niagara peninsula energy

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Ontario Energy Board
P.O. Box 2319
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2300 Yonge Street
Toronto, ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Re: Niagara Peninsula Energy Inc. Application for 2011 Distribution Rates
Board File Number: EB-2010-0138
Response to Interrogatories – OEB Staff

Dear Ms. Walli:

Please find attached Niagara Peninsula Energy Inc.'s responses to interrogatories on its 2011 Electricity Distribution Cost of Service Rate Application. Two hard copies will follow by courier.

If further information is required, please contact Suzanne Wilson, Vice-President Finance at 905-353-6004 or Suzanne.Wilson@npei.ca.

Yours truly,

Brian Wilkie
President & CEO

Cc: Intervenors of Record

1. Responses to Letters of Comment

Several letters of comment have been filed with the Board concerning this rate application. Please confirm whether a reply was sent from NPEI to the authors of the letter. If confirmed, please file the replies with the Board. If not confirmed, please explain why a response was not sent and whether the applicant intends to respond.

Response:

Following publication of the Notice of Application and Hearing, Niagara Peninsula Energy Inc. has not received any letters of comment. All letters of comment were directed to the OEB in accordance with the NOA and hence NPEI has not sent any replies to the authors.

2. Asset Management Plan

Ref: Exh 1, p. 13; Exh 8, p. 25

a) When was the Asset Management Plan scheduled to be received from Kinectrics, and when does NPEI expect to file the plan?

b) Will the Asset Management Plan address capital expenditures that will lower NPEI's Distribution Loss Factor?

Response:

a) The Asset Condition Assessment and Asset Management Plan documents were received from Kinectrics on February 10, 2011. The Asset Management Plan was submitted to the OEB on February 14, 2011. Please see Appendix A.

b) The asset management plan did not specifically highlight capital expenditures that directly lower NPEI's Distribution Loss Factor (DLF). Several capital projects in 2011 will contribute to lowering NPEI's DLF. Rebuild, replacement, and rehabilitation projects typically reduce the DLF due to the standardized materials used in construction (larger conductor sizes, loss evaluated distribution transformers, etc.) These types of projects also contribute to a reduction in DLF due to the fact that they provide increased capacity of the circuit, station, etc. Increased capacity permits re-configuration of the distribution system for the purpose of minimizing losses. Per Exhibit 2, page 121, the following 2011 projects will contribute to lowering NPEI's DLF:

Project #	Project Description
2011-0001	KERR ST – LUNDY'S LANE – U/G REPLACEMENT
2011-0003	DOUBLE CCT – MONTROSE – MCLEOD TO CANADIANA
2011-0005	RIALL ST – DORCHESTER TO ST PAUL O/H EXTN
2011-0007	DUNN/DRUMMOND/SYMMES/MAIN

3. Low Income Energy Assistance Program (LEAP)

Ref: Exh 1, p. 34

a) Please confirm that NPEI has not included an amount in its requested revenue requirement for the emergency financial assistance component of the Low Income Energy Assistance Program (LEAP).

b) Please provide the following calculation: 0.12% of the total distribution revenue proposed by the applicant for the 2011 Test Year.

Response:

a) NPEI confirms it has not included any amount in our requested revenue requirement for the emergency financial assistance component of LEAP.

b) The LEAP amount would be 0.12% times $32,421,330 = $38,906

4. Stranded Meters

Ref: Exh 2, p. 25

a) What amount does NPEI expect to recover from stranded meters by resale or scrap? What proportion of the expected total recovery has been realized to date?

b) Since transferring stranded meter costs to the sub-account of account 1555, has NPEI continued to record depreciation expenses in order to reduce the net book value through accumulated depreciation? If so, please provide the depreciation expense amounts for the period from the time the stranded meters were transferred to the sub-account to December 31, 2010.

c) If no depreciation expenses were recorded, please provide the depreciation expense amount that would have been applicable for the period from the time the stranded meters were transferred to the subaccount to December 31, 2010.

d) Were carrying charges recorded for the stranded meter cost balances in the sub-account, and if so, please provide the total carrying charges recorded to December 31, 2010.

e) If the amount that NPEI is transferring, $4,175,010, does not reflect depreciation, carrying charges, and salvage, please provide an estimate of the amount that will ultimately be recorded for stranded meters.

f) Please describe how NPEI intends to recover stranded meter costs in rates, including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

Response:

a) To date NPEI has received $8,208 in scrap proceeds, for 38,195 conventional meters. Based on the average scrap value per meter, NPEI expects to receive an additional $2,458 in scrap proceeds. The table below provides a summary of NPEI's actual and forecast scrap recoveries.

	Summary of Scrap Proceeds		
	# of Meters	**$**	**%**
Scrap proceeds received to date	38,195	8,207.75	78.2%
Forecast of additional scrap proceeds to be received	10,663	2,291.38	21.8%
Forecast of total scrap proceeds	48,858	10,499.13	100.0%

b) Since transferring stranded meter costs to the sub-account of account 1555 NPEI has not continued to record depreciation expenses. The following table outlines the stranded meter costs in 2009, up to June 30th of 2010 and from July 1 to December 31, 2010.

c)

Year Stranded	Dec 2009	up to June 30th 2010	July 1 to Dec 31 2010	Total 2010	LTD at Dec 2010
# of Meters	5,454	28,828	11,131	39,959	45,413
Cost	631,139.73	3,163,008.18	1,220,749.20	4,383,757.38	5,014,897.11
Accumutated Depreciation	(400,378.14)	(2,204,477.16)	(893,894.32)	(3,098,371.48)	(3,498,749.62)
Net Book Value	206,761.14	958,531.02	326,854.88	1,285,385.90	1,516,147.49

The smart meters commenced deployment in December of 2009 and these additions are included in the $4,175,009 smart meter additions being transferred to rate base in 2010. The assumption is the majority of stranded meters were stranded by June 30th or half of 2010. NPEI's depreciation policy up to December 31, 2009 was to take a full year's depreciation in the year of acquisition and nil in the year of disposal. Therefore, no depreciation was taken in 2010 on these meters. NPEI's smart meters installed, replaces these stranded meters and hence depreciation is only taken on the new meters in service.

d) Had NPEI not transferred any smart meters to rate base or stranded any meters in 2010 and excluding 2010 additions of non-smart meters the depreciation expense on meters would have been $232,977.

e) NPEI confirms that no carrying charges have been recorded on the stranded meter sub-account of 1555.

f) NPEI confirms the amount being transferred to rate base in the amount of $4,175,010 as per the smart meter audit report (Exhibit 9 page 40) does not reflect depreciation, carrying charges or salvage value. It only includes the purchase of the smart meters up to June 30th, the installation costs up to June 30th and other capital costs as at June 30th. The table below outlines the estimated total for smart meters to be stranded.

Year Stranded	LTD at Dec 2010	Estimate 2011	Grand Total
# of Meters	45,413	3,445	48,858
Cost	5,014,897.11	377,817.00	5,392,714
Accumutated Depreciation	(3,498,749.62)	(276,656.72)	(3,775,406)
Net Book Value	1,516,147.49	101,160.28	1,617,308

For smart meter capital additions between July 1st 2010 and December 31, 2010 in the amount of $286,494 the depreciation expense for 2010 over 25 years applying the half year rule is $5,729.87. This depreciation expense has been recorded in a sub-account of 1556. The capital additions of $286,494 remain in Account 1555 at December 31,2010 and will be transferred to rate base in a future rate application.

g) NPEI proposes to file a final disposition of smart meter costs rate rider application in the future once all costs are known. As at December 31, 2010 the balance for future disposition including the smart meter recoveries to date is $623,224. NPEI will continue to incur smart meter capital and operating costs including depreciation in 2011 up to the date of final disposition as well as continue to recover the $1.00 smart meter rate rider. NPEI will propose a disposition period at the time of final disposition since all costs are unknown at this time. The recovery of the smart meter rate rider in 2011 is expected to be $850,000 and allowing for expenditures in 2011 to be $226,776 to reach a break even point.

5. Service Reliability Indices

Ref: Exh 2, p. 11

a) Does NPEI confirm that SAIDI in the Peninsula West service area was 1.84 in 2006 and 3.38 in 2007, as reported in the OEB statistical yearbook?

b) What was the SAIDI for the Peninsula West service area in 2010?

c) If the index continued the apparent unfavourable trend over the previous four years, please describe any steps that NPEI has undertaken or is planning to improve the reliability of service in that area.

Response:

a) NPEI confirms the SAIDI in the Peninsula West service area was 1.84 in 2006 and 3.38 in 2007 as reported in the OEB statistical yearbook.

b) The SAIDI for the Peninsula West service area in 2010 was 1.72.

c) The SAIDI for the Peninsula West service area over the past four years was as follows:

Year	SAIDI
2006	1.84
2007	3.38
2008	1.99
2009	5.41
2010	1.72

The un-favourable trend from year-to-year SAIDI for the former Peninsula West area of NPEI's service territory was evaluated following the merger. Two major contributors to the un-favourable SAIDI values were identified:

1) The distribution system configuration and installed switching devices provided a limited capability to sectionalize the distribution system following an outage event.

2) Large lengths of 27.6 kV circuit were connected directly to the supply station protective device. A lack of downstream sectionalizing and reclosing devices was apparent.

NPEI started in 2009 to correct these deficiencies by initiating a program to annually install a number of feeder sectionalizing and protective devices in high priority locations. In 2010, NPEI's distribution system performed with an improved SAIDI compared to previous years in the former Peninsula West Utilities area of the service territory. NPEI expects this to continue in future years commencing in 2011 as additional points of sectionalizing and protective devices are installed.

6. Load Forecast Model

Ref: Exh 3, p. 31 (Table 3-7); p. 34

In order to understand why the coefficient of "CDM kWh Saved" is substantially greater than unity (in absolute terms):

a) Does NPEI have consumption statistics that would be able to show whether new customers (and/or newcomers in the population) consume lower kWh than those who are established in the service area?

b) As an alternative to dropping the CDM variable, did NPEI estimate a regression model in which the coefficient of CDM would be constrained at -1.0 or some value nearer to -1 than to -9? In other words, did NPEI estimate a model that would forecast kWh purchases gross of cumulative CDM savings, while retaining the population or customer count variable?

Response:

a) NPEI does not have any statistics that would indicate the level of consumption for newer customers relative to established customers.

b) NPEI has interpreted this interrogatory to be a request for a regression model in which the "CDM kWh Saved" variable is replaced with an explanatory variable that represents cumulative life-to-date CDM kWh savings. NPEI has prepared such a model that includes the cumulative CDM kWh amounts shown in the table below. The Population variable was retained in this model.

Month	Cumulative CDM kWh Saving (For Staff IR 6b)
Jan-02	-
Feb-02	-
Mar-02	-
Apr-02	-
May-02	-
Jun-02	-
Jul-02	-
Aug-02	-
Sep-02	-
Oct-02	-
Nov-02	-
Dec-02	-
Jan-03	-
Feb-03	-
Mar-03	-
Apr-03	-
May-03	-
Jun-03	-
Jul-03	-
Aug-03	-
Sep-03	-
Oct-03	-
Nov-03	-
Dec-03	-
Jan-04	-
Feb-04	-
Mar-04	-
Apr-04	-
May-04	-
Jun-04	-
Jul-04	-
Aug-04	-
Sep-04	-
Oct-04	-
Nov-04	-
Dec-04	-
Jan-05	64,076
Feb-05	128,151
Mar-05	192,227
Apr-05	256,302
May-05	320,378
Jun-05	384,454
Jul-05	448,529
Aug-05	512,605
Sep-05	576,680
Oct-05	640,756
Nov-05	704,832
Dec-05	768,907
Jan-06	1,117,148
Feb-06	1,465,389
Mar-06	1,813,631
Apr-06	2,161,872
May-06	2,510,113
Jun-06	2,858,354
Jul-06	3,206,595
Aug-06	3,554,837
Sep-06	3,903,078
Oct-06	4,251,319
Nov-06	4,599,560
Dec-06	4,947,801

Month	Cumulative CDM kWh Saving (For Staff IR 6b)
Jan-07	5,603,266
Feb-07	6,258,731
Mar-07	6,914,196
Apr-07	7,569,660
May-07	8,225,125
Jun-07	8,880,590
Jul-07	9,536,055
Aug-07	10,191,519
Sep-07	10,846,984
Oct-07	11,502,449
Nov-07	12,157,914
Dec-07	12,813,378
Jan-08	13,720,092
Feb-08	14,626,805
Mar-08	15,533,518
Apr-08	16,440,231
May-08	17,346,945
Jun-08	18,253,658
Jul-08	19,160,371
Aug-08	20,067,084
Sep-08	20,973,798
Oct-08	21,880,511
Nov-08	22,787,224
Dec-08	23,693,937
Jan-09	24,606,419
Feb-09	25,518,901
Mar-09	26,431,383
Apr-09	27,343,865
May-09	28,256,347
Jun-09	29,168,829
Jul-09	30,081,311
Aug-09	30,993,792
Sep-09	31,906,274
Oct-09	32,818,756
Nov-09	33,731,238
Dec-09	34,643,720
Jan-10	35,753,227
Feb-10	36,862,734
Mar-10	37,972,241
Apr-10	39,081,748
May-10	40,191,255
Jun-10	41,300,762
Jul-10	42,410,269
Aug-10	43,519,776
Sep-10	44,629,283
Oct-10	45,738,790
Nov-10	46,848,297
Dec-10	47,957,804
Jan-11	49,126,951
Feb-11	50,296,098
Mar-11	51,465,245
Apr-11	52,634,392
May-11	53,803,539
Jun-11	54,972,686
Jul-11	56,141,833
Aug-11	57,310,980
Sep-11	58,480,127
Oct-11	59,649,275
Nov-11	60,818,422
Dec-11	61,987,569

The summary output of the regression analysis is as follows:

Includes Cumulative CDM kWh and Population

Regression Statistics	
Multiple R	0.969737783
R Square	0.940391369
Adjusted R Square	0.935649773
Standard Error	2622236.458
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	9.5461E+15	1.36373E+15	198.3280382	4.76093E-51
Residual	88	6.05099E+14	6.87612E+12		
Total	95	1.01512E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-298207398.3	61483756.18	-4.850181851	5.28287E-06	-420393441.3	-176021355.4
Heating Degree Days	24420.62187	1985.962068	12.2966205	8.25082E-21	20473.93967	28367.30408
Cooling Degree Days	196532.6038	10459.25379	18.79030835	1.49366E-32	175747.0352	217318.1725
Ontario Real GDP Monthly %	33731.4074	221158.9585	0.152521099	0.879125113	-405775.5401	473238.3549
Number of Days in Month	2884656.783	342906.4507	8.412372464	6.63411E-13	2203202.284	3566111.283
Cumulative CDM kWh	-0.43023135	0.104399197	-4.121021657	8.50858E-05	-0.637702811	-0.222759889
Spring Fall Flag	-5085669.335	724218.818	-7.022282781	4.37132E-10	-6524902.022	-3646436.648
Population	2288.970228	679.7669628	3.367286664	0.001127472	938.0762611	3639.864196

This model results in predicted purchases of 1,193 GWh for the 2011 Test Year. The adjusted R-Square value is 0.94 and the regression coefficient for the Cumulative CDM variable is -0.43.

NPEI notes that in the regression model above, the Ontario Real GDP explanatory variable appears to be no longer statistically significant. The following table displays the summary output from the regression analysis when the Ontario GDP variable is removed:

Includes Cumulative CDM kWh and Population, GDP Removed

Regression Statistics	
Multiple R	0.969729659
R Square	0.940375611
Adjusted R Square	0.936355989
Standard Error	2607807.794
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	9.54594E+15	1.59099E+15	233.9462957	3.01032E-52
Residual	89	6.05259E+14	6.80066E+12		
Total	95	1.01512E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-306655699.8	26538099.03	-11.55530016	2.10527E-19	-359386336.2	-253925063.5
Heating Degree Days	24445.9274	1968.129936	12.420891	3.87658E-21	20535.29523	28356.55958
Cooling Degree Days	196649.8898	10373.55157	18.95685277	5.28764E-33	176037.8642	217261.9153
Number of Days in Month	2883172.4	340882.2549	8.45797151	4.96047E-13	2205846.635	3560498.165
Cumulative CDM kWh	-0.443666045	0.055730655	-7.960897699	5.2256E-12	-0.554401668	-0.332930423
Spring Fall Flag	-5081332.864	719678.6125	-7.060558388	3.50487E-10	-6511318.907	-3651346.822
Population	2388.471029	189.9758007	12.57250145	1.94044E-21	2010.993167	2765.94889

In this model, the Adjusted R-Square value is 0.94, the coefficient of the Cumulative CDM variable is -0.44, and all of the explanatory variables appear to be statistically significant. This model results in predicted purchases of 1,191 GWh for the test year.

The following table compares the results of the two models above that include the Cumulative CDM variable to the regression model that NPEI is proposing in the application:

Model Version	V4 from Application	Staff IR #6 b	Staff IR #6 b without GDP
Explanatory Variables Included	HDD, CDD, GDP Index, Number of Days, CDM, Spring/Fall, Population	HDD, CDD, GDP Index, Number of Days, Cumulative CDM, Spring/Fall, Population	HDD, CDD, Number of Days, Cumulative CDM, Spring/Fall, Population
2010 Bridge Year Predicted Purchases (GWh)	1,230.38	1,219.20	1,219.66
2011 Test Year Predicted Purchases (GWh)	1,277.01	1,192.93	1,191.37
Adjusted R-Squared Value	0.937	0.936	0.936
Population regression coefficient	680.78	2,288.97	2,388.47
CDM kWh Saved Coefficient	(9.00)	n/a	n/a
Cumulative CDM kWh Saved Coefficient	n/a	(0.43)	(0.44)

7. Comparison of 2010 Load Forecast versus Actual System Purchases
Ref: Exh 3, p. 36 (Table 3-8)

a) Please provide the actual system purchases in 2010, the actual Cooling Degree Days, and if possible the actual Heating Degree Days.

b) Please provide any updated analysis on how well the forecast model performed in forecasting 2010 purchases, after taking account of actual versus average weather data.

Response:

a) NPEI's 2010 system purchases are shown in the following table:

Month	kWh Purchases
Jan	112,413,953
Feb	98,822,728
Mar	99,590,880
Apr	88,866,064
May	97,708,833
Jun	106,489,650
Jul	129,819,711
Aug	125,064,295
Sep	98,983,964
Oct	93,865,161
Nov	96,656,392
Dec	111,304,958
Total	1,259,586,591

The actual 2010 Heating Degree Days and Cooling Degree Days for NPEI's service territory are as follows:

Month	Actual 2010 Weather Data HDD	CDD
Jan	653.3	0.0
Feb	551.1	0.0
Mar	434.7	0.0
Apr	253.2	0.0
May	129.4	22.4
Jun	15.0	60.6
Jul	1.9	174.6
Aug	1.4	145.7
Sep	49.5	40.2
Oct	218.2	0.5
Nov	392.4	0.0
Dec	600.5	0.0

b) Using NPEI's proposed forecast model, the 12 year average HDD and CDD values that were used in the application were replaced with the actual 2010 weather data given above. This results in the 2010 predicted purchase changing from 1,230 GWh (using average weather data) to 1,246 GWh (using 2010 actual weather data).

The table below indicates how the predicted purchase value compares to NPEI's actual 2010 purchases:

Actual 2010 GWh Purchases	1,259.59
Predicted 2010 GWh Purchases (using actual HDD and CDD)	1,245.62
GWh Difference	(13.97)
% Difference	-1.1%

8. Forecast Purchases and Billed Energy

Ref: Exh 3, p. 38 (Table 3-11a); Exh 8, p. 25 (Table 8-21)

Is the variable “System Purchases” measured to include losses of 0.45% or to exclude these losses? Is the Distribution Loss Factor of 1.0513 the appropriate conversion factor to use from Predicted Purchases to Weather Normalized Billed Energy, or should it be 1.056 as proposed for the Total Loss Factor in Exhibit 8?

Response:

The system purchase values presented in Table 3-11a exclude the 0.45% Supply Facility losses. Since the Supply Facility Loss Factor (“SFLF”) has already been removed from the purchased kWh, NPEI submits that the appropriate factor to convert from these purchased amounts to billed energy is the average Distribution Loss Factor (“DLF”) of 1.0513.

As indicated in Table 8-21, NPEI is proposing a Total Loss Factor of 1.056 for a Secondary Metered Customer, which is the product of the SFLF of 1.0045 and the average DLF of 1.0513.

9. Other Operating Revenue

Ref: Exh 3, p. 56 (Table 3-31)

a) Please provide the actual 2010 revenue from Sale of Scrap Materials within account 4215, and provide an explanation of why there has been a downward trend that is forecast to continue in the test year.

b) Please provide a description of revenues that are included in Miscellaneous within account 4235, including the actual amount in 2010 if available, and explain why the forecast for the test year is near the bottom of the range observed in Table 3-31.

Response:

a) The Actual 2010 Sale of Scrap Materials within account 4215 was $27,164.29 which is comparable to 2009. The downward trend is due to less transformers have been sold for scrap.

b) The following table provides a description of the Miscellaneous within account 4235 Miscellaneous, including the 2010 actual "miscellaneous" within Miscellaneous Revenue:

Account 4235 Miscellaneous Revenue

"Miscellaneous" Breakdown	Actual Amounts				
	2010	2009	2008	2007	2006
Project Billings	55,007	60,450	21,906	209,368	262,279
Spot Sheets and Temp Service	20,209	19,052	25,328	15,288	19,473
FX on Cash and AP balances	9,570	662	2,654	(1,425)	1,032
Water Billing Fixed Asset Recovery	18,112	18,112	18,112	18,112	18,112

Write off Stale dated Chqs	10,398	17,636	9,641	11,924	13,366
Visa rewards cash back	7,343	4,931	4,037	2,763	-
Sale of Stock	2,475	-	-	19,216	21,133
One-time Adjustment for outstanding deposit liability	-	87,779	-	-	-
Recover union negotiation labour costs	-	-	11,554	-	6,514
Power Diversions (thefts)				443	34,661
Miscellaneous	674	1,386	(1,103)	3,134	6,425
	123,788	210,008	92,129	278,824	382,996

After removing the one-time adjustment made in 2009, the total would be $122,229. The amount included for the rate application for the Test Year ($121,680) is higher than the post merger three year average excluding the one-time adjustment noted above. (92,129 +122,229 + 123,788). Prior to the merger in 2006 and 2007, Peninsula West Utilities performed more maintenance recoverable work and as a result the Project billings were much higher in those two years as noted above.

10. Bad Debt Expense

Ref: Exh 4, p. 31 (Table 4-5A) and p. 44

a) What was the actual Bad Debt Expense at year-end 2010?

b) Please confirm that the projected decrease from the Bridge Year to the Test Year of $15,100 is the result of a change to monthly billing, and that no adjustment has been made for economic conditions.

Response:

a) The actual unaudited 2010 Bad Debt expense is $324,286.

b) The projected decrease from the Bridge Year of $15,100 was a result of the change to monthly billing and no adjustment was being made for economic conditions.

The 2010 actual bad debt expense of $324,286 is much lower than the Bridge Year amount of $425,100 by $100,814. The reduction is due to the change to monthly billing and an increase in the internal and external resources focused on collections.

11. Ontario Municipal Employees Retirement System Pension Costs

Ref: Exh 4, p. 78, Table 4-17

OMERS announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013. It appears that NPEI has calculated a cost of OMERS premiums for 2010, together with an increase of 2.5% for 2011.

Does NPEI have a proposal on how to recover the cost with OMERS increases after that?

Response:

The premiums calculated for the Bridge Year were $621,059. The 2010 Actual OMERS premiums were $634,212, a shortfall of $13,135. Using the new OMERS rates along with the 2011 estimated contributory earnings the 2011 OMERS premiums are estimated at $ 710,350 which is $73,765 under the 2011 estimate used in the Test Year in the rate application. NPEI is proposing to request permission from the OEB to track the difference in a variance account for future disposal, make an adjustment now in the rate application or discuss at a settlement conference.

12. Employee Costs

Ref: Exh 4, p. 76 (Table 4-15)

a) Please confirm that the total Salary and Wages in the test year (summing the rows for Management and Non-Union) is approximately 42% more than in 2009, and that the total number of employees in these categories is approximately 9% more.

b) Please explain this seemingly disproportionate increase in salary and wages.

Response:

a) The FTE's were calculated as the actual number of employees as at the end of each calendar year. Taking into account start dates and maternity leaves in 2009, 2010 and 2011 the FTE's have been revised as follows:

	Last Rebasing Year	Historical Year (Bridge Year -1)	Bridge Year	Test Year
Number of Employees (FTEs including Part-Time)	2004	2009	2010	2011
Management	18	22.44	21.33	24
Non-Union	21	8.78	10.26	14

The increase from 2009 to the Test Year for Management and Non-Union is 22% up from the original submission of 9%. The increase in Total Salary and Wages is 16% from 2010 over 2009 and 23% from 2011 over 2010 resulting in a 42% increase from 2011 over 2009. Five of the fourteen non-union FTE's are management contracts.

13. Employee Costs

Ref: Exh 6, p. 11

"Job performance increases" is listed as a cost driver that has contributed to the revenue deficiency.

a) What is the amount of these increases (approximately, if precise data is not available).

b) Please also provide a year-by-year breakdown of these increases.

Response:

a) The Job performance increases refers to executive and management employees who are not at the top level of pay in their respective pay bands according to the job evaluation schedule which has five pay levels for each pay band and based on the employees job performance evaluation of that year receive a job performance increase as well as the cost of living 3% increase until the employee reaches their top level.

b) The approximate increase before benefits related only to job performance increases is as follows: 2009 = $25K, 2010 = $45K and 2011 = $40K.

14. Depreciation Expense

Ref: Exh 4, pp. 86-88 (Tables 4-24, -25,-26)

Depreciation expense for Meters (account 1860) is shown in the three years 2009 – 2011 as $206,512, $174,327, and $259,578.

a) Please confirm that NPEI's proposal is to include Smart Meters in Rate Base @ $4,175,010 as of mid-2010, and confirm that the annual depreciation expense @ 4% would be approximately $160,000.

b) Please explain the pattern of meter depreciation over the three years, including how depreciation of Smart Meters is reflected in the annual amounts.

Response:

a) The annual depreciation expense for the proposed Smart Meters in rate base @ $4,175,010 at 4% would be $167,000 and for 2010 NPEI has applied the half year rule so that depreciation on these smart meters is $83,500 which is included in the Bridge year and a full $167,000 of depreciation expense was included in the Test year which is included in the Service Revenue Requirement.

Meter depreciation for 2010 is calculated as follows:

Cost of Non-Smart meter assets remaining in rate base	1,984,158
Accumulated Depreciation non-smart assets	(546,846)
NBV (see Note below)	1,437,312
2010 depreciation expense	**80,205**
2010 smart meters added to rate base	4,175,010
2010 depreciation expense smart meters	**83,500**

Meters to be stranded in 2011 (Cost)	377,817
Depreciation expense	**15,113**
2010 non-smart meter additions	192,245
2010 depreciation expense non-smart meters	**3,845**
Total 2010 depreciation expense (sum of **bold**)	182,663
Correction to 2009 depreciation expense	25,246
Total 2010 depreciation expense	207,909

Note: Estimated life remaining at end of 2009 on additions of 340,000 is 16 years, on additions of 1,281,000 is 17 years and on additions of $363,158 is 24 years.

As a result the 2010 depreciation expense in the rate application is overstated by $23,954 ($231,863-207,909). The $231,863 is shown in Exhibit 4, page 87 column j.

The depreciation expense for meters for 2011 will be

Non-smart meters	80,205
Smart meters full year	167,000
Meters to be stranded in 2011	0
Non-smart meter additions 2010 full year	7,690
Non-smart meter additions (185,185) 2011 half year	3,704
Total	258,895

The depreciation recorded in the rate application for meters for the Test Year 2011 is $253,645 per Exhibit 4 page 88 column j, a difference of $4,954.

b) Depreciation per the rate application Exhibit 4 pages 86-88 is as follows:

2009 = 206,512

2010 = 174,327

2011 = 259,578

The depreciation for 2010 of 174,327 is calculated on a NBV $4,358,170. The disposal column recorded a disposal of only the cost of the stranded meters ($3,163,008) and omitted the accumulated depreciation balance ($2,204,477) on the stranded meters. The correct disposal amount should be $958,531. Please see the revised Table-25 for 2010 below.

The revised Table calculates 2010 depreciation at $262,506, which is more in line with 2009 and 2011.

