Needs For and Alternatives To

APPENDIX 13.1

NFAT Reliability Evaluation

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NFAT RELIABILITY EVALUATION

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1. Introduction

One of the important factors that should be considered in evaluating power system enhancement alternatives is the reliability benefit associated with each option. Risk based or probabilistic reliability evaluation is widely accepted in power industry to determine the ability of a power system to perform its intended function. The numerous uncertainties facing industry particularly in recent years drive a need to use probabilistic evaluation methodology in power system reliability evaluations. The electric power industry particularly in North America is, therefore, moving towards using a probabilistic approach [1-4]. In 2004, the Planning Committee (PC) of the North American Electric Reliability Council (NERC) recommended that each NERC region or sub-region should establish a resource adequacy criterion (or criteria) based on probabilistic metrics such as the loss of load expectation (LOLE) or the loss of load probability (LOLP) and perform probabilistic resource adequacy assessment periodically in order to demonstrate the regional or sub-regional resource adequacy requirements are being satisfied [1]. In 2008, the Reliability First Corporation (RFC) developed and approved a standard in order to establish common criteria in resource adequacy evaluation for the RFC region. The standard puts in force the use of a probabilistic approach in resource adequacy evaluation [2] and approved by the Federal Energy Regulatory Commission of the United States of America [3]. In 2010, NERC's Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) recommended a common generation and transmission reliability modeling methodology and a common set of probabilistic reliability indices for the purpose of resource adequacy assessment across NERC [4]. The GTRPMTF recommendations particularly emphasize on the inclusion of major transmission restrictions in resource adequacy evaluation [4]. In 2012, NERC initiated a mandatory probabilistic reliability assessment to compliment the NERC long term reliability assessment (LTRA) [5].

Power system reliability evaluation has been extensively developed using probabilistic methods and various indices can be used to measure the reliability associated with a particular power system [6, 7, 8]. Currently the most commonly used index is the LOLE [6, 7, 8]. The LOLE measures the likelihood of the system not being able to carry the desired load. Generally each utility sets its own level of acceptable criterion but a LOLE of 0.1 days/year on an annual base is unofficially used across North America particularly for resource adequacy assessment [1, 2, 9]. As the LOLE index is not often easily interpreted and understood, therefore it is sometimes translated into another reliability index of Peak Load Carrying Capability (PLCC) [6]. The PLCC is the maximum system peak load that can be carried by the system without violating the acceptable LOLE criterion.

The studies described in this report examine the reliability of Manitoba Hydro's preferred power resource development plan and its alternatives [10] using a probabilistic assessment model. The model employs a Monte Carlo simulation technique which has been widely accepted and used in electric power system reliability assessments for years [11]. The probabilistic assessment presented in this report provides reliability projections for a 25-year planning horizon from 2017 to 2041. Each of the alternatives evaluated in this study is briefly described as follows:

Preferred Plan: The Keeyask generating station with a 2019/2020 In-Service-Date (ISD), the Conawapa Generating Stations with an ISD of 2024/2025, their associated domestic AC transmission facilities and a new Canada-USA transmission interconnection of 750 MW/750 MW (Export/Import) with an ISD of 2019/2020. The addition of 245 MW simple cycle gas turbine (SCGT) in 2041.

All Gas: The addition of 245 MW SCGT in 2022, 2025, 2028 and 2034 respectively and the addition of 357 MW combined cycle gas turbine (CCGT) in 2031, 2037 and 2040 respectively.

Keeyask Gas: The Keeyask generating station with an ISD of 2022/2023 followed by the addition of 245 MW SCGT in 2029 and 2032 respectively and the addition of 357 MW CCGT in 2034, 2038 and 2041 respectively.

Keeyask Gas Tie: The Keeyask generating station with an ISD of 2019/2020 followed by the addition of 245 MW SCGT in 2024 and 2029 respectively and the addition of 357 MW CCGT in 2032, 2038 and 2041 respectively. This plan also includes a new Canada-USA transmission interconnection of 250 MW/50 MW (Export /Import) with an ISD of 2019/2020.

The addition of Keeyask, Conawapa generating stations and the new Canada-USA transmission interconnection are in for a complete calendar year.

2. Analysis Tool and Evaluation Methodology

The fundamental approaches used to calculate reliability indices in a probabilistic evaluation can be generally described as being either direct analytical evaluation or Monte Carlo simulation. Analytical techniques represent the system by analytical models and evaluate the system reliability indices from these models using mathematical solutions. Reliability assessment of large interconnected power systems using analytical methods mandates numerous approximations and assumptions that can often lead to inaccurate results. The Monte Carlo method can avoid some of these problems and provide more accurate results by simulating the actual process and the random behavior of the system.

