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December 9, 2015

BY RESS & OVERNIGHT COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Enersource Hydro Mississauga Inc. Application for Distribution Rates Effective January 1, 2016, Board File No. EB-2015-0065 Interrogatory Responses

Please find attached Enersource's responses to interrogatories in the above captioned proceeding.

Two hard copies of this letter and interrogatory responses will be sent to the Board in addition to filing this via RESS.

If you have any questions, please do not hesitate to contact me at (905) 283-4098.

Sincerely,

(Original signed by)

Gia M. DeJulio
Director, Regulatory Affairs

cc. Norm Wolff, Executive Vice-President and Chief Financial Officer, Enersource
Jane Scott, Project Advisor, Ontario Energy Board
Richard Lanni, Counsel, Ontario Energy Board
Fred Cass, Aird & Berlis LLP
All Intervenors, On Record

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Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 1:

Ref: Tab 2, pg. 46, Table 2

Please provide the percentage increase for both RPP and non RPP Residential customers at the 10th percentile level of consumption based on 2016 Delivery (Subtotal C) divided by 2015 Total Bill. Should either percentage be greater than 10%, please provide a mitigation plan.

Response:

The percentage increase for RPP and non-RPP residential customers at the 10^{th} percentile level based on 2016 Delivery divided by 2015 Total Bill is 4.4% and 5.0%, respectively. Below are the bill impacts for residential RPP and Non-RPP customers based on the above specifications.

Rate Class	**Residential RPP**	
Loss Factor	**0.0360**	
Consumption	**315**	**kWh**
<u>If Billed on a kW basis:</u>		
Demand		**kW**

	Current Board-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 13.22	1	$ 13.22	$ 15.75	1	$ 15.75	$ 2.53	19.14%
Distribution Volumetric Rate	$ 0.0133	315	$ 4.19	$ 0.0102	315	$ 3.21	$ (0.98)	-23.31%
Rate Rider for Application of Tax Change	$ -	1	$ -	$ 0.01	1	$ 0.01	$ 0.01	
ICM Rate Rider (Fixed)	$ -	1		$ 1.03	1	$ 1.03	$ 1.03	
ICM Rate Rider (Variable)	$ -	315		$ -	315	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 17.41**			**$ 20.00**	**$ 2.59**	**14.90%**
Line Losses on Cost of Power	$ 0.1021	11	$ 1.16	$ 0.1021	11	$ 1.16	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	315	$ -	$ 0.0003	315	$ 0.09	$ 0.09	
Low Voltage Service Charge	$ 0.0002	315	$ 0.06	$ 0.0002	315	$ 0.06	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 19.42**			**$ 22.11**	**$ 2.69**	**13.84%**
RTSR - Network	$ 0.0081	315	$ 2.55	$ 0.0079	315	$ 2.49	$ (0.06)	-2.47%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0062	315	$ 1.95	$ 0.0064	315	$ 2.02	$ 0.06	3.23%
Sub-Total C - Delivery (including Sub-Total B)			**$ 23.92**			**$ 26.61**	**$ 2.69**	**11.24%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	326	$ 1.44	$ 0.0044	326	$ 1.44	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	326	$ 0.42	$ 0.0013	326	$ 0.42	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	315	$ 2.21					
Ontario Electricity Support Program (OESP)				$ -	-	$ -		
TOU - Off Peak	$ 0.0800	202	$ 16.13	$ 0.0800	202	$ 16.13	$ -	0.00%
TOU - Mid Peak	$ 0.1220	57	$ 6.92	$ 0.1220	57	$ 6.92	$ -	0.00%
TOU - On Peak	$ 0.1610	57	$ 9.13	$ 0.1610	57	$ 9.13	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 60.41**			**$ 60.90**	**$ 0.48**	**0.80%**
HST	13%		$ 7.85	13%		$ 7.92	$ 0.06	0.80%
Total Bill (including HST)			$ 68.27			$ 68.81	$ 0.55	0.80%
Ontario Clean Energy Benefit [1]			$ (6.83)					
Total Bill on TOU (including OCEB)			**$ 61.44**			**$ 68.81**	**$ 7.38**	**12.01%**

RPP Percentage Increase:

2016 Delivery Subtotal	$ 2.69
2015 Total Bill	$ 61.44
RPP Percentage Increase	**4.4%**

Rate Class Residential Non-RPP
Loss Factor 0.0360
Consumption 315 kWh
If Billed on a kW basis:
Demand kW

	Current Board-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.22	1	$ 13.22	$ 15.75	1	$ 15.75	$ 2.53	19.14%
Distribution Volumetric Rate	$ 0.0133	315	$ 4.19	$ 0.0102	315	$ 3.21	$ (0.98)	-23.31%
Rate Rider for Application of Tax Change	$ -	1	$ -	$ 0.01	1	$ 0.01	$ 0.01	
ICM Rate Rider (Fixed)	$ -	1	$ -	$ 1.03	1	$ 1.03	$ 1.03	
ICM Rate Rider (Variable)	$ -	315	$ -	$ -	315	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 17.41**			**$ 20.00**	**$ 2.59**	**14.90%**
Line Losses on Cost of Power	$ 0.1021	11	$ 1.16	$ 0.1021	11	$ 1.16	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	315	$ -	$ 0.0015	315	$ 0.47	$ 0.47	
Low Voltage Service Charge	$ 0.0002	315	$ 0.06	$ 0.0002	315	$ 0.06	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 19.42**			**$ 22.49**	**$ 3.07**	**15.79%**
RTSR - Network	$ 0.0081	315	$ 2.55	$ 0.0079	315	$ 2.49	$ (0.06)	-2.47%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0062	315	$ 1.95	$ 0.0064	315	$ 2.02	$ 0.06	3.23%
Sub-Total C - Delivery (including Sub-Total B)			**$ 23.92**			**$ 26.99**	**$ 3.07**	**12.82%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	326	$ 1.44	$ 0.0044	326	$ 1.44	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	326	$ 0.42	$ 0.0013	326	$ 0.42	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	315	$ 2.21					
Ontario Electricity Support Program (OESP)					-	$ -		
TOU - Off Peak	$ 0.0800	202	$ 16.13	$ 0.0800	202	$ 16.13	$ -	0.00%
TOU - Mid Peak	$ 0.1220	57	$ 6.92	$ 0.1220	57	$ 6.92	$ -	0.00%
TOU - On Peak	$ 0.1610	57	$ 9.13	$ 0.1610	57	$ 9.13	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 60.41**			**$ 61.28**	**$ 0.86**	**1.43%**
HST	13%		$ 7.85	13%		$ 7.97	$ 0.11	1.43%
Total Bill (including HST)			$ 68.27			$ 69.24	$ 0.97	1.43%
Ontario Clean Energy Benefit [1]			$ (6.83)					
Total Bill on TOU (including OCEB)			**$ 61.44**			**$ 69.24**	**$ 7.80**	**12.70%**

Non-RPP Percentage Increase:

2016 Delivery Subtotal	$	3.07
2015 Total Bill	$	61.44
Non-RPP Percentage Increase		**5.0%**

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 2:

Ref 1: Tab 2, pg. 21, Table 4
Ref 2: Tab 2, pg. 23, Table 5

In Table 4 referenced above, Enersource shows a Distribution System Plan 2016 Capex of $73,985k. Please reconcile this to the $76,738,831+$400,000-$2,131,250 = $75,007,581 as shown on Table 5 for 2016.

Response:

Capital Spend - 2016 Forecast

	Forecast	
	2016	
System Service	$17,200	
System Renewal	$34,735	
System Access	$12,008	
General Plant	$12,796	
Subtotal	$76,739	
LRT	$400	
Gross Capital Spend	$77,139	
CIAC	($2,131)	
Subtotal	$75,008	
Borrowing Costs	$483	
1557 - Meter Cost Deferrals	($1,506)	Large Commercial Meters
TOTAL	$73,985	

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 3:

Ref: Tab 2, pg. 21, Table 5

Please update Table 5 with year to date actuals for 2015.

Response:

Below is Table 5 with year to date actuals for 2015.

Capital Spend 2012 to 2021

	Actual 2010	Actual 2011	Actual 2012	COS 2013	Actual 2013	Actual 2014	Initial Fcst 2015	Updated Fcst 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	YTD Actual Oct-15	
System Service	$11,866,989	$11,857,869	$9,860,395	$12,084,000	$10,711,823	$11,227,758	$16,267,139	$16,496,973	$17,200,000	$13,015,000	$13,130,000	$12,825,000	$13,105,000	$13,490,000	$12,421,975	
System Renewal	$14,656,133	$11,421,921	$16,224,485	$16,376,000	$20,887,175	$31,256,743	$35,203,614	$36,058,509	$34,735,000	$37,242,500	$38,240,000	$40,280,000	$38,570,000	$38,490,000	$27,682,942	
System Access	$29,144,851	$14,325,984	$11,493,425	$9,458,000	$10,054,863	$9,474,167	$14,632,780	$16,451,573	$12,007,831	$9,516,237	$9,472,967	$9,412,212	$9,437,700	$9,367,700	$15,358,427	
General Plant	$5,484,172	$9,097,375	$7,005,798	$11,187,616	$6,830,748	$6,230,459	$10,585,191	$10,681,993	$12,796,000	$11,337,000	$10,280,500	$10,794,000	$10,754,862	$9,984,236	$6,853,559	
Total	$61,152,144	$46,703,148	$44,584,102	$49,105,616	$48,484,610	$58,189,127	$76,688,724	$79,689,048	$76,738,831	$71,110,737	$71,123,467	$73,311,212	$71,867,562	$71,331,936	$62,316,903	
Administration Building	$45,785	($45,785)	$22,214,255	-	-	-	-	-	-	-	-	-	-	-	-	
Hydro One TS Payments	-	-	-	-	-	-	-	$40,478,700	-	-	-	-	-	-	$40,378,000	Accrued in 2015
LRT	-	-	-	-	-	-	-	-	$400,000	$8,400,000	$8,650,000	$8,750,000	$7,800,000	$1,200,000	-	
Total	$45,785	($45,785)	$22,214,255	-	-	-	-	$40,478,700	$400,000	$8,400,000	$8,650,000	$8,750,000	$7,800,000	$1,200,000	$40,378,000	
TOTAL GROSS	$61,197,929	$46,657,363	$66,798,357	$49,105,616	$48,484,610	$58,189,127	$76,688,724	$120,167,748	$77,138,831	$79,510,737	$79,773,467	$82,061,212	$79,667,562	$72,531,936	$102,694,903	
CIAC - System Service	-	-	-		($2,545,304)	($277,014)	($60,878)	$86,617	-	-	-	-	-	-	$86,617	
CIAC - System Renewal	-	($187,840)	-		($32,979)	($12,549)	-	-	-	-	-	-	-	-	-	
CIAC - System Access	($8,483,566)	($4,310,273)	($1,248,222)	($2,933,000)	($3,365,340)	($3,848,650)	($5,594,013)	($5,741,508)	($2,131,250)	($2,131,250)	($2,131,250)	($2,131,250)	($2,131,250)	($2,131,250)	($5,540,494)	
CIAC - General Plant	-	-	-		-	-	-	-	-	-	-	-	-	-	-	
CIAC - LRT	-	-	-	-	-	-	-	-	-	($3,000,000)	($3,000,000)	($3,000,000)	($3,000,000)	($200,000)	-	
CIAC	($8,483,566)	($4,498,114)	($1,248,222)	($2,933,000)	($5,943,622)	($4,138,213)	($5,654,891)	($5,654,892)	($2,131,250)	($5,131,250)	($5,131,250)	($5,131,250)	($5,131,250)	($2,331,250)	($5,453,877)	
TOTAL NET	$52,714,363	$42,159,249	$65,550,135	$46,172,616	$42,540,987	$54,050,914	$71,033,833	$114,512,857	$75,007,581	$74,379,487	$74,642,217	$76,929,962	$74,536,312	$70,200,686	$97,241,025	
Borrowing Costs	$313,599	$403,470	$682,930	$273,834	$378,593	$347,518	$482,550	$482,550	$483,000	$486,000	$486,000	$486,000	$486,000	$486,000	$319,175	
Total Additions (Gross + Bc	$61,511,528	$47,060,833	$67,481,287	$49,379,450	$48,863,202	$58,536,645	$77,171,274	$120,650,299	$77,621,831	$79,996,737	$80,259,467	$82,547,212	$80,153,562	$73,017,936	$103,014,077	

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INTERROGATORY 4:

Ref 1: Tab 2, pg. 23, Table 5
Ref 2: EB-2012-0033, Exhibit 2, Tab 2, Schedule 2, Appendix 1, Table 17.6

Combining the information from the above two references, we can compare the original forecast versus actual and updated forecast for capital spending as per the table below ($000). Please explain:

a) The changes that have occurred in Enersource's system and operating conditions since the filing in 2012 and this ICM application that have resulted in the large variances in capital expenditures from forecasted to actual for 2014 and forecasted to updated forecast for 2015 and 2016.
b) The material year over year increases from 2014 to 2016 in each of the four investment categories.

	Source	Table 17.6	Table 6	Table 17.6	Table 6	Table 17.6	Table 6	Table 17.6	Table 6	Table 17.6	Table 6
		2012 Forecast	2012 Actual	2013 Forecast	2013 Actual	2014 Forecast	2014 Actual	2015 Forecast	2015 Updated Forecast	2016 Forecast	2016 Updated Forecast
System Service	System Capacity – Growth Driven Investment	9,312	9,860	11,134	10,712	10,329	11,228	10,507	16,267	10,686	17,200
System Renewal	System Systainment – Reliability Driven Investment	14,483	16,225	16,326	20,887	18,329	31,257	19,319	35,204	20,939	34,735
System Access	System Expansion & Upgrades – Customer Driven Investment	10,675	11,493	5,525	10,055	5,968	9,474	5,293	14,633	5,268	12,008
(included above)	Non-System Requirements - Regulatory Driven Investment										
General Plant	Non-System Requirements – Internally-Driven Investment	29,472	29,220	13,187	6,831	10,725	6,231	9,646	10,585	9,317	12,796
	TOTAL CAPITAL EXPEDITURES	63,942	66,798	46,172	48,485	45,351	58,190	44,765	76,689	46,210	76,739
	Variance		4.5%		5.0%		28.3%		71.3%		66.1%
	Hydro One TS payments										41,656
	LRT										400
	TOTAL CAPITAL EXPEDITURES										118,795

Response:

a) In EB-2012-0033, Enersource identified the need for significant capital investment in its distribution system in the near future. The AMP reflected the need to replace or substantially refurbish many of Enersource's distribution system assets that were installed during the City of Mississauga's boom development years of the 1970's, 1980's, and 1990's.

Enersource's capital expenditures projections for 2016, presented in the 2013 COS, were largely based on limited inspection programs and data available.

Since then, Enersource established an Asset Management Division in 2013 whose focus would be the development of the Distribution System Plan ('DSP"). The new division is responsible for assessing the health of Enersource's distribution assets, overseeing the asset management processes, outlining the need for capital asset replacements and ensuring asset inspections and maintenance activities are performed to optimize the asset life cycles.

Through an ever-improving inspection, testing and maintenance planning and project prioritization process, Enersource has developed a plan that paces spending while still meeting the service requirements of the distribution system and general plant assets.

The DSP is based on a multitude of inputs including, but not limited to, Asset Condition Assessment, system capacity/load forecast, asset information extracted from testing and inspection reports, information from the Integrated Operating Model ("IOM"), the Automated Mapping/Facilities Management ("AM/FM"), as well as Enersource's JD Edwards/ERP ("JDE") and Customer Care and Billing ("CC&B") systems.

Due to the improvement in the quality of asset data, centralization of asset management practices and better coordination of these activities, Enersource now has a clearer understanding of the condition of its assets and is able to better forecast planned expenditures for the near future.

As indicated in the Table above, actual historical capital spend has increased steadily through 2012 to 2015 and is expected to continue for 2016-2025. The increased spending in capital expenditures for 2013-2015 is not included in the rates approved by the Board in EB-2012-0033, and is not part of the incremental capital requested by Enersource in this Application. Normally these investments are not funded by ratepayers until the next full rebasing.

Enersource has determined that these investments were necessary and in some cases mandatory to maintain current overall levels of system safety and reliability.

Figure 1 below is the latest health index summary for Enersource's major assets. It illustrates that equipment such as underground cables, wooden poles, and motorized overhead switches have very poorly deteriorating health indexes due to the fact that equipment installed during the strong growth period in Missisauga in the 1970's, 80's and 90's are now reaching end of life.

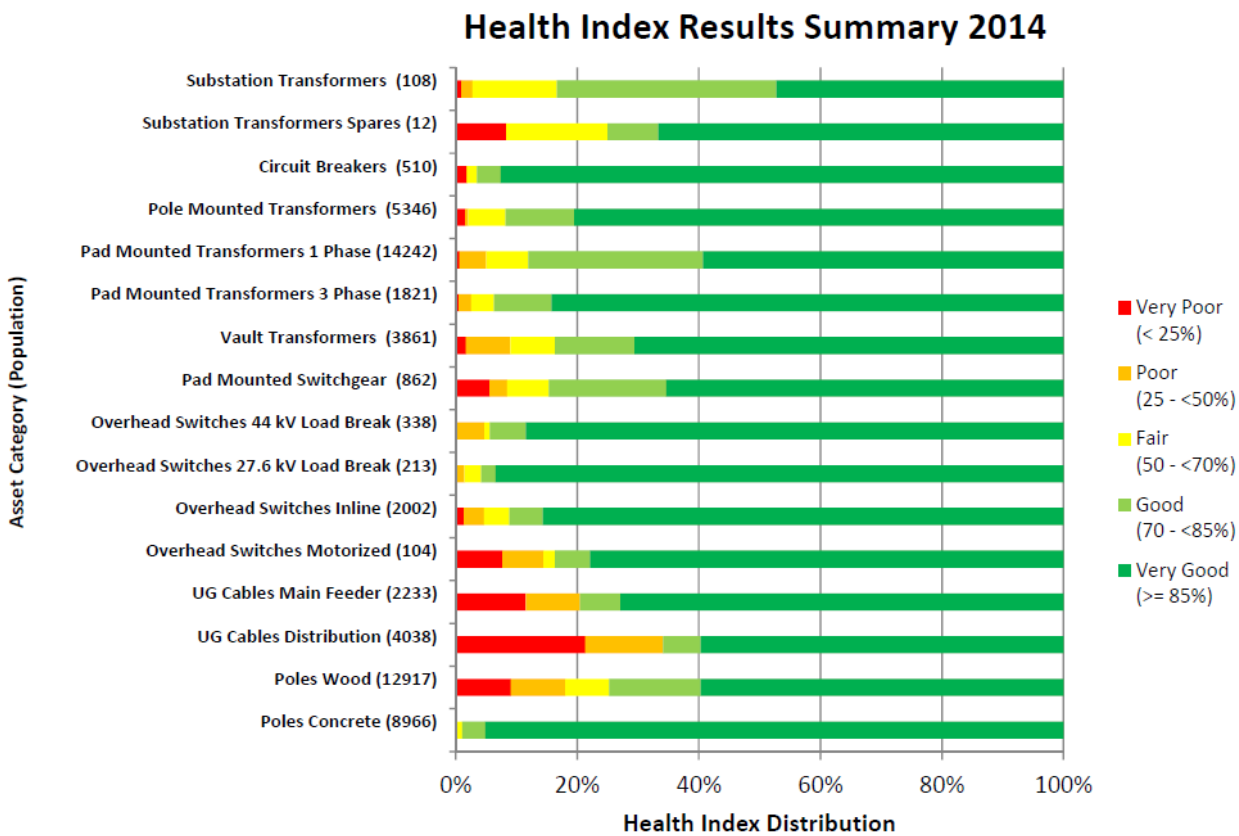

Figure 1 – Health Index Summary for Major Assets

As evident from Figure 2 below, cable faults are the largest driver in electricity service interruptions. Most of the failed cables were direct-buried and without jacket insulation that were poorly designed compared to the newest technology. As a result, this older style of cable is more prone to failure and requires considerable capital investment to replace.

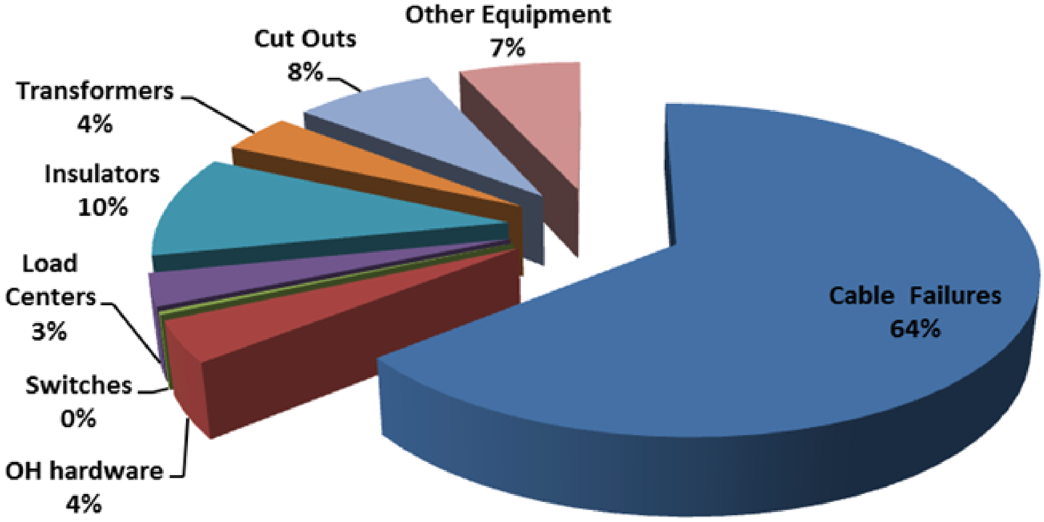

Figure 2 – Customer Interruption Minutes due to Equipment Failures (2015 YTD)

b) Below are the material year over year increases from 2014 to 2016 in each of the four investment categories.

System Service

Description	Actual 2014	Current 2015 Forecast	Change	Comments	Forecast 2016	Forecast Change	Forecast Comments
Municipal Substation Construction & Upgrades	5,850	9,056	3,205	7 major substation upgrades compared to 4 in the prior year	11,600	2,544	3 land purchases in addition to sustained spend on substation upgrades
Subtransmission Expansion	3,514	4,722	1,208	4 major projects compared to 2 in the prior year	2,400	(2,322)	Increased focus on substransmission renewal as opposed to expansion
Automation / SCADA Replacement and Enhancement Program	1,863	2,719	855	SCADA system major upgrade	3,200	481	More station RTU and protection relay replacements as this spend is partly correlated with increased substation expenditure
System Service - Total	11,228	16,497	5,269		17,200	703	

System Renewal

Description	Actual 2014	Current 2015 Forecast	Change	Comments	Forecast 2016	Forecast Change	Forecast Comments
Subdivision Renewal Program	9,307	13,865	4,558	8 major (greater than $1M) rebuilds compared to 4 in the prior year	13,250	(615)	Fewer rebuilds compared to prior year offset by higher costs for some of the rebuilds
Overhead Distribution Renewal and Sustainment	5,051	7,866	2,815	2 major (greater than $1M) rebuilds compared to none in the prior year	6,090	(1,776)	1 major (greater than $1M) rebuilds compared to two in the prior year
Subtransmission Renewal	-	10	10		4,200	4,190	Change in focus from subtransmission expansion to renewal
Transformer Replacement	12,635	10,000	(2,635)	Fewer TX replacements as 2014 was unusually high to due to significant PCB and leaking transformer replacments	7,125	(2,875)	Fewer TX replacements as replacements of PCB and leaking TXs nears completion
Underground Distribution Renewal and Sustainment	3,848	3,998	150	Consistent with prior year	3,750	(248)	Consistent with prior year
Emergency Replacement Program	416	320	(96)	Consistent with prior year	320	0	Consistent with prior year
System Renewal - Total	31,257	36,059	4,802		34,735	(1,324)	

System Access

Description	Actual 2014	Current 2015 Forecast	Change	Comments	Forecast 2016	Forecast Change	Forecast Comments
Road Projects	580	1,393	813	2014 had unusually low activity partly related to being an election year. Activity has picked up in 2015.	3,000	1,607	Increase expected due to various road authorities increased infrastructure spend
Light Rail Transit	-	-	-		400	400	LRT project expected to begin
New Subdivisions	1,205	4,388	3,183	Significant OTC projects compared to prior year	800	(3,588)	Lower OTC activity expected
Industrial & Commercial Services	4,774	5,800	1,026	Significantly more industrial/commerical activity compared to prior year	2,600	(3,200)	Ind/Comm activity expected to normalize going forward
Residential Service Upgrades	-	460	460		125	(335)	
Smart Metering Large Commercial	414	919	505	Increased activity as program to change out large commerical meters became fully active mid 2015 with hiring of subcontractor..	1,506	587	Program became fully active in mid 2015. This will continue throughout 2016 with all meter change outs expected to be completed.
Wholesale Metering	52	260	208	Metering upgrade of a transformer station	1,263	1,003	A major upgrade of a transformer station
Metering Equipment	1,411	1,264	(147)	Consistent with prior year	1,172	(92)	Consistent with prior year
Smart Metering	-	-	-		-	-	
Smart Metering in New Condos	719	1,778	1,059	Due to increased condominium development in Mississauga as well as increased activity in retrofits	1,387	(391)	Lower activity for retrofits
Green Energy - FIT/MicroFIT	319	190	(129)	Less FIT projects compared to 2014	155	(35)	Lower activity expected
System Access - Total	9,474	16,452	6,977		12,408	(4,044)	

General Plant

Description	Actual 2014	Current 2015 Forecast	Change	Comments	Forecast 2016	Forecast Change	Forecast Comments
Engineering & Asset Systems	659	1,134	475	Increased spend due to various Asset Management initiatives	1,510	376	Increased spend due to major software upgrades
Rolling Stock	926	2,773	1,847	Increased fleet replacements primarily bucket trucks and step vans	2,775	2	Consistent with prior year
Information Technology	493	784	292	Increased hardware expenditure	671	(113)	Consistent with prior year
JDE / ERP System	883	1,899	1,016	JDE enhancements and Asset Management initiatives	2,185	286	Planned implementation of new asset management software
Meter to Cash	686	1,603	916	CC&B enhancements as well as upgrades due to regulatory changes	2,470	867	Major upgrade for CC&B
Grounds & Buildings	2,417	2,240	(178)	Consistent with prior year	2,985	745	Planned upgrades/equipment replacements in Derry and Mavis buildings
Acquisition of Administrative Building	-	-	-		-	-	
Major Tools	167	250	83	Correlated to increased overall capital spend	200	(50)	Consistent with prior year
General Plant - Total	6,230	10,682	4,452		12,796	2,114	

Total Capital

Description	Actual 2014	Current 2015 Forecast	Change	Comments	Forecast 2016	Forecast Change	Forecast Comments
System Service	11,228	16,497	5,269		17,200	703	
System Renewal	31,257	36,059	4,802		34,735	(1,324)	
System Access	9,474	16,452	6,977		12,408	(4,044)	
General Plant	6,230	10,682	4,452		12,796	2,114	
Total	58,189	79,689	21,500		77,139	(2,550)	
Hydro One Contributions	-	40,479	40,479		-	(40,479)	

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 5:

Ref 1: Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 3 – Incentive Rate-Setting Applications, July 16, 2015, Section 3.3.2.3
Ref 2: Attachment H, Sheet 10b

The first reference above states "The OEB's general guidance on the application of the half-year rule was originally provided in the Supplemental Report. In this report the OEB determined that the half- year rule should not apply so as not to build a deficiency for the subsequent years of the IRM plan term. This approach is unchanged in the new ACM/ICM policy. However, the OEB's approach in decisions has been to apply the half-year rule in cases in which the ICM request coincides with the final year of a distributor's IRM plan term1."

a) When is Enersource planning its next rebasing?
b) In the second reference above, in Cells K55 and K56 appear to show that Enersource has used the half year rule in calculating the depreciation related to the CCRA true ups. From K57 it is not clear whether the half year rule was used for the 2016 Distribution System Plan capex. If Enersource is planning to rebase in 2017, please confirm that Enersource used the half year rule for all projects in determining the revenue requirement related to the requested Incremental Capital Module, or conversely if Enersource is not planning to rebase in 2017, please recalculate the revenue requirement related to the requested Incremental Capital Module using a full year of depreciation for all projects.

Response:

a) Enersource is currently in the third year of its four-year 3rd Generation IR mechanism cost of service plan. Enersource will not rebase its rates before the expiry of this current rate-setting plan, such expiry being December 31, 2016.

b) Enersource used the half year rule for all projects in determining the revenue requirement related to the requested ICM based on the assumption that Enersource will rebase in 2017.

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 6:

Ref 1: Tab 2, pg. 21, Table 4
Ref 2: Attachment J, Schedule B and Attachment L, Schedule B

The first reference shows $41.7M of the requested incremental capital is for a true up of the Connection and Cost Recovery Agreements (CCRA) for Cardiff and Winston Churchill TSs. The second references provide the expected load and revenue for each station.

a) Please provide detailed calculations for each station for (1) the original capital contribution and (2) the requested true up, including total costs, annual loads, rates and discount rates.
b) Was Cardiff TS trued up after 5 years in 2010? If so, please provide the details. If not, why not?
c) Attachment J, Schedule B for Cardiff TS shows a guaranteed revenue date of May 1, 2012 for the Line Connection Pool Work and May 1, 2026 for the Transformation Connection Pool Work, however the Attachment K, Schedule B for Winston Churchill TS does not show any guaranteed revenue dates. Were guaranteed revenue dates for Winston Churchill TS determined?
d) If so, please provide.

Response:

a) Enersource was recently advised by HONI that no true-up amount is required for Cardiff TS. Given this recent information, Enersource's revised incremental revenue requirement excluding Cardiff is $5,520K, a reduction of $101K from the requested ICM amount of $5,621K.

   With regards to Churchill Meadows TS, attached are the transformation, network, and connection pool spreadsheets provided by HONI. These spreadsheets highlight the original capital contributions, the requested true-up, the total costs, annual loads and discount rates.

b) Cardiff TS was not trued up after five years. HONI advised that an internal review was performed at the five year true up period, and based upon that review, it was determined that no true up was required at that time.

   Please also see response to a) above.

c) Guaranteed revenue dates for Churchill Meadows TS were not determined.

d) See response to c) above.

Date:	18-Mar-15
Project #	13157

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 1st true-up

Facility Name:	Churchill Meadows TS
Description:	Draft 5-year true-up with Draft CDM adjustments
Customer:	Enersource

<-------- Project year ended - annualized from In-Service Date -------->

		In-Service Date												
	Month	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27
	Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
							1st true-up					*2nd true-up*		
		0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast														
Load Forecast (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)			1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61
Incremental Revenue - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)
Ontario Capital Tax and Municipal Tax - $K			(230.1)	(225.8)	(221.8)	(218.2)	(214.8)	(211.7)	(208.9)	(206.3)	(203.9)	(201.7)	(199.6)	(197.8)
Net Revenue/(Costs) before taxes - $k		0.0	(272.1)	(267.8)	(263.8)	(260.2)	(256.8)	(253.7)	(250.9)	(248.3)	(245.9)	(243.7)	(241.6)	(239.8)
Income Taxes - $k		0.0	425.6	731.8	679.1	630.6	586.0	545.0	507.2	472.5	440.5	411.2	384.1	359.2
Operating Cash Flow (after taxes) - $k		0.0	153.4	464.0	415.2	370.4	329.2	291.2	256.3	224.2	194.7	167.5	142.5	119.5
	Cumulative PV @ 5.61%													
PV Operating Cash Flow (after taxes) - $k (A)	**2,455.6**	**0.0**	**149.3**	**427.5**	**362.3**	**306.0**	**257.5**	**215.7**	**179.8**	**148.9**	**122.4**	**99.7**	**80.3**	**63.8**
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(23,635.0)												
- Overheads - $k		(2,847.1)												
- AFUDC - $k		(849.9)												
Total upfront capital expenditures - $k		**(27,332.0)**												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		**(27,332.0)**												
Capital Contributions - $k														
Previous capital contribution/(credit)		0.0	0.0	0.0	0.0	0.0								
Current capital contribution/(credit)							0.0							
PV of annual capital contribution		0.0	0.0	0.0	0.0	0.0	0.0							
Total PV		**0.0**												
PV Proceeds on disposal of assets - $k		**0.0**												
PV CCA Residual Tax Shield - $k		**163.1**												
PV Working Capital - $k		**(1.6)**												
PV Capital (after taxes) - $k (B)	**(27,170.5)**	**(27,170.5)**												
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(24,714.9)**	**(27,170.5)**	**(27,021.2)**	**(26,593.7)**	**(26,231.4)**	**(25,925.4)**	**(25,667.9)**	**(25,452.2)**	**(25,272.4)**	**(25,123.4)**	**(25,001.0)**	**(24,901.3)**	**(24,820.9)**	**(24,757.2)**

	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
			3rd true-up										
	13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Load Forecast (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61
Incremental Revenue - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
On-going OM&A Costs - $k	(42.0)	(42.0)	(42.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)
Ontario Capital Tax and Municipal Tax - $K	(196.0)	(194.5)	(193.0)	(191.7)	(190.4)	(189.3)	(188.2)	(187.3)	(186.4)	(185.6)	(184.8)	(184.1)	(183.5)
Net Revenue/(Costs) before taxes - $k	(238.0)	(236.5)	(235.0)	(256.7)	(255.4)	(254.3)	(253.2)	(252.3)	(251.4)	(250.6)	(249.8)	(249.1)	(248.5)
Income Taxes - $k	336.3	315.3	295.9	285.8	269.4	254.3	240.4	227.7	215.9	205.1	195.2	186.0	177.6
Operating Cash Flow (after taxes) - $k	98.3	78.8	60.9	29.1	14.0	0.0	(12.8)	(24.6)	(35.5)	(45.5)	(54.7)	(63.1)	(70.9)
PV Operating Cash Flow (after taxes) - $k (A)	**49.7**	**37.7**	**27.6**	**12.5**	**5.7**	**0.0**	**(4.7)**	**(8.5)**	**(11.6)**	**(14.1)**	**(16.0)**	**(17.5)**	**(18.6)**
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(24,707.5)**	**(24,669.7)**	**(24,642.1)**	**(24,629.6)**	**(24,623.9)**	**(24,623.9)**	**(24,628.6)**	**(24,637.1)**	**(24,648.7)**	**(24,662.8)**	**(24,678.8)**	**(24,696.3)**	**(24,714.9)**

Discussion Only

Discounted Cash Flow Summary

Economic Study Horizon - Years:	**25**
Discount Rate - %	**5.61%**

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		0.0		0.0	
PV OM&A Costs		(651.1)		(651.1)	
PV Ontario Capital Tax and Municipal Tax		(2,798.0)		59.8	2,857.8
PV Income Taxes		1,155.5		(5,392.9)	(6,548.4)
PV CCA Tax Shield		4,912.4		1,715.1	(3,197.3)
PV Capital - Upfront	(27,332.0)		(27,332.0)		
Add: PV **Capital Contribution**	**0.0**	(27,332.0)	**31,602.8**	4,270.8	31,602.8
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(1.6)		(1.6)	
PV Surplus / (Shortfall)		**(24,714.9)**		**(0.0)**	**24,714.9**
Profitability Index*		**0.1**		**(1.0)**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2010	2,416.4	2,416.4	
1st true-up	2015	29,186.4		38,340.5
Total		**31,602.8**	**2,416.4**	**38,340.5**
Contribution Required (before HST)				**38,340.5**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	27-Jul-10	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets except for Land

Calculation Time Stamp: 18-Mar-15, 6:37 PM

Date:	18-Mar-15
Project #	13157

SUMMARY OF CONTRIBUTION CALCULATIONS
Network Pool - 1st true-up

Facility Name:	Churchill Meadows TS
Description:	Draft 5-year true-up with Draft CDM adjustments
Customer:	Enersource

<-------- Project year ended - annualized from In-Service Date -------->

		In-Service Date												
	Month	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27
	Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
							1st true-up					*2nd true-up*		
		0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast														
Load Forecast (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)			2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31
Incremental Revenue - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)
Ontario Capital Tax and Municipal Tax - $K			(2.1)	(2.0)	(2.0)	(1.9)	(1.9)	(1.9)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)	(1.7)
Net Revenue/(Costs) before taxes - $k		0.0	(6.0)	(5.9)	(5.9)	(5.8)	(5.8)	(5.8)	(5.7)	(5.7)	(5.7)	(5.7)	(5.7)	(5.6)
Income Taxes - $k		0.0	5.3	8.3	7.7	7.3	6.8	6.4	6.1	5.7	5.4	5.1	4.9	4.6
Operating Cash Flow (after taxes) - $k		0.0	(0.7)	2.3	1.9	1.4	1.0	0.7	0.3	0.0	(0.3)	(0.6)	(0.8)	(1.0)
	Cumulative PV @ 5.61%													
PV Operating Cash Flow (after taxes) - $k (A)	(5.3)	**0.0**	**(0.7)**	**2.2**	**1.6**	**1.2**	**0.8**	**0.5**	**0.2**	**0.0**	**(0.2)**	**(0.3)**	**(0.4)**	**(0.5)**
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(211.8)												
- Overheads - $k		(25.3)												
- AFUDC - $k		(7.0)												
Total upfront capital expenditures - $k		**(244.0)**												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		**(244.0)**												
Capital Contributions - $k														
Previous capital contribution/(credit)		0.0	0.0	0.0	0.0	0.0								
Current capital contribution/(credit)							0.0							
PV of annual capital contribution		0.0	0.0	0.0	0.0	0.0	0.0							
Total PV		**0.0**												
PV Proceeds on disposal of assets - $k		**0.0**												
PV CCA Residual Tax Shield - $k		**1.6**												
PV Working Capital - $k		**(0.1)**												
PV Capital (after taxes) - $k (B)	(242.6)	**(242.6)**												
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	(247.9)	**(242.6)**	**(243.2)**	**(241.1)**	**(239.4)**	**(238.3)**	**(237.5)**	**(237.0)**	**(236.7)**	**(236.7)**	**(236.9)**	**(237.3)**	**(237.7)**	**(238.2)**

Month	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27
Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
			3rd true-up										
	13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast													
Load Forecast (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31
Incremental Revenue - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
On-going OM&A Costs - $k	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)	(3.9)
Ontario Capital Tax and Municipal Tax - $K	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)
Net Revenue/(Costs) before taxes - $k	(5.6)	(5.6)	(5.6)	(5.6)	(5.6)	(5.6)	(5.5)	(5.5)	(5.5)	(5.5)	(5.5)	(5.5)	(5.5)
Income Taxes - $k	4.4	4.2	4.0	3.8	3.7	3.5	3.4	3.3	3.1	3.0	2.9	2.8	2.8
Operating Cash Flow (after taxes) - $k	(1.2)	(1.4)	(1.6)	(1.8)	(1.9)	(2.0)	(2.2)	(2.3)	(2.4)	(2.5)	(2.6)	(2.7)	(2.7)
PV Operating Cash Flow (after taxes) - $k (A)	**(0.6)**	**(0.7)**	**(0.7)**	**(0.8)**	**(0.8)**	**(0.8)**	**(0.8)**	**(0.8)**	**(0.8)**	**(0.8)**	**(0.8)**	**(0.7)**	**(0.7)**
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(238.9)**	**(239.5)**	**(240.3)**	**(241.0)**	**(241.8)**	**(242.6)**	**(243.4)**	**(244.2)**	**(244.9)**	**(245.7)**	**(246.5)**	**(247.2)**	**(247.9)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.61%**

		Before Cont $k		**After Cont** $k	**Impact** $k
PV Incremental Revenue		0.0		0.0	
PV OM&A Costs		(53.2)		(53.2)	
PV Ontario Capital Tax and Municipal Tax		(24.7)		4.0	28.7
PV Income Taxes		26.1		(46.3)	(72.4)
PV CCA Tax Shield		48.0		18.4	(29.6)
PV Capital - Upfront	(244.0)		(244.0)		
Add: PV **Capital Contribution**	**0.0**	(244.0)	**321.3**	77.2	321.3
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.1)		(0.1)	
PV Surplus / (Shortfall)		**(247.9)**		**0.0**	**247.9**
Profitability Index*		**(0.0)**		**(1.0)**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2010	0.0	0.0	
1st true-up	2015	321.3		422.0
Total		**321.3**	**0.0**	**422.0**
Contribution Required (before HST)				**422.0**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	27-Jul-10	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 18-Mar-15, 6:40 PM

Date:	18-Mar-15
Project #	13157

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - 1st true-up

Facility Name:	Churchill Meadows TS
Description:	Draft 5-year true-up with Draft CDM adjustments
Customer:	Enersource

	Cumulative PV @ 5.61%	In-Service Date	<------- Project year ended - annualized from In-Service Date				------->							
Month		Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27
Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
							1st true-up					2nd true-up		
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)			0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Incremental Revenue - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)
Ontario Capital Tax and Municipal Tax - $K			(8.3)	(8.2)	(8.0)	(7.9)	(7.7)	(7.6)	(7.5)	(7.4)	(7.3)	(7.2)	(7.1)	(7.1)
Net Revenue/(Costs) before taxes - $k		0.0	(24.2)	(24.1)	(23.9)	(23.8)	(23.6)	(23.5)	(23.4)	(23.3)	(23.2)	(23.1)	(23.0)	(23.0)
Income Taxes - $k		0.0	21.4	33.6	31.5	29.6	27.8	26.2	24.7	23.3	22.0	20.8	19.8	18.8
Operating Cash Flow (after taxes) - $k		0.0	(2.8)	9.5	7.6	5.8	4.2	2.6	1.3	(0.0)	(1.2)	(2.3)	(3.3)	(4.2)
PV Operating Cash Flow (after taxes) - $k (A)	(22.1)	**0.0**	**(2.8)**	**8.8**	**6.6**	**4.8**	**3.2**	**2.0**	**0.9**	**(0.0)**	**(0.8)**	**(1.4)**	**(1.8)**	**(2.2)**
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(860.7)												
- Overheads - $k		(102.7)												
- AFUDC - $k		(28.5)												
Total upfront capital expenditures - $k		**(991.9)**												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		**(991.9)**												
Capital Contributions - $k														
Previous capital contribution/(credit)		0.0	0.0	0.0	0.0	0.0								
Current capital contribution/(credit)							0.0							
PV of annual capital contribution		0.0	0.0	0.0	0.0	0.0	0.0							
Total PV		**0.0**												
PV Proceeds on disposal of assets - $k		**0.0**												
PV CCA Residual Tax Shield - $k		**6.5**												
PV Working Capital - $k		**(0.5)**												
PV Capital (after taxes) - $k (B)	(985.9)	**(985.9)**												
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	(1,008.1)	**(985.9)**	**(988.7)**	**(979.9)**	**(973.3)**	**(968.5)**	**(965.3)**	**(963.3)**	**(962.5)**	(962.5)	(963.2)	(964.6)	(966.4)	(968.6)

Month	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27	Jul-27
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
			3rd true-up										
	13	14	15	16	17	18	19	20	21	22	23	24	25
Load Forecast (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Incremental Revenue - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
On-going OM&A Costs - $k	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)	(15.9)
Ontario Capital Tax and Municipal Tax - $K	(7.0)	(6.9)	(6.9)	(6.8)	(6.8)	(6.7)	(6.7)	(6.6)	(6.6)	(6.6)	(6.5)	(6.5)	(6.5)
Net Revenue/(Costs) before taxes - $k	(22.9)	(22.8)	(22.8)	(22.7)	(22.7)	(22.6)	(22.6)	(22.5)	(22.5)	(22.5)	(22.4)	(22.4)	(22.4)
Income Taxes - $k	17.9	17.0	16.3	15.6	14.9	14.3	13.7	13.2	12.8	12.3	11.9	11.6	11.3
Operating Cash Flow (after taxes) - $k	(5.0)	(5.8)	(6.5)	(7.2)	(7.8)	(8.3)	(8.8)	(9.3)	(9.7)	(10.1)	(10.5)	(10.8)	(11.1)
PV Operating Cash Flow (after taxes) - $k (A)	**(2.5)**	**(2.8)**	**(3.0)**	**(3.1)**	**(3.2)**	**(3.2)**	**(3.2)**	**(3.2)**	**(3.2)**	**(3.1)**	**(3.1)**	**(3.0)**	**(2.9)**
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	(971.2)	(974.0)	(976.9)	(980.0)	**(983.1)**	**(986.3)**	**(989.6)**	**(992.8)**	**(995.9)**	**(999.1)**	**(1,002.2)**	**(1,005.2)**	**(1,008.1)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.61%**

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		0.0		0.0	
PV OM&A Costs		(216.9)		(216.9)	
PV Ontario Capital Tax and Municipal Tax		(100.3)		16.4	116.6
PV Income Taxes		106.2		(188.3)	(294.5)
PV CCA Tax Shield		195.2		74.8	(120.5)
PV Capital - Upfront	(991.9)		(991.9)		
Add: PV **Capital Contribution**	**0.0**	(991.9)	**1,306.5**	314.6	1,306.5
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.5)		(0.5)	
PV Surplus / (Shortfall)		**(1,008.1)**		**(0.0)**	**1,008.1**
Profitability Index*		**(0.0)**		**(1.0)**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2010	0.0	0.0	
1st true-up	2015	1,306.5		1,716.2
Total		**1,306.5**	**0.0**	**1,716.2**
Contribution Required (before HST)				**1,716.2**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions

Other Assumptions		**Notes:**
In-Service Date:	27-Jul-10	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 18-Mar-15, 6:39 PM

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 7:

Ref 1: Tab 2, pg. 21
Ref 2: Attachment L, Schedule B

Why is the amount due to HONI for Winston Churchill TS ($40.4M) greater than the total of the actual engineering and construction cost of the Transformation Connection Pool Work ($27.33M) and actual engineering and construction cost of the Line Connection Pool Work ($0.99M) and the actual engineering and construction cost of the network customer allocated work ($0.24M) = $25.56M?

Response:

The amount due of $40.479 million for Churchill Meadows TS is derived from HONI's CCRA model according to the methodology and inputs prescribed in the Transmission System Code. The HONI NPV model relies on a discounted cash flow methodology which takes into consideration the present value of incremental revenues, capital costs, OM&A, and taxes. Please see response to 2-Staff-6 part a) where the transformation, network, and connection pool spreadsheets were provided.

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 8:

Ref 1: Tab 2, pg. 27
Ref 2: Tab 2, pg. 25

In the first reference, Enersource states that it “plans to build a new substation to meet future supply needs in its 27.6kV service territory” and that “Erindale TS T1/T2 is forecasted to be overloaded”. In the second reference, Enersource states that “The proposed station [Cardiff TS] was designed to offload Erindale TS T1T2”
Please explain why Enersource would plan to build a new station to offload Erindale TS, when Cardiff TS, which was also built to off load the same station, has not seen its load materialize and as a result Enersource customers are required to pay HONI $1.3M?

Response:

The need for Cardiff TS was identified in 2003 to meet existing and future demand growth in the north and central Mississauga over the mid term period (2003-2015). The proposed station was placed in service in 2005 and it offloaded Erindale TS T1/T2 and Bramalea TS T1/T2.

In May 2014, HONI carried out the Needs Screening for GTA West Southern Subregion to forecast future demand growth over the the mid term period (2015-2023). The screening process identified a need for additional station capacity at Erindale TS T1/T2 (refer to Appendix A), above of what was being offloaded by Cardiff TS.

Subsequently, the IESO (formerly OPA), initiated the Scoping Assessement that further reaffirmed the need for offloading Erindale TS T1/T2 and recommended that wires based planning be pursued directly between HONI and Enersource (refer to Appendix B)[1]. This study confirmed that the peak load at Erindale TS T1/T2 has reached the transformational capacity, and is expected to exceed it by up to 40 MW by 2023.

Consequenly, HONI and Enersource continued working together summarizing their study findings under the ‘Local Planning Report for Erindale TS T1/T2 DESN Capacity Relief’ (refer to Appendix C). Several options were considered, namely:

1. Build new transformer station

[1] The Scoping Assessment Outcome Report by the OPA, dated September 19, 2014, concluded that the identified Erindale TS T1/T2 capacity needs do not require regional coordination, as Enersource and Hydro One agree that available transformation capacity exists adjacent to the limiting asset, and options for providing the required relief should be investigated as soon as possible. Any necessary infrastructure investments will be planned directly between Enersource and Hydro One Transmission.

2. Transfer existing 27.6kV load from Erindale TS to Trafalgar TS or Cooksvile TS

3. Build new 44/27.6kV substation

It was concluded that options 1 and 2 are not practical due to relatively high project costs associated with building a new transformer station and the operational challenges of transferring the load under option 2. Based on the study findings, Enersource concluded in their long term plan to build a substation to meet that future demand.

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS SCREENING REPORT

Region: Greater Toronto Area (GTA) West
Sub-Region: Southern Sub-Region

Revision: Final
Date: May 30, 2014

Prepared by: GTA West Southern Sub-Region Study Team

GTA West Southern Sub-Region Study Team

Company	Name
Hydro One Networks Inc. (Lead Transmitter)	Paul Cook Dhvani Shah
Ontario Power Authority	Alexandra Barrett
Independent Electricity System Operator	Phillip Woo
Burlington Hydro Inc.	Joe Saunders
Enersource Hydro Mississauga Inc.	Branko Boras
Hydro One Networks Inc. (Distribution)	Charlie Lee
Milton Hydro Distribution Inc.	Ron Brajovic
Oakville Hydro Electricity Distribution Inc.	Mike Brown

Disclaimer

This Needs Screening Report was prepared for the purpose of identifying potential needs in the GTA West Southern Sub-Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Screening Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Screening Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Screening Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Screening Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Screening Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Screening Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS SCREEN EXECUTIVE SUMMARY

NAME	Paul Cook		
LEAD	Hydro One Networks Inc.		
REGION	GTA West – Southern Sub-Region		
START DATE	April 2, 2014	**END DATE**	June 1, 2014

1. INTRODUCTION

The purpose of this Needs Screening report is to undertake an assessment of the GTA West Southern Sub-Region, determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary, such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One, and other parties as required..

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both, are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Screening for the GTA West Southern Sub-Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Needs Screening for this Sub-Region was triggered on April 2, 2014 and was completed on June 1, 2014.

3. SCOPE OF NEEDS SCREENING

The scope of this Needs Screening assessment was limited to the next 10 years because relevant data and information collected was up to the year 2023. Needs emerging over the next 10 years and requiring coordinated planning may be further assessed in the next planning cycle or as part of the OPA-led Scoping Assessment to develop a 20-year IRRP with strategic direction for the Region.

The assessment included a review of transmission system connection facilities capability which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and assets approaching end of useful life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the OPA, the Independent Electricity System Operator (IESO), and Hydro One transmission, provided information for the GTA West Southern Sub-Region. The information included load forecast, historical load, Conservation and Demand Management (CDM), Distributed Generation (DG), load restoration and performance information along with end-of-useful life of any major equipment. See Section 4 for further details.

5. ASSESSMENT METHODOLOGY

The assessment primary objective over the study period (2014 to 2023) is to identify the electrical infrastructure needs in the region. The study reviewed available information, load forecast and conducted single and double contingency analysis to confirm need, if and when required. See Section 5 for further details.

6. RESULTS

I REGIONAL SUPPLY CAPACITY

A. 230 kV transmission lines

- Thermal limits for several transmission circuits between Richview TS and Trafalgar TS (R14T, R17T, R19TH & R21TH) may be exceeded in the near term during certain contingency situations. This issue is being studied by the OPA as part of the bulk system planning studies.
- Thermal limits for transmission circuits between Richview TS and Manby TS are nearing capacity and require reinforcement in the near term. While these circuits are not part of the study area, they affect the loading on the transmission circuits between Cooksville TS and Oakville TS#2. This need is being addressed as part of the Central Toronto IRRP.

B. Area Connection Capacity

- Peak load on Erindale T1/T2 27.6 kV DESN has reached normal supply capacity and requires further assessment.
- Peak load on Erindale TS T5/T6 44 kV DESN, Tomken TS T1/T2 44 kV DESN, Lorne Park TS, and Oakville TS#2 may approach normal supply capacity by the end of the 10-year study period. The loading at these stations will be monitored and assessed in the next planning cycle for GTA West.

II SYSTEM RELIABILITY, OPERATION AND RESTORATION

Generally speaking, there are no significant system reliability and operating issues for one element out of service. However, for the loss of two elements, load restoration as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria may not be met in some cases. Further study is required.

III AGING INFRASTRUCTURE / REPLACEMENT PLAN

During the study period, plans to replace major equipment do not affect the capacity needs identified. Transformer replacements at Cooksville TS are expected to increase the normal supply capacity at the station. See Section 6.3 for details.

7. RECOMMENDATIONS

Based on the assessment, the study team's recommendation is that coordinated regional planning is further required to assess some of the needs identified in Section 6 of this Needs Screening. Accordingly, the OPA should initiate Scoping Assessment for this Sub-Region. See Section 7 for further details.

It is expected that the plan for this subregion will be appended to the overall GTA West Regional Plan.

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1 INTRODUCTION

This Needs Screening report provides a summary of needs that are emerging in the GTA West Southern Sub-Region over the next ten years. The development of the Needs Screening report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this Needs Screening report is to undertake an assessment of the GTA West Southern Sub-Region, determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a wires-only only solution is necessary, such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One, and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by the GTA West Southern Sub-Region Needs Screening study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by the Local Distribution Companies (LDCs), Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for GTA West Southern Sub-Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Ontario Power Authority
3.	Independent Electricity System Operator
4.	Burlington Hydro Inc.
5.	Enersource Hydro Mississauga Inc.
6.	Hydro One Networks Inc. (Distribution)
7.	Milton Hydro Distribution Inc.
8.	Oakville Hydro Electricity Distribution Inc.

2 REGIONAL ISSUE / TRIGGER

The Needs Screening for the GTA West Southern Sub-Region was triggered in response to the OEB's new Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, with Group 1 Regions being reviewed first. The GTA West Region belongs to Group 1.

This region is divided into two sub-regions: GTA West Northern Sub-Region and GTA West Southern Sub-Region. A Needs Screening has been triggered for the GTA West Southern Sub-Region. For the GTA West Southern Sub-Region, the Needs Screening was triggered on April 2, 2014 and was completed on June 1, 2014. The GTA West Northern Sub-Region currently has an IRRP under development and was initiated prior to the new Regional Infrastructure Planning process.

3 SCOPE OF NEEDS SCREENING

This Needs Screening covers the GTA West Southern Sub-Region over an assessment period of 2014 to 2023. The scope of the Needs Screening includes a review of system capability, which covers transformer station loading and transmission thermal and voltage analysis. System reliability, operation, load security and restoration, and asset sustainment issues were also briefly reviewed as part of this screening.

3.1 GTA West Southern Sub-Region Description and Connection Configuration

The scope of this Needs Screening covers the GTA West Southern Sub-Region. This Sub-Region is roughly bordered geographically by Highway 427 to the east, Tremaine Road to the west, Lake Ontario to the south and Highway 407 on the north. This Sub-Region comprises the municipalities of Mississauga and Oakville. The GTA West Southern Sub-Region is highlighted in yellow in Figure 1.

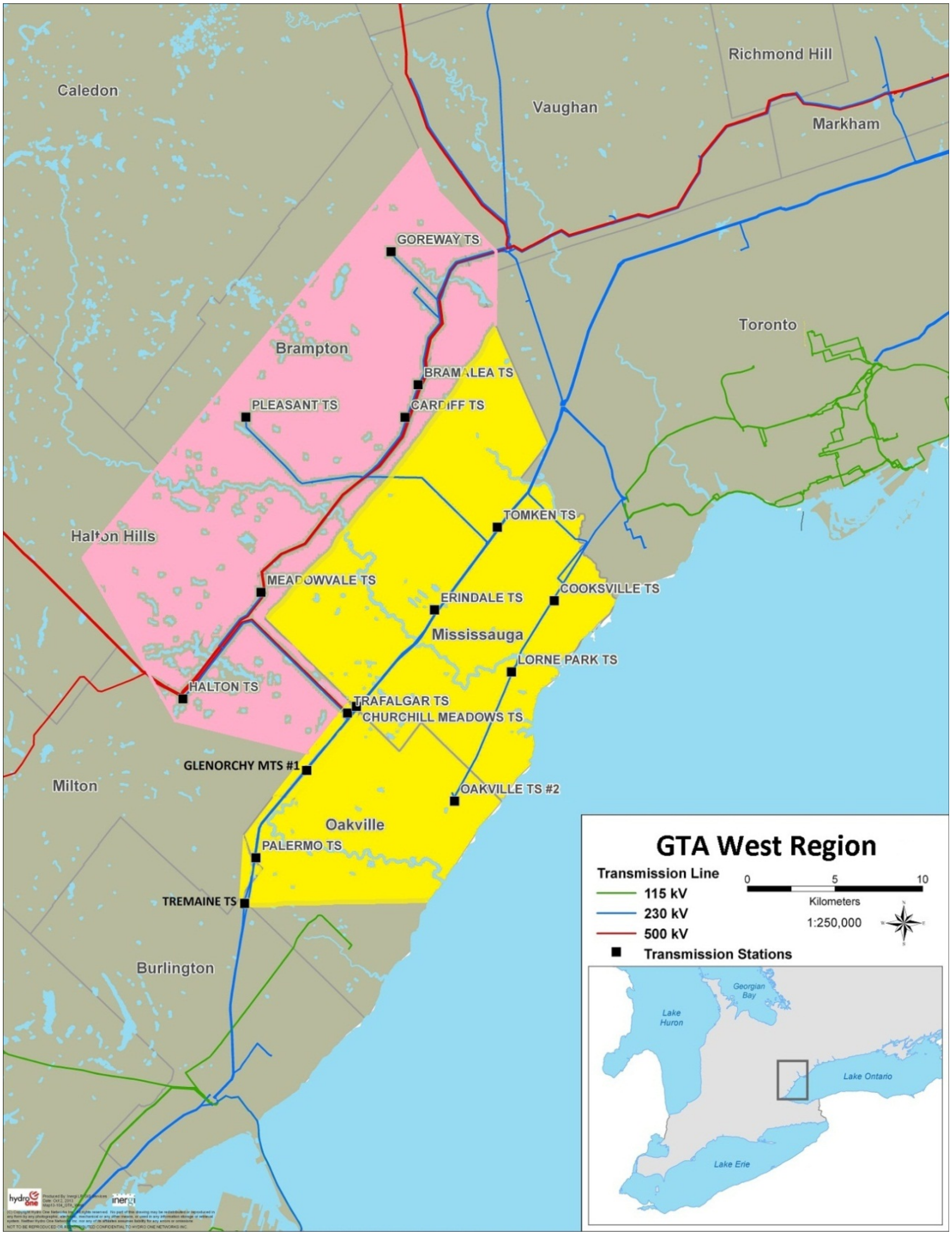

Figure 1: GTA West Southern Sub-Region Map

3.2 Electrical Areas

The GTA West Region was divided into the following electrical areas (sub-regions):

- GTA West, Northern Sub-Region
- GTA West, Southern Sub-Region

Electrical supply to the GTA West Southern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities as shown in Figure 2. This Sub-Region is roughly bounded electrically by the Richview TS to Manby TS 230 kV transmission lines on the east, the Richview TS to Trafalgar TS to Burlington TS 230 kV transmission lines on the north and the Manby TS to Cooksville TS to Oakville TS 230 kV transmission lines on the south. The distribution system in this Sub-Region is at two voltage levels, 44 kV and 27.6 kV.

The following circuits are not included in the GTA West Southern Sub-Region

- The 230 kV tap to Halton TS and Meadowvale TS, and all the circuits and stations on or north of the Parkway Belt Corridor, including the 230 kV tap to Kleinburg TS and the 230 kV tap to Jim Yarrow MTS and Pleasant TS. These circuits are included in the GTA West Northern Sub-Region.
- The circuits and stations supplied from the Richview TS to Manby TS transmission corridor. These circuits are included in the Metro Toronto Region.
- The 115 kV circuits B7 and B8, Bronte TS and Burlington TS. These circuits are included in the Burlington-Nanticoke Region.

A single line diagram of the 230 kV system in the GTA West Southern Sub-Region is shown in Figure 2 below.

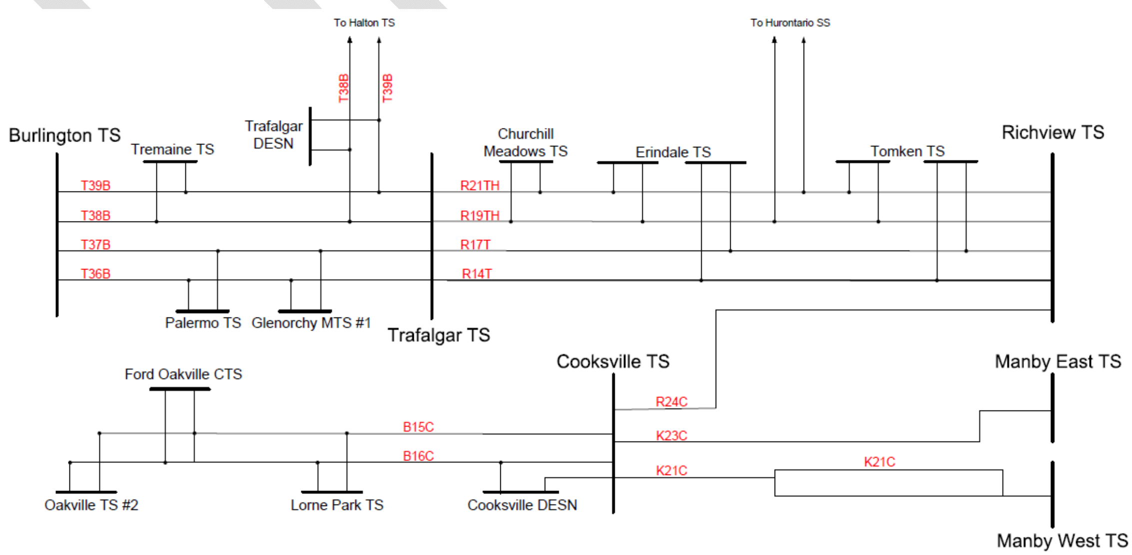

Figure 2: Single Line Diagram – GTA West Southern Sub-Region

4 INPUTS AND DATA

In order to conduct this Needs Screening, study team participants provided the following information and data to Hydro One:

- IESO provided:
  - i. Historical regional coincident peak load and station non-coincident peak load;
  - ii. A list of existing reliability and operational issues.
- LDCs provided historical net load (2011-2013) and gross load forecast (2014-2023).
- Hydro One provided transformer, station and line ratings.
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by the OPA.
- Any relevant planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the load growth rates at the stations in the GTA West Southern Sub-Region over the 2014-2023 study period is summarized in Table 2 below.

Table 2: Average Annual Gross Load Growth Rates

Sub-Area	Near Term (2014-2018)	Mid-Term (2019-2023)
44 kV System	1.1%	0.4%
27.6 kV System	1.4%	1.8%
Total Sub-Region	1.3%	1.4%

Note that the average load growth in the 27.6 kV system west of Trafalgar TS has been approximated due to load transfers between stations from other Regions or Sub-Regions.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Screening assessment:

1. The Region is summer peaking so this assessment is based on summer peak loads.

2. Forecast loads are based on the anticipated forecast growth rates provided by the Region's LDCs using historical 2013 summer peak load as reference point.
3. The 2013 historical peak loads are adjusted for extreme weather conditions according to Hydro One methodology.
4. A station annual load growth rate based on LDCs forecast is assumed over the study period.
5. Gross load forecast is used to develop a worst-case scenario to identify needs. Net load forecast is only used to assess if needs can be deferred beyond the study period.
6. Review and assess the impact of any on-going or planned development project in GTA West Southern Sub-Region during the study period.
7. Review and assess the impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as auto transformers, cables and stations.
8. To identify the emerging needs in each area, the study was performed observing all elements in service and one or two elements out of service.
9. Station capacity adequacy is assessed by comparing non-coincident peak load with the station's normal supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal supply capacity for transformer stations in this Sub-Region as determined by the summer 10-Day Limited Time Rating (LTR).
10. Transmission adequacy assessment is primarily based on :
    - Stations loads are coincident with relevant peak.
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one or two elements out of service, the system is to be capable of supplying forecast demand with circuit loading within their Long-Term Emergency (LTE) ratings and transformers within their 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per ORTAC criteria.

This needs screening assessment was conducted to identify emerging needs and to determine whether further coordinated regional planning should be undertaken or not for the Sub-Region. It is expected that studies in the subsequent regional planning process will undertake detailed analysis and also assess ORTAC performance requirements, including loss of two elements.

6 RESULTS

This section summarizes the results of the Needs Screening in the GTA West Southern Sub-Region.

6.1 Transmission Capacity Needs

6.1.1 230kV Region Supply

With one element out of service, loading on the Richview TS to Trafalgar TS circuits may exceed their LTE ratings in the near term, while under high FETT flows. This issue requires further assessment and is being dealt with by OPA-led bulk power system planning.

The loading on the 230 kV Richview TS to Manby TS circuits is expected to exceed the circuit LTE rating over the near-term. This issue is being assessed as part of the OPA-led IRRP for Central Toronto.

6.1.2 230kV Connection Facilities

There are several needs emerging in this subregion. Some of the needs identified during the study period include, but not limited to, the following:

- Existing peak load on the Erindale TS T1/T2 27.6 kV DESN is above that DESN's normal supply capacity. Peak load at this station is forecast to exceed capacity by about 40 MW by the end of the 10-year study period. Therefore, further assessment is required.
- Palermo TS is currently loaded up to its normal supply capacity. The load at the station is forecast to remain constant for the next 10 years as load growth in the area will be managed by transfers to Tremaine TS and to Glenorchy MTS #1.
- The forecast peak loads at Erindale TS T5/T6 44 kV DESN, Tomken TS T1/T2 DESN, Lorne Park TS and Oakville TS #2 may approach, but do not exceed, their respective normal supply capacity by the end of the 10-year study period.

6.2 System Reliability, Operation and Load Restoration

Generally speaking, there are no significant system reliability and operating issues for one element out of service.

The load interrupted due to the loss of a double-circuit line is well below the limit of 600 MW during the study period. The total load on 230kV transmission circuits R19TH and

R21TH may approach, but will not exceed, 600 MW for loss of a double-circuit line by the end of the 10-year study period.

Load restoration under peak load conditions as per ORTAC criteria may not be met for the loss of two elements and requires further study.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

During the study period:

- All four transformers at Cooksville TS are scheduled to be replaced by end of 2014. The 10-day LTR of the new transformers is expected to be higher than that of the existing transformers, thus increasing the normal supply capacity of both DESNs. No transmission issues are expected as a result.
- There are no significant lines sustainment plans scheduled in the near term for circuits in this subregion.

6.4 Other Considerations

The stations in southern Mississauga and east Oakville, namely Cooksville TS, Lorne Park TS and Oakville TS, are supplied radially from Richview TS via five 230kV circuits, which also terminate at Manby TS. On July 8, 2013, a severe rainstorm caused flooding and complete station outages at Richview and Manby transformer stations. As a result of this extreme event, customers normally supplied from Cooksville TS, Lorne Park TS, and Oakville TS experienced prolonged power outage. Subsequent steps in the planning process for this area will investigate the technical and economic feasibility of options for mitigating this risk.

7 RECOMMENDATIONS

Based on the Needs Screening assessment, the study team's recommendations are as follows:

a) Coordinated regional planning is further required by the OPA to undertake Scoping Assessment for the following needs identified in Section 6.
    - Erindale TS T1/T2 27.6kV DESN – there is an immediate need for increased transformation capacity. This issue may be managed in the interim by distribution load transfers.
    - Load restoration for the loss of two elements.

As part of its Scoping Assessment process, the OPA will determine if the OPA-led IRRP process and/or the transmitter-led RIP process (for wires solutions) should be further undertaken.

b) The following potential needs in Section 6 will be monitored and assessed in the next Regional Planning cycle for the GTA West area.
   - Normal supply capacity at Erindale TS T5/T6 44 kV DESN, Tomken TS T1/T2 DESN, Lorne Park TS and Oakville TS #2.
   - Monitor and assess load growth on 230kV transmission circuits R19TH and R21TH for loss of a double-circuit line (600MW limit)

The Northern subregion of GTA West region currently has an OPA-led IRRP study underway. It is expected that the plan for this subregion will be appended to the overall GTA West Regional Plan.

8 NEXT STEPS

Following the Needs Screening process, the next regional planning step, based on the results of this report, is for OPA to initiate a Scoping Assessment(s) to determine which of the needs in Section 7a) require an IRRP and/or RIP.

9 REFERENCES

- Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
- Tremaine TS SIA and CCRA
- Glenorchy MTS #1 SIA and CCRA
- IESO 18-Month Outlook

ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
FETT	Flow East Towards Toronto
GTA	Greater Toronto Area
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTR	Limited Time Rating
LV	Low-voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NS	Needs Screening
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

GTA West

Southern Sub-Region

Scoping Assessment Outcome Report

September 1, 2014

Prepared by GTA West Southern Sub-Region Team

ONTARIO POWER AUTHORITY

GTA West Southern Sub-Region Study Team

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Scoping Assessment Outcome Report Summary

Region: **Sub-Region:**	**Greater Toronto Area ("GTA") West** **Southern Sub-Region** **("GTA West Southern Sub-Region" or "Southern Sub-Region")**		
Start Date	June 24, 2014	End Date	September 19, 2014

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first stage in the regional planning process, the Needs Screening, was carried out by Hydro One Networks Inc. ("Hydro One") for the GTA West Southern Sub-Region, which roughly encompasses the City of Mississauga, and the eastern portion of the Town of Oakville. The final Needs Screening report was issued on May 30, 2014, and concluded that there are needs in the area that may require regional coordination. The conclusion resulted in the Ontario Power Authority initiating this Scoping Assessment.

The purpose of this Scoping Assessment is to:

- Determine whether coordinated regional planning is required;
- Determine the appropriate regional planning approach (Regional Infrastructure Plan ("RIP") or an Integrated Regional Resource Plan ("IRRP"); and,
- Establish a draft terms of reference, including a working group, in the case where either an IRRP or RIP is the recommended approach for the GTA West Southern Sub-Region.

2. Team

The Scoping Assessment was carried out with the same regional participants that were involved in the Needs Screening process as follows:

- The Ontario Power Authority ("OPA")
- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")
- Burlington Hydro Inc. ("Burlington Hydro")
- Enersource Hydro Mississauga Inc. ("Enersource")
- Hydro One Networks Inc. ("Hydro One Distribution")
- Milton Hydro Distribution Inc. ("Milton Hydro")
- Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro")

Although needs were identified in only some of the LDC service territories, participation was encouraged from all LDCs involved the Scoping Assessment.

3. Categories of Needs, Analysis and Results

Two major categories of needs have been identified for the GTA West Southern Sub-Region: Capacity, and Load Restoration. The referenced transmission facilities are shown on the following map of the area:

Figure 1: GTA West Southern Sub-Region

CAPACITY

The 230/27.6 kV transformers at Erindale TS (T1/T2) have been identified to be loaded above their 10-day Limited Time Rating ("LTR") during summer peak.

Analysis:

Historical data trends confirm this situation has been present for a number of years. The application of Conservation and Demand Management ("CDM") targets shows that overload has the potential to remain flat over the long term[1]. Uptake of distributed generation ("DG") in the Southern Sub-regional area has been insufficient to address needs. Capacity is available at adjacent transformation facilities, and utilizing this existing capacity should be investigated as soon as possible.

LOAD RESTORATION

Three areas within the GTA West Southern Sub-Region do not meet load restoration levels based on the application of the Ontario Resource and Transmission Assessment Criteria ("ORTAC"). Details on these areas, and their respective load levels are included in the following table:

[1] Near term: 0-5 years
Mid term: 5-10 years
Long term: 10-20 years

Table 1: Restoration Summary

		30 minute Restoration		4 hour Restoration	
Area	**Peak 10 yr load**	**Required to meet criteria**	**Available**	**Required to meet criteria**	**Available**
1. West of Cooksville B15/16C Oakville, Ford Oakville, Lorne Park	267 MW	17 MW	46 MW	117 MW	110 MW
2. Richview x Trafalgar R19/21TH Churchill Meadows, Erindale T5/T6, Tomken T3/T4, Jim Yarrow MTS	576 MW	326 MW	165 MW	426 MW	465 MW
3. Richview x Trafalgar R14/17T Erindale T1/T2 T3/T4, Tomken T1/T2	515 MW	265 MW	115 MW	365 MW	390 MW

Analysis:
Evaluation of load restoration transfer capacity confirms needs. A bulk system planning study is being conducted by the OPA for West GTA which will consider measures directly impacting load restoration capability along the Richview x Trafalgar corridor, and Cooksville West area.

4. Conclusion

The Scoping Assessment concludes that the identified Erindale TS T1/T2 capacity needs do not require regional coordination, as Enersource and Hydro One agree that available transformation capacity exists adjacent to the limiting asset, and options for providing the required relief should be investigated as soon as possible. Any necessary infrastructure investments will be planned directly between Enersource and Hydro One Transmission.

For the load restoration needs along the Richview x Trafalgar corridor and West of Cooksville area, the scoping report recommends that these needs be considered within the ongoing bulk system planning study currently being carried out in the Western portion of the GTA. This bulk system study is considering electricity needs in the municipalities of Oakville, Mississauga, Toronto, Brampton, Milton, Halton Hills and Caledon, and is being coordinated with other electricity planning studies in these areas. The OPA will ensure that relevant regional specific information is incorporated in the analysis.

With the load restoration needs being addressed through other planning studies, the scoping assessment has found that regional coordination via a Regional Infrastructure Plan (RIP) or an Integrated Regional Resource Plan (IRRP) is not needed at this time.

Introduction

This Scoping Assessment Outcome Report is part of the OEB's formalized regional planning process. The Scoping Assessment was led by the OPA in collaboration with the regional participants identified in Section 2.0 to determine the regional planning approach for the GTA West Southern Sub-Region to address the needs identified by Hydro One in its Needs Screening Report.

Hydro One's Need Screening was only carried out for the GTA West Southern Sub-Region, as coordinated regional planning for the Northern Sub-Region, known as the Northwest GTA ("NW GTA"), was already underway. Within the Southern Sub-Region, the Needs Screening Report recommended that scoping be undertaken to identify the appropriate planning approach to address the following:

- Erindale TS T1/T2 27.6 kV DESN – there is an immediate need for increased transformation capacity.
- Load restoration for the loss of two elements.

Other needs have been identified which are currently being addressed in other OPA-led planning activities. These consist of capacity constraints on the Richview to Trafalgar corridor, and Richview to Manby circuits (addressed through the West GTA bulk system planning study and the Central-Toronto IRRP, respectively). As a result, they are not subject to this Scoping Assessment.

Additionally, load restoration under peak load conditions as per the IESO's ORTAC may not be met in some pockets in the Southern Sub-region. It was also agreed that these load restoration needs would be further investigated as part of this Scoping Assessment. Based on information provided by Hydro One, it was also confirmed that there is no end-of-life replacement needs for major facilities in the Southern Sub-Region within the period investigated by the Scoping Assessment.

A copy of the GTA West Southern Sub-Region Needs Screening Report is available on the Hydro One GTA West Regional Planning website, http://www.hydroone.com/RegionalPlanning/GTAWest, or is linked here.

The OPA, in collaboration with regional participants (Enersource, Oakville Hydro, Burlington Hydro, Milton Hydro, Hydro One Distribution, Hydro One Transmission, and the IESO), reviewed the information collected as part of the Needs Screening, along with additional information on potential wires and non-wires alternatives.

The purpose of the Scoping Assessment is to:

- Determine whether coordinated regional planning is required;
- Determine the appropriate regional planning approach (RIP or an IRRP); and,
- Establish a draft terms of reference, including working group participants, in the case where an IRRP or RIP is the recommended approach for the Southern Sub-Region.

Categories of Needs, Analysis, and Results

A Scoping Assessment kick-off meeting was held on June 24, 2014, among the regional participants (OPA, Hydro One Transmission, the IESO, Enersource, Oakville Hydro, Burlington Hydro, Milton Hydro, and Hydro One Distribution) to further discuss the needs identified in the Needs Screening Report for the GTA West Southern Sub-Region.

A summary of the relevant needs is provided below:

Capacity Needs

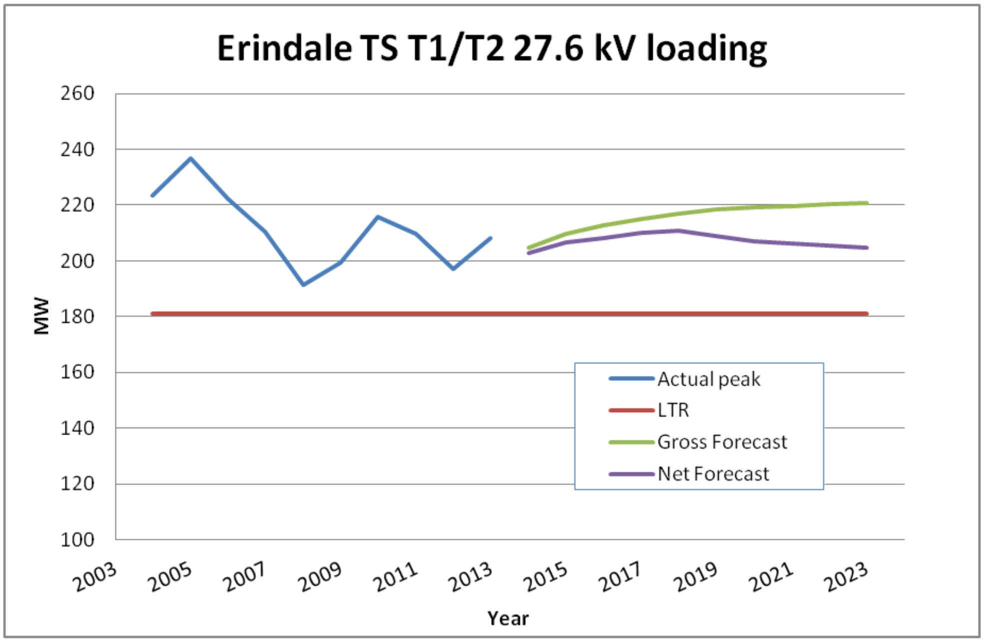
The T1/T2 27.6kV facilities at Erindale TS have been exceeding their summer 10-day Limited Time Rating ("LTR") during summer peak consistently for the past several years.

The combination of transformers and capacitor banks at this station provides a total capacity of 191 MVA, or approximately 181 MW when assuming a 0.95 power factor. During the recent 2013 summer peak, electrical demand hit 208 MW, or 115% of the 10-day LTR of the station, the limit for normal operating conditions. Supplementary information gathered from Enersource as part of the Scoping Assessment has shown that this overloading condition has existed each summer in the past 10 years[2], and operational measures were used to mitigate risks. Further planning is required to address this ongoing overload and develop an appropriate solution.

Going forward, the 10-year forecast shows demand is expected to continue to exceed LTR. However, the effect of provincially mandated conservation targets are expected to stabilize the growth rate, and keep the overload steady at approximately 25-30 MW. Historical (coincident) peak demand, along with the Gross and Net (planning level) forecasts are shown in Figure 2 below:

[2] Peak data not yet available for 2014

Figure 2: Erindale TS Loading



Conservation measures can play a valuable role by limiting the extent of the overload on the Erindale TS T1/T2 transformers. Local LDCs will be delivering conservation programs in the area to support meeting their CDM targets as part of the new Conservation First Framework. After accounting for LDC conservation targets, the increase in the amount of load relief required is mitigated and held at historical levels (as shown in the figure above). Given the immediacy of the capacity needs and the amount of incremental CDM required to meet the remaining capacity requirements, additional targeted conservation is deemed to be an unfeasible solution in the near term.

Additionally, DG contracts in the Erindale service territory currently total 7.1 MW of capacity, primarily made up of solar Feed in Tariff ("FIT") projects, and a bioenergy project procured through the Renewable Energy Standard Offer Program ("RESOP"). Given the dense, largely residential load served by Erindale T1/T2, and the historic uptake in the area, it is not expected that up to 30-40 MW of new capacity could be procured to meet this need.

Capacity is available at other step down stations in the general vicinity of Erindale TS. This allows the possibility of supplying this shortfall through implementing transmission and distribution solutions. When capacity is available at adjacent stations, these types of solutions are typically the lowest cost option due to minimal new infrastructure requirements. Stations in the vicinity of Erindale TS that are projected to have surplus capacity over the next 10 years are listed in the table below:

Table 2: Stations in Vicinity of Erindale TS

Station	Available Capacity	Notes
Erindale TS	T3/T4 (44kV): 37 MW T5/T6 (44kV): 17 MW	44/27.6 kV conversion required
Tomken TS	T1/T2 (44 kV): 25 MW T3/T4 (44 kV): 33 MW	44/27.6 kV conversion required
Lorne Park TS	(27.6 kV): 19 MW	Limited capacity available Non adjacent service territory: No intertie potential
Cooksville TS	T3/T4 (27.6 kV): 60 MW T5/T6 (27.6 kV): 24 MW	Non adjacent service territory: No intertie potential
Churchill Meadows TS	(44 kV): 74 MW	44/27.6 kV conversion required
Trafalgar TS	(27.6 kV): 34 MW	Requires feeder crossing of 403 highway

The available capacity is based on the minimum difference between the net (planning level) forecast and facility rating over the 10-year planning horizon. As a result, anticipated growth is already accounted for in this table.

Load Security and Restoration Assessment

Three areas within the GTA West Southern Sub-Region have been identified as being at risk for not meeting restoration levels as defined in ORTAC. ORTAC indicates that for the loss of two elements, any load in excess of 250 MW should be restored within 30 minutes, and any load in excess of 150 MW should be restored within 4 hours. The assessment should also consider restoration of all loads within 8 hours. Because West GTA is a densely populated area, it is assumed that sufficient maintenance and operations workforce are nearby to perform necessary repairs and restore loads within 8 hours. As a result, this analysis will only focus on 30 minute and 4 hour restoration capability.

The table below shows the anticipated 10-year peak for four areas that were investigated for Restoration needs (based on the net, planning level forecast), and the corresponding amount of load that should be restored within 30 minutes and 4 hours, respectively. Available distribution system restoration capability was supplied by LDCs based on the existing system configuration, and compared to ORTAC to determine where restoration needs may exist.

Note that one of the four areas investigated, Burlington x Trafalgar T36/37B, was found to have adequate restoration capability:

Table 3: Restoration Summary

		30 minute Restoration		4 hour Restoration	
Area Circuit Affected stations	**Peak 10 yr load**	**Required to meet criteria**	**Available**	**Required to meet criteria**	**Available**
West of Cooksville B15/16C Oakville, Ford Oakville, Lorne Park	267 MW	17 MW	46 MW	117 MW	110 MW
Richview x Trafalgar R19/21TH Churchill Meadows, Erindale T5/T6, Tomken T3/T4, Jim Yarrow MTS	576 MW	326 MW	165 MW	426 MW	465 MW
Richview x Trafalgar R14/17T Erindale T1/T2 T3/T4, Tomken T1/T2	515 MW	265 MW	115 MW	365 MW	390 MW
Burlington x Trafalgar T36/37B Palermo TS, Glenorchy MTS #1	230 MW	--	65 MW	80 MW	140 MW

It is also acceptable under ORTAC for distributors and transmitters to agree to a lower level of reliability, where it is agreed that "satisfying the security and restoration criteria on facilities not designated as part of the bulk system is not cost justified…"[3]. Applications for exemption are to be jointly submitted to the IESO by the affected distributor and transmitter.

It should also be noted that the vulnerability to loss of supply for customers in the Cooksville West area was highlighted during the July 8, 2013 summer rain storm. This section of line was interrupted for several hours due to outages at Richview TS and Manby TS. Although this was a low probability extreme event, Enersource and Oakville Hydro have indicated that there are ongoing concerns about this reliability risk.

The OPA is currently carrying out a bulk system planning study for West GTA, which includes consideration for restoration needs identified for the Richview x Trafalgar corridor. Solutions to address bulk system needs have the potential to impact restoration capabilities throughout the area, including West of Cooksville. This study is expected to be complete by the end of 2014.

[3] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

Recommendation

Two categories of needs have been identified for the GTA West Southern Sub-Region: capacity needs at Erindale TS T1/T2 and load restoration needs along several double circuit corridors.

For Erindale TS T1/T2 27.6kV, given that the capacity need is immediate, but that available capacity exists on the Enersource system, it is recommended that wires based planning be pursued. Additionally, since all potentially affected stations serve Enersource load exclusively, it is recommended that this capacity need be addressed directly between Hydro One Networks Transmission and Enersource as part of regular customer planning, and not through a coordinated regional planning process.

For load restoration needs along the Richview x Trafalgar corridor and West of Cooksville area, it is recommended that these needs be considered as part of the ongoing bulk system planning study for West GTA. The OPA will regularly update Enersource, Oakville Hydro, and other affected or interested LDCs on the study progress, and ensure regional specific information is incorporated in the analysis. Should the bulk system planning study not resolve these load restoration needs, the planning approach is to revisit this issue as part of the OEB's ongoing regional planning process.

Scoping Assessment Outcome Report Summary
Addenda: Results of Public Comment Period

Region: **Sub-Region:**	**Greater Toronto Area ("GTA") West** **Southern Sub-Region** **("GTA West Southern Sub-Region" or "Southern Sub-Region")**

Introduction

As part of the Ontario Energy Board's ("OEB") formalized Regional Planning process endorsed by the OEB in August 2013, the draft Scoping Assessment report is to be made available for public review with an opportunity for comments. Comments received are to be considered by the study team prior to a final decision on the Scoping Assessment outcome.

Comments

On August 19th, 2014, the Draft Scoping Assessment Outcome report was posted to the OPA website for a 2 week public comment period. A notifying email was sent out to all parties who had signed up to receive updates for the West GTA Planning Region. No comments were received.

Response

Comments were not received for the draft GTA West Southern Sub-Region Scoping Assessment. As a result, the draft document will be marked as final without material updates to the content or conclusions. The final Scoping Assessment will be posted to the OPA website by September 19th, 2014, completing this phase of the regional planning process.

Hydro One Networks Inc.
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LOCAL PLANNING REPORT

ERINDALE TS T1/T2 DESN CAPACITY RELIEF

GTA WEST – SOUTHERN SUBREGION

Revision: 0
Date: July 9, 2015

Prepared by:

Hydro One Networks Inc.

Enersource Hydro Mississauga Inc.

GTA West Region Local Planning Study Team	
Organization	**Name**
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Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending preferred solution(s) to address local needs identified in the Needs Assessment and Scoping Assessment Reports for GTA West – Southern Subregion that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	GTA West Southern Subregion
LEAD	Hydro One Networks Inc. (HONI)

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only solutions to address local needs identified in GTA West Southern Subregion. The development of the LP report is in accordance with the regional planning process as set out in the Planning Process Working Group (PPWG) Report to the Ontario Energy Board's (OEB) and mandated in the Transmission System Code (TSC) and Distribution System Code (DSC).

The Needs Assessment process for GTA West Southern Subregion, completed in May 2014, identified potential needs in the subregion over the next ten years (2014 to 2023). One of these needs is a need for additional station capacity at Erindale TS T1/T2 DESN. The peak load at Erindale TS T1/T2 DESN has reached the DESN's capacity, and is expected to exceed it by up to 40 MW by 2023.

The Scoping Assessment process, completed in September 2014, concluded that the Erindale TS T1/T2 DESN station capacity need can be addressed by a Local Planning process between HONI and the affected LDCs, in this case Enersource Hydro Mississauga Inc.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

This report addresses the local need for additional transformation capacity at Erindale TS T1/T2 DESN.

3. OPTIONS CONSIDERED

(1) **New DESN** – Transfer some existing 27.6 kV load from Erindale TS to a new DESN
(2) **Load transfer** – Transfer some existing 27.6 kV load from Erindale TS to Trafalgar TS or Cooksville TS
(3) **New Distribution Station (DS)** – Build a new 44/27.6kV DS. This DS will be supplied from a 44kV feeder out of one of the neighbouring DESNs in the area, like Erindale TS T3/T4 DESN, Churchill Meadows TS, or Tomken TS.

4. PREFERRED SOLUTION

Option (1) and (2) are not practical, due to relatively high project costs associated with (1) and the operational challenges of transferring the load in (2). Option (3) is the most feasible option and is currently being reviewed by Enersource. Under this option, Enersource will build a new 44/27.6kV DS.

5. NEXT STEPS

Enersource will assess and develop an implementation plan to build a new DS by the end of Q3 2015.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

The Needs Assessment process for GTA West Southern Subregion, completed in May 2014, identified potential needs in the subregion over the next ten years (2014 to 2023). One of these needs is a need for additional station capacity at Erindale TS T1/T2 DESN. The peak load at Erindale TS T1/T2 DESN has reached the DESN's capacity, and is expected to exceed it by up to 40 MW by 2023.

The Scoping Assessment process, completed in September 2014, concluded that the Erindale TS T1/T2 DESN station capacity need can be addressed by a Local Planning process between HONI and the affected LDCs (i.e., Enersource).

This Local Planning report was jointly prepared by HONI and Enersource to assess a number of alternative solutions and provide a recommendation to meet this station capacity need.

Erindale TS Local Area

Erindale TS consists of 3 DESN's, namely:

- T1/T2 DESN, with 27.6 kV distribution voltage level, supplied by R14T and R17T
- T3/T4 DESN, with 44 kV distribution voltage level, supplied by R14T and R17T
- T5/T6 DESN with 44 kV distribution voltage level, supplied by R19TH and R21TH

R14T and R17T are 230 kV double-circuit lines connecting Trafalgar TS and Richview TS. R19TH and R21TH are 230 kV double-circuit lines connecting Trafalgar TS, Richview TS, and Hurontario SS. Single line diagram of the GTA West Southern Subregion is shown in Figure 1 below.

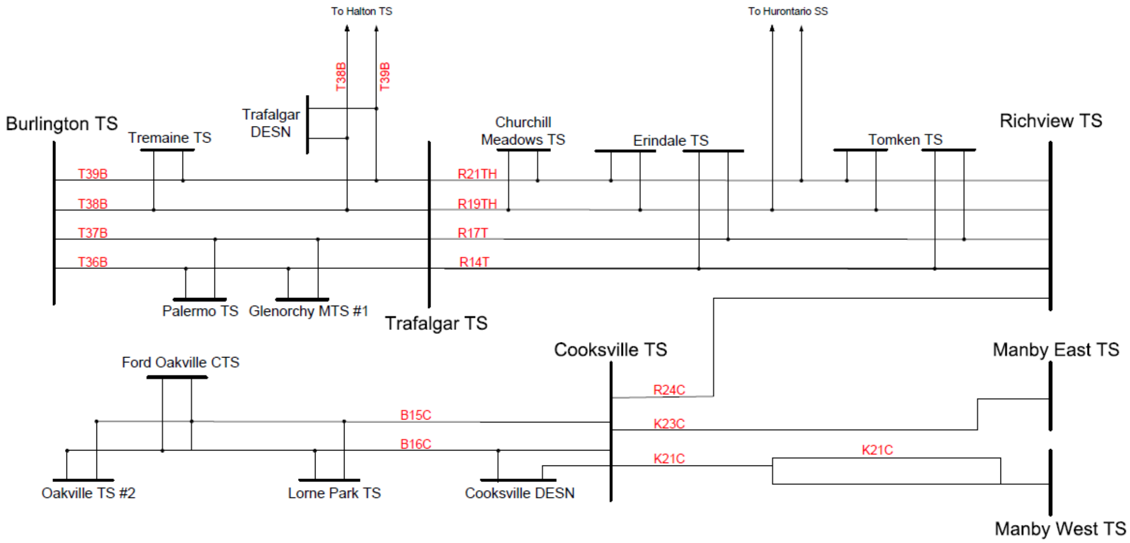

Figure 1. GTA West Southern Subregion Single Line Diagram

2 OPTIONS CONSIDERED

A number of options for providing the required relief, shown below, are being investigated. Any necessary infrastructure investment will be planned directly between Enersource and HONI.

Transmission Option:

(1) **New DESN** – Transfer some existing 27.6 kV load from Erindale TS to a new DESN

- Since the load is expected to be constant (no load growth) over the next 10 years, this option will be expensive and not economically viable.

Distribution Options:

(2) **Load transfer** – Transfer some existing 27.6 kV load from Erindale TS to Trafalgar TS or Cooksville TS

- Cooksville TS and Trafalgar TS are separated from Erindale T1/T2 by 44 kV service area. It would be operationally challenging and expensive to run a new 27.6 kV through 44 kV service territories.

(3) **New Distribution Station (DS)** – Build a new DS to utilize extra 44 kV station capacity at Erindale TS T3/T4 DESN, Churchill Meadows TS, or Tomken TS to offload Erindale TS T1/T2 DESN

- There is extra capacity available in the area 44 kV system that can be utilized by building a step down (44/27.6 kV) Distribution Station. This new DS will be supplied from a 44kV feeder. This is the most viable option that Enersource is currently reviewing. Under this option, Enersource will build the new DS, own it, and recoup the costs through the distribution rates.

3 PREFERRED SOLUTION

This is primarily a distribution planning issue that will involve planning and building a new DS by the LDC to utilize the extra 44 kV station capacity available at the neighbouring stations, such as Erindale TS (T3/T4) DESN, Churchill Meadows TS, or Tomken TS. Enersource Hydro Mississauga will assess and develop an implementation plan to build a new DS by the end of Q3 2015.

4 NEXT STEPS

A summary of the next steps, actions/solutions and timelines required to address the local needs are as follows:

Table 1. Solutions and Timeframe

Item #	Need	Action / Recommended Solution	Lead Responsibility	Timeframe
1	Erindale TS T1/T2 DESN capacity	• Assess and develop an implementation plan to build a new DS	Enersource	End of Q3, 2015

5 REFERENCES

i) GTA West Southern Subregion Need Assessment Report. Available online at: http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Needs%20Assessment%20Report%20-%20GTA%20West%20-%20Southern%20Subregion.pdf

ii) GTA West Southern Subregion Scoping Assessment Report. Available online at: http://www.ieso.ca/Documents/Regional-Planning/GTA_West/Scoping-Assessment-Outcome-Report-September-2014.pdf

6 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 9:

Ref: Tab 2, pg. 38

In its application, Enersource states that the revenue shortfall is partly due to an economic downturn that occurred in 2008. Winston Churchill TS was put into service on July 27, 2010.

a) When was construction of the station started?
b) Was a reassessment of the need for the station done in light of the economic downturn in 2008?
c) Was there any thought of delaying or cancelling construction of the station in light of the economic downturn?
d) Did the CCRAs allow Enersource to cancel the projects before construction started and just pay HONI's costs to date?

Response:

a) The Connection and Cost Recovery Agreement ("CCRA") between Enersource and Hydro One Networks Inc. (HONI) for the Churchill Meadows Transformer Station (TS) was signed on December 23, 2008.

   Following execution of the CCRA, Enersource completed a temporary pole line to support the project, and construction of the TS commenced in March, 2009.

b) The need for the TS was based on the GTA West Supply Study completed in February, 2006, as originally filed in this Application at Tab 3 Attachment K. Results of the study were based on load forecasts with information provided by Enersource, Hydro One Brampton, Toronto Hydro-Electric System, Halton Hills Hydro, Milton Hydro, and HONI Distribution. Given the long-term view of the study period, and the expectation that reduction in load driven by the economic downturn would be short-term, Enersource did not seek to reassess the results and recommendation for the TS that emerged from the GTA West Study.

c) Cancellation of the project was not considered at that time, as it was not anticipated that the need for the TS would be significantly reduced in the medium or long term as a rebound of demand was anticipated based on previous downturns. Also, a delay or cancellation would have triggered potentially significant vendor penalties (payable by Enersource indirectly via its obligations to HONI pursuant to the CCRA) resulting from the long lead times required for the procurement of major equipment such as transformers, breakers, and high voltage switchgear. That is, by the time construction began, HONI had already incurred significant cost obligations.

At the time of construction, Enersource could not have known how extensive (both in quantum and time) the downturn in the economy would become, nor how successful the conservation culture initiative would be.

d) The CCRA, Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach states:

“Notwithstanding any other term of the Agreement, if at any time prior to the In-Service date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One’s Engineering and Construction Cost (plus Taxes) of the Line Connection Pool work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.”

As mentioned in c), cancellation would have triggered potentially significant vendor cancellation costs, and it would have been imprudent for Enersource to have paid these significant indirect costs to HONI, especially as it considered the drop in load to be temporary.

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 10:

Ref 1: Tab F – Calculation of Renewable Generation Provincial Amount
Ref 2: Supplementary Evidence, Balance of Accounts 1531, 1532 & 1533

Sheet 1 of Tab F shows the total revenue requirement for 2016 for Renewable Generation connections is $155,153, with $50,142 being a direct benefit to Enersource's customers and $105,010 to come from the Provincial Rate Protection.

a) Please confirm that Enersource is not planning to apply the $0.020/customer rate rider to recover the direct benefit portion in 2016.
b) Please confirm that Enersource did not apply the GEA rate rider related to the direct benefit portions shown on Sheet 1 of Tab F for 2013-2015.
c) Please provide reconciliation between the capital amounts, OM&A and revenue requirement shown in Reference 1 and the 2014 balances for Accounts 1531, 1532 and 1533 shown in Reference 2.

Response:

a) Enersource does not plan on applying for the $0.020/customer rate rider to recover the direct benefit portion.

b) Enersource did not apply the GEA rate rider related to the direct benefit amounts shown on Sheet 1 of Tab F for 2013-2015. Enersource has only applied the Board-approved amounts to be recovered from all provincial customers from its 2013 COS application and 2014 and 2015 IRM applications.

c) See below for a reconciliation between the capital, OM&A and revenue requirement amounts shown in Reference 1 and the balances in accounts 1531,1532 and 1533.

Capital Reconciliation :

USofA Balances	US OF A	2014	2013	2012
Renewable Connection Capital	1531	531,493	471,895	380,664

	2014	2013
2014 cumulative capital expenditures	**518,366**	**465,756**
Carrying charges	13,126	6,138
Total 2014 cumulative capital expenditures	**531,493**	**471,895**

Calculation of 2014 average net fixed assets:	**2014**	**2013**
Cumulative capital expenditures	518,366	465,756
Less: CIP	(8,713)	(62,310)
Net cumulative capital expenditures	**509,653**	**403,446**
2014 average net fixed assets	**456,550**	

The capital amount in the supplementary information which reflects the 2014 balance in account 1531 (ref 2) is comprised of cumulative capital expenditures of $518,366 and carrying charges of $13,126. This capital expenditure balance used to calculate 2014 average net fixed assets of $456,550 in Tab F page 1 is referenced on Tab F page 4.

OM&A Reconciliation :

USofA Balances	US OF A	2014	2013	Change
Renewable Connection OM&A	1532	126,046	66,875	59,171

2014 Incremental OM&A Deferral Amount:	
Depreciation	34,414
OM&A	**23,439**
Carrying charges	1,318
Total 2014 OM&A	**59,171**

The OM&A amount in the supplementary information reflects the 2014 cumulative OM&A balance in account 1532 (ref 2). The 2014 OM&A expenditures of $59,171 is comprised of depreciation of $34,414, OM&A of $23,439 and carrying charges of $1,318. The OM&A amount of $24,439 is referenced in Tab F page 1 under ‘2014 Actual’.

Revenue Requirement/Funding Adder Reconciliation:

USofA Balances	**US OF A**	**2014**	**2013**	**2012**
Renewable Generation Connection Funding Adder	1533	(134,730)	(64,699)	0
2014 Cumulative Approved Provincial Funding:				
EB-2013-0033 approved funding adder		(64,270)		
EB-2013-0124 approved funding adder		(68,640)		
Carrying charges		(1,820)		
Total cumulative approved funding amounts		**(134,730)**		

The funding adder amount in the supplementary information (ref 2) reflects the OEB-approved provincial funding amounts from Enersource's 2013 COS application and 2014 IRM application. The OEB-approved balances are referenced on Tab F, page 2. Enersource received total approved funding of $215,882 which includes $82,972 from EB-2014-0068 (2015 IRM application). Enersource's calculated revenue requirement for renewable generation which includes actuals for 2010 – 2014 and forecasts for 2015 and 2016 totals $438,613, with $117,721 being a direct benefit to Enersource's customers and $320,892 to come from the provincial rate protection. Enersource has requested approval to recover $105,010 from all provincial rate payers which is the difference between the revenue requirement (provincial portion) of $320,892 and previously-approved funding of $215,882.

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 11:

Ref 1: Supplementary Evidence Capital Planning Overview 2016-2021 pg.7
Ref 2: Capital Expenditure Projects 2016 Budget

The Capital Planning Overview states that:

> "The Project Prioritization phase ranks each project based on their value and allows for all projects to be evaluated based on the same criteria to determine what projects will provide the most value to the business while minimizing the risks. A Preliminary Project List is created based on the prioritization process and understanding of risk/impact if the proposed project is not approved."

a) For all projects shown on the Capital Expenditure Projects 2016 Budget list please provide the project's prioritization position with respect to the other projects on the list.
b) Please provide further details on how a project's prioritization position is determined.
c) Once prioritization is done, how is it decided whether or not a project will proceed or be deferred?
d) Please provide a list of projects which Enersource has deferred from 2016 into future years.

Response:

a) Please see attached spreadsheet Appendix A.

b) Each project is first assessed to determine if it is mandatory. A project is considered mandatory ("Regulatory Mandatory") if it is required to meet regulatory obligations including the criteria below:

- Project where there is an immediate risk to worker or public safety;
- Project identified as a result of customer request;
- Highway or roadway relocations, and upgrades needed to accommodate municipal, provincial, or federal infrastructure improvements; and
- Project required to become or remain compliant with applicable legislation and/or regulation.

A project is also categorized as Regulatory Mandatory (albeit somewhat of a misnomer) if it is required pursuant to Enersource's IT infrastructure road map, e.g., version upgrades to maintain vendor support.

If a project is considered Regulatory Mandatory, the project is further categorized as able to be deferred or not able to be deferred. In the prioritization exercise of the business cases, projects defined as Regulatory Mandatory do not require further categorization under the Customer Focus, Operational Effectiveness, and Financial Performance categories, as the project goes to the head of the line.

Projects not considered manadatory are weighted based on the following categories, criteria and weightings:

Customer Focus	30%
Operational Effectiveness	50%
Financial Performance	20%
	100%

Customer Focus:	
Service Quality	20%
Customer Satisfaction	60%
Reputational Risk	20%
	100%

Operational Effectiveness:	
Safety (Customer & Employee)	25%
Environmental Impact/risk	15%
System Reliability/ System Expansion/ System Renewal	60%
	100%

Financial Peformance:	
Cost Efficiencies and ongoing costs	50%
Impact on Revenue Requirement	50%
	100%

Operations personnel completing the project business cases rate the projects based on the best suited descriptions within the criteria categories:

Customer Focus:

Service Quality

10 - Improvement from non-compliance to compliance
8 - Significant improvement to ESQR
5 - Improvement of multiple ESQRs
3 - Makes an improvement or prevents degradation of 1 ESQR
0 - No impact on any ESQR

Customer Satisfaction

10 - Direct positive impact that will be reflected on next customer survey

8 - Adds value or service that customers have identified through survey or some other means

5 - Improves customer experience (a large user or 1,000 RES customers)

3 - Positive improvement to customer experience (non-quantifiable)

0 - No impact on Customer Service

Reputational Risk

10 - Prevents or significantly reduces likelyhood of irreparable brand damage

8 - Positive impact on brand

5 - Helps preserve brand

3 - May mitigate brand risk

0 - No brand impact

Operational Effectiveness:

Safety

10 - Potential loss of life

8 - Non-reversible injury

5 - Medical aid injury

3 - First aid injury

0 - No safety risk

Environmental

10 - Environmental disaster

8 - High environmental impact

5 - Medium environmental impact

3 - Low environmental impact

0 - None

System Reliability

10 - Prevent 100,000 customer minutes of outage

8 - Prevent 80,000 customer minutes of outage

5 - Prevent 50,000 customer minutes of outage

3 - Prevent 30,000 customer minutes of outage

0 - No impact on customer minutes of outage

System Expansion

10 - New infrastructure to avert major system constraint/risk

8 - New infrastructure required to support service capacity

5 - Upgrade existing infrastructure to support existing service capacity

3 - Provide system capacity without compromising service to existing customers

0 - No Impact on system capacity

System Renewal

10 - ACA health index "Very Poor"

8 - ACA health index "Poor"

5 - ACA health index "Fair"

3 - ACA health index "Good"
0 - ACA health index "Very Good" or N/A

Financial Performance:

Cost Efficiences

10 - > $100,000
8 - > $80,000
5 - > $50,000
3 - > $30,000
0 - No significant amount

Ongoing Costs

-0 - No significant amount
-3 - < $30,000
-5 - < $50,000
-8 - < $80,000
-10 < $100,000

Each choice within the above categories assigns a score to the priority of the project. The total of each category is multiplied by the weighting of the category. The weighted scores for each category are added together for a total score.

In addition to the total score assessed by the primary categories listed above, the following elements must be considered: age of the asset; resources required; urgency or timing; and project complexity. Options are as follows:

Urgency (Regulatory only)

Not Applicable
Mandatory - Deferral of project will result in non-compliance with regulations.
Required - Deferral of project not recommended and will impact the schedule for multi-year programs.
Required – Deferral of project not recommended. Project required to proceed and will displace projects in future years.
Desired – Deferral of project can be accommodated and may not impact or displace projects in future years.
Optional – Deferral of project does not have material impact on system operations or asset health.

Average Age of Assets to be Replaced

Year(s) __ (1-50 years)
Greater than 50 years

Available Resources

Yes
No

Project Urgency/Timing (Non-quantitative, non-mandatory)

< 3 months
3 to 6 months
6 month to 1 year
1 year to 3 years
3 to 5 years
> 5 years

Project Complexity

Low
Medium
High

c) In addition to b) above, recall page 18 of the Manager's Summary which states:

"*The forecasted investment plan takes into consideration customer expectations and preferences, public policy responsiveness and stakeholder requirements. Enersource prioritizes projects and programs based on a set of business values, and assessments are made regarding investment proposals which have the greatest impact on the business values. Due to resource constraints (e.g., appropriate funding, labour availability, information technology support) and other considerations such as the rate impact to customers, other stakeholders and the environmental requirements, projects and programs are selected and prioritized based on supplemental quantitative and qualitative analysis.*

One of the primary goals for Enersource is to pace and prioritize capital investments in a manner that considers resource needs and rate impacts. To facilitate the achievement of this goal, Enersource reviews and analyzes programs and projects both qualitatively and quantitatively based on Enersource's Comprehensive Asset Management Policy ("CAMP").

At a high level, the long-term objective of Enersource's CAMP is to achieve an investment plan that is:

- ***Risk based**: Incorporate risk management appropriately into decision making strategy;*
- ***Sustainable**: Optimize asset life cycle value;*
- ***Multi-disciplinary**: Asset management accountability framework crosses departmental and discipline boundaries;*
- ***Integration Oriented**: View assets in their total relative value context;*
- ***Optimal**: Strike the right balance amongst competing objectives, such as short-term performance and reliability versus long-term planning and sustainability; and*

- ***Systematic:*** *Rigorously applied in a structured management system complete with a monitoring framework and evidentiary structures and tools."*

d) Please see attached spreadsheet Appendix A.

ENERSOURCE HYDRO MISSISSAUGA
CAPITAL EXPENDITURE PROJECTS
2016 BUDGET

#	Business Unit	Description	Budget	Business Case #	In Service Date	Mandatory?	SCORE Customer Focus	SCORE Operational Effectiveness	SCORE Financial Performance	TOTAL	Position
	C0504 - Substation Upgrade	Mini Orlando MS	$ 2,850,000	2016-C0504-1	2016	No	4.8	30.0	-	34.8	20
	C0504 - Substation Upgrade	Orr MS	$ 1,500,000	2016-C0504-2	2016	No	-	33.8	10.0	43.8	8
	C0504 - Substation Upgrade	Rifle Range MS	$ 2,350,000	2016-C0504-3	2016	No	-	33.8	-	33.8	21
	C0504 - Substation Upgrade	Cawthra MS	$ 800,000	2016-C0504-4	2016	No	-	33.8	-	33.8	21
	C0504 - Substation Upgrade	Webb MS	$ 2,800,000	2016-C0504-5	2017	No	-	30.0	-	30.0	23
	C0504 - Substation Upgrade	Mini Britannia - Land	$ 500,000	2016-C0504-6	2016	No	-	30.0	-	30.0	23
	C0504 - Substation Upgrade	Duke MS - Land	$ 500,000	2016-C0504-7	2016	No	-	30.0	-	30.0	23
	C0504 - Substation Upgrade	Site Enhancements	$ 300,000	2016-C0504-8	2016	No	-	40.0	-	40.0	12
	C0504 - Substation Upgrade		**$ 11,600,000**								
1	C0507 - Subtransmission Expansion	Churchill Meadows Feeder Egress (Easement) - TS to Winston Churchill	$ 450,000	2016-C0507-1A	Q4 2016	No	11.4	32.3	-	43.7	9
2	C0507 - Subtransmission Expansion	Port - Stavebank to Elizabeth	$ 300,000	2016-C0507-1B	Q4 2016						
3	C0507 - Subtransmission Expansion	Cawthra - Burnhamthorpe to Bloor	$ 900,000	2016-C0507-1C	Q4 2016						
4	C0507 - Subtransmission Expansion	Webb MS Feeder Egress - Section 1	$ 750,000	2016-C0507-1D	Q4 2016						
	C0507 - Subtransmission Expansion		**$ 2,400,000**								
1	C0576 - Auto Switches/SCADA	U/G installation of SCADA/Automation switches	$ 700,000	2016-C0576-1	2016	No	5.4	30.0	-	35.4	15
2	C0576 - Auto Switches/SCADA	O/H installation of SCADA/Automation switches	$ 780,000	2016-C0576-2	2016	No	5.4	30.0	-	35.4	15
3	C0576 - Auto Switches/SCADA	Station RTU & Protection Relay and Battery & Charger Replacements	$ 945,000	2016-C0576-3	2016	No	-	30.0	-	30.0	23
5	C0576 - Auto Switches/SCADA	RTU System Enhancements	$ 405,000	2016-C0576-4	2016	No	5.4	30.0	-	35.4	15
6	C0576 - Auto Switches/SCADA	SCADA Master Upgrade	$ 150,000	2016-C0576-5	2016	No	-	30.0	-	30.0	23
7	C0576 - Auto Switches/SCADA	WiMAX Wireless Network Project	$ 220,000	2016-C0576-6	2016	No	-	30.0	-	30.0	23
	C0576 - Auto Switches/SCADA		**$ 3,200,000**								
	SYSTEM SERVICE		**$ 17,200,000**								
1	C0505 - Subdivision Rebuild	Ellengale - Ibbetson Cres/ Shamir	$ 2,000,000	2016-C0505-1A	2016	No	28.8	48.5	5.0	82.3	2
2	C0505 - Subdivision Rebuild	Rockwood - Fieldgate/ Maple Ridge	$ 1,500,000	2016-C0505-1B	2016						
3	C0505 - Subdivision Rebuild	Clarkson - Bromsgrove/ Cramer/Sherhill	$ 1,750,000	2016-C0505-1C	2016						
4	C0505 - Subdivision Rebuild	Campobella/ Argentia	$ 1,000,000	2016-C0505-1D	2016						
5	C0505 - Subdivision Rebuild	Baldwin/ Melton	$ 1,500,000	2016-C0505-1E	2016						
6	C0505 - Subdivision Rebuild	Malton - Wrenwood/ Rockhill/ Bayswater	$ 1,500,000	2016-C0505-1F	2016						
7	C0505 - Subdivision Rebuild	Woodlands/ Wiltshire	$ 1,500,000	2016-C0505-1G	2016						
8	C0505 - Subdivision Rebuild	Autumn Harvest Section 3 - Wagondust	$ 1,500,000	2016-C0505-1H	2016						
9	C0505 - Subdivision Rebuild	Mississauga Valley Blvd feeder - North side	$ 1,000,000	2016-C0505-1I	2016						
	C0505 - Subdivision Rebuild		**$ 13,250,000**								
1	C0561 - Overhead Rebuilds	2016 Overhead Switch Replacement Program	$ 300,000	2016-C0561-1A	2016	No	27.0	48.5	10.0	85.5	1
2	C0561 - Overhead Rebuilds	2016 Insulator Replacement Program	$ 300,000	2016-C0561-1B	2016						
3	C0561 - Overhead Rebuilds	2016 Stores Small Capital Material	$ 400,000	2016-C0561-1C	2016						
4	C0561 - Overhead Rebuilds	2016 Wood Pole Installations	$ 400,000	2016-C0561-1D	2016						
5	C0561 - Overhead Rebuilds	2016 Concrete Pole Installations	$ 800,000	2016-C0561-1E	2016						
6	C0561 - Overhead Rebuilds	2016 Misc Capital (FIs, Term Poles, Animal Protection, Grounding Replacments	$ 200,000	2016-C0561-1F	2016						
7	C0561 - Overhead Rebuilds	Vermouth/Breckonridge	$ 360,000	2016-C0561-1G	2016						
8	C0561 - Overhead Rebuilds	Holburne - Section 1	$ 360,000	2016-C0561-1H	2016						
9	C0561 - Overhead Rebuilds	Meadow Wood/Country Club	$ 1,170,000	2016-C0561-1I	2016						
#	C0561 - Overhead Rebuilds	Hull/Studley	$ 720,000	2016-C0561-1J	2016						
#	C0561 - Overhead Rebuilds	Wharton Way/Berkel	$ 360,000	2016-C0561-1K	2016						
#	C0561 - Overhead Rebuilds	Credit Woodlands - Section 2	$ 720,000	2016-C0561-1L	2016						
	C0561 - Overhead Rebuilds		**$ 6,090,000**								
1	C0562 - Subtransmission Renewal	Bloor - Cawthra to Tomken	$ 600,000	2016-C0562-1A	2016	No	18.0	48.5	3.0	69.5	3
2	C0562 - Subtransmission Renewal	Lakeshore - Seneca to Cawthra	$ 690,000	2016-C0562-1B	2016						
3	C0562 - Subtransmission Renewal	Park - Hurontario to Kane	$ 960,000	2016-C0562-1C	2016						
4	C0562 - Subtransmission Renewal	Queen - Briarwood to Seneca	$ 600,000	2016-C0562-1D	2016						
5	C0562 - Subtransmission Renewal	Goreway - Derry to City Limits	$ 1,200,000	2016-C0562-1E	2016						
6	C0562 - Subtransmission Renewal	Stavebank MS - Feeder Egress	$ 150,000	2016-C0562-1F	2016						
	C0562 - Subtransmission Renewal		**$ 4,200,000**								
1	C0563 - U/G TX/Replace/Overhaul	Underground Transformer and Equipment Renewal	$ 4,125,000	2016-C0563-1	2016	Yes	14.4	20.8	-	35.2	18
	C0563 - U/G TX/Replace/Overhaul		**$ 4,125,000**								
1	C0564 - O/H TX/Replace/Overhaul	Overhead Transformer and Equipment Renewal	$ 3,000,000	2016-C0564-1	2016	Yes	14.4	28.3	-	42.7	10
	C0564 - O/H TX/Replace/Overhaul		**$ 3,000,000**								
1	C0565 - U/G Cable Replace	Pad Mounted Switchgear Replacement	$ 1,780,000	2016-C0565-1	Q4 2016	No	15.0	35.0	-	50.0	5
2	C0565 - U/G Cable Replace	Primary Distribution Equipment Replacement	$ 475,000	2016-C0565-2	Q4 2016	No	15.0	22.5	-	37.5	14
3	C0565 - U/G Cable Replace	Underground Cable and Splice Replacement	$ 1,400,000	2016-C0565-3	Q4 2016	No	12.0	33.3	-	45.3	7
4	C0565 - U/G Cable Replace	Secondary Cable Replacements	$ 95,000	2016-C0565-4	Q4 2016	No	10.2	-	-	10.2	44
	C0565 - U/G Cable Replace		**$ 3,750,000**								
1	C0567 - Emergency Replacements	Emergency Replacements	$ 320,000	2016-C0567-1	2016	Yes	14.4	20.8	-	35.2	18
	C0567 - Emergency Replacements		**$ 320,000**								
	SYSTEM RENEWAL		**$ 34,735,000**								
1	C0531 - Roads	QEW - Hurontario to Mississauga Road	$ 1,500,000	2016-C0531-1A	2016	Yes	10.2	-	3.0	13.2	40
2	C0531 - Roads	MCLAUGHLIN ROAD WIDENING - EGLINTON TO PARKWOOD	$ 600,000	2016-C0531-1B	2016						
3	C0531 - Roads	GOREWAY at CITY LIMITS (GRADE SEPARATION)	$ 300,000	2016-C0531-1C	2016						
4	C0531 - Roads	TORBRAM ROAD - Grade Separation	$ 300,000	2016-C0531-1D	2016						
5	C0531 - Roads	Various Intersections	$ 300,000	2016-C0531-1E	2016						
6	C0531C - CIAC - Roads	Customer Contributions	$ (600,000)								
	C0531 - Roads		**$ 2,400,000**								
1	C0532 - LRT	Design - Underground	$ 200,000	2016-C0532-1	2022						
2	C0532 - LRT	Design - Overhead	$ 200,000	2016-C0532-1	2022						
	C0532 - LRT		**$ 400,000**								
1	C0541 - New Subdivisions(OfferConnect)	New Subdivisions	$ 800,000	16-C0541/C0542/C0544	Q4 2016						
2	C0541C - CIAC - New Subdivisions (OTC	Customer Contributions	$ (500,000)								
	C0541 - New Subdivisions(OfferConnect)		**$ 300,000**								
1	C0542 - Ind/Comm Services	Industrial/Commercial Services	$ 2,600,000	16-C0541/C0542/C0544	Q4 2016						
2	C0542C - CIAC Ind/Comm Services	Customer Contributions	$ (1,000,000)								
	C0542 - Ind/Comm Services		**$ 1,600,000**								
1	C0544 - Residential Service Upgrades	Residential Service Upgrades	$ 125,000	16-C0541/C0542/C0544	Q4 2016						
2	C0544C - CIAC Residential Service Upgı	Customer Contributions	$ (31,250)								
	C0544 - Residential Service Upgrades		**$ 93,750**								
1	C0594 - Smart Meters Large Users	900 Large Commercial Interval Meter Replacement Project	$ 936,947	2016-C0594-1	December-01-16	Yes	-	-	10.0	10.0	45
2	C0594 - Smart Meters Large Users	Collector (Gatekeeper) Replacement/Removal	$ 568,564	2016-C0594-2	December 2016	Yes	7.2	12.0	-	19.2	34
	C0594 - Smart Meters Large Users		**$ 1,505,511**								
1	C0597 - Grid Supply Point Metering	TCP/IP GSP Conversion & Reseal	$ 163,320	2016-C0597-1	2016	Yes	1.8	-	3.0	4.8	51
2	C0597 - Grid Supply Point Metering	Tomken Upgrade	$ 1,100,000	2016-C0597-2	2016	Yes	-	-	-	-	59
	C0597 - Grid Supply Point Metering		**$ 1,263,320**								
2	C0598 - Metering	Maint and Replace Small Comm Non-Demand	$ 212,000	2016-C0598-1	Q4 2016	Yes	1.8	-	-	1.8	58
3	C0598 - Metering	New Installations Small Comm Non-Demand	$ 200,000	2016-C0598-2	2016	Yes	9.0	-	-	9.0	46
4	C0598 - Metering	New Installations Large Comm/Ind with Demand	$ 175,000	2016-C0598-2	2016						
5	C0598 - Metering	New Residential Installs - Customer Engineering	$ 170,000	2016-C0598-2	2016						
6	C0598 - Metering	Residential Maintenance	$ 165,000	2016-C0598-1	Q4 2016						
7	C0598 - Metering	PMU - Maintenance/Failure	$ 150,000	2016-C0598-3	2016	Yes	12.6	15.0	-	27.6	30
8	C0598 - Metering	PMU - New Installs	$ 100,000	2016-C0598-4	2016	Yes	9.0	-	-	9.0	46
	C0598 - Metering		**$ 1,172,000**								
1	C0899 - Smart Meters - New Condos	New IMS	$ 1,023,000	2016-C0899-1	Q2 2016	Yes	9.0	-	-	9.0	46
2	C0899 - Smart Meters - New Condos	Retrofit IMS	$ 364,000	2016-C0899-1	Q2 2016						
	C0899 - Smart Meters - New Condos		**$ 1,387,000**								
1	C0900 - Green Energy - FIT/MicroFIT	FIT & MicroFIT Projects	$ 155,000	2016-C0900-1	2016	Yes	14.4	2.3	-	16.7	37
	C0900 - Green Energy - FIT/MicroFIT		**$ 155,000**								
	SYSTEM ACCESS		**$ 10,276,581**								
1	C0581 - Engineering & Asset Systems	Hardware Refresh	$ 280,000	2016-C0585-1	2016	Yes	-	-	-	-	59
2	C0581 - Engineering & Asset Systems	InService Upgrade	$ 125,000	2016-C0581-1	Q4 2016	Yes	25.8	15.0	-	40.8	11
3	C0581 - Engineering & Asset Systems	G/Technology Upgrade	$ 70,000	2016-C0581-2	Q4 2016	Yes	15.0	13.0	-	28.0	29
4	C0581 - Engineering & Asset Systems	SmartPlant Foundation Upgrade	$ 320,000	2016-C0581-3	June, 2016	Yes	6.0	13.0	-	19.0	35
5	C0581 - Engineering & Asset Systems	Miscellaneous Engineering Software	$ 30,000	2016-C0581-4	2016	Yes	3.0	-	-	3.0	57
6	C0581 - Engineering & Asset Systems	IOM Automated Switch Planning	$ 60,000	2016-C0581-5A	2016	No	24.0	21.3	7.0	52.3	4
7	C0581 - Engineering & Asset Systems	AM/FM/GIS Subtransmission Conversion	$ 70,000	2016-C0581-6A	2016	No	24.6	-	-	24.6	31
8	C0581 - Engineering & Asset Systems	IOM Mobile Deployment - Phase 2	$ 75,000	2016-C0581-5B	2016						
9	C0581 - Engineering & Asset Systems	Transformer Load Analysis Integration to AM/FM	$ 20,000	2016-C0581-6B	2016						
#	C0581 - Engineering & Asset Systems	Major Equipment Location Tracking	$ 95,000	2016-C0581-6C	2016						
#	C0581 - Engineering & Asset Systems	Asset Inspection Enhancements	$ 65,000	2016-C0581-6D	2016						
#	C0581 - Engineering & Asset Systems	IOM Defects	$ 300,000	2016-C0581-5D	2016						
	C0581 - Engineering & Asset Systems		**$ 1,510,000**								
1	C0584 - Rolling Stock	Bucket Trucks	$ 1,190,000	2016-C0584-1	2016						
2	C0584 - Rolling Stock	Dump Trucks	$ 535,000	2016-C0584-1	2016						
3	C0584 - Rolling Stock	Pickup Trucks	$ 645,000	2016-C0584-1	2016						
4	C0584 - Rolling Stock	Trailers	$ 120,000	2016-C0584-1	2016						
5	C0584 - Rolling Stock	Vans	$ 285,000	2016-C0584-1	2016						
	C0584 - Rolling Stock		**$ 2,775,000**			**Yes**	3.6	7.5	3.0	14.1	39
1	C0585 - Computer Equip	Email Messaging System Upgrade	$ 65,000	2016-C0585-1	2016						
2	C0585 - Computer Equip	Mobile Phone platform renewal/upgrade	$ 52,000	2016-C0585-1	2016						
3	C0585 - Computer Equip	Printer Platform upgrade	$ 44,000	2016-C0585-1	2016						
4	C0585 - Computer Equip	All-In-Ones Toshiba Printers/Copiers/scanners upgrade	$ 145,000	2016-C0585-1	2016						
5	C0585 - Computer Equip	BladeCentre Chassis Mavis Datacentre upgrade	$ 45,000	2016-C0585-1	2016						
6	C0585 - Computer Equip	Microsoft Licensing True up	$ 50,000	2016-C0585-1	2016						
7	C0585 - Computer Equip	Virtual Hold for Customer Service	$ 140,000	2016-C0585-1	2016						
8	C0585 - Computer Equip	IT Assets Inventory tool	$ 80,000	2016-C0585-1	2016						
9	C0585 - Computer Equip	Additional hardware	$ 50,000	2016-C0585-1	2016						
	C0585 - Computer Equip		**$ 671,000**								
1	C0588 - ERP System	JDE Major Version Upgrade	$ 600,000	2016-C0588-1	2017	Yes	-	-	-	-	59
2	C0588 - ERP System	Flex Time Tracking Upgrade/Migration	$ 100,000	2016-C0588-1	2016						
3	C0588 - ERP System	Additional software licenses/enhancements and hardware	$ 75,000	2016-C0588-1	2016						
4	C0588 - ERP System	Microsoft Business Intelligence Phase 2	$ 200,000	2016-C0588-2	Q2 2016	No	15.0	15.0	8.0	38.0	13
5	C0588 - ERP System	Long Term Asset Planning Solution	$ 750,000	2016-C0588-3	2017	No	19.2	27.0	-	46.2	6
6	C0588 - ERP System	IBM Cognos - JDE Intergration - Operating vs Capital Tracking by Employee	$ 80,000	2016-C0588-1	2016						
7	C0588 - ERP System	Customer Service Live Chat	$ 30,000	2016-C0588-1	2016						
8	C0588 - ERP System	AP - Link - EFT	$ 50,000	2016-C0588-1	2016						
9	C0588 - ERP System	Asset Maintenance Management - Substations	$ 300,000	2016-C0581-6H	2016						
	C0588 - ERP System		**$ 2,185,000**								
1	C0589 - Meter to Cash	Oracle Web Self Service Module Phase 1	$ 400,000	2016-C0589-1	2016	No	14.4	-	-	14.4	38
2	C0589 - Meter to Cash	Monthly billing	$ 725,000	2016-C0589-2	Q4 2016	Yes	11.4	-	-	11.4	42
3	C0589 - Meter to Cash	Deposit review process	$ 50,000	2016-C0589-5A	Q4 2016	Yes	15.0	-	8.0	23.0	32
4	C0589 - Meter to Cash	IMS collections	$ 40,000	2016-C0589-5B	Q4 2016						
5	C0589 - Meter to Cash	Cash Processing and scanning equipment	$ 75,000	2016-C0589-5C	Q4 2016						
6	C0589 - Meter to Cash	Automate notice: Residential customers	$ 30,000	2016-C0589-5D	Q4 2016						
7	C0589 - Meter to Cash	PrimeRead TOU billing replacement	$ 200,000	2016-C0589-3	2016	Yes	3.0	15.0	-	18.0	36
8	C0589 - Meter to Cash	CC&B Upgrade	$ 950,000	2016-C0589-4	October-31-16	Yes	-	-	-	-	59
	C0589 - Meter to Cash		**$ 2,470,000**								
1	C0591 - Grounds & Building	Mavis Asphalt	$ 225,000	2016-C0591-1	Q3 2016	No	-	6.3	-	6.3	49
2	C0591 - Grounds & Building	Infrastructure and Security upgrades (Electrical, fire and life safety)	$ 200,000	2016-C0591-2	Q3 2016	No	1.8	14.8	5.0	21.6	33
3	C0591 - Grounds & Building	Energy conservation, waste reduction and Health & Safety programs	$ 150,000	2016-C0591-3	Q3 2016	No	1.8	7.5	3.0	12.3	41
4	C0591 - Grounds & Building	Mavis HVAC & Mechanical Upgrades	$ 100,000	2016-C0591-4	Q4 2016	No	-	3.8	-	3.8	52
5	C0591 - Grounds & Building	Building Automation System	$ 200,000	2016-C0591-5	Q4 2016	No	-	-	-	-	59
6	C0591 - Grounds & Building	Mavis Building Envelope	$ 500,000	2016-C0591-6	Q4 2016	No	-	3.8	-	3.8	52
7	C0591 - Grounds & Building	Derry HVAC Upgrades	$ 500,000	2016-C0591-7	Q4 2016	No	-	-	-	-	59
8	C0591 - Grounds & Building	Mavis Building Reno to Middle Tower Main Floor	$ 225,000	2016-C0591-8	Q4 2016	No	-	3.8	-	3.8	52
9	C0591 - Grounds & Building	Mavis Warehouse Wall, Walkway and Trades Training Centre	$ 300,000	2016-C0591-9	Q4 2016	No	-	3.8	-	3.8	52
#	C0591 - Grounds & Building	Mavis Warehouse Offices and Washroom	$ 300,000	2016-C0591-10	Q4 2016	No	-	3.8	-	3.8	52
#	C0591 - Grounds & Building	Computer Room Halon Conversion	$ 285,000	2016-C0591-11	Q2 2016	No	7.2	3.8	-	11.0	43
	C0591 - Grounds & Building		**$ 2,985,000**								
1	C0595 - Major Tools Constr	Major Tools	$ 200,000	2016-C0595-1	2016	No	-	6.3	-	6.3	49
	C0595 - Major Tools Constr		**$ 200,000**								
	GENERAL PLANT		**$ 12,796,000**								
	NET CAPITAL EXPENDITURES (EXCLUDING HYDRO ONE TS PAYMENTS)		**$ 75,007,581**								

ENERSOURCE HYDRO MISSISSAUGA
CAPITAL EXPENDITURE PROJECTS
2016 BUDGET

Business Unit	Description	Budget	Business Case #	In Service Date
Hydro One TS Payments		$ 41,656,000		
NET CAPITAL EXPENDITURES BEFORE ADJUSTMENTS		**$ 116,663,581**		
Add: AFUDC - Allowance for Funds Used During Construction		$ 483,000		
Less: Recovery through Variance Account 1557 - Smart Meters Large Users		$ (1,505,511)		
NET CAPITAL EXPENDITURES		**$ 115,641,070**		
Less: Capex Materiality Threshold		$ (44,104,679)		
INCREMENTAL CAPITAL MODULE REQUEST AMOUNT		**$ 71,536,391**		

Regulatory / Public Policy Responsiveness			Customer Focus			Operational Effectiveness					Financial Performance		
Mandatory?	Category	Can it be deferred?	Service Quality	Customer Satisfaction	Reputational Risk	Safety (Customer & Employee)	Environmental Impact/risk	System Reliability	System Expansion	System Renewal	Cost Efficiencies	One-Time Costs	Ongoing Costs

RANKINGS										
Customer Focus			Operational Effectiveness					Financial Performance		
rvice Qual	mer Satisf	utational	stomer &	mental Imp	tem Reliab	tem Expan	tem Renev	st Efficienc	e-Time Co	ngoing Cos

30%			50%					20%
20%	60%	20%	25%	15%	60%			50%
Customer Focus			Operational Effectiveness					cial Perforr
rvice Qual	mer Satisf	utational	stomer &	mental Imp	tem Reliab	tem Expan	tem Renev	ncies & On

SCORE				
Customer Focus	Operational Effectiveness	Financial Performance	TOTAL	Position

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 12:

Ref 1: Supplementary Evidence, pg.6
Ref 2: Supplementary Evidence – 2016 Capital Expenditure Projects Budget

In the first reference, Enersource states that "if these costs are not recovered in rates, Enersource will have to reconsider its future approach to maintaining its high reliability".

Should Enersource's request for an additional $29.9M in capital expenditures (ICM request of $71.5M – CCRA true-up of $41.6M) to be included in the ICM rate rider not be approved, which specific projects from the list provided in the Supplementary Evidence - 2016 Capital Expenditure Projects Budget would Enersource not complete or delay and what would be the impact on Enersource's reliability?

Response:

Enersource would make very little, if any, change to its 2016 capital budget, but would re-evaluate capital spending plans for 2017 and subsequent years, in the context of the OEB's denial of this incremental capital funding request. Although not all capital spending is related to reliability (i.e., environmental risks, such as removing PCB-containing and/or leaking transformers; safety risks, such as removing a pole line that has deteriorated and requires replacement – see 2-Staff-11 for more details on prioritizing projects), re-evaluation would include consultation with shareholders and customers to consider how decreasing reliability would be tolerated.

Failure to receive OEB approval of requested capital funding will affect Enersource's future reliability, which has been decreasing over the past two years. It is very difficult to predict quantitatively the effects on Enersource's system reliability metrics (i.e., SAIDI and SAIFI) from deferring or cancelling individual projects. Qualitatively however, failure to invest in these capital projects will increase the frequency and duration of customer service interruptions in specific vulnerable areas of Mississauga, which will be measurable after the fact. By not re-investing in the system in priority areas, SAIDI and SAIFI metrics will continue to deteriorate.

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 13:

Ref 1: Supplementary Evidence Capital Planning Overview 2016-2021 pg.7
Ref 2: Capital Expenditure Projects 2016 Budget

Please complete the following table:

$000	Actual			Forecast						
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
SS	9,860	10,712	11,228	16,267	17,200					
SR	16,225	20,887	31,257	35,204	34,735					
SA net	10,245	4.111	5,336	8,978	10,277					
GP	7,006	6,831	6,231	10,585	12,796					
Total	43,336	42,541	54,051	71,034	75,008					
AFUDC					483					
1557					-1,506					
Total	43,336	42,541	54,051	71,034	73,985					

Response:

Below is the completed table, Net Capital Spend 2012 to 2021.

Net Capital Spend 2012 to 2021

	Actual			Forecast							
	2012	2013	2014	2015 - Initial	2015 - Current	2016	2017	2018	2019	2020	2021
System Service	$9,860	$8,167	$10,951	$16,206	$16,584	$17,200	$13,015	$13,130	$12,825	$13,105	$13,490
System Renewal	$16,224	$20,854	$31,244	$35,204	$36,059	$34,735	$37,243	$38,240	$40,280	$38,570	$38,490
System Access	$10,245	$6,690	$5,626	$9,039	$10,710	$10,277	$12,785	$12,992	$13,031	$12,106	$8,236
General Plant	$7,006	$6,831	$6,230	$10,585	$10,682	$12,796	$11,337	$10,281	$10,794	$10,755	$9,984
Total	$43,336	$42,541	$54,051	$71,034	$74,034	$75,008	$74,379	$74,642	$76,930	$74,536	$70,201
Borrowing Costs	$683	$379	$348	$483	$483	$483	$486	$486	$486	$486	$486
1557 - Meter Cost Deferrals	-	-	-	-	-	($1,506)	-	-	-	-	-
TOTAL	$44,019	$42,920	$54,398	$71,516	$74,517	$73,985	$74,865	$75,128	$77,416	$75,022	$70,687

NOTES:

- 2015 Forecast - OEB used Gross figure for System Service; however, there was a customer contribution in 2015. They put all contributions to System Access so the total is in balance.
- Excludes Hydro One contribution payment for Churchill Meadows TS.

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 14:

Supp - Ref 1: Supplementary Evidence Business Cases for Projects included in the ICM

Based on the information provided in each project's business case the following table was prepared by OEB staff. Based on this information, Enersource has $47,211,000 ($46,260,000+$951,000) of capital work that can be deferred until after 2016.

a) Please explain why Enersource is not able to defer sufficient projects such that it does not require an ICM for an additional $29.9M in capital expenditures?

Project #	Mandatory?	Defer?	Total	Cat	Project
C0581 1-4	Yes	No	$ 545,000	GP	Engineering and Asset Systems
C0581 5-6	No	N/A	$ 985,000	GP	Engineering and Asset Systems
C0584	Yes	No	$ 2,775,000	GP	Rolling Stock
C0585	Yes	Yes	$ 951,000	GP	Desktops-Laptops Platform upgrade
C0588 1	Yes	N/A	$ 935,000	GP	System Upgrades JDE, Flex Time Tracking
C0588 2-3	No	N/A	$ 950,000	GP	JDE ERR System
C0589 2-5	Yes	No	$ 2,070,000	GP	Monthly Billing
C0589 1	No	N/A	$ 400,000	GP	Customer Web Self service
C0591	No	N/A	$ 2,985,000	GP	Mavis Rd Grounds and Buildings
C0595	No	N/A	$ 200,000	GP	Major Tools
C0531	Yes	No	$ 2,400,000	SA	Road Projects
C0532			$ 400,000	SA	LRT
C0541	Yes	No	$ 1,993,750	SA	Services
C0594	Yes	No	$ 1,505,511	SA	Smart Meters Large Users recovered through 1557
C0597	Yes	No	$ 1,263,320	SA	Wholesale Meter Upgrades
C0598	Yes	No	$ 1,172,000	SA	Metering
C0899	Yes	No	$ 1,387,000	SA	Smart Meters in Condos
C0900	Yes	No	$ 155,000	SA	MicroFIT
C0505	No	N/A	$ 13,250,000	SR	Subdivision Rebuild
C0561	No	N/A	$ 6,090,000	SR	Overhead Rebuilds
C0562	No	N/A	$ 4,200,000	SR	Subtransmission Renewal
C0563	Yes	No	$ 4,125,000	SR	U/G Transformer Replacement
C0564	Yes	No	$ 3,000,000	SR	O/H Transformer Replacement
C0565	No	No	$ 3,750,000	SR	Padmounted Switchgear
C0567			$ 320,000	SR	Emergency Replacements
C0504	No	N/A	$ 11,600,000	SS	Substation Upgrades
C0507	No	N/A	$ 2,400,000	SS	Subtransmission Expansion
C0576	No	N/A	$ 3,200,000	SS	Auto Switches/SCADA
TOTAL			$ 75,007,581		
Mandatory and cannot be deferred			$ 24,046,581		
Not Mandatory and can be deferred			$ 46,260,000		
Mandatory but can be deferred			$ 951,000		
Not Mandatory but cannot be deferred			$ 3,750,000		

Response:

The business cases provided are a work-in-progress toward formalizing the experience and knowledge that Enersource uses every day based on decades of on-the-ground operations. The business case template is a tool being adopted to facilitate thoughtful and more particular choices on the path to system renewal. In addition to the template's definition of a "Mandatory" project, other considerations used to determine priority are financial funding, cash flow, and labour limitations.

Please see 2-Staff-11 for Enersource's definition of Regulatory Mandatory (included in the $24,047 + $951, as calculated by Board Staff) and a description of Enersource's prioritization method.

Although a project may not be considered Regulatory Mandatory based on its prioritization method, it may rate highly in categories also important to the business such as customer satisfaction, safety, reliability, and balance between cost efficiencies and ongoing costs. The non-mandatory projects identified (part of the $46,260 + $3,750 as calculated by Board Staff) were determined to be of significant influence to Enersource's operations.

Responses to Ontario Energy Board Staff Interrogatories

INTERROGATORY 15:

Ref 1: Supplementary ICM Evidence Summary pg. 7
Ref 2: Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5 – Consolidated Distribution System Plan Filing Requirements, March 28, 2013, Section 5.1.3

The first reference above refers to Enersource's Distribution System Plan (DSP) and states that a draft copy could be provided with the caveat that it will be updated as customer input is received. The second reference states "The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications." Please file a copy of Enersource's draft DSP, with the understanding that it will be updated subject to customer input.

Response:

Please find attached Enersource's draft Distribution System Plan for the years 2016 to 2021.

Consultation with customers is continuing, currently via a 'video dialogue', accompanied by an online survey at www.enersource.com/survey.

Enersource Hydro Mississauga Inc.

Distribution System Plan

2015

Executive Summary

In 2013, Enersource Hydro Mississauga Inc. (Enersource or the Company) established an Asset Management Division (AMD) responsible for the development of the Distribution System Plan (DSP) and Long Term Investment Portfolio (LTIP). The division's first priority was to create a Comprehensive Asset Management Policy (CAMP), stating that Enersource will adopt practices to optimize the performance and lifecycle costs of all of its assets in a safe, reliable, and sustainable manner. The Company's policy for the stewardship and management of these assets is to strike the best possible balance among risk, performance, and costs in a sustainable fashion that maximizes enterprise value while complying with all health, safety, environmental, and regulatory requirements. The objective of the DSP is to ensure the alignment of the LTIP with the CAMP when determining investments in electricity infrastructure, equipment, and general plant.

The DSP and LTIP support Enersource's strategy of adopting a complete lifecycle approach for all asset investments from the initial risk identification, preparation, design, acquisition, operation and maintenance to the decommissioning and removal or disposal of assets. To comply with Enersource's CAMP, the Company will maintain regulatory compliance, monitor risk during the lifecycle of an asset, and establish and maintain a conformance and quality framework to allow for continuous improvement.

Enersource embraces innovation and progressively implements best practices. The Company is committed to fostering a work environment that is committed to the asset management systems and complete lifecycle strategy.

The DSP also describes Enersource's service territory and gives a high level description of the subtransmission and distribution systems. This provides context of the topographical outline before assessing system performance and reliability history.

Where applicable, in the cases of System Service and System Access, Enersource considers Conservation and Demand Management (CDM) programs prior to engaging in any major capital investments (as exemplified in the Downtown Core expansion).

The DSP and LTIP are based on several inputs including, but not limited to, Asset Condition Assessment (ACA), system capacity/load forecast, asset information extracted from testing and inspection reports, information from the Integrated Operating Model (IOM), the Automated Mapping/Facilities Management (AM/FM), as well as Enersource's JD Edwards/Enterprise Resource Planning (JDE), and Customer Care and Billing (CC&B) systems.

Enersource's historical high standard of maintenance and sustainment practices have resulted in most of the distribution system assets being in an acceptable operational state. However, over the course of time and standard use, a large number of assets are expected to require replacement at increasing rates over the near and mid-term, especially transformers and underground cables. This is evidenced by a large number of distribution assets, installed during times of rapid growth in Mississauga, that are soon expected to approach the end of their useful life. This DSP outlines the tactics and activities that

Enersource will undertake in order to address such issues through proactive planning, risk evaluation, and the continuation of existing programs and projects.

The approach applied in the development of the DSP and LTIP is founded on key factors including system planning, prioritization, and the execution of capital projects in a sustainable manner. The objective of these activities is to select the projects and programs that deliver the required functions at the desired level of service and financial performance. These projects and programs have been summarized according to the Ontario Energy Board's (OEB) investment categories that include requirements for System Access, System Renewal, System Service, and General Plant.

System Access investments are modifications (including asset relocation) to a distribution system that a distributor must perform in order to provide customers (including generator customers) with access to electricity services via the distribution system.

System Renewal investments involve replacing and/or refurbishing system assets to extend their original service life and thereby maintain the ability of the distribution system to provide customers with electricity services.

System Service investments ensure the distribution system continues to meet distributor objectives while addressing anticipated future customer electricity service requirements.

Finally, General Plant investments are modifications, replacements, or additions to a distributor's assets that are not part of its distribution system, including land and buildings, tools and equipment, rolling stock, and electronic devices and software used to support day to day business and operations activities.

Enersource evaluates its capital investments, and creates its DSP and LTIP, based on the following business values from the OEB's Renewed Regulatory Framework for Electricity (RRFE):

- Regulatory/Public Policy Responsiveness: the ability to meet obligations mandated by government;
- Operational Effectiveness: the ability to continuously improve productivity and cost performance while delivering on system reliability and quality objectives;
- Customer Focus: services are provided in a manner reflective of identified customer preferences; and
- Financial Performance: financial viability is maintained and operational effectiveness savings are sustainable.

Based on the business value evaluations and numerous identified inputs, program and project business cases are developed under each investment category, which are then used to establish the near to medium term capital expenditure forecasts contained within this DSP. Overall, the DSP recommendations are consistent with previous Enersource investment activities and outline a continuation of programs and System Renewal projects. To address the impending increase in assets that are expected to reach end-of-life in the near and medium terms, this plan also identifies several initiatives under development and consideration that will allow Enersource to continually improve its asset management practices.

To ensure Enersource's DSP considers customer preferences, pursuant to the OEB's RRFE, Enersource has engaged Decision Partners Inc., a third party consultant, to conduct broad, professional, and scientific research on customers' behaviour regarding the DSP. This work is now underway. The customer input will be considered in the final version of the DSP to ensure that distribution services are provided in a manner responsive to customer preferences.

Overall, Enersource plans to significantly increase its System Renewal projects over this DSP's timeframe. The Company has met with potential third-party contractors that are committed to increasing their workforces over the next few years in order to meet Enersource's forecasted renewal project increases. The increase in investment is required due to the age and condition of a significant portion of Enersource's overhead and underground system assets, and to ensure the Company's distribution system continues to remain safe and reliable. Enersource has also seen a significant increase in operating and maintenance costs in recent years and is committed to reversing this trend.

After considering the System Renewal investment increases and what is required for System Service (two new substations for the Downtown Core, one additional substation to meet the 27.6kV electricity demand forecast), and System Access updates to support Light Rail Transit, Enersource reviewed its General Plant investment proposals and re-prioritized many planned activities over the entire DSP period. By more smoothly pacing General Plant investments over the DSP time frame, Enersource was able to maintain a relatively stable year-to-year investment portfolio that ensured sufficient funds would be available, labour resources would not be overly committed, and customer rates would be kept reasonable.

The chart below in **Figure 1** shows Enersource's actual and proposed capital investment portfolio expenditures between 2011-2021:

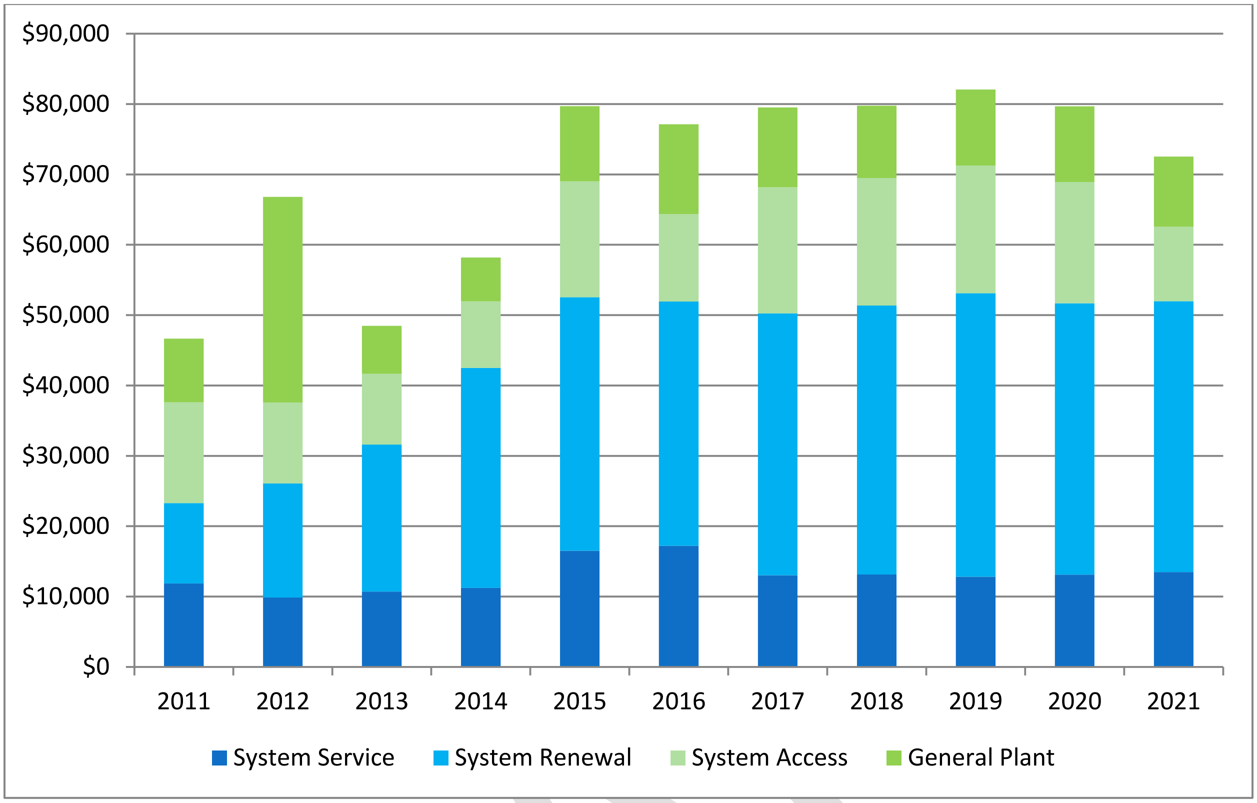

Figure 1. Enersource's actual and proposed capital investment portfolio expenditures (2011-2021)

How the DSP is Organized

The DSP has been divided into three main sections. The first section provides stakeholders with an overview of the information filed in the plan including, but not limited to, key elements that affect the rates, the sources of cost savings, information on coordinated planning with third parties, and performance measurements for continuous improvement. The second section provides an overview of information pertaining to Enersource's asset management processes and the direct links between the asset management system and the proposed capital expenditures outlined in the DSP. The final section explains Enersource's capital investments resulting from the asset management planning processes and the capacity of the distribution system to connect new electricity demand and embedded generation customers.

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Glossary

Acronym	Meaning
ACA	Asset Condition Assessment
AIC	Asset Investment Council
AMD	Asset Management Division
AM/FM	Automated Mapping/Facilities Management
AMI	Advanced Metering Infrastructure
AMRC	Advanced Metering Regional Collectors
AOD	Asset Operations Division
BCM	Business Continuity Management
BRT	Bus Rapid Transit
CAIDI	Customer Average Interruption Duration Index
CAMP	Comprehensive Asset Management Policy
CC&B	Customer Care and Billing
CCTV	Closed-Circuit Television
CDM	Conservation and Demand Management
CEA	Canadian Electricity Association
CEATI	Centre for Energy Advancement through Technological Innovation
CIA	Connection Impact Assessment
COS	Cost of Service
CRM	Customer Relationship Management
CSA	Canadian Standards Association
DEG	Distributed Energy Generation
DESN	Dual Element Spot Network
DGA	Dissolved Gas Analysis
DSC	Distribution System Code
DSP	Distribution System Plan
EAC	Executive Advisory Committee
E&AS	Engineering and Asset Systems
EBT	Electronic Business Transactions
E&GIA	Electricity and Gas Inspection Act
EPAC	Electric Power Accessories Corporation
EPSRA	Electric Power System Reliability Assessment
ERP	Enterprise Resource Planning
ESA	Electrical Safety Authority
ESQR	Electrical Service Quality Requirements
FCI	Fault Current Indicator
FIT	Feed-In-Tariff
GE	General Electric
GEA	Green Energy Act
GIS	Geographic Information System
GPS	Global Positioning System
GTA	Greater Toronto Area
GTAA	Greater Toronto Airports Authority
HONI	Hydro One Networks Inc.

HV	High Voltage
HVAC	Heating, Ventilation and Air Conditioning
ICM	Incremental Capital Module
IEEE	Institute of Electrical and Electronics Engineers
IESO	The Independent Electricity System Operator
IMS	Individual Metered Suite
IOM	Integrated Operating Model
IR	Infrared
IRRP	Integrated Regional Resource Planning
IT	Information Technology
JDE	JD Edwards (Enterprise Resource Planning)
KPI	Key Performance Indicator
LDC	Local Distribution Company
LRT	Light Rail Transit
LTIP	Long Term Investment Portfolio
LTR	Limited Time Rating
LV	Low Voltage
MC	Measurement Canada
MDM/R	Meter Data Management and Repository
MED	Major Event Date
MIST	Metered Inside System Timeframe
MPLS	Multiprotocol Label Switching
MS	Municipal Substation
MSP	Metering Service Provider
MTO	Ministry of Transportation of Ontario
MWM	Mobile Workforce Management
OEB	Ontario Energy Board
OH (or O/H)	Overhead
OM&A	Operating, Maintenance and Administration
OMS	Outage Management System
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PCB	Polychlorinated Biphenyl
PDSB	Peel District School Board
PUCC	Public Utility Coordinating Committee
PVC	Polyvinyl Chloride
QA	Quality Assurance
QC	Quality Control
RESOP	Renewable Energy Standard Offer Program
RIP	Regional Infrastructure Planning Processes
RRFE	Renewed Regulatory Framework for Electricity
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCC	Service Continuity Committee

SD	Solid Dielectric
SPF	SmartPlant Foundation
TCP/IP	Transmission Control Protocol/Internet Protocol
TS	Transformer Station
TSC	Transmission System Code
UG	Underground
XLPE	Cross-Linked Polyethylene

1. Distribution System Plan (OEB Chapter 5.2)

On March 28, 2013, the OEB issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, which outline the OEB's expectations regarding a distributor's asset management processes and long term capital expenditure plans. Enersource has prepared this DSP and organized the required information using the section headings in accordance with the OEB's Chapter 5 Filing Requirements.

The DSP outlines an integrative approach to the cost-effective planning and operation of Enersource's electricity distribution system to ensure the network is managed in an efficient, reliable, and sustainable manner and provides value to its customers. Operating and maintaining an electricity distribution system requires a significant amount of investments and Enersource is committed to undertaking prudent capital projects and maintenance plans in order to ensure customers receive value in the most cost efficient and effective manner.

The DSP is divided into three sections:

Section 1- Distribution System Plan

The Distribution System Plan section provides a brief description of the information filed in the DSP including, but not limited to, key elements that affect the rates, the sources of cost savings, information on coordinated planning with third parties, and performance measurements for continuous improvement.

Section 2 - Asset Management Process

The Asset Management Process section provides an overview of the information filed on Enersource's asset management processes and the direct links between the asset management system and the proposed capital expenditures outlined within this DSP.

Section 3 - Capital Investment Plan

The Capital Investment Plan section outlines Enersource's capital investments derived from the asset management processes as described in Section 2. In addition, detailed information on the Company's capital expenditure planning process and the capacity of the distribution system to connect new load and embedded generation has been included in Section 3.

1.1 Distribution System Plan Overview (OEB Chapter 5.2.1)

The purpose of the DSP is to consolidate Enersource's practices as they relate to the planning and execution of capital investments associated to System Access, System Renewal, System Service, and General Plant through its asset management process. The DSP outlines capital expenditures for the forecast years (2016-2021) and other internally driven activities, while considering information received from customer engagement initiatives.

Enersource is committed to continuously enhancing its asset management system and processes, and has made several improvements since its last cost of service (COS) application. In 2013, Enersource created a new Asset Management Division (AMD) to oversee Asset Planning and Analysis. The new division is responsible for assessing the health of Enersource's distribution assets, overseeing the asset management process, outlining the need for capital asset replacements, and ensuring inspections and maintenance are performed to optimize the asset life cycles.

1.1.1 Key Elements of the DSP

The objective of the DSP is to make recommendations for the addition, replacement, disposal, and maintenance of Enersource's assets in an efficient manner that realizes value and achieves the Company's performance outcomes. The goal of the DSP is to outline how Enersource effectively manages its assets on a life-cycle basis, with investment plans that are prioritized and aligned with the CAMP.

The DSP supports Enersource's performance objective outcomes with regard to the planning, prioritization, and execution of programs and projects which are identified and classified into the following OEB requirement categories:

System Access Investments - modifications (including asset relocation) to Enersource's distribution system that the Company is obligated to perform to provide customers (including generator customers) with access to electricity services via the distribution system.

System Renewal Investments - involve replacing and/or refurbishing system assets to extend their original service life and thereby maintain the ability of Enersource's distribution system to provide customers with electricity services.

System Service Investments - modifications to Enersource's distribution system to ensure it continues to meet the Company's objectives while addressing anticipated future customer electricity service requirements.

General Plant Investments - modifications, replacements or additions to Enersource's assets that are not part of its distribution system, including land and buildings; tools and equipment; rolling stock and electronics devices and software used to support day to day business and operations activities.

Table 1 below summarizes the proposed investments required to ensure Enersource is able to provide a safe, secure, and reliable supply of electricity, meet system load growth demands and complete all regulatory driven initiatives.

Table 1. Total Capital Expenditures over the DSP Period

Description	2016	2017	2018	2019	2020	2021
System Service	17,200	13,015	13,130	12,825	13,105	13,490
System Renewal	34,735	37,243	38,240	40,280	38,570	38,490
System Access	12,408	17,916	18,123	18,162	17,238	10,568
General Plant	12,796	11,337	10,281	10,794	10,755	9,984
Total	**77,139**	**79,511**	**79,773**	**82,061**	**79,668**	**72,532**

1.1.2 Sources of Cost Savings

The DSP outlines Enersource's prioritization and optimization of distribution system expenditures. As outlined in Section 2 Asset Management Processes, Enersource aims to smoothly pace capital investments while minimizing the risks associated with reliability, safety, customer impact, environment, and providing value to stakeholders. As shown in Section 3 Capital Expenditure Plan, business cases are created for each investment to evaluate project alternatives that provide the greatest business value and minimize risk in a cost effective manner. Capital expenditures are prioritized in order to minimize overall risk to Enersource's business values while ensuring a balanced level of spending and efficient use of limited resources.

Enersource is focused on improving productivity and developing efficiencies as sources of cost savings in both capital and OM&A programs. For example, asset lifecycle optimization and an increased level of asset management planning would result in real (both capital and OM&A) savings. The following list outlines key areas of cost savings on which Enersource is focusing:

Operational Productivity

Enersource strives to create a culture of ongoing improvement. Whether through process improvement or by leveraging new technology, the Company continues to explore new ways to effectively provide the best value to customers. The following is a list of current initiatives:

Balanced Scorecard – Implementation of a wide range of Key Performance Indicators (KPIs) across all divisions and departments to measure and monitor productivity across the Company.

Third Party Coordination - Planning and coordination of work with third parties provides for potential cost savings.

4kV to 13.8kV & 27.6kV Conversion Program – Implementation of projects that replace distribution assets that are beyond end-of-life for specified areas. Enersource also works to proactively eliminate the need to invest in more expensive substation-class assets and equipment by better utilizing available capacity at higher standard voltages of 13.8kV and 27.6kV systems. In 2007 and 2010, Enersource upgraded a portion of its distribution system in the Streetsville area from 4kV to 13.8kV, thereby allowing the Company to decommission two substations: Alpha Mills Municipal Substation (MS) and Ontario MS. Similar conversion from 4kV to 27.6kV is expected in the future in the south end of Mississauga that will require replacement of distribution assets to allow for greater connection capacity. The eventual decommissioning of 4kV substations will provide operational costs savings in the following areas:

- Reduced labour and expenditures required to maintain the electrical assets within the substations;
- Reduced labour and expenditures related to the cleaning, maintenance, security monitoring and regular inspections of the substations;
- Elimination of potential environmental risks from transformer oil spills associated with a failure of a substation power transformer; and
- Reduced expenditures for utilities and taxes upon disposal of the substation properties.

Planning Effectiveness

Through an ever-improving inspection, testing and maintenance planning and project prioritization process, Enersource has developed a plan that paces spending while meeting the service requirements of the distribution system and General Plant assets. Two evolving programs aimed at helping the Company achieve this goal are:

- Detailed inspection programs which provide valuable insight into the condition of switchgear units (in the field) that are critical components of Enersource's distribution system. As a result, Enersource is able to develop a more effective maintenance program (e.g., dry-ice cleaning) to target switchgear units that are likely to cause an outage. This ensures outages are minimized, thereby reducing time spent on troubleshooting and switching. Similar inspection programs have been developed for poles and transformers, with a plan to roll existing substation inspection methodologies into the process; and

- Enersource has implemented a pilot project with Microsoft to develop a business intelligence solution that consolidates data from Integrated Operating Model (IOM), the Automated Mapping/Facilities Management (AM/FM), JD Edwards/Enterprise Resource Planning (JDE) and Customer Care and Billing (CC&B) systems. This will allow Enersource to complete better long term planning and asset investment while having detailed and accurate information on various asset data including loading, asset record information, customer information, and asset value, etc.

Increased Use of New Technology

When replacing assets at the end-of-life or evaluating projects to improve reliability, Enersource incorporates new technologies where feasible. This includes:

- Replacing end-of-life switches with smart, Supervisory Control and Data Acquisition (SCADA) controlled switches capable of remote operation, thus reducing crew and truck time previously required for switching and power restoration;

- By third quarter 2015, Enersource is expected to complete the pole numbering project that will see each pole tagged and numbered with a barcode in order to improve asset management and inspection capabilities. Major benefits include:

    - Recording of all assets attached to the poles, and their condition, including photographs
    - GPS locations to save line crew driving and preparation time
    - Improved tracking of inspections and conditions of poles;

- Installing fault current indicators (FCIs) based on historical reliability information and evaluation of single line diagrams for ideal installation locations. Enersource has partnered with Siemens, BlackBerry, Mohawk College and McMaster University to implement WiMAX. This technology will allow Control Room operators to determine the location of the fault, thus hastening switching and restoration time by reducing time spent on finding the fault;

- Installing various types of equipment such as cut-out cover ups, bolt covering discs and fibreglass cut-out brackets to reduce outages caused by animal contact; and

- Enersource is in the process of implementing the Mobile Workforce Management (MWM) tool for operational crews, trouble trucks and metering field staff. The purpose of MWM is to address three core requirements: centralized dispatching, electronic processing of timesheets, and electronic tracking of work progress. MWM tools will enable the following:

    - Increase in daily job completion rates
    - Decrease kilometers driven and reduce fuel consumption
    - Reduce overtime
    - Reduce administrative load of field service teams
    - Eliminate paper-based timesheets and improve accuracy
    - Improve customer satisfaction
    - Provide better tracking and reporting of work completed.

Centre for Energy Advancement through Technological Innovation (CEATI)

CEATI is committed to providing technology solutions to its electrical utility participants to advance the industry through the sharing and development of practical and applicable knowledge. These innovations address issues pertinent to day-to-day operations, planning and management of distribution assets.

In addition to enabling information sharing through interest groups and industry conferences, CEATI brings participants together to collaborate on technical projects. The outcome of these projects may have a significant impact on the infrastructure that Enersource plans to use in the future. In 2015, Enersource joined over 120 organizations including electricity and gas utilities, governmental agencies and provincial and state research bodies such as Hydro One Networks Inc. (HONI), PowerStream, Hydro Ottawa, Toronto Hydro-Electric System Limited, National Research Council, Ontario Power Generation, and the Ontario Power Authority (now the Independent Electricity System Operator or IESO).

1.1.3 DSP Period

This DSP covers the 2012 to 2015 historical years, the 2016 Bridge Year, and the 2017 to 2021 Test Years.

1.1.4 Currency of Information

All asset information, including inspection, maintenance and operating data provided to Kinectrics for the ACA is current as of December 31, 2014. Reliability metrics and analysis presented in this DSP include all outage information up to December 31, 2014.

1.1.5 Updates from Previous Filing

Enersource has not previously filed a DSP. Since the most recent cost of service (COS) submission April 27, 2012, the Company has filed an Incremental Capital Module (ICM).

1.1.6 Aspects of the DSP Contingent on Future Events

The execution of distribution system capital investment programs often involves co-ordination with external organizations. Enersource has identified several projects that are dependent on external factors for scope and timing. These projects include:

- Municipal Road Relocation / Upgrade Projects
  System Access investments required to facilitate road relocation projects may be dependent upon the City of Mississauga;

- Regional Road Relocation / Upgrade Projects
  System Access investments required to facilitate road relocation projects may be dependent upon the Region of Peel;

- Ministry of Transportation Road Relocation Projects
  System Access investments required to facilitate road relocation projects may be dependent upon the Ministry of Transportation;

- Regional Planning Projects
  Enersource is participating in two Regional Infrastructure Planning Processes (RIP) with HONI. The Company continues to participate in and support both the Integrated Regional Resource Planning (IRRP) and the RIP processes and will make the required investments into projects arising from the plans as identified; and

- Customer Connections
  System Access investments toward the expansion of Enersource's distribution system may be required; the timing of which is dependent on the location and service requirements of new customers, which are outside the Company's control.

1.2 Coordinated Planning with Third Parties (OEB Chapter 5.2.2)

1.2.1 Regional Planning

On May 17, 2013 the OEB provided notice of proposed amendments to the Transmission System Code (TSC) and the Distribution System Code (DSC). The proposed amendments outlined how to implement the Board's policies set out in its October 18, 2012 Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (RRFE Board Report). The changes included the framework for a more structured approach to regional infrastructure planning among distributors, HONI and the IESO.

On November 14 and December 3, 2013, HONI launched regional planning efforts with Regional Infrastructure Planning Needs Screening conference calls for two planning regions in which Enersource participates, namely GTA West Southern Sub-Region and GTA North Western Sub-Region. The objective of this is to develop long-term electricity plans that integrate all relevant options such as: CDM, distributed generation, large-scale generation, transmission, and distribution.

Enersource is serviced via 11 transformer stations owned by HONI. Four transformer stations are shared among several utilities, including Hydro One Brampton, Toronto Hydro and Oakville Hydro. **Figure 2** illustrates Enersource's Service Area and the location of HONI transformer stations servicing Enersource territory and municipal substations.

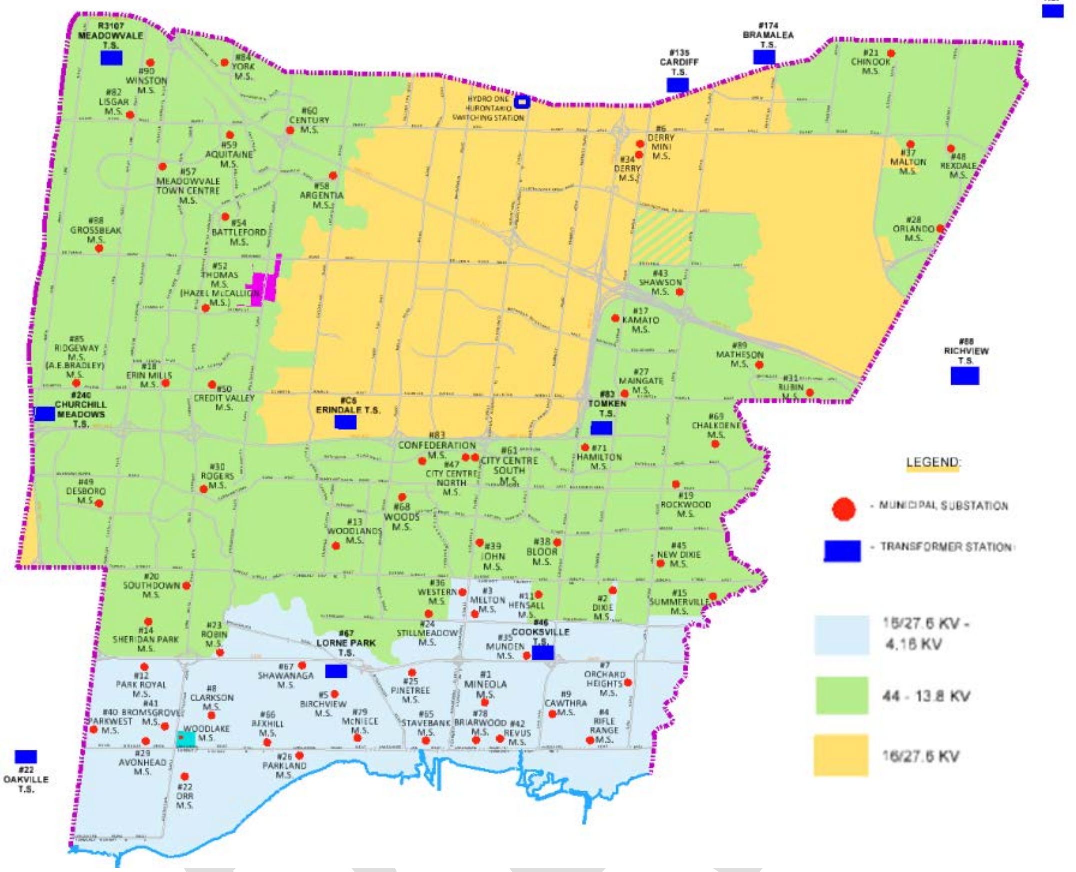


Figure 2. Enersource's Service Area

Enersource has provided HONI with a Long Term Load Forecast report within prescribed timelines outlined in the RIP and IRRP processes.

HONI, in collaboration with the study team that included Enersource and other neighbouring utilities, completed the Needs Screening and issued the Final Needs Screening Report for GTA West Southern Sub-Region and GTA North Western Sub-Region on May 30 and June 27, 2014, respectively.

In the Needs Screening Report for GTA West Southern Sub-Region, the study team recommended that further coordinated regional planning will be required to assess the needs identified in the report, namely the Erindale Transformer Stations (TS) T1/T2 27.6kV system which is forecasted to reach normal supply capacity within the next 10 years. It was further recommended that the IESO initiate a Scoping Assessment for this Sub-Region. On September 1, 2014, the IESO completed the Scoping Assessment highlighting two major categories of needs:

Capacity

Erindale TS T1/T2 is forecasted to be overloaded above the 10-day Limited Time Rating (LTR) during summer peak. It was also concluded that the capacity needs for Erindale TS T1/T2 should be addressed through available transformation capacity existing adjacent to the limiting assets. Enersource and HONI are currently planning the necessary infrastructure investments for this project, which will be further discussed in this DSP. Also included in this DSP is the investment for securing land and installing a substation comprised of two step-down transformers rated 44/27.6kV, as outlined in Section 3.5. The load will be supplied from HONI's Churchill Meadows TS.

Load Restoration

Load restoration needs along the Richview-Trafalgar corridor and west of the Cooksville area were also identified. The current radial transmission supply configuration from Richview and Manby Transformer Stations does not provide operational flexibility. This has considerably impacted the supply of power to the region, specifically the southern part of Mississauga and Oakville. In fact, a large storm on July 8, 2013 highlighted this major risk and lack of operational flexibility. The scoping report recommended that the requirement of further load restoration must be considered within the ongoing Bulk System Planning study currently under way in the Western portion of the GTA. This study is considering electricity needs in the municipalities of Oakville, Mississauga, Toronto, Brampton, Milton, Halton Hills and Caledon, and is being coordinated with other electricity planning studies in these areas. In addition, the scoping assessment has found that regional coordination via an RIP or an IRRP is not needed at this time.

1.2.2 Public Utility Coordinating Committee

Enersource participates in the Public Utility Coordinating Committee (PUCC), which provides a forum for communication between utilities, the City of Mississauga (the City) and the Region of Peel, in order to ensure safe and efficient management of the infrastructure within road allowances and other rights-of-way. Regular and effective communication between the City and the owners of infrastructure in the City creates an efficient and coordinated effort for all parties involved.

The PUCC meets on a quarterly basis and discusses common issues, shares information, and develops solutions to concerns or project-related matters. Issues include efficiency enhancements through improved construction scheduling coordination, damage prevention initiatives, and development of standards.

The PUCC was formed to ensure that projects undertaken on any City road allowance are completed using current standards and are recorded for future reference through the Municipal Consent Approval process.

The PUCC is responsible for:

- Approving non-standard locations of utility installations based on the understanding that wherever possible, utilities will be placed in the approved standard corridor locations;
- Developing appropriate policies and procedures regarding construction and utility installations;

- Improve communication and the exchange of information among the road allowance stakeholders;
- Coordinate the scheduling of the road allowance, capital improvement and maintenance projects; and
- Chair quarterly meetings.

Members of the PUCC include:

- MTS-Allstream
- Bell Canada
- City of Mississauga Transportation and Works
- City of Mississauga Recreation and Parks
- Cogeco Data Services
- Enbridge Gas Distribution Inc.
- Enersource
- FCI Broadband (Rogers Communications Partnership Co.)
- GT Fiber Services Inc.
- GTAA/Toronto Pearson International Airport
- Hydro One Network Services
- Hydro One Telecom Inc.
- Region of Peel – Public Works
- Rogers Communications Partnership
- TELUS Communications
- TeraGo Networks
- Union Gas Limited.

1.2.3 LDC Inter-Utility Standards Working Group

This working group was created in February, 2012 to provide participating utilities the opportunity to share knowledge and experience in the area of distribution utility design standards, construction practices, and equipment and material standards.

Members include Enersource, London Hydro, PowerStream, Veridian Connections, Toronto Hydro, Horizon Utilities Corporation, Peterborough Distribution, and Whitby Hydro Electric Corporation.

Benefits of this working group include:

- Enables utilities to present an issue in order for the group to provide advice and/or relate their experiences in solving a similar problem;
- To notify others of equipment or material failures within a particular utility in order to alert others or to identify common failures;
- To share experiences regarding the use of new equipment or materials;
- To highlight new technologies or work practices that may benefit others; and
- To share standards among utility members.

1.2.4 HONI - LDC Generation Working Group

The LDC Generation Working Group provides an opportunity for its members to discuss, develop and potentially adopt policies and best practices relating to LDC distributed generation connections. This allows for better management of the grid when using distributed energy resources, plus effectively and consistently delivering services to generators.

Current committee representation includes Enersource, HONI, Kingston Hydro, Horizon Utilities, Newmarket-Tay Power Distribution, Greater Sudbury Hydro, PowerStream, and Toronto Hydro.

Some of the working group's current activities include:

- Discussing emerging issues around LDC Distributed Generation connections and sustainment;
- Providing and gathering feedback on proposed enhancements to LDC Distributed Generation processes prior to implementation;
- Allowing LDC representatives to identify emerging issues from their perspectives;
- Identifying emerging operational issues and determining the correct forum for addressing them; and
- Discussing operational issues related to connecting and operating distributed generation.

The working group is designed to assume an advisory role rather than act as a decision-making body. In this role, the HONI - LDC Generation Working Group will provide recommendations to HONI and the IESO. Feedback from the working group will be considered in ongoing business decisions. The IESO participates in these meetings and regularly provides updates on new IESO policies and processes related to generation connections.

Some of the benefits are:

- Aiding in the development of both the IESO's and HONI's distributed generation connection processes;
- Providing input on the IESO's and HONI's distributed generation connections and process sustainment; and
- Sharing and gaining knowledge and experience among utility members.

1.2.5 Customer Consultation

Enersource recognizes the importance of customer feedback and regularly engages Simul Corp., an external research firm, to conduct a bi-annual customer satisfaction survey. The survey helps Enersource understand the satisfaction levels of its customers relative to Ontario and national comparators. In addition, it helps Enersource understand how customer perception, issues and concerns are changing over time.

To ensure Enersource's DSP accurately considers customer feedback, Enersource has engaged Decision Partners Inc., a third party consultant, to conduct broad, professional and scientific research on the input of customers regarding the DSP. This work is now underway. The customer feedback will be integrated into the final DSP to ensure that distribution services are provided in a manner responsive to customer preferences. This will be accomplished by:

- Identifying the benefits the DSP represents to customers;
- Considering factors relating to customer preferences that were identified in the course of planning investment projects and activities; and
- Identifying whether consultation(s) have or are expected to affect Enersource's DSP.

