November 29, 2013

Delivered by Courier and Filed Electronically via RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
26th Floor, Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli

Re: PowerStream Inc. (OEB Electricity Distributor Licence ED-2004-0420)
2014 IRM Distribution Rate Application – Board File No. EB-2013-0166
Interrogatory Responses

Accompanying this letter, please find two copies of PowerStream Inc.'s Interrogatory Responses filed in accordance with the Board's Procedural Order No. 1.

The Responses have been filed electronically via RESS and delivered by e-mail to the intervenor of record in this matter.

If you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

Original signed by Tom Barrett

Tom Barrett
Manager, Rate Applications

Encls.
cc: Mr. Colin A. Macdonald, PowerStream Inc.

EB-2013-0166

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by PowerStream Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2014.

POWERSTREAM INC.

INTERROGATORY RESPONSES

November 29, 2013

PowerStream Inc. (PowerStream) has organized its responses to interrogatories from Board Staff and the intervenors into the following sections:

- Incremental Capital Module
- Retail Transmission Service Rates
- LRAM Claim
- Deferral and Variance Accounts

Within each section, PowerStream has listed by source then numerically:

- Board Staff
- Energy Probe Research Foundation (EP)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition

INCREMENTAL CAPITAL MODULE

Board Staff Interrogatory No. 1

Ref: Application, Manager's Summary - page 9

On page 9 of the Manager's Summary, PowerStream states:

> The Price Cap index of 0.98% is calculated in the Board's Rate Generator model, based on the preliminary 4th GIRM parameters. PowerStream recognizes that certain parameter values, including the price escalator (GDP-IPI) of 2.0%, Total Productivity Factor ("TPF") of 0.72% and the stretch factor of 0.3% are proxy values that will be adjusted to the Board approved values at the time of preparing the 2014 rate order.

a) Please confirm that PowerStream intends to update its calculation of the ICM threshold to reflect updates to the Board's price cap adjustment parameters for 2014 rates (PCI Parameters).

Response:

a) Confirmed.

PowerStream notes that the Board’s ICM model is locked and PowerStream is unable to update for the Board’s price cap adjustment parameters for 2014. PowerStream will work with Board Staff to update this as part of the draft rate order process.

PowerStream has recalculated the ICM threshold based on the Board’s 2014 PCI Parameters as shown below:

Table Staff 1-1: Board's 2014 Price Cap Index (PCI)

Price Escalator (GDP-IPI)	1.70%
Less Productivity Factor	0.00%
Less Stretch Factor	-0.30%
Price Cap Index	1.40%

Table Staff 1-2: Threshold Test

Price Cap Index	1.40%	A
Growth	0.88%	B
Dead Band	20%	C
Depreciation Expense	$ 32,852,415	D
Rate Base	$ 832,077,120	G = E + F
Depreciation Expense	$ 32,852,415	H
Threshold Test	178.03%	I = 1 + (G / H) * (B + A * (1 + B)) + C
Threshold CAPEX	$ 58,488,777	J = H *I

Table Staff 1-3: Calculation of Eligible Incremental Capital Amount

2014 Non-Discretionary Capital Budget (Including ICM Projects)	$ 69,815,617
Threshold CAPEX (as calculated above)	$ 58,488,777
Eligible Incremental Capital Amount	$ 11,326,840

The updated PCI has increased the Threshold CAPEX from $51.6 million (M) to $58.5M and reduced the Eligible Incremental Capital Amount from $18.2M to $11.3M.

Board Staff Interrogatory No. 5

Ref: Manager's Summary - page 12

Ref: Application, EB-2012-0161 - Ex. B1/T.1/Sch.6, pages 30 - 33

On page 12 of the Manager's Summary, PowerStream states:

PowerStream's process is to prepare a two-year capital budget and a five year capital plan each year. The last approved capital budget was for the 2013 and 2014 calendar years. Once the 2013 and 2014 Capital Budget is approved by the Executive and the Board of Directors, the 2013 portion becomes the capital plan for 2013. The 2014 portion represents the best information at the time as to what capital work will need to be done in 2014.

As part of its annual capital planning and budgeting process in 2013, PowerStream updates the five year capital plan for 2014 to 2018. The updated five year capital plan and the 2014 portion of the 2013-2014 capital budget is then the starting point for the 2014-2015 capital budget build.

On pages 30 through 33 of Exhibit B1, Tab 1, Schedule 6 of PowerStream's last cost of service application, PowerStream provided a discussion of its forecast capital expenditures in 2014 and 2015, as compared to, 2013. On page 31 PowerStream indicated total capital expenditures of approximately $114M in 2013 and $116M in 2014. PowerStream also noted expected total capital expenditures of approximately $121M in 2015.

a) Given that PowerStream had expected relatively consistent capital expenditures in both 2013 and 2014, in its last cost of service application, please explain the changes in circumstances that have led to PowerStream filing for additional capital funding in 2014.

b) Please provide the total updated capital budget forecast for 2014, including a break-down of the discretionary work into major capital projects.

c) In its last cost of service application, PowerStream had forecast a slight increase in capital spending for 2015. Based on its current five year capital plan and two-year capital budget, is PowerStream anticipating that it will seek additional capital funding in its 2015 rate application?

Response:

a) The level of capital expenditures for 2014 that was presented in the last cost of service rate application is relatively consistent to 2013 and no new circumstances have arisen to alter the level of capital spending in 2014. However, PowerStream's capital spending has increased in recent years due in large part to the need to replace aging infrastructure. As a result, the depreciation recovered in Board-approved rates does not contain sufficient funding for new capital spending.

In the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673),* dated September 17, 2008, the Board considered the question of how much capital spending a distributor can be reasonably expected to fund through existing rates, before additional funding may be requested. This consideration can be found in section 2.3 - Incremental Capital Module Materiality Threshold starting on page 22. The Board concluded on page 33 that:

"Accordingly, the Board has determined that the appropriate CAPEX to depreciation threshold value to establish materiality for the incremental capital module should be distributor-specific and derived using the following formula:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);

d = depreciation expense included in base rates ($);

g = distribution revenue change from load growth (%); and

PCI = price cap index (% inflation less productivity factor less stretch factor).

The values for "RB" and "d" are the Board-approved amounts in the distributor's base year rate decision.

That the level of required non-discretionary capital spending is not supported by current rates is clearly demonstrated by the Board's Incremental Capital Workform ("ICM Model") using the Board approved formula (Application Appendix F-1).

In PowerStream's case, the formula generates a threshold test value of 157.08% which is then applied to the 2013 approved depreciation expense of $32.9 million (M) resulting in a threshold CAPEX of $51.6M. Only non-discretionary capital additions in excess of the $51.6M are eligible for ICM funding. PowerStream has $69.8M in non-discretionary capital additions required in 2014, resulting in an Eligible Incremental Capital Amount of $18.2M.

Implicit in the Board's formula is that funding for new capital additions during the IRM period is derived from depreciation expense. This is based on the fact that depreciation represents recovery of amounts previously spent and provides funding for new capital spending.

Annual depreciation may be considered as a proxy amount for the level of annual capital additions. In a sense, annual depreciation represents an average of the annual capital additions over an extended period of time.

There are four reasons why this proxy amount is inadequate to fund the current capital requirements:

- Higher levels of capital spending and additions compared to historical levels of capital spending and additions, as PowerStream has recognized and acted on the need to replace aging infrastructure;

- Much of the 2013 depreciation expense is based on older historical cost of capital additions which are at much lower levels than 2013 and 2014 capital additions;

- There is no depreciation in rates for many of the assets being replaced, due to 100% funding by developers prior to the year 2000; and

- The change to longer useful lives under MIFRS after depreciating on shorter useful lives under CGAAP until 2010 causes a discontinuity which results in lower depreciation expense in 2013 than if PowerStream had depreciated the capital additions on the basis of MIFRS for the last 30 years of typical asset useful life.

The Board-approved capital additions for 2013 are $82.8M. This compares to capital additions of $61.9M for 2007 and $57.8M for 2006. Historically capital additions were even lower than the 2006 and 2007 levels. This increase in the level of capital additions is in part due to the need to replace aging infrastructure.

The average useful life of PowerStream’s assets is 30 years. Depreciation is based on historical costs of assets that are acquired up to 60 years ago at much lower costs than current costs. In real terms the dollar amount of 2013 depreciation expense will fund the replacement of fewer assets than those that must be replaced.

The impact of lower historical levels of additions and lower historical costs on the funding in depreciation is illustrated in Example 2 below.

In many cases the assets being replaced, such as distribution assets in residential subdivisions installed prior to the year 2000, were 100 per cent funded by developers. For these assets, the cost recorded on the books, net of contributed capital, is $0 and there is no amount in depreciation for funding the replacement of these assets.

The impact of lower levels of additions and lower costs prior to 2000, due to higher levels of contributed capital, on the funding in depreciation is illustrated in Example 3 below.

PowerStream moved from CGAAP to MIFRS in 2011. PowerStream rebased under MIFRS in 2013. The change to MIFRS has also affected the amount of 2013 depreciation expense available to fund new capital additions during IRM. Under MIFRS the weighted average useful life of capital assets is 30 years. Under CGAAP the weighted average useful life was 23 years.

If PowerStream had been depreciating under MIFRS for the last 30 or more years then there would be 2013 depreciation on assets purchased between 23 and 30 years ago. Under CGAAP, the capital costs of assets, purchased between 23 and 30 years ago, are fully depreciated under CGAAP and there is no 2013 depreciation expense for these capital additions in approved rates.

The added impact, of fully depreciated assets under CGAAP that would have continued to be depreciated under MIFRS (had MIFRS been the method used for the life of the assets), on the funding in depreciation is illustrated in Example 4 below.

PowerStream has prepared the following examples in Table Staff 5-1 below to illustrate the impact of these factors.

The values used are for purposes of illustration only. For ease of illustration it has been assumed that PowerStream has only one type of asset with a useful life of 30 years and full year depreciation has been used; these assumptions are not expected to have a material impact on the results. Thirty years has been chosen as this is the average useful life under MIFRS of

PowerStream's assets. Depreciation expense has been calculated by amortizing the cost of the additions over the average life of 30 years.

Example 1 assumes the 2013 level of capital additions of $82.8M has been constant over the last 30 years.

In Example 1, the 2013 depreciation expense would be $82.8M. If this amount had been used to set 2013 rates it would provide funding of $82.8M for capital additions in 2014.

Note that PowerStream's approved rates contain only $32.8M in depreciation expense and not the $82.8M required to fund 2014 capital additions at the same level as 2013 capital additions.

Example 2 has the same level of capital additions in 2013 of $82.8M but this level of spending is the result of 3.5% year over year increases in costs due to inflation and growth.

In Example 2, the 2013 depreciation expense would be $51.8M, based on the lower average cost of capital additions of $51.8M over 30 years. If this amount had been used to set 2013 rates it would provide funding of $51.8M for capital additions in 2014.

Example 3 uses the capital additions in Example 2 and reduces the capital additions prior to the year 2000 by 30% to illustrative the effect of the fact that many assets were fully funded by developers during that period.

In Example 3, the 2013 depreciation expense would be $45.2M, based on the lower average cost of capital additions over 30 years of $45.2M which includes the impact of fully contributed assets prior to the year 2000. If this amount had been used to set 2013 rates it would provide funding of $45.2M for capital additions in 2014.

Example 4 uses the capital additions in Example 3 and removes the depreciation on assets added in 1984 through 1990. Based on an average asset life of 23 years under CGAAP, these assets would have been fully depreciated in 2013 and not included in the depreciation expense for 2013.

In Example 4, the 2013 depreciation expense would be $39.8M, based on the lower average cost of capital additions of $45.2M. Depreciation expense in this case is less than the average capital additions due to assets fully depreciated under the shorter useful life under CGAAP. If this amount had been used to set 2013 rates, it would provide funding of $39.8M for capital additions in 2014.

These examples clearly demonstrate how these factors result in much lower depreciation in rates than what is required to fund 2014 capital additions.

Example 4 is the scenario that most closely reflects PowerStream's current circumstances. Although the numbers are only representative they clearly illustrate the short-fall in funding capital additions in 2014 from depreciation. It also illustrates that the assumption that the approval of $82.8M of capital additions in 2013 rates provides adequate funding for a similar level of 2014 capital additions is invalid.

Table Staff 5-1: Depreciation Funding Illustrative Examples ($000)

	Example 1: Constant Level of Additions		Example 2: Increasing Level of Additions		Example 3: Pre 2000 100% Contribution		Example 4: CGAAP shorter life	
Year	Capital Additions	2013 Depreciation Expense	Capital Additions	2013 Depreciation Expense	Capital Additions	2013 Depreciation Expense	Capital Additions	2013 Depreciation Expense
1984	$ 82,777	$ 2,759	$ 29,458	$ 982	$ 20,621	$ 687	$ 20,621	
1985	$ 82,777	$ 2,759	$ 30,526	$ 1,018	$ 21,368	$ 712	$ 21,368	
1986	$ 82,777	$ 2,759	$ 31,633	$ 1,054	$ 22,143	$ 738	$ 22,143	
1987	$ 82,777	$ 2,759	$ 32,781	$ 1,093	$ 22,947	$ 765	$ 22,947	
1988	$ 82,777	$ 2,759	$ 33,970	$ 1,132	$ 23,779	$ 793	$ 23,779	
1989	$ 82,777	$ 2,759	$ 35,202	$ 1,173	$ 24,641	$ 821	$ 24,641	
1990	$ 82,777	$ 2,759	$ 36,479	$ 1,216	$ 25,535	$ 851	$ 25,535	
1991	$ 82,777	$ 2,759	$ 37,802	$ 1,260	$ 26,461	$ 882	$ 26,461	$ 882
1992	$ 82,777	$ 2,759	$ 39,173	$ 1,306	$ 27,421	$ 914	$ 27,421	$ 914
1993	$ 82,777	$ 2,759	$ 40,593	$ 1,353	$ 28,415	$ 947	$ 28,415	$ 947
1994	$ 82,777	$ 2,759	$ 42,066	$ 1,402	$ 29,446	$ 982	$ 29,446	$ 982
1995	$ 82,777	$ 2,759	$ 43,591	$ 1,453	$ 30,514	$ 1,017	$ 30,514	$ 1,017
1996	$ 82,777	$ 2,759	$ 45,172	$ 1,506	$ 31,621	$ 1,054	$ 31,621	$ 1,054
1997	$ 82,777	$ 2,759	$ 46,811	$ 1,560	$ 32,768	$ 1,092	$ 32,768	$ 1,092
1998	$ 82,777	$ 2,759	$ 48,509	$ 1,617	$ 33,956	$ 1,132	$ 33,956	$ 1,132
1999	$ 82,777	$ 2,759	$ 50,268	$ 1,676	$ 35,188	$ 1,173	$ 35,188	$ 1,173
2000	$ 82,777	$ 2,759	$ 52,091	$ 1,736	$ 41,673	$ 1,389	$ 41,673	$ 1,389
2001	$ 82,777	$ 2,759	$ 53,981	$ 1,799	$ 53,981	$ 1,799	$ 53,981	$ 1,799
2002	$ 82,777	$ 2,759	$ 55,938	$ 1,865	$ 55,938	$ 1,865	$ 55,938	$ 1,865
2003	$ 82,777	$ 2,759	$ 57,967	$ 1,932	$ 57,967	$ 1,932	$ 57,967	$ 1,932
2004	$ 82,777	$ 2,759	$ 60,070	$ 2,002	$ 60,070	$ 2,002	$ 60,070	$ 2,002
2005	$ 82,777	$ 2,759	$ 62,248	$ 2,075	$ 62,248	$ 2,075	$ 62,248	$ 2,075
2006	$ 82,777	$ 2,759	$ 64,506	$ 2,150	$ 64,506	$ 2,150	$ 64,506	$ 2,150
2007	$ 82,777	$ 2,759	$ 66,846	$ 2,228	$ 66,846	$ 2,228	$ 66,846	$ 2,228
2008	$ 82,777	$ 2,759	$ 69,270	$ 2,309	$ 69,270	$ 2,309	$ 69,270	$ 2,309
2009	$ 82,777	$ 2,759	$ 71,783	$ 2,393	$ 71,783	$ 2,393	$ 71,783	$ 2,393
2010	$ 82,777	$ 2,759	$ 74,386	$ 2,480	$ 74,386	$ 2,480	$ 74,386	$ 2,480
2011	$ 82,777	$ 2,759	$ 77,084	$ 2,569	$ 77,084	$ 2,569	$ 77,084	$ 2,569
2012	$ 82,777	$ 2,759	$ 79,880	$ 2,663	$ 79,880	$ 2,663	$ 79,880	$ 2,663
2013	$ 82,777	$ 2,759	$ 82,777	$ 2,759	$ 82,777	$ 2,759	$ 82,777	$ 2,759
2013 Depreciation Expense		$ 82,777		$ 51,762		$ 45,174		$ 39,807
Average additions		$ 82,777	$ 51,762		$ 45,174		$ 45,174	

b) The total updated capital expenditures budget forecast for 2014 is provided in the table below.

Table Staff -2: Capital Budget Forecast for 2014

Major Category	Sub Category	2014 Capital Budget	Non-Discretionary	Discretionary	Discretionary Projects
		Net of Contributed Capital			
General Plant	Operations Interest Capitalization	1,290,000	0	1,290,000	Interest capitalization
General Plant	Information / Communication Systems	20,229,330	1,495,660	18,733,670	New CIS Project
General Plant	Tools	683,156	0	683,156	Tools for various departments
General Plant	Buildings	2,710,310	0	2,710,310	Renovation at Patterson office
General Plant	Fleet	1,198,400	0	1,198,400	Purchase of large vehicles
General Plant	Emerging Operations Capital	53,500	0	53,500	Emerging projects
		26,164,696	**1,495,660**	**24,669,036**	
System Access	Emerging Development Capital	585,808	585,808	0	Change in budget
System Access	Road Authority Projects	10,017,557	10,017,557	0	Change in budget
System Access	Subdivision / Services	12,802,237	12,802,237	0	Change in budget
System Access	Metering	2,118,912	1,533,227	585,685	Suite Metering
System Access	Growth Driven Lines Projects	683,715	683,715	0	Long Term Load Transfer
System Access	Customer RGEN	0	0	0	Customer Contribution
		26,208,229	**25,622,544**	**585,685**	
System Renewal	Emergency / Restoration	9,312,802	8,721,411	591,391	Minor restoration projects
System Renewal	Lines Replacement Program/Projects	29,074,411	29,074,411	0	Change in budget
System Renewal	Stations Replacement Program/Project	469,434	407,256	62,178	Replacement of heavy outdoor concrete pit covers
		38,856,647	**38,203,078**	**653,569**	
System Service	Sustainment Driven Lines Project	2,775,752	0	2,775,752	Various reliability type projects
System Service	Additional Capacity(Transformer/Municipal Station)	6,340,786	6,340,786	0	New Vaughan TS#4 and Painswick MS in-service beyond 2014
System Service	Growth Driven Lines Projects	5,153,304	5,153,304	0	Various development type projects
System Service	Emerging Sustainment Capital	1,453,709	0	1,453,709	Emerging Reliability Projects
System Service	Transformer / Municipal Stations	1,285,233	35,188	1,250,045	Automatice feeder restoration project and other projects
		17,008,784	**11,529,278**	**5,479,506**	
	Sub-Total	**108,238,356**	**76,850,560**	**31,387,796**	
	Less in-service beyond 2014		**6,340,786**		
	Total		**70,509,774**		

c) PowerStream has not made any plans regarding requesting additional capital funding in its 2015 IRM rate application. After the completion of the 2014 rate application process, PowerStream will complete the Board's ICM Model as part of preparing its 2015 IRM application and conduct its analysis at that time.

Board Staff Interrogatory No. 6

Ref: Application, Manager's Summary – pages 12, 13 and 16

On pages 12 and 13 of the Application, PowerStream states:

For the purposes of this application, PowerStream has concentrated its efforts on identifying the non-discretionary projects that will be included in the final 2014 capital budget.

PowerStream cannot provide a list of 2014 discretionary capital with any certainty at this time. The discretionary capital list will be finalized once the results of the IRM/ICM process are known and PowerStream understands the capital funding that is available.

On page 16 of the Application, PowerStream states:

If PowerStream does not obtain the requested ICM funding, it will have to reconsider the amount of capital spending and adjust to maintain its financial stability. This may result in deferring some of the capital work that needs to be done to maintain the distribution system at the current level of reliability and prevent further degradation.

a) Please provide PowerStream's best estimate of its discretionary capital budget, at this time. Please include brief descriptions of the types of activities that would be undertaken.

b) Please discuss the impact on PowerStream's system planning were the Board to not approve PowerStream's ICM request.

c) Were the Board to approve only a sub-set of eligible capital projects for ICM funding, please provide a list prioritizing the projects for which PowerStream is seeking additional capital funding.

Response:

a) Please refer to Board Staff Interrogatory No. 5(b).

b) PowerStream believes that the projects presented for ICM are non-discretionary; that these projects are necessary to ensure a safe and reliable distribution system; and that the engineering analysis completed by PowerStream is consistent with the analysis contemplated in Chapter 5 (Consolidated Distribution System Plan Filing Requirements) of the "Ontario Energy Board Filing Requirements For Electricity Distribution Rate Applications" dated July 17, 2013, and, in particular Section 5.3 – Asset Management Process. Should the Board not approve the projects as presented, PowerStream would be required to re-assess its path for asset replacement and would have to consider which of these non-discretionary programs could not be performed in 2014.

c) PowerStream is unable to provide a prioritized list. PowerStream has an optimization process to decide which capital projects are funded or not funded. As part of that process capital projects are scored on both value and risk and put through an optimization tool. The Optimization tool considers the scores, the total project costs and the total portfolio costs. A team of senior leaders at PowerStream then reviews the optimized results and discusses at length what projects are included or not. A prioritized list is not created as part of the process.

   Should the Board approve only a sub-set of eligible capital projects for ICM funding, PowerStream will re-optimize the 2014 capital portfolio, using the same process and consider the Board's conclusions in deciding which projects to fund.

Board Staff Interrogatory No. 7

Ref: Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, EB-2007-0673, September 17, 2008 – page 31.

On page 31 of the Supplemental Report on the 3rd generation IRM, the Board states the following regarding the use if the ICM:

> The intent is not to have an IR regime under which distributors would habitually have their CAPEX reviewed to determine whether their rates are adequate to support the required funding. Rather, the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates.

Board staff notes that the ICM has evolved to the extent that "unplanned" is no longer a criteria for an ICM project. However, with the exception of one unique case (e.g. Toronto Hydro), most ICM projects approved have been for unusual projects, such as entire transformer station replacements/rebuilds.

a) Please discuss how PowerStream's ICM request is consistent with the Board's interpretation of the use of the ICM, as set out in the Supplemental Report on 3rd Generation IRM.

Response:

a) PowerStream strongly agrees with Board Staff's comment that the Board's interpretation of ICM has evolved over time. The Report of the Board on the Renewed Regulatory Framework for Electricity Distributors, dated October 18, 2012 ("RRFE Report"), on page 18, makes the following statement regarding ICM:

"In 2011, the Board revised its *Filing Requirements for Electricity Transmission and Distribution Applications* to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains."

The Board's current "Filing Requirements For Electricity Distribution Rate Applications" dated July 17, 2013 ("Filing Requirements"), Chapter 3, Section 3.3.1 Incremental Capital Module on page 14 provides the following criteria for ICM:

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

PowerStream submits that its request for ICM funding is consistent with the current criteria set out by the Board as shown above:

- The RRFE report removed the criteria for "unusual" and "unanticipated".
- The amounts exceed the Board-defined materiality threshold
- The projects proposed for the ICM funding:
    - have a significant influence on PowerStream's operation;
    - are non-discretionary;
    - are clearly outside the base upon which rates were derived; and
    - are prudent.

Board Staff Interrogatory No. 8

Ref: Application, Appendix G-2 - pages 1 - 7

On page 4 of Appendix G-2 of the Application, PowerStream states:

> The cables that are identified for replacement are direct buried cables. The direct buried cables are being replaced with new cable that will be installed in ducts. Ducts provide mechanical protection against external factors in the future, cables can be pulled out from the duct and replaced more easily than replacing a direct buried cable.

a) Please confirm whether or not the proposed replacement of direct buried cable with new cable installed in ducts is for main feeders exclusively, or if PowerStream intends to install express feeders in ducts, as well.

Response:

a) In accordance with PowerStream's current design and construction standards, replacement of direct buried cables (feeder, express or primary subdivision cables) are installed with new cables in duct.

Board Staff Interrogatory No. 9

Ref: Application, Appendix G-5 - pages 1 - 10

On pages 1 through 10 of Appendix G-5 of the Application, PowerStream summarizes two system capacity relief projects in Barrie and Richmond Hill. PowerStream notes that these projects are to provide additional capacity to areas that are currently at capacity and are expecting significant loads to be energized in the near term. The two projects total $3.9M.

a) Please confirm whether or not the requested capital funding of $3.9M is net of any capital contributions that will be provided by developers in Richmond Hill and Barrie. If not, please indicate the anticipated amounts of capital contributions that will be required, if any.

Response:

a) PowerStream confirms that the capital costs of $3.9M are net of any capital contributions.

   No capital contributions will be received on these projects. Each project benefits many customers and PowerStream has no basis to request capital contributions.

Board Staff Interrogatory No. 10

Ref: Application, Appendix H-3 - pages 3 and 4

On page 3 of Appendix H-3 of the Application, PowerStream states it is in the second year of a ten year program to replace the first generation of IConF type Sensus smart meters deployed in 2007. PowerStream noted that there were 85,000 meters of this type that are currently deployed. On page 4

PowerStream notes that "as the Regional Network Interface (RNI) receives annual firmware upgrades, at some point it will no longer support the IConF meter.

a) Has PowerStream contacted the vendor to determine how long the IConF meters will continue to be supported with firmware updates? If so, what response did PowerStream receive?

b) How many meters is PowerStream proposing to replace per year?

c) PowerStream is replacing meters that are currently reflected in rate base and that have a significant remaining useful life. How do PowerStream's estimated $196,100 in meter upgrade costs reflect these factors?

Response:

a) PowerStream has contacted the vendor. The vendor has indicated it will continue to support firmware updates and has not specified the point in time where support will end.

b) PowerStream will replace 2,000 meters in 2014. PowerStream will continue to replace these meters over the period to 2022 with larger annual quantities being replaced closer to the ten year seal expiry and the end of life.

The $196,100 represents the installed cost of the new meters. The net book value of the meters removed from service will be deducted from fixed assets and recorded as a derecognition expense under modified IFRS.

Board Staff Interrogatory No. 11

Ref: Application, Appendix H-4 - page 5

Table 1 from Appendix H-4 of the Application, summarizing the historical expenditures for each of the categories of emergency replacement work, is reproduced below.

Table 1: Historical Expenditures				
Year	2013 Budget	2012 Actual	2011 Actual	2010 Actual
Poles, Conductors and Devices, Transformers	$ 6,640,392	$5,135,602	$6,680,567	$6,418,993
Major Storms and Accidents	$1,347,684	$1,392,799	$685,238	$427,289
Switching Equipment	$1,702,109	$1,806,249	N/A	N/A
Station Assets	$518,086	$540,706	$244,928	$102,726
TOTAL	$10,208,271	$8,875,356	$7,610,733	$6,949,008

On page 5 of Appendix H-4, PowerStream states that "forecast expenditures for the replacement work are determined based on historical expenditures." Table 2, reproduced below from Appendix H-4, summarizes PowerStream's expected budget for emergency replacement work in 2014.

Table 2: 2014 Budget	
Poles, Conductors and Devices, Transformers	$5,229,149
Major Storms and Accidents	$1,307,712
Switching Equipment	$1,687,130
Station Assets	$497,420
TOTAL	$8,721,411

a) Why does PowerStream not provide any historical expenditures for the Switching Equipment class of replacement work in 2011 and 2012?

b) Please provide further details on the methodology PowerStream uses to translate its historical emergency replacement costs to expected amounts for 2014. Please provide actual costs to date in 2013, for PowerStream's emergency replacement work.

c) In Appendix G-1, PowerStream provides details regarding its Pole Replacement Program along with an estimated budget of $4.75M for 2014. Please provide the actual historical costs for PowerStream's pole replacement program from 2013 to 2010. Please explain the distinction between what work is classified as part of the pole replacement program and what is considered an emergency replacement. Please confirm that there is no overlap between the requested costs for the two programs.

d) PowerStream experienced a significant jump in historical costs related to major storms and accidents between 2011 and 2012. Please explain the reasons for the jump between those two historical years. PowerStream maintained the 2012 level of costs in its 2013 budget. Please comment on whether or not PowerStream has experienced similar levels of actual emergency replacement work in 2013.

e) Similar to d) PowerStream experienced a jump in historical costs related to station assets between 2011 and 2012. Please summarize the reasons for the jump and whether or not PowerStream has experienced similar levels of actual emergency replacement work for station assets in 2013.

Response:

a) PowerStream provided historical expenditures for the Switching Equipment class of replacement work for 2012, so we assume that the question pertains to 2010 and 2011.

Prior to 2012, expenditures in the Switching Equipment replacement class were grouped together with the Poles/ Conductors/ Devices/ Transformers class, and it is not possible to determine the portions of the overall Poles/ Conductors/ Devices/ Transformers expenditures for 2010 and 2011 that were attributable to Switching Equipment replacements. In 2012, PowerStream commenced tracking Switching Equipment replacement expenditures as a separate class.

b) Accurately predicting the level of equipment failure leading to emergency replacement presents a significant challenge. PowerStream bases its Emergency Replacement budgets on historical trends in expenditures over the past few years. The 2014 Budget was established at a level consistent with 2012 actual expenditures which operations management feels represents the expected level of activity.

Actual expenditures to November 20, 2013 for PowerStream's Emergency Replacement work are as follows:

Table Staff 11-1: Emergency Replacements 2013 Year to Date

Description	2013 Actuals (to date)
Poles, Conductors/Devices and Transformers	$ 4,577,745
Major Storms and Accidents	$ 1,254,479
Switching Equipment	$ 1,698,822
Station Assets	$ 723,560
TOTAL	**$ 8,254,606**

c) Costs for PowerStream's pole replacement program from 2010 to 2013 are shown below:

Table Staff 11-2: Pole Replacement from 2010-2013

Program	2010		2011		2012		2013 (Forecast)	
	# of Units	$	# of Units	$	# of Units	$	# of Units	$
Planned Pole Replacement Program	127	$1.7 M	117	$1.2 M	315	$4.32 M	363	$5.0 M

The planned pole replacement program is a proactive program to replace poles to prevent pole failures. Pole testing data and strength analysis results are used to determine which poles require replacement.

The emergency replacement of poles includes replacement of failed poles and poles that are identified as requiring immediate replacement.

There is no overlap between the requested costs for the two programs.

d) The increase in actual expenditures from 2011 to 2012 for the Major Storms/Accidents category was due to a significant increase in such incidents from 2011 to 2012 that affected PowerStream's distribution system. Storms include significant weather events such as snow, ice, sleet, rain, lightning or wind. Accidents include incidents such as vehicle accidents, contractor equipment affecting PowerStream's overhead system, and contractor dig-ins. In 2011, there were a total of 156 outages caused by storms and accidents. In 2012, this figure increased to 318. Because the scope of system damage in an outage can vary, there is not necessarily a direct relationship between the number of outages and expenditures. However, the sharp spike in outages due to Storms/Accidents from 2011 to 2012 does indicate significant increased activity in this category, leading to greater expenditures.

Up to November 27, 2013, PowerStream experienced a total of 252 outages due to Storms/Accidents, with actual expenditures of $1,320,049. Both the number of outages and the year-to-date expenditures are in line with 2012 Actuals for this class of emergency replacement.

e) In 2011, PowerStream kept track of Emergency Replacements for stations differently and not all costs were tracked in the same manner as was done in 2012. Actual expenditures to-date in 2013 for Emergency Replacement costs in stations are $725,000.

Board Staff Interrogatory No. 12

Ref: 2014 Incremental Capital Workform - Sheet C1.1

A section of sheet C1.1 of the 2014 Incremental Capital Workform is reproduced below.

Load Actual - 2012 Actual

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C
Residential	Customer	kWh	301,603	2,765,593,704	0
General Service Less Than 50 kW	Customer	kWh	30,636	1,019,490,760	0
General Service 50 to 4,999 kW	Customer	kW	4,687	4,581,886,335	12,165,749
Large Use	Customer	kW	1	26,670,727	81,464
Standby Power	Connection	kW	0	0	0
Unmetered Scattered Load	Connection	kWh	2,816	12,933,395	0
Sentinel Lighting	Connection	kW	117	413,091	1,071
Street Lighting	Connection	kW	81,933	60,734,607	165,019

PowerStream's RRR 2.1.5 filing for the 2012 year shows the following values:

Rate Class	Billed Customers or Connections	Billed kWh/kW (as applicable)
Residential	304,801	2,772,334,989
GS < 50 kW	30,773	1,019,024,366
GS 50 to 4,999 kW	4,768	12,166,846
Large Use	1	81,464
Unmetered Scattered Load	2,842	12,970,917
Sentinel Lighting	115	1,073
Street Lighting	82,520	167,382

a) Please reconcile the difference between the data provided in the Incremental Capital Workform and PowerStream's 2012 RRR 2.1.5 filing. If the values were entered in error, please indicate the error and Board staff will make the appropriate change to the model.

Response:

a) "Billed Customers or Connections" values in the Incremental Capital Workform are based on the 2012 average actual customers or connections for January-December period, while “Billed Customers or Connections” values in PowerStream’s 2012 RRR 2.1.5 filing represent 2012 actual year-end numbers.

“Billed kWh/Billed kW” values in the Incremental Capital Workform represent 2012 actual final consumption/demand figures, as based on the final run of unbilled revenue accruals, while “Billed kWh/Billed kW” values in the PowerStream’s 2012 RRR 2.1.5 filing represent 2012 actual consumption/demand figures as based on the first run of the unbilled revenue report.

PowerStream submits that the correct values have been entered into the Incremental Capital Workform.

EP Interrogatory No. 1

Ref: 2014 IRM Application

Please reconcile the distribution revenue growth factor of 0.92% shown on page 15 (line 11) with the 0.88% factor shown on Sheet E1.1 in Appendix F-1.

Response:

The growth factor of 0.88% shown on Sheet E1.1 in Appendix F-1 is correct. The OEB model calculates growth as the change in revenue comparing the 2013 approved billing determinants at approved 2013 rates to 2012 actual billing determinants at approved 2013 rates. The growth factor shown on page 15 (line 11) is a clerical error.

EP Interrogatory No. 2

Ref: 2014 IRM Application, Appendix F-1

a) What is the source of the stretch factor of 0.3% as shown on page 11?

b) Does PowerStream propose that the price escalator shown on page 11 be updated to reflect the figure approved by the Board for January 1, 2014? Please explain.

Response:

a) PowerStream selected the middle group which in previous Board IRM models was used as the default pending release of the Board's assignment of stretch factors. The Board has released the stretch factors for 2014 and PowerStream has been assigned to the middle group (3).

b) Please see the response to Board Staff Interrogatory No. 1(a) above.

EP Interrogatory No. 3

Ref: 2014 IRM Application

a) For each of the projects/line items shown in Table 4-2, please provide the corresponding actual expenditures in each of 2010 through 2013, along with any forecasts, if available, for 2015 through 2018.

b) Please explain why the Eligible Capital Projects shown in Table 4-2 that total $33,886,187 appear to be the sum of the Incremental Capital CAPEX of $33,106,612 and the Amortization Expense of $779,575 shown in Table 4-3.

Response:

a) Please refer to table below.

Table EP3-1: Summary of Capital Additions 2010 to 2013

	Non-Discretionary Capital Additions and Eligible Capital Projects Summary								
	Actual			Q4 Forecast	Budget				
Project Description	2010	2011	2012	2013	2014	2015	2016	2017	2018
System Access									
Customer service Request	$ 3,939,167	$ 4,822,559	$ 15,328,626	$ 13,919,908	$ 12,462,448	$ 13,863,108	$ 14,891,458	$ 16,037,044	$ 16,638,854
Other 3rd party infrastructure development	$ 6,534,724	$ 7,845,031	$ 2,516,956	$ 3,371,183	$ 11,716,684	$ 10,488,374	$ 9,267,610	$ 6,751,246	$ 7,519,011
Mandated service obligations	$ 335,926	$ 380,316	$ 1,150,252	$ 1,626,980	$ 1,533,227	$ 1,362,092	$ 1,687,000	$ 1,329,000	$ 1,683,000
Sub-total System Access	**$ 10,809,817**	**$ 13,047,906**	**$ 18,995,834**	**$ 18,918,071**	**$ 25,712,359**	**$ 25,713,574**	**$ 25,846,068**	**$ 24,117,290**	**$ 25,840,865**
System Renewal									
Emergency Replacements	$ 7,716,861	$ 7,077,686	$ 8,875,356	$ 10,618,537	$ 8,721,411	$ 8,822,909	$ 8,965,788	$ 9,079,813	$ 9,225,490
Pole Replacements	$ 1,687,811	$ 1,160,109	$ 4,327,783	$ 5,028,675	$ 4,775,873	$ 4,933,378	$ 5,047,432	$ 5,163,139	$ 5,280,545
Cable remediation	$ 1,009,727	$ 3,145,708	$ 2,741,327	$ 17,812,859	$ 20,183,168	$ 17,238,066	$ 18,747,884	$ 18,251,393	$ 18,779,509
Switchgear and transformer replacements	$ 1,580,570	$ 996,302	$ 1,510,162	$ 2,686,892	$ 3,931,290	$ 3,210,357	$ 3,303,921	$ 2,875,417	$ 2,931,209
Station replacements	$ 1,698,775	$ 1,219,226	$ 1,382,223	$ 1,462,867	$ 1,062,733	$ 1,347,877	$ 1,104,875	$ 953,506	$ 136,176
Sub-total System Renewal	**$ 13,693,744**	**$ 13,599,031**	**$ 18,836,851**	**$ 37,609,830**	**$ 38,674,475**	**$ 35,552,587**	**$ 37,169,900**	**$ 36,323,268**	**$ 36,352,929**
System Service									
Distribution system capacity relief	$ 1,267,537	$ 5,510,013	$ 1,487,360	$ 3,902,718	$ 3,933,123	$ 8,195,729	$ 2,867,176	$ 34,369,878	$ 4,177,596
Sub-total System Service	**$ 1,267,537**	**$ 5,510,013**	**$ 1,487,360**	**$ 3,902,718**	**$ 3,933,123**	**$ 8,195,729**	**$ 2,867,176**	**$ 34,369,878**	**$ 4,177,596**
General Plant									
Information and communication systems	$ 1,754,923	$ 1,378,999	$ 1,139,288	$ 1,201,239	$ 1,495,660	$ 2,948,475	$ 2,826,940	$ 3,313,790	$ 3,324,865
Sub-total General Plant	**$ 1,754,923**	**$ 1,378,999**	**$ 1,139,288**	**$ 1,201,239**	**$ 1,495,660**	**$ 2,948,475**	**$ 2,826,940**	**$ 3,313,790**	**$ 3,324,865**
Grand total	**$ 27,526,021**	**$ 33,535,949**	**$ 40,459,333**	**$ 61,631,858**	**$ 69,815,617**	**$ 72,410,365**	**$ 68,710,084**	**$ 98,124,226**	**$ 69,696,255**

NOTE: Costs in year 2010 is based on CGAP and all other years are based on MIFRS

b) The Eligible Capital Projects amount of $33,886,187, shown in Table 4-2 of the Application, represents the capital cost of the eligible capital projects. The capital cost is entered into the Board's Incremental Capital Project Summary model ("Project Model"). There is a Project Model completed for each eligible project.

The amounts shown in Table 4-3 under Incremental Capital CAPEX are the "Closing Net Fixed Asset" amounts coming from each of the Project Models, which is the capital cost less the depreciation.

The depreciation and CCA amounts from the Project Models are calculated on the capital costs shown in Table 4-2, not the Incremental Capital CAPEX shown in Table 4-3.

Consideration of this interrogatory leads PowerStream to think that the allocation of the depreciation and capital cost allowance (CCA) on the ratio of the eligible capital amount of $18,209,851 to the Incremental Capital CAPEX of $33,106,612 may be incorrect. Table EP-IRR#3-1 below shows the results of allocating based on the ratio of the eligible capital amount of $18,209,851 to the Capital Costs of $33,886,187.

Table EP-IRR#3-2: Capital Summaries to Workform Translation

ACTUAL SUMMARIES

#	Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Underground Cable Rehabilitation	$20,183,168	$451,251	$1,614,653
ICP 2	System Renewal - Pole Replacements	4,775,873	109,181	382,070
ICP 3	System Renewal - Station Replacements	1,062,733	38,140	85,019
ICP 4	System Renewal - Switchgear and Transformer Replacement	3,931,290	90,092	314,503
ICP 5	System Capacity Relief	3,933,123	90,911	314,650
	Total	$33,886,187	$779,575	$2,710,895

INPUT TO 2014 ICM WORKSHEET

#	Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Underground Cable Rehabilitation	$10,846,085	$242,494	$867,687
ICP 2	System Renewal - Pole Replacements	$2,566,472	$58,672	$205,318
ICP 3	System Renewal - Station Replacements	$571,094	$20,496	$45,688
ICP 4	System Renewal - Switchgear and Transformer Replacement	$2,112,607	$48,414	$169,009
ICP 5	System Capacity Relief	$2,113,592	$48,854	$169,087
ICP 6				
	Total	$18,209,851	$418,930	$1,456,788

The revised amounts for depreciation of $418,930 and CCA of $1,456,788 were entered into the Incremental Capital Workform sheet “Incremental Capital Adjustment”. The revised Incremental Revenue Requirement of $1,340,859 is a decrease of $565 from the original filing. There is a negligible impact on the ICM rate riders.

PowerStream will file an updated Incremental Capital Workform and rate riders as part of the draft rate order.

EP Interrogatory No. 4

Ref: 2014 IRM Application

a) Please confirm that PowerStream has followed the Filing Requirements and has included a full year of depreciation expense in the calculation of the revenue requirement shown in Table 4-4.

b) Please confirm that PowerStream has followed the Filing Requirements and has included a full year of capital cost allowance in the calculation of PILs in the calculation of the revenue requirement shown in Table 4-4.

c) Please confirm that the use of the full year of depreciation noted in (a) above is different than PowerStream's depreciation methodology used for regular capital additions.

d) Please confirm that when the requested capital additions are moved from Account 1508 to rate base upon rebasing, the net book value to be transferred will be based on the accumulated amortization of the assets in Account 1508, and not on PowerStream's normal depreciation policy.

Response:

a) Confirmed.

b) Confirmed.

c) PowerStream confirms that the use of the full year depreciation differs from PowerStream's methodology. PowerStream's depreciation methodology is to record depreciation monthly based on the month that an asset goes into service. Assets going into service in January would receive 12 months of depreciation. Assets going into service in December would receive 1 month of depreciation.

d) PowerStream cannot confirm that the depreciation to be recorded on the assets in Account 1508 will not be based on PowerStream's normal depreciation policy.

PowerStream has reviewed the Board guidance in the “Filing Requirements For Electricity Distribution Rate Applications” dated July 17, 2013, section 3.3.1.7 ICM Accounting Treatment. PowerStream notes that the Board has not specified any different method of depreciation for these assets.

In the absence of any other direction from the Board, PowerStream will record depreciation on the ICM capital additions using its normal depreciation methodology

This question seems to imply that the depreciation would be recorded on the same basis as used in the ICM model, i.e. full year depreciation on 2014 ICM capital additions. PowerStream does not agree that this is required.

PowerStream notes that its current approved rates contain only a half-year of depreciation on the 2013 capital additions. Despite this PowerStream will record a full year of depreciation on those assets in 2014.

EP Interrogatory No. 5

Ref: 2014 IRM Application, Appendices G & H

a) Please confirm that the numbers in the following table are accurate and reflect the information provided in Appendices G-1 through G-5 and H-1 through H-5. If required, please provide any corrections.

b) Please explain why PowerStream has used the five projects shown in Appendix G to justify the incremental capital CAPEX as shown in Table 4-3 given that the total expenditures for these projects is actually less than that incurred in 2013.

c) Why did PowerStream not use Third Party Infrastructure Development as one of the projects to justify the incremental capital CAPEX shown in Table 4-3 given that it has the biggest increase in 2014 relative to 2013?

d) Please confirm that the incremental non-discretionary CAPEX in 2014 relative to 2013 is actually $2,576,233, as shown in the table above.

e) The second column in Table 4-3 is labeled "Incremental Capital CAPEX". Please explain what these figures are incremental to.

f) Please add a column to the above table showing the Board approved 2013 non-discretionary capital expenditures in the same level of detail. Please include new line items if all of the non-discretionary expenditures do not fit in the existing line items.

Response:

a) Confirmed with one correction, Station and Automated Switch Replacement in 2014 should be $1,062,733. Please refer to table below.

Table EP 5-1: Non-Discretionary Capital Additions 2013 and 2014

Non-Discretionary Capital Additions	2014	2013	Change	2013 (Board Approved)
Pole Replacement Program	4,775,873	4,895,466	(-119,593)	4,038,806
Cable Remediation	20,183,168	19,358,647	824,521	17,217,200
Switching Units & Transformers	3,931,290	3,530,841	400,449	2,987,461
Station and Automated Switch Replacement	1,062,733	1,574,727	(-511,994)	1,015,029
System Capacity Relief	3,933,123	4,564,637	(-631,514)	4,303,701
Total - Appendix G	**33,886,187**	**33,924,318**	**(-38,131)**	**29,562,197**
Customer Service Work	12,462,448	12,693,767	(-231,319)	11,695,457
Third Party Infrastructure Development	11,716,684	6,406,909	5,309,775	6,279,604
Mandated Service Obligations	1,533,227	2,579,056	(-1,045,829)	638,706
Emergency Replacement	8,721,411	10,208,271	(-1,486,860)	9,409,215
Information Communication	1,495,660	1,428,063	67,597	1,440,069
Total - Appendix H	**35,929,430**	**33,316,066**	**2,613,364**	**29,463,051**
Total - Appendix G & H	**69,816,617**	**67,240,384**	**2,575,233**	**59,025,248**

b) PowerStream has used the Board’s Incremental Capital Workform model and calculated the materiality threshold as $51.6 M. This model uses the Board’s prescribed formula as per the Board’s Filing Requirements for Electricity Distribution Rate Applications; dated July 17, 2013, section 3.3.1.1 ICM Materiality Threshold. The five projects identified are non-discretionary projects that contribute to PowerStream’s capital spending being above the materiality threshold. This approach is consistent with the Board’s guidance on ICM which allows non-discretionary projects to be considered and no longer requires the projects to be “unusual” or “unanticipated”. See the response to Board Staff Interrogatory No. 5(a) for additional information.

c) In determining which projects were to be considered to justify the incremental capital projects PowerStream first grouped like projects together per the “Ontario Energy Board Filing Requirements For Electricity Distribution Rate Applications” dated July 17, 2013, Chapter 5 Consolidated Distribution System Plan Filing Requirements. PowerStream then considered the principle funding mechanisms for the grouped projects. PowerStream did consider including the Third Party Infrastructure Development within the incremental capital projects since the total dollar amount of qualifying projects already selected well exceeded the eligible capital amount after applying the materiality threshold.

d) Please see the answer to EP Interrogatory No. 5(a).

e) The term “Incremental Capital CAPEX” is taken from the Board’s Incremental Capital Workform on sheet E3.1 “Summary of Incremental Capital Projects (ICPs)”. It is the “Eligible Incremental Capital Amount” as calculated on that sheet and is incremental to the Threshold CAPEX calculated on sheet E2.1.

f) Please see EP Interrogatory No. 5(a).

EP Interrogatory No. 6

Ref: 2014 IRM Application & EB-2012-0161 Decision and Settlement Agreement

a) Please confirm that the agreed to level of capital expenditures in 2013 was $114,279,000. If this cannot be confirmed, please provide the agreed upon figure.

b) What is the projected actual level of capital expenditures in 2013?

c) Based on the Settlement Agreement and the Board Decision, what was the level of additions to rate base (net of the capital contributions) approved for 2013?

d) What is the projected actual level of additions to rate base for 2013, again net of capital contributions.

Response:

a) The agreed level of capital expenditures in 2013 was $112,279,000 after an increase to contributed capital of $2,000,000.

b) The projected actual level of rate base capital expenditure in 2013 is $98.6M

c) The approved capital additions to rate base (net of the capital contributions) approved for 2013 was $82.8M.

d) The projected actual level of additions to rate base for 2013 is approximately $80M net of capital contributions.

SEC Interrogatory No. 1

[Application, p. 8]

Please advise the number of years the incremental capital rate riders are expected to be in effect, i.e. the number of years until "the next cost of service rates".

Response:

PowerStream filed its last cost of service application in 2012 for rates effective January 1, 2013. PowerStream intends to file an IRM application for 2015 rates. PowerStream expects the incremental capital rate riders to be in effect for 2014 and 2015 and perhaps longer.

SEC Interrogatory No. 2

[Application, p. 10]

Please file the most recent internal update of the Kinectrics Asset Condition Assessment.

Response:

The most recent internal update of the Kinectrics Asset Condition Assessment is attached as Appendix A, Asset Condition Assessment Technical Report.

SEC Interrogatory No. 3

[Application, p. 10]

Please advise which of the ICM projects are multi-year projects that are expected to continue beyond 2014. Please advise whether ICM applications are expected to be filed for any of 2015, 2016, or 2017, and if so for which years. Please provide any memoranda, plans, or other documents dealing with the possibility, likelihood or intention of filing ICM applications in any of those years.

Response:

All of the ICM projects are planned to be completed in 2014. Projects that will continue beyond 2014 have been excluded from the list of 2014 non-discretionary capital projects included in this application.

Many of these projects are part of multi-year programs. Please see the response to EP Interrogatory No. 3(a) which provides planned program expenditures through to 2018.

Please see the response to Board Staff Interrogatory No. 5(c) regarding PowerStream's plans for subsequent ICM applications. There are no memoranda, plans, or other documents dealing with the possibility, likelihood or intention of filing ICM applications in any of those years.

SEC Interrogatory No. 4

[Application, p. 12]

Please file the 2014-2018 capital plan.

Response:

Please find PowerStream’s most recent 10 year capital plan, which includes the years 2014 to 2018, attached as Appendix B, Ten Year Capital Plan.

SEC Interrogatory No. 5

[Application, p. 13]

Please provide the most current estimate of the total capital budget for 2014, and any breakdown currently available of that budget.

Response:

Please refer to Board Staff Interrogatory No. 5(b).

SEC Interrogatory No. 6

[Application, p. 14]

Please provide a table showing, using the same categories as Table 4-2 or additional categories if required, the Non-discretionary capital additions for each of 2009 through 2013, using actuals for 2009 through 2012, and current forecast (e.g. 10+2) for 2013.

Response:

Please see EP Interrogatory No. 3(a).

The information for 2009 cannot be provided because Barrie Hydro and PowerStream recorded information using different methods.

SEC Interrogatory No. 7

[Application, p. 16]

Please advise, for each of the categories of 2014 Non-Discretionary Capital Additions listed in Table 4-2, the amount in that category that is non-discretionary by reason of criterion 5 on the list of ICM criteria.

Response:

PowerStream has assessed each project against criterion 5, a material increase in cost (beyond the time value of money), if the project is necessary but undertaken at a later time.

For all the categories listed in Table 4-2 there is a potential increase in costs if these projects are not undertaken.

These projects are high risk and non-discretionary. If any of these projects are not undertaken PowerStream could expect consequences as result of not being able to connect customers, not providing reliable power, or not maintaining safe assets. Consequences could include being sanctioned by regulatory bodies, having other parties complete the work at an unknown cost to PowerStream, litigation and/or increased costs to complete work at less than optimal conditions.

SEC Interrogatory No. 8

[Application, p. 16]

"If Powerstream does not obtain the requested ICM funding, it will have to reconsider the amount of capital spending and adjust to maintain its financial stability." Please prioritize all of the Non-Discretionary Capital Additions such that, for any given non-discretionary capital additions budget approved by the Board for ICM treatment, the parties can determine how much of each category will be spent in 2014. If it is easier to do this including discretionary capital as well, please prepare the prioritization for the entire capital budget, rather than just the non-discretionary component, but identify in the prioritization list which items are discretionary, and which are not.

Response:

Please see the answer to Board Staff Interrogatory No. 6(c).

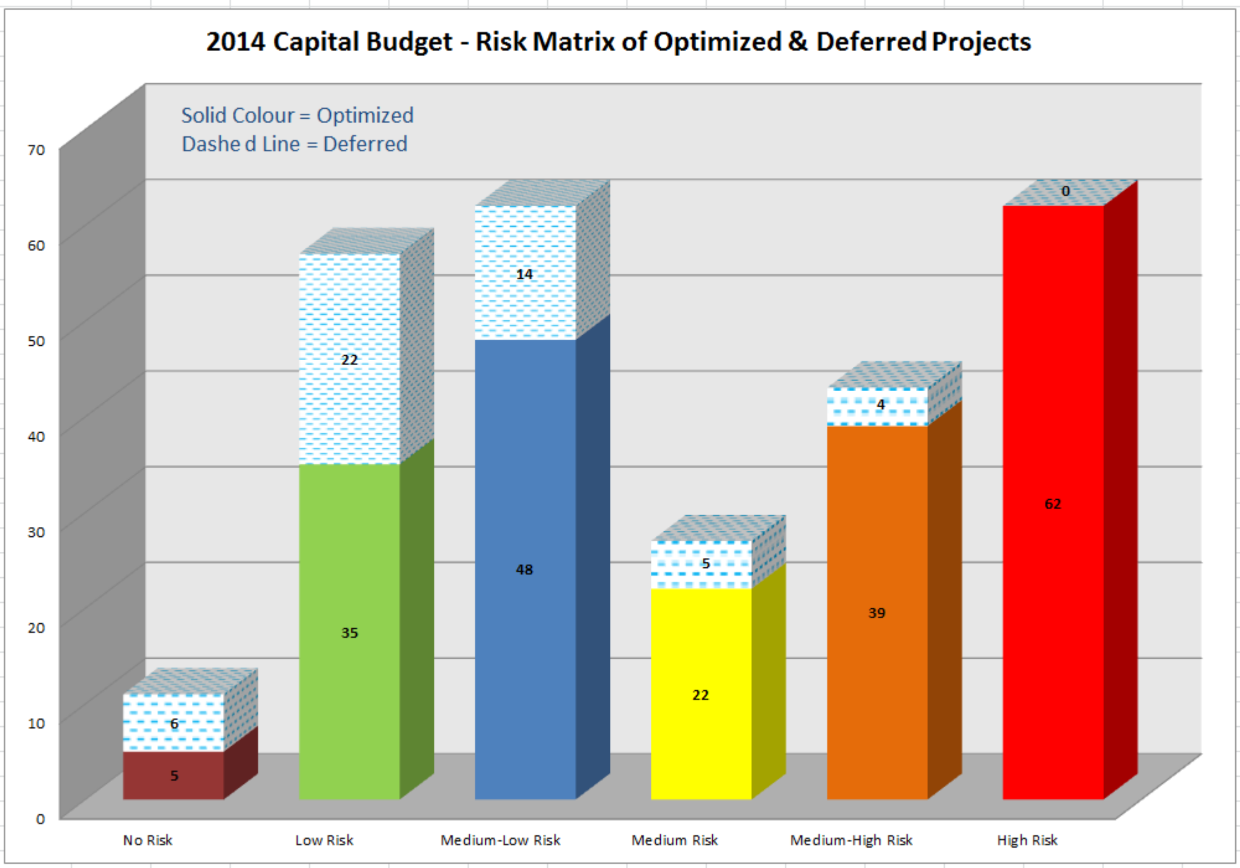
SEC Interrogatory No. 9

[Application, p. 16]

Please provide the "risk matrix chart" from Optimizer for all capital projects that was used to determine which projects that were considered "red risk". Please include in the chart all projects that were considered, and their risk level, and not just those determined to be red risk.

Response:

Table SEC 9-1: Optimizer Risk Matrix Chart



SEC Interrogatory No. 10

[App. G-1]

With respect to the Pole Replacement Program:

a. p. 1. Please provide the report from the inspection and testing program showing the need to replace 400 poles.

b. p. 1. Please confirm that PowerStream defines “poor” condition to be 60% capacity or less.

c. p. 2. Please advise the aggregate number of poles to be replaced, in all programs, in 2014.

d. p. 2. Please provide a table showing the total poles replaced each year in all programs for 2009 through 2013, and the total amount spent to do so. Please disaggregate in that table the # and $ component that is through the Pole Replacement Program, rather than through other programs.

e. p. 3. Please provide the benchmarks used by the Applicant to determine the reasonableness of the installation costs listed in Table 1.

f. p. 3. Please confirm that the labour costs listed in Table 2 total more than 35% of the total costs of pole replacement. Please confirm that the cost per pole is unchanged from the 2013 COS application. Please confirm that no additional staff are being hired for, or assigned to, the Pole Replacement Program relative to 2013.

g. p. 4. Please advise how many of the Applicant’s 42,100 poles carry wires at 27.6 kV or higher.

h. p. 5. Please provide a table showing the number of catastrophic pole failures for each year from 2003 through 2012. Please either exclude, or disaggregate, failures caused by external causes, such as major storms or automobile strikes.

Response:

a) Please refer to attached Appendix C, 2014 Pole Replacement Candidates.

b) Pole strength of 60% capacity or less would classify a pole in the “poor” condition category. There are other conditions that may classify a pole as “poor” condition. PowerStream defines “poor” condition to be Category 1 and 2 as defined in PowerStream’s 2014 IRM Application, Appendix G-1, pages 1 and 2.

c) PowerStream plans to replace 400 poles in 2014 under the planned pole replacement program. Due to different ways of budgeting, PowerStream is unable to provide the number of poles to be replaced in the other programs for 2014.

d) The information for the planned pole replacement program can be found in the response to Board Staff Interrogatory No. 11 (c).

Based on reporting limitations, PowerStream is unable to provide the number and costs of poles to be replaced in the other programs.

The information for 2009 cannot be provided because Barrie Hydro and PowerStream recorded information using different methods.

e) The installation costs indicated in Table 1 are based on a typical configuration. The actual installation cost for a specific pole may be higher or lower than what is indicated in Table 1.

The unit cost of each pole installation is widely varied and is dependent on the type of the pole configuration, including for example the height, number of primary circuits, field conditions, and the presence of other equipment such as switches, transformers, secondary and joint use, etc.

f) PowerStream confirms that:

- The labour costs listed in Table 2 total more than 35% of the total costs of pole replacement.
- The cost per pole is unchanged from the 2013 COS application
- No additional staff are being hired for, or assigned to, the Pole Replacement Program relative to 2013.

g) It is estimated that there are 28,000 poles that carry wires at 27.6 kV or higher.

h) There have not been any catastrophic pole failures which were not caused by external causes, such as major storms or automobile strikes.

SEC Interrogatory No. 11

[App. G-2]

With respect to the Cable Remediation Program:

a. p. 1. Please provide the PowerStream document that sets out the multi-year Cable Remediation Plan.

b. p. 2. Please advise the expected remaining life of cables that are 26-30 years old, and explain how many years cable injection extends that life. By way of example, if cable with a 50 year life is injected after 30 years, is its life still 50 years (30+20), or is it extended to 70 years?

c. p. 4. Please confirm that all 119 km. of cable to be remediated in 2014 have been tested directly and show "advanced insulation degradation". Please advise what percentage of that cable has already failed, if any.

d. p. 4. Please provide a table showing the number of km. of cable remediated and the cost, broken down by injection and by replacement, for each of the years 2009 through 2013.

e. p. 6. Please provide details of the first two projects on Table 3, which are also listed on Table 2, and show a breakdown of the total budgets for both injection and replacement for those two projects.

f. p. 7. Please restate Table 4 on the basis of failures per 100 km of line, by year. Please confirm that the Applicant has not introduced any material changes in how primary cable and splice failures are calculated or measured in the period 2005 through 2014.

Response:

a) The report that set out the multi-year Cable Remediation Plan is attached as Appendix D, Five Year Capital Plan.

b) According to the Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board", the useful lives of various types of underground cable are listed in the table below.

Table SEC 11-1: Underground Cable Useful Life Table (Kinectrics)

Cable Type	Minimum Useful Life (MIN UL)	Typical Useful Life (T UL)	Maximum Useful Life (MAX UL)
Primary Non-Tree Retardant XLPE - Direct Buried	20 Years	25 Years	30 Years
Primary Non-Tree Retardant XLPE - In Duct	20 Years	25 Years	30 Years
Primary Tree Retardant XLPE - Direct Buried	25 Years	30 Years	35 Years
Primary Tree Retardant XLPE - In Duct	35 Years	40 Years	55 Years

The primary cause of cable failures is due to the phenomena of "water treeing" in the insulation. Research indicates that cable injection extends the life of cable for another 20 years and deals with the issue of "water treeing". The cable injection service providers warrant the cable for another 20 years after they have been injected. As such, a cable which was injected at an age of 26 -30 years can be expected to have a useful life of another 20 years, or a total life of 46-50 years. For the example provided, injecting the cable with 50 year life at 30 years will only extend the life to 50 years, not 70.

c) PowerStream performs sample testing on random sections within the identified areas. Sample cable segments which represent 89 km of cable have been tested with the results indicating that insulation is aged and deteriorated. Since the cables in a particular subdivision are of the same vintage and installed using the same techniques the sample testing provides an accurate picture of the conditions of the cables in the subdivision.

Since 2012 there have been 173 failures in the area where the cable is being injected and/or replaced. This represents 145 failures per 100km of cable as compared to the system wide failure rate of approximately 1.5 failures per 100km. Please refer to SEC Interrogatory No. 11(f).

d) Please refer to the 2 tables below.

Table SEC 11-2: Cable Replacement 2010 to 2013

Cable Replacement				
	Actual			Q4 Forecast
Year	2010	2011	2012	2013
Cost	$983,286	$ 2,829,932	$1,931,017	$15,018,692
km	2.66	10.33	9.06	50.3

Table SEC 11-3: Cable Injection 2010 to 2013

Cable Injection				
	Actual			Q4 Forecast
Year	2010	2011	2012	2013
Cost	$26,441	$ 315,776	$810,310	$2,794,167
Km	0.41	9.57	25.1	91.21

e) Please refer to Appendix E, SEC Interrogatory No. 11(e).

f) Please refer to table below.

Table SEC 11-4: Cable Failures 2005 to 2013

Number of Primary Cable and Splice Failures by Year									
Cause	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013 (YTD)**
Cable in Service (Km)	n/a	n/a	n/a	n/a	7172	7722	7889	7998	8081
Primary Cable and Splice Failure	70	52	70	75	75	81	103	123	111
Failure per 100 km					1.04	1.04	1.30	1.53	1.37

The data on cable in-service prior to 2009 is not available, and as such, the failures per km have not been calculated.

PowerStream confirms that there have been no material changes in way of reporting or calculating the primary cable and splice failures during the period 2005 through 2013.

SEC Interrogatory No. 12

[App. G-3]

With respect to the Switching Units and Transformers Replacement Program:

a. p. 1. Please provide details on the "calculated asset health index" referred to.

b. p. 3. Please confirm that all submersible transformers have been classified as "poor" condition in 2014.

c. p. 4. Please confirm that there are no padmount transformers classified as Code A. Please advise how many are classified as Code B, and how the Applicant determined which of those should be replaced in 2014.

d. p. 4. Please provide a table showing switchgear failures as a percentage of the total number of switchgear in the system, for the period 2005 through 2012.

e. p. 6. Please provide a table showing, for each of the four projects listed in Table 1, the number of units replaced, and the total cost, for each of 2009 through 2013

Response:

a) Please refer to attached Appendix F, SEC Interrogatory No. 12(a).

b) Not all of the submersible transformers in PowerStream's service territory have been classified as "poor" condition.

The units that are selected for replacement in 2014 are obsolete and in "poor" condition. PowerStream only replaces the "worst" units on a prioritized basis. The rest of the units will still be in-service. It is expected that, as time goes on, some of the existing units will deteriorate and will be reclassified to “poor” condition.

c) Currently there are no known padmount transformers classified as Code A.

On an on-going basis, PowerStream may identify new Code A transformers in the field. When this occurs, PowerStream must expedite the replacement to maintain system reliability and public safety.

Currently, based on the inspection results to date, there are 89 Code B transformers. The worst 50 units, which will be replaced in 2014, were selected based on a detailed condition analysis.

d) Please refer to table below.

Table SEC 12-1: Switchgear Failures 2005 to 2013

All Switchgear Failures									
Cause	2005	2006	2007	2008	2009	2010	2011	2012	2013 (YTD)
Total Number of Switchgear	n/a	n/a	n/a	n/a	1744	1772	1798	1816	1825
Number of Failures	7	16	16	21	20	15	30	24	25
Failure %					1.1%	0.8%	1.6%	1.3%	1.3%

e) Please refer to table below

Table SEC 12-2: Switchgear & Transformer Replacements 2010 to 2013

Switching Units and Transformers Replacement from 2010-2013								
	2010		2011		2012		2013	
	# of Units	$	# of Units	$	# of Units	$	# of Units	$
Pad-Mounted Switchgear Replacement	25	1,450,531	12	532,697	7	697,178	20	1,005,979
Mini-Rupter Switches Replacement	n/a*	0	n/a*	0	n/a*	0	n/a*	0
Submersible Transformer Replacement	13	130,038	20	479,131	32	812,985	24	1,263,913
Pad-Mounted Transformer Replacement	n/a*	0	n/a*	0	n/a*	0	54	417,000

Notes:

- The information for 2009 cannot be provided because Barrie Hydro and PowerStream recorded information using different methods.
- n/a* - No planned program existed. These assets were replaced as they failed.
- Costs in year 2010 is based on CGAAP and all other years are based on MIFRS

SEC Interrogatory No. 13

[App. G-4]

With respect to the Station and Automated Switch Equipment Replacement Program:

a. p. 1. Please advise why, unlike other asset categories, there is no category for this equipment that applies to healthy equipment.

b. p. 4. Please provide the normal expected life of the equipment to be replaced in Markham TS#1. If the life is longer than the 27 years to date, please explain why this equipment requires early replacement.

Response:

a) There is an asset condition assessment model developed for the Station Circuit breakers, however, there is no model developed for the automated switches. The automated switches are inspected and either a Code A (replace immediately) or Code C (inspect on the next cycle) is assigned. The automated switches are sealed units and the inspection provides minimal information on the asset's health. The replacement decision is typically dependent on age and any issues encountered during operation of the switch, such as a failure to open or close either remotely or locally. Replacement decisions are also driven by obsolescence issues.

b) The normal expected life of circuit breakers at PowerStream transformer stations, including Markham TS#1, is expected to be 45 years.

The 2014 plan includes replacement of four of these circuit breakers in Markham TS#1. The breakers were manufactured in 1982 and placed into service in 1986.

The breakers are being replaced before the end of their normal expected life for the following reasons:

- These breakers are not reliable – These are GEC Alstom type OX 36 breakers. At this time PowerStream has 11 of these breakers still in service. The oldest of these breakers are at Markham TS#1. The OX 36 breakers have a history of failures; the most recent failure was in October 2013 when an OX 36 breaker failed to close. Please refer to VECC Interrogatory No. 10(b).

- When a Transformer Station (TS) feeder breaker fails while attempting to clear a feeder fault, it is typical to have approximately 240,000 Customer Minutes of Interruption (CMI), which is a significant impact on our customers.

- The GEC Alstom OX 36 breakers are obsolete – They are no longer built or supported by the manufacturer.

- The OX 36 breakers are difficult to maintain - Replacement parts are only available by scavenging parts from previously replaced, failed circuit breakers of the same type.

SEC Interrogatory No. 14

[App. G-5]

Please provide a table showing the total km., and the cost, for capacity relief projects for each of 2009 through 2013.

Response:

Please refer to table below

Table SEC 14-1: Capacity Relief Projects 2010 to 2013

Year	Total (km)	Cost ($)
2010	6.7	$2,790,147.20
2011	3	$6,931,358.27
2012	5.5	$4,570,225.78
2013	27.1	$8,448,208.87

The information for 2009 cannot be provided because Barrie Hydro and PowerStream recorded information using different methods.

SEC Interrogatory No. 15

[App. H-2, p. 4]

Please provide information on the source and development of the budgets for the YRRT projects. Please explain each of the three marginal notes for those projects in Table 1.

Response:

The development of the budget for the York Region Rapid Transit (YRRT) projects is based on upcoming work as identified by YRRT Project Managers and driven from the VivaNext Master Plan (see attached Appendix G, SEC Interrogatory No.15). Due to the large scale of this multi-year endeavour PowerStream staff meet regularly throughout the year with YRRT to understand project needs and timing. The YRRT has broken down the project into phases. Each phase is reviewed by PowerStream's Capital Design department. The budget estimates for the YRRT projects are developed through a review of the plant that will be impacted within the project limits. Field information (number of switchgears, transformers, poles, switches and underground cable) is collected in order to determine the scope of work and from that high level budget estimates for each phase are assembled.

The three marginal notes reflect PowerStream's estimate of percentage of project and in-service completion of the three YRRT phases for 2014.

SEC Interrogatory No. 16

[App. H-3]

With respect to the Mandated Service Obligations:

a. p. 3. Please confirm that the personnel who normally did re-verification in 2007 through 2011 were included in the Applicant's cost of service for those years. Please confirm that the work those personnel did on smart meters was not included in the amounts recovered by the Applicant from ratepayers for the smart meter program.

b. p. 3. Please confirm that the IConF meters are being replaced prior to the end of their originally anticipated useful life.

c. p. 4. Please provide the document setting out the "ten year replacement strategy".

Response:

a) PowerStream personnel performing meter re-verification work are hourly paid staff and their time is charged against work orders specific to the work they are doing. The work order may be a capital project or it may be an operation or maintenance work order. Their wages and related costs are budgeted in a similar manner. Meter re-verification work is budgeted and charged to capital workorders.

For employees involved in the Smart Meter program, their time spent on installing smart meters was budgeted against the work order for smart meters and not charged to OM&A. Similarly to the extent that these employees are budgeted to capital work, their cost appears in the capital budget and not the OM&A budget.

PowerStream confirms that no meter re-verification costs were included in the smart meter cost recovery amounts approved for recovery from rate payers.

b) Please see the response to Board Staff interrogatory No. 10(b).

c) The documentation for the meter replacement program is provided in the Application in Appendix H-3.

SEC Interrogatory No. 17

[App. H-5, p. 4]

Please explain why upgrading the website is considered to be non-discretionary.

Response:

PowerStream's website has been used primarily to deliver static communication to customers. As technology evolves, today's modern websites not only offer a wide variety of real-time information to customers, but also act as an interface which allows customers to push information back to our systems using their mobile devices. This includes customer self-services options, time-of-use data, green button data/apps, reports/updates on power outages as well as dynamic account information.

This investment aligns with expectations in the “Ontario Energy Board Filing Requirements For Electricity Distribution Rate Applications” dated July 17, 2013, Chapter 5 Consolidated Distribution System Plan Filing Requirements. It is customer focused and public policy responsive.

In particular it allows PowerStream to meet the requirement to provide customers ready access to their time-of-use (TOU) data as part of the Ontario Government smart meter/ TOU initiative.

PowerStream expects to encounter technological challenges using its current website to accommodate the growing volume of data required to serve customers who choose to use the website as their primary source of contact with the company. In order for PowerStream to offer its customers a secure and reliable web interface, a new website built to current technology and security standards is required.

VECC Interrogatory No. 1

Reference: Management Summary, Page 13

Preamble: PowerStream indicates that both the risk of not completing a project and the value of completing a project are considered.

a) Please explain how the value of completing the project is considered in the review process to prioritize projects.

Response:

a) As described in Board Staff Interrogatory No. 6(c) capital projects are scored on both the value of completing the project and the risk of deferring the project. Both value and risk are measured against five strategic objectives: Customer Focus; Regulatory Excellence; Operational Excellence; Growth & Sustainability; and High Performance Culture. The projects, once scored, are then put through an Optimization tool. The optimization tool considers the value scores, the risk scores, the total project costs and the total portfolio costs. A team of senior leaders at PowerStream then reviews the optimized results and decides which projects are included or not.

VECC Interrogatory No. 2

Reference: Management Summary, Pages 15-16

Preamble: PowerStream indicates it has used the criteria for non-discretionary that was accepted by the Board in Toronto-Hydro Electricity Systems Limited rate case (EB-2012-0064).

a) For each of the projects listed in Table 4-2 on Page 14, please indicate which of the THESL's five criteria apply to each project.

Response:

Please see the table below.

Table VECC 2-1: Non-discretionary Criteria by Project

Project Description	(1) Statue, Code, provincial policy or equivalent	(2) Consideration for safety of public and workers	(3) Existing or imminent reliability degradations	(4) Existing or imminent capacity shortages	(5) Material Increase in cost, if the project is necessary but undertaken at a later time.
Customer service request	X				X
Other 3rd party infrastructure development	X				X
Mandated service obligations	X				X
Emergency replacement	X	X	X		X
Pole replacement	X	X	X		X
Cable remediation			X		X
Switchgear and transformer replacement		X	X		X
Station Replacements			X		X
Distribution System Capacity Relief				X	X
Information & Communications Systems				X	X

VECC Interrogatory No. 3

Reference: Appendices G-1 to G-5, Appendix H

a) Please identify the projects that could be categorized as unusual and unanticipated.

Response:

a) PowerStream notes that the Board's filing requirements have removed "unusual" and "unanticipated" from the criteria for ICM as discussed in the response to Board Staff Interrogatory No. 7(a).

There are no projects that could be categorized as "unusual" and "unanticipated" with the exception of the higher than normal level of spending for Other 3rd Party Infrastructure.

VECC Interrogatory No. 4

Reference: 2014 IRM Application & EB-2012-0161 Decision and Settlement Agreement

a) What is the year to date and projected year end capital expenditures for 2013?
What is the year to date and projected year end in-service additions to rate base for 2013, net of capital contributions.

Response:

a) The actual year to date (YTD) capital expenditures for 2013, as of November 22, 2013, are $70.6M net of contributed capital. The projected year end capital expenditure for 2013 is $98.6M, net of contributed capital.

b) The actual YTD in-service capital additions for 2013 are $51.0M net of contributed capital. The projected year end in-service capital additions for 2013 are $80M net of contributed capital.

VECC Interrogatory No. 5

Reference: Appendix G-1, Page 2, Pole Replacement Program

a) Please provide a breakdown of the 2014 capital budget between category 1 (256 poles) and category 2 (144 poles) pole replacements.

Response:

a) Category 1 - 256 poles, $3,056,559

Category 2 - 144 poles, $1,719,314

VECC Interrogatory No. 6

Reference: Appendix G-2, Page 7, Table 4, Cable Remediation

a) Please provide the year to date failure history for 2013.

Response:

a) The year to date failure history (as of Nov 20^{th}, 2013) is 111. Please refer to SEC Interrogatory No. 11(f).

VECC Interrogatory No. 7

Reference: Appendix G-2, Table 2 & Table 3, Cable Remediation

Preamble: VECC calculates that the cost per metre for 2014 cable injection projects is $69 compared to $261 per metre for 2014 cable replacement projects.

a) Please provide the cost per metre for injection and replacement for the years 2009 to 2013 and discuss any variances.

b) Please provide a breakdown of the $/m for the 2014 cable injection and cable replacement projects in terms of design cost, labour cost, contract cost and material cost.

Response:

a) Please see the two tables below.

Table VECC 7-1: Cable Replacement 2010 to 2013

Cable Replacement				
	Actual			Q4 Forecast
Year	2010	2011	2012	2013
Cost	$983,286	$ 2,829,932	$1,931,017	$15,018,692
km	2.66	10.33	9.06	50.3
($/m)	$369.66	$273.95	$213.14	$298.58

Table VECC 7-2: Cable Injection 2010 to 2013

Cable Injection				
	Actual			Q4 Forecast
Year	2010	2011	2012	2013
Cost	$26,441	$ 315,776	$810,310	$2,794,167
Km	0.41	9.57	25.1	91.21
($/m)	64.4902	32.99645	32.2833	30.634437

<u>Cable Replacement Unit Cost:</u>

The actual costs per meter of cable replacement from 2010 to 2013 range from $213 to $369. The 2014 cost estimate per meter of $261 is within this range.

It should be noted that the actual cable replacement cost varies depending on the actual specific field conditions and configurations, such as:

- Open trench or directional boring;
- In boulevard or in roadway/driveway;
- Size of the cable replaced three phase feeder cable (e.g. 1000 kcmil) or small size single phase cable (e.g. 1/0); and
- Any adjacent facilities.

<u>Cable Injection Unit Cost:</u>

The actual costs per meter of cable injection from 2010 to 2013 range from $31 to $64. The 2014 cost estimate per meter of $69 is outside of this range.

In 2014, the areas for cable injections are primarily commercial/industrial, in the Markham service territory. This territory, when initially installed, comprised of Mini-Rupter switches and multiple splices in the primary cable systems. These factors drive the cost estimate per meter higher compared to other areas that have been injected.

It should be noted that the actual cable injection cost varies depending on the actual specific field conditions and configurations, such as:

- Number of splices in the cable segment;
- Location of splices (on boulevard or underneath the drive way). In many cases the splices may need to be dug up and replaced to facilitate the injection;
- Are there existing strand-filled cable portion within the cable segment? Because strand-filled cable blocks the injection fluid, the cable segment may need to be replaced;
- Size of the cable - large size three phase feeder cable (e.g.1000 kcmil) or small size single phase cable (e.g.1/0);
- Adverse weather condition (e.g. raining) may slow down the process which will increase the unit cost;
- Area where the cable is being injected – industrial/Commercial customers typically require the injection work to be done during the weekend to avoid outages.

b) Please refer to the table below.

Table VECC 7-3: 2014 Cable Replacement and Injection Cost Summary

2014 Cable Injection Cost Breakdown for 57,000 m		
Item	**Cost ($)**	**Cost ($/m)**
Labour (PowerStream)	292,175	5.13
Contractor (Labour and Material)	3,395,157	59.56
Inventory Material (PowerStream)	214,000	3.75
Design Cost (PowerStream)	51,250	0.90
Total	**$3,952,582**	

2014 Cable Replacement Cost Breakdown for 62,173 m		
Item	**Cost ($)**	**Cost ($/m)**
Labour (PowerStream)	597,200	9.61
Contractor (Labour and Material)	14,728,809	236.90
Inventory Material (PowerStream)	558,544	8.98
Design Cost (PowerStream+ Contractor)	346,033	5.57
Total	**$16,230,586**	

VECC Interrogatory No. 8

Reference: Appendix G-2, Page 7, Cable Remediation

Preamble: PowerStream has calculated that the cable remediation program will save over 450,00 CMI versus a “do nothing” approach and the CMI saved is expected to provide an equivalent customer monetary value (outage avoidance) in the order of $4M.

a) Please provide the calculations and assumptions underlying the above savings.

Response:

a) The cables selected for injection or replacement are at end of life. The financial risk calculations of cable failures are based on the assumptions and estimates below.

- a failure rate of 0.5 is calculated per km of cable (2 failures in subdivision of 4km)
- a mix of 70% residential and 30% industrial/commercial customers are within the areas selected.

- Duration of interruption:	3 hours
- Number of residential transformers	12 transformers
- Number of customers in the residential loop	120 customers
- Number of customers affected in an outage: 120/2	60 customers (half loop)
- Customer load: 120 customers x 3 kW	360 kW
- Customer load affected in an outage: 360 kW/2	180 kW (half loop)
- Total connected load in industrial/commercial loop	4000 kW
- Customer load affected in industrial/commercial loop	2000 kW (half loop)
- Number of Customer in the industrial loop	4 customers
- Number of Customers affected in an outage	2 customers (half loop)
- Customer Interruption Cost (Frequency)	$2.00/kW (Residential)
- Customer Interruption Cost (Duration)	$4.00/kWh (Residential)

- Customer Interruption Cost (Frequency)	$ 20/kW (Industrial)
- Customer Interruption Cost (Duration)	$ 30/kWh (Industrial)

The **financial risk** cost is estimated as follows:

Cost to Residential Customers

- Customer Interruption Cost (Frequency) = 180 kW x $2/kW x 0.5 failures/km x 119x 0.70 = 14,994
- Customer Interruption Cost (Duration) = 180 kW x 3 hours x $4/kWh x 0.5 failures/km x119 x 0.70 = $89,964

Total Cost to Residential Customers (Interruption) = $14,994 + $89,964 = $104,958

Cost to Industrial Customers

- Customer Interruption Cost (Frequency) = 2000 kW x $20/kW x 0.5 failures/km x 119x 0.30 = $714,000
- Customer Interruption Cost (Duration) = 2000 kW x 3 hours x $30/kWh x 0.5 failures/km x119 x 0.30 = $3,213,000

Total Cost to Industrial (Interruption) = $714,000 + $3,213,000 = $3,927,000

Total Cost to Customers (Interruption) = $104,958 + $3,927,000 = <u>$4,031,958</u>

The customer service reliability impact resulted by cable failures is expressed in CMI (Customer Minutes of Interruption).

The **CMI** is estimated as follows:

CMI to Residential Customers

CMI = 60 customers x 3 hours x 60 minutes x 0.5 x 119 x 0.70 = 449,820 CMI

CMI to Industrial Customers

CMI: 2 x 3 x 60 x 0.5 x 119 x0.30 = 6426 CMI

Total CMI = 449,820 + 6426 = <u>456,246</u>

VECC Interrogatory No. 9

Reference: Appendix G-3, Switching Units and Transformers

a) Page 1 – Please provide the weightings for each of the factors used to calculate the switchgear asset health index.

b) Page 1 - Please discuss how a “poor” health index condition is determined for switchgear.

c) Page 2 - Please provide the weightings for each of the factors used to calculate the Mini-Rupter asset health index.

d) Page 2 - Please discuss how a “poor” health index condition is determined for Mini-rupters.

e) Please confirm the number of padmount switchgears and Mini-rupter switches in the system, the quantity of each that have a “poor” health index condition, and how PowerStream determined which of those should be replaced in 2014.

f) Page 3 - Please discuss how a “poor” health index condition is determined for Submersible Transformers.

g) Page 4 – Please provide the 2013 year to date switchgear failures.

h) Page 5 – Please confirm the number of submersible transformers in the system, the quantity that have a “poor” health index condition, and how PowerStream determined which of those should be replaced in 2014.

i) Page 7, Reliability Benefit - Please provide the calculations and assumptions underlying the CMI savings and equivalent customer monetary value identified.

Response:

a) The details on the calculated health index are described below.

Switchgear and Mini-Rupter Switch

Health Index Formulation: The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index (HI) formulation are provided in the tables.

Table VECC 9-1: Distribution Switchgear/Mini-Rupter Health Index Parameters and Weights

#	Distribution Switchgear/Mini-Rupter Condition Parameters	Air Type Weight	Oil Type Weight
1	Age	2	5
2	IR record	2	2
3	Field inspection	5	5
4	Failure rate	*	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria #1 to #3. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criterion #4

Figure VECC9-1: Distribution Switchgear/Mini-Rupter Health Index flowchart.

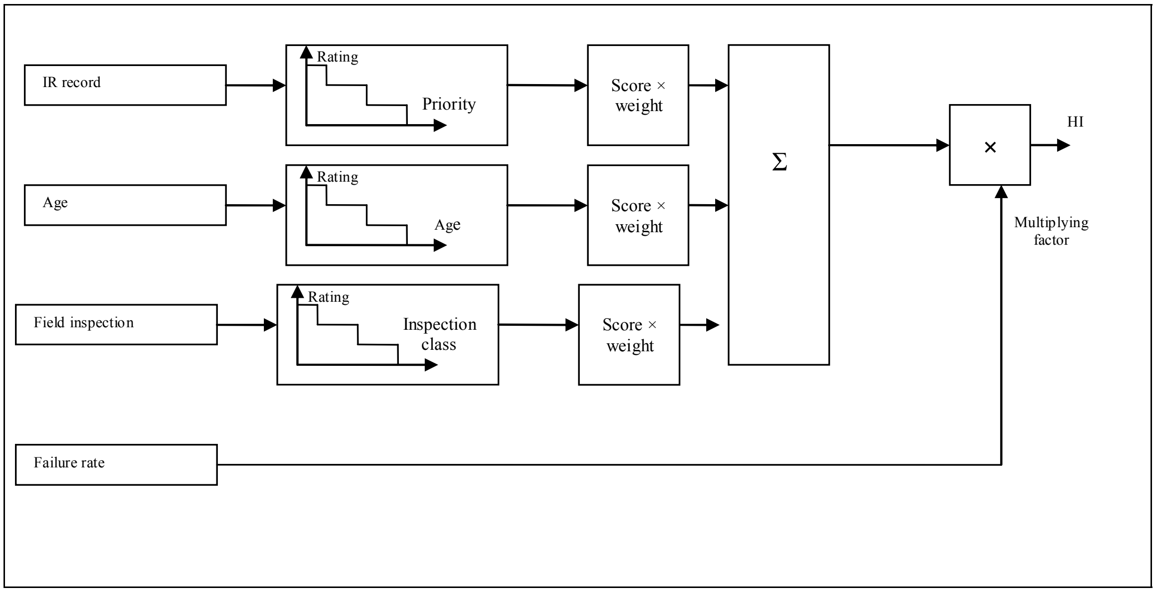


Table VECC 9-2: Distribution Switchgear/Mini-Rupter Parameter #1: Age/condition Criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	41-60 years old
D	1	61-70 years old
E	0	> 70 years old

Table VECC 9-3: Distribution Switchgear/Mini-Rupter Parameter #2: IR record condition criteria

Condition Factor	Factor	Condition Criteria Description
A	0	Corrective measures are required at the earliest possible time.
B	2	Corrective measures are required at the next available opportunity or shutdown.
C	3	Corrective measures are required as scheduling permits.
D	4	Normal maintenance cycle can be followed.

Table VECC9-4: Distribution Switchgear/Mini-Rupter Parameter #3: Field inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	0	Corrective measures are required at the earliest possible time.
B	2	Corrective measures are required at the next available opportunity or shutdown.
C	3	Corrective measures are required as scheduling permits.
D	4	Normal maintenance cycle can be followed.

b) A “poor” health index for switchgear is determined as a heath index of 50 and below using the above methodology.

c) Please see response to part (a) above.

d) A “poor” health index Mini-Rupter switch is determined as a heath index of 50 and below using the methodology described in part (a) above.

e) 1. Padmount Switchgear:
Total number of switchgear units = 1805 units
Number of switchgear units with “poor” health index = 86 units
PowerStream prioritized the worst 30 units of the 86 units for 2014.

2. Mini-Rupter Switch:
Total number of Mini-Rupter switch units = 433 units
Number of Mini-Rupter switch units with “poor” health index = 23 units
PowerStream prioritized the worst 15 units of the 23 units for 2014.

f) Please refer to attached Appendix H, VECC Interrogatory No. 9(f).

g) The year to date (as of Nov 20th, 2013) switchgear failures is 25. Refer to SEC Interrogatory No. 12(d).

h) Total number of submersible transformer units = 208 units
Number of submersible transformer units with “poor” health index = 148 units
PowerStream prioritized the worst 9 units for 2014, based on the program to remove the remaining submersible transformers that are installed at the bottom of streetlight poles. The balance of the submersible transformer units are run to failure.

i) Please refer to attached Appendix I, VECC Interrogatory No. 9(i).

VECC Interrogatory No. 10

Reference: Appendix G-4, Station and Automated Switch Replacement

a) Page 2 – For each of the projects, please identify the condition rating as Category 1 or Category 2.

b) Page 4 – For the Planned Circuit Breaker Replacement Markham TS#1 – Bus #2, please provide additional details on the health index assessment as well as the historical failures.

c) Page 4 - Please confirm the number of RTUs in the system, the quantity that are at end of life, the quantity that have been replaced in each of the years 2009 to 2013, and how PowerStream determined which of those should be replaced in 2014.

Response:

a) Replacement of Automated Switches – Category 2

RTU Replacement Program – Category 2

b) The circuit breaker health index is comprised of the nine condition parameters shown in Table VECC 10-1, below. Each of the parameters is assigned a *weight*, relative to the importance of the parameter to the overall health of the circuit breaker.

Table VECC 10-1: Circuit Breaker Condition Parameters

#	CB Condition Parameters	Weight
1	Bushing/Insulator Condition	3
2	Leaks (OCB only)	3
3	Tank and Control/Mechanism Box	2
4	Control and Mechanism Box Components	2
5	Foundation and Support Steel Grounding	2
6	Overall Condition	4
7	Time/Travel	3
8	Contact Resistance	4
9	Number of Corrective Maintenance	4

The condition of each circuit breaker is assessed annually against each of the parameters. The score for each parameter is assigned a score of 0 to 5 with 0 representing very poor condition and 5 representing very good condition.

Table VECC10- 2: Circuit Breaker Health Index Categories

Category	Range	
Very Poor	0	30
Poor	31	50
Fair	51	70
Good	71	85
Very Good	86	100

The scores for each of the condition parameters are totalized and an overall *Health Index* score, out of 100, is determined. The *Health Index* of the circuit breaker can then be determined as *Very Poor* to *Very Good* using the criteria shown in Table 2.

The GEC Alstom OX 36 breakers at Markham TS #1 received and overall *Health Index* score of 46. As can be seen in Table VECC 10-2, a score of 46 translates to a *Poor Health Index.*

A summary of the OX 36 breaker historical failures on Bus #2, for the last ten years is shown below in Table VECC 10-3.

Table VECC 10-3: MTS #1 Bus #2 Breaker Failure Summary

Date	Breaker	Failure Type
1/27/2004	M4	Failed to open
1/13/2009	M6	Failed to close
5/2/2010	M6	Failed to close
8/3/2010	M4	Failed to close
3/25/2011	M4	Failed to close
5/2/2011	M4	Failed to close
10/23/2013	M8	Failed to close
10/24/2013	M4	Failed to close

c) The following table shows the total number of RTUs and the end of the life RTUs.

Table VECC 10-4: RTU Summary

Total Number of RTUs	383
End of Life RTUs	57

PowerStream has identified 8 locations from based on criticality of locations (such as the number of customers on the feeder, switch location), age, obsolesce and condition.

The following table shows the quantities that have been replaced under the planned and unplanned projects. The unplanned quantities represent RTUs that have failed during operation.

Table VECC 10-4: RTU Replacements 2010 to 2013

RTU Replaced			
Year	Planned	Unplanned	Total
2010	12	7	19
2011	5	8	13
2012	5	4	9
2013	9	5	14

RETAIL TRANSMISSION SERVICE RATES

Board Staff Interrogatory No. 13

Ref: 2014 RTSR Workform - Sheet 4

A section of Sheet 4 of the 2014 RTSR Workform is reproduced below.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor
Residential	kWh	2,772,334,986		1.0345
General Service Less Than 50 kW	kWh	1,019,024,366		1.0345
General Service 50 to 4,999 kW	kW		6,730,683	
General Service 50 to 4,999 kW – Interval Metered	kW		5,358,368	
Large Use	kW		159,258	

Board staff is unable to reconcile the non-loss adjusted metered kW for the GS 50 to 4,999 kW and Large Use classes with the values in PowerStream's 2012 RRR 2.1.5 filing (shown in interrogatory above).

a) Please reconcile the difference between the data provided in the RTSR Workform and PowerStream's 2012 RRR 2.1.5 filing. If the values were entered in error, please indicate the error and Board staff will make the appropriate change to the model.

Response:

a. "Non-Loss Adjusted Metered kW" for GS 50 to 4,999 kW and Large Use classes as reported in the 2014 RTSR Workform is adjusted to reflect the reclassification of a customer. The customer was reclassified from GS 50 to 4,999 kW to Large Use class, based on their load, effective April 1, 2013.

The reconciliation to PowerStream's 2012 RRR 2.1.5 is provided in Table Staff 13-1 below.

Table Staff 13-1: Reconciliation RTSR Workform to 2012 RRR 2.1.5 - Demand for GS>50 kW and Large Use Classes

		RRR 2.1.5 (2012 data)	Re-classification to Large use	2014 RTSR Workform (Sheet 4)
GS 50 to 4,999 kW	kW	6,730,682.85	0	**6,730,682.85**
GS 50 to 4,999 kW (interval Metered)	kW	5,436,163.08	(77,795)	**5,358,368.30**
Total: GS 50 to 4,999 kW	**kW**	**12,166,845.93**		
Large Use	**kW**	**81,463.68**	77,795	**159,258.46**

LOST REVENUE ADJUSTMENT MECHANISM VARIANCE ACCOUNT

VECC Question # 11

Reference: Appendix K

a) Please confirm the LRAM claim reflects the measure lives and unit savings related to the Every Kilowatt Counts program that have expired beginning in 2010, noting that the input assumptions including the measure life, unit kWh savings and free ridership for Compact Fluorescent Lights (CFLs) and Seasonal Light Emitting Diodes (LED) were changed in 2007 and again in 2009.

b) Please adjust the LRAM claim as necessary to reflect the measure lives and unit savings for any/all measures that have expired starting in 2011.

Response:

a) The calculation of PowerStream – Barrie rate zone 2014 LRAM is based on the "2006-2010 Final OPA CDM Results for PowerStream Inc.", which contains the most up to date measure lives and units savings issued by the OPA.

b) PowerStream has calculated its LRAM claim using the net savings for 2011 and 2012 as per the "2006-2010 Final OPA CDM Results for PowerStream Inc." report. PowerStream believes that the OPA report has already made the requested adjustment - no further adjustment is required.

DEFERRAL AND VARIANCE ACCOUNTS

Board Staff Interrogatory No. 2

Ref: Application, Manager's Summary - page 32

On page 32 of the Manager's Summary, PowerStream states the following regarding the GEA plan filed with its 2013 cost of service application:

PowerStream had filed for GEA funding rate adders based on the planned spending but this request was withdrawn at the request of Board Staff and intervenors who felt that a detailed Green Energy Plan was needed, rather than the Basic Green Energy Act Plan filed by PowerStream, if funding adders were to be approved. In the absence of funding adders, PowerStream seeks approval to dispose of certain GEA deferral accounts based on the actual balances as at December 31, 2012.

a) Please confirm whether or not PowerStream is proposing to dispose of the GEA deferral accounts on a final basis. If so, please explain why in PowerStream's view it would be reasonable for the Board to dispose of the accounts in the absence of a prudence review.

b) If not, were the Board to approve the use of funding adders, would PowerStream accept the disposition of costs requested in this application, subject to a future prudence review in its next cost of service application?

Response:

a) PowerStream is agreeable to either a final disposition with prudence review at this time, if permitted, or a funding adder approach as mentioned in part (b).

b) PowerStream is agreeable to disposition of these amounts through funding adders subject to a future prudence review in its next cost of service application.

Board Staff Interrogatory No. 3

Ref: Application, Manager's Summary - pages 34 and 35

Ref: Application, Appendix M - page 7

Ref: Application, EB-2012-0161 - Ex. B1/T. 1/Sch. 5, pages 13 - 23

On page 34 of the Manager's Summary, PowerStream indicates that is seeks to update its compensation claim for Renewable Generation Connection Rate Protection ("RGCRP"). PowerStream states that its request for 2014 has been updated to include:

- the revenue requirement for the eligible investments made in 2012 for the years 2012, 2013 and 2014, taken from the model attached as Appendix M; and

- the 2014 revenue requirement on the eligible investments made up to the end of 2011, taken from the model filed and approved in 2013 (see Appendix N).

On page 7 of Appendix M of the Application, PowerStream shows investments for renewable generation connections in 2012. The table indicating investments and the amounts eligible for RGCRP is reproduced below.

Calculation of Direct benefits

		Actual 2012	Direct Benefit	Eligible Amount
Capital spending			6%	
WiMax Communication Network		$ 254,459	$ 15,268	$ 239,191
CIS modifications for FIT		$ 33,067	$ 1,984	$ 31,083
Fault Level Reduction and Station programming		$ 354,973	$ 21,298	$ 333,675
Total		**$ 642,499**	**$ 38,550**	**$ 603,949**

On pages 13 - 22 of Ex. B1/T. 1/Sch. 5 of PowerStream's 2013 cost of service application, PowerStream describes a project to update its CIS system that was included in its capital expenditures for 2012 and 2013.

a) Please provide an overall description, a breakdown of the costs, as well as, a description of the nature of the costs for the three projects indicated in the above table, and on page 7 of Appendix M. In the description, please indicate PowerStream's procurement process for selecting vendors and 3rd party service providers, as well as, the nature of the services/products procured.

