MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

CAPITAL EXPENDITURE FORECAST

INDEX

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

CAPITAL EXPENDITURE FORECAST

4.0 OVERVIEW

Tab 4 summarizes the Capital Expenditure Forecast (CEF14) and the capital investments required to meet the growing energy needs of Manitoba and to replace aging utility assets.

Sections 4.1 and 4.2 discuss Manitoba Hydro's Capital Expenditure forecast for Electric Operations (CEF14). Section 4.3 provides an overview of major new generation and transmission capital expenditures. Section 4.4 provides an overview of sustaining capital expenditure requirements. Section 4.5 summarizes the assets that are projected to enter into service. Section 4.6 provides more detailed information with respect to the condition of Manitoba Hydro's assets and future sustaining capital requirements.

The key conclusions with respect to Tab 4 are:

1. Historically, the reliability performance of Manitoba Hydro's electric system has been excellent, but has recently begun to degrade with the condition of the Corporation's assets more and more contributing to the decline in reliability.

2. Manitoba Hydro is entering a period of extensive capital investment to meet the growing energy requirements of Manitoba, to replace aging utility assets and address increased capacity needs on the system.

3. Manitoba Hydro's projected costs and revenue requirements are significantly increasing due to the investment in assets and are the key factors driving the need for rate increases.

4. The proposed 3.95% rate increases are the minimum required to continue to deliver a reliable energy supply to Manitobans, to which they are accustomed, and fund Power Smart Programs to assist customers in meeting their energy needs.

5. The key reliability risks associated with inadequate funding as a result of rate increases lower than 3.95% include:
    i. Reliability would degrade further; outages would be longer and more frequent;
    ii. Increased safety risks to public and staff; and
    iii. Increased maintenance and emergency costs.

4.1 CAPITAL EXPENDITURE FORECAST

The Capital Expenditure Forecast is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the Province. Expenditures included in the CEF provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner. A copy of CEF14 is included as Appendix 4.1.

The CEF for the current year and subsequent nineteen year period is submitted annually to the MHEB for approval. Since capital construction projects typically span several years, each year's CEF is presented to the MHEB as a revision to the previous year's approved CEF. In addition to the identification of new projects, changes to previously approved projects are also identified.

Business Units' initiate capital expenditure proposals to meet energy load growth demands within the Province, to respond to specific customer service extension requirements, to improve the efficiency and reliability of the energy delivery system or to take advantage of revenue generating opportunities in the export market. Once the need for a capital project is identified, a Capital Project Justification (CPJ) is prepared by the initiating department. The CPJ contains detailed information relative to each project such as system load growth statistics, business case analysis, risk assessment, and other pertinent details. The requirement and justification for the project is reviewed at the department, division and business unit level before the CPJ is forwarded to either the responsible Vice-President or the Executive Committee of Manitoba Hydro for approval. Projects greater than $50 million require approval of the Executive Committee, items below $50 million are approved at the Business Unit level. Depending on the nature and complexity of the project, the CPJ may also be advanced to Manitoba Hydro's Planning Review Committee.

CPJs are scrutinized to confirm the need for the project based on the following criteria: system reliability, safety, efficiency, customer service, environmental impacts and corporate profitability. Further consideration is given to the priority of proposed projects and whether projects of lesser priority can be displaced so overall funding levels remain within the MHEB approved CEF limits. Risks of not proceeding with the project are also assessed based on information provided within the CPJ. All projects are assessed for environmental impacts.

During the year, actual expenditures on projects are reported monthly to Business Unit Management and the Executive Committee. Variance explanations are provided for any significant variances from the approved CEF. This information is also reported to the MHEB at their regularly scheduled meetings.

Each Vice-President oversees the portfolio of capital projects within their approved target. Advancement and deferral of capital projects occurs throughout the year to manage within annual approved funding levels. Available capital is allocated to asset categories in a prioritized manner to mitigate overall operational and financial risk.

4.2 ELECTRIC OPERATIONS CAPITAL EXPENDITURE FORECAST (CEF14)

The CEF includes Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability and a number of specifically identified large projects or "major items" as well as numerous unspecified smaller projects referred to as "base items." Major and base items together comprise sustaining capital.

Figure 4.1 below provides a breakdown of Major New Generation and Transmission and sustaining capital by Business Unit over the 2014/15 to 2016/17 timeframe and the 10 year forecast period.

Figure 4.1 Summary of Electric Capital Expenditure Forecast CEF14

(in millions of $)	2014/15	2015/16	2016/17	Cumulative to 2023/24*
Major New Generation & Transmission	**1 452**	**1 914**	**2 463**	**11 671**
Sustaining Capital (Major & Base)	**571**	**577**	**610**	**5 661**
Generation Operations	132	132	132	1 336
Transmission	125	125	125	1 350
Customer Service & Distribution	236	241	268	2 212
Customer Care & Marketing	3	4	4	39
Human Resources & Corporate Services	75	75	55	597
Finance & Regulatory	0	0	0	2
Target Adjustment	-	-	25	125
Total Electric	**2 023**	**2 491**	**3 073**	**17 332**

Figure 4.2 below illustrates projected capital expenditures by major category to 2023/24.

Figure 4.2 Capital Expenditure Forecast- Electric Operations

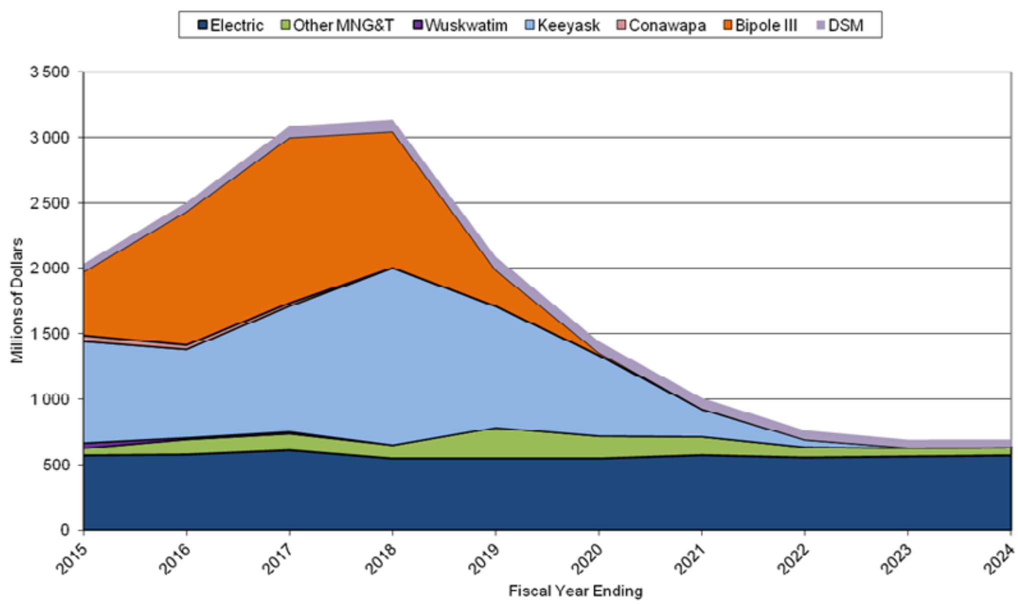


Figure 4.3 provides a summary of CEF14, related to Electric operations, and shows a reduction of $3.5 billion for the 10 year period to 2023/24 as compared to CEF13.