Research will be conducted with all customers in three groups, including:

- Residential Customers
- Non-Residential Customers
- Large Use Customers, the City of Mississauga, the hospitals and school boards.

This exercise will confirm Enersource's commitment to educate, and seek the input of, its customers, demonstrate how Enersource has considered that input, and revise its DSP accordingly. Effective customer consultation is based on in-depth insight into people's values, interests and priorities, in short, their mental models. Decision Partners' methodology is based on its proprietary Mental Modeling Technology™ (MMT™) which is an evidence-based, science-informed process specifically designed for understanding and influencing judgment, decision making, and behaviour.

The consultant has conducted 46 in-depth research interviews with three cohorts of customers and stakeholders, including: 15 Residential Customers, 15 Non-Residential Customers, and 16 Large Use Customers and Other Stakeholders (key intervenor groups). The consultant has worked closely with the Enersource team to ensure a broad sampling of customers (geographically and along other signification classifications).

The in-depth interviews provided foundational research which identified that Enersource's value proposition – what it takes to deliver electricity safely and reliably – was not understood by most customers. Building on the findings of the foundational research, Decision Partners, and its Interactive Decision Support Technology™ (IDST) partner, MedRespond, proposed an engagement solution that would first clarify Enersource's distribution role within the larger electricity system, then enable engagement of a broad range of residential and non-residential customers in thoughtful "conversations" with Enersource leaders about the DSP, who would listen and respond to customers' questions and comments in an online, virtual customer engagement environment.

Consultation with customers is continuing, currently via a 'video dialogue', accompanied by an online survey at www.enersource.com/survey. The results of the survey will provide Enersource with insights into customer preferences and will be used to align investment planning activities with the DSP.

1.3 Performance Measurement for Continuous Improvement (OEB Chapter 5.2.3)

A key consideration of Enersource's performance objectives outcomes, and reflected within this DSP, is the concept of balancing customer expectations and preferences, public policy responsiveness, and stakeholder requirements in the most operational, cost effective, and sustainable manner.

Since most of Enersource's assets are estimated to have a long useful life and are funded or recovered through distribution rates, Enersource must ensure the appropriate funding is available in order to minimize the cash flow constraint that may occur when undertaking long-term investments.

Enersource must ensure that its workforce is committed to the Company's performance objectives outcomes, and be able to identify risks, assess stakeholder requirements, and maintain/replace assets either directly or by overseeing third parties and other subcontracting firms. Since a significant number of Enersource's employees have expertise and are nearing retirement age, industry competition for additional resources is strong and has been identified as a significant constraint within this DSP.

To complement and continuously improve Enersource's strategic and capital expenditure plans, programs and projects are fully assessed and are evaluated to ensure alignment with the Company's CAMP and other corporate strategies. To facilitate the achievement of this goal, Enersource performs quantitative and qualitative analysis and risk assessments on each significant program or project. Enersource then considers the impact investments will have on distribution rates while ensuring the recommendations are prioritized and selected based on customer value, operational performance, stakeholder needs, and risk mitigation.

1.3.1 Methods, Measures, and Metrics

Table 2. Methods, Measures and Metrics

Business Outcome	Key Success Factor	Key Indicator Groups	Key Performance Indicators
Health & Safety	Keep personnel, service providers and the public safe	• Employee safety incidents • Service provider safety incidents • Public safety incidents	Lost Time Incidents
			Medical Aid Injuries
			First Aid Injuries
			Vehicle Accidents
			Property Damage
			Property Theft
			Public Electrical Safety Measure

Business Outcome	Key Success Factor	Key Indicator Groups	Key Performance Indicators
Distribution System Reliability	Acceptable long term reliability performance of distribution system	• Reliability	SAIDI
			SAIFI
Network Asset Operations & Management	Ensure planned capital expenditure completed on time and budget	• System Access • System Service • System Renewal • General Plan	Discretionary Capital Expenditures on plan
			Discretionary Capital Expenditures completed on time/as planned
Service Quality Measure	Meet all compliance standards	• Regulatory service quality indicators results • Legal violations • License conditions violations	Call Centre - ESQRs
			New Service Connections
			Appointments
			Billing Accuracy
Employee Measures	Ensure healthy and engaged workforce	• Employee absenteeism • Employee retention • Employee driving	Employee Absenteeism
			Employee Voluntary Turnover
			Employee Preventable Incidents

1.3.2 Performance Trends

The following sections provide a summary of performance trends over the historical period using the methods and measures identified above.

Customer Oriented Performance

Enersource regularly seeks customer feedback on their satisfaction with the services provided by the Company. Satisfaction levels have proven to be greatly impacted by system reliability. Where gaps are found, the appropriate actions are identified to address the issues. Service reliability is integral to all work undertaken as part of system planning and asset management. Annually, Enersource undertakes a thorough review of system reliability and identifies planned works under applicable investment categories which are designed to directly impact system reliability.

Customer value is at the centre of Enersource's Corporate Strategic Objectives. Customers are engaged on an ongoing basis and their feedback is incorporated into distribution system planning. Enersource engages customers with two surveys: Customer Satisfaction Survey and a DSP Consultation. The results provide the Company with the KPIs which Enersource uses to identify areas of improvement and benchmark its accomplishments against results of other utilities.

System Reliability Performance Indicator

Key measures of reliability are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI). Frequency relates to the number of outages whereas duration relates to the outage time. Enersource tracks System Reliability Performance Indicators, as shown in **Table 3 and Figures 3-5**, to ensure that power is provided to customers on a reliable basis. Interruption categories such as defective equipment and adverse weather-related outages have been progressively trending upward. Improvements to the asset management processes are underway to enhance the Company's ability to prioritize end-of-life asset replacements. Maintenance, inspection, and testing of existing assets are essential to ensure equipment operates as expected and to identify potential failures before they occur. Enersource's objective is to maintain the System Reliability Performance Indicators year over year.

Table 4. Trends in reliability indices 2010-2014 (including Major Event Days ("MED")

KPI	2010	2011	2012	2013	2014
SAIDI	35	53.3	41.91	320.29*	40.51
3-Yr Average SAIDI	30.41	41.65	43.4	138.5	134.24
SAIFI	1.32	1.97	1.71	2.72	1.14
3-Yr Average SAIFI	1.08	1.49	1.67	2.13	1.86
CAIDI	26.5	27	24.6	117.9	35.6
3-Yr Average CAIDI	28.1	28.2	26.03	56.5	59.4

includes two MEDs (July storm and flood, and December ice storm)

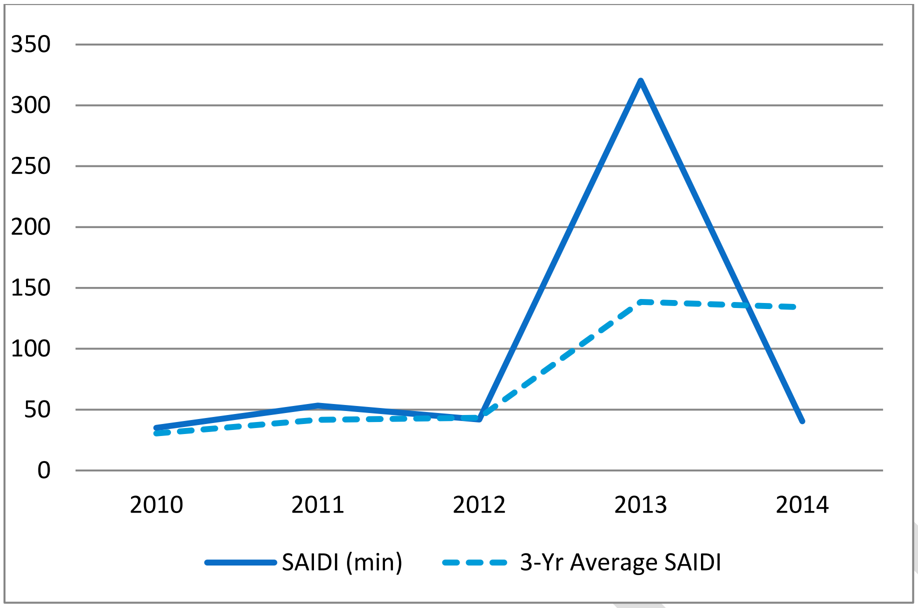


Figure 3. Trends in SAIDI 2010-2014

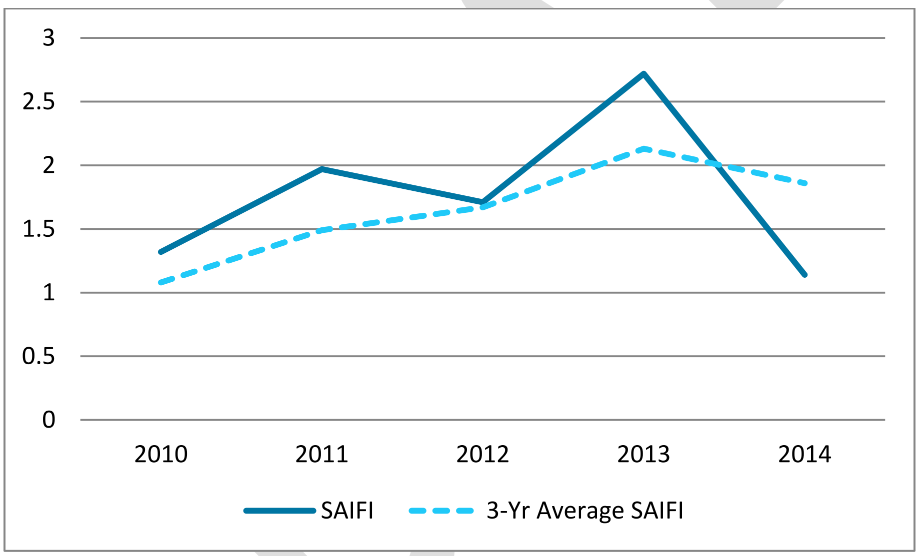


Figure 4. Trends in SAIFI 2010-2014

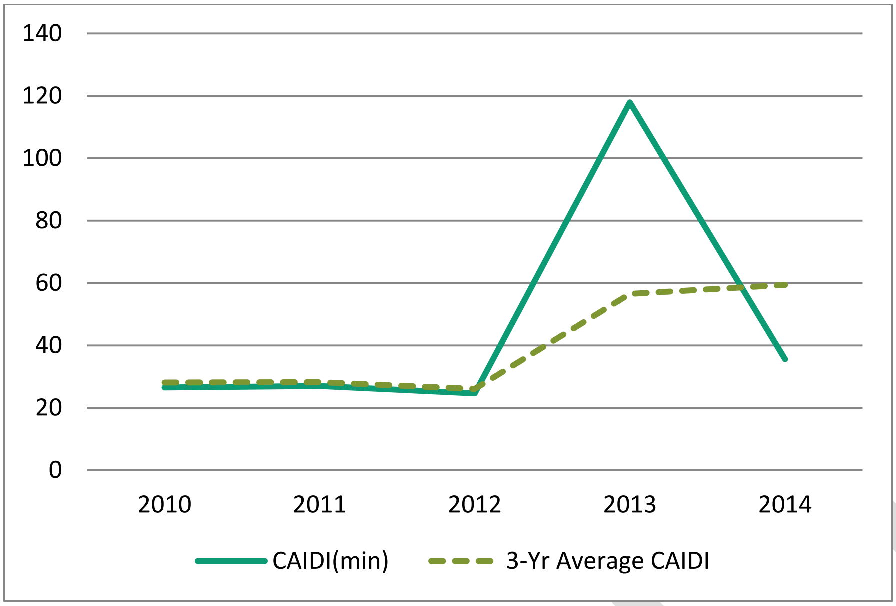


Figure 5. Trends in CAIDI 2010-2014

1.3.3 Impact on the DSP

Enersource's Corporate Strategic Objectives and targets provide the framework for the DSP. The Company tracks the KPIs listed in previous sections, which are used to set benchmarks to ensure Enersource's objectives of continuous improvement are achieved across all areas of the Company.

2. Asset Management Process (OEB Chapter 5.3)

2.1 Asset Management System Overview (OEB Chapter 5.3.1)

The objective of the DSP is to make recommendations for additions, replacement, disposal, and maintenance of assets in an efficient manner that realizes value and achieves Enersource's established performance outcomes. The goal of the DSP, updated annually, is to then outline how Enersource effectively manages its assets on a life-cycle basis with investment plans that are prioritized and aligned with the CAMP.

2.1.1 Asset Management Framework – Goals and Objectives

The DSP has been based on the following key factors: planning, prioritization and execution of programs and projects. The investments have been identified and classified into the following categories:

System Access - modifications (including asset relocation) to Enersource's distribution system that it is obligated to perform in order to provide customers (including generator customers) with access to electricity services via the distribution system.

System Renewal - involve replacing and/or refurbishing system assets to extend their original service life and thereby maintain the ability of Enersource's distribution system to provide customers with electricity services.

System Service - modifications to Enersource's distribution system to ensure the distribution system continues to meet the Company's objectives while addressing anticipated future customer electricity service requirements.

General Plant - modifications, replacements or additions to Enersource's assets that are not part of its distribution system, including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities.

Asset management is an Enersource-wide discipline guided by the following principles for the development and implementation of asset related programs or projects:

Risk-based: Incorporate risk management appropriately into decision making strategy

Sustainable: Optimize asset life cycle value

Multi-disciplinary: Asset management accountability framework crosses departmental and discipline boundaries

Integration Oriented: View assets in their total relative value context

Optimal: Strike the right balance among competing objectives such as short-term performance and reliability versus long-term planning and sustainability

Systematic: Rigorously applied in a structured management system complete with a monitoring framework and evidentiary structures and tools.

Enersource formalized these guiding principles into its CAMP in 2013, reinforcing that good asset management practices must be an integrated business discipline involving planning, finance, engineering, maintenance and operations.

In order to strike the optimal balance among risks, performance, and costs in a sustainable fashion that maximizes value while complying with all health, safety, environmental and regulatory requirements, Enersource established an asset management framework that will allow it to continuously improve its current asset management system and planning processes, as shown in **Figure 6**.

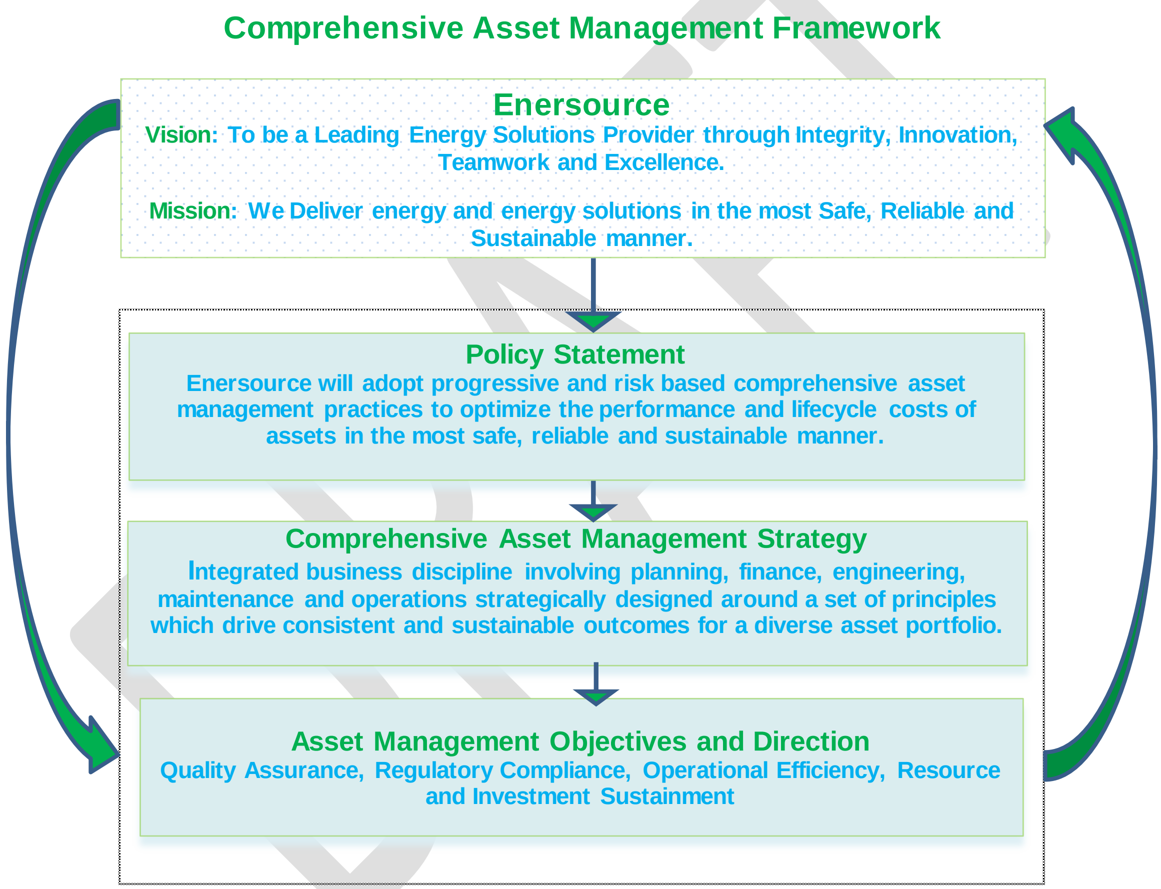


Figure 6. Enersource Asset Management Framework

2.1.2 Asset Management Implementation and Components

Enersource views its current asset management system as a set of tools, policies, plans, and business processes used to direct, coordinate, and control investment activities. It provides Enersource with a method to reduce risk and give assurance that the asset management objectives will be achieved on a consistent basis.

Enersource has five main focus areas which it takes into account when establishing its yearly business plans:

- Corporate Risk
- Stakeholder Engagement
- Workforce
- Value Creation
- Asset Management.

Enersource uses these focus areas to establish the short and long term organizational objectives which are used to align the business planning activities.

Enersource's Senior Management and Executive Advisory Committee (EAC) establish the Company's objectives and goals, which are then approved, in principle, by the Board of Directors. The EAC consists of the Chief Executive Officer, Executive Vice Presidents, Vice Presidents, and Director-level staff. This top down objective-setting approach is to ensure that when detailed plans are created, they align with the objectives and values set out and approved by the Board of Directors.

Enersource currently evaluates its business plan and investment projects and programs against the following business values:

- Regulatory/Public Policy Responsiveness
- Operational Effectiveness/Safety
- Customer Focus
- Financial Performance.

In order to establish a realistic investment plan that takes into consideration customer expectations and preferences, public policy responsiveness and stakeholder requirements, Enersource prioritizes projects and programs based on the business values listed above. Projects are ranked based on which investments have the greatest impact on the business values. Assuming there were no constraints, all investments with a positive impact on the business values would be approved. Due to resource constraints (e.g., appropriate funding, labour availability, information technology support) and other considerations such as the impact on the customer, other stakeholders and the environment, projects and programs are selected and prioritized based on supplemental quantitative and qualitative analysis.

After the top down objectives have been approved, the detailed capital budgeting process begins with an assessment and evaluation of Enersource's current and future distribution, intangible, and General Plant asset needs and requirements. Recommendations are then made on the timing of asset additions, replacements and disposals. Considerations include strategic or top down objectives, operational requirements and constraints, asset condition, asset age, criticality, reliability information, new capacity or regulatory requirements, environmental and other stakeholder impacts.

Each recommendation is assessed and draft business cases are prepared by the main business unit sponsors, along with other key stakeholders, for each proposed project or program. Each business case includes a description of the investment driver, scope, forecasted cost, and potential benefit/risk mitigation anticipated from each project or program.

Projects and programs are selected by assessing and balancing labour availability and funding with other needs and constraints within each division and across the Company. The recommendations are further prioritized by performing risk evaluations that identify impacts the project or program will have on Enersource's business values.

Each proposal is reviewed to ensure alignment with Enersource's overall asset management strategy and to determine if the project or program is realistically achievable in the timeframe proposed.

After the selected draft proposals have been reviewed, projects and programs are consolidated into the DSP. This selection exercise is conducted annually. The consolidated draft DSP is presented to Enersource's Asset Investment Council AIC (as per Enersource's CAMP). The appropriate signing authority within each line of business approves each of the respective capital asset project or program proposals to be presented to the Board of Directors.

Any single capital or intangible expenditure proposed in the DSP that exceeds $2,500,000 must receive separate approval from the Board of Directors before any action can be taken. Any capital or intangible expenditures that in aggregate exceed $5,000,000 and that are transferred or redirected between established investment categories during the calendar year must also receive separate approval from the Board of Directors before any transfer or action can be undertaken.

After the DSP is approved in principle by the Board of Directors, it is incorporated into the overall annual business plan which receives formal approval through a Board of Directors' resolution. The annual capital investment plan includes all electricity infrastructure, equipment, building improvements, land and intangible asset requirements (e.g., software and permanent easement rights).

Adjustment to Approved Capital Plan - Overview

While the annually-approved DSP is a consolidation of Enersource's business cases and proposals which have been reviewed, assessed, evaluated, planned and prioritized based on numerous quantitative and qualitative analyses, the actual execution of the plan may vary from the DSP due to:

- Changes in customer and stakeholder requirements (e.g., regional plans, unexpected growth, unplanned road widening, etc.);
- Changes in business priorities from new or evolving information;
- Changes in external requirements (e.g., government directives, new technical standards, environmental regulations); and
- Major events (e.g., storms, equipment failures, etc.).

Adjustment to the approved capital plan process follows the same initial steps as described in the planning process. The next step in the Adjustments to the Approved Plan process is to assess resource requirements of the new or revised proposal against the original Approved Plan.

The following two issues must then be resolved:

1. If the proposal can be executed within the budgeted category by the business unit sponsor and the Vice President, Asset Management Strategy, then the proposal is accepted and communicated to the appropriate signing authority; or
2. If the proposal cannot be executed within the budgeted category by the business unit sponsor and the Vice President, Asset Management Strategy, then an alternative proposal is made to the AIC for consideration. If the recommendation is accepted, the proposal is approved by the appropriate signing authority.

Should an individual adjustment proposal exceed $2,500,000, the revised proposal must be sent to the Board of Directors for approval. If it is determined that the changes, transfers and or redirections are, in aggregate, over $5,000,000, a summary of the proposed Adjustments to the Capital Plan must be sent to the Board of Directors for approval.

Asset Life Cycle Management – Process and Procedures

The planning process includes evaluations, which are completed for each asset class and for each project or program. The evaluations involve identifying the significance of each asset, project and program and how risk affects the main business value categories. This process also includes gauging the consequences of not proceeding with new capital or sustainment investments. The listing of asset classes is provided under Section 2.4 Asset Lifecycle Risk Management.

Project Evaluation

In order to effectively prioritize projects and programs included in the DSP, Enersource performs assessments of the associated business values listed above. The objective is to eliminate, control or mitigate risks associated with each business value and to ensure that the highest risks are addressed first. The Project Evaluation phase defines project alternatives and creates business cases in support of the feasible alternatives. Unless mandated, project alternatives are evaluated based on their impact to Enersource's business values.

Project concepts are first reviewed to determine if they are a mandatory project. Such projects are typically dictated by regulatory requirements resulting from changes to the *Electricity Act* or the *Ontario Energy Board Act,* and resulting changes to the OEB's Distribution System Code, and/or other OEB codes or instruments. They range from customer connections to line relocations, to restoring power in a timely fashion.

Non-mandated project concepts are evaluated and possible alternatives are developed to meet the desired objectives of the project. This assessment is done through a business case development. Project alternatives are then scored by identifying their risk and/or benefit as it relates to Enersource's business values.

Project Prioritization

The Project Prioritization phase ranks projects based on their value and allows for each to be evaluated based on the same criteria in order to determine which will provide the most value to the business while minimizing risks. A Preliminary Project List is created based on the prioritization process and understanding of risk/impact if the proposed project is not approved. The project list considers available funds and resources to complete the work. The proposed investment projects and programs are reviewed by Enersource's Executive Management Team and Board of Directors before proceeding to execution. This ensures that Corporate Strategic Objectives are met through the proposed investment plan.

Execution

The Execution phase follows Enersource's internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow employees to perform project work in an economically efficient, cost effective, and safe manner.

Continuous Improvement

The next stage of the asset management system is to review the results achieved from the execution of the projects and programs. Enersource has adopted an asset management conformance and continuous improvement framework as illustrated below in **Figure 7**.

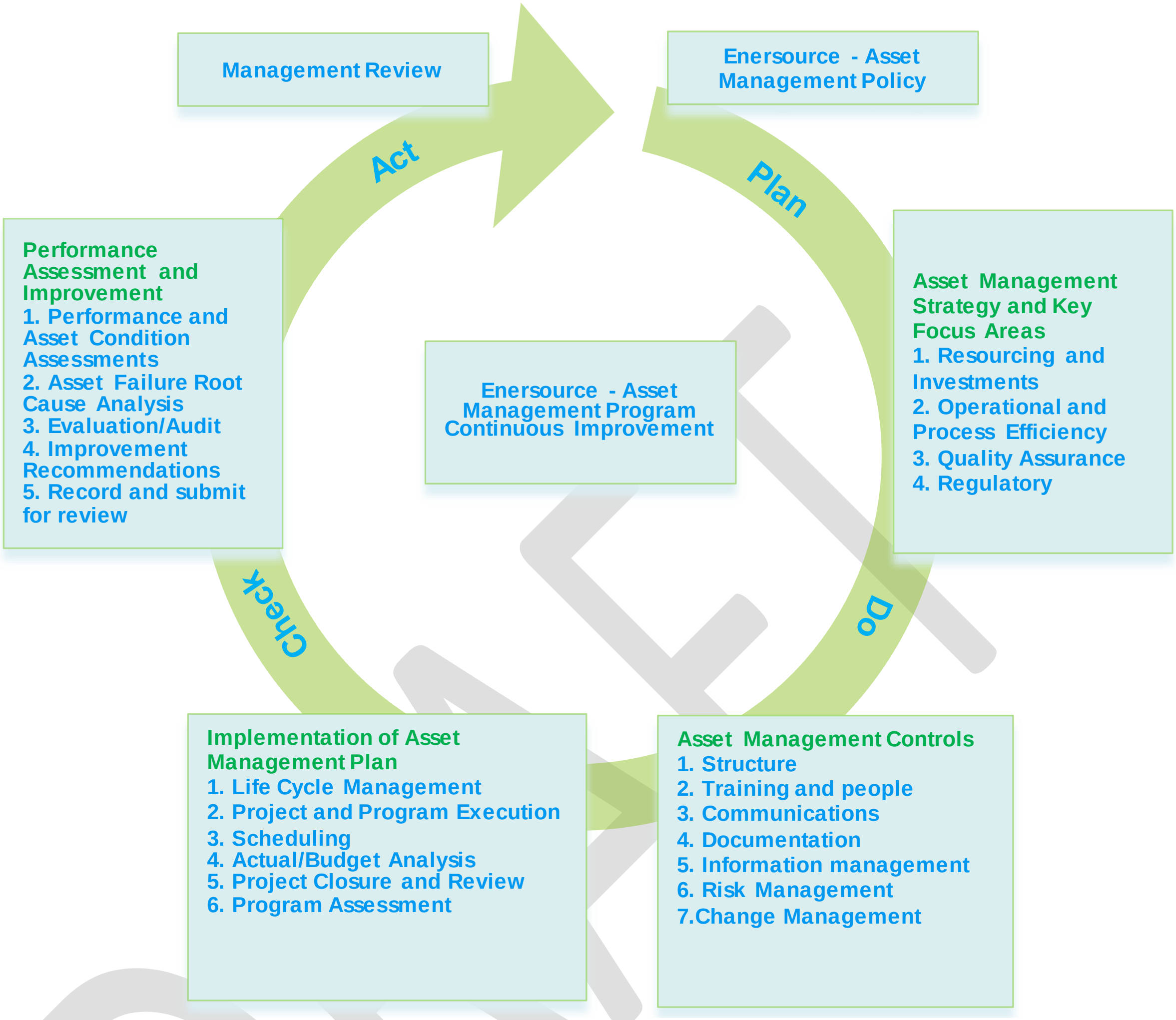


Figure 7. Continuous Improvement Framework

2.1.2.1 Asset Condition Assessment

In the past, sustaining capital investments have dominated over other types of capital investments. However, in recent years it has become clear that significant investments are required to address operational, redundancy, safety, non-discretionary, and obsolescence issues.

Conducting an Asset Condition Assessment (ACA) is a process whereby the conditions of all key distribution infrastructure asset categories are assessed. This process employs the health indexing methodology used widely by utilities in Canada and around the world. Health indexing is considered a fundamental element without which an asset management program/plan would be seriously deficient. Conducting an ACA is good practice and the OEB has expressed its expectation that Enersource must be in a position to provide asset condition studies and other analyses which support its capital and investment strategies.

In early 2011, Enersource first engaged Kinectrics Inc. (Kinectrics), an independent third-party expert, to perform an ACA of Enersource's assets and provide an objective opinion on their condition . The results of Kinectrics' 2013 ACA report provided significant input in this DSP. In addition, Enersource is currently working with Kinectrics to finalize the 2014 ACA study and its findings will be used to inform further updates to the DSP.

The ACA provided the Health Index distribution for all infrastructure assets in each class, and a 10-year condition-based replacement plan. As stated above, the ACA report has been used as one of the inputs to this DSP. It has helped Enersource evaluate its existing programs (renewal, sustainment, expansion, and regulatory) and develop new ones in order to address the required replacement rates for all asset groups considered in the ACA. Enersource's six-year capital and investment plan, which addresses some of the issues identified in the ACA, has been included within this DSP under Programs and Projects.

2.1.2.2 Information Technology (IT) Asset Management Process

Information Technology (IT) is an essential division of any organization's operation. IT systems enable businesses to automate and optimize their processes and efficiently execute their operations. Enersource relies on its IT assets and systems to meet its daily operational demands such as control of the electrical grid and enterprise applications (i.e., financial reporting, JDE and CC&B) as well as meeting external operational requirements (i.e., providing Meter Data Management and Repository (MDM/R)) with daily smart meter data.

The IT asset management plan includes asset procurement, operation, maintenance, replacement, and disposition of the assets. The primary objectives of Enersource's IT Asset Management Plan (IT AMP) are as follows:

- Ensure assets are utilized effectively, maximizing their value to the utility and in turn, to ratepayers;
- Ensure high reliability and scalability of assets in order to meet required service levels, minimizing business downtime and lost productivity;
- Minimize life-cycle cost, including the operation, maintenance, replacement and disposal of each asset; and
- Ensure assets conform to IT standards and protocols, minimizing security risks and operational risks.

Enersource's IT AMP includes both hardware and software assets and consists of two main components, as shown in **Figure 8:**

- Sustaining existing systems and business functionality
- Enhancement initiatives.

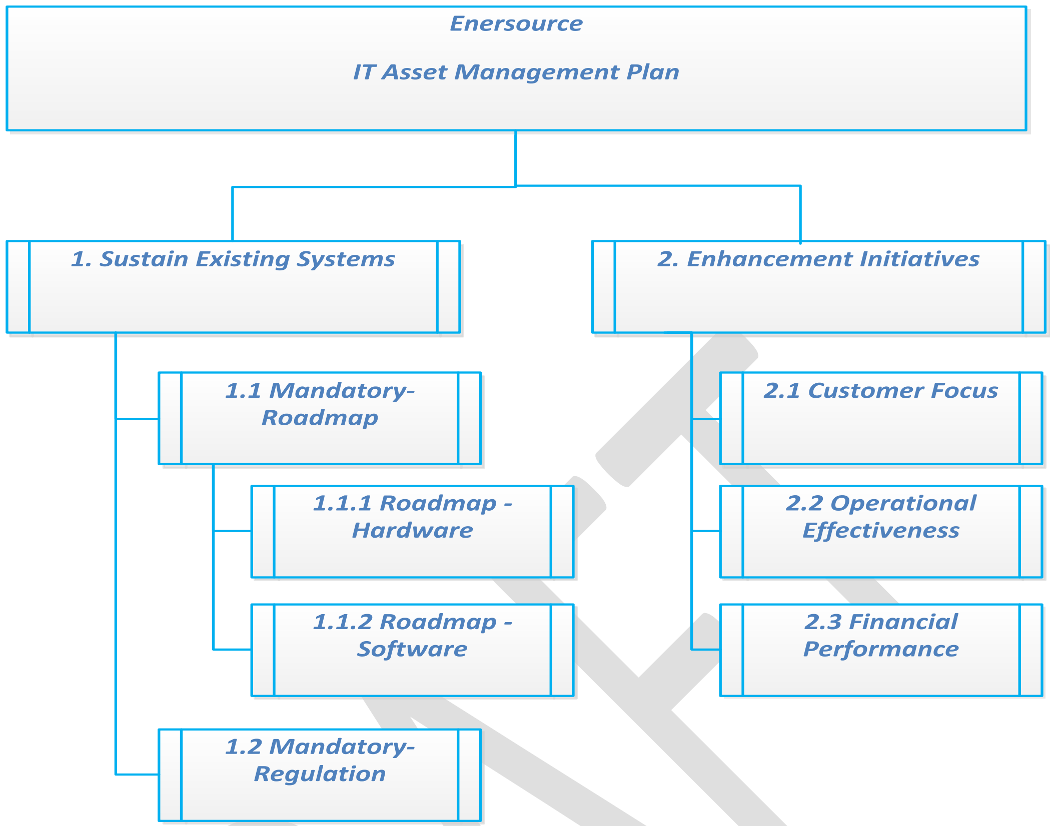


Figure 8. IT Asset Management Plan

The planning process for IT assets begins with prioritizing the investments. Prioritization consists of four drivers as shown in **Table 5**.

Table 5. Prioritization drivers

Investment Drivers	Objective
Regulatory / Public Policy Responsiveness	Services are provided to address a regulatory requirement or mandate. This category includes IT roadmap projects as they are necessary in order to maintain vendor support.
Customer Focus	Services are provided in order to respond to customer needs and/or preferences.
Operational Effectiveness	Continuous improvement in productivity and cost performance is achieved, and system reliability and quality improvement are gained.
Financial Performance	Financial viability is maintained, and savings from operational effectiveness are achieved.

2.1.2.2.a - Enersource IT Asset Management

Enersource uses multiple IT systems to support its business processes and to ensure continued execution of its daily operations. The IT systems allow employees to effectively perform their daily functions. These systems are critical tools for all business areas of the organization including but not limited to, accounting, engineering, distribution grid control, and customer care. Most important, the IT infrastructure (i.e., network, servers, etc.) acts as the backbone to the entire IT asset systems.

In today's complex utility environment there is a greater need for sophisticated systems that can provide the business with automation, process optimization, information sharing, and better decision-making using factual data analytics. In addition, over the last few years there has been a paradigm shift in the way customers interact with their utility. There is a need to empower customers with information to help them make informed decisions about matters that could impact them (i.e., usage data, outages, etc.) with one goal being to enhance the culture of conservation. It is anticipated that technology will continue to change the way most customers interact with Enersource.

2.1.2.2.b - Asset Register

Asset Registers represent the primary repository sources of storing various assets types and corresponding information associated with those assets. There are several systems used to acquire, update and maintain the diverse set of assets at Enersource.

i. Geographical Information System (GIS) system
ii. Integrated Operating Model (IOM)
iii. Supervisory Control and Data Acquisition (SCADA) system.

i. Geographical Information System (GIS)

Enersource's Geographical Information System (GIS) holds locational and attributes data on electricity distribution assets within the Company's service territory. Enersource's GIS data is used for operational, maintenance, design, construction, and asset management requirements.

The Asset Management group ensures that an accurate record of the electricity distribution network and connectivity is available on Enersource GIS maps reflecting live conditions of electrical plant in the field. In addition, the key attributes associated with each asset are recorded in forms of intelligent maps. The information can then be queried and extracted to satisfy specific requests for information (e.g., electrical connectivity, age of assets, testing records, equipment types and system feeder analysis).

Maintenance of GIS records is controlled by the Asset Management group which has instituted procedures to capture, update and maintain Enersource's electricity distribution asset data. All GIS data entries including, but not limited to, new plant, attribute updates, plant removal, and any other spatial data are completed in the Intergraph's G/Technology and IOM environments. All GIS data entries undergo a rigorous quality assurance and quality control process by the Asset Management group before they are posted to the GIS production environment.

The majority of GIS information input is from capital projects that result in additions or renewal of the distribution system. Examples include drawings pertaining to new subdivisions, new commercial and residential installations, new substations, and various road work.

The remaining 30% of GIS information input comes from operational sources (e.g., plant energization and in-service processes, device switching open points on feeders, discrepancy verification), maintenance sources (e.g., attribute information arising from inspection or maintenance) and other discrete sources (e.g., joint use, street lighting, land base, orthographic imaging, etc.).

ii. Integrated Operating Model (IOM)

The IOM is a computer-based system that provides a single-user interface for monitoring the grid, allowing for faster, more informed decision-making. The IOM consolidates information on location and attributes of distribution equipment, real-time crew location and active outages. The IOM also performs the core requirements of an Outage Management System (OMS) which uses outage probability modeling to help the Control Room Operators determine the most likely source of an outage and to prioritize restoration efforts.

At Enersource, the type, duration and cause of each outage is recorded based on operations executed by the Control Room Operators into the IOM; this information is the source of reliability statistics. If equipment fails in the field, a follow-up report is created in the IOM and used for tracking and prioritizing follow-up maintenance activities. In addition to providing the basis for reliability statistics, the outage information stored in the IOM is used to investigate the worst-performing feeders and to identify worst reliability areas.

The IOM tracks all activities, outages and problems associated with the distribution system, including information on equipment failures. Outage event records include information on the type of equipment that has failed, its location in the field, the duration and cause of the outage, and the number of customers affected. This application brings together multiple operational inputs and provides a dynamic picture of reliability performance of Enersources's distribution system.

iii. Supervisory Control and Data Acquisition (SCADA)

The SCADA system provides real-time data on key assets in the field (e.g., stations, circuit breakers, automated switches). It allows the Control Room Operators to monitor real-time asset status and performance and to configure (through device switching) the distribution system on an ongoing basis in order to optimize system performance and the supply of power to Enersource's customers. Typical data collected through SCADA is used to operate the distribution system and includes information such as equipment status (on/off), current flow (amps) and alarms related to critical station equipment (relay triggers).

SCADA data is archived and provides an historical record of system performance that allows for detailed engineering and operating analysis to provide future direction and plans for improving system performance. SCADA real-time data is available to operations and engineering staff through the corporate networks via a web browser. Archived SCADA data is available to select users through a data historian application located on the corporate network.

2.1.2.3 Asset Capacity Utilization/Constraint Assessment

Enersource regularly assesses the loading capability of the distribution system in an effort to maintain adequate and reliable supply to customers. System planning is carried out for system additions and upgrades while considering regulatory requirements for the connection of customers and consideration for safety, environment, and reliability. With respect to annual system utilization, Enersource's Control Room monitors substation and feeder loading on a daily basis to ensure that both transformer and feeder loading is maintained within established guidelines. The loading of HONI transformer stations should not exceed the limited time rating (LTR) for that station. The loading of substation transformers should not exceed the nameplate rating for the transformer for prolonged periods of time. Enersource main feeders are typically rated at 600 amps maximum and are monitored and balanced by Control Room Operators to ensure loading of approximately 350 amps at any given time. This ensures that enough capacity contingency is available in the event of a cable fault or major system issue whereby feeder switching is required for restoration or from additional loading that typically occurs during summer months.

Enersource currently owns and operates 66 substations with 109 substation transformers. Listed below in **Table 6** are substations that have exceeded the transformer capacity between the 2013-2014 periods. The overloading at these substations is closely monitored by the Control Room and System Planning group and arrangements are made to balance the loading on adjacent substations to minimize substation overloading. In addition, the System Planning group runs long-term peak demand forecasts to assess if substation additions or upgrades are required to address future loading requirements, as is the case with the Downtown 21 area.

Table 6. System Peaks in Overloaded Substations

Substation	2012 System Peak Day Load (MVA)	2013 System Peak Day Load (MVA)	2014 System Peak Day Load (MVA)	Substation Capacity Limit (MVA)	Exceeding Capacity
20 - Southdown	41.0	37.9	24.0	40	Yes
39 - John	23.2	23.2	15.4	20	Yes
48 - Rexdale	22.4	23.1	13.9	20	Yes
50 - Credit Valley	23.8	19.0	18.8	20	Yes
52 - Thomas	40.9	39.6	21.4	40	Yes
59 - Aquitaine	21.8	24.2	15.6	20	Yes

In order to ensure optimal utilization of its assets, Enersource has developed design guidelines and standards to provide its design technicians with a reference in regards to transformer, cable and foundation sizing, fusing and maximum capacities allowed on sub-transmission, local distribution and main feeder cables. The guide is to ensure that the equipment supplying services is adequate to supply customers' needs and meets Enersource's reliability criteria. This is especially important in high rise residential buildings and industrial services, where replacement of equipment after initial installation is difficult and much more expensive than installation of proper equipment during initial construction.

Tables 7-11 outline system planning design criteria which are used for engineering purposes.

Table 7. Maximum Cable Load and Fusing for Industrial and Commercial Customers

Voltage	Preferred 3Φ Transformation – Local Distribution Feeder (1/0)	Matching PMH Fuse – Local Distribution Feeder	Matching Cutout Fuse Local Distribution Feeder	Maximum 3Φ Transformation Distribution Main Feeder (1000 kcmil)*	Maximum 3Φ Transformation Subtransmission Feeder (1000 kcmil)
2.4/4.16 kV	800	100 E	100 K	3,500	-
8.0/13.8 kV	2,400	100 E	100 K	11,500	-
16.0/27.6 kV	4,800	100 K	100 K	23,000	-
44 kV	-	-	-	-	42,700

Table 8. Residential Distribution Transformers (100 kVA) – Number of Transformers per Feeder per Phase

Voltage	Optimal Number of Transformers on Local Distribution Feeder per Phase	Maximum Number of Transformers on Local Distribution Feeder per Phase
2.4/4.16 kV	2	3
8.0/13.8 kV	8	10
16.0/27.6 kV	12	16

Table 9. Residential Distribution Transformers (100 kVA) – Number of Customers per Transformer

Voltage	Maximum Number of Connections per 100 kVA U/G Transformer	Optimal Number of Residential Customers per 100 kVA O/H Transformer	Maximum Number of Residential Customers per 100 kVA O/H Transformer	Optimal Number of Townhouse Customers per 100 kVA U/G Transformer	Maximum Number of Townhouse Customers per 100 kVA U/G Transformer
2.4/4.16 kV	14	20	25	20	25
8.0/13.8 kV	14	20	25	20	25
16.0/27.6 kV	14	20	25	20	25

Table 10. Single- Phase Transformers and Secondary Cables Reference Sheet for Residential Services

Service size	Maximum Current	Transformer size	O/H Conductor Size and Number of Runs	Enersource Part Number	U/G Cable Size and Number of Runs	Enersource Part Number
		120/240 V	Triplex		Triplex	
100 A	80 A	100 kVA	#4	16,840	3/0	16,857
200 A	160 A	100 kVA	1/0	16,844	3/0	16,858
400 A	320 A	100 kVA	2-1/0 or 250SB	16,844 or 16,815	2-3/0	16,858
600 A	480 A	167 kVA	-	-	3-3/0	16,858

Table 11. Load Fusing for Local Distribution Feeders

Total Transformation	Number of Phases	2.4/4.16 kV	8.0/13.8 kV	16.0/27.6 kV
100 kVA	1	65	20	10
167 kVA	1	100	30	15
150 kVA	3	30	10	6
300 kVA	3	65	20	10
500 kVA	3	-	30	15
750 kVA	3	-	50	25
1,000 kVA	3	-	65	30
1,500 kVA	3	-	100	50
2,000 kVA	3	-	100	65
2,500 kVA	3	-	125/140	80
3,000 kVA	3	-	-	100

2.1.2.4 Historical Period - Customer Interruptions Caused by Equipment Failure

System reliability is a key system performance measurement of an LDC. The OEB requires that every LDC maintains reliability performance within its own historical three-year range. In order to meet this requirement, Enersource has implemented several system reliability programs.

Enersource uses industry standards to measure and benchmark system reliability performance. The System Reliability Performance definitions are set by the Service Continuity Committee (SCC); a subcommittee of the Canadian Electricity Association (CEA). Enersource follows guidelines set out by the CEA's Electric Power System Reliability Assessment program (EPSRA) which governs system reliability statistics for the entire electricity industry.

Key measures of reliability are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI). Frequency relates to the number of outages whereas duration relates to the outage time. Enersource implemented the IOM in 2009, which enhanced the ability to track reliability statistics. These indices are used to measure overall system performance and to benchmark against comparable utilities.

Reliability results for the last five years are shown below.

Additional information regarding reliability results, incident cause classification, and equipment statistics of outages from 2010 to 2014 are listed in **Tables 12-15** and **Figures 9-11.**

Table 12. Reliability Statistics with Major Event Days (MED's) in 2010-2014

Metric	2010	2011	2012	2013	2014
Interruptions	2,083	1,027	923	1,310	1,203
Customers Affected	251,366	380,771	335,736	541,642	228,251
Customer Minutes	6,673,600	10,277,717	8,242,559	63,887,058	8,134,215
SAIDI (minutes)	35	53.3	41.91	320.29	40.51
SAIFI	1.32	1.97	1.71	2.72	1.14
CAIDI (minutes)	26.5	27	24.6	117.9	35.6

Table 13. Reliability Statistics in 2010-2014 (without MED's)

Metric	2010	2011	2012	2013	2014
Interruptions	2,083	1,027	923	1,087	1,159
Customers Affected	251,366	380,771	335,736	280,787	195,258
Customer Minutes	6,673,600	10,277,717	8,242,559	7,182,677	6,365,209
SAIDI (minutes)	35	53.3	41.91	36.01	31.7
SAIFI	1.32	1.97	1.71	1.41	0.97
CAIDI (minutes)	26.5	27	24.6	25.6	32.6

Table 14. Cause Code Statistics in 2010-2014 (without MED's)

Cause Code	2010	2011	2012	2013	2014
Unknown/Other	100,669	180,650	64,476	112,949	86,335
Foreign Interference	466,580	882,668	792,130	780,569	1,041,488
Scheduled	1,939,026	682,740	411,417	990,732	983,108
Loss of Supply (HONI)	362,222	1,893,664	236,671	964,794	19,106
Tree Contacts	257,916	893,379	415,925	345,010	324,014
Lightning	62,454	38,475	57,711	39,552	13,157
Defective Equipment	3,051,586	5,219,938	4,869,365	3,763,595	3,808,219

Cause Code	2010	2011	2012	2013	2014
Weather	422,209	49,927	1,387,837	162,298	84,281
Adverse Environment	0	19,492	0	21,060	3,000
Human Element	10,938	416,784	7,027	2,118	2,501
Total	**6,673,600**	**10,277,717**	**8,242,559**	**7,182,677**	**6,365,209**

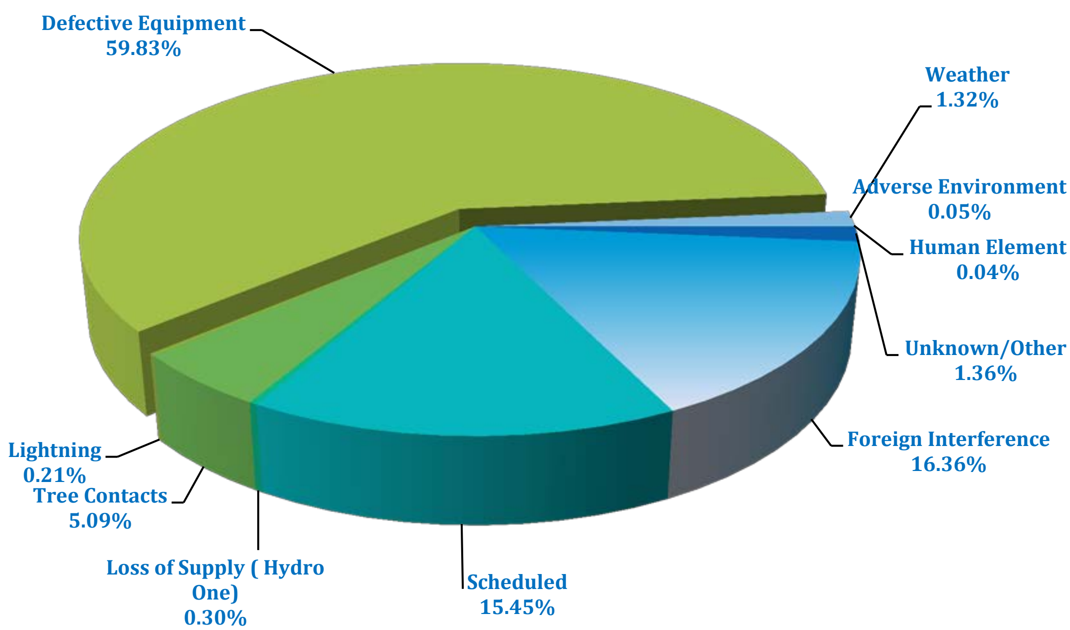


Figure 9. Customer Minutes by Cause in 2014 (without MED's)

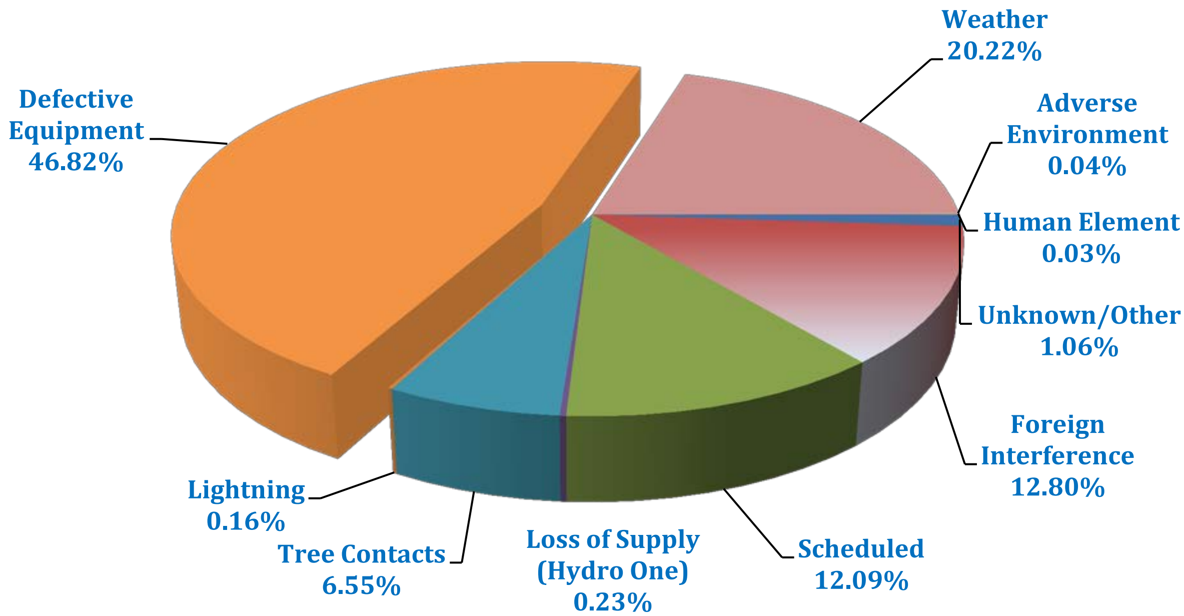


Figure 10. Customer Minutes by Cause in 2014 (with MED's)

Table 15. Equipment Failure Statistics (2010-2014)

Cause Codes	2010	2011	2012	2013	2014
Underground Cable	2,120,732	2,881,575	2,727,177	1,720,513	1,610,094
Fuse	39,211	38,392	50,685	27,675	7,392
Insulator	2,687	42,884	156,102	301,820	170,207
Switchgears	68,884	421,281	49,230	221,229	544,465
Overhead Equipment	230,471	1,098,335	425,638	521,462	692,494
Others/Unknown	62,183	133,394	83,825	110,227	78,817
Splices	277,098	262,275	807,069	196,638	192,193
Switches	24,938	86,549	262,899	151,604	291,775
Elbows/Terminations	55,984	62,340	70,562	219,763	39,223
Transformers	169,398	192,913	236,178	292,664	181,559
Total	**3,051,586**	**5,219,938**	**4,869,365**	**3,763,595**	**3,808,219**

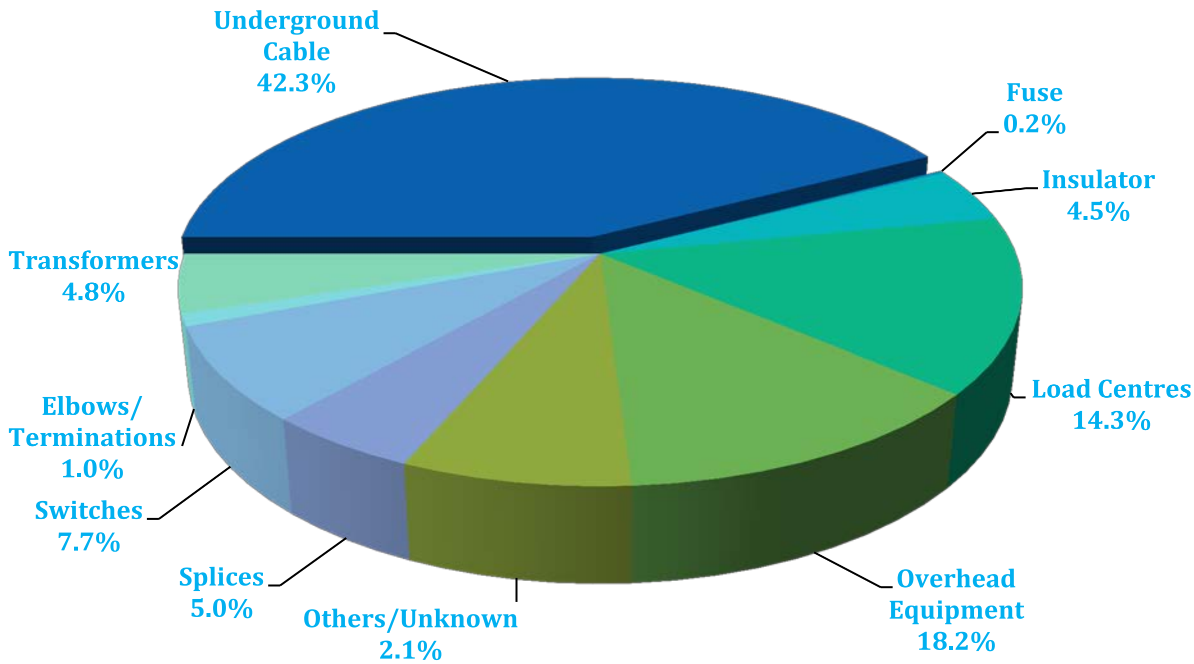


Figure 11. Equipment Failures in 2014

2.1.2.5 Reliability-Based 'Worst Performing Feeder'

The programs and projects included in this section deal with the replacement of underground cables and components that have reached their expected end-of-life and have been determined to create unacceptable operational risks.

Underground cable failures are the leading cause of equipment failures in the distribution system and present a significant amount of operational risk to Enersource. To address this issue, the Company executes its ongoing cable replacement program based on a significant amount of qualitative and quantitative analysis. On an annual basis, the worst performing areas of the underground cable system are identified and ranked according to operational risk, impact to customers, and financial consequences, while considering labour availability and other constraints.

Criteria used to identify the worst performing areas include: number of cable failures, age of the cable, cable type installed and how critically customers are affected. Most cables installed before 1989 either do not have a jacket and/or were not installed in ducts and thus, are more susceptible to failure. The typical life expectancy for new or replacement underground cable is approximately 40 years.

Locations for yearly rebuild projects are prioritized by using three years' worth of operational data, ranked by equipment age, and the number and type of customers involved. Once rebuild locations are selected, the projects are included in the following year's capital renewal plans, budgeted for and designed. To optimize work efficiencies, renewal projects typically involve replacement of the complete underground system including cables, transformers, switchgears and other system components that are also nearing the end of their useful life.

Many utilities use different methods to identify areas with poor performance and implement various programs and improvements. Worst feeder ranking is most commonly used to identify poor performing feeders and many utilities implement programs to improve feeder performance.

Enersource has reviewed several presentations/methods used by other utilities to identify worst feeders in the system. These include:

- Feeder Vulnerability Study - HONI performance analysis
- Feeder Reliability Management - Toronto Hydro
- Worst Performing Feeders - Power System Solutions International
- Worst Feeder Methodology - Presented by Hydro Ottawa at 2012 EDIST conference.

Enersource used an electronic spreadsheet in the past to list the worst feeders. In 2011, Enersource began following the Hydro Ottawa methodology with some variations. This methodology was tested using software spreadsheets before being implemented in Enersource's IOM reporting tool to identify the worst feeders in the system.

Enersource has enhanced its worst feeder reports and applies improved methodology to identify operational impacts at the transformers level in the system. Some of the reasons for this change are identified below:

- Normal system configuration and abnormal configuration can skew reliability measures;
- Worst feeder may not identify worst area of the system;
- IOM statistics are recorded against each transformer (with few exceptions);
- Inspection data and manufacturer information can be used to refine reporting on reliability impacts at the transformer level;
- Transformer outage data helps indicate poor performing areas in the system; and
- History and details of reliability statistics of each transformer remains in the IOM data base for future reference.

Methodology

Enersource is using the weighting methodology as shown in Table 16.

Table 16. Worst Performing Feeder Weighting Methodology

Occurrence date	Weight	Customers affected	Customer minutes	Number of sustained outages
Current year	0.4	0.3	0.3	0.4
1^{st} year prior to current	0.3	0.3	0.3	0.4
2^{nd} year prior to current	0.3	0.3	0.3	0.4

Once the rank for each transformer is calculated based on reliability history, additional factors are considered to select poor performance areas and equipment that is at the end-of-life or that must be replaced due to regulatory requirements.

Below are factors that determine areas that need to be rebuilt:

- Reliability – based on the Worst Feeder methodology
- Transformers that are leaking oil
- Transformers that contain PCB
- Health Index of the cables and transformers
- Frequency of cable failures
- Age of the cables and transformers
- Transformers located in rear lots.

Once the projects are selected using the factors shown above, they are scrutinized to ensure the project scope and boundaries are properly defined.

Figure 12 is an example of one of the detailed visual maps used to indicate where Enersource has had significant reliability issues over the last three years, along with asset health condition.

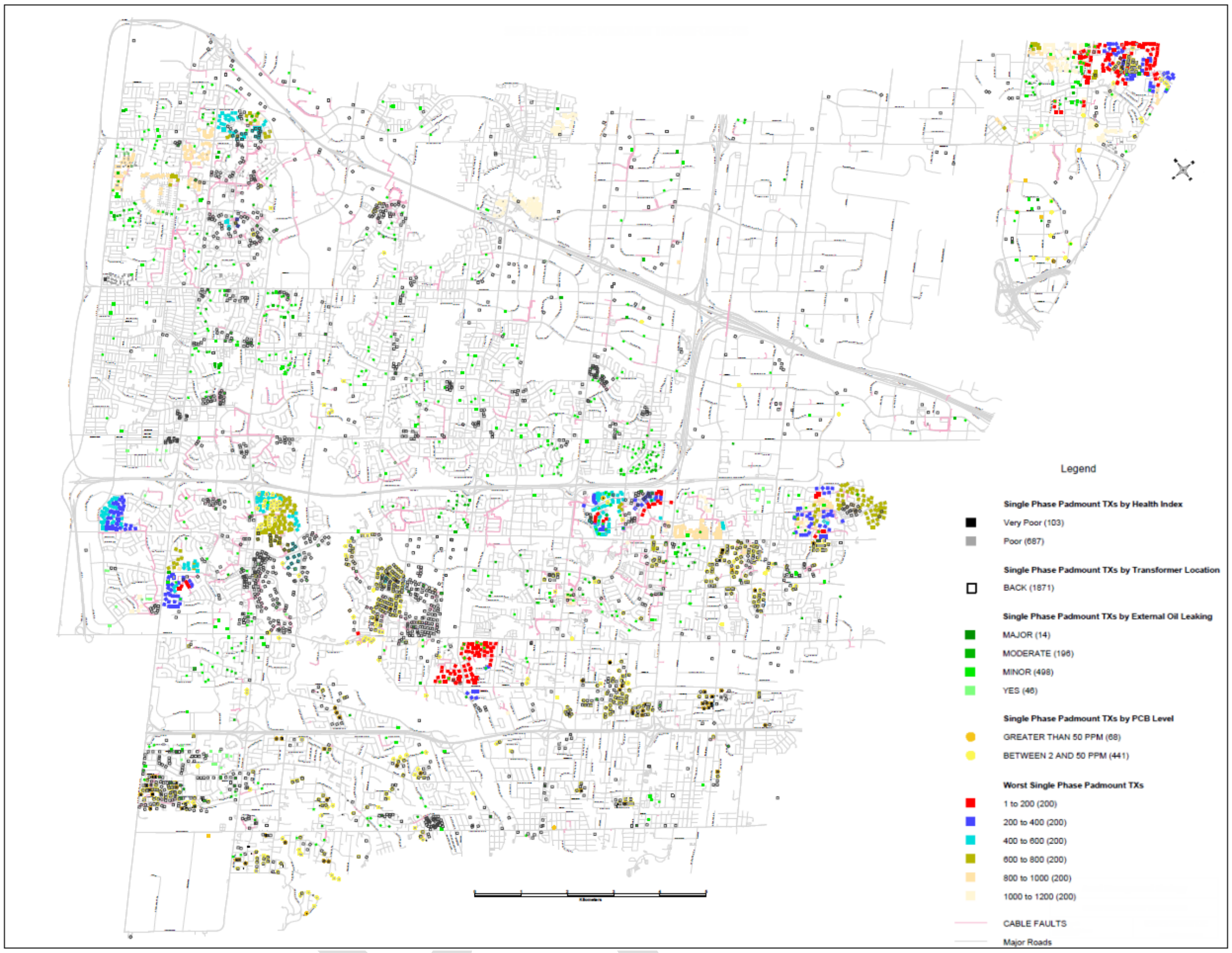


Figure 12. Enersource Underground Reliability Performance (2012-2014)

2.1.2.6 Reliability Risk/Consequence of Failure Analysis

Enersource uses a Risk Model Matrix to identify the risk associated with not undertaking an investment. Project concepts are first reviewed to determine if they are a mandatory project. Mandatory projects are typically dictated by the OEB via the DSC or other regulatory instruments. Projects range from customer connections, to line relocations, to restoring power in a timely fashion. These projects are then prioritized based on whether they pose immediate concerns to safety, environment, or constrain the operation of the system. Immediate concerns move directly to the execution phase, may take precedence over planned projects and cause deferral or delays. Otherwise, the projects are prioritized against Enersource's business values and are scheduled to be completed in a timely manner.

Non-mandated projects are evaluated and possible alternatives are developed which meet the desired objectives of the project. This evaluation is done through business case development which evaluates alternatives against pre-defined investment criteria and proposed recommendation(s).

Project alternatives are then scored by identifying their risks and/or benefits as they relate to Enersource's business values through use of the Risk Matrix. The prioritization is shown in **Tables 17-19**.

Table 17. Customer Focus

Score	Service Quality i.e., does the project improve a Customer Service ESQR metric?	Customer Satisfaction i.e., does the project add Customer Value?	Reputational Risk i.e., does the project reduce or eliminate a reputational risk?
10	Improvement from non-compliance to compliance	Direct positive impact that will be reflected on next customer survey	Prevents or significantly reduces likelihood of irreparable brand damage
8	Significant improvement to ESQR	Adds value or service that customers have identified through survey or ~~some~~ other means	Positive impact on brand
5	Improvement of multiple ESQRs	Improves customer experience (a large user or 1,000 residential customers)	Helps preserve brand
3	Makes an improvement or prevents degradation of one ESQR	Positive improvement to customer experience (non-quantifiable)	May mitigate brand risk
0	No impact on ESQR	No impact on customer service	No brand impact

Table 18. Operational Effectiveness

Score	Safety (Customer & Employee) i.e., this project mitigates exposure that could cause:	Environmental Impact/Risk i.e., this project mitigates exposure that could cause:	System Reliability i.e., this project maintains or improves system reliability:	System Expansion i.e., this project increases system capacity:	System Renewal i.e., this project is for replacement of distribution assets where:
10	Potential loss of life	Environmental disaster	Prevent 100,000 customer minutes of outage	New infrastructure to avert major system constraint/risk	ACA health index "Very Poor"

Score	Safety (Customer & Employee) i.e., this project mitigates exposure that could cause:	Environmental Impact/Risk i.e., this project mitigates exposure that could cause:	System Reliability i.e., this project maintains or improves system reliability:	System Expansion i.e., this project increases system capacity:	System Renewal i.e., this project is for replacement of distribution assets where:
8	Non-reversible injury	High environmental impact	Prevent 80,000 customer minutes of outage	New infrastructure required to support service capacity	ACA health index "Poor"
5	Medical aid injury	Medium environmental impact	Prevent 50,000 customer minutes of outage	Upgrade existing infrastructure to support existing service capacity	ACA health index "Fair"
3	First aid injury	Low environmental impact	Prevent 30,000 customer minutes of outage	Provide system capacity without compromising service to existing customers	ACA health index "Good"
0	No safety risk	None	No impact on customer minutes of outage	No Impact on system capacity	ACA health index "Very Good" or N/A

Table 19. Financial Performance

Score	Cost Efficiencies i.e., this project will save/avoid operational costs or create revenue of:	Ongoing Costs i.e., this project will incur/create ongoing cost of:
10	> $100,000	< $30,000
8	> $80,000	< $50,000
5	> $50,000	< $80,000
3	> $30,000	< $100,000
0	No significant amount	No significant amount

2.2 Overview of Assets Managed (OEB Chapter 5.3.2)

This section provides a summary of Enersource's distribution service area, demographics, and condition of the assets managed. It also summarizes the current state of the system loading as it relates to station and feeder capacity.

2.2.1 Description and Explanation of Distribution System Features

Enersource owns and operates the electricity distribution system in the City of Mississauga (City or Mississauga) and serves over 203,000 customers, including homes and businesses. Enersource is governed by the *Electricity Act, 1998,* and regulated by the OEB under the *Ontario Energy Board Act, 1998*.

The current City, incorporated in 1974, was formed through the amalgamation of the Town of Mississauga and the villages of Port Credit and Streetsville, together with portions of the Townships of Toronto Gore and Trafalgar.

In 2000, the name Enersource emerged, associated with the commercial restructuring of the Company, a process that resulted in several affiliates including Enersource Hydro Mississauga Inc.

Enersource and its founding utilities achieved many innovations over the years. From the early 1900's as the first township to contract for electricity with Ontario Hydro, to the 1950's as it began to innovate with underground distribution through residential neighborhoods, Enersource set a record as a municipal utility by supporting the development of 1,000 electrically-heated homes.

Enersource's territory covers 288 square km which includes 1,797 km of overhead line circuits, 3,383 km of underground line circuits and over 25,000 distribution transformers. A map of Enersource's service territory is shown in **Figure 13**.

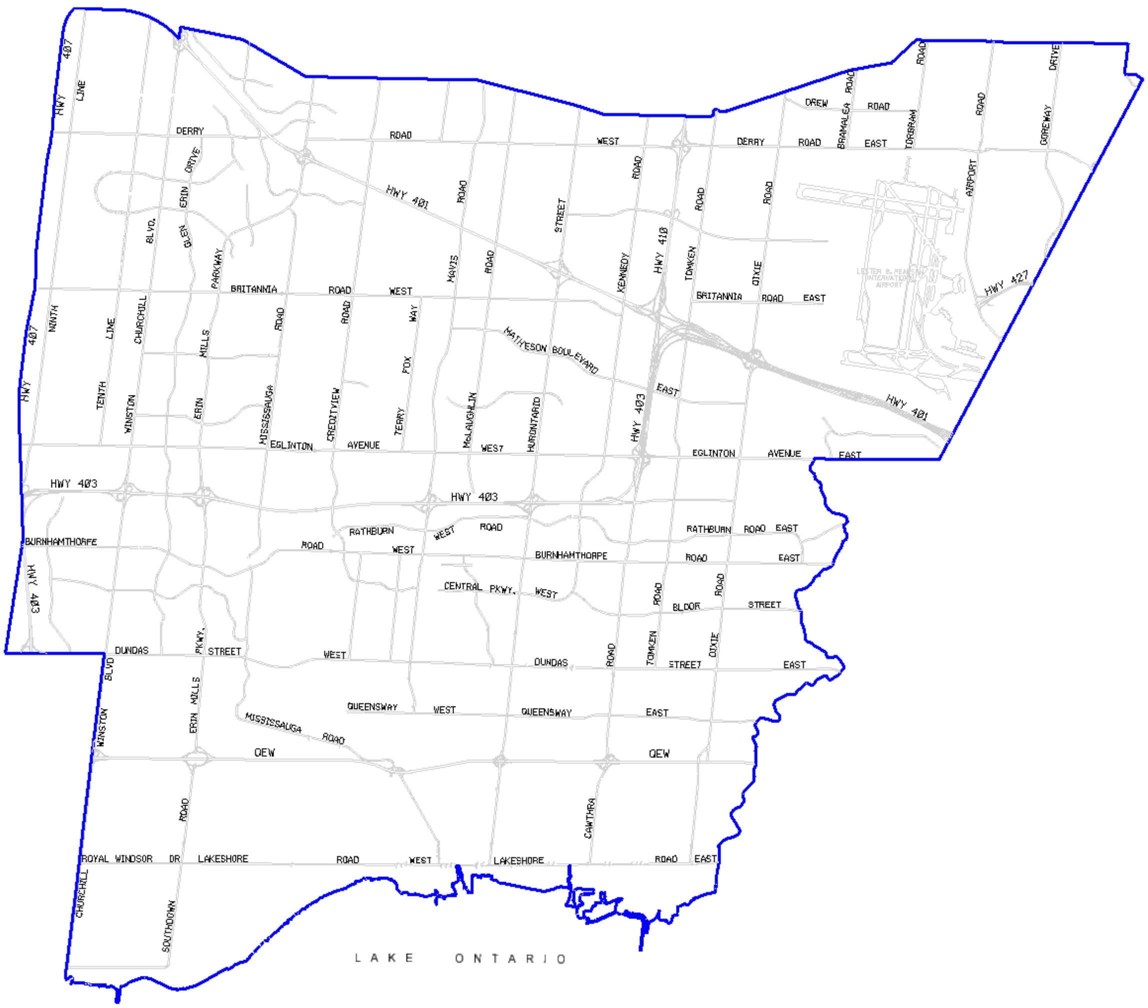


Figure 13. Map of Enersource Territory

Climate Normals Comparison

For comparisons to other major Ontario cities, climate normals for Toronto, as recorded by the Government of Canada, are used.

Compared to other major cities, Mississauga is characterized by having generally average wind speeds and winters with lower snowfall.

Although Enersource strives to complete capital work throughout the year, work must be scheduled to accommodate the winter months during which time there are greater hazards to field crews and added challenges such as snow removal, before work can even begin.

The data presented in **Figures 14-18** represents the climate normals from 1981-2010 as recorded by the Government of Canada.

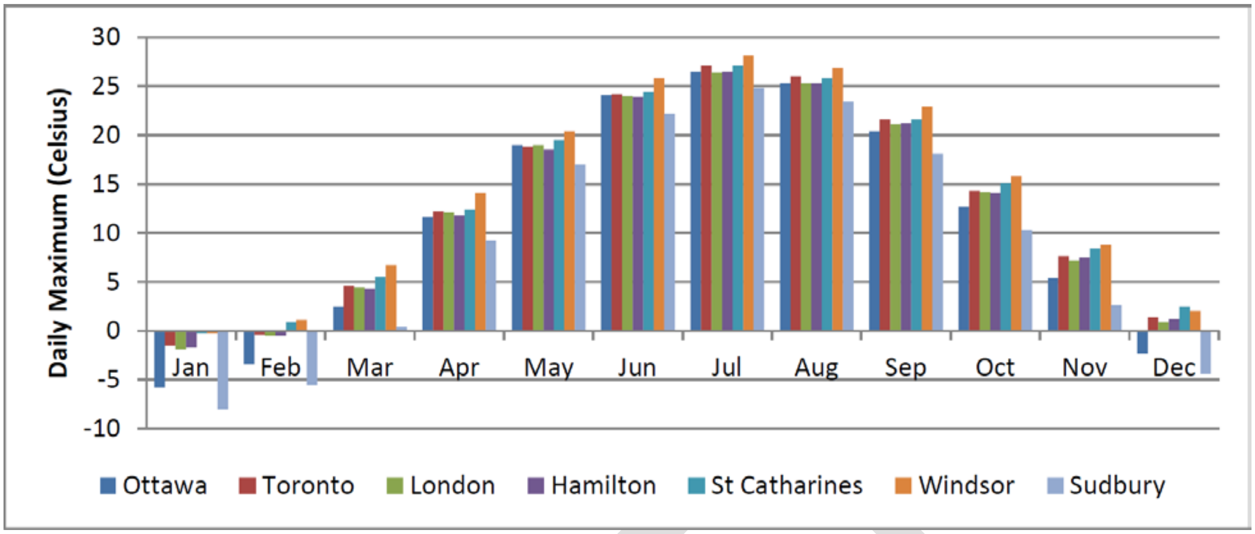


Figure 14. Daily Maximum Temperature

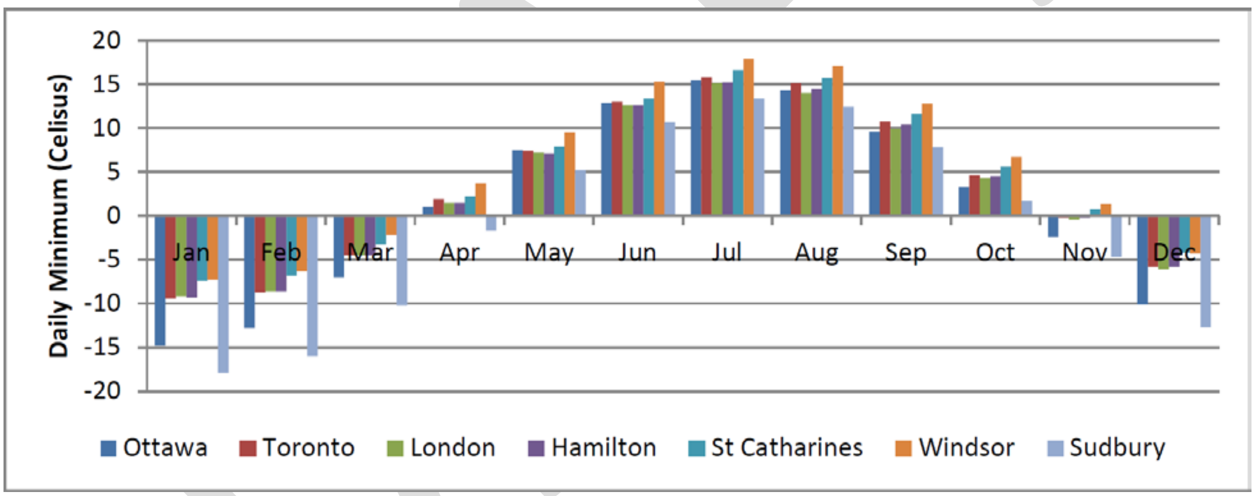


Figure 15. Daily Minimum Temperature

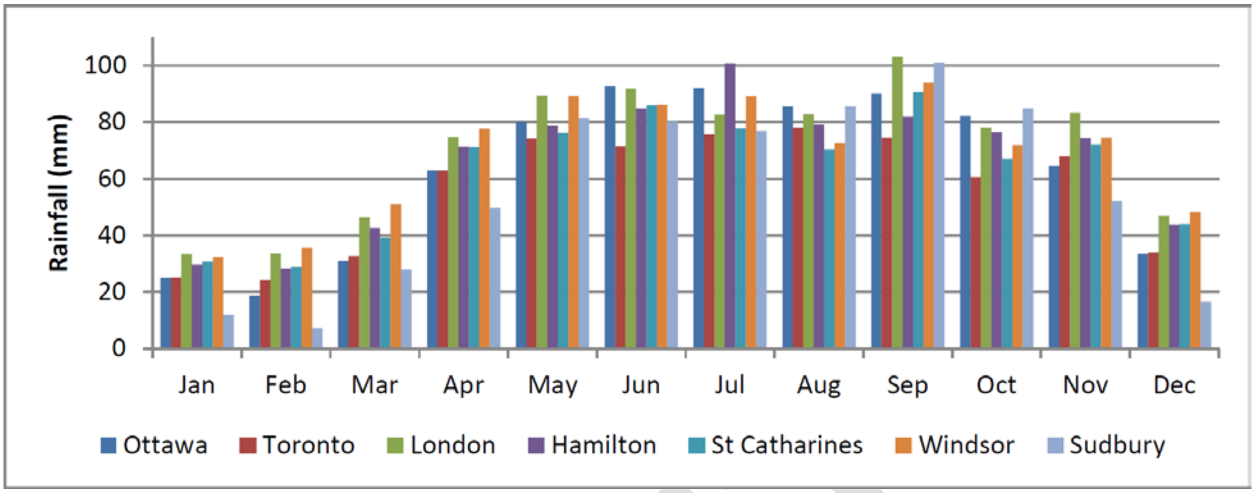


Figure 16. Rainfall

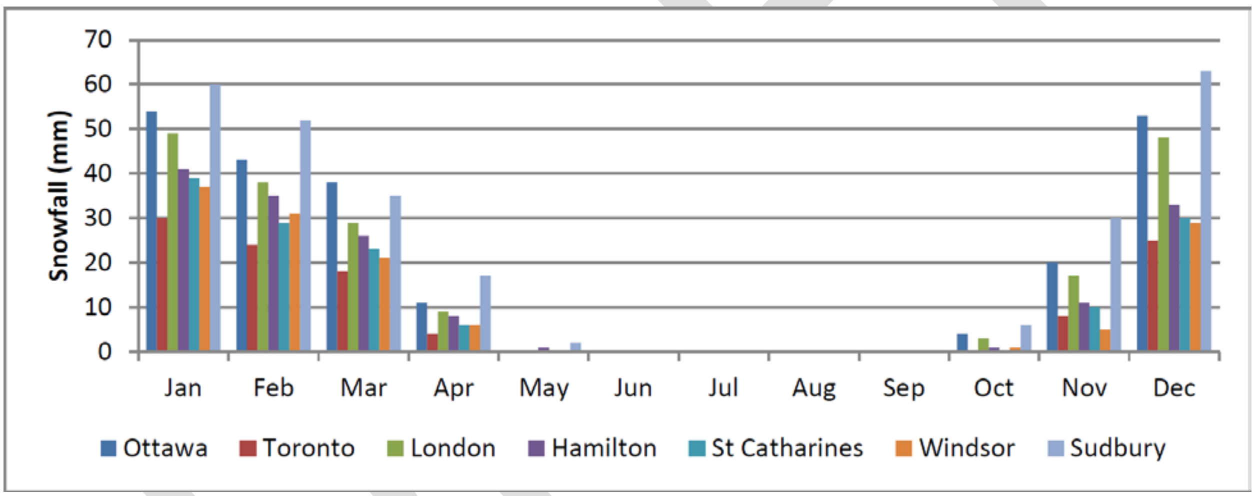


Figure 17. Snowfall

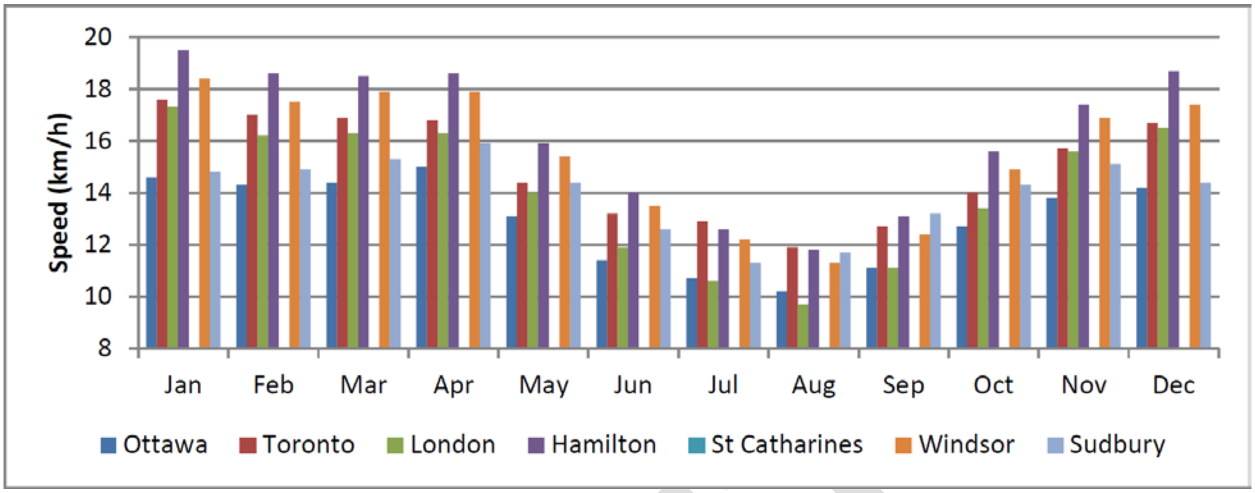


Figure 18. Wind speed

Temperature Profile

The Mississauga region temperature profile requires that Enersource equipment be able to operate under a temperature range of -40 to +40 degrees Celsius. Various pieces of equipment that contain inert gasses may not operate reliably at the lower end of this range and thus require extra heaters to ensure reliable operation. Extra heaters on equipment causes design changes and non-standard equipment procurement. The need for additional heaters may require a larger initial capital investment than that of a similar equipment model in areas with a warmer temperature range.

Ice Accumulation & Snow Loading

According to CSA Standard CAN/CSA C22.3 No.1 'Overhead Systems', Mississauga is located in an area of Ontario designated as "Heavy Loading", and as such requires designs to account for a radial thickness of 0.5" of ice covering overhead lines. Due to this possible ice accumulation, civil structures (concrete and wood poles) must be able to withstand ~~a~~ significant ice build-up without impacting structural integrity. This requires that larger class sizes and/or an increase in the number of poles be used when designing overhead systems.

Harsh winters also result in an increased use of road salts which can lead to premature rusting of pad mounted and pole mounted equipment located along the road. The salt spray from roadways also impacts operating and maintenance costs by increasing the need to wash porcelain insulators to prevent tracking and flash overs which lead to asset failures. The presence of road salt causes an increased need to repaint and repair rusted pad mounted and pole mounted equipment.

2.2.2 System Configuration

System Description

Enersource owns and operates the electrical power system in Mississauga. The system can be divided into two main categories: subtransmission and distribution.

Subtransmission System

Enersource's subtransmission system operates at a voltage of 44kV. The system receives electricity from HONI's Transformer Stations (TS) where voltage is transformed from 230kV to 44kV.

The HONI TS sites are: Meadowvale TS, Churchill Meadows TS, Erindale TS, Tomken TS, Bramalea TS, and Woodbridge TS. Enersource's subtransmission system is comprised of two areas: West 44kV and East 44kV, as illustrated in **Figure 19** below.

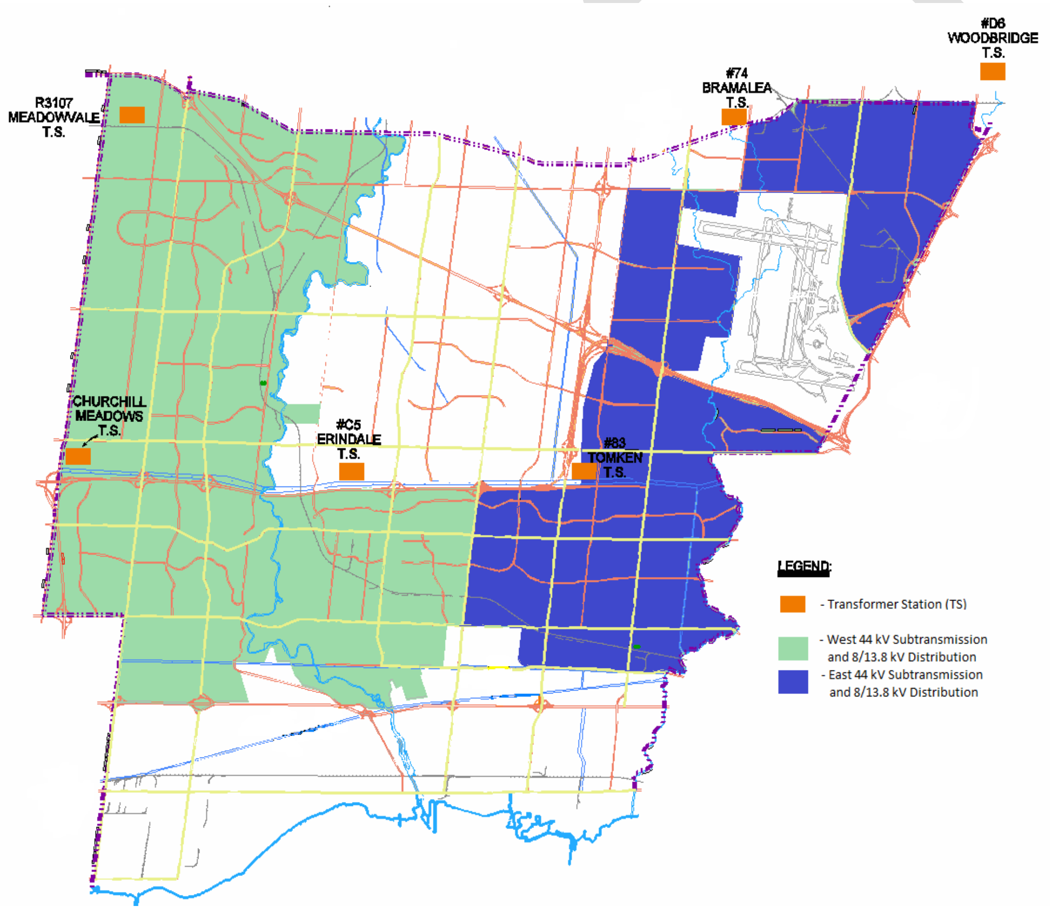


Figure 19. Map of Enersource 44kV subtransmission system

Distribution System

Enersource's distribution system operates at the voltages of 16/27.6kV, 8/13.8kV, and 2.4/4.16kV.

The system receives electricity from two sources: HONI's TS's where voltage is transformed from 230kV to 16/27.6kV, or Enersource's substations sites where the voltage is transformed from 44kV to 8/13.8kV or from 16/27.6kV to 2.4/4.16kV

The HONI TS sites are: Oakville TS, Lorne Park TS, Cooksville TS, Richview TS, Erindale TS, Cardiff TS, and Bramalea TS.

Enersource supply points consist of 66 substations utilizing 108 power transformers that vary in capacity from 3 MVA to 20 MVA. In addition, 58 distribution feeders are supplied directly from HONI's TS's.

Enersource has divided its distribution system into four areas: North 16/27.6kV, South 16/27.6kV and 2.4/4.16kV, West 8/13.8kV and East 8/13.8kV as illustrated in **Figure 20** below.

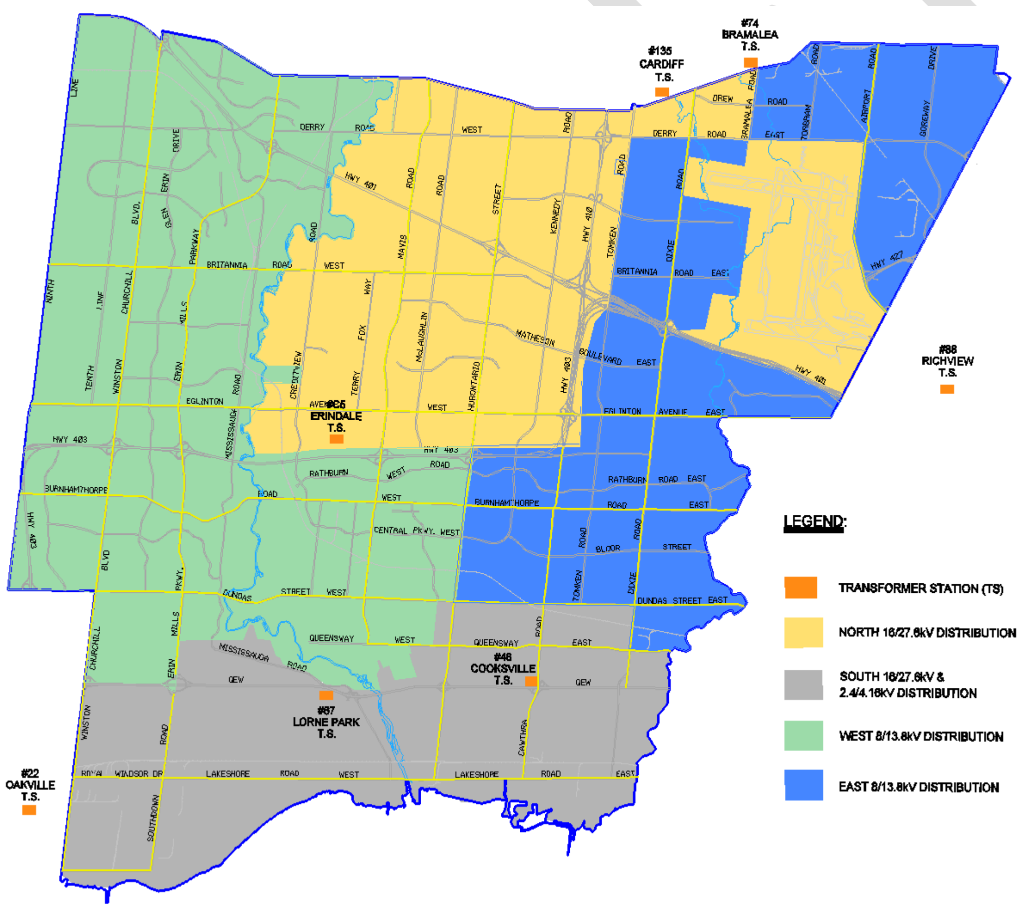


Figure 20. Map of Enersource distribution system

North 16/27.6kV Distribution System

The North 16/27.6kV System consists mainly of distribution equipment which is connected directly to HONI TS feeders.

HONI TS sites are: Erindale TS, Bramalea TS, Cardiff TS, and Richview TS.

This area contains one Enersource substation site (Mini Derry) comprised of two step-down transformers rated 44/27.6kV. The overall North 16/27.6kV distribution system utilizes 36 distribution feeders, four of which are supplied by the Mini-Derry substation and 32 are supplied by HONI TS sites.

The area serviced by this system is illustrated in **Figure 21** below.

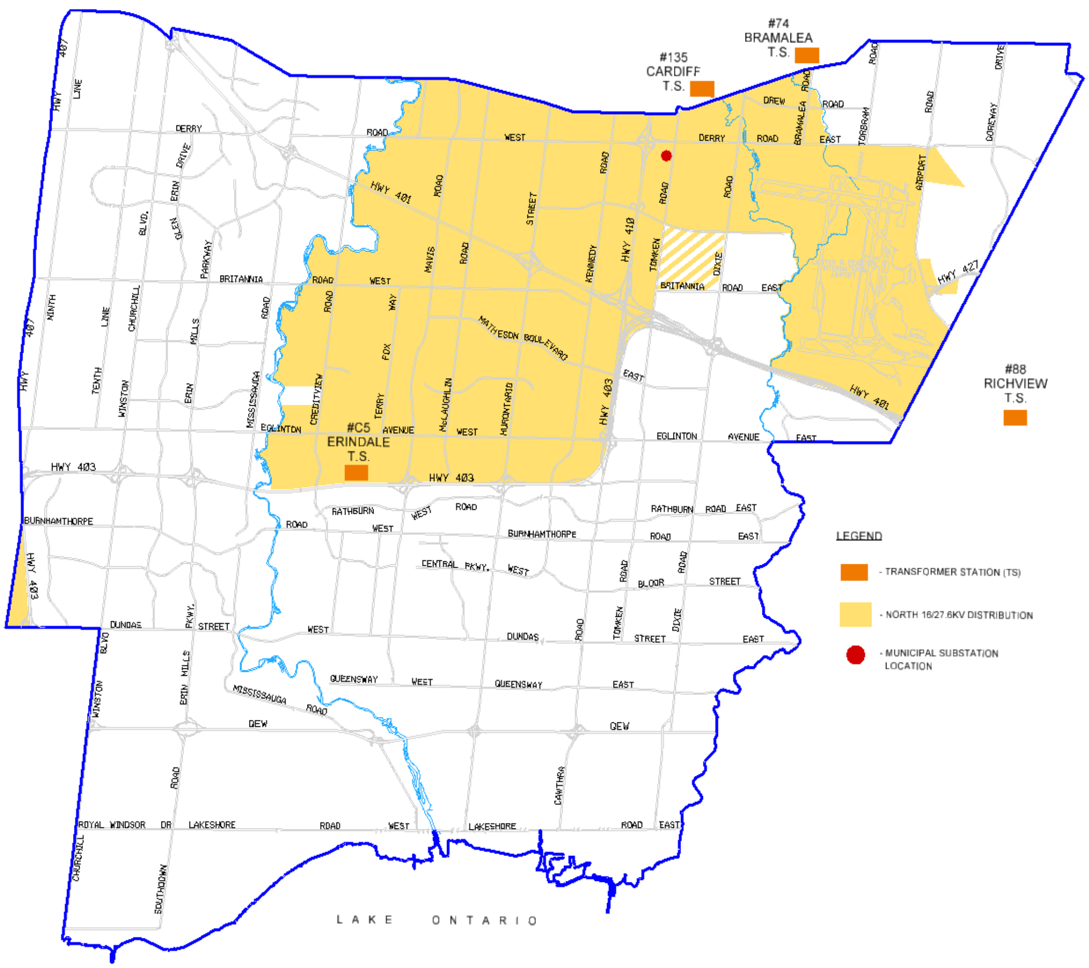


Figure 21. Map of Enersource North 16/27.6kV distribution system

South 16/27.6kV and 2.4/4.16kV Distribution System

The South 16/27.6kV System is composed of several large and small customers connected directly to HONI TS supply. Enersource's MS's further step down the voltage to the 2.4/4.16kV distribution system.

HONI TS sites are: Oakville TS, Lorne Park TS, and Cooksville TS.

This area contains 25 substations comprised of 42 step-down transformers rated 27.6/4.16kV. The 2.4/4.16kV distribution system consists of 100 feeders.

The area serviced by this system is illustrated in **Figure 22** below.

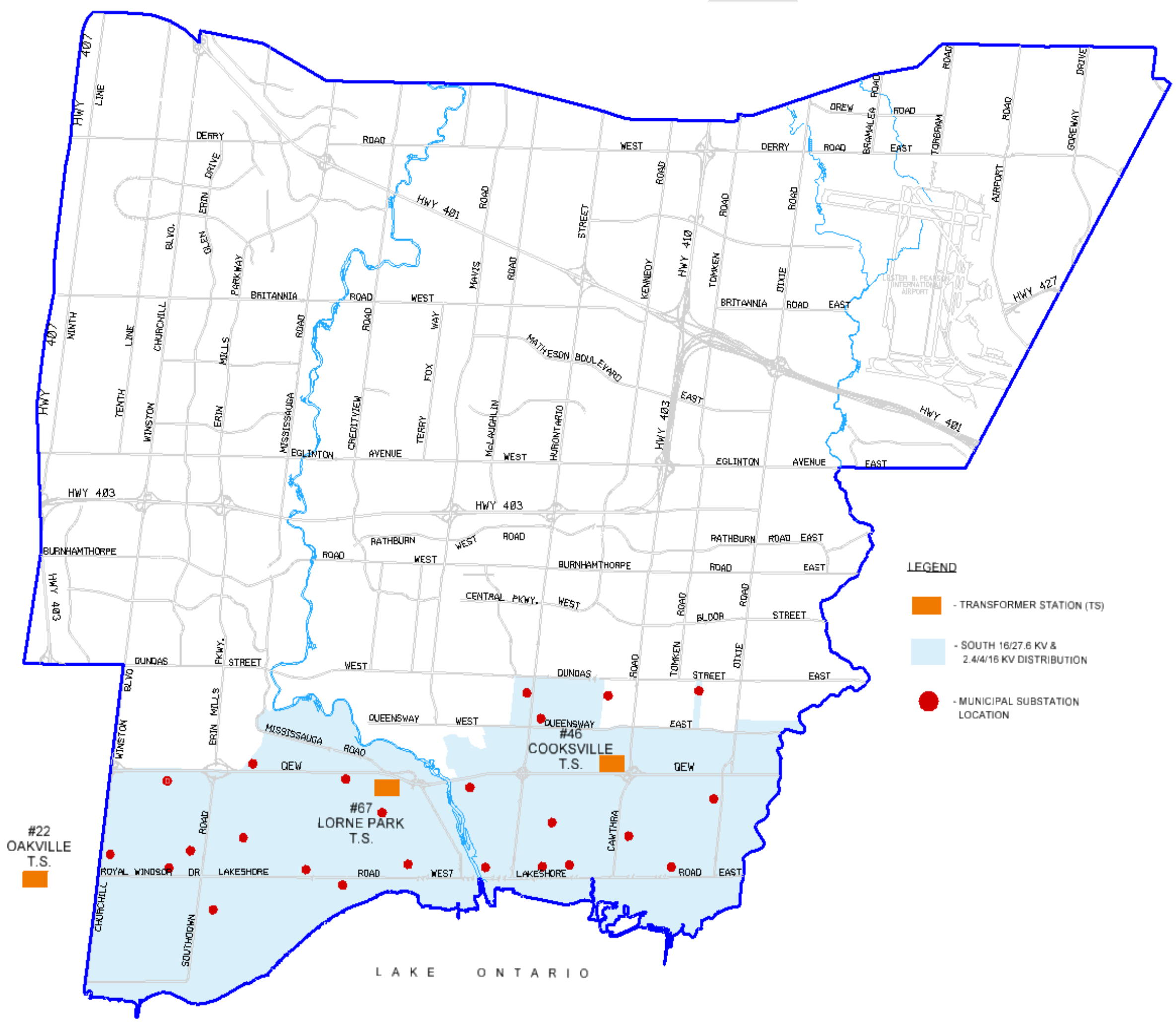


Figure 22. Map of Enersource South 16/27.6 and 2.4/4.16kV distribution systems

West 8/13.8kV Distribution System

The West 8/13.8kV Distribution System covers the same geographical area as the 44kV sub transmission system, as shown in **Figure 19**. However, due to the large area and number of customers, the 8/13.8kV distribution system has been divided into west and east distribution systems, which is consistent with the division between the west and east 44kV subtransmission systems. All customers on this West 8/13.8kV system are connected directly to the distribution feeders supplied by Enersource MS's.

This area contains 23 substation sites comprised of 37 step-down transformers rated 44/13.8kV. This distribution system utilizes 137 distribution feeders.

The area serviced by this system is illustrated in **Figure 23** below:

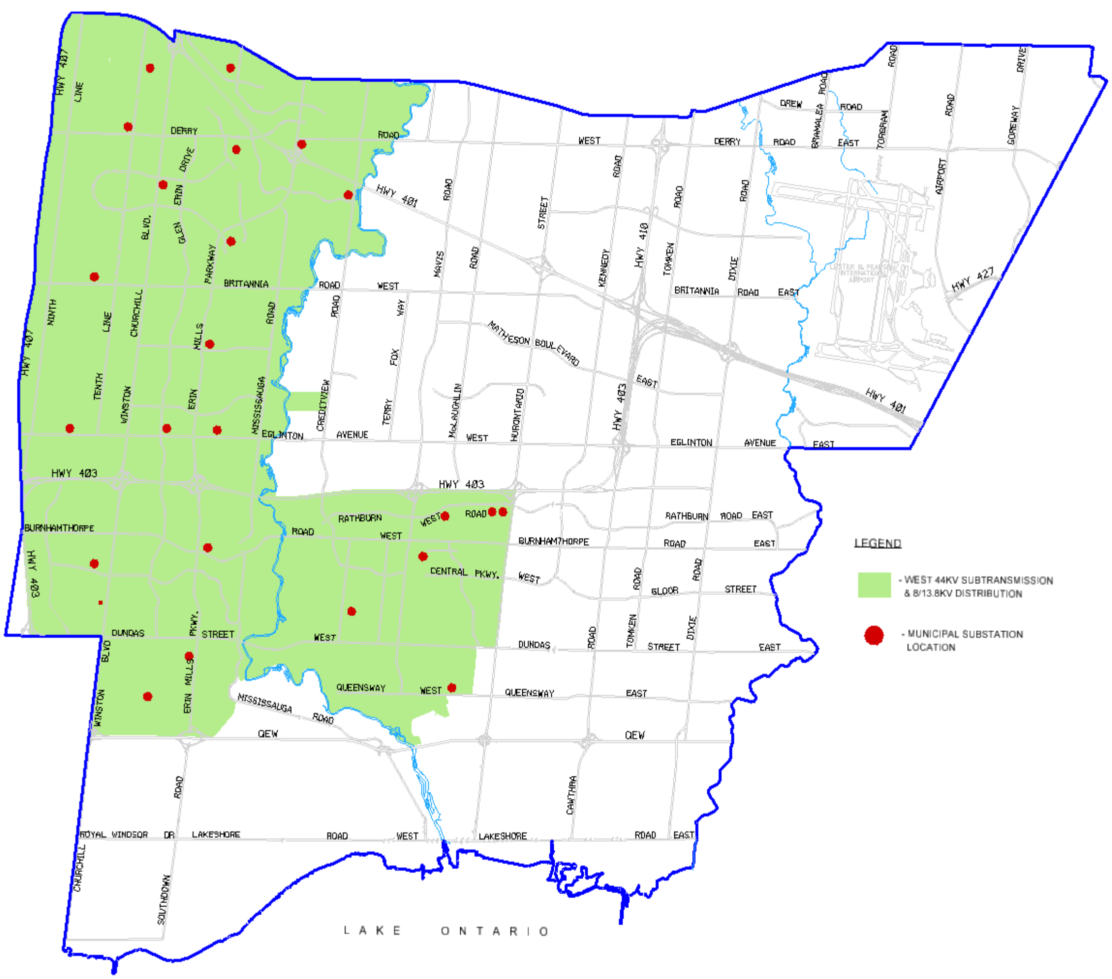


Figure 23. Map of Enersource West 8/13.8kV distribution system

East 8/13.8kV Distribution System

All customers on this system are connected directly to the distribution feeders supplied by Enersource MS's.

This area contains 17 substation sites comprised of 29 step-down transformers rated 44/13.8kV. This distribution system utilizes 88 distribution feeders.

The area serviced by this system is illustrated in **Figure 24** below:

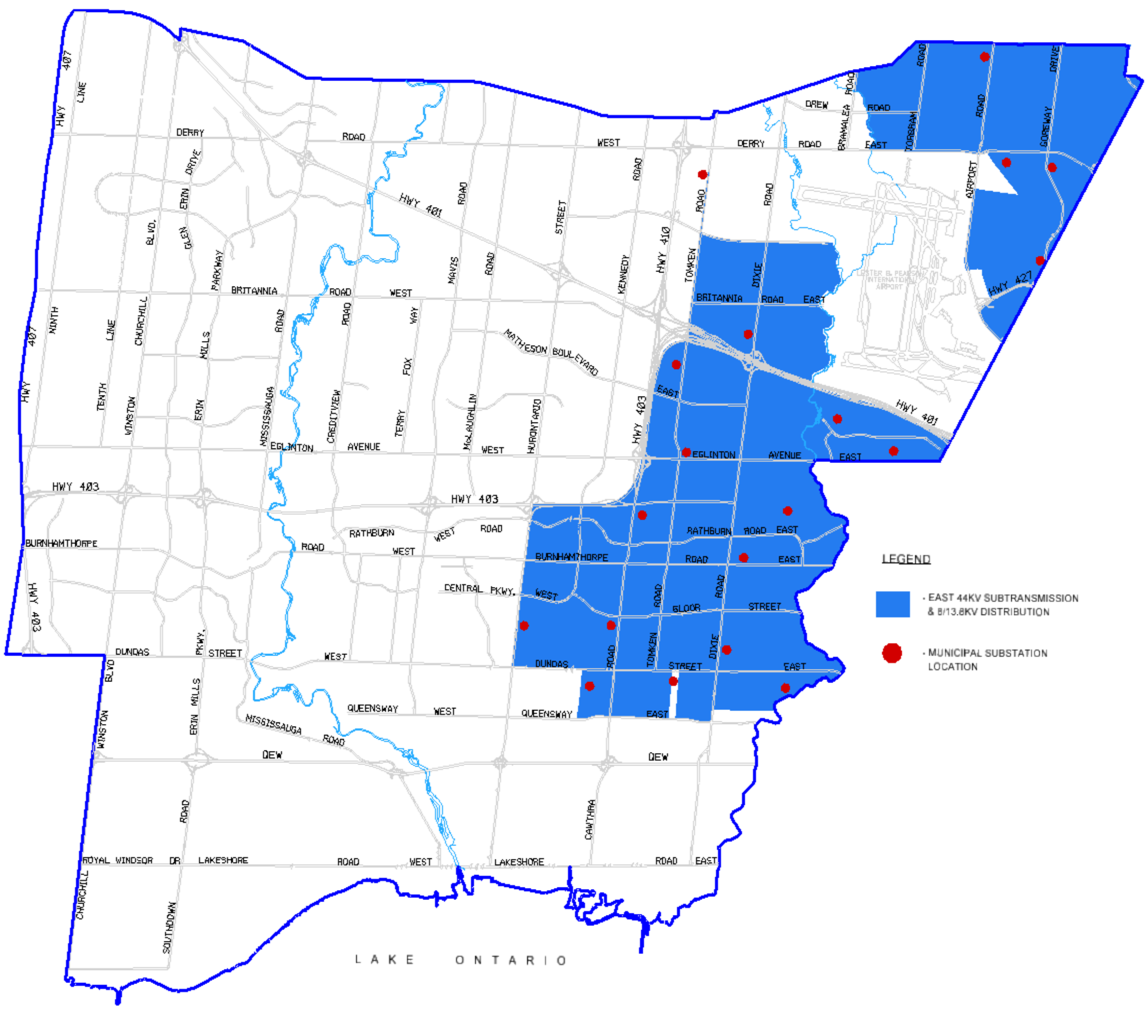


Figure 24. Map of Enersource east 8/13.8kV distribution system

Tables 20-22 present a summary of the system configurations.

Table 20. Length of underground and overhead systems

Location	Total Circuit Length (km)	Total Conductor Length (km)
Underground	3,383	6,271
Overhead	1,797	5,139
Total	**5,180**	**11,410**

Table 21. Number and length of circuits and conductors by voltage level

Voltage Level (kV)	Number of Circuits	Underground Circuits Length (km)	Underground Conductors Length (km)	Overhead Circuits Length (km)	Overhead Conductor Length (km)
4.16	130	280	421	276	676
8.32	3	0	0	2	3
13.8	291	2,140	3,942	543	1,537
27.6	139	931	1,814	494	1,478
44	79	31	94	482	1,446
Total	**642**	**3,383**	**6,271**	**1,797**	**5,139**

Table 22. Number and capacity of municipal stations

Secondary Voltage Level (kV)	Number of Stations	Number of Transformers	Total Transformation (MVA)
4.16	25	42	181
13.8	40	64	1,260
27.6	1	2	40
Total	**66**	**108**	**1,481**

2.2.3 Asset Demographics and Condition

The following section summarizes the demographics and condition assessment for the major asset classes within Enersource's distribution system. Asset condition is based upon a health index computation which is unique for each asset class. In instances where detailed asset information is lacking, the asset condition is computed based on the age of the asset (i.e. age-based condition).

Shown in **Table 23** and **24** below is the asset demographics with associated health index contribution and the asset management strategy (i.e., replacement) for each asset category.

Table 23. Asset Health Index Summary

Asset Category		Population	Average Health Index	Health Index Distribution: Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	Average Age
Substation Transformers	In Service	108	82%	< 1%	2%	14%	36%	47%	22
	Spares	12	80%	8%	0%	17%	8%	67%	33
Circuit Breakers		510	94%	2%	< 1%	2%	4%	93%	20
Pole Mounted Transformers		5346	92%	2%	< 1%	6%	11%	80%	21
Pad Mounted Transformers	1 Phase	14242	87%	< 1%	4%	7%	29%	59%	21
	3 Phase	1821	94%	< 1%	2%	4%	9%	84%	16
Vault Transformers		3861	87%	2%	7%	7%	13%	71%	27
Pad Mounted Switchgear		862	84%	6%	3%	7%	19%	65%	19
Overhead Switches	44 kV	338	95%	0%	5%	< 1%	6%	88%	20
	27.6 kV	213	97%	0%	1%	3%	2%	93%	18
	Inline	2002	93%	1%	3%	4%	5%	86%	18
	Motorized	104	85%	8%	7%	2%	6%	78%	16
Underground Cables *Note that results are given in terms of conductor-km	Main Feeder	2233	78%	12%	9%	0%	7%	73%	18
	Distribution	4038	70%	21%	13%	0%	6%	60%	21
Poles	Wood	12917	79%	9%	9%	7%	15%	60%	27
	Concrete	8966	97%	0%	< 1%	1%	4%	95%	20

Table 24. Asset Management Strategy

Type	Analysis	Strategy	Frequency
Substation	Switchgear Inspections	Preventative	1 Year
	Breaker & Recloser	Preventative	4-6 Years
	Station Switches	Preventative	1 Year
	SCADA Inspections	Preventative/Predictive	1 Year
	Relay	Preventative	4-6 Years
	Station Inspections	Predictive/Corrective	1 Month
	Battery Maintenance	Predictive	1 Year
	Transformer Maintenance	Preventative	3-5 Years
	Transformer Doble Test	Predictive	3-5 Years
	Transformer Oil Analysis	Predictive	1 Year
	Transformer Tapchanger Maintenance	Preventative/Predictive	3-5 Years
	Padmounted Switchgear IR and Visual Inspection	Predictive/Corrective	5 Years
Distribution	Switchgear Dry Ice Cleaning	Preventative	3-5 Years
	All Transformers Visual Inspection	Predictive/Corrective	3 Years
	Graffiti Abatement	Corrective	1 Year
	Vault Dry Ice Cleaning	Preventative	5 Years
	Vegetation Management	Preventative/Corrective	3 Years
	O/H Visual & Pole Inspection	Predictive/Corrective	3 Years
	Critical Switch Operation	Preventative	1 Year
	O/H Insulator Washing	Preventative	2 Years
	O/H IR Inspection	Predictive	1 Year

2.2.3.1 Station Transformers

In Enersource's distribution system, substation transformers are critical pieces of equipment, whose function is to provide transformation from high voltage transmission and subtransmission lines to a lower voltage to distribute throughout the City. Enersource has 108 station transformers with varying secondary voltages: 42 units at 4.16kV, 65 units at 13.8kV, and two units at 27.6kV. **Figure 25** shows age demographics of stations transformers.

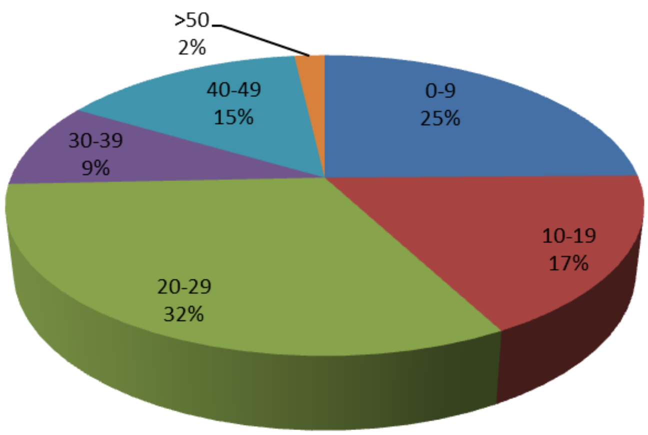


Figure 25. Station Transformer Age Demographics

Enersource acquires various test data to assist in tracking the transformer asset condition. This includes the results of Doble testing, oil analysis (including dissolved gas analysis or DGA), in addition to any findings acquired through routine transformer and transformer tapchanger maintenance. Through various tests and inspections, the concentration and rate of concentration change of dissolved gasses, and quality of the overall mineral oil can be monitored. Once these key indicators reach unacceptable levels, the transformer will be scheduled for off-line inspection and possibly require refurbishment or replacement. **Figure 26** outlines the condition of station transformers using health index computation methodology.

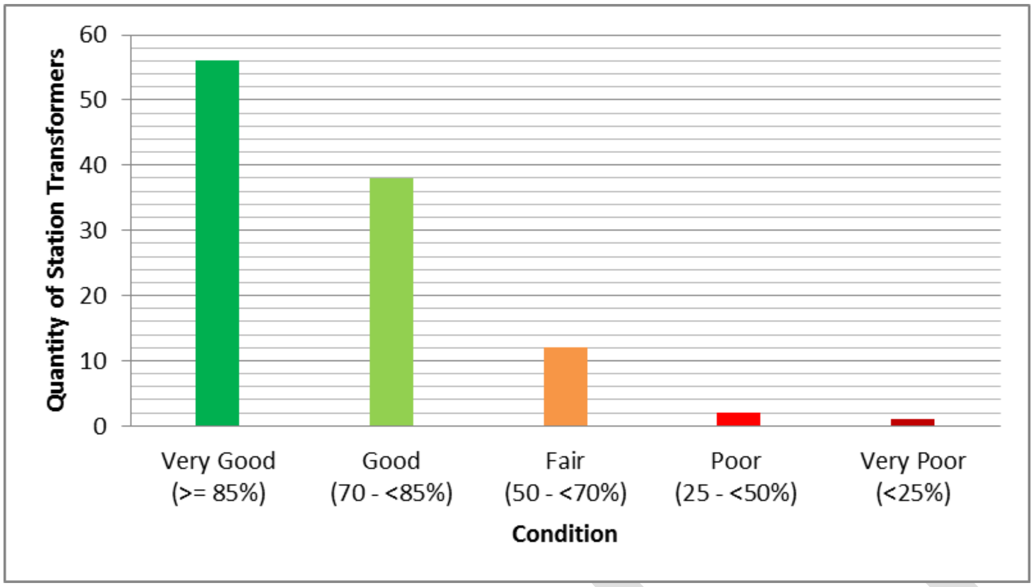


Figure 26. Station Transformer Condition

2.2.3.2 Circuit Breakers

Enersource owns and maintains 510 circuit breakers and assemblies in 66 substations. The station circuit breaker assets consist of breakers, switches, bus insulation, support structures, protection and control systems, arrestors, control wiring, ventilation, and fuses.

Figure 27 shows the average age of station circuit breakers is 20 years with approximately 15% of the population being 40 years or older with age distribution.

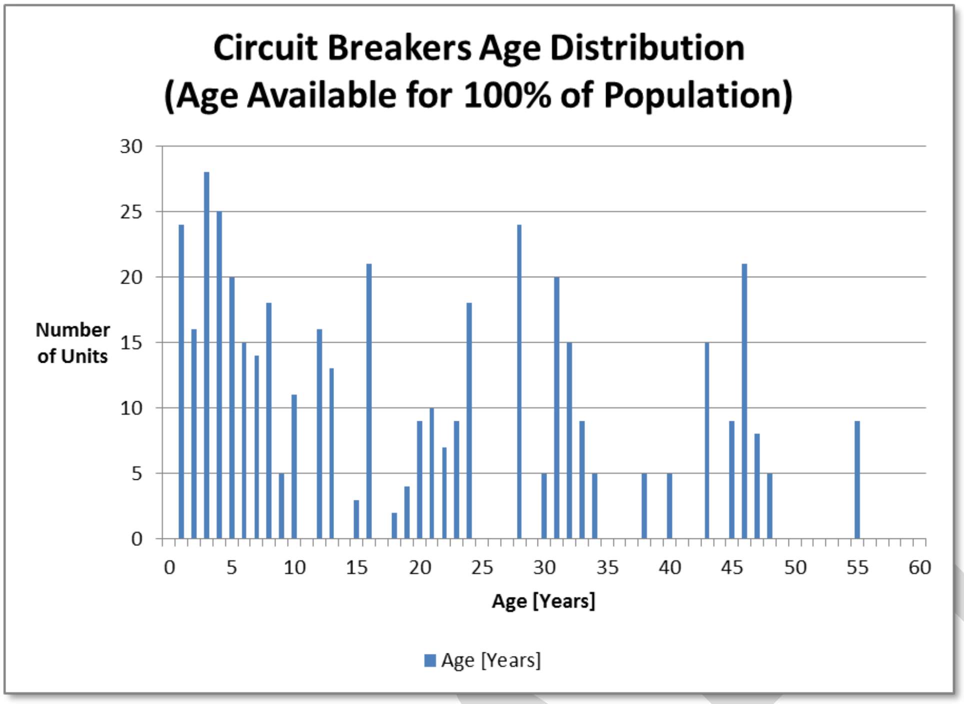


Figure 27. Circuit Breakers Age Distribution

The health index for circuit breakers takes into account many functional and supporting parts. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation and supporting structures. Analysis includes condition parameters such as operating mechanism, contact performance, arc extinction, insulation level, lubrication, contact resistance, tank condition, arc chute life, service record, and the interrupting medium (oil, SF6, Vacuum, Air-Magnetic). The equipment is then reviewed for functional obsolescence and the availability of spare parts. The health index is calculated using this information and the age of the equipment.

With a population of 510 circuit breakers, the average health index for the group was 94% with approximately 2% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 28**.

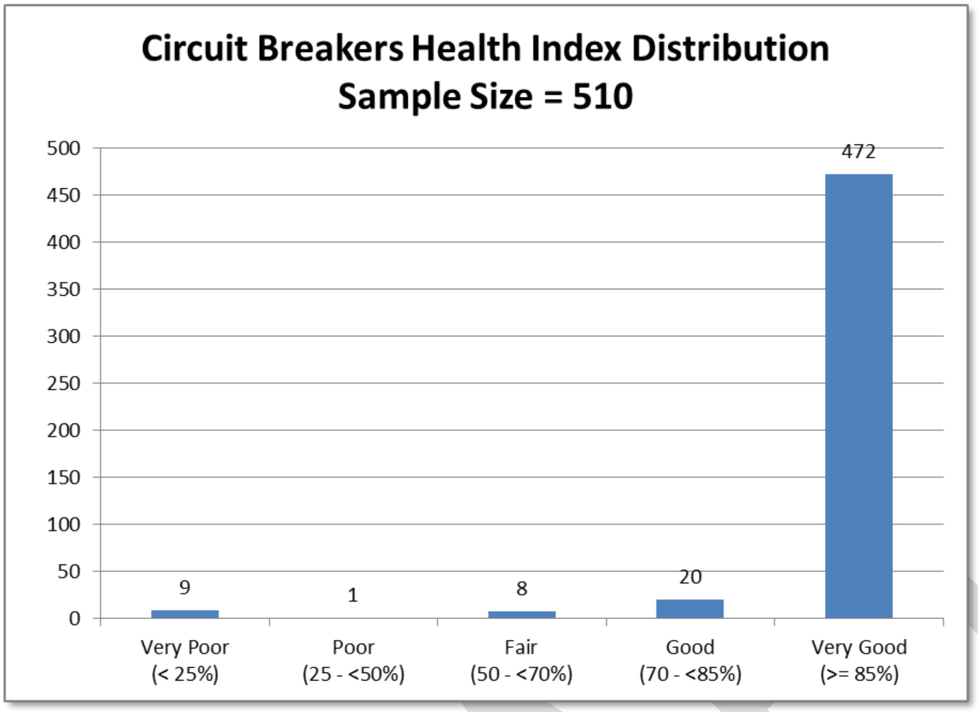


Figure 28. Circuit breakers health index distribution (unit)

2.2.3.3 Pad Mounted Switchgears

Enersource owns and operates a distribution pad mounted switchgear population of over 860 units. These switchgear units provide connectivity, feeder protection, switching and isolation capability, and in some cases remote operation capability and load breaking capability. There are many different types of pad mounted switchgears used to service various applications and that are installed in various projects as a result of a constant need to find more reliable equipment. Like many other electricity utilities in Ontario, Enersource has had reliability issues (including premature failures) with air insulated switchgear as they face day-to-day contaminants. Within the last five years, as vacuum (solid dielectric) switchgear units gained in popularity, Enersource conducted pilot project and cost benefit analysis and moved to replacing air insulated gear with this newer technology that improves reliability and reduces ongoing maintenance costs (e.g., dry ice cleaning).

Demographic information for pad mounted switchgear assets, such as purchase date, installation date, serial number, ratings, etc., are stored in the GIS system. Currently, Enersource is in the process of improving accuracy of data by conducting comprehensive annual inspections and collecting asset data via ruggedized tablets.

The average age of all units was 19 years with approximately 37% of the population being 25 years or older, as shown in **Figure 29**.

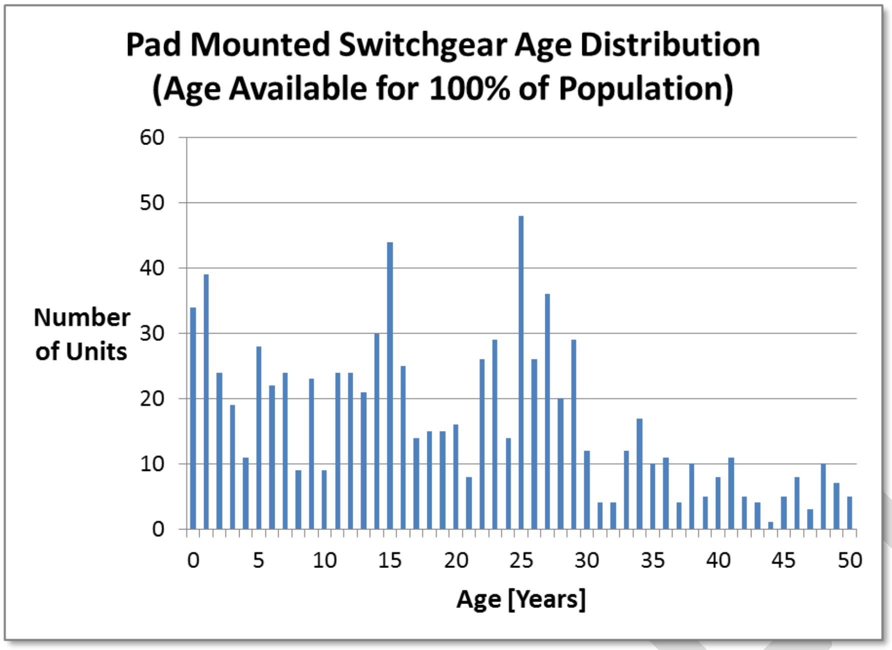


Figure 29. Pad Mounted Switchgear Age Distribution

The health index for pad mounted switchgears takes into account many attributes obtained through switchgear inspections. These include physical condition (such as corrosion, quality of the paint finish, contaminants, i.e., dirt and salt due to road traffic), switch/fuse condition (including remaining life of the arc suppressor), insulation (including cypoxy insulators and fiber flash barriers), and existing service records. The health index is calculated using this information and the age of the equipment.

With a population of 862 pad mounted switchgears, the average health index for the group was 84% with approximately 8% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 30**.

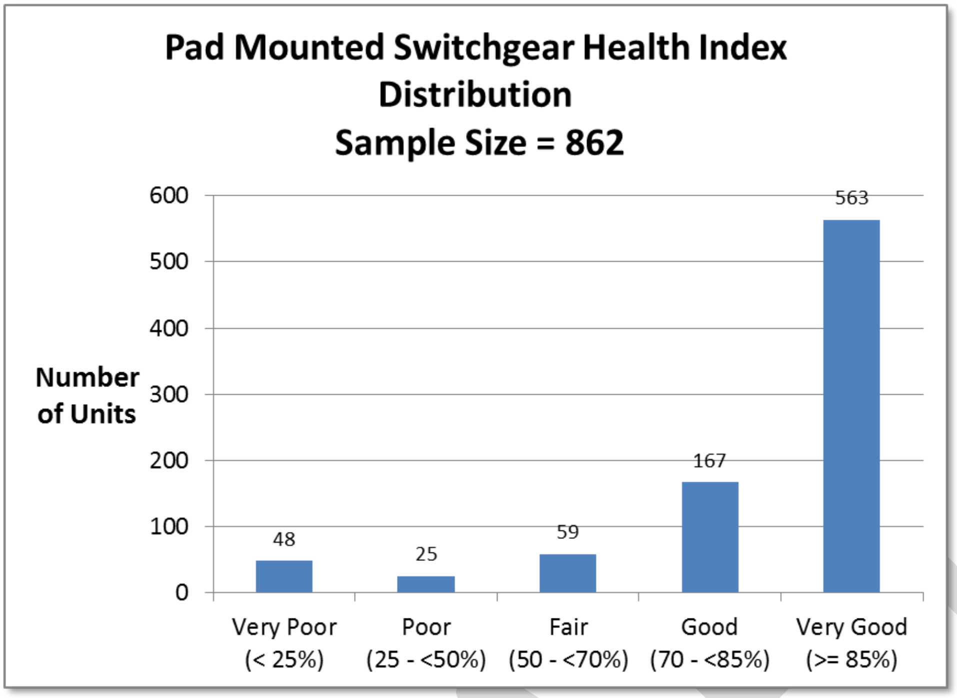


Figure 30. Pad Mounted Switchgear Health Index Distribution (unit)

2.2.3.4 Overhead Line Switches

Enersource owns and operates various types of overhead switches. These switches are typically classified based on their voltage level and function. This includes load break switches on the 44kV and 27.6kV system, both manual operation and motorized and gang operated, and a large population of single phase in-line switches, both single and double insulator. These switches provide connectivity, switching, and isolation capability. This enables a dynamic distribution system that can react to planned isolation and emergency situations while keeping the majority of customers with power. Enersource has a population of 338 load break switches at the 44kV level, 213 load break switches at the 27.6 kV level, 104 motorized load break switches and 2,002 inline switches.

The average age of all 44kV load break switches was 20 years with approximately 9% of the population being 40 years or older, as shown in **Figure 31**.

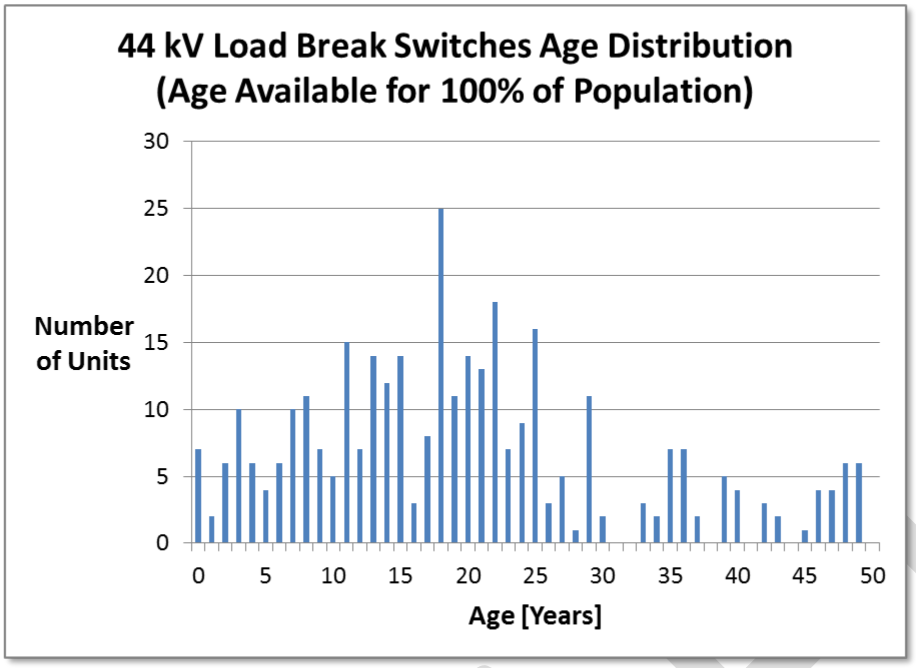


Figure 31. Age Distribution of 44 kV Load Break Switches

The average age of all 27.6kV load break switches was 18 years with approximately 6% of the population being 40 years or older, as shown in **Figure 32**.

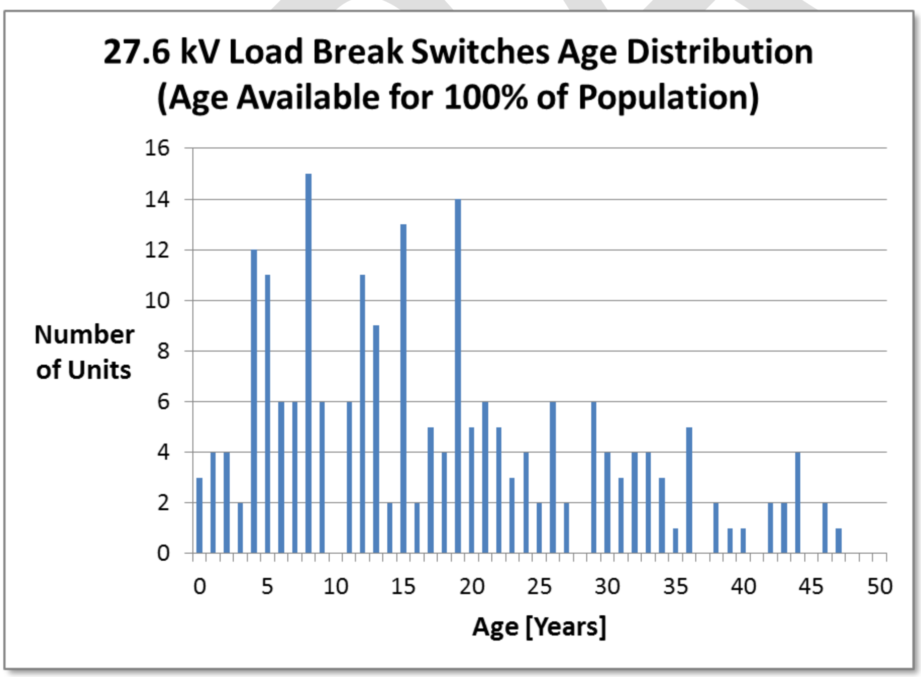


Figure 32. Age Distribution 27.6 kV Load Break Switches

The average age of all motorized switches was 16 years with approximately 27% of the population being 25 years or older, as shown in **Figure 33**.

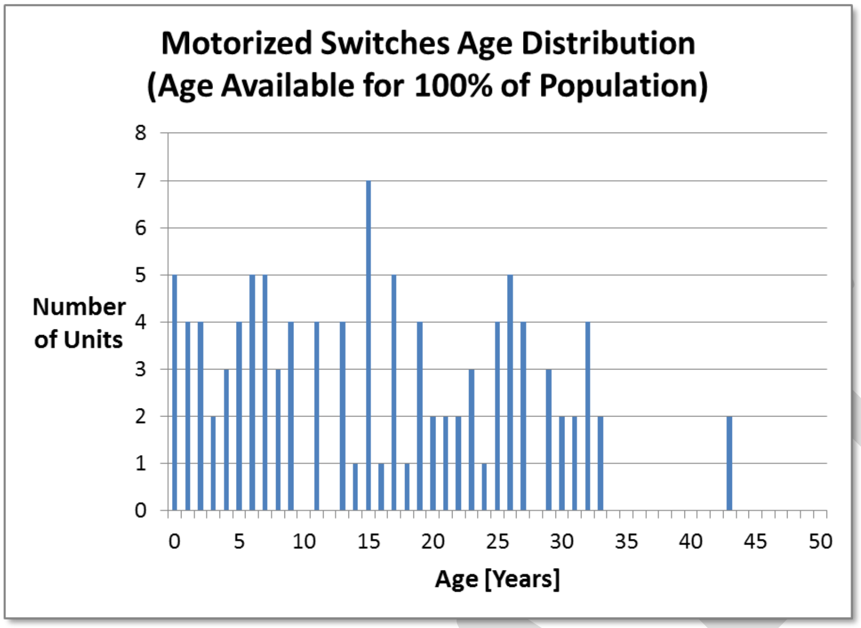


Figure 33. Motorized Switches Age Distribution

The average age of all in-line switches was 18 years with approximately 12% of the population being 40 years or older, as shown in **Figure 34**.

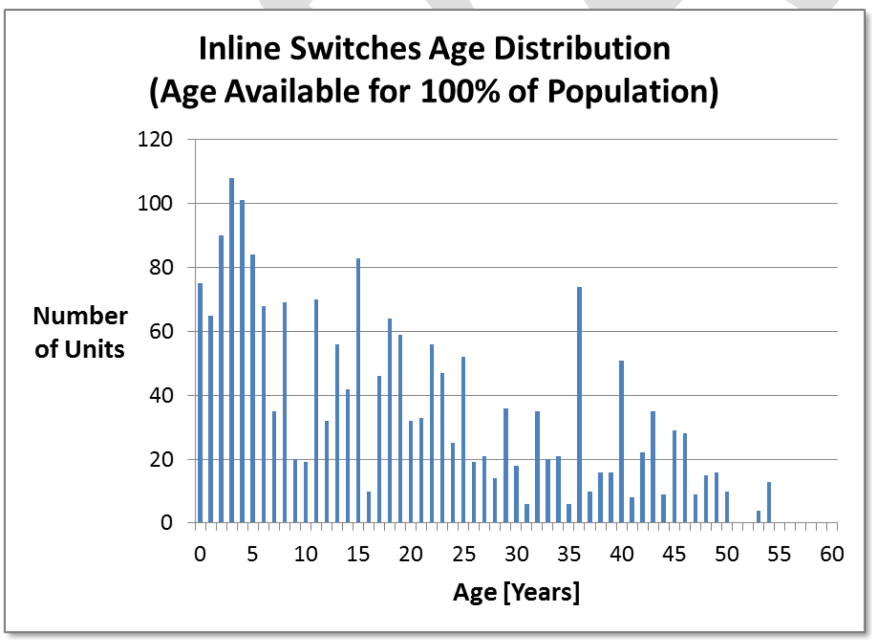


Figure 34. In-Line Switch Age Distribution

Overhead switches are typically run-to-failure unless a technical or health and safety issue has been identified. The heath index of these overhead switches is comprised of an age related component and results of Infra-red thermal scans, including a further de-rating based on switch type history.

The average health index for the group of 44kV load break switches, with a population of 338, was 95% with approximately 5% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 35**.

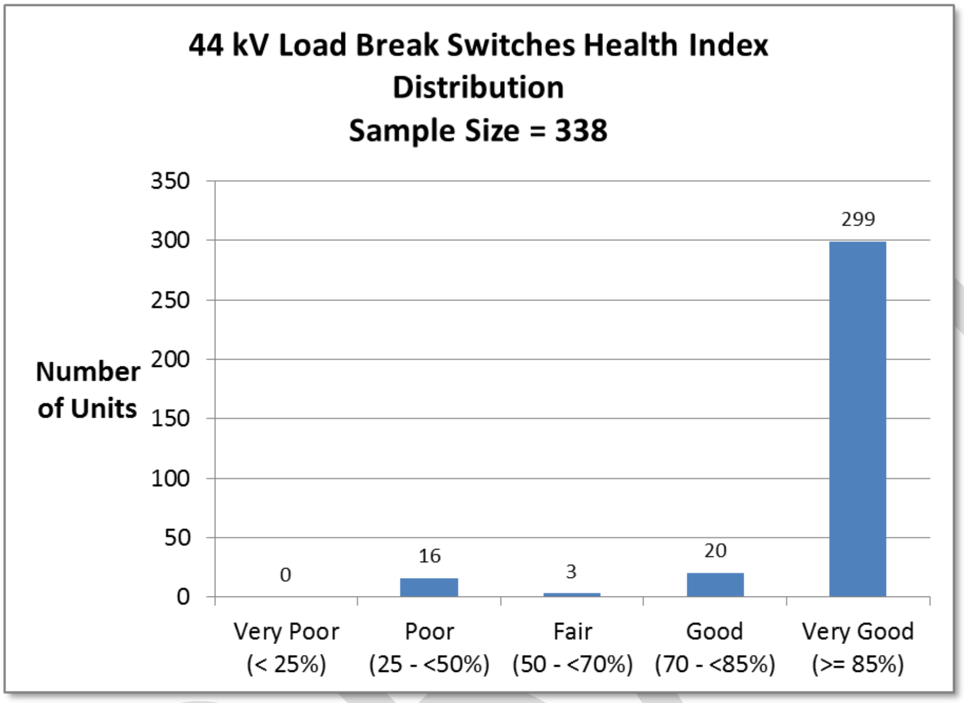


Figure 35. Health Index Distribution of 44 kV Load Break Switches (Unit)

The average health index for the group of 27.6kV load break switches, with a population of 213, was 97% with approximately 1% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 36**.

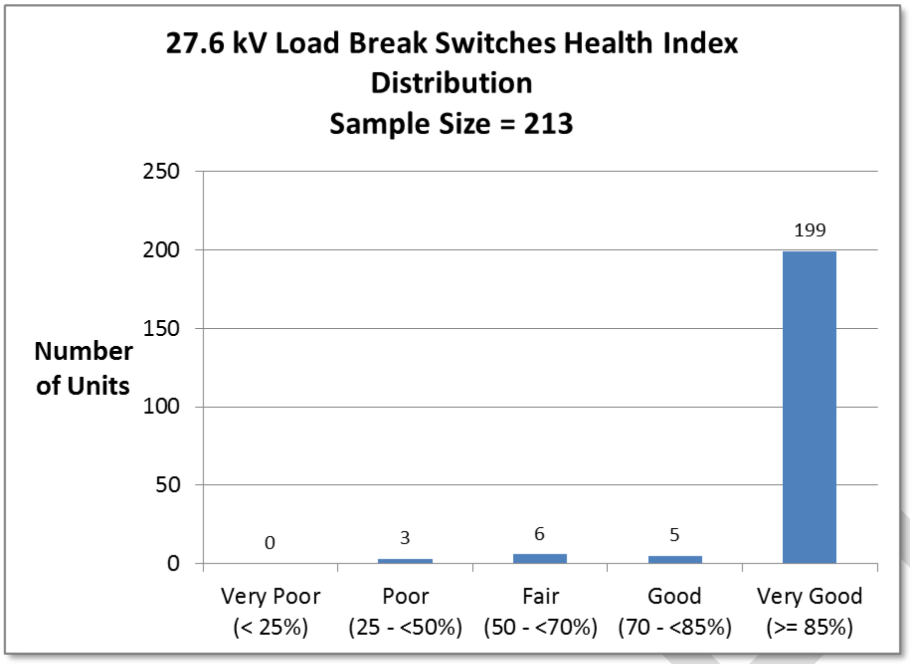


Figure 36. Health Index Distribution of 27.6kV Load Break Switches (Unit)

The average health index for the group of motorized load break switches, with a population of 104, was 85% with approximately 14% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 37**.

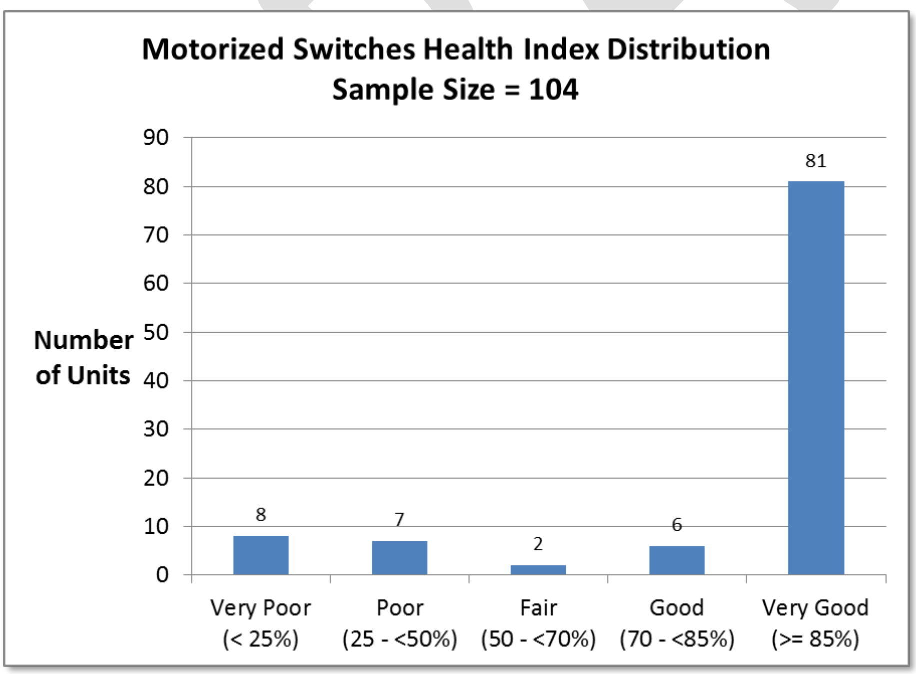


Figure 37. Motorized Switches Health Index Distribution (Unit)

The average health index for the group of in-line switches, with a population of 2,002, was 93% with approximately 5% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 38**.

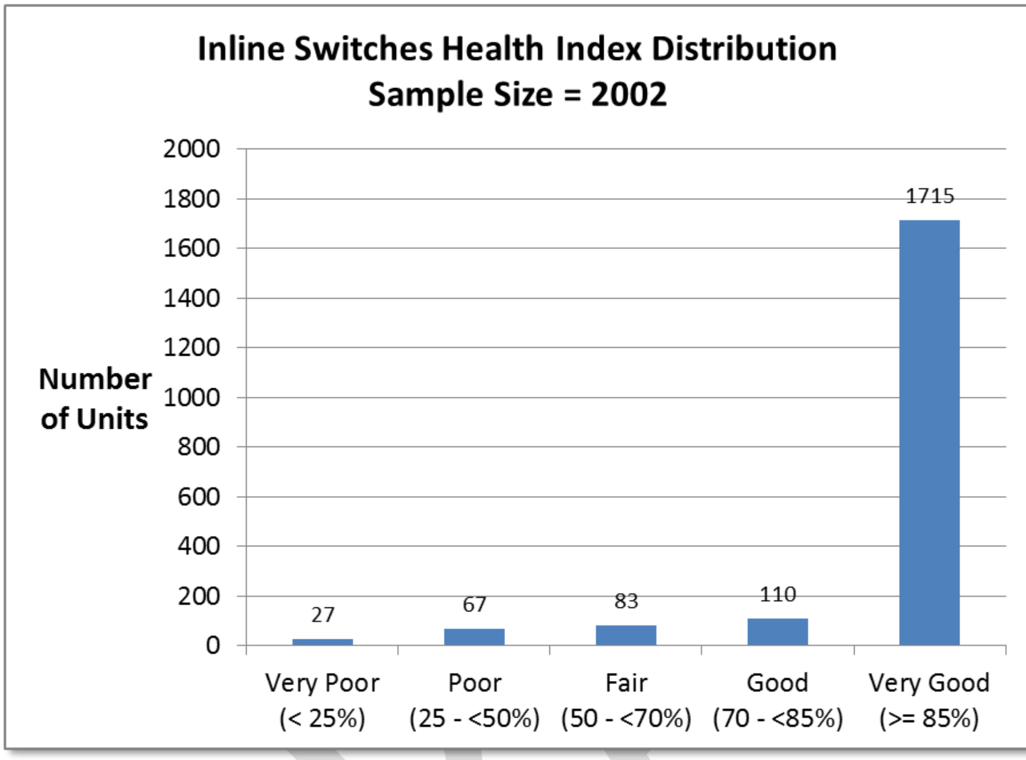


Figure 38. In Line Switches Health Index Distribution (Unit)

2.2.3.5 Overhead Conductor

Enersource owns and operates over 1,800 km in overhead circuit length (over 5,100 km in overhead conductor length). Due to the rarity of overhead conductor failures, Enersource only performs infrared inspections on its overhead assets (e.g., switches, insulators). The conductors are replaced during pole top equipment work or pole replacement projects (such as rebuilds or road widenings).

2.2.3.6 Distribution Poles

Enersource owns over 12,900 wood poles and over 8,900 concrete poles. The average age of wood poles was 27 years with approximately 14% of the population 45 years or older. The average age of concrete poles is 20 years with approximately 13% of the population 45 years or older, as shown in **Figures 39** and **40**.

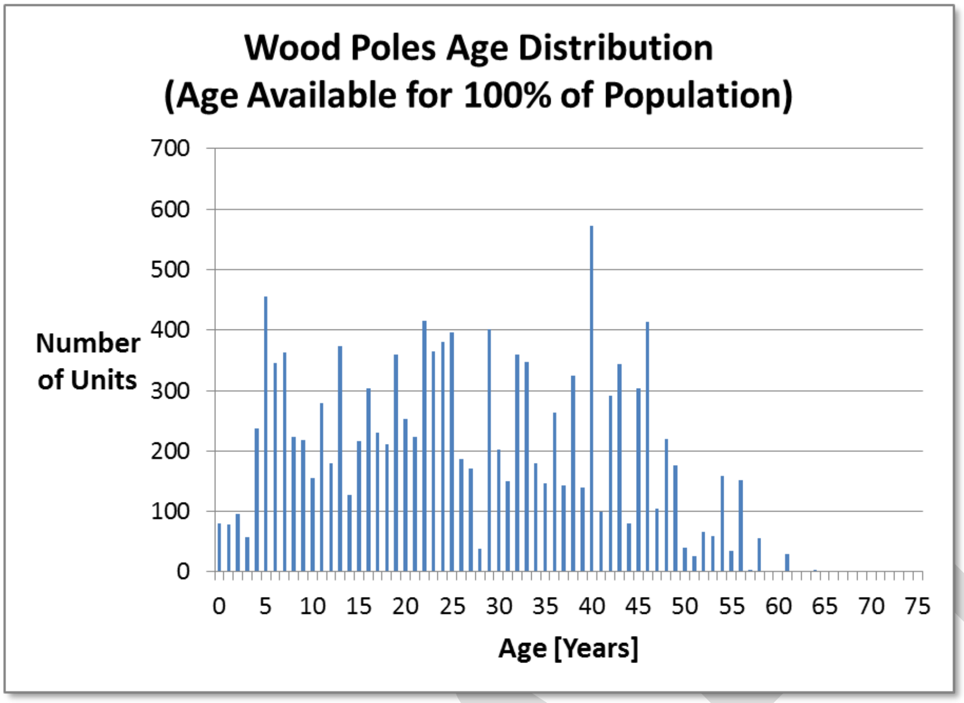


Figure 39. Wood Pole Age Distribution

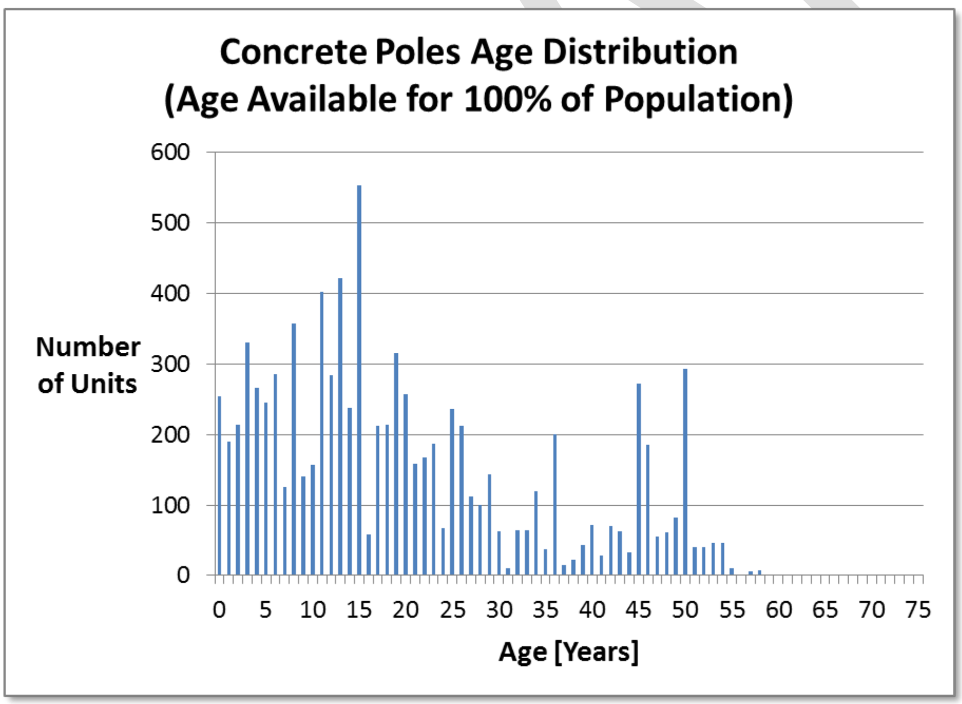


Figure 40. Concrete Pole Age Distribution

In recent years Enersource has increased its inspection program and has now inspected 100% of the poles in Mississauga. The overall health index for wood and concrete poles is based on data provided to

Kinectrics as part of Enersource's asset condition assessment report. Based on the Kinectrics report, the average health index for wood poles was determined to be 88% with approximately 3% of the population in 'poor' or 'very poor' condition, as shown in **Figure 41**.

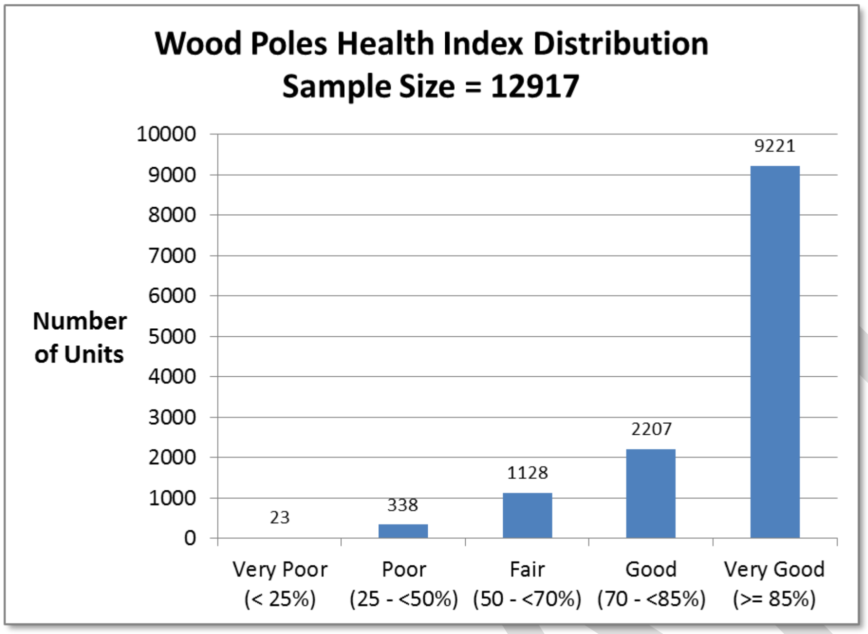


Figure 41. Wood pole Health Index Distribution (Unit)

The average health index for concrete poles was determined to be 97%. Less than 1% of the samples were in 'poor' or 'very poor' condition, as shown in **Figure 42**.

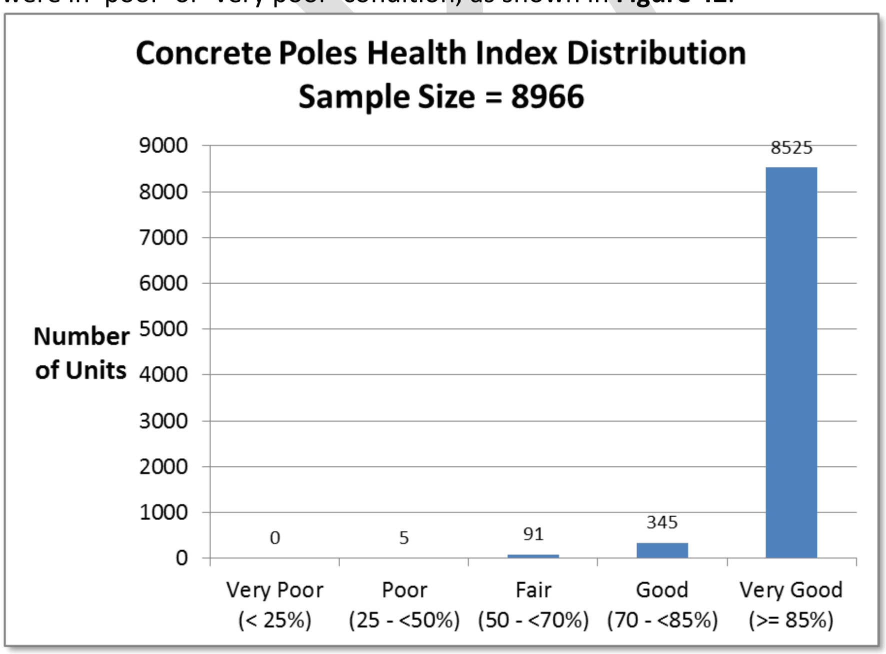


Figure 42. Concrete Pole Health Index Distribution (Unit)

2.2.3.7 Underground Distribution Cables (XLPE)

Enersource owns and operates 3,383 km in underground circuit length (6,271 km in underground conductor length) of polymer conductor. Typically this conductor will be of type XLPE (Cross-Linked Polyethylene). These cables are installed throughout Mississauga as main feeders and distribution feeders. Cables are installed in either concrete encased duct, direct buried duct, or are direct buried. New installations of underground cable are installed in duct to assist in future replacement due to failure or end of life. Existing direct buried cables cannot be easily replaced, adding to cost and labour requirements, and typically require extensive excavation to install new duct structure to more easily install new cable both now and in the future.

The average age of main feeder cables was 18 years/conductor-km with approximately 4% being 40 years or older, as shown in **Figure 43**.

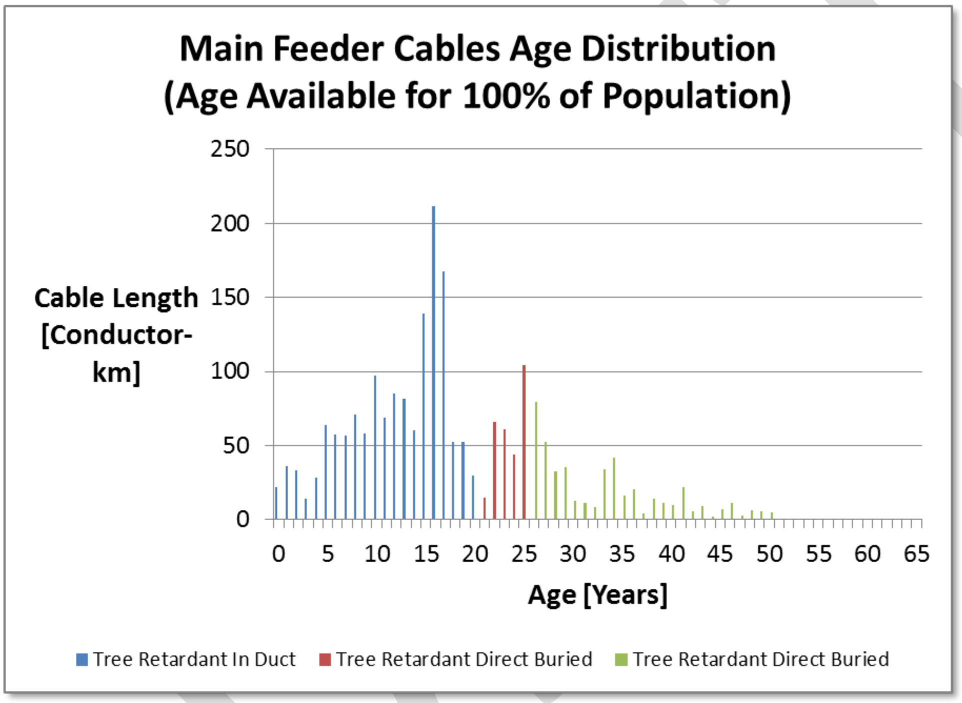


Figure 43. Main Feeder Cables Age Distribution

The average age of distribution cables is 21 years/conductor-km with approximately 7% being 40 years or older, as shown in **Figure 44**.

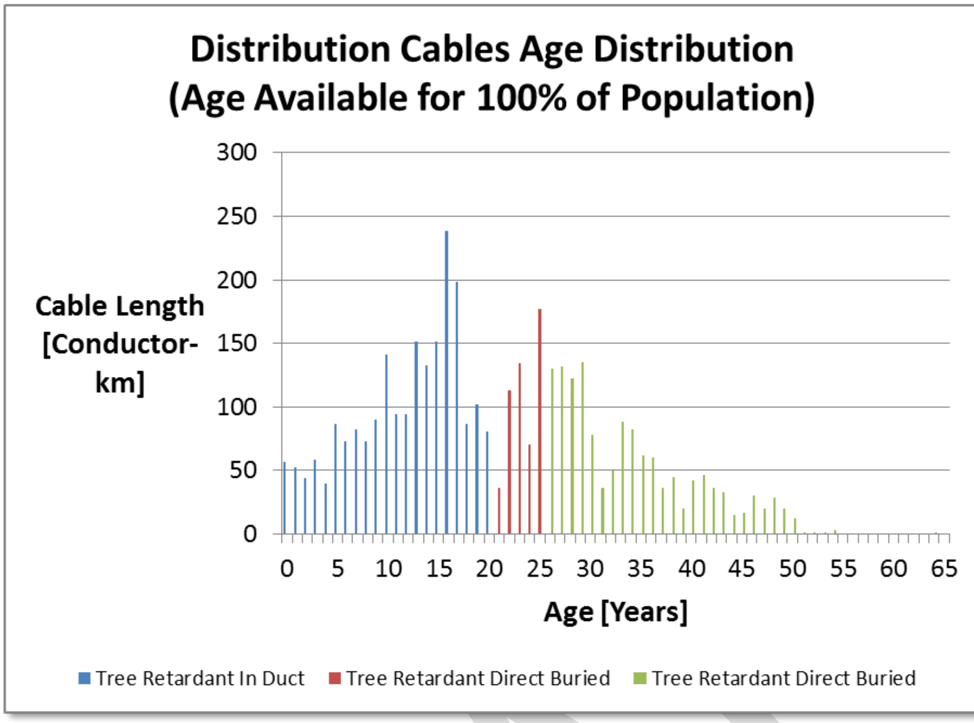


Figure 44. Distribution Cables Age Distribution

Health index ratings for underground distribution cables are based primarily on age, failure history, and type of installation as outlined above. In addition, the occurrence of failures over a five-year span is used to de-rate the health of cables. Enersource has also evaluated several cable testing methodologies, such as tan-delta, polarization-depolarization, and partial discharge, aimed at finding a method to more accurately determine cable health. However, these alternate methodologies are currently not used to determine cable health index.

A total of 2,233 conductor-km of main feeder cables was assessed at an average health index of 78% with approximately 20% of the population in 'poor' or 'very poor' condition, as shown in **Figure 45**.

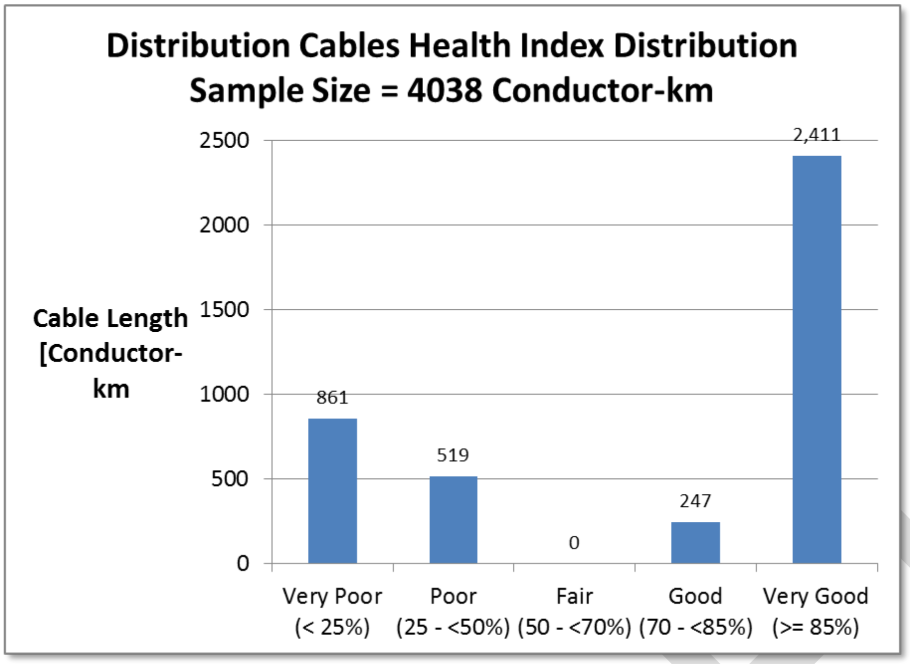


Figure 45. Main Feeder Cables Health Index Distribution (Unit)

A total of 4,038 conductor-km of distribution cables were assessed at an average health index of 70% with approximately 34% of the population in 'poor' or 'very poor' condition, as shown in **Figure 46**.

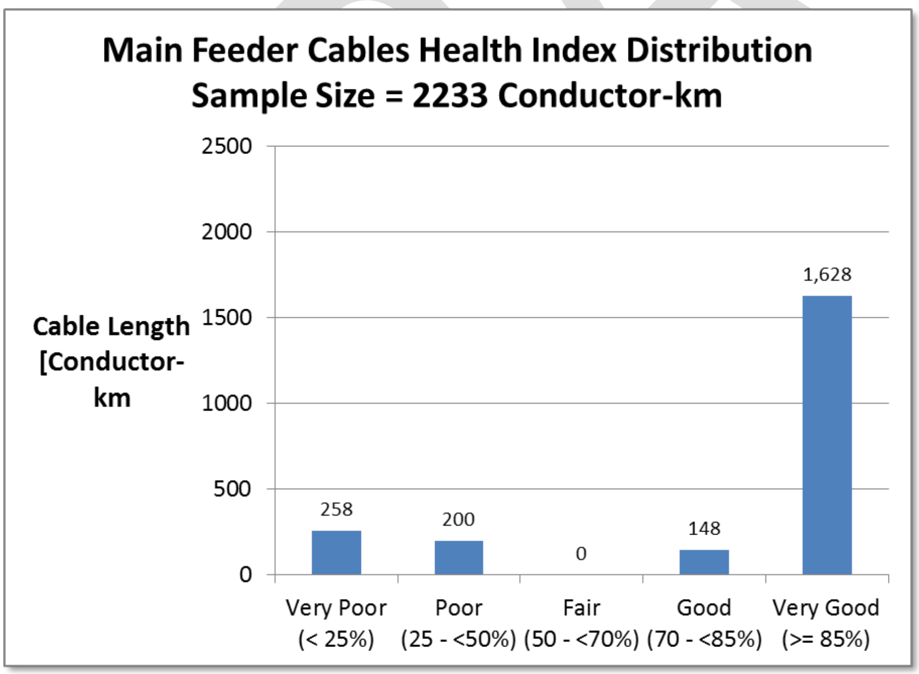


Figure 46. Distribution Cables Health Index Distribution (Unit)

2.2.3.8 Pole Mounted Transformers

Enersource owns and operates 5,346 pole mounted transformers. Demographic information for pole mounted transformer assets, such as date of purchase, installation date, serial number, percentage impedance, ratings, etc. are stored in the GIS system.

The average age of population was 21 years with approximately 9% of the population being 45 years or older, as shown in **Figure 47**.

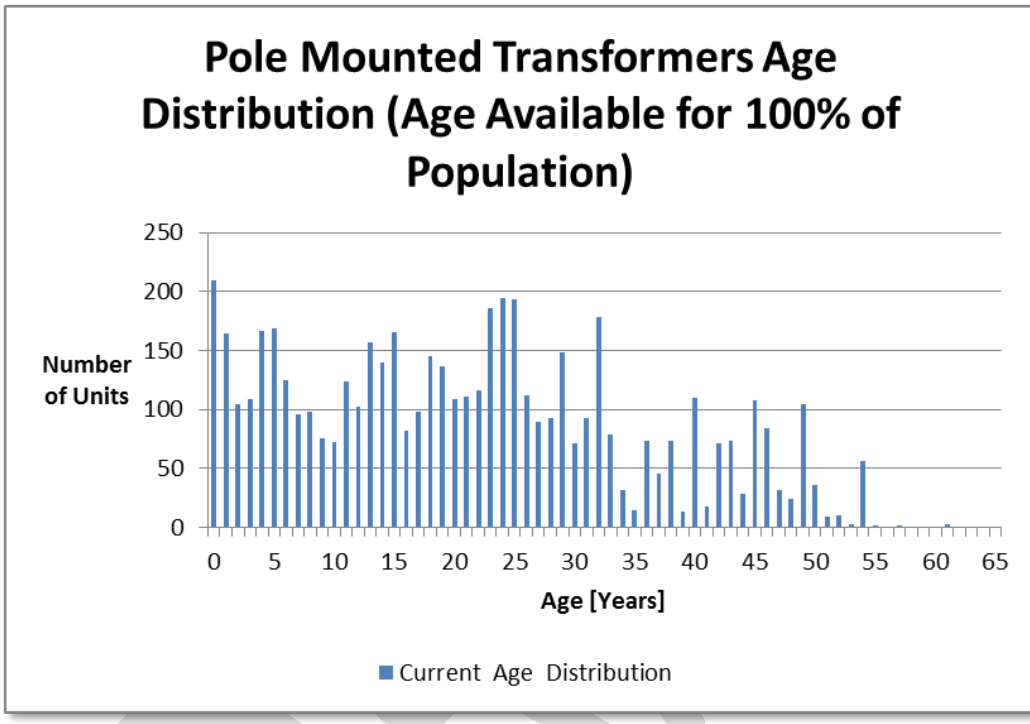


Figure 47. Pole Mounted Transformers Age Distribution

In addition to age, the health index of a pole mounted transformer will be reflective of PCB content (if greater than the industry accepted value of 2 ppm), results from infrared scanning, and prior history with a specific manufacturer.

The average health index for the group was 92% with approximately 2% of the population found to be in ‘poor’ or ‘very poor’ condition, as shown in **Figure 48**.

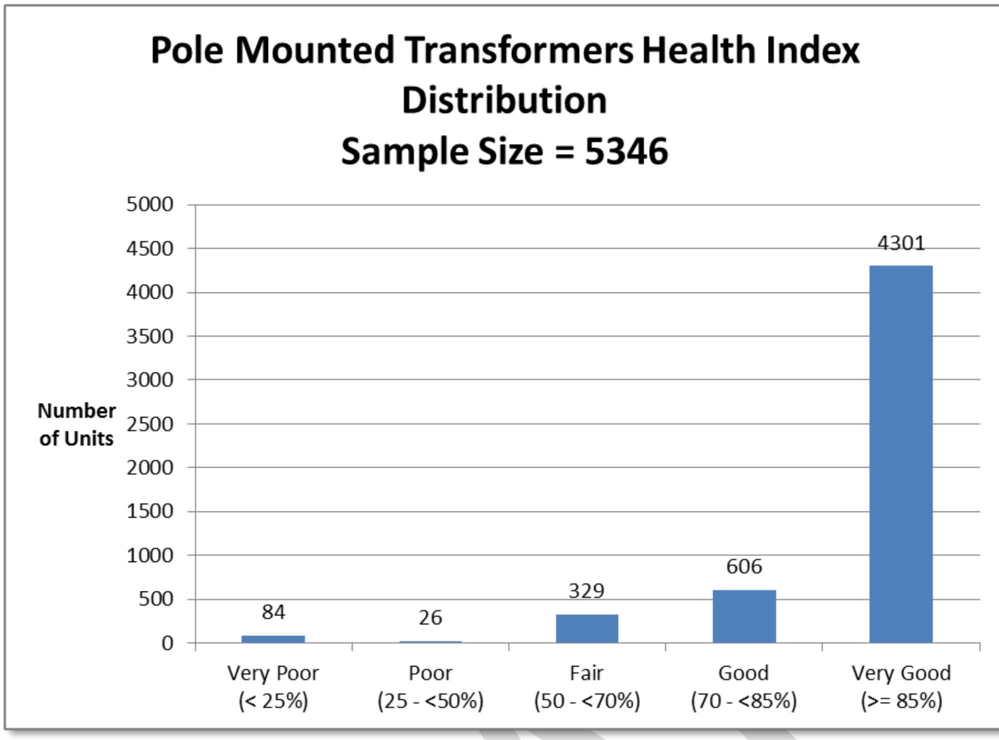


Figure 48. Pole Mounted Transformers Health Index Distribution (Unit)

2.2.3.9 Single Phase Pad Mounted Transformers

Enersource owns and operates 14,242 single phase pad mounted transformers. These units are primarily located in residential neighbourhoods with each unit providing power for up to 14 typical homes. Demographic information for single phase pad mounted assets, such as date of purchase, installation date, serial number, percent impedance, ratings, etc., are stored in the GIS system.

The average age of all single-phase units was 21 years with approximately 10% of the population being 35 years or older, as shown in **Figure 49**.

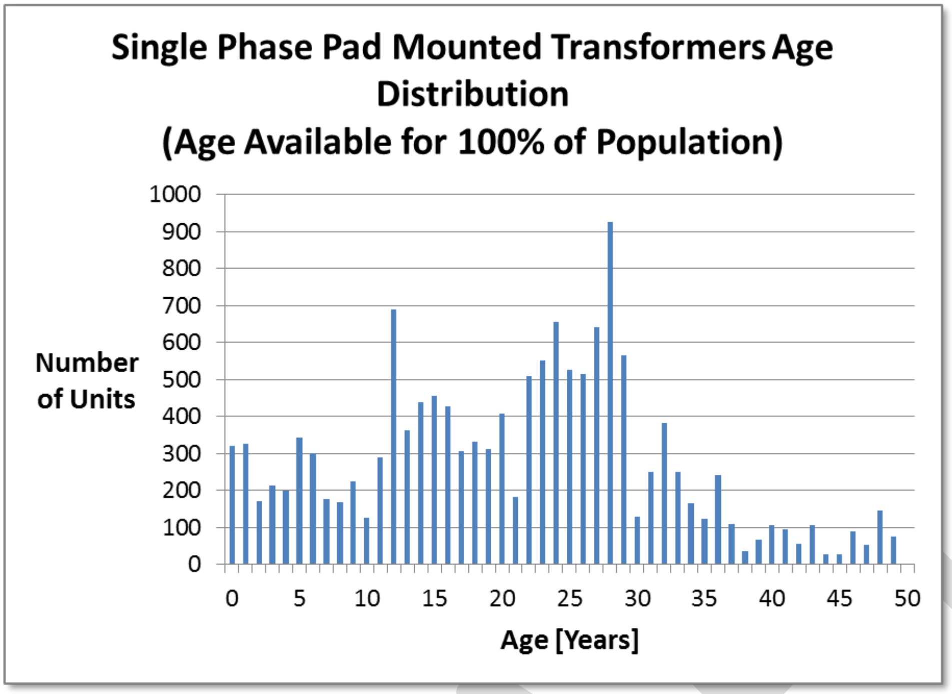


Figure 49. Single-Phase Pad Mounted Transformers Age Distribution

In addition to age, the health index of a single phase pad mounted transformers will be reflective of PCB content (if greater than the industry accepted value of 2 ppm), its service record, physical condition (including signs of corrosion, oil level / leaks, evidence of overheating i.e., boiling over), and prior history with specific manufacturers.

The average health index for the group was 87% with approximately 5% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 50**.

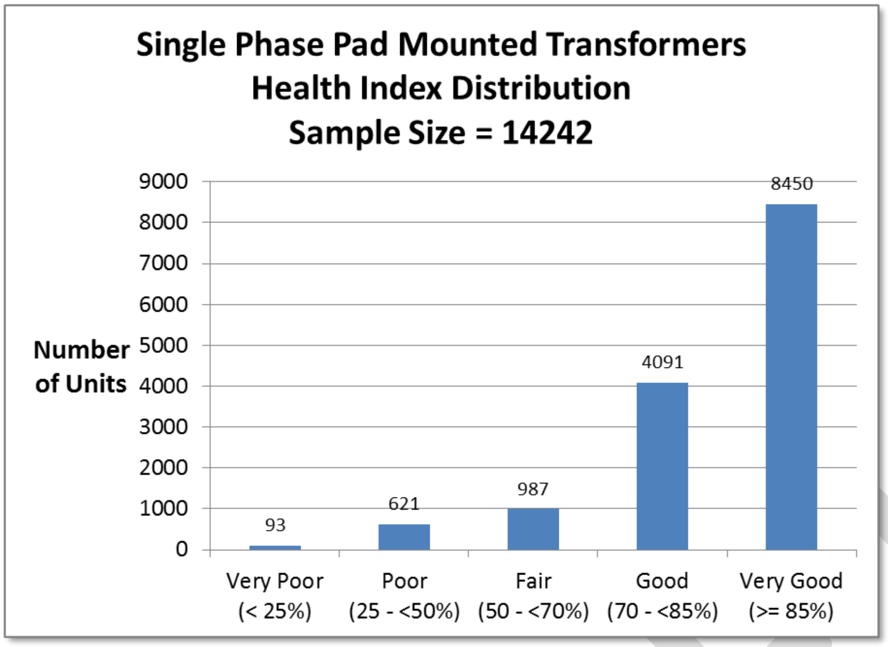


Figure 50. Single-Phase Pad Mounted Transformers Health Index Distribution (Unit)

2.2.3.10 Three Phase Pad Mounted Transformers

Enersource owns and operates 1,821 three phase pad mounted transformers. These units are primarily located in industrial and commercial areas and vary greatly in size depending on customer requirements. Demographic information for three phase pad mounted assets, such as date of purchase, installation date, serial number, percentage impedance, ratings, etc., are stored in the GIS system.

The average age of all three phase units is 16 years with approximately 5% of the population being 35 years or older, as shown in **Figure 51**.