2.1 Brief Description of MARS Program

The computing tool used for the calculation of the reliability indices in this study is the Multi-Area Reliability Simulation (MARS) program developed by General Electric Company [11]. It uses a sequential Monte Carlo simulation technique to calculate the reliability indices of a generation system that is made up of a number of interconnected areas. Generating units and an hourly load profile are assigned to each area. MARS performs a chronological hourly simulation of the interconnected system, comparing the hourly load in each area to the total available generation in the area taking into account the random outages of thermal generating units, availability of interconnection tie lines and the energy limited nature of hydro and wind resources. If an area's available generation, including assistance from other areas, is less than its load, the area is in a loss of load state for that hour and statistics required to compute the reliability indices are collected. This process is continued for all of the hours in a sample year. The Monte Carlo simulation is repeated for a large number of sample years in order to obtain the desired level of accuracy. The accuracy of the indices estimated by a simulation technique is normally improved by increasing the number of sample years. It is, however, not practical to run the simulation for a very large number of samples in order to achieve an extremely high level of accuracy. The number of samples used in the studies described in this report is 5,000 for each year depending on the type of the study and the case representing a particular resource development scenario. A detailed description of the simulation program can be found in [11].

2.2 Assessment Methodology

MH proposed a multi-area approach for modeling HVdc transmission in MARS for power system reliability evaluation [12]. In the proposed approach each transmission component of a HVdc link is represented as a fictitious area. The component forced outage events are modeled by simulating the forced unavailability of transmission interfaces between these fictitious areas. This approach is used in the modeling and evaluation of reliability performance of the alternatives considered in the studies described in this report. A summary of the HVdc system reliability data used in this study is provided in Appendix A. Figure 1 shows the MARS representation of the MH system which is common to all options described previously.

Except for the two physical areas of the MH Northern Collector System and the MH Southern System, all of the other areas are fictitious areas with no load and generation. These fictitious areas are connected through unidirectional interfaces. The forced outage of each fictitious area can be simulated by random failures of interfaces downstream of that area. The actual and fictitious areas and interfaces connecting these areas shown in Figure 1 are briefly described as follows:

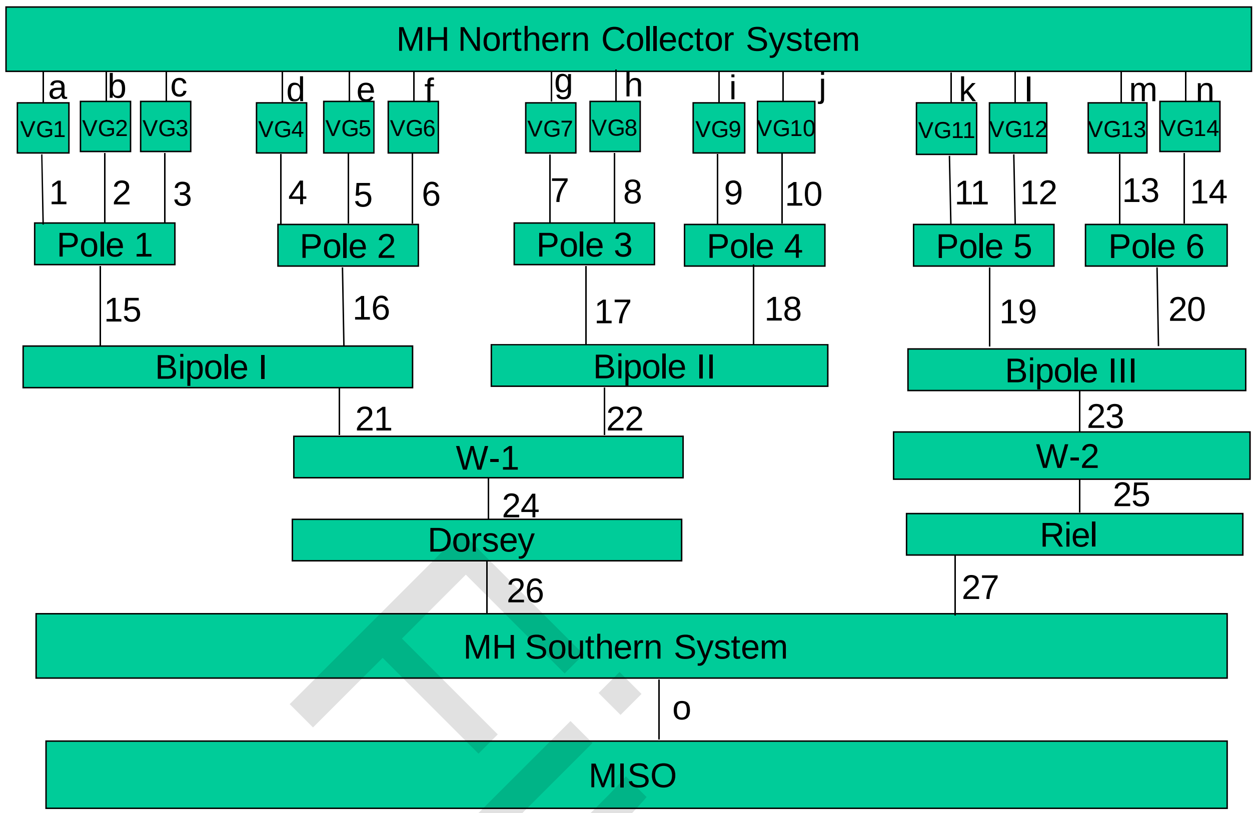

Figure 1: Manitoba Hydro System Representation in MARS

MH Northern Collector System: There is no load in this area and generation includes the existing and future hydraulic generation, for example the Keeyask and Conawapa generating stations in the Northern Collector System which is connected to the HVdc transmission. The interfaces connecting this area to Areas VG1 through VG14 (Interfaces a through n) are assumed to be 100% reliable.