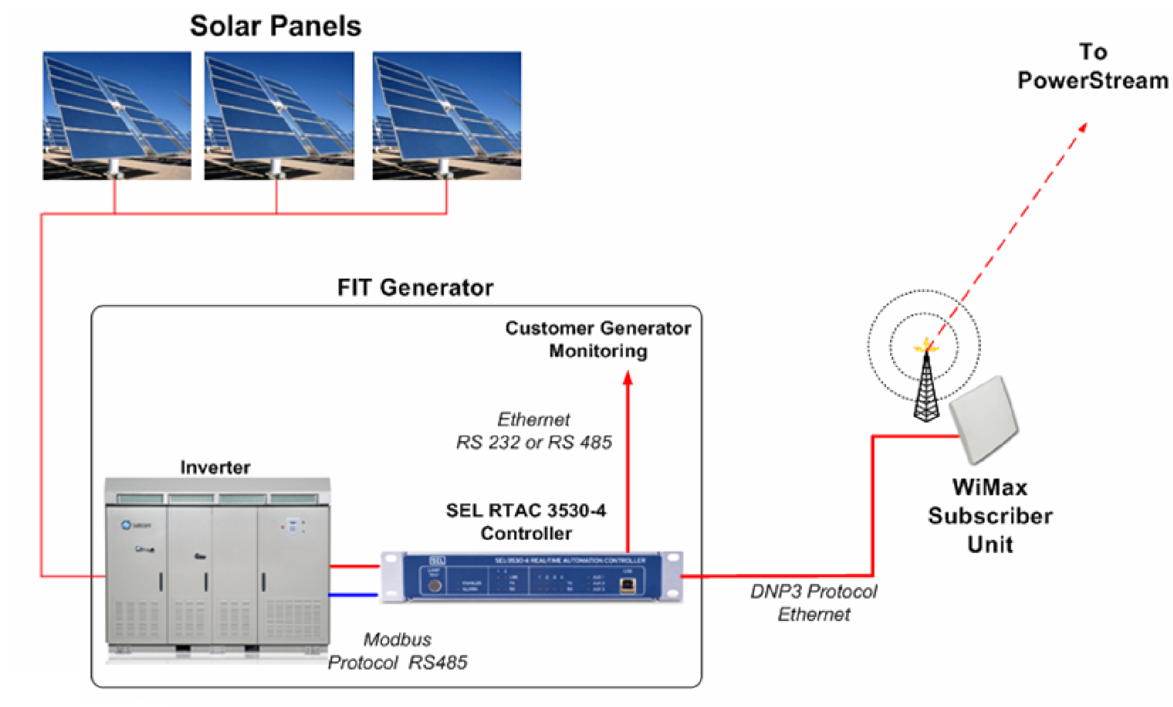
b) Please confirm whether or not the costs for CIS modifications for FIT customers are incremental to CIS upgrade costs approved in rates in PowerStream's 2013 cost of service application.

Response:

a) The program descriptions and cost breakdowns are provided below.

WiMax Communication Network:

PowerStream’s operations require real time contact with generators to monitor output power and have the ability to shut a generator down in the event of an emergency. In order to facilitate communication between PowerStream’s control room and generators, it has been determined that a WiMax Communication Network is required to cover the extent of PowerStream’s large distribution territory. Generators are required to purchase a WiMax Receiver (Subscriber Unit) and a Signal Controller (SEL-3530 RTAC) at their own expense, as part of their generator’s connection agreement with PowerStream. The following diagram illustrates the expected equipment layout to be located at a customer owned generator.



Project Scope: The WiMax Project was initiated in 2011. 2012 activity was primarily focused on the construction of the WiMax Network for Feed-in-Tariff (FIT) generators and involved completing the nodes in Aurora, Alliston, and Vaughan. Specific 2012 work included the installation of the communication towers, procurement of the WiMax equipment and installing this equipment on the towers.

Project Benefit: PowerStream's control room will have the functionality to monitor renewable generators connected to PowerStream's distribution system in the Aurora, Alliston, and Vaughan service territories. This new capability will support the maintenance of grid stability by allowing the remote shutdown of a generator in the event of an emergency and confirm a generator is off during maintenance periods which will ensure the safety of staff working on the distribution system.

Opportunity: The WiMax Network's bandwidth is scalable and can be expanded if required to accommodate future generators.

Equipment Purchases:

- Vaughan(VTS1) Communication Tower supply and installation
  - RFQ responders: Black& Veetch, Glentel, and Point to Point
  - Project awarded to Point to Point Communications based on price
- Alliston(MS431) Communication Tower supply and installation
  - RFQ responders: Kelcom, Glentel, and Point to Point
  - Project awarded to Kelcom based on price
- 6'x8' Communication House for Alliston
  - PowerStream Standard Comm. Shed Purchased from PTMW Inc.
- WiMax Base Stations and Antennas
  - Equipment purchased from RuggedCOM
- WiMax License Fees with Industry Canada
- Various Station Fence and Ground Grid Expansions
- Engineering Contractor's Support
- Labour and Burdens

Table Staff 3-1: WiMax 2012 Cost Breakdown ($)

2012 WiMax Communications Network					
Work order	Consulting (1)	installation and Construction (2)	Internal Labour (3)	Equipment or materials (4)	Totals
308140	3,500	89,147	44,027	135,248	271,922
306407	39	5,480	37,812	(54,138)	(10,807)
Allocated costs (5)	(90)	(2,412)	(2,086)	(2,068)	(6,656)
Totals	3,449	92,215	79,753	79,042	254,459
Notes:					
1) Consultants provided technical expertise and knowledge towards the planning, design and construction of the units. Supported PowerStream management in other related matters.					
2) Contractors built the Wimax units and removed, repaired and replaced ground areas					
3) PowerStream staff to lead, cooridinate and manage the project including transportation costs					
4) Point to point communications, base station, convertors, data cable, high power antennae,					
5) Other renewable generation costs and credits to be allocated to specific projects [carrying charges, depreciation, burden clearing]					

Customer Information System ("CIS") Modifications for Renewable Generation:

The Green Energy Act introduced in 2009, which resulted in the FIT and MicroFIT programs, is intended to encourage customers to connect renewable generation to the electricity grid. PowerStream is obligated to accept connections to the distribution system and are therefore obligated to modify its billing system to accommodate a new category of customers.

PowerStream's billing system was originally designed and developed to produce bills for customers who consume electricity from the power grid. The introduction of the FIT and MicroFIT programs mandated PowerStream to modify the billing system to handle electricity producers in addition to consumers.

The system work involved the modification of existing CIS programs and the creation of new programs to accommodate electricity generation. It was determined there are multiple physical configuration options. As a result, the system had to be designed to accept multiple meter readings for a single premise and calculate costs based on a specific set of rules associated with the particular configuration.

Specifically, the software had to be modified or new modules created to accommodate three specific scenarios:

1) Net Metering – In this scenario, one meter measures both electricity consumption and production. The billing system was modified to accept both readings from a single meter and perform a calculation to determine the difference. The customer is billed on the difference but only if the consumption is greater than the generation. In the event that electricity generation exceeds consumption the customer will not receive a rebate. Instead the rebate amount is applied to future bills.

2) Parallel Metering - In this scenario, the load and the generator each have their own meter. The billing system will accept readings from both meters, send a normal bill for consumption, and produce a value upon which the customer will receive a rebate for the electricity generated.

3) Series Metering - This is similar to parallel metering, however the generator meter is connected behind the customer`s load meter and the calculation is based on the difference between the reading of each meter.

Additionally, work was required to develop new statements to supplement the existing bills for FIT and MicroFIT customers which included detailing electricity consumption and production. As is common with most software development projects comprehensive planning, design and testing was conducted to ensure the modified system would meet all regulatory and business requirements.

CIS Procurement Process:

The PowerStream billing system was originally developed by a company called T&W Info Systems(“T&W”) over 25 years ago using a programming language known as Business Basic (BBX). Over the years, T&W has maintained the system to support PowerStream’s changing business requirements. Currently, PowerStream is the only remaining user of this system in the world. Therefore it was determined that sourcing alternate developers with experience in BBX and T&W`s level of business knowledge would not be efficient nor prudent. Accordingly, PowerStream selected T&W to develop and implement the required software modifications to accommodate renewable generation.

Table Staff 3-2: 2012 CIS Modification Cost Breakdown ($)

2012 CIS Modifications – Renewable Generation			
Work order	Programming Contractor (1)	Internal Labour (2)	Totals
308140	30,846	3,085	33,931
Allocated costs (3)	(813)	(51)	(864)
Totals	30,033	3,034	33,067

Notes:

(1) T&W is the contractor procured to do the required programming work

(2) PowerStream project management oversight

(3) Additional other costs and credits to be applied proportionally to various Renewable generation projects. [carrying charges, depreciation, IFRS adjustments, burden clearing]

Fault Level Reduction:

PowerStream’s four ‘Jones’ type transformer stations (“TS”), MTS#1, MTS#2, MTS#3 and MTS#3E, are subject to high fault currents causing them to exceed their short circuit limiting capacity due to their close proximity with Hydro One’s Parkway Transformer Station. The fault levels increased beyond 18kA when Hydro One’s Parkway TS was commissioned in 2004, thereby making the Pickering Nuclear Power Plant electrically closer to PowerStream’s transformation stations in Markham. The Transmission System and Connection Point Performance Standards in the OEB’s Transmission System Code advise that the 3-phase fault level in the 27.6kV distribution system be no more than 17kA. Additionally, PowerStream’s Conditions of Service states that “for 16,000/27,600 V supply, the Customer's protective equipment shall have a three-phase, short circuit rating of 800 MVA (17kA) symmetrical.”

Therefore, it is important for PowerStream to implement fault level reduction to comply with the Transmission System Code and agree with our conditions of service. If fault level reduction equipment were not installed customers connecting near the transformer stations will have an increased risk of equipment damage and FIT installations would not be permitted because they will contribute to higher fault levels.

In order to provide short circuit capacity for potential generators in the area, PowerStream installed fault level reduction reactors at the four stations. This countermeasure will increase each station’s available generation connection capacity by 15MW, providing an overall addition of 60MW of generation capacity in the Markham area.

<u>Project Scope:</u> Install three phase fault level reduction reactors at PowerStream’s Markham Transformer Stations MTS#1, MTS#2, MTS#3 and MTS#3E to improve fault current levels.

Project Benefit: Will increase Renewable Generation capacity in Markham by 60MW as documented in the Green Energy Plan.

Opportunity: The reactors will supply additional protection for three-phase load customers on the feeder by limiting phase to phase fault current.

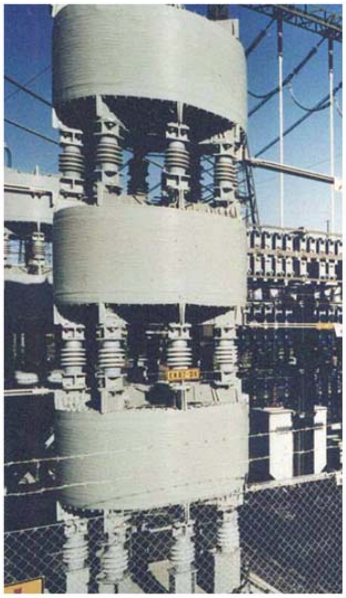
Technical Study:

In September 2011, Kinectrics Inc. was contracted to perform a feasibility study of PowerStream's Reactor Implementation strategy and its impact to the distribution grid.

Study Results:

PowerStream can reduce the three-phase fault level at the 28kV bus to less than 17 kA, by adding a reactor of 0.5 Ohm or higher. The actual size of the series reactor was determined by PowerStream to be 0.75 Ohms.

The following photo illustrates a three-phase stacked current limiting reactor.



Three-phase stacked current limiting reactor
(courtesy of Trench)

<u>Fault Level Reduction Procurement Process:</u>

An RFP for the procurement of the current limiting reactors was prepared by PowerStream's Procurement Department. Upon closing, submissions from Trench, MVA Power and Alstom were assessed based on price and technical compliance. A comparison of the three submissions was conducted. The Alstom price was the lowest of the three submissions. The MVA Power and Trench proposals were 19% and 26% higher respectively.

Similarly an RFP was issued by Procurement for Engineering Services. Submissions were received from AMEC, CIMA+, Genivar and Tetra Tech. CIMA+'s submission was the lowest of the four. Tetra Tech, Genivar and AMEC were 4%, 14% and 117% costlier respectively.

In each of the above cases, only reputable pre-qualified vendors were permitted to bid on the RFP.

Table Staff 3-3: Fault Level Reduction 2012 Cost Breakdown ($)

2012 Fault Level Reduction				
Work order	Consulting (1)	Internal Labour (2)	Equipment or materials (3)	Totals
308141	79,188	16,626	85,750	181,564
308142	0	16,625	165,489	182,114
Allocated costs (4)	(1,895)	(796)	(6,014)	(8,705)
Totals	77,293	32,455	245,225	354,973

Notes:

1) Consultants provided technical expertise and knowledge in planning, designing and construction of the fault level reduction project. Supported PowerStream management in other related matters.
2) PowerStream staff to lead, coordinate and manage the project including transportation costs
3) Current limiting reactors, Pedestals with meters,
4) Other renewable generation costs and credits to be allocated to specific projects [carrying charges, depreciation, burden clearing]

b) Table below describes the CIS modification work required to support renewable generation for the years 2010 to 2012. The period 2010 to 2011 represent the programming work that was submitted and approved in PowerStream's 2013 cost of service (COS) rate application. The 2012 work is the incremental system development work submitted in this 2014 IRM application.

These costs are separate and distinct from CIS modification to the billing system to meet other requirements, unrelated to FIT and microFIT, that were included in the 2013 COS rate application.

Table Staff 3-4: CIS Modifications Summary

PERIOD	DESCRIPTION OF CIS MODIFICATIONS
2010 – 2011	1) Meetings to strategize plan and develop a solution to automate the calculation of energy usage for billing purposes for new generation customers. Initially calculated manually. The design, implementation and testing of this solution was the primary focus of the 2010-2011 activities. 2) Automate and setup of new accounts by project type 3) Modify existing accounts to recognize both registers on the meter 4) Allow 2 reading entries and calculate consumption. 5) Store/bank unused generation for net metering customers and allow it to be passed on for up to 12 months 6) Calculate bill charges 7) Print bills, including supplementary statements itemizing individual registers reads, exhibit resulting consumption and showing banked consumption to the customer 8) Update bills
2012	1) As a result of issues related to billing through the MV-RS, Itron meter based software application, the billing system for the generator customers was disabled. Therefore programming modifications were required in order that the generator customer accounts could be correctly read through the MV-RS. 2) Bill printing through the web and to PowerStream’s third party vendor, Kubra, was not in the original user acceptance testing requirements. At the onset it was assumed that the electronic files used to print in-house bills and other information could be utilized with minimal changes to the billing formats and structure for Kubra and web recipients. However, it was determined that the electronic files were not compatible. As a result electronic file transfers to Kubra and the web were disabled. Program modifications were required to the digital files in order to enable the external bill printing.

Board Staff Interrogatory No. 4

Ref: Application, Manager's Summary - pages 35 and 38

On page 35 of the Manager's Summary, PowerStream shows a balance in account 1535 Smart Grid OM&A of $803,499. On page 38 of the Manager's Summary, PowerStream states:

Smart grid OM&A costs consists of costs for employees on the Smart Grid team, consultant costs and costs related to knowledge gathering and sharing activities (conferences, trade shows, meetings, training). Some of the main activities are discussed below.

No further details or breakdown of the OM&A costs related to smart grid are provided. The $803,499 in OM&A requested for disposition represents that vast majority of the $840,791 total revenue requirement for Smart Grid activities that PowerStream is proposing to recover through the Smart Grid Cost Disposition Rate Rider.

a) Please provide a detailed break-down of the Smart Grid OM&A costs sought for recovery for each of the Smart Grid activities indicated in the Manager's Summary.

b) Where OM&A costs were for the services of external parties (e.g. consultants) please describe the methods and considerations used to procure their services.

c) Where OM&A costs are for PowerStream employees, please explain the nature of the costs and how they are incremental to costs built in base rates.

Response:

a) Below is a summary table categorizing PowerStream's 2012 smart grid OM&A expenditures. The Green Energy Act of 2009 encourages local distribution companies to become active participants in developing and promoting new Smart Grid ("SG") technologies through demonstration projects. In assessing and developing viable SG demonstration projects requires personnel with very strong technical backgrounds and effective leadership skills. Accordingly PowerStream selected a small senior management team within the organization to take charge of this new area.

Table Staff 4-1: Summary of Smart Grid OM&A Costs:

Summary 2012 Smart Grid OM&A Expenditures

Description	External Consulting (1)	Labour (2)	Trade Shows, Training, Education, conferences and meetings (4)	SG Educational & Presentation Materials (3)	Totals
Smart Grid General & admin.	$ 112,159	$ 417,997	$ 57,096	$ -	$ 587,252
Smart Grid materials	$ -	$ -	$ -	$ 56,563	$ 56,563
Allocated Costs (note 5)	$ 12,811	$ 133,890	$ 6,521	$ 6,462	$ 159,684
Totals	$ 124,970	$ 551,887	$ 63,617	$ 63,025	$ 803,499

Notes and Explanations:

1) Consultants provided technical expertise and knowledge towards the planning, design and construction of smart grid initiatives. Supported PowerStream management in other related matters.

2) Full time and contract PowerStream staff plan, coordinate and manage various smart grid projects including transportation costs. Active participation in regulatory working groups and other industry collaborative projects - See additional schedule for details

3) Production of documents and other brochures for various trade shows and industry collaborative activities.

4) Costs associated with participation in Industry collaboration conferences and meetings, regulatory working groups, various trade shows and training and education. See also labour worksheet for details

5) Other smart grid costs and credits to be allocated proportionally to other cost categories [e.g. carrying charges, depreciation,]. Labour burden charges were identified and therefore applied directly to labour category

SMART GRID 2012 LABOUR BREAKDOWN BY ACTIVITY

SMART GRID ACTIVITIES	**Amount**
University of Waterloo study	$25,094
Updated SG Strategy	$75,283
Digital Fault Indicator Trial	$25,094
Electric Vehicle Trials	$50,189
Geomagnetic Induced Current Sensor Trial	25,094
V2H Demonstration Initiative	100,377
Home Area Network	75,094
Development of materials for shows and conferences	25,094
Stakeholder Communications	25,094
Industry Collaboration	50,189
Regulatory Working Groups [OEB, IESO]	50,189
Education and Conferences	25,094
TOTAL LABOUR ACTIVITY	$551,887

Notes:
1) Refer to pages 35 to 40 of the Application for details on these activities

b) PowerStream engaged a number of contractors and consultants to provide technical expertise and advice in developing our smart meter programs and trials. PowerStream recognized that two members of the SG team were retiring over the 2013 to 2014 period. Therefore a succession plan was required. Accordingly PowerStream hired Martin Rovers, formerly of Better Place Inc., on contract to lead some of our SG programs. Mr. Rovers was selected due to his expertise, knowledge and leadership in the area of electric vehicle charging stations.

ML and Company was hired as a consultant to provide expertise in the area of stakeholder communications. Previous successful working experience with ML and company was the primary reason for this selection.

Various other contractors were hired to provide materials for smart grid activities. For these smaller purchases, PowerStream selected those companies where there was very good past service and an effective working relationship.

c) The employee costs are for employees dedicated to the Smart Grid program. Their costs were not included in the 2013 OM&A budget used to set 2013 rates.

LIST OF APPENDICES

PowerStream
Asset Condition Assessment
Technical Report

Revision 1 – March 8, 2012

Revision 2 – November 27, 2012

Notes:

- **The Original Report, dated April 05, 2009, was prepared by PowerStream Inc., Kinectrics Inc., and BIS Consulting, LLC**
- **This version of the report, Revision 1 – March 8, 2012, was prepared by PowerStream Inc.**

Table of Contents

1. Introduction

PowerStream is the second largest municipally-owned electricity distribution company in Ontario, delivering power to more than 330,000 customers residing or owning a business in communities located immediately north of Toronto and in Central Ontario. The communities we serve include Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan. PowerStream owns and operates distribution assets valued at approximately $950.6 million, including 11 transformer stations and 54 municipal substations.

PowerStream has implemented an asset management program for its station and distribution assets. The program includes the development of Health Indices, risk-based economic analyses (probability of failure and criticality), and recommended Asset Sustainability Plans (replacements).

A key part of the asset management program is Asset Condition Assessment (ACA), involving collection and interpretation of condition and performance data to enable informed investment decisions. The primary purpose of the ACA is to detect and quantify long-term degradation, which would necessitate major capital expenditure. The result of the ACA is an optimized life-cycle plan based on asset sustainability.

PowerStream uses the ACA methodology developed by Kinectrics Inc. and BIS Consulting, LLC to run the ACA models.

On an on-going basis, PowerStream continues to fine-tune the ACA models and update the parameters to reflect PowerStream's current asset information. Examples of the parameters include: asset physical condition, testing data, customer interruption cost, replacement cost, failure probability curve, consequence of asset failure, etc.

The ACA model results are taken into consideration when PowerStream prioritizes and selects capital projects to be submitted for approval in the annual budgeting process.

In theory, the number and timing of replacement units recommended by the ACA models ("Econometric Replacement Results") is considered "optimal" or "ideal" from a pure economic viewpoint. In practice, however, PowerStream incorporates engineering judgment and operations input with the econometric model results to prudently spread out the replacement programs over a longer period of time. The intent of spreading the replacement requirement over a number of years is to smooth out the budget, resource and rate impacts while managing the incremental risk of asset failure.

As a result of this approach, the annual numbers of replacement units proposed in the annual budget may be different from those recommended by the ACA models.

This report will discuss the Asset Condition Assessment Framework and provide the status of PowerStream ACA programs for the following assets:

- TS Transformer
- MS Transformer
- Circuit Breaker
- 230 kV Switch
- MS Primary Switch
- Station Capacitor

- Station Reactor
- Distribution Transformer
- Distribution Switchgear
- Wood Pole
- Distribution UG Primary Cable

For each of the above asset class the following items will be covered:

- Summary of Asset Class
- Asset Degradation
- Health Index Formulation and Results
- Failure Probability
- Intervention Mode
- Econometric Replacement Results
- Conclusion

2. Asset Condition Assessment Framework

The general ACA framework is a two-step process:

- Asset Evaluations
- Program Development

Asset Evaluations

The Asset Evaluations step translates condition and criticality information into repeatable, quantitative measures. Asset Evaluations will cover the following:

- Health Index
- Failure Rate
- Criticality
- Risk Matrix
- Projected Failure Quantity and Reactive Capital

Health Index

Asset Evaluations involves a technical condition assessment, wherein condition information is translated into a quantitative Health Index. The Health Index is based on information such as equipment age, historical utilization, maintenance, and visual inspections.

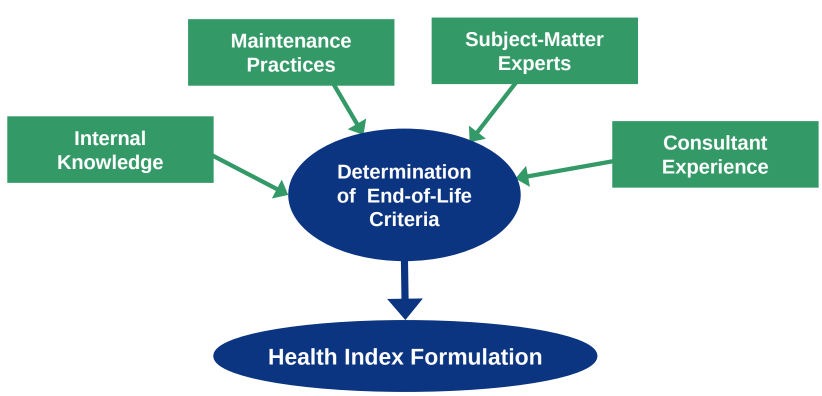


Figure 1. The Health Index establishes the condition of the asset population relative to end of life.

To illustrate the formulation of health index, an example for a 230kV Switch is shown below.

Sample Heath Index for 230kV Switch

Factor	Maximum Score (A)	Actual Score (B)	Weight (C)	Weighted Score (D) = (B x C)	Maximum Possible Weighted Score (E) = (A x C)
Age	4	3	3	9	12
Expert Feedback	4	3	10	30	40
Load	4	2	3	6	12
Switch Contact	4	4	5	20	20
Blade/Arm	4	3	5	15	20
Mechanism	4	3	5	15	20
Arc Break	4	3	5	15	20
Lock/Handle	4	3	1	3	4
		Total Score (F):		**113**	**148**
		Health Index (HI) = (F/E):		**76%**	**100%**

Each factor is given a Maximum Score (A) and a Weight (C). The Actual Score (B) of each factor is determined by its condition. The Weighted Score (D) is determined by multiplying the Actual Score by the Weight. The Total Score (F) is the sum of all Weighted Scores for all factors.

The final Heath Index is calculated by the Total Score divided by the Maximum Possible Score (E).

The Health Index Formulation for each of PowerStream's assets will be described in greater detail in the "Health Index Formulation and Results" portions of this report.

Failure Rate

The model includes failure probability curves, projecting failures as a function of age and type. The failure probability curve, or hazard rate, is a conditional probability; for example, the chance of a transformer failing at age 30 given it is 30 years old. The curves are based on the experience of PowerStream's technical experts and Industry Standards. Over time, failure data will be collected to determine if any changes are warranted to the curves.

Failure probability can vary within an asset class. For example, different types of breakers (e.g., air, SF6, etc.) may have different failure probability curves. Because of this, the failure probability curve, and hence risk cost, for an asset may be different before replacement than after if replacement is not "in-kind".

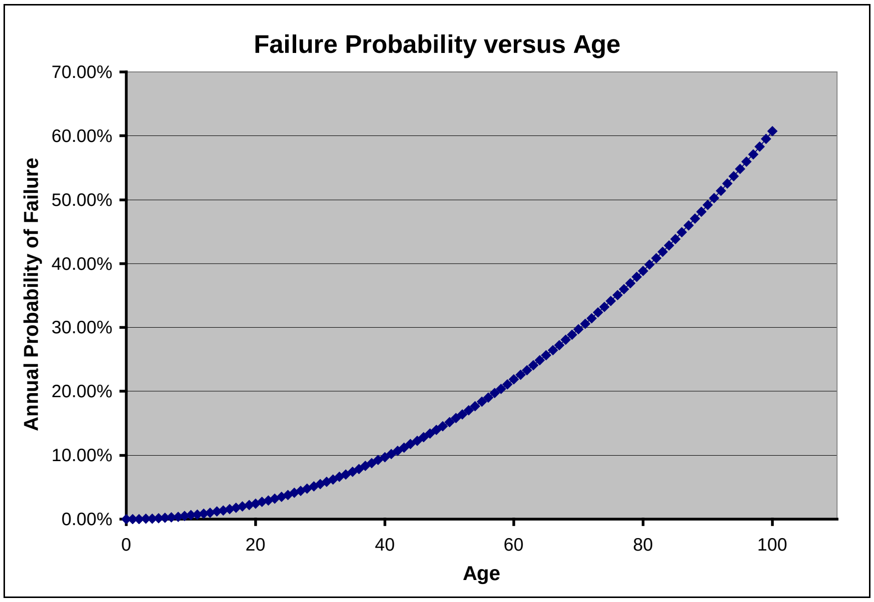


Figure 2. The failure probability curve projects conditional failure probability versus age.

Criticality

The consequences of an asset failure include the replacement cost of the failed asset and customer outage impacts. The expected consequence may be the average of multiple failure scenarios, weighted by their relative probabilities. All costs must be expressed in dollar terms for consistent prioritization.

An asset management-based system of justifying expenditures must consider not only the direct costs to the utility, but also the costs to its customers in lost power and inconvenience. Customer outage costs can be estimated using a willingness to pay or willingness to accept method. The method evaluates outage consequences based on how much customers are willing to pay to avoid them, or what payment they would require to accept them. There have been a number of studies published related to customer interruption cost or value of lost load. The studies were reviewed and results correlated with our own experience with respect to average interruption time, average frequency of loss, average load lost and other factors for residential and commercial/industrial premises. Average costs for $/kW and $/kWh could then be estimated. For this study PowerStream has elected to use the following customer interruption costs, which can be updated at a later stage pending the future availability of additional relevant customer impact studies.

Table 1. Customer Interruption Costs

Customer Interruption Cost

	Residential	Mixed Residential, Commercial & Industrial (approx. 30% Res, 70% C & I)	Purely Commercial & Industrial (100% C & I)
$/kW (Frequency Cost)	$2.00	$20.00	$20.00
$/kWh (Duration Cost)	$4.00	$20.00	$30.00

Risk Matrix

The Asset Evaluations step also includes defining the inputs for an asset risk assessment. Risk is calculated by multiplying asset failure probability times the consequence of asset failure. The failure probability is an annual failure rate, based on end of life failures. The consequence of asset failure is related to the criticality of the asset, is defined in dollar terms, and is also intended to reflect customer impact.

The risk matrix summarizes the condition and criticality of an asset. The risk matrix plots the current age failure probability versus the consequence of failure (criticality). The blue diamonds represent the entire asset population, while the red diamonds relate to the assets recommended for immediate intervention. An example for circuit breakers is shown below.

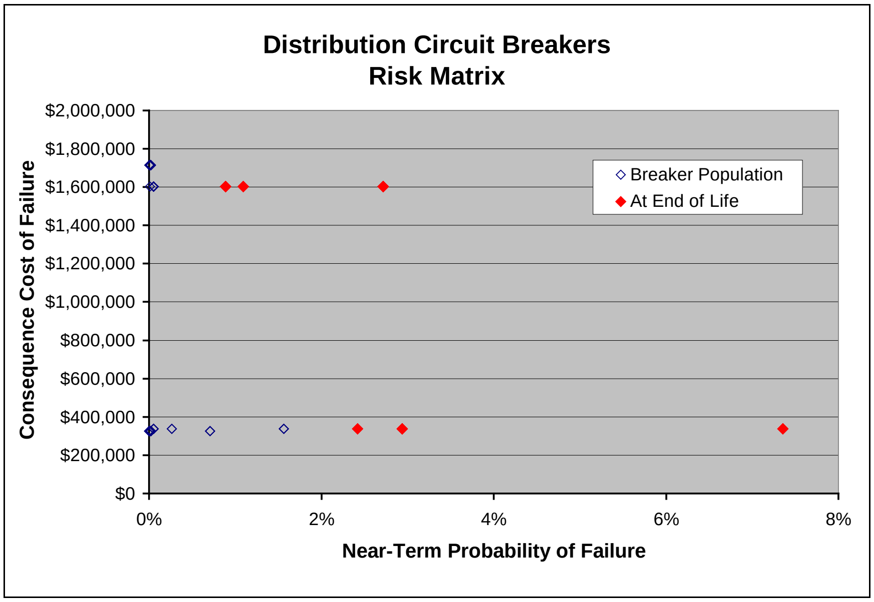


Figure 3. The risk matrix plots consequence cost of failure versus failure probability.

<u>Projected Failure Quantity and Reactive Capital</u>

The projected failures account for system-wide annual failures. The reactive capital is an estimate of the reactive replacement spending associated with the projected failures. An example for distribution transformers is shown below.

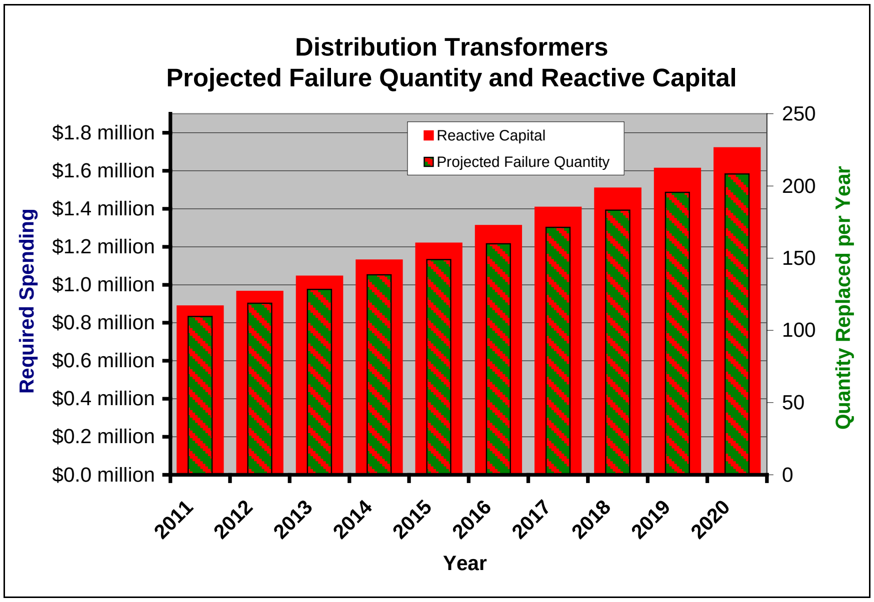


Figure 4. Projected failures and associated reactive replacement spending.

Program Development

The Program Development step involves defining intervention modes to mitigate asset risk, performing analyses to minimize asset life-cycle cost, and recommending long-range spending. Program Development will cover the following:

- Intervention Modes
- Risk-Based Economic Analysis
- Spending Justification and Prioritization
- Econometric Replacement Results

Intervention Modes

Intervention modes are actions that can be done to mitigate asset risk, such as rehabilitation, replacement, monitoring, or purchase of spares. Intervention modes may affect the probability or consequence of failure.

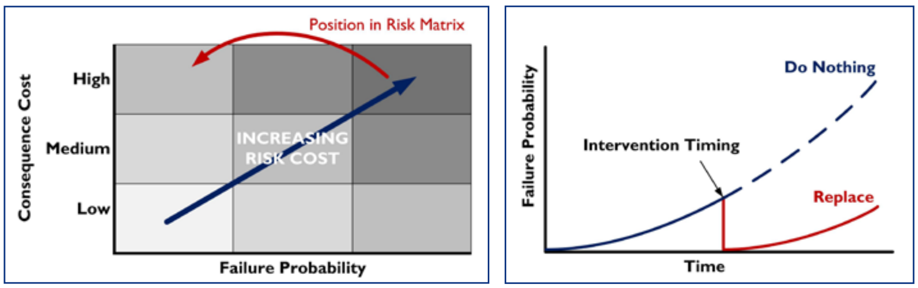


Figure 5. Effect of replacement on risk mitigation.

The simplest example is "in-kind" replacement, whereby an old asset with relatively high failure probability is replaced with a new one with lower failure probability.

Risk-Based Economic Analysis

The risk-based economic analysis determines the asset least life-cycle cost by balancing the risk of failure against the benefit of delaying capital expenditures.

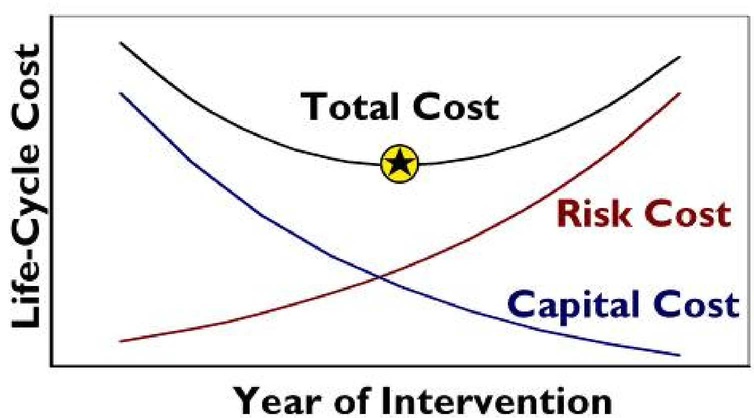


Figure 6. Life-cycle optimization.

The economic analysis methodology compares the available intervention alternatives to determine the lowest cost strategy (e.g., inject cable in 10 years, and then replace cable in 30 years). The methodology projects the performance effects of each strategy (i.e., mitigating failure probability or consequence of failure) to determine the optimal intervention timing.

The risk-based economic analysis methodology justifies spending decisions by determining the economically optimal timing of asset expenditures based on the associated asset risk profiles and related capital costs for interventions. Applying the same methodology to all the assets in an asset class produces a consistent spending program. The associated benefits and costs of delaying from the optimal timing provide the basis for a benefit/cost ratio for prioritization of limited resources.

Existing assets may be replaced with shorter-life assets. This means that the life-cycle cost of the new asset is different than the existing asset. The methodology in this case requires two steps, as shown below.

1. Calculate the annualized life-cycle cost of the new asset.
2. Identify the year in which the risk cost of the existing asset reaches this value. In that year, it is less expensive to replace the assets than to continue operating the existing asset.

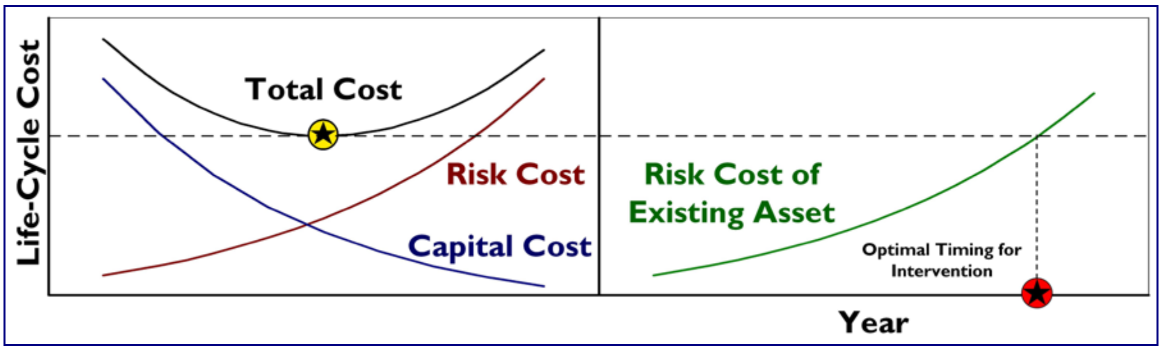


Figure 7. Optimizing replacement timing of assets.

Spending Justification and Prioritization
Limited resources should be directed toward programs with higher benefit/cost ratios. A benefit/cost ratio is calculated for all assets recommended for an intervention in the current or next year. In the case of asset replacements, benefit is the avoided cost of delaying replacement for one year. If an asset should be replaced this year, but replacement is delayed for one year, the incremental cost is the difference between the asset's risk cost and the annualized cost of the new asset. The graph below indicates the additional risk cost resulting from delaying intervention.

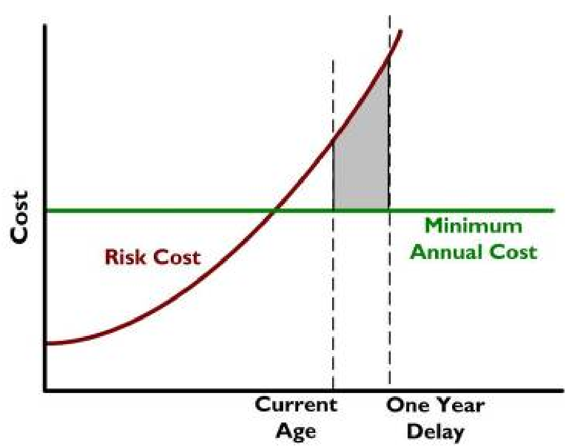


Figure 8. Incremental Benefit of Replacement this Year instead of Next Year.

The shaded area represents the net incremental benefit of replacement. This quantity is compared to the cost of the replacement to calculate benefit/cost ratio, which is used for prioritization.

Econometric Replacement Results

The economic model projects the optimal intervention timing for each asset analyzed. The econometric replacement results are generated by combining the optimal intervention timings and the associated capital costs. An example for MS Primary Switches is shown below.

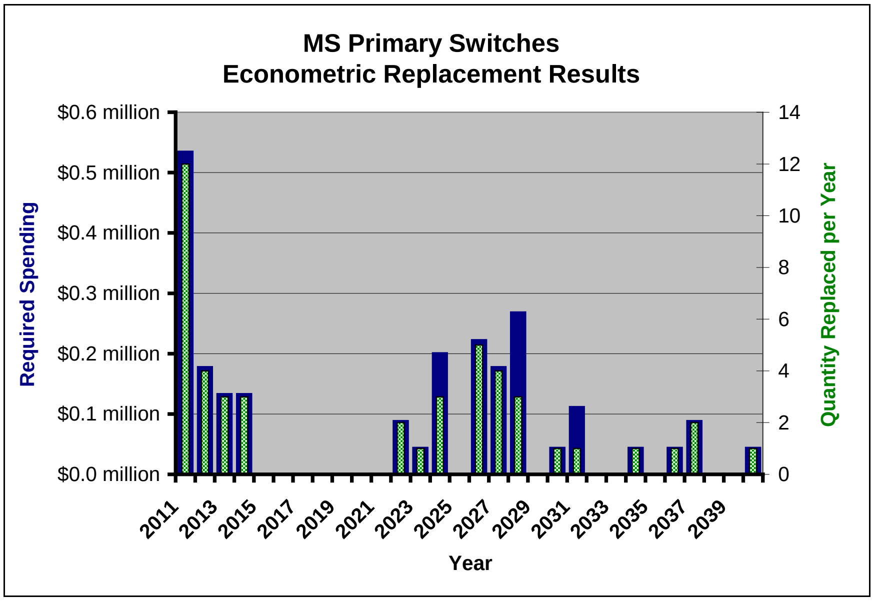


Figure 9. Econometric replacement results and associated capital costs.

3. Asset Class Details and Results

3.1 TS Transformers

Summary of Asset Class

Transformer Station (TS) Transformers are highly complex assets with a very high price per unit. A number of methods are available to assess condition and status. PowerStream employs most of them, which enabled detailed analysis of asset condition to be completed efficiently. Risk analysis was more complex as redundancy needed to be addressed and different intervention options evaluated (most importantly levels of spares).

Data Sources Available

Comprehensive demographic and condition data is available. Test data is available, which includes DGA tests, standard oil tests, and Doble power factor tests. Comprehensive load data is also available, which was useful both for condition and criticality assessments.

Demographics

Number of units: 22
Typical life expectancy (years): 30-60 (as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board")
Estimated replacement cost: $1.5 to 3.5 million

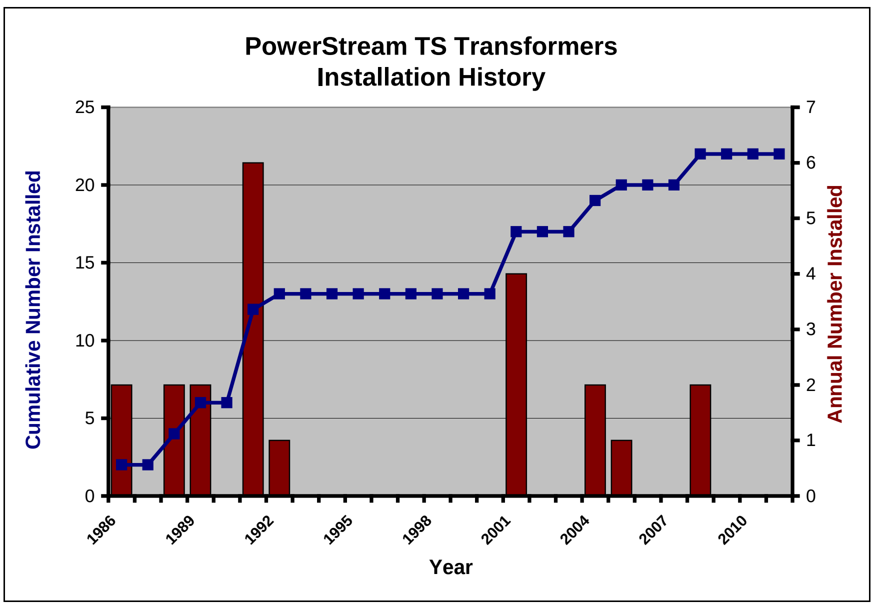


Figure 10. TS transformers installation history.

Asset Degradation

TS transformers are employed to step-down the transmission voltage to distribution voltage levels. TS transformers vary in capacity and ratings over a broad range.

For a majority of transformers, end of life (EOL) is expected to be defined by the failure of an insulation system and, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains. Therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and the insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). As the paper ages the DP value gradually decreases. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharges which can be initiated if the level of moisture is allowed to rise in the paper or if there are other minor defects within active areas of the transformer.

The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure.

Other condition assessment techniques for TS transformers include Doble (power factor) testing, infrared surveys, partial discharge detection and location using ultrasonic’s and/or electromagnetic detection and frequency response analysis.

Load tap changers (LTCs) are prone to failure resulting from either mechanical or electrical degradation. Active maintenance is required for tap changers in order to manage these issues. It is normal practice to maintain tap changers either at a fixed time interval or after a number of operations. During operation wear of contacts and build up of oil degradation products, resulting from arcing activity during make and break of contacts, are the primary degradation processes. Maintenance, cleaning and replacement of contacts and any defective components in the mechanism, and changing or reprocessing of oil are the primary maintenance activities that deal with these issues. Oil analysis for tap changers is considered more difficult than oil analysis for transformers due to the generation of gases and general degradation of the oil during arcing under normal LTC operation.

The health indicator parameters for TS transformers usually include:

- Condition of the bushings
- Condition of transformer tank
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 30 to 60 years. Many transformers in service are now approaching this age but failure rates remain low and there is little evidence that many are at, or near, end-of-life (EOL). There are a number of contributory factors to the long life of transformers such as regular and effective maintenance practices. In addition, the loading of many of these transformers has been relatively light during their working life.

Health Index Formulation and Results

The following charts provide the main condition parameters that are used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Transformer Inspections:

Transformer Visual Inspection Criteria	Weight
Bushing Condition	3
Main Tank/ Controls	0.5
Conservator	0.5
Oil Leaks	1
Foundation/Grounding	0.5
Radiator/Cooling	0.5
Overall Physical	2

Trans-former Health Index

Transformer Testing:

Weight	Transformer Testing Analysis Criteria
4	DGA Analysis
4	Furan Analysis
4	Winding Doble Test
2	Thermograph
3	Oil Quality Test

Tap Changer Criteria:

Tap Changer Criteria	Weight
Tank Condition	0.5
Gaskets/Seals	0.5
Control & Mechanism	1
Tank Leaks	1
Overall Physical	2

Figure 11. TS transformers Health Index flowchart.

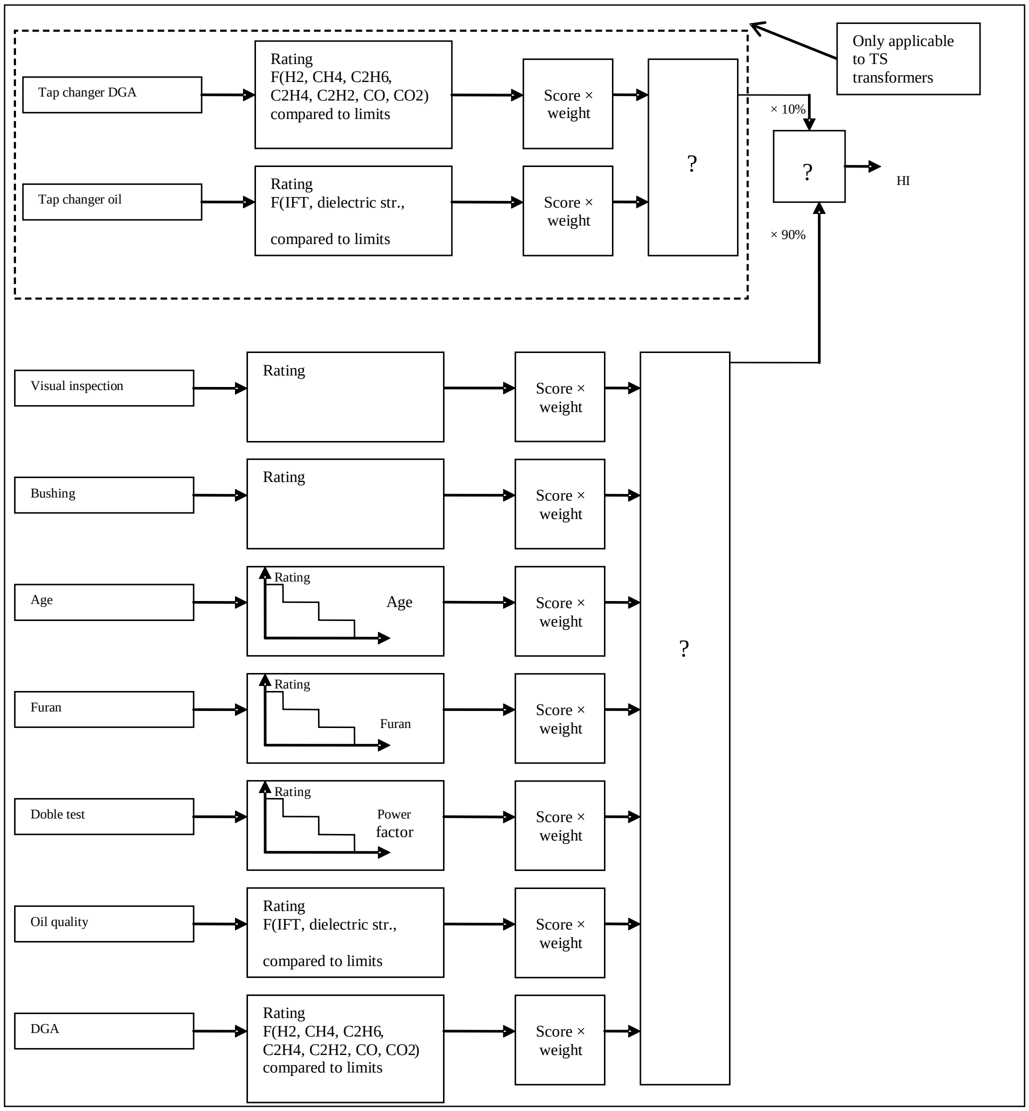


Figure 4. TS transformers Health Index formulation flowchart.

Table 2. TS transformers Health Index parameters and weights

#	Transformers Condition Parameters	Weight
1	Bushing Condition	3
2	Oil Leaks	1
3	Main Tank/Cabinets and Controls	0.5
4	Conservator/Oil Preservation System (Airbag Integrity)	0.5
5	Radiators/Cooling System	0.5
6	Foundation/Support Steel/Ground	0.5
7	Overall Power Transformer	2
8	DGA Oil Analysis*	4
9	Furan Oil Analysis*	4
10	Age	2
11	Winding Doble Test	4
12	Oil Quality Test	3

*In the case of a score of E, overall Health Index is divided by 2

Tap changers are responsible for a high percentage of transformer failures. Therefore, in developing a relevant health index for transformers, it is appropriate to include information specific to tap changers. The Table below shows the Health Index formulation for tap changers.

Table 3. TS transformers tap changers Health Index condition parameters and weights

#	Tap Changers Condition Parameters	Weight
1	Tank Condition	0.5
2	Tank Leaks	1
3	Gaskets, Seals and Pressure Relief	0.5
4	LTC Control and Mechanism Cabinet	0.5
5	Control and Mechanisms Cabinet Component and operation	0.5
6	Overall Tap Changer Condition	2
7	DGA, Moisture, Metal Content	4
8	Oil Quality Tests	3

Table 4. TS transformer parameter #1: bushing condition

Condition Factor	Factor	Condition Criteria Description
A	4	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	3	Bushings are not broken, however minor chips and cracks are visible. Cementing and fasteners are secure.
C	2	Bushings are not broken, however major chips, and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	1	Bushings are broken/damaged or cementing and fasteners are not secure.
E	0	Bushings, cementing or fasteners are broken/damaged beyond repair.

Table 5. TS transformer parameter #2: oil leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress. If left uncorrected it could cause operational and/or environmental problems.
E	0	Oil leaks or moisture ingress have resulted in complete failure or damage/degradation beyond repair.

Table 6. TS transformer parameter #3: transformer main tank/cabinets and control condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets – no evidence of condensation, moisture or insect ingress. No rust or corrosion on weld seals, flanges, valve fittings, gauges, monitors. All wiring, terminal blocks, switches, relays, monitoring and control devices are in good condition.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in cabinets
C	2	Some rust and corrosion on both tank and on cabinets.
D	1	Significant corrosion on main tank and on cabinets. Defective sealing leading to water ingress and insects/rodent damage.
E	0	Corrosion, water ingress or insect/rodent damage or degradation is beyond repair.

Table 7. TS transformer parameter #4: transformer conservator/oil preservation system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body conservator tank. No rust, corrosion on weld seals, flanges, valve fittings, gauges, monitors.
B	3	No rust or corrosion on conservator.
C	2	Some rust and corrosion on conservator.
D	1	Significant rust and corrosion on conservator. Could lead to major oil leakage or water ingress.
E	0	Major oil leakage or water ingress has resulted in damage/degradation beyond repair. Any seal failure on a sealed tank transformer. Note: For transformers employing sealed tanks or air bags, a failure of the seal would be indicated by the presence of air in the tank, which can be detected by measuring oxygen or nitrogen content while conducting gas in oil analysis.

Table 8. TS transformer parameter #5: transformer radiators/cooling system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body of radiators. Fan and pump enclosures are free of rust and corrosion and securely mounted in position, pump bearings are in good condition and fan controls are operating per design.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Fan and pump enclosures damaged/degraded beyond repair.

Table 9. TS transformer parameter #6: transformer foundation/support steel/grounding condition

Condition Factor	Factor	Condition Criteria Description
A	4	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are tight, free of corrosion and made directly to tanks, radiators, cabinets and supports, without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Foundation, supports, or grounding damaged/degraded beyond repair.

Table 10. TS transformer parameter #7: overall power transformer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Power transformer externally is clean, and corrosion free. All primary and secondary connections are in good condition. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems, mounted on the power transformer, are in good condition. No external evidence of overheating or internal overpressure. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table 11. TS transformer parameter #8: DGA oil analysis

Condition Factor	Factor	Condition Criteria Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6	<=50	<=100	<=150	<=250	<=500	>500	3
C2H4	<=65	<=100	<=150	<=250	<=500	>500	3
C2H2	<=3	<=10	<=50	<=100	<=200	>200	5
CO	<=700	<=800	<=900	<=1100	<=1300	>1300	1
CO2	<=3000	<=3500	<=4000	<=4500	<=5000	>5000	1

Table 12. TS transformer parameter #9: transformer furan analysis

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 100 PPB of 2-furaldehyde and no significant change from last test
B	3	Between 100 and 250 PPB of 2-furaldehyde and no significant change from last test
C	2	Between 250 and 500 PPB of 2-furaldehyde or significant change from last test
D	1	Between 500 and 1000 of 2-furaldehyde and significant change from last test
E	0	Greater than 1000 PPB of 2-furaldehyde

Table 13. TS transformer parameter #10: age

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	40-60 years old
D	1	Greater than 60 years old
E	0	Not Applicable

Table 14. TS transformer parameter #11: winding Doble test

Condition Factor	Factor	Condition Criteria Description
G	4	Values well within acceptable ranges; power factor less than 0.5 %
D	2	Values considerably exceed acceptable levels; power factor between 0.5 - 1%
I	1	Values exceed acceptable ranges; power factor between 1 – 2%.
B	0	Values are not acceptable> 2%, immediate attention required; power factor greater than 2%

G = Good
D = De-graded
I = Investigate
B = Bad

Table 15. TS transformer parameter #12: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	**2**	**3**	**4**	**Weight**
*** Moisture PPM (T ^{o}C Corrected)** U $\leq$ 69 kV	<=20	<=30	<=40	>40	4
*** Moisture PPM (T ^{o}C Corrected)** 230 kV $\leq$U	<=15	<=20	<=25	>25	
*** Dielectric Str. kV 1mm D1816** 230 kV $\leq$U	>30	>28	>=25	Less than 25	3
*** Dielectric Str. kV 1mm D1816** U $\leq$ 69 kV	>23	>20	>=18	Less than 18	
*** Dielectric Str. kV D877**	>40	>30	>20	Less than 20	
*** IFT dynes/cm** U $\leq$ 69 kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT dynes/cm** 230 kV $\leq$U	> 32	25-32	20-25	Less than 20	

Table 16. TS transformer tap changer parameter #1: tank condition

Condition Factor	Factor	Condition Criteria Description
A	4	No external corrosion or rust on the LTC tank, conservator or switch compartments. No rust or corrosion on tank, cover plates, weld seals, flanges, valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be made acceptable

Table 17. TS transformer tap changer parameter #2: tank leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No external corrosion or rust on the LTC tank, conservator or switch compartments. No rust or corrosion on tank, cover plates, weld seals, flanges, valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be made acceptable

Table 18. TS transformer tap changer parameter #3: gaskets, seals and pressure relief condition

Condition Factor	Factor	Condition Criteria Description
A	4	No external sign of deterioration of tank gaskets, weld seams or gaskets on valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC. Weather seal of LTC mechanism cabinet is in good condition. Dynamic seals of drive shaft are in good condition.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be brought into acceptable condition.

Table 19. TS transformer tap changer parameter #4: LTC control and mechanism cabinet

Condition Factor	Factor	Condition Criteria Description
A	4	No external or internal rust in cabinets. No rust, corrosion or paint peeling on cabinets, sealing very effective – no evidence of moisture or insect ingress or condensation. All control devices are in good condition.
B	3	No rust or corrosion, some evidence of slight moisture ingress or condensation in mechanism cabinet or control circuitry.
C	2	Some rust and corrosion on mechanism cabinet or some deterioration of control circuitry, requires corrective maintenance within the next several months.
D	1	Significant corrosion on mechanism cabinet or significant deterioration of control circuitry. Defective sealing leading to water ingress and insects/rodent damage. Requires immediate corrective action.
E	0	Corrosion, water ingress, or insect/rodent damage/degradation that is beyond repair.

Table 20. TS transformer tap changer parameter #5: control and mechanism cabinet component condition

Condition Factor	Factor	Condition Criteria Description
A	4	Wiring, terminal blocks, relays, heaters, motors, contactors and switches all in good condition. LTC operating mechanism, shafts, brakes, gears, bearings, indicators are free from corrosion, abrasion or obstruction and are lubricated. No sign of overheating or deterioration on any electrical or mechanical components.
B	3	A small percentage of the wiring, terminal blocks, relays and switches are in a degraded condition. LTC operating mechanism is in good condition
C	2	About 20% of the wiring, terminal blocks, relays and switches are in a degraded condition. LTC operating mechanism is in fair condition.
D	1	Significant amount of wiring, terminal blocks, relays and switches are in very poor condition. Fuses blow periodically. One or more of the LTC operating mechanism components is in imminent danger of failure. Requires immediate corrective action.
E	0	Components have failed or are damaged/degraded beyond repair.

Table 21. TS transformer tap changer parameter #6: overall tap changer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Tap changer external components, including the mechanism cabinet components, are all in good operating condition, and free from corrosion, deformation, cracks and obstruction. No external evidence of overheating or switch contact failure. Operation counter readings are below the critical range for this type of LTC. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	More than two characteristics that are unacceptable and cannot be brought into acceptable condition.

Table 22. TS transformer tap changer parameter #7: oil analysis (DGA metal content)

Condition Factor	Factor	Condition Criteria Description
A	4	Oil tests passed; DGA overall factor<3 or limited metal content
E	0	Any failed oil test; DGA overall factor>3 or serious metal content

Table 23. TS transformer tap changer parameter #8: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	**2**	**3**	**4**	**Weight**
*** Moisture PPM (T ^{o}C Corrected)** $U \leq 69$ kV	<=20	<=30	<=40	>40	4
*** Moisture PPM (T ^{o}C Corrected)** 230 kV $\leq U$	<=15	<=20	<=25	>25	
*** Dielectric Str. kV 1mm D1816** 230 kV $\leq U$	>30	>28	>=25	Less than 25	3
*** Dielectric Str. kV 1mm D1816** $U \leq 69$ kV	>23	>20	>=18	Less than 18	
*** Dielectric Str. kV D877**	>40	>30	>20	Less than 20	
*** IFT dynes/cm** $U \leq 69$ kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT dynes/cm** 230 kV $\leq U$	> 32	25-32	20-25	Less than 20	

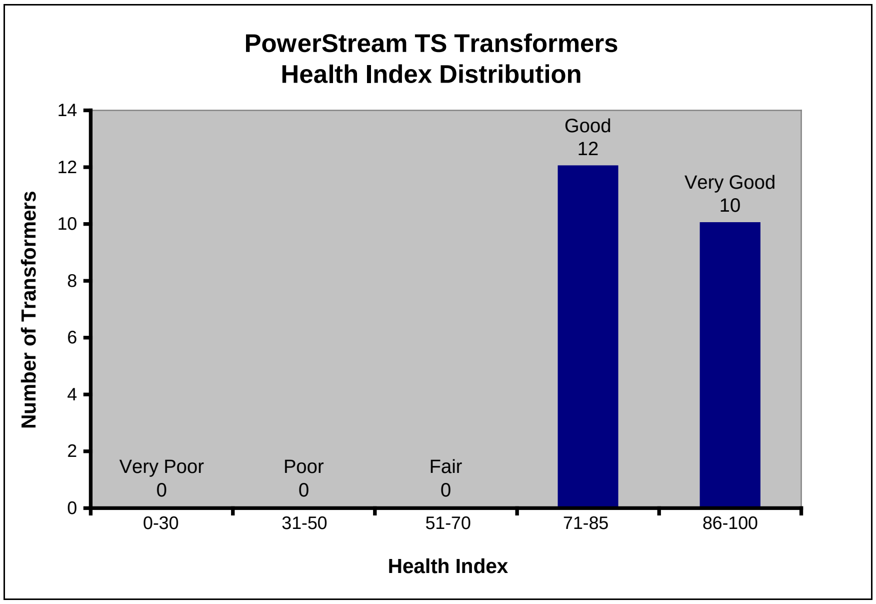


Figure 5. TS transformers Health Index histogram.

Location	Position	Manufacturer	Model	MVA Nameplate	Age	Health Index
Greenwood -Vaughan MTS #1	T1	TTI	ABB	125	22	74
Greenwood -Vaughan MTS #1	T2	TTI	ABB	125	22	77
Greenwood -Vaughan MTS #1 Expansion	T3	ABB	ABB	125	19	86
Greenwood -Vaughan MTS #1 Expansion	T4	ABB	MR	125	6	86
Torstar - Vaughan MTS #2	T1	ABB	ABB	125	20	84
Torstar - Vaughan MTS #2	T2	ABB	ABB	125	20	84
Lorna Jackson - Vaughan MTS #3	T1	ABB	MR	125	10	86
Lorna Jackson - Vaughan MTS #3	T2	ABB	MR	125	10	86
Lazenby MTS1 - Richmond Hill MTS#1	T1	Hyundai	MR	125	20	87
Lazenby MTS1 - Richmond Hill MTS#1	T2	Hyundai	MR	125	20	87
Lazenby MTS1 - Richmond Hill MTS#2	T1	Pauwels	MR	83	10	86
Lazenby MTS1 - Richmond Hill MTS#2	T2	Pauwels	MR	83	10	95
J.V. Fry - Markham MTS#1	T1	Ferranti Packard	FP	83	25	78
J.V. Fry - Markham MTS#1	T2	Ferranti Packard	FP	83	25	78
A.M. Walker - Markham MTS#2	T1	TTI	ASEA	83	23	80
A.M. Walker - Markham MTS#2	T2	TTI	ASEA	83	23	80
D.H. Cockburn - Markham MTS#3	T1	ABB	ABB	83	20	77
D.H. Cockburn - Markham MTS#3	T2	ABB	ABB	83	20	82
D.H. Cockburn - Markham MTS#3 Expansion	T3	Pauwels	MR	83	7	83
D.H. Cockburn - Markham MTS#3 Expansion	T4	Pauwels	MR	83	7	83
Fabro TS -Markham TS#4	T1	ABB	MR	125	3	94
Fabro TS -Markham TS#4	T2	ABB	MR	125	3	94

Figure 6. TS transformers Health Index results.

As can be seen the lowest Health Index is 74 which is classified as Good (71-85), again showing that the overall transformer fleet is in satisfactory condition.

Failure Probability

The TS transformer failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- Shape = 3.00, Scale = 50.5

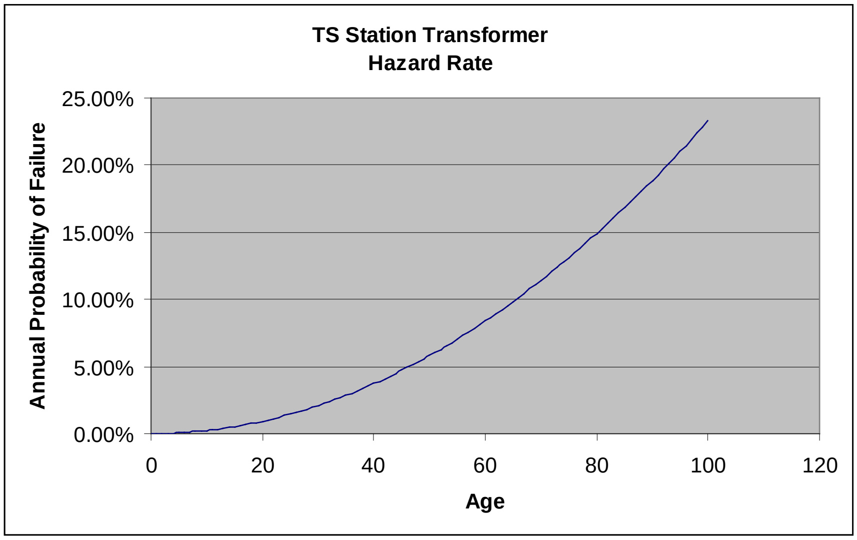


Figure 7. TS transformer hazard rate curve.

The curve fits the failure experience of other utilities with larger populations.

Failure Effects

At PowerStream, all TS's have Dual Element Spot Network (DESN) arrangement, which allows a second transformer to carry all load in the case of a single TS transformer failure. As a result, failure of a single TS transformer will not cause a customer outage. Failure of the second transformer in the station is assumed to cause a 360-hour outage for all customers. Outage costs are based on peak loading.

Risk Matrix

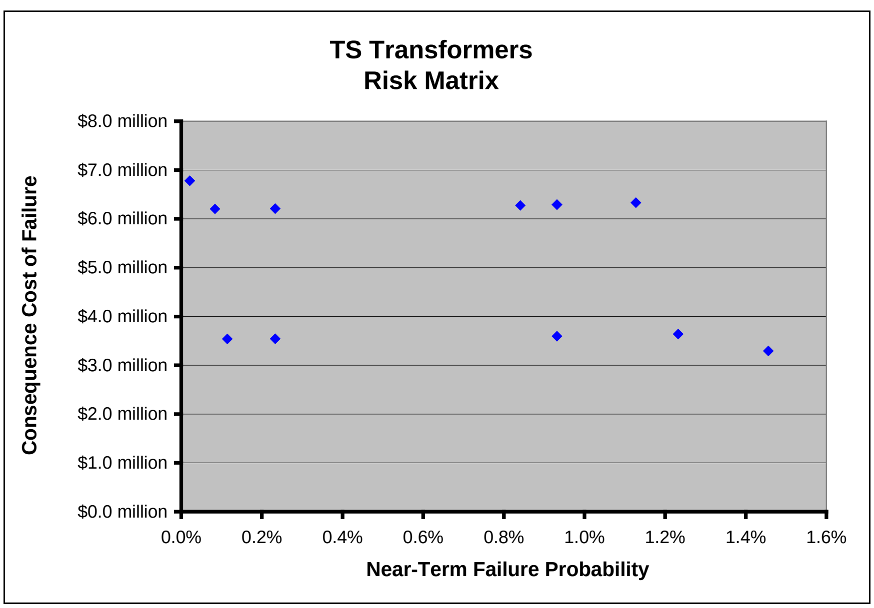


Figure 8. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode

The intervention mode modeled for TS transformers is replacement in-kind.

Econometric Replacement Results

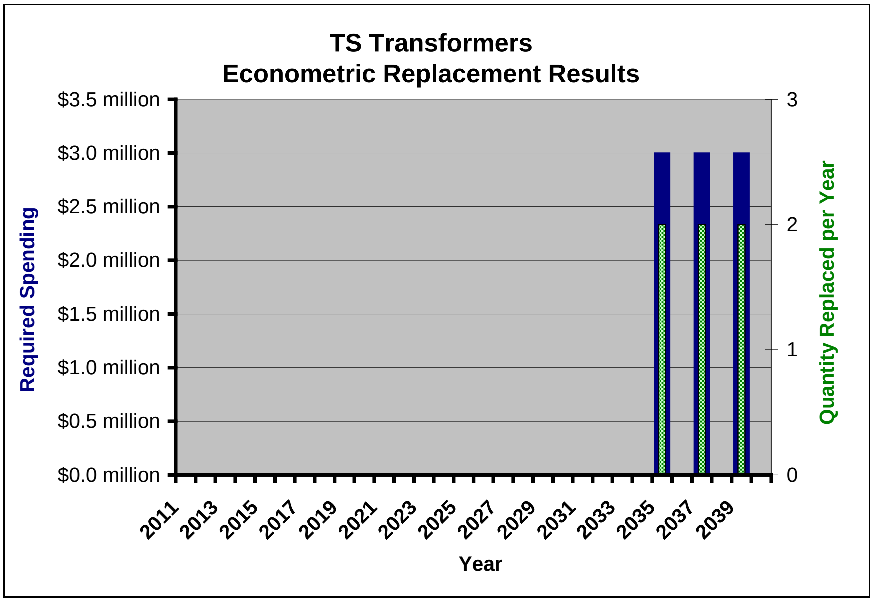


Figure 9. TS transformer econometric replacement results.

Conclusions

- Recommendations:
  - No replacement is proposed in the next five years.
- Gaps:
  - None identified.

3.2 MS Transformers

Summary of Asset Class

Municipal Station (MS) transformers are highly complex assets with a high price per unit.

Many methods are available to assess condition and status; PowerStream employs most of them, which enabled detailed analysis of asset condition to be completed efficiently.

<u>Data Sources Available</u>
Comprehensive demographic and condition data is available. Test data is available, which includes DGA tests, standard oil tests, and limited visual condition.

<u>Demographics</u>
Number of units: 65 (2 of which are not in-service)
Typical life expectancy (years): 30-60 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 “Asset Amortization Study for the Ontario Energy Board”
Estimated replacement cost: $300,000 - $700,000

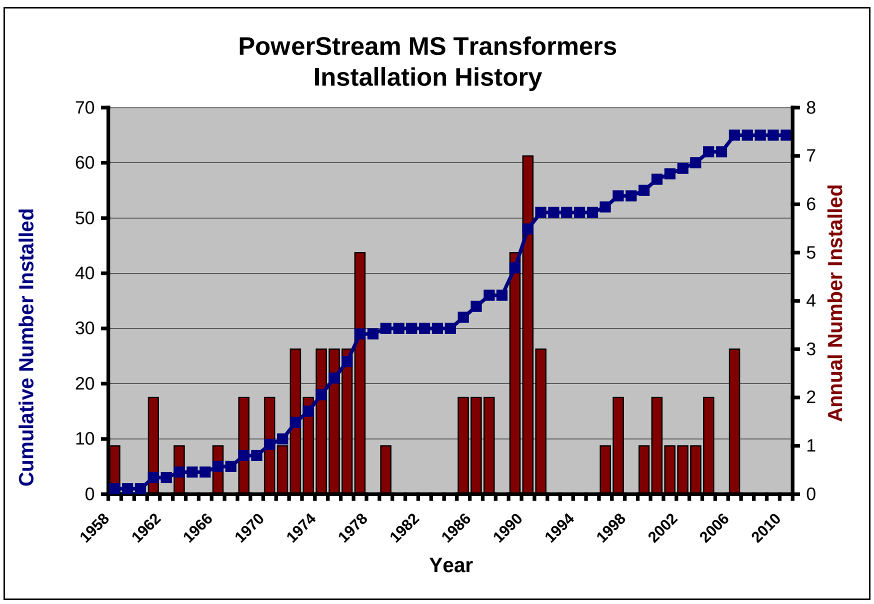


Figure 18. MS transformers installation history.

Asset Degradation

MS transformers are employed to step down the sub-transmission voltage or higher distribution voltage to lower distribution voltage levels.

For a majority of transformers, end of life (EOL) is expected to be defined by the failure of an insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains. Therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and the insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). As the paper ages the DP value gradually decreases. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharges which can be initiated if the level of moisture is allowed to rise in the paper or if there are other minor defects within active areas of the transformer.

The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure.

Other condition assessment techniques for MS transformers include Doble (power factor) testing, infrared surveys, partial discharge detection and location using ultrasonics and/or electromagnetic detection and frequency response analysis.

The health indicator parameters for MS transformers usually include:

- Condition of the bushings
- Condition of transformer tank
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 30 to 60 years. Many transformers in service are now approaching this age but failure rates remain low with few units at, or near, EOL. There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Health Index Formulation and Results

The following figure and charts provide the main condition parameters that are used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Transformer Inspections:

Transformer Visual Inspection Criteria	Weight
Main Tank/ Controls	0.5
Conservator	0.5
Oil Leaks	1
Foundation/Grounding	0.5
Radiator/Cooling	0.5
Overall Physical	2

Trans-former Health Index

Transformer Testing:

Weight	Transformer Testing Analysis Criteria
4	DGA Analysis
3	Oil Quality Test

Figure 19. MS transformers Health Index flowchart.

Table 24. MS transformer Health Index parameters and weights

#	MS Transformer Condition Parameters	Weight
1	Oil Leaks	1
2	Transformer Main Tank/Cabinets and Control Condition	0.5
3	Transformer Conservator/Oil Preservation System Condition	0.5
4	Transformer Radiators/Cooling System Condition	0.5
5	Transformer Foundation/Support Steel/Grounding Condition	0.5
6	Overall Power Transformer Condition	2
7	DGA Oil Analysis	4
8	Furan Oil Analysis*	4
9	Winding Doble Test	4
10	Bushing Condition	3
11	Oil Quality Test	3
12	Age	2

Table 25. MS transformer parameter #1: oil leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress. If left uncorrected it could cause operational and/or environmental problems.
E	0	Oil leaks or moisture ingress have resulted in complete failure or damage/degradation beyond repair.

Table 26. MS transformer parameter #2: transformer main tank/cabinets and control condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets – no evidence of condensation, moisture or insect ingress. No rust or corrosion on weld seals, flanges, valve fittings, gauges, monitors. All wiring, terminal blocks, switches, relays, monitoring and control devices are in good condition.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in cabinets
C	2	Some rust and corrosion on both tank and on cabinets.
D	1	Significant corrosion on main tank and on cabinets. Defective sealing leading to water ingress and insects/rodent damage.
E	0	Corrosion, water ingress or insect/rodent damage or degradation is beyond repair.

Table 27. MS transformer parameter #3: transformer conservator/oil preservation system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body conservator tank. No rust, corrosion on weld seals, flanges, valve fittings, gauges, monitors.
B	3	No rust or corrosion on conservator.
C	2	Some rust and corrosion on conservator.
D	1	Significant rust and corrosion on conservator. Could lead to major oil leakage or water ingress.
E	0	Major oil leakage or water ingress has resulted in damage/degradation beyond repair. Note: For transformers employing sealed tanks or air bags, a failure of the seal would be indicated by the presence of air in the tank, which can be detected by measuring oxygen or nitrogen content while conducting gas in oil analysis.

Table 28. MS transformer parameter #4: transformer radiators/cooling system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body of radiators. Fan and pump enclosures are free of rust and corrosion and securely mounted in position, pump bearings are in good condition and fan controls are operating per design.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Fan and pump enclosures damaged/degraded beyond repair.

Table 29. MS transformer parameter #5: transformer foundation/support steel/grounding condition

Condition Factor	Factor	Condition Criteria Description
A	4	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are tight, free of corrosion and made directly to tanks, radiators, cabinets and supports, without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Foundation, supports, or grounding damaged/degraded beyond repair.

Table 30. MS transformer parameter #6: overall power transformer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Power transformer externally is clean, and corrosion free. All primary and secondary connections are in good condition. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems, mounted on the power transformer, are in good condition. No external evidence of overheating or internal overpressure. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table 31. MS transformer parameter #7: DGA oil analysis

Condition Factor	Factor	Condition Criteria Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6	<=50	<=100	<=150	<=250	<=500	>500	3
C2H4	<=65	<=100	<=150	<=250	<=500	>500	3
C2H2	<=3	<=10	<=50	<=100	<=200	>200	5
CO	<=700	<=800	<=900	<=1100	<=1300	>1300	1
CO2	<=3000	<=3500	<=4000	<=4500	<=5000	>5000	1

Table 32. MS transformer parameter #8: transformer furan analysis

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 100 PPB of 2-furaldehyde and no significant change from last test
B	3	Between 100 and 250 PPB of 2-furaldehyde and no significant change from last test
C	2	Between 250 and 500 PPB of 2-furaldehyde or significant change from last test
D	1	Between 500 and 1000 of 2-furaldehyde and significant change from last test
E	0	Greater than 1000 PPB of 2-furaldehyde

Table 33. MS transformer parameter #9: winding Doble test

Condition Factor	Factor	Condition Criteria Description
G	4	Values well within acceptable ranges; power factor less than 0.5 %
D	2	Values considerably exceed acceptable levels; power factor between 0.5 - 1%
I	1	Values exceed acceptable ranges; power factor between 1 – 2%.
B	0	Values are not acceptable> 2%, immediate attention required; power factor greater than 2%

G = Good
D = De-Graded
I = Investigate
B = Bad

Table 34. MS transformer parameter #10: bushing condition

Condition Factor	Factor	Condition Criteria Description
A	4	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	3	Bushings are not broken, however minor chips and cracks are visible. Cementing and fasteners are secure.
C	2	Bushings are not broken, however major chips, and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	1	Bushings are broken/damaged or cementing and fasteners are not secure.
E	0	Bushings, cementing or fasteners are broken/damaged beyond repair.

Table 35. MS transformer parameter #11: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	**2**	**3**	**4**	**Weight**
*** Moisture PPM (T ^{o}C Corrected)** U $\leq$ 69 kV	<=20	<=30	<=40	>40	4
*** Moisture PPM (T ^{o}C Corrected)** 230 kV $\leq$U	<=15	<=20	<=25	>25	
*** Dielectric Str. kV 1mm D1816** 230 kV $\leq$U	>30	>28	>=25	Less than 25	3
*** Dielectric Str. kV 1mm D1816** U $\leq$ 69 kV	>23	>20	>=18	Less than 18	
*** Dielectric Str. kV D877**	>40	>30	>20	Less than 20	
*** IFT dynes/cm** U $\leq$ 69 kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT dynes/cm** 230 kV $\leq$U	> 32	25-32	20-25	Less than 20	

Table 36. MS transformer parameter #12: age

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	40-60 years old
D	1	Greater than 60 years old
E	0	Not Applicable

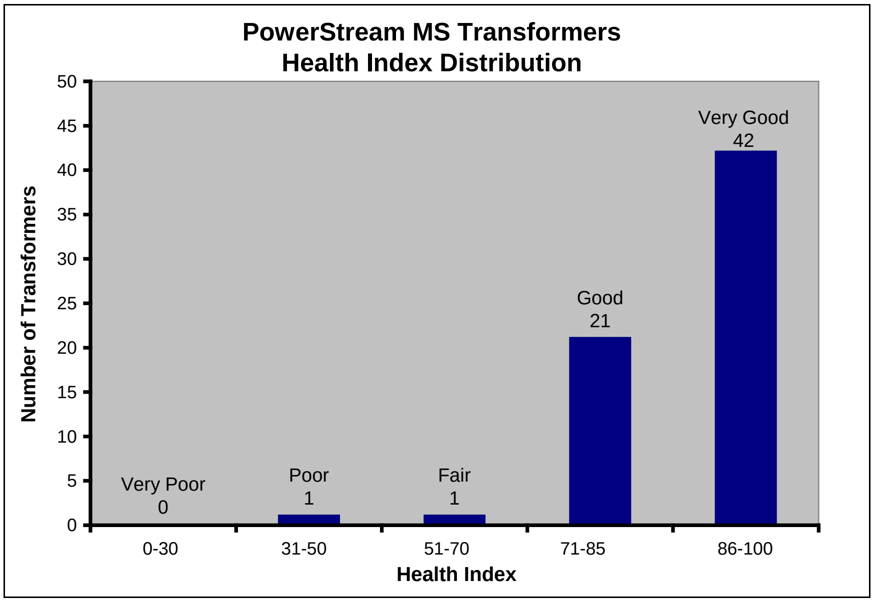


Figure 20. MS transformers Health Index histogram.

The Health of the transformer population is generally satisfactory. Only 1 transformer is in Fair condition. The unit indicated as Poor in Figure 20 is currently out of service.

Location	Position	Manufacturer	MVA Nameplate	Age	Health Index
Amber MS-T1	T1	West	10	39	90
Amber MS-T2	T2	Moloney	10	39	33
Baythorn MS-T1	T1	FPE	7.5	35	92
Baythorn MS-T2	T2	Northern Transformer	7.5	35	92
Morgan MS-T1	T1	Moloney	5	34	95
Morgan MS-T2	T2	Moloney	5	34	87
John Street MS-T1	T1	Ferranti Packard	10	37	91
John Street MS-T2	T2	Moloney	10	37	84
Elder Mills MS-T1	T1	Ferranti Packard	5	15	75
Rainbow MS-T1	T1		10	41	75
Concord MS-T1	T1	West	15	41	73
King MS-T1	T1	West	5	50	89
Aurora MS#1-T1	T1	ABB	10	10	97
Aurora MS#1-T2	T2	Ferranti Packard	10	27	88
Aurora MS#2-T1	T1	Ferranti Packard	10	32	86
Aurora MS#3-T1	T1	Federal Pioneer	10	22	86
Aurora MS#3-T2	T2	Federal Pioneer	10	21	89
Aurora MS#4-T1	T1	Northern Transformer	10	5	94
Aurora MS#4-T2	T2	West	10	38	88
Aurora MS#5-T1	T1	Northern Transformer	10	15	97
Aurora MS#5-T2	T2	Northern Transformer	10	9	97
Aurora MS#6-T1	T1	Northern Transformer	10	14	93
Aurora MS#6-T2	T2	West	10	38	94
Aurora MS#7-T1	T1	Northern Transformer	10	5	97
Aurora MS#8-T1	T1	Northern Transformer	10	5	97
ANNE NORTH-301-T1	301-T1	Federal Pioneer	20	22	91
SAUNDERS-302-T1	302-T1	Federal Pioneer	20	22	91
FERNDALE SOUTH-303-T1	303-T1	Federal Pioneer	20	22	88
BIG BAY POINT-304-T1	304-T1	Federal Pioneer	20	21	86
HOLLY-305-T1	305-T1	Ferranti	20	11	93
LITTLE LAKE-306-T1	306-T1	Federal Pioneer	20	21	79
HURONIA-307-T1	307-T1	Northern	10	8	75
Park Place-308-T1	308-T1	Ferranti	20	11	86
John-321-T1	321-T1	Moloney	10	34	78
Melborne-322-T1	322-T1	Federal Pioneer	10	35	75
8th Line-323-T2	323-T2	Northern	10	21	81
Reagans-324-T1	324-T1	Northern	10	12	73
8th Ave-330-T1	330-T1	Northern	10	20	94
14th Line-331-T1	331-T1	Northern	10	7	100
14th Line-331-T2	331-T2	Northern	10	7	100
Patterson-336-T1	336-T1	B.G. High Voltage	7.5	21	93
ANNE TEMP-402-T1	402-T1	C.G.E.	5	45	73
BLAKE-404-T1	404-T1	TTI	10	22	92
BROCK-405-T1	405-T1	TTI	10	21	92
BURTON-406-T1	406-T1	Moloney	5	37	81
CUNDLES EAST-407-T1	407-T1	General Electric	5	48	84
CUNDLES WEST-408-T1	408-T1	Federal Pioneer	5	36	86
DUCKWORTH-409-T1	409-T1	Westinghouse	5	43	60
FERNDALE-410-T1	410-T1	Westinghouse	5	26	85
INNISFIL-411-T1	411-T1	Federal Pioneer	5	34	87
JOHNSON-412-T1	412-T1	Federal Pioneer	10	24	91
LETITIA-413-T1	413-T1	Federal Pioneer	5	34	84
LITTLE-414-T1	414-T1	C.G.E.	5	39	90
MARY-415-T1	415-T1	TTI	10	21	90
ST. VINCENT-417-T1	417-T1	TTI	10	24	75
WELLINGTON-418-T1	418-T1	TTI	10	20	75
PERRY -419-T1	419-T1	Federal Pioneer	10	20	77
Fox-421-T1	421-T1	ABB	5	14	89
Robert-422-T1	422-T1	Federal Pioneer	5	25	87
Bellisle-423-T1	423-T1	Porter	5	36	76
Centennial-424-T1	424-T1	Markham Electric	6	18	87
Dufferin-431-T1	431-T1	Westinghouse	5	50	78
Fletcher-432-T1	432-T1	C.G.E.	5	40	94
Nolan-834-T1	834-T1	Westinghouse	10	26	90
Mill St.-835-T1	835-T1	Markham Electric	6	36	84

Figure 21. MS transformers Health Index results.

Failure Probability

The MS Transformer failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- Shape = 3.00, Scale = 74.77

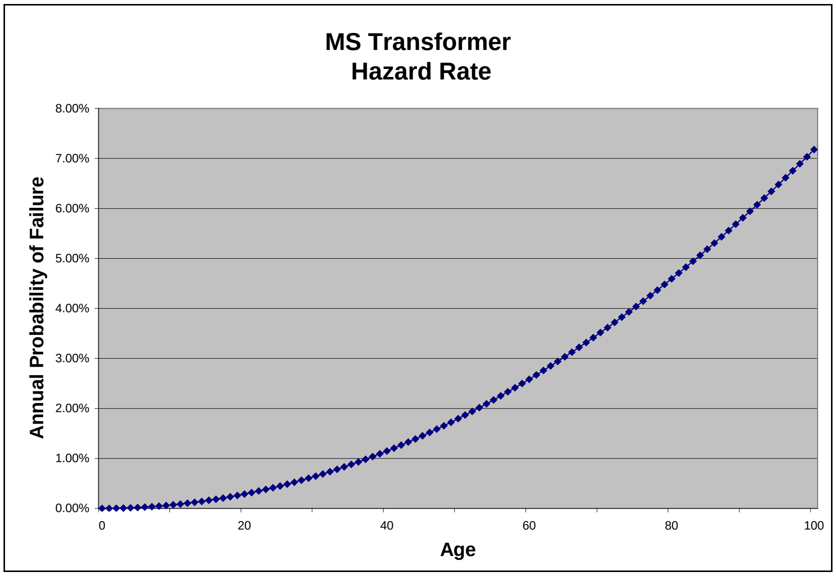


Figure 22. MS transformer hazard rate curve.

The curve fits the failure experience of other utilities with larger populations.

<u>Failure Effects</u>

MS transformer failures are assumed to cause a 5-hour outage, mitigated, in most cases, through switching to other MS transformers. Outage costs are based on peak loading.

<u>Risk Matrix</u>

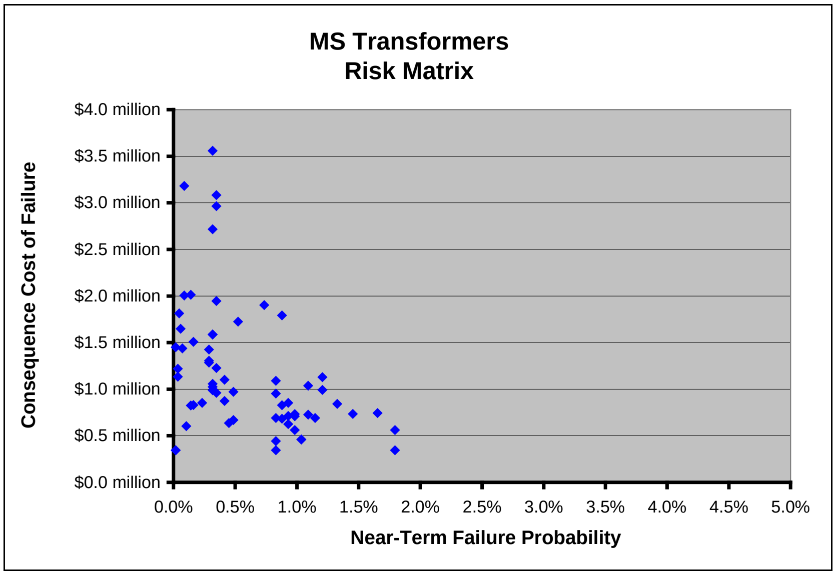


Figure 23. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode

The intervention mode modeled for MS transformers is replacement in-kind.

Econometric Replacement Results

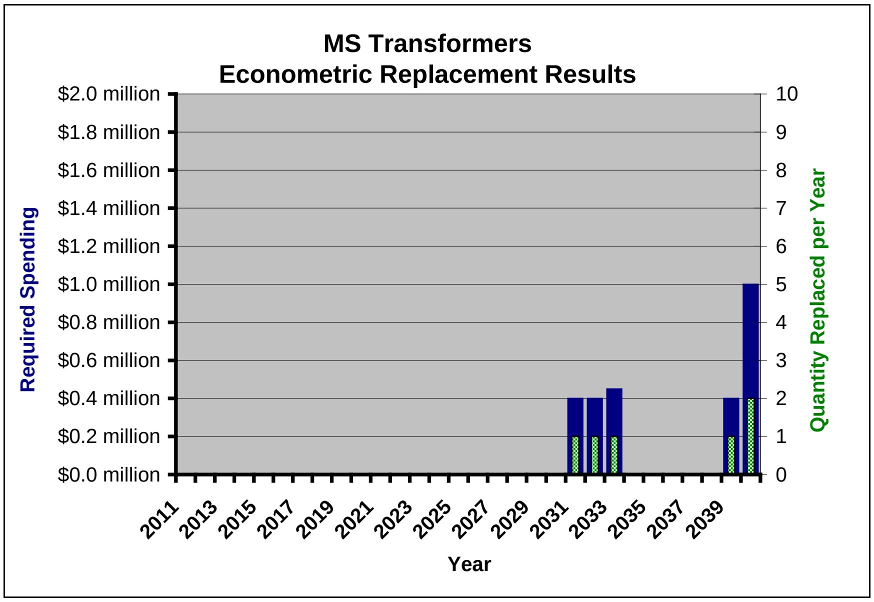


Figure 24. MS transformers econometric replacement results.

Conclusions

- Recommendations:
  - o No replacement is proposed in the next five years.
- Gaps:
  - o None identified.

3.3 Circuit Breakers

Summary of Asset Class

Circuit breakers are highly complex assets with a moderate price per unit. Types include vacuum, oil, air, and SF6 breakers.

There is limited end-of-life condition data available; health index formulation is based on industry best-practice with an emphasis on mechanical degradation indicators. Mechanical and electrical condition data is collected on an ongoing basis.

Data Sources Available

The data sources available for circuit breakers include assumed loading, nameplate, and general demographic information.

Demographics

Number of units: 399 (386 with HI assessments)
Typical life expectancy (years): 35-65 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"
Estimated replacement cost: $160,000 - $212,000

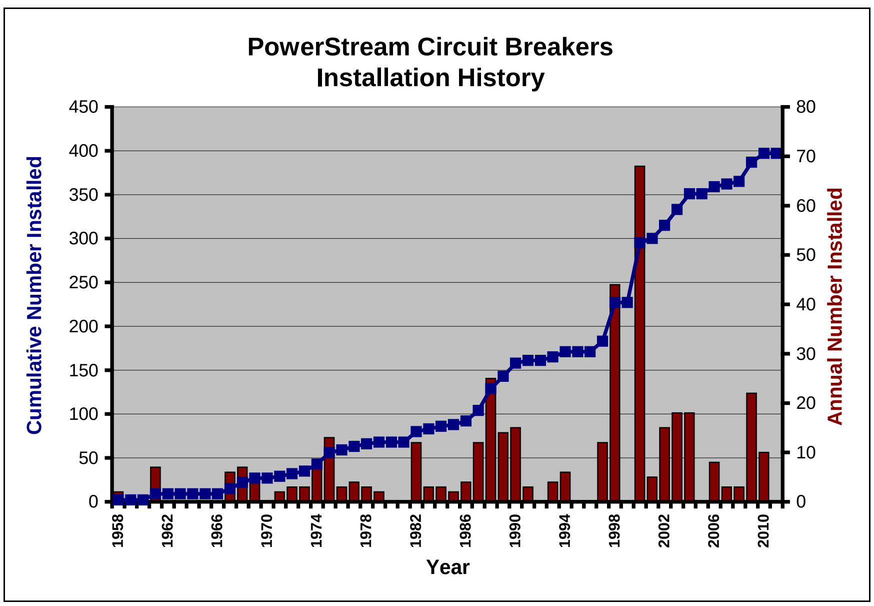


Figure 25. Circuit breaker installation history.

Asset Degradation

The station circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. Circuit breakers designs have evolved over the years and many different types are currently in use. Commonly used circuit breaker types include oil circuit breakers, vacuum breakers, magnetic air circuit breakers and SF6 circuit breakers.

Station circuit breakers have many moving parts that are subject to wear and stress. They frequently “make” and “break” high currents and experience the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker’s specific duties. The International Council on Large Electric Systems’ (CIGRE) has identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete
- Maintenance overhaul requirements
- Circuit breaker age

Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

- Corrosion
- Effects of moisture
- Bushing/insulator deterioration
- Mechanical

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problems in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil and gas leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections
- Oil contamination and/or leakage
- Deterioration of concrete foundation affecting stability of breakers

The diagnostic tests to assess the condition of circuit breakers include:

- Visual inspections
- Travel time tests
- Contact resistance measurements
- Bushing - Doble (Power Factor) Test
- Stored energy tests (Air/Hydraulic/Spring Recharge Time)
- Insulating medium tests

As indicated above, the useful life of circuit breakers can vary significantly depending on the duty cycle and typically lies within a broad range of 35 to 65 years
Consequences of circuit breaker failure may be significant as they can directly lead to catastrophic failure of the protected equipment, leading to customer interruptions, health and safety consequences and adverse environmental impacts.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

The following figure illustrates the HI formulation for circuit breakers.

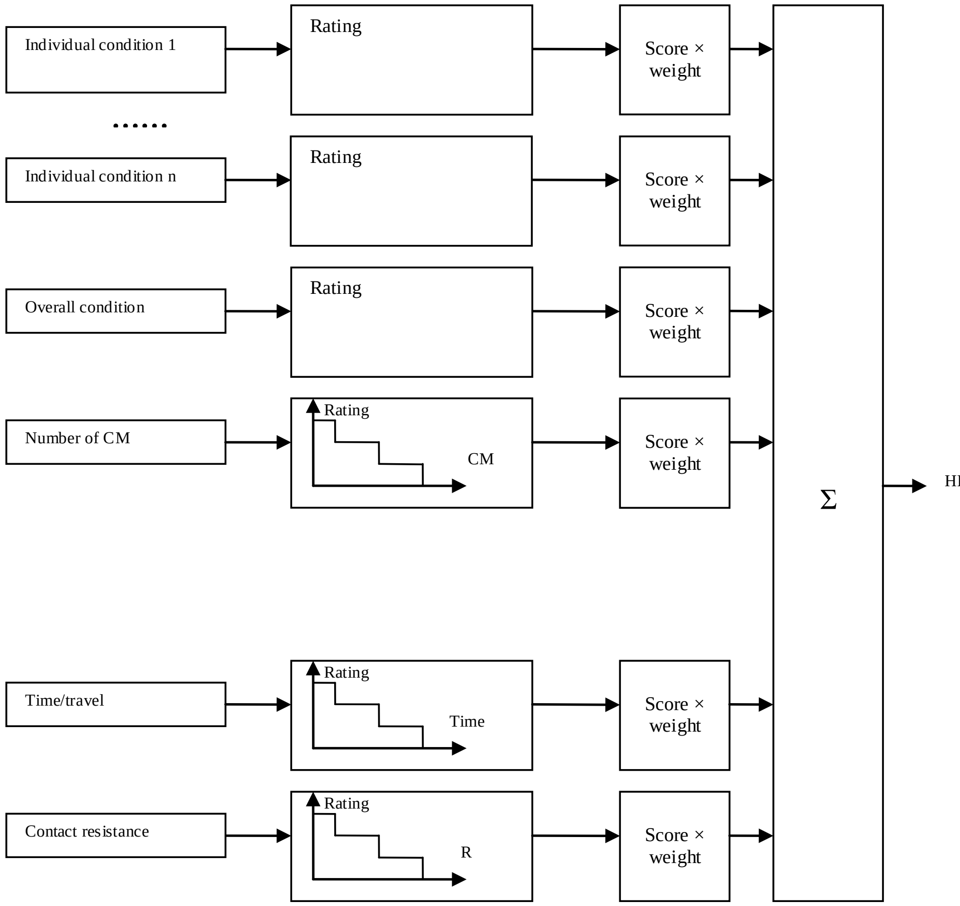


Figure 26. Circuit breaker Health Index formulation flowchart.

