Exhibit 2:

RATE BASE

Exhibit 2: Rate Base

Tab 1 (of 6): Overview

RATE BASE OVERVIEW

Greater Sudbury's last approved Rate Base amount was $76,020,014 as approved in the 2009 COS rate application EB-2008-0230. Greater Sudbury forecasts its 2013 Test Year Rate Base to be $88,079,710.

In accordance with the Board's Filing Requirements, the Rate Base used to determine the 2013 Test Year revenue requirement includes the average of the opening and closing balances for net capital assets plus a working capital allowance. The net book value (NBV) of capital assets is defined as gross assets in service minus accumulated depreciation and contributed capital from third parties. Average cost is defined as the average gross costs of assets in service minus the gross contributed capital received from third parties. Similarly, average accumulated depreciation is defined as the average gross accumulated depreciation minus gross accumulated contributed capital.

Capital assets include property, plant and equipment as well as intangible assets. These have been referred to as "capital assets" throughout this Application.

Greater Sudbury's Rate Base continues to grow commensurate with its enhanced capital spending as approved by the Board in the 2009 Cost of Service decision (EB-2008-0230) and its investment in smart meters. Exhibit 2, Tab 1 Schedule 1, Attachment 1 details the changes to Greater Sudbury's rate base from 2009 to 2013. Exhibit 2, Tab 1, Schedule 2 discusses the factors impacting rate base year over year.

Sudbury (ED-2002-0559)

2013 EDR Application (EB-2012-0126) version: 1

November 9, 2012

X22 Rate Base Trend

	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2012 Projection	2013 Projection
Net Capital Assets in Service:						
Opening Balance	61,391,589	60,941,846	63,607,436	64,843,012	65,442,489	68,090,111
Ending Balance	64,978,247	63,607,436	64,843,012	65,442,489	68,090,111	79,344,639
Average Balance	63,184,918	62,274,641	64,225,224	65,142,750	66,766,300	73,717,375
Working Capital Allowance *(see below)*	13,435,096	13,311,200	13,068,383	14,694,079	15,451,517	14,362,335
Total Rate Base	**76,620,014**	**75,585,841**	**77,293,607**	**79,836,829**	**82,217,817**	**88,079,710**

Expenses for Working Capital

	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2012 Projection	2013 Projection
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	3,571,216	3,652,054	3,432,872	3,763,302	5,156,619	6,914,732
3550-Distribution Expenses - Maintenance	1,745,098	1,502,331	1,681,643	1,497,531	2,339,512	2,163,820
3650-Billing and Collecting	2,515,358	2,194,104	1,937,276	2,321,708	1,779,703	3,146,864
3700-Community Relations	206,736	142,484	343,169	439,836		78,108
3800-Administrative and General Expenses	3,631,137	3,943,844	512,111	4,929,864	3,047,169	3,261,093
3950-Taxes Other Than Income Taxes	200,000	166,452	23,784	-656		
Total Eligible Distribution Expenses	11,869,545	11,601,270	7,930,855	12,951,585	12,323,003	15,564,617
3350-Power Supply Expenses	77,697,760	77,140,065	79,191,698	85,008,941	90,687,113	94,914,882
Total Expenses for Working Capital	89,567,305	88,741,335	87,122,553	97,960,526	103,010,116	110,479,500
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	13.0%
Working Capital Allowance	**13,435,096**	**13,311,200**	**13,068,383**	**14,694,079**	**15,451,517**	**14,362,335**

RATE BASE VARIANCE ANALYSIS

The materiality threshold for Greater Sudbury's rate base is $115,000, which has been calculated in the manner prescribed by the filing guidelines. Exhibit 1, Tab 1, Schedule 2, Attachment 1 contains tables demonstrating the variances in Rate Base in each of the years of the IRM period. A Rate Base Variance Table, indicating year over year variances has been included at Exhibit 2, Tab 1, Schedule 2, Attachment 1. A high level explanation has been provided below for instances where the variance has exceeded the materiality threshold.

2009 Actual Vs. 2010 Actual

There was a decline in Working Capital allowance of $242,817, largely due to a reduction in eligible distribution expenses. The reduction in expenses was due primarily to the results of an actuarial evaluation of Greater Sudbury's future pension benefit in 2010 which, at the time, resulted in a gain, which was recorded in account 5645 per OEB direction, offsetting Greater Sudbury’s expenses. It should be noted that while this gain in included in the determination of rate base for the historical years, no actuarial gain or loss has been included in the 2012 Bridge Year or 2013 Test Year determination of rate base. The reduction in working capital allowance, only mitigated the overall increase in rate base of $1,707,766, which was driven by an increase in capital that caused a $1,950,583 increase in average net capital.

2010 Actual Vs. 2011 Actual.

The $2,543,223 increase in Rate Base in 2011 was caused by a $1,625,696 increase in Working Capital allowance due to higher power supply expenses, higher eligible distribution expenses owing again to actuarial valuations of future pension benefits that in this time period resulted in a loss. In addition there was a $917,527 increase in average capital as a result of elevated levels of capital spending approved in Greater Sudbury's 2009 Cost of Service rate application.

2011 Actual vs. 2012 Projection.

There is a projected increase to Rate Base of $2,380,988 for this period. The increase is driven by an increase in Working Capital allowance (caused by a $5,678,172 increase in power supply costs) and a $1,623,550 increase to Average Net Fixed Assets. The large increase to fixed assets relates to higher capital spending as was approved in Greater Sudbury's last Cost of Service decision EB-2008-0230.

2013 Projection vs. 2012 Projection.

In 2013 Greater Sudbury anticipates a $5,861,893 increase to Rate Base. This increase is due to higher capital spending and the anticipated inclusion of smart meters in the year's ending net capital balance. The 2013 Rate Base includes a decrease of $1,089,182 in working capital allowance that is due to a reduction in the Board Approved percentage used to calculate this number from 15% to 13%.

Sudbury (ED-2002-0559)

2013 EDR Application (EB-2012-0126) version: 1

November 9, 2012

X23 Rate Base Variance Analysis

Variances > $115,000 are shown in bold

	2013 Projection	2012 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	68,090,111	65,442,489	**2,647,622**	**4.0%**
Ending Balance	79,344,639	68,090,111	**11,254,528**	**16.5%**
Average Balance	73,717,375	66,766,300	**6,951,075**	**10.4%**
Working Capital Allowance *(see below)*	14,362,335	15,451,517	**-1,089,182**	**(7.0%)**
Total Rate Base	**88,079,710**	**82,217,817**	**5,861,893**	**7.1%**

Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	6,914,732	5,156,619	**1,758,113**	**34.1%**
3550-Distribution Expenses - Maintenance	2,163,820	2,339,512	**-175,692**	**(7.5%)**
3650-Billing and Collecting	3,146,864	1,779,703	**1,367,161**	**76.8%**
3700-Community Relations	78,108		78,108	
3800-Administrative and General Expenses	3,261,093	3,047,169	**213,924**	**7.0%**
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	15,564,617	12,323,003	**3,241,614**	**26.3%**
3350-Power Supply Expenses	94,914,882	90,687,113	**4,227,770**	**4.7%**
Total Expenses for Working Capital	110,479,500	103,010,116	**7,469,384**	**7.3%**
Working Capital factor	13.0%	15.0%	-0	(13.3%)
Working Capital Allowance	**14,362,335**	**15,451,517**	**-1,089,182**	**(7.0%)**

Sudbury (ED-2002-0559)

2013 EDR Application (EB-2012-0126) version: 1

November 9, 2012

X23 Rate Base Variance Analysis

Variances > $115,000 are shown in bold

	2012 Projection	2011 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	65,442,489	64,843,012	**599,477**	**0.9%**
Ending Balance	68,090,111	65,442,489	**2,647,622**	**4.0%**
Average Balance	66,766,300	65,142,750	**1,623,550**	**2.5%**
Working Capital Allowance *(see below)*	15,451,517	14,694,079	**757,438**	**5.2%**
Total Rate Base	**82,217,817**	**79,836,829**	**2,380,988**	**3.0%**

Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	5,156,619	3,763,302	**1,393,317**	**37.0%**
3550-Distribution Expenses - Maintenance	2,339,512	1,497,531	**841,980**	**56.2%**
3650-Billing and Collecting	1,779,703	2,321,708	**-542,005**	**(23.3%)**
3700-Community Relations		439,836	**-439,836**	**(100.0%)**
3800-Administrative and General Expenses	3,047,169	4,929,864	**-1,882,695**	**(38.2%)**
3950-Taxes Other Than Income Taxes		-656	656	100.0%
Total Eligible Distribution Expenses	12,323,003	12,951,585	**-628,582**	**(4.9%)**
3350-Power Supply Expenses	90,687,113	85,008,941	**5,678,172**	**6.7%**
Total Expenses for Working Capital	103,010,116	97,960,526	**5,049,590**	**5.2%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**15,451,517**	**14,694,079**	**757,438**	**5.2%**

Sudbury (ED-2002-0559)

2013 EDR Application (EB-2012-0126) version: 1

November 9, 2012

X23 Rate Base Variance Analysis

Variances > $115,000 are shown in bold

	2011 Actual	2010 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	64,843,012	63,607,436	**1,235,576**	**1.9%**
Ending Balance	65,442,489	64,843,012	**599,477**	**0.9%**
Average Balance	65,142,750	64,225,224	**917,527**	**1.4%**
Working Capital Allowance *(see below)*	14,694,079	13,068,383	**1,625,696**	**12.4%**
Total Rate Base	**79,836,829**	**77,293,607**	**2,543,223**	**3.3%**

Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	3,763,302	3,432,872	**330,430**	**9.6%**
3550-Distribution Expenses - Maintenance	1,497,531	1,681,643	**-184,112**	**(10.9%)**
3650-Billing and Collecting	2,321,708	1,937,276	**384,432**	**19.8%**
3700-Community Relations	439,836	343,169	96,667	28.2%
3800-Administrative and General Expenses	4,929,864	512,111	**4,417,753**	**862.7%**
3950-Taxes Other Than Income Taxes	-656	23,784	-24,440	(102.8%)
Total Eligible Distribution Expenses	12,951,585	7,930,855	**5,020,730**	**63.3%**
3350-Power Supply Expenses	85,008,941	79,191,698	**5,817,243**	**7.3%**
Total Expenses for Working Capital	97,960,526	87,122,553	**10,837,973**	**12.4%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**14,694,079**	**13,068,383**	**1,625,696**	**12.4%**

Sudbury (ED-2002-0559)

2013 EDR Application (EB-2012-0126) version: 1

November 9, 2012

X23 Rate Base Variance Analysis

Variances > $115,000 are shown in bold

	2010 Actual	2009 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	63,607,436	60,941,846	**2,665,590**	**4.4%**
Ending Balance	64,843,012	63,607,436	**1,235,576**	**1.9%**
Average Balance	64,225,224	62,274,641	**1,950,583**	**3.1%**
Working Capital Allowance *(see below)*	13,068,383	13,311,200	**-242,817**	**(1.8%)**
Total Rate Base	**77,293,607**	**75,585,841**	**1,707,766**	**2.3%**

Expenses for Working Capital

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	3,432,872	3,652,054	**-219,182**	**(6.0%)**
3550-Distribution Expenses - Maintenance	1,681,643	1,502,331	**179,312**	**11.9%**
3650-Billing and Collecting	1,937,276	2,194,104	**-256,828**	**(11.7%)**
3700-Community Relations	343,169	142,484	**200,685**	**140.8%**
3800-Administrative and General Expenses	512,111	3,943,844	**-3,431,733**	**(87.0%)**
3950-Taxes Other Than Income Taxes	23,784	166,452	**-142,668**	**(85.7%)**
Total Eligible Distribution Expenses	7,930,855	11,601,270	**-3,670,415**	**(31.6%)**
3350-Power Supply Expenses	79,191,698	77,140,065	**2,051,633**	**2.7%**
Total Expenses for Working Capital	87,122,553	88,741,335	**-1,618,782**	**(1.8%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**13,068,383**	**13,311,200**	**-242,817**	**(1.8%)**

Sudbury (ED-2002-0559)

2013 EDR Application (EB-2012-0126) version: 1

November 9, 2012

X23 Rate Base Variance Analysis

Variances > $115,000 are shown in bold

	2009 Actual	2009 Approved	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	60,941,846	61,391,589	**-449,743**	**(0.7%)**
Ending Balance	63,607,436	64,978,247	**-1,370,812**	**(2.1%)**
Average Balance	62,274,641	63,184,918	**-910,277**	**(1.4%)**
Working Capital Allowance *(see below)*	13,311,200	13,435,096	**-123,895**	**(0.9%)**
Total Rate Base	**75,585,841**	**76,620,014**	**-1,034,173**	**(1.3%)**

Expenses for Working Capital

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	3,652,054	3,571,216	80,839	2.3%
3550-Distribution Expenses - Maintenance	1,502,331	1,745,098	**-242,767**	**(13.9%)**
3650-Billing and Collecting	2,194,104	2,515,358	**-321,254**	**(12.8%)**
3700-Community Relations	142,484	206,736	-64,252	(31.1%)
3800-Administrative and General Expenses	3,943,844	3,631,137	**312,707**	**8.6%**
3950-Taxes Other Than Income Taxes	166,452	200,000	-33,548	(16.8%)
Total Eligible Distribution Expenses	11,601,270	11,869,545	**-268,275**	**(2.3%)**
3350-Power Supply Expenses	77,140,065	77,697,760	**-557,695**	**(0.7%)**
Total Expenses for Working Capital	88,741,335	89,567,305	**-825,970**	**(0.9%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**13,311,200**	**13,435,096**	**-123,895**	**(0.9%)**

Exhibit 2: Rate Base

Tab 2 (of 6): Capital Asset Policies

CAPITALIZATION POLICY

Chapter 2 of the Filing Requirements dated June 28, 2012 from the OEB states that applicants that must adopt IFRS for financial reporting purposes by January 1, 2013, must adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS.

In September, 2012, the International Accounting Standards Board (IASB) and the Accounting Standards Board (AcSB) decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2014. As a result of this decision, the 2013 Cost of Service application has been revised to reflect CGAAP reporting as opposed to MIFRS reporting requirements.

Effective January 1, 2013, staff have developed the budget with the implementation of updated CGAAP accounting policies for capitalization of assets that will reflect the requirements of MIFRS with respect to capitalization of overheads. In addition, amortization reflects the implementation of updated asset useful lives which have been revised as a result of an internal review of the useful lives of major capital components in conjunction with an OEB Board initiated asset useful lives study completed by Kinectrics. Staff will be bringing formalized policies to the GSU Board for formal approval at a later date.

The updated amortization figures reflect the new accounting policies as well as the updated calculations developed with the assistance of BDO Dunwoody.

Greater Sudbury records capital assets at cost in accordance with CGAAP and Article 410 of the Accounting Procedures Handbook (“APH”). All expenditures by the Corporation are classified as either capital or operating expenditures. The intention of these classifications is to allocate costs across accounting periods in a manner that appropriately matches those costs with the related current and future economic benefits.

Accordingly, all expenditures are capitalized that are material in amount and which meet the definition of a capital asset. Those terms are defined as follows:

- The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. Greater Sudbury does not currently capitalize interest on funds for construction.
- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.
- Individual items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.

A copy of Greater Sudbury's capitalization policy is attached as Appendix 1.

Direct internal costs are assigned on the basis of timesheets submitted and include labour and equipment charges. Internal labour is based on average hourly rates for each operational area, plus a burden rate representing statutory and extended benefits.

Equipment charges for rolling stock used in capital operations are charged to capital at average hourly rates representing operating expenses and amortization.

Indirect internal costs applied to projects represent the costs of management labour and overhead necessary to facilitate capital investments as well as engineering indirect costs. Operations supervision and engineering overhead costs are applied to projects based on a percentage of direct labour costs. Overhead rates are established each year during the budget process based on the level of capital work in the budget and overall costs of the respective departments.

Materials issued to projects attract an overhead intended to recover the cost of operating the stores and procurement department.

Table 1 below describes overhead rates applied to capital over the period 2009 through 2013.

Table 1 – Greater Sudbury Capital Burdens

Burdens	2009	2010	2011	2012	2013
Payroll Burden - Low	28.81%	27.06%	26.88%	30.78%	32.04%
Payroll Burden - High	56.46%	64.75%	56.56%	61.81%	47.16%
Stores Material	16.23%	16.23%	16.26%	16.26%	8.00%
Vehicle Overhead					
Class A	$ 7.31	$ 7.32	$ 8.17	$ 8.90	$ 6.79
Class B	$ 14.62	$ 14.63	$ 8.17	$ 8.90	$ 6.79
Class C	$ 32.89	$ 32.92	$ 51.04	$ 55.62	$ 42.46
Class D	$ 73.09	$ 73.16	$ 51.04	$ 55.62	$ 42.46
Operations Supervision	45.77%	51.78%	59.92%	62.75%	21.91%
Engineering	35.48%	35.59%	42.83%	43.81%	17.98%
Admin	9.20%	8.68%	9.06%	7.02%	0.00%

Account 1576 'Accounting Changes Under CGAAP'

Per the OEB letter dated July 17, 2012, the Board will permit electricity distributors electing to remain on CGAAP in 2012 to implement regulatory accounting changes for depreciation expense and capitalization policies effective on January 1, 2012. This new variance account has been created and authorized for distributors to record the financial differences arising from these accounting changes.

Greater Sudbury has deferred implementation of MIFRS to January 1, 2014 and as such no amounts are recorded in Account 1576.

For sake of clarity, Greater Sudbury does not consider a change in overhead rates from year to year or a change in useful lives under CGAAP a change in accounting practice.

Opening Balances on January 1, 2013

Greater Sudbury will elect to use the deemed cost election under IFRS for opening balance sheet values for its capital assets. Under this election, the deemed cost at the date of transition becomes the new MIFRS cost basis. In Greater Sudbury's case, on January 1, 2013, the opening accumulated depreciation and contributed capital are both set to $NIL and the opening cost equates to the December 31, 2012 CGAAP net book value. This net book value is defined as the original capital cost less accumulated depreciation less contributed capital.

Also at the date of transition to MIFRS, and in accordance with IAS 36 'Impairment of Assets', an entity will also test for impairment on each item for which the deemed cost election is used. Greater Sudbury Hydro Inc reviewed this additional requirement as at January 1, 2013 and determined that it will not have any impairment at the date of transition.

Items No Longer Capitalized

With the change in capitalization of overhead costs, whereby only those costs deemed 'directly attributable to capital' form part of the overhead, indirect management and overhead costs will be included with OM&A in the 2013 Test Year under CGAAP. If the fully burdened overhead rate applied in 2013, then $983,813 would have been capitalized under CGAAP. Instead, this level of costs will be expensed and OM&A has been increased in the 2013 Revenue Requirement accordingly.

Certain other less significant items will no longer be capitalized under MIFRS as well. These will include, under most circumstances, indirect training, travel, meals, feasibility studies, consulting and support costs.

POLICY/PROCEDURES MANUAL

Section:	**FINANCE**	**Approval Date:**	**2008-09-22**
Title:	**CAPITALIZATION**	**Supersedes:**	**NEW**
		Review Date:	**2011-09-22**
Policy No.:	**F-1**	**Page No.:**	**1 of 6**

POLICY

Applicability

This policy applies to the capitalization of assets for Greater Sudbury Utilities Inc.

Purpose

This policy describes the process and specific criteria used for determining if expenditures should be capitalized on the Balance Sheet or expensed to operations in the period incurred. Expenditures are capitalized if they meet generally accepted accounting principles. Capital assets are expected to provide future economic benefits for more than one year. Any expenditure that can be identified as directly attributable with the acquisition, construction, development or betterment of an asset should be capitalized and amortized over the useful life of the asset.

Guidelines

Tangible Assets

Property, plant and equipment are identified as tangible assets provided that they are held for use in the production or supply of goods and services, are intended for a continuing use, and are not intended for sale in the ordinary course of business.

Intangible Assets

An intangible asset is a right or non-physical resource, which provides a benefit or advantage to the company.

Goodwill

When an asset is acquired for a cost over and above the net amount of the acquired assets and assumed liability, the excess cost is considered goodwill.

Capital Assets

Capital assets include tangible and intangible assets, exclusive of goodwill.

Betterment

Betterment is a cost that is incurred to enhance the service potential of a capital asset. Expenditures for betterments are capitalized. This enhancement in service potential can include an increase in the physical output or service capacity, decrease in associated operating costs, extension in the useful life of the asset, or improvement in the quality of the asset's output.

Repair

A repair is a cost which is incurred to maintain the existing service potential of a capital asset. Expenditures for repairs are expensed in the period in which they occurred.

Development

The development of an asset includes work to prepare an asset for further capital work and would typically include development of a piece of land for construction of a transformer station or other distribution plant. If the associated project is not completed with an asset put into service, these costs would be expensed.

Materiality

All expenditures for capital assets and betterments will be capitalized subject to materiality limits as set out in this policy. At times the administrative costs of capitalizing an asset may outweigh the intended benefits. While an expenditure may meet the definition to qualify as a capital asset, a dollar level is set, and if an expenditure falls below, it is not capitalized. This level is known as a materiality limit.

Materiality Limit

For identifiable assets the materiality value for capitalization for new assets or addition to existing assets will be $500.00 for both distribution plant and general plant.

For grouped assets the value of capitalization will be $1000.00 based on a single occurrence for distribution plant and $500 for general plant. Where programs are established for ongoing betterment work this minimum will not be applicable.

Readily Identifiable Assets (Discrete)

A capital asset that has a cost over $500.00 and is easily identifiable, so the asset can be individually tracked and recorded.

Grouped Assets

For efficiency, capital assets may be grouped if, by their nature, it would be impractical to identify individual units. These grouped assets are managed as a pool for the purpose of amortization.

Capitalized Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Costs include all expenditures necessary to put a capital asset into service including all overhead costs that are eligible under this policy.

Overhead costs must be directly attributable to construction activity at the utility. This will be interpreted to mean that the overhead costs to be charged to capital are those that would not exist if Greater Sudbury Utilities did not construct its own capital assets. Eligible costs may appear fixed in the short term but would be eliminated over time (in 3 to 5 years) if GSUi did not have a capital program. Overhead costs that are capitalized include such costs as salaries and benefits of construction and engineering personnel not directly chargeable to project costs and the cost of administrative and support services that are required as a result of construction activity.

Capital Related Overhead Expenses

Per Allocation Procedures.

Amortization

Capital assets are generally amortized based on a method and life set by the OEB, which is considered a suitable indicator of estimated useful life of our industry.

Large and unique capital expenditures will be reviewed on an individual basis to determine the expected life and appropriate method of amortization.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. Spare transformers and meters are held for the purpose of backing up transformers and meters in service in existing distribution system. Transformers and meters received for the purpose of expanding the distribution system will only be capitalized once they are put into service and will remain in inventory until that time.

Policy Compliance

All current practices will comply with the Accounting Procedures Handbook issued by the OEB and the CICA handbook. There will be no exceptions to the requirements of this policy in the execution of day-to-day business. Employees must report incidents on non-compliance relating to this policy in a timely manner to the Policy Owner. Non-compliance issues of a serious nature will be immediately reported to the President & Secretary. Determination of “non-compliance issues of a serious nature” will be the responsibility of the Policy Owner.

PROCEDURE

Applicability

This procedure applies to the costing of Greater Sudbury Utilities activities pertaining to Capital, Maintenance, and Work for Others.

GSUi has developed cost allocation rates to distribute directly attributable costs to its three major activities of Maintenance, Capital and Work for Others. These rates are based on management’s best estimates of the applicable cost allocation determination.

Guidelines

Separate allocation rates are determined for the following activities:

Direct Labour Rate

The hourly labour rate recovers direct labour, benefits, and non-productive time costs. It will be applied to all direct hours charged to Maintenance, Distribution Capital, and Work for Others through timesheet reporting.

Supervision Rate

The supervision burden rate charges all applicable Capital, Maintenance, and Work for Others' activities. This rate allocates the costs associated with the supervision of internal labour and outside services.

Engineering Rate

The engineering burden rate recovers the direct cost of the Engineering Department. It will be applied to Distribution Capital projects and Work for Others where applicable.

Vehicle and Equipment Rates

Vehicle and equipment burden rates capture the full costs associated with fleet usage (maintenance, fuel, license, insurance, amortization, fleet overheads). Individual rates will be developed for major vehicle classifications based on expected utilization. Charges to the three major work activities will be accomplished through vehicle timesheet reporting.

Administrative Costs Rate

An Administrative Costs burden rate charges all capital work with its share of overheads that have been determined to be directly attributable to capital programs. Overheads include the identified costs of departments that do not charge time directly to capital projects by timesheets. These departments include Procurement, Facilities, Human Resources/Safety & Training, Information Technology, Finance, Regulatory Services, and Corporate Costs.

Procedures

Burden rates will be developed by the Finance Department each year, as applicable, in conjunction with the development of the annual budget.

Recoveries against actual costs will be monitored during the year as part of the forecast management process and adjusted if over or under recovered through a true-up process. True-ups completed as required based on materiality limits of the organization.

Compliance

Any exceptions to the requirements of this procedure must be approved by the President & Secretary and disclosed as an addendum to the procedure.

File Number:	EB-2012-0126
Exhibit:	2
Tab:	2
Schedule:	1
Attachment:	2
Date:	9 November, 2012

Appendix 2-D
Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under MIFRS or an alternate accounting

	(A) [1]	(B)	(C)	(D)	(E) [1]	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on PP&E Historic Year**	**Dollar Impact on PP&E Bridge Year**	**Dollar Impact on PP&E Test Year**	**Dollar Impact - PP&E Variance Test versus Bridge**	**Dollar Impact - PP&E Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead**
employee benefits			$ 423,500	$ 423,500	$ 423,500	Y	Directly attributable
costs of site preparation				$ -	$ -		
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		
administration and other general overhead costs			$ 1,213,925	$ 1,213,925	$ 1,213,925	Y	Directly attributable
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	$ 1,637,425	$ 1,637,425	$ 1,637,425		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under MIFRS or an alternate accounting standard and are included in OM&A.

	(A) [1]	(B)	(C)	(D)	(E) [1]	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on OM&A Historic Year**	**Dollar Impact on OM&A Bridge Year**	**Dollar Impact on OM&A Test Year**	**Dollar Impact - OM&A Variance Test versus Bridge**	**Dollar Impact - OM&A Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead**
employee benefits			$ 88,786	$ 88,786	$ 88,786	N	Not directly attributable
costs of site preparation				$ -	$ -		
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising and promotional				$ -	$ -		
costs of conducting business in a new location or with a new class of customer (including costs of				$ -	$ -		
administration and other general overhead costs			$ 895,027	$ 895,027	$ 895,027	N	Not directly attributable
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	$ 983,813	$ 983,813	$ 983,813		

Notes:

1 If the applicant chooses to adopt IFRS or an alternate accounting standard for financial reporting purposes in 2013, the applicant does not need to complete Columns A, E. If the applicant adopts IFRS or an alternate accounting standard for financial reporting purposes in 2012, the applicant must complete all columns.

ASSET RETIREMENT POLICY

Retirement of Property, Plant and Equipment (PP&E) or Intangible Assets

International Accounting Standard ("IAS") #16 paragraph 68 requires the recognition immediately into income for gains or losses on the disposal of PP&E. This would include retirements of assets as per IAS #16 paragraph 67 which states:

> *"The carrying amount of an item of property, plant and equipment shall be derecognized:*
>
> *(a) On disposal; or*
>
> *(b) When no future economic benefits are expected from its use or disposal.*

Upon adoption of IFRS on January 1, 2014, Greater Sudbury will follow the guidance provided in Account 4357 'Gain from Retirement of Utility and Other Property' and Account 4362 'Loss from Retirement of Utility and Other Property', Article 410 of the APH and the July 2012 FAQ#23.

Prior to 2014, these two accounts were not allowed under CGAAP because the accounting treatment requires the use of Account 2105 'Accumulated Depreciation of Electric Utility Plant – Property, Plant and Equipment' for retirement gains or losses. The Board's IFRS guidance on page 15 in Article 410 of the APH states:

> *"Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense (on the income statement), and disclose the amount separately."*

Greater Sudbury does not have sufficient historical data on which to base a forecast of the amount of gains or losses expected as a result of derecognizing pooled assets. No amounts have been included in this rate application as an estimate of the gains or losses for retirements of pooled assets..

In consideration of the OEB's Decision in Hydro Ottawa's 2012 COS rate application (EB-2011-0054), no request is made for a variance account to track the actual retirement gains and losses in comparison to the NIL amount included in the Revenue Requirement for pooled assets. As with Hydro Ottawa, Greater Sudbury is unable to demonstrate there is volatility for gains or losses because it does not have sufficient historical data. In response, Greater Sudbury Hydro Inc will use the actual amounts recorded in Accounts 4357 and 4362 starting in 2014 and be in a better position to forecast the applicable amounts in its 2017 COS rate application.

Disposals of Utility and Other Property

As a matter of clarification, Greater Sudbury will continue to use Account 4355 'Gain on Disposition of Utility and Other Property' and Account 4360 'Loss on Disposition of Utility and Other Property' when applicable. These two accounts will continue to be used for all disposals, which are not retirements, of items of PP&E or intangible assets.

DEPRECIATION POLICY

Greater Sudbury uses the straight line method of amortization which reflects a constant charge to income for the service as a function of time, based on the estimated average useful life of the asset. Greater Sudbury records a half year of amortization expense on new capital assets in the year they are added. The estimated average useful lives of various asset categories are consistent with Board policy.[1]

CGAAP

Under CGAAP, for the years 2009 to 2012, the depreciation rates used by Greater Sudbury Hydro Inc have not changed. The depreciation rates used are outlined in Exhibit 2, Tab 2, Schedule 4, Attachment 1; those rates have not changed since the approval of the 2009 COS application. They reflect a rational and systematic allocation of cost over future periods appropriate to the nature of the property, plant and equipment.

IFRS

International Accounting Standard 16 ‘Property, Plant and Equipment’ (“IAS 16”) requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the item to be depreciated separately. It also requires that entities perform a review of its useful lives, depreciation methods, and residual values on an annual basis.

Greater Sudbury Hydro Inc has, through internal analysis, determined the new components of its assets and reviewed useful lives. Both were accomplished by reference to the *Depreciation Study for Use by Electricity Distributors* (EB-2010-0178) (the “Kinectrics Report”) and our Asset Assessment Report. Greater Sudbury is proposing useful lives for its assets that are within the ranges suggested as a guideline by the Kinectrics Report.

---

[1] Ontario Energy Board, 2006 Electricity Distribution Rate Handbook, May 11, 2005, Appendix B

The depreciation rates used by Greater Sudbury are outlined in Exhibit 2, Tab 2, Schedule 3, Attachment 1. They reflect an updated, rational and systematic allocation of cost of PP&E over future periods.

Remaining Useful Lives at Beginning of 2013 (test year)

Greater Sudbury Inc has elected to use the deemed cost election under IFRS 1 for opening balance sheet values for its capital assets. Under this exemption the deemed cost as at January 1, 2013 becomes the new IFRS cost basis.

As at January 1, 2013 of the comparative year under MIFRS, all of the existing capital assets were analyzed to determine their remaining useful lives in relation to the new useful lives determined under IFRS. Therefore, under IFRS for 2013 and subsequent years, the deemed cost amounts will be depreciated over the remaining useful lives of the corresponding assets. The depreciation expense will form part of the total depreciation expense for 2013 and subsequent years along with the depreciation expense on new capital additions in 2013 and subsequent years which will be calculated for IFRS purposes using the IFRS useful lives as outlined in Exhibit 2, Tab 2, Schedule 3, Attachment 1.

Asset Retirement Obligations

Greater Sudbury does not have any asset retirement obligations and therefore there is no corresponding depreciation amount included for the 2013 Test Year.

Half-Year Rule

For rate making purposes, Greater Sudbury Hydro Inc follows the “half-year” rule where capital additions in the 2013 Test Year attract six months of depreciation expense.

For accounting purposes, Greater Sudbury follows the same practice.

2013 Depreciation Expense - Revised Useful Lives

Depreciation expense in 2013 is forecast to be reduced since many of the useful lives established in the Kinectrics Report are longer than the rates previously used. As shown in Table 1 below, the total reduction in depreciation expense with updated useful lives for the 2013 Test Year is $2,167,296.

Table 1 – Comparison of Depreciation with existing useful lives versus revised useful lives

CGAAP Depreciation Expense with 2013 useful lives	$6,044,160
CGAAP Depreciation Expense with 2013 useful lives	$3,876,864
Reduction in Depreciation Expense	$2,167,296

Account 1576 'Accounting Changes Under CGAAP'

Per the OEB letter dated July 17, 2012, the Board will permit electricity distributors electing to remain on CGAAP in 2012 to implement regulatory accounting changes for depreciation expense and capitalization policies effective on January 1, 2012. Greater Sudbury has elected to make this change effective January 1, 2013. No adjustments have been posted to account 1576.

Assets Components and Depreciation Rates

		CGAAP		CGAAP EUL	
OEB Class	**Asset Component Description**	**Years**	**Rate**	**Years**	**Rate**
1805	Land	NA	NA	NA	NA
1808	Buildings/Fixtures - Structure & Contents	50	2.0%	50	2.0%
1808	Buildings/Fixtures - Building Improvments	15	6.7%	25	4.0%
1820	Dist Stn Equip<50kV - Building	50	2.0%	50	2.0%
1820	Dist Stn Equip<50kV - Transformers/Bushings	30	3.3%	45	2.2%
1820	Dist Stn Equip<50kV - Switch Gear	30	3.3%	45	2.2%
1820	Dist Stn Equip<50kV - Breakers	30	3.3%	45	2.2%
1820	Dist Stn Equip<50kV - Relays	30	3.3%	20	5.0%
1820	Dist Stn Equip<50kV - Reclosers	30	3.3%	45	2.2%
1820	Dist Stn Equip<50kV - All Other Items Substation	30	3.3%	20	5.0%
1820	Dist Stn Equip<50kV - All Other Items Distribution Stn Switch	30	3.3%	45	2.2%
1820	Dist Stn Equip<50kV - All Other Items Battery Bank/Charger	30	3.3%	20	5.0%
1820	Dist Stn Equip<50kV - All Other Items - Parking lots/fences	30	3.3%	25	4.0%
1830	Poles (fully dressed)	25	4.0%	40	2.5%
1835	O/H Conductors/Devices - Primary Conductor	25	4.0%	50	2.0%
1835	O/H Conductors/Devices - Secondary Conductor	25	4.0%	50	2.0%
1835	O/H Conductors/Devices - All other items	25	4.0%	50	2.0%
1840	UG Conduit	25	4.0%	50	2.0%
1840	Manholes and Vaults	25	4.0%	50	2.0%
1840	Underground Conduit - All other items	25	4.0%	50	2.0%
1845	UG Conductors/Devices - Primary Buried	25	4.0%	40	2.5%
1845	UG Conductors/Devices - Primary Buried in Duct	25	4.0%	40	2.5%
1845	UG Conductors/Devices - Secondary	25	4.0%	40	2.5%
1845	UG Conductors/Devices - All other items	25	4.0%	40	2.5%
1850	OH Transformers - 3 Phase Dressed (fully dressed)	25	4.0%	40	2.5%
1850	OH Transformers - Single Phase (fully dressed)	25	4.0%	40	2.5%
1850	OH Transformers - All Other Items	25	4.0%	40	2.5%
1855	Services - Secondary	25	4.0%	40	2.5%
1855	Services - All Other Items	25	4.0%	40	2.5%
1860	Meters - Single Phase	25	4.0%	25	4.0%
1860	Meters - Polly Phase & Interval	25	4.0%	25	4.0%
1860	Meters - Smart	25	4.0%	15	6.7%
1860	Meters - Metering Equipment	25	4.0%	45	2.2%
1860	Meters - Wholesale Metering	25	4.0%	30	3.3%
1860	Meters - All Other Items	25	4.0%	25	4.0%
1915	Office Furniture and Equipment	10	10.0%	10	10.0%
1920	Computer H/W - PCs, Laptops, Printers, Servers, ect	5	20.0%	5	20.0%
1611	Computer S/W - All	5	20.0%	5	20.0%
1930	Large Trucks	8	12.5%	12	8.3%
1930	Small Trucks and Vans	4	25.0%	8	12.5%
1940	Tools, Shop and Garage Equipment	10	10.0%	10	10.0%
1955	Communication Equipment	10	10.0%	10	10.0%
1955	Communication Equipment - Fibre	25	4.0%	25	4.0%
1980	System Supervisory Equipment	15	6.7%	20	5.0%

CAPITAL CONTRIBUTION POLICY

Greater Sudbury records capital contributions in OEB Account 1995 Contributions and Grants - Credit, which is a contra account within capital assets. The inclusion of the contribution amounts in this account causes them to be netted from capital assets.

Capital contributions are used to offset depreciation expense over the same time period as the underlying capital asset is amortized.

CGAAP

Greater Sudbury's current policy under CGAAP is to record capital contributions in OEB Account 1995 'Contributions and Grants – Credit', which is a contra account within capital assets. This account is netted against capital assets to provide the net cost. Under CGAAP, for 2013, the amounts received as contributed capital will be recorded to Account 1995.

IFRS

Greater Sudbury Hydro Inc will be taking the additional one-year IFRS deferral as per the decision by the IASB and the ACSB in September, 2012. Greater Sudbury therefore will be adopting IFRS on January 1, 2014. Greater Sudbury will be electing to use the IFRS 1 exemption regarding the treatment of capital contributions and thus capital contributions received after January 1, 2013 (IFRS comparative year) are treated as a liability.

The unamortized balance in Account 1995 will be set to NIL at January 1, 2013 and will become part of the calculation of the new IFRS deemed cost amounts for the related capital assets. This allocation will be done on the same basis as the related capital asset components were determined using the IFRS 1 deemed cost exemption.

For the comparative 2012 year, the amounts received and initially recorded to Account 1995 under CGAAP will be remain in that account. For 2014 and subsequent years, contributed capital received will be recorded to Account 2440, and therefore capital assets will be presented on a gross basis.

Amortization of Contributed Capital

Under CGAAP, and for 2013, all amounts recorded in Account 1995 will continue to be amortized as a credit to depreciation expense on a straight-line basis over revised useful lives. Under IFRS, the amortization of Account 2440 will commence in 2013 (IFRS comparative year) and will be recorded to Account 4245 'Government and Other Assistance Directly Credited to Income' which is an offset to depreciation expense. The contributions received in 2013 and subsequent years will be componentized and amortized on the same basis as the related underlying assets to ensure proper matching.

If necessary, the amortization period of the capital contributions recorded in Account 2440 will be adjusted on an ongoing basis to reflect any changes in the remaining useful lives of the underlying capital assets to ensure consistent matching.

Ratemaking Considerations

For ratemaking purposes in the 2013 test year, the net unamortized balance of Account 2440 will be included with property, plant and equipment and treated as an offset to rate base. The amortization of Account 2440 will be included as an offset to depreciation expense as shown in OEB Appendix 2-CG 'Depreciation and Amortization Expense' in Exhibit 4, Tab 7, Schedule 1, Attachment 4.

Exhibit 2: Rate Base

Tab 3 (of 6): Fixed Assets

GROSS ASSETS

Greater Sudbury has provided Table 1 below as a summary of the closing gross asset balances by function as indicated in the Ontario Energy Board's Accounting Procedures Handbook, Effective January 1, 2012. The detailed breakdown by major plant account is included in Appendix 2-B, which is located at Exhibit 2, Tab 3, Schedule 2, Attachment 2. This appendix also includes the additions and disposals for each asset account for each year from 2007 through to the 2013 Test Year, all presented on a CGAAP basis.

The additions shown for accounts 1611 through to 1995 in the above noted Appendix 2-B do not include amounts relating to assets under construction. Any assets under construction are included in account 2055 Work In Process. Also worth noting is the inclusion of account 1330, an inventory account relating to Plant Materials and Operating Supplies. During Greater Sudbury's 2011 Financial Statement Audit, an entry was proposed by the independent external auditors to include Capital Inventory as a part of Fixed Assets on Greater Sudbury's Financial Statements. The amount is shown as Capital Inventory on the notes the 2011 Financial Statements (Exhibit 1, Tab 3, Schedule 3, Attachment 1) and are included in the Capital Assets amount shown on the Balance Sheet. Greater Sudbury has included them in the above noted Appendix 2-B to be consistent with its Financial Statement presentation, however the amount shown in account 1330 and 2055 are not included in the calculation of Rate Base and amortization has never been calculated on either balance.

Table 1 – Gross Assets by Function

	2009 CGAAP	2010 CGAAP	2011 CGAAP	2012 CGAAP	2013 CGAAP
Intangible Plant *Accounts 1606-1612*	1,853,569	2,378,553	2,514,296	2,762,472	3,412,819
Distribution Plant *Accounts 1805-1875*	162,192,737	168,985,845	175,321,782	183,807,138	192,737,721
General Plant *Accounts 1905-1990*	10,009,890	10,637,950	11,016,401	11,709,912	13,180,667
Total	**174,056,196**	**182,002,348**	**188,852,480**	**198,279,521**	**209,331,207**

Gross Asset Variances

A table detailing the requested Gross Asset variances has been included at Exhibit 2, Tab 3, Schedule 1, Attachment 1.

2009 Board Approved vs. 2009 Actual - Greater Sudbury's actual gross capital additions for 2009 fell short of the Board approved levels for the following reasons;

1. Greater Sudbury experienced delays in filing its 2009 Cost of Service application, EB-2008-0230. These delays resulted in a delayed decision that was not released until December 1, 2009.

2. Key engineering and planning staff were occupied for a significant part of the year in the Cost of Service application process. The participation of these staff limited the amount of time they could devote to capital works.

3. Greater Sudbury had applied for and ultimately received approval for capital to implement a CIS constructed on the SAP software platform. The project was a partnership between Cambridge North Dumfries Hydro (Cambridge), London Hydro (London) and Greater Sudbury. London was the lead partner and would

host the application. This partnership had been previously formed into a cooperative venture call CODAC, originally there had been a variety of other LDCs that for one reason or another determined they would not continue with the group.

By combining efforts, certain synergies and economic efficiencies were gained and it was felt by the group that the inclusion of multiple companies, at least in part, reduced the risk of project scope creep and cost overruns as each member would have a say in the direction of the project.

In November of 2009 serious concerns with respect to the implementation project were beginning to appear. In December the new software integrator that London hired indicated that the work completed to date had been fundamentally incorrect and that the project would have to be restarted. The project partners could not get a commitment to a cost to complete. Cambridge announced that it was exiting the partnership based on the cost uncertainty. This left Greater Sudbury alone in the partnership with London discussing the cost split to continue. Previously London had been responsible for 50% of the costs with Cambridge and Sudbury picking up 25% each. At this point Greater Sudbury began to seek alternatives for its Customer Service Billing software. When Greater Sudbury approached Harris Computer Systems they offered large discounts, guaranteed price and a very short implementation schedule.

Based on the risk of continuing Greater Sudbury made the decision to write off the SAP investment to date and pursue the less functional but significantly less expensive Harris NorthStar option.

Variances Resulting from Actual Results & Projections

All other variances included in Exhibit 2, Tab 3, Schedule 1, Attachment 1 relate to annual capital activity. Annual amounts of gross assets are comprised of additions and disposals. Each capital addition that exceeds Greater Sudbury's materiality level of $115,000 has been explained at Exhibit 2, Tab 4, Schedule 2, with the exception of the addition of Smart Meters in 2013. The details of the Smart Meter program and additions are included at Exhibit 9, Tab 4.

The annual variances related to disposals over the materiality threshold are detailed below. The continuity schedules (OEB Appendix 2-B) are included at Exhibit 2, Tab 2 Schedule 3, Attachment 2.

<u>Disposals</u>

1. 2011 Actual (See OEB Appendix 2-B 2011)
    a. Account 1930 had a disposal of $441,361 related to two tension stringers totaling $114,782, three small vehicles totaling $63,057 and two bucket trucks totaling $263,522.
2. 2012 Projection (See OEB Appendix 2-B 2012)
    a. Account 1930 has a forecasted disposal of $123,814 related to the disposal of 5 small vehicles (trucks and trailers).
3. 2013 Projection (See OEB Appendix 2-B 2012 CGAAP)
    a. Account 1930 has a forecasted disposal of $458,502 relating to 2 bucket trucks with a capital cost of $371,887 and 2 small vehicles with a capital cost of $86,615.
    b. Account 1860 (Meters) includes the disposal of the Stranded Meter assets. Details of this disposal can be found at Exhibit 9, Tab 1, Schedule 3.

Variance Analysis on Gross Assets (CGAAP)

Account	Description	2009 Board Approved	2009 Actual	Variance 2009 from 2009 Actual	2010 Actual	Variance 2010 from 2009 Actual	2011 Actual	Variance 2011 from 2010 Actual	2012 CGAAP	Variance 2012 from 2011 Actual	2013 CGAAP	Variance 2013 from 2012 Actual
1611	Computer Software (Formally known as Account 1925)	$ 3,600,490	$ 1,853,569	**$ 1,746,921**	$ 2,378,554	**$ (524,985)**	$ 2,514,296	**$ (135,742)**	$ 2,762,471	**$ (248,175)**	$ 3,412,818	**$ (650,347)**
1612	Land Rights (Formally known as Account 1906)		$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1805	Land	$ 890,772	$ 890,958	**$ (186)**	$ 857,298	**$ 33,660**	$ 857,298	**$ -**	$ 862,867	**$ (5,569)**	$ 862,867	**$ -**
1808	Buildings	$ 9,380,505	$ 9,230,593	**$ 149,912**	$ 9,230,593	**$ -**	$ 9,230,593	**$ -**	$ 9,230,593	**$ -**	$ 9,230,593	**$ -**
1808	Building Improvements	$ -	$ 406,174	**$ (406,174)**	$ 567,528	**$ (161,354)**	$ 726,880	**$ (159,352)**	$ 1,037,258	**$ (310,378)**	$ 2,003,258	**$ (966,000)**
1815	Transformer Station Equipment >50 kV	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 16,565,704	$ 16,086,489	**$ 479,215**	$ 16,299,670	**$ (213,181)**	$ 16,461,161	**$ (161,491)**	$ 17,841,131	**$ (1,379,970)**	$ 20,290,231	**$ (2,449,100)**
1825	Storage Battery Equipment	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 14,433,646	$ 15,311,139	**$ (877,493)**	$ 16,383,183	**$ (1,072,044)**	$ 17,990,851	**$ (1,607,668)**	$ 19,262,924	**$ (1,272,073)**	$ 20,719,315	**$ (1,456,391)**
1835	Overhead Conductors & Devices	$ 40,549,330	$ 39,646,169	**$ 903,161**	$ 40,866,691	**$ (1,220,522)**	$ 41,702,868	**$ (836,177)**	$ 42,704,509	**$ (1,001,641)**	$ 44,040,549	**$ (1,336,040)**
1840	Underground Conduit	$ 20,314,576	$ 18,478,948	**$ 1,835,628**	$ 19,095,050	**$ (616,102)**	$ 19,957,117	**$ (862,067)**	$ 20,958,582	**$ (1,001,465)**	$ 21,441,258	**$ (482,676)**
1845	Underground Conductors & Devices	$ 17,667,951	$ 18,969,279	**$ (1,301,328)**	$ 19,989,151	**$ (1,019,872)**	$ 20,666,103	**$ (676,952)**	$ 21,444,919	**$ (778,816)**	$ 21,955,958	**$ (511,039)**
1850	Line Transformers	$ 24,830,371	$ 24,951,584	**$ (121,213)**	$ 26,909,416	**$ (1,957,832)**	$ 27,928,855	**$ (1,019,439)**	$ 29,516,258	**$ (1,587,403)**	$ 30,788,944	**$ (1,272,686)**
1855	Services (Overhead & Underground)	$ 9,183,429	$ 9,441,545	**$ (258,116)**	$ 9,977,240	**$ (535,695)**	$ 10,971,051	**$ (993,811)**	$ 12,011,838	**$ (1,040,787)**	$ 12,921,566	**$ (909,728)**
1860	Meters	$ 9,002,812	$ 8,779,859	**$ 222,953**	$ 8,810,025	**$ (30,166)**	$ 8,829,005	**$ (18,980)**	$ 8,936,259	**$ (107,254)**	$ 1,859,558	**$ 7,076,701**
1860	Meters (Smart Meters)	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ 6,623,624	**$ (6,623,624)**
1905	Land	$ (55,369)	$ -	**$ (55,369)**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 44,315	$ 44,315	**$ -**	$ 44,315	**$ -**	$ 44,315	**$ -**	$ 44,315	**$ -**	$ 44,315	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 93,649	$ -	**$ 93,649**	$ -	**$ -**	$ 153,987	**$ (153,987)**	$ 525,497	**$ (371,510)**	$ 730,312	**$ (204,815)**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 4,238,494	$ 4,500,502	**$ (262,008)**	$ 5,041,489	**$ (540,987)**	$ 5,163,079	**$ (121,590)**	$ 5,265,344	**$ (102,265)**	$ 5,925,292	**$ (659,948)**
1935	Stores Equipment	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 1,701,785	$ 1,667,431	**$ 34,354**	$ 1,741,756	**$ (74,325)**	$ 1,819,609	**$ (77,853)**	$ 1,972,419	**$ (152,810)**	$ 2,132,419	**$ (160,000)**
1945	Measurement & Testing Equipment	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 2,205,659	$ 2,212,830	**$ (7,171)**	$ 2,212,830	**$ -**	$ 2,220,587	**$ (7,757)**	$ 2,287,512	**$ (66,925)**	$ 2,337,512	**$ (50,000)**
1955	Communication Equipment (Smart Meters)	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ 16,502	**$ (16,502)**
1975	Load Management Controls Utility Premises	$ -	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**
1980	System Supervisory Equipment	$ 1,245,223	$ 1,542,695	**$ (297,472)**	$ 1,555,443	**$ (12,748)**	$ 1,572,708	**$ (17,265)**	$ 1,572,708	**$ -**	$ 1,952,199	**$ (379,491)**
1985	Miscellaneous Fixed Assets	$ 42,117	$ 42,117	**$ -**	$ 42,117	**$ -**	$ 42,117	**$ -**	$ 42,117	**$ -**	$ 42,117	**$ -**
1995	Contributions & Grants	$ (11,376,685)	$ (12,251,664)	**$ 874,979**	$ (13,513,098)	**$ 1,261,434**	$ (14,578,301)	**$ 1,065,203**	$ (15,652,645)	**$ 1,074,344**	$ (16,356,435)	**$ 703,790**
	TOTAL	$ 164,558,774	$ 161,804,532	**$ 2,754,242**	$ 168,489,251	**$ (6,684,719)**	$ 174,274,179	**$ (5,784,928)**	$ 182,626,876	**$ (8,352,697)**	$ 192,974,772	**$ (10,347,896)**

ACCUMULATED DEPRECIATION

Exhibit 2, Tab 3, Schedule 2, Attachment 1 provides a quantitative variance analysis on accumulated depreciation for each year from 2009 through to the 2013 Test Year.