VG1-VG14: These MARS fictitious areas are defined for modeling HVdc system valve group outage events by simulating random failures of Interfaces 1 to 14.

Pole 1-6: These MARS fictitious areas are defined for modeling HVdc system single pole failure events by simulating random outages of Interfaces 15 to 20.

Bipole I, Bipole II and Bipole III: These MARS fictitious areas were set for modeling HVdc system bipole outages by simulating random failures of Interfaces 21-23.

W-1 and W-2: These are MARS fictitious areas for modeling severe weather related outages of Bipole I, Bipole II and Bipole III by simulating random forced outage of Interfaces 24 and 25.

Dorsey: This is a MARS fictitious area for modeling Dorsey converter station outage through forced unavailability of Interface 26.

Riel: This MARS fictitious area can be used to model Riel converter station forced unavailability by simulating outage of Interface 27.

MH Southern System: This area includes all of Manitoba load, Winnipeg River Generating System, all wind farms, other hydraulic generating stations connected through AC transmission to Winnipeg including Wuskwatim, Jenpeg, Grand Rapids and Laurie River, Brandon and Selkirk units and all the future gas additions. The program assumes that there are no transmission limits within this area. The Interface connecting this area to Area MISO (Interface o) is assumed to be 100% reliable.

MISO: This area includes all load and generation in western MISO system. The program assumes that there are no transmission limits within this area.

3. Major Assumptions

The projected available energy for each hydraulic generating station is calculated using the Splash program and inputs to the MARS program. All hydro resources are modeled as energy limited resources at a typical water condition represented by 1984 flow year. The load model used in the study was obtained with reference to the 2010/2011 Manitoba Hydro peak load forecast for 2010/2011-2030/2031 [13]. The forecast peak loads used in this study for the period from 2017-2041 are provided in Appendix B. The 8760 point hourly load records of a typical year (2002) were used to model the annual load curve shape. It is assumed in this study that interconnected assistance is possible only from the USA (Western MISO Region) but not from neighboring Canadian utilities because Manitoba Hydro has no planning or operating reserve sharing agreement with these utilities and there is limited firm transmission capability available from both Saskatchewan and Ontario to Manitoba Hydro. The following major assumptions are made in the studies described in this report:

1) Available energy from hydraulic stations for the Preferred-Plan is represented by the energy predicted for the 2022 load year for the planning horizon from 2017-2024 and the 2028 load year for the planning horizon 2025-2041 respectively.
2) Available energy from hydraulic stations for the All Gas and the Keeyask Gas Tie options is represented by the energy predicted for the corresponding 2022 load year for the entire 25-year planning horizon.
3) Available energy from hydraulic stations for the Keeyask Gas option is represented by the energy predicted for the 2028 load year for the entire 25-year planning horizon.
4) All northern rectifier stations including Radisson, Henday and Keewatinoow are assumed to be 100% reliable.
5) A 7-step normally distributed load forecast uncertainty (LFU) with 5% standard deviation as shown in Appendix C is considered for respecting the uncertainties associated with the forecast peak load.

6) Up to 1450 MW, 750 MW and 700 MW import capability from MISO were modeled respectively for the Preferred Plan, the Keeyask Gas Tie and the other two options. Assistance from MISO through the Canada-USA transmission interface is available only if the reliability of MISO system is better than 0.1 days/year of LOLE.
7) A 2300 MW Bipole III with ISD of 2017 for all options and an additional 100 MW AC transmission from North to South with an ISD of 2025 for the Preferred-Plan.
8) HVdc system component reliability data were based on the outage estimates for the economic study regarding the sizing of Bipole III. The data are shown in Appendix A.
9) Bipole I, Bipole II and Bipole III weather related outages due to tornado occurs only in summer (June, July and August) with a 1 in 17 year return period and due to wind/storm occurs only in winter (December, January and February) with a 1 in 50 year return period [14].
10) Bipole I, Bipole II and Bipole III weather related outage duration is assumed to be 6 weeks [14].
11) Both Dorsey and Riel converter stations are assumed to have the same outage frequency and duration. It is assumed that the event can occur any time of a year with a 1 in 200 year return period and the average duration is assumed to be a year [14].
12) All SCGT units are modeled as two-state units with 5% forced outage rate (FOR) [15]. All CCGT units are modeled as three-state units assuming each of them is consisting of a host SCGT with 5% FOR coupled with a single heat recovery steam generator (HRSG) with 2% FOR. The HRSG will be forced out due to either the forced outage of the host SCGT or an independent forced outage of the HRSG itself. The state space diagrams of a CCGT are provided in Appendix D of this report.
13) All export and import contracts are modeled as deterministic load modifier. Export contracts are scheduled as 7x4 schedules and import contracts are assumed to be available with 100% capacity factor in winter.

4. Loss of Load Expectation

The relative reliability level of the Preferred Plan and its alternatives is determined based on a series of comparative analyses for a 25-year planning horizon from 2017 to 2041. The 2017 is chosen as the first year by which Bipole III is assumed to be in service. The system reliability level of the alternatives examined in this study is compared in terms of LOLE in days/year and the results are shown in Figure 2. It can be seen from Figure 2 that the system LOLE over the study period is not constant but varies with time depending on the demand and resource scenarios. Increases in the LOLE in Figure 2 are a result of load growth, while decreases in LOLE are a result of the addition of resources and/or increase in transmission capacity. Figure 2 also shows that the reliability performance of the Preferred Plan is better than those of the other alternatives.