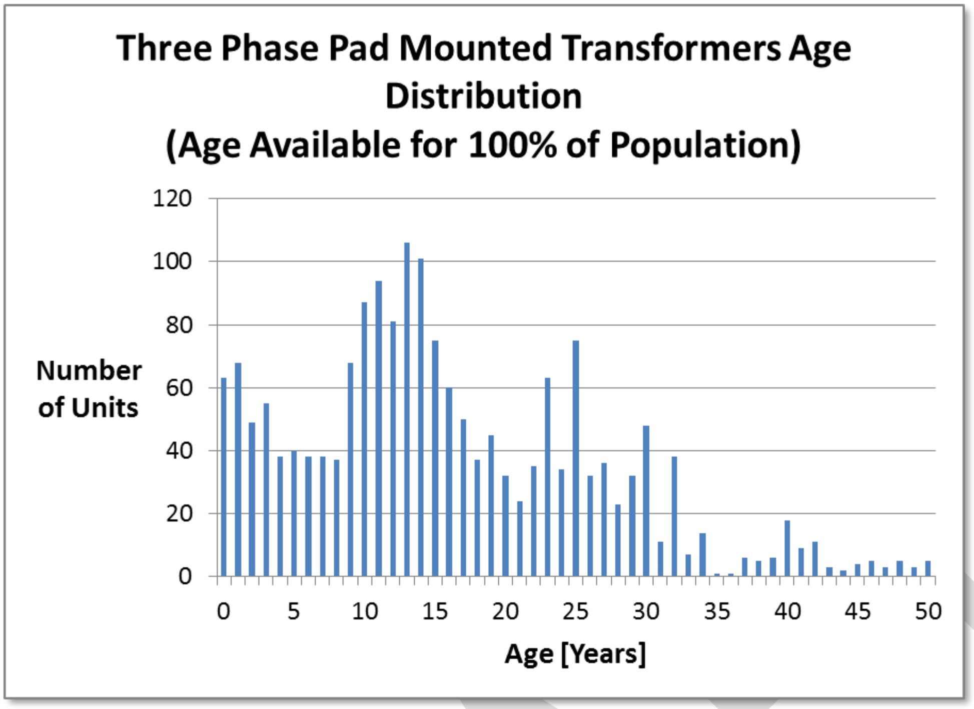


Figure 51. Three-Phase Pad Mounted Transformers Age Distribution

In addition to age, the health index of a three phase pad mounted transformer will be reflective of PCB content (if greater than the industry accepted value of two ppm), its service record, physical condition (including signs of corrosion, oil level / leaks, evidence of overheating i.e., boiling over), and prior history with specific manufacturers.

The average health index for the group was 94% with approximately 3% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 52**.

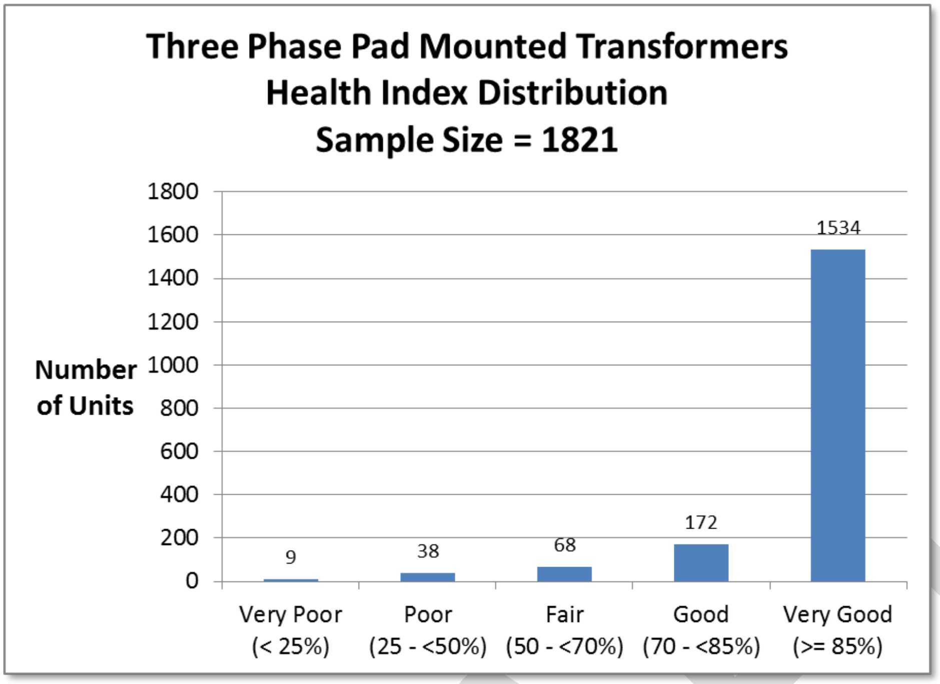


Figure 52. Three-Phase Pad Mounted Transformers Health Index Distribution (Unit)

2.2.3.11 Vault Transformers

Enersource owns and operates 3,861 vault transformers, which are typically located in approximately 1,300 building vaults servicing large customers. Vault transformers have had a resurgence in recent years as new developments in the Mississauga's downtown core are designed, combined with city restrictions on pad mounted transformers being placed in city boulevards in the city's downtown area. The population of vault transformers is projected to increase in the next decade. Demographic information for transformer vault assets, such as date of purchase, installation date, serial number, percent impedance, ratings, etc. are stored in the GIS system.

The average age of all single phase vault transformers was 27 years with approximately 23% of the population being 35 years or older, as shown in **Figure 53**.

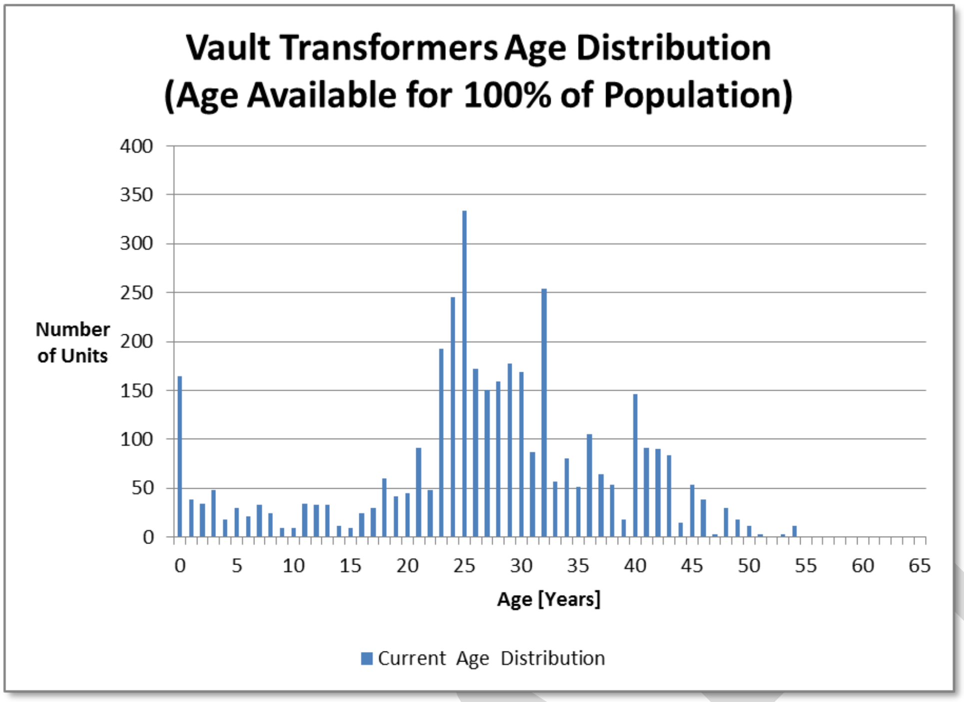


Figure 53. Vault Transformer Age Distribution

In addition to age, the health index of a vault transformer will be reflective of PCB content (if greater than the industry accepted value of two ppm), its service record, and physical condition (including signs of corrosion, oil level / leaks, evidence of overheating i.e., boiling over).

The average health index for the group was 87% with approximately 9% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 54**.

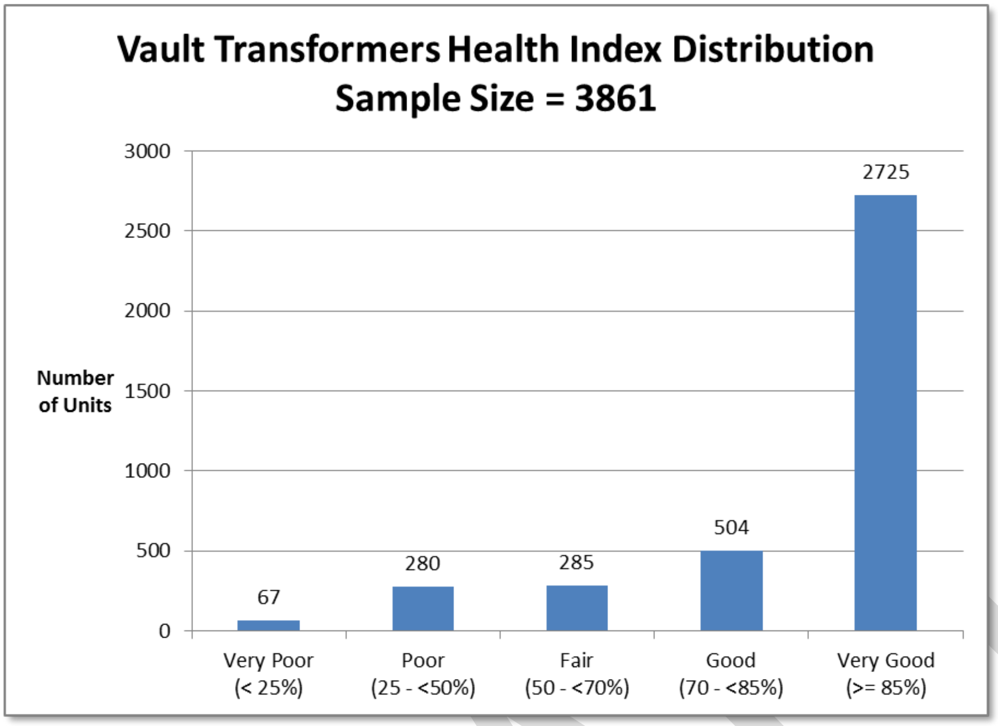


Figure 54. Vault Transformer Health Index Distribution (Unit)

ACA Condition Based Health Index Summary

Figure 55 below summarizes an overall condition based health index distribution for all major asset class types in graphical format.

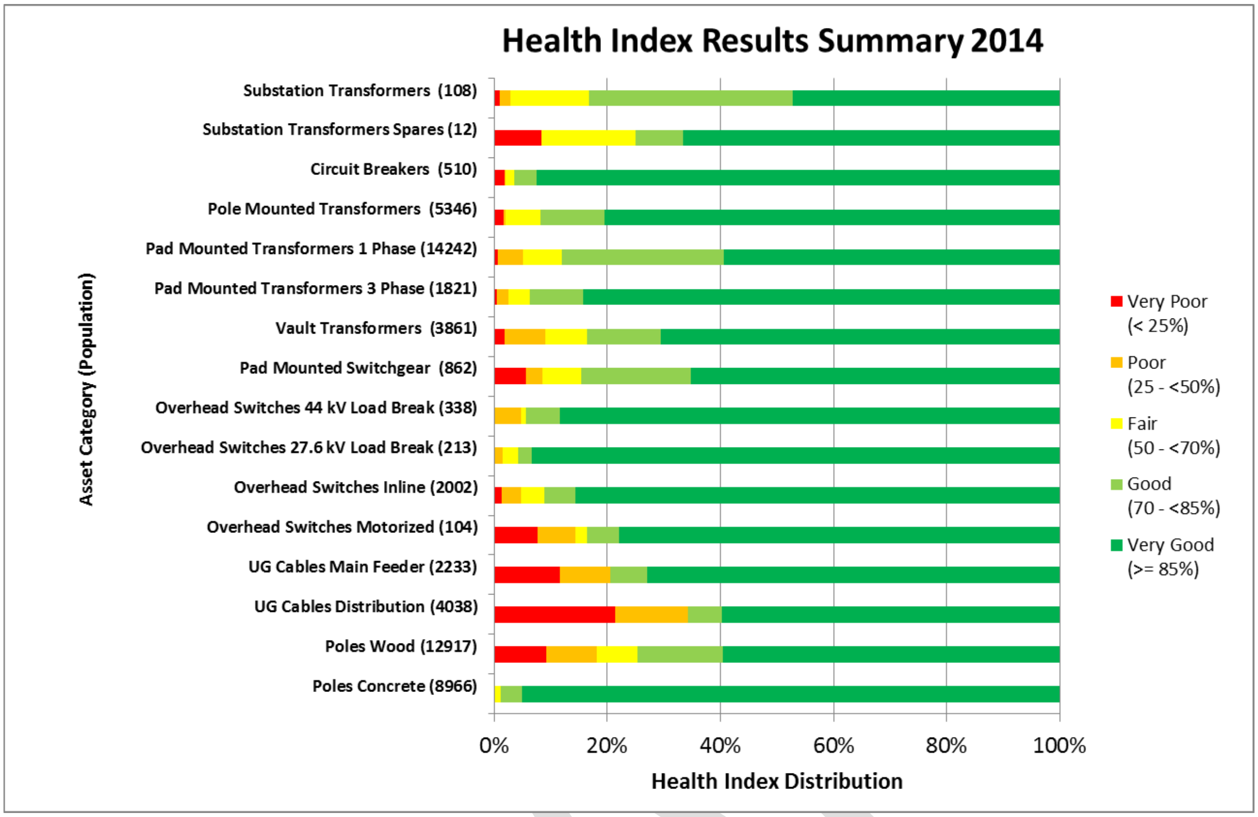


Figure 55. Health Index Results Summary – Condition Based

Municipal Substation Transformer

As stated earlier, substation transformers constitute one of the largest investments in a distribution utility's system and a significant asset to Enersource. In accordance with accepted engineering and utility practices, Enersource conducts monthly and yearly inspections in order to detect developing weaknesses or impending failures. The Company also conducts preventive maintenance based on elapsed time (typically every five years).

At the end of 2014 there were 108 transformers installed in Enersource's substations. The average age of the population is 22 years with a health index of 83%. Approximately 17% of all units are 40 years or older.

Based on the ACA report (which takes into account health index or condition assessment only), Enersource should replace seven transformers over the next 10 years.

Substation Circuit Breakers

Substation circuit breakers are used to interrupt short circuits that may occur in the system. They are inspected on a monthly basis and tested every five years in accordance with Enersource's practices.

At the end of 2014 there were 510 circuit breakers installed in Enersource's substations. The average age of the population is 20 years with a health index of 94%. Approximately 15% of all units are 40 years or older.

Based on the ACA report (which takes into account health index or condition assessment only), Enersource should replace 15 circuit breakers in the next ten years.

Pole Mounted Transformers

Pole mounted transformers are overhead transformers that can supply up to 25 customers, and if they fail, the environmental, reliability, and customer impact is minimal. Utility practice is to run pole mounted transformers to failure. If the entire area is scheduled for a rebuild, then the transformers are replaced along with the poles, conductors, insulators, and other pole line hardware. The majority of the pole mounted transformers were inspected in 2014.

At the end of 2014 there were 5,346 pole mounted transformers installed. The average age of the population is 21 years with a health index of 92%. Approximately 9% of all units are 45 years or older.

Based on the ACA report, Enersource should replace 449 pole mounted transformers in the next 10 years.

Pad Mounted Transformers

Pad mounted transformers share similar functions as the pole mounted transformers, but are located in a secure steel cabinet and mounted on a concrete pad. They also are run to failure or are replaced during a rebuild of an area. The majority of the pad mounted transformers were inspected in 2012 and 2013, and 2014 with inspections continuing throughout 2015.

Single-Phase Pad Mounted Transformer

At the end of 2014 there were 14,242 single phase pad mounted transformers installed. The average age of the population is 21 years with a health index of 87%. Approximately 10% of all units are 35 years or older.

Based on the ACA report, Enersource should replace 1,591 single phase pad mounted transformers in the next 10 years.

Three-Phase Pad Mounted Transformer

At the end of 2014 there were 1,821 three phase pad mounted transformers installed. The average age of the population is 16 years with a health index of 94%. Approximately 5% of all units are 35 years or older.

Based on the ACA report (which takes into account condition assessment only), Enersource should replace 78 three phase pad mounted transformers in the next 10 years.

Vault Transformers

Vault transformers are predominantly used to supply power to industrial or commercial customers. Sometimes the transformers are also used to supply apartment buildings or townhouse complexes. About 88% of the vault transformers were inspected by the end of 2014.

At the end of 2014 there were 3,861 vault transformers installed. The average age of the population is 27 years with a health index of 87%. Approximately 23% of all units are 35 years or older.

Based on the ACA report, Enersource should replace 603 vault transformers in the next 10 years.

Pad Mounted Switchgear

The switchgear unit consists of a low profile pad mounted enclosure with various internal compartments housing cable terminations, switches, and protection equipment. Its main purpose is to control the flow of the current and protect cables, transformers and other components from excessive current under fault conditions.

At the end of 2014 there were 862 pad mounted switchgears installed. The average age of the population is 19 years with a health index of 84%. Approximately 37% of all units are 25 years or older.

Based on the ACA report, Enersource should replace 128 pad mounted switchgears in the next 10 years.

Overhead Switches

The primary function of overhead switches is to allow for the isolation of line sections or equipment for maintenance, safety or other operating requirements. While most switches are manually operated, a project is currently in place to install additional remotely controlled switches at key locations, in order to aid prompt power restoration in the event of an outage.

44 kV Load Break Switches:

At the end of 2014 there were 338 of 44 kV load break switches installed. The average age of the population is 20 years with a health index of 95%. Approximately 9% of all units are 40 years or older.

Based on the ACA report, Enersource should replace 20 of the 44 kV load break switches in the next 10 years.

27.6 kV Load Break Switches:

At the end of 2014 there were 213 of 27.6 kV load break switches installed. The average age of the population is 18 years with a health index of 97%. Approximately 6% of all units are 40 years or older.

Based on the ACA report, Enersource should replace seven of the 27.6 kV load break switches over the next 10 years.

In Line Switches:

At the end of 2014 there were 2,002 in line switches installed. The average age of the population is 18 years with a health index of 93%. Approximately 12% of all units are 40 years or older.

Based on the ACA report, Enersource should replace 303 in line switches over the next 10 years.

Motorized Switches:

At the end of 2014 there were 104 motorized switches installed. The average age of the population is 16 years with a health index of 85%. Approximately 27% of all units are 25 years or older.

Based on the ACA report, Enersource should replace 25 motorized switches in the next 10 years.

Underground Primary Cables

Distribution underground feeder cables are one of the more challenging assets for electricity systems, from a condition assessment and asset management viewpoint. They are generally considered to be the most expensive components, due to the high cost of materials and very high cost of installation and maintenance.

It is extremely difficult, and therefore quite expensive, to obtain meaningful condition information for buried cables. Underground cable systems, unlike overhead lines, do not suffer from weather induced faults and can have better reliability records.

According to the ACA report, underground primary cables are the worst assets as per the health index compared to the other assets groups.

Main Feeder Cables:

At the end of 2014 there was a total of 2,233 conductor-km of main feeder cables installed. The average age of the population is 18 years per conductor-km with a health index of 78%. Approximately 4% of all segments are 40 years or older.

Based on the ACA report, Enersource should replace 678 conductor-km in the next 10 years.

Distribution Cables:

At the end of 2014 there was a total of 4,038 conductor-km of distribution cables installed. The average age of the population is 21 years per conductor-km with a health index of 70%. Approximately 7% of all segments are 40 years or older.

Based on the ACA report, Enersource should replace 1,775 conductor-km in the next 10 years.

Poles

Poles serve as support structures for overhead conductors, switches, transformers and other devices. In addition to Enersource`s equipment, the poles often support streetlights and third party attachments such as telephone, cable TV, and fiber communication cables. Poles are made of wood, concrete and steel. The vast majority of Enersource's poles are wood or concrete.

Wood Poles:

At the end of 2014 there were a total of 12,917 wood poles installed. The average age of the population is 27 years with a health index of 88%. Approximately 14% of all units are 45 years or older.

Based on the ACA report, Enersource should replace 2,394 wood poles in the next 10 years.

Concrete Poles:

At the end of 2014 there were a total of 8,966 concrete poles installed. The average age of the population is 20 with a health index of 97%. Approximately 13% of all units are 45 years or older.

Based on the ACA report, Enersource should replace 116 concrete poles in the next 10 years.

2.2.4 Information on General Plant Assets

General Plant assets include Enersource's assets that are not part of its distribution system, including land and buildings, tools and equipment, fleet and IT hardware and software used to support daily business and operations.

The General Plant assets are broken down into following sections:

- Rolling Stock
- Grounds and Buildings
- Information Technology
- Engineering and Asset Systems
- JDE / ERP System
- Meter to Cash
- Major Tools.

2.2.4.1 Rolling Stock

Enersource requires a fleet of specialized vehicles to complete daily activities, including the construction and maintenance of the electricity distribution system, and to allow for quick restoration of power due to electricity distribution system disturbances.

To effectively manage fleet assets, Enersource has adopted a strategy with the following goals:

- Provide safe, reliable and efficient vehicles and equipment to meet operational needs in consultation with the end user;

- Compliance with legislation and regulations;
- Compliance with accepted industry norms and practices;
- Cost effectiveness;
- Optimization of fleet size kept to minimum levels to ensure equipment is being fully used;
- Standardization of equipment specifications;
- Environmental considerations such as fuel economy and exhaust emissions;
- Disposal through reputable commercial vehicle resellers; and
- Implement computerized maintenance program to improve cost and maintenance tracking.

To achieve these goals , Enersource maintains a multiple year capital plan which is essential for both short and long term budgeting and planning. The plan lists all current vehicles and proposes future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Another long term goal of the fleet plan is to evenly distribute annual capital expenditures in order to minimize the rate impact to customers.

The proposed replacement ages for each vehicle class are outlined below and is based on manufacturers' recommendations and repair history:

- Light vehicles are replaced after three - five years, or 170,000 km
- Service trucks are replaced after five - eight years or 200,000 km
- Heavy equipment trucks are replaced after eight - 12 years, or after 230,000 km
- Work equipment is replaced on a condition based assessment.

Additional capital may also be required to meet equipment requirements resulting from succession planning and work program increases.

Maintaining appropriate levels of capital fleet spending will lead to:

- Reduced repair and maintenance costs
- Decreased down time and increased fleet utilization
- Safer equipment for personnel to operate
- Reduced environmental impacts (alternative fuel considerations, compliance with new diesel standards)
- Increased service equipment diagnostics.

2.2.4.2 Grounds and Buildings

Enersource has three main buildings used for business operations: a corporate office, operations centre and a business continuity recovery building. These buildings were constructed between 1963 and 2012. **Table 25** outlines Enersource's buildings and supporting information.

Table 25. Summary of Enersource Buildings

Location	Type	Year built	Square footage	# of Employees
2185 Derry Road	Corporate Office	1994, renovated in 2012	79,400	146
3240 Mavis Road	Operations Centre	1963, 1979, 1991	Office - 50,000 Warehouse/ Garage - 75,000	291
5045 Glen Erin Drive	Business Continuity Management (BCM) Operations Centre	2012	2,500	None

2.2.4.3 Information Technology (IT)

Enersource has embraced the use of technology to aid efficiency enhancements in several areas. The IT infrastructure provides the foundation on which Enersource's business operates. The following systems/applications are part of the IT infrastructure:

- Corporate network (which includes data, email, voice services, and web environments);
- IT infrastructure security system (e.g., resources access, assets and data protection and availability);
- Servers supporting many critical applications used throughout the Company; and
- Corporate telecommunications infrastructure including telephone system, wireless devices platform and the call centre voice queuing system.

2.2.4.4 Engineering and Asset Systems

The Engineering and Asset Systems (E&AS) department provides IT tools required to assist in the management of field assets. These include software and hardware used by employees, including both office and field personnel.

The largest two software systems utilized by Asset Management and Asset Operations, include the IOM and AM/FM.

SmartPlant Foundation (SPF) is the document management system for engineering records, providing document security based on the user, the access type requested and the document class. The system houses revisions, approved and as-constructed drawings, easements and permits. It also issues location numbers for switches and transformers. There are dozens of workflows used to manage business processes and the system is integrated to both AM/FM and JDE.

Specialized equipment, including wide-format plotters, engineering workstations~~,~~ and field lap-tops, are used on a daily basis by employees.

2.2.4.5 JDE / ERP System

Enersource uses JDE as its Enterprise Resource Planning (ERP) tool. It is a modular, scalable and integrated information management software system that facilitates the flow of information across the Enersource's various departments.

JDE and its supporting applications automate business processes:

- Finance – General Ledger, Accounts Payable, Accounts Receivable, Fixed Assets
- Operations – Service Orders (program/project cost)
- Supply Chain – Inventory/Warehouse Management, Procurement
- Human Resources – Employee Management.

JDE also interfaces with other major applications such as AM/FM and CC&B system to ensure data integrity and simplification of business processes.

2.2.4.6 Meter to Cash

Meter to Cash systems are comprised of all IT systems involved in the meter to cash process including Meter Reading, Advanced Metering Infrastructure (AMI) systems, Meter Data Management, Wholesale and Retail Settlement, EBT transactions, MDM/R transactions, Billing, Cash, Collections, Business Intelligence and related field activity systems, including interfaces among these systems. Interfaces to JDE, CRM and AM/FM applications are also supported.

CC&B and the surrounding suite of applications address:

- Customer account management/premise management
- Cash and collections
- Customer contact tracking and management
- Metering/meter management
- Meter reading/estimating;
- Rates engine
- Billing/bill creation
- Analysis and reporting.

2.2.4.7 Major Tools

In order to maintain and operate an electricity system and a fleet of approximately 200 vehicles, investment in quality tools is paramount. Each truck is furnished with basic hand tools and equipment while specialized items are limited to specific trucks, (e.g., chainsaws on forestry vehicles, cable cutters and crimpers on underground vehicles). Tool expenditures of $7,500 or more per item is classified as a major tool and requires additional internal approvals. This category covers the purchase of such items as:

- Mud tracks – to allow vehicles to traverse over wet ground and/or buried pipelines;
- Temporary grounds – to create a safe work area for employees working within a de-energized area;
- Battery operated devices – provide better ergonomics tools for staff to reduce the risk of injury when repairing underground cables in splice pits and sleeving overhead conductors;
- Cable locating equipment – to locate buried electrical cables for internal work and to identify cables for other utilities so they can perform their work without causing cable damage; and
- Fault finding equipment – to aid in locating underground cable faults requiring repair.

2.3 Asset Lifecycle Optimization Policies and Practice (OEB Chapter 5.3.3)

This section of the DSP outlines Enersource's asset lifecycle optimization policies and practices.

Enersource's approach is to maximize the lifecycle of an asset while providing reliable service in a cost effective manner. In order to optimize the lifecycle of its assets, Enersource has numerous remediation programs for maintaining the distribution system and general plant integrity, and assesses whether an aged asset is suited for refurbishment or replacement based on criteria that are pertinent to a given asset class.

A determining factor for Enersource's asset lifecycle optimization policies and practices is an understanding of the condition of assets in the field. This is accomplished through a regular and effective inspection program. Effective testing, inspections, and maintenance programs ensure that adequate information is gathered in order to properly prioritize asset replacement and refurbishment while balancing operation and maintenance costs. Enersource uses health indexing on all major asset groups to prioritize asset refurbishment and replacement and ensure an effective proactive replacement strategy.

Using asset health indexes when developing a proactive replacement strategy ensures that dedicated resources are acquired and costs and customer outage impact is minimized.

2.3.1 Inspection and Maintenance Programs

2.3.1.1 Underground and Overhead Assets

Enersource has an extensive inspection program for its overhead and underground distribution assets. All overhead and underground plant is visually inspected and electronically recorded in the GIS system through the use of hand held computer tablets. Substation assets are inspected on a monthly basis to ensure compliance with the OEB's minimum inspection requirements.

Annual overhead inspections include transformers, poles, insulators, switches, arrestors, and hardware attachments, such as guy wires, cross arms, and ground wires. Underground system inspections include transformers, bushings, elbows vaults, and pad mounted switchgear. The inspection program also includes detailed inspection of high voltage electrical rooms (i.e., vaults) with components such as transformers, switches, cabling, doors, ceilings, drains, and internal lights.

Computer tablets powered with Intergraph's MobileLink software allow Enersource to carry out detailed inspections on each asset group. Gathered data is then validated against the GIS asset records using an automated Quality Assurance and Quality Control process and any validation exceptions are corrected prior to being imported into the GIS. This ensures that Enersource is using the most accurate asset data when planning its asset lifecycle optimization work.

Once all inspection data is imported into the GIS, detailed maps are generated using Intergraph's GeoMedia software. This allows Enersource to identify critical areas that require System Renewal for both underground and overhead asset components, as well as future maintenance initiatives.

2.3.1.1.1 Vault Maintenance

Enersource has approximately 1,300 vaults in its distribution system and deploys a detailed maintenance program that includes CO_2 washing followed by infrared (IR) inspection of the main components within the vault. CO_2 washing has proven to be effective in removing contamination such as salt and dirt that contributes to tracking and flashover. All vault equipment components are washed prior to performing the IR scan. CO_2 washing consists of mixing carbon dioxide with clean compressed air at the spraying nozzle and safely removing surface contamination from the energized equipment. During the cleaning process the dry-ice particles are propelled at high velocities to impact and clean the surface. The particles are accelerated by compressed air, just as with other blasting type systems. This process allows Enersource to clean vaults without disrupting power to customers and is proven to be environmentally friendly and safe for the field crews.

2.3.1.1.2 Poles

Enersource carries out detailed inspections of both wood and concrete poles, and the results are used as inputs to develop the asset health indexing for poles. Visual inspections identify potential risk of pole failures and interruptions of service to customers. All inspection records are collected using computer tablets with automated QA/QC process to ensure correct data is being recorded by field inspectors and imported into the GIS system in a timely manner. Any immediate concerns are appropriately dealt with and follow-up work is scheduled for resolution.

2.3.1.1.3 Porcelain Insulator Washing

Porcelain insulator washing is required annually to prevent failures in the overhead distribution system. Insulators are prone to contamination especially due to road salt or other airborne contaminants which can result in pole fires, flashovers, and power interruption. Insulator washing is carried out without the need for isolation of the overhead circuits and the resulting customer interruptions. During washing, a visual inspection and identification of any damaged equipment in the overhead infrastructure is also noted.

This program is very cost effective and proactive since it reduces the chance of pole fires and, consequently, lessens the threat to system reliability.

2.3.1.1.4 Critical Switch Program

Enersource's critical switch program is designed to maintain and inspect switches identified as having a high consequence of failure (e.g., motorized switches). These switches are selected based on the requirements to interrupt higher loads, supply many customers or critical customers such as hospitals, large customers, etc. The regular inspection program ensures all areas are visited and problems detected before they lead to:

- Impairing the safety of Enersource employees or the public;
- Negatively impacting system reliability and reducing the quality of service to customers; and/or

- Seriously reducing the life expectancy of the equipment and thereby increasing costs via equipment replacement.

2.3.1.1.5 Overhead Load break Switch Maintenance Inspection and Testing

The distribution system has different types of switches to facilitate distribution of electrical energy. A load interrupter is one form of switch used in the overhead electricity power system. These three phase switches are among the most important components of the distribution system; they are infrared inspected annually and maintained when issues are found.

The objective of this program is to perform preventive maintenance to ensure the proper performance of the switch over its expected life. During the maintenance of 44kV and 27.6kV loadbreak switches, the following tasks are performed:

- Inspect the switch blade
- Check grounding
- Check the minimum clearance between shut contact and interrupting unit
- Check all contacts and clean if necessary
- Check handle location
- Check pipe for couplings and make adjustments if necessary
- Check location and connection of ground strap
- Check SCADA operation
- Record maintenance information.

2.3.1.1.6 Pad mounted Switchgear Dry Ice Cleaning

Air-insulated switchgears are CO_2 washed to remove contamination such as road salt or dirt that contributes to tracking and flashover, as shown in **Figure 56**. To ensure effective IR scanning, the switches are washed prior to performing an IR scan. The carbon dioxide is mixed with clean compressed air at the spraying nozzle and safely removes surface contamination from both energized and de-energized internal equipment. CO_2 washing allows switchgear to be cleaned while energized, is environmentally friendly, safe, and increases system reliability by removing surface contamination that can lead to flashover.

Figure 56. 27.6 kV Switchgear Dry Ice Cleaning

2.3.1.1.7 Infrared Inspection Program

On an annual basis, the entire overhead primary system is IR scanned at which time hot spots on the system that need immediate repairs or replacement are identified. Any other significant problems on the overhead system that may require immediate attention (such as broken insulators) are also reported to the Control Room Operator who creates an IOM follow-up report to overhead maintenance crews for resolution. A sample infrared inspection report is shown in **Figure 57** below.

Item #31

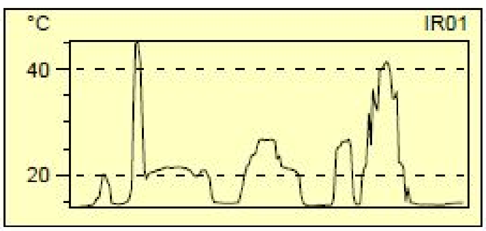
Location

SWITCH LOCATION #S0519,
CREDITVIEW ROAD AT ARGENTIA ROAD,
MISSISSAUGA.

Description

ROAD AND FIELD PHASE STRESSCONE TERMINATIONS AT CONDUCTORS.

Object parameter	Value
Emissivity	0.96
Object distance	12.0 m
Ambient temperature	20.2°C



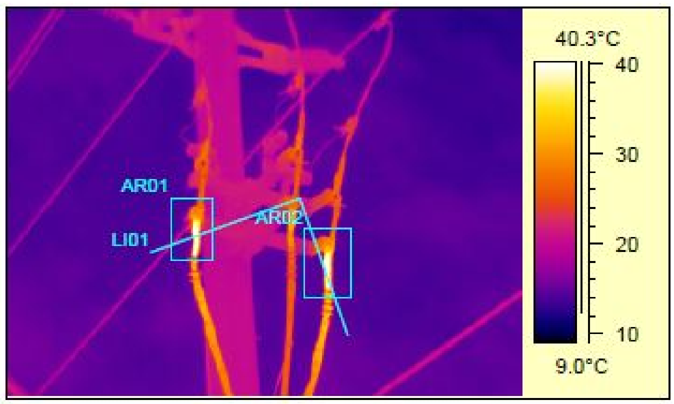


Figure 57. Infrared Inspection Report

2.3.1.1.8 Vegetation Management

Enersource's distribution system has approximately 1,800 km (circuit length) of overhead lines. Tree contacts with overhead lines account for approximately 5% of the power outages that occur in Mississauga on an annual basis, and can also be a danger to persons and property. The importance of tree trimming is to:

- Reduce power interruption due to short circuit to ground or between phases
- Reduce animal contacts by reducing animal accessibility to power lines via trees
- Prevent damage to conductors, hardware, and poles
- Mitigate danger to persons and property within the vicinity due to fire and falling conductors hardware, poles, and trees
- Mitigate danger of electric shock potential from electricity energizing vegetation.

The Forestry program is an integral part of maintaining a safe and reliable distribution system and is part of the overall maintenance plan for conductor assets. The Forestry team handles numerous tree trimming activities such as planned line clearing, following up on Control Room calls, responding to customer calls, system emergencies, and trimming trees for the installation of new power lines. There has been an increase in demand and a heightened awareness of the need for tree trimming in Mississauga due to recent events such as the 2013 ice storm as well as the infestation of the Emerald Ash Borer.

Routine tree-trimming occurs on a four-year cycle and requires that the City be divided into four north-south blocks in order to provide equal division of the heavier tree covered south areas and less dense north areas. A map of the maintenance areas is shown in **Figure 58** below.

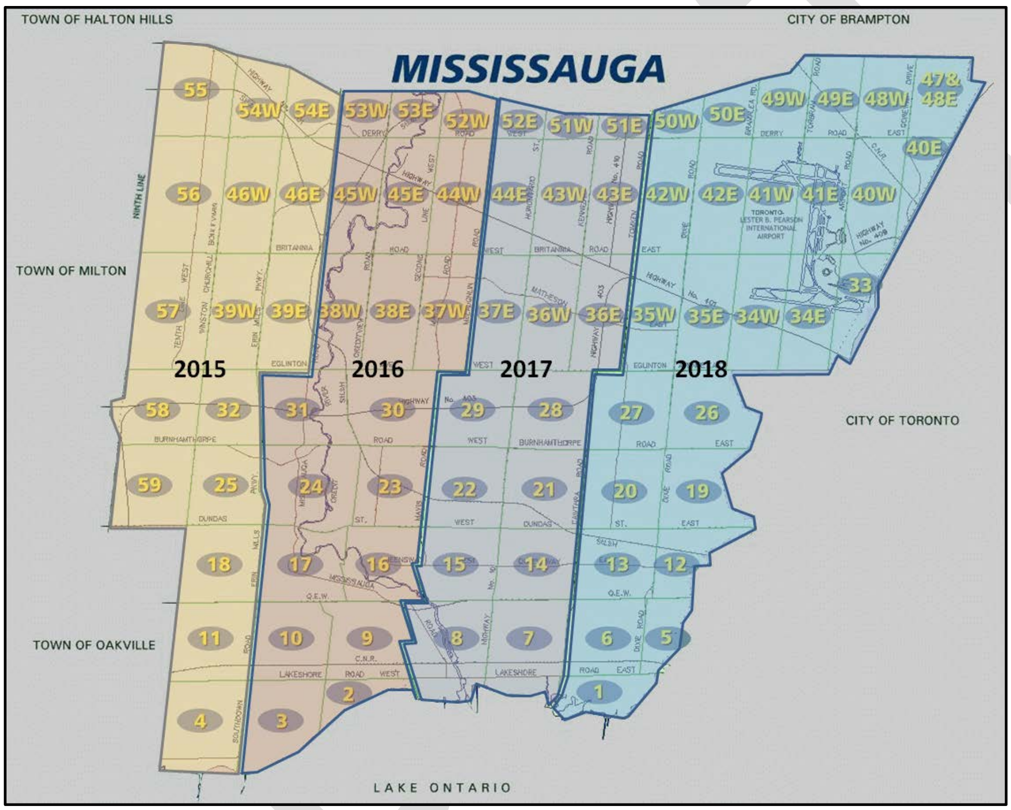


Figure 58. Map of 2015-2018 Vegetation Cut Plan

2.3.2.1 Substation(s)

Enersource's substations are used to transform subtransmission voltages to distribution voltages in order to ensure safe and reliable delivery of power. Within a substation, power transformers play a critical role in making the power usable to Enersource's customers. When a subtransmission line comes into the substation, it goes through a transformer that steps down voltages from 44kV to 13.8kV or 27.6kV to 4.16kV. The typical transformer sizes are 3, 5, 10 or 20 MVA. The life expectancy of a substation power transformer is approximately 40 years and with proper maintenance, this target can be achieved.

After transformation to lower voltages, a substation distributes electricity through many feeders which are dispersed geographically and can be used to back up one another in the event of a feeder outage or failure. Feeder outages and reconfigurations are necessary to isolate faulty equipment or to make safe work zones for construction or repair work.

Enersource currently has 66 active municipal substations (MS) throughout Mississauga. Enersource's substations have protection and control systems to protect the transformers and switchgears as well as any load centres within the vicinity. The protection and control components include protective relays along with programming and wiring. The protection and control system is used, via the circuit breakers, to isolate faults on equipment inside the substation or downstream in the distribution network.

The relays also monitor and record equipment status and telemetry. With battery backup, the relays continue to function in the event of a power outage. This information is transmitted to the SCADA system which collects data from substations as well as switchgears and switches fitted with remote terminal units (RTU's). This information is displayed in the Control Room for system monitoring. System Control Operators monitor the status of these devices and respond to abnormal events. The operators can then control these devices remotely via the SCADA to reconfigure and reroute power in the event of an outage.

Enersource's substations represent a major component of Enersource's distribution system and are considered its most significant assets. A substation contains very expensive equipment and a component failure can adversely affect a critical customer or large number of customers. Therefore, Enersource treats its substation equipment with high importance and inspects, maintains, and replaces components proactively in order to ensure safe and reliable power delivery.

The inspection and testing programs consist of the following:

- Monthly inspections
- Power transformer insulating oil testing
- Doble testing
- Tap changer maintenance
- Preventive maintenance.

2.3.2.1.1 Inspection Programs

The inspections consist of visual assessments of the building and grounds as well as the electrical equipment inside the substations. The building and grounds are checked for fence and gate/door integrity, vandalism, vegetation and environmental hazards such as transformer oil or SF_6 (sulphur hexaflouride) gas leaks. The electrical equipment checks include inspection of the power transformer fans, battery and battery charger readings and protection relay flags.

All monthly inspection findings are recorded and corrective actions are undertaken as required.

2.3.2.1.2 Power Transformer Insulating Oil Testing

Power transformers undergo annual dissolved gas analysis (DGA) and oil quality analysis. Both are important diagnostic tools that are used to monitor the condition of the transformer. Emphasis is placed on these tests for detecting insulation breakdown, water in the oil, stressing of the coils, and localized overheating and arcing that can lead to failure of the transformer. Currently, Enersource uses a third-party laboratory to carry out testing of oil samples, including comparison of results of previous transformer oil samples, and providing detailed recommendations for the transformer.

DGA analysis is performed using portable equipment as well as DGA online monitoring. Online DGA equipment is used for continuous monitoring of transformer gas concentrations and can be used to set alarms at specific gas concentration thresholds. DGA online monitoring systems are part of Enersource's standard installations and can send DGA data to SCADA when an alarm threshold is reached.

DGA and oil quality tests identify abnormalities within the transformer and provide detailed information to allow for sound decision making for future operation and maintenance of the transformer.

Doble Testing

Doble testing equipment is used to assess the overall power factor, winding turns ratio, leakage reactance and exciting current of the transformer. These tests detect moisture in the oil or insulation, detect contamination in the transformer bushing, determine the electrical insulation quality, and locate bad connections and winding movement. The Doble equipment provides test results and expected values and thresholds to effectively translate the results. Doble testing, DGA testing and oil quality analysis complement each other to provide clear indication of the overall health of the transformer.

2.3.2.1.4 Preventive Maintenance Programs

Substation electrical equipment is maintained on a regular schedule. The objective is to perform preventive maintenance approximately once every five years on each substation. This time interval can be reduced or increased based on operating conditions, equipment type, and operating experience with the equipment.

Types of substation maintenance activities include:

- Transformer maintenance
- Tap changer maintenance
- Switchgear maintenance
- Protection relay maintenance
- Batteries and battery charger maintenance.

2.3.2.1.4.1 Transformer Maintenance

Transformer maintenance activities are based on the following documents and standards:

- Manufacturer's instruction book
- IEEE 62-1995 IEEE Guide for Diagnostic Field Testing of Electric Power Apparatus Part 1: Oil Filled Power Transformers, Regulators, and Reactors
- Doble transformer maintenance and test guide.

The following maintenance tasks are performed on every oil-filled power transformer:

- Inspect and test all controls, wiring, fans, alarms and gauges
- In-depth inspection of transformer cooling system (check for leaks and proper operation)
- In-depth inspection of transformer bushings, cleaning, waxing if needed
- Doble test transformer and bushings
- Inspect pressure controls
- Inspect and test the tap changer.

2.3.2.1.4.2 Tap Changer Maintenance

Oil filled tap changer maintenance activities include:

- Recording the position of the tap changer
- Inspecting the physical and mechanical condition
- Verifying correct auxiliary device operation
- Verifying the correct liquid level in all tanks
- Performing tests as recommended by the manufacturer
- Verifying operation of heaters and grounding

- An internal inspection which includes removing the oil and cleaning carbon residue and debris from compartment
- Inspecting the contacts for wear and alignment
- Tightening electrical and mechanical connections to calibrated specifications
- Inspecting the tap changer components for signs of moisture, cracks, electrical tracking or excessive wear and then refilling the tank with filtered oil.

2.3.2.1.4.3 Switchgear Maintenance

Substation switchgear maintenance is based on the manufacturer's recommendation and consists of the following work:

- Busbar, enclosure and insulator maintenance
- External visual inspection
- Check and tighten connections
- Check and clean enclosure.

Circuit breaker maintenance includes the following work:

- Lubricate, clean, adjust, and align control mechanism
- Contact resistance measurement
- Test tripping and closing circuits.

2.3.2.1.4.4 Protection Relay Maintenance

Three types of relays are used to clear faults that occur in the distribution grid. The maintenance performed on each type of relay is as follows:

Electromechanical (GE IAC type) relays

- Visual inspection
- Mechanical adjustment and inspection
- Electrical tests and adjustments.

Electronic Relays (MCGG and UR types)

Since there are no moving parts in these electronic relays, there is no physical wear due to usage. Maintenance consists of secondary injection tests to verify the tripping time accuracy of the relays.

2.3.2.1.4.5 Battery & Battery Charger Maintenance

The battery and battery charger maintenance consists of the following activities:

- Record the room temperature
- Measure and record each battery voltage
- Record the charging current.

2.3.2 Renewal Programs

2.3.2.1 Underground Assets

Remediation programs for maintaining the underground assets consist of the following:

- Pad Mounted Switchgear Renewal
- Primary Distribution Equipment Renewal
- Pad Mounted Transformer Replacement Program
- Underground Cable and Splice Renewal
- Secondary Cable Renewal.

2.3.2.1.1 Pad Mounted Switchgear Renewal

Pad mounted switchgear units are used in distribution loops; they supply residential subdivisions and commercial/industrial customers. Switchgear units are used to isolate and control other distribution equipment and provide operational flexibility to reconfigure the loops for maintenance, restoration or other operating requirements. Because each unit can have up to 500 customers connected to it, a failure can have a significant impact on the customers. As a result, a proactive yearly plan targets poor switchgears for replacement or cleaning.

As outlined in Appendix C of the DSC, the minimum inspection requirements for the distribution system within an urban environment are to be scheduled and inspected on a three-year cycle. As such, Enersource inspects its 862 pad mounted switchgears in adherence with the DSC requirement and all inspection information is recorded into the GIS via field computer tablets.

Pad mounted switchgear are critical components of the underground distribution system and have significant reliability and safety risk due to condition, age, and design/installation practices. Switchgear degradation has shown a strong correlation with a number of factors, such as condition of mechanical components, contamination due to dirt, moisture and corrosion. The population targeted for replacement consists of 27.6kV air insulated switchgears, based on safety and reliability concerns since the 27.6kV units have shown a tendency to fail or flash over. Poor condition of 15kV switchgear units are also being targeted for replacement with a new type of solid-dielectric switchgear to reduce safety concerns and maintenance costs. These units use a magnetic actuator for fault interruption which is proven to be safer for field operation compared to its air-insulated counterparts.

Based on the yearly inspection results and the health index calculation, several switchgear are recommended for replacement, as shown in **Figure 59** below. This ensures funding and effort are directed to the correct switchgear locations for replacement in the most efficient manner.

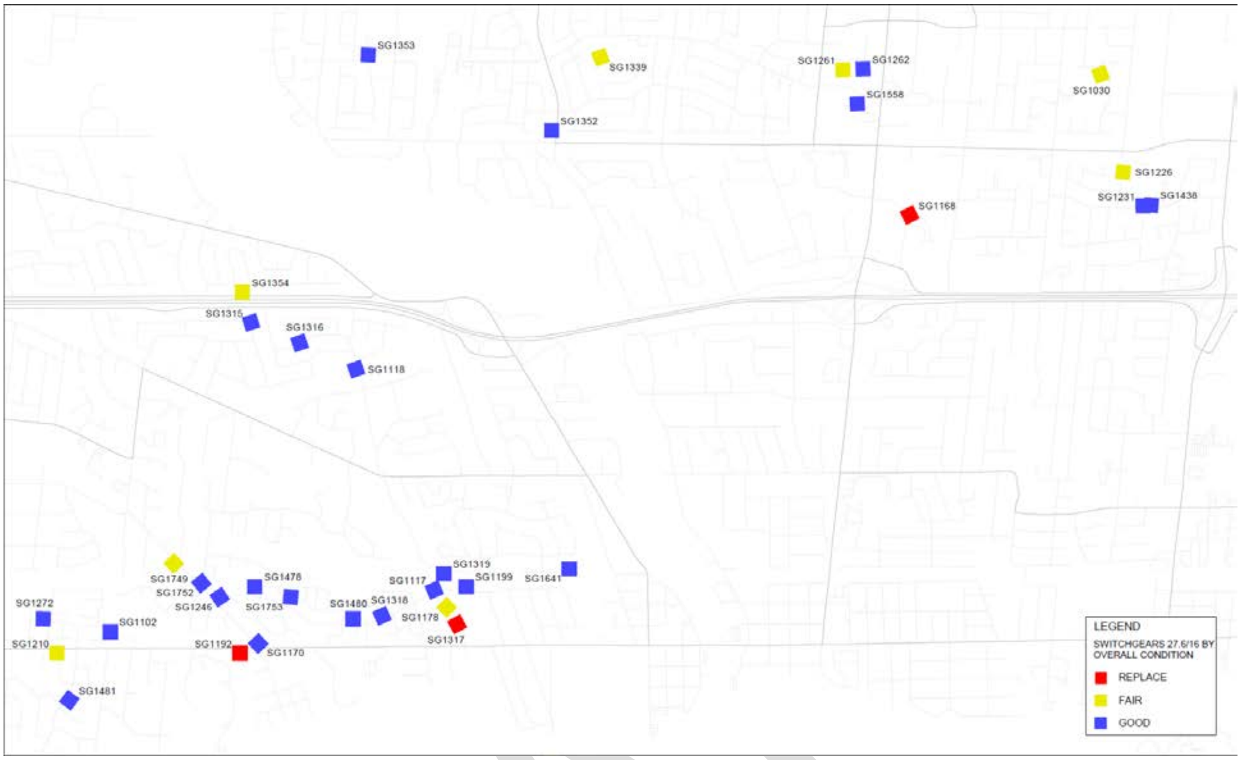


Figure 59. Switchgear Overall Condition

2.3.2.1.2 Primary Distribution Equipment Renewal Program

In addition to the main system components such as transformers, switchgears, cables, etc., the underground distribution system also consists of smaller, auxiliary components such as elbows, inserts, lightning arresters, fault indicators, etc. Without these auxiliary accessories, the main components of the system become inoperable, making replacement of this equipment before failure necessary.

Some of the auxiliary system components installed in transformers, such as elbows and inserts, are used in order to perform switching operations, isolations, and restoration. Therefore, their condition directly influences system reliability as well as the safe operation of the equipment.

Other auxiliary devices, such as fault indicators, are used to troubleshoot system outages. Their proper operation influences restoration time and in turn, overall reliability of the system. After significant research, Enersource has begun to use a new type of fault indicator which is much easier to install at transformer and switchgear locations. The new fault indicators allow Enersource to find cable faults more rapidly which helps reduce power outage times.

In addition, equipment condition is routinely assessed by operations personnel when performing work on a transformer, switchgear, or other asset replacements. If a defective component is found, the crew notifies the Control Room, a report is created, and a maintenance crew is dispatched to perform necessary repairs.

2.3.2.1.3 Pad Mounted Transformer Replacement Program

Enersource uses a two-tiered approach to transformer remediation. It first collects and analyzes critical asset data on each transformer, including inspection, physical location (e.g., rear lot), asset condition and reliability data. This information is used to help identify future underground subdivision rebuild areas.

The following asset data are collected:

- Transformer age
- Inspection reported condition (e.g., poor, fair)
- Leaking transformer (both PCB and non-PCB)
- Physical location of transformer (e.g., rear or front lot)
- Reliability data from IOM
- Cable faults.

As shown in **Figure 60** below, a detailed map is generated and reviewed by both the Asset Operations and Asset Management teams to determine areas that qualify for underground renewal projects. This allows Enersource to replace transformers that have reached end-of-life or are found to be leaking and thus pose a safety and environmental risk, and/or have exhibited reliability issues. This information is used to determine areas that require an extensive underground renewal and is a major component within the overall System Renewal investment category.

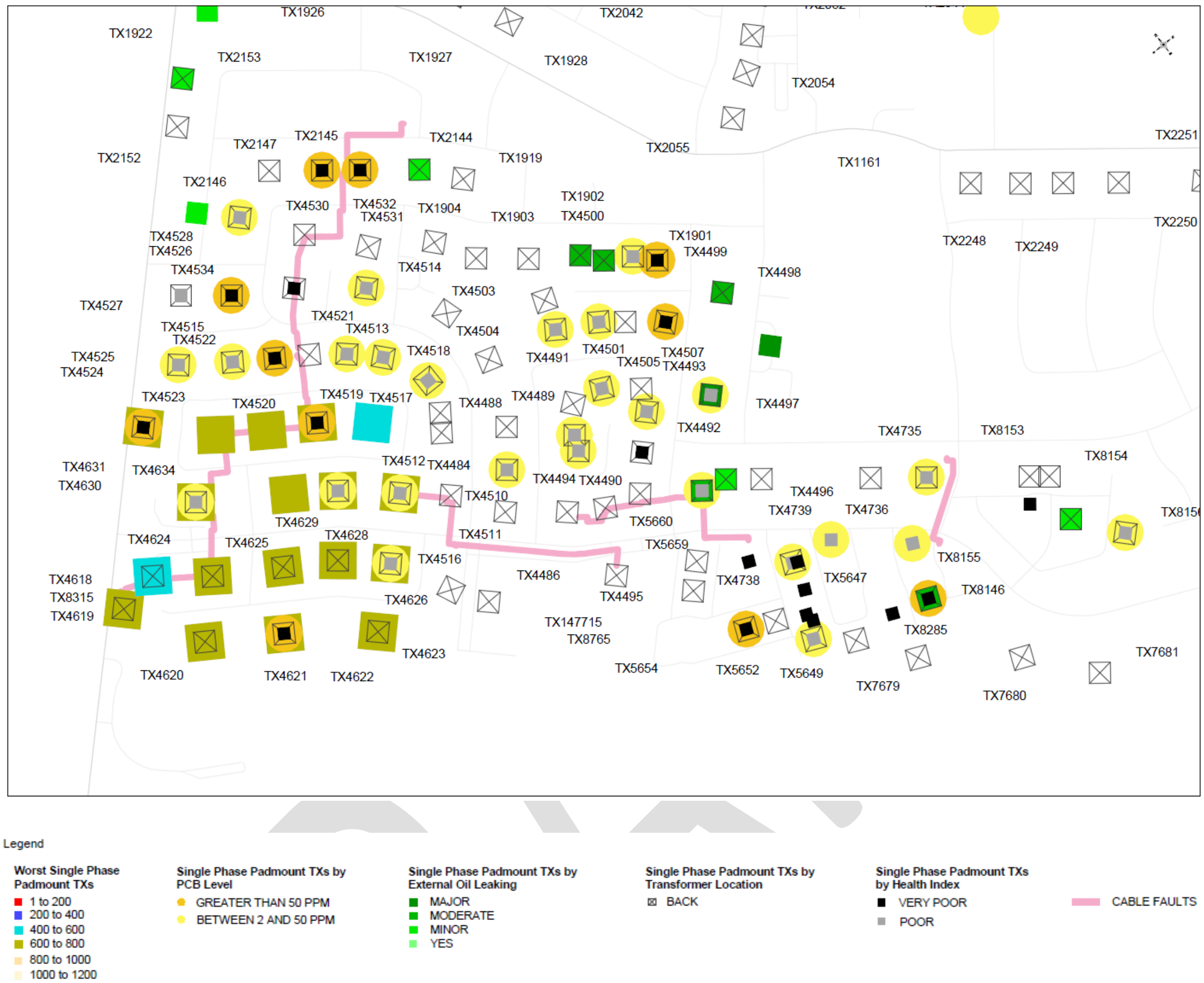


Figure 60. Analysis of Underground Areas with Aging Assets and Poor Reliability

In addition, Enersource identifies and replaces individual pad mounted transformers that have reached end-of-life, have shown to be in poor condition, or have shown signs of leakage.

2.3.2.1.4 Underground Cable and Splice Renewal Program

Primary underground cables and overhead conductors are used to transport power from HONI's transformer station either directly to Enersource's distribution system or to an Enersource substation. At a substation, the 44kV or 27.6kV voltage is then converted through a substation transformer to either 13.8kV or 4.16kV. From there, customers are either directly connected to the system or the voltage is converted further by the distribution transformers at 8kV or 2.4kV down to secondary voltages such as 120/240, 120/208 or 346/600V, depending on the location within the City. The older primary cables are either direct buried or installed in a separate direct buried PVC duct if installed along the City boulevards. Underground cable failures are the leading cause, accounting for 50% of equipment failures in the distribution system.

Typically, underground cable failures are caused by degradation of the insulation, which is the dielectric medium that insulates the central conductor from the grounded concentric neutral wires. Insulation failure can be caused by several factors, for example:

- Contaminated materials during the manufacturing stage
- Poor adhesion of the extruded insulation shield
- Imperfections at the conductor shield-insulation interface
- Water inside the conductor strands, or at the concentric neutral wires
- Fault currents
- Voltage surges from lightning and switching.

To address this risk, Enersource has an extensive cable replacement program. On an annual basis, the worst performing areas of the underground cable system are identified and cables are either replaced individually or form part of a larger underground renewal project.

The impact of a single cable failure on reliability varies greatly depending on the cable size, voltage level, type of customer supplied and location of the cable. The subtransmission main feeder cables typically supply a substation so the failure of a cable supplying a single substation may result in a disruption of power affecting up to 5,000 customers.

Main feeder cables typically supply several pad mounted switchgear units and can deliver power to up to 1,000 customers. The local distribution cables that are connected to the pad mounted switchgear units or overhead distribution system will typically supply up to 500 customers. Distribution cable failures will result in a power outage to all nearby customers connected and will momentarily trip the substation breaker as the fuse isolates, thus affecting even more customers.

Main feeder cable failures will result in a significant increase in number of customers affected and increase the length of time of the outage. In 2014, Enersource experienced 135 feeder cable failures that affected reliability significantly, which resulted in over 2,650,000 customer outage minutes. Of those 135 cable failures, 28 were main feeder failures that resulted in over 770,000 customer outage minutes, and impacted close to 18,000 customers.

2.3.2.1.5 Secondary Cable Renewal Program

The distribution system has over 203,000 customers, the majority of which are connected to a distribution transformer via an underground secondary service cable. Based on past experience, secondary cables are less prone to failure compared to primary cables of the same age. This is mainly due to less electrical stress and fewer fault current spikes. However when secondary cables fail, they must be immediately repaired. Every year, many underground residential and industrial/commercial services fail beyond reasonable repair and require complete replacement. These failures typically result in outages to single residential or industrial/commercial businesses.

The secondary cable renewal program targets replacements based on their condition and number of failures, rather than their age or size. This program entails the spot replacement of secondary services, over various parts of the city that are at end-of-life and are beyond reasonable repair.

2.3.2.2 Overhead Assets

The projects and programs under this section encompass the replacement of poles, attachments, and overhead pole lines that have reached their end-of-life or have been determined to be a potential public or employee safety concern.

This section is divided into two main types:

- Overhead distribution pole line renewal projects
- Poles, accessories, and pole mounted transformers renewal programs.

2.3.2.2.1 Overhead Distribution Pole Line Renewal Program

Overhead distribution pole line renewal projects are required to replace overhead distribution infrastructure to ensure it is kept at a safe and acceptable performance level.

The main components of the overhead system are poles, pole mounted transformers, switches, conductors and associated overhead hardware such as insulators, fuses and lightning arresters. Pole lines deteriorate over time and their strength may be reduced, resulting in a risk of failure, especially under adverse weather conditions.

Overhead assessments including safety, environmental, regulatory, reliability, reputational, and financial risks are made to determine which investments have the greatest impact on the business values. Assuming there were no constraints, all overhead investments with a positive impact on the business values would be approved. Due to resource constraints such as appropriate funding, internal and external labour availability, projects are selected and prioritized based on the assessments.

Enersource completed a full inspection of its overhead system during the 2014-2015 period. The inspection data is then used to identify the overhead assets that need to be addressed as well as their relative priority in relation to the business values. The hierarchy of criteria that was used to prioritize the projects is as follows:

1) **Poles in 'poor' condition** – Clusters of poles in poor condition represent the greatest safety risk to the public and to Enersource personnel who may need to work on the poles (i.e., switching, service work, etc.), as shown in **Figure 61**. In addition, they also pose significant reliability risk. If any of these clusters also include another priority criterion, that cluster will be ranked as having higher priority. For example, a cluster of poles in 'poor' condition and having PCB transformers (priority 2) will be ranked higher than a similar cluster that does not have PCB transformers.

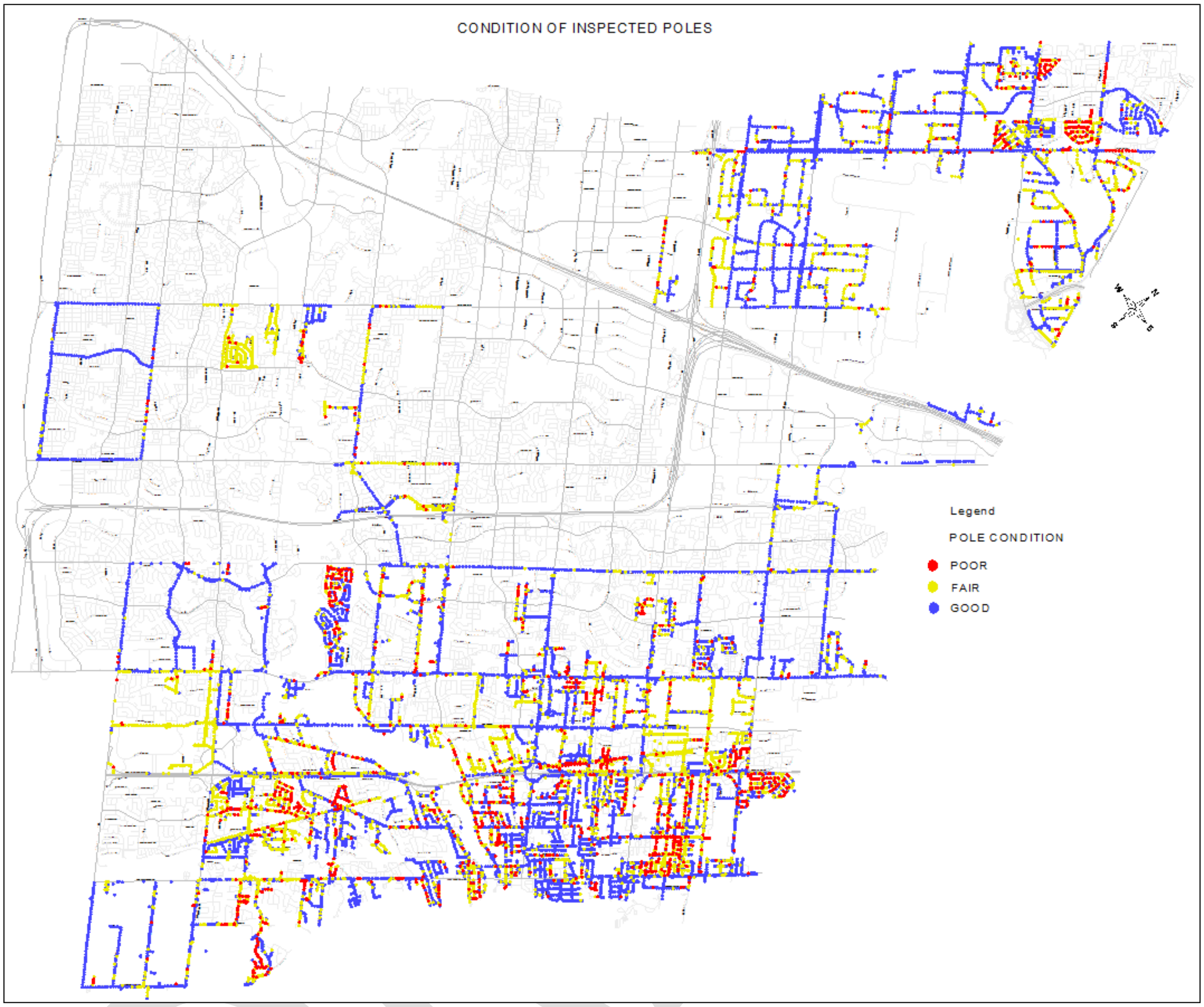


Figure 61. Pole Condition from Field Inspections

2) **PCB transformers < 50 PPM PCBs, > 2 PPM PCBs** – Transformers containing PCB oil can pose a major safety, environmental, regulatory, financial, and reputational risk. The category of transformers with PCB content greater than 50 ppm are not being considered in the renewal program as Enersource is on track to have all such transformers removed by the end of 2015, as shown in **Figure 62**.

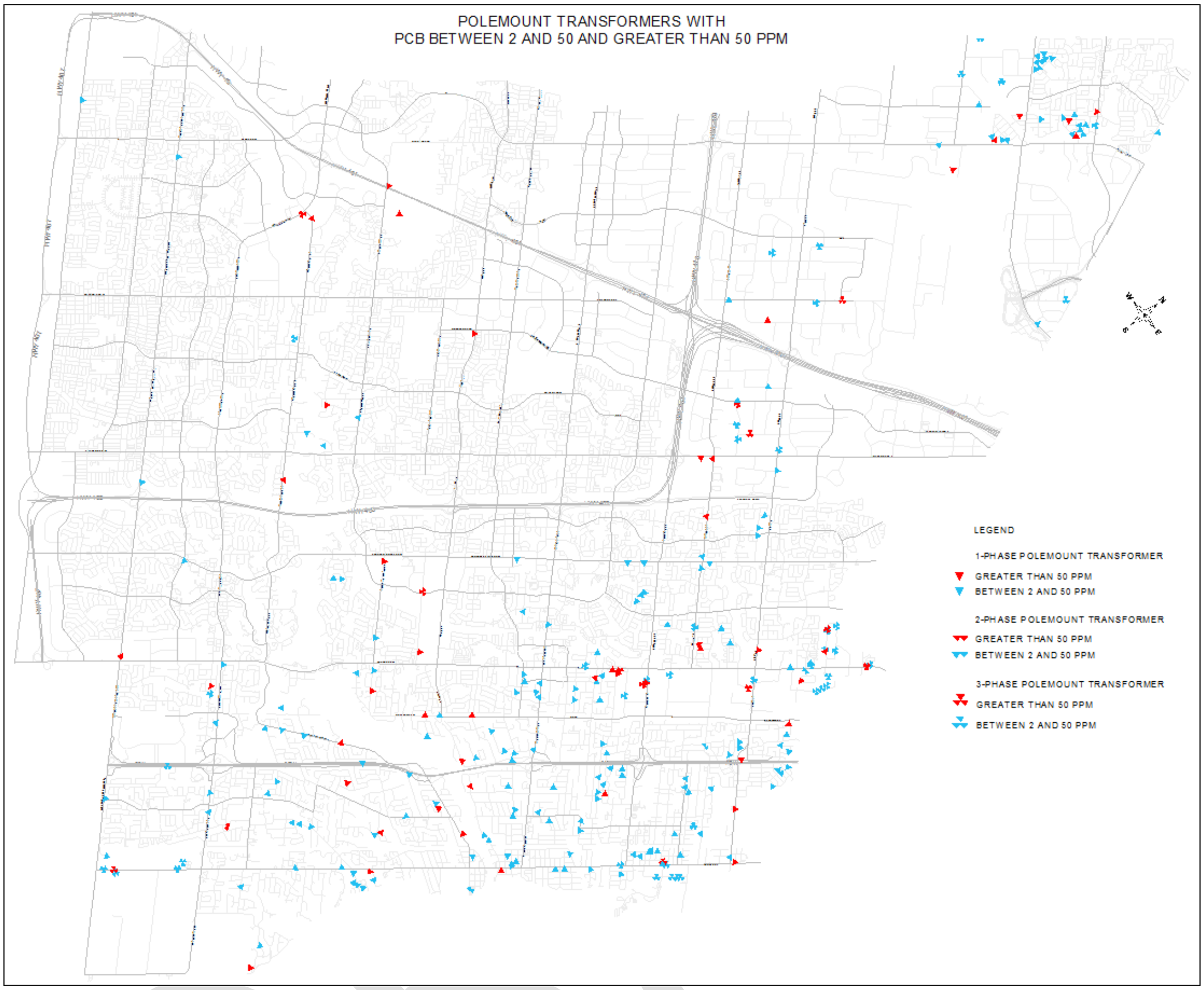


Figure 62. List of Pole Mounted Transformers with PCB Content

3) **'Major Leak' transformers** – Non-PCB transformers that have been identified as having a major oil leak pose an environmental, financial, and reputational risk. The list of non-PCB leaking transformers is shown in **Figure 63**.

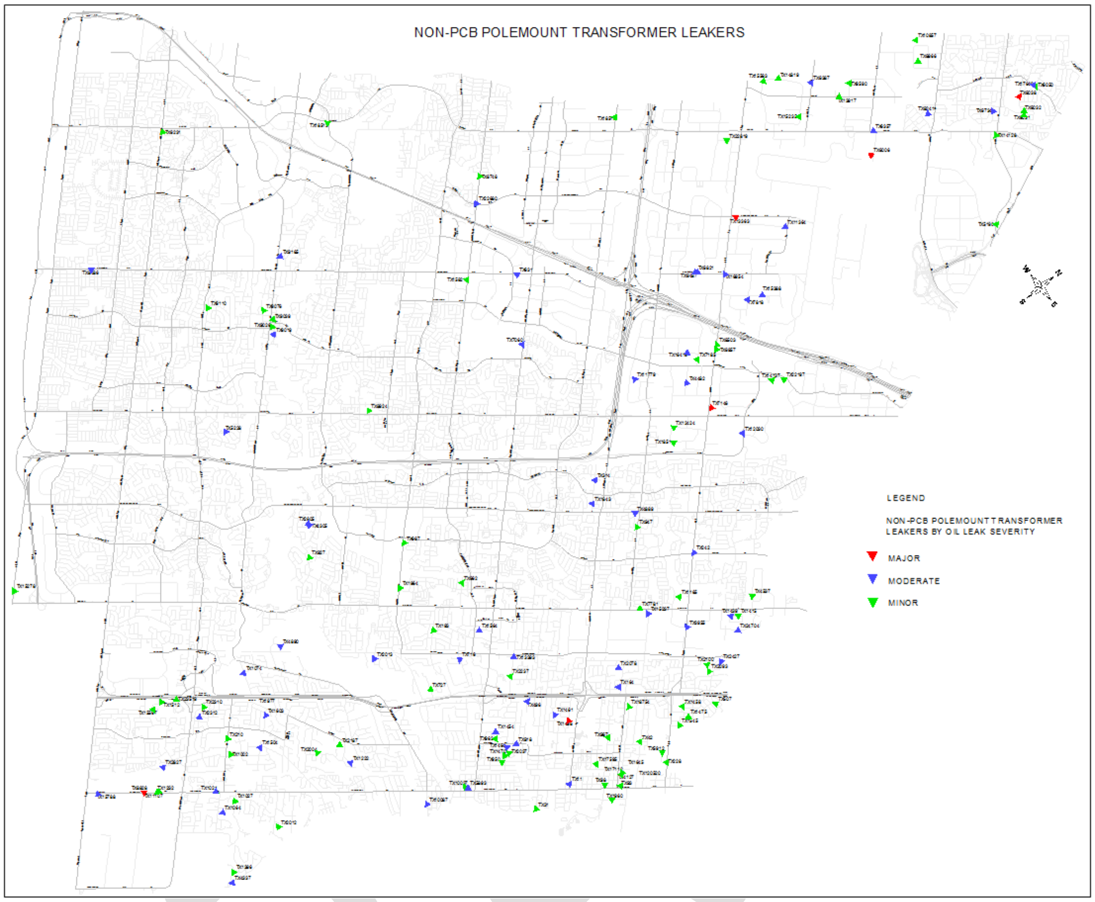


Figure 63. Leaking Pole Mounted Leaking Transformers (Non-PCB)

4) **Top Nine Large Customers** – Large customers (with demand of 5 MW or greater) and hospitals pose increased reliability risk as outages can adversely impact their businesses and operations and can cause major reputational damage to Enersource. An example of distribution feeders supplying large customers and hospitals is shown in **Figure 64**.

LARGE CUSTOMER AND HOSPITAL FEEDERS

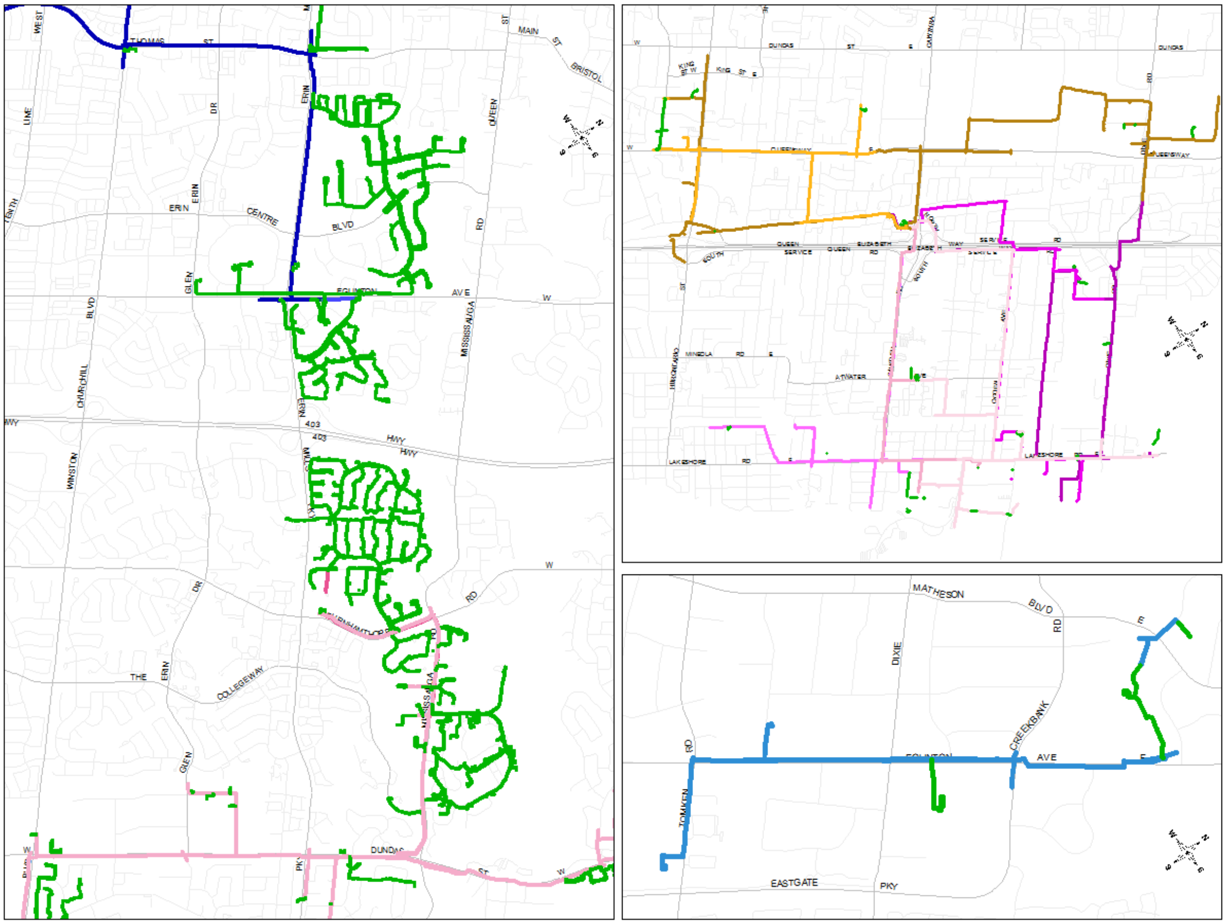


Figure 64. Feeders Supplying Large Customers and Hospitals

5) **Poles 35 years or older** - As shown in **Figure 65**, areas where the majority of poles are older than 35 years old are given higher priority as they have passed or are nearing the end of their useful lives. The financial impact (i.e., asset write-down) would be minimized as these assets would be fully or almost fully depreciated.

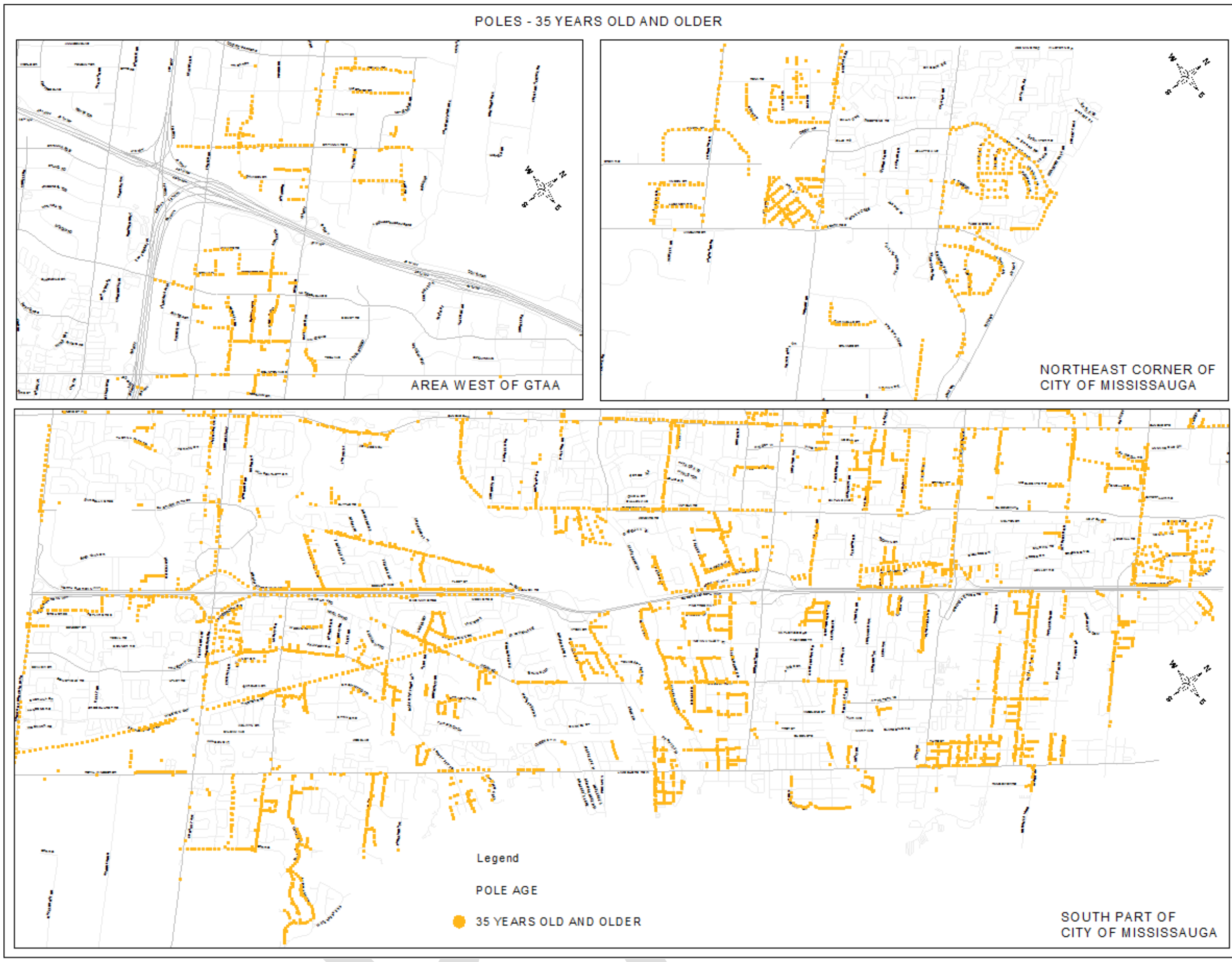


Figure 65. Location of Poles 35 Years or Older

The list of projects for overhead distribution renewal is determined based on the evaluation process of using pole inspection data and assessing need against Enersource's business values. The selected overhead System Renewal projects are then designed and constructed to meet all relevant safety and regulatory requirements.

2.3.2.2.2 Poles, Accessories & Transformers Renewal Programs

As stated earlier, the main components of the overhead system are poles, pole mounted transformers, switches, conductors, and associated overhead hardware such as insulators, fuses and lightning arresters. This program deals with the replacement of overhead components, switches, and associated equipment that have reached their expected end-of-life, namely:

- Concrete poles
- Wood poles
- Overhead wwitches

- Insulators
- Polemounted transformers.

Failure of overhead equipment can result from exposure to various adverse conditions and causes, including:

- Mechanical stress on operating linkages, operating rods and springs
- Contacts due to wear and tear during fault interrupting conditions
- Exposure to contaminants such as salt and pollutants and extreme environmental weather conditions
- Chemical contamination such as dust and powder produced by arc erosion during switching and fault interruptions
- Thermal stress resulting from localized heating and varying load currents.

The condition of overhead equipment is identified via:

- Inspections program
- Additional field assessments carried by staff doing work in the area
- Known reliability performance issues/customer outages
- Non-compliance with current standards
- Infrared and radio frequency testing results.

2.3.2.2.3 Wood and Concrete Pole Renewal Program

Poles in 'poor' condition not identified as a part of a distribution System Renewal project are replaced under this program. This is required to ensure that substandard wood poles, cross arms, and concrete poles that have reached their end-of-life are replaced on an annual basis. This program also ensures the replacement of poles deemed to be in 'poor' condition and considered an emergency. By way of example, this would include rotten poles or those affected by a failure or event such as a pole fire, damage from vehicle contact, weather storm, or tree falling on the power line.

A major component of Enersource's overhead distribution system is wood and concrete poles. Enersource has over 12,900 wood poles and over 8,900 concrete poles which support approximately 1,800 km of overhead primary and over 1,200 km of overhead secondary circuits. Under this program, poles are replaced based on their condition rather than their age, location, or system improvements.

Poles deteriorate over time and when their strength is reduced to the point there is a risk of failure under adverse weather conditions, they are deemed to be at end-of-life. The safe, reliable operation of the distribution system depends on the condition of pole assets. Pole condition is routinely assessed by operational personnel performing work such as switching or other asset replacement (such as transformers, insulators, and lightning arrestors). Furthermore, during the pole numbering project undertaken in 2014, Enersource flagged numerous poles that are in poor condition and in need of replacement under the Overhead Renewal Program.

Because wood is a naturally grown material all such poles differ in internal structure and consequently in mechanical strength. Degradation of strength can result from naturally occurring fungi that attack the wood, which results in decay. The severity of the degradation depends on several factors such as location, treatment, type of wood, and installation practices. Wood poles can also be damaged by woodpeckers, termites, or pole fires, which are caused by current leakage during insulator tracking. In addition, in the past, some wood poles were painted grey with the goal of improving visual appeal; however, the paint trapped moisture inside the pole which has accelerated decay.

Failures of concrete poles may be caused by deterioration of the steel re-bars inside the pole due to exposure to corrosive chemicals in the soil or winter road salt. The severity of the degradation depends on several factors such as location, rusting of the exposed re-bars, and whether a protective coating was used on the ground section of the pole.

Since distribution and subtransmission poles support bare overhead wires and other equipment, pole failure is very serious, especially since the public may come in contact with live conductors. In addition, depending on the number of circuits supported by the pole and the voltage, failure may disrupt power to thousands of customers.

Enersource carries out detailed field inspection of wood and concrete poles and associated distribution equipment (e.g., transformers and overheard switches). The condition of the poles is recorded through computer field tablets and imported into the GIS. Subsequent geo-spatial maps are generated to identify areas that require pole replacement, as shown in **Figure 66** below.

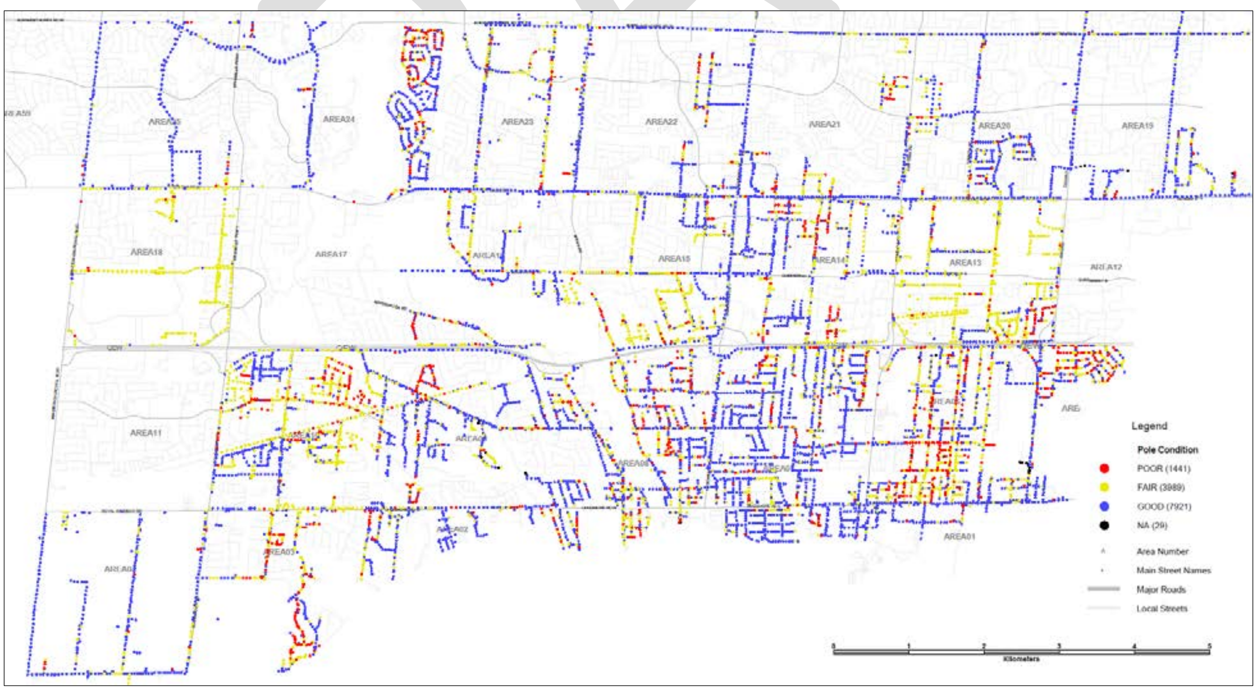


Figure 66. Pole Condition

2.3.2.2.4 Overhead Switch Renewal Program

Switches are one of the key components of the power system. They are used to reconfigure an electrical circuit by interrupting the current flow, or to isolate conductors. In addition, fused cutouts are used to protect transformers and underground conductors under fault conditions.

Enersource utilizes four types of overhead switches:

- Loadbreak switches (load interrupter)
- Remotely-controlled switches
- In-line switches
- Fused cutouts.

The overhead distribution system has approximately 570 gang-operated, three-phase load break switches and over 2,000 in-line solid blade switches, cutouts, and other components.

In most cases when an overhead switch failure occurs, it is caused by contamination of the insulator, which can lead to a flashover and further degradation of the insulating medium. Sometimes contamination will cause leakage current to develop across the insulator, or other parts of the switch that are not meant to carry current. As a result, these parts may overheat and cause the switch to fail. Also, the loadbreak switch mechanism that suppress the arc when the switch contacts are opening can sometimes fail, causing arcing and damage to the switch contacts.

In addition, when overhead switches are not operated over a long period of time, the switch contacts seize, preventing the crew from operating the switch.

System impact from an overhead switch failure can be very significant because they are typically installed on overhead main feeders that may supply multiple substations or subtransmission feeders. Failure of an overhead switch installed near HONI's transformer station may interrupt power to several thousand customers, including large commercial and industrial customers.

To ensure that switches on the system are in proper working condition, all switching equipment is inspected each year with an infrared camera for arcing and overheating. During switching operation or as a follow-up to trouble calls, a number of overhead switches have been found to be beyond repair and require replacement. In addition, Enersource continues to replace equipment with porcelain insulating components such as cutouts, standoff insulators, and mid-span openers that have proven to be susceptible to failure, with new equipment that contains polymer insulators.

The inspection and maintenance performed annually in the loadbreak switch maintenance program identifies a number of switches beyond economic repair that require replacement.

Enersource carries out both proactive and reactive replacement programs of overhead switches in its distribution system.

A type of polymer switch was identified as an area of concern due to its likelihood of premature failure, confirmed through field failures and testing analysis completed by the manufacturer. As a result, Enersource has created a program to replace these faulty switches to mitigate the risk of extended customer outages associated with the reactive replacement of defective switches. This tactic also reduces the safety risk to employees and the public. A sample area with these switches identified through the overhead inspection program is shown in **Figure 67** below.

Figure 67. Sample Area Identifying the Location of SMD-20 Switch

2.3.2.2.5 Insulator Renewal Program

The system impact from the failure of an overhead insulator is also very significant, as it could support an overhead main feeder conductor that may supply multiple substations or subtransmission feeders. The failure of an overhead insulator installed near a TS may directly interrupt power to several thousand customers, including large commercial and industrial customers.

In the past few years, a number of outages on the overhead system was caused by porcelain or EPAC insulator tracking or breaking. These outages ranged from intermittent power interruptions to a few hundred customers, to sustained outages that affected several thousands of customers. In some cases, porcelain insulator tracking caused pole fires which resulted in prolonged outages and caused damage to other distribution equipment. During a freezing rain storm in March, 2015, there were 25 pole fires in one night, caused by insulator tracking from road salt.

In addition, when porcelain insulators track, they may heat up to a point where they may shear, posing a safety hazard to the public or to Enersource personnel working near the defective insulator.

Through the pole and infrared inspection programs, the locations of porcelain and EPAC insulators are being identified (an example is shown in **Figure 68** below). The key locations will be prioritized and these insulators will be replaced with more reliable and safer silicone insulators. Approximately 1,000-2,000 insulators will be replaced each year for the next 10 years.

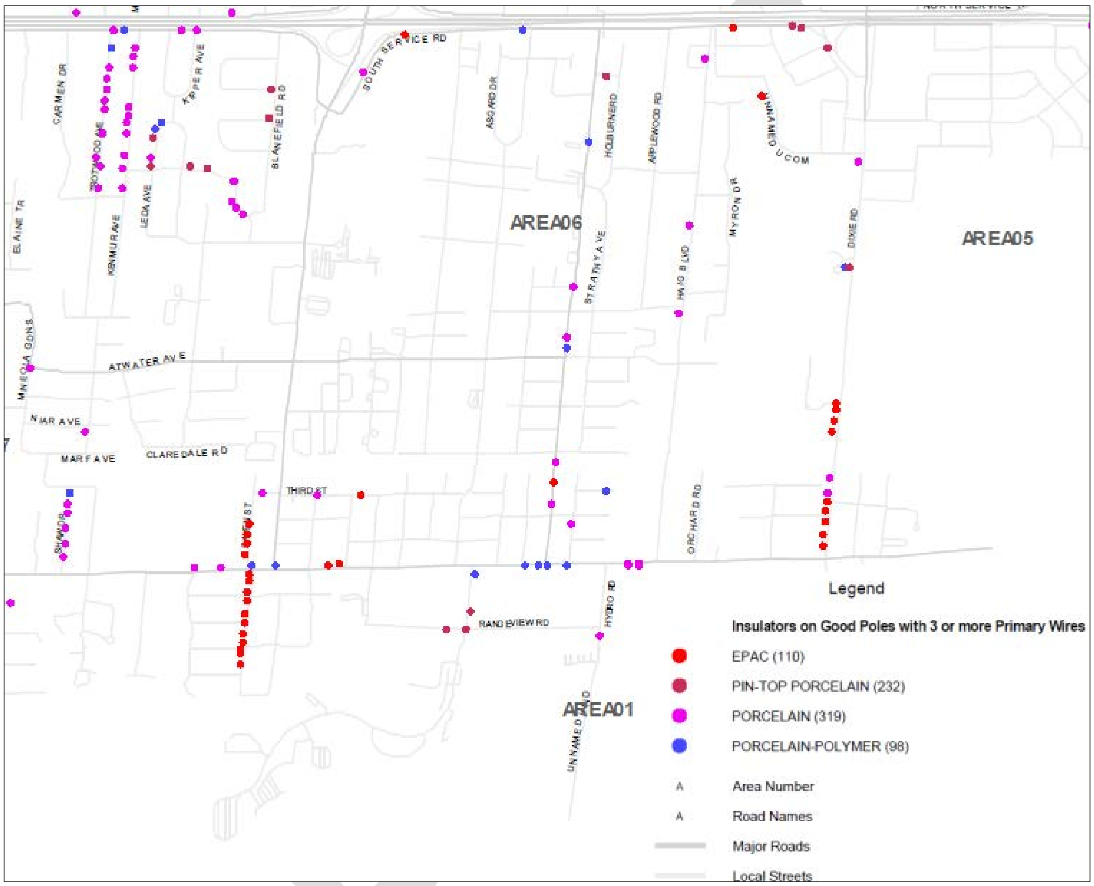


Figure 68. Porcelain and EPAC Insulator Locations

2.3.2.2.6 Pole-Mounted Transformer Renewal Program

Similar to the pad mounted transformers, the main purpose of the pole mounted transformers is to lower the primary voltage to secondary voltage levels acceptable to residential, industrial or commercial customers. Pole mounted transformers are not as affected by rust or vehicle accidents since they are not installed as close to traffic as pad mounted transformers.

The pole mounted transformers are similar in construction to single phase pad mounted transformers and therefore mostly fail due to insulation breakdown at which time they must be immediately replaced. Because a transformer failure in a residential area may only affect 10 to 20 customers, outage customer minutes and time is minimal. However, a transformer failure for an industrial/commercial customer could prove costly to their business.

Transformer condition is routinely assessed by Enersource personnel performing work such as switching, responding to trouble calls, or outages. The outside crews advise the Control Room of transformers that are in poor condition at which time the Control Room would generate an IOM report and send it to the Overhead Maintenance Department for follow-up. In addition to replacements of failed transformers, this program also provides for replacements of rusted, leaking, or overloaded transformers.

The program is needed to allow for the planned and unplanned replacement of overhead transformers that are in poor condition in various parts of the City.

2.3.2.2.7 Fault Indicator Replacement

Enersource has deployed numerous fault indicators of varying types throughout its distribution system. The replacement program is aimed at adding fault indication to areas where it is absent, as well as replacing older fault indicators that are technologically obsolete or prone to malfunction.

Fault Indicators are significant to the distribution system because they reduce fault locating times, improving outage response and, consequently, outage restoration times. They also help determine the root cause of transient faults (i.e., auto reclosures). The deployment of functional fault indicators are crucial to maintaining high levels of reliability and customer service and to achieving gains in operational efficiency.

2.3.2.3 Substation and Automation Assets

2.3.2.3.1 Substation Renewal Program

Enersource has 66 municipal substations in service. They are as follows:
- 52 bungalow building style substations
- 14 outdoor substations.

Based on Enersource's significant asset class ranking, substation equipment has the highest significance to the Company's sustainability as an organization and to its business values. Therefore, Enersource proactively replaces substation equipment before a major failure occurs which could negatively impact customers, system reliability, and the Company's reputation. Among the list of critical equipment in the ACA, substation equipment was identified as the second most significant to the sustainability of the organization. Therefore, it is imperative that such equipment is replaced before a failure occurs.

Enersource's proactive replacement strategy considers the health index, location, number of customers served, transformer protection enhancement opportunity (implementing transformer differential protection) and the condition of other substation assets, including buildings and grounds. The component replacement program addresses assets such as switchgears, circuit breakers, protection relays, transformers, enclosures, tap changers, batteries, and battery chargers that have reached end-of-life and can no longer fulfill their intended function.

A smaller but essential program that Enersource carries out each year is to replace the battery chargers and batteries which are critical for substation operations. In the event of a substation power failure batteries continue to supply power to the protection relays, the Remote Terminal Units (RTU's) and to the control mechanism for circuit breaker operation. These batteries are continually charged by battery chargers that use AC voltage, rectifies them to a useable DC voltage. The substation battery chargers and DC systems have an approximate life cycle of 10 years. The substation batteries have an approximate life cycle up to 15 years inside a climate-controlled substation.

2.3.2.3.2 Automation/SCADA Renewal Program

The SCADA and protection system are considered critical assets for proper operation of Enersource's distribution system. To ensure that there is an appropriate level of automation to satisfy operational requirements, Enersource identifies the system automation and SCADA needs in two ways:

- Tracking the age of remotely controlled switches and substation auxiliary components from the result of inspection programs; and
- Identifying the worst performing supply points on the electrical grid from the result of system planning studies; new remotely controlled switch locations are selected to increase system performance.

The electricity power grid is designed to automatically react to external events to ensure public safety. This could be to instantly shut off power for sustained events (such as a contractor digging into underground cables) or could cause sub-second momentary outages for events such as tree contacts. This ensures homes, businesses, and safety services such as traffic lights are not unnecessarily exposed to long outages.

The SCADA system provides Enersource with the ability to monitor and control its distribution system and is connected to 66 substations and 240 field automated switches with a total of 15,500 digital, analog, and control points. Communication from the SCADA to the substations have traditionally been via S4T4 serial communication lines.

The S4T4 serial leased line communication links between the substation RTU's is a legacy system that is slow and approaching obsolescence. To improve this communication infrastructure, Enersource plans to upgrade the S4T4 communication infrastructure to a more robust IP-based Multiprotocol Label Switching (MPLS) technology.

MPLS technology provides multiple advantages over the legacy S4T4 technology such as:

- The ability to remotely connect to the protection devices at the substation
- Remote monitoring of the communication circuit health

- Advanced cyber security and ability to connect multiple services such as phone, internet and security cameras, on the same MPLS network.

Once a substation is selected to undergo this communication technology upgrade, the protection relays and the RTU will also be upgraded.

2.3.2.3.3 Automated Switches Renewal Program

To ensure the continued safe and efficient operation of the electricity system, remotely controlled overhead and underground load break switches allows Enersource to restore power to a large number of customers in the event of a power outage.

A major trend in the electricity utility industry is a move towards increased system automation and remote operation. In recent years, Enersource has been steadily increasing the amount of automated switchgears in its distribution system, resulting in improved system reliability and decreased outage durations. It is imperative that this move towards increased automation continues in order to ensure continued improvement of the system.

The majority of Enersource's automated switchgears are on the 27.6/16kV distribution system. Many of the first generation switchgears were installed over 20 years ago, and have been gradually losing their effectiveness in recent years. In particular, remote operations are not as reliable and many older switchgears must resort to manual operation which, during a power failure, leads to an increase in outage duration.

It is imperative that Enersource upgrade these aging units in order to avoid diminishing system reliability in the future. New switchgears use the latest solid dielectric technology and have proven to be reliable in the high voltage as well as the automation components. A comprehensive automation study was completed to identify high priority areas and considered factors including historical reliability (momentary and sustained outages), number of affected customers, and existing automation in the vacinity.

Scada-Mate switches are deployed on the 27.6kV system while Alduti-Rupter switches are deployed on the 44kV system. Enersource has strong in-house expertise in working with these switches and the associated automation, and with this knowledge can maximize switch functionality and continue to improve it, even after the initial installation.

A typical overhead automation project involves the installation of one or two automated switches in close proximity to a substation. Such an arrangement allows for a substation's incoming subtransmission feed to be transferred quickly to an alternative feed in the case of an upstream fault. This will result in greatly reducing outage durations, thereby improving system reliability performance.

2.3.3 Expansion Programs

2.3.3.1 Downtown Core

The Downtown Core began its development in 1973 with the construction of the newly built Square One Shopping Centre. At that time, the Downtown Core consisted of little more than Square One and large amounts of vacant farmland. Square One has undergone many expansions over the past four decades, during which time the Downtown Core has seen an increase in high-rise residential and office development.

Figure 69. Square One Shopping Centre After and Before Construction

Today, the Downtown Core is the focus of the Urban Growth Centre for Mississauga and houses the City's cultural and institutional centres, as well as being a regional centre and major transportation hub for the Greater Toronto Area. The Core also contains the Civic Centre, the Living Arts Centre, the Central Library, the YMCA and Kariya Park. Additionally, this area is comprised of a mix of office buildings and high-rise residential apartments focused around the retail commercial development within and around Square One. Recently the Downtown Core has seen the emergence of Celebration Square, the completion of the new Sheridan College Campus, new commercial development along Rathburn Road and improvements to the LRT and BRT transit terminal.

The Mississauga Official Plan was adopted by City Council in September, 2010 where the Downtown Core, shown in **Figure 70**, was identified as part of a new urban structure. This new urban centre focuses growth in areas with existing service, proposed service, and infrastructure capacity, particularly transit and community infrastructure. The Downtown Core is intended to be a vibrant regional centre where residents are able to live, work, and play.

Figure 70. Today's Mississauga Downtown Core

Downtown Planning Districts and Projected Loads

The City of Mississauga's Official Plan outlines basic goals and objectives, and provides direction for long term growth and development within the City. The Official Plan is divided into nine planning districts. Specific policies and land use maps define a long term plan for the road system, land use development, and other details regarding the Downtown Core. The districts, along with the corresponding potential development summary, are shown below in **Figure 71**.

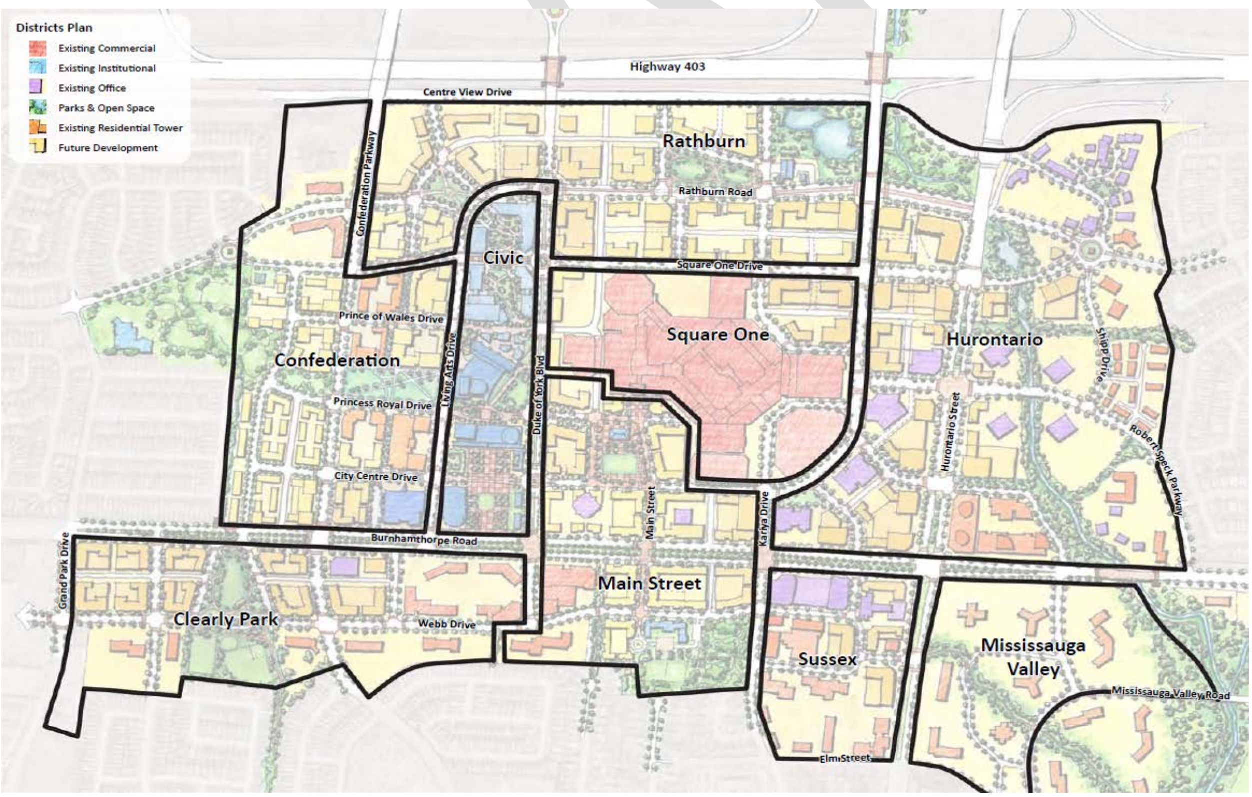


Figure 71. Downtown 21 Planning Districts

Enersource has forecasted electricity demand in each of the City planning districts. The loads projected are for the complete Downtown Core and are based on the Downtown 21 build out potential. Where available, the loads have been projected based on applications that specify the number of units or commercial space that will be available. The loads for other buildings, where such information is not available, have been estimated based on the type of building, approximate building footprint, and number of floors. In cases where no information regarding future buildings are available, the load for the area is based on the load of a similar area that was completed in the past. The projected load for each district is shown in **Figure 72**.

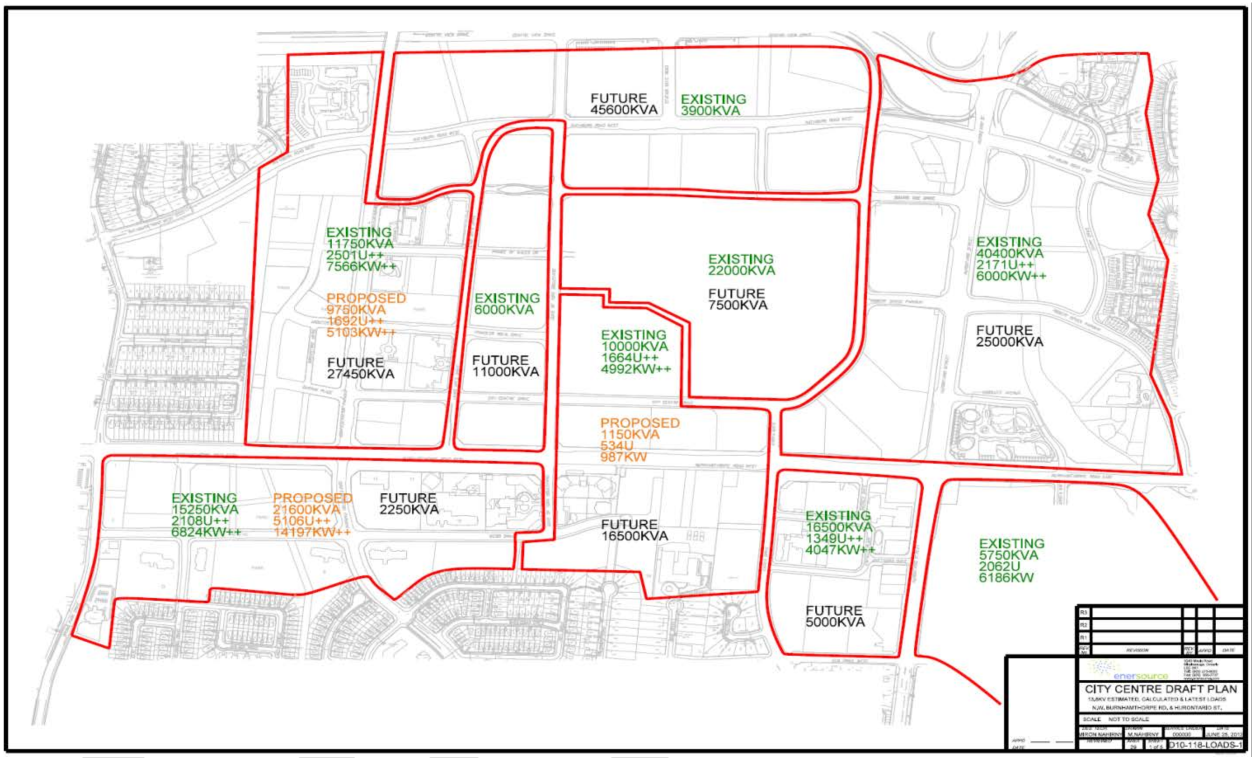


Figure 72. Present and future loads in Downtown 21 Planning Districts

Table 26. Planning Districts, Potential Population, and Estimated Load

Planning District	Category	DT21 Potential	Existing Load (MVA)	Estimated Load (MVA)
Main Street	Population	12,316	10	27.65
	Employment	4,221		
Civic	Population	5,500 Students	6	17
	Employment	2,650		
Confederation	Population	22,246	11.75	48.95
	Employment	20		
Cleary Park	Population	16,004	15.25	39.1
	Employment	603		
Rathburn	Population	0	3.9	49.5
	Employment	28,636		
Hurontario	Population	6,057	40.4	65.4
	Employment	25,423		
Square One	Population	0	22	29.5
	Employment	4,087		
Sussex	Population	6,402	16.5	21.5
	Employment	5,574		
Mississauga Valley	Population	6,070	5.75	5.75
	Employment	199		

Existing Load and Supply Points in the Downtown Core

Currently, there are approximately 65 buildings in the Downtown Core and three substations: Woods MS, Confederation MS, and City Centre MS. These substations are equipped with either two or three power transformers and most of their capacity is dedicated to supply the existing load in the Downtown Core. In addition, John MS, located on Hurontario Street near John Street, also provides power to the Downtown 21 area, especially to Mississauga Valley and Sussex districts. The total connected transformation in the Downtown Core is approximately 130 MVA. The current capacity available for all districts of the Downtown 21 area is approximately 140 MVA. The small over-capacity allows for short term growth and N-1 contingency in the Downtown Core. A detailed breakdown of the existing loads, based on the planning districts and existing substation sites, is shown below, in **Figure 73**.

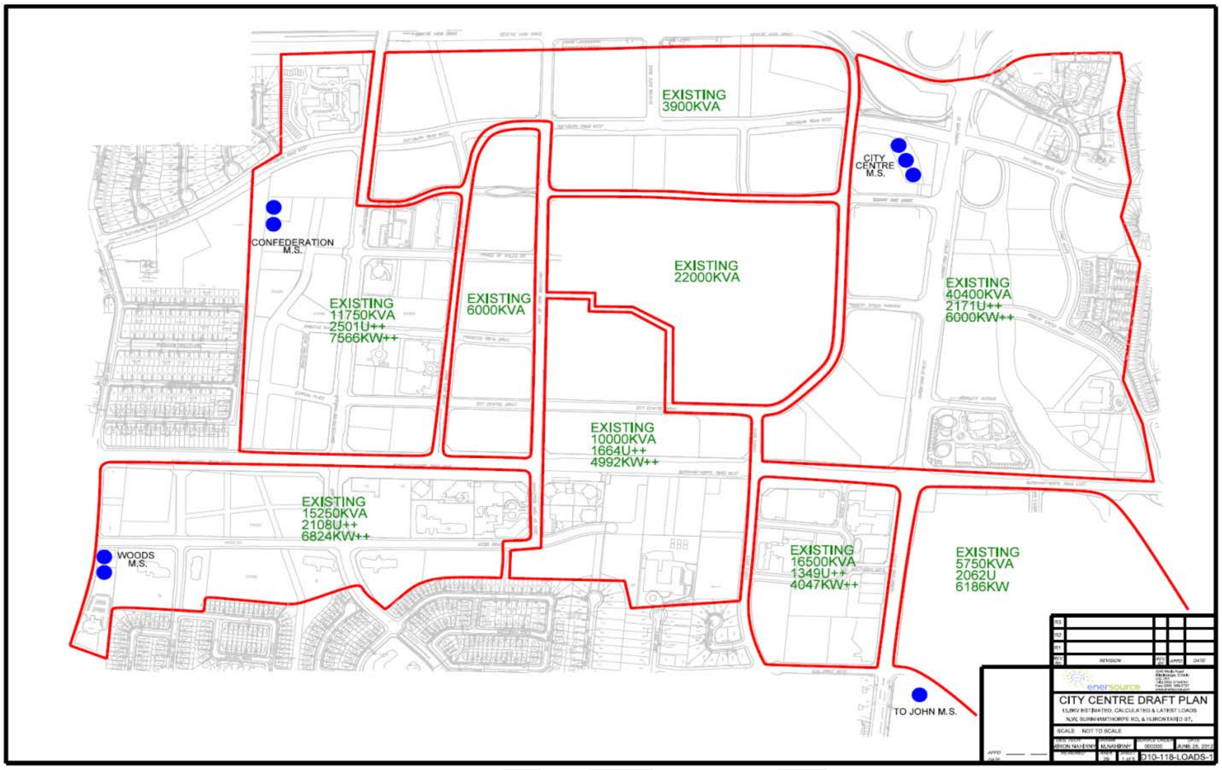


Figure 73. Existing Loads and Substations

Based on the proposed model and Master Plan provided by the City, it is estimated that upon completion of Downtown 21, the combined transformation load will increase to approximately 300 MVA. Enersource will have to expand its infrastructure in the Downtown Core and increase the number of substations in order to reliably supply power to all the buildings. At least 10 substation transformers will need to be dedicated to meet the future demand in the Downtown Core, in order to allow for contingency. Future transformers will have to be installed at Woods MS site and possibly Confederation MS, depending on land availability. In addition, two new substation sites will need to be purchased and new substations will have to be constructed. The new substation sites are required because City Centre MS site cannot be further expanded and John MS, due to its distance from the City Centre, cannot be further utilized for new load in the Downtown Core.

2.3.3.2 CDM Initiatives in Downtown Core

Enersource plans to run a Conservation and Demand Management (CDM) program in the Downtown Core to reduce the expected load growth. The CDM program projects a reduction of 1,887 kW off the projected incremental system demand in the Downtown Core as shown in **Table 27** below. This is equivalent to the annual reduction of 1% on incremental load and is consistent with the CDM 2011-2014 targets (90% of 92 MW of summer peak demand). Also, the new 2015 -2020 Conservation energy reduction targets of 483 GWH should result in approximately 1% peak demand load reduction per annum over the six year period to 2020.

Table 27. Downtown Core Conservation Estimates

District	Existing Load (kW)	Proposed Future Load (kW)	Incremental Load (kW)	Annual Conservation Target (kW): 1% of Incremental Load
Confederation District	17,500	61,700	44,200	442
Civic District	10,250	15,000	4,750	48
Cleary Park District	15,250	41,400	26,150	262
Rathburn District	5,850	46,700	40,850	409
Square One District	13,000	22,000	9,000	90
Main Street District	11,300	29,500	18,200	182
Sussex District	15,000	21,500	6,500	65
Hurontario District	21,250	55,500	34,250	343
Mississauga Valley District	7,750	12,500	4,750	48
Total	**117,150**	**305,800**	**188,650**	**1,887**

After considering the CDM program, a substantial amount of additional capacity is still required to meet future demand. The added system capacity is required to supply the remaining projected load growth after the CDM program has been considered.

2.3.3.2 Proposed Supply Points in the Downtown Core

Enersource will ultimately need an additional four to five substation transformers dedicated to supply load in the Downtown Core in order to meet the future load growth and peak demand when Downtown 21 is completed. The following options were reviewed and considered, in regards to the location of the new transformers.

2.3.3.3 Confederation MS Expansion and Duke MS

In 2012, after careful review was undertaken of the existing distribution feeders and supply from Confederation MS, which currently has two transformers and an anticipated demand from the northern part of the Downtown Core. This process determined that additional feeders and capacity will be required to supply future buildings between Rathburn Road and Centre View Drive. The current property allows for the installation of a transformer and breaker lineup to increase the capacity at Confederation MS. However, the City has proposed an extension of Square One Drive to Rathburn Road, which will require a portion of the land to be used for the new road. The remaining substation property will then be too small to accommodate an additional transformer and the high voltage equipment associated with it.

Originally, Enersource asked the City to swap the land to the west of the substation to allow for the relocation of the pad mounted switchgears, which are in conflict with the proposed Square One Drive extension. Additionally, at the time, only a limited number of feeders were available in the area and the relocation of the switchgear required the relocation of all pad mounted equipment in front of the substation to a new location. This meant that the substation had to be completely de-energized for an extended period of time.

Due to the already limited capacity in the Downtown Core, the risk associated with taking a double substation out of service, with no backup available in case of an emergency, was too great. Therefore, the only option was to construct another substation along Centre View Drive prior to switchgear relocation and Square One Drive construction.

In recent conversations with the City, Enersource was advised that a developer owns the land in the Downtown Core that is adjacent to Confederation MS. The Developer is willing to sell the land to the City, which in turn could be swapped for the land taken up by the Square One Drive expansion. Below is a sketch showing the existing Confederation MS land, as well as the lands owned by the developer.

Detailed sketches showing the existing substation location and the lands owned by the developer are shown below, in **Figures 74** and **75**. Additionally, **Figure 76** shows an overlay of the proposed road and the existing substation.

Figure 74. Existing Station Location and Developer's Property

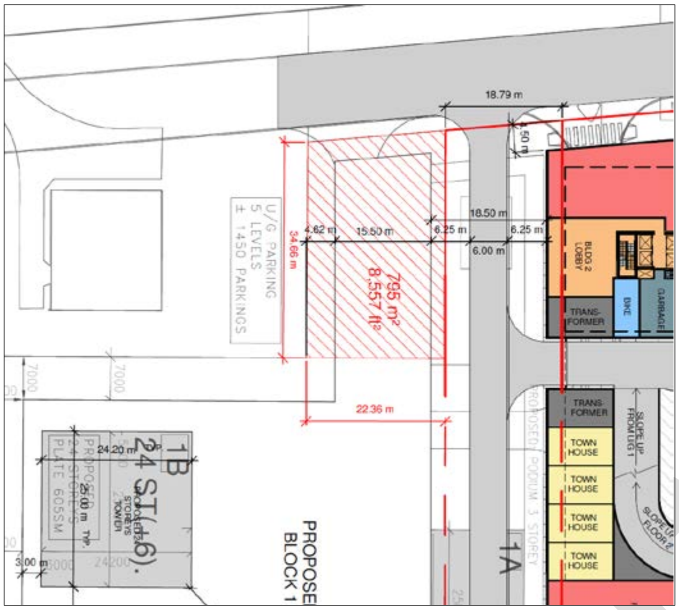


Figure 75. Existing Substation and Switchgear Locations

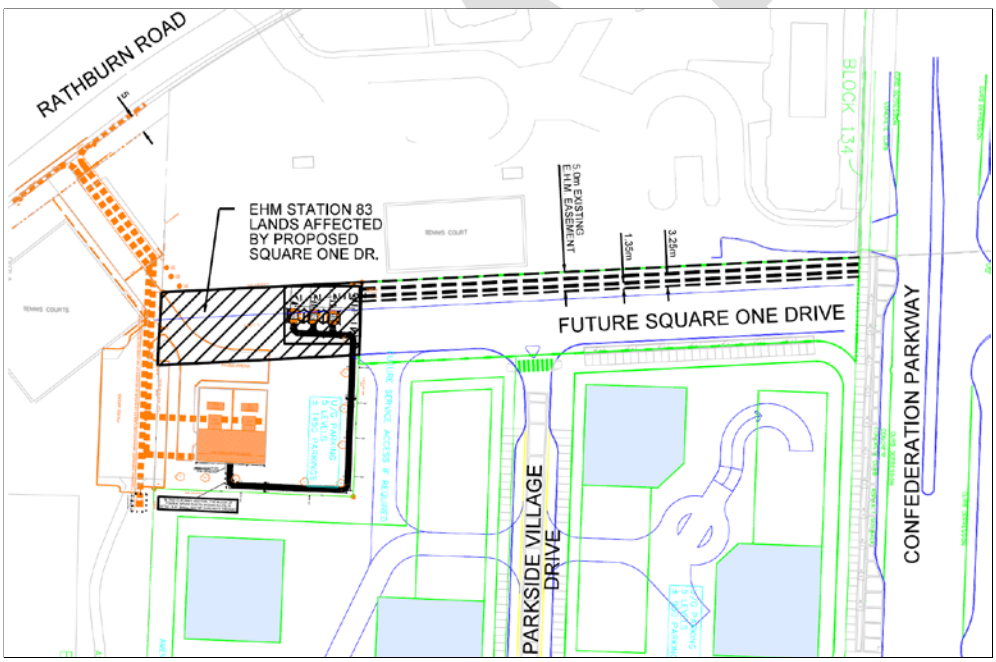


Figure 76. Existing Substation Location and the Proposed Square One Drive

Since 2012, several feeder upgrades and extension projects in the northern and central part of the Downtown Core were under way. In 2016, Enersource plans on installing a new pole line along Centre View Drive, from Mavis Road to Station Gate Road. All of these upgrades will allow for a partial transfer of capacity from City Centre MS and Woods MS.

After careful review of all factors, including the latest option which involves a land purchase and trade, as well as feeder upgrades in the area, Enersource has concluded that relocation of the existing switching units can be done with the de-energization of half of the substation during the time of construction. This option presents more risks when compared with the construction of a new substation along Centre View Drive, but for a short period of time, the level of risk is tolerable as it would meet the N-1 contingency level. Because of the new anticipated load in the north area of the Downtown Core, additional capacity is required and will have to be addressed by the construction of a new substation along Centre View Drive, between Confederation MS and City Centre MS.

Due to uncertainty regarding land availability for the new substation and the unpredictable timing of future developments and load growth in the north section of the Downtown Core, Enersource will need to secure the required substation land prior to the relocation of the switches in front of Confederation MS. At the same time, because of the possibility of a land transfer at Confederation MS, the actual construction of the new substation, Duke MS, can be postponed and the substation does not have to be energized prior to the commencement of the Square One Drive expansion.

After reviewing the current sites along Centre View Drive, it was determined that the best remaining site for the new substation is west of Duke of York Blvd., the area to the north east of the existing movie theatre as shown in **Figure 77** below. The majority of the area required for the substation is currently owned by the City and the additional area that may be required below is owned by a developer. Alternately, the new substation could be located east of the proposed location, along Centre View Drive.

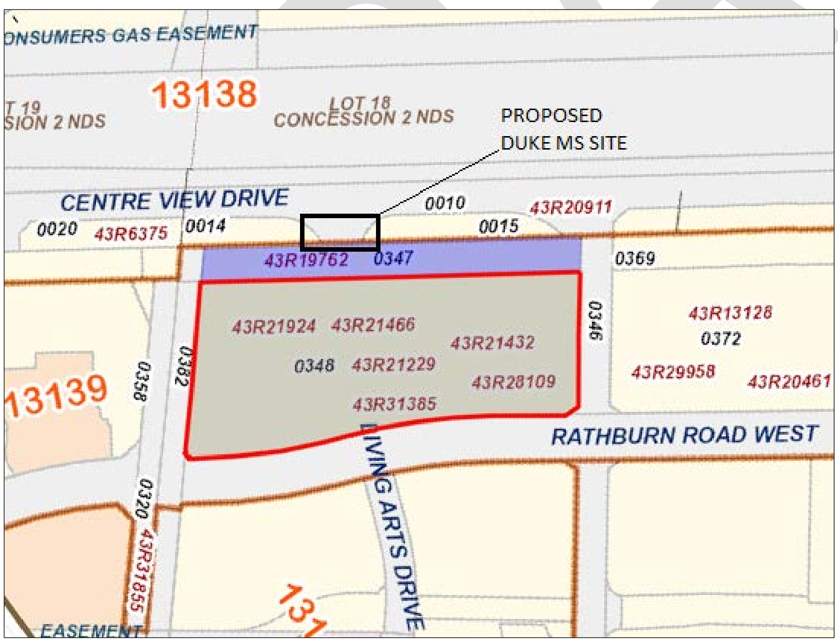


Figure 77. Proposed Duke MS Location

There are several other issues associated with the extension of Square One Drive, such as vehicle traffic control (due to close proximity of the road to the station), easement requirements, building access and other issues that must be addressed prior to land transfer and agreement acceptance between Enersource and the City.

City Centre MS Expansion Alternative

There are three 20 MVA transformers installed at the City Centre MS site where the existing infrastructure, including duct banks and switchgears, is fully utilized. The installation of any additional transformers and feeders will require a major reconstruction of the substation and the associated civil infrastructure. In addition, new feeders coming out of the substation will have de-rated capacity due to main feeder cable congestion and restricted duct bank configuration. As a result, the installation of an additional transformer is not economical and does not meet the technical requirements needed to supply load in the Downtown Core efficiently.

John MS Expansion Alternative

The John MS site has sufficient space for the installation of an additional transformer. However, the new feeders coming out of the substation cannot be extended north to the Downtown Core unless a new, second pole line is constructed along the west side of Hurontario Street from John MS to Burnhamthorpe Road. Considering future projects, including the LRT along Hurontario Street, it is unlikely that Enersource will be granted permission to install a new pole line on the west side of Hurontario Street, in addition to the existing pole line on the east side.

2.3.3.5 Future Substation Needs

With the exception of the above mentioned locations, the only substation site that can be expanded without a need to purchase or transfer land is Woods MS. This substation is currently equipped with two transformers and seven feeders, where the additional transformer will increase the number of feeders to 10. Any further expansions, as in the case of City Centre MS, will not be economical or efficient, due to substation cable congestion and the major reconstruction of civil structures at the substation.

Consequently, an additional three to four transformers will need to be installed in new locations. Due to existing infrastructure in the Downtown Core and predicted location of the new load, it is recommended to install the new transformers at two separate locations: one in the northern part and one in the southern part of the Downtown Core. After careful review and consideration of the existing feeder locations, future development and locations of the existing substations, the optimal location for the northern substation is near the intersection of Centre View Drive and Duke of York Blvd. (Duke MS). The optimal location of the second substation is near the intersection of Webb Drive and Kariya Drive (Webb MS). **Figure 78** shows the existing and proposed substation locations in the Downtown Core.

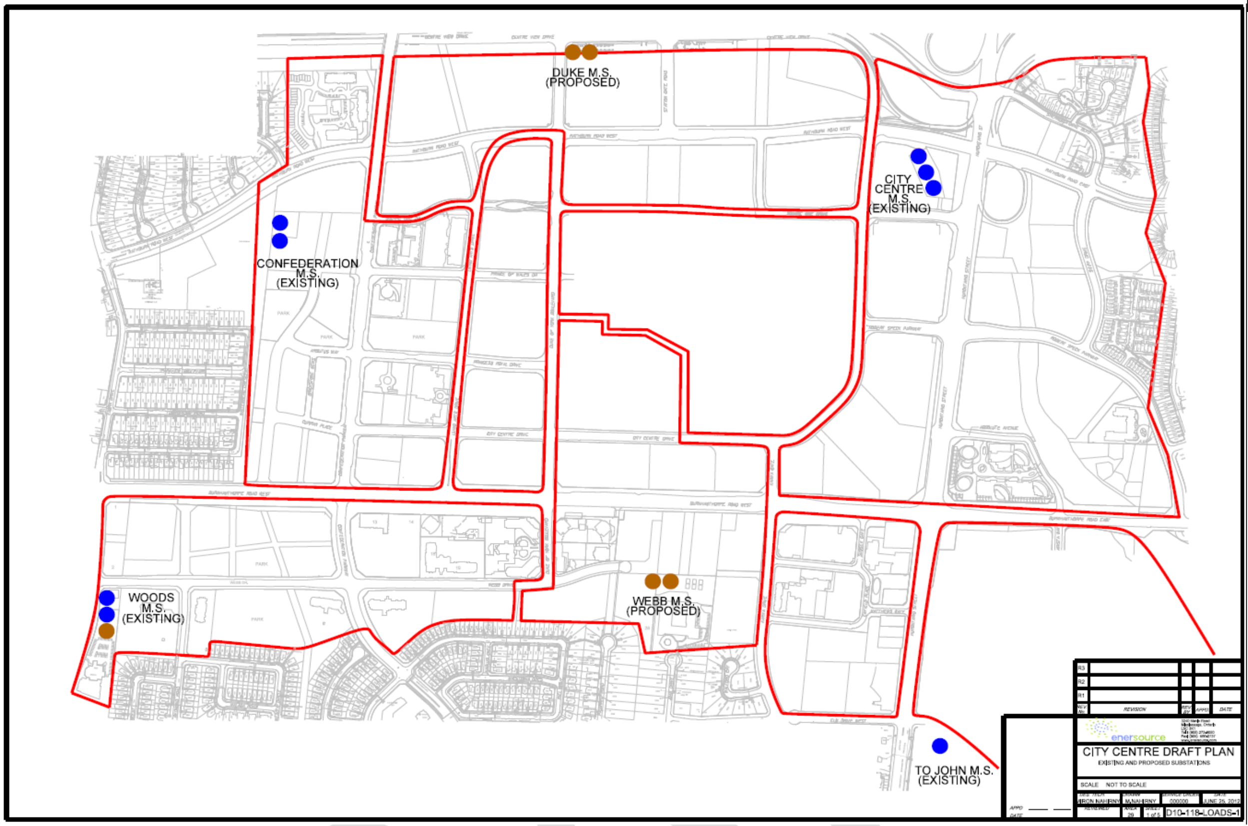


Figure 78. Existing and Proposed Substation Locations in the Downtown Core

2.3.3.6 Webb MS Substation

Originally, the Webb MS substation was proposed at the edge of Kariya Park, to service some of the load on the south side of the Downtown Core. However, after several meetings with the City, it was decided that the location had to be changed. Several developers in the area were approached in regards to the available land.

After two years of negotiations with the City and the developer, it was determined that the new substation will be constructed at the northeast corner of Webb Drive and B-Street as shown in **Figure 79** below.

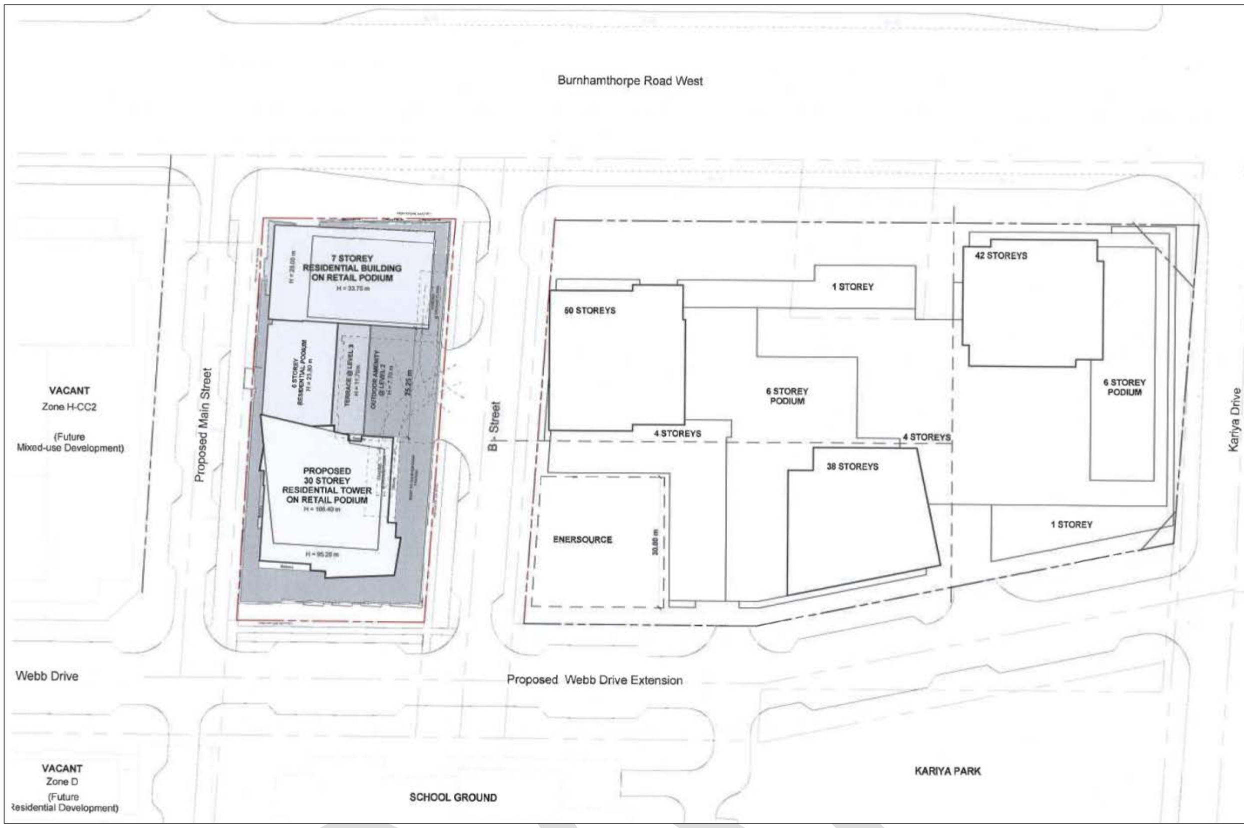


Figure 79. Proposed Location of Webb MS

Enersource's typical substation footprint is 50 square meters, but considering the challenges with the property in the Downtown Core, Enersource will utilize a different layout and reduce the site to approximately 30 square meters. In addition, to meet maintenance and construction requirements, the City will allow Enersource to block a portion of B-Street or Webb Drive to allow for setup of heavy lifting equipment for replacement of the substation transformers.

While the Webb MS substation will be designed and constructed for dual transformer setup, the substation will initially be equipped with only one high voltage transformer. The second transformer will be added at a later date, as the load from the new buildings in the southern part of the Downtown Core materializes.

To reduce the pad mounted equipment outside of the substation building, a different approach is being reviewed. Instead of using seven outgoing breakers inside the substation and three to four switchgears outside, a different configuration of using 10 smaller footprint outgoing breakers inside the substation and no switchgears immediately outside the building is being reviewed. This approach will reduce a need for pad mounted equipment and will maintain the same level of switching flexibility and reliability.

The building facade will match the surrounding buildings and the substation will be constructed as part of a four storey townhouse development. It is likely that the substation building will be constructed initially and the facade finish will be constructed later, at the same time as the rest of the townhouse development.

Additionally, to ensure that the proposed substation blends in with the high rise towers, the developer and the City have requested Enersource to construct a roof over the transformer. To address that requirement, Enersource is reviewing an option of installing a removable louver roof, which will provide adequate ventilation to the substation and to allow for replacement of the transformers.

The substation will be supplied with two 44kV circuits, connected to the overhead lines on Hurontario Street. **Figure 80** below shows the proposed location of the underground cables and overhead pole line. The outgoing feeder egress will be underground and installed along Webb Drive, B-Street and Main Street as shown in **Figure 82**.

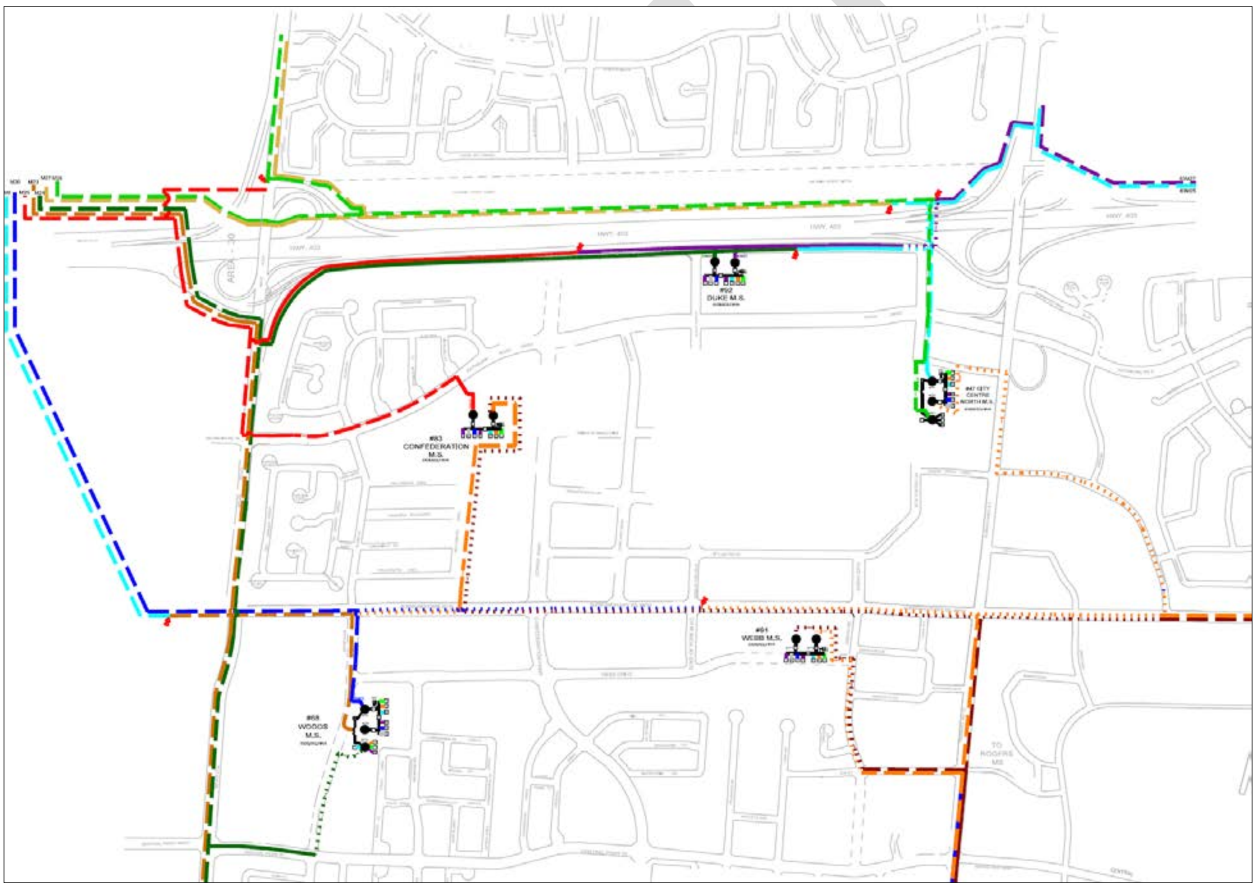


Figure 80. Proposed Supply Points to the Downtown Substations

2.3.3.7 Underground Distribution Infrastructure

Substations convert voltage from subtransmission levels to distribution levels. Then, through a series of feeder breakers and switches, the power is directed to loads in the area. In addition to the equipment installed at the substations, a network of underground cables, ducts and cable chambers is necessary to deliver power to customers. **Figure 81** shows the existing duct and manhole system in the Downtown Core.

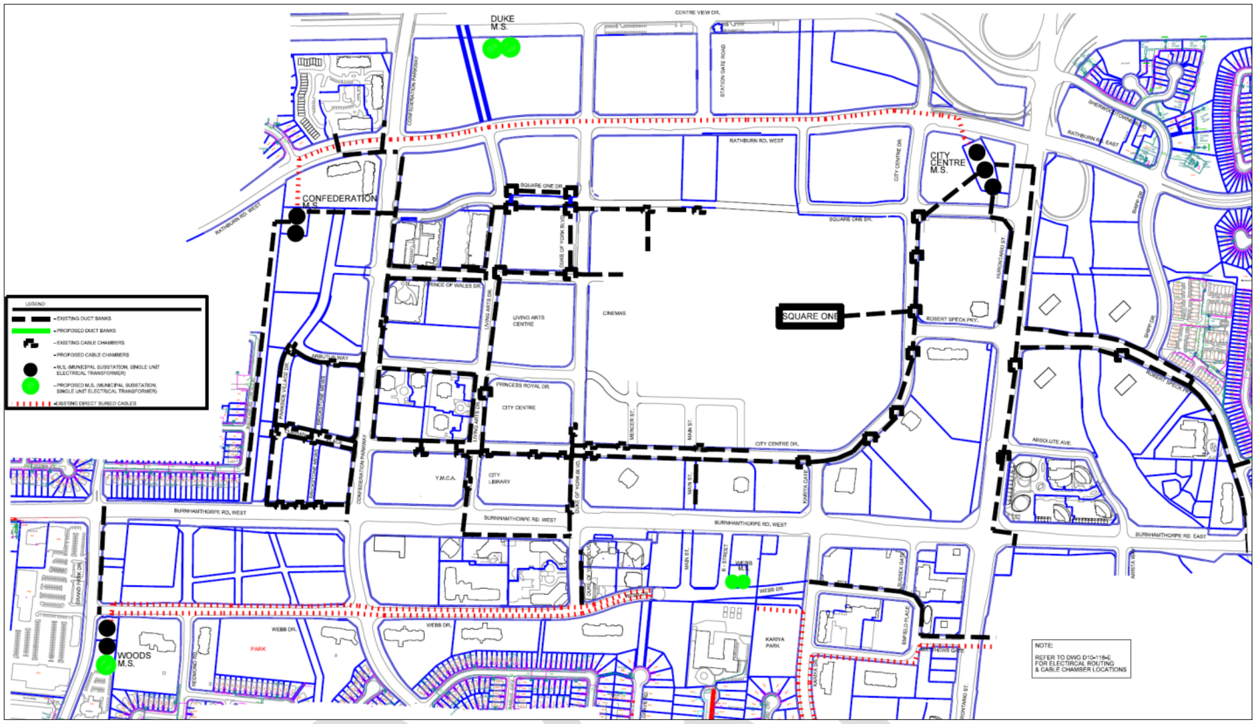


Figure 81. Existing Underground Distribution Infrastructure

The existing underground infrastructure is sufficient to supply the current demand in the Downtown Core. However, in order to meet future demand, old cables in the existing ducts must be replaced and new duct banks with new cables and manholes must be added. Since all distribution infrastructure is located in a common trench below grade, it is much more efficient and economical to install concrete encased ducts and manholes before construction of the permanent buildings. This avoids issues with space in the common trench, and prevents expensive repairs and restoration to new road surfaces, sidewalks and landscaping. In addition, power disruption to buildings and the expensive rental of generators can be avoided if duct banks and manholes are installed prior to building construction. **Figure 82** shows the duct bank and manhole system proposed for the Downtown Core. The figure includes existing and proposed installations.

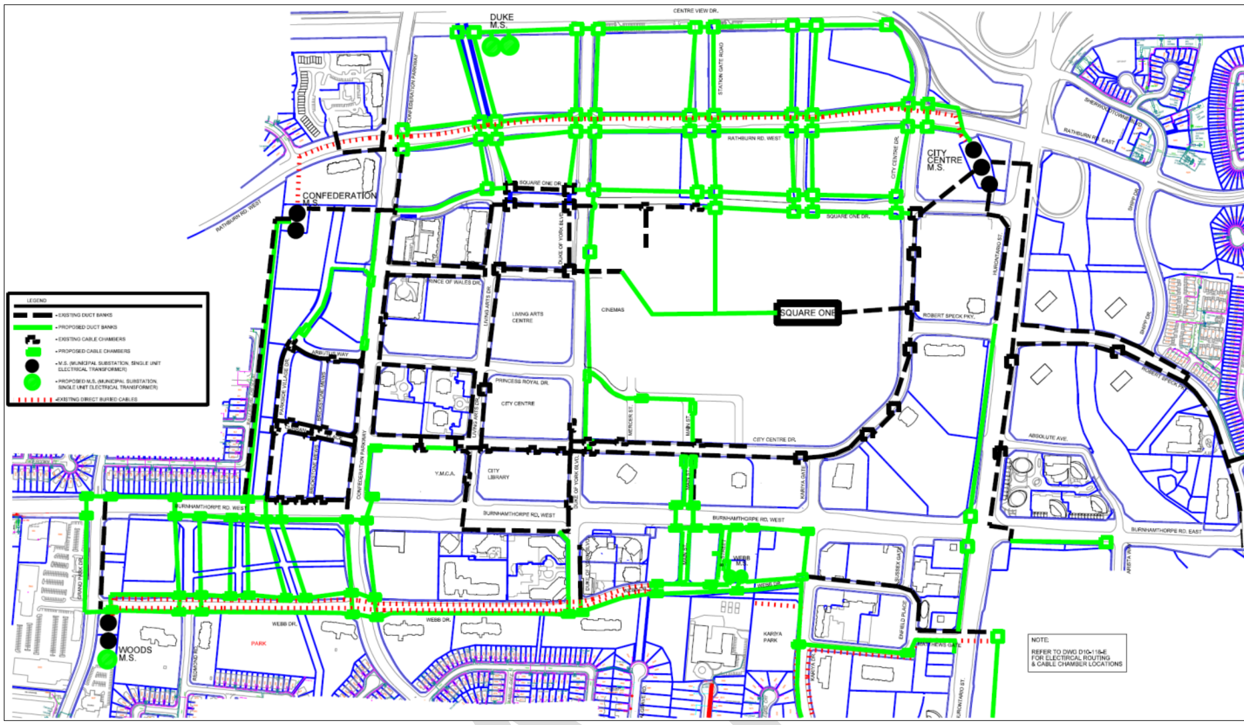


Figure 82. Existing and proposed underground distribution infrastructure in the Downtown Core.

2.3.4 Information Technology Assets

2.3.4.1 Sustain Existing System Program

2.3.4.1.1 Hardware

Enersource employees utilize IT systems on a daily basis. This is achieved through the following categories:

- Endpoint hardware i.e., desktop computers, laptops, tablets, plotters, printers, phones, and mobile devices
- Back-end hardware i.e., servers, storage, computing, network, databases, etc.

For hardware assets Enersource utilizes the hardware refresh program as shown in Table 28.

Table 28. Hardware Category

Hardware Category	Lifecycle
Desktop (single-task users and task-oriented users)	4 years
Desktop (specialized users), laptops, tablets, GPS units, etc.	3 years
Printers, plotters, etc.	5 – 6 years (dependent on vendor support expiry)
Monitors, projectors	6 years
Servers, data storage, switches, voice and telecommunications, etc.	4 – 8 years (dependent on vendor support expiry)

This hardware refresh program is needed in order to maintain the reliability of IT assets. Dependable IT assets enable Enersource employees to effectively complete their daily tasks by reducing downtime and lost productivity. Where applicable, Enersource utilizes the approach of replacing all of its assets in a category at the same time rather than spreading the replacement cycle over multiple years. For example, all desktops are replaced at the same time in order to ensure asset standardization across the organization. A standardized desktop infrastructure forms the foundation for desktop optimization. It is by standardizing desktop hardware and software that organizations can ultimately advance toward a more flexible, agile, and optimized infrastructure.

Ad-hoc desktop purchases often driven by price or by departmental and end-user preferences can ultimately prove much more costly when a comprehensive view of desktop lifecycle costs is taken into account. While the cost of equipment and software remains relatively constant whether a company uses a staggered replacement cycle or a single enterprise-wide deployment, the maintenance costs associated with a staggered cycle can be considerably higher than a single-cycle approach. This is attributed to maintaining and supporting multiple inconsistent computing platforms, operating systems, applications and one-off configurations. For other hardware types (i.e., servers, data storage) the replacement cycle is determined based on the asset type, vendor support coverage, and acceptable performance of the hardware.

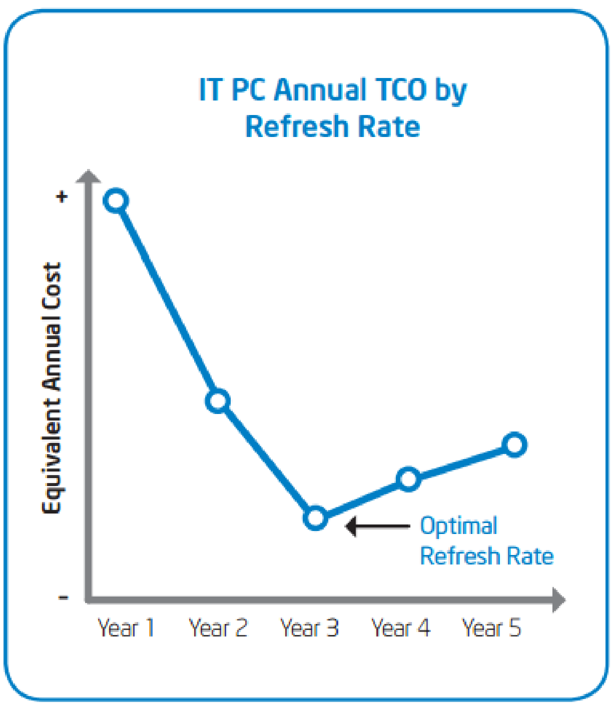


Figure 83. Intel White Paper - PC Total Cost of Ownership by Refresh Rate

2.3.4.1.2 Software

Software renewal includes planned software upgrades and maintenance required to maintain vendors' support and reliable system operation. These upgrade projects are considered technical upgrades.

Projects in this software roadmap program typically include the following activities:

- Engage vendor(s) to provide upgrade assistance
- Upgrade underlying infrastructure
- Configure the application to ensure compatibility with underlying components
- Configure the application to meet existing business requirements
- Integrate with other utility IT systems, as needed
- Complete regression testing to ensure the upgrade is successful
- Train business users of the new features
- Deploy the new systems and release them to the business users.

Enersource's practice is to ensure that it has continuous vendor support during the asset life-cycle, particularly with back-end hardware (i.e., servers, switches) as well as all core corporate applications, such as engineering, finance, customer care and billing applications. Maintaining vendor support is a critical component of the asset plan for the following reasons:

- **Availability of replacement parts**: most hardware vendors commit to four to eight years of parts availability.
- **Security risks**: security fixes and vulnerability patches are often not available for older systems.
- **Cost Avoidance**: having an out-of-support asset could prove more costly since Enersource may have to procure specialized technical resources to maintain the outdated asset.

2.3.4.2 Mandatory-Regulation

These are known future planned system changes related to regulatory initiatives. For example, on January 16, 2014, the OEB issued a Notice of Proposal to Amend a Code in which it proposed to require a distributor to install an interval meter (i.e., a 'MIST meter') on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. These accounts must bill as MIST by August 2020. This initiative requires system changes and implementation in order to accomplish the required results of billing customers with over 50 kW as MIST.

These mandatory initiatives are captured under the 'sustain existing systems' program because they are mandatory in order for Enersource to meet its regulatory obligations to the OEB.

2.3.4.3 Enhancement Initiatives Program

The second component of Enersource's IT AMP is the 'Enhancement Initiatives' program which addresses future system enhancements that are driven to fulfill the benefits shown in Table 29.

Table 29. Benefits of Enhancement Initiatives program

Category	Benefits
Customer Value	• Software enhancements provide process optimization and automation which allows Enersource to utilize its resources more efficiently, in turn, benefits customers/ratepayers • Software enhancements allow Enersource to provide more positive customer-centric service because new enhancements often provide greater flexibility in providing customers with up-to-date data, among other things.
Operational Reliability	• Software issues could pose risks to the business, or cause inefficient use of resources due to the need for manual controls or workarounds • Software enhancements help meet growing business needs while ensuring appropriate controls are in place • Software enhancement provides necessary data to help Enersource make informed decisions using factual data analytics.

Projects in this program utilize Enersource's standard investment prioritization and evaluation process.

Table 30. Prioritization Drivers

Investment Drivers	Objective
Regulatory/Public Policy Responsiveness	Services are provided to address a regulatory requirement or mandate. This category includes IT roadmap projects as they are mandated in order to maintain vendor support.
Customer Focus	Services are provided in a manner that responds to an identified customer need or preference.
Operational Effectiveness	Continuous improvement in productivity and cost performance is achieved and delivers system reliability and quality objectives.
Financial Performance	Financial viability is maintained and savings from operational effectiveness are sustainable.

Project prioritization process is followed to ensure that resources are utilized according to consistent investment drivers as outlined above. Projects in this program normally involve the following activities:

- Evaluation of business needs
- Assessment of available solution(s)
- Determine acceptable solution both from the business perspective and IT support perspective
- Engage vendor(s) to provide necessary assistance e.g., code development
- Configure the application to ensure compatibility with underlying components
- Configure the application to meet business requirements
- Integrate with other utility IT systems, as needed
- Complete testing of new functionality
- Complete regression testing of existing functionality
- Train business users of the new features and functionality
- Deploy the new systems and release them to business users.

When business applications are initially deployed, functionality is typically limited to the scope of the original business requirement. Subsequent application changes may result from:

- Change in business needs whether to address new requirement(s) or optimize an existing process
- Vendor release of service pack(s) to address open issues/defects
- Utilize new application functionality to maximize productivity, eliminate manual workarounds, or enhance user experience.

2.3.5 Facilities Remediation

Enersource has three main buildings used for business operations: the Corporate Office on Derry Road, Operations Centre on Mavis Road and a Disaster Recovery building on Glen Erin Drive. These buildings were constructed between 1963 and 2012.

The Derry Road building received substantial renovations in 2012 to ensure a healthy and productive work environment for the administration staff that was transferred to the facilility. Based on Building Conditions Assessments, the 23 year-old HVAC system will need to be replaced in the near future.

The BCM Operations Centre was constructed in 2012 and will not need any significant improvements over the DSP period.

The Mavis Road Operations Centre was constructed in three phases between 1963 to 1991. Generally, up to 2013, the Mavis facility received only minimal capital improvements during a period of busy growth years whereby Enersource was adding staff, to the point that a congested and unsafe work environment was created. With the move of the administration staff to the Derry Road facility in 2012, Enersource was able to start renovation projects to support the 'Mavis Facilities Plan' and to address issues raised in the Building Condition Assessment. Since then, a number of projects such as the men's locker/shower room, metering department work area, and the north tower office space have been completed. Additional projects over the next six years will address remaining projects from the Mavis Facilities Plan and the Building Condition Assessment.

Enersource building facilities must be reasonably current and in good working order. Based on regular assessments, all buildings require various investments to maintain them in a good state of repair, improve productivity, accommodate growth and change in the workforce, and address identified health and safety risks. As described above, the three facilities are of various ages.

The areas of concern for Enersource facilities that require expenditures are:

- HVAC (heating, ventilation and air conditioning)
- Structural (building envelope, walls and windows)
- Equipment (furniture, elevators)
- Mechanical and Electrical (i.e., plumbing, electrical components)
- Security (access control, CCTV, building automation system)
- Life Safety (fire suppression, sprinklers, fire alarm panels)
- Exterior (i.e., pavement, fencing, landscaping).

2.3.6 Fleet Replacement

Enersource requires a fleet of specialized vehicles to complete many daily activities, including the construction and maintenance of the electricity distribution system, and to allow for quick restoration of power due to electricity distribution system disturbances. Degradation of fleet assets could jeopardize worker safety and negatively affect electricity distribution system performance and response to outages.

To effectively manage fleet assets, Enersource has adopted a fleet strategy with the following goals:

- To provide safe, reliable, and efficient vehicles and equipment to meet the operational needs in consultation with the end user;
- Compliance with legislation and regulations;
- Compliance with accepted industry norms and practices;
- Cost effectiveness;
- Optimization of size of fleet - kept to minimum levels to ensure equipment is being fully used;
- Standardization of equipment specifications;
- Environmental considerations such as fuel economy, exhaust emissions;
- Disposal through reputable commercial vehicle and equipment resellers; and
- Implement computerized maintenance program to improve cost analysis and maintenance tracking.

To achieve the goals outlined above, Enersource maintains a multiple year capital plan. This plan is an essential tool for both short and long term budgeting and planning. This plan lists all the current vehicles and proposes the future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Another long term goal of the fleet plan is to smoothly pace the annual capital expenditures to ensure the rate impact to customers is minimized.

Contributing to the proposed replacement date of individual vehicles are factors such as vehicle age, mileage, engine hours, operation costs, maintenance costs, and general mechanical condition of the vehicle. As vehicles approach their expected replacement date, individual assessments of each vehicle are performed to determine if vehicles may be retained longer, since they are in better than average condition, or need to be replaced earlier due to being in poorer condition.

Vehicles are not always replaced "like for like". Prior to replacement of a vehicle, an assessment of the current fleet needs is made with the applicable Enersource personnel to determine if an alternate vehicle type or size would be more beneficial.

The proposed replacement ages for each vehicle class are outlined below. Present replacement criteria are based on manufacturers' recommendations and repair history.

- Light vehicles are replaced after 3 - 5 years, or 170,000 km;
- Service trucks are replaced after 5 - 8 years or 200,000 km;
- Heavy equipment trucks are replaced after 8 – 12 years, or after 230,000 km; and
- Work equipment is replaced based on condition assessment.

As of June, 2015, Enersource has 190 vehicles and the distribution is as seen in **Figure 84** below.

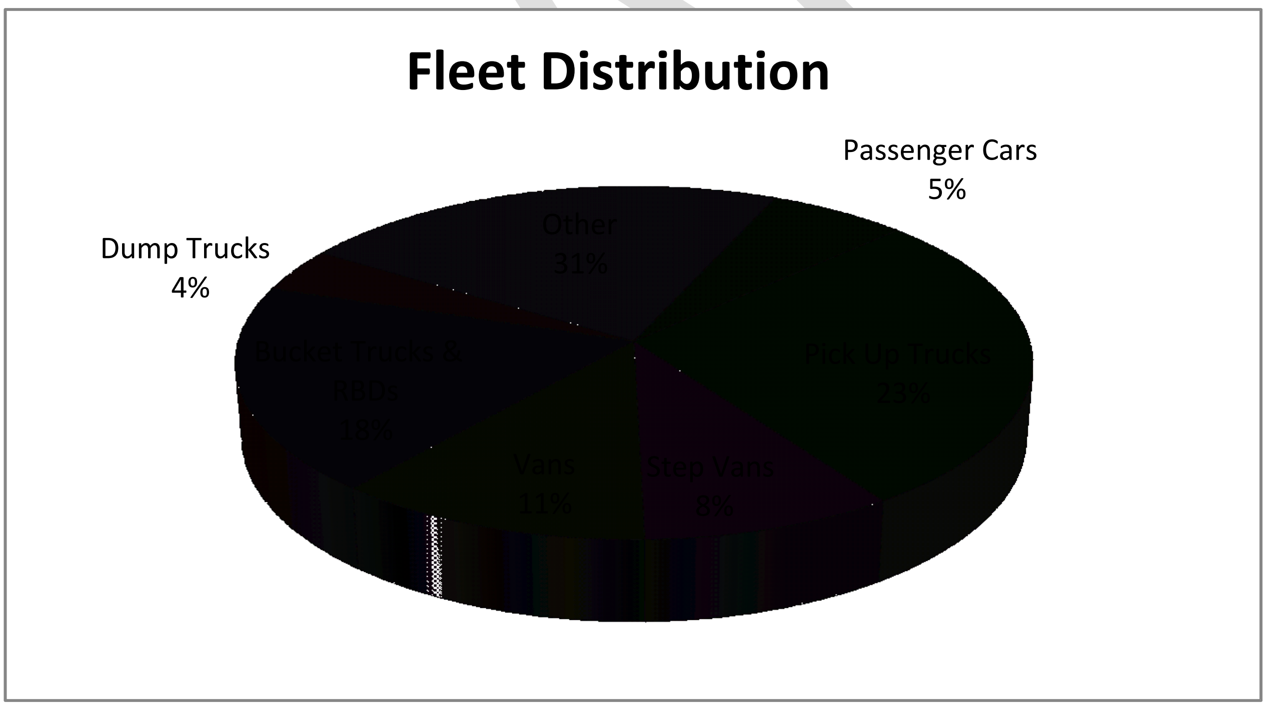


Figure 84. Fleet distribution by type

Additional capital may also be required to meet equipment requirements for staff growth, resulting from succession planning and work program increases.

Maintaining appropriate levels of capital spending on fleet will lead to:

- Reduced repair and maintenance costs;
- Decreased down time and increased fleet utilization;
- Safer equipment for personnel to operate;
- Reduced environmental impacts (alternative fuel considerations, compliance with new diesel standards); and
- Increased service equipment diagnostics.

2.4 Asset Lifecycle Risk Management

Enersource currently evaluates its business plan and investment projects and programs against the following significant business values:

- Regulatory/Public Policy Responsiveness
- Operational Effectiveness/Safety
- Customer Focus
- Financial Performance.

The risks associated with the business values are assessed as follows:

Regulatory/Public Policy Responsiveness - Does Enersource remain fully compliant in all legal and regulatory aspects of its operations? Will increased activity in embedded generation, future micro grids and electric cars have an impact on the service offering to customers?

Operational Effectiveness/Safety - Is Enersource's distribution system designed, constructed and maintained with safety in mind, for both Enersource employees and the public? Are critical assets maintained properly and replaced prior to their expected end-of-useful life? Is there sufficient staff that are trained and developed to have sustainabe operations?

Customer Focus – What is the impact of asset failure to customers? Do the projects and programs sustain or deliver more reliable power to customers? Will there be stranded assets? Are Enersource's information systems secured? Are all stakeholders' and customers' preferences considered when projects and programs are prioritized?

Financial Risks - Is the condition of the existing assets evaluated to ensure they are repaired or replaced effectively to achieve the lowest long term owning costs? Is there sufficient cash flow available when required?

Each business value was then assigned a weighting based on the significance and probability as can be seen in **Table 31**.

Table 31. Business value weighting.

Investment Driver / Business Value	Significance	Probability	Risk Score	Weighting
Regulatory/Public Policy Responsiveness	5	3	4	Mandatory Yes/No
Operational Effectiveness/Safety	5	3	3.5	50%
Customer Focus	4	2	3	30%

Investment Driver / Business Value	Significance	Probability	Risk Score	Weighting
Financial Performance	3	2	2.5	20%

Enersource then reviewed and assessed each of its asset classes against the business values. The process to evaluate asset classes was completed through an internal multi-disciplinary working group consisting of expert representatives from several departments and was led by the Asset Management Division with the assistance of Internal Audit & Enterprise Risk Division. Each asset class was evaluated based on the significance and the effect each class potentially would have on the business values listed above. Once the group completed the ranking for each asset class from 1-5, the ranking score was multiplied by the business value weighting. The following list of asset classes has been ranked from the highest to lowest based on the significance to Enersource's sustainability as an organization and can be seen in **Table 32**.

Table 32. Significant asset classes

Asset Class	Estimated Useful Lives	Regulatory/Public Policy Responsiveness	Operational Effectiveness/Safety	Customer Focus	Financial Performance	Total
Municipal Distribution Station Equipment	40	17%	44%	11%	6%	78%
Major Software – Corporate/ Enterprise	10	17%	33%	15%	12%	77%
Computer Equipment – Corporate/ Enterprise	10	17%	33%	12%	12%	74%
SCADA / Protection and DC Systems	15	15%	39%	11%	5%	69%
Wholesale Meters	25	21%	19%	9%	7%	57%
Rolling Stock - Single Buckets, Dump trucks & Cranes	8	13%	31%	8%	5%	56%
Rolling Stock - Double Buckets and RBDs	12	13%	31%	8%	5%	56%

Asset Class	Estimated Useful Lives	Regulatory/Public Policy Responsiveness	Operational Effectiveness/Safety	Customer Focus	Financial Performance	Total
Air Insulated switchgear	25	4%	30%	8%	5%	46%
Building & Fixtures – Other Construction	20	15%	23%	6%	2%	46%
UG Cable System	40	8%	24%	8%	5%	45%
Pad mounted Transformer	35	8%	26%	8%	2%	44%
OH Wood Pole System	45	6%	27%	8%	2%	43%
OH Concrete Pole System	55	4%	28%	8%	2%	43%
Major Tools	10	11%	28%	3%	1%	43%
Rolling Stock - Pick-up Trucks and Vans	5	11%	22%	6%	2%	42%
Building & Fixtures – Brick, Stone, Concrete & Steel	60	6%	23%	6%	5%	40%
OH Transformer System	45	8%	23%	5%	1%	38%
Land	N/A	15%	11%	8%	2%	36%
Meters	25	11%	12%	9%	2%	34%
Solid Dielectric Switchgear	35	4%	16%	8%	5%	32%
Rolling Stock - Trailers & Off Road Equipment	15	11%	14%	6%	1%	32%
Easements	N/A	11%	11%	8%	2%	32%
Rolling Stock - Automobiles	4	11%	12%	6%	1%	29%
SCADAmate / Reclosures	25	4%	15%	6%	2%	27%
Smart Meters	15	11%	8%	6%	1%	26%
Overhead Switches/Fuses	40	2%	18%	3%	1%	24%

Asset Class	Estimated Useful Lives	Regulatory/Public Policy Responsiveness	Operational Effectiveness/Safety	Customer Focus	Financial Performance	Total
Comp Equip – Networking and Printing	5	6%	7%	6%	1%	21%
System Software - Office Automation & Collaboration	5	6%	7%	6%	1%	21%
Minor Software	2	6%	7%	6%	1%	21%
Underground Accessories	20	2%	10%	6%	1%	20%
General Equipment	10	4%	12%	2%	1%	19%
Overhead Fault Indicators	10	2%	7%	6%	1%	17%
Duct, Foundations	50	2%	7%	2%	4%	14%
Computer Equipment – Desktop or Laptops and Security Infrastructure	3	2%	5%	2%	0%	9%

3. Capital Expenditure Plan (OEB Chapter 5.4)

3.1 Summary (OEB Chapter 5.4.1)

3.1.1 Load Connection Capability

Enersource services an urban territory with limited area for greenfield development. The growth in its service area is largely driven by the redevelopment and re-intensification of existing and previously developed areas. In 2014, Enersource prepared a long term load forecast report as part of its Regional Planning collaborative effort with HONI, IESO, and neighbouring utilities. Enersource's capacity and ability to connect new customers is summarized by the operating areas listed below.

To better understand asset capacity utilization and constrained areas, Enersource has developed a long term peak demand projection for each of the four areas of the distribution power system outlined in subsequent sections. Enersouce takes into account ongoing and future CDM programs and their effect on short and long term demand projections.

The City went through a very aggressive expansion period spanning the mid 1980's to the mid 2000's. Over the last 15 years, Mississauga has effectively transitioned from a rapidly growing suburban community to a mature urban community with an emphasis on intensification, redevelopment, and transit. Enersource's rate of expansion has slowed relative to the past peak periods, and the available green space for further development has been significantly reduced. Currently, the City is under-going a post-greenfield phase. Population growth will be accommodated through intensification and redevelopment within existing built-up areas and Mississauga will continue to focus on higher density housing forms, particularly apartment and condominium development in the Downtown Core, infill projects in major community nodes, and through redevelopment along planned intensification corridors.

North 16/27.6kV System

In the North 16/27.6kV system, residential, industrial, and commercial development is still occurring and this trend is expected to continue in the near term. This portion of the system is nearing transformation capacity to adequately serve its customers. Through the Needs Screening process initiated by HONI and the IESO (formerly OPA), it was identified that a peak load on Erindale TS T1/T2 has reached normal supply capacity and will require further assessment. In the near future, Enersource will require additional capacity to service the North 16/27.6kV system; these new capacity needs are being addressed under System Service investment category. Historical actual and forecasted peak demand for this area is shown below in **Figure 85** North 16/27.6kV Distribution.

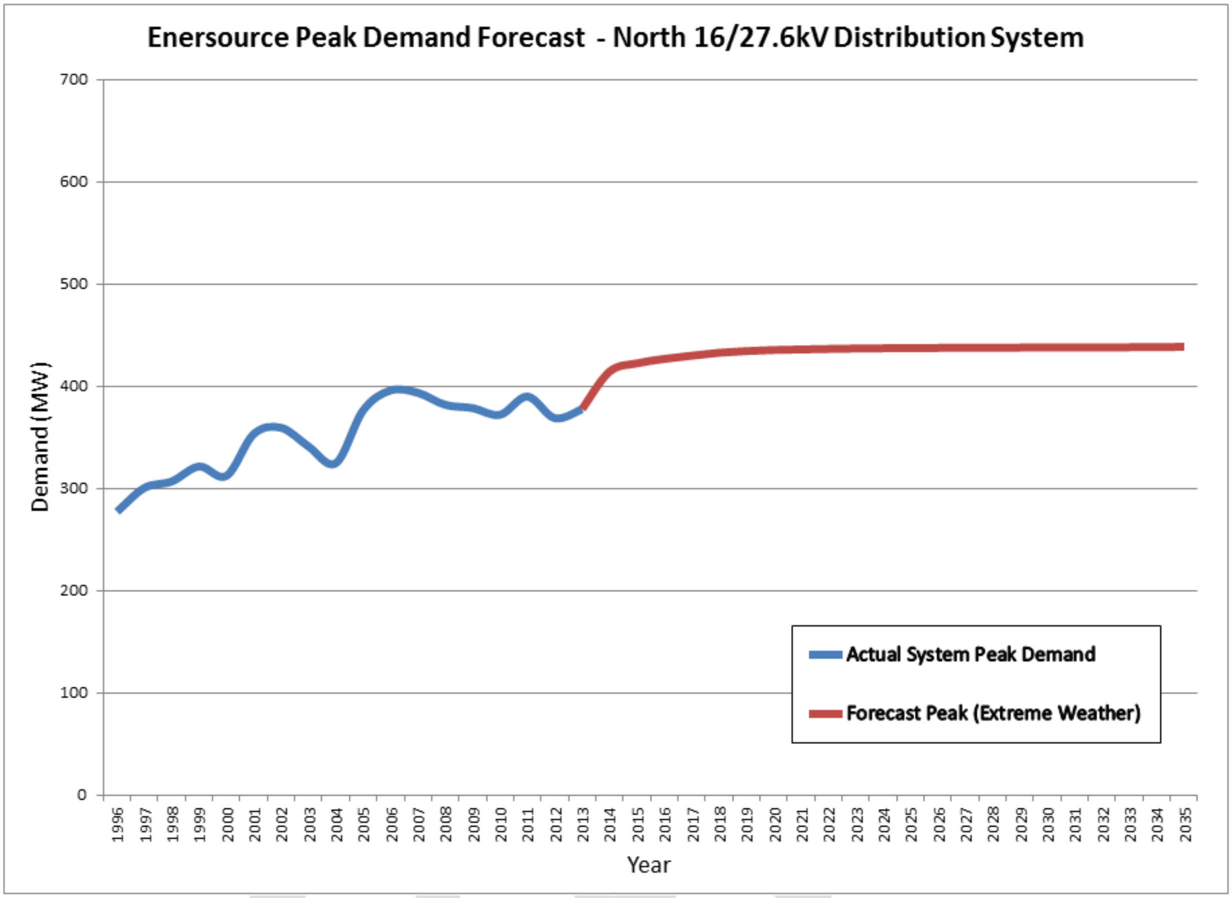


Figure 85. Enersource Peak Demand Forecast - North 16/27.6kV Distribution System – Extreme Weather Scenario (1996-2035)

South 16/17.6kV and 2.4/4.16kV Distribution

In the South 16/27.6kV region, redevelopment growth is projected through a number of new condominiums, industrial/commercial developments and at the water and wastewater pumping stations. The Lakeview, Clarkson, Herridge, and Lorne Park pumping stations continue to slowly expand and increase their load as more pumps and water mains are added. Historical actual and forecasted peak demand for this area is shown below in **Figure 86** South 16/27.6kV Distribution.

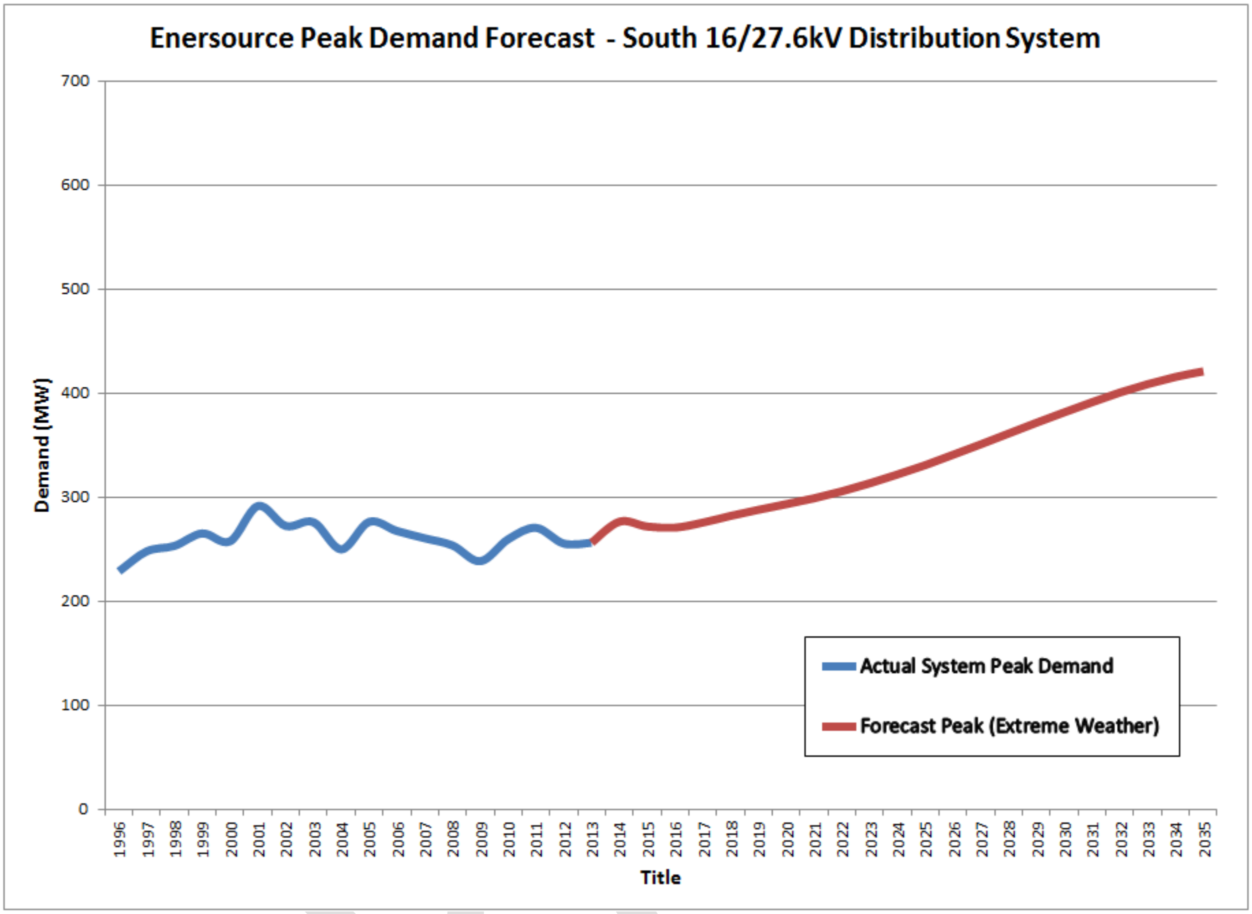


Figure 86. Enersource Peak Demand Forecast - South 16/27.6kV Distribution System – Extreme Weather Scenario (1996-2035)

West 44kV Subtransmission and 8/13.8kV Distribution

The West 44kV system continues to serve predominantly condominium, residential and industrial/commercial loads. This part of the system will be further loaded by significant new condominium loads that are planned and under construction in the City Centre, along Eglinton Avenue in the west end of the city, and in new industrial/commercial loads in the Meadowvale area. Historical actual and forecasted peak demand for this area is shown below in **Figure 87** West 44kV Subtransmission and 8/13.8kV Distribution Load Growth.