Account	Description	Openning Balance	Less Fully Depreciated	Net for Depreciation	Disposal	Additions	Closing Balance 2006	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Adjustments	Total Depreciation
		(a)	(b)	© =(a) - (b)	(c1)	(d)		(e)= (©-c1)+.50x(d)	(f)	(g)=1/(f)	(h)=(e)/(f)	(i)	(j)=(h)+(i)
1805	Land	507,274	0	507,274		0	507,274	507,274			0	0	0
1806	Land Rights	1,598,170	0	1,598,170		0	1,598,170	1,598,170	25	0.04	63,927	(7,077)	56,850
1808	Buildings and Fixtures	111,638	0	111,638		0	111,638	111,638	25	0.04	4,466	5,196	9,661
1810	Leasehold Improvements	0	0	0		0	0	0			0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,558,514	0	6,558,514		0	6,558,514	6,558,514	40	0.03	163,963	(18,985)	144,978
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,507,465	924,634	3,582,831		185,185	4,692,651	3,675,424	25	0.04	147,017	(17,443)	129,574
1825	Storage Battery Equipment	0	0	0		0	0	0			0	0	0
1830	Poles, Towers and Fixtures	28,665,012	8,329,566	20,335,446		2,860,613	31,525,625	21,765,752	25	0.04	870,630	(38,060)	832,570
1835	Overhead Conductors and Devices	31,395,023	2,048,498	29,346,525		1,231,327	32,626,350	29,962,188	25	0.04	1,198,488	(30,602)	1,167,885
1840	Underground Conduit	10,367,640	0	10,367,640		1,175,040	11,542,680	10,955,160	25	0.04	438,206	(265,743)	172,464
1845	Underground Conductors and Devices	54,396,854	321,277	54,075,577		1,723,794	56,120,648	54,937,474	25	0.04	2,197,499	110,123	2,307,622
1850	Line Transformers	31,103,686	3,366,951	27,736,735		1,384,010	32,487,696	28,428,740	25	0.04	1,137,150	(13,656)	1,123,494
1855	Services	3,459,629	0	3,459,629		486,923	3,946,552	3,703,090	25	0.04	148,124	(2)	148,121
1860	Meters	6,677,338	1,340,931	5,336,407	958,531	4,369,541	10,088,349	6,562,647	25	0.04	262,506	(30,643)	231,863
1865	Other Installations on Customer's Premises	440	0	440		0	440	440	25	0.04	18	(18)	0
1905	Land	508,970	0	508,970		0	508,970	508,970			0	0	0
1906	Land Rights	0	0	0		0	0	0			0	0	0
1908	Buildings and Fixtures	12,391,184	1,817,234	10,573,950		188,557	12,579,740	10,668,228	60	0.02	177,804	32,829	210,633
1910	Leasehold Improvements	120,252	120,252	(0)		0	120,252	(0)	3	0.33	(0)	0	0
1915	Office Furniture and Equipment	1,107,299	628,664	478,635		70,564	1,177,863	513,917	10	0.10	51,392	23,133	74,524
1920	Computer Equipment - Hardware	2,624,840	1,953,498	671,341		273,500	2,898,340	808,091	5	0.20	161,618	85,739	247,358
1925	Computer Software	1,920,006	1,735,390	184,616		278,954	2,198,960	324,093	1	1.00	324,093	(44,810)	279,283
1930	Transportation Equipment	5,484,897	3,706,634	1,778,263		824,149	6,309,047	2,190,338	8	0.13	273,792	124,602	398,395
1935	Stores Equipment	200,261	182,660	17,601		18,900	219,161	27,051	10	0.10	2,705	804	3,509
1940	Tools, Shop and Garage Equipment	1,566,110	1,257,226	308,884		94,342	1,660,452	356,055	10	0.10	35,605	26,969	62,574
1945	Measurement and Testing Equipment	183,146	133,421	49,725		4,690	187,835	52,070	5	0.20	10,414	17,601	28,015
1950	Power Operated Equipment	0	0	0		0	0	0			0	0	0
1955	Communication Equipment	158,934	92,379	66,555		2,843	161,777	67,977	4	0.25	16,994	1,872	18,866
1960	Miscellaneous Equipment	67,903	46,643	21,260		5,049	72,952	23,785	5	0.20	4,757	1,691	6,448
1970	Load Management Controls - Customer Premises	0	0	0		0	0	0			0	0	0
1975	Load Management Controls - Utility Premises	0	0	0		0	0	0			0	0	0
1980	System Supervisory Equipment	128,961	128,961	0		0	128,961	0	15	0.07	0	0	0
1985	Sentinel Lighting Rentals	0	0	0		0	0	0			0	0	0
1990	Other Tangible Property	0	0	0		0	0	0			0	0	0
1995	Contributions and Grants	(16,320,649)	0	(16,320,649)		(1,200,000)	(17,520,649)	(16,920,649)	25	0.04	(676,826)	23,080	(653,746)
2005	Property under Capital Lease	143,036	143,036	0		0	143,036	0	25	0.04	0	0	0
	Total before Work in Process	**189,633,833**	**28,277,856**	**161,355,977**	**958,531**	**13,977,982**	**202,653,283**	**167,386,437**			**7,014,340**	**(13,400)**	**7,000,940**
	Work in Process												
	Total after Work in Process	**189,633,833**	**28,277,856**	**161,355,977**	**958,531**	**13,977,982**	**202,653,283**	**167,386,437**			**7,014,340**	**(13,400)**	**7,000,940**

15. Long Term Debt

Ref: Exh 5, pp. 3, 13-14

a) Does NPEI consider that the terms of the promissory note might enable it to negotiate a lower interest rate, based on the phrasing in the notes that the rate is based on what the Ontario Energy Board may permit regulated distribution corporations to recover for rate-making purposes?

b) Would any of NPEI's capital projects have qualified for Infrastructure Ontario loans when it borrowed money from Scotiabank or TD?

c) What was the date of issuance of the latter loan from Scotiabank (last row in Table 5-1)?

Response:

a) Yes NPEI does consider that the terms of the promissory note might enable it to negotiate a lower interest rate, however both of the promissory notes were fixed rate instruments that have a fixed interest rate that was the Board's deemed long-term debt rate at the time of issuance, and that both of these notes payable were approved by the Board in Niagara Falls Hydro's 2006 EDR application.

b) The smart meter expenditure may have qualified for Infrastructure Ontario loan. NPEI received proposals from Scotiabank, TD and the Royal Bank when reviewing the financing options for the smart meter expenditures. The above three named banks were the banks being used by NPEI at that time. The $9.0 million dollar loan with TD was the refinancing of the former Pen West Utilities $9.5M loan which came due and this loan would probably not have qualified since it was not specifically related to capital projects.

c) The date of issuance of the Smart Meter loan was September 30, 2010 with a five year term until September 30. 2015. Please see an updated Table 5-1 below:

Table 5-1: 2011 Weighted Average Cost of Capital

Description	Debt Holder	Affiliated with LDC?	Date of Issuance	Principal Balance at December 31, 2011	Term (Years)	Rate%	Interest Cost Per Amortization Schedule
Long term note payable	City of Niagara Falls	Y	April 1, 2000	$22,000,000	20	7.25%	$1,595,000
Long term note payable	Niagara Falls Hydro Holding Corporation	Y	April 1, 2000	$3,605,090	20	7.25%	$261,369
Long term bank loan	Scotiabank	N	June 1, 2004	$3,398,502	10	6.44%	$192,771
Term loan	TD	N	July 19, 2009	$7,965,243	10	4.58%	$348,793
Term loan smart meters	Scotiabank	N	September 30, 2010	$4,143,643	10	4.97%	$215,605
Total				$41,112,478			$2,613,538
Weighted Average Cost of Long Term Debt						6.36%	

16. Cost Allocation

Ref: Exh 7, p. 11

The data in the model shows that there are 52 customers with Sentinel Lights, and there are 563 connections.

Has NPEI verified the assumption that the average number of sentinel lights per customer is nearly 11?

Response:

The data in the Cost Allocation model for Sentinel Lights only included the Niagara Falls area customers, the total number of Sentinel Light customers should be 343 customers, NF = 52 and PW area = 291. The Township of West Lincoln has 64, the Town of Lincoln has 50, the Town of Pelham has 60 and another customer has 15.

By changing the Cost Allocation model for Sentinel Lights the following impact on rates occurs keeping all other data static:

	Current	**Change in # of customers**
Sentinel Fixed	$7.19	$7.21
Sentinel Variable	$8.9771/kw	$9.0127/kw
GS> 50 Fixed	$222.81	$222.80
GS> 50 Variable	$4.0311/kw	$4.0310/kw

A revised Cost Allocation Model and Rate Design Model have been included.

17. Low Voltage Cost Forecast in Working Capital

Reference: Exh 2, p.154, Table 2-30; Hydro One Networks Rate Order EB-2009-0096

NPEI's forecast of LV Charges of $360,512 appears to be based on Hydro One Sub-transmission rates with the effective date May 1 2010.

a) Please provide an updated forecast using the rates that became effective January 1, 2011 [EB-2009-0096, rate order filed December 17, 2010, pp. 22-23]. Include documentation showing NPEI's assumptions concerning rate riders # 3, #4, #6, and #8 which expire on various dates during 2011

b) Please provide an alternative calculation of NPEI's LV cost in 2011 with the assumption that Hydro One Networks had no rate riders. If there is a material difference, please provide NPEI's views on the validity of the forecast in part a) for costs during the IRM years following 2011.

Response:

a) The table below provides an updated forecast of NPEI's 2011 LV Charges based on the Hydro One Sub-Transmission ("ST") rates that became effective January 1, 2011, as per the Rate Order filed December 17, 2010 in EB-2009-0096.

NPEI 2011 LV Charges - Based on Hydro One Rates Effective Jan 1, 2011

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Component	**Charge Determinant per Month**	**May 2010 Rate**	**Jan 2011 Rate (not including riders)**	**Rider #4 (Expires April 30, 2011)**	**Rider #8 (expires Dec 31, 2011)**	**Rider #3 (expires April 30, 2011)**	**Rider #6 (expires Dec 31, 2011)**	**2011 Forecast**	**Monthly/Yearly**	**Multiplier**	**LV Charge (2011 Base Rates) @ 12 months**	**LV Charge (Rider #4) @ 4 months**	**LV Charge (Rider #8) @ 12 months**	**LV Charge (Rider #3) @ 4 months**	**LV Charge (Rider #6) @ 12 months**	**Total LV Charge**
Service Charge	$/Delivery Pt	$211.47	$292.56	-$65.78	$5.19			10	Month	12	$35,107.20	-$2,631.20	$622.80	$0.00	$0.00	$33,098.80
Meter Charge	$/Meter	$252.71	$466.14	-$192.48	$8.26			2	Month	12	$11,187.36	-$1,539.84	$198.24	$0.00	$0.00	$9,845.76
Common ST Lines Charge	$/KW	$0.442	$0.668	-$0.195	$0.012	-$0.012	$0.058	228,296	Year	1	$152,501.73	-$14,839.24	$2,739.55	-$913.18	$13,241.17	$152,730.02
Specific Primary Lines Charge	$/KM	$279.80	$490.79	-$188.93	$8.70											
LVDS	$/KW	$1.427	$1.944	-$0.430	$0.034			54,705	Year	1	$106,346.52	-$7,841.05	$1,859.97	$0.00	$0.00	$100,365.44
Specific ST Lines Charges	$/KM	$361.05	$633.28	-$243.77	$11.23			0.13	Month	12	$987.92	-$126.76	$17.52	$0.00	$0.00	$878.68
HVDS Low	$/KW	$2.794	$3.541	-$0.930	$0.063											
HVDS High	$/KW	$1.025	$1.597	-$0.500	$0.028	-$0.012	$0.058	145,889	Year	1	$232,984.73	-$24,314.83	$4,084.89	-$583.56	$8,461.56	$220,632.80
									Totals		**$539,115.46**	**-$51,292.92**	**$9,522.97**	**-$1,496.74**	**$21,702.73**	**$517,551.50**

In the table above, column D contains the ST rates that became effective Jan 1, 2011 excluding rate riders. The Hydro One Rate Rider charges #4, #8, #3 and #6 are shown in columns E to H. As per the October 2009 Accounting Procedures Handbook Frequently Asked Questions, Rate Rider #3A was approved to implement the disposition of several of Hydro One's deferral and variance account balances. The FAQ states "The distributor should consider how best to allocate or redistribute the rate rider 3A amount to its own accounts. An approach the distributor could use to record the rate rider 3A amount in its related accounts is to break out the rider amount into separate charge/bill components in relation to each account." NPEI has taken this approach to allocate Rate Riders #3A, and also the 2010 RAR #6A. Therefore, the rates that are included in columns G and H of the table above represent only the portion of these riders that NPEI allocates to LV.

NPEI notes that Riders #3 and #4 are effective until April 30, 2011, while Riders #6 and #8 are effective to December 31, 2011. Accordingly, NPEI has calculated the updated forecast for 2011 LV charges to include the base rates for twelve months, Riders #6 and #8 for twelve months, and Riders #3 and #4 for four months.

The total updated 2011 forecast, based on the Jan 1, 2011 ST rates is $517,552 (column Q of the table). The total dollar amounts relating to each rate component (base rates and rate riders) are displayed separately in columns L through P.

b) In the table above, column L represents the calculation of NPEI's 2011 forecast LV charges under the assumption that Hydro One had no rate riders. Under this scenario, the 2011 LV forecast would be $539,115, compared to $517,552 when rate riders are included. NPEI submits that the difference is not material, and that the forecast derived in part a) is a reasonable estimate for LV costs during the subsequent IRM period.

18. Recovery of LV Cost in LV Rate Riders

Reference: Exh 1, p. 76, Table 1-6; Exh 8, p. 14, Table 8-11

NPEI is applying for approval of an LV rate rider for the GS < 50 kW class of $0.0003 per kWh. It appears that the LV rate riders are calculated on the basis of total LV costs of $360,512 being recovered from only five rate classes, not including the General Service < 50 kW class.

a) Please update the proposed rate riders to be consistent with current HONI ST Rates.

b) If necessary, please provide a corrected allocation and calculation of LV rate riders reflecting an allocation to the GS < 50 kW class.

Response:

a) Based on the updated 2011 LV forecast of $517,552, as calculated in response to interrogatory 17a), the allocated LV dollar amounts by customer class and resulting rate riders are set out in the tables below:

Low Voltage Costs Allocated by Customer Class - Updated for 2011 HONI ST Rates

Customer Class	Retail Transmission Connection Rate ($)		Basis for Allocation ($)	Allocation Percentages	Allocated $
	per KWh	per kW			
Residential	0.0045		2,051,621	38.30%	198,220.63
GS < 50 kW	0.0039		474,527	8.86%	45,847.15
GS >50		1.5483	2,796,301	52.20%	270,169.07
Large Use			0	0.00%	0.00
Sentinel Lights		1.2938	1,047	0.02%	101.12
Street Lighting		1.1895	23,917	0.45%	2,310.83
USL	0.0040		9,343	0.17%	902.70
TOTALS			**5,356,756**	**100.00%**	**517,551.50**

RATES - Low Voltage Adjustment - Updated for 2011 HONI ST Rates

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	198,220.63	459,406,923	0	kWh	0.0004	
GS < 50 kW	45,847.15	121,437,543	0	kWh	0.0004	
GS >50	270,169.07	623,806,670	1,806,009	kW		0.1496
Large Use	0.00	0	0	kW		0.0000
Sentinel Lights	101.12	292,817	809	kW		0.1250
Street Lighting	2,310.83	7,467,591	20,107	kW		0.1149
USL	902.70	2,335,428	0	kWh	0.0004	
TOTALS	**517,551.50**	**1,214,746,971**	**1,826,926**			

b) In NPEI's application, Table 8-11 did not display correctly. The row for the General Service < 50 kW class was omitted and the proposed rates for the General Service > 50 kW, Sentinel and Streetlighting classes in this table are incorrect.

NPEI confirms, however, that the proposed LV rate riders included elsewhere in the Application are correct, and were based the appropriate allocation to all six of NPEI's customer classes. In particular, the correct LV rate riders are included in the following sections:

- Table 1-6 Schedule of Proposed Rates and Charges – Niagara Falls (Exhibit 1, pp. 76-78).
- Table 1-6.1 Schedule of Proposed Rates and Charges – Peninsula West (Exhibit 1, pp. 79-81).
- Proposed Rates and Charges (Exhibit 8, pp. 37-43)
- Appendix 8-A Bill Impacts

The corrected Table 8-11, based on the original 2011 LV forecast of $360,512 is presented below.

Table 8-11 Corrected - Low Voltage Charges - Determination of Rates										
	Retail TX		Billing Determinants		Allocation of LV Charges			LV Charge Rates		
	Per kWh	per kW	Calculated kWh	Calculated kW	Retail Tx Con Revenue - Basis for Allocation	Allocation Percentages	Allocated	Volumetric Rate Type	Low Voltage Rates/kWh	Low Voltage Rates/ kW
Residential	$0.0045		459,406,923		2,051,621	38.3%	138,075	kWh	$0.0003	
GS < 50	$0.0039		121,437,543		474,527	8.9%	31,936		$0.0003	
General Service 50 to 4999 kW		$1.5483	623,806,670	1,806,009	2,796,301	52.2%	188,192	kW		$0.1042
Streetlight		$1.1895	7,467,591	20,107	23,917	0.4%	1,610	kW		$0.0801
Sentinel Lights		$1.2938	292,817	809	1,047	0.0%	70	kW		$0.0871
Unmetered Scattered Load	$0.0040		2,335,428	0	9,343	0.2%	629	kWh	$0.0003	
TOTAL			**1,214,746,971**	**1,826,926**	**5,356,756**	**100.0%**	**$360,512**			

19. Retail Transmission Service Rates

Ref: Exh 8, Appendix 8-B, p. 83; Hydro One Networks Rate Order EB-2010-0002

New Uniform Transmission Rates have been approved since NPEI filed its application on November 26, 2010.

a) Please update the IESO portion of the table on p. 83 with the newly approved Uniform Transmission Rates.

b) Please explain how the rates have been calculated in the Hydro One portion of the table on p. 83, including why there is a reference to UTR's at the head of two of the columns.

Response:

Note: In NPEI's Application, Appendix 8-B did not transfer entirely into the pdf document. Several pages were omitted, and other pages were truncated. NPEI has included a complete copy of Appendix 8-B as an appendix to these interrogatory responses.

a) NPEI has updated the IESO portion of the Forecast Wholesale Transmission table to reflect the new 2011 UTRs that were recently approved in EB-2010-0002:

Forecast Wholesale Transmission

IESO

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	179,169	$ 3.2200	$ 576,924	195,406	$ 0.7900	$ 154,371	123,378	$ 1.7700	$ 218,379	$ 372,750
February	134,614	$ 3.2200	$ 433,458	129,375	$ 0.7900	$ 102,206	118,223	$ 1.7700	$ 209,255	$ 311,461
March	155,523	$ 3.2200	$ 500,784	155,523	$ 0.7900	$ 122,863	115,603	$ 1.7700	$ 204,617	$ 327,480
April	136,656	$ 3.2200	$ 440,033	139,675	$ 0.7900	$ 110,343	105,104	$ 1.7700	$ 186,034	$ 296,378
May	129,981	$ 3.2200	$ 418,540	136,240	$ 0.7900	$ 107,630	104,265	$ 1.7700	$ 184,549	$ 292,179
June	189,846	$ 3.2200	$ 611,303	191,737	$ 0.7900	$ 151,472	144,322	$ 1.7700	$ 255,450	$ 406,922
July	173,697	$ 3.2200	$ 559,305	174,350	$ 0.7900	$ 137,736	132,698	$ 1.7700	$ 234,875	$ 372,612
August	213,910	$ 3.2200	$ 688,789	218,129	$ 0.7900	$ 172,322	162,874	$ 1.7700	$ 288,287	$ 460,609
September	158,604	$ 3.2200	$ 510,705	160,492	$ 0.7900	$ 126,788	121,059	$ 1.7700	$ 214,274	$ 341,063
October	135,996	$ 3.2200	$ 437,907	136,156	$ 0.7900	$ 107,563	99,849	$ 1.7700	$ 176,733	$ 284,296
November	149,812	$ 3.2200	$ 482,393	152,275	$ 0.7900	$ 120,298	111,918	$ 1.7700	$ 198,095	$ 318,392
December	159,205	$ 3.2200	$ 512,641	163,732	$ 0.7900	$ 129,348	119,493	$ 1.7700	$ 211,503	$ 340,851
Total	1,917,013	$ 3.2200	$ 6,172,781	1,953,089	$ 0.7900	$ 1,542,941	1,458,786	$ 1.7700	$ 2,582,051	$ 4,124,992

Hydro One

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Line Transformation Units Billed	Line Transformation Rate	Line Transformation Amount	Total Line Amount
	Includes Hydro One Rate Rider B1.3 UTR's and Sub-Transmission Cell M48			Includes Hydro One Rate Rider B1.3 UTR's and Sub-Transmission Cell M50						
January	36,164	$ 2.6970	$ 97,534	36,168	$ 0.6150	$ 22,243	54,610	$ 1.5000	$ 81,915	$ 104,158
February	34,552	$ 2.6970	$ 93,187	34,584	$ 0.6150	$ 21,269	57,858	$ 1.5000	$ 86,787	$ 108,056
March	30,462	$ 2.6970	$ 82,156	30,634	$ 0.6150	$ 18,840	56,701	$ 1.5000	$ 85,051	$ 103,891
April	30,152	$ 2.6970	$ 81,320	30,192	$ 0.6150	$ 18,568	53,607	$ 1.5000	$ 80,411	$ 98,979
May	24,940	$ 2.6970	$ 67,263	25,013	$ 0.6150	$ 15,383	47,553	$ 1.5000	$ 71,330	$ 86,712
June	32,517	$ 2.6970	$ 87,698	32,561	$ 0.6150	$ 20,025	33,653	$ 1.5000	$ 50,480	$ 70,505
July	31,233	$ 2.6970	$ 84,235	31,260	$ 0.6150	$ 19,225	41,005	$ 1.5000	$ 61,508	$ 80,732
August	37,014	$ 2.6970	$ 99,826	37,060	$ 0.6150	$ 22,792	23,028	$ 1.5000	$ 34,542	$ 57,334
September	30,438	$ 2.6970	$ 82,091	30,438	$ 0.6150	$ 18,719	49,987	$ 1.5000	$ 74,981	$ 93,700
October	29,128	$ 2.6970	$ 78,558	44,223	$ 0.6150	$ 27,197	70,000	$ 1.5000	$ 105,000	$ 132,197
November	30,216	$ 2.6970	$ 81,493	30,216	$ 0.6150	$ 18,583	59,217	$ 1.5000	$ 88,826	$ 107,408
December	34,242	$ 2.6970	$ 92,351	34,348	$ 0.6150	$ 21,124	57,982	$ 1.5000	$ 86,973	$ 108,097
Total	381,058	$ 2.6970	$ 1,027,712	396,697	$ 0.6150	$ 243,969	605,201	$ 1.5000	$ 907,801	$ 1,151,770

Total

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Line Transformation Units Billed	Line Transformation Rate	Line Transformation Amount	Total Line Amount
January	215,333	$ 3.1322	$ 674,459	231,574	$ 0.7627	$ 176,614	177,988	$ 1.6872	$ 300,294	$ 476,908
February	169,166	$ 3.1132	$ 526,644	163,959	$ 0.7531	$ 123,475	176,081	$ 1.6813	$ 296,042	$ 419,517
March	185,985	$ 3.1343	$ 582,940	186,157	$ 0.7612	$ 141,703	172,304	$ 1.6811	$ 289,669	$ 431,372
April	166,808	$ 3.1255	$ 521,353	169,867	$ 0.7589	$ 128,912	158,711	$ 1.6788	$ 266,445	$ 395,356
May	154,921	$ 3.1358	$ 485,803	161,253	$ 0.7629	$ 123,013	151,818	$ 1.6854	$ 255,879	$ 378,892
June	222,363	$ 3.1435	$ 699,001	224,298	$ 0.7646	$ 171,497	177,975	$ 1.7189	$ 305,929	$ 477,426
July	204,930	$ 3.1403	$ 643,540	205,610	$ 0.7634	$ 156,961	173,703	$ 1.7063	$ 296,383	$ 453,344
August	250,923	$ 3.1429	$ 788,615	255,189	$ 0.7646	$ 195,114	185,902	$ 1.7366	$ 322,829	$ 517,943
September	189,042	$ 3.1358	$ 592,796	190,930	$ 0.7621	$ 145,508	171,046	$ 1.6911	$ 289,255	$ 434,763
October	165,124	$ 3.1277	$ 516,465	180,379	$ 0.7471	$ 134,760	169,849	$ 1.6587	$ 281,733	$ 416,493
November	180,028	$ 3.1322	$ 563,886	182,491	$ 0.7610	$ 138,880	171,135	$ 1.6766	$ 286,920	$ 425,801
December	193,447	$ 3.1274	$ 604,991	198,080	$ 0.7597	$ 150,472	177,475	$ 1.6818	$ 298,476	$ 448,948
Total	2,298,070	$ 3.1333	$ 7,200,493	2,349,786	$ 0.7605	$ 1,786,909	2,063,987	$ 1.6908	$ 3,489,853	$ 5,276,762

b) On August 20, 2010, the Board issued an Excel workbook for distributors to complete as part of their 2011 electricity rate applications to assist in calculating Retail Transmission Service Rates. NPEI utilized this Board-issued model in its application.

The Excel file included pre-populated UTR and Hydro One transmission rates data. The Hydro One rates referenced in the interrogatory were approved in EB-2009-0096, and consist of the HONI transmission rates for the ST class plus the portion of Rate Rider #6A that is allocated to the transmission accounts. The components of these rates are given in the table below:

EB-2009-0096	**Network ($/kW)**	**Line Connection ($/kW)**	**Transformation Connection ($/kW)**
ST Tx Rates	2.650	0.640	1.500
Rate Rider #6A	0.047	(0.025)	-
Total Used in RTSR Model	2.697	0.615	1.500

The references to UTRs at the head of two of the columns were included in the workform, as provided by the Board. The UTR and HONI rates are populated in a sheet named “B1.3 UTRs and Sub-Transmission”. Therefore, in NPEI’s view, this reference is simply indicating where the formulas in the cells are linked, and confirming that the relevant portion of Rate Rider #6A has been included.

20. Niagara West Transformer Corporation

Ref: Exh 1, p. 68

NPEI receives power through several TSs and DSs owned by Hydro One Networks, and through one TS owned by Niagara West Transformer Corporation.

Please provide information on NPEI's purchases from the latter, including what proportion these costs are of NPEI's transmission and/or Low Voltage costs.

Response:

NPEI is charged by Niagara West for Transformation Connection costs only; no portion of NPEI's Network, Line Connection or Low Voltage cost is related to Niagara West.

The Board-provided RTSR workform that was submitted by NPEI includes two sections for 2009 historical transmission costs: one for the IESO and one for Hydro One. NPEI included the transformation connection charges from Niagara West in the Hydro One section. The table below breaks out NPEI's 2009 transformation costs. As can be seen from the table, the dollar amounts billed by Niagara West in 2009 represent 8.3% of NPEI's Transformation Connection costs and 5.5% of NPEI's total connection costs.

NPEI 2009 Connection Costs	kW Billed	$	% of Total $
Transformation Connection			
IESO	1,458,786	2,325,839	72.6%
Hydro One	428,264	614,309	19.2%
Niagara West	176,937	265,407	8.3%
	2,063,987	3,205,555	100.0%
Line Connection			
IESO	1,953,089	1,367,163	86.0%
Hydro One	396,697	222,984	14.0%
Niagara West			0.0%
	2,349,786	1,590,147	100.0%
Total Connection			
IESO		3,693,001	77.0%
Hydro One		837,293	17.5%
Niagara West		265,407	5.5%
		4,795,702	100.0%

In 2010, Transformation Connection charges payable Niagara West represents 5.5% of NPEI's total connection costs:

NPEI 2010 Connection Costs	$	% of Total $
IESO (Transformation and Line Connection)	4,415,875	81.2%
Hydro One (Transformation and Line Connection)	719,018	13.2%
Niagara West (Transformation)	300,741	5.5%
Total Connection	5,435,633	100.0%

21. Transmission Cost Component of the Cost of Power

Ref: Exh 2, pp 151-152

a) Please confirm that NPEI's forecast of transmission costs for the purpose of the working capital allowance was based on its own retail transmission service rate revenues from the 2010 tariff.

b) Please provide an update of the transmission cost component of the Working Capital Allowance for the test year consistent with NPEI's response to the previous interrogatory.

Response:

a) NPEI confirms that the transmission cost component of the Working Capital Allowance for the test year was based on the Retail Transmission Service Rates from the 2010 tariff for the Niagara Falls service area.

b) NPEI has updated the transmission component of the Working Capital Allowance with the rates that were calculated based on updating the UTRs, as discussed in Interrogatory #19. The revised 2011 Cost of Power calculation is given in the table below.

Electricity - Commodity Class per Load Forecast	2011 Forecasted Metered kWhs - RPP	2011 Loss Factor	2011		
Residential	388,590,040	1.0560	410,347,303	$0.06215	$25,503,085
Street Lighting	6,569,845	1.0560	6,937,692	$0.06215	$431,178
Sentinel Lighting	179,047	1.0560	189,072	$0.06215	$11,751
GS<50kW	101,825,576	1.0560	107,526,818	$0.06215	$6,682,792
GS>50kW	88,078,213	1.0560	93,009,737	$0.06215	$5,780,555
Intermediate		1.0560	0	$0.06215	$0
Unmetered Scattered Load	1,211,706	1.0560	1,279,549	$0.06215	$79,524
TOTAL	**586,454,426**		**619,290,171**		**$38,488,884**

Electricity - Commodity Class per Load Forecast	2011 Forecasted Metered kWhs - Non-RPP	2011 Loss Factor	2011		
Residential	70,816,883	1.0560	74,781,940	$0.06062	$4,533,281
Street Lighting	897,746	1.0560	948,011	$0.06062	$57,468
Sentinel Lighting	113,770	1.0560	120,140	$0.06062	$7,283
GS<50kW	19,611,967	1.0560	20,710,046	$0.06062	$1,255,443
GS>50kW	535,728,457	1.0560	565,724,040	$0.06062	$34,294,191
Intermediate		1.0560	0	$0.06062	$0
Unmetered Scattered Load	1,123,722	1.0560	1,186,640	$0.06062	$71,934
TOTAL	**628,292,545**		**663,470,818**		**$40,219,601**

Transmission - Network Class per Load Forecast		Volume Metric	2011		
Residential		kWh	485,129,243	$0.0061	$2,945,196
Street Lighting		kW	20,107	$1.7148	$34,479
Sentinel Lighting		kW	809	$1.6794	$1,359
GS<50kW		kWh	128,236,864	$0.0055	$705,075
GS>50kW		kW	1,806,009	$2.2682	$4,096,472
Intermediate		kW		$0.0000	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0055	$13,560
TOTAL					**$7,796,140**

Transmission - Connection Class per Load Forecast		Volume Metric	2011		
Residential		kWh	485,129,243	$0.0046	$2,253,933
Street Lighting		kW	20,107	$1.2375	$24,883
Sentinel Lighting		kW	809	$1.3460	$1,089
GS<50kW		kWh	128,236,864	$0.0041	$521,320
GS>50kW		kW	1,806,009	$1.6108	$2,909,162
Intermediate		kW	0	$0.0000	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0042	$10,264
TOTAL					**$5,720,652**

Wholesale Market Service					
Class per Load Forecast			**2011**		
Residential		kWh	485,129,243	$0.0052	$2,522,672
Street Lighting		kWh	7,885,703	$0.0052	$41,006
Sentinel Lighting		kWh	309,212	$0.0052	$1,608
GS<50kW		kWh	128,236,864	$0.0052	$666,832
GS>50kW		kWh	658,733,777	$0.0052	$3,425,416
Intermediate		kWh	0	$0.0052	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0052	$12,824
TOTAL					**$6,670,357**

Rural Rate Assistance					
Class per Load Forecast			**2011**		
Residential		kWh	485,129,243	$0.0013	$630,668
Street Lighting		kWh	7,885,703	$0.0013	$10,251
Sentinel Lighting		kWh	309,212	$0.0013	$402
GS<50kW		kWh	128,236,864	$0.0013	$166,708
GS>50kW		kWh	658,733,777	$0.0013	$856,354
Intermediate		kWh	0	$0.0013	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0013	$3,206
TOTAL					**$1,667,589**

	2011
4705-Power Purchased	$78,708,485
4708-Charges-WMS	$6,670,357
4714-Charges-NW	$7,796,140
4716-Charges-CN	$5,720,652
4730-Rural Rate Assistance	$1,667,589
4750-Low Voltage	$360,512
TOTAL	**100,923,735**

22. Specific Service Charges

Ref: Conditions of Service, section 2.4.1.3 “Additional Charges”; Exh 8, pp. 40 and 43

a) NPEI’s Conditions of Service lists a charge “credit check fee”. Is this charge a uniform amount that should be included on the tariff sheet?

b) Does NPEI’s list of additional charges include any other items that should be on the tariff sheet? Please explain NPEI’s criteria for charges that it lists in the Conditions of Service which are not to be included on the tariff sheet.