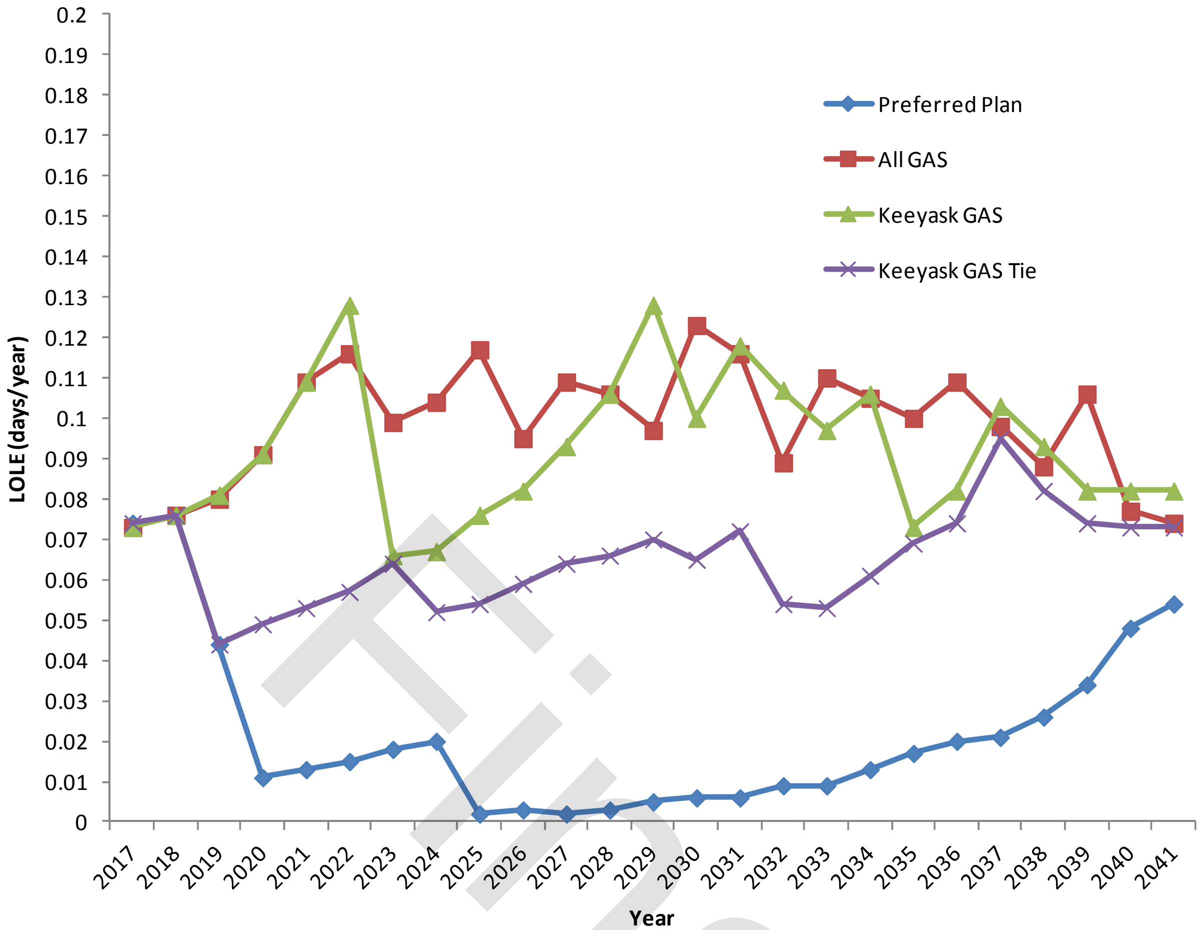

Figure 2: Comparison of Loss of Load Expectation

5. Reliability Worth

A comparison of system reliability in terms of the EUE index and associated risk costs (or cost of unnerved energy) for the Preferred Plan and its alternatives is presented. The basic idea is that the system enhancement options improve system reliability or reduces system risk. The degree of improvement of each alternative is, however, different. The relative reduction in risk cost for each option can be evaluated by comparing the associated risk cost of these alternatives. The annual risk cost for each option is obtained by converting the index of the EUE into a monetary value using an interrupted energy assessment rate (IEAR) [6] of $10/kWh in constant 2017 dollars. The IEAR of $10/kWh is chosen with reference to a study on the cost of unserved energy commissioned by MH [16]. The relative reliability benefit of the Preferred Plan is evaluated in terms of reduction in risk cost as compared to other alternatives. The reduction in risk cost is expressed in 2017 present worth. Detailed risk cost calculations for both the base case and the sensitivity cases are provided in Appendix E of this report. Figure 3 summarizes the results presented in Appendix E. It can be seen from Figure 3 that the Preferred Plan is worth $101 million more than the All Gas option, $105 million more than the Keeyask Gas option, and $56 million more than the Keeyask Gas Tie option. It should be noted that the risk cost estimates in this study are based on an IEAR of $10/kWh. It is not an exact value, but it is a reasonable assumption. If a different IEAR is used, the risk cost reductions would be different.