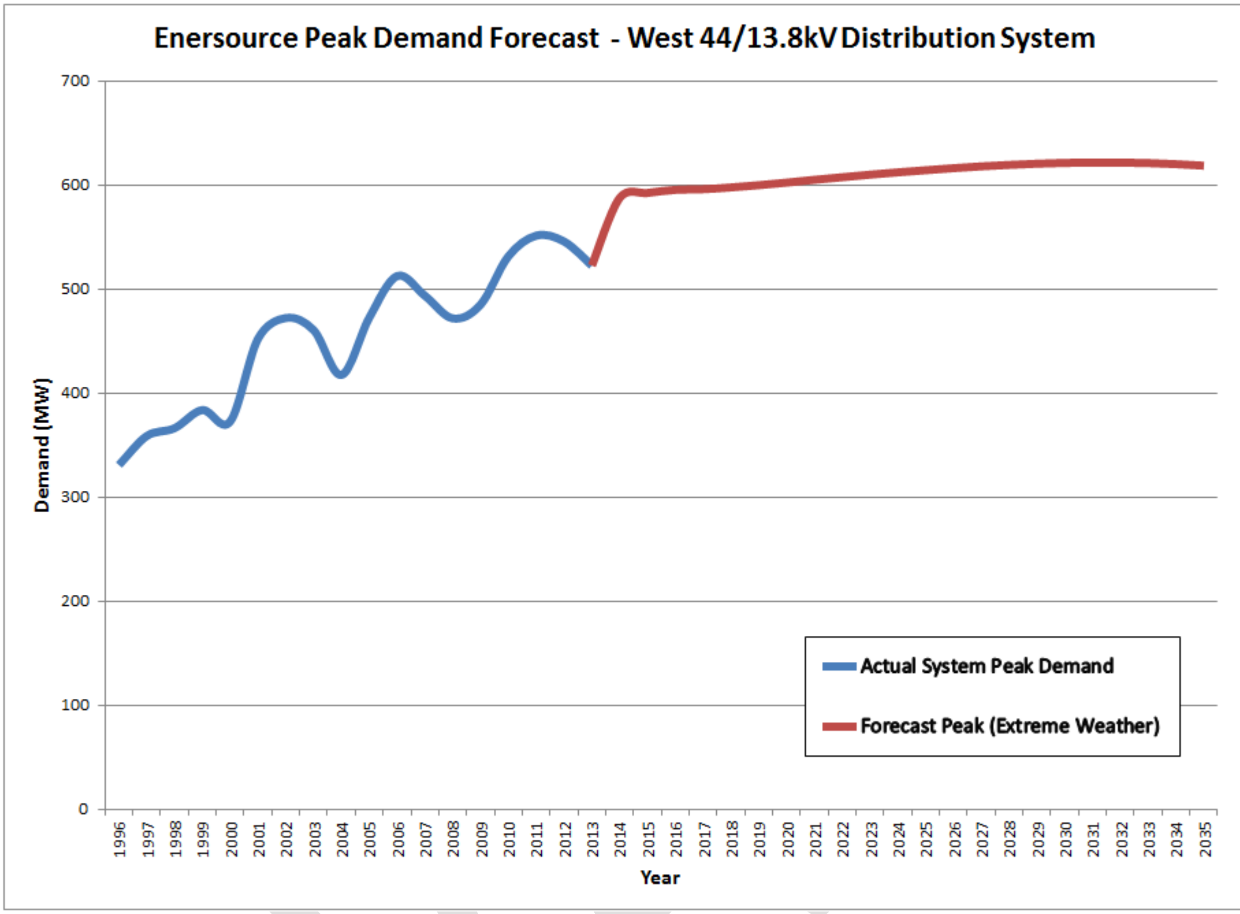


Figure 87. Enersource Peak Demand Forecast - West 44/13.8kV Distribution System – Extreme Temperature Scenario (1996-2035)

East 44kV Subtransmission and 8/13.8kV Distribution

The East 44kV system continues to serve predominantly industrial/commercial loads. This part of the system is projected to experience moderate near term growth through additional new commercial and industrial loads from existing service upgrades and new customers. Historical actual and forecasted peak demand for this area is shown below in **Figure 88** East 44kV Subtransmission and 8/13.8kV Distribution Load Growth.

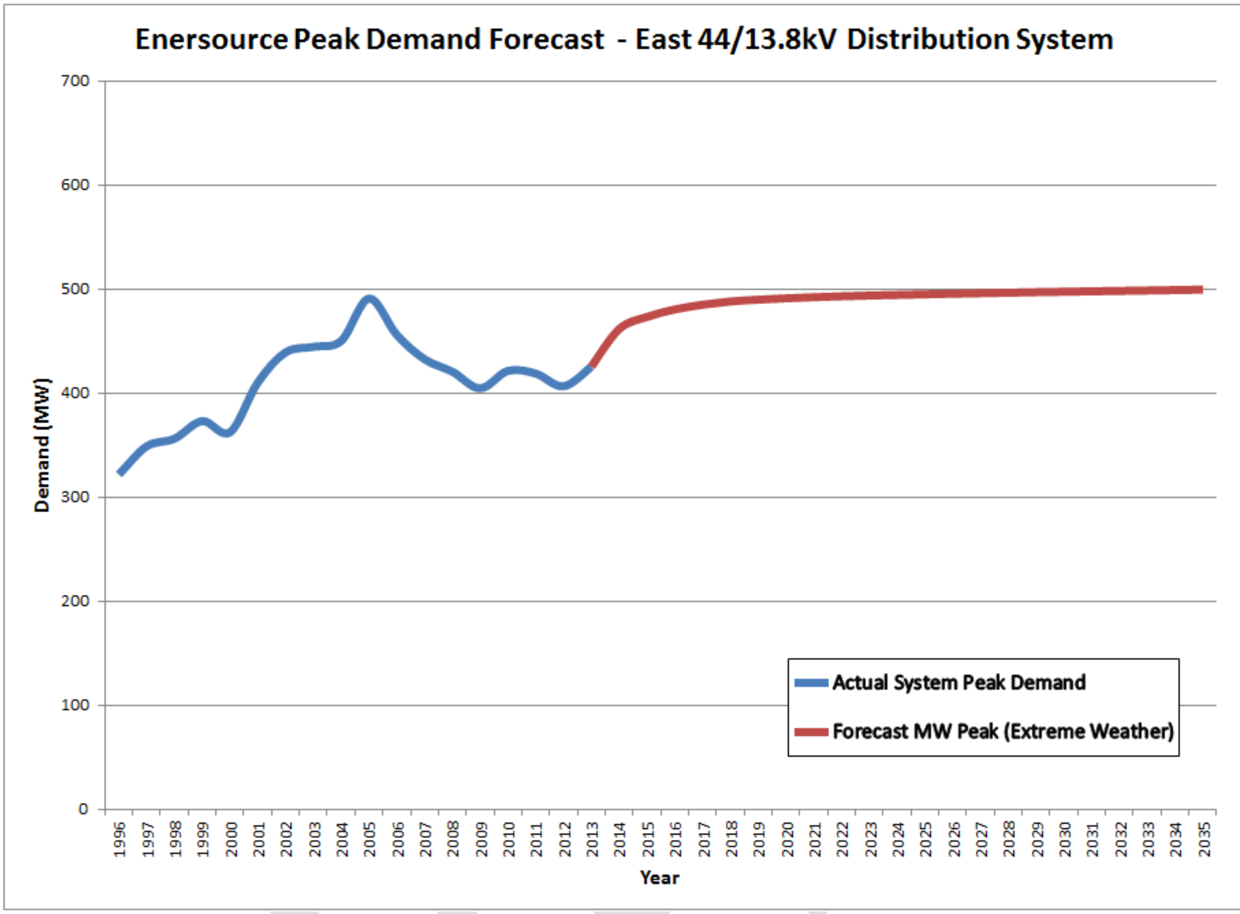


Figure 88. Enersource Peak Demand Forecast - East 44/13.8kV Distribution System – Extreme weather scenario (1996-2035)

Downtown 21

Downtown 21 is the master plan for Mississauga's City Centre aimed at creating a more vibrant and transit-oriented urban centre. The City Council approved a new planning framework for the downtown that aims to transform Mississauga from suburban to an urban centre. As shown in **Figure 89**, some of the major Downtown 21 initiatives are as follows:

- Development of Main Street
- Extension of East-West Streets
- Expansion of Square One Shopping Mall
- Burnhamthorpe Road Project.

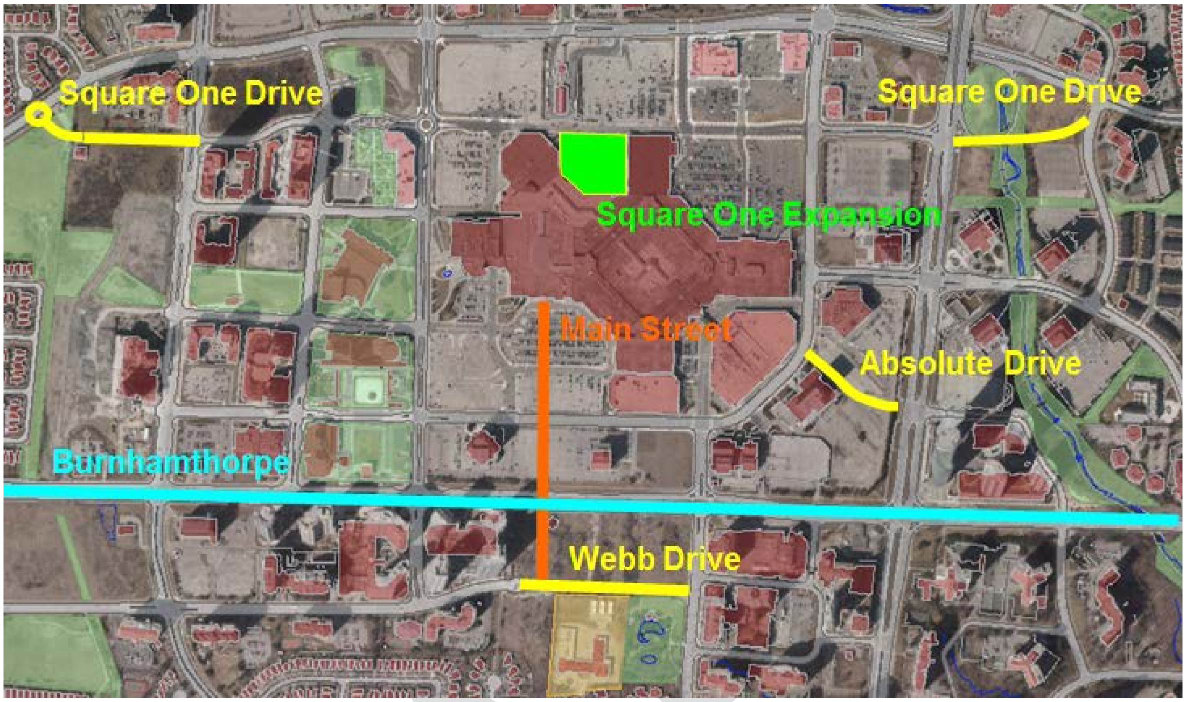


Figure 89. Downtown 21 Initiatives

In addition, the Downtown 21 master plan will focus on building office building infrastructure in hopes to make downtown the major urban destination for future office, employment and creative economic growth in Mississauga. Existing and future residential and commercial buildings envisioned in the Downtown 21 framework are shown in **Figure 90**.

The current electrical supply in downtown Mississauga will be inadequate to meet the future proposed infrastructure needs that are planned in the Downtown 21 master plan and thus, Enersource will need to make major investments such as:

- Installing new subtransmission circuits
- Building new substations and increasing capacity at existing substations
- Installing new distribution feeders and reconfiguring existing feeders.

To accommodate future growth in the Downtown Core, Enersource is proposing transformational capacity be added as discussed in Section 2.3.3. Expansion Programs.

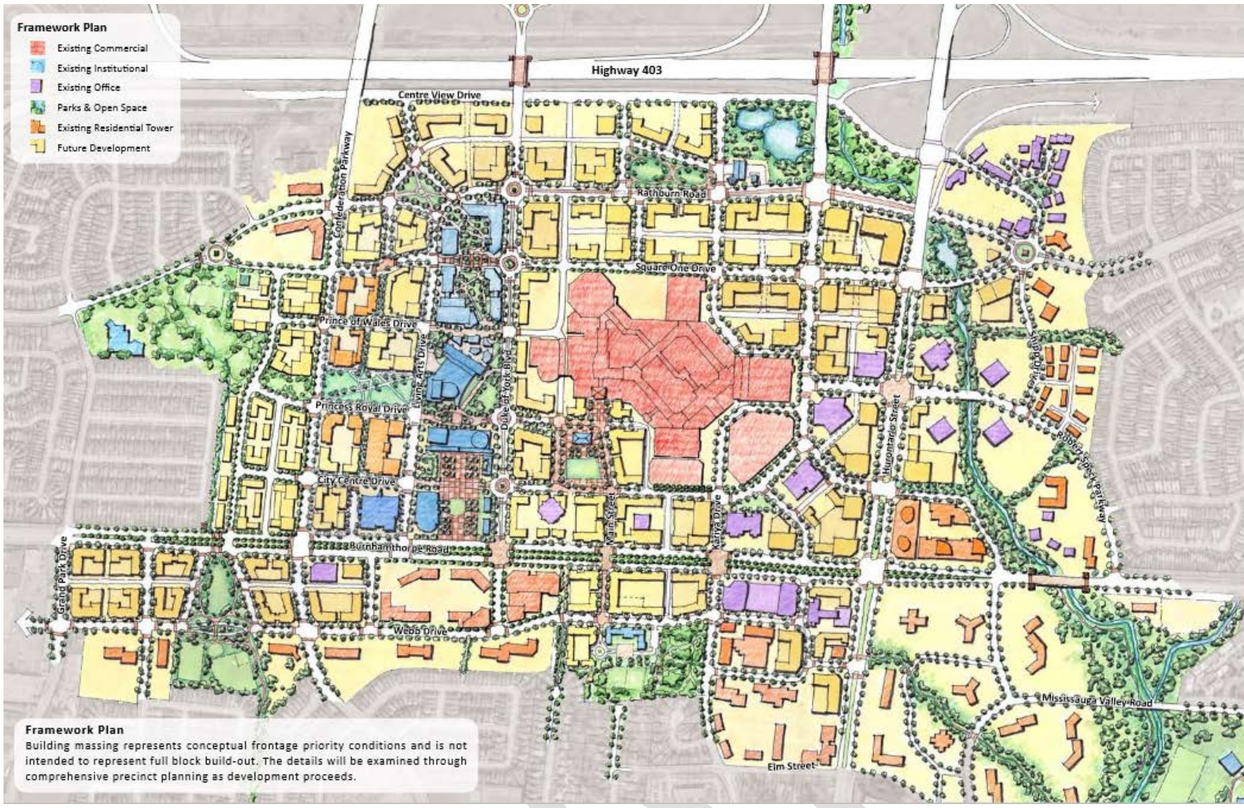


Figure 90. Downtown 21 Framework Plan

Lakeview Revitalization

The Lakeview revitalization is a joint effort by the City, Province of Ontario, and Ontario Power Generation. This major initiative envisions the development of a cultural hub, housing developments and employment corridor on the grounds of the old Lakeview Generating Station in the southeast part of Mississauga. As outlined in the Lakeview Master Plan, this initiative is expected to develop 8,000 housing units, result in 15,000 to 20,000 new residents, and bring 7,000 to 9,000 new jobs to the area. The proposed land use layout is shown in **Figure 91**.

Figure 91. Lakeview Master Site Plan.

This DSP time period does not include significant expenditures relating to the Lakeview Master Site Plan.

Lakeshore Road/Port Credit Re-Intensification

Both sides of Lakeshore Road between Hurontario Street and Stavebank Road are characterized by low rise apartment buildings and mixed use commercial offices and restaurants. In the coming years, this area is expected to go through a major revitalization that will see its low rise buildings turned into mid-rise apartment buildings. The current 4.16kV distribution network is inadequate to supply projected demand, and Enersource is currently considering replacing its aging 4.16kV distribution network with 27.6kV to accommodate the future growth.

The DSP does not include significant expenditures relating to the Lakeshore Road Re-Intensification at this time except for the rebuilding of an overhead line on Park Street, west of Hurontario Street.

Hurontario Light Rail Transit (LRT)

Light Rail Transit (LRT) is a transportation system being developed by the Province of Ontario to connect Mississauga's Port Credit neighbourhood and Brampton. The LRT project supports Mississauga's vision of becoming a vibrant and modern urban centre and ensures the long-term urban intensification of downtown Mississauga. With the development of LRT infrastructure, all of the Downtown Core will be within a five-minute walk of a transit station. Accordingly, five transit stations are proposed within the Downtown Core that will require installation or relocation of electricity distribution infrastructure. The current proposed scope of the LRT system is shown in **Figure 92**. With the development of the LRT system, Enersource will have to ensure that new distribution infrastructure is built and that the reconfiguration of the existing distribution network is carried out in order to ensure adequate supply to the Downtown Core. The new transit line would serve Mississauga along the Hurontario corridor, running between Port Credit and Steeles Ave., and connecting with existing transit routes in the GTA.

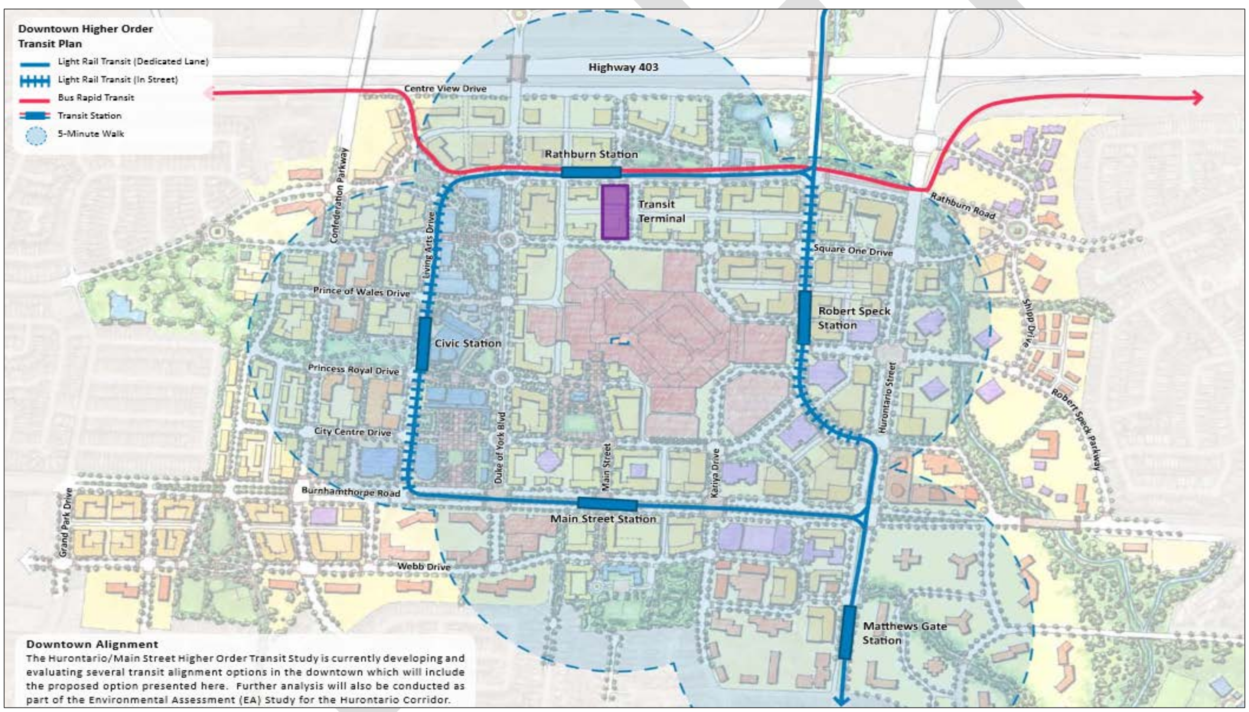


Figure 92. LRT Plan

In April 2015, the Province of Ontario announced that the LRT project will move ahead in support of the Moving Ontario Forward plan aimed at increasing transit ridership, reducing travel times, managing congestion, connecting people to jobs, and improving the economy. Currently, the construction of the LRT is expected to start in 2018 and the in-service date is expected in 2022. Consequently, Enersource has made provisions in its capital budgets under System Access investment category to ensure adequate funds are available to conduct the work required to accommodate construction of the LRT (e.g., relocation of overhead assets).

3.1.2 Total Annual Capital Expenditures by Category

Tables 33-34 and **Figure 93** below summarize the historical and proposed investments that were and will be required to ensure that Enersource is able to provide a safe, secure and reliable supply of electricity, meet system load growth demands, and complete all regulatory driven initiatives.

Table 33. Historical expenditures by investment category (2011-2015) ($000's)

Description	2011	2012	2013	2014	2015
System Service	11,858	9,860	10,712	11,228	16,497
System Renewal	11,422	16,224	20,887	31,257	36,058
System Access	14,326	11,493	10,055	9,474	16,452
General Plant	9,052	29,220	6,831	6,230	10,682
Churchill Meadows CCRA payment	-	-	-	-	40,479
Total	**46,657**	**66,798**	**48,485**	**58,189**	**120,168**

Table 34. Projected Expenditures by Investment Category (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
System Service	17,200	13,015	13,130	12,825	13,105	13,490
System Renewal	34,735	37,243	38,240	40,280	38,570	38,490
System Access	12,408	17,916	18,123	18,162	17,238	10,568
General Plant	12,796	11,337	10,281	10,794	10,755	9,984
Total	**77,139**	**79,511**	**79,773**	**82,061**	**79,668**	**72,532**

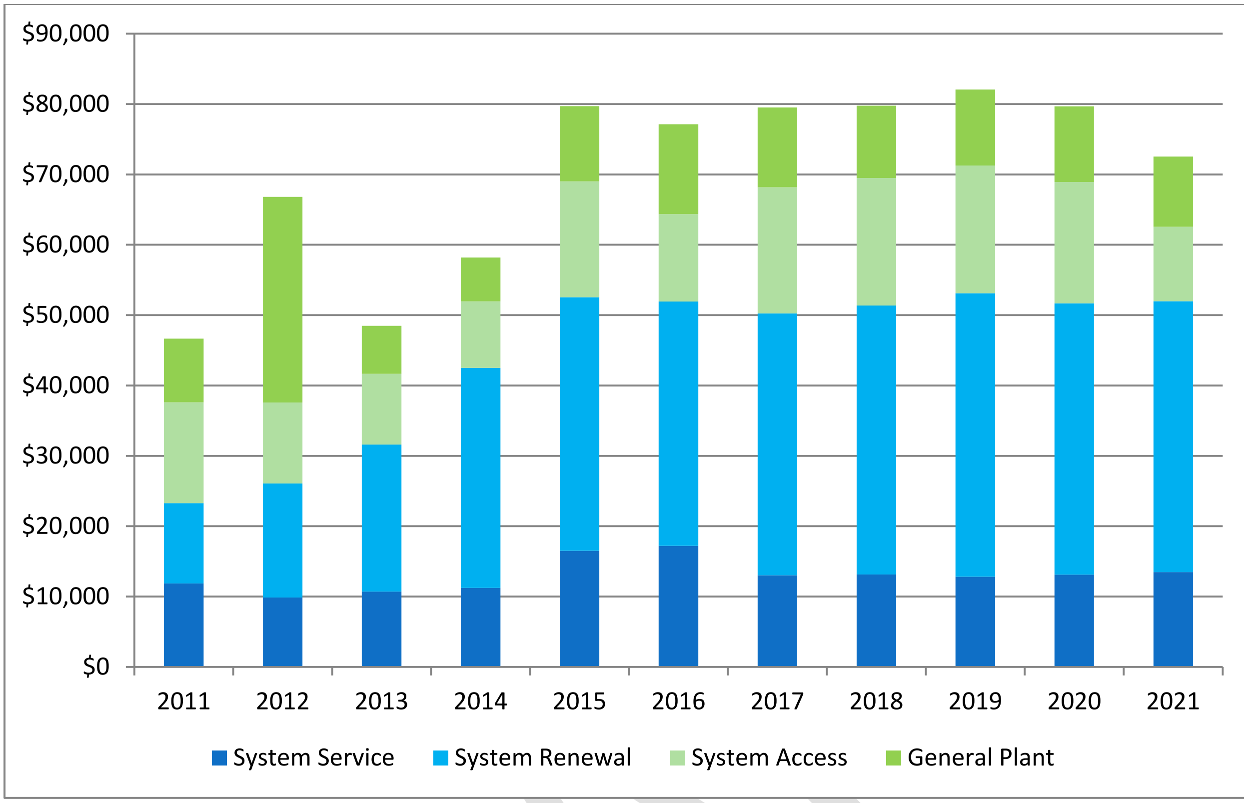


Figure 93. Enersource's Investment Portfolio (2011-2021)

3.1.3 Capital Expenditures Description by Category

This section provides a brief description of capital expenditures within each OEB prescribed category and how such investments are driven by Enersource's asset management process. The justification for the overall scope and level of investment for the capital expenditures in each of the categories listed below is provided in Section 3.5: Justification of Capital Expenditures.

Budgets

System Access

The System Access investment program proposed investments from 2016 through 2021 are shown in **Table 35**.

Table 35. System Access Expenditures by Capital Program (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
Road Projects	3,000	3,000	3,000	3,000	3,000	3,000
Light Rail Transit	400	8,400	8,650	8,750	7,800	1,200
New Subdivisions	800	800	800	800	800	800

Description	2016	2017	2018	2019	2020	2021
Industrial & Commercial Services	2,600	2,600	2,600	2,600	2,600	2,600
Residential Service Upgrades	125	125	125	125	125	125
Smart Metering Large Commercial	1,506	-	-	-	-	-
Wholesale Metering	1,263	33	43	35	65	10
Metering Equipment	1,172	1,427	1,384	1,337	1,337	1,337
Smart Metering	-	-	-	-	-	-
Smart Metering in New Condos	1,387	1,407	1,426	1,446	1,446	1,446
Green Energy - FIT/MicroFIT	155	125	95	70	65	50
Total	**12,408**	**17,916**	**18,123**	**18,162**	**17,238**	**10,568**

System Access initiatives are investments required to meet customer service obligations in accordance with the OEB'S DSC and Enersource's Conditions of Service. System Access projects include the following:

- Connecting new customers
- Building new subdivisions
- Road authority projects (e.g., relocating system plant for roadway reconstruction projects).

Enersource uses an economic evaluation methodology prescribed in the DSC to determine the level of capital contributions for each project, which is to be included in the annual capital budgets. Due to the mandatory nature of System Access projects, these investments cannot be deferred and must proceed as planned to ensure Enersource's compliance with the DSC and its Conditions of Service.

System Renewal

The System Renewal Investment program historical and proposed investments from 2016 through 2021 are shown in **Table 36**.

Table 36. System Renewal expenditures by Capital Program (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
Subdivision Renewal Program	13,250	15,750	16,800	18,000	18,000	18,000
Overhead Distribution Renewal and Sustainment	6,090	6,360	6,270	6,810	6,450	7,620
Subtransmission Renewal	4,200	3,000	2,850	3,150	3,300	4,050
Transformer Replacement	7,125	7,313	7,500	7,500	6,000	4,000

Description	2016	2017	2018	2019	2020	2021
Underground Distribution Renewal and Sustainment	3,750	4,500	4,500	4,500	4,500	4,500
Emergency Replacement Program	320	320	320	320	320	320
Total	**34,735**	**37,243**	**38,240**	**40,280**	**38,570**	**38,490**

System Renewal investments are driven by long term plans to replace assets that are near or at the end of their useful lives. The Asset Management Planning Process is the main driver for determining proposed projects and expenditures within the System Renewal category. System Renewal strategies are prioritized based on condition of assets, age, as well as the impact on system reliability. In particular, the Kinectrics' Asset Condition Assessment (ACA) and replacement recommendations were used as the basis for determining the investment requirements for System Renewal. The level of spending within System Renewal is driven by the assessment of project criticality, asset condition, reliability, and safety.

Asset Condition Assessment Investment Requirements

Table 37 below illustrates the forecasted number of assets flagged for replacement. This forecast and the asset health index distribution were the key outputs of the ACA process carried out by Kinectrics. The timing of replacements, as identified by Kinectrics, represents the optimum timing for asset renewal. As such, the year one values are substantially higher than subsequent years due to the high percentage of Enersource's distribution system with a health index of either 'very poor' or 'poor' and recommended for immediate replacement.

Table 37. Condition-based replacement schedule by asset category

Years from Now	Asset Category															
	Substation Transformers		Circuit Breakers	Pole Mounted Transformers	Pad Mounted Transformers		Vault Transformers	Pad Mounted Switchgear	Overhead Switches				Underground Cables *Note that results are given in terms of conductor-km		Poles	
	In Service	Spares			1 Phase	3 Phase			44 kV	27.6 kV	Inline	Motorized	Main Feeder	Distribution	Wood	Concrete
0	3	N/A	10	58	177	6	89	31	1	0	32	5	254	799	1021	3
1	0	N/A	0	49	161	7	67	16	2	0	29	3	91	259	709	5
2	0	N/A	0	40	148	7	62	11	2	0	26	3	59	159	499	5
3	0	N/A	0	35	139	7	58	9	2	0	26	2	51	126	372	8
4	1	N/A	0	33	126	7	55	6	2	0	29	2	46	101	297	10
5	0	N/A	0	34	124	8	53	8	1	1	27	3	41	82	256	13
6	1	N/A	0	36	126	8	50	7	1	0	28	1	37	70	235	15
7	1	N/A	0	39	136	6	46	6	2	2	27	2	34	62	234	14
8	0	N/A	0	40	141	6	43	10	1	0	26	1	33	59	238	19
9	0	N/A	0	42	151	9	40	12	3	2	26	2	32	58	240	24

System Service

System Service investments are required to support the expansion, operation, and reliability of the distribution system. These types of investments are primarily identified through Enersource's planning process. For example, although overall load growth in Enersource's service territory is expected to stay fairly low during the forecasted period, there are specific areas within the service territory that require capacity investments to accommodate growth.

The reliability driven investment program proposed investments from 2016 through 2021 are shown in **Table 38**.

Table 38. System Service expenditures by Capital Program (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
Municipal Substation Construction & Upgrades	11,600	8,200	8,000	7,800	7,650	7,900
Subtransmission Expansion	2,400	2,650	2,400	2,400	2,400	2,400
Automation / SCADA Replacement and Enhancement Program	3,200	2,165	2,730	2,625	3,055	3,190
Total	**17,200**	**13,015**	**13,130**	**12,825**	**13,105**	**13,490**

General Plant

The General Plant investment program proposed investments from 2016 through 2021 are shown in **Table 39**.

Table 39. General Plant Expenditures by Capital Program (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
Engineering & Asset Systems	1,510	1,187	1,391	1,228	1,345	1,293
Rolling Stock	2,775	2,244	2,033	3,011	2,298	1,946
Information Technology	671	456	572	1,040	870	560
JDE/ERP System	2,185	2,000	1,180	1,320	1,637	1,410
Meter to Cash	2,470	2,055	2,180	1,420	1,830	2,000
Grounds & Buildings	2,985	3,195	2,725	2,575	2,575	2,575
Major Tools	200	200	200	200	200	200
Total	**12,796**	**11,337**	**10,281**	**10,794**	**10,755**	**9,984**

3.1.4 Regional Planning Process or Regional Infrastructure Plan Impact

The Regional Planning carried out with HONI has confirmed the capacity overloading at Erindale TS T1/T2 during summer peak. Thus, Enersource has made a provision in its capital plan to build a 40 MVA substation that will be fed from Churchill Meadows TS (44kV system) and provide transformational capacity to feed 27.6kV load currently supplied by Erindale TS T1/T2.

3.1.5 Customer Engagement Activities

Enersource has endeavoured to maintain a customer-centric approach to the DSP and capital planning pursuant to the RRFE and the OEB's filing requirements.

Enersource's day-to-day customer engagement opportunities have guided decision-making in the DSP and capital expenditure programs. Through the asset management process, Enersource addresses customer needs on a case-by-case basis and is responsive to customer preferences. This type of engagement, which has included key account meetings and discussions with customers following events such as storms and other unplanned outages, has historically allowed for efficient planning at both the macro and micro levels of the distribution system.

To ensure Enersource's DSP formally considers customer preferences, pursuant to the OEB's RRFE, Enersource engaged Decision Partners Inc., a third party consultant, to conduct broad, professional, and scientific research on customers' behaviour regarding the DSP. This work is now underway. The consultant is responsible for the following:

- Designing the customer consultation process in consultation with Enersource
- The collection of customer feedback
- The documentation of customer engagement results.

Enersource has worked with Decision Partners to design a multi-faceted customer engagement program that combines traditional consultation elements and qualitative and quantitative research elements. Consultation with customers is continuing, currently via a 'video dialogue', accompanied by an online survey at www.enersource.com/survey. Enersource will use the information gathered to ensure customer preferences are documented and included in proposed capital plans and the overall DSP.

3.1.6 System Development Expectations

This section describes how Enersource expects the distribution system to develop over the next six years, including in relation to load and customer growth, smart grid development, and the accommodation of future renewable energy generation projects.

3.2 Capital Expenditures Planning Process Overview (OEB Chapter 5.4.2)

3.2.1 Objectives

Enersource's capital expenditure planning objectives are as follows:

- To align with Enersource's corporate strategic objectives of Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance;
- To optimize projects by ranking investment criteria and comparing project benefits;
- To ensure that investments are financially sound using the approved budget and required resources;
- To provide optimal customer service by assessing value and maintaining reliability at levels preferred by customers;
- To provide cost efficiency by considering timing of projects, resources, and contingency scenarios;
- To improve future investment decisions by analyzing historical investment trends; and
- To pace investment expenditures to minimize rate impact.

The capital planning process is undertaken annually as a component of Enersource's annual financial and business planning process which includes the development of detailed departmental business plans. Investment requirements and implementation plans to achieve identified objectives are included in the business plans. Objectives requiring significant (greater than $150,000) investment or requiring cross departmental resources are specifically identified and supported by a business case.

The capital and operational expenditure requests identified in the business plans are compiled and assessed against Enersource's capital planning objectives identified above. The quantity and timing of resources required to execute the prioritized list of projects are assessed for resource availability.

Enersource's asset management objectives focus on identifying asset needs and enhancing the distribution system, as well as capital planning objectives identified to maximize the outcome of the invested capital, based on the available budget.

Enersource also ensures that focus is placed on assessing and implementing customer distributed generation, including solar generation projects under the Feed-In-Tariff (FIT) or microFIT programs. Enersource works closely with generation customers regarding their connection proposals, ensuring that the equipment and design meets all required standards and regulations. Enersource will complete a connection impact assessment to verify that connection at the proposed location is viable and that the proposed generation will not negatively impact the grid.

3.2.2 Policies, Regional Planning and Non-Distribution System Alternatives

Enersource is currently involved in an Integrated Regional Resource Planning process (IRRP) as developed by the IESO and updated by the OEB. The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC), and develops regionally integrated solutions to address identified needs. These include: conservation, demand management, distributed generation, large-scale generation, transmission, and distribution. Enersource continues to work with HONI and the IESO to develop optimal solutions to the transmission and bulk system needs within the Mississauga area.

3.2.3 Prioritization and Pacing of Investments

Enersource's forecasted investment plan is realistic and takes into consideration customer expectations and preferences, public policy responsiveness, and stakeholder requirements. Enersource prioritizes projects and programs based on a set of business values, and assessments are made regarding investment proposals which have the greatest impact on the business values. Due to resource constraints (e.g., funding, labour availability, information technology support) and other considerations such as the rate impact to customers, other stakeholders and environmental requirements, projects and programs are selected and prioritized based on supplemental quantitative and qualitative analysis.

One of Enersource's primary goals is to pace and prioritize capital investments in a manner that considers resource needs and rate impacts. To facilitate this goal, Enersource reviews and analyses programs and projects both qualitatively and quantitatively.

In the initial phase of the capital investment process, Enersource compiles developer/site plan submissions from the City and developers, and then assesses how the distribution system must be developed in order to meet the anticipated electrical demand. Enersource also seeks to determine from the City, the Region of Peel, and the Ministry of Transportation - Ontario (MTO) their respective road, water main, and wastewater projects anticipated for the next five to 10 years. These projects are considered mandatory and are included in System Service or System Access investment categories within this DSP.

In addition to including development plans, Enersource receives input from internal Subject Matter Experts (SMEs) in order to identify other risk areas and projects required to maintain the reliability and safety of the distribution system. Condition assessments are also used to assess future project requirements. Asset condition and environmental concerns are assessed, at which time urgent issues are noted. In some cases, simple maintenance tasks are not sufficient, prompting the need for a capital renewal project. In these situations a project is initiated, designed, planned and estimated to fix the problem(s).

Enersource systematically plans and evaluates its multi-year project portfolio and creates a prioritized list of projects that are used as the basis for the capital investment plan included in this DSP. The optimization of future programs and projects allows Enersource to invest in the appropriate areas of the distribution system and General Plant assets in order to mitigate risk and improve overall value.

As stated above, Enersource considers System Service and System Access investments mandatory. The programs and projects that fall under System Renewal involve replacing and/or refurbishing system assets to extend the original service life of the assets. Modifications fall under General Plant: for example, replacements or additions to Enersource's assets that are not part of its distribution system, including land and buildings, tools and equipment, rolling stock and electronics devices and software used to support day to day business and operations activities.

The pace of investment during the 2016-2021 period is driven mainly by System Renewal needs. The rationale and decision-making framework that ultimately yielded this proposed pacing are described in Section 2.1.1. At a high level, the long-term objective of Enersource's CAMP is to achieve an investment plan that is:

- **Risk based**: Incorporate risk management appropriately into decision-making strategy;
- **Sustainable**: Optimize asset life cycle value;
- **Multi-disciplinary**: Asset management accountability framework crosses departmental and discipline boundaries;
- **Integration Oriented**: View assets in their total relative value context;
- **Optimal**: Strike the right balance among competing objectives, such as short-term performance and reliability versus long-term planning and sustainability; and
- **Systematic:** Rigorously applied in a structured management system complete with a monitoring framework and evidentiary structures and tools.

An asset reaches its economic end-of-life when the annualized capital cost of replacing the asset becomes less than the annualized risk cost of continuing to operate the asset. Replacing the asset sooner than the optimal intervention time risks wasting its remaining useful life. Conversely, replacing the asset after the optimal intervention time risks incurring unnecessary and avoidable costs associated with asset failure. The objective of this risk-based approach is to minimize the total lifecycle or operational cost of the equipment in order to maximize the value derived from the assets. Enersource believes that by efficient and effective planning, it can renew a portion of its distribution system annually in order to help reduce customer outages, weather related failures, mitigate environmental concerns, while ensuring distribution rates that are just and reasonable and predicable.

The Company plans to significantly increase its System Renewal projects over this DSP timeframe. Enersource has met with potential third-party contractors that are committed to increasing their workforce over the next few years in order to meet the forecasted renewal project increases. To ensure Enersource's distribution system continues to remain safe and reliable, increased investments are required due to the age and condition of a significant portion of Enersource's overhead and underground system. Enersource has also seen a significant increase in operating and maintenance costs over the last few years, due to the condition of aged assets, and is committed to reversing this trend.

After considering the System Renewal investment increases and what is required for System Service (Substations – two for the Downtown Core and one to meet the 27.6kV load forecast) and System Access (LRT), Enersource reviewed its General Plant investment proposals submitted by the SMEs and re-prioritized many of the planned activities over the entire DSP period. By distributing the General Plant investments over the DSP time frame, Enersource was able to maintain a relatively stable year-to-year investment plan that ensured sufficient cash flows would be available, labour resources would not be overly committed, and customer rate changes would be predictable.

3.2.4 Details of the Mechanisms Used by the Distributor to Engage Customers

Please see sections 1.2.5 Customer Consultation and 3.1.6 Customer Engagement Activities.

3.2.5 Method and Criteria Used to Prioritize REG Investments

Enersource prioritizes Renewable Energy Generation (REG) investments based on customer requests and follows regulated timelines outlined in the OEB's DSC. Enersource works closely with customers, HONI, the IESO, and the ESA to integrate all proposed residential and commercial customer generation projects into the grid. As outlined in Section 3.3, numerous projects of varying generation capacity are proposed and connected to the distribution system every year.

The connection process for integrating the generation projects into the distribution system involves the following:

- Analyzing the generation capacity of the connecting feeder and interface transformer;
- Verifying that the relevant substation transformer can accept reverse flow;
- Ensuring that the short circuit changes and voltage fluctuations will cause no material impacts on either the distribution or transmission grid;
- Reviewing the proposed single line diagram, electrical protection scheme and site plan for adherence to all Enersource, ESA and IESO standards and requirements.

In instances where proposed generation connection is not possible, Enersource will work with the customer to provide an alternative solution. This solution may involve expanding the distribution system to meet customer needs or relocating the project to a property that meets all applicable connection requirements. Where work on the distribution system is required for the connection, the project is coordinated to ensure regulatory timelines are met while optimizing crew time.

3.3 System Capability Assessment for Renewable Energy Generation (OEB Chapter 5.4.3)

This section describes distributed energy generation (DEG) facilities (including renewable generation) in Enersource's distribution system.

Enersource currently has a number of DEG facilities connected to the grid. These facilities are mostly a part of the IESO-administered programs (FIT, microFIT, RESOP), net metering and load displacement. The Company has conducted numerous feasibility assessments for other kinds of projects that may be characterized as DEG facilities – battery energy storage, for example. **Figure 94** illustrates currently existing DEG facilities within Enersource service territory.

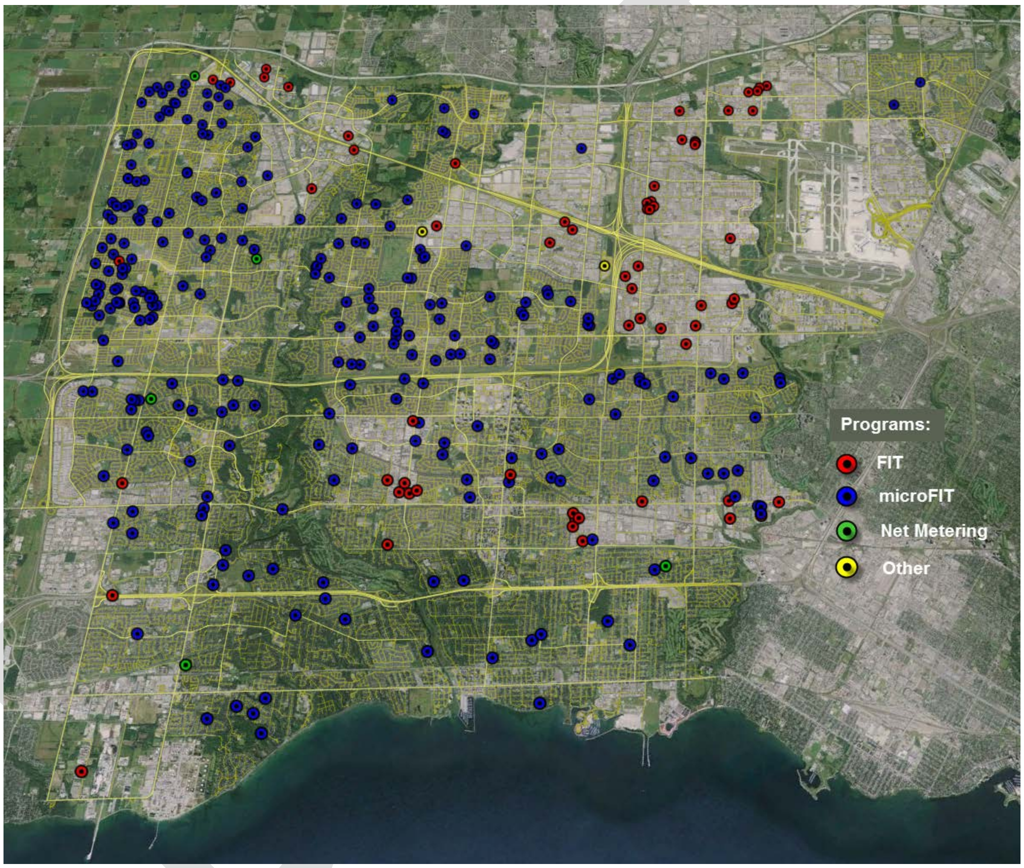


Figure 94. Currently Connected DEG Facilities

3.3.1 Applications from Renewable Generators

As of the end of June, 2015, Enersource has connected 67 small-sized projects with the cumulative capacity of 11.5 MW. Additionally, 47 projects with the cumulative capacity of over 8.6 MW have been approved and are currently in the process of being connected to the distribution system. A summary of DEG facility connections for the historical period 2008 to 2015 is outlined in **Table 40**.

Table 40. Number of DEG Connections (as of the end of June, 2015)

	2005	2008	2009	2010	2011	2012	2013	2014	2015 to date	Total
# of Micro connections	-	-	4	28	35	57	64	41	49	278
Micro connections (kW)	-	-	4	149	226	346	420	326	472	1,943
# of Small connections	-	1	1	-	10	6	10	28	11	67
Small connections (kW)	-	25	50	-	1,725	1,185	2,350	5,027	1,130	11,492
# of Medium connections	1	-	-	-	-	-	-	-	-	1
Medium connections (kW)	5,625	-	-	-	-	-	-	-	-	5,625

Note: DEG connections based on meter installation dates

Of the 345 connected DEG facilities, only two are not powered by solar panels. **Figure 95** illustrates the generation capacity of DEG facilities broken down by fuel type.

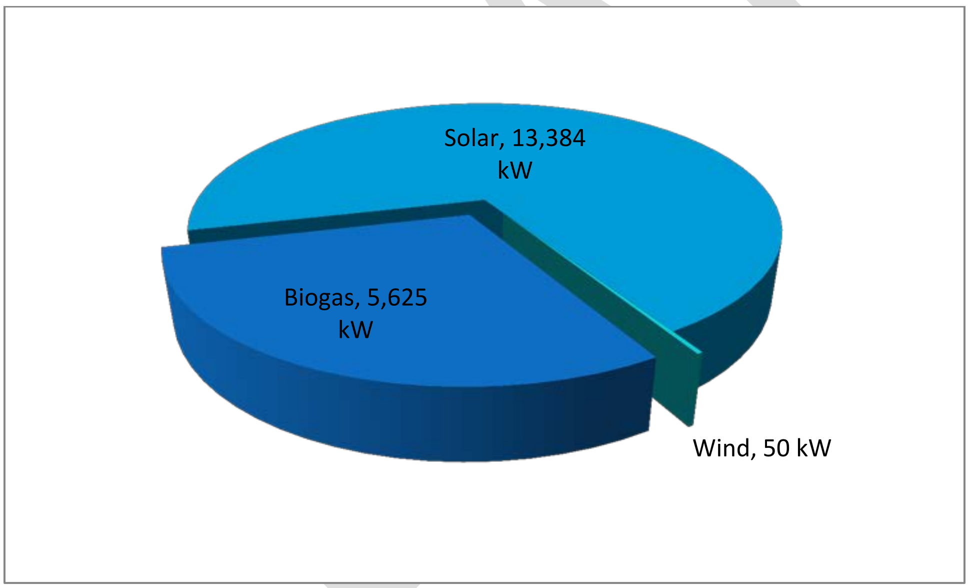


Figure 95. DEG Facility Generation Capacity by Fuel Type

3.3.2 The Number and the Capacity of Renewable Generation Connections Anticipated

Customers have been steadily interested in DEG projects as evidenced by Enersource's historical connection figures above in **Table 40**. The majority of applications received are for FIT initiatives, with little interest in net metering at this point.

In 2014, the Peel District School Board (PDSB) was awarded 70 FIT 3.0 contracts within Enersource's service area and the Company is currently processing connection impact assessments (CIAs) for these projects. Additionally, 14 projects with cumulative capacity of almost 2.2 MW have been deemed feasible and are currently in progress.

A DEG connection forecast shown in **Table 41** has been compiled based on historical trends, completed assessments, and anticipated projects. The forecast assumes that the microFIT program will transition to a net metering program in 2017, and that no major changes wil be introduced to the FIT program.

Table 41. Forecasted Number of DEG Connections

	2015	2016	2017	2018	2019	2020	2021
Number of micro generation facilities	80	65	65	20	30	30	30
micro generation capacity (kW)	570	570	570	180	270	270	270
Number of small generation facilities	20	30	20	20	15	10	5
small generation capacity (kW)	3,500	5,250	3,500	3,500	2,625	1,750	875
Number of medium generation facilities	1	1	-	-	-	-	-
medium generation capacity (kW)	1,400	2,000	-	-	-	-	-

Generation categories were adopted from the OEB's DSC in the following manner:

- Micro-embedded generation facility: name-plate rated capacity of 10 kW or less;
- Small embedded generation facility: not a micro-embedded generation facility with name-plate rated capacity of 500 kW or less if connected to a less than 15 kV line, and 1 MW or less if connected to a 15 kV or greater line;
- Mid-sized (medium) embedded generation facility: not a small embedded generation facility with name-plate rated capacity of 10 MW or less;
- Large embedded generation facility: name-plate rated capacity of more than 10 MW.

3.3.3 The Capacity of Enersource's Distribution System to Connect Renewable Energy Generation

Table 42 illustrates both the distribution capacity of Enersource's system to accommodate DEG facilities and transmission capacity allocated by HONI. 'Connected and In Progress' column represents all DEG facilities that are connected to the distribution system, are in the process of getting connected, or have completed their CIA, resulting in capacity allocation.

Table 43. DEG Station Capacity

HONI Transformer Station	DESN	Bus	Connected and In Progress (kW)	Distribution Capacity available (kW)	Transmission Capacity allocated (kW)
Bramalea TS	DESN 1	B	1,560	880	2,500
	DESN 1	Y	710	790	1,800
Churchill Meadows TS	DESN	BY	1,150	9,440	5,000
Erindale TS	DESN 1	E	966	7,930	5,000
	DESN 1	Q	8,113	5,450	5,000
	DESN 2	YZ	1,417	15,780	5,000
	DESN 3	BJ	1,331	14,460	5,000
Lorne Park TS	DESN	B	1,269	3,530	5,000
	DESN	J	29	4,770	N/A
Meadowvale TS	DESN	EZ	1,788	11,880	5,000
Oakville TS	DESN	E	0	1,900	N/A
	DESN	Z	601	590	1,000
Tomken TS	DESN 1	BY	5,807	8,790	7,000
	DESN 2	EZ	2,019	14,180	5,000
Woodbridge TS	DESN 1	Q	10	1,900	N/A
TOTAL			**26,770**	**102,270**	**52,300**

Enersource anticipates almost 25 MW of DEG facilities to be connected by the end of 2021 as shown above in **Table 41**. As shown above in

Table 43, Enersource has an additional 102 MW of distribution capacity for connection of DEG facilities. Future connections have to be coordinated with HONI to ensure there is adequate capacity at the transformer stations beyond what is currently allocated, as shown in

Table 43.

3.3.4 Constraints Related to the Connection of Renewable Generation

Connection constraints for DEG facilities can come from (i) the rating of the supplying distribution transformers; (ii) load in the supplying distribution feeder; or (iii) restriction in the supplying transformer station (e.g., short circuit or thermal capacity).

The difference between the proposed DEG facility size and the minimum load must not exceed the supplying transformer rating. If the proposed DEG facility size exceeds the transformer rating, Enersource will work with the customer to upgrade the distribution transformer.

The cumulative DEG capacity on a single feeder must not exceed the minimum load. **Table 44** indicates the feeders that have reached their maximum DEG capacity. Enersource uses industry accepted safety factors in the feeder capacity calculations.

Table 44. Feeders with No capacity to Accommodate DEG Facilities

Feeder	Capacity Consumed (kW)
74M7	745
C5M37	6144.7
C5M41	918
24F2	350
14F4	184
90F6	250
24F4	700
38F4	1005
17F1	750
17F3	500
17F4	325
15F5	250

Note that M-class denotes sub transmission feeders, F-class – distribution feeders.

There are several HONI transformer stations within Enersource's service territory with restricted or constrained connection capacity for DEG facilities. This information is summarized in **Table 45**. Enersource is currently unaware of any plans to eliminate the listed restrictions.

Table 45. HONI Station Restrictions for DEG Facilities

HONI station	Restriction
Bramalea TS DESN 2	Thermal capacity
Bramalea TS DESN 3	Thermal and short circuit capacity
Cardiff TS DESN	Short circuit capacity
Cooksville TS DESN 1	Short circuit capacity

Cooksville TS DESN 2	Short circuit capacity
Richview TS DESN3	Short circuit capacity

While Enersource has enough capacity to accommodate the anticipated DEG connections, the generation proponents might face geographical constraints due to HONI transformer station capacity restrictions.

3.3.5 Constraints for an Embedded Distributor that may Result from the Connections

Enersource does not have any embedded distributors within the service territory.

3.4 Capital Expenditure Summary (OEB Chapter 5.4.4)

System Service

Expenditures on System Service projects are expected to increase slightly in 2016 and flatten out over the remaining term of the DSP. Because development of new infrastructure in Mississauga is almost at capacity, subtransmission expansion is expected to decrease, with focus shifting to subtransmission renewal at a balanced rate over the remaining test years.

- 2012 actuals of $9,860,395 were $1,997,475 lower than 2011 actuals of $11,857,869 due to decreases in substation upgrades and subtransmission expansion and renewal;
- 2013 actuals of $10,711,823 were $851,429 higher than 2012 due to an increase in substation upgrades;
- 2014 actuals of $11,227,758 were $515,935 higher than 2013 due to an increase in subtransmission expansion and renewal;
- 2015 forecast of $16,267,139 is $5,039,381 higher than 2014 due to significant increases in scheduled substation upgrades, higher subtransmission expansion, and major upgrades of the SCADA system;
- 2016 forecast of $17,200,000 is $932,861 higher than 2015 due to scheduled substation upgrades offset by a shift in focus of subtransmission activities from expansion to renewal;
- 2017 forecast of $13,015,000 is $4,189,000 lower than 2016 due to lower substation upgrade requirements;
- 2018 forecast of $13,130,000 is $115,000 higher than 2017 due to an increase in SCADA switch replacements;
- 2019 forecast of $12,825,000 is $305,000 lower than 2018 due to lower substation upgrade requirements;
- 2020 forecast of $13,105,000 is $280,000 higher than 2019 due to an increase in SCADA switch replacements; and
- 2021 forecast of $13,490,000 is $385,000 higher than 2020 due to an increase in substation upgrades.

System Renewal

Expenditures for System Renewal are expected to increase by about 20% over the next five years. Increasing costs in this area are mainly due to a significant portion of the distribution equipment installed in the 1970’s, 1980’s, and early 1990’s having aged and reached the end of its expected useful life.

- 2012 actuals of $16,224,485 were $4,802,564 higher than 2011 actuals of $11,421,921 due to increases in transformer replacements, overhead, underground, and subdivision rebuilds;
- 2013 actuals of $20,887,175 were $4,662,691 higher than 2012 due to increases in transformer replacements, overhead and subdivision rebuilds;

- 2014 actuals of $31,256,743 were $10,369,568 higher than 2013 due to significant efforts to remove and replace leaking and PCB transformers. In addition, an accounting policy change regarding the capitalization of major spares resulted in a $5,000,000 increase to capital;
- 2015 forecast of $35,203,614 is $3,946,870 higher than 2014 due to more planned subdivision renewals and overhead rebuilds;
- 2016 forecast of $34,735,000 is $468,614 lower than 2015 due to lower transformer replacement spend offset by higher subtransmission renewal projects;
- 2017 forecast of $37,242,500 is $2,507,500 higher than 2016 due to an increase in major subdivision rebuild projects and underground rebuilds;
- 2018 forecast of $38,240,000 is $997,500 higher than 2017 due to a continued focus on renewing deteriorating subdivision infrastructure;
- 2019 forecast of $40,280,000 is $2,040,000 than 2018 due to a continued focus on renewing deteriorating subdivision infrastructure;
- 2020 forecast of $38,570,000 is $1,710,000 lower than 2019 due to fewer planned transformer replacements; and
- 2021 forecast of $38,490,000 is $80,000 lower than 2020 due to fewer transformer replacements offset by higher subtransmission renewal projects.

System Access

Expenditures on System Access projects are primarily dependent on customer requirements and are mandatory per Enersource's Conditions of Services and the Distribution System Code. The primary driver for spending over the test period is the LRT project that will run from the south end of Mississauga into Brampton.

- 2012 actuals of $11,493,425 were $2,832,559 lower than 2011 actuals of $14,325,984 due to fewer Offer to Connect (OTC) projects;
- 2013 actuals of $10,054,863 were $1,438,562 lower than 2012 due to fewer mandated road projects and fewer wholesale metering projects;
- 2014 actuals of $9,474,167 were $580,696 lower than 2013 due to decreases in mandated road and OTC projects, partially offset by higher industrial/commercial services;
- 2015 forecast of $14,632,780 is $5,158,613 higher than 2014 due to higher OTC and industrial/commercial services;
- 2016 forecast of $12,407,831 is $2,224,949 lower than 2015 due to fewer OTC projects offsetting increased road projects;
- 2017 forecast of $17,916,237 is $5,508,406 higher than 2016 due to significant activities for the LRT project;
- 2018 forecast of $18,122,967 is $206,731 higher than 2017 due to a slight increase in LRT spend;
- 2019 forecast of $18,162,212 is $39,245 higher than 2018 due to a slight increase in LRT spend;
- 2020 forecast of $17,237,700 is $924,512 lower than 2019 due to lower activity in the LRT project; and

- 2021 forecast of $10,567,700 is $6,670,000 lower than 2020 due to completion of the LRT project.

General Plant

Overall, expenditures in General Plant are expected to be flat over the test period. Facilities, rolling stock, and IT expenditures have been planned to maintain and renew existing assets with minimal year over year impact.

- 2012 actuals of $29,220,053 were $20,168,463 higher than 2011 actuals of $9,051,590 due to acquisition of the administration building partially offset by lower spend on the JD Edwards system;
- 2013 actuals of $6,830,748 were $22,389,305 lower than 2012 due to the administration building acquisition in the prior year, with lower IT spend offset by higher facilities spend;
- 2014 actuals of $6,230,459 were $600,289 lower than 2013 due to lower rolling stock spend;
- 2015 forecast of $10,585,191 is $4,354,732 higher than 2014 due to minor JDE upgrades and higher rolling stock spend;
- 2016 forecast of $12,796,000 is $2,210,809 higher than 2015 due to improvements to the Meter to Cash system;
- 2017 forecast of $11,337,000 is $1,459,000 lower than 2016 due to lower rolling stock replacements and Engineering & Asset Systems (E&AS) spend;
- 2018 forecast of $10,280,500 is $1,056,500 lower than 2017 due to lower JDE and facilities spend;
- 2019 forecast of $10,794,000 is $513,500 higher than 2018 due to higher rolling stock and IT hardware spend offset by lower Meter to Cash spend;
- 2020 forecast of $10,754,862 is $39,138 lower than 2019 due to higher Meter to Cash spend offset by lower rolling stock spend; and
- 2021 forecast of $9,984,236 is $770,626 lower than 2020 due to lower spends in fleet, IT hardware, and JDE upgrades.

3.5 Justification of Capital Expenditures (OEB Chapter 5.4.5)

This section provides the justification and supporting information for investments that have been included in the DSP. The underlying data, information, and analysis are included to support the forecasted capital expenditures as proposed by Enersource.

3.5.1 Overall Plan

The Overall Plan section provides comparative data from the historic period of 2011-2015 and the forecast period of 2016-2021 by investment category and by primary drivers.

3.5.1.1 Comparative Expenditures by Category

Tables 46-47 and **Figure 96** depict the expenditures by investment category over the historic period of 2011-2015 and the projected expenditures for the forecast period of 2016-2021.

Table 46. Historical Expenditures by Investment Category (2011-2015) ($000's)

Description	2011	2012	2013	2014	2015
System Service	11,858	9,860	10,712	11,228	16,267
System Renewal	11,422	16,224	20,887	31,257	35,204
System Access	14,326	11,493	10,055	9,474	14,633
General Plant	9,052	29,220	6,831	6,230	10,585
Total	**46,657**	**66,798**	**48,485**	**58,189**	**76,689**

Table 47. Projected Expenditures by Investment Category (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
System Service	17,200	13,015	13,130	12,825	13,105	13,490
System Renewal	34,735	37,243	38,240	40,280	38,570	38,490
System Access	12,408	17,916	18,123	18,162	17,238	10,568
General Plant	12,796	11,337	10,281	10,794	10,755	9,984
Total	**77,139**	**79,511**	**79,773**	**82,061**	**79,668**	**72,532**

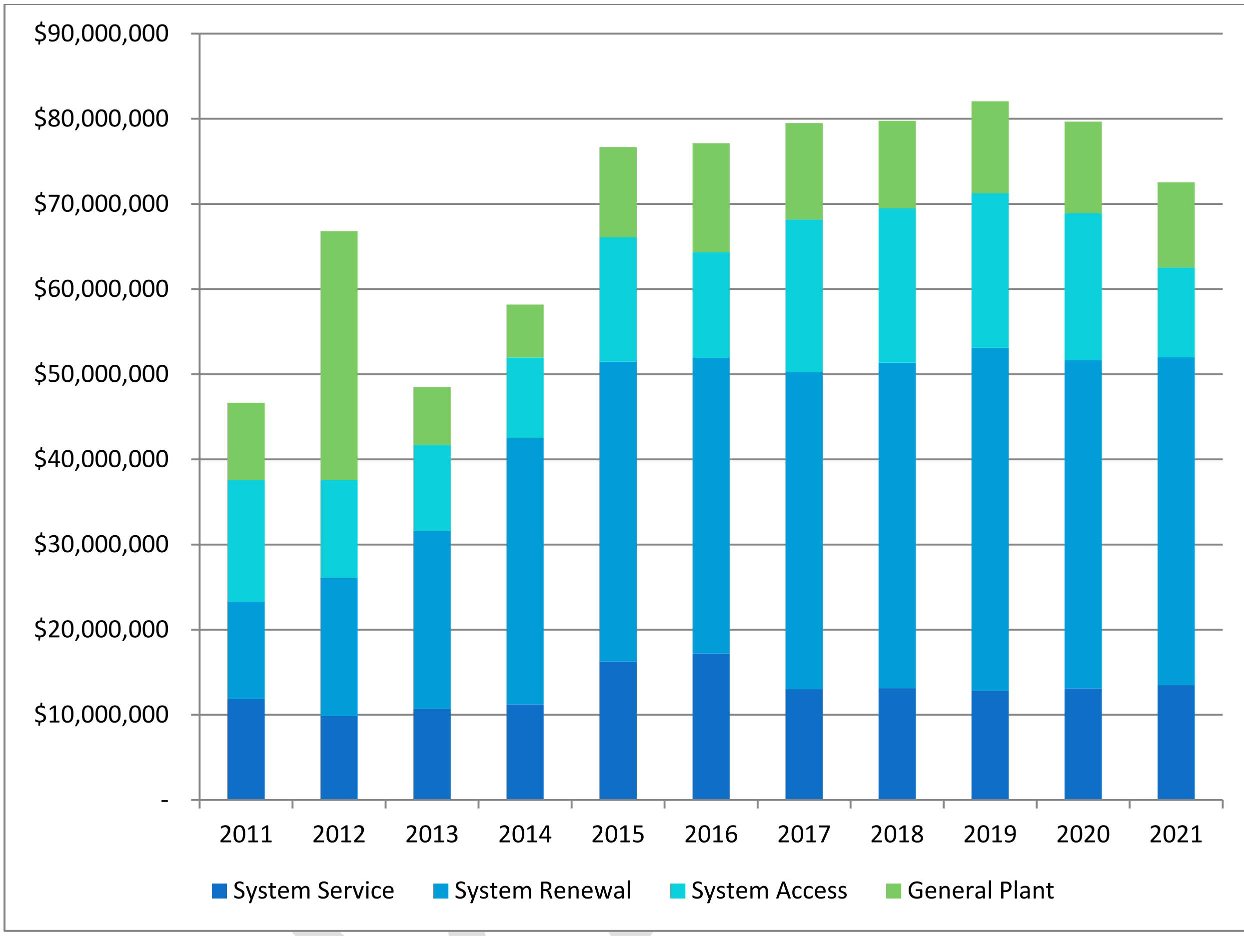


Figure 96. Enersource's Investment Portfolio (2011-2021)

3.5.1.2 Forecast Impact to System Operating and Maintenance Costs

Forecast impact to operation and maintenance costs vary by each of the investment categories, as described below.

System Access

System Access investments are mandatory, non-discretionary projects initiated by customers or third parties (e.g., City of Mississauga, Region of Peel, Ministry of Transportation, etc.). The projects include the following:

- New connections and subdivisions (including industrial/commercial) connections
- Road authority projects that require the relocation of distribution system assets
- Metering
- Other customer initiated work
- Renewable Generation projects, FIT/microFIT.

System Access projects can introduce new distribution assets to the system, which results in an increase of equipment requiring regular maintenance which in turn creates additional points of potential failure within the distribution grid. In addition, these projects may include the expansion of the communication infrastructure and would result in ongoing licencing fees.

System Service

System Service investments represent the costs associated with growing the distribution system and addressing capacity, reliability and safety initiatives. An increased number of assets installed in the distribution grid, will result in increased maintenance and potential failure points within the system. In addition, these projects may include the expansion of the communication infrastructure and may result in incurring ongoing licencing fees.

System Renewal

System Renewal investments are projects and programs directed toward replacing or rehabiliting aging infrastructure. As an asset ages, the costs associated with operating the asset increases as inspection and maintenance activities become more frequent and onerous. However, when an asset is replaced, while maintenance is still required, it may involve less time and resources, thus resulting in lower operating and maintenance costs. In addition, as an asset ages and its condition deteriorates there is a higher likelihood of failure which may result in higher operating costs associated with emergency work required to replace faulty equipment and restore power to customers. Thus, through risk-based approached planning and pro-active replacement projects and programs, Enersource chooses to renew certain portions of its distribution system, thereby reducing customer outages, weather related failures, and avoiding additional operating costs.

General Plant

General plant investments are focused on Information Technology and Information Systems, buildings, facilities, fleet, and major tools.

3.5.1.3 Justification and Investment Drivers

The drivers by investment category from the historic period moving through the forecast period have been summarized in **Table 48** below.

Table 48. Investment Drivers by Category

Investment Category	Investment Drivers
System Access	• **Third Party Requirements** o Plant relocation or upgrade to an existing service • **Customer Connection Requests** o Request for new load or generation connection • **Mandated Service Obligations** o Regulatory requirement typically fromthe OEB's DSC

Investment Category	Investment Drivers
System Renewal	• **Assets at end of Service Life** o Risk of failure ▪ Asset at risk of failure o Failure ▪ Asset no longer meets functional and operational requirements o Substandard Performance ▪ Asset performs below technical and operational requirements
System Service	• **Capacity Constraints** o Need for additional system capacity at substations or distribution circuits to accommodate planned or realized load • **Reliability** o Need for system upgrade to mitigate/improve reliability performance in areas with high frequency and duration of power interruptions • **System Efficiency** o Need for improved system operability and efficiency
General Plant	• **System Support** o Requirement for fleet/vehicles to meet business needs • **Major Tools** o Requirement for major tools and equipment for business needs • **Information Technology** o Requirement for IT software, hardware and systems • **Grounds & Building** o Requirement for building infrastructure investments

3.5.1.4 Distributor's System Capability Assessment

Over the period 2016-2021, Enersource will be addressing several system constraints that were identified during the Regional Planning initiative and internal system planning work. Mississauga's Downtown Core is expected to expand substantially as part of an overall vision outlined by the City in the Downtown 21 Plan. As part of this plan, the Downtown Core will be the centre of new urban structure focused on growth to areas with existing service, proposed service and infrastructure capacity, particularly transit and community infrastructure. Detailed planning determined that the transformational capacity in the Downtown Core is expected to increase to approximately 300 MVA, which is beyond the current transformation capacity of 140 MVA. Enersource has been working closely with the City of Mississauga and developers proposing new commercial and residential towers in the Downtown Core to determine the timing and load requirement. As a result, Enersource is proposing to construct two new substations in the Downtown Core, as shown in **Figure 97**.

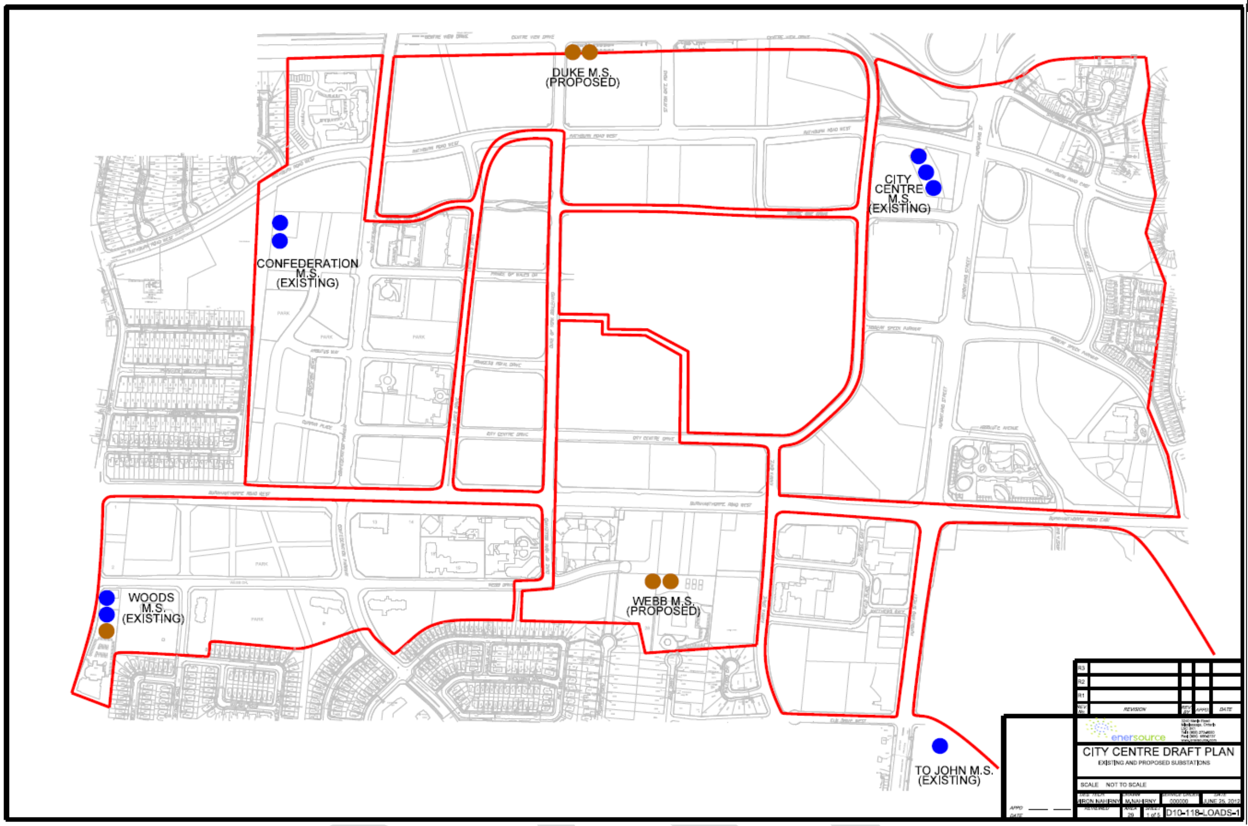


Figure 97. Proposed Locations for New Substations

The first substation, Webb MS, is planned for 2016-2017 period and will provide additional transformation capacity to meet the load requirements of new residential high-rise buildings planned in the Downtown Core. While the Webb MS substation will be designed and constructed for dual transformer setup, the substation will initially be equipped with only one high voltage transformer. The second transformer will be added at a later date, as the load from the new buildings in the southern part of the Downtown Core materializes.

The second substation, Duke MS, is planned for 2020-2021 and will provide additional transformation capacity to meet load requirements for new commercial buildings planned in the Square One area, north of Rathburn Road. Similar to Webb MS, Duke MS will be designed and constructed for dual transformer setup.

In addition, based on the system planning load forecast, the installation of a new substation is required in the area of Mavis, south of Highway 401 in order to provide additional capacity for the planned commercial/industrial development in the area. Moreover, during the Regional Planning effort with HONI and participating utilities, including Enersource, it was determined that Erindale TS T1/T2 is expected to be overloaded above the 10-day LTR during summer peak, and that over-capacity should be addressed through available transformation capacity existing adjacent to the limiting assets. Proposed Mini-Britannia MS is planned to be fed from the 44kV subtransmission system and will provide transformational capacity to feed 27.6kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on the 44kV system via Churchill Meadows TS.

3.5.2 Material Investments

This section describes Enersource's capital programs and projects that meet the materiality threshold of $750,000 in each of the four investment categories (System Access, System Renewal, System Service and General Plant) for the forecast years of 2016 through 2021.

3.5.2.1 System Access

System Access investments include modifications to Enersource's distribution system in order to provide a customer, both load and generation, with access to electricity services, as outlined in the OEB's DSC. **Table 49** details Enersource's expenditures by capital program within System Access from 2016 through 2021.

Table 49. System Access Expenditures by Capital Program (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
Road Projects	3,000	3,000	3,000	3,000	3,000	3,000
Light Rail Transit	400	8,400	8,650	8,750	7,800	1,200
New Subdivisions	800	800	800	800	800	800
Industrial & Commercial Services	2,600	2,600	2,600	2,600	2,600	2,600
Residential Service Upgrades	125	125	125	125	125	125
Smart Metering Large Commercial	1,506	-	-	-	-	-
Wholesale Metering	1,263	33	43	35	65	10
Metering Equipment	1,172	1,427	1,384	1,337	1,337	1,337
Smart Metering	-	-	-	-	-	-
Smart Metering in New Condos	1,387	1,407	1,426	1,446	1,446	1,446
Green Energy - FIT/MicroFIT	155	125	95	70	65	50
Total	**12,408**	**17,916**	**18,123**	**18,162**	**17,238**	**10,568**

3.5.2.1.1 Road Projects

The road projects initiative is in response to the OEB's DSC, Section 3.4. – Relocation of Plant that requires Enersource to address relocation of its assets upon certain third party requests.

Projects in this category involve the relocation of Enersource's distribution system assets to support road relocation and road reconstruction projects at the request of the Region of Peel, City of Mississauga, or the Ministry of Transportation. The initiation and timing for the execution of these projects is outside of Enersource's control and therefore the timing and value of this required investment is subject to change.

Enersource adheres to the *Public Service Works on Highways Act* and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of labour and labour saving devices.

To the fullest extent possible, Enersource coordinates its proposed distribution system projects with these stakeholders in order to maximize efficiencies and minimize disruptions to the public. Enersource holds regular planning discussions with these stakeholders and actively participates in Public Utilities Coordination Committee meetings in order to better identify the scope and number of road authority projects forecast in future years.

3.5.2.1.2 Light Rail Transit

In April 2015, the Province of Ontario made an announcement that the Hurontario LRT project is proceeding in support of the Moving Ontario Forward plan aimed at increasing transit ridership, reducing travel times, managing congestion, connecting people to jobs and improving the economy. Based on preliminary timelines provided by the Province, Enersource expects that construction work and thus, relocation of overhead assets, will be carried out from 2017 through 2020 period and anticipated completion in 2021. This aligns with the Province's proposed in-service date for the LRT in 2022.

3.5.2.1.3 New Subdivisions

This is an ongoing capital expenditure comprised of non-discretionary projects initiated by developers where investment is required to enable customers to connect to Enersource's distribution system. Enersource uses the economic evaluation methodology as prescribed by the DSC to determine the amount, if any, of capital contributions for each subdivision project. These investments are driven by subdivision developers and cannot be deferred. Expenditures related to new subdivision project costs are forecasted using a number of factors which include the following:

- Historical levels of activity and investment
- Known developments in the planning stages using the City's zoning information and permit applications
- City of Mississauga plans
- Review of economic factors.

Although these factors are used as a basis for capital expenditure forecasts, there is a high likelihood that actual expenditures will vary significantly because each of the above driving factors may vary considerably from underlying assumptions made during the capital planning phase. Enersource tracks proposed developments from information provided by the City's Planning and Building department and uses this information to estimate future loading requirements. The number of concept draft plans and rezoning applications are a good indication of capital expenditures required in future years. Subdivision development is primarily dependent on the local economy. Growth has been steady in this sector over the past few years with townhouses and high-rise condominium towers dominating the new construction, as the City transitions into a mature urban community through its emphasis on intensification and redevelopment, evident from the large number of high-rise building construction projects in the Downtown Core and northwest part of Mississauga.

The 2016 to 2021 investment requirements for new subdivisions, as provided above in **Table 49**, are aligned with the decreasing trend in availability of green space for building new subdivisions.

3.5.2.1.4 Industrial & Commercial Services

This is an ongoing capital expenditure comprised of non-discretionary projects initiated by customers or developers where investment is required to enable customers to connect to Enersource's distribution system. This program includes requests for new connection and upgrade of services for commercial and industrial customers. New condominium, industrial, commercial, and residential subdivision projects are initiated by developers and property owners.

Commercial development is largely influenced by the state of the local economy and commercial vacancy rates. The majority of commercial development work is occurring in the northwest corner of the City. Commercial growth has been slow but steady over the past few years.

Industrial and Commercial Services proposed investments from 2016 through 2021 are shown above in **Table 49**.

3.5.2.1.5 Smart Metering Large Commercial

The remaining class of customers with a significant number of mechanical meters is the large commercial/industrial greater than 50 kW. In May 2014, the OEB mandated utilities to replace mechanical meters with meters capable of providing hourly interval data for billing purposes using the existing Advanced Metering Infrastructure (AMI) communication capability to backhaul the usage data to their billing systems. The OEB directed that all replacements be completed by 2020.

Enersource created a separate business unit to track the costs of this project in a deferral account which will be disposed or cleared through a future rate hearing. Enersource intends on completing the replacement of the remaining 1,800 large mechanical meters by the end of 2016.

Smart Metering Large Commercial proposed investments from 2016 through 2021 are shown above in **Table 49**.

3.5.2.1.6 Wholesale Metering

All wholesale metering installations used for settlement in the Ontario electricity wholesale market must be registered with the IESO and conform to the specifications outlined in the IESO Market Rules.

Furthermore, each wholesale metering installation must also comply in accordance with Measurement Canada's (MC) rules and regulations. Specifically, all instrument transformers and meters must be approved by MC for use. If any of the instrument transformers are not approved by MC, the non-compliant units must be replaced or approved at the earliest seal expiry date.

All market participants are required to assume ownership of their wholesale meters from HONI per the Market Rules and ensure these meters are compliant with current IESO and MC standards. Enersource is responsible for the costs of installing and maintaining the metering installations. However, the Company must contract the services of an IESO-registered Metering Service Provider (MSP) who is authorized to register the wholesale meter installation for operation in the IESO wholesale electricity market. Furthermore, Enersource is required to contract HONI to perform certain aspects of the upgrade (i.e., construction, installation, and commissioning) since the transformer stations are HONI's property and related work must only be completed by HONI.

Failure to comply with the IESO Market Rules exposes Enersource to market sanctions, potential fines, and increased electrical losses applied against Enersource. As such, in 2015 Enersource plans to undertake wholesale metering upgrades at Tomken TS. While this transformer station has market compliant wholesale metering equipment, it is not in a closed enclosure and therefore, the station is not fully compliant with the wholesale market rules. Due to HONI's plan to replace the protection and control building at Tomken TS, Enersource has only one viable option which is to move to bus metering with a full upgrade on the 44kV bus. Enersource has previously completed such upgrades at other transformer stations.

As a part of the compliance requirements, Enersource is required to provide access to the metering equipment to the IESO auditor on an as-requested basis. The IESO-registered MSP and Enersource staff are required to be onsite in order to ensure compliance of installation and equipment to the IESO Market Rules.

As part of the wholesale metering maintenance program and the MC regulation, Enersource must ensure wholesale meters are changed prior to their seal expiry date. Over the next two years, the Company will be required to change up to 36 meters and will upgrade communication at these sites to an internet networking protocol (i.e. TCP/IP), greatly reducing communication issues encountered with wired telephone lines and ensure consistent and full data retrieval.

Wholesale Metering proposed investments from 2016 through 2021 are shown above in **Table 49**.

3.5.2.1.7 Metering Equipment

Metering involves measuring various aspects of power usage in order for utilities to understand usage trends and bill customers for electricity usage. New metering installations are required in order to support the growth of Enersource's customer base. Operation and maintenance of existing metering equipment is necessary in order to collect and provide automated meter reading data as the first stage of Enersource's meter to cash process. The reliability and accuracy of the metering equipment is paramount to Enersource's customer bills and directly impacts Enersource's revenue stream and financial risk.

The vast majority of the meters are now smart meters or meters that can be read remotely. Maintenance of existing metering installations and their communication components remains a critical function to ensure consistent and complete data for routine billing and to provide hourly data to the provincial Meter Data Management and Repository (MDM/R). Incorrect installation or setup and/or lack of maintenance could result in a metering failure resulting in incorrect customer billing, potential loss of revenue and damage to Enersource's reputation.

Enersource has several initiatives underway including:

- Large Commercial Mechanical meter replacements with MIST interval meters pursuant to OEB Decision EB-2013-0311 released May 21, 2014; Enersource plans to complete the conversion to smart metering for Large Commercial services by the end of 2016;
- Gatekeeper (Collector or Advanced Metering Regional Collectors (AMRC)) Replacement due to the addition of the mechanical meters; it is necessary to replace the existing gatekeepers to accommodate the additional data channels that must be collected in order to correctly bill for large commercial usage; Enersource plans to complete the replacement and removal of the existing gatekeepers by the end of 2016;
- Upgrading of existing metering equipment due to customer electrical service upgrades;
- Replacing obsolete or damaged meters;
- Replace related aging metering equipment (instrument transformers older than 45 years in 2016, older than 40 years in 2017);
- Conversion from 2.5 elements to three elements metering;
- New service installations (Residential and Commercial/Industrial);
- Primary Metering installations and upgrades;
- Installation of Individually Metered Suite (IMS) metering in condominium buildings, new build development and retrofitting of existing condominium buildings and rental apartment buildings; and
- Revenue metering reverification under MC guidelines for residential, small commercial and IMS metering.

Revenue metering is federally regulated under the *Electricity and Gas Inspection Act* (E&GIA), governed by MC. Under MC regulations, all revenue meters must be approved, routinely inspected and maintained. At periods specified by MC, the revenue meters must be removed from service and verified as performing accurately and within MC prescribed tolerances. Verification of the meter performance is completed by an MC-accredited meter verifier using certified equipment as required by the E&GIA.

Under MC regulations, retail customers require a revenue meter for measuring and billing electricity use. Enersource owns and operates approximately 197,000 retail revenue meters in the residential and small commercial classes, 4,500 in the large commercial/industrial classes and nine Large Users.

Historically, approximately 500 of these revenue meters are removed or replaced each year due to random failures, damage or functional obsolescence.

Included in this category is the replacement of mechanical meters for GS>50 kW customers, as described above.

In order to provide the hourly interval data mandated under the OEB initiative, as mentioned above, Enersource must replace all currently deployed gatekeeper meters with newer technology capable of collecting additional hourly interval information. The existing gatekeepers use older technology, that is not only incapable of supporting this requirement but is also extremely slow and causes communication issues. The proposed replacement gatekeepers will greatly improve communications and allow for the AMI application to utilize the outage notification (Call-in on Failure) functionality thereby improving outage management as a by-product of the replacement of the collectors. The upgraded gatekeepers are also capable of managing data from a larger number of smart meters. The total number of collectors to be deployed can be reduced while still maintaining the same backhaul coverage for the AMI systems. The new collectors are required for the daily collection of hourly interval data required to bill the large commercial customers as directed by the OEB.

Metering Equipment proposed investments from 2016 through 2021 are shown above in **Table 49**.

3.5.2.1.8 Smart Metering in New Condos

Smart metering in condominiums is part of the Government's plan to create a conservation culture in Ontario. The legislation provides condominium boards with the authority to have smart meters installed within their building.

In compliance with the DSC, Enersource provides individual metered suites (IMS) as an option for both new and existing condominium buildings. When requested by a master consumer, a distributor shall install unit smart meters that meet the specifications prescribed by Ontario Regulation 389/10. Smart metering also allows the building owner to individually meter suites within the building.

Historically, condominium buildings were bulk metered and received one bill for the entire building. This electricity bill was paid by the condominium corporation and included suites and common area electricity usage. Under this scenario, there was little incentive to reduce electricity use within the suites because usage costs were included uniformly in the condominium fee. Suite owners were not directly responsible for their own electricity bill which may have resulted in higher overall electricity usage. With the implementation of suite meters, suite owners are now given the opportunity to manage their own electricity use. Benefits of this program include, but are not limited to:

- Providing the most equitable way to accurately allocate electricity costs as suite owners pay only for what they use;
- Empowering suite owners with a tool to monitor and manage their own usage; and

- Promoting conservation by encouraging suite owners to participate in energy conservation programs to further reduce their electricity usage.

Similar to the residential and general service system, the smart metering system for new condominiums meets AMI functional specifications. The smart meter system for condominiums interfaces to the MDM/R and uploads daily consumption information for all the customers into the central system. The MDM/R receives the data, validates, estimates, and prepares the meter data for billing. The billing data is then sent by the MDM/R to Enersource for use in its CC&B system for customer billing.

Enersource is responsible for installing, supporting and developing, and implementing processes that are required to be put in place for a fully functional smart meter system, including:

- System procurement
- System installation
- Project management
- Deployment logistics
- Mobile workforce management
- Customer and community communications
- Process re-engineering
- Interface development to the MDM/R
- System testing
- Contract management
- Audit of system security
- Quality control.

In 2013, Enersource installed approximately 1,450 suite meters. The 2015 budget predicts a moderate increase (1,550) in the number of suite meters to be installed.

Enersource continues to expand its efforts in installing IMS, with over 11,500 units currently being metered. This technology is mainly used in condominiums, but is also applicable for use in metered rental units and apartment buildings through retrofitting. Enersource utilizes Power Line Carrier technology to allow the individual meters to communicate to a transponder which collects the usage data for the suites. This effectively allows the system to utilize the existing electrical wiring in the building as a communication medium thereby saving space and cost. Enersource uses a combination of wired phone lines, and where applicable, wireless communication protocols to contact the transponder/collector and download the data.

In January 2015, Enersource was approached by a rental apartment building to provide individual suite metering. This is Enersource's first such installation of IMS metering and it is expected to bring additional requests once the first building has been successfully converted.

Smart Metering in New Condominiums Proposed Investments from 2016 through 2021 are shown above in **Table 49**.

3.5.2.1.9 Green Energy – Renewable Generation, FIT/MicroFIT

Enacted in May, 2009, the Gre*en Energy Act* (GEA) was introduced to encourage renewable generation, energy conservation, and the creation of green jobs. A key GEA element to enable renewable generation is the IESO's Feed-in-Tariff (FIT) program.

The FIT program is divided into two streams: large projects above 10 kW and up to 500 kW follow the FIT process for connection; and smaller projects of 10 kW or less follow the microFIT process for connection. Typically, it is residential customers who apply for microFIT projects whereas business and large industrial customers apply for the FIT projects. The program rules, contracts, and prices are administered by the IESO.

Enersource has the responsibility to connect renewable generators in accordance with the IESO's FIT program rules, OEB codes, ESA requirements, and Enersource standards, as outlined in the Company's Conditions of Service.

Green Energy and FIT proposed investments from 2016 through 2021 are shown above in **Table 49**.

3.5.2.2 System Service

System Service investments include modifications to Enersource's distribution system in order to provide a customer, both load and generation, with access to electricity services, as outlined in the DSC.

System Service investments are modifications to Enersource's distribution system to ensure the distribution system continues to meet the Company's objectives while addressing anticipated future customer electricity service requirements.

The capital programs listed below ensure the continuation of Enersource's capability to provide a safe, secure and reliable supply of electricity to customers. Growth is predicted through the combined use of 1) growth projections; 2) historical growth patterns; and 3) load forecast models.

In 2013, approximately 13% of the power was delivered to large industrial and commercial customers, who account for less than 0.001% of the total number of Enersource customers. Individual large customers can add significant load to the system and provide unique challenges to connect and supply. Some customers may need to be connected in areas where there is insufficient capacity, necessitating construction of new feeders or substations to meet their specific needs.

Table 50 details Enersource's expenditures by Capital Program within System Service from 2016 through 2021.

Table 50. System Service Expenditures by Capital Program (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
Municipal Substation Construction & Upgrades	11,600	8,200	8,000	7,800	7,650	7,900
Subtransmission Expansion	2,400	2,650	2,400	2,400	2,400	2,400
Automation / SCADA Replacement and Enhancement Program	3,200	2,165	2,730	2,625	3,055	3,190
Total	**17,200**	**13,015**	**13,130**	**12,825**	**13,105**	**13,490**

3.5.2.2.1 Substation Construction & Upgrades

Enersource currently owns and operates 66 substations within its service territory. A substation transforms power from 44kV to 8/13.8kV or from 16/27.6kV to 2.4/4.16kV. Substations are capital intensive and are critical components of the electricity distribution system. Impact from a failure of a substation can be very significant due to the large number of affected customers. The outage duration of a substation failure is usually relatively long due to the amount of switching required to supply customers from other nearby substations.

There has been an increase in failure rates of the magnetic air circuit breakers (two failures in the past 12 months). Furthermore, there has been scarcity of spare parts combined with the possibility of arc chutes containing asbestos. Enersource plans to replace all switchgear units housing magnetic air circuit breakers with modern circuit breakers by 2023.

Substation site enhancement consists of small projects at different sites in order to preserve or improve the substation site condition. They include roof replacements, paving, small civil construction projects and adding gravel in the transformer yards. The Station RTU and protection relay replacement projects will coincide with the substation rebuild projects in order to minimize cost and system down time. Substation RTU and protection relay replacement projects will improve system reliability, minimize communication downtime, and improve cyber security. It will also be possible to remotely connect to the protection devices and monitor any service interruptions at the substations.

There are situations when, in order to promote standardization and to better serve Enersource customers, the substation layout configuration is modified and the transformers are replaced not because they have approached the end-of-life but because they would not fit in the new configuration. The replaced transformers become spare inventory units or are used to replace other units that are in worse condition~~s~~ and prone to failure.

Based on the substation renewal programs identified in Section 2.3.2.3.1, Enersource has programs to increase substation capacity in response to system load growth forecast. Substation renewal projects on the other hand, aim to rebuild/replace substation equipment that is at the end of service life as identified through inspection, maintenance, and asset condition analysis.

Municipal substation construction and upgrades proposed investments from 2016 through 2021 are shown above in **Table 50**.

3.5.2.2.1.1 New Construction

As outlined in Section 2.3.3 Expansion Programs, the following are proposed new substations to satisfy load growth in the service territory.

Mini – Orlando Substation (44kV – 27.6kV)

Based on the system planning load forecast, a new substation is required in the area of Mavis, south of Highway 401. It is a growth driven investment in order to provide additional capacity for the planned commercial/industrial development in the area.

The new substation will add 40 MVA of capacity by the end of 2016 and the project scope includes the following work:

- 2015
  - Acquisition of one 20 MVA on-load power transformer
  - Acquisition of one high voltage 46 kV switchgear
  - Acquisition of one low voltage 35 kV solid dielectric switchgear (operated at 27.6 kV)
- 2016
  - Acquisition of one 20 MVA on-load power transformer
  - Acquisition of one high voltage 46 kV switchgear
  - Acquisition of one low voltage 35 kV solid dielectric switchgear (operated at 27.6 kV).

At completion, the substation will house two power transformers, two high voltage switchgears and two low voltage switchgears, which will deliver power via four 27.6 kV feeders.

Webb MS (44kV-13.8kV)

Based on system planning load forecast a new substation is required in Mississauga's Downtown Core. It is a growth driven investment needed in order to provide additional capacity for the planned residential, commercial, and transit infrastructure development in the area.

This project consists of adding 20 MVA of capacity by the end of 2017. The project scope includes the following work:

- Completion of the municipal substation building (2016)
- Order placed on the following major substation equipment 2016)
    - HV switchgear
    - LV switchgear

- Power Transformer

- Installation and commissioning of the above equipment (2017).

At completion, the substation will house one 20 MVA power transformer, one high voltage switchgear and two low voltage switchgear units which will deliver power via eight 13.8 kV feeders. The substation will have provision to add an additional 20 MVA of future capacity at completion of load growth projection.

Duke MS (44kV-13.8kV)

Based on system planning loading forecast and a new substation is required in Mississauga's Downtown Core. It is a growth driven investment needed in order to provide additional capacity for the planned residential/commercial and transit infrastructure development in the area.

This project consists of adding 20 MVA of capacity by the end of 2021. The project scope for 2020 includes the following:

- Completion of the municipal substation building
- Placing on order the following major substation equipment
  - HV switchgear
  - LV switchgear
  - Power transformer.

Upon completion in 2021, the substation will house one 20 MVA power transformer, one high voltage switchgear and two low voltage switchgear units which will deliver power via eight 13.8 kV feeders. The substation will have provision to add an additional 20 MVA of future capacity at completion of load growth projection.

Mini - Britannia Substation (44kV – 27.6kV)

Based on the system planning load forecast, a new substation is required to be installed in the Britannia – Credit View area. It is a capacity driven investment. During the Regional Planning effort with HONI and participating utilities, including Enersource, it was determined that Erindale TS T1/T2 is expected to be overloaded above 10-day LTR during summer peaks. The peak load at Erindale TS T1/T2 has reached the capacity, and is expected to exceed it by as much as 40 MW by 2023. In addition, as outlined in Section 1.2., it was concluded that the capacity needs to Erindale TS T1/T2 should be addressed through available transformation capacity existing adjacent to the limiting assets.

The proposed Mini-Britannia MS is planned to be supplied from Churchill Meadows TS (44kV system) and provide additional capacity to feed the 27.6kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on the 44kV system via Churchill Meadows TS.

The new station will add 40 MVA of capacity by the end of 2019 and the project scope includes the following work:

- 2018
  - Acquisition of one 20 MVA on-load power transformer
  - Acquisition of one high voltage 46 kV switchgear
    - Place on order for a pre-engineered electrical house (E-House) which comes complete with a low voltage 38kV metal clad switchgear line-up (to be operated at 27.6 kV)
  - 2019
    - Acquisition of one 20 MVA on-load power transformer
    - Acquisition of one high voltage 46 kV switchgear
    - Delivery of the electrical house (E-House) housing the 38 kV arc resistant metal clad switchgear
    - Installation and commissioning of the substation components.

At completion, the substation will house two power transformers, two high voltage switchgears and two low voltage switchgear units that will deliver power via four 27.6kV feeders.

3.5.2.2.1.2 Substation Rebuild

Enersource proactively replaces substation equipment before a major failure occurs which could negatively impact customers, system reliability, and the Company's reputation.

Enersource's proactive replacement strategy considers the health index, location, number of customers served, transformer protection enhancement opportunity, and the condition of other substation assets, including buildings and grounds. The component replacement program addresses individual assets such as switchgears, circuit breakers, protection relays, transformers, enclosures, tap changers, batteries, and battery chargers that have reached end-of-life and can no longer fulfill their intended function.

The list of substation rebuild projects is listed below in **Table 51**. The detailed description and drivers for each rebuild investment is outlined in the LTIP.

Table 51. Substation Equipment Replacement by Year.

Replacement year	Station	TX1	TX2	LVSG1	LVSG2	HVSG1	HVSG2
2016	Cawthra MS	✓				✓	
	Orr MS	✓		✓		✓	
	Rifle Range MS	✓	✓	✓	✓	✓	✓
2017	Avonhead MS			✓			
	Parkland MS	✓		✓		✓	
	Pinetree MS			✓			
	Stavebank MS	✓		✓		✓	
	Summerville MS				✓		

Replacement year	Station	TX1	TX2	LVSG1	LVSG2	HVSG1	HVSG2
2018	Bloor MS			✓			
	City Centre North MS			✓	✓		
	Hensall MS		✓				✓
	Western MS			✓			
	York MS	✓		✓		✓	
2019	City Centre South MS			✓			
	Park Royal MS		✓				✓
	Rockwood MS	✓		✓	✓	✓	
	Shawson MS			✓			
2020	Hamilton MS			✓			
	John MS			✓			
	Meadowvale MS			✓			
	Western MS	✓				✓	
	Woodlands MS			✓	✓		
2021	Battleford MS			✓			
	Munden MS	✓		✓		✓	
	Rogers MS			✓	✓		
	Shawanaga MS	✓					
	Summerville MS	✓				✓	

Note: TX stands for transformer, LVSG – low voltage switchgear, HVSG – high voltage switchgear.

Substation rebuild program proposed investments from 2016 through 2021 are shown above in **Table 50**.

3.5.2.2.1.3 Automation / SCADA Replacement and Enhancement Program

Enersource's automation enhancement program will ensure continued safe and efficient operation of the electrical grid.

As much as possible, these automation enhancement projects are planned to coincide with the substation upgrade projects which minimizes cost and system down time. The following programs are planned over the next five years:

- S4T4 replacement to MPLS (Multiprotocol Label Switching)
- Battery and battery charger replacement
- Overhead automated switches
- Underground automated switches.

S4T4 Replacement to MPLS

The S4T4 conversion to MPLS program will continue for the next five years. To minimize cost and system down time, this replacement program will coincide with the substation rebuild projects. Any newly constructed substations will be equipped with MPLS communication. The station RTU and protection relay replacement projects complete with MPLS communication will improve system reliability, minimize communication downtime, and improve cyber security. It will also be possible to remotely connect to the protection devices as well as monitor any communication interruptions to the substation.

Battery and battery charger replacement

Station battery and charger replacement projects will coincide with the substation rebuild projects. The Substation rebuild provides the opportunity to replace the existing charger and batteries without requiring additional system outages. Under this program, new battery and battery chargers will be installed in the proposed new substations.

Overhead & Underground Automated Switches

In 2014, a comprehensive system automation study was conducted in order to prioritize each substation in terms of its potential impact and importance to the overall system. Factors such as historical reliability (momentary and sustained outages), customers affected, and existing automation were considered in the study. As a result of the study a number of switches were targeted as ideal candidates for automation upgrade projects.

The detailed list of automation/SCADA replacement and enhancement projects included in the DSP is outlined in the LTIP. Automation/SCADA replacement and enhancement program proposed investments from 2016 through 2021 are shown above in **Table 50**.

3.5.2.3 System Renewal

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of Enersource's distribution system to provide customers with electricity services.

Maintaining reliability is one of the key success factors of Enersource and helps reduce operational risks. To maintain reliability Enersource actively tracks outage cause and effect. Based on this information Enersource has ongoing renewal, upgrade, and replacement programs.

Enersource currently evaluates and prioritizes its renewal programs and projects against the significant business values described under Section 2.1 and again are listed below:

- Regulatory/Public Policy Responsiveness
- Operational Effectiveness/Safety
- Customer Focus
- Financial Performance

Table 52 below details Enersource's expenditures by capital program within System Renewal from 2016 through 2021.

Table 52. System Renewal Expenditures by Capital Program (2016-2021) ($000's)

Description	2016	2017	2018	2019	2020	2021
Subdivision Renewal Program	13,250	15,750	16,800	18,000	18,000	18,000
Overhead Distribution Renewal and Sustainment	6,090	6,360	6,270	6,810	6,450	7,620
Subtransmission Renewal	4,200	3,000	2,850	3,150	3,300	4,050
Transformer Replacement	7,125	7,313	7,500	7,500	6,000	4,000
Underground Distribution Renewal and Sustainment	3,750	4,500	4,500	4,500	4,500	4,500
Emergency Replacement Program	320	320	320	320	320	320
Total	**34,735**	**37,243**	**38,240**	**40,280**	**38,570**	**38,490**

3.5.2.3.1 Subdivision Renewal Program

Programs and projects included within this section deal with the replacement of underground cables and components that have reached their expected end-of-life and have been determined to create unacceptable operational risks.

The actual locations of the yearly rebuild projects are prioritized by using three years' worth of operational data, ranked by age and number and type of customers involved. Once the rebuild locations are selected, the projects are included in the following year's capital renewal plans, budgeted for, and designed. To optimize work efficiencies, renewal projects typically involve the replacement of the complete underground system including cables, transformers, switchgear, and other system components that are also near the end of their useful life.

Below are the factors used to determine the areas that need to be rebuilt:

- Reliability – based on the worst feeder methodology
- Transformers that are leaking oil
- Transformers that contain PCB
- Health Index of the cables and transformers
- Frequency of cable failures
- Age of the cables and transformers that are located in rear lots.

Moreover, a detailed map, as shown in **Figure 98,** allows Enersource to determine areas that qualify for underground renewal projects. This ensures replacement of transformers that have reached end-of-life or are found to be leaking and thus pose a safety and environmental risk and/or have exhibited reliability issues. The detailed list of subdivision renewal projects included in the DSP is outlined in the LTIP.

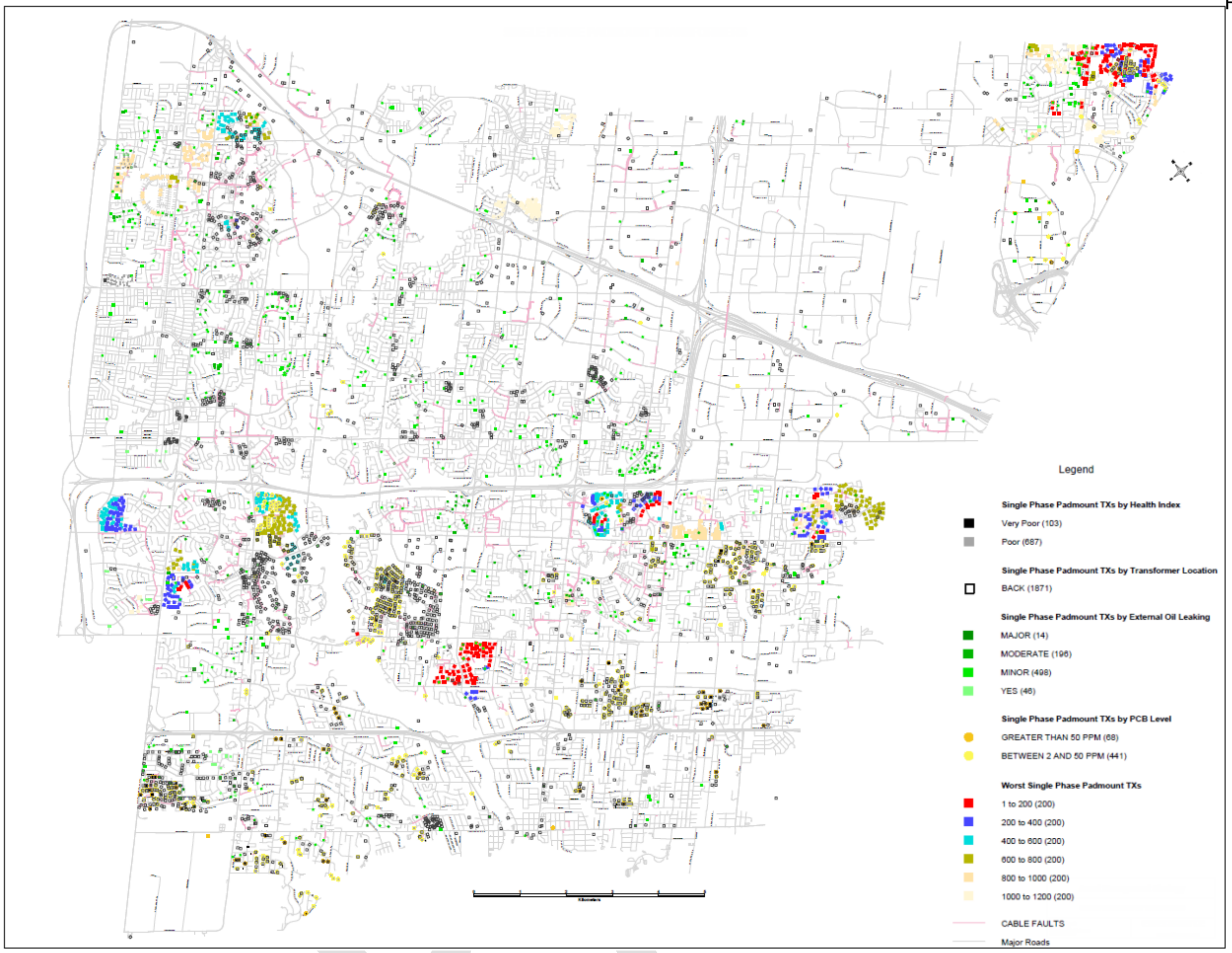


Figure 98. Enersource Underground Reliability Performance (2012-2014)

Subdivision renewal program proposed investments from 2016 through 2021 are shown above in **Table 52**.

3.5.2.3.2 Overhead Distribution Renewal and Sustainment

Program and projects under this section deal with the replacement of overhead pole lines and attachments that have reached their expected end-of-life or have been determined to be a potential employee or public safety concern.

Overhead assessments are made regarding investment proposals and which investments have the greatest impact on the business values. Assuming there were no constraints, all overhead investments with a positive impact would be approved. Due to resource constraints such as funding, internal and external labour availability, and other considerations inlcuding impact on customers, stakeholders and the environment, programs and projects are selected and prioritized based on supplemental quantitative and qualitative analysis.

Overhead recommendations are made on the timing of system asset additions, replacements and disposals, taking into consideration factors mainly around operational requirements, labour constraints, asset condition, age, criticality, reliability information, new capacity or regulatory requirements, as well as environmental and other stakeholder impacts.

Enersource's overhead System Renewal projects are then selected, designed, and constructed with employee and public safety in mind. The operational risks associated with overhead also plays an important role in determining which projects are undertaken. Since overhead distribution systems are more susceptible to the impact of weather and external forces, the impact of asset failures on Enersource's business values may be substantial.

The detailed list of overhead distribution renewal and sustainment projects included in the DSP is outlined in the LTIP. Overhead distribution renewal and sustainment proposed investments from 2016 through 2021 are shown above in **Table 52**.

3.5.2.3.3 Subtransmission Renewal

Overhead subtransmission pole line renewal projects are required to replace overhead subtransmission infrastructure to ensure it is kept at a safe and acceptable performance level.

The overhead subtransmission system consists of the main feeders that run throughout the City typically on the main arterial roadways and rights-of-way. They are the main backbone of the City's electricity supply, and failure of any main feeder would likely result in a major safety risk and major reliability issue.

The main components of the overhead system are poles, pole top transformers, switches, conductors and associated overhead hardware such as insulators, fuses and lightning arresters. Pole lines deteriorate over time and their strength may be reduced which introduces a risk of failure, especially under adverse weather conditions.

Overhead assessments are made to determine which investments have the greatest impact on the business values. These include safety, environmental, regulatory, reliability, reputational, and financial. Assuming there were no constraints, all overhead investments with a positive impact on the business values would be approved. Due to resource constraints such as appropriate funding, internal and external labour availability, projects are selected and prioritized based on the assessments.

Enersource completed a full inspection of its system in 2014/2015. The inspection data is then used to identify the overhead assets that need to be addressed as well as their relative priority in relation to the business values. The hierarchy of criteria that was used to prioritize the projects is as follows:

- Poles in 'poor' or 'fair' condition: These represent the greatest safety risk to the public and Enersource workers working on or near the poles. For a subtransmission line, both 'poor' and 'fair' pole conditions are of concern due to the higher level of safety risk associated with the taller poles and more circuits located on main roadways. The fact that they consist of taller poles with more circuits also makes them subject to higher level of forces that can cause failure would likely result in a major reliability issue. This is in contrast to distribution lines where the focus is primarily on 'poor' pole conditions;

- PCB transformers at less than 50 ppm PCBs, greater than 2 pmm PCBs: transformers containing PCBs pose a major safety risk (carcinogen), environmental risk, regulatory risk (Ministry of Environment directive), financial risk (spill remediation), and reputational risk. Note that the category of transformers greater than 50 ppm are not considered, as Enersource is on track to have all such transformers removed by the end of 2015;

- 'Major Leak' transformers: non-PCB transformers that have been identified as having a major oil leak. These pose an environmental risk (environmental damage), financial risk (spill remediation), and reputational risk;

- Top nine large customers and hospitals: large customers and hospitals pose increased reliability risk as outages can impact their businesses and operations with the potential to cause significant financial/critical losses for customers and major reputational damage to Enersource; and

- Majority of poles greater than 35 years old: areas where the majority of poles are older than 50 years are considered because the financial impact of asset write-downs is minimized.

Based on this assessment, the list of projects for overhead subtransmission renewal is determined and projects are then designed and constructed to meet all relevant safety and regulatory requirements.

The detailed list of projects included in the DSP is outlined in the LTIP. Subtransmission renewal proposed investments from 2016 through 2021 are shown above in **Table 52**.

3.5.2.3.4 Transformer Replacement

Distribution transformers are one of the key components of the power system. Their purpose is to lower the primary voltage to secondary voltage levels acceptable to residential, industrial, or commercial customers.

Typically transformer failures are random events that occur for various reasons, most common being insulation breakdown. Lightning-induced failures typically result from turn-to-turn winding failures at or near the end turns of the windings. Lightning surges are random and may be decreased by the installation of lightning arrestors on the distribution system. Deterioration of insulation is also a function of time and temperature. Transformer temperature, in turn, is related to loading. The thermal stress leads to the aging and decomposition of both the oil and cellulose used as an insulating material inside the transformer. Once the insulation fails, the transformer windings are short circuited. Because it is uneconomical to try to repair or refurbish a distribution transformer, such equipment that fails in the field is automatically replaced by a new unit.

Some of the older single-phase pad mount transformers are rusted, especially those installed near roads or sidewalks due to salt application in winter time. This will negatively impact on the transformer and affect performance and operation. The transformer will either rust at the back near the tank, eventually causing the cooling oil to leak out, or rust at the cable compartment. The rusted cable compartment may pose a potential public hazard since it may leave exposed energized parts. As a result, these transformers are replaced immediately.

Every year a number of transformers fail which results in outages to customers. Sometimes transformers are found to be damaged by vehicle contact or are leaking oil and require changing before they fail. A transformer failure in a residential area may only affect 10 to 12 customers so outage effects are minimal. However a transformer failure in an industrial/commercial area could prove costly to those businesses.

In addition, as shown below in **Table 53** the overall transformer inspection program has identified the number of transformers that will need to be replaced. Moreover, field inspections have confirmed that 65 units with PCB concentrations greater than 2 ppm are currently leaking in the field and require immediate replacement. In addition, 1,892 transformer units with no PCB are found to be leaking in the field and will need replacement as well.

Table 53. Transformers Showing Signs of Leakage and Containing PCB

Transformer Type	PCB Leaker	PCB Non-Leaker (>2ppm)	Non-PCB Leaker
Single-Phase Pad Mount	3	474	682
Three-Phase Pad Mount	4	23	63
Vault Transformers	42	197	790
Pole Mount Transformers	16	290	357
Total	65	984	1,892

Transformers are essential elements of the electricity distribution system and when they fail or become unsafe, they must be immediately replaced, as is the equipment attached to it, such as elbows, inserts, fault indicators, or arrestors.

Transformer Replacement - Underground

The program is needed to allow for the planned and unplanned replacement of underground transformers that are in poor condition or fail in various parts of the city. Transformers are replaced when a failure occurs, or are identified as damaged or rusting beyond safe limits.

There are over 15,000 underground transformers on the system. Enersource staff routinely assess transformer condition through work such as switching, and when responding to trouble calls or outages.

As a result of the ACA and the routine asset inspection program, which includes transformers on a three-year inspection frequency, a number of transformers have been identified for replacement due to the transformer condition and/or the presence of PCBs.

As shown below in **Table 53**, the underground transformer inspection program has identified number of transformers that need to be replaced.

These leaking and/or rusted transformers must be replaced since they do not meet safety standards and may result in environmental damage, remediation costs and potential regulatory penalties as a result of a future leak. These units have been included in the six year transformer replacement plan.

Single Phase Pad Mount Transformer Replacement

Enersource's asset inspection program includes the inspection of single phase pad mount transformers and identified 691 which show signs of leaking, of which three units have a PCB concentration above 2 ppm. These transformers should be changed to prevent environmental damage, remediation costs, and potential regulatory penalties as a result of a current or future leak. Many of these units are in residential areas including in backyards or boulevards and are visible to the public. These units have been included in the six-year transformer replacement plan.

Three Phase Pad Mount Transformer Replacement

Enersource recognizes that transformers have been identified as a concern in the ACA and that the future replacement rate should be increased.

Enersource's asset inspection program has identified 67 three-phase pad mount transformers which are leaking, of which four units have a PCB concentration above 2 ppm. These transformers should be changed to prevent environmental damage, remediation costs and potential regulatory penalties as a result of a current or future leak. These units have been included in the five-year transformer replacement plan.

Vault Transformer Replacement

Enersource's asset inspection program has identified 832 vaults which show signs of leakage, of which 42 units contain oil with PCB levels above 2 ppm. These units need to be replaced to ensure reliable service and to prevent environmental damage, remediation costs, and potential regulatory penalties as a result of a future leak. These units have been included in the five-year transformer replacement plan.

Transformer Replacement - Overhead

Transformer condition is routinely assessed by performing work such as switching, responding to trouble calls or outages. The outside crews advise the Control Room of transformers that are in poor condition typically leaking oil.

Enersource will be inspecting transformers on a rolling three-year basis and will be proactively changing transformers in poor condition or leaking oil.

Through ongoing inspection, many overhead transformers are visited up-close, with those requiring immediate attention being changed out. Some transformers were identified for future replacement based on the severity of the issues.

As a result of the routine asset inspection program, which includes transformers on a three-year inspection frequency, a number of transformers have been identified for replacement as a result of the transformer condition or based on the PCB concentration of the oil contained within. As shown above in **Table 53**, the overhead transformer inspection program has identified number of transformers that need to be replaced.

The inspection program has identified a total of 357 non-PCB leakers and 16 units leaking with PCB concentrations greater than 2 ppm. These units should be changed to prevent environmental damage, remediation costs, and potential regulatory penalties as a result of a future leak.

Underground Distribution Renewal and Sustainment

This section has four program sub-components:

- Pad Mounted Switchgear Renewal
- Primary Distribution Equipment Renewal
- Underground Cable and Splice Renewal
- Secondary Cable Renewal.

Pad Mounted Switchgear Renewal Program

The electricity distribution system consists of several important components to deliver electricity to customers. Enersource uses pad mounted switchgear as an integral component on the underground primary distribution system. These switchgear units serve as an electricity distribution location as well as a switching point. There are approximately 852 switchgear units in the distribution system of which 8% are motorized and monitored via SCADA.

Air insulated switchgear have increasingly been experiencing failures due to age, design configurations, and application voltage levels. This results in power quality, reliability and maintenance issues. These types of faults may expose customers to multiple power interruptions and may take days to troubleshoot and locate the problem. As Enersource's system ages, this type of failure has become even more prevalent.

Several different options were explored to mitigate the deteriorating performance of air insulated switching units. Enersource has selected solid dielectric technology for the pad mounted switchgear replacement program. These units have a projected life span of 50 years and will enhance reliability performance as compared to air insulated switchgear.

In 2009, two pilot projects were approved and implemented in order to evaluate the Solid Dielectric (SD) products. Four automated units from two different companies were installed in the 13.8kV distribution system at Credit Valley MS. Following the evaluation of these units, Enersource started replacing the end-of-life air insulated pad-mounted switchgear with SD switchgear in 2011.

In March, 2013 Enersource experienced a failure on one of the SD switchgear units installed on the 16/27.6kV system. The failed unit was returned to the manufacturer for analysis and Kinectrics was hired as a third party consultant to jointly conduct the failure review. The root cause analysis included a review of the manufacturing process and in-depth examination of the failed components. After the review, Enersource determined that it would only install 35kV switchgear on the 16/27.6kV distribution system to ensure the units were capable of handling the associated electrical loads and voltage fluctuations.

Primary Distribution Equipment Renewal Program

In addition to the main underground system components such as transformers, switchgears, and cables, the underground distribution system also consists of smaller, auxiliary components such as elbows, inserts, lightning arresters, fault indicators, etc. Without these auxiliary accessories, the main components of the system can become inoperable; therefore, replacement of this equipment before failure is necessary.

Some of the auxiliary system components, such as elbows and inserts, are used to perform switching operations, isolations and restoration. Therefore their condition directly influences system reliability as well as the safe operation of equipment.

The useful life for elbows and inserts, which are used in the operation of transformers, varies significantly. Based on past experience, elbows are typically found to be in poor condition after 20 to 25 years, and need changing along with their inserts.

Other auxiliary devices, such as fault indicators, are used when troubleshooting a system outage. Their proper operation influences restoration time and, in turn, overall system reliability. Enersource has found through past experience that 20 years for transformer fault indicators is a typical useful life.

In addition, equipment condition is routinely assessed by operations personnel performing work on a transformer or switchgear, such as switching or other asset replacement. If a defective component is found, the crew notifies the Control Room and if the crew on site cannot make the necessary repairs then a maintenance crew is dispatched to perform necessary repairs.

Underground Cable and Splice Renewal Program

Underground primary cables are another key component of the distribution power system. They are one of the most expensive components to replace, due to the high costs of both materials and installation.

Typically, underground cable failures are caused by degradation of the insulation, the dielectric medium that insulates the central conductor from the grounded concentric neutral wires. Insulation failure can be caused by several factors, for example:

- Contaminated materials during the manufacturing stage
- Poor adhesion of the extruded insulation shield
- Imperfections at the conductor shield-insulation interface
- Water inside the conductor strands or at the concentric neutral wires
- Fault currents
- Voltage surges from lightning and switching.

The impact on customers depends on whether the cable is a subtransmission cable, main feeder distribution cable, or local distribution feeder cable. The subtransmission cables typically supply an MS; therefore, a failure of a cable supplying a single station may result in a disruption of power for up to 5,000 customers.

The local distribution feeder cable is connected to a pad mounted switchgear or the overhead distribution system and typically will supply up to 500 customers. Cable failure will result in a power outage to all customers connected and typically will momentarily trip the substation breaker as the fuse isolates the fault affecting on average up to 1,000 customers.

In addition to cable spot replacement, this program also incorporates heat shrink splice replacement. In the past, several thousand heat shrink cable splices were installed on the system. Later, it was discovered that a vast majority of them failed prematurely. As a result, Enersource took a proactive approach and decided to replace all known heat shrink splices with new cold shrink splices that perform considerably better. Cable and splice failures remain the largest contributor to customer outage time.

Secondary Cable Renewal Program

The distribution system has over 203,000 customers, the majority of which are connected to a distribution transformer via an underground secondary service cable. Based on past experience, secondary cables are less prone to failure compared to primary cables of the same age, which is mainly due to less electrical stress and fewer fault current spikes. However, when secondary cables fail, they need to be immediately repaired, as they are needed to supply customers with power. Every year a number of underground residential and industrial/commercial services fail beyond reasonable repair and require complete replacement. These failures typically result in outages to single residential or industrial/commercial businesses.

This renewal program does not target any specific area, but rather underground secondary cables, over various parts of the City that have been determined to be at the end of their useful lives. They are replaced individually. Under this program, rather than replacing secondary cables based on age or size, they are replaced based on their condition and number of failures. This program entails the spot replacement of secondary services, over various parts of the City that are at the end-of-life and are beyond reasonable repair.

Underground distribution renewal and sustainment program proposed investments from 2016 through 2021 are shown above in **Table 52**.

3.5.2.4 General Plant

General plant investments are modifications, replacements or additions to Enersource's assets that are not part of its distribution system. These include land and buildings, tools and equipment, rolling stock and electronics devices and software used to support day to day business and operations activities.

This section has eight components:

- Engineering and Asset Systems
- Rolling Stock
- Information Technology
- JDE/ERP System
- Meter to Cash
- Grounds and Buildings
- Major Tools.

Table 54 details Enersource's expenditures by Capital Program within General Plant from 2016 through 2021

Table 54. General Plant Expenditures by Capital Program (2016-2021)

Description	2016	2017	2018	2019	2020	2021
Engineering & Asset Systems	1,510	1,187	1,391	1,228	1,345	1,293
Rolling Stock	2,775	2,244	2,033	3,011	2,298	1,946
Information Technology	671	456	572	1,040	870	560
JDE / ERP System	2,185	2,000	1,180	1,320	1,637	1,410
Meter to Cash	2,470	2,055	2,180	1,420	1,830	2,000
Grounds & Buildings	2,985	3,195	2,725	2,575	2,575	2,575
Major Tools	200	200	200	200	200	200
Total	**12,796**	**11,337**	**10,281**	**10,794**	**10,755**	**9,984**

Engineering and Asset Systems

The Engineering and Asset Systems (E&AS) capital budget provides information technology tools to assist in the management of field assets. These tools include software and hardware for 170 people, including both office and field personnel. The budget assists Enersource in improving efficiency and reliability, reducing costs, and ensuring the safety of staff and the public.

To ensure that all computer hardware is current, it is replaced on a three or four year cycle, depending upon the life-span of the equipment. Workstations (high-end PCs used for running engineering applications), monitors, servers and field computers are replaced on an appropriate schedule to ensure that the equipment complies with current standards. Plotters, or wide-format printers for the output of drawings and maps, have a five to eight year life cycle.

If additional licenses of engineering software applications are required so that information and analysis capability can be made available to more of Enersource's internal and field personnel, the E&AS budget is utilized. Software upgrades for any of the engineering systems are funded through this budget.

The largest two software systems include the IOM and AM/FM systems. Any projects related to these two systems are funded through the E&AS capital budget.

SmartPlant Foundation (SPF) is the document management system for the engineering records, providing document security based on the user, the access type requested, and the document class. The system houses revisions, approved, and as-constructed drawings, easements and permits. It also issues location numbers for switches and transformers. There are dozens of workflows used to manage business processes and the system is integrated to both AM/FM and JDE.

Engineering and Asset Systems proposed investments from 2016 through 2021 are shown above in **Table 54**.

Rolling Stock

Enersource requires a fleet of specialized vehicles to complete many daily activities, including the construction and maintenance of the electricity distribution system, and to allow for quick restoration of power due to electricity distribution system disturbances. Degradation of fleet assets could jeopardize worker safety and negatively affect electricity distribution system performance and response to outages.

Rolling stock proposed investments from 2016 through 2021 are shown above in **Table 54**.

Information Technology

The IT infrastructure group provides and maintains the foundation on top of which the applications of the business operate. The team provides:

- Support and maintenance of the corporate network (which includes data, email, voice services, and web environments) and to provide a highly reliable and available environment;
- Security of the IT infrastructure, resources access, assets and data protection and availability;
- Availability of all servers supporting the many business critical applications used throughout the Company and provides service and support of these systems as required;
- Support to the end user community on all IT systems, applications and peripherals, as well as voice services related issues;
- Management of the corporate telecommunications infrastructure which includes telephone system, wireless devices platform, and the Call Centre voice queuing system; and

- Assistance in the implementation of new capital and operating projects by providing consulting, planning and implementation expertise in the commissioning of new applications and processes.

Information Technology proposed investments from 2016 through 2021 are shown above in **Table 54**.

JDE/ERP System

As stated earlier, Enersource uses Oracle J.D. Edwards (JDE) as its Enterprise Resource Planning (ERP) tool. It is a modular, scalable, and integrated information management software system that facilitates the flow of information across the different divisions at Enersource.

JDE and its auxiliary applications automate business processes:

- Finance – General Ledger, Accounts Payable, Accounts Receivable, Fixed Assets
- Operations – Service Orders (program/project cost)
- Supply Chain – Inventory/Warehouse Management, Procurement
- Human Resources – Employee Management.

JDE also interfaces with other major applications within Enersource such as AM/FM/GIS and the Customer Care and Billing (CC&B) system to ensure data integrity and simplification of business processes.

In addition to JDE, the department is also responsible for the other enterprise applications that extend across other IT departments and are used by multiple business units. This includes:

- Business Intelligence systems (e.g., IBM Cognos)
- REVEAL – used as a centralized reporting repository
- SharePoint – for the corporate Intranet and external Internet site.

JDE/ERP System proposed investments from 2016 through 2021 are shown above in **Table 54**.

Meter to Cash

The Meter to Cash team supports all meter to cash functions, providing on going day to day operations and maintenance, upgrades and implementation of new functionality (in accordance with business needs and regulatory requirements). The systems are comprised of all of those involved in the meter to cash process including Meter Reading, AMI systems, Meter Data Management, Wholesale and Retail Settlement, EBT transactions, MDM/R transactions, Billing, Cash, Collections, Business Intelligence and related field activity systems, including interfaces among these systems. Interfaces to JDE, CRM and AM/FM applications are also supported.

CC&B and the surrounding suite of applications address:

- Customer account management/premise management
- Cash and collections
- Customer contact tracking and management
- Metering/meter management
- Meter reading/estimating
- Rates engine
- Billing/bill creation
- Analyses and reporting.

Meter to Cash proposed investments from 2016 through 2021 are shown above in **Table 54**.

Grounds and Buildings

Capital expenditures are required to acquire and maintain Enersource workspaces and service facilities to acceptable standards. The existing facilities allow for flexible work areas and a safe work environment. Some key projects will see major upgrades in the following areas: HVAC, asphalt replacement, building envelope and windows.

Enersource building facilities are required to be reasonably current and in good working order. Based on regular assessments of building condition, all buildings require various investments to maintain them in a good state of repair, improve productivity within the work environment, accommodate growth and change in the workforce, and address identified health and safety risks. As described above, the three facilities are of various ages.

The areas of concern for Enersource facilities that require expenditures are:

- HVAC (Heating & air conditioning)
- Structural (Building envelope, walls and windows)
- Equipment (Furniture, Elevators)
- Mechanical & Electrical (i.e., Plumbing, Electrical components)
- Security (Access Control, CCTV, Building Automation System);
- Life Safety (Fire suppression, Sprinklers, Fire Alarm Panels)
- Exterior (i.e., pavement, fencing, landscaping).

Grounds and Buildings proposed investments from 2016 through 2021 are shown above in **Table 54**.

Please see section 2.3.5 Facilities Remediation for more detail.

Major Tools

In order to maintain and operate an electrical system and operate a fleet of over 200 vehicles, investment in quality tools is paramount. Each truck is furnished with basic hand tools and equipment while specialized items are limited to specific trucks, (examples include: chainsaws on Forestry vehicles, cable cutters and crimpers on underground vehicles). Funding for tool expenditures of $7,500 or more per item is classified as a 'major tool' and requires additional internal approvals. This category of funds covers the purchase of such items as:

- Mud tracks – to allow vehicles to traverse over wet ground and/or over buried pipelines
- Ground leads - to allow for the safe operation of personnel and equipment on isolated electrical equipment
- Battery operated devices – to allow for repair of underground cable in splice pits and provide better ergonomics for staff
- Cable locating equipment – to find buried operational cables so that other utilities can perform their construction work without causing cable damage
- Fault finding equipment – to aid in locating underground cable faults requiring repair.

Major Tools proposed investments from 2016 through 2021 are shown above in **Table 54**.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 1:

Ref: Tab 2 – Manager's Summary

(T2/pp. 22-23)

As set in out in Table 5 the total gross capital budget in the four investment categories for 2015 is $76,688,724, which is approximately the same as the 2016 forecast of $76,738,831. It states that the increased forecasted capital expenditures for 2015 are not included in the rates approved by the Board in EB-2012-0033 and are not part of the incremental capital requested by Enersource in this application. If Enersource did not need to request an Incremental Capital Module (ICM) for 2015 where the forecasted capital budget is approximately the same as the 2016 forecast and $29M above the materiality threshold in both years (excluding the Hydro One TS payments) why is Enersource applying for an ICM in 2016?

Response:

Enersource relied on the information available at the time of its 2015 IRM application (June – July, 2014) in deciding whether to file for a 2015 ICM rate rider. At that time, the capital budget for 2015 was forecasted at approximately $67 million. The material increase in Enersource's 2015 actual and forecasted capital expenditures is due to an increase in customer connection requests as well as significant costs to replace leaking transformers which will continue in the near future.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 2:

Ref: Tab 2 – Manager's Summary

(T2/pp. 31-32)

Why is the Province of Ontario, in support of the Moving Ontario Forward Plan, not paying the capital dollars to carry out the work required to accommodate construction of the Hurontario LRT (relocation of overhead assets)?

Response:

In April 2015, the Province of Ontario announced that the LRT project is moving ahead in support of the Moving Ontario Forward plan aimed at increasing transit ridership, reducing travel times, managing congestion, connecting people to jobs, and improving the economy. Currently, the construction of the LRT is expected to start in approximately 2018 and the in-service date is expected to be in 2022. Consequently, Enersource has made provisions in its capital budgets under the system access investment category to ensure adequate funds are available to carry out the work required to accommodate construction of the LRT (e.g. relocation of overhead assets). The total net project costs are expected to be $23.0M, with gross costs of $35.2M offset by contributions from Metrolinx totaling $12.2M.

The following table outlines Enersource's proposed six year capital expenditure forecast. Based on the Metrolinx's proposed guidelines, Metrolinx will compensate the Utilities 100% for "like-for-like" relocations only. Due to the size of the project, age and condition of certain distribution assets along the proposed route, as well as expected increases in demand along the corridor, replacing "like-for-like" will not be possible. During 2016, Enersource is only forecasting capital expenditures on distribution design initiatives.

Draft LRT Budget 2016-2021

($000's)	2016	2017	2018	2019	2020	2021	Total
Design	400	400	250	250			1,300
Underground		4,000	4,400	4,500	4,300	700	17,900
Overhead		4,000	4,000	4,000	3,500	500	16,000
Subtotal	400	8,400	8,650	8,750	7,800	1,200	35,200
Contribution (Metrolinx)		(3,000)	(3,000)	(3,000)	(3,000)	(200)	(12,200)
Total	**400**	**5,400**	**5,650**	**5,750**	**4,800**	**1,000**	**23,000**

<u>Per DSC:</u>
3.4 Relocation of Plant
3.4.1 When requested to relocate distribution plant, a distributor shall exercise its rights and discharge its obligations in accordance with existing legislation such as the Public Service Works on Highways Act, regulations, formal agreements, easements and common law. In

the absence of existing arrangements, a distributor is not obligated to relocate the plant. However, the distributor shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner shall include a response to the requesting party that explains the feasibility or infeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.

Relocation projects are negotiated on a case by case basis to ensure a fair and reasonable charge based on cost recovery principles. Per the Public Services Works on Highways Act, the road authority and the operating corporation may agree upon the apportionment of the cost of labour employed in such taking up, removal or change, but, subject to section 3, in default of agreement such cost shall be apportioned equally between the road authority and the operating corporation, and all other costs of the work shall be borne by the operating corporation.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 3:

Ref: Tab 2 – Manager's Summary

(T2/pp. 42-44)

Please set out the distribution rate increases for residential customers arising out of this application (at 800 and 1000 kWh/month consumption levels). How much of that increase is related to the ICM?

Response:

The distribution rate increase (Sub-total B Distribution) for residential RPP customers at 800 kWh is 4.77%. Excluding the ICM rate rider of $1.03 for residential customers, the distribution rate increase would be 1.07%.

The distribution rate increase (Sub-total B Distribution) for residential RPP customers at 1000 kWh is 2.45%. Excluding the ICM rate rider of $1.03 for residential customers, the distribution rate decrease would be (0.83%).

INTERROGATORY 4

Ref: Tab 2 – Manager's Summary

(T2/p. 42)

The Council is interested in seeing the actual bill impacts that will be experienced by customers in 2016. Please provide a schedule setting out the bill impacts (at 800 and 1000 kWh/month consumption levels) including the elimination of the Debt Retirement Charge, the elimination of the Ontario Clean Energy Benefit, the implementation of the Ontario Electricity Support Program and the RPP change effective November 1, 2015

Response:

Table 1 below shows the total bill impact for residential customers consuming 800 kWh and 1000 kWh of electricity per month. The bill impacts presented include the impact of the elimination of the Debt Retirement Charge, the elimination of the Ontario Clean Energy Benefit, the implementation of the Ontario Electricity Support Program, the RPP change effective November 1, 2015 and the updated 2016 wholesale market service rate.

Table 1: Proposed 2016 Total Monthly Bill Impacts for Residential Customers at 800 kWh and 1000 kWh consumption levels

Customer Type	Monthly Consumption (kWh)	Current Total Monthly Charges ($)	Proposed Total Monthly Charges* ($)	Change ($)	Change (%)
Residential	800	138.37	149.20	10.83	7.82
Residential	1,000	169.34	181.46	12.12	7.16

Rate Class	**Residential RPP**
Loss Factor	**0.0360**
Consumption	**800** kWh
If Billed on a kW basis:	
Demand	kW

	Current Board-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.22	1	$ 13.22	$ 15.75	1	$ 15.75	$ 2.53	19.14%
Distribution Volumetric Rate	$ 0.0133	800	$ 10.64	$ 0.0102	800	$ 8.16	-$ 2.48	-23.31%
Rate Rider for Application of Tax Change	$ -	1	$ -	$ 0.01	1	$ 0.01	$ 0.01	
ICM Rate Rider (Fixed)	$ -	1	$ -	$ 1.03	1	$ 1.03	$ 1.03	
ICM Rate Rider (Variable)	$ -	800	$ -	$ -	800	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 23.86**			**$ 24.95**	**$ 1.09**	**4.57%**
Line Losses on Cost of Power	$ 0.1077	29	$ 3.10	$ 0.1077	29	$ 3.10	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	800	$ -	$ 0.0003	800	$ 0.24	$ 0.24	
Low Voltage Service Charge	$ 0.0002	800	$ 0.16	$ 0.0002	800	$ 0.16	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 27.91**			**$ 29.24**	**$ 1.33**	**4.77%**
RTSR - Network	$ 0.0081	800	$ 6.48	$ 0.0079	800	$ 6.32	-$ 0.16	-2.47%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0062	800	$ 4.96	$ 0.0064	800	$ 5.12	$ 0.16	3.23%
Sub-Total C - Delivery (including Sub-Total B)			**$ 39.35**			**$ 40.68**	**$ 1.33**	**3.38%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	829	$ 3.65	**$ 0.0036**	829	$ 2.98	-$ 0.66	-18.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	829	$ 1.08	$ 0.0013	829	$ 1.08	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	800	$ 5.60				-$ 5.60	-100.00%
Ontario Electricity Support Program (OESP)				**$ 0.0011**	**829**	**$ 0.91**	$ 0.91	
TOU - Off Peak	$ 0.0830	512	$ 42.50	$ 0.0830	512	$ 42.50	$ -	0.00%
TOU - Mid Peak	$ 0.1280	144	$ 18.43	$ 0.1280	144	$ 18.43	$ -	0.00%
TOU - On Peak	$ 0.1750	144	$ 25.20	$ 0.1750	144	$ 25.20	$ -	0.00%
Total Bill on TOU (before Taxes)			**$136.05**			**$132.03**	**-$ 4.02**	**-2.96%**
HST	13%		$ 17.69	13%		$ 17.16	-$ 0.52	-2.96%
Total Bill (including HST)			$153.74			$149.20	-$ 4.54	-2.96%
***Ontario Clean Energy Benefit* [1]**			-$ 15.37				$ 15.37	-100.00%
Total Bill on TOU (including OCEB)			**$138.37**			**$149.20**	**$ 10.83**	**7.82%**

Rate Class	**Residential RPP**
Loss Factor	**0.0360**
Consumption	**1,000** kWh
If Billed on a kW basis:	
Demand	kW

	Current Board-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 13.22	1	$ 13.22	$ 15.75	1	$ 15.75	$ 2.53	19.14%
Distribution Volumetric Rate	$ 0.0133	1,000	$ 13.30	$ 0.0102	1,000	$ 10.20	-$ 3.10	-23.31%
Rate Rider for Application of Tax Change	$ -	1	$ -	$ 0.01	1	$ 0.01	$ 0.01	
ICM Rate Rider (Fixed)	$ -	1	$ -	$ 1.03	1	$ 1.03	$ 1.03	
ICM Rate Rider (Variable)	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.52**			**$ 26.99**	**$ 0.47**	**1.77%**
Line Losses on Cost of Power	$ 0.1077	36	$ 3.88	$ 0.1077	36	$ 3.88	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	1,000	$ -	$ 0.0003	1,000	$ 0.30	$ 0.30	
Low Voltage Service Charge	$ 0.0002	1,000	$ 0.20	$ 0.0002	1,000	$ 0.20	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 31.39**			**$ 32.16**	**$ 0.77**	**2.45%**
RTSR - Network	$ 0.0081	1,000	$ 8.10	$ 0.0079	1,000	$ 7.90	-$ 0.20	-2.47%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0062	1,000	$ 6.20	$ 0.0064	1,000	$ 6.40	$ 0.20	3.23%
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.69**			**$ 46.46**	**$ 0.77**	**1.69%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	1,036	$ 4.56	**$ 0.0036**	1,036	$ 3.73	-$ 0.83	-18.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	1,036	$ 1.35	$ 0.0013	1,036	$ 1.35	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	1,000	$ 7.00				-$ 7.00	-100.00%
Ontario Electricity Support Program (OESP)				**$ 0.0011**	**1,036**	**$ 1.14**	$ 1.14	
TOU - Off Peak	$ 0.0830	640	$ 53.12	$ 0.0830	640	$ 53.12	$ -	0.00%
TOU - Mid Peak	$ 0.1280	180	$ 23.04	$ 0.1280	180	$ 23.04	$ -	0.00%
TOU - On Peak	$ 0.1750	180	$ 31.50	$ 0.1750	180	$ 31.50	$ -	0.00%
Total Bill on TOU (before Taxes)			**$166.50**			**$160.58**	**-$ 5.92**	**-3.56%**
HST	13%		$ 21.65	13%		$ 20.88	-$ 0.77	-3.56%
Total Bill (including HST)			$188.15			$181.46	-$ 6.69	-3.56%
Ontario Clean Energy Benefit [1]			-$ 18.81				$ 18.81	-100.00%
Total Bill on TOU (including OCEB)			**$169.34**			**$181.46**	**$ 12.12**	**7.16%**

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 5:

Ref: Supplementary Evidence – Filed October 2, 2015

(Supplementary ICM Evidence Summary p. 1)

Re: Filing Requirements for Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications - Chapter 3 Incentive Rate-Setting Applications July 16, 2015 p.17

The eligibility for Incremental Capital Investment includes:

- Materiality: A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
- Need: The distributor must pass the Means Test (as defined in the ACM Report). Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the 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.

a) Please provide Enersource's definition of "significant Influence on the operation of the distributor" as it has been used in determining which projects should be eligible for ICM treatment.

b) Enersource's supplementary evidence states that each discrete business case (project) was prioritized based on the drivers: Customer Focus; Operational Effectiveness; Public Policy Responsiveness; and Financial Performance. Please match each business case (project) to the claimed driver.

Response:

a) Enersource deems issues that meet one or more of the following criteria as having a significant influence on its operations:

- If important enough to bring to the Board of Directors or a committee of the Board of Directors for approval;
- If it includes a threat to the safety of employees and/or the public;
- If it presents an environmental threat;

- If it addresses compliance with legislation and/or regulations; and/or
- If it presents a risk of a material impact to the organization.

This is not necessarily an exhaustive list, and other items, assessed on a case by case basis, may be considered to have significant influence on Enersource's operations.

b) Please see response to 2-Staff-11.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 6:

Ref: Supplementary Evidence – Filed October 2, 2015

(Supplementary Evidence – 2016 Capital Expenditure Projects Budget pp. 1-5)

Please provide a table listing Enersource's capital expenditure projects similar to the table provided for 2016, for 2014 actuals and 2015 forecast.

Response:

Please see response to 2-Staff-3.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 7:

Ref: Supplementary Evidence – Filed October 2, 2015

(Supplementary Evidence - 2016 Capital Expenditure Projects Budget p. 3/Supplementary ICM Evidence Summary p. 2)

The total spend for System Access is shown to be $10,276,581 in the Supplementary Evidence -2016 Capital Expenditure Projects Budget and $12,007,831 in the Supplementary ICM Evidence Summary. Please explain the difference between these dollar values.

Response:

Below is the 2016 Capital Budget – System Access.

2016 Capital Budget - System Access

	2016 Forecast
Gross (Excluding LRT)	$12,007,831
LRT	$400,000
Total Gross	$12,407,831
CIAC - Customer Contributions	($2,131,250)
Net	**$10,276,581**

The LRT project is shown separately in the Evidence summary to facilitate year over year comparisons to the base capital spend.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 8:

Ref: Supplementary Evidence – Filed October 2, 2015

(Supplementary ICM Evidence Summary Table 1 p. 6)

Please allocate the Contributions in Aid of Construction to the appropriate discrete project.

Response:

Enersource does not forecast CIAC on an individual project level, but instead considers prior history as well as the nature of expected jobs; when a lower portion of the planned customer jobs is labour, the forecast contribution is lower.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 9:

Ref: Supplementary Evidence – Filed October 2, 2015

(PowerStream Inc. EB-2013-0166 Settlement Agreement dated February 4, 2014, p. 9)

In PowerStream's approved Settlement Agreement it was determined that for projects to be eligible for ICM they must meet one or more of the following criteria: (1) Statute, code, provincial policy, or equivalent external requirement; (2) Considerations of safety for the public and for workers operating in, on, or around equipment; (3) Existing or imminent reliability degradations*; (4) Existing or imminent capacity shortages*; (5) A material increase in cost (beyond the time value of money), if the project is necessary but undertaken at a later time. *Inclusion in the non-discretionary category is dependent on the level of risk - only projects rated as "High Risk" are included. Please match each of the discrete projects that Enersource is requesting ICM treatment for with one or more of the criteria listed above.

Response:

Enersource took an outcome-based approach to prioritizing its projects as defined in the Board's Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach ("RRFE"). Enersource structured the ICM component of its 2016 Price Cap IR application on the requirements identified in the 2015 Filing Requirements for Electricity Distribution Rate Applications issued on July 16, 2015.

Please see response to 2-Staff-11 for details of Enersource's project criteria and ratings.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 10:

Ref: General Questions

Is Enersource's Application being filed on a stand-alone basis, or does it assume that the proposed merger between Enersource, PowerStream Inc., Horizon Utilities Inc. and the acquisition of Hydro One Brampton Inc. will go ahead? Now that all of the relevant municipalities and shareholders have approved plans to merge how does this impact Enersource's Application?

Response:

This Application is being filed on a stand-alone basis. Enersource's Application is not affected by the municipal and shareholder approvals of the proposed merger, which has not been consummated.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 11:

Ref: General Questions

Please provide all materials provided to Enersource's shareholders pursuant to their consideration of the merger.

Response:

This question is out of scope, for the same reasons as those set out in the OEB's *Decision on Threshold Question* in PowerStream EB-2015-0003.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 12:

Ref: General Questions

To the extent the merger is approved by the OEB, how will Enersource ensure that merger savings will flow to it customers going forward?

Response:

This question is out of scope, for the same reasons as those set out in the OEB's *Decision on Threshold Question* in PowerStream EB-2015-0003.

Responses to Consumers Council of Canada Interrogatories

INTERROGATORY 13:

Ref: General Questions

If the proposed merger occurs, and it results in savings for the merged entity, why is it appropriate to set rates for Enersource at this time on a stand-alone basis? Why would this be in the best interests of Enersource's customers?

Response:

This question is out of scope, for the same reasons as those set out in the OEB's *Decision on Threshold Question* in PowerStream EB-2015-0003.

Responses to Energy Probe Research Foundation Interrogatories

INTERROGATORY 1:

Ref: 2016 Price Cap Application filed August 17, 2015, Attachment H

Please confirm that on sheet 6 of Attachment H, the figures reflect the EB-2012-0033 2013 Board approved figures and not 2014 actuals. If this cannot be confirmed, please explain.

Response:

Enersource confirms that on sheet 6 of Attachment H, the figures reflect the EB-2012-0033 2013 Board-approved figures.

Responses to Energy Probe Research Foundation Interrogatories

INTERROGATORY 2:

Ref: 2016 Price Cap Application filed August 17, 2015, Attachment H

Please update Attachment H to reflect an inflation factor of 2.1%.

Response:

Attachment H (Capital Module Applicable to ACM and ICM) has been updated to reflect an inflation factor of 2.1%.

The updated revenue requirement calculation can be found below, Sheet 11, Incremental Capital Adj., of the Board's 2016 Capital Module. The incremental revenue requirement of $5.4 million is summarized below:

Incremental Capital Adjustment	**Revenue Requirement ($000's)**
Eligible Incremental Capital	68,480
Less: Depreciation Expense	1,212
Incremental Capital to be included in Rate Base	67,268
Return on Rate Base	4,377
Depreciation Expense	1,213
Incremental Grossed Up PILs	(206)
Incremental Revenue Requirement	**5,383**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Fixed and Variable Rate Riders | Variable Only Rate Rider | Fixed Only Rate Rider

rsource Hydro Mississauga Inc.

Calculation of incremental rate rider. Choose one of the 3 options:

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	From Sheet 8	From Sheet 8	Col C * Col I total	Col D * Col I total	Col E * Col I total		From Sheet 4	From Sheet 4	From Sheet 4	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	23.33%	16.04%	0.00%	1,255,929	863,296	0	2,119,225	179,182	1,469,096,847		0.99	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 KW	7.14%	6.32%	0.00%	384,114	340,239	0	724,353	17,809	647,112,058		1.80	0.0005	0.0000
GENERAL SERVICE 50 TO 499 KW	2.74%	0.00%	21.36%	147,756	0	1,149,881	1,297,637	3,890	2,104,160,255	6,035,821	3.17	0.0000	0.1905
GENERAL SERVICE 500 TO 4,999 KW	7.54%	0.00%	8.58%	405,709	0	461,663	867,372	469	2,087,036,250	4,709,432	72.09	0.0000	0.0980
LARGE USE	1.14%	0.00%	3.94%	61,385	0	211,861	273,246	9	1,002,165,609	1,741,185	568.38	0.0000	0.1217
UNMETERED SCATTERED LOAD	0.25%	0.14%	0.00%	13,214	7,775	0	20,989	2,967	11,501,822		0.37	0.0007	0.0000
STREET LIGHTING	0.69%	0.00%	0.80%	37,251	0	42,985	80,236	49,829	31,923,315	90,306	0.06	0.0000	0.4760
Total	**42.83%**	**22.50%**	**34.67%**	**2,305,358**	**1,211,311**	**1,866,390**	**5,383,059**	**254,155**	**7,352,996,156**	**12,576,744**			
							5,383,059 *From Sheet 11, B13*						

Note: As per the OEB's letter issued July 16, 2015 (EB-2012-0410), Residential Rates will be applied on a fixed basis only.

Responses to Energy Probe Research Foundation Interrogatories

INTERROGATORY 3:

Ref: 2016 Price Cap Application filed August 17, 2015, pages 22-24

a) Please explain why the CIAC is significantly lower in 2016 than in the previous three years, as shown in Table 5.

b) Please provide a table that shows the CIAC by year, along with the gross capital expenditures to which the contributions are applied and explain any significant different in the ratios between 2016 and the three previous years.

c) Please provide a copy of the Distribution System Plan referred to.

d) Please expand Table 5 and 6 to include figures for the timeframe of the DSP referenced in the evidence.

e) Please update Table 5 to reflect the most recent year-to-date actuals available for 2015, along with the current forecast for the remainder of the year.

f) Please confirm that all of the $116,663,581 in net capital expenditures forecast for 2016 are forecast to be in service by the end of 2016. If this cannot be confirmed, please indicate the amount that is expected to be in service by the end of the year.

Response:

a) and b)

Below is the CIAC Summary 2013 – 2021.

c) Please see 2-Staff-15.

d) and e)

Below is the updated Table 5 and 6, Gross Capital Spend – 2010 to 2021.

f) Historically, approximately $7 million of Construction in Progress (CIP) carries over into the following year and thus, would not be in service. However, since approximately $7 million CIP carries over from the prior year, the total capital expenditure amount of $116,663,581 is assumed to be in service in 2016 for the purposes of the ICM.

Enersource Hydro Mississauga
CIAC Summary
2013 - 2021

Business Unit	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
SYSTEM ACCESS (EXCL. LRT)	**(3,365,340)**	**(3,848,650)**	**(5,741,508)**	**(2,131,250)**	**(2,131,250)**	**(2,131,250)**	**(2,131,250)**	**(2,131,250)**	**(2,131,250)**
Non-typical CIAC:									
SYSTEM ACCESS - LRT	-	-	-	-	(3,000,000)	(3,000,000)	(3,000,000)	(3,000,000)	(200,000)
SYSTEM SERVICE	(2,545,304)	(277,014)	86,617	-	-	-	-	-	-
SYSTEM RENEWAL	(32,979)	(12,549)	-	-	-	-	-	-	-
SUBTOTAL	**(2,578,283)**	**(289,563)**	**86,617**	**-**	**(3,000,000)**	**(3,000,000)**	**(3,000,000)**	**(3,000,000)**	**(200,000)**
TOTAL CIAC	**(5,943,622)**	**(4,138,213)**	**(5,654,892)**	**(2,131,250)**	**(5,131,250)**	**(5,131,250)**	**(5,131,250)**	**(5,131,250)**	**(2,331,250)**

- CIAC for System Service and System Renewal is not typical and is not planned for future years. Contributions in 2013 were primarily related to a refund regarding the Churchill Meadows TS constructed by Hydro One. LRT contributions have also been excluded since they are a non-typical significant individual project.

- CIAC for System Access relates primarily to Offers to Connect, Industrial/Commercial projects, and Road projects. The ratios of CIAC to applicable Gross Capital spend are:

CIAC as % of Gross Capital Spend:

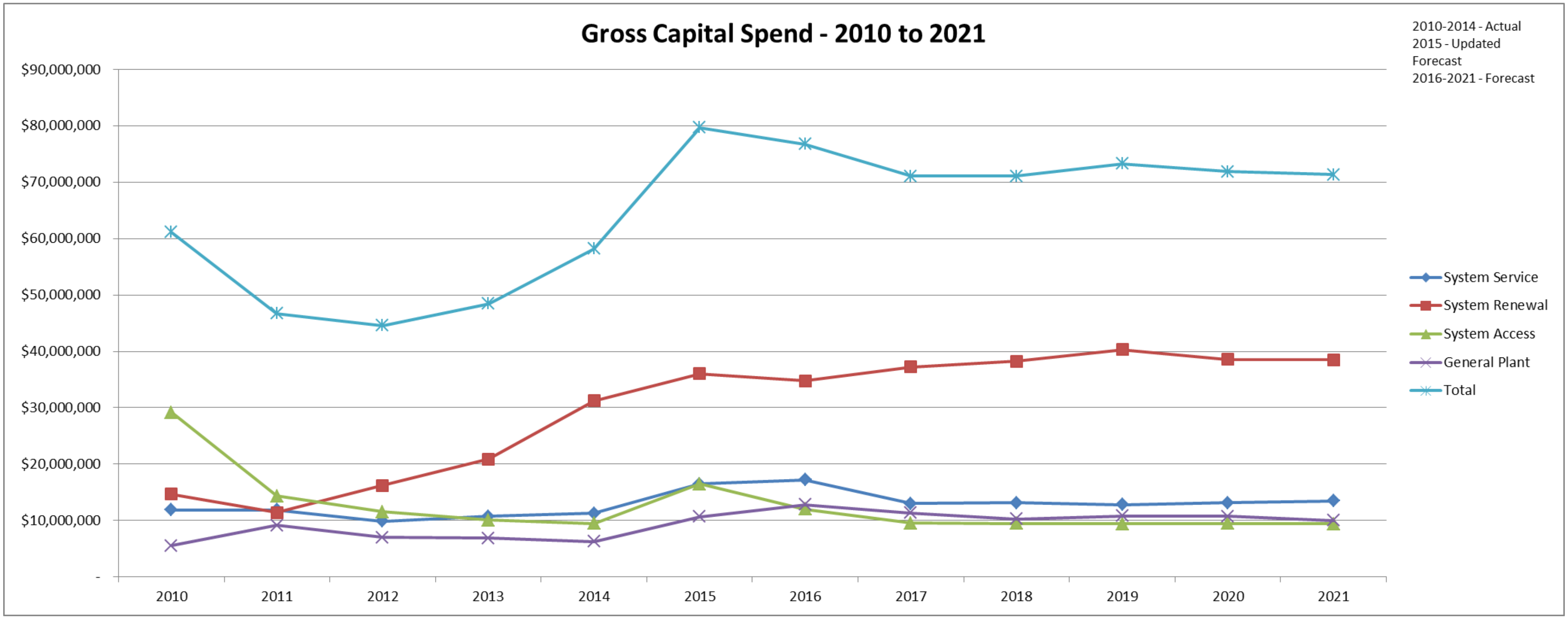
	2013	2014	2015	2016	2017	2018	2019	2020	2021
Gross System Access Capital (to which CIAC applies)	7,280,066	6,879,045	12,231,446	6,680,000	6,650,000	6,620,000	6,595,000	6,590,000	6,575,000
CIAC - System Access (Excl. LRT)	(3,365,340)	(3,848,650)	(5,741,508)	(2,131,250)	(2,131,250)	(2,131,250)	(2,131,250)	(2,131,250)	(2,131,250)
Net System Access (to which CIAC applies)	3,914,727	3,030,395	6,489,937	4,548,750	4,518,750	4,488,750	4,463,750	4,458,750	4,443,750
% CIAC to Gross Capital spend	***46%***	***56%***	***47%***	***32%***	***32%***	***32%***	***32%***	***32%***	***32%***

2016 CIAC % of Gross Capital was forecast to be lower primaily due to an expectation of lower contributions relating to Road and Industrial/Commercial projects. Relocation projects are negotiated on a case by case basis to ensure a fair and reasonable charge based on cost recovery principles. Per the Public Services Works on Highways Act, the road authority and the operating corporation may agree upon the apportionment of the cost of labour employed in such taking up, removal or change, but, subject to section 3, in default of agreement such cost shall be apportioned equally between the road authority and the operating corporation, and all other costs of the work shall be borne by the operating corporation. When forecasting contributions, Enersource considers prior history as well as the nature of expected jobs; when a lower portion of the planned customer job is labour, the contribution is lower.

FOR ICM: (Table 5)

Capital Spend 2012 to 2021

	Actual	Actual	Actual	COS	Actual	Actual	Initial Fcst	Updated Fcst	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	YTD Actual
	2010	2011	2012	2013	2013	2014	2015	2015	2016	2017	2018	2019	2020	2021	Oct-15
System Service	$11,866,989	$11,857,869	$9,860,395	$12,084,000	$10,711,823	$11,227,758	$16,267,139	$16,496,973	$17,200,000	$13,015,000	$13,130,000	$12,825,000	$13,105,000	$13,490,000	$12,421,975
System Renewal	$14,656,133	$11,421,921	$16,224,485	$16,376,000	$20,887,175	$31,256,743	$35,203,614	$36,058,509	$34,735,000	$37,242,500	$38,240,000	$40,280,000	$38,570,000	$38,490,000	$27,682,942
System Access	$29,144,851	$14,325,984	$11,493,425	$9,458,000	$10,054,863	$9,474,167	$14,632,780	$16,451,573	$12,007,831	$9,516,237	$9,472,967	$9,412,212	$9,437,700	$9,367,700	$15,358,427
General Plant	$5,484,172	$9,097,375	$7,005,798	$11,187,616	$6,830,748	$6,230,459	$10,585,191	$10,681,993	$12,796,000	$11,337,000	$10,280,500	$10,794,000	$10,754,862	$9,984,236	$6,853,559
Total	$61,152,144	$46,703,148	$44,584,102	$49,105,616	$48,484,610	$58,189,127	$76,688,724	$79,689,048	$76,738,831	$71,110,737	$71,123,467	$73,311,212	$71,867,562	$71,331,936	$62,316,903
Administration Building	$45,785	($45,785)	$22,214,255	-	-	-	-	-	-	-	-	-	-	-	-
Hydro One TS Payments	-	-	-	-	-	-	-	$40,478,700	-	-	-	-	-	-	$40,378,000
LRT	-	-	-	-	-	-	-	-	$400,000	$8,400,000	$8,650,000	$8,750,000	$7,800,000	$1,200,000	-
Total	$45,785	($45,785)	$22,214,255	-	-	-	-	$40,478,700	$400,000	$8,400,000	$8,650,000	$8,750,000	$7,800,000	$1,200,000	$40,378,000
TOTAL GROSS	$61,197,929	$46,657,363	$66,798,357	$49,105,616	$48,484,610	$58,189,127	$76,688,724	$120,167,748	$77,138,831	$79,510,737	$79,773,467	$82,061,212	$79,667,562	$72,531,936	$102,694,903
CIAC - System Service	-	-	-		($2,545,304)	($277,014)	($60,878)	$86,617	-	-	-	-	-	-	$86,617
CIAC - System Renewal	-	($187,840)	-		($32,979)	($12,549)	-	-	-	-	-	-	-	-	-
CIAC - System Access	($8,483,566)	($4,310,273)	($1,248,222)	($2,933,000)	($3,365,340)	($3,848,650)	($5,594,013)	($5,741,508)	($2,131,250)	($2,131,250)	($2,131,250)	($2,131,250)	($2,131,250)	($2,131,250)	($5,540,494)
CIAC - General Plant	-	-	-		-	-	-	-	-	-	-	-	-	-	-
CIAC - LRT	-	-	-	-	-	-	-	-	-	($3,000,000)	($3,000,000)	($3,000,000)	($3,000,000)	($200,000)	-
CIAC	($8,483,566)	($4,498,114)	($1,248,222)	($2,933,000)	($5,943,622)	($4,138,213)	($5,654,891)	($5,654,892)	($2,131,250)	($5,131,250)	($5,131,250)	($5,131,250)	($5,131,250)	($2,331,250)	($5,453,877)
TOTAL NET	$52,714,363	$42,159,249	$65,550,135	$46,172,616	$42,540,987	$54,050,914	$71,033,833	$114,512,857	$75,007,581	$74,379,487	$74,642,217	$76,929,962	$74,536,312	$70,200,686	$97,241,025


Gross Capital Spend - 2010 to 2021
2010-2014 - Actual
2015 - Updated Forecast
2016-2021 - Forecast
$90,000,000
$80,000,000
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
-
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
System Service
System Renewal
System Access
General Plant
Total

Responses to Energy Probe Research Foundation Interrogatories

INTERROGATORY 4:

Ref: 2016 Price Cap Application filed August 17, 2015, pages 25-27

a) Please explain fully, including any calculations, or correspondence with Hydro One, on how Enersource has arrived at the payment of $41,665,000 for the Hydro One TS.

b) Is the $41,665,000 the total contribution expected to be paid for this TS to Hydro One? If not, please provide the total expected contribution and the anticipated breakdown of this amount by year.

c) If the $41,665,000 is the estimated total contribution to be paid to Hydro One, please confirm that Enersource is required to make the entire payment in 2016. If this cannot be confirmed, please explain why Enersource has included this amount in 2016.

Response:

a) Please see response to 2-Staff-6 part a).

b) Please see response to 2-Staff-6 part a).

c) Enersource has received an invoice from HONI for the payment of $40.479 million related to the Churchill Meadows TS. Payment is now expected to be made by the end of 2015.

Responses to Energy Probe Research Foundation Interrogatories

INTERROGATORY 5:

Ref: 2016 Price Cap Application, Supplementary Evidence - 2016 Capital Expenditure Projects Budget filed October 2, 2015

a) Please confirm that the forecasts shown represent the most recent forecast used by Enersource for 2016.

b) Please indicate which projects/expenditures could be deferred to 2017 without any significant impact on the operations of Enersource.

c) Please identify any project/expenditure that may be impacted by a merger with other distributors in 2016.

Response:

a) Confirmed.

b) Please see response to 2-Staff-12.

c) None.

Responses to Energy Probe Research Foundation Interrogatories

INTERROGATORY 6:

Ref: 2016 Price Cap Application, Supplementary Evidence - 2016 Capital Expenditure Projects Budget filed October 2, 2015 & Project Business Cases

Please provide a live Excel spreadsheet that contains the information found in the 2016 Capital Expenditure Projects Budgets Spreadsheet with the following information added as new columns for each project, taken from the project business cases (using the numerical figures used in the business case):

a) Regulatory/Public Policy Responsiveness - Is the project mandatory? Yes or No?

b) Customer Focus
   i) Service Quality
   ii) Customer Satisfaction
   iii) Reputational Risk

c) Operational Effectiveness
   i) Safety (Customer & Employees)
   ii) Environmental Impact/risk
   iii) System Reliability
   iv) System Renewal

d) Financial Performance
   i) Cost Efficiencies
   ii) Ongoing Costs.

Response:

a), b), c), and d)

Please see response to 2-Staff-11.

Responses to Energy Probe Research Foundation Interrogatories

INTERROGATORY 7:

Ref: Project Business Cases

For each of (a), (b), (c) and (d) noted in Interrogatory #6, please provide the numerical figures that could be used and describe each numerical option. As an example, if the results can range from 0 to 10 for some of the categories, what do each of the numbers mean in the context of the performance categories?

Response:

Please see response to 2-Staff-11.

Responses to School Energy Coalition Interrogatories

INTERROGATORY 1:

Ref: Tab 2 – Manager's Summary

[Tab 2, p. 2]

Please provide all information available to the Applicant explaining why the Application, including an extensive ICM claim, was not filed until August 17, 2015, and the ICM supporting information was not filed until October 2, 2015. Please confirm that the Applicant is still seeking rates effective January 1, 2016.

Response:

The Updated Filing Requirements and Process for 2016 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications issued by the OEB on July 16, 2015 identified the IRM Stream Assignment by distributor for 2016 which documents the filing deadline. Enersource was identified as Stream 1 with a filing date of August 17, 2015.

Prior to the August 17, 2015 filing deadline, Enersource received information from HONI indicating that a true-up of the Churchill Meadows TS would be necessary but the amount of the true-up had not yet been confirmed. Enersource was then later advised by HONI that a true-up payment for the Cardiff TS would also be payable, again with the amount not finalized.

Enersource notified Board staff in advance of the IRM filing deadline that an Incremental Capital Module ("ICM") would likely be necessary but details were as yet not finalized. The quantum of the HONI CCRA true-up payments, combined with the need for significant incremental capital expenditures in 2016, provided the necessary evidence for Enersource to file an ICM. Enersource advanced its normal 2016 detailed budget timeline to make project details available but resources were stretched to finalize documentation and ensure review by stakeholders in time to submit with the IRM filing deadline.

Enersource is seeking rates effective January 1, 2016.

Responses to School Energy Coalition Interrogatories

INTERROGATORY 2

Ref: Tab 2 – Manager's Summary

[Tab 2, p. 5]

Please discuss the advantages and disadvantages to the customers of clearing the deferral and variance accounts over one year, as opposed to a different time period, with particular regard to the rate impacts on individual customer classes

Response:

The Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (the "EDDVAR Report") states that the default disposition period to clear Group 1 account balances by means of a rate rider should be one year. However, a distributor is permitted to "propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate."[1] A shorter disposition period reduces carrying costs and the potential for intergenerational equity issues. Enersource did review the impact of a two-year disposition period for the deferral and variance accounts; however, this did not result in a material change to the rate impacts on individual customer classes.

Table 1 (for RPP customers) and Table 2 (for non-RPP customers) below provide comparisons of the bill impacts between a one-year disposition period (as filed in the Supplementary Evidence on September 23, 2015) and a two-year disposition period, for the deferral and variance accounts.

Table 1: Proposed 2016 Total Monthly Bill Impacts for RPP Customers

Customer Type	Monthly Consumption (kWh)	Total Bill Impact 1-year disposition (%)	Total Bill Impact 2-year disposition (%)	Change (%)
Residential	800	7.51	7.39	(0.12)
GS < 50 kW	2,000	12.68	12.57	(0.11)
Unmetered Scattered Load	300	13.19	13.07	(0.12)

[1] Ontario Energy Board EB-2008-0046 Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative, dated July 31, 2009, at p. 24.

Table 2: Proposed 2016 Total Monthly Bill Impacts for Non-RPP Customers

Customer Type	Monthly Consumption/Demand (kWh / kW)	Total Bill Impact 1-year disposition (%)	Total Bill Impact 2-year disposition (%)	Change (%)
Residential	800	8.32	7.82	(0.50)
GS < 50 kW	2,000	14.10	13.28	(0.82)
Unmetered Scattered Load	300	14.31	13.65	(0.66)
GS 50 – 499 kW Interval	230	1.44	0.96	(0.48)
GS 50-499 kW Non-Interval	230	1.85	1.16	(0.69)
GS 500 – 4999 kW Interval	2,250	4.35	2.51	(1.84)
GS 500 – 4999 kW Non-Interval	2,250	5.36	3.01	(2.35)
Large Use (> 5000 kW) Class A	5,000	0.38	0.40	0.02
Large Use (> 5000 kW) Class B	5,000	1.83	1.13	(0.70)

The greatest bill impacts are to the General Service < 50 kW and Unmetered Scattered Load rate classes and this is almost entirely due to the impact of the elimination of the Ontario Clean Energy Benefit effective January 1, 2016.

Responses to School Energy Coalition Interrogatories

INTERROGATORY 3:

Ref: Tab 2 – Manager's Summary

[Tab 2, p. 16]

Please provide the most recent Strategic Plan, and the most recent Distribution System Plan, of the Applicant or, if those documents are already on file with the Board, an evidence reference for those documents. If there are any material changes between the proposed capital spending in 2016, and the most recent Distribution System Plan, please provide a detailed explanation/justification of each of those differences.

Response:

Please find attached Enersource's most recent Strategic Plan.

Please see Supp-Staff-15 for Enersource's draft Distribution System Plan.

There are no material changes between the proposed capital spending in 2016 and the draft DSP, other than the timing of the CCRA payment to HONI for Churchill Meadows TS (i.e., HONI has now demanded payment in mid-December, 2015 versus Enersource ICM forecast in early 2016) and the recent advice from HONI that a CCRA payment for Cardiff TS is no longer payable.

more than energy™

Enersource Hydro Mississauga Inc.
EB-2015-0065
2016 Price Cap IR
Interrogatory Responses
2-SEC-3
Filed: December 9, 2015

Growth Component of Strategy

Development Committee
November 7th, 2014

enersource
more than energy™

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Strategic Focus

Integrated Utility & Power Services Company

Creating **Shareholder Value** and generating new streams of stable **Net Income**

Utility Infrastructure Company focused on **rate-regulated assets**

Enersource

Shareholder Value & stable Net Income

Focus on & Grow

Maintain or Leverage

Regulated

Non-Regulated

Distribution & Transmission

Services

[Streetlighting, LED Conversion, etc]

Enersource

Integrated Utility & Power Services Company

Board approved pursuit of:

- ✓ consolidation opportunities within the Ontario LDC sector.
- ✓ acquisitions of and investments in rate regulated businesses.

Board required additional information about:

- long-term revenue contracts in businesses not presently conducted by its LDC.

Responses to School Energy Coalition Interrogatories

INTERROGATORY 4:

Ref: Tab 2 – Manager's Summary

[Tab 2, p. 20, 23]

Please provide a table showing actuals for each year 2006-2014, and forecast 2015-2020, of the following, each broken down into System Renewal, System Service, System Access, and General Plant:

a) Capital spending
b) Capital Contributions
c) Capital additions
d) Depreciation.

Response:

a) Please see response to 2-Staff-3.

b) Please see response to 2-Staff-3.

c) and d)

Enersource records capital expenditures and contributions based on the four categories as per Chapter 5 filing requirements (i.e., System Renewal, System Service, etc.), but does not record capital additions or depreciation based on these categories.

Capital additions for accounting and regulatory purposes represent additions to individual asset components (such as transformers, poles, switchgear, cable, etc.) of Property, Plant and Equipment ("PP&E"). These capital additions are based on pooled assets which consist of expenditures for a combination of multiple projects. For example, capital additions for the asset type 'padmount transformers' are allocated from many individual projects categorized as system renewal, system service, or system access. Furthermore, each individual project expenditure is allocated to various individual components of PP&E, and depreciated based on the useful life of that component.

It is not consistent with Enersource's accounting methods to present capital additions and depreciation in the above-requested categories, and to do so would require a calculation of such capital additions and depreciation expenses for each individual project which would be very time-consuming.

Instead, both additions and depreciation are presented by major components of PP&E in Enersource's asset continuity schedules.

Responses to School Energy Coalition Interrogatories

INTERROGATORY 5:

Ref: Tab 2 – Manager's Summary

[Tab 2, p. 27, 34]

Please confirm that the revenue shortfall arises because the Applicant committed to a greater load growth than actually transpired, in large part due to natural and government-driven conservation that was not forecast by the Applicant.

Response:

The government-driven initiatives and natural conservation played an important part in lower load growth than anticipated. However, the economic downturn of 2008-2009, which persisted for several years, has been a major driver for historical actual load being lower than what had been forecasted.

Responses to School Energy Coalition Interrogatories

INTERROGATORY 6:

Ref: Tab 2 – Manager's Summary

[Tab 2, p. 31-32]

Please provide a full budget for the costs of the Hurontario LRT work to be done by the Applicant, broken down by year, and also a similar breakdown for the costs to be borne by Hydro One Brampton for the same project.

Response:

Below is the draft LRT budget 2016-2021.

Draft LRT Budget 2016-2021

($000's)	2016	2017	2018	2019	2020	2021	Total
Design	400	400	250	250			1,300
Underground		4,000	4,400	4,500	4,300	700	17,900
Overhead		4,000	4,000	4,000	3,500	500	16,000
Subtotal	400	8,400	8,650	8,750	7,800	1,200	35,200
			(3,000)	(3,000)	(3,000)	(200)	(12,200)
Contribution (Metrolinx)		(3,000)					
Total	**400**	**5,400**	**5,650**	**5,750**	**4,800**	**1,000**	**23,000**

Enersource does not have access to the Hydro One Brampton costs.

Responses to School Energy Coalition Interrogatories

INTERROGATORY 7:

Ref: Tab 2 – Manager's Summary

[Tab 2, p. 33-36]

Please provide references for each past decision by the Board approving either the Churchill Meadows TS or the Cardiff TS.

Response:

The decisions in proceedings RP-2007-0706 and EB-2012-0033 approved Enersource's request for Churchill Meadows TS. Please see references identified below:

RP-2007-0706, Executive Summary pg. 515, 520, 556
RP-2007-0706, EHM Project Business Case pg. 558
EB-2012-0033, Exhibit 2, Tab 1, Schedule 1, Page 7
EB-2012-0033, Exhibit 2, Tab 2, Schedule 1, Page 7

Responses to School Energy Coalition Interrogatories

INTERROGATORY 8

Ref: Tab 2 – Manager's Summary

[Tab 2, p. 40]

Please explain why it is appropriate to recover the incremental capital projects by fixed and variable rate riders. Please provide numerical analysis showing how the proposed rate base additions would be allocated and then recovered if done on a cost of service basis.

Response:

Enersource proposed a combination of fixed and variable riders for the calculation of the ICM rate rider. The rate rider for the residential class was applied on a fixed basis in accordance with the Board's policy on Rate Design for Residential Electricity Customers.

Enersource requested approval in its 2013 Cost of Service application, EB-2012-0033, to collect its proposed revenue requirement from all customer classes in similar percentages as the current rates (i.e. 2012 rates), except for adjustments made as a result of the cost allocation study. Enersource received approval to recover the approved revenue requirement based on its proposed rate design which included a combination of fixed and variable rates.

Enersource used the Board's 2016 Capital Module applicable to ACM and ICM published July 30, 2015 to calculate the proposed fixed and variable rate riders for all customer classes. The module provides three options for the calculation of the incremental revenue requirement – fixed and variable riders; variable only rate rider; and fixed only rate rider. The Module uses the applicant's most current allocation of revenues to appropriately allocate the incremental revenue requirement to the classes which is consistent with Enersource's rate design methodology in its 2013 Cost of Service application. As the Board's Capital Module uses the applicant's current allocation of revenues, Enersource agrees that the Board's Module provides the most appropriate allocation of the requested incremental revenue requirement.

The following analysis compares the allocation of the incremental revenue requirement by rate class from the Board's model (Sheet 8, Revenue Proportions) to Enersource's 2013 Cost of Service allocation:

Table 1: 2013 Cost of Service approved revenue allocation by rate class

$000's	2013 Approved Distribution Revenue Allocation			Fixed & Variable % of Total Revenue	
Customer Class	**Fixed $**	**Variable $**	**Total $**	**Fixed %**	**Variable %**
Residential	27,235	18,317	45,552	23.09	15.52
General Service < 50 KW	8,389	7,023	15,412	7.11	5.95
Unmetered Scattered Load	287	154	441	0.24	0.13
General Service 50 – 499 KW	3,296	26,041	29,337	2.79	22.07
General Service 500 – 4999 KW	8,818	11,100	19,918	7.48	9.41
Large Use	1,349	4,644	5,993	1.14	3.94
Street Lighting	819	522	1,341	0.69	0.44
Total	**50,193**	**67,801**	**117,964**	**42.54**	**57.46**

Table 2: Revenue allocation comparison

	2013 Cost of Service Approved Allocation		Capital Module Allocation (2016 Application)	
Customer Class	**Fixed %**	**Variable %**	**Fixed %**	**Variable %**
Residential	23.09	15.52	23.33	16.04
General Service < 50 KW	7.11	5.95	7.14	6.32
Unmetered Scattered Load	0.24	0.13	0.25	0.14
General Service 50 – 499 KW	2.79	22.07	2.74	21.36
General Service 500 – 4999 KW	7.48	9.41	7.54	8.58
Large Use	1.14	3.94	1.14	3.94
Street Lighting	0.69	0.44	0.69	0.80
Total	**42.54**	**57.46**	**42.83**	**57.17**

Responses to School Energy Coalition Interrogatories

INTERROGATORY 9:

Ref: Supplementary ICM Evidence

[Supplementary Evidence, throughout]

For each of the capital projects that are included in the proposed ICM for 2016, please provide a detailed explanation of how, if at all, the Applicant has taken into account, in assessing costs, benefits, timing, and prioritization of the projects, the potential impacts of:

a) The Distribution Sector Review Panel Report, 2012
b) The Report of the Premier's Advisory Council on Government Assets, April, 2015 (the Clark Report)
c) The Board's Report on Ratemaking Associated with Distributor Consolidation, March, 2015
d) The announcement by the Applicant and three other utilities in April 2015 that they would merge.

Please provide a detailed explanation of the risks to the Applicant and its customers of proceeding with <u>each</u> of the proposed ICM projects at this time. Please ensure that the explanation for each ICM project includes full quantification of those risks, and describes all mitigation activities the Applicant expects to use to minimize the cost of those risks, in each case as it applies to that particular project.

Response:

a), b), c), and d)
The listed reports and announcement did not factor into Enersource's assessment and prioritization of the ICM capital projects. Whether Enersource's announced merger proceeds or not, Enersource will need to undertake these budgeted capital expenditures for all of the reasons already provided in its pre-filed evidence.

Supplementary Questions below the numbered questions:
Please see the details provided in the business cases in the Supplementary Evidence, filed on October 2, 2015.

Please also see the response to 2-Staff-11 for details of the proposed ICM projects.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 1:

Ref:

a) Please provide Enersource's customer growth rate from 2010 to 2016.