Response:

a) It was an error to include “credit check fee”. The document has been updated.

Additional Charges

In addition to the monthly service charge for distribution services, the distribution volumetric charge, and competitive electricity charges, miscellaneous charges may include as provided in the Tariff of rates and charges. This is not an inclusive list.

- New Account set-up fee;
- NSF or Returned Cheque;
- Collection visit;
- Reconnection after hours;
- Reconnection during hours;
- Secondary Service installation;
- Temporary Service installation;
- Arrears certificates;
- Interest charges;
- Street lighting;
- Embedded generation charges; and
- Various equipment rentals;

b) There are two additional items that are on the list and not included in the tariff sheet. These are capital project related: embedded generation charges and various equipment rentals.

23. PILS

Ref: Exh 4, p. 92; NPEI COS Tax Model 20101126 (Excel spreadsheet)

The amount for PILs in Exhibit 4 and throughout the application is $1,725,276. However, the tax model submitted in support of the application ('PILs, Tax Provision' last page of the PILs Income Taxes Work Form, shows an amount of $679,290 as "Corporate PILs/Income Tax Provision Gross Up" bringing the total to $2,404,586 as the "Tax Provision for Test Year Rate Recovery".

Please confirm the correct PILs proxy amount.

Response:

The correct PILS proxy amount is $1,725,276. In the COS Tax Model Sheet O. Taxable Income Test Year, cell C13's description is "Net Income before Tax" and as a result this cell was incorrectly linked. NPEI has re-linked this cell to Sheet "A" Data Input Sheet cell G46 which is Return on Equity (Regulated Income). Sheet Q PILS, Tax Provision now has a Tax Provision for Test Year Rate Recovery of $1,725,276 which is consistent with other supporting models included in the rate application.

An updated COS Tax Model has been included.

24. Deferred PILs Accounts

Ref: Exhibit 9, Table 9-1

According to the Accounting Procedures Handbook, Frequently Asked Questions issued in April 2003, the amounts recorded in account 1562, Deferred PILs account, and account 1563, Deferred PILs Contra Account should be the same, with reverse signs. The balances filed by NPEI in the pre-filed evidence for these two accounts are not the same (account 1562 has a credit of $4,747,283, and account 1563 has a debit balance of $3,972,809). Although, these accounts are not requested for disposition in this proceeding, for the record,

a) Please provide an explanation as to why the numbers are not equal,

b) Did NPEI change the method for recording entries into these accounts to Method 3 from another Method from 2001 to 2005?

c) If NPEI did change the method for recording entries in its PILs accounts, please provide the date when this change took place.

Response:

a) The difference in the balances of accounts 1562 and 1563 relates to carrying charges that NPEI recorded incorrectly on the principal balance of account 1562. According to Question 2 of the April 2003 Frequently Asked Questions (Alternative 3, Entry 4), the offset to the carrying charge entries should have been account 1563. However, NPEI used account 4405 Interest and Dividend Income prior to January 1, 2009 and account 6035 for the fiscal year ending 2009 to record the carrying charges on 1562. NPEI has booked a correcting entry in 2010, which will result in the balances in accounts 1562 and 1563 being equal (with opposite signs) as required. These carrying charges are related to regulatory assets and liabilities and are hence excluded from the Service Revenue Requirement.

NPEI notes that there is $24,000 in both the 2010 Bridge Year forecast and the 2011 Test Year forecast carrying charge expense included in the application, in account 6035 Other Interest Expense, relating to projected carrying charges on account 1562. Since NPEI will now record these charges in 1563, the forecast for 6035 should be reduced. This change will not impact NPEI's Service Revenue Requirement, since carrying charges on regulatory assets are not included in the revenue requirement calculation.

b) NPEI did not change its method of recording the PILs entries. It was NPEI's intention to consistently apply Alternative 3. However, as noted above in part a), NPEI has been recording the carrying charges incorrectly, which has now been corrected.

c) N/A.

25. Other Deferred Credits

Ref: Exh 9, p. 33

NPEI has reported an amount for account 2425 under section 2.1.7 filing for December 31, 2009. However, the pre-filed evidence including the continuity schedule does not show a balance for this account.

a) Please reconcile 2.1.7 to the continuity schedule for account 2425, and provide an explanation for the difference.

b) What does the amount in this account pertain to?

c) Is the balance in this account a regulatory asset that can only be cleared through a Decision of the Board?

d) Is NPEI planning to bring this account balance to Board in a future proceeding for disposition? If so, when?

Response:

a) NPEI confirms that its RRR filing 2.1.7 for 2009 included an amount of ($116,350) in account 2425, but no balance for this account was included in the regulatory asset continuity schedules that were filed in the application. NPEI did not include the balances in 2425 on the continuity schedules because NPEI does not consider these items to be regulatory liabilities.

b) The full balance of account 2425 pertains to deferred revenue deposits received by NPEI relating to feasibility studies for the OPA's Standard Offer program. Prior to receiving the deposits, NPEI reviewed the Accounting Procedures Handbook, and determined that account 2425 Other Deferred Credits was the appropriate account to record these liabilities.

c) NPEI does not consider the balance in this account to be a regulatory liability, and submits that a Decision of the Board is not necessary to clear the balance.

d) NPEI does not plan to bring this account before the Board for disposition in a future proceeding.

Appendix A
Asset Management Plan

Niagara Peninsula Energy Incorporated

Asset Management Plan
2011 – 2015

niagara
peninsula
energy

TABLE OF CONTENTS

1 Executive Summary

1.1 Objective of AMP

Niagara Peninsula Energy Inc.'s (NPEI) Asset Management Plan provides a high level overview of the corporation as well as a summary of the corporate objectives, strategies, and practices that go into developing a business plan.

The resultant business plan is summarized in this document for the period 2011-2015 with more details, such as major projects and programs, included for 2011, by dividing expenditures in the major investment buckets under capital, O&M, Billing and Collecting and General and Administrative categories.

The Asset Management Plan could and should be used as a means of sharing information about NPEI and the rational for investments it makes with customers, shareholders, regulators and the general public.

1.2 AMP Components

The Asset Management Plan includes a number of sections. The following is a brief description of the contents for each section:

<u>About NPEI – Section 2</u>

This section provides a description of NPEI's company's overview, geographic location and demand and energy consumption (both historical and forecasted).

<u>Corporate Information – Section 3</u>

This section provides high level corporate information that governs decision making processes and includes vision, mission statement, and corporate values.

<u>System Description and Reliability Performance – Section 4</u>

This section gives a description of the NPEI's distribution system and provides information on all supply points, SCADA, major asset categories and reliability performance, including historical values for SAIFI, SAIDI and CAIDI.

<u>Major External Challenges – Section 5</u>

This section lists external challenges that, in order to be addressed properly, require NPEI to make significant investments, mostly capital in nature. These external challenges include Smart Grid development, DG connections, new loads, both residential and commercial, and municipal infrastructure improvement projects, such as a road widening.

Internal Initiatives – Section 6

This section describes major internal initiatives aimed at improving the performance of NPEI's distribution system. These initiatives include a number of programs, such as replacement of high voltage switching kiosks and submersible transformers, inspection and replacement of poles and pad mounted equipment, and vegetation management.

Business Practices –Section 7

This section describes NPEI's business practices and approach specifically regarding replacement and maintenance of existing distribution assets.

Asset Condition Assessment – Section 8

This section presents results and recommendations from the Asset Condition Assessment study for the distribution assets performed by an external consultant (Kinectrics Inc).

2011 Business Plan – Section 9

This section presents 2011 Business Plan divided into 6 major buckets: Sustainment Capital, Development Capital, Other Capital, Operations & Maintenance, Billing and Collecting and General and Administration. Major programs and projects are also identified within each investment bucket.

2012-2015 Business Plan – Section 10

This section presents the 2012-2015 Business Plans for each of the years in the range using the same buckets as for 2011 Business Plan but without identifying major projects and programs.

2 About NPEI

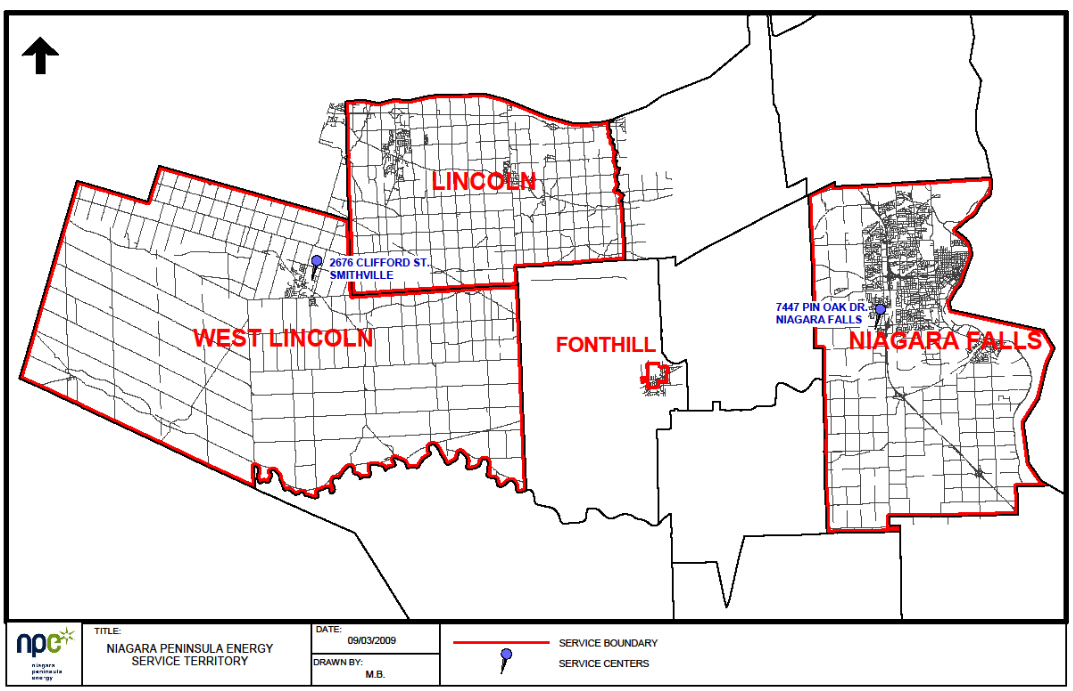
2.1 Company Overview

Niagara Peninsula Energy Inc. (NPEI) was established in 2008 as a result of the amalgamation of Niagara Falls Hydro Incorporated and Peninsula West Utilities Limited. NPEI is a medium sized utility in the Province of Ontario and is responsible for providing all regulated electricity distribution services to over 50,000 residential and business customers in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham. Niagara Peninsula Energy has a service area of 827 sq. km.

The table below shows NPEI's Provincial ranking in 3 major categories: number of customers, Net Book Value of Assets and geographic territory.

	Area (sq. km.)	Number of Customers	NBV ($M)
NPEI	827	> 50,000	101
Ontario Rank	6	14	9

2.2 Geographic Map



NPEI's neighboring utilities are Fortis, Welland Hydro, Niagara-on-the Lake Hydro, Hydro One, Horizon Utilities, Haldimand County Hydro and Grimsby Power.

2.3 Customer Base

Niagara Peninsula Energy Inc. (NPEI) services approximately 45,616 residential and 5,311 commercial customers. Customers in urban portions of the service territory are as follows:

Area	Size	Customers
Niagara Falls Urban	60.8 sq. km.	31,850
Beamsville	10.3 sq. km.	4,153
Vineland	5.9 sq. km.	1,714
Fonthill	1.8 sq. km.	1,161

The majority of NPEI's service territory is rural. NPEI has 748.2 sq. km. of rural territory servicing approximately 12,049 customers.

2.4 Demand and Energy

2.4.1 Energy Usage

The following table summarizes NPEI's energy usage in 2009 and 2010 to present. The remaining columns for 2012 to 2015 are the projected demand forecast for NPEI:

	Energy (gWh)						
Month	2009	2010	2011	2012	2013	2014	2015
January	118	112	117	117	117	118	118
February	98	99	103	103	103	103	104
March	102	100	103	104	104	104	105
April	92	89	92	93	92	93	93
May	91	98	101	102	102	102	103
June	98	107	111	111	111	111	112
July	106	130	135	135	135	136	136
August	118	125	130	130	130	131	131
September	97	98	102	102	102	102	103
October	94	95	99	99	99	99	100
November	94	95	98	99	99	99	100
December	110	111	115	116	116	116	117

Legend:

	Actual Usage Data
	Forecasted Using the Weather Normalization Model
	Forecasted Based on Assumptions

Energy Usage Forecast Assumptions:

In the years 2012 through 2015, a moderate energy growth of 0.5% is expected year to year. In 2013, NPEI anticipates that energy usage will drop by 0.25% based on the expected completion of the Ontario Power Generation tunnel project in Niagara Falls.

2.4.2 *Demand*

The following table summarizes NPEI's demand between 2009 and 2015. From 2009 to August 2010, the demand values were obtained from metered data. The remainder of the table contains the projected demand values based on the assumptions stated below:

	Demand (MW)						
Month	2009	2010	2011	2012	2013	2014	2015
January	180	190	187	188	185	186	187
February	183	181	190	191	187	188	189
March	187	167	181	182	178	179	180
April	150	156	156	157	153	154	155
May	157	220	198	199	196	197	198
June	223	223	241	242	239	240	241
July	205	261	265	266	262	264	265
August	255	253	271	272	268	270	271
September	187	188	196	197	193	194	195
October	161	163	169	170	166	167	168
November	177	179	186	187	184	184	185
December	194	196	202	204	201	202	203

Legend:

(green)	Actual Demand Data
(blue)	Forecasted Based on Assumptions

Demand Forecast Assumptions:

In the years 2011 through 2015, the forecasted demand is based on the energy usage forecast and average load factor per month from 2009 and 2010. In 2013, NPEI anticipates that demand will drop by 3 MW based on the expected completion of the Ontario Power Generation tunnel project in Niagara Falls. The tunnel project's demand on NPEI's system averages 3 MW per month.

2.4.3 Load Factor

The following table summarizes NPEI's calculated load factor between 2009 and 2015:

	Demand (MW)						
Month	2009	2010	2011	2012	2013	2014	2015
January	89.6%	80.9%	85.3%	85.3%	86.7%	86.7%	86.7%
February	73.2%	74.7%	74.0%	74.0%	75.1%	75.1%	75.1%
March	74.6%	81.9%	78.3%	78.3%	79.6%	79.6%	79.6%
April	84.0%	78.1%	81.0%	81.0%	82.6%	82.6%	82.6%
May	79.2%	60.9%	70.0%	70.0%	71.1%	71.1%	71.1%
June	60.2%	65.5%	62.8%	62.8%	63.6%	63.6%	63.6%
July	71.3%	68.1%	69.7%	69.7%	70.5%	70.5%	70.5%
August	63.7%	67.7%	65.7%	65.7%	66.4%	66.4%	66.4%
September	71.1%	71.1%	71.1%	71.1%	72.2%	72.2%	72.2%
October	79.9%	79.9%	79.9%	79.9%	81.3%	81.3%	81.3%
November	72.4%	72.4%	72.4%	72.4%	73.6%	73.6%	73.6%
December	77.8%	77.8%	77.8%	77.8%	79.0%	79.0%	79.0%

Legend:

	Calculated Load Factor

3 Corporate Information

3.1 Vision Statement

Niagara Peninsula Energy is committed to delivering environmentally responsible and sustainable energy for the future of our communities.

3.2 Mission Statement

Niagara Peninsula Energy delivers safe, efficient and reliable electricity through dedicated employees in an environmentally sustainable and technologically focused manner. We provide excellence in customer service and respond to the needs of our communities.

3.3 Corporate Values

Niagara Peninsula Energy and its staff will maintain conduct with commitment to the values of:

- Integrity- we are ethical and our actions are truthful and trustworthy
- Fairness- we treat everyone equally and free of bias
- Responsibility- we provide services with safety first for our customers and employees
- Respect- we listen to each other and see value that each member of the team brings and respect the needs of our stakeholders
- Transparency- we are open and accountable for our actions and decisions

4 System Description and Reliability Performance

4.1 System Description

NPEI's distribution system consists of 1059 km of overhead primary feeders and 482 km of underground primary cable. The distribution system operates at one of the following four primary voltages:

- 27.6kV
- 13.8kV
- 8.32kV
- 4.16kV

NPEI's distribution system receives power from the Hydro One operated transmission system through one of the following supply points:

Substation Name	Primary Voltage	Secondary Voltage	# of Transformers	Station Owner	City/Town
Pelham DS	27.6 kV	4.16 kV	1	NPEI	Fonthill
Station DS	27.6 kV	4.16 kV	1	NPEI	Fonthill
Beamsville TS	115 kV	27.6 kV	2	Hydro One	Lincoln
Campden DS	27.6 kV	8.32 kV	1	NPEI	Lincoln
Greenlane DS	27.6 kV	8.32 kV	2	NPEI	Lincoln
Jordan DS	27.6 kV	8.32 kV	1	NPEI	Lincoln
Vineland DS	115 kV	27.6 kV	2	Hydro One	Lincoln
Kalar TS	115 kV	13.8 kV	2	NPEI	Niagara Falls
Murray TS	115 kV	13.8 kV	4	Hydro One	Niagara Falls
NF Station 3	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 6	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 7	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 8	13.8 kV	4.16 kV	2	NPEI	Niagara Falls
NF Station 10	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 14	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 17	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 18	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 22	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 23	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
Stanley TS	13.8 kV	4.16 kV	2	Hydro One	Niagara Falls
Bismark DS	27.6 kV	8.32 kV	1	Hydro One	West Lincoln
Niagara West TS	230 kV	27.6 kV	2	NWTC	West Lincoln
Smithville DS	27.6 kV	8.32 kV	1	NPEI	West Lincoln

NPEI monitors its distribution system through a supervisory control system at its main office located in Niagara Falls. The system is used to monitor and control all TS supply breakers feeding NPEI's distribution system. The Supervisory Control and Data Acquisition System ("SCADA") is monitored twenty-four hours a day, seven days a week.

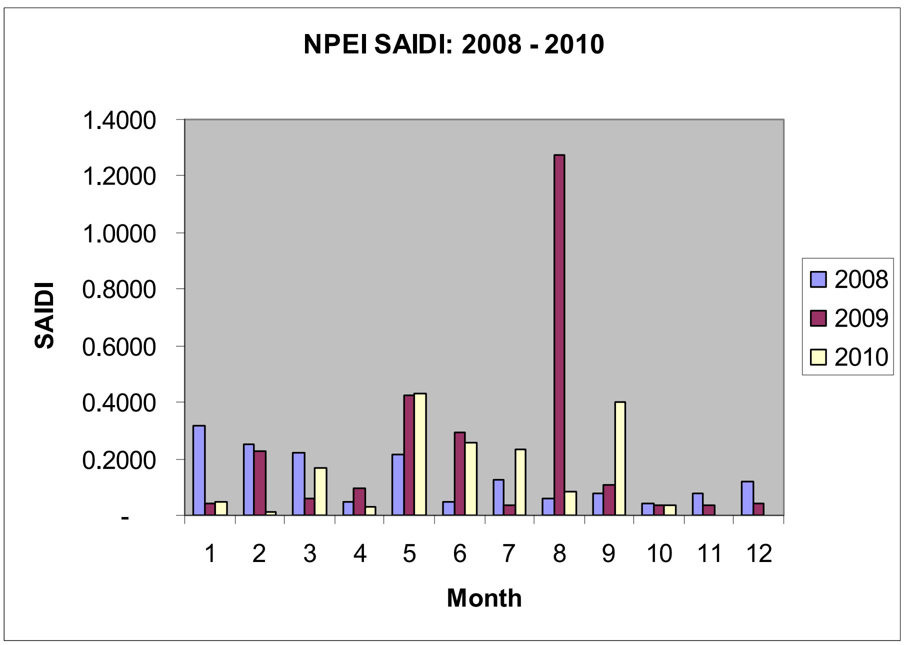
4.2 Main Asset Categories

The table below shows the number of assets in each of NPEI's major asset categories:

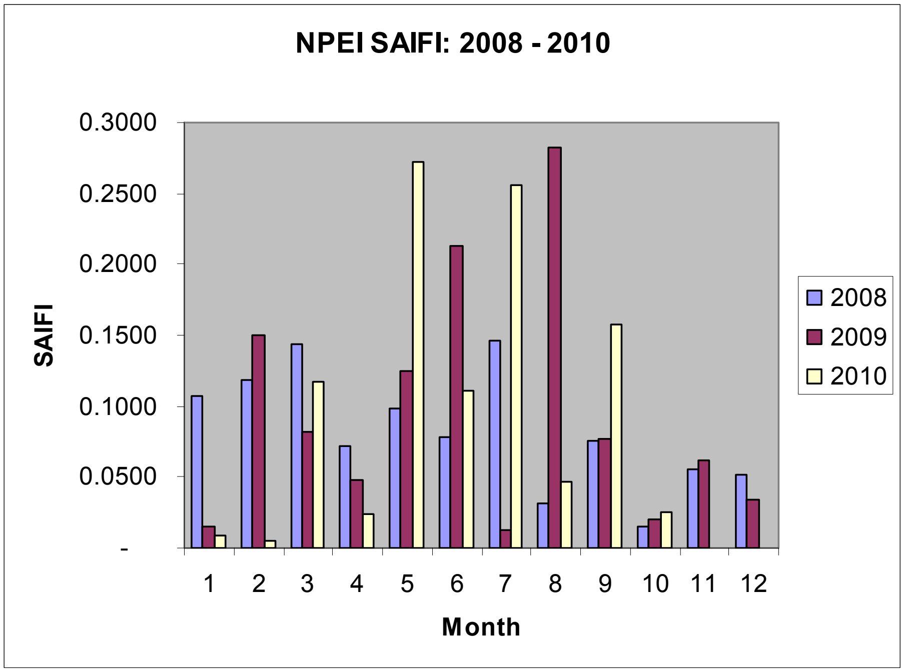
Asset Description	Population
Station Power Transformers	21
Large Pad Mounted Transformers (> 750 kVA)	56
Standard Pad Mounted Transformers (< 750 kVA)	2408
Pole Top Transformers	6835
Poles	22247
Pad Mounted Switchgear	89

4.3 System Performance

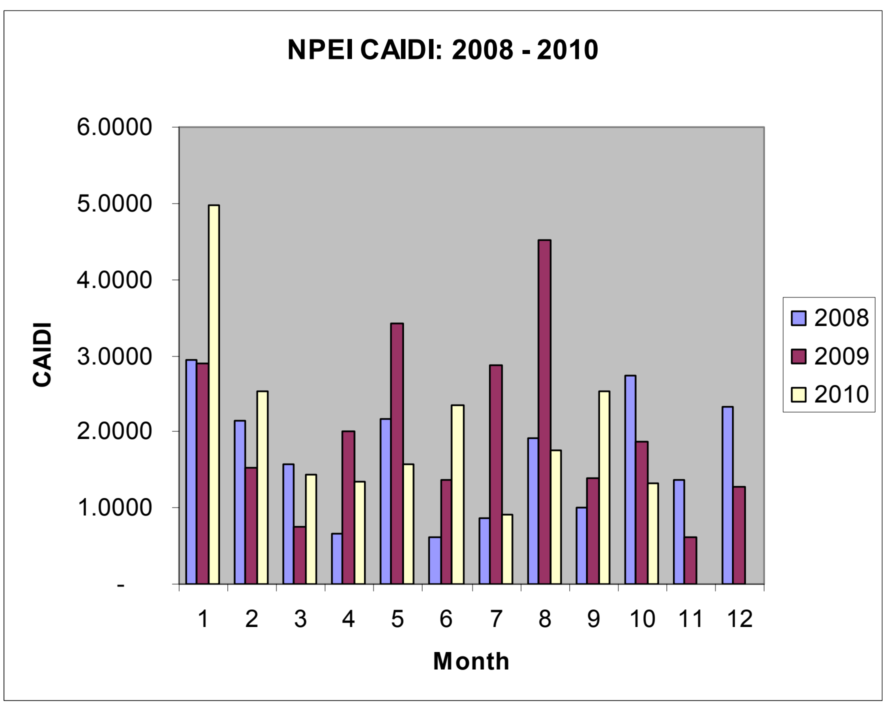
The following chart summarizes NPEI's System Average Interruption Duration Index (SAIDI) by month for 2008 through 2010:



The following chart summarizes NPEI's System Average Interruption Frequency Index (SAIFI) by month for 2008 through 2010:



The following chart summarizes NPEI's Customer Average Interruption Duration Index (CAIDI) by month for 2008 through 2010:



NPEI has compiled outage data used to derive SAIDI, SAIFI, and CAIDI since the merger. This data as well as historical values from the former two utilities indicate higher than desired values for SAIDI, specifically in the western portion of NPEI's service territory. Following the merger, NPEI has implemented initiatives that specifically target improving this index such as the installation of feeder sectionalizing and advanced reclosing devices. In 2010 NPEI's distribution system performed with an improved SAIDI compared to previous years.

5 Major External Challenges

5.1 Smart Grid

NPEI is in the early stages of developing a formal smart grid strategy. NPEI leverages a mature geographic information system (GIS) to manage asset data. NPEI'S high level strategy is to build on the current GIS functionality in support of smart grid operations.

NPEI is currently implementing a work force management / outage management (WFMS/OMS) system that leverages GIS data. This system is used to manage the distribution of work to NPEI crews as well as to manage the distribution system operationally. NPEI has a long term strategy to integrate smart meters and smart devices with the OMS as the foundation of its smart grid.

Smart Grid technologies are factored into new equipment purchases where feasible from a technical and cost perspective.

5.2 DG Connections

NPEI currently has 30 microFIT connections on its system and is averaging 5 new connections per month as of December 2010. NPEI also has 1.25MW of generation connected under the FIT program as well as applications for an additional 10MW.

5.3 Municipal Commitments – Load Growth

NPEI has experienced a moderate and consistent level of load growth in the residential customer class. Approximately 500 new residential customer connections have been performed per year since the incorporation of NPEI.

Commercial development in NPEI's service area has been consistent since incorporation. Approximately 1.5 MVA of new commercial load has been connected to NPEI's system per year.

Currently, NPEI does not supply any significant industrial sector load.

NPEI anticipates that the level of growth in both the residential and commercial customer classes will remain consistent in the coming years. A capital expenditure allowance has been established to permit the connection of new customer loads based upon historical levels.

5.4 Municipal Commitments – Infrastructure

NPEI's capital expenditures have been influenced significantly by external factors in recent years. Federal and provincial stimulus funding for infrastructure improvements has resulted in a substantial increase in municipally driven construction activities. Due to obligations under the Municipal Act to accommodate road reconstruction projects, NPEI has substantially increased capital expenditures related to these activities.

We anticipate that a return to pre-stimulus infrastructure spending levels will reduce the capital requirement for these types of projects. Going forward, NPEI has allocated capital funding for such projects based on pre-stimulus historical requirements. As such projects are externally driven; NPEI may experience elevated levels of investments in this area.

6 Major Internal Initiatives

6.1 Information Technology Initiatives

NPEI manages data related to its assets in a corporate geographic information system (GIS). The GIS is Intergraph's G/Technology system designed and customized for electric utilities based in Ontario. All of the distribution assets that are managed by NPEI are modeled within the GIS. NPEI has invested heavily in GIS data as it provides a foundation for managing the lifecycle of assets. NPEI has integrated the GIS to its corporate customer information system (CIS), financial systems, analysis software, and its outage management system.

Inspection data collected by NPEI is linked to specific asset features within GIS. The GIS is used to analyze inspection results and prioritize the required corrective maintenance or replacement activities. Any maintenance activity and associated data is also tracked in the GIS.

NPEI routinely uses Distribution Engineering Simulation Software (DESS) to analyze the distribution system. NPEI has integrated DESS with the GIS to ensure that the model used for engineering analysis is kept current with minimal effort. DESS supports decisions made by NPEI's engineering and operations staff related to the design and operation of the distribution system.