Table 37. Circuit breakers Health Index parameters and weights

#	CB Condition Parameters	Weight
1	Bushing/Insulator Condition	3
2	Leaks (OCB only)	3
3	Tank and Control/Mechanism Box	2
4	Control and Mechanism Box Components	2
5	Foundation and Support Steel Grounding	2
6	Overall Condition	4
7	Time/Travel	3
8	Contact Resistance	4

Table 38. Circuit breaker parameter #1: bushing/insulator condition

Condition Factor	Factor	Condition Criteria Description
A	4	Bushings/Support Insulators are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	3	Bushings/Support Insulators are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	2	Bushings/Support Insulators are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	1	Bushings/Support Insulators are broken/damaged, or cementing or fasteners are not secure.
E	0	Bushings/Support Insulators, cementing or fasteners are broken/damaged beyond repair.

Table 39. Circuit breaker parameter #2: leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces. No oil leakage or water ingress at any of the flanges, manholes, covers, breathers, pipes or gauges. Oil levels are acceptable.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress at the bushings, or at one other location indicate the immediate need for a major reconditioning or replacement.
E	0	Significant oil leakage and moisture ingress resulting in damage/degradation beyond repair.

Table 40. Circuit breaker parameter #3: tank and control/mechanism box

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets. No rust, corrosion or paint peeling on tanks or cabinets, sealing very effective – no evidence of moisture or insect ingress or condensation.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in mechanism box.
C	2	Some rust and corrosion on both tank and on mechanism box, requires corrective maintenance within the next several months.
D	1	Significant corrosion on main tank and on mechanism box. Defective sealing leading to water ingress and insects/rodent damage. Requires immediate corrective action.
E	0	Corrosion, water, insect or rodent damage or degradation beyond repair.

Table 41. Circuit breaker parameter #4: control and mechanism components

Condition Factor	Factor	Condition Criteria Description
A	4	Wiring, terminal blocks, relays, contactors and switches all in good condition. Operating mechanism, trip and close coils, relays, auxiliary switches, motors, compressors, springs are all in good condition. No sign of overheating or deterioration. Linkages, drive rods, trip latches are clean, lubricated, free from cracks, distortion, abrasion or obstruction. Mechanical integrity of dampers/dashpots, and oil levels, is acceptable. No visible evidence of poor mechanism settings, looseness, loss of adjustment, excess bearing wear or other out of tolerance operation.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Control and mechanism components are damaged/degraded beyond repair.

Table 42. Circuit breaker parameter #5: foundation and support steel grounding

Condition Factor	Factor	Condition Criteria Description
A	4	Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are direct to tank, cabinets, supports without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Supports or grounding are damaged/degraded beyond repair.

Table 43. Circuit breaker parameter #6: overall condition

Condition Factor	Factor	Condition Criteria Description
A	4	Breaker externally is clean, corrosion free. All primary and secondary connections are in good condition. No external evidence of overheating. Number of breaker operations on counter, and run timer readings on auxiliary motors, are below average range for age of breaker. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	The circuit breaker is damaged/degraded beyond repair.

Table 44. Circuit breaker parameter #7: time/travel

Condition Factor	Factor	Condition Criteria Description
A	4	Close travel, wipe, overtravel, rebound and time are all within specified limits. Trip time and velocity are within specified limits. Trip free time is within specified limits. Interpole close and trip contact time spread is within specified limits for the specific application.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Two or more of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table 45. Circuit breaker parameter #8: contact resistance

Condition Factor	Factor	Condition Criteria Description
A	4	Values well within specifications with high margins
B	3	Values close to specification (little or no margin)
C	2	Values do not meet specification (by a small amount)
D	1	Values do not meet specification (by a significant margin)
E	0	Values do not meet specification and cannot be brought into specification condition.

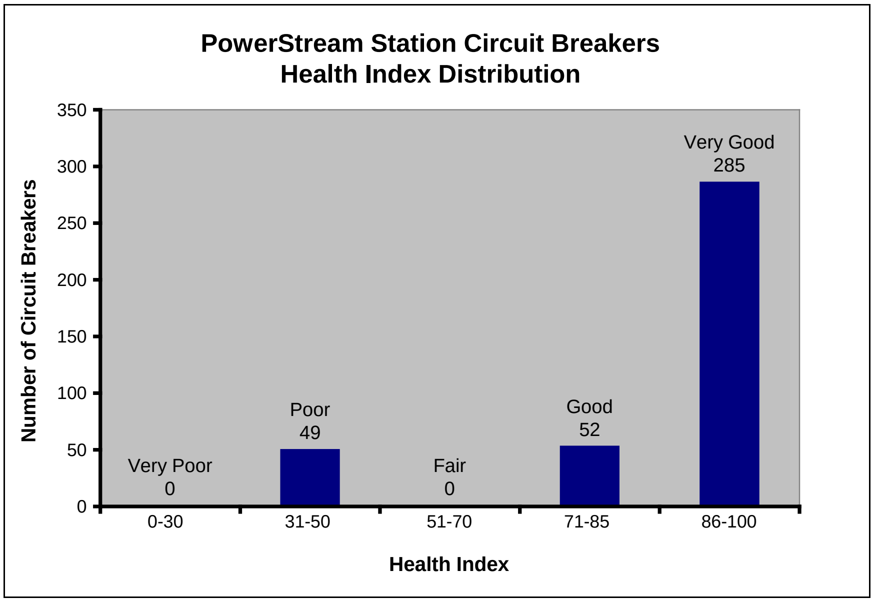


Figure 27. Station Circuit Breakers Index histogram.

Failure Probability

The circuit breaker failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- **Gas insulated VAC / Air**- Shape = 3.00, Scale = 74.77
- **OCB** - Shape = 3.00, Scale = 59.8
- **SF6** - Shape = 3.00, Scale = 52.4

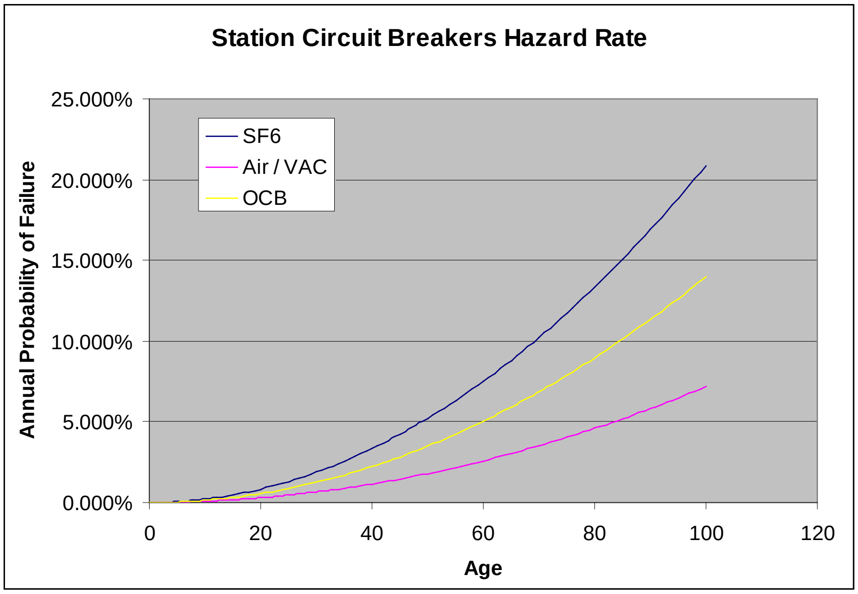


Figure 28. Circuit breaker hazard rate curves.

The curves fit the failure experience of other utilities with larger populations.

<u>Failure Effects</u>

Circuit breakers are assumed to fail with two dominant failure modes: operational failure and catastrophic failure. The relative probability and costs of each failure mode occurring differs for obsolete versus non-obsolete breakers. The failure effects are summarized in the following figures:

Effects of Distribution Circuit Breaker Failure
Non-Obsolete Breaker

Failure Mode 1		
Relative Probability	50%	
Description	Operational failure	
Effect	Repair required; non-destructive	
Cost		
Direct cost	15%	Percent of replacement cost
Outage cost	2	Hours that breaker is out
Occurrence factor	3	Occurrences over life of breaker

Failure Mode 2		
Relative Probability	50%	
Description	Failure to open; catastrophic	
Effect		
Cost		
Direct cost	115%	Percent of replacement cost
Outage cost	2	Full station is out

Figure 29. Non-obsolete circuit breaker failure effects.

Effects of Distribution Circuit Breaker Failure
Obsolete Breaker

Failure Mode 1		
Relative Probability	40%	
Description	Operational failure	
Effect	Repair required; non-destructive	
Cost		
Direct cost	30%	Percent of replacement cost
Outage cost	2	Hours that breaker is out
Occurrence factor	3	Occurrences over life of breaker

Failure Mode 2		
Relative Probability	60%	
Description	Failure to open; catastrophic	
Effect		
Cost		
Direct cost	130%	Percent of replacement cost
Outage cost	2	Full station is out

Figure 30. Obsolete circuit breaker failure effects.

Risk Matrix

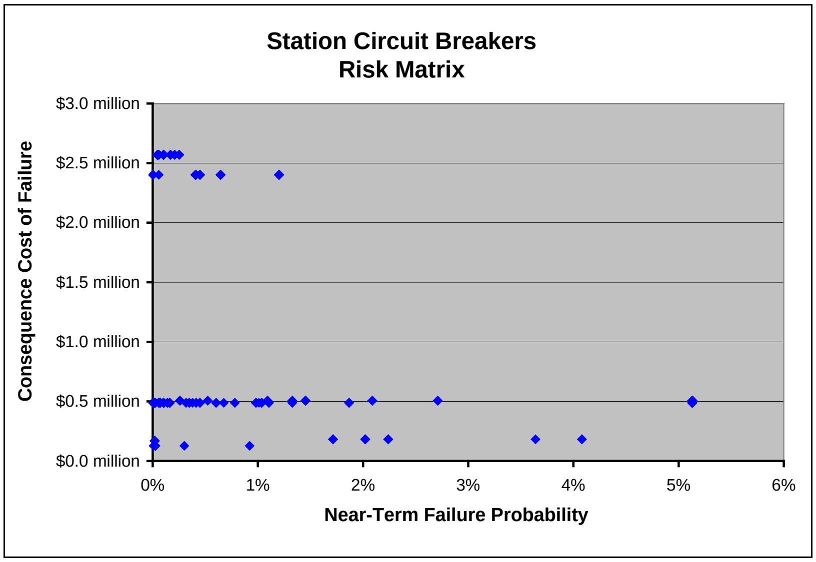


Figure 31. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode

The intervention mode modeled for circuit breakers is replacement in-kind. The replacement costs vary by circuit breaker type and size.

Econometric Replacement Results

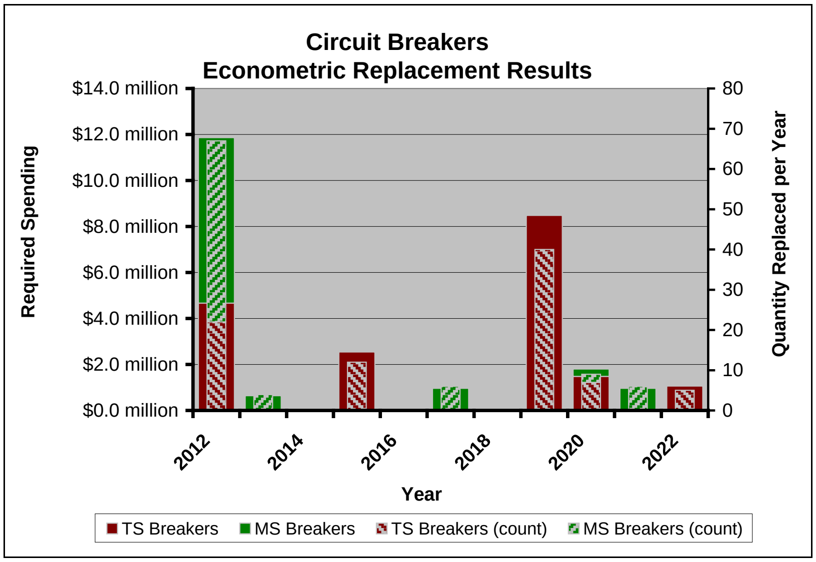


Figure 32. Circuit beaker econometric replacement results.

Conclusions

- Recommendations:
  - o Near-term circuit breaker replacements are warranted.
- Gaps:
  - o Some breakers missing contact resistance data.

3.4 230kV Switches

Summary of Asset Class
230kV switches are moderately complex assets with a moderate price per unit.

A 230 kV switch failure is assumed to have no consequence cost. No load will be lost as the remaining transformer will be able to carry the load of the companion transformer (there may be a momentary outage).

Health index formulation is based on industry best-practice.

Data Sources Available
Comprehensive demographic and condition data was made available.

Demographics
Number of units: 22
Typical life expectancy (years): 30-60 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 “Asset Amortization Study for the Ontario Energy Board”
Estimated replacement cost: $46,280

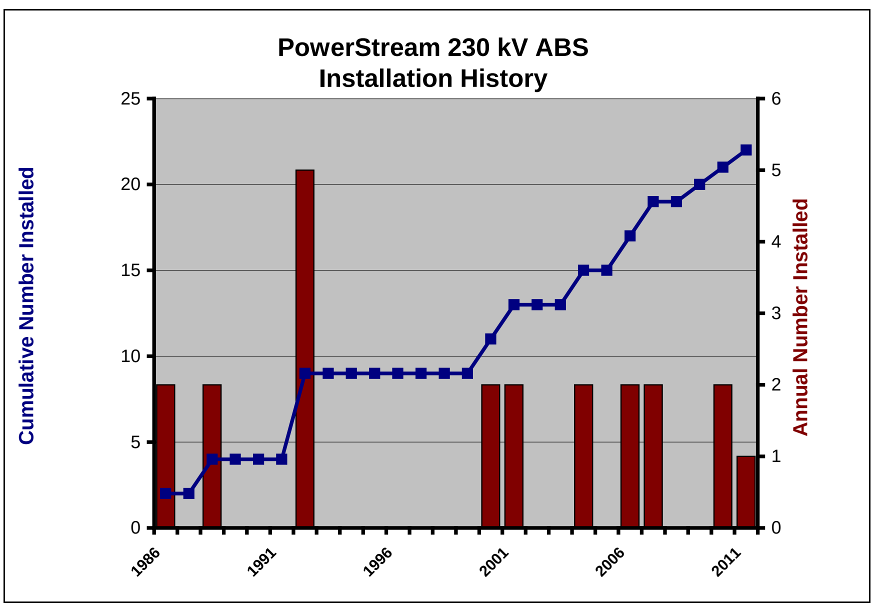


Figure 33. 230kV switches installation history.

Asset Degradation
This asset group consists of transmission air break switches. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of switches are rated for load

interruption, others are designed to be operated only under no load conditions. These switches can be operated only when the current through the switch is zero or near zero (e.g. line charging current). Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in the open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road de-icing salt is used.

The condition assessment of switches involves visual inspections which can reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on switches.
The following parameters can be considered in establishing the asset health index formulation:

- Condition of switch blades (contacts)
- Operating arm and switch mounting

- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Age of disconnect switch
- Expert feedback

The average life expectancy of switches is approximately 40 years. Consequences of switch failure may include customer interruption and health and safety consequences for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 46. 230kV switches Health Index parameters and weights

#	230kV Switch Condition Parameters	Weight
1	Age	3
2	Expert Feedback	10
3	Load	3
4	Switch Contact	5
5	Blade/Arm	5
6	Mechanism	5
7	Arc Break	5
8	Lock/Handle	1

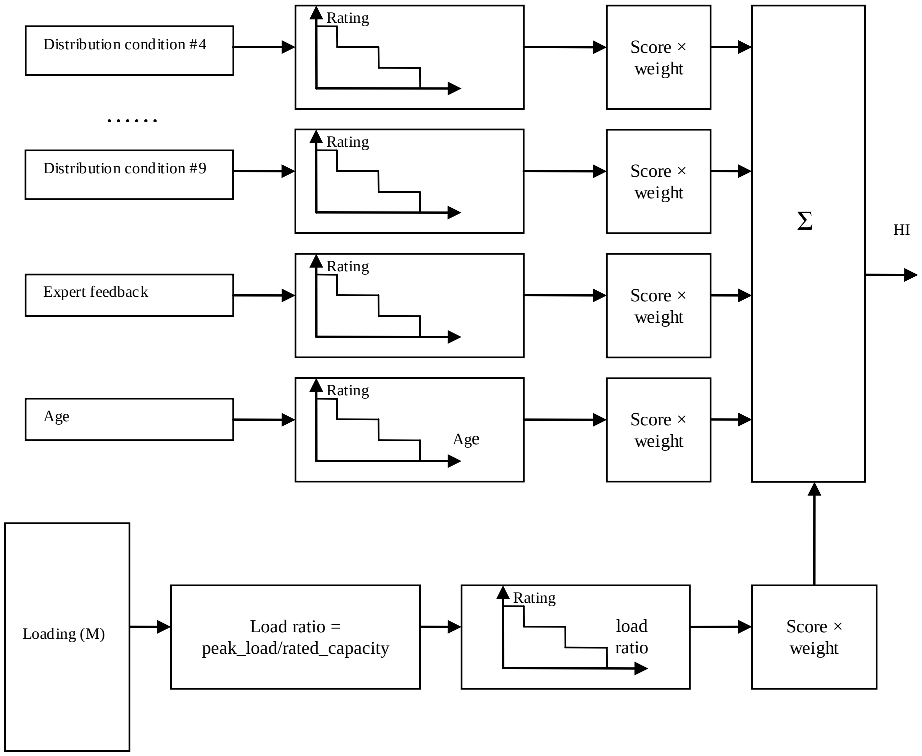


Figure 34. 230kV switches Health Index flowchart.

Table 47. 230kV switches parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	<10 years old
B	3	10-19 years old
C	2	20-29 years old
D	1	30-39 years old
E	0	>=40 years old

Table 48. 230kV switches parameter #2: expert feedback

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 49. 230kV switches parameter #3: loading condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	N < 1
B	3	1 <= N < 1.1
C	2	1.1 <= N < 1.2
D	1	1.2 <= N < 1.4
E	0	N >= 1.4

Where N = peak load / rated capacity

Table 50. 230kV switches parameter #4: switch contact resistance criteria

Condition Factor	Factor	Condition Criteria Description
A	4	[0,200) uΩ
B	3	[200, 250) uΩ
D	1	[250, 300) uΩ
E	0	[300, ∞) uΩ

Table 51. 230kV switches parameters #5-8: inspection asset condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

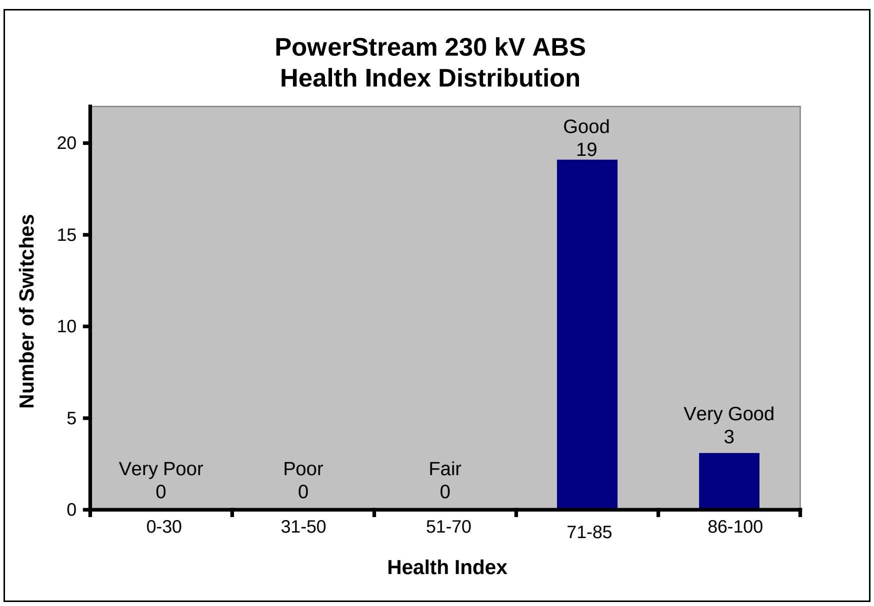


Figure 35. 230kV switches Health Index histogram.

Failure Probability

The 230kV switch failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry best practice. The Weibull curve parameters are:

- Shape = 3.00, Scale = 66.9

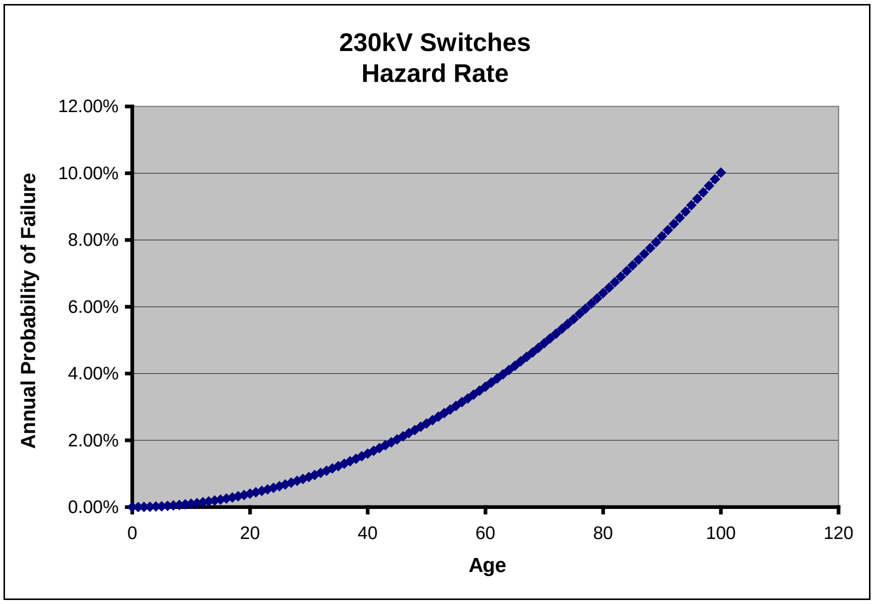


Figure 36. 230kV switches hazard rate curve.

<u>Failure Effects</u>

The dominant failure mode assessed for a 230kV switch is catastrophic failure requiring replacement.

The failure effects are based on the following assumptions:

- In the event of a loss of a 230 kV switch, no load will be lost as the remaining transformer will be able to carry the load of the companion transformer. There may be a momentary outage. The transmission circuit may need to be isolated for a few hours to allow the defective switch to be isolated and replaced. During this period, stations on same transmission circuit would be at single contingency status.

Risk Matrix

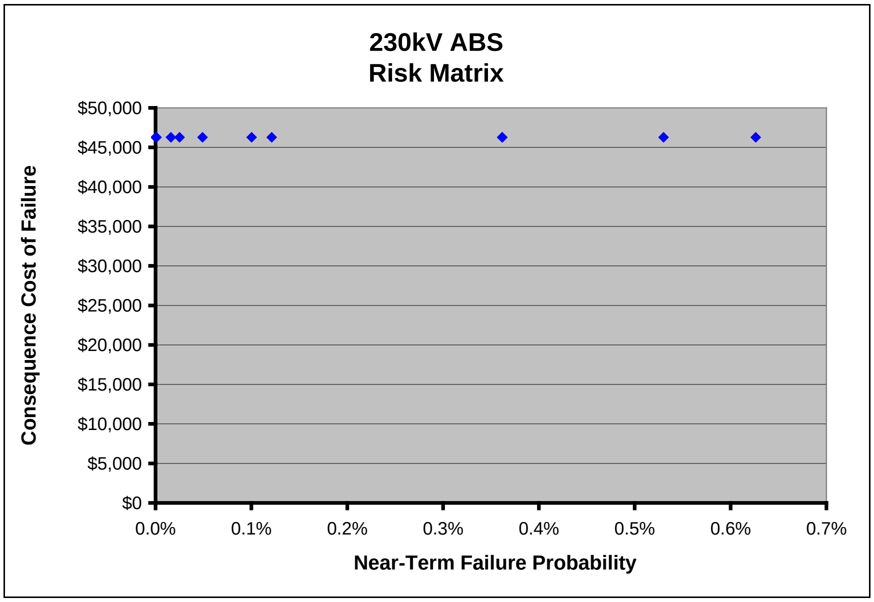


Figure 37. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

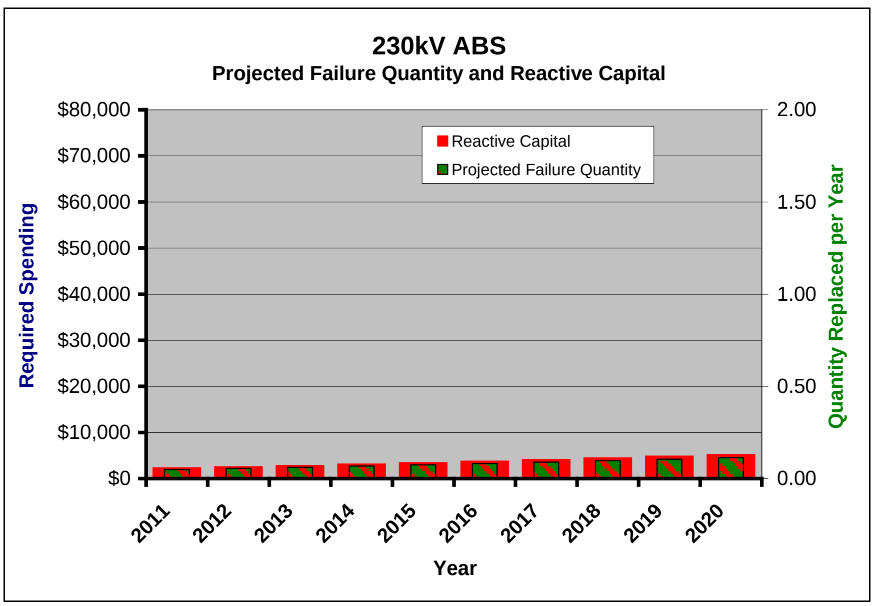


Figure 38. 230kV switches projected failure quantity and reactive capital.

Intervention Mode

The intervention mode modeled for 230kV switches is replacement in-kind. The replacement costs vary by type and size.

Econometric Replacement Results

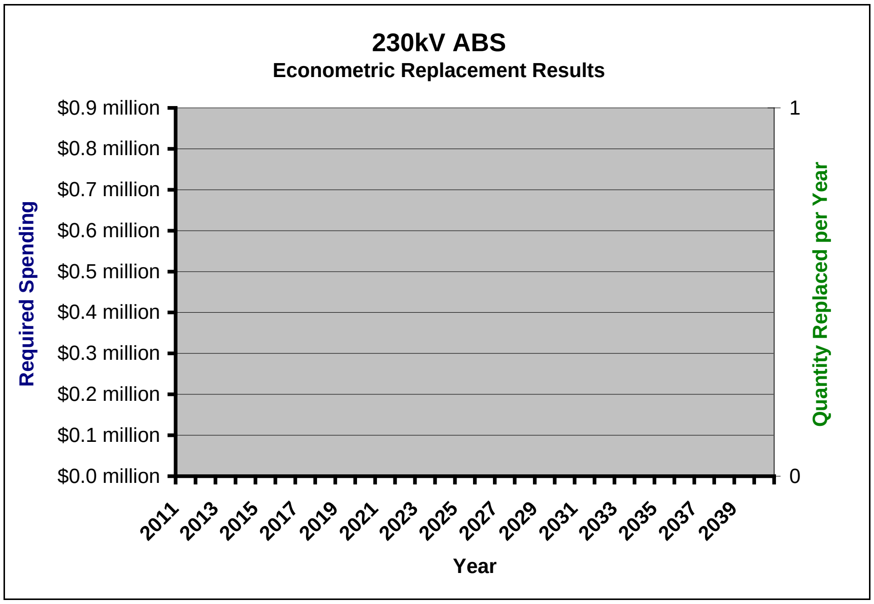


Figure 39. 230kV switches econometric replacement results.

Conclusions

- Recommendations:
    - One unit is proposed for replacement for the next five years due to obsolescence and no replacement stock (Richmond Hill RHTS1_T2SW2). PowerStream will replace this switch in 2012 at a cost of $70,584.
- Gaps:
    - None identified.

3.5 MS Primary Switches

Summary of Asset Class

MS primary switches are moderately complex assets with a moderate price per unit.

Health index formulation is based on industry best-practice and condition data is collected.

Data Sources Available

Assumed loading, nameplate, and general demographic data.

Demographics

Number of units: 66

Typical life expectancy (years): 30-60 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 “Asset Amortization Study for the Ontario Energy Board”

Estimated replacement cost: $45,000 - $113,000

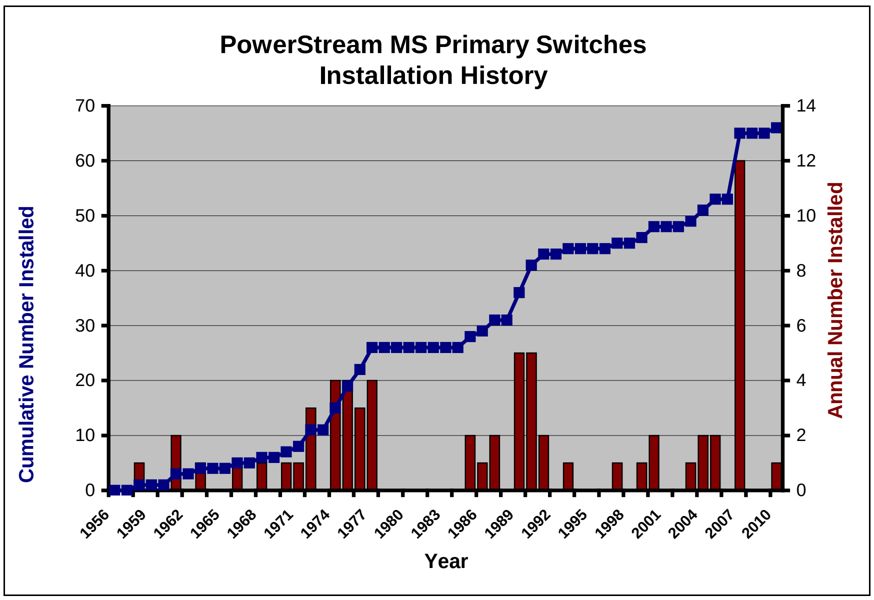


Figure 40. MS primary switches installation history.

Asset Degradation

This asset group consists of municipal station air break and fused switches. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of switches are rated for load interruption, others are designed to be operated only under no load conditions. These switches can be operated only when the current through the switch is zero or near zero (e.g. line charging current). Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in the open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road de-icing salt is used.

The condition assessment of switches involves visual inspections which can reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on switches.

The following parameters can be considered in establishing the asset health index formulation:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Age of disconnect switch
- Expert feedback

The average life expectancy of switches is approximately 40 years. Consequences of switch failure may include customer interruption and health and safety consequences for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 52. MS primary switches Health Index parameters and weights

#	MS Primary Switch Condition Parameters	Weight
1	Age	3
2	Expert Feedback	10
3	Load	3
4	Switch Contact	5
5	Blade/Arm	5
6	Mechanism	5
7	Fuse	3
8	Arc Break	5
9	Lock/Handle	1

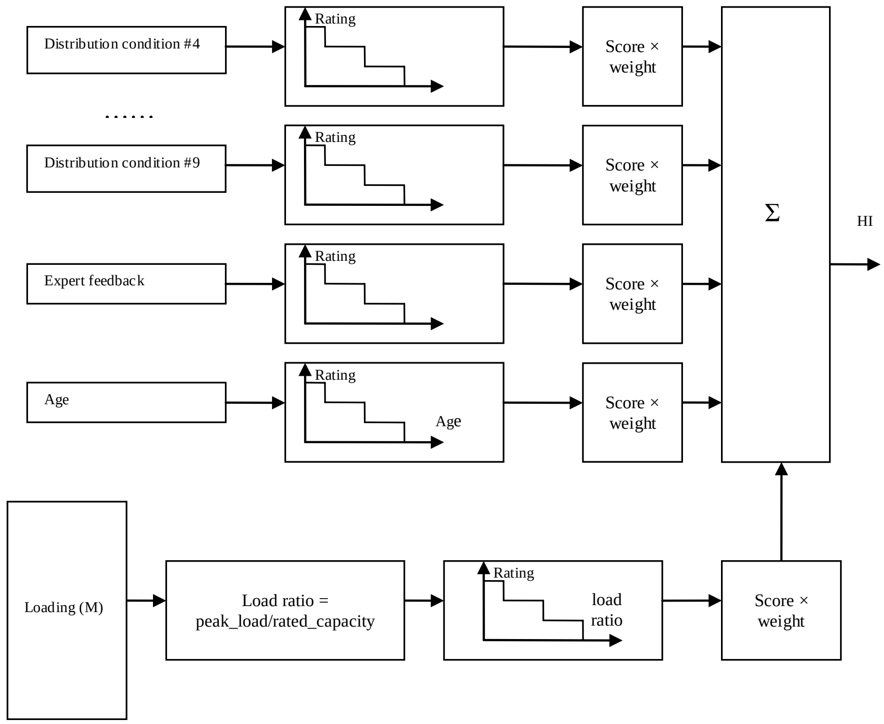


Figure 41. MS primary switches Health Index flowchart.

Table 53. MS primary switches parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	< 20 years old
B	3	20-39 years old
C	2	40-49 years old
D	1	50-59 years old
E	0	>=60 years old

Table 54. MS primary switches parameter #2: expert feedback

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 55. MS primary switches parameter #3: loading condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	N < 1
B	3	1 <= N < 1.1
C	2	1.1 <= N < 1.2
D	1	1.2 <= N < 1.4
E	0	N >= 1.4

Where N = peak_load / rated_capacity

Table 56. MS primary switches parameter #4: switch contact condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	[0,200) uΩ
B	3	[200, 250) uΩ
D	1	[250, 300) uΩ
E	0	[300, ∞) uΩ

Table 57. MS primary switches parameters #5-9: inspection asset condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

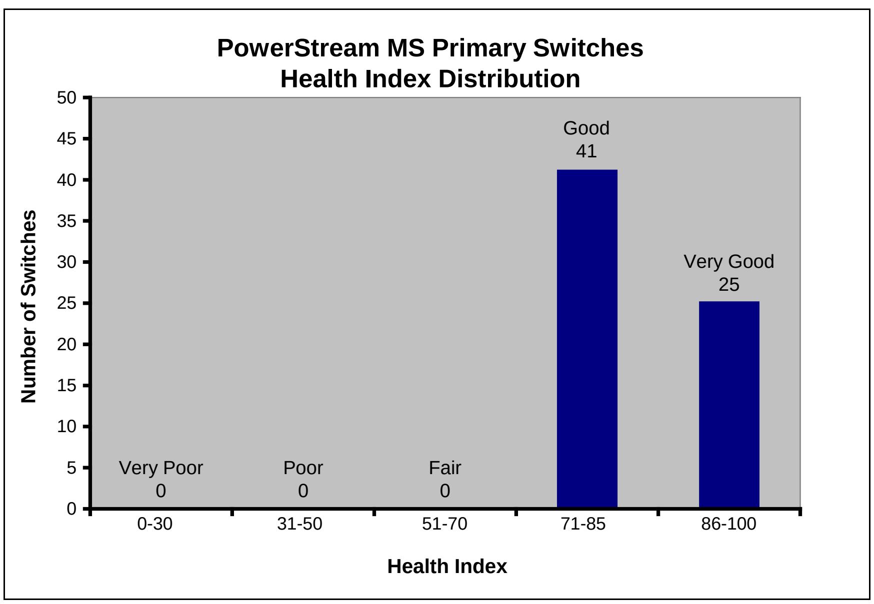


Figure 42. MS primary switches Health Index histogram.

Failure Probability

The MS primary switch failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry best practice. The Weibull curve parameters are:

- Shape = 3.00, Scale = 74.77

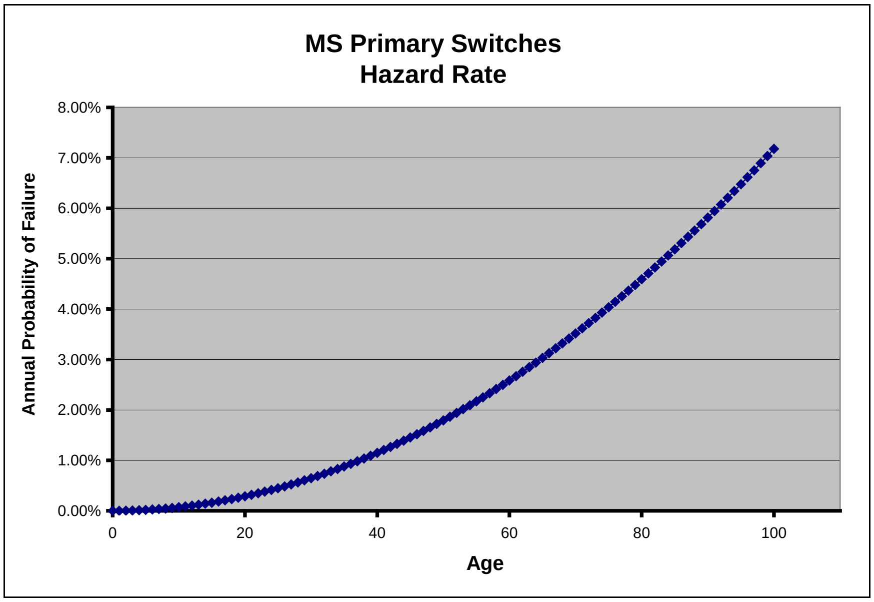


Figure 43. MS primary switches hazard rate curve.

<u>Failure Effects</u>

The dominant failure mode assessed for MS primary switches is catastrophic failure requiring replacement. The failure effects by type and size are summarized below.

Description	Type	Loss of Peak Load (kW)	Outage Duration (hours)
Pole Mounted Load Interrupter Switch & Fuse	Pole	5,167	3
Load Interrupter Switch & Fuse In Metal Clad Enclosure	Enclosure	5,167	3

Figure 44. MS primary switches failure effects.

The failure effects are based on the following assumptions:

Total peak load for all transformers = 341,000 kW
Total number of transformers = 65
Average Loss of Peak Load (kW) =341,000 kW/65 =5167 kW

Risk Matrix

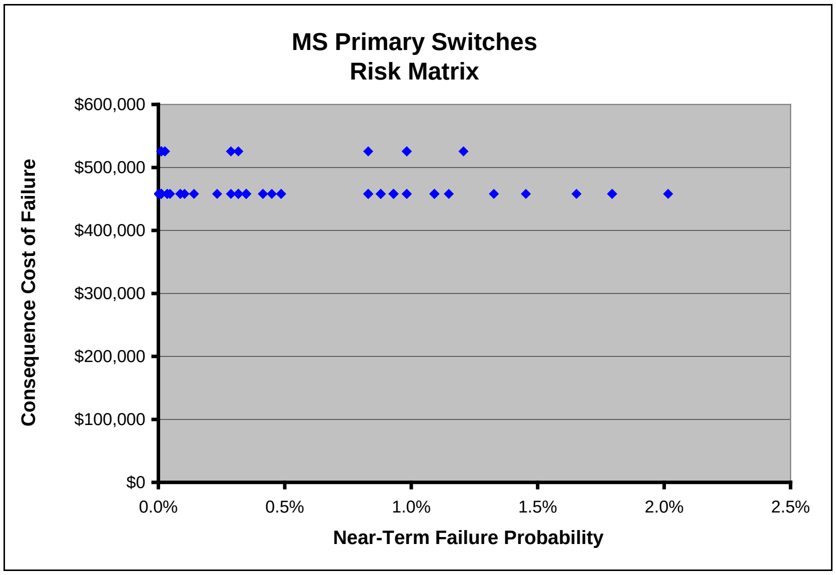


Figure 45. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

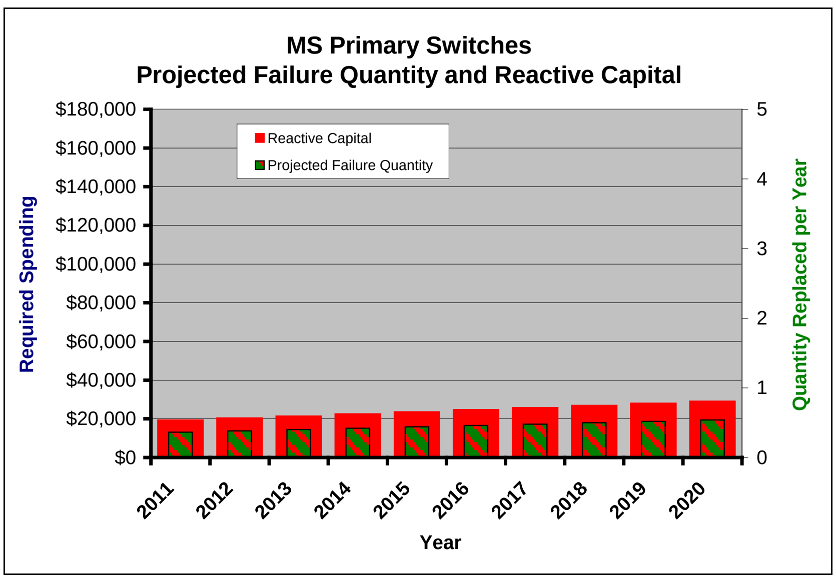


Figure 46. MS primary switches projected failure quantity and reactive capital.

Intervention Mode

The intervention mode modeled for MS primary switches is replacement in-kind. The replacement costs vary by type and size. The replacement costs are summarized below.

Material Cost	Material Cost plus Overhead and Burden	Replacement Labour Hours	Replacement Labour Cost Plus Overhead and Burden	Truck Hours	Truck Cost plus Overhead and Burden	Type	Total
$30,000	$39,600	60	$3,420	30	$1,590	Pole	$44,610
$80,000	$105,600	80	$4,560	40	$2,120	Enclosure	$112,280

Figure 47. MS primary switches replacement costs.

Econometric Replacement Results

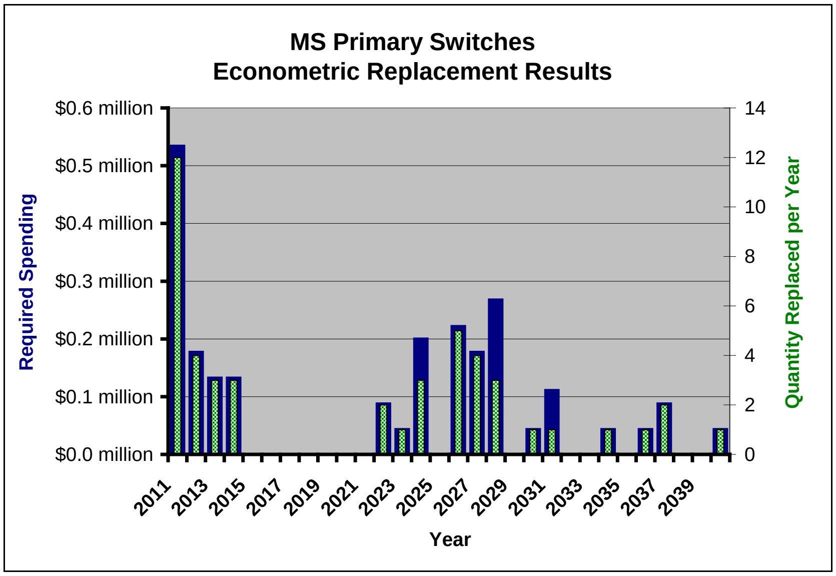


Figure 48. MS primary switches econometric replacement results.

Conclusions

- Recommendations:
    - The model recommends replacement based on econometric risk-assessment. When we incorporate engineering judgment and operations input with the econometric model results, we have concluded that the MS primary switches are still in satisfactory working condition and that the incremental risk of asset failure, by deferring replacement, can be managed. Therefore, no replacement is recommended at this time. PowerStream will continue to monitor condition of primary switches.
- Gaps:
    - None identified

3.6 Station Capacitors

Summary of Asset Class

Station capacitors are moderately complex assets with a moderate price per unit.

The dominant failure mode assessed for station capacitors is a can failure. Loss of a single unit or the entire capacitor bank will not affect station load. Capacitor bank replacements are justified based on increasing risk of can failures and associated annual costs.

Health index formulation is based on industry best-practice, and condition data is collected.

Data Sources Available

Nameplate and general demographic data.

Demographics

Number of units: 5 banks

Typical life expectancy (years): 25-40 years per can as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"

Estimated replacement cost: $110,000 for a bank

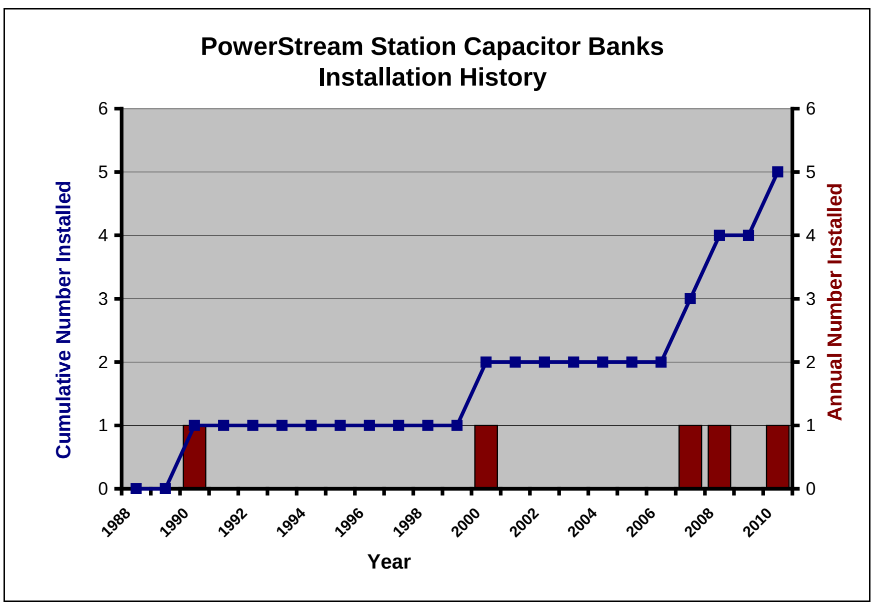


Figure 49. Station capacitors installation history.

Asset Degradation

The primary function of capacitors is to improve the quality of the electrical supply and the efficient operation of the power system. The major applications include power factor improvement and voltage regulation.

In practical implementation, such asset functions in the form of capacitor bank, i.e., a combination of various capacitor units. The operation of capacitors requires much fewer switching-on/switching-off operations. The main degradation processes associated with capacitors include:

- Imbalance due to fuse (either internally or externally) failure
- Capacitor unit fluid leaking
- Insulator problem

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

In externally fused, fuseless or unfused capacitor banks, the failed element within the can is short-circuited by the weld that naturally occurs at the point of failure (the element fails short-circuited). This short circuit puts the whole group of elements out of service, increasing the voltage on the remaining groups. Several capacitor elements breakdowns may occur before the external fuse (if exists) removes the entire unit. The external fuse will operate when a capacitor unit becomes essentially short circuited, isolating the faulted unit. Internally fused capacitors have individual fused capacitor elements that are disconnected when an element breakdown occurs (the element fails opened). The risk of successive faults is minimized because the fuse will isolate the faulty element within a few cycles. The degree of imbalance introduced by an element failure is less than that which occurs with externally fused units (since the amount of capacitance removed by blown fuse is less) and hence a more sensitive imbalance protection scheme is required when internally fused units are used.

Capacitor unit fluid leaking is mainly due to mechanical damage to the capacitor case. Insulator problems can be either insulator crack, or pollution on insulators.

The condition assessment of capacitors involves visual inspections which can reveal the extent of problems, as well as utility experts' feedback that tells the general status. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on capacitors.

The following parameters can be considered in establishing the asset health index formulation:

- Visual inspection on capacitors
- Visual inspection on insulators
- Age of capacitors
- Expert feedback

The average life expectancy of capacitors is approximately 30 years. This can, however, be prolonged by individually replacing the faulty units. Consequences of capacitors failure may include local under-voltage and lack of reactive power for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 58. Station capacitors Health Index parameters and weights

#	Station Capacitor Condition Parameters	Weight
1	Age	10
2	Expert feedback	15
3	Visual inspection	5
4	Insulators	1

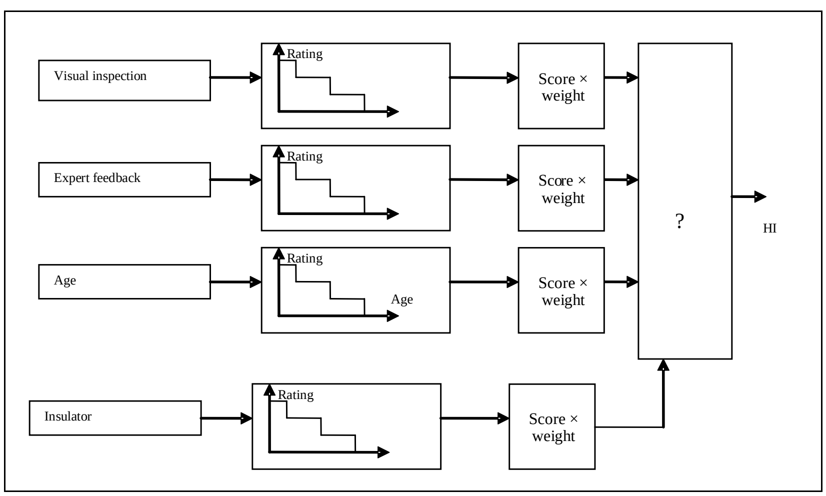


Figure 50. Station capacitors Health Index flowchart.

Table 59. Station capacitors parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	<20 years old
B	3	20-29 years old
C	2	30-39 years old
D	1	40-49 years old
E	0	>=50 years old

Table 60. Station capacitors parameter #2: expert feedback condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 61 Station capacitors parameter #3: visual inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 62 Station capacitors parameter #4: insulator condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

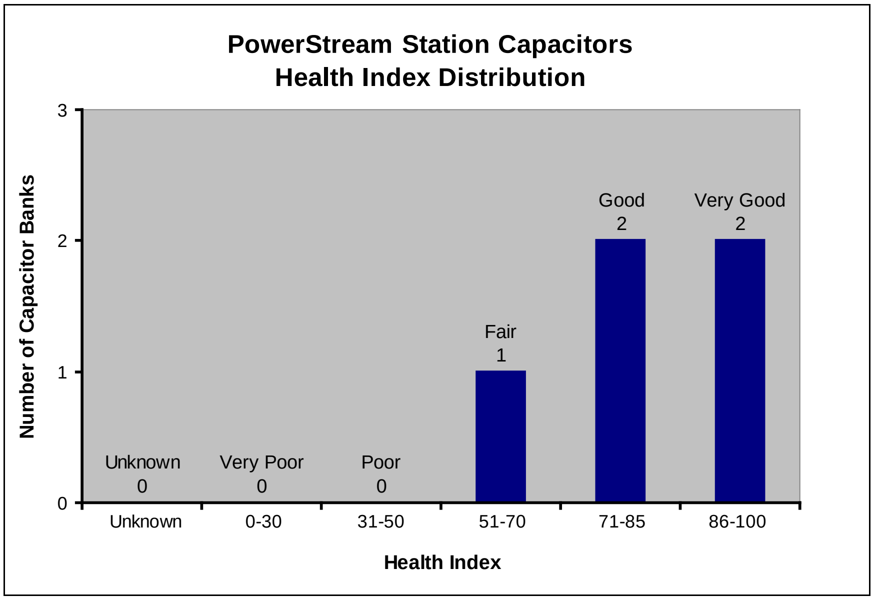


Figure 51. Station capacitors Health Index histogram.

Failure Probability

The station capacitor cans failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- Shape = 3.00, Scale = 37.41

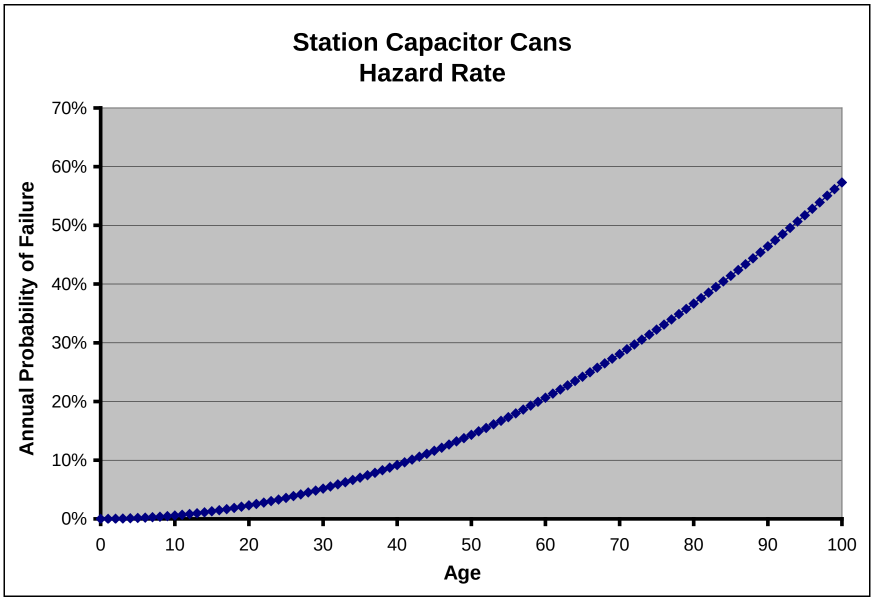


Figure 52. Station capacitors hazard rate curve.

<u>Failure Effects</u>

The dominant failure mode assessed for station capacitors is a can failure requiring replacement of the can. The loss of a single unit or the entire capacitor bank will not affect the station load.

Risk Matrix

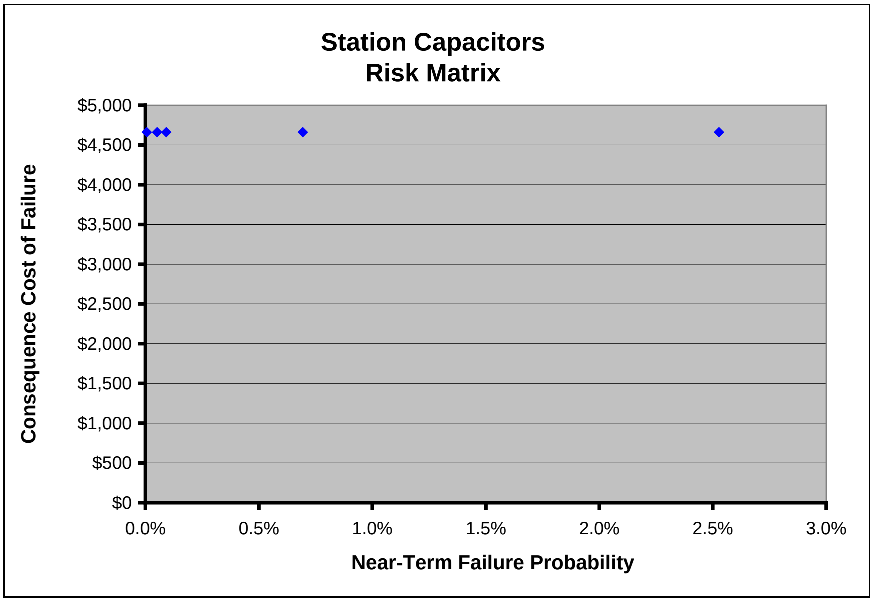


Figure 53. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

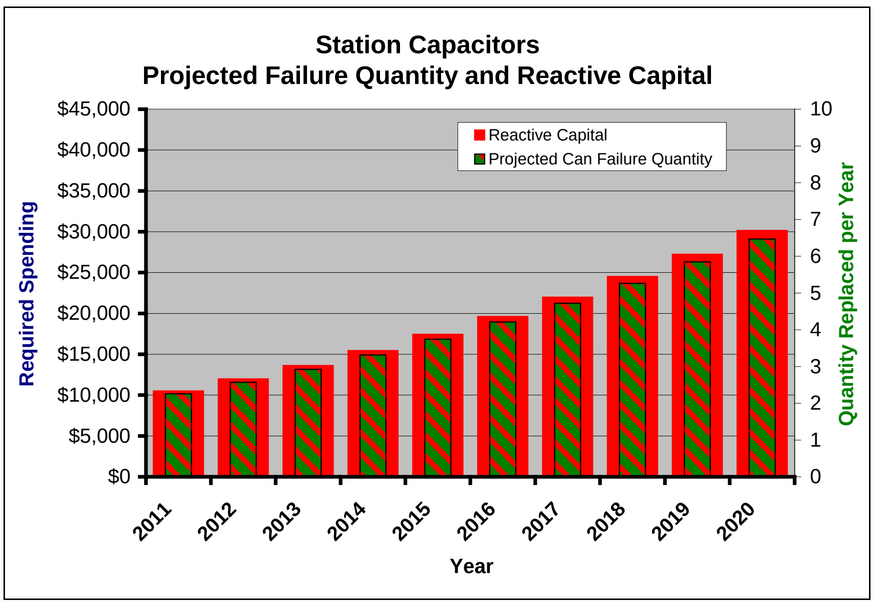


Figure 54. Station capacitors projected failure quantity and reactive capital.

Intervention Mode

The intervention mode modeled for station capacitors is capacitor bank replacement in-kind. The replacement costs vary by type and size.

Econometric Replacement Results

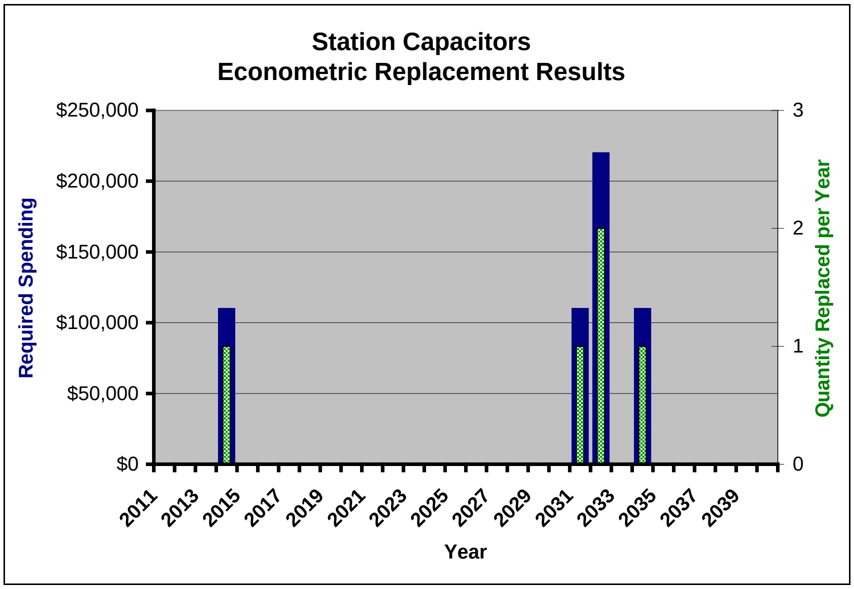


Figure 55. Station capacitors econometric replacement results.

Conclusions

- Recommendations:
  - The model recommends replacement based on econometric risk-assessment. When we incorporate engineering judgment and operations input with the econometric model results, we have concluded that the station capacitors are still in satisfactory working condition and that the incremental risk of asset failure, by deferring replacement, can be managed. Therefore, no replacement is recommended at this time. PowerStream will continue to monitor condition of station capacitors.
  - Continue capturing condition data per health index formulation and update the model.
  - Continue capturing can condition and age at failure to support customized failure probability curves and health index correlations.
- Gaps:
  - None identified.

3.7 Station Reactors

Summary of Asset Class

Station reactors are moderately complex assets with a moderate price per unit.

A station reactor failure is assumed to have no consequence cost. Loss of a station reactor, no load will be lost as the remaining transformer will be able to carry the load of the companion transformer, there may be a momentary outage. No risk-based planned replacement program is recommended.

Health index formulation is based on industry best-practice.

Data Sources Available

Nameplate and general demographic data.

Demographics

Number of units: 34

Typical life expectancy (years): 25-60 as per Kinectrics Inc. Report No: K-418238-RA-0001-R00 “Useful Life Of Transmission/Distribution System Asset And Their Components”

Estimated replacement cost: $41,270

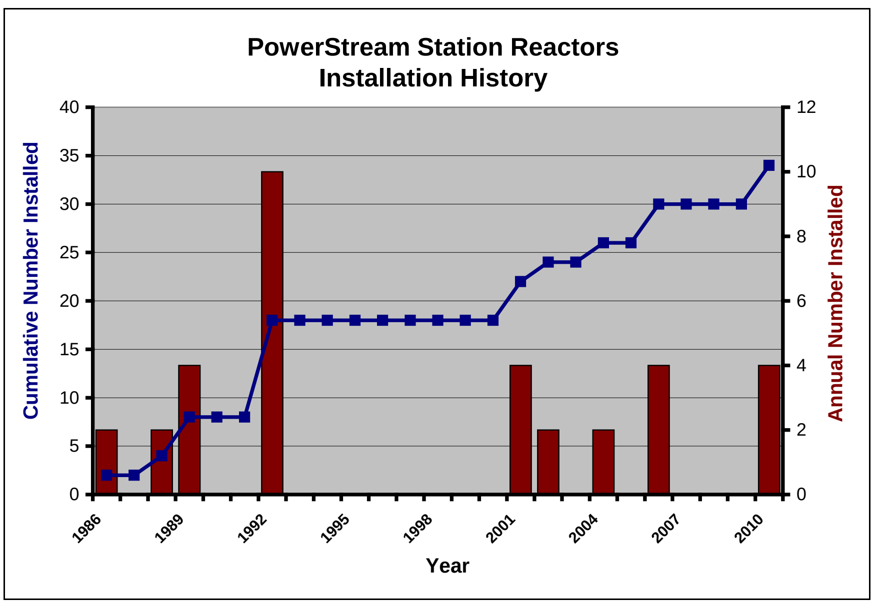


Figure 56. Station reactors installation history.

Asset Degradation

The primary function of reactors is to limit the short circuit current of a line when there is a short circuit. It can also be used to absorb reactive power, or as part of a filtering circuit.

When being used as a current limiting component, a reactor is connected in series with other components in a line. When being used to absorb reactive power, a shunt reactor is adopted. Because of such character, in normal case a reactor does not require switching operation once it is put in service.

Unlike other assets, reactors are almost maintenance free. They can be in operation for decades without any failure reported. The condition assessment of reactors involves mainly visual inspections and expert feedbacks.

The average life expectancy of reactors can be over 70 years.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 63. Station reactors Health Index parameters and weights

#	Distribution Condition Parameters	Weight
1	Age	10
2	Expert feedback	15
3	Visual inspection	5

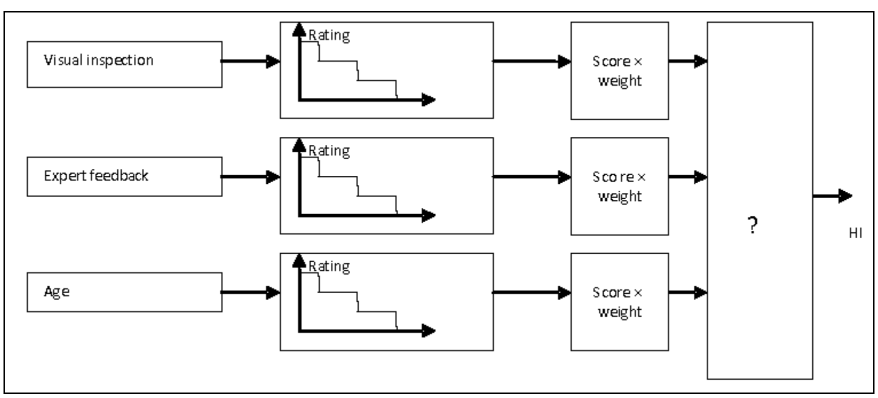


Figure 57. Station reactors Health Index flowchart.

Table 64. Station reactors parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	< 50 years old
B	3	50-74 years old
C	2	75-99 years old
D	1	100-149 years old
E	0	>=150 years old

Table 65. Station reactors parameter #2: expert feedback condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 66. Station reactors parameter #3: visual inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

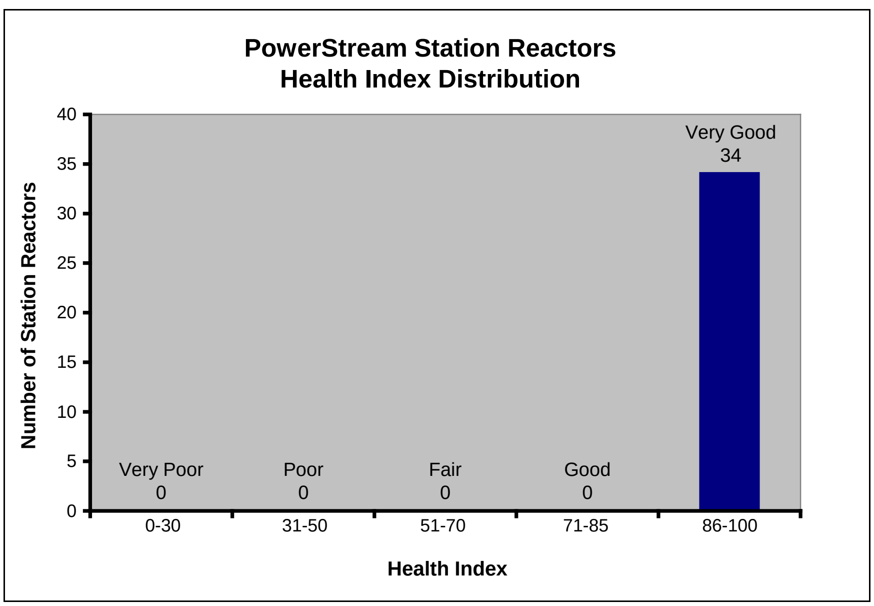


Figure 58. Station reactors Health Index histogram.

Failure Probability

The station reactor cans failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- Shape = 3.00, Scale = 66.9

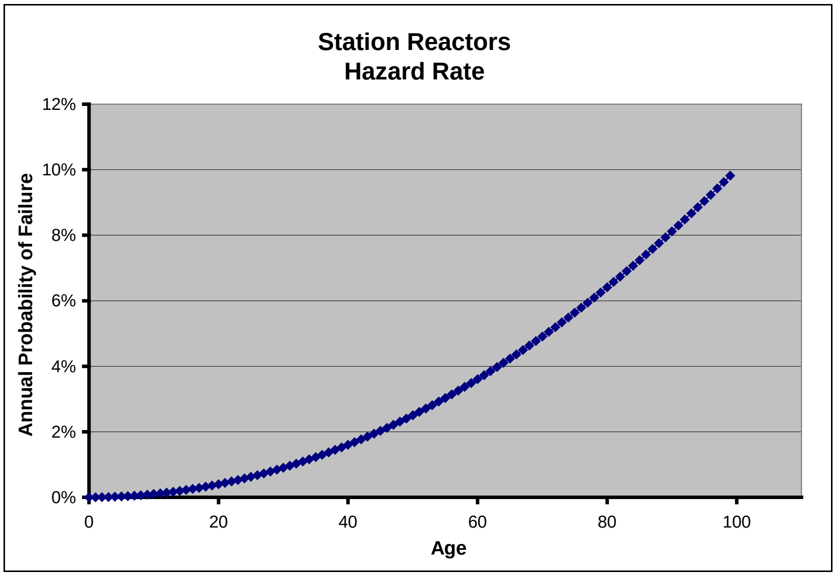


Figure 59. Station reactors hazard rate curve.

<u>Failure Effects</u>

The dominant failure mode assessed for station reactors is catastrophic failure requiring replacement. The loss of a station reactor, no load will be lost as the remaining transformer will be able to carry the load of the companion transformer, there may be a momentary outage.

<u>Risk Matrix</u>

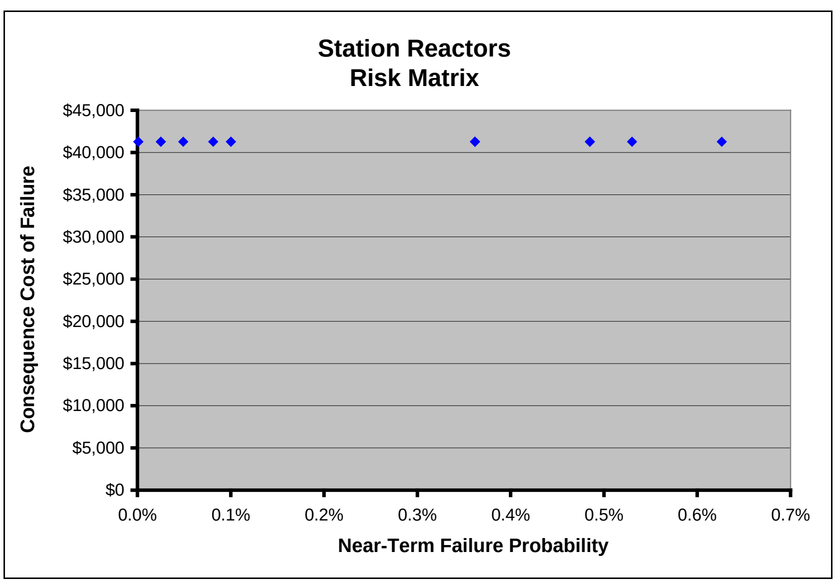


Figure 60. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

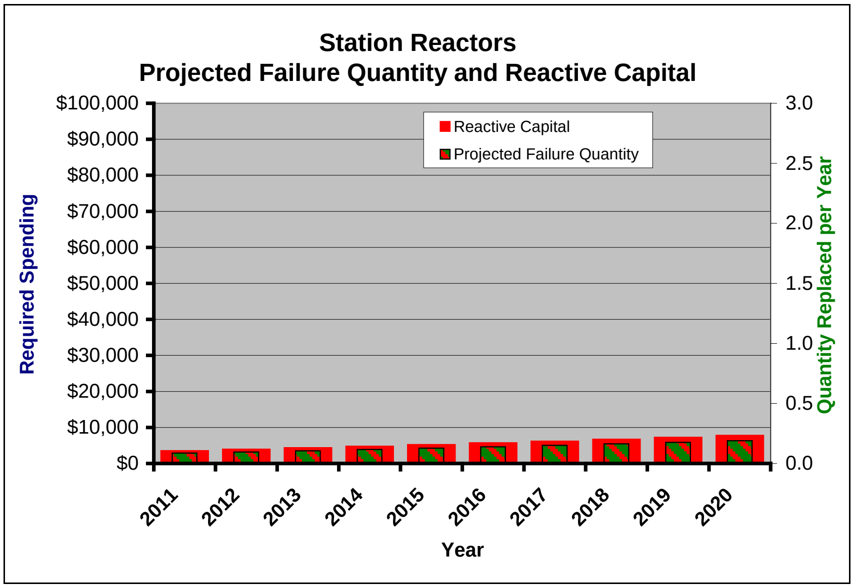


Figure 61. Station reactors projected failure quantity and reactive capital.

Intervention Mode

The intervention mode modeled for station reactors is replacement in-kind.

Econometric Replacement Results

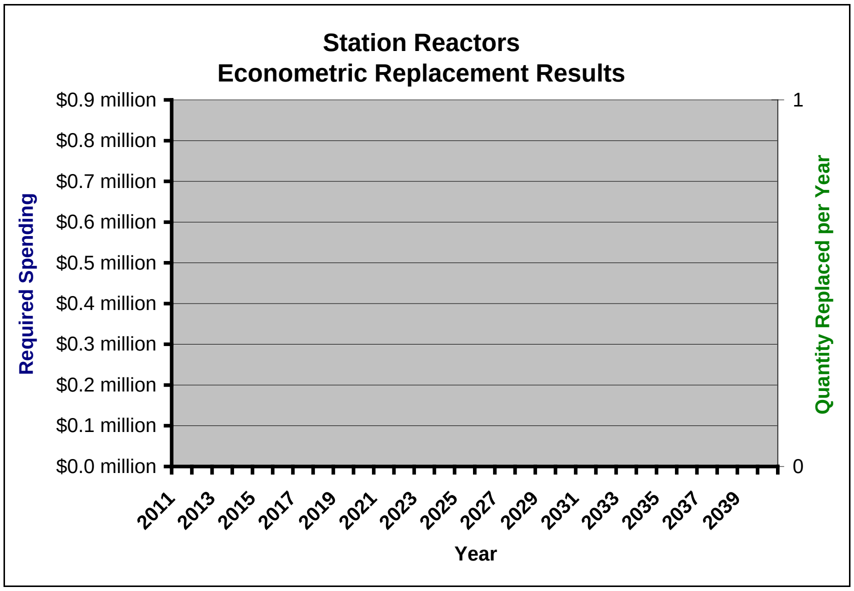


Figure 62. Station reactors econometric replacement results.

Conclusions

- Recommendations:
  - No replacement is proposed in the next five years.
- Gaps:
  - None identified.

3.8 Distribution Transformers

Summary of Asset Class

Distribution Transformers are moderately complex assets with a relatively low price per unit.

Limited end-of-life condition data available; health index formulation is based on industry best-practice and condition data is collected in conjunction with PowerStream's distribution transformer inspection process.

Data Sources Available
Assumed loading, nameplate, and general demographic data.

Demographics
Number of units: 43,535
Typical life expectancy (years): 25-60 as per Kinectrics Inc. Report No: K-418099-RA-001-R000
Estimated replacement cost: $3,000 - $30,000

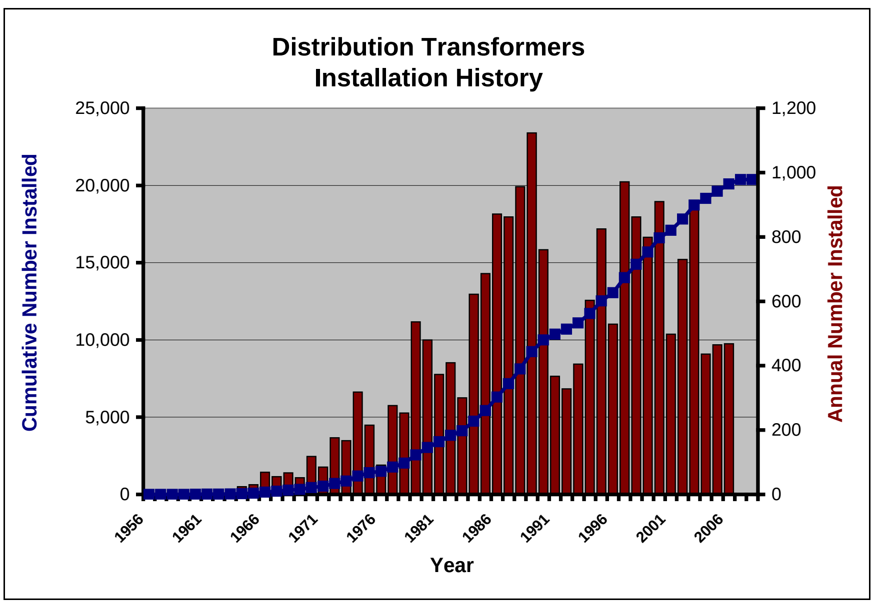


Figure 63. Distribution transformers installation history.

Due to data gaps within our distribution transformer population, the above chart includes only transformers with a known installation date.

Asset Degradation

PowerStream's distribution transformer asset class consists of all transformers used to step down power from medium voltage to utilization voltage. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid, while the rest are of dry submersible type. All of these designs employ sealed tank construction.

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers may, sometimes, need to be removed from service as a result of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of the transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors can be considered in developing the health index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- PCB level
- Transfer operating age and winding temperature profile
- Failure rate

The consequences of distribution transformer failure are mostly reliability impacts and relatively minor. This is why most utilities run their distribution transformers for residential services to failure. However, for larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts may be high, transformers may be replaced as they are near the end of life.

PowerStream has capacity and processes in place to effectively to manage asset failure at the current annual failure rate (3 year average = 14 overhead transformers + 48 underground transformers = 62 transformers total per year). Rate of change of failure in future years expected to be moderate and manageable. Any emerging significant deviations from expected reactive spend would trigger a program review.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 67. Distribution transformer Health Index parameters and weights

#	Distribution Transformer Condition Parameters	Weight
1	Age	4
2	PCB	1
3	Loading history (weighted average)	*
4	Failure rate	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 and #2. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criteria #3 and #4. Refer to Table for details on the multiplying factors.

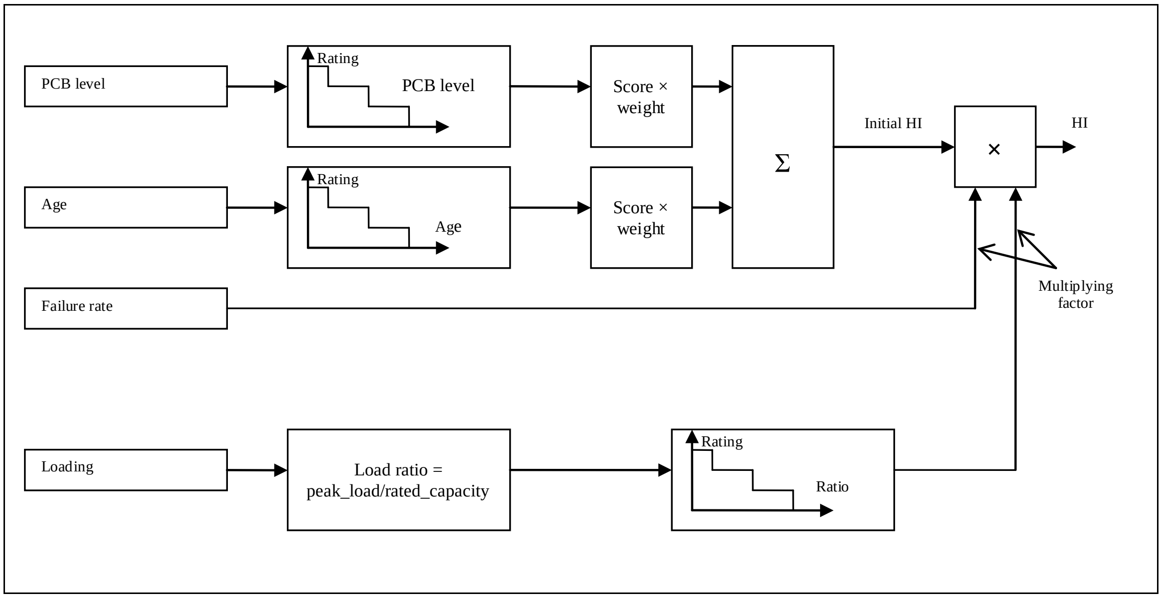


Figure 64. Distribution transformers Health Index flowchart.

Table 68. Distribution transformer parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	21-30 years old
C	2	31-40 years old
D	1	41-50 years old
E	0	>50 years old

Table 69. Distribution transformer parameter #2: PCB level criteria

Condition Factor	Factor	Condition Criteria Description
A	4	PCB < 5 mg/L
B	3	5 <= PCB < 50 mg/L
D	1	50 mg/L <= PCB < 500 mg/L
E	0	PCB >= 500 mg/L

Table 70. Distribution transformer parameter #3: loading criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	N < 1.26
B	0.9	1.26 <= N < 1.5
C	0.7	1.5 <= N < 1.6
D	0.5	1.6 <= N < 1.67
E	0.3	N >= 1.68

Where N = (Peak Load)/(Rated Capacity)

The loading condition is not assigned a weight in the HI formulation. Instead it is used as a multiplying factor for final HI results.

Table 71. Distribution transformer parameter #4: failure rate

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05
B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4
E	0.6	M >= 0.4

Where M = Failure Rate x Age

The failure rate condition is not assigned a weight in HI formulation. Instead it is used as a multiplying factor for final HI results.

Transformer Size	Voltage	Failure Rate *
300 – 10,000 kVA	0.16 – 15 kV	0.0052
300 – 10,000 kVA	> 15 kV	0.011
> 10,000 kVA		0.0153

- Failure rate is based on the survey data in IEEE Gold book (IEEE Std 493-1997)

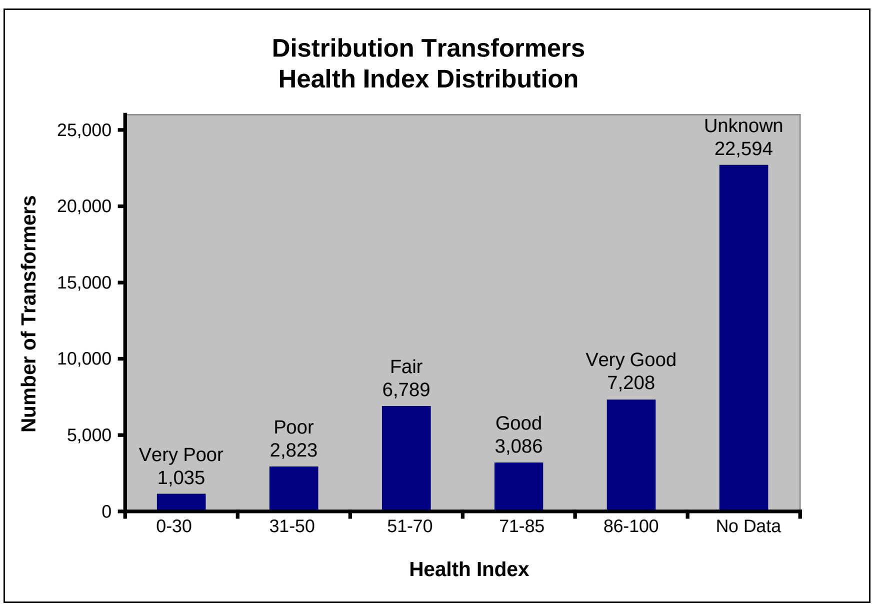


Figure 65. Distribution transformers Health Index histogram.

Failure Probability

The distribution transformer failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated to match the historic failures experienced by PowerStream. The Weibull curve parameters are:

- Shape = 3.00, Scale = 83.24

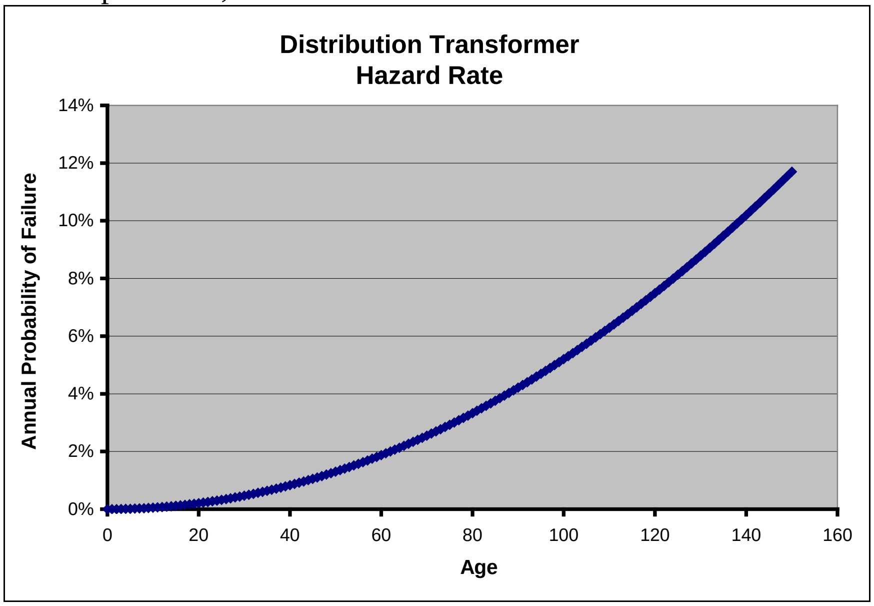


Figure 66. Distribution transformer hazard rate curve.

Failure Effects

The dominant failure mode assessed for distribution transformers is core damage failure requiring replacement. The failure effects by type and size are summarized the figure below:

Description	Type	Phases	Size	LOOKUP	Estimated # of Customers without Supply due to Loss of Equipment	Loss of Peak Load (kW)	Outage Duration (hours)
1-phase 25 kVA	Overhead	1	25	Overhead-1-25	5	20	3
1-phase 50 kVA	Overhead	1	50	Overhead-1-50	8	32	3
1-phase 100 kVA	Overhead	1	100	Overhead-1-100	16	64	3
1-phase 167 kVA	Overhead	1	167	Overhead-1-167	30	120	3
3-Phase 50 kVA	Overhead	3	50	Overhead-3-50	4	100	4
3-Phase 100 kVA	Overhead	3	100	Overhead-3-100	7	170	4
3-Phase 167kVA	Overhead	3	167	Overhead-3-167	10	300	4
3-Phase 250kVA	Overhead	3	250	Overhead-3-250	7	444	4
3-Phase 333kVA	Overhead	3	333	Overhead-3-333	10	575	4
3-Phase 750kVA	Overhead	3	750	Overhead-3-750	11	635	4
3-Phase 50 kVA	Vault	3	50	Vault-3-50	4	100	4
3-Phase 100 kVA	Vault	3	100	Vault-3-100	7	170	4
3-Phase 167kVA	Vault	3	167	Vault-3-167	10	300	4
3-Phase 250 kVA	Vault	3	250	Vault-3-250	7	444	4
3-Phase 333kVA	Vault	3	333	Vault-3-333	10	575	4
3-Phase 750kVA	Vault	3	750	Vault-3-750	11	635	4
1-phase 50 kVA	Padmount	1	50	Padmount-1-50	8	32	3
1-phase 100 kVA	Padmount	1	100	Padmount-1-100	16	64	3
1-phase 167 kVA	Padmount	1	167	Padmount-1-167	30	120	3
3-Phase 150 kVA	Padmount	3	150	Padmount-3-150	4	100	4
3-Phase 300 kVA	Padmount	3	300	Padmount-3-300	7	170	4
3-Phase 500 kVA	Padmount	3	500	Padmount-3-500	10	300	4

Figure 67. Distribution transformer failure effects.

Projected Failure Quantity and Reactive Capital

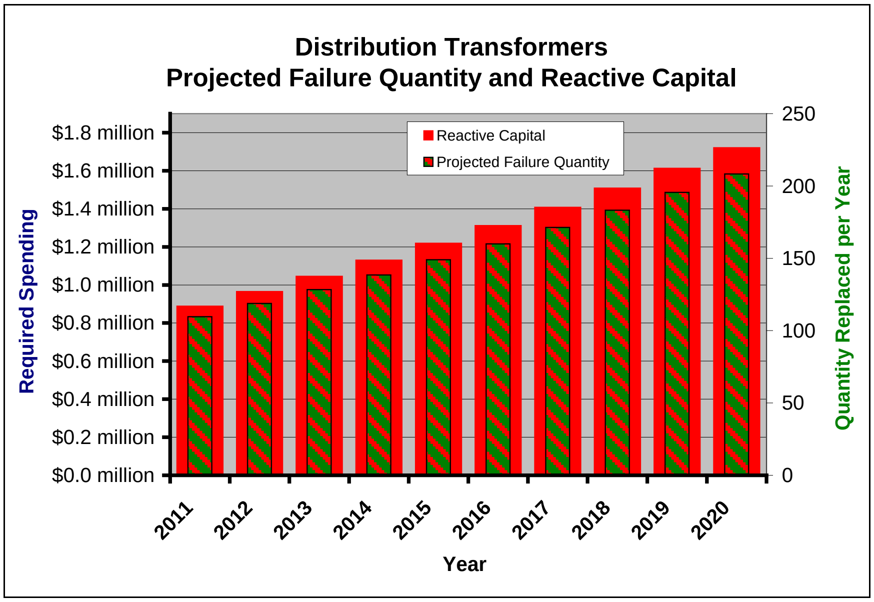


Figure 68. Distribution transformers projected failure quantity and reactive capital.

The "Projected Failure Quantity" shows the estimated result for the total population, which assumes that the portion of Distribution Transformers with missing data will have similar characteristics as those with data.

Intervention Mode

The intervention mode modeled for distribution transformers is replacement in-kind. The replacement costs vary by type and size. The replacement costs are summarized in the figure below:

Description	PowerStream Stock Code	Secondary Voltage	Have Spare	Type	Phases	Size	LOOKUP	Replacement Cost
1-phase 25 kVA	3162025	120/240	Y	Overhead	1	25	Overhead-1-25	$3,426
1-phase 50 kVA	3162050	120/240	Y	Overhead	1	50	Overhead-1-50	$4,226
1-phase 100 kVA	3162100	120/240	Y	Overhead	1	100	Overhead-1-100	$5,526
1-phase 167 kVA	3162167	120/240	Y	Overhead	1	167	Overhead-1-167	$7,126
3-Phase 50 kVA	3163050	600/347	Y	Overhead	3	50	Overhead-3-50	$5,404
3-Phase 100 kVA	3163100	600/347	Y	Overhead	3	100	Overhead-3-100	$6,604
3-Phase 167kVA	3163167	600/347	Y	Overhead	3	167	Overhead-3-167	$8,204
1-Phase 50 kVA	3172050	120/208	Y	Vault	1	50	Vault-1-50	$6,990
1-Phase 100 kVA	3172100	120/208	Y	Vault	1	100	Vault-1-100	$8,716
1-Phase 167kVA	3172167	120/208	Y	Vault	1	167	Vault-1-167	$10,841
3-Phase 100 kVA	3173100	600/347	Y	Vault	3	100	Vault-3-100	$9,115
3-Phase 167kVA	3173167	600/347	Y	Vault	3	167	Vault-3-167	$11,240
3-Phase 250 kVA	3173250	600/347	Y	Vault	3	250	Vault-3-250	$17,614
1-phase 50 kVA	4162050	120/240	Y	Padmount	1	50	Padmount-1-50	$7,298
1-phase 100 kVA	4162100	120/240	Y	Padmount	1	100	Padmount-1-100	$9,278
1-phase 167 kVA	4162167	120/240	Y	Padmount	1	167	Padmount-1-167	$9,542
3-Phase 150 kVA	7302150	120/208	Y	Padmount	3	150	Padmount-3-150	$21,144
3-Phase 300 kVA	7302300	120/208	Y	Padmount	3	300	Padmount-3-300	$25,104
3-Phase 500 kVA	7302500	120/208	Y	Padmount	3	500	Padmount-3-500	$28,536
3-Phase 150 kVA	7306150	600/347	Y	Padmount	3	150	Padmount-3-150	$21,804
3-Phase 300 kVA	7306300	600/347	Y	Padmount	3	300	Padmount-3-300	$25,764
3-Phase 500 kVA	7306500	600/347	Y	Padmount	3	500	Padmount-3-500	$29,724

Figure 69. Distribution transformers replacement costs.

Econometric Replacement Results

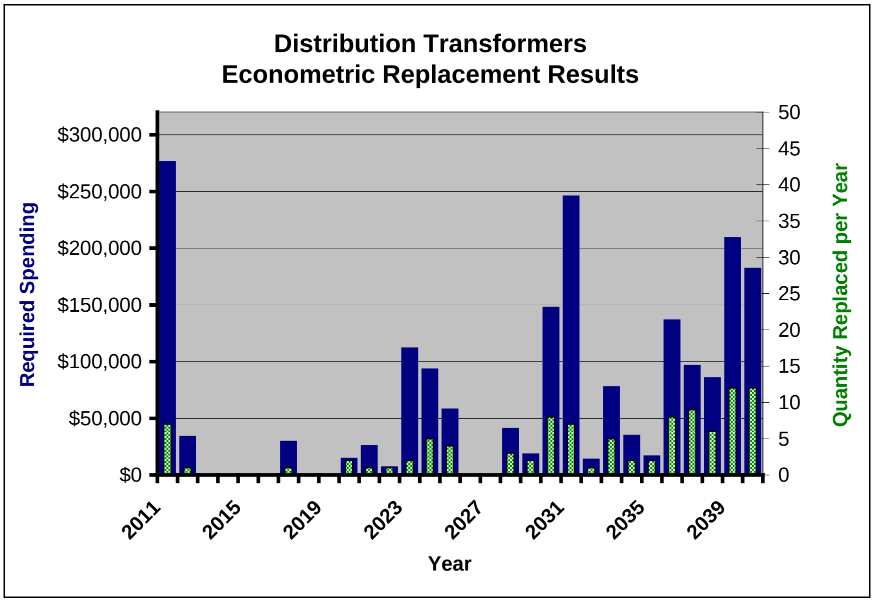


Figure 70. Distribution transformers econometric replacement results.

The econometric and reactive spending results are extrapolated to account for missing demographic data.

Conclusions

- Recommendations:
  - No risk-based planned replacement program is recommended.
  - Operate the distribution transformers program on a run-to-failure basis.
  - Continue to collect field data to update and run the ACA model.
  - Continue to collect nameplate data and update the model.
  - Capture transformer condition and age at failure to support customized failure probability curves and health index correlations.
  - Continue to monitor annual failure rates to identify any emerging deviations from expected reactive spend.
- Gaps:
  - Demographic and condition data not available for entire population. Data collection is in progress.

3.9 Distribution Switchgear

Summary of Asset Class

Distribution switchgear is a moderately complex asset with a moderate price per unit.

Limited demographic and condition data available; health index formulation is based on industry best-practice, and asset data is collected on an ongoing basis as a result of PowerStream's Switchgear inspection process.

Data Sources Available
Assumed loading, nameplate, and general demographic data.

Demographics
Number of units: 1,739
Typical life expectancy (years): 30-85 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"
Estimated replacement cost: $2,000 - $100,000

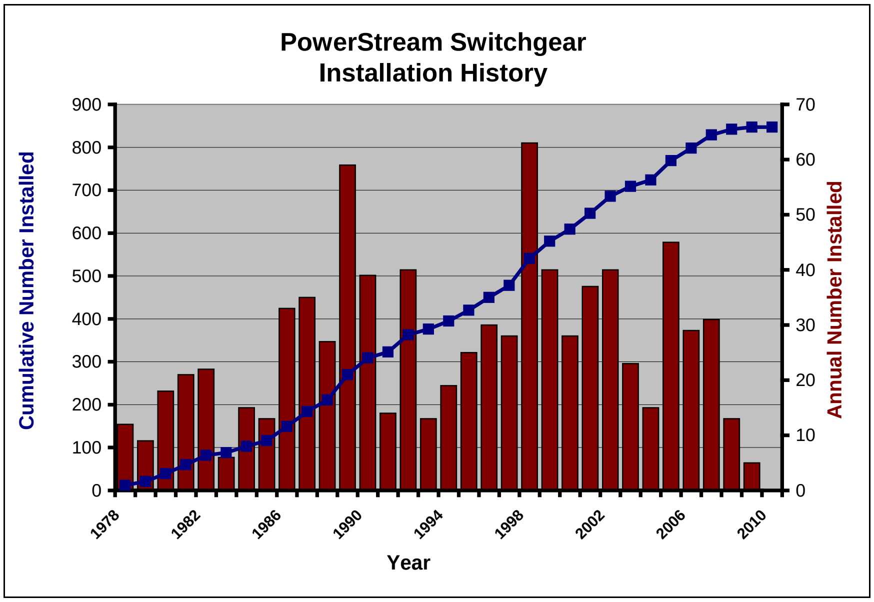


Figure 71. Distribution switchgear installation history.

Due to data gaps within our distribution switchgear population, the above chart includes only switchgear with a known installation date.

Asset Degradation

This asset group covers the switchgear units used in distribution loops supplying residential subdivisions and commercial/industrial customers. The switchgear population comprises of different types of interrupting medium such as air, oil, gas, and solid dielectric. Switchgear units are utilized to isolate/control other equipment, and to reconfigure the loops for maintenance, restoration or other operating requirements.

Switchgear degradation depends on a number of factors, such as condition of mechanical mechanisms, degradation of solid insulation, and corrosion. The important issues tend to be obsolescence or specific/generic defects.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end-of-life, just short of failure. To optimize the life of this asset and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without total replacement of the switchgear.

The switchgear health and condition can be indicated by the following parameters:

- Equipment age
- Presence of hotspots
- Condition mechanical mechanism
- Condition of bus insulation
- Failure rate

The life expectancy for medium voltage distribution switchgear is 25 to 50 years. Failure consequences include customer interruptions and employee safety.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 72. Distribution switchgear Health Index parameters and weights

#	Distribution Switchgear Condition Parameters	Air Type Weight	Oil Type Weight
1	Age	2	5
2	IR record	2	2
3	Field inspection	5	5
4	Failure rate	*	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 to #3. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criterion #4.