Response:

Enersource
Customer Growth Rate
2010 - 2016

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Forecast	2016 Forecast
Total Number of Customers	192,960	195,381	197,746	199,871	201,359	203,467	205,464
Annual Customer Growth Rate		1.25%	1.21%	1.07%	0.74%	1.05%	0.98%

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 2:

Ref: Manager's Summary Page 28

Preamble: Enersource indicates that the main reason for increasing costs in System Renewal is due to a significant portion of the distribution equipment that was installed in the 1970's, 1980's and early 1990's having aged and reached the end of its expected useful life.

a) Please discuss how Enersource evaluated asset age versus asset condition in determining the timing of its asset renewal programs in 2016.

b) Please confirm Enersource's reliability goal related to the increased spending under System Renewal.

Response:

a) Enersource uses a two-tiered approach to transformer remediation.

In the first tier, Enersource collects and analyzes critical asset data on each transformer, including inspection, physical location (e.g., rear versus front lot), asset condition, and reliability data. This information is used as one of the inputs in the decision model to help identify future underground subdivision rebuild areas.

The following asset data is collected:

- Transformer Age;
- Inspection reported condition (e.g., poor, fair);
- Leaking Transformer (both PCB and non-PCB);
- Physical location of transformer (e.g., rear or front lot);
- Reliability data from IOM; and
- Cable faults.

A detailed map, as shown in Figure 1 below, is generated and reviewed by both the Asset Operations and Asset Management teams to determine areas that qualify for underground renewal projects. This allows Enersource to replace transformers that have reached the end-of life or are found to be leaking and thus pose a safety and environmental risk and/or have exhibited reliability issues. This information is used to select areas that require extensive underground renewal, which is a major component within the overall System Renewal investment category.

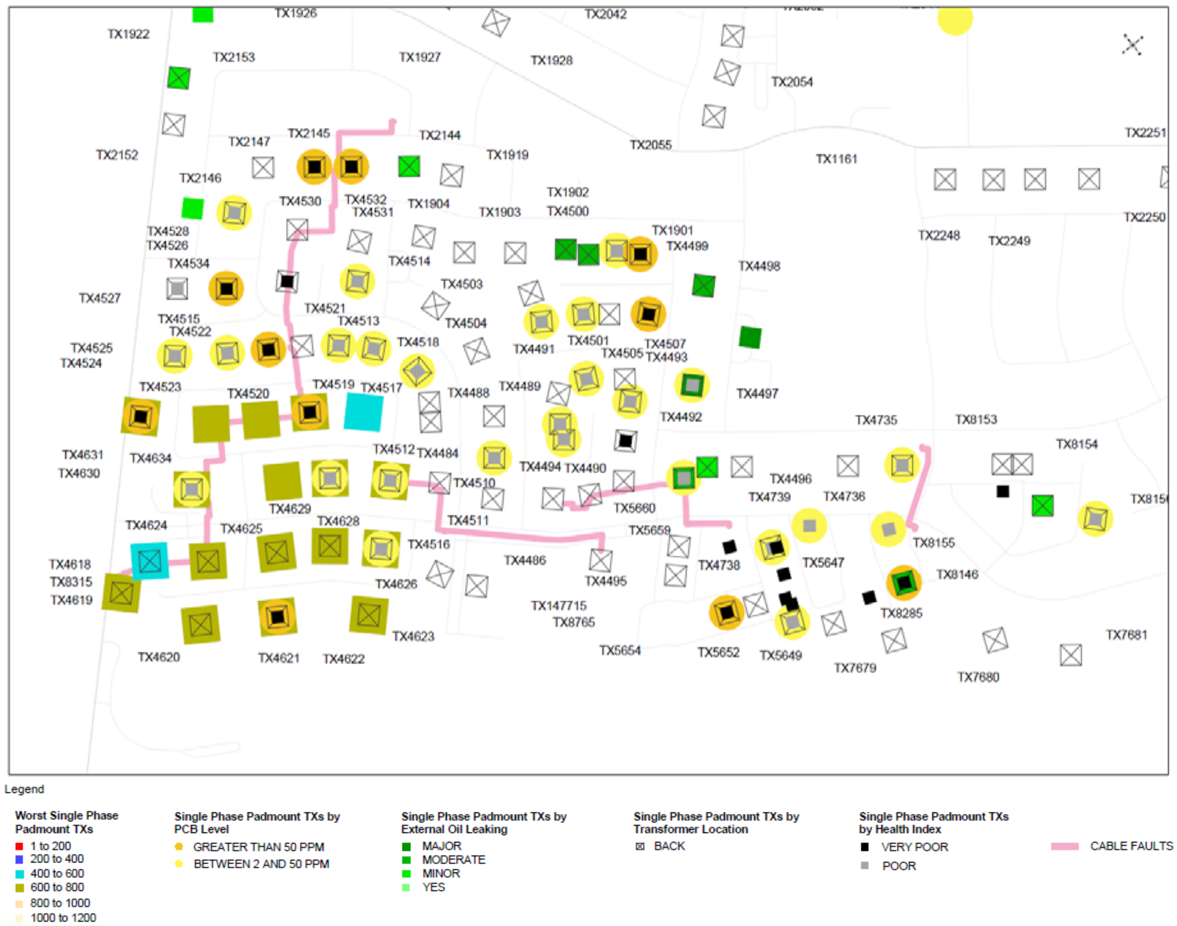

Figure 1. Analysis of underground areas with aging assets and poor reliability.

In the second tier, individual pad mounted transformers requiring replacement are identified. Enersource carries out planned replacement of these individual pad mounted transformers that have reached the end of life, have shown to be in poor condition, and/or have shown signs of leakage.

b) A substantial amount of Enersource's equipment was installed during the significant growth in the City from the 1970's to the 1990's. As a result, a large portion of Enersource's assets is coming up for renewal and Enersource is committed to using available inspection records and asset condition results to identify critical assets due for replacement. Essentially, Enersource is looking to replace aging equipment in order to maintain existing reliability levels.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 3:

Ref: October 2, 2015 Supplementary ICM Evidence, 2016 Capital Expenditures Projects Budget Pages 1-5

a) Please provide a list of the planned (proactive) replacement programs that are new in 2016.

Response:

a) Enersource has an extensive planned replacement program for its distribution assets, including but not limited to overhead, underground, and substations. Enersource continues to inspect assets and to ensure accuracy of assets records, which allow the company to more accurately identify areas for proactive replacement. However, there are no new planned (proactive) replacement programs in 2016.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 4:

Ref: Manager's Summary Page 28 Table 7

Preamble: Table 7 provides Equipment Failure Statistics (minutes) for the years 2010 to 2014.

a) Please reproduce Table 7 to include another column for year to date data for 2015.

b) Please reproduce Table 7 to include only the minutes for each cause code for equipment that is not at or beyond end of life.

Response:

a) Shown below is Table 7 reproduced with 2015 year to date results included. Also, note that data was corrected for 2014.

Cause Codes	2010	2011	2012	2013	2014	Jan - Nov 2015
Underground Cable 500_CBL	2,141,769	2,881,575	2,727,180	1,720,513	1,610,094	2,795,959
Fuse 500_FUSE	39,211	38,392	50,685	27,675	7,392	25,914
Insulator 500_INSU	2,687	42,884	156,102	301,820	170,207	399,569
Switchgears 500_LC	68,884	421,281	49,230	221,229	544,465	130,527
Overhead Equipment 500_OHH	171,436	760,691	199,454	300,843	485,876	208,503
Others/Unknown	121,218	471,038	310,009	330,846	285,435	411,799
Splices 500_SPL	277,098	262,275	807,069	196,638	192,193	57
Switches 500_SWCH	24,938	86,549	262,899	151,604	291,775	12,413
Elbows/Terminations 500_TERM	64,835	62,340	70,562	219,763	39,223	133,806
Transformers 500_TX	169,398	192,913	236,178	292,664	181,559	156,167
Total	**3,081,474**	**5,219,938**	**4,869,368**	**3,763,595**	**3,808,219**	**4,274,714**

b) The Integrated Operating Management system ("IOM") is currently not tracking the minutes for each cause code for equipment that is not at or beyond end of life. Enersource is currently evaluating work required to carry out more accurate tracking of failed equipment and subsequent, failure analysis.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 5:

Ref:

a) Please provide Enersource's SAIDI and SAIFI results for the years 2010 to 2014 and the forecast for 2015 and 2016.

b) Please provide Enersource's SAIDI and SAIFI results for the years 2010 to 2014 excluding Loss of Supply and Major Event Days.

c) Please provide the contribution to SAIDI and SAIFI from Defective Equipment for the years 2010 to 2014.

d) Please provide the total number of Customer Interruptions and Customer Interruption Minutes for the years 2010 to 2014 and 2015 year to date.

Response:

a) Table 1 shows Enersource's SAIDI and SAIFI results for the years 2010 to 2014, and the forecast for 2015 and 2016, including Loss of Supply and Major Event Days.

	2010	2011	2012	2013	2014	2015 Forecast	2016 Forecast
SAIDI	35.0	53.3	41.9	320.3	40.5	41.1	42.8
SAIFI	1.32	1.97	1.71	2.72	1.14	1.41	1.66

Table 1: SAIDI and SAIFI including Loss of Supply and MED

b) Table 2 shows Enersource's SAIDI and SAIFI results for the years 2010 to 2014, excluding Loss of Supply and Major Event Days.

	2010	2011	2012	2013	2014
SAIDI	33.1	43.5	40.7	31.2	31.6
SAIFI	1.10	1.54	1.36	0.90	0.97

Table 2: SAIDI and SAIFI excluding Loss of Supply and MED

c) Table 3 shows the contribution to SAIDI and SAIFI from Defective Equipment for the years 2010 to 2014.

	2010	2011	2012	2013	2014
Contribution of Defective Equipment to SAIDI	45.7%	50.8%	59.1%	52.4%	59.8%
Contribution of Defective Equipment to SAIFI	33.5%	33.4%	46.8%	32.7%	52.6%

Table 3: Contribution from Defective Equipment

d) Table 4 shows total number of customers affected by sustained outages for the years 2010 to 2014 and 2015 year to date, with and without Major Event Days.

Customers Affected (Sustained)	2010	2011	2012	2013	2014	Jan - Nov 2015
W/O MED	251,366	380,771	335,736	280,787	195,258	324,230
With MED	251,366	380,771	335,736	541,642	228,251	324,230

Table 4: Yearly Total Number of Customers Affected

Table 5 shows Customer Interruption Minutes for the years 2010 to 2014 and 2015 year to date, with and without Major Event Days.

Customer Minutes	2010	2011	2012	2013	2014	Jan - Nov 2015
W/O MED	6,673,600	10,277,717	8,242,559	7,182,677	6,365,209	8,550,729
With MED	6,673,600	10,277,717	8,242,559	63,887,058	8,134,215	8,550,729

Table 5: Yearly Customer Interruption Minutes

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 6:

Ref: Manager's Summary Page 28 Table 7

a) Please provide a Table to show the Equipment Failure Statistics for 2010 to 2014 and 2015 year to date for each of the cause codes in Table 7, on the basis of number of interruptions (outages).

b) Please provide the same Table as part (a) that includes only the number of interruptions related to equipment that was not at or beyond end of life.

Response:

a) Shown below is Table 7 reproduced with 2015 year to date results included.

Cause Codes	2010	2011	2012	2013	2014	Jan - Nov 2015
Underground Cable 500_CBL	153	199	190	189	147	224
Fuse 500_FUSE	23	15	19	13	8	11
Insulator 500_INSU	4	7	6	9	11	11
Switchgears 500_LC	8	13	5	10	23	9
Overhead Equipment 500_OHH	10	14	19	12	11	16
Others/Unknown	47	80	62	56	68	69
Splices 500_SPL	6	2	12	7	13	1
Switches 500_SWCH	6	7	9	8	7	5
Elbows/Terminations 500_TERM	17	10	9	16	13	34
Transformers 500_TX	46	38	67	89	64	56
Total	**320**	**385**	**398**	**409**	**365**	**436**

b) As noted in the response to AMPCO-4, the Integrated Operating Management ("IOM") system is currently not capable of tracking the number of interruptions related to equipment that was not at or beyond end of life. Enersource is currently evaluating work required to carry out more accurate tracking of failed equipment and subsequent failure analysis.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 7:

Ref: Manager's Summary Page 28 Table 7

a) Please provide the type of equipment captured under "Overhead Equipment".

b) Please explain the equipment captured under the Cause Code "Others".

c) Please explain the reason for an equipment failure being categorized as "Unknown".

d) Please provide a breakdown of the types of switches captured under "Switches".

e) Please provide a breakdown of the types of transformers captured under "Transformers".

Response:

a) The equipment captured under the cause code "Overhead Equipment" includes overhead conductors, jumpers, cutouts, lighting arrestors, fault indicators, secondary conductors, and overhead hardware (insulators, poles, crossarms).

b) The equipment captured under the cause code "Others" includes items that do not fall into other standard codes. Examples include meter bases, neutral wires, and secondary buses.

c) The equipment captured under the cause code "Unkown" includes customer interruptions with no apparent cause or reason which could have contributed to the outage.

d) The equipment captured under the cause code "Switches" includes distribution switches, reclosers, and load interrupters.

e) The equipment captured under the cause code "Transformers" includes padmount transformers (single and three phase), polemount, power class, submersible, kiosk, and vaults.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 8:

Ref: Manager's Summary Page 29

Preamble: The evidence states "Figure 3 is a summary of Enersource's ACA condition-based health index by asset type for all major assets, based on the results of Enersource's Asset Condition Assessment ("ACA") performed by Kinectrics Inc."

a) Please provide a copy of Enersource's Asset Condition Assessment ("ACA") performed by Kinectrics Inc. referred to above, and the date of the results.
b) Please provide a copy of the ACA review undertaken prior to the ACA referred to in the preamble, and the date of these results.

Response:

a) Attached is a copy of Enersource's Asset Condition Assessment ("ACA") performed by Kinectrics Inc.

b) Attached is a copy of the ACA review.

ENERSOURCE HYDRO MISSISSAUGA
2013 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418089-RA-0003-R01

July 14, 2014

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

DISCLAIMER

ENERSOURCE HYDRO MISSISSAUGA
2013 ASSET CONDITION Assessment

Kinectrics Report: K-418089-RA-0003-R01

July 14, 2014

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Reviewed and Approved by:

Yury Tsimberg, M.Eng, P.Eng
Director – Asset Management

Dated: 2014-07-14

To: Enersource Hydro Mississauga
3240 Mavis Road
Mississauga, Ontario
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Revision History

Revision Number	Date	Comments	Approved
R00	2014-05-31	Draft report	Yury Tsimberg
R01	2014-07-14	Final report	Yury Tsimberg

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INTRODUCTION

Enersource Hydro Mississauga (Enersource) recognized a need to perform an Asset Condition Assessment (ACA) on its key distribution assets. An assessment produces a quantifiable evaluation of asset condition, aids in prioritizing and allocating sustainment resources, and facilitates the development of a Distribution System Plan. This undertaking spans several years and, thus allows Enersource to monitor the trend in asset condition changes and to incrementally improve its assessment process and asset management practices.

In early 2011, Enersource selected and engaged Kinectrics Inc (Kinectrics) to perform ACAs on Enersource's key distribution assets for four years, beginning in 2011. The initial 2011 and 2012 assessments covered Enersource's asset population, based on the available condition data, as of the end of 2010 and 2011 respectively. The results were presented in the reports entitled "Enersource Hydro Mississauga 2011 Asset Condition Assessment", dated November 28, 2011 and "Enersource Hydro Mississauga 2012 Asset Condition Assessment", dated December 21, 2012. This report presents results for the third year assessment and is based on the available condition data as of the end of 2013.

The category and sub-categories of assets included in this study are as follows:

- Substation Transformers
  - In Service
  - Spares
- Substation Circuit Breakers
- Pole Mounted Transformers
- Pad Mounted Transformers
  - 1 Phase
  - 3 Phase
- Vault Transformers
- Pad Mounted Switchgears
- Overhead Line Switches
  - 44 kV
  - 27.6 kV
  - Inline
  - Motorized
- Underground Cables
  - Main Feeder
  - Distribution
- Poles
  - Wood
  - Concrete

For each asset category, the Health Index formulation, Health Index distribution, condition-based flagged-for-action plan, and a data assessment in terms of the data availability indicator (DAI) and data gap analysis are given.

Note that the asset condition assessment methodology remained unchanged from the initial assessment performed in 2011 and is as described in the initial Kinectrics report titled "Enersource Hydro Mississauga 2011 Asset Condition Assessment". However, due to changes in data collected in 2013, the Health Index formulations were adjusted to incorporate the newly available data.

HEALTH INDEX RESULTS

Table 1 shows a summary of the Health Index evaluation results. Figure 1 presents the same information graphically. The population and sample size, or number of assets with sufficient data for Health Indexing, are given. Also shown are the average Health Index value, Health Index Distribution, and average DAI for each group.

It can be seen from the results that Underground Cables category was, on average as an asset group, in the worst condition. There were 21% and 35% of the units in "poor" or "very poor" condition for main feeder and distribution cables respectively.

Other groups of concern were Pad Mounted Switchgear, Pole Mounted Transformers and Vault Transformers. The percentages of assets in "poor" or "very poor" condition are 10%, 9% and 10%, respectively.

CONDITION BASED FLAGGED FOR ACTION PLAN

The condition-based Flagged-for-Action plan for the first year and the next 10 years is shown for each asset group in Table 2. Table 3 shows the 10 year Flagged-for-Action plan. It should be noted that for some asset categories the quantity determined for the current year plan, shown in Table 2, may be significantly larger than the quantities determined for near future subsequent years. This is generally the case when there is a large quantity of assets that are at or very near the end of their maximum useful lives. Because such assets would have a high failure rate, large quantities will be flagged for intervention in the first year. Since the assessment methodology assumes that all units flagged for intervention are replaced, the quantities determined for near future subsequent years may be significantly smaller than that of the first year. In reality, only some of the units flagged for action in the first year will be dealt while the remaining units will be addressed in subsequent years.

It is important to note that the flagged-for-action plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units that are expected to be candidates for replacement or other action. While the Condition-Based Flagged-for-Action Plan can be used as a guide or input to Enersource's Distribution System Plan, it is not expected that it be followed directly or as the final deciding factor in making sustainment capital decisions. There are numerous other factors and considerations that will influence Enersource's Asset Management decisions, such as obsolescence, system expansion, regulatory requirements, municipal demands, etc.

In the first year, over 10% of main feeder underground cables and over 20% of distribution underground cables were flagged for action.

During the next 10 years, about 30% or higher of Underground Cables (both main feeder and distribution lines) and Pad Mounted Switchgear were determined to be eligible for replacement. Among the other asset groups, Pole Mounted Transformers, Vault Transformers and Wood Poles had more than 10% of their population eligible for replacement.

A summary of the results is shown in the tables and figures below.

Table 1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution: Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	Average Age	Average DAI
Substation Transformers	In Service	108	108	83%	0%	3%	13%	34%	50%	21	75%
	Spares	9	9	87%	0%	0%	22%	11%	67%	36	29%
Circuit Breakers		510	510	95%	2%	< 1%	< 1%	3%	94%	19	51%
Pole Mounted Transformers		5334	5334	90%	2%	7%	2%	15%	74%	22	82%
Pad Mounted Transformers	1 Phase	14189	14189	89%	< 1%	5%	3%	15%	77%	21	99%
	3 Phase	1784	1784	92%	< 1%	2%	1%	8%	88%	16	99%
Vault Transformers		3900	3900	89%	2%	8%	4%	12%	76%	27	76%
Pad Mounted Switchgear		852	852	79%	5%	5%	18%	24%	48%	19	59%
Overhead Switches	44 kV	354	354	89%	0%	< 1%	5%	26%	69%	19	88%
	27.6 kV	219	219	94%	0%	0%	2%	14%	84%	16	69%
	Inline	1946	1946	96%	< 1%	< 1%	3%	7%	89%	18	69%
	Motorized	97	97	88%	0%	0%	8%	24%	68%	15	63%
Underground Cables (in conductor-km)	Main Feeder	2246	2246	77%	12%	9%	0%	7%	72%	18	100%
	Distribution	4022	4022	69%	22%	13%	0%	6%	59%	21	100%
Poles	Wood	12602	12602	93%	< 1%	3%	2%	10%	85%	26	100%
	Concrete	8194	8194	97%	0%	0%	< 1%	5%	95%	28	100%

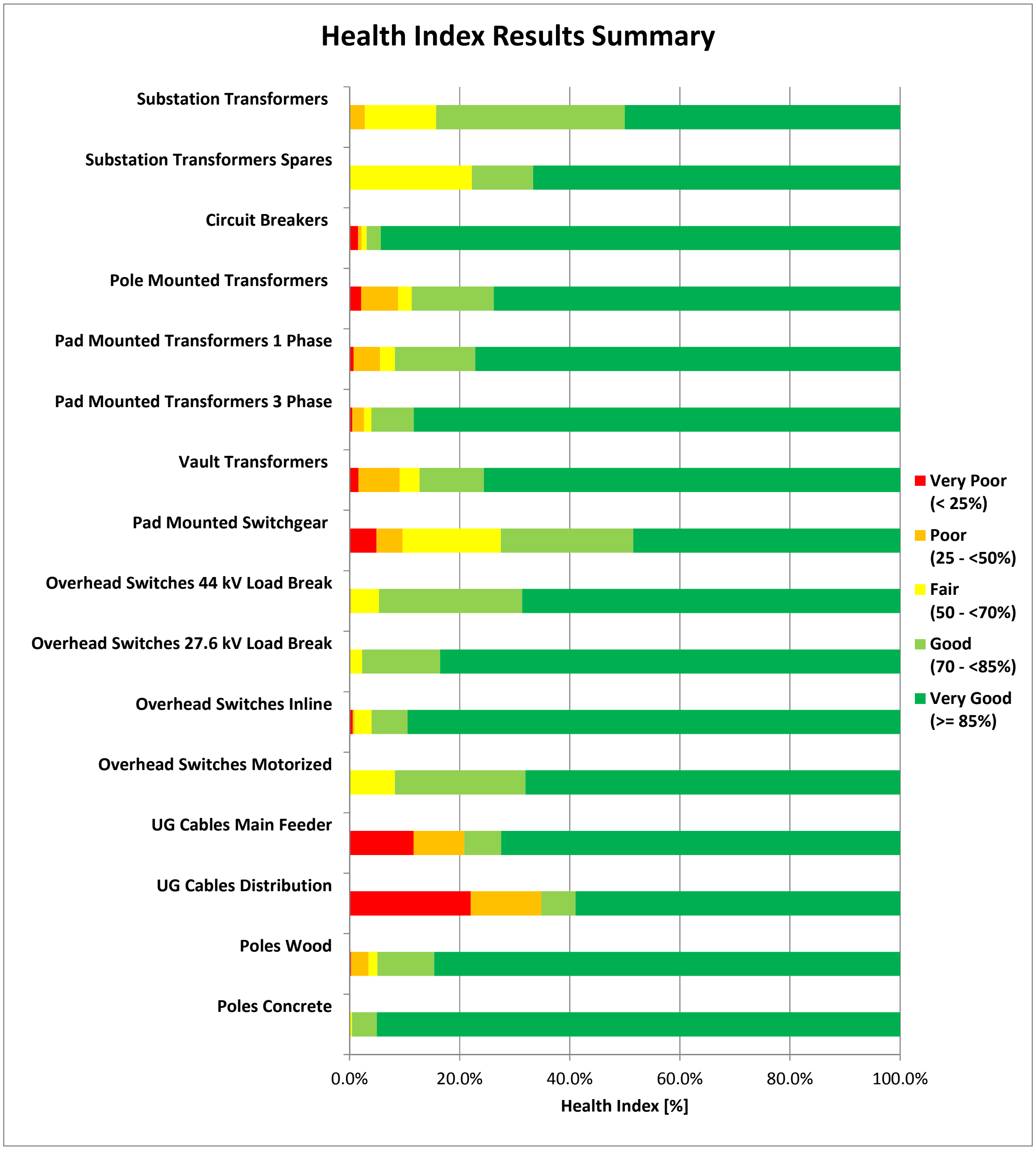

Figure 1 Health Index Results Summary (Graphical)

Table 2 Condition-Based Flagged-for-Action Plan for Year 1

Asset Category		1st Year Replacement		10 Year Replacement in Total		Replacement Strategy
		Quantity	Percentage	Quantity	Percentage	
Substation Transformers	In Service	3	2.8%	9	8.3%	proactive
	Spares	N/A	N/A	N/A	N/A	N/A
Circuit Breakers		11	2.2%	24	4.7%	proactive
Pole Mounted Transformers		125	2.3%	629	11.8%	reactive
Pad Mounted Transformers	1 Phase	164	1.2%	1062	7.5%	reactive
	3 Phase	7	0.4%	51	2.9%	reactive
Vault Transformers		78	2.0%	445	11.4%	reactive
Pad Mounted Switchgear		37	4.3%	249	29.2%	proactive
Overhead Switches	44 kV	0	0.0%	6	1.7%	reactive
	27.6 kV	0	0.0%	0	0.0%	reactive
	Inline	10	0.5%	52	2.7%	reactive
	Motorized	0	0.0%	0	0.0%	reactive
Underground Cables (conductor-km)	Main Feeder	268	11.9%	697	31.0%	reactive
	Distribution	856	21.3%	1821	45.3%	reactive
Poles	Wood	170	1.3%	1968	15.6%	proactive
	Concrete	17	0.2%	349	4.3%	proactive

Table 3 Ten-Year Condition-Based Flagged-for-Action Plan

Replacement Year	Asset Category															
	Substation Transformers		Circuit Breakers	Pole Mounted Transformers	Pad Mounted Transformers		Vault Transformers	Pad Mounted Switchgear	Overhead Switches				Underground Cables (conductor-km)		Poles	
	In Service	Spares			1 Phase	3 Phase			44 kV	27.6 kV	Inline	Motorized	Main Feeder	Distribution	Wood	Concrete
1	3	N/A	11	125	164	7	78	37	0	0	10	0	268	856	170	17
2	0	N/A	0	108	163	8	66	25	0	0	5	0	84	225	166	21
3	0	N/A	0	90	146	7	58	21	0	0	4	0	62	161	176	22
4	1	N/A	0	73	131	8	51	23	0	0	2	0	54	128	183	27
5	0	N/A	0	58	114	7	45	25	1	0	4	0	48	104	190	33
6	2	N/A	1	47	87	5	38	25	1	0	3	0	43	86	202	33
7	1	N/A	5	39	71	3	32	23	0	0	4	0	38	74	209	40
8	0	N/A	1	33	59	2	28	26	2	0	6	0	36	66	216	46
9	0	N/A	0	29	60	2	25	23	1	0	6	0	33	62	224	51
10	2	N/A	6	27	67	2	24	21	1	0	8	0	31	59	232	59

DATA ASSESSMENT

Data assessment includes determining the data availability indicator (DAI) of each unit, as well as identifying the data gaps for each asset group. Data availability is a measure of the amount of data that an individual unit has in comparison with the set of data currently available in for its respective asset category. Data gaps are items that are indicators of asset degradation, but are currently not collected or available for any asset in an asset category. The more minimal the data gaps, the higher the quality of available condition data and Health Index formulas.

Most of the required condition data for Substation Transformers was available. At 75%, the average of DAI of this group was slightly better than in the previous year. There has been an improvement in the collection of loading and inspection data. The loading data were available for 97% of the population in 2013, while only available for 88% of the population in 2012. More than 60% of the population had inspection data in 2013, whereas roughly 55% of population had such data in 2012. The data gaps remained the same as the past year (refer to the report “Enersource Hydro Mississauga 2012 Asset Condition Assessment”) and included infrared thermography and grounding condition.

Data for Circuit Breakers included age, contact resistance, and inspection results. The average DAI for this asset group improved from 46% last year to 51% this year. Age was available for all units, contact resistance measurement availability increased from 50% to 67%, and inspection record availability remained at approximately 30%. No new data types had been collected so the data gaps remained the same as those given in 2012 ACA report.

In 2012 study, the assessment was age-based for Pad Mounted Transformers. In the spring of 2012, Enersource launched a visual inspection program for this asset group, and inspection data was collected and incorporated in the 2013 Health Index formulation. This includes inspection on tank corrosion and oil leaks. The other data gap items from the 2012 ACA report remained the same.

The average data availability indicator for Vault Transformers improved from 35% last year to 76% this year. Age is available for the entire population and inspections were available for most of the population. One of the data gaps noted in the 2012 report, named “access”, was addressed with data collection in 2013. The other data gap items remained.

In addition to condition data, replacement records are being collected for pole, pad, and vault transformers. These records will be used in developing Enersource specific failure curves.

The average DAI for the Pad Mounted Switchgear group was 59%, a 25% improvement over last year’s 34%. Age was available for all units. Inspection data, gathered from linemen inspections and dry ice cleaning, was available for approximately 50% of the population. There were no data gaps for this asset group because all condition data required by the Health Index formula were collected through linemen inspections and dry ice cleaning. It should be noted, however, that only half of the population had inspection data during the past 5 years. Such data should be collected for the remainder of the population.

Age and inspections were available for Overhead Line Switches. For 44 kV switches, the average DAI was 88%. Age was known for all units; inspection records were available for approximately 77% of the population. For 27.6 kV switches, the average DAI was 69%. Age was known for all units; inspection records were available for approximately 38% of the population. The average DAI for the In Line switch sub-category was 69%. Age was known for nearly all units; approximately 58% of the population was found to have a solid blade switch inspection record. The average DAI for the Motorized switch sub-category was 63%. Age was known for all units; inspection records were available for approximately 26% of the population.

Note that for all switch types, inspection records have not been updated since the 2012 ACA. As such, the same inspection data were used in both the 2012 and 2013 studies. Further, for all switch types, no new types of condition data have been collected and the data gaps noted in the 2012 report remain to be addressed.

Age data was available for Underground Cables and because age was known for all segments, the average DAI for both Main Feeder and Distribution Cables sub-categories was 100%. The data gaps noted in the 2012 report, however, remained to be addressed.

Only age was available for Wood and Concrete Poles. Because the assessment was age based and the age of all poles was known, the DAIs of both sub-categories was 100%. Since last year's assessment, no new data types had been collected for this asset category and the data gaps noted in the 2012 report remained to be addressed.

2012 TO 2013 AUDIT

In 2012 an Asset Condition Assessment (ACA) for key distribution assets was conducted for Enersource by Kinectrics. Between 2012 and 2013, Enersource took steps to adopt the recommendations prescribed by the 2012 ACA and to improve the quality of its condition data. As described in this report, a subsequent ACA was conducted by Kinectrics for Enersource's assets as of 2013. In addition, Kinectrics assessed the changes with respect to ACA between the 2012 and 2013. This section of the report describes the findings.

Asset Categories

Health Index (HI) formulation and results from 2012 and 2013 were compared for the asset categories and sub-categories included in the 2012 and 2013 assessments.

Audit Results

For each asset category, the following aspects were compared between 2012 and 2013:

1. Health Index Formulation
2. Population and Sample Size
3. Health Index Distribution

Changes in Health Index Formulation

Since 2012, Enersource has made significant efforts with respect to collecting more condition data for several asset categories. Thus, for some asset categories, the Health Index formulas were changed so that the newly collected data could be included. The asset categories and changes to Health Index are described below:

- Pole Mounted Transformers: incorporated visual inspection condition data, including tank corrosion, oil leak and overall condition assessment
- Pad Mounted Transformers: incorporated visual inspection condition data, including tank corrosion and oil leak

Changes in Population and Sample Size

Table 4 summarizes the Change in Population and in Sample Size between 2012 and 2013. Graphical representations of the data are given on Figure 2 and Figure 3.

Table 4 Summary Change in Population and Sample Size

Asset		Population				Sample Size		
		Population Count 2012	Population Count 2013	Population Change by Counts	Population Change by %	% Sample Size 2012	% Sample Size 2013	Sample Size Change by %
Substation Transformers	In Service	104	108	4	4%	100%	100%	0%
	Spares	12	9	-3	-25%	100%	100%	0%
Circuit Breakers		497	510	13	3%	95%	100%	5%
Pole Mounted Transformers		5384	5334	-50	-1%	100%	100%	0%
Pad Mounted Transformers	1 Phase	14196	14189	-7	0%	100%	100%	0%
	3 Phase	1755	1784	29	2%	100%	100%	0%
Vault Transformers		3891	3900	9	0%	100%	100%	0%
Pad Mounted Switchgear		781	852	71	9%	100%	100%	0%
Overhead Switches	44 kV	346	354	8	2%	100%	100%	0%
	27.6 kV	224	219	-5	-2%	100%	100%	0%
	Inline	1884	1946	62	3%	100%	100%	0%
	Motorized	88	97	9	10%	100%	100%	0%
Underground Cables *	Main Feeder	2242	2246	4	0%	100%	100%	0%
	Distribution	4004	4022	18	0%	100%	100%	0%
Poles	Wood	12766	12602	-164	-1%	100%	100%	0%
	Concrete	7854	8194	340	4%	100%	100%	0%

* data in conductor-km

Changes in Population

The population increase in Substation In-Service Transformers and decrease in Substation Spare Transformers is mainly due to putting three of 2012 spare units in service in 2013. Additionally, a new transformer was installed and put in service.

The population increase in Circuit Breakers is a result of many newly installed units in 2013, mainly at Erin Mills and Melton substations.

The populations of Pole Mounted Transformers, Pad Mounted Transformers and Vault Transformers remained relatively steady.

The population of Pad Mounted Switchgear increased by nearly 10%. This was mainly due to new installation of VISTA type switchgear as well as newly included solid dielectric type switchgear, both at 27.6 kV and 4.16/13.8 kV levels.

The population of 44 kV, 27.6 kV, and Inline Overhead Switches remained relatively steady. The increase for inline and motorized switches was mainly due to new installation under the automation oriented program in 2013.

The population of Underground Cables remained relatively steady, for both main feeder and distribution cables.

The population of Wood Poles remained relatively steady. The increase for Concrete Poles was mainly due to new installation as well as replacement of old wood poles with concrete poles, in late 2012 and 2013.

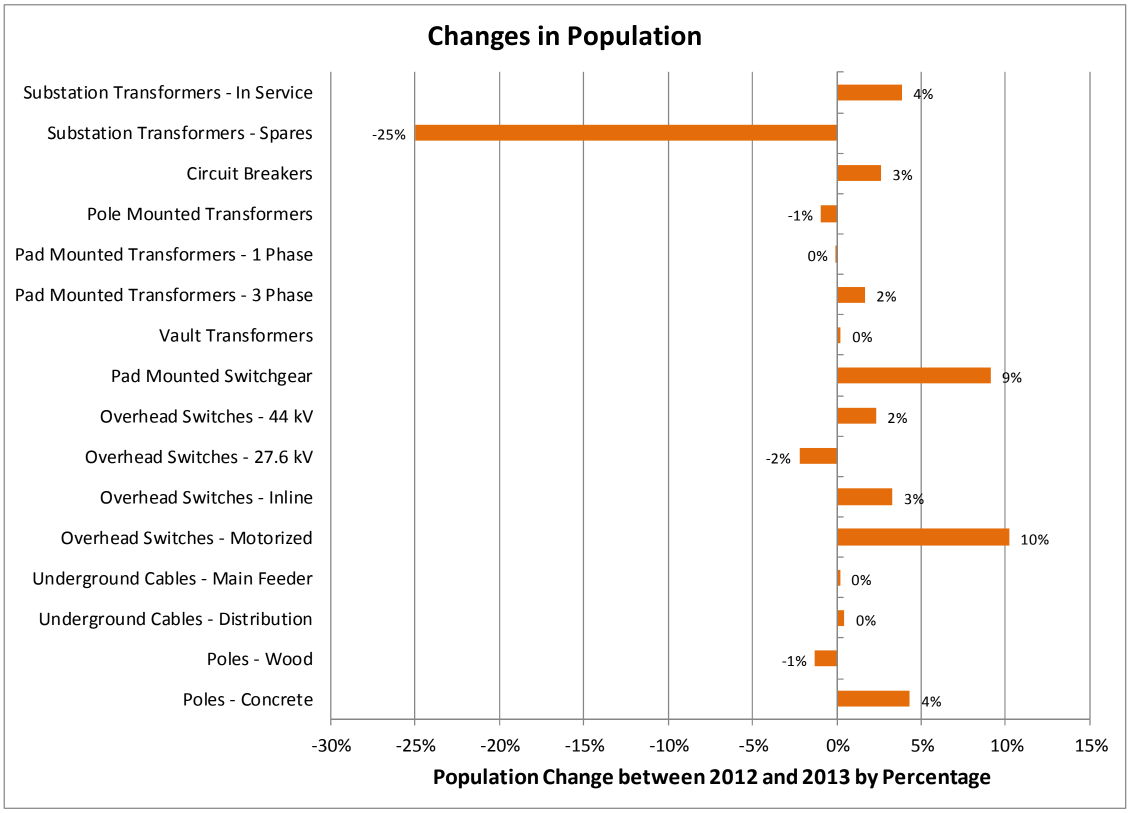

Figure 2 Changes in Population

Changes in Sample Size

Ideally, condition data should be available for every asset within a population. Failing that, the larger the sample size, or subset of assets with sufficient condition information, the more confidence there is in extrapolating the ACA results over an entire asset population.

The sample size for Circuit Breakers improved by 5% and is now 100%.

For all the other asset groups, the sample size in 2013 was 100%, the same as for 2012 study.

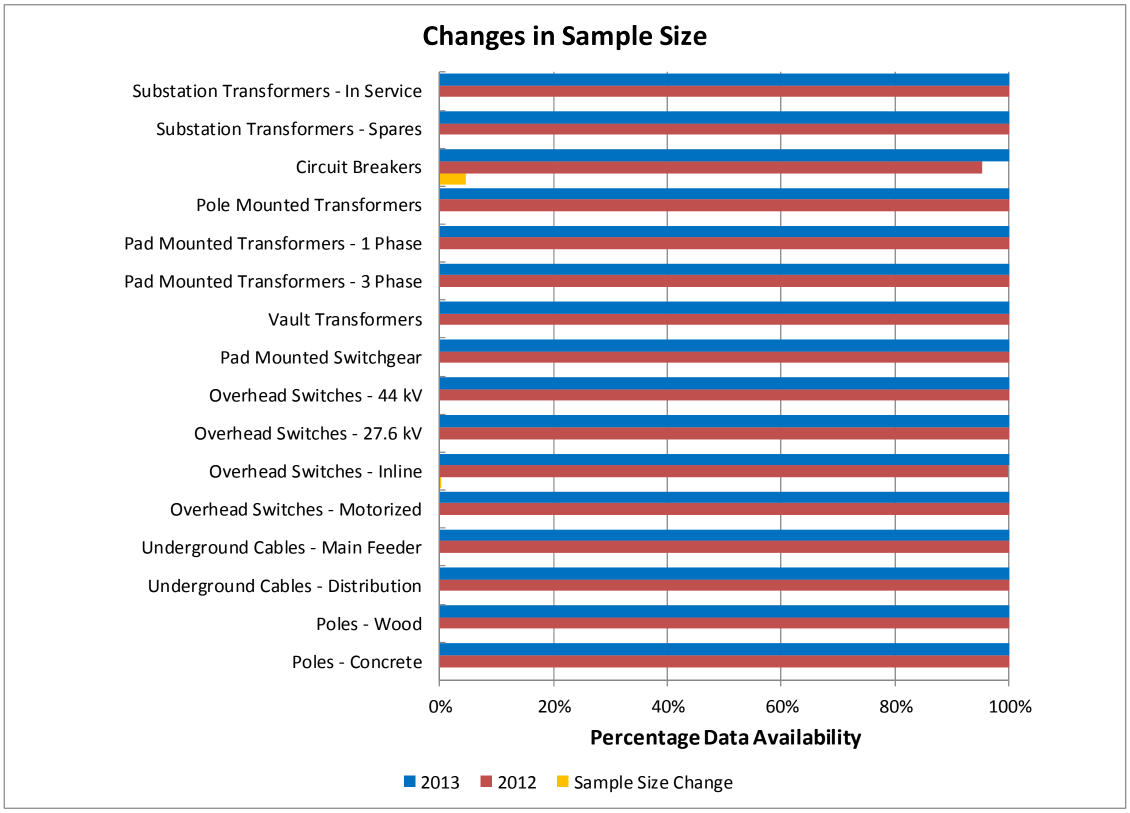

Figure 3 Changes in Sample Size

Changes in Health Index Distribution

The changes in Health Index distribution between 2012 and 2013 are summarized in Table 5 and graphically shown in Figure 4.

The overall trend with respect to Health Index distribution was assessed. Assets that showed an increasing percentage of “good” and/or “very good” or a decrease of “very poor”, “poor”, and/or “fair” were classified as having overall improved health distributions. Conversely, asset classes with a decreasing percentage of “good” and/or “very good” or an increasing percentage of “very poor”, “poor”, and/or “fair” were classified as having an overall decline in health.

Substation Transformers In Service: The trend shows a general decline in overall condition. Compared with the results in 2012, the numbers of units classified as “very good” and “good” in 2013 dropped by 2% each. The decline might be partially attributed to improved condition data availability than the 2012 ACA.

Substation Transformers Spares: The trend shows a general decline in overall condition. While some units had their HI results decreased due to aging (no other information available), some other units classified as “very good” in 2012 were put in service in 2013. This changed the total population and overall HI distribution for spare units.

Circuit Breakers: The trend shows an improvement in overall condition. In 2012 about 88% breakers were classified as "very good". In 2013 this percentage increased to 94%. This change was mainly attributed to about 20 newly installed and about 20 replaced breakers in 2013.

Pole Mounted Transformers: The trend shows a decline in overall condition. The change may be partially attributed to obtaining improved asset condition information through closing of some data gaps. In 2012 the ACA study was age based while n 2013, the ACA study included some additional condition information from visual inspections.

Pad Mounted Transformers 1-phase and 3-phase: In both cases, the trend shows a slight decline in overall condition. The change may be partially attributed to obtaining improved asset condition information through closing of some data gaps. In 2012 the ACA study was age based. In 2013, the ACA study included some additional condition information from visual inspections.

Vault Transformers: The trend shows an improvement in overall condition. The change may be partially attributed to more credible information for the asset group, given that data availability increased between 2012 and 2013.

Pad Mounted Switchgear: The trend shows a slight decline in overall condition. The change may be partially attributed to more credible information for the asset group. Compared to 2012, data availability increased.

Overhead Switches 44 kV, Inline and Motorized: In all three categories, the trend shows a slight decline in overall condition. The decline is attributed to aging. Because no new inspection data were available beyond the 2012 inspections records, the only difference between the 2012 and 2013 assessments were age of switches. Because units are older in 2013, the 2013 HIs were lower than the 2012 HIs.

Overhead Switches 27.6 kV: The trend shows a slight improvement in overall condition. The improvement was mainly attributed to a series of new installations and decommissioning since 2012 ACA study.

Underground Cables, Main Feeder and Distribution: In both categories, the trend shows a substantial decline in overall condition. The change was attributed to revision of failure curves for cables manufactured prior to 1989 to better reflect Enersource's experiences. In the 2013 assessment, such cables were assumed to be direct buried and non tree-retardant. Such cables comprise 20% and 35% of entire main feeder and distribution lines respectively, and it was found that these cables are approaching end of life.

Poles, Wood and Concrete: In both cases, the trend shows a slight decline in overall condition. The decline was attributed to aging, as the ACA studies were age based in both 2012 and 2013.

Table 5 Summary Change in Health Index Distribution

Asset	Year	Very Poor		Poor		Fair		Good		Very Good		Average Health Index	
		% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	%	Change
Substation Transformers - In Service	2012	0.0%	0%	1.0%	2%	10.6%	2%	36.5%	-2%	51.9%	-2%	84.1%	-1%
	2013	0.0%		2.8%		13.0%		34.3%		50.0%		82.7%	
Substation Transformers - Spares	2012	0.0%	0%	0.0%	0%	0.0%	22%	16.7%	-6%	83.3%	-17%	92.4%	-5%
	2013	0.0%		0.0%		22.2%		11.1%		66.7%		87.0%	
Circuit Breakers	2012	6.1%	-5%	0.2%	0%	1.3%	0%	4.2%	-2%	88.2%	6%	91.4%	4%
	2013	1.6%		0.6%		1.0%		2.5%		94.3%		95.3%	
Pole Mounted Transformers	2012	2.8%	-1%	2.2%	4%	1.1%	1%	5.2%	10%	88.7%	-15%	93.2%	-4%
	2013	2.1%		6.7%		2.5%		14.9%		73.8%		89.7%	
Pad Mounted Transformers - 1 Phase	2012	4.5%	-4%	2.0%	3%	2.0%	1%	2.8%	12%	88.8%	-12%	89.8%	-1%
	2013	0.7%		4.8%		2.7%		14.6%		77.2%		88.5%	
Pad Mounted Transformers - 3 Phase	2012	2.8%	-2%	1.6%	1%	1.9%	-1%	1.4%	6%	92.3%	-4%	91.4%	1%
	2013	0.5%		2.1%		1.3%		7.7%		88.3%		92.2%	
Vault Transformers	2012	3.9%	-2%	2.9%	5%	6.9%	-3%	13.0%	-1%	73.3%	2%	86.8%	3%
	2013	1.6%		7.5%		3.6%		11.7%		75.6%		89.5%	
Pad Mounted Switchgear	2012	6.9%	-2%	6.0%	-1%	9.3%	8%	20.2%	4%	57.5%	-9%	79.5%	-1%
	2013	4.9%		4.7%		17.8%		24.1%		48.5%		79.0%	
Overhead Switches - 44 kV	2012	0.0%	0%	0.3%	0%	4.3%	1%	24.9%	1%	70.5%	-2%	89.6%	0%
	2013	0.0%		0.3%		5.1%		26.0%		68.6%		89.1%	
Overhead Switches - 27.6 kV	2012	0.0%	0%	0.4%	0%	1.8%	0%	16.5%	-2%	81.3%	2%	94.0%	0%
	2013	0.0%		0.0%		2.3%		14.2%		83.6%		94.5%	
Overhead Switches - Inline	2012	0.6%	0%	0.2%	0%	2.0%	1%	6.2%	0%	91.1%	-2%	96.5%	-1%
	2013	0.6%		0.4%		3.1%		6.5%		89.5%		95.6%	
Overhead Switches - Motorized	2012	0.0%	0%	0.0%	0%	5.7%	3%	25.0%	-1%	69.3%	-1%	89.1%	-1%
	2013	0.0%		0.0%		8.2%		23.7%		68.0%		88.5%	
Underground Cables - Main Feeder	2012	0.0%	12%	0.4%	9%	1.0%	-1%	1.1%	6%	97.4%	-25%	97.0%	-20%
	2013	11.7%		9.2%		0.0%		6.7%		72.5%		77.3%	
Underground Cables - Distribution	2012	0.1%	22%	0.9%	12%	2.0%	-2%	2.8%	3%	94.2%	-35%	96.6%	-28%
	2013	22.0%		12.8%		0.0%		6.2%		59.0%		68.6%	
Poles - Wood	2012	0.0%	0%	0.3%	3%	3.6%	-2%	10.7%	0%	85.4%	-1%	93.9%	-1%
	2013	0.3%		3.2%		1.6%		10.3%		84.6%		92.9%	
Poles - Concrete	2012	0.0%	0%	0.0%	0%	0.0%	0%	0.2%	4%	99.8%	-5%	98.7%	-2%
	2013	0.0%		0.0%		0.4%		4.5%		95.0%		97.0%	

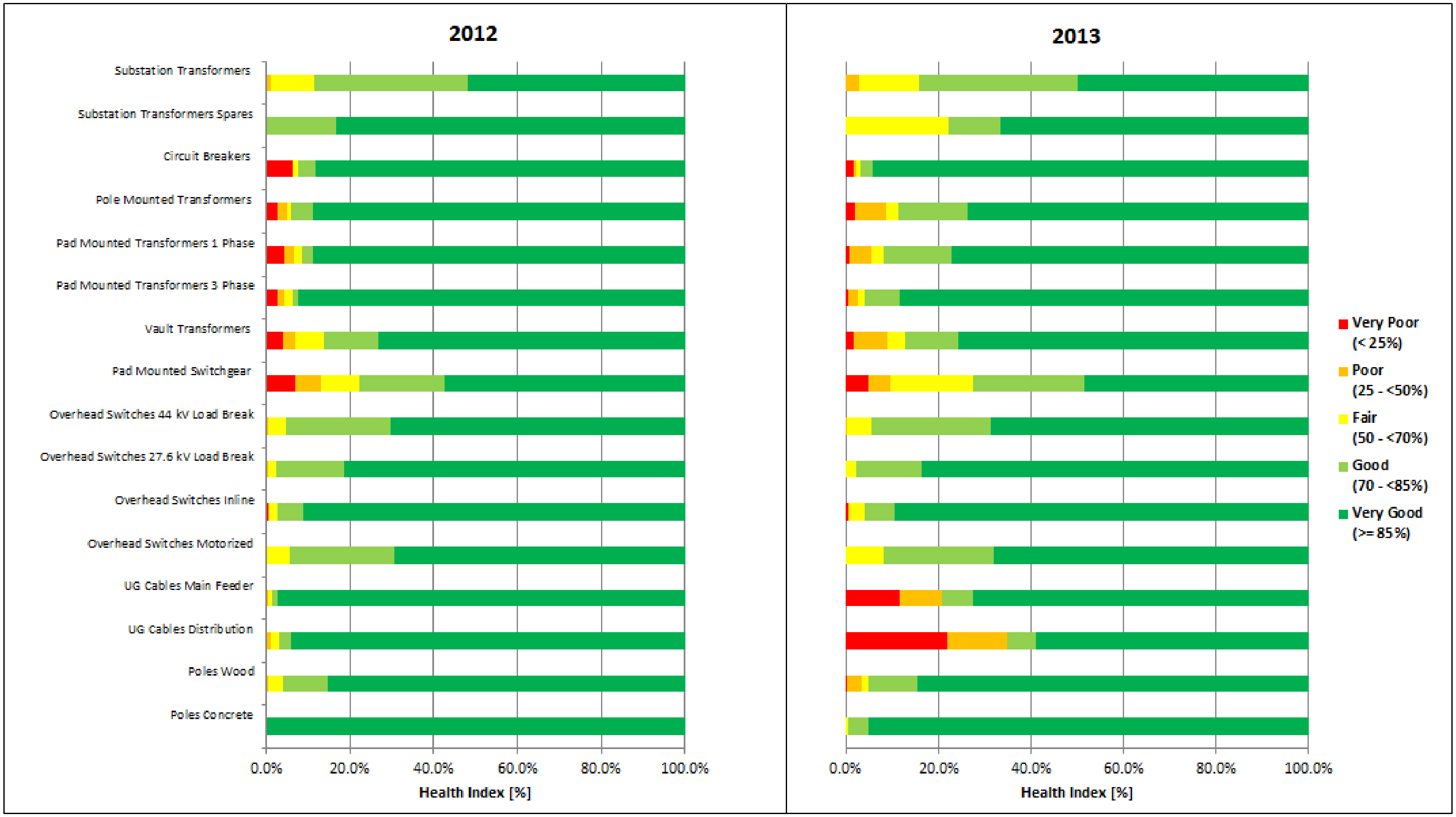

Figure 4 Changes in Health Index

CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for nine of Enersource's key distribution asset categories. For each asset category, the Health Index distribution was determined and a condition-based Flagged-for-Action plan was developed.

2. The Underground Cables category was found to be in the worst condition. Over 20% and 30% of the main feeder and distribution cables populations, respectively, were in "poor" or "very poor" condition.

3. Other asset categories of concern were Pad Mounted Switchgear, Pole Mounted Transformers and Vault Transformers. For all these three asset categories, about 10% of assets in "poor" or "very poor" condition.

4. The Underground Cables category was determined to have the highest flagged for action percentage among all the asset groups, given that over 10% of the population requires action in the first year. Within the next 10 years, a total of 30% of the population requires action.

5. Although in the first year Pad Mounted Switchgear had less than 5% of units flagged for action, nearly 30% of the population is flagged for action within the next 10 years.

6. During the 10-year period starting from now, Pole Mounted Transformers, Vault Transformers and Wood Poles would have over 10% of their populations flagged for action.

7. The average DAI for Substation Transformers improved over last year. Loading test and inspection data were available for more units.

8. The average DAI for Circuit Breakers improved because the number of units with test data increased. However, because no new data types had been collected, the data gaps remained the same as in the 2012 ACA report.

9. Since the 2012 assessment, some inspection data listed as data gaps in the 2012 report was collected and incorporated in the Pole Mounted Transformer and Pad Mounted Transformer 2013 Health Index formulations.

10. The average data availability indicator for Vault Transformers improved greatly this year. This year more inspection data of vault transformers was collected, and one of the data gap items, "access", listed in the 2012 report was included in the 2013 Health Index assessment.

11. In addition to condition data, replacement records are being collected for distribution transformers. These records will be used in developing Enersource-specific failure/replacement curves.

12. The average DAI of Pad-Mounted Switchgear improved substantially this year. In 2013 condition data were available for approximately half of the population, compared with only approximately a quarter of the population in 2012. There are no data gaps for this asset.

13. For Overhead Line Switches, inspection records have not been updated since the 2012 ACA. Also, no other new types of condition data have been collected and the data gaps noted in the 2012 report remained to be addressed.

14. Age data were available for Underground Cables and because age was known for all segments, the average DAI for both Main Feeder and Distribution Cables sub-categories was 100%. The data gaps noted in the 2012 report remained to be addressed.

15. Only age was available for Wood and Concrete Poles. Because the assessment was age based and the age of all poles was known, the DAIs of both sub-categories was 100%. Since last year's assessment, no new data types had been collected for this asset category and the data gaps noted in the 2012 report remained to be addressed.

16. Enersource had some infra-red tests performed on distribution transformers. This information was, however, not available in an electronic format useable for this study. It is recommended that the infra-red test data be stored and sorted out in a standardized and systematic way, so that it may be used as input for future condition assessments.

17. It is recommended that the data availability indicator (DAI) for each asset category be brought to 100% and maintained at that level. For example, Doble test data were only available for 50% of substation transformers. Ensuring that all substation transformers have Doble data will further improve the overall DAI of that asset category.

18. For each asset category it is recommended that the data gaps be addressed in order of the priority given in this report.

19. It is recommended that Metal-Clad Switchgear be included as a separate asset category.

20. Because only limited failure statistics was available at this time, an exponentially increasing failure rate and corresponding probability of failure model were assumed in this study. It is recommended that Enersource continue to collect failure statistics so that Enersource-specific failure models can be developed and used in future assessments. Note that this is already being done for distribution transformers and underground cables. Similar collection of failure data should be extended to all asset classes.

21. It is important to note that the Flagged-for-Action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence Enersource's Asset Management Plan, such as obsolescence, system growth, regulatory requirements, municipal initiatives, etc.

APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

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1. SUBSTATION TRANSFORMERS

1.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

1.1.1. Condition and Sub-Condition Parameters

Table 1-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Insulation	11	Table 1-2
2	Cooling	1	Table 1-3
3	Sealing & Connection	2	Table 1-4
4	Service Record	6	Table 1-5

Table 1-2 Insulation Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Quality	8	Table 1-6
2	Oil DGA	10	Table 1-7
3	Winding Doble	10	Table 1-8
4	Bushing (worst case condition of primary and secondary bushing)	5	Table 1-9

Table 1-3 Cooling Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Winding Temp Gauge	1	Table 1-9
2	Oil Temp Gauge	1	Table 1-9
3	Mech Box – Fan Supply	1	Table 1-9

Table 1-4 Sealing & Connection Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Corrosion / Paint Condition	1	Table 1-9
2	Tank Oil Level	2	Table 1-9
3	Gasket (worst case condition of conservator cover, rad)	3	Table 1-9

Table 1-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Loading	5	Table 1-10
2	Age	3	Figure 1-1

1.1.2. Condition Criteria

<u>Oil Quality</u>

The "Oil Quality" parameter is a composite of the following oil properties: moisture, dielectric strength, interfacial tension, color, and acidity.

Table 1-6 Oil Quality Test Criteria

Score	Description
4	Overall Factor is less than 1.2
3	Overall Factor between 1.2 and 1.5
2	Overall Factor is between 1.5 and 2.0
1	Overall Factor is between 2.0 and 3.0
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 °C Corrected) (From DGA test)		<=20	<=30	<=40	>40	4
Dielectric Str. [kV] D877		>40	>30	>20	Less than 20	3
Interfacial Tension (IFT)* [dynes/cm]	230 kV ≤ V	>32	25-32	20-25	Less than 20	2 *
	69 kV <V< 230	>30	23-30	18-23	Less than 18	
	V ≤ 69 kV	>25	20-25	15-20	Less than 15	
Color		Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number*	230 kV ≤ V	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <V< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	V ≤ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

For example if all data is available, Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{12}$

Oil DGA

Table 1-7 Transformer DGA Criteria

Score	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

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

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	**2**
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	**1**
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	**1**

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Winding Doble Test

Table 1-8 Winding Doble Test Criteria

Score	Description
4	power factor reading $\leq$ 0.3%
3	0.3% < power factor reading $\leq$ 0.5%
2	0.5% < power factor reading $\leq$ 0.7%
1	0.7% < power factor reading $\leq$ 1.0%
0	power factor reading > 1.0%

Age

Assume that the failure rate Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 40 and 60 years the probability of failures (P_f) for Substation Transformers are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

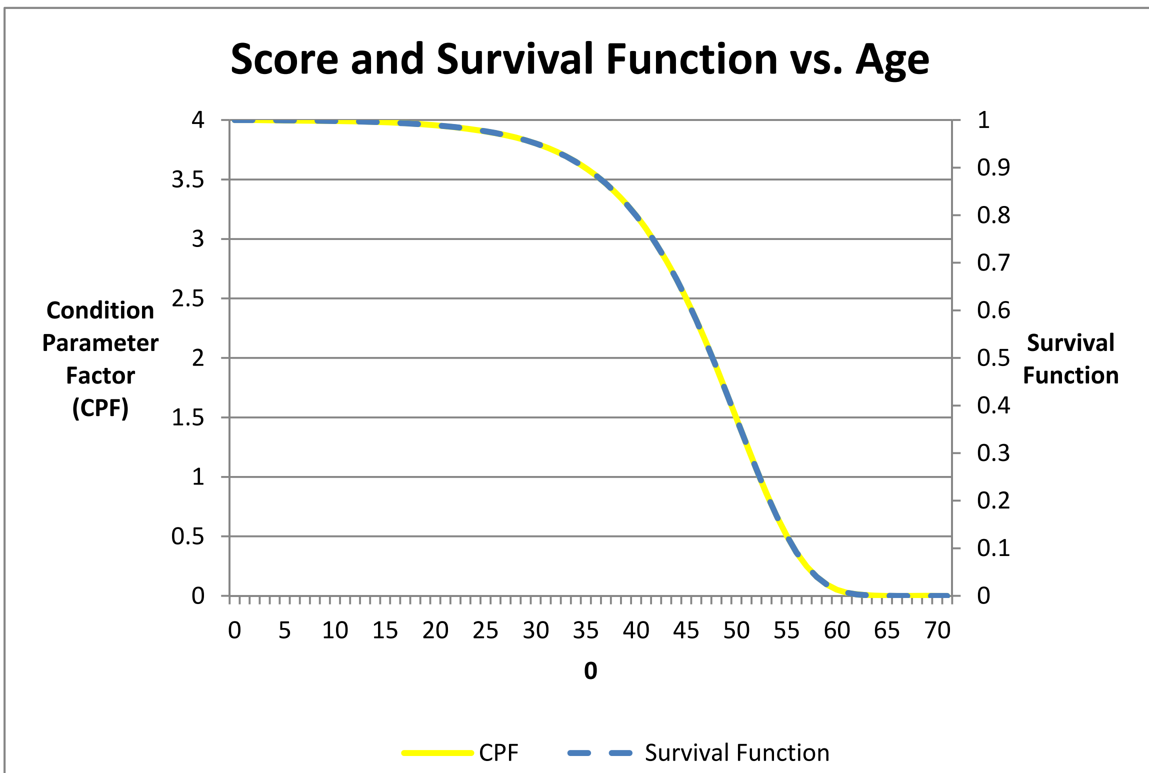

Figure 1-1 Substation Transformers Age Criteria

Visual Inspections

Table 1-9 Visual Inspection Criteria

Score	Condition Description
4	OK
0	Not OK

Loading History

Table 1-10 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

1.2. Age Distribution

The average age of all in service units was 21. The age distribution for in service Substation Transformers was as follows: Approximately 16% of all units were 40 or older.

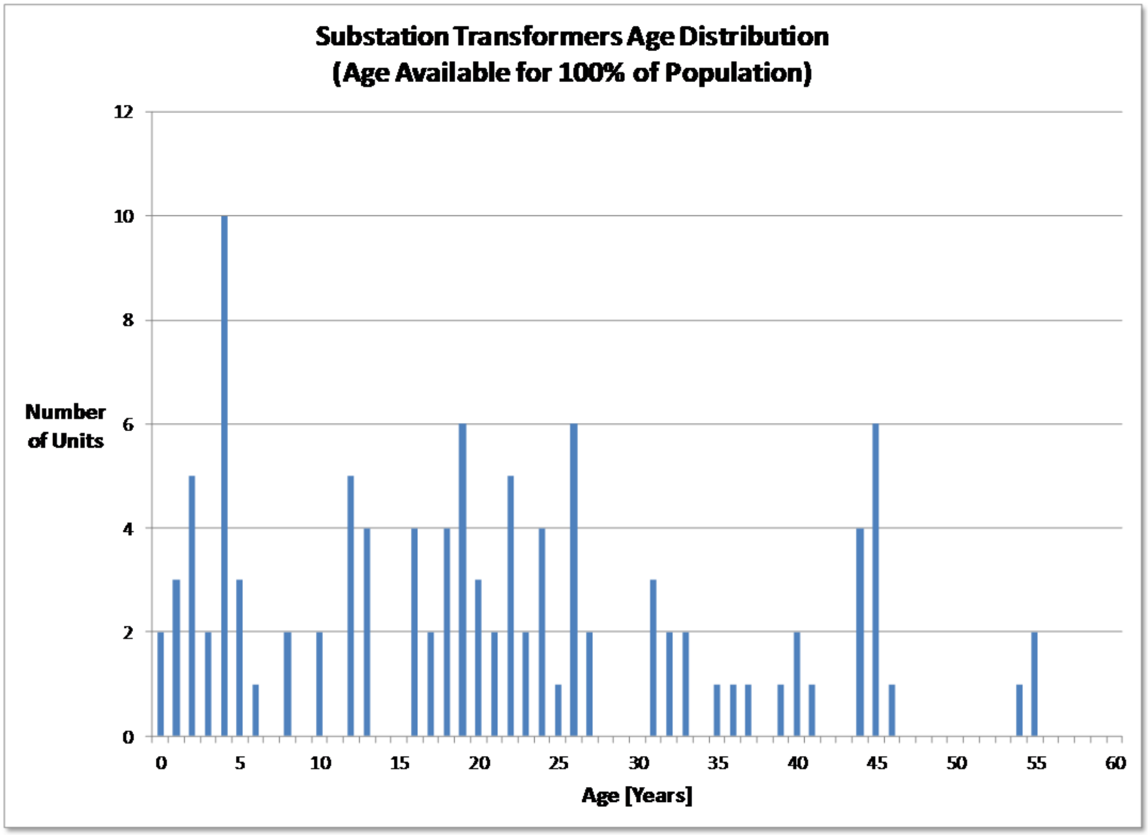

Figure 1-2 Substation Transformers Age Distribution

1.3. Health Index Results

There were 108 in service Substation Transformers at EHM. Of these, there were 108 units with sufficient data for a Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units were shown:

The average Health Index for this asset group was 83%. Three units were found to be in "poor" condition.

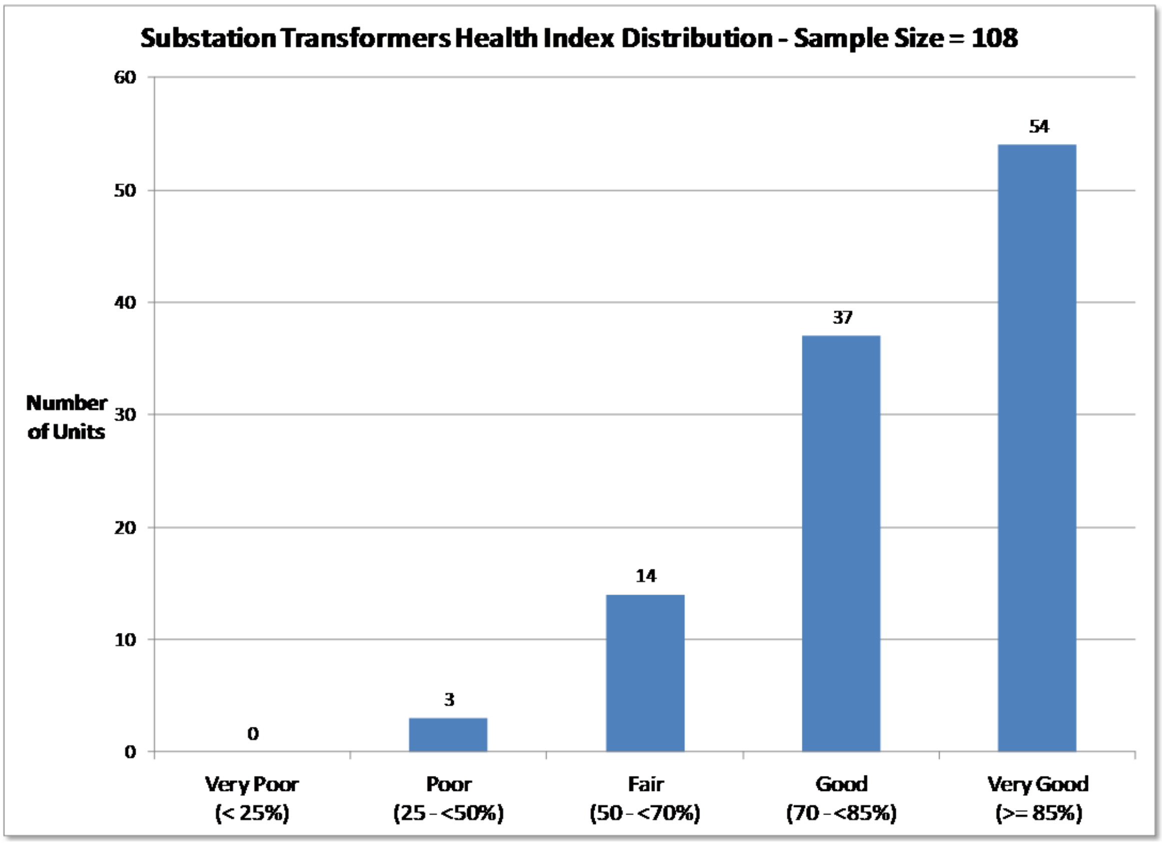

Figure 1-3 Substation Transformers Health Index Distribution (Unit)

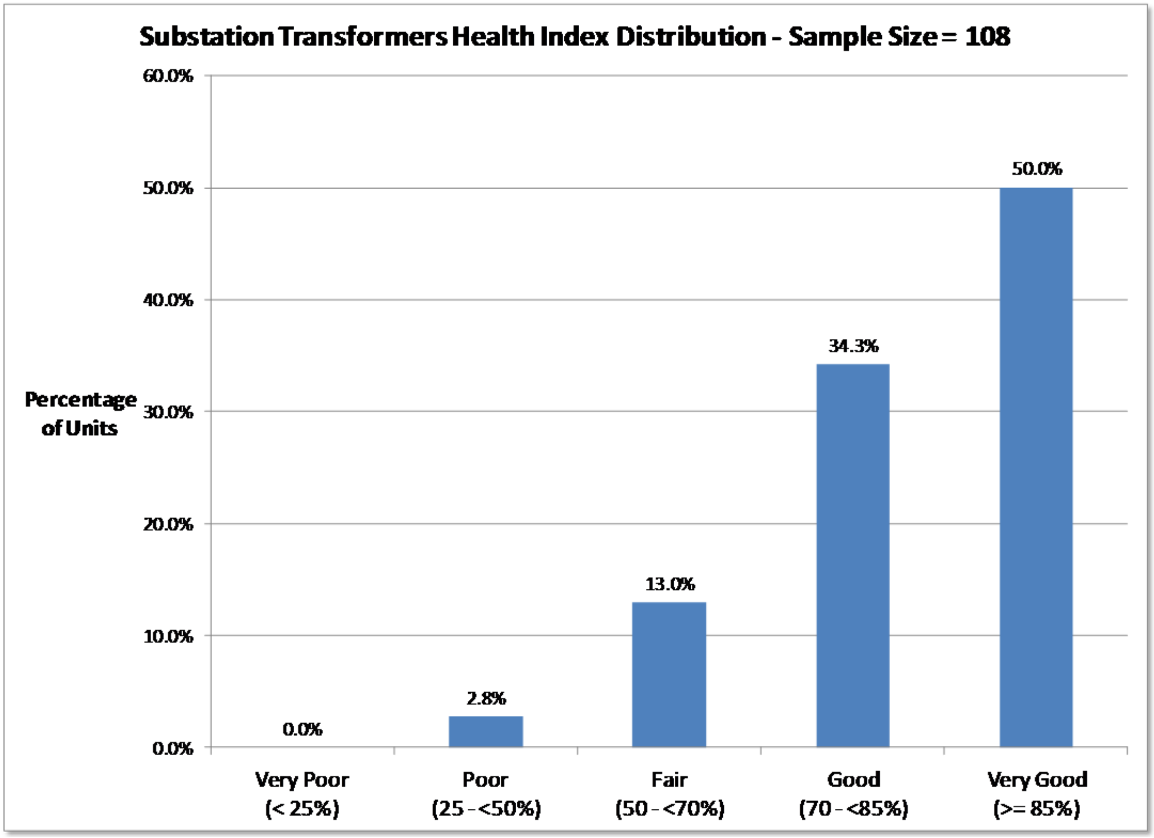

Figure 1-4 Substation Transformers Health Index Distribution (Percentage)

1.4. Condition-Based Flagged-for-Action Plan

It is assumed that Substation Transformers are proactively replaced.

A unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one.

Each unit's criticality is defined as follows:

$$\text{Criticality} = (\text{Criticality}_{max} - \text{Criticality}_{min}) * \text{Criticality\_Multiple} + \text{Criticality}_{min}$$

where:

$\text{Criticality}_{max} = 1/(80\%) = 1.25$ (the segments with highest relative importance should be replaced when their POF reaches 80%)

$\text{Criticality}_{min} = 1/(95\%) = 1.0526$ (the segments with lowest relative importance can wait until their POF reaches 95% to be replaced)

$$Criticality\_Multiple = \frac{\sum_{CF=1}^{\forall CF}(CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF}(WCF_{CF})}$$

The factors, weights and the score system of each factor are as follows:

Criticality Factor (CF)	Weight (WCF)	Score (CFS)
Number of Customers	25	Low=0 High=1
Oil Containment	10	Yes=0 No=1
Location (near water creeks)	50	No=0 Yes=1
Transformer Primary Protection	15	Breaker =0 Fuse=1

The table below shows examples of criticalities for three separate units.

	Example 1			Example 2			Example 3		
Criticality Factor	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**
Number of Customers	Low	0	0	High	1	25	High	1	25
Oil Containment	Yes	0	0	No	1	10	No	1	10
Location (near water creeks)	No	0	0	No	0	0	Yes	1	50
Transformer Primary Protection	Breaker	0	0	Breaker	0	0	Fuse	1	15
	Criticality Multiple		0	Criticality Multiple		0.35	Criticality Multiple		1
	Criticality		(1.25-1.0526) *0 + 1.0526 = **1.0526**	**Criticality**		(1.25-1.0526) *0.35 + 1.0526 = **1.1217**	**Criticality**		(1.25-1.0526)*1 + 1.0526 =**1.25**

As previously noted a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. The flagged-for-action plan for in service Substation Transformers was as follows:

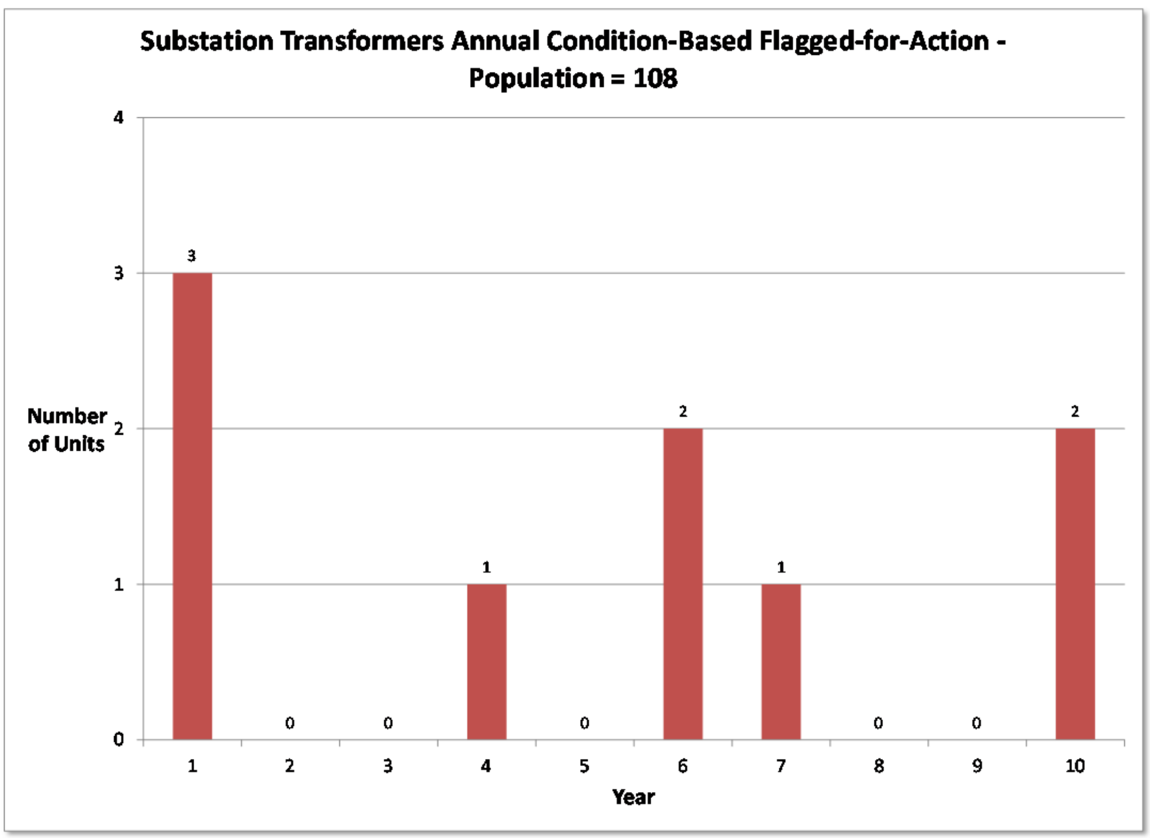

Figure 1-5 Substation Transformers Condition-Based Flagged-for-Action Plan

1.5. Spare Substation Transformers

There were 9 Spare Substation Transformers at EMH. Their age distribution was as follows. Approximately 44% of all units were 40 or older.

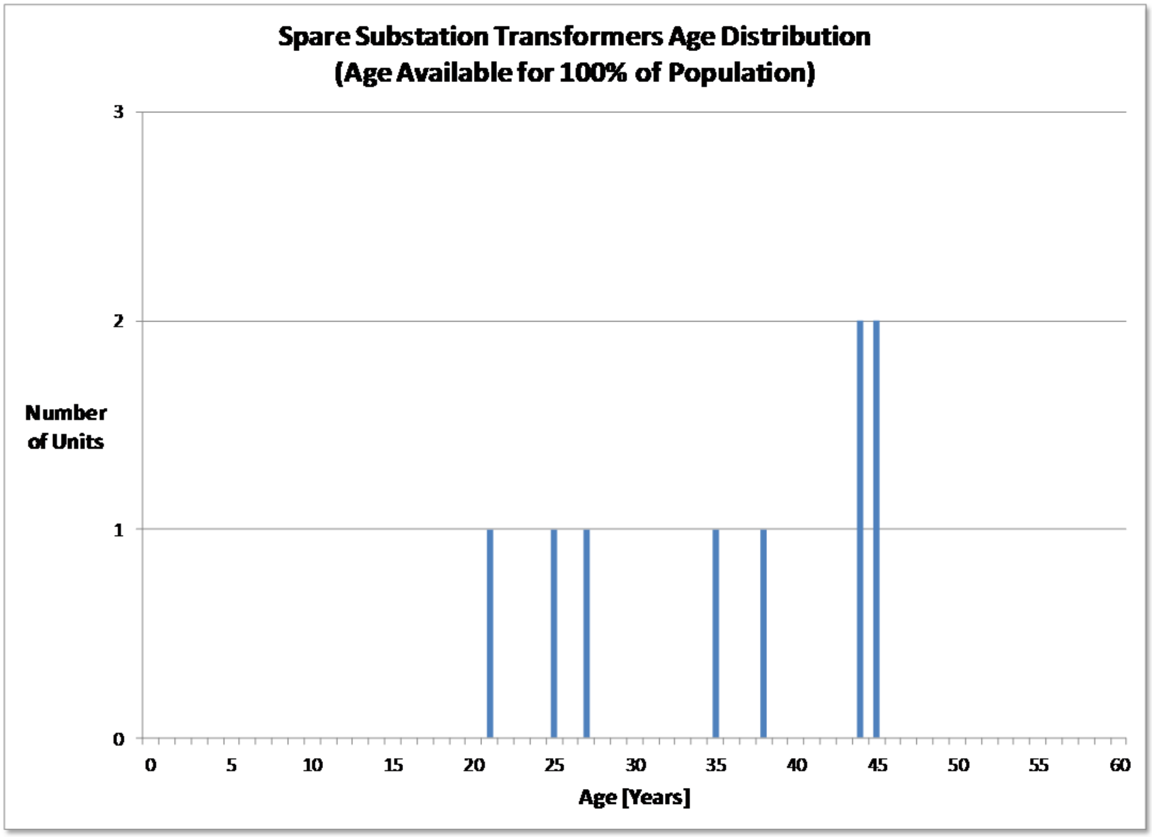

Figure 1-6 Spare Substation Transformers Age Distribution

Of the 9 Spare Substation Transformers at EHM, there were 9 units with sufficient data for a Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units were shown below. The average Health Index for this asset group was 87%.

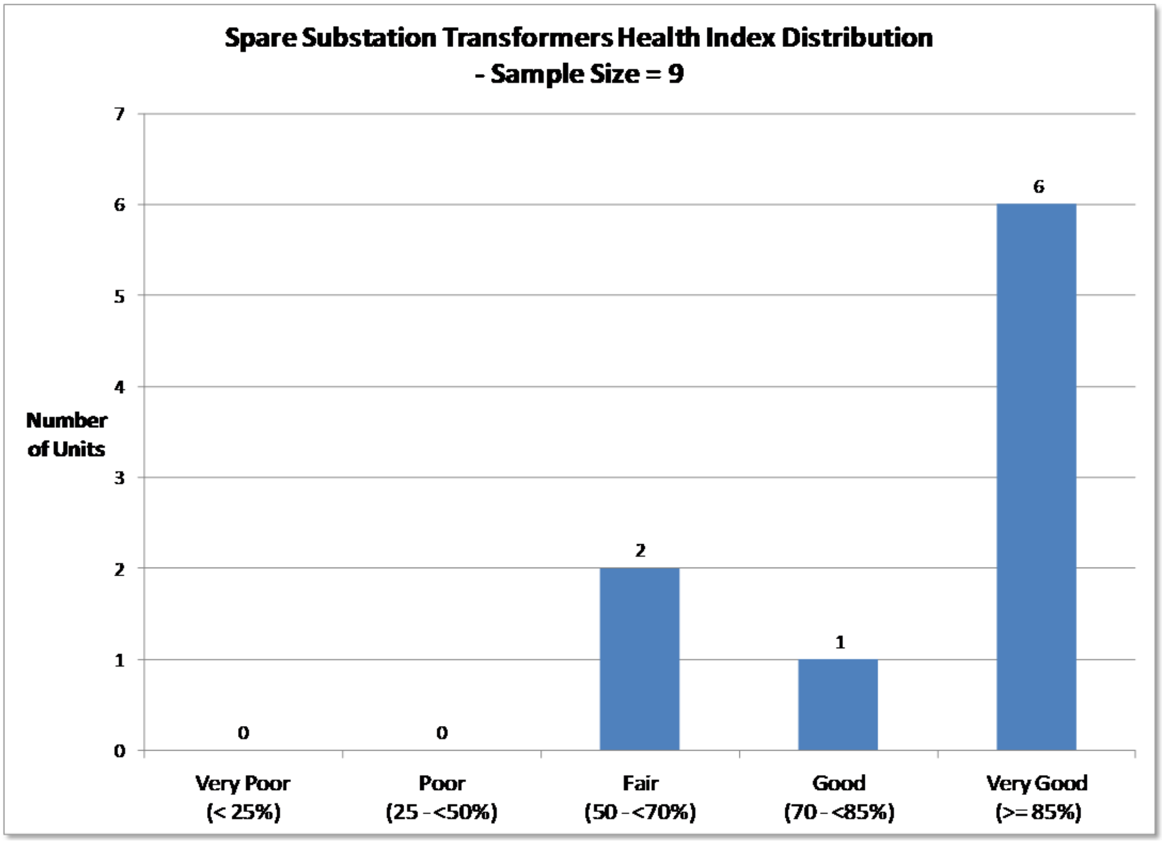

Figure 1-7 Spare Substation Transformers Health Index Distribution (Unit)

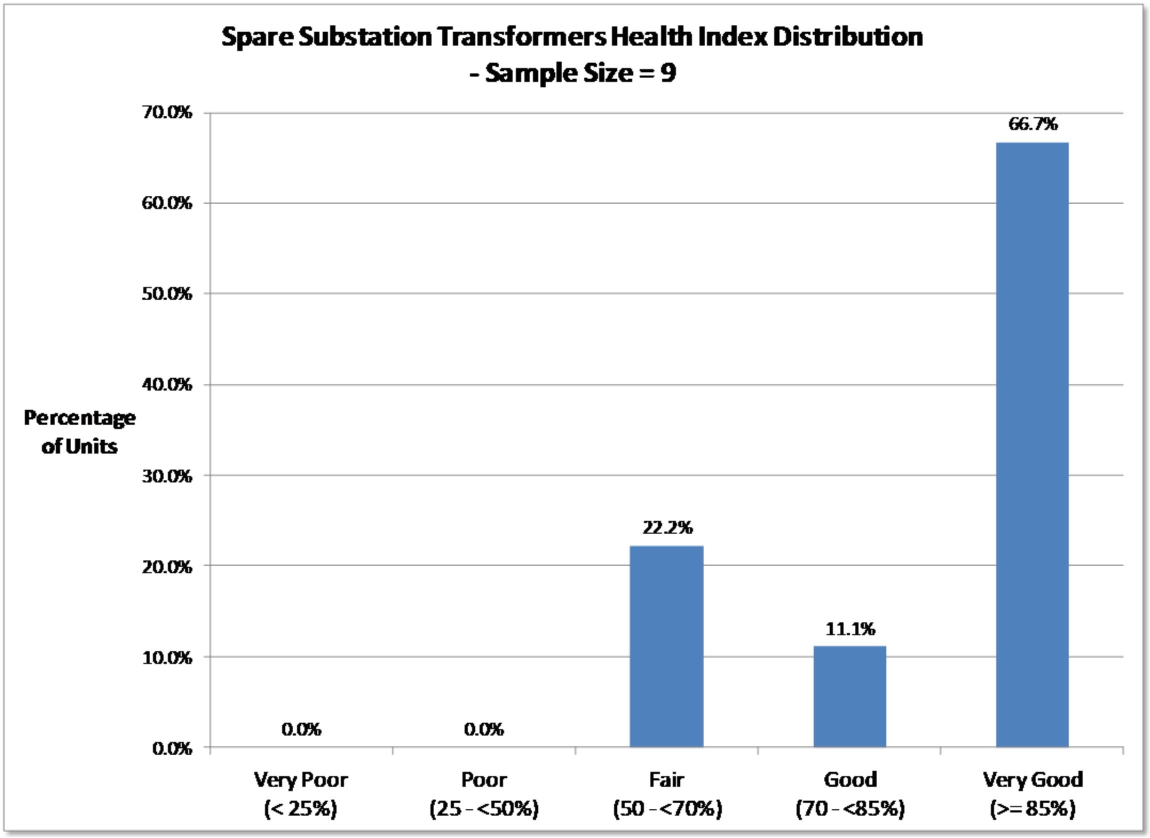

Figure 1-8 Spare Substation Transformers Health Index Distribution (Percentage)

1.6. Data Assessment

The data for in service Substation Transformers included inspection results, loading, age, and oil quality, dissolved gas analysis, and Doble tests.

Data Availability Indicator

The data availability distribution for the entire population was as follows:

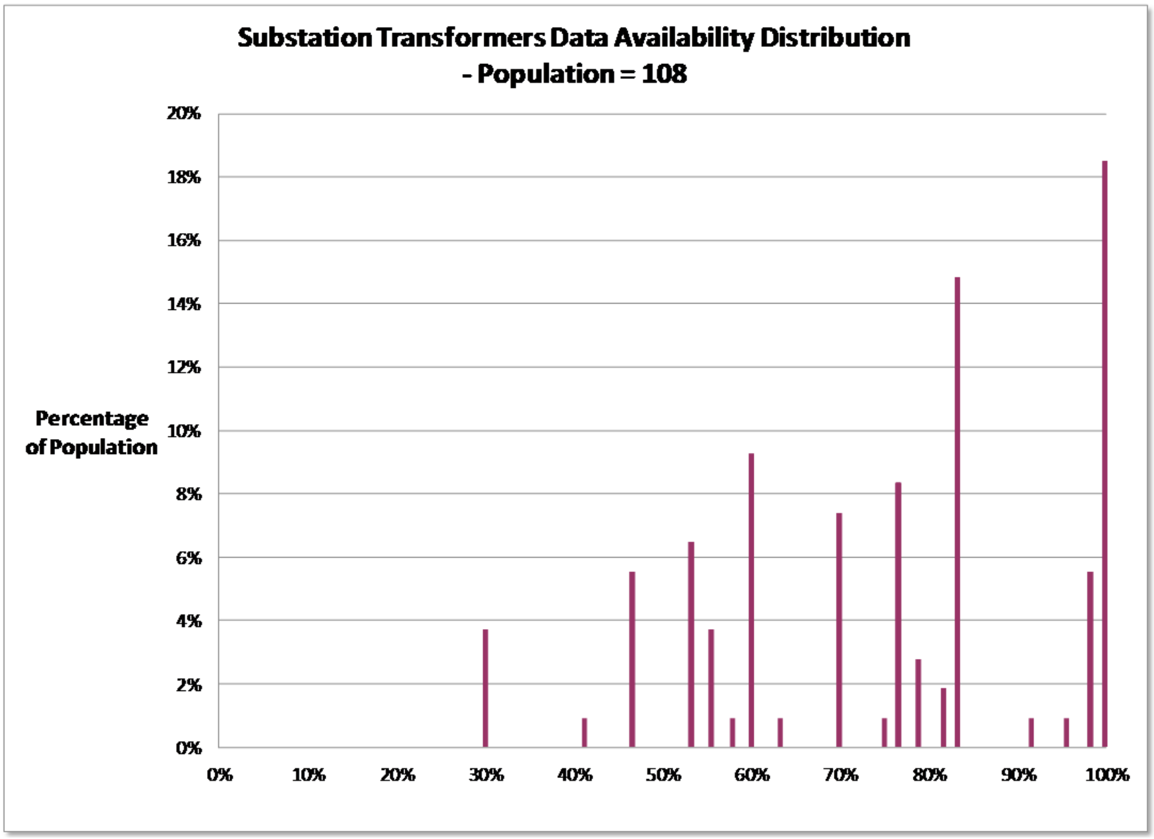

Figure 1-9 Substation Transformers Data Availability Distribution

At 75%, the average of DAI of this group was slightly better as compared to the previous year. There had been an improvement in the collection of loading and inspection data. More than 60% of the population had inspection data in 2013, whereas roughly 55% of population had such data in 2012.

Data Gap

The data gaps for this asset category remained the same as last year. Most of the critical data were already available and included in the Health Index formula. The data gaps included infrared thermography and grounding condition.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Infrared (IR) Thermography	Sealing & Connection	☆☆☆	Cooling system	Poor ventilation/circulation	IR camera scan
			Transformer connection	Poor connection	
Grounding		☆	Grounding electrode conductor	Poor connection	Visual inspection

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2. CIRCUIT BREAKERS

2.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

2.1.1. Condition and Sub-Condition Parameters

Table 2-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m				Sub-Condition Parameters
		Oil	SF6	Vacuum	Air Magnetic	
1	Operating Mechanism	14	11	7	14	Table 2-2
2	Contact Performance	7	7	7	7	Table 2-3
3	Arc Extinction	9	5	2	5	Table 2-4
4	Insulation	2	2	2	2	Table 2-5
5	Service Record	5	5	5	5	Table 2-6
De-Rating Factor (DRF)	De-rate based on: Manufacturer					Table 2-11

Table 2-2 Operating Mechanism Sub-Condition Parameters and Weights (m=1)

n	Sub-condition Parameter	$WCPF_n$				Condition Criteria Table
		Oil	SF6	Vacuum	Air Magnetic	
1	Lubrication	9	7	5	9	Table 2-7
2	Linkage	5	4	2	5	Table 2-7
De-Rating	De-rate based on: Mechanism Type					Table 2-10

Table 2-3 Contact Performance Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Contact Resistance	1	Table 2-9
2	Contact (Inspection)	1	Table 2-7

Table 2-4 Arc Extinction Sub-Condition Parameters and Weights (m=3)

n	Sub-condition Parameter	$WCPF_n$				Condition Criteria Table
		Oil	SF6	Vacuum	Air Magnetic	
1	Tank	1	1			Table 2-7
2	Arc Chute				1	Table 2-7

Table 2-5 Insulation Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Insulation	1	Table 2-7

Table 2-6 Service Record Sub-Condition Parameters and Weights (m=5)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	1	Figure 2-1

2.1.2. Condition Criteria

Visual Inspection

Table 2-7 Visual Inspection Criteria

Score	Condition Description
4	OK
0	Not OK

Measurement

Breaker timing and contact resistance measurements indicate the proper function of the breaker as designed. It is crucial that the breaker meets these specifications for proper and reliable operation

Table 2-8 Resistance Test Criteria

Score	Condition Description
4	Measurement <= 80% Specification limit *
3	Measurement (80%, 100%] specification limit
1	Measurement (100%, 120%] specification limit
0	Measurement > 120% specification limit

* CB type dependent (see Table 2-9)

Table 2-9 Contact Resistance Specification Limit

Breaker Type	Contact Resistance Specification Limit [μΩ]			
	<= 69 kV	110 – 230 kV	345 kV	765 kV
Oil	300	600	900	
Gas	150	150	150	300
Vacuum & Air Magnetic	250	250	250	250

Operating Mechanism

Table 2-10 Multiplier for Operating Mechanism

Multiplier	Operating Type
1	Solenoid
0.9	Spring

Age

Assume that the failure rate Circuit Breakers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 40 and 60 years the probability of failures (P_f) for Circuit Breakers are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

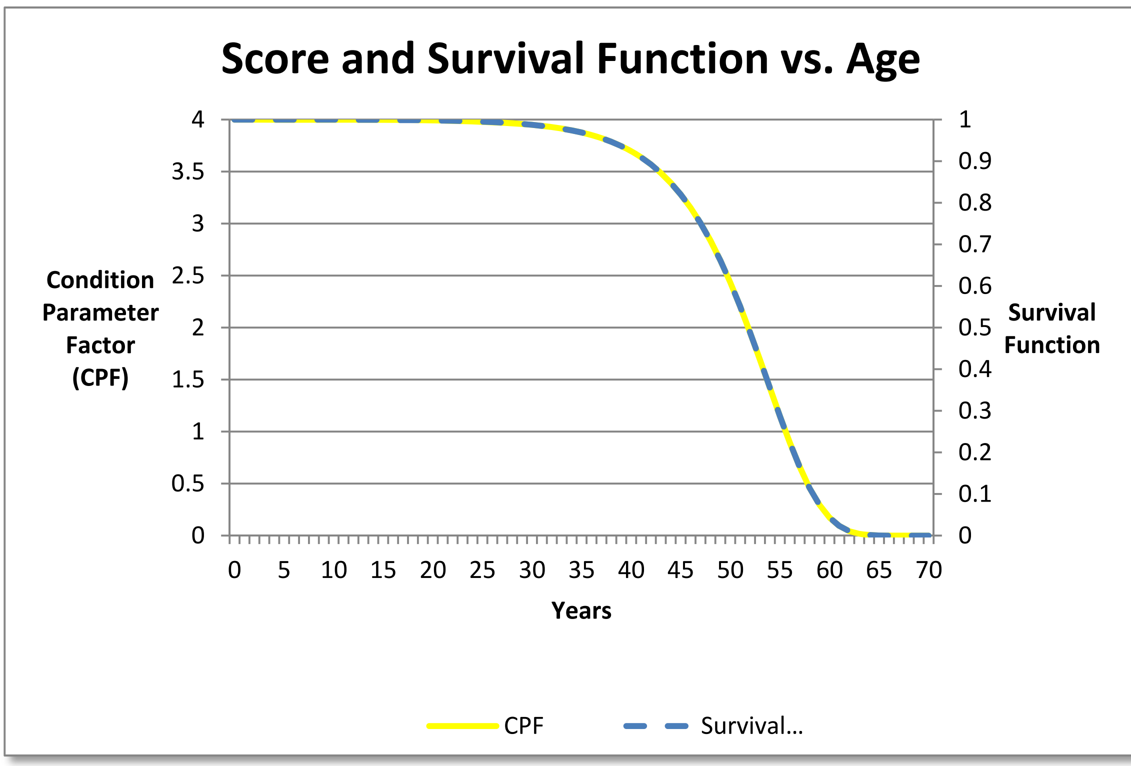

Figure 2-1 Circuit Breakers Age Criteria

De-Rating Factor (DRF)

Table 2-11 De-Rating Criteria

n	Parameter	De-Rating Multiplier (DR_n)	DRF
1	Manufacturer	Table 2-12	DRF = DR_1

Table 2-12 Manufacturer De-Rating Multiplier (DR_1)

n	Manufacturer	De-Rating Multiplier
1	Manufacturer X	.25 (Very Poor)
2	Manufacturer Y	.25 (Very Poor)
3	All Other Manufacturers	1

2.2. Age Distribution

The age distribution for this asset class was shown on the figure below. The average age of the population was 19 years old; however, 14% of the population were 40 years or older.

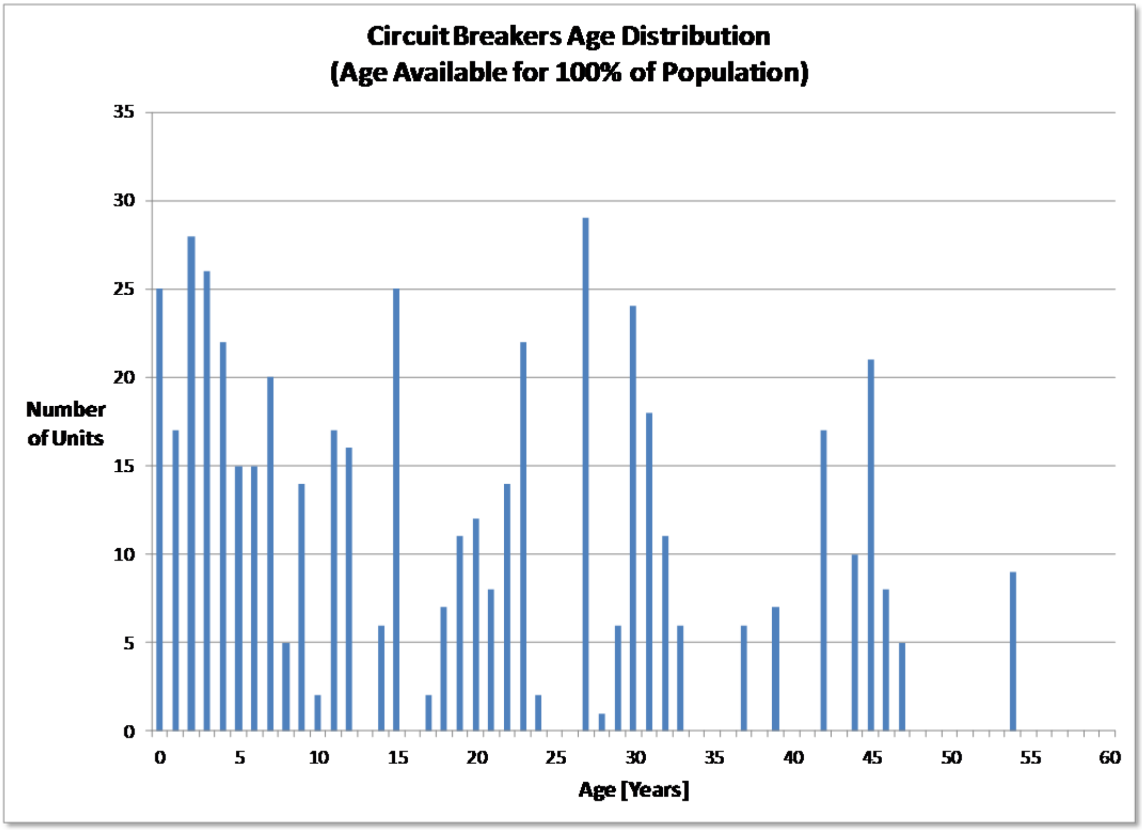

Figure 2-2 Circuit Breakers Age Distribution

2.4. Health Index Results

There were 510 Circuit Breakers at EHM. Of these, there were 510 units with sufficient data for a Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units were shown in the following diagrams.

The average Health Index for this asset group was 95%. Approximately 2% of the population was found to be in "poor" or "very poor" condition.

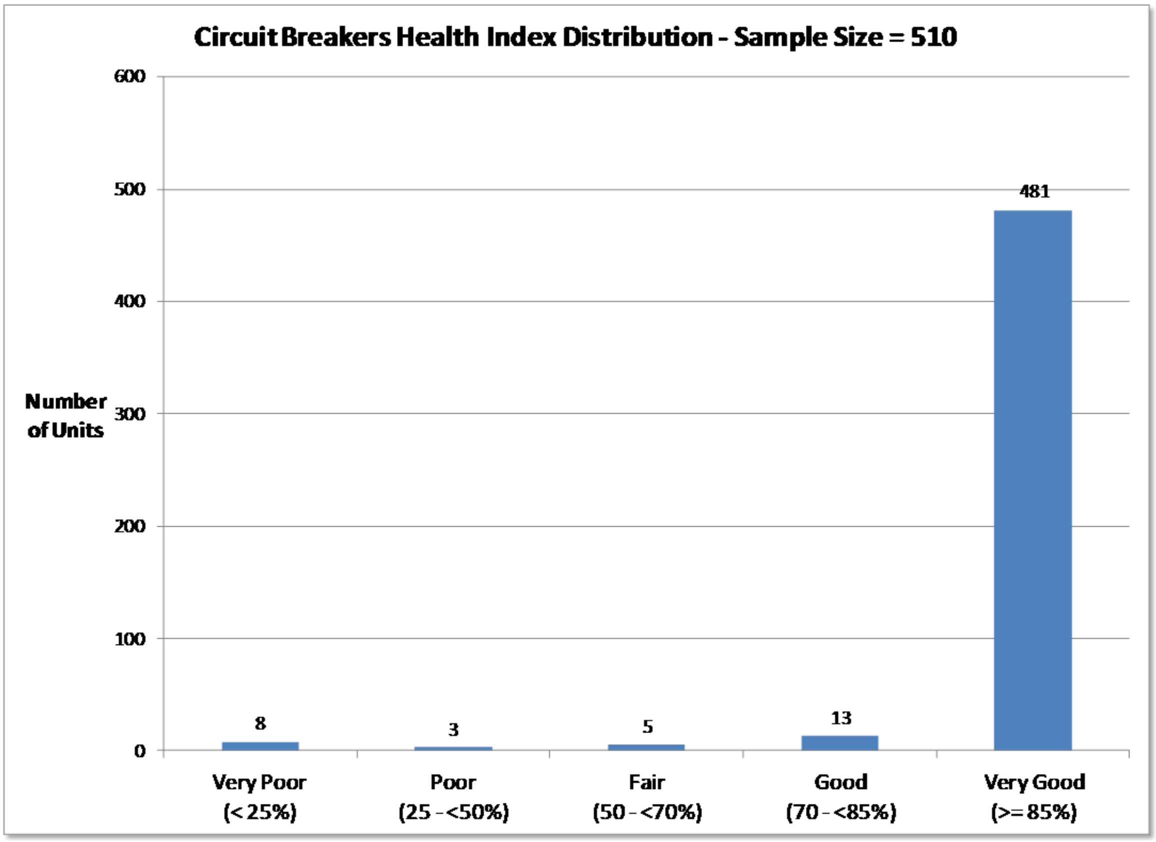

Figure 2-3 Circuit Breakers Health Index Distribution (Unit)

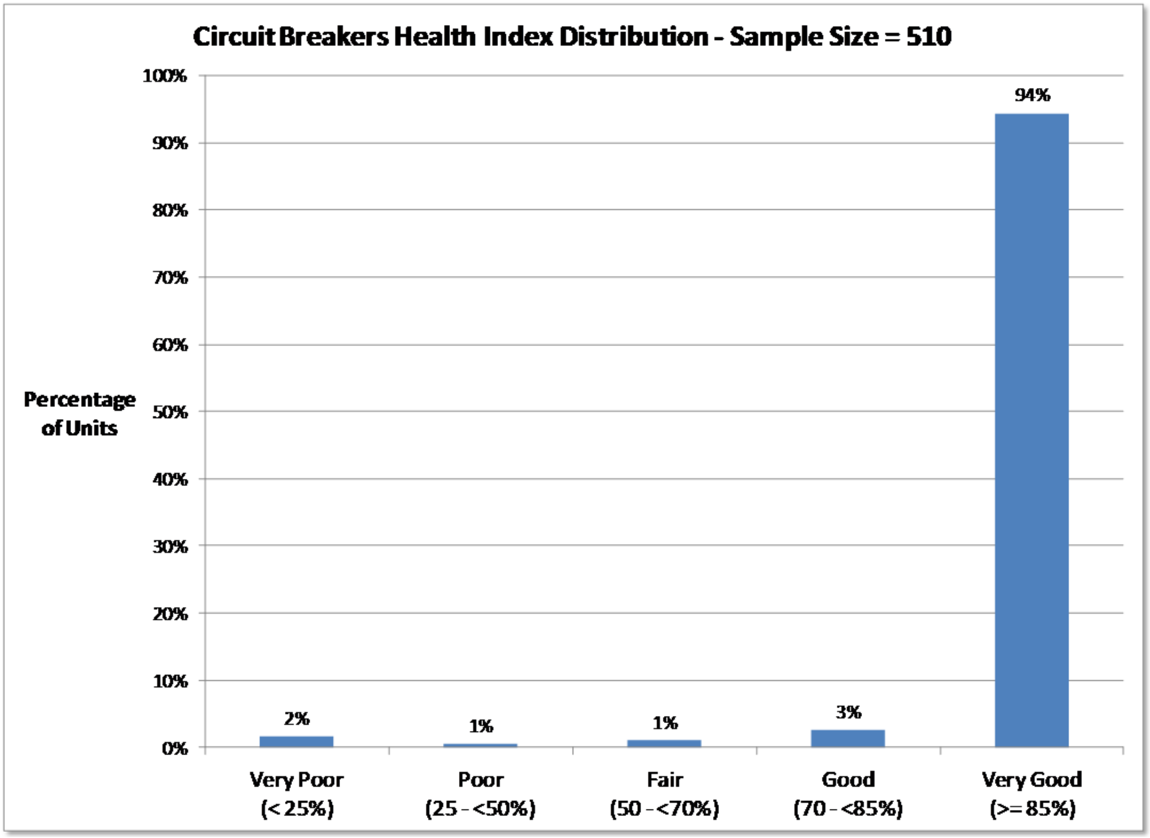

Figure 2-4 Circuit Breakers Health Index Distribution (Percentage)

2.5. Condition-Based Flagged-for-Action Plan

It is assumed that Circuit Breakers were proactively replaced.

A unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. All units are assumed to have equal criticalities, selected such that a unit with a probability of failure of 80% becomes a candidate for replacement. i.e. Criticality = 1.25.

The flagged-for-action plan for Circuit Breakers was given below:

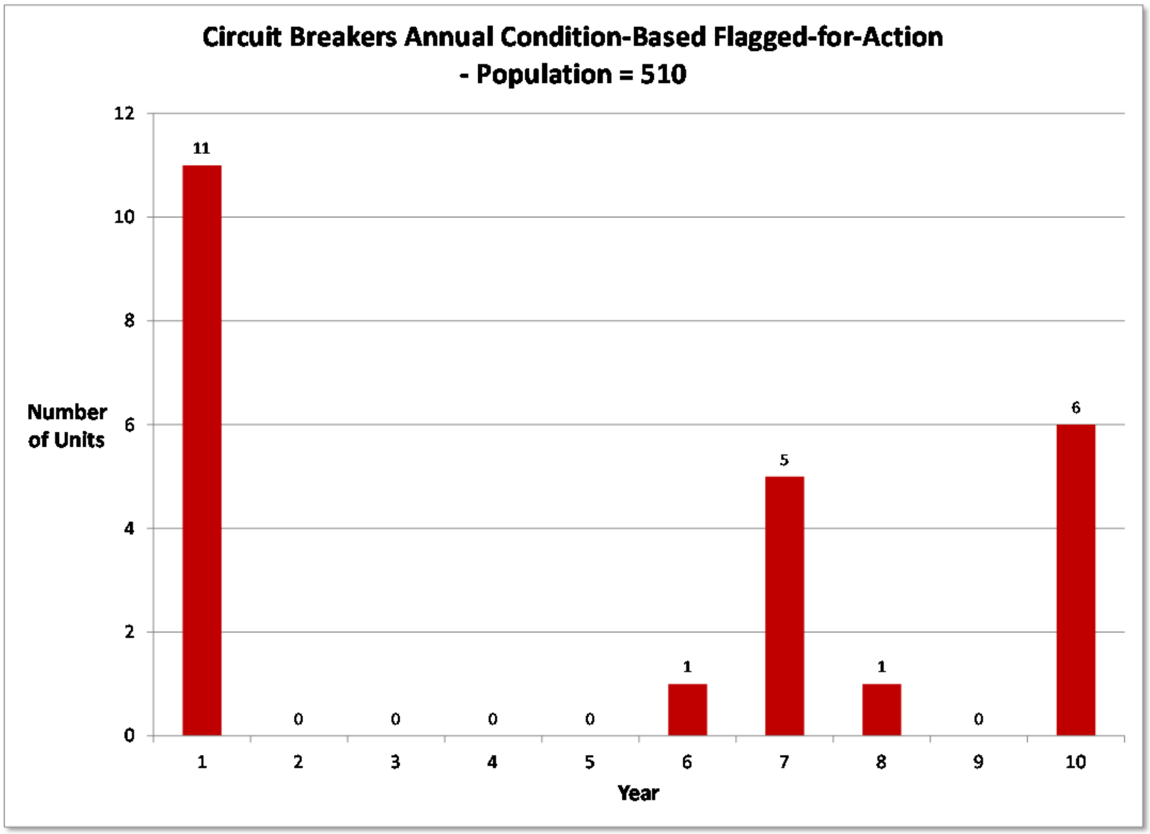

Figure 2-5 Circuit Breakers Condition-Based Flagged-for-Action Plan

Note that the large number of replacements in the first year. This was mainly due to a certain type that had been found to be prone to failures.

2.6. Data Analysis

The data available for this asset category included age, contact resistance, and inspection results.

Data Availability Indicator

The data availability distribution for the entire population was as follows:

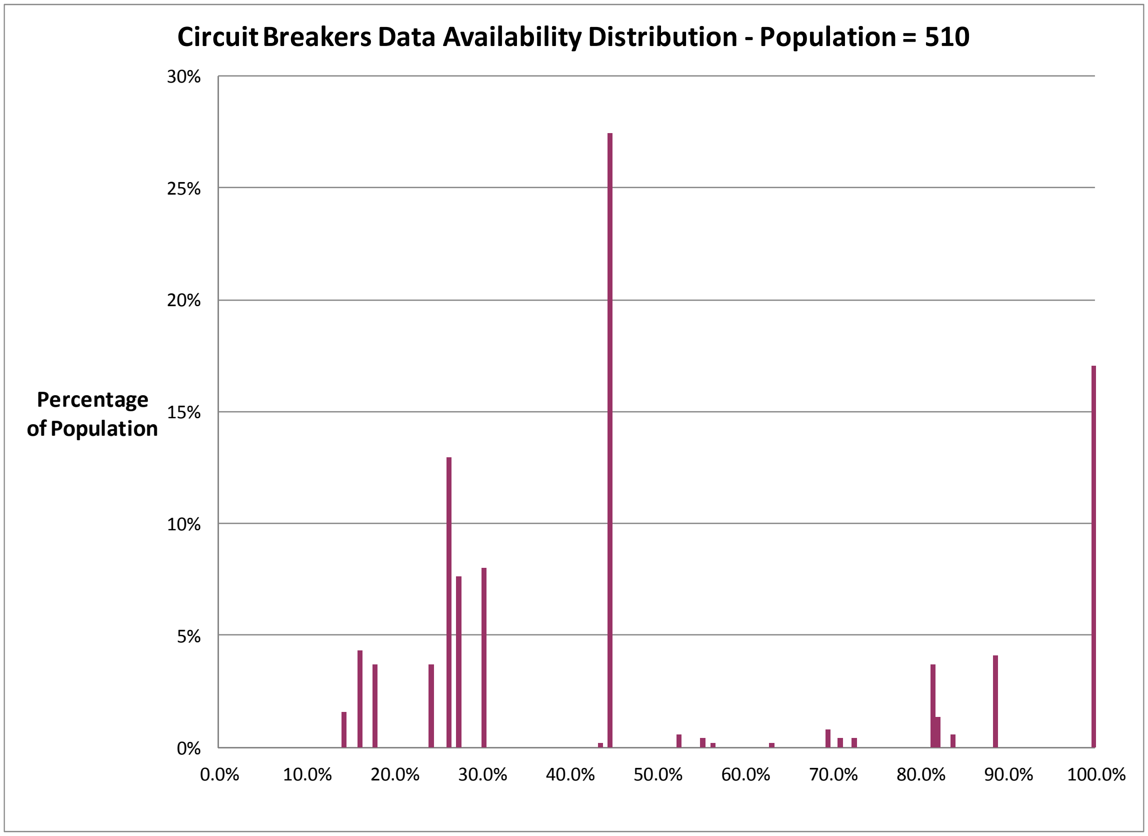

Figure 2-6 Circuit Breakers Data Availability Distribution

The average DAI for this asset group had improved from 46% last year to 51% this year. Age was available for all units, contact resistance measurement availability increased from 50% to 67%, and inspection record availability remained at approximately 30%.

Data Gap

No new data types had been collected for this asset group. The data gaps remained the same as the past year.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Timing Test Results	Contact Performance	☆☆☆	Close/Trip timing	Trip time too long Close time too long	On-site testing
Arc Contact		☆	Arc contact	Contact erosion	Visual inspection or on-site testing
Vacuum Bottle	Arc Extinction	☆☆☆	Vacuum bottle	Vacuum pressure low	On-site testing
Insulation	Insulation	☆☆	Insulator	Insulation damage	Visual inspection
Operating Counter	Service Record	☆	Circuit breaker	Number of operation cycles a CB has completed since installation	On-site reading (Using breaker operation counter)
Loading		☆	CB load	Loading History: e.g. hourly peak loads	Operation record

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3. POLE MOUNTED TRANSFORMERS

3.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

3.1.1. Condition and Sub-Condition Parameters

Table 3-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	3	Table 3-2
2	Connection and Insulation	5	Table 3-3
3	Service Record	5	Table 3-4
De-Rating Factor (DRF)	De-rate based on: Manufacturer, PCB Content, IR		Table 3-8

Table 3-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Tank Corrosion	1	Table 3-5

Table 3-3 Connection and Insulation Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Leak	1	Table 3-5

Table 3-4 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	2	Table 3-6
2	Age	1	Figure 3-1
3	Overloading	1	Table 3-7

3.1.2. Condition Criteria

Visual Inspection

Table 3-5 Visual Inspection Criteria

Score	Condition Description	
	Corrosion	Leak
4	NO	NONE
3	MI	MINOR
2	MO	MODERATE
1	YE	YES
0	MA	MAJOR

Table 3-6 Visual Inspection Criteria (Overall)

Score	Condition Description
4	EXCELLENT
3	GOOD
2	FAIR / AVERAGE
1	POOR / BAD / MAINTENANCE
0	REPLACE

Overloading

Table 3-7 Overloading Criteria

Score	Condition Description
4	N
0	Y

Age

Assume that the failure rate Pole Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 45 and 60 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

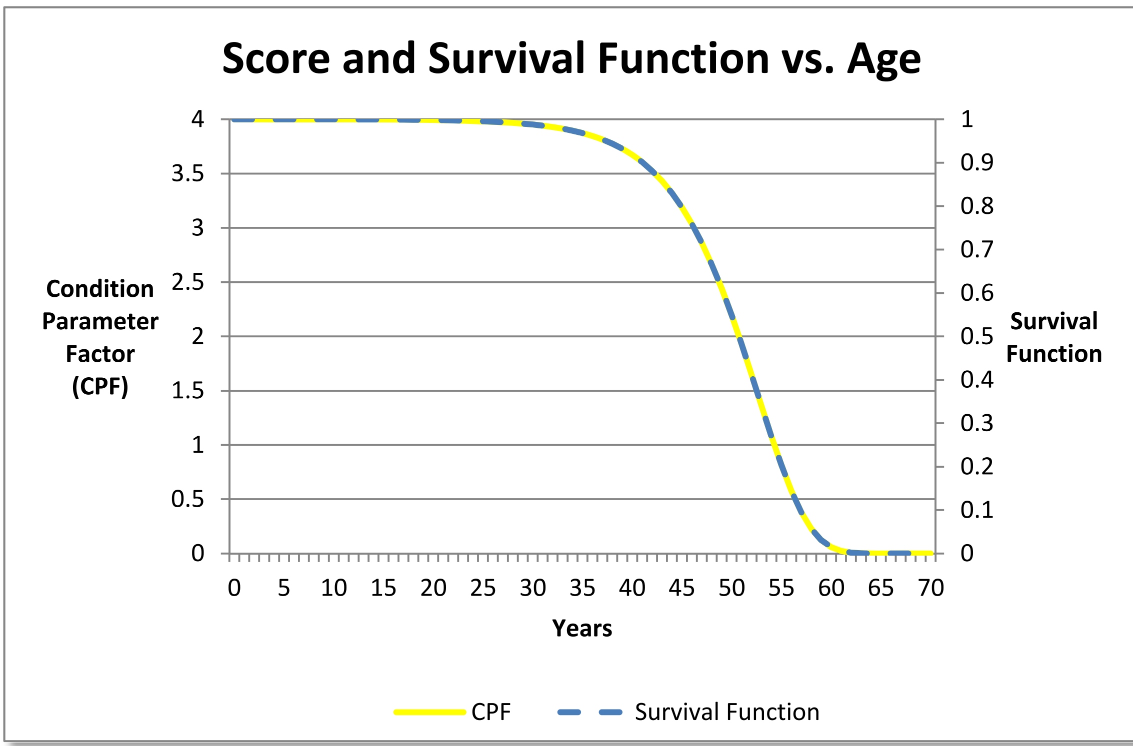

Figure 3-1 Pole Mounted Transformers Age Criteria

De-Rating Factor (DRF)

Table 3-8 De-Rating Criteria

n	Parameter	De-Rating Multiplier (DR_n)	DRF
1	Manufacturer	Table 3-9	$DRF = MIN(DR_1, DR_2, DR_3)$
2	PCB Content	Table 3-10	
3	IR	Table 3-11	

Table 3-9 Manufacturer De-Rating Multiplier (DR_1)

Manufacturer	De-Rating Multiplier
Manufacturer X	0.5
Manufacturer Y	0.9
All Other Manufacturers	1

Table 3-10 PCB De-Rating Multiplier (DR_2)

PCB Content	De-Rating Multiplier
0 < PCB < 2 ppm	1
2 < PCB < 50 ppm	0.5
PCB > = 50 ppm	0.25

Table 3-11 IR De-Rating Multiplier (DR_3)

IR Priority	De-Rating Multiplier
Red priority	0.7
Yellow priority	0.85
White priority	0.95

3.2. Age Distribution

The average age of the population was 22. Approximately 8% of the population was 45 years or older. The age distribution for this asset class was as follows:

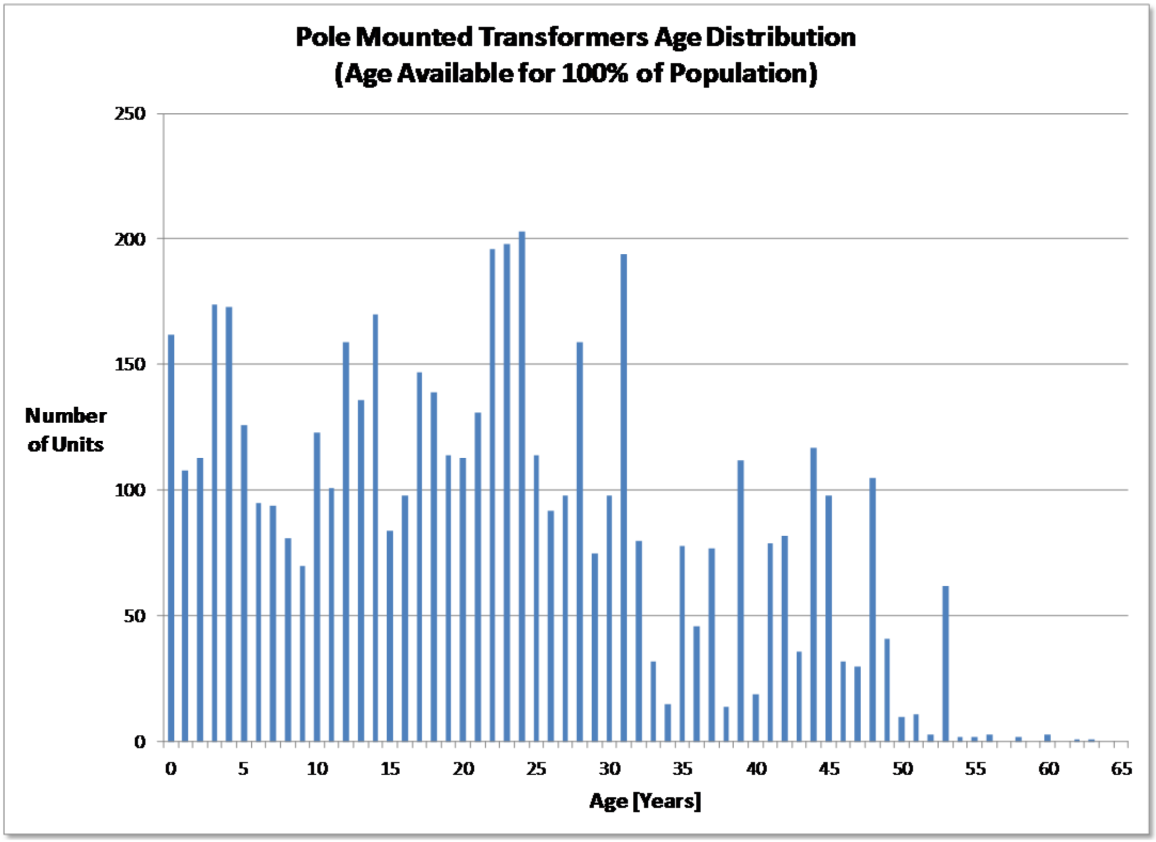

Figure 3-2 Pole Mounted Transformers Age Distribution

3.4. Health Index Results

There were 5334 Pole Mounted Transformers at EHM. Of these, there were 5334 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 90%. Approximately 9% of the population was found to be in "poor" or "very poor" condition.

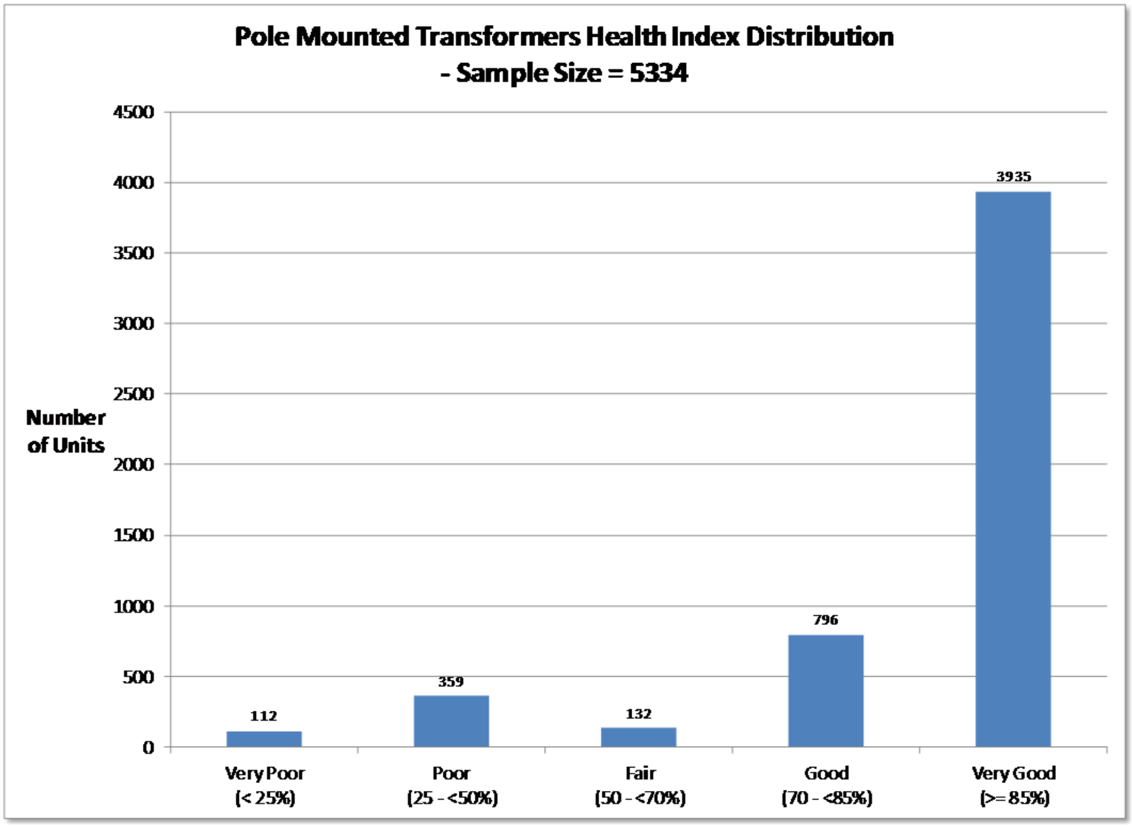

Figure 3-3 Pole Mounted Transformers Health Index Distribution (Unit)

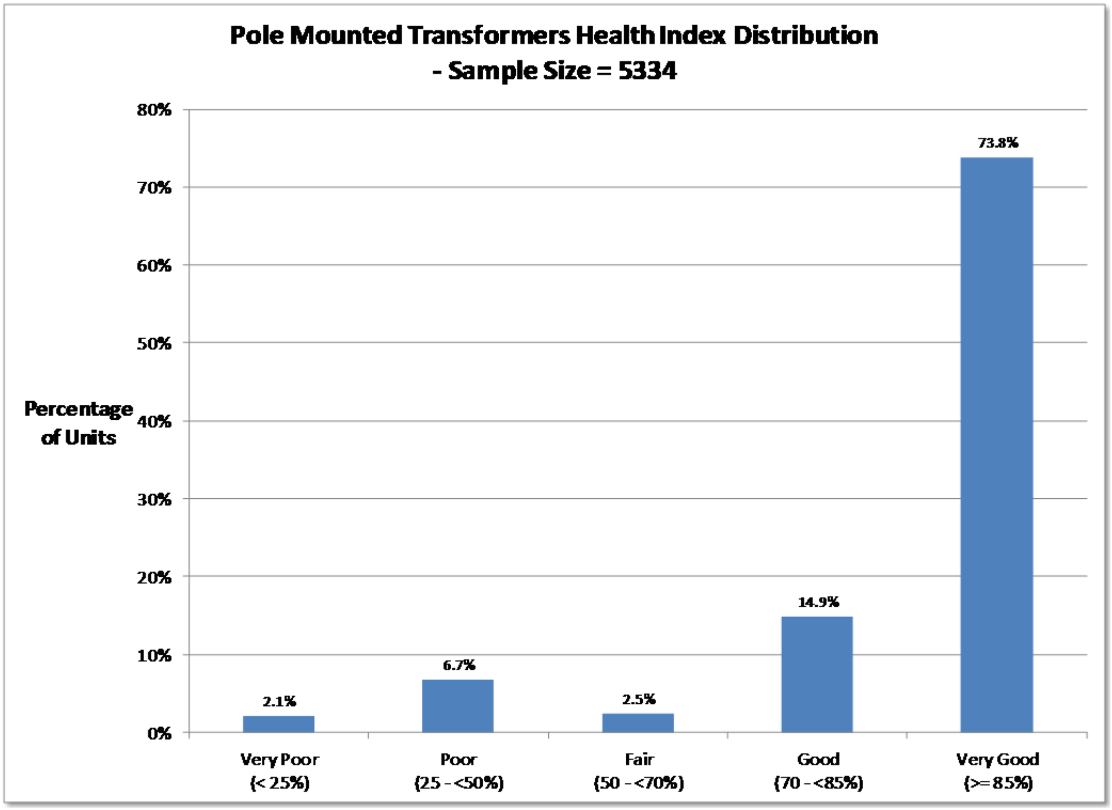

Figure 3-4 Pole Mounted Transformers Health Index Distribution (Percentage)

3.5. Condition-Based Flagged-for-Action Plan

As it is assumed that Pole Mounted Transformers were reactively replaced, the flagged-for-action plan was based on the asset failure rate.

The flagged-for-action plan for Pole Mounted Transformers was as follows:

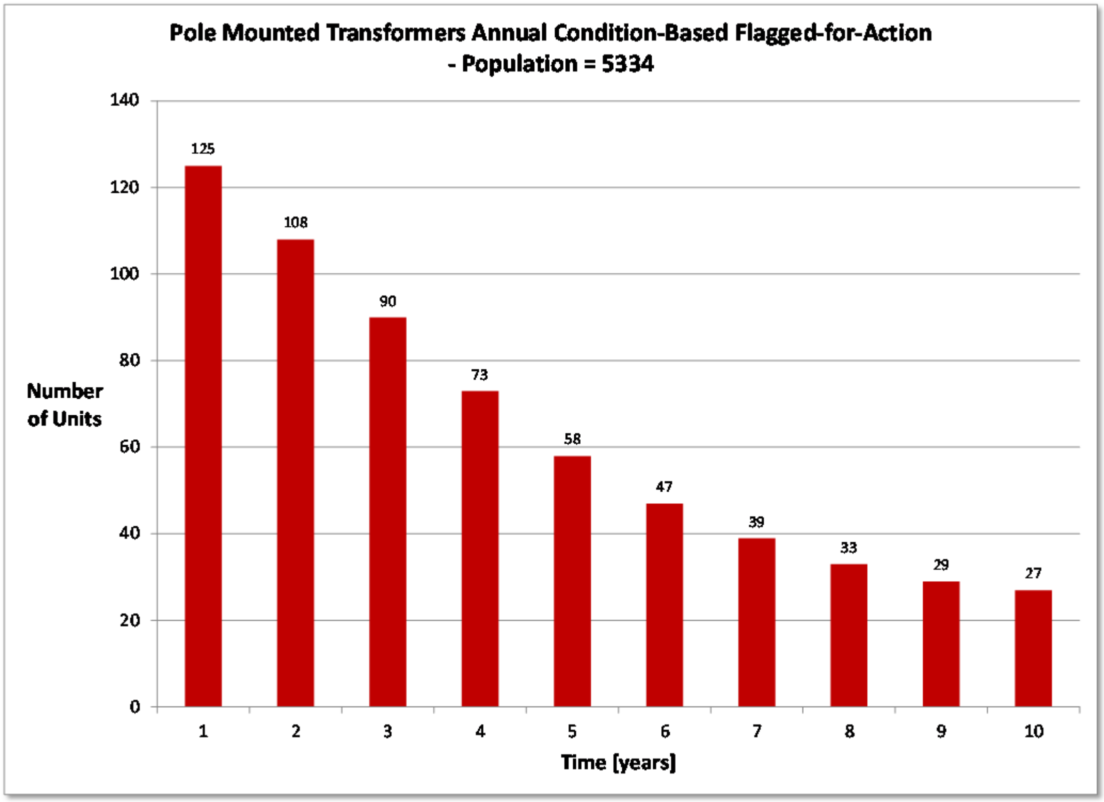

Figure 3-5 Pole Mounted Transformers Condition-Based Flagged-for-Action Plan

3.6. Data Analysis

The average DAI for this asset category was 82%.

Since the 2012 assessment, visual inspection data on tank corrosion, oil leak, overall and overloading were collected and incorporated in the 2013 Health Index formulation. The other data gaps noted in the 2012 report remained to be addressed. Note although in this project oil boiling was adopted to indicate overloading condition, more accurate loading information was preferred. So loading still remained to be a data gap item.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Connection	Connection and Insulation	☆ ☆	Transformer connection	Poor connection	Visual inspection
Grounding		☆	Transformer tank	Poor grounding wire connection	Visual inspection
Bushing		☆ ☆	Porcelain	Crack / Dirt	Visual inspection
Loading	Service Record	☆ ☆	Transformer load	Loading History: e.g. hourly peak loads	Operation record

According to Enersource, the condition status of connection, grounding and insulator bushing was inspected during infra-red tests. In this study, such information was however not stored in a way that could be easily extracted in electronic format. It is recommended that in the future study, the infra-red test data regarding the above parameters be stored and sorted out in a standardized and systematic way, so as to be incorporated in Health Index formulation.

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4. PAD MOUNTED TRANSFORMERS

4.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

4.1.1. Condition and Sub-Condition Parameters

Table 4-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	3	Table 4-2
2	Connection and Insulation	5	Table 4-3
3	Service Record	5	Table 4-4
De-Rating Factor (DRF)	De-rate based on: Manufacturer, PCB Content		Table 4-8

Table 4-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Tank Corrosion	1	Table 4-5

Table 4-3 Connection and Insulation Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Leak	1	Table 4-5

Table 4-4 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	2	Table 4-6
2	Age	1	Figure 4-1
3	Overloading	1	Table 4-7

4.1.2. Condition Criteria

Visual Inspection

Table 4-5 Visual Inspection Criteria

Score	Condition Description	
	Corrosion	Leak
4	NO	NONE
3	MI	MINOR
2	MO	MODERATE
1	YE	YES
0	MA	MAJOR

Table 4-6 Visual Inspection Criteria (Overall)

Score	Condition Description
4	EXCELLENT
3	GOOD
2	FAIR / AVERAGE
1	POOR / BAD / MAINTENANCE
0	REPLACE

Overloading

Table 4-7 Overloading Criteria

Score	Condition Description
4	N
0	Y

Age

Assume that the failure rate Pad Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

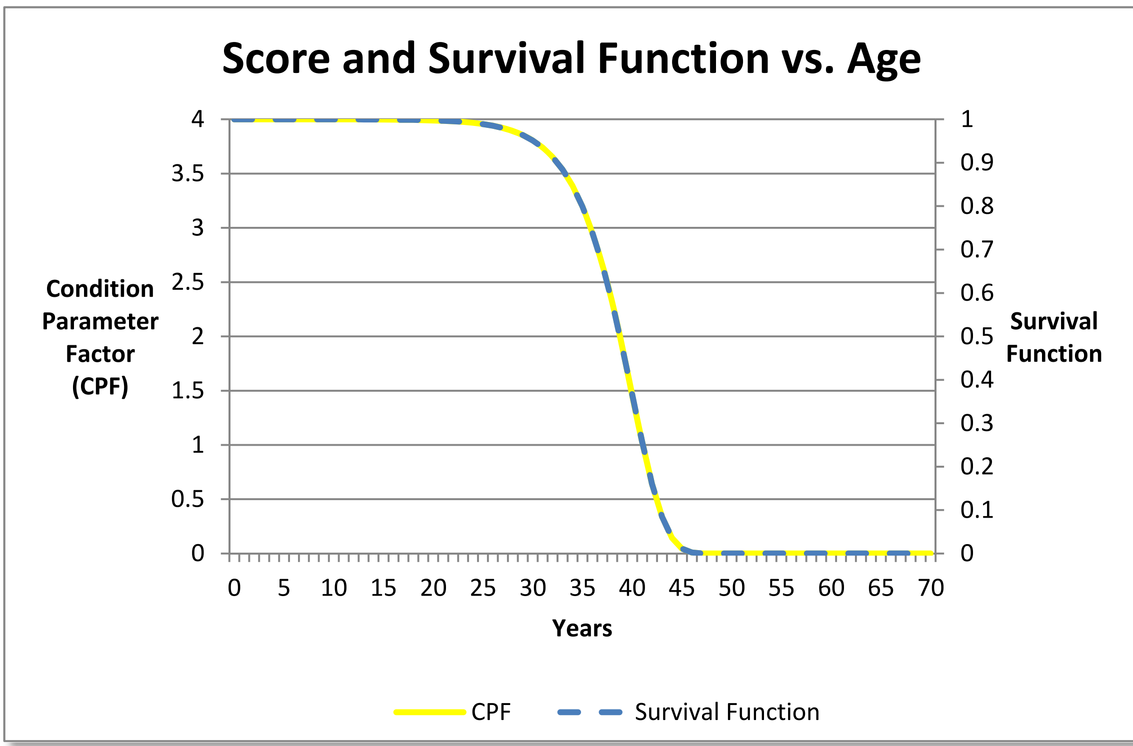

Figure 4-1 Pad Mounted Transformers Age Criteria

De-Rating Factor (DRF)

Table 4-8 De-Rating Criteria

n	Parameter	De-Rating Multiplier (DR_n)	DRF
1	Manufacturer	Table 4-9	$DRF = MIN(DR_1, DR_2)$
2	PCB Content	Table 4-10	

Table 4-9 Manufacturer De-Rating Multiplier (DR_1)

Manufacturer	De-Rating Multiplier
Manufacturer X	0.5
Manufacturer Y	0.9
Manufacturer Z	0.9
All Other Manufacturers	1

Table 4-10 PCB De-Rating Multiplier (DR_2)

PCB Content	De-Rating Multiplier
0 < PCB < 2 ppm	1
2 < PCB < 50 ppm	0.5
PCB > = 50 ppm	0.25

4.2. Age Distribution

Single Phase Pad Mounted Transformers

The average age of all single phase units was 21 years. Approximately 10% of the population was 35 years or older.

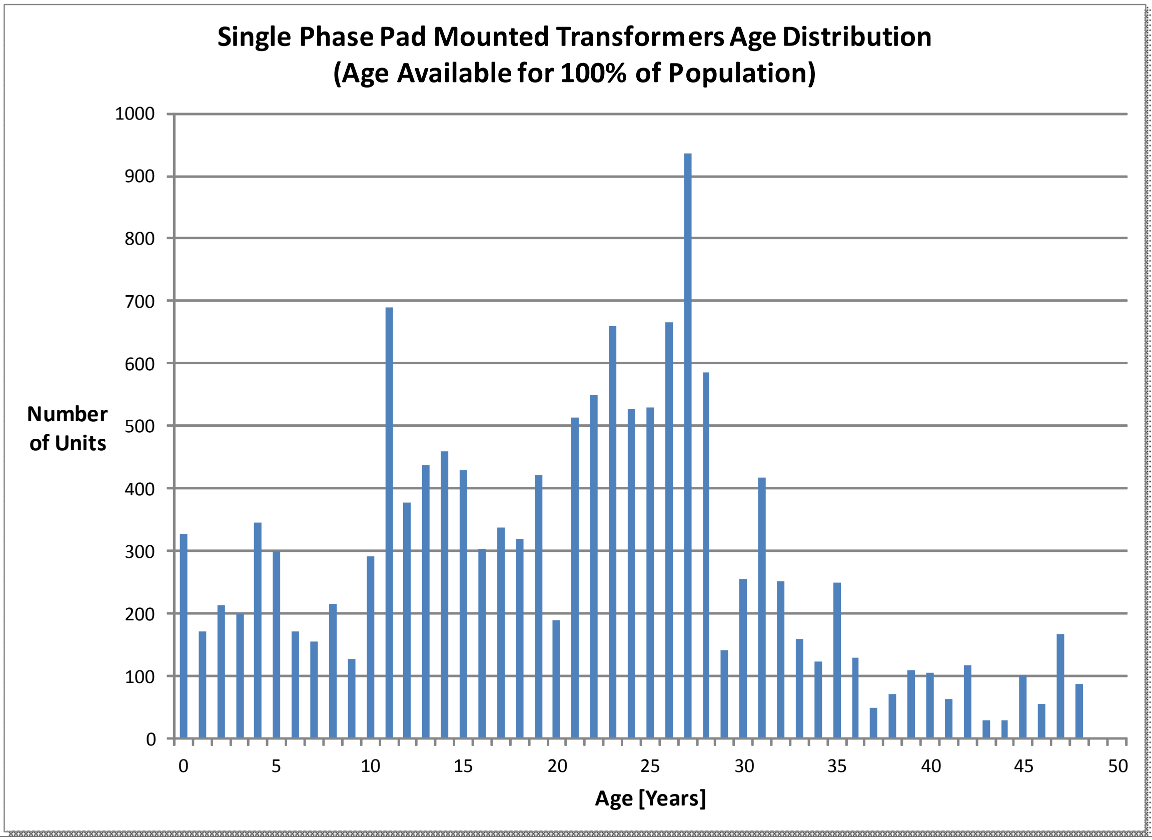

Figure 4-2 Single Phase Pad Mounted Transformers Age Distribution

Three Phase Pad Mounted Transformers

The average age of all three phase units was 16 years. Approximately 5% of the population was 35 years or older.

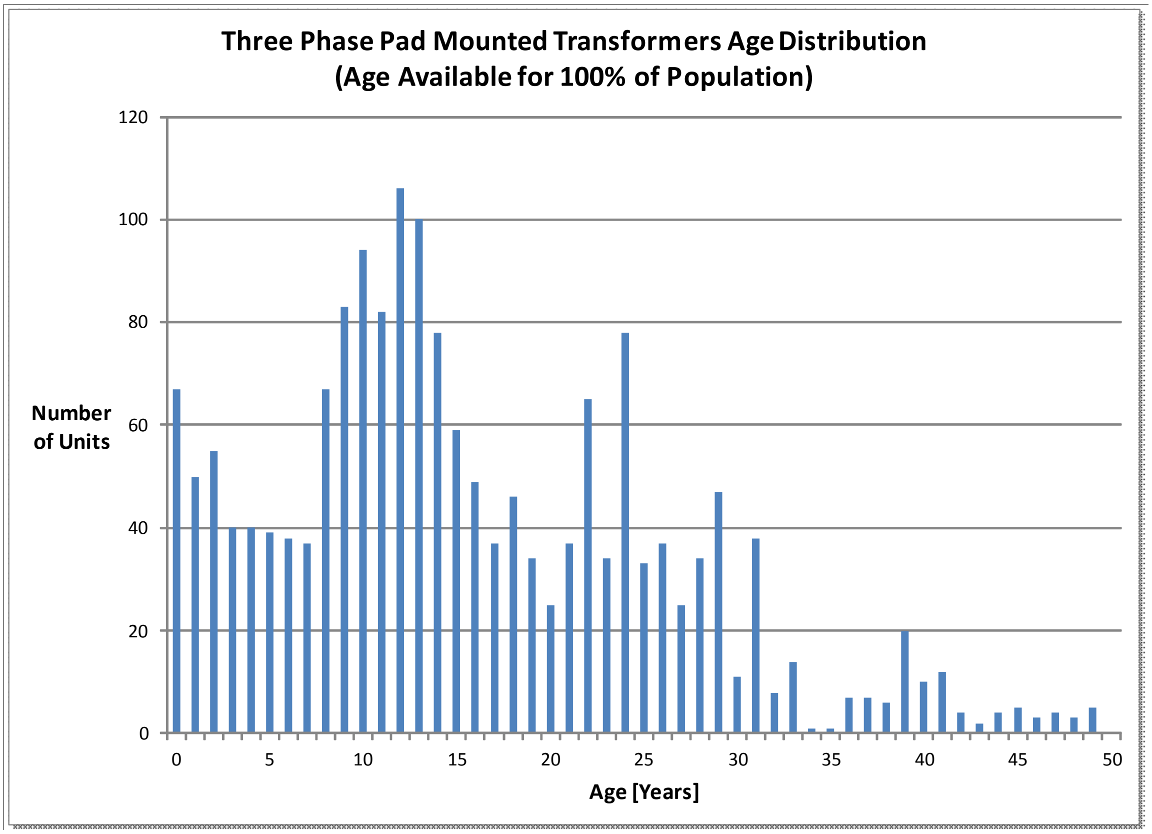

Figure 4-3 Three Phase Pad Mounted Transformers Age Distribution

4.3. Health Index Results

Single Phase Pad Mounted Transformers

There were a total of 14189 Single Phase Pad Mounted Transformers at EHM. Of these, there were 14189 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 89%. Approximately 6% of the population was found to be in “poor” or “very poor” condition.

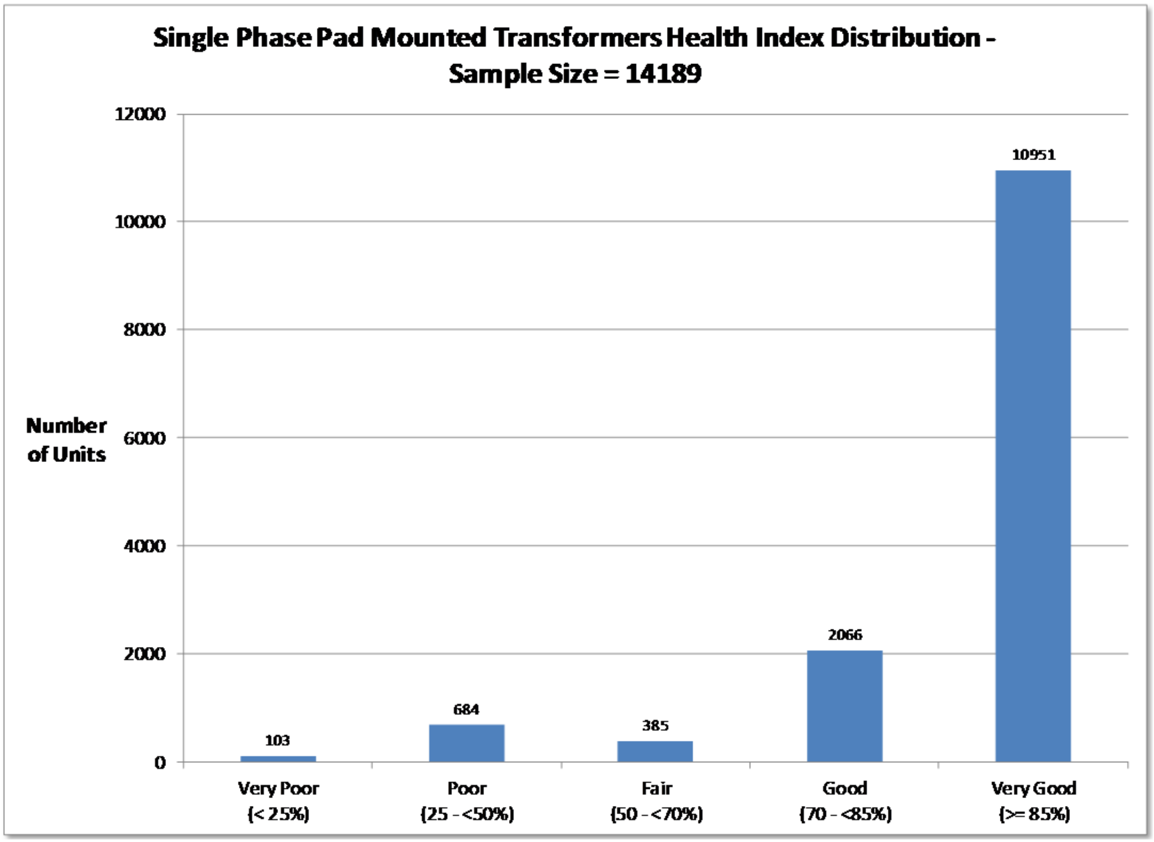

Figure 4-4 Single Phase Pad Mounted Transformers Health Index Distribution (Unit)

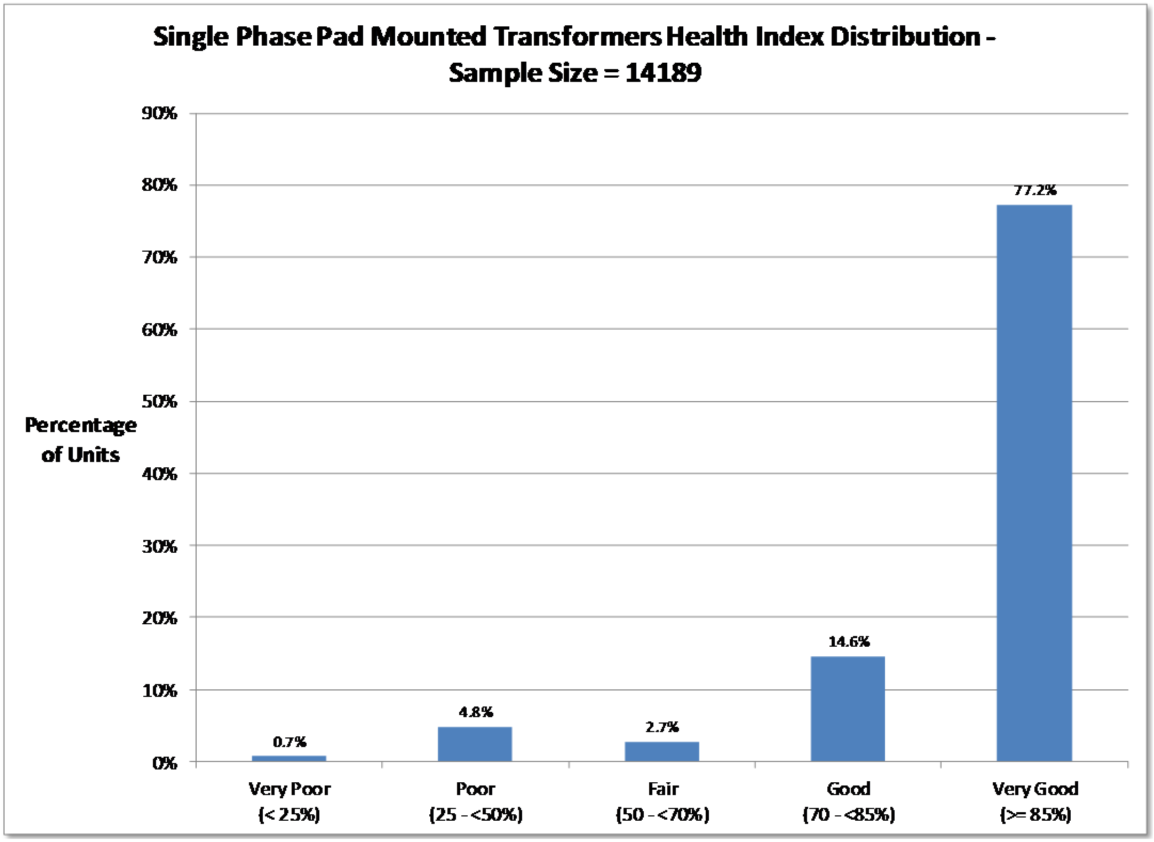

Figure 4-5 Single Phase Pad Mounted Transformers Health Index Distribution (Percentage)

Three Phase Pad Mounted Transformers

There were a total of 1784 Three Phase Pad Mounted Transformers at EHM. Of these, there were 1784 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 92%. Nearly 3% of the population was found to be in "poor" or "very poor" condition.

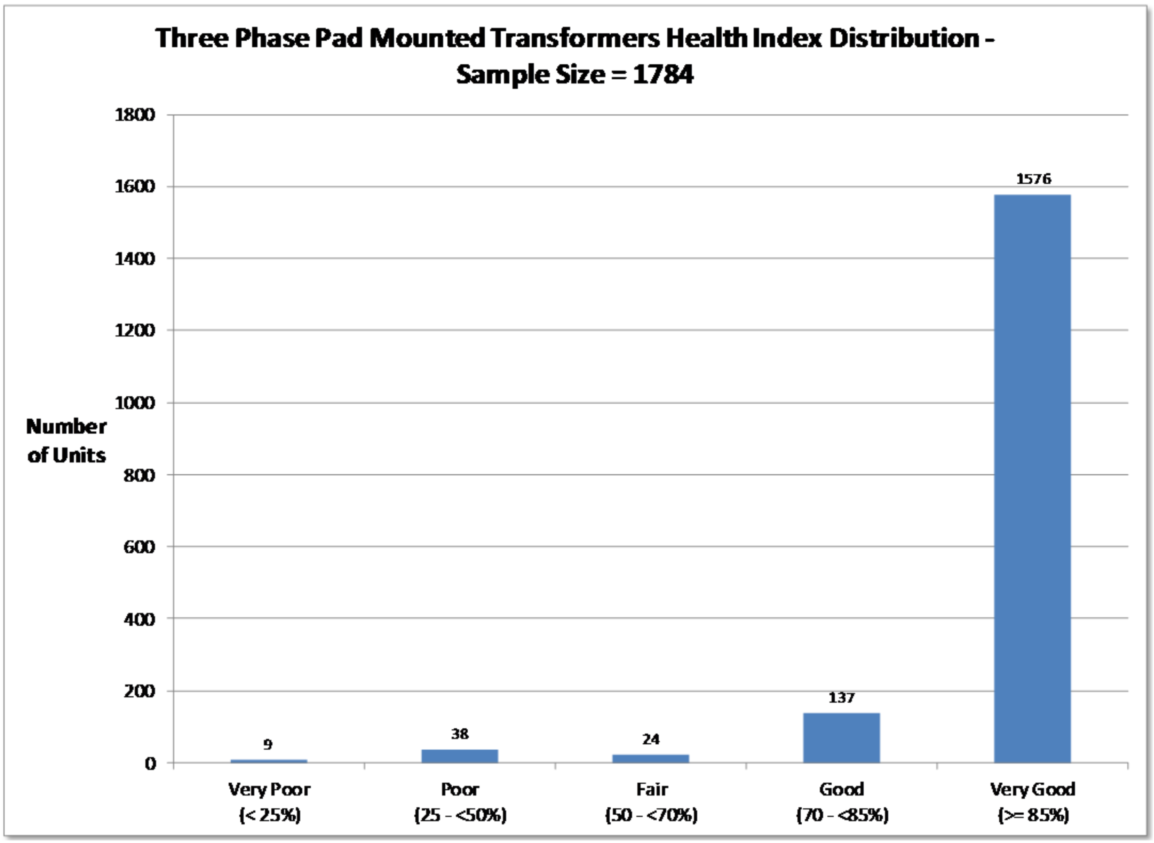

Figure 4-6 Three Phase Pad Mounted Transformers Health Index Distribution (Unit)

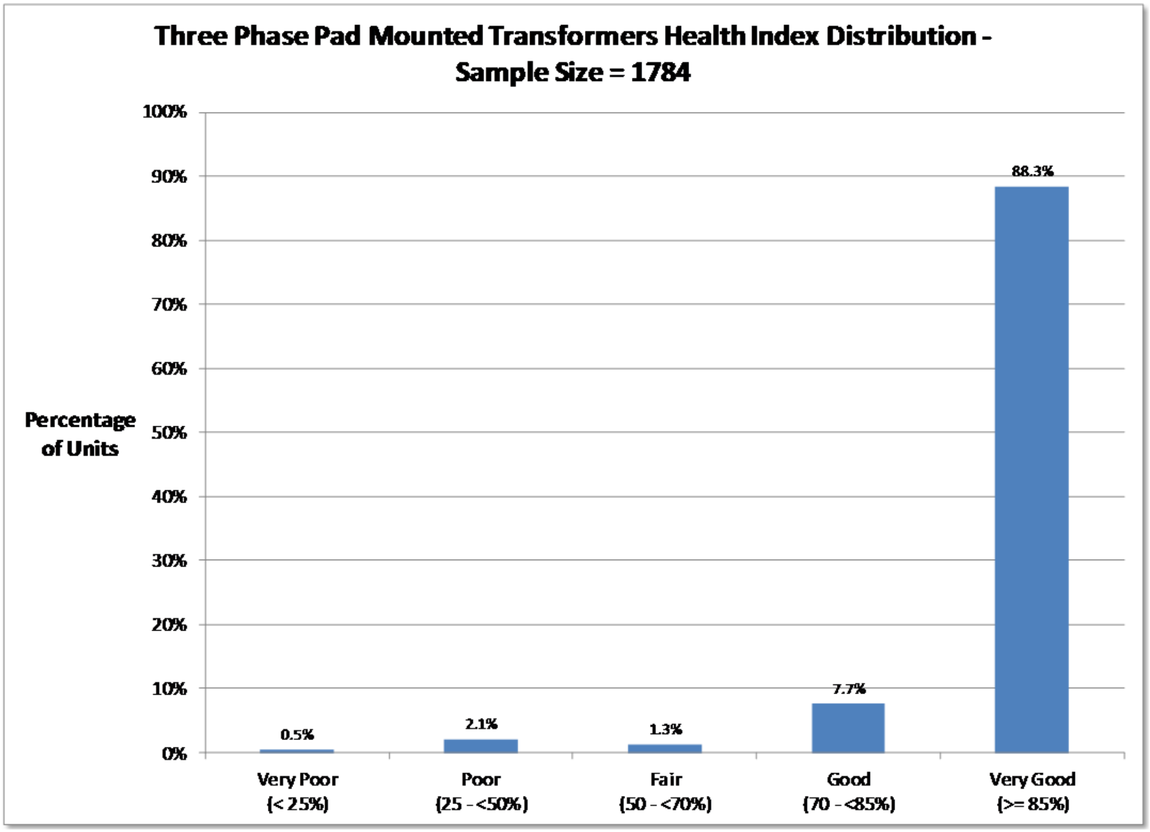

Figure 4-7 Three Phase Pad Mounted Transformers Health Index Distribution (Percentage)

4.4. Condition-Based Flagged-for-Action Plan

As it is assumed that Pad Mounted Transformers were reactively replaced, the flagged-for-action plan was based on the asset failure rate.

Single Phase Pad Mounted Transformers

The replacment plan was as follows:

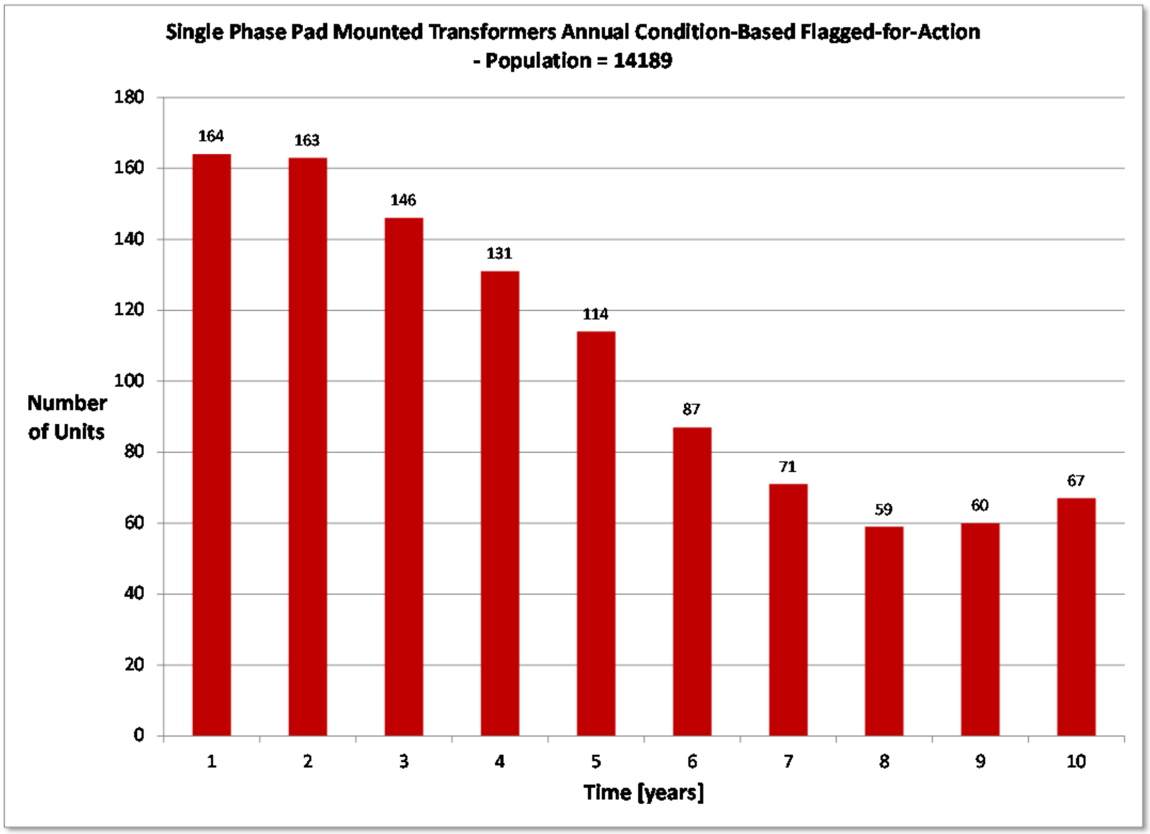

Figure 4-8 Single Phase Pad Mounted Transformers Condition-Based Flagged-for-Action Plan

Three Phase Pad Mounted Transformers

The replacment plan was as follows:

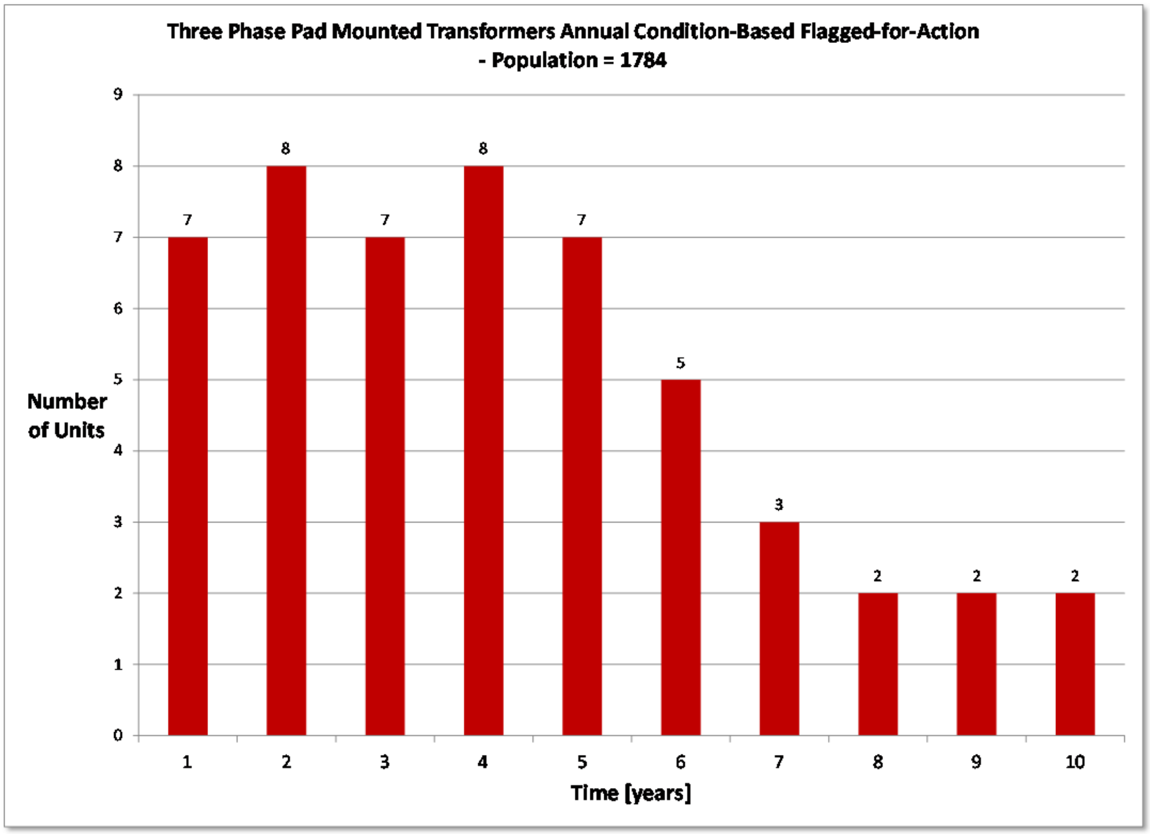

Figure 4-9 Three Phase Pad Mounted Transformers Condition-Based Flagged-for-Action Plan

4.5. Data Analysis

The average DAI for this asset category was almost 100% for both single phase and three phase Pad Mounted Transformers.

Since the 2012 assessment, visual inspection data on tank corrosion, oil leak, overall and oil boiling were collected and incorporated in the 2013 Health Index formulation. The other data gaps noted in the 2012 report remained to be addressed. Note although in this project oil boiling was adopted to indicate overloading condition, more accurate loading information was preferred. So loading still remained to be a data gap item.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Connection	Connection and Insulation	☆☆☆	Transformer connection	Poor connection / hot spots	Visual inspection or IR scan
Grounding		☆	Transformer tank	Poor grounding wire connection	Visual inspection
Base		☆	Transformer foundation	Erosion	Visual inspection
Bushing		☆☆	Porcelain	Crack / Dirt	Visual inspection
Loading	Service Record	☆☆	Transformer load	Loading History: e.g. hourly peak loads	Operation record

According to Enersource, the condition status of connection, grounding and insulator bushing is inspected during infra-red tests. In this study, such information was however not stored in a way that could be easily extracted in electronic format. It is recommended that in the future study, the infra-red test data regarding the above parameters be stored and sorted out in a standardized and systematic way, so as to be incorporated in Health Index formulation.

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5. VAULT TRANSFORMER

5.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

5.1.1. Condition and Sub-Condition Parameters

Table 5-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical condition	7	Table 5-2
2	Connection and Insulation	5	Table 5-3
3	Service Record	5	Table 5-4
De-Rating Factor (DRF)	De-rate based on PCB Content		Table 5-7

Table 5-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Corrosion	3	Table 5-5
2	Access	1	Table 5-5

Table 5-3 Connection & Insulation Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Leak	1	Table 5-5

Table 5-4 Service Record Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	1	Table 5-6
2	Age	1	Figure 5-1

5.1.2. Condition Criteria

Visual Inspections

Table 5-5 Visual Inspection Criteria

Score	Condition Description		
	Corrosion	Leak	Access
4	NO	NONE	GOOD
3	MI	MINOR	
2	MO	MODERATE	BLOCKED
1	YE	YES	BAD
0	MA	MAJOR	NO

Table 5-6 Visual Inspection Criteria (Overall)

Score	Condition Description
4	EXCELLENT
3	GOOD
2	FAIR / AVERAGE
1	POOR / BAD / MAINTENANCE
0	REPLACE

Age

Assume that the failure rate Vault Transformer exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

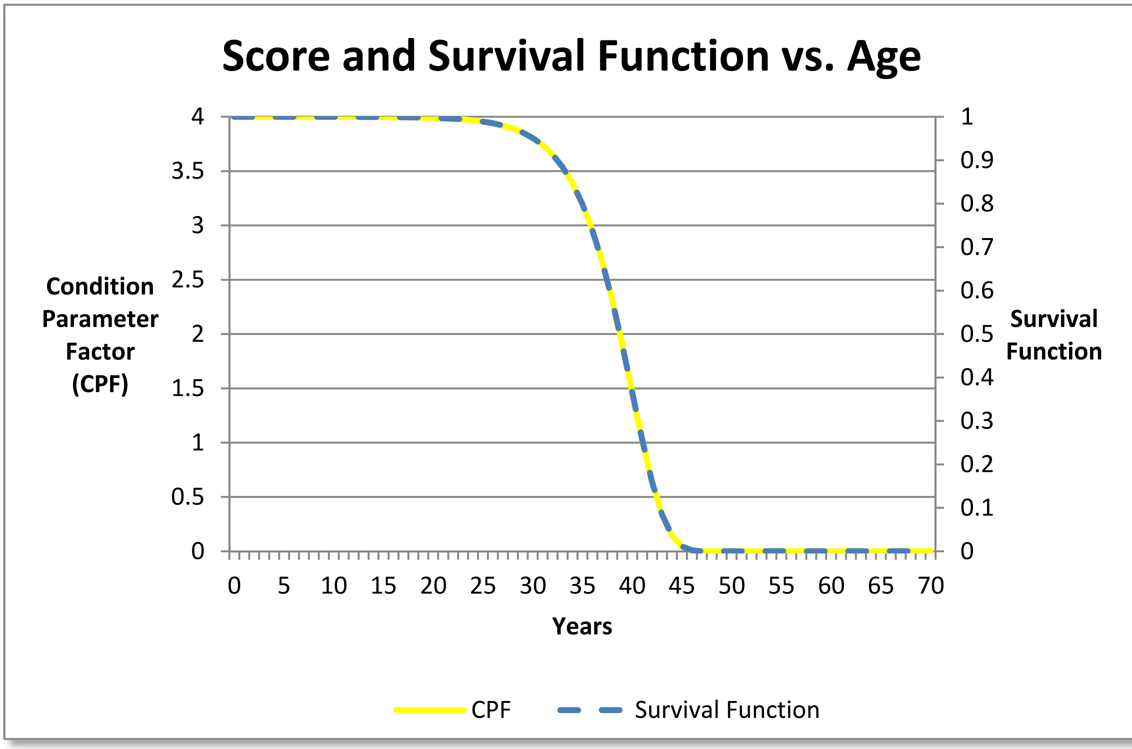

Figure 5-1 Vault Transformer Age Criteria

De-Rating Factor (DRF)

Table 5-7 PCB De-Rating Multiplier

PCB Content	De-Rating Multiplier
0 < PCB < 2 ppm	1
2 < PCB < 50 ppm	0.5
PCB > = 50 ppm	0.25

5.2. Age Distribution

The average age of all single phase units was 27 years. Approximately 25% of the population was 35 years or older.

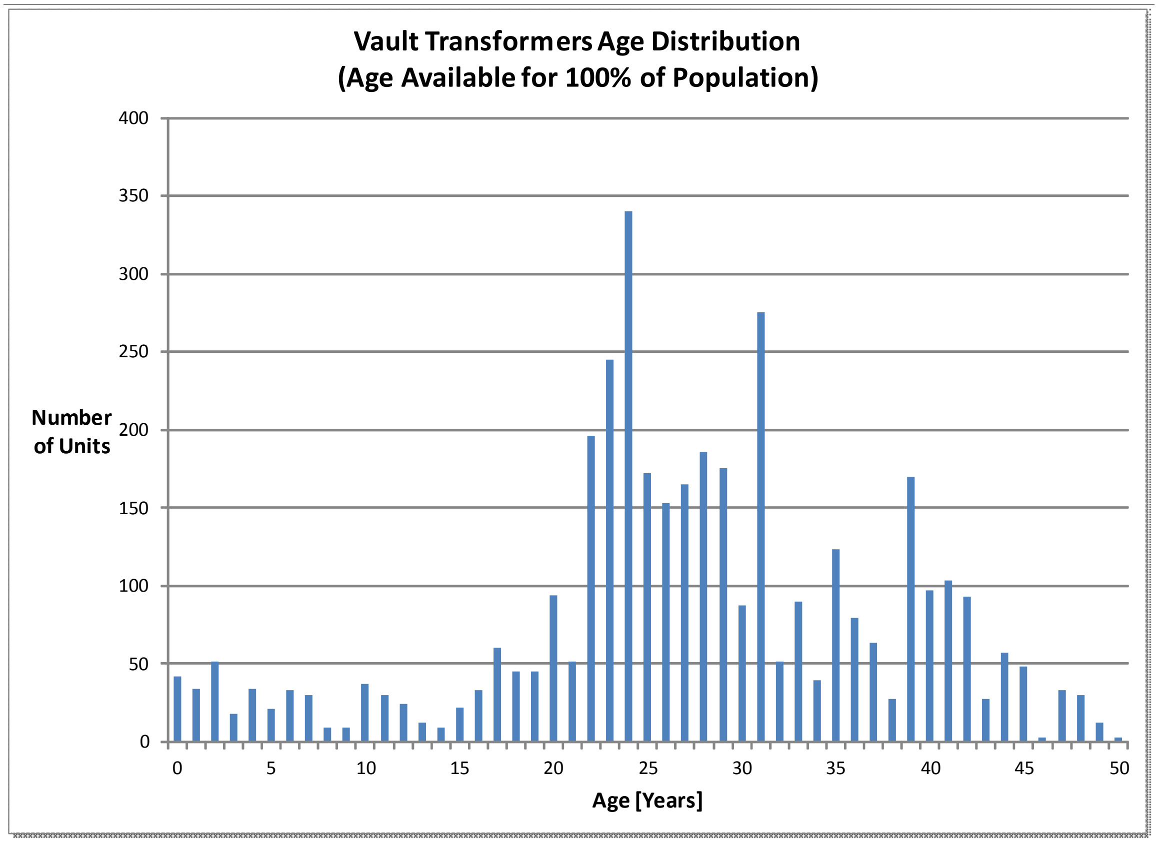

Figure 5-2 Vault Transformer Age Distribution

5.3. Health Index Results

There were 3900 Vault Transformers at EHM. Of these, there were 3900 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 89%. Approximately 10% of the population was in “poor” or “very poor” condition.

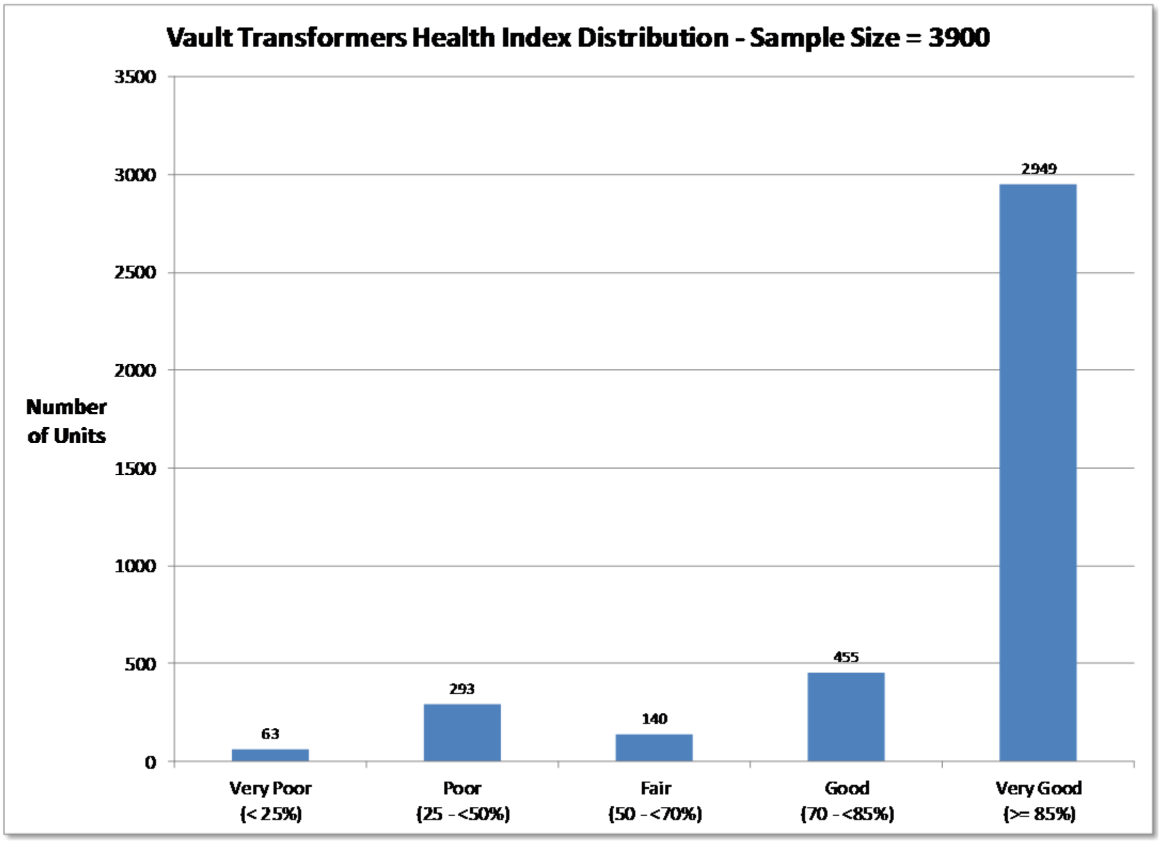

Figure 5-3 Vault Transformer Health Index Distribution (Unit)

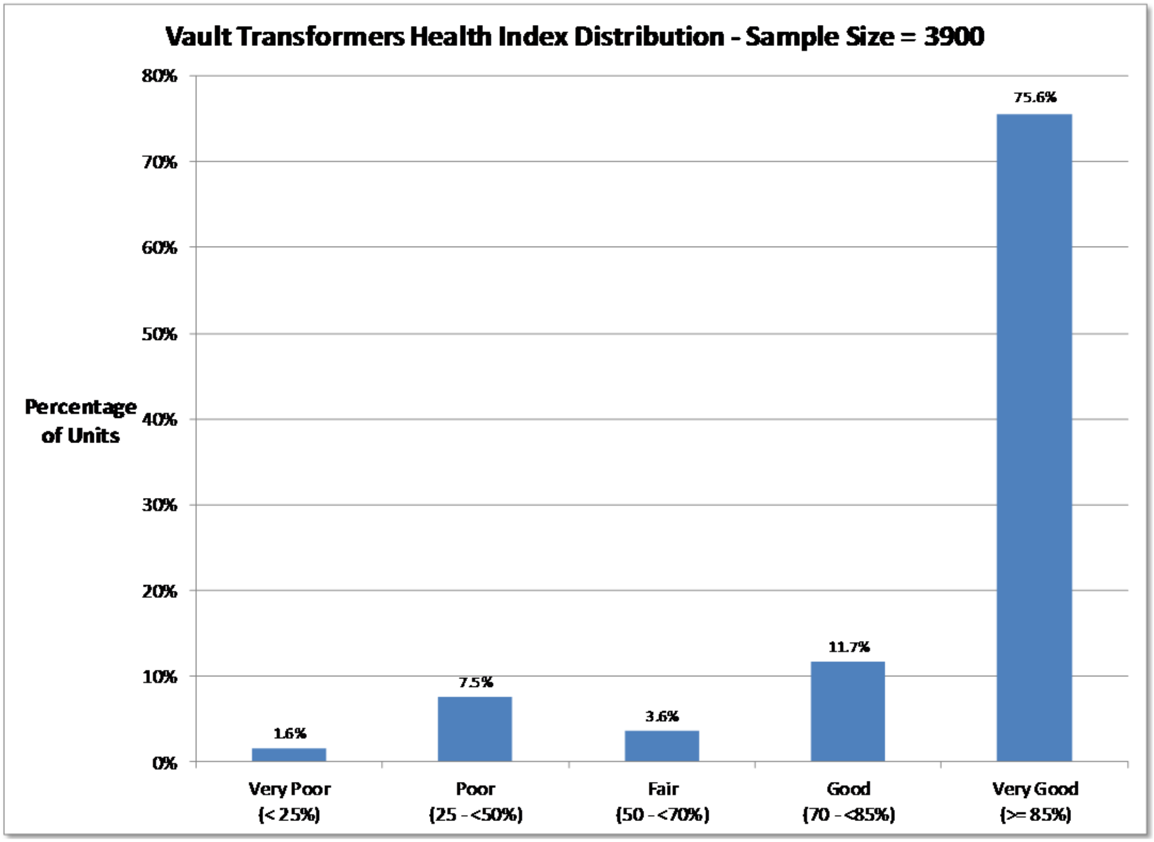

Figure 5-4 Vault Transformer Health Index Distribution (Percentage)

5.4. Condition-Based Flagged-for-Action Plan

As it is assumed that Vault Transformer were reactively replaced, the flagged-for-action plan was based on the asset failure rate.