Variances in accumulated depreciation are a direct result of annual depreciation expenses and disposals of assets. Continuity Schedules (OEB Appendix 2-B) have been provided for 2007, 2008, 2009, 2010, 2011, 2012 Bridge Year and 2013 Test Year at Exhibit 2, Tab 3, Schedule 2, Attachment 2. These schedules provide the details of the depreciation expense for each asset account. Details of disposals have been provided at Exhibit 2, Tab 3, Schedule 1.

Variance Analysis on Accumulated Depreciation (CGAPP)

Account	Description	2009 Board Approved	2009 Actual	Variance 2009 from 2009 Actual	2010 Actual	Variance 2010 from 2009 Actual	2011 Actual	Variance 2011 from 2010 Actual	2012 CGAAP	Variance 2012 from 2011 Actual	2013 CGAAP	Variance 2013 from 2012 Actual
1611	Computer Software (Formally known as Account 1925)	$ (2,287,004)	$ (1,544,888)	$ (742,116)	$ (1,667,938)	$ 123,050	$ (1,857,062)	$ 189,124	$ (2,084,577)	$ 227,515	$ (2,505,442)	$ 420,865
1612	Land Rights (Formally known as Account 1906)	$ 1,007	$ -	$ 1,007	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ (3,932,444)	$ (3,926,704)	$ (5,740)	$ (4,097,281)	$ 170,577	$ (4,281,167)	$ 183,886	$ (4,464,729)	$ 183,562	$ (4,700,719)	$ 235,990
1810	Leasehold Improvements	$ -	$ (30,140)	$ 30,140	$ (62,596)	$ 32,456	$ (105,743)	$ 43,147	$ (164,548)	$ 58,805	$ (258,558)	$ 94,010
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ (9,925,931)	$ (9,905,546)	$ (20,385)	$ (10,348,104)	$ 442,558	$ (10,784,866)	$ 436,762	$ (11,231,678)	$ 446,812	$ (11,751,067)	$ 519,389
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ (7,212,026)	$ (7,273,151)	$ 61,125	$ (7,835,539)	$ 562,388	$ (8,443,154)	$ 607,615	$ (9,066,071)	$ 622,917	$ (9,442,006)	$ 375,935
1835	Overhead Conductors & Devices	$ (24,619,802)	$ (24,772,621)	$ 152,819	$ (25,927,990)	$ 1,155,369	$ (27,101,912)	$ 1,173,922	$ (28,327,212)	$ 1,225,300	$ (28,816,580)	$ 489,368
1840	Underground Conduit	$ (10,398,152)	$ (10,108,914)	$ (289,238)	$ (10,798,164)	$ 689,250	$ (11,505,873)	$ 707,709	$ (12,178,407)	$ 672,534	$ (12,426,697)	$ 248,290
1845	Underground Conductors & Devices	$ (9,485,866)	$ (9,406,517)	$ (79,349)	$ (10,128,919)	$ 722,402	$ (10,875,772)	$ 746,853	$ (11,665,862)	$ 790,090	$ (12,096,369)	$ 430,507
1850	Line Transformers	$ (15,450,491)	$ (15,402,125)	$ (48,366)	$ (16,242,312)	$ 840,187	$ (17,105,712)	$ 863,400	$ (17,959,297)	$ 853,585	$ (18,446,725)	$ 487,428
1855	Services (Overhead & Underground)	$ (5,483,383)	$ (5,464,011)	$ (19,372)	$ (5,783,352)	$ 319,341	$ (6,127,309)	$ 343,957	$ (6,493,840)	$ 366,531	$ (6,704,513)	$ 210,673
1860	Meters	$ (6,200,000)	$ (6,091,872)	$ (108,128)	$ (6,355,155)	$ 263,283	$ (6,593,129)	$ 237,974	$ (6,817,822)	$ 224,693	$ (993,565)	$ (5,824,257)
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,486,060)	$ 1,486,060
1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ (4,500)	$ -	$ (4,500)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ (38,898)	$ (38,898)	$ -	$ (39,837)	$ 939	$ (40,775)	$ 938	$ (41,714)	$ 939	$ (42,652)	$ 938
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ (15,399)	$ 15,399	$ (83,347)	$ 67,948	$ (331,211)	$ 247,864
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ (93,649)	$ -	$ (93,649)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ (3,225,764)	$ (3,130,422)	$ (95,342)	$ (3,553,837)	$ 423,415	$ (3,531,956)	$ (21,881)	$ (3,874,323)	$ 342,367	$ (3,631,286)	$ (243,037)
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ (1,215,461)	$ (1,216,883)	$ 1,422	$ (1,295,447)	$ 78,564	$ (1,378,378)	$ 82,931	$ (1,467,837)	$ 89,459	$ (1,560,002)	$ 92,165
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ (1,066,590)	$ (1,068,049)	$ 1,459	$ (1,148,984)	$ 80,935	$ (1,227,772)	$ 78,788	$ (1,309,066)	$ 81,294	$ (1,396,205)	$ 87,139
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,775)	$ 5,775
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisory Equipment	$ (1,092,864)	$ (1,102,779)	$ 9,915	$ (1,162,505)	$ 59,726	$ (1,219,258)	$ 56,753	$ (1,274,602)	$ 55,344	$ (1,305,289)	$ 30,687
1985	Miscellaneous Fixed Assets	$ (40,007)	$ (42,117)	$ 2,110	$ (42,117)	$ -	$ (42,117)	$ -	$ (42,117)	$ -	$ (42,117)	$ -
1995	Contributions & Grants	$ 2,191,197	$ 2,328,540	$ (137,343)	$ 2,843,836	$ (515,296)	$ 3,405,664	$ (561,828)	$ 4,010,282	$ (604,618)	$ 4,312,705	$ (302,423)
	TOTAL	$ (99,580,628)	$ (98,197,097)	$ (1,383,531)	$ (103,646,241)	$ 5,449,144	$ (108,831,690)	$ 5,185,449	$ (114,536,767)	$ 5,705,077	$ (113,630,133)	$ (906,634)

File Number:	EB-2012-0126
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	9 November, 2012

Appendix 2-B
Fixed Asset Continuity Schedule-CGAAP

Year 2007

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 1,896,350			$ 1,896,350	$ (1,868,085)	$ (11,340)		$ (1,879,425)	$ 16,924
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land		$ 890,772			$ 890,772	$ -			$ -	$ 890,772
47	1808	Buildings		$ 8,965,818	$ 264,775		$ 9,230,593	$ (3,394,281)	$ (180,649)		$ (3,574,930)	$ 5,655,663
13	1808	Buildings Improvements		$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -		$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 14,800,136	$ 303,275		$ 15,103,411	$ (8,659,571)	$ (400,773)		$ (9,060,344)	$ 6,043,067
47	1825	Storage Battery Equipment		$ -	$ -		$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 11,362,944	$ 959,653		$ 12,322,597	$ (4,619,698)	$ (848,321)		$ (5,468,019)	$ 6,854,578
47	1835	Overhead Conductors & Devices		$ 34,902,133	$ 1,805,898		$ 36,708,031	$ (22,291,174)	$ (811,056)		$ (23,102,230)	$ 13,605,801
47	1840	Underground Conduit		$ 16,439,256	$ 767,574		$ 17,206,830	$ (8,196,553)	$ (618,195)		$ (8,814,748)	$ 8,392,082
47	1845	Underground Conductors & Devices		$ 16,258,082	$ 612,582		$ 16,870,664	$ (7,435,180)	$ (620,520)		$ (8,055,700)	$ 8,814,964
47	1850	Line Transformers		$ 22,229,713	$ 1,005,091		$ 23,234,804	$ (13,130,757)	$ (735,565)		$ (13,866,321)	$ 9,368,483
47	1855	Services (Overhead & Underground)		$ 8,308,540	$ 360,244		$ 8,668,784	$ (4,957,213)	$ (159,063)		$ (5,116,276)	$ 3,552,508
47	1860	Meters		$ 8,424,114	$ 228,698		$ 8,652,812	$ (5,309,403)	$ (258,490)		$ (5,567,893)	$ 3,084,919
47	1860	Meters (Smart Meters)		$ -	$ -		$ -	$ -			$ -	$ -
N/A	1905	Land		$ -	$ -		$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -		$ -				$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -		$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 44,315	$ -		$ 44,315	$ (36,082)	$ (939)		$ (37,021)	$ 7,294
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -		$ -				$ -	$ -
10	1920	Computer Equipment - Hardware		$ 93,649	$ -		$ 93,649	$ (93,649)			$ (93,649)	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -		$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -		$ -				$ -	$ -
10	1930	Transportation Equipment		$ 3,745,967	$ 255,827	$ (291,506)	$ 3,710,288	$ (3,081,759)	$ (219,733)	$ 291,506	$ (3,009,986)	$ 700,302
8	1935	Stores Equipment			$ -		$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 1,282,361	$ 89,424		$ 1,371,785	$ (979,136)	$ (71,191)		$ (1,050,327)	$ 321,458
8	1945	Measurement & Testing Equipment		$ -	$ -		$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -		$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 2,185,674			$ 2,185,674	$ (830,933)	$ (78,219)		$ (909,152)	$ 1,276,521
8	1955	Communication Equipment (Smart Meters)		$ -	$ -		$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -		$ -	$ -			$ -	$ -
47	1980	System Supervisory Equipment		$ 1,245,223	$ -		$ 1,245,223	$ (939,214)	$ (59,190)		$ (998,404)	$ 246,820
47	1985	Miscellaneous Fixed Assets		$ 39,634	$ 2,482		$ 42,117	$ (38,144)	$ (621)		$ (38,765)	$ 3,352
47	1995	Contributions & Grants		$ (7,772,884)	$ (1,823,272)		$ (9,596,155)	$ 1,011,854	$ 383,846		$ 1,395,700	$ (8,200,455)
	2055	Work in Process		$ 127,923	$ 17,498	$ (71,749)	$ 73,672	$ -			$ -	$ 73,672
		Total		**$ 145,469,719**	**$ 4,849,750**	**$ (363,255)**	**$ 149,956,214**	**$ (84,848,978)**	**$ (4,690,018)**	**$ 291,506**	**$ (89,247,490)**	**$ 60,708,724**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (219,733)
Stores Equipment	$ (67,004)
Net Depreciation	$ (4,403,280)

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

File Number:	EB-2012-0126
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	9 November, 2012

Appendix 2-B
Fixed Asset Continuity Schedule-CGAAP

Year **2008**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 1,896,350	$ 30,076	$ (395,541)	$ 1,530,884	$ (1,879,425)	$ (17,355)	$ 395,541	$ (1,501,240)	$ 29,644
CEC	1612	Land Rights (Formally known as Account 1906)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1805	Land		$ 890,772	$ -		$ 890,772	$ -	$ -		$ -	$ 890,772
47	1808	Buildings		$ 9,230,593	$ -		$ 9,230,593	$ (3,574,930)	$ (175,969)		$ (3,750,899)	$ 5,479,694
13	1808	Buildings Improvements		$ -	$ 166,005		$ 166,005	$ -	$ (11,067)		$ (11,067)	$ 154,938
47	1815	Transformer Station Equipment >50 kV		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 15,103,411	$ 545,457		$ 15,648,868	$ (9,060,344)	$ (418,955)		$ (9,479,298)	$ 6,169,569
47	1825	Storage Battery Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 12,322,597	$ 984,389		$ 13,306,986	$ (5,468,019)	$ (886,086)		$ (6,354,105)	$ 6,952,881
47	1835	Overhead Conductors & Devices		$ 36,708,031	$ 1,542,681		$ 38,250,712	$ (23,102,230)	$ (832,004)		$ (23,934,234)	$ 14,316,478
47	1840	Underground Conduit		$ 17,206,830	$ 538,885		$ 17,745,715	$ (8,814,748)	$ (639,750)		$ (9,454,498)	$ 8,291,216
47	1845	Underground Conductors & Devices		$ 16,870,664	$ 1,130,091		$ 18,000,755	$ (8,055,700)	$ (665,724)		$ (8,721,423)	$ 9,279,331
47	1850	Line Transformers		$ 23,234,804	$ 612,939		$ 23,847,743	$ (13,866,321)	$ (759,010)		$ (14,625,331)	$ 9,222,411
47	1855	Services (Overhead & Underground)		$ 8,668,784	$ 419,446		$ 9,088,230	$ (5,116,276)	$ (171,672)		$ (5,287,948)	$ 3,800,282
47	1860	Meters		$ 8,652,812	$ 88,699		$ 8,741,511	$ (5,567,893)	$ (261,718)		$ (5,829,611)	$ 2,911,900
47	1860	Meters (Smart Meters)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -		$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 44,315	$ -		$ 44,315	$ (37,021)	$ (939)		$ (37,960)	$ 6,355
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware		$ 93,649	$ -	$ (93,649)	$ -	$ (93,649)	$ -	$ 93,649	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment		$ 3,710,288	$ 859,350	$ (513,356)	$ 4,056,282	$ (3,009,986)	$ (333,319)	$ 513,356	$ (2,829,949)	$ 1,226,332
8	1935	Stores Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 1,371,785	$ 180,931		$ 1,552,717	$ (1,050,327)	$ (84,234)		$ (1,134,561)	$ 418,156
8	1945	Measurement & Testing Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ 2,185,674	$ 7,335		$ 2,193,009	$ (909,152)	$ (78,953)		$ (988,105)	$ 1,204,904
8	1955	Communication Equipment (Smart Meters)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisory Equipment		$ 1,245,223	$ -		$ 1,245,223	$ (998,404)	$ (50,626)		$ (1,049,030)	$ 196,194
47	1985	Miscellaneous Fixed Assets		$ 42,117	$ -		$ 42,117	$ (38,765)	$ (3,352)		$ (42,117)	$ -
47	1995	Contributions & Grants		$ (9,596,155)	$ (1,867,297)		$ (11,463,452)	$ 1,395,700	$ 458,538		$ 1,854,238	$ (9,609,214)
	2055	Work in Process		$ 73,672	$ 822,832	$ (56,174)	$ 840,330	$ -			$ -	$ 840,330
		Total		**$ 149,956,214**	**$ 6,061,819**	**$ (1,058,720)**	**$ 154,959,313**	**$ (89,247,490)**	**$ (4,932,194)**	**$ 1,002,546**	**$ (93,177,139)**	**$ 61,782,175**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (333,319)
Stores Equipment	$ (84,234)
Net Depreciation	$ (4,514,642)

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

Appendix 2-B
Fixed Asset Continuity Schedule-CGAAP

Year 2009

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 1,530,884	$ 323,775	$ (1,091)	$ 1,853,569	$ (1,501,240)	$ (43,757)	$ 109	$ (1,544,888)	$ 308,681
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 890,772	$ 186		$ 890,958	$ -			$ -	$ 890,958
47	1808	Buildings		$ 9,230,593	$ -		$ 9,230,593	$ (3,750,899)	$ (175,805)		$ (3,926,704)	$ 5,303,889
13	1808	Buildings Improvements		$ 166,005	$ 240,169		$ 406,174	$ (11,067)	$ (19,073)		$ (30,140)	$ 376,034
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 15,648,868	$ 437,621		$ 16,086,489	$ (9,479,298)	$ (426,248)		$ (9,905,546)	$ 6,180,942
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 13,306,986	$ 2,004,153		$ 15,311,139	$ (6,354,105)	$ (919,046)		$ (7,273,151)	$ 8,037,988
47	1835	Overhead Conductors & Devices		$ 38,250,712	$ 1,395,458		$ 39,646,169	$ (23,934,234)	$ (838,387)		$ (24,772,621)	$ 14,873,548
47	1840	Underground Conduit		$ 17,745,715	$ 733,234		$ 18,478,948	$ (9,454,498)	$ (654,415)		$ (10,108,914)	$ 8,370,035
47	1845	Underground Conductors & Devices		$ 18,000,755	$ 968,525		$ 18,969,279	$ (8,721,423)	$ (685,094)		$ (9,406,517)	$ 9,562,762
47	1850	Line Transformers		$ 23,847,743	$ 1,103,842		$ 24,951,584	$ (14,625,331)	$ (776,793)		$ (15,402,125)	$ 9,549,460
47	1855	Services (Overhead & Underground)		$ 9,088,230	$ 353,315		$ 9,441,545	$ (5,287,948)	$ (176,063)		$ (5,464,011)	$ 3,977,534
47	1860	Meters		$ 8,741,511	$ 38,348		$ 8,779,859	$ (5,829,611)	$ (262,260)		$ (6,091,872)	$ 2,687,987
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 44,315			$ 44,315	$ (37,960)	$ (939)		$ (38,898)	$ 5,417
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 4,056,282	$ 495,784	$ (51,564)	$ 4,500,502	$ (2,829,949)	$ (352,036)	$ 51,564	$ (3,130,422)	$ 1,370,080
8	1935	Stores Equipment		$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 1,552,717	$ 114,715		$ 1,667,431	$ (1,134,561)	$ (82,322)		$ (1,216,883)	$ 450,548
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 2,193,009	$ 19,821		$ 2,212,830	$ (988,105)	$ (79,944)		$ (1,068,049)	$ 1,144,781
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisory Equipment		$ 1,245,223	$ 297,472		$ 1,542,695	$ (1,049,030)	$ (53,750)		$ (1,102,779)	$ 439,916
47	1985	Miscellaneous Fixed Assets		$ 42,117			$ 42,117	$ (42,117)			$ (42,117)	$ -
47	1995	Contributions & Grants		$ (11,463,452)	$ (788,212)		$ (12,251,664)	$ 1,854,238	$ 474,302		$ 2,328,540	$ (9,923,124)
	2055	Work in Process		$ 840,330	$ 8,221	$ (840,330)	$ 8,221	$ -			$ -	$ 8,221
		Total		**$ 154,959,313**	**$ 7,746,424**	**$ (892,984)**	**$ 161,812,753**	**$ (93,177,139)**	**$ (5,071,632)**	**$ 51,673**	**$ (98,197,098)**	**$ 63,615,655**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (358,357)
Stores Equipment	$ (78,664)
Net Depreciation	$ (4,634,610)

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

File Number:	EB-2012-0126
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	9 November, 2012

Appendix 2-B
Fixed Asset Continuity Schedule-CGAAP

Year **2010**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 1,853,569	$ 651,781		$ 2,505,350	$ (1,544,888)	$ (135,730)		$ (1,680,618)	$ 824,732
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 890,958	$ 32,745	$ (66,404)	$ 857,298	$ -			$ -	$ 857,298
47	1808	Buildings		$ 9,230,593			$ 9,230,593	$ (3,926,704)	$ (170,577)		$ (4,097,281)	$ 5,133,312
13	1808	Buildings Improvements		$ 406,174	$ 161,355		$ 567,528	$ (30,140)	$ (32,457)		$ (62,596)	$ 504,932
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 16,086,489	$ 213,182		$ 16,299,670	$ (9,905,546)	$ (442,557)		$ (10,348,104)	$ 5,951,567
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 15,311,139	$ 1,072,044		$ 16,383,183	$ (7,273,151)	$ (562,387)		$ (7,835,539)	$ 8,547,644
47	1835	Overhead Conductors & Devices		$ 39,646,169	$ 1,220,522		$ 40,866,691	$ (24,772,621)	$ (1,155,368)		$ (25,927,990)	$ 14,938,702
47	1840	Underground Conduit		$ 18,478,948	$ 616,102		$ 19,095,050	$ (10,108,914)	$ (689,251)		$ (10,798,164)	$ 8,296,885
47	1845	Underground Conductors & Devices		$ 18,969,279	$ 1,019,872		$ 19,989,151	$ (9,406,517)	$ (722,402)		$ (10,128,919)	$ 9,860,232
47	1850	Line Transformers		$ 24,951,584	$ 1,957,831		$ 26,909,416	$ (15,402,125)	$ (840,187)		$ (16,242,312)	$ 10,667,104
47	1855	Services (Overhead & Underground)		$ 9,441,545	$ 535,694		$ 9,977,240	$ (5,464,011)	$ (319,341)		$ (5,783,352)	$ 4,193,888
47	1860	Meters		$ 8,779,859	$ 30,167		$ 8,810,025	$ (6,091,872)	$ (263,283)		$ (6,355,155)	$ 2,454,871
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 44,315			$ 44,315	$ (38,898)	$ (939)		$ (39,837)	$ 4,478
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 4,500,502	$ 540,987		$ 5,041,489	$ (3,130,422)	$ (423,415)		$ (3,553,837)	$ 1,487,652
8	1935	Stores Equipment		$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 1,667,431	$ 74,325		$ 1,741,756	$ (1,216,883)	$ (78,564)		$ (1,295,447)	$ 446,309
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 2,212,830			$ 2,212,830	$ (1,068,049)	$ (80,935)		$ (1,148,984)	$ 1,063,846
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisory Equipment		$ 1,542,695	$ 12,748		$ 1,555,443	$ (1,102,779)	$ (59,726)		$ (1,162,505)	$ 392,938
47	1985	Miscellaneous Fixed Assets		$ 42,117			$ 42,117	$ (42,117)			$ (42,117)	$ -
47	1995	Contributions & Grants		$ (12,251,664)	$ (1,261,434)		$ (13,513,098)	$ 2,328,540	$ 515,295		$ 2,843,836	$ (10,669,263)
	1330	WIP - Capital Inventory		$ -	$ 1,022,658		$ 1,022,658	$ -			$ -	$ 1,022,658
	2055	Work in Process		$ 8,221	$ 228,308	$ (8,221)	$ 228,308	$ -			$ -	$ 228,308
				$ -			$ -	$ -			$ -	$ -
Total prior to Board ordered removal of CIS related to water billing				**$ 161,812,753**	**$ 8,128,885**	**$ (74,625)**	**$ 169,867,012**	**$ (98,197,098)**	**$ (5,461,822)**	**$ -**	**$ (103,658,920)**	**$ 66,208,092**
12	1611	Computer Software		$ -	$ (126,796)		$ (126,796)	$ -	$ 12,680		$ 12,680	$ (114,117)
Total subsequent to Board ordered removal of CIS related to water billing				**$ 161,812,753**	**$ 8,002,089**	**$ (74,625)**	**$ 169,740,216**	**$ (98,197,098)**	**$ (5,449,143)**	**$ -**	**$ (103,646,240)**	**$ 66,093,976**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (423,415)
Stores Equipment	$ (78,564)
Net Depreciation	$ (4,959,843)

File Number:	EB-2012-0126
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	9 November, 2012

Appendix 2-B
Fixed Asset Continuity Schedule-CGAAP

Year **2011**

				Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 2,505,350	$ 138,685		$ 2,644,035	$ (1,680,618)	$ (214,777)		$ (1,895,395)	$ 748,640
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 857,298			$ 857,298	$ -			$ -	$ 857,298
47	1808	Buildings		$ 9,230,593			$ 9,230,593	$ (4,097,281)	$ (183,886)		$ (4,281,167)	$ 4,949,426
13	1808	Buildings Improvements		$ 567,528	$ 159,351		$ 726,880	$ (62,596)	$ (43,147)		$ (105,743)	$ 621,136
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 16,299,670	$ 161,491		$ 16,461,161	$ (10,348,104)	$ (436,763)		$ (10,784,866)	$ 5,676,295
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 16,383,183	$ 1,607,668		$ 17,990,851	$ (7,835,539)	$ (607,615)		$ (8,443,154)	$ 9,547,697
47	1835	Overhead Conductors & Devices		$ 40,866,691	$ 836,177		$ 41,702,868	$ (25,927,990)	$ (1,173,923)		$ (27,101,912)	$ 14,600,956
47	1840	Underground Conduit		$ 19,095,050	$ 862,068		$ 19,957,117.49	$ (10,798,164)	$ (707,708)		$ (11,505,873)	$ 8,451,245
47	1845	Underground Conductors & Devices		$ 19,989,151	$ 676,951		$ 20,666,102.61	$ (10,128,919)	$ (746,853)		$ (10,875,772)	$ 9,790,331
47	1850	Line Transformers		$ 26,909,416	$ 1,019,440		$ 27,928,855	$ (16,242,312)	$ (863,401)		$ (17,105,712)	$ 10,823,143
47	1855	Services (Overhead & Underground)		$ 9,977,240	$ 993,811		$ 10,971,051	$ (5,783,352)	$ (343,958)		$ (6,127,309)	$ 4,843,742
47	1860	Meters		$ 8,810,025	$ 18,980		$ 8,829,005	$ (6,355,155)	$ (237,975)		$ (6,593,129)	$ 2,235,876
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 44,315			$ 44,315	$ (39,837)	$ (939)		$ (40,775)	$ 3,540
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ 153,987		$ 153,987	$ -	$ (15,399)		$ (15,399)	$ 138,588
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 5,041,489	$ 562,950	$ (441,361)	$ 5,163,079	$ (3,553,837)	$ (419,479)	$ 441,361	$ (3,531,956)	$ 1,631,123
8	1935	Stores Equipment		$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 1,741,756	$ 77,854		$ 1,819,609	$ (1,295,447)	$ (82,930)		$ (1,378,378)	$ 441,232
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 2,212,830	$ 7,757		$ 2,220,587	$ (1,148,984)	$ (78,788)		$ (1,227,772)	$ 992,815
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisory Equipment		$ 1,555,443	$ 17,265		$ 1,572,708	$ (1,162,505)	$ (56,753)		$ (1,219,258)	$ 353,450
47	1985	Miscellaneous Fixed Assets		$ 42,117			$ 42,117	$ (42,117)			$ (42,117)	$ -
47	1995	Contributions & Grants		$ (13,513,098)	$ (1,065,203)		$ (14,578,301)	$ 2,843,836	$ 561,828		$ 3,405,664	$ (11,172,637)
	1330	WIP - Capital Inventory		$ 1,022,658	$ 105,162		$ 1,127,820	$ -			$ -	$ 1,127,820
	2055	Work in Process		$ 228,308	$ 430,859	$ (228,308)	$ 430,858	$ -			$ -	$ 430,858
				$ -				$ -				
Total prior to Board ordered removal of CIS related to water billing				**$ 169,867,012**	**$ 6,765,253**	**$ (669,669)**	**$ 175,962,596**	**$ (103,658,920)**	**$ (5,652,465)**	**$ 441,361**	**$ (108,870,024)**	**$ 67,092,572**
12	1611	Computer Software		$ (126,796)	$ (2,942)		$ (129,739)	$ 12,680	$ 25,654		$ 38,333	$ (91,406)
Total subsequent to Board ordered removal of CIS related to water billing				**$ 169,740,216**	**$ 6,762,310**	**$ (669,669)**	**$ 175,832,857**	**$ (103,646,240)**	**$ (5,626,811)**	**$ 441,361**	**$ (108,831,691)**	**$ 67,001,167**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (419,479)
Stores Equipment	$ (82,930)
Net Depreciation	$ (5,124,402)

File Number:	EB-2012-0126
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	9 November, 2012

Appendix 2-B
Fixed Asset Continuity Schedule-CGAAP

Year **2012**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 2,644,035	$ 248,175		$ 2,892,210	$ (1,895,395)	$ (253,463)		$ (2,148,858)	$ 743,353
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 857,298	$ 5,569		$ 862,867	$ -			$ -	$ 862,867
47	1808	Buildings		$ 9,230,593			$ 9,230,593	$ (4,281,167)	$ (183,562)		$ (4,464,729)	$ 4,765,863
47	1808	Buildings Improvements		$ 726,880	$ 310,379		$ 1,037,258	$ (105,743)	$ (58,805)		$ (164,548)	$ 872,711
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 16,461,161	$ 1,379,969		$ 17,841,131	$ (10,784,866)	$ (446,812)		$ (11,231,678)	$ 6,609,452
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 17,990,851	$ 1,272,073		$ 19,262,924	$ (8,443,154)	$ (622,917)		$ (9,066,071)	$ 10,196,853
47	1835	Overhead Conductors & Devices		$ 41,702,868	$ 1,001,641		$ 42,704,509	$ (27,101,912)	$ (1,225,300)		$ (28,327,212)	$ 14,377,297
47	1840	Underground Conduit		$ 19,957,117	$ 1,001,465		$ 20,958,582	$ (11,505,873)	$ (672,534)		$ (12,178,407)	$ 8,780,176
47	1845	Underground Conductors & Devices		$ 20,666,103	$ 778,816		$ 21,444,919	$ (10,875,772)	$ (790,090)		$ (11,665,862)	$ 9,779,057
47	1850	Line Transformers		$ 27,928,855	$ 1,587,403		$ 29,516,258	$ (17,105,712)	$ (853,584)		$ (17,959,297)	$ 11,556,962
47	1855	Services (Overhead & Underground)		$ 10,971,051	$ 1,040,787		$ 12,011,838	$ (6,127,309)	$ (366,531)		$ (6,493,840)	$ 5,517,998
47	1860	Meters		$ 8,829,005	$ 107,254		$ 8,936,259	$ (6,593,129)	$ (224,693)		$ (6,817,822)	$ 2,118,437
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 44,315			$ 44,315	$ (40,775)	$ (939)		$ (41,714)	$ 2,601
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 153,987	$ 371,510		$ 525,497	$ (15,399)	$ (67,948)		$ (83,347)	$ 442,150
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 5,163,079	$ 193,456	$ (91,191)	$ 5,265,344	$ (3,531,956)	$ (430,191)	$ 87,824	$ (3,874,323)	$ 1,391,020
8	1935	Stores Equipment		$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 1,819,609	$ 152,809		$ 1,972,419	$ (1,378,378)	$ (89,459)		$ (1,467,837)	$ 504,582
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 2,220,587	$ 66,925		$ 2,287,512	$ (1,227,772)	$ (81,294)		$ (1,309,066)	$ 978,447
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisory Equipment		$ 1,572,708			$ 1,572,708	$ (1,219,258)	$ (55,344)		$ (1,274,602)	$ 298,106
47	1985	Miscellaneous Fixed Assets		$ 42,117			$ 42,117	$ (42,117)			$ (42,117)	$ -
47	1995	Contributions & Grants		$ (14,578,301)	$ (1,074,344)		$ (15,652,645)	$ 3,405,664	$ 604,619		$ 4,010,282	$ (11,642,363)
	1330	WIP - Capital Inventory		$ 1,127,820			$ 1,127,820	$ -			$ -	$ 1,127,820
	2055	Work in Process		$ 430,858	$ 1,669,878		$ 2,100,736	$ -			$ -	$ 2,100,736
				$ -				$ -				
Total prior to Board ordered removal of CIS related to water billing				**$ 175,962,596**	**$ 10,113,766**	**$ (91,191)**	**$ 185,985,171**	**$ (108,870,024)**	**$ (5,818,847)**	**$ 87,824**	**$ (114,601,047)**	**$ 71,384,124**
12	1611	Computer Software		$ (129,739)			$ (129,739)	$ 38,333	$ 25,948		$ 64,281	$ (65,458)
Total subsequent to Board ordered removal of CIS related to water billing				**$ 175,832,857**	**$ 10,113,766**	**$ (91,191)**	**$ 185,855,432**	**$ (108,831,691)**	**$ (5,792,899)**	**$ 87,824**	**$ (114,536,766)**	**$ 71,318,667**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (430,191)
Stores Equipment	$ (89,459)
Net Depreciation	$ (5,273,248)

File Number:	EB-2012-0126
Exhibit:	2
Tab:	3
Schedule:	2
Attachment:	2
Date:	9 November, 2012

Appendix 2-B
Fixed Asset Continuity Schedule-CGAAP

Year 2013

			Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Smart Meter & Stranded Meters**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Smart Meter & Stranded Meters**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 2,892,210	$ 375,000	$ 275,347		$ 3,542,557	$ (2,148,858)	$ (364,835)	$ (81,979)		$ (2,595,671)	$ 946,886
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 862,867				$ 862,867	$ -				$ -	$ 862,867
47	1808	Buildings	$ 9,230,593				$ 9,230,593	$ (4,464,729)	$ (235,990)			$ (4,700,719)	$ 4,529,873
47	1808	Buildings Improvements	$ 1,037,258	$ 966,000			$ 2,003,258	$ (164,548)	$ (94,010)			$ (258,558)	$ 1,744,701
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 17,841,131	$ 2,449,100			$ 20,290,231	$ (11,231,678)	$ (519,388)			$ (11,751,067)	$ 8,539,164
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 19,262,924	$ 1,456,391			$ 20,719,315	$ (9,066,071)	$ (375,935)			$ (9,442,006)	$ 11,277,309
47	1835	Overhead Conductors & Devices	$ 42,704,509	$ 1,336,040			$ 44,040,549	$ (28,327,212)	$ (489,368)			$ (28,816,580)	$ 15,223,969
47	1840	Underground Conduit	$ 20,958,582	$ 482,676			$ 21,441,258	$ (12,178,407)	$ (248,291)			$ (12,426,697)	$ 9,014,561
47	1845	Underground Conductors & Devices	$ 21,444,919	$ 511,039			$ 21,955,958	$ (11,665,862)	$ (430,508)			$ (12,096,369)	$ 9,859,588
47	1850	Line Transformers	$ 29,516,258	$ 1,272,686			$ 30,788,944	$ (17,959,297)	$ (487,429)			$ (18,446,725)	$ 12,342,219
47	1855	Services (Overhead & Underground)	$ 12,011,838	$ 909,728			$ 12,921,566	$ (6,493,840)	$ (210,673)			$ (6,704,513)	$ 6,217,053
47	1860	Meters	$ 8,936,259		$ (7,076,701)		$ 1,859,558	$ (6,817,822)	$ (44,090)	$ 5,868,347		$ (993,565)	$ 865,993
47	1860	Meters (Smart Meters)	$ -	$ 100,000	$ 6,523,624		$ 6,623,624	$ -	$ (438,242)	$ (1,047,818)		$ (1,486,060)	$ 5,137,565
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 44,315				$ 44,315	$ (41,714)	$ (939)			$ (42,652)	$ 1,662
8	1915	Office Furniture & Equipment (5 years)	$ -				$ -	$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 525,497	$ -	$ 204,815		$ 730,312	$ (83,347)	$ (146,062)	$ (101,801)		$ (331,211)	$ 399,102
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 5,265,344	$ 1,118,450		$ (458,502)	$ 5,925,292	$ (3,874,323)	$ (215,465)		$ 458,502	$ (3,631,286)	$ 2,294,005
8	1935	Stores Equipment	$ -				$ -	$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,972,419	$ 160,000			$ 2,132,419	$ (1,467,837)	$ (92,165)			$ (1,560,002)	$ 572,417
8	1945	Measurement & Testing Equipment	$ -				$ -	$ -				$ -	$ -
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 2,287,512	$ 50,000			$ 2,337,512	$ (1,309,066)	$ (87,140)			$ (1,396,205)	$ 941,307
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -		$ 16,502		$ 16,502	$ -	$ (1,650)	$ (4,125)		$ (5,775)	$ 10,727
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisory Equipment	$ 1,572,708	$ 379,491			$ 1,952,199	$ (1,274,602)	$ (30,686)			$ (1,305,289)	$ 646,911
47	1985	Miscellaneous Fixed Assets	$ 42,117				$ 42,117	$ (42,117)	$ -			$ (42,117)	$ -
47	1995	Contributions & Grants	$ (15,652,645)	$ (703,790)			$ (16,356,435)	$ 4,010,282	$ 302,422			$ 4,312,705	$ (12,043,731)
	1330	WIP - Capital Inventory	$ 1,127,820				$ 1,127,820	$ -				$ -	$ 1,127,820
	2055	Work in Process	$ 2,100,736	$ 101,536		$ (1,735,494)	$ 466,778	$ -				$ -	$ 466,778
			$ -					$ -					
Total prior to Board ordered removal of CIS related to water billing			**$ 185,985,171**	**$ 10,964,348**	**$ (56,413)**	**$ (2,193,996)**	**$ 194,699,109**	**$ (114,601,047)**	**$ (4,210,442)**	**$ 4,632,624**	**$ 458,502**	**$ (113,720,362)**	**$ 80,978,747**
12	1611	Computer Software	$ (129,739)				$ (129,739)	$ 64,281	$ 25,948			$ 90,229	$ (39,510)
Total subsequent to Board ordered removal of CIS related to water billing			**$ 185,855,432**	**$ 10,964,348**	**$ (56,413)**	**$ (2,193,996)**	**$ 194,569,371**	**$ (114,536,766)**	**$ (4,184,494)**	**$ 4,632,624**	**$ 458,502**	**$ (113,630,134)**	**$ 80,939,237**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (215,465)
Stores Equipment	$ (92,165)
Net Depreciation	$ (3,876,864)

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

Exhibit 2: Rate Base

Tab 4 (of 6): Capital Plan

PROJECT/PROGRAM CLASSIFICATIONS

Included at Exhibit 2, Tab 4, Schedule 2 is a description of each of the Capital Projects Greater Sudbury has completed over the past 5 historic years and the planned investments in the Bridge and Test years. Greater Sudbury has categorized the projects into three distinct aspects; "statutory capital investments", " plant renewal" and "new connections".

Statutory capital investments are investments made as a result of some legislative or other legal obligation. The Public Service Works on Highways Act requires LDC's to relocate plant located on a highway within a 90 day period once notified by the road authority of the need to do so. This act results in the expenditure of hundreds of thousands of capital dollars each and every fiscal year to rebuild electrical plant that, in the majority, has not reached the end of its useful life and would not be considered as a justifiable expenditure except for the statutory obligation to move.

Plant renewal refers to replacement of existing infrastructure which has limited life of varying lengths, depending on the item. Maintaining that infrastructure in reliable operating condition requires ongoing investment of funds.

New connections relate to the LDC's "obligation to connect" and the obligation to maintain voltage, reliability and protection standards. This includes newly constructed extensions and upgrades to the distribution system required to meet new and existing customer demands. This also includes allocations for system security improvements and similar internally driven additions.

SUMMARY OF CAPITAL EXPENDITURES

Included below is a summary of capital expenditures greater than the materiality threshold of $115,000 over the past five historical years, the Bridge Year and the Test Year. OEB Appendix 2-A is presented at Exhibit 2, Tab 4, Schedule 2, Attachment 1.

Project Name: Meter Installations						
Project Investment Category: Statutory Requirement						
Key Project Drivers: Government Regulations (Measurement Canada)						
Project Description: Prior to smart meter implementation, this account was for the re-verification of meter samples. 2010 was our mass role out, thus deferring sample testing for the next five years.						
Future Benefit: Increased reliability						
Project Start Date: Ongoing			**Project In-Service Date**: As installed			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$225,198	$312,739	$38,309	$30,067	$12,848	$105,878	$100,000

Project Name: Emergency Plant Replacement						
Project Investment Category: Plant Renewal						
Key Project Drivers: Equipment failures (cable, switches, poles)						
Project Description: The scope of this project is to capture the costs of major plant replacement that fail prematurely and or unexpectedly.						
Future Benefit: Increased reliability and safety of new distribution system						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$233,140	$266,113	$141,201	$164,765	$344,283	$378,215	$126,227

Project Name: Failed Transformers						
Project Investment Category: Plant Renewal						
Key Project Drivers: Equipment failures (Transformers)						
Project Description: The scope of this project is to capture the costs to refurbish and replace transformers that fail prematurely and or unexpectedly.						
Future Benefit: Increased reliability and safety of new transformers						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$370,336	$44,869	$182,213	$451,953	$151,333	$267,362	$130,737

Project Name: PCB						
Project Investment Category: Plant Renewal						
Key Project Drivers: Government Regulations						
Project Description: In accordance with Government regulations, electrical utilities must have all equipment containing PCB's out of service by a predetermined date, somewhere around 2020. Sudbury Hydro is working towards this mandate by undertaking predetermined areas of the City each year.						
Future Benefit: Improving the environment						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$137,343	$25,007	$37,204	$74,577	$14,811	$155,070	$47,368

Project Name: Major Substation Repairs						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated asset, reliability and safety						
Project Description: The scope of this project is to capture costs for substation failures, remedial actions and planned substation rehabilitation to address areas of major concerns such as safety and or operating issues.						
Future Benefit: Increased reliability and safety of new distribution system assets.						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$480,569	$65,498	$496,057	$418,107	$138,156	$1,367,772	$178,800

Project Name: System Betterment						
Project Investment Category: Plant Renewal						
Key Project Drivers: Customer requests, statutory requirements, public safety						
Project Description: The scope of this project is to satisfy customer requests for new services, relocate plant from locations from where we have no legal right and upgrade plant that may be a public safety issue .						
Future Benefit: Increased reliability and safety of new distribution system						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$744,153	$1,162,734	$921,029	$1,364,122	$663,862	$1,022,305	$402,654

Project Name: Overhead Services						
Project Investment Category: New Connections						
Key Project Drivers: Customer requests for new or upgraded services.						
Project Description: The scope of this project was to capture all costs associated with the connection of new and upgraded customer services.						
Future Benefit: Not applicable, customer driven						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$73,465	$94,315	$91,965	$151,654	$154,580	$166,024	$62,401

Project Name: Underground Services						
Project Investment Category: New Connections						
Key Project Drivers: Customer requests for new or upgraded services.						
Project Description: The scope of this project is to capture costs associated with the connection of new and upgraded customer services.						
Future Benefit: Not applicable, customer driven.						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$81,434	$113,611	$91,649	$158,116	$156,553	$107,167	$61,569

Project Name: City Roadworks						
Project Investment Category: Statutory Requirement						
Key Project Drivers: City Plant upgrades or relocations						
Project Description: The scope of this project is to relocate plant as required to accommodate City plant relocations and upgrades (typically roads)						
Future Benefit: Meets the statutory requirement						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$681,412	$20,637	$77,999	$140,690	$8,816	$	$339,004

Project Name: Subdivisions						
Project Investment Category: New Connections						
Key Project Drivers: Developer Requests						
Project Description: The scope of this project is to collect cost for the design and installation of distribution systems as requested by developers for subdivisions.						
Future Benefit: Not applicable, customer driven						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$40,261	$42,948	$250,926	$59,003	$27,233	$63,917	$85,470

Project Name: Commercial Development						
Project Investment Category: New Connections						
Key Project Drivers: Customer Requests for service						
Project Description: The scope of this project is to satisfy the request generated by commercial developers and their need for new services at new establishments.						
Future Benefit: Meets the statutory "obligation to serve" requirement						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$60,360	$131,614	$143,861	$129,685	$(79,755)	$46,100	(1,507)

Project Name: Building						
Project Investment Category: Plant Renewal						
Key Project Drivers: End of life						
Project Description: The scope of this project identifies each year the building needs, involving the replacement or improvement of major building systems or structural elements, prioritized and then developed as part of the annual budget.						
Future Benefit: Building reliability						
Project Start Date: Ongoing			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$96,310	$132,044	$208,453	$49,650	$159,351	$310,379	$966,000

Project Name: Porcelain Insulator Replacement						
Project Investment Category: Plant Renewal						
Key Project Drivers: Failure of porcelain insulators						
Project Description: The scope of this project was to replace all 15kv, post type, clamp top porcelain insulators with epoxy insulators. The porcelain insulators were cracking and breaking off causing public and worker safety.						
Future Benefit: Reliability and safety of the distribution system						
Project Start Date: 2007			**Project In-Service Date**: As installed			
Total Project Cost: $1,239,875						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$525,741	$274,813	$439,321				

Project Name: Pole Replacement Program						
Project Investment Category: Plant Renewal						
Key Project Drivers: Undersized Conductor, deteriorated asset						
Project Description: The scope of this project is to replace the undersized 4/0 44kv aged conductor and 50yr old poles on one section of 44kv feeder.						
Future Benefit: Increased reliability and safety of the distribution system						
Project Start Date: 2007			**Project In-Service Date**: As installed			
Total Project Cost: $962,491						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$164,917	$346,976	$450,598				$254,383

Project Name: Tools and Equipment						
Project Investment Category: Plant Renewal						
Key Project Drivers: Obsolescence , end of life, technological innovation.						
Project Description: The scope of this project is to capture costs for the purchase of tools and equipment to replace those that have either met their end of life or need upgrading due to technological change.						
Future Benefit: Enhanced productivity and safety						
Project Start Date: Ongoing			**Project In-Service Date**: As installed			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$89,424	$180,931	$114,715	$74,325	$77,854	$152,809	$160,000

Project Name: Vehicles						
Project Investment Category: Plant renewal						
Key Project Drivers: End of life, technological advancement						
Project Description: The scope of this project is based on the need to maintain vehicles and major equipment functionality and provide safe, reliable tools and equipment.						
Future Benefit: Vehicle replacement supports a safe working environment, which reduces costs from lost time accidents caused by equipment failure and maintains productivity.						
Project Start Date: Ongoing			**Project In-Service Date**: As introduced to fleet			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$255,827	$859,351	$495,784	$540,984	$562,950	$193,456	$1,118,450

Project Name: Sherwood Park (Phase I, II & III)						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated Asset, Reliability and safety						
Project Description: The scope of this project was to replace 50yr old underground distribution system including duct, cabling and transformers. This project was started in 2009 and completed in 2011.						
Future Benefit: Increased reliability and safety of the distribution system						
Project Start Date: 2007			**Project In-Service Date**: Ongoing			
Total Project Cost: $601,443						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$159,705	$727	$8,829	$141,219	$290,963		

Project Name: Albinson – Haig to Douglas						
Project Investment Category: Plant Renewal						
Key Project Drivers: Undersized conductor, Deteriorated asset.						
Project Description: The scope of this project was to replace the undersized #6 copper primary conductor and the 1950's vintage poles.						
Future Benefit: Reliability and safety of the distribution system.						
Project Start Date: 2007			**Project In-Service Date**: 2007			
Total Project Cost: $123,470						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$123,470						

Project Name: Tilton Lake						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated Asset						
Project Description: The scope of this project was to replace and relocate 50yr old poles from out of a swamp to a joint use pole line owned by Bell Canada						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2007			**Project In-Service Date**: 2007			
Total Project Cost: $318,845						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
$271,027		47,818				

Project Name: Falconbridge 44kV						
Project Investment Category: New Connections						
Key Project Drivers: To get rid of a legacy whole sale connection to the ISO grid						
Project Description: The scope of this project was to install a new utility owned 44kv feed to our Falconbridge substation. When we purchased the distribution system from the mining company the substation was fed from a deteriorated 22kv line owned by Hydro One. Hydro One was considering abandoning this line.						
Future Benefit: Reliability of the distribution system						
Project Start Date: 2008			**Project In-Service Date**: 2008			
Total Project Cost: $233,041						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
	$233,041					

Project Name: Gary Avenue Rebuild						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated Asset (50yr old poles)						
Project Description: The scope of this project was to replace and relocate 50yr old, 35'poles that were back lot and ran through a school yard.						
Future Benefit: Increased reliability and safety of new distribution system assets.						
Project Start Date: 2008			**Project In-Service Date**: 2009			
Total Project Cost: $1,172,275						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
	$724,421	$446,070	$1,784			

Project Name: Webbwood Drive Rebuild

Project Investment Category: Plant Renewal

Key Project Drivers: Deteriorated asset, 4kv to 12kv conversion

Project Description: The scope of this project was to replace deteriorated underground plant including duct, cabling and transformation. Converting from 4kv to 12kv prepares for future line rebuild of Lorne St.

Future Benefit: Reliability and safety of the distribution system

Project Start Date: 2008 | **Project In-Service Date**: 2008

Total Project Cost: $161,739

2007	2008	2009	2010	2011	2012 (Budget)	2013 (Budget)
	$161,739					

Project Name: Beatrice Underground Rebuild

Project Investment Category: Plant Renewal

Key Project Drivers: Deteriorated Asset (35 yr old cable)

Project Description: The scope of this project was to replace the 35 yr old cable, duct and transformers in this 1970's built subdivision.

Future Benefit: Reliability and safety

Project Start Date: 2009 | **Project In-Service Date**: 2009

Total Project Cost: $184,992

2007	2008	2009	2010	2011	2012 (Budget)	2013 (Budget)
		$184,992				

Project Name: GIS

Project Investment Category: Plant Renewal

Key Project Drivers: Obsolescence

Project Description: This project was created to capture cost for the purchase of a new GIS software to replace our home grown product that was technologically out of date.

Future Benefit: Improved productivity, interoperability and reliability.