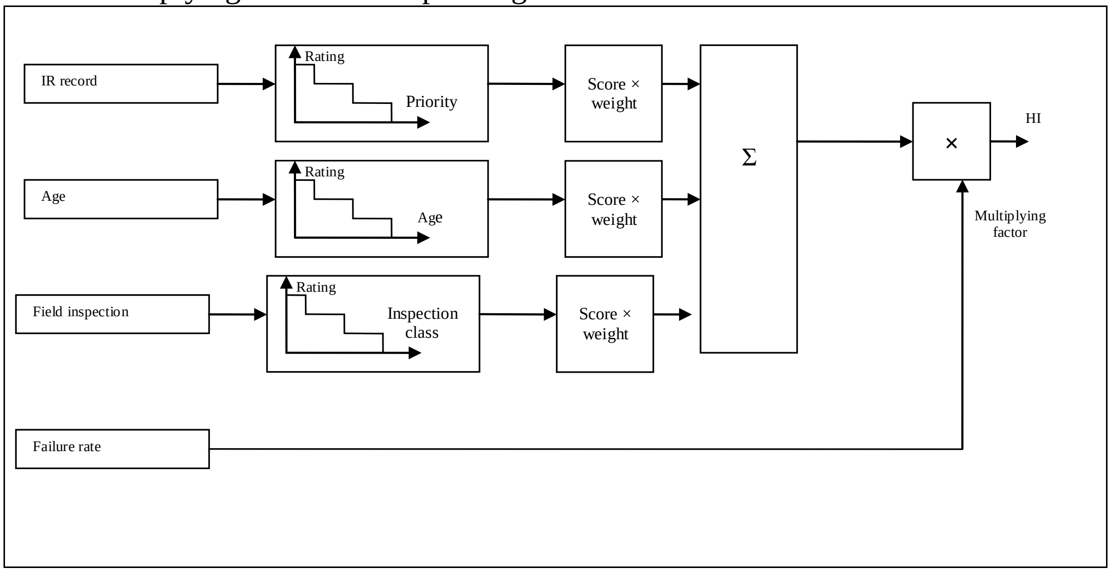


Figure 72. Distribution switchgear Health Index flowchart.

Table 73. Distribution switchgear parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	41-60 years old
D	1	61-70 years old
E	0	> 70 years old

Table 74. Distribution switchgear parameter #2: IR record condition criteria

Condition Factor	Factor	Condition Criteria Description
A	0	Corrective measures are required at the earliest possible time.
B	2	Corrective measures are required at the next available opportunity or shutdown.
C	3	Corrective measures are required as scheduling permits.
D	4	Normal maintenance cycle can be followed.

Table 75. Distribution switchgear parameter #3: field inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	0	Corrective measures are required at the earliest possible time.
B	2	Corrective measures are required at the next available opportunity or shutdown.
C	3	Corrective measures are required as scheduling permits.
D	4	Normal maintenance cycle can be followed.

Table 76. Distribution switchgear parameter #4: failure rate criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05
B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4
E	0.6	M >= 0.4

Where M = failure rate x age

Failure rate for distribution switchgear = 0.0048, calculated based on IEEE Gold book (IEEE Std 493-1997).

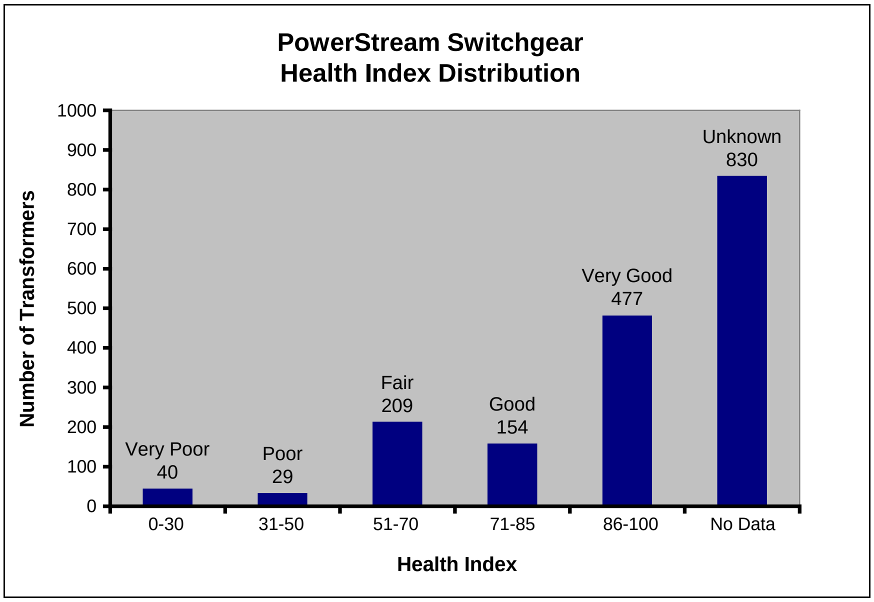


Figure 73. Distribution switchgear Health Index histogram.

Failure Probability

The distribution switchgear failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated to match the historic failures experienced by PowerStream. The Weibull curve parameters are:

- Shape = 3.00, Scale = 40.53

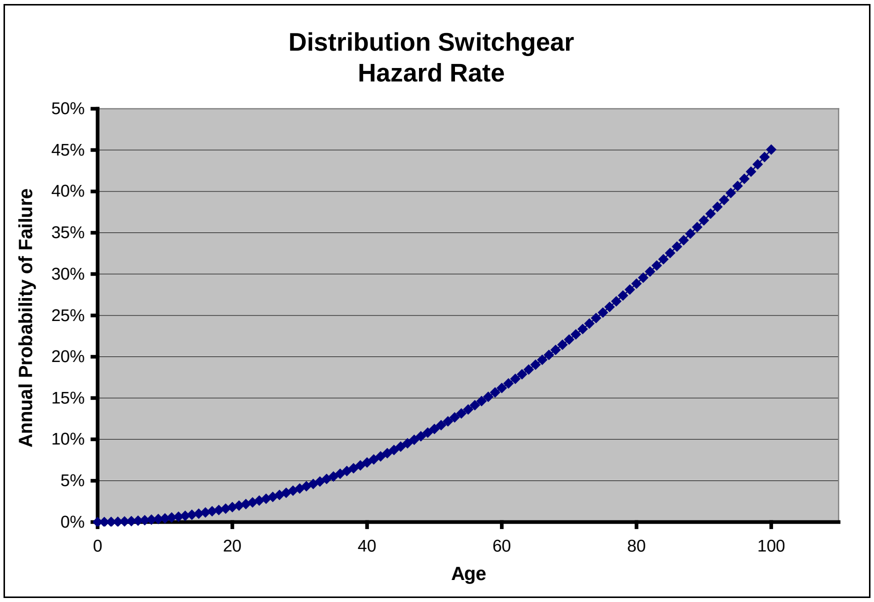


Figure 74. Distribution switchgear hazard rate curve.

Failure Effects

The failure effects by customers served are summarized below.

Description	Lookup	Loss of Peak Load (kW)	Outage Duration (hours)
Industrial and Commercial Customers	C&I	3,780	3
Residential Subdivisions	Residential	1,440	3
Mixed	Mixed	2,610	3

Figure 75. Distribution switchgear failure effects.

The failure effects are based on the following assumptions:

- For switchgear units supplying Industrial/Commercial Customers: On average each "loop" has a maximum of 10,000 connected kVA. On average there are 10 switchgear units in a "loop", each switchgear supplies two customers each with an average XFMR size of 500 kVA at an assumed L.F. of 70% & 90% P.F. Upon a switchgear failure, one-half of the loop (on average 5 switchgear units) will be lost for 3 hours, while the failed switchgear will take a total of 8 hrs for replacement. One-half of the loop means 5 x 2 x 500 kVA x 0.7 x 0.9 = 3150 kW for 3 hour (9,450 kWhrs). For the unit that failed we have 2 x 500 kVA x 0.7 x 0.9 = 630 kW for 5 hours (3 hours have already lapsed) = 3,150 kWhrs.
- For switchgear units supplying Residential Subdivisions: On average Switchgear-to-Switchgear there are thirty 50 kVA transformers and each

transformer on average has 8 customers and each customer on average has a peak load of 4 kW. The Normal open point (N.O.) is located at midpoint, therefore 15 transformers per phase on each side or 45 transformers in total (for the 3-phases). Upon a switchgear failure, one-half of the loop (on average 45 transformers, 360 customers or 1440 kW) will be lost for 3 hours (time taken to isolate/switch & restore). This means 45 transformers x 8 customers x 4 kW or a peak load of 1,440 kW for 3 hours or 4,320 kWhrs.

Risk Matrix

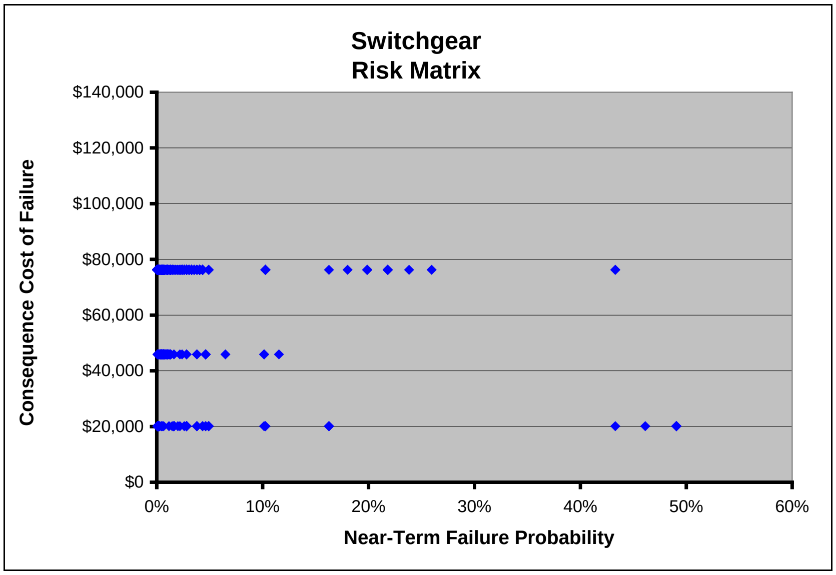


Figure 76. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

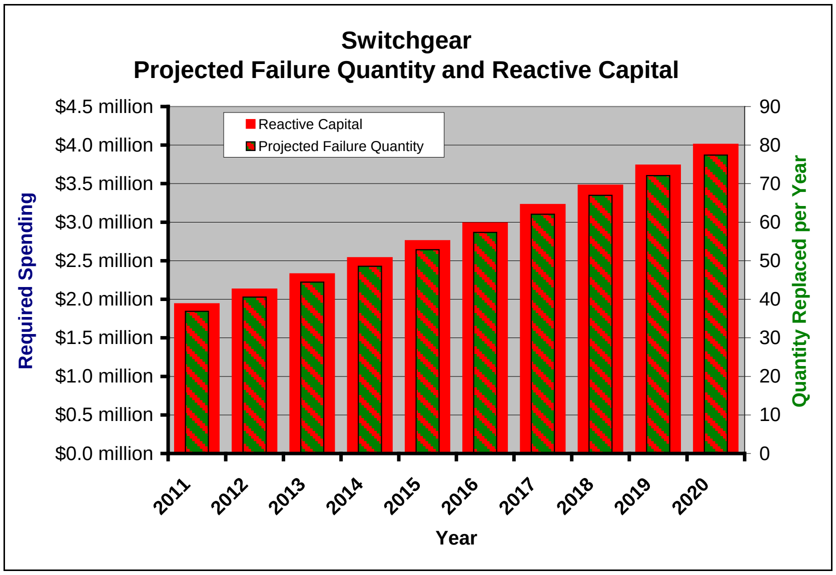


Figure 77. Distribution switchgear projected failure quantity and reactive capital.

The "Projected Failure Quantity" shows the estimated result for the total population, which assumes that the portion of Switchgear with missing data will have similar characteristics as those with data.

Intervention Mode

The intervention mode modeled for distribution switchgear is replacement in-kind. The replacement costs are summarized below.

Material Cost	Material Cost plus Overhead and Burden	Replacement Labour Hours	Replacement Labour Cost Plus Overhead and Burden	Truck Hours	Truck Cost plus Overhead and Burden	Type	Total
$41,000	$54,120	24	$1,368	12	$636	PMH	$56,124
$74,000	$97,680	24	$1,368	12	$636	Vista Gear	$99,684
	$0	24	$1,368	12	$636	FP	$2,004
	$0	24	$1,368	12	$636	CPP	$2,004
$18,000	$23,760	24	$1,368	12	$636	PMO	$25,764
$41,000	$54,120	24	$1,368	12	$636	PVI	$56,124
	$0	24	$1,368	12	$636	PNI	$2,004

Figure 78. Distribution switchgear replacement costs.

Econometric Replacement Results

PowerStream's switchgear population serves two types of customers – residential, and commercial/industrial. Customer type has an impact on the customer interruption cost calculation in the model and, therefore, on the econometric replacement results. PowerStream will validate and update customer type information.

The econometric replacement results were calculated for two scenarios:

- Assuming all loads are residential
- Assuming all loads are commercial/industrial

The results are shown below.

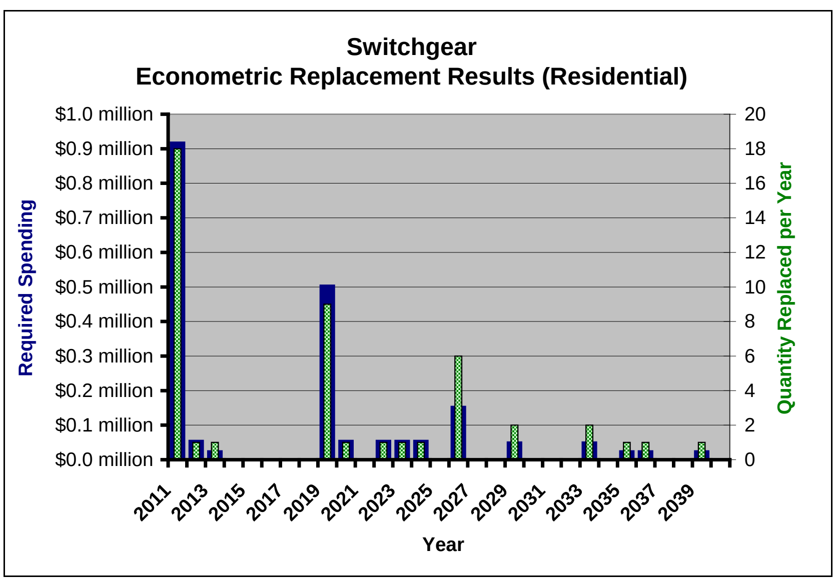


Figure 79. Distribution switchgear econometric replacement results – assumed residential.

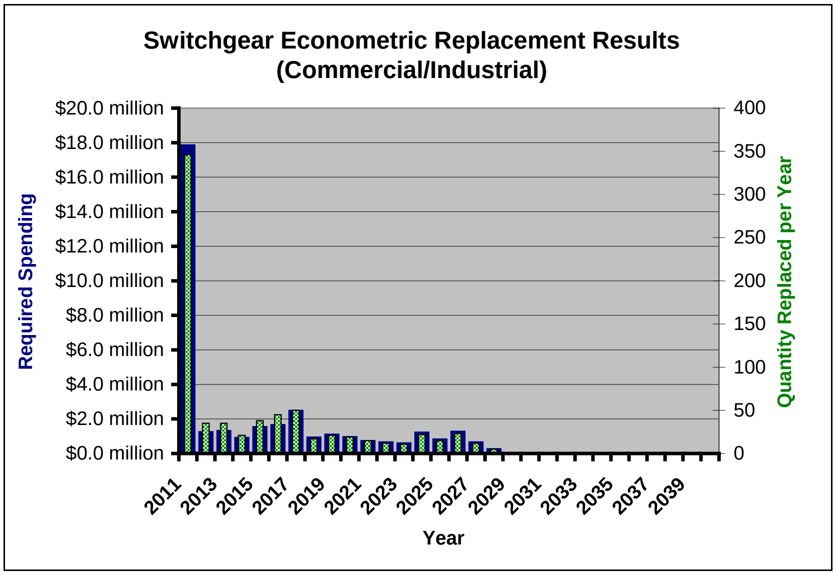


Figure 80. Distribution switchgear econometric replacement results – assumed commercial/industrial.

In the scenario of all loads assumed to be commercial/industrial, an immediate requirement for high spending is identified by the ACA model. The number and timing of switchgear replacement units is considered "optimal" or "ideal" from a pure economic viewpoint. For switchgear, we incorporated engineering judgment and operations input with the econometric model results to prudently spread out the switchgear replacement program over a longer period of time. The intent of spreading the replacement requirement over a number of years is to smooth out the budget, resource, and rate impacts while managing the incremental risk of asset failure.

In the near-term, PowerStream expects to replace on average 20 units per year under the planned switchgear replacement program. This is in addition to those units that will be replaced under emergency due to unit failure (3 year average for emergency replacement was 23 units per year). Rate of change of failure in future years is expected to be moderate and manageable. Any emerging significant deviations from expected reactive spend would trigger a program review.

PowerStream's planned Switchgear replacement and Projected Failure Quantity are shown in the chart below.

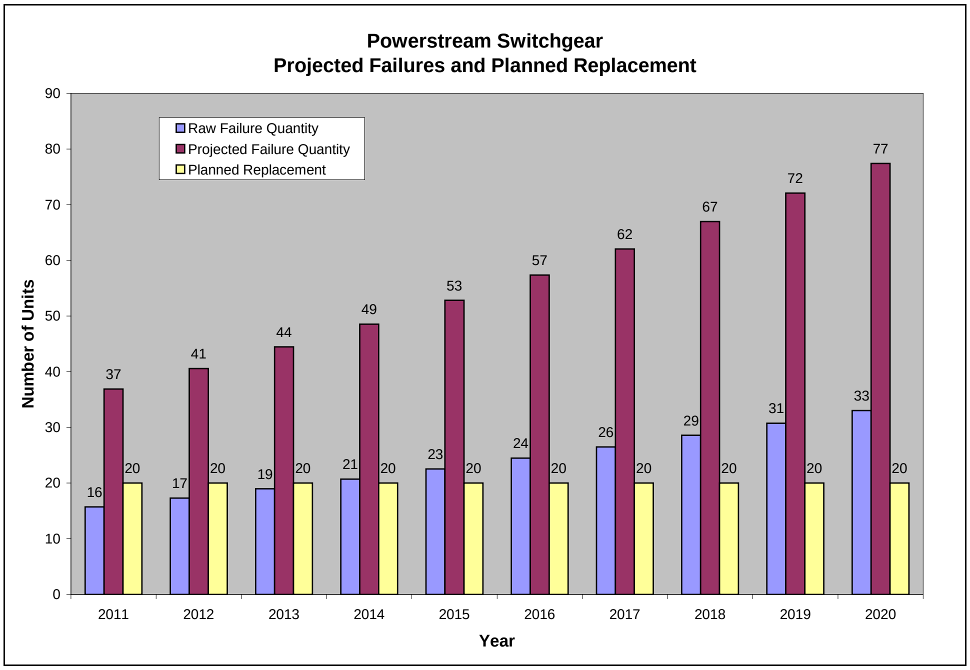


Figure 81. Distribution switchgear projected failures and planned replacements.

The "Projected Failure Quantity" shows the estimated number of failures for the total population, which assumes that the portion of Switchgear with missing data will have similar characteristics as those with data. The "Raw Failure Quantity" shows only the estimated number of failures for Switchgear with sufficient data.

Conclusions

- Recommendations:
  - Near-term switchgear replacements are warranted.
  - Update and validate customer type information.
  - Continue to collect nameplate and customer type data, and update the model (reduce "unknown" population).
  - Continue to capture condition data per health index formulation and update the model.
  - Capture switchgear condition and age at failure to support customized failure probability curves and health index correlations.
  - Continue to monitor annual failure rates to identify any emerging deviations from expected reactive spend.
- Gaps:
  - Demographic and condition data not available for entire population. Data collection is in progress.
  - Customer type information requires further validation.

3.10 Wood Poles

Summary of Asset Class

Wood poles are moderately complex assets with a low price per unit.

Wood pole failures are very rare due to comprehensive replacement programs. Wood pole testing contractors make replacement recommendations based on test results and minimum physical life remaining. Program recommendations are based on the pole testing results and PowerStream's pole replacement prioritization indices.

Health index formulation is based on industry best-practice.

Data Sources Available

General demographic and condition data acquired during wood pole test program.

Demographics

Number of units: 46,414

Typical life expectancy (years): 35-75 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"

Estimated replacement cost: $12,000

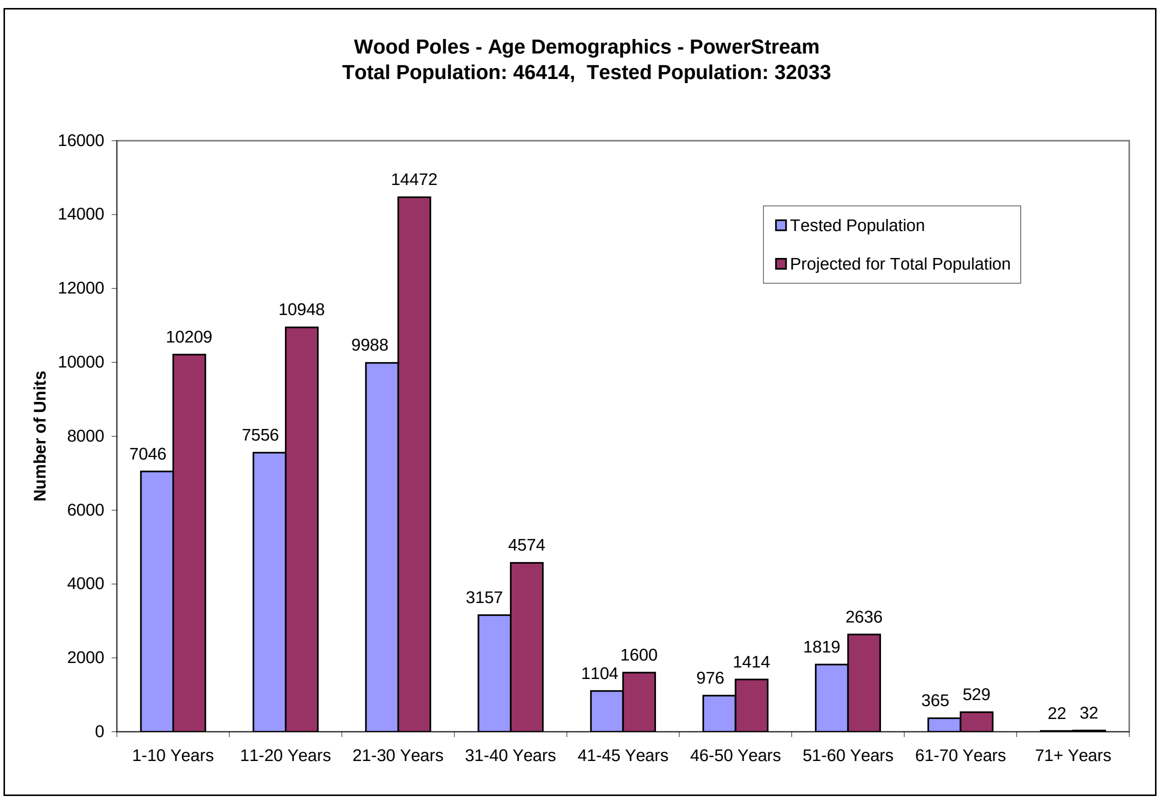


Figure 82. Wood poles age demographics.

There are some data gaps with respect to pole age. The "Projected" numbers show the estimated result, assuming that the portion of poles with missing data will have similar characteristics as those with data.

Asset Degradation

Overhead distribution lines consist of electrical conductors supported on insulators and mechanical structures. The support structure is usually a single wood or concrete pole. At locations with high mechanical loading, such as dead ends, angles and corners, the poles will be supported by guy wires attached to anchors installed in the ground.

Wood poles are the most common form of support for medium voltage overhead circuits as well as sub-transmission lines, however concrete poles are also used extensively especially in urban areas.

Distribution line design dictates usage of the poles varying in height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into classes (1 to 7), which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable or other telecommunications facilities.

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

To prevent attack and decay of wood poles they are treated with preservatives prior to being installed. The preservatives have two functions, firstly to keep out moisture that is necessary to support the attacking fungus, and secondly as a biocide to kill off the fungus spores. Over the period of wood pole use in the electricity industry, the nature of the preservatives used has changed, as the chemicals previously used have become unacceptable from an environmental viewpoint. Nevertheless, effective and acceptable preservatives are available and poles well treated prior to installation have a long life (typically in excess of 50 years) prior to decay resulting in significant damage.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species, the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

There are many factors considered by utilities when establishing condition of poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The following criteria can be used in establishing health and condition of poles:

- Pole strength (through lab testing on selected samples)
- Existence of cracks
- Woodpecker or insect caused damage for wood poles
- Wood rot
- Damage due to fire or mechanical damage
- Condition of guy wires
- Pole plumbness

The life expectancy of wood poles ranges from 35 to 75 years. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for significant number of customers.

Prioritization Index Formulation and Results

PowerStream has developed a wood pole replacement prioritization system to select pole replacement candidates. The details are described below.

The Wood Pole Prioritization method is shown on the following diagram.

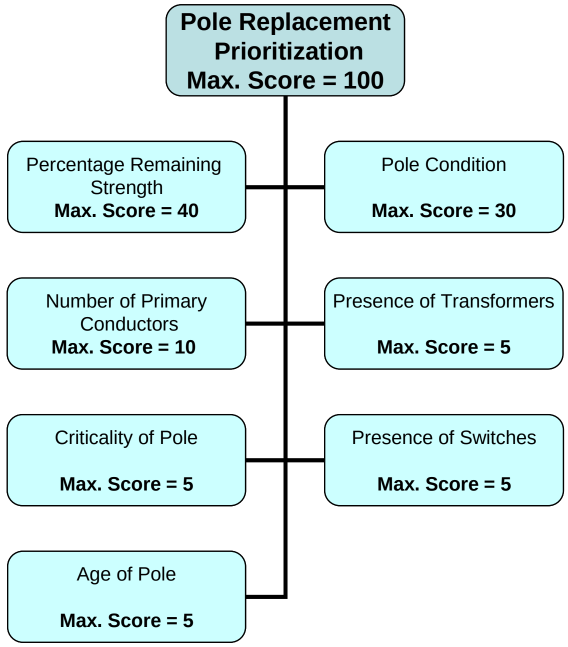


Figure 83. Wood poles Prioritization Index.

Wood Pole Prioritization Index Formulation

The parameters and scores used to form the overall prioritization score are shown in the following table.

Table 77. Wood poles Prioritization Index Parameters and Scores

POLE PRIORITIZATION CRITERIA SUMMARY		
Index	Criteria	Score Range
1	Percentage Remaining Strength	0 - 40
2	Condition	0 - 30
3	Presence of Transformers	0 - 5
4	Number of Primary Conductors	0 - 10
5	Presence of Switches	0 - 5
6	Criticality of Pole	0 - 5
7	Age of Pole	0 - 5
Maximum Score		100

The most important 2 parameters are Percentage Remaining Strength and Pole Condition. After these 2 parameters are considered to narrow down the candidate list, the remaining parameters will be used to further prioritize replacement among the candidates.

Pole Remaining Strength

This parameter references the percentage remaining strength of a pole from the pole test data and uses that number to assign a score. The scoring values are as follows:

Table 78. Wood poles Criteria #1: Remaining Strength

Remaining Strength (%)	Score
0 - 39	40
40 - 59	35
60 - 69	5
70 - 89	0
90 and Above	0

Remaining strength is scored heavily at a maximum of 40 due to the fact that it is based on a physical test of the pole and is the most accurate numerical representation of quality that can be obtained. This is the dominant field used in the priority determination.
Any pole that is ten years or less in age at the date of inspection will not be tested for remaining strength and therefore will be assumed to have 100% remaining strength by the model.

Pole Conditions

This parameter references the remarks and comments made by the pole testing contractor. Engineering judgment will be exercised to determine the overall Pole Condition score.

Table 79. Wood poles Criteria #2: Pole Condition

Pole Condition	Score
Extensive Cracks, Split Top, Rotten, Carpenter Ants, Fire, Bent Pole, Top Decay	0 - 30

Presence of Transformers

Pole top transformers add considerable weight to the top of pole and each transformer is an important asset that would be lost in pole failure.
This field checks the pole test data for the presence of transformers and returns a score based on the value.
The scoring values are as follows:

Table 80. Wood poles Criteria #3: Transformer Presence

Presence of Transformer	Score
YES	5
NO	0

Number of Primaries

This field references the number of primary conductors from the contractor's pole test data and returns a score based on the value. The more primary conductors present on a pole, the higher potential consequence of outages when the pole fails.

The scoring values are as follows:

Table 81. Wood poles Criteria #4: Number of Primaries

# of Primary Conductors	Score
0 - 2 primaries	0
3 - 5 primaries	2
6 - 8 primaries	6
9 - 11 primaries	8
12 primaries and over	10

Presence of Switches

The scoring values are as follows:

Table 82. Wood poles Criteria #5: Switch Presence

Switch Presence	Score
YES	5
NO	0

The intent of this column is to take into account poles with various types of switches/dips/risers on them. The scoring table will take into account various types of switches and give them a higher priority based on their type.

Criticality of Circuit

The scoring values are as follows:

Table 83. Wood poles Criteria #6: Criticality

Criticality of Circuit	Score
Low	0
High	5

The intent of this parameter is to assign values to poles based on the criticality of the services. The more critical the customer, the higher of a priority they become. For example a critical service might include a hospital, water supply, sewer system, etc. Poles with high exposure to the public, such as schools malls, and bus stops, will also be taken into consideration to enhance public safety precautions. Engineering judgment will be exercised to determine the Criticality score.

Pole Age

The prioritization model calculates the poles age based on the install date and current year inputs and references it to the scoring table. The pole age is scored as follows:

Table 84. Wood poles Criteria #7: Pole Age

Pole Age	Score
0 - 19 Years	0
20 - 29 Years	2
30 - 39 Years	3
40 - 49 Years	4
50 - 59 Years	5

The pole age is scored relatively low because the age of a pole is not a strong indication of its condition, or its priority and importance to the distribution system. There is no definitive correlation between the age of a pole and its overall condition.

Final Pole Priority Score

This field sums the values of each of the scoring columns together to get a final score.

Pole Priority Rank Classification

This field takes the value of the final priority score and references a table to assign a pole Priority Ranking Category, listed below:

Table 85. Wood poles Classification

Priority Score	Rank
0 - 9	Very Low
10 - 19	Low
20 - 29	Medium
30 - 39	High
40+	Very High

Failure Probability

The wood pole failure probability (hazard rate) curve is based on a Weibull curve, using PowerStream's actual pole replacement data. The Weibull curve parameters are:

- Shape = 2.88, Scale = 45.54

Figure 84. Wood poles hazard rate curve.

Failure Effects

The dominant failure mode assessed for wood poles is catastrophic failure requiring replacement.

Intervention Mode

Wood poles are replaced based on pole testing recommendations and prioritization index results. Risk-based analyses are not used to justify pole replacements.

Replacement Program Results

The long-range replacement program is based on pole inspection and testing recommendations. Pole inspection and testing recommendations were analyzed to develop a pole prioritization tool to better manage the program.

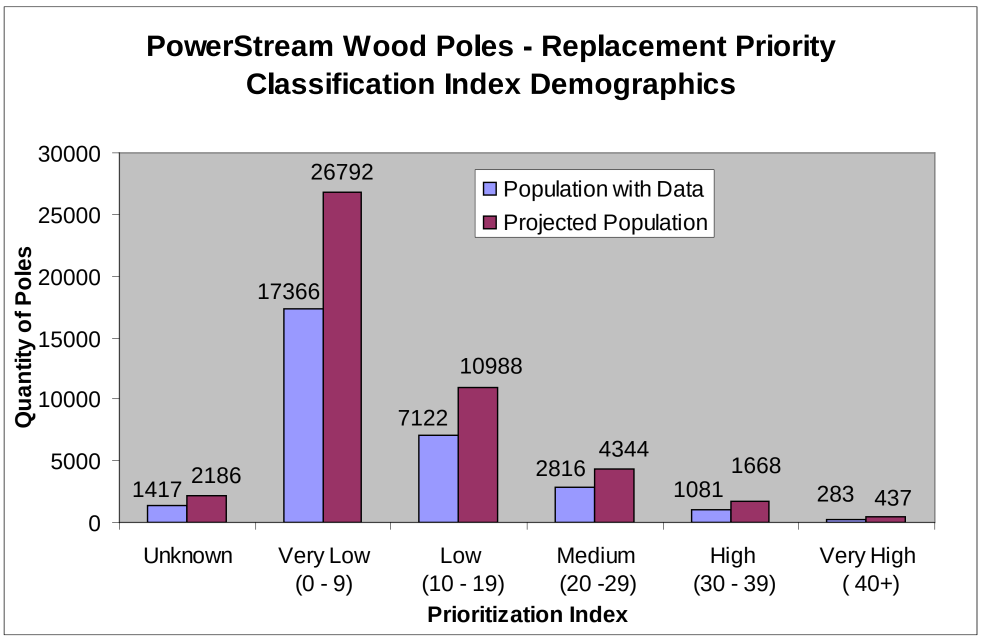


Figure 85. Wood poles Prioritization Index histogram.

Conclusions

- Recommendations:
  - Replace an average of 300 - 400 poles per year for the next five years to deal with the high and very high replacement priority groups.
  - Continue collecting inspection and failure data and updated customized wood pole failure curves.
  - Continue capturing condition data per pole prioritization formulation and update the model.
- Gaps:
  - Remaining wood pole demographics.
  - Discrepancies between GIS records and test data records.

3.11 Distribution Primary Cables

Summary of Asset Class

Underground Distribution primary cable is a moderately complex asset with a moderate price per meter.

Data Sources Available

Cable installation by drawing number, length, year, cable type, installation method (i.e., conduit, direct bury).

Demographics

Number of units: 7,836 km (cable meters)
Typical life expectancy (years): 20-55 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 “Asset Amortization Study for the Ontario Energy Board”
Estimated replacement cost: $188 - $400/m (cable only), $340 - $660/m (in conduit)

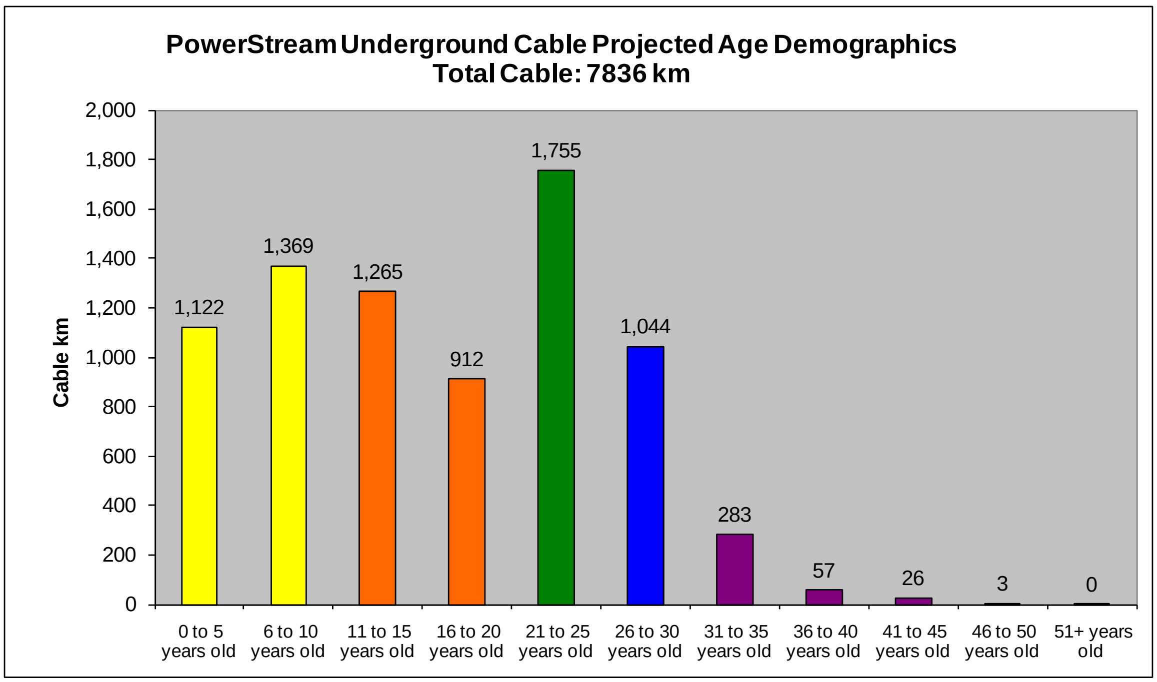


Figure 86. Distribution primary cable age demographics.

Asset Degradation

As cable is put in services, the following factors will affect the cable properties, performance, and degradation process:

- Mechanical Stress (e.g. the pulling of cable during transportation and installation)
- Electrical Stress (e.g. overloading cable under normal and emergency conditions)
- Operation Practices (e.g. emergency load transfer among feeders)
- Maintenance Practice (e.g. commissioning testing, fault locating, restoration practice, splicing practice)

- Environment Conditions (e.g. direct buried, chemical corrosion, water ingress)
- The forming of “water trees” which will reduce the strength of the insulation and eventually lead to insulation breakdown and cable failure
- Corrosion of concentric neutral wires
- External Factors (e.g. dig-in by contractors)
- Impurity, by-products, and contaminants, etc. and defect during manufacturing process

Health Index Formulation and Results

Age and installation conditions play a big part in determining cable health indices. It has been decided to use age grouping as a basis for our cable management plans as there is a strong correlation, in the general cable population, between cable age and end-of-life status. Within the age groupings, cable testing will provide additional information to determine the cable health index and, together with service quality data, will determine overall cable replacement priority. PowerStream has developed a cable prioritization system to select cable replacement and cable injection candidates.

The following factors are considered in developing the prioritization index for underground primary cable:

- Age
- Neutral Corrosion
- Insulation Corrosion
- Splices
- Number of Outages
- Customers Affected
- Restoration Time
- Cost Benefit
-

The Cable Prioritization method is shown on the following diagram.

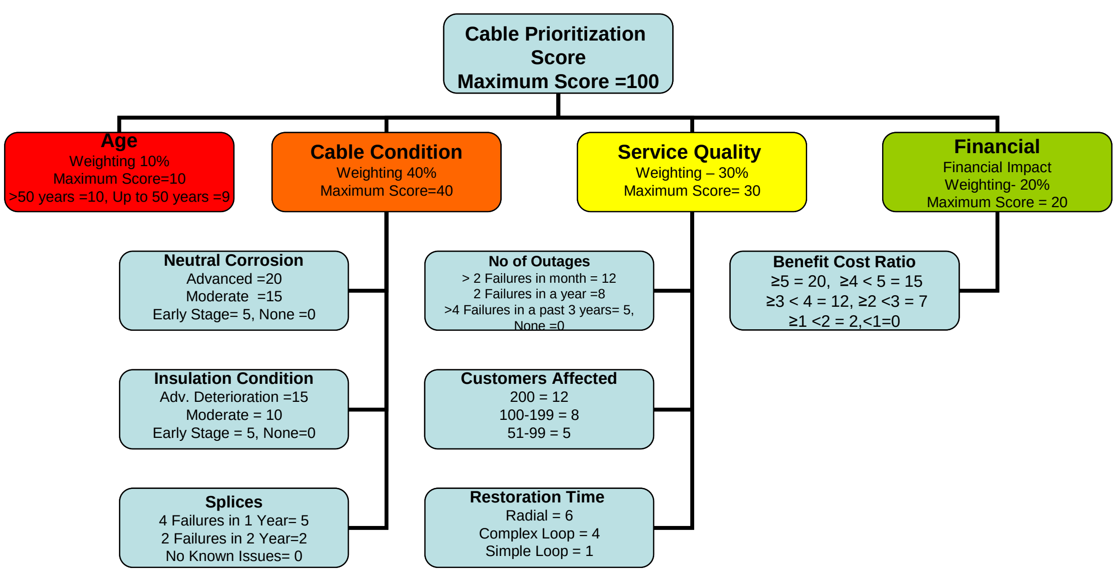


Figure 87. Cable Prioritization method.

Failure Probability

The Underground Cable failure probability (hazard rate) curves are based on a Weibull curve, which is calibrated to match the historic failures experienced by PowerStream. The Weibull curve parameters are:

- **Direct Buried Cables Unjacketed-** Shape = 4.39, Scale = 35.54
- **Direct Buried Jacketed -** Shape = 4.39, Scale = 37.39
- **Conduit Unjacketed Cables -** Shape = 2.51, Scale = 55.17
- **Conduit Jacketed Cables -** Shape = 2.51, Scale = 59.33

The underground cable failure probability (hazard rate) curves are based on failure histories from other utilities with similar cable:

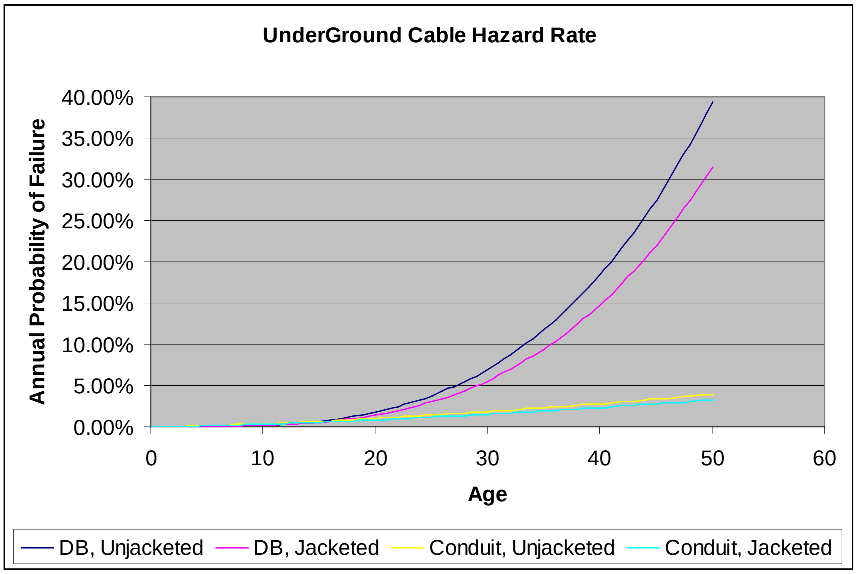


Figure 88. Distribution primary cable hazard rate curve.

<u>Failure Effects</u>

It is assumed that a cable fault on a 1-phase residential looped subdivision will impact 800 kVA (half the loop, 50 amps). For a 3-phase industrial/commercial subdivision, it is assumed that 3,350 kVA will be impacted (half the loop, 70 amps).

Intervention Mode

PowerStream will address the cable aging issue by a combination of cable injection and cable replacement on a prioritized basis. Cable injection is assumed to rejuvenate the cable by 20 years.

Replacement and Injection Program Results

There are two methods of intervention to address the cable aging issue:

- Cable Replacement – replace existing cable
- Cable Injection – extend existing cable service life

The Cable Replacement option is more expensive than the Cable Injection option with respect to initial capital cost. But it has the advantage of new cable that will be utilized for a longer time. In comparing the two options: the extra life expected from injected cable is 15-20 years; the life of new cable is expected to be 50-55 years; the cost/benefit ratio is 15% better for cable injection compared to new cable. Cable injection is viable for only a certain population of cable.

Currently, PowerStream is experimenting with Cable Injection technology to gain more experience. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. If it is determined that Cable Injection is no longer a viable option, then Cable Replacement will become the only alternative. In that case, the quantity that is proposed for Injection will be proposed for Replacement.

The Cable Replacement plan will be ongoing as we will continually need to replace cable as it gets older. This report will cover the first 20 years of the plan. It is expected that the Cable Replacement plan will continue at a similar spending level after the first 20 years.

The Cable Injection plan will take place over a period of 10 years. After 10 years all suitable candidates for injection will be exhausted, therefore this plan will terminate after 10 years.

To develop a general plan to address the cable issue (a 20 year plan for cable replacement, and a 10 year plan for cable injection) the cable population is divided into the following 5 groups:

- Group 1: 31 years and older
- Group 2: Between 26 – 30 years
- Group 3: Between 21 – 25 years
- Group 4: Between 11 – 20 years
- Group 5: Between 1 – 10 years

Group 1: 31 years and older:

It is estimated that PowerStream has approx. 370 km of cable older than 30 years. This population is the older generation of cable that was manufactured with old technologies and processes, using inferior insulation material (non tree-retardant XLPE). In addition, due to age, and installation method (direct buried) the neutral wires are likely corroded. Samples of recent cable failures show that the neutral wires have corroded beyond repair. Cables in this population may be at or close to end-of-life stage and are candidates for cable replacement. As a result Group 1 is excluded from Cable Injection.

Group 2: Between 26 – 30 years:

It is estimated that PowerStream has approx. 1,044 km of cable between 26 – 30 years.

This population is also the older generation of cable as described in Group 1 above. It is assumed that the cable components have not deteriorated significantly yet. Cables within this population could be candidates for cable injection. However, it should be noted that a significant portion of this group may not be viable candidates for cable injection, depending on forthcoming tests. For our purposes we assume that 50% (i.e. 522 km) of this population is not suitable for injection and must be replaced, this quantity will be managed under the Cable Replacement Program. The remaining quantity 50% (i.e. 522 km) of this population is suitable candidates for injection, this quantity will be managed under the Cable Injection Program. This issue is covered in detail in the next Section – Cable Injection.

Group 3: Between 21 – 25 years:

It is estimated that PowerStream has approx. 1,755 km of cable between 21 – 25 years. This population is a newer generation of cable that was manufactured with new technologies and processes (similar to Group 4 and Group 5), for example, the use of tree-retardant XLPE for insulation and triple extrusion process. Because water trees are not a concern for this group of cable, and Injection's main purpose is to repair water trees, Injection is not effective for this group of cable. In addition, this population has likely been manufactured using strand-filled material, which does not allow the injection fluid to flow through and therefore injection is not possible. This population of cable will need to be addressed at the end of the 20-year period once the first two groups of cable have been dealt with.

Group 4: Between 11 – 20 years:

It is estimated that PowerStream has approx. 2,177 km of cable between 11 – 20 years. At the end of the 20-year proposed plan, this population should still maintain a low failure rate and it is estimated a portion of this group will still operate better than Group 3.

Group 5: Between 1 – 10 years:

It is estimated that PowerStream has approx. 2,501 km of cable between 1 – 10 years. Because this cable is new, it is not an immediate concern. It is assumed it will last well beyond the end of the 20-year plan.

<u>20-Year Cable Replacement Plan:</u>

The intent of this program is to start to address the aging cable population in a timely manner so that the future spending level (after 20 years) will be manageable.

To address the Group 1 population of 370 km of cable older than 30 years, and 50% of the Group 2 population of 522 km of cable between 26 – 30 years (total = 370 km + 522 km = 892 km), it is recommended to:

- Replace 8.5 km in 2012 (same level as 2011)
- Replace 47 km per year for the subsequent 19 years from 2013 – 2031

At this rate, all of the 892 km will have been replaced by 2032.
Currently, PowerStream does not have sufficient physical condition and test data to determine the degree of deterioration and to estimate the remaining life of the cable population.

PowerStream, beginning in 2012, will conduct cable testing (e.g. Tan Delta tests, Partial Discharge tests) to further assess the condition of cable to:

- Determine which intervention method (replacement vs. injection) is more suitable to a specific location.
- Determine the appropriate quantity and timing of cable intervention (replacement/injection).
- Validate and prioritize the cable replacement/injection projects.

The following chart shows the cable age profile projections resulting from the proposed plan. The quantities are shown 10 years and 20 years into the program.

- The blue bars indicate the resulting age profiles 10 years into the program.
- The red bars indicate the resulting age profiles 20 years into the program.

Figure 89. Underground cable projected age demographics.

Based on the above chart, after 20 years PowerStream will have 1,509 km of cable that is 41 to 45 years old. While this is a higher quantity of cable in the age range as compared to the quantity at the start of the program, these cables will be 2nd and 3rd generation cable with improved production quality and corresponding longer expected service life as compared to the cable being addressed in the first 20 year replacement program. At that time this group of cable will be in or entering end-of-life conditions, therefore the replacement program will likely continue at a suitable replacement level to address this population of cable.

The above demonstrates that the proposed 20 year Cable Replacement plan during the first 20 years will result in cable demographics that are reasonably well distributed after 20 years (similar to the first 20 years), supporting the premise that this is the correct level of cable replacement for this asset class.

The recommended cable replacement quantities and costs are shown in the chart below. 2012 costs include the costs of planned projects. For 2013 and onward, the average cost of $281 per meter is used.

Figure 90. Recommended cable replacement costs and quantities.

Underground Cable Injection

The criteria for selecting Cable Injection candidates are listed below:

- Pre to mid 1980’s (approx. 26 years old in 2011)
- Not solid core
- Non strand-filled

- Concentric neutral not corroded significantly
- No electrical trees present (Cable Injection can repair water trees and not electrical trees)
- Not having too many splices within a cable segment

Group 1 cables (31 years and older) are assumed to be close to end-of-life. Samples of recent cable failures show that the neutral wires have corroded beyond repair. As a result Group 1 is excluded from Cable Injection.

Group 2 cables (26-30 years) could be candidates for Cable Injection provided that the above conditions are met. It should be noted that a significant portion of this group may not be viable candidates for cable injection, depending on forthcoming tests. We assume that 50% (i.e. 522 km) of this population is suitable for injection.
Groups 3, 4 and 5 cables (25 years or younger in 2011) are assumed to have been manufactured with new technologies and processes using tree-retardant XLPE and triple extrusion process and strand-filled material. In general, water trees are not a concern and therefore injection is not effective. As a result Groups 3, 4, and 5 are excluded from cable injection.

Because the Cable Injection option has a number of limitations, a portion the Group 2 population may not be candidates for Cable Injection. For example, it may be more economical to replace cables if there are multiple phases in a trench, or multiple splices in a segment. Another example is during cable failure repair, operations staff adds two new splices to the segment, and one piece of new cable between the splices. As the new piece of cable is strand-filled, injection is not possible for this cable segment. Furthermore, depending on the design and condition of the cable at a specific location (e.g. strand-filled, neutral corrosion, electrical trees) the Cable Injection process may not be feasible at all.

To determine feasibility of cable injection, cable will be tested using cable diagnostic testing such as Tan Delta and Partial Discharge (PD) tests.

PowerStream will, beginning in 2012, conduct cable testing (e.g. Tan Delta tests, Partial Discharge tests) to further assess the condition of cable to:

- Determine which intervention method (replacement vs. injection) is more suitable to a specific location
- Determine the appropriate quantity and timing of cable intervention (replacement/injection)
- Validate and prioritize the cable replacement/injection projects

As PowerStream is still experimenting with cable injection technologies and processes, we will proceed with injection projects prudently. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. If it is determined that Cable Injection is no longer a viable option, then Cable Replacement will become the only alternative. In that case, the quantity that is proposed for Injection will be proposed for Replacement.

10-Year Cable Injection Plan:

To address the 50% of the Group 2 population of 522 km of cable aging between 26 – 30 years, it is recommended to:

- Inject 8 km in 2012 (same level as 2011)
- Inject 57 km per year for the subsequent 9 years from 2013 – 2022

10 years is the optimal time period to get the benefit of the injection program for Group 2. If we extend the period beyond the 10 years, the remaining population of Group 2 may become too old to remain suitable candidates for injection.

At this rate all of the 522 km cable between 26-30 years will have been rehabilitated by 2022.

The recommended cable injection quantities and costs are shown in the chart below using the average cost of $72 per meter.

Figure 91. Recommended cable injection cost and quantities.

Conclusions

- Recommendations:
  - Proceed with injection and replacement plans as outlined above.
  - Conduct cable testing to identify candidates for cable replacement and cable injection.
  - Use cable prioritization to determine the appropriate quantity and timing of cable intervention (replacement/injection).
- Gaps:
  - Cable test data.
  - Cable demographic information.

PowerStream Inc.

Corporate Ten Year Capital Plan

2014 - 2023

Prepared by: S. Cunningham & T. D'Onofrio

June 2013

TABLE OF CONTENTS

SUMMARY

As part of PowerStream's Capital Budget process and planning cycle, business units have developed 10 year capital plans for the years 2014 - 2023. The plan presented here summarizes the business units 10 year capital plans into one corporate capital plan for the same years. In addition, this document describes PowerStream's Capital Investment Process.

CAPITAL INVESTMENT PROCESS

PowerStream's Capital Investment Process is guided by its Asset Investment Strategy (AIS) and utilizes the following five steps on an annual basis:

Step One: Business units develop their initial ten year capital plans as part of the annual capital planning cycle consistent with the Asset Investment Strategy.

Step Two: A Corporate Ten Year Plan (this plan) is developed based on the submitted business unit ten year plans as part of the capital planning cycle.

Step Three: Business units prepare detailed budgets for their ten year plan and prepare business cases for projects in year one and year two of their ten year plans as part of the annual budget process.

Step Four: The year one and year two detailed budgets for all business units are prioritized through the Optimizer process.

Step Five: Approved and prioritized projects for year one are readied for execution in the next fiscal year and approved and prioritized projects for year two are readied for incorporation in a rate application (as required by the OEB schedule).

These five steps, including timeframe, are shown in Table 1. The details of each step are provided following Table 1.

Table 1 - Capital Investment Process	
Steps	**Time Frame**
1 - Business units develop their initial ten year capital plans	**January - April**
2 - A Corporate Ten Year Plan is developed	**May - June**
3 - Business units prepare detailed budgets	**June - August**
4 - Optimizer process	**September**
5 - Issue approved budget	**October**

Step One – Business Unit Ten Year Capital Plans

PowerStream's Capital Investment Process incorporates a ten year plan with the first two years being as accurate as can be. Business units that have major capital expenditures put together their own ten year departmental plans. Early in the calendar year a request is sent out by the Engineering Services division to all business units in PowerStream to prepare ten year capital plans. These plans are developed over the January to March period and submitted to the Engineering Services division for review and consolidation. These ten year plans serve as the starting base for the development of the Corporate Ten Year Plan (this plan).

The business unit ten year capital plans serve four purposes: i) assist business units in their future planning and enable the business units to provide an accurate two year budget; ii) forms the basis of the information provided in a rate application for the forward looking years; iii) provides the Finance team with information for their financial planning; and iv) provides for smoother, more consistent capital spending year-over-year.

Business units provide details in their ten year plans on forecasted capital spending requirements and describe the process by which they have determined the capital spending requirement. Specific projects and costs identified in the plans are generally preliminary and the projects identified in the plans may or may not be approved for execution at this point. The business units include in their plans information on the 10 year capital requirements.

Step Two – Corporate Ten Year Capital Plan

The business unit ten year plans are summarized into a Corporate Ten Year Plan (this plan). The information is combined from the following business units:

- Engineering Planning
- Distribution Design
- Operations
- Lines
- Supply Chain Management Services
- Information Services
- Capital Budget Supervisor (Misc. Capital)

The information in the Corporate Ten Year Plan is used by the Finance Department in their financial models to consider affordability. In addition, information in the ten year plan is used in rate planning for the forward looking years.

Step Three – Budgets for Ten Years

Once the Corporate Ten Year Plan is complete, the detailed build of their ten year plan begins with the information inputted in a database called the Capital Budget Management System. For each project the following information is provided: identification information; justification, resource requirements, and estimated costs. Year one and two reflect the most accurate years. The projects identified in the first two years of the ten year plan form the capital projects put forth for optimization. The information inputted into the database form a mini business case for distribution projects less than $500,000 and technology projects less $100,000. For any specific distribution project (non-program) that is greater than $500,000 and technology project greater than $100,000 a full business case is provided and submitted for approval.

Step Four – Determining the Portfolio of Projects

Once project identification is complete, the business units in conjunction with the Capital Budget Supervisor answer a series of questions about each project. The questions asked are aligned with PowerStream’s Asset Investment Strategy (AIS). The answers to the questions form the basis for scoring both the value of the project to the corporation and the risk to the corporation if the project is not completed in the planned year. The Capital Budget Supervisor participates with the business units across the organization in answering questions to ensure consistent interpretation of the questions and answers.

Once the questionnaires are all answered, the data is compiled and loaded into Optimizer. Optimizer is a proprietary software tool purchased by PowerStream from UMS Group. Optimizer is an Excel based software tool that takes the capital portfolio, the value and risk scores given to each project, the cost for each project, and a budget envelope and then calculates an optimum project list for the overall budget envelope. The Optimizer tool is capable of running several scenarios such as project list being optimized for the least amount of risk, optimized for the most amount of value or optimized for the most value at the least amount of risk. All capital projects in the corporation are run through the Optimizer tool with projects from IS, Fleet, Station Construction and Lines Construction being considered through the same tool.

With the output from various scenarios from the Optimizer software, PowerStream's Optimizer team has discussions as to which projects will be approved as part of the two year capital budget. Members of the Optimizer team include key senior leaders from each of the business units who have major capital spend across the corporation, Rates & Regulatory and Organizational Effectiveness.

Deriving the capital budget follows both a top-down and bottom-up approach. The high level budget envelope is developed as a joint effort among the Finance, Rates & Regulatory and Engineering departments. The Finance department uses the output from the Corporate Ten Year Plan in a financial model to determine affordability and impact on financial soundness and customers. As a result, a target budget envelope is determined. The Optimizer team uses the target budget envelope as a starting point in deliberations. Various scenarios are run through Optimizer, both below and above the targeted envelope. The value and risk level between the scenarios is considered. The Optimizer team provides feedback on the feasibility of the target budget envelope and adjustments to the envelope are made and a final decision is reached after discussion amongst the Optimizer team and the applicable business unit representatives.

Step Five – Final Capital Project Portfolio

The final list approved by the Optimizer team forms the basis for the two year capital budget. The first year of the capital plan is approved by the PowerStream's Executive Management Team (EMT) and Board of Directors for execution for the following year. The second year of the two year plan is also approved by the PowerStream's EMT and Board of Directors and forms the basis of the information provided in a rate case for the test year.

It is reasonably expected, although not a certainty that the majority of the projects identified in the second year of the two year plan will become approved projects in the first year of the subsequent year's two year plan. Business units have the ability to put forward changed, new or alternative projects based on new information garnered during the year. Projects are rescored each year to determine if value or risk has changed. Optimization of projects may also change based on updates to the Asset Investment Strategy (AIS).

POWERSTREAM'S ASSET INVESTMENT STRATEGY

PowerStream's Asset Investment Strategy (AIS) is the framework for decision making for the capital expenditure program. This investment and risk framework is built into the Optimizer tool and process. The AIS helps define the portfolio of investments that will achieve the Company's strategic value expectations within the Company's defined risk tolerance boundaries. This includes providing guidance to make effective short-term (one year) and long-term (two to five year) investment decisions, and to maximize the value of the assets to the company.

Within PowerStream's AIS, strategic value is defined as the array of business objectives (called AIS objectives) that the company must consider to achieve the overall corporate business strategy and objectives. These business objectives are aligned to the overall corporate strategy and objectives and success is measured against a series of success criteria. See Table 2 below for a listing of the AIS objectives and success criteria. The objectives are quantified as more than simply a financial or dollar value consideration and extend beyond why we are in business, in an attempt to quantify the most critical considerations that drive the company's ability to remain in business and effectively service customers. The AIS objectives and success criteria are reviewed annually to ensure continued alignment with the overall corporate business strategy and objectives.

PowerStream's AIS defines risk in its broadest terms, primarily, but not exclusively, in terms of strategic, financial and operational (or technical) risk. The risks considered are quantified for each element used in defining AIS strategic value and are a result of direct or indirect loss due to failed internal processes, people, systems, work practices, or, from external events. Risk is viewed from the perspective of both probability and consequence.

Table 2
AIS Objectives and Success Criteria

AIS Objectives	Success Criteria for each Objective
Customer Focus	Improved Customer Minute Interruptions (CMI)
	External Customer Satisfaction
	External Customer Communication
Operational Excellence	Process Improvements
	Hard & Soft Financial Savings
	Internal Service Capacity
Regulatory Excellence	Compliance
	Rate Ready Organization
	Maintained or Improved Service Quality Indicator (SQI)
Growth & Sustainability	Distribution System Capacity
	Revenue Recovery Factors
	Environmental Impact
High Performance Culture	Employee Wellness & Satisfaction
	Safe Work Place
	Technological Innovation

SUMMARY DESCRIPTION OF MAJOR CATEGORIES OF CAPITAL EXPENDITURES

PowerStream sorts its capital investments into four major categories and a number of sub-categories as laid out in Table 3. Summary descriptions of the major categories are as follows:

Sustainment Capital – Sustainment Capital is defined to include projects that replace/enhance capital assets to maintain the reliability of the distribution system so that it will continue to function within established performance standards. Sub categories include: Emergency / Restoration; Replacement Programs; Sustainment Driven Lines Projects; Transformer/Municipal Station Projects; and Emerging PowerStream Projects.

Development Capital – This major category includes projects that involve system expansion or relocation due to customer service requests. Sub categories include: Subdivisions/Services; Road Authority Projects; Growth Driven Transformer/Municipal Stations; Growth Driven Lines Projects; Emerging Development Capital; and Distributed Generation.

Operations Capital – This major category includes projects that support the day-to-day operations of PowerStream. Sub categories include: Buildings; Fleet; Metering; Spare Parts; Tools; Information/Communication Systems; Emerging Operations; and Interest Capitalization.

Table 3 – Major and Sub-Categories for Capital Budget	
1. Sustainment Capital	
1a	Replacement Program
1b	Sustainment Driven Lines Projects
1c	Emergency / Restoration
1d	Transformer / Municipal Stations
1e	Emerging Sustainment Capital
2. Development Capital	
2a	Subdivision / Services

2b	Road Authority Projects
2c	Growth Driven Transformer / Municipal Stations - Additional Capacity
2d	Growth Driven Lines Projects
2e	Emerging Development Capital
2g	Distributed Generation Connections
3. Operations Capital	
3a	Metering
3b	Fleet
3c	Tools
3d	Buildings
3e	Information / Communication Systems
3f	Purchase of spare equipment
3g	Emerging Operations Capital
3i	Interest Capitalization

DETAILED CATEGORY AND SUB-CATEGORY DESCRIPTION

Following is a detailed description of the categories and sub-categories of capital spending used at PowerStream.

Sustainment Capital

Sustainment Capital is defined to include projects that replace/enhance capital assets to maintain the reliability of the distribution system so that it will continue to function within established performance standards. In general, this includes the replacement of overhead and underground lines, system reconfigurations, voltage conversions, upgrading of equipment (not primarily for expansion of capacity), planned asset replacements based on the results of the Asset Condition Assessment (ACA) process (poles, transformers, distribution switchgears, underground primary cables, station circuit breakers and reclosers). Sustainment capital is further broken down into a number of sub-categories as described below.

Replacement Program

This sub-category covers the replacement of overhead line, underground line and station as identified as needing replacement through the Asset Condition Assessment (ACA) process. PowerStream's ACA process is described in Exhibit B1, Tab 2, Schedules 4 and 5. These yearly programs include: Wood Pole Replacement program; Underground Switchgear Replacement program; Station Circuit Breaker Replacement program; and other replacement programs (RTU's, Transformers and Switches).

Sustainment Driven Lines Projects

This sub-category is for those projects that are not capacity driven (i.e. load growth related), but are required to sustain the distribution system and ensure reliability. These projects are identified through technical studies or through an identified reliability need. Included in this category are: Cable Replacement Projects, Voltage Conversion Projects; Underground Cable Injection program, System Re-configuration Projects; Radial Supply Remediation Projects; Distribution Automation Projects; Reliability Driven Projects and Fault Indicator Installation.

Emergency / Restoration

This sub-category covers capital costs of repair and restoration of the distribution system. Work is required as a result of ongoing power outages or identified through inspection as needing repair due to a hazardous safety condition or potential imminent failure. The work is divided into programs, specifically, Replacement of Failed Distribution Equipment; Replacement of Distribution Equipment due to Storm Events; and Replacement of Distribution Equipment due to Accidents.

Replacement of Failed Distribution Equipment covers the emergency replacement of all failed equipment within PowerStream's distribution system due to unexpected failure. These failures generally result in power interruptions to our customers and the failed equipment is removed and replaced with serviceable electrical equipment restoring power.

Replacement of Distribution Equipment due to Storm Events covers replacement of major distribution equipment damaged during storm events including poles, transformers, lines, services, and switching devices. The distribution components replaced are necessary to restore power to our customers and restore the operating system to safely working conditions. The projection for this capital budget item is estimated based on the past 5 years of historical spending due to the year over year variability in annual severe weather patterns.

Replacement of Distribution Equipment due to Accidents covers the cost associated with replacement of major equipment damaged by vehicle accidents and foreign interference. The replacement costs are tracked and where possible collection is made from the party causing the damage to PowerStream's distribution equipment. Costs recovered from third parties are attributable to revenue.

Transformer / Municipal Stations

This sub-category is for those Municipal Stations (MS – stations that transform from 44kv or 27.6 kv to a lower distribution voltage such as 13.8 kv) and Transformer Stations (TS – stations greater than 100 MVA that transform from high voltages 230 kv to 27.6 kv) projects that are not capacity driven, but are required to sustain PowerStream's fleet of eleven TS's and fifty-four MS's. Sustainment activities include projects to: replace worn out equipment, improve reliability, enhance operability & maintainability, and to improve & maintain safety.

Emerging Sustainment Capital

This sub-category covers sustainment projects that are unforeseen. Despite the best efforts of the budget team to identify all of the capital requirements for the budget year, there are projects that arise after the budget has been approved. Projects are typically required due to an unforeseen circumstance or were missed during budget preparation but if not completed in the current year would have a negative impact on the day-to-day operation of the distribution system. Every effort is made to defer the projects to the next budget year. Project leaders requesting to tap into these funds are required to have appropriate approval prior to work commencing.

Development Capital

Development Capital is defined to include projects that enable system expansion required as a result of customer growth and relocation projects due to municipal and regional requirements as a result of growth in the communities served by PowerStream. Development Capital is further broken down into a number of sub-categories as described below.

Subdivision / Services

This sub-category covers the costs to connect new customers to the system. The work is divided into programs as follows: Layouts; New Services; New Subdivisions; and Secondary Services.

Layouts consist of work to make ready the system for new residential infill services, upgrading of residential services and small commercial services. A layout is completed for each customer. The customer's service could be underground or overhead and is the connection from the main plant on the boulevard to the building. Costs are shared between the customer and PowerStream. In accordance with the Distribution System Code (DSC), the Local Distribution Company (LDC) is required to provide the customer with a basic connection allowance for each residential service. This basic connection credit equates to 30m of an overhead service and 10m of an underground service.

New Services consists of new and/or upgraded primary services to industrial, commercial and institutional customers. These services are normally underground from the existing distribution or sub-transmission system and up to and including the padmount transformer. Typically customers contribute 100% of the cost for new services. In accordance with the DSC, these services are considered a connection and are 100% recoverable (deemed as 'Lies Along' – these are new services where facilities exist to service the customers).

New Subdivisions consist of the primary and secondary underground cables as well as transformers installed to the street line of each lot within a new residential "Greenfield" subdivision development. In accordance with the DSC, the development cost is put through an economic model to determine the LDC share and the Developer share based on revenues from the development.

Secondary Services: Secondary underground services are installed from the street to the meter base for each lot. This work allows for the connection of the secondary service to the padmount transformer which in turn provides power to the customer's unit. These services are installed as the houses within the development are built and are normally installed within 5 years of the new subdivision being installed. In accordance with the DSC, these service costs are put through the economic model and shared at time of the OTC.

Road Authority Projects

As communities within PowerStream's service territory continue to grow, it is accompanied by road construction, re-alignment and widening of existing roads, as well as the installation of new water and sewer infrastructure. This development work is controlled by Provincial, Regional and Municipal authorities. Because PowerStream's distribution system is located on the road allowance, at the request of the road authority, it must be relocated to accommodate this development work. Each year, PowerStream reviews the five and ten year road authority plans for development to identify where distribution system conflicts exist and to budget for resolution of these conflicts. The majority of these projects involve relocating portions of the distribution system. These projects are usually cost shared with the road authority as per provincial legislation. This sub-category covers the costs for these relocations.

Growth Driven Transformer / Municipal Station Projects

This sub-category covers construction projects of new or upgrades of existing transformer and municipal station capital projects that PowerStream must complete to provide sufficient capacity to supply new customers and load growth from existing customers. Every year PowerStream prepares a load forecast and studies the system to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

Growth Driven Lines Projects

This sub-category covers construction of new or upgrades of existing distribution or subtransmission lines that PowerStream must complete to provide sufficient feeder and component capacity to supply new customers and load growth from existing customers. PowerStream uses the load forecast and studies the system to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

Emerging Development Capital

This sub-category covers customer projects due to the customer's emerging needs throughout the year. Projects are typically required due to either a relocation required by a customer or the expansion of the distribution system for the customer. In the case of relocations, the customer typically pays 100% of the costs. In the case of a required expansion of the distribution system, costs are shared as per the requirements of the DSC and PowerStream's Conditions of Service (COS).

Distributed Generation Connections

This sub-category covers the costs to connect new distributed generation customers to the system. In accordance with the DSC, these costs are shared by the customer and PowerStream. The customer is responsible to cover the cost of connection. PowerStream will cover system expansion costs at or below a distributed generation customer's renewable energy expansion cap.

Operations Capital

Operations Capital is defined to include projects that support the day-to-day operation of PowerStream. Operations Capital is further broken down into a number of sub-categories as described below.

Metering

This sub-category involves the installation or replacement of meters. The work involves the upgrades or replacement of wholesale or retail meters and includes the following: Wholesale Meter Upgrades; Failed Meter/Transformer Replacements; Meter Re-verifications; Smart Meters (AMI/MDMR/TOU); and Upgrades of 2.5 Element Meters.

Wholesale Meter Upgrades consist of projects to upgrade PowerStream Wholesale Meters. PowerStream is directly connected to the IESO (Independent Electrical System Operator) grid at several points. Each of these connection points entails a wholesale metering point and meter. Normally upgrades are required due to requirements set out by the IESO.

Failed Meter/Transformer Replacements consists of the replacement of meters, wire, instrument transformers and associated test equipment for revenue billing meter systems which periodically fail. When a revenue meter fails replacement must take place as soon as possible to minimize the time that customer energy consumption data is lost.

Meter Re-verifications are required due to regulations under the Electricity and Gas Inspection Act enforced by Measurement Canada to ensure that all revenue meters meet strict accuracy and operational standards over the life of the meter. The process of removing and testing the meter is referred to as re-verification.

Smart Meter (AMI/MDMR/TOU) deployment has been a primary focus of PowerStream since 2006 when the Provincial Government mandated the replacement of the electromechanical billing meters with the new Smart Meter and AMI (Advanced Meter Infrastructure) two–way communication systems. The costs for installation of the Smart Meters were covered under Smart Meter deferral accounts prior to 2012. Going forward capital spending associated with Smart Meters ((AMI, MDM/R (Meter Data Repository) and TOU (Time-of-Use)) are covered in this category and support the continued functioning of the newly installed system.

Upgrade of 2.5 Element Meters is a program to upgrade existing two and one half (2.5) element meters to the more modern three (3) element meters. The older fuse link test blocks often have fuses operate or blow which causes loss of potential to the meter, which in turn causes the meter to inaccurately (under-recording) measure the actual energy consumed. The result is lost revenue that may go undetected for long periods of time until a meter inspection reveals the blown fuse.

Fleet

This sub-category involves the purchase of three vehicle classifications: Heavy vehicles, Light/Medium vehicles and Miscellaneous. PowerStream has forty-three heavy duty units which are aerial devices and radial boom derricks for working on distribution lines. PowerStream has 156 light/medium units which are vans, pickup trucks and automobiles used across the organization by various roles such as Line Supervisors, Sub-foreman, Line technicians, Inspectors, Locaters, etc. PowerStream has sixty miscellaneous units including pole trailers, general use trailers, tension machines and forklifts. These units are either used to move material or assist in the distribution line work.

A vehicle is considered for replacement based on an expected life. PowerStream has established an expected life for each class of vehicle. Replacement is determined by achieving years of use, mileage or hours of use as per manufacturer's recommendations for replacement. This expected life replacement approach is in keeping with industry practice and is important to assist PowerStream's ability to forecast vehicle spending, assist PowerStream in achieving a lower risk of catastrophic vehicle failure and enhancing PowerStream's ability to negotiate long term procurement contracts with vendors and realize savings.

Tools

This sub-category involves the purchase of tools that are required for new/replacement installations of the distribution system. Tools include hydraulic cable cutters & crimpers, insulated sticks and barriers, hoisting equipment. These purchased tools replace worn out or broken tools used by the staff on a daily basis for their work

Buildings

This sub-category involves the purchase, replacement or rehabilitation of major assets related to one of PowerStream's three main centres of operation at Patterson Rd. in Barrie, Addiscott in Markham, and Cityview in Vaughan.

The Patterson Rd facility in Barrie was built in 1990. The Cityview Blvd. facility in Vaughan was primarily constructed in 2007 and ready for occupancy in early 2008 and the Addiscott facility in Markham was primarily constructed in 2009 and ready for occupancy in early 2010.

Relevant projects include changes to: exterior (i.e. pavement, fencing, lighting, stores yard); interior (i.e. furniture); mechanical (i.e. plumbing); structural (i.e. windows, doors, wall partitions); and HVAC (Heating & air conditioning).

Information / Communication Systems

This sub-category consists of projects for new or upgrades to PowerStream's information technology or communication systems across the organization.

In 2011, PowerStream engaged KPMG to facilitate the development of a business driven Information Services (IS) Strategic Plan. The process involved extensive input from the management and executive teams and resulted in development of five strategic initiatives. Subsequently, a list of projects which support the achievement of the strategy was developed and prioritized by the senior management. The result was a five year IS Roadmap and Investment Plan. Projects are categorized into the five strategic initiatives as follows: Developing Information Capital; Delivering Outstanding Customer Service; Achieving Operational Excellence; Building a Foundation for Innovation; and Maintaining our Infrastructure.

Projects within Developing Information Capital will enable PowerStream to develop, retain and share corporate knowledge. The evolution of Smart Metering and the convergence of Operational networks with IS networks is resulting in exponential growth of data. Establishing an enterprise data model and standards will facilitate the transformation of data into valuable and trusted corporate information upon which business decisions are based.

Projects within Customer Service Excellences will give PowerStream the ability to provide customers, the rate payers, with best possible service at the lowest cost. While it is recognised that every dollar invested is ultimately to benefit the customer, this category describes those investments which have a direct impact on PowerStream's customers. These projects are aimed to provide modern and valuable customer services and include a new CIS Implementation and Customer Facing Process Improvements.

Projects within Achieving Operational Excellence are aimed towards applications and initiatives that improve business processes primarily through automation. In the past PowerStream has experienced rapid growth through mergers and acquisitions, and PowerStream's processes have evolved either by merging and adapting multiple processes or by simply adopting a process from a former company. The same methodology was applied to applications which supported the processes. While this strategy was successful in quickly bringing companies together, it didn't take full advantage of scale or opportunities to apply new technology. New applications to support operational excellence include an Enterprise Asset Management System, a Workforce Management Solution (WFMS), and hardware and software to support a mobile Workforce solution.

Projects within Building a Foundation for Innovation Investments are geared toward improving how Information Services serves the corporation. Initiatives include development and updating of Information Services Governance framework to ensure alignment with business units remains strong and development and updating of Enterprise Architecture Standards to help manage the growing requirement to add and integrate new systems and data sources.

Projects within Maintain our Infrastructure spending is required to maintain and keep up-to-date PowerStream's computer assets including both hardware and application software.

- **Hardware** – PowerStream has personal computers distributed amongst three locations including select field personnel. PowerStream utilizes a centralized printing model as much as possible. High capacity multi-function printers are also located throughout the various offices. There are additional stand-alone or small workgroup printers to meet specific needs. In addition, PowerStream's has a large number of servers to manage the applications and data. Annual funding is required to replace any equipment which no longer meets minimum requirements. Minimum requirements are dictated either by unacceptable performance, or lack of compatibility with applications or other systems. PowerStream continuously looks for opportunities to extend the lifecycle of hardware and software.

- **Application Software** – PowerStream's major application systems include: an Enterprise Resource Planning (ERP) system [JD Edwards Enterprise]; a Customer Information System (CIS) [T&W Information Systems]; a Graphical Information System (GIS) [ESRI]; an Outage Management System [Responder]; a Design System [Designer]; SCADA [Survalent]; and a Station Information System [Cascade]. PowerStream utilizes the Microsoft Office suite, SharePoint, and Exchange mail for general desktop use. Telecom support includes a Voice Over Internet Protocol (VOIP) telephone system and hardware to support fibre connectivity between all work centres and several sub-stations. Upgrades to existing applications are considered necessary when there is lack of vendor support; lack of compatibility with versions used by business partners and customers; new features are available which provide additional functionality to improve efficiency; or lack of compatibility with new software or hardware.

Purchase of Spare Equipment

This sub-category is for the purchase of key equipment in stations that will be held in reserve and used for system spares in the event that a failure of the key equipment occurs.

Emerging Operations Capital

This sub-category covers monies for operations projects that are unforeseen. Despite the best efforts of the budget team to identify all of the capital requirements for the budget year, there are projects that arise after the budget has been approved. Projects are typically required due to an unforeseen circumstance or were missed during budget preparation but if not completed in the current year would have a negative impact on the day-to-day operation of the distribution system. Every effort is made to defer the projects to the next budget. Project leaders requesting to tap into these funds are required to have appropriate approval prior to work commencing.

Interest Capitalization

This sub-category covers monies for interest capitalization. Under IFRS, interest capitalization is defined as the borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset cost. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use. PowerStream has determined this period of time as those projects that span over 4 months in duration. To assist in project management these costs are kept track of in one category within the Capital Budget.

POWERSTREAM'S 10 YEAR CAPITAL PLAN

Table 4a is the capital plan for the year's 2014 to 2018 and table 4b is the capital plan for the year's 2019 to 2023. The information is combined from the following business unit reports:

- Engineering Planning
- Distribution Design
- Operations
- Lines
- Supply Chain Services
- Information Services
- Capital Supervisor (Misc. Capital)

All reports give a general description of the work required for their business unit. Included in each of the business unit reports is a description of the methodology used to determine spending requirements. Project costs are aligned to the major capital categories described in Table 3 above.

Table 4a - 10 Year Capital Plan ($ 000)					
Rate Category	**2014**	**2015**	**2016**	**2017**	**2018**
Sustainment					
Emergency / Restoration	10,188,167	10,493,168	10,767,300	10,948,988	11,339,045
Replacement Program	7,019,863	7,193,716	7,370,932	7,599,107	7,735,848
Sustainment Driven Lines Projects	28,458,844	27,616,143	26,531,431	26,821,568	25,893,243
Transformer/Municipal Station	2,507,952	5,451,492	2,452,970	1,772,759	2,469,158
Emerging Sustainment	1,912,162	1,961,532	2,075,354	2,265,476	1,808,576
TOTAL SUSTAINMENT	**50,086,987**	**52,716,052**	**49,197,987**	**49,407,897**	**49,245,870**
Development					
Subdivisions/Services	12,011,089	13,018,091	14,054,068	15,128,520	16,260,447
Road Authority Projects (includes YRRT)	14,068,257	10,081,132	7,668,655	5,295,395	5,855,325
Emerging Development Capital	515,925	567,043	623,272	685,124	753,162
Distributed Generation Connections	0	0	0	0	0
Growth Driven Transformer/Municipal Stations	7,973,317	23,608,707	8,375,816	6,227,946	4,643,670
Growth Driven Lines Projects	6,283,543	12,286,843	24,182,622	26,960,485	2,786,593
TOTAL DEVELOPMENT	**40,852,132**	**59,561,816**	**54,904,433**	**54,297,470**	**30,299,197**
Operations					
Buildings	1,462,763	883,168	169,784	260,015	76,000
Fleet	3,103,964	3,973,090	3,286,525	3,398,549	4,101,625
Information / Communication Systems	28,238,990	8,107,237	11,187,725	8,632,270	10,907,520
Metering	3,192,000	3,282,250	2,885,150	2,497,550	2,805,350
Spare Parts	38,000	319,749	19,000	19,000	104,671
Tools	598,310	556,130	506,540	533,910	520,800
Emerging Operations Capital	71,250	71,250	71,250	47,500	47,500
Interest Capitalization	1,335,763	1,393,972	1,266,841	1,254,949	891,139
TOTAL OPERATIONS	**38,041,039**	**18,586,846**	**19,392,815**	**16,643,743**	**19,454,604**
TOTAL	**128,980,158**	**130,864,713**	**123,495,236**	**120,349,110**	**98,999,672**

Table 4b - 10 Year Capital Plan ($ 000)

Rate Category	2019	2020	2021	2022	2023
Sustainment					
Emergency / Restoration	11,552,733	11,860,812	12,095,141	12,420,300	12,874,491
Replacement Program	7,923,765	8,115,468	8,292,063	8,491,674	8,695,421
Sustainment Driven Lines Projects	26,432,958	27,142,025	27,862,750	28,646,116	29,661,960
Transformer/Municipal Station	4,222,246	2,092,910	3,286,497	3,668,009	2,304,071
Emerging Sustainment	1,822,857	1,876,377	1,930,338	2,134,390	2,660,059
TOTAL SUSTAINMENT	**51,954,559**	**51,087,592**	**53,466,789**	**55,360,488**	**56,196,003**
Development					
Subdivisions/Services	17,421,349	18,630,226	19,896,578	21,191,905	22,544,707
Road Authority Projects (includes YRRT)	8,918,847	5,041,002	5,799,476	4,973,172	4,913,089
Emerging Development Capital	828,003	910,328	1,000,886	1,100,500	1,210,075
Distributed Generation Connections	0	0	0	0	0
Growth Driven Transformer/Municipal Stations	22,848,893	2,633,358	3,128,957	0	0
Growth Driven Lines Projects	4,545,750	16,261,161	6,479,000	12,540,000	12,540,000
TOTAL DEVELOPMENT	**54,562,842**	**43,476,076**	**36,304,897**	**39,805,577**	**41,207,871**
Operations					
Buildings	95,000	489,250	475,000	475,000	475,000
Fleet	3,327,529	3,325,000	3,327,782	3,325,000	3,328,060
Information / Communication Systems	12,622,460	8,306,895	7,500,915	7,745,730	7,805,580
Metering	2,805,350	2,805,350	2,805,350	2,805,350	2,805,350
Spare Parts	19,000	19,000	19,000	19,000	19,000
Tools	507,300	524,248	566,390	576,365	593,190
Emerging Operations Capital	47,500	19,000	19,000	19,000	19,000
Interest Capitalization	1,282,708	1,099,183	1,022,508	1,094,271	1,117,553
TOTAL OPERATIONS	**20,706,847**	**16,587,926**	**15,735,945**	**16,059,716**	**16,162,733**
TOTAL	**127,224,247**	**111,151,594**	**105,507,630**	**111,225,781**	**113,566,606**

Table 5 lists major projects that require a high level of spend in a given year. The high level of spend in a given year causes unavoidable fluctuations in the general level of overall capital required in a given year.

Table 5 - Major Projects ($ 000)

SPECIAL PROJECTS	2014	2015	2016	2017	2018
CIS	17,800	0	0	0	0
TRANSFORMER/MUNICIPAL STATIONS	7,973	23,608	8,376	6,228	4,644
LINES WORK ASSOCIATED TO TS/MS	661	0	9,405	18,537	0
YRRT	8,665	5,496	2,594	0	0
TOTAL	35,100	29,104	20,375	24,766	4,644

COMPARISON TO PREVIOUS 5 YEAR PLANS

This section compares and explains variances only between 5 year plans.

Table 6 shows costs and variances from plans prepared in 2011 and 2012. Below are explanations for the comparison. Table 6 is in this document because the <u>2013 COS rate filing was based on the 5 year plan prepared in 2011</u>. Plans prepared in 2011 covered years 2012– 2016 and plans prepared in 2012 cover years 2013-2017.

Table 6 - 5 YEAR PLAN COMPARISON

SUB CATEGORY	2013 (prepared in 2012)	* 2013 (prepared in 2011)	2014 (prepared in 2012)	2014 (prepared in 2011)	2015 (prepared in 2012)	2015 (prepared in 2011)	2016 (prepared in 2012)	2016 (prepared in 2011)	2017 (prepared in 2012)	2017 (prepared in 2011)
Sustainment										
Emergency/Restoration	9,802	9,527	10,063	10,517	10,332	10,794	10,609	11,080	10,894	na
Replacement Program	8,917	7,979	8,430	8,054	8,447	8,028	7,378	8,394	7,446	na
Sustainment Driven Lines Projects	23,630	23,238	26,294	23,702	24,180	24,114	23,806	23,066	21,389	na
Transformer/Municipal Stations	4,182	2,673	4,901	5,773	6,164	4,288	3,923	5,290	1,928	na
Emerging Sustainment	2,847	2,847	2,876	1,300	2,905	1,300	2,935	1,300	2,966	na
Total Sustainment	**49,378**	**46,264**	**52,564**	**49,346**	**52,028**	**48,524**	**48,651**	**49,130**	**44,623**	**na**
Development										
Emerging Development	435	435	471	220	511	230	554	240	601	na
Road Authority Projects	12,985	13,044	19,555	7,460	12,258	7,340	7,111	7,160	8,425	na
Subdivision/Services	11,499	11,673	13,120	11,410	14,660	13,420	16,340	15,440	18,140	na
Growth Driven Lines Projects	5,590	6,545	2,848	6,502	19,753	10,028	22,530	19,631	16,758	na
Additional Capacity (TS/MS)	3,469	5,984	7,316	9,398	20,508	21,414	5,474	2,134	2,499	na
RGEN-Customer Initiated	0	0	0	23	0	16	0	16	0	na
Total Development	**33,978**	**37,681**	**43,310**	**35,013**	**67,690**	**52,448**	**52,009**	**44,621**	**46,423**	**na**
Operations										
Information/Communication Systems	22,883	22,397	12,775	12,751	9,170	8,197	8,134	8,524	5,770	na
Fleet	2,933	2,933	3,296	3,000	3,456	3,000	1,524	3,000	2,492	na
Tools	616	597	518	544	486	491	505	517	552	na
Purchase of Spare Equipment	15	128	331	30	30	30	30	0	30	na
Metering	2,947	2,620	1,967	1,842	2,077	1,992	2,047	1,942	1,977	na
Emerging Operations Capital	320	120	320	500	320	500	320	500	320	na
Buildings	21	221	149	149	220	223	171	106	131	na
Interest Capitalization	1,845	1,317	1,807	1,430	1,150	1,150	1,040	1,040	1,018	na
Total Operations	**31,580**	**30,333**	**21,163**	**20,246**	**16,909**	**15,583**	**13,771**	**15,629**	**12,290**	**na**
TOTAL	**114,936**	**114,278**	**117,037**	**104,605**	**136,627**	**116,555**	**114,431**	**109,380**	**103,336**	**na**

2013 Comparison – Total Difference = $658,000

In 2013 there were minor budget cost revisions across all categories. Sub-categories that had significant adjustments to budgets were replacement program, transformer/municipal stations and additional capacity (TS/MS). Within replacement programs the average budget unit cost for pole and switchgear replacements is increased to reflect updated 2012 project costing analysis. Additional projects from the Station Sustainment department increased costs within the transformer/municipal category. These costs are offset by the realignment of new transformer station in-service dates resulting in reduced costs within additional capacity (TS/MS) category.

2014 Comparison – Total Difference = $12,432,000

In 2014 there were minor budget cost revisions across all categories. The Development category had significant adjustments within a number of sub-categories including road authority, subdivisions, growth driven lines projects, and additional capacity (TS/MS). Projects pertaining to York Region Rapid transit (YRRT) were revised based on updated information. This increased road authority by $12.1 M. Subdivisions/Services increased $1.7M reflecting a forecasted increase in growth. These increases were offset partially by a reduction in spending of $3.7 M for growth driven lines projects and $2.1 M in additional capacity for TS/MS. Costs were reduced due to the realignment of new transformer station in-service dates. Within the Sustainment category, the sub-category emerging sustainment was increased to accommodate unexpected replacements of underground cable that have to be replaced immediately to ensure reliability and cannot wait to be replaced in future years. The addition of a $2.4M underground cable replacement project is the reason for the increase within sustainment driven lines projects category.

2015 Comparison – Total Difference = $20,072,000

In 2015 there were minor budget cost revisions across all categories. The Development category had significant adjustments to budgets within a number of sub-categories including road authority, and growth driven lines projects. Updated information on YRRT increased road authority by $5M. Growth driven lines projects increased significantly as a result of an updated schedule for the new Vaughan TS #4 schedule to be in-service in 2016. Phase 1 pole line integrations from the new transformer station are scheduled to be constructed in 2015 at a budget cost of $7.7M. Within the Sustainment category, the sub-category emerging sustainment was increased to accommodate unexpected underground cable replacements similarly to 2014. Transformer / Municipal stations increased to include the $1.8M refurbishment of a municipal station in Aurora originally scheduled for 2013 but deferred into 2015. The IS department increased their budget by $1.0M to reflect the needs of the IS Strategic Plan completed in 2011.

2016 Comparison – Total Difference = $5,051,000

In 2016 there were minor budget cost revisions across all categories. The Development category had major adjustments to the growth driven lines projects and additional capacity (TS/MS) categories. Increase in growth driven projects are due to increased costs for phase 2 pole line integrations from the new Vaughan transformer station #4. Additional capacity (TS/MS) cost increase is due to the realignment of all new transformer/municipal stations. In addition, the sub-category subdivision/services increased as a result of an updated projection of customer growth. Within the Sustainment category, similarly to 2014 and 2015, the emerging sustainment sub-category was increased to accommodate unexpected underground cable replacements. Lastly, the Fleet department reduced the purchase of vehicles by half to $1.5M for the year 2016 in the updated capital plan.

2017 Comparison – NA

Table 7 shows costs and variances from plans prepared in 2012 and 2013. Below are explanations for the comparison. Plans prepared in 2012 covered years 2013– 2017 and plans prepared in 2013 cover years 2014-2018.

Table 7 - 5 YEAR PLAN COMPARISON

SUB CATEGORY	2014 (prepared in 2013)	2014 (prepared in 2012)	2015 (prepared in 2013)	2015 (prepared in 2012)	2016 (prepared in 2013)	2016 (prepared in 2012)	2017 (prepared in 2013)	2017 (prepared in 2012)	2018 (prepared in 2013)
Sustainment									
Emergency/Restoration	10,188,167	10,063,000	10,493,168	10,332,000	10,767,300	10,609,000	10,948,988	10,894,000	11,339,045
Replacement Program	7,019,863	8,430,000	7,193,716	8,447,000	7,370,932	7,378,000	7,599,107	7,446,000	7,735,848
Sustainment Driven Lines Projects	28,458,844	26,294,000	27,616,143	24,180,000	26,531,431	23,806,000	26,821,568	21,389,000	25,893,243
Transformer/Municipal Stations	2,507,952	4,901,000	5,451,492	6,164,000	2,452,970	3,923,000	1,772,759	1,928,000	2,469,158
Emerging Sustainment	1,912,162	2,876,000	1,961,532	2,905,000	2,075,354	2,935,000	2,265,476	2,966,000	1,808,576
Total Sustainment	**50,086,987**	**52,564,000**	**52,716,052**	**52,028,000**	**49,197,987**	**48,651,000**	**49,407,897**	**44,623,000**	**49,245,870**
Development									
Emerging Development	515,925	471,000	567,043	511,000	623,272	554,000	685,124	601,000	753,162
Road Authority Projects	14,068,257	19,555,000	10,081,132	12,258,000	7,668,655	7,111,000	5,295,395	8,425,000	5,855,325
Subdivision/Services	12,011,089	13,120,000	13,018,091	14,660,000	14,054,068	16,340,000	15,128,520	18,140,000	16,260,447
Growth Driven Lines Projects	6,283,543	2,848,000	12,286,843	19,753,000	24,182,622	22,530,000	26,960,485	16,758,000	2,786,593
Additional Capacity (TS/MS)	7,973,317	7,316,000	23,608,707	20,508,000	8,375,816	5,474,000	6,227,946	2,499,000	4,643,670
RGEN-Customer Initiated	0	0	0	0	0	0	0	0	0
Total Development	**40,852,132**	**43,310,000**	**59,561,816**	**67,690,000**	**54,904,433**	**52,009,000**	**54,297,470**	**46,423,000**	**30,299,197**
Operations									
Information/Communication Systems	28,238,990	12,775,000	8,107,237	9,170,000	11,187,725	8,134,000	8,632,270	5,770,000	10,907,520
Fleet	3,103,964	3,296,000	3,973,090	3,456,000	3,286,525	1,524,000	3,398,549	2,492,000	4,101,625
Tools	598,310	518,000	556,130	486,000	506,540	505,000	533,910	552,000	520,800
Purchase of Spare Equipment	38,000	331,000	319,749	30,000	19,000	30,000	19,000	30,000	104,671
Metering	3,192,000	1,967,000	3,282,250	2,077,000	2,885,150	2,047,000	2,497,550	1,977,000	2,805,350
Emerging Operations Capital	71,250	320,000	71,250	320,000	71,250	320,000	47,500	320,000	47,500
Buildings	1,462,763	149,000	883,168	220,000	169,784	171,000	260,015	131,000	76,000
Interest Capitalization	1,335,763	1,807,000	1,393,972	1,150,000	1,266,841	1,040,000	1,254,949	1,018,000	891,139
Total Operations	**38,041,039**	**21,163,000**	**18,586,846**	**16,909,000**	**19,392,815**	**13,771,000**	**16,643,743**	**12,290,000**	**19,454,604**
TOTAL	**128,980,158**	**117,037,000**	**130,864,713**	**136,627,000**	**123,495,236**	**114,431,000**	**120,349,110**	**103,336,000**	**98,999,672**

Note: Ten year plan prepared in 2013 had costs reduced by 5% anticipating a reduction to the Direct Labour Cost burden.

2014 Comparison – Total Difference = + $11,943,158

In 2014 all three main categories saw adjustments to budget cost with operation category having the most significant adjustment. The sustainment category saw a decrease in total spending. Sustainment sub-categories pertaining to lines work saw some reworking and reclassifying of projects as up to date information became available. Sub-category transformer/municipal stations saw a $2.4 M decrease. The Markham TS #2 capacitor bank installation worth $1,105,675 was deferred till 2023 along with other projects such as Lazenby TS storage facility, replacement of legacy RTU and recloser controllers at Morgan MS, transformer temperature monitoring at Aurora MS #1 & #2 and video surveillance at PowerStream north stations and Vaughan TS#3 being deferred till 2015. Development category also saw a total spending decrease with road authority sub-category adjusted to remove $3,000,000 slated for undergrounding of overhead lines and reprioritizing schedules based on better information of time lines. Better information of time lines is also the reason for the decrease in spending for subdivision/services sub-category. The above sub-category costs within development were offset with the increase to growth driven lines projects as better information of time lines for new load becomes available. The operation category saw a significant increase in cost primarily due to the Customer Information System (CIS) underspend from previous years of $10,000,000. Other increase adjustments were in sub-categories metering and buildings. A calculation error of $1,093,905 was noted within metering's budget calculation and the primary reason for the increase to buildings was for a new project to extend parking lot at the Cityview head office and the addition of new projects.

2015 Comparison – Total Difference = - $5,762,287

In 2015 there were budget cost revisions across all categories. The development category had significant decrease in total costs within most sub-categories including road authority, subdivisions, and growth driven lines projects based on better information of time lines and revised loading information. Within the operation category the increase in total cost can be attributed to metering and buildings subcategories. Metering increase in costs was attributed to a calculation error from previous plan caught in current plan. Buildings increase is due to the addition of new projects under new leadership. Information/communication systems saw a decrease primarily due to deferring the Enterprise Asset Management System to year 2016. Sustainment category totals saw minor changes however reduced spending in transformer/municipal stations, emerging sustainment and replacement program sub-categories were offset with the introduction of a new annual project within sustainment driven lines projects to remediate rear lot pole lines at a cost of $3,000,000 plus.

2016 Comparison – Total Difference = + $9,064,236

In 2016 there were budget cost revisions across all categories. The operation category had significant increase adjustments to budgets within a number of sub-categories most notably Information/communication systems primarily due to the Enterprise Asset Management System moved from 2015 in previous plan to 2016 in current plan complete with adjusted increase implementation cost based on up to date information. Fleet reported increase in cost primarily due to up to date information. Metering increase in costs was attributed to a calculation error from previous plan caught in current plan. Emerging operation saw a decrease in anticipating reductions in emerging costs as we continuing to educate project leaders in the budget and planning processes. The development category increase in total cost can be attributed to the re-alignment of projects and cost adjustments which is typically associated with projects in development category due to receiving up to date information of time lines and revised system loading. All work within this category is dependent on others readiness for PowerStream to commence work and load profile of our distribution system. Sustainment category saw minor increase to total cost. Transformer/municipal stations deferred projects to other years while sustainment driven lines increased with the inclusion of a new project to remediate rear lot pole lines.