The condition-based flagged-for-action plan was as follows:

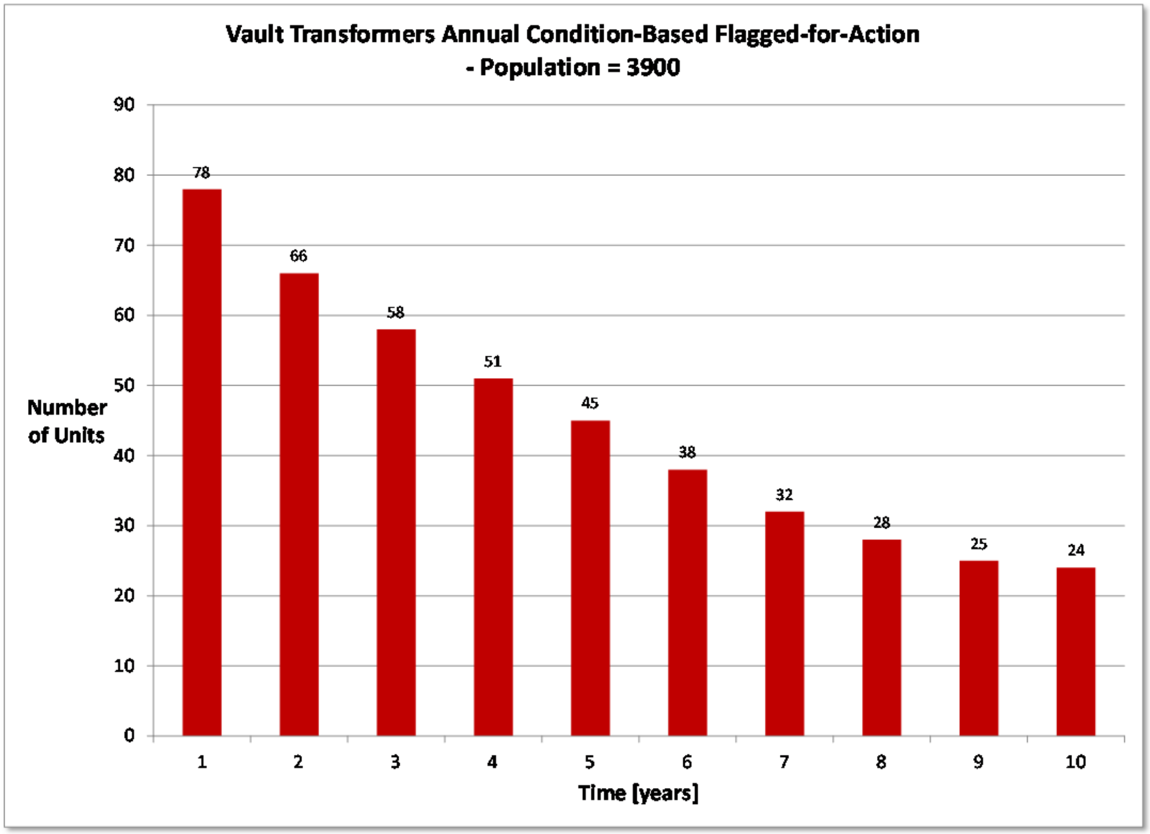

Figure 5-5 Vault Transformer Condition-Based Flagged-for-Action Plan

5.5. Data Analysis

The condition data for this asset category included visual inspection results and age.

Data Availability Indicator

The data availability distribution for this asset class was as follows.

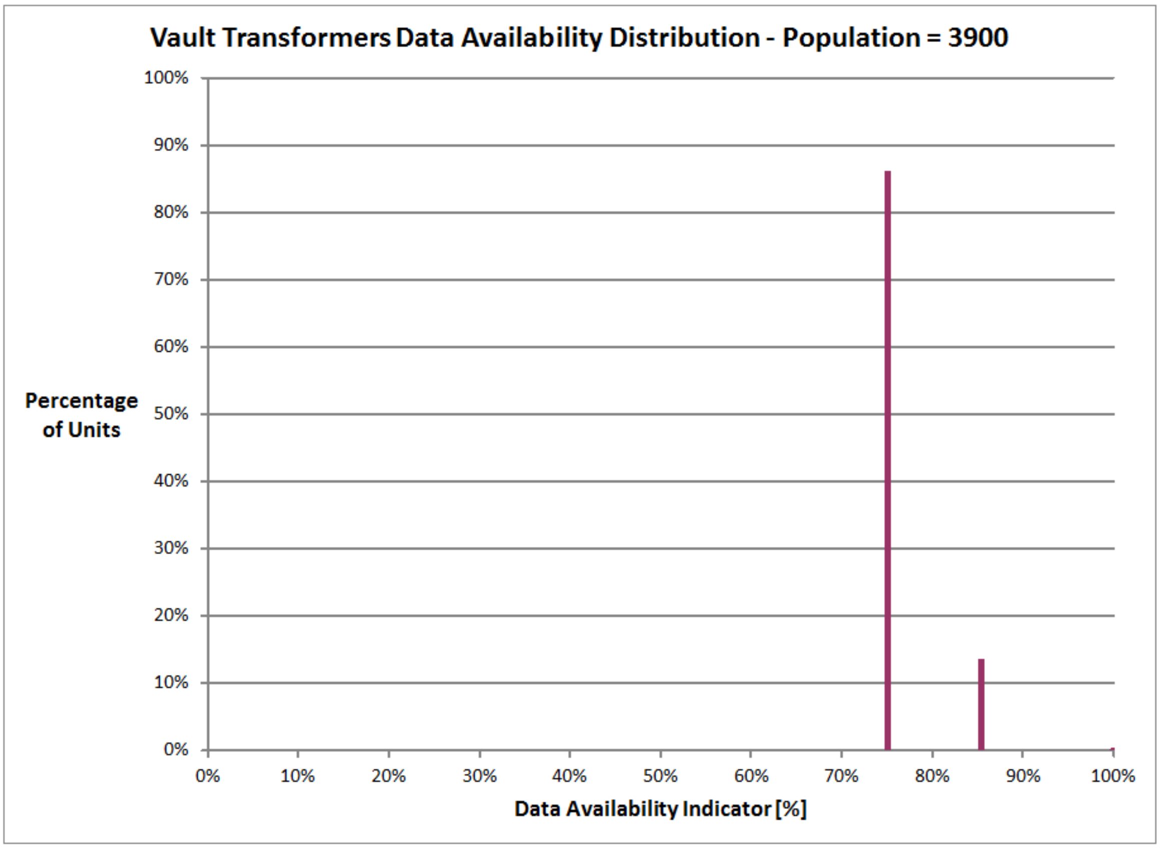

Figure 5-6 Vault Transformer Data Availability Distribution

The average data availability indicator for this asset category had improved from 35% last year to 76% this year. Age was available for the entire population and most inspection data were available for all the population.

Data Gap

Since the 2012 assessment, data collection covered more units in 2013. Some data gaps noted in the 2012 report, however, remained to be addressed, as shown below.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Connection	Connection & Insulation	✮ ✮ ✮	Transformer connection	Poor connection / hot spots	Visual inspection or IR scan
Loading	Service Record	✮ ✮	Transformer load	Loading History: e.g. hourly peak loads	Operation record

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6. PAD MOUNTED SWITCHGEAR

6.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

6.1.1. Condition and Sub-Condition Parameters

Table 6-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	6	Table 6-2
2	Switch/Fuse Condition	3	Table 6-3
3	Insulation	3	Table 6-4
4	Service Record	8	Table 6-5

Table 6-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Corrosion	4	Table 6-6
2	Access	1	Table 6-6
3	Debris/Dirt	1	Table 6-6
4	Paint	1	Table 6-6
5	Base (Grade/Fill)	1	Table 6-6

Table 6-3 Switch/Fuse Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Switch	1	Table 6-6
2	Arc Suppressor	1	Table 6-6

Table 6-4 Insulation Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Insulator	2	Table 6-6
2	Barriers	1	Table 6-6

Table 6-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	3	Table 6-7
2	Age	1	Figure 6-1

6.1.2. Condition Criteria

Visual Inspections

Table 6-6 Visual Inspection Criteria (OK/Not OK)

Score	Condition Description
4	OK or no inspection description
0	Not OK or any defect inspection description

Table 6-7 Visual Inspection Criteria (Life Grade)

Score	Condition Description (per Enersource Inspection Records)
4	5 (Best)
3	4
2	3
1	2
0	1 (Worst)

Age

Assume that the failure rate Pad Mounted Switchgear exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 25 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

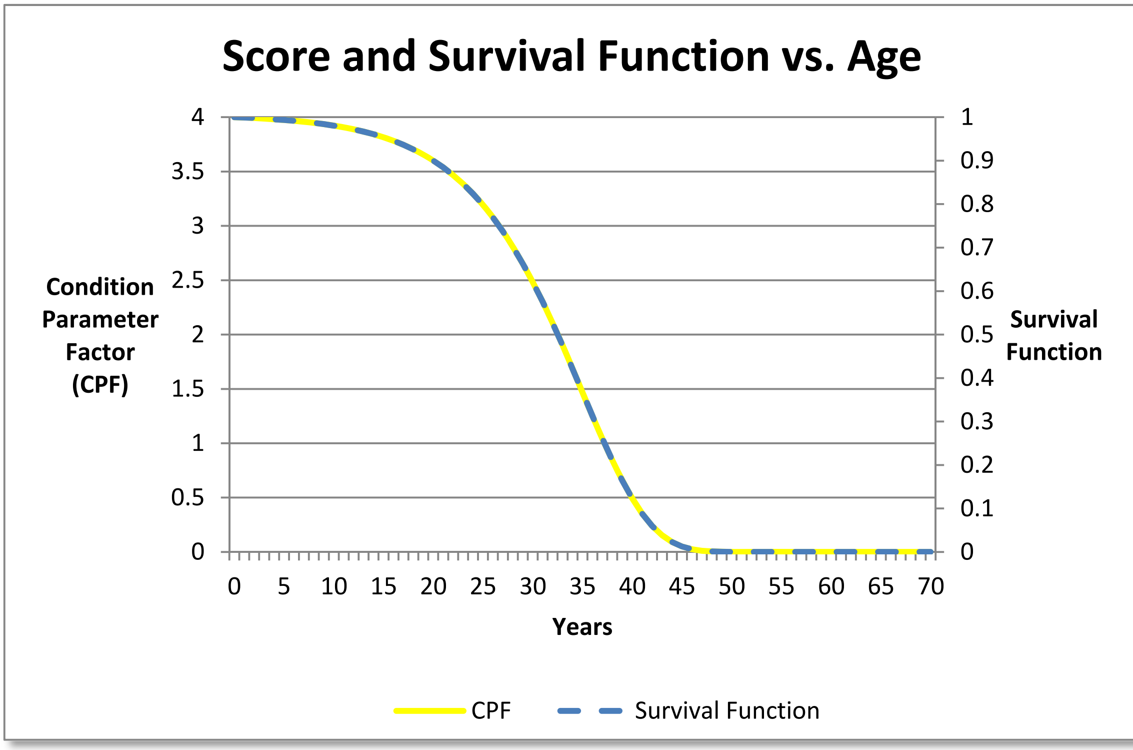

Figure 6-1 Pad Mounted Switchgear Age Criteria

6.2. Age Distribution

The average age of all units was 19 years. Approximately 32% of the population was 25 years or older.

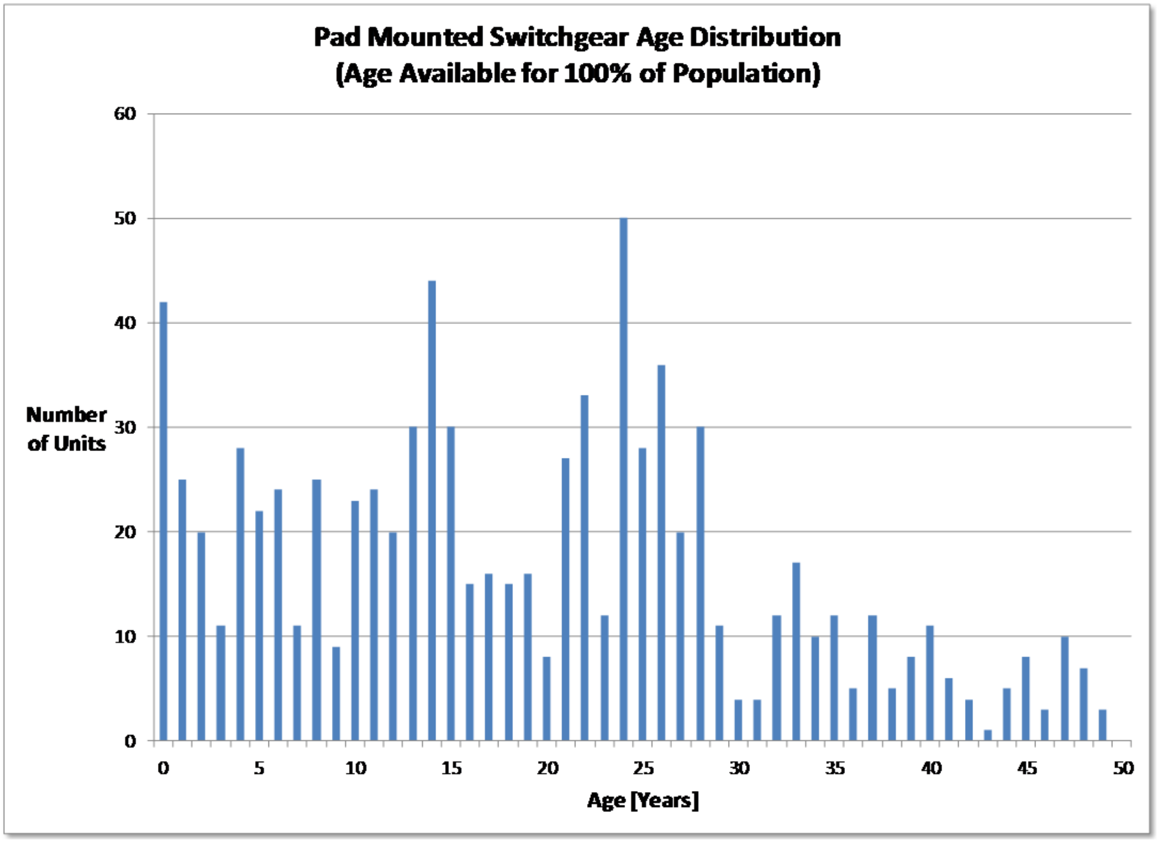

Figure 6-2 Pad Mounted Switchgear Age Distribution

6.3. Health Index Results

There were 852 Pad Mounted Switchgear at EHM. Of these, there were 852 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 79%. About 10% of the population was in "poor" or "very poor" condition.

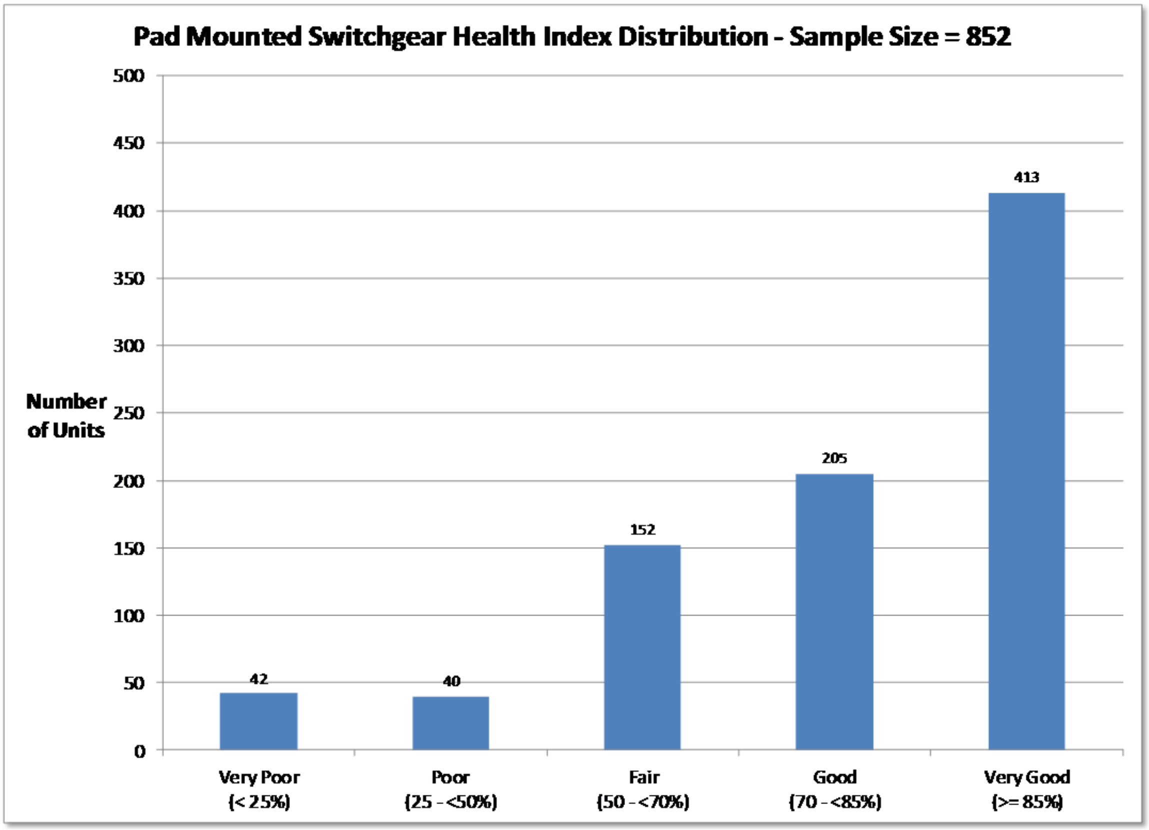

Figure 6-3 Pad Mounted Switchgear Health Index Distribution (Unit)

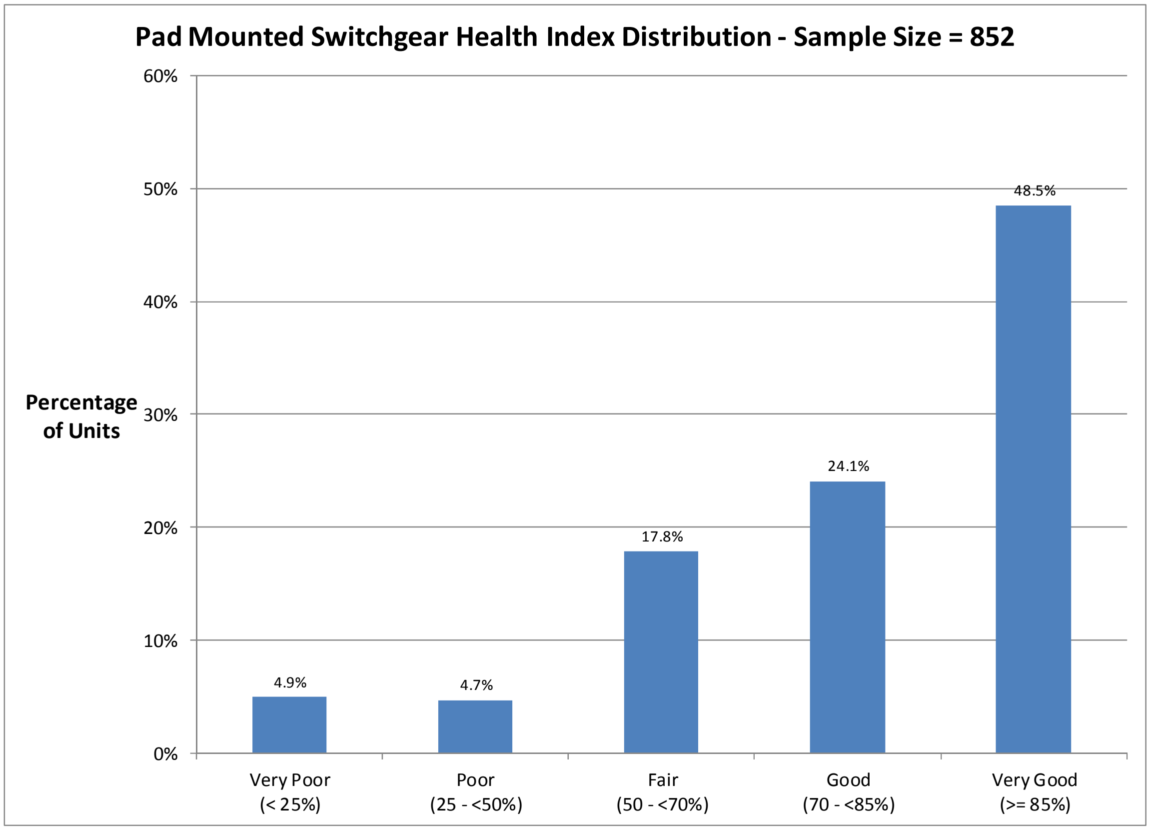

Figure 6-4 Pad Mounted Switchgear Health Index Distribution (Percentage)

6.4. Condition-Based Flagged-for-Action Plan

As it is assumed that Pad Mounted Switchgear were reactively replaced, the flagged-for-action plan was based on the asset failure rate.

The condition-based flagged-for-action plan was as follows:

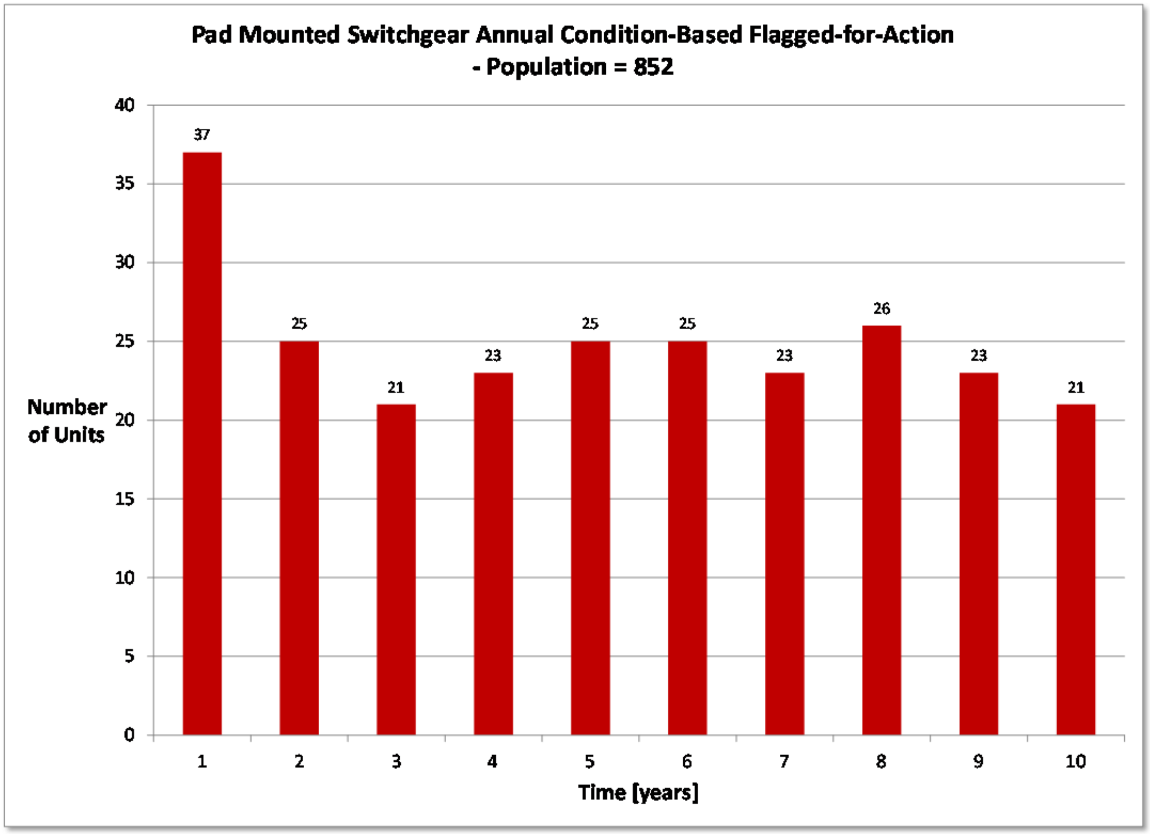

Figure 6-5 Pad Mounted Switchgear Condition-Based Flagged-for-Action Plan

6.5. Data Analysis

The data for this asset category included visual inspection results and age.

Data Availability Indicator

The data availability distribution for this asset class was as follows.

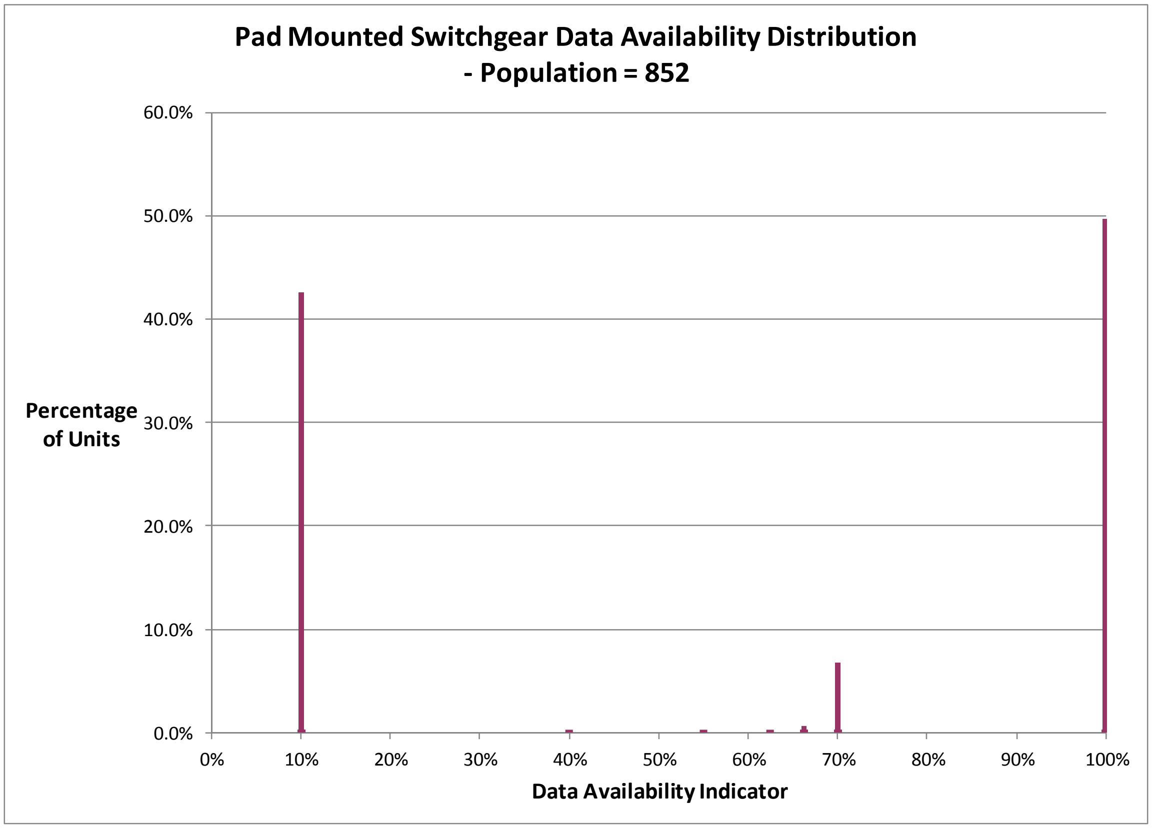

Figure 6-6 Pad Mounted Switchgear Data Availability Distribution

The average DAI of all units was 59%, a 25% improvement over last year's 34%. Age was available for all units. Inspection data, gathered from linemen inspections and dry ice cleaning, was available for over 50% of the population.

Data Gap

There were no data gaps for this asset group because all condition data required by the Health Index formula were collected through inspections and dry ice cleaning. It should be noted, however, that only half of the population had inspection data. Such data should be collected for the remainder of the population.

7. OVERHEAD LINE SWITCHES

This study includes four sub-categories of overhead line switches: 44 kV, 27.6 kV, Inline, and Motorized.

Note that Enersource continues to validate the classification and population counts of its overhead line switches. This assessment is based on the best available information to date.

7.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

7.1.1. Condition and Sub-Condition Parameters

Table 7-1 Condition Parameter and Weights

m	Condition parameter	WCP_m		Sub-Condition Parameters
		Manual	Motorized	
1	Service Record	1	1	Table 7-2
De-Rating Factor (DRF)*	De-rate based on: Switch Type (R9/R10), IR Scan			Table 7-5

*For Load Break Switches only (44 kV and 27.6 kV)

Table 7-2 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	6	Figure 7-1
2	Overall Switch Condition	4	Table 7-4
3	Missing Parts*	1	Table 7-3
4	Damaged Parts*	1	Table 7-3

* For Load Break Switches only (44 kV and 27.6 kV)

7.1.2. Condition Criteria

<u>Visual Inspections (OK / Not OK)</u>

Table 7-3 Visual Inspection Criteria (OK / Not OK)

Score	Condition Description
4	OK
0	Not OK

Table 7-4 Visual Inspection Criteria (Good / Bad)

Score	Condition Description (per Enersource Inspection Records)
4	Good
3	Okay
0	Bad

<u>Age</u>

Assume that the failure rate Overhead Line Switches exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for 27.6 kV, 44 kV, and Inline Switches are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

For motorized switches, the ages of 25 and 35 are used.

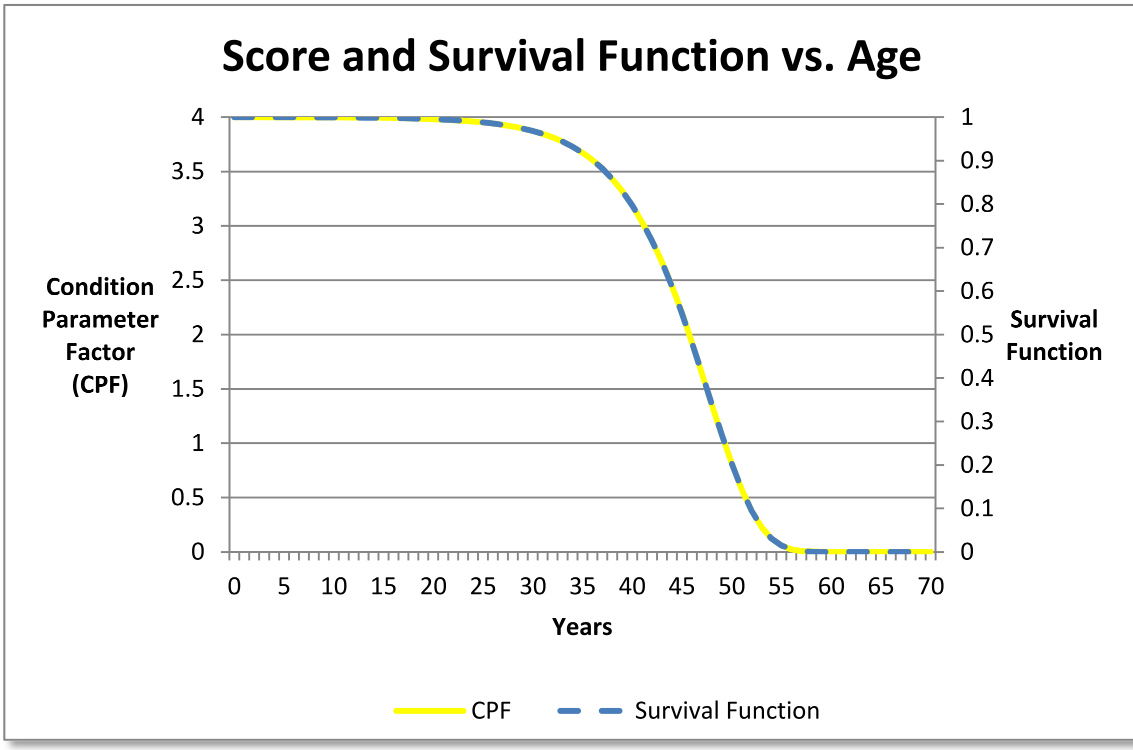

Figure 7-1 Overhead Line Switches Criteria (Non-Motorized and Inline)

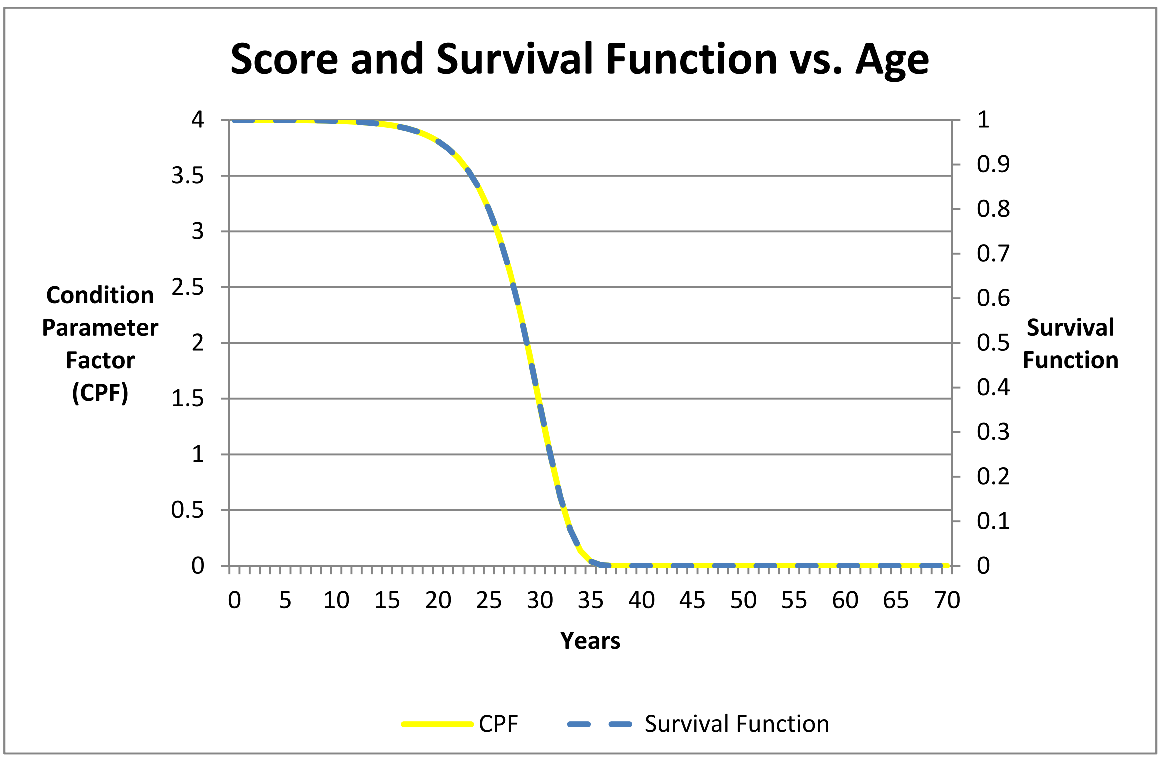

Figure 7-2 Overhead Line Switches Criteria (Motorized)

De-Rating Factor (DRF)

Table 7-5 De-Rating Criteria

n	Parameter	De-Rating Multiplier (DR_n)	DRF
1	Switch Type	Table 7-6	DRF = MIN(DR_1, DR_2)
1	IR Scan	Table 7-7	

Table 7-6 Switch Type De-Rating Multiplier (DR_1)

Switch Type	De-Rating Multiplier
R9	0.9
All Others	1

Table 7-7 IR De-Rating Multiplier (DR_2)

IR Priority	De-Rating Multiplier
Red priority	0.7
Yellow priority	0.85
White priority	0.95

7.2. Age Distribution

44 kV Load Break Switches

The average age of all units was 19 years. Approximately 7% of the population was 40 years or older.

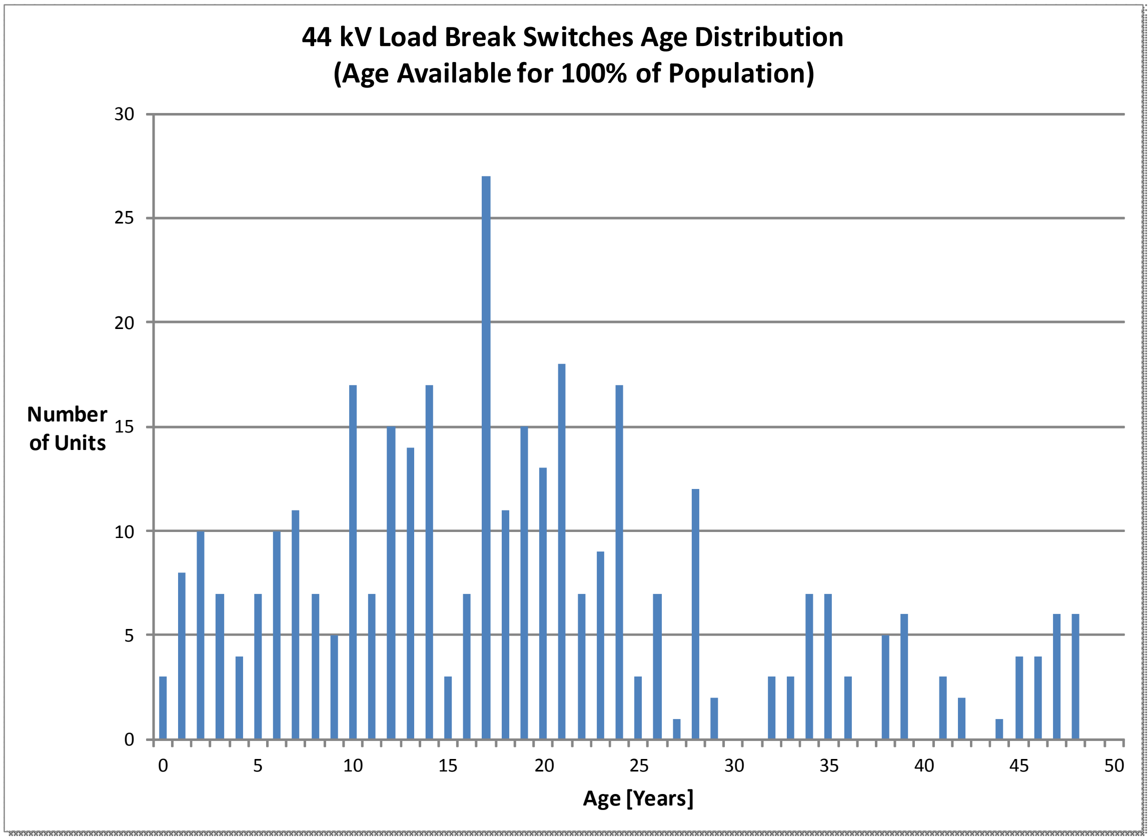

Figure 7-3 44 kV Load Break Switches Age Distribution

27.6 kV Load Break Switches

The average age of all units was 16 years. Approximately 5% of the population was 40 years or older.

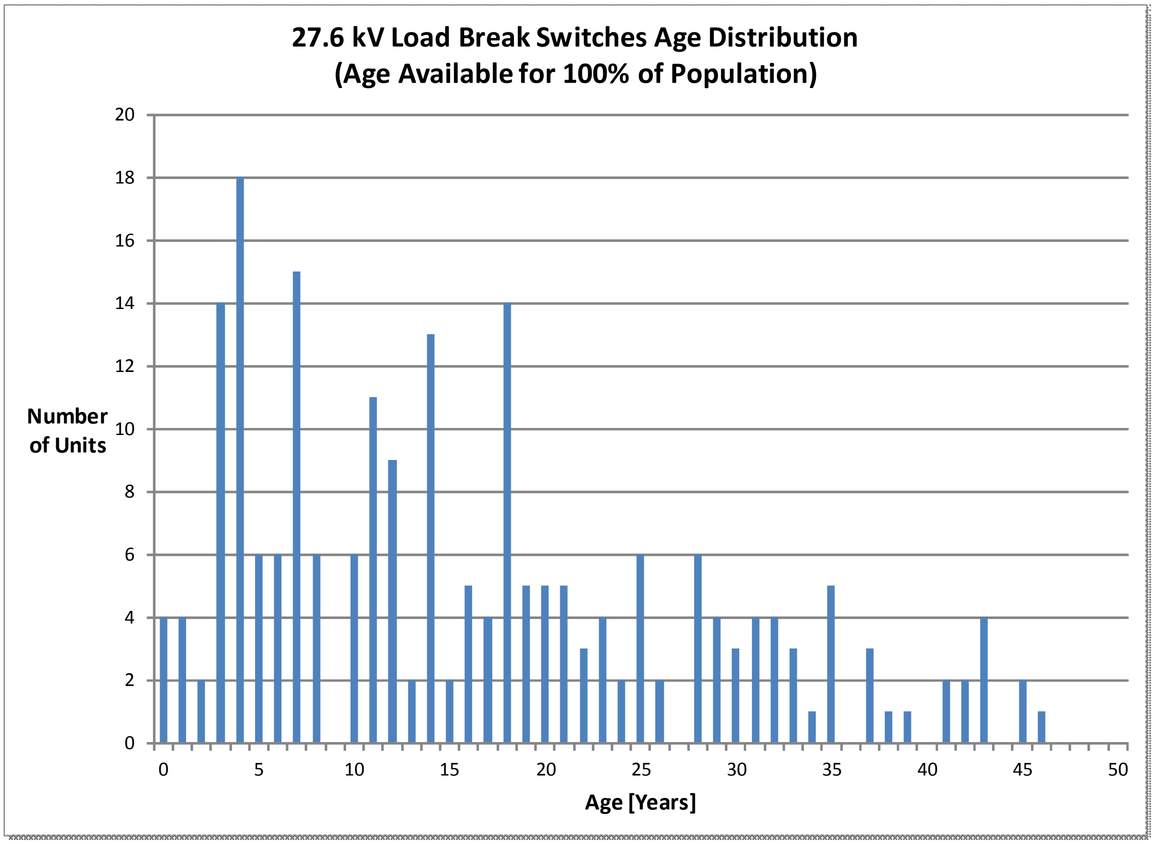

Figure 7-4 27.6kV Load Break Switches Age Distribution

In Line Switches

The average age of all units was 18 years. Approximately 10% of the population was 40 years or older.

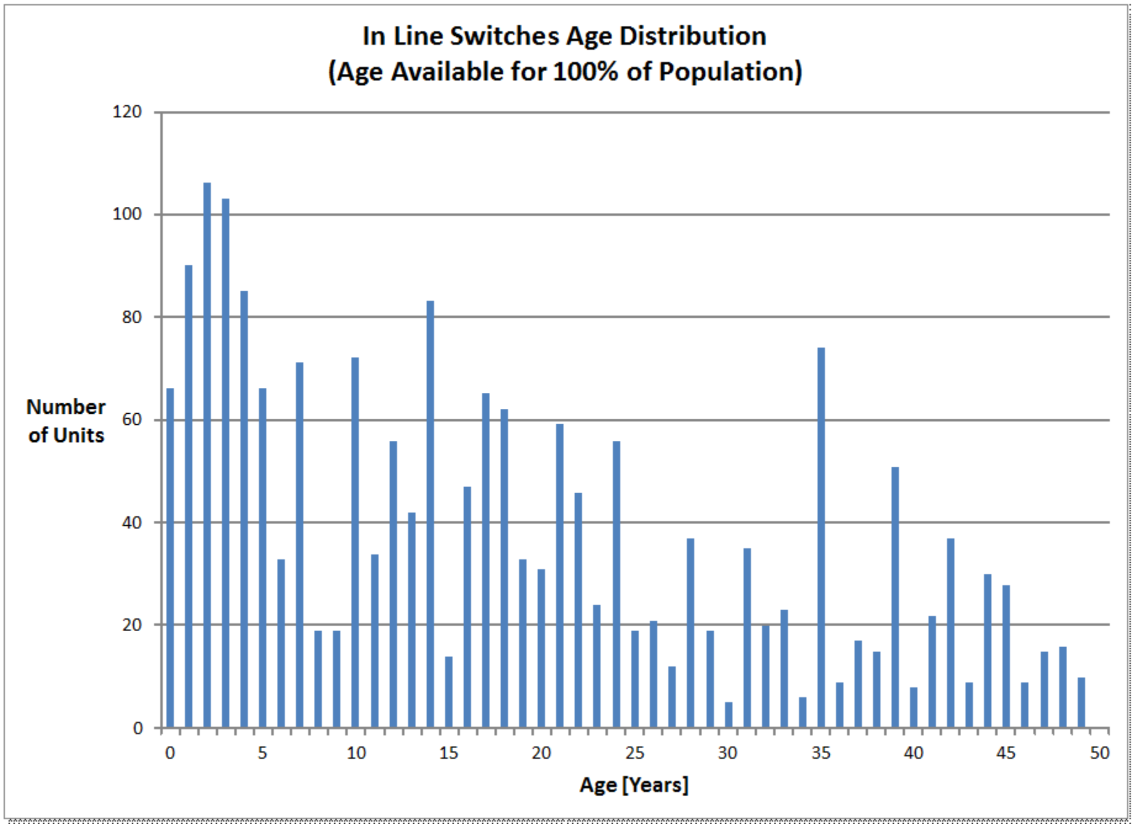

Figure 7-5 In Line Switches Age Distribution

Motorized Switches

The average age of all units was 15 years. Approximately 23% of the population was 25 years or older.

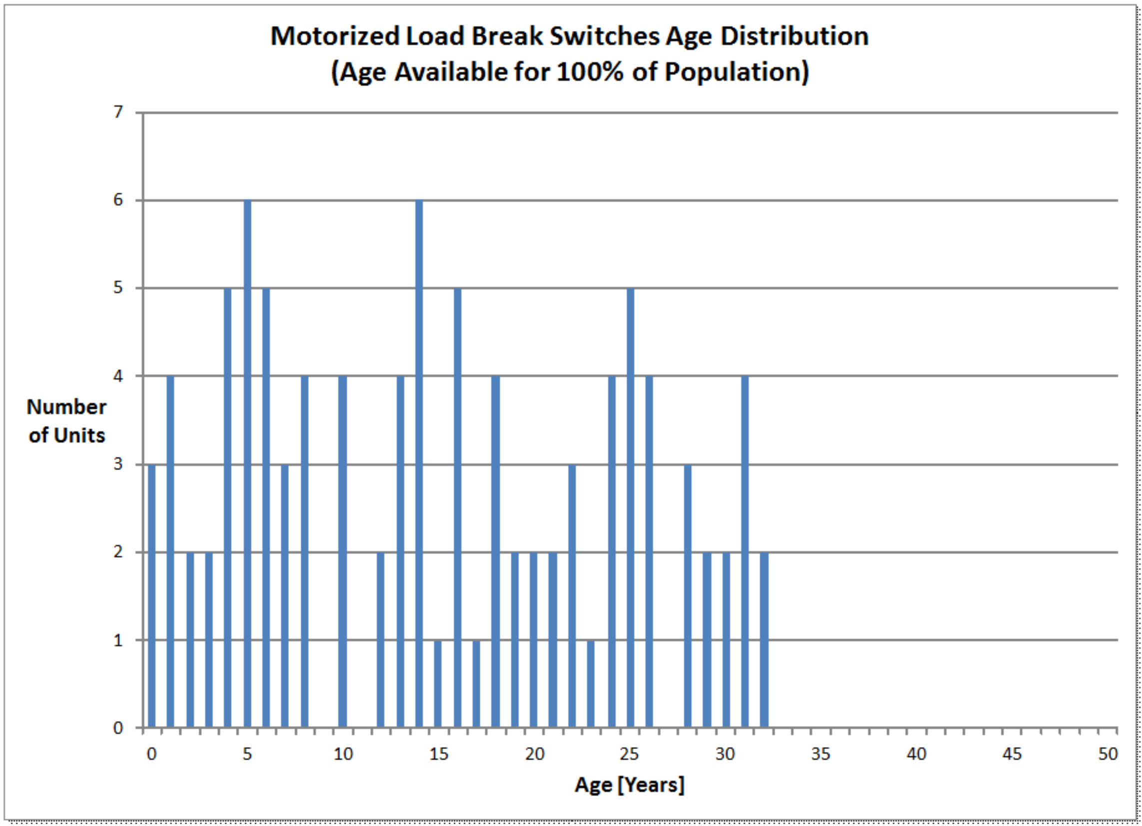

Figure 7-6 Motorized Switches Age Distribution

7.3. Health Index Results

44 kV Load Break Switches

There were 354 *44 kV Load Break Switches* at EHM. Of these, there were 354 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 89%. Approximately <1% were in "poor" or "very poor" condition.

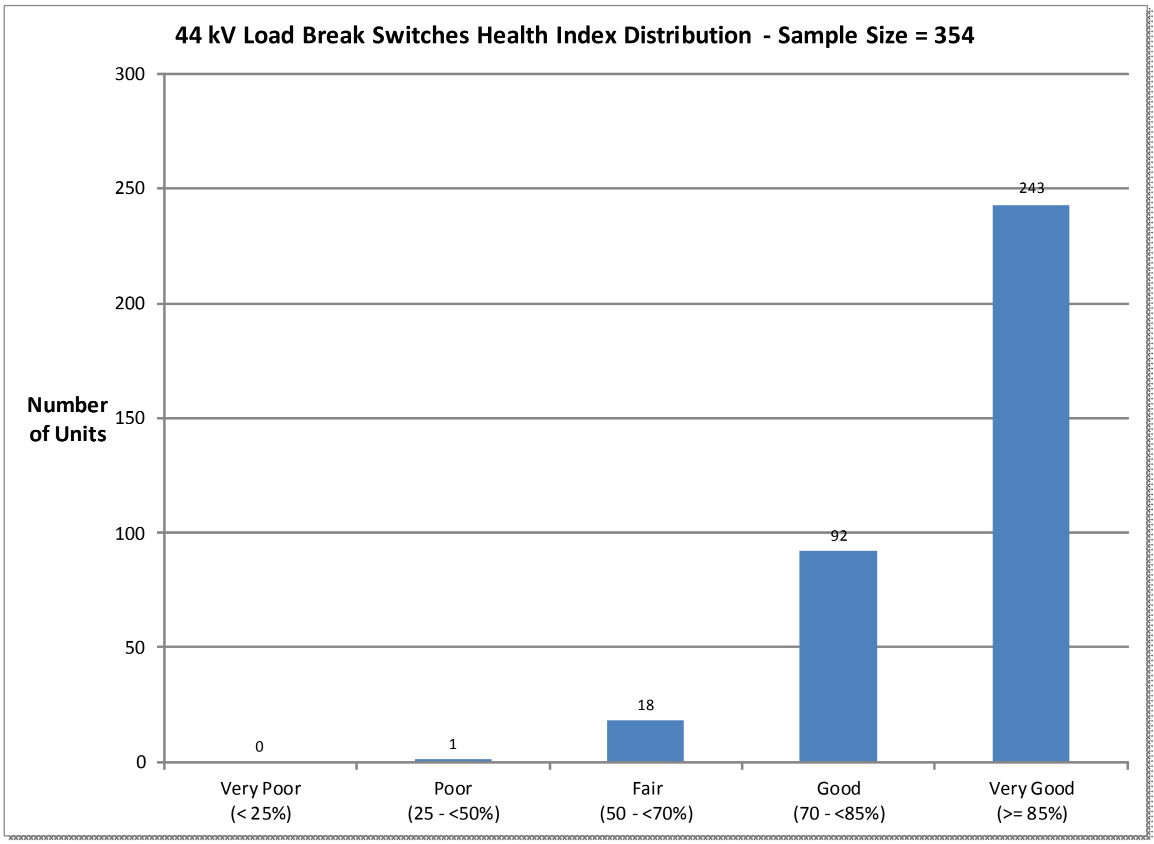

Figure 7-7 44 kV Load Break Switches Health Index Distribution (Unit)

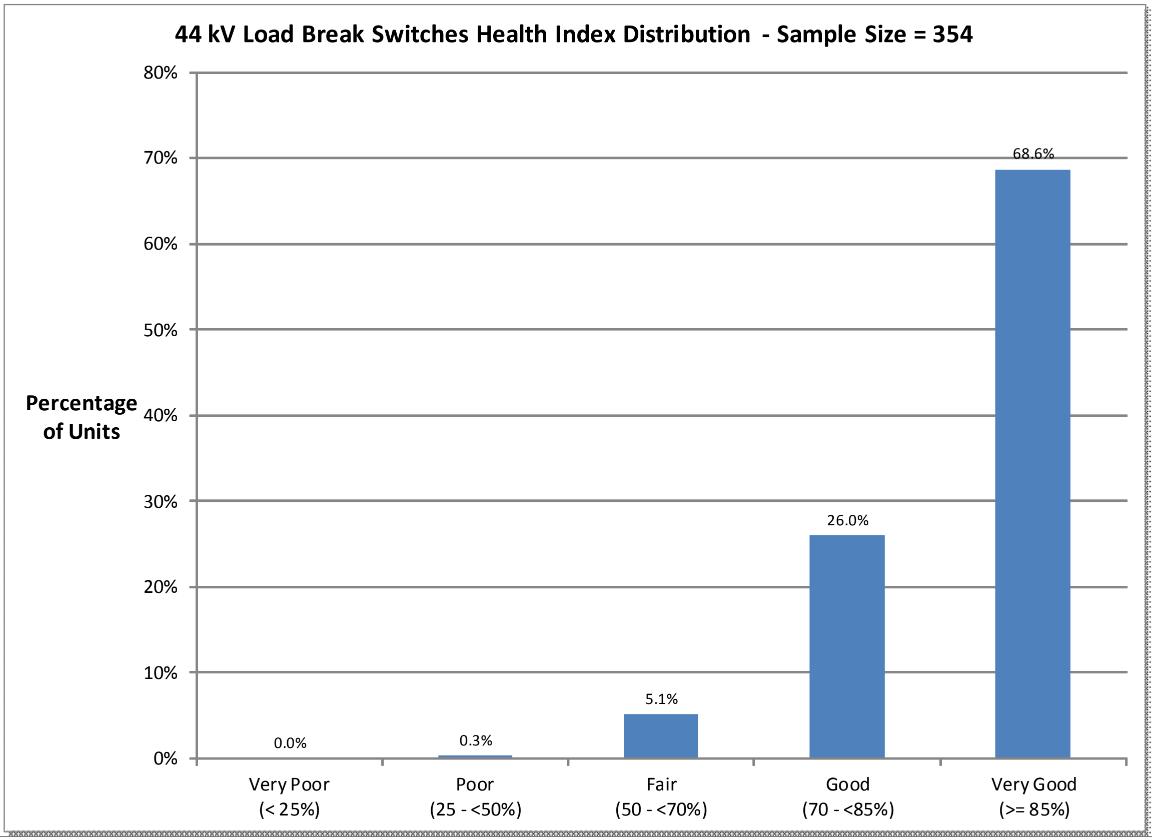

Figure 7-8 44 kV Load Break Health Switches Index Distribution (Percentage)

27.6 kV Load Break Switches

There were 219 *27.6 kV Load Break Switches*. Of these, there were 219 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 94%. None of the population was in "poor" or "very poor" condition.

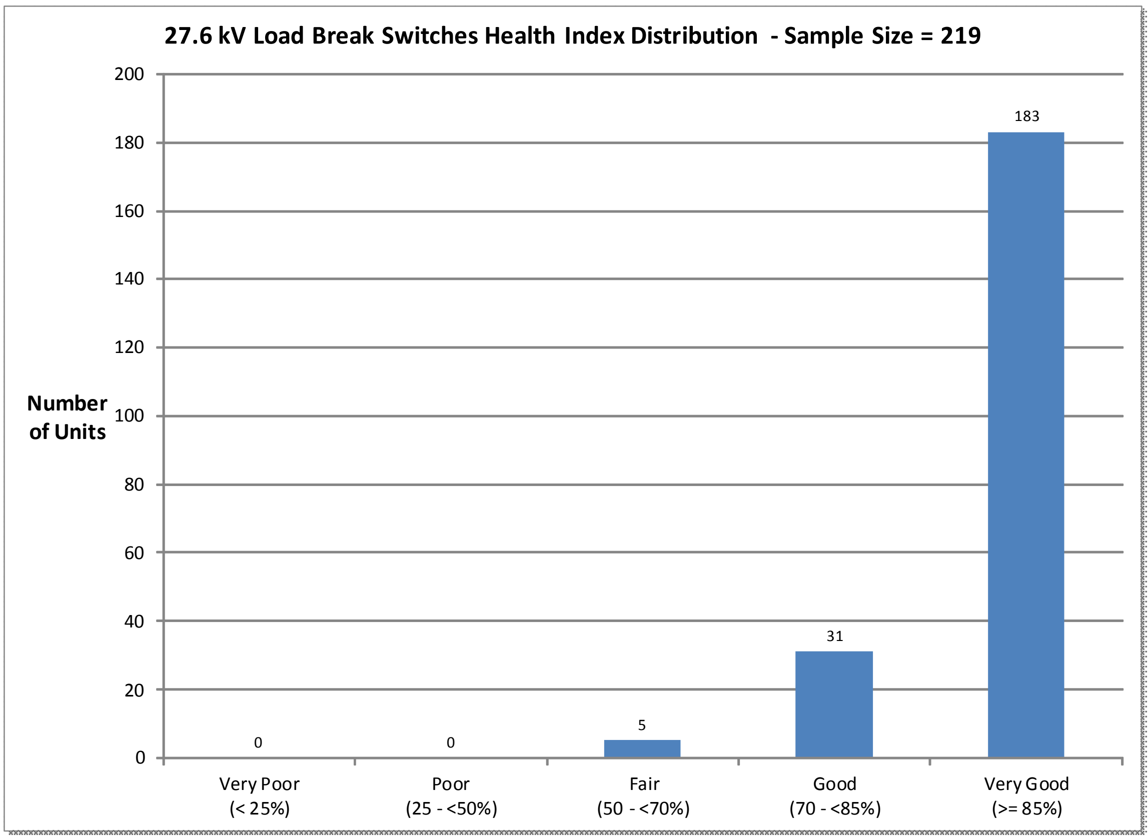

Figure 7-9 27.6kV Load Break Switches Health Index Distribution (Unit)

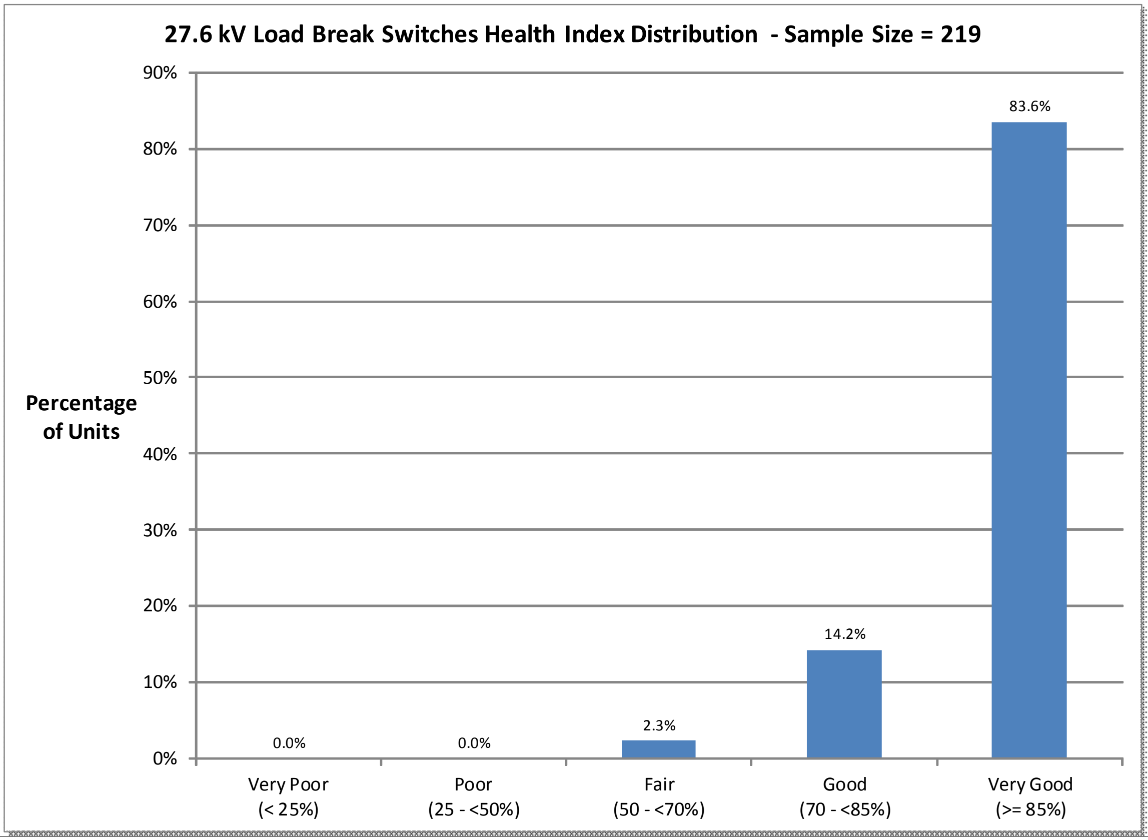

Figure 7-10 27.6kV Load Break Switches Health Index Distribution (Percentage)

In Line Switches

There were 1946 *In Line Switches* at EHM. Of these, there were 1946 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 96%. Approximately <1% of the population was in "poor" or "very poor" condition.

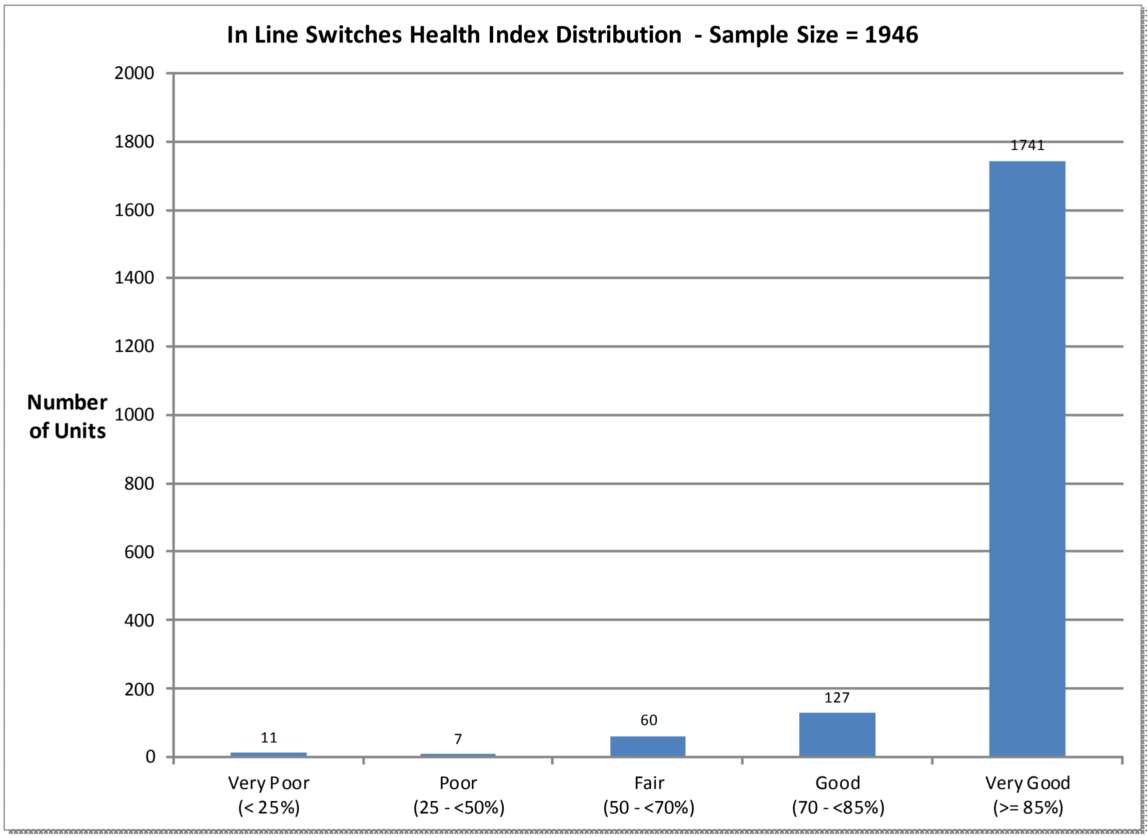

Figure 7-11 In Line Switches Health Index Distribution (Unit)

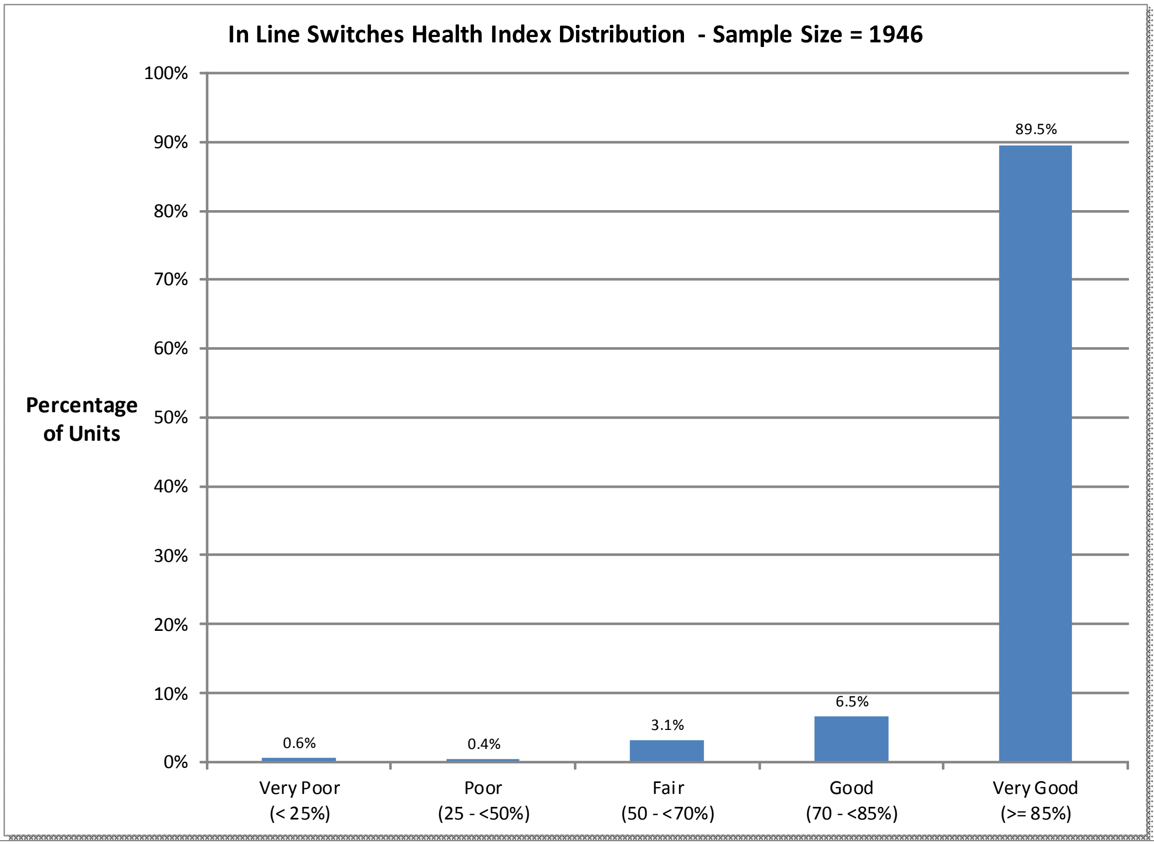

Figure 7-12 In Line Switches Health Index Distribution (Percentage)

Motorized

There were 97 Motorized Switches at EHM. Of these, there were 97 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 88%. None were in "poor" or "very poor" condition.

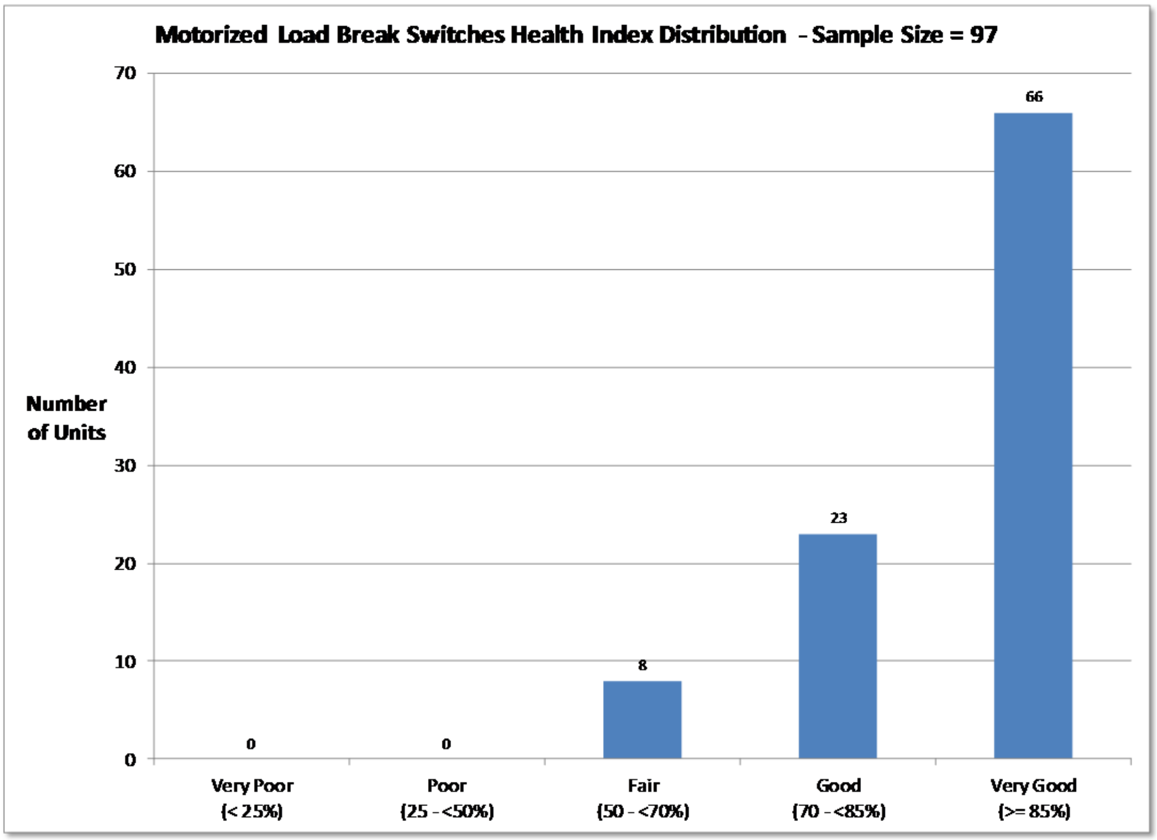

Figure 7-13 Motorized Switches Health Index Distribution (Unit)

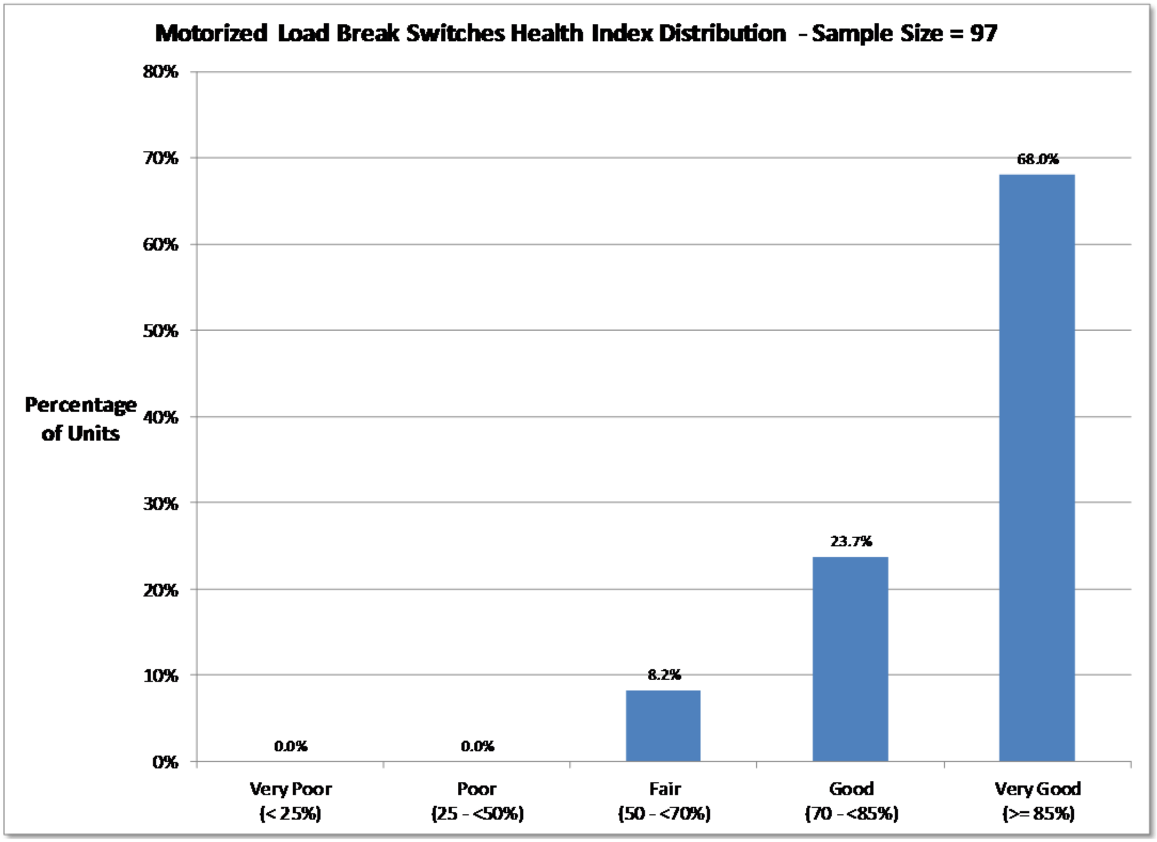

Figure 7-14 Motorized Health Index Distribution (Percentage)

7.4. Condition-Based Flagged-for-Action Plan

As it is assumed that Overhead Line Switches were reactively replaced, the flagged-for-action plan was based on the asset failure rate.

The condition-based flagged-for-action plan was as follows:

44 kV Load Break Switches

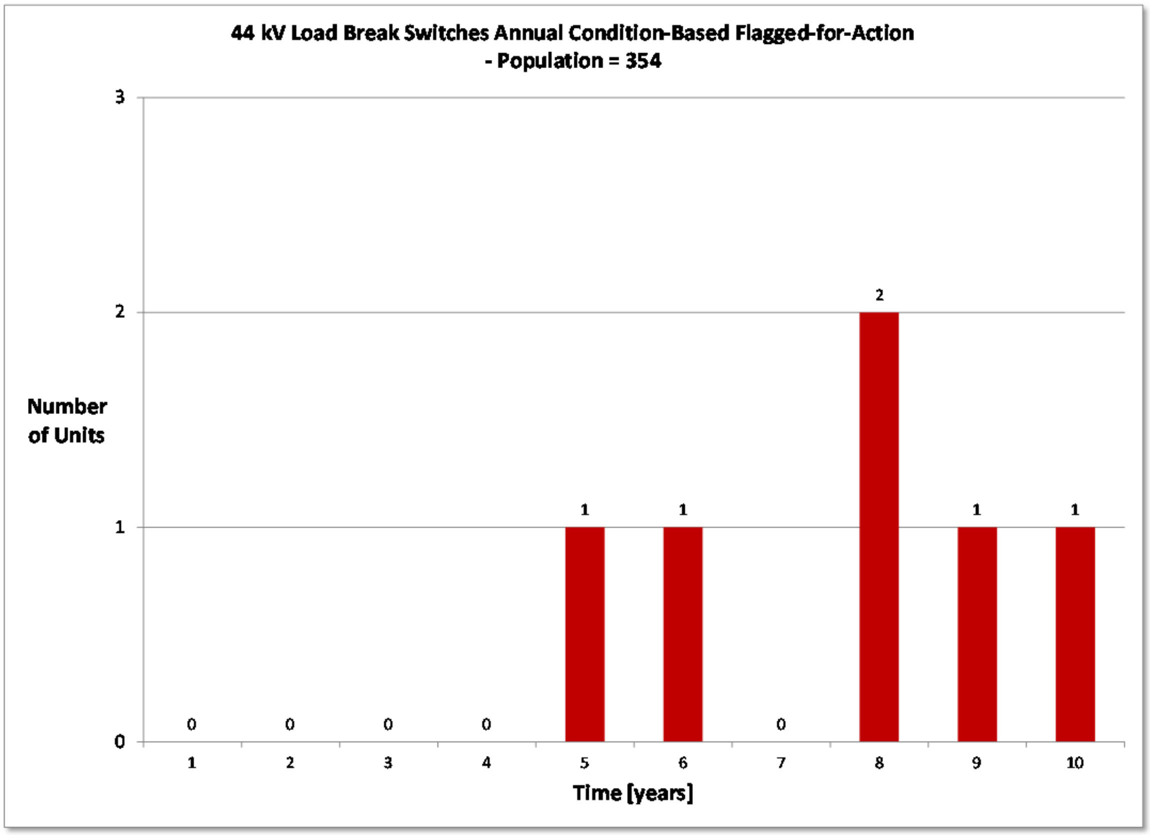

Figure 7-15 44 kV Load Break Switches Condition-Based Flagged-for-Action Plan

27.6 kV Load Break Switches

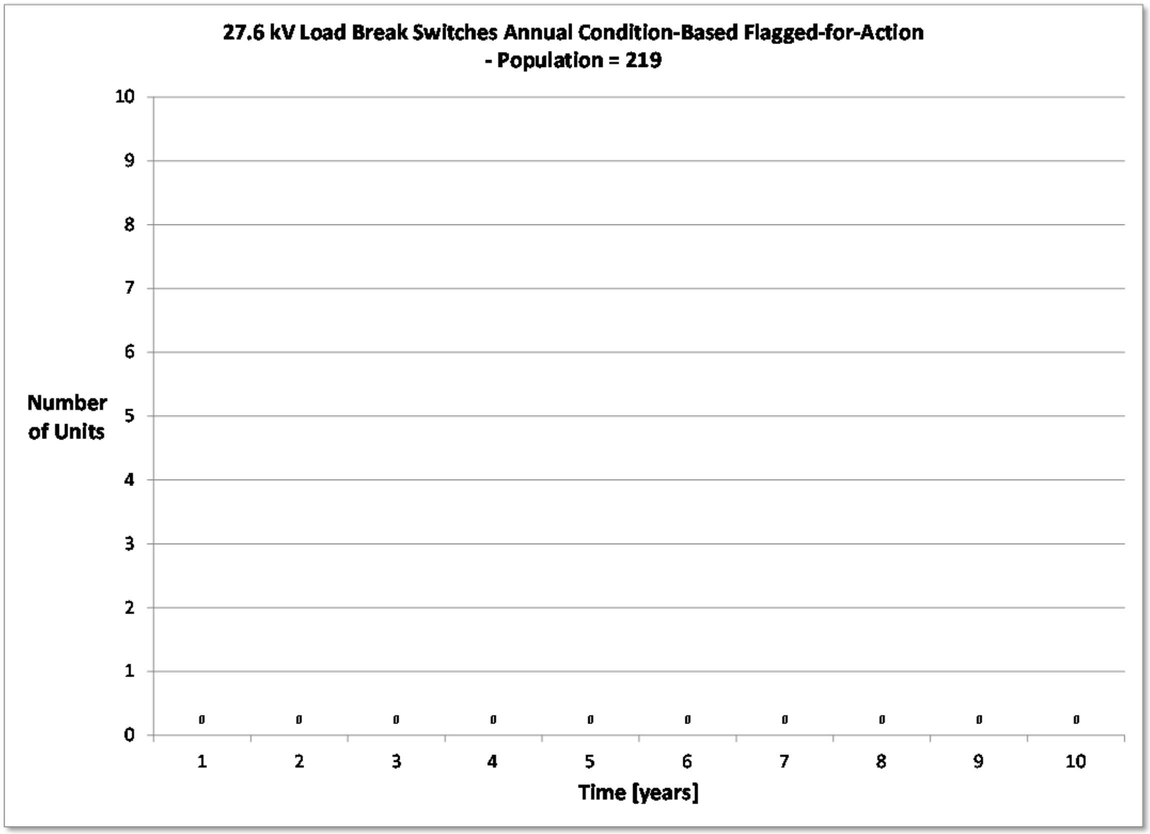

Figure 7-16 27.6kV Load Break Switches Condition-Based Flagged-for-Action Plan

In Line Switches

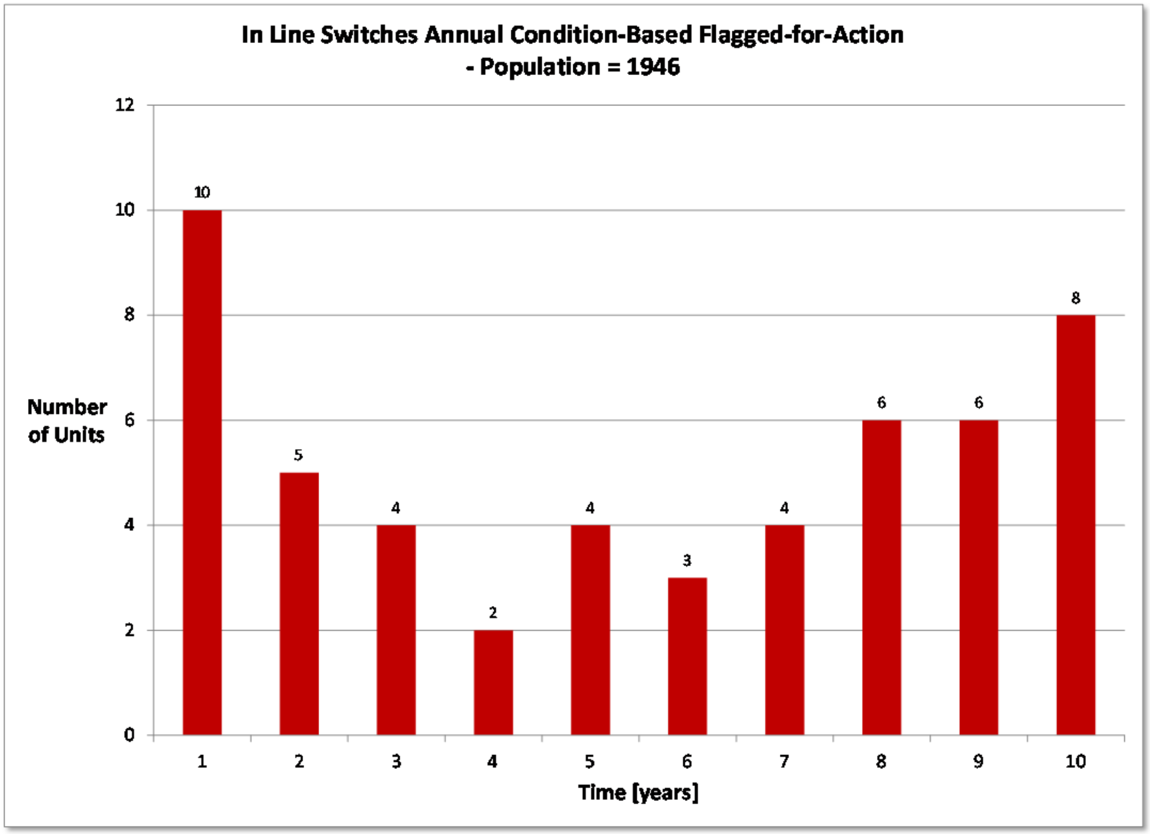

Figure 7-17 In Line Switches Condition-Based Flagged-for-Action Plan

Motorized Switches

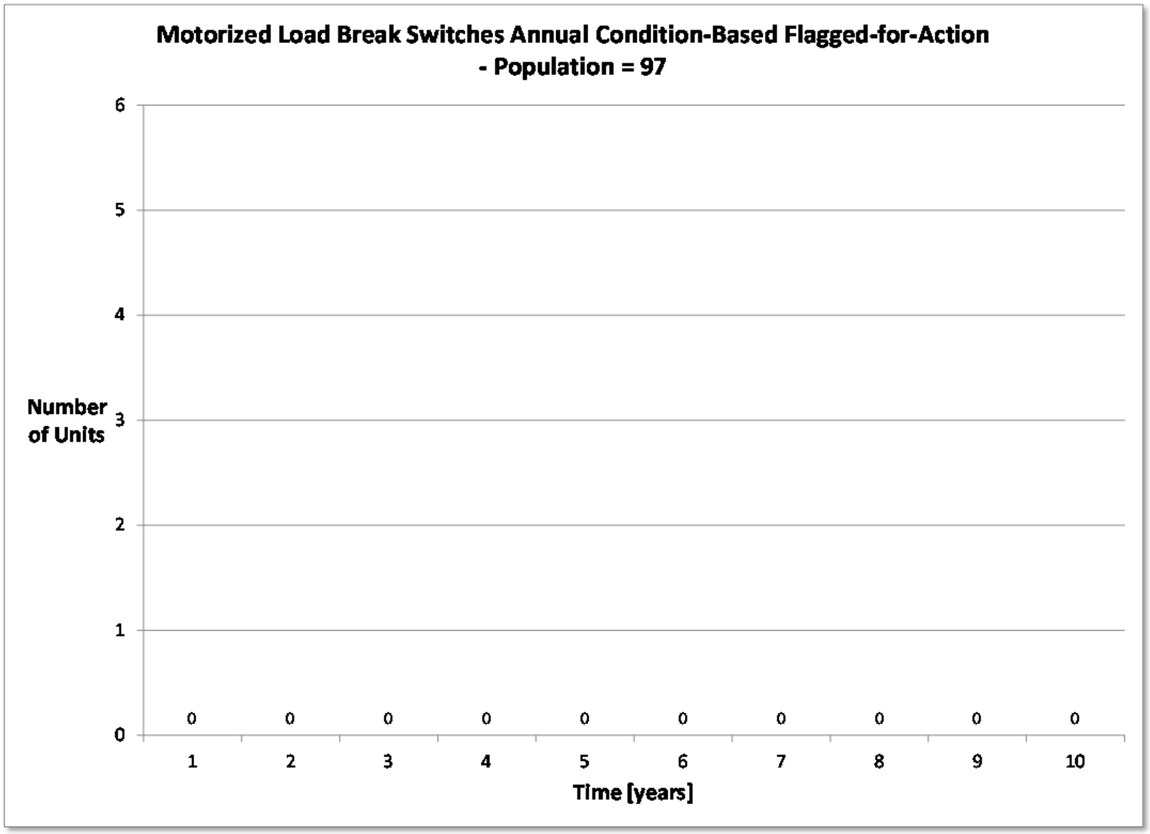

Figure 7-18 Motorized Condition-Based Flagged-for-Action Plan

7.5. Data Analysis

Age and inspection data were available for this asset category.

Data Availability Indicator

The data availability distribution for this asset class was as follows.

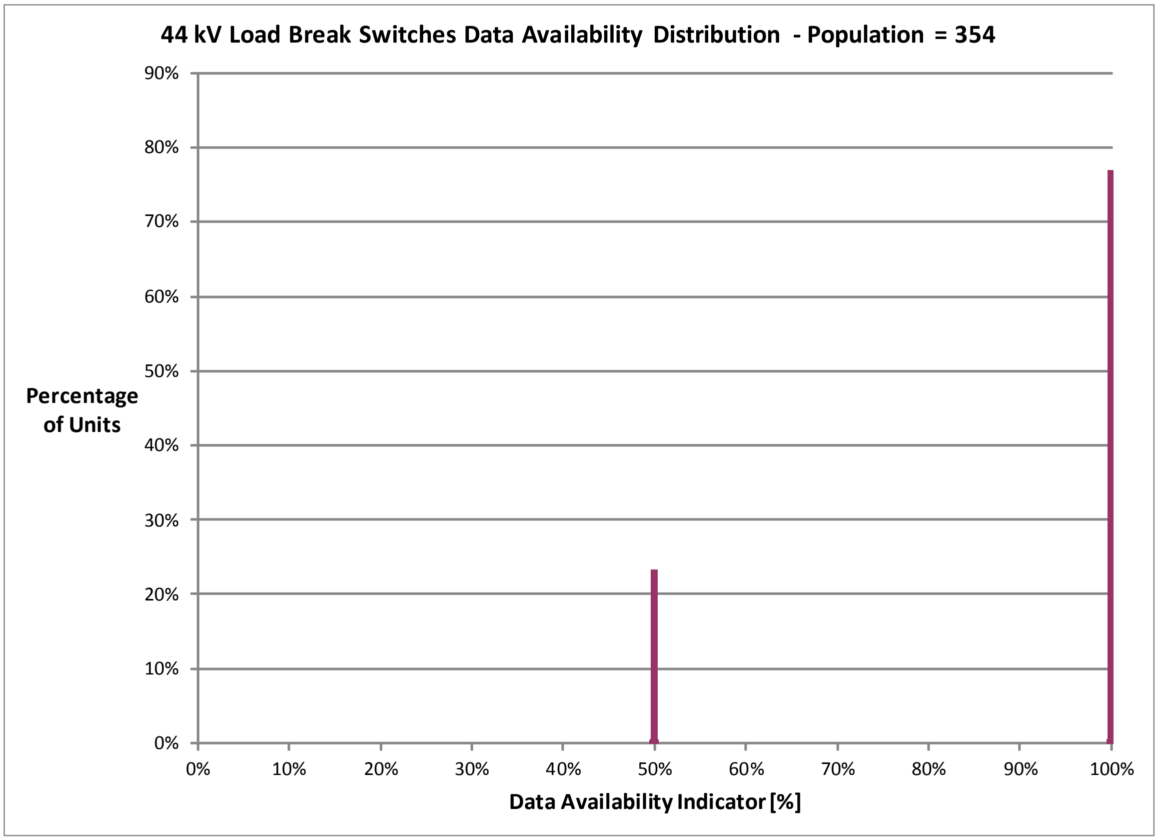

Figure 7-19 44 kV Load Break Switches Data Availability Distribution

The average DAI for this sub-category was 88%. Age was known for all units; inspection records were available for approximately 77% of the population.

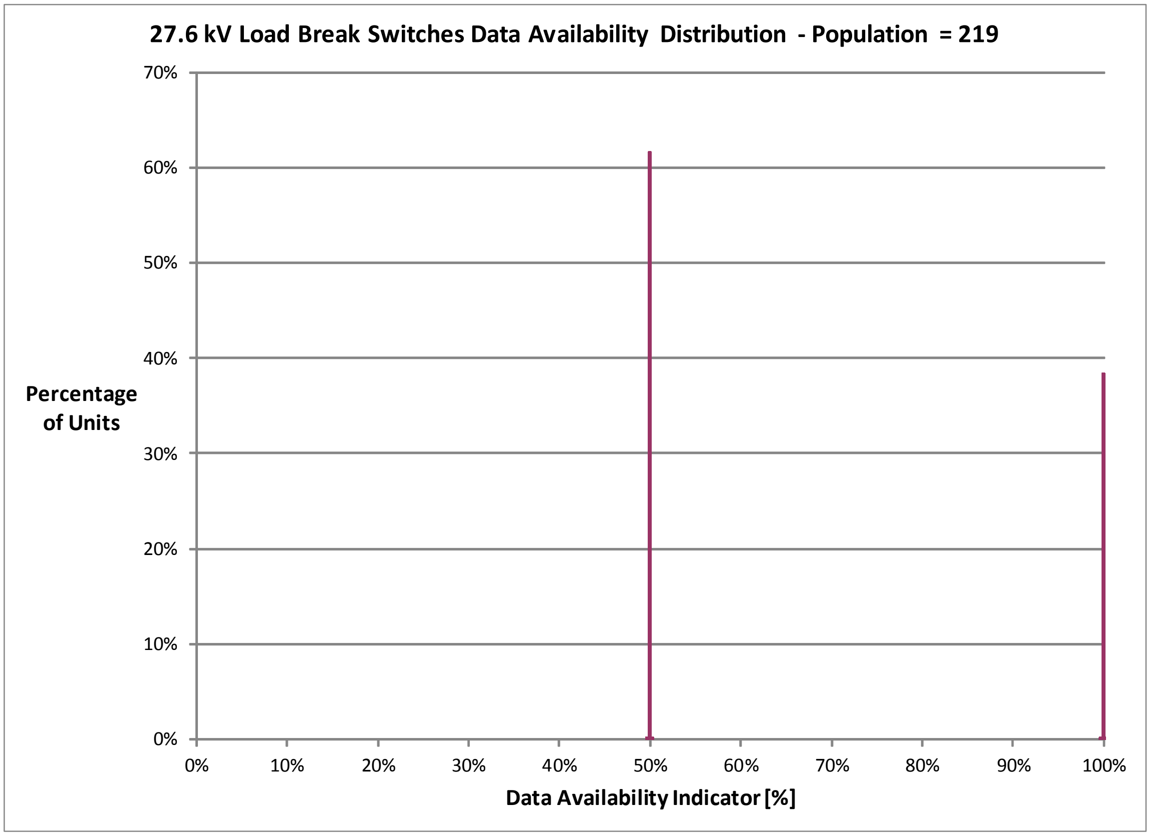

Figure 7-20 27.6 kV Load Break Switches Data Availability Distribution

The average DAI for this sub-category was 69%. Age was known for all units; inspection records were available for approximately 38% of the population.

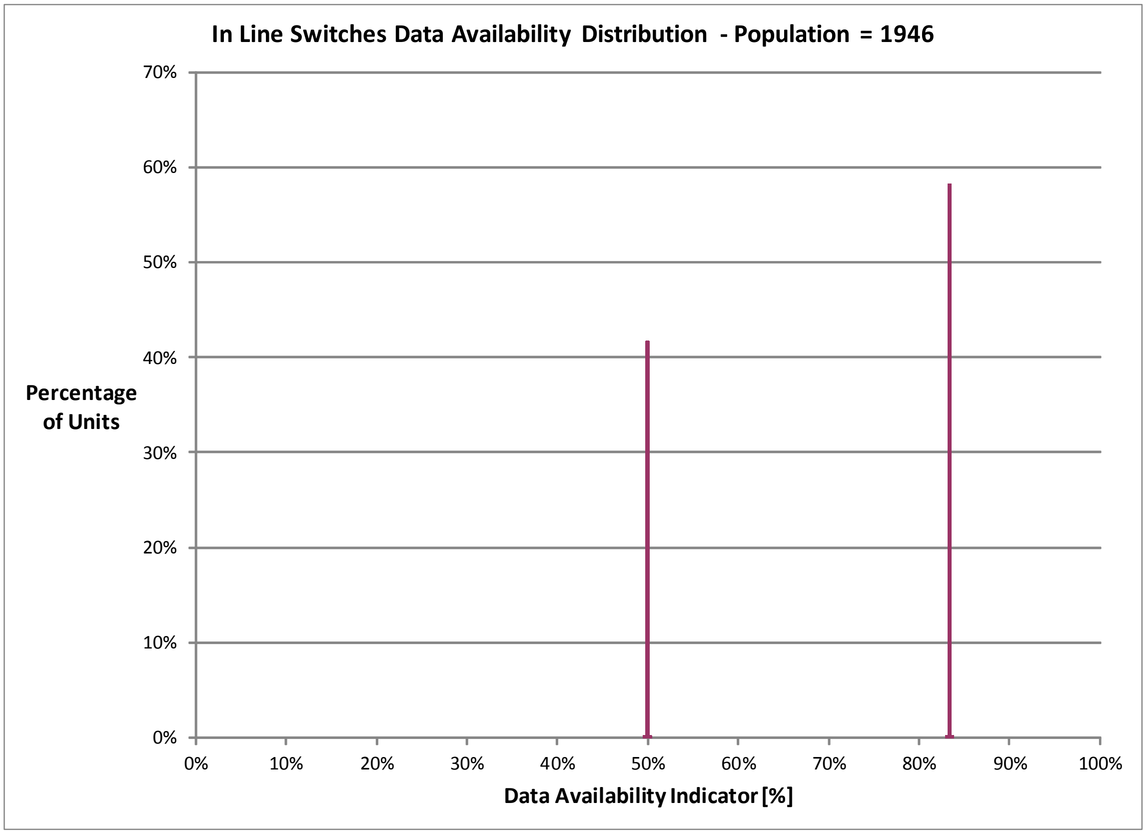

Figure 7-21 In Line Switches Data Availability Distribution

The average DAI for this sub-category is 69%. Age was known for nearly all units. Approximately 58% of the population was found to have a solid blade switch inspection record.

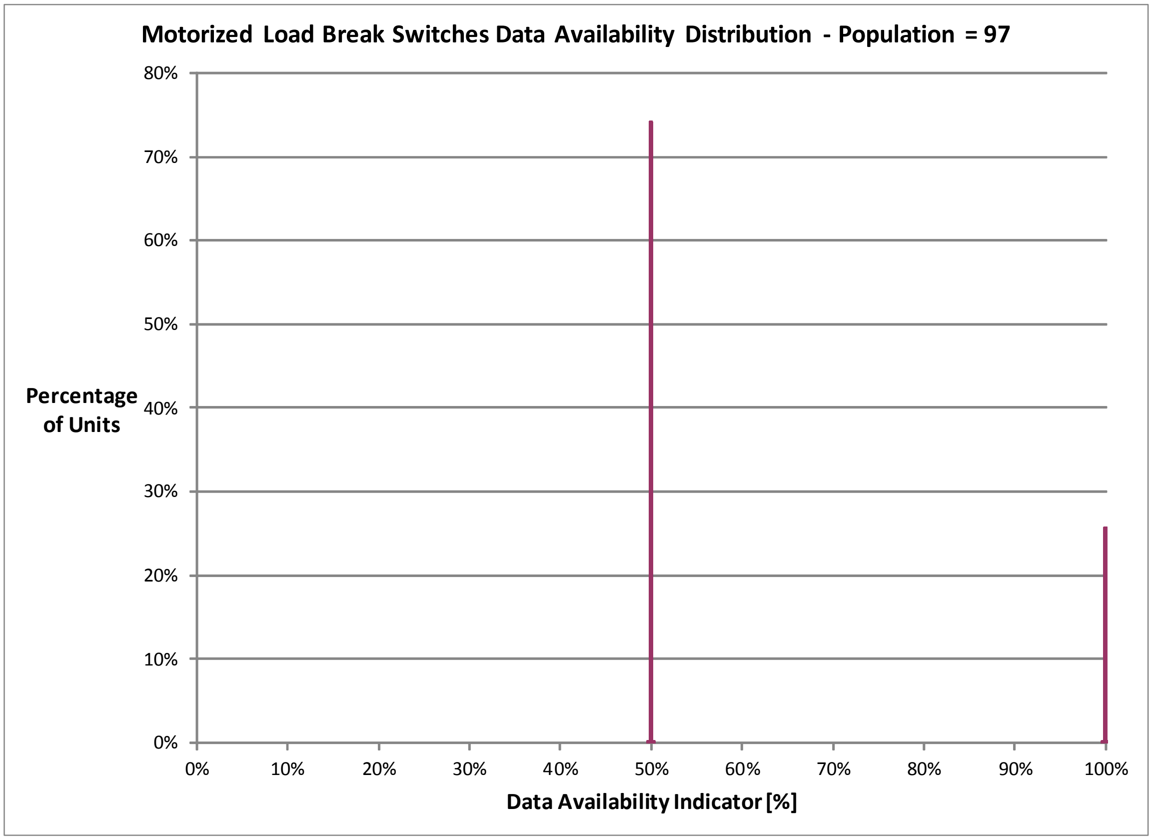

Figure 7-22 Motorized Switches Data Availability Distribution

The average DAI for this sub-category was 63%. Age was known for all units; inspection records were available for approximately 26% of the population.

Data Gap

For all switch types, no new types of condition data had been collected in 2013 and the data gaps noted in the 2012 report remained to be addressed. Please refer to "Enersource Hydro Mississauga 2012 Asset Condition Assessment" for details.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Motor/Manual Operation	Operation Mechanism	☆☆☆	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection
Mechanical Support		☆	Switch support	Loose installation	On-site visual inspection
Arc Horn	Arc Extinction	☆	Switch operation	Arc horn surface worn-out	On-site visual inspection
Arc Interrupter		☆☆	Switch arc extinction	Arc extinction part surface worn-out	On-site visual inspection
Insulator	**Insulation**	☆	Support insulator	Crack	On-site visual inspection
Switch Condition	**Service Record**	☆☆☆	Blade	Blade condition	On-site visual inspection

According to Enersource, starting from 2014 the infra-red test data will be available. As the infra-red tests cover some of the above condition parameters, this will improve data availability for future ACA study.

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8. UNDERGROUND PRIMARY CABLES

8.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

8.1.1. Condition and Sub-Condition Parameters

Table 8-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	1	Table 8-2
DRF	De-Rating based on number of failures		Table 8-3

Table 8-2 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	1	Figure 8-3

8.1.2. Condition Criteria

<u>Age</u>

Assume that the failure rate Underground Primary Cables exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

All the underground cables in this study are of XLPE type. There are three sub categories of such cables based on different installation timelines: Non TR direct buried (before 1989), TR direct buried (1989 to 1993), and TR in-duct (after 1993).

For non TR direct buried cables, assuming that at the ages of 20 and 35 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve.

For TR direct buried cables, the ages of 25 and 40 were used.

For TR in-duct cables, the ages of 40 and 55 were used.

The following curves show the survival curves for each cable type. Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figures.

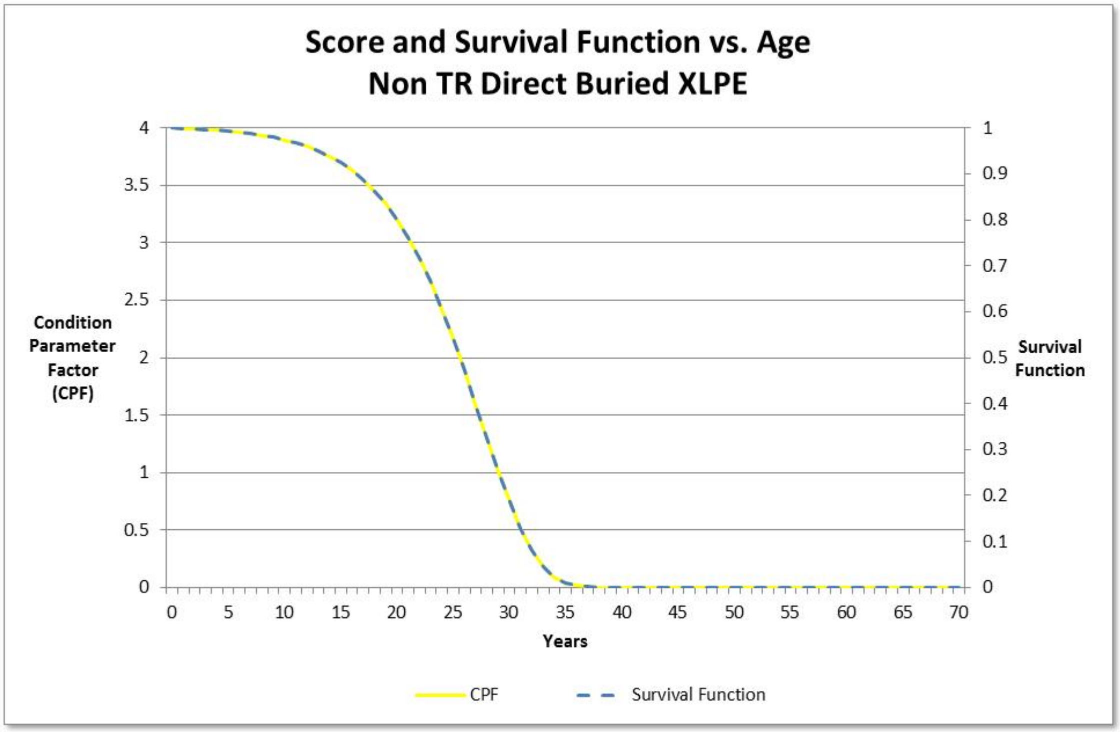

Figure 8-1 Underground Primary Cables Age Criteria – Non TR Direct Buried XLPE

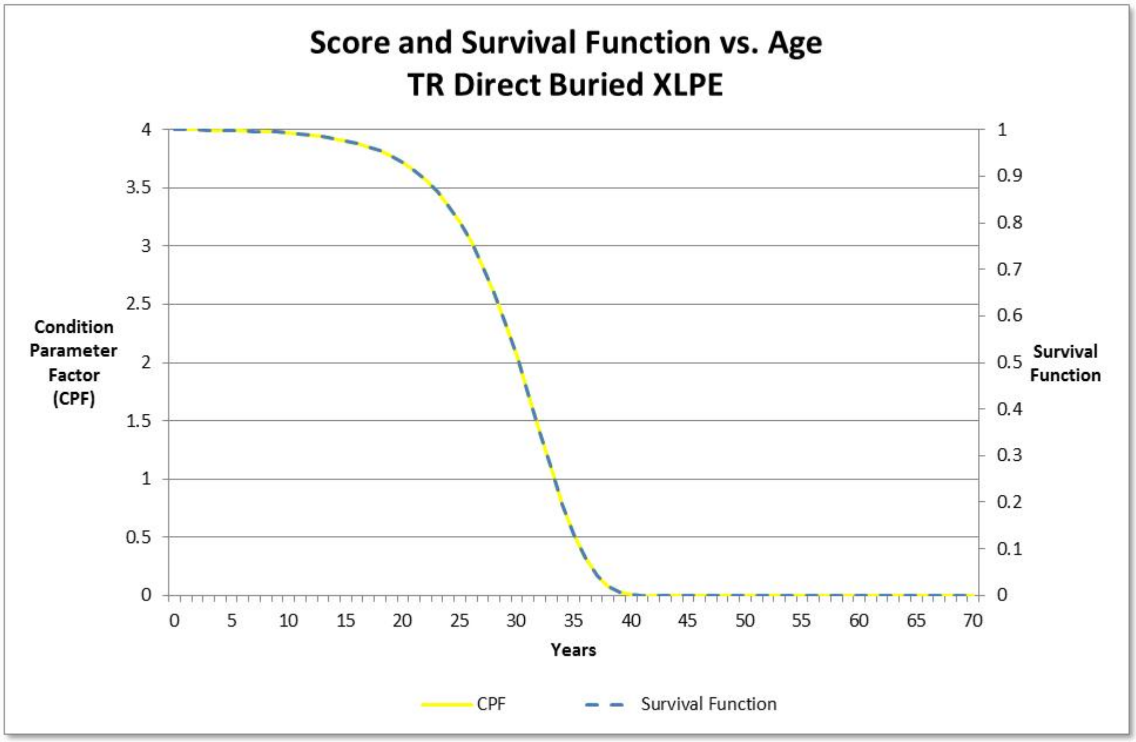

Figure 8-2 Underground Primary Cables Age Criteria – TR Direct Buried XLPE

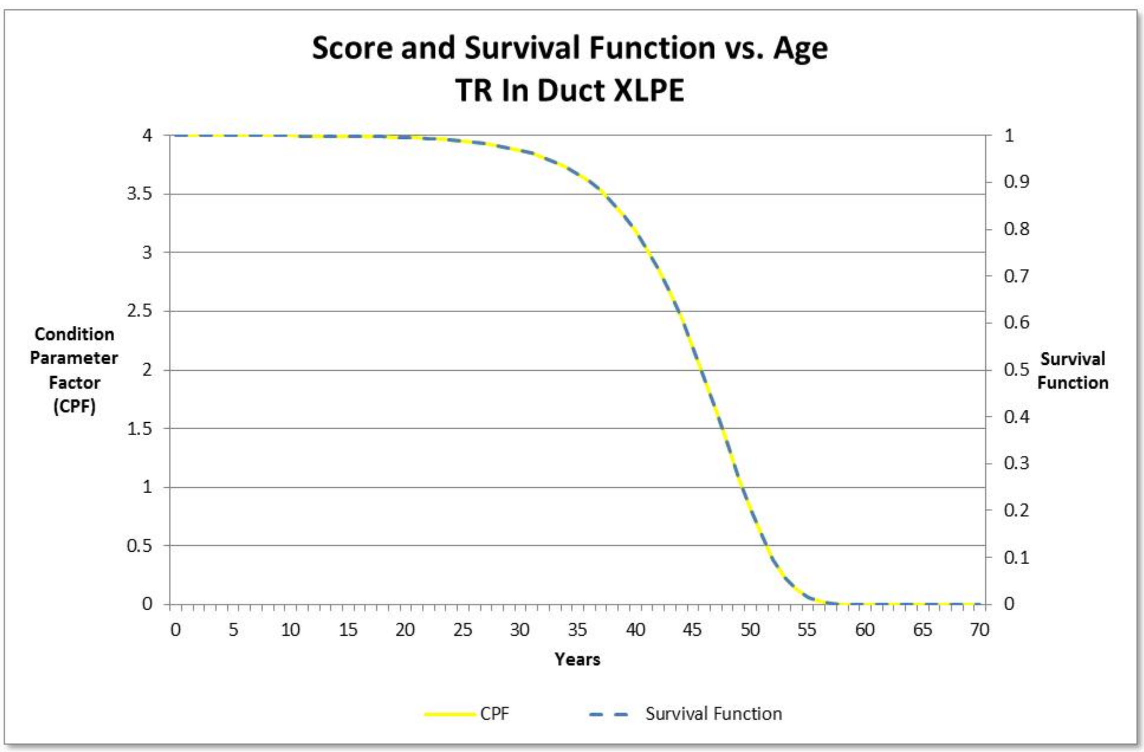

Figure 8-3 Underground Primary Cables Age Criteria – TR In-Duct XLPE

De-Rating Factor (DRF)

Table 8-3 Number of Failures De-Rating Criteria

Number of Failures in 5 Years	De-Rating Multiplier
0	1
1	0.95
2	0.9
3	0.85
4	0.8

8.2. Age Distribution

Main Feeder Cables

The average age was 18 years / conductor-km. Approximately 4% were 40 years or older. The age distribution for this asset class was as follows:

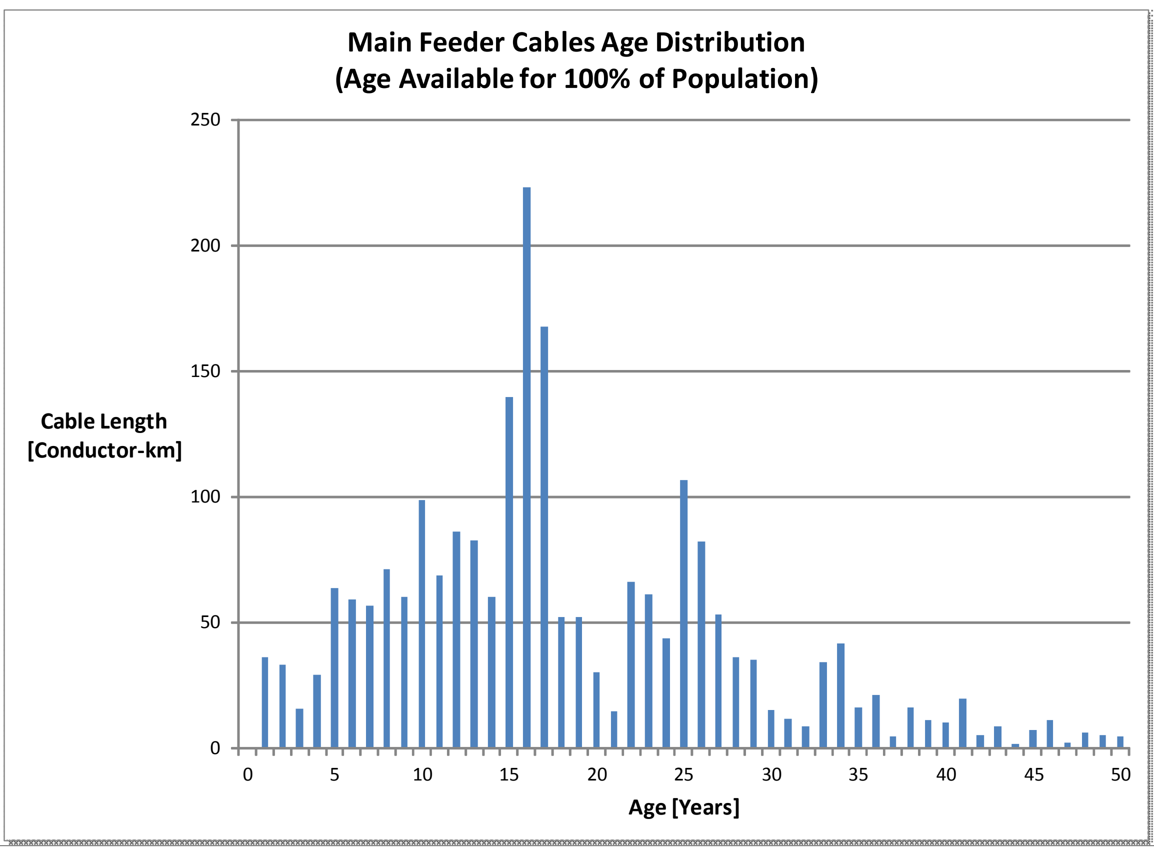

Figure 8-4 Main Feeder Cables Age Distribution

Distribution Cables

The average age was 21 years / conductor-km. Approximately 8% were 40 years or older.

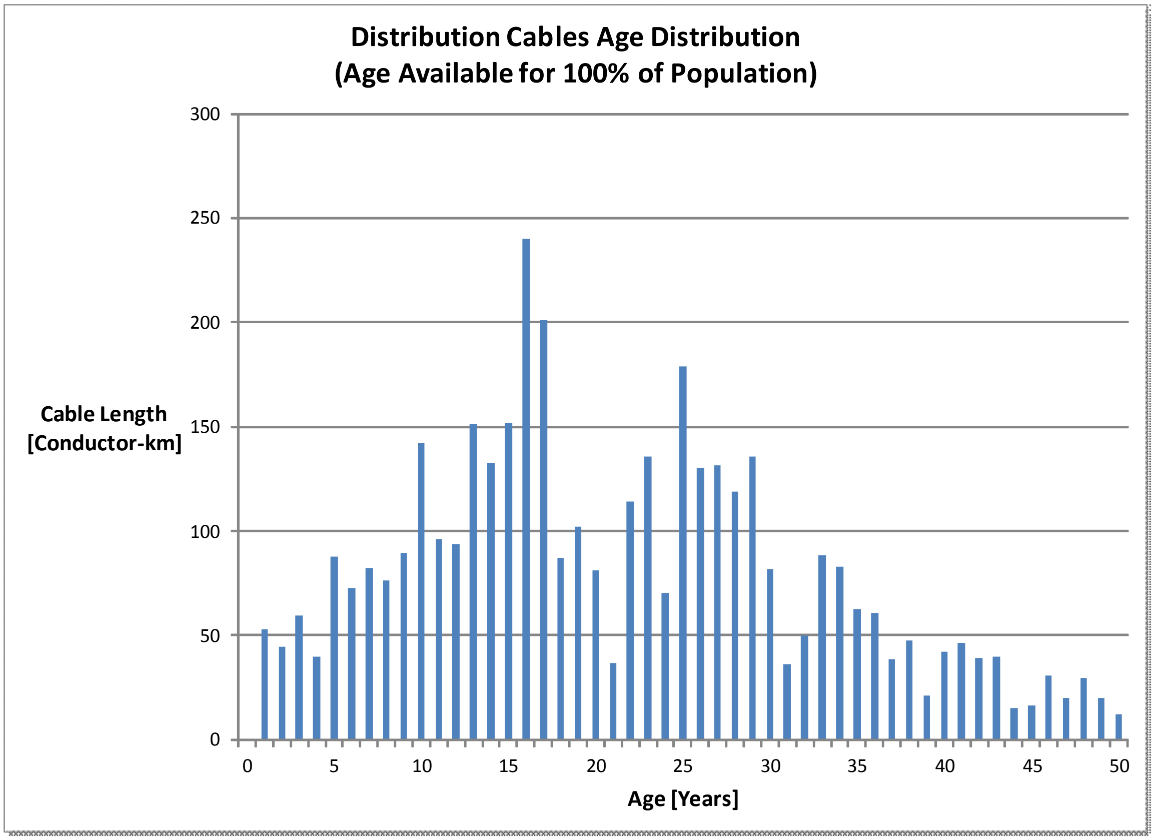

Figure 8-5 Distribution Cables Age Distribution

8.3. Health Index Results

Main Feeder

A total of 2246 conductor-km of Main Feeder Cables had sufficient data for a Health Indexing.

The average Health Index for this asset group was 77%. Approximately 21% of population was in "poor" or "very poor" condition.

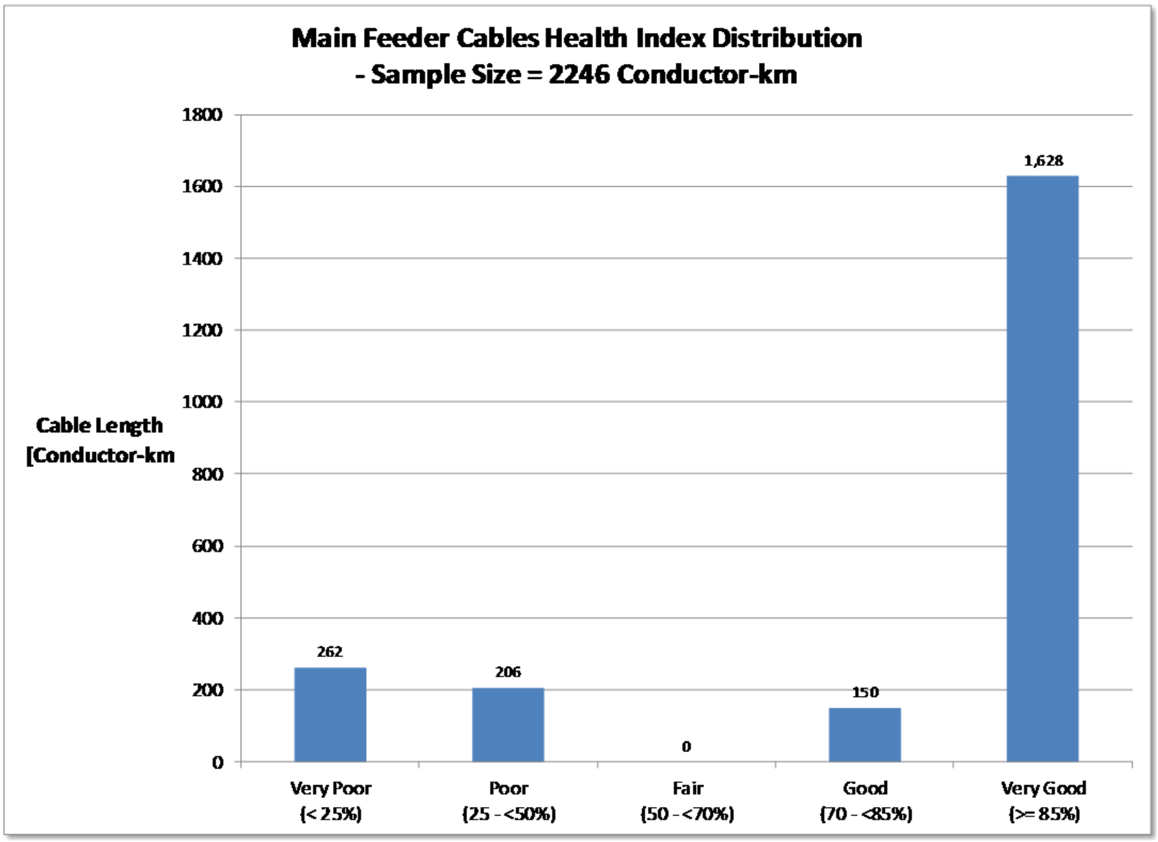

Figure 8-6 Main Feeder Cables Health Index Distribution (Unit)

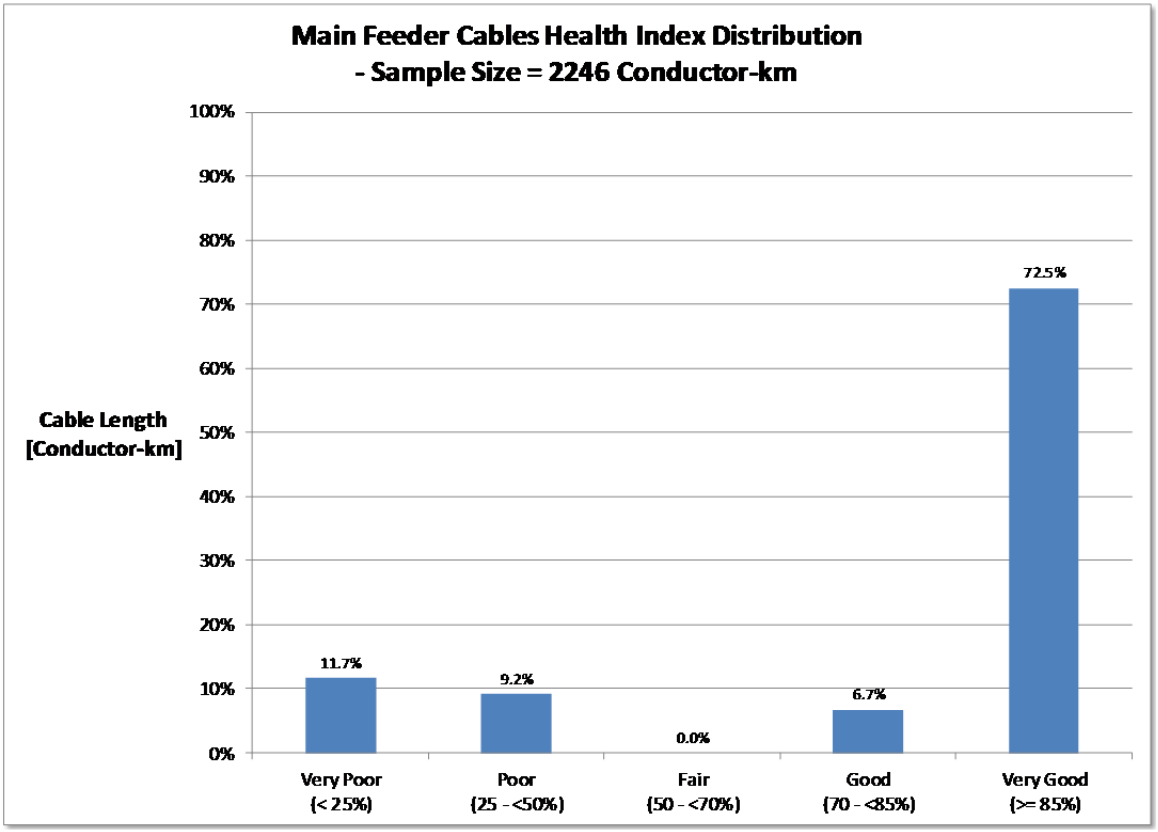

Figure 8-7 Main Feeder Cables Health Index Distribution (Percentage)

Distribution Cables

A total of 4022 conductor-km of Distribution Cables had sufficient data for a Health Indexing.

The average Health Index for this asset group was 69%. Approximately 35% of the samples were in “poor” or “very poor” condition.

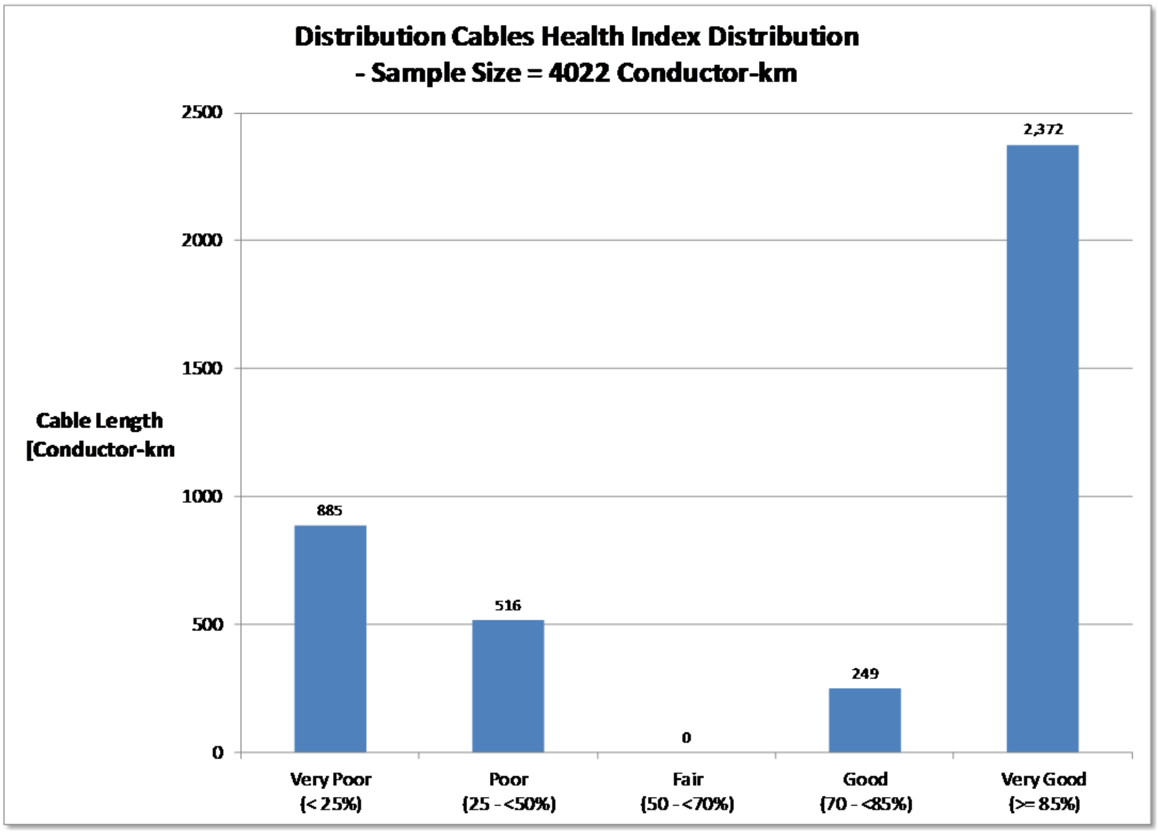

Figure 8-8 Distribution Cables Health Index Distribution (Unit)

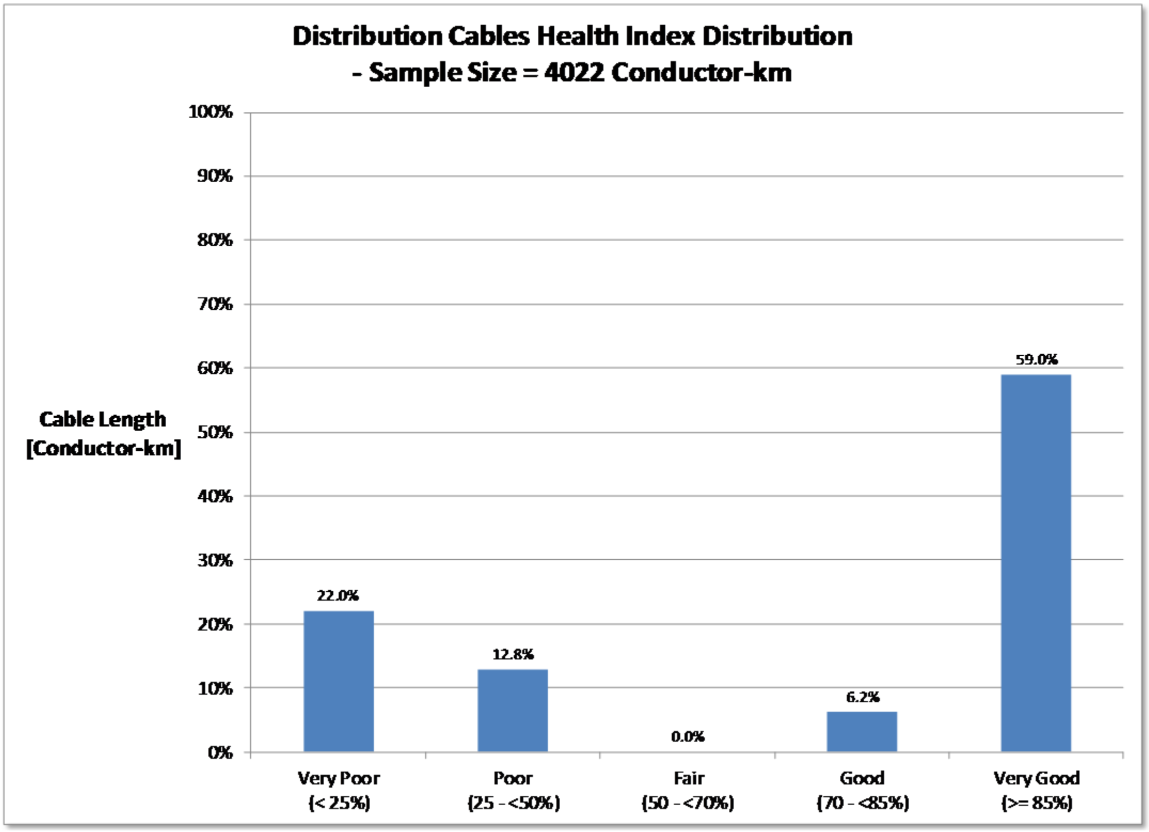

Figure 8-9 Distribution Cables Health Index Distribution (Percentage)

8.4. Condition-Based Flagged-for-Action Plan

As it is assumed that Underground Primary Cables were reactively replaced, the flagged-for-action plan was based on the asset failure rate..

Main Feeder Cables

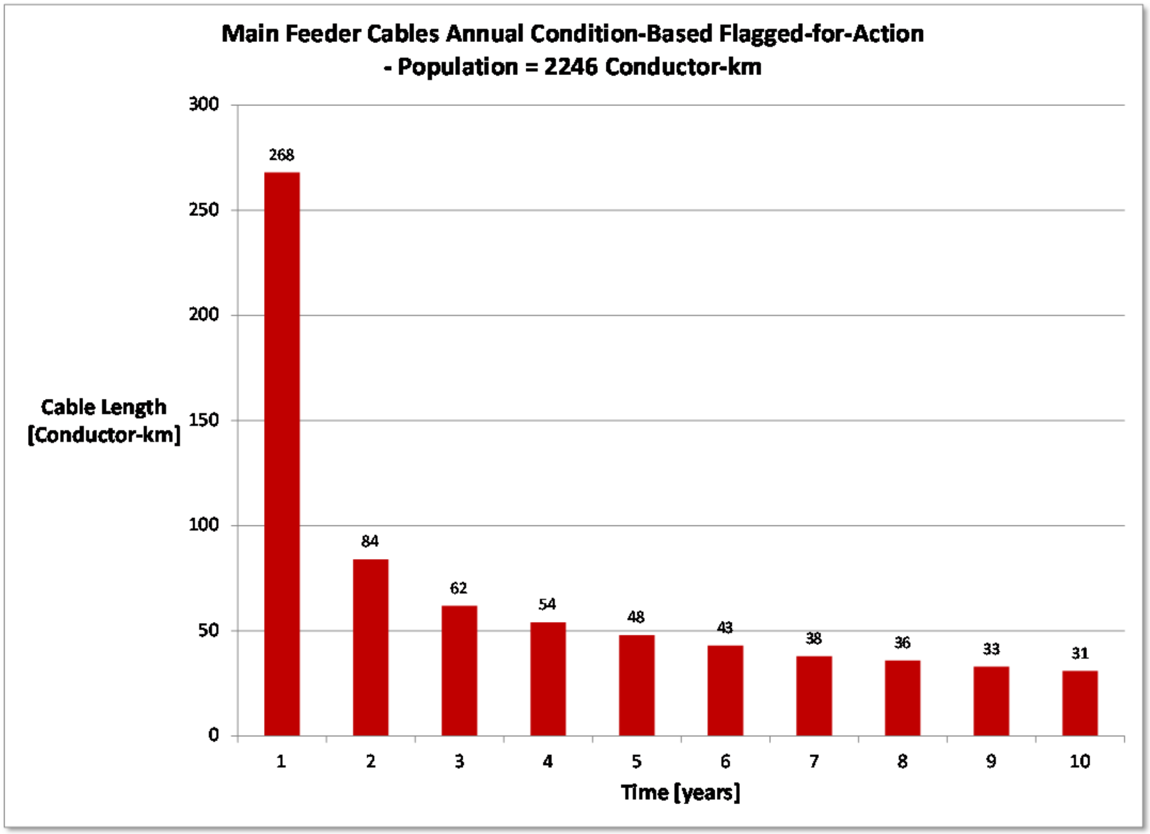

Figure 8-10 Main Feeder Cables Condition-Based Flagged-for-Action Plan

Distribution Cables

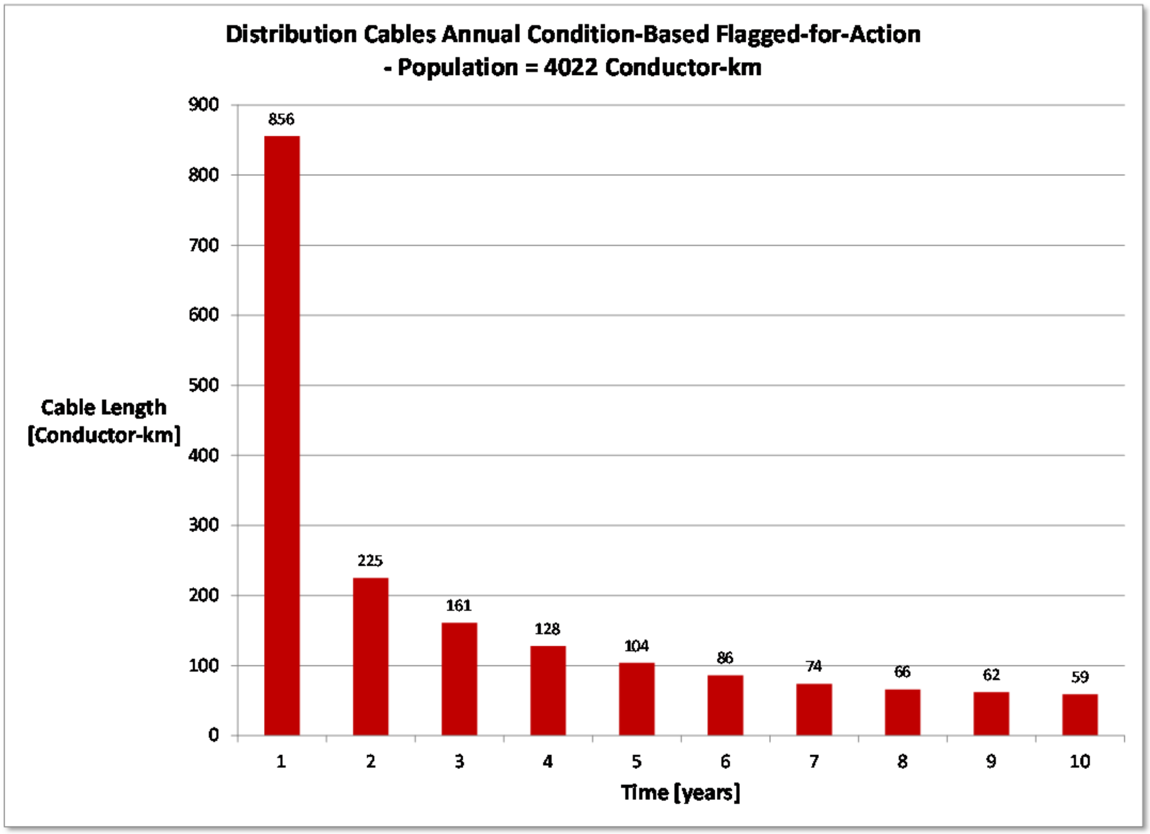

Figure 8-11 Distribution Cables Condition-Based Flagged-for-Action Plan

8.5. Data Analysis

Age was the only condition data available for this asset group. Only segments with known ages, for both Main Feeder and Distribution Cables, were assessed. As such, the DAI for all segments was 100%.

The data gaps noted in the 2012 report, however, remained to be addressed. Please refer to "Enersource Hydro Mississauga 2012 Asset Condition Assessment" for details.

<table>
<tr><th>Data Gap (Sub-Condition Parameter)</th><th>Parent Condition Parameter</th><th>Priority</th><th>Object or Component Addressed</th><th>Description</th><th>Source of Data</th></tr>
<tr><td rowspan="5">Splice & Termination</td><td rowspan="6">Physical Condition</td><td rowspan="5">☆☆</td><td rowspan="3">Cable splice</td><td>Under/over-compressed connector</td><td rowspan="5">On-site visual inspection</td></tr>
<tr><td>Improper ground connection</td></tr>
<tr><td>Loose bolt</td></tr>
<tr><td rowspan="2">Cable termination</td><td>Sealing issue</td></tr>
<tr><td>Insulation erosion</td></tr>
<tr><td>Overall</td><td>☆☆</td><td>Cable segment</td><td>Count of total corrective maintenance work orders issued on cable segment during a specific time window</td><td>Operation record</td></tr>
<tr><td>Loading</td><td>Operation Condition</td><td>☆☆☆</td><td>Cable segment</td><td>Loading History: e.g. hourly peak Loads</td><td>Operation record</td></tr>
</table>

9. POLES

9.1. Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

9.1.1. Condition and Sub-Condition Parameters

Table 9-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	1	Table 9-2

Table 9-2 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	1	Figure 9-1 Figure 9-2

9.1.2. Condition Criteria

Age

Assume that the failure rate Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 45 and 65 years the probability of failures (P_f) for Wood Poles are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

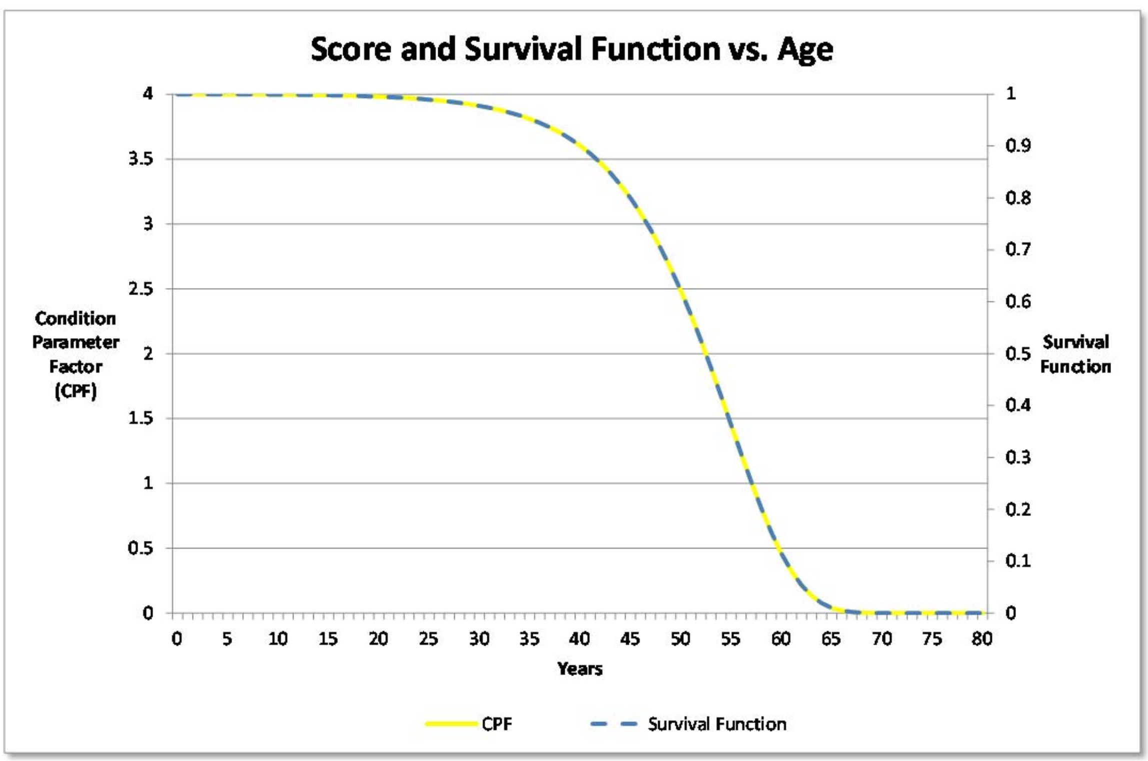

Figure 9-1 Wood Pole Age Criteria

For Concrete Poles, the ages at 20% and 99% probabilities of failure are 55 and 80 years, respectively.

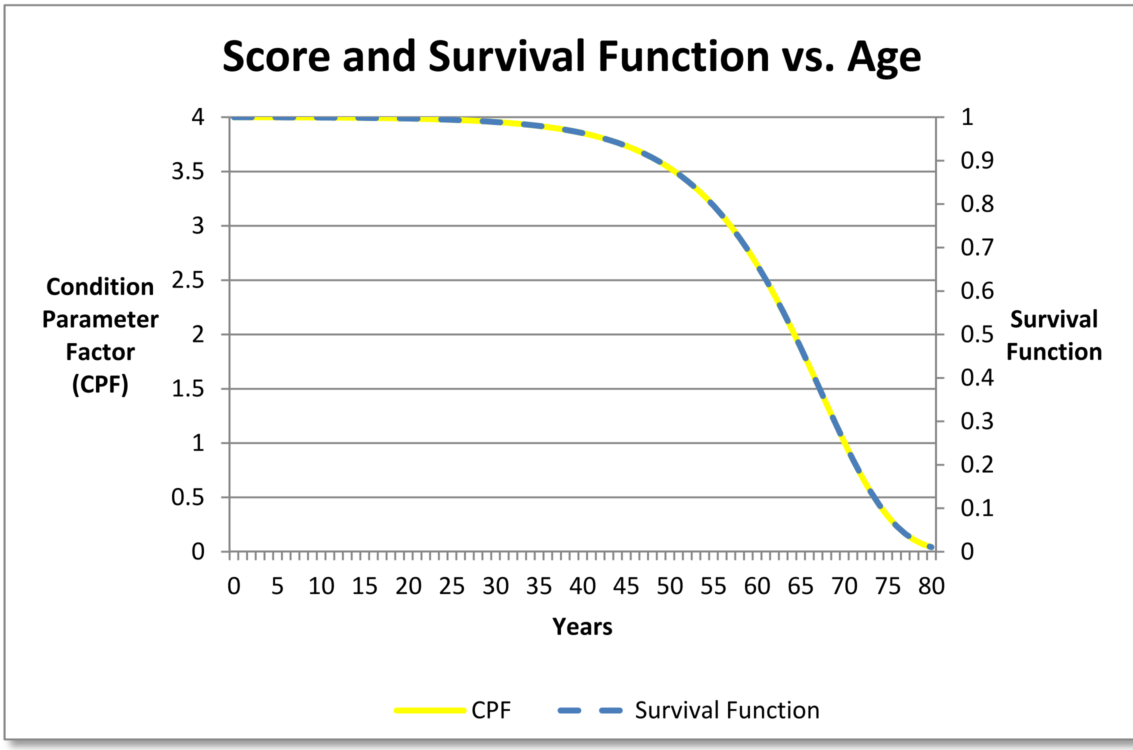

Figure 9-2 Concrete Pole Age Criteria

9.2. Age Distribution

The age distribution for this asset class was as follows:

Wood Poles

The average age for wood poles was 26. Approximately 12% of the population was 45 years or older.

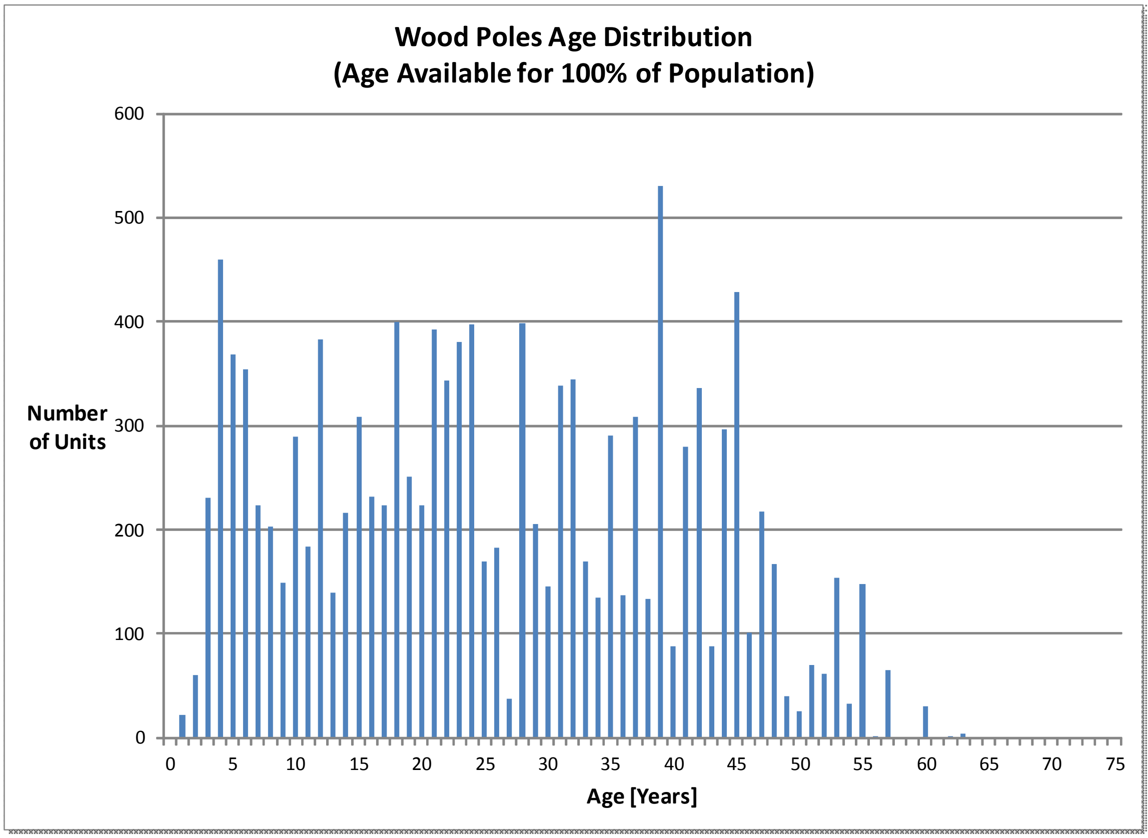

Figure 9-3 Wood Poles Age Distribution

Concrete Poles

The average age for concrete poles was 28 years. About 16% of all poles were 45 years or older.

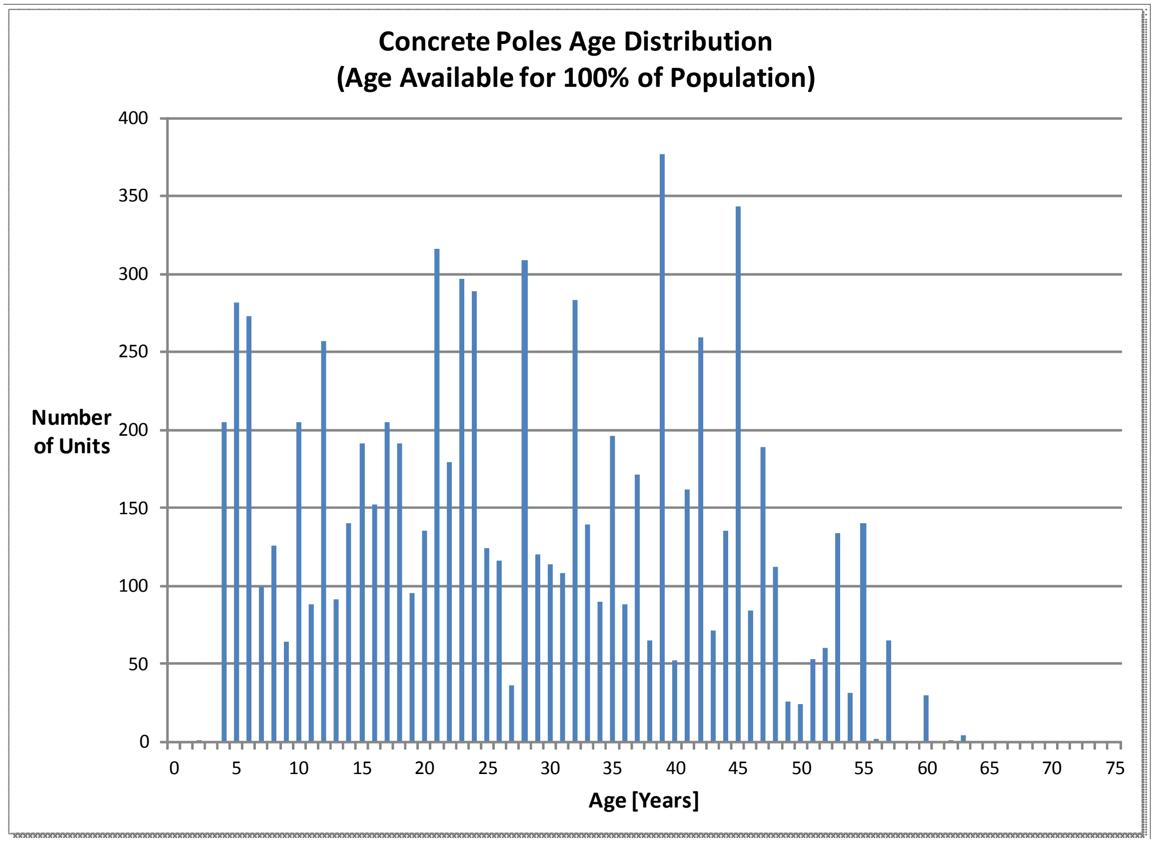

Figure 9-4 Concrete Poles Age Distribution

9.3. Health Index Results

Wood Poles

There were 12602 Wood Poles at EHM. Of these, there were 12602 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 93%. Approximately 3% of the samples were in "poor" or "very poor" condition.

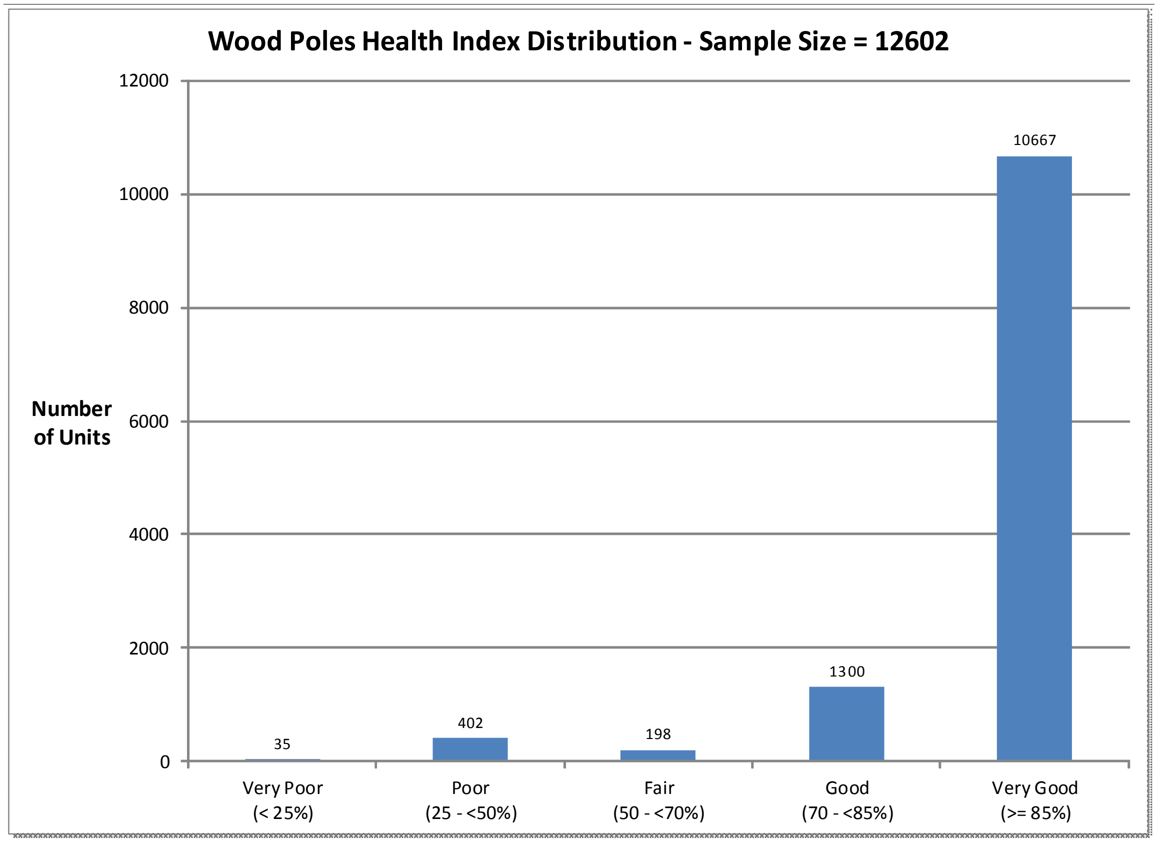

Figure 9-5 Wood Poles Health Index Distribution (Unit)

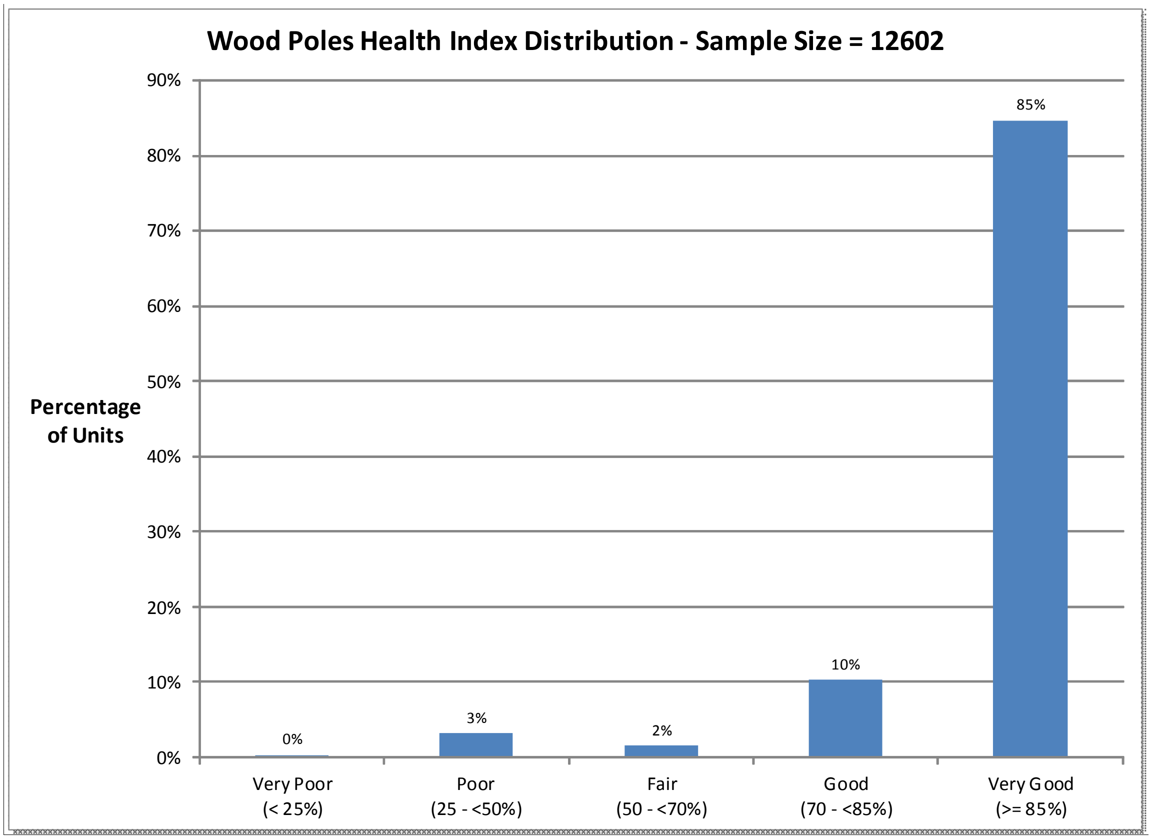

Figure 9-6 Wood Poles Health Index Distribution (Percentage)

Concrete Poles

There were 8194 Concrete Poles at EHM. Of these, there were 8194 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was nearly 97%. None of the samples were in "poor" or "very poor" condition.

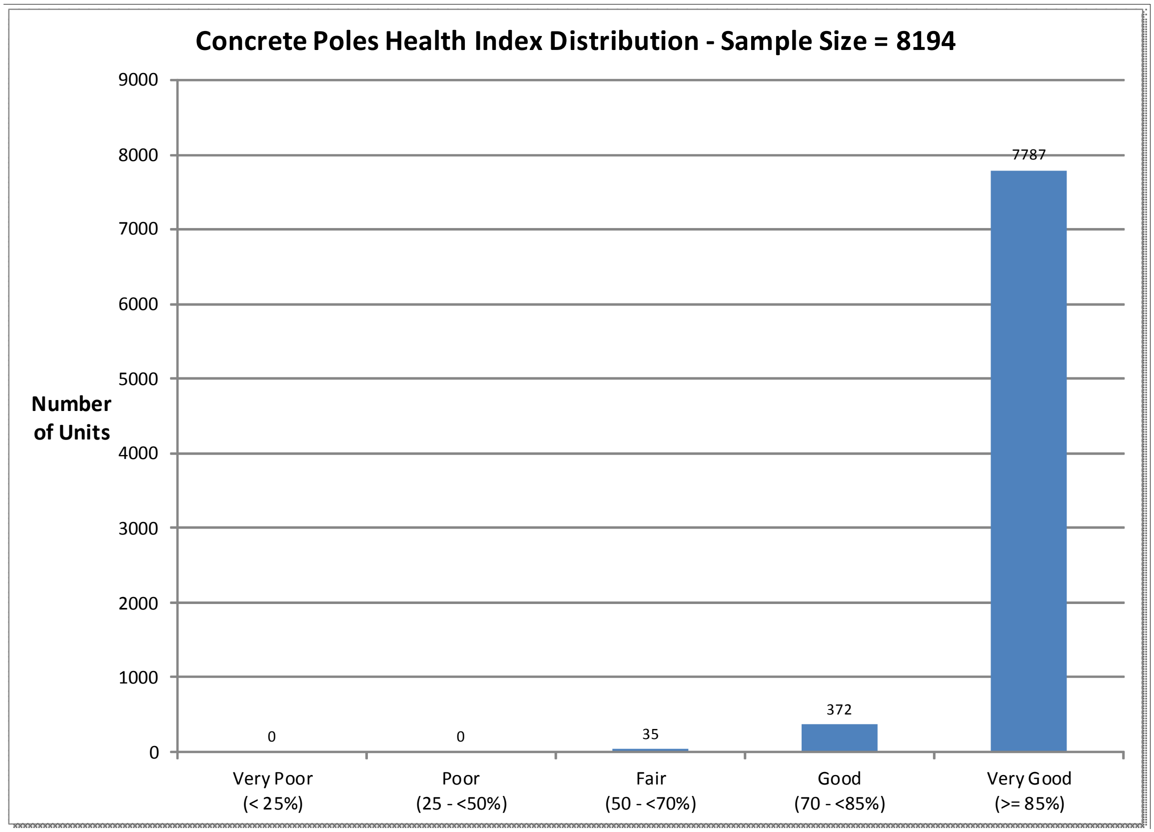

Figure 9-7 Concrete Poles Health Index Distribution (Unit)

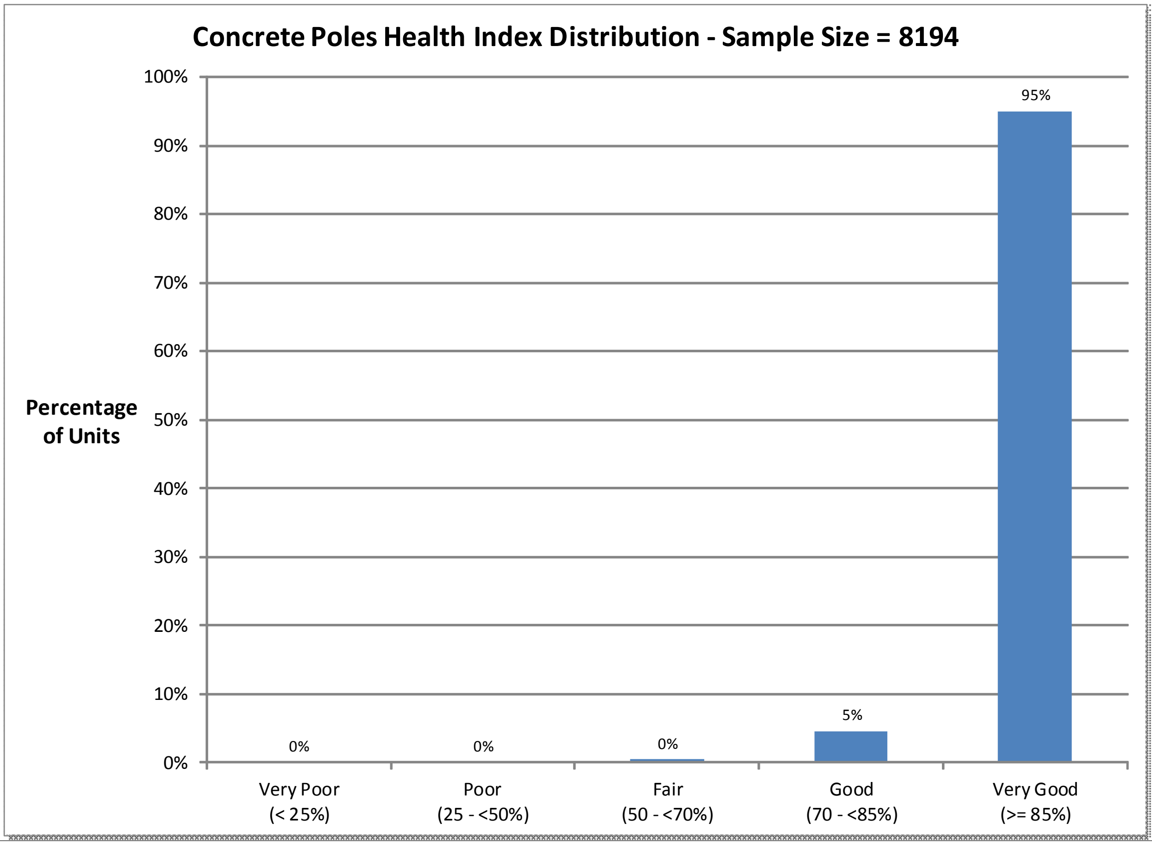

Figure 9-8 Concrete Poles Health Index Distribution (Percentage)

9.4. Condition-Based Flagged-for-Action Plan

The number of units that are estimated to fail was based on the failure rate. In addition, since Poles were proactively replaced, the flagged-for-action plan also included a planned replacement of 1% of units that are over 45 years old and 55 years old for Wood and Concrete Poles respectively.

Wood Poles

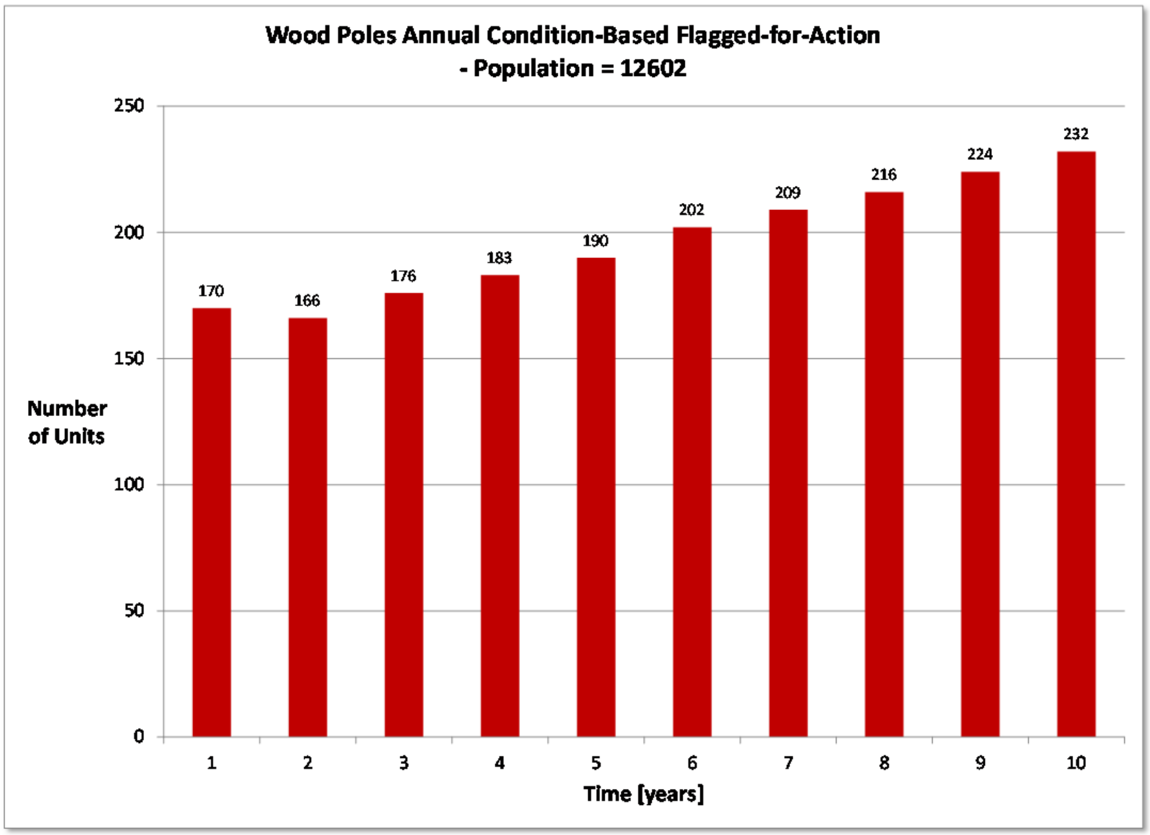

Figure 9-9 Wood Poles Condition-Based Flagged-for-Action Plan

Concrete Poles

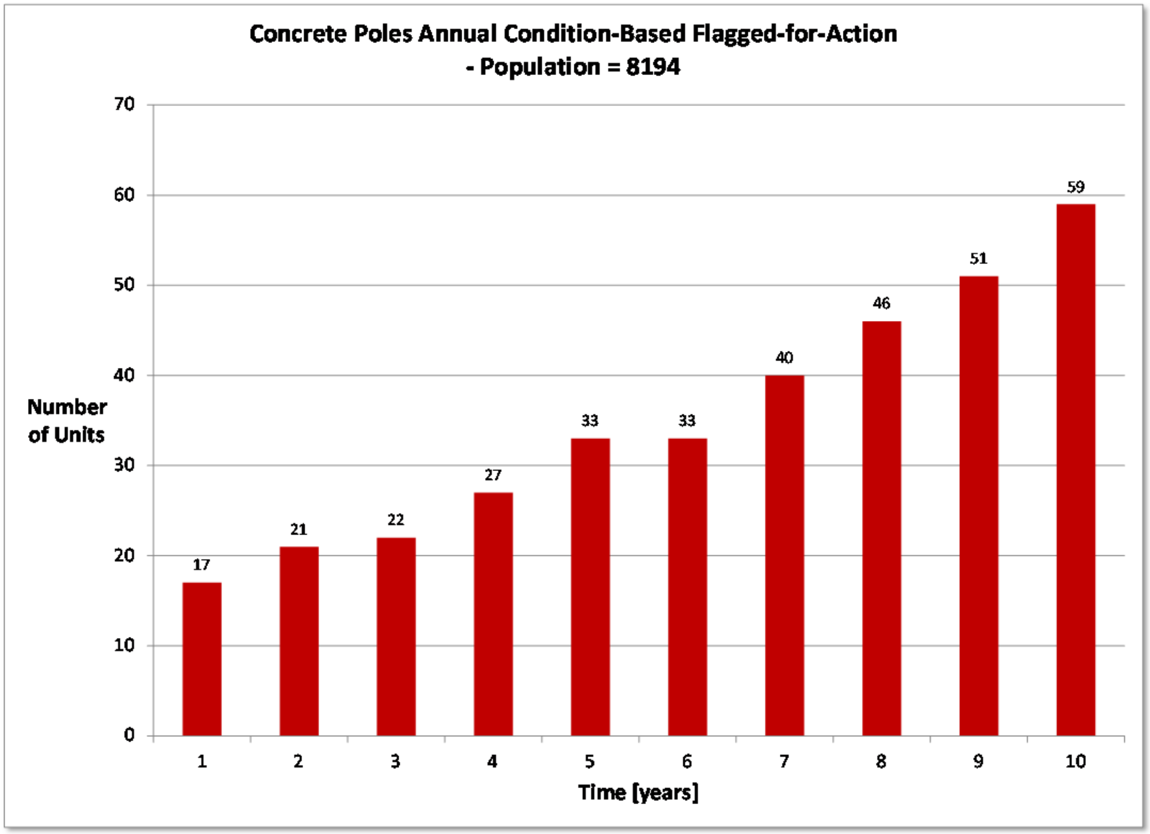

Figure 9-10 Concrete Poles Condition-Based Flagged-for-Action Plan

9.5. Data Analysis

Age was the only condition data available for this asset group. The age of all poles was known, giving DAIs of 100% for both wood and concrete poles.

Since last year's assessment, no new data types had been collected for this asset category. The data gaps noted in the "Enersource Hydro Mississauga 2012 Asset Condition Assessment" remained to be addressed.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Pole Strength (Wood Poles only)	Pole Strength	☆☆☆	Pole	Ratio of actual circumference over the original circumference	On-site testing
Physical Damage	Physical Condition	☆☆	Pole	Damage due to external forces (vehicle, lightning etc.) Biological damage (ant, woodpecker etc)	On-site visual inspection
Physical Status	Physical Condition	☆☆	Pole	Rot Separation Void Lean	On-site visual inspection
Cross Arm	Pole Accessory	☆☆	Cross arm	Deterioration or other damages Misalignment	On-site visual inspection

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Riser		☆	Riser	Deterioration or other damages	On-site visual inspection
Grounding		☆	Pole	Deterioration of grounding wire	On-site visual inspection

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ENERSOURCE HYDRO MISSISSAUGA 2014 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418089-RA-0004-R01

July 30, 2015

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DISCLAIMER

ENERSOURCE HYDRO MISSISSAUGA
2014 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418089-RA-0004-R01

July 30, 2015

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Revision History

Revision Number	Date	Comments	Approved

EXECUTIVE SUMMARY

In 2011 Enersource Hydro Mississauga (Enersource) determined a need to perform a condition assessment of its key distribution assets. Enersource selected and engaged Kinectrics Inc. (Kinectrics) to perform the Asset Condition Assessment (ACA). Subsequent assessments were conducted in 2011 and 2013. This report presents the results for the fourth, 2014, ACA.

The asset groups included in the 2014 ACA are as follows: substation transformers, circuit breakers, distribution transformers (pole mounted, pad mounted, and vault), pad mounted switchgears, overhead line switches, underground cables, and poles. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

It was found that underground cables have the highest percentages in poor to very poor condition. Wood poles, vault transformers, and pad mounted switchgear also have large quantities that are classified as poor or very poor.

In terms flagged for action, it was found that over 11% of main feeder underground cables and nearly 20% of distribution underground cables are currently flagged for action. Furthermore, within the next 10 years, more than 30% of the underground cable population should be addressed.

Also of significance is that presently, 8% of wood poles have been flagged for action. This includes poles that require action because of the insulation used. In the next 10 years 32% of all wood poles will need to be addressed.

In the past year Enersource has made improvements with respect to inspection programs and condition data collection. Availability of inspection information was improved for Station Transformers and Circuit Breakers. Visual inspection information is now being collected for poles and the Health Index formula has been improved accordingly. Enersource should continue with the improvements made inspections and gathering data. It is recommended that Overhead Switches also be inspected.

The results presented in this study are based solely on asset condition as determined by available data. Note that there are numerous other considerations that may influence Enersource’s planning process. Among these are obsolescence, system growth, corporate priorities, technological advancements, etc.