NPEI is currently implementing an outage management system (OMS). The GIS provides the data utilized by the OMS and as such, the two systems have been integrated. The OMS automates several stages of outage management for operations staff at the utility. The system tracks and manages calls, predicts probable points of failure, and provides a mechanism to dispatch outage related work orders to field crews electronically. Beyond outage type work flows, the system also provides work force management capability. The system is utilized to mange work assignment to operations field staff electronically.

6.2 Kiosk/Submersible Replacement Program

NPEI’s distribution system contains approximately 200 legacy switching cubicle installations referred to as kiosks. A kiosk is a masonry structure with a metal or concrete lid that contains primary voltage switching apparatus. These installations do not conform to current distribution standards and are at end of life. The installations are inspected on a 5 year cycle to confirm condition. The inspection results are assessed annually to prioritize units that require replacement with new equipment. In a typical year, NPEI replaces 15 to 20 kiosks.

NPEI also has submersible distribution transformer installations on its system which are at end of life. These installations do not meet current standards and are subject to premature failure. A program is in place to replace these installations with pad mounted transformation. At the end of 2010, NPEI had 18 submersible installations remaining on its distribution system. NPEI typically replaces approximately 20 of these installations a year which will lead to the elimination of submersible transformers from the system by the end of 2011.

6.3 Pole Replacement Program

NPEI has been inspecting and testing poles on its distribution system since 2004. Approximately 5000 poles are tested per year. Wood poles are tested using a sound and bore method. Steel and concrete poles are visually inspected. All overhead distribution apparatus installed on poles are visually inspected at the time of the pole test.

The resulting data from the annual pole testing program is analyzed in order to prioritize the required pole replacements. NPEI replaces between 150 and 250 poles annually under the pole replacement program.

6.4 Switchgear Replacement Program

NPEI has 89 primary voltage switchgear installations on its distribution system. Approximately 20 units are inspected annually. The inspection consists of a visual condition assessment, infrared scan, and ultrasonic scan.

The resulting data from the annual switchgear inspection program is analyzed in order to prioritize the required switchgear replacements. NPEI replaces approximately 4 units per year under the switchgear replacement program.

6.5 Vegetation Management

Following the merger in 2008, NPEI adjusted its tree trimming program for the overall service area. The western portion of the service area (Lincoln, West Lincoln and Fonthill) is split into 4 trimming areas (1 per year) based on experience in growth rate. The eastern portion of the service area (Niagara Falls) is split into 5 trimming areas (1 per year).

6.6 Other Reliability Initiatives

NPEI strives to improve reliability on its distribution system through the design and incorporation of features such as:

- Wildlife Bushing Guards
- Insulated Drop Leads
- Insulated Switch Brackets/Bases
- Over Insulated Components
- Increased Designed Clearances
- Encapsulated Switching and Terminal Components
- Covered Line Wire
- Advanced Reclosers and Controls

The application of these components minimizes the occurrence of foreign interference with the distribution system that negatively impacts the reliability of service to our customers.

7 Business Practices

7.1 Proactive vs. Reactive Replacements

Based on replacement practices, assets can be divided into 2 distinct categories: assets that are replaced "reactively" only when they fail, and assets that are replaced "pro-actively" based on their condition before they fail.

Failure of assets that are replaced "proactively" usually does not result in significant cost and/or risk to corporate objectives and values. Conversely, failure of assets that are replaced "reactively" usually results in significant incremental cost over and above planned replacement cost and, furthermore, poses high risk to objectives and values.

NPEI "proactively" replaces distribution facilities as part of the Internal Initiatives described in the Section 6.

7.2 Maintenance Practices

NPEI follows the requirements outlined in the distribution system code. The following table summarizes maintenance practices on major equipment within NPEI's asset base:

Equipment	Cycle	What is Done
TS/DS Inspection	Monthly	Visual Inspection
Station Transformers	Annually	Oil Analysis, Dissolved Gas Analysis, Visual Inspection
Large Padmounted Transformers	Annually	Oil Analysis, Dissolved Gas Analysis, Visual Inspection
Small Padmounted Transformers	5 Year Cycle	Infrared Scan, Ultrasonic Scan, Visual Inspection
Poles	5 Year Cycle	Sound and Bore (Structural Integrity Assessment), Treatment Application, Component Inspection
Switchgear	5 Year Cycle	Infrared Scan, Ultrasonic Scan, Visual Inspection
Manholes/Civil Structures	5 Year Cycle	Visual Inspection, Cleaning
Switching Kiosks	5 Year Cycle	Condition Review, Prioritized Elimination of Legacy Equipment
Vegetation Management	5 Year Cycle	5 Year Cutback

7.3 Work Integration

NPEI adjusts its maintenance practices and sustainment capital programs due to their inherent interdependencies and to account for internal initiatives. An adjustment is made in situations where commercial and operational benefits can be achieved. Examples of this include:

- Reducing capital replacement cost projections to account for distribution plant that will be replaced as a part of an externally driven project, such as a municipal road widening
- Initiation of a rebuild project rather than per pole replacement approach due to the quantity of identified deficiencies in a test area
- Extension in maintenance activities to provide increased life expectancy in distribution assets where a known end of service date exists

8 Asset Condition Assessment

NPEI retained the services of Kinectrics Inc. to carry out an Asset Condition Assessment of NPEI's key distribution assets. The resulting Distrubtion Asset Condition Assessment report is included in Appendix A of this document.

9 2011 Business Plan

9.1 Sustaining Capital with Major Project Types

Item	Project Type	Sustainment Capital
1	Replacement of distribution facilities due to deteriorated condition	$2,005,619
2	Line extensions/relocations due to municipal road work requirements	$388,370
3	Replacement of poles identified with limited structural integrity	$1,226,524
4	Required overhead line rebuild of deteriorated facilities identified in the pole condition survey	$776,740
5	Replacement of kiosks and submersible transformers	$480,835
6	Minor Betterments	$488,926
		$5,367,014
	Less Capital Contributions	$-100,000
	Total	**$5,267,014**

9.2 Development Capital with Major Project Types

Item	Project Type	Development Capital
1	Expansion of the primary distribution system to accommodate load growth and reliability requirements	$1,295,495
2	Subdivisions and new residential services	$631,059
3	Demand based system requirements for new commercial service connections and expansions	$1,156,938
	Projects under materiality	$194,185
		$3,227,677
	Less Capital Contributions	$-750,000
	Total	**$2,527,677**

9.3 Other Capital

Item	Type	Other Capital
1	Metering	$185,185
2	Vehicles	$462,963
3	Other Capital	$659,954
	Total	**$1,308,102**

9.4 O&M with Major Categories

Item	Type	Other Capital
1	Stations	$190,778
2	Overhead Lines	$1,921,782
3	Underground	$651,140
4	Other	$3,378,406
	Total	**$6,142,106**

9.5 Billing and Collecting with Major Categories

Item	Type	Other Capital
1	Billing	$3,302,566
2	Collecting	$893,163
3	Community Relations	$81,464
	Total	**$4,277,193**

9.6 General and Administration

Item	Type	Other Capital
1	G & A	$3,876,136

10 2012-2015 Business Plan

10.1 Sustaining Capital

Year	Amount
2012	$5,223,331
2013	$5,320,205
2014	$5,368,186
2015	$5,464,149

10.2 Development Capital

Year	Amount
2012	$2,766,249
2013	$2,908,623
2014	$2,981,100
2015	$3,101,559

10.3 Other Capital

Year	Amount
2012	$1,324,074
2013	$1,273,148
2014	$1,273,148
2015	$1,273,148

10.4 O&M

Year	Amount
2012	$6,278,477
2013	$6,418,728
2014	$6,562,315
2015	$6,709,323

10.5 Billing and Collecting

Year	Amount
2012	$4,365,422
2013	$4,463,294
2014	$4,563,847
2015	$4,667,161

10.6 General and Administration

Year	Amount
2012	$3,963,342
2013	$4,052,768
2014	$4,144,473
2015	$4,238,521

Appendix A – NPEI Distribution Asset Condition Assessment Report

The remaining pages of this document contain the Distribution Asset Condition Assessment Report produced by Kinectrics Incorporated.

Niagara Peninsula Energy Inc

Distribution Asset Condition Assessment

Kinectrics Report: K-418046-RC-001-R3

February 10, 2011

PRIVATE INFORMATION

Kinectrics Inc., 800 Kipling Avenue, Unit 2, Toronto, Ontario, Canada M8Z 6C4

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Niagara Peninsula Energy Inc.

@Kinectrics Inc., 2011.

DISTRIBUTION ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418046-RC-001-R3

February 10, 2011

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Dated: Feb 9, 2011

Revision History

Revision Number	Date	Comments	Approved
R0	December 20, 2010	Initial Draft	N/A
R1	January 28, 2011	Final Draft	N/A
R2	February 9, 2011	Final Report	SC
R3	February 10, 2011	Final Report (re-formatted)	

EXECUTIVE SUMMARY

Niagara Peninsula Energy Inc (NPEI) retained Kinectrics Inc. (Kinectrics) to carry out an Asset Condition Assessment (ACA) of NPEI's key distribution assets. The assets were divided into several Asset Groups. For each of these Asset Groups, the ACA included the following tasks:

- Derive Health Indexes
- Conduct Field Surveys
- Provide Capital Replacement Plan
- Recommend condition data gap closure strategy

This report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

Information Availability and Health Index Methodology

The general methodology for Asset Condition Assessment is described, while each Asset Group is presented in detail in its own section. Where appropriate, the formulations were modified based on the expert opinion of NPEI staff, for example air-insulated pad mounted switchgear located near major roads were automatically assigned poor condition and, thus, flagged for replacement. Field observations generally supported the Health Index distribution derived using Kinectrics' methodology. Some differences could be attributed to the fact that the field survey observations weigh all the condition parameters equally while the Health Index formulation used a weighted sum of condition parameters scores.

Health Index Results Summary

For six of the seven Asset Groups there was sufficient asset information to calculate Health Indexes. Table ES - 1 shows, for each of the seven Asset Group, the total number of assets, sample size, and Health Index distribution. Detailed results for each Asset Group are shown in Section C RESULTS AND FINDINGS.

Table ES - 1 Health Index Results Summary

ASSET			SAMPLE SIZE		HEALTH INDEX DISTRIBUTION				
No	Description	Population	Units	%	Very Poor	Poor	Fair	Good	Very Good
1	Power Transformers	21	*21*	*100%*	0%	17%	26%	22%	35%
2	Large Pad Mounted Transformers	56	*51*	*91%*	0%	2%	6%	27%	65%
3	Standard Pad Mounted Transformers	2,408	*716*	*30%*	5%	1%	1%	4%	89%
4	Pole Top Transformers	6,835	*6,711*	*98%*	1%	4%	11%	17%	67%
5	Poles	22,247	*5,985*	*27%*	0%	5%	6%	28%	61%
6	Pad Mounted Switchgear	89	*38*	*43%*	8%	34%	3%	18%	37%

Capital Replacement Plan

The Capital Replacement Plan (CRP) includes two aspects: the number of units that are planned to be replaced and the corresponding replacement cost. For asset categories 2 through 6 capital requirements for the whole population were extrapolated from the sample and the comments regarding appropriateness of such an assumption were included in Section C for each of these asset categories.

The number of units to be replaced was estimated based on asset condition and the corresponding probability of failure. Table ES - 2 summarizes the assumed replacement cost, replacement plan approach, and resultant capital replacement plan in the first year as well as the capital replacement plan approach. Assets which are 'run to failure' are replaced reactively, compared to those assets which are replaced proactively.

Table ES - 2 Capital Replacement Plan Summary

Asset	Assumed Replacement Cost	Units to Replace in First Year	Planned Capital Replacement Cost in First Year	CRP Approach
Power Transformers	$300,000	1	$300,000	Proactive
Large Pad Mounted Transformers	$45,000	0	$0	Proactive
Standard Pad Mounted Transformers	$15,000	31	$465,000	Proactive
Pole Top Transformers	$5,000	38	$190,000	Reactive
Poles	$5,000	160	$800,000	Reactive
Pad Mounted Switchgear	$75,000	5	$375,000	Proactive

The scheduling of capital expenditure for assets which are replaced **proactively** has been levelized so replacement is done over a period of time after the optimal replacement year. Those assets which are replaced **reactively** also have a levelized schedule so replacement is done over a period of time before the optimal replacement year. This methodology is to ensure that run to failure assets are replaced before they fail.

Figure ES – 1 presents the Overall Levelized Capital Replacement Plan. This is the total replacement projections for all the assets over the next five (5) years in 2011 dollars (cost does not take inflation rates into account).

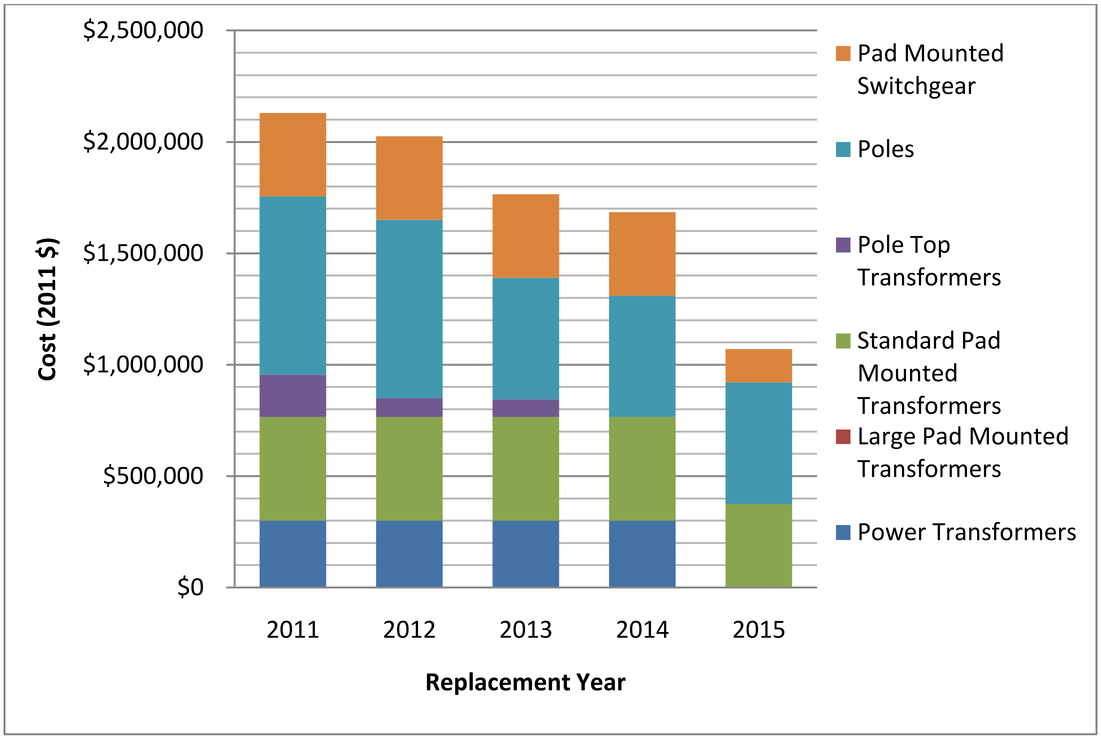

Figure ES - 1 Five Year Capital Replacement Plan

Conclusions and Recommendations

1. There was generally sufficient condition data available for Power Transformers, Large Pad-mounted Transformers, Poles (inspected after 2008) and Switchgear.

2. For Pole-mounted transformers, only age and operating practices were available (i.e., number of customers serviced by each transformer). Gathering and recording detailed inspection data should be considered.

3. For Standard Pad Mounted Switchgear, age was provided for 87% of the population however sufficient data was provided for only 28% of the population. It is recommended that NPEI collect data for a greater population of Pad Mounted Switchgear.

4. For Poles that have not been inspected, age is only available for half of the population. Sufficient age and inspection data should be collected for the rest of the population.

5. Sufficient data was not available for Underground Cables. It is recommended that inspection and maintenance information be collected for these assets to enable future asset condition assessment.

6. Comparison of poles with adequate condition data vs poles with only age known shows that the former have a better overall condition than the latter. This is due to the fact that over the last several years substantial capital investments were made to achieve that. It is therefore recommended that capital investments be made to bring be made to bring the rest of the pole population to the same Health Index distribution as the subset with adequate condition data.

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A INTRODUCTION

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To: Niagara Peninsula Energy
7447 Pin Oak Drive
Niagara Falls, ON L2E 6S5

INTRODUCTION

Niagara Peninsula Energy Inc (NPEI) supplies electricity to homes and businesses and is regulated by the Ontario Energy Board.

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 90 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and components and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

NPEI retained the services of Kinectrics to carry out condition assessment of its electrical distribution system assets.

A considerable portion of this work was devoted to the development of Health Indices based on the information provided by NPEI, a brief visual field survey conducted by Kinectrics and the expert opinion of NPEI staff.

This report presents the findings of the NPEI's distribution assets condition assessment and includes the development of Health Indices for the specified Asset Groups.

Objective

Kinectrics performed an Asset Condition Assessment of NPEI's electrical distribution system. The following distribution system assets, referred to as Asset Groups throughout this report, were covered under the scope of work for this project:

1 Power Transformers
2 Large Pad-Mounted Transformers
3 Standard Pad-Mounted Transformers
4 Pole-Top Transformers
5 Poles
6 Pad Mounted Switchgear

As part of the asset condition assessment, a visual inspection of the power system physical assets was conducted by Kinectrics. The objective of the inspections was to confirm the average condition of the equipment as indicated by the condition data bases provided to Kinectrics.

Scope of the Work

The project includes the following:

1 Provide Recommended Health Index formulations used to derive Health Indices
2 Calculate and provide Health Index distribution for each of the aforementioned asset categories
3 Provide Capital Replacement Plan
4 Identify condition data gaps and provide recommendations for their prioritized closure

These areas and the factors of assessments covered under this project, are based on Kinectrics experience and familiarity with the industry requirements, and provides rational for the capital replacement expenditures being sought by NPEI. As such, the results will help NPEI in its service rate application submission to the OEB and will provide a basis for a medium to long-term capital plan for its distribution assets. It is worth noting, however, that replacement requirement due to poor asset condition is not the only basis for developing a capital plan: other factors, such as obsolescence, design flaws, exposure to severe environmental conditions, system requirements, etc. should also be taken into account when developing such plan.

Visual field inspection was conducted at several locations and included:

- 3 locations of three-phase pad mounted transformers
- 2 locations of overhead switches
- 5 locations of wood poles
- 2 locations of pole mounted transformers,
- 1 location of pad mounted switchgear
- 2 locations of distribution station transformers.

All of the locations were inspected directly by Kinectrics staff that traveled to the sites accompanied by a NPEI employee. The sample locations were scattered at 11 geographic areas within the service territory of NPEI.

Deliverables

The deliverables in this report include the following information:

- Short description of the asset groups being considered in the study
- Discussion of asset degradation and end-of-life issues
- Health Index results for the Asset Groups
- Description of methodology for assessment of asset replacements
- Capital replacement plan
- Data Gap Closure
- Field inspection results

B ASSET CONDITION ASSESSMENT METHODOLOGY

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Health Indexing

Health Indexing quantifies equipment condition based on numerous condition criteria that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index (HI) 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 differs from maintenance testing, 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 that are used to derive the Health Index. In formulating a Health Index, condition parameters are ranked and evaluated, through the assignment of corresponding weights, based on their contribution to asset degradation. The condition parameter score is an evaluation of an asset with respect to a condition parameter.

A condition parameter may also be comprised of several sub-condition parameters. For example, a parameter called "insulation" for power transformers may be a composite of Oil Quality and Oil DGA.

The Health Index, which is a function of the condition parameter scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)}$$

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)

While weightings are assigned based on the priority level of condition parameters, scores represent the evaluation of an asset against condition criteria. A condition criterion is the scale that is used to determine an asset's score for a particular parameter.

Consider, for example, a system where the Health Index is described under one of the following five categories: very poor, poor, fair, good, and very good. A scoring system of 0 through 4 corresponds to the "very poor" through "very good" categorization. Consider a parameter "age" for which this scoring system is applied. The condition criteria will define the age that constitutes scores of 0 through 4 (i.e. a pole mounted transformer that is 50 years old will receive a score of 0; whereas one that is 2 years old will receive the maximum score of 4). Note that in this study, the condition criteria scoring system consist of values from zero (0) through four (4), with 0 being the worst and 4 being the best score.

De-rating factors are also used to adjust a calculated Health Index to reflect certain conditions. These may be factors that may or may not be related to asset condition, but contribute to the asset's risk of failure. For example, an air-insulated Pad Mounted Switchgear by a major roadway is prone to problems. Dominant parameters may be used as de-rating factors. These are asset properties that are considered to be of such importance that its status has a dominant impact on the value of the Health Index. De-rating factors are used to reduce the Health Index of an asset by a certain percentage. If a calculated Health Index is, say, 90%, a de-rating factor of 80% will reduce the effective Health Index to 90% x 80% = 72%.

Relating Health Index to Effective Age

Once the Health Index of an asset is determined, its *effective age* can be evaluated by establishing a relationship between its Health Index and its probability of failure. Effective age is different from chronological age in that it is based on the asset's condition and the stress stresses applied to the asset.

Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides the best model. The failure rate equation is in the form of:

$$f = e^{\beta(t-\alpha)}$$

where

f = failure rate of an asset (frequency or the number of expected failures per year) at time t

t = time

α, β = constant parameters that control the rise of the curve

The corresponding probability of failure is given as:

$$P_f = 1 - e^{-(f-e^{\alpha\beta})/\beta}$$

where

P_f = probability of failure

f = failure rate of an asset

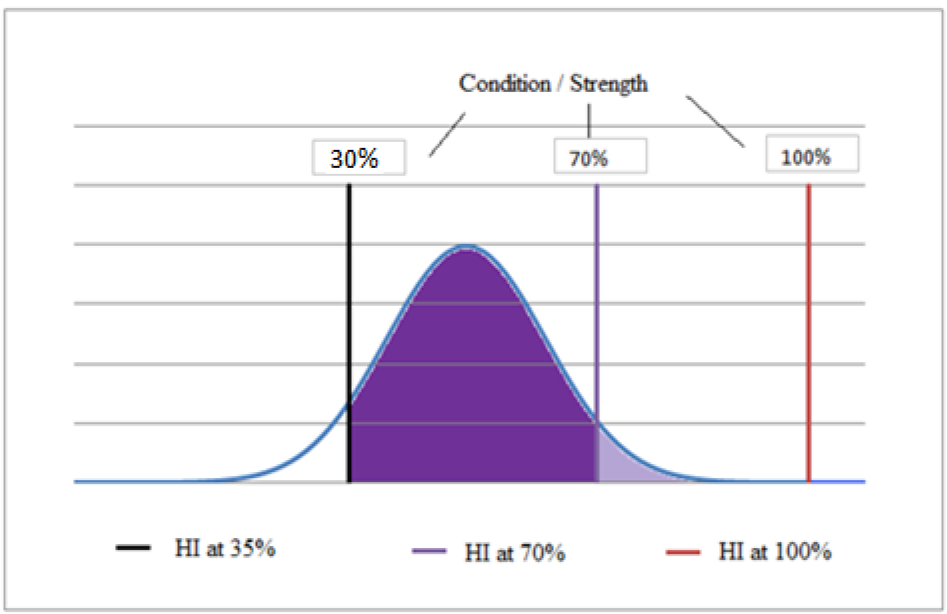
α, β = constant parameters that control the rise of the curve

Different assets 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 control the location and steepness of 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.

Quantitative Relationship Between Health Index and Probability of Failure

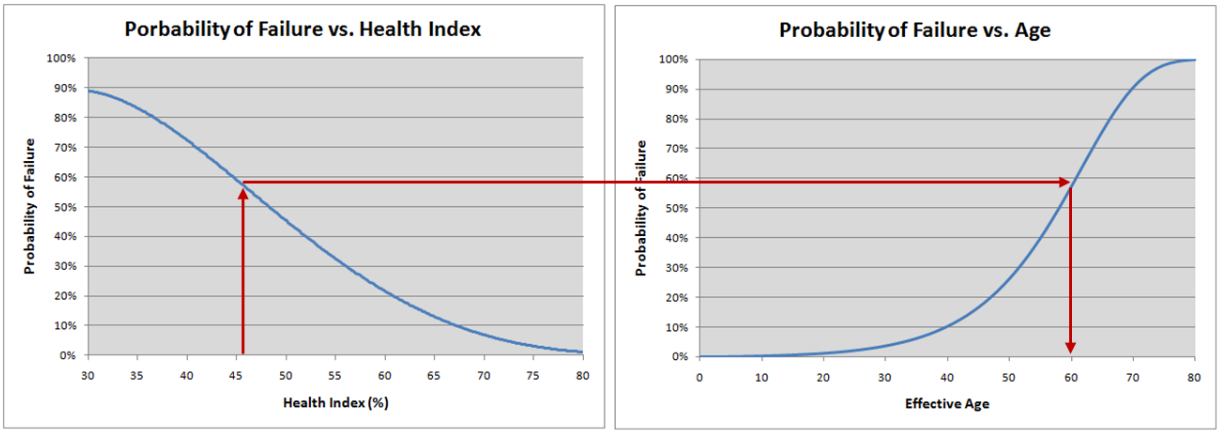
Failure of an asset occurs when the stress that an asset experiences exceeds is strength. Assuming that stress is not constant and the stress probability is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure.

Consider the Health Index to be a representation of condition. Two Health Index points and the probabilities of failure at those Health Index points can be used to find the probabilities of failure at other Health Index values. This is illustrated in the figure below. The vertical line represents condition (Health Index) and the area under the curve to the right of the line represents the probability of failure.
A Health Index of 100% represents an asset that is in brand new condition and a Health Index of 30% at its end of life. Moving the vertical line left from 100% to 30%, the probabilities of failure at other Health Indices can be found.



Effective Age and Remaining Life

The effective age associated with a particular Health Index is found by first plotting the Probability of Failure vs. Health Index curve. This is the area under the probability density curve between the 100% and 30% Health Index points. This curve is shown on the left hand graph of the figure below. The associated probability of failure is then found on Probability of Failure vs. Age graph (right hand graph). The effective age is read from the horizontal axis of the right hand graph.



Relationship between Health Index and Effective Age

The remaining life can be estimated as the difference between the asset's maximum life expectancy and its effective age. For example, a pole mounted transformer that has an effective age of 35 years will have a remaining life of 45-35 = 10 years.

Capital Replacement Plan

Simple Replacement

Asset groups that have little consequence of failure or that are run to failure are reactively replaced. The number of predicted failures multiplied by the replacement cost per unit at the year of failure determined the yearly investments for the asset group.

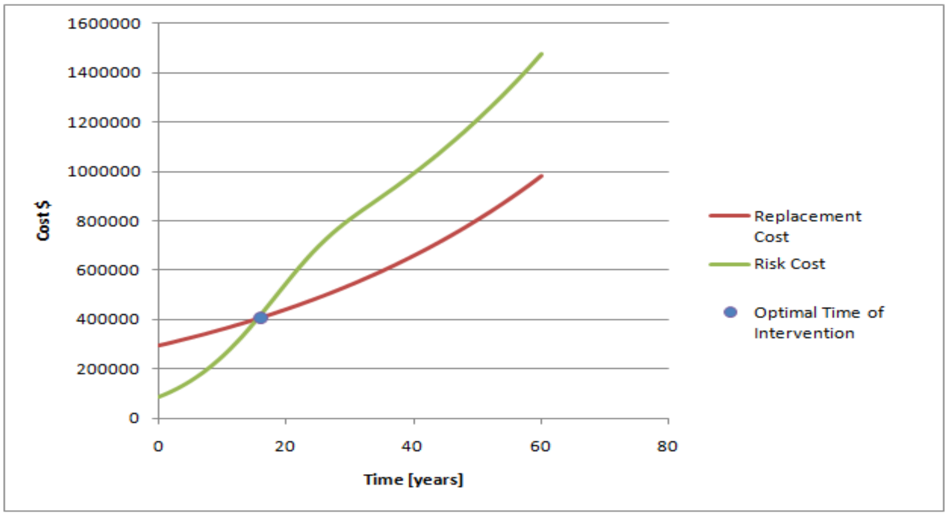
Risk Analysis

For assets that are have a high consequence of failure (i.e. power transformers), risk analysis determined the economic optimal time of intervention. Planned replacement cost, cost of failure, and risk cost were considered.

The utility's *costs of failure* for an asset can include the replacement cost of the asset, any collateral damage to adjacent equipment, environmental clean-up costs, overtime labour premiums, and the lost revenue. Some utilities also include the cost of interruptions to customers. For this analysis, the cost of failure was estimated as a multiple of its planned replacement cost. For non-critical power transformers, the cost of failure was defined as 1.5 times the planned replacement cost, whereas for critical power transformers, the cost of failure multiple was 2.

The *risk cost* is defined as the failure cost times the probability of failure, probability of failure is dependent on an asset's effective age.

The optimal time of intervention (refurbishment or replacement) was found as the point where the risk cost begins to exceeds the replacement cost. The number of units that were flagged for replacement in a given year times replacement cost for the given year determined the investment required for that year.



Data Gap Closure

Prioritized strategy for data gap closure is included for each asset category using 3 priority levels, from the highest (3 stars) to the lowest (a single star). It is recommended to start collecting condition data for the highest priority condition parameters as this will improve credibility of the Health Index results the most. This is the case for both assets with some condition data available and assets with no condition data available.

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C RESULTS AND FINDINGS

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1 Power Transformers

The application of substation station transformers generally involves the step down of a higher to lower voltage. Power transformers vary in capacity and ratings over a broad range.

Station transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary, secondary and, possibly, tertiary windings
- Laminated iron core
- Internal insulating media
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

1.1 Degradation Mechanism

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

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units with a probable high risk of failure. It is the ideal means on which to base an ongoing management strategy for aging transformers, identifying units that warrant consideration for continued use, consideration of remedial measures to extend life or identification of transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for substation transformers include the use of online monitors, capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks, DC insulation resistance measurements and no-load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index, and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonic and/or electromagnetic detection and frequency response analysis.