2017 Comparison – Total Difference = + $17,013,110

In 2017 there were significant budget cost revisions across all categories. The Development category had significant adjustments to the growth driven lines projects and additional capacity (TS/MS) sub-categories reflecting the in-service dates for Harvie Road, Mill Street and Dufferin South municipal stations and pole line integrations for those municipal stations and Vaughan TS#4 which has an expected in-service date of 2016. Subdivisions/services and road authority projects reflect a decrease in spending primarily based on up to date information. Sustainment category saw an increase primarily due to a new project to remediate rear lot pole lines. The operation category had significant increase most notably Information/communication systems primarily due to the Enterprise Content Management System moved from 2016 in previous plan to 2017 in current plan complete with adjusted increase implementation cost based on up to date information. Metering increase in costs was attributed to a calculation error from previous plan caught in current plan. Emerging operation saw a decrease in anticipating reductions in emerging costs as we continuing to educate project leaders in the budget and planning processes.

2018 Comparison – NA

2014 Pole Replacement Candidates

The report from inspection and testing program showing the need to replace 400 poles is attached.

Category 1 (Based on Remaining Strength)

Count	Pole Number	Date of Install	Pole Class	Pole Length (ft.)	Species	Pole Condition	Remaining Strength (%)	Remaining Strenght Score	Number of Primaries Score	Presence of Transformer Score	Pole Condition Score	Criticality of Pole Score	Pole Age Score	Pole Prioritization Score	Location
1	P7771	1974	Class 5	35	Pine	Cracks - Moderate,	30	40	0		30	0	3	73	Penetanguishene
2	P9738	1976	Class 4	40	WC	Cracks - Moderate,	30	40	0		30	0	3	73	Tottenham
3	P9728	1958	Class 5	35	Cedar	Cracks - Moderate,	30	40	0		30	0	5	75	Tottenham
4	P3156	1973	Class 4	55	WC	Cracks - Slight,	30	40	0		30	0	4	74	Barrie
5	P3559	1972	Class 4	40	WC	Cracks - Moderate,	30	40	0		30	0	4	74	Barrie
6	P5206	1948	Class 5	35	JP	Cracks - Moderate,	30	40	0	5	30	0	5	80	Barrie
7	P5205	1955	Class 5	35	JP	Cracks - Moderate,	30	40	0		30	0	5	75	Barrie
8	P7372	1986	3	35	Pine	Carpenter ants	30	40	0	5	30	0	2	77	Penetanguishene
9	P7195	1980	4	40	Pine	Carpenter ants	30	40	2	5	30	3	3	83	Penetanguishene
10	P7093	1985	5	30	Pine	Carpenter ants	30	40	0		30	0	2	72	Penetanguishene
11	P10215	1968	5	35	Pine	Carpenter ants	30	40	2		30	3	4	79	Tottenham
12	P8802	1952	6	35	JP	Cracks - Moderate,	30	40	0		30	0	5	75	Alliston
13	P9855	1978	5	35	JP	Carpenter ants	30	40	0		30	0	3	73	Thornton
14	P9797	1956	5	35	JP	Carpenter ants	30	40	2		30	3	5	80	Thornton
15	P5374	1969	5	35	JP	Carpenter ants	30	40	0		30	0	4	74	Barrie
16	P6812	1995	4	40	Cedar	Carpenter ants	30	40	2	5	30	3	0	80	Penetanguishene
17	P7279	1971	5	35	Cedar	Carpenter ants	30	40	2	5	30	3	4	84	Penetanguishene
18	P8698	1988	4	45	Cedar	Carpenter ants	30	40	2		30	3	2	77	Alliston
19	P8056	1967	5	35	Cedar	Carpenter ants	30	40	2		30	3	4	79	Alliston
20	P12227	1977	4	55	Cedar	Carpenter ants	30	40	6		30	5	3	84	Tottenham
21	P12225	1977	4	55	Cedar	Carpenter ants	30	40	6		30	5	3	84	Tottenham
22	P12222	1977	4	55	Cedar	Carpenter ants	30	40	6		30	5	3	84	Tottenham
23	P9914	1985	4	50	Cedar	Carpenter ants	30	40	6		30	5	2	83	Tottenham
24	P9917	1974	4	50	Cedar	Carpenter ants	30	40	6		30	5	3	84	Tottenham
25	P9736	1967	4	45	Cedar	Carpenter ants	30	40	2		30	3	4	79	Tottenham
26	P9382	1989	3	55	Cedar	Carpenter ants	30	40	6		30	5	2	83	Beaton
27	42	1950	Class 5	35	Western Cedar	Checking	30	40	2	5	20	3	5	75	VAUGHAN
28	3562	1973	Class 3	60	South. Yellow Pine		30	40	6	5		5	4	60	MARKHAM
29	3602	1973	Class 3	60	South. Yellow Pine		30	40	6			5	4	55	MARKHAM
30	3522	1973	Class 3	60	South. Yellow Pine		40	35	6			5	4	50	MARKHAM
31	4	1972	Class 3	40	Western Cedar		40	35	2			3	4	44	RICHMOND HILL
32	85-10	1970	Class 3	45	Western Cedar	Top Decay, Checking	40	35	2		20	3	4	64	VAUGHAN
33	3633	1990	Class 3	55	Western Cedar	Top Decay, Butt Rot,	40	35	6		30	5	2	78	MARKHAM
34	52460	1950	Class 5	40	Jack Pine	Checking	40	35	2		20	3	5	65	VAUGHAN
35	9321-6	1988	Class 3	35	South. Yellow Pin	Insect Infest.	40	35			30		2	67	MARKHAM
36	199-1	1989	Class 3	50	Western Cedar		40	35	6			5	2	48	MARKHAM
37	52461	1950	Class 5	40	Jack Pine	Checking	40	35	2			2	5	44	VAUGHAN
38	50	1959	Class 4	40	Western Cedar	Checking	40	35	2		20	2	5	64	VAUGHAN
39	85-8	1970	Class 3	45	Western Cedar	Top Decay	40	35	2		30	2	4	73	VAUGHAN
40	303	1989	Class 3	50	Western Cedar	Checking	40	35	2		20	2	2	61	RICHMOND HILL
41	p63	1994	Class 3	50	Western Cedar	Checking	40	35	6		20	5	0	66	AURORA
42	53588	1993	Class 2	60	Western Cedar	Bent Pole	40	35	6		30	5	2	78	VAUGHAN
43	29	1981	Class 3	50	Western Cedar	Checking	40	35	2		20	2	3	62	MARKHAM
44	4	1988	Class 3	50	Western Cedar		40	35	2	5		2	2	46	MARKHAM
45	54731-2	1955	Class 5	40	Jack Pine	Checking	40	35					5	40	VAUGHAN
46	6901	1964	Class 4	40	Jack Pine	Top Decay, Checking	40	35	1		20	1	4	61	MARKHAM
47	330	1983	Class 3	50	Western Cedar		40	35	2		30	2	3	72	MARKHAM
48	243	1996	Class 4	40	Western Cedar	Checking	40	35	1	5		1	0	42	RICHMOND HILL
49	641	1985	Class 3	50	Western Cedar	Checking	40	35	4			4	2	45	VAUGHAN
50	26	1989	Class 3	50	Western Cedar		40	35	2			2	2	41	VAUGHAN
51	438	1989	Class 3	45	Western Cedar	Top Decay, Butt Rot,	40	35	4		30	4	2	75	VAUGHAN
52	85-9	1997	Class 3	45	Western Cedar		40	35	2			2	1	40	VAUGHAN
53	484	1989	Class 3	45	Western Cedar	Checking	40	35	1		20	1	2	59	VAUGHAN
54	6912	1983	Class 4	40	Western Cedar		40	35					3	38	MARKHAM
55	452	1989	Class 4	40	Western Cedar	Top Decay, Butt Rot,	40	35	2		20	2	2	61	VAUGHAN
56	6895	1966	Class 4	40	Western Cedar	Checking	40	35	2		20	2	4	63	MARKHAM
57	170	1995	Class 3	50	Western Cedar	Checking	40	35	1	5	20	1	0	62	RICHMOND HILL
58	52	1982	Class 4	45	Western Cedar	Bent Pole, Checking	40	35	1	5	30	1	3	75	RICHMOND HILL
59	58	1988	Class 3	50	Western Cedar	Checking	40	35	2		20	2	2	61	VAUGHAN
60	134	1989	Class 4	50	Western Cedar	Top Decay, Checking	40	35	6		30	5	2	78	RICHMOND HILL
61	21	1988	Class 2	40	South. Yellow Pine		40	35					2	37	MARKHAM
62	240	1989	Class 3	50	Western Cedar	Checking	40	35	2		20	2	2	61	VAUGHAN
63	58	1950	Class 5	35	Jack Pine	Bent Pole, Checking	40	35	2		30	2	5	74	VAUGHAN
64	85-5	1970	Class 3	45	Western Cedar		40	35	2			2	4	43	VAUGHAN
65	324	1983	Class 3	50	Western Cedar	Checking	40	35	2	5	20	2	3	67	MARKHAM
66	113b	1972	Class 3	50	Western Cedar		40	35	6	5		5	4	55	MARKHAM
67	297	1996	Class 4	40	Western Cedar	Checking	40	35	1	5	20	1	0	62	RICHMOND HILL
68	224	1979	Class 4	40	Western Cedar	Checking	40	35	1		20	1	3	60	VAUGHAN
69	85-12	1970	Class 3	45	Western Cedar		40	35	2			2	4	43	VAUGHAN
70	22	1972	Class 3	40	Western Cedar	Checking	40	35	1	5		1	3	45	RICHMOND HILL
71	p50	1980	Class 4	40	Western Cedar	Checking	40	35	2		20	2	3	62	AURORA
72	47	1936	Class 5	30	Jack Pine	Checking	40	35	2		20	2	5	64	VAUGHAN
73	336	1983	Class 3	50	Western Cedar		40	35	2		20	2	3	62	MARKHAM
74	62	1936	Class 5	35	Jack Pine		40	35	2			2	5	44	VAUGHAN
75	57	1950	Class 5	35	Jack Pine		40	35	2	5	30	2	5	79	VAUGHAN
76	32	1982	Class 4	40	Western Cedar	Bent Pole, Checking	40	35	1	5	30	1	3	75	RICHMOND HILL
77	327	1989	Class 4	50	Western Cedar	Bent Pole, Checking,	40	35	6		20	5	2	68	RICHMOND HILL
78	23	1982	Class 4	40	Western Cedar	Checking	40	35	1	5	20	1	3	65	RICHMOND HILL
79	24	1982	Class 4	45	Western Cedar	Checking	40	35	1		20	1	3	60	RICHMOND HILL
80	45	1989	Class 4	40	Western Cedar	Checking	40	35	2		20	2	2	61	MARKHAM
81	482	1989	Class 3	45	Western Cedar	Checking	40	35	1		20	1	2	59	VAUGHAN
82	20	1998	Class 3	55	Western Cedar	Checking	40	35	6		20	5	0	66	VAUGHAN
83	40	1985	Class 3	55	Western Cedar	Checking	40	35	2		20	2	2	61	VAUGHAN
84	434	1989	Class 3	40	Western Cedar	Top Decay, Checking	40	35	2		20	2	2	61	VAUGHAN
85	p39	1986	Class 3	55	Western Cedar	Checking	40	35	6	5	20	5	2	73	AURORA
86	50A	1988	Class 3	50	Western Cedar	Checking	40	35	2		20	2	2	61	VAUGHAN
87	440	1989	Class 3	45	Western Cedar		40	35	2			2	2	41	VAUGHAN
88	52244	1989	Class 3	40	Western Cedar	Checking	40	35	1		20	1	2	59	VAUGHAN
89	85-7	1970	Class 3	45	Western Cedar		40	35	2			2	4	43	VAUGHAN
90	20	1979	Class 4	40	Western Cedar		40	35	1			1	3	40	VAUGHAN
91	46	1959	Class 4	40	Western Cedar	Checking	40	35	1		20	1	5	62	VAUGHAN
92	459	1989	Class 4	40	Western Cedar	Checking	40	35	4		20	4	2	65	VAUGHAN
93	75	1950	Class 5	35	Western Cedar	Checking	40	35	2		20	2	5	64	VAUGHAN
94	52241-1	1980	Class 4	40	Western Cedar	Top Decay, Loose	40	35	1	5	30	1	3	75	VAUGHAN
95	11	1957	Class 4	35	Red Pine		40	35	1			1	5	42	VAUGHAN
96	436	1989	Class 3	45	Western Cedar	Top Decay, Checking	40	35	2		30	2	2	71	VAUGHAN
97	85-13	1997	Class 3	45	Western Cedar	Checking	40	35	2		20	2	16	75	VAUGHAN
98	63	1982	Class 3	50	Western Cedar	Top Decay, Checking	40	35	2	5	30	2	3	77	VAUGHAN
99	60	1950	Class 5	45	Jack Pine		40	35	2			2	5	44	VAUGHAN
100	76	1992	Class 4	40	Western Cedar		40	35	2			2	2	41	RICHMOND HILL
101	432	1989	Class 3	40	Western Cedar	Top Decay, Checking	40	35	2		30	2	2	71	VAUGHAN
102	18	1979	Class 4	40	Western Cedar		40	35	1			1	3	40	VAUGHAN
103	p49	1980	Class 5	30	Western Cedar	Checking	40	35			20		3	58	AURORA
104	43	1982	Class 4	35	Western Cedar		40	35					3	38	RICHMOND HILL
105	11	1996	Class 4	35	Western Cedar	Checking	40	35			20		0	35	RICHMOND HILL
106	103	1987	Class 3	55	Western Cedar	Checking	40	35	2	5	20	2	2	46	VAUGHAN
107	272	1992	Class 4	45	Western Cedar	Checking	40	35	2		20	2	2	41	RICHMOND HILL
108	P8082	1984	4	40	Pine	Cracks - Slight, Pole	48	35	2		30	2	2	71	Alliston
109	p52	1989	Class 3	50	Western Cedar	Checking	48	35	6		20	5	2	68	AURORA
110	4157	1988	Class 2	65	South. Yellow Pine		49	35	6			5	2	48	MARKHAM
111	6918	1964	Class 4	40	Western Cedar	Top Decay, Checking	49	35	1		30	1	4	71	MARKHAM
112	11	1988	Class 3	50	Western Cedar		49	35	6			5	2	48	MARKHAM
113	3502	1989	Class 3	55	South. Yellow Pine		50	35	6			5	2	48	MARKHAM
114	8820	1987	Class 2	60	South. Yellow Pine		50	35	6			5	2	48	MARKHAM
115	4778	1987	Class 3	55	South. Yellow Pine		50	35	6			5	2	48	MARKHAM
116	551	1949	Class 4	40	Douglas Fir		50	35	2			2	5	44	VAUGHAN
117	p35	1982	Class 3	40	South. Yellow Pin	Checking	50	35	2		20	2	3	62	AURORA
118	1401-2	1988	Class 3	50	Western Cedar	Checking	50	35	6		20	5	2	68	RICHMOND HILL
119	82	1992	Class 2	40	South. Yellow Pine		50	35	1			1	2	39	MARKHAM
120	4882	1987	Class 3	55	South. Yellow Pine		51	35	6			5	2	48	MARKHAM
121	851	1989	Class 3	55	Western Cedar		51	35	2			2	2	41	VAUGHAN
122	8706	1987	Class 2	60	South. Yellow Pine		51	35	6			5	2	48	MARKHAM
123	28	1992	Class 4	45	South. Yellow Pine		51	35					2	37	MARKHAM
124	152-1	1992	Class 2	40	South. Yellow Pine		51	35	1			1	2	39	MARKHAM
125	126	1994	Class 3	55	Western Cedar	Checking	52	35	2		20	2	0	59	MARKHAM
126	4884	1987	Class 3	55	South. Yellow Pine		52	35	6			5	2	48	MARKHAM
127	52512	1950	Class 5	45	Jack Pine	Checking	52	35	1		20	1	5	62	VAUGHAN
128	85-6	1970	Class 3	45	Western Cedar		52	35	2			2	4	43	VAUGHAN
129	241	1984	Class 2	60	Jack Pine		52	35	6			5	2	48	VAUGHAN
130	3b	1974	Class 5	35	Douglas Fir		52	35	1			1	3	40	VAUGHAN
131	107a	1985	Class 2	50	Western Cedar	Checking	52	35	6		20	5	2	68	VAUGHAN
132	208	1989	Class 3	45	Western Cedar		52	35	1			1	2	39	RICHMOND HILL
133	164	1995	Class 3	50	Western Cedar		52	35	1			1	0	37	RICHMOND HILL
134	38	1979	Class 3	50	Western Cedar		52	35	2			2	3	42	VAUGHAN
135	432	1983	Class 3	50	Western Cedar		52	35	2			2	3	42	MARKHAM
136	4100	1987	Class 3	55	South. Yellow Pine		52	35	6			5	2	48	MARKHAM
137	146	1992	Class 2	40	South. Yellow Pine		52	35	1			1	2	39	MARKHAM

138	9848-4	1979	Class 4	45	South. Yellow Pine		52	35					3	38	MARKHAM
139	p29	1986	Class 3	45	Western Cedar	Checking	53	35	1		20	1	2	59	AURORA
140	4862	1987	Class 3	55	South. Yellow Pine		53	35	6			5	2	48	MARKHAM
141	72-1	1992	Class 2	40	South. Yellow Pine		53	35	1			1	2	39	MARKHAM
142	6894	1966	Class 4	40	Western Cedar	Top Decay, Checking	53	35	1		30	1	4	71	MARKHAM
143	488	1989	Class 4	40	Western Cedar	Checking	53	35	1		20	1	2	59	VAUGHAN
144	p9	1985	Class 3	50	South. Yellow Pin	Checking	53	35	2		20	2	2	61	AURORA
145	p39	1984	Class 3	55	Western Cedar	Checking	53	35	6		20	5	2	68	AURORA
146	p61	1994	Class 5	35	Western Cedar	Checking	53	35			20		0	55	AURORA
147	148	1989	Class 3	40	Western Cedar		53	35	1			1	2	39	RICHMOND HILL
148	303	1996	Class 4	40	Western Cedar	Checking	53	35	1		20	1	0	57	RICHMOND HILL
149	53e	1998	Class 2	50	Western Cedar	Checking	53	35	6	5	20	5	0	71	MARKHAM
150	2904	1988	Class 2	50	Western Cedar	Checking	53	35	2		20	2	2	61	MARKHAM
151	1727	1988	Class 2	40	South. Yellow Pine		53	35	6			5	2	48	MARKHAM
152	8766	1988	Class 2	40	South. Yellow Pine		53	35	6			5	2	48	MARKHAM
153	89	1988	Class 2	65	South. Yellow Pine		53	35	6			5	2	48	MARKHAM
154	62-1	1988	Class 2	45	South. Yellow Pine		53	35					2	37	MARKHAM
155	30	1992	Class 4	45	South. Yellow Pine		53	35					2	37	MARKHAM
156	25	1992	Class 4	45	South. Yellow Pine		53	35					2	37	MARKHAM
157	113	1988	Class 2	65	South. Yellow Pine		53	35	6			5	2	48	MARKHAM
158	89	1988	Class 2	65	South. Yellow Pine		53	35	6			5	2	48	MARKHAM
159	5803	1988	Class 2	65	South. Yellow Pine		53	35	6			5	2	48	MARKHAM
160	15	1992	Class 2	40	South. Yellow Pine		53	35	1			1	2	39	MARKHAM
161	11	1992	Class 4	40	South. Yellow Pine		53	35	1			1	2	39	MARKHAM
162	124	1985	Class 3	45	South. Yellow Pine		53	35	2			2	2	41	MARKHAM
163	P9148	1983	4	40	Pine	Cracks - Slight, Pole	54	35	2		30	2	3	72	Alliston
164	21	1981	Class 3	50	Western Cedar	Checking	54	35	2		20	2	3	62	MARKHAM
165	7751	1994	Class 3	50	Western Cedar		54	35	6			5	0	46	MARKHAM
166	4732	1987	Class 3	55	South. Yellow Pine		54	35	6			5	2	48	MARKHAM
167	4882-1	1987	Class 3	55	South. Yellow Pine		54	35	6			5	2	48	MARKHAM
168	4888	1987	Class 3	55	South. Yellow Pine		54	35	6			5	2	48	MARKHAM
169	152	1992	Class 2	40	South. Yellow Pine		54	35	1			1	2	39	MARKHAM
170	630	1998	Class 2	60	Western Cedar	Checking	54	35	2		20	2	0	59	VAUGHAN
171	99	1982	Class 3	45	Western Cedar		54	35	2			2	3	42	RICHMOND HILL
172	79	1982	Class 3	45	Western Cedar		54	35	2			2	3	42	RICHMOND HILL
173	9321-3	1988	Class 3	50	South. Yellow Pin	Insect Infest.	54	35			30		2	67	MARKHAM
174	12	1988	Class 2	40	South. Yellow Pine		54	35	1			1	2	39	MARKHAM
175	9402-7	1989	Class 4	40	South. Yellow Pine		54	35					2	37	MARKHAM
176	31	1988	Class 3	50	Western Cedar		54	35	6			5	2	48	MARKHAM
177	62-1	1992	Class 2	40	South. Yellow Pine		54	35	1			1	2	39	MARKHAM
178	112-1	1992	Class 2	40	South. Yellow Pine		54	35	1			1	2	39	MARKHAM
179	100	1990	Class 3	50	Western Cedar		55	35	6			5	2	48	MARKHAM
180	8842	1987	Class 2	60	South. Yellow Pine		55	35	6			5	2	48	MARKHAM
181	219a	1972	Class 5	35	Jack Pine	Checking	55	35			20		4	59	VAUGHAN
182	553	1949	Class 4	40	Douglas Fir	Checking	55	35	2		20	2	6	65	VAUGHAN
183	42	1988	Class 3	50	Western Cedar	Checking	55	35	2		20	2	2	61	VAUGHAN
184	p50	1991	Class 3	50	Western Cedar		55	35	2			2	2	41	AURORA
185	31	1982	Class 3	45	Western Cedar		55	35	2			2	3	42	RICHMOND HILL
186	8582	1987	Class 2	60	South. Yellow Pine		55	35	6			5	2	48	MARKHAM
187	17	1992	Class 4	45	South. Yellow Pine		55	35	1			1	2	39	MARKHAM
188	32-1	1992	Class 2	40	South. Yellow Pine		55	35	1			1	2	39	MARKHAM
189	142	1995	Class 3	50	Western Cedar	Checking	56	35	1		20	1	18	75	RICHMOND HILL
190	7720	1996	Class 2	60	Western Cedar		56	35					0	35	MARKHAM
191	8860	1987	Class 2	60	South. Yellow Pine		56	35	6			5	2	48	MARKHAM
192	3	1988	Class 3	50	Western Cedar		56	35	6			5	2	48	MARKHAM
193	85-11	1970	Class 3	45	Western Cedar	Checking	56	35	2		20	2	4	63	VAUGHAN
194	p9	1990	Class 3	45	Western Cedar		56	35	2			2	2	41	AURORA
195	234	1979	Class 4	40	Western Cedar		56	35	1			1	3	40	VAUGHAN
196	104	1994	Class 3	55	Western Cedar		56	35	2			2	0	39	MARKHAM
197	9542	1985	Class 2	50	South. Yellow Pine		56	35	2			2	2	41	MARKHAM
198	3	1992	Class 4	40	South. Yellow Pine		56	35	1			1	2	39	MARKHAM
199	467	1987	Class 4	40	South. Yellow Pine		56	35	1			1	2	39	VAUGHAN
200	241b	1979	Class 4	35	Western Cedar	Checking	57	35			20		3	58	VAUGHAN
201	8384	1988	Class 2	60	South. Yellow Pine		57	35	6			5	2	48	MARKHAM
202	9849	1977	Class 4	45	Western Cedar		57	35	2			2	3	42	MARKHAM
203	5050	1987	Class 3	55	South. Yellow Pine		57	35	2			2	2	41	MARKHAM
204	40	1992	Class 2	40	South. Yellow Pine		57	35	1			1	2	39	MARKHAM
205	52492	1950	Class 3	40	Jack Pine		57	35	1			1	5	42	VAUGHAN
206	79	1950	Class 6	30	Jack Pine	Checking	57	35	2		20	2	5	64	VAUGHAN
207	p63	1989	Class 3	60	Western Cedar	Checking	57	35	6		20	5	2	68	AURORA
208	111	1990	Class 4	35	Western Cedar		57	35					2	37	RICHMOND HILL
209	64	1982	Class 3	55	Western Cedar	Checking	57	35	6		20	5	3	69	VAUGHAN
210	77	1982	Class 2	45	Western Cedar		57	35	2			2	3	42	RICHMOND HILL
211	80	1992	Class 4	40	Western Cedar	Checking	57	35	1		20	1	2	59	RICHMOND HILL
212	147	1988	Class 4	50	Western Cedar		57	35	2			2	2	41	MARKHAM
213	8728	1988	Class 2	40	South. Yellow Pine		57	35	6			5	2	48	MARKHAM
214	199	1990	Class 3	50	Western Cedar		57	35	2			2	2	41	MARKHAM
215	138	1992	Class 2	40	South. Yellow Pine		57	35	1			1	2	39	MARKHAM
216	6884	1962	Class 4	40	Jack Pine	Checking	57	35	1		20	1	5	62	MARKHAM
217	p78	1984	Class 3	45	Lodgepole Pine	Checking	57	35	2		20	2	2	61	RICHMOND HILL
218	350	1983	Class 3	50	Western Cedar	Checking	58	35	2		20	2	3	62	MARKHAM
219	179	1988	Class 3	50	Western Cedar	Checking	58	35	2		20	2	2	61	MARKHAM
220	56219	1970	Class 3	45	Western Cedar	Checking	58	35	2		20	2	4	63	VAUGHAN
221	659	1956	Class 4	40	Jack Pine	Checking	58	35	2		20	2	5	64	VAUGHAN
222	702	1959	Class 4	40	Western Cedar		58	35	1			1	5	42	VAUGHAN
223	p51	1989	Class 4	50	South. Yellow Pine		58	35	2			2	2	41	AURORA
224	192	1989	Class 3	45	Western Cedar		58	35	1			1	2	39	RICHMOND HILL
225	351	1989	Class 4	50	Western Cedar	Checking	58	35	6		20	5	2	68	RICHMOND HILL
226	44	1959	Class 4	40	Western Cedar		58	35	1			1	5	42	VAUGHAN
227	8138-2	1978	Class 3	60	Western Cedar	Checking	58	35	2		20	2	3	62	VAUGHAN
228	54	1990	Class 3	50	Western Cedar		58	35	6			5	2	48	MARKHAM
229	366	1983	Class 3	50	Western Cedar	Checking	58	35	2		20	2	3	62	MARKHAM
230	8744	1987	Class 2	60	South. Yellow Pine		58	35	6			5	2	48	MARKHAM
231	6892	1966	Class 4	40	Western Cedar	Top Decay, Checking	58	35	1		30	1	4	71	MARKHAM
232	223	1987	Class 5	30	Red Pine		58	35					2	37	VAUGHAN
233	8992	1988	Class 2	40	South. Yellow Pine		58	35	6			5	2	48	MARKHAM
234	75	1989	Class 3	50	Western Cedar	Checking	59	35	6		20	5	2	68	MARKHAM
235	p66	1992	Class 3	50	Western Cedar	Checking	59	35	6		20	5	2	68	AURORA
236	p64	1986	Class 3	50	Western Cedar		59	35	6			5	2	48	AURORA
237	310	1983	Class 3	50	Western Cedar	Checking	59	35	2		20	2	3	62	MARKHAM
238	320	1983	Class 3	50	Western Cedar	Checking	59	35	2		20	2	3	62	MARKHAM
239	9323-7	1989	Class 3	35	South. Yellow Pin	Insect Infest.	59	35			30		2	67	MARKHAM
240	9402-14	1989	Class 4	40	South. Yellow Pine		59	35	1			1	2	39	MARKHAM
241	11	1988	Class 2	40	South. Yellow Pine		59	35					2	37	MARKHAM
242	169	1989	Class 3	45	Western Cedar		59	35	2			2	2	41	VAUGHAN
243	311-1	1966	Class 3	40	Western Cedar	Loose Hardwre	59	35			20		4	59	VAUGHAN
244	749	1974	Class 5	40	Douglas Fir		59	35	1			1	3	40	VAUGHAN
245	555	1949	Class 4	40	Douglas Fir	Checking	59	35	2		20	2	5	64	VAUGHAN
246	276	1998	Class 3	50	Western Cedar	Checking	59	35			20		0	55	VAUGHAN
247	29	1973	Class 3	50	Western Cedar	Checking	59	35	2		20	2	4	63	VAUGHAN
248	p31	1986	Class 3	50	Western Cedar		59	35	6			5	2	48	AURORA
249	215	1988	Class 3	50	Western Cedar	Checking	59	35	2		20	2	2	61	MARKHAM
250	40	1992	Class 4	40	South. Yellow Pine		59	35					2	37	MARKHAM
251	463	1986	Class 4	40	South. Yellow Pin	Checking	59	35	1		20	1	2	59	VAUGHAN
252	451	1987	Class 4	40	South. Yellow Pin	Checking	59	35	1		20	1	2	59	VAUGHAN
253	9323-10	1989	Class 3	35	South. Yellow Pin	Insect Infest.	59	35			30		2	67	MARKHAM
254	4	1992	Class 4	45	South. Yellow Pine		59	35					2	37	MARKHAM
255	5224-1	1988	Class 2	55	South. Yellow Pine		59	35	2			2	2	41	MARKHAM
256	2	1988	Class 3	50	Western Cedar		60	35	2			2	2	41	MARKHAM

Category 2 (Based on Pole Condition and Priortization Score)

Count	Pole Number	Date of Install	Pole Class	Pole Length (ft.)	Species	Pole Condition	Remaining Strength (%)	Remaining Strength Score	Number of Primaries Score	Presence of Transformer Score	Pole Condition Score	Criticality of Pole Score	Pole Age Score	Pole Prioritization Score	Location
1	24	1957	Class 4	40	Western	Top Decay, Bent Pole, Split Top, Checking,	74		6	5	30	5	5	51	VAUGHAN
2	P9190	1960	5	40	Cedar	Carpenter ants damage - Slight, Cracks -	67	5	2	5	30	3	5	50	Alliston
3	P9177	1950	5	35	Cedar	Carpenter ants damage - Slight, Cracks -	68	5	2	5	30	3	5	50	Alliston
4	P9786	1967	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	79		6	5	30	5	4	50	Thornton
5	P7112	1969	4	55	Cedar	Cracks - Slight, Pole top feathering/split/rot -	82		6	5	30	5	4	50	Penetang
6	P9617	1974	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	76		6	5	30	5	3	49	Tottenham
7	P7709	1974	4	55	Cedar	Cracks - Slight, Pole top feathering/split/rot -	83		6	5	30	5	3	49	Penetang
8	P9906	1974	4	50	Cedar	Cracks - Slight, Pole top feathering/split/rot -	76		10		30	5	3	48	Tottenham
9	P7061	1974	4	50	Cedar	Cracks - Slight, Pole top feathering/split/rot -	77		10		30	5	3	48	Penetang
10	P10962	1977	4	55	SP	Cracks - Slight, Pole top feathering/split/rot -	79		10		30	5	3	48	Bradford
11	8872	1980	Class 3	65	Western	Top Decay, Bent Pole, Checking	85		10		30	5	3	48	VAUGHAN
12	370	1988	Class 3	50	Western	Fire Damage, Split Top, Insect Infest.	62	5	2	5	30	3	2	47	MARKHAM
13	P7513	1965	3	45	Cedar	Carpenter ants damage - Slight, Cracks -	75		8		30	5	4	47	Penetang
14	P6963	1970	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	78		8		30	5	4	47	Penetang
15	P7512	1965	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	78		8		30	5	4	47	Penetang
16	P7509	1965	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	79		8		30	5	4	47	Penetang
17	P7508	1965	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	81		8		30	5	4	47	Penetang
18	P7516	1964	3	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	81		8		30	5	4	47	Penetang
19	P7510	1965	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	82		8		30	5	4	47	Penetang
20	P7514	1965	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	84		8		30	5	4	47	Penetang
21	p33	1956	Class 4	40	Western	Checking	62	5	6	5	20	5	5	46	VAUGHAN
22	92	1961	Class 3	50	Western		68	5	6	5	20	5	5	46	MARKHAM
23	P7048	1975	4	50	Cedar	Cracks - Slight, Pole top feathering/split/rot -	76		8		30	5	3	46	Penetang
24	P7045	1974	4	50	Cedar	Cracks - Slight, Pole top feathering/split/rot -	78		8		30	5	3	46	Penetang
25	P10972	1977	4	55	SP	Cracks - Slight, Pole top feathering/split/rot -	79		8		30	5	3	46	Bradford
26	P9904	1974	4	50	Cedar	Cracks - Slight, Pole top feathering/split/rot -	81		8		30	5	3	46	Tottenham
27	2	1950	Class 5	40	Western	Top Decay, Split Top, Checking	71		2	5	30	3	5	45	VAUGHAN
28	82	1950	Class 6	30	Jack Pine	Split Top, Checking	71		2	5	30	3	5	45	VAUGHAN
29	P4994	1969	4	40	Cedar	Cracks - Slight, Pole top feathering/split/rot -	75		6		30	5	4	45	Barrie
30	3677	1990	Class 3	55	Western	Butt Rot, Bent Pole	76		8		30	5	2	45	MARKHAM
31	P4996	1969	4	50	Cedar	Cracks - Slight, Pole top feathering/split/rot -	78		6		30	5	4	45	Barrie
32	P3374	1963	4	40	Pine	Cracks - Slight, Pole top feathering/split/rot -	78		2	5	30	3	5	45	Barrie
33	P7060	1971	3	45	SP	Cracks - Slight, Pole top feathering/split/rot -	79		6		30	5	4	45	Penetang
34	3699	1990	Class 3	55	Western	Top Decay, Butt Rot, Bent Pole	79		8		30	5	2	45	MARKHAM
35	69	1936	Class 5	35	Western	Top Decay	82		2	5	30	3	5	45	VAUGHAN
36	71	1952	Class 5	35	Western	Top Decay, Split Top, Checking	83		2	5	30	3	5	45	VAUGHAN
37	P8882	1969	5	40	Cedar	Carpenter ants damage - Slight, Cracks -	68	5	2		30	3	4	44	Alliston
38	P6726	1969	5	40	Cedar	Carpenter ants damage - Slight, Crack to GL,	70		2	5	30	3	4	44	Penetang
39	P6724	1969	5	35	Cedar	Carpenter ants damage - Slight, Cracks -	73		2	5	30	3	4	44	Penetang
40	P7589	1970	4	40	Cedar	Carpenter ants damage - Slight, Cracks -	74		2	5	30	3	4	44	Penetang
41	P9792	1964	4	45	Cedar	Carpenter ants damage - Slight, Cracks -	75		2	5	30	3	4	44	Thornton
42	P10417	1969	6	40	Cedar	Cracks - Slight, Pole top feathering/split/rot -	76		2	5	30	3	4	44	Bradford
43	P9185	1967	5	35	Cedar	Cracks - Slight, Crossarm rot - Moderate,	76		2	5	30	3	4	44	Alliston
44	P10677	1969	4	40	Cedar	Cracks - Slight, Pole top feathering/split/rot -	77		2	5	30	3	4	44	Bradford
45	P7214	1972	5	35	Cedar	Cracks - Slight, Pole top feathering/split/rot -	78		2	5	30	3	4	44	Penetang
46	P2425	1969	4	45	Pine	Cracks - Slight, Pole top feathering/split/rot -	79		2	5	30	3	4	44	Barrie
47	P9625	1976	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	79		6		30	5	3	44	Tottenham
48	P6722	1969	5	35	Cedar	Cracks - Slight, Pole top feathering/split/rot -	80		2	5	30	3	4	44	Penetang
49	P2446	1968	3	45	Pine	Cracks - Slight, Crossarm rot - Slight, Pole	81		2	5	30	3	4	44	Barrie
50	P10653	1969	4	40	Cedar	Cracks - Slight, Pole top feathering/split/rot -	82		2	5	30	3	4	44	Bradford
51	P7360	1972	4	35	Pine	Cracks - Slight, Crossarm rot - Slight, Pole	86		2	5	30	3	4	44	Penetang
52	P10131	1974	4	40	Cedar	Carpenter ants damage - Slight, Cracks -	69	5	0	5	30	0	3	43	Tottenham
53	5902	1988	Class 3	50	Western	Butt Rot, Insect Infest.	72		6		30	5	2	43	MARKHAM
54	9266	1987	Class 3	60	Western	Butt Rot, Bent Pole	74		6		30	5	2	43	MARKHAM
55	P10489	1974	5	40	Cedar	Crack to GL, Pole top feathering/split/rot -	76		2	5	30	3	3	43	Bradford
56	327	1989	Class 4	50	Western	Bent Pole, Checking, Insect Infest.	76		6		30	5	2	43	RICHMOND
57	P10227	1974	4	40	Cedar	Cracks - Slight, Pole top feathering/split/rot -	77		2	5	30	3	3	43	Tottenham
58	P10954	1974	5	40	Cedar	Cracks - Slight, Pole top feathering/split/rot -	79		2	5	30	3	3	43	Bradford
59	8178	1988	Class 3	60	Western	Butt Rot, Loose Hardwre, Insect Infest.	98		6		30	5	2	43	MARKHAM
60	20f	1978	Class 3	30	Red Pine	Bent Pole, Checking, Insect Infest.	N/A		2	5	30	3	3	43	VAUGHAN
61	9846	1988	Class 3	45	Western	Butt Rot, Bent Pole	68	5	2		30	3	2	42	MARKHAM
62	438	1989	Class 3	45	Western	Top Decay, Butt Rot, Checking	69	5	2		30	3	2	42	VAUGHAN
63	20	1989	Class 3	45	Western	Butt Rot, Bent Pole	76		2	5	30	3	2	42	MARKHAM
64	P7196	1970	5	30	Cedar	Cracks - Slight, Crossarm rot - Slight, Pole	77		2		30	5	4	41	Penetang
65	52478-1	1950	Class 5	30	Jack Pine	Butt Rot	64	5	0		30	0	5	40	VAUGHAN
66	224	1955	Class 3	45	Western	Top Decay, Butt Rot, Bent Pole	67	5	0		30	0	5	40	MARKHAM
67	6903-1	1960	Class 4	30	Western	Top Decay, Butt Rot, Checking	67	5	0		30	0	5	40	MARKHAM
68	P8520	1960	6	30	Cedar	Carpenter ants damage - Slight, Crack to GL,	67	5	0		30	0	5	40	Alliston
69	P3345	1960	7	30	Cedar	Cracks - Slight, Pole top feathering/split/rot -	67	5	0		30	0	5	40	Barrie
70	6911	1960	Class 4	40	Jack Pine	Top Decay, Butt Rot, Checking	68	5	0		30	0	5	40	MARKHAM
71	P10521	1961	5	35	Cedar	Crack to GL, Pole top feathering/split/rot -	69	5	0		30	0	5	40	Bradford
72	30	1950	Class 5	35	Western	Top Decay, Split Top, Checking	69	5	0		30	0	5	40	VAUGHAN
73	58	1950	Class 5	35	Jack Pine	Bent Pole, Checking	72		2		30	3	5	40	VAUGHAN
74	77	1950	Class 4	40	Western	Checking, Insect Infest.	73		2		30	3	5	40	VAUGHAN
75	P10514	1961	6	30	Cedar	Cracks - Slight, Pole top feathering/split/rot -	75		0	5	30	0	5	40	Bradford
76	84	1950	Class 6	30	Jack Pine	Split Top, Checking	75		2		30	3	5	40	VAUGHAN
77	89	1950	Class 6	30	Jack Pine	Split Top, Checking	75		2		30	3	5	40	VAUGHAN
78	P10511	1961	5	35	Cedar	Cracks - Slight, Pole top feathering/split/rot -	76		0	5	30	0	5	40	Bradford
79	96	1950	Class 5	30	Jack Pine	Top Decay, Bent Pole, Checking	77		2		30	3	5	40	VAUGHAN
80	88	1950	Class 6	30	Jack Pine	Top Decay, Split Top, Checking	78		2		30	3	5	40	VAUGHAN
81	97	1950	Class 5	30	Jack Pine	Top Decay, Bent Pole	78		2		30	3	5	40	VAUGHAN
82	P4770	1959	4	40	Pine	Cracks - Slight, Pole top feathering/split/rot -	78		0	5	30	0	5	40	Barrie
83	P3474	1960	Class 5	35	Pine	Cracks - Moderate, Crossarm rot - Slight,	80		0	5	30	0	5	40	Barrie
84	P5386	1960	Class 5	35	Pine	Cracks - Slight, Pole top feathering - Slight,	81		0	5	30	0	5	40	Barrie
85	P1598	1960	Class 4	40	Pine	Cracks - Slight, Crossarm rot - Slight, Pole	88		0	5	30	0	5	40	Barrie
86	P863	1963	Class 4	45	Pine	Crack to GL, Surface Rot below GL - Moderate	98		6		30	5	5	40	Barrie
87	P2944	1949	Class 5	35	JP	Crack to GL, Pole top feathering - Slight,	108		0	5	30	0	5	40	Barrie
88	P10416	1969	5	35	Cedar	Crack to GL, Pole top feathering/split/rot -	74		2		30	3	4	39	Bradford
89	P10708	1968	4	40	Cedar	Crack to GL, Crossarm rot - Slight, Pole top	76		2		30	3	4	39	Bradford
90	P10679	1968	4	35	Cedar	Cracks - Slight, Crossarm rot - Slight, Pole	78		2		30	3	4	39	Bradford
91	P7545	1972	4	35	Cedar	Cracks - Slight, Crossarm rot - Slight, Pole	80		2		30	3	4	39	Penetang
92	P7205	1971	5	35	Cedar	Cracks - Slight, Pole top feathering/split/rot -	80		2		30	3	4	39	Penetang
93	P6959	1970	4	40	Cedar	Cracks - Slight, Pole top feathering/split/rot -	81		2		30	3	4	39	Penetang
94	6	1988	Class 2	55	Western	Checking	61	5	6		20	5	2	38	VAUGHAN
95	737-2	1983	Class 3	55	Western	Top Decay, Split Top, Loose Hardwre,	63	5	0		30	0	3	38	VAUGHAN
96	P10956	1974	4	40	Cedar	Crack to GL, Pole top feathering/split/rot -	75		2		30	3	3	38	Bradford
97	P10953	1974	5	40	Cedar	Cracks - Slight, Crossarm rot - Slight, Pole	76		2		30	3	3	38	Bradford
98	P10676	1974	4	40	Cedar	Cracks - Slight, Pole top feathering/split/rot -	76		2		30	3	3	38	Bradford
99	P9745	1974	4	45	Cedar	Cracks - Slight, Pole top feathering/split/rot -	79		2		30	3	3	38	Tottenham
100	P5094	1977	4	40	Pine	Cracks - Slight, Pole top feathering/split/rot -	80		2		30	3	3	38	Barrie
101	59	1982	Class 3	50	Western	Top Decay, Bent Pole, Checking	92		2		30	3	3	38	VAUGHAN
102	53	1936	Class 5	35	Jack Pine		67	5	2		20	5	5	37	VAUGHAN
103	452	1989	Class 4	40	Western	Top Decay, Butt Rot, Checking	70		2		30	3	2	37	VAUGHAN
104	469	1989	Class 4	40	Western	Top Decay, Butt Rot, Checking	77		2		30	3	2	37	VAUGHAN
105	754	1989	Class 3	55	Western	Carpenter Ants, Checking, Insect Infest.	82		2		30	3	2	37	VAUGHAN
106	448	1986	Class 5	40	Western	Top Decay, Butt Rot, Checking, Insect Infest.	87		2		30	3	2	37	VAUGHAN
107	242	1989	Class 3	60	Western	Bent Pole, Checking, Insect Infest.	101		2		30	3	2	37	VAUGHAN
108	49	1936	Class 5	30	Jack Pine	Checking	61	5	2		20	3	5	35	VAUGHAN
109	58477	1950	Class 5	35	Jack Pine	Top Decay, Split Top, Checking	72		0		30	0	5	35	VAUGHAN
110	52478	1950	Class 3	40	Jack Pine	Split Top	72		0		30	0	5	35	VAUGHAN
111	41	1952	Class 5	40	Western	Top Decay, Split Top, Checking	73		0		30	0	5	35	VAUGHAN
112	171-1	1959	Class 3	40	Western	Top Decay, Bent Pole	74		0		30	0	5	35	VAUGHAN
113	60-1	1950	Class 5	35	Jack Pine	Top Decay, Split Top, Checking	75		0		30	0	5	35	VAUGHAN
114	647	1950	Class 6	30	Jack Pine	Split Top, Checking	75		0		30	0	5	35	VAUGHAN
115	222	1994	Class 3	50	Western	Butt Rot, Loose Hardwre, Insect Infest.	77		2		30	3	0	35	MARKHAM
116	54731-1	1955	Class 5	40	Jack Pine	Fire Damage, Split Top	80		0		30	0	5	35	VAUGHAN
117	76	1950	Class 5	35	Western	Top Decay, Checking	80		0		30	0	5	35	VAUGHAN
118	66	1936	Class 5	35	Western	Insect Infest.	81		2		25	3	5	35	VAUGHAN
119	53124-2	1946	Class 5	35	Western	Top Decay, Split Top	82		0		30	0	5	35	VAUGHAN
120	53124-2	1946	Class 5	35	Western	Top Decay, Split Top	82		0		30	0	5	35	VAUGHAN
121	49-4	1955	Class 3	55	Western	Top Decay, Split Top, Checking	84		0		30	0	5	35	VAUGHAN
122	621	1950	Class 6	22	Jack Pine	Top Decay	88		0		30	0	5	35	VAUGHAN
123	P414	lot Know	Class 5	35	Cedar	Crack to GL, Pole top feathering/split/rot -	97		0	5	30	0	0	35	Barrie
124	p49	1955	Class 6	30	Jack Pine	Butt Rot, Checking	N/A		0		30	0	5	35	AURORA
125	e	1969	Class 6	30	Western	Top Decay, Bent Pole, Checking	86		0		30	0	4	34	VAUGHAN
126	458	1989	Class 4	40	Western	Checking	N/A		2		25	5	2	34	VAUGHAN
127	456	1989	Class 4	40	Western	Checking	N/A		2		25	5	2	34	VAUGHAN
128	454	1989	Class 4	40	Western	Checking	N/A		2		25	5	2	34	VAUGHAN
129	52241	1980	Class 3	40	Western	Top Decay, Bent Pole, Split Top, Checking	81		0		30		3	33	VAUGHAN
130	334-1	1983	Class 3	55	Western	Bent Pole, Checking, Insect Infest.	129		0		30	0	3	33	VAUGHAN
131	6454-5	1990	Class 3	40	Western	Top Decay, Butt Rot, Bent Pole	75		0		30	0	2	32	MARKHAM
132	133	1988	Class 2	40	Western	Bent Pole, Insect Infest.	84		0		30	0	2	32	MARKHAM
133	6454-7	1990	Class 3	40	Western	Top Decay, Butt Rot, Bent Pole	88		0		30	0	2	32	MARKHAM
134	9	1957	Class 4	35	Red Pine	Checking	63	5	0		20	0	5	30	VAUGHAN
135	3	1959	Class 4	40	Western		68	5	0		20	0	5	30	VAUGHAN
136	12	1945	Class 5	30	Red Pine		68	5	0		20	0	5	30	VAUGHAN
137	48	1936	Class 5	35	Jack Pine		72		2		20	3	5	30	VAUGHAN
138	68	1936	Class 5	35	Western		73		2		20	3	5	30	VAUGHAN
139	47	1936	Class 5	30	Jack Pine	Checking	75		2		20	3	5	30	VAUGHAN
140	62	1936	Class 5	35	Jack Pine		75		2		20	3	5	30	VAUGHAN
141	67	1936	Class 5	35	Western	Checking	86		2		20	3	5	30	VAUGHAN
142	15	1996	Class 4	35	Western	Top Decay, Butt Rot, Checking, Insect Infest.	92		0		30	0	0	30	RICHMOND
143	21	1959	Class 5	35	Jack Pine		N/A		2		20	3	5	30	VAUGHAN
144	9494					Pole is in front of 51 Glenbourne Park Dr. Not in	N/A		0		30	0	0	30	MARKHAM

5 Year Capital Plan

System Planning & Standards
Station Design & Construction

2014 – 2018

Draft 4 – April 10, 2013

Prepared by: Engineering Planning

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

This report describes the Capital Plan recommendations by the Engineering Planning Division (System Planning & Standards, Stations Design & Construction). The Capital Plan covers in detail the first five years (2014-2018), and provides a high level future outlook for the second five years (2019-2023).

System Planning & Standards proposes capital projects to:
- Accommodate future specific customer connections
- Accommodate system load growth
- Maintain or improve system reliability and customer service
- Remedy distribution system anomalies
- Replace aging, end-of-life equipment based on the results of the Asset Condition Assessment (ACA) process

Station Design and Construction proposes capital projects to:
- Design and construction of new transformer stations (TS)
- Design and construction of new municipal substations (MS)
- Design and construction of enhancements or refurbishment of transformer or municipal stations
- Design and construction of communications infrastructure for TS, MS, Remote Terminal Unit (RTU) and generation facilities

The report lists the capital projects into three major rate case categories:

1) <u>**Sustainment Capital**</u>

1a. Replacement Program
- Pole Replacement Program (1a.1)
- Underground Switchgear Replacement Program (1a.2)

1b. Sustainment Driven Lines Projects
- Cable Replacement Projects (1b.1)
- Cable Injection Projects (1b.2)
- Lines Asset Replacement Projects (1b.3)
- Conversion Projects (1b.4)
- System Reconfiguration Projects (1b.5)
- Radial Supply Remediation Projects (1b.6)
- Distribution Automation Lines Projects (1b.7)
- Reliability Driven Lines Projects (1b.8)
- Safety, Environment Driven Lines Projects (1b.9)
- Compliance to External Directives / Standards Lines Projects (1b.10)
- Rear Lot Supply Remediation Projects (1b.11)

1c. Emergency / Restoration
- Transformer Replacement Projects (1c.1)

1d. Transformer / Municipal Stations
- Station Asset Replacement Projects (1d.1)
- Safety, Environment Driven Station Projects (1d.2)
- Compliance to External Directives / Standards Station Projects (1d.3)
- Distribution Automation Station Projects (1d.4)
- Reliability Driven Station Projects (1d.5)
- Operability and Maintainability Projects (1d.6)

2) <u>**Development Capital**</u>

2c. Additional Capacity (Transformer / Municipal Stations)

2d. Growth Driven Lines Projects

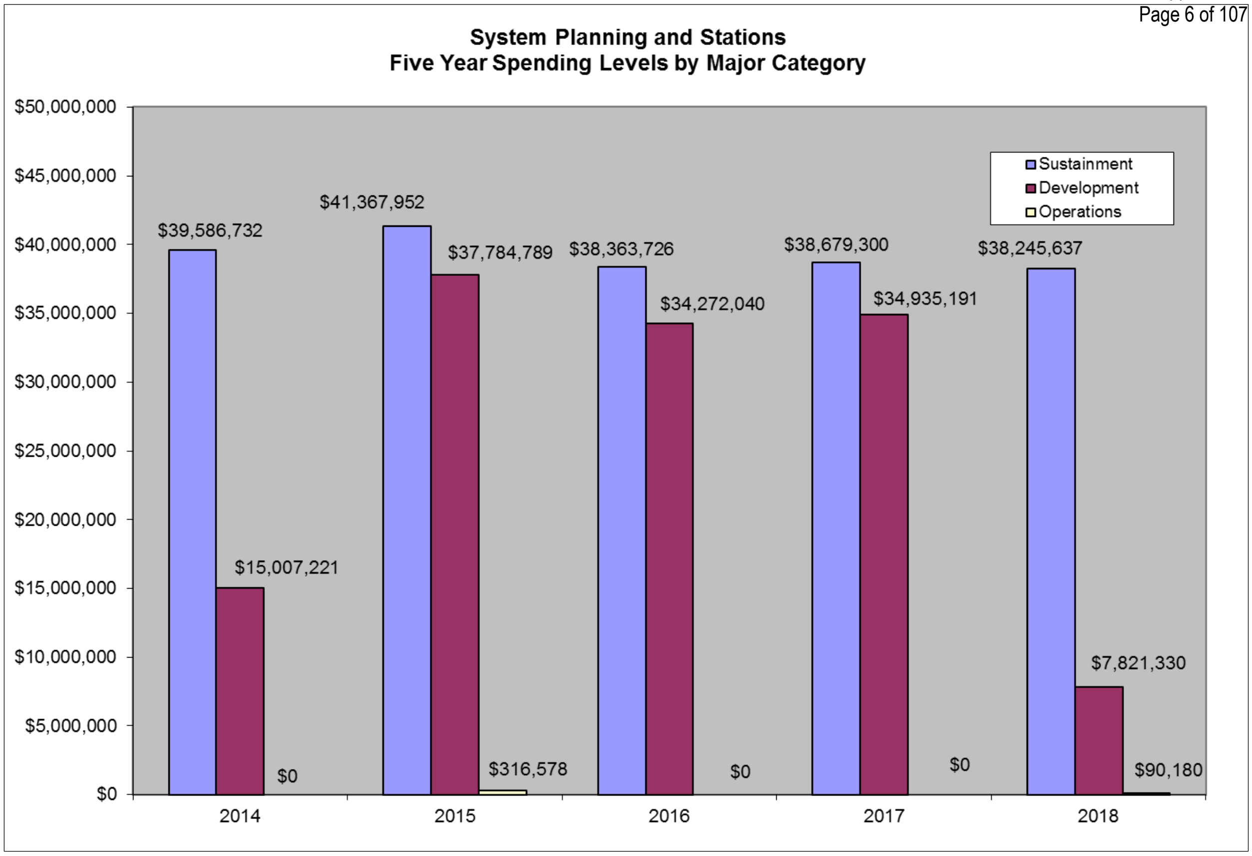
3) Operations Capital
3f. Purchase of Spare Equipment

These rate case categories are further defined by controllable (driven by legal, governmental or regulatory needs) and non-controllable project types (selected by PowerStream).

Funding Requirements for the First Five Years (2014-2018)

The total funding requirements for the first five years (2014-2018) is summarized below.

Summary of Spending: PowerStream SP&S, SD&C								
Division	**OEB Category**	**Ex. Type**	**2014**	**2015**	**2016**	**2017**	**2018**	**TOTALS**
System Planning & Standards	Sustainment - North & South	Total	$38,162,507	$36,610,263	$36,732,376	$37,435,238	$36,028,737	$184,969,121
		Controllable	$37,873,223	$36,320,245	$36,421,052	$37,201,246	$35,808,737	$183,624,503
		Non-Controllable	$289,284	$290,018	$311,324	$233,992	$220,000	$1,344,618
	Development - North & South	Total	$10,799,351	$17,273,344	$30,435,679	$34,935,191	$3,087,256	$96,530,821
		Controllable	$10,799,351	$17,273,344	$30,435,679	$34,935,191	$3,087,256	$96,530,821
		Non-Controllable	$0	$0	$0	$0	$0	$0
	Operations - North & South	Total	$0	$0	$0	$0	$0	$0
		Controllable	$0	$0	$0	$0	$0	$0
		Non-Controllable	$0	$0	$0	$0	$0	$0
						SP & S	**TOTAL =**	**$281,499,942**
Station Design & Construction	Sustainment - North & South	Total	$1,424,225	$4,757,689	$1,631,350	$1,244,062	$2,216,900	$11,274,226
		Controllable	$1,424,225	$4,538,599	$1,631,350	$1,244,062	$2,216,900	$11,055,136
		Non-Controllable	$0	$219,090	$0	$0	$0	$219,090
	Development - North & South	Total	$4,207,870	$20,511,445	$3,836,361	$0	$4,734,074	$33,289,750
		Controllable	$4,207,870	$20,511,445	$3,836,361	$0	$4,734,074	$33,289,750
		Non-Controllable	$0	$0	$0	$0	$0	$0
	Operations - North & South	Total	$0	$316,578	$0	$0	$90,180	$406,758
		Controllable	$0	$316,578	$0	$0	$90,180	$406,758
		Non-Controllable	$0	$0	$0	$0	$0	$0
						SD & C	**TOTAL =**	**$44,970,734**
Controllable - Total			**$54,304,669**	**$78,960,211**	**$72,324,442**	**$73,380,499**	**$45,937,147**	**$324,906,968**
Non-Controllable - Total			**$289,284**	**$509,108**	**$311,324**	**$233,992**	**$220,000**	**$1,563,708**
Sustainment - Total			**$39,586,732**	**$41,367,952**	**$38,363,726**	**$38,679,300**	**$38,245,637**	**$196,243,347**
Development - Total			**$15,007,221**	**$37,784,789**	**$34,272,040**	**$34,935,191**	**$7,821,330**	**$129,820,571**
Operations - Total			**$0**	**$316,578**	**$0**	**$0**	**$90,180**	**$406,758**
Grand Total			**$54,593,953**	**$79,469,319**	**$72,635,766**	**$73,614,491**	**$46,157,147**	**$326,470,676**



PowerStream - Capital Work Plan from Planning and Stations							
1. Sustainment Capital							
Category		**2014**	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
1a	Replacement Program	$7,279,329	$7,462,333	$7,648,876	$7,839,060	$8,032,998	**$38,262,596**
1b	Sustainment Driven Lines Projects	$28,560,990	$26,719,719	$26,523,917	$26,825,216	$25,843,924	**$134,473,766**
1c	Emergency / Restoration	$309,386	$363,440	$375,000	$386,250	$397,837	**$1,831,913**
1d	Transformer / Municipal Stations	$1,424,225	$4,757,689	$1,631,350	$1,244,062	$2,067,114	**$11,124,440**
1e	Emerging Sustainment Capital	$2,012,802	$2,064,771	$2,184,583	$2,384,712	$1,903,764	**$10,550,632**
	Total Sustainment:	**$39,586,732**	**$41,367,952**	**$38,363,726**	**$38,679,300**	**$38,245,637**	**$196,243,347**
2. Development Capital							
Category		**2014**	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
2c	Additional Capacity (Transformer / Municipal Stations)	$8,392,965	$24,851,270	$8,816,648	$6,555,733	$4,734,074	**$53,350,690**
2d	Growth Driven Lines Projects	$6,614,256	$12,933,519	$25,455,392	$28,379,458	$3,087,256	**$76,469,881**
	Total Development:	**$15,007,221**	**$37,784,789**	**$34,272,040**	**$34,935,191**	**$7,821,330**	**$129,820,571**
3. Operations Capital							
Category		**2014**	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
3f	Purchase of Spare Equipment	$0	$316,578	$0	$0	$90,180	**$406,758**
	Total Operations:	**$0**	**$316,578**	**$0**	**$0**	**$90,180**	**$406,758**
Grand Total							
		2014	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
	Grand Total:	**$54,593,953**	**$79,469,319**	**$72,635,766**	**$73,614,491**	**$46,157,147**	**$326,470,676**

Funding Requirements for the Second Five Years (2019-2023)

The total funding requirements for the second five years (2019-2023) is summarized below.

Summary of Spending: PowerStream SP&S, SD&C								
Division	**OEB Category**	**Ex. Type**	**2019**	**2020**	**2021**	**2022**	**2023**	**TOTALS**
System Planning & Standards	Sustainment - North & South	Total	$36,813,783	$37,822,569	$38,848,498	$40,102,141	$42,041,163	$195,628,154
		Controllable	$36,769,783	$37,778,569	$38,804,498	$40,058,141	$42,041,163	$195,452,154
		Non-Controllable	$44,000	$44,000	$44,000	$44,000	$0	$176,000
	Development - North & South	Total	$7,865,000	$18,769,775	$10,113,639	$13,200,000	$13,200,000	$63,148,414
		Controllable	$7,865,000	$18,769,775	$10,113,639	$13,200,000	$13,200,000	$63,148,414
		Non-Controllable	$0	$0	$0	$0	$0	$0
	Operations - North & South	Total	$0	$0	$0	$0	$0	$0
		Controllable	$0	$0	$0	$0	$0	$0
		Non-Controllable	$0	$0	$0	$0	$0	$0
						SP & S	**TOTAL =**	**$258,776,568**
Station Design & Construction	Sustainment - North & South	Total	$3,762,226	$1,743,844	$3,133,332	$3,518,057	$2,065,524	$14,222,983
		Controllable	$3,762,226	$1,743,844	$3,133,332	$2,124,749	$1,229,524	$11,993,675
		Non-Controllable	$0	$0	$0	$1,393,308	$836,000	$2,229,308
	Development - North & South	Total	$20,971,466	$1,119,193	$0	$0	$0	$22,090,659
		Controllable	$20,971,466	$1,119,193	$0	$0	$0	$22,090,659
		Non-Controllable	$0	$0	$0	$0	$0	$0
	Operations - North & South	Total	$0	$0	$0	$0	$0	$0
		Controllable	$0	$0	$0	$0	$0	$0
		Non-Controllable	$0	$0	$0	$0	$0	$0
						SD & C	**TOTAL =**	**$36,313,642**
Controllable - Total			**$69,368,475**	**$59,411,381**	**$52,051,469**	**$55,382,890**	**$56,470,687**	**$292,684,902**
Non-Controllable - Total			**$44,000**	**$44,000**	**$44,000**	**$1,437,308**	**$836,000**	**$2,405,308**
Sustainment - Total			**$40,576,009**	**$39,566,413**	**$41,981,830**	**$43,620,198**	**$44,106,687**	**$209,851,137**
Development - Total			**$28,836,466**	**$19,888,968**	**$10,113,639**	**$13,200,000**	**$13,200,000**	**$85,239,073**
Operations - Total			**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grand Total			**$69,412,475**	**$59,455,381**	**$52,095,469**	**$56,820,198**	**$57,306,687**	**$295,090,210**

General Outlook (2019-2023)

PowerStream will add new station and distribution assets (e.g. TS, MS, circuit breaker, pole, cable, transformer, switchgear, etc.) to accommodate customer load growth, which is forecasted in the range 2%-2.5% per year.

As assets age and deteriorate, PowerStream will prioritize asset replacement to maintain the integrity of the electrical distribution system and customer service. PowerStream will continue to monitor, inspect, and maintain these assets.

Significant Capital Projects

Some significant capital projects during the next ten years are listed below.

- Cable Replacement
- Cable Injection
- Pole Replacement
- New Vaughan TS#4
- New Markham TS#5
- New Painswick South MS
- New Harvie Rd. MS
- New Mill St. MS#2
- New Dufferin South MS#2
- New Little Lake MS#2

2 INTRODUCTION

This report describes the Capital Plan recommendations by the Engineering Planning Division (System Planning & Standards and Stations Design & Construction). The Capital Plan covers in detail the first five years (2014-2018), and provides a high level future outlook for the second five years (2019-2023).

Engineering Planning will use the information in this report to prepare and submit the annual capital budget.

The projects listed have not been approved through PowerStream's formal budget process.

To facilitate the sorting and grouping of projects, projects are listed according to the major categories, sub-categories, and minor categories. There are cases where a project is driven by and provides benefit to more than one category. In those cases, the final category is based on the primary driver and primary benefit of the project.

Because this report covers the controllable capital projects for both the distribution and stations assets in the corporation, it serves as a key component of the corporation's Asset Management Plan. As future emerging issues arise, Engineering Planning will adjust the scope, cost, timing, and priority of individual projects accordingly.

Annually, PowerStream will submit, review, and approve the proposed projects for the upcoming budget year according to PowerStream annual budget process. Engineering Planning will monitor, revisit and revise the Five Year Capital Plan every year, or more often as required.

3 SCOPE & STRUCTURE

Annually, Engineering Planning completes a Five Year Capital Plan Report. The report summarizes future capital work programs and projects recommended by Engineering Planning (System Planning & Standards and Stations Design & Construction). The report covers in detail the capital plan for the first five year (2014-2018), and also provides a high level future five year outlook for the second five years (2019-2023).

The report includes the following sections:

- Executive Summary
- Section 1 provides the introduction
- Section 2 describes the scope and structure of the report
- Section 3 provides the category definitions
- Section 4 describes the methodology and process to determine the spending levels
- Section 5 describes the process for project justification and budget approval
- Section 6 describes the proposed projects in detail
- Section 7 provides the summary of the first five year capital plan (2014-2018)
- Section 8 provides a high level future outlook for the second five years (2019-2023)
- Section 9 describes the changes made to this five year capital plan (2014-2018) in comparison to the previous five year capital plan (2013-2017)
- Section 10 (Appendix A) provides the listing of all projects for the first five years (2014-2018)
- Section 11 (Appendix B) provides the listing of all projects for the second five years (2019-2023)

4 CATEGORY DEFINITIONS

The following table lists the categories applicable to System Planning & Standards and Station Design & Construction.

Categories for Five Year Capital Plan	
1. Sustainment	
1a Replacement Program	
	1a.1 Pole Replacement Program
	1a.2 Undergound Switchgear Replacement Program
1b Sustainment Driven Lines Projects	
	1b.1 Cable Replacement Projects
	1b.2 Cable Injection Projects
	1b.3 Lines Asset Replacement Projects
	1b.4 Conversion Projects
	1b.5 System Reconfiguration Projects
	1b.6 Radial Supply Remediation Projects
	1b.7 Distribution Automation Lines Projects
	1b.8 Reliability Driven Lines Projects
	1b.9 Safety, Environment Driven Lines Projects
	1b.10 Compliance to External Directives / Standards Lines Projects
	1b.11 Rear Lot Supply Remediation Projects
1c Emergency / Restoration	
	1c.1 Transformer Replacement Projects
1d Transformer / Municipal Stations	
	1d.1 Station Asset Replacement Projects
	1d.2 Safety, Environment Driven Station Projects
	1d.3 Compliance to External Directives / Standards Station Projects
	1d.4 Distribution Automation Station Projects
	1d.5 Reliability Driven Station Projects
	1d.6 Operability and Maintainability Projects
1e Emerging Sustainment Capital	
	1e.1 Emerging Sustainment Capital
2. Development	
2c Additional Capacity (Transformer / Municipal Stations)	
	2c.1 Additional Capacity (Transformer / Municipal Stations)
2d Growth Driven Lines Projects	
	2d.1 Growth Driven Lines Projects
3. Operations	
3f Purchase of Spare Equipment	
	3f.1 Purchase of Spare Equipment

4.1 Major Category Definitions

Sustainment Capital

This category includes projects that replace assets that are at end of life or projects that enable improved safety, reliability or efficiency in the operation of the distribution system. Capital projects included in this Engineering Planning Five Year Capital Plan are:

- 1a) Replacement Programs
- 1b) Sustainment Driven Lines Projects
- 1c) Emergency / Restoration
- 1d) Transformer / Municipal Stations
- 1e) Emerging Sustainment Capital

Development Capital

This category includes projects that involve system expansion or relocation due to growth and/or to satisfy external demands. Capital projects included in this Engineering Planning Five Year Capital Plan are:

- 2c) Additional Capacity (Transformer/Municipal Stations)
- 2d) Growth Driven Lines Projects

Operations Capital

This category includes projects that support the day-to-day operations of PowerStream. Capital projects included in this Engineering Planning Five Year Capital Plan are:

- 3f) Purchase of Spare Equipment

4.2 Sub-Category and Minor Category Definitions

1a. Replacement Program

This category mainly covers the replacement of distribution assets. It includes the following:

- Pole Replacement Program (1a.1)
- Underground Switchgear Replacement Program (1a.2)

1a.1 Pole Replacement Program

Wood poles are critical components of the distribution system as many types of equipment are attached to them (conductors, transformers, switches, street lights, telecommunication attachments, etc.). As a pole's physical condition and structural strength deteriorate, the pole may become inadequate for its intended function, and should be replaced to maintain the integrity of the distribution system.

Every year, on a prioritized basis, with data acquired from the pole testing program, PowerStream selects a number of poles for replacement.

1a.2 Underground Switchgear Replacement Program

As the existing distribution switchgear population ages and deteriorates, a number of units will require replacement to maintain the integrity of the distribution system. On a prioritized basis, based on the results of the inspection, maintenance and analysis, PowerStream will select a number of switchgear units for planned replacement. This program will only cover costs for the planned switchgear replacement and not emergency switchgear replacement (i.e. does not cover replacement cost after the switchgear unit has already failed. The emergency replacement cost is covered under the Lines department budget).

1b. Sustainment Driven Lines Projects

This category mainly covers the Lines projects that are not capacity driven. It includes the following:

1b.1 Cable Replacement

PowerStream has a significant quantity of underground primary cable, the vast majority of which is direct buried, with the balance in duct. As the cable gets older and the condition deteriorates, it will fail. Initially PowerStream can repair or replace the faulted cable segment under reactive emergency response. But if the cable fails too often, it will result in unacceptable service to the customers, and unacceptable repair costs to PowerStream. PowerStream will prioritize and replace end-of-life cable to maintain system reliability.

1b.2 Cable Injection

The injection plan was based on the assumption that Cable Injection is a viable option for a certain quantity of cable. As the cable gets older, the cable insulation may develop premature aging caused by a phenomenon known as "water treeing". Water trees will reduce the breakdown strength of the insulation and eventually lead to cable failure. The Cable Injection process will inject silicone chemicals down the strands of the cable, which will improve the strength of the insulation, and therefore extend the life of the cable.

1b.3 Lines Asset Replacement Projects (e.g. Splice, Vault, Duct Bank, Mini-Rupter, Submersible Transformer)

Currently PowerStream does not have proactive replacement programs for splices, vaults and duct banks. Going forward, PowerStream will start an inspection program for civil structures and use the inspection results to prioritize possible proactive replacement.

Submersible Transformers

In 2008 System Control identified 91 submersible equipment locations in PowerStream South requiring retro-fitting to meet a new operations switching procedure. The existing submersible unit design and installation do not provide sufficient access to allow the field staff to perform switching operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers.

The retro-fitting work, including installation of switches, splicing out and replacing the submersible transformer with a switchable padmount transformer, will make the design and installation similar to the majority of other existing locations in the system. This work will facilitate normal work procedures for the field staff.

All identified south locations will be rectified by the end of 2013.

In 2010, Lines Department identified 57 submersible transformer locations in PowerStream North requiring replacement to meet new operations switching procedure. These units are obsolete, they are no longer manufactured, and spare parts are non-existent. The existing installations do not provide sufficient access to allow the field staff to perform switching operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers. The plan is to replace all of the identified transformers with padmount transformers by the end of 2015.

Mini-Rupter Switches

In 2013 PowerStream will start to review the performance of the existing Mini-Rupter switch population. There are concerns about the reliability and operability of these switches. The switches are installed inside vaults. Field crews are not willing to operate these switches live. As a result, additional switching operations at adjacent switchable locations are required which would increase outage time to customers, and have a negative impact on system reliability. Lines and System Planning proposed to replace these switches with solid dielectric switches.

1b.4 Conversion Projects

PowerStream has a number of Municipal Stations (MS) providing supply feeders at 13.8 kV, 8.32 kV and 4.16 kV levels. In general, 13.8 kV, 8.32 kV and 4.16 kV systems have higher distribution losses than the 27.6 kV system.

A number of the MSs have a single transformer and a long radial feeder(s) with no backup. This configuration can have a negative impact on system reliability. Lack of immediate backup sources can add to outage duration.

Remediation projects are formulated to convert the affected areas to the interconnected 27.6 kV supply system in phases and to eventually decommission the MS.

1b.5 System Re-configuration Projects

System Planning, in consultation with System Control and Lines, will recommend projects to resolve feeder load balancing and load transfer capability under normal and emergency situations. Operations and safety issues will be considered.

1b.6 Radial Supply Remediation Projects

The vast majority of PowerStream's distribution system is designed as an open loop system with multiple interconnections between feeders. Under this supply scheme, when feeder A is out of service, an adjacent feeder B may be able to pick up a portion of feeder A's load, subject to feeder B's capacity and other operating constraints. As a result, the extent of customer interruptions can be reduced. This will have a positive impact for system reliability.

In some areas of PowerStream's service territory, however, there are locations where customers only have a radial supply (there is only one path between the customers and the source of supply). Under this supply scheme, when the source of supply is out of service (due to failure, repair, maintenance), the downstream customers will have total service interruptions, as there are no alternate supplies available. As a result, these customers will experience outages longer than those customers with alternate supply paths. This will have a negative impact to system reliability.

The remediation projects are formulated based on the following criteria:

- Number of customers and the length of radial supplies
- Requirements from System Control
- Total kVA load connected
- Feasibility to remediate

1b.7 Distribution Automation Lines Projects

In general, distribution automation will improve power outage restoration and therefore system reliability; however, PowerStream cannot justify the automation of the whole distribution system due to the high costs. As a result, the decision on quantity and location of automation equipment must be made on a case-to-case basis and be guided by the following three criteria:

- <u>Economic Consideration:</u> the cost of a distribution automation project must be less than the benefit of the reliability improvement, calculated using customer interruption frequency and duration.

- <u>Feeder Loading Consideration:</u> to facilitate back-up and emergency load transfer, distribution automation equipment must be installed so that the feeder segment loading can be limited to a certain threshold, based on specific feeder configuration.

- <u>System Control Consideration:</u> to facilitate control room operations, distribution automation equipment must be installed based on specific feeder operating conditions.

1b.8 Reliability Driven Lines Projects

PowerStream's Reliability Committee monitors and discusses reliability performance at the system, feeder, and component levels. The Committee comprises members from various business units across the organization, and has the mandate to review reliability performance and make recommendations to manage and improve reliability. Both outage duration and outage frequency are taken into consideration. In addition momentary outages (outages that are less than 1 minute in duration) are also taken into consideration.
Reliability driven projects are proposed to maintain or improve current levels of service to customers.

Feeders with deteriorating reliability statistics are targeted for review, and remedial action plans are developed to improve reliability.

Each year PowerStream identifies a group of Worst Performing Feeders (WPF) to focus on improving the reliability performance of those feeders.

1b.9 Safety, Environment Driven Projects

This category covers the capital work that PowerStream must complete to comply with Health, Safety and Environmental regulations, standards and guidelines.

1b.10 Compliance to External Directives / Standards Lines Projects

This category covers the capital work that PowerStream must complete to comply with external directives/standards such as:

- OEB (e.g. Long Term Load Transfer; Distribution System Code)
- OPA (e.g. Regional Joint Studies which lead to future capital spending needs; metering configuration acceptable for FIT/micro FIT program)
- ESA (e.g. ungrounded delta transformers; clearance issues)
- IESO (e.g. wholesale meter upgrades; market rules for power factor requirements)
- Other Regulatory Standards (e.g. CSA 22.3 No.1–10)
- Grade 1 Construction Requirements for Highway 400 series overhead crossings

1b.11 Rear Lot Supply (Backyard Construction) Remediation Projects

This category covers the capital work that PowerStream must complete to address the operations and customer service issues in areas with rear lot supply. The main concerns are deteriorating equipment and difficult access for crews to perform maintenance, repair and trouble response work.

<u>1c Emergency / Restoration Projects</u>

This category covers the urgent replacement of padmount transformers identified through the inspection program.

1c.1 Padmount Transformer Replacement

It was PowerStream's past practice to operate the padmount transformers on a run-to-failure basis. Starting in 2013, PowerStream will begin the replacement of padmount transformers based on inspection results. Each year, only those transformers identified as requiring immediate intervention will be replaced.

<u>1d. Transformer / Municipal Stations</u>

This category mainly covers the Station projects that are not capacity driven.

1d.1. Station Asset Replacement Projects

This category mainly covers the replacement of Station Assets using the ACA Process, and includes the following:

<u>Station Circuit Breaker Replacement</u>

Station circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage.

A number of station circuit breaker units (mostly ABB Type HKSA and Outdoor GEC Type OX36) have been identified by the ACA Model as needing replacement, mostly due to age, condition, obsolescence, and historical failures.

<u>230 kV Switches</u>

This asset group consists of air break switches at TS. The primary function of switches is to allow isolation of transmission line sections or equipment for maintenance, safety or other operating requirements.

Primary Switches
This asset group consists of station air break and fused switches at Municipal Substations. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements.

Station Reactors
This asset group consists of reactors at stations. The primary function of reactors is to limit the short circuit current of a line when there is short circuit. It can also be used to absorb reactive power, or be used as part of a filtering circuit.

Station Capacitors
This asset group consists of capacitors at stations. The primary function of capacitors is to improve the quality of the electrical supply and the efficient operation of the power system. The major applications include power factor improvement and voltage regulation.

MS Transformers
This asset group consists of power transformers at MS's. The MS transformers are used to step down the sub-transmission voltage or higher distribution voltage to lower distribution voltage levels.

TS Transformers
This asset group consists of power transformers at TS's. The TS transformers are used to step down the transmission voltage to distribution voltage levels.

1d.2 Safety, Environment Driven Station Projects
This category covers the capital work that PowerStream must complete at TS/MS to comply with Health, Safety and Environmental regulations, standards and guidelines.

1d.3 Compliance to External Directive / Standards Stations Projects
This category covers the capital work that PowerStream must complete to comply with external directives/standards such as:

- OPA (e.g. Regional Joint Studies which lead to future capital spending needs; metering configuration acceptable for FIT/micro FIT program)
- IESO (e.g. wholesale meter upgrades; market rules for power factor requirements)

1d.4 Distribution Automation Station Projects
This category covers the capital projects that PowerStream must complete at TS/MS to prepare and operate the distribution system to meet PowerStream's initiatives on Distribution Automation.

1d.5 Reliability Driven Station Projects
This category covers the capital projects that PowerStream must complete at TS/MS to maintain system reliability.

- Maintain reliability: The reliability of all system components, including the reliability of Transformer Stations is monitored by PowerStream's Reliability Committee. The Reliability Committee initiates projects to maintain service to customers. Reliability is measured using the previous 3 year moving averages of SAIDI, SAIFI and CAIDI.

1d.6 Operability and Maintainability Station Projects
This category is for Station projects that are not capacity driven, but are required to sustain PowerStream's fleet of 11 TSs and 54 MSs. Sustainment activities include projects to: replace worn out equipment, maintain or improve reliability, enhance operability & maintainability, and to improve & maintain safety.

- Replace worn out equipment: These projects include the replacement of Station Plant Assets not included in the ACA Process. All station equipment except for station circuit breakers, transformers, primary switches, capacitors and reactors are included.

- Enhance operability: Operability enhancement projects include projects to improve transformer station Supervisory Control and Data Acquisition (SCADA) functionality.

- Enhance Maintainability: Maintainability enhancement projects include projects to improve the ability of the Stations Sustainment and Protection & Control departments to carry out transformer station maintenance activities. Examples of enhance maintainability projects include the addition of monitoring equipment, network management systems, spare components and on-site storage.

1e Emerging Sustainment Capital
This category covers the emerging capital projects that PowerStream must complete to sustain the distribution system. In most cases the specific projects cannot be identified during the budget time. PowerStream will identify specific projects to resolve the emerging issues on an as-needed basis.

2c Additional Capacity (Transformer / Municipal Stations)
This category covers the capital projects that PowerStream must complete at TS/MS to provide sufficient capacity to supply new customers and load growth from existing customers, including purchase of land and easements.

Every year System Planning conducts load forecast studies to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

2d Growth Driven Lines Projects
This category covers the Lines capital projects to provide sufficient capacity to supply new customers and load growth from existing customers, including purchase of land and easements. Examples of this category are: feeder egress, feeder integration, new feeders, and additional circuits on existing pole lines.

Every year System Planning conducts load forecast studies to identify capacity short falls and recommends projects to ensure sufficient capacity prior to peak customer load growth demands.

PowerStream continues to experience a high level of growth. Growth is one of the major drivers for the short term capital augmentation expenditures. Capacity adequacy issues are addressed through feeder upgrades and the completion of new stations and associated feeders.

3f Purchase of Spare Equipment
This category covers the purchase of spare equipment to manage the risk of equipment failure.

5 METHODOLOGY & PROCESS TO DETERMINE THE SPENDING LEVEL

This section describes the existing PowerStream methodology and process to identify future capital projects.

- Distribution Planning Process
- Planning Guidelines, Standards, and Practices
- Asset Condition Assessment (ACA)
- Stations Design and Construction Process

5.1 Distribution Planning Process

PowerStream follows the established planning cycle consisting of seven (7) steps:

1. Review of System Performance
2. Determination of Augmentation Needs
3. Development of Alternative Options to support Augmentation Needs
4. Selection of Preferred/Optimal Options
5. Option Approval and Incorporation into the Budgeting Process
6. Implementation of Options
7. Evaluation of Resultant Performance

Figure 1 summarizes the planning process at PowerStream.

PowerStream also conducts system studies and uses the results of the following studies to formulate proposal for capital projects:

- Load Balancing & System Reconfiguration Plan for PowerStream South (27.6 kV system)
- Load Balancing & System Reconfiguration Plan for PowerStream North (44 kV and 13.8 kV systems)
- Studies for anomalies in the distribution system, such as radial supplies or poorly performing segments of the system
- Worst Performing Feeders (WPF)
- Distribution Automation
- Load Forecast
- Equipment Failure Database and Forensic Analysis
- Asset Condition Assessment (ACA)

PowerStream has developed a Planning Philosophy which covers activities relating to:

- Distribution Design
- Distribution Capacity Planning
- Distribution Risk Assessment
- Distribution Reliability Planning

Distribution Design

Nearly all loads, within PowerStream service area, are supplied from Dual Element Spot Network (DESN) transformer stations either owned by PowerStream or Hydro One Networks Inc.
With the exception of some radial feeders, the vast majority of the distribution feeders are in an “open grid design” arrangement, whereby multiple feeders traverse a distribution area with multiple interconnections between the feeders at various normal open points. In the event of a fault on a feeder or loss of supply to a particular feeder, adjacent feeders have the ability to pick-up supply to customers after operator intervention.

Distribution Capacity Planning and Risk Assessment

At the transmission line and station transformer level, PowerStream adopts an (N-1) standard. This (N-1) standard provides for the planned or unplanned removal from service any one 230 kV transmission line or station transformer without a sustained interruption to customer loads.

At the distribution feeder level (<50 kV supply), PowerStream adopts an (N-0) standard. Most events at the distribution level will result in a sustained interruption to customer loads until alternative supply sources are accessed. With increased distribution automation devices and Smart Grid investment, sustained interruptions to customers are expected to decrease in frequency and duration.

Reliability Planning

Power Stream measures distribution system reliability in terms of industry and regulator accepted reliability indices. These indices are customer oriented and have units of “frequency of outage per year” and “outage duration in hours”.

SAIDI
= System Average Interruption Duration Index
= Customer Hours
System Customers
(i.e. the average length of interruption per customer on the system)

SAIFI
= System Average Interruption Frequency Index
= Customers Affected
System Customers
(i.e. the average number of times an interruption occurred per customer on the system)

CAIDI
= Customer Average Interruption Duration Index
= Customer Hours
Customers Affected = SAIDI/SAIFI
(i.e. the average length of interruption per customer interrupted)

MAIFI
= Momentary Average Interruption Frequency Index
= *Number of Momentary Interruptions*
System Customers
(i.e. the average number of times a momentary interruption occurred per customer on the system)

In addition to the above four reliability indices, a fifth index, Index of Reliability (IOR), is also being used by the industry:

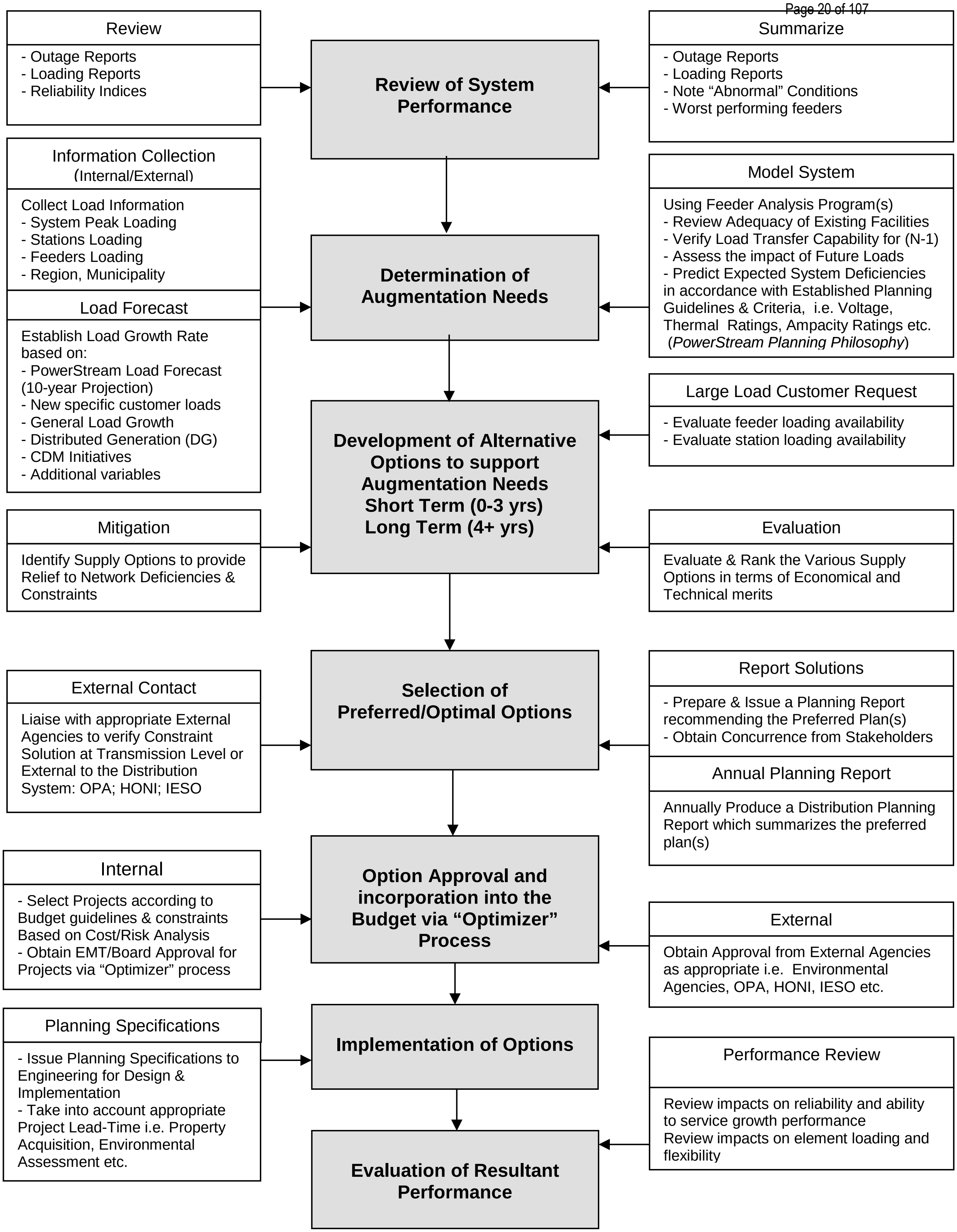
IOR = Index of Reliability
(also called RI = Reliability Index; also called ASAI = (Average System Availability Index)
= (8760 – SAIDI) / 8760

Reliability performance data is further categorized as:

- All Events
- Excluding Loss of Supply (LOS)
- Excluding Major Event Days (MED)
- Excluding Loss of Supply & Major Event Days

Reliability performance is being monitored by the PowerStream Reliability Committee. Significant deviations from target reliability would trigger appropriate planning responses to restore service reliability to target levels.

Figure 1 – Distribution System Planning Process



5.2 Planning Standards, Guidelines, and Practices

System Voltages
The primary supply voltages for PowerStream shall be 4.16 kV, 8.32 kV, 13.8 kV, 27.6 kV and 44 kV. Selection is governed by the Conditions of Service.

Load Forecast (Practice)
An annual summer/winter peak demand load forecast is prepared by System Planning for each transformer station and associated feeders (usually over a 10 year window) forming the basis of all planning assessments in the current year. Distribution facilities are planned and designed to meet the expected peak demand as outlined in the official corporate forecast.

Feeder Loading (Guideline)
All 27.6 kV and 44 kV feeders shall be designed for full backup capability over peak loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders. In order to facilitate this restoration capability, three-phase 27.6 kV and 44 kV feeder loading will be planned to a maximum of 400 amps and 600 amps under normal and emergency operation respectively.

A planned load guide of 300 amps shall be used for 13.8 kV, 8.32 kV, and 4.16 kV feeders.

In certain industrial/commercial areas a normal operating limit greater than 400 amps is acceptable provided remotely controlled switching is available for load transfer to adjacent feeder(s) during an emergency condition.

All feeders should not be loaded over their thermal limits of the most limiting component.

Station Transformer Loading (Guideline)
Station Transformers maximum allowable loading, under contingency conditions, is the 10-day limited time rating (LTR). This loading is 1.4 and 1.6 of the transformer-cooled rating for summer and winter respectively. Transformation capacity will be added when a station reaches 100% of its 10 day limited time rating (LTR).

Number of Feeders at Transformer Stations (Practice)
For the purpose of determining the number of feeders from a transformer station, an average loading of 15 MVA per feeder will be used (e.g. 27.6 kV nominal voltage, transformer capacity 75/100/125 MVA, Summer 10-day LTR of 170 MVA, the number of feeders is 12 with an average load per feeder of 14.2 MVA). Additional feeders should be planned and placed into service when the average summer peak load per feeder exceeds 15 MVA.

Municipal Station (MS) Loading (Guideline)
Municipal Stations are supplied from 44 kV or 27.6 kV circuits, and step down the voltage to one of the three distribution voltage levels: 13.8 kV, 8.32 kV, and 4.16 kV. Each MS typically has 2 to 4 feeders, supplying a combination of three phase and single phase loads.

MS load back-up is required under contingency conditions (e.g. station equipment failure) and non-contingency purposes (e.g. planned outage for maintenance or capital work). Under these situations, the MS load is transferred to adjacent MS or MS's via feeder ties between stations.

Feeder Egress Cable & Overhead Conductor Size (Practice)
For 27.6 kV feeder egress, 1000 kcmil Cu, XLPE (in a concrete encased duct bank where required) will be used from the TS feeder breaker to the cable riser switch or to a suitable point (a switch) where the feeder separates and takes an overhead route. The concentric neutral shall be single-point bonded, grounded at the station end. The riser end shall be terminated with a 3 kV arrestor, without an isolator and a 2/0 copper ground lead. A separate neutral conductor shall be used consisting of no more than two sizes smaller than the phase conductor.

For 13.8 kV, 8.32 kV, and 4.16 kV feeder egress, 500 kcmil Cu, XLPE will be used.

For the overhead part of the feeder main conductor, 556 kcmil Al will be used. Overhead laterals of more than 200 amps that could be tied to another feeder or feeder lateral will also have 556 kcmil Al conductors. The neutral conductor will also be 556 kcmil Al within a distance of 1.0 km from the transformer station. Beyond a distance of 1.0 km, from the transformer station, 336 kcmil or 3/0 ACSR will be used as the system neutral.

Planning Horizon (Practice)
Short-Term Planning Horizon = 0 - 5 years
Long-Term Planning Horizon = 5+ years

Economic Analysis (Practice)
Lowest life cycle cost using discounted cash flow analysis. The economic analysis should include capital and maintenance.

First Contingency
First contingency (N-1) must be covered. Sufficient backup facilities should be planned so that primary supply can be restored from an alternate source at peak demand in contingency of a “major network component” failure.

Distribution Automation
Distribution automation through remote switching is to be provided when cost justified ensuring that any load lost during single contingencies can be restored in a minimum amount of time.

Industry Standards
Industry distribution system planning standards that are an integral part of “good utility practice” and are common to all distribution utilities are used as guidelines at PowerStream.

Protection Philosophy
PowerStream’s distribution system is primarily an overhead system. Feeder protection shall incorporate appropriate auto-reclose settings to mitigate the impact of transient faults. In certain circumstances the auto-reclose setting will be disabled where all faults on the circuit are expected to be permanent in nature. In general, “trip saving” protection will be enabled to allow fuses and reclosers to isolate faults where they provide the first line of protection. There are, however, cases in PowerStream North, where “fuse saving” protection may be used.

Transformer Stations (TS)
All new transformation facilities will be built as Dual Element Spot Network (DESN) Stations.

Currently, two types of DESN stations exist within the PowerStream service territory, Bermondsey type and Jones type. New stations will be Bermondsey type (75/125 MVA) stations. The smaller (50/83 MVA) Jones type stations will be considered in areas of low growth and areas of limited growth due to service boundary constraints.

Municipal Stations (MS)
Municipal Stations will continue to be constructed as required in areas of 44 kV primary supply. The MS secondary supply voltage shall be 27.6 kV or 13.8 kV as determined by the nature and configuration of the load.

Municipal Stations will not be constructed in areas of 27.6 kV primary supply. New load will not be added to existing Municipal Stations unless a 27.6 kV supply is not available or not financially justified. Existing MS load shall be converted to 27.6 kV when cost/reliability justified.

5.3 Asset Condition Assessment (ACA) Process

PowerStream continues to fine-tune the ACA models and update the parameters to reflect PowerStream situations. Examples of the parameters include: asset physical condition, testing data, customer interruption cost, replacement cost, failure probability curve, and consequence of asset failure, etc.

The typical Asset Management process gathers engineering and other technical information from numerous sources and ties them to the annual budgeting process. The typical Asset Management process has four steps:

- Data capture
- Asset evaluations, which translate condition and criticality information into repeatable, quantitative measures
- Program development, which is a risk-based economic analysis to justify and prioritize spending programs. For the ACA project, the spending programs we are most interested in are risk-management replacement and rehabilitation programs
- Program execution through the Budgeting process

PowerStream has adopted an Asset Management Framework created by Kinectrics Inc. as illustrated in Figure 2.

Each year, ACA data is collected and ACA models are run to generate asset health index, benefit/cost ratios and recommended timing of intervention actions.

One of the goals of the ACA program is to address the population of assets that are “very poor” or “poor” condition in the next ten years. This will be done on a prioritized basis, taking into consideration the risk cost of asset failure and the benefit of proactive replacement.

Currently, PowerStream has ACA models for the following assets:

- TS Transformer
- MS Transformer
- Station Breakers and Recloser
- MS Primary Switch
- 230 kV TS Switch
- Station Capacitor
- Station Reactor
- Distribution Transformer
- Distribution Switchgear
- Underground Primary Cable
- Wood Poles

Figure 2 – Asset Management Framework

As the first step in adopting optimal asset management, an objective yardstick needs to be developed for accurate and quantitative measurement of the health and condition of major assets, which would provide repeatable results.

By taking into consideration asset health degradation processes and historic failure modes, appropriate algorithms are developed, relating the results of visual inspections, laboratory tests and other relevant demographic and operating parameters to a normalized health indicator, referred to as “Health Index”.

Health indices determined in this manner, allow sifting and ranking of the entire population of a specific asset class into five categories: “very poor”, “poor”, “fair”, “good”, and “very good”. They will also permit quantitative determination of asset failure risk for each category, using probabilistic techniques.

All consequences of failure for each asset class are identified, and the overall impact of failure risk of an asset is quantified using probabilistic techniques. Practical risk mitigation options for each asset category are identified and cost estimates for each mitigation option are prepared. With this model, optimal investment decisions are made by balancing the value of risk against the risk mitigation costs.

PowerStream Overall Asset Condition Assessment Process is illustrated in Figure 3.