Figure 4.3 Change in Cost Flow from CEF13 to CEF14 ($ millions)

Electric Only	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
CEF13	**2 013**	**2 422**	**2 496**	**2 326**	**2 030**	**1 845**	**1 337**	**1 719**	**2 281**	**2 322**	**20 792**
Incr (Decr)	9	69	577	799	48	(414)	(339)	(968)	(1 601)	(1 641)	(3 460)
CEF14	**2 023**	**2 491**	**3 073**	**3 125**	**2 078**	**1 432**	**999**	**751**	**679**	**681**	**17 332**

The decrease of $3,460 million in capital expenditures over the ten year forecast period is comprised of the following:

Figure 4.4 Breakdown of CEF14 10 Year Cost Flow Change

	Total Projected Cost	**10 Year Increase (Decrease)**
	($ Millions	
Conawapa - Generation	397	(6 052)
Bipole III - Transmission Line	1 655	407
Bipole III - Converter Stations	2 675	881
Bipole III - Collector Lines	260	71
Keeyask - Generation	6 496	349
Demand Side Management	NA	463
Base Capital Target	NA	422
Additional North South Trasmission	-	(90)
Gillam Redevelopment and Expansion Program	266	(77)
Dorsey 230KV Zone Building	-	(63)
Slave Falls Major Overhauls	126	(63)
Pointe du Bois Powerhouse Rebuild	1 852	(19)
New Adelaide Station - 66/12kV	62	62
Other System Upgrades		249
		(3 460)

4.3 MAJOR NEW GENERATION & TRANSMISSION CAPITAL EXPENDITURES

The CEF14 includes Major New Generation & Transmission projects which significantly increase capacity and energy or provide increased reliability for the transmission system.

As noted in Figure 4.5, Major New Generation & Transmission expenditures continue to increase primarily due to the commencement of construction of the Bipole III Reliability project and the Keeyask Generating Station.

Figure 4.5 New Major Generation & Transmission 2013-2017

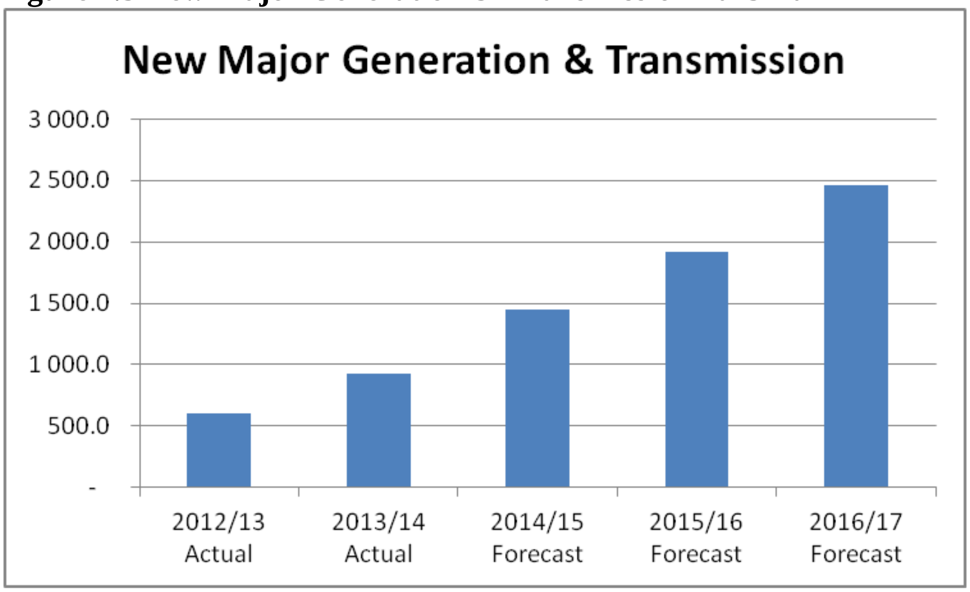


Figure 4.6 below summarizes the significant Major New Generation and Transmission capital projects.

Figure 4.6 Major New Generation & Transmission Capital Expenditure Forecast CEF14

(in millions of $)	2014/15	2015/16	2016/17	Cumulative to 2023/24*
Wuskwatim - Generation	41	13	15	68
Keeyask - Generation	776	676	962	5 579
Grand Rapids Hatchery Upgrade & Expansion	2	5	9	23
Conawapa - Generation	43	31	21	96
Kelsey Improvements & Upgrades	14	9	13	37
Kettle Improvements & Upgrades	7	24	25	138
Pointe du Bois Spillway Replacement	114	52	4	170
Pointe du Bois - Transmission	16	17	14	51
Gillam Redevelopment and Expansion Program (GREP)	20	22	23	212
Bipole III - Transmission Line	203	360	381	1 514
Bipole III - Converter Stations	221	581	829	2 356
Bipole III - Collector Lines	58	76	52	227
Bipole III - Community Development Initiative	2	2	2	8
Riel 230/ 500 kV Station	36	6	-	42
Manitoba-Minnesota Transmission Project	7	33	100	348
Demand Side Management	52	59	77	676
Target Adjustment	(161)	(51)	(61)	(12)
Other	-	-	-	139
Total	**1 452**	**1 914**	**2 463**	**11 671**

* Excludes capital expenditures prior to 2013/14

The following sections provide a summary of cost updates with respect to the significant Major New Generation & Transmission projects and Electric Demand Side Management.

4.3.1 Bipole III Reliability Project

In August 2013, the Province of Manitoba issued an Environmental Act licence for the Bipole III Reliability project and construction has commenced with a planned in-service date of 2018/19, which represents a deferral of nine months from October 2017.

CEF14 incorporates a more detailed scope based on an issued Environmental Act licence, approved finalized route and right-of-way width and up-to-date market information. In addition, the revised estimate incorporates the awarding of major contracts and the selection of LCC technology, which has resulted in synchronous condensers being included in the updated estimate. The rating for the Bipole III Reliability project was increased from 2000MW to 2300MW to ensure adequate spare HVDC transmission on the northern collector system. Figure 4.7 provides an explanation of the major changes in the cost estimates.

Figure 4.7 Bipole III Reliability Total Project Cost Update

Cost Breakdown (in millions of dollars)	CEF 14	CEF 13	Increase	Explanation for change
HVdc Converter Stations (Riel & Keewatinohk)	1 878.3	1 208.8	669.5	- Increased for awarded contracts: HVdc Equipment, AC Switchyard, Site Development, Camp, Camp Operations, etc. - Addition of Synchronous Condensers to project scope as result of LCC converter technology selection - Increase to 2300 MW converters
500kV T-Line	1 191.0	889.0	302.0	- Increase for extended Licencing process - Increase for revised property acquisition costs - Increased clearing costs - Increase due to additional towers required
AC Collectors	198.2	115.0	83.2	- Addition of station upgrade and breaker replacement scope of work - Estimated increase to construction costs
Riel 230kV Expansion	228.7	133.4	95.3	- Increase from attribution of Riel Sectionalization costs (realized costs) - Estimated increase to construction costs
Contingency & Reserves	347.6	203.0	144.6	- Contingency & reserves included based on analysis and recommendation of 3rd party risk and contingency expert
Interest & Escalation	747.8	730.8	17.0	
Community Development Initiative	62.0	60.8	1.2	
TOTAL	**4 653.6**	**3 340.8**	**1 312.8**	

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow.