The health indicator parameters for substation transformers usually include:

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

1.1.1 *Failure Mechanism of Station Transformers*

1.1.1.1 Thermal Aging:

Thermal aging involves the progress of chemical and physical changes because of chemical degradation reactions, polymerization, depolymerization, and diffusions.

1.1.1.2 Electrical Aging:

Electrical aging, as it relates to AC, impulse, or switching involves the effects of the following:

- partial discharges
- treeing
- electrolysis
- increased temperatures produced by high dielectric losses
- space charges

1.1.1.3 Mechanical Aging

Mechanical aging involves the following:

- fatigue failure of insulation components caused by a large number of low-level stress cycles
- thermo mechanical effects caused by thermal expansion and or contraction
- rupture of insulation by high levels of mechanical stress such as may be caused by external forces or operation condition of the equipment
- Insulation creep or flow under electrical, thermal, or mechanical stresses

1.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DF$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF_n} \times \mathrm{WCPF_n})}{\sum_{n=1} \beta_n (\mathrm{CPF_{n.max}} \times \mathrm{WCPF_n})} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter
DF --- De-rating Factor

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

1.3 Condition and Sub-Condition Parameters

Table 1-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Insulation	4	4
2	Sealing & Connection	1	4
3	Service record	3	4

Table 1-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Oil Quality	4	4
2	Oil DGA	5	4

1.3.1 *Oil Quality*

Table 1-3 Oil Quality Test

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

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

Table 1-4 Oil Quality Overall Factoring

		Scores				
		1	2	3	4	Weight
Dielectric Str. kV D877		>40	>30	>20	Less than 20	3
IFT* dynes/cm	230 kV $\leq$ U	>32	25-32	20-25	Less than 20	2 *
	69 kV <U< 230	>30	23-30	18-23	Less than 18	
	U $\leq$ 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 $\leq$ U	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <U< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	U $\leq$ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

1.3.2 *Oil Dissolved Gas Analysis (DGA)*

Table 1-5 Transformer DGA

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

*In the case of a score other than A, 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 B, 0.85 for score C, 0.75 for score D and 0.5 for score E.

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

Table 1-6 Oil DGA Overall Factoring

	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

Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Table 1-7 Sealing & Connection (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Tank Oil Leak	1	4
2	Conservator Oil Level	1	4

Table 1-8 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Age	1	4

1.3.3 *Age*

Table 1-9 Transformer Age

Condition Rating	CPF	Description
A	4	0-19
B	3	20-29
C	2	30-44
D	1	45-54
E	0	>=55

1.4 Health Index Results

The total population of assets for this category is 23. The Sample Size or total number of assets within the population that have data is 23, which means there was data for each asset.

The year purchased was assumed to the transformers age. There was full data for Oil dissolved gas analysis (DGA). It is recommended that data be collected on moisture ppm, power factor (for winding doble score), as well as collecting data on grounding and IR thermography.

The Health Indexing Result by Unit and Percentage are presented below:

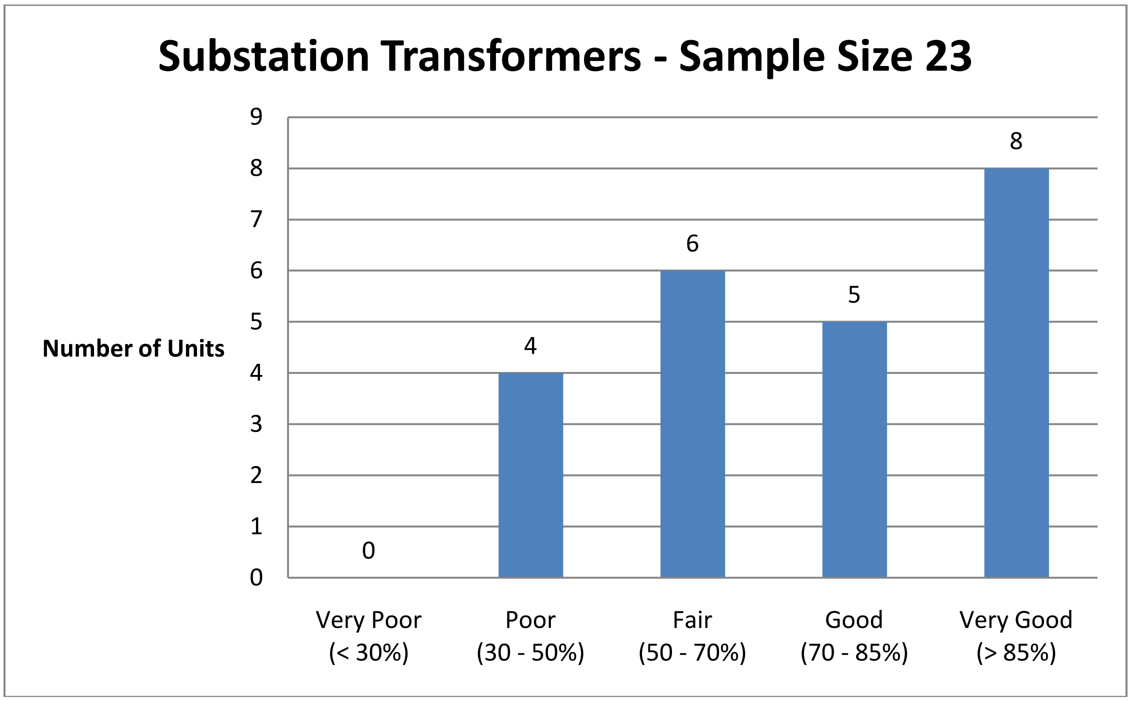

Figure 1-1 Health Index Distribution by Units

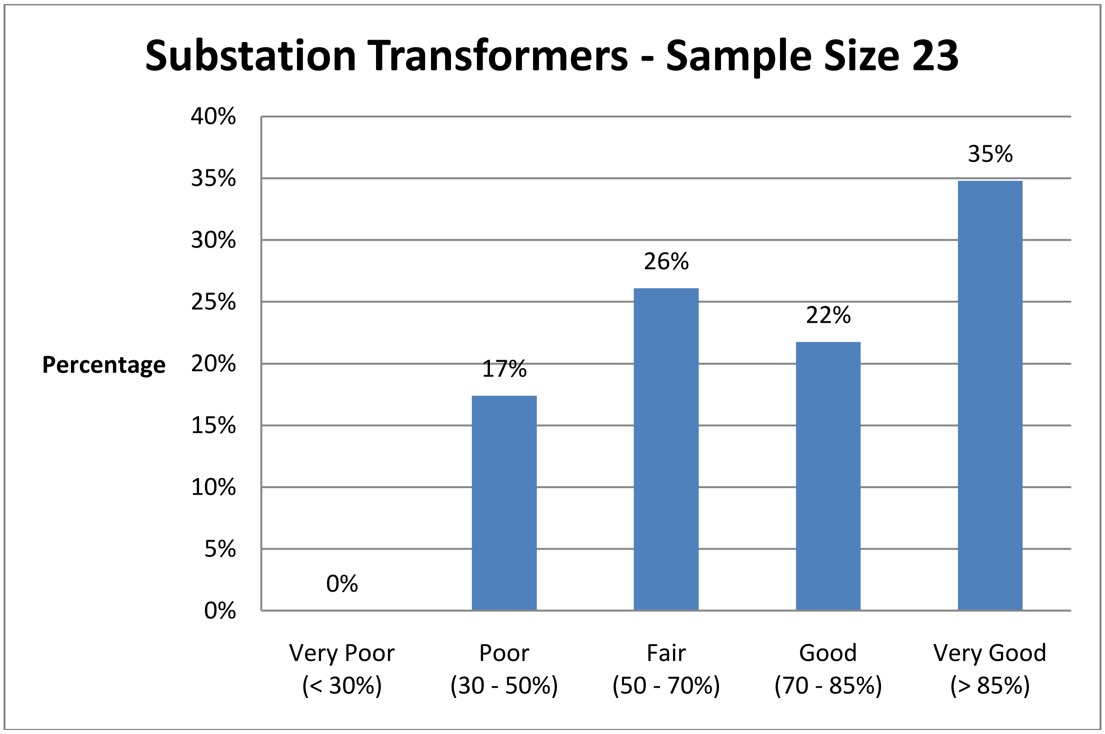

Figure 1-2 Health Index Distribution by Percentage

The exact rating for each Transformer is presented below:

Table 1-10 Substation Health Index Score and Criticality

Transformer No	Substation Name	HI Score	HI Rating	Critical
SD71844-3	SMITHVILLE DS - NF1844	38%	POOR	YES
SD1856-T2	GREEN LANE D.S. - NF 1856	43%	POOR	YES
SD71844-1	SMITHVILLE DS - NF1844	50%	POOR	YES
SD71844-2	SMITHVILLE DS - NF1844	50%	POOR	YES
SD1856-T1	GREEN LANE D.S. - NF 1856	56%	FAIR	YES
800089	VIRGINIA A-144	59%	FAIR	NO
800095	MARGARET A-127	61%	FAIR	YES
800073	ARMOURY A-113	61%	FAIR	NO
800084	ALLENDALE A-175	69%	FAIR	NO
SD1850	CAMPDEN D.S. - NF 1850	69%	FAIR	YES
SD001	STATION ST. D.S.	74%	GOOD	NO
800100	O'NEIL A-148	81%	GOOD	NO
800082	ALLENDALE A-175	81%	GOOD	NO
800295	LEWIS A-119	78%	GOOD	NO
800077	ONTARIO A-115	78%	GOOD	NO

800389	DRUMMOND A-122	86%	VERY GOOD	NO
800052	PARK A-33	86%	VERY GOOD	NO
800054	VIRGINIA A-144	88%	VERY GOOD	NO
2515T2	KALAR TS	93%	VERY GOOD	NO
800388	PEW A-135	93%	VERY GOOD	NO
800053	SWAYZE A-145	100%	VERY GOOD	NO
2515T1	KALAR TS	100%	VERY GOOD	NO
SD1836	JORDAN D.S. - NF 1836	100%	VERY GOOD	YES

1.5 Field Inspection Results

Four Power Transformers were inspected. The data can be found in Section E FIELD INSPECTION FORMS and the summary is shown in Figure 1-3 below. There were no major concerns with the units inspected.

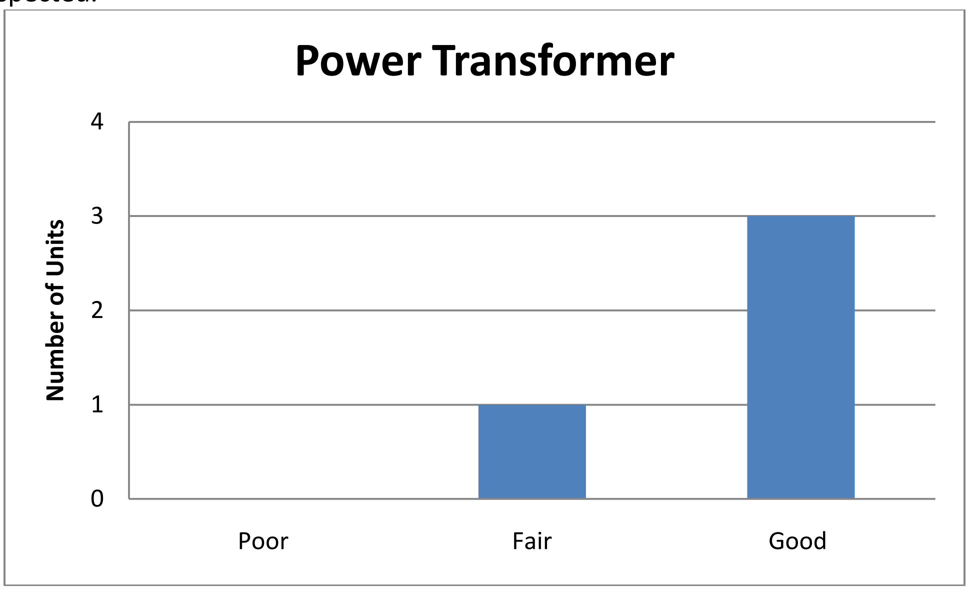

Figure 1-3 Field Inspection Results

1.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 25 years the probability of failure is 10% and at age of 45 years the probability of failure is 90%.

1.6.1 *Optimal Capital Replacement Plan*

Figure 1-4 shows the number of Transformer units that will need to be replaced over the next 20 years for the whole population extrapolated from the results for the sample with adequate condition data. Given the full sample size (100%) the recommendations are for the entire population.

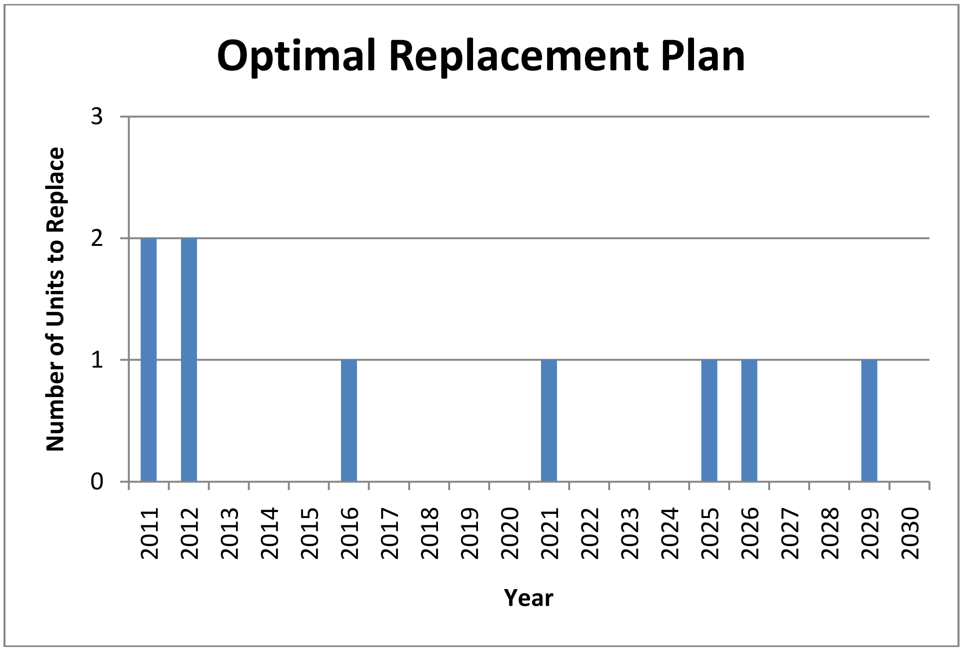

Figure 1-4 Optimal Replacement Plan

1.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 2 units in the next year. While this is optimal based on NPEI's Power Transformers HI scores, it may not be ideal financially.

Power Transformers are replaced **proactively**. The Levelized replacement plan allows for Transformers that would optimally be replaced in one year to be replaced over a period of time in the future.

Figure 1-5 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

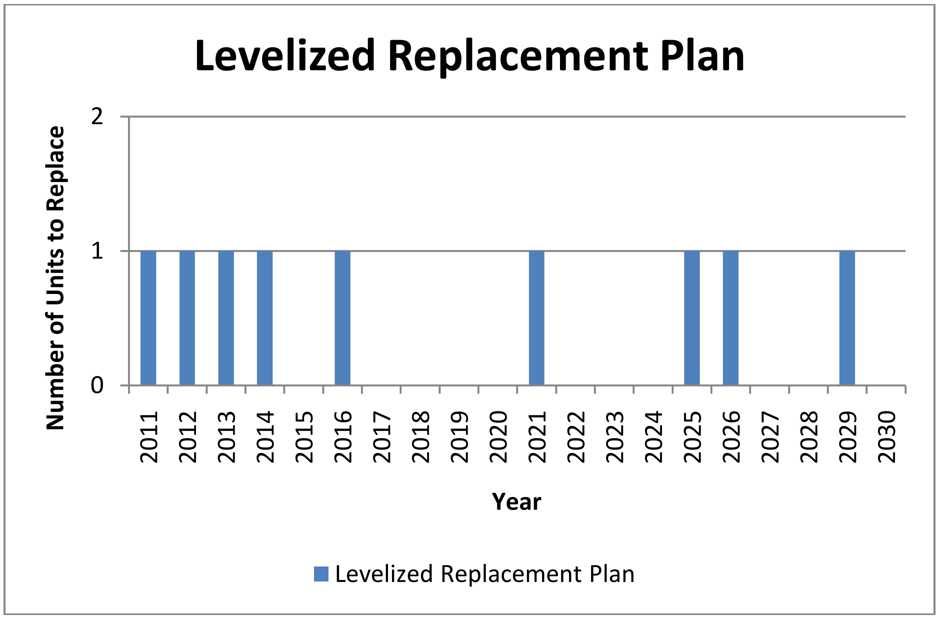

Figure 1-5 Levelized Replacement Plan

1.7 Data Gap Closure

The following table summarizes the data gap for power transformers in this project.

Table 1-11 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Insulation	Winding Doble	☆☆
Cooling	Temperature	☆☆
Sealing & connection	Grounding	☆
	IR thermography	☆☆☆
Service record	Loading	☆☆

IR thermography is a useful approach in detecting hot spots due to a loose connection or leakage. In this project, it also can address the temperature issue in cooling system as well as the transformer loading status, when the data on those 2 parameters are unavailable.

In the sub-system of insulation, another parameter "oil quality" indirectly addresses the winding insulation deterioration, as it detects on some contents that are the consequence of insulation deterioration (moisture, oxygen due to cellulose degradation).

2 Large Pad Mounted Transformers

Pad Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. For the purposes of this report, the pad-mounted transformer has been componentized into the transformer itself and the enclosure. Large Pad Mounted Transformers are Pad Mounted Transformers greater than 700 kVA.

2.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

2.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DF$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF_n} \times \mathrm{WCPF_n})}{\sum_{n=1} \beta_n (\mathrm{CPF_{n.max}} \times \mathrm{WCPF_n})} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter
DF --- De-rating Factor

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

2.3 Condition and Sub-Condition Parameters

Table 2-1 Condition Weights and Maximum CPS

M	Condition parameter	WCP_m	$CPS_{m.max}$
1	Insulation	4	4
2	Sealing & Connection	1	4
3	Service Record	3	4

Table 2-2 Insulation (m=1) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Oil Quality	4	4
2	Oil DGA	5	4

2.3.1 *Oil Quality*

Table 2-3 Oil Quality Test

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

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

Table 2-4 Oil Quality Overall Factoring

		Scores				
		1	2	3	4	Weight
Dielectric Str. kV D877		>40	>30	>20	Less than 20	3
IFT* dynes/cm	230 kV $\leq$ U	>32	25-32	20-25	Less than 20	2 *
	69 kV <U< 230	>30	23-30	18-23	Less than 18	
	U $\leq$ 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 $\leq$ U	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <U< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	U $\leq$ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

2.3.2 *Oil Dissolved Gas Analysis (DGA)*

Table 2-5 Transformer DGA

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

*In the case of a score other than A, 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 B, 0.85 for score C, 0.75 for score D and 0.5 for score E.

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

Table 2-6 Oil DGA Overall Factoring

	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

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Table 2-7 Sealing & Connection (m=2) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Tank Oil Leak	1	4
2	Conservator Oil Level	1	4

Table 2-8 Service Record (m=3) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Age	1	4

2.3.3 *Age*

The age used was based on the manufacture date on the name plate of the transformer.

Table 2-9 Transformer Age

Condition Rating	CPF	Description
A	4	0-19
B	3	20-29
C	2	30-44
D	1	45-54
E	0	>=55

2.4 Health Index Results

The total population of assets for this category is 56. The Sample Size or total number of assets within the population that have data is 51.

The Health Indexing Result by Unit and Percentage are presented below:

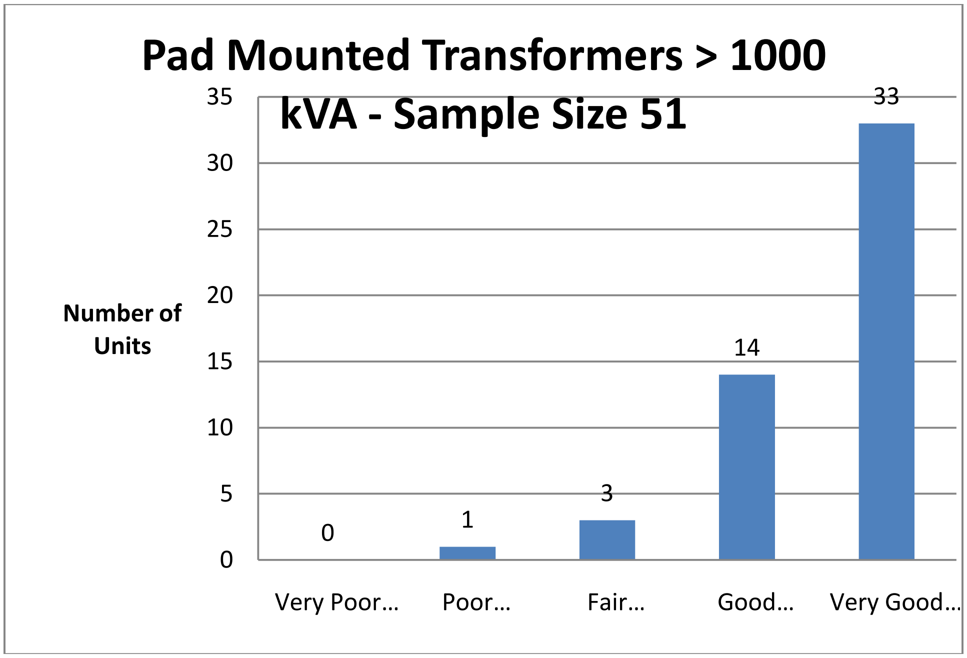

Figure 2-1 Health Index Distribution by Units

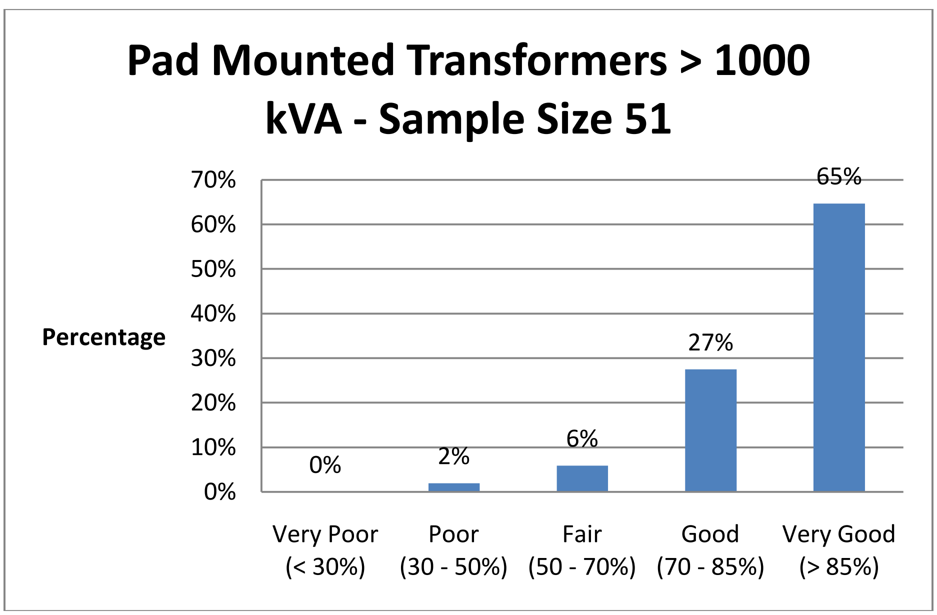

Figure 2-2 Health Index Distribution by Percentage

The exact rating for each Transformer is presented below:

Table 2-10 Pad Mounted Transformer Health Index Score

Transformer No	Substation Name	HI Score	HI Rating
800135		50%	POOR
	SMITHVILLE 85	60%	FAIR
800105		63%	FAIR
732	FROST ROAD	69%	FAIR
2529		75%	GOOD
800515	DOUBLE TREE	75%	GOOD
800109		78%	GOOD
	NO NAMEPLATE	80%	GOOD
800554		81%	GOOD
800129	STATION 52	81%	GOOD
800128	STATION 52	81%	GOOD
800197		81%	GOOD
800148	HEDGSON	81%	GOOD
800127	DAYS INN FALLVIEW	81%	GOOD
800210	MANSIONS OF FOREST GLEN	81%	GOOD
800116	BUCKLEY TOWER	81%	GOOD
800126		84%	GOOD
77045	INDUSTRIAL PARK	86%	VERY GOOD
800526	DAYS INN VICTORIA AVE	86%	VERY GOOD
494	HILLSIDE DRIVE (5050)	86%	VERY GOOD
3040	SOUTH SERVICE RD	88%	VERY GOOD
800413	SUPER 8	90%	VERY GOOD
9201	BARTLETT ROAD (4306)	91%	VERY GOOD
3176	4927 ONTARIO ST.	91%	VERY GOOD
1652	SECOND AVE	93%	VERY GOOD
800568		93%	VERY GOOD
800546	NF COMM CENTRE	93%	VERY GOOD
800587		93%	VERY GOOD
800430	SWAGELOK	100%	VERY GOOD
800465		100%	VERY GOOD
301	4655 BARTLETT	100%	VERY GOOD
546	4927 ONTARIO ST.	100%	VERY GOOD
800550	NIAGARA REGION	100%	VERY GOOD
800601		100%	VERY GOOD
599	ONTARIO ST (SOBEYS)	100%	VERY GOOD
800589		100%	VERY GOOD
73201	PEARSON STREET	100%	VERY GOOD

81	FROST ROAD	100%	VERY GOOD
8099	4758 CHRISTIE ST.	100%	VERY GOOD
629	TWENTY THIRD ST	100%	VERY GOOD
800414	TGI FRIDAYS	100%	VERY GOOD
202	JORDAN ROAD	100%	VERY GOOD
800532		100%	VERY GOOD
800585		100%	VERY GOOD
800443	NPE BUILDING	100%	VERY GOOD
83005	REGIONAL ROAD 20 EAST	100%	VERY GOOD
800586		100%	VERY GOOD
800490	GOLDEN HORSESHOE	100%	VERY GOOD
800584		100%	VERY GOOD
800588		100%	VERY GOOD
99121	NORTH SERVICE RD	NO DATA	
800147	EVENTIDE HOME	NO DATA	
229	DURHAM ROAD	NO DATA	

2.5 Field Inspection Results

Field inspections were only done on Standard Pad Mounted Transformers.

2.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 25 years the probability of failure is 10% and at age of 45 years the probability of failure is 90%.

2.6.1 *Optimal Capital Replacement Plan*

Figure 2-3 shows the number of Transformer units that will need to be replaced over the next 20 years for the whole population extrapolated from the results for the sample with adequate condition data. Given a significant sample size (93%) there is a high degree of confidence that the recommendations for the sample and the whole population are the same.

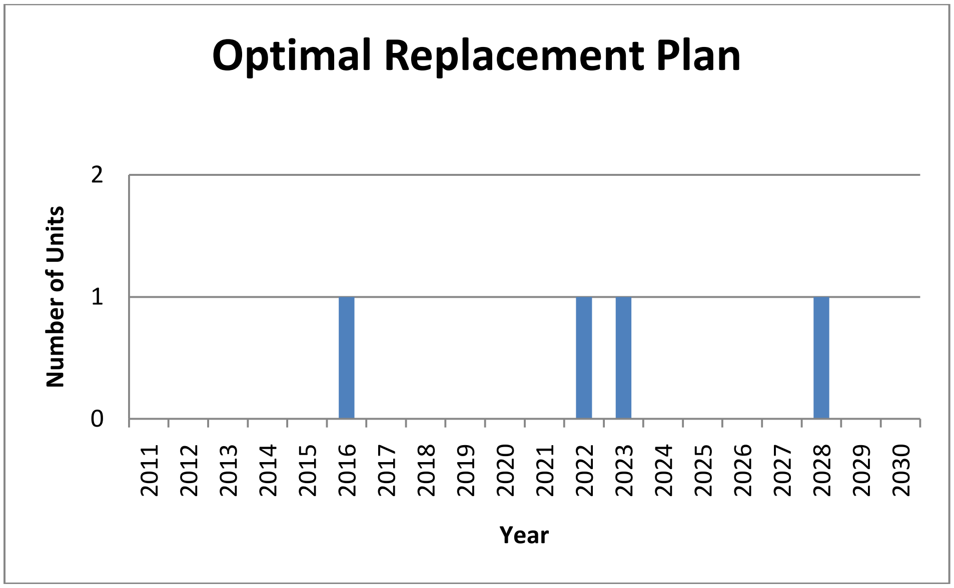

Figure 2-3 Optimal Replacement Plan

2.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing no units in the next 5 years. There are no peaks in replacement years.

Large Pad Transformers are replaced **proactively**. The Levelized replacement plan allows for Transformers that would optimally be replaced in one year to be replaced over a period of time.

Figure 2-4 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time, it is the same as the optimal replacement plan.

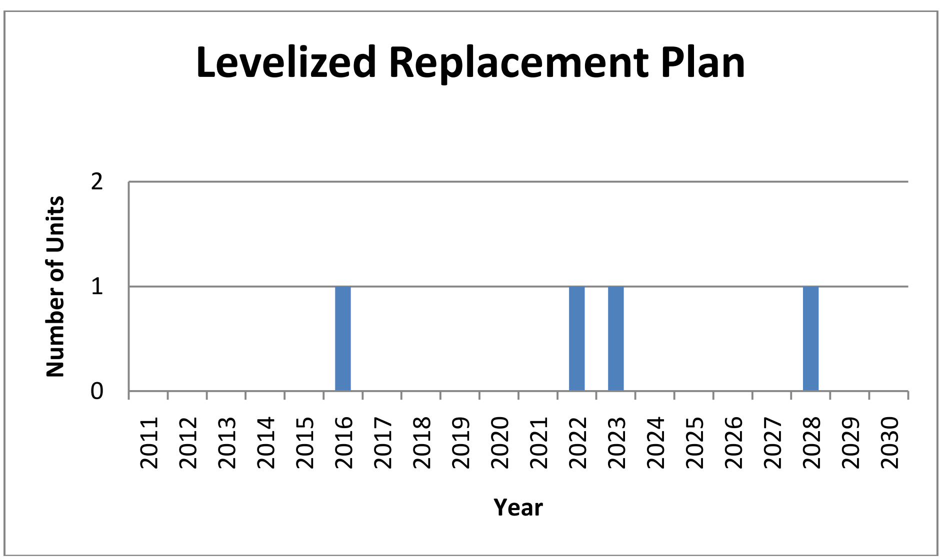

Figure 2-4 Levelized Replacement Plan

2.7 Data Gap Closure

The following table summarizes the data gap for large pad mounted transformers in this project.