Every year asset conditions and test data are collected and ACA asset models are run to generate results.
Meetings among stakeholders are held to ensure the following three-step process is followed before a project is recommended for annual budget approval:

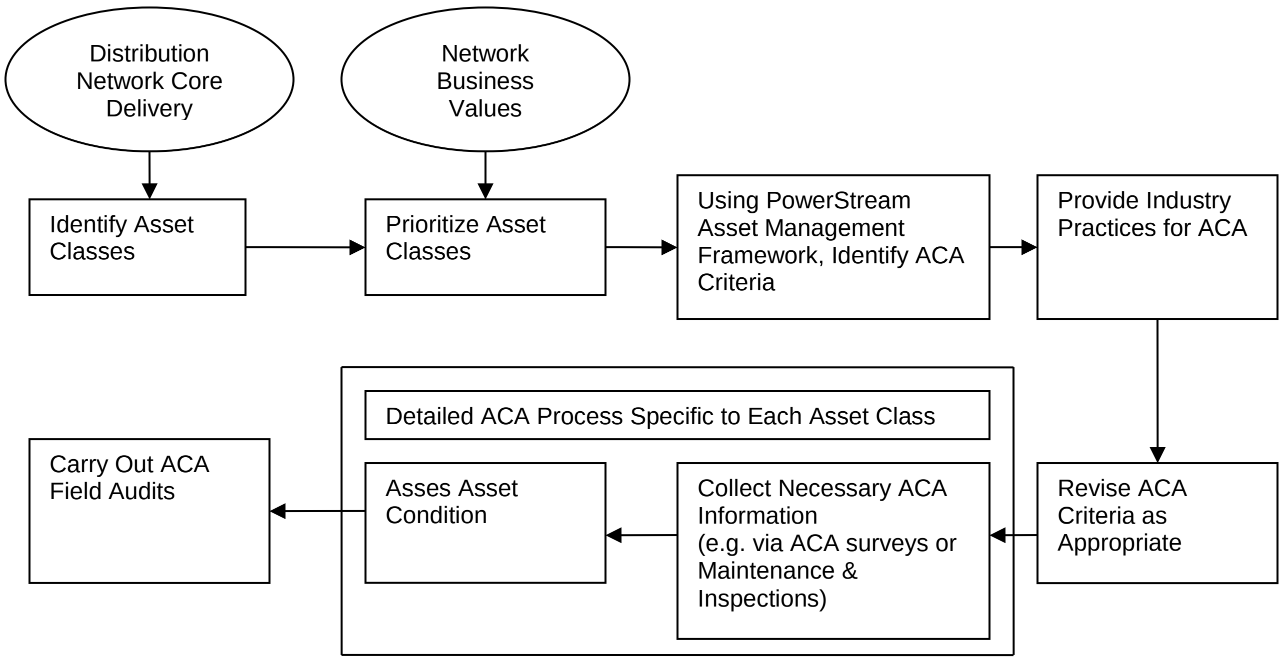
Step 1: Results of the ACA Model: results indicating that asset replacement is required;

Step 2: Operational Requests: requests are based on experience from System Control on those assets that limit the efficient operations of the distribution system; and

Step 3: Lines and Operations Feedback: these feedbacks are from field staff on those assets that have visually or functionally deteriorated worse than the assessment results from the ACA model. In addition, any safety related issues will be taken into consideration.

Although in theory, the number of replacement units recommended by the ACA models is considered "optimal" or "ideal" under economic viewpoint; in reality, however, PowerStream uses engineering judgment and operations input to spread out the replacement programs over a longer period of time. The intent of spreading the replacement over a number of years is to manage additional risk of asset failure, and smooth out the budget and resource impact.
As a result of this approach, the annual numbers of replacement units proposed in the annual budget may be different from those recommended by the ACA models.

Figure 3 - PowerStream Overall Asset Condition Assessment Process



5.4 Station Design and Construction Process

This section describes the existing methodology and process the Stations Design & Construction group uses to identify future capital projects. The process to determine spend levels is described below. The process is also shown in process map form in Figure 4.1.

5.4.1 Identify Needs

The Identify Needs step determines the need for a station project. The need for a sustainment (not capacity driven) station project can be identified by Station Design & Construction (SD&C), Stations Sustainment (SS), Operations (OPS), Protection & Control (P&C), and System Planning (SP). The System Planning group identifies station plant asset replacement and capacity driven projects. Sustainment activities include projects to: replace worn out equipment, improve reliability, enhance operability & maintainability and to improve and maintain safety.

5.4.2 Management of Stations Change (MOSC) Committee Meeting

Management of Station Change (MOSC) committee reviews recommended changes & improvements to stations to ensure the quality and cost effectiveness of proposals.

5.4.3 Concept Design

High level concept designs are developed by the assigned Project Engineer. The objective of the concept design step is to validate the program, explore the most promising alternative design solutions, and provide a reasonable basis for analyzing the project cost. The concept design may include:

- Overview of the project
- Background and history of the project
- A space profile and specialized facility needs
- Major equipment lists
- Program issues and objectives

In some instances, sketches could be developed as part of concept design activity.

5.4.4 Develop Cost Estimate

In order to estimate the cost the following steps are taken:

Request budgetary quotes - the preliminary budget quotes for the potential equipment required for the station are needed. The Project Engineer generates a request to potential external suppliers for budgetary quotes.

Request Work Hours - the work hours that are estimated to be spent by other departments and stakeholders are needed. The Project Engineer generates a request to SS and P&C for Work Hour estimates.

Cost Estimation – the estimates are performed by the Project Engineer based on the project specifications and the inputs received from Stations Sustainment work hour estimates, P&C work hour estimates, and external suppliers budgetary quotes.

5.4.5 Develop Business Case

A business case is developed for the budget approval of the new station project. The Business Case typically consists of the high level concept design, cost estimates and timelines.

5.4.6 Corporate Capital Budget Development

The Capital Budget Coordinator puts together the Capital Budget after consolidating all the business cases that have a preliminary approval to be prioritized by the *Optimizer*® tool.

5.4.7 Run Optimizer and Prioritize Projects

The approved business case information from all the approved business cases are entered into the *Optimizer*® tool enabling prioritization of the projects. The *Optimizer*® results are then forwarded to senior management for approval.

5.4.8 Resubmit to Next Planning Cycle

The business case is resubmitted in the Next Planning Cycle if senior management decides not to pursue the project this year and chooses to defer the project to future years.

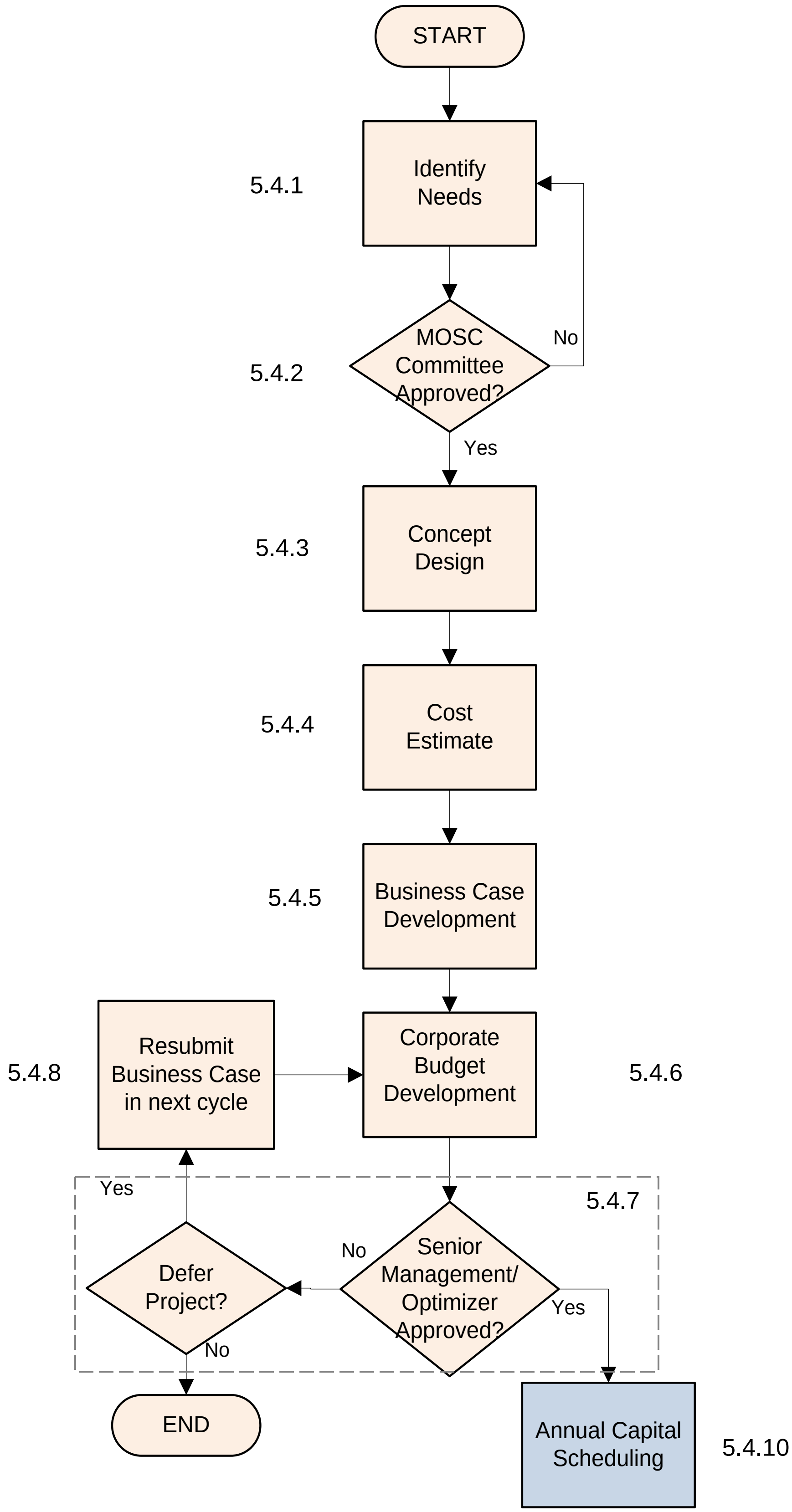
5.4.9 Cancel Project Proposal

Senior management and/or the Stations Group determine that the project is no longer worth pursuing in its present form for future budget cycles. The project is cancelled and withdrawn from future planning cycles.

5.4.10 Project Scheduled

The approved project is scheduled for implementation.

Figure 5.1 – Process to Determine Spend Levels



6 CAPITAL PROJECT JUSTIFICATION & BUDGET APPROVAL

PowerStream follows a process to ensure capital projects are well justified and prioritized, and capital funds approval is prudent.

The procedure governing the justification and approval of the annual capital projects is described in PowerStream Procedure No. FCS-F-01 "Justification of Capital Projects & Related Expenditures" which is posted on PowerStream's INFLOW site.

Each proposed project must be substantiated by a budget form ("mini business case") in PowerStream's Capital Budget Management System (CBMS). In addition, for those proposed projects that meet the following criteria, a "full business case" must also be completed and approved prior to budget submission.

- Non-program projects, greater than $500,000.
- Projects not funded within the current year's approved capital budget or are funded from emerging funds, greater than $250,000, net of contributed capital.
- New or current capital programs of an on-going, recurring nature included in the annual, planned capital budget and not listed in the listing of program type projects under the mini business case.

For each proposed project, an Optimizer Scoring Form must be completed, in which a number of questions must be answered. Each proposed project is scored based on PowerStream "Strategic Objectives and Success Criteria Weightings", which included the following criteria for the 2013 Budget year:

Criteria	Weighting Factor
Business Excellence	26.2%
Customer Satisfaction	31.9%
Financial	20.1%
Health & Safety	15.1%
Environmental Sustainability	6.7%

The criteria and weighting factors are reviewed on a periodic basis.

7 FIVE YEAR CAPITAL PLAN

Appendix A lists the capital projects proposed by Engineering Planning for the first five years (2014 – 2018). Appendix B lists the capital projects proposed by Engineering Planning for the second five years (2019 – 2023).

7.1 Replacement Program (1a)

This category covers the following two asset replacement programs.

- Pole Replacement Program (1a.1)
- Underground Switchgear Replacement Program (1a.2)

Pole Replacement Program (1a.1)

PowerStream has 43,347 wood poles in service.

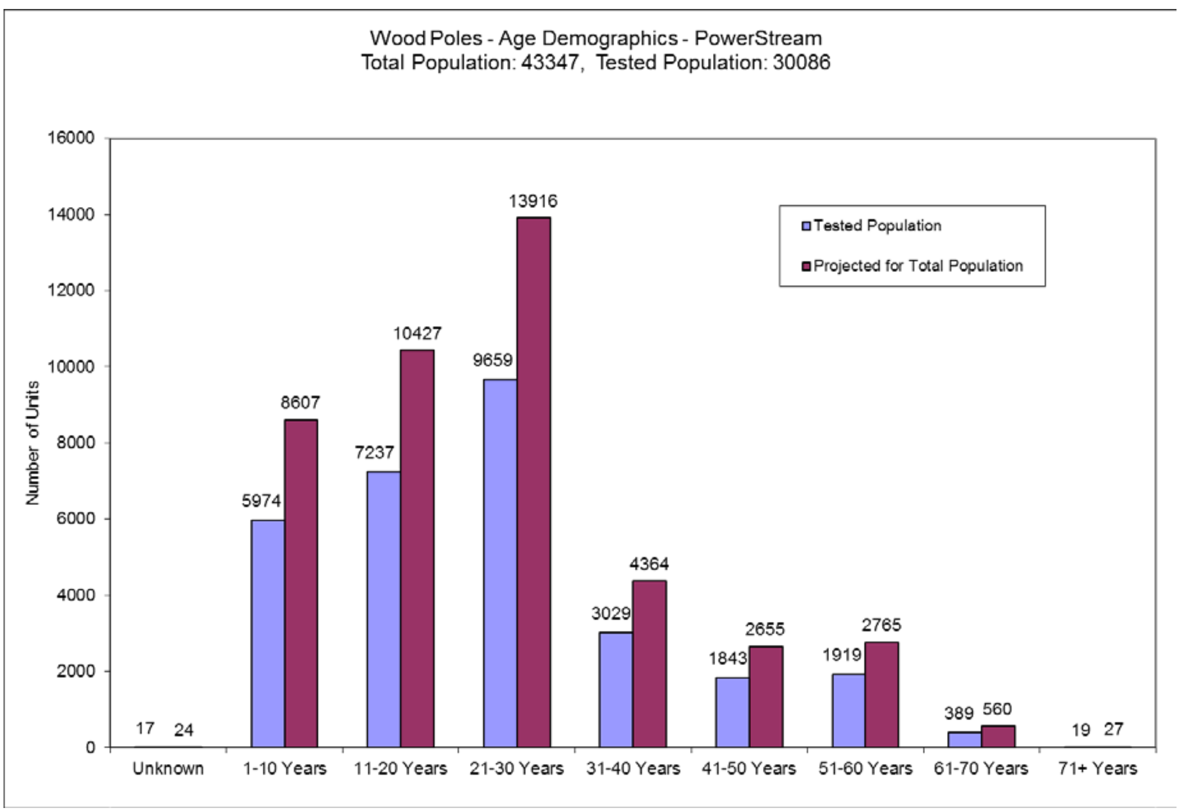
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

- *Useful life of **Wood Poles** is 35-75 years with typical useful life of 45 years.*

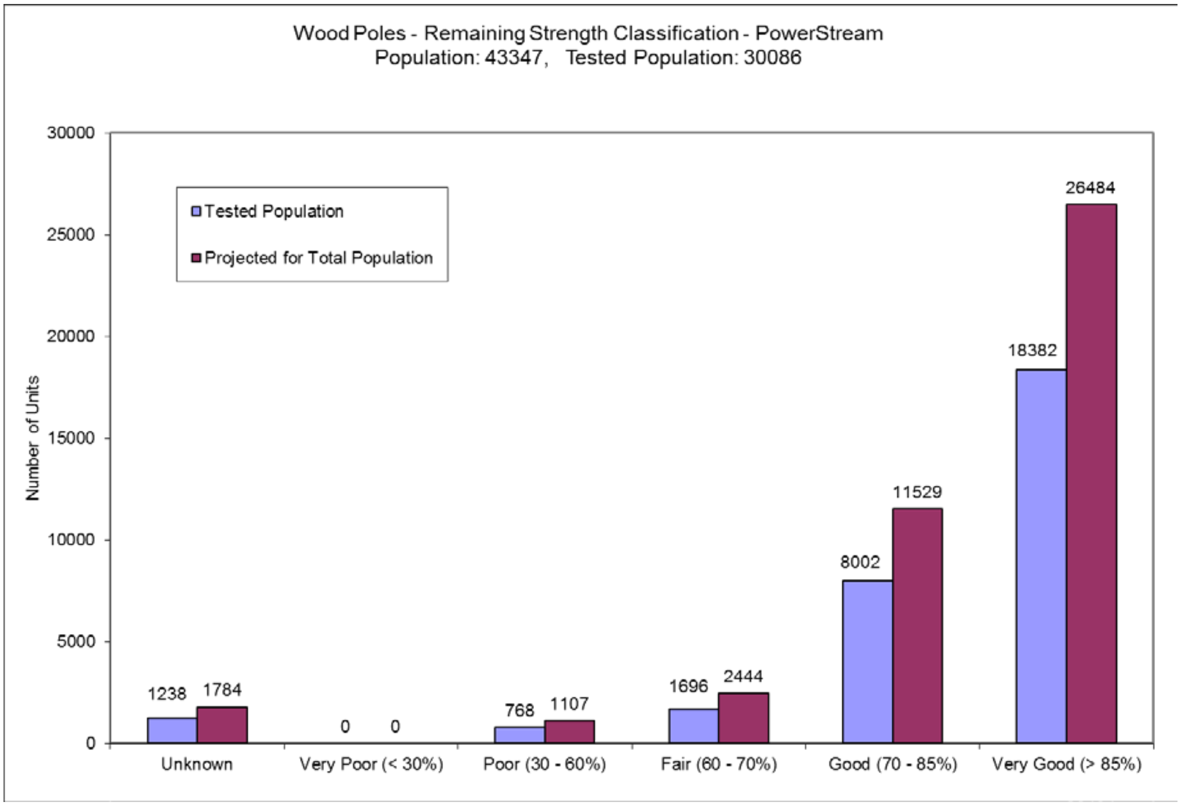
At PowerStream, for IFRS purposes, a useful life of 45 years is used for wood poles.

There are some data gaps with respect to pole age and pole condition. The "Projected" numbers show the estimated result, assuming that the portion of poles with missing data will have similar characteristics as those with data.

The following chart shows the Age demographics for Wood Poles in PowerStream.



The following chart shows the Condition demographics for Wood Poles in PowerStream.



Poles are a critical component of the distribution system as many types of equipment are attached to them (conductors, transformers, switches, street lights, telecommunication attachments, etc.). As a pole's physical condition and structural strength deteriorate, the pole may become inadequate for its intended function, and should be replaced to maintain the integrity of the distribution system.

The PowerStream pole testing program has revealed that a number of poles need to be replaced. One of the criteria used for replacement is "per cent remaining strength" as per CSA Standard C22.3 No. 1-10. Clause 8.3.1.3 of CSA Standard C22.3 No. 1-10 states that "when the strength of a structure has deteriorated to 60% of the required capacity, the structure shall be reinforced or replaced".

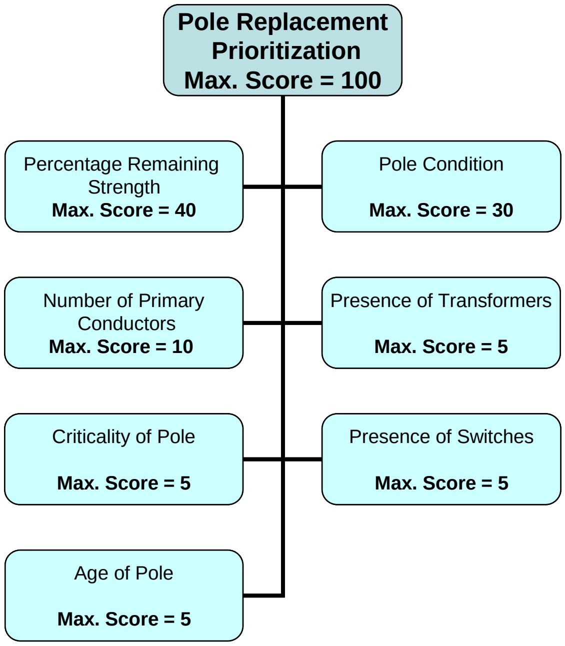
Poles that have been identified by the pole testing contractor as "need to be replaced" or poles that have a remaining strength of less than 60% present a safety risk to the public and staff if they fail when people are in the proximity of the poles. In addition if they fail, reliability and customer service will be negatively impacted.

Every year, on a prioritized basis, a number of poles are proposed for replacement due to the pole conditions and remaining strength. The replacement will have positive impact on PowerStream's goals to maintain public & staff safety, system reliability, and to meet OEB & CSA requirements.

The following criteria will be taken into consideration to prioritize the pole replacement program:

- Remaining Strength
- Pole Condition
- Number of Primaries
- Number of Transformers
- Switch on the pole
- Criticality of the pole (how important it is to the system)
- Age

The following chart shows the weight of each criterion in the pole prioritization model:



It is estimated that there are approx. 1,000 poles in the "poor" condition. It is expected that as the existing poles age and deteriorate, new testing results will show additional poles in poor condition.
To address the pole condition concern, it is recommended to replace 400 poles per year. It is expected that the pole replacement program will be an on-going program to maintain the integrity of the distribution system.

Cost of Pole Replacement (1a.1)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1a.1	Pole Replacement Program	$4,956,094	$5,071,697	$5,188,949	$5,307,899	$5,428,597	$25,953,236

Underground Switchgear Replacement Program (1a.2)

PowerStream has approx. 1851 distribution switchgear units in service.

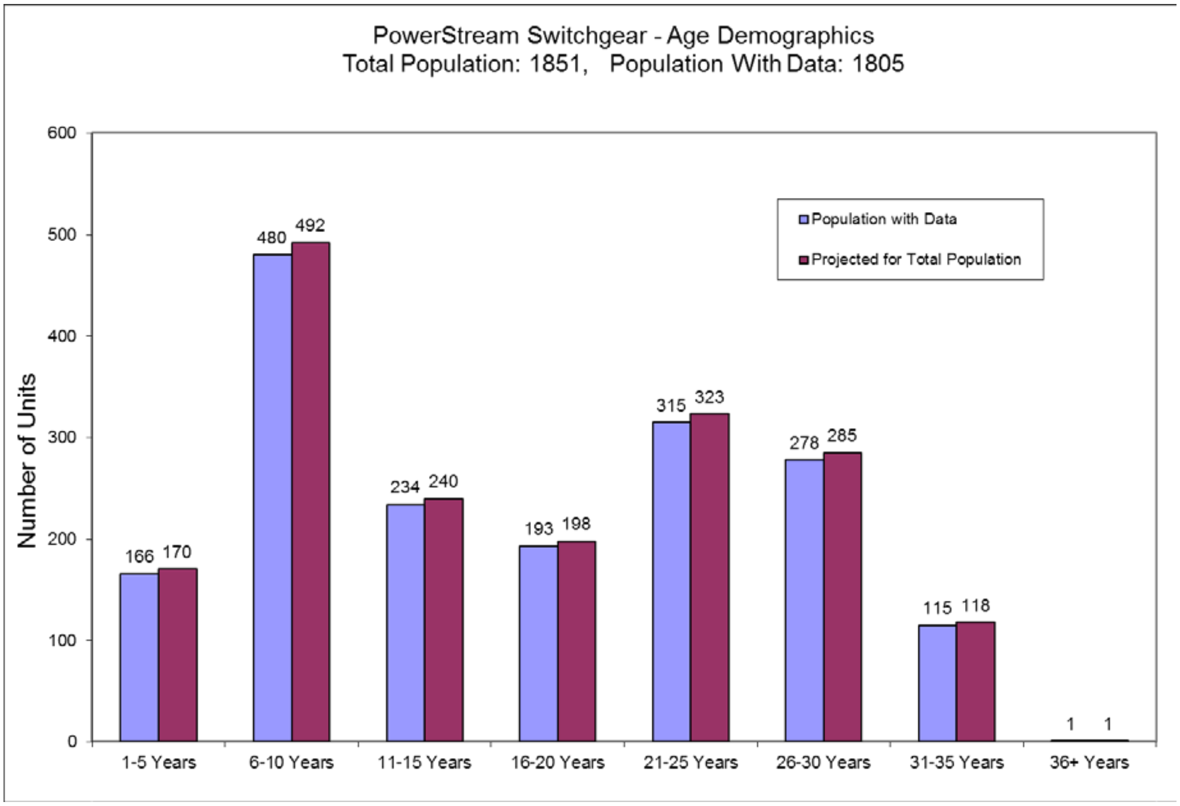
According to ***Kinectrics Inc. Report "Asset*** **Amortization Study for the Ontario Energy Board"**:

- *Useful life of* ***Pad-Mounted Switchgear*** *is 20-45 years with typical useful life of 30 years.*

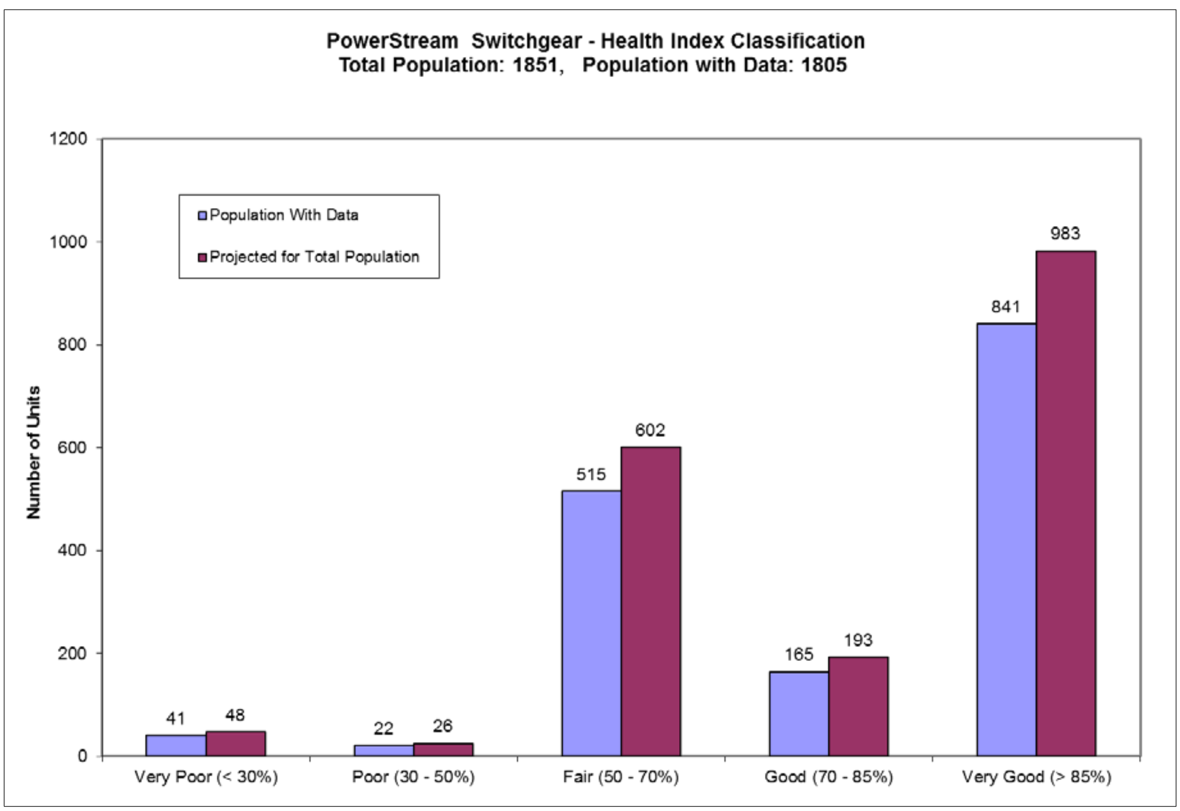
At PowerStream, for IFRS purposes, a useful life of 35 years is used for switchgear.

There are some data gaps with respect to distribution switchgear. The "Projected" numbers show the estimated result, assuming that the portion of Switchgear units with missing data will have similar characteristics as those with data.

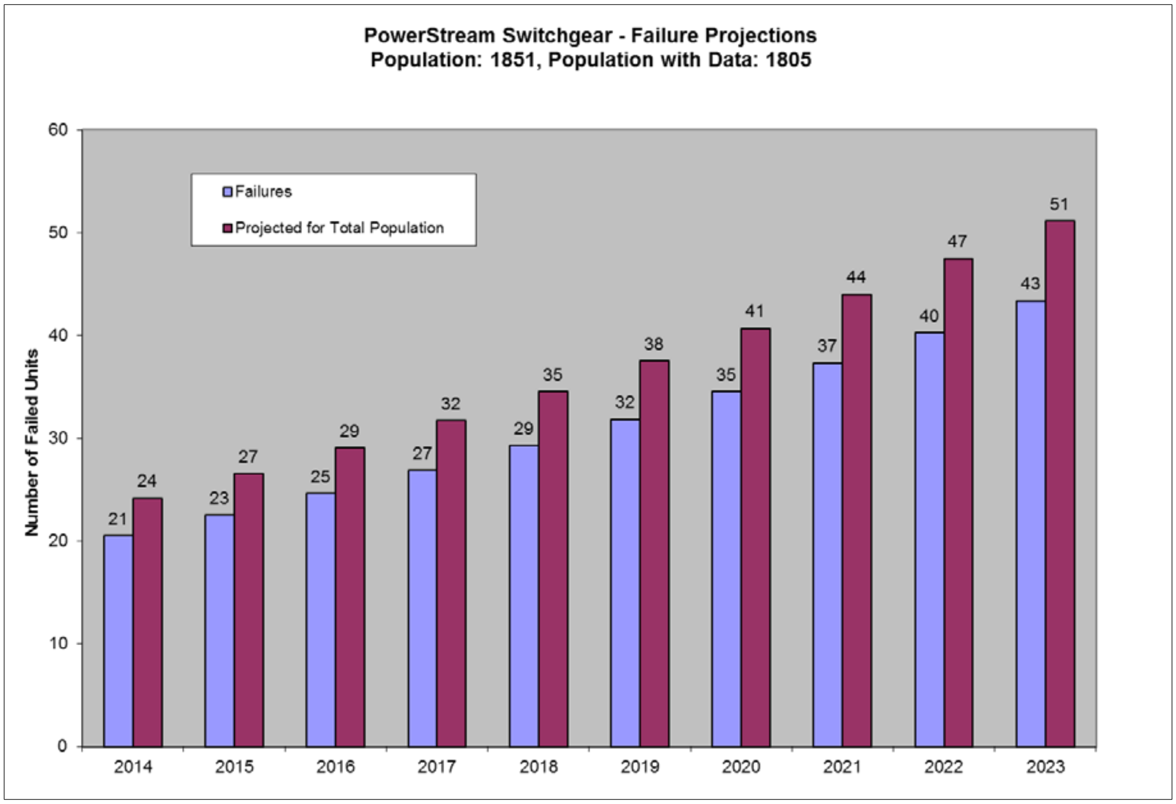
The Age demographics for Underground Switchgears are shown in the following chart.



The Condition demographics for Underground Switchgears are shown in the following chart.



The ACA Model projection of future switchgear failures is shown in the following chart.



PowerStream has experienced 15, 30, and 24 switchgear failures in 2010, 2011, and 2012 respectively (an average of 23 units per year). Budget requirement for emergency replacement of switchgear will be prepared and submitted by the Lines Department. As a result, the cost of switchgear emergency replacement is not included in this Five Year Capital Plan Report.

It is estimated that PowerStream has 74 switchgear units in very poor and poor condition. To maintain system reliability and customer service, on a prioritized basis, a number of switchgear units will be identified and recommended for proactive replacement.

It is expected that as the existing distribution switchgear units age and deteriorate, new inspection and analysis results will show additional switchgear units in poor condition. As a result, it is expected that the switchgear replacement program will be an on-going program to maintain the integrity of the distribution system.

Among the switchgear population in PowerStream South, it is estimated that there are approx. 1,000 units are PHM type. The operational concerns of PMH units are listed below.

- PMH units are live-front and are obsolete design. They are not approved for new installation and for planned replacement of existing units. PowerStream's long-term plan is to eventually phase out all PMH units.
- PMH units require regular maintenance (e.g. the cost of dry-ice cleaning is $500).
- PMH units are rated at 25 kV, but are operated at 27.6 kV. This increases the risk of flash over, especially with the presence of contamination and moisture.
- Failure rate of PMH units is high. PowerStream has experienced cases of flash over in units that are not old and units that had been recently maintained.

- During emergencies, sometimes a failed PMH unit is replaced with another PMH unit. During emergency, the trouble response crew has to restore power quickly for the customers. Because of the time constraint at the job site, the crew cannot wait for the concrete foundation and cable terminations to be modified to facilitate for the installation of new switchgear unit of different design and dimension. As a result, the crew has to use a new PHM unit. This will have the reverse impact on PowerStream's plan to reduce and phase out PMH units.

It is recommended to replace 30 units per year.

Cost of Underground Switchgear Replacement (1a.2)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1a.2	Undergound Switchgear Replacement Program	$2,323,235	$2,390,636	$2,459,927	$2,531,161	$2,604,401	**$12,309,360**

7.2 Sustainment Driven Lines Projects (1b)

This category mainly covers the Lines projects that are not capacity driven. It includes the following:

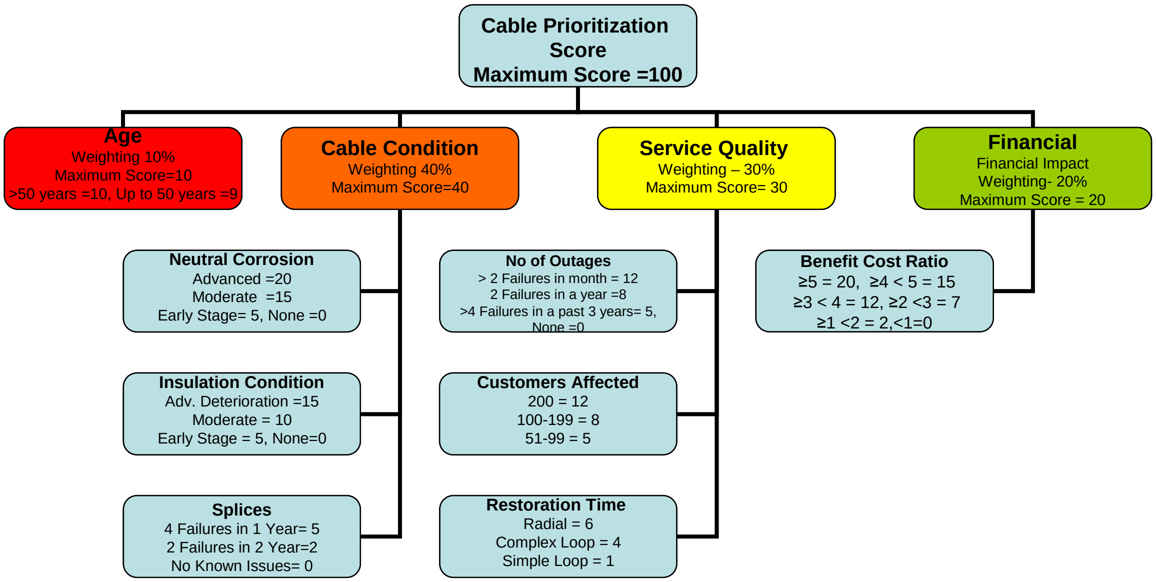
- Cable Replacement Projects (1b.1)
- Cable Injection Projects (1b.2)
- Lines Asset Replacement Projects (1b.3)
- Conversion Projects (1b.4)
- System Re-configuration Projects (1b.5)
- Radial Supply Remediation Projects (1b.6)
- Distribution Automation Lines Projects (1b.7)
- Reliability Driven Lines Projects (1b.8)
- Safety, Environment Driven Lines Projects ((1b.9)
- Compliance to External Directives / Standards Lines Projects (1b.10)
- Rear Lot Supply Remediation (1b.11)

Underground Cable Replacement and Cable Injection Prioritization Methodology

PowerStream's approach to manage the cable population is summarized below:

- PowerStream will address the cable aging issue by a combination of cable injection and cable replacement on a prioritized basis.
- PowerStream will conduct testing to determine the condition of the cable.
- PowerStream has developed a cable prioritization system to select cable replacement and cable injection candidates.
- The cable replacement program will last for 20 years initially and continue at the similar rate afterward.
- The cable injection program will last for 10 years then terminate.

The Prioritization Methodology for Cable Replacement and Cable Injection is shown on the following diagram.



The details of the underground cable replacement and injection programs are described below.

Cable Replacement (1b.1)

PowerStream has approx. 8,000 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

- *The useful lives of various types of underground cable are listed below.*

Cable Type	Minimum Useful Life (MIN UL)	Typical Useful Life (T UL)	Maximum Useful Life (MAX UL)
Primary Non-Tree Retardant XLPE - Direct Buried	**20 Years**	**25 Years**	**30 Years**
Primary Non-Tree Retardant XLPE - In Duct	**20 Years**	**25 Years**	**30 Years**
Primary Tree Retardant XLPE - Direct Buried	**25 Years**	**30 Years**	**35 Years**
Primary Tree Retardant XLPE - In Duct	**35 Years**	**40 Years**	**55 Years**

At PowerStream, for IFRS purposes, a useful life of 35 years is used for pre-1987 cable and a useful life of 45 years is used for post-1987 cable.

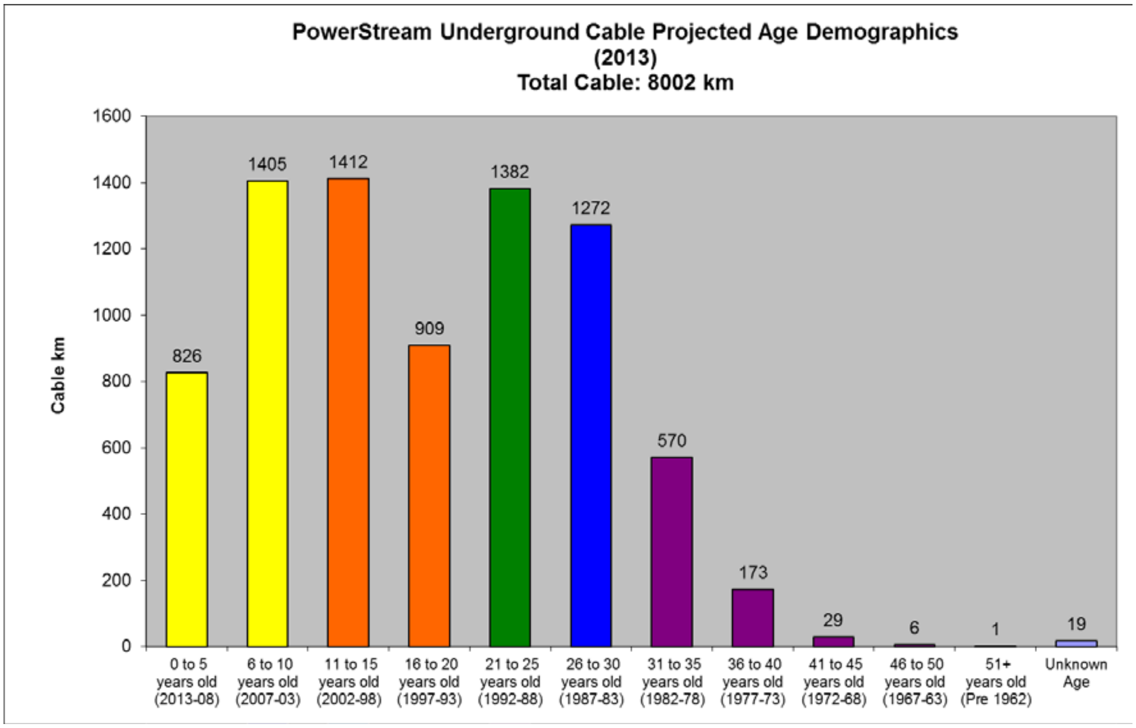
The Kinectrics Report indicates that the useful life is dependent on a number of Utilization Factors listed below.

- Mechanical Stress
- Electrical Stress
- Operating Practices
- Environment Conditions

- Maintenance Practices
- External Factors

There are some data gaps with respect to cable age. The “Projected” numbers show the estimated result, assuming that the portion of cable with missing data will have similar characteristics as those with data.

The current Age Demographics for Underground cable is shown in the following chart.



As the cable gets older and the condition deteriorates, it will fail. Initially PowerStream can repair or replace the faulted cable segment under reactive emergency response. But if the cable fails too often, it will result in unacceptable service to the customer, and unacceptable repair costs to PowerStream.

There are two methods of intervention to address the cable aging issue:
- Cable Replacement – replace existing cable
- Cable Injection – extend existing cable service life

The Cable Replacement option is more expensive than the Cable Injection option with respect to initial capital cost, but it has the advantage of new cable that will be utilized for a longer time. In comparing the two options: the extra life expected from injected cable is 15-20 years; the life of new cable is expected to be 50-55 years; the cost/benefit ratio is 15% better for cable injection compared to new cable. Cable injection is viable for only a certain population of cable.

Currently, PowerStream is conducting field trial with Cable Injection technology to gain more experience. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. If it is determined that Cable Injection is no longer a viable option, then Cable Replacement will become the only alternative. In that case, the quantity that is proposed for Injection will be proposed for Replacement.

PowerStream will address its Underground Cable assets by using a combination of Cable Replacement and Cable Injection as a means of intervention. The Cable Replacement plan (discussed later in this Section) will be on-going as we will continually need to replace cable as it gets older. This report will cover the first 20 years of the plan. It is expected that the Cable Replacement plan will continue at a similar spending level after the first 20 years.

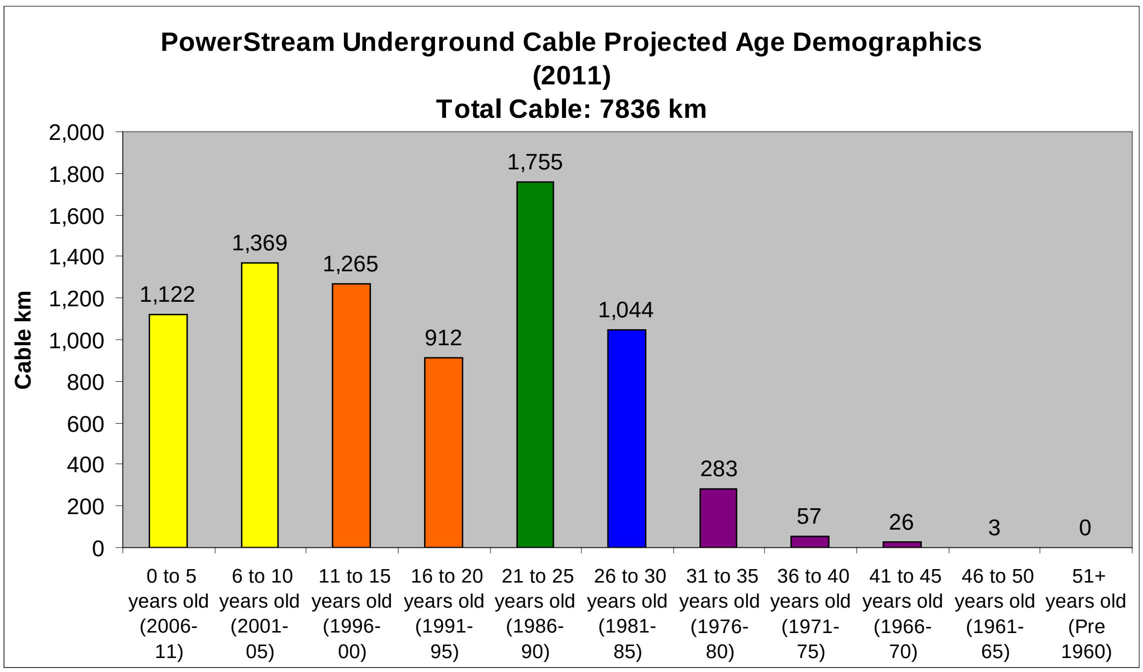
The Cable Injection plan (discussed in the next Section - Cable Injection) will take place over a period of 10 years. After 10 years all suitable candidates for injection will be exhausted, therefore this plan will not be on-going.

20-Year Cable Replacement Plan:
In 2011, a general plan to address the cable issue (a 20 year plan for cable replacement, and a 10 year plan for cable injection) was developed and approved by PowerStream management.

To develop the cable plan, the 2011 cable age demographics was used to divide the cable population into the following 5 groups:

- Group 1: 31 years and older (1980 and older)
- Group 2: Between 26 – 30 years (1981-1985)
- Group 3: Between 21 – 25 years (1986 – 1990)
- Group 4: Between 11 – 20 years (1991 – 2000)
- Group 5: Between 1 – 10 years (2001 and younger)

The 2011 cable age demographics and age groups are described below.



Group 1: 31 years and older (1980 and older):
It is estimated that PowerStream has approx. 370 km of cable older than 30 years.
This population is the older generation of cable that was manufactured with old technologies and processes, using inferior insulation material (non-tree-retardant XLPE). In addition, due to age, and installation method (direct buried) the neutral wires are likely corroded. Samples of recent cable failures show that the neutral wires have corroded beyond repair. Cables in this population may be at or close to end-of-life stage and are candidates for cable replacement. As a result Group 1 is excluded from Cable Injection.

Group 2: Between 26 – 30 years (1981 – 1985):
It is estimated that PowerStream has approx. 1,044 km of cable between 26 – 30 years.
This population is also the older generation of cable as described in Group 1 above. It is assumed that the cable components have not deteriorated significantly yet. Cables within this population could be candidates for cable injection. However, it should be noted that a significant portion of this group may not be viable candidates for cable injection, depending on forthcoming tests. For our purposes we assume that 50% (i.e. 522 km) of this population is not suitable for injection and must be replaced, this quantity will be managed under the Cable Replacement Program. The remaining quantity 50% (i.e. 522 km) of this

population is suitable candidates for injection, this quantity will be managed under the Cable Injection Program. This issue is covered in detail in the next Section – Cable Injection.

Group 3: Between 21 – 25 years (1986 – 1990):
It is estimated that PowerStream has approx. 1,755 km of cable between 21 – 25 years.
This population is a newer generation of cable that was manufactured with new technologies and processes (similar to Group 4 and Group 5), for example, the use of tree-retardant XLPE for insulation and triple extrusion process. Because water trees are not a concern for this group of cable, and cable injection's main purpose is to repair water trees, injection is not effective for this group of cable. In addition, this population has likely been manufactured using strand-filled material, which does not allow the injection fluid to flow through and therefore injection is not possible. This population of cable will need to be addressed at the end of the 20-year period once the first two groups of cable have been dealt with.

Group 4: Between 11 – 20 years (1991 – 2000):
It is estimated that PowerStream has approx. 2,177 km of cable between 11 – 20 years.
At the end of the 20-year proposed plan, this population should still maintain a low failure rate and it is estimated a portion of this group will still operate better than Group 3.

Group 5: Between 1 – 10 years (2001 and younger):
It is estimated that PowerStream has approx. 2,501 km of cable between 1 – 10 years.
Because this cable is new, it is not an immediate concern. It is assumed it will last well beyond the end of the 20-year plan.

The intent of this program is to start to address the aging cable population in a timely manner so that the future spending level (after 20 years) will be manageable.

To address the Group 1 population of 370 km of cable older than 30 years, and 50% of the Group 2 population of 522 km of cable between 26 – 30 years (total = 370 km + 522 km = 892 km), it is recommended to replace 47 km per year from 2013 – 2031. At this rate, all of the 892 km will have been replaced by 2032.

Currently, PowerStream does not have sufficient physical condition and test data to determine the degree of deterioration and to estimate the remaining life of the cable population.

In 2012 PowerStream started conducting cable testing (Tan Delta test) to assess the condition of cable to:

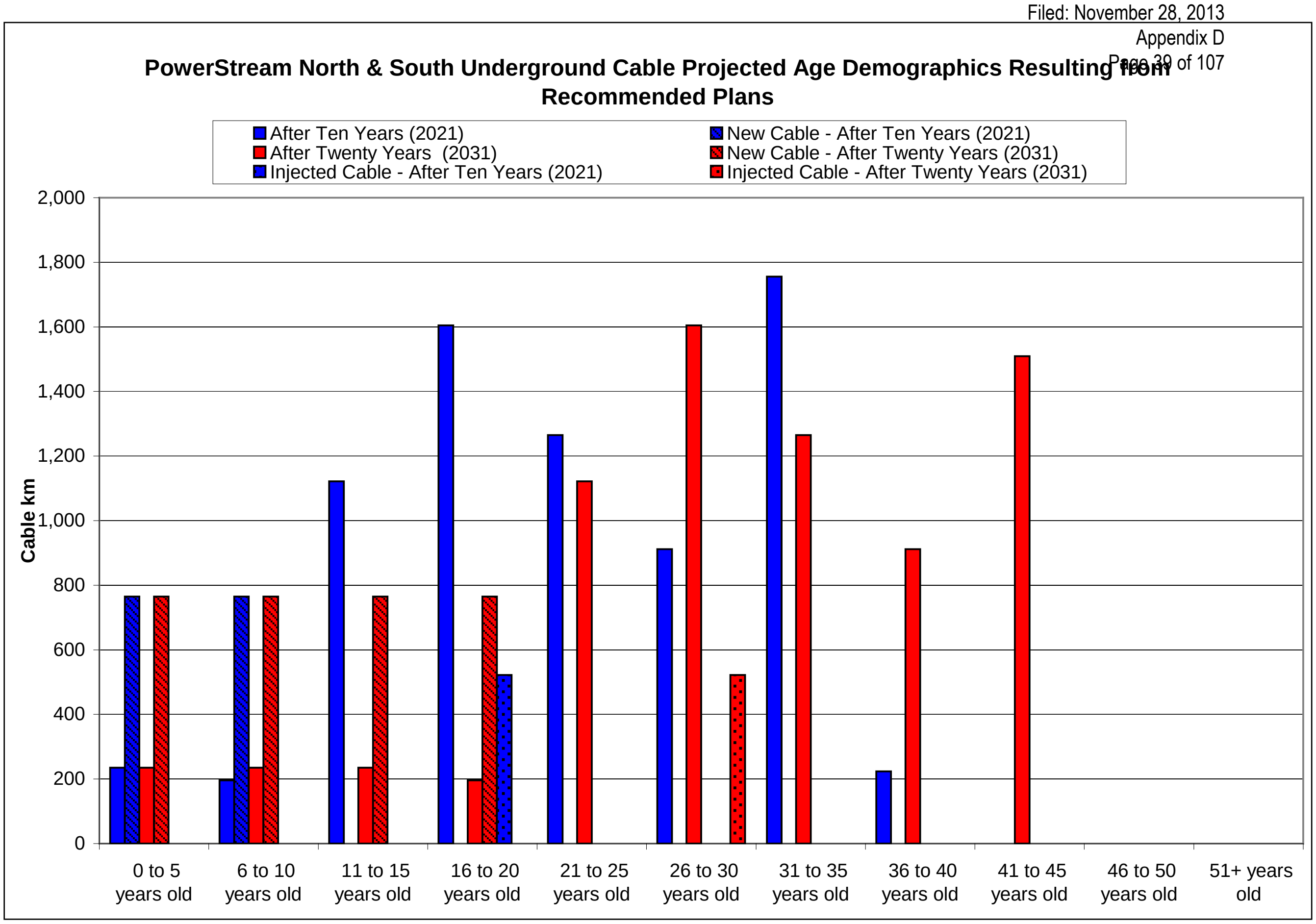
- Determine which intervention method (replacement vs. injection) is more suitable to a specific location.
- Determine the appropriate quantity and timing of cable intervention (replacement / injection).
- Validate and prioritize the cable replacement/injection projects.

The following chart shows the cable age profile projections resulting from the proposed plan.

The quantities are shown 10 years and 20 years into the program.

The blue bars indicate the resulting age profiles 10 years into the program.

The red bars indicate the resulting age profiles 20 years into the program.



Based on the above chart, after 20 years PowerStream will have 1,745km of cable that is 41 to 45 years old. While this is a higher quantity of cable in the age range as compared to the quantity at the start of the program, these cables will be 2nd and 3rd generation cable with improved production quality and corresponding longer expected service life as compared to the cable being addressed in the first 20 year replacement program. At that time this group of cable will be in or entering end-of-life conditions, therefore the replacement program will likely continue at a suitable replacement level to address this population of cable.

The above demonstrates that the proposed 20 year Cable Replacement plan during the first 20 years will result in cable demographics that are reasonably well distributed after 20 years (similar to the first 20 years), supporting the premise that this is the correct level of cable replacement for this asset class.

Status of Cable Replacement/Injection Programs
PowerStream will keep track of its cable replacement and cable injection programs in order to determine their progress. The progress in 2012 of the programs is summarized in the following table:

Cable Status				
Year	**Planned Replacement (m)**	**Actual Replacement (m)**	**Planned Injection (m)**	**Actual Injection (m)**
2011	**10,151**	**10,332**	**8,000**	**9,566**
2012	**8,461**	**9,061**	**10,000**	**25,103**
2013	**51,343**	**To be updated in Dec.**	**68,406**	**To be updated in Dec.**

Cost of Cable Replacement (1b.1)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.1	Cable Replacement Projects	$16,844,793	$13,933,827	$14,331,929	$14,741,300	$15,312,065	**$75,163,914**

Cable Injection (1b.2)

As the cable gets older, the cable insulation may develop a premature aging process caused by a phenomenon known as "water treeing". Water trees will reduce the breakdown strength of the insulation and eventually lead to cable failure. The Cable Injection process will inject silicone chemicals down the strands of the cable. The silicone fluid will diffuse out of the strands through the strand shield and into the insulation. The fluid then polymerizes with water (or moisture) and the silicone molecule grows and fills all water trees and voids. This increases the dielectric strength of the cable and thus extends the life of the cable.

It should be noted that cable dielectric failure may result from causes other than “water treeing” alone. Some examples include impurity, presence of by-products, contaminants, gas, electric trees, etc. As a result, there are many cases where the cable injection process is not effective.

A pilot project on Cable Injection was started in 2009 and completed in 2010. The final report recommended that PowerStream continue with cable injection to polyethylene cable of earlier vintage.

The criteria for selecting Cable Injection candidates are listed below.

- Pre 1989
- Not solid core
- Not strand-filled
- Concentric neutral not corroded significantly
- No electrical trees present (Cable Injection only can repair water trees and not electrical trees)
- Not having too many splices within a cable segment

Group 1 cables (31 years and older in 2011) are assumed to be close to end-of-life. Samples of recent cable failures show that the neutral wires have corroded beyond repair. As a result Group 1 is excluded from Cable Injection.

Group 2 cables (26-30 years in 2011) could be candidates for Cable Injection provided that the above conditions are met. It should be noted that a significant portion of this group may not be viable candidates for cable injection, depending on forthcoming tests. We assume that 50% (i.e. 522 km) of this population is suitable for injection.

Groups 3, 4 and 5 cables (25 years or younger in 2011) are assumed to have been manufactured with new technologies and processes using tree-retardant XLPE and triple extrusion process and strand-filled material. In general, water trees are not a concern and therefore injection is not effective. As a result Groups 3, 4, and 5 are excluded from cable injection.

Because the Cable Injection option has a number of limitations, a portion the Group 2 population may not be candidates for Cable Injection. For example, it may be more economical to replace cables if there are multiple phases in a trench, or multiple splices in a segment. Another example is during cable failure repair, operations staff adds two new splices to the segment, and one piece of new cable between the splices. As the new piece of cable is strand-filled, injection is not possible for this cable segment. Furthermore, depending on the design and condition of the cable at a specific location (e.g. strand-filled, neutral corrosion, electrical trees) the Cable Injection process may not be feasible at all.

To determine feasibility of cable injection, cable will be tested using cable diagnostic testing such as Tan Delta tests.

In 2011 PowerStream completed 2 cable injection projects using two different contractors.
In 2012 PowerStream completed 2 cable injection projects using two different contractors.
In 2013, PowerStream will proceed with cable injection projects to continue to gain experience.

PowerStream, beginning in 2012, conducted cable testing (Tan Delta tests) to further assess the condition of cable to:

- Determine which intervention method (replacement vs. injection) is more suitable to a specific location.
- Determine the appropriate quantity and timing of cable intervention (replacement/injection).
- Validate and prioritize the cable replacement/injection projects.

The Tan Delta test results were very beneficial for PowerStream to determine the severity of cable degradation and to prioritize the cable candidates. PowerStream plans to continue with the Tan Delta testing process.

As PowerStream is still gaining experience with cable injection technologies and processes, proceeding with injection projects will be done prudently. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. If it is determined that Cable Injection is no longer a viable option, then Cable Replacement will become the only alternative. In that case, the quantity that is proposed for Injection will be proposed for Replacement.

10-Year Cable Injection Plan:
To address the 50% of the Group 2 population of 522 km of cable aging between 26 – 30 years, it is recommended to:

Inject 57 km per year from 2013 – 2022.

10 years is the optimal time period to get the benefit of the injection program for Group 2. If we extend the period beyond the 10 years, the remaining population of Group 2 may become too old to remain suitable candidates for injection.

At this rate all of the 522 km cable between 26-30 years will have been rehabilitated by 2022.

Cost of Cable Injection (1b.2)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.2	Cable Injection Projects	$4,103,660	$4,219,823	$4,339,040	$4,461,402	$4,587,004	**$21,710,929**

Lines Asset Replacement Projects (1b.3)
This work covers the following:
- Overhead Transformer Replacement
- Underground Transformer Replacement

Overhead Transformer Replacement

PowerStream has 7,280 Overhead Transformers in service.

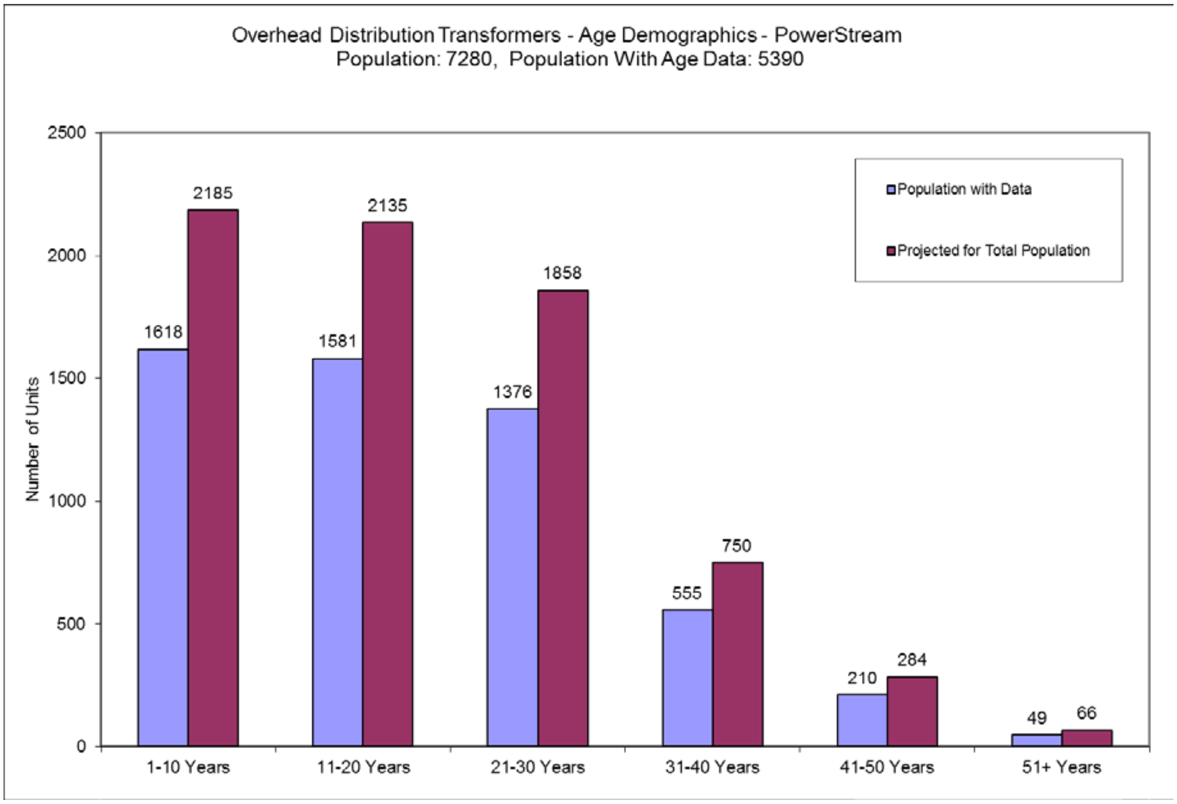
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

- *Useful life of **Overhead Transformers** is 30-60 years with typical useful life of 40 years.*

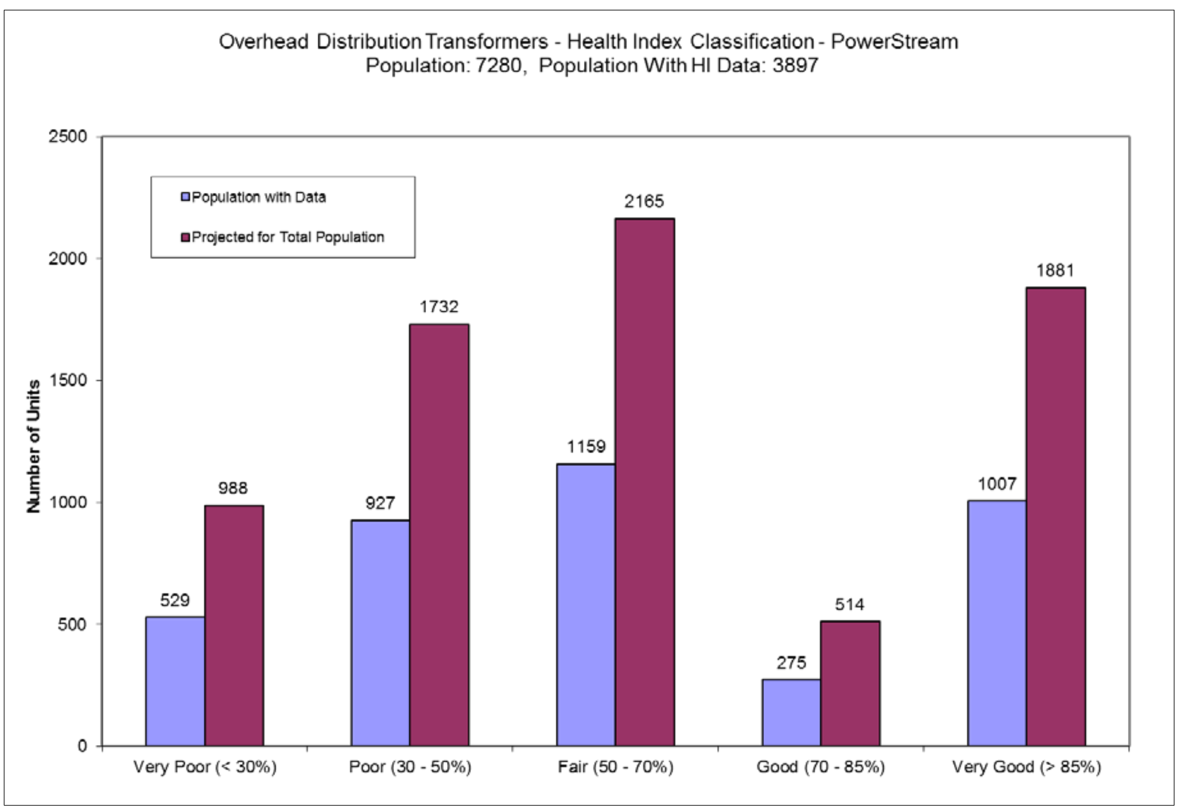
At PowerStream, for IFRS purposes, a useful life of 40 years is used for Overhead Transformers.

There are some data gaps with respect to Overhead Transformers age and condition. The "Projected" numbers show the estimated result, assuming that the portion of Transformers with missing data will have similar characteristics as those with data.

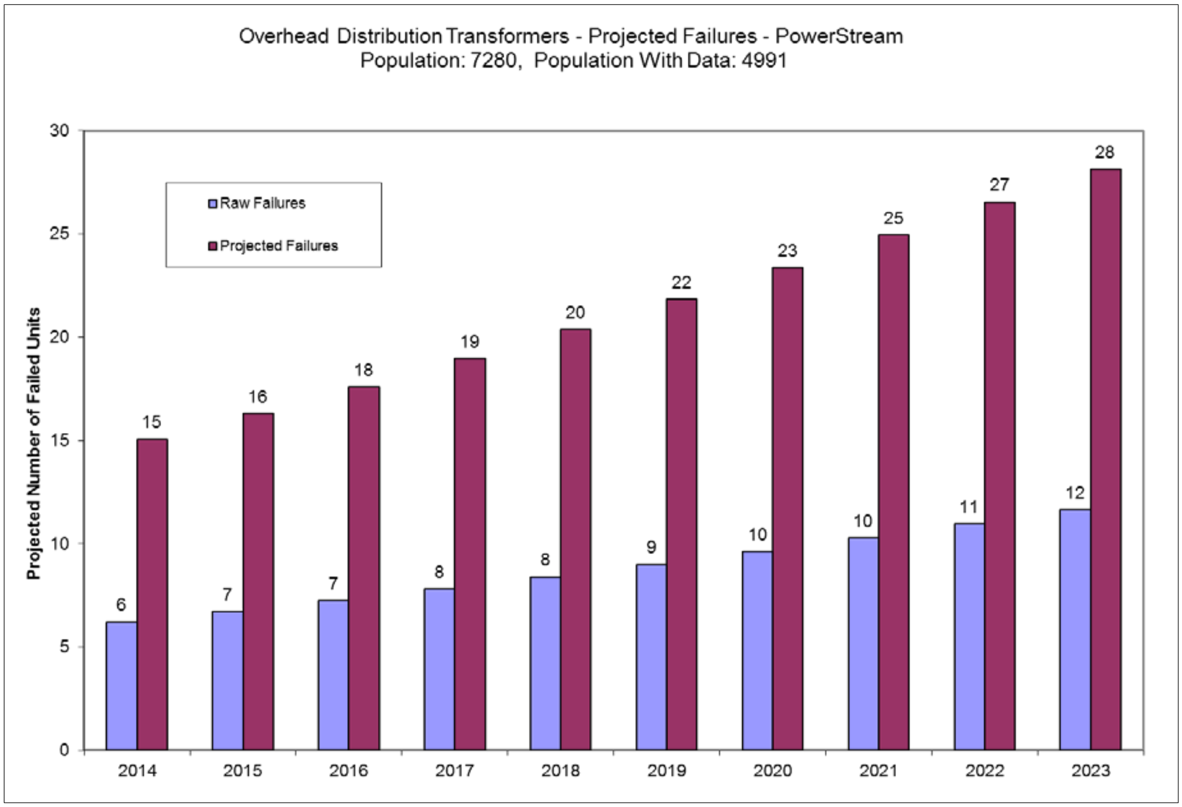
The age demographics for Overhead Transformers are shown in the following chart.



The Condition demographics for Overhead Transformers are shown in the following chart.



The ACA Model projection of future Overhead Transformer failures is shown in the following chart.



With regards to Overhead Transformers, PowerStream will operate based on a run-to-failure approach. It was determined that proactive replacement of Overhead Transformer is not cost effective.

The risk and consequence of failure is low. PowerStream has experienced 15, 19, and 44 Overhead Transformer failures in 2010, 2011, and 2012 respectively (an average of 26 units per year). Budget requirements for emergency replacement of Overhead Transformers will be prepared and submitted by the Lines Department.

PowerStream presently has sufficient capability and effective process and procedures to manage these asset failures at the current failure rate.

As a result of this approach, this Five Year Capital Plan does not propose any planned replacement of Overhead Transformers. Therefore, no cost is included in this Five Year Capital Plan.

Underground Transformer Replacement
PowerStream has 34,867 Underground Transformers in service.
In this section, there are two types of Underground Transformers being discussed:

- Padmount Transformers
- Submersible Transformers

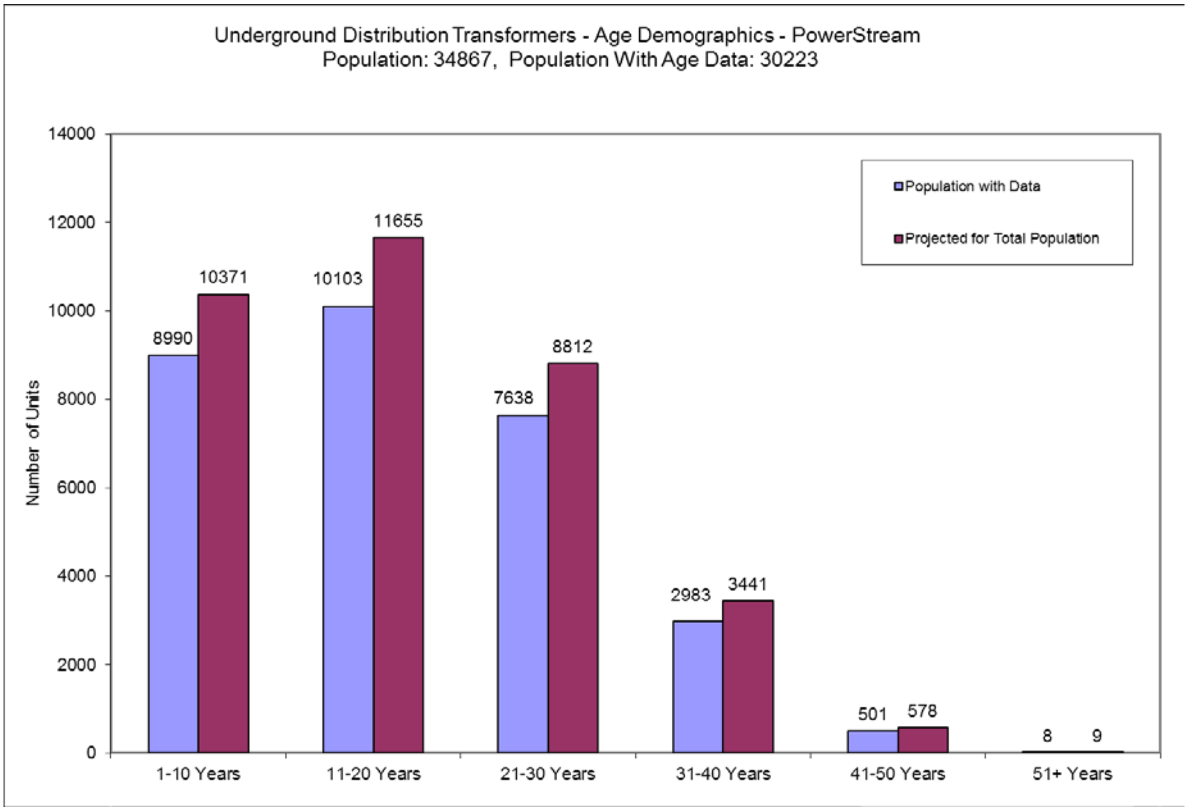
According to **Kinectrics Inc. Report “Asset Amortization Study for the Ontario Energy Board”**:

- *Useful life of a **Padmount Transformer** is 25-45 years with typical useful life of 40 years.*
- *Useful life of a **Submersible Transformer** is 25-45 years with typical useful life of 35 years.*

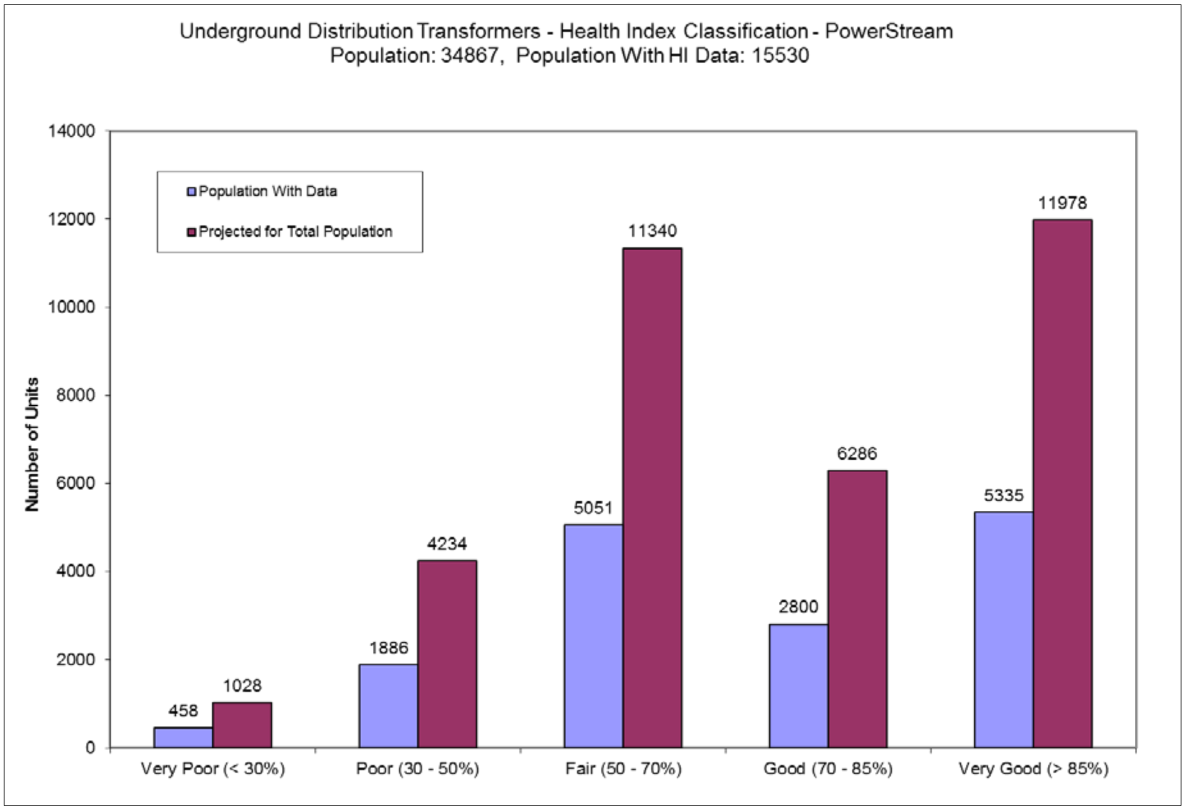
At PowerStream, for IFRS purposes, a useful life of 30 years is used for both Padmount and Submersible type transformers.

There are some data gaps with respect to Underground Transformers age and condition. The “Projected” numbers show the estimated result, assuming that the portion of Transformers with missing data will have similar characteristics as those with data.

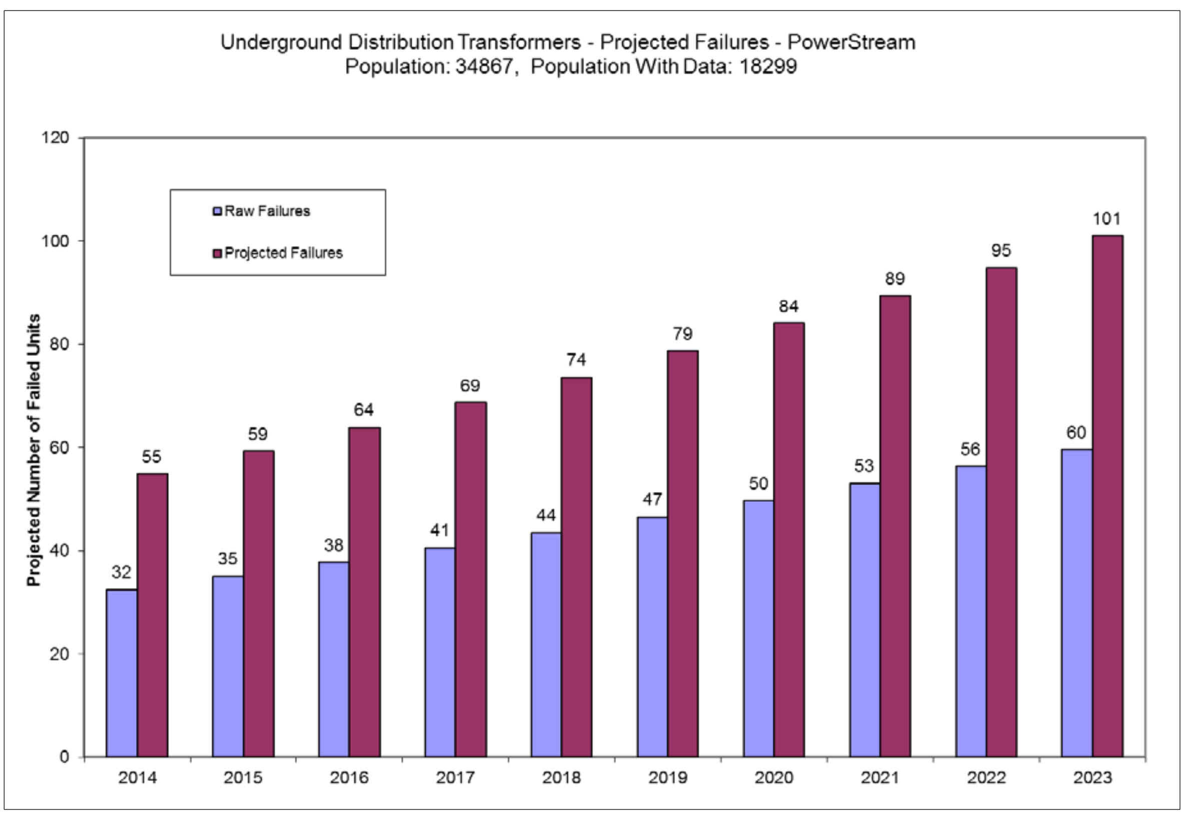
The Age demographics for Underground Transformers are shown in the following chart.



The Condition demographics for Underground Transformers are shown in the following chart.



The ACA Model projection of future Underground Transformer failures is shown in the following chart.



Padmount Transformer Replacement

With regards to Padmount Transformers, PowerStream used to operate based on a run-to-failure approach. However, starting from 2013, a proactive replacement project has commenced to replace the worst 50 units based on the results of the inspection program. This work is grouped under Category 1c Emergency / Restoration (see Section 7.3 – Emergency / Restoration).

Submersible Transformer Replacement in PowerStream South

In 2008 System Control identified 91 equipment locations to be retro-fitted to meet a new operations switching procedure. Of the 91 locations, 23 locations are in Richmond Hill and 68 in Markham.

The existing submersible unit design and installation do not provide sufficient access to allow field staff to perform switching operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers. The retro-fitting work includes installation of switches, splice out, and replacement of submersible transformers with Padmount transformers. This will make the design and installation similar with the majority of other existing locations in the system, facilitating normal work procedures for field staff.

The project received approval and started in 2009 and continued in 2010, 2011, 2012 and will continue in 2013. The intent was to complete the project over a period of 5 years. It is expected that all the identified locations will have been rectified by the end of 2013.

Submersible Transformer Replacement in PowerStream North

In 2010 Lines Department identified 57 submersible transformer locations in the Barrie area to be retrofitted to meet the new operations switching procedure.

The existing installations do not provide sufficient access to allow field staff to perform switching and maintenance operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers.

The transformers are obsolete and no longer purchased by PowerStream. These units are of a very old vintage, dating back to 1967 and are at end-of-life. They are no longer manufactured, and spare parts are non-existent.

The concerns with continued operation of this supply system are summarized under the following 9 items:

1. The transformer units are connected using non-load break equipment which means they cannot be connected or disconnected while energized. As a result, portions of the circuit must be isolated when work is required on any part of the primary system, resulting in approx. 18 hours of interruption when an unplanned event occurs.

2. The isolation can affect several transformers pending the circuit configuration and may disrupt up to 100 customers at a time.

3. Trouble response work becomes very complicated because of the fusing design. The fuse is connected to a non-conductive fiberglass support system held in place with metal bolts to a metal structure. Faults have occurred passing through the bolts to the grounded equipment. This path cannot be seen from any opening, and is impossible to confirm without dismantling the unit.

4. Failures such as described in item 3 above have resulted in the fuse housing being by-passed and the terminations being bolted together in order to restore the circuit.

5. Replacement parts are not available.

6. The physical size of the units restricts any use of live line techniques and requires a "hands on" approach which requires isolation. This would typically involve disconnection, potential testing and grounding.

7. The vault that contains the transformer is undersized. There is only 8 cm (3 inch) between the vault wall and the transformer. As a result, cable movement is next to impossible and work on

connections is very limited. The lack of clearance within the unit also prevents access to the potential test points and approved grounding equipment is not available.

8. The primary cable installed between these units is non-jacketed cable. At many locations, the concentric neutral wires have corroded significantly or are non-existent. This is a concern for line staff who rely on system neutral to be able to effectively ground their work zone.

9. Secondary cable is comprised of many tee taps which several services may be connected to. As a result, in the event of a "burn-off", several services can be out of power.

For the above reasons, the submersible transformers should be replaced.

The issues were discussed in the PowerStream Reliability Committee meeting of July 7, 2010. The Reliability Committee has agreed that the units should be replaced.

The project received approval and started in 2011, continued in 2012 and will continue in 2013. The intent was to complete the project over a period of 5 years. It is expected that all the identified locations will have been rectified by the end of 2015.

Mini-Rupter Switch Replacement

In 2013 PowerStream will start to review the performance of the existing Mini-Rupter switch population. There are concerns about the reliability and operability of these switches. The switches are installed inside vaults. Field crews are not willing to operate these switches live. As a result, additional switching operations at adjacent switchable locations are required which would increase outage time to customers, and have a negative impact on system reliability. Lines and System Planning proposed to replace these switches with solid dielectric switches.

Cost of Lines Asset Replacement Projects (1b.3)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.3	Lines Asset Replacement Projects	$1,731,604	$1,716,975	$551,113	$0	$0	$3,999,692

Conversion Projects (1b.4)

The objective of voltage conversion projects is to improve power supply reliability, and reduce line losses and maintenance.

In Power Stream North (Barrie, Bradford, Alliston, Thornton, Penetanguishene, Beeton & Tottenham) there are three distribution voltages: 4.16 kV, 8.32 kV and 13.8 kV. These voltages are well established within their particular supply area and there are no plans to carry out planned voltage conversion in PowerStream North.

There are three distribution voltages in Power Stream South (Markham, Richmond Hill and Vaughan, and Aurora) network: 27.6 kV, 13.8 kV and 8.32 kV. For the most part, PowerStream uses the 27.6 kV voltage level to distribute electricity. A small amount of load (2%) is supplied at 13.8 kV or 8.3 kV from Municipal Stations (MS).

The 13.8 kV and 8.3 kV systems are fed from substations in Vaughan and Markham in the form of isolated islands. There are two 27.6 kV/13.8 kV substations and two 27.6 /8.3 kV substations in Markham. There are three 27.6/8.3 kV substations and one 27.6/13.8 kV substation and in Vaughan. There are no 13.8 kV or 8.3 kV systems in Richmond Hill.

A Municipal Station typically comprises one or two step down (27.6/8.3 or 13.8 kV) transformers, and associated switches, circuit breakers that are enclosed within a fenced area.

The MS’s are very lightly loaded due to voltage conversion efforts made in the past. For example, the transformer capacity in Rainbow MS is 13.3 MVA, but the peak load on the transformers was 0.6 MW in 2010.

The presence of 13.8 kV and 8.3 kV systems causes extra losses on the system due to 27.6 kV/13.8 kV or 27.6 kV/8.3 kV transformation and higher losses in 13.8 kV and 8.3 kV feeders.

The 13.8 kV and 8.3 kV systems are also costly in that additional 13.8 kV & 8.3 kV rated equipment has to be carried in inventory even though the 13.8 kV and 8.3 kV systems supply only 2% of system loads. The MS stations were built between 1958 and 1976. Some units are approaching end-of-life and there is potential for significant expenditure to repair and replace aging units. Amber, Morgan, John and Elder Mills substations have experienced power transformers failures between 1989 and 2010.

Low voltage supply areas are located in isolated areas similar to "islands". Some of them are supplied by one single transformer or single feeder. Any transformer or feeder failure will cause prolonged outage to the customers.

Net Present Value (NPV) method is used to justify voltage conversion projects.

The conversion projects for the next ten years are listed below.

- Concord MS (Phase 1, Phase 2, and Phase 3)
- Elder Mills MS (3F2 and 3F3)
- Amber MS F3
- Morgan MS

Cost of Conversion Projects (1b.4)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.4	Conversion Projects	$1,122,440	$495,000	$55,000	$1,355,244	$0	**$3,027,684**

System Re-configuration Projects (1b.5)

System Planning, in consultation with System Control and Lines, recommend a number of projects to resolve feeder loading balancing and load transfer capability under normal and emergency situations. Operations and safety issues will be considered.

Cost of System Re-configuration Projects (1b.5)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.5	System Reconfiguration Projects	$31,794	$0	$0	$0	$0	**$31,794**

Radial Supply Remediation Projects (1b.6)

Distribution networks can be designed to distribute power in a number of different ways depending on the nature of the load and the level of reliability needed. There are five types of networks: Radial, Dual Radial, Closed Loop, Open Grid (Open Loop), and Network Supply.

Open Grid is the most common method of supply in urban areas. The primary reason is that it is less costly than other systems, and provides a reasonable level of reliability. It is also much simpler to analyze, plan, design and operate. In the Open Grid network, multiple feeders traverse a distribution area with multiple interconnections between the feeders at various points, i.e. normal open points. In the event of a fault on a feeder or loss of supply to a particular feeder, adjacent feeders could pick up supply to customers, except for those customers in the faulted area. The ability of adjacent feeders to pick up load is limited by the preloaded state and spare capacity available.

PowerStream's distribution network has been designed as an Open Grid network. "PowerStream Planning Philosophy" recommended to continue with the current "open grid" feeder design and to provide for full backup capability over peak loading periods through switching of load to adjacent feeders.

Radial supply situations do exist in PowerStream South. A report titled "PowerStream Radial Supply Review" was completed in 2007 to review radial supplies in PowerStream South and recommend necessary remediation to minimize the impact of radial supplies at reasonable cost.

PowerStream North also has areas that are supplied radially; however, no study has been carried out to identify the specific areas. A study to identify areas that are radially supplied will be carried out in 2012.

Cost of Radial Supply Remediation Projects (1b.6)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.6	Radial Supply Remediation Projects	$0	$0	$1,038,487	$0	$0	$1,038,487

Distribution Automation Lines Projects (1b.7)

Distribution automation switches/reclosers are proposed to be installed at strategic locations to achieve the following 2 objectives:

- To reduce feeder down time in case of outages;
- To reduce number of customers affected by outages

It is estimated that there is an incremental outage time saving of 30 minutes between manual switching versus remote automatic switching which is estimated to save 6000 CMI/year on one automatic switch installation.

Every year PowerStream's System Planning department ranks feeders based on the FAIDI, FAIFI and SAIFI contributions to the systems and determines the Worst Performing Feeders. Planning also reviews the outage causes, the load on the feeders and location of existing automatic switches and calculates the benefits (CMI reduction) of installing additional switches and re-closers. Typically, radial feeders divided into half are expected to improve the reliability by 25%, and radial feeders divided into thirds improve the reliability to 33%.

In addition, there are approximately 40 existing overhead RTU controlled switches that are at or close to end-of-life (fail to close/open remotely). It is recommended that these units be replaced with automatic switches.

It is recommended to install 23 new units and replace 5 existing end-of-life units in 2014 through 2018.

Cost of Distribution Automation Lines Projects (1b.7)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.7	Distribution Automation Lines Projects	$2,419,883	$2,475,169	$2,530,758	$2,585,744	$2,194,590	$12,206,144

Reliability Driven Lines Projects (1b.8)

PowerStream system reliability performance over the last 3 years (2010, 2011, and 2012), are shown in Table below.

Three Year Average (2010-2012)				
CATEGORY	SAIFI	CAIDI (min)	SAIDI (min)	IOR
All Events	1.286	50.700	63.400	0.99988
LOS Excluded	1.111	47.870	52.480	0.99990
LOS and MED Excluded	1.096	48.000	51.660	0.99990

PowerStream has a target of achieving 99.999% Reliability ("Five 9's", IOR = 0.99999) by the end of 2015. PowerStream Reliability Committee has a five year work plan, subject to budget approval, to achieve the corporate target.

This reliability work plan examines all the factors that have impacts on reliability, discusses the initiatives that have positive impact on reliability, and recommends projects and associated cost to improve reliability over the next five years.

Work programs include analyzing the outages causes; determining ways to improve service restoration time; Worst Performing Feeders designation and maintenance; distribution automation; and inspection and training of contractors/personnel.

Improving Service Restoration Times:
The initiatives under this program are geared to improve the trouble crew coverage and response time in an event of a fault and are funded through Lines Maintenance programs. As a result no cost is included in this report.

Worst Performing Feeder (WPF)
Each year PowerStream planning looks at average 3 year FAIDI, FAIFI and SAIDI contribution of the feeder to the overall indices to identify the Worst Performing Feeders so that remediation work can be prioritized on a feeder-by-feeder basis.

This feeder specific work plan includes the following:

- Feeder Patrol
- Tree Trimming
- Wildlife Guard
- Infrared Inspection
- Insulator Washing
- Lightning Arrestor
- Fault Indicator
- Feeder Re-configuration
- Feeder Protection Review

The work is funded through Lines Maintenance programs. As a result no cost is included in this report.

Inspection and Training
Effective inspection and maintenance programs help identify potential reliability problems, and initiate remedial actions to prevent or reduce the extent of future outages.

It is recognized that work on distribution assets require a trained workforce and it is also essential to ensure that the contractors working on PowerStream's system are trained. This program includes work specific training (e.g. splicing) to PowerStream staff and contractors, and are funded through Lines Maintenance programs. As a result no cost is included in this report.

Cost of Reliability Driven Lines Projects (1b.8)
The table below is based on the elbow/bushing replacement cost.

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.8	Reliability Driven Lines Projects	$503,223	$379,750	$79,565	$0	$0	$962,538

Safety, Environment Driven Lines Projects (1b.9)
This category covers the capital work that PowerStream must complete to comply with Health, Safety and Environmental regulations, standards and guidelines. There is no specific Safety, Environmental driven project or program recommended by system planning at this time.

Compliance to External Directives / Standards Lines Projects (1b.10)
This category covers the capital work that PowerStream must complete to comply with external directives/standards such as:

- Long Term Load Transfers (LTLT)

- Ungrounded Delta Transformers
- ESA Clearance Issues
- Highway 400 series Overhead Crossing Remediation Projects

Long Term Load Transfers (LTLT)
Section 6.5 of the Distribution System Code covers Long Term Load Transfers (LTLT). LDC's have until June 30, 2014 to complete the Long Term Load Transfers. Also, starting November 2011, the OEB will require an updated implementation Plan from the LDC's.

A total of 108 LTLT customers exist in proximity to service area boundaries between Hydro One Networks and PowerStream North. There are 72 Hydro One Networks' LTLT customers to be transferred from Hydro One Networks to PowerStream North. There are 17 LTLT customers to be transferred from PowerStream North to Hydro One Networks. There are 19 LTLT customers to remain as Hydro One Networks customers. PowerStream is in the process of formulating a Plan to eliminate all LTLT by late 2013.

Ungrounded Delta Transformers
Background:
The Ontario Electrical Safety Authority issued Bulletin DSB-04-11 on May 12, 2011, to all Local Distribution Companies. The title of the bulletin was "Delta Conversion and OESC Requirements". The System Planning department conducted an internal investigation and discovered that PowerStream has 367 installations where wye connected distribution transformers feed delta connected services. It was understood that these installations did not comply with the bulletin.

A pilot project of $250k was implemented in 2012 to install a separate neutral conductor from the transformers to the service panel(s) and upgrade the metering. Transformers with small number of customers were selected in the pilot project.

It was discovered in the pilot project that it is extremely costly or technically not feasible to install a separate neutral conductor from the transformers to the service panel(s) for some transformers feeding large number of customers.

Extensive study has been performed by Planning and Standard on feasibility of application of 27.6kV/600V delta transformers, and 27.6kV/600V open delta transformers in PowerStream. The plan was not pursued due to concerns on safety from Lines.

A meeting with ESA was held on Feb 25, 2013 to discuss and clarify Delta-Wye Remediation Program. PowerStream stated that the delta customers will remain as delta if floating wye supply is allowed.

ESA stated that:

> *ESA does see no issues on replacing a 600V delta-secondary transformer bank with a 600V ungrounded-wye-secondary bank, from the Ontario Electric Safety Code (OESC) and the customers' safety perspective, provided that:*
> 1) *Blocking any possible future connection between the secondary star-point (i.e. the three X2 terminals) and the system neutral or ground is in place, i.e., there no 3 phase 4 wire customers are supplied by the transformer.*
> 2) *PowerStream has an installation standard in place.*

On March 13, 2013 System Planning & Standards submitted Standard 16-610A "Replacement of 600V Delta Bank with 347/600V Floating Wye Bank for Supply to Delta Customers only 4.16/2.4 to 27.6/16 kV" to ESA for review. ESA confirmed the standard does not violate OESC.

In light of the new information from ESA, for approx. 300 remaining existing wye transformer feeding delta service installations, PowerStream can cost effectively comply ESA requirement by bringing the existing installations into compliance with Standard 16-610A, i.e., by removing connection between the secondary star-point (i.e. the three X2 terminals) and the system neutral or ground if the transformer supplied 600V

delta customers ONLY. The purpose is to prevent phase to ground fault current going back to the star point.
However, if a transformer supplies both 600V delta and 600V wye customers at the same time, it does not comply with ESA requirement. In this case, one separate 600V wye transformer bank for the 600V wye customers will need to be installed, or the 600V delta customers will need to be converted into wye connection.

Remediation Plan:

1. Field check and determine how the star point is connected for existing transformers feeding delta customers, and if they supply 600V delta and 600V wye customers at the same time.
2. Convert the existing installations into Standard 16-610A if a transformer supplies delta customers only.
3. Install one separate 600V wye transformer bank for the 600V wye customers, or convert the 600V delta customers into wye connection, if a transformer supplies both 600V delta and 600V wye customers at the same time.
4. In 2012, PowerStream completed the conversion of 26 transformers affecting 45 customers. $400k has been allocated as part of the 2013 capital budget. Based on new information from ESA, the future expenditure could be reduced dramatically. It is recommended to budget $200k per year for the next 5 years (2014-2018). After 2018 it is expected that only a small number of locations will remain, and the budget requirement is estimated at $40k per year from 2019 – 2023.

ESA Clearance Issues
The proposed work program will mitigate clearance issues in PowerStream North at various locations in Alliston and Tottenham to comply with ESA and CSA Rules as they arise. Ontario Electrical Safety Code Rule 75-312 & CSA 22.3 No. 1-10 both state that the minimum horizontal & vertical clearance to a building, structure, etc. is 3m (10ft.) & 4.8m (16ft), respectively. PowerStream has adopted the above “Rule” and has issued Construction Standard 03-4 to comply with CSA and the Electrical Safety Code.

Highway 400 series Overhead Crossing Remediation Projects
PowerStream will conduct engineering reviews to assess compliance to Grade 1 Construction Requirements at all Highway 400 series overhead crossing (Hwy 400, Hwy 404, and Hwy 407). It is anticipated that there would be cases that the existing installation does not meet Grade 1 Construction requirements and remediation work must be implemented. Solutions may range from simple work such as replacing components/upgrading down guys, to complicated work such as replacing the pole line. Preliminary information shows there are 38 highway crossing locations in-service now, including 18 across Hwy 400, 6 across Hwy 404, and 14 across Hwy 407.

Cost of Compliance to External Directive / Standards Lines Projects (1b.10)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.10	Compliance to External Directives / Standards Lines Projects	$1,803,593	$212,768	$231,759	$233,992	$220,000	**$2,702,112**

Rear Lot Supply Remediation Projects (1b.11)
This category covers the capital work that PowerStream must complete to address the operations and customer service concerns on rear lot supply.

The Reliability Committee has requested System Planning to develop a plan to review all existing rear lot supply areas. The review will provide:
- Criteria for end-of-life asset conditions
- Methodology for life cycle cost
- Design options

The following five managing options should be considered:
1. Keep existing rear lot, but increase maintenance/inspection
2. Replace existing rear lot with new rear lot, and improve design
3. Replace existing rear lot with new front lot overhead

4. Hybrid – Replace rear lot primary & transformer with new front lot underground primary & transformer, and replace (or keep) pole line and secondary at rear lot
5. Replace existing rear lot with front lot underground

Each location should be evaluated individually and justification/approval should be done on a case-by-case basis. The criteria for consideration are:

- Cost versus risk
- Asset condition
- Reliability/capacity impact
- Health & safety /operating impact

To determine the Life Cycle Net Present Value, the following items should be considered:

- Initial installation cost
- Frequency of failure
- Outage duration
- Consequence of failure
- Risk cost (failure probability x consequence cost)
- Maintenance cost
- Customer Minutes of Interruption (CMI)

The analysis of one sample subdivision is summarized below.

Analysis Results - One Subdivision (177 Customers)					
	Option 1	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Average Annual CMI	22,068	17,532	10,519	12,623	8,415
Initial Installation Cost	$0	$1,362,279	$1,362,279	$2,190,805	$3,336,017
Initial Cost Per Customer	$0	$7,696	$7,696	$12,377	$18,848
Total Initial Cost (All Customers)	$0	$31,232,363	$31,232,363	$50,227,608	$76,483,373
Total NPV for 100 Years	$2,083,225	$2,251,943	$1,892,316	$2,917,910	$4,242,891

Based on the results, the average initial installation cost varies with the Option selected.

- Option 1: $0 per customer
- Option 2: $7,698 per customer
- Option 3: $7,696 per customer
- Option 4 (Hybrid): $12,377 per customer
- Option 5: $18,848 per customer

Option 3 is not a feasible option because it will face extreme protest and opposition from the local residents and politicians. Customers who never had overhead line in front of their houses will view the installation as a step backward which reduces the value of their houses. In other jurisdictions, customers were able to lobby politicians and blocked the projects.