4.3.2 Keeyask Generating Station

In July 2014 the Province of Manitoba issued an Environmental Act licence for the Keeyask Generating Station and construction has commenced with a planned in-service date of 2019/20.

The Keeyask Project budget was updated in March 2014 as part of the Needs For and Alternatives To review. The last detailed project estimate was completed in 2009. The budget includes bid prices from the major contractors including the General Civil Contract. Figure 4.8 provides an explanation of the major changes in the cost estimates.

Figure 4.8 Keeyask Generating Station Total Project Cost Update

Cost Breakdown (in millions of dollars)	CEF 14	CEF 13	Variance	Comments
Generating Station (Including GCC and KIP)	3 681.1	3 060.6	620.5	Increase related to: - updated base expenditures from 2013$ to 2014$ on generating station and KIP - post-construction adverse effects and operational employment which were previously excluded from the estimates. Accretion is also added. - commitments made in EIS and CEC hearings related to the environment and social mitigation. - direct negotiated service contracts, interface management, forebay clearing, and community monitoring. - stage 5 engineering and construction management staff augmentation. - Increase for awarded contracts. - unforeseen conditions related to the north access road construction, and work areas site development.
Construction Power	30.4	30.4	0.0	No Change
Licensing & Planning	393.0	397.3	(4.3)	Decrease related to transfer of budget for adverse effects.
Transmission (excluding contingency)	142.1	138.3	3.8	Increase related to updated base expenditures from 2013$ to 2014$.
Contingency & Management Reserves	685.2	1 063.7	(378.5)	Decrease related to: - Contingency and labour reserve revised based on updated risk model. - Escalation reserve revised based on updated escalation reserve model.
Interest & Escalation	1 564.2	1 530.3	33.9	Increase due to Interest on higher base costs and an advanced general civil contract cash flow; partially offset by decreased Escalation indexing from the increase to 2014$.
TOTAL	**6 496.0**	**6 219.6**	**276.4**	

Note: Sunk Costs are included in each project component

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow.

4.3.3 Conawapa Generating Station

For CEF14 forecast purposes, it is assumed that the Conawapa Generating Station has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of the planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by Fall of 2016). Remaining expenditures in the forecast include capitalized interest on construction in process through to August 2016, the wrap up of preliminary engineering studies and limited environmental and aboriginal studies.

Figure 4.9 Conawapa Total Project Cost Update

(in millions of dollars)	CEF 14	CEF 13	Decrease	Explanation
Conawapa GS	397	10 492	(10 095)	Majority of expenditures have been suspended pending re-evaluation of the business case. Remaining expenditures are for the wrap up of preliminary engineering studies and limited environmental and aboriginal studies including capitalized interest on construction in progress through August 2016.

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow and expenditures previously forecast outside the 10 year timeframe.

4.3.4 Demand Side Management

Manitoba Hydro's DSM plan targets the achievement of 1,136 MW and 3,978 GWh of savings over the next 15 years and involves an investment of more than a billion dollars and will be relied upon to meet 66% of projected load growth during this period. Figure 4.10 provides an explanation of the major changes over the 10 year forecast period associated with the updated DSM plan.

Figure 4.10 DSM 10 Year Cost Flow Update

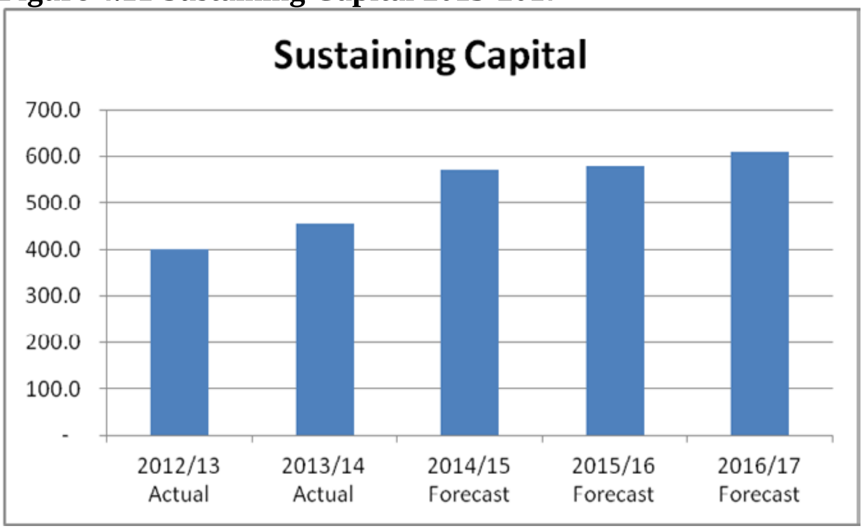
Cost breakdown (in millions) 10 Year	CEF 14	CEF 13	Increase / (Decrease)	Explanation
Residential Energy Efficiency Programs	$68.7	$4.9	$63.8	Extended and enhanced program offerings and added new programs including but not limited to introducing Residential LED Lighting program and increased insulation incentives and introduced free energy assessments for electrically heated homes.
Commercial Energy Efficiency Programs	$210.4	$69.7	$140.7	Extended and enhanced program offerings and added new programs including but not limited to adding direct installation of high efficiency pre-rinse spray valves to the Commercial Kitchen program, higher performance levels beyond the new energy code for buildings, and increased incentives and technical assistance to support energy modeling under the Commercial New Buildings program, and increased incentives under the Refrigerator Retirement, Commercial Lighting, Commercial Building Envelope, Commercial CO2 Sensors, and Commercial Refrigeration programs.
Industrial Energy Efficiency Program	$102.0	$27.7	$74.4	Enhanced program offering by expanding financial and technical support for embedded energy managers in large commercial and industrial facilities under the Industrial Performance Optimization Program.
Load Management Program	$65.8	$57.7	$8.0	Enhanced program offering by increasing incentives in the Curtailable Rates Program.
Load Displacement & Alternative Energy Programs	$97.8	$8.8	$89.0	Added customer sited load displacement program.
Conservation Rates	$26.3	-	$26.3	Added conservation rates for residential and commercial customers.
Fuel Choice Program	$55.1	-	$55.1	Added fuel choice program.
Support & Contingency	$50.1	$44.7	$5.4	Increased activities to support the enhanced DSM portfolio such as increased program evaluation activities including external evaluation consulting services.
Demand Side Management	**$676.2**	**$213.4**	**$462.8**	

4.4 SUSTAINING CAPITAL EXPENDITURES (MAJOR & BASE CAPITAL)

Sustaining capital includes items identified in CEF14 as either Major or Base capital expenditures and consists of additions, improvements and replacements of existing infrastructure.

Capital targets established for fiscal years 2014/15 through 2020/21 in CEF14 considered increased requirements for aging infrastructure based upon asset condition assessments as well as expansion requirements to support customer growth. The target adjustment of $25 million annually beginning in 2016/17 through 2020/21 provides funding to address future priorities. Investment in sustaining capital has increased $428 million over the ten year forecast period in order to maintain reliability and address anticipated load and customer growth as further discussed in Section 4.6.