Project Start Date: 2009 | **Project In-Service Date**: 2009

Total Project Cost: Ongoing, see annual costs below

2007	2008	2009	2010	2011	2012 (Budget)	2013 (Budget)
		$302,438	$45,300	$52,902	$91,500	

Project Name: Jarvi Road Rebuild						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated Asset, inaccessible , reliability and safety						
Project Description: The scope of this project was to relocate a deteriorated pole line from in a swamp, out to the road.						
Future Benefit: Increased reliability and safety of distribution system assets.						
Project Start Date: 2009			**Project In-Service Date**: 2009			
Total Project Cost: $275,614						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
		$269,658	$5,956			

Project Name: Louis Street Rebuild						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated plant, safety and reliability						
Project Description: The scope of this project was to eliminate a safety issue in a deteriorated access hole and tie this into the 4kv to 12kv conversion planned for this area.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date:			**Project In-Service Date**:			
Total Project Cost: $375,555						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
		$194,271	$179,078	$2,206		

Project Name: Montague to Whissell Rebuild						
Project Investment Category: Plant renewal						
Key Project Drivers: Undersized conductor, deteriorated asset						
Project Description: The scope of this project was to replace the undersized 4/0 conductor with 556MCM and replace 50yr old poles.						
Future Benefit: Reliability and load flexibility						
Project Start Date: 2009			**Project In-Service Date**:			
Total Project Cost: $845,920						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
		$643,826	$202,094			

Project Name: SCADA						
Project Investment Category: Plant renewal						
Key Project Drivers: Replace obsolete host hardware and software						
Project Description: The scope of this project was to upgrade both the hardware and software of the existing SCADA VAX system to Worldview for windows.						
Future Benefit: Reliability						
Project Start Date: 2009			**Project In-Service Date**: Ongoing			
Total Project Cost: Ongoing, see annual costs below						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
	$10,260	$297,472	$15,730	$19,065	$675	$346,045

Project Name: Southlane Road Rebuild						
Project Investment Category: Plant renewal						
Key Project Drivers: Bell Aliant request for pole upgrade						
Project Description: The scope of this project was to increase the height and class of poles to accommodate new Bell plant						
Future Benefit: Increased reliability and safety of distribution system						
Project Start Date: 2009			**Project In-Service Date**: 2009			
Total Project Cost: $291,334						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
		$287,849	$3,485			

Project Name: Sparks Street Rebuild						
Project Investment Category: Plant renewal						
Key Project Drivers: Restricted primary conductor						
Project Description: The scope of this project was to increase the size of the primary conductor from #6 to 336MCM and to replace the 40+yr old poles						
Future Benefit: Reliability, safety and load flexibility.						
Project Start Date: 2009			**Project In-Service Date**: 2009			
Total Project Cost: $420,330						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
		$415,025	$5,305			

Project Name: Falconbridge Voltage Conversion						
Project Investment Category: Plant Renewal						
Key Project Drivers:						
Project Description: The scope of this project was to convert the existing delta primary to wye. We purchased this distribution system from the local mining company and as part of the purchase agreement we were to convert the system.						
Future Benefit: Reliability and safety						
Project Start Date: 2009			**Project In-Service Date**: 2010			
Total Project Cost: $256,114						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
		$48,923	$207,191			

Project Name: Annie Street 4kV to 12kV Conversion						
Project Investment Category: Plant Renewal						
Key Project Drivers: Obsolescence, Deteriorated Asset, reduced losses						
Project Description: The scope of this project was to convert the 4kv system supplied by our Annie substation to 12kv						
Future Benefit: Increased reliability and safety of the distribution system						
Project Start Date: 2010			**Project In-Service Date**: 2010			
Total Project Cost: $1,286,298						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
		$2,395	$1,093,081	$190,822		

Project Name: CIS – Harris Billing System						
Project Investment Category: Plant Renewal						
Key Project Drivers: Obsolete customer information system						
Project Description: The scope of this project was to capture the costs for the purchase of a new customer information system. Our existing system was no longer being supported. Actual capital costs were $603,498, however per the Board's order, 21.04% of the cost has been removed from GSHi asset's for the portion deemed to be relating to water billing.						
Future Benefit:						
Project Start Date: 2010			**Project In-Service Date**: 2010			
Total Project Cost: $487,744						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
			$476,702	$11,042		

Project Name: Kingsway Rebuild						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated Asset						
Project Description: The scope of this project was to replace the deteriorated concrete distribution poles with wood poles. The poles deteriorated prematurely due the high volume of salt on the Kingsway.						
Future Benefit: Increased reliability and safety of new distribution system assets.						
Project Start Date:			**Project In-Service Date**:			
Total Project Cost: $145,129						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
			$145,129			

Project Name: Shaughnessy Rebuild						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated plant, 4kv to 12kv conversion						
Project Description: The scope of this project was to replace deteriorated underground plant including duct, cabling and transformation. Converting from 4kv to 12kv help tie in with the Annie project proceeding at the same time.						
Future Benefit: Increased reliability and safety of distribution system						
Project Start Date:			**Project In-Service Date**:			
Total Project Cost: $248,278						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
	$1,407	$4,217	$237,772	$4,882		

Project Name: Kennedy Street Rebuild						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated plant, insufficient service height, safety and reliability						
Project Description: The scope of this project was to replace 40' 1960's vintage poles with 50' poles to meet CSA clearance requirements for services crossing the roadway.						
Future Benefit: Increased reliability and safety of our distribution system						
Project Start Date: 2011			**Project In-Service Date**: 2011			
Total Project Cost: $161,259						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
				$153,987	$7,272	

Project Name: Automated Vehicle Locator						
Project Investment Category: Plant Renewal						
Key Project Drivers: Safety						
Project Description: The scope of this project is to install a GPS system in our vehicle radios so the control room can verify the locations of both our fleet and contractor vehicles.						
Future Benefit: Safety						
Project Start Date: 2011			**Project In-Service Date**: 2011			
Total Project Cost: $159,621						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
				$150,471	$9,150	

Project Name: Beech Street Rebuild						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated plant, overhead to underground conversion						
Project Description: The scope of this project was to replace deteriorated overhead plant with new underground.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2011			**Project In-Service Date**: 2011			
Total Project Cost: $131,180						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
				$131,180		

Project Name: Highway 69 South Rebuild						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated Asset (50yr old poles)						
Project Description: The scope of this project was to replace and relocate 50yr old poles that run along Hwy 69S off road in inaccessible areas to a joint pole line built by Bell Canada						
Future Benefit: Increased reliability and safety of the distribution system						
Project Start Date: 2011			**Project In-Service Date**: 2011			
Total Project Cost: $551,546						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
				$551,546		

<table>
<tr><td colspan="7">Project Name: Kingsway Area</td></tr>
<tr><td colspan="7">Project Investment Category: Plant Renewal</td></tr>
<tr><td colspan="7">Key Project Drivers: Undersized Conductor, Deteriorated Asset</td></tr>
<tr><td colspan="7">Project Description: The scope of this project was to replace the undersized #6 copper primary conductor and 1960's vintage poles</td></tr>
<tr><td colspan="7">Future Benefit: Reliability and safety of the distribution system</td></tr>
<tr><td colspan="3">Project Start Date: 2011</td><td colspan="4">Project In-Service Date: 2011</td></tr>
<tr><td colspan="7">Total Project Cost: $673,796</td></tr>
<tr><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012 (Budget)</th><th>2013 (Budget)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>$673,796</td><td></td><td></td></tr>
</table>

<table>
<tr><td colspan="7">Project Name: Lorne Street Rebuild</td></tr>
<tr><td colspan="7">Project Investment Category: Plant Renewal</td></tr>
<tr><td colspan="7">Key Project Drivers: Deteriorated Asset, inaccessible , reliability and safety</td></tr>
<tr><td colspan="7">Project Description: The scope of this project is to relocate a deteriorated pole line from rear lot along the tracks out to the road. This rebuild also tied into the future relocation of our Centennial Substation</td></tr>
<tr><td colspan="7">Future Benefit: Increased reliability and safety of distribution system assets.</td></tr>
<tr><td colspan="3">Project Start Date: 2011</td><td colspan="4">Project In-Service Date: 2011, 2012</td></tr>
<tr><td colspan="7">Total Project Cost: $700,096</td></tr>
<tr><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012 (Budget)</th><th>2013 (Budget)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>$323,690</td><td>$376,406</td><td></td></tr>
</table>

<table>
<tr><td colspan="7">Project Name: Madison Avenue Rebuild</td></tr>
<tr><td colspan="7">Project Investment Category: Plant renewal</td></tr>
<tr><td colspan="7">Key Project Drivers: Deteriorated plant, undersized conductor, safety and reliability</td></tr>
<tr><td colspan="7">Project Description: The scope of this project was to replace the undersized #6 primary conductor and 1960's vintage poles.</td></tr>
<tr><td colspan="7">Future Benefit: Increased reliability and safety of the distribution system.</td></tr>
<tr><td colspan="3">Project Start Date: 2011</td><td colspan="4">Project In-Service Date: 2011</td></tr>
<tr><td colspan="7">Total Project Cost: $310,211</td></tr>
<tr><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012 (Budget)</th><th>2013 (Budget)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>$310,211</td><td></td><td></td></tr>
</table>

Project Name: Regent Street Rebuild						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated Asset						
Project Description: The scope of this project was to replace the deteriorated 1950's vintage pole line.						
Future Benefit: Increased reliability and safety of the distribution system						
Project Start Date: 2011			**Project In-Service Date**: 2011			
Total Project Cost: $402,534						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
				$268,955	$133,579	

Project Name: Herbert/Garland						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated asset (35yr old cable).						
Project Description: The scope of this project was to replace 35yr old cable, duct and transformers in this 1970's built subdivision.						
Future Benefit: Increased reliability and safety of the distribution assets.						
Project Start Date: 2012			**Project In-Service Date**: 2012b			
Total Project Cost: $365,797						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
					$365,797	

Project Name: Copper Cliff Gardens						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated Asset						
Project Description: The scope of this project was to replace the 35yr old cable, duct and transformation in this 1970;s built townhouse complex						
Future Benefit: Increased reliability and safety of the distribution system						
Project Start Date: 2012			**Project In-Service Date**: 2012			
Total Project Cost: $557,547						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
					$557,547	

Project Name: Westmount Restricted Conductor						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated plant, undersized conductor, safety and reliability						
Project Description: The scope of this project was to replace the undersized #6 primary conductor and 1960's vintage poles.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2012			**Project In-Service Date**: 2012			
Total Project Cost: $639,619						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
					$639,619	

Project Name: Donwood Park – Underground Rebuild						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated Asset (35yr old cable)						
Project Description: The scope of this project was to replace the 35yr old cable, duct and transformers in this 1970's built subdivision.						
Future Benefit: Increased reliability and safety of new distribution system assets.						
Project Start Date: 2011			**Project In-Service Date**: 2011			
Total Project Cost: $814,674						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
				$428,787	$385,887	

Project Name: Substation Security						
Project Investment Category: Plant Renewal						
Key Project Drivers: Safety and Security						
Project Description: The scope of this project is to update existing or install new security systems at our substations						
Future Benefit: Safety and security						
Project Start Date: ongoing			**Project In-Service Date**: ongoing			
Total Project Cost:						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
	$7,335	$19,821		$7,757	$66,925	$50,000

<table>
<tr><td colspan="7">Project Name: Control Room Mapping</td></tr>
<tr><td colspan="7">Project Investment Category: Plant Renewal</td></tr>
<tr><td colspan="7">Key Project Drivers: Conversion of key process from paper to electronic; information sharing</td></tr>
<tr><td colspan="7">Project Description: Installation of high-resolution screen and new office equipment to facilitate the transition of Control Room activities from paper to electronic processes.</td></tr>
<tr><td colspan="7">Future Benefit: Increased operational awareness for key personnel/decision-makers.</td></tr>
<tr><td colspan="3">Project Start Date: 2012</td><td colspan="4">Project In-Service Date: 2012</td></tr>
<tr><td colspan="7">Total Project Cost: $364,238</td></tr>
<tr><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012 (Budget)</th><th>2013 (Budget)</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>$364,238</td><td></td></tr>
</table>

<table>
<tr><td colspan="7">Project Name: 44kV Motorized Switches</td></tr>
<tr><td colspan="7">Project Investment Category: Plant Enhancement</td></tr>
<tr><td colspan="7">Key Project Drivers: Reliability</td></tr>
<tr><td colspan="7">Project Description: The scope of the project is to install remotely-operable 44kV line switches at key locations (as determined through consultation between the Control Room /Operations/Engineering) within the distribution system.</td></tr>
<tr><td colspan="7">Future Benefit: Increased reliability, decrease operational burdens.</td></tr>
<tr><td colspan="3">Project Start Date: 2012</td><td colspan="4">Project In-Service Date: 2013</td></tr>
<tr><td colspan="7">Total Project Cost: $964,667</td></tr>
<tr><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012 (Budget)</th><th>2013 (Budget)</th></tr>
<tr><td></td><td></td><td>$81,943</td><td>$44,163</td><td>$32,886</td><td>$371,850</td><td>$433,825</td></tr>
</table>

Project Name: West Nipissing						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated asset, reliability and safety						
Project Description: The scope of this project was to replace 1950's vintage poles and construct to meet CSA clearance requirements.						
Future Benefit: Increased reliability and safety of our distribution system.						
Project Start Date: 2012			**Project In-Service Date**: 2012			
Total Project Cost: $200,000						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
					$200,000	

Project Name: Vanier Lane						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated asset, safety and reliability						
Project Description: The scope of this project was to replace 1950's vintage poles and construct to meet CSA clearance requirements.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2013			**Project In-Service Date**: 2013			
Total Project Cost: $451,083						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
					$150,000	$301,083

Project Name: Hillsdale, Mark, Lakeview conversion						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated assets (40+ yr old poles), voltage conversion, reliability and safety.						
Project Description: The scope of this project was to replace the 40yr old poles and prepare for the voltage conversion of Cressey Substation.						
Future Benefit: Reliability and safety of the distribution system.						
Project Start Date: $2013			**Project In-Service Date**: $2013			
Total Project Cost: $						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
						$302,723

Project Name: Prete, Benny, Connaught conversion						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated asset, voltage conversion, reliability and safety						
Project Description: The scope of this project was to replace the 40yr old poles and prepare for the Cressey Substation conversion.						
Future Benefit: Increased reliability and safety of the distribution system>						
Project Start Date: 2013			**Project In-Service Date**: 2013			
Total Project Cost: $178,232						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
						$178,232

Project Name: Gary/ Madison						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated asset, reliability and safety.						
Project Description: The scope of this project was to replace the 35yr old cable, duct and transformers in this 1970's built subdivision.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2013			**Project In-Service Date**: 2013			
Total Project Cost: $334,661						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
						$334,661

Project Name: Eden Point Underground Rebuild						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated asset, replacement of submersible transformers.						
Project Description: The scope of this project was to replace the 35yr old cable, duct and submersible transformers in this 1970's built subdivision.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2013			**Project In-Service Date**: 2013			
Total Project Cost: $204,415						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
						$204,415

Project Name: Sunnyside Rd Rebuild						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated asset, reliability and safety.						
Project Description: The scope of this project is to relocate and renew 50+ yr old plant from its location along the lake out to the road.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2013			**Project In-Service Date**: 2013			
Total Project Cost: $373,753						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
						$373,753

Project Name: West Nipissing Conversion						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated plant, system conversion 4kv to 12kv						
Project Description: The scope of this project was to rebuild the feeders out of MS34 and convert to 12kv to prepare for the voltage conversion of MS34.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2013			**Project In-Service Date**: 2013			
Total Project Cost: $302,722						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
						$302,722

Project Name: McFarlane Lk Rd						
Project Investment Category: Plant Renewal						
Key Project Drivers: Deteriorated asset, inaccessible, reliability and safety.						
Project Description: The scope of this project was to upgrade existing plant and relocate out to road accessibility. Also, we will extend a feeder to create a loop between two of our substations.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2012			**Project In-Service Date**: 2013			
Total Project Cost: $250,000						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
					$250,000	$532,128

<table>
<tr><td colspan="7">Project Name: Beatty St Rebuild</td></tr>
<tr><td colspan="7">Project Investment Category: Plant Renewal</td></tr>
<tr><td colspan="7">Key Project Drivers: Deteriorated asset, reliability and safety.</td></tr>
<tr><td colspan="7">Project Description: The scope of this project is to replace the undersized #6 conductor and the 1950's vintage poles.</td></tr>
<tr><td colspan="7">Future Benefit: Increased reliability and safety of the distribution system.</td></tr>
<tr><td colspan="3">Project Start Date: 2013</td><td colspan="4">Project In-Service Date: 2013</td></tr>
<tr><td colspan="7">Total Project Cost: $204,917</td></tr>
<tr><td>2007</td><td>2008</td><td>2009</td><td>2010</td><td>2011</td><td>2012 (Budget)</td><td>2013 (Budget)</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td>$204,917</td></tr>
</table>

<table>
<tr><td colspan="7">Project Name: Renewable Generation Connections</td></tr>
<tr><td colspan="7">Project Investment Category: New Connections</td></tr>
<tr><td colspan="7">Key Project Drivers: Government Regulations, Plant Enhancement</td></tr>
<tr><td colspan="7">Project Description: The scope of the project is the purchase and successful deployment of technological solution(s) that will aid the utility in combating the purveyance of power quality problems arising from the mandatory connection obligation of distributed generation .</td></tr>
<tr><td colspan="7">Future Benefit: Continued ability to meet ANSI standard for voltage at customer service entrance; mitigation of sustained, localized high voltages to be achieved through the use of advanced monitoring and control technology.</td></tr>
<tr><td colspan="3">Project Start Date: 2013</td><td colspan="4">Project In-Service Date: 2013</td></tr>
<tr><td colspan="7">Total Project Cost: $284,913</td></tr>
<tr><td>2007</td><td>2008</td><td>2009</td><td>2010</td><td>2011</td><td>2012 (Budget)</td><td>2013 (Budget)</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td>$284,913</td></tr>
</table>

<table>
<tr><td colspan="7">Project Name: Copper Cliff Rebuild</td></tr>
<tr><td colspan="7">Project Investment Category: Plant renewal</td></tr>
<tr><td colspan="7">Key Project Drivers: Undersized conductor, deteriorated asset.</td></tr>
<tr><td colspan="7">Project Description: The scope of this project was to replace the undersized #6 copper primary conductor and 1950's vintage poles</td></tr>
<tr><td colspan="7">Future Benefit: Increased reliability and safety of the distribution system.</td></tr>
<tr><td colspan="3">Project Start Date: 2013</td><td colspan="4">Project In-Service Date: 2013</td></tr>
<tr><td colspan="7">Total Project Cost: $238,735</td></tr>
<tr><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012 (Budget)</th><th>2013 (Budget)</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td>$238,735</td></tr>
</table>

<table>
<tr><td colspan="7">Project Name: Outage Management System</td></tr>
<tr><td colspan="7">Project Investment Category: Plant Renewal</td></tr>
<tr><td colspan="7">Key Project Drivers: Reliability, Operational Efficiency, Customer Satisfaction</td></tr>
<tr><td colspan="7">Project Description: Installation of a software package that automates the process(es) involving key personnel during a contingency event. The software will enable faster identification of faulted line segments, reduce switching time, improve reliability-indices and enhance the customer experience as it relates to an outage at their premise.</td></tr>
<tr><td colspan="7">Future Benefit: Increased operational awareness for key personnel/decision-makers, improved SAIDI,SAIFI,CAIDI performance, decreased operational cost in response to a contingency, improved customer relations/satisfaction performance.</td></tr>
<tr><td colspan="3">Project Start Date: 2013</td><td colspan="4">Project In-Service Date: 2013</td></tr>
<tr><td colspan="7">Total Project Cost: $315,000</td></tr>
<tr><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012 (Budget)</th><th>2013 (Budget)</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>$90,000</td><td>$225,000</td></tr>
</table>

Project Name: Arthur Substation						
Project Investment Category: Plant renewal						
Key Project Drivers: Deteriorated asset, reliability and safety						
Project Description: The scope of this project is to rebuild the Arthur St. substation. Arthur requires replacement to a more modern residential design, it is 50+ yrs old and we have had noise complaints in the neighbourhood.						
Future Benefit: Increased reliability and safety of the distribution system.						
Project Start Date: 2013			**Project In-Service Date**: 2013			
Total Project Cost: $1,974,164						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
						$1,974,164

Project Name: Digital Relay Modernization						
Project Investment Category: Plant renewal						
Key Project Drivers: Obsolete hardware						
Project Description: The scope of this project is to upgrade the existing out of date relays with new electronic relays.						
Future Benefit: Reliability of the distribution system.						
Project Start Date: 2013			**Project In-Service Date**: 2013			
Total Project Cost: $174,165						
2007	**2008**	**2009**	**2010**	**2011**	**2012 (Budget)**	**2013 (Budget)**
						$174,165

File Number:	EB-2012-0126
Exhibit:	2
Tab:	4
Schedule:	2
Attachment:	1
Date:	9 November 2012

Appendix 2-A
Capital Projects Table

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Meter Installations							
Distribution Station Equipment <50kV		$ 165,841					
Poles, Towers & Fixtures				$ 350			
Meters	$ 228,698	$ 144,873	$ 38,348	$ 30,167	$ 17,453	$ 107,254	$ 100,000
Computer Software		$ 2,025					
Contributions	$ (3,500)		$ (39)	$ (450)	$ (4,605)	$ (1,376)	
Sub-Total	**$ 225,198**	**$ 312,739**	**$ 38,309**	**$ 30,067**	**$ 12,848**	**$ 105,878**	**$ 100,000**
Emergency Plant Replacement							
Distribution Station Equipment <50kV				$ 51,245			
Poles, Towers & Fixtures	$ 19,469		$ 58,294	$ 30,094	$ 44,796	$ 49,211	$ 16,424
Overhead Conductors & Devices	$ 17,529		$ 15,787	$ 13,442	$ 8,378	$ 9,204	$ 3,072
Underground Conduit, Conductors & Devices	$ 193,811	$ 260,479	$ 54,671	$ 48,522	$ 218,855	$ 240,425	$ 80,240
Line Transformers	$ 2,331	$ 5,634	$ 12,449	$ 21,462	$ 40,509	$ 44,502	$ 14,852
Services (Overhead & Underground)					$ 31,745	$ 34,873	$ 11,639
Sub-total	**$ 233,140**	**$ 266,113**	**$ 141,201**	**$ 164,765**	**$ 344,283**	**$ 378,215**	**$ 126,227**
Failed Transformers							
Line Transformers	$ 370,336	$ 44,869	$ 182,213	$ 451,953	$ 151,333	$ 267,362	$ 130,737
Sub-total	**$ 370,336**	**$ 44,869**	**$ 182,213**	**$ 451,953**	**$ 151,333**	**$ 267,362**	**$ 130,737**
PCB							
Line Transformers	$ 137,343	$ 25,007	$ 37,204	$ 74,577	$ 14,811	$ 155,070	$ 47,368
Sub-Total	**$ 137,343**	**$ 25,007**	**$ 37,204**	**$ 74,577**	**$ 14,811**	**$ 155,070**	**$ 47,368**
Major Substation Repairs							
Building Improvements			$ 31,716	$ 103,742			
Buildings	$ 168,464	$ 33,960					
Land				$ 32,745		$ 5,569	
Distribution Station Equipment <50kV	$ 304,475	$ 323,397	$ 437,621	$ 161,904	$ 161,491	$ 1,379,969	$ 178,800
Poles, Towers & Fixtures		$ 4,312	$ 9,701	$ 15,766			
Overhead Conductors & Devices			$ 5,945				
Underground Conduit, Conductors & Devices	$ 7,630		$ 11,074	$ 103,950			
Contributions		$ (296,171)			$ (23,335)	$ (17,766)	
Sub-total	**$ 480,569**	**$ 65,498**	**$ 496,057**	**$ 418,107**	**$ 138,156**	**$ 1,367,772**	**$ 178,800**
System Betterment							
Poles, Towers & Fixtures	$ 412,463	$ 441,832	$ 408,523	$ 622,595	$ 319,718	$ 462,769	$ 181,940
Overhead Conductors & Devices	$ 442,220	$ 539,942	$ 127,526	$ 272,720	$ 6,970	$ 105,628	$ 41,528
Underground Conduit, Conductors & Devices	$ 358,860	$ 289,408	$ 175,824	$ 314,831	$ 109,734	$ 196,117	$ 77,104
Line Transformers	$ 137,914	$ 164,306	$ 255,545	$ 172,557	$ 203,694	$ 212,363	$ 83,492
Services (Overhead & Underground)				$ 6,473	$ 61,537	$ 47,285	$ 18,590
Contributions	$ (607,304)	$ (272,754)	$ (46,389)	$ (25,054)	$ (37,791)	$ (1,857)	
Sub-total	**$ 744,153**	**$ 1,162,734**	**$ 921,029**	**$ 1,364,122**	**$ 663,862**	**$ 1,022,305**	**$ 402,654**
Overhead Services							
Services (Overhead & Underground)	$ 197,270	$ 207,237	$ 189,266	$ 249,995	$ 245,842	$ 227,842	$ 162,401
Contributions	$ (123,805)	$ (112,922)	$ (97,301)	$ (98,341)	$ (91,262)	$ (61,818)	$ (100,000)
Sub-total	**$ 73,465**	**$ 94,315**	**$ 91,965**	**$ 151,654**	**$ 154,580**	**$ 166,024**	**$ 62,401**
Underground Services							
Services (Overhead & Underground)	$ 162,974	$ 195,696	$ 162,017	$ 238,197	$ 243,905	$ 175,961	$ 141,569
Contributions	$ (81,540)	$ (82,085)	$ (70,368)	$ (80,081)	$ (87,352)	$ (68,794)	$ (80,000)
Sub-total	**$ 81,434**	**$ 113,611**	**$ 91,649**	**$ 158,116**	**$ 156,553**	**$ 107,167**	**$ 61,569**
City Roadworks							
Poles, Towers & Fixtures	$ 246,176	$ 30,758	$ 618	$ 39,998	$ 4,367		$ 58,230
Overhead Conductors & Devices	$ 438,921	$ 19,206	$ 206	$ 139,688	$ 7,583		$ 203,359
Underground Conduit, Conductors & Devices	$ 120,140	$ 7,703	$ 210,420	$ 19,566	$ 1,502		$ 28,484
Line Transformers	$ 88,631			$ 14,462			$ 21,053
Services (Overhead & Underground)				$ 19,150	$ 1,644		$ 27,878
Contributions	$ (212,456)	$ (37,030)	$ (133,245)	$ (92,174)	$ (6,280)		
Sub-total	**$ 681,412**	**$ 20,637**	**$ 77,999**	**$ 140,690**	**$ 8,816**	**$ -**	**$ 339,004**
Subdivisions							
Poles, Towers & Fixtures	$ 13,202	$ 19,425	$ 1,038		$ 106		
Overhead Conductors & Devices	$ 10,544	$ 15,552	$ 1,308				
Underground Conduit, Conductors & Devices	$ 361,644	$ 368,653	$ 154,874	$ 226,618	$ 99,980	$ 310,113	$ 148,277
Line Transformers	$ 72,551	$ 56,498	$ 28,872	$ 76,386	$ 59,491	$ 184,528	$ 88,230
Services (Overhead & Underground)					$ 11,609	$ 36,008	$ 17,217
Contributions	$ (417,680)	$ (417,180)	$ 64,834	$ (244,001)	$ (143,953)	$ (466,732)	$ (168,254)
Sub-total	**$ 40,261**	**$ 42,948**	**$ 250,926**	**$ 59,003**	**$ 27,233**	**$ 63,917**	**$ 85,470**
Commercial Development							
Poles, Towers & Fixtures	$ 18,962	$ 30,729	$ 35,358	$ 44,150	$ 69,541	$ 42,615	$ 30,048
Overhead Conductors & Devices	$ 48,915	$ 52,751	$ 31,331	$ 65,580	$ 51,137	$ 132,928	$ 28,983
Underground Conduit, Conductors & Devices	$ 153,019	$ 328,184	$ 370,587	$ 223,041	$ 314,268	$ 107,702	$ 140,683
Line Transformers	$ 176,426	$ 350,050	$ 202,172	$ 518,012	$ 147,539	$ 215,594	$ 152,014
Services (Overhead & Underground)		$ 19,055		$ 235	$ 7,505	$ 3,263	$ 2,301
Meters					$ 880		
Contributions	$ (336,962)	$ (649,155)	$ (495,587)	$ (721,333)	$ (670,625)	$ (456,002)	$ (355,536)
Sub-Total	**$ 60,360**	**$ 131,614**	**$ 143,861**	**$ 129,685**	**$ (79,755)**	**$ 46,100**	**$ (1,507)**
Building							
Carpet/Paint/Flooring	$ 46,495	$ 54,570			$ 8,444		
Fencing/Exterior/Roof	$ 20,859		$ 70,893	$ 24,345	$ 96,434		
Window/Doors	$ 23,489	$ 8,196					
New Walls/Offices/Construction	$ 5,000	$ 62,099	$ 129,568	$ 6,250	$ 19,045		
Renovate washrooms						$ 100,000	
Modifications to server room						$ 25,379	
New Roof						$ 155,700	
Lighting Conversion							$ 110,064
Geothermal Energy System							$ 615,221
Fuel Conversion							$ 208,000
Other Miscellaneous	$ 467	$ 7,179	$ 7,992	$ 19,055	$ 35,428	$ 29,300	$ 32,715

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Sub-Total	**$ 96,310**	**$ 132,044**	**$ 208,453**	**$ 49,650**	**$ 159,351**	**$ 310,379**	**$ 966,000**
Porcelain Insulator Replacement							
Poles, Towers & Fixtures	$ 15,557	$ 2,932	$ 285,808				
Overhead Conductors & Devices	$ 510,184	$ 271,881	$ 153,513				
Sub-Total	**$ 525,741**	**$ 274,813**	**$ 439,321**	**$ -**	**$ -**	**$ -**	**$ -**
Pole Replacement Program							
Poles, Towers & Fixtures	$ 112,188	$ 160,976	$ 246,453				$ 254,383
Overhead Conductors & Devices	$ 52,729	$ 186,000	$ 205,950				
Line Transformers							
Contributions			$ (1,805)				
Sub-total	**$ 164,917**	**$ 346,976**	**$ 450,598**	**$ -**	**$ -**	**$ -**	**$ 254,383**
Tools & Equipment							
Tools, Shop & Garage Equipment	$ 89,424	$ 180,931	$ 114,715	$ 74,325	$ 77,854	$ 152,809	$ 160,000
Sub-total	**$ 89,424**	**$ 180,931**	**$ 114,715**	**$ 74,325**	**$ 77,854**	**$ 152,809**	**$ 160,000**
Vehicles							
Small Vehicles (Trucks/Cars/Vans)	$ 255,827	$ 187,266	$ 204,613	$ 53,251	$ 46,316	$ 193,456	$ 40,000
Trailers		$ 27,065	$ 20,237	$ 118,440	$ 12,600		$ 20,000
Large Vehicles (Step Vans/Bucket/Boom Trucks)		$ 645,020	$ 270,935	$ 369,293	$ 504,034		$ 1,058,450
Sub-total	**$ 255,827**	**$ 859,351**	**$ 495,784**	**$ 540,984**	**$ 562,950**	**$ 193,456**	**$ 1,118,450**
Sherwood Park (Phase I, II & III)							
Underground Conduit, Conductors & Devices	$ 159,705	$ 727	$ 8,829	$ 89,981	$ 249,646		
Line Transformers				$ 51,238	$ 30,200		
Services (Overhead & Underground)					$ 11,117		
Sub-total	**$ 159,705**	**$ 727**	**$ 8,829**	**$ 141,219**	**$ 290,963**	**$ -**	**$ -**
Albinson - Haig to Douglas							
Poles, Towers & Fixtures	$ 5,840						
Overhead Conductors & Devices	$ 105,893						
Line Transformers	$ 11,737						
Sub-total	**$ 123,470**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Tilton Lake							
Poles, Towers & Fixtures	$ 94,507		$ 47,818				
Overhead Conductors & Devices	$ 169,087						
Line Transformers	$ 7,433						
Sub-total	**$ 271,027**	**$ -**	**$ 47,818**	**$ -**	**$ -**	**$ -**	**$ -**
Falconbridge 44kV							
Distribution Station Equipment <50kV		$ 45					
Poles, Towers & Fixtures		$ 74,930					
Overhead Conductors & Devices		$ 54,150					
Underground Conduit, Conductors & Devices		$ 103,916					
Sub-Total	**$ -**	**$ 233,041**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Gary Avenue Rebuild							
Poles, Towers & Fixtures		$ 215,732	$ 20,472				
Overhead Conductors & Devices		$ 395,597	$ 136,431				
Underground Conduit, Conductors & Devices		$ 109,329	$ 226,595	$ 1,784			
Line Transformers		$ 3,763	$ 62,572				
Sub-Total	**$ -**	**$ 724,421**	**$ 446,070**	**$ 1,784**	**$ -**	**$ -**	**$ -**
Webbwood Drive Rebuild							
Underground Conduit, Conductors & Devices		$ 119,240					
Line Transformers		$ 42,499					
Sub-total	**$ -**	**$ 161,739**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Beatrice Underground Rebuild							
Underground Conduit, Conductors & Devices			$ 184,992				
Sub-total	**$ -**	**$ -**	**$ 184,992**	**$ -**	**$ -**	**$ -**	**$ -**
GIS							
Computer Software			$ 302,438	$ 45,300	$ 52,901	$ 91,500	
Sub-total	**$ -**	**$ -**	**$ 302,438**	**$ 45,300**	**$ 52,901**	**$ 91,500**	**$ -**
Jarvi Road Rebuild							
Poles, Towers & Fixtures			$ 208,082				
Overhead Conductors & Devices			$ 55,469	$ 5,956			
Line Transformers			$ 6,107				
Sub-total	**$ -**	**$ -**	**$ 269,658**	**$ 5,956**	**$ -**	**$ -**	**$ -**
Louis Street Rebuild							
Underground Conduit, Conductors & Devices			$ 152,478	$ 156,882	$ 2,206		
Line Transformers			$ 41,793	$ 22,196			
Sub-total	**$ -**	**$ -**	**$ 194,271**	**$ 179,078**	**$ 2,206**	**$ -**	**$ -**
Montague to Whissell Rebuild							
Poles, Towers & Fixtures			$ 437,642	$ 34,038			
Overhead Conductors & Devices			$ 143,447	$ 135,286			
Underground Conduit, Conductors & Devices			$ 5,776				
Line Transformers			$ 56,961	$ 32,770			
Sub-total	**$ -**	**$ -**	**$ 643,826**	**$ 202,094**	**$ -**	**$ -**	**$ -**
SCADA Software							
System Supervisory Equipment		$ 10,260	$ 297,472	$ 15,730	$ 19,065	$ 675	$ 346,045
Sub-total	**$ -**	**$ 10,260**	**$ 297,472**	**$ 15,730**	**$ 19,065**	**$ 675**	**$ 346,045**
Southlane Road Rebuild							
Poles, Towers & Fixtures			$ 111,828	$ 3,485			
Overhead Conductors & Devices			$ 159,844				
Line Transformers			$ 24,488				
Contributions			$ (8,311)				
Sub-total	**$ -**	**$ -**	**$ 287,849**	**$ 3,485**	**$ -**	**$ -**	**$ -**
Sparks Street Rebuild							
Poles, Towers & Fixtures			$ 74,255	$ 1,834			
Overhead Conductors & Devices			$ 99,634				
Underground Conduit, Conductors & Devices			$ 95,792	$ 1,015			
Line Transformers			$ 145,344	$ 2,456			
Sub-total	**$ -**	**$ -**	**$ 415,025**	**$ 5,305**	**$ -**	**$ -**	**$ -**
Falconbridge Voltage Conversion							
Poles, Towers & Fixtures			$ 11,360	$ 12,082			
Overhead Conductors & Devices			$ 36,066	$ 99,169			
Underground Conduit, Conductors & Devices			$ 1,497	$ 35,108			
Line Transformers				$ 60,832			
Sub-total	**$ -**	**$ -**	**$ 48,923**	**$ 207,191**	**$ -**	**$ -**	**$ -**
Annie St. 4kV to 12kV Conversion							
Poles, Towers & Fixtures			$ 2,395	$ 121,314	$ 65,635		
Overhead Conductors & Devices				$ 359,105	$ 40,889		
Underground Conduit, Conductors & Devices				$ 208,805	$ 21,402		

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Line Transformers				$ 396,007	$ 62,896		
Services (Overhead & Underground)				$ 7,850			
Sub-Total	**$ -**	**$ -**	**$ 2,395**	**$ 1,093,081**	**$ 190,822**	**$ -**	**$ -**
CIS - Harris Billing System							
Computer Software				$ 476,702	$ 11,042		
Sub-Total	**$ -**	**$ -**	**$ -**	**$ 476,702**	**$ 11,042**	**$ -**	**$ -**
Kingsway Rebuild							
Poles, Towers & Fixtures				$ 100,585			
Overhead Conductors & Devices				$ 44,544			
Sub-total	**$ -**	**$ -**	**$ -**	**$ 145,129**	**$ -**	**$ -**	**$ -**
Shaughnessy Rebuild							
Poles, Towers & Fixtures				$ 7,393			
Overhead Conductors & Devices				$ 10,005	$ 4,882		
Underground Conduit, Conductors & Devices		$ 1,407	$ 4,217	$ 146,326			
Line Transformers				$ 57,667			
Services (Overhead & Underground)				$ 16,381			
Sub-total	**$ -**	**$ 1,407**	**$ 4,217**	**$ 237,772**	**$ 4,882**	**$ -**	**$ -**
Automated Vehicle Locator					$ -		
Computer Software					$ 153,987	$ 7,272	
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 153,987**	**$ 7,272**	**$ -**
Kennedy Street Rebuild							
Poles, Towers & Fixtures					$ 55,619	$ 4,134	
Overhead Conductors & Devices					$ 5,634	$ 944	
Underground Conduit, Conductors & Devices					$ 59,285	$ 1,753	
Line Transformers					$ 8,708	$ 1,897	
Services (Overhead & Underground)					$ 21,225	$ 422	
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 150,471**	**$ 9,150**	**$ -**
Beech Street Rebuild							
Poles, Towers & Fixtures					$ 10,221		
Overhead Conductors & Devices					$ 19,647		
Underground Conduit, Conductors & Devices					$ 85,868		
Line Transformers					$ 15,444		
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 131,180**	**$ -**	**$ -**
Highway 69 South Rebuild							
Poles, Towers & Fixtures					$ 290,793		
Overhead Conductors & Devices					$ 255,580		
Line Transformers					$ 5,173		
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 551,546**	**$ -**	**$ -**
Kingsway Area							
Poles, Towers & Fixtures					$ 220,040		
Overhead Conductors & Devices					$ 179,849		
Underground Conduit, Conductors & Devices					$ 631		
Line Transformers					$ 61,374		
Services (Overhead & Underground)					$ 211,902		
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 673,796**	**$ -**	**$ -**
Lorne Street Rebuild							
Poles, Towers & Fixtures					$ 246,787	$ 169,383	
Overhead Conductors & Devices					$ 64,836	$ 143,034	
Line Transformers						$ 26,348	
Services (Overhead & Underground)					$ 12,067	$ 37,641	
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 323,690**	**$ 376,406**	**$ -**
Madison Avenue Rebuild							
Poles, Towers & Fixtures					$ 142,224		
Overhead Conductors & Devices					$ 37,683		
Underground Conduit, Conductors & Devices					$ 14,527		
Line Transformers					$ 51,781		
Services (Overhead & Underground)					$ 63,350		
Meters					$ 646		
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 310,211**	**$ -**	**$ -**
Regent Street Rebuild							
Poles, Towers & Fixtures					$ 136,487	$ 21,255	
Overhead Conductors & Devices					$ 27,723	$ 914	
Underground Conduit, Conductors & Devices					$ 10,480	$ 657	
Line Transformers					$ 89,315	$ 22,090	
Services (Overhead & Underground)					$ 4,950	$ 88,663	
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 268,955**	**$ 133,579**	**$ -**
Hebert/Garland Underground Rebuild							
Poles, Towers & Fixtures						$ 7,316	
Underground Conduit, Conductors & Devices						$ 226,794	
Line Transformers						$ 87,791	
Services (Overhead & Underground)						$ 43,896	
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 365,797**	**$ -**
Copper Cliff Gardens Rebuild							
Poles, Towers & Fixtures						$ 11,151	
Underground Conduit, Conductors & Devices						$ 345,679	
Line Transformers						$ 133,811	
Services (Overhead & Underground)						$ 66,906	
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 557,547**	**$ -**
Westmount Restricted Conductor							
Poles, Towers & Fixtures						$ 287,828	
Overhead Conductors & Devices						$ 243,056	
Line Transformers						$ 44,773	
Services (Overhead & Underground)						$ 63,962	
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 639,619**	**$ -**
Donwood Park - Underground Rebuild							
Poles, Towers & Fixtures					$ 876	$ 6,998	
Underground Conduit, Conductors & Devices					$ 291,390	$ 216,934	
Line Transformers					$ 71,107	$ 83,974	
Services (Overhead & Underground)					$ 65,414	$ 41,987	
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 428,787**	**$ 349,893**	**$ -**
Substation Security							
Communication Equipment		$ 7,335	$ 19,821		$ 7,757	$ 66,925	$ 50,000
Sub-Total	**$ -**	**$ 7,335**	**$ 19,821**	**$ -**	**$ 7,757**	**$ 66,925**	**$ 50,000**
Control Room Electronic Mapping							
Computer Hardware						$ 364,238	
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 364,238**	**$ -**

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
44kV Motorized Switches							
Overhead Conductors & Devices			$ 81,943	$ 44,163	$ 32,886	$ 371,850	$ 433,825
Sub-Total	**$ -**	**$ -**	**$ 81,943**	**$ 44,163**	**$ 32,886**	**$ 371,850**	**$ 433,825**
West Nipissing							
Poles, Towers & Fixtures						$ 90,370	
Overhead Conductors & Devices						$ 20,627	
Underground Conduit, Conductors & Devices						$ 38,298	
Line Transformers						$ 41,471	
Services (Overhead & Underground)						$ 9,234	
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 200,000**	**$ -**
Vanier Lane Rebuild							
Poles, Towers & Fixtures						$ 23,868	$ 97,852
Overhead Conductors & Devices						$ 1,027	$ 94,239
Underground Conduit, Conductors & Devices						$ 738	$ 23,545
Line Transformers						$ 24,806	$ 58,711
Services (Overhead & Underground)						$ 99,561	$ 26,737
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 150,000**	**$ 301,084**
Hillsdale, Mark, Lakeview Conversion							
Poles, Towers & Fixtures							$ 90,817
Overhead Conductors & Devices							$ 45,408
Line Transformers							$ 136,225
Services (Overhead & Underground)							$ 30,273
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 302,723**
Prete, Benny Connaught Conversion							
Poles, Towers & Fixtures							$ 53,470
Overhead Conductors & Devices							$ 26,735
Line Transformers							$ 80,204
Services (Overhead & Underground)							$ 17,823
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 178,232**
Gary/Madison Rebuild							
Poles, Towers & Fixtures							$ 6,693
Underground Conduit, Conductors & Devices							$ 207,489
Line Transformers							$ 80,319
Services (Overhead & Underground)							$ 40,160
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 334,661**
Eden Point Underground Rebuild							
Poles, Towers & Fixtures							$ 4,088
Underground Conduit, Conductors & Devices							$ 126,738
Line Transformers							$ 49,060
Services (Overhead & Underground)							$ 24,529
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 204,415**
Sunnyside Road Line Relocation to Road							
Poles, Towers & Fixtures							$ 149,501
Overhead Conductors & Devices							$ 104,651
Line Transformers							$ 44,850
Services (Overhead & Underground)							$ 74,751
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 373,753**
West Nipissing Conversion							
Poles, Towers & Fixtures							$ 90,817
Overhead Conductors & Devices							$ 45,408
Line Transformers							$ 136,225
Services (Overhead & Underground)							$ 30,272
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 302,722**
McFarlane Road							
Poles, Towers & Fixtures						$ 87,500	$ 186,245
Overhead Conductors & Devices						$ 62,500	$ 133,032
Line Transformers						$ 37,500	$ 79,819
Services (Overhead & Underground)						$ 62,500	$ 133,032
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 250,000**	**$ 532,128**
Beatty Street Rebuild							
Poles, Towers & Fixtures							$ 95,901
Overhead Conductors & Devices							$ 65,573
Underground Conduit, Conductors & Devices							$ 17,705
Line Transformers							$ 3,279
Services (Overhead & Underground)							$ 22,459
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 204,917**
Renewable Generation Connections							
Distribution Station Equipment <50kV							$ 284,913
Overhead Conductors & Devices							
Line Transformers							
Services (Overhead & Underground)							
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 284,913**
Copper Cliff Rebuild							
Poles, Towers & Fixtures							$ 76,873
Overhead Conductors & Devices							$ 28,648
Line Transformers							$ 39,869
Services (Overhead & Underground)							$ 93,345
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 238,735**
Outage Management Systems							
Computer Software						$ 90,000	$ 225,000
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 90,000**	**$ 225,000**
Arthur Substation							
Distribution Station Equipment <50kV							$ 1,811,222
Underground Conduit, Conductors & Devices							$ 129,496
System Supervisory Equipment							$ 33,446
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,974,164**
Digital Relay Modernization							
System Supervisory Equipment							$ 174,165
Sub-total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 174,165**
Miscellaneous							
28M6 Montague to Whissell			$ 1,275				
Centennial Load Area Voltage Conversion			$ 93,977				
Webpage Design		$ 16,700	$ 21,337				
Webbwood			$ 70,003				
ERP/Warehouse Automation							$ 75,000
Barrydowne 44kV Conductor			$ 114,780				

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Bell Park Conversion				$ 50,676	$ 7,907		
Building Maintenance				$ 7,963			
Change Porcelain Cutouts				$ 11,341	$ 92,720		
Southbay				$ 69,456			
Asset Management					$ 70,000		
Levert-New Feeder					$ 57,640		
Falconbridge Hwy, Huntington to Lasalle		$ 8,065					
SAP Customer Information System		$ 1,092					
Kingsway/Levesque Restircted Conduit						$ 16,983	
44kV Tie 28M4/9M4 Design							
WN-Sentinel Lights	$ 2,482						
Algonquin (Culver to Regent) Rebuild							$ 71,295
Pine Street East							$ 96,240
Kelly Lake Road - 4/0 to 556mcm							$ 33,952
Fault Indicators							$ 18,287
Partnersoft/Fieldstaker Platform						$ 66,000	
BPISI Project							$ 75,000
Ministry of Transportation Road Work	$ 15,678						
Sub-Total	**$ 18,160**	**$ 25,857**	**$ 301,372**	**$ 139,436**	**$ 228,267**	**$ 82,983**	**$ 369,774**
Construction Work in Progress	$ 17,498	$ 822,832	$ 8,221	$ 228,308	$ 430,859	$ 1,669,878	$ 101,536
Capital Inventory Work in Progress				$ 1,022,658	$ 105,162		
Total	***$ 4,849,750***	***$ 6,061,819***	***$ 7,746,424***	***$ 8,002,089***	***$ 6,762,310***	***$ 10,113,766***	***$ 10,964,348***
Per Capital Asset Continuities	4,849,750	6,061,819	7,746,424	8,002,089	6,762,310	10,113,766	10,964,348
Difference	-	-	-	-	-	-	-

Notes:

1 Please provide a breakdown of the major components of each capital project. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

Greater Sudbury Hydro Inc.

Capital Asset Management Plan

Prepared By: **Mark Van de Rydt, P.Eng.**
Distribution Engineer

Submitted To: **B.A. (Brian) McMillan, P.Eng.**
V.P. Distribution Electrical Systems

Date: **October 30, 2012**

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

1 EXECUTIVE SUMMARY

The *Institute of Asset Management* defines **Asset Management** as ”the set of disciplines, methods, procedures & tools to optimize the whole life business impact of costs, performance and risk exposures (associated with the availability, efficiency, quality, longevity and regulatory/safety/environmental compliance) of the company’s physical assets”.

At Greater Sudbury Hydro Inc, the Asset Management Plan will form the backbone from which all future capital and maintenance expenditures are conceived. We desire to achieve a business philosophy that focuses on optimizing the balance between financial performance, established risks and desired operating performance.

The scope of the plan is limited to the management of the physical assets associated with the distribution system. The objectives of our plan are to report on the performance of the distribution system and to identify risks and challenges that would adversely affect our ability to continue to deliver on our corporate goals.

Financial Performance

The delivery of the capital program, to be on or below budget or approved forecast, is identified as a performance measure within our strategic objectives. Our ability to meet this objective is heavily tied to the quality of the plan.

Although capital spending can vary between some budget programs, the performance to-date has tracked relatively close to plans and budgets. The 2011 capital program was delivered within 9.3% of the approved budget.

Managing ageing infrastructure and system capacity issues will continue to present challenges. Our asset condition assessment studies have shown an urgent need to increase asset replacement spending in the areas of Substation Transformers and GSHI-owned Wood Poles.

Overall, we have identified the need for an increase in capital spending of $1.7M in fiscal 2013 over 2011 levels.

Operating Performance

System Reliability is a measure of operating performance. Our objective is to maintain the 3-year average system reliability, while implementing programs that result in improvement in areas with known reliability problems.

The 3-year averages for the two key measures of reliability, System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency (SAIFI) have both been relatively constant. The two leading causes affecting outage frequency and duration are loss of supply and defective equipment.

Continued efforts will focus on identifying and adopting leading indicators that enable us to make improvements from a proactive approach rather than reactive.

GSHI has performed well over the last five years, however, we will continue to face multiple challenges for the next decade. Those challenges include the management of an ageing infrastructure, ensuring the system has sufficient capacity to meet projected load growth as well as new satisfying new demands initiated by the Green Energy Act.

We will continue to optimize capital sustainment investments through asset management processes based on sound engineering, asset condition assessment programs and adherence with regulation.

GSHI's most significant expected replacements were found to be for Substation Transformers and GSHI-owned Wood Poles. Three Substation Transformers (nearly 6% of the population of 53) and approximately 283 wood poles, 2.3% of the population, are candidates for replacement in the current year.

Table 1-1 YEAR 1 OPTIMAL CONDITION-BASED REPLACEMENT PLAN

Asset	Sub-Category	Optimal Condition-Based Replacement Plan for Year 1 [Number of Units]	Replacement Strategy
Substation Transformers	-	3	proactive
Pole Mounted Transformers	-	17	reactive
Pad Mounted Transformers	-	2	reactive
Overhead Line Switches	-	2	reactive
Sudbury Hydro Wood Poles	All	283	proactive
	44 kV	28	proactive
	Non-44 kV	252	proactive
Sudbury Hydro Concrete Poles	All (Non-44 kV)	1	proactive
Bell Wood Poles	All	63	proactive
	44 kV	1	proactive
	Non-44 kV	59	proactive
City Wood Poles	All (Non-44 kV)	4	proactive
City Concrete Poles	All (Non-44 kV)	16	proactive
City Steel Poles	All (Non-44 kV)	6	proactive
City Aluminum Poles	All (Non-44 kV)	24	proactive
City Anodized Aluminum Poles	All (Non-44 kV)	2	proactive
Hydro One Wood Poles	All	8	proactive
	44 kV	5	proactive
	Non-44 kV	1	proactive
Private Wood Poles	All	24	proactive
	44 kV	0	proactive
	Non-44 kV	24	proactive
Private Concrete Poles	All	0	proactive
	44 kV	0	proactive
	Non-44 kV	0	proactive
Private Steel Poles	All (Non-44 kV)	1	proactive
Private Aluminum Poles	All (Non-44 kV)	0	proactive

2 BACKGROUND

2.1 Period Covered

The Asset Management Plan covers a period of ten years from the fiscal year beginning on January 1, 2013 until the year ending December 2022. To a large extent, the focus of the plan is on the next five years. General forecasts projecting out toward the year 2022 will be reviewed annually.

2.2 PURPOSE OF THE PLAN

The intention of the Asset Management Plan (AMP) is to document the asset management practices used by Greater Sudbury Hydro Inc (GSHI) as part of an optimized lifecycle strategy for our distribution assets. The objectives of the AMP are to demonstrate that the assets deliver the required functions at the desired level of performance and that this level of performance is sustainable for the foreseeable future and stays within the targeted levels of risk.

Our plan is a key component of our planning process. Addressed in the plan are the financial, technical, and management elements needed for making sound innovative or best-practice asset management decisions.

The plan looks ahead for 10 years onward from the fiscal year beginning on January 1, 2013. The main focus of the plan is the next five years. Beyond five years, projections are inherently fraught with inaccuracy. Based on long-term trends including, but not limited to, customer demand growth and distributed generation proliferation, it is likely that new projects, as well as some planned projects, may change in the latter half of the 10 period of the plan.

Our plan focuses on optimizing the lifecycle costs for each distribution system asset group (including creation, operation, maintenance, renewal and disposal) to meet agreed service levels and future demand. Each year, we aim to take advantage of new information and advancements in technology to make refinements to the plan.

Greater Sudbury Hydro Inc's distribution system assets range in age from new to over 50 years old. The management of these assets is critical to providing safe, reliable and efficient electricity distribution services to our customers.

A fundamental requirement of effective development and management of a distribution system is effective system planning. The plan is the documented output of GSHI distribution system planning and provides short and long-range direction for distribution system development, reliability improvements, asset inspection and replacement programs, as well as increases to overall system capacity.

3 PERFORMANCE

The following sections summarize the performance measures with respect to system reliability, system capacity and deployment of the sustainment capital programs. An overview has been provided on the risk analysis and an outlook related to capital requirements associated with the ongoing management of the distribution system.

3.1 Key Measure: Reliability

Despite annual variations in the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI), the 5-year averages have remained relatively constant at acceptable levels.

The two leading causes affecting outage frequency and duration continue to be Loss of Supply and Defective Equipment. The two causes that seem to be trending upward are Unknown/Other and Scheduled Outages.