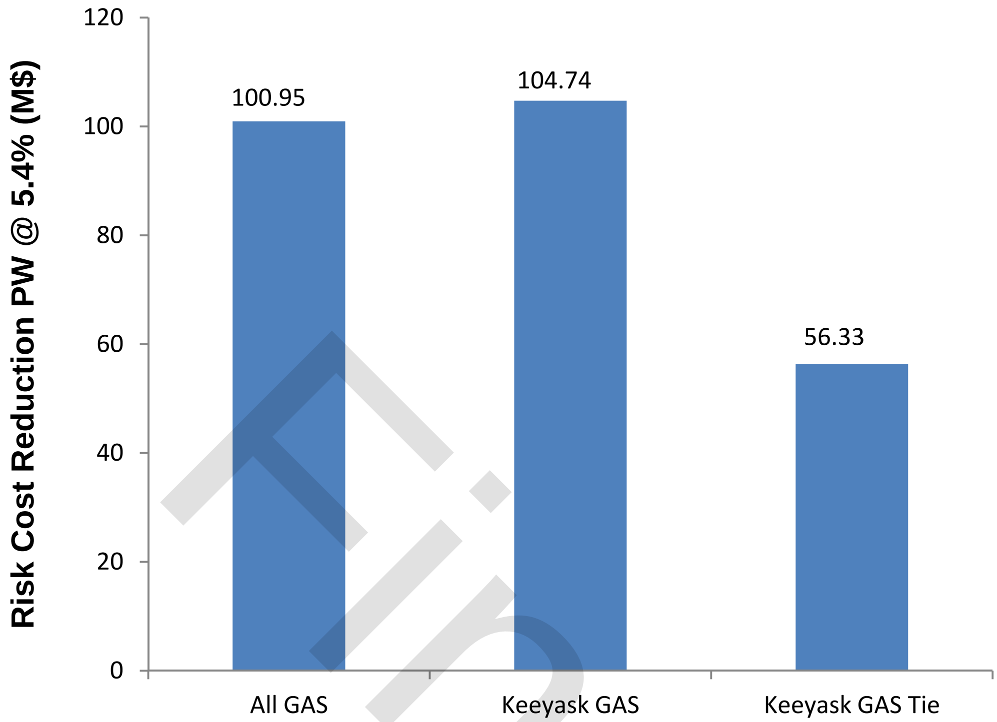

Figure 3: Relative Worth of the Preferred Plan as Compared to the Alternatives

6. Peak Load Carrying Capability

As noted earlier that the LOLE index can be translated into another reliability index of PLCC [6]. The maximum peak load that can be carried by a system while satisfying a specified reliability criterion is known as the PLCC. The reliability criterion chosen for this study is the LOLE of 0.1 days/year. The PLCC analysis is conducted for the entire planning horizon for the Preferred Plan and its alternatives. Figure 4 compares the system PLCC for the Preferred Plan and its alternatives at the LOLE criterion of 0.1 days. The projected peak load for the evaluation time horizon is also shown in Figure 4. It can be seen from Figure 4 that there are deficits in PLCC as compared to the forecast peak load for the Keeyask Gas option and All Gas option. The maximum deficit for the Keeyask Gas option is approximately 93 MW in 2029 and it is about 102 MW in 2036 for the All Gas option. It can be concluded from the PLCC analysis that on average the Preferred Plan can carry approximately 15% more load than the All Gas and the Keeyask Gas options and it can carry roughly 10% more load than the Keeyask Gas Tie option.