Figure 4.11 Sustaining Capital 2013-2017



The following figure provides a further breakdown of sustaining capital for the first three forecast years of CEF14. Capital expenditures have been broken down by asset type, identifying the investment required to maintain reliable service.

Figure 4.12 CEF14 Sustaining Capital by Asset Type

(in millions of dollars)	2015	2016	2017
Generation Operation			
Turbines	19.7	13.4	15.8
Generators	14.4	17.8	20.1
Auxiliary Systems (Sewer, Water, Fire, etc)	12.4	10.3	12.5
Transformers	12.4	7.4	7.9
Licensing	10.4	10.8	8.3
Instrumentation & Controls	9.0	15.1	11.8
Townsite Infrastructure	8.9	10.4	5.0
Breakers	8.9	4.3	1.3
Spillway & Water Controls	7.4	13.5	24.1
Powerhouse, Dams, Dykes	6.7	7.6	8.1
Physical Security & Public Safety	5.4	3.2	2.0
AC Supporting Electrical Systems	5.2	7.6	6.4
Governors	4.6	3.9	1.6
Exciters	2.9	3.5	3.7
Tools & Equipment	2.4	2.2	1.4
Communication Systems & Equipment	1.4	1.2	1.9
	132.0	**132.0**	**132.0**
Transmission			
Station Equipment	16.3	15.2	13.9
Station Civil Infrastructure	15.9	9.1	2.8
Transformers	15.2	12.5	12.6
Communication Systems & Equipment	14.5	7.2	8.6
Protection Relays & Control, Metering & SCADA	13.8	7.2	3.2
HVDC Synchronous Condensers	9.0	8.8	2.9
Steel Structures	7.3	12.4	34.0
Wood Poles	6.7	33.2	14.1
Breakers	6.7	5.3	3.7
Battery Banks	4.0	2.5	1.9
Conductor Attachments	3.6	4.4	5.1
HVDC Valve Group	2.8	0.7	0.1
Tools & Equipment	2.4	1.6	1.4
Land & Easements	2.3	1.1	10.2
Overhead Conductors	1.8	2.4	9.5
System Control Centre	0.4	0.3	0.3
Diesel Generation	0.4	-	-
HVDC Smoothing Reactors	0.1	0.4	0.5
Other	1.8	0.9	0.1
	125.0	**125.0**	**125.0**
Customer Services & Distribution			
Poles	43.3	38.5	48.3
Overhead Conductors	39.1	33.3	33.8
Underground Cables	31.3	37.3	45.5
Station Breakers and Other Station Equipment	23.8	29.6	28.7
Overhead Transformers	22.5	18.2	22.2
Station Transformers	21.0	23.1	24.7
Padmount Transformers	17.9	12.2	15.7
Street Lights	11.0	10.8	12.8
Ductlines & Manholes	7.9	16.0	13.2
Station Site Prep	6.0	9.2	9.3
Land & Easement	3.7	0.4	0.0
Buildings	4.4	10.1	12.7
Equipment	1.4	1.2	1.4
Steel Structures	0.8	0.7	-
Other	1.3	-	-
	235.5	**240.9**	**268.3**
Customer Care & Energy Conservation			
Meters & Meter Transformers	3.2	4.0	4.1
	3.2	**4.0**	**4.1**
Human Resources & Corporate Services			
Computers & IT Systems	29.0	29.1	29.6
Buildings	22.4	24.3	9.3
Fleet	21.0	18.9	13.3
Land & Easements	1.7	1.8	1.8
Tools & Equipment	0.9	0.9	0.9
	75.0	**75.0**	**55.0**
Finance Regulatory			
Tools & Equipment	0.2	0.2	0.2
	0.2	**0.2**	**0.2**
Target Adjustment	-	-	25.0
Sustaining Capital Total	**570.9**	**577.0**	**609.6**

4.5 CAPITAL IN-SERVICE

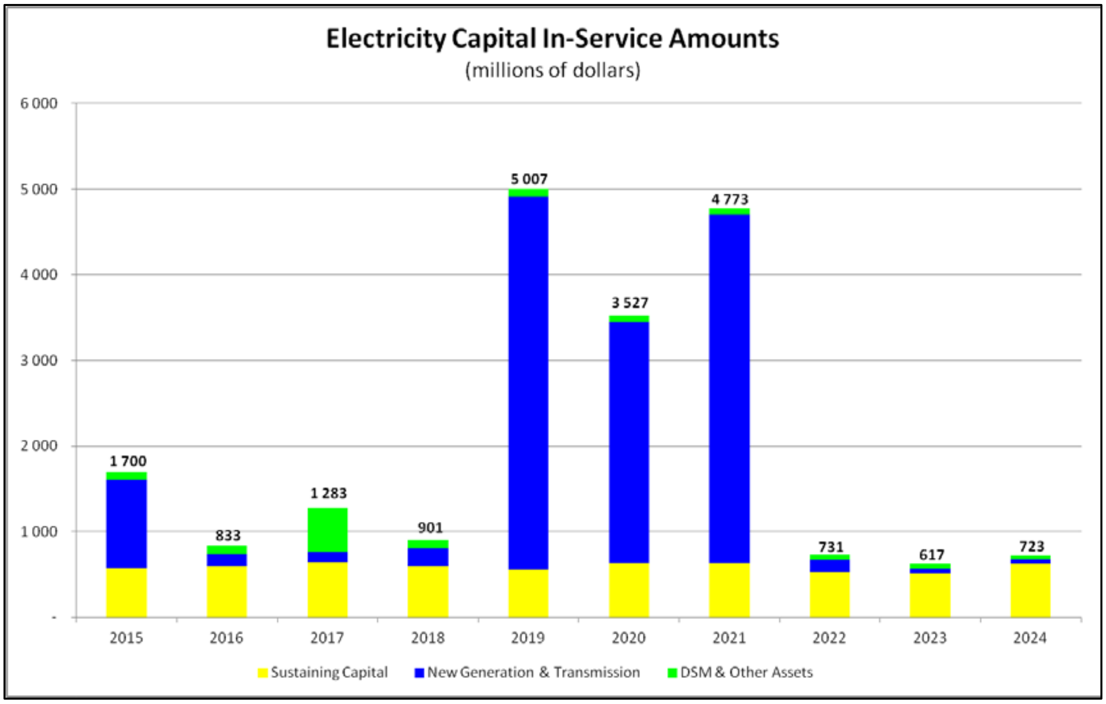
While assets are under construction, the capital expenditures and associated financing costs are held in construction work in progress. Once these assets are placed into service, the associated carrying costs (depreciation and finance expense) form part of the Corporation's revenue requirements.

Figures 4.13 and 4.14 provide a summary of the amount of capital that is forecast to go in service, as well as deferred assets that will commence amortization for the first three forecast years as well as the 10 year forecast period. Figure 4.13 indicates that $1.7 billion, $0.8 billion and $1.3 billion of assets are projected to be placed in-service in 2014/15, 2015/16 and 2016/17 respectively. The most significant assets being placed in-service during this period include the Pointe du Bois spillway replacement, and the Riel 230/500kV Station in 2014/15. In this three year period, there is also approximately $1.8 billion of sustaining capital expenditures that will be placed into service, and $0.2 billion of DSM expenditures that will commence amortization.