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I INTRODUCTION

Enersource Hydro Mississauga (Enersource) recognized a need to perform an Asset Condition Assessment (ACA) on its key distribution assets. An assessment produces a quantifiable evaluation of asset condition, aids in prioritizing and allocating sustainment resources, and facilitates the development of a Distribution System Plan. This undertaking spans several years and thus allows Enersource to monitor the trend in asset condition changes and to incrementally improve its assessment process and asset management practices.

In early 2011, Enersource selected and engaged Kinectrics Inc. (Kinectrics) to perform the first ACA on Enersource's key distribution assets. This assessment covered Enersource's asset population as of the end of 2010. Second and third assessments were conducted for Enersource's 2011 and 2013 populations respectively. This report presents results for the fourth year assessment and is based on the available data as of the end of 2014.

I.1 Objective and Scope of Work

The category and sub-categories of assets included in this study are as follows:

- Substation Transformers
  - In Service
  - Spares
- Substation Circuit Breakers
- Pole Mounted Transformers
- Pad Mounted Transformers
  - 1 Phase
  - 3 Phase
- Vault Transformers
- Pad Mounted Switchgears
- Overhead Line Switches
  - 44 kV
  - 27.6 kV
  - Inline
  - Motorized
- Underground Cables
  - Main Feeder
  - Distribution
- Poles
  - Wood
  - Concrete

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of the Asset Condition Assessment methodology
- For each asset category the following are included (**Error! Reference source not found.**):
    - Health Index formulation
    - Age distribution
    - Health Index distribution
    - Condition-based Flagged For Action Plan
    - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis
- An audit describing the key changes between 2013 and 2014

II ASSET CONDITION ASSESSMENT METHODOLOGY

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a condition-based Flagged for Action Plan for each asset group. The methods used are described in the subsequent sections.

II.1 Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the degradation factors that lead to an asset's end of service life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Colour".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DR$$

Equation 1

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (WCPF_n)}$$

Equation 2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient (1 if available; 0 if not available)
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter (1 if available; 0 if not available)
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e. $CPF_{max} = 4$.
De-Rating multipliers are applied to the calculated HI. These may be used to represent the impact of non-condition issues such as design or operating environment.

II.1.1 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 ≤ Health Index < 50%
Fair	50 ≤ Health Index <70%
Good	70 ≤ Health Index <85%
Very Good	Health Index ≥ 85%

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 **Condition Based Flagged for Action Plan**

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides a good model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f	= failure rate per unit time
t	= time
γ, β	= constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in failure rate studies of multiple power system asset groups, the following variation of the failure rate formula has been adopted:

$$f(t) = e^{\beta(t-\alpha)}$$

Equation 4

f	= failure rate of an asset (percent of failure per unit time)
t	= age (years)
α, β	= constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function is therefore:

$$P_f(t) = 1 - e^{-(f - e^{-\alpha\beta})/\beta}$$

Equation 5

P_f	= cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 45 and 65 the asset has cumulative probabilities of failure of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 72 and 0.131 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{-\alpha\beta})/\beta} \; = \; 1 - e^{-(e^{0.131(t-72)} - e^{-9.432})/0.131}$$

The failure rate and probability of failure graphs are as shown:

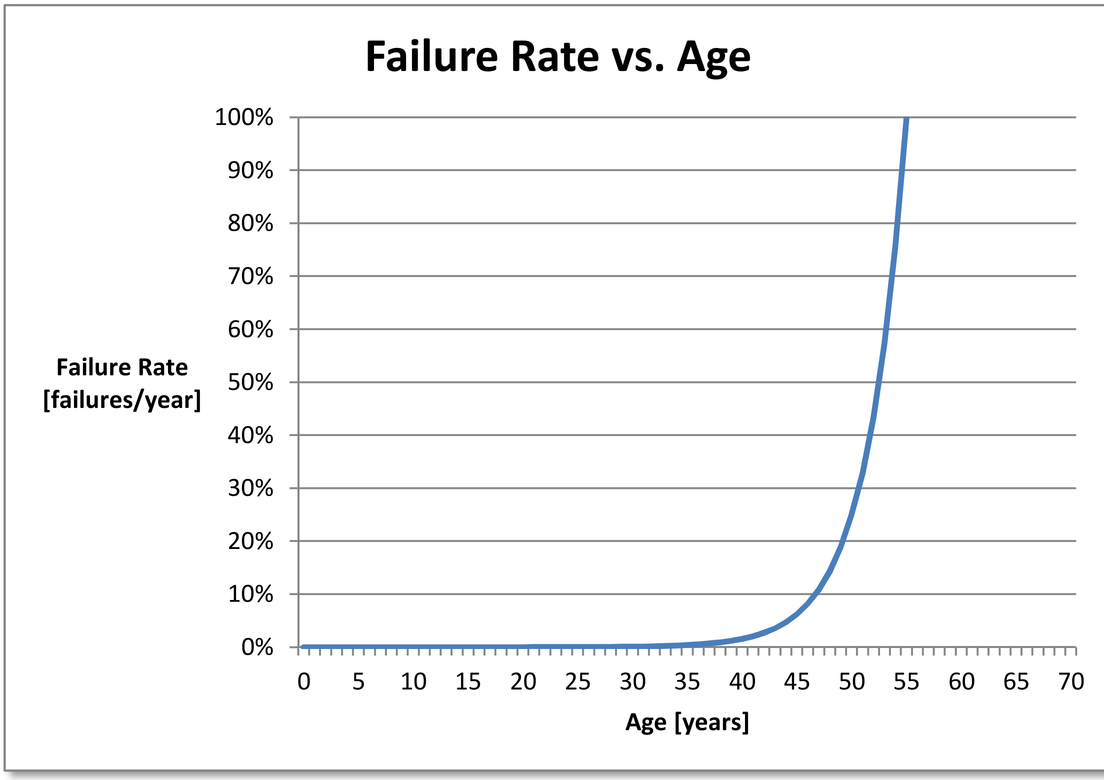

Figure II-1 Failure Rate vs. Age

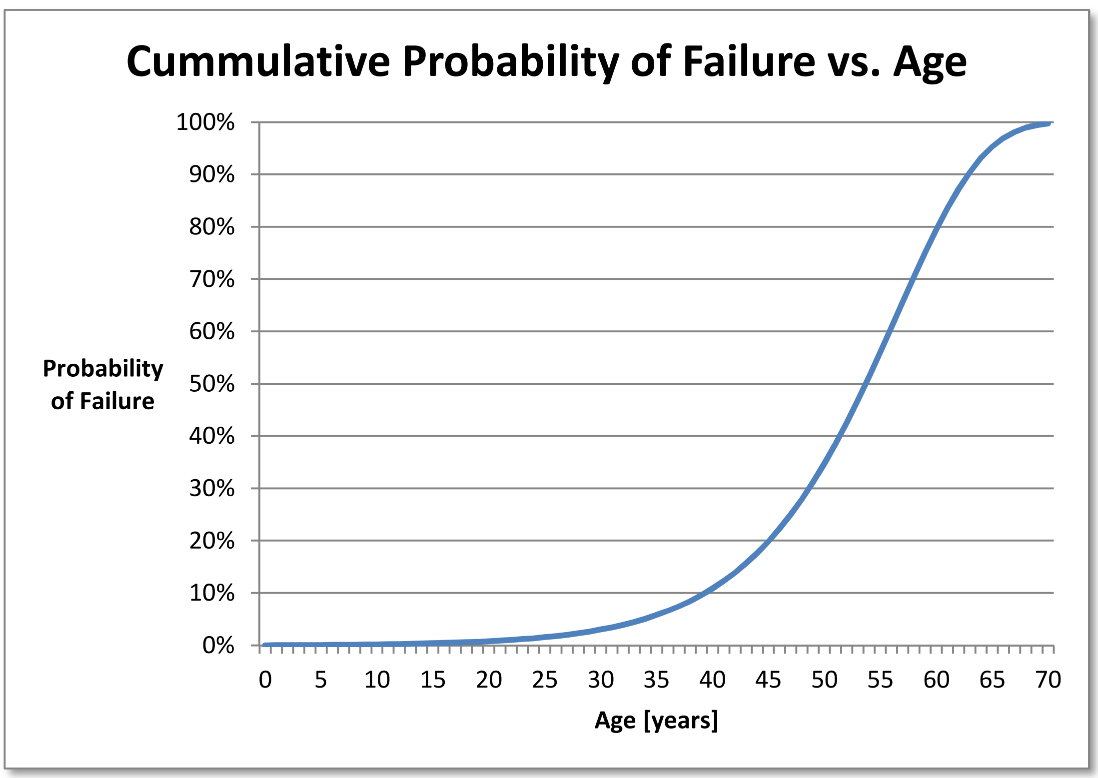

Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Flagged for Action Plan Using a Reactive Approach

Because the consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

$$f(t) = e^{\beta(t-\alpha)}$$

with α and β determined from the probability of failure of each asset class.

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

II.2.3 Projected Flagged for Action Plan Using a Proactive Approach

For certain asset classes, the consequence of an asset failure is significant, and, as such, these assets are proactively addressed prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

If there are no dominant sources, it can be assumed that the stress to which an asset is exposed is not constant and will have a somewhat normal frequency distribution. This is illustrated by the probability density curve of stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset.

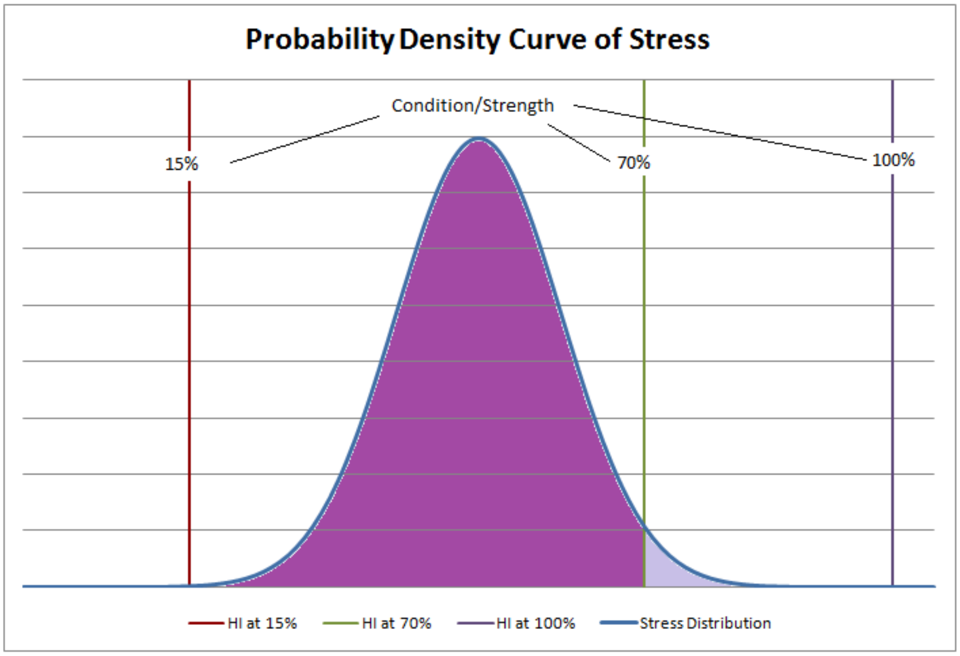

Figure II-3 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand most levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and probability of failure, assume two "points" on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The probability of failure at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

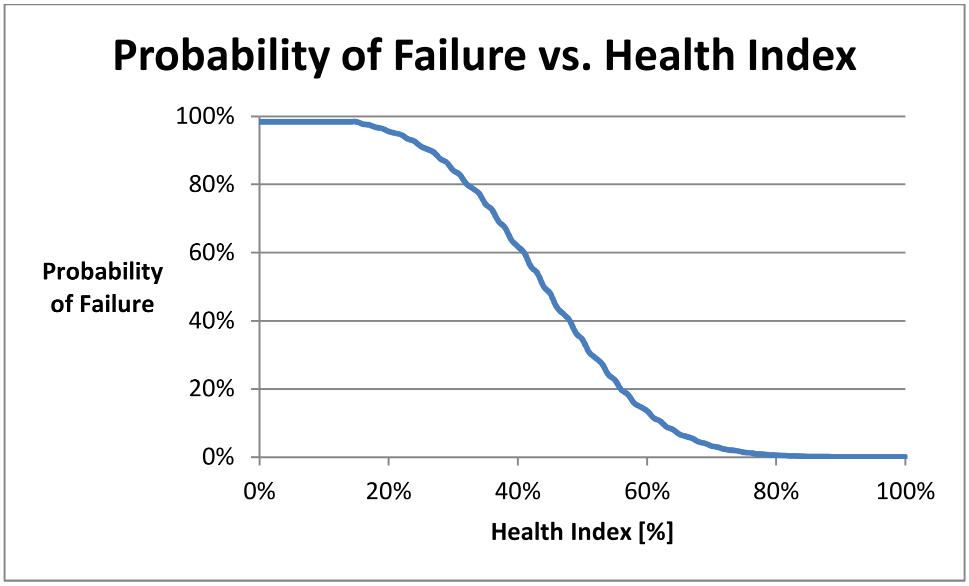

Figure II-4 Probability of Failure vs. Health Index

Condition-Based Flagged for Action Plan

To develop a Flagged for Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure. The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

In this study, it is assumed that the unit that has the highest relative consequence of failure has a criticality of 1.43. When its risk value, the product of its probability of failure and criticality, is greater than or equal to 1, the unit is flagged for action. In this case, if the unit with the criticality value of 1.43 has a POF = 70%, its risk will be 1.43*0.7 = 1 and it will be flagged for action.

II.3 Data Assessment

The condition data used in this study were provided by Enersource and included the following:

- Test Results (e.g. Oil Quality, DGA)
- Inspection Records
- Loading
- Make, Model, and Type
- Age

There are two components that assess the availability and quality of data used in this study: data availability indicator (DAI) and data gap.

II.3.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\ m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n \times WCFn}{\sum_{n=1}^{\forall n} (WCPFn)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? (β = 1 if available; 0 if not)
m	**Name**		**n**	**Name**		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

$$DAI_{CP1} = (1*1) / (1) = 1$$
$$DAI_{CP2} = (1*2 + 1*4 + 0*5) / (2 + 4 + 5) = 0.545$$
$$DAI_{CP3} = (0*1) / (1) = 0$$

$$\begin{aligned} DAI &= (DAI_{CP1}*WCP_1 + DAI_{CP2}*WCP_2 + DAI_{CP3}*WCP_3) / (WCP_1 + WCP_2 + WCP_3) \\ &= (1*1 + 0.545*2 + 0*3) / (1 + 2 + 3) \\ &= 35\% \end{aligned}$$

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score. Provided that the condition parameters used in the Health Index formula are of good quality and there are little data gaps, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

II.3.2 Data Gap

The Health Index formulations developed and used in this study are based only on Enersource's available data. There are additional parameters or tests that Enersource may not collect but that are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	☆☆☆
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	☆☆
Low	Helpful data; least indicative of asset deterioration	☆

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulas.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for “Tank Corrosion” on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆☆	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

III RESULTS

This section summarizes the findings of this study.

III.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table III-1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), average age and average DAI are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in Figure III-5. Note that the Health Index distribution percentages are based on the asset group's sample size.

It can be seen from the results that Underground Cables category was, on average as an asset group, in the worst condition. Approximately 20% of main feeder and 34% of distribution cables were classified as "poor" or "very poor".

Another group of concern is Wood Poles where 18% are in "poor" or "very poor" condition. It should also be noted that 9% of Vault Transformers and 8% of Pad Mounted Switchgear classified as "poor" or "very poor". While 14% of Motorized Overhead Switches and are found to be "poor" or "very poor", this represents only 15 of 104 switches.

Table III-1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age	Average DAI
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)		
Substation Transformers	In Service	108	108	82%	< 1%	2%	14%	36%	47%	22	84%
	Spares	12	12	80%	8%	0%	17%	8%	67%	33	45%
Circuit Breakers		510	510	94%	2%	< 1%	2%	4%	93%	20	71%
Pole Mounted Transformers		5346	5346	92%	2%	< 1%	6%	11%	80%	21	75%
Pad Mounted Transformers	1 Phase	14242	14242	87%	< 1%	4%	7%	29%	59%	21	89%
	3 Phase	1821	1821	94%	< 1%	2%	4%	9%	84%	16	70%
Vault Transformers		3861	3861	87%	2%	7%	7%	13%	71%	27	78%
Pad Mounted Switchgear		862	862	84%	6%	3%	7%	19%	65%	19	39%
Overhead Switches	44 kV	338	338	95%	0%	5%	< 1%	6%	88%	20	42%
	27.6 kV	213	213	97%	0%	1%	3%	2%	93%	18	36%
	Inline	2002	2002	93%	1%	3%	4%	5%	86%	18	34%
	Motorized	104	104	85%	8%	7%	2%	6%	78%	16	41%
Underground Cables *Note that results are given in terms of conductor-km	Main Feeder	2233	2233	78%	12%	9%	0%	7%	73%	18	100%
	Distribution	4038	4038	70%	21%	13%	0%	6%	60%	21	100%
Poles	Wood	12917	12917	79%	9%	9%	7%	15%	60%	27	55%
	Concrete	8966	8966	97%	0%	< 1%	1%	4%	95%	20	55%

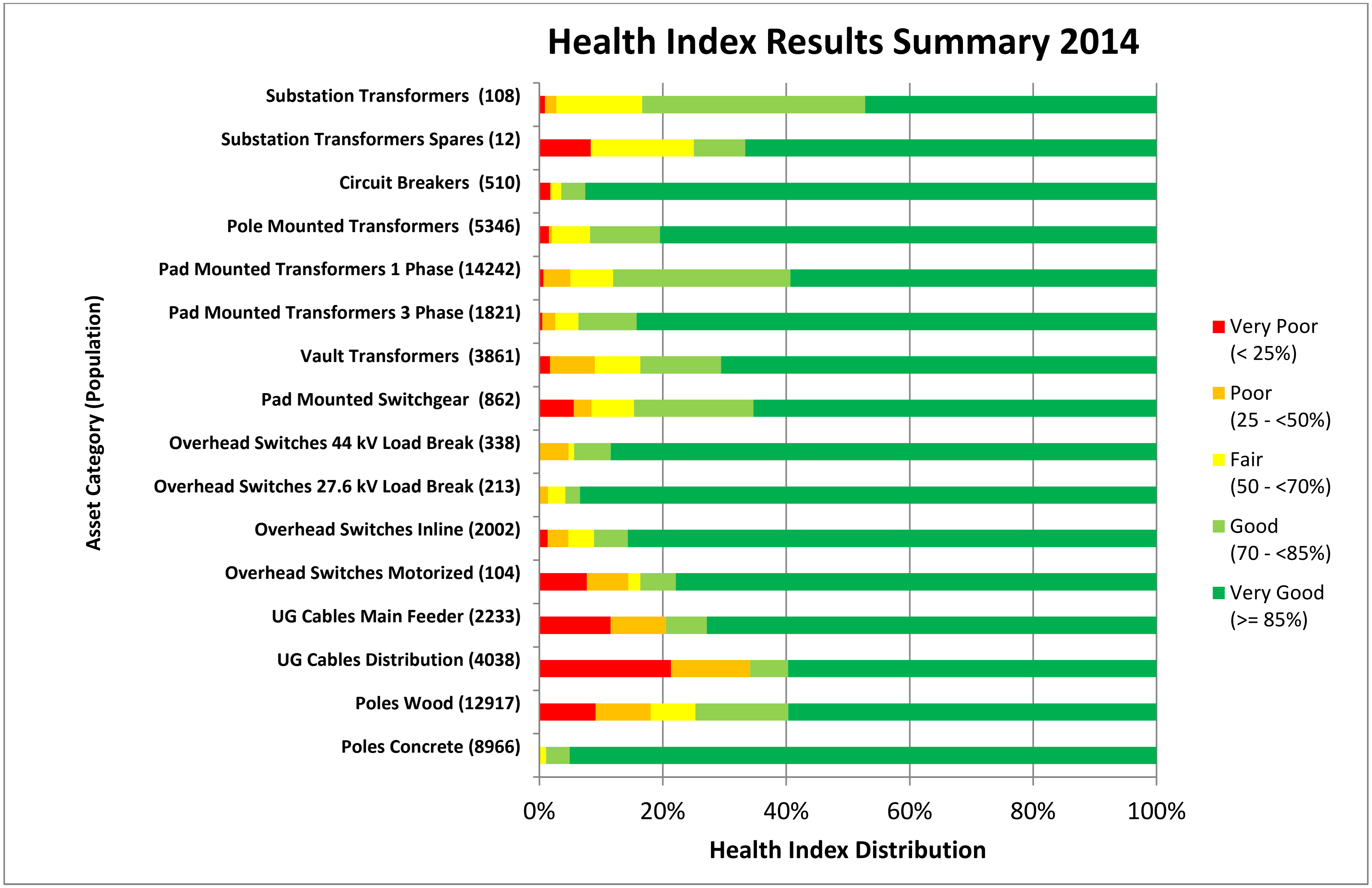

Figure III-5 Health Index Results Summary

Table III-2 Year 1 Flagged for Action

Asset Category		First Year Flagged for Action (0 years from now)		10 Year Flagged for Action Total (years 0 through 9)		Action Strategy
		Quantity	Percentage	Quantity	Percentage	
Substation Transformers	In Service	3	2.8%	6	5.6%	proactive
	Spares	N/A	N/A	N/A	N/A	N/A
Circuit Breakers		10	2.0%	10	2.0%	proactive
Pole Mounted Transformers		58	1.1%	406	7.6%	reactive
Pad Mounted Transformers	1 Phase	177	1.2%	1429	10.0%	reactive
	3 Phase	6	0.3%	71	3.9%	reactive
Vault Transformers		89	2.3%	563	14.6%	reactive
Pad Mounted Switchgear		31	3.6%	116	13.5%	reactive
Overhead Switches	44 kV	1	0.3%	17	5.0%	reactive
	27.6 kV	0	0.0%	5	2.3%	reactive
	Inline	32	1.6%	276	13.8%	reactive
	Motorized	5	4.8%	24	23.1%	reactive
Underground Cables	Main Feeder	254	11.4%	678	30.4%	reactive
*Note that results are given in terms of conductor-km	Distribution	799	19.8%	1775	44.0%	reactive
Poles	Wood	1021	7.9%	4101	31.7%	proactive
	Concrete	3	0.0%	116	1.3%	proactive

III.2 **Condition-Based Flagged for Action Plan**

The Flagged for Action Plan estimates the number of units expected to require attention in a given year. Table III-2 shows the Year 1 (current year) and 10 Year cumulative Flagged for Action Plan. Table III-3 shows the 10 Year Flagged for Action Plan annually; Figure III-6 shows the results graphically.

It is evident from Table III-3 and Figure III-6 that there may be significantly larger quantities of assets flagged for action in the first year than in subsequent years. This is generally the case when there is a large quantity of assets that are at or near the end of their service lives. Because such assets would have high probabilities of failure, large quantities will be flagged for intervention in the first year. Since the assessment methodology assumes that all units flagged for action are replaced, the quantities flagged for action in year 2 or later may be significantly smaller than that of the first year. In reality, only some of the units flagged for action in the first year will be dealt while the remaining units will be addressed in subsequent years.

At present, over 11% of main feeder underground cables and nearly 20% of distribution underground cables were flagged for action. Within the next 10 years, more than 30% of underground cable population is flagged for action.

Presently, 1021 or 8% of wood poles have been flagged for action. This includes poles that require action because of the insulation used. In the next 10 years 32% of all wood poles will need to be addressed.

It is important to note that the Flagged for Action plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units that are expected to be candidates for replacement or other action. While this condition-based Flagged for Action Plan can be used as a guide or input to Enersource's Distribution System Plan, it is <u>not</u> expected that it be followed directly or as the final deciding factor in making sustainment capital decisions. There are numerous other factors and considerations that will influence Enersource's Asset Management decisions, such as obsolescence, system expansion, regulatory requirements, municipal demands, etc.

Table III-3 Ten Year Flagged for Action Plan

Years from Now	Asset Category															
	Substation Transformers		Circuit Breakers	Pole Mounted Transformers	Pad Mounted Transformers		Vault Transformers	Pad Mounted Switchgear	Overhead Switches				Underground Cables *Note that results are given in terms of conductor-km		Poles	
	In Service	Spares			1 Phase	3 Phase			44 kV	27.6 kV	Inline	Motorized	Main Feeder	Distribution	Wood	Concrete
0	3	N/A	10	58	177	6	89	31	1	0	32	5	254	799	1021	3
1	0	N/A	0	49	161	7	67	16	2	0	29	3	91	259	709	5
2	0	N/A	0	40	148	7	62	11	2	0	26	3	59	159	499	5
3	0	N/A	0	35	139	7	58	9	2	0	26	2	51	126	372	8
4	1	N/A	0	33	126	7	55	6	2	0	29	2	46	101	297	10
5	0	N/A	0	34	124	8	53	8	1	1	27	3	41	82	256	13
6	1	N/A	0	36	126	8	50	7	1	0	28	1	37	70	235	15
7	1	N/A	0	39	136	6	46	6	2	2	27	2	34	62	234	14
8	0	N/A	0	40	141	6	43	10	1	0	26	1	33	59	238	19
9	0	N/A	0	42	151	9	40	12	3	2	26	2	32	58	240	24

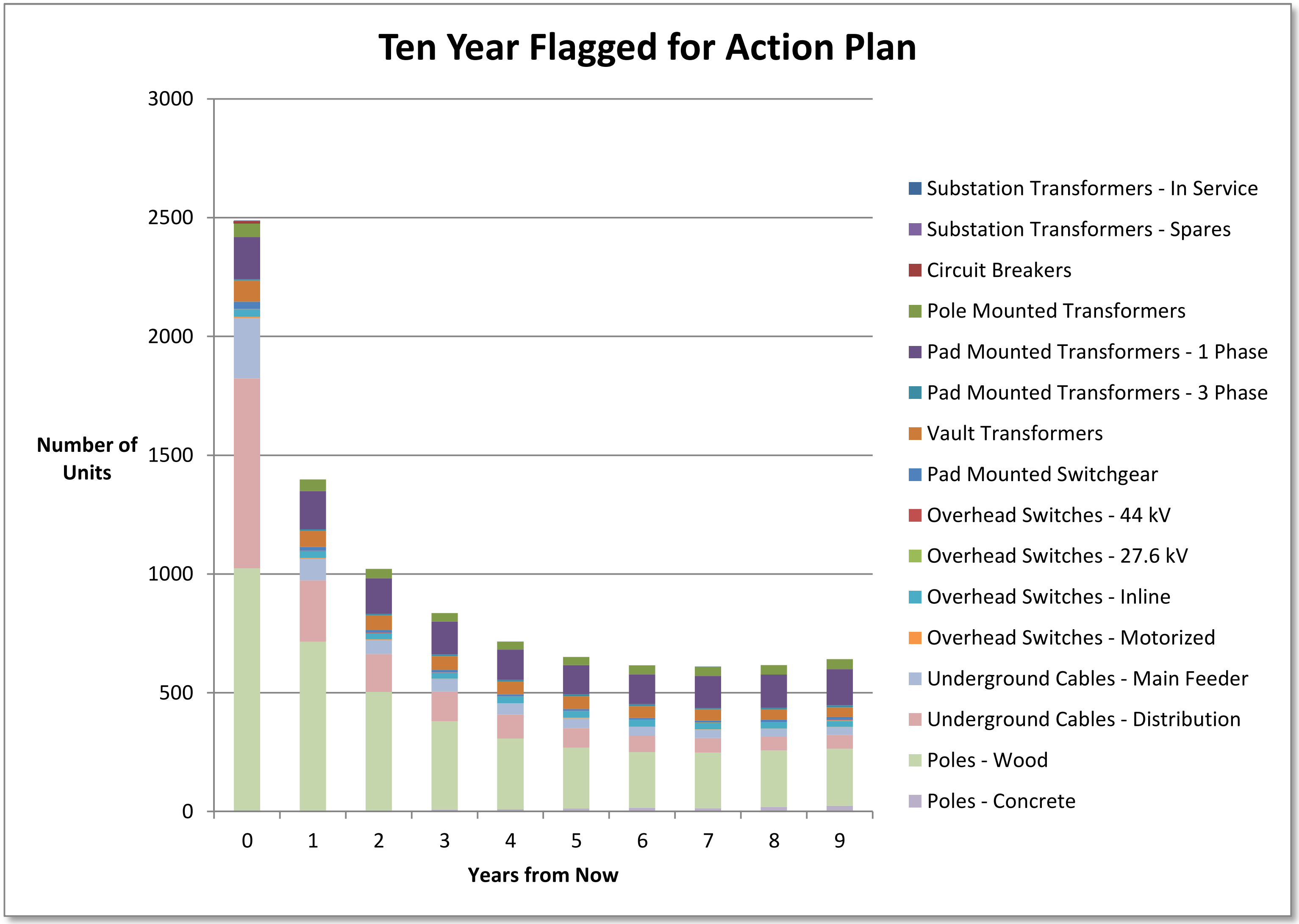

Figure III-6 Ten Year Flagged for Action Plan

III.3 **Data Assessment Results**

Data assessment includes determining the data availability indicator (DAI) of each unit, as well as identifying the data gaps for each asset group. Data availability is a measure of the amount of data that an individual unit has in comparison with the set of data currently available in for its respective asset category. Data gaps are items that are indicators of asset degradation, but are currently not collected or available for <u>any</u> asset in an asset category. The more minimal the data gaps, the higher the quality of available condition data and Health Index formulas.

Most of the required condition data for Substation Transformers was available. At 84%, the average of DAI of this group was slightly better than in the previous year. There has been an improvement in the collection of inspection data. Nearly 80% of the population had inspection data in 2013, whereas roughly 60% of population had such data in 2012.

Data for Circuit Breakers included age, contact resistance, and inspection results. The average DAI for this asset group improved significantly from 51% last year to 71% this year. This is a result of an improvement in the collection of inspection data. No new data types had been collected so the data gaps remained the same as those given in 2013 ACA report.

Although the average DAI of Pole Mounted Transformers has dropped from 82% last year to 75% this year, in this case this is not a significant cause for concern. This year, the Health Index formula weights were modified to better account for the inspection data and such re-adjustment likely impacted the overall DAI. Nearly all units had inspection information. The data gaps remain the same as those given in the 2013 ACA report.

The average DAI of Pad Mounted Transformers has dropped from 100% to 89% for 1-phase and 70% this 3-phase year. This is because additional visual inspection data (e.g. paint, access, foundation condition), were added to the Health Index formula. Such data should be collected for all pad mounted transformers so as to improve the DAI. The condition of the foundation has been included in the HI formula; other data gaps remain the same as those from the 2013 report.

The average DAI of Vault Transformers has improved from 76% to 78% this year. Although transformer overloading condition was indirectly assumed by determining if oil showed signs of boiling over, more precise loading data would be preferred. It therefore remains as a data gap.

The average Pad Mounted Switchgear DAI was 39%, a drop from last year's 59%. Age was available for all units. Inspection data, gathered from linemen inspections and dry ice cleaning, increased from 50% last year to 56% this year. The drop in DAI is a result of incorporating more inspection data (e.g. water in vault, foundation condition, insulation condition, connection condition, overheating) into the HI formula. Such information should be collected for all units to improve the DAI.

The data used for overhead switch assessment included age and visual inspections. Visual inspections, however, were limited and no new inspection data has been available from recent years. In the 2014 assessment, the decision was made to exclude very old inspection data (i.e. inspections from 2012 or later were included). This, in combination with the revised HI, caused the DAI for the four overhead switch types to drop significantly. It is recommended that visual inspections be conducted to gather condition information. The data gaps remain the same as those given in the 2013 ACA report.

Age data was available for Underground Cables and because age was known for all segments, the average DAI for both Main Feeder and Distribution Cables sub-categories was 100%. Loading information has been collected and will be incorporated in subsequent assessments. Enersource should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta). Such information will provide good, objective data input into the Health Index.

In 2013, the assessment for both Wood and Concrete poles were based on age only. Because age was known for most poles, the 2013 DAIs for both wood and concrete poles was 100%. In 2014 Enersource launched a pole inspection program wherein visual inspection information was gathered. The Health Index formulas for wood and concrete poles were revised to include inspection data. Because less than 40% of poles were inspected, the DAI for both wood and concrete poles dropped to 55%. The only data gap for this asset category is pole strength.

III.4 **2013 to 2014 Audit**

This section describes the changes identified between the 2013 and 2014 ACA.

The asset categories assessed in 2014 are the same as those in 2013. Now new categories or sub-categories have been added or removed. For each asset category, the following aspects were compared between 2013 and 2014:

Health Index Formulation

1. Health Index Formulation
2. Population and Sample Size
3. Health Index Distribution

Changes in Health Index Formulation

Since 2013, Enersource has made significant efforts with respect to collecting more condition data for several asset categories. Thus, for some asset categories, the Health Index formulas were changed so that the newly collected data could be included. The asset categories and changes to Health Index are described below:

- *Pole Mounted Transformers*: Minor change in condition parameter weights to better account for visual inspection information. The visual inspection information was first used in the 2012 ACA.

- *Pad Mounted Transformers*: Incorporated additional visual inspection condition data (e.g. paint, access, foundation condition).

- *Vault Transformers*: Incorporated additional visual inspection condition data (e.g. water in vault, access, over-heating).

- *Pad Mounted Switchgear*: Incorporated additional visual inspection condition data (e.g. water in vault, foundation condition, insulation condition, connection condition, overheating).

- *Overhead Line Switches*: The inspection program for these assets has been limited, however Enersource expects that it will be more extensive in the near future. As such, the Health Index formula was modified to include currently available condition data (e.g. insulator condition, switch condition, confirmed operation status). Additionally, the age scoring criteria for Motorized switches were revised such that the assumed service life is 35 years instead of 55 years.

- *Wood Poles*: An extensive pole inspection program was recently deployed and visual inspection data were incorporated (e.g. physical condition, including decay, mechanical damage, top feathering).

- *Concrete Poles*: The inspection program for concrete poles is not yet as extensive as that of wood poles. However, available visual inspection data were incorporated (e.g. mechanical damage, cracks).

Changes in Population and Sample Size

Table III-4 summarizes the change in population and in sample size between 2013 and 2014. A graphical representation of the population change is show Figure III-7.

Table III-4 Summary Change in Population and Sample Size

Asset		Population				Sample Size		
		Population Count 2013	Population Count 2014	Population Change by Counts	Population Change by %	% Sample Size 2013	% Sample Size 2014	Sample Size Change by %
Substation Transformers	In Service	108	108	0	0%	100%	100%	0%
	Spares	9	12	3	33%	100%	100%	0%
Circuit Breakers		510	510	0	0%	100%	100%	0%
Pole Mounted Transformers		5334	5346	12	0%	100%	100%	0%
Pad Mounted Transformers	1 Phase	14189	14242	53	0%	100%	100%	0%
	3 Phase	1784	1821	37	2%	100%	100%	0%
Vault Transformers		3900	3861	-39	-1%	100%	100%	0%
Pad Mounted Switchgear		852	862	10	1%	100%	100%	0%
Overhead Switches	44 kV	354	338	-16	-5%	100%	100%	0%
	27.6 kV	219	213	-6	-3%	100%	100%	0%
	Inline	1946	2002	56	3%	100%	100%	0%
	Motorized	97	104	7	7%	100%	100%	0%
Underground Cables *	Main Feeder	2246	2233	-13	-1%	100%	100%	0%
	Distribution	4022	4038	16	0%	100%	100%	0%
Poles	Wood	12602	12917	315	2%	100%	100%	0%
	Concrete	8194	8966	772	9%	100%	100%	0%

* data in conductor-km

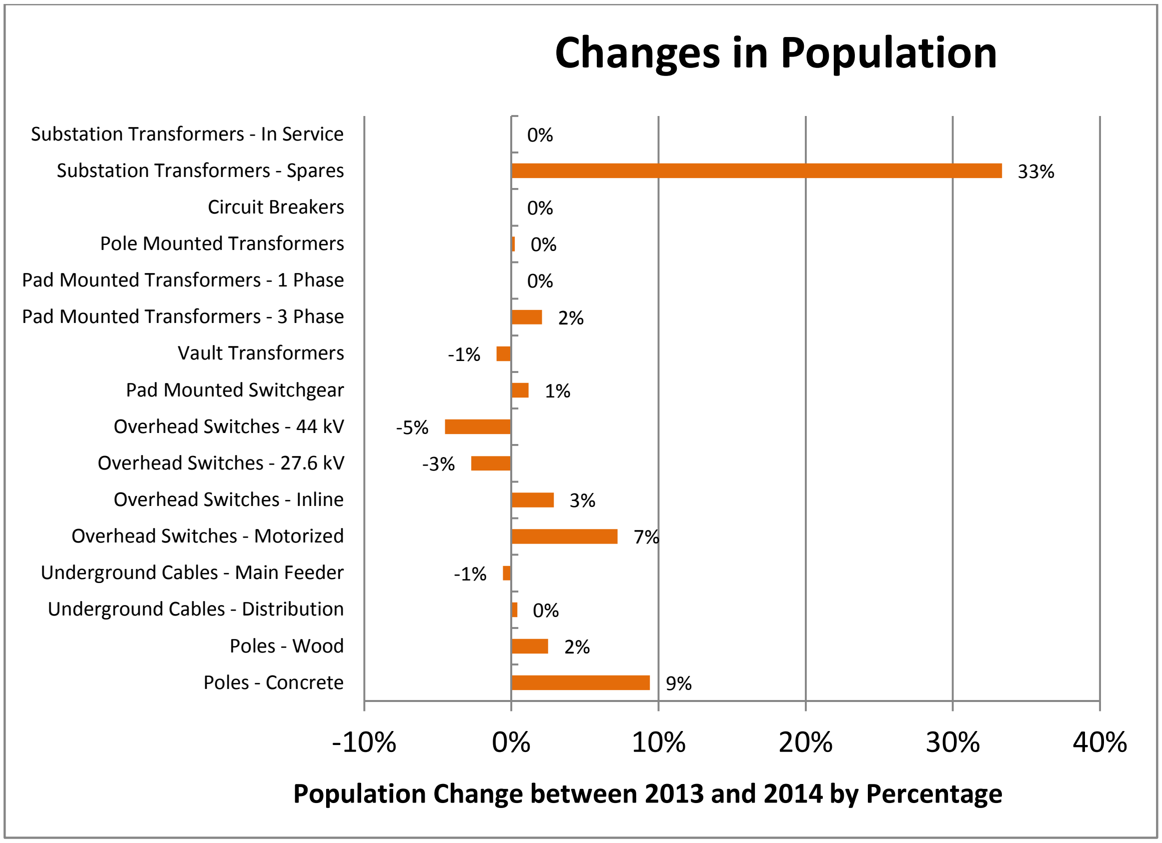

Figure III-7 Change in Population

For a majority of the asset classes, the change in populations remained fairly steady, within ± 5%. The asset classes that have larger populations in 2014 than in 2013 are as follows:

- Three spare substation transformers were added, resulting in a 33% population increase.
- New motorized overhead line switches were installed under the new automation orientation program, resulting in a 7% increase.
- New concrete pole installations and replacement of some wood poles with concrete poles resulted in a 9% population increase.

In both 2013 and 2014, the sample size for all asset categories is 100%. All asset included in the assessment had sufficient data for Health Indexing.

Changes in Health Index Distribution

The changes in Health Index distribution between 2013 and 2014 are summarized in Table III-5 and graphically shown in Figure III-8. The overall trend with respect to Health Index distribution was assessed. Assets that showed an increasing percentage of “good” and/or “very good” or a decrease of “very poor”, “poor”, and/or “fair” were classified as having overall improved health distributions. Conversely, asset classes with a decreasing percentage of “good” and/or “very good” or an increasing percentage of “very poor”, “poor”, and/or “fair” were classified as having an overall decline in health.

Substation Transformers In Service: The trend shows a slight decline in overall condition. There was a 1% increase in units categorized as "very poor".

Substation Transformers Spares: The trend shows a general decline in overall condition. There was an 8% increase in units categorized as "very poor".

Circuit Breakers: The trend shows a slight decline in overall condition. The average HI decreased from 95% to 94% in 2014. Because many more breakers had inspection data available in 2014, this may be partially attributed to improved knowledge of breaker condition.

Pole Mounted Transformers: The trend shows an improvement in overall condition. There are less units being classified as "poor" or "very poor", while more are classified as "very good".

Pad Mounted Transformers 1-phase and 3-phase: In both cases, the trend shows a downward shift in overall condition. Fewer units are being classified as "very good", while more are being classified as "good" or "fair". This may be partially attributed to the revised HI formula of 2014 where additional visual inspection data was incorporated.

Vault Transformers: The trend shows a slight decline in overall condition. Fewer units are classified as "very good", while more are classified as "good" or "fair". This may be partially attributed to the revised HI formula of 2014 where additional visual inspection data was incorporated.

Pad Mounted Switchgear: The trend shows a significant improvement in overall condition. There was a 17% increase in units categorized as "very good". This may be partially attributed to the revised HI formula of 2014 where additional visual inspection data was incorporated.

Overhead Switches: For the 27.6 kV and 44 kV categories, the trends show improvements in overall condition. The percentage of units classified as "very good" increased for these categories. For Inline switches there was a slight decline in overall condition; more inline switches were classified as "poor" or "very poor". Motorized switches show a significant decline, with 15% more of the population being categorized as "poor" or "very poor". This is mainly a result of the revised age scoring criteria. It should be noted that the Health Index formula for overhead switches was significantly changed due to limited inspection data. The changes in Health Index may therefore be partially attributed to this change.

Underground Cables, Main Feeder and Distribution: The overall health of underground cables remained fairly steady.

Poles, Wood and Concrete: Wood poles showed a significant decline on overall condition. This apparent change is likely due to the revised HI formula that incorporates inspection data. The newly implemented inspection program has allowed for significant improvement in knowledge of wood pole condition. Concrete appears to have remained fairly steady. The planned future concrete pole inspections will also improve knowledge with this asset category.

Table III-5 Summary Change in Health Index Distribution

Asset	Year	Very Poor		Poor		Fair		Good		Very Good		Average Health Index	
		% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	%	Change
Substation Transformers - In Service	2013	0.0%	1%	2.8%	-1%	13.0%	-2%	34.3%	1%	50.0%	1%	82.7%	1%
	2014	0.9%		1.9%		11.1%		35.2%		50.9%		83.3%	
Substation Transformers - Spares	2013	0.0%	8%	0.0%	0%	22.2%	-6%	11.1%	-3%	66.7%	0%	87.0%	-7%
	2014	8.3%		0.0%		16.7%		8.3%		66.7%		80.3%	
Circuit Breakers	2013	1.6%	0%	0.6%	-1%	1.0%	1%	2.5%	2%	94.3%	-3%	95.3%	-2%
	2014	2.0%		0.0%		1.8%		4.5%		91.7%		93.4%	
Pole Mounted Transformers	2013	2.1%	-1%	6.7%	-6%	2.5%	4%	14.9%	-4%	73.8%	7%	89.7%	2%
	2014	1.6%		0.5%		6.2%		11.3%		80.5%		91.9%	
Pad Mounted Transformers - 1 Phase	2013	0.7%	0%	4.8%	0%	2.7%	4%	14.6%	14%	77.2%	-18%	88.5%	-1%
	2014	0.7%		4.4%		6.9%		28.7%		59.3%		87.4%	
Pad Mounted Transformers - 3 Phase	2013	0.5%	0%	2.1%	0%	1.3%	2%	7.7%	2%	88.3%	-4%	92.2%	2%
	2014	0.5%		2.1%		3.7%		9.4%		84.2%		94.2%	
Vault Transformers	2013	1.6%	0%	7.5%	0%	3.6%	4%	11.7%	1%	75.6%	-5%	89.5%	-2%
	2014	1.7%		7.3%		7.4%		13.1%		70.6%		87.3%	
Pad Mounted Switchgear	2013	4.9%	1%	4.7%	-2%	17.8%	-11%	24.1%	-5%	48.5%	17%	79.0%	5%
	2014	5.6%		2.9%		6.8%		19.4%		65.3%		83.6%	
Overhead Switches - 44 kV	2013	0.0%	0%	0.3%	4%	5.1%	-4%	26.0%	-20%	68.6%	20%	89.1%	6%
	2014	0.0%		4.7%		0.9%		5.9%		88.5%		94.7%	
Overhead Switches - 27.6 kV	2013	0.0%	0%	0.0%	1%	2.3%	1%	14.2%	-12%	83.6%	10%	94.5%	2%
	2014	0.0%		1.4%		2.8%		2.3%		93.4%		96.6%	
Overhead Switches - Inline	2013	0.6%	1%	0.4%	3%	3.1%	1%	6.5%	-1%	89.5%	-4%	95.6%	-3%
	2014	1.3%		3.3%		4.1%		5.5%		85.7%		92.9%	
Overhead Switches - Motorized	2013	0.0%	8%	0.0%	7%	8.2%	-6%	23.7%	-18%	68.0%	10%	88.5%	-3%
	2014	7.7%		6.7%		1.9%		5.8%		77.9%		85.4%	
Underground Cables - Main Feeder	2013	11.7%	0%	9.2%	0%	0.0%	0%	6.7%	0%	72.5%	0%	77.3%	0%
	2014	11.5%		8.9%		0.0%		6.6%		72.9%		77.8%	
Underground Cables - Distribution	2013	22.0%	-1%	12.8%	0%	0.0%	0%	6.2%	0%	59.0%	1%	68.6%	1%
	2014	21.3%		12.9%		0.0%		6.1%		59.7%		69.7%	
Poles - Wood	2013	0.3%	9%	3.2%	6%	1.6%	6%	10.3%	5%	84.6%	-25%	92.9%	-14%
	2014	9.1%		8.9%		7.2%		15.1%		59.7%		79.1%	
Poles - Concrete	2013	0.0%	0%	0.0%	0%	0.4%	1%	4.5%	-1%	95.0%	0%	97.0%	0%
	2014	0.0%		0.1%		1.0%		3.8%		95.1%		97.1%	

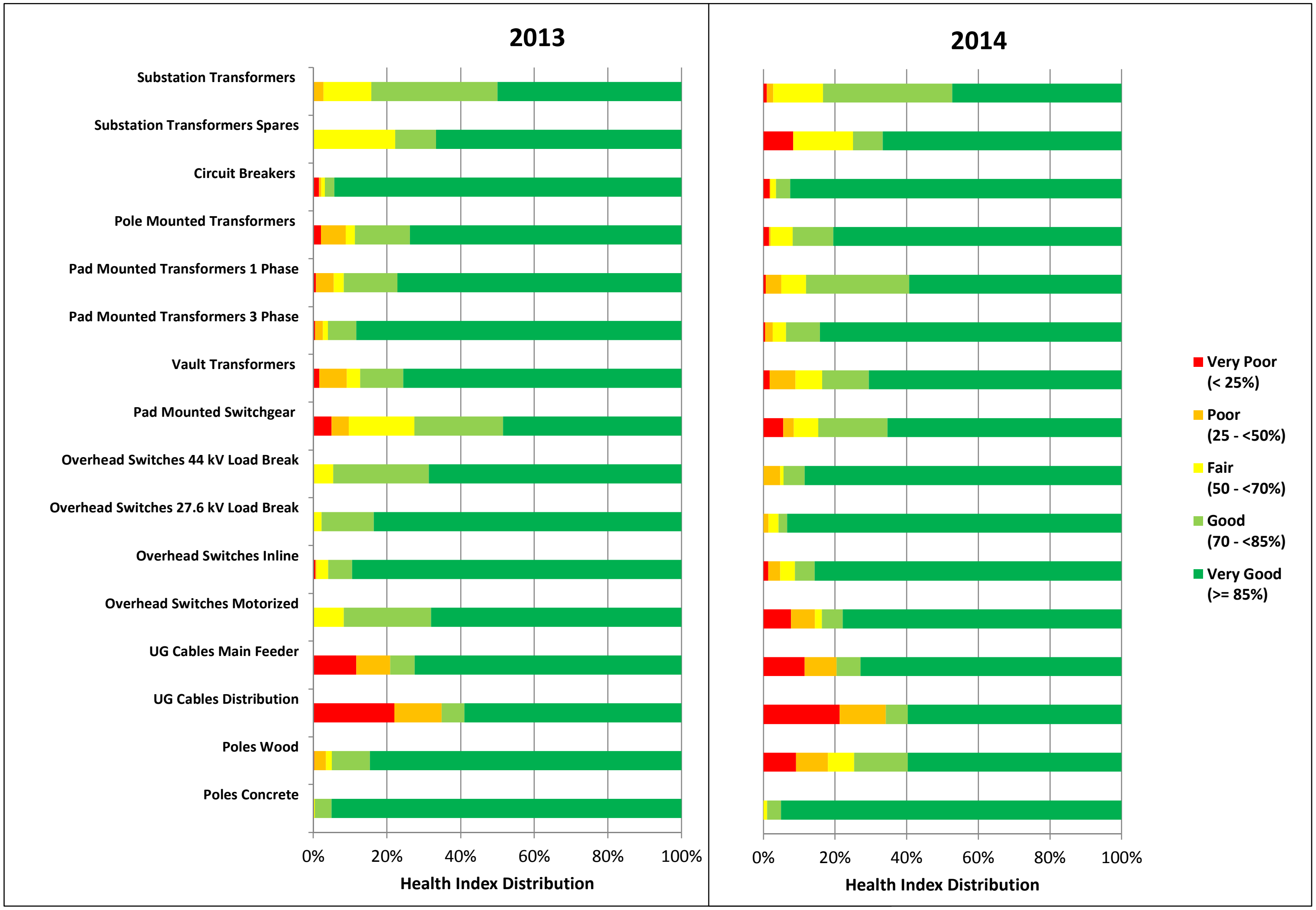

Figure III-8 Change in Health Index Distribution

IV CONCLUSIONS AND RECOMMENDATIONS

This section summarizes the findings of this study.

1. An Asset Condition Assessment was conducted for nine of Enersource's key distribution asset categories. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

2. The Underground Cables category was found to be in the worst condition. Approximately 20% of main feeder and 34% of distribution cables were classified as "poor" or "very poor".

3. Another group of concern is Wood Poles where 18% are in "poor" or "very poor" condition. It should also be noted that 9% of Vault Transformers and 8% of Pad Mounted Switchgear classified as "poor" or "very poor".

4. The Underground Cables category was determined to have the highest flagged for action percentage among all the asset groups. At present, over 11% of main feeder and nearly 20% of distribution cables were flagged for action. Within the next 10 years, more than 30% of underground cable population is flagged for action.

5. Presently, 8% of wood poles have been flagged for action. This includes poles that require action because of the insulation used. In the next 10 years 32% of all wood poles will need to be addressed.

6. The availability of inspection records were improved for in-service Substation Transformers and Circuit Breakers, resulting in increased DAIs. Data gaps are the same as those identified in 2013.

7. There has been a decrease in the average DAIs of Pad Mounted Transformers. This is because additional visual inspection data has been included in the HI formulas. Such data should be collected for all pad mounted transformers so as to improve the DAI.

8. The average DAI of Vault Transformers has improved from 76% to 78% this year.

9. The average Pad Mounted Switchgear DAI was 39%, a drop from last year's 59%. Although inspection data increased from 50% last year to 56% this year, additional inspection data (e.g. water in vault, foundation condition, insulation condition, connection condition, overheating) were incorporated into the HI formula. This caused the DAI to decrease. It is recommended that all inspection information be collected for all units.

10. The data used for overhead switch assessment included age and visual inspections. Visual inspections, however, were limited and no new inspection data has been available from recent years. In the 2014 assessment, the decision was made to exclude very old inspection data (i.e. inspections from 2012 or later were included). This, in combination with the revised HI, caused the DAI for the four overhead switch types to

drop significantly. It is recommended that visual inspections be conducted to gather condition information.

11. Age data were available for Underground Cables and because age was known for all segments, the average DAI for both Main Feeder and Distribution Cables sub-categories was 100%. Enersource may consider diagnostic testing as such information will provide good, objective data for the Health Index.

12. As a result of Enersource's newly launched pole inspection program, visual inspection information as incorporated into the Health Index assessment. Because less than half of poles have been inspected, the DAIs for both wood and concrete poles dropped to 55%. Inspections data collected from the remainder of the population will be incorporated into subsequent year's assessment.

13. It is recommended that the data availability indicator (DAI) for each asset category be brought to 100% and maintained at that level. i.e. data for all condition parameters used in the HI formulas should be collected for all assets.

14. For each asset category it is recommended that the data gaps be addressed in order of the priority given in this report.

15. Because only limited failure statistics was available at this time, an exponentially increasing failure rate and corresponding probability of failure model were assumed in this study. It is recommended that Enersource continue to collect failure statistics so that Enersource-specific failure models can be developed and used in future assessments. Note that this is already being done for distribution transformers and underground cables. Similar collection of failure data should be extended to all asset classes.

16. It is important to note that the Flagged for Action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence Enersource's Asset Management Plan, such as obsolescence, system growth, regulatory requirements, municipal initiatives, etc.

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V APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

1 SUBSTATION TRANSFORMERS

1.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

1.1.1 Condition and Sub-Condition Parameters

Table 1-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Insulation	11	Table 1-2
2	Cooling	1	Table 1-3
3	Sealing & Connection	2	Table 1-4
4	Service Record	6	Table 1-5

Table 1-2 Insulation Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Quality	8	Table 1-6
2	Oil DGA	10	Table 1-7
3	Winding Doble	10	Table 1-8
4	Bushing (worst case condition of primary and secondary bushing)	5	Table 1-9

Table 1-3 Cooling Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Winding Temp Gauge	1	Table 1-9
2	Oil Temp Gauge	1	Table 1-9
3	Mech Box – Fan Supply	1	Table 1-9

Table 1-4 Sealing & Connection Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Corrosion / Paint Condition	1	Table 1-9
2	Tank Oil Level	2	Table 1-9
3	Gasket (worst case condition of conservator cover, rad)	3	Table 1-9

Table 1-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Loading	5	Table 1-10
2	Age	3	Figure 1-1

1.1.2 Condition Criteria

Oil Quality

The "Oil Quality" parameter is a composite of the following oil properties: moisture, dielectric strength, interfacial tension, color, and acidity.

Table 1-6 Oil Quality Test Criteria

Score	Description
4	Overall Factor is less than 1.2
3	Overall Factor between 1.2 and 1.5
2	Overall Factor is between 1.5 and 2.0
1	Overall Factor is between 2.0 and 3.0
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 °C Corrected) (From DGA test)		<=20	<=30	<=40	>40	4
Dielectric Str. [kV] D877		>40	>30	>20	Less than 20	3
Interfacial Tension (IFT)* [dynes/cm]	230 kV ≤ V	>32	25-32	20-25	Less than 20	2 *
	69 kV <V< 230	>30	23-30	18-23	Less than 18	
	V ≤ 69 kV	>25	20-25	15-20	Less than 15	
Color		Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number*	230 kV ≤ V	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <V< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	V ≤ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

For example if all data is available, Overall Factor = $\frac{\sum Score_i \times Weight_i}{12}$

Oil DGA

Table 1-7 Transformer DGA Criteria

Score	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

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

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	**2**
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	**1**
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	**1**

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Winding Doble Test

Table 1-8 Winding Doble Test Criteria

Score	Description
4	power factor reading $\leq$ 0.3%
3	0.3% < power factor reading $\leq$ 0.5%
2	0.5% < power factor reading $\leq$ 0.7%
1	0.7% < power factor reading $\leq$ 1.0%
0	power factor reading > 1.0%

Age

Assume that the failure rate Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 40 and 60 years the probability of failures (P_f) for Substation Transformers are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

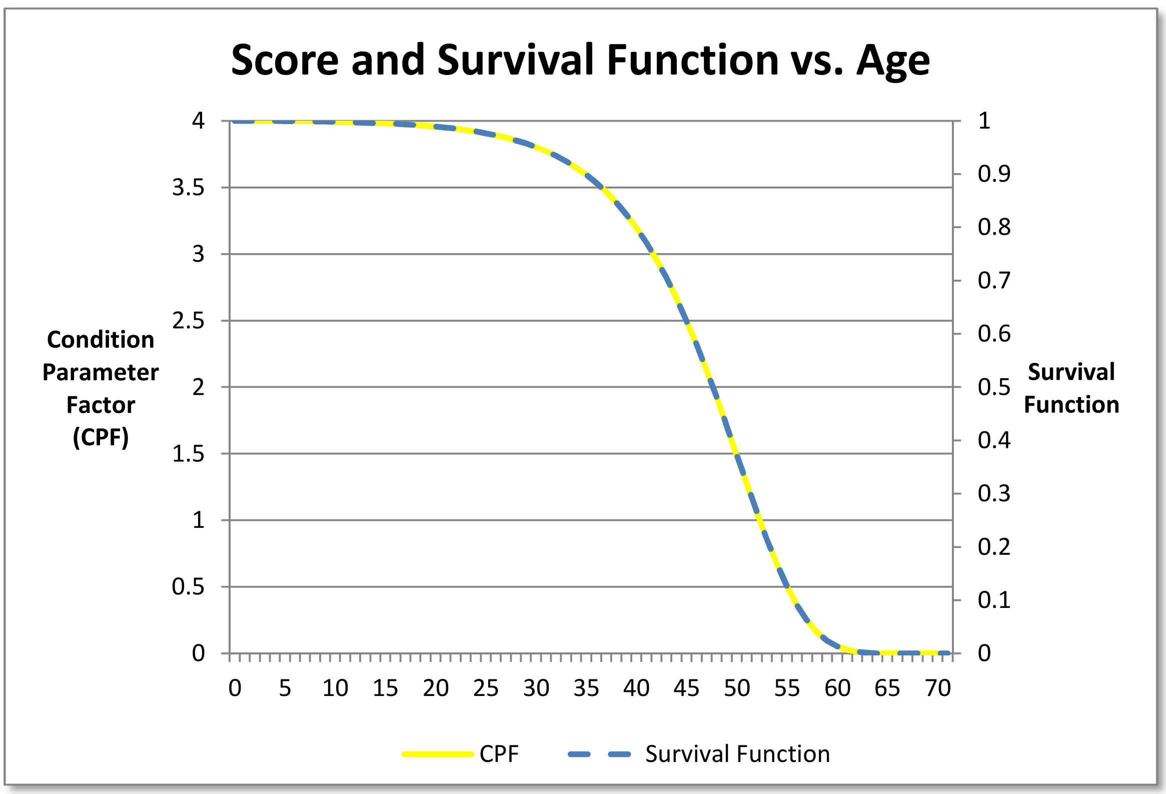

Figure 1-1 Substation Transformers Age Criteria

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Visual Inspections

Table 1-9 Visual Inspection Criteria

Score	Condition Description
4	OK
0	Not OK

Loading History

Table 1-10 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

1.2 Age Distribution

The average age of all in service units was 22. The age distribution for in service Substation Transformers was as follows: Approximately 17% of all units were 40 or older.

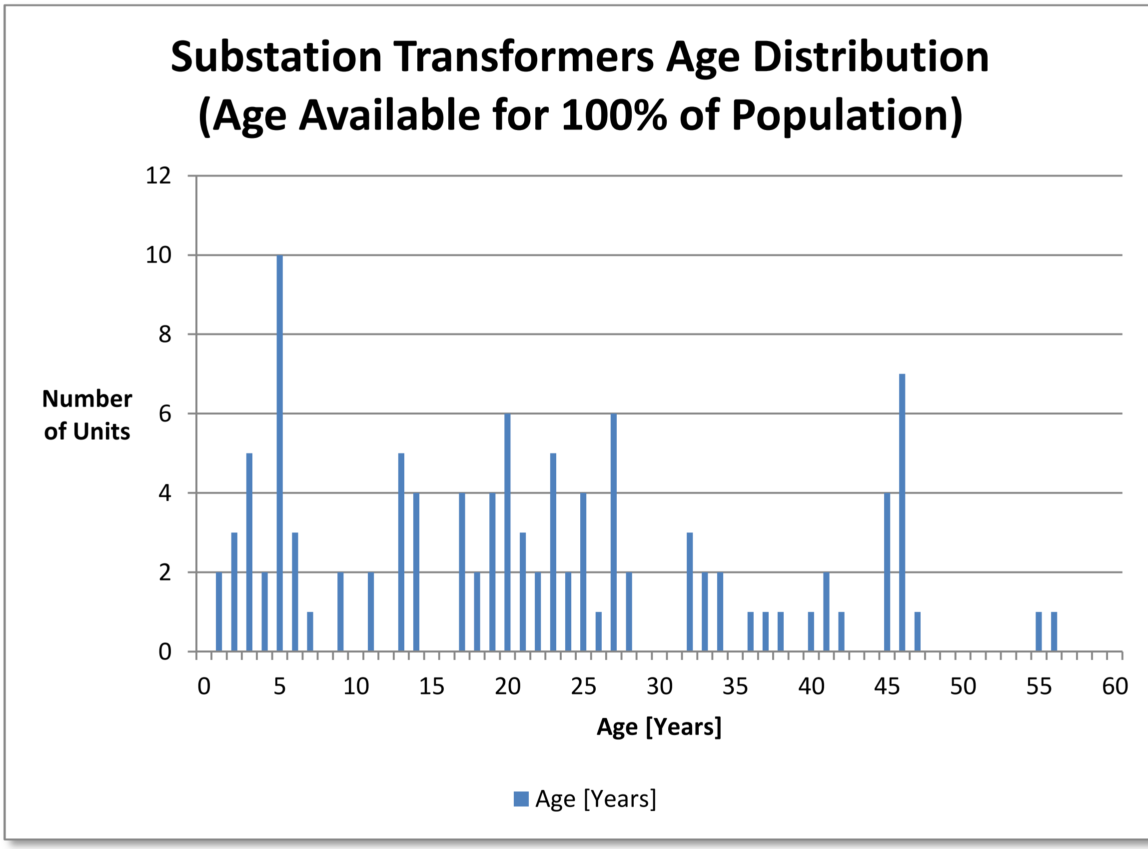

Figure 1-2 Substation Transformers Age Distribution

1.3 Health Index Results

There were 108 in service Substation Transformers at Enersource. Of these, there were 108 units with sufficient data for a Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units are shown:

The average Health Index for this asset group was 83%. Three units were found to be in "poor" condition.

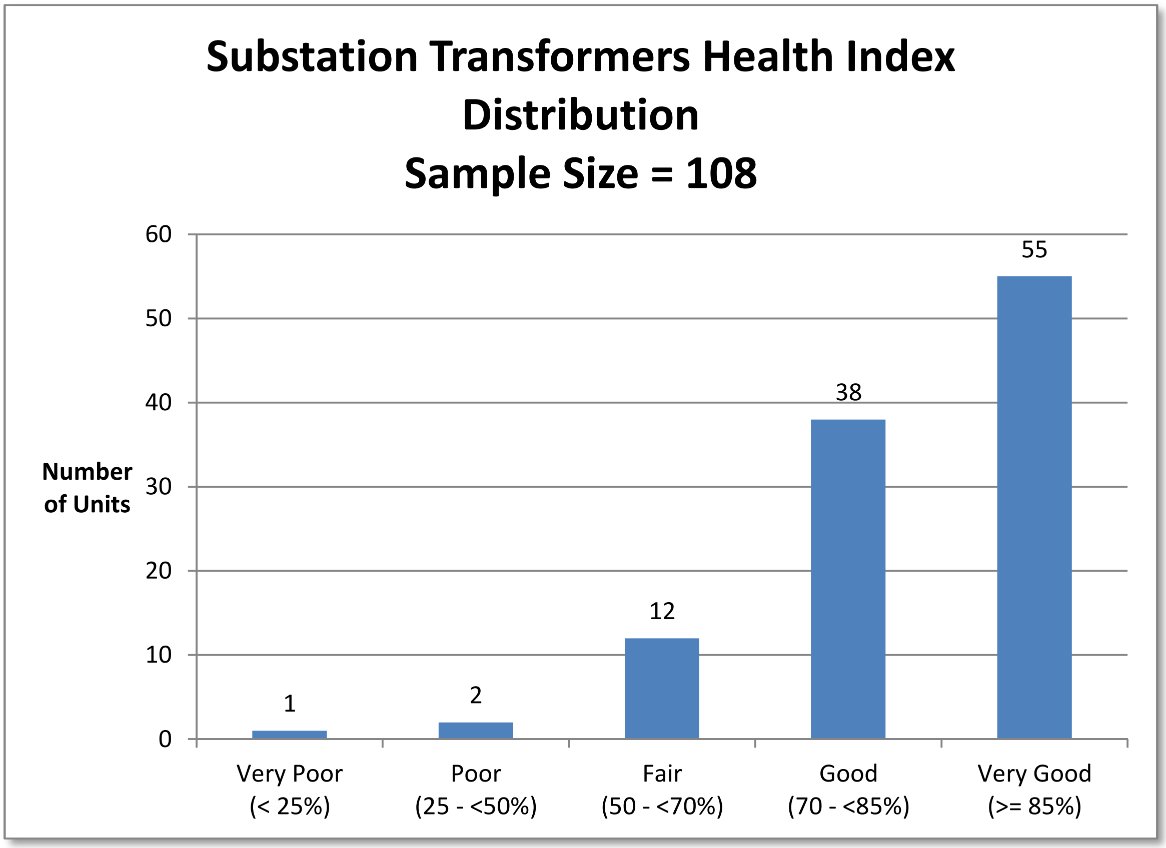

Figure 1-3 Substation Transformers Health Index Distribution (Unit)

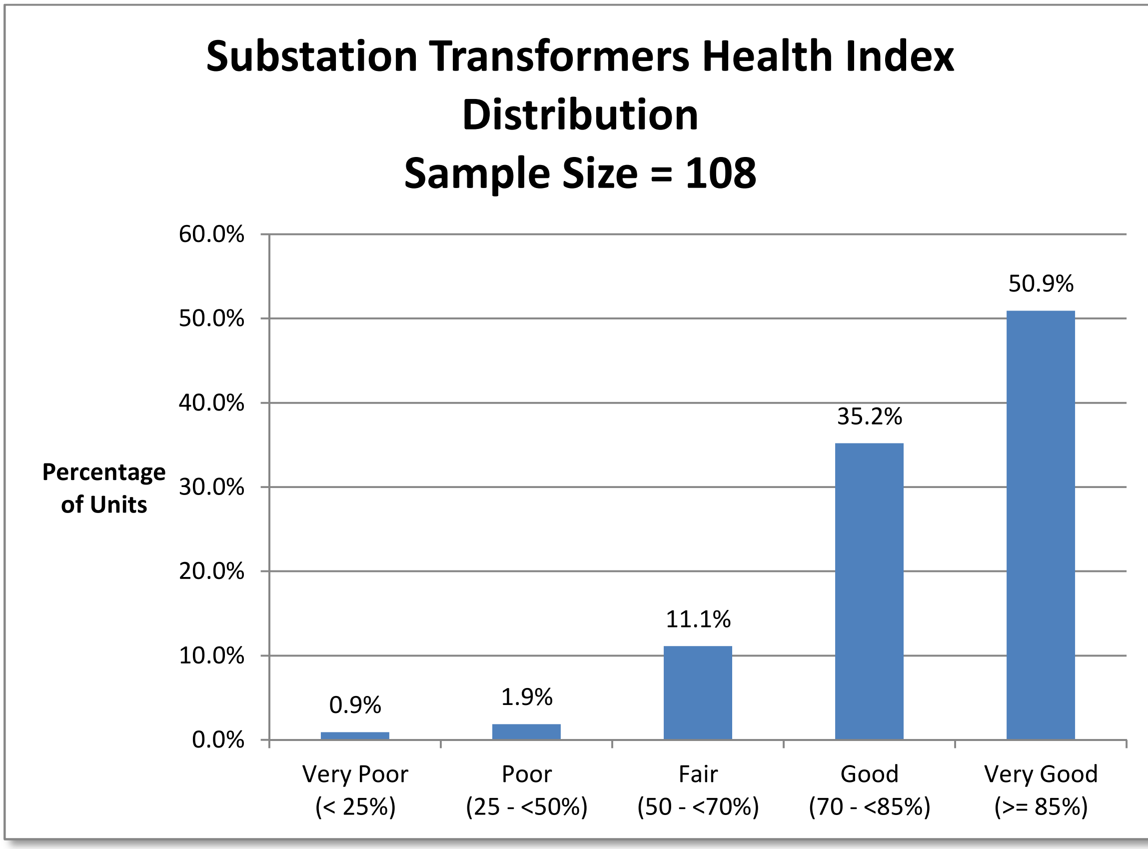

Figure 1-4 Substation Transformers Health Index Distribution (Percentage)

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1.4 Flagged for Action Plan

It is assumed that Substation Transformers are proactively replaced.

In this study, a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one.

Each unit's criticality is defined as follows:

$$Criticality = (Criticality_{max} - Criticality_{min}) * Criticality\_Multiple + Criticality_{min}$$

where:

$Criticality_{max} = 1/(70\%) = 1.43$ (the units with highest relative importance should be replaced when their POF reaches 70%)

$Criticality_{min} = 1/(90\%) = 1.11$ (the units with lowest relative importance can wait until their POF reaches 90% to be replaced)

$$Criticality\_Multiple = \frac{\sum_{CF=1}^{\forall CF}(CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF}(WCF_{CF})}$$

The factors, weights and the score system of each factor are as follows:

Criticality Factor (CF)	Weight (WCF)	Score (CFS)
Number of Customers	25	Low=0 High=1
Oil Containment	10	Yes=0 No=1
Location (near water creeks)	50	No=0 Yes=1
Transformer Primary Protection	15	Breaker =0 Fuse=1

The table below shows examples of criticalities for three separate units.

	Example 1			Example 2			Example 3		
Criticality Factor	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**
Number of Customers	Low	0	0	High	1	25	High	1	25
Oil Containment	Yes	0	0	No	1	10	No	1	10
Location (near water creeks)	No	0	0	No	0	0	Yes	1	50
Transformer Primary Protection	Breaker	0	0	Breaker	0	0	Fuse	1	15
	Criticality Multiple		0	Criticality Multiple		0.35	Criticality Multiple		1
	Criticality		(1.43-1.11) *0 + 1.11 = **1.11**	**Criticality**		(1.43-1.11) *0.35 + 1.11 = **1.22**	**Criticality**		(1.43-1.11) *1 + 1.11 =**1.43**

As previously noted a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. The flagged for action plan for in service Substation Transformers was as follows:

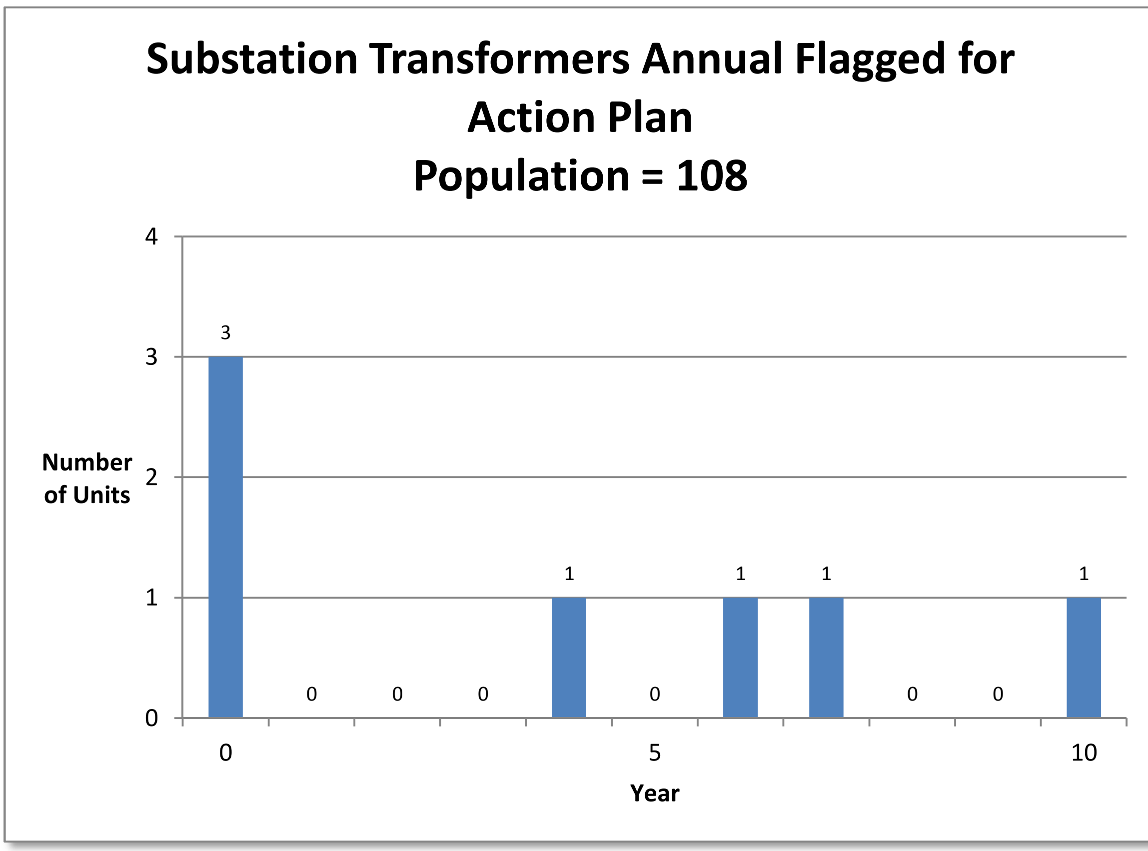

Figure 1-5 Substation Transformers Flagged for Action Plan

1.5 Spare Substation Transformers

There were 12 Spare Substation Transformers at EMH. Their age distribution was as follows. Approximately 50% of all units were 40 or older.

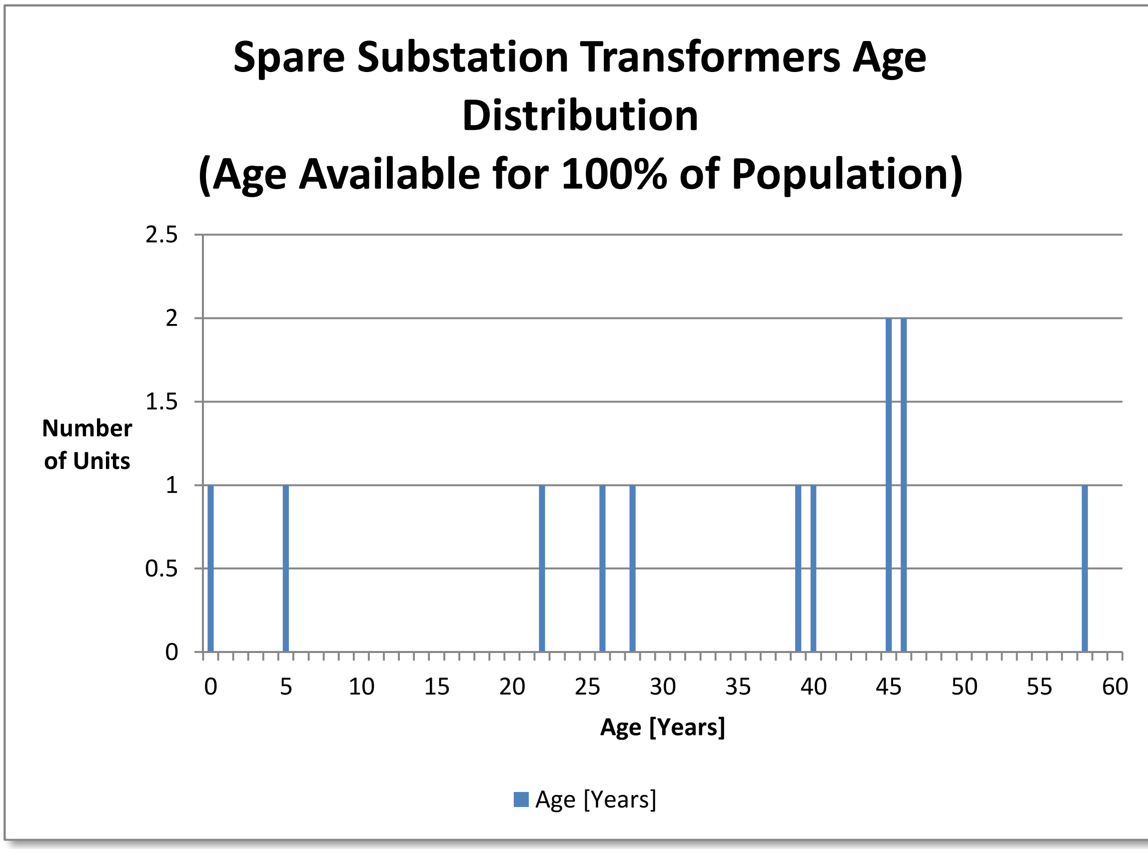

Figure 1-6 Spare Substation Transformers Age Distribution

Of the 12 Spare Substation Transformers at Enersource, there were 12 units with sufficient data for a Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units are shown below. The average Health Index for this asset group was 80%.

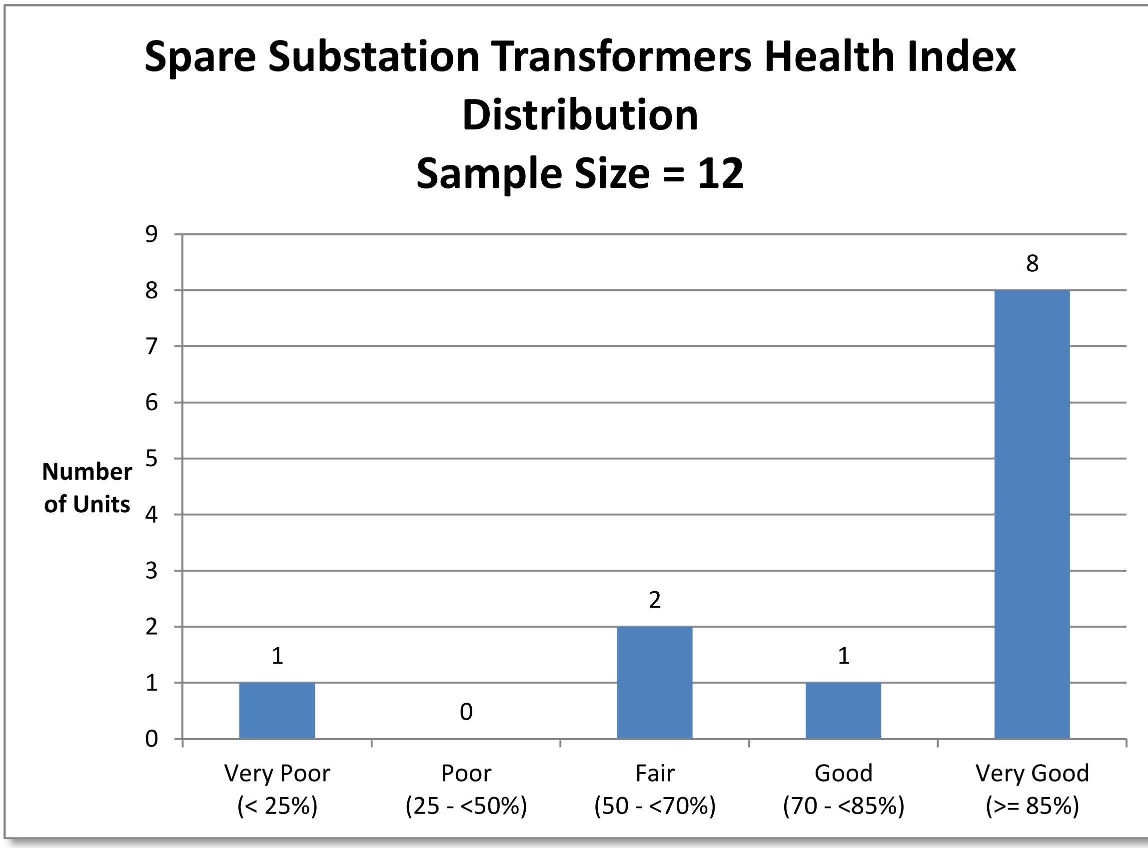

Figure 1-7 Spare Substation Transformers Health Index Distribution (Unit)

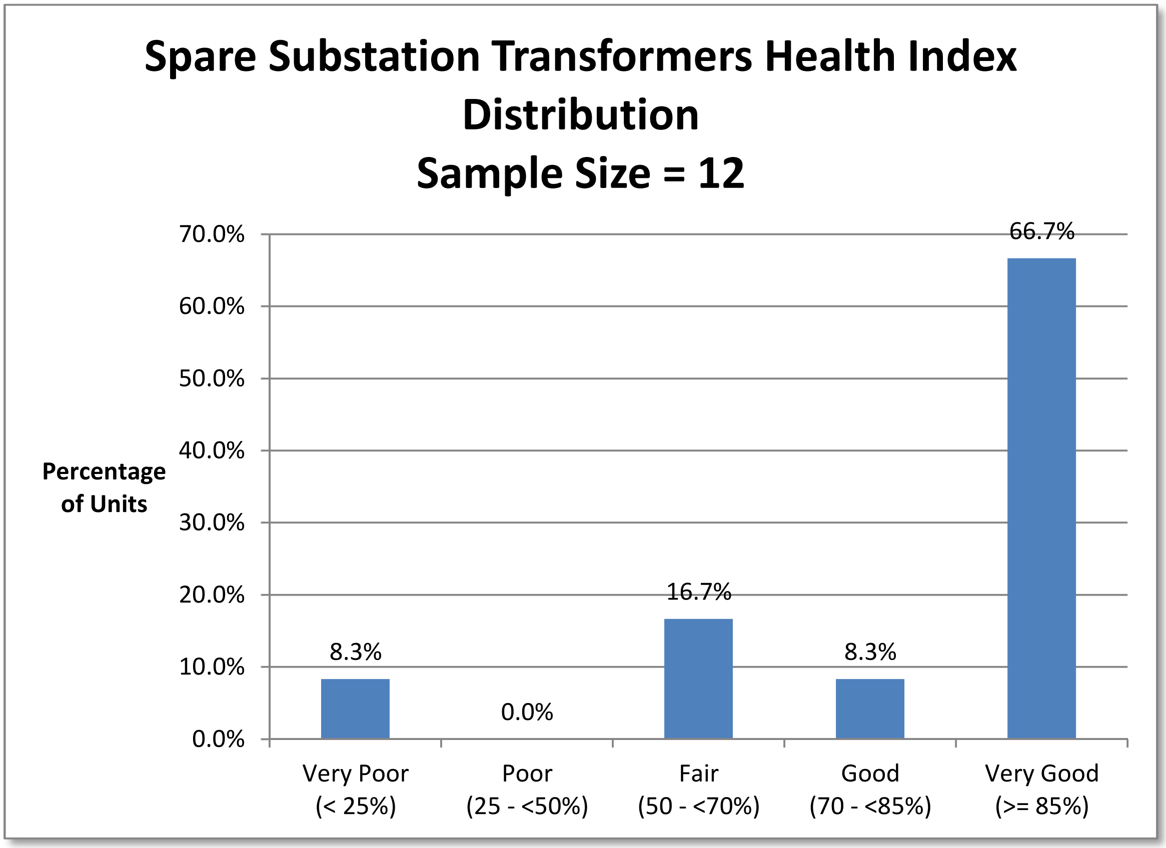

Figure 1-8 Spare Substation Transformers Health Index Distribution (Percentage)

1.6 Data Assessment

The data for in service Substation Transformers included inspection results, loading, age, and oil quality, dissolved gas analysis, and Doble tests.

At 84%, the average of DAI of this group was slightly better as compared to the previous year. In 2013, about 60% of the population had inspection data in 2013, whereas roughly 80% of the population had inspections in 2014.

The data gaps for this asset category remained the same as last year. Most of the critical data were already available and included in the Health Index formula. The data gaps included infrared thermography and grounding condition.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Infrared (IR) Thermography	Sealing & Connection	☆☆☆	Cooling system	Poor ventilation/circulation	IR camera scan
			Transformer connection	Poor connection	
Grounding		☆	Grounding electrode conductor	Poor connection	Visual inspection

2 CIRCUIT BREAKERS

2.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

2.1.1 Condition and Sub-Condition Parameters

Table 2-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m				Sub-Condition Parameters
		Oil	SF6	Vacuum	Air Magnetic	
1	Operating Mechanism	14	11	7	14	Table 2-2
2	Contact Performance	7	7	7	7	Table 2-3
3	Arc Extinction	9	5	2	5	Table 2-4
4	Insulation	2	2	2	2	Table 2-5
5	Service Record	5	5	5	5	Table 2-6
De-Rating Factor (DRF)	De-rate based on: Manufacturer					Table 2-11

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Table 2-2 Operating Mechanism Sub-Condition Parameters and Weights (m=1)

n	Sub-condition Parameter	$WCPF_n$				Condition Criteria Table
		Oil	SF6	Vacuum	Air Magnetic	
1	Lubrication	9	7	5	9	Table 2-7
2	Linkage	5	4	2	5	Table 2-7
De-Rating	De-rate based on: Mechanism Type					Table 2-10

Table 2-3 Contact Performance Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Contact Resistance	1	Table 2-9
2	Contact (Inspection)	1	Table 2-7

Table 2-4 Arc Extinction Sub-Condition Parameters and Weights (m=3)

n	Sub-condition Parameter	$WCPF_n$				Condition Criteria Table
		Oil	SF6	Vacuum	Air Magnetic	
1	Tank	1	1			Table 2-7
2	Arc Chute				1	Table 2-7

Table 2-5 Insulation Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Insulation	1	Table 2-7

Table 2-6 Service Record Sub-Condition Parameters and Weights (m=5)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	1	Figure 2-1

2.1.2 Condition Criteria

Visual Inspection

Table 2-7 Visual Inspection Criteria

Score	Condition Description
4	OK
0	Not OK

Measurement

Breaker timing and contact resistance measurements indicate the proper function of the breaker as designed. It is crucial that the breaker meets these specifications for proper and reliable operation

Table 2-8 Resistance Test Criteria

Score	Condition Description
4	Measurement <= 80% Specification limit *
3	Measurement (80%, 100%] specification limit
1	Measurement (100%, 120%] specification limit
0	Measurement > 120% specification limit

* CB type dependent (see Table 2-9)

Table 2-9 Contact Resistance Specification Limit

Breaker Type	Contact Resistance Specification Limit [μΩ]			
	<= 69 kV	110 – 230 kV	345 kV	765 kV
Oil	300	600	900	
Gas	150	150	150	300
Vacuum & Air Magnetic	250	250	250	250

Operating Mechanism

Table 2-10 Multiplier for Operating Mechanism

Multiplier	Operating Type
1	Solenoid
0.9	Spring

Age

Assume that the failure rate Circuit Breakers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 60 years the probability of failures (P_f) for Circuit Breakers are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

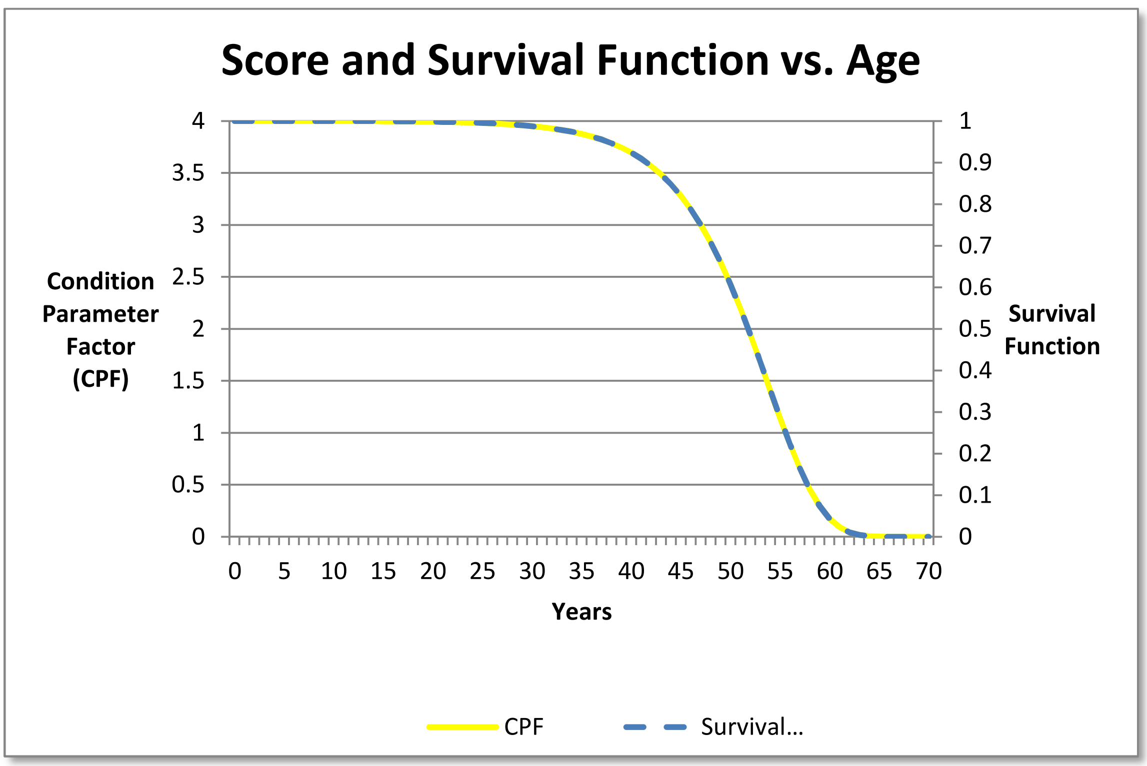

Figure 2-1 Circuit Breakers Age Criteria

De-Rating Factor (DRF)

Table 2-11 De-Rating Criteria

n	Parameter	De-Rating Multiplier (DR_n)	DRF
1	Manufacturer	Table 2-12	$DRF = DR_1$

Table 2-12 Manufacturer De-Rating Multiplier (DR_1)

n	Manufacturer	De-Rating Multiplier
1	Manufacturer X	.25 (Very Poor)
2	Manufacturer Y	.25 (Very Poor)
3	All Other Manufacturers	1

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2.2 Age Distribution

The age distribution for this asset class is shown on the figure below. The average age of the population was 20 years old; however, 15% of the population were 40 years or older.

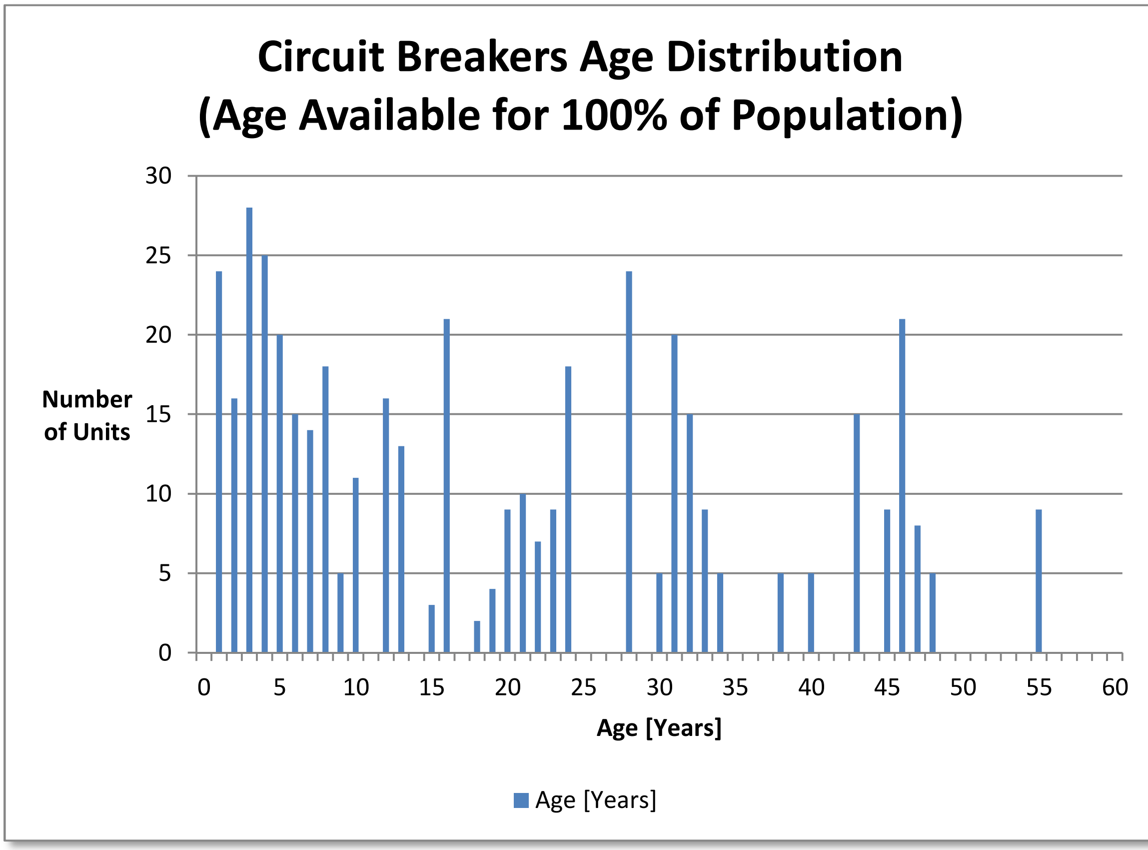

Figure 2-2 Circuit Breakers Age Distribution

2.4 Health Index Results

There were 510 Circuit Breakers at Enersource. Of these, there were 510 units with sufficient data for a Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units are shown in the following diagrams.

The average Health Index for this asset group was 94%. Approximately 2% of the population was found to be in "poor" or "very poor" condition.

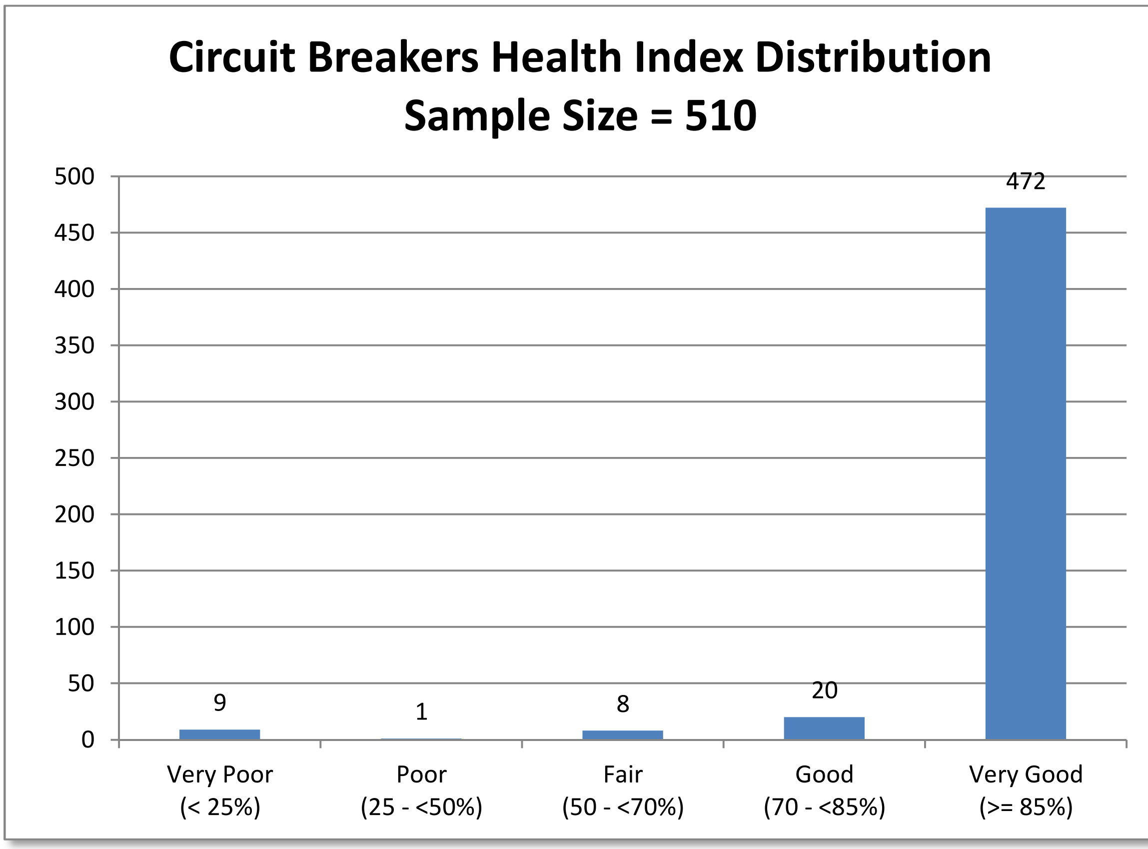

Figure 2-3 Circuit Breakers Health Index Distribution (Unit)

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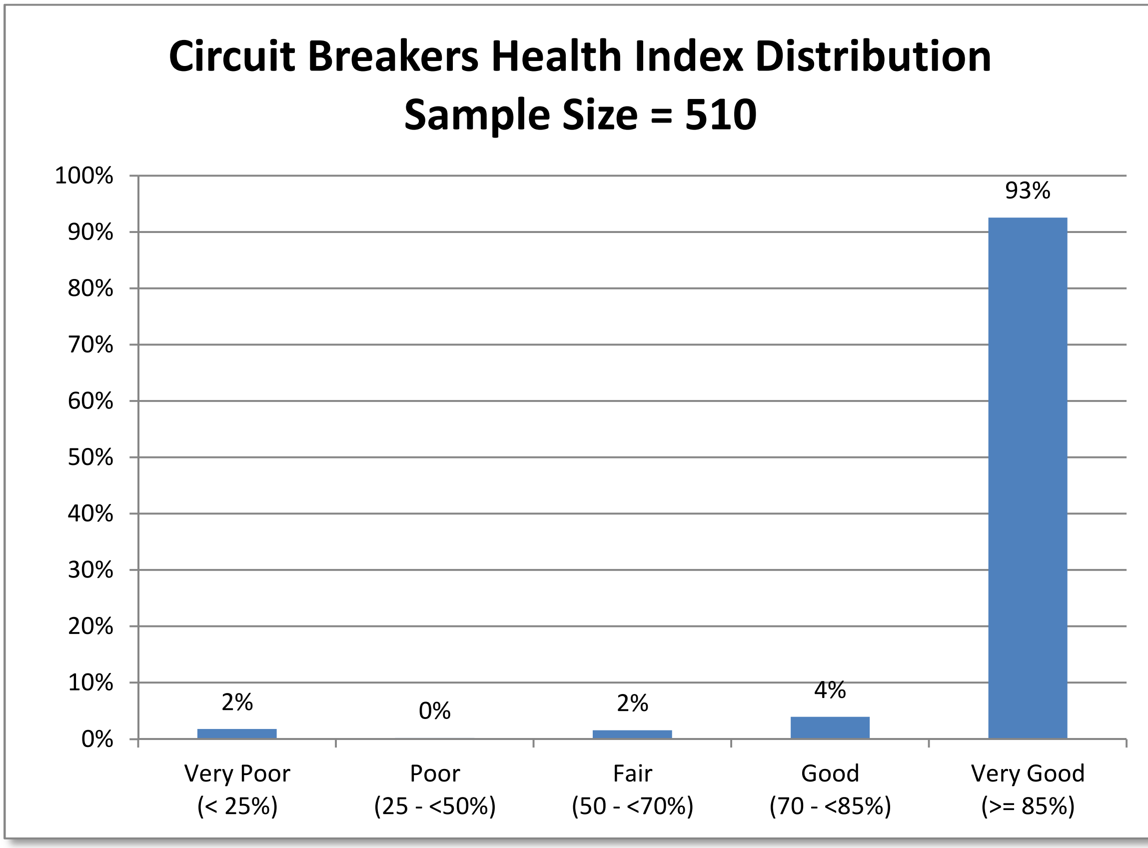

Figure 2-4 Circuit Breakers Health Index Distribution (Percentage)

2.5 Flagged for Action Plan

It is assumed that Circuit Breakers were proactively replaced.

A unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. All units are assumed to have equal criticalities, selected such that a unit with a probability of failure of 70% becomes a candidate for replacement. i.e. Criticality = 1.43.

The flagged for action plan for Circuit Breakers was given below:

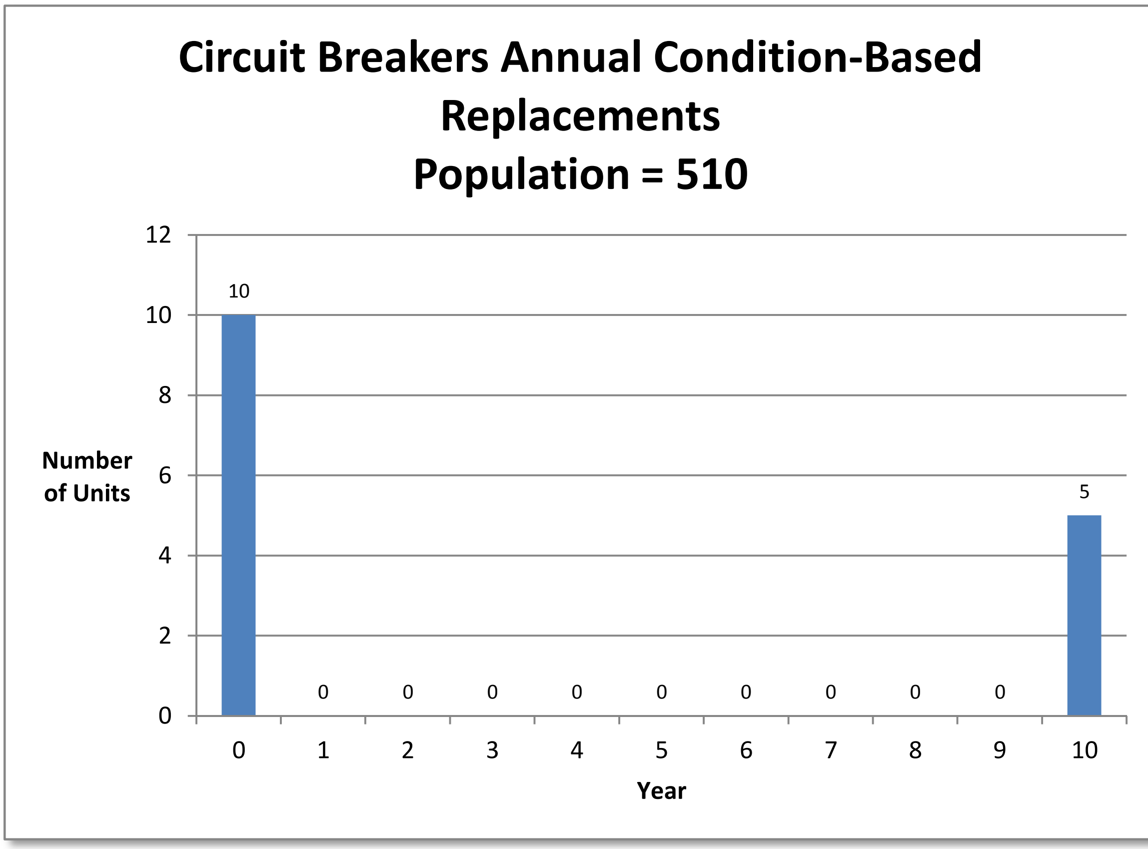

Figure 2-5 Circuit Breakers Flagged for Action Plan

Note that the large number of replacements in the first year. This was mainly due to a certain type that had been found to be prone to failures.

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2.6 Data Analysis

The data available for this asset category included age, contact resistance, and inspection results.

The average DAI for this asset group had improved from 51% last year to 71% this year. This is a result of an improvement in the collection of inspection data.

No new data types had been collected for this asset group. The data gaps remained the same as the past year.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Timing Test Results	Contact Performance	☆☆☆	Close/Trip timing	Trip time too long Close time too long	On-site testing
Arc Contact		☆	Arc contact	Contact erosion	Visual inspection or on-site testing
Vacuum Bottle	Arc Extinction	☆☆☆	Vacuum bottle	Vacuum pressure low	On-site testing
Insulation	Insulation	☆☆	Insulator	Insulation damage	Visual inspection
Operating Counter	Service Record	☆	Circuit breaker	Number of operation cycles a CB has completed since installation	On-site reading (Using breaker operation counter)
Loading		☆	CB load	Loading History: e.g. hourly peak loads	Operation record

3 POLE MOUNTED TRANSFORMERS

3.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

3.1.1 Condition and Sub-Condition Parameters

Table 3-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	1	Table 3-2
2	Connection and Insulation	1	Table 3-3
3	Service Record	2	Table 3-4
De-Rating Factor (DRF)	De-rate based on: Manufacturer, PCB Content		Table 3-8

Table 3-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Tank Corrosion	1	Table 3-5

Table 3-3 Connection and Insulation Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Leak	1	Table 3-5

Table 3-4 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	2	Table 3-6
2	Age	1	Figure 3-1
3	Overloading	1	Table 3-7

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3.1.2 Condition Criteria

Visual Inspection

Table 3-5 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Table 3-6 Visual Inspection Criteria (Overall)

Score	Condition Description
4	EXCELLENT
3	GOOD
2	FAIR / AVERAGE
1	POOR / BAD / MAINTENANCE
0	REPLACE

Overloading

Table 3-7 Overloading Criteria

Score	Condition Description
4	N
0	Y

Age

Assume that the failure rate Pole Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 45 and 60 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

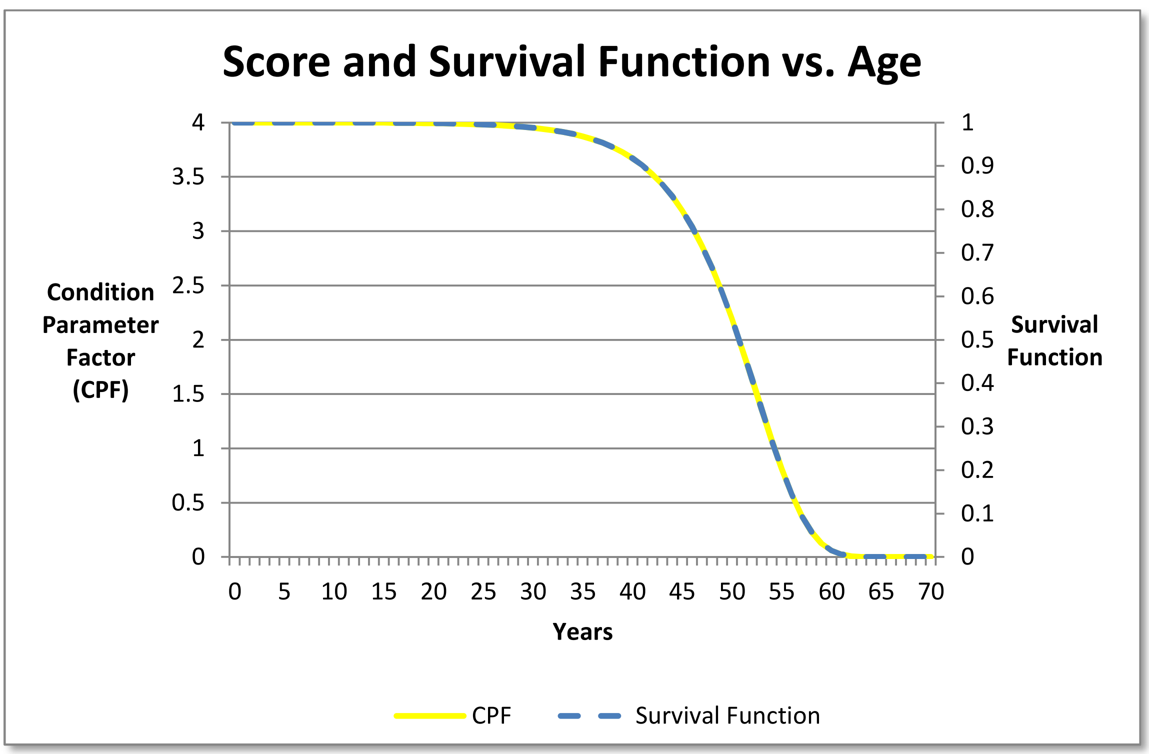

Figure 3-1 Pole Mounted Transformers Age Criteria

De-Rating Factor (DRF)

Table 3-8 De-Rating Criteria

n	Parameter	De-Rating Multiplier (DR_n)	DRF
1	Manufacturer	Table 3-9	DRF = MIN(DR_1 , DR)
2	PCB Content	Table 3-10	

Table 3-9 Manufacturer De-Rating Multiplier (DR_1)

Manufacturer	De-Rating Multiplier
Manufacturer X	0.5
Manufacturer Y	0.9
All Other Manufacturers	1

Table 3-10 PCB De-Rating Multiplier (DR_2)

PCB Content	De-Rating Multiplier
0 < PCB < 2 ppm	1
2 < PCB < 50 ppm	0.5
PCB > = 50 ppm	0.25

3.2 Age Distribution

The average age of the population was 21. Approximately 9% of the population was 45 years or older. The age distribution for this asset class was as follows:

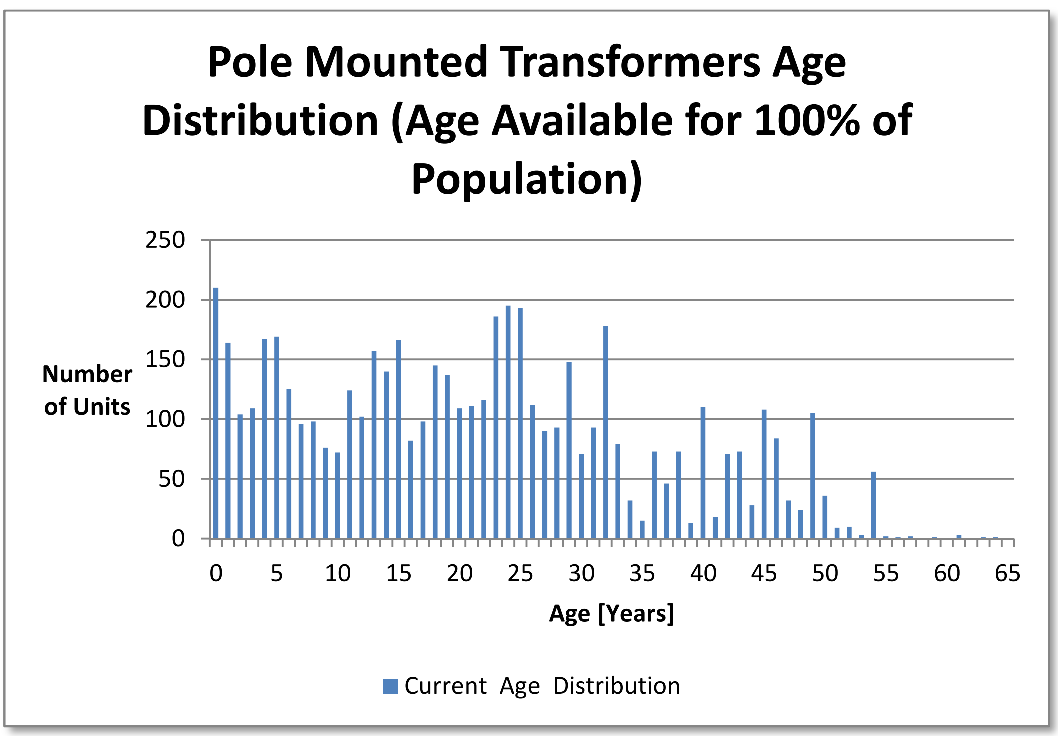

Figure 3-2 Pole Mounted Transformers Age Distribution

3.3 Health Index Results

There were 5346 Pole Mounted Transformers at Enersource. Of these, there were 5346 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 92%. Approximately 2% of the population was found to be in "poor" or "very poor" condition.

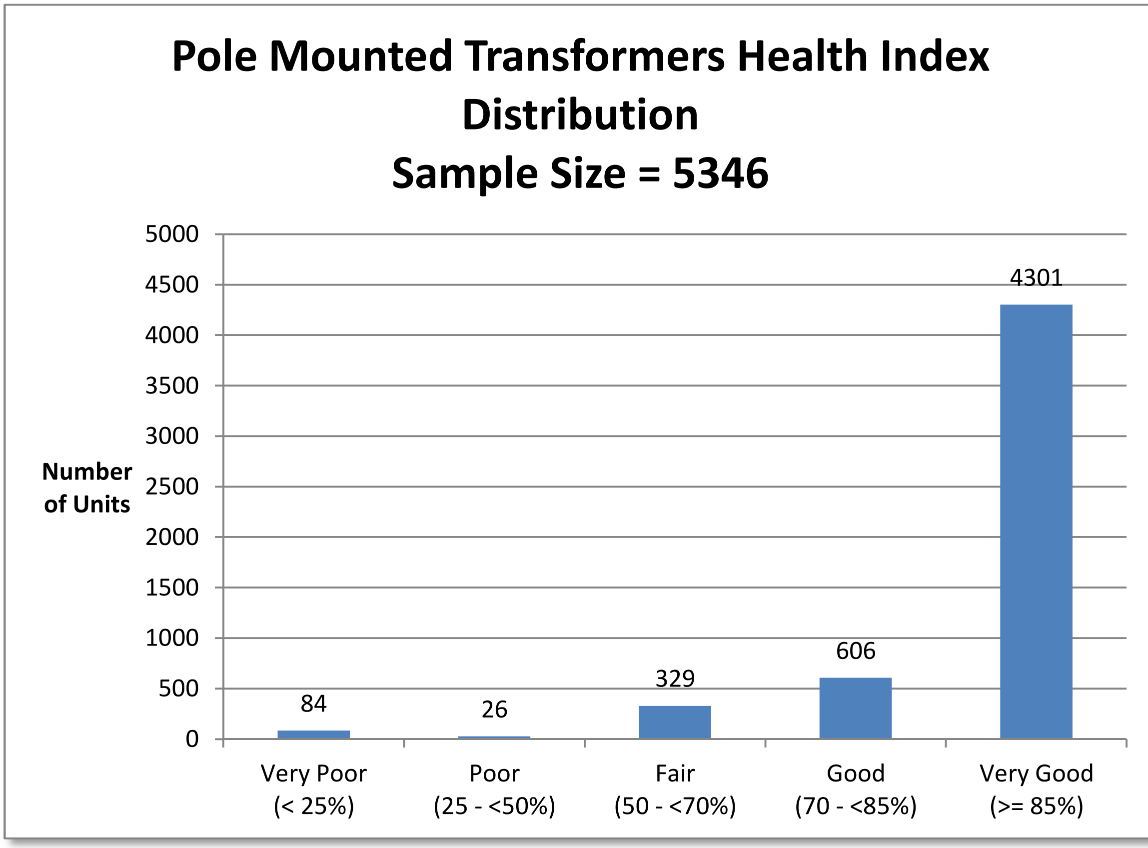

Figure 3-3 Pole Mounted Transformers Health Index Distribution (Unit)

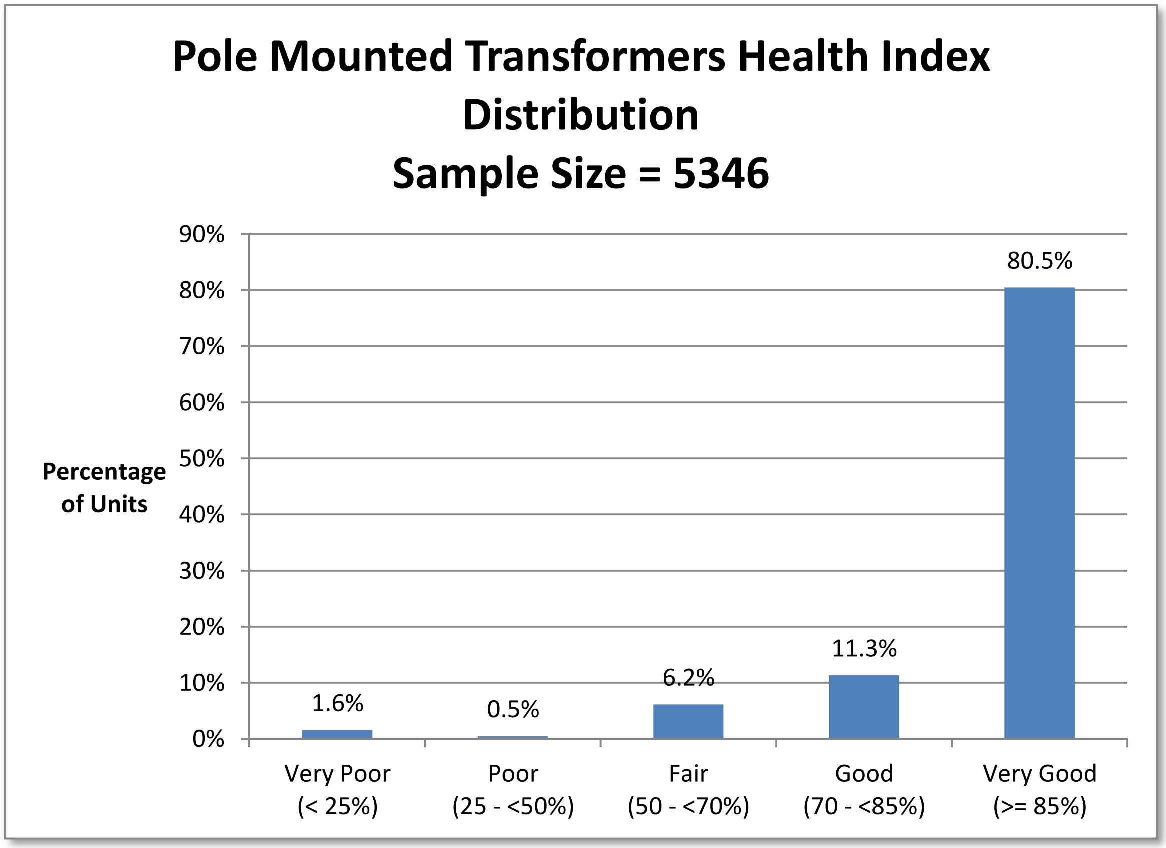

Figure 3-4 Pole Mounted Transformers Health Index Distribution (Percentage)

3.4 Flagged for Action Plan

As it is assumed that Pole Mounted Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate.

The flagged for action plan for Pole Mounted Transformers was as follows:

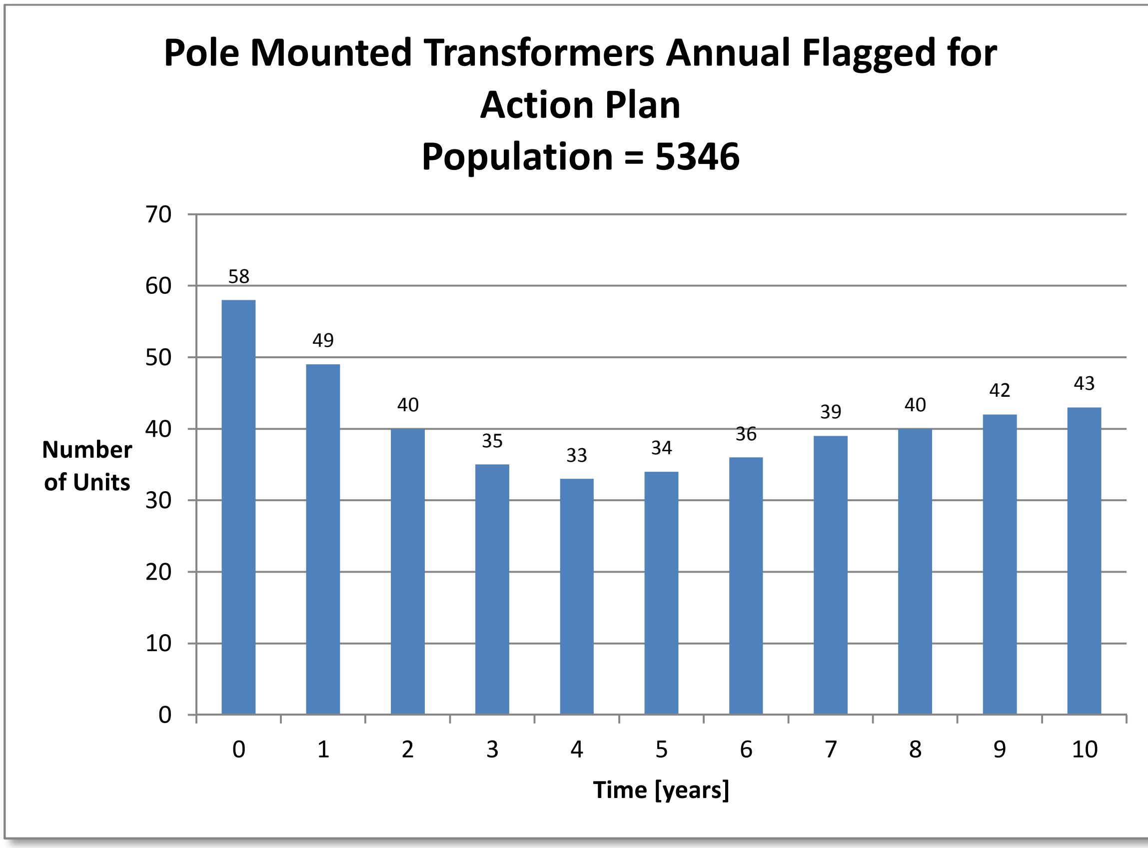

Figure 3-5 Pole Mounted Transformers Flagged for Action Plan

3.5 Data Analysis

Although the average DAI has dropped from 82% last year to 75% this year, in this case this is not a significant cause for concern. This year, the Health Index formula weights were modified to better account for the inspection data and such re-adjustment likely impacted the overall DAI. Nearly all units had inspection information.

The data gaps are the same as that as last year's and are as follows. Note although in this project oil boiling was adopted to indicate overloading condition, more accurate loading information was preferred. So loading still remained to be a data gap item.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Connection	Connection and Insulation	☆☆	Transformer connection	Poor connection	Visual inspection
Grounding		☆	Transformer tank	Poor grounding wire connection	Visual inspection
Bushing		☆☆	Porcelain	Crack / Dirt	Visual inspection
Loading	Service Record	☆☆	Transformer load	Loading History: e.g. hourly peak loads	Operation record

According to Enersource, the condition status of connection, grounding and insulator bushing was inspected during infra-red tests. In this study, such information was however not stored in a way that could be easily extracted in electronic format. It is recommended that in the future study, the infra-red test data regarding the above parameters be stored and sorted out in a standardized and systematic way, so as to be incorporated in Health Index formulation.

4 PAD MOUNTED TRANSFORMERS

4.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

4.1.1 Condition and Sub-Condition Parameters

Table 4-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	1	Table 4-2
2	Connection and Insulation	1	Table 4-3
3	Service Record	2	Table 4-4
De-Rating Factor (DRF)	De-rate based on: Manufacturer, PCB Content		Table 4-7

Table 4-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Corrosion	5	Table 4-5
2	Paint	2	Table 4-5
3	Access	1	Table 4-5
4	Base	2	Table 4-5

Table 4-3 Connection and Insulation Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Leak	1	Table 4-5

Table 4-4 Service Record Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	2	Table 4-6
2	Age	1	Figure 4-1

4.1.2 Condition Criteria

Visual Inspection

Table 4-5 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Table 4-6 Visual Inspection Criteria (Overall)

Score	Condition Description
4	EXCELLENT
3	GOOD
2	FAIR / AVERAGE
1	POOR / BAD / MAINTENANCE
0	REPLACE

Age

Assume that the failure rate Pad Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

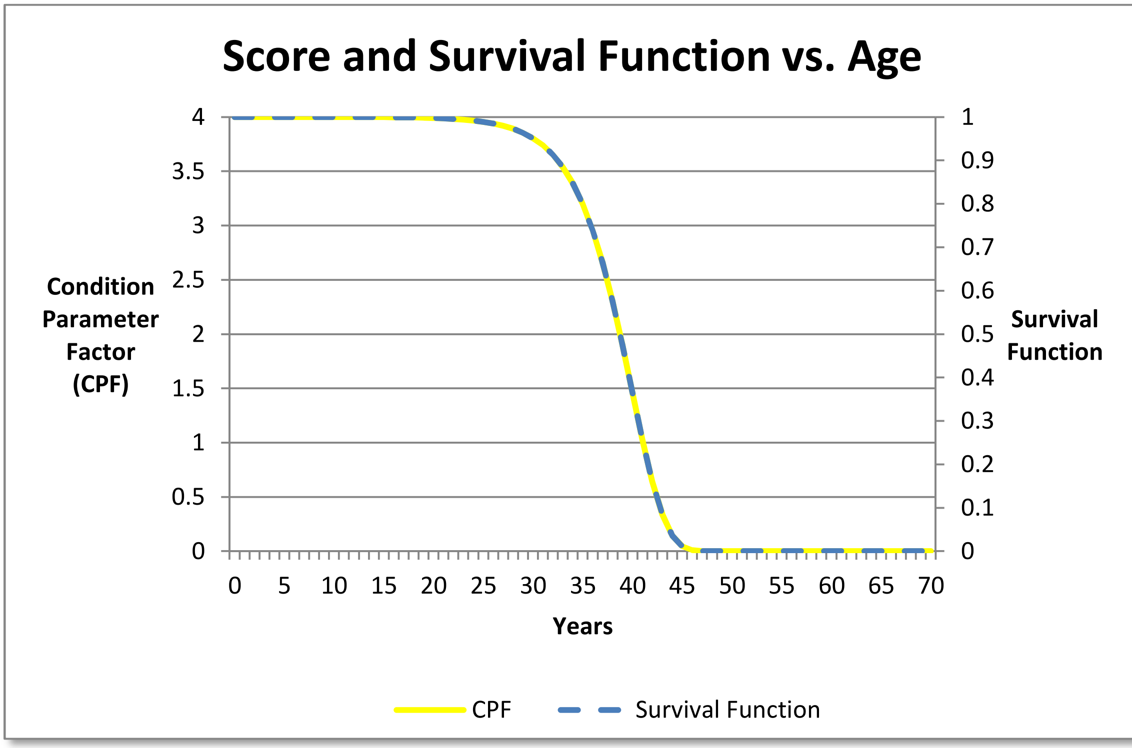

Figure 4-1 Pad Mounted Transformers Age Criteria

De-Rating Factor (DRF)

Table 4-7 De-Rating Criteria

n	Parameter	De-Rating Multiplier (DR_n)	DRF
1	Manufacturer	Table 4-8	DRF = MIN(DR_1 , DR_2)
2	PCB Content	Table 4-9	

Table 4-8 Manufacturer De-Rating Multiplier (DR_1)

Manufacturer	De-Rating Multiplier
Manufacturer X	0.5
Manufacturer Y	0.9
Manufacturer Z	0.9
All Other Manufacturers	1

Table 4-9 PCB De-Rating Multiplier (DR_2)

PCB Content	De-Rating Multiplier
0 < PCB < 2 ppm	1
2 < PCB < 50 ppm	0.5
PCB > = 50 ppm	0.25

4.2 Age Distribution

Single Phase Pad Mounted Transformers

The average age of all single phase units was 21 years. Approximately 10% of the population was 35 years or older.

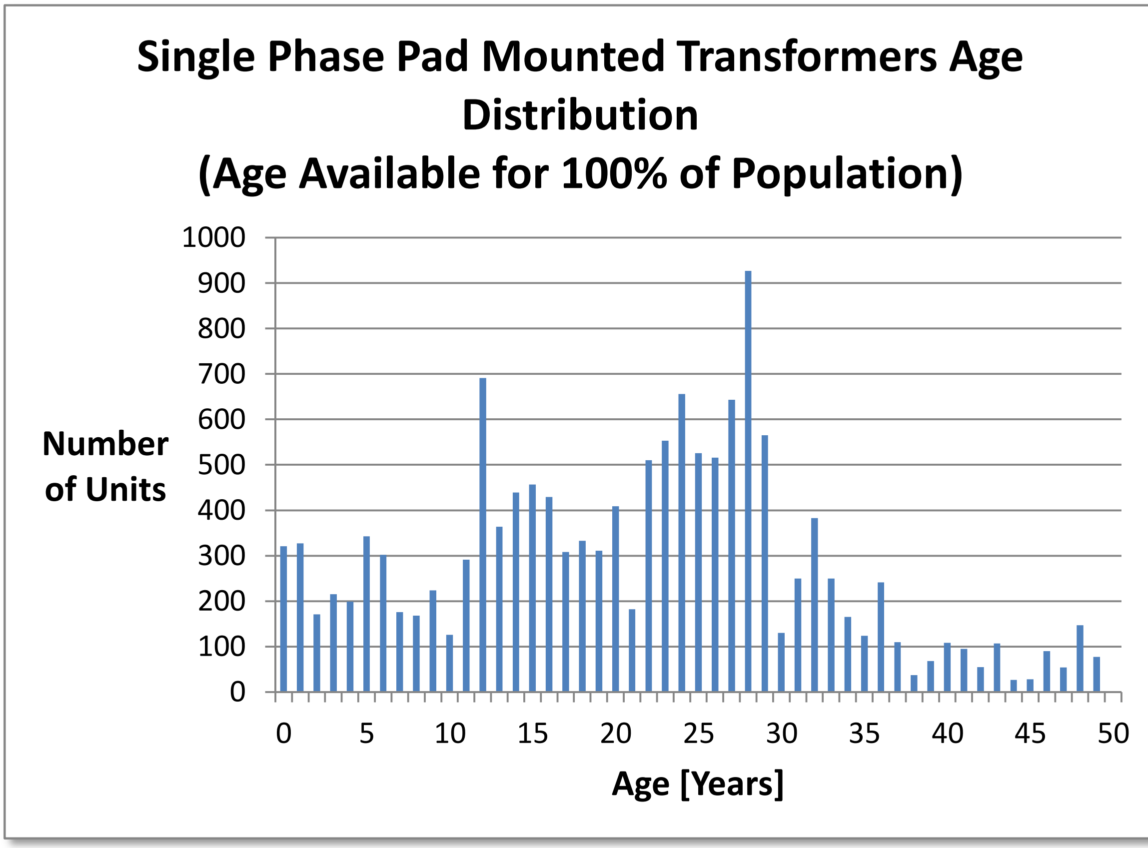

Figure 4-2 Single Phase Pad Mounted Transformers Age Distribution

Three Phase Pad Mounted Transformers

The average age of all three phase units was 16 years. Approximately 5% of the population was 35 years or older.

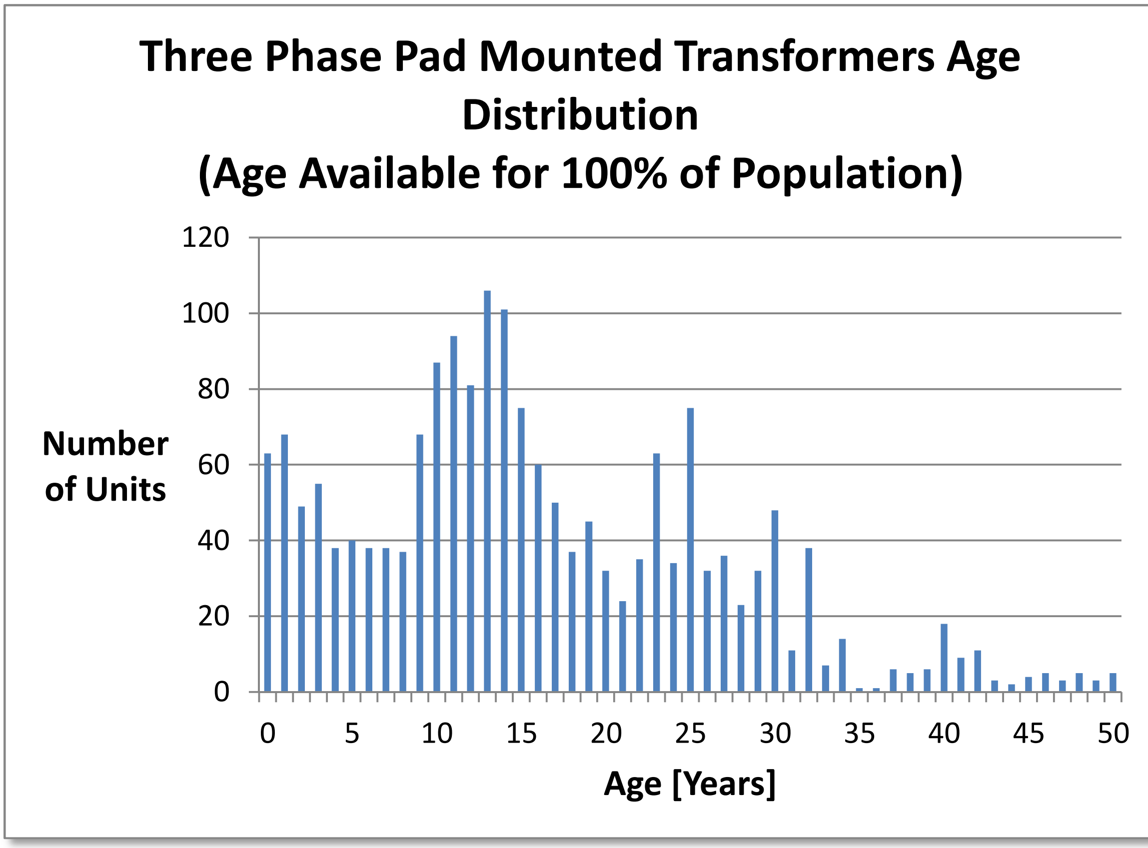

Figure 4-3 Three Phase Pad Mounted Transformers Age Distribution

4.3 Health Index Results

Single Phase Pad Mounted Transformers

There were a total of 14242 Single Phase Pad Mounted Transformers at Enersource. Of these, there were 14242 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 87%. Approximately 5% of the population was found to be in “poor” or “very poor” condition.

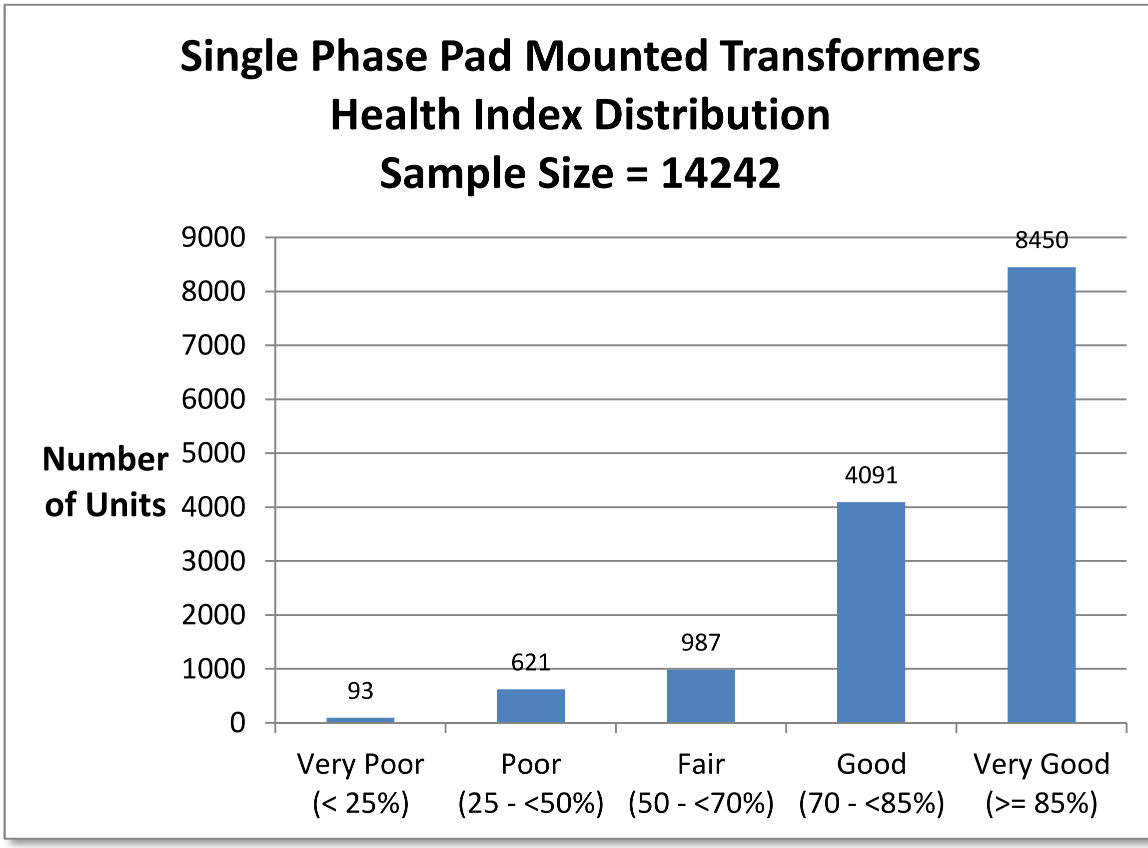

Figure 4-4 Single Phase Pad Mounted Transformers Health Index Distribution (Unit)

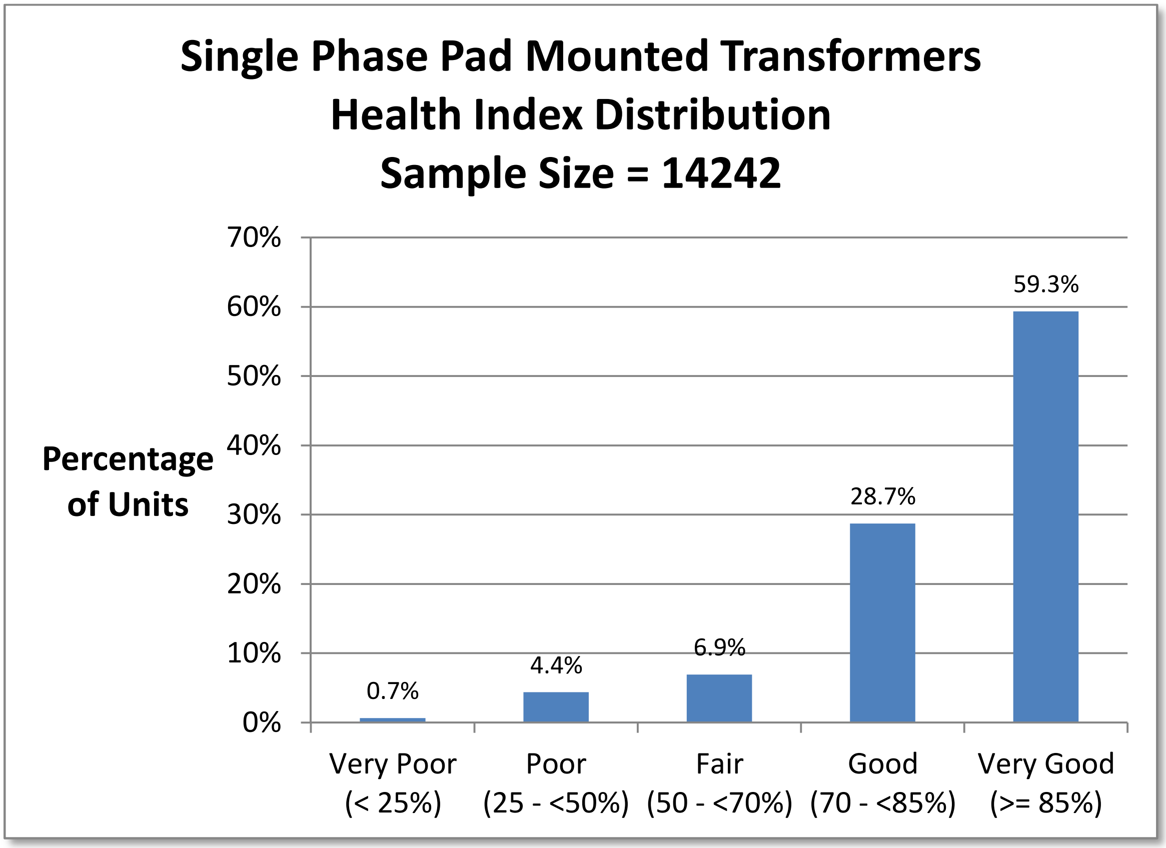

Figure 4-5 Single Phase Pad Mounted Transformers Health Index Distribution (Percentage)

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Three Phase Pad Mounted Transformers

There were a total of 1821 Three Phase Pad Mounted Transformers at Enersource. Of these, there were 1821 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 94%. Nearly 3% of the population was found to be in "poor" or "very poor" condition.

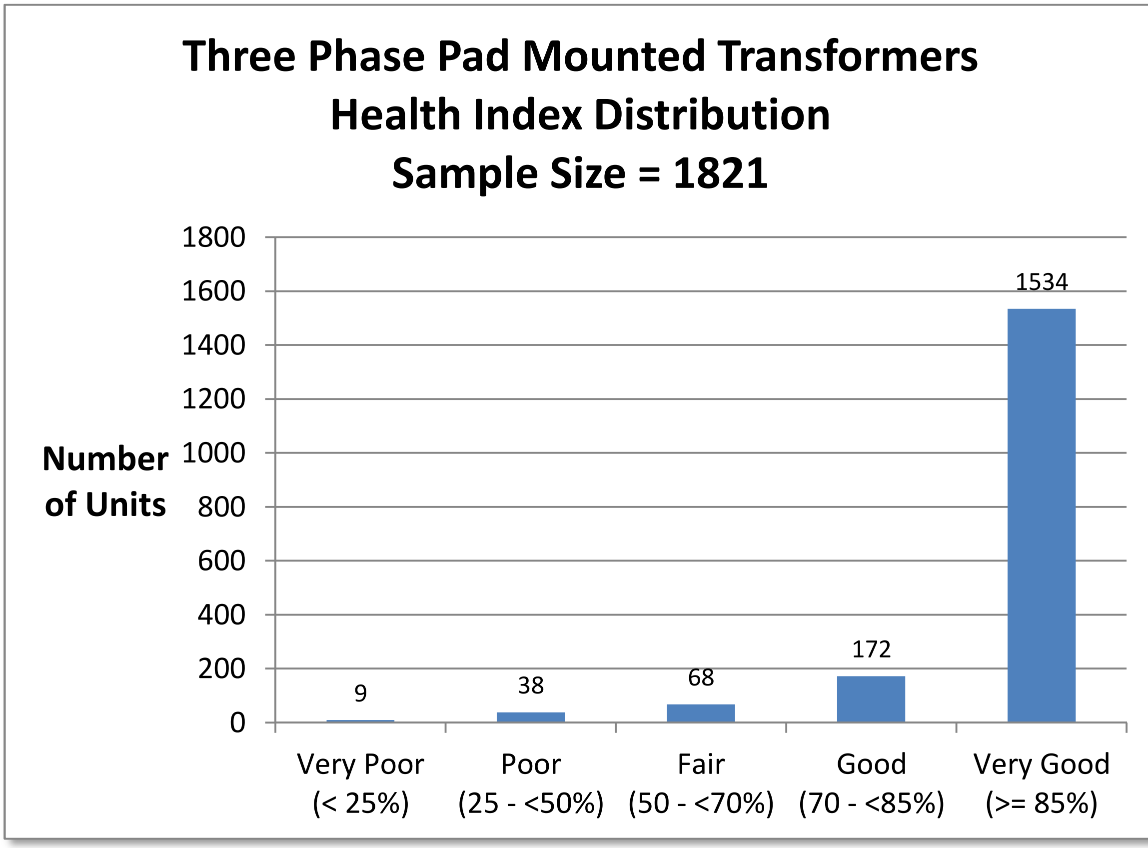

Figure 4-6 Three Phase Pad Mounted Transformers Health Index Distribution (Unit)

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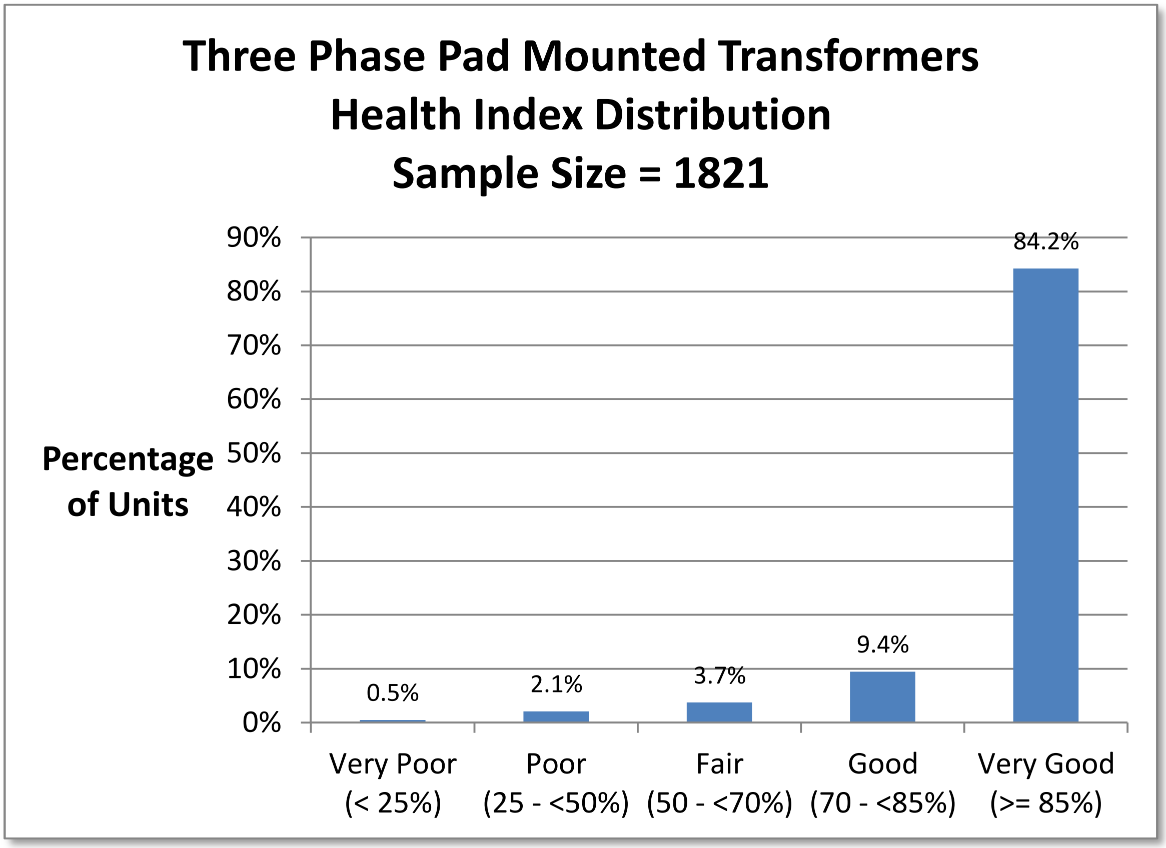

Figure 4-7 Three Phase Pad Mounted Transformers Health Index Distribution (Percentage)

4.4 Flagged for Action Plan

As it is assumed that Pad Mounted Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate.

Single Phase Pad Mounted Transformers

The replacment plan was as follows:

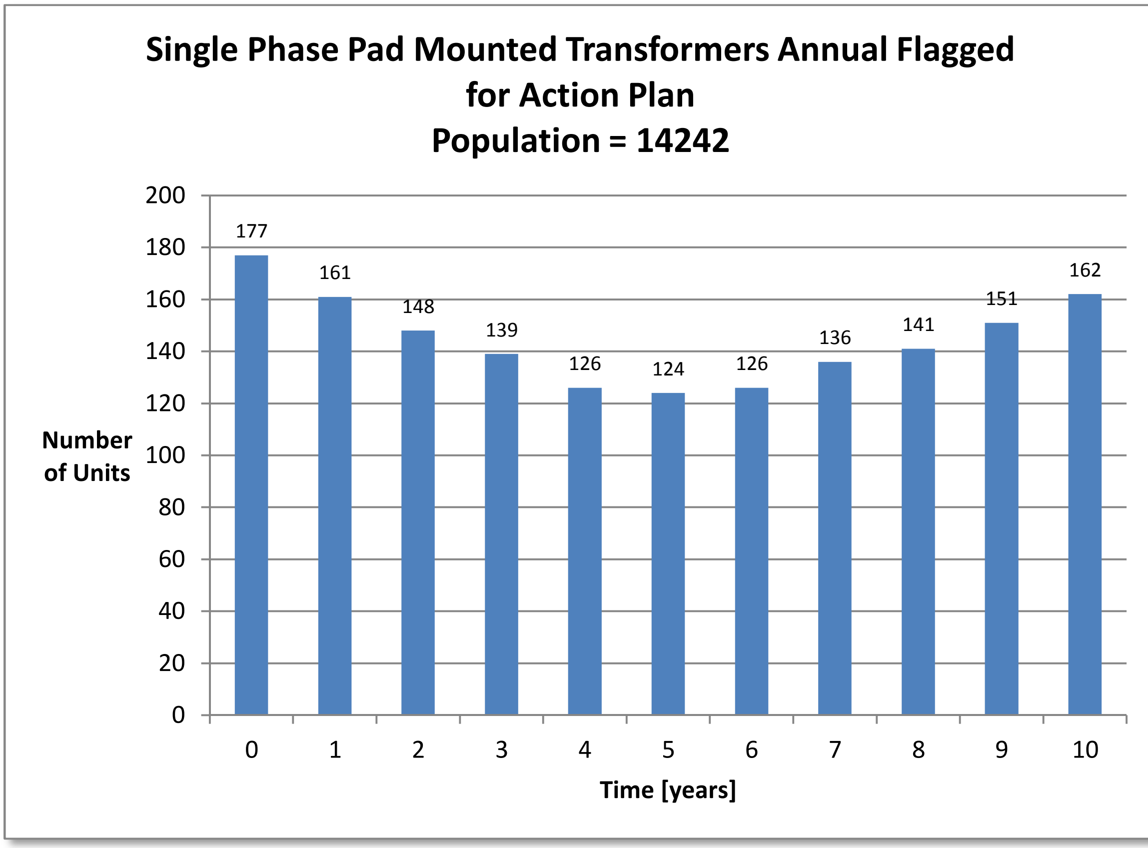

Figure 4-8 Single Phase Pad Mounted Transformers Flagged for Action Plan

Three Phase Pad Mounted Transformers

The replacment plan was as follows:

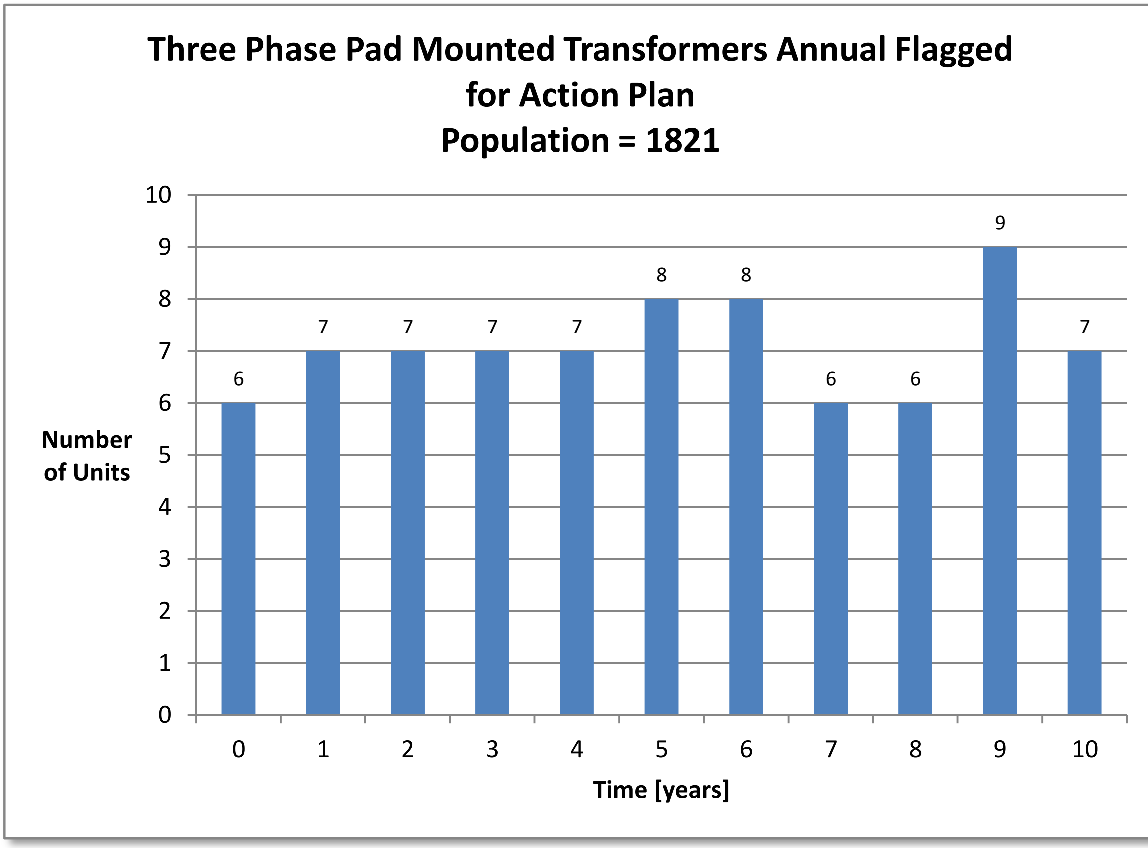

Figure 4-9 Three Phase Pad Mounted Transformers Flagged for Action Plan

4.5 Data Analysis

The average DAI has dropped from 100% to 89% for 1-phase and 70% for 3-phase year this. This is because additional visual inspection data (e.g. paint, access, foundation condition), were added to the Health Index formula.

The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Connection	Connection and Insulation	☆☆☆	Transformer connection	Poor connection / hot spots	Visual inspection or IR scan
Grounding		☆	Transformer tank	Poor grounding wire connection	Visual inspection
Bushing		☆☆	Porcelain	Crack / Dirt	Visual inspection
Loading	Service Record	☆☆	Transformer load	Loading History: e.g. hourly peak loads	Operation record

According to Enersource, the condition status of connection, grounding and insulator bushing is inspected during infra-red tests. In this study, such information was however not stored in a way that could be easily extracted in electronic format. It is recommended that in the future study, the infra-red test data regarding the above parameters be stored and sorted out in a standardized and systematic way, so as to be incorporated in Health Index formulation.

5 VAULT TRANSFORMER

5.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

5.1.1 Condition and Sub-Condition Parameters

Table 5-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical condition	3	Table 5-2
2	Connection and Insulation	2	Table 5-3
3	Service Record	4	Table 5-4
De-Rating Factor (DRF)	De-rate based on PCB Content		Table 5-8

Table 5-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Corrosion	8	Table 5-5
2	Access	1	Table 5-5
3	Housekeeping (water)	1	Table 5-5

Table 5-3 Connection & Insulation Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Leak	1	Table 5-5

Table 5-4 Service Record Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	2	Table 5-6
2	Age	1	Figure 5-1
3	Loading (oil boiling over)	1	Table 5-7

5.1.2 Condition Criteria

Visual Inspections

Table 5-5 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Table 5-6 Visual Inspection Criteria (Overall)

Score	Condition Description
4	EXCELLENT
3	GOOD
2	FAIR / AVERAGE
1	POOR / BAD / MAINTENANCE
0	REPLACE

Overloading

Table 5-7 Overloading Criteria

Score	Condition Description
4	N
0	Y

Age

Assume that the failure rate Vault Transformer exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

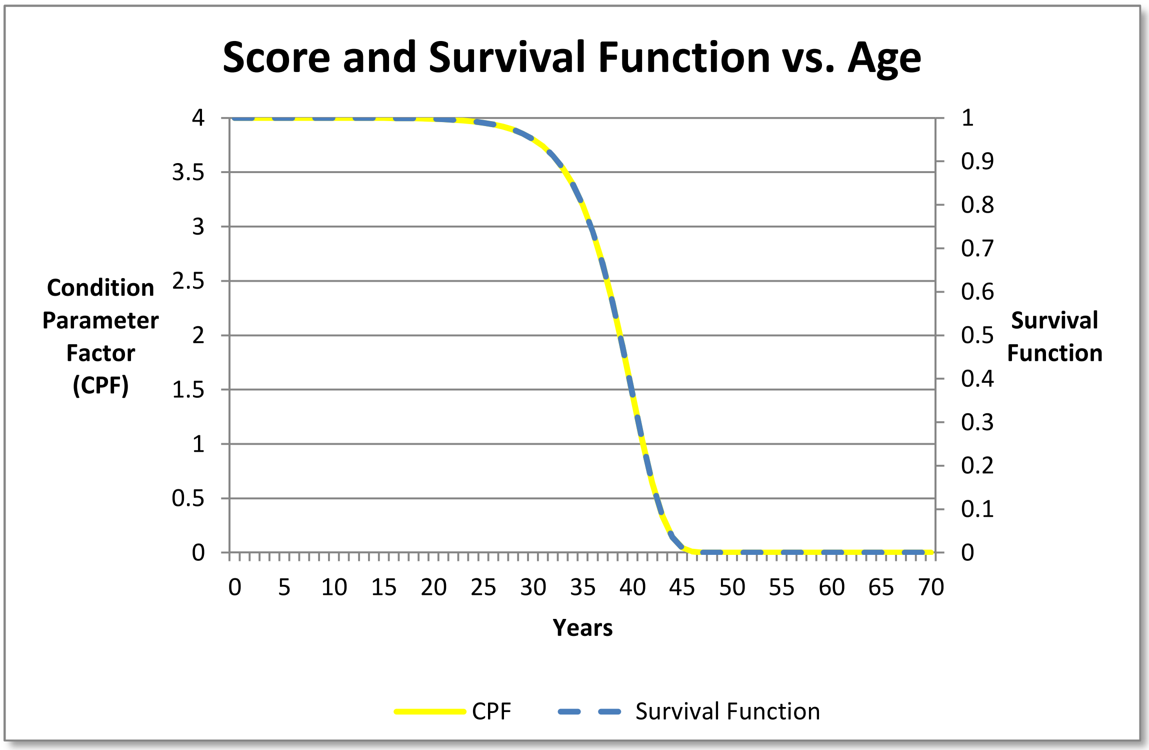

Figure 5-1 Vault Transformer Age Criteria

De-Rating Factor (DRF)

Table 5-8 PCB De-Rating Multiplier

PCB Content	De-Rating Multiplier
0 < PCB < 2 ppm	1
2 < PCB < 50 ppm	0.5
PCB > = 50 ppm	0.25

5.2 Age Distribution

The average age of all single phase units was 27 years. Approximately 23% of the population was 35 years or older.

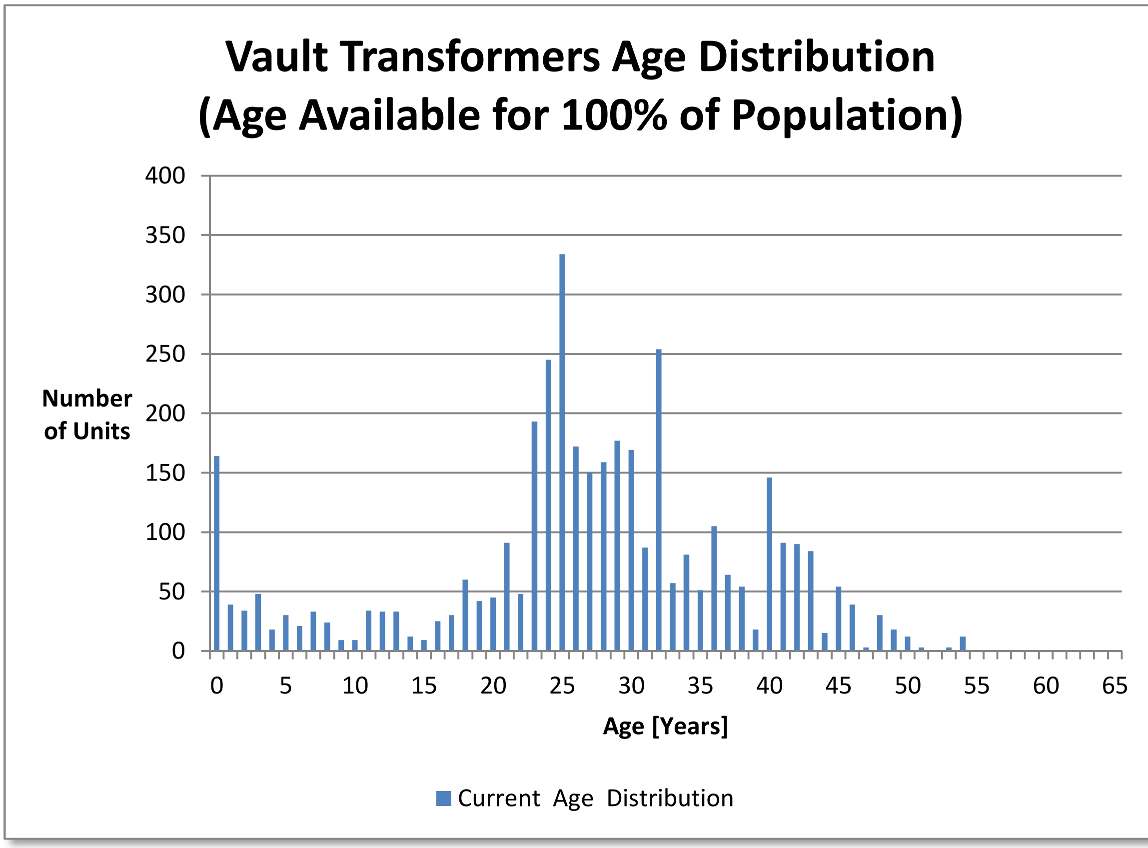

Figure 5-2 Vault Transformer Age Distribution

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5.3 Health Index Results

There were 3861 Vault Transformers at Enersource. Of these, there were 3861 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 87%. Approximately 9% of the population was in "poor" or "very poor" condition.

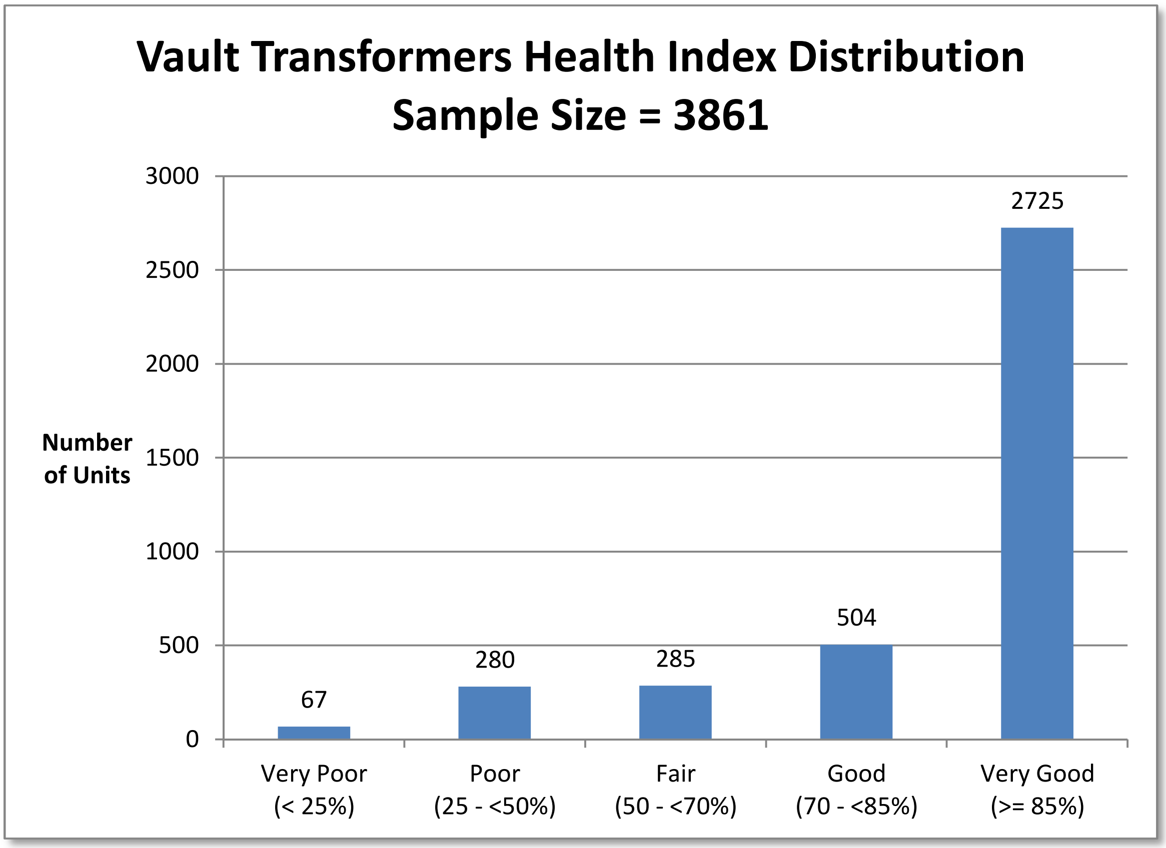

Figure 5-3 Vault Transformer Health Index Distribution (Unit)

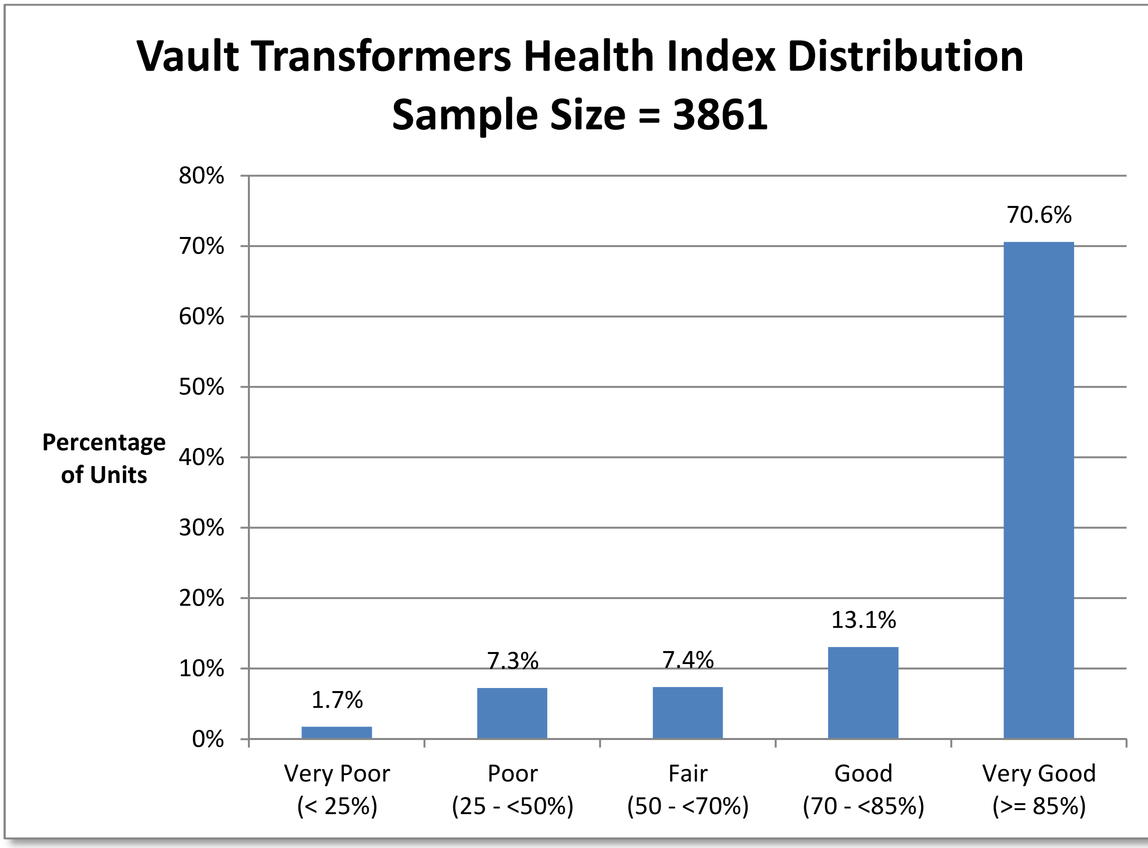

Figure 5-4 Vault Transformer Health Index Distribution (Percentage)

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5.4 Flagged for Action Plan

As it is assumed that Vault Transformer were reactively replaced, the flagged for action plan was based on the asset failure rate.

The Flagged for Action Plan was as follows:

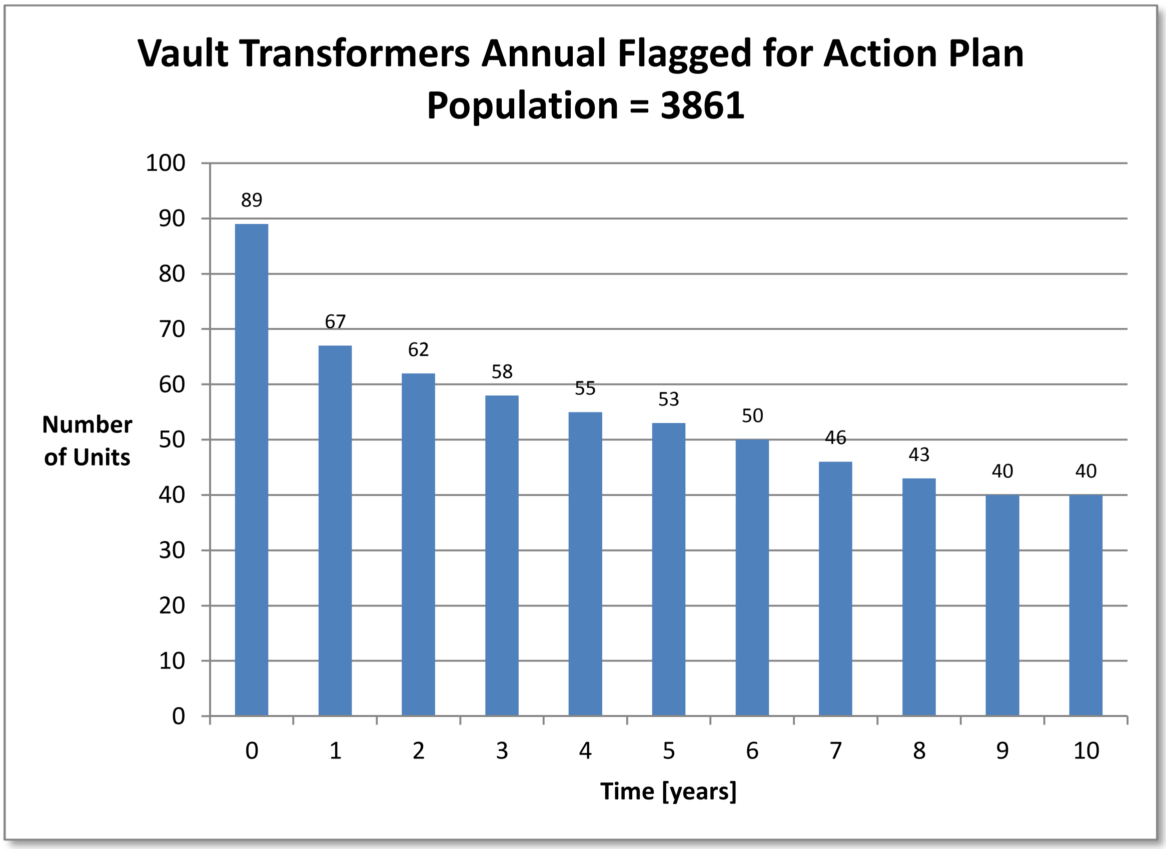

Figure 5-5 Vault Transformer Flagged for Action Plan

5.5 Data Analysis

The condition data for this asset category included visual inspection results and age. The average DAI has improved from 76% to 78% this year.

Although transformer overloading condition was indirectly assumed by determining if oil showed signs of boiling over, more precise loading data would be preferred. It therefore remains as a data gap.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Connection	Connection & Insulation	☆☆☆	Transformer connection	Poor connection / hot spots	Visual inspection or IR scan
Loading	Service Record	☆☆	Transformer load	Loading History: e.g. hourly peak loads	Operation record

6 PAD MOUNTED SWITCHGEAR

6.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

6.1.1 Condition and Sub-Condition Parameters

Table 6-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	2	Table 6-2
2	Switch/Fuse Condition	1	Table 6-3
3	Insulation	4	Table 6-4
4	Service Record	4	Table 6-5

Table 6-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Corrosion	6	Table 6-6
2	Concrete Pad	1	Table 6-6
3	Base (Grade/Fill)	1	Table 6-6
4	Excess Moisture	2	Table 6-6

Table 6-3 Switch/Fuse Sub-Condition Parameters and Weights (m=2)

N	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Arc Suppressor	3	Table 6-6
2	Fuse holders	1	Table 6-6

Table 6-4 Insulation Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Support Insulators	1	Table 6-6
2	Switch Insulators	1	Table 6-6
3	Barriers	1	Table 6-6
4	Cable Terminations	1	Table 6-6
5	Connections	1	Table 6-6
6	Discoloration	1	Table 6-6
7	Tracking	1	Table 6-6

Table 6-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	2	Table 6-7
2	Overheating	2	Table 6-6
2	Age	1	Figure 6-1

6.1.2 Condition Criteria

Visual Inspections

Table 6-6 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Score	Condition Description
4	OK or no inspection description
0	Not OK or any defect inspection description

Table 6-7 Visual Inspection Criteria (Life Grade)

Score	Condition Description (per Enersource Inspection Records)
4	5 (Best)
3	4
2	3
1	2
0	1 (Worst)

Age

Assume that the failure rate Pad Mounted Switchgear exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \; P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 25 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

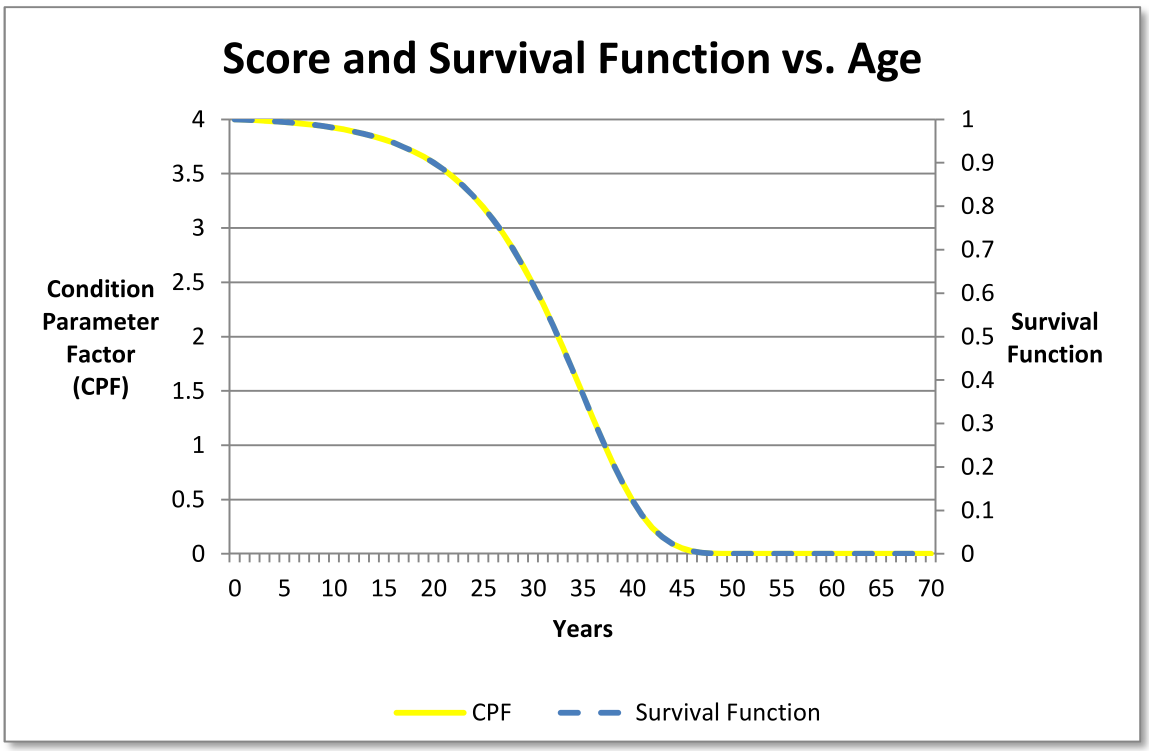

Figure 6-1 Pad Mounted Switchgear Age Criteria

6.2 Age Distribution

The average age of all units was 19 years. Approximately 37% of the population was 25 years or older.