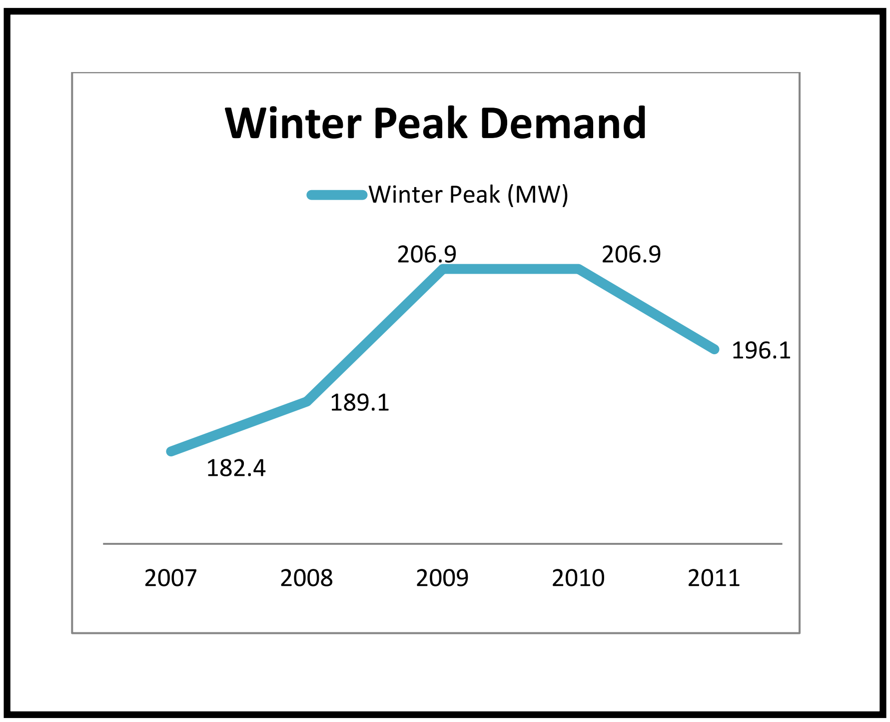
The number of "Scheduled Outages" has increased for two reasons: more rigorous safety procedures regarding worker safety and the type of work being undertaken. The Occupational Health & Safety Act requires that an Employer do "Everything reasonable in the circumstances for the safety of the worker" and the Infrastructure Health & Safety Association has embarked on "ZeroQuest", a path to zero Lost-Time Injuries (LTI) in the sector by 2011. GSHI has embraced both these concepts over the years. The worker and supervisory culture has moved slowly, but steadily, towards the performance of Hazard Analysis and Job Planning that have resulted in more frequent (and longer) Planned Outages. This practice is **fully** supported by Senior Management at GSHI. Most recently, the Management System used to manage GSHI received certification from SAI Global Certification Services for both the ISO 9001 and OHSAS 18001 standards.

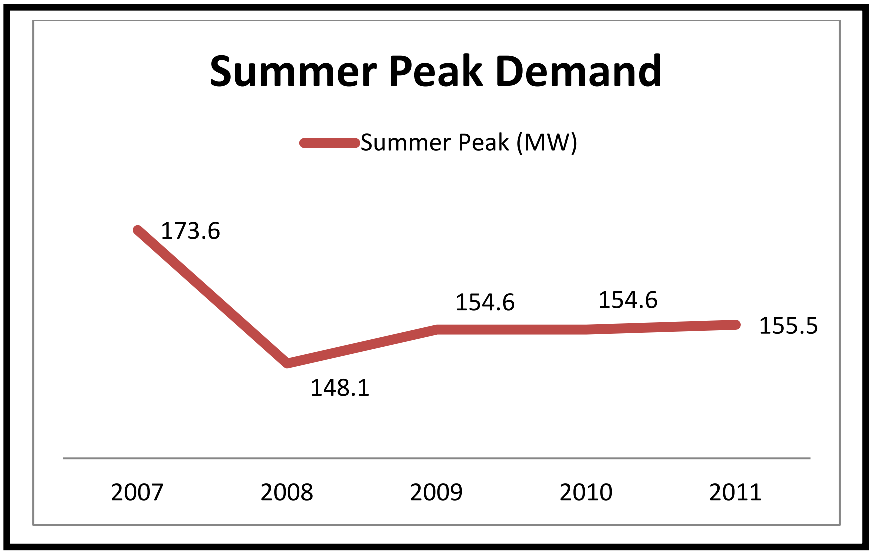
3.2 Key Measure: System Capacity

GSHI continues to be a winter-peaking system. The 2009 system peak was significantly higher than peaks experienced in 2007 and 2008. The 5-year average peak demand is approximately 196 MW.

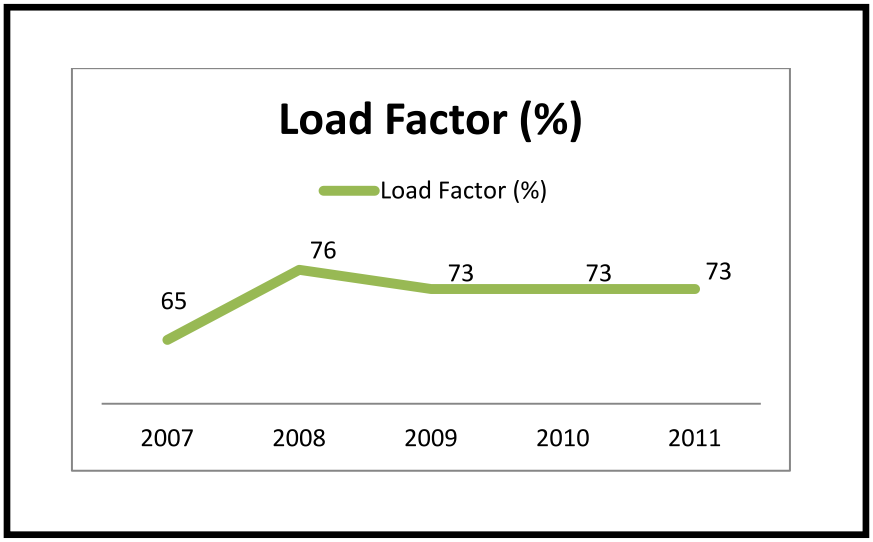
The distribution system experiences a markedly diminished peak demand over the summer months, with the 5-year average at approximately 157 MW.

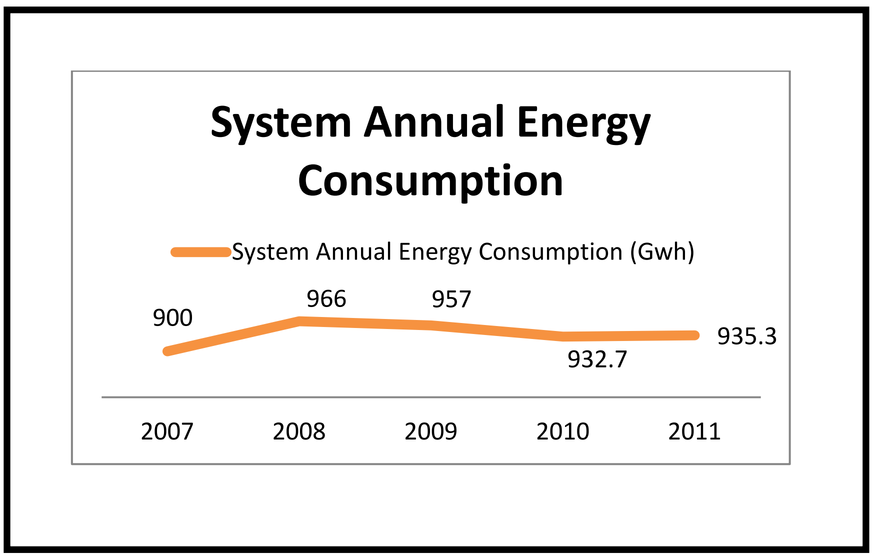
Load Factor (ratio of average load to maximum load) is fairly constant over the 5 year window at value of 72%.





In 2011, reporting of Annual Energy Consumption (Energy Purchased) replaced the previously reported Annual Energy Delivered (Energy Sold). Since 2008, annual energy has been in decline, due partly to the effects of distributed generation initiatives in the Province of Ontario, as well as increased penetration of demand-side management initiatives. This trend is expected to continue; however growth will continue in certain geographic pockets of the distribution system.





3.3 Key Measure: System Demographics

Table 2-1 GSHI Major Asset Categories

Asset Description	Quantity
Distribution Stations	31
Power Transformers	54
SCADA Systems	1
Distribution Transformers (pole, pad-mounted)	5,543
Distribution Poles	12,377
Underground Cables (equivalent 3-phase km)	228
Overhead Conductors (equivalent 3-phase km)	745
Submersible Cables (equivalent 1-phase km)	4.5
Electrical Meters	~47,000

GSHI delivers approximately 1,000 GWh of energy per annum, of which residential consumption accounts for approximately 42.5%, general service 56.5%, streetlighting 1% and losses 5.3% of total deliveries.

In summary, GSHI's profile consists of the following:

System Characteristics	Description
Sub-Transmission Voltage(s)	22/44kV
Distribution Voltage(s)	4.16kV; 12.47kV
Winter Peak (All-Time High)	206 MW
Summer Peak	174 MW
Annual Energy Delivered (5-year Average)	938 GWh
Total Customers (2011 year-end) • Residential Customers • Commercial Customers	46,748 42,279 4,469

	Area, sq. km	# of Customers	NBV, $M total Assets
GSHI	410	46,502	105
Rank	15 of 77	19 of 77	17 of 77

3.4 System Reliability Performance Measures

Definitions

Interruption – A sustained loss of voltage/electrical supply on all phases to the customers supply point. Notwithstanding, if the customer's system is not able to accept electricity from GSHI's system this is not considered an outage. This does not include Partial Power (loss on some of the phases supplying a customer), or sags/deformations, these are power quality events.

Loss of Supply - Is a primary cause classification which is utilized in outage reporting and recording. This term indicates a situation in which the system was ready to accept energy from a supplier, yet the supplier of the energy was not able to perform the service at the desired time. The term "Loss of Supply" therefore indicates a situation where GSHI's system is without power for a reason that is beyond the control of GSHI.

System Average Interruption Frequency Index (SAIFI) - This index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area. In words, the definition is:

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

This index is reported both including and excluding Loss of Supply (LoS). **SAIFI including LoS** provides information as to the total interruptions which are seen by the "average" customer. **SAIFI excluding LoS** indicates the "average" customer interruptions which are the result of causes under the direct control of GSHI.

System Average Interruption Duration Index (SAIDI) - Designed to provide information about the average time a customer is interrupted. In words, the definition is:

$$\text{SAIDI} = \frac{\text{Total hours of customer interruptions}}{\text{Total number of customers served}}$$

This index is reported both including and excluding Loss of Supply (LoS). As with SAIFI, the **SAIDI including LoS** provides information as to the total duration of interruption which is seen by the "average" customer, where **SAIDI excluding LoS** provides an indication as to the duration which the "average" customer is interrupted as the result of causes under the direct control of GSHI.

Customer Average Interruption Duration Index (CAIDI) - CAIDI represents the average time required to restore power to the average customer per sustained outage. In words, the definition is:

$$CAIDI = \frac{\text{Total hours of customer interruption}}{\text{Total number of customer interruptions}}$$

3.4.1 Historical Performance

The figures below depict GSHI's historical reliability performance for fiscal year 2007 through 2011.

Figure 3-1 Historical System SAIFI

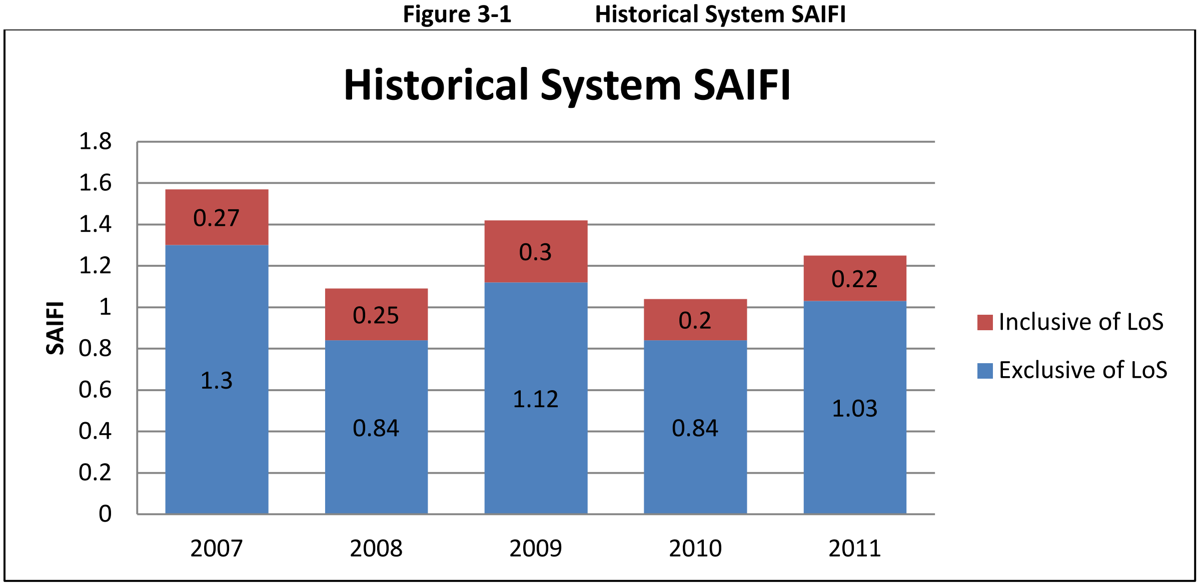
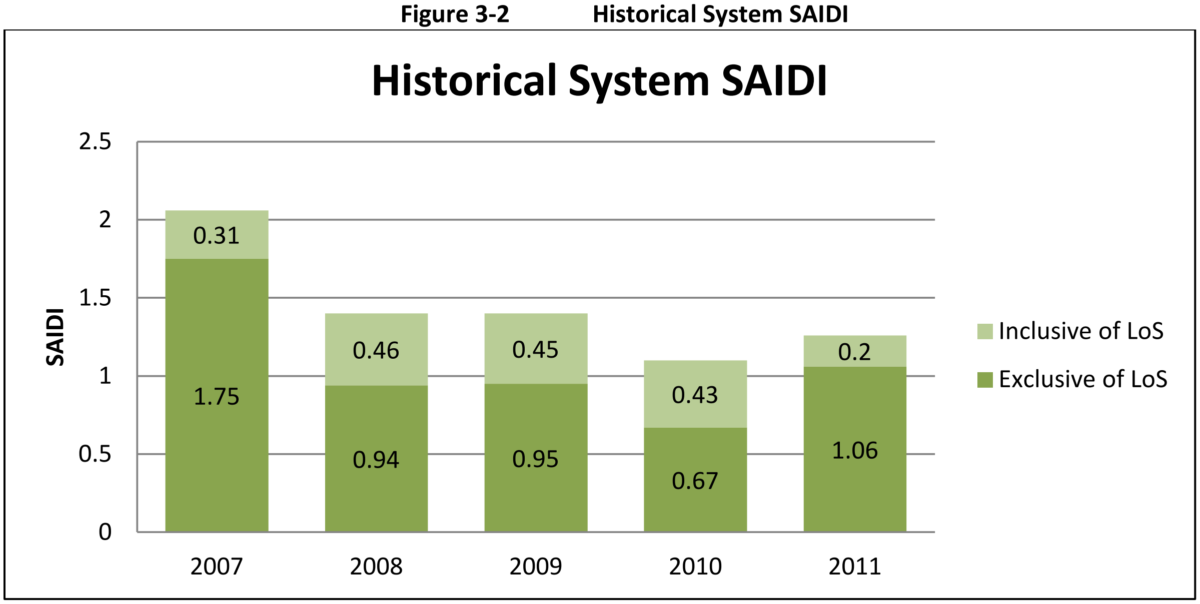


Figure 3-2 Historical System SAIDI



Cause of Service Interruption

0 Unknown/Other Customer interruption(s) with no apparent cause that contributed to the outage

1 Scheduled Outage Customer interruptions due to the disconnection at a pre-selected time for the purpose of construction or preventive maintenance

2 Loss of Supply Customer interruptions due to problems in the bulk electricity supply system

3 Tree Contacts Customer interruptions cased by faults resulting from tree contact with energized circuits

4 Lightning Customer interruptions due to lighting striking the distribution system, resulting in an insulation breakdown and/or flash-overs

5 Defective Equipment Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance

6 Adverse Weather Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events)

7 Adverse Environment Customer interruptions due to equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing

8 Human Element Customer Interruptions due to the interface of distributor staff with the system

9 Foreign Interference Customer interruptions beyond the control of the distributor, such as animals, vehicles, dig-ins, vandalism, sabotage and foreign objects

3.4.2 Reliability Analysis

System reliability has two primary components: frequency and duration. *Frequency* relates most directly to the causal aspect of system interruptions whereas *duration* relates most directly to operation of the system. System Average Interruption Frequency Index (SAIFI) can be regarded as the "cause" and System Average Interruption Duration Index (SAIDI) regarded as the "effect". Additional correlation on system interruptions based on the 10 Primary Causes outlined in the Electricity Reporting and Record Keeping Requirements provide further statistical data that can be used as indicators of system issues where remediation should be undertaken to improve performance. Reliability scores are evaluated for trending and patterns as seasonal and annual variations are not always indicative of system deficiencies.

Despite annual variations in the SAIFI and SAIDI, the 3-year averages have remained relatively constant at acceptable levels since 2007.

System average interruption frequency and duration indices have been broken out by primary cause as shown in the figures below. These indicate that the two leading causes for outage frequency continue to be Loss of Supply and Defective Equipment.

Figure 3-3 SAIFI by Outage Cause 2007 to 2011

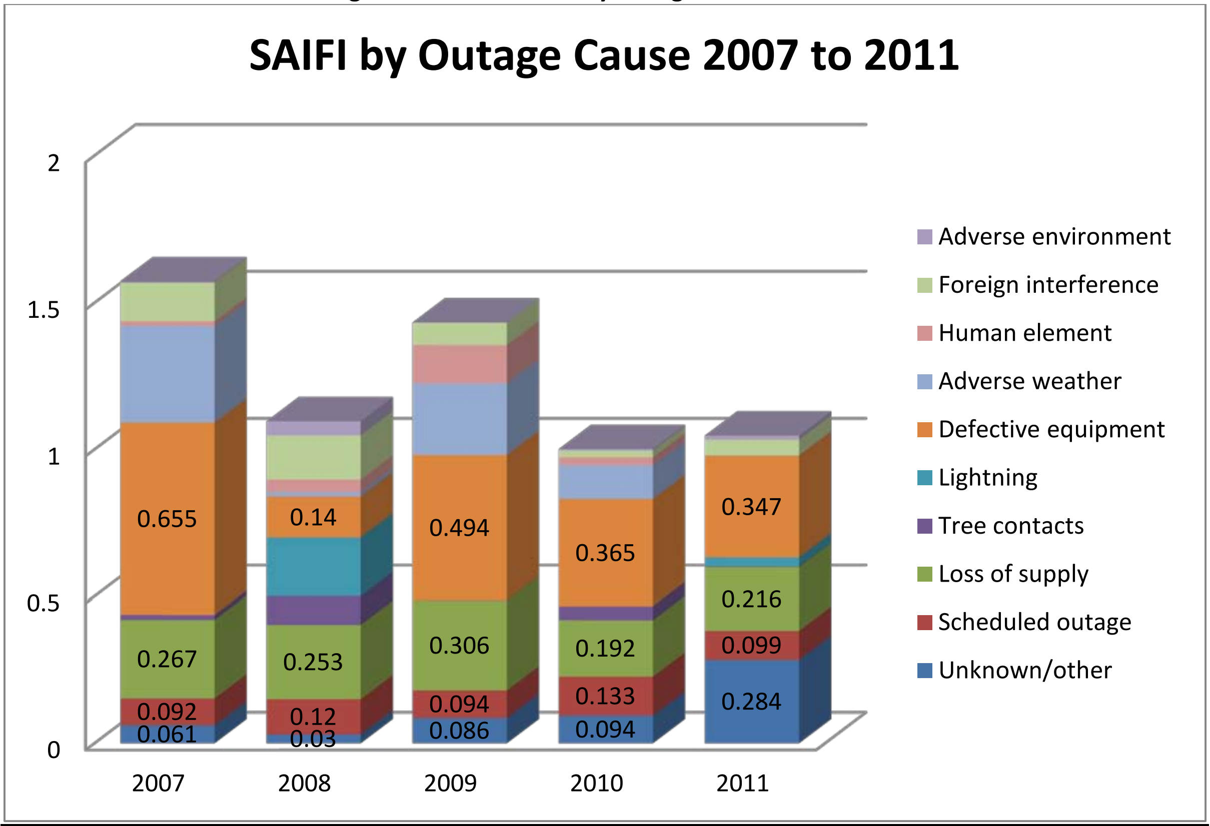
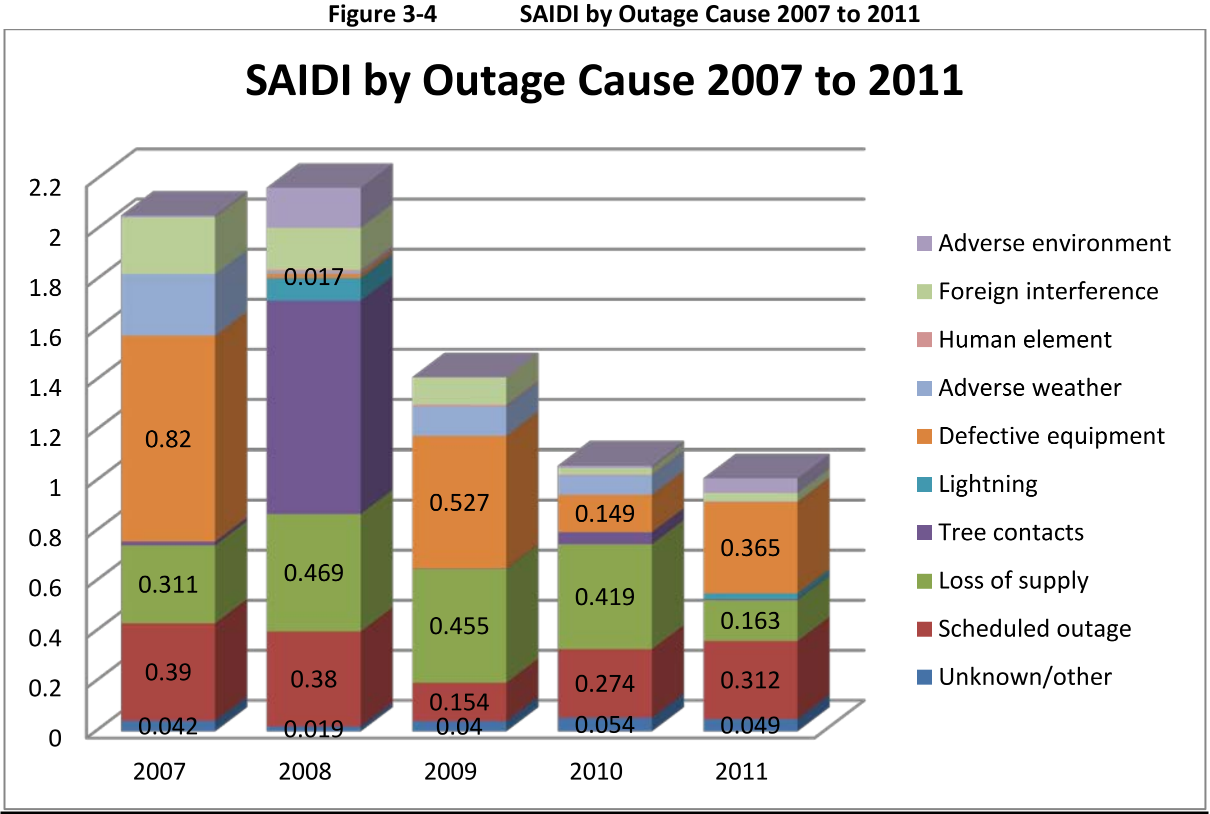


Figure 3-4 SAIDI by Outage Cause 2007 to 2011



4 Outlook

4.1 Asset Management

Continued focus will be required in managing the ageing infrastructure associated with the GSHI distribution system. Key areas of focus will continue to be the management of poles, pole mounted transformers, pad mounted transformers, substation transformers and underground conductor.

With respect to GSHI's wood poles, based on the current asset demographics and failure projections, a levelized replacement rate of 297-300 wood poles per year is recommended to maintain the current failure rates over the next 10 years. Beyond 2025, it is expected that replacement rates will need to be increased to 308-312 poles per year.

With respect to underground conductors, GSHI currently manages approximately 720km of conductors with operating voltages of 44kV and lower. Approximately 68.5% (495km) of the system consists of low voltage secondary conductors with the rest being trunk cable. Strategies will continue to evaluate the optimal replacement levels of all forms of underground conductor.

Distribution (pole mounted and pad mounted) transformer replacement is largely driven by Federal PCB Regulation SOR 2008-273. Under this regulation, all equipment with PCB concentrations greater than 50 PPM must be removed from service prior to the end of 2025 (and for some equipment 2014). Replacements are further driven by common degradation mechanisms such as corrosion of the tank, deterioration or breakage of the bushings, deterioration of internal switching or fusing devices, internal insulating materials and oil.

From the view of both financial and operational risk, substation transformers are the most important asset deployed on the distribution system. Asset condition assessment results for this asset group are concerning, as they show that approximately 23% of the population are in poor condition. Many of the units in this asset group are ageing, with the average age of the population at 43 years. Because substation transformers are a crucial element with major consequences of failure, replacement plans must be put into place in an expedient manner that addresses the poor health of the overall asset population.

4.2 System Capacity

GSHI routinely assesses the capability and reliability of the distribution system in an effort to maintain adequate and reliable supply to its customers. Where gaps are found, appropriate plans for additions and modifications consistent with all regulatory requirements and with due consideration for safety, environmental, financial and supply system reliability/ security are developed. In this regard, the supply needs in the service area have been assessed to determine if additions and/or modifications are required to maintain an adequate and reliable/secure TS capacity. At this time, we have not identified any requirement to expand the capacity of the distribution system beyond its current capabilities.

5 ASSET MANAGEMENT POLICY, STRATEGY AND PROCESS

5.1 Asset Management Policy

GSHI does not presently have a formal corporate Asset Management Policy

5.2 Asset Management Strategy

Within the overall context of asset management lie four key elements: Physical assets, human assets, financial assets and intangible assets. The scope of GSHI's asset management strategy is exclusively limited to the physical assets associated with the distribution system. As such, the scope of the asset management strategy is focused on managing the distribution assets in a way that is;

1. Consistent with supporting the organizational strategic plan
2. Consistent with the implementation of ongoing organizational risk management
3. Consistent with meeting all regulatory requirements
4. Consistent with defined performance requirements

5.3 Organizational Strategic Plan

At Greater Sudbury Hydro Inc, it is our commitment to keep the lights on, keep the rates low and ensure the health and safety of the public, our employees and their families. To achieve these goals, we will continually operate, maintain and improve our systems through responsible investments in people, processes, and equipment. Exceptional OH&S performance and continual improvement is who we are and what we do. The policies and procedures in our systems provide direction and structure; and meet the requirements of the OH&S Act, other statutory/regulatory obligations and ISO 9001 and OHSAS 18001 requirements. We will measure our performance to ensure that we will continually improve.

5.4 Support to Risk Management

Risk needs to be controlled and mitigated to achieve the desired outcome. The objective is to avoid catastrophe, reduce uncertainty and improve predictability.

In the context of physical asset management for the distribution system, risk is defined as the product of an asset's probability of failure and its consequence of failure.

In the context of GSHI's overall program planning, formal risk evaluations will be completed for each project as the Asset Management Plan is unfolded. The risk evaluation is in the context of the consequences of not proceeding with the capital investment. The consequences will be evaluated on a technical, socio-political and financial basis, each weighted accordingly. Investment prioritization is then completed in accordance with the investment risk score, those with the highest risk score taking the highest priority ranking.

5.5 Asset Management Process

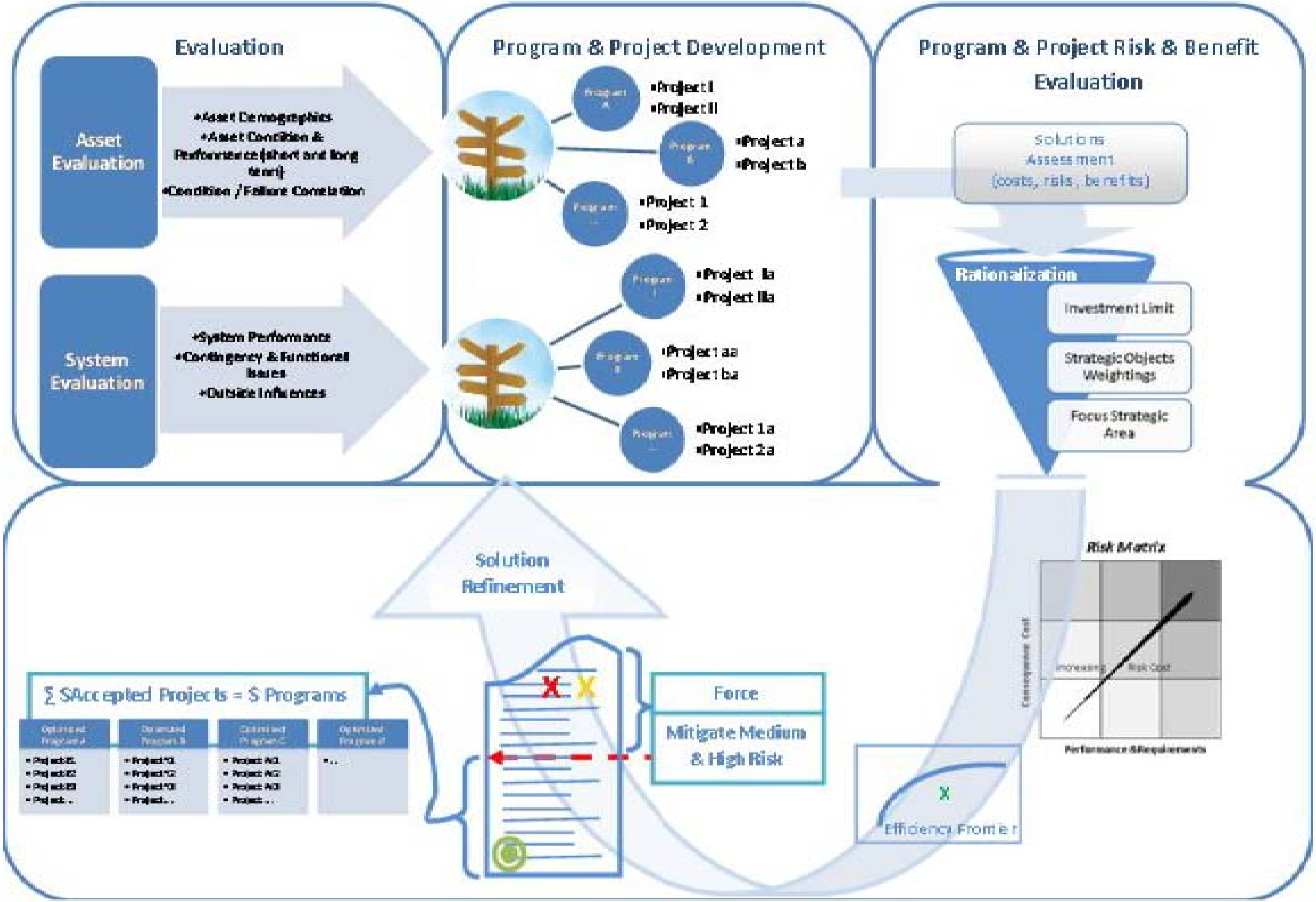
The asset management process proposed by GSHI would be an iterative process that would generally consists of the following steps: Asset Evaluation, Program and Project Development and the Program and Project Risk & Benefit Evaluation. The results of those evaluations are foreseen to be used to produce a list of projects by sustainment capital program. The main focus will be toward the next five years with a longer-term outlook being produced using the available information.

The asset evaluation focuses on each class of asset for which GSHI has sufficient data such that informed decisions may be made. The evaluation requires multiple sources of data such as asset demographics, asset condition, reliability information, environmental impact and failure data. The data is computed and is foreseen to be used to produce a priority list of projects by asset class. The scoring process for each class of asset can be found within the specific sections of this document. The list of projects will be correlated with the planning projects and between related-asset classes to create an optimized usage of resources.

The program and project development will consist of the consolidation of a preliminary list of projects by program to evaluate the distribution of overall capital. At this point, a few iterations of this step and the previous step will engage the iterative process until a final list of projects is achieved.

This overall list of projects will finally be evaluated against the corporate objectives and potential technical, financial and socio-political risks. Risk matrices will be produced for the overall risk, the technical risks and the socio-political risks. These risk matrices are foreseen to be useful in mapping the criticality of each program and project relative to one another.

Assets & Planning Budget Development



5.6 Asset Condition Assessment Methodology

In early 2011, GSHI selected and engaged Kinectrics Inc (Kinectrics) to perform an Asset Condition Assessment (ACA) on GSHI's key distribution assets. The Asset Condition Assessment Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Replacement Plan for each asset group. The methods used are described in the subsequent sections.

5.6.1 Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Colour".

In formulating a Health Index, condition parameters are ranked, through the assignment of weights, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weightings, is therefore given by:

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

where

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

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter
DR	De-Rating Multiplier

5.7 Data Assessment

The condition data used in the various asset condition assessment(s) included the following:

- Asset Properties (e.g. age, PCB content, location information)
- Test Results (e.g. Oil Quality, DGA)
- Non-Conformance Logs

There are two components that assess the availability and quality of data used in the various asset condition assessment(s): Data Availability Indicator (DAI) and Data Gap.

5.7.1 Data Availability Indicator (DAI)

The *Data Availability Indicator* (DAI) is a measure of the amount of condition parameter data that an asset has available, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$HI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\,m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_{n\max} \times WCFn)}{\sum_{n=1}^{\forall n} (CPF_{n.\max} \times WCPFn)}$$

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data Availability Coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

It is important to note that DAI is measured against the parameters that make up the Health Index formula for a particular asset and that the Health Index formula is based only on data that is collected by GSHI. There are additional parameters that are important indicators of degradation that may not be currently collected by GSHI. Note that an asset may have a high DAI value, yet, the quality of the parameters used in the Health Index formula may require refinement. When the condition parameters used in the Health Index formula are of good quality, have few data gaps and a high value of DAI, there will be a high degree of confidence that the Health Index score accurately reflects that particular asset's condition.

5.7.2 Data Gap

The set of unavailable data are referred to as *data gaps*. A data gap is the case where none of the units in an asset group has data for a particular asset condition criteria. The situation where data is provided for only a subset of the asset population is not considered as a data gap.

As part of the Asset Condition Assessment performed by Kinectrics for GSHI in 2011, the data gaps for each asset category were identified. In addition, the missing data items were ranked in terms of importance. There were three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	☆☆☆
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	☆☆
Low	Helpful data; least indicative of asset deterioration	☆

It was generally recommended that data collection be initiated for the most critical items because such information would yield higher-quality Health Index formulations.

GSHI is currently in the process of working with a software firm named PartnerSoft to implement a system that standardizes and computerizes inspection records. Going forward, it is GSHI's goal that the inspection-based parameters presented in the Asset Condition Assessment report filed by Kinectrics be included as standard inspection items. It is also expected that the data gap inspection parameters identified for Pole and Pad Mounted Transformers, Overhead Line Switches, and Poles be incorporated into the new inspection system.

Breakers, Reclosers, Pad-Mounted Switchgear and Underground Cables are not included in this report. This is because there was insufficient data collected for these asset categories. It is GSHI's goal to begin collecting data for these asset categories so that they may be included in future assessments.

6 Distribution Asset Lifecycle Management

6.1 Wood Poles

The GSHI overhead distribution system is supported both electrically and mechanically by a system of supporting poles and fixtures. The reliability and safety of the overhead distribution system is contingent on the performance of these poles and fixtures.

Wood poles are used to support primary distribution lines at voltages ranging from 4.16 kV to 44 kV. The wood species commonly used for distribution wood poles predominantly include Red Pine, Jack Pine and Western Red Cedar (WRC), either butt-treated or full-length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used.

Distribution line design standards dictate usage of poles of varying height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into Classes (1 to 7) which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable and/or other telecommunications facilities.

Concrete poles are not used extensively in the GSHI system. They are available with round, square and octagonal cross-sections in lengths up to 60 feet. The strength of the pole is specified by a Class from A to D indicating light to heavy duty. They are supplied with a variety of pre-determined attachment patterns. Concrete poles are a relatively expensive option compared to wood or steel poles. They are heavy to transport and install. They have a clean matte appearance that is stable over long time periods and blends in to most environments. They have a longer expected service life than wood or steel. They are harder to climb and to make attachments-to once they are in service.

GSHI owns and/or operates plant on approximately 15,450 wood poles. In addition, GSHI owns approximately 165 concrete poles. The current levelized replacement program is focused on the wood poles on which GSHI operates due to the age and population of this asset class. Pole replacement projects are medium to low complexity projects with an average cost of approximately $7,500 to $12,000 per pole.

Based on the current asset demographics and failure projections, a levelized replacement rate of 297-300 wood poles per year is recommended to maintain the current failure rates over the next 10 years. Beyond 2025, it is expected that replacement rates will need to be increased to 308-312 poles per year. If proactive management of this asset class is not maintained, it is projected that the labour resource requirements to maintain GSHI's wood pole assets will exceed a sustainable level.

For any Asset Management process, demographic information is fundamental. Information might include quantities, location, type and age. GSHI's Geographic Information System (GIS) contains a registry of all distribution system assets. The available information on distribution poles includes location, number (and type) of circuits, voltage levels and any equipment mounted to the pole. This information may be used to evaluate the number of customers served, redundancy and safety/environmental risks, which in turn help to determine the consequence(s) of a pole failure. Finally, while consistent information of wood pole age is not always readily available, an asset condition assessment using asset-specific condition criteria was undertaken by Kinectrics and was employed by GSHI to evaluate a general "health index" of the wood pole asset class.

The wood pole asset base consists of both GSHI-owned poles as well as poles that are owned by a third party on which GSHI is a tenant. As both types of poles support GSHI distribution circuits, they have been included together in this analysis.

6.1.1 Wood Pole Demographics

GSHI owns 12,377 wood poles and 165 non-wood poles. Further, we operate on an additional 3,075 wood poles which are owned by third parties. Demographics for these assets have been extrapolated from the asset information stored in the GIS system. Health Indices results are as calculated from the Asset Condition Assessment report conducted by Kinectrics Inc on behalf of GSHI in 2011.

Figure 6-1 Sudbury Hydro All Wood Pole Health Index Distribution

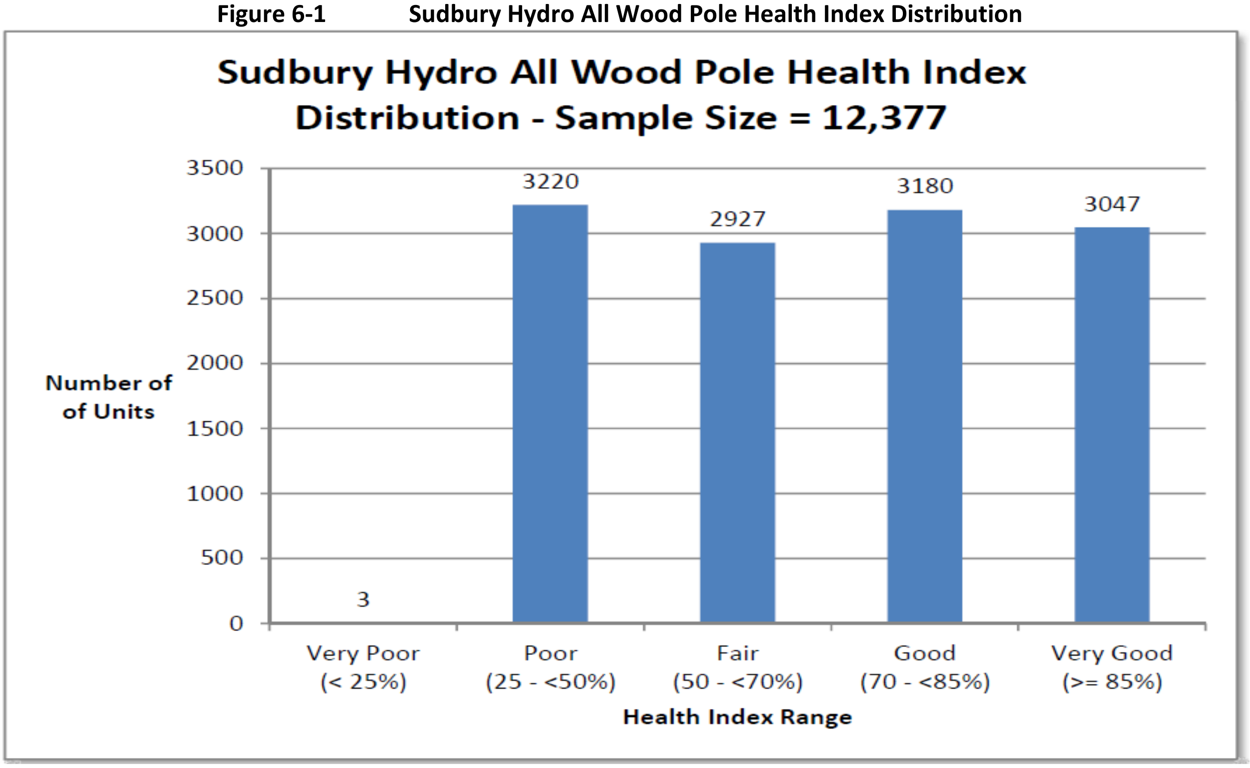


Figure 6-2 Bell All Wood Pole Health Index Distribution

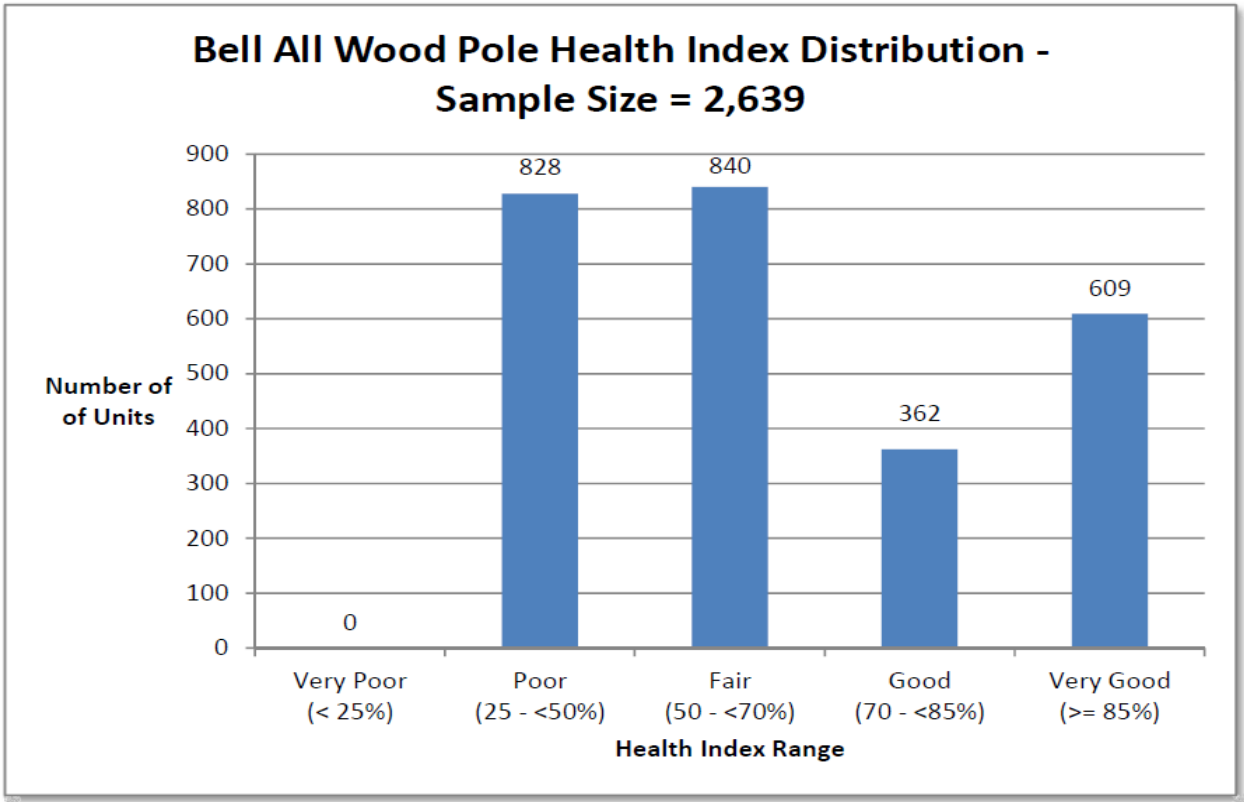


Figure 6-3 Hydro One All Wood Pole Health Index Distribution

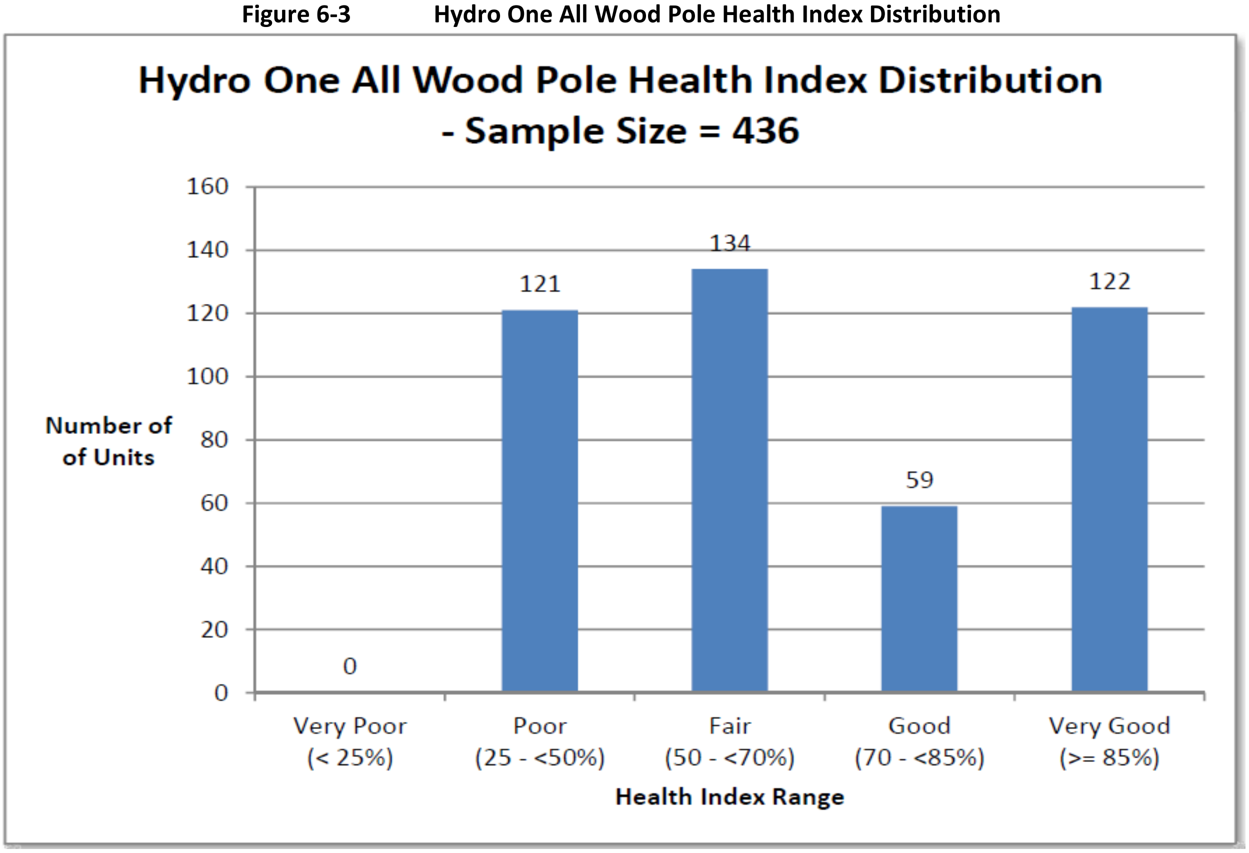


Figure 6-4 Sudbury Hydro All Wood Pole Age Distribution

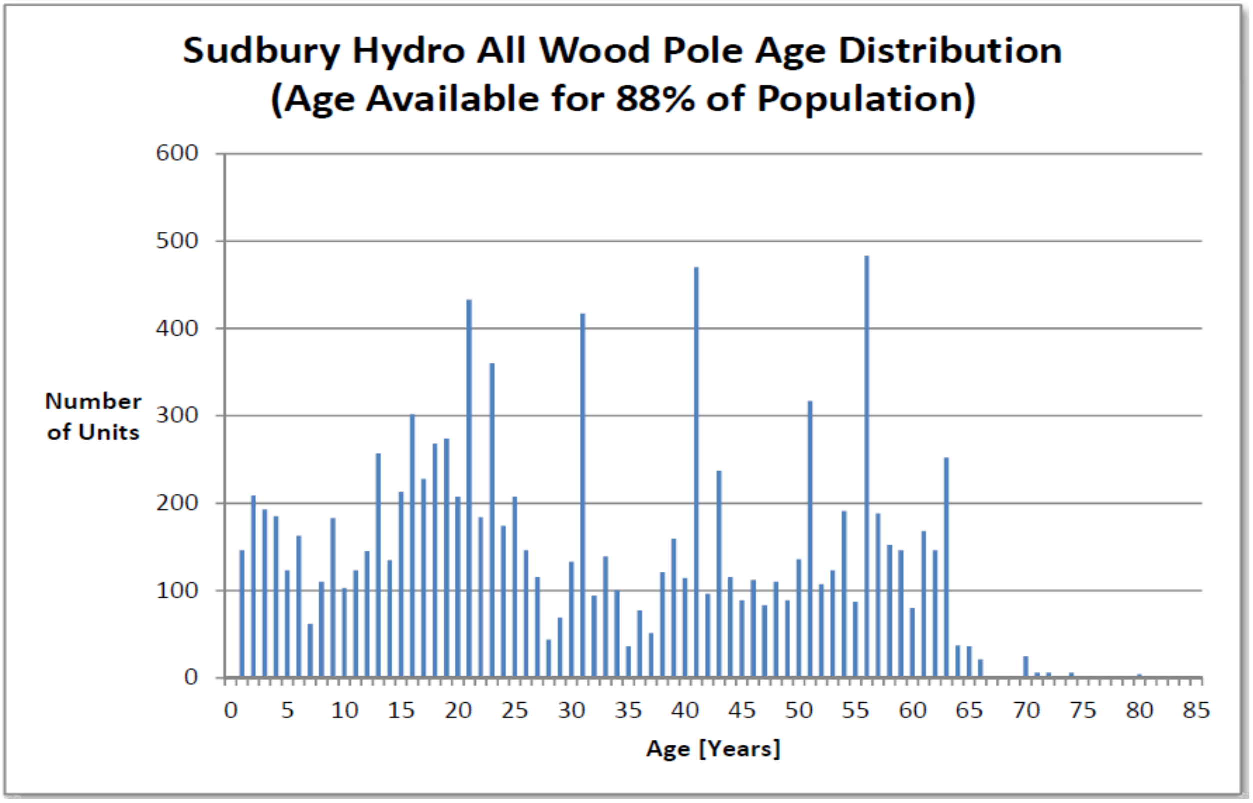


Figure 6-5 Bell All Wood Pole Age Distribution

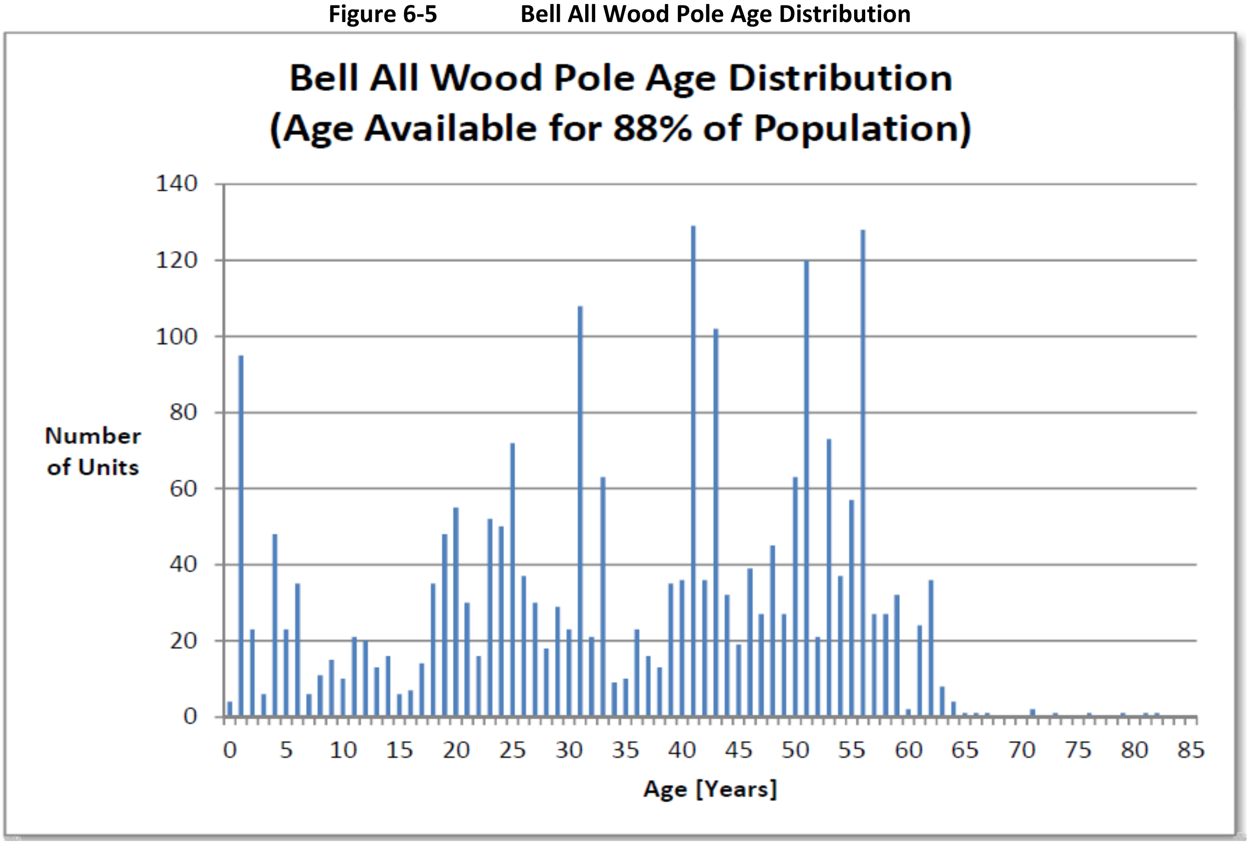
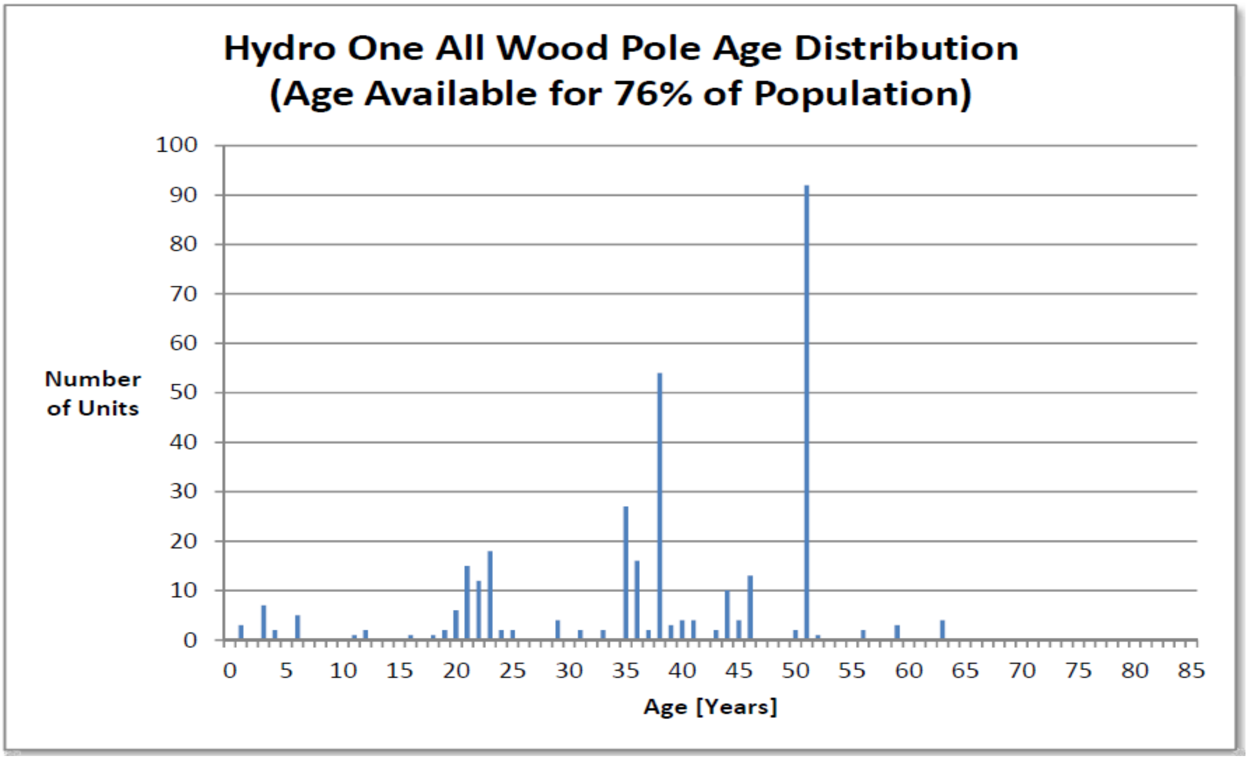


Figure 6-6 **Hydro One All Wood Pole Age Distribution**



The average age of Sudbury Hydro-owned wood poles is 32 years. Similarly, the average age is 35 and 38 years for Bell and Hydro One-owned wood poles respectively.