Figure 4.13 Electricity Capital In-Service Amounts

(millions of dollars)	2015	2016	2017	Cumulative 10 Year Total
Wuskwatim - Generation	40	4	26	70
Keeyask - Generation	-	-	-	6 496
Grand Rapids Hatchery Upgrade & Expansion	-	-	-	24
Kelsey Improvements & Upgrades	17	8	15	41
Kettle Improvements & Upgrades	6	24	24	141
Pointe du Bois Spillway Replacement	477	91	4	572
Pointe du Bois - Transmission	21	0	10	59
Gillam Redevelopment and Expansion Program (GREP	18	24	24	210
Bipole III - Transmission Line	0	0	-	1 593
Bipole III - Converter Stations	123	-	-	2 657
Bipole III - Collector Lines	4	-	13	260
Bipole III - Community Development Initiative	-	-	-	62
Riel 230/500kV Station	329	0	-	330
Manitoba-Minnesota Transmission Project	-	-	-	349
Generating Station Improvements & Upgrades	-	-	-	139
New Generation & Transmission Sub Total	**1 036**	**152**	**116**	**13 003**
				-
Demand Side Management	52	59	77	676
Conawapa - Generation	-	-	397	397
Other	36	29	53	138
DSM & Other Assets Sub Total	**88**	**89**	**526**	**1 211**
				-
Generation Operations	154	188	85	1 466
Transmission	88	94	168	1 346
Customer Service & Distribution	259	234	296	2 303
Customer Care & Energy Conservation	3	4	4	39
Human Resources & Corporate Services	72	73	64	600
Finance & Regulatory	0	0	0	2
Target Adjustment	-	-	25	125
Sustaining Capital Sub Total	**576**	**593**	**642**	**5 882**
				-
TOTAL	**1 700**	**833**	**1 283**	**20 096**

Figure 4.14 Electricity Capital In-Service Amounts 2014/15-2023/24



4.6 INVESTING TO MAINTAIN RELIABLE SERVICE

Manitoba Hydro's asset management has enabled the Corporation to defer hundreds of millions of dollars of capital investment to date. However, increased investments are required for generation, transmission and distribution system renewal and capacity expansion in order to support the growth requirements of Manitoba Hydro's customers. These capital investments are needed to sustain the Corporation's current electric infrastructure considering the increasing pressures associated with aging infrastructure and the need to provide more capacity to accommodate increased demand resulting from increased population and business growth. CEF14 forecasts capital expenditures of $493 million, $498 million and $525 million in 2014/15, 2015/16, and 2016/17, respectively for investment in generation, transmission and distribution assets (does not include expenditures associated with corporate infrastructure).

4.6.1 Impacts of Aging Infrastructure on Reliability

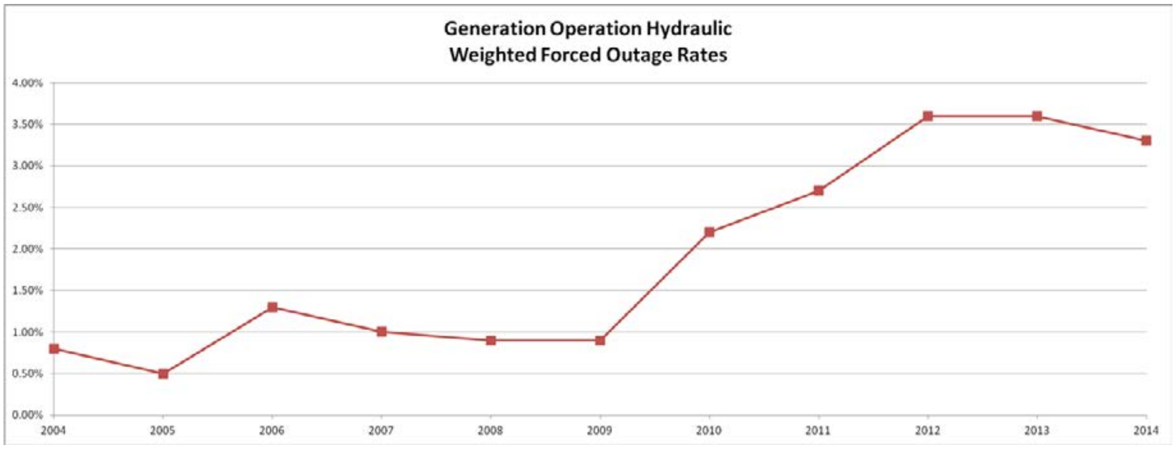
Manitoba Hydro has prudently invested in the electrical system which has provided reliable service to customers for decades. Where system reliability risk dictates, Manitoba

Hydro has installed redundant capacity to ensure that it can supply load in the event of an outage in an acceptable timeframe. Contingency plans, such as the transfer of load to available stations, the use of mobile stations, and allowing temporary overloads on equipment where it can be determined that such overloads are not expected to appreciably reduce equipment life, allow the Corporation to supply load at acceptable voltage levels after a system outage occurs.

In the past, Manitoba Hydro has been able to effectively deal with capacity challenges on its system by taking advantage of redundant capacity and contingency plans which has allowed the Corporation to defer capacity upgrades while maintaining reliability levels. However, the number of areas of the electric system with capacity challenges is growing, and this is the result of an aging system and strong load growth in some parts of the Province. Consequently, Manitoba Hydro's ability to respond to these challenges without negatively impacting reliability is diminishing.

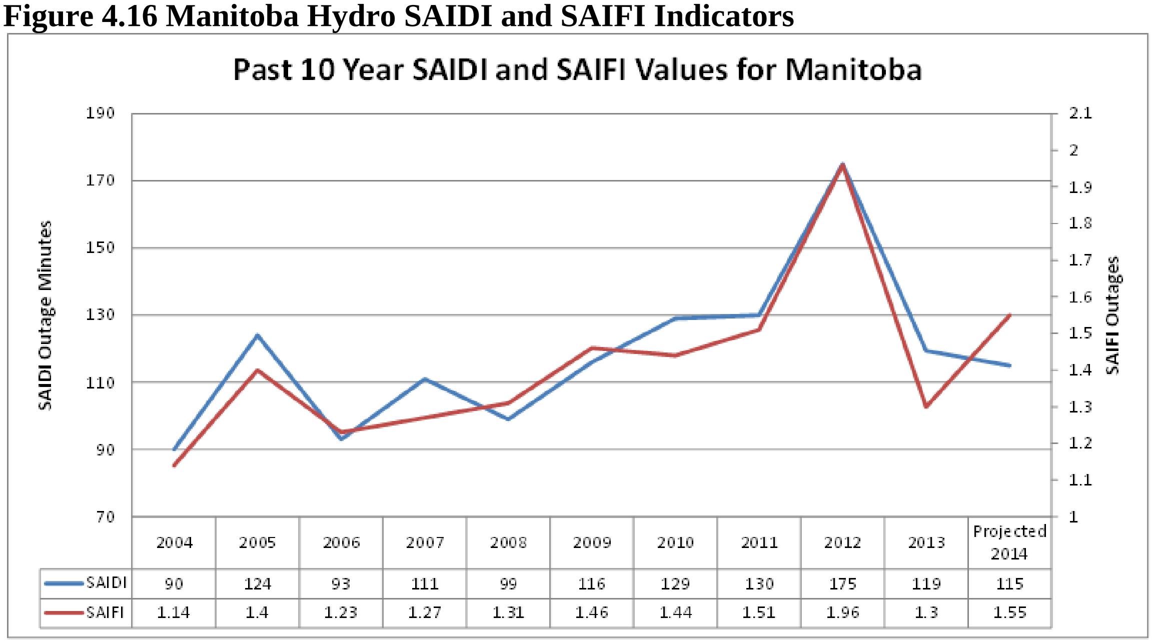
Reliability is critical for Manitoba Hydro and its customers. Historically, the reliability performance of Manitoba Hydro's electric system has been excellent, but has recently begun to degrade. While reliability is impacted by factors such as adverse weather, tree contacts, and the lengthening of restoration time due to changes in work procedures to conform to safety, legal and environmental requirements, the condition of Manitoba Hydro's assets is contributing more and more to the decline in reliability. This is evident in Manitoba Hydro's performance in key reliability indicators. As illustrated in Figure 4.15 below, generation forced outage rates have significantly increased in the past four years.

