
Distance >>	700 Miles	1120 Kilometer
Install Self Supporting Lattice, Guyed Lattice and Tubular Steel Pole Structures, with Hardware & Insulator Assemblies: Labor, Equipment and Materials	$ 356,400,000	$ 356,400,000
Install Foundations and Anchorage: Labor, Equipment and Materials	115,300,000	115,300,000
Install Triple Bundle Conductors, Shield Wire and OPGW and Regen Sites: Labor, Equipment and Materials	216,400,000	216,400,000
Install Access Road, Construction Pads, BMP Measures, Resoration, Clearing, Etc: Labor, Equipment and Materials	$ 30,600,000	$ 30,600,000
Survey: Labor, Equipment and Materials	2,000,000	2,000,000
Provide Geotech,Field Offices, Multi Purpose Yards, Mob and DeMob Costs, Contingency, and Fixed Fee Adder Costs: Labor, Equipment and Materials	$209,000,000	$209,000,000
Routing, Permitting, Environmental Assessment, Property Acquisition	$144,140,000	$144,140,000
TOTALS >>	**$ 1,073,840,000**	**$ 1,073,840,000**
Cost - Mile/Km >>	**$ 1,534,057**	**$ 958,786**

Assumptions
Self Supported Lattice Towers - 50%
Guyed Lattice Towers - 45%
Tube Steel Mitigation Towers - 5%
1,450 Average Span

APPENDIX F

Transmission Project Summary Schedule



APPENDIX G

Transmission System Loss Estimates

Table A1- Tabulation of Load Losses for the Existing System and Preferred Option 2A

	Existing System with No BP III, No New US Tie Line)						Preferred Option 2A with BP III + New US Tie Line)							
Season	Summer Off-Peak		Summer Peak		Winter Peak		Summer Off-Peak		Summer Peak			Winter Peak		
US Export	0	2175	0	2175	0	878	0	2175	0	2175	2925	0	2175	2784
Generation	2529	4958	3747	6130	5215	6169	2531	4850	3746	6104	6926	5160	7613	8260
Incremental Generation		2429		2383		954		2319		2358	3180		2453	3100
Load	2435	2435	3577	3577	4910	4910	2425	2435	3577	3577	3577	4910	4910	4910
Load + Exports	2435	4610	3577	5752	4910	5788	2425	4610	3577	5752	6502	4910	7085	7694
Total Losses (AC + DC)	101	343	170	374	308	378	112	239	177	329	423	267	529	566
Export Losses	0	242	0	204	0	70	0	127	0	152	246	0	262	299
System Losses, Percent of Load	4.2%	7.4%	4.8%	6.5%	6.3%	6.5%	4.6%	5.2%	5.0%	5.7%	6.5%	5.4%	7.5%	7.4%
Incremental Losses, Percent of Export		10.0%		8.6%		7.4%		5.5%		6.5%	7.8%		10.8%	9.7%
Total Bipole Loading MW	1578	3541	1589	3541	3046	3541	1534	2740	2511	3916	4724	2908	5320	5570.
Total Bipole Losses MW	38.9	194	39.2	194.1	143.5	194.1	24.8	78.7	65.6	160.0	232.7	88.8	295.	323
Incremental Bipole Losses for US Exports, MW	0	155	0	155	0	51	0	54	0	94	167	0	207	235

Table 1 Definitions:

- Incremental generation =MH generation at a specified US export level minus MH generation with no US exports.
- Export losses = difference of the losses at a specified US export level minus the losses for no US exports.
- Total Bipole Loading = the sum of power flowing into Bipoles I, II, and III
- Total Bipole Losses =sum of power flowing from the ac system into each Bipoles converters minus the power delivered to the ac system at the Bipole inverters.

Table A2—Power Flow Cases supplied by Manitoba Hydro

Cases without New Tie Line and without BPIII	Generation	BP1	BP2	BP3	Load	Losses
No US tie line-No BPIII Summer Peak 2020 Load 0 MW Export to US	3747	744.8	844.2	0	3577	170
No US tie line-No BPIII Summer Peak 2020 Load 2175 MW Export to US	6130	1658.2	1883.2	0	3577	374
No US tie line-No BPIII Summer Off Peak 2020 Load 0 MW Export to US	2529	739.6	838.4	0	2435	101
No US tie line-No BPIII Summer Off Peak 2020 Load 2175 MW Export to US	4958	1658.2	1883.2	0	2435	343
No US tie line-No BPIII Winter Peak 2020 Load 0 MW Export to US	5215	1426.8	1619.6	0	4910	308
No US tie line-No BPIII Winter Peak 2020 Load 878 MW Export to US	6169	1658.2	1883.2	0	4910	378

Table A3—Power Flow Cases supplied by Manitoba Hydro

Cases without New Tie Line and with all Bipoles In Service	Generation	BP1	BP2	BP3	Load	Losses
No US tie line-Summer Peak 2020 Load 0 MW Export to US	3732	791.2	853.6	853	3577	175
No US tie line-Summer Peak 2020 Load 2175 MW Export to US	6089	1235.4	1332.8	1333.6	3577	335
No US tie line-Summer Off Peak 2020 Load 0 MW Export to US	2540	410.6	443	442.2	2425	118
No US tie line-Summer Off Peak 2020 Load 2175 MW Export to US	4870	853	921	919	2434	259
No US tie line-Winter Peak 2020 Load 0 MW Export to US	5182	1254	1353	1353.8	4901	352
No US tie line-Winter Peak 2020 Load 2175 MW Export to US	7633	1688.2	1823.8	1826.2	4910	545

Table A4—Power Flow Cases supplied by Manitoba Hydro

Cases with the Preferred Plan	Generation	BP1	BP2	BP3	Load	Losses
Preferred Plan Summer Peak 2020 Load 0 MW Export to US	3746	795.4	858.2	857.6	3577	177
Preferred Plan Summer Peak 2020 Load 2175 MW Export to US	6104	1240	1338	1338.6	3577	329
Preferred Plan Summer Peak 2020 Load 2925 MW Export to US	6926	1495.4	1613.4	1615.6	3577	423
Preferred Plan Summer Off Peak 2020 Load 0 MW Export to US	2531	486.2	524.6	523.6	2435	112
Preferred Plan Summer Off Peak 2020 Load 2175 MW Export to US	4850	867.8	936.4	935.8	2435	239
Preferred Plan Summer Off Peak 2020 Load 2925 MW Export to US	5671	1124.2	1212.8	1213.2	2435	309
Preferred Plan Winter Peak 2020 Load 0 MW Export to US	5160	921.2	994	993.6	4910	267
Preferred Plan Winter Peak 2020 Load 2175 MW Export to US	7613	1683.8	1816.8	1820.2	4910	529
Preferred Plan Winter Peak 2020 Load 2784 MW Export to US	8260	1762.4	1902.4	1905.8	4910	566