Because the managing option selected at each location is not known until the actual analysis is carried out, for budgeting purpose, we assume that the average cost is the average of the three options which is = (7,698 + 12,377 + 18,848) / 3 = $12,974 per customer.

In 2013, we are implementing Option 4 (Hybrid) at the Romfield Phase 3 project in Markham.

There are 4,058 customers being supplied by rear lot.
We assume that PowerStream can complete the remediation as follows.

- One location in PowerStream North per year, approximate scope of work is half of Romfield Phase 3 (88 customers)
- One location in PowerStream South per year, approximate scope of work is same size as Romfield Phase 3 (177 customers)

Based on the above assumption, each year PowerStream can complete two projects involving (88 + 177 = 265 customers). At this rate, it will take 16 years to complete all remediation work involving 4,058 customers.

CMI Saving:
The CMI saving depends on the option selected, compared to Option 1.

- Option 2: CMI Saving = 22,068 – 17,532 = 4,532 CMI
- Option 4: CMI Saving = 22,068 – 12,623 = 9,445 CMI
- Option 5: CMI Saving = 22,068 – 8,415 = 13,653 CMI

Average CMI Saving = (4,532 + 9,445 + 13,653) / 3 = 9,210 CMI per subdivision

Cost of Rear Lot Supply Remediation Projects (1b.11)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b.11	Rear Lot Supply Remediation Projects	$0	$3,286,407	$3,366,266	$3,447,534	$3,530,265	$13,630,472

Cost of Sustainment Driven Lines Projects (1b)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1b	Sustainment Driven Lines Projects	$28,560,990	$26,719,719	$26,523,917	$26,825,216	$25,843,924	$134,473,766

7.3 Emergency / Restoration (1c)

This category covers the urgent capital work that PowerStream must complete replace equipment identified through the inspection program.

Padmount Transformer Replacement (1c.1)

With regards to Padmount Transformers, PowerStream used to operate based on a run-to-failure approach. However, in 2013, a proactive replacement project will commence to replace the worst 50 units based on the results of the inspection program.

PowerStream had 38, 50 and 70 Underground Transformer failures (including Padmount Transformer and Submersible Transformer) in 2010, 2011, and 2012 respectively (average 53 units per year). Budget requirements for emergency replacement of Underground Transformers will be prepared and submitted by the Lines Department. As a result, the cost of Underground Transformer emergency replacement is not included in this Five Year Capital Plan Report.

It is recommended that continuing the planned replacement of 50 Underground Transformers per year, prioritized based on the results of the inspection program, be implemented.

Cost of Emergency / Restoration Projects (1c)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1c	Emergency / Restoration	$309,386	$363,440	$375,000	$386,250	$397,837	$1,831,913

7.4 Transformer / Municipal Stations (1d)

Transformer Station Sustainment Driven Projects

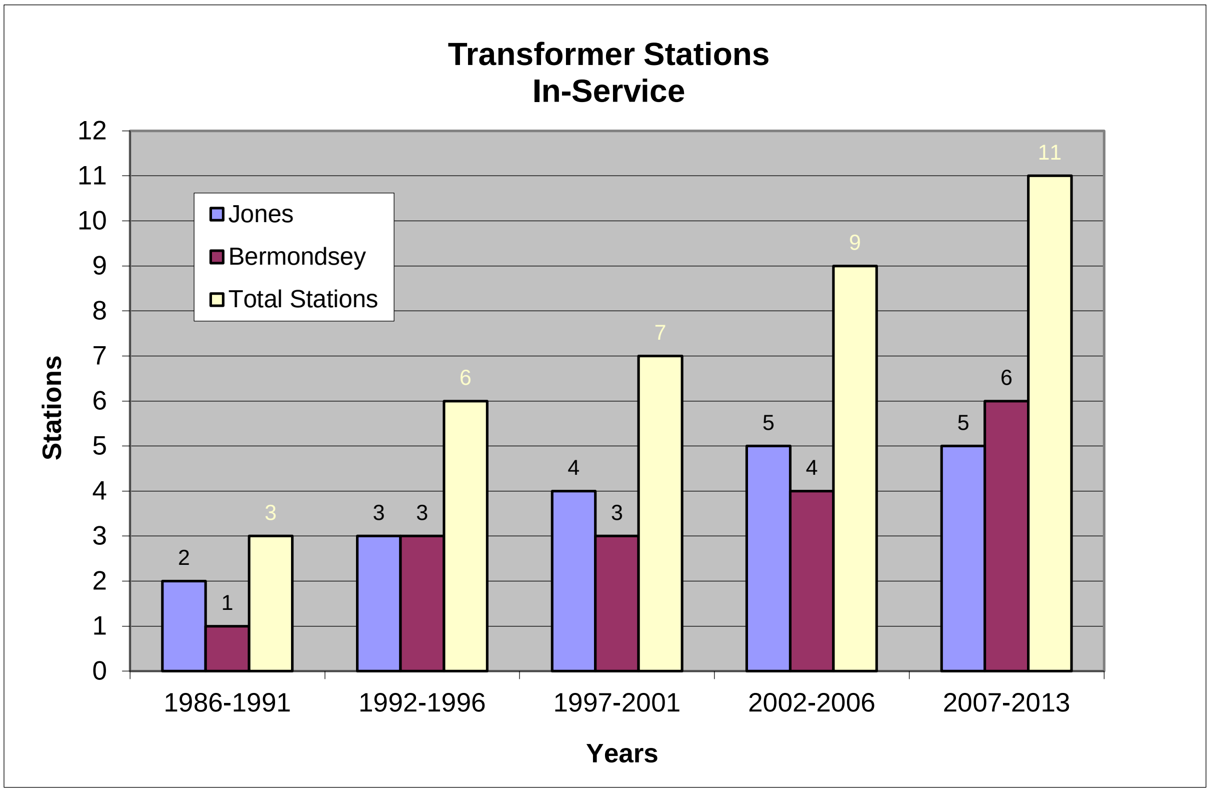
This category is for those Transformer Station (TS) projects that are not capacity driven, but are required to sustain PowerStream's fleet of eleven TS's. Sustainment activities include projects to: replace worn out equipment, improve reliability, enhance operability & maintainability, and to improve & maintain safety.

PowerStream's fleet of eleven transformer stations can be divided into two groups:

- **Jones** – A Jones station consists of two 50/83 MVA two winding transformers, two main breakers, a bus tie breaker and eight feeders. There are five Jones stations, of which two are equipped with single 20 MVar capacitor banks and breakers.

- **Bermondsey** - A Bermondsey station consists of two 75/125 MVA three winding transformers, four main breakers, a bus tie breaker and twelve feeders. There are six Bermondsey stations, of which three are equipped with dual 20 MVar capacitor banks and breakers.

The graph below shows the number of each type of transformer station as well as an indication of the ages of the stations.



As can be seen in the above figure; PowerStream's fleet of stations ranges in age from nearly new to over twenty-five years old. A number of trends and challenges have arisen as time has passed and as the stations have aged, as follows:

- Rising fault levels on the Bulk Electrical System, coupled with the requirement to accommodate renewable generators, that further increase the fault levels at our stations and on our 28kV feeders, has created a requirement to reduce fault levels on the 28kV busses at three of our TS's by introducing fault level limiting air core reactors.

- PowerStream has adopted a *Trip Saving* feeder protection strategy. As a result, the obsolete feeder protections need to be upgraded at two of our stations in Markham.

- A number of the 28kV transformer bushings have a design flaw that shortens their useful life. This problem became evident on one of the 230/28kV transformers at Markham TS#1 where a bushing failed and started a fire. As a result, a multi-year program to replace all of this type of bushing and to install on-line bushing monitoring has been initiated.

- Due to the increasing costs of copper, steel and mineral oil; the replacement cost of station transformers has increased to about three million dollars each. For this reason a program has been initiated to install on-line monitoring equipment on the station transformers in an effort to detect incipient problems and take proactive steps to correct the causes of problems, instead of waiting for the transformer fail to then repairing or replacing it. The four stations in Markham have been equipped with the on-line monitoring equipment. A multi-year program is in place to equip the remaining station transformers in Richmond Hill and Vaughan.

- Since September 11, 2001 there has been a heightened awareness of the need for physical and cyber security at our stations. Also, as the price of copper has been increasing; there has been a corresponding increase in copper theft from our stations that has increased the need for security. For these reasons we have embarked on a multi-year program to install video surveillance and improve outdoor lighting at our stations.

- In response to increased cyber threats and attacks on electrical utilities; the North American Electrical Reliability Corporation (NERC) has developed a set of Critical Infrastructure Protection (CIP) standards. The Ontario Independent Electrical System Operator (IESO) has adopted these standards and requires *Generators* and *Transmitters* in Ontario to comply with them. PowerStream is a *Distributor* and is not yet required to comply with the NERC CIP standards. However, PowerStream's transformer stations are connected directly to the Bulk Electricity System (BES). For this reason and, because the CIP standards are viewed as good utility practices; PowerStream has voluntarily adopted the CIP standards. A number of station projects are planned to improve our cyber security by implementing the CIP standards.

- The IESO requires that stations connected to the BES have 90% or better power factor. For this reason capacitors have recently been installed at Vaughan TS #2. We expect to be required to add capacitor banks at stations in Richmond Hill and Markham.

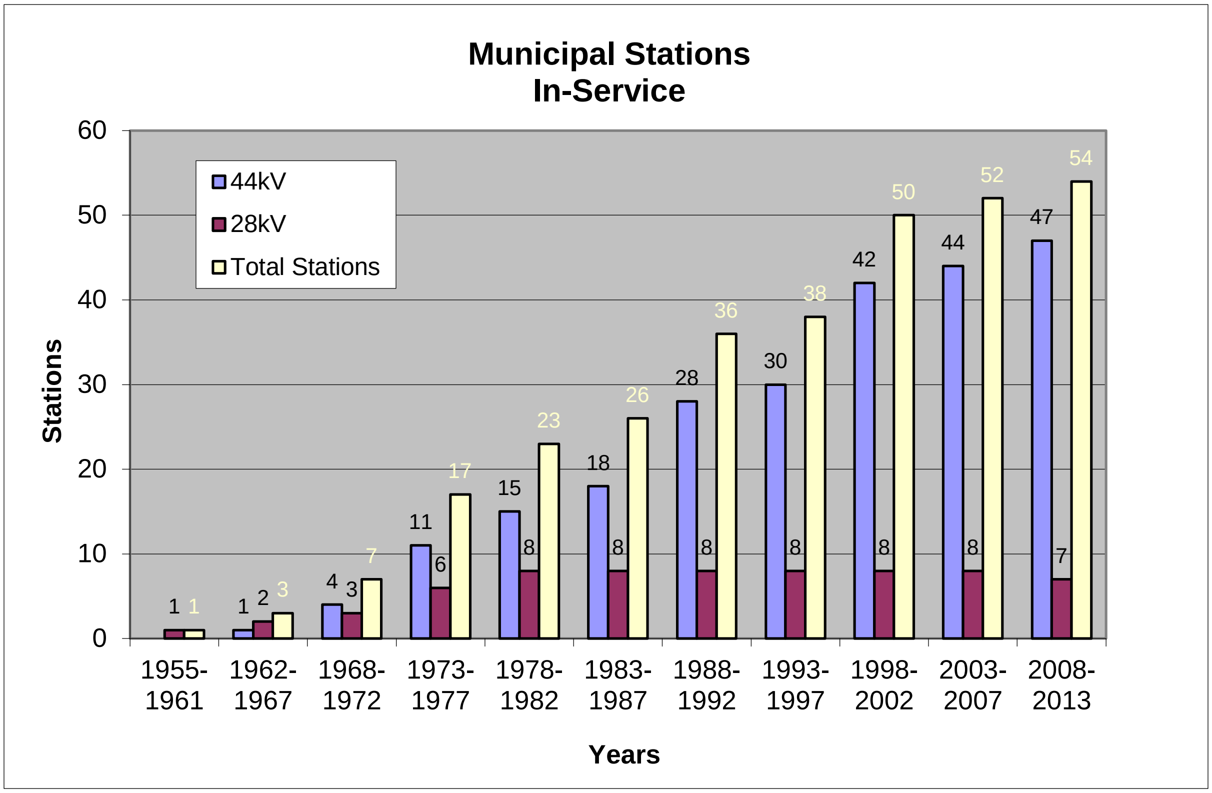
Municipal Station Sustainment Driven Projects

This category is for those Municipal Station (MS) projects that are not capacity driven, but are required to sustain PowerStream's fleet of 54 MS's. Sustainment activities include projects to: replace worn out equipment, improve reliability, enhance operability & maintainability, and to improve & maintain safety. PowerStream's fleet of 54 municipal stations can be divided into two groups:

- **44kV Primary Voltage** – The 44kV MS's are supplied from Hydro One TS's in Alliston, Aurora, Barrie, Beeton, Bradford, Penetang, Thornton and Tottenham. These stations typically have one or two transformer with a 44kV primary winding & a 4 to 13.8kV secondary winding and two to four feeders.

- **28kV Primary Voltage** – The 28kV MS's are supplied from PowerStream TS's in Markham and Vaughan. These stations typically have one or two transformers with a 28kV primary winding, a 13.8kV secondary winding and four feeders.

The graph below shows the number of each type of municipal station as well as an indication of the ages of the stations.



As can be seen in the above figure; PowerStream's fleet of municipal stations ranges in age from nearly new to over fifty years old. A number of trends and challenges have arisen as time has passed and as the stations have aged, as follows:

- Due to the increasing costs of copper, steel and mineral oil; the replacement cost of our municipal station transformers has increased significantly. For this reason a program has been initiated to install on-line monitoring equipment on the larger, 10 to 20MVA transformers, in an effort to detect incipient problems and take proactive steps to correct the causes of problems, instead of waiting for the transformer fail to then repairing or replacing it. The 20MVA transformers in Barrie have already been equipped with on-line monitoring equipment. A multi-year program is in place to equip the station transformers in Aurora with on-line monitoring and to add on-line gas-in-oil monitoring to the 20MVA transformers in Barrie.

- Since September 11, 2001 there has been a heightened awareness of the need for physical security at our stations. Also, as the price of copper has been increasing; there has been a corresponding increase in copper theft from our stations that has increased the need for security. For these reasons we have embarked on a multi- year program to install video surveillance at our larger municipal stations.

- The Ministry of the Environment has enacted legislation regarding and prohibiting oil spills. PowerStream's 230/28kV transformers all have oil containment facilities. All MS's built since 2007 and many of the larger municipal station transformers have been equipped with oil containment. A multi-year program is in place to equip the remaining MS transformers with oil containment.

- Many of the older MS's are equipped with reclosers and interrupters that are in need of replacement or refurbishment.

This category includes the following types of projects:

- Station Plant Asset Replacement (1d.1)
- Safety, Environment Driven Station Projects (1d.2)
- Compliance to External Directive / Standards Station Projects (1d.3)
- Distribution Automation Station Projects (1d.4)
- Reliability Driven Station Projects (1d.5)
- Operability and Maintainability Projects (1d.6)

Station Asset Replacement Projects (1d.1)

This category includes replacement of the following station components:

- Station Circuit Breakers
- 230 kV Switches
- Primary Switches
- Station Reactors
- Station Capacitors
- MS Transformers
- TS Transformers

Station Circuit Breaker Replacement

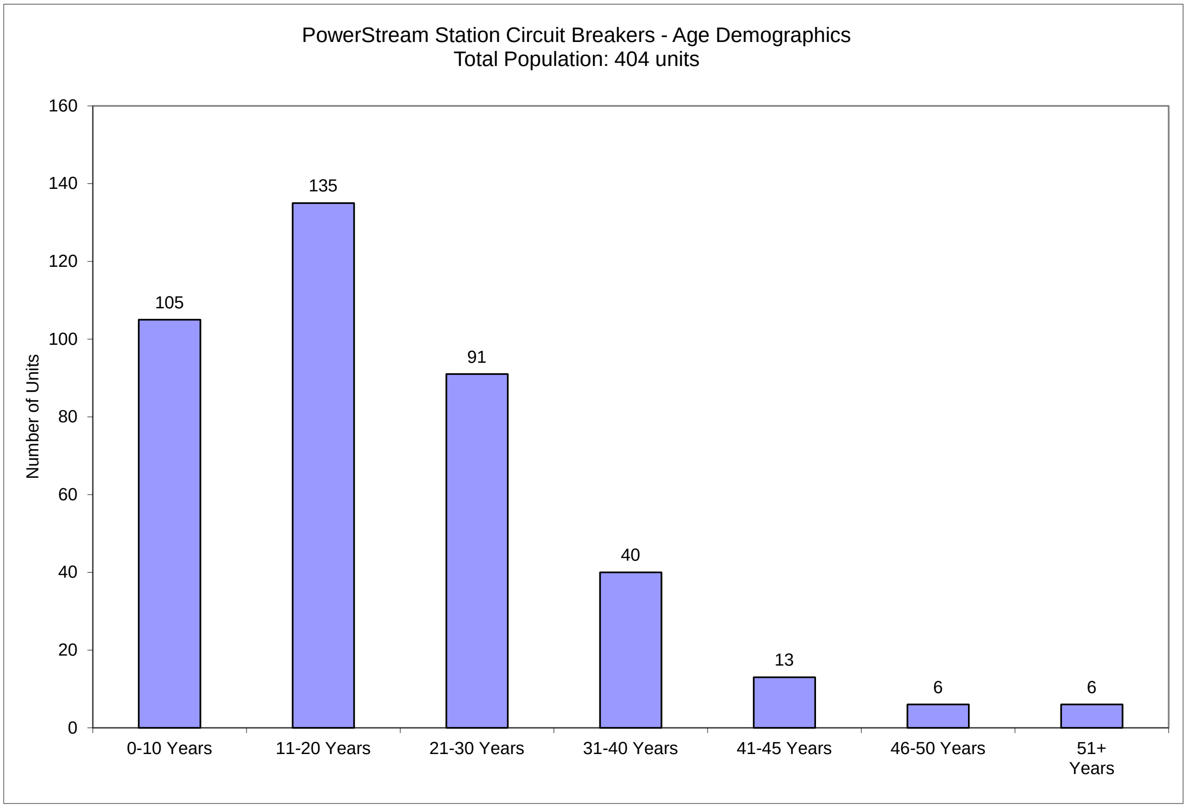
PowerStream has 399 station circuit breakers in service. This population includes 8 switch & fuse units installed at some MS's in place of a circuit breaker.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

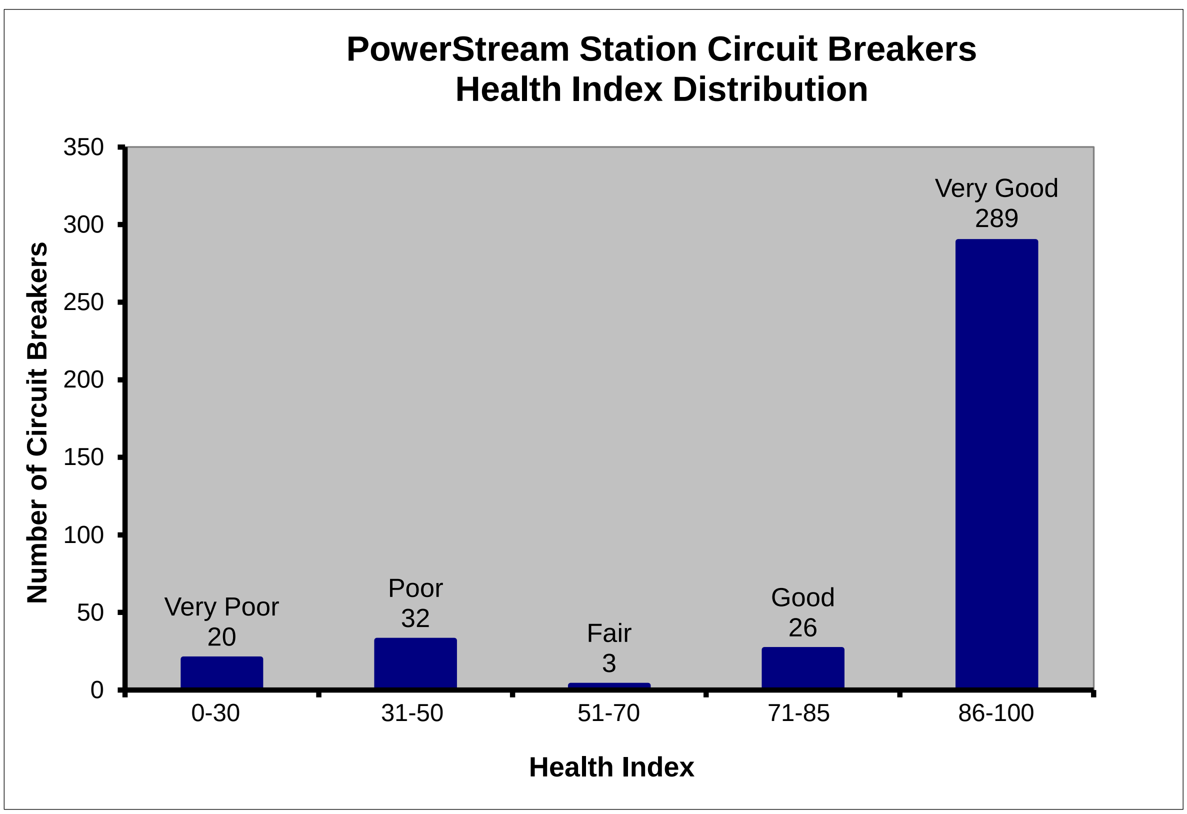
- *Useful life of **Station Independent Circuit Breakers** is 35-65 years with typical useful life of 45 years.*

At PowerStream, for IFRS purposes, a useful life of 30 years is used for station circuit breakers. Of the 399 station circuit breakers PowerStream has in service; 9 are older than 45 years.

The Age demographics for station circuit breakers are shown in the following chart.



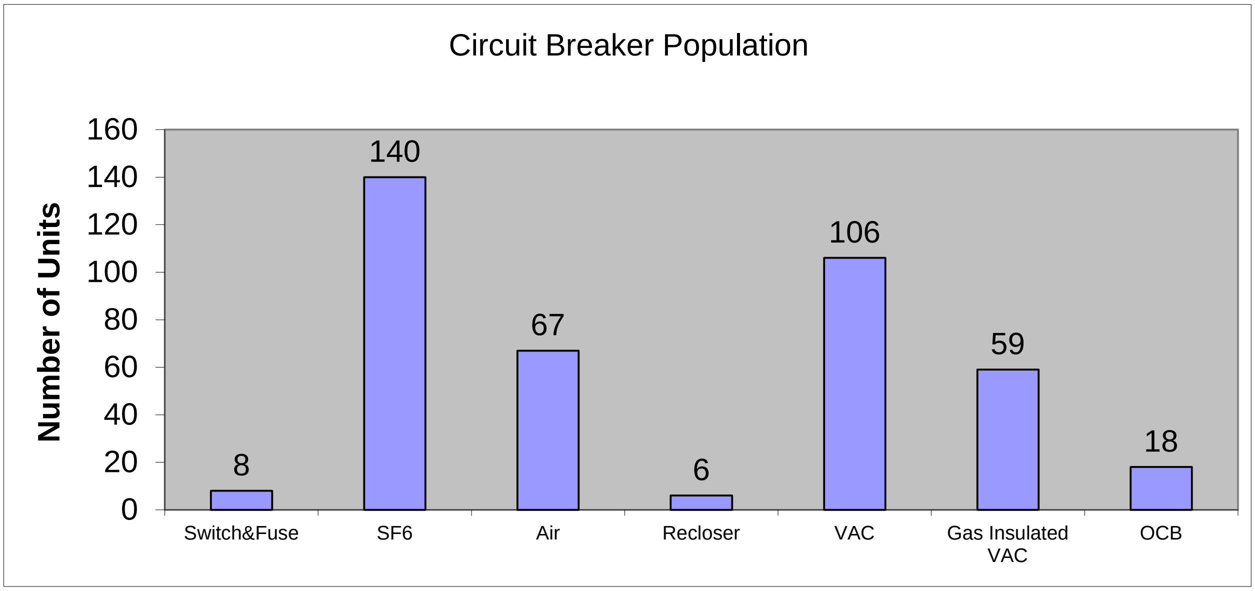
The Condition demographics for station circuit breakers are shown in the following chart.



There are seven Circuit Breaker / Switch & Fuse types in PowerStream.

- Gas Insulated Vacuum Circuit Breaker (Gas Insulated VAC)
- Oil Circuit Breaker (OCB)
- Recloser
- Air Circuit Breaker (Air)
- Vacuum Circuit Breaker (Vac)
- SF6 Circuit Breaker (SF6)
- Switch & Fuse

A chart showing the number of each circuit breaker / switch & fuse type is included below.



A number of station circuit breaker units (mostly ABB Type HKSA and Outdoor GEC Type OX36) have been identified by the ACA Model as needing replacement, mostly due to age, condition, obsolescence, and historical failures. These will continue to be monitored for the condition of the Circuit Breakers.

We are in the process of replacing 5 units in 2013 at Richmond Hill TS1 (consisting of 4 transformer breakers and 1 bus tie breaker), then approximately 6 units per year afterward. The costs are included at the end of this section. The 5 circuit breaker units for 2013 are listed below:

- Bus Tie Breaker AB
- Transformer Breaker T1A
- Transformer Breaker T1B
- Transformer Breaker T2A
- Transformer Breaker T2B

Also, 2 spare breakers Type HD4 2000A for Main or Tie breakers, 2 Ground Test Device (GTD), and 2 breaker carriers are being procured in 2013.

230 kV Switch Replacement

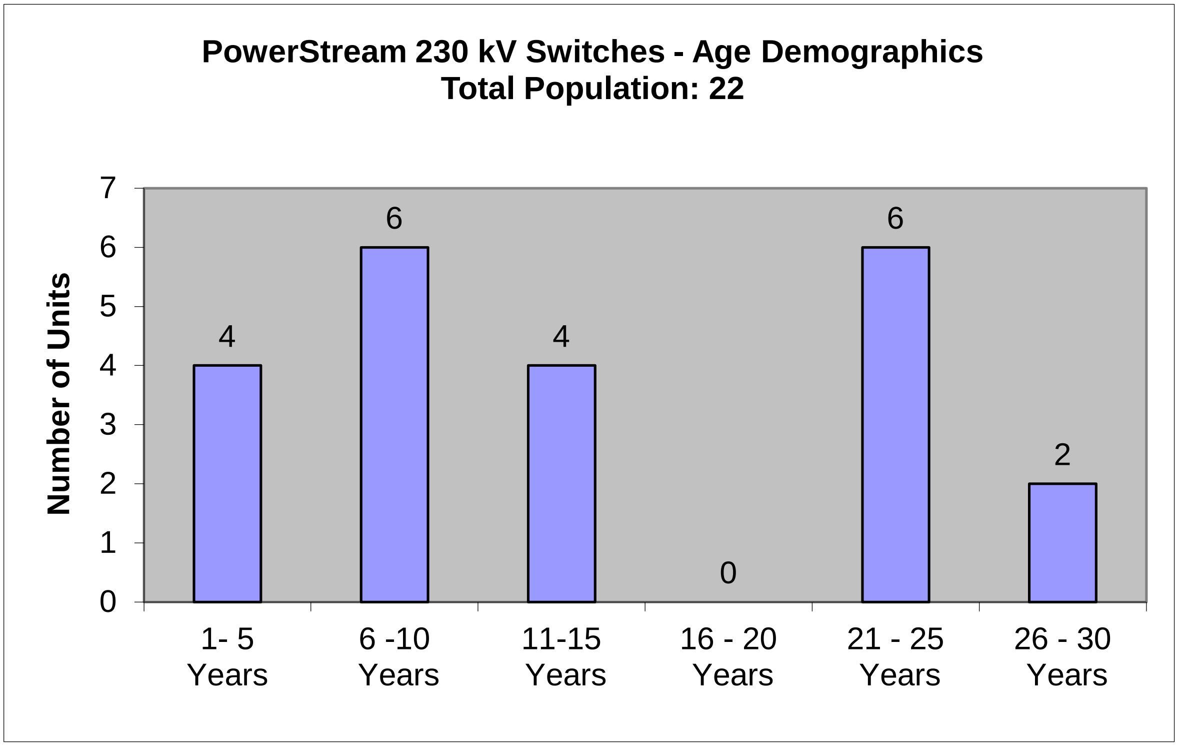
PowerStream has 22 - 230 kV Switches in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board":**

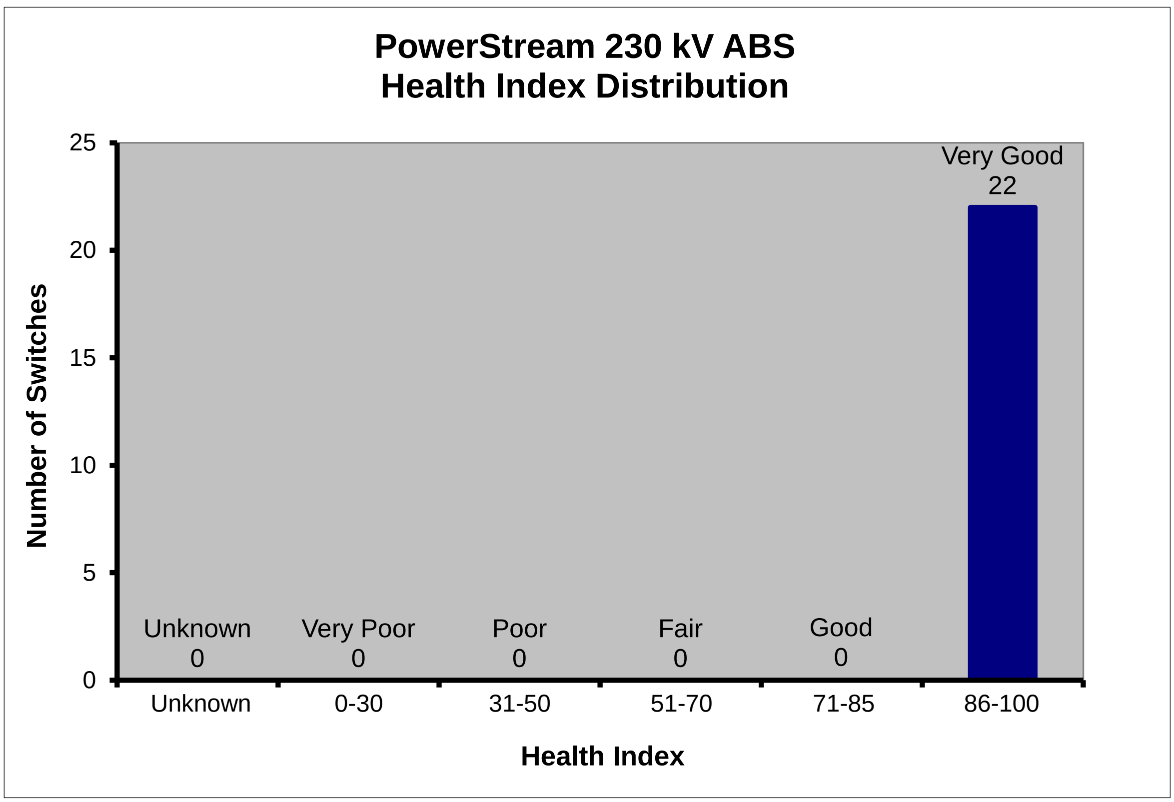
- *Useful life of **Station Switches** is 30-60 years with typical useful life of 50 years.*

At PowerStream, for IFRS purposes, a useful life of 40 years is used for 230 kV switches.

The Age demographics for 230 kV Air Break Switches (ABS) is shown in the following chart.



The Condition demographics for 230 kV ABS are shown in the following chart.



There were 2 Pursley 230kV Switches at Richmond Hill TS1. One switch was replaced in 2011 (RHTS1_T1SW1) due to obsolescence and mechanical failure (failed to open). The remaining switch at Richmond Hill TS1 (RHTS1_T2SW2) was replaced in 2012. No other replacement is recommended at this time.

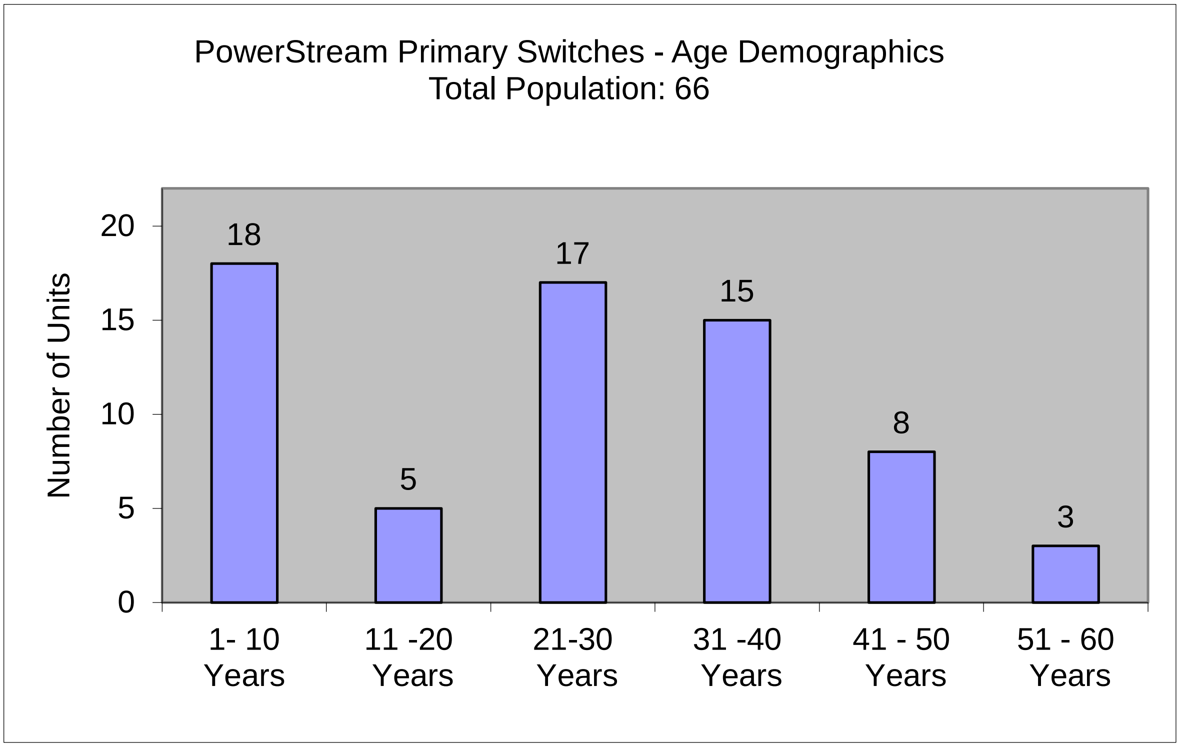
Primary Switch Replacement

PowerStream has 66 Primary Switches in service.

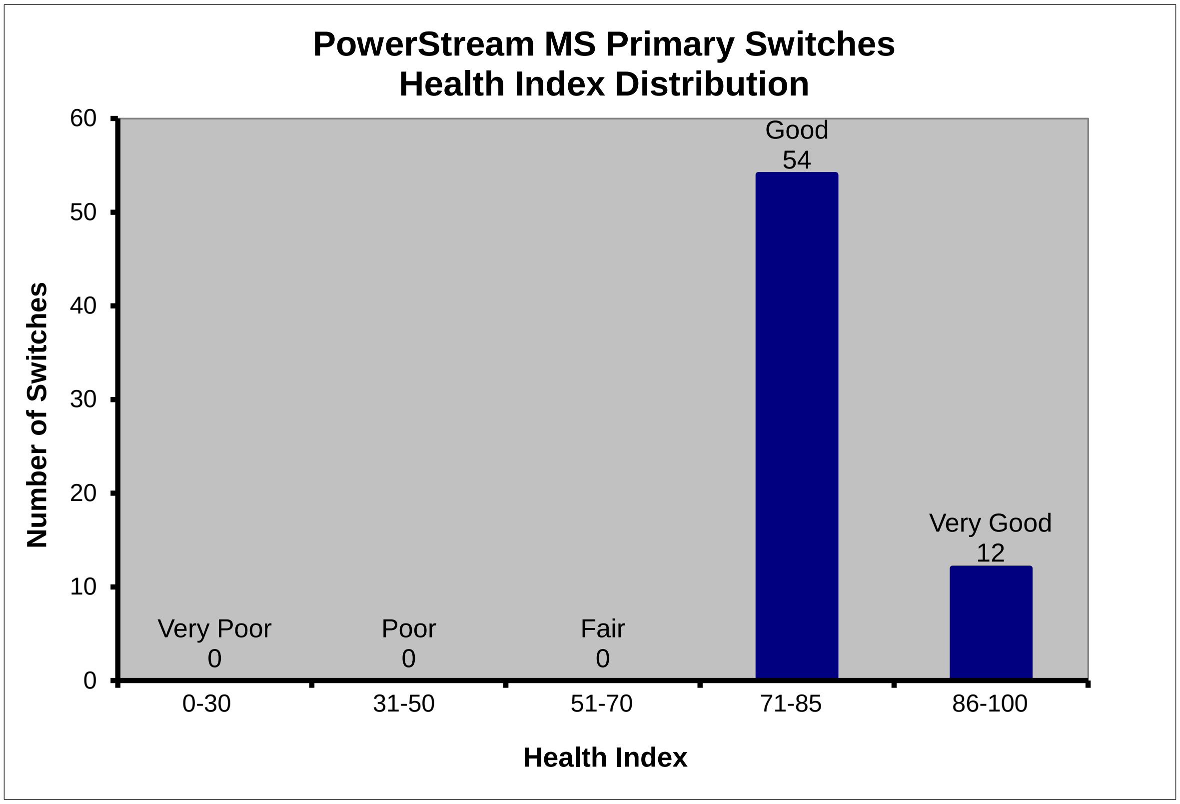
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

- *Useful life of **Station Switches** is 30-60 years with typical useful life of 50 years.*

At PowerStream, for IFRS purposes, a useful life of 40 years is used for Primary Switches.
The Age demographics for MS Primary Switches are shown in the following chart.



The Condition demographics for MS Primary Switches are shown in the following chart.



No replacement of primary switches is recommended at this time.

Station Reactor Replacement

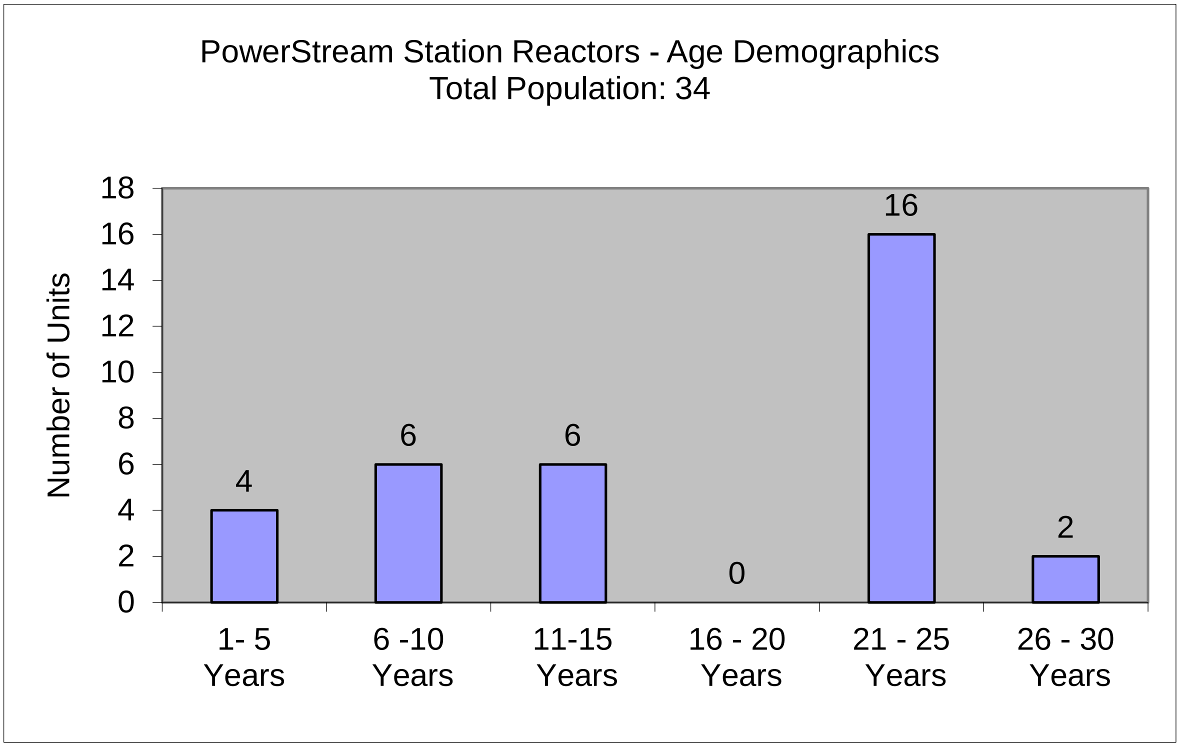
PowerStream has 34 Station Reactors in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for PowerStream":**

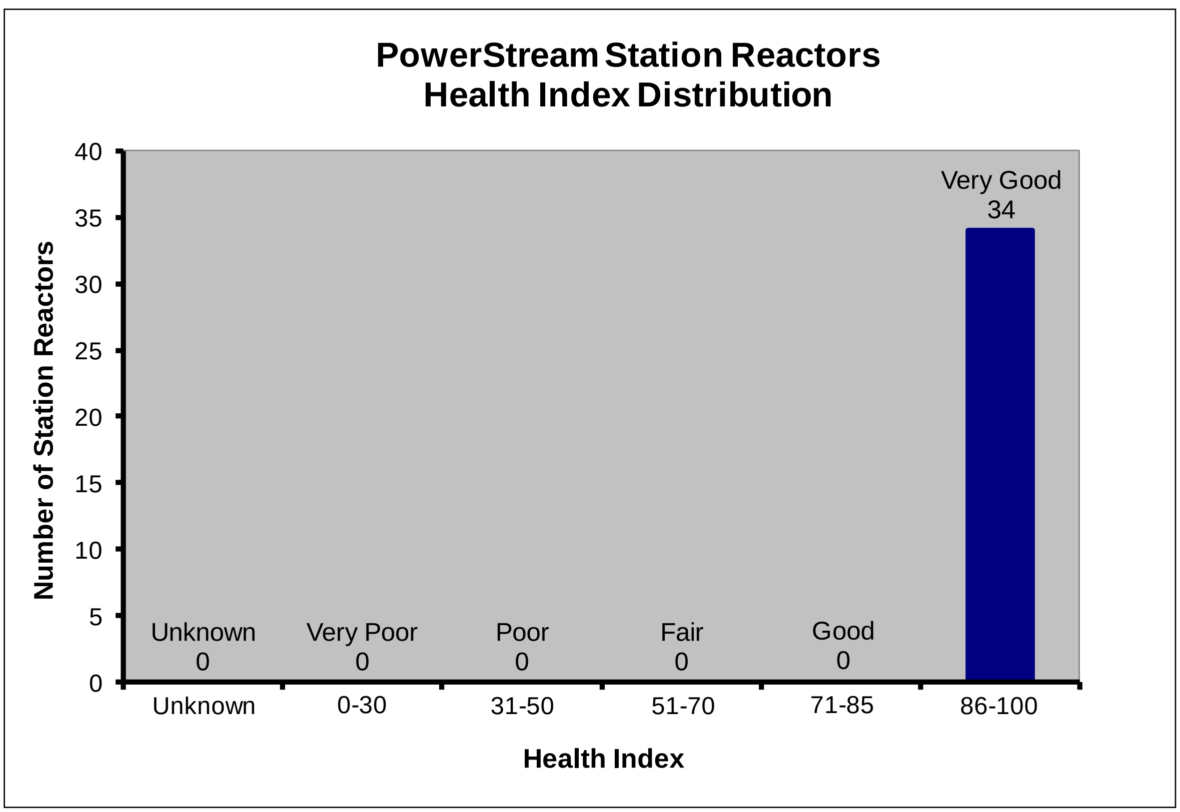
- *Useful life of **Inductors** is 25-60 years with a typical useful life of 45 years.*

At PowerStream, for IFRS purposes, a useful life of 40 years is used for Station Reactors.

The Age demographics for Station Reactors are shown in the following chart.



The Condition demographics for Station Reactors are shown in the following chart.



No replacement is recommended at this time.

Station Capacitor Replacement

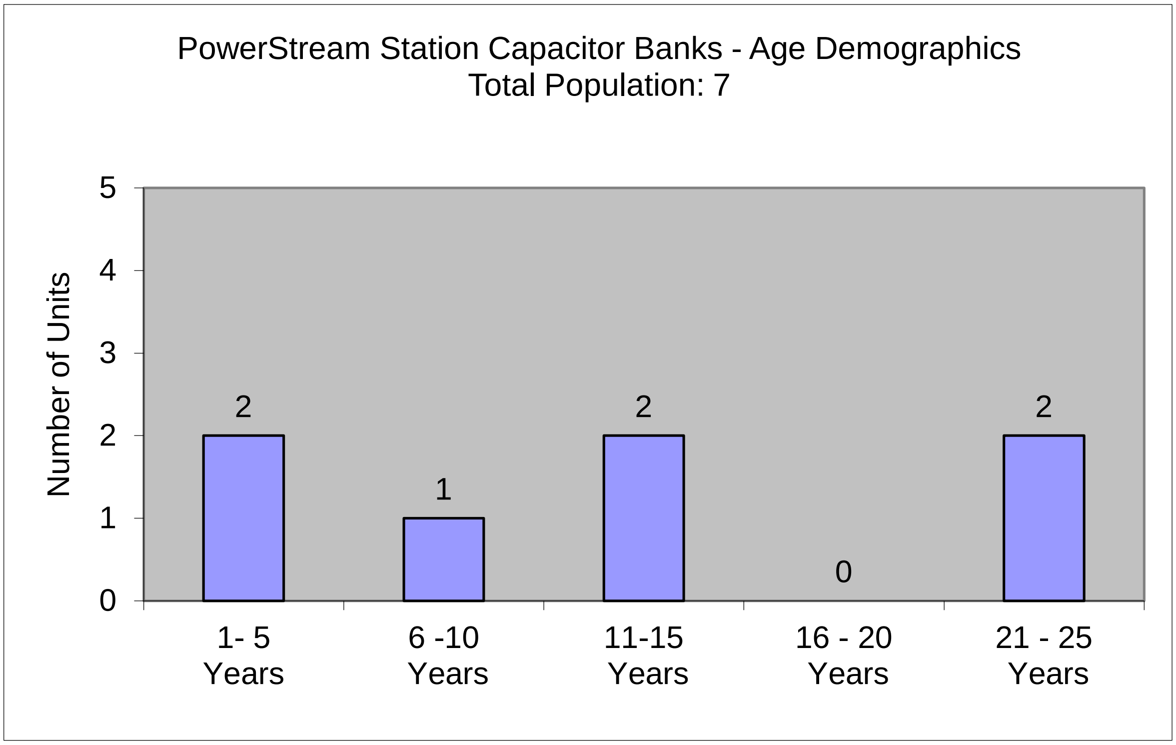
PowerStream has 7 Capacitor Banks in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board":**

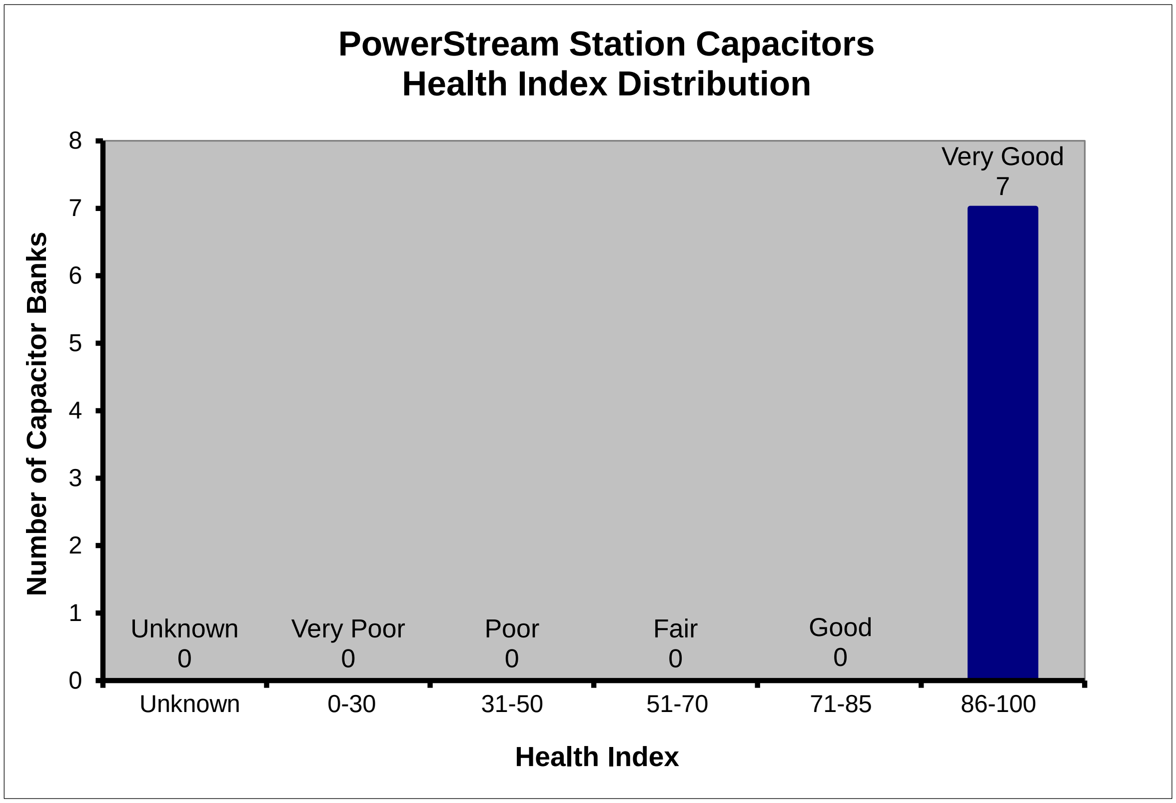
- *Useful life of **Capacitor Banks** is 25-40 years with typical useful life of 30 years.*

At PowerStream, for IFRS purposes, a useful life of 30 years is used for Capacitor Banks.

The Age demographics for Station Capacitor Banks are shown in the following chart.



The Condition demographics for Station Capacitor Banks are shown in the following chart.



The consequence of failure of the Capacitor bank is very low. Generally, only individual can(s) will fail within the Capacitor bank; in those cases, the individual can(s) will be replaced without causing customer outages. In addition, PowerStream has a Station Maintenance program in place to monitor the Capacitor banks. Therefore, no capacitor bank replacement is recommended at this time.

MS Transformer Replacement

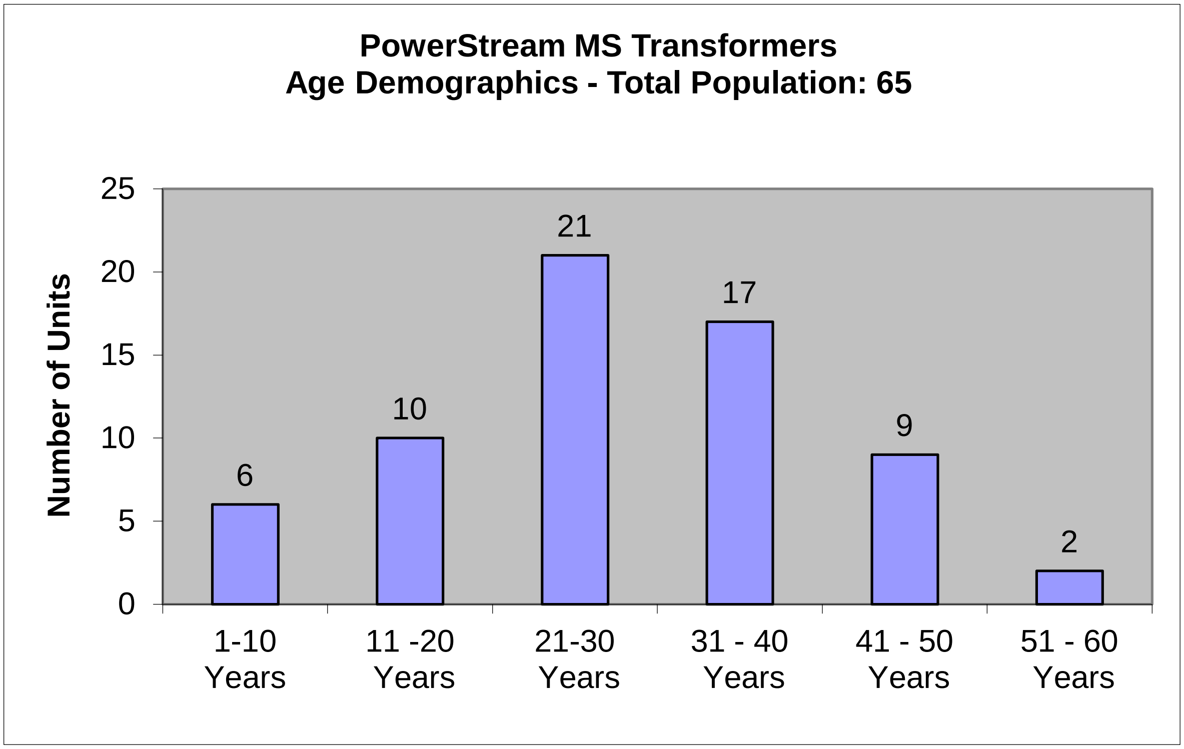
PowerStream has 65 MS Transformers in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board":**

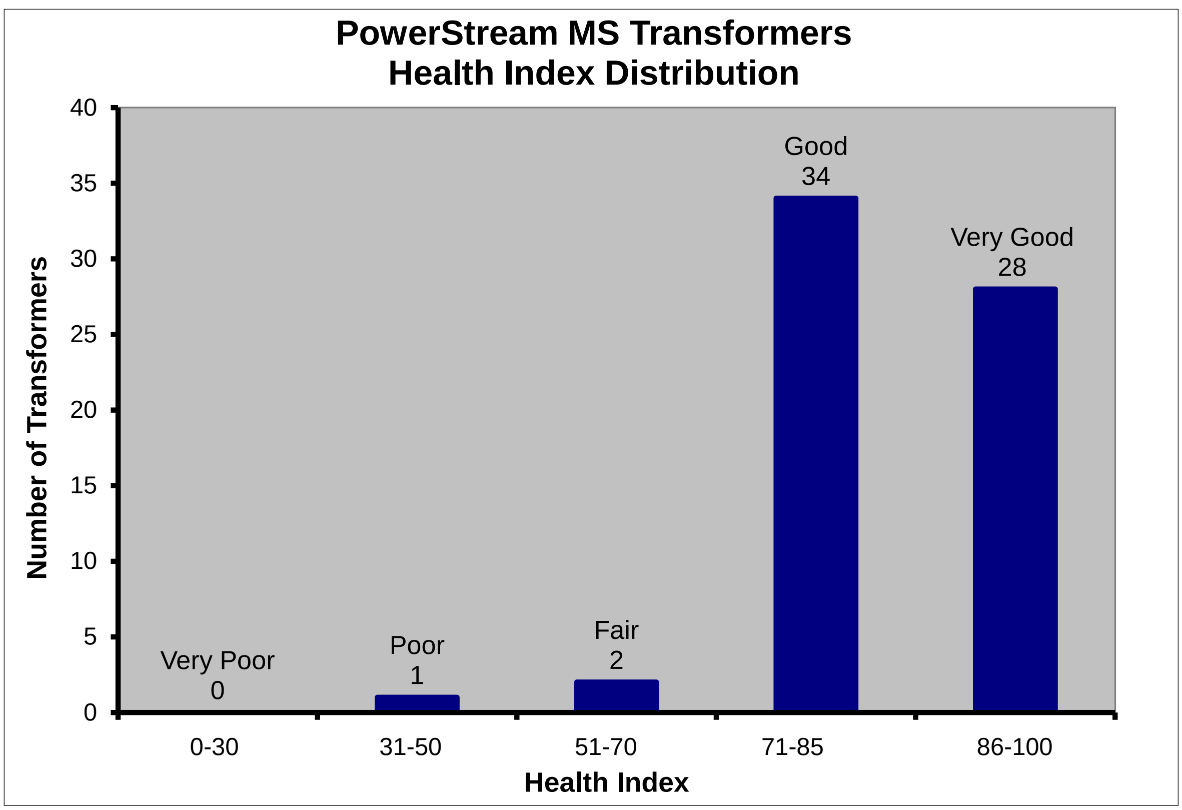
- *Useful life of **Power Transformers** is 30-60 years with typical useful life of 45 years.*

At PowerStream, for IFRS purposes, a useful life of 40 years is used for MS Transformers.

The Age demographics for MS Transformers are shown in the following chart.



The Condition demographics for MS Transformers are shown in the following chart. One unit is not in service and not included in the chart.



The one transformer rated as 'Poor' is T1 at MS307, Huronia MS in the Barrie area. The transformer had some poor dissolved gas analysis (DGA) test results in 2012. The transformer is only 10 years old and our Stations Sustainment group is conducting additional tests to determine the cause of the poor DGA test results. No replacement is recommended at this time.

TS Transformer Replacement

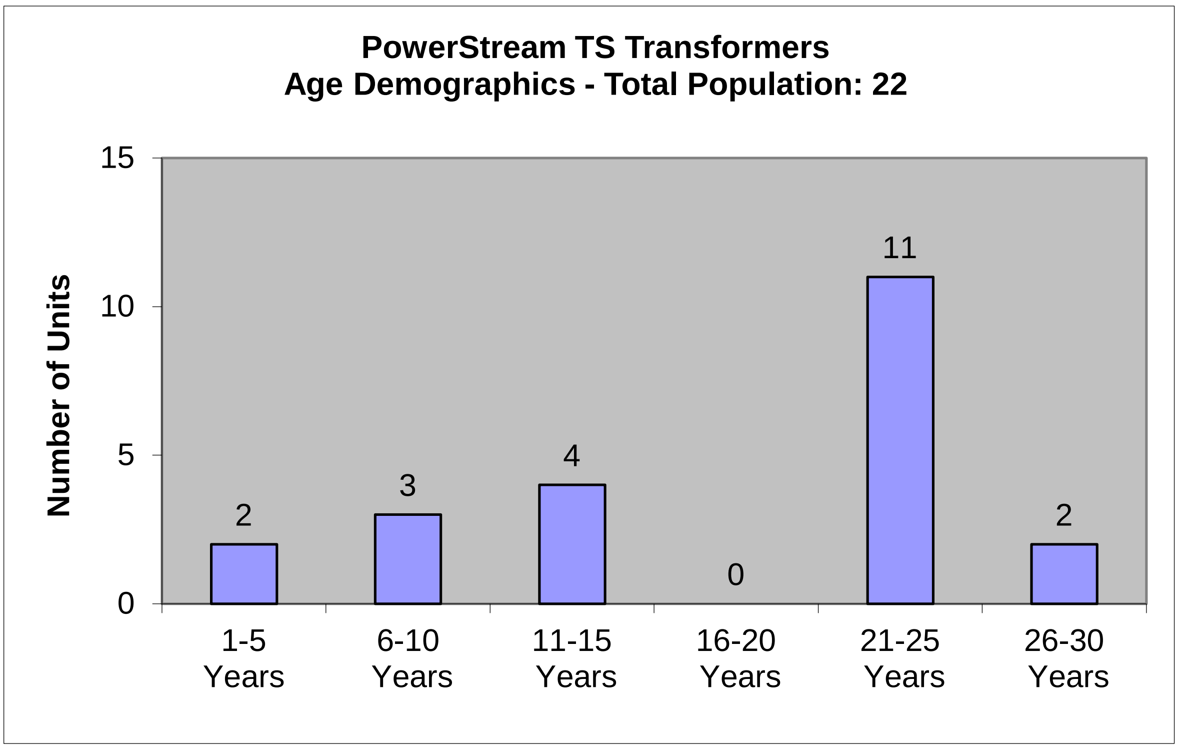
PowerStream has 22 TS Transformers in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board":**

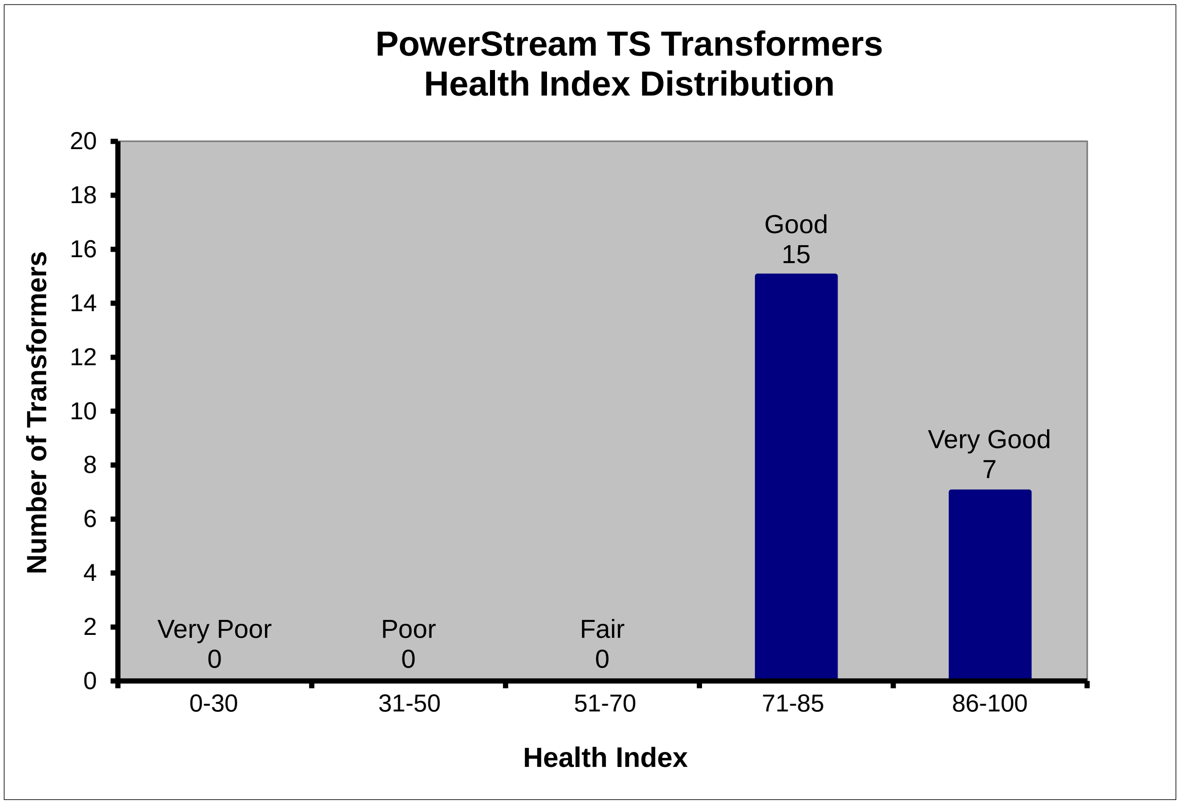
- *Useful life of **Power Transformers** is 30-60 years with typical useful life of 45 years.*

At PowerStream, for IFRS purposes, a useful life of 40 years is used for TS Transformers.

The Age demographics for TS Transformers are shown in the following chart.



The Condition demographics for TS Transformers are shown in the following chart.



No TS transformer replacements are recommended at this time.

Cost of Station Plant Asset Replacement (1d.1)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1d.1	Station Asset Replacement Projects	$422,624	$677,554	$555,045	$407,857	$0	$2,063,080

Safety, Environment Driven Station Projects (1d.2)

These projects cover the Arc Flash Implementation Program at various stations.

Cost of Safety, Environment Driven Station Projects (1d.2)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1d.2	Safety, Environment Driven Station Projects	$48,043	$12,070	$12,070	$12,343	$21,808	$106,334

Compliance to External Directives / Standards Station Projects (1d.3)

There are no specific projects recommended for the first five years under this category. The costs associated with WiMax Networks and MicroFIT and FIT generators are covered under a separate budget and are excluded from this report.

Cost of Compliance to External Directives / Standards Station Projects (1d.3)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1d.3	Compliance to External Directives / Standards Station Projects	$0	$0	$0	$0	$0	$0

Distribution Automation Station Projects (1d.4)

Automatic feeder restoration projects are planned for Vaughan TS#1 and Markham TS#3. These projects are a Station Design initiatives with Smart Grid Support, to develop the intelligent fault isolating strategies needed to improve PowerStream's reliability. The VTS#1 based project involves the implementation of an Automatic Feeder Restoration proof of concept on 4 feeders: 20M21, 20M22, 5122M11, and 36M3. The MTS#3 based project involves the implementation of an Automatic Feeder Restoration proof of concept on 3 feeders: 26M14, 26M17 and 26M18.The projects are expected to reduce the annual average CMI on these 7 feeders by a total of 885,218 minutes.

The HMI at Richmond Hill TS#1 is planned for replacement in 2018 at a cost of $87,886. This project is due to the problems and lack of support from the manufacturer for the existing system.

Cost of Distribution Automation Station Projects (1d.4)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1d.4	Distribution Automation Station Projects	$307,652	$316,581	$814,938	$335,194	$761,286	$2,535,651

Reliability Driven Station Projects (1d.5)

This category is for those Transformer Station (TS) and Municipal Station (MS) projects that are required to sustain the reliability of PowerStream’s fleet of TS’s and MS’s. This category includes the following projects:

Low Voltage Bushing Replacement - Transformer Station (2014 - 2017)
Replace the low voltage bushings on T1 & T2 at Markham TS #3 in 2014 and T1 & T2 on Vaughan TS #3 in 2015.

In November 2007, one of the low voltage (LV) bushings on T2 transformer at MTS #1 failed and was replaced along with the other T2 LV bushings. Investigation has shown that there is a design flaw in the bushings. The LV bushings on MTS #1 T1 were replaced in 2010 and the bushings on MTS #2 T1 & T2 were replaced in 2012. The low voltage bushings on MTS #3 T1 & T2, VTS #1 T1 & T2 and VTS #3 T1 & T2 are to be replaced as well.

The estimated LV bushing replacement costs are shown below in Table 10.

Year	Station	Cost	Project ID
2014	Markham TS#3 T1 & T2	$232,000	100268
2015	Vaughan TS #3	$273,000	100334

Table 10 – PS Low Voltage Bushing Replacement - Project Costs

Protection upgrade - Richmond Hill TS #2 (2017/18)
This project was initiated in response to problems with and lack of manufacturer support for the existing Alstom protection relays at Lazenby TS #2.

The project scope includes the following:

- Upgrade Bus, Line & Transformer protections
- Upgrade Bus 1 feeder protections
- Upgrade Bus 2 feeder protections

Engineering would be provided by Stations Design & Construction, installation to be completed by P&C.

The estimated protection upgrade costs are shown below in Table 11.

Year	Station	Cost	Project ID
2015	Lazenby #2 Bus, Line & Transformer Protection	$263,000	101003
2017	Lazenby #2 Feeder Protection – Bus 1	$489,000	100327
2018	Lazenby #2 Feeder Protection – Bus 2	$380,000	101620

Table 11 – PS Lazenby Protection Upgrade - Project Costs

Feeder Protection Upgrade - Markham (2013-2016)
This project was initiated because Markham TS #1, #2 & # 3 feeder protections did not have high set instantaneous elements (50a). The feeder protections at these stations are also an older design that cannot accept the settings required to implement PowerStream's Trip Saving protection philosophy.

The scope of this project is to replace the feeder protections at Markham TS #1 in 2010 (Completed), MTS#2 Bus J in 2013 (in progress), MTS#2 Bus Q in 2014, and MTS #3 in 2015/2016.

The estimated feeder protection upgrade costs are shown below in Table 12.

Year	Station	Cost	Project ID
2014	Markham TS#2 Bus Q	$153,000	101167
2015	Markham TS#3 Bus E	$161,000	100128
2016	Markham TS#3 Bus Z	$163,000	101055

Table 12 – PS MTS#2 and MTS#3 Feeder Protection Upgrade - Project Costs

Separate Transformer & Breaker SCADA Alarms Markham TS #1 & TS #2 (2016)

Decouple Transformer Gas/Differential Alarms and breaker SF6/trouble alarms at MTS #1 & #2. This project was originally submitted for 2009, but deferred to 2016 because of low priority.

Currently the Transformer Gas/Differential Alarms and breaker SF6/trouble alarms appear as one combined alarm on the station annunciator and on the SCADA. If one of the combined alarms comes into the control room, the system controller does not know if the problem is Transformer Gas, Transformer Differential Alarms, Breaker SF6 or Breaker trouble. Separating these alarms will give the system controller more specific information when one of these situations occurs. The scope of this project will be to separate each of the combined transformer and breaker alarms into two separate alarms.

The approximate cost of the project is $77,268, including burdens.

Refurbish Aurora MS#1- Replace Reclosers and 13.8kV Bus (2015)
This project was initiated as a result of numerous outages in 2006 and 2007 at Aurora MS #1. The outages were caused by problems on the 13.8kV bus and reclosers, as follows:

- A Red phase insulator failed on the secondary bus causing a lengthy station outage;
- The F2 recloser failed and was replaced by a similar vintage recloser borrowed from John MS in Markham;
- MS 1 is the only station with outdoor bus in Aurora and, as such, is susceptible to outages caused by animal related flashovers; and
- MS 1 is 40 years old and there is reason to believe the outdoor equipment may be reaching the end of its useful life.

The project scope includes replacing the existing outdoor 13.8kV bus and reclosers with enclosed switches and vacuum interrupters similar to the design of the new Aurora MS 7. The existing transformers, 44kV structures and SCADA RTU would be retained.

This project is expected to be completed in 2015 at an estimated cost of $1,800,000. However, a study of the refurbishment options is underway. Once the report has been completed, the cost estimate may be revised.

KDU-11/KDU-10 Replacement Projects – 230kV Line Protection
The KDU-11 and KDU-10 relays are used for 230kV line protection at a number of PowerStream's transformer stations. These relays are legacy electromechanical relays that are unreliable and are becoming impossible to have repaired. An IED replacement would allow connection to the substation LAN, allow for 3Io and 3Vo guarding and provide enhanced fault and status reporting.

The KDU-11 relays at Richmond Hill TS #1 have been replaced as part of a 2011 capital initiative. The KDU11 relays are planned to be replaced at VTS#1-T1T2 and VTS#2 in 2014 at an estimated cost of $115,000. The KDU-10 relays are Markham TS#1 and TS#2 are planned for replacement in 2015 at an estimated cost of $113,880.

Cost of Reliability Driven Station Projects (1d.5)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1d.5	Reliability Driven Station Projects	$499,474	$2,613,221	$162,867	$488,668	$1,133,461	**$4,897,691**

Operability and Maintainability Projects (1d.6)

This category is for those Transformer Station (TS) and Municipal Station (MS) projects that are required to sustain the operability and maintainability of PowerStream's fleet of TS's and MS's. This category includes the following projects:

Connect TS's to Town Water & Sewage (2015*)*
At present there is no washroom facility at Lazenby TS #1 & #2 and the sewage at Jackson TS is stored in a holding tank.

The scope of these projects will be to:

- Connect Jackson TS to town water & sewage and eliminate the sewage holding tank, if water and sewage are available.
- Connect Lazenby TS #1 to town water & sewage and install washroom facilities.

This will be a 2015 project at an estimated cost of $219,000, including burdens.

Lazenby Storage Facility (2015)
PowerStream recently completed consolidating its East and West Service Centres into one new service centre in Markham. As a result of these changes there will be a net reduction in the amount of storage space available for transformer station spare parts and workshop space for trades staff. For this reason Asset Management proposes to store spare parts for transformer stations at the Richmond Hill TS site. The storage structure will also be heated and used as a shop facility.

The estimated cost to construct an on-site storage facility at Richmond Hill Transformer Station is $291,000, including burdens.

Markham TS#4 Heating Improvements (2014)
The purpose of the improvement is to improve the indoor heating so that a temperature of 20 degrees Celsius can be achieved in the winter. Presently the heating system is not capable of heating the interior of the switchgear building above 15 degrees Celsius.

The estimated cost to improve the heating system at Markham TS#4 is $77,700 including burdens.

Replacement of Legacy RTU and Recloser Controllers at Morgan MS (2015)
This project entails the installation of new communication equipment, 2 new Cooper Form 6 Recloser Controllers and 2 new SEL2411s programmable I/O devices at Morgan MS, replacing the legacy, end of life, TG5100 RTU and aging Form 3 Recloser Controllers and problematic leased Bell line.

The RTU has reached end of life and there are no replacement parts for it. In order to keep it going, if some component of the RTU fails, there is a scramble to find something to get it running again. The same is true for the existing Form 3 Recloser control. They have reached end of life. The new Form 6 is a RTU and Recloser Control all in one. The Form 6 allows more versatility in protection settings and provides more extensive fault recording and reporting capabilities which will help decrease outage times. Replacing the RTU with the new Form 6 also allows the utilization the existing DNP licensed wireless footprint from MTS3 and the ability to retire the problematic and expensive Bell leased land line at $1,000/month.

This will be a 2014 project at an estimated cost of $110,000, including burdens.

Station Service Transfer Panels (2014/2015)
The purpose of these improvements is to install electrical transfer panels in the stations that have only one supply from switchgear or supply to street service. This is of value when the station is out of service for maintenance to maintain light, heat & D/C system charging for testing purposes.

The estimated costs to make the modifications are:

MS408, Cundles W. Barrie, MS323 8th Line Bradford - $42,000
MS324 Reagans Bradford, MS834 Nolan Tottenham - $54,000
For two Aurora MS - $42,000

In 2015, the modification is to be made at MS336 in Beeton at a cost of $10,692.

The above estimates include burdens.

Transformer Temperature Monitoring (2014-2016)
This project will provide real time transformer temperature monitoring and telemetry to PowerStream's control room and to Station Maintenance staff. The scope of this project will be to provide transformer temperature telemetry for the transformers at six Aurora stations. The transformer temperature monitoring and telemetry equipment will be installed over a three year period between 2014 and 2016. The expected costs are:

Aurora MS 1 & 2 - $82,000 (2015)
Aurora MS 3 & 4 - $84,000 (2015)
Aurora MS 5 & 6 - $86,000 (2016)

The above estimates include burdens.

Painswick South Capacitor Bank (2015)

A capacitor bank is proposed for installation at the upcoming Painswick South MS to improve the efficiency of the station. It is planned for 2015 at a cost of $341,343.

Cost of Operability and Maintainability Projects (1d.6)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1d.6	Operability and Maintainability Projects	$146,432	$1,138,263	$86,430	$0	$150,559	**$1,521,684**

Cost of Transformer / Municipal Station Projects (1d)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1d	Transformer / Municipal Station Projects	$1,424,225	$4,757,689	$1,631,350	$1,244,062	$2,067,114	$11,124,440

7.5 Emerging Sustainment Capital (1e)

This category covers the following:

Emerging Sustainment Capital (1e.1)

Emerging Sustainment Capital (1e.1)

Currently, there are planned Cable replacement projects for North and South which targets particular subdivisions based on age/outage information. These planned projects are identified and submitted for capital funding during the budget approval cycle.

In some cases cable not identified for replacement in a particular budget year begins to fail to the point where repair is no longer a viable or reliable option and security of customer supply is put at high risk. At this point the cable needs to be replaced immediately and is treated as an emerging project. The projects submitted under this category will be evaluated by System Planning in conjunction with System Control, Lines and Customer Services.

As the cable system gets older we expect that the rate of cable failures will increase and that cabling in some of the residential or industrial sub divisions will have to be addressed in emergency as opposed to planned replacement.

Cost of Emerging Sustainment Capital (1e)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
1e	Emerging Sustainment Capital	$2,012,802	$2,064,771	$2,184,583	$2,384,712	$1,903,764	$10,550,632

7.6 Additional Capacity (Transformer / Municipal Stations) (2c)

This category covers the following:

- Additional Capacity (Transformer / Municipal Stations) (2c.1)

Additional Capacity (Transformer / Municipal Stations) (2c.1)

This category covers the following:

- Additional Capacity Station Projects at TS
- Additional Capacity Station Projects at MS

Additional Capacity Station Projects at TS

The goal of these projects is to maintain sufficient system capacity to supply load growth in PowerStream.

PowerStream's Planning Philosophy was approved in 2007, and recommended:

> *Adopt station transformer loading of 1.4 per unit (pu) and 1.6 per unit (pu) of forced cooled rating, for summer and winter, respectively and accept an annual insulation loss of life of 2%.*

This overloading is referred to as the 10 day limited time rating (LTR).

There are constraints that must be considered when developing potential options. These are:

- The availability of adequate 230 kV supply;
- The availability of land, preferably close to the area of expected load growth and adjacent or near existing 230 kV lines; and
- The suitability of the option based on the Class EA requirements.

PowerStream performs annual load forecast and system capacity adequacy assessment to assess future need for additional transformation and distribution facilities for PowerStream service territory.

The PowerStream Load Forecast 2011-2020 concluded that additional transformation capacity and associated distribution facilities will be required in 2016 and in 2020 to provide service for the growing load.

Transformation capacity could be in conjunction with new transmission facilities, could be coupled to existing transformer stations and existing transmission facilities, or could require new land to construct a station on.

There is a need for a new Vaughan TS#4, expected to be in service in 2016, and a new Markham TS#5, expected to be in service in 2020.

The station portion cost of Vaughan TS#4 is estimated at $26.5M, and includes the following:

- Stations – Purchase of Land - $2.2M (2014)
- Stations – Phase 1 is estimated at $4,207,870 (2014)
- Stations – Phase 2 is estimated at $19,084,622 (2015)
- Stations – Phase 3 is estimated at $1,005,602 (2016)

The distribution feeder egress and grid integration cost of Vaughan TS#4 is estimated at $27.5M and is included in Section 7.7 - Growth Driven Lines Projects (2d.1).

The station portion cost of Markham TS#5 is estimated at $29.0M, and includes the following:

- Purchase of Land - $2.2M (2019)
- Stations – Phase 1 is estimated at $4,734,074 (2018)
- Stations – Phase 2 is estimated at $20,971,466 (2019)
- Stations – Phase 3 is estimated at $1,119,193 (2020)

The distribution feeder egress and grid integration cost of Markham TS#5 is estimated at $31.9M and is included in section 7.7 - Growth Driven Lines Projects (2d.1).

Additional Capacity Station Projects at MS
PowerStream performs load forecast and system capacity adequacy assessment annually to assess future need for additional transformation and distribution facilities for PowerStream's service territory.

The primary goal of MS projects is to maintain existing municipal stations (MS) below their computed firm rating. Also, to have sufficient spare capacity such that if there is a loss of one station, the neighbouring two stations can accommodate the lost capacity.

System Planning has identified requirements for 5 new MS's.

- Painswick South MS (in-service date 2015)
- Harvie Rd. MS (in-service date 2017)
- Mill St. MS#2 (in-service date 2017)
- Dufferin South MS#2 (in-service date 2017)
- Little Lake MS#2 (in-service date 2020)

Painswick South MS (in-service date 2014)
The proposed general location of this station is Yonge St. and Mapleview in Barrie.

This station is required for capacity relief of the existing Big Bay Point Rd. MS (MS304). The 2010 summer peak loading on this station was 26.1 MVA or 116% of the ONAN rating. This station has an ONAN rating of 22.5 MVA. The maximum "normal" station load is 25 MVA limited by the 44 kV feeder loading.

This area continues to experience subdivision and industrial/commercial growth and it is expected that the station peak will be 30 MVA by the summer of 2013.

Also, an important issue is backup capability. Loss of the station transformer, the load cannot be fully backed up by the neighboring stations (Saunders MS - loaded to 93% of ONAN rating and Huronia MS - loaded to 100% of ONAN rating). Partial capacity relief to Saunders and Huronia MS will be provided by Park Place MS. Huronia MS, in turn, can provide partial (2 to 3 MVA) relief to Big Bay Point MS.

Full capacity relief will be provided by the proposed Painswick South MS with a proposed in-service date of 2014.

The project is divided into phases as follows:

- 2013 – Purchase of Land - $750K
- 2014 – Station Work – Year 1 of 2
- 2015 – Station Work – Year 2 of 2
- 2014 – 44 kV Supply to the new MS (cost is included in Section 7.7 - Growth Driven Lines Projects)
- 2014 – 13.8 kV Feeder Integration (cost is included in Section 7.7 - Growth Driven Lines Projects)

Harvie Rd. MS (in-service date 2017)
The proposed general location of this station is Harvie Rd. and Veterans Drive just east of HWY 27 in Barrie.

This station is required for capacity relief of the existing Holly MS (MS305) and Ferndale Dr. MS (MS303). The 2010 summer peak loading on Holly MS was 21.7 MVA (96.4% of ONAN rating) and Ferndale Dr. MS it was 19.7 MVA (87.6% of ONAN rating).

Both Holly and Ferndale Dr. MS have an ONAN rating of 22.5 MVA. The maximum "normal" station load is 25 MVA limited by the 44 kV feeder loading.

This area continues to experience growth and it is expected that Holly MS station peak will be over 25 MVA by the summer of 2014, while Ferndale Dr. MS peak will be over 23 MVA during the same period.

Also, an important issue is backup capability. Loss of the station transformer at either of these two stations, the load cannot be fully backed up by the neighboring stations (Saunders MS - loaded to 93% of ONAN rating and Huronia MS - loaded to 100% of ONAN rating). Partial relief (approx. 1,500 kVA) to Holly and Ferndale Dr. stations will be provided by Park Place MS.

Full capacity relief will be provided by the proposed Harvie Rd. MS with a proposed in-service date of 2017.

The project is divided into phases as follows:

- 2014 – Purchase of Land - $715K
- 2015 – Station Work – Year 1 of 2
- 2017 – Station Work – Year 2 of 2
- 2017 – 44 kV Supply to the new MS (cost is included in Section 7.7 - Growth Driven Lines Projects)
- 2017 – 13.8 kV Feeder Integration (cost is included in Section 7.7 - Growth Driven Lines Projects)

Mill St. MS#2 (in-service date 2017)
The proposed general location of this station is near Mill St. in Tottenham. This station is required for capacity relief for the existing Mill St. East MS (MS 835) in Tottenham. The proposed station is 44 -

8.32kV, 10 MVA with 3 Feeders.
The project is divided into phases as follows:

- 2016 – Purchase of Land - $660K
- 2016 – Station Work – Year 1 of 2
- 2017 – Station Work – Year 2 of 2
- 2017 – 44 kV Supply to the new MS (cost is included in Section 7.7 - Growth Driven Lines Projects)
- 2017 – 8.32 kV Feeder Integration (cost is included in Section 7.7 - Growth Driven Lines Projects)

Dufferin South MS#2 (in-service date 2017)
The proposed general location of this station is near Dufferin Street and Industrial Parkway in Alliston.

The proposed substation is required to provide capacity relief to 8th Ave. MS (MS330) and Dufferin South MS (MS431) (conversion will be required), and also to supply a proposed Industrial Subdivision at the corner of Dufferin St. & Industrial Pkwy.

The proposed station is 44-13.8 kV Substation consisting of 2 x 10 MVA transformers with bus tie normally open and 4x13.8 kV Feeders.

The project is divided into phases as follows:

- 2015 – Purchase of Land - $770K
- 2016 – Station Work – Year 1 of 2
- 2017 – Station Work – Year 2 of 2
- 2017 – 44 kV Supply to the new MS (cost is included in Section 7.7 - Growth Driven Lines Projects)
- 2017 – 13.8 kV Feeder Integration (cost is included in Section 7.7 - Growth Driven Lines Projects)

Little Lake MS#2 (in-service date 2020)
The proposed general location is in Barrie.
The proposed station is required for capacity relief of Little Lake MS (MS306)

The proposed station is 44-13.8 kV Substation consisting of 2 x 10 MVA transformers with bus tie normally open and 4x13.8 kV Feeders.

The project is divided into phases as follows:

- 2019 – Purchase of Land - $880K
- 2020 – Station Work – Year 1 of 2
- 2021 – Station Work – Year 2 of 2
- 2020 – 44 kV Supply to the new MS (cost is included in Section 7.7 - Growth Driven Lines Projects)
- 2020 – 13.8 kV Feeder Integration (cost is included in Section 7.7 - Growth Driven Lines Projects)

Cost of Additional Capacity (Transformer / Municipal Stations) (2c)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
2c	Additional Capacity (Transformer/Municipal Stations)	$8,392,965	$24,851,270	$8,816,648	$6,555,733	$4,734,074	$53,350,690

7.7 Growth Driven Lines Projects (2d)

This category covers the following:

- Growth Driven Lines Projects (2d.1)

Growth Driven Lines Projects (2d.1)

The primary goal of these projects is to maintain feeder peak loading below 400 amps under normal conditions and to comply with calculated feeder egress ratings during normal and contingency conditions. This is required to maintain reliable supply to customers.

PowerStream Planning Philosophy was approved in 2007 and recommended:

> *Using 400 amps as the maximum planned feeder loading under normal conditions and 600 amps under contingency conditions.*

All 27.6 kV and 44 kV feeders shall be designed for full backup capability over peak loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders. To facilitate this restoration capability, three phase feeder loading will be planned to a maximum of 400 amps under normal operation and 600 amps under contingency conditions.

In certain industrial/commercial areas a normal operating limit greater than 400 amps is acceptable provided remotely controlled switching is available for load transfer to adjacent feeder(s) during emergency condition.

Engineering Planning has prepared various reports to document feeder cable egress information and ampacity for all PowerStream transformer stations and municipal stations using CYME software (CYMCAP) based on duct structures, cables and cable bonding schemes. These feeder loading limits have been retained for use in this system optimization and feeder balancing plan. The 27.6 kV and 44 kV feeder peak loading has to be below 400 amps or the calculated feeder egress rating, whichever is lower.

The majority of capital line project work originates from construction driven by the various municipalities within PowerStream service area for servicing new subdivisions, industrial, commercial and institutional developments.

Some significant projects are:

- Vaughan TS#4 - Distribution portion
- Markham TS#5 - Distribution portion
- Painswick South MS - Distribution portion
- Harvie St. MS – Distribution portion
- Mill St. MS#2 – Distribution portion
- Dufferin South MS#2 – Distribution portion
- Little lake MS#2 – Distribution portion

Vaughan TS#4

The total cost of the distribution portion of Vaughan TS#4 is estimated at $27.5M, and includes the following:

- Feeder Integration Phase 1 - $7.7M (2015)
- Feeder Integration Phase 2 - $9.9M (2016)
- Feeder Integration Phase 3 - $9.9M (2017)

Markham TS#5

The total cost of the distribution portion of Markham TS#5 is estimated at $31.9M, and includes the following:

- Feeder Integration Phase 1 - $9.9M (2020)
- Feeder Integration Phase 2 - $11M (2022)
- Feeder Integration Phase 3 - $11M (2023)

Painswick South MS

The total cost of the distribution portion of Painswick South MS is estimated at $696K, and includes the following:

- 44 kV Supply - $322,744 (2014)
- 13.8 kV Feeder Integration - $373,061 (2014)

Harvie St. MS
The total cost of the distribution portion of Harvie St. MS is estimated at $571K, and includes the following:

- 44 kV Supply - $268,312 (2017)
- 13.8 kV Feeder Integration - $302,654 (2017)

Mill St. MS#2
The total cost of the distribution portion of Mill St. MS#2 is estimated at $784K, and includes the following:

- 44 kV Supply - $383,581 (2017)
- 8.32 kV Feeder Integration - $400,378 (2017)

Dufferin South MS#2
The total cost of the distribution portion of Dufferin South MS#2 is estimated at $582K, and includes the following:

- 44 kV Supply - $272,602 (2017)
- 13.8 kV Feeder Integration - $309,397 (2017)

Little Lake MS#2
The total cost of the distribution portion of Little Lake MS#2 is estimated at $617K, and includes the following:

- 44 kV Supply - $306,126 (2020)
- 13.8 kV Feeder Integration - $310,886 (2020)

Cost of Growth Driven Lines Projects (2d)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
2d	Growth Driven Lines Projects	$6,614,256	$12,933,519	$25,455,392	$28,379,458	$3,087,256	$76,469,881

7.8 Purchase of Spare Equipment (3f)

This category covers the following:

- Purchase of Spare Equipment (3f.1)

Purchase of Spare Equipment (3f.1)

This category includes the following projects.

Purchase of a Critical Spare - 2000A Siemens SPS2-38-31.5 outdoor SF6 breaker. (2014)
Spare (To be potentially used at Cockburn, Walker and Fry TS's)
This project entails purchasing a new spare 2000 amp Siemens SPS2-38-31.5 Sf6 breaker to be stored at Cockburn TS. Presently there are no spare 2000 amp outdoor type circuit breakers of this type in the system. There are spare 1200 amp outdoor feeder circuit breakers available, however we have no spare 2000 amp outdoor type circuit breakers of which are more critical. This spare breaker will be the identical spare for the installed 2000 amp circuit breakers at Fry, Walker, Cockburn T1-T2. It will also serve as a retrofit emergency spare for the Cockburn T3-T4 breakers. Spares and parts will be tracked in CASCADE using the spare/parts functionality. This is part of establishing a baseline of spare parts.

In order to properly maintain and repair failed equipment in a quick turnaround time, critical spares and spare parts are required to be on-hand and readily available. This purchase will ensure that in the event of an emergency where a replacement is required, we will have the appropriate spares available.

The estimated cost to purchase the spare 2000A Siemens ***SPS2-38-31.5 outdoor SF6 breaker*** is $154,000, including burdens.

Spare HD4 Circuit Breakers and Ground & Test Devices (GTD) for Greenwood TS. (2014)
This project entails acquiring one 1200 Amp spare HD4 breaker, one 2000 Amp spare HD4 breaker and two 1200 Amp GTD's for Greenwood TS. Replacement of aged HKSA breakers with new HD4 breakers was completed in 2010 as per the ACA program. Spare HD4 breakers and two 1200 Ground & Test Devices (GTD's) are required by Operations and Station Maintenance. Acquiring this equipment will increase system reliability and allow for planned and unplanned outages.

The estimated cost to purchase the spare HD4 circuit breakers and GTD for Greenwood TS#1 is $162,527, including burdens.