Figure 4.15 Hydraulic Generation Forced Outage Rates



Likewise, Manitoba Hydro's recent performance on the System Average Interruption Duration Index (SAIFI) and the System Average Interruption Frequency Index (SAIDI) indicators (with the exception of 2013 which reflects lower than normal storm activity) shows a trend of increased outage frequency and duration.

Figure 4.16 Manitoba Hydro SAIDI and SAIFI Indicators



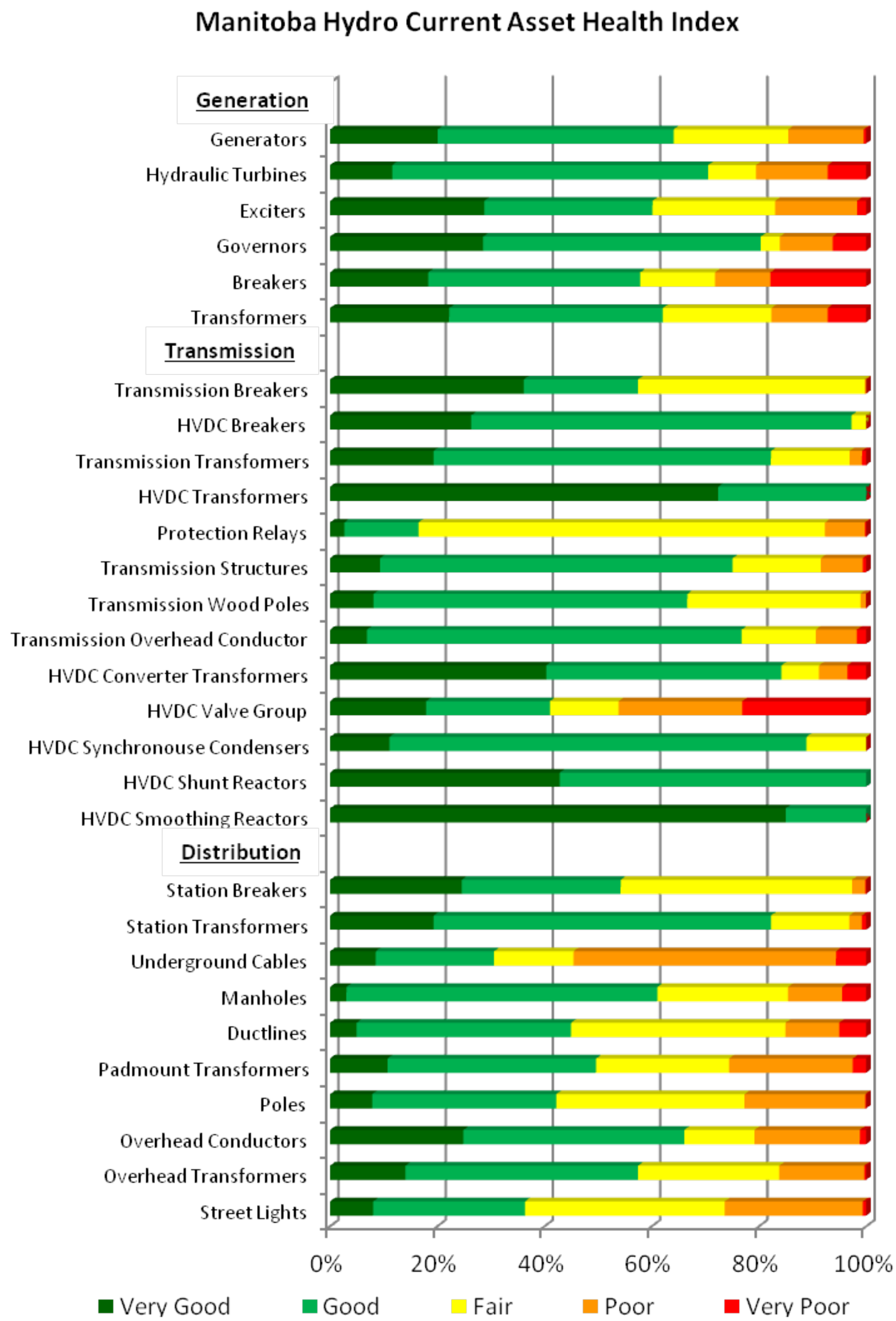
Manitoba Hydro has been taking actions for many years to mitigate the impacts of aging infrastructure on reliability performance, such as implementing an integrated pole maintenance program that has allowed the Corporation to extend the pole asset serviceable life well-beyond industry standards, and more recently, leveraging cable silicone injection technology to extend the serviceable life of underground cables. However, significant capital investments are required to address aging infrastructure and increased capacity needs on the system.

A considerable amount of Manitoba Hydro's assets were installed prior to 1960 when many of the first generating stations and transmissions systems were built (1911-1950) and a large portion of the province was electrified (1940-1960). Many of these assets have been well maintained or overhauled and are still in operation, providing decades of valuable service to the Corporation and its ratepayers. A large number of assets were subsequently installed from 1960 through to 1990 when generating stations were developed on northern Manitoba river systems along with the supporting HVDC system to transport the electricity to customers in the south.

Many components of this generation, transmission and distribution system are coming due for replacement, with some components requiring investments in the short term. Some of Manitoba Hydro's assets are in poor condition with ages well beyond industry standards and present a significant risk of failure which can result in customer outages and/or load shedding. Some of these assets types, such as breakers, generators, wood poles and valve groups, also require significant resources, lead time and capital investment to address their present condition. Though assets are being continually maintained, current levels of system reliability will not be sustained with current asset replacement rates.

As Appendix 4.2 to this Tab, Manitoba Hydro has included its Electric Infrastructure Condition Assessment Report. The report provides an overview of the condition of major electrical assets and their demographics, as well as an overview of critical assets' life expectancy versus the current replacement rates and the quantities of assets in critical condition. Manitoba Hydro used an Asset Health Index (AHI) to quantify equipment condition based on numerous parameters, as described in section 3 of Appendix 4.2. A condition index was calculated for each asset indicating whether the asset type is in very poor, poor, fair, good or very good condition. Figure 4.17 below provides a summary of current AHI results for Manitoba Hydro's generation, transmission and distribution asset types.