Sub-system	Condition	Data Collection Priority
Sealing & connection	Grounding	✯
	IR thermography	✯ ✯ ✯
Service record	Loading	✯ ✯
	Age	✯ ✯

IR thermography is a useful approach in detecting hot spots due to a loose connection or leakage. In this project, it also can address the transformer loading status, when the data on such parameter are unavailable.

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3 Standard Pad-Mounted Transformers

Pad Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. For the purposes of this report, the pad-mounted transformer has been componentized into the transformer itself and the enclosure. Standard Pad Mounted Transformers are smaller than 750 kVA.

3.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

3.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF}_n \times \mathrm{WCPF}_n)}{\sum_{n=1} \beta_n (\mathrm{CPF}_{n.\max} \times \mathrm{WCPF}_n)} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

3.3 Condition and Sub-Condition Parameters

Standard Pad Mounted Transformers that are base type **Collar** are **de-rated** to **30%** of the calculated Health Index Value.

Table 3-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Physical condition	3	4
2	Connection & insulation	5	4
3	Service record	5	4
4	Testing	10	4

Table 3-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Access (ok/not ok)	1	4

Table 3-3 Connection & insulation (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Oil contamination (ok/not ok)	2	4
2	Grounding	1	4
3	Insulator (ok/not ok)	4	4
4	Enclosure	1	4

Table 3-4 Testing (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	IR Scan (Pass/Fail)	1	4
2	Ultra Sound (Pass/Fail)	1	4

3.3.1 *Enclosure*

Table 3-5 Enclosure Rating Score

ENCLOSURE

Condition Rating	CPF	Condition Description
A	4	Good
B	3	Graffiti
C	2	Needs Repainting
D	0	Rusting
E	0	Rusting and Graffiti
F	0	Rusting and Needs Repairs
G	0	Rusting and Needs Repainting

3.3.2 *Grounding*

Table 3-6 Grounding Rating Score

GROUNDING

Condition Rating	CPF	Condition Description
A	4	6
A	4	4
A	4	3
A	4	2
E	0	1
E	0	Other

Table 3-7 Service Record (m=3) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Inspection result	2	4
2	Age	1	4

3.3.3 *Age*

Table 3-8 Age Rating Score

Age		
Condition Rating	**Description**	**CPF**
A	0	4
B	24	3
C	30	2
E	40	0

3.4 Health Index Results

The total population of assets for this category is 2408. The Sample Size or total number of assets within the population that have data other than age is 716.

The Health Indexing Result by Unit and Percentage are presented below for both the population of 716 (age and other data):

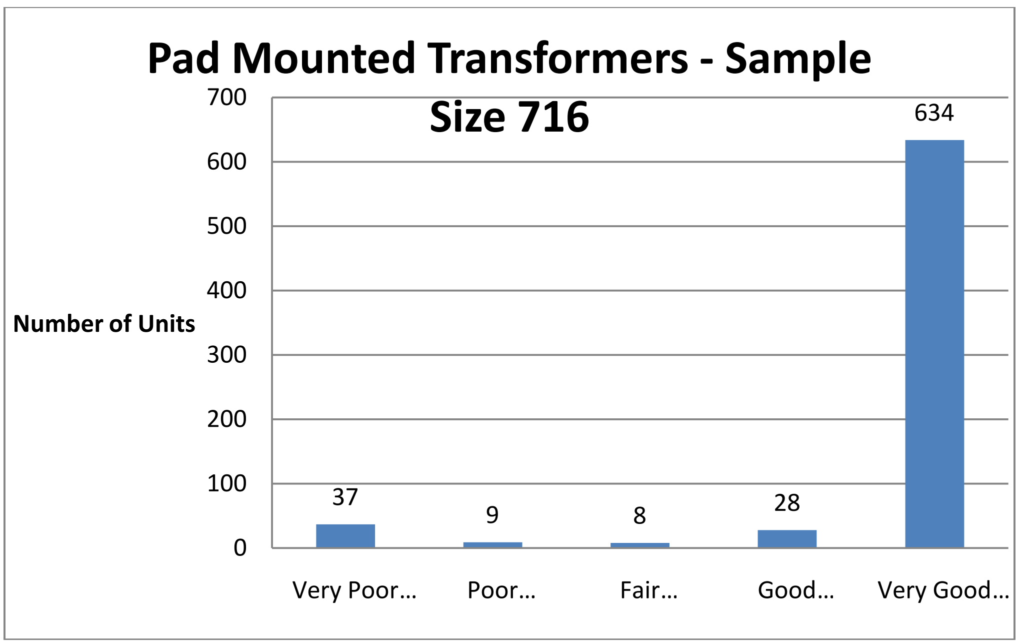

Figure 3-1 Health Index Distribution by Unit

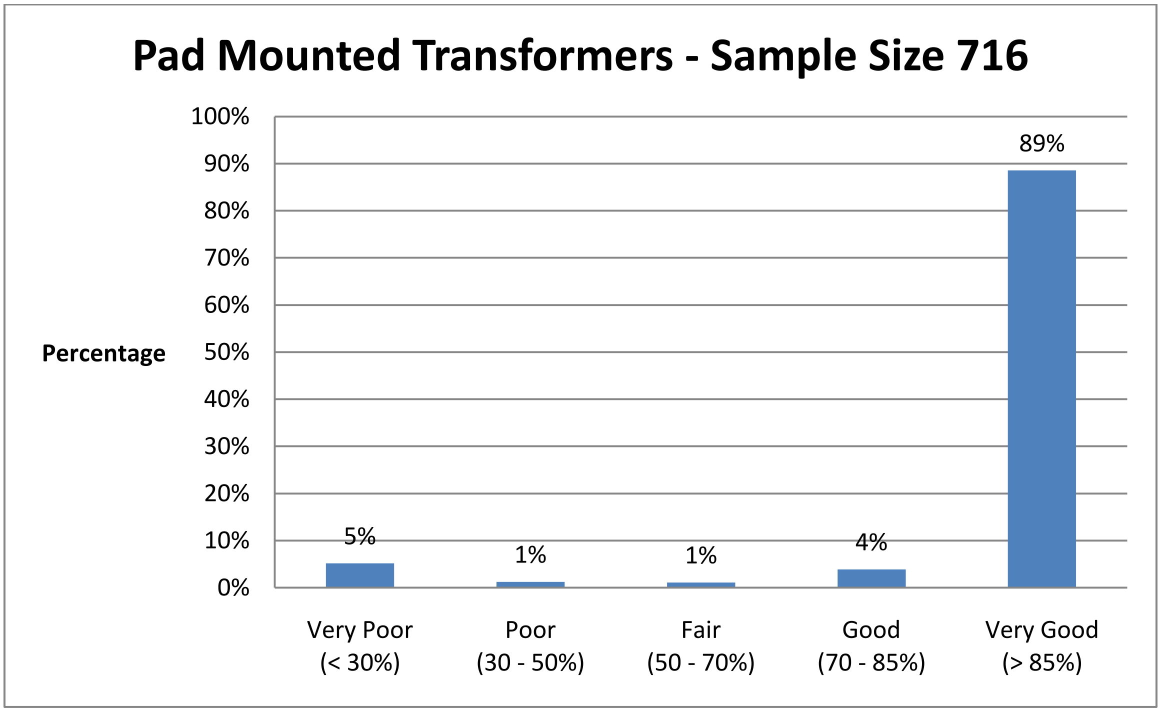

Figure 3-2 Health Index Distribution by Percentage

3.5 Field Inspection Results

Five Standard Pad Mounted Transformers were inspected. The data can be found in Section E FIELD INSPECTION FORMS and the summary is shown in Figure 3-3 below. Most of the units were in good to fair condition. The unit in poor condition was rated this way because of Pad Condition, Main Cabinet Condition and Overall Condition.

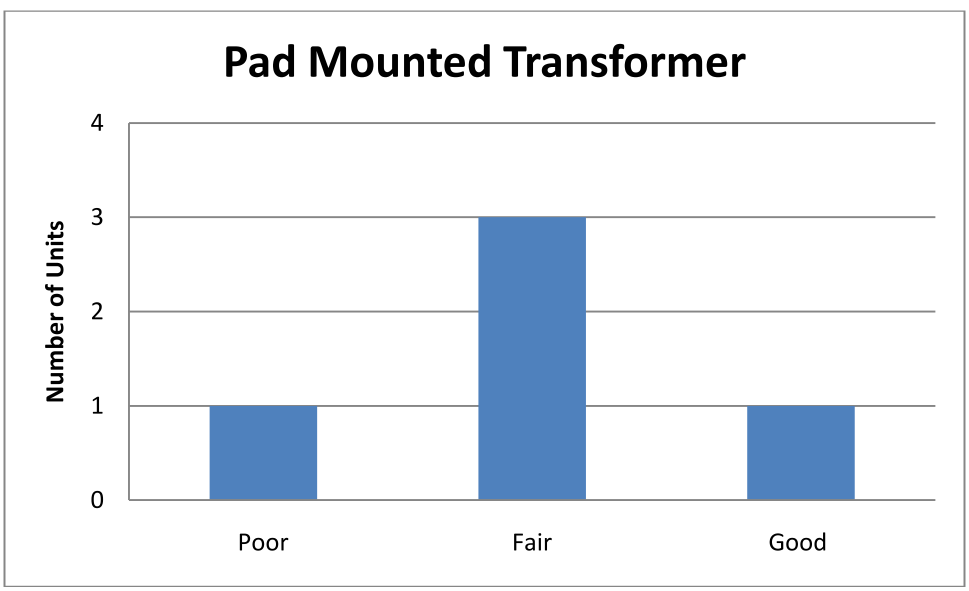

Figure 3-3 Field Inspection Results

The field inspection data indicates a different pattern than the sample case. This may be because only 30% of NPEI's were included in the Health Index sample (716 units) that may not represent NPEI's total population's Health Index.

3.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 25 years the probability of failure is 10% and at age of 45 years the probability of failure is 90%.

3.6.1 *Optimal Replacement Plan*

Figure 3-4 the number of Transformer units that will need to be replaced over the next 20 years. The result was extrapolated from the 28% sample with more than just condition data available to the whole population. Since Health Index distribution based on age alone that was available for the whole population is similar to the sample's Health Index distribution, it appears that the sample was representative of the whole population.

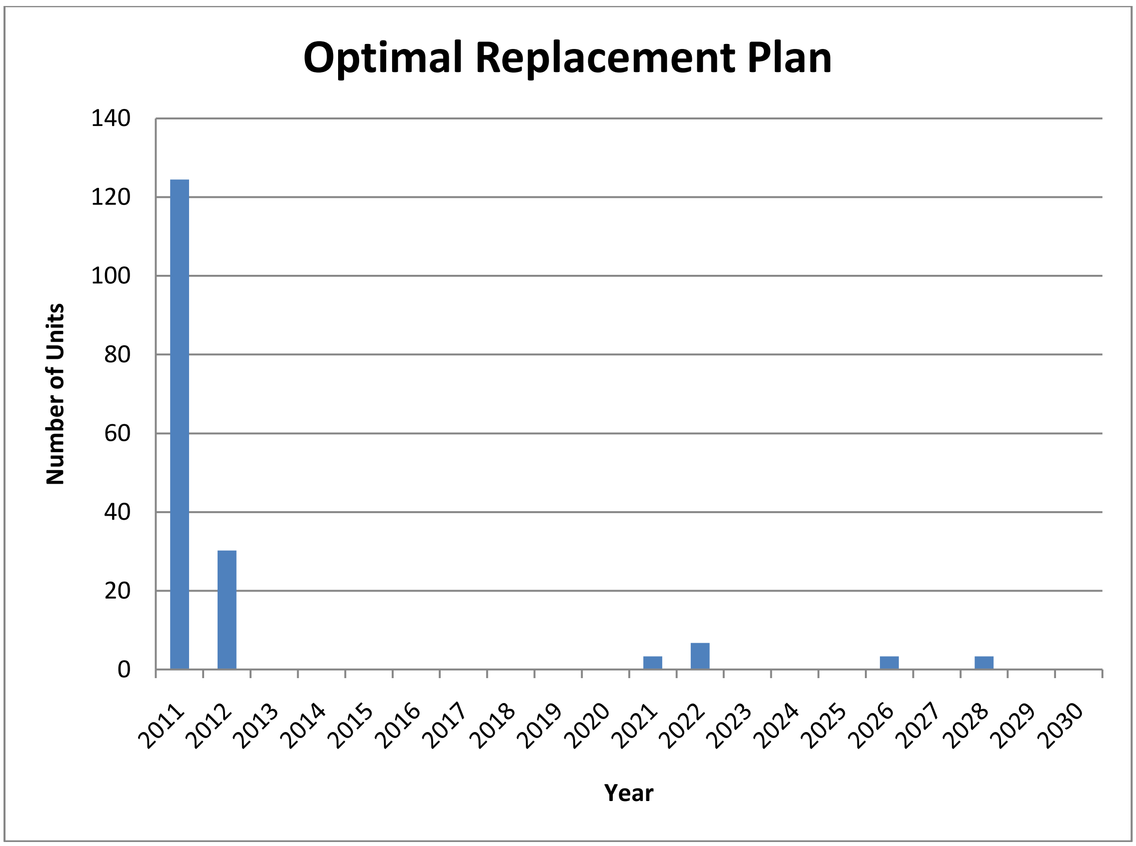

Figure 3-4 Optimal Replacement Plan

3.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 124 units in the next year. While this is optimal based on NPEI's Pad Mounted Transformers HI scores, it may not be ideal financially.

Standard Pad Transformers are typically replaced reactively (end of life.) However NPEI is replacing those transformers with collar type bases **proactively**. The Levelized replacement plan allows for Transformers that would optimally be replaced in one year to be replaced over a period of 5 years.

Figure 3-5 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

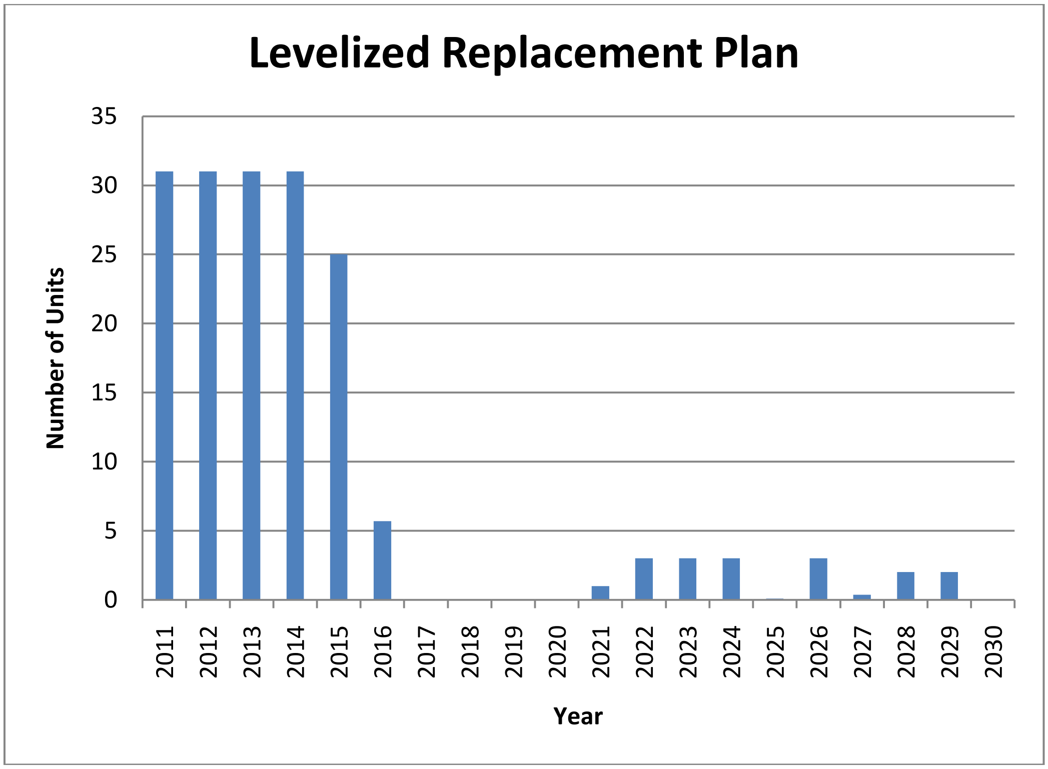

Figure 3-5 Levelized Replacement Plan

3.7 Data Gap Closure

The same information that has been collected for the sample needs to be collected for the remaining population.

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4 Pole-Mounted Transformers

Distribution pole top transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

4.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

4.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF}_n \times \mathrm{WCPF}_n)}{\sum_{n=1} \beta_n (\mathrm{CPF}_{n.\max} \times \mathrm{WCPF}_n)} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

4.3 Condition and Sub-Condition Parameters

Table 4-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Operating Practices	2	4
2	Service record	1	4

Table 4-2 Operating Practices (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Operating Practices	1	4

4.3.1 *Operating Practices*

Table 4-3 Customer Score Rating

CUSTOMERS		
Condition Rating	**Description**	**CPF**
A	0	4
B	10	3
C	20	2
E	40	0

Table 4-4 Service Record (m=2) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Age	1	4

4.3.2 *Age*

Table 4-5 Age Score Rating

Age		
Condition Rating	**Description**	**CPF**
A	0	4
B	24	3
C	30	2
E	40	0

4.4 Health Index Results

The total population of assets for this category is 6835. The Sample Size or total number of assets within the population that have data is 6711.

The year purchased was assumed to the transformers age. The other condition parameter was the number of customers serviced by the transformer.

The Health Indexing Result by Unit and Percentage are presented below:

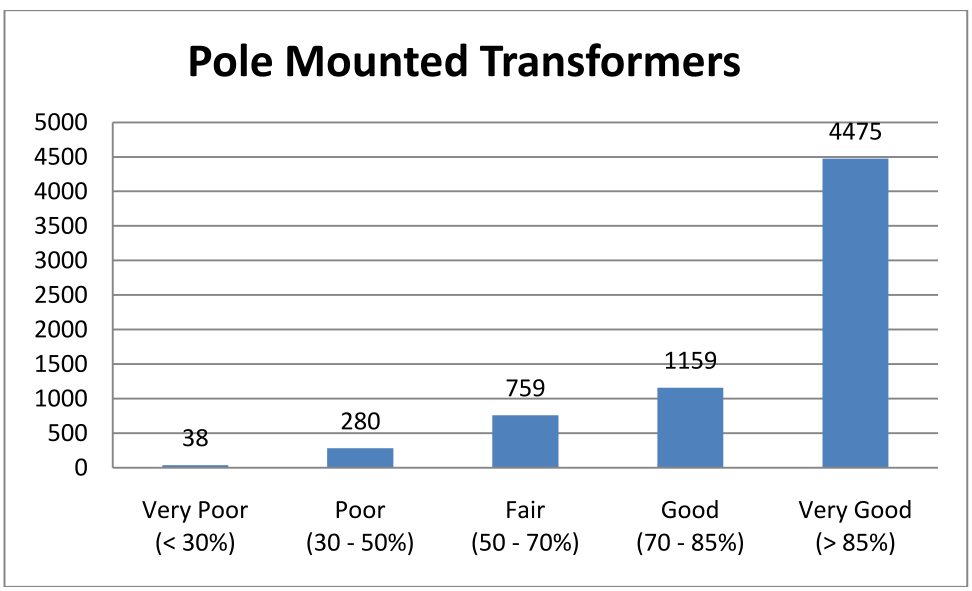

Figure 4-1 Health Index Distribution by Unit

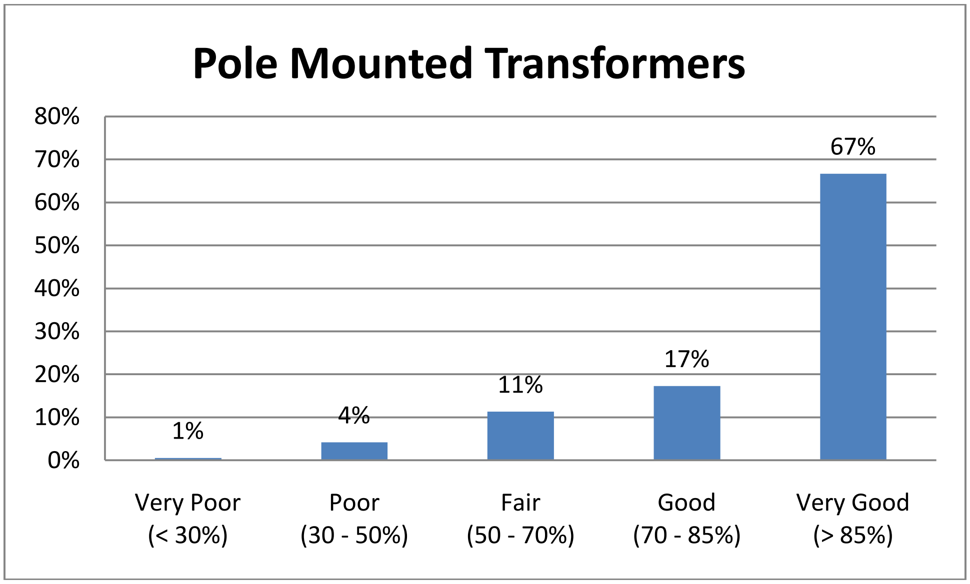

Figure 4-2 Health Index Distribution by Percentage

4.5 Field Inspection Results

Two Pole Mounted Transformers were inspected. The data can be found in Section E FIELD INSPECTION FORMS and are summarized in Figure 4-3 below. The units were in good and fair condition.

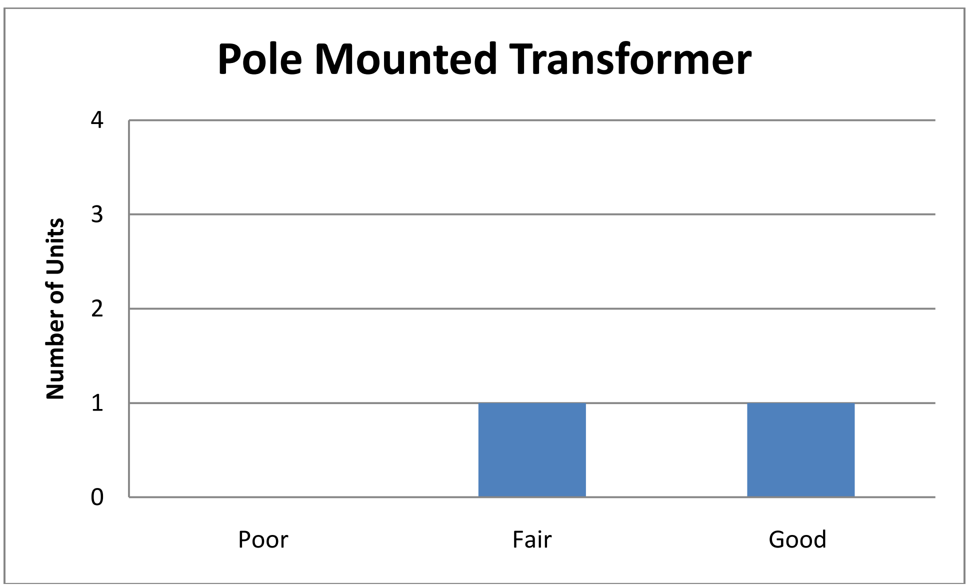

Figure 4-3 Field Inspection Results

4.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%.

4.6.1 *Optimal Replacement Plan*

Figure 4-4 shows the number of Transformer units that will need to be replaced over the next 20 years for the whole population extrapolated from the results for the sample with adequate condition data. Given a significant sample size (98%) there is a high degree of confidence that the recommendations for the sample and the whole population are the same.

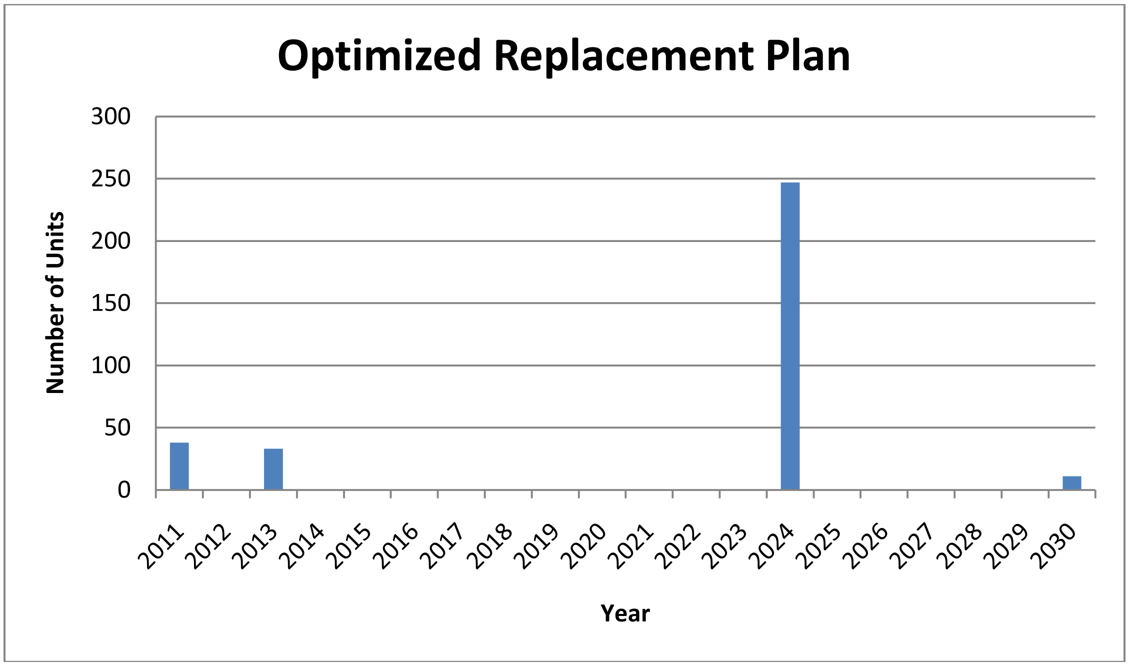

Figure 4-4 Optimal Replacement Plan

4.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 247 units in 2024. While this is optimal based on NPEI's Pole Mounted Transformers HI scores, it may not be ideal financially.

Pole Mounted Transformers are typically replaced **reactively** (end of life.) Since the HI scores indicate the majority of failures happening over the next 25 years, NPEI can take a Levelized approach by replacing assets before they are estimated to fail. The Levelized replacement plan allows for Transformers that would optimally be replaced in 2024 year to be replaced over a period of 5 years (2020-2024).

Figure 4-5 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

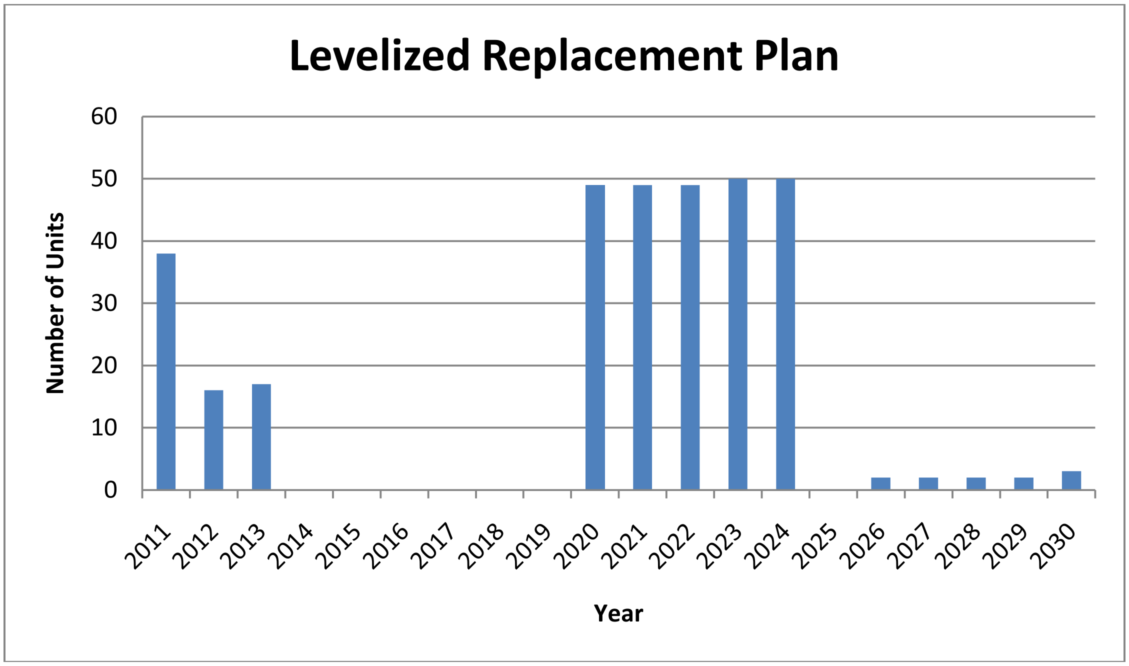

Figure 4-5 Levelized Replacement Plan

4.7 Data Gap Closure

The following table summarizes the data gap for pole mounted transformers in this project.