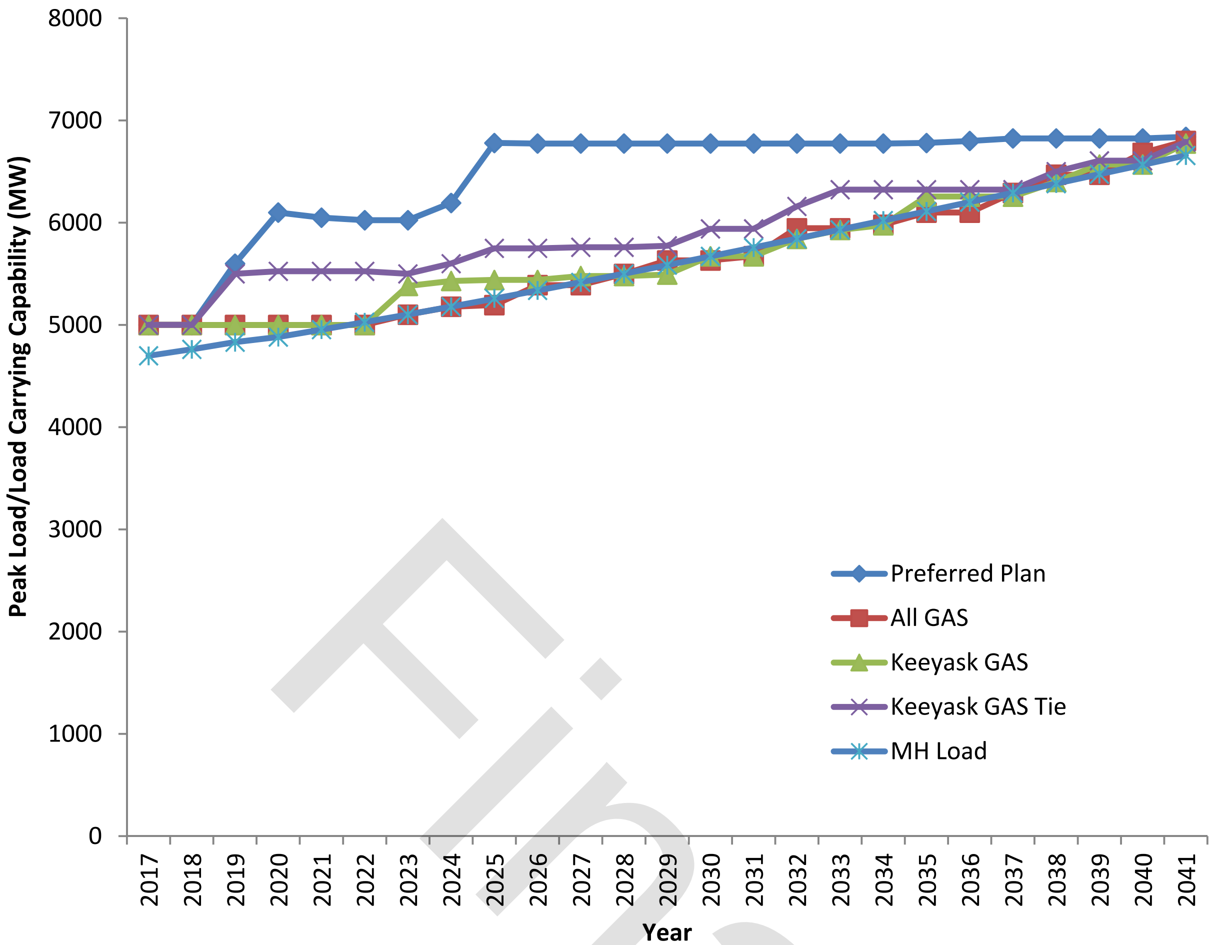

Figure 4: Comparison of Peak Load Carrying Capability

7. Summary and Conclusions

The methodology, models, assumptions and results of the reliability evaluation on the preferred power resource development plan and its alternatives are presented. The reliability assessment employs a probabilistic simulation technique which is based on a multi-area Monte Carlo Simulation approach. The Manitoba Hydro system is represented as a number of sub-areas in the multi-area simulation model in which each transmission component of a HVdc link is represented as a fictitious area. The HVdc component forced outage events are modeled by simulating the forced unavailability of transmission interfaces between these fictitious areas. The western MISO system is modeled as the external area to the Manitoba Hydro system.

A series of comparative studies is performed to compare the relative reliability level of the Preferred Plan and its alternatives in terms of LOLE, reliability worth and PLCC. The study results indicate that the reliability level of the Preferred Plan is significantly superior to that of its alternatives. Analyses on reliability worth show that the Preferred Plan is worth $101 million more than the All Gas option, $105 million more than the Keeyask Gas option, and $56 million more than the Keeyask Gas Tie option under current assumptions. Peak load carrying capability assessment shows that there are some deficits in all the alternatives to the Preferred Plan. On average, the Preferred Plan is able to carry approximately 10-15% more load than its alternatives. It should be, however, noted that the focus of the studies described in this report is to compare the relative reliability of the resource development options but not the absolute reliability level of these alternatives.

REFERENCES

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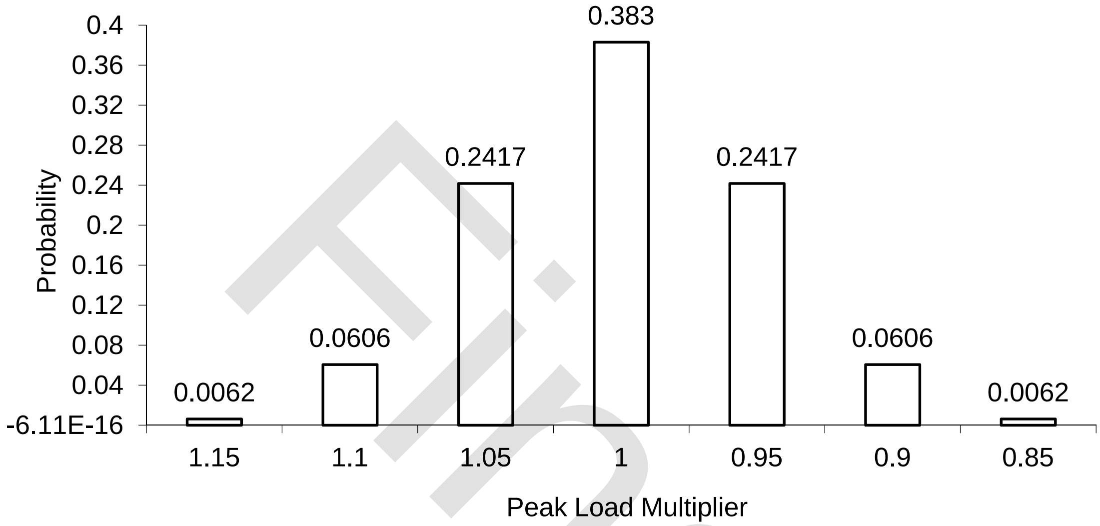
Appendix A: A Summary of HVdc System Reliability Data