Figure 4.17 Current Asset Health Index by Asset Type



Manitoba Hydro can effectively manage its assets through the use of maintenance, spares and contingency strategies when the majority of assets in a particular asset class are in fair to very good condition. However, as larger percentages of these assets fall into the poor and very poor categories, system failures regretfully will occur more frequently.

It is notable that the majority of critical assets are being replaced at levels substantially less than their anticipated lifespan. Today, a majority of the asset types have equipment which remains in service well beyond industry expectations, without causing significant impact to reliability. Going forward, as a larger percentage of assets age beyond life expectancy, significant changes to current replacement rates[1] will be required to mitigate the negative impacts of aging infrastructure on the electrical system. Figure 4.18 illustrates turnover at current replacement rates[2], indicating that replacement rates in the majority of Manitoba Hydro's asset types need to be increased to better align with life expectancy.

Figure 4.18 Asset Type Life Expectancy and Turnover at Current Replacement Rates

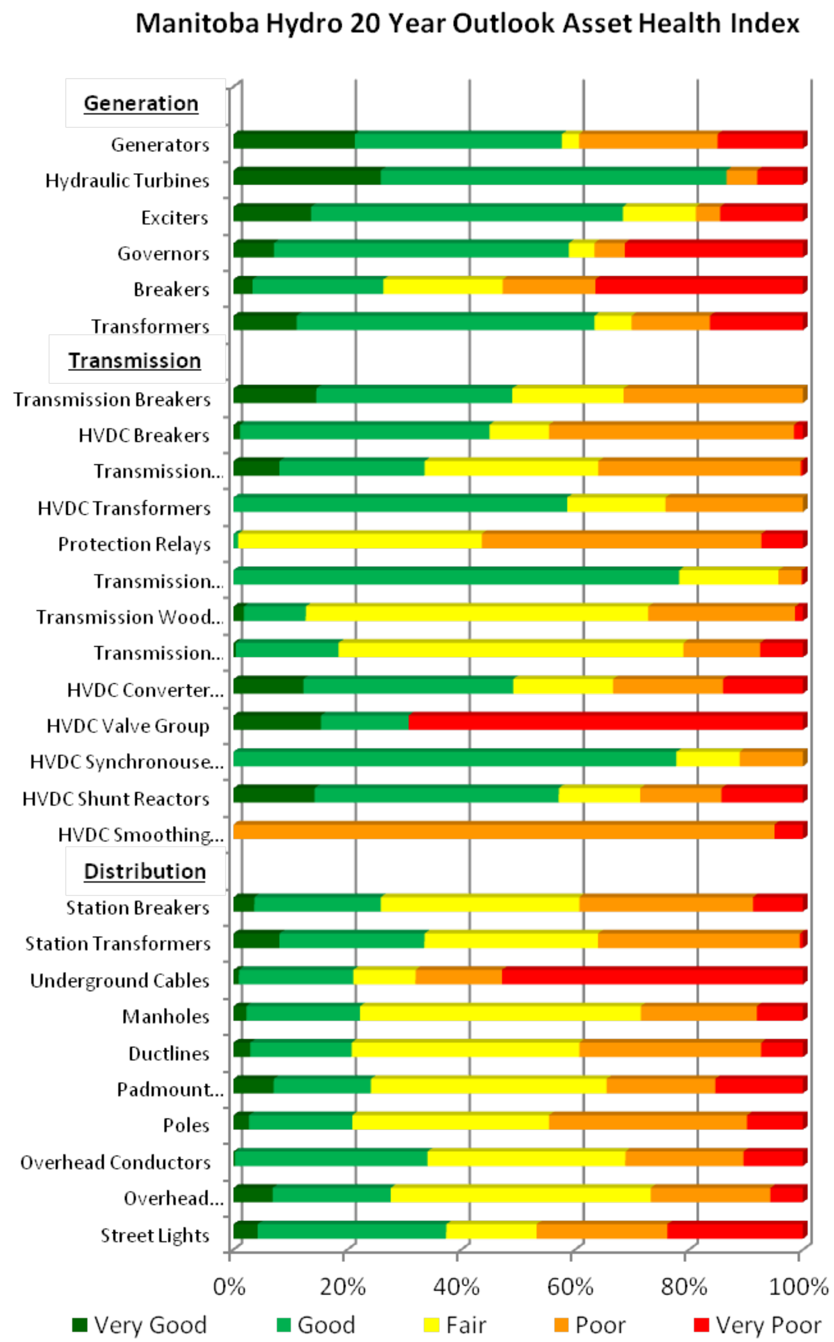
Business Unit	Asset	Life Expectancy (years)	Turnover at Current Replacement Rates (years)
Generation	Generators	60	117
	Hydraulic Turbines	90-100	84
	Exciters	50-90	117
	Governors	20-125	50
	Breakers	60-65	129
	Transformers	40-70	150
Transmission	Transmission Breakers	60-65	149
	HVDC Breakers	60-65	58
	Transmission Transformers	40-70	152
	HVDC Transformers	40-70	70
	Transmission Structures	85	285
	Transmission Wood Poles	75	255
	Transmission Overhead Conductor	85	410
	HVDC Converter Transformers	40-50	73
	HVDC Valve Group	25	48
	HVDC Synchronouse Condensers	65	65
	HVDC Shunt Reactors	35	55
	HVDC Smoothing Reactors	25	30

[1] The replacement rate is the average number of assets replaced each year divided by the total number of in service assets.
[2] Turnover at Current Replacement Rate is the number of years it would take to replace all our existing in service assets at current replacement rates.

Business Unit	Asset	Life Expectancy (years)	Turnover at Current Replacement Rates (years)
Distribution	Station Breakers	60-65	180
	Station Transformers	40-70	370
	Underground Cables	30-70	328
	Manholes	80	500
	Ductlines	100	378
	Padmount Transformers	50	70
	Wood Poles	70	200
	Overhead Conductors	100	200
	Overhead Transformers	75	70
	Street Lights	50-70	100

The original cost of Manitoba Hydro’s electric assets is approximately $16 billion with an estimated replacement value many multiples higher due to inflation, increases in commodity prices and other factors. An asset portfolio of this size requires significant reinvestment to ensure that performance and safety standards are achieved. As a result, it is essential that investments on asset renewal be undertaken. Manitoba Hydro will continue to extend the life of its assets to the extent feasible based on economic and risk assessments, however, current replacement rates do not allow for a sustainable electrical system in the near future. Figure 4.19 demonstrates the impact to asset health if current replacement rates are maintained, indicating a trend toward less asset reliability as more slip into the poor and very poor condition.

Figure 4.19- 20 Year Outlook Asset Health Index by Asset Type



As discussed in Appendix 4.2, it is expected that over the next 20 years more assets will slip into poor and very poor condition, which will result in lower reliability than experienced historically, reduced revenues, increased safety risks to public and employees, increased maintenance costs, increased emergency restoration costs and consequential damages. In addition, internal resource levels to address both maintenance and asset replacement requirements would be strained and the ability to secure external resources may be limited.