6.1.2 Wood Pole Health Index

There are many factors considered by utilities when establishing condition for wood poles. These include species 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 required safety and security obligations.

The only available information for Poles was age and inspection information on pole damage and whether it is leaning. Data gaps for this asset group includes pole strength test (if applicable to the pole's age and type), and more detailed inspection information (e.g. rot, spalling, corrosion, cracks).

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

6.1.2.1 Condition and Sub-Condition Parameters

Table 6-1 Condition Weights and Maximum CPS

M	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Pole Strength**	0*	4
2	Physical Condition	3	4
3	Service Record	10	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

**This parameter only applies for wood poles that are 20 years or older

Table 6-2 Pole Strength (m=1) Weights and Maximum CPF

N	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Pole Strength	Dependent on Strength Test Method	1	4

Table 6-3 Physical Condition (m=2) Weights and Maximum CPF

N	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Damage (vehicle, lightning, etc.)	Table 6-5	1	4
2	Lean	Table 6-6	1	4
3	Rot (wood pole)	Table 6-5	0*	4
4	Animal Damage (wood pole)	Table 6-5	0*	4
5	Spalling (concrete)	Table 6-5	0*	4
6	Rebar Corrosion (concrete)	Table 6-5	0*	4
7	Pole Corrosion (steel)	Table 6-5	0*	4
8	Separation	Table 6-5	0*	4
9	Voids / Holes	Table 6-5	0*	4
10	Cracks	Table 6-5	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

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

N	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age***	Figure 6-7	2	4

*** Age is determined by the pole installation date. If no Installation Date was available, the Date of Manufacture was used.

6.1.2.2 Condition Parameter Criteria

Visual Inspection

Table 6-5 Inspection Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear – Working as Required
2	Wear or Failed – Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed – Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Yes or No

Table 6-6 Yes or No Criteria

CPF	Condition Description
4	Yes
1	No

Age

Assume that the failure rate for Distribution Asset Lifecycle Management exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)

t = time

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

The corresponding survivor function is therefore:

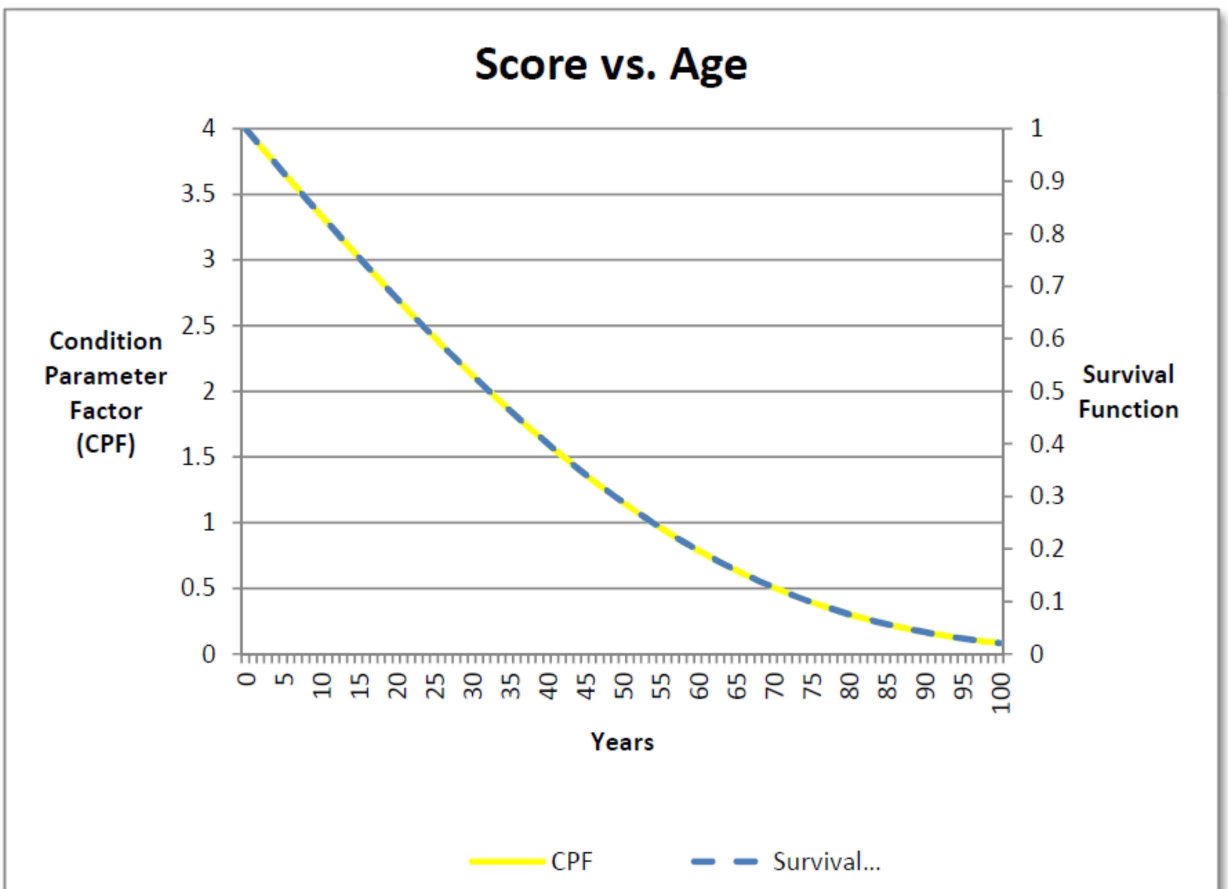
$$S_f = 1 - P_f = e^{-(f - e^{\alpha\beta})/\beta}$$

S_f = survivor function

P_f = cumulative probability of failure

Assuming that at the ages of 45 and 75 years the probability of failures (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for wood poles is also shown in the figure below:

Figure 6-7 Score Vs. Age



It can be seen from the results that wood poles are, on average as an asset group, in the worst condition of all GSHI distribution assets. Approximately 31% of all wood poles owned by Bell are in poor or very poor condition. Approximately 28% of all wood poles owned by Hydro One are in poor or very poor condition. Similarly, 26% of all wood poles owned by Sudbury Hydro are in poor or very poor condition.

6.1.3 Assessment of Wood Pole Asset Class

Although wood poles are proactively replaced, the number of expected replacements per year is based on asset failure rate, f(t). In those situations where Sudbury Hydro owns attachments on other Third Party-owned poles, we will strive to achieve the recommended levelized replacement rate through execution of the pertinent clause(s) in the respective Joint-Use Agreement(s).

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is given.

Figure 6-8 Sudbury Hydro All Wood Pole Annual Levelized Replacements

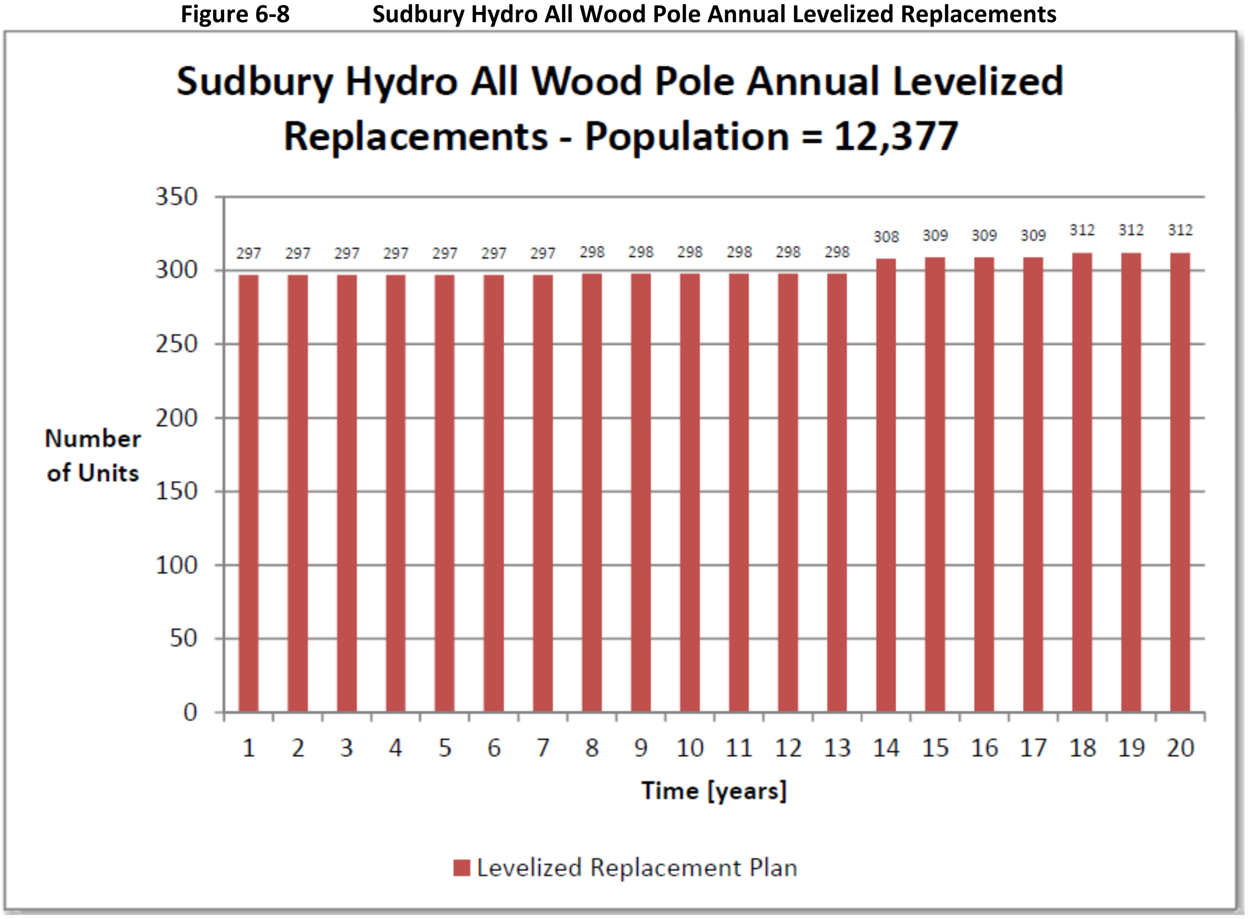


Figure 6-9 Bell All Wood Pole Annual Levelized Replacements

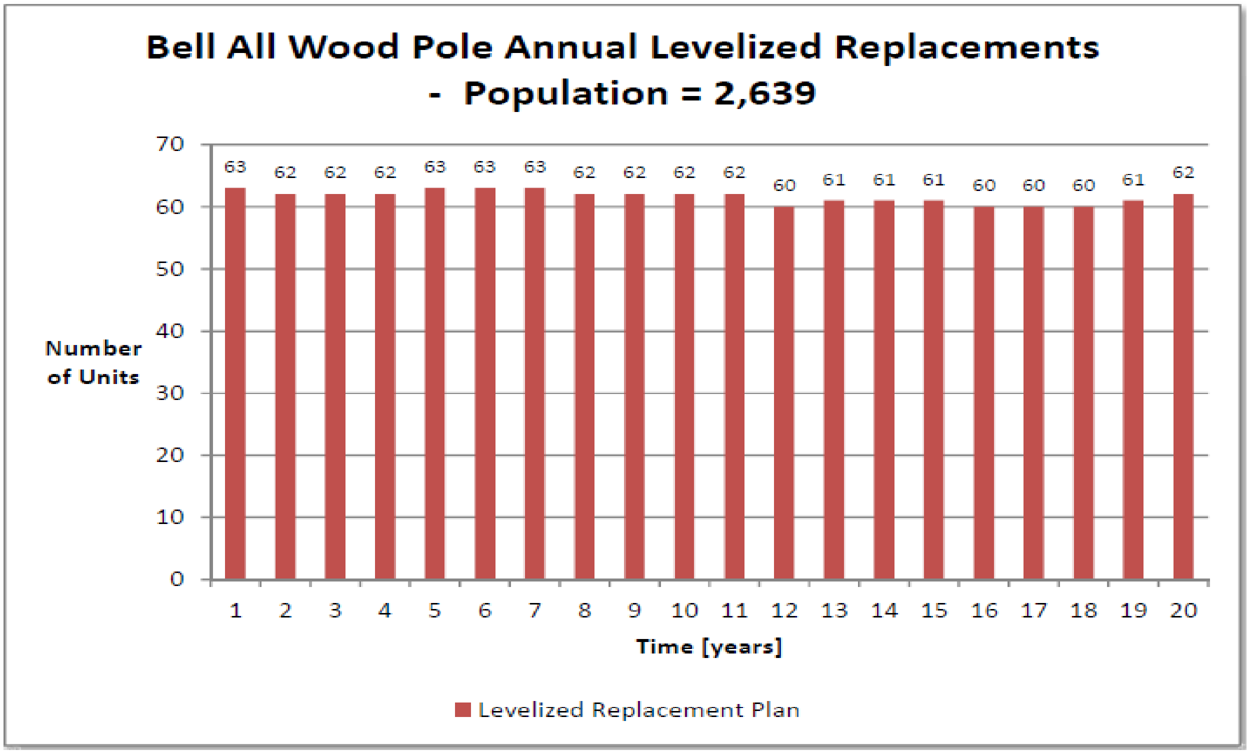
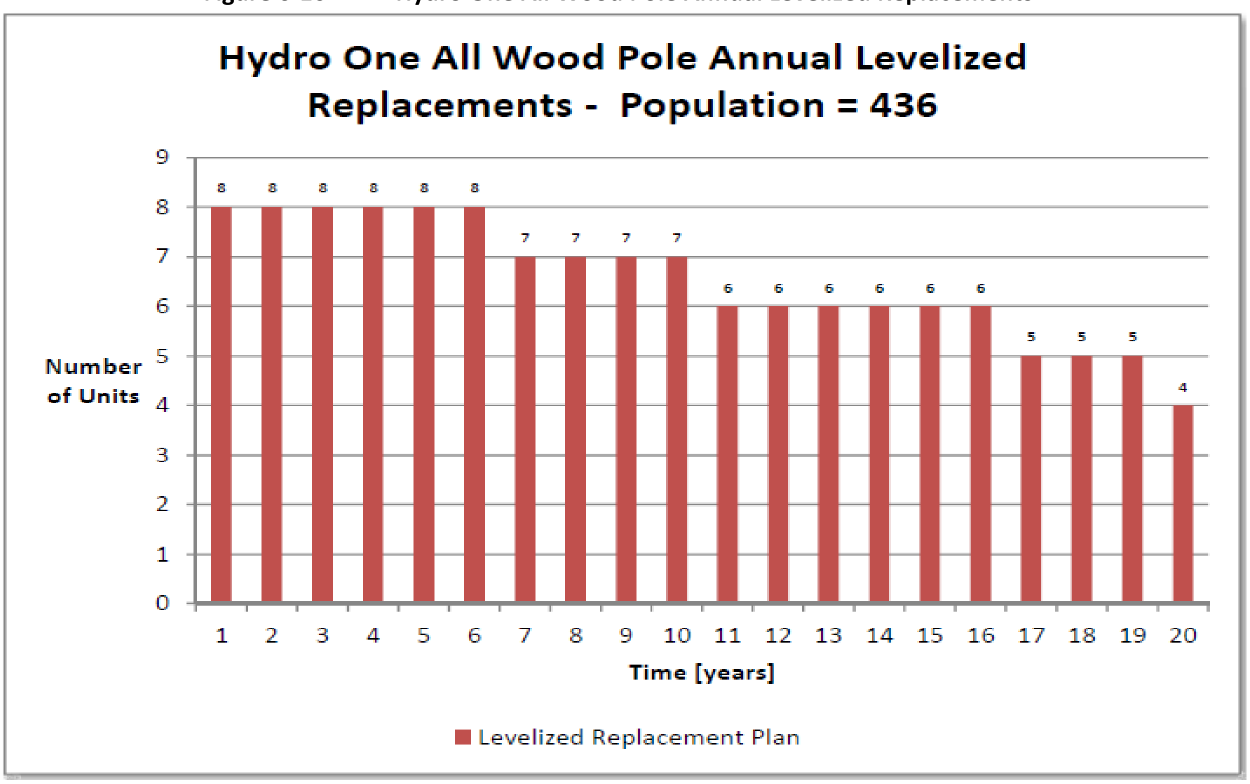


Figure 6-10 Hydro One All Wood Pole Annual Levelized Replacements



It is recommended that an annual capital replacement program be put in place to proactively replace poles in poor and very poor condition.

Other Utilities that have come before the Board have argued that a good approach to pole replacement would be to test poles and replace individual assets that fail t to meet the 65% strength test of CSA. However, implementation of Ontario Regulation 22/04 in February 2005 has had a significant impact on pole replacement and line design. In many instances, the use of Standards that more closely follow the CSA specification has resulted in like-for-like pole replacement being rejected in favour of a complete line re-design to meet the safety objectives of the Regulation. Therefore, it is the intent of GSHI to perform minimal like-for-like pole replacements. Each line section will be analyzed relative to the safety objectives of Ontario Regulation 22/04 and the "replace or rebuild" decision will be based upon the analysis results.

The data available for wood poles includes age and inspections. The average DAI for wood poles is currently 88%. The Asset Condition Assessment (ACA) report prepared by Kinectrics in 2011 outlines the data gap items that Sudbury Hydro plans to address going forward so as to further increase the confidence level in the stated Health Index value of the individual units within the wood pole asset group.

6.1.3.1 Financial Impact

Projected costs of the replacement programs have been developed based on budgeting estimates of $7,500 for a planned pole replacement and $12,500 for unplanned. The higher cost of unplanned pole replacements is due to the loss of efficiencies due to the one-off nature of these replacements.

Projected resource requirements have been based on the historical per-unit labour hours:
- 71 Labour Hours for a planned pole replacement
- 115 Labour hours for an unplanned pole replacement
- 115 Labour Hours plus an additional 12 hours for plant failure replacement based on an assumed 4 hours required for a 3 person crew to secure the failed pole.

The projected potential construction pole replacement labour base is 21,087 labour hours in 2013. The primary benefit of a planned replacement program can be seen to be the reduction in unplanned work labour hours. If replacement levels are reduced or postponed significantly, the required planned replacement levels to bring the asset class into a manageable position in future years is expected to be significant.

6.1.4 Assessment of Non-Wood Pole Asset Class

There are a small number of non-wood GSHI-owned poles in the distribution system. The GIS system contains a registry of currently-available data on these assets. Currently, the non-wood asset class is sufficiently limited and in reasonable condition. As such, a planned replacement program is not required for this asset class. Moving forward, inspection of GSHI's concrete poles during the course of regularly scheduled wood pole inspections will be used to identify replacement requirements. At this time, methods and procedures for evaluating the remaining life of these non-wood poles needs to be developed.

6.2 POLE MOUNTED TRANSFORMERS

The pole mounted transformer asset class includes roughly 4,255 service transformers which convert electrical power from its primary distribution voltage to service level voltage.

Pole mounted transformer replacement is largely driven by Federal PCB Regulation SOR 2008-273. Under this regulation, all equipment with PCB concentrations greater than 50 PPM must be removed from service prior to the end of 2025 (and for some equipment 2014). Replacements are further driven by common degradation mechanisms such as corrosion of the tank, deterioration or breakage of the bushings, deterioration of internal switching or fusing devices, internal insulating materials and oil.

Based on the available demographic information, a levelized replacement rate of 34 units annually is currently recommended. This replacement rate has been based on age-related criteria. Analysis has identified that age, while loosely related to condition, may not adequately project failure probability. Further collection of failure information and operating conditions for these units will be required to improve failure projections and proactively plan replacement requirements to maintain this asset class.

Replacement of a pole mounted transformer is a low-complexity job with an average cost of approximately $3,000 to $5,000.

6.2.1 POLE MOUNTED TRANSFORMER DEMOGRAPHICS

Demographic information for the pole mounted transformer asset class such as manufacture date, manufacturer and ratings are all stored in GSHI's GIS system. This information may be used to evaluate the number of customers served, redundancy, safety, environmental risks, and, in turn, the consequence of the failure of a distribution pole mounted transformer. GSHI owns and operates roughly 4,255 pole mounted transformers.

Figure 6-11 Pole-Mounted Transformers Age Distribution

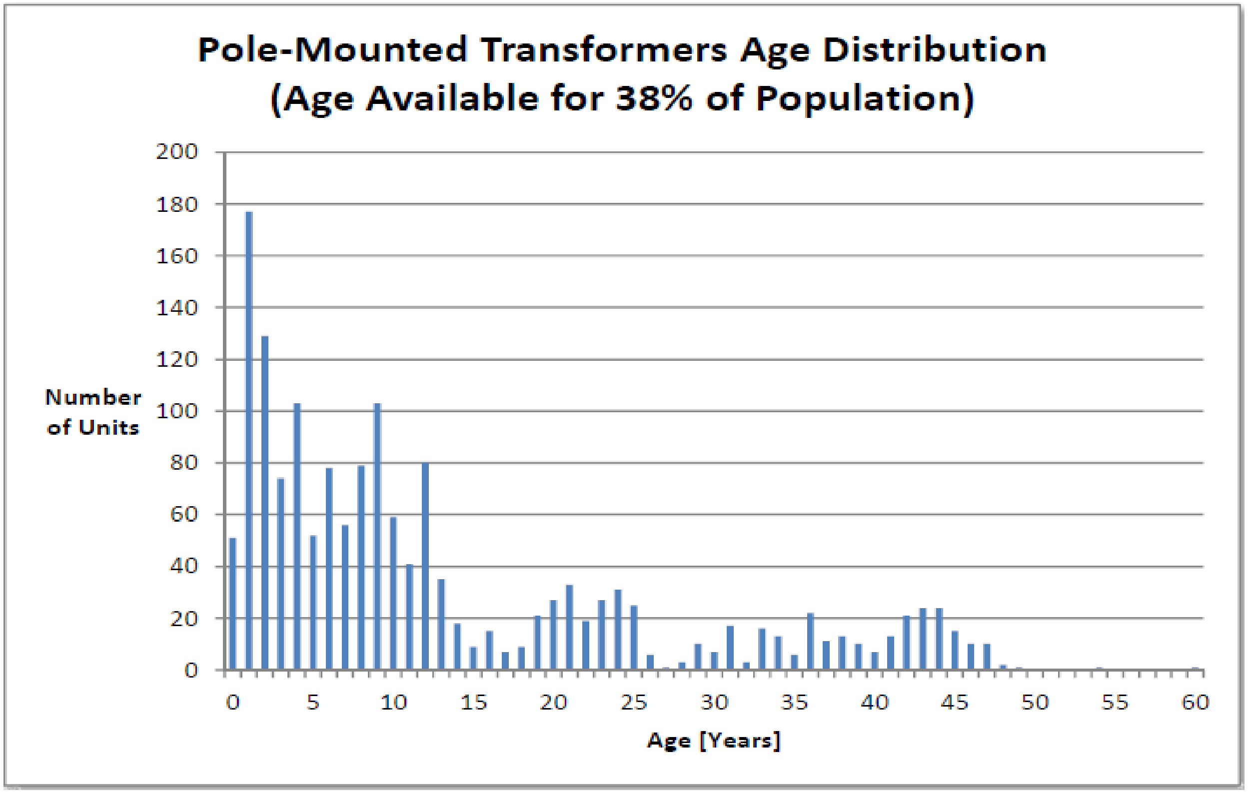
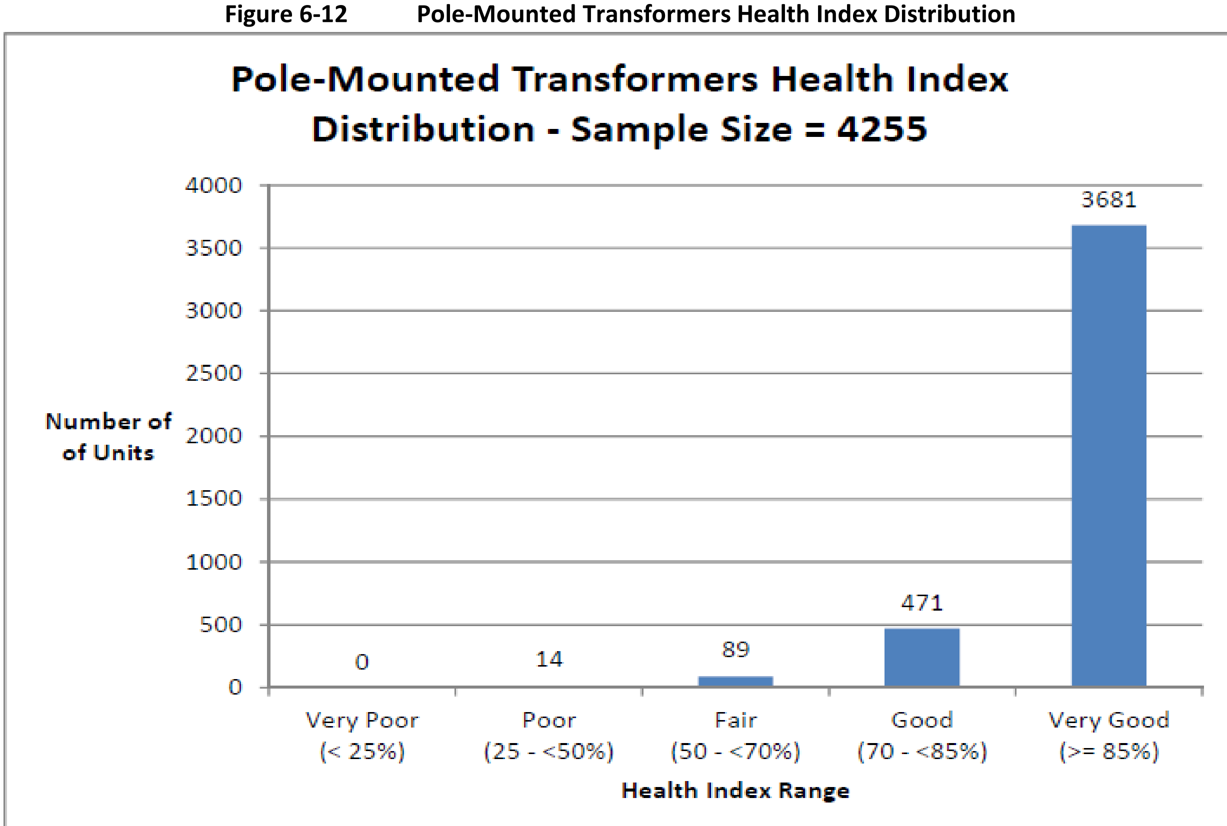


Figure 6-12 Pole-Mounted Transformers Health Index Distribution



6.2.2 Pole Mounted Transformer Health Index

Age can be related to the condition of pole mounted transformers; however, the relationship is not linear. The life of a transformer's internal insulation is related to temperature-rise and duration. Thus, transformer life is affected by electrical loading profiles and ambient temperature changes. Other degradation factors, such as mechanical damage, exposure to corrosive salts and voltage surges all have a strong effect on the health of the pole mounted transformer asset class. Moving forward, collection of condition data as it relates to pole mounted transformers through visual inspections or new technologies will allow for improvements and planning for this asset class. Visual inspection provides considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual observation and can be collected during the course of pole inspections.

While not currently available, 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. Benefits of integrating such condition information into the asset planning process will be evaluated for potential future deployment.

6.2.2.1 Condition and Sub-Condition Parameters

Table 6-7 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Physical Condition	2	4
2	Connection & Insulation	1	4
3	Service Record	7	4
	De-rating multiplier (DR) based on PCB and Proximity to Major Road	De-Rating Multiplier Table 6-15	Overall HI multiplier

Table 6-8 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Corrosion	Table 6-11	3	4

Table 6-9 Connection & Insulation (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Oil Leak	Table 6-12	2	4
2	Connection	Table 6-11	4	4
3	Grounding	Table 6-11	1	4
4	Bushing	Table 6-11	4	4

Table 6-10 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 6-13	1	4
2	Age	Figure 6-13	2	4
3	Loading	Table 6-14	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

6.2.2.2 Condition Parameter Criteria

Visual Inspections

Table 6-11 Inspection Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear, Working as Required
2	Wear or Failed, Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed, Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Yes or No

Table 6-12 Yes or No Criteria

CPF	Condition Description
4	Yes
1	No

Overall Condition

Table 6-13 Overall Condition Criteria

CPF	CPF
4	Number of closed Corrective Maintenance (CM) Counts in past 3 years is 0
3	Number of closed CM Counts in past 3 years is $\leq$ 1
0	Number of closed CM Counts in past 3 years is $\geq$ 2
Note: A non-conformance log with an "issues resolved" date is counted as a closed corrective maintenance (CM) record.	

Age

Assume that the failure rate for Distribution Asset Lifecycle Management exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)

t = time

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

The corresponding survivor function is therefore:

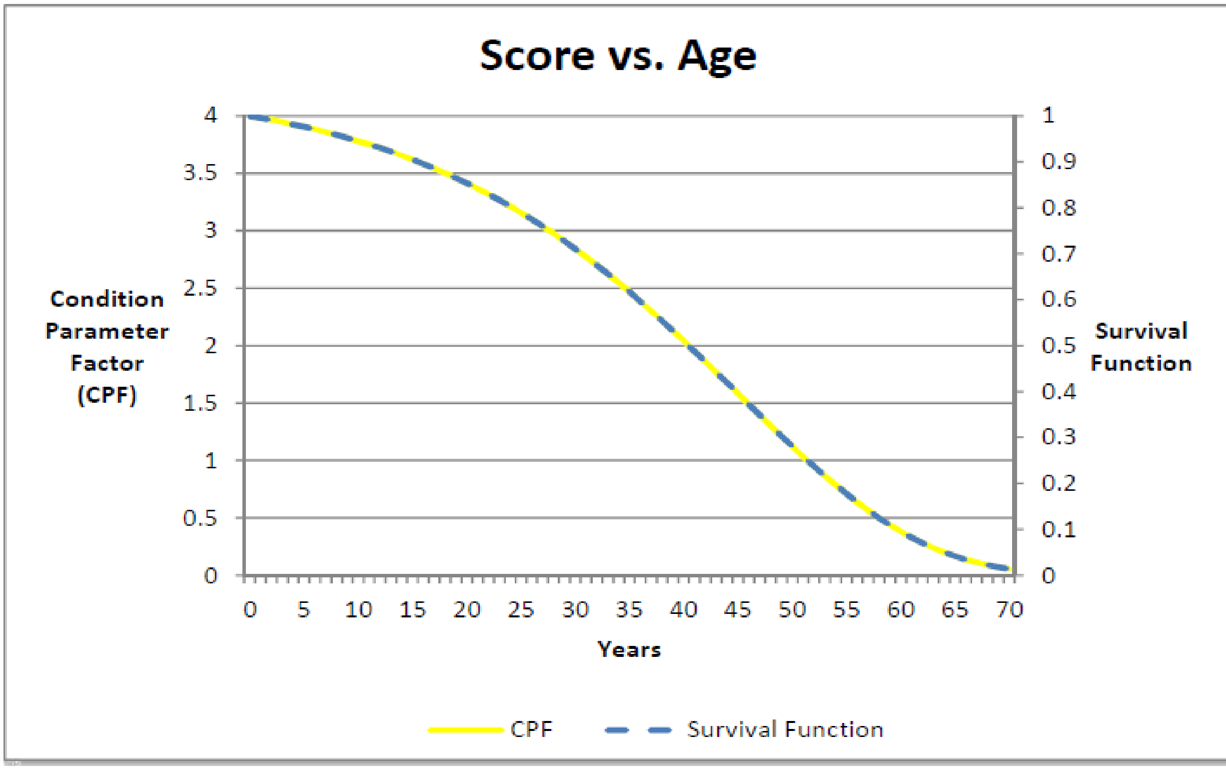
$$S_f = 1 - \ P_f = e^{-(f-e^{\alpha\beta})/\beta}$$

S_f = survivor function

P_f = cumulative probability of failure

Assuming that at the ages of 45 and 65 years the probability of failure (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

Figure 5-13 Score Vs. Age



Loading History

Table 6-14 Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2

NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

De-Rating (DR) Multiplier

Table 6-15 De-Rating Multiplier

n	Sub-Condition Parameter	De-Rating Criteria Lookup Table	DR
1	PCB	Table 6-16	DR = MIN (DR1, DR2)
2	Major Road Vicinity	Table 6-17	

Table 6-16 De-Rating Multiplier Criteria (PCB)

Multiplier	Condition Description
1	PCB < 50 ppm
0.25	PCB > = 50 ppm

Table 6-17 De-Rating Multiplier Criteria (Major Road Vicinity)

Multiplier	Condition Description
1	Not close to major roads
0.8	Close to major roads

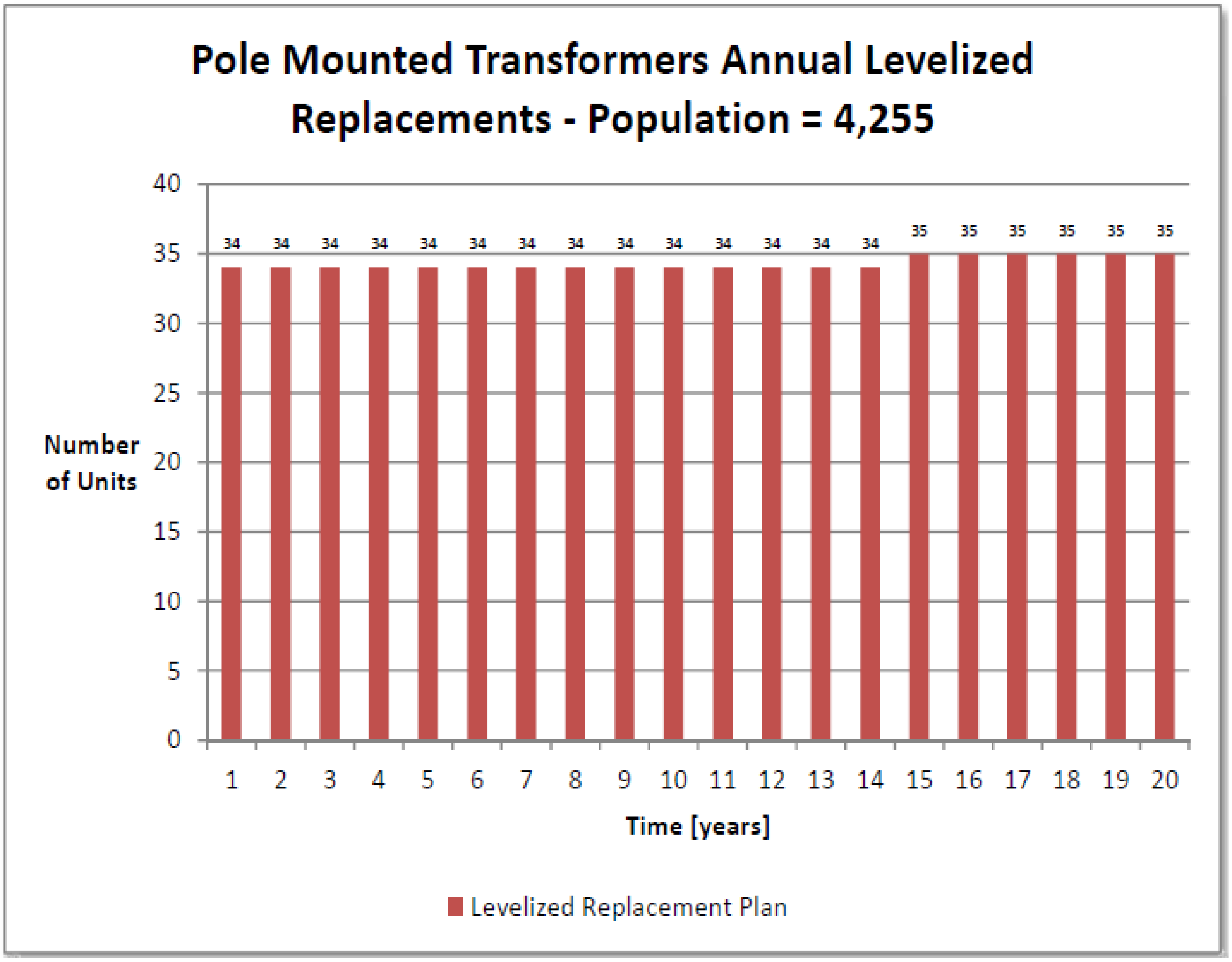
It can be seen from the results that the average Health Index value for this asset group is 96%.

6.2.3 Assessment of Pole Mounted Transformer Asset Class

As it is assumed that pole mounted transformers are reactively replaced, the number of expected replacements per year is based on asset failure rate, f(t).

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is given.

Figure 6-14 Pole Mounted Transformers Annual Levelized Replacements



The data available for pole mounted transformers includes age, inspections, PCB content and location. The average DAI for pole mounted transformers is currently 71%. However, data related to Age, which has a substantial weight in the Health Index formula, is available for only 38% of the asset population. The Asset Condition Assessment (ACA) report prepared by Kinectrics in 2011 outlines the data gap items that Sudbury Hydro plans to address going forward so as to further increase the confidence level in the stated Health Index value of the individual units within the pole mounted transformer asset group.

6.3 Pad Mounted Transformers

The pad mounted transformer asset class includes roughly 1,288 service transformers which convert electrical power from its primary distribution voltage to service level voltage.

Replacements are driven by common degradation mechanisms such as corrosion of the tank, deterioration or breakage of the bushings, deterioration of internal switching or fusing devices, internal insulating materials and oil. Additionally, larger pad mounted transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they approach near the end of life (EOL) before actual failure.

Based on the available demographic information, a levelized replacement rate of 15 units annually is currently recommended. This replacement rate is based on age-related criteria. Analysis has identified that age, while loosely related to condition, may not adequately project failure probability. Further collection of failure information and operating conditions for these units will be required to improve failure projections and proactively plan replacement requirements to maintain this asset class.

Replacement of a pad mounted transformer is a medium-complexity job with an average cost of approximately $7,500 to $65,000.

6.3.1 Pad Mounted Transformer Demographics

Demographic information for the pad mounted transformer asset class such as manufacture date, manufacturer and ratings are all stored in GSHI's GIS system. This information may be used to evaluate the number of customers served, redundancy, safety, environmental risks, and, in turn, the consequence of the failure of a distribution pad mounted transformer. GSHI owns and operates roughly 1,288 pad mounted transformers.

Figure 6-15 Pad-Mounted Transformers Age Distribution

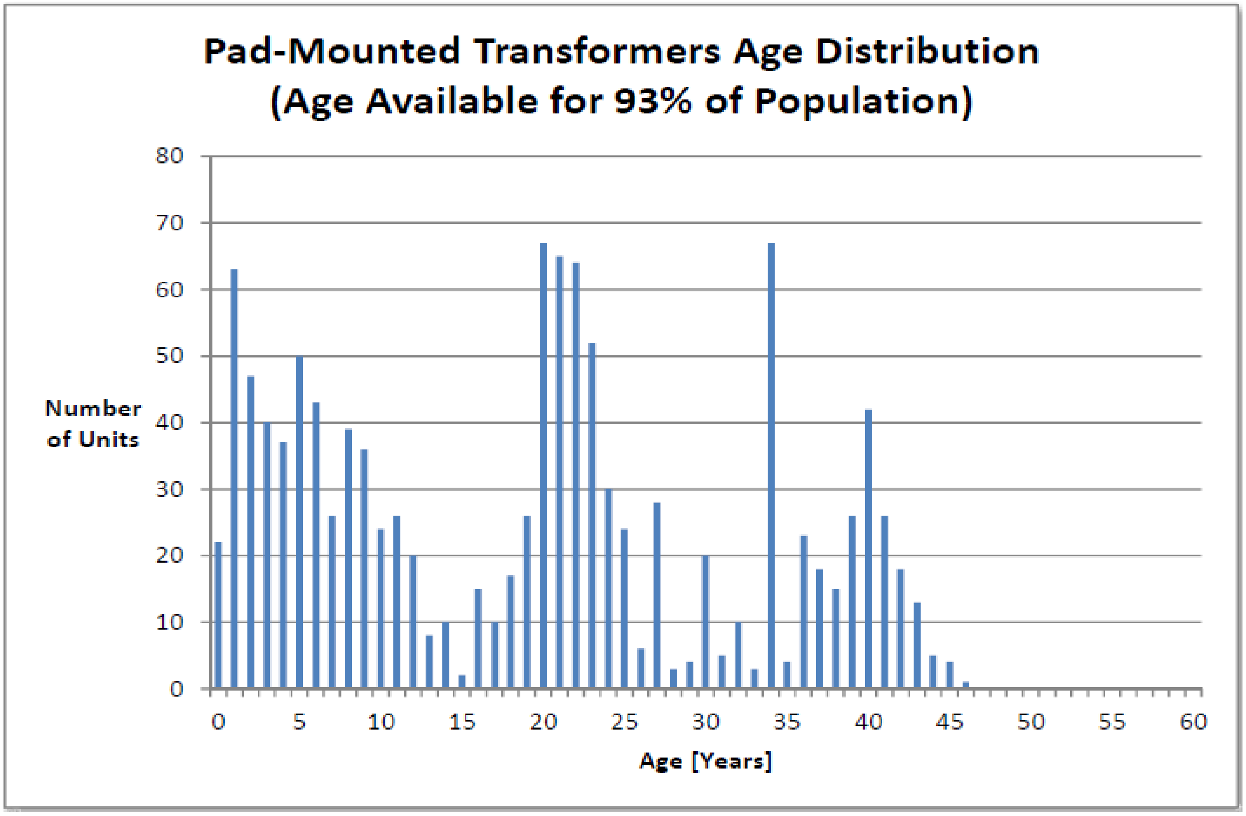
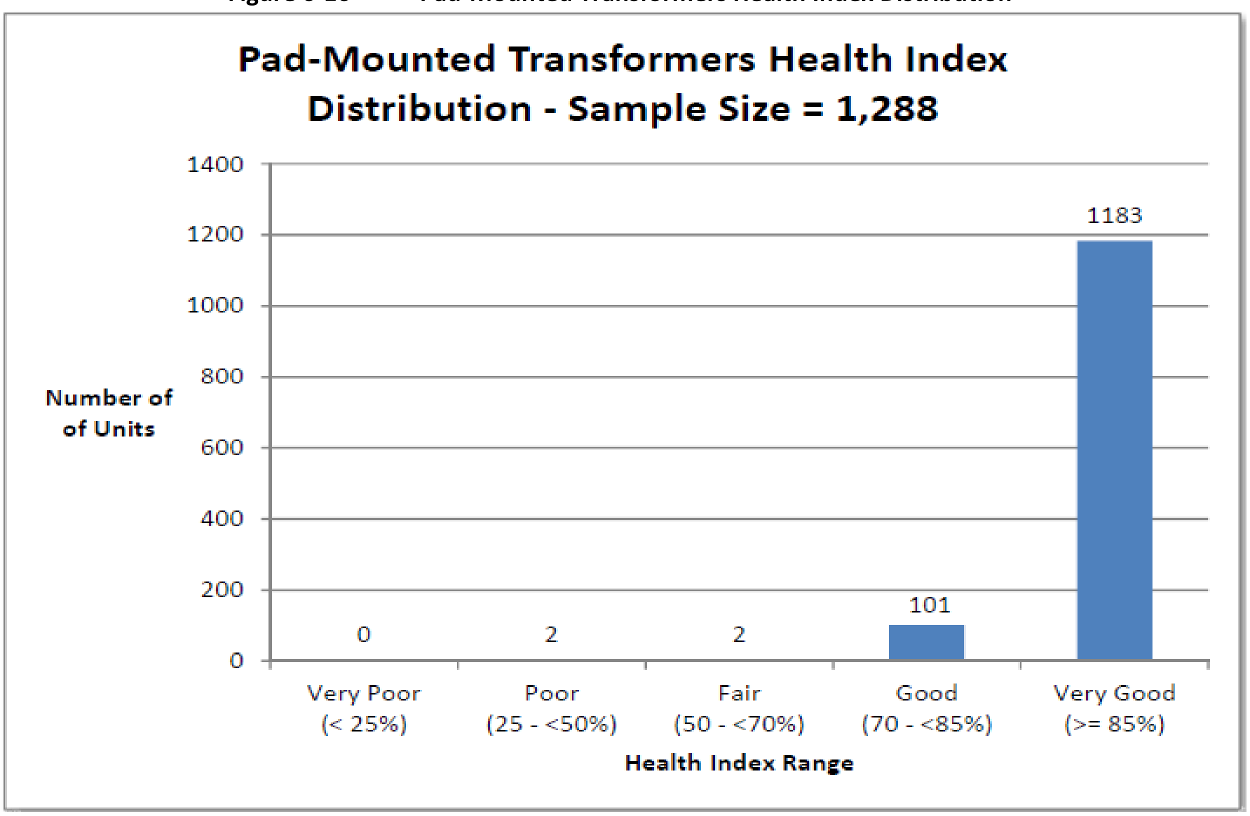


Figure 6-16 Pad-Mounted Transformers Health Index Distribution



6.3.2 Pad Mounted Transformer Health Index

Age can be related to the condition of pad mounted transformers; however, the relationship is not linear. The life of a transformer's internal insulation is related to temperature-rise and duration. Thus, transformer life is affected by electrical loading profiles and ambient temperature changes. Other degradation factors, such as mechanical damage, exposure to corrosive salts and voltage surges all have a strong effect on the health of the pad mounted transformer asset class. Moving forward, collection of condition data as it relates to pad mounted transformers through visual inspections or new technologies will allow for improved planning for this asset class. Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings and rusting of tanks can all be established by visual observation and can be collected during the course of typical inspections.