Parameter	Value
Bipole I Valve Group Failure Rate	5.23 f/year
Bipole I Valve Group Outage Duration	19.64 h
Bipole I Pole Failure Rate	5.75 f/year
Bipole I Pole Outage Duration	1.21 h
Bipole I Bipole Failure Rate	0.65 f/year
Bipole I Bipole Outage Duration	0.79 h
Bipole II Valve Group Failure Rate	8.07 f/year
Bipole II Valve Group Outage Duration	9.09 h
Bipole II Pole Failure Rate	6.02 f/year
Bipole II Pole Outage Duration	2.16 h
Bipole II Bipole Failure Rate	0.74 f/year
Bipole II Bipole Outage Duration	1.31 h
Bipole III Valve Group Failure Rate	6.62 f/year
Bipole III Valve Group Outage Duration	10.06 h
Bipole III Pole Failure Rate	6.36 f/year
Bipole III Pole Outage Duration	1.85 h
Bipole III Bipole Failure Rate	0.66 f/year
Bipole III Bipole Outage Duration	1.05 h
Weather Related Outage Frequency Due to Tornado (occur in summer only)	1 in 17 years
Weather related Outage Frequency Due to wind/storm (occur in winter only)	1 in 50 years
Weather Related Outage Duration	6 weeks
Converter Station Outage Frequency	1 in 200 years
Converter Station Outage Duration	1 year

Appendix B: Peak Load Forecast for the Study Period

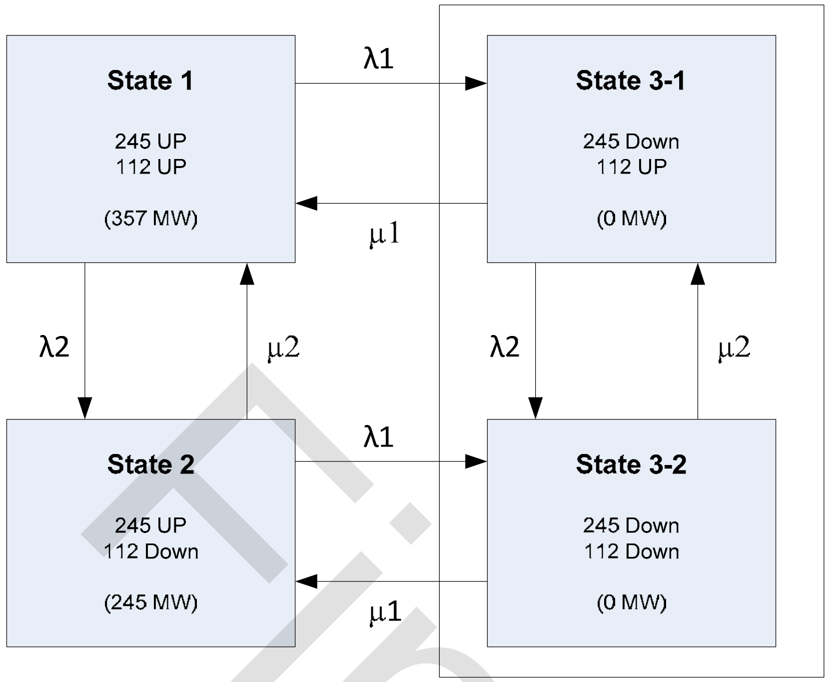
Planning Year	Forecast Peak Load (MW)
2017	4699
2018	4762
2019	4832
2020	4882
2021	4955
2022	5027
2023	5101
2024	5179
2025	5260
2026	5339
2027	5417
2028	5499
2029	5586
2030	5672
2031	5758
2032	5843
2033	5931
2034	6022
2035	6112
2036	6202
2037	6292
2038	6383
2039	6475
2040	6567
2041	6658

Appendix C: A seven-step normally distributed Load Forecast Uncertainty Model

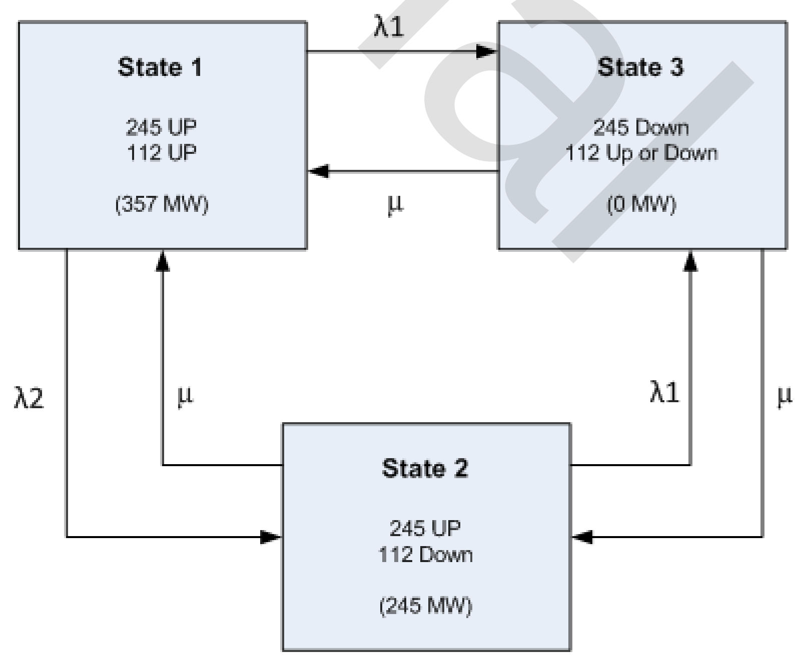


Appendix D: State Space Model of CCGT

(4 States reduced to 3 States)