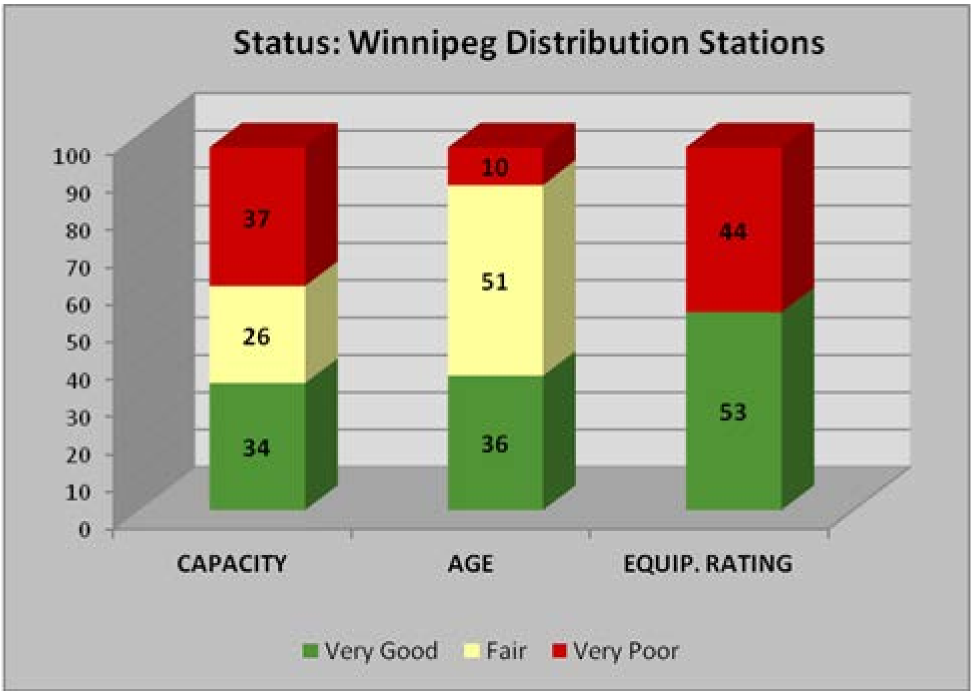
4.6.2 Capacity Constraints Impacting System Performance & Customer Growth

In conjunction with the impacts of aging infrastructure, Manitoba Hydro is facing significant capacity issues. Electric load in an increasing number of service areas has grown to the point where Manitoba Hydro may not be able to adequately supply load in the event of an outage despite contingency plans. Capacity challenges also make it more difficult to respond to customer connection requests. The Corporation has identified a number of capital investment priorities for its distribution and transmission systems related to capacity and investments are being undertaken and will be required in the near future to address these capacity issues.

For example, significant capital investment in distribution stations in Winnipeg and rural Manitoba is required as a large number of the stations are currently overloaded. There are 276 distribution stations in rural Manitoba; 19 of these are loaded above their maximum capacity, while 27 stations are at or above 80% of their loading limit. There are areas of the Province experiencing load growth much higher than the system average. In addition, there are areas of the province where the distribution system is near its end of life. In areas where these issues intersect, investment requirements become more important, such as in the Steinbach area, the Morden/Winkler area, Western oil fields, Brandon South and the Eastern Lake Winnipeg Area. As is noted below, the transmission system that supports the distribution in these areas is also facing capacity challenges.

Likewise, current Winnipeg distribution system capacity is not sufficient to meet current or future loads, which results in a high likelihood of extended outages to customers. Figure 4.20 provides an overview of the current status of the distribution system in the City of Winnipeg.

Figure 4.20 Status of Distribution Stations in Winnipeg



There are 97 distribution stations supplying the City of Winnipeg; 37 stations are currently loaded beyond their maximum capacity, and 26 stations are at or above 80% of their loading limit. The in-service dates of substation capacity projects can be deferred by transferring load to other, less loaded stations; however, the use of this strategy has been exhausted and is no longer practical. Contingency plans have become ineffective to restore full load in the event of an outage. Furthermore, ten of the distribution stations are 61 years or older, exceeding the design life of the equipment, and 44 stations have fault levels that exceed equipment ratings under certain operating conditions, such as during extreme low temperatures where electrical demand is typically highest.

Based on current capital plans, Manitoba Hydro is working towards reducing the percentage of overloaded distribution stations in Winnipeg to 20% by 2020 and in rural Manitoba by 5% in 2015 with a long term objective of ensuring that no stations exceed their maximum rating. Achieving this objective requires significant investments today and in the coming years. This issue is of significant concern, not only as it limits Manitoba Hydro's ability to supply electricity reliably to existing customers, but also in light of the expected load additions in many areas of the Province, including downtown Winnipeg where load additions are much larger than anticipated. It is estimated that service extensions are required for approximately 5,300 new electric customers each year across the Province.

Similarly, Manitoba Hydro's transmission system is facing significant capacity issues. There are a number of areas in the transmission system where significant investments are required in order to address higher than average load growth, deteriorating voltage levels, and/or impacts of increasing transmission system capacity on some existing system equipment. Manitoba Hydro has also identified a number of high-priority transmission capital investments to address capacity requirements that will need to be undertaken.

As noted above, Manitoba Hydro has experienced higher than average load growth in areas such as the eastern Lake Winnipeg area, the Winkler/Morden area, and the Steinbach area which exceed the firm capacity of its stations, and/or result in low voltage issues. In the Eastern Lake Winnipeg, load has grown beyond the maximum capacity of Pine Falls Station, a key station that supplies the area, and over the next several years, the load is expected to grow to the point that overloads could not be reduced to acceptable levels by transferring load to other stations, potentially resulting in transformer damage or rotating load shed in a difficult to serve region of the Province.

With respect to the Morden/Winkler area, the 115 kV transmission system supplying the area can experience low voltage issues, particularly during peak load conditions and outages on the system. In such cases, rotating load shed during peak winter loading conditions may be required to restore system voltages to acceptable levels.

Likewise, the Winnipeg area has become heavily loaded due to load growth and upgrades to the transmission system are required, including the construction of a new transmission line, in order to protect against blackouts, and improve the system performance and reliability during normal operations as the load grows in southern Manitoba. In addition, as the capacity of the Winnipeg area transmission system continues to increase, the ratings of some system protection/interrupting equipment in the area are expected to be exceeded. This necessitates the replacement of breakers in order to avoid potential harm to employees, the public and infrastructure.

As well, steady load growth in Western Manitoba has resulted in deteriorating voltages on the transmission system in the Portage South area, which is impacting local load and Saskatchewan export capabilities and the ability to supply new oil pipeline related load.

If the capacity-related projects are not undertaken, customers in the impacted areas would be at a higher risk of extended outages and there is a risk that Manitoba Hydro could potentially be subject to significant financial penalties if having to report North American Electric Reliability Corporation violations.

Addressing the above matters will require investments in new transmission lines, investments to address station overloading, capacity upgrades and new construction to accommodate future load growth.

The continued provision of safe and reliable service requires Manitoba Hydro to undertake investments today and in the near future. The proposed rate increases will ensure that there is adequate funding available to make the necessary investments.