While not currently available, 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. Benefits of integrating such condition information into the asset planning process will be evaluated for potential future deployment.

6.3.2.1 Condition and Sub-Condition Parameters

Table 6-18 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Physical Condition	2	4
2	Connection & Insulation	1	4
3	Service Record	7	4
	De-rating multiplier (DR) based on proximity to Major Road	Table 6-27	Overall HI multiplier

Table 6-19 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Corrosion	Table 6-22	3	4

Table 6-20 Connection & Insulation (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Oil Leak	Table 6-23	2	4
2	Connection	Table 6-22	4	4
3	Grounding	Table 6-22	1	4
4	Bushing	Table 6-22	4	4
5	Elbow	Table 6-24	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 6-21 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 6-24	1	4
2	Age	Figure 6-17	2	4
3	Loading	Table 6-26	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

6.3.2.2 Condition Parameter Criteria

Visual Inspections

Table 6-22 Inspection Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear – Working as Required
2	Wear or Failed – Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed – Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Yes or No

Table 6-23 Yes or No Criteria

CPF	Condition Description
4	Yes
1	No

Overall Condition

Table 6-24 Overall Condition Criteria

CPF	Condition Description
4	Number of closed Corrective Maintenance (CM) Counts in past 3 years is 0
3	Number of closed CM Counts in past 3 years is $\leq$ 1
0	Number of closed CM Counts in past 3 years is $\geq$ 2
Note: A non-conformance log with an "issues resolved" date is counted as a closed corrective maintenance (CM) record	

OK or Not OK

Table 6-25 OK or Not OK Criteria

CPF	Condition Description
4	OK
1	Not OK

Age

Assume that the failure rate for Distribution Asset Lifecycle Management exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)

t = time

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

The corresponding survivor function is therefore:

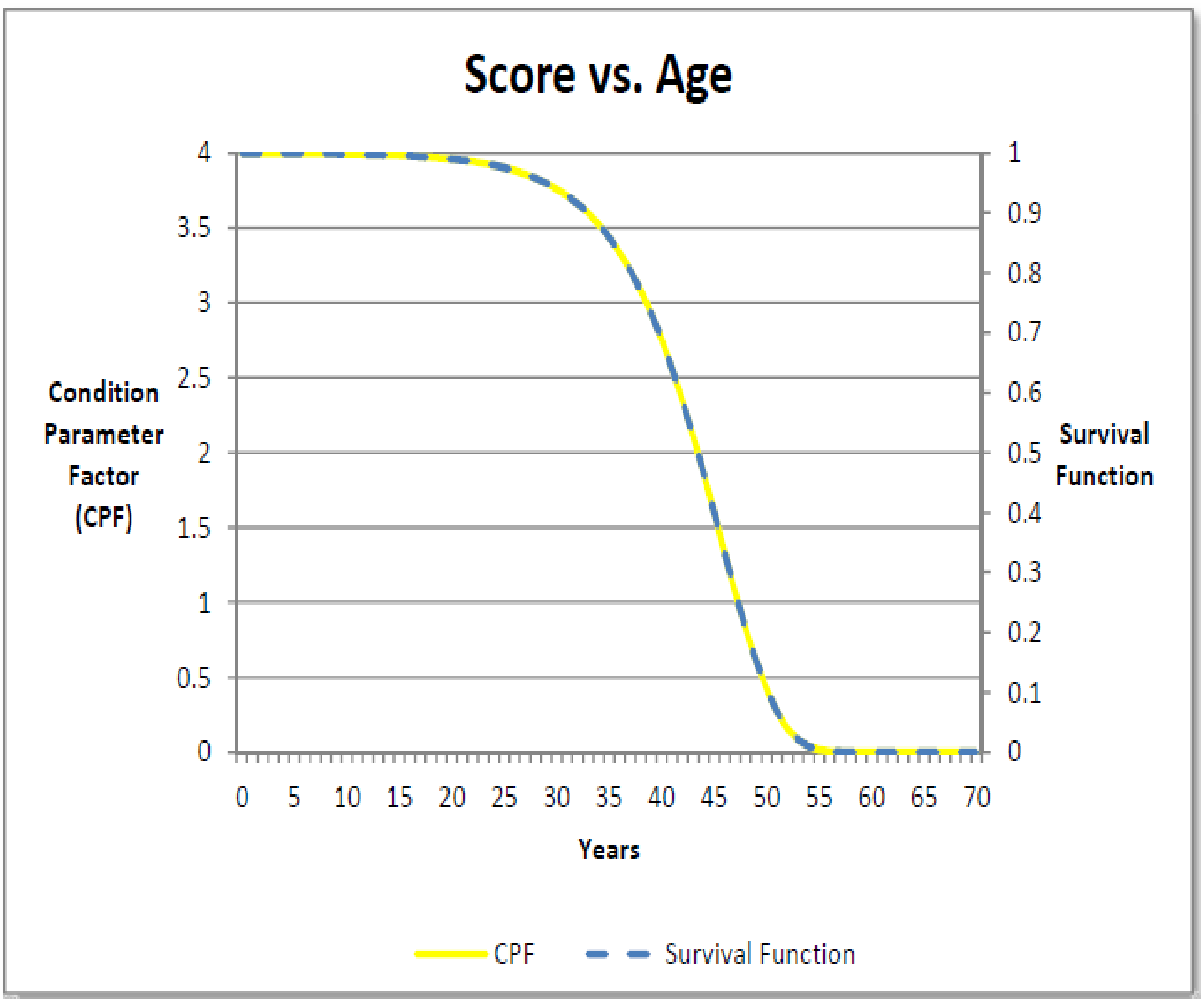
$$S_f = 1 - P_f = e^{-(f-e^{\alpha\beta})/\beta}$$

S_f = survivor function

P_f = cumulative probability of failure

Assuming that at the ages of 45 and 50 years the probability of failure (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

Figure 6-17 Score Vs. Age



Loading History

Table 6-26 Loading History

Data: S1, S2, S3, …, SN   recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA\times 4+NB\times 3+NC\times 2+ND\times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

De-Rating (DR) Multiplier

Table 6-27 De-Rating Multiplier (Major Road Vicinity)

Multiplier	Condition Description
1	Not close to major roads
0.8	Close to major roads

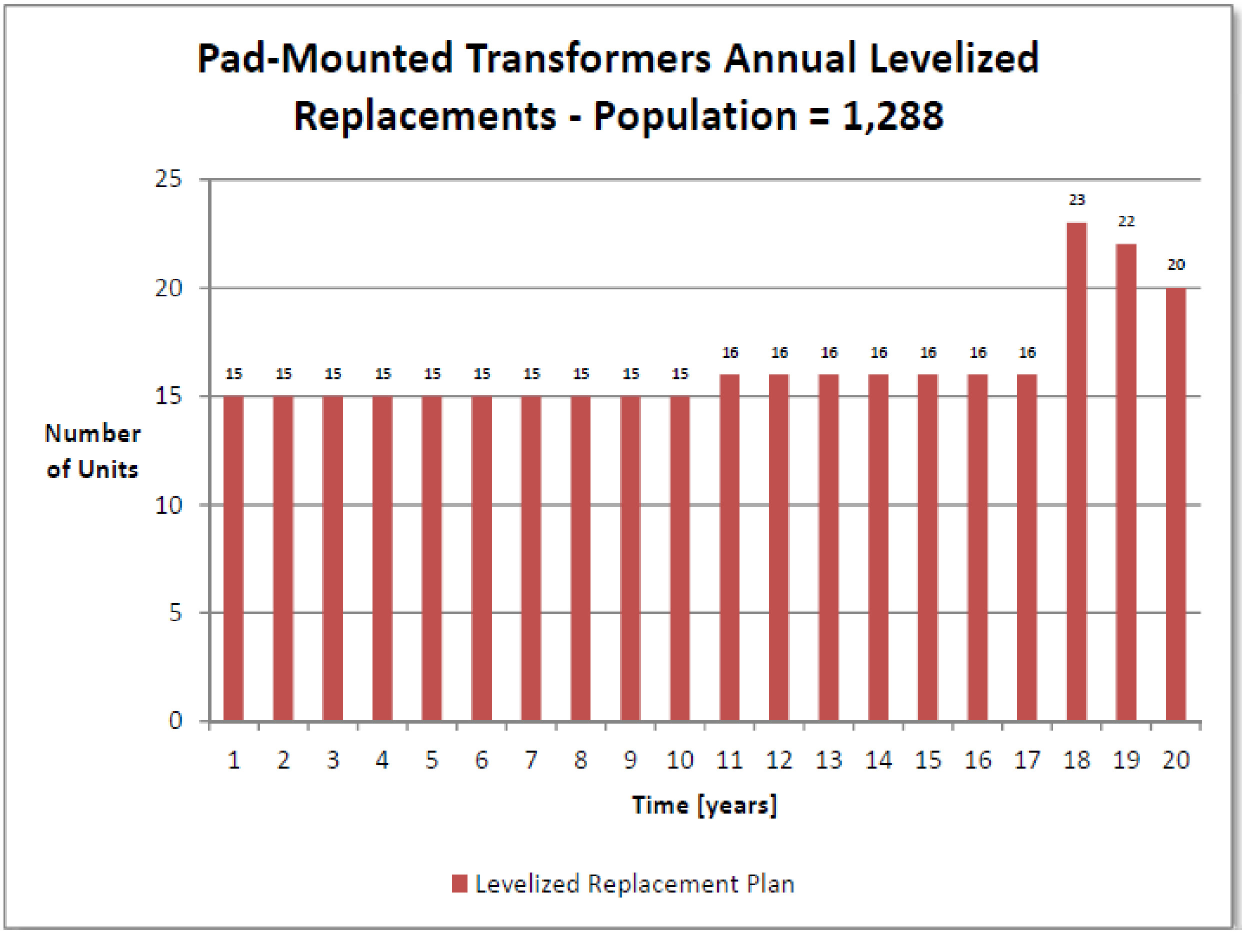
It can be seen from the results that the average Health Index value for this asset group is 97%.

6.3.3 Assessment of Pad Mounted Transformer Asset Class

As it is assumed that pad mounted transformers are reactively replaced, the number of expected replacements per year is based on asset failure rate, f(t).

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is given.

Figure 6-18 Pad-Mounted Transformers Annual Levelized Replacements



The data available for pad mounted transformers includes age, inspections, PCB content and location. The average DAI for pad mounted transformers is currently 97%. In this asset group, much of the required data have been incorporated in the Health Index formula. Still, additional helpful data remains to be collected. The Asset Condition Assessment (ACA) report prepared by Kinectrics in 2011 outlines the data gap items that Sudbury Hydro plans to address going forward so as to further increase the confidence level in the stated Health Index value of the individual units within the pad mounted transformer asset group.

6.4 Overhead Line Switches

The overhead line switch asset class includes roughly 1,771 units whose primary function is to facilitate isolation of line sections or equipment for maintenance, safety or other operating requirements.

Replacements are driven by common degradation mechanisms such as corrosion around mechanical linkages , loose connections or blades falling out of alignment. The asset class is typically a run-to-failure asset class unless a technical and/or safety issue has been identified.

Based on the available demographic information, a levelized replacement rate of 7 units annually is currently recommended.

Replacement of overhead line switches is a low-complexity job with an average cost of approximately $1,000 to $2,000.

6.4.1 Overhead Line Switch Demographics

Demographic information for the overhead line switch asset class such as location, manufacturer and ratings are all stored in GSHI's GIS system. This information may be used to evaluate the number of customers served, redundancy, safety, environmental risks, and, in turn, the consequence of the failure of an overhead line switch. GSHI owns and operates roughly 1,771 overhead line switches.

Figure 6-19 Overhead Line Switches Age Distribution

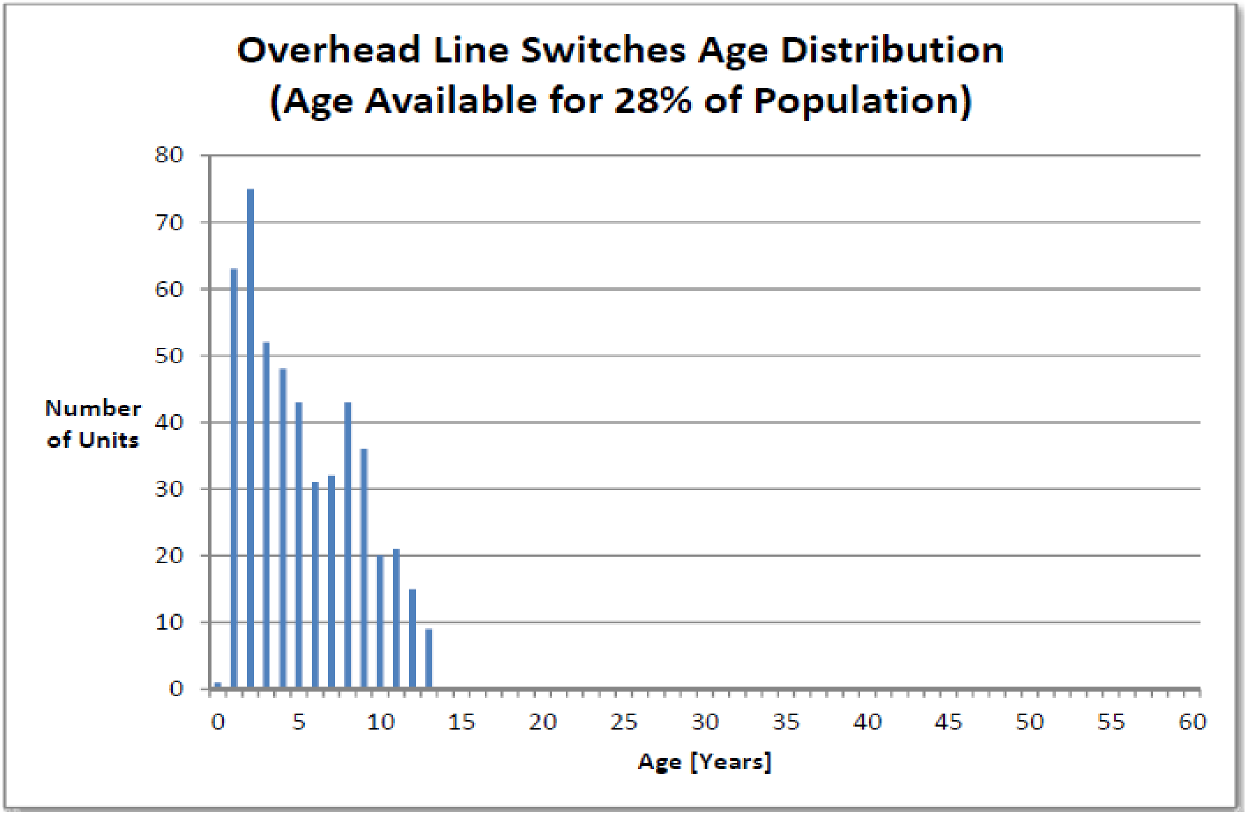
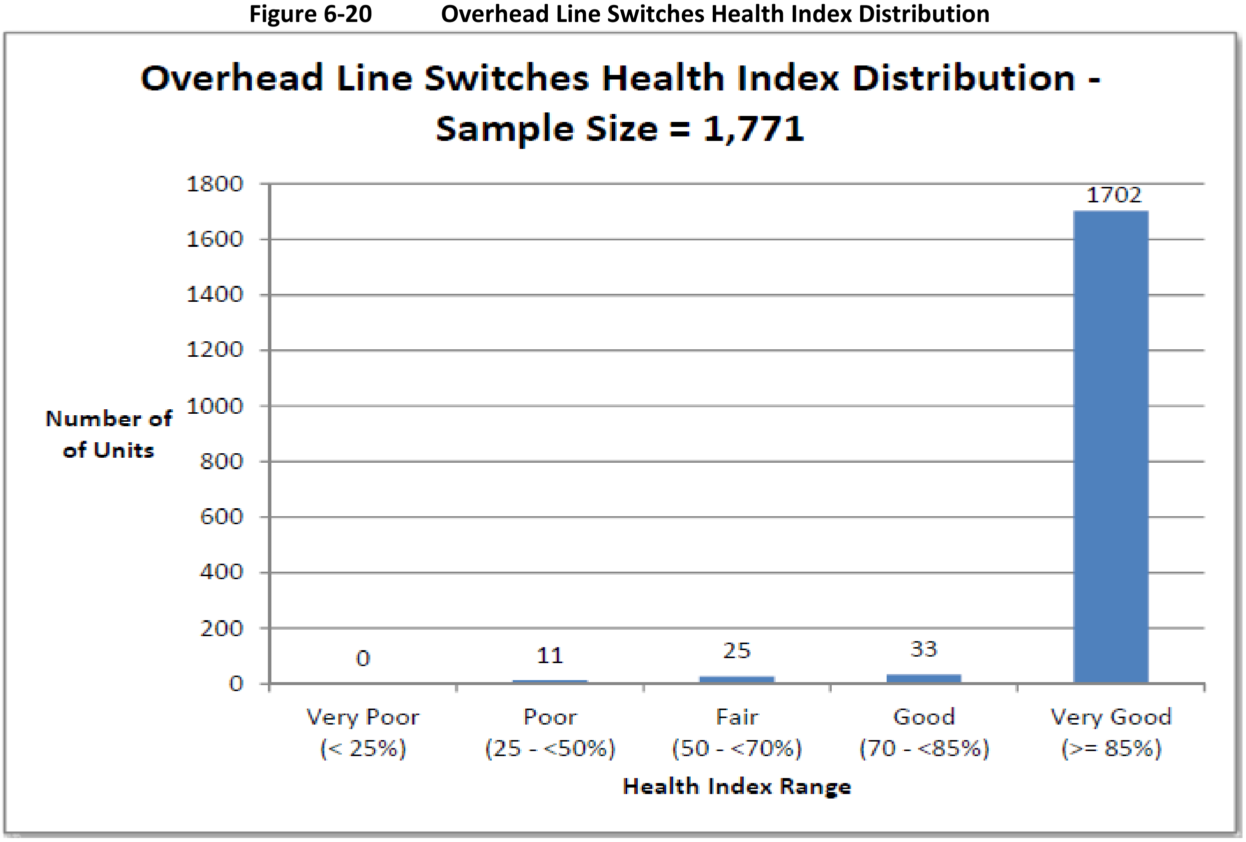


Figure 6-20 Overhead Line Switches Health Index Distribution



6.4.2 Overhead Line Switch Health Index

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

6.4.2.1 Condition and Sub-Condition Parameters

Table 6-28 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Operating Mechanism	14	4
2	Arc Extinction	5	4
3	Insulation	2	4
4	Service Record	2	4

Table 6-29 Operating Mechanism (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Switch	Table 6-33	1	4
2	Manual Operation (manually operated switch)	Table 6-33	0*	4
3	Motor Mechanism (motorized switch)	Table 6-33	0*	4
4	Remote Operation (remotely operated switch)	Table 6-33	0*	4
5	Switch Mounting	Table 6-35	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 6-30 Arc Extinction (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Arc Interrupter	Table 6-33	1	4
2	Arc Horn	Table 6-33	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 6-31 Insulation (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Insulator	Table 6-33	1	4

Table 6-32 Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 6-34	1	4
2	Age	Figure 6-21	3	4

6.4.2.2 Condition Parameter Criteria

Visual Inspection

Table 6-33 Switch Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear – Working as Required
2	Wear or Failed – Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed – Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Overall Condition

Table 6-34 Overall Condition Criteria

CPF	Condition Description
4	Number of closed Corrective Maintenance (CM) Counts in past 3 years is 0
3	Number of closed CM Counts in past 3 years is ≤ 1
2	Number of closed CM Counts in past 3 years is =2
0	Number of closed CM Counts in past 3 years is ≥ 3

Note: A non-conformance log with an "issues resolved" date is counted as a closed corrective maintenance (CM) record

OK or Not OK

Table 6-35 OK or Not OK Criteria

CPF	Condition Description
4	OK
1	Not OK

Age

Assume that the failure rate for Distribution Asset Lifecycle Management exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)

t = time

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

The corresponding survivor function is therefore:

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

S_f = survivor function

P_f = cumulative probability of failure

Assuming that at the ages of 45 and 55 years the probability of failure (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

Figure 6-21 Score Vs. Age

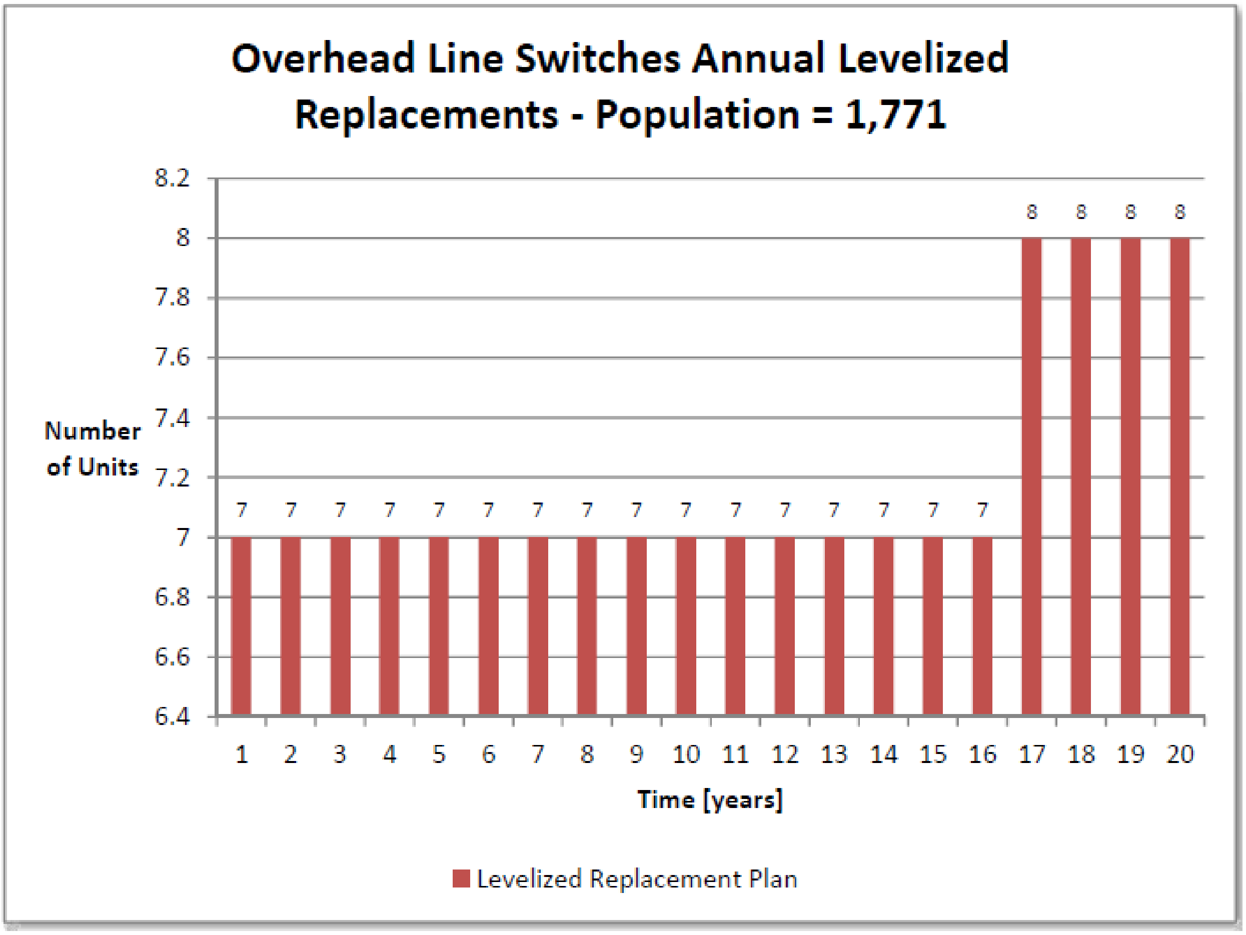
It can be seen from the results that the average Health Index value for this asset group was 99%.

6.4.3 Assessment of Overhead Line Switch Asset Class

As it is assumed that overhead line switches are reactively replaced, the number of expected replacements per year is based on asset failure rate, f(t).

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is given.

Figure 6-22 Overhead Line Switches Annual Levelized Replacements



The data available for overhead line switches includes age, inspections, and location. The average DAI for overhead line switches is currently 94%. Although age is available for only 28% of the population, the weight of "Age" is such that it does not have a significant impact on the DAI. Still, additional helpful data remains to be collected. The Asset Condition Assessment (ACA) report prepared by Kinectrics in 2011 outlines the data gap items that Sudbury Hydro plans to address going forward so as to further increase the confidence level in the stated Health Index value of the individual units within the overhead line switches asset group.

7 SUBSTATION ASSET LIFECYCLE MANAGEMENT

7.1 STATION TRANSFORMERS

From the view of both financial and operational risk, station transformers are the most important asset deployed on the distribution system. A significant proportion of station transformers employed by North American utilities were installed in the 1950s, 1960s or early 1970s. Despite the fact that the number of transformer failures arising due to End-of- Life (EOL) has to-date been relatively small, there is awareness that a majority of the transformer population will soon be reaching its end-of-life, which may significantly impact transformer failure rates.

The station transformer asset class includes 53 units whose primary function is to provide for the voltage transformation of subtransmission-level voltages down to distribution-voltage levels such as 4kV and 22kV.

Replacements are driven by such items as the condition and degradation of the insulating oil and insulating paper. Traditionally, utilities have operated "run-to-failure" regimes supported by regular inspection and maintenance programs. The age profile and operational significance of the station transformer population are such that the financial and operating consequences of increased failures are very high.

Replacement of station transformers during substation rebuilds is a high-complexity job with an average cost of approximately $300,000 to $2,500,000. In addition, station transformer replacements are often coordinated with upgrades to such items as oil containment, ground grid, cables and protection and control monitoring equipment.

Based on the available demographic information, three separate and distinct replacement plans are proposed; optimal, levelized and levelized (deferred). Because station transformers are a crucial distribution system component with major consequences of failure, it is recommended that investments be made in an expedient manner.

7.1.1 STATION TRANSFORMER DEMOGRAPHICS

The station transformer population is ageing. The average age of this asset class is 43 years. Nearly 50% of all units are aged 45 years or older.

Figure 7-1 Substation Transformers Age Distribution

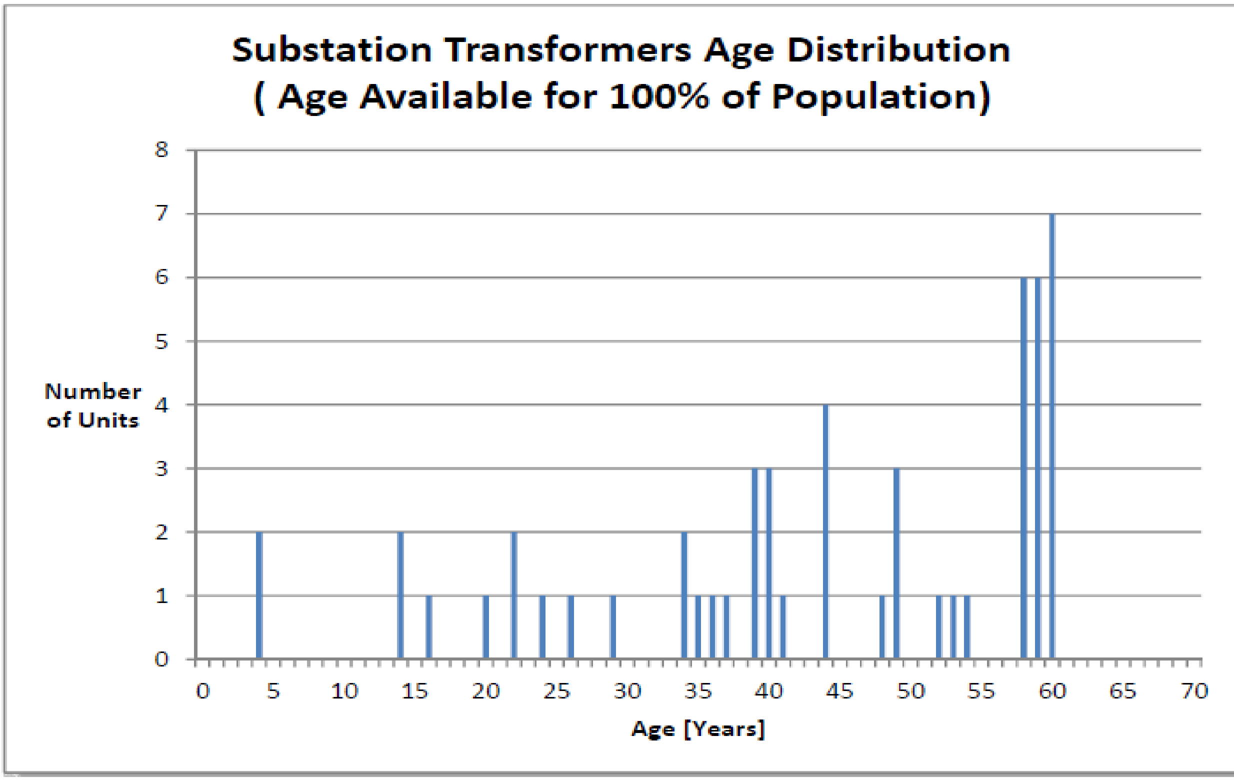
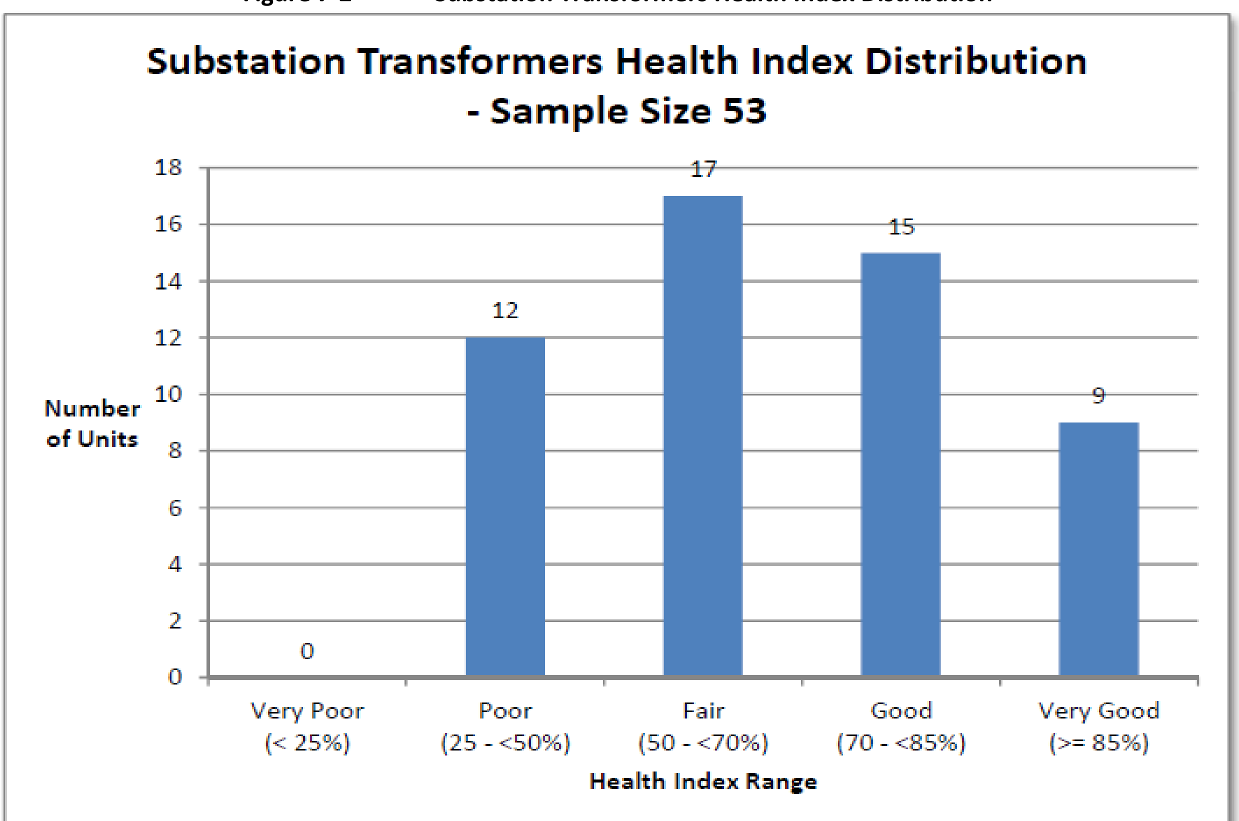


Figure 7-2 Substation Transformers Health Index Distribution



7.1.2 Station Transformer Health Index

The condition assessment of station transformers involves age, inspection results, oil quality, dissolved gas analysis and Doble tests as per General Electric (GE) tests and inspections.

7.1.2.1 Condition and Sub-Condition Parameters

Table 7-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Insulation	6	4
2	Cooling	0*	4
3	Sealing & connection	3	4
4	Service Record	3	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 7-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Oil Quality	Table 7-6	8	4
2	Oil DGA	Table 7-7	10	4
3	Winding/Doble	Table 7-8	10	4
4	Bushing	Table 7-9	5	4

Table 7-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Cooling System Status	Table 7-10	1	4

Table 7-4 Sealing & Connection (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Visual Appearance	Table 7-9	1	4
2	General Condition	Table 7-9	1	4
3	Corrosion	Table 7-9	1	4
4	Dirt	Table 7-9	1	4
5	Paint	Table 7-9	1	4
6	Tank Oil Leak	Table 7-9	5	4
7	Primary Connection	Table 7-9	3	4
8	Secondary Connection	Table 7-9	3	4
9	Grounding	Table 7-9	4	4
10	IR Thermography	Table 7-10	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 7-5 Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Loading	Table 7-11	0*	4
2	Age	Figure 7-3	3	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

7.1.2.2 Condition Parameter Criteria

Oil Quality

Table 7-6 Oil Quality Test Criteria

CPF	Description
4	Overall factor is less than 1.2
3	Overall factor between 1.2 and 1.5
2	Overall factor is between 1.5 and 2.0
1	Overall factor is between 2.0 and 3.0
0	Overall factor is greater than 3.0

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

		Scores				
		1	2	3	4	**Weight**
Moisture PPM (T ^{o}C Corrected) (From DGA test)		<=20	<=30	<=40	>40	4
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

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

For example if all data is available, overall Factor = $\dfrac{\sum Score_i \times Weight_i}{12}$

Oil DGA

Table 7-7 Oil DGA Criteria

CPF	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

*In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

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

Dissolved Gas	**Scores**						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	**2**
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	**1**
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	**1**

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

Winding Doble Test

Table 7-8 Winding Doble Test Criteria

CPF	**Description**
4	%PF < 0.5%
3	0.5% < %PF < 0.7%
2	0.7% < %PF < 1%
1	1.0% < %PF < 2.0%
0	%PF > 2.0%

Age

Assume that the failure rate for Substation Asset Lifecycle Management exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)

t = time

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

The corresponding survivor function is therefore:

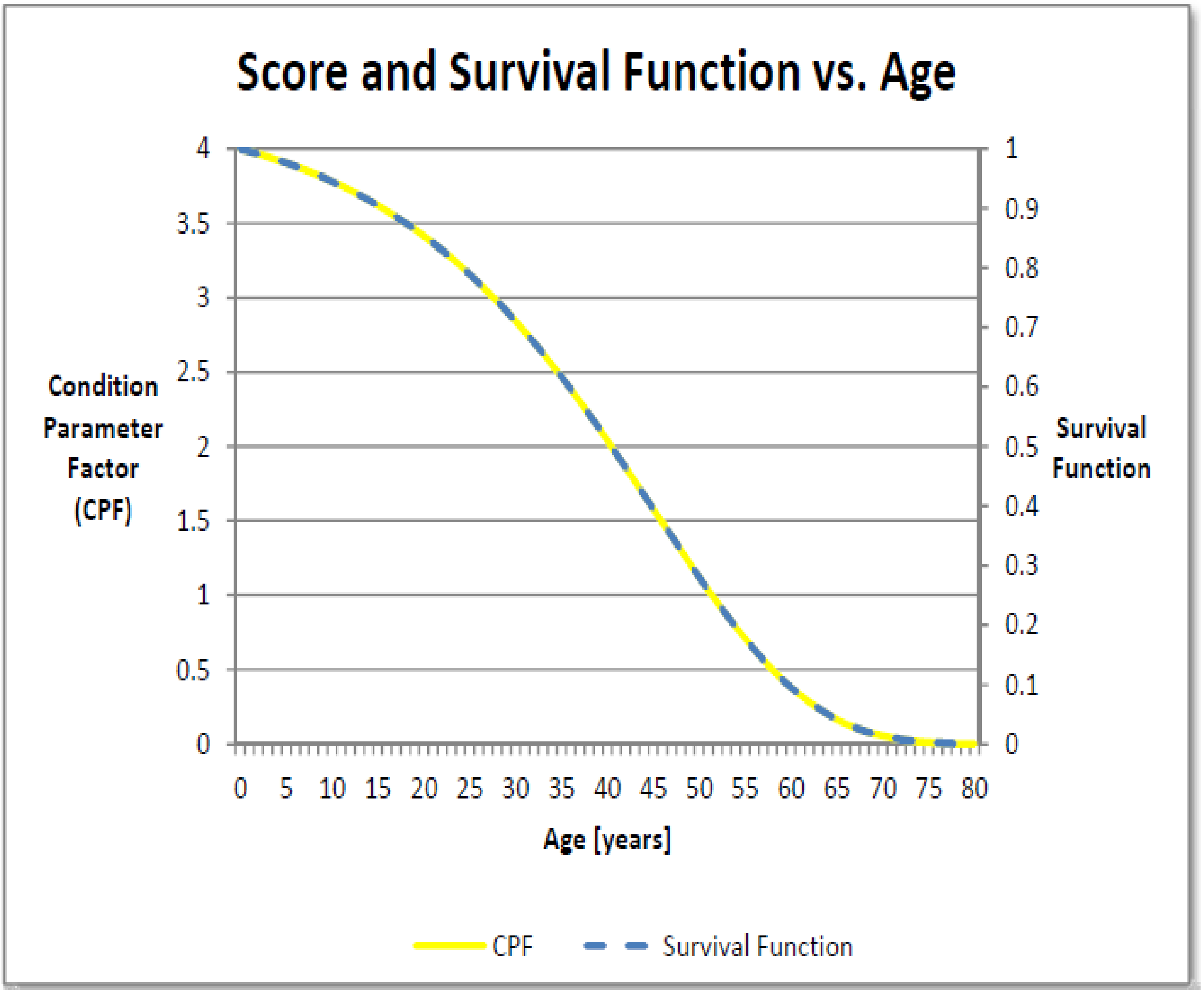
$$S_f = 1 - P_f = e^{-(f-e^{\alpha\beta})/\beta}$$

S_f = survivor function

P_f = cumulative probability of failure

Assuming that at the ages of 45 and 60 years the probability of failures (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

Figure 7-3 Score and Survival Function Vs. Age



Visual Inspections

Table 7-9 Inspection Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear, Working as Required
2	Wear or Failed, Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed, Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

OK or Not OK

Table 7-10 OK or Not OK Criteria

CPF	Condition Description
4	OK
0	Not OK

Loading History

Table 7-11 Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

It can be seen from the results that the average Health Index value for this asset group is 66%.

7.1.3 Assessment of Station Transformer Asset Class

As it is assumed that station transformers are proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 of the Kinectrics 2011 Asset Condition Assessment (ACA) Report was applied for this asset class.

As noted in Section II of the Report, a unit becomes a candidate for replacement when its risk (the product of its probability of failure and *criticality* rating), is greater than or equal to one. The probability of failure is as determined by the Health Index. Criticality is determined as shown below:

The minimum criticality, Criticality_{min}, is 1.25. This value is selected such that a unit with a probability of failure of 80% becomes a candidate for replacement (i.e. 80% * 1.25 = 1). The maximum criticality, $\text{Criticality}_{max,}$ is twice the base criticality ($\text{Criticality}_{max,}$ = 1.25*2 = 2.5).

Each unit's criticality is defined as follows:

$$\text{Criticality} = (\text{Criticality}_{max} - \text{Criticality}_{min}) * \text{Criticality\_Multiple} + \text{Criticality}_{min}$$

where the Criticality_Multiple (CM) is defined by criticality factors, weights, and scores:

$$CM = \frac{\sum_{CF=1}^{\forall CF} (CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF} (WCF_{CF})}$$

Where

CFS	Criticality Factor Score
WCF	Weight of Condition Factor

The factors, weights and the score system of each factor are as follows:

Table 7-12 Criticality Factors

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)
Location (near waterbeds)	Environmental stewardship is of the utmost importance.	35	No = 0 Yes = 1
Number of Customers	Reliable service to the greatest number of customers is vital. Does the transformer service more than 1000 customers?	25	Low = 0 High = 1
Bus Structure (open/enclosed)	Is the transformer under consideration located in an open-bus scheme within a residential subdivision? Can public safety be affected if a catastrophic failure were to occur?	20	No = 0 Yes = 1
Backup Capabilities	Can the transformer under consideration be backed-up with the portable?	10	Yes =0 No = 1
Oil Containment	All of our Stations (as of Oct 2011) do not have Oil Containment capabilities, hence the low relative score.	5	Yes =0 No = 1
Transformer Primary Protection	Is the unit's primary protection a fuse or breaker?	5	Breaker = 0 Fuse = 1

The table below shows examples of criticalities for three separate units:

Table 7-13 Criticality Multiple Examples

	Example 1			Example 2			Example 3		
Criticality Factor	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**
Location (near waterbeds)	No	0	0	Yes	1	35	Yes	1	35
Number of Customers	Low	0	0	High	1	25	High	1	25
Bus Structure (open/enclosed)	No	0	0	No	0	0	Yes	1	20
Backup Capabilities	Yes	0	0	Yes	0	0	No	1	10
Oil Containment	Yes	0	0	Yes	0	0	No	1	5
Transformer Primary Protection	Breaker	0	0	Breaker	0	0	Fuse	1	5
	Criticality Multiple		0	Criticality Multiple		0.6	Criticality Multiple		1
	Criticality$_{Example1}$		(2.5-1.25)*0 + 1.25 = 1.25	**Criticality$_{Example2}$**		(2.5-1.25) *0.6 + 1.25 = 2	**Criticality$_{Example3}$**		(2.5-1.25)*1 + 1.25 =2.5

The health index values for each station transformer asset have been tabulated below:

Table 7-14 Health Index Results for Each Substation Transformer Unit

	Transformer Name	Serial Number	Data Availability	Age	Health Index
1	West Nip 35T1	TAG6235298	52.3%	34	**25.4%**
2	Cressey 3T1 Blue Phase	165310	52.3%	60	**31.0%**
3	Cressey 3T1 Red Phase	166027	52.3%	60	**34.5%**
4	Cressey 3T1 White Phase	166026	52.3%	60	**38.4%**
5	Cressey 3T2 Red Phase	165309	52.3%	60	**38.4%**
6	Cressey 3T2 White Phase	166024	52.3%	60	**38.4%**
7	Cressey 3T2 Blue Phase	166023	52.3%	60	**38.4%**
8	Cressey 3T1 Spare	166019	52.3%	60	**38.4%**
9	Kathleen 2T1 Red Phase	506264	52.3%	59	**38.8%**
10	Kathleen 2T1 White Phase	150480	52.3%	59	**38.8%**
11	Kathleen 2T2 Red Phase	150483	52.3%	59	**48.1%**
12	Kathleen 2T2 Blue Phase	166025	52.3%	59	**48.1%**
13	Dash 19T2	291966	52.3%	34	**54.6%**
14	Upper Coniston 31T1 302396 Phase	286651	52.3%	40	**55.4%**
15	Upper Coniston 31T1 302395 Phase	T602231	52.3%	40	**55.4%**
16	Kathleen 2T1 Blue Phase	150482	52.3%	59	**55.5%**
17	Kathleen 2T2 White Phase	150481	52.3%	59	**55.5%**
18	Cressey 3T3	166021	52.3%	53	**59.1%**
19	Dash 19T1	3442	52.3%	34	**63.8%**
20	Gemmell 11T1	302396	52.3%	44	**64.2%**
21	Gemmell 11T2	None	84.8%	22	**64.5%**
22	Regent 9T1	166017	100.0%	49	**65.2%**
23	Main 17T2	293695	52.3%	14	**65.7%**
24	Centennial 14T1	238850	52.3%	44	**65.8%**
25	Upper Coniston 31T1 302397 Phase	T0621001	52.3%	40	**67.0%**
26	Ramsey 10T2	302395	52.3%	41	**68.1%**
27	Tedman 12T1	290990	100.0%	36	**69.5%**
28	Mansour Mining 29T1	238849	52.3%	39	**69.6%**
29	Martilla 8T1	165308	79.8%	49	**69.8%**
30	Robinson 15T1	65050	52.3%	22	**70.2%**
31	Richard Lake 21T1	S1388301	84.8%	44	**70.4%**
32	Capreol 32T1	T55101	81.1%	54	**71.2%**

	Transformer Name	Serial Number	Data Availability	Age	Health Index
33	West Nip 37T1	C10111	84.8%	22	**72.1%**
34	Arthur 5T1	166020	79.8%	52	**72.2%**
35	Lasalle 7T2	166018	52.3%	35	**72.4%**
36	Paris 13T1	S1418601	79.8%	44	**72.4%**
37	Copper Cliff 25T1	293655	84.8%	37	**76.3%**
38	Ramsey 10T1	64708	100.0%	48	**77.1%**
39	Broder 24T1	282072	52.3%	24	**78.6%**
40	West Nip Spare	1829510101	52.3%	17	**81.4%**
41	Falconbridge 33T1	285187	52.3%	29	**81.7%**
42	Long Lake 20T1	293694	52.3%	16	**81.7%**
43	Moonlight 18T1	302397	79.8%	49	**82.6%**
44	Lasalle 7T1	166016	52.3%	39	**84.4%**
45	Levert 6T1	166022	100.0%	39	**88.3%**
46	Main 17T1	1829610101	100.0%	14	**90.3%**
47	Mobile 99T1	1721410101	100.0%	26	**90.6%**
48	Lower Coniston 30T1	283312	52.3%	20	**95.1%**
49	West Nip 36T1	13669	84.8%	21	**96.0%**
50	West Nip 38T1	13710	52.3%	15	**96.8%**
51	West Nip 34T1	214436	52.3%	11	**97.9%**
52	Barrydowne 16T1	291983	52.3%	4	**99.4%**
53	Spare at Moonlight	A3S6923	52.3%	4	**99.4%**

7.1.4 Replacement Plan

Three condition-based replacement plans for Station Transformers are shown below.

The "optimal" plan flags a unit for replacement in the year that its risk (product of probability of failure and criticality) becomes greater than or equal to one.

As it may not always be feasible to replace as per the optimal plan a "levelized", or smoother, replacement plan may allow a utility to better manage capital investments. Shown below are two types of such a plan: *accelerated* and *deferred*.

In the accelerated plan, asset replacements are moved forward by a maximum of 5 years. I.e. A unit may be flagged for replacement before its risk is equal to one.

In the deferred plan, replacements are pushed back or deferred such that a unit is flagged for replacement when its probability of failure is 85%.