Let : $\mu 1 = \mu 2 = \mu$



Appendix E: Comparison of EUE Index and Risk Cost Reduction

Table E-I: EUE Index (MWh/year) and Risk Cost Reduction (M$/year) for the Preferred Plan and the All Gas Option

Year	All Gas (MWh)	Preferred Plan (MWh)	Difference in EUE (MWh)	Difference in Risk Cost (M$)
2017	830	830	0.00	0
2018	888.7	888.7	0.00	0
2019	930	360.6	569.4	5.69
2020	1237.1	43.8	1193.3	11.93
2021	1221.4	55.3	1166.1	11.66
2022	1029.3	68.8	960.5	9.61
2023	1042.5	80.6	961.9	9.62
2024	1232.3	113.1	1119.2	11.19
2025	948.2	12.9	935.3	9.35
2026	969	16	953	9.53
2027	1055.5	20.3	1035.2	10.35
2028	958.5	11.3	947.2	9.47
2029	910.9	31.8	879.1	8.79
2030	1014.2	33.7	980.5	9.81
2031	682.8	35.4	647.4	6.47
2032	740.2	37.7	702.5	7.03
2033	777.6	59.8	717.8	7.18
2034	624.1	71.6	552.5	5.53
2035	643.9	84	559.9	5.60
2036	813	101.7	711.3	7.11
2037	473.2	123.8	349.4	3.49
2038	489.3	159	330.3	3.30
2039	574.8	198.6	376.2	3.76
2040	447.6	270	177.6	1.78
2041	377.6	220.6	157	1.57
2017 Present Worth @5.4% Discount Rate				**100.95**

Table E-2: EUE Index (MWh/year) and Risk Cost Reduction (M$/year) for the Preferred Plan and the Keeyask Gas Option

Year	Keeyask Gas (MWh)	Preferred Plan (MWh)	Difference in EUE (MWh)	Difference in Risk Cost (M$)
2017	830	830	0.00	0.00
2018	888.7	888.7	0.00	0.00
2019	960.4	360.6	599.8	6.00
2020	1246.3	43.8	1202.5	12.03
2021	1252.6	55.3	1197.3	11.97
2022	1344.4	68.8	1275.6	12.76
2023	703.5	80.6	622.9	6.23
2024	846.5	113.1	733.4	7.33
2025	844.2	12.9	831.3	8.31
2026	922.8	16	906.8	9.07
2027	1007.9	20.3	987.6	9.88
2028	1356.2	11.3	1344.9	13.45
2029	1041.6	31.8	1009.8	10.10
2030	947.7	33.7	914	9.14
2031	1080.1	35.4	1044.7	10.45
2032	950.1	37.7	912.4	9.12
2033	940.6	59.8	880.8	8.81
2034	637.9	71.6	566.3	5.66
2035	597.9	84	513.9	5.14
2036	739.5	101.7	637.8	6.38
2037	784.3	123.8	660.5	6.61
2038	497.6	159	338.6	3.39
2039	528.7	198.6	330.1	3.30
2040	612.6	270	342.6	3.43
2041	353.8	220.6	133.2	1.33
2017 Present Worth @5.4% Discount Rate				**104.74**

Table E-3: EUE Index (MWh/year) and Risk Cost Reduction (M$/year) for the Preferred Plan and the Keeyask Gas Tie Option

Year	Keeyask Gas Tie (MWh)	Preferred Plan (MWh)	Difference in EUE (MWh)	Difference in Risk Cost (M$)
2017	830	830	0.00	0.00
2018	888.7	888.7	0.00	0.00
2019	931.8	360.6	571.2	5.71
2020	502.2	43.8	458.4	4.58
2021	477	55.3	421.7	4.22
2022	532.7	68.8	463.9	4.64
2023	578	80.6	497.4	4.97
2024	547.4	113.1	434.3	4.34
2025	456.5	12.9	443.6	4.44
2026	519	16	503	5.03
2027	580.9	20.3	560.6	5.61
2028	718.5	11.3	707.2	7.07
2029	496.8	31.8	465	4.65
2030	544.2	33.7	510.5	5.11
2031	612.6	35.4	577.2	5.77
2032	446.4	37.7	408.7	4.09
2033	371.1	59.8	311.3	3.11
2034	413.7	71.6	342.1	3.42
2035	483.6	84	399.6	4.00
2036	658.7	101.7	557	5.57
2037	651.4	123.8	527.6	5.28
2038	391.9	159	232.9	2.33
2039	429.1	198.6	230.5	2.31
2040	543.3	270	273.3	2.73
2041	277.8	220.6	57.2	0.57
2017 Present Worth @5.4% Discount Rate				**56.33**