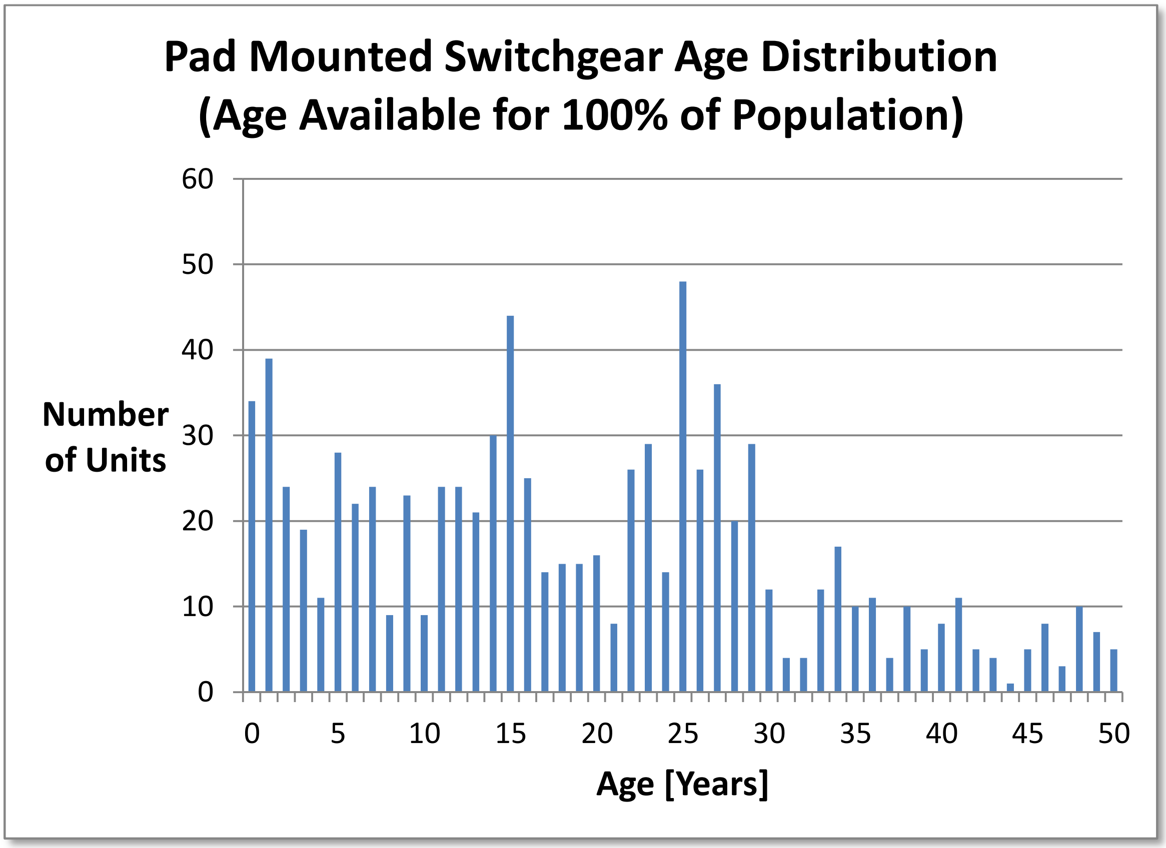

Figure 6-2 Pad Mounted Switchgear Age Distribution

6.3 Health Index Results

There were 862 Pad Mounted Switchgear at Enersource. Of these, there were 862 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 84%. About 8% of the population was in “poor” or “very poor” condition.

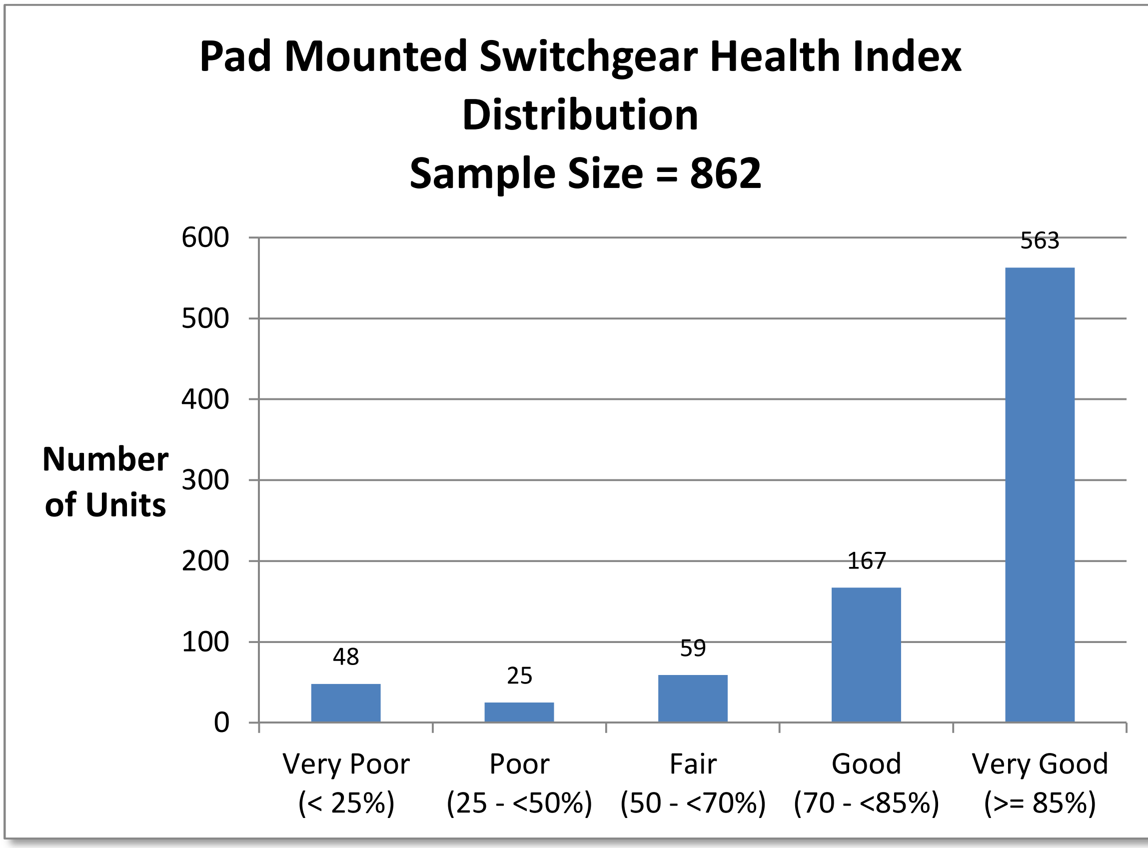

Figure 6-3 Pad Mounted Switchgear Health Index Distribution (Unit)

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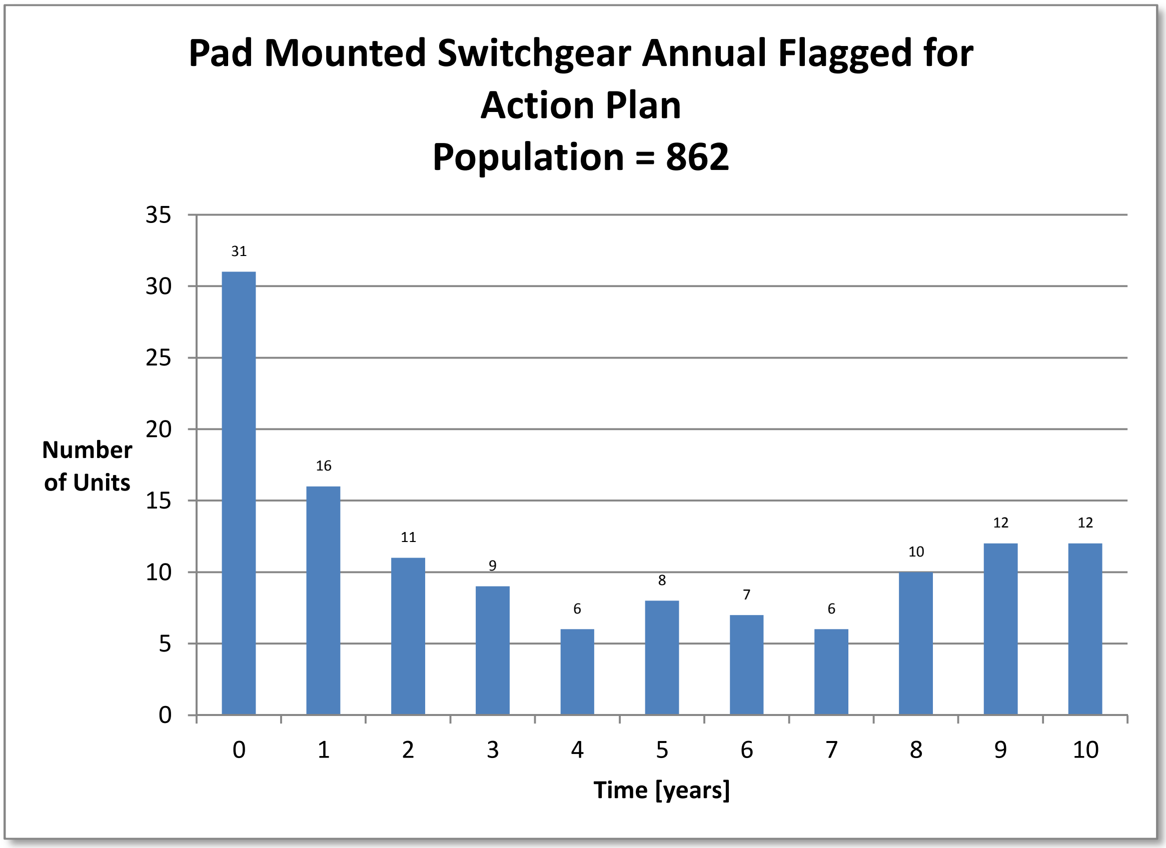

Figure 6-4 Pad Mounted Switchgear Health Index Distribution (Percentage)

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6.4 Flagged for Action Plan

As it is assumed that Pad Mounted Switchgear were reactively replaced, the flagged for action plan was based on the asset failure rate.

The Flagged for Action Plan was as follows:

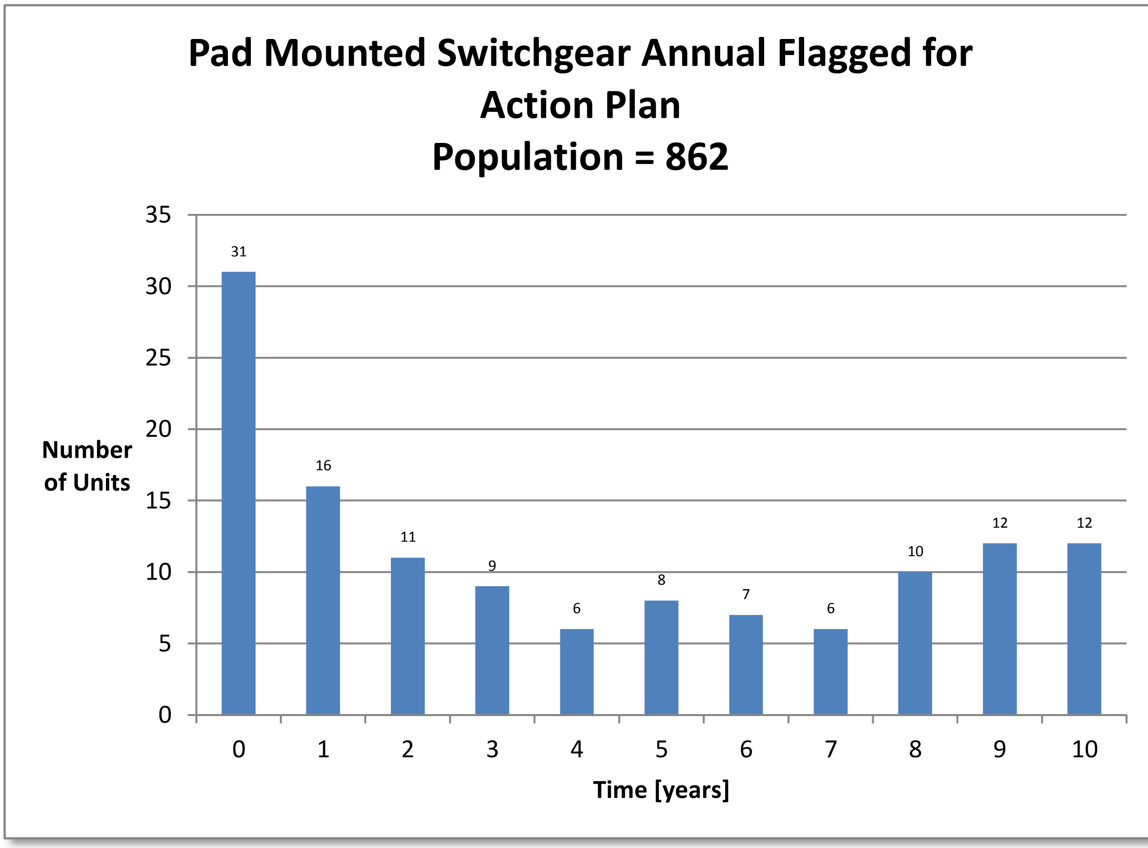

Figure 6-5 Pad Mounted Switchgear Flagged for Action Plan

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6.5 Data Analysis

The average DAI of all units was 39%, a drop from last year's 59%. Age was available for all units. Inspection data, gathered from linemen inspections and dry ice cleaning, increased from 50% last year to 56% this year. The drop in DAI is a result of incorporating more inspection data (e.g. water in vault, foundation condition, insulation condition, connection condition, overheating) into the HI formula. Such information should be collected for all units to improve the DAI.

Data Gap

There were no data gaps for this asset group because all condition data required by the Health Index formula were collected through inspections and dry ice cleaning. It should be noted, however, that only half of the population had inspection data. Such data should be collected for the remainder of the population.

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7 OVERHEAD LINE SWITCHES

This study includes four sub-categories of overhead line switches: 44 kV, 27.6 kV, Inline, and Motorized.

Note that Enersource continues to validate the classification and population counts of its overhead line switches. This assessment is based on the best available information to date.

7.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

7.1.1 Condition and Sub-Condition Parameters

Table 7-1 Condition Parameter and Weights

m	Condition parameter	WCP_m		Sub-Condition Parameters
		Manual	Motorized	
1	Operating Mechanism	4	4	Table 7-2
2	Contact Performance	3	3	Table 7-3
3	Insulation	2	2	Table 7-4
4	Service Record	4	4	Table 7-5

Table 7-2 Operating Mechanism Sub-Condition Parameters and Weights

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Operations Record	1	Table 7-7

Table 7-3 Contact Performance Sub-Condition Parameters and Weights

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Switch Blade	1	Table 7-6

Table 7-4 Insulation Sub-Condition Parameters and Weights

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Insulator	1	Table 7-6

Table 7-5 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	1	Figure 7-1

7.1.2 Condition Criteria

Operations Record

Table 7-6 Operations Records Criteria

Score	Condition Description
4	Operated in Last Year
0	Not Operated in Last Year

Visual Inspections

Table 7-7 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age

Assume that the failure rate Overhead Line Switches exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for 27.6 kV, 44 kV, and Inline Switches are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

For motorized switches, the ages of 25 and 35 are used.

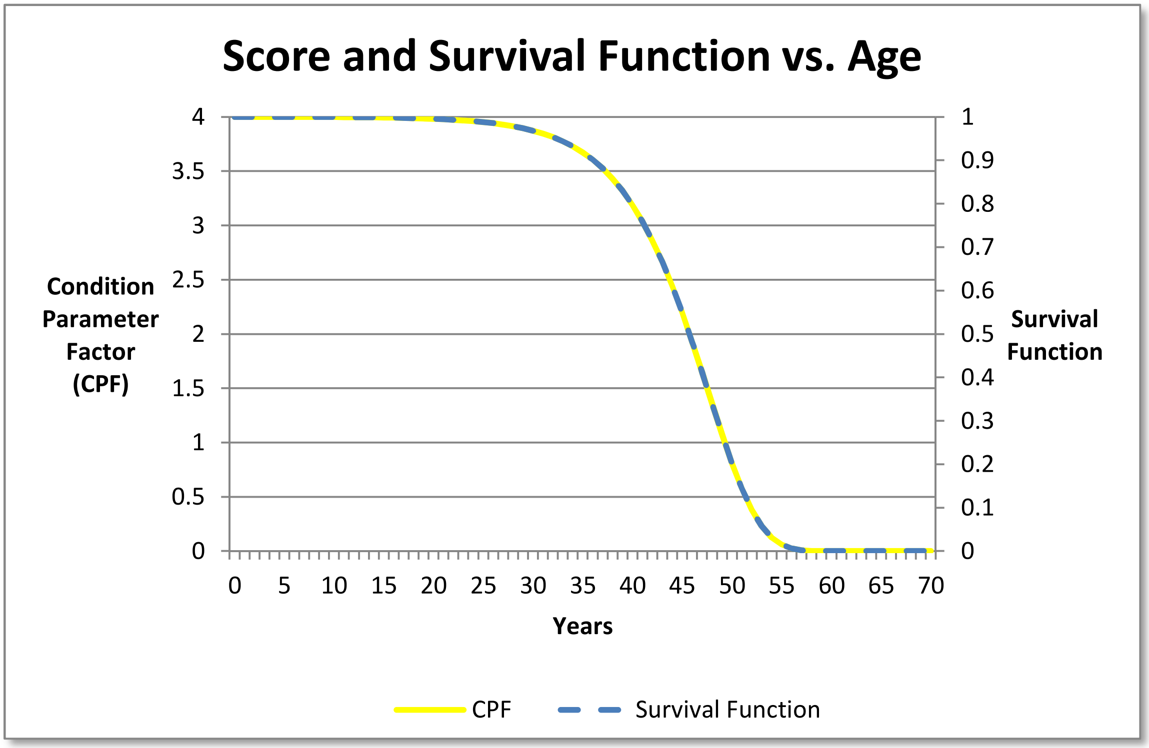

Figure 7-1 Overhead Line Switches Criteria (Non-Motorized and Inline)

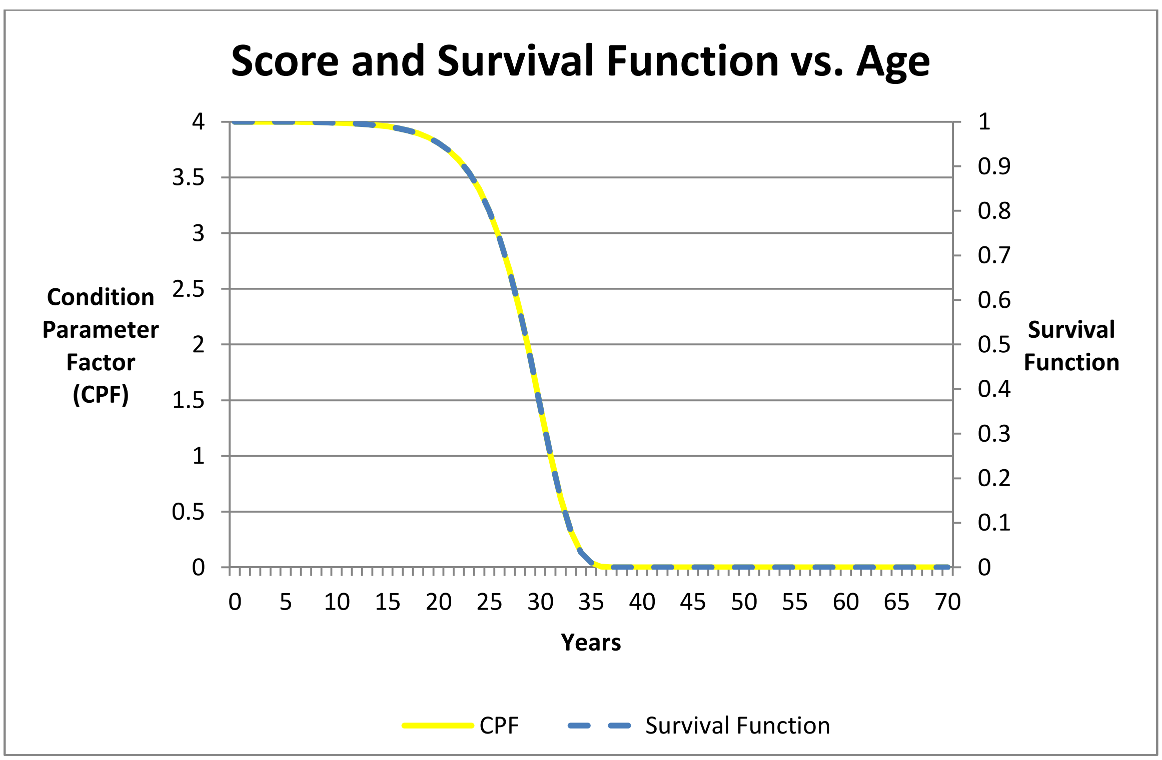

Figure 7-2 Overhead Line Switches Criteria (Motorized)

7.2 Age Distribution

44 kV Load Break Switches

The average age of all units was 20 years. Approximately 9% of the population was 40 years or older.

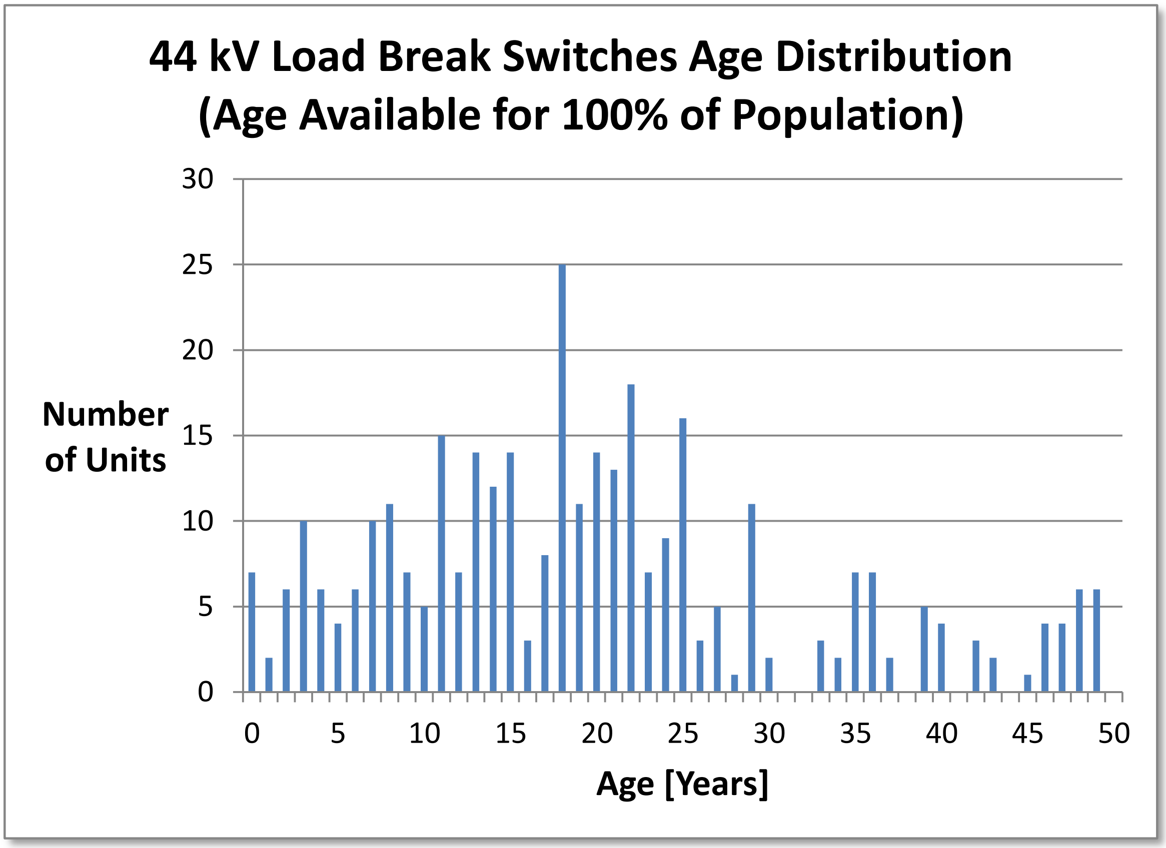

Figure 7-3 44 kV Load Break Switches Age Distribution

27.6 kV Load Break Switches

The average age of all units was 18 years. Approximately 6% of the population was 40 years or older.

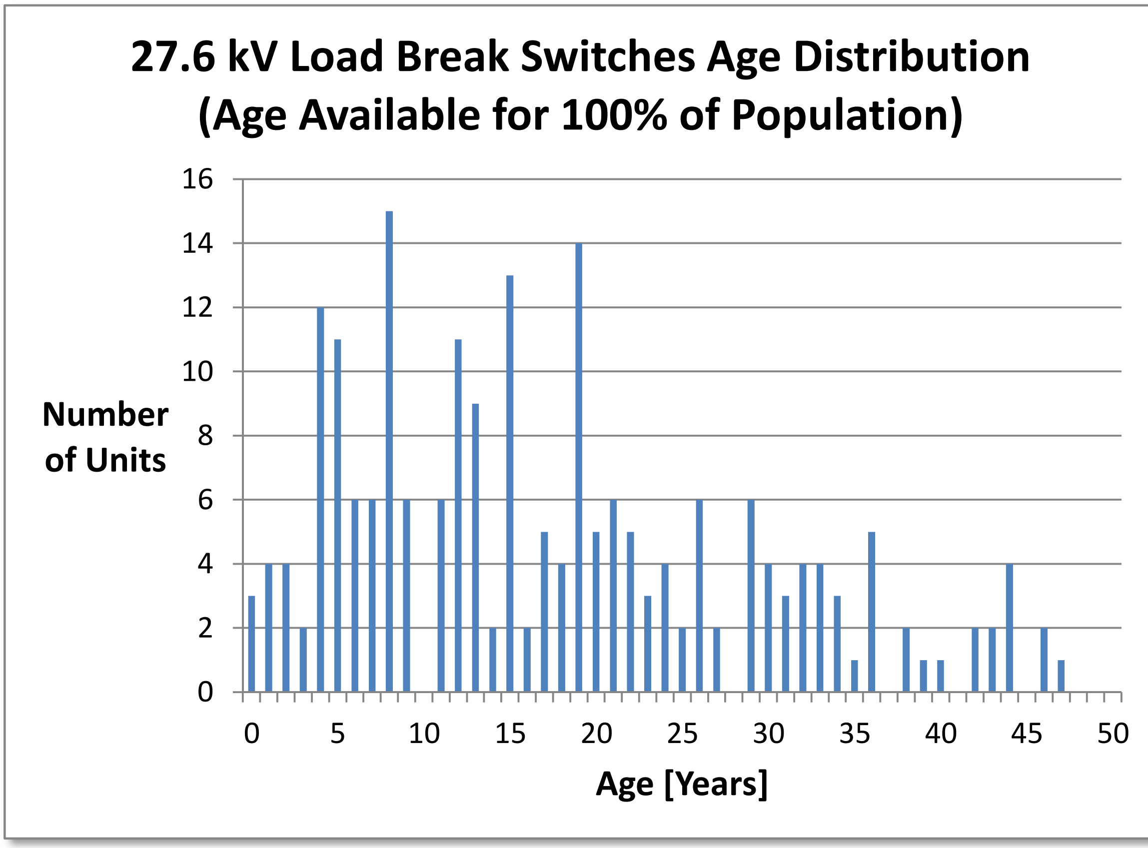

Figure 7-4 27.6kV Load Break Switches Age Distribution

In Line Switches

The average age of all units was 18 years. Approximately 12% of the population was 40 years or older.

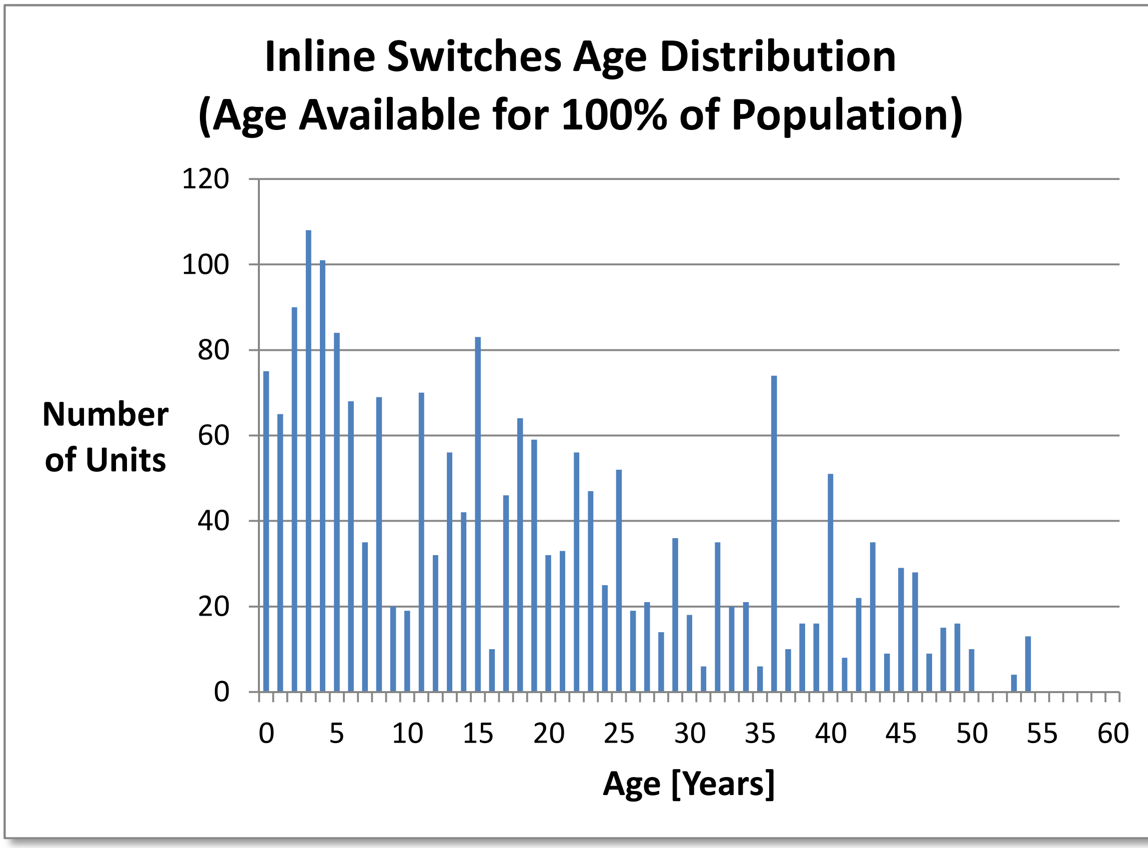

Figure 7-5 In Line Switches Age Distribution

Motorized Switches

The average age of all units was 16 years. Approximately 27% of the population was 25 years or older.

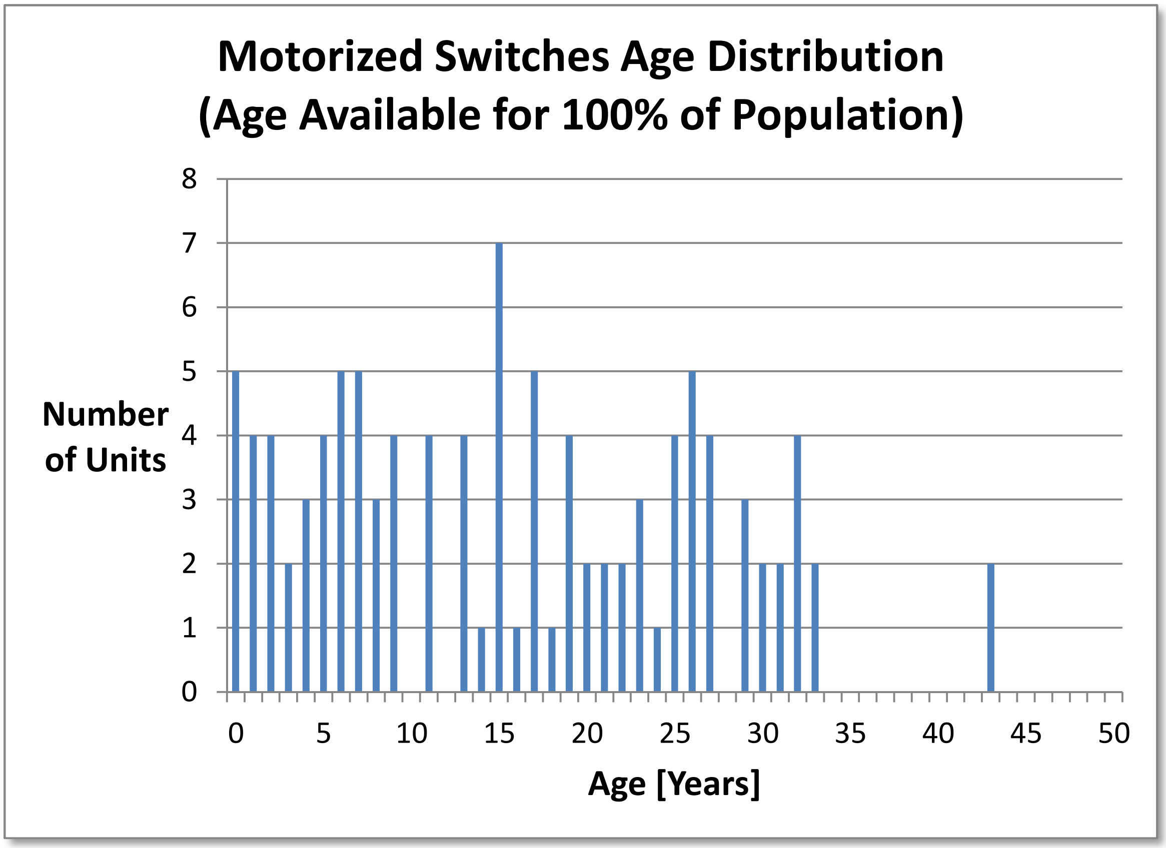

Figure 7-6 Motorized Switches Age Distribution

7.3 Health Index Results

44 kV Load Break Switches

There were 338 *44 kV Load Break Switches* at Enersource. Of these, there were 338 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 95%. Approximately 5% were in "poor" or "very poor" condition.

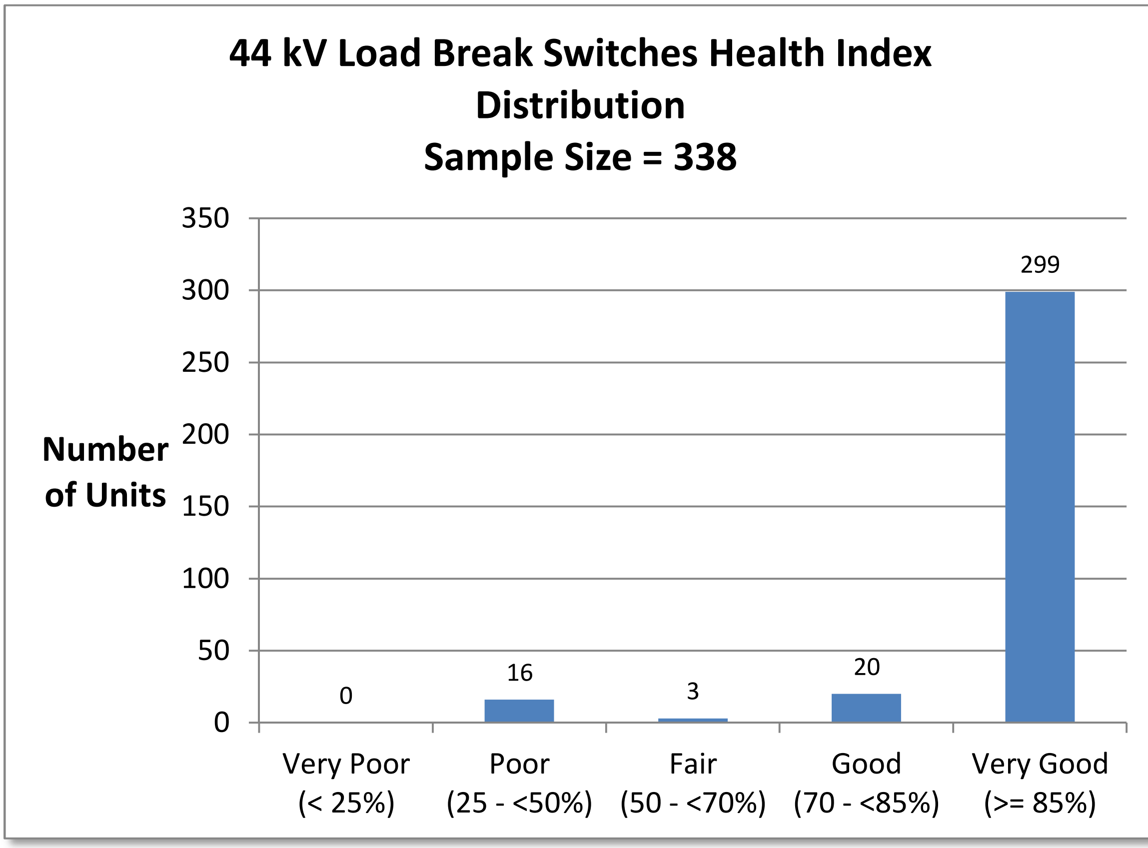

Figure 7-7 44 kV Load Break Switches Health Index Distribution (Unit)

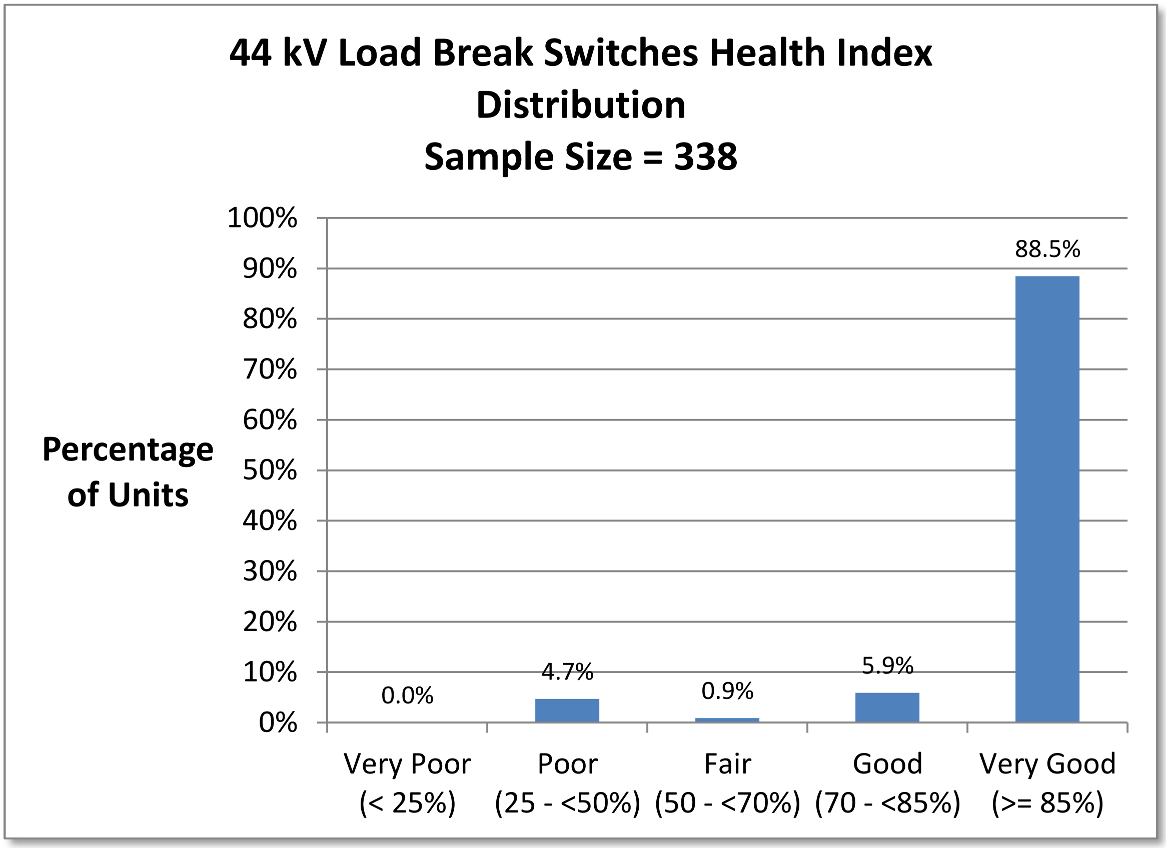

Figure 7-8 44 kV Load Break Health Switches Index Distribution (Percentage)

27.6 kV Load Break Switches

There were 213 *27.6 kV Load Break Switches*. Of these, there were 213 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 97%. Approximately 1% was in "poor" or "very poor" condition.

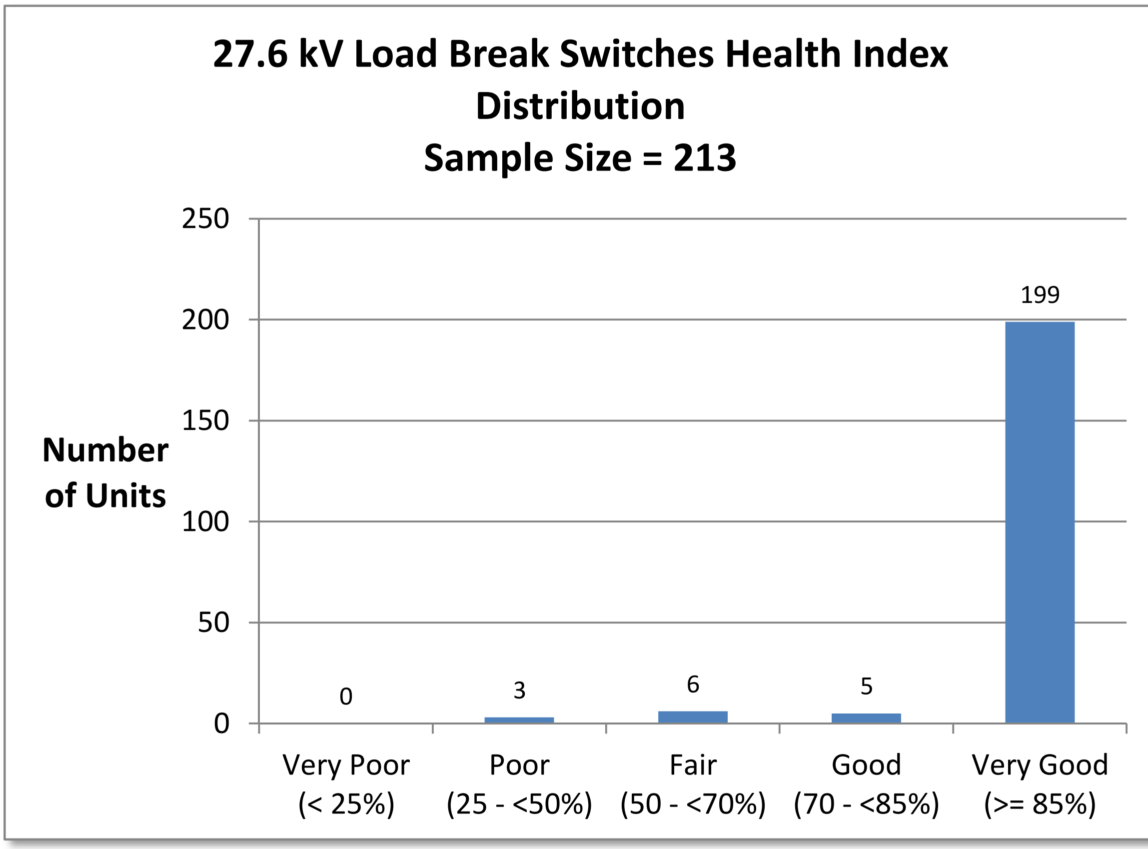

Figure 7-9 27.6kV Load Break Switches Health Index Distribution (Unit)

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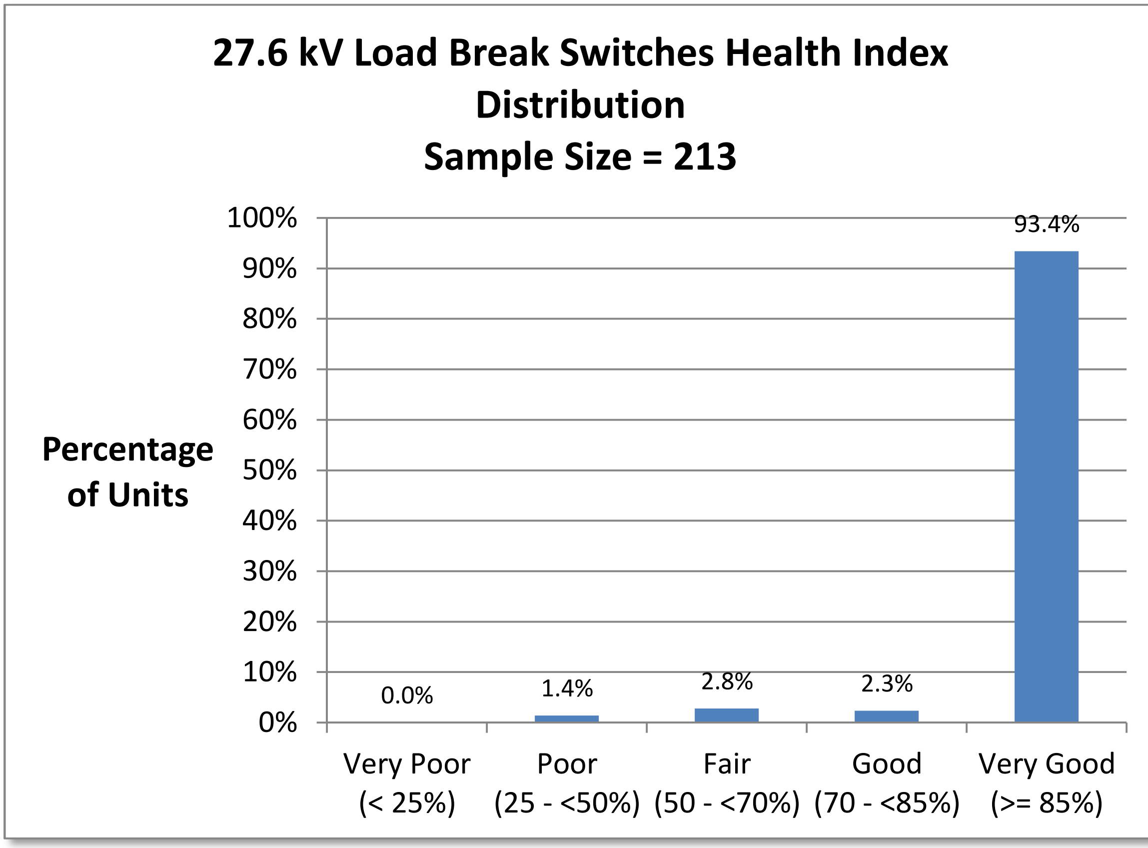

Figure 7-10 27.6kV Load Break Switches Health Index Distribution (Percentage)

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In Line Switches

There were 2002 *In Line Switches* at Enersource. Of these, there were 2002 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 93%. Approximately 5% of the population was in "poor" or "very poor" condition.

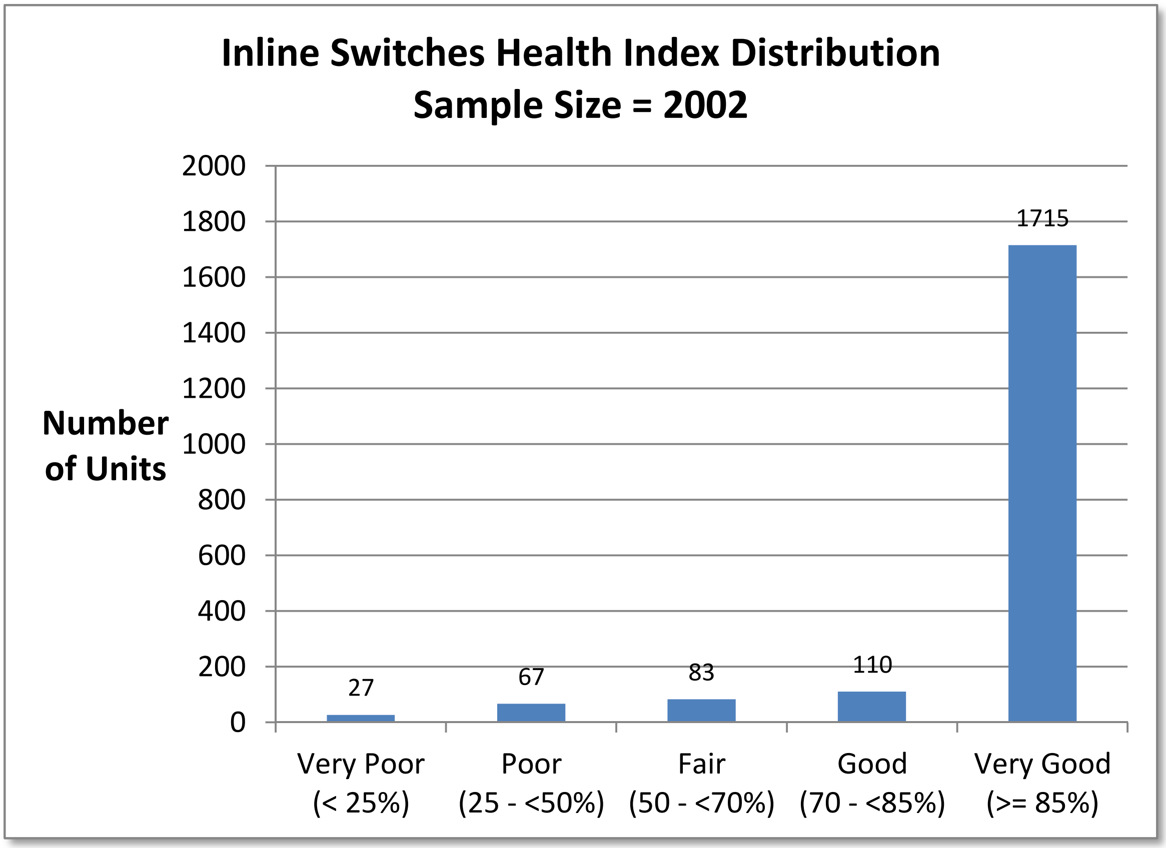

Figure 7-11 In Line Switches Health Index Distribution (Unit)

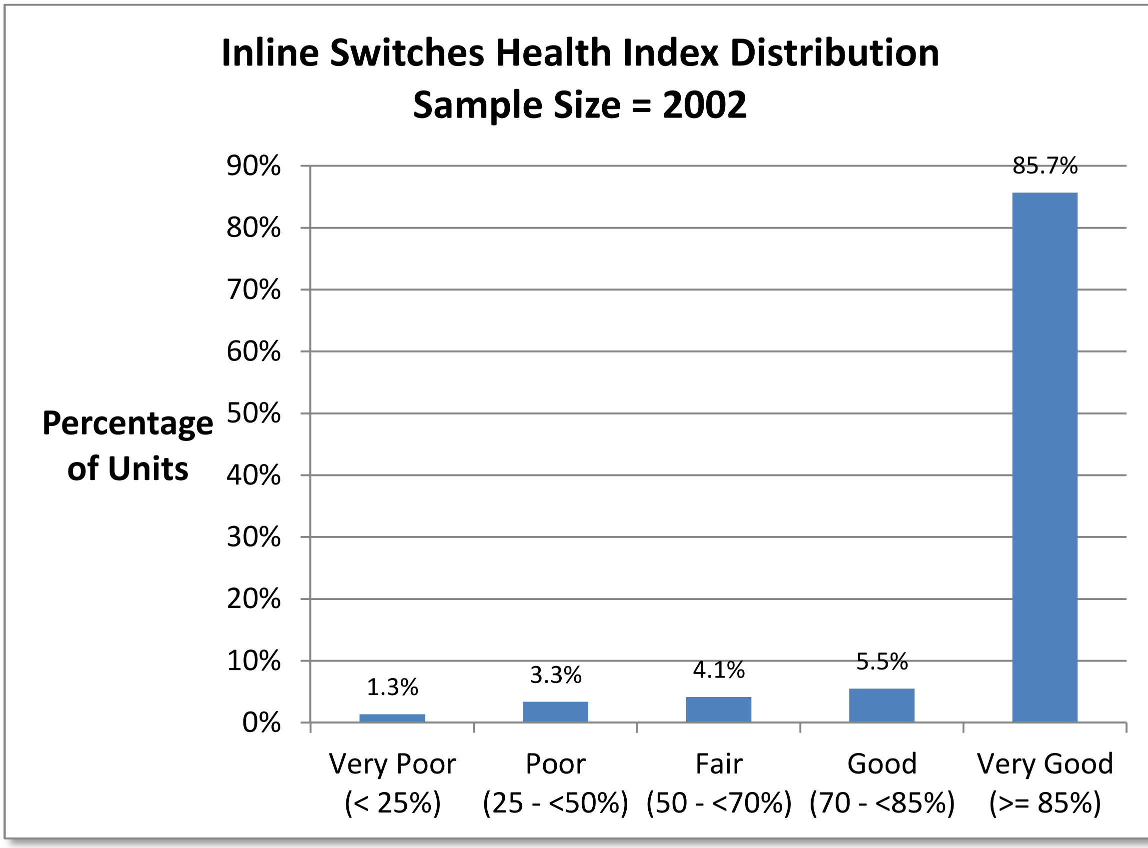

Figure 7-12 In Line Switches Health Index Distribution (Percentage)

Motorized

There were 104 Motorized Switches at Enersource. Of these, there were 104 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 85%. Approximately 14% of the samples were in "poor" or "very poor" condition.

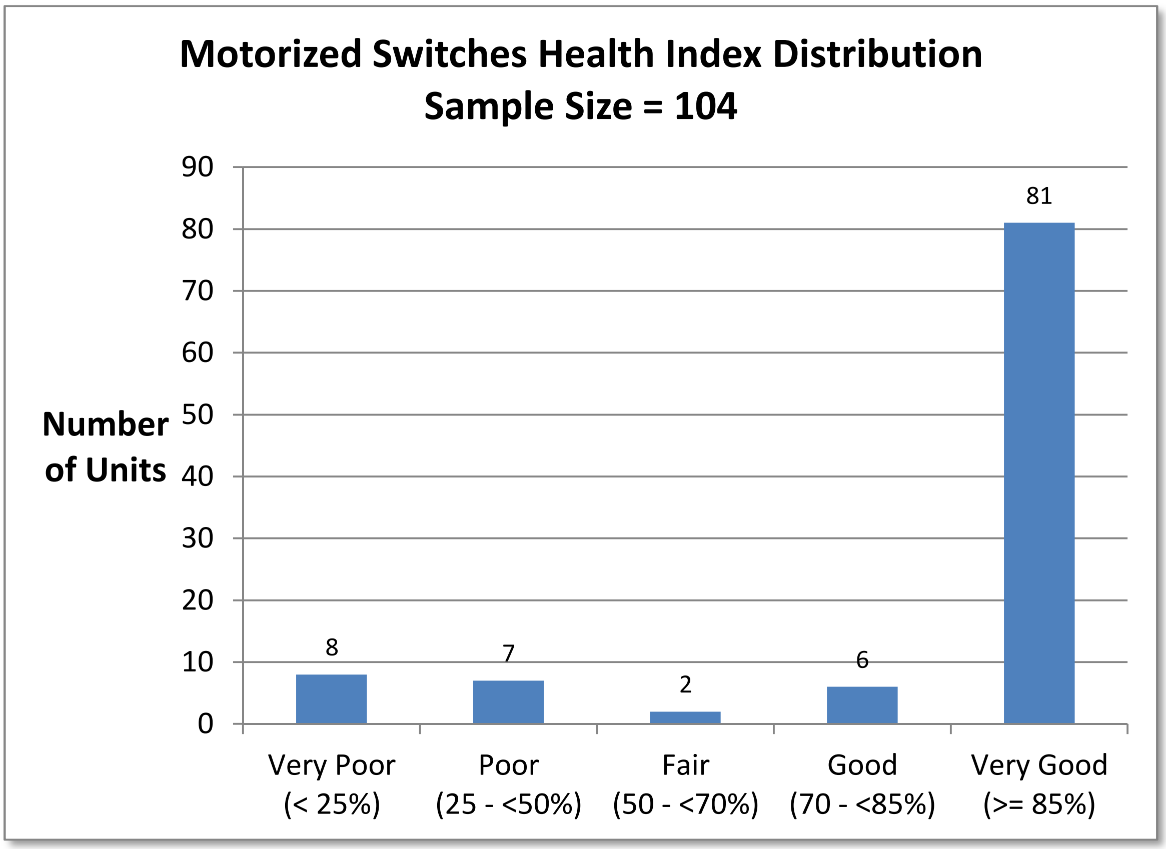

Figure 7-13 Motorized Switches Health Index Distribution (Unit)

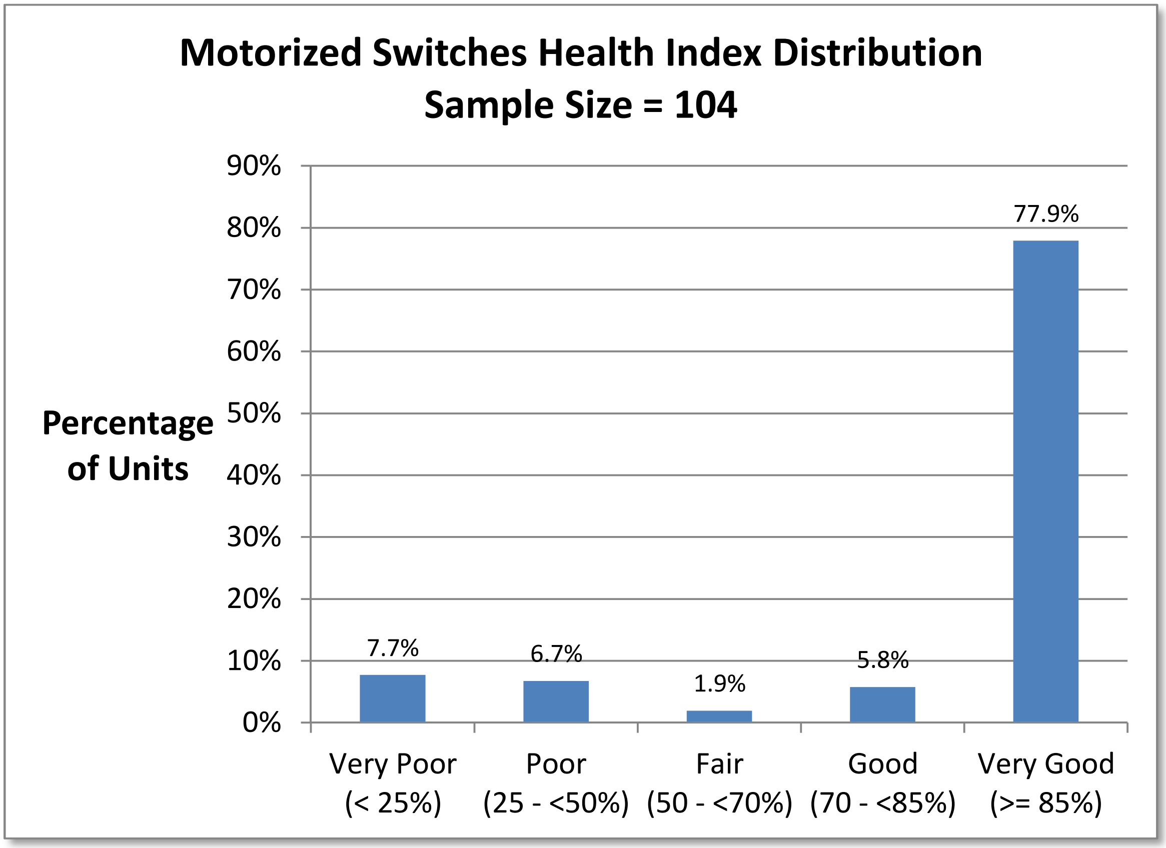

Figure 7-14 Motorized Health Index Distribution (Percentage)

7.4 Flagged for Action Plan

As it is assumed that Overhead Line Switches were reactively replaced, the flagged for action plan was based on the asset failure rate.

The Flagged for Action Plan was as follows:

44 kV Load Break Switches

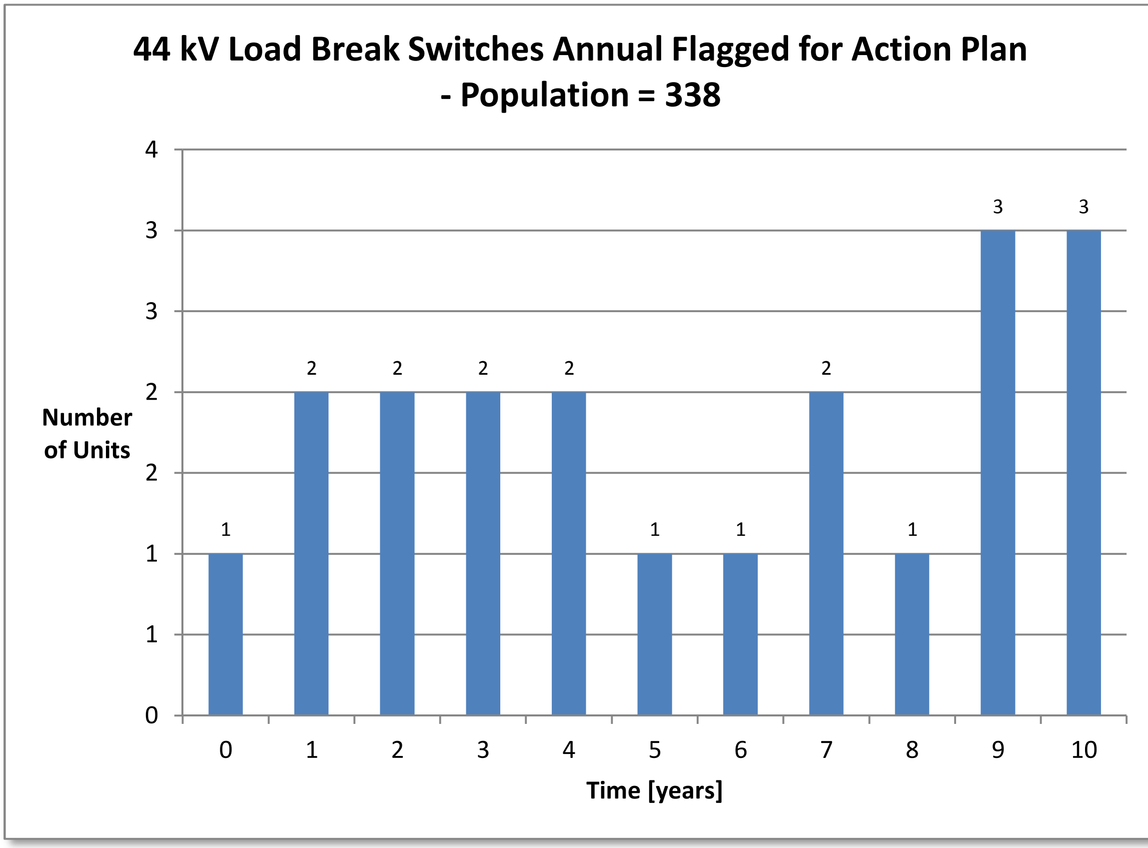

Figure 7-15 44 kV Load Break Switches Flagged for Action Plan

27.6 kV Load Break Switches

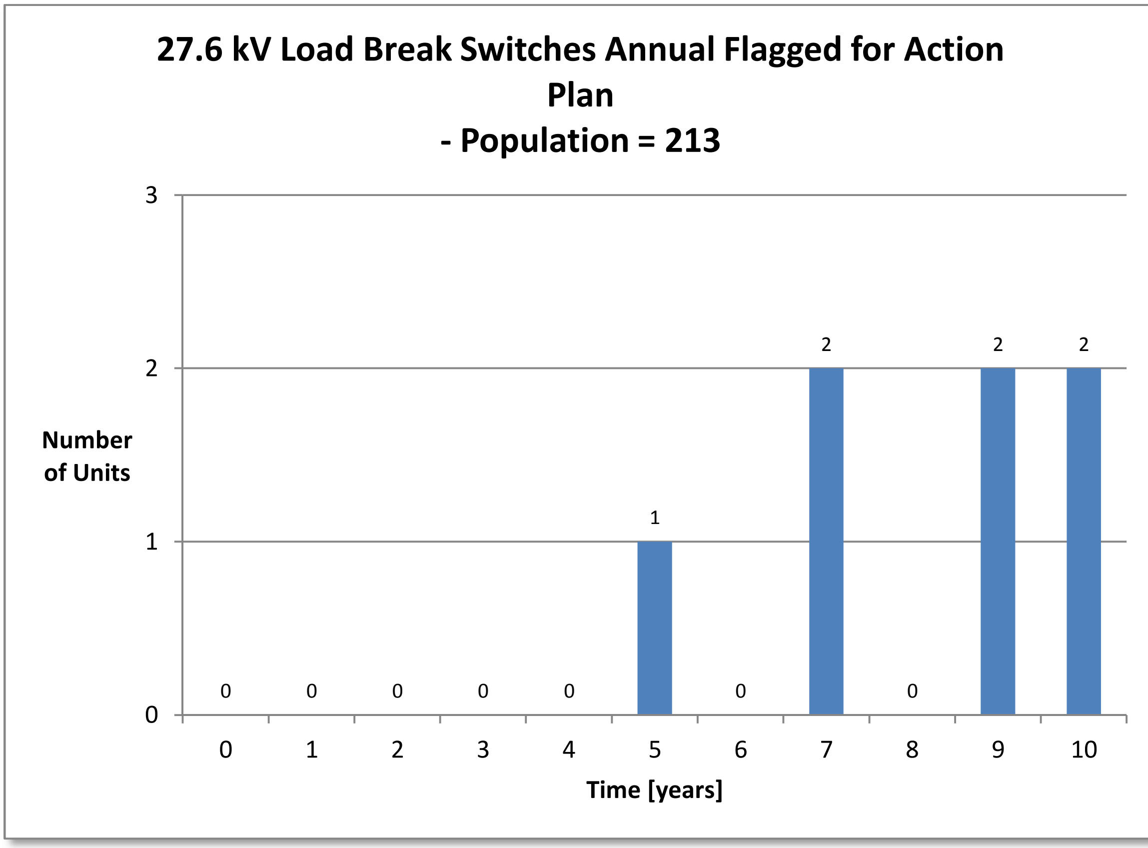

Figure 7-16 27.6kV Load Break Switches Flagged for Action Plan

In Line Switches

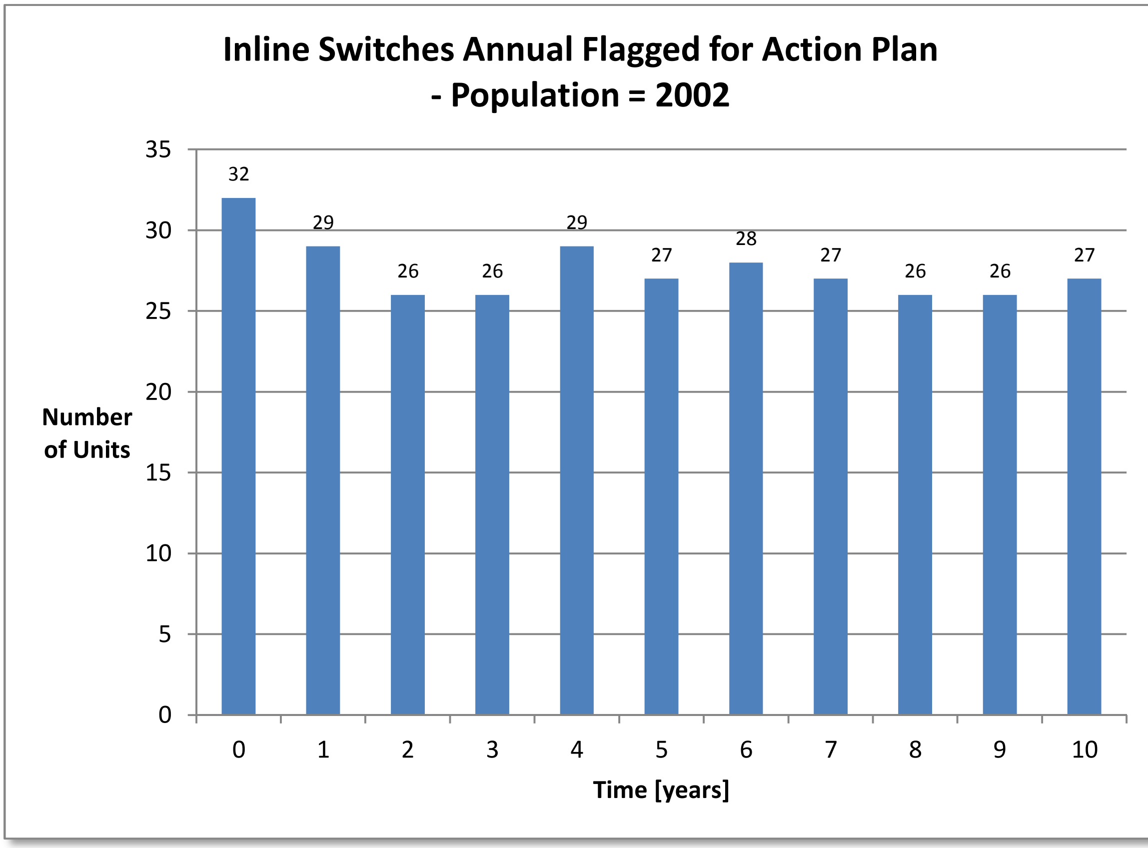

Figure 7-17 In Line Switches Flagged for Action Plan

Motorized Switches

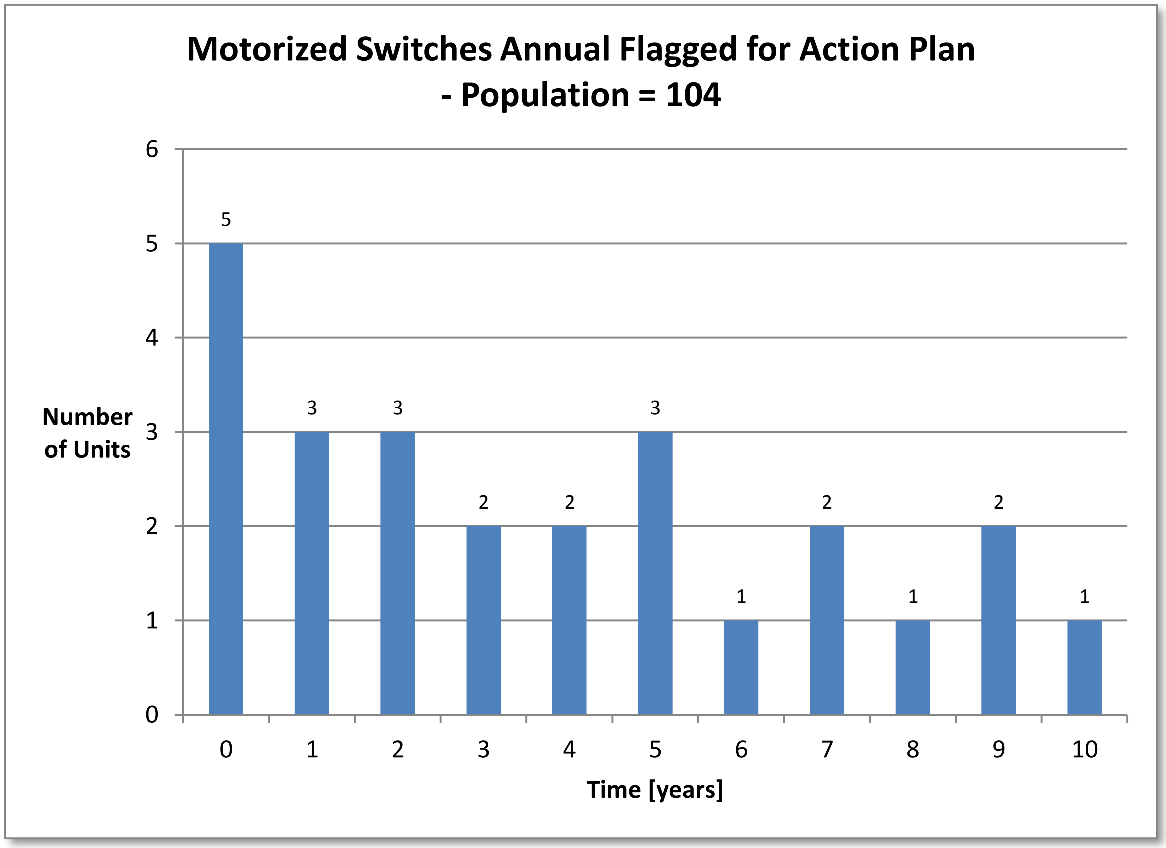

Figure 7-18 Motorized Flagged for Action Plan

7.5 Data Analysis

The data used for overhead switch assessment included age and visual inspections. Visual inspections, however, were limited and no new inspection data has been available from recent years. In the 2014 assessment, the decision was made to exclude very old inspection data (i.e. inspections from 2012 or later were included). This, in combination with the revised HI, caused the DAI for the four overhead switch types to drop significantly. It is recommended that visual inspections be conducted to gather condition information.

The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Motor/Manual Operation	Operation Mechanism	☆☆☆	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection
Mechanical Support		☆	Switch support	Loose installation	On-site visual inspection
Arc Horn	Arc Extinction	☆	Switch operation	Arc horn surface worn-out	On-site visual inspection
Arc Interrupter		☆☆	Switch arc extinction	Arc extinction part surface worn-out	On-site visual inspection
Insulator	**Insulation**	☆	Support insulator	Crack	On-site visual inspection
Switch Condition	**Service Record**	☆☆☆	Blade	Blade condition	On-site visual inspection

8 UNDERGROUND PRIMARY CABLES

8.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

8.1.1 Condition and Sub-Condition Parameters

Table 8-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	1	Table 8-2
DRF	De-Rating based on number of failures		Table 8-3

Table 8-2 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	1	Figure 8-3

8.1.2 Condition Criteria

8.1.2.1 <u>Age</u>

Assume that the failure rate Underground Primary Cables exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

All the underground cables in this study are of XLPE type. There are three sub categories of such cables based on different installation timelines:

1. non-tree retardant (Non-TR), direct buried (before 1989)
2. tree retardant (TR), direct buried (1989 to 1993)
3. tree retardant (TR), in-duct (after 1993).

For non-TR direct buried cables, assuming that at the ages of 20 and 35 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve.

For TR direct buried cables, the ages of 25 and 40 were used.

For TR in-duct cables, the ages of 40 and 55 were used.

The following curves show the survival curves for each cable type. Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figures.

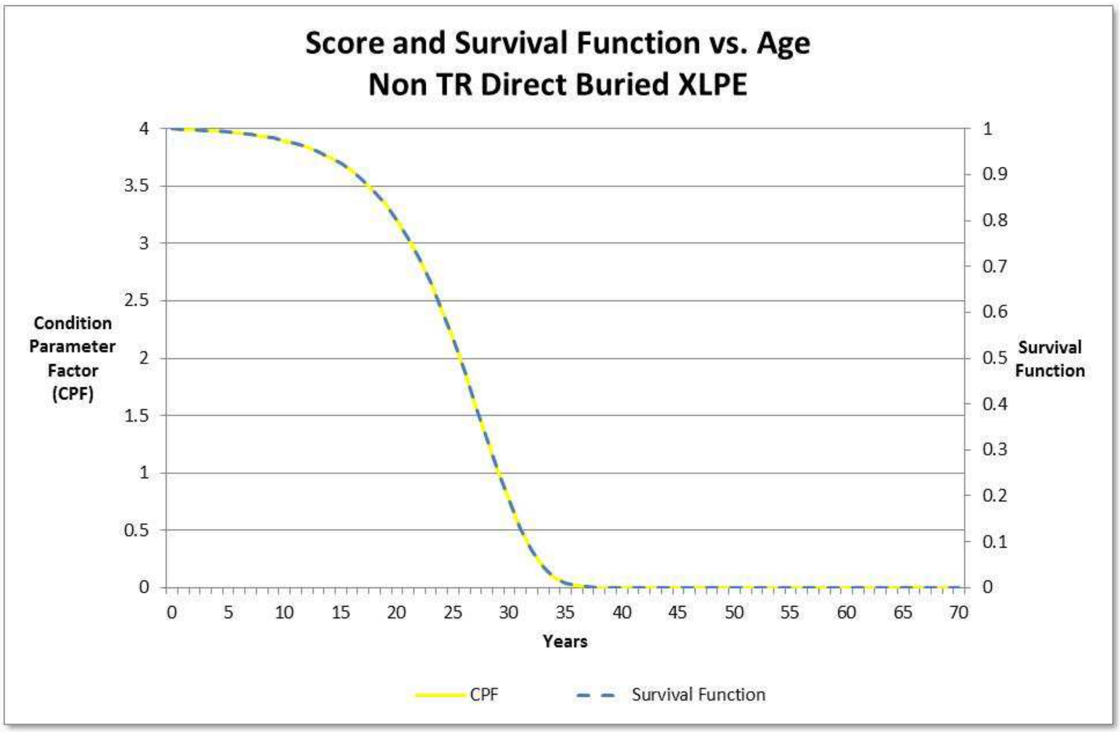

Figure 8-1 Underground Primary Cables Age Criteria – Non TR Direct Buried XLPE

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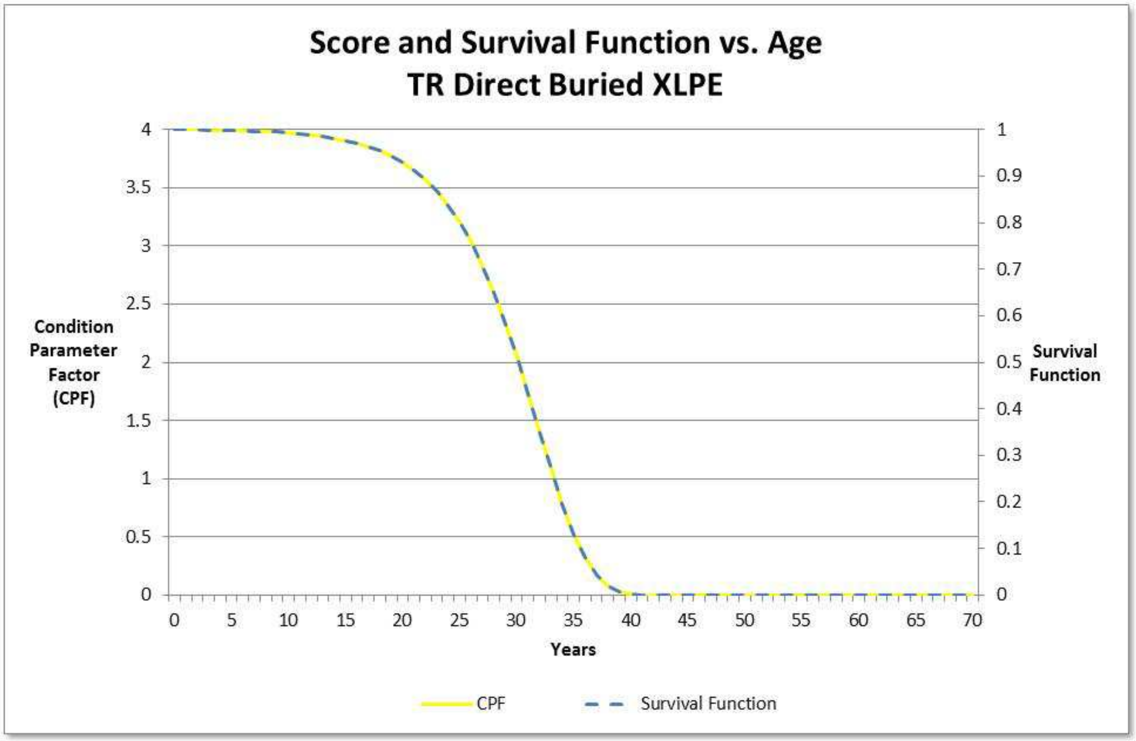

Figure 8-2 Underground Primary Cables Age Criteria – TR Direct Buried XLPE

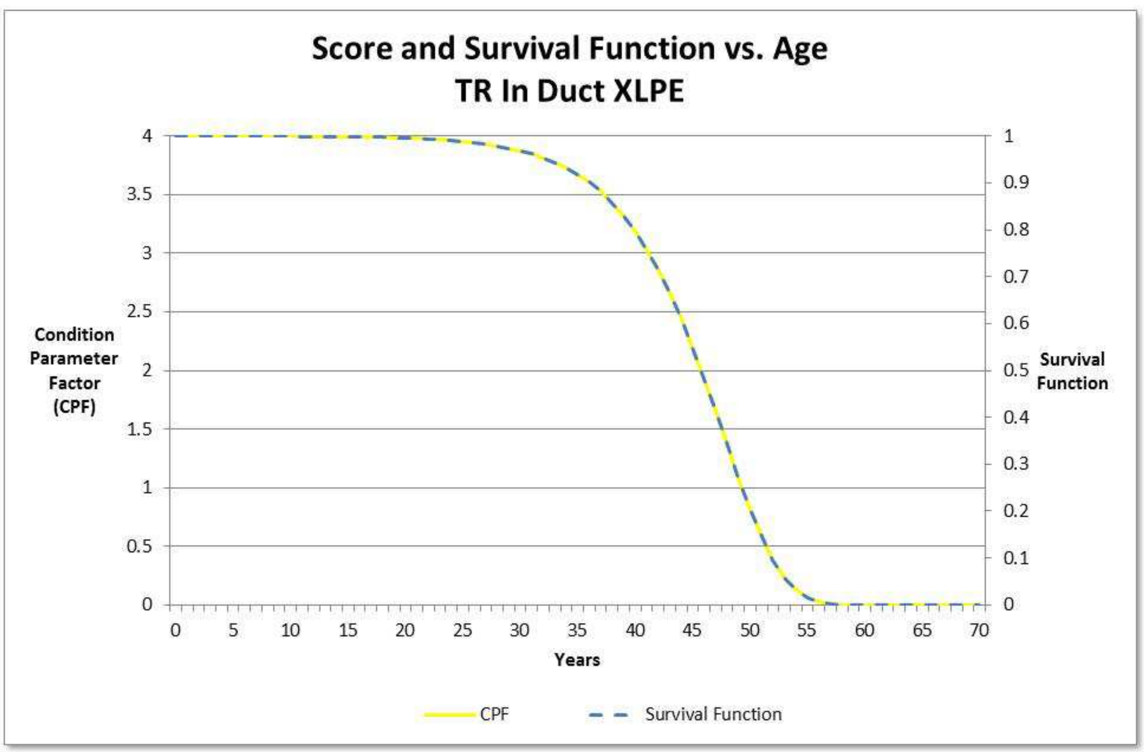

Figure 8-3 Underground Primary Cables Age Criteria – TR In-Duct XLPE

De-Rating Factor (DRF)

Table 8-3 Number of Failures De-Rating Criteria

Number of Failures in 5 Years	De-Rating Multiplier
0	1
1	0.95
2	0.9
3	0.85
4	0.8

8.2 Age Distribution

Main Feeder Cables

The average age was 18 years / conductor-km. Approximately 4% were 40 years or older. The age distribution for this asset class was as follows:

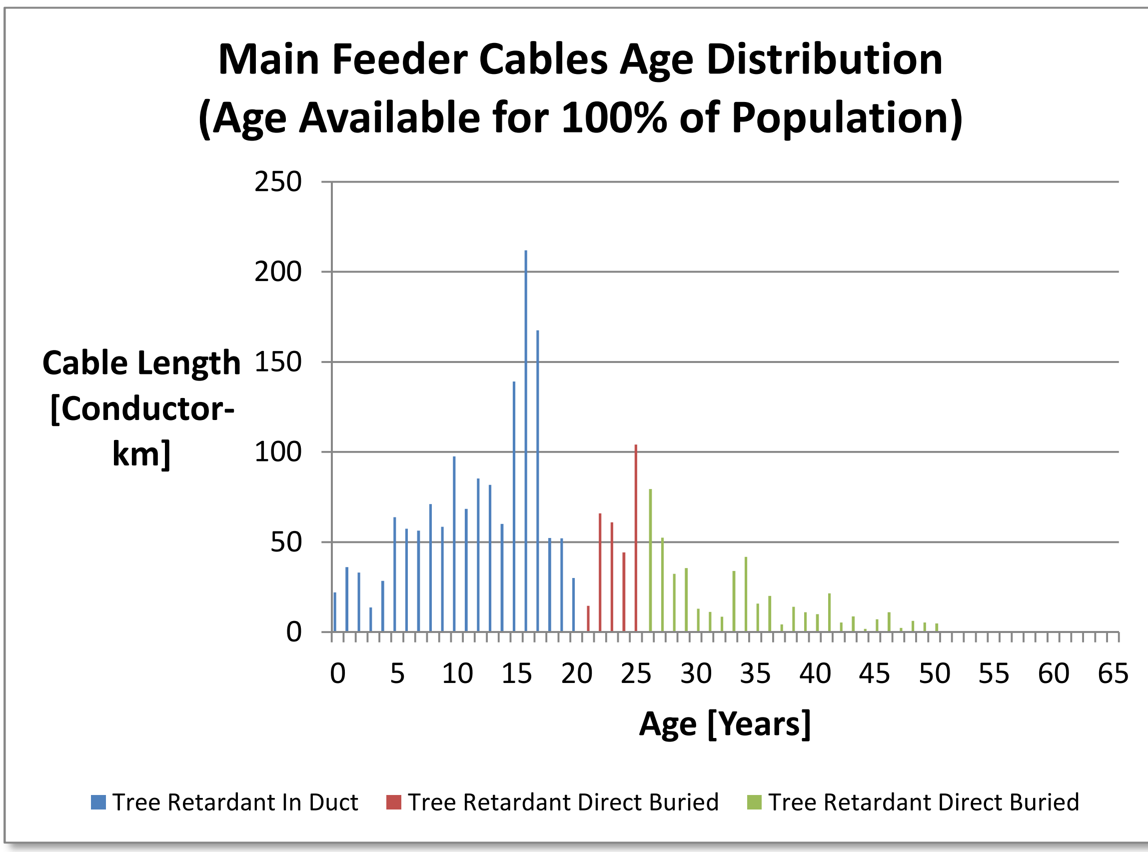

Figure 8-4 Main Feeder Cables Age Distribution

Distribution Cables

The average age was 21 years / conductor-km. Approximately 7% were 40 years or older.

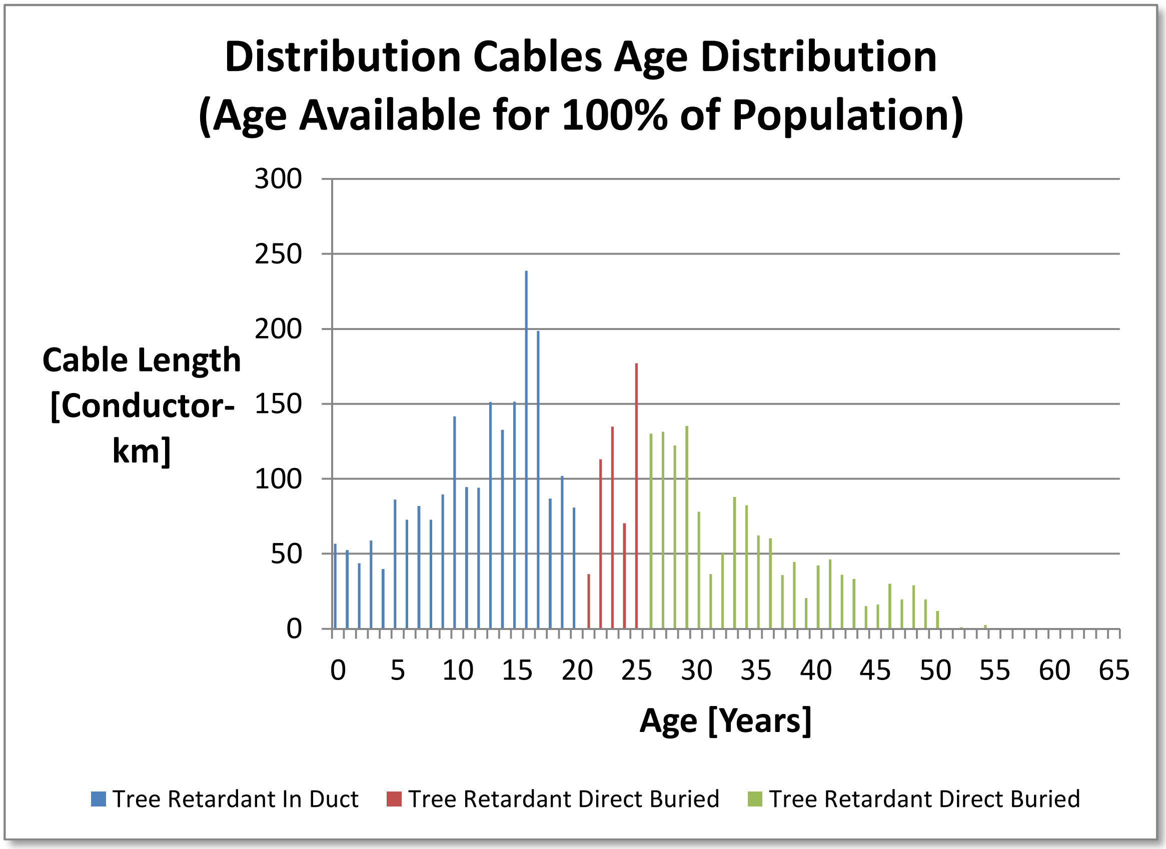

Figure 8-5 Distribution Cables Age Distribution

8.3 Health Index Results

Main Feeder

A total of 2233 conductor-km of Main Feeder Cables had sufficient data for a Health Indexing.

The average Health Index for this asset group was 78%. Approximately 20% of population was in “poor” or “very poor” condition.

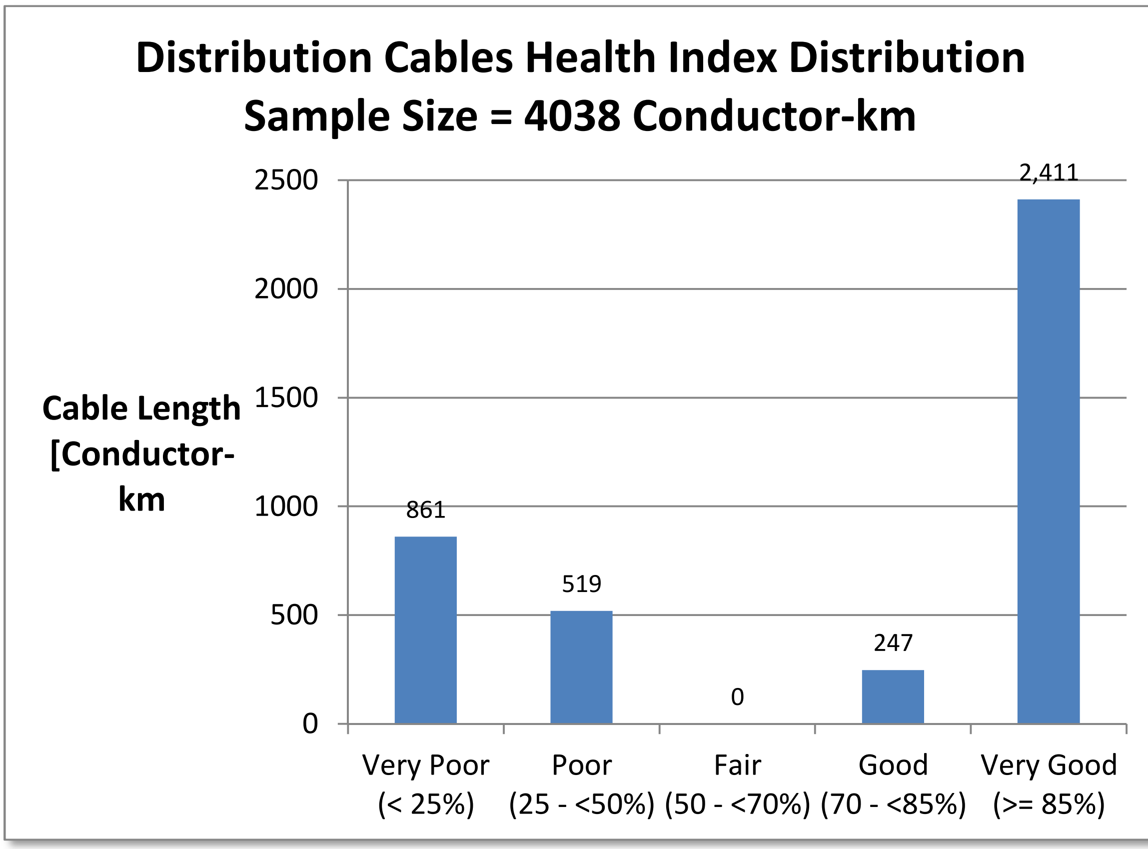

Figure 8-6 Main Feeder Cables Health Index Distribution (Unit)

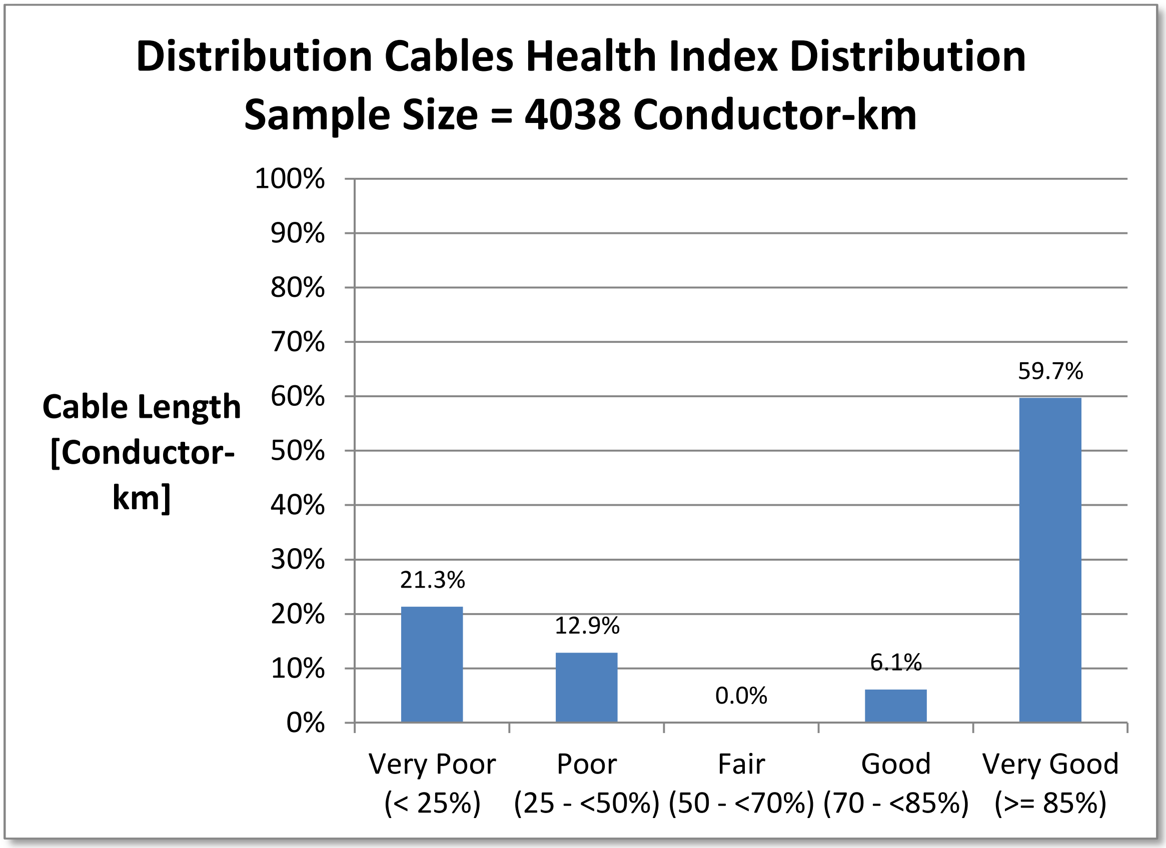

Figure 8-7 Main Feeder Cables Health Index Distribution (Percentage)

Distribution Cables

A total of 4038 conductor-km of Distribution Cables had sufficient data for a Health Indexing.

The average Health Index for this asset group was 70%. Approximately 34% of the samples were in "poor" or "very poor" condition.

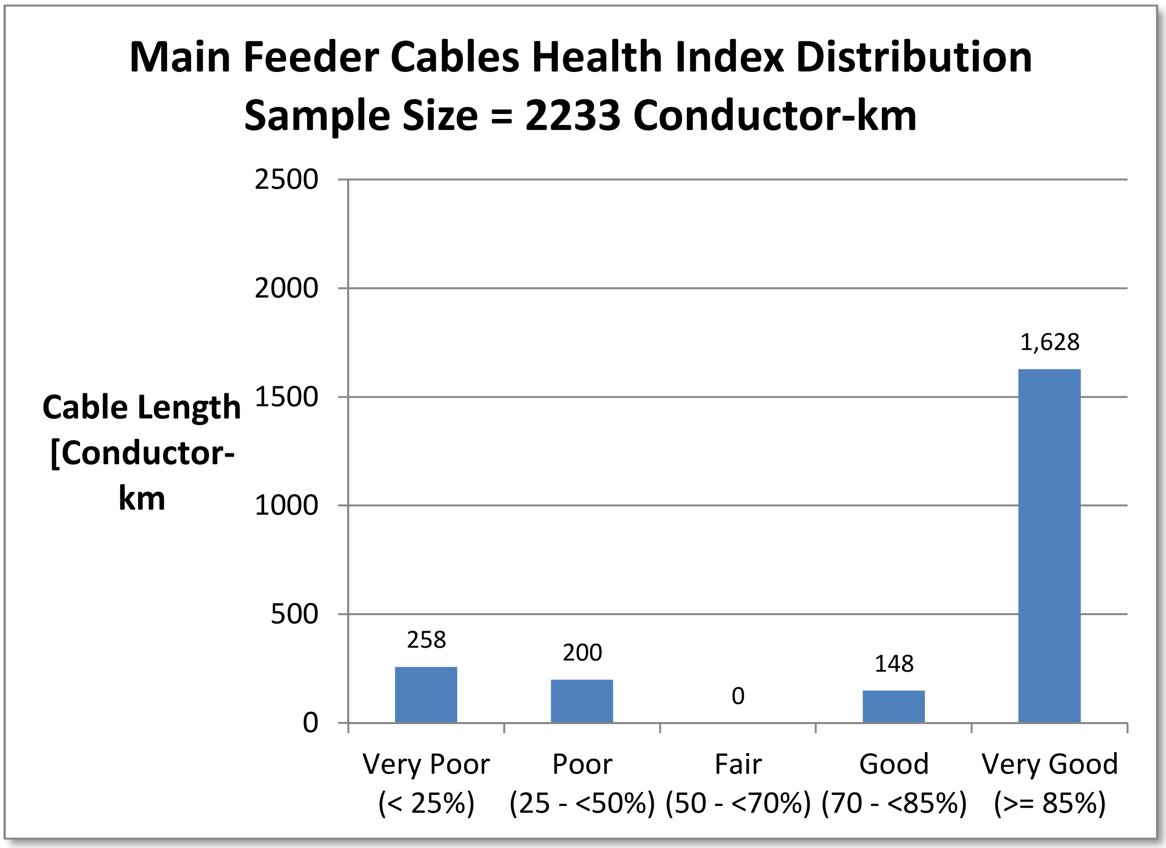

Figure 8-8 Distribution Cables Health Index Distribution (Unit)

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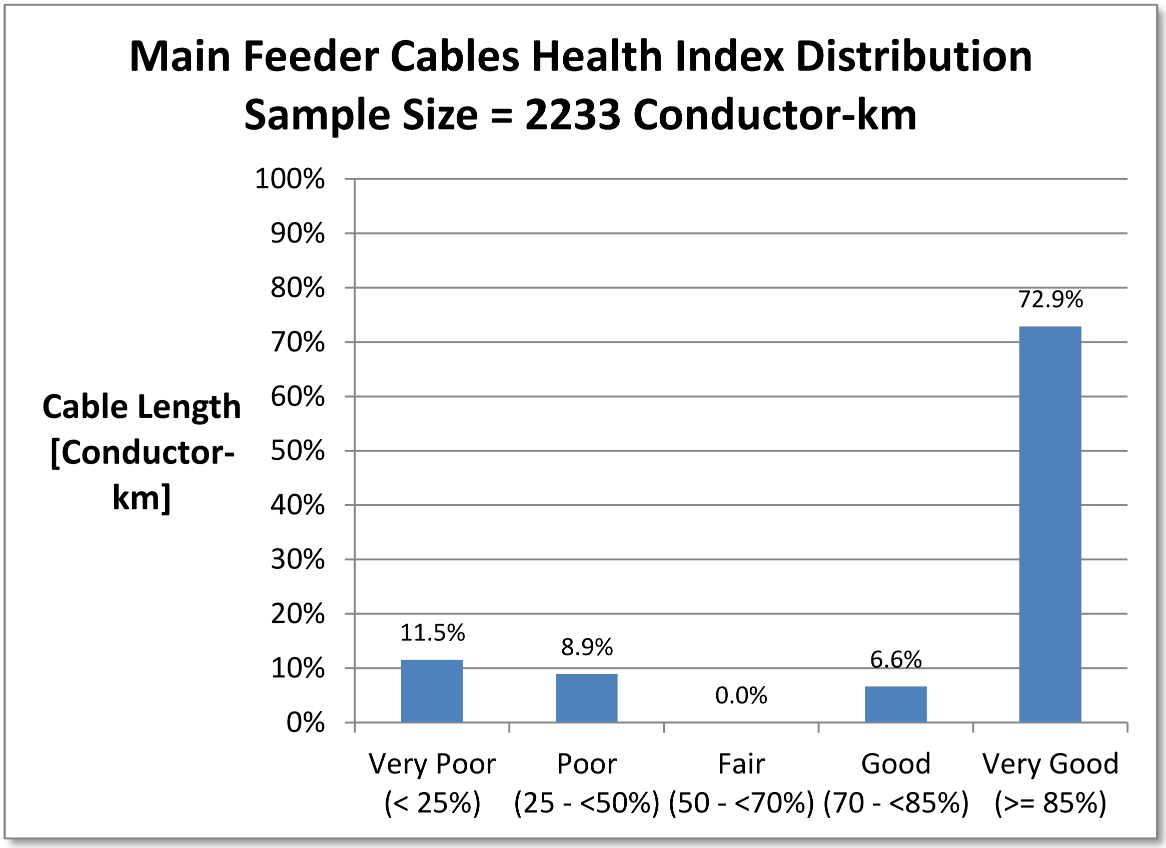

Figure 8-9 Distribution Cables Health Index Distribution (Percentage)

8.4 Flagged for Action Plan

As it is assumed that Underground Primary Cables were reactively replaced, the flagged for action plan was based on the asset failure rate.

Main Feeder Cables

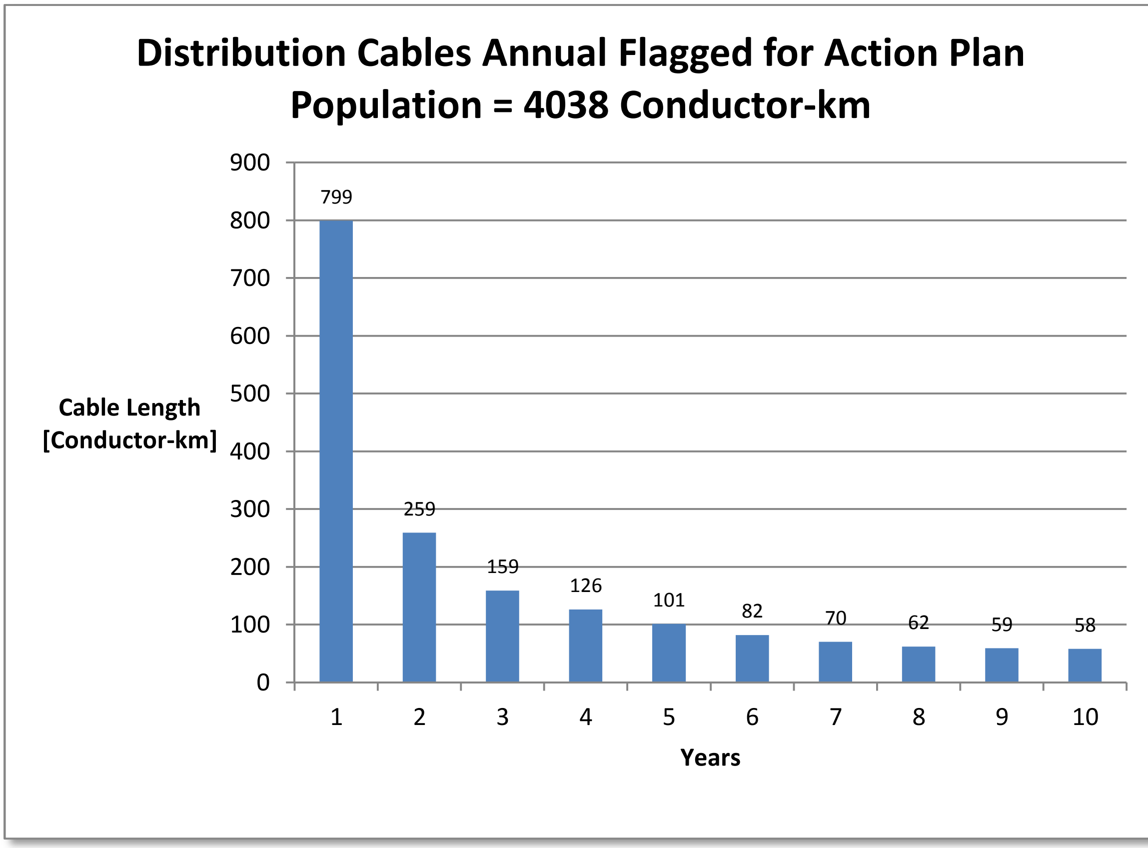

Figure 8-10 Main Feeder Cables Flagged for Action Plan

Distribution Cables

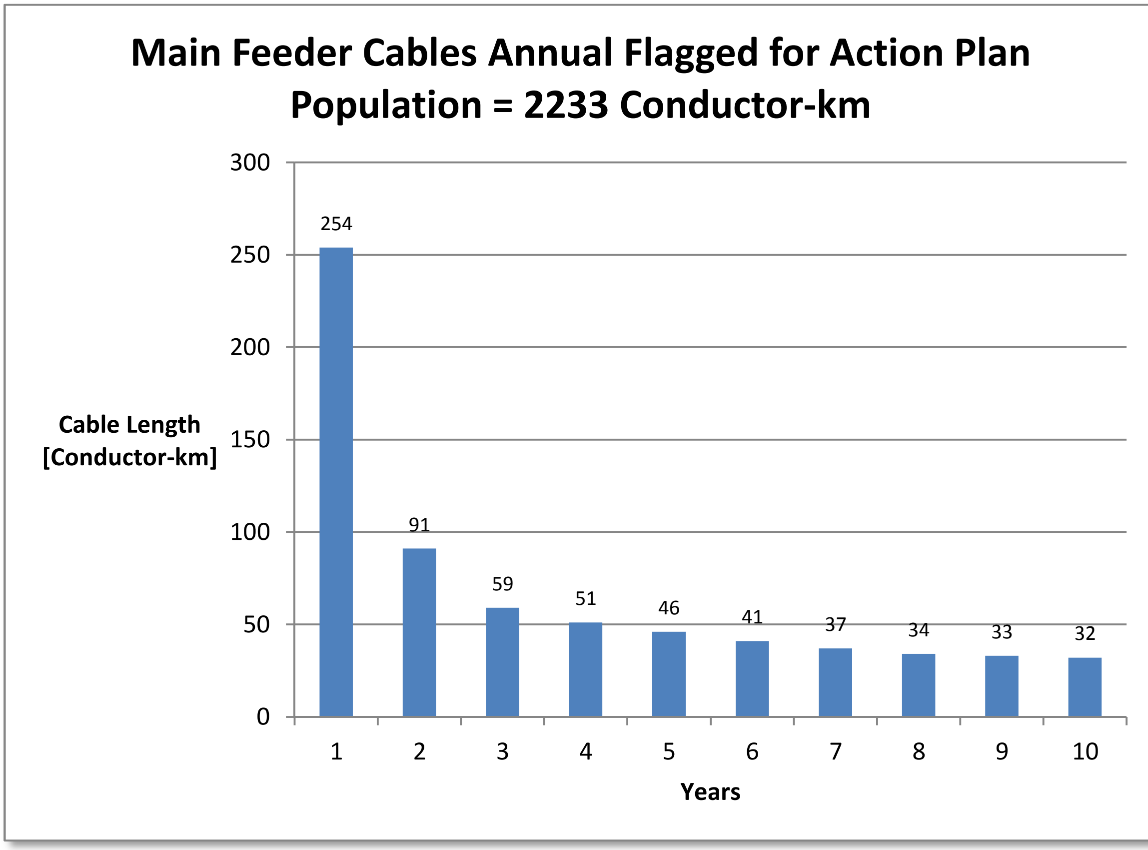

Figure 8-11 Distribution Cables Flagged for Action Plan

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8.5 Data Analysis

Age was the only condition data available for this asset group. Only segments with known ages, for both Main Feeder and Distribution Cables, were assessed. As such, the DAI for all segments was 100%.

The data gaps noted in the 2013 report, however, remained to be addressed. Note that loading data has been collected. Although it was not included in 2013, it will be incorporated into subsequent assessments.

Additionally, Enersource should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta). Such information will provide good, objective data input into the Health Index.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Splice & Termination	Physical Condition	☆☆	Cable splice	Under/over-compressed connector	On-site visual inspection
				Improper ground connection	
				Loose bolt	
			Cable termination	Sealing issue	
				Insulation erosion	
Overall		☆☆	Cable segment	Count of total corrective maintenance work orders issued on cable segment during a specific time window	Operation record

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9 POLES

9.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

9.1.1 Condition and Sub-Condition Parameters

Table 9-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Pole Strength*	0	Table 9-2
2	Physical Condition	6	Table 9-3
3	Pole Accessories	1	Table 9-4
4	Service Record	3	Table 9-5

*Data not available, so at present, set weight to 0

Table 9-2 Pole Strength Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Pole Strength	1	Test Dependent

Table 9-3 Physical Condition Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$ Wood	$WCPF_n$ Concrete	Condition Criteria Table
1	Physical Damage*	9	9	Table 9-6
2	Lean	1	1	Table 9-6

*Physical damage for Wood Poles includes: Above Ground Decay, Below Ground Decay, External Shell Decay, Internal Decay, Mechanical Damage, Cracks, Feathering
For Concrete Poles, Physical damage includes Mechanical Damage and Cracks.

Table 9-4 Pole Accessories Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Cross Arm	1	Table 9-6
2	Ground Wire	3	Table 9-6
3	Guy	2	Table 9-6

Table 9-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	1	Figure 9-1 Figure 9-2

9.1.2 Condition Criteria

Visual Inspections

Table 9-6 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age

Assume that the failure rate Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 45 and 65 years the probability of failures (P_f) for Wood Poles are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

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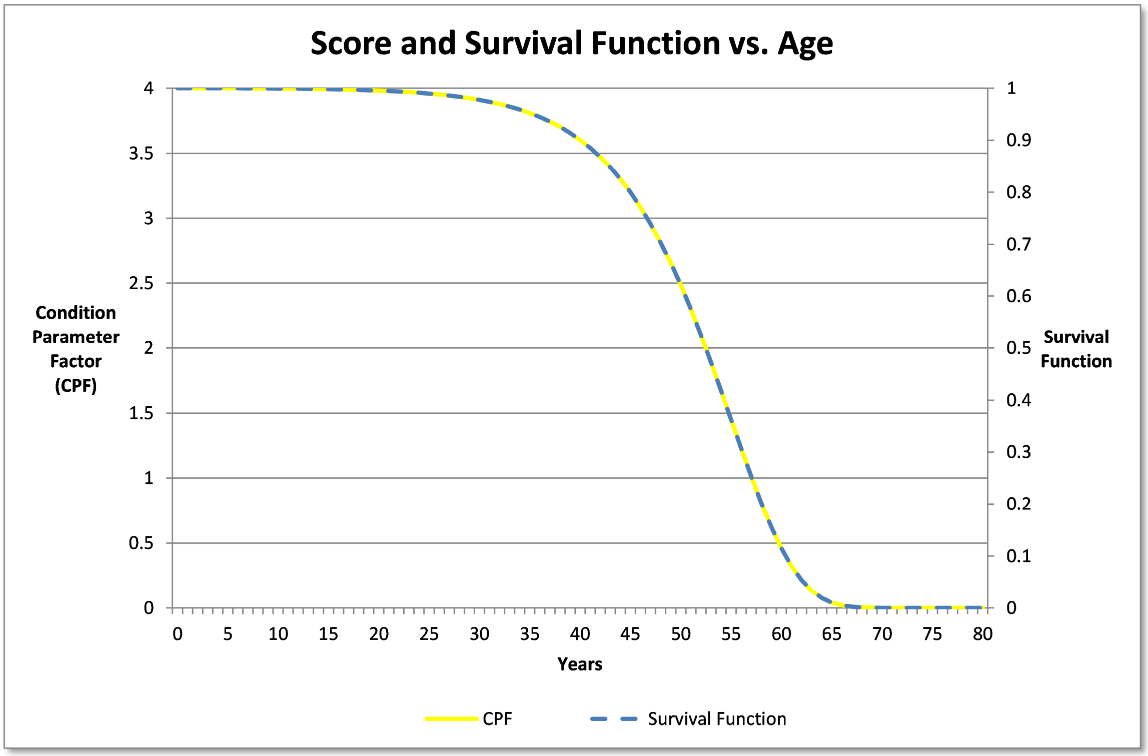

Figure 9-1 Wood Pole Age Criteria

9.1.2.1 For Concrete Poles, the ages at 20% and 99% probabilities of failure are 55 and 80 years, respectively.

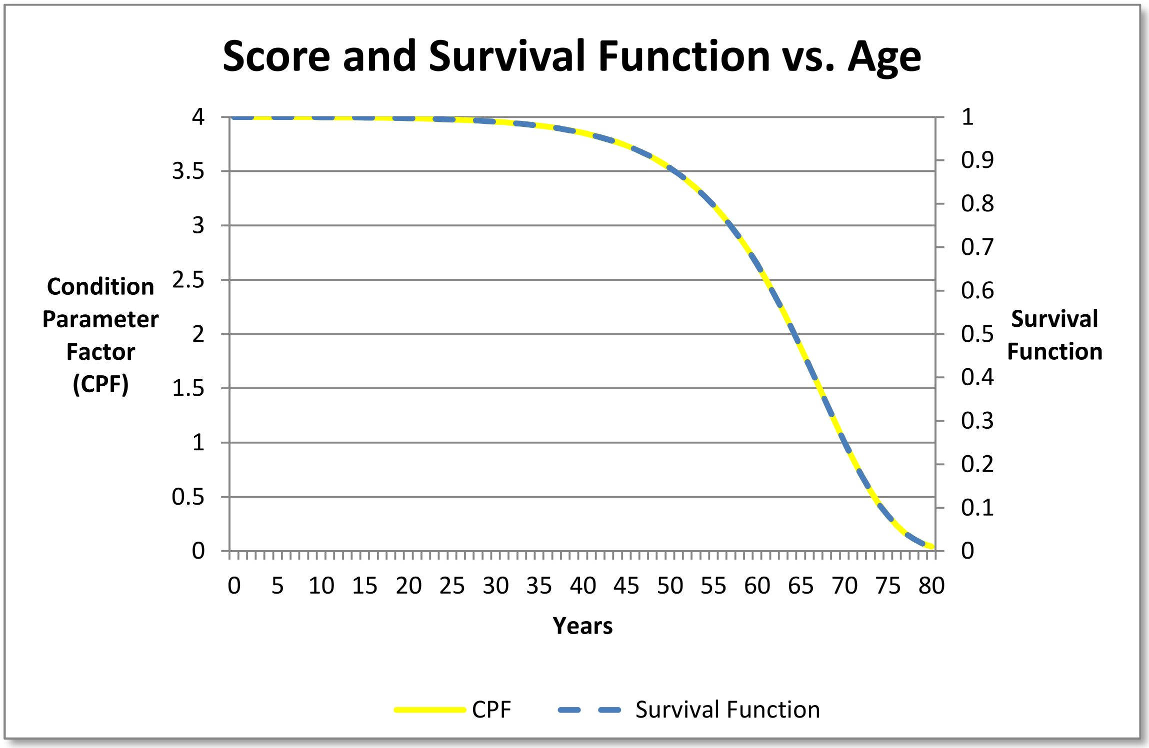

Figure 9-2 Concrete Pole Age Criteria

9.2 Age Distribution

The age distribution for this asset class was as follows:

Wood Poles

The average age for wood poles was 27. Approximately 14% of the population was 45 years or older.

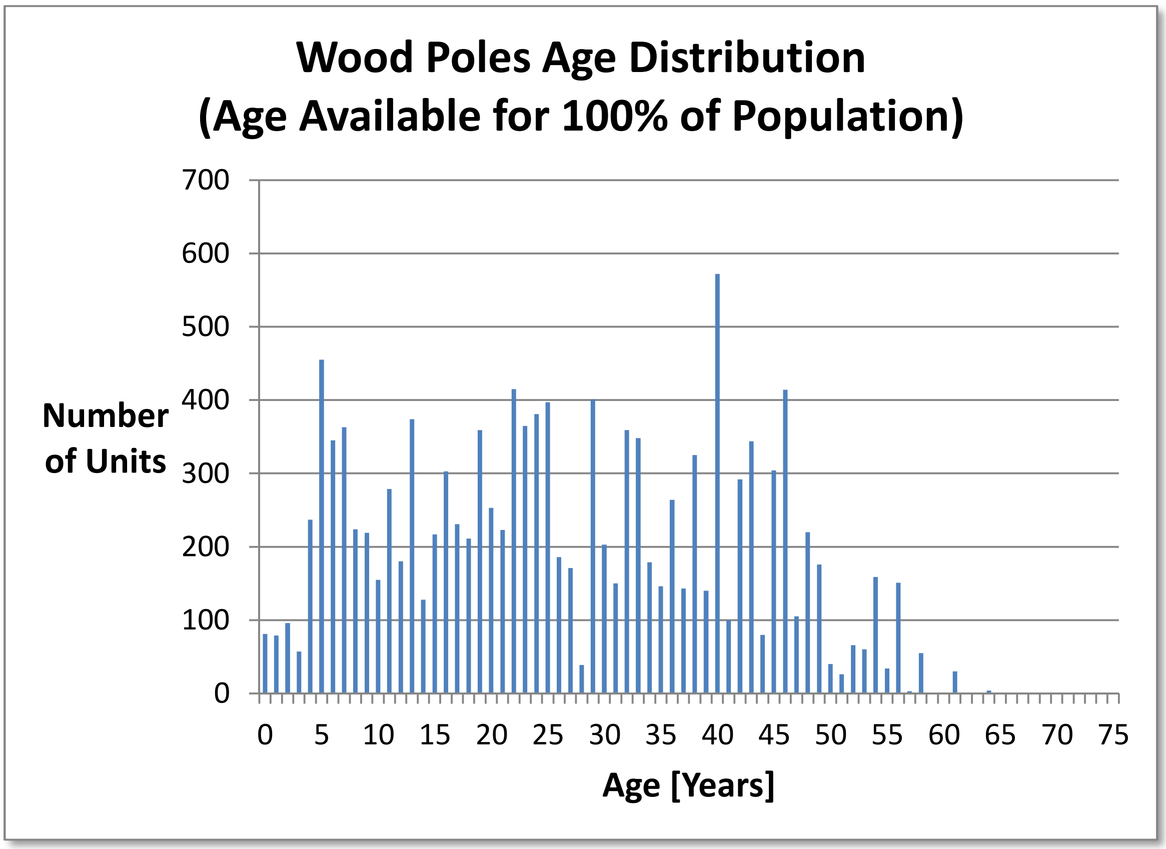

Figure 9-3 Wood Poles Age Distribution

Concrete Poles

The average age for concrete poles was 20 years. About 13% of all poles were 55 years or older.

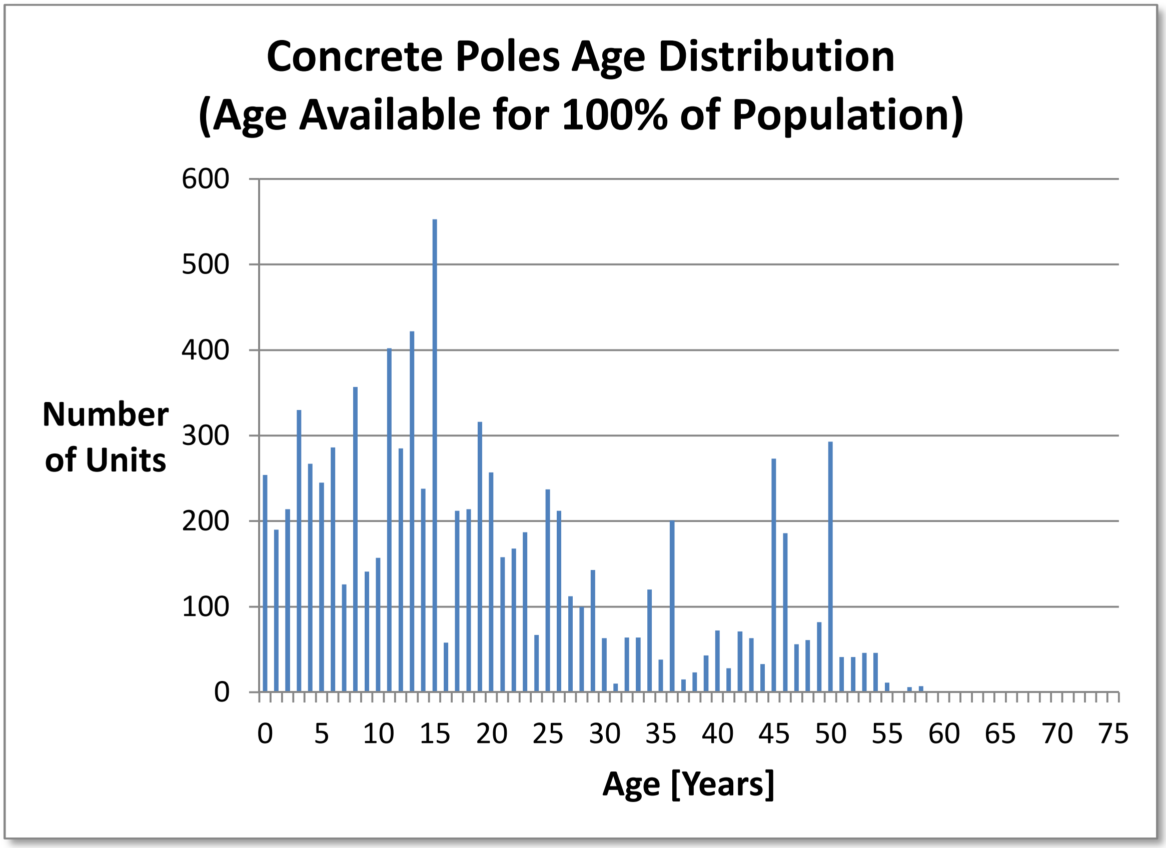

Figure 9-4 Concrete Poles Age Distribution

9.3 Health Index Results

Wood Poles

There were 12917 Wood Poles at Enersource. Of these, there were 12917 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 88%. Approximately 3% of the samples were in "poor" or "very poor" condition.

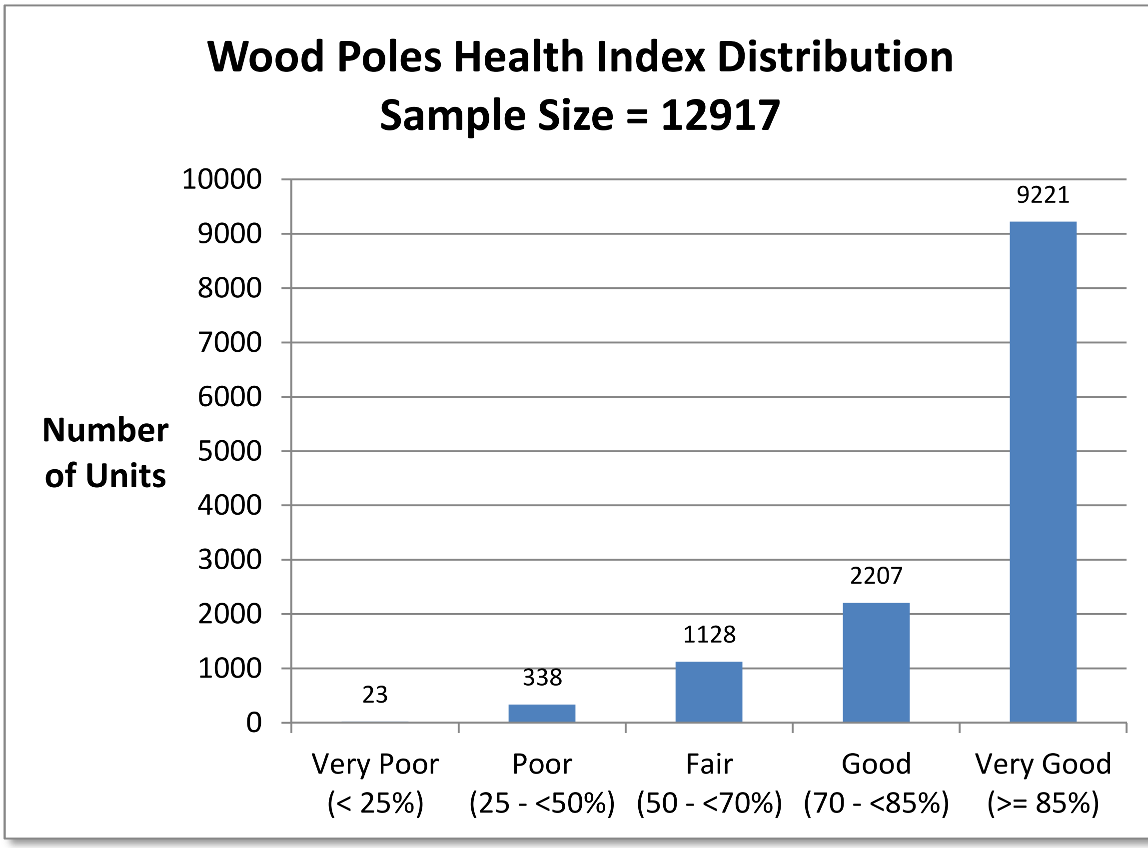

Figure 9-5 Wood Poles Health Index Distribution (Unit)

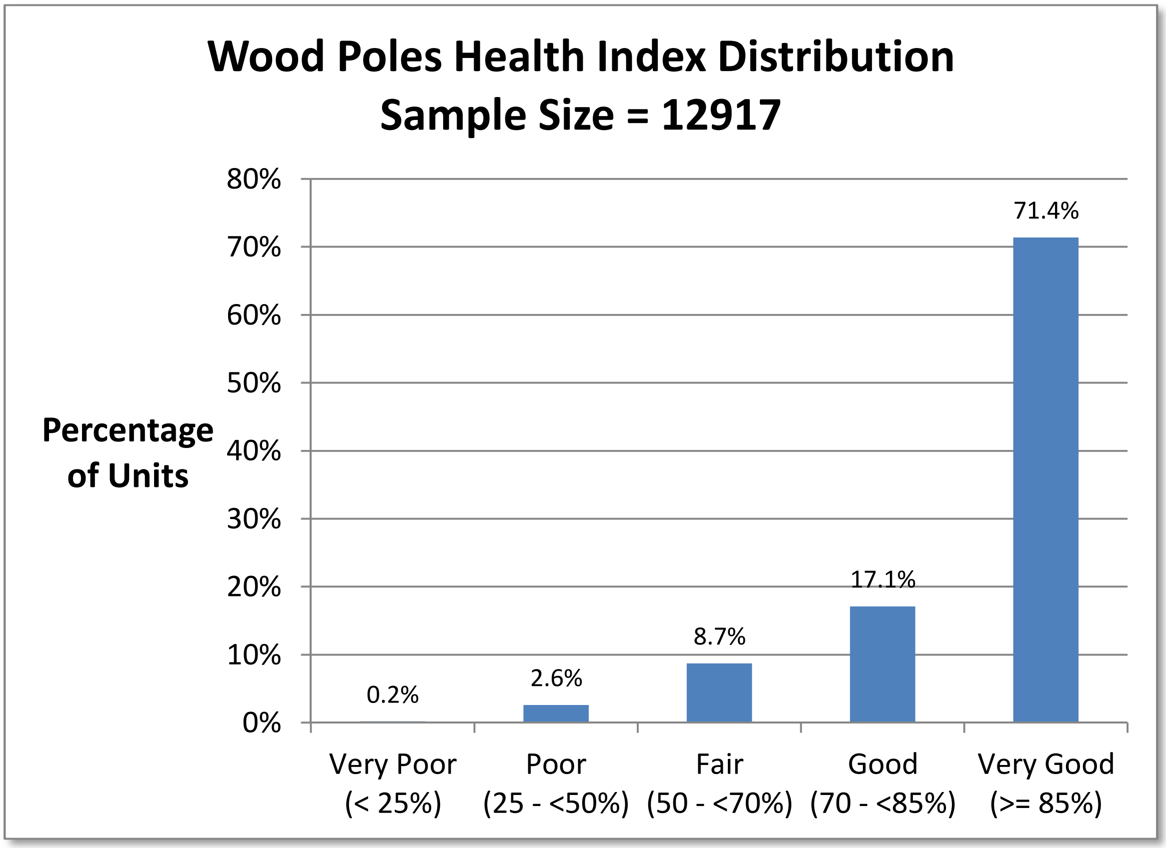

Figure 9-6 Wood Poles Health Index Distribution (Percentage)

Concrete Poles

There were 8966 Concrete Poles at Enersource. Of these, there were 8966 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was nearly 97%. Approximately <1% of the samples were in “poor” or “very poor” condition.

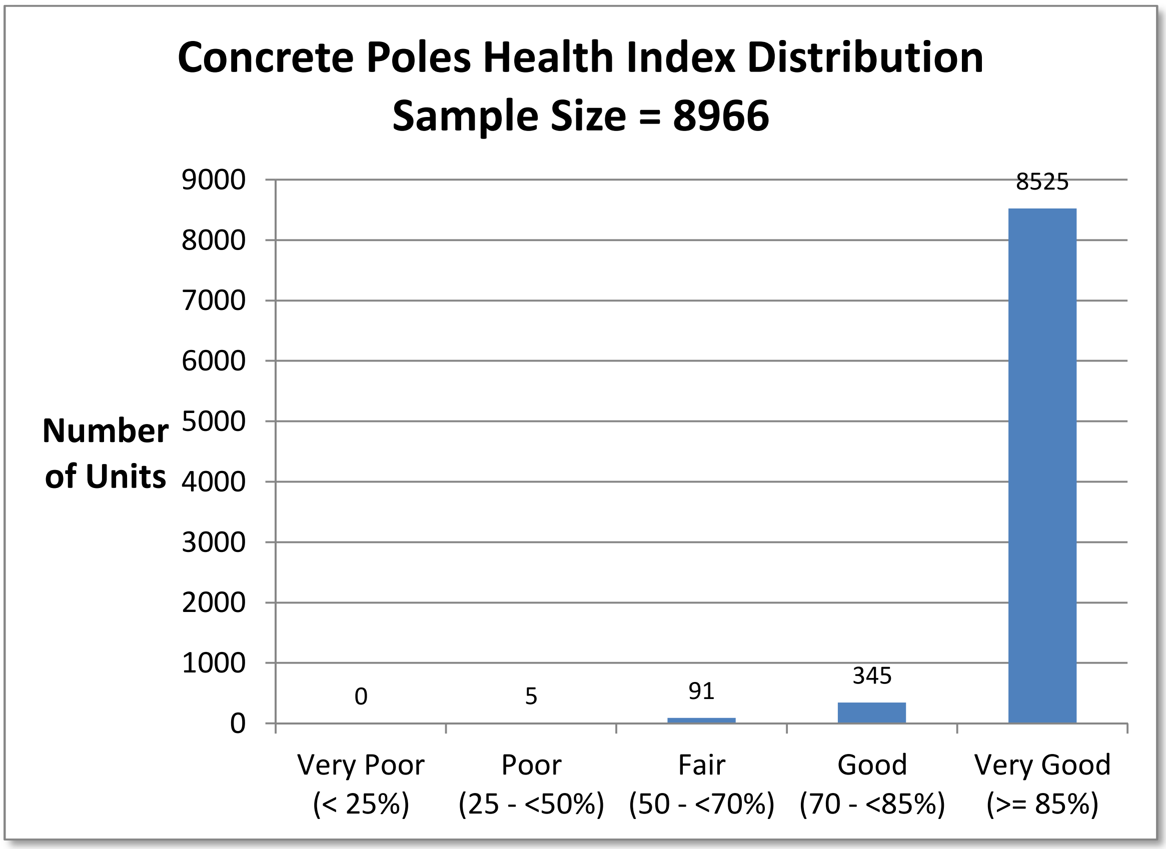

Figure 9-7 Concrete Poles Health Index Distribution (Unit)

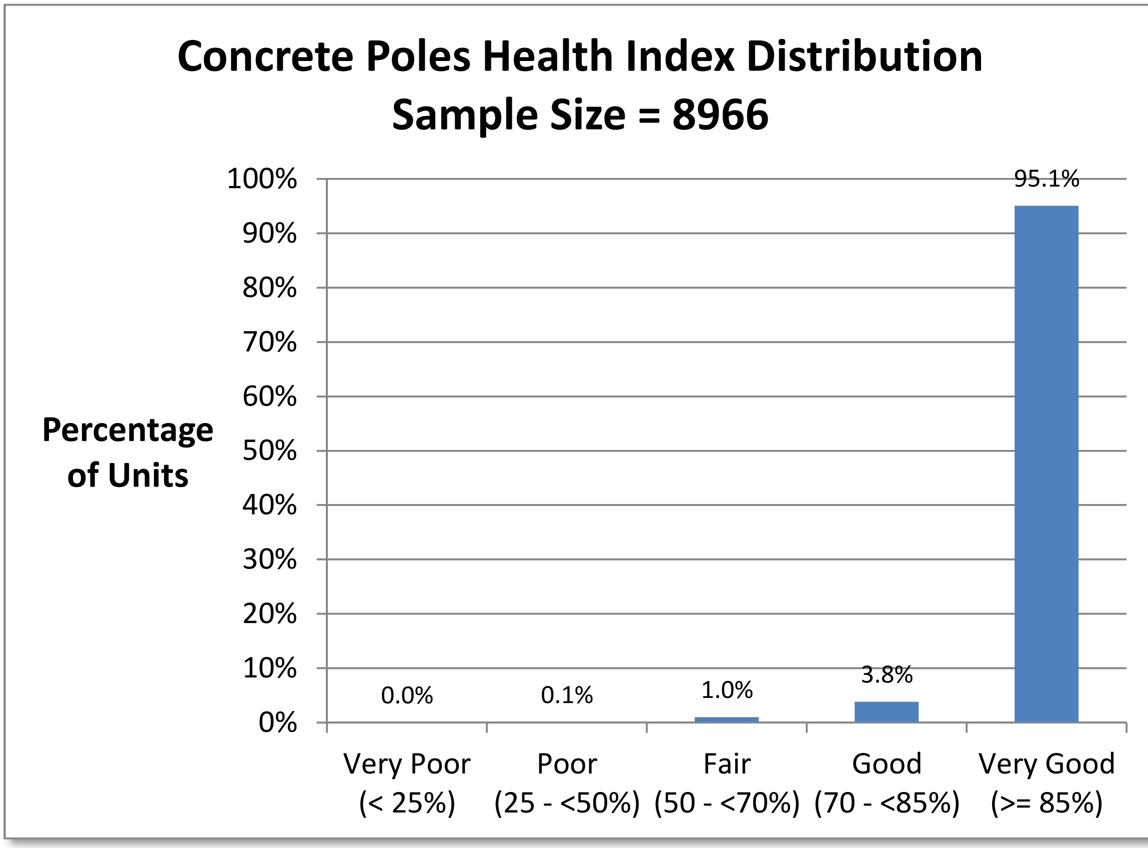

Figure 9-8 Concrete Poles Health Index Distribution (Percentage)

9.4 Flagged for Action Plan

The number of units that are estimated to fail was based on the failure rate. In addition, since Poles were proactively replaced, the flagged for action plan also included a planned replacement of 1% of units that are over 45 years old and 55 years old for Wood and Concrete Poles respectively.

Wood Poles

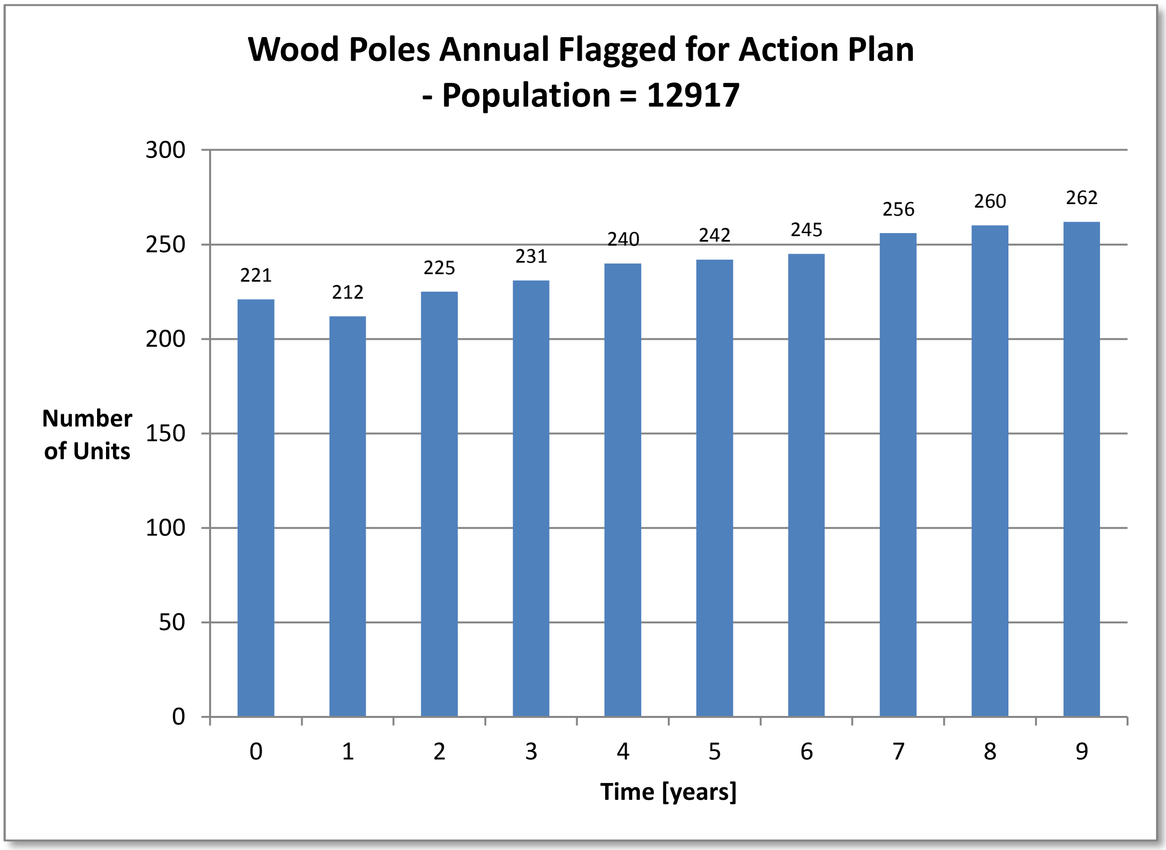

Figure 9-9 Wood Poles Flagged for Action Plan

Concrete Poles

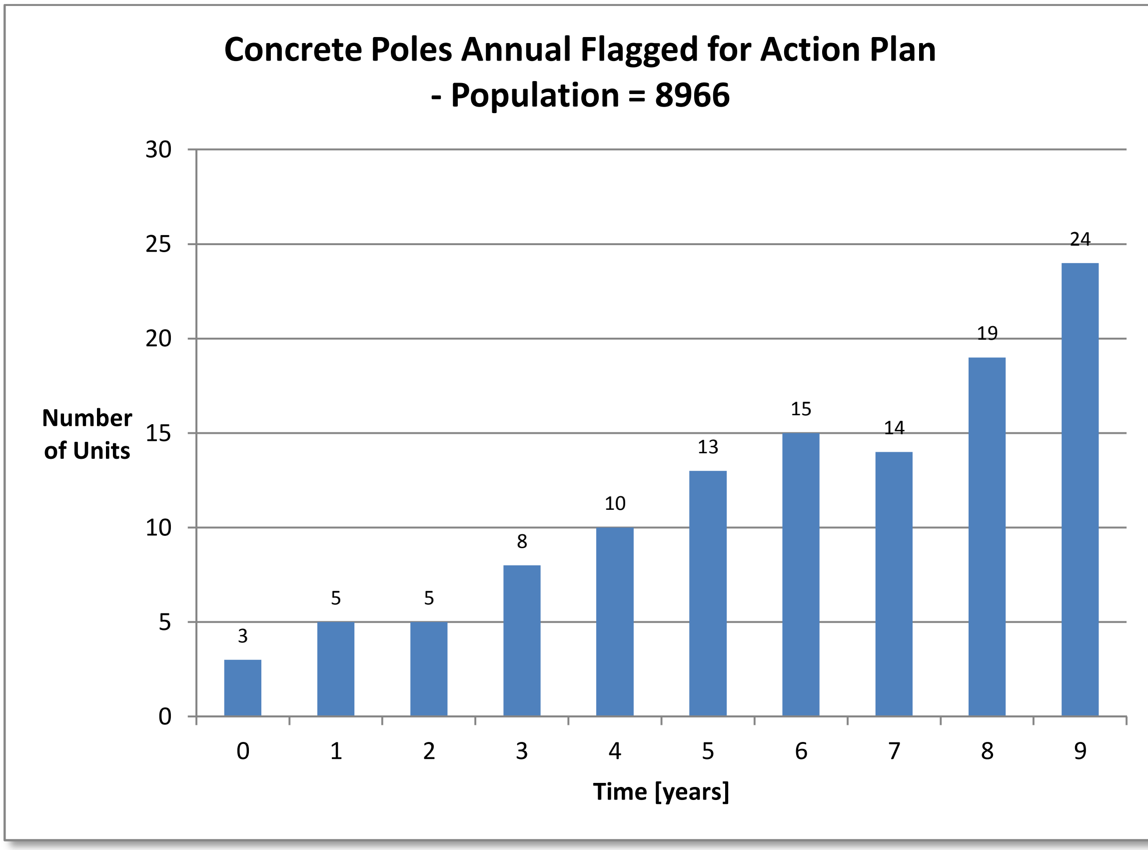

Figure 9-10 Concrete Poles Flagged for Action Plan

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9.5 Data Analysis

In 2013, the assessment for both Wood and Concrete poles were based on age only. Because age was known for most poles, the 2013 DAIs for both wood and concrete poles was 100%. In 2014 Enersource launched a pole inspection program wherein visual inspection information was gathered. In 2014, the Health Index formulas for wood and concrete poles were revised to include inspection data. Because less than 40% of wood poles were inspected, the DAI for wood poles dropped to 55%. Similarly, because only 40% of concrete poles had inspection data, the DAI dropped to 55%.

The data gap is now as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Pole Strength (Wood Poles only)	Pole Strength	☆☆☆	Pole	Example: Ratio of actual circumference over the original circumference	On-site testing

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 9:

Ref: Manager's Summary Page 30 Figure 3

a) Please provide the data requested in the Table provided as Appendix A.

b) Please discuss the general timing of replacement for assets in each of the following categories: very poor, poor, fair, good and very good condition.

Response:

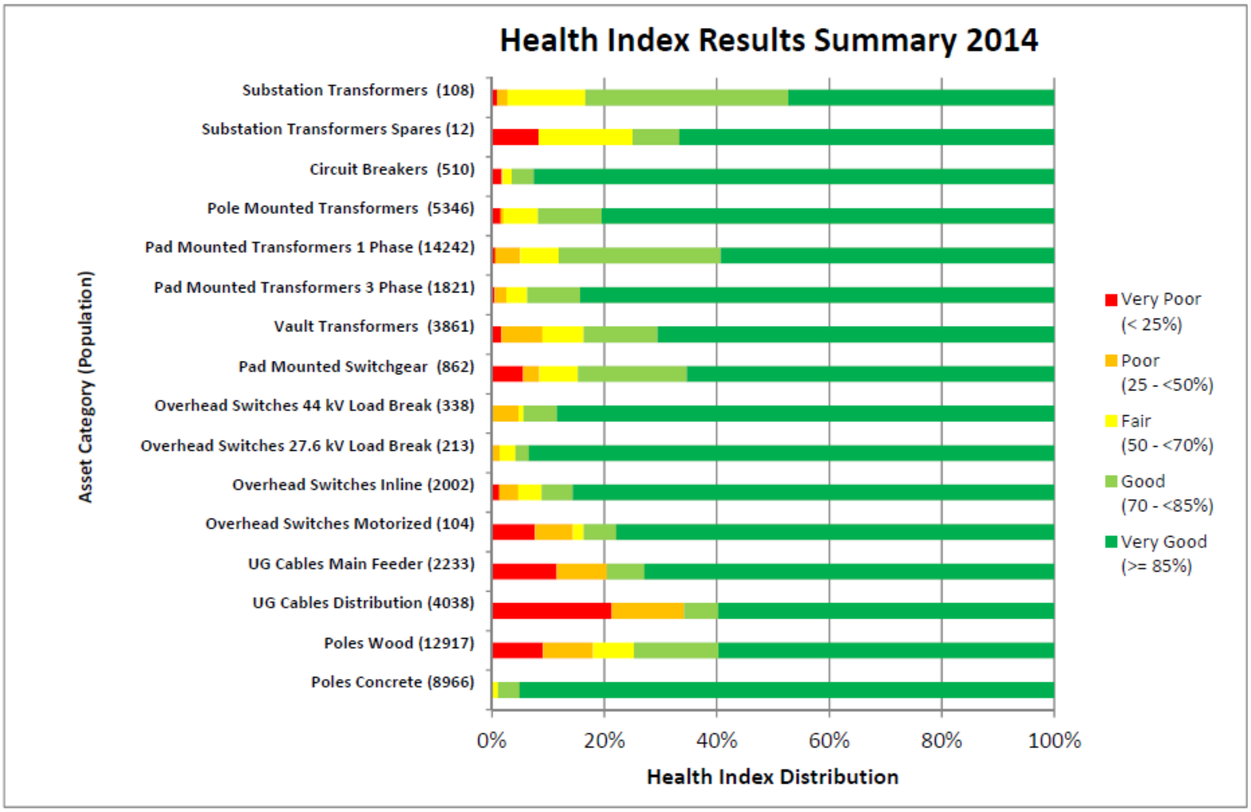
a) The data requested is attached in Appendix A.

b) On an annual basis, Enersource works with Kinectrics to carry out Asset Condition Assessement ("ACA") of its major assets. The summary of the 2014 health index results are shown in the figure below.

As evident from this chart, there are a number of asset groups that have equipment in a 'very poor' or 'poor' condition. Enersource places priority on replacing assets that are in a 'very poor' or 'poor' condition. The Asset Management and Asset Operations groups work together to identify areas that have assets in 'very poor' or 'poor condition' and identify the relevant project(s) to be assessed with the prioritization process as outlined in the response to 2-Staff-11.

The replacement of assets in 'very poor' or 'poor' condition will also be dependent on availability of resources and capital investment which will also be assessed during the prioritization process for non-mandatory projects.

Ongoing inspection and maintenance of all major assets allows Enersource to monitor the condition of its assets and any deterioriation of a particular asset or asset group would be captured in the annual ACA and flagged for replacement during the project selection and prioritization stage.


Health Index Results Summary 2014
Substation Transformers (108)
Substation Transformers Spares (12)
Circuit Breakers (510)
Pole Mounted Transformers (5346)
Pad Mounted Transformers 1 Phase (14242)
Pad Mounted Transformers 3 Phase (1821)
Vault Transformers (3861)
Pad Mounted Switchgear (862)
Overhead Switches 44 kV Load Break (338)
Overhead Switches 27.6 kV Load Break (213)
Overhead Switches Inline (2002)
Overhead Switches Motorized (104)
UG Cables Main Feeder (2233)
UG Cables Distribution (4038)
Poles Wood (12917)
Poles Concrete (8966)
Asset Category (Population)
0%
20%
40%
60%
80%
100%
Health Index Distribution
Very Poor (< 25%)
Poor (25 - <50%)
Fair (50 - <70%)
Good (70 - <85%)
Very Good (>= 85%)

	Asset	Population	Condition - Quantities					%	%	%	%	%	Number of Units Planned for Replacement		Number of Units Replaced				
			Very Good	Good	Fair	Poor	Very Poor	Very Good	Good	Fair	Poor	Very Poor	2015	2016	2010	2011	2012	2013	2014
1	**Substation Transformers**	108	51	39	15	2	1	47%	36%	14.0%	2.0%	< 1%	2	4	4	1	3	4	0
2	**Substation Transformer Spares**	12	8	1	2	0	1	67%	8%	17.0%	0.0%	8.0%	N/A	N/A	0	0	0	0	0
3	**Circuit Breakers**	510	472	20	8	1	9	93%	4%	2.0%	< 1%	2.0%	33	17	28	17	16	15	13
4	**Pole Mounted Transformers**	5346	4301	606	329	26	84	80%	11%	6.0%	< 1%	2.0%	200	200	162	109	98	154	205
5	**Pad Mounted Transformers 1 Phase**	14242	8450	4091	987	621	93	59%	29%	7.0%	4.0%	< 1%	350	350	200	213	170	322	315
6	**Pad Mounted Transformers 3 Phase**	1821	1534	172	68	38	9	84%	9%	4.0%	2.0%	< 1%	70	70	37	55	48	68	65
7	**Vault Transformers**	3861	2725	504	285	280	67	71%	13%	7.0%	7.0%	2.0%	250	200	18	44	34	40	166
8	**Pad Mounted Switchgear**	862	563	167	59	25	48	65%	19%	7.0%	3.0%	6.0%	40	40	17	25	23	35	34
9	**Overhead Switches 44 kV Load Break**	338	299	20	3	16	0	88%	6%	< 1%	5.0%	0.0%	10	10	6	10	6	2	7
10	**Overhead Switches 27.6 kV Load Break**	213	199	5	6	3	0	93%	2%	3.0%	1.0%	0.0%	5	5	12	2	4	4	3
11	**Overhead Switches Inline**	2002	1715	110	83	67	27	86%	5%	4.0%	3.0%	1.0%	75	75	101	108	90	63	73
12	**Overhead Switches Motorized**	104	81	6	2	7	8	78%	6%	2.0%	7.0%	8.0%	5	5	3	2	4	4	5
13	**UG Cables Main Feeder**	2233	1628	148	0	200	258	73%	7%	0.0%	9.0%	12.0%	40	50	26	13	33	36	22
14	**UG Cables Distribution**	4038	2411	247	0	519	861	60%	6%	0.0%	13.0%	21.0%	60	70	39	59	35	52	56
15	**Poles Wood**	12917	7707	1945	935	1153	1177	60%	15%	7.0%	9.0%	9.0%	500	500	403	306	254	214	282
16	**Poles Concrete**	8966	8525	345	91	5	0	95%	4%	1.0%	< 1%	0.0%	100	100	101	77	63	53	70

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 10:

Ref:

a) Please provide the End of Life data requested in the Table provided as Appendix B.

	Asset	Population	End of Life (EOL)	# At or Beyond EOL in 2015
1	Substation Transformers			
2	Substation Transformer Spares			
3	Circuit Breakers			
4	Pole Mounted Transformers			
5	Pad Mounted Transformers 1 Phase			
6	Pad Mounted Transformers 3 Phase			
7	Vault Transformers			
8	Pad Mounted Switchgear			
9	Overhead Switches 44 kV Load Break			
10	Overhead Switches 27.6 kV Load Break			
11	Overhead Switches Inline			
12	Overhead Switches Motorized			
13	UG Cables Main Feeder			
14	UG Cables Distribution			
15	Poles Wood			
16	Poles Concrete			

Response:

Response:

a) Table 1 shows the End of Life data for Enersource's equipment in the Table provided as Appendix B. The asset useful life was used to compute EOL for Enersource's major assets,

	Asset	Population	End of Life (EOL)	# At or Beyond EOL in 2015
1	Substation Transformers	108	40	18
2	Substation Transformer Spares	12	40	7
3	Circuit Breakers	510	40	77
4	Pole Mounted Transformers	5,346	45	506
5	Pad Mounted Transformers 1 Phase	14,242	35	1547
6	Pad Mounted Transformers 3 Phase	1,821	35	101
7	Vault Transformers	3,861	35	973
8	Pad Mounted Switchgear	862	25	329
9	Overhead Switches 44 kV Load Break	338	40	35
10	Overhead Switches 27.6 kV Load Break	213	40	13
11	Overhead Switches Inline	2,002	40	265
12	Overhead Switches Motorized	104	25	29
13	UG Cables Main Feeder	2,233	40	95
14	UG Cables Distribution	4,038	40	323
15	Poles Wood	12,917	45	1928
16	Poles Concrete	8,966	55	71

Table 1: Equipment End of Life Data

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 11:

Ref:

a) Please provide the failure data requested in the Table provided as Appendix C.

No. of Failures

	Asset	2010	2011	2012	2013	2014	2015
1	Substation Transformers						
2	Circuit Breakers						
3	Substation Transformer Spares						
4	Pole Mounted Transformers						
5	Pad Mounted Transformers 1 Phase						
6	Pad Mounted Transformers 3 Phase						
7	Vault Transformers						
8	Pad Mounted Switchgear						
9	Overhead Switches 44 kV Load Break						
10	Overhead Switches 27.6 kV Load Break						
11	Overhead Switches Inline						
12	Overhead Switches Motorized						
13	UG Cables Main Feeder						
14	UG Cables Distribution						
15	UG Secondary Cable						
16	Poles Wood						
17	Poles Concrete						

Response:

Currently, Enersource does not have a complete set of failure data for the above listed assets. As outlined in its Distribution System Plan (see SUPP-Staff-15), Enersource is working on connecting its major information systems, cleaning up asset records and defining process workflows that will allow it to carry out more advanced data analysis, such as the analysis of the failure rate of its major assets. Nevertheless, Enersource carries out detailed inspection of its major assets and subsequent asset condition assessments to determine assets that require replacement due to deteriorating condition (e.g., rotting poles, leaking transformers etc.). This ensures that capital dollars are spent on assets that are at risk of failure and may impact publich safety, environment, reliability, etc. For more information on Enersource's methodology for replacing assets at risk of failure and how the projects are being selected and prioritized, please refer to the response to 2-Staff-11.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 12:

Ref:

a) Please provide the historical spending data requested in the Table provide as Appendix D.

	Actual					Forecast	
	2010	2011	2012	2013	2014	2015	2016
OVERHEAD							
1 Overhead Switch Replacement Program							
$							
# of Switches Replaced							
2 Insulator Replacement Program							
$							
# of Insulators Replaced							
3 Wood Pole Replacement							
$							
# of Wood Poles Replaced							
4 Concrete Pole Replacement							
$							
# of Concrete Poles Replaced							
5 Overhead Transformer and Equipment Renewal							
$							
# of O/H Transformers Replaced							
UNDERGROUND							
6 U/G Transformer and Equipment Renewal							
$							
# of U/G Transformers Replaced							
7 Padmounted Switchgear Replacement							
$							
# of Pad Mounted Switchgear Replaced							
8 Underground Cable and Splice Replacement							
$							
# of km completed							
9 Secondary Cable Replacement							
$							
# of km completed							

Response:

Below is the table showing historical spending data.

		Actual					Forecast	
		2010	2011	2012	2013	2014	2015	2016
	OVERHEAD							
1	**Overhead Switch Replacement Program**							
	$	207,115	131,086	136,444	263,186	336,196	500,000	300,000
	# of Switches Replaced	42	28	29	72	86	115	75
2	**Insulator Replacement Program**							
	$	158,138	45,489	43,946	193,936	239,808	300,000	300,000
	# of Insulators Replaced	635	143	150	623	768	892	900
3	**Wood Pole Replacement**							
	$	433,757	360,038	559,289	326,986	469,075	364,923	400,000
	# of Wood Poles Replaced	70	26	38	35	60	38	40
4	**Concrete Pole Replacement**							
	$	248,892	188,633	363,427	261,158	982,323	819,926	800,000
	# of Concrete Poles Replaced	15	13	28	14	47	40	40
5	**Overhead Transformer and Equipment Renewal**							
	$	237,607	242,340	266,695	570,086	1,871,787	2,038,991	3,000,000
	# of O/H Transformers Replaced	41	42	46	90	179	188	300
	UNDERGROUND							
6	**U/G Transformer and Equipment Renewal**							
	$	1,019,605	564,639	1,092,903	2,489,183	5,546,800	5,867,851	4,125,000
	# of U/G Transformers Replaced	91	50	94	179	371	471	300
7	**Padmounted Switchgear Replacement**							
	$	434,493	699,257	696,107	747,073	1,312,525	1,996,602	1,780,000
	# of Pad Mounted Switchgear Replaced	15	17	13	13	24	32	30
8	**Underground Cable and Splice Replacement**							
	$	1,158,782	888,782	1,821,877	1,089,866	2,008,320	1,195,215	1,400,000
	# of km completed	5,705	6,749	7,877	4,876	7,665	7,613	8,000
9	**Secondary Cable Replacement**							
	$	106,174	70,859	69,943	71,182	60,120	31,128	95,000
	# of km completed	622	774	762	643	585	287	950

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 13:

Ref: Supplementary Evidence – System Renewal Business Case 2016-C0561-1 Page 1 of 27

Preamble: Enersource indicates that the pole line will be upgraded to current design and construction standards.

a) Has Enersource implemented new design and construction standards since its last Cost of Service Application (EB-2012-0033)?

b) If yes to part (a):

-i) please explain the differences between the current design and construction standards compared to the previous design and construction standards including cost.

Response:

a) Enersource has not made any significant changes to its design and construction standards since its last Cost of Service Application (EB-2012-0033).

b) As noted above, Enersource has not made any significant changes to its design and construction standards. The System Renewal Business Case, 2016-C0561-1, is referring to overhead rebuild projects that require replacement of overhead distribution equipment that dates back as far back as the 1960's and has reached the end of its useful life.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 14:

Ref: Supplementary Evidence – System Renewal Business Case# 2016-C0561

Preamble: Enersource indicates the planned replacement of pole lines cost much less than emergency or reactive replacements and are less disruptive to customers.

a) Please provide the cost difference between a planned wood pole replacement compared to a reactive pole replacement and show the calculation.

Response:

Enersource's practice is not to run poles to failure, not only due to the cost differential factor but also to avoid other potential risks as explained below.

Some of the factors taken into consideration in deciding to adopt a planned replacement program vs. a reactive approach are:

- *Cost* –Typically, a planned job would be done during regular business hours and take into consideration the coordination of various activities. In a planned job all of the activities would be arranged ahead of time such as crew, stakeouts, switching, materials, and trucks, as well as sending notices in advance to affected customers. This approach ensures crew are available to perform the work as scheduled, and that all materials, vehicles and tools are ready. It also allows customers the time to make alternative arrangements, if necessary, such as back up power, amending schedules, or vacating their properties during the work period.

  Instead, in an emergency or unplanned urgent job, as a result of a wood pole failure, the work would likely be done during overtime hours when crews are unscheduled but on-call. Generally, this work would be done in a much more difficult environment, not prepared as needed, which would likely result in the job taking longer, or being completed in a temporary fashion, which would require further work at a point in the future, increasing the cost of the job. Enersource must act in haste in such a situation, not necessarily the most efficient and cost effective decision-making, in order to coordinate all of the activities listed above. All of these elements result in a premium paid to perform the same work as a planned replacement.

  Below is an example of an estimate for a 45 foot pole replacement on a radial circuit for a scheduled job vs. emergency replacement. The unplanned option assumes the work is performed during off-hours and includes extra time spent on diagnosing the problem, organizing the crew, travel time, time to order materials (assuming they are available; if not, Enersource would have to find time-consuming alternative options), organize stakeouts, switching, and getting all other activities coordinated. The uplanned replacement amounts to a 40% premium over the planned replacement job.

		Planned		Un-planned
Labour Costs	$	6,047.78	$	9,330.75
Materials	$	1,603.80	$	1,603.80
Supervision	$	575.35	$	1,067.20
Equipment and other costs	$	1,450.45	$	1,522.45
Total Job Cost Estimate	**$**	**9,677.38**	**$**	**13,524.20**

- *Safety issues* – if poles are left to "run to failure' this could create significant risk in public and worker safety. Catastrophic pole failures create unacceptable risks to the public and Enersource's workers. Enersource, as a licensed electricity distributor, has an obligation to operate its distribution system in a safe manner. Enersource takes this responsibility very seriously and takes every reasonable step to ensure that safe conditions on its distribution system are maintained at all times.

- *Reliability* - catastrophic pole failures also present potentially severe and prolonged reliability impacts. Even under ideal environmental conditions, the loss of one or more poles and the associated feeders can interrupt power to hundreds or thousands of customers for several hours.

- *Customer impact* – an unplanned interruption of electricity due to a pole failure is more than just inconvenient. Most functions require electricity, and not all customers have the benefit of back up power sources, or if they do the power may be limited to only critical uses and/or for a limited amount of time. Customers who operate businesses will likely suffer financial consequences when power is interrupted unexpectedly.

- *Interferes with planned work* – Emergency repairs are usually prioritized at the expense of planned work. Planned work may be pushed or cancelled completely. This may result in a delay to important system remediation, negatively affecting customers who were expecting and prepared for the work to be completed. This change of plans detrimentally affects both Enersource and its customers.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 15:

Ref: Supplementary Evidence – System Renewal Business Case# 2016-C0561-4

a) Please provide the number of wood pole failures and concrete pole failures for the years 2010 to 2014 and 2015 year to date for poles that were not at or beyond Expected Useful Life.

b) PowerStream is undertaking a pole reinforcement program in addition to its pole replacement program to extend the life of certain poles. Has Enersouce considered implementing a similar program. If not, why not?

c) Please provide a listing of all of the expenditures in 2016 in addition to the Wood Pole Installations Program that include wood pole replacements and the corresponding number of forecast replacements in each.

d) Please provide a listing of all of the expenditures in 2016 in addition to the Concrete Pole Installations Program that include concrete pole replacements and the corresponding number of forecast replacements in each.

Response:

a) Please refer to the response to AMPCO-10 and AMPCO-11.

b) As noted in the response to AMPCO-9, Enersource has close to 9% or over 1,100 of wood poles that are in 'very poor' condition. These are the poles that require immediate attention and need to be replaced to minimize the risk of failure. Due to a large number of poles required for immediate replacement, Enersource will be focusing on replacing these poles in 'very poor condition'. In addition, Enersource's Asset Management continues to evaluate available technologies and procedures for pole reinforcement and run appropriate pilot projects to evaluate its effectiveness. Enersource recognizes that continuous improvements and scan of available technologies is key to having strong asset management practices.

c) and d)

Below is the listing all of the expeditures in 2016, in addition to the Wood Pole Installations Program and the Concrete Pole Installations Program.

Business Unit	Description	2016 Budget	# of Poles	
C0504 - Substation Upgrade		**$ 11,600,000**	**-**	
C0507 - Subtransmission Expansion	Port - Stavebank to Elizabeth	$ 750,000	25	Concrete
C0507 - Subtransmission Expansion	Cawthra - Burnhamthorpe to Bloor	$ 900,000	30	Concrete
C0507 - Subtransmission Expansion	Webb MS Feeder Egress - Section 1	$ 750,000	25	Concrete
C0507 - Subtransmission Expansion		**$ 2,400,000**	**80**	
C0576 - Auto Switches/SCADA		**$ 3,200,000**	**-**	
SYSTEM SERVICE		**$ 17,200,000**	**80**	
C0505 - Subdivision Rebuild		**$ 13,250,000**	**-**	
C0561 - Overhead Rebuilds	2016 Overhead Switch Replacement Program	$ 300,000		
C0561 - Overhead Rebuilds	2016 Insulator Replacement Program	$ 300,000		
C0561 - Overhead Rebuilds	2016 Stores Small Capital Material	$ 400,000		
C0561 - Overhead Rebuilds	2016 Wood Pole Installations	$ 400,000		
C0561 - Overhead Rebuilds	2016 Concrete Pole Installations	$ 800,000		
C0561 - Overhead Rebuilds	2016 Misc Capital (FIs, Term Poles, Animal Protection, Grounding Replacments)	$ 200,000		
C0561 - Overhead Rebuilds	Vermouth/Breckonridge	$ 360,000	20	Wood
C0561 - Overhead Rebuilds	Meadow Wood/Country Club	$ 1,296,000	72	Wood
C0561 - Overhead Rebuilds	Hull/Studley	$ 720,000	40	Wood
C0561 - Overhead Rebuilds	Credit Woodlands - Section 2 - Credit Heights Drive	$ 810,000	45	Wood
C0561 - Overhead Rebuilds	Robin MS Feeder Egress	$ 504,000	28	Wood
C0561 - Overhead Rebuilds		**$ 6,090,000**	**205**	
C0562 - Subtransmission Renewal	Bloor - Cawthra to Tomken	$ 600,000	20	Concrete
C0562 - Subtransmission Renewal	Lakeshore - Seneca to Cawthra	$ 690,000	23	Concrete
C0562 - Subtransmission Renewal	Queen - Briarwood to Seneca	$ 600,000	20	Concrete
C0562 - Subtransmission Renewal	Goreway - Derry to City Limits	$ 1,200,000	40	Concrete
C0562 - Subtransmission Renewal	Stavebank MS - Feeder Egress	$ 150,000	5	Concrete
C0562 - Subtransmission Renewal	North Sheridan Way - Robin MS To Mississauga	$ 960,000	32	Concrete
C0562 - Subtransmission Renewal		**$ 4,200,000**	**140**	
C0563 - U/G TX/Replace/Overhaul		**$ 4,125,000**	**-**	
C0564 - O/H TX/Replace/Overhaul		**$ 3,000,000**	**-**	
C0565 - U/G Cable Replace		**$ 3,750,000**	**-**	
C0567 - Emergency Replacements		**$ 320,000**	**-**	
SYSTEM RENEWAL		**$ 34,735,000**	**345**	
C0531 - Roads	QEW - Hurontario To Mississauga Road	$ 1,500,000	50	Concrete
C0531 - Roads	Mclaughlin Road Widening - Eglinton To Parkwood	$ 600,000	20	Concrete
C0531 - Roads	Goreway At City Limits (Grade Separation)	$ 300,000	10	Concrete
C0531 - Roads	Torbram Road - Grade Separation	$ 300,000	10	Concrete
C0531 - Roads	Various Intersections	$ 300,000	10	Concrete
C0531 - Roads		**$ 3,000,000**	**100**	
C0532 - LRT		**$ 400,000**	**-**	
C0541 - New Subdivisions(OfferConnect)		**$ 800,000**	**-**	
C0542 - Ind/Comm Services		**$ 2,600,000**	**-**	
C0544 - Residential Service Upgrades		**$ 125,000**	**-**	
C0594 - Smart Meters Large Users		**$ 1,505,511**	**-**	
C0597 - Grid Supply Point Metering		**$ 1,263,320**	**-**	
C0598 - Metering		**$ 1,172,000**	**-**	
C0899 - Smart Meters - New Condos		**$ 1,387,000**	**-**	
C0900 - Green Energy - FIT/MicroFIT		**$ 155,000**	**-**	
SYSTEM ACCESS		**$ 12,407,831**	**100**	
C0581 - Engineering & Asset Systems		**$ 1,510,000**	**-**	
C0584 - Rolling Stock		**$ 2,775,000**	**-**	
C0585 - Computer Equip		**$ 671,000**	**-**	
C0588 - ERP System		**$ 2,185,000**	**-**	
C0589 - Meter to Cash		**$ 2,470,000**	**-**	
C0591 - Grounds & Building		**$ 2,985,000**	**-**	
C0595 - Major Tools Constr		**$ 200,000**	**-**	
GENERAL PLANT		**$ 12,796,000**	**-**	
TOTAL GROSS CAPITAL EXPENDITURES		**$ 77,138,831**	**525**	
CUSTOMER CONTRIBUTIONS		**$ (2,131,250)**	**-**	
TOTAL NET CAPITAL EXPENDITURES		**$ 75,007,581**	**525**	

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 16:

Ref: Supplementary Evidence – System Renewal Business Case# 2016-C0565-3

a) PowerStream is undertaking a cable injection program in addition to its cable replacement program that is significantly less costly per metre. Has Enersource considered implementing a similar cable injection program? If not, why not?

Response:

In 2015, Enersource joined the Centre for Energy Advancement through Technological Innovation ("CEATI"). CEATI is a user-driven organization that offers technology solutions to its electricity utility participants, who are brought together to collaborate and act jointly to advance the industry through the sharing and developing of practical and applicable knowledge.

Currently, Enersource is working with CEATI and participating utilities to identify and evaluate different cable rejuvenation technologies available on the market, compare their advantages and disadvantages, and evaluate the effectiveness of the rejuvenation practices in terms of improving cable insulation integrity.

Enersource is also in discussion with other Ontario utilities and cable rejuvenation vendors to better understand effectiveness of this program.

In the near future, once the effectiveness of the program has been validated, Enersource will commence with a cable rejuvenation pilot project. However, Enersource is not planning any expenditures in this area in 2016.

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 17:

Ref:

a) Please provide the most recent calculation of Enersource's regulated return.

Response:

Below is the most recent calculation of Enersource's regulated return.

Enersource's regulated return calculation		RRR 2.1.5.6 Distributor Submission for the Reporting Period of 2014
Regulated net income, as per RRR 2.1.7		$26,002,226
Less:		
Future/deferred taxes		$(21,672)
Non rate regulated items		$17,423
Adjustment to interest expense - for deemed debt		$1,663,998
Adjusted regulated net income		$24,342,477

Deemed Equity Calculation:		
Rate Base:		
Cost of power		$740,188,024
Operating expenses		$52,431,185
Total		$792,619,209
Working capital allowance %		13.50%
Total working capital allowance		$107,003,593
Fixed Assets		
Opening balance - regulated fixed assets (NBV)	$525,899,107	
Closing balance - regulated fixed assets (NBV)	$550,494,641	
Average regulated fixed assets	$ 538,196,874	$538,196,874
Total rate base		**$645,200,467**
Regulated deemed short-term debt %	4%	$25,808,019
Regulated deemed long-term debt %	56%	$361,312,262
Regulated deemed equity %	40%	$258,080,187
		$645,200,467

Regulated Rate of Return on Deemed Equity		
Achieved ROE% (Appears on Scorecard)		**9.43%**
Deemed ROE% from most recent cost of service application	**last approved EDR**	**8.93%**
Difference - maximum deadband 3%		**0.50%**

Interest adjustment on deemed debt:		
Regulated deemed short-term debt - as above	$ 25,808,019	6.67%
Regulated deemed long-term debt - as above	$ 361,312,262	93.33%
	$ 387,120,280	100.00%
Approved Short-term debt rate %	2.08%	0.14%
Approved Long-term debt rate %	5.09%	4.75%
Weighted Average debt rate %		4.89%
Regulated deemed debt - as above	$387,120,280	
Weighted average debt rate (%)	4.89%	
Deemed interest	$18,927,601	
Interest expense as per the OEB trial balance	$16,663,658	
Difference	$2,263,943	
Utility tax rate	26.50%	
Tax effect on interest expense	$(599,945)	
Interest adjustment on deemed debt:	$1,663,998	

Responses to Association of Major Power Consumers in Ontario Interrogatories

INTERROGATORY 18:

Ref: October 2, 2015 Supplementary ICM Evidence, 2016 Capital Expenditures Projects Budget Pages 2

a) Please provide the Emergency Replacement spending for the years 2010 to 2014 and forecast for 2015.

Response:

a) Below is the Emergency Replacement – Capital Spending table.

Emergency Replacement - Capital Spending

	Actual					Forecast						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Emergency Replacements	$328,344	$137,287	$290,056	$302,140	$415,577	$320,000	$320,000	$320,000	$320,000	$320,000	$320,000	$320,000

NOTES:

2010 and 2011 are estimated since emergency replacements were not tracked in a separate business unit until 2012. Since they were not capitalized, no burden or admin is included in the costs.