Sub-system	Condition Parameter	Data Collection Priority
Physical condition	Corrosion	☆ ☆
Connection & insulation	Oil leak	☆ ☆
Service record	Loading	☆ ☆ ☆

As a pole mounted transformer is a run-to-failure asset, its service record has much impact on its life cycle. While corrosion and oil leak provide visual inspection on the external signs of degradation, its loading history can be used to estimate its actual aging process.

5 Poles

The asset referred to in this category is the fully dressed pole ranging in size from 30 to 75 feet. This includes the pole, cross arm, bracket, insulator, and anchor & guys. The most important component with respect to useful life is the pole itself.

5.1 Degradation Mechanism

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on the electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests, such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers that record and analyze the vibration caused by a hammer blow to identify patterns that indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonic, X-rays, electrical resistance measurement have also been widely used.

There are many factors considered by utilities when establishing condition of wood poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The life expectancy of wood poles ranges from 40 to 80 years, with 60 years being the mean. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for a significant number of customers.

5.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DF$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF_n} \times \mathrm{WCPF_n})}{\sum_{n=1} \beta_n (\mathrm{CPF_{n.max}} \times \mathrm{WCPF_n})} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter
DF --- De-rating Factor

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

5.3 Condition and Sub-Condition Parameters

Those Poles that are **Red Cedar Butt Treated** have been **de-rated** to 80% of their calculated Health Index Value.

Table 5-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Pole physical	3	4
2	Pole accessories	1	4
3	Overall	4	4

Table 5-2 Pole Physical (m=2) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	$CPF_{n.max}$
1	Animal Damage	2	4
2	Lean	1	4
3	Rot / Soft	2	4
4	Crack	2	4
5	Hole / Void	2	4
6	Hollow	2	4
7	Chunk	2	4
8	Damp / Wet	2	4
9	Bend / Hit / Damage	2	4
10	Poor Top	2	4

Table 5-3 Pole Accessory (m=3) Weights and Maximum CPF

N	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
2	Guy Wire	OK = 4; All others = 0	3	4
3	Defective Ground	OK=4; Exposed/connection issue/rod above grade= 2; Damaged = 0	2	4
4	Crossarm	OK=4; Crooked/Loose = 2; Damaged = 0	1	4
5	Riser (Cable Guard)	OK=4; Exposed/Loose = 2; Damaged = 0	1	4

Table 5-4 Overall (m=4) Weights and Maximum CPF

N	Sub-condition parameter	$WCPF_n$	$CPF_{n.max}$
1	Overall	3	4
3	Age	2	4

5.3.1 *Age*

Table 5-5 Pole Age

Condition Rating	CPF	Condition Description
A	4	0
B	3	10
C	2	25
D	1	40
E	0	>50

5.4 Health Index Results

The total population of assets for this category is 22,247. The Sample Size or total number of assets within the population that have data is 5985. However those pole recently inspected were of newer vintage. Age was provided for 13,135 units (encompassing the 4943 units of the 5985 sample) so a comparison of the age range of the sample, as compared to the 13,135 population was done.

The Health Indexing Result by Unit and Percentage and the age range comparison of the sample to a broader sample of the pole population are presented below:

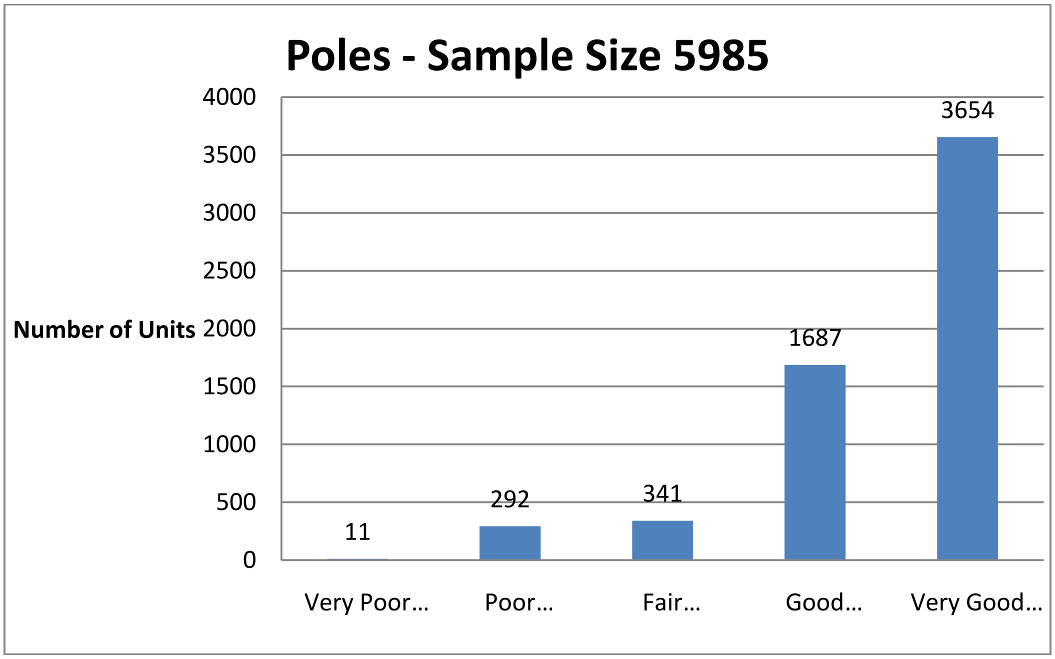

Figure 5-1 Health Index Distribution by Unit

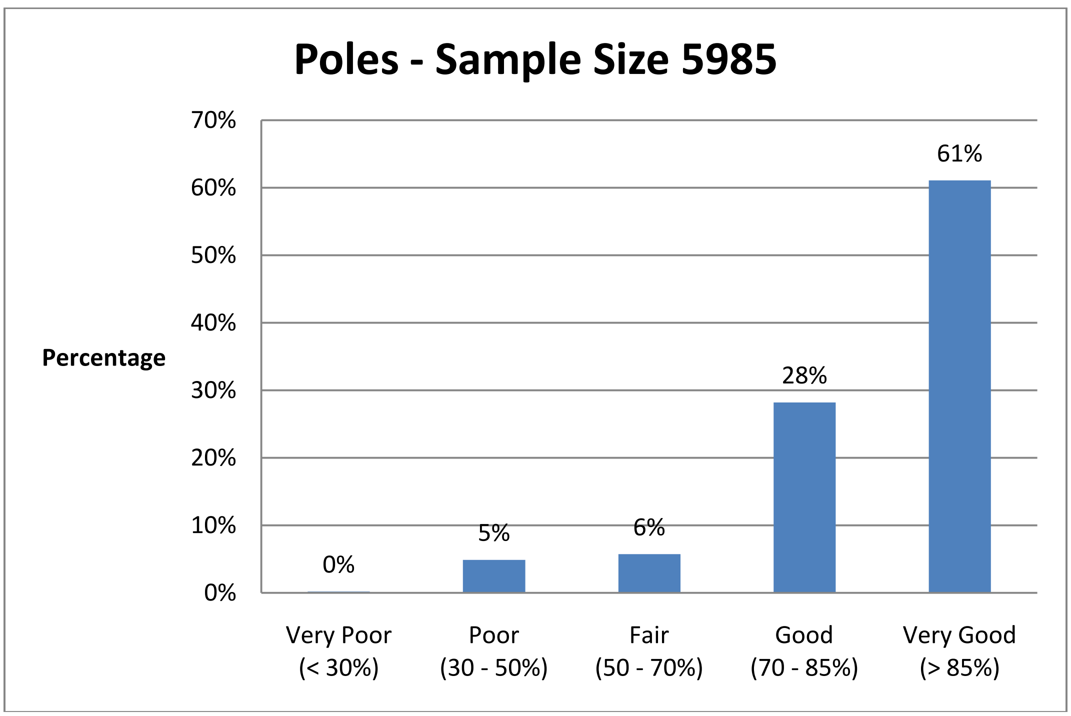

Figure 5-2 Health Index Distribution by Percentage

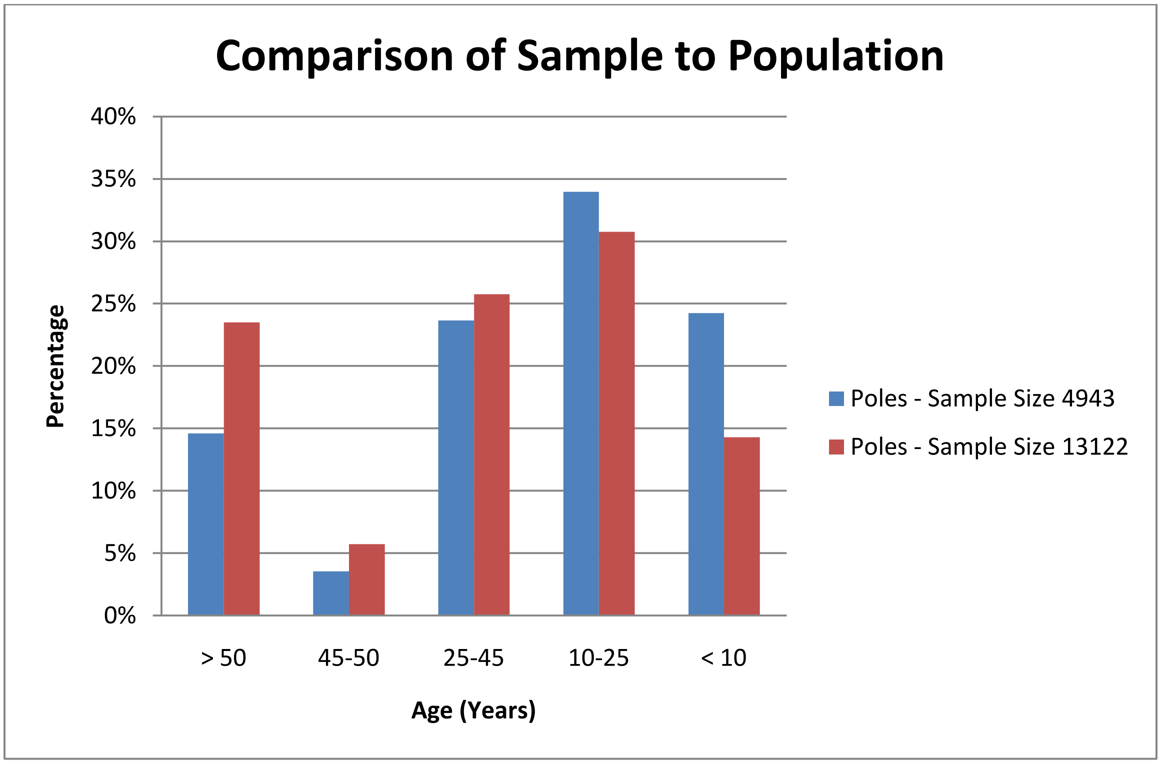

Figure 5-3 Comparison of Sample Age Data to a Larger Sample of the Population Age Data

5.5 Field Inspection Results

Four Poles were inspected. The data can be found in Section E FIELD INSPECTION FORMS and are summarized in Figure 5-4 below. The units were in good and fair condition.

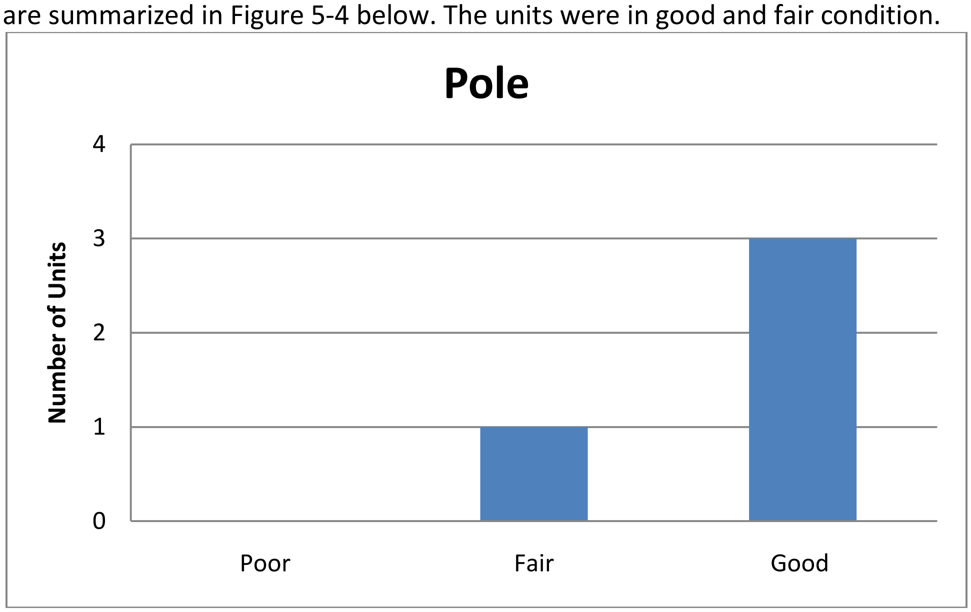

Figure 5-4 Field Inspection Results

5.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 40 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%.

5.6.1 *Optimal Capital Replacement Plan*

Figure 5-5 shows the number of Poles that will need to be replaced over the next 20 years extrapolated for the whole population from the sample (27% of the population) with adequate condition data. However, it could be seen from Figure 5-3 that the overall condition of the poles in the sample is better than that for the population with only age available due to the investments made in testing and replacing poles found to be in poor condition. Therefore, to achieve similar Health Index distribution for the whole population more capital expenditures than what is shown would be required.

A separate analysis which is beyond the scope of this project would be required to estimate the incremental capital amount needed to improve overall condition of the whole pole population to the level of the poles in the sample with adequate condition data.

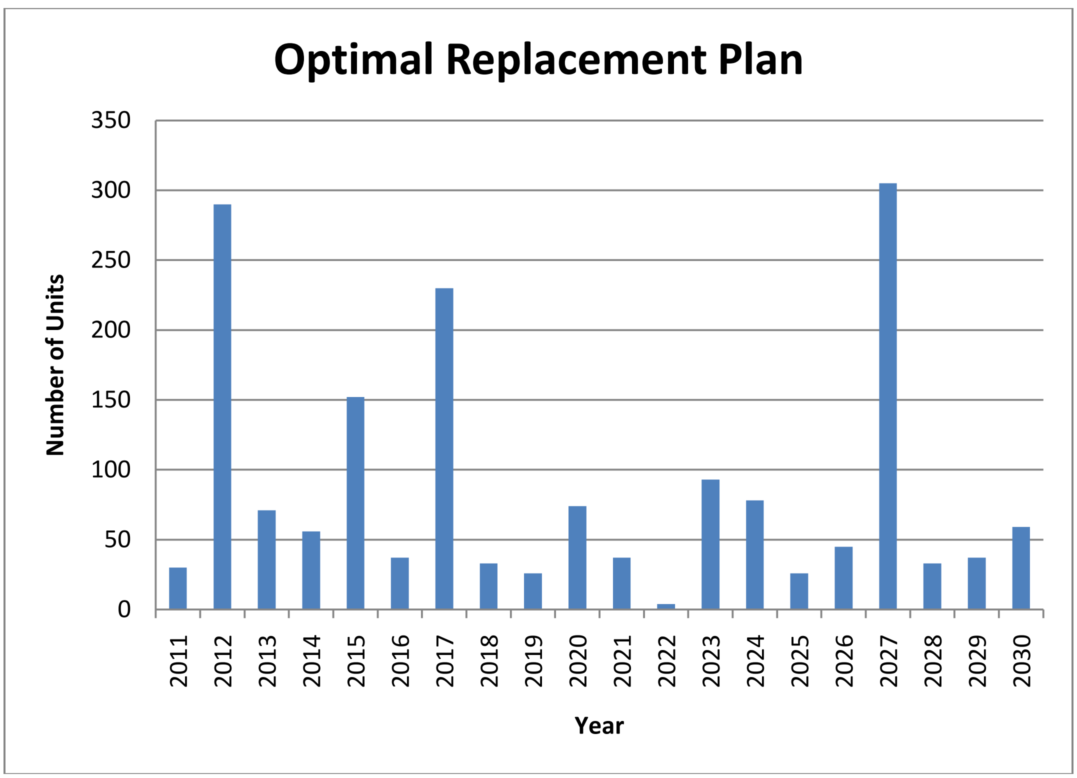

Figure 5-5 Optimal Replacement Plan

5.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 30 units next year. While this is optimal based on NPEI's Pole HI scores, it may not be ideal financially.

Poles are typically replaced **reactively** (end of life.) Since the HI scores indicate the majority of failures happening in spikes over the next 30 years, NPEI can take a Levelized approach by replacing assets before they are estimated to fail.

Figure 5-6 shows a Levelized capital replacement plan, where replacements pole can occur over a longer period of time.

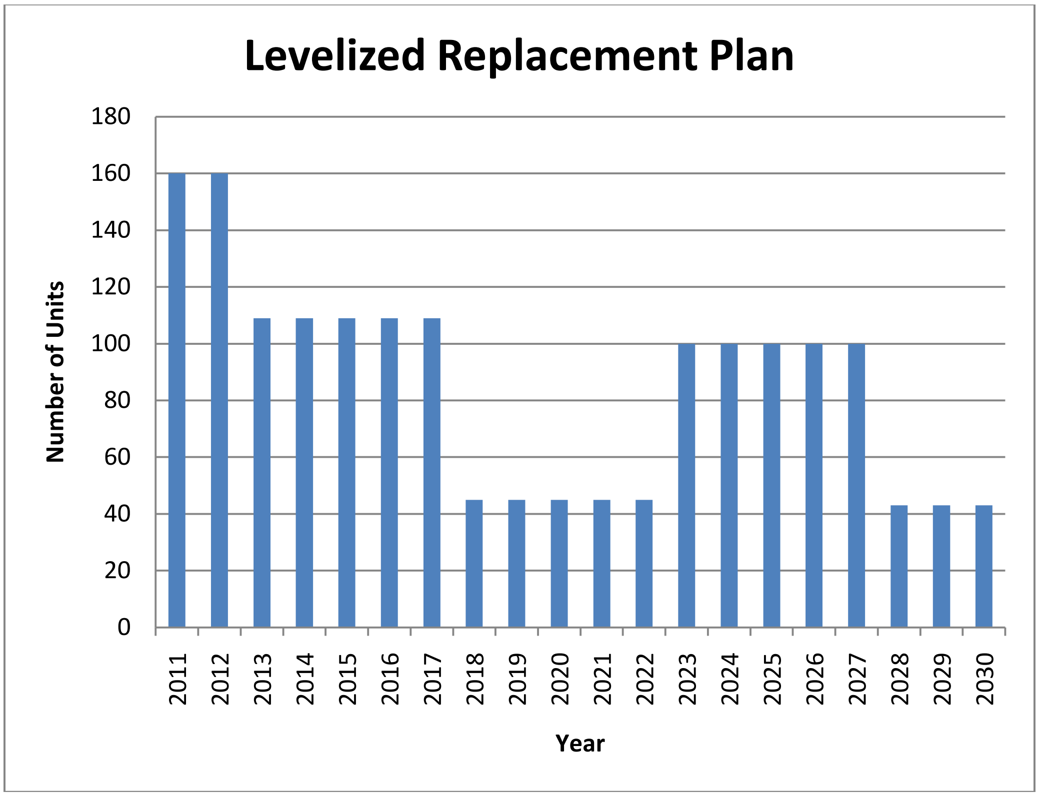

Figure 5-6 Levelized Replacement Plan

5.7 Data Gap Closure

The only data gap for poles in this project is the measured pole strength. It represents the actual physical size changes due to pole degradation. It is useful in scheduling reinforcement or replacement.

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6 Pad Mounted Switchgear

This asset class consists of pad mounted switchgear. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements.

6.1 Degradation Mechanism

The main degradation processes associated with line switches include:

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

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

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

6.2 Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF}_n \times \mathrm{WCPF}_n)}{\sum_{n=1} \beta_n (\mathrm{CPF}_{n.\max} \times \mathrm{WCPF}_n)} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter

CPF --- Sub-Condition Parameter Factor

WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

6.3 Condition and Sub-Condition Parameters

Switchgear that is **Air Insulated** and near a **major roadway** is **de-rated** to **30%** of the calculated Health Index Value.

Table 6-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Physical Condition	3	4
2	Switch Condition	5	4
3	Insulation	7	4
4	Service record	5	4
5	Testing	10	4

Table 6-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Enclosure	3	4
2	Access (ok/not ok)	1	4
3	Base (ok/not ok)	2	4

Table 6-3 Switch/Fuse Condition (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Grounding	1	4

Table 6-4 Insulation (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Insulator (ok/not ok)	1	4

Table 6-5 Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Inspection result (Pass/Fail)	1	4

Table 6-6 Tests (m=5) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	IR Scan (Pass/Fail)	1	4
2	Ultrasonic (Pass/Fail)	1	4

6.4 Health Index Results

The total population of assets for this category is 89. The Sample Size or total number of assets within the population that have data is 38.

The Health Indexing Result by Unit and Percentage are presented below:

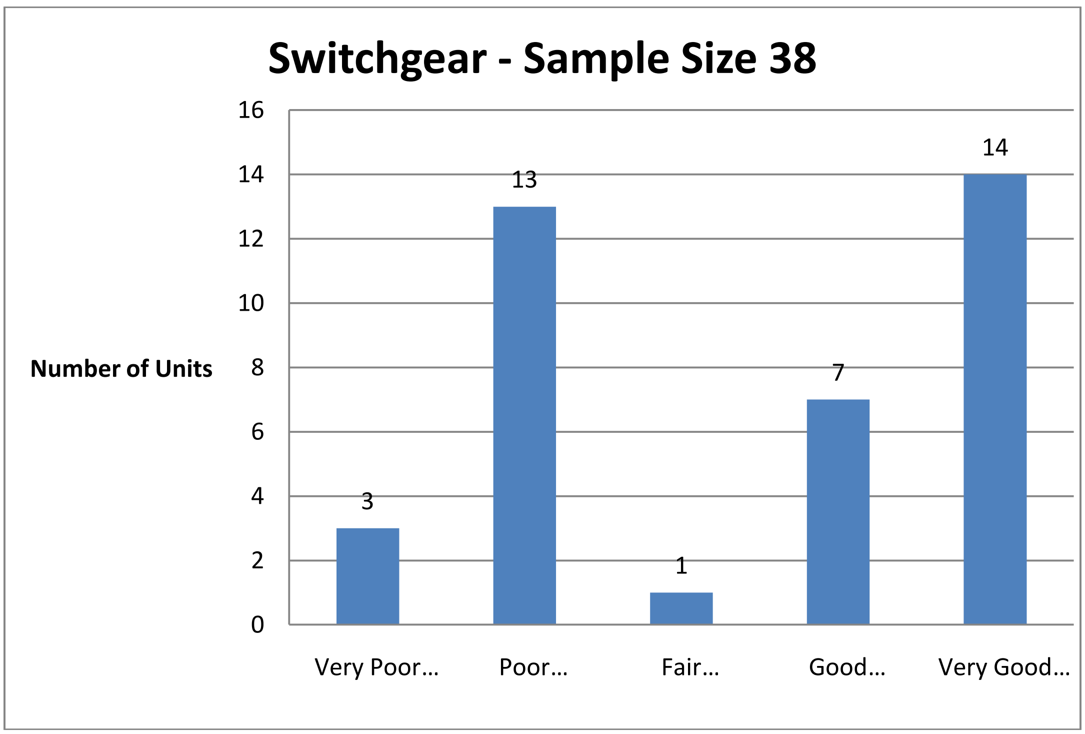

Figure 6-1 Health Index Distribution by Unit

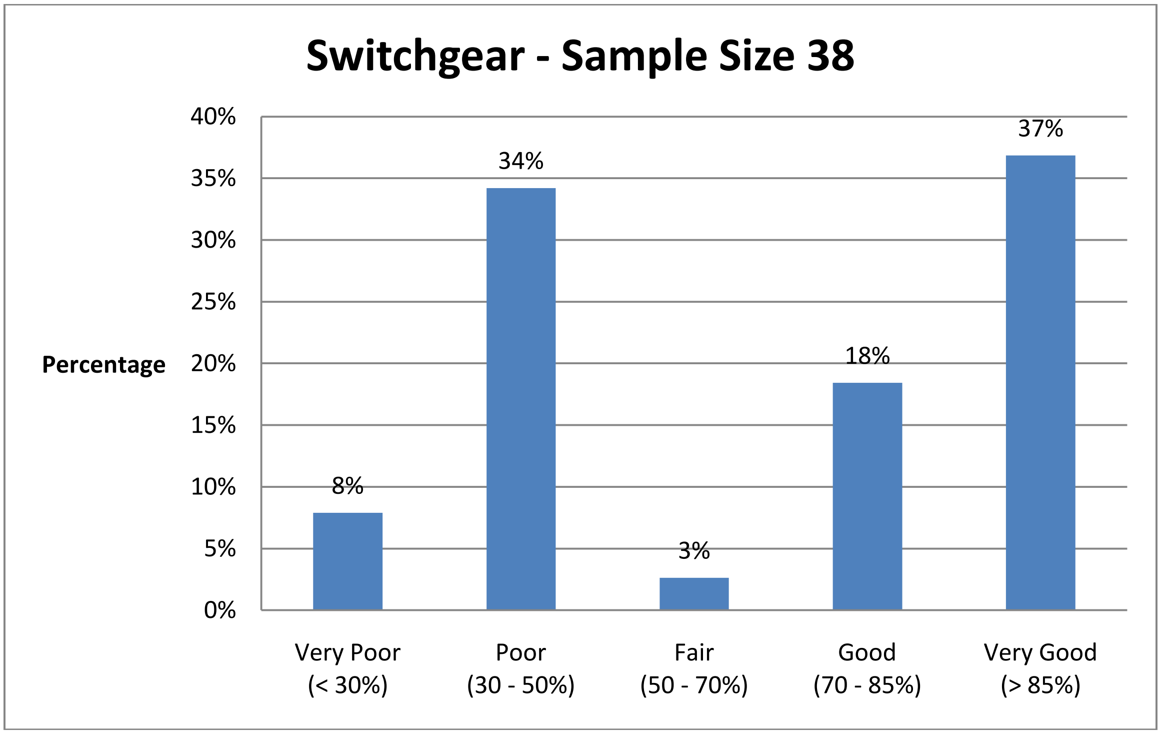

Figure 6-2 Health Index Distribution by Percentage

6.5 Field Inspection Results

On Pad Mounted Switchgear was inspected. The data can be found in Section E FIELD INSPECTION FORMS and are summarized in Figure 6-3 below.

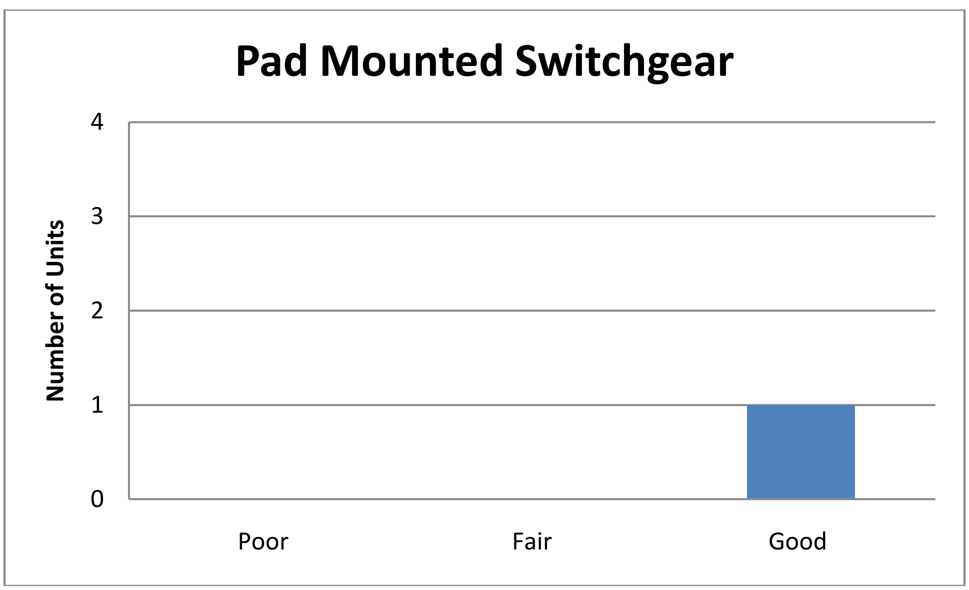

Figure 6-3 Field Inspection Results

6.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 20 years the probability of failure is 10% and at age of 45 years the probability of failure is 90%.

6.6.1 *Optimal Capital Replacement Plan*

Figure 6-4 shows the number of Pad Mounted Switchgear units that will need to be replaced over the next 20 years extrapolated from the sample with adequate condition data (43%). There is no basis to confirm or deny whether this assumption is reasonable, so it is recommended to accelerate a process of collecting condition data for the reminder of the population.