Cost of Purchase of Spare Equipment (3f)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2014	2015	2016	2017	2018	5 Yr. Total
3f	Purchase of Spare Equipment	$0	$316,578	$0	$0	$90,180	$406,758

8 SUMMARY OF THE FIRST FIVE YEARS CAPITAL (2014-2018)

8.1 Funding based on Major Categories (2014-2018)

PowerStream - Capital Work Plan from Planning and Stations

	Category	2014	2015	2016	2017	2018	5 Yr. Total
1	Sustainment	$39,586,732	$41,367,952	$38,363,726	$38,679,300	$38,245,637	**$196,243,347**
2	Development	$15,007,221	$37,784,789	$34,272,040	$34,935,191	$7,821,330	**$129,820,571**
3	Operations	$0	$316,578	$0	$0	$90,180	**$406,758**
	Total:	**$54,593,953**	**$79,469,319**	**$72,635,766**	**$73,614,491**	**$46,157,147**	**$326,470,676**

8.2 Funding based on Sub-Categories (2014-2018)

PowerStream - Capital Work Plan from Planning and Stations

	Category	2014	2015	2016	2017	2018	5 Yr. Total
	1. Sustainment Capital						
1a	Replacement Program	$7,279,329	$7,462,333	$7,648,876	$7,839,060	$8,032,998	**$38,262,596**
1b	Sustainment Driven Lines Projects	$28,560,990	$26,719,719	$26,523,917	$26,825,216	$25,843,924	**$134,473,766**
1c	Emergency / Restoration	$309,386	$363,440	$375,000	$386,250	$397,837	**$1,831,913**
1d	Transformer / Municipal Stations	$1,424,225	$4,757,689	$1,631,350	$1,244,062	$2,067,114	**$11,124,440**
1e	Emerging Sustainment Capital	$2,012,802	$2,064,771	$2,184,583	$2,384,712	$1,903,764	**$10,550,632**
	Total Sustainment:	**$39,586,732**	**$41,367,952**	**$38,363,726**	**$38,679,300**	**$38,245,637**	**$196,243,347**
	2. Development Capital						
	Category	**2014**	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
2c	Additional Capacity (Transformer / Municipal Stations)	$8,392,965	$24,851,270	$8,816,648	$6,555,733	$4,734,074	**$53,350,690**
2d	Growth Driven Lines Projects	$6,614,256	$12,933,519	$25,455,392	$28,379,458	$3,087,256	**$76,469,881**
	Total Development:	**$15,007,221**	**$37,784,789**	**$34,272,040**	**$34,935,191**	**$7,821,330**	**$129,820,571**
	3. Operations Capital						
	Category	**2014**	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
3f	Purchase of Spare Equipment	$0	$316,578	$0	$0	$90,180	**$406,758**
	Total Operations:	**$0**	**$316,578**	**$0**	**$0**	**$90,180**	**$406,758**
	Grand Total						
		2014	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
	Grand Total:	**$54,593,953**	**$79,469,319**	**$72,635,766**	**$73,614,491**	**$46,157,147**	**$326,470,676**

8.3 Funding based on Minor Categories (2014-2018)

PowerStream - Capital Work Plan from Planning and Stations							
1. Sustainment Capital							
	Category	**2014**	**2015**	**2016**	**2017**	**2018**	**5 Yr.**
1a	**Replacement Program**	**$7,279,329**	**$7,462,333**	**$7,648,876**	**$7,839,060**	**$8,032,998**	**$38,262,596**
	1a.1 Pole Replacement Program	$4,956,094	$5,071,697	$5,188,949	$5,307,899	$5,428,597	**$25,953,236**
	1a.2 Undergound Switchgear Replacement Program	$2,323,235	$2,390,636	$2,459,927	$2,531,161	$2,604,401	**$12,309,360**
1b	**Sustainment Driven Lines Projects**	**$28,560,990**	**$26,719,719**	**$26,523,917**	**$26,825,216**	**$25,843,924**	**$134,473,766**
	1b.1 Cable Replacement Projects	$16,844,793	$13,933,827	$14,331,929	$14,741,300	$15,312,065	**$75,163,914**
	1b.2 Cable Injection Projects	$4,103,660	$4,219,823	$4,339,040	$4,461,402	$4,587,004	**$21,710,929**
	1b.3 Lines Asset Replacement Projects	$1,731,604	$1,716,975	$551,113	$0	$0	**$3,999,692**
	1b.4 Conversion Projects	$1,122,440	$495,000	$55,000	$1,355,244	$0	**$3,027,684**
	1b.5 System Reconfiguration Projects	$31,794	$0	$0	$0	$0	**$31,794**
	1b.6 Radial Supply Remediation Projects	$0	$0	$1,038,487	$0	$0	**$1,038,487**
	1b.7 Distribution Automation Lines Projects	$2,419,883	$2,475,169	$2,530,758	$2,585,744	$2,194,590	**$12,206,144**
	1b.8 Reliability Driven Lines Projects	$503,223	$379,750	$79,565	$0	$0	**$962,538**
	1b.9 Safety, Environment Driven Lines Projects	$0	$0	$0	$0	$0	**$0**
	1b.10 Compliance to External Directives / Standards Lines Projects	$1,803,593	$212,768	$231,759	$233,992	$220,000	**$2,702,112**
	1b.11 Rear Lot Supply Remediation Projects	$0	$3,286,407	$3,366,266	$3,447,534	$3,530,265	**$13,630,472**
1c	**Emergency / Restoration**	**$309,386**	**$363,440**	**$375,000**	**$386,250**	**$397,837**	**$1,831,913**
	1c.1 Transformer Replacement Projects	$309,386	$363,440	$375,000	$386,250	$397,837	**$1,831,913**
1d	**Transformer / Municipal Stations**	**$1,424,225**	**$4,757,689**	**$1,631,350**	**$1,244,062**	**$2,067,114**	**$11,124,440**
	1d.1 Station Asset Replacement Projects	$422,624	$677,554	$555,045	$407,857	$0	**$2,063,080**
	1d.2 Safety, Environment Driven Station Projects	$48,043	$12,070	$12,070	$12,343	$21,808	**$106,334**
	1d.3 Compliance to External Directives / Standards Station Projects	$0	$0	$0	$0	$0	**$0**
	1d.4 Distribution Automation Station Projects	$307,652	$316,581	$814,938	$335,194	$761,286	**$2,535,651**
	1d.5 Reliability Driven Station Projects	$499,474	$2,613,221	$162,867	$488,668	$1,133,461	**$4,897,691**
	1d.6 Operability and Maintainability Projects	$146,432	$1,138,263	$86,430	$0	$150,559	**$1,521,684**
1e	**Emerging Sustainment Capital**	**$2,012,802**	**$2,064,771**	**$2,184,583**	**$2,384,712**	**$1,903,764**	**$10,550,632**
	1e.1 Emerging Sustainment Capital	$2,012,802	$2,064,771	$2,184,583	$2,384,712	$1,903,764	**$10,550,632**
	Sustainment:	**$39,586,732**	**$41,367,952**	**$38,363,726**	**$38,679,300**	**$38,245,637**	**$196,243,347**
2. Development Capital							
	Category	**2014**	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
2c	**Additional Capacity (Transformer / Municipal Stations)**	**$8,392,965**	**$24,851,270**	**$8,816,648**	**$6,555,733**	**$4,734,074**	**$53,350,690**
	2c.1 Additional Capacity (Transformer / Municipal Stations)	$8,392,965	$24,851,270	$8,816,648	$6,555,733	$4,734,074	**$53,350,690**
2d	**Growth Driven Lines Projects**	**$6,614,256**	**$12,933,519**	**$25,455,392**	**$28,379,458**	**$3,087,256**	**$76,469,881**
	2d.1 Growth Driven Lines Projects	$6,614,256	$12,933,519	$25,455,392	$28,379,458	$3,087,256	**$76,469,881**
	Development:	**$15,007,221**	**$37,784,789**	**$34,272,040**	**$34,935,191**	**$7,821,330**	**$129,820,571**
3. Operations Capital							
	Category	**2014**	**2015**	**2016**	**2017**	**2018**	**5 Yr. Total**
3f	**Purchase of Spare Equipment**	**$0**	**$316,578**	**$0**	**$0**	**$90,180**	**$406,758**
	3f.1 Purchase of Spare Equipment	$0	$316,578	$0	$0	$90,180	**$406,758**
	Operations:	**$0**	**$316,578**	**$0**	**$0**	**$90,180**	**$406,758**
Grand Total							
	Grand Total:	**$54,593,953**	**$79,469,319**	**$72,635,766**	**$73,614,491**	**$46,157,147**	**$326,470,676**

9 SUMMARY OF THE SECOND FIVE YEARS CAPITAL (2019-2023)

9.1 Funding based on Major Categories (2019-2013)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2019	2020	2021	2022	2023	5 Yr. Total
1	Sustainment	$40,576,009	$39,566,413	$41,981,830	$43,620,198	$44,106,687	**$209,851,137**
2	Development	$28,836,466	$19,888,968	$10,113,639	$13,200,000	$13,200,000	**$85,239,073**
3	Operations	$0	$0	$0	$0	$0	**$0**
Total:		**$69,412,475**	**$59,455,381**	**$52,095,469**	**$56,820,198**	**$57,306,687**	**$295,090,210**

9.2 Funding based on Sub-Categories (2019-2013)

PowerStream - Capital Work Plan from Planning and Stations							
1. Sustainment Capital							
Category		2019	2020	2021	2022	2023	5 Yr. Total
1a	Replacement Program	$8,230,805	$8,432,598	$8,638,487	$8,848,604	$9,063,075	**$43,213,569**
1b	Sustainment Driven Lines Projects	$26,407,166	$27,148,553	$27,902,210	$28,721,806	$29,786,116	**$139,965,851**
1c	Emergency / Restoration	$409,772	$422,065	$434,727	$447,000	$557,096	**$2,270,660**
1d	Transformer / Municipal Stations	$3,609,469	$1,588,063	$2,974,471	$3,356,062	$1,900,338	**$13,428,403**
1e	Emerging Sustainment Capital	$1,918,797	$1,975,134	$2,031,935	$2,246,726	$2,800,062	**$10,972,654**
	Total Sustainment:	**$40,576,009**	**$39,566,413**	**$41,981,830**	**$43,620,198**	**$44,106,687**	**$209,851,137**
2. Development Capital							
Category		2019	2020	2021	2022	2023	5 Yr. Total
2c	Additional Capacity (Transformer / Municipal Stations)	$24,051,466	$2,771,956	$3,293,639	$0	$0	**$30,117,061**
2d	Growth Driven Lines Projects	$4,785,000	$17,117,012	$6,820,000	$13,200,000	$13,200,000	**$55,122,012**
	Total Development:	**$28,836,466**	**$19,888,968**	**$10,113,639**	**$13,200,000**	**$13,200,000**	**$85,239,073**
3. Operations Capital							
Category		2019	2020	2021	2022	2023	5 Yr. Total
3f	Purchase of Spare Equipment	$0	$0	$0	$0	$0	**$0**
	Total Operations:	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grand Total							
		2019	2020	2021	2022	2023	5 Yr. Total
	Grand Total:	**$69,412,475**	**$59,455,381**	**$52,095,469**	**$56,820,198**	**$57,306,687**	**$295,090,210**

9.3 Funding based on Minor Categories (2019-2023)

PowerStream - Capital Work Plan from Planning and Stations							
1. Sustainment Capital							
	Category	2019	2020	2021	2022	2023	5 Yr.
1a	**Replacement Program**	**$8,230,805**	**$8,432,598**	**$8,638,487**	**$8,848,604**	**$9,063,075**	**$43,213,569**
	1a.1 Pole Replacement Program	$5,551,099	$5,675,459	$5,801,727	$5,929,967	$6,060,235	**$29,018,487**
	1a.2 Undergound Switchgear Replacement Program	$2,679,706	$2,757,139	$2,836,760	$2,918,637	$3,002,840	**$14,195,082**
1b	**Sustainment Driven Lines Projects**	**$26,407,166**	**$27,148,553**	**$27,902,210**	**$28,721,806**	**$29,786,116**	**$139,965,851**
	1b.1 Cable Replacement Projects	$15,747,973	$16,196,249	$16,657,270	$17,131,407	$17,619,060	**$83,351,959**
	1b.2 Cable Injection Projects	$4,715,942	$4,848,320	$4,962,238	$5,123,806	$5,267,130	**$24,917,436**
	1b.3 Lines Asset Replacement Projects	$0	$0	$0	$0	$0	**$0**
	1b.4 Conversion Projects	$0	$0	$0	$0	$0	**$0**
	1b.5 System Reconfiguration Projects	$0	$0	$0	$0	$0	**$0**
	1b.6 Radial Supply Remediation Projects	$0	$0	$0	$0	$0	**$0**
	1b.7 Distribution Automation Lines Projects	$2,263,076	$2,314,723	$2,381,084	$2,449,247	$2,807,379	**$12,215,509**
	1b.8 Reliability Driven Lines Projects	$0	$0	$0	$0	$0	**$0**
	1b.9 Safety, Environment Driven Lines Projects	$0	$0	$0	$0	$0	**$0**
	1b.10 Compliance to External Directives / Standards Lines Projects	$44,000	$44,000	$44,000	$44,000	$0	**$176,000**
	1b.11 Rear Lot Supply Remediation Projects	$3,636,175	$3,745,261	$3,857,618	$3,973,346	$4,092,547	**$19,304,947**
1c	**Emergency / Restoration**	**$409,772**	**$422,065**	**$434,727**	**$447,000**	**$557,096**	**$2,270,660**
	1c.1 Transformer Replacement Projects	$409,772	$422,065	$434,727	$447,000	$557,096	**$2,270,660**
1d	**Transformer / Municipal Stations**	**$3,609,469**	**$1,588,063**	**$2,974,471**	**$3,356,062**	**$1,900,338**	**$13,428,403**
	1d.1 Station Asset Replacement Projects	$874,452	$0	$949,527	$0	$0	**$1,823,979**
	1d.2 Safety, Environment Driven Station Projects	$141,810	$28,412	$147,919	$29,991	$30,812	**$378,944**
	1d.3 Compliance to External Directives / Standards Station Projects	$836,499	$0	$0	$1,393,308	$836,000	**$3,065,807**
	1d.4 Distribution Automation Station Projects	$782,822	$804,958	$827,708	$851,097	$778,632	**$4,045,217**
	1d.5 Reliability Driven Station Projects	$820,929	$622,203	$829,854	$812,562	$111,587	**$3,197,135**
	1d.6 Operability and Maintainability Projects	$152,957	$132,490	$219,463	$269,104	$143,307	**$917,321**
1e	**Emerging Sustainment Capital**	**$1,918,797**	**$1,975,134**	**$2,031,935**	**$2,246,726**	**$2,800,062**	**$10,972,654**
	1e.1 Emerging Sustainment Capital	$1,918,797	$1,975,134	$2,031,935	$2,246,726	$2,800,062	**$10,972,654**
	Sustainment:	**$40,576,009**	**$39,566,413**	**$41,981,830**	**$43,620,198**	**$44,106,687**	**$209,851,137**
2. Development Capital							
	Category	2019	2020	2021	2022	2023	5 Yr. Total
2c	**Additional Capacity (Transformer / Municipal Stations)**	**$24,051,466**	**$2,771,956**	**$3,293,639**	**$0**	**$0**	**$30,117,061**
	2c.1 Additional Capacity (Transformer / Municipal Stations)	$24,051,466	$2,771,956	$3,293,639	$0	$0	**$30,117,061**
2d	**Growth Driven Lines Projects**	**$4,785,000**	**$17,117,012**	**$6,820,000**	**$13,200,000**	**$13,200,000**	**$55,122,012**
	2d.1 Growth Driven Lines Projects	$4,785,000	$17,117,012	$6,820,000	$13,200,000	$13,200,000	**$55,122,012**
	Development:	**$28,836,466**	**$19,888,968**	**$10,113,639**	**$13,200,000**	**$13,200,000**	**$85,239,073**
3. Operations Capital							
	Category	2019	2020	2021	2022	2023	5 Yr. Total
3f	**Purchase of Spare Equipment**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	3f.1 Purchase of Spare Equipment	$0	$0	$0	$0	$0	**$0**
	Operations:	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grand Total							
	Grand Total:	**$69,412,475**	**$59,455,381**	**$52,095,469**	**$56,820,198**	**$57,306,687**	**$295,090,210**

9.4 General Outlook (2019-2023)

The general outlook is summarized below.

System Reliability and Customer Services

PowerStream will continue to manage system reliability and maintain reasonable customer services.

Asset Demographics and Condition

PowerStream will continue to add new station and distribution assets (e.g. circuit breaker, pole, cable, transformer, switchgear, etc.) to serve our customers. As time goes on, assets will reach end-of-life and need to be replaced. PowerStream will continue to monitor, inspect, and maintain the assets. Asset condition will be taken into consideration to prioritize the annual asset replacement programs.

System Load Growth and Capacity of Supply
PowerStream will experience a system load growth from 2 to 2.5% per year.

9.5 Specific Outlook (2019-2023)

The specific outlook is summarized below.
All costs indicated below are in 2013 dollars. In the project listing (Appendix B), the annual project costs are increased by 3% year over year to account for the general inflation.

Replacement Program (1a)

Pole Replacement (1a.1)
Annual quantity will remain the same at 400 poles. Annual cost is approx. $4,8M (400 poles x $12,000). The proposed pole replacement program is reasonable and realistic to address approximately 1% of the pole population. On an on-going basis, poles continue to deteriorate and need to be replaced to maintain the integrity of the distribution system.

Underground Switchgear Replacement (1a.2)
Annual quantity will remain the same at 30 units. Annual cost is approx. $2,3M (30 units x $76,004),
The proposed distribution switchgear replacement program is expected to continue at the same level to address the normal rate of deterioration.

Sustainment Driven Lines Projects (1b)

Underground Cable Replacement (1b.1)
Annual quantity will remain the same at 47,000m. Annual cost is approx. $13,2M (47,000m x $281).
The proposed cable replacement program is a 20 year program which is expected to continue after the first 20 years at the same level. The proposed cable replacement is reasonable and realistic to address less than 1% of the cable population. On an on-going basis, cables continue to deteriorate and need to be replaced to maintain the integrity of the distribution system.

Underground Cable Injection (1b.2)
Annual quantity will remain the same at 57,000m until 2023, then terminate. Annual cost is approx. $4,1M (57,000m x $72)
The proposed cable injection program is a 10 year program. It is expected that the program will terminate by 2023.

Conversion Projects (1b.4)
It is expected that one Conversion project at one MS in Vaughan area will be completed over a period of 5 years. Annual cost is approx. $400K

Distribution Automation (1b.7)
It is expected that work volume will remain the same. Annual cost is approx. $2,4M

Rear Lot Supply Remediation Projects (1b.11)
It is expected that the spending level will remain the same. Annual cost is approx. $3,3M

<u>Transformer / Municipal Stations (1d)</u>

Station Asset Replacement Projects (1d.1)
It is estimated that the 230kV disconnect switches will require replacement at Markham TS#1 in 2019 at a cost of $88,000 and Markham TS#2 in 2021 at a cost of $96,000.

The switchgear line-ups at Innisfil MS411 and Duckworth MS409 are 52 and 45 years old respectively. Replacement of the two line-ups is recommended to ensure reliable service in the area and to update to safer standards. It is proposed to replace the switchgear at MS411 in 2019 at a cost of $787,000 and at MS409 in 2021 at a cost of $853,000.

Safety, Environment Driven Station Projects (1d.2)
The arc flash mitigation program is expected to continue through to 2023 at an average annual cost of $29,000.

It is anticipated that two Municipal Stations will require ground grid refurbishing over the next ten years to maintain safe step and touch levels in the stations. $114,000 has been budgeted for 2019 and $119,000 for 2021 to undertake such projects.

Compliance to External Directives / Standards Station Projects (1d.3)
20MVar Capacitor Banks are planned for installation at Greenwood TS Expansion in 2019, Lazenby TS#1 in 2022 and Markham TS#2 in 2023. The capacitor banks are intended to improve the capacity of the transformer station and meet IESO’s requirement to improve power factor. The average cost of each project is about $1,000,000.

Distribution Automation Station Projects (1d.4)
Automatic feeder restoration projects are initiatives with intelligent fault isolating capabilities for improved reliability. There are projects planned for the 2019 to 2023 time period on an annual basis. The average cost per year is expected to be about $800,000.

Human Machine Interface (HMI) systems are computing platforms that provide local monitoring and control of the relay and protection system at a transformer station. HMI installations are planned for the three Markham transformer stations, where there are no HMI’s, over a three year period starting in 2019. Replacement of the Lazenby TS2 HMI is planned for 2022 as the software in the existing system is becoming more difficult to use and local vendor support is not available. The average annual cost is expected to be $92,000.

Reliability Driven Station Projects (1d.5)
It is expected that Stations will pursue its programs to replace the mechanical and obsolete protections at older stations with new electronic protection systems. This includes feeder, line, transformer and bus protections. The new relays provide valuable fault diagnostics and monitoring capabilities that greatly enhance problem solving. It is expected that the annual cost will be about $712,000 annually through to 2023.

Operability and Maintainability Projects (1d.6)
There are obsolete revenue metering, Digital Analog Converters (DACs) Inverter and original Remote Terminal Unit (RTU) units at the older transformer stations that need to be removed from the stations because the units will not be used again, they are taking up valuable space in the control buildings and the existing wiring to these units could cause confusion for the P&C technicians. The average annual cost to remove the equipment over a 5 year period is $61,000.

A plan is in place to enhance the vegetation at one transformer station each year at an average annual cost of $77,000. The purpose of the vegetation enhancements is to improve security and maintain good visual appearance.

It is proposed to install electrical transfer panels in the municipal stations that have only one supply from switchgear to allow an alternate supply from street service. This is of value when the station is out of service for maintenance to maintain light, heat & D/C system charging for testing purposes. The average annual cost is $17,000.

It has been determined that the 20MVar capacitor bank at Markham TS#3 is not fit for service in this installation and is expected to be removed from the site in 2019 at a cost of $20,000.

Additional Capacity (Transformer / Municipal Stations) (2c)

New TS (Markham TS#5) (2023)

This project depends on the results of the York Region Supply Study.
The in-service date for the new TS depends on many factors including the Conservation & Demand Management (CDM) target achievement. Currently the York Region Supply Study indicates an in-service date of 2024. This is based on the scenario that PowerStream will achieve 100% of the CDM target. Since 2024 is outside of this five year window, the cost of Markham TS#5 is not included in this report. It is noted here because should PowerStream only achieve 50% of the CDM target, the in-service date could advance to 2020.

10 COMPARISON TO PREVIOUS FIVE YEAR CAPITAL PLAN

At the overall level, the changes between the previous Five Year Capital Plan (2013-2017) and the current Five Year Capital Plan (2014-2018) are shown in the following table.

Five Year Capital Plan Comparison						
	2013	2014	2015	2016	2017	2018
2013-2017 Capital Plan Annual Total (A)	$47,193,671	$51,395,212	$81,349,582	$68,748,440	$51,822,778	N/A
2014-2018 Capital Plan Annual Total (B)	N/A	$54,593,953	$79,469,319	$72,635,766	$73,614,491	$46,157,147
Annual Difference (B-A)	N/A	$3,198,741	-$1,880,263	$3,887,326	$21,791,713	N/A

The differences in quantity and cost are summarized below.

Cable Replacement

- Romfield Phase 4 (originally planned for 2014) and Phase 5 (originally planned for 2015), are now combined into one project – "Romfield Phase 4", planned for 2014

Station Asset Replacement Projects

- Station asset replacement projects cost increases

Reliability Driven Station Projects

- Reliability driven station projects cost increases

Emerging Sustainment Capital

- Emerging Sustainment Capital cost increases because we have added "Unforeseen projects initiated by North and South"

Additional Capacity (Transformer / Municipal Stations)

- Aurora MS9 has been deferred from 2014 to 2019
- Harvie MS in-service date has been deferred from 2014 to 2016
- Painswick South MS Year 1 was deferred from 2013 to 2014, Year 2 was deferred from 2013 to 2014
- New Dufferin South MS#2 is proposed
- Vaughan TS4 Land Purchase was deferred from 2013 to 2014

Growth Driven Lines Projects

- Additional projects have been proposed

11 APPENDIX A – LISTING OF CAPITAL PROJECTS FOR THE FIRST FIVE YEARS (2014-2018)

PowerStream 5-Year (2014 - 2018) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#1	230kV Line Protection Upgrade Markham TS#1	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations					$51,351
PSS#2	27.6 kV Additional Cct on Dufferin St from Major Mackenzie Dr. to Teston Rd	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning				$194,755	
PSS#3	27.6 kV Additional Cct on Steeles Ave from Jane St to Keels St	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$1,103,931		
PSS#4	27.6 kV Additional Cct on Woodbine Ave from Elgin Mills to 19th Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning				$166,833	
PSS#5	27.6 kV Additional Cct's (2) on Hwy 7 from South Towncenter to Warden	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$386,330		
PSS#6	27.6 kV Pole Line on 14th Ave.	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$1,272,764		
PSS#7	27.6 kV Pole Line on Reesor Rd	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$1,526,096			
PSS#8	2x44kV circuits (23M22 & 23M23)from Midhurst TS2 to Essa Rd. and Mapleview Dr. in three segments (Phase 1, Phase 2, Phase 3)	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning		$6,232,206	$4,600,750	$6,259,110	
PSS#9	44 kV Supply to Dufferin St. South MS#2 - Alliston	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning				$272,602	
PSS#10	Add one additional 27.6 kV Cct on 19th Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning				$346,407	
PSS#11	Amber MS Feeder F3 Conversion Phase 2	Sustainment	Richard Wang	1b.4 Conversion Projects	Planning	$251,922				
PSS#12	Arc Flash Implementation Program	Sustainment	David Burns	1d.2 Safety, Environment Driven Station Projects	Stations	$11,527	$12,070	$12,070	$12,343	
PSS#13	Arc Flash Mitigation Projects	Sustainment	David Burns	1d.2 Safety, Environment Driven Station Projects	Stations					$21,808
PSS#14	Aurora MS2 Feeder Protection Upgrades	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations					$59,993
PSS#15	Aurora MS6 Expansion	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$517,000			
PSS#16	Automatic Feeder Restoration Program	Sustainment	David Burns	1d.4 Distribution Automation Station Projects	Stations	$307,652	$316,581	$737,670	$335,194	$673,400
PSS#17	Bayfield & Livingstone X Little Lake MS. Double Circuit existing 23M8 Circuit from Bayfield & Livingstone to Little Lake MS.	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning					$2,433,633

PowerStream 5-Year (2014 - 2018) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#18	Baythorn MS Arc Flash Mitigation	Sustainment	Glenn Allen	1d.2 Safety, Environment Driven Station Projects	Stations	$36,516				
PSS#19	Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning				$581,279	
PSS#20	Bus Differential Protection Upgrade - MTS1	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations					$259,293
PSS#21	Cable Injection Program (ACA) - 2014 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning	$796,730				
PSS#22	Cable Injection Program (ACA) - 2014 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning	$3,226,080				
PSS#23	Cable Injection Program (ACA) - 2015 - DESIGN ONLY in 2014 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning	$16,170				
PSS#24	Cable Injection Program (ACA) - 2015 - DESIGN ONLY in 2014 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning	$64,680				
PSS#25	Cable Injection Program (ACA) - 2015 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning		$819,298			
PSS#26	Cable Injection Program (ACA) - 2015 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning		$3,317,750			
PSS#27	Cable Injection Program (ACA) - 2016 - DESIGN ONLY in 2015 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning		$16,555			
PSS#28	Cable Injection Program (ACA) - 2016 - DESIGN ONLY in 2015 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning		$66,220			
PSS#29	Cable Injection Program (ACA) - 2016 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning			$842,466		
PSS#30	Cable Injection Program (ACA) - 2016 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning			$3,411,874		
PSS#31	Cable Injection Program (ACA) - 2017 - DESIGN ONLY in 2016 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning			$16,940		
PSS#32	Cable Injection Program (ACA) - 2017 - DESIGN ONLY in 2016 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning			$67,760		
PSS#33	Cable Injection Program (ACA) - 2017 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning				$866,252	
PSS#34	Cable Injection Program (ACA) - 2017 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning				$3,508,525	
PSS#35	Cable Injection Program (ACA) - 2018 - DESIGN ONLY in 2017 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning				$17,325	
PSS#36	Cable Injection Program (ACA) - 2018 - DESIGN ONLY in 2017 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning				$69,300	
PSS#37	Cable Injection Program (ACA) - 2018 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning					$890,674
PSS#38	Cable Injection Program (ACA) - 2018 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning					$3,607,780

PowerStream 5-Year (2014 - 2018) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#39	Cable Injection Program (ACA) - 2019 - DESIGN ONLY in 2018 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning					$17,710
PSS#40	Cable Injection Program (ACA) - 2019 - DESIGN ONLY in 2018 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning					$70,840
PSS#41	Cable Rehabilitation, Romfield Subdivision, Markham (Primary Cable, Transformers) - Phase 4	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$3,298,128				
PSS#42	Cable Replacement Program (ACA) - 2014 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$2,639,780				
PSS#43	Cable Replacement Program (ACA) - 2014 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$10,559,120				
PSS#44	Cable Replacement Program (ACA) - 2015 - DESIGN ONLY in 2014 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$69,553				
PSS#45	Cable Replacement Program (ACA) - 2015 - DESIGN ONLY in 2014 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$278,212				
PSS#46	Cable Replacement Program (ACA) - 2015 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning		$2,716,866			
PSS#47	Cable Replacement Program (ACA) - 2015 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning		$10,867,463			
PSS#48	Cable Replacement Program (ACA) - 2016 - DESIGN ONLY in 2015 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning		$69,900			
PSS#49	Cable Replacement Program (ACA) - 2016 - DESIGN ONLY in 2015 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning		$279,598			
PSS#50	Cable Replacement Program (ACA) - 2016 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning			$2,796,139		
PSS#51	Cable Replacement Program (ACA) - 2016 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning			$11,184,560		
PSS#52	Cable Replacement Program (ACA) - 2017 - DESIGN ONLY in 2016 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning			$70,246		
PSS#53	Cable Replacement Program (ACA) - 2017 - DESIGN ONLY in 2016 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning			$280,984		
PSS#54	Cable Replacement Program (ACA) - 2017 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning				$2,877,665	
PSS#55	Cable Replacement Program (ACA) - 2017 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning				$11,510,672	
PSS#56	Cable Replacement Program (ACA) - 2018 - DESIGN ONLY in 2017 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning				$70,593	
PSS#57	Cable Replacement Program (ACA) - 2018 - DESIGN ONLY in 2017 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning				$282,370	
PSS#58	Cable Replacement Program (ACA) - 2018 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning					$2,961,513
PSS#59	Cable Replacement Program (ACA) - 2018 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning					$11,846,071

PowerStream 5-Year (2014 - 2018) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#60	Cable Replacement Program (ACA) - 2019 - DESIGN ONLY in 2018 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning					$70,939
PSS#61	Cable Replacement Program (ACA) - 2019 - DESIGN ONLY in 2018 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning					$283,756
PSS#62	Capacity Relief to Melbourne MS (MS322), Increase Capacity from 10 MVA to 20 MVA and add one 13.8 kV Feeder.	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning				$1,120,552	
PSS#63	Capacity Relief to Melbourne MS (MS322), Increase Capacity from 10 MVA to 20 MVA and add one 13.8 kV Feeder."	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning			$664,541		
PSS#64	Concord MS Conversion to 27.6 kV - Phase 1	Sustainment	Richard Wang	1b.4 Conversion Projects	Planning	$183,326				
PSS#65	Concord MS Conversion to 27.6 kV - Phase 2	Sustainment	Richard Wang	1b.4 Conversion Projects	Planning	$402,556				
PSS#66	Concord MS Conversion to 27.6 kV - Phase 3	Sustainment	Richard Wang	1b.4 Conversion Projects	Planning		$495,000			
PSS#67	Concord MS Conversion to 27.6 kV - Phase 4	Sustainment	Richard Wang	1b.4 Conversion Projects	Planning				$1,320,000	
PSS#68	Connect TS's to Town Water & Sewage	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations		$219,090			
PSS#69	DACS Inverters and RTU's removal from MTS1	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations					$20,645
PSS#70	Distribution Automation Switches / Reclosers - North	Sustainment	Riaz Shaikh	1b.7 Distribution Automation Lines Projects	Planning	$603,552	$619,353	$635,455	$650,955	$662,122
PSS#71	Distribution Automation Switches / Reclosers - South	Sustainment	Riaz Shaikh	1b.7 Distribution Automation Lines Projects	Planning	$1,379,488	$1,415,601	$1,451,717	$1,487,832	$1,532,468
PSS#72	Double ccts 27.6 kV Pole Line on 16th Ave from 9th Line to Reesor Road MS	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning				$1,318,350	
PSS#73	Dufferin South MS #2 - New 44-13.8 kV, 2x10MVA, 4-Feeders MS - Year 1 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning			$1,470,779		
PSS#74	Dufferin South MS #2 - Purchase Site for New Substation - Alliston	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning		$770,000			
PSS#75	Dufferin South MS#2 - 13.8 kV Feeder Integration	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning				$309,397	
PSS#76	Dufferin South MS#2 - New 44-13.8kV, 2x10MVA, 4-Feeders MS - Year 2 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning				$2,932,938	
PSS#77	Elder Mill MS Conversion Decommission	Sustainment	Richard Wang	1b.4 Conversion Projects	Planning			$55,000		
PSS#78	Elder Mill MS Conversion- Part 2 (3F2)	Sustainment	Richard Wang	1b.4 Conversion Projects	Planning	$284,636				
PSS#79	Emerging Cable Replacement Projects	Sustainment	Riaz Shaikh	1e.1 Emerging Sustainment Capital	Planning	$1,018,336	$1,019,491	$1,020,646	$1,021,801	$500,000

PowerStream 5-Year (2014 - 2018) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#80	Extend 16kV Single Phase on Kipling Ave South from Kirby to Teston Rd	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning	$233,618				
PSS#81	Extend 23M8 Circuit on Bayfeild St. from Livingstone to Cundles	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning		$456,842			
PSS#82	Extend two 27.6 kV ccts (24M2 & 24M7) on 14th Ave from 9th to Reesor Road	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning	$787,248				
PSS#83	Feeder Egress Cable Replacement at TS's/MS's	Sustainment	Bob Braletic	1b.1 Cable Replacement Projects	Stations					$149,786
PSS#84	Feeder Protection Upgrade at MTS#2 - Q Bus	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations	$152,844				
PSS#85	Feeder Protection Upgrade at MTS#3 - E Bus	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations		$161,257			
PSS#86	Feeder Protection Upgrade at MTS#3 - Z Bus	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations			$162,867		
PSS#87	Harvie Rd. MS - 13.8kV Feeder Integration	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning				$302,654	
PSS#88	Harvie Rd. MS - 44kV Supply to Harvie Rd. MS	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning				$268,312	
PSS#89	Harvie Rd. MS - New 20MVA MS in Barrie - Year 1 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Stations		$1,426,823			
PSS#90	Harvie Rd. MS - New 20MVA MS in Barrie - Year 2 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Stations			$2,830,759		
PSS#91	HMI Upgrades - Richmond Hill TS1	Sustainment	Bob Braletic	1d.4 Distribution Automation Station Projects	Stations					$87,886
PSS#92	Hydro One Asset Purchase - Alliston	Sustainment	Joe Bonadie	1b.8 Reliability Driven Lines Projects	Planning		$302,500			
PSS#93	Hydro One Asset Purchase - Barrie	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning		$302,500			
PSS#94	Install 27.6 kV Pole Line on Dufferin St. - Phase 1	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$676,236			
PSS#95	Install 2nd 27.6 kV Cct on Woodbine Ave from Elgin Mills Rd to 19th Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning					$224,623
PSS#96	Install 6km of one Additional 27.6 kV Cct on Bathurst St with road widening	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$431,841		
PSS#97	Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$1,742,411			
PSS#98	Install One Additional 27.6 kV Cct on Elgin Mills Rd - Part 1 Leslie St to Bayview Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$345,356			
PSS#99	Install One Additional 27.6 kV Cct on Elgin Mills Rd - Part 2 Leslie St to Woodbine Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$369,061			
PSS#100	Install Two Additional 27.6kV Ccts on 16th Ave Install 2nd cct on Leslie St	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning	$3,552,516				

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#101	KDU-10 Replacement MTS#1	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations		$56,940			
PSS#102	KDU-10 Replacement MTS#2	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations		$56,940			
PSS#103	KDU-11 Replacement VTS#1	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations	$57,498				
PSS#104	KDU-11 Replacement VTS#2	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations	$57,498				
PSS#105	Lazenby Storage Facility	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations		$290,752			
PSS#106	Letitia MS (MS413)- Increase Capacity from 5MVA to 10MVA	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning		$1,050,033	$1,087,616		
PSS#107	Long Term Load Transfer (LTLT) - Alliston	Sustainment	Joe Bonadie	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$51,752				
PSS#108	Long Term Load Transfer (LTLT) - Bradford	Sustainment	Joe Bonadie	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$49,490				
PSS#109	Long Term Load Transfer (LTLT) - Tottenham (Adjala Townline)	Sustainment	Joe Bonadie	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$195,499				
PSS#110	Low Voltage Bushing Replacement - Transformer Station	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations	$231,634	$272,763			
PSS#111	Markham TS#4 Heating Improvements	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations	$7,704				
PSS#112	Markham TS#5 Class EA Study	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning					$154,000
PSS#113	Mill St. MS #2 - 44 kV Supply to Mill St. MS#2	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning				$383,581	
PSS#114	Mill St. MS #2 - New 44-8.32kV, 10 MVA, 3-Feeder MS - Site Purchase	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning			$660,000		
PSS#115	Mill St. MS #2 - New 44-8.32kV, 10 MVA, 3-Feeder MS - Year 1 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning			$1,097,351		
PSS#116	Mill St. MS #2 - New 44-8.32kV, 10 MVA, 3-Feeder MS - Year 2 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning				$2,502,243	
PSS#117	Mill St. MS #2- 8.32 kV Feeder Integration	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning				$400,378	
PSS#118	Minirupter (Vault) Switch Replacement	Sustainment	Riaz Shaikh	1b.3 Lines Asset Replacement Projects	Planning	$541,471	$546,292	$551,113		
PSS#119	Morgan MS Conversion to 27.6 kV (Design)	Sustainment	Richard Wang	1b.4 Conversion Projects	Planning				$35,244	
PSS#120	MS Feeder Protection Upgrades - AMS5	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations					$129,047
PSS#121	New 13.8 kV Load Interrupter Switch (LIS)	Sustainment	Joe Bonadie	1b.5 System Reconfiguration Projects	Planning	$31,794				

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#122	New 44 kV Feeder (13M7) Barrie TS X Huronia & Big Bay Pt. Rd.	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning			$4,115,166		
PSS#123	New 44 kV Feeder (13M7) Barrie TS X Huronia & Big Bay Pt. Rd. - Design Only	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning		$79,081			
PSS#124	New Markham TS #5 - 1st Year of 3 Year Project	Development	Gerry Reesor	2c.1 Additional Capacity (Transformer / Municipal Stations)	Stations					$4,734,074
PSS#125	New Vaughan TS #4 - 1st Year of 3 Year Project	Development	Gerry Reesor	2c.1 Additional Capacity (Transformer / Municipal Stations)	Stations	$4,207,870				
PSS#126	New Vaughan TS #4 - 2nd Year of 3 Year Project	Development	Gerry Reesor	2c.1 Additional Capacity (Transformer / Municipal Stations)	Stations		$19,084,622			
PSS#127	New Vaughan TS #4 - 3rd Year of 3 Year Project	Development	Gerry Reesor	2c.1 Additional Capacity (Transformer / Municipal Stations)	Stations			$1,005,602		
PSS#128	Obsolete Revenue Metering Removal at MTS1	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations					$20,645
PSS#129	Painswick South MS - 13.8kV Feeder Integration	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning	$373,061				
PSS#130	Painswick South MS - 44kV Supply to Painswick South MS	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning	$322,744				
PSS#131	Painswick South MS - New 44-13.8kV, 20 MVA, 4-Feeder Substation - Year 1 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning	$1,270,095				
PSS#132	Painswick South MS - New 44-13.8kV, 20 MVA, 4-Feeder Substation - Year 2 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning		$2,519,792			
PSS#133	Painswick South MS Capacitor Bank	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations		$341,343			
PSS#134	Penetanguishene, 98M3 Feeder - Restring 1/0 acsr with 556 Al, from LC105 to SW LT103	Sustainment	Joe Bonadie	1b.8 Reliability Driven Lines Projects	Planning	$342,707				
PSS#135	Phase 2 Design (continue from Phase 1). 2x44kV circuits (23M22 & 23M23)from Midhurst TS2 to Essa Rd. and Mapleview Dr. in three segments (Phase 1, Phase 2, Phase 3)	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning	$78,540				
PSS#136	Phase 3b. - Completion of 44 kV express feeder (23M26)from Ferndale & Essa Rd. to Essa Rd. & Mapleview Dr.	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning	$1,214,125				
PSS#137	Planned Circuit Breaker Replacement Innisfil MS411	Sustainment	Gerry Reesor	1d.1 Station Asset Replacement Projects	Stations			$173,968		
PSS#138	Planned Circuit Breaker Replacement Markham TS#1 - Bus #2	Sustainment	Gerry Reesor	1d.1 Station Asset Replacement Projects	Stations	$422,624				
PSS#139	Planned Circuit Breaker Replacement Markham TS#2 - J bus	Sustainment	Gerry Reesor	1d.1 Station Asset Replacement Projects	Stations		$291,784			
PSS#140	Planned Circuit Breaker Replacement Markham TS#2 - Q Bus	Sustainment	Gerry Reesor	1d.1 Station Asset Replacement Projects	Stations		$385,770			
PSS#141	Planned Circuit Breaker Replacement Markham TS#3 - E Bus	Sustainment	Gerry Reesor	1d.1 Station Asset Replacement Projects	Stations			$381,077		

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#142	Planned Circuit Breaker Replacement Markham TS#3 - E-Bus	Sustainment	Gerry Reesor	1d.1 Station Asset Replacement Projects	Stations				$407,857	
PSS#143	Planned Distribution Switchgear Replacement Program (ACA) - 2014 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning	$415,043				
PSS#144	Planned Distribution Switchgear Replacement Program (ACA) - 2014 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning	$1,908,192				
PSS#145	Planned Distribution Switchgear Replacement Program (ACA) - 2015 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning		$426,536			
PSS#146	Planned Distribution Switchgear Replacement Program (ACA) - 2015 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning		$1,964,100			
PSS#147	Planned Distribution Switchgear Replacement Program (ACA) - 2016 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning			$438,322		
PSS#148	Planned Distribution Switchgear Replacement Program (ACA) - 2016 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning			$2,021,605		
PSS#149	Planned Distribution Switchgear Replacement Program (ACA) - 2017 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning				$450,409	
PSS#150	Planned Distribution Switchgear Replacement Program (ACA) - 2017 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning				$2,080,752	
PSS#151	Planned Distribution Switchgear Replacement Program (ACA) - 2018 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning					$462,808
PSS#152	Planned Distribution Switchgear Replacement Program (ACA) - 2018 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning					$2,141,593
PSS#153	Planned Pole Replacement Program (ACA) - 2014 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning	$387,024				
PSS#154	Planned Pole Replacement Program (ACA) - 2014 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning	$4,569,070				
PSS#155	Planned Pole Replacement Program (ACA) - 2015 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning		$396,625			
PSS#156	Planned Pole Replacement Program (ACA) - 2015 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning		$4,675,072			
PSS#157	Planned Pole Replacement Program (ACA) - 2016 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning			$406,403		
PSS#158	Planned Pole Replacement Program (ACA) - 2016 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning			$4,782,546		
PSS#159	Planned Pole Replacement Program (ACA) - 2017 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning				$416,362	
PSS#160	Planned Pole Replacement Program (ACA) - 2017 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning				$4,891,537	
PSS#161	Planned Pole Replacement Program (ACA) - 2018 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning					$426,508
PSS#162	Planned Pole Replacement Program (ACA) - 2018 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning					$5,002,089

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#163	Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$526,421		
PSS#164	Pole line installation on Dufferin St - Phase 2	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$675,004		
PSS#165	Protection Upgrade - Richmond Hill TS # 2 - Bus 1	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations				$488,668	
PSS#166	Protection Upgrade - Richmond Hill TS # 2 - Bus 2	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations					$380,395
PSS#167	Purchase of a Critical Spare - 2000A Siemens SPS2-38-31.5 outdoor SF6 breaker.	Operations	Gerry Reesor	3f.1 Purchase of Spare Equipment	Stations		$154,000			
PSS#168	Purchase Site for New MS, Harvie Rd. MS - Barrie	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning	$715,000				
PSS#169	Radial Supply Remediation/Conversion - 13.8 kV to 27.6 kV on Miller Ave	Sustainment	Richard Wang	1b.6 Radial Supply Remediation Projects	Planning			$1,038,487		
PSS#170	Reagens Ind. Pky. MS (MS324) F2 Feeder: Restring the existing 1/0 ACSR with 556 Al - Bradford	Sustainment	Joe Bonadie	1b.8 Reliability Driven Lines Projects	Planning	$160,516				
PSS#171	Rear Lot Supply Remediation Project - 2015 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning		$1,095,597			
PSS#172	Rear Lot Supply Remediation Project - 2015 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning		$2,190,810			
PSS#173	Rear Lot Supply Remediation Project - 2016 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning			$1,122,221		
PSS#174	Rear Lot Supply Remediation Project - 2016 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning			$2,244,045		
PSS#175	Rear Lot Supply Remediation Project - 2017 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning				$1,149,312	
PSS#176	Rear Lot Supply Remediation Project - 2017 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning				$2,298,222	
PSS#177	Rear Lot Supply Remediation Project - 2018 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning					$1,176,891
PSS#178	Rear Lot Supply Remediation Project - 2018 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning					$2,353,374
PSS#179	Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$1,397,000		
PSS#180	Rebuild 27.6 kV pole line into 4 Ccts on Warden Ave from Hwy 7 to 16th Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$1,046,185		
PSS#181	Rebuild 27.6 kV Pole Line on Reesor Rd - DESIGN ONLY	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning	$52,404				
PSS#182	Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$686,730			
PSS#183	Refurbish 13.8 kV Portion of Aurora MS1	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations		$1,800,973			

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#184	Replace Fairview HWY 400 Crossing	Sustainment	Riaz Shaikh	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$304,392				
PSS#185	Replace Georgian Drive & HWY 400, 13.8 kV Crossing	Sustainment	Riaz Shaikh	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$304,392				
PSS#186	Replace Royal Victoria Hospital (RVH) HWY 400 Crossing	Sustainment	Riaz Shaikh	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$304,392				
PSS#187	Replace St. Vincent HWY 400 Crossing	Sustainment	Riaz Shaikh	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$304,392				
PSS#188	Replacement of End of Life Automated Switches/Reclosers	Sustainment	Riaz Shaikh	1b.7 Distribution Automation Lines Projects	Planning	$436,843	$440,215	$443,586	$446,957	
PSS#189	Replacement of Legacy RTU and Recloser Controllers at Morgan MS	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations		$110,251			
PSS#190	Replacement of Pad Mount Transformer in South	Sustainment	Riaz Shaikh	1c.1 Transformer Replacement Projects	Planning	$309,386	$363,440	$375,000	$386,250	$397,837
PSS#191	Second Supply to Doney Cr.	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning					$275,000
PSS#192	Separate Transformer & Breaker SCADA Alarms - Markham TS # 1 & TS # 2	Sustainment	Gerry Reesor	1d.4 Distribution Automation Station Projects	Stations			$77,268		
PSS#193	Spare 1200A Circuit Breakers for Richmond Hill TS#1	Operations	Bob Braletic	3f.1 Purchase of Spare Equipment	Stations					$90,180
PSS#194	Spare HD4 Circuit Breakers and Ground & Test Devices (GTD) for Greenwood TS.	Operations	Bob Braletic	3f.1 Purchase of Spare Equipment	Stations		$162,578			
PSS#195	Station Service transfer panels	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations		$10,692			
PSS#196	Station Service transfer panels - PS North	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations	$96,602				
PSS#197	Station Service transfer panels - PS South	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations	$42,126				
PSS#198	Station Vegetation Enhancements at TS's and MS's	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations					$72,666
PSS#199	Submersible Transformer & Vault Replacement - 2014 - North	Sustainment	Quan Tran	1b.3 Lines Asset Replacement Projects	Planning	$1,137,982				
PSS#200	Submersible Transformer & Vault Replacement - 2015 - DESIGN ONLY in 2014 - North	Sustainment	Quan Tran	1b.3 Lines Asset Replacement Projects	Planning	$52,151				
PSS#201	Submersible Transformer & Vault Replacement - 2015 - North	Sustainment	Quan Tran	1b.3 Lines Asset Replacement Projects	Planning		$1,170,683			
PSS#202	Survey and Engineering Design for Overhead Crossing for Hwy 407	Sustainment	Riaz Shaikh	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$82,500				
PSS#203	Survey and Engineering Design for Overhead Highway Crossing	Sustainment	Riaz Shaikh	1b.8 Reliability Driven Lines Projects	Planning		$77,250	$79,565		
PSS#204	Switchyard Lighting Upgrades in TS's	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations					$36,603

PowerStream 5-Year (2014 - 2018) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2014	2015	2016	2017	2018
PSS#205	T1/T2 Differential Protection Upgrade - MTS1	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations					$253,382
PSS#206	Transformer Temperature Monitoring - Aurora MS #1, & #2	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations		$82,066			
PSS#207	Transformer Temperature Monitoring - Aurora MS #3 & #4.	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations		$84,069			
PSS#208	Transformer Temperature Monitoring - Aurora MS #5, & #6	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations			$86,430		
PSS#209	Unforeseen Projects Initiated by North	Sustainment	Riaz Shaikh	1e.1 Emerging Sustainment Capital	Planning	$260,702	$273,802	$387,850	$473,033	$487,190
PSS#210	Unforeseen Projects Initiated by South	Sustainment	Riaz Shaikh	1e.1 Emerging Sustainment Capital	Planning	$733,764	$771,478	$776,087	$889,878	$916,574
PSS#211	Upgrade Bus, Line & Transformer protections - Richmond Hill TS #2	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations		$264,348			
PSS#212	Vaughan TS #4 - Land Purchase	Development	Richard Wang	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning	$2,200,000				
PSS#213	Vaughan TS#4 Feeder Integration - Phase 1	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning				$7,675,800	
PSS#214	Vaughan TS#4 Feeder Integration - Phase 2	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$9,900,000		
PSS#215	VTS#4 Feeder Integration - Phase 3	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning				$9,900,000	
PSS#216	Wye Transformer Supplying Delta Service Remediation	Sustainment	Richard Wang	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$206,784	$212,768	$231,759	$233,992	$220,000
					Totals	$54,593,953	$79,469,319	$72,635,766	$73,614,491	$46,157,147
					Sustainment	$39,586,732	$41,367,952	$38,363,726	$38,679,300	$38,245,637
					Development	$15,007,221	$37,784,789	$34,272,040	$34,935,191	$7,821,330
					Operations	$0	$316,578	$0	$0	$90,180

12 APPENDIX B – LISTING OF CAPITAL PROJECTS FOR THE SECOND FIVE YEARS (2019-2023)

PowerStream 5-Year (2019 - 2023) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2019	2020	2021	2022	2023
PSS#1	230kV Line Protection Upgrade Markham TS#2	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations		$89,844			
PSS#2	230kV Line Protection Upgrade Markham TS#3	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations				$92,167	
PSS#3	230kV Switch Replacements	Sustainment	Bob Braletic	1d.1 Station Asset Replacement Projects	Stations	$87,946				
PSS#4	230kV Switch Replacements - 2021	Sustainment	Bob Braletic	1d.1 Station Asset Replacement Projects	Stations			$96,118		
PSS#5	Add one Additional 27.6 kV Cct on Major Mack and 9th Line	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning	$440,000				
PSS#6	Arc Flash Mitigation Projects	Sustainment	David Burns	1d.2 Safety, Environment Driven Station Projects	Stations	$27,652	$28,412	$29,192	$29,991	$30,812
PSS#7	Aurora MS3 Feeder Protection Upgrades	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations	$66,574				
PSS#8	Aurora MS4 Expansion	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning	$495,000				
PSS#9	Automatic Feeder Restoration Program	Sustainment	David Burns	1d.4 Distribution Automation Station Projects	Stations	$693,252	$713,684	$734,712	$756,356	$778,632
PSS#10	Breaker/Switchgear replacements at North MS's	Sustainment	Gerry Reesor	1d.1 Station Asset Replacement Projects	Stations	$786,506		$853,409		
PSS#11	Build new 27.6kV pole Line on Teston Rd between Keele St and Dufferin St	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$2,200,000		
PSS#12	Build Two 27.6 kV Ccts on 19th Ave from Woodbine Ave to Warden Ave	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning					$2,200,000
PSS#13	Bus Differential Protection Upgrade - MTS2	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations	$264,248				
PSS#14	Bus Differential Protection Upgrade - MTS3	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations		$269,257			
PSS#15	Bus Differential Protection Upgrade - VTS1	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations			$274,325		
PSS#16	Bus Differential Protection Upgrade - VTS2	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations				$279,448	
PSS#17	Cable Injection Program (ACA) - 2019 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning	$915,751				
PSS#18	Cable Injection Program (ACA) - 2019 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning	$3,709,716				

PowerStream 5-Year (2019 - 2023) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2019	2020	2021	2022	2023
PSS#19	Cable Injection Program (ACA) - 2020 - DESIGN ONLY in 2019 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning	$18,095				
PSS#20	Cable Injection Program (ACA) - 2020 - DESIGN ONLY in 2019 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning	$72,380				
PSS#21	Cable Injection Program (ACA) - 2020 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning		$941,504			
PSS#22	Cable Injection Program (ACA) - 2020 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning		$3,814,416			
PSS#23	Cable Injection Program (ACA) - 2021 - DESIGN ONLY in 2020 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning		$18,480			
PSS#24	Cable Injection Program (ACA) - 2021 - DESIGN ONLY in 2020 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning		$73,920			
PSS#25	Cable Injection Program (ACA) - 2021 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning			$945,953		
PSS#26	Cable Injection Program (ACA) - 2021 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning			$3,921,960		
PSS#27	Cable Injection Program (ACA) - 2022 - DESIGN ONLY in 2021 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning			$18,865		
PSS#28	Cable Injection Program (ACA) - 2022 - DESIGN ONLY in 2021 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning			$75,460		
PSS#29	Cable Injection Program (ACA) - 2022 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning				$995,120	
PSS#30	Cable Injection Program (ACA) - 2022 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning				$4,032,436	
PSS#31	Cable Injection Program (ACA) - 2023 - DESIGN ONLY in 2022 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning				$19,250	
PSS#32	Cable Injection Program (ACA) - 2023 - DESIGN ONLY in 2022 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning				$77,000	
PSS#33	Cable Injection Program (ACA) - 2023 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning					$1,023,024
PSS#34	Cable Injection Program (ACA) - 2023 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning					$4,145,931
PSS#35	Cable Injection Program (ACA) - 2024 - DESIGN ONLY in 2023 - North	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning					$19,635
PSS#36	Cable Injection Program (ACA) - 2024 - DESIGN ONLY in 2023 - South	Sustainment	Quan Tran	1b.2 Cable Injection Projects	Planning					$78,540
PSS#37	Cable Replacement Program (ACA) - 2019 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$3,047,753				
PSS#38	Cable Replacement Program (ACA) - 2019 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$12,191,035				

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2019	2020	2021	2022	2023
PSS#39	Cable Replacement Program (ACA) - 2020 - DESIGN ONLY in 2019 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$71,286				
PSS#40	Cable Replacement Program (ACA) - 2020 - DESIGN ONLY in 2019 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning	$285,142				
PSS#41	Cable Replacement Program (ACA) - 2020 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning		$3,136,455			
PSS#42	Cable Replacement Program (ACA) - 2020 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning		$12,545,853			
PSS#43	Cable Replacement Program (ACA) - 2021 - DESIGN ONLY in 2020 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning		$71,632			
PSS#44	Cable Replacement Program (ACA) - 2021 - DESIGN ONLY in 2020 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning		$286,528			
PSS#45	Cable Replacement Program (ACA) - 2021 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning			$3,227,696		
PSS#46	Cable Replacement Program (ACA) - 2021 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning			$12,910,820		
PSS#47	Cable Replacement Program (ACA) - 2022 - DESIGN ONLY in 2021 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning			$71,979		
PSS#48	Cable Replacement Program (ACA) - 2022 - DESIGN ONLY in 2021 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning			$287,914		
PSS#49	Cable Replacement Program (ACA) - 2022 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning				$3,321,549	
PSS#50	Cable Replacement Program (ACA) - 2022 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning				$13,286,238	
PSS#51	Cable Replacement Program (ACA) - 2023 - DESIGN ONLY in 2022 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning				$72,325	
PSS#52	Cable Replacement Program (ACA) - 2023 - DESIGN ONLY in 2022 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning				$289,300	
PSS#53	Cable Replacement Program (ACA) - 2023 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning					$3,418,094
PSS#54	Cable Replacement Program (ACA) - 2023 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning					$13,672,422
PSS#55	Cable Replacement Program (ACA) - 2024 - DESIGN ONLY in 2023 - North	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning					$72,672
PSS#56	Cable Replacement Program (ACA) - 2024 - DESIGN ONLY in 2023 - South	Sustainment	Quan Tran	1b.1 Cable Replacement Projects	Planning					$290,686
PSS#57	DACS Inverters and RTU's removal from MTS2	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations	$21,023				
PSS#58	DACS Inverters and RTU's removal from MTS3	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations		$21,402			

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2019	2020	2021	2022	2023
PSS#59	DACS Inverters and RTU's removal from RHTS1 & RHTS2	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations			$43,560		
PSS#60	DACS Inverters and RTU's removal from VTS1 & VTS2	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations				$44,317	
PSS#61	DACS Inverters and RTU's removal from VTS3	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations					$22,537
PSS#62	Decommission Capacitor Bank - MTS#3	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations	$20,064				
PSS#63	Distribution Automation Switches / Reclosers - North	Sustainment	Riaz Shaikh	1b.7 Distribution Automation Lines Projects	Planning	$684,634	$688,928	$706,515	$724,441	$787,959
PSS#64	Distribution Automation Switches / Reclosers - South	Sustainment	Riaz Shaikh	1b.7 Distribution Automation Lines Projects	Planning	$1,578,442	$1,625,795	$1,674,569	$1,724,806	$2,019,420
PSS#65	Emerging Cable Replacement Projects	Sustainment	Riaz Shaikh	1e.1 Emerging Sustainment Capital	Planning	$515,000	$530,450	$546,363	$562,754	$701,327
PSS#66	Feeder Egress Cable Replacement at TS's/MS's	Sustainment	Bob Braletic	1b.1 Cable Replacement Projects	Stations	$152,757	$155,781	$158,861	$161,995	$165,186
PSS#67	Greenwood Expansion 20MVar Cap Bank	Sustainment	Gerry Reesor	1d.3 Compliance to External Directives / Standards Station Projects	Stations	$836,499				
PSS#68	Ground Grid Refurbishment - 2019	Sustainment	Bob Braletic	1d.2 Safety, Environment Driven Station Projects	Stations	$114,158				
PSS#69	Ground Grid Refurbishment - 2021	Sustainment	Bob Braletic	1d.2 Safety, Environment Driven Station Projects	Stations			$118,727		
PSS#70	HMI Upgrades - MTS1	Sustainment	Bob Braletic	1d.4 Distribution Automation Station Projects	Stations	$89,570				
PSS#71	HMI Upgrades - MTS2	Sustainment	Bob Braletic	1d.4 Distribution Automation Station Projects	Stations		$91,274			
PSS#72	HMI Upgrades - MTS3	Sustainment	Bob Braletic	1d.4 Distribution Automation Station Projects	Stations			$92,996		
PSS#73	HMI Upgrades - Richmond Hill TS2	Sustainment	Bob Braletic	1d.4 Distribution Automation Station Projects	Stations				$94,741	
PSS#74	Install capacitor banks at Lazenby TS	Sustainment	Gerry Reesor	1d.3 Compliance to External Directives / Standards Station Projects	Stations				$1,393,308	
PSS#75	Install capacitor banks Markham TS #2	Sustainment	Gerry Reesor	1d.3 Compliance to External Directives / Standards Station Projects	Stations					$836,000
PSS#76	Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$3,300,000			
PSS#77	Jackson TS GIS refurbishment	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations				$84,147	
PSS#78	Little Lake MS#2 - 13.8kV Feeder Integration	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning		$310,886			

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2019	2020	2021	2022	2023
PSS#79	Little Lake MS#2 - 44 kV Supply	Development	Joe Bonadie	2d.1 Growth Driven Lines Projects	Planning		$306,126			
PSS#80	Little Lake MS#2 - New 44-13.8kV, 20MVA, 4-Feeder MS - Year 1 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning		$1,652,763			
PSS#81	Little Lake MS#2 - New 44-13.8kV, 20MVA, 4-feeder MS - Year 2 of 2	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning			$3,293,639		
PSS#82	Little Lake MS#2 - Purchase Site	Development	Joe Bonadie	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning	$880,000				
PSS#83	Major Mac, New pole line installation	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning	$1,100,000				
PSS#84	Markham TS #4 Feeder Egress Part 4	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$3,300,000			
PSS#85	Markham TS #5 - Land Purchase	Development	Richard Wang	2c.1 Additional Capacity (Transformer / Municipal Stations)	Planning	$2,200,000				
PSS#86	Markham TS#3E Feeder Protection replacement - Bus 1	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations			$179,944		
PSS#87	Markham TS#3E Feeder Protection replacement - Bus 2	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations				$167,922	
PSS#88	Markham TS#5 Feeder Integration - Phase 1	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning		$9,900,000			
PSS#89	Markham TS#5 Feeder Integration - Phase 2	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning				$11,000,000	
PSS#90	Markham TS#5 Feeder Integration - Phase 3	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning					$11,000,000
PSS#91	MS Feeder Protection Upgrades - AMS6	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations	$132,172				
PSS#92	New Markham TS #5 - 2nd Year of 3 Year Project	Development	Gerry Reesor	2c.1 Additional Capacity (Transformer / Municipal Stations)	Stations	$20,971,466				
PSS#93	New Markham TS #5 - 3rd Year of 3 Year Project	Development	Gerry Reesor	2c.1 Additional Capacity (Transformer / Municipal Stations)	Stations		$1,119,193			
PSS#94	Obsolete Revenue Metering Removal at MTS2	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations	$21,023				
PSS#95	Obsolete Revenue Metering Removal at MTS3	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations		$21,402			
PSS#96	Obsolete Revenue Metering Removal at RHTS1 & RHTS2	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations			$43,560		
PSS#97	Obsolete Revenue Metering Removal at VTS1 & VTS2	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations				$44,317	
PSS#98	Obsolete Revenue Metering Removal at VTS3	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations					$22,537

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2019	2020	2021	2022	2023
PSS#99	Planned Distribution Switchgear Replacement Program (ACA) - 2019 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning	$475,527				
PSS#100	Planned Distribution Switchgear Replacement Program (ACA) - 2019 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning	$2,204,179				
PSS#101	Planned Distribution Switchgear Replacement Program (ACA) - 2020 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning		$488,576			
PSS#102	Planned Distribution Switchgear Replacement Program (ACA) - 2020 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning		$2,268,563			
PSS#103	Planned Distribution Switchgear Replacement Program (ACA) - 2021 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning			$501,964		
PSS#104	Planned Distribution Switchgear Replacement Program (ACA) - 2021 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning			$2,334,796		
PSS#105	Planned Distribution Switchgear Replacement Program (ACA) - 2022 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning				$515,702	
PSS#106	Planned Distribution Switchgear Replacement Program (ACA) - 2022 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning				$2,402,935	
PSS#107	Planned Distribution Switchgear Replacement Program (ACA) - 2023 - North	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning					$529,801
PSS#108	Planned Distribution Switchgear Replacement Program (ACA) - 2023 - South	Sustainment	Quan Tran	1a.2 Undergound Switchgear Replacement Program	Planning					$2,473,039
PSS#109	Planned Pole Replacement Program (ACA) - 2019 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning	$436,847				
PSS#110	Planned Pole Replacement Program (ACA) - 2019 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning	$5,114,252				
PSS#111	Planned Pole Replacement Program (ACA) - 2020 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning		$447,387			
PSS#112	Planned Pole Replacement Program (ACA) - 2020 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning		$5,228,072			
PSS#113	Planned Pole Replacement Program (ACA) - 2021 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning			$458,129		
PSS#114	Planned Pole Replacement Program (ACA) - 2021 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning			$5,343,598		
PSS#115	Planned Pole Replacement Program (ACA) - 2022 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning				$469,083	
PSS#116	Planned Pole Replacement Program (ACA) - 2022 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning				$5,460,884	
PSS#117	Planned Pole Replacement Program (ACA) - 2023 - North	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning					$480,254
PSS#118	Planned Pole Replacement Program (ACA) - 2023 - South	Sustainment	Quan Tran	1a.1 Pole Replacement Program	Planning					$5,579,981

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2019	2020	2021	2022	2023
PSS#119	Rear Lot Supply Remediation Project - 2019 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning	$1,212,199				
PSS#120	Rear Lot Supply Remediation Project - 2019 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning	$2,423,976				
PSS#121	Rear Lot Supply Remediation Project - 2020 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning		$1,248,565			
PSS#122	Rear Lot Supply Remediation Project - 2020 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning		$2,496,696			
PSS#123	Rear Lot Supply Remediation Project - 2021 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning			$1,286,022		
PSS#124	Rear Lot Supply Remediation Project - 2021 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning			$2,571,596		
PSS#125	Rear Lot Supply Remediation Project - 2022 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning				$1,324,602	
PSS#126	Rear Lot Supply Remediation Project - 2022 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning				$2,648,744	
PSS#127	Rear Lot Supply Remediation Project - 2023 - North	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning					$1,364,340
PSS#128	Rear Lot Supply Remediation Project - 2023 - South	Sustainment	Quan Tran	1b.11 Rear Lot Supply Remediation Projects	Planning					$2,728,207
PSS#129	Rebuild exiting pole line on 16th Ave into 4 ccts - from Dufferin to Yonge St	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning	$2,750,000				
PSS#130	Rebuild Pole Line on 14th Ave into 4 cct -From Warden Ave to Kennedy Rd	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$2,420,000		
PSS#131	Rebuild pole line on Jane St into 4 ccts from Steeles to Hwy 7	Development	Richard Wang	2d.1 Growth Driven Lines Projects	Planning			$2,200,000	$2,200,000	
PSS#132	Replacement of Pad Mount Transformer in South	Sustainment	Riaz Shaikh	1c.1 Transformer Replacement Projects	Planning	$409,772	$422,065	$434,727	$447,000	$557,096
PSS#133	Station Service Transfer Panels	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations	$16,734	$14,101	$17,383	$17,710	$18,064
PSS#134	Station Vegetation Enhancements at TS's and MS's	Sustainment	Bob Braletic	1d.6 Operability and Maintainability Projects	Stations	$74,113	$75,585	$77,085	$78,613	$80,169
PSS#135	Switchyard Lighting Upgrades in TS's	Sustainment	Gerry Reesor	1d.6 Operability and Maintainability Projects	Stations			$37,875		
PSS#136	T1/T2 Differential Protection Upgrade - MTS2	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations	$258,218				
PSS#137	T1/T2 Differential Protection Upgrade - MTS3	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations		$263,102			
PSS#138	T1/T2 Differential Protection Upgrade - VTS1	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations			$268,039		

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Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2019	2020	2021	2022	2023
PSS#139	T1/T2 Differential Protection Upgrade - VTS2	Sustainment	Bob Braletic	1d.5 Reliability Driven Station Projects	Stations				$273,025	
PSS#140	T1/T2 Transformer Differential Protection Upgrade Markham TS#1	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations	$99,717				
PSS#141	T1/T2 Transformer Differential Protection Upgrade Markham TS#2	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations			$107,546		
PSS#142	T1/T2 Transformer Differential Protection Upgrade Markham TS#3	Sustainment	Gerry Reesor	1d.5 Reliability Driven Station Projects	Stations					$111,587
PSS#143	Unforeseen Projects Initiated by North	Sustainment	Riaz Shaikh	1e.1 Emerging Sustainment Capital	Planning	$487,223	$501,414	$515,605	$585,000	$729,086
PSS#144	Unforeseen Projects Initiated by South	Sustainment	Riaz Shaikh	1e.1 Emerging Sustainment Capital	Planning	$916,574	$943,270	$969,967	$1,098,972	$1,369,649
PSS#145	Wye Transformer Supplying Delta Service Remediation	Sustainment	Richard Wang	1b.10 Compliance to External Directives / Standards Lines Projects	Planning	$44,000	$44,000	$44,000	$44,000	

	2019	2020	2021	2022	2023
Totals	$69,412,475	$59,455,381	$52,095,469	$56,820,198	$57,306,687
Sustainment	$40,576,009	$39,566,413	$41,981,830	$43,620,198	$44,106,687
Development	$28,836,466	$19,888,968	$10,113,639	$13,200,000	$13,200,000
Operations	$0	$0	$0	$0	$0

APPENDIX E

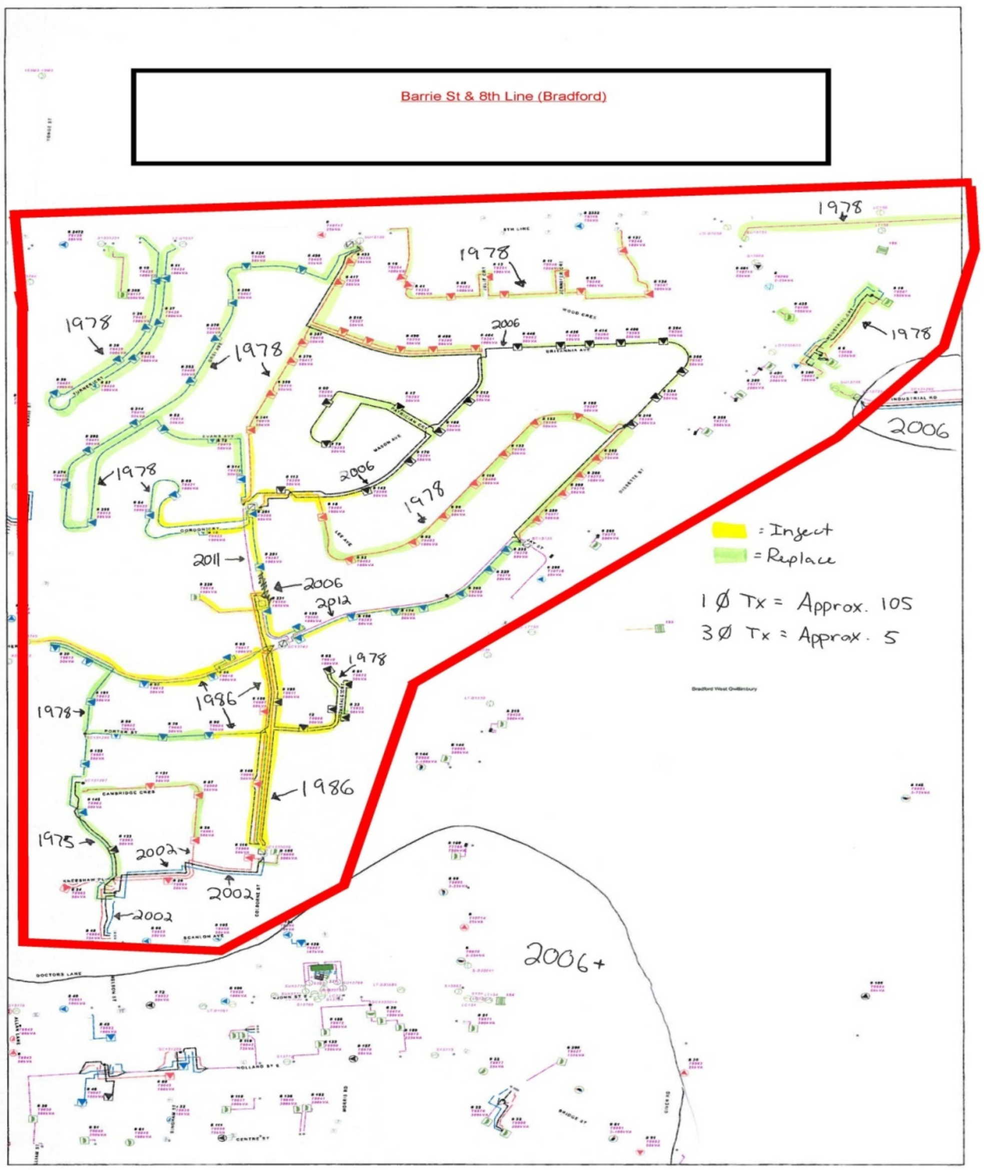
The details of the two projects and the breakdown of the total budgets for both injection and replacement are shown below.

1. Barrie Street & 8th Line (Bradford)

- Barrie St & 8th Line total length is approx. 13,085m. The plan is to replace 10,040 m and inject 3,045m of cable.
- See Figure 1 for a map showing injection candidates highlighted in yellow (the green highlighted segments are for replacement).

Cable Replacement Cost Breakdown -Barrie Street/8th Line	
Item	**Cost ($)**
Labour (PowerStream)	96,439
Contractor (Labour and Material)	2,378,480
Inventory Material (PowerStream)	90,196
Design Cost (PowerStream+ Contractor)	55,879
Total	**2,620,994**

Cable Injection Cost Breakdown -Barrie Street/8th Line	
Item	**Cost ($)**
Labour (PowerStream)	$15,608
Contractor (Labour and Material)	$181,373
Inventory Material (PowerStream)	$11,432
Design Cost (PowerStream)	$2,738
Total	**211,151**


Barrie St & 8th Line (Bradford)
1978
1978
1978
1978
2006
1978
1978
2006
2006
1978
2011
2006
2012
1978
1978
1986
1986
1975
2002
2002
2002
2006+
= Inject
= Replace
1 Ø Tx = Approx. 105
3 Ø Tx = Approx. 5

2. M50: Bayview-John-Leslie-Hwy7 (Markham)

- Bayview/John/Leslie/Hwy 7 total length is approx. 43,076m. The plan is to replace 26,000m and inject 17,076 of cable. See Figure 2 for a map showing injection candidates highlighted in yellow (the green highlighted segments are for replacement).

Cable Replacement Cost Breakdown -Bayview/John/Leslie-Hwy7	
Item	**Cost ($)**
Labour (PowerStream)	252,700
Contractor (Labour and Material)	6,232,376
Inventory Material (PowerStream)	236,343
Design Cost (PowerStream+ Contractor)	146,421
Total	**6,867,841**

Cable Injection Cost Breakdown -Bayview/John/Leslie-Hwy7	
Item	**Cost ($)**
Labour (PowerStream)	87,529
Contractor (Labour and Material)	1,017,118
Inventory Material (PowerStream)	64,110
Design Cost (PowerStream)	15,353
Total	**3,952,582**

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APPENDIX F

SEC Interrogatory No. 12.a

The details on the calculated health index are described below.

Switchgear and Mini-Rupter Switch

Health Index Formulation

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index (HI) formulation are provided in the tables.

Table 1: Distribution Switchgear/Minirupter Health Index Parameters and Weights

#	Distribution Switchgear/Minirupter Condition Parameters	Air Type Weight	Oil Type Weight
1	Age	2	5
2	IR record	2	2
3	Field inspection	5	5
4	Failure rate	*	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 to #3. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criterion #4.

Figure 1: Distribution Switchgear/Minirupter Health Index Flowchart.

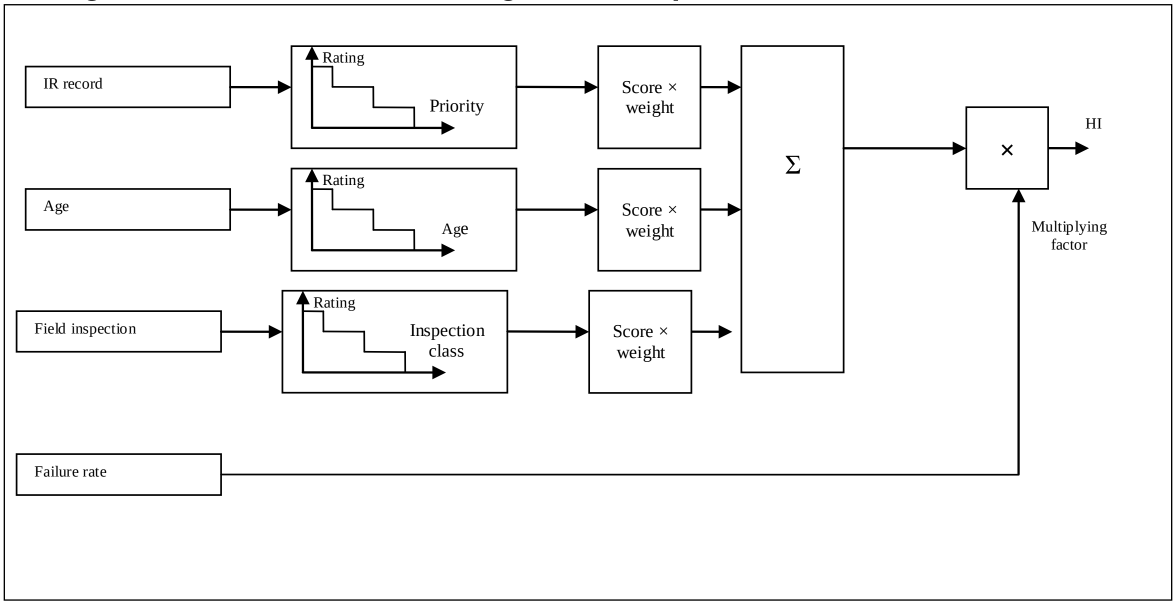


Table 2: Distribution Switchgear/Minirupter Parameter #1: Age/condition Criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	41-60 years old
D	1	61-70 years old
E	0	> 70 years old

Table 3: Distribution Switchgear/Minirupter Parameter #2: IR Record Condition Criteria

Condition Factor	Factor	Condition Criteria Description
A	0	Corrective measures are required at the earliest possible time.
B	2	Corrective measures are required at the next available opportunity or shutdown.
C	3	Corrective measures are required as scheduling permits.
D	4	Normal maintenance cycle can be followed.

Table 4: Distribution Switchgear/Minirupter Parameter #3: Field Inspection Condition Criteria

Condition Factor	Factor	Condition Criteria Description
A	0	Corrective measures are required at the earliest possible time.
B	2	Corrective measures are required at the next available opportunity or shutdown.
C	3	Corrective measures are required as scheduling permits.
D	4	Normal maintenance cycle can be followed.

Table 5: Distribution Switchgear/Minirupter Parameter #4: Failure Rate Criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05
B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4
E	0.6	M >= 0.4

Where : M = failure rate x age

Failure rate for distribution switchgear = 0.0048, calculated based on IEEE Gold book (IEEE Std 493-1997).

Transformers

Health Index Formulation

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 6: Distribution Transformer Health Index Parameters and Weights

#	Distribution Transformer Condition Parameters	Weight
1	Age	4
2	PCB	1
3	Loading history (weighted average)	*
4	Failure rate	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 and #2. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criteria #3 and #4. Refer to Table for details on the multiplying factors.

Figure 2: Distribution Transformers Health Index Flowchart

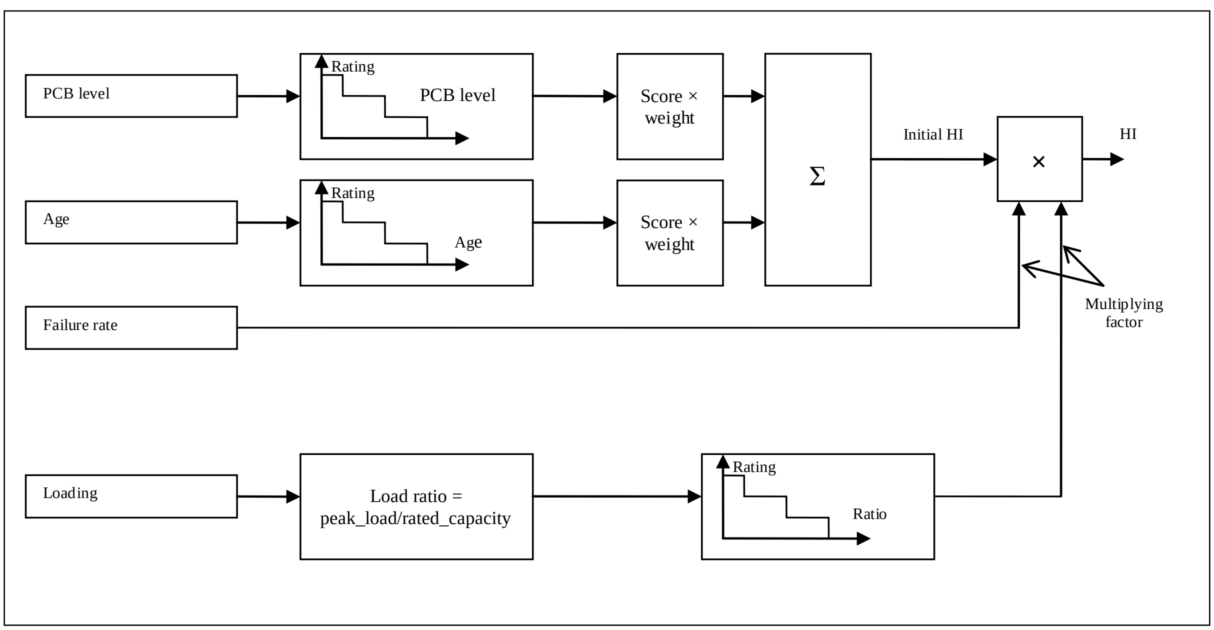


Table 7: Distribution Transformer Parameter #1: Age/condition Criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	21-30 years old
C	2	31-40 years old
D	1	41-50 years old
E	0	>50 years old

Table 8: Distribution Transformer Parameter #2: PCB Level Criteria

Condition Factor	Factor	Condition Criteria Description
A	4	PCB < 5 mg/L
B	3	5 <= PCB < 50 mg/L
D	1	50 mg/L <= PCB < 500 mg/L
E	0	PCB >= 500 mg/L

Table 9: Distribution Transformer Parameter #3: Loading Criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	N < 1.26
B	0.9	1.26 <= N < 1.5
C	0.7	1.5 <= N < 1.6
D	0.5	1.6 <= N < 1.67
E	0.3	N >= 1.68

WhereN = (Peak Load) / (Rated Capacity)

The loading condition is not assigned a weight in the HI formulation. Instead it is used as a multiplying factor for final HI results.

Table 10: Distribution Transformer Parameter #4: Failure Rate

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05
B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4
E	0.6	M >= 0.4

Where : M = Failure Rate x Age

The failure rate condition is not assigned a weight in HI formulation. Instead it is used as a multiplying factor for final HI results.

Transformer Size	Voltage	Failure Rate *
300 – 10,000 kVA	0.16 – 15 kV	0.0052
300 – 10,000 kVA	> 15 kV	0.011
> 10,000 kVA		0.0153

- Failure rate is based on the survey data in IEEE Gold book (IEEE Std 493-1997)

APPENDIX H

VECC Interrogatory No. 9F

A "poor" health index for submersible transformer is determined as a heath index between 31 and 50. The obsolescence of the submersible transformer is also taken into consideration when prioritizing the replacement.

Health Index Formulation

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 1: Distribution Transformer Health Index Parameters and Weights

#	Distribution Transformer Condition Parameters	Weight
1	Age	4
2	PCB	1
3	Loading history (weighted average)	*
4	Failure rate	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 and #2. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criteria #3 and #4. Refer to Table for details on the multiplying factors.

Figure 1: Distribution Transformers Health Index flowchart

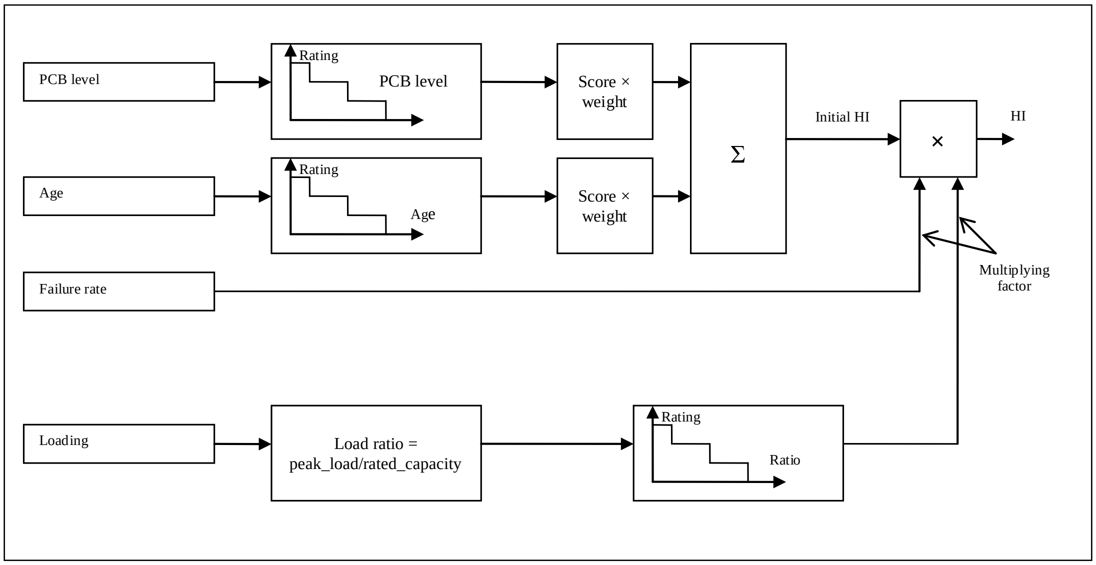


Table 2: Distribution Transformer Parameter #1: Age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	21-30 years old
C	2	31-40 years old
D	1	41-50 years old
E	0	>50 years old

Table 3: Distribution Transformer Parameter #2: PCB level criteria

Condition Factor	Factor	Condition Criteria Description
A	4	PCB < 5 mg/L
B	3	5 <= PCB < 50 mg/L
D	1	50 mg/L <= PCB < 500 mg/L
E	0	PCB >= 500 mg/L

Table 4: Distribution Transformer Parameter #: Loading Criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	N < 1.26
B	0.9	1.26 <= N < 1.5
C	0.7	1.5 <= N < 1.6
D	0.5	1.6 <= N < 1.67
E	0.3	N >= 1.68

Where N = (Peak Load) / (Rated Capacity)

The loading condition is not assigned a weight in the HI formulation. Instead it is used as a multiplying factor for final HI results.

Table 5. Distribution Transformer Parameter #4: Failure rate

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05
B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4
E	0.6	M >= 0.4

Where M = Failure Rate x Age

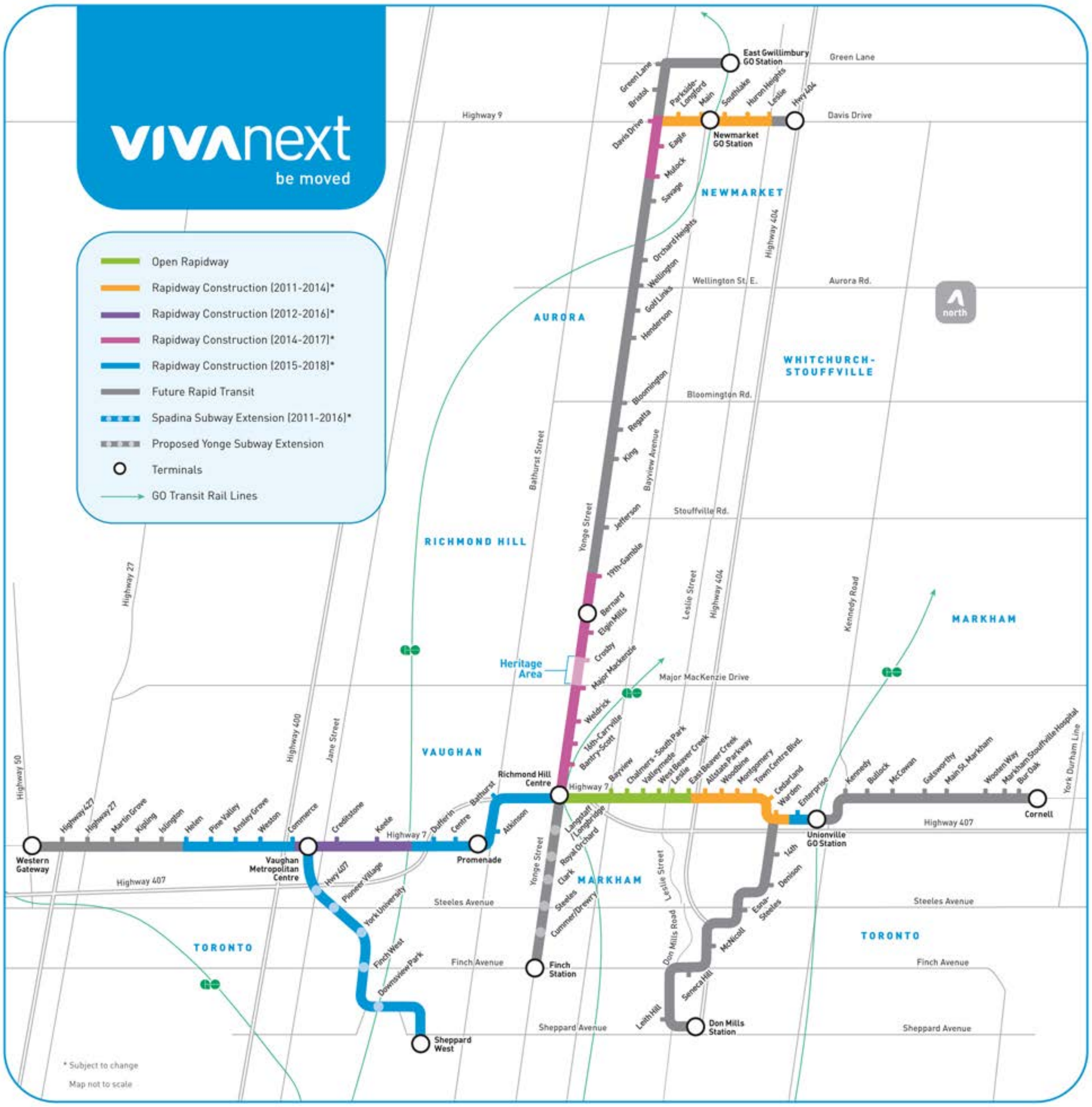
The failure rate condition is not assigned a weight in HI formulation. Instead it is used as a multiplying factor for final HI results.

Transformer Size	Voltage	Failure Rate *
300 – 10,000 kVA	0.16 – 15 kV	0.0052
300 – 10,000 kVA	> 15 kV	0.011
> 10,000 kVA		0.0153

Failure rate is based on the survey data in IEEE Gold book (IEEE Std 493-1997).

APPENDIX G

SEC Interrogatory No. 15



APPENDIX I

VECC Interrogatory No. 9I

CMI Savings

Switchgear:
The failure effects by customers served are summarized in the table below.

Description	Lookup	Loss of Peak Load (kW)	Outage Duration (hours)
Industrial and Commercial Customers	C&I	3,780	3
Residential Subdivisions	Residential	1,440	3
Mixed	Mixed	2,610	3

The failure effects are based on the following assumptions:

- For switchgear units supplying **Industrial/Commercial Customers**: On average each "loop" has a maximum of 10,000 connected kVA.
- On average there are 10 switchgear units in a "loop", each switchgear supplies two customers each with an average transformer size of 500 kVA at an assumed load factor of 70% & 90% power factor.
- Upon a switchgear failure, one-half of the loop (on average 5 switchgear units) will be lost for 3 hours, while the failed switchgear will take a total of 8 hrs for replacement. One-half of the loop means 5 x 2 x 500 kVA x 0.7 x 0.9 = 3150 kW for 3 hours (9,450 kWhrs). For the unit that failed - 2 x 500 kVA x 0.7 x 0.9 = 630 kW for 5 hours (3,150 kWhrs).
- Total load lost = 3150 kW+630 kW = 3,780 kW
- Since the units that will be replaced represent the worst in the system a failure rate of 0.2 (1in 5 years) is estimated. Approximately 90% of switchgears are supplying to industrial customers and 10% are installed in residential loops.
- The total load lost for the population is as follows
5 x 2 x 500kVA x 0.7 x 0.9 x 0.2 0x 30 = 18,900 kW for the half loop
2 x 500kVA x 0.7 x 0. 9x 0.20 x 30= 3,780 kW for the unit which is failed totaling to 18,900 kW + 3,780 kW = 22,680 kW x .90 = 20,412 kW
- Customer Minutes of Interruption (CMI) **Industrial** =5x2x8x60x0.20x30 + 8x2x60x.20x30 = **34,560 CMI x 0.90 = 31,104 CMI**
- For switchgear units supplying **Residential Subdivisions**: On average Switchgear-to-Switchgear there are thirty 50 kVA

transformers and each transformer on average has 8 customers and each customer on average has a peak load of 3 kW.

- The Normal open point (N.O.) is located at midpoint, therefore 15 transformers per phase on each side or 45 transformers in total (for the 3-phases).
- Upon a switchgear failure, one-half of the loop (on average 45 transformers, 360 customers or 1440 kW) will be lost for 3 hours (time taken to isolate/switch & restore). This means 45 transformers x 8 customers x 3 kW or a peak load of 1,080 kW for 3 hours or 3,240 kWhrs.
- Total load lost = 1,080 x 0.20 x 30 x.10 = 648kW
- Customer Minutes of Interruption (CMI) = 360 x 3 x 6 0x 0.2 x 30 x 0.1= **38,880 CMI**
- **Total CMI for the population = 31,104 + 38,880 = 69,984 CMI**

Minirupter Switches:
The failure effects are based on the following assumptions:

- These switches typically supplying **Industrial/Commercial Customers**: On average each switch has a maximum of 1,500 connected kVA.
- A load factor of 70% & power factor of 90% is assumed.
- Upon a switch failure, the connected load will be lost for 5 hours, while the failed switch is replaced.
- Since the units that will be replaced represent the worst in the system a failure rate of 0.2 (1 in 5 years) is estimated
- The total load lost is calculated as follows: 5 x 1500 kVA x 0.7 x 0.9x15x0.2 = 14175 kW for 5 hours = 70,875 kWh.
- The CMI is calculated as follows = 5 x 1 x 15 x 0.2 x 60 = 900 CMI

Submersible Transformer:
The failure effects are summarized below

- **Residential Subdivisions**: On average there are 10 transformers in a loop and each transformer on average has 7 customers and each customer on average has a peak load of 3 kW.
- A failure rate of 0.2 (1 in 5 year) is estimated for these end of life units
- Upon a failure, one-half of the loop (on average 5 transformers, 35 customers or 105 kW) will be lost for 18 hours (time taken to isolate/switch & restore). This means 5 transformers x 7 customers x 3 kW x 0.2 x 9 or a peak load of 189 kW for 18 hours or 3402 kWhrs

- **Customer Minutes of Interruption (CMI) = 35x18x60x0.2x9= 68,040 CMI**

Pad-Mount Transformer:

The calculation is based on residential customer

- Duration of interruption: 4 hours for each unit.
- Upon a transformer failure, about 10 customers which will lose power for 4 hours until the transformer is replaced.
- Each transformer is assumed to be 50 kVA with load factor of 0.7 and power factor of 0.9.
- A failure rate of 0.06 (1 in 15 years) is estimated for this population.
- Number of customers affected in an outage: = 10 customers
- Customer load affected in an outage: 1 transformers x 50 kVA x 0.7 LF x 0.9 x 50 x 0.06 = 94.5 kW for 4 hours,
- (Total = 94.5 kW x 4 hrs = 378 kWh)
- The CMI is calculated as follows:
- **CMI = 10 customers x 4 hours x 60 minutes x 0.06x 50 = 7,200 CMI per transformer failure.**

Customer Interruption Cost Calculation (Underground Equipment)

Switchgear:

Industrial Customers:

Upon a switchgear unit failure, one half of the loop (on average 5 switchgear units) will be lost. One of the 5 units is the unit that fails which will be lost for 8 hours. The remaining 4 units will be lost for 3 hours.

- Each switchgear unit supplies 2 customers, each customer has one 500 kVA transformer with a load factor of 0.7 and a power factor of 0.9.

- Number of customers affected in an outage: 5 switchgears x 2 customers/switchgear = 10 customers.

Since the units that will be replaced represent the worst in the system a failure rate of 0.2 (1in 5 years) is estimated.

Approximately 90% of switchgears are supplying to industrial customers and 10% installed in residential loops.

Total number of switchgears to be replaced: 30

Customer load affected in an outage: 4 swgr x 2 transformers x 500 kVA x 0.7 LF x 0.9 PF = 2,520 kW for 3 hours, plus 1 swgr x 2 transformers x 500 kVA x 0.7 LF x 0.9 PF = 630 kW for 8 hours (Total = 2,520 kW x 3 hrs + 630 kW x 8 hrs = 12,600 kWh)

- Customer Interruption Cost (Frequency): $20.00/kW (Commercial & Industrial)

- Customer Interruption Cost (Duration): $30.00/kWh (Commercial & Industrial)

Residential Customers
For switchgear units supplying **Residential Subdivisions**: On average Switchgear-to-Switchgear there are thirty 50 kVA transformers and each transformer on average has 8 customers and each customer on average has a peak load of 4 kW.
The Normal open point (N.O.) is located at midpoint, therefore 15 transformers per phase on each side or 45 transformers in total (for the 3-phases).
Upon a switchgear failure, one-half of the loop (on average 45 transformers, 360 customers or 1440 kW) will be lost for 3 hours (time taken to isolate/switch & restore). This means 45 transformers x 8 customers x 3 kW or a peak load of 1,080 kW for 3 hours
Total load lost = 1,080x0.20x30x.10 = 648kW
Customer Interruption Cost (Frequency): $2.00/kW (Residential)
Customer Interruption Cost (Duration): $4.00/kWh (Residential)

Cost to Industrial Customers
- Customer Interruption Cost (Frequency) = (2,520 kW + 630 kW) x $20/kW x 0.2 failures per year x 30 (Total number of Units replaced) x 0.90 (Industrial customers) = $340,200
- Customer Interruption Cost (Duration) = 12,600 kWh x $30/kWh x 0.2 failures/year x 30 x 0.90 = $2,041,200
-Total Cost to Industrial Customers (Interruption) = $340,000 + $2,041,200 = $2,381,200

Cost to Residential Customers
-Customer Interruption Cost (Frequency) = 1080 kW xS2/kW x 0.2x 30 x 0.10 = $1,296
-Customer Interruption Cost (Duration) = 1080 kW x 3hr x $4/ kWH x0.2 failures per year x 30 x 0.10= $7,776
-Total Cost to Residential Customers = $9,072

Total Cost for Industrial and Residential Customers = $2,381,200+ $9,072 = $2,390,272

Minirupter Switches:
The failure effects are based on the following assumptions:
These switches typically supplying **Industrial/Commercial Customers**: On average each switch has a maximum of 1,500 connected kVA.
A load factor of 70% and a power factor of 90% is assumed.

Upon a switch failure, the connected load will be lost for 5 hours, while the failed switch is replaced.
Since the units that will be replaced represent the worst in the system a failure rate of 0.2 (1 in 5 years) is estimated

The total load lost is calculated as follows: 5 x 1500 kVA x 0.7 x 0.9x15x0.2 = 14,175 kW for 5 hours = 70,875 kWh.
Customer Interruption Cost (Frequency): $20.00/kW (Commercial & Industrial)
Customer Interruption Cost (Duration): $30.00/kWh (Commercial & Industrial)

Customer Interruption Cost (Frequency) = 14,175 kW x $20/kW = 283,500
Customer Interruption Cost (Duration) = 14,175kW x 5hr x $30/kW = 2,126,250

Total Cost to Customers= $283,500+ $2,126,250 = $2,409,750

Submersible Transformers:
The financial risk calculations are based on the following assumptions and estimates (per submersible transformer unit):
- Frequency of interruption: 0.1 failures/year (i.e. 1 failure in 10 years), for those units that are identified for replacement
- Duration of interruption: 18 hours
- Number of transformers: 1 transformer
- Number of customers in the loop: 70 customers
- Number of customers affected in an outage: 70/2 = 35 customers (half loop)
- Customer load: 70 customers x 3 kW = 210 kW
- Customer load affected in an outage: 210 kW/2 = 105 kW (half loop)
- Customer Interruption Cost (Frequency): $2.00/kW (Residential)
- Customer Interruption Cost (Duration): $4.00/kWh (Residential)

The financial risk cost is estimated as follows:
Cost to Customers:
- Customer Interruption Cost (Frequency) = 105 kW x $2/kW x 0.1 failures/year x 9 = $189
- Customer Interruption Cost (Duration) = 105 kW x 18 hrs x $4/kWh x 0.1 failures/years 9= $6,804

Total Cost to Customer = $189 + $6804 = $6,993

Pad Mount Transformer:
Upon a transformer failure, one half of the loop (10 transformers) will be lost. One of the 10 units is the transformer which fails and the customers for that will be lost for 4 hours. The remaining 9 units will be lost for 2 hours
- Each transformer supplies 10 customers, each customer has approximately 5 kVA load.
- Number of customers affected in an outage: 10 transformers x 10 = 100 customers
- Customer load affected in an outage: 9 transformer x 50 kVA x 0.7 LF x 0.9 PF = 283.5 kW for 2 hours, plus 1 transformer x 50 kVA x 0.7 LF x 0.9 PF = 31.5 kW for 4 hours (Total = 283.5 kW x 2 hrs + 31.5 kW x 6 hrs = 756 kWh)
- Customer Interruption Cost (Frequency): $2/kW (Residential)
- Customer Interruption Cost (Duration): $4/kWh (Residential)

Cost to Customers:
- Customer Interruption Cost (Frequency) = (283.5 kW + 31.5 kW) x $2/kW x 0.06 failures/year x50 = $ 1,890
- Customer Interruption Cost (Duration) = 756 kWh x $4/kWh x 0.06 failures/year x 50= $ 9,072

Total Cost to Customers= $1,890 + $9,072 = $ 10,962

Total Cost to Customers for Underground Equipment:

Equipment	Interruption Cost
Switchgear	$2,390,272
Minirupter Switches	$2,409,750
Submersible Transformer	$6,993
Pad Mount Transformer	$10,962
Total	**$ 4,817,977**