Figure 7-4 Substation Transformers Annual Optimal Replacements

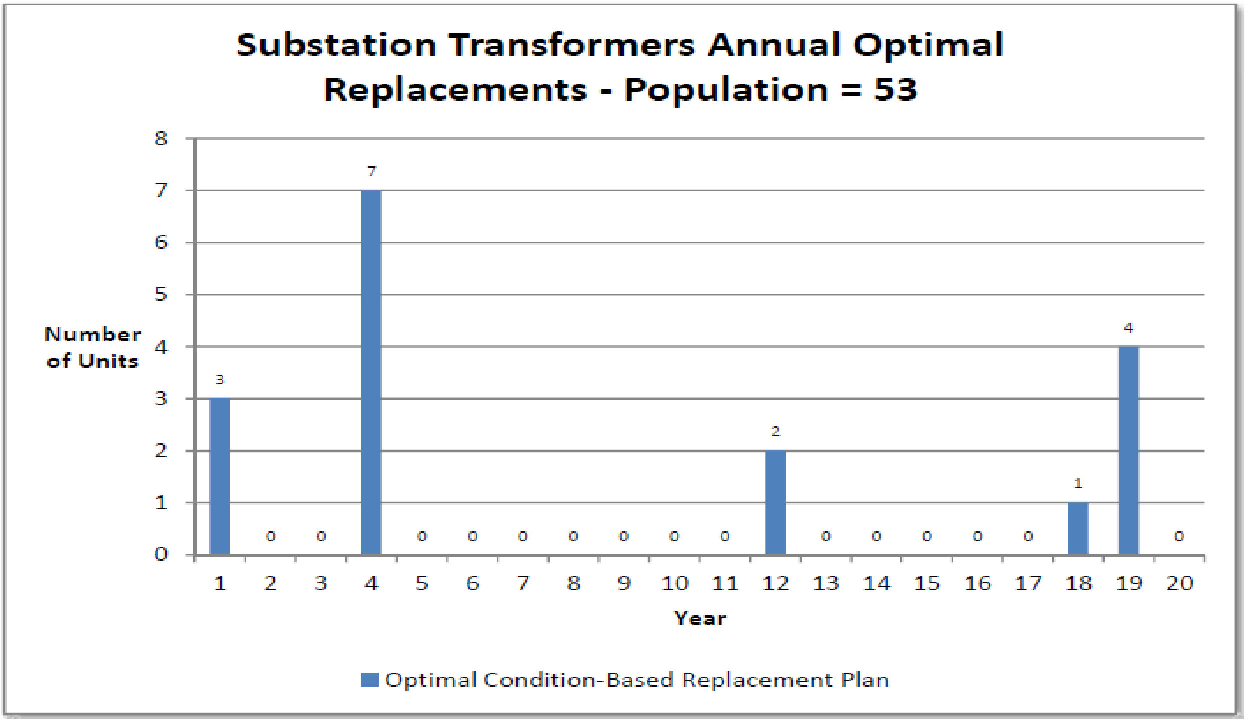


Figure 7-5 Substation Transformers Annual Levelized Replacements

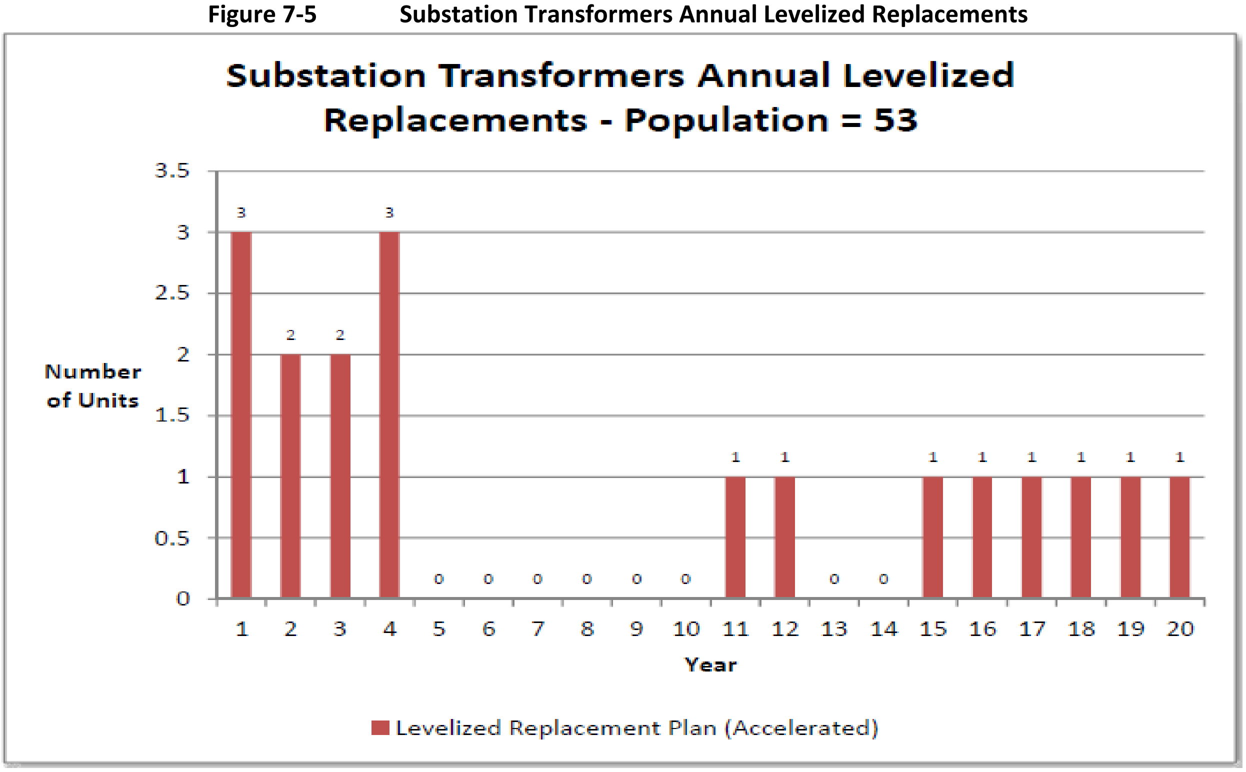
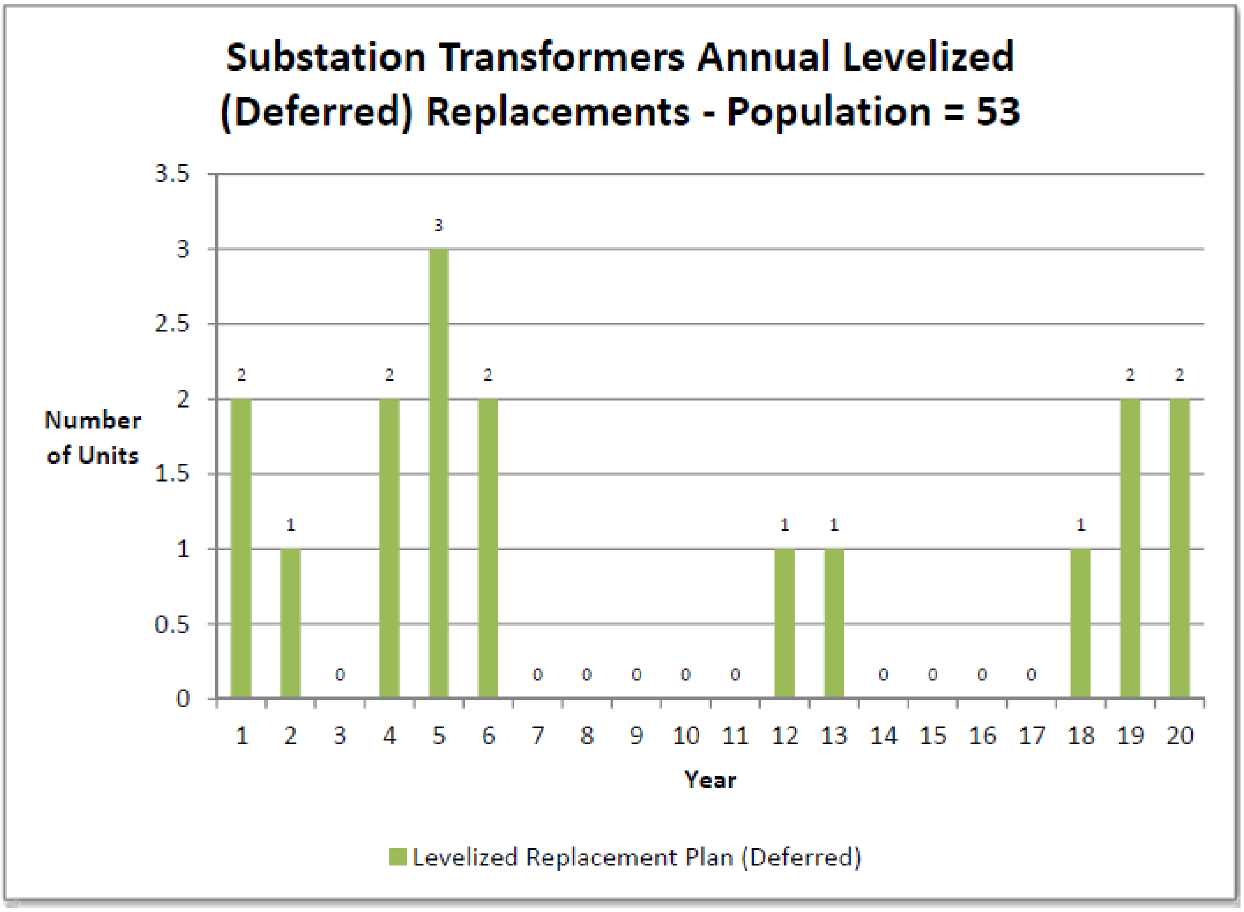


Figure 7-6 Substation Transformers Annual Levelized (Deferred) Replacements



The optimal criticality and replacement year for each unit is shown in the table below:

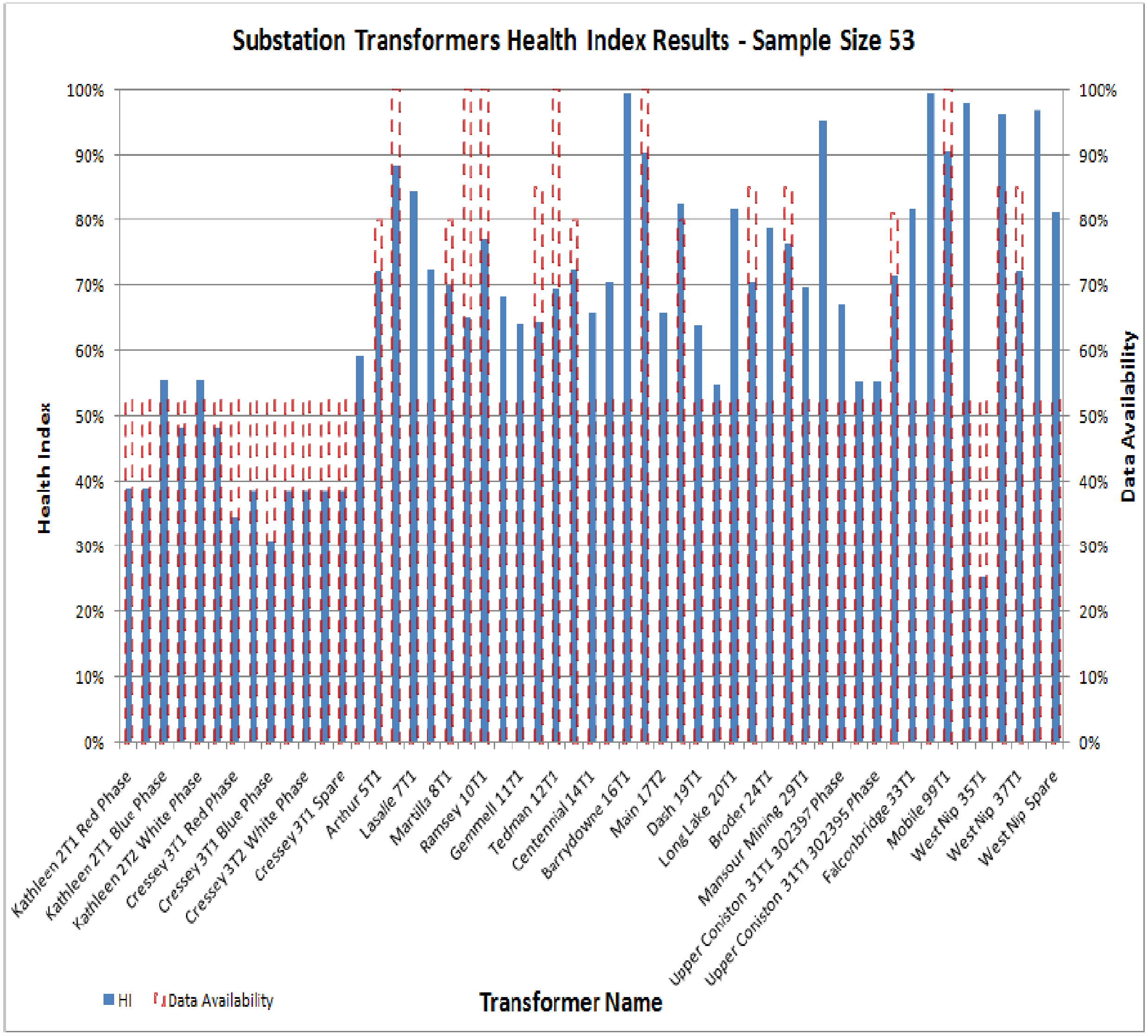
Table 7-15 Optimal Replacement for Each Substation Transformer Unit

Rank	Transformer Name	Serial Number	Age	Criticality Multiple	Health Index	Optimal Replacement Year
1	West Nip 35T1	TAG6235298	34	1.63	**25.4%**	**0**
2	Cressey 3T1 Blue Phase	165310	60	1.50	**31.0%**	**0**
3	Cressey 3T1 Red Phase	166027	60	1.50	**34.5%**	**0**
4	Cressey 3T1 White Phase	166026	60	1.50	**38.4%**	**3**
5	Cressey 3T2 Red Phase	165309	60	1.50	**38.4%**	**3**
6	Cressey 3T2 White Phase	166024	60	1.50	**38.4%**	**3**
7	Cressey 3T2 Blue Phase	166023	60	1.50	**38.4%**	**3**
8	Cressey 3T1 Spare	166019	60	1.50	**38.4%**	**3**
9	Kathleen 2T1 Red Phase	506264	59	1.50	**38.8%**	**3**
10	Kathleen 2T1 White Phase	150480	59	1.50	**38.8%**	**3**
11	Kathleen 2T2 Red Phase	150483	59	1.50	**48.1%**	**11**
12	Kathleen 2T2 Blue Phase	166025	59	1.50	**48.1%**	**11**
13	Dash 19T2	291966	34	1.56	**54.6%**	**17**
14	Upper Coniston 31T1 302396 Phase	286651	40	1.56	**55.4%**	**18**
15	Upper Coniston 31T1 302395 Phase	T602231	40	1.56	**55.4%**	**18**
16	Kathleen 2T1 Blue Phase	150482	59	1.50	**55.5%**	**18**
17	Kathleen 2T2 White Phase	150481	59	1.50	**55.5%**	**18**
18	Regent 9T1	166017	49	2.00	**65.2%**	**20**
19	Centennial 14T1	238850	44	2.00	**65.8%**	**20**
20	Cressey 3T3	166021	53	1.50	**59.1%**	**over 20 years**
21	Arthur 5T1	166020	52	2.25	**72.2%**	**over 20 years**
22	Dash 19T1	3442	34	1.56	**63.8%**	**over 20 years**
23	Gemmell 11T2	None	22	1.56	**64.5%**	**over 20 years**
24	Main 17T2	293695	14	1.56	**65.7%**	**over 20 years**
25	Ramsey 10T2	302395	41	1.69	**68.1%**	**over 20 years**
26	Copper Cliff 25T1	293655	37	2.31	**76.3%**	**over 20 years**
27	Upper Coniston 31T1 302397 Phase	T0621001	40	1.56	**67.0%**	**over 20 years**
28	Capreol 32T1	T55101	54	1.88	**71.2%**	**over 20 years**
29	Tedman 12T1	290990	36	1.56	**69.5%**	**over 20 years**
30	Robinson 15T1	65050	22	1.56	**70.2%**	**over 20 years**
31	Richard Lake 21T1	S1388301	44	1.50	**70.4%**	**over 20 years**

Rank	Transformer Name	Serial Number	Age	Criticality Multiple	Health Index	Optimal Replacement Year
32	Gemmell 11T1	302396	44	1.25	**64.2%**	**over 20 years**
33	West Nip 37T1	C10111	22	1.56	**72.1%**	**over 20 years**
34	Lasalle 7T2	166018	35	1.56	**72.4%**	**over 20 years**
35	Falconbridge 33T1	285187	29	2.06	**81.7%**	**over 20 years**
36	Mansour Mining 29T1	238849	39	1.38	**69.6%**	**over 20 years**
37	Ramsey 10T1	64708	48	1.69	**77.1%**	**over 20 years**
38	Martilla 8T1	165308	49	1.25	**69.8%**	**over 20 years**
39	Broder 24T1	282072	24	1.56	**78.6%**	**over 20 years**
40	Long Lake 20T1	293694	16	1.63	**81.7%**	**over 20 years**
41	Paris 13T1	S1418601	44	1.25	**72.4%**	**over 20 years**
42	Lasalle 7T1	166016	39	1.56	**84.4%**	**over 20 years**
43	Levert 6T1	166022	39	1.56	**88.3%**	**over 20 years**
44	West Nip 34T1	214436	11	1.63	**97.9%**	**over 20 years**
45	Main 17T1	1829610101	14	1.56	**90.3%**	**over 20 years**
46	Lower Coniston 30T1	283312	20	1.56	**95.1%**	**over 20 years**
47	West Nip 36T1	13669	21	1.56	**96.0%**	**over 20 years**
48	West Nip 38T1	13710	15	1.50	**96.8%**	**over 20 years**
49	West Nip Spare	1829510101	17	1.25	**81.4%**	**over 20 years**
50	Moonlight 18T1	302397	49	1.25	**82.6%**	**over 20 years**
51	Mobile 99T1	1721410101	26	1.25	**90.6%**	**over 20 years**
52	Barrydowne 16T1	291983	4	1.25	**99.4%**	**over 20 years**
53	Spare at Moonlight	A3S6923	4	1.25	**99.4%**	**over 20 years**

The data available for station transformers includes age, inspection results, oil quality, dissolved gas analysis and Doble tests as per the General Electric (GE) test and inspections. The average DAI for station transformers is currently 63%. All units had age, oil quality and DGA tests available. A majority of units, however, do not have Doble tests and the inspection data that indicates the condition components such as bushings, tank and connections. Other additional helpful data remains to be collected. The Asset Condition Assessment (ACA) report prepared by Kinectrics in 2011 outlines the data gap items that Sudbury Hydro plans to address going forward so as to further increase the confidence level in the stated Health Index value of the individual units within the station transformer asset group.

Figure 7-7 Substation Transformers Health Index Results



8 STATION REFURBISHMENTS

8.1 STATION ENHANCEMENT DISCUSSION

The station refurbishment programs at GSHI aim to sustain and extend the life of minor equipment within substations.

Transformer Oil Refurbishment

Annual oil condition tests are performed on all station transformers and analyzed to identify degradation of the insulating oil. Degrading oil will lessen the lifespan of a transformer unit as oil is integral to the insulation and cooling of transformers. Units identified requiring attention will have the oil filtered and enhanced to extend the life of the unit. The list of projects is dependent on the oil analysis results.

Transformer Refurbishment

The transformer refurbishment project involves painting transformers and leaking gaskets. Painting of the transformers is done to prevent external rust on the transformer, thus extending the life of the units and preventing harmful environmental releases. Leaking and "sweating" (oil seepage is evident but not actively leaking) gaskets are replaced to prevent oil loss and oil contamination. Units are identified during monthly station inspections and prioritized based on the visual assessment.

Porcelain Insulator Replacement

Porcelain insulators pose a Health and Safety risk due to the possibility of hairline fractures (which are not easily identified during visual inspection) that may lead to a catastrophic failure event. This project replaces porcelain insulators on structures located within substations.

8.2 STATION CONDUCTOR REPLACEMENT

Transformer Cable Replacement (44 and 12kV)

The transformer replacement project replaces aged lead cables between the station transformer secondary and the substation switchgear. These PILC cables are connected to the transformers with oil-filled connection boxes and are typically direct-buried. The project replaces the PILC cables with XLPE cables installed in duct for mechanical protection. This upgrade eliminates the oil-filled connection boxes and replaces them with dry-air boxes, thus eliminating a potential oil leak mechanism.

9 Automation

9.1 Substation Automation

The substation automation class of assets is usually designated as the SCADA (Supervisory Control and Data Acquisition) system in substations and in distribution.

GSHI's SCADA asset class system is used to monitor and control station and distribution system equipment. It consists of four main components:

Master Equipment - real time and historical servers and databases, communication processes and equipment, operator interfaces

Communication Equipment - radios and contracted services

Communication Infrastructure - fibre, leased copper landline, wireless (data radio & cellular)

Remote Equipment - remote terminal units (RTU's), intelligent end devices (IED's - relays, meters, etc.)

Presently, we have SCADA equipment in 31 substations, 3 generating stations, 11 pole-top switches and 13 dedicated FCI (faulted-circuit indicators) at miscellaneous locations throughout the distribution system. We also have two control rooms and one master system, one located at 500 Regent St and the other, a hot-standby, located in our Dash M.S substation.

The SCADA projects can be of low to high complexity and range in cost from a few thousand dollars to the millions of dollars depending on the project scope.

The SCADA system is dependent on the IT system for some communication and for support and is vitally important to a number of miscellaneous stakeholders within the company. The current focus in substation automation is to bring meaningful data back to the Asset Management group for analysis. This approach is expected to provide support to condition-based assessments on major assets. Ongoing sustainment of the SCADA system is required to stay ahead of technological obsolescence of the related hardware. As existing RTUs typically have an economic useful life of 20 years, it is GSHI's practice to replace the existing asset population of RTUs during regularly scheduled major station maintenance to combat the issue of obsolescence.

9.2 DISTRIBUTION AUTOMATION

9.2.1 *ELECTRONIC OVERHEAD SWITCHES*

Six locations have been proposed for the installation of remotely-operated switches, preferable with reclosing abilities. The automated switches will reduce the duration of outages. The switch locations are existing normally-open points Martindale T.S. and Clarabelle T.S., or are strategic locations to allow for sectionalizing of the feeders in GSHI's service territory. Six locations have been identified for automation:

- **LI32** which is located on Whissell Ave and is the normal open point between the 9M3 and 28M6 feeders. The existing switch is a manual gang-operated load break switch.
- **LI34** which is located on Sunday St and is the normal open point between the 9M3 and 9M1 feeders. The existing switch is a manual gang-operated load break switch.
- **LI47** which is located on King St and carries the 28M6 feeder. The existing switch is a manual gang-operated load break switch.
- **LI74** which is on Barry Downe Rd and carries the 9M1 feeder. The existing switch is a manual gang-operated load break switch.
- **LI77** which is on Main St and carries the 28M6 feeder. The existing switch is a manual gang-operated load break switch.
- **LI29** which is located on Lasalle Blvd and carries the 9M2 feeder. The existing switch is a manual gang-operated load break switch.

By installing the remotely-operable switches at these and future locations, restoration and isolation of potential outages in the GSHI service territory can become automated. The switches can reduce the outage time from an assumed time of two hours, to 30 minutes or less for each switch. These upgrades are expected to have a large impact system reliability performance measures.

9.2.2 *ELECTRONIC RELAYS*

GSHI's station relay asset class consists of a number of fault detection and control relays, generally classified as electro-mechanical, electronic or microprocessor based. They measure abnormal conditions on the system and initiate an appropriate control action such as tripping a breaker to protect the integrity of distribution system equipment. Approximately 20% of the asset population have thus far been upgraded from the electro-mechanical vintage.

Station relays were historically replaced in parallel with planned station switchgear/transformer replacements or upgrade projects, yet we are planning to decouple these activities. The station protection and control equipment and philosophy need to be upgraded to adhere to current industry standards. The costs associated with relay replacements range from $35,000 to $60,000 per station depending on the complexity of the protection scheme and if any civil structures are required to house the protection equipment. Projects can range from 6 to 12 months in duration. Future relay replacements will be driven by Operator requirement for increased distribution system awareness due to the proliferation of distributed generation connections as mandated by the Green Energy & Green Economy Act.

9.2.3 Distribution Management System (DMS)

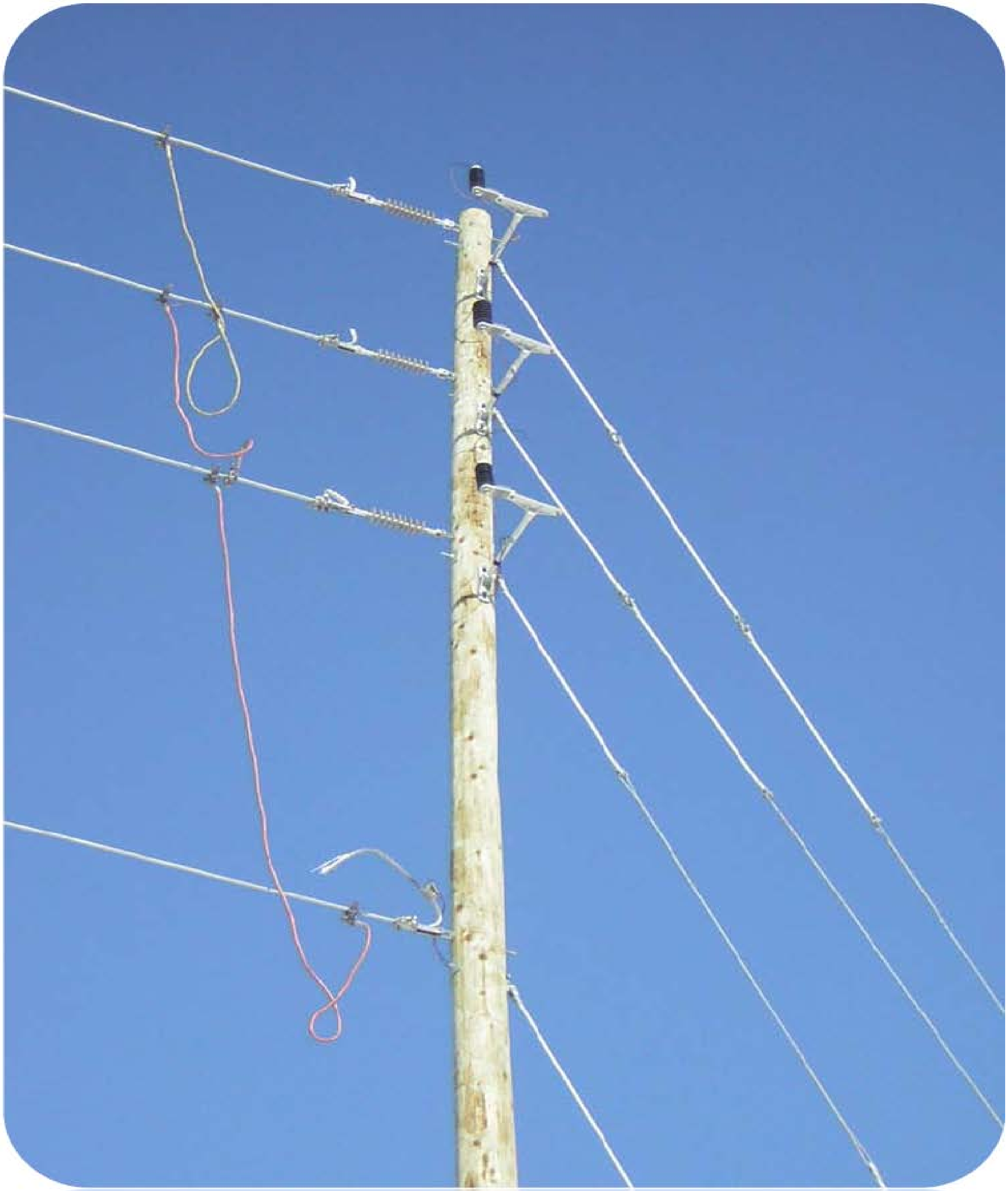
To achieve cost savings and improve customer service, a distribution management system (DMS) that provides real-time response to adverse or unstable conditions is a must. In the bi-directional flow distribution system, software programs provide system situational awareness to instantly detect and react to power disturbances with minimal customer (and generator) impact. The DMS system provides a seamless visualization and situational awareness view, with real-time performance. The DMS integrates all relevant network information from all relevant sources in a dynamic system topology model. The interface provides new intuitive techniques to the presentation of data in order to yield more informative and accurate information based on system connectivity.

In the future, self-healing technologies will mesh seamlessly with classical outage management systems as both are managing outages, though in different ways. The self-healing system's response to a failure will be automatic and adaptive to the current real-time network, whether the network topology is normal or abnormal. Traditionally, Outage Management Systems have performed only where manual field switching is typically performed. The distribution system of the near future will combine both of the technologies in a single network, which will alter the behaviour of the classical OMS. OMS needs to be part of a much broader, proactive program of system intelligence.

The integration of distributed generation will be phased in over a number of years, so the permeation of DMS with OMS, as well as the influence of AMI, will be moving daily. Since DMS and OMS operate from the same network model, and their basic operations impact each other, the lines of demarcation between DMS and OMS are disappearing - OMS will become more real-time in nature. By combining real-time OMS and DMS functionality, telemetry and integrated security, smart distribution systems are poised as a true self-healing network. With the future distribution system's real-time, high-performance platform, it will be able to handle the loading and generation conditions of a worst-case storm scenario by integrating distribution management, outage management and distribution automation for optimum operational efficiency and safety. This consolidated OMS/DMS will be an important step in developing the next generation system.

The estimated annual capital and maintenance expenditures related to the purchase and ongoing use of a modern DMS solution are contained within GSHI's *Basic Plan to Enable Bill 150 The Green Energy and Economy Act* (GEA plan).

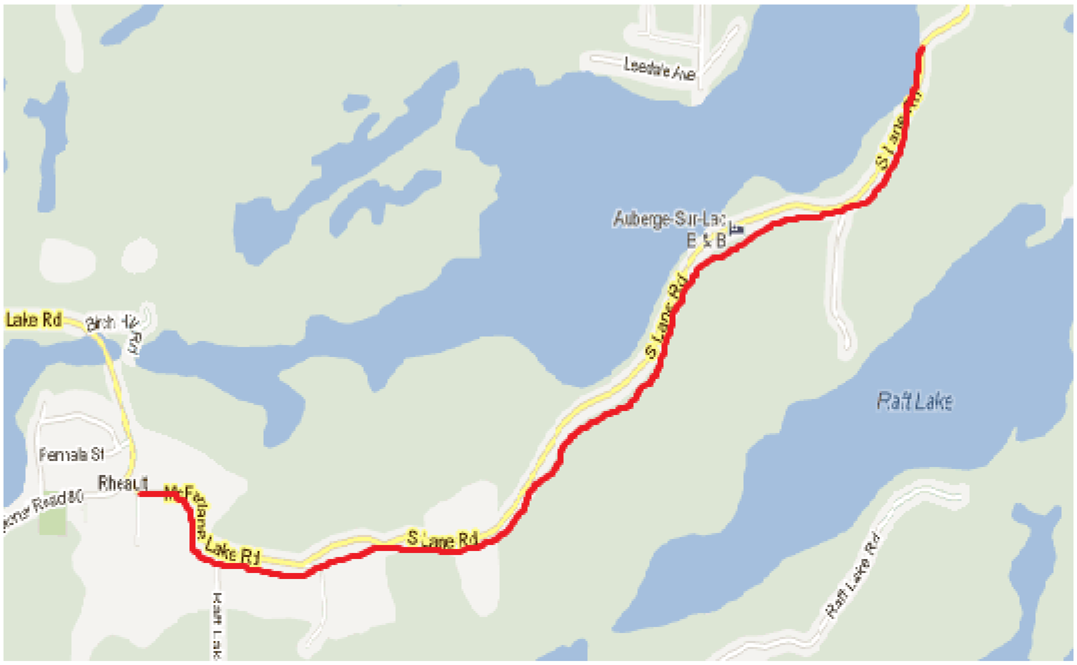
10 Distribution Enhancement Fiscal Year 2013



10.1 Line Extensions

10.1.1 McFarlane Lake Rd - Three Phase Extension

Currently, the three phase feeder egress from Long Lake MS20 is not adequately backed up in case of an unforeseen contingency. The scope of this project will be to upgrade existing 1950's-vintage plant along South Lane Rd/McFarlane Lake Rd and relocate the line out to road accessibility. The completion of this project will allow Richard Lake MS21 to back up Long Lake MS20.



10.2 System Voltage Conversions

10.2.1 Hillsdale, Mark, Lakeview Plant Renewal

Cressey MS3 is an antiquated 4.16kV station that supplies varied types of customer, from residential to industrial. The station itself, along with a large proportion of the electrical distribution system in its vicinity, is 60+ years old. The area currently supplied by this station will be transferred to operate at 12.47kV. In advance of the conversion of MS3 to 12.47kV, accelerated pole replacements are planned for Hillsdale, Mark, and Lakeview St, as well as the upgrading of the insulation to the 12.47kV level for all distribution-class insulators and transformers in the region.

10.2.2 Prete, Benny, Connaught Plant Renewal

Cressey MS3 is an antiquated 4.16kV station that supplies varied types of customer, from residential to industrial. The station itself, along with a large proportion of the electrical distribution system in its vicinity, is 60+ years old. The area currently supplied by this station will be transferred to operate at 12.47kV. In advance of the conversion of MS3 to 12.47kV, accelerated pole replacements are planned for Prete, Benny, and Connaught St, as well as the upgrading of the insulation to the 12.47kV level for all distribution-class insulators and transformers in the region.

10.2.3 West Nipissing Conversion

West Nipissing MS34 is an antiquated 4.16kV station that supplies mainly residential customers in the town of Sturgeon Falls. The station itself, along with a large proportion of the electrical distribution system in its vicinity, is 60+ years old. The area currently supplied by this station will be transferred to operate at 12.47kV. In advance of the conversion of MS34 to 12.47kV, accelerated pole replacements are planned for the surrounding community and will include the upgrading of the insulation to the 12.47kV level for all distribution-class insulators and transformers in the region.

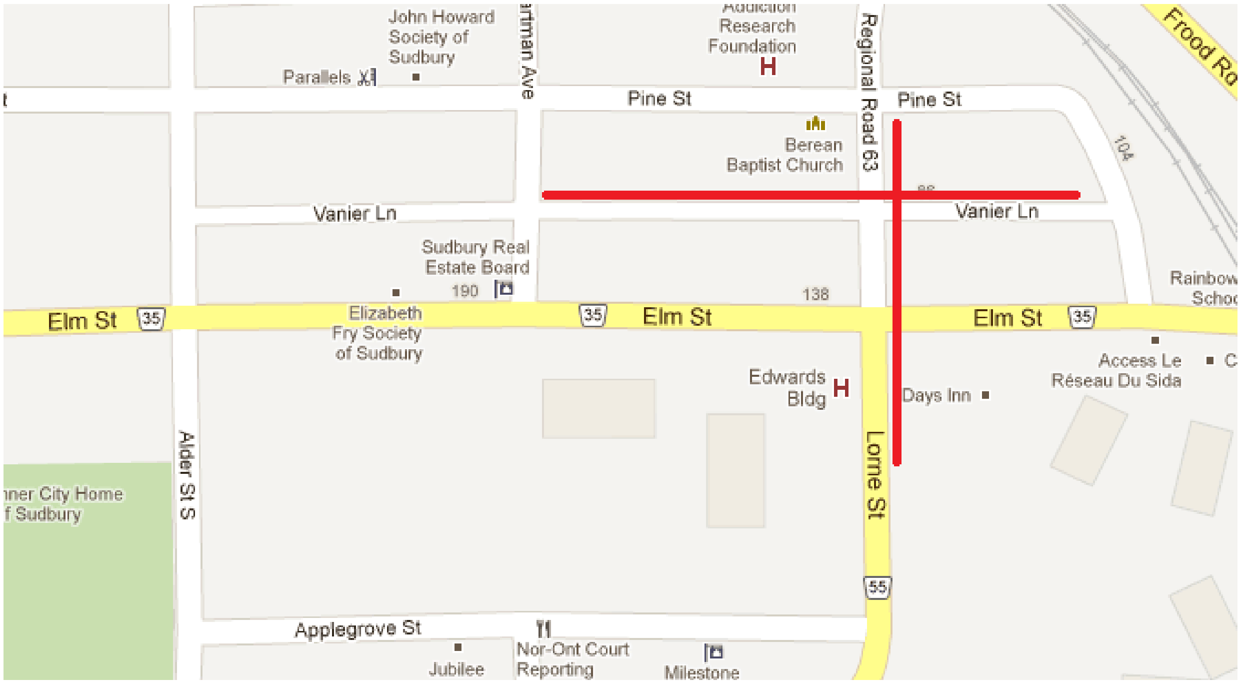
10.2.4 Gatchell/Cressey

Cressey MS3 is an antiquated 4.16kV station that supplies varied types of customer, from residential to industrial. The station itself, along with a large proportion of the electrical distribution system in its vicinity, is 60+ years old. The area currently supplied by this station will be transferred to operate at 12.47kV. In advance of the conversion of MS3 to 12.47kV, accelerated pole replacements are planned for miscellaneous streets in the Gatchell/Cressey area. The upgrading of the insulation to the 12.47kV level for all distribution-class insulators and transformers in the region will be undertaken as part of this project.

10.3 System Reliability Enhancements

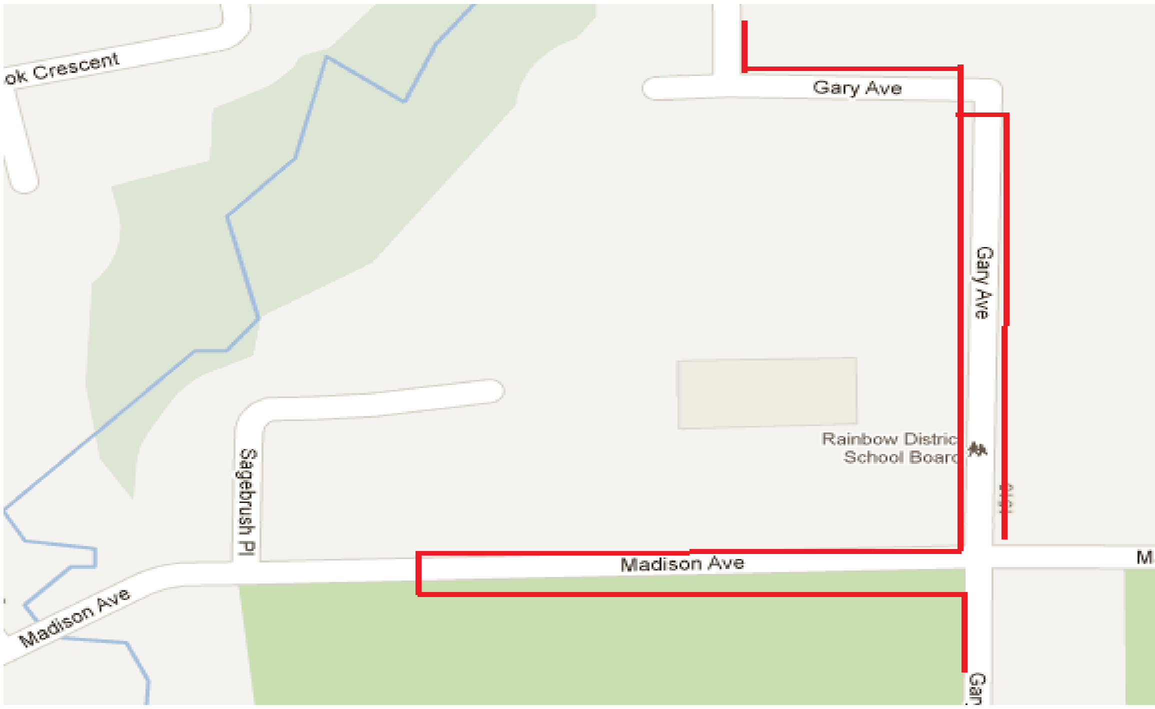
10.3.1 Vanier Lane Plant Renewal

Vanier Lane Plant Renewal has been identified as a major project due to proximity of the energized overhead conductors to existing building rooftops. At present, the businesses and private residences along Vanier Lane are fed rear lot from a 1950s-vintage pole line that offers inadequate horizontal clearances between our distribution system and our customers. The scope of the project is to convert the overhead line to an underground scheme that will increase reliability and safety in the affected area.



10.3.2 GARY/MADISON AVE UNDERGROUND REBUILD

The Gary/Madison Ave subdivision is currently serviced by a directly-buried distribution system that, at an age of 45 years, has nearly reached end-of-life. The rebuild will entail installation of new underground conductors in a mechanically-protected duct system, along with replacement of existing live-front transformers. The service feed for residences will be brought out to the road allowance to ameliorate future maintenance activities and to have the existing electrical service(s) removed from various privately-owned locations.

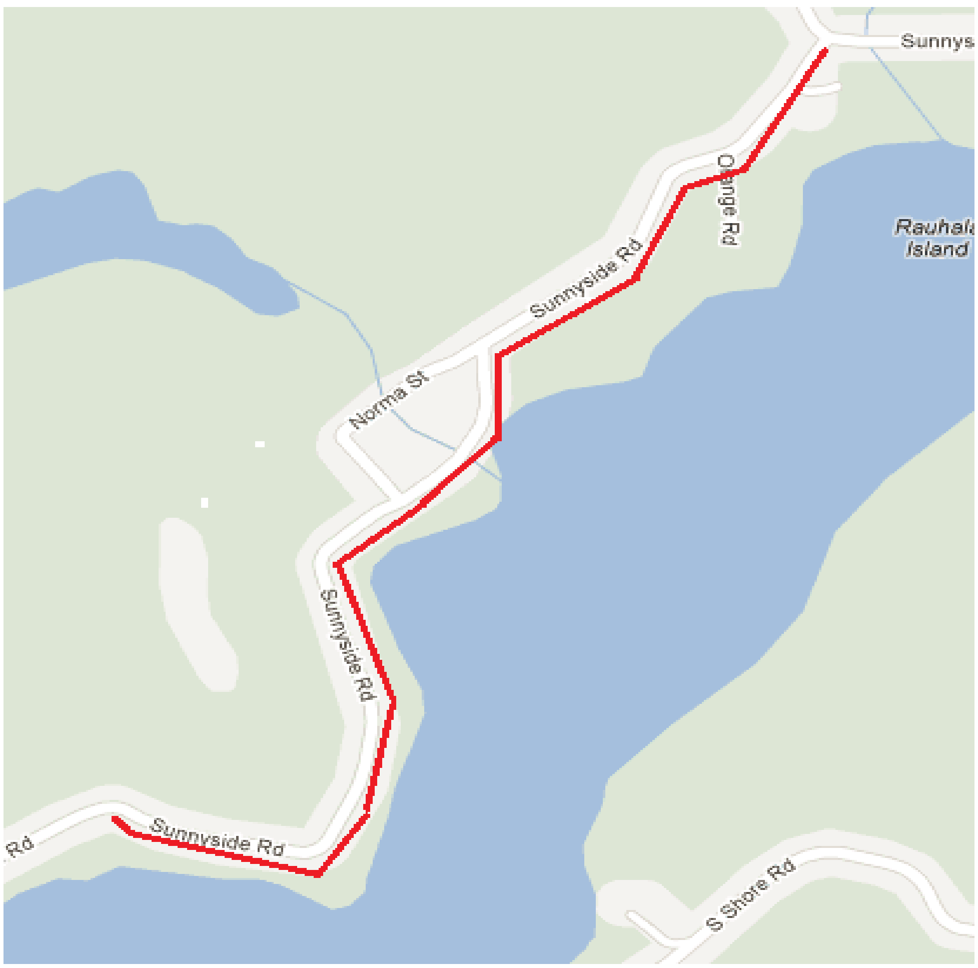


10.3.3 Eden Point Underground Rebuild

Eden Point Dr is currently serviced by a directly-buried underground distribution system that is fast reaching end-of-life. The 1970's-vintage system is comprised of directly-buried conductors and antiquated submersible transformers. The rebuild will entail installation of new underground conductors in a mechanically-protected duct system, along with replacement of existing submersible transformers with those of the pad-mounted variety.

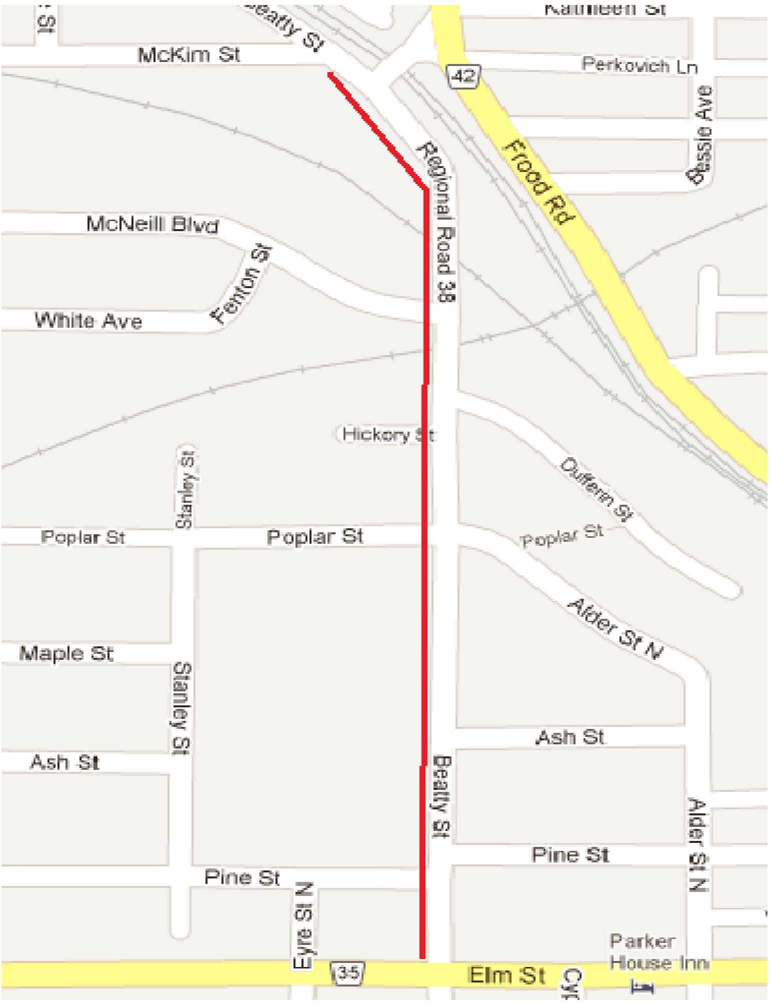
10.3.4 Sunnyside Rd Overhead Rebuild

The residents of Sunnyside Rd between Jarvi Rd and Sandy Cove Rd have since the 1950s been serviced from an overhead pole line that is located along the lake's edge. Operationally, the pole line is difficult to access by Line and Maintenance crews. A contingency event resulting in the physical loss of a section of this line would result in a difficult and prolonged outage for this area. As well, the poles, conductors and associated equipment are already at, or nearing, end-of-life. The project is being undertaken to re-locate the distribution system from its current position along the lake to the public road allowance.



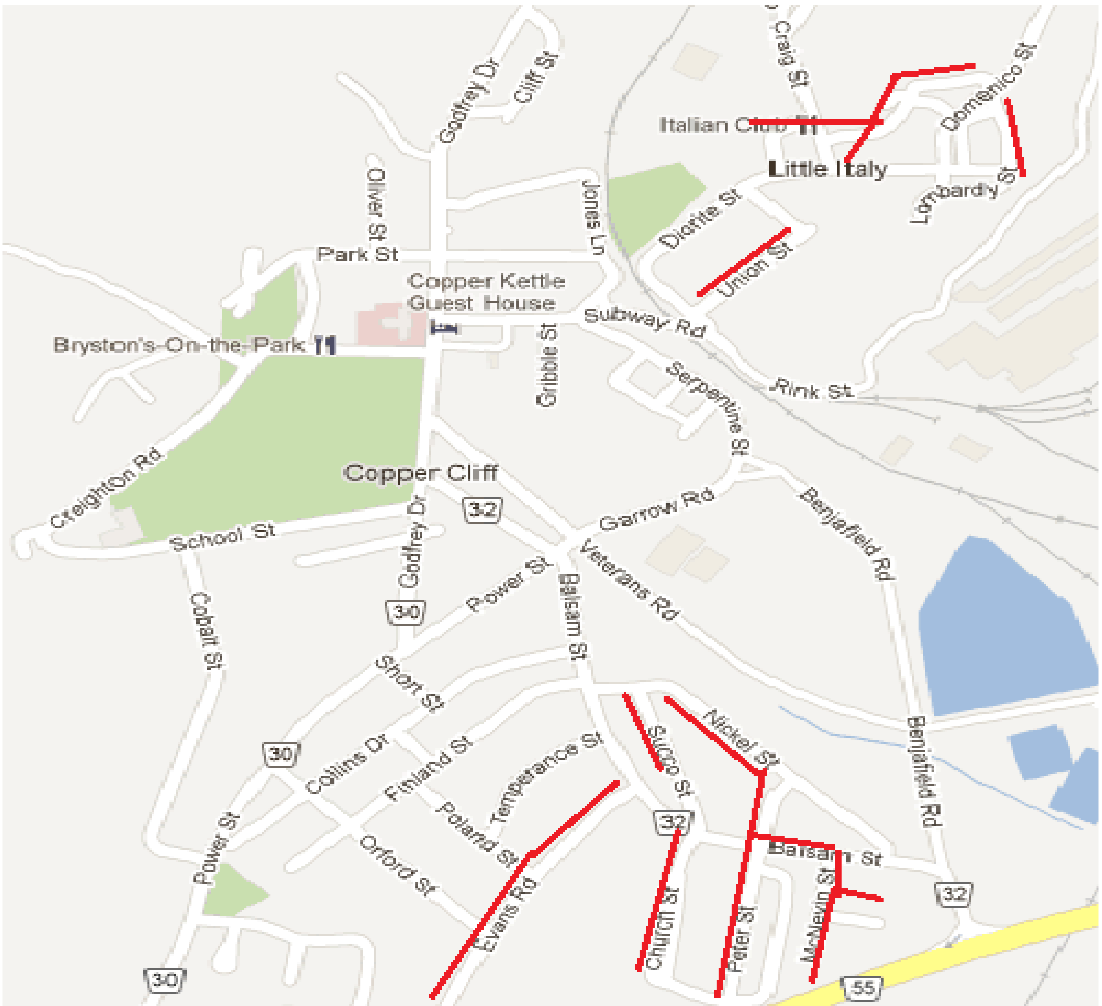
10.3.5 BEATTY ST OVERHEAD REBUILD

The Beatty St overhead line rebuild is being undertaken to improve service reliability in the area by replacing the 1950s-vintage plant that has reached end-of-life. The line will be rebuilt to current CSA standards.



10.3.6 Copper Cliff

The town of Copper Cliff is currently being serviced predominantly by a 1950's-vintage overhead distribution system. The #6 copper primary overhead conductors located in several areas as depicted below are a known safety hazard. Current protocol to work on a pole with this type of primary conductor is to de-energize the line section, resulting in potentially long outages for our customers. The completion of this project will remove the conductor in its entirety from the town of Copper Cliff. In addition to the removal of this hazard, the poles themselves have reached end-of-life and various rebuild scenarios will be developed to rebuild the pertinent street(s).



11 Risk Management

The Asset Management Process involves assessing a project or program activity from two perspectives: the downside risk of not undertaking the activity, and the benefit or disadvantage of undertaking the activity. As the asset management framework and processes mature, focus for this disclosure report has been on risk management, namely identifying, assessing and prioritizing activities based on the negative ramifications of not funding a project or program activity.

The suggested direction for managing risk of a predictable calamitous event may be focused on monitoring, reducing, or controlling the probability or the consequence or both of it happening. We concentrate on the physical aspects of risk associated with managing the distribution system assets. The objective is to avoid catastrophe, reduce uncertainty and improve predictability.

For distribution system assets, risk is defined as the product of an asset's probability of failure and its consequence of failure.

Health indexing and probability of failure have already been discussed in previous sections. In our plan, the metric used to measure consequence of failure is referred to a *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values beings examples. For Substation transformers, factors that impact criticality may include things like number of customers served or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

It is assumed that each asset group has a base criticality value, Criticality_{min}. The individual units in the asset group are assigned criticalities that are multiples of Criticality_{min}. A unit becomes a candidate for replacement when its risk value, the product of its probability of failure and criticality, is greater than or equal to 1.

In the example below, Asset 1 and Asset 2 are candidates for replacement:

Table 11-1 Sample Replacement Ranking

Asset Name	Age	Health Index (HI)	Consequence of Failure (Criticality)	Probability of Failure (POF) Corresponding to HI	Risk (POF*Criticality)	Replacement Ranking
Asset 1	41	30.00%	2	78.20%	1.564	1
Asset 2	29	30.00%	1.5	78.20%	1.173	2
Asset 3	37	30.00%	1	78.20%	0.782	3
Asset 4	42	50.00%	2	12.80%	0.256	4
Asset 5	18	50.00%	1.5	12.80%	0.192	5
Asset 6	20	50.00%	1	12.80%	0.128	6

11.1 Optimal and Levelized Replacement Plans

The optimal Condition-Based Replacement plan shows the optimal time of replacement, namely when the risk cost is equal to one for proactively-replaced assets and the time of expected failure for run-to-failure assets. As it may not always be feasible to replace as per the optimal plan, a "levelized" or smoother replacement plan may allow for better management of capital investments.

The levelized replacement plan for proactively-replaced assets allows for investments to be accelerated or deferred for a limited number of years. The levelized plan for reactively-replaced assets suggests replacing assets prior to their time of expected failure.

Greater Sudbury Hydro Inc./
Hydro du Grand Sudbury Inc.

KINECTRICS

GREATER SUDBURY HYDRO
2011 ASSET CONDITION ASSESSMENT

September 28, 2012

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

DISCLAIMER

GREATER SUDBURY HYDRO
2011 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418067-RA-0001-R00

April 11, 2012

Prepared by:

Katrina Lotho, BE.Sc, B.Sc., P.Eng
Engineer

LICENSED PROFESSIONAL ENGINEER
K. LOTHO
100157472
09/28/12
PROVINCE OF ONTARIO

Reviewed and Approved by:

Yury Tsimberg, M.Eng, P.Eng
Director – Asset Management

Dated: Sept. 28, 2012

To: Greater Sudbury Hydro
500 Regent Street
P.O. Box 250
Sudbury, Ontario
P3E 4P1

Revision History

Revision Number	Date	Comments	Approved
R00	September 28, 2012	Final	Yury Tsimberg

EXECUTIVE SUMMARY

Greater Sudbury Hydro (GSH) determined a need to perform a condition assessment of its key distribution assets. Such an undertaking would result in a quantifiable evaluation of asset condition, aid in prioritizing and allocating sustainment resources, as well as facilitate the development of an Asset Management Plan.

In early 2011, GSH selected and engaged Kinectrics Inc (Kinectrics) to perform an Asset Condition Assessment (ACA) on GSH's key distribution assets.

The assets were divided into the following categories:

- Substation Transformers
- Pole Mounted Transformers
- Pad Mounted Transformers
- Overhead Line Switches
- Poles
    - Sudbury Hydro (wood, concrete)
    - Bell (wood)
    - Hydro One (wood)
    - Private (wood, concrete, steel, aluminum)

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year condition-based replacement plan
- Identifying and prioritizing the data gaps for each group

This Asset Condition Assessment Report summarizes the methodology used, outlines specific approaches used in this project, and presents the resulting findings and recommendations.

Asset Condition Assessment Methodology

The Asset Condition Assessment Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Replacement Plan for each asset group.

Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health, relative to a brand new asset, and is given in terms of percentage, with 100% representing an asset in brand new condition.

The condition data used in this study were obtained from GSH and included the following:

- Asset Properties (e.g. age, PCB content, location information)
- Test Results (e.g. Oil Quality, DGA)
- Non-Conformance Logs

A Health Index was calculated for each asset with sufficient condition data. As well, in order to provide an effective overview of the condition of each asset group, the Health Index Distribution for each asset category was determined.

Condition-Based Replacement Plan

Once the Health Indices were calculated, a replacement plan based on asset condition was developed. The Condition-Based Replacement Plan outlines the number of units that are expected to be replaced in the next 20 years. The numbers of units were estimated using either a *reactive* or *proactive* approach.

For assets with a relatively small consequence of failure, units are generally replaced *reactively* or on failure. The replacement plan for such an approach is based on the asset group's failure rate. This approach incorporates the possibility that assets may fail prematurely, prior to their expected typical end of lives.

In the *proactive* approach, units are assumed not to fail and are considered for replacement prior to failure. For asset groups that fall under this approach, a Risk Assessment study was conducted to determine the units eligible for replacement. This process establishes a relationship between an asset's Health Index and the corresponding probability of failure. Also involved was the quantification of asset criticality through the assignment of weights and scores to factors that impact the decision for replacement. The combination of criticality and probability of failure determines risk and replacement priority for that unit.

Health Index Results

Table 1 shows a summary of the Health Index evaluation results. The Health Index distribution and percentage of the population in poor and very poor condition are shown. As well, the average age of each asset category is given.

It can be seen from the results that wood poles, regardless of owners, on average as an asset group, are in the worst condition. Over 26% of Sudbury Hydro's and privately owned poles are in poor or very poor condition. Twenty-eight percent (28%) and 31% of Hydro One's and Bell's wood poles respectively are in poor or very poor condition.

Also of concern are Substation Transformers where approximately 23% of the population is in poor condition. Many of the units in this asset group are aging, with the average age of the population at 43 years.

Pole and Pad-Mounted Transformers, Overhead Line Switches, and Concrete, Steel, and Aluminum poles are generally in good condition. For these asset categories, less than 1% of the assets are categorized as poor or very poor.

Table 1 Health Index Results Summary

Asset	Sub-Category	Health Index Distribution (% of Sample Size)					Total of Poor and Very Poor (% of Sample Size)	Average Age
		Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (≥85%)		
Substation Transformers	-	0%	23%	32%	28%	17%	23%	43
Pole Mounted Transformers	-	0%	<1%	2%	11%	87%	<1%	13
Pad Mounted Transformers	-	0%	<1%	<1%	8%	92%	<1%	19
Overhead Line Switches	-	0%	<1%	1%	2%	96%	<1%	5
Sudbury Hydro Wood Poles	All	<1%	26%	24%	26%	25%	26%	32
	44 kV	0%	7%	33%	34%	26%	7%	24
	Non-44 kV	<1%	29%	22%	25%	24%	29%	33
Sudbury Hydro Concrete Poles	All (Non-44 kV)	0%	0%	10%	40%	50%	0%	38
Bell Wood Poles	All	0%	31%	32%	14%	23%	31%	35
	44 kV	0%	<1%	3%	9%	88%	<1%	6
	Non-44 kV	0%	33%	33%	14%	19%	33%	37
Hydro One Wood Poles	All	0%	28%	31%	14%	28%	28%	38
	44 kV	0%	34%	39%	13%	13%	34%	38
	Non-44 kV	0%	9%	7%	14%	70%	9%	33
Private Wood Poles	All	<1%	25%	22%	17%	35%	26%	34
	44 kV	0%	0%	55%	0%	45%	0%	23
	Non-44 kV	<1%	26%	22%	18%	35%	26%	34
Private Concrete Poles	All	0%	0%	0%	0%	100%	0%	2
	44 kV	0%	0%	0%	0%	100%	0%	2
	Non-44 kV	0%	0%	0%	0%	100%	0%	-
Private Steel Poles	All (Non-44 kV)	0%	0%	12%	51%	37%	0%	45

Condition Based Replacement Plan

Table 2 shows the condition-based replacement plan for the first year and the asset replacement strategy is shown for each asset group.

GSH's most significant expected replacements were found to be for Substation Transformers and GSH-owned Wood Poles. Three Substation Transformers (nearly 6% of the population of 53) and approximately 283 wood poles, 2.3% of the population, are candidates for replacement in the current year.

Table 2 Year 1 Optimal Condition-Based Replacement Plan

Asset	Sub-Category	Optimal Condition-Based Replacement Plan for Year 1 [Number of Units]	Replacement Strategy
Substation Transformers	-	3	proactive
Pole Mounted Transformers	-	17	reactive
Pad Mounted Transformers	-	2	reactive
Overhead Line Switches	-	2	reactive
Sudbury Hydro Wood Poles	All	283	proactive
	44 kV	28	proactive
	Non-44 kV	252	proactive
Sudbury Hydro Concrete Poles	All (Non-44 kV)	1	proactive
Bell Wood Poles	All	63	proactive
	44 kV	1	proactive
	Non-44 kV	59	proactive
Hydro One Wood Poles	All	8	proactive
	44 kV	5	proactive
	Non-44 kV	1	proactive
Private Wood Poles	All	24	proactive
	44 kV	0	proactive
	Non-44 kV	24	proactive
Private Concrete Poles	All	0	proactive
	44 kV	0	proactive
	Non-44 kV	0	proactive
Private Steel Poles	All (Non-44 kV)	1	proactive
Private Aluminum Poles	All (Non-44 kV)	0	proactive

Data Assessment Results

Age, oil quality and dissolved gas analysis test were available for all Substation Transformers. A majority of the units, however, did not have Doble tests and inspection data that indicate the condition of transformer components such as bushings, tank, and connections. No cooling system information, IR scan results, or loading were available for any of the units.

For Pole and Pad Mounted Transformers, Overhead Line Switches, and Poles, it was assumed that no entry in the Non-Conformance Log means that an asset has been visually inspected and is in good condition.

While Pole Mounted Transformers are assumed to have all inspection data related to tank condition, grounding, connection, and bushings, age is available for only 38% of the population. As well, Loading data was not available for any of the units.

Pad Mounted transformers are also assumed to have inspection data related to tank condition, grounding, connection, and bushings. Data quality may be improved by collecting Loading information and information regarding the condition of elbows.

For Overhead Line Switches, it is assumed that the condition of the switch, arc interrupter, and insulator are known. Age, however, was only available for 28% of the population. An important data gap for this asset group is condition information on the switch operating mechanism.

The only available information for Poles were age and inspection information indicating pole damage and whether or not a pole is leaning. Data gaps for this asset group includes pole strength test (if applicable to the pole's age and type), and more detailed inspection information (e.g. rot, spalling, corrosion, cracks).

Conclusions and Recommendations

An Asset Condition Assessment was conducted for six of GSH's key distribution assets, namely Substation Transformers, Pad and Pole-Mounted Transformers, Overhead Line Switches, and Wood and Concrete Poles. Additionally, six other pole categories with varying owners (Bell, Hydro One, and Private) of varying types (wood, concrete, steel, and aluminum) were assessed. For each asset category, the Health Index distribution was determined and a condition-based replacement plan was developed.

Pole and Pad-Mounted Transformers, Overhead Line Switches, and Concrete, Steel, and Aluminum poles are generally in good to very good condition.

Of all the asset groups, Wood Poles, regardless of its owners, were found generally to be in the worst condition. Over 25% of all wood poles are in poor or very poor condition. It is recommended that an annual capital replacement programs be put in place to proactively replace poles in poor and very poor condition.

Another area of concern is GSH Substation Transformers where 23% were found in poor condition. Additionally, the population is aging; the average age of the population is 43 years.

Because Substation Transformers are a crucial distribution system component with major consequences of failure, it is recommended that investments be made in an expedient manner to address this issue.

While oil quality and DGA tests were available for all Substation Transformers, Doble tests and inspection records are available for only a limited number of units. It is recommended that this information be collected for the remainder of the population. As well, it is recommended that information regarding the transformer cooling system, IR scans, and loading data be collected.

Currently, problems found during inspections of Pole and Pad-Mounted Transformers, Overhead Line Switches, and Poles are recorded in the Non Conformance Log. It is recognized that GSH is currently in the process of working with PartnerSoft to implement a system that standardizes and computerizes inspection records. It is recommended that the inspection-based parameters presented in this study be included as standard inspection items. It is also recommended that the data gap inspection parameters identified for Pole and Pad Mounted Transformers, Overhead Line Switches, and Poles be incorporated into the new inspection system.

Breakers, Reclosers, Pad-Mounted Switchgear and Underground Cables were not included in this study. This is because there was insufficient data collected for these asset categories. It is recommended that GSH begin collecting data for these asset categories so that they may be included in future assessments.

It is important to note that the replacement plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence GSH's Asset Management Plan.

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

I INTRODUCTION

This page is intentionally left blank.

I Introduction

Greater Sudbury Hydro Inc. (GSH) is a local distribution company that provides electricity to over 46,000 customers in the City of Greater Sudbury and within the Municipality of West Nipissing. The company structure is an Ontario Business Corporation and its shareholders are the City of Greater Sudbury. Activities, performance standards, and rates are 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 has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

In early 2011, GSH selected and engaged Kinectrics Inc (Kinectrics) to perform an Asset Condition Assessment (ACA) on GSH's key distribution assets.

The Asset Condition Assessment Report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

I.1 Objective and Scope of Work

The assets in this study are categorized as follows:

- Substation Transformers
- Pad Mounted Transformers
- Pole Mounted Transformers
- Overhead Line Switches
- Sudbury Hydro Poles
    - Wood
    - Concrete
- Bell Poles
    - Wood
- Hydro One
    - Wood
- Private
    - Wood
    - Concrete
    - Steel
    - Aluminum

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year condition-based replacement plan
- Identifying and prioritizing the data gaps for each group

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of methodology for condition assessment of replacement plan (Section II)
- Description of the data assessment procedure (Section III)
- For each asset category the following are included (VI Appendix A: Results and Findings for Each Asset Category: Section 1 – Section 12):
  - Short description of the asset groups and a discussion of asset degradation and end-of-life issues
  - Age distribution
  - Health Index formulation
  - Health Index distribution
  - Condition-based Replacement Plan
  - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis

II ASSET CONDITION ASSESSMENT METHODOLOGY

This page is intentionally left blank.

II Asset Condition Assessment Methodology

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Replacement Plan for each asset group. The methods used are described in the subsequent sections.

II.1 Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Colour".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weightings, is therefore given by:

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

Equation 1

where

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

Equation 2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e. $CPF_{max} = 4$.

II.1.1 Health Index Example

Consider the asset class "Oil Circuit Breaker". The condition and sub-condition parameters, as well as their weights are shown on Table II-3.

Table II-3 Oil Circuit Breaker Condition and Sub-Condition Parameters

Health Index Formula for Oil Circuit Breakers			
Condition Parameters		**Sub-Condition Parameters**	
Name	**Weights (WCP)**	**Name**	**Weights (WCPF)**
Operating Mechanism	14	Lubrication	9
		Linkage	5
		Cabinet	2
Contact Performance	7	Closing Time	1
		Trip Time	3
		Contact Resistance	1
		Arcing Contact	1
Arc Extinction	9	Moisture	8
		Leakage	1
		Tank	2
		Oil Level	1
		Oil Quality	8
Insulation	2	Insulation	1
Service Record	5	Operating Counter	2
		Loading	2
		Age	1

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the "worst" and "best" scores respectively. The maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is therefore "4".

Scores are determined using *condition criteria*. The criterion defines the score of a particular parameter. Consider, for example, the age criteria given on Table II-4. An asset that is 35 years old will receive a score of "2" for "Age".

Table II-4 Age Criteria

Parameter Score	Condition Description
4	0-19
3	20-29
2	30-39
1	40-44
0	45+

Table II-5 shows a sample Health Index evaluation for a particular oil breaker. The sub-condition parameter scores (CPFs) shown are assumed values between 0 through 4.

The Condition Parameter Score (CPS) is evaluated as per Equation 2. The Health Index (HI) is calculated as per Equation 1. As no de-rating factors are defined, there is no multiplier for the final Health Index.

Table II-5 Sample Health Index Calculation

Condition Parameters	Operating Mechanism			Contact Performance			Arc Extinction			Insulation			Service Record		
Sub-Condition Parameters Scores (CPF) Weights (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)
	Lubrication	4	9	Closing Time	2	1	Moisture	4	8	Insulation	4	1	Operating Counter	3	2
	Linkage	2	5	Trip Time	3	3	Leakage	3	1				Loading	4	2
	Cabinet	3	2	Contact Resistance	2	1	Tank	3	2				Age	3	1
				Arcing Contact	3	1	Oil Level	2	1						
							Oil Quality	3	8						
Condition Parameter Score (CPS)	Operating Mechanism CPS (4*9 + 2*5 + 3*2) / (9+5+2) = 3.25			Contact Performance CPS (2*1 + 3*3 + 2*1 + 3*1) / (1+3+1+1) = 2.67			Arc Extinction CPS (4*8 + 3*1 + 3*2 + 2*1 + 3*8) / (8+1+2+1+8) = 3.35			Insulation CPS (4*1) / (1) = 4			Service Record CPS (3*2 + 4*2 + 3*1) / (2+2+1) = 3.4		
Weights (WCP)	*Weight = 14*			*Weight = 7*			*Weight =9*			*Weight = 2*			*Weight = 5*		
Health Index (HI)	**HI** = $\frac{3.25*14 + 2.67*7 + 3.35*9 + 4*2 + 3.4*5}{(14 + 7 + 9 + 2 + 5)*4}$ = **80.6%**														

II.1.2 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 $\leq$ Health Index < 50%
Fair	50 $\leq$ Health Index <70%
Good	70 $\leq$ Health Index <85%
Very Good	Health Index $\geq$ 85%

Note that for critical asset groups, such as Station Transformers, the Health Index of each individual unit is given.

II.2 Condition-Based Replacement Methodology

The Condition-Based Replacement plan outlines the number of units that are projected to be replaced in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the reactive approach, units are considered for replacement prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides the best model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f = failure rate per unit time
t = time
γ, β = constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' expertise in failure rate study of multiple power system asset groups, the following variation of the failure rate formula is adopted:

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

Equation 4

f = failure rate of an asset (percent of failure per unit time)
t = age (years)
α, β = constant parameters that control the rise of the curve

The corresponding probability of failure function is therefore:

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

Equation 5

P_f = cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the 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.

Consider, for example, an asset class where at the ages of 25 and 65 the asset has cumulative probabilities of failure of 10% and 99% respectively. It follows that when using Equation 5, α and β are calculated as 74 and 0.093 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)}-e^{\alpha\beta})/\beta} = 1 - e^{-(e^{0.093(t-74)}-e^{-6.882})/0.093}$$

The failure rate and probability of failure graphs are as shown:

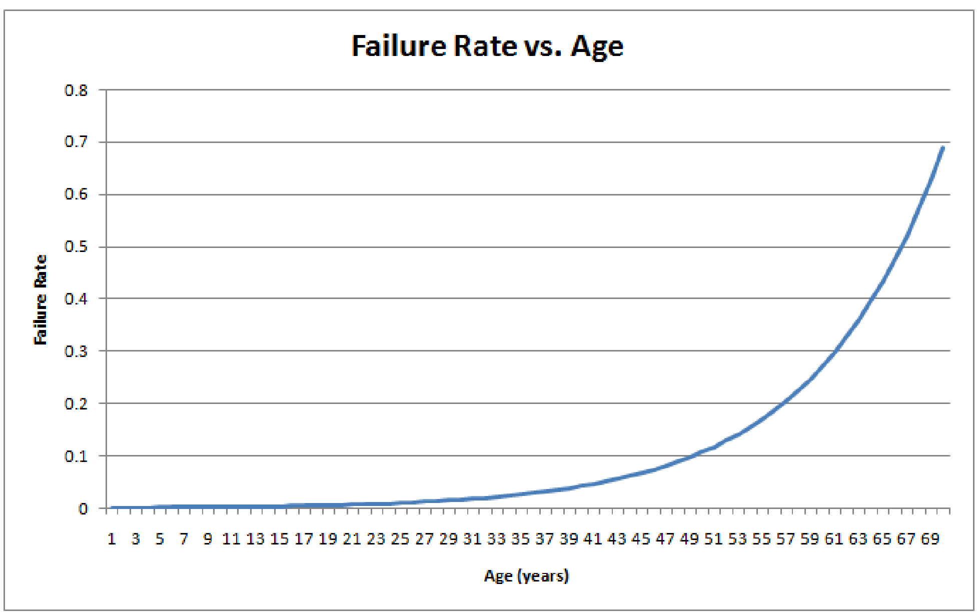


Figure II-1 Failure Rate vs. Age

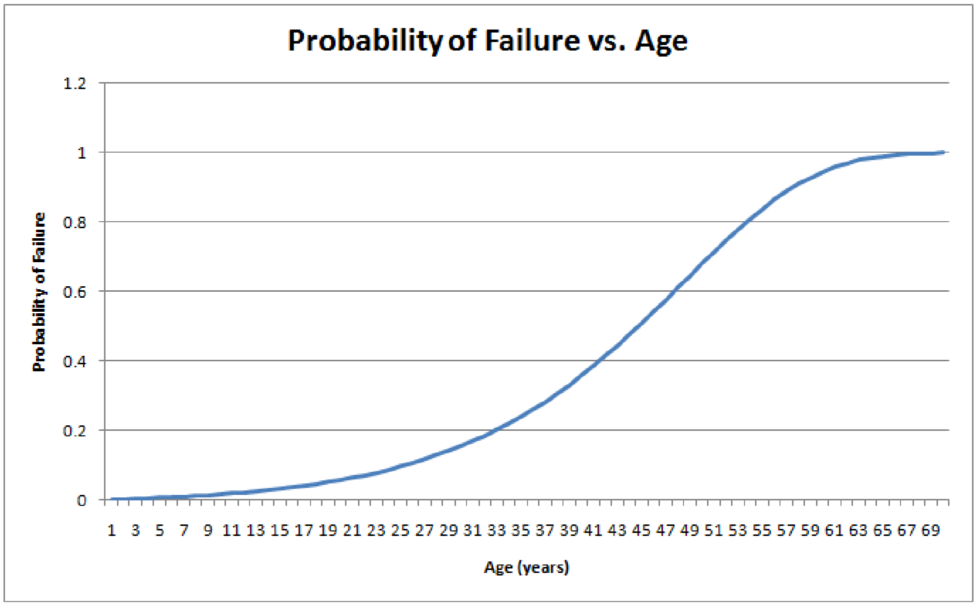


Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Replacement Plan Using a Reactive Approach

Because their consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

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

with α and β determined from the probability of failure of each asset class.

An example of such a replacement plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age, as opposed to the chronological age of the asset.

II.2.3 Projected Replacement Plan Using a Proactive Approach

For certain asset classes, the consequence of asset failure is significant, and, as such, these assets are proactively replaced prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

Failure of an asset occurs when the stress to which an asset is exposed exceeds its strength. Assuming that stress is not constant, and that stress is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure. This is illustrated in the figure below. A vertical line represents condition or strength (Health Index) and the area under the curve to the right of the Health Index line represents the probability of failure.

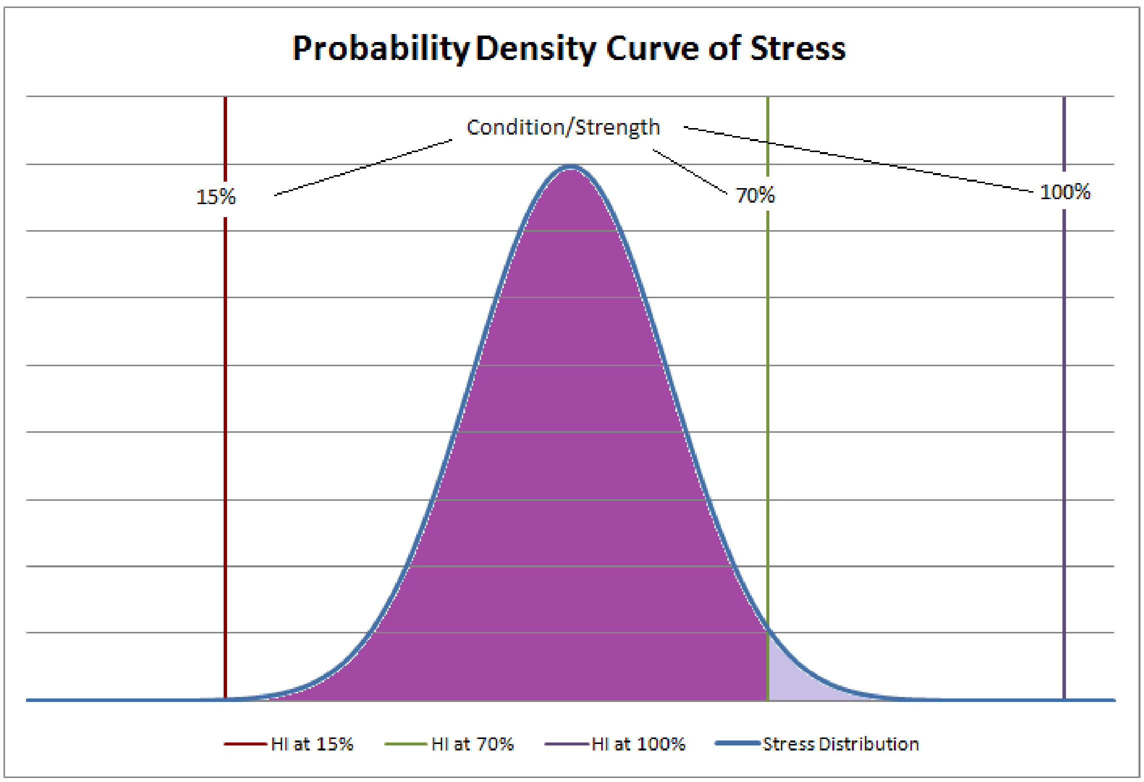


Figure II-3 Stress Curve

Two points of Health Index and probability of failure are needed to generate the probability of failure at other Health Index values. A Health Index of 100% represents an asset that is in brand new condition and a Health Index of 15% represents the asset's end of life. The 100% and 15% conditions are plotted on the stress curve by finding the points at which the areas under the stress curve are equal to $P_{f\ 100\%}$(age at 100% Health Index) and $P_{f\ 15\%}$ = P_f(age at 15% Health Index). By moving the vertical line left from 100% to 15%, the probabilities of failure for other Health Indices can be found.

The probability of failure at a particular Health Index is found from plotting the Health Index on the X-axis and the area under the probability density curve to the right of the Health Index line on the Y-axis as shown on the graph of the figure below.

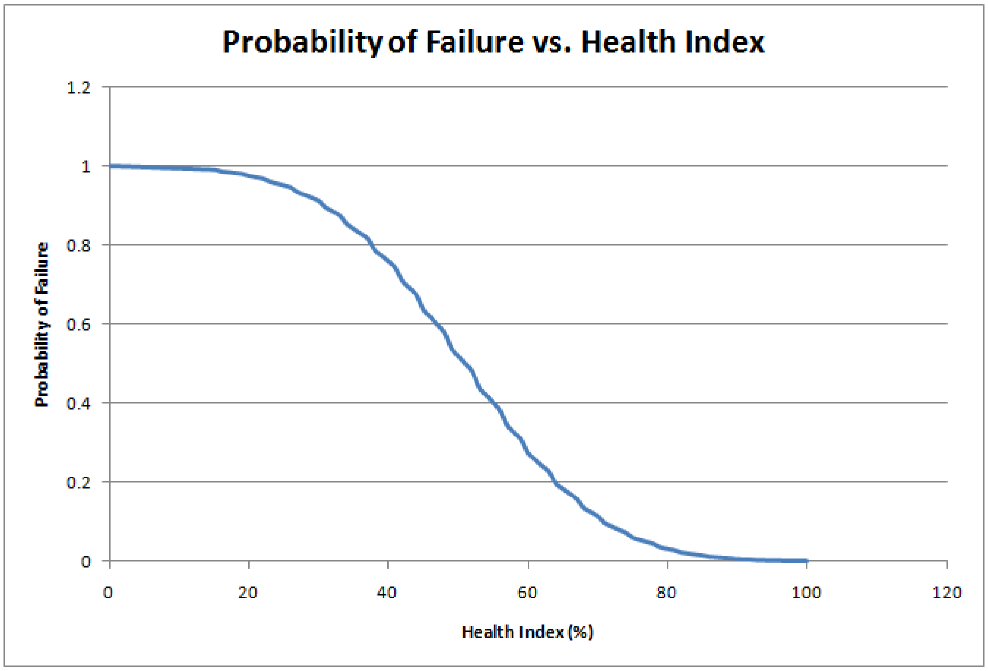


Figure II-4 Probability of Failure vs. Health Index

<u>Relating Health Index to Effective Age</u>

Once the relationship between probability of failure and Health Index has been found, the "effective age" of an asset can be determined. The "effective age" is different from chronological age in that it is based on the asset's condition and the stresses that are applied to the asset.

The probability of failure associated with a specific Health Index can be found using the Probability of Failure vs. Health Index (Figure II-4) and Probability of Failure vs. Age (Figure II-2). The probability of failure at a particular Health Index can be found from Figure II-4. The same probability of failure is located on Figure II-2, and the effective age is on the horizontal axis of Figure II-2. See example on the figure below where a Health Index of 60% corresponds to an effective age of 35 years.

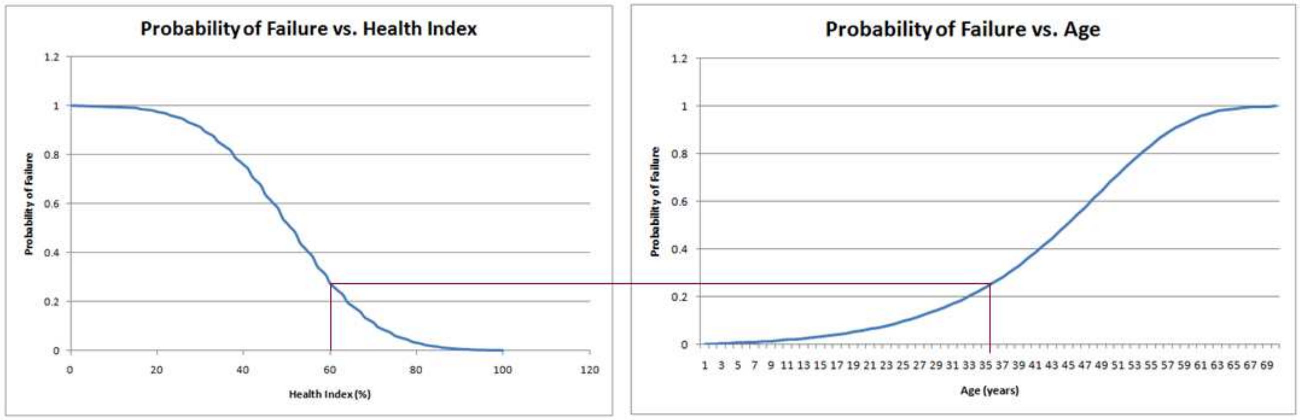


Figure II-5 Effective Age

Condition-Based Replacement Plan

In order to develop a replacement plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure.

The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

It is assumed in this study that each asset group has a base criticality value, $Criticality_{min}$. The individual units in the asset group are assigned Criticalities that are multiples of $Criticality_{min}$. A unit becomes a candidate for replacement when its risk value, the product of its probability of failure and criticality, is greater than or equal to 1.

In the example shown below, Asset 1 and Asset 2 are candidates for replacement.

Table II-6 Sample Replacement Ranking

Asset Name	Age	Health Index (HI)	Consequence of Failure (Criticality)	Probability of Failure (POF) Corresponding to HI	Risk (POF*Criticality)	Replacement Ranking
Asset 1	41	30.00%	2	78.20%	1.564	1
Asset 2	29	30.00%	1.5	78.20%	1.173	2
Asset 3	37	30.00%	1	78.20%	0.782	3
Asset 4	42	50.00%	2	12.80%	0.256	4
Asset 5	18	50.00%	1.5	12.80%	0.192	5
Asset 6	20	50.00%	1	12.80%	0.128	6

II.3 Optimal and Levelized Replacement Plans

The optimal Condition-Based Replacement plan shows the optimal time of replacement, namely when the risk cost is equal to one for proactively replaced assets and the time of expected failure for run to failure assets. As it may not always be feasible to replace as per the optimal plan, a "levelized" or smoother replacement plan may allow a utility to better manage capital investments.

The levelized replacement plan for proactively replaced assets allows for investments to be accelerated or deferred for a limited number of years. The levelized plan for reactively replaced assets suggests replacing assets prior to their time of expected failure.

III DATA ASSESSMENT

This page is intentionally left blank.

III Data Assessment

The condition data used in this study were obtained from Greater Sudbury Hydro and included the following:

- Asset Properties (e.g. age, PCB content, location information)
- Test Results (e.g. Oil Quality, DGA)
- Non-Conformance Logs

There are two components that assess the availability and quality of data used in this study: Data Availability Indicator (DAI) and Data Gap.

III.1 **Data Availability Indicator (DAI)**

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the “best” overall weighted, total condition parameters score. The formula is given by:

$$HI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\,m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_{n\max} \times WCFn)}{\sum_{n=1}^{\forall n} (CPF_{n.\max} \times WCPFn)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data Availability Coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

For example, say an asset has condition parameters A, B, and C with weights of 1, 2, and 3 respectively. Condition parameter scores are rated from 0 through 4, so the maximum score is 4. The maximum product of score and weight is therefore given by (maximum score)*weight.

Thus, for conditions A, B, and C, the maximum products are 4*1 = 4, 4*2 = 8, and 4*3 = 12 respectively. It follows that the sum of maximum products for all possible conditions = 4+8+12 = 24. If asset X only has data for conditions A and B, the sum of maximum product of available conditions = 4+8 = 12. Its DAI is therefore 12/24 = 50%.

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score.

It is important to note that DAI is measured against the parameters make up the Health Index formula and that the Health Index formula is based only on data that is collected by GSH. There are additional parameters are important indicators of degradation that may not be collected (discussed in Section III.2). An asset may have a high DAI but the quality of parameters used in the Health Index formula may need improvement. When the condition parameters used in the Health Index formula are of good quality with little data gaps and the DAI is high, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

III.2 Data Gap

The Health Index formulations developed and used in this study are based solely on GSH's available data. There are additional parameters or tests that GSH may not collect but nonetheless are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	✮✮✮
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	✮✮
Low	Helpful data; least indicative of asset deterioration	✮

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulations.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for "Tank Corrosion" on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	✫ ✫	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

This page is intentionally left blank.

IV RESULTS

This page is intentionally left blank.

IV Results

This section summarizes the findings of this study.

Health Index Results

A summary of the Health Index evaluation results is shown in Table IV-1. The population and sample size, or number of assets with sufficient data for Health Indexing, are given. For each group the Health Index Distribution, Percentage in Poor and Very Poor Condition, and average Health Index are shown. Also given are the average age of each group and the percentage of the population for which age is available.

It can be seen from the results that wood poles are, on average as an asset group, in the worst condition. Approximately 31% of all wood poles owned by Bell are in poor or very poor condition. Approximately 28% of all wood poles owned by Hydro One are in poor or very poor condition. Similarly, 26% of all wood poles owned by Sudbury Hydro and privately owned are in poor or very poor condition.

Also of concern are Substation Transformers where approximately 23% of the population is in poor condition. Many of the units in this asset group are aging, with the average age of the population at 43 years.

Pole and Pad Mounted Transformers, Overhead Line Switches, and Concrete, Steel, and Aluminum poles are generally in good condition. For these asset categories, less than 1% of the assets are categorized as poor or very poor.

Condition Based Replacement Plan

The condition-based replacement plan for the first year and the asset replacement strategy is shown for each asset group in Table IV-2.

Table IV-3 shows the 20 year optimized and levelized replacement plan.

It is important to note that the replacement plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units for replacement. While the Condition-Based Replacement Plan can be used as a guide or input to GSH's Asset Management Plan, it is not expected that it be followed directly or as the final deciding factor in sustainment and capital decisions. There are numerous other factors and considerations that will influence GSH's asset management decisions.

GSH's most significant expected replacements were found to be for Substation Transformers and GSH-owned Wood Poles. Three Substation Transformers (nearly 6% of the population of 53) and approximately 283 wood poles, 2.3% of the population, are candidates for replacement in the current year.

Table IV-1 Health Index Results Summary

Asset	Sub-Category	Population	Sample Size	Health Index Distribution (% of Sample Size)					Total of Poor and Very Poor (% of Sample Size)	Average Health Index	Age Availability (% of Population with Age Data)	Average Age
				Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (≥ 85%)				
Substation Transformers	-	53	53	0%	23%	32%	28%	17%	23%	66%	100	43
Pole Mounted Transformers	-	4255	4255	0%	<1%	2%	11%	87%	<1%	96%	38	13
Pad Mounted Transformers	-	1288	1288	0%	<1%	<1%	8%	92%	<1%	97%	93	19
Overhead Line Switches	-	1771	1771	0%	<1%	1%	2%	96%	<1%	99%	28	5
Sudbury Hydro Wood Poles	All	12377	12377	<1%	26%	24%	26%	25%	26%	68%	88	32
	44 kV	1431	1431	0%	7%	33%	34%	26%	7%	74%	92	24
	Non-44 kV	10946	10946	<1%	29%	22%	25%	24%	29%	67%	88	33
Sudbury Hydro Concrete Poles	All (Non-44 kV)	165	165	0%	0%	10%	40%	50%	0%	88%	55	38
Bell Wood Poles	All	2639	2639	0%	31%	32%	14%	23%	31%	65%	88	35
	44 kV	141	141	0%	<1%	3%	9%	88%	<1%	93%	99	6
	Non-44 kV	2498	2498	0%	33%	33%	14%	19%	33%	63%	88	37
Hydro One Wood Poles	All	436	436	0%	28%	31%	14%	28%	28%	67%	76	38
	44 kV	320	320	0%	34%	39%	13%	13%	34%	60%	91	38
	Non-44 kV	116	116	0%	9%	7%	14%	70%	9%	88%	33	33
Private Wood Poles	All	1307	1307	<1%	25%	22%	17%	35%	26%	70%	79	34
	44 kV	11	11	0%	0%	55%	0%	45%	0%	73%	100	23
	Non-44 kV	1296	1296	<1%	26%	22%	18%	35%	26%	70%	79	34

Asset	Sub-Category	Population	Sample Size	Health Index Distribution (% of Sample Size)					Total of Poor and Very Poor (% of Sample Size)	Average Health Index	Age Availability (% of Population with Age Data)	Average Age
				Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (≥ 85%)				
Private Concrete Poles	All	13	13	0%	0%	0%	0%	100%	0%	100%	46	2
	44 kV	6	6	0%	0%	0%	0%	100%	0%	99%	100	2
	Non-44 kV	7	7	0%	0%	0%	0%	100%	0%	100%	0	-
Private Steel Poles	All (Non-44 kV)	49	49	0%	0%	12%	51%	37%	0%	82%	63	45
Private Aluminum Poles	All (Non-44 kV)	32	32	0%	0%	0%	0%	100%	0%	97%	91	10

Table IV-2 Year 1 Condition Based Replacements

Asset	Sub-Category	Optimal Condition-Based Replacement Plan for Year 1 [Number of Units]	Replacement Strategy
Substation Transformers	-	3	proactive
Pole Mounted Transformers	-	17	reactive
Pad Mounted Transformers	-	2	reactive
Overhead Line Switches	-	2	reactive
Sudbury Hydro Wood Poles	All	283	proactive
	44 kV	28	proactive
	Non-44 kV	252	proactive
Sudbury Hydro Concrete Poles	All (Non-44 kV)	1	proactive
Bell Wood Poles	All	63	proactive
	44 kV	1	proactive
	Non-44 kV	59	proactive
Hydro One Wood Poles	All	8	proactive
	44 kV	5	proactive
	Non-44 kV	1	proactive
Private Wood Poles	All	24	proactive
	44 kV	0	proactive
	Non-44 kV	24	proactive
Private Concrete Poles	All	0	proactive
	44 kV	0	proactive
	Non-44 kV	0	proactive
Private Steel Poles	All (Non-44 kV)	1	proactive
Private Aluminum Poles	All (Non-44 kV)	0	proactive

Table IV-3 Twenty Year Condition Based Replacement Plan

Asset	Sub-Category	Replacement Strategy	Replacement Year																			
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Substation Transformers	-	Optimal	3	0	0	7	0	0	0	0	0	0	0	2	0	0	0	0	0	1	4	0
		Levelized (Deferred)	2	1	0	2	3	2	0	0	0	0	0	1	1	0	0	0	0	1	2	2
		Levelized (Accelerated)	3	2	2	3	0	0	0	0	0	0	1	1	0	0	1	1	1	1	1	1
Pole Mounted Transformers	-	Optimal	17	18	18	21	23	24	27	29	30	32	36	37	40	42	44	45	46	49	51	53
		Levelized	34	34	34	34	34	34	34	34	34	34	34	34	34	34	35	35	35	35	35	35
Pad Mounted Transformers	-	Optimal	2	4	5	8	11	11	13	15	18	20	20	22	22	22	22	22	25	23	22	20
		Levelized	15	15	15	15	15	15	15	15	15	15	16	16	16	16	16	16	16	23	22	20
Overhead Line Switches	-	Optimal	2	2	2	3	3	3	4	5	4	6	6	7	10	10	10	10	14	13	14	16
		Levelized	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8
Sudbury Hydro Wood Pole	All	Optimal	283	288	289	291	294	296	297	300	302	305	306	308	308	304	306	311	314	312	312	312
		Levelized	297	297	297	297	297	297	297	298	298	298	298	298	298	308	309	309	309	312	312	312
	44	Optimal	28	29	28	26	26	29	27	26	26	29	25	26	27	22	28	25	26	23	24	27
		Levelized	28	28	28	27	27	27	27	27	27	27	26	26	26	25	25	25	26	25	25	25
	Non-44 kV	Optimal	252	254	257	257	259	257	260	263	266	266	265	267	268	268	269	269	271	272	271	274
		Levelized	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	265	265	265	265	265
Sudbury Hydro Concrete Pole	All (Non-44)	Optimal	1	1	1	1	1	1	1	1	1	1	2	1	1	2	1	1	1	2	1	1
		Levelized	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Asset	Sub-Category	Replacement Strategy	Replacement Year																			
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Bell Hydro Wood Pole	All	Optimal	63	62	62	62	63	61	63	63	63	61	63	60	58	62	63	58	60	62	59	64
		Levelized	63	62	62	62	63	63	63	62	62	62	62	60	61	61	61	60	60	60	61	62
	44	Optimal	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Levelized	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Non-44 kV	Optimal	59	58	56	57	58	56	58	58	59	58	59	58	56	59	57	56	57	59	57	62
		Levelized	59	58	57	57	57	57	57	58	58	59	59	58	58	57	57	57	57	57	60	60
Hydro One Wood Pole	All	Optimal	8	8	8	8	7	7	7	7	8	7	5	7	6	5	6	6	6	5	6	4
		Levelized	8	8	8	8	8	8	7	7	7	7	6	6	6	6	6	6	5	5	5	4
	44	Optimal	5	5	5	4	4	4	4	4	5	4	4	4	4	4	4	5	4	3	6	3
		Levelized	5	5	5	4	4	4	4	4	5	4	4	4	4	4	4	5	5	4	4	3
	Non-44 kV	Optimal	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Levelized	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Private Wood Pole	All	Optimal	24	23	22	21	21	21	20	21	20	18	22	20	19	21	17	20	19	17	22	18
		Levelized	24	23	22	21	21	21	21	20	20	20	20	20	20	20	19	19	19	19	19	18
	44	Optimal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Levelized	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Non-44 kV	Optimal	24	23	22	21	21	20	20	20	19	18	20	19	19	21	17	20	19	17	22	18
		Levelized	24	23	22	21	21	20	20	20	19	19	19	19	19	19	19	19	19	20	20	18
Private Concrete Pole	All	Optimal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Levelized	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	44	Optimal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Levelized	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Asset	Sub-Category	Replacement Strategy	Replacement Year																			
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	Non-44 kV	Optimal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Levelized	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Private Steel Pole	All (Non-44)	Optimal	1	1	0	0	1	0	0	1	0	0	1	0	0	0	1	0	0	1	0	0
		Levelized	1	1	0	0	1	0	0	1	0	0	1	0	0	0	1	0	0	1	0	0
Private Aluminum Pole	All (Non-44)	Optimal	0	0	0	0	0	0	0	0	1	0	0	1	0	1	0	0	1	0	0	1
		Levelized	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A = Indicates that there is little variation in expected replacements, therefore levelization is not required																						

Data Assessment Results

Age, oil quality and dissolved gas analysis tests were available for all Substation Transformers. A majority of the units, however, did not have Doble tests and inspection data that indicate the condition of transformer components such as bushings, tank, and connections. No cooling system information, IR scan results, or loading were available for any of the units.

For Pole and Pad Mounted Transformers, Overhead Line Switches, and Poles, it was assumed that no entry in the Non-Conformance Log means that an asset has been visually inspected and is in good condition.

While Pole Mounted Transformers are assumed to have all inspection data related to tank condition, grounding, connection, and bushings, age is available for only 38% of the population. As well, Loading data was not available for any of the units.

Pad Mounted transformers are also assumed to have inspection data related to tank condition, grounding, connection, and bushings. Data quality may be improved by collecting Loading information and information regarding the condition of elbows.

For Overhead Line Switches, it is assumed that the condition of the switch, arc interrupter, and insulator are known. Age, however, was only available for 28% of the population. An important data gap for this asset group is condition information on the switch operating mechanism.

The only available information for Poles was age and inspection information on pole damage and whether it is leaning. Data gaps for this asset group includes pole strength test (if applicable to the pole's age and type), and more detailed inspection information (e.g. rot, spalling, corrosion, cracks).

V CONCLUSIONS AND RECOMMENDATIONS

This page is intentionally left blank.

V Conclusions and Recommendations

1. An Asset Condition Assessment was conducted for six of GSH's key distribution assets, namely Substation Transformers, Pad and Pole Mounted Transformers, Overhead Line Switches, and Wood and Concrete Poles. Additionally, six other pole categories with varying owners (Bell, Hydro One, and Private) of varying types (wood, concrete, steel, aluminum, and anodized aluminum) were assessed. For each asset category, the Health Index distribution was determined and a condition-based replacement plan was developed.

2. Of all the asset groups, Wood Poles, regardless of its owners, were found generally to be in the worst condition. Over 26% of Sudbury Hydro's and privately owned poles are in poor or very poor condition. Twenty-eight percent (28%) and 31% of Hydro One's and Bell's wood poles respectively are in poor or very poor condition. It is recommended that an annual capital replacement programs be put in place to proactively replace poles in poor and very poor condition.

3. It was found that 23% of GSH's Substation Transformers are in poor condition. Additionally, the population is aging; the average age of the population is 43 years and nearly 50% of all units are 45 years or older. Because Substation Transformers are a crucial distribution system component with major consequences of failure, it is recommended that investments be made in an expedient manner to address this issue.

4. Pole and Pad Mounted Transformers, Overhead Line Switches, and Concrete, Steel, and Aluminum poles are generally in good to very good condition.

5. GSH's most significant expected replacements were found to be for Substation Transformers and GSH-owned Wood Poles. Three Substation Transformers (nearly 6% of the population of 53) are candidates for replacement in the current year. Over 280 wood poles, 2.3% of the population, may be considered for replacements.

6. While oil quality and DGA tests were available for all Substation Transformers, Doble tests and inspection records are available for only a limited number of units. It is recommended that this information be collected for the remainder of the population. As well, it is recommended that information regarding the transformer cooling system, IR scans, and loading data be collected.

7. Currently, problems found during inspections of Pole and Pad Mounted Transformers, Overhead Line Switches, and Poles are recorded in the Non Conformance Log. A disadvantage of such a system is that if a unit is inspected and no issues are found, there is no record that the unit was inspected and is in good condition. Another disadvantage of the Non Conformance Log is that it does not facilitate the use of standardized inspection items or components, or a standard point system to evaluate the item or component being inspected. The user is free to enter comments, making it difficult to search for specific problems.

   It is recognized that GSH is currently in the process of working with PartnerSoft to implement a system that standardizes and computerizes inspection records. It is recommended that the inspection-based condition and sub-condition parameters presented in this study be included as standard inspection items. Such parameters can be found in the Health Index formula for each asset group. The suggested point systems, or condition criteria, for evaluating the parameters are also included.

From an Asset Condition Assessment standpoint, standardized inspections will not only ensure that all critical items are collected during inspections, it will also facilitate the data collection and the process of Health Index evaluation. Ultimately, it will result in a higher degree of confidence in the Health Index.

8. It is recommended that the data gap inspection parameters identified for Pole and Pad Mounted Transformers, Overhead Line Switches, and Poles be incorporated into the new inspection system. Data gap inspection parameters are identified in the Data Gap section of each asset category (e.g. condition of elbows for Pad Mounted transformers, condition of switch operating mechanism for Overhead Line Switches, rot and cracks for Poles). In addition, they are included, with suggested point system, in the Health Index Formula section of each asset category.

9. Breakers, Reclosers, Pad Mounted Switchgear and Underground Cables were not included in this study. This is because there was insufficient data collected for these asset categories. It is recommended that GSH begin collecting data for these asset categories so that they may be included in future assessments. Please refer to VII Appendix B: Condition Data for Additional Asset Groups for suggested parameters.

10. It is important to note that the replacement plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence GSH's Asset Management Plan.

VI APPENDIX A: RESULTS AND FINDINGS FOR EACH ASSET CATEGORY

This page is intentionally left blank.

1 Substation Transformers

While substation power transformers can be employed in either step-up or step-down mode, a majority of the applications in distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For distribution stations, power transformer ratings typically range from 3 MVA to 30 MVA. The units included in this study range from 3 MVA to 20 MVA.

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

- Primary and secondary windings
- Laminated iron core
- Internal insulating mediums
- 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

The primary and secondary windings are installed on a laminated iron core and serve as the coils in which electromotive force is produced when alternating magnetic flux passing through the core links with the windings. The internal insulating mediums provide insulation for energized coils. Insulating oil serves as the insulating medium as well as serves as the coolant. Due to its low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress, mineral oil is the most widely used transformer insulating material. The transformer coil insulation is reinforced with different forms of solid insulation that include wood-based paperboard (pressboard), wrapped paper and insulating tapes. Because the dielectric strength of oil is approximately half that of the pressboard, the dielectric stress in the oil ends up being higher than that in the pressboard, and the design structure is usually limited by the stress in the oil. The insulation on the conductors of the winding may be enamel or wrapped paper which is either wood or nylon based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful streamers in the oil, thereby increasing the strength of the structure. Heavy paper wrapping is also usually used on the leads coming from the windings.

The main tank holds the active components of the transformer in an oil volume and maintains a sealed environment through the normal variations of temperature and pressure. Typically, the main tank is designed to withstand a full vacuum for initial and subsequent oil fillings and is able to sustain a positive pressure. The main tank also supports the internal and external components of the transformers. Main tank designs can be classified into 2 types: those being conservator type or sealed type. Conservator types have an externally-mounted tank that usually holds 10% of the main tank's volume. As the transformer oil expands and contracts due to system loading and ambient changes, the corresponding oil volume change must be accommodated. This tank is used to provide a holding mechanism for the expansion and contraction of the main tank's oil over these temperature variations. The liquid seal also provides some protection against moisture ingress into the insulation systems. A sealed tank design incorporates a gas header on top of the oil volume using nitrogen or dry air. This gas header can be either in a positive pressure or vacuum mode depending on the system loading or ambient changes. The pressure and vacuum conditions of a sealed tank design are controlled by the use of a regulator that ensures the tank is within its design limits.

Bushings are used to facilitate the egress of conductors to connect ends of the coils to a power supply system in an insulated, sealed (oil-tight and weather-tight) manner. A bushing is typically composed of an outer porcelain body mounted on a metallic flange. The phase leads are either independent paper-insulated or are an integral part of the bushing. At higher voltage levels, additional insulation is incorporated in the form of mineral oil and/or wound paper leads installed within the porcelain column.

The purpose of a cooling system in a power transformer is to efficiently dissipate heat generated due to copper and iron losses and to help maintain the windings and insulation temperature within acceptable range. The utilization of a number of cooling stages allows for an increase in load carrying capability. Loss of any stage or cooling element may result in a forced de-rating of the transformer. Transformer cooling system ratings are typically expressed as:

- Self-cooled (radiators) with designation as ONAN (oil natural, air natural)
- Forced cooling first stage (fans) with designation as ONAF (oil natural, air forced)
- Forced cooling second stage (fans and pumps) with designation as OFAF (oil forced, air forced)

An off-load tap changer allows the transformer turns ratio to be altered over a small range to effect changes in output voltage as required. An off-load tap changer typically allows for an adjustment of 5% above nominal and 5% below nominal voltage in 2 ½ % steps. An off-load tap changer must only be operated with the transformer off potential. Under-load tap changers (ULTCs) allow for automatic voltage regulation in response