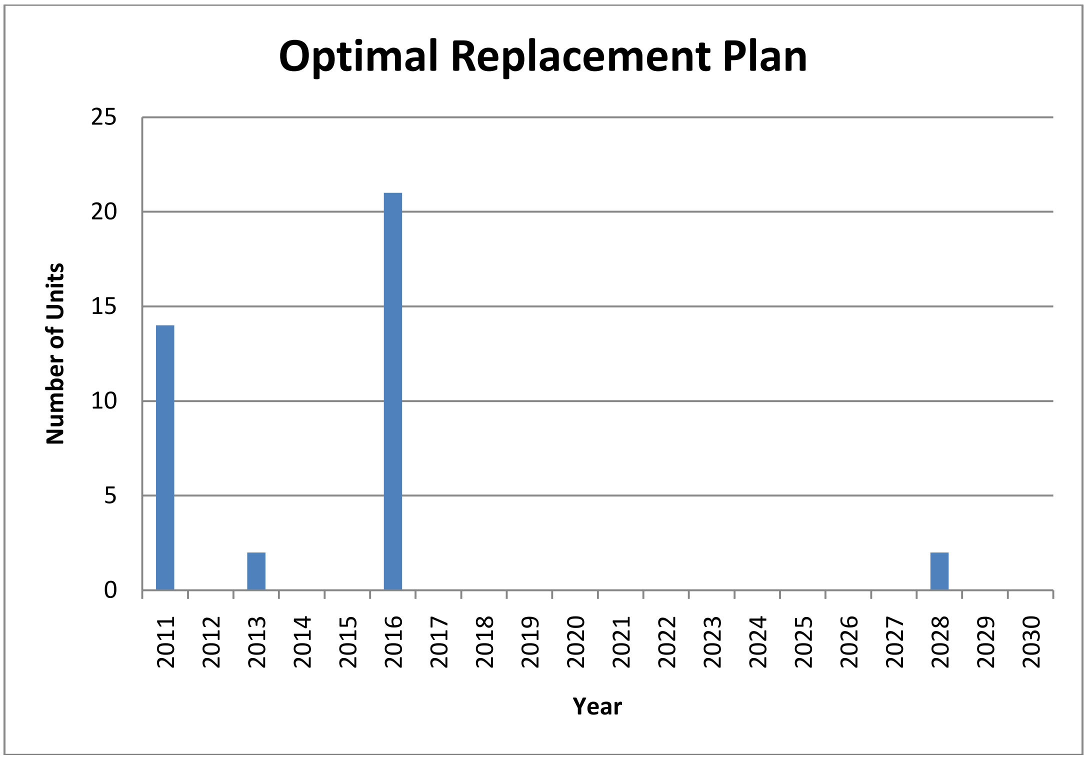

Figure 6-4 Optimal Replacement Plan

6.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 14 units next year. While this is optimal based on NPEI's Pad Mounted Switchgear HI scores, it may not be ideal financially.

Standard Pad Transformers are typically replaced reactively (end of life.) However NPEI is replacing those transformers that are air insulated and near a major roadway **proactively**. The Levelized replacement plan allows for Switchgear that would optimally be replaced in one year to be replaced over a period of 5 years.

Figure 6-5 shows a Levelized capital replacement plan, where switchgear replacements can occur over a longer period of time.

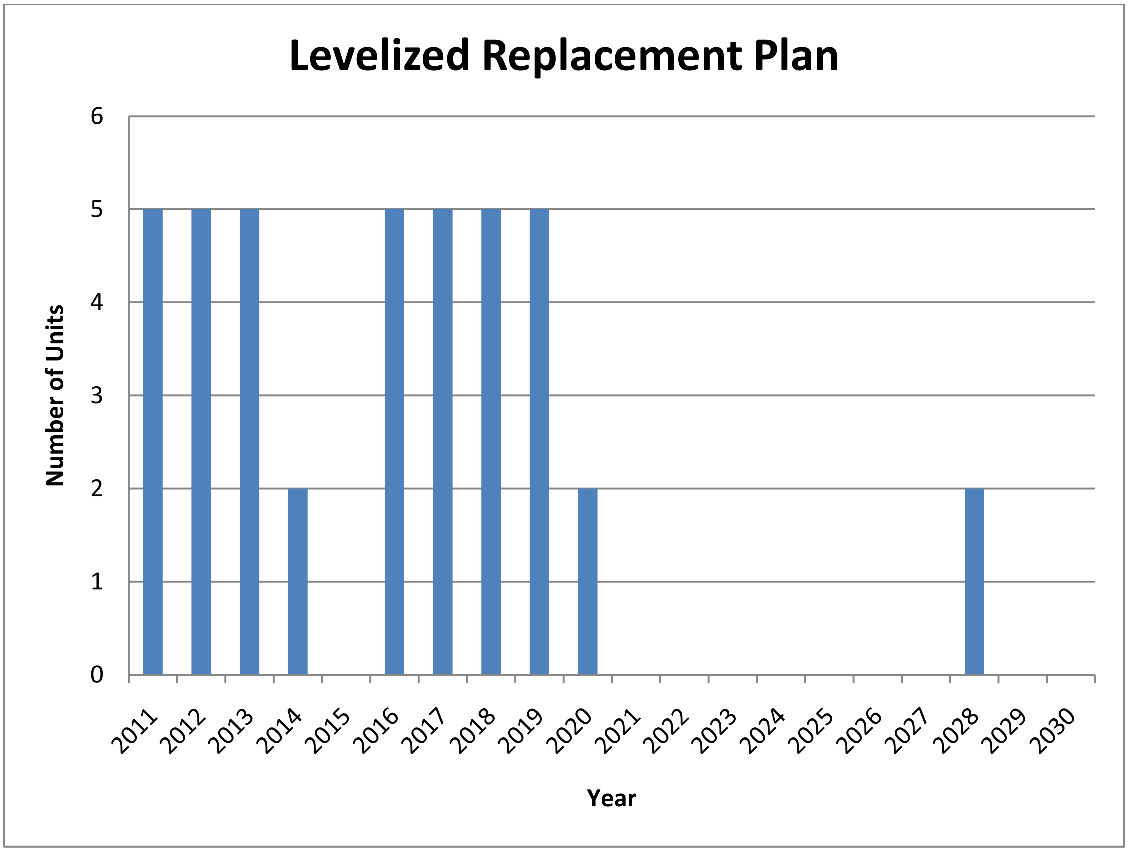

Figure 6-5 Levelized Replacement Plan

6.7 Data Gap Closure

The following table summarizes the data gap for pad mounted switchgear in this project.

Sub-system	Condition Parameter	Data Collection Priority
Physical condition	Debris/dirty	☆
Switch/fuse condition	Switch condition	☆ ☆ ☆
	Arc chute	☆ ☆
Insulation	Barriers	☆ ☆
Service record	Age	☆

Switch main contact and its arc suppression parts are the main device inside pad mounted switchgear.

D CONCLUSIONS AND RECOMMENDATIONS

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Conclusions and Recommendations

1. There was generally sufficient condition data available for Power Transformers, Large Pad-mounted Transformers, Poles (inspected after 2008) and Switchgear.

2. For Pole-mounted transformers, only age is available and operating practices (i.e., customers). Gathering and recording detailed inspection data should be considered.

3. For Standard Pad Mounted transformers, age was provided for 87% of the population however sufficient data was provided for only 28% of the population. It is recommended that NPEI collect data for a greater population of Pad Mounted Transformers.

4. For Poles that have not been inspected, age is only available for half of the population. Sufficient age and inspection data should be collected for the rest of the population.

5. Sufficient data was not available for Underground Cables. It is recommended that inspection and maintenance information be collected for these assets to enable future asset condition assessment.

6. A separate study is required to determine appropriate increase in the pole replacement program over the levels extrapolated from the sample with adequate condition data to achieve the desired overall Health Index distribution (similar to that of the sample).

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E FIELD INSPECTION FORMS

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Asset Condition Survey
Transformer Stations

Substation	Kalar TS
Op Desn	73 MVA
Age	Built 2004
HV / LV	115kV / 13.8kV
Location	Kalar Rd

1.0 Power Transformer — Age

1.1 Inspections — Circle ONLY one

1.1 Bushing Condition	A B C D N U
1.2 Oil Leaks	A B C D N U
1.3 Main Tank/Cabinets Condition	A B C D N U
1.4 Radiators and Conservator Condition	A B C D N U
1.5 Gaskets and Seals Condition	A B C D N U
1.6 Pumps and Fans Condition	A B C D N U
1.7 Primary Connectors/Conductors Condition	A B C D N U
1.8 Secondary Connections/Control Condition	A B C D N U
1.9 Foundation/Support Steel/Grounding Condition	A B C D N U
1.10 Fire Protection/Spill Containment	A B C D N U
1.12 Overall Power Transformer Condition	A B C D N U

Tapchangers (if applicable) (On-Load Tap Changers)

1.13 Tank Condition	A B C D N U
1.14 Tank Leaks	A B C D N U
1.15 Gaskets/Seals/Pressure Relief Condition	A B C D N U
1.16 LTC Control and Mechanism Cabinet Condition	A B C D N U
1.17 Control and Mechanism Cabinet Components	A B C D N U
1.18 Overall Tap Changer Condition	A B C D N U

2 Breakers — Voltage, Age

2.1 Bushing Condition	A B C D N U
2.2 Tank Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Controls and Mechanism	A B C D N U
2.5 Overall Breaker Condition	A B C D N U

3 Metal Clad Switch Gear Assemblies — Voltage, Age

3.1 Structure Integrity (paint, corrosion, water leaks)	A B C D N U
3.2 General Condition (evidence of maintenance)	A B C D N U
3.3 Overall Switchgear Assembly Condition	A B C D N U

4 Buildings — Age

4.1 Condition of structure (roof, walls)	A B C D N U
4.2 Condition of doors and locks	A B C D N U
4.3 Condition of Lightning	A B C D N U
4.4 Overall Building Condition	A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.)

Inspector Name and Date — Name: G. Ebersberger — Date: Nov 18, 2010

(write any comments or concerns on the back of this form)

6/8/2006 Survey Form-1/1 Transformer Stations VI Form.xls

Asset Condition Survey
Transformer Stations

Substation	Station 17	100
Op Desn	5000 kVA	102
Age	1974 (1999 Tx)	103
HV / LV	13.8KV	104
Virginia Rd Location	Station 17	105

1.0 Power Transformer	Age		107
1.1 Inspections		Circle ONLY one	
1.1 Bushing Condition		A B C D N U	109
1.2 Oil Leaks		A B C D N U	110
1.3 Main Tank/Cabinets Condition		A B C D N U	111
1.4 Radiators and Conservator Condition		A B C D N U	112
1.5 Gaskets and Seals Condition		A B C D N U	113
1.6 Pumps and Fans Condition		A B C D N U	114
1.7 Primary Connectors/Conductors Condition		A B C D N U	115
1.8 Secondary Connections/Control Condition		A B C D N U	116
1.9 Foundation/Support Steel/Grounding Condition		A B C D N U	117
1.10 Fire Protection/Spill Containment		A B C D N U	118
1.12 Overall Power Transformer Condition		A B C D N U	119
Tapchangers (if applicable)			
1.13 Tank Condition		A B C D N U	122
1.14 Tank Leaks		A B C D N U	123
1.15 Gaskets/Seals/Pressure Relief Condition		A B C D N U	124
1.16 LTC Control and Mechanism Cabinet Condition		A B C D N U	125
1.17 Control and Mechanism Cabinet Components		A B C D N U	126
1.18 Overall Tap Changer Condition		A B C D N U	127
2 Breakers	Voltage		129
	Age		130
2.1 Bushing Condition		A B C D N U	131
2.2 Tank Condition		A B C D N U	132
2.3 Oil Leaks		A B C D N U	133
2.4 Controls and Mechanism		A B C D N U	134
2.5 Overall Breaker Condition		A B C D N U	135
3 Metal Clad Switch Gear Assemblies	Voltage		137
	Age		138
3.1 Structure Integrity (paint, corrosion, water leaks)		A B C D N U	139
3.2 General Condition (evidence of maintenance)		A B C D N U	140
3.3 Overall Switchgear Assembly Condition		A B C D N U	141
4 Buildings (Newer)	Age		143
4.1 Condition of structure (roof, walls)		A B C D N U	144
4.2 Condition of doors and locks		A B C D N U	145
4.3 Condition of Lightning		A B C D N U	146
4.4 Overall Building Condition		A B C D N U	147

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 150

Inspector Name and Date — Name: [illegible] — Date: Nov 18, 2010 — 152

(write any comments or concerns on the back of this form)

Asset Condition Survey
Transformer Stations

Substation	Pelham Station
Op Desn	
Age	6mos Refurbish
HV / LV	27.6KV 14.160KV
Location	Fonthill

1.0 Power Transformer — Age

1.1 Inspections — Circle ONLY one

1.1 Bushing Condition	A B C D N U
1.2 Oil Leaks	A B C D N U
1.3 Main Tank/Cabinets Condition	A B C D N U
1.4 Radiators and Conservator Condition	A B C D N U
1.5 Gaskets and Seals Condition	A B C D N U
1.6 Pumps and Fans Condition	A B C D N U
1.7 Primary Connectors/Conductors Condition	A B C D N U
1:8 Secondary Connections/Control Condition	A B C D N U
1.9 Foundation/Support Steel/Grounding Condition	A B C D N U
1.10 Fire Protection/Spill Containment	A B C D N U
1.12 Overall Power Transformer Condition	A B C D N U

Tapchangers (If applicable)

1.13 Tank Condition	A B C D N U
1.14 Tank Leaks	A B C D N U
1.15 Gaskets/Seals/Pressure Relief Condition	A B C D N U
1.16 LTC Control and Mechanism Cabinet Condition	A B C D N U
1.17 Control and Mechanism Cabinet Components	A B C D N U
1.18 Overall Tap Changer Condition	A B C D N U

2 Breakers — Voltage / Age

2.1 Bushing Condition	A B C D N U
2.2 Tank Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Controls and Mechanism	A B C D N U
2.5 Overall Breaker Condition	A B C D N U

3 Metal Clad Switch Gear Assemblies — Voltage / Age

3.1 Structure Integrity (paint, corrosion, water leaks)	A B C D N U
3.2 General Condition (evidence of maintenance)	A B C D N U
3.3 Overall Switchgear Assembly Condition	A B C D N U

4 Buildings — Age

4.1 Condition of structure (roof, walls)	A B C D N U
4.2 Condition of doors and locks	A B C D N U
4.3 Condition of Lightning	A B C D N U
4.4 Overall Building Condition	A B C D N U

Data sources used

Misc inspection record ☐ Interviews ☐ Photos taken (no.)

Inspector Name and Date — Name: G. [illegible] — Date: Nov. 18, 2010

(write any comments or concerns on the back of this form)

Asset Condition Survey
Transformer Stations

Substation	Station 10	101
Op Desc	5 MVA	102
Age	April 1996	103
HV / LV	13.8 KV / 416/240	104
Location		105

1.0 Power Transformer

Age		107

1.1 Inspections — Circle ONLY one

1.1 Bushing Condition	**A** B C D N U	109
1.2 Oil Leaks	A B C D **N** U	110
1.3 Main Tank/Cabinets Condition	**A** B C D N U	111
1.4 Radiators and Conservator Condition	**A** B C D N U	112
1.5 Gaskets and Seals Condition	**A** B C D N U	113
1.6 Pumps and Fans Condition	**A** B C D N U	114
1.7 Primary Connectors/Conductors Condition	**A** B C D N U	115
1.8 Secondary Connections/Control Condition	**A** B C D N U	116
1.9 Foundation/Support Steel/Grounding Condition	**A** B C D N U	117
1.10 Fire Protection/Spill Containment	A B C D N U	118
1.12 Overall Power Transformer Condition	**A** B C D N U	119

Tapchangers (if applicable) Off-Load.

1.13 Tank Condition	**A** B C D N U	122
1.14 Tank Leaks	A B C D **N** U	123
1.15 Gaskets/Seals/Pressure Relief Condition	A **B** C D N U	124
1.16 LTC Control and Mechanism Cabinet Condition	A **B** C D N U	125
1.17 Control and Mechanism Cabinet Components	**A** B C D N U	126
1.18 Overall Tap Changer Condition	A **B** C D N U	127

2 Breakers

Hydate SF6 Outside

Voltage		129
Age		130
2.1 Bushing Condition	A **B** C D N U	131
2.2 Tank Condition	A **B** C D N U	132
2.3 Oil Leaks	A **B** C D N U	133
2.4 Controls and Mechanism	A **B** C D N U	134
2.5 Overall Breaker Condition	A **B** C D N U	135

3 Metal Clad Switch Gear Assemblies

Voltage	1960's	137
Age		138
3.1 Structure Integrity (paint, corrosion, water leaks)	A **B** C D N U	139
3.2 General Condition (evidence of maintenance)	A **B** C D N U	140
3.3 Overall Switchgear Assembly Condition	A **B** C D N U	141

4 Buildings

Age		143
4.1 Condition of structure (roof, walls)	A **B** C D N U	144
4.2 Condition of doors and locks	**A** B C D N U	145
4.3 Condition of Lightning	**A** B C D N U	146
4.4 Overall Building Condition	**A** B C D N U	147

Data sources used

Misc inspection record ☐ Interviews ☐ Photos taken (no.) 150

Inspector Name and Date — Name: G. Ebersbager — Date: Nov. 16, 2010 151

(write any comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation	
Op Desn	
Age	10 Yrs
Voltage	13.8 kv.
Location	Kalar TS/Beechwood

1.0 Pad Mounted Switchgear

	Circle ONLY one
1.1 Main Cabinet Condition	A B C D N U
1.2 Pad Condition	A B C D N U
1.3 Insulators Condition	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Electrical Connections Condition	A B C D N U
1.7 Signs of Over Heating?	A B C D N U
1.7 Overall Condition	A B C D N U

Cables and Terminations

1.8 Cable Condition	A B C D N U
1.9 Termination Condition	A B C D N U
1.1 Neutral Condition	A B C D N U
1.11 Overall Cable Condition	A B C D N U

2 Pad Mounted Transformer

Location #800561 150kva.

2.1 Main Cabinet Condition	A B C D N U
2.2 Pad Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Operating Temperature	A B C D N U
2.5 Overall Transformer Condition	A B C D N U

Cables and Terminations

2..5 Cable Condition	A B C D N U
2.6 Termination Condition	A B C D N U
2.7 Neutral Condition	A B C D N U
2.8 Overall Cable Condition	A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.)

Inspector Name and Date — Name: G Ebersberger — Date: Nov. 18, 2010

(write any comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation
Op Desn
Age
Voltage 16 KV · 1Ø 75KVA
Location Various - Manola St W. of Victoria Ave (off Hwy 8)

1.0 Pad Mounted Switchgear

	Circle ONLY one
1.1 Main Cabinet Condition	A B C D N U
1.2 Pad Condition	A B C D N U
1.3 Insulators Condition	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Electrical Connections Condition	A B C D N U
1.7 Signs of Over Heating?	A B C D N U
1.7 Overall Condtion	A B C D N U

Cables and Terminations

1.8 Cable Condition	A B C D N U
1.9 Termination Condition	A B C D N U
1.1 Neutral Condition	A B C D N U
1.11 Overall Cable Condition	A B C D N U

2 Pad Mounted Transformer Location

(Minor) Heat Damage to tanks Throughout Subd.

2.1 Main Cabinet Condition	A B C D N U
2.2 Pad Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Operating Temperature	A B C D N U
2.5 Overall Transformer Condition	A B C D N U

Cables and Terminations

2..5 Cable Condition	A B C D N U
2.6 Termination Condition	A B C D N U
2.7 Neutral Condition	A B C D N U
2.8 Overall Cable Condition	A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.)

Inspector Name and Date — Name — Date

(write any comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation	
Op Desn	
Age	12-1965.
Voltage	8.2kV / 120 240V. 1Ø
Location	Belin Station.

1.0 Pad Mounted Switchgear

	Circle ONLY one
1.1 Main Cabinet Condition	A B C D N U
1.2 Pad Condition	A B C D N U
1.3 Insulators Condition	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Electrical Connections Condition	A B C D N U
1.7 Signs of Over Heating?	A B C D N U
1.7 Overall Condtion	A B C D N U

Cables and Terminations

1.8 Cable Condition	A B C D N U
1.9 Termination Condition	A B C D N U
1.? Neutral Condition	A B C D N U
1.11 Overall Cable Condition	A B C D N U

2 Pad Mounted Transformer

Location

On Submersible Tx Pad, 1940s.

2.1 Main Cabinet Condition	A B C D N U
2.2 Pad Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Operating Temperature	A B C D N U
2.5 Overall Transformer Condition	A B C D N U

Cables and Terminations

2..5 Cable Condition	A B C D N U
2.6 Termination Condition	A B C D N U
2.7 Neutral Condition	A B C D N U
2.8 Overall Cable Condition	A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.)

Inspector Name and Date — Name: G Ebersberg — Date: Nov. 18, 2010

(write any comments or concerns on the back of this form)

Asset Condition Survey
Overhead Distribution

Substation	
Op Desn	
Age	Unknown
Voltage	
Location	Kalar TS

1.0 Remotely Operated Pole Mounted Load Break Switch

	Circle ONLY one
1.1 Insulator Condition	A B C D N U
1.2 Mechanical Support Condition	A B C D N U
1.3 Signs of Over Heating?	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Motor Operator and Control Condition	A B C D N U
1.7 Overall Condtion	A B C D N U

2 Manually Operated Pole Mounted Load Break Switch

1.1 Insulator Condition	A B C D N U
1.2 Mechanical Support Condition	A B C D N U
1.3 Signs of Over Heating?	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Overall Condtion	A B C D N U

3 Pole Location

1.1 Holes and Cracks ?	A B C D N U
1.2 Rot ?	A B C D N U
1.3 Cross arm Condition	A B C D N U
1.4 Overall Pole Condtion	A B C D N U

3 Pole Mounted Transformer Location

1.1 Tank Integrity	A B C D N U
1.2 Oil Leak	A B C D N U
1.3 Bushing Condition	A B C D N U
1.4 Electrical Connections	A B C D N U
1.5 Signs of Overheating?	A B C D N U
1.6 Overall Transformer Condition	

Data sources used

Misc inspection record ☐ Interviews ☐ Photos taken (no.)

	Name	Date
Inspector Name and Date	G. [illegible]	Nov 18, 2010

(write any comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation		101
Op Desn	XLPE / PILC	102
Age		103
Voltage	13.8KV	104
Location	Various	105

1.0 Pad Mounted Switchgear

	Circle ONLY one	
1.1 Main Cabinet Condition	A B C D N U	108
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condition	A B C D N U	116

Cables and Terminations

(Sulphurous Soil).
Black Corrosion.
350 MCM, 600 MCM.

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.1 Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer Location 125

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Mtce inspection record [ ] Interviews [ ] Photos taken (no.) [ ] 141

Inspector Name and Date — Name: G. Ebers[illegible] — Date: Nov. 18, 2010 144

(write any comments or concerns on the back of this form)

Asset Condition Survey
Overhead Distribution

Substation		101
Op Desn		102
Age	A 16 KV.	103
Voltage		104
Location	Pelham Corners	105

1.0 Remotely Operated Pole Mounted Load Break Switch

	Circle ONLY one	
1.1 Insulator Condition	A B C D N U	109
1.2 Mechanical Support Condition	A B C D N U	110
1.3 Signs of Over Heating?	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Motor Operator and Control Condition	A B C D N U	114
1.7 Overall Condtion	A B C D N U	115

2 Manually Operated Pole Mounted Load Break Switch

1.1 Insulator Condition	A B C D N U	120
1.2 Mechanical Support Condition	A B C D N U	121
1.3 Signs of Over Heating?	A B C D N U	122
1.4 Contact Condition	A B C D N U	123
1.5 Operating Mechanism Condition	A B C D N U	124
1.6 Overall Condtion	A B C D N U	125

3 Pole

Location

1.1 Holes and Cracks ?	A B C D N U	120
1.2 Rot ?	A B C D N U	121
1.3 Cross arm Condition	A B C D N U	122
1.4 Overall Pole Condtion	A B C D N U	123

3 Pole Mounted Transformer

Location Pelham MS

1.1 Tank Integrity	A B C D N U	130
1.2 Oil Leak	A B C D N U	131
1.3 Bushing Condition	A B C D N U	132
1.4 Electrical Connections	A B C D N U	133
1.5 Signs of Overheating?	A B C D N U	135
1.6 Overall Transformer Condition		

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 140

	Name	Date	
Inspector Name and Date	G. Ebrahim	Nov 18, 2010	142

(write any comments or concerns on the back of this form)

Asset Condition Survey
Overhead Distribution

Substation		101
Op Dean		102
Age		103
Voltage		104
Location	McLeod Rd. Overpass	105

1.0 Remotely Operated Pole Mounted Load Break Switch

	Circle ONLY one	
	A B C D N U	109
1.1 Insulator Condition	A B C D N U	110
1.2 Mechanical Support Condition	A B C D N U	111
1.3 Signs of Over Heating?	A B C D N U	112
1.4 Contact Condition	A B C D N U	113
1.5 Operating Mechanism Condition	A B C D N U	114
1.6 Motor Operator and Control Condition	A B C D N U	115
1.7 Overall Condition		

2 Manually Operated Pole Mounted Load Break Switch

1.1 Insulator Condition	A B C D N U	120
1.2 Mechanical Support Condition	A B C D N U	121
1.3 Signs of Over Heating?	A B C D N U	122
1.4 Contact Condition	A B C D N U	123
1.5 Operating Mechanism Condition	A B C D N U	124
1.6 Overall Condition	A B C D N U	125

Location

3 Pole

1.1 Holes and Cracks ?	A B C D N U	130
1.2 Rot ?	A B C D N U	131
1.3 Cross arm Condition	A B C D N U	132
1.4 Overall Pole Condtion	A B C D N U	133

Location

3 Pole Mounted Transformer

1.1 Tank Integrity	A B C D N U	130
1.2 Oil Leak	A B C D N U	131
1.3 Bushing Condition	A B C D N U	132
1.4 Electrical Connections	A B C D N U	133
1.5 Signs of Overheating?	A B C D N U	135
1.6 Overall Transformer Condition		

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 140

Inspector Name and Date

Name G Ebeshleger

Date Nov 18, 2010 142

... comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation		101
Op Dem	SF6 G+W.	102
Age		103
Voltage		104
Location	Niagara Square Mall	105

1.0 Pad Mounted Switchgear

	Circle ONLY one	
1.1 Main Cabinet Condition	A B C D N U	109
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condtion	A B C D N U	116

Cables and Terminations

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.1 Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer Location [ ] 125

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Misc inspection record [ ] Interviews [ ] Photos taken (no.) [ ] 141

Inspector Name and Date — Name: G.E Dersbergen — Date: Nov. 18, 2010 144

(write any comments or concerns on the back of this form)

5/9/2008 Survey Form-1/1 Underground Distribution VI Form.xls

Asset Condition Survey
Underground Distribution

Substation		101
Op Desn		102
Age		103
Voltage		104
Location	Niagara Square	105

1.0 Pad Mounted Switchgear

Circle ONLY one

1.1 Main Cabinet Condition	A B C D N U	109
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condition	A B C D N U	116

Cables and Terminations

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.1 Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer Location: 500 KVA #[illegible] 125

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 141

	Name	Date	
Inspector Name and Date	[illegible]	[illegible]	144

(write any comments or concerns on the back of this form)

6/9/2006 Survey Form-1/1 Underground Distribution VI Form.xls

Asset Condition Survey
Underground Distribution

Substation		101
Op Desc		102
Age		103
Voltage		104
Location	Pelham Corners	105

1.0 Pad Mounted Switchgear

	Circle ONLY one	
1.1 Main Cabinet Condition	A B C D N U	109
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condtion	A B C D N U	116

Cables and Terminations

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.1 Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer Location 126

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Misc inspection record ☐ Interviews ☐ Photos taken (no.) 140

Inspector Name and Date — Name: G. [illegible] — Date: Nov. 18, 2010 141
(write any comments or concerns on the back of this form)

5/9/2008 Survey Form-1/1 Underground Distribution V! Form.xls

Asset Condition Survey
Underground Distribution

Substation	Stn 28
Op Desn	
Age	
Voltage	13.8KV
Location	Lundy's Lane at Montrose

1.0 Pad Mounted Switchgear

	Circle ONLY one
1.1 Main Cabinet Condition	A B C D N U
1.2 Pad Condition	A B C D N U
1.3 Insulators Condition	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Electrical Connections Condition	A B C D N U
1.7 Signs of Over Heating?	A B C D N U
1.7 Overall Condtion	A B C D N U

Cables and Terminations

1.8 Cable Condition	A B C D N U
1.9 Termination Condition	A B C D N U
1.1 Neutral Condition	A B C D N U
1.11 Overall Cable Condition	A B C D N U

2 Pad Mounted Transformer — Location

2.1 Main Cabinet Condition	A B C D N U
2.2 Pad Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Operating Temperature	A B C D N U
2.5 Overall Transformer Condition	A B C D N U

Cables and Terminations

2..5 Cable Condition	A B C D N U
2.6 Termination Condition	A B C D N U
2.7 Neutral Condition	A B C D N U
2.8 Overall Cable Condition	A B C D N U

Data sources used

Mtce inspection record [ ] Interviews [ ] Photos taken (no.)

Inspector Name and Date — Name: G Ebbehenger — Date: Nov 18, 2010

(write any comments or concerns on the back of this form)

5/9/2005 Survey Form 4.8

Asset Condition Survey
Overhead Distribution

Substation		101
Op Dsgn		102
Age		103
Voltage	4800	104
Hwy 20 at Victoria Ave Location	Pelham Corners	105

1.0 Remotely Operated Pole Mounted Load Break Switch

	Circle ONLY one	
1.1 Insulator Condition	A B C D N U	109
1.2 Mechanical Support Condition	A B C D N U	110
1.3 Signs of Over Heating?	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Motor Operator and Control Condition	A B C D N U	114
1.7 Overall Condtion	A B C D N U	115

2 Manually Operated Pole Mounted Load Break Switch

1.1 Insulator Condition	A B C D N U	120
1.2 Mechanical Support Condition	A B C D N U	121
1.3 Signs of Over Heating?	A B C D N U	122
1.4 Contact Condition	A B C D N U	123
1.5 Operating Mechanism Condition	A B C D N U	124
1.6 Overall Condtion	A B C D N U	125

3 Pole Location

1.1 Holes and Cracks ?	A B C D N U	130
1.2 Rot ?	A B C D N U	131
1.3 Cross arm Condition	A B C D N U	132
1.4 Overall Pole Condtion	A B C D N U	133

3 Pole Mounted Transformer Location

1.1 Tank Integrity	A B C D N U	130
1.2 Oil Leak	A B C D N U	131
1.3 Bushing Condition	A B C D N U	132
1.4 Electrical Connections	A B C D N U	133
1.5 Signs of Overheating?	A B C D N U	135
1.6 Overall Transformer Condition		

Data sources used

Misc inspection record ☐ Interviews ☐ Photos taken (no.) 140

Inspector Name and Date — Name: G Ebbeling — Date: Nov 13, 2010 — 142

(write any comments or concerns on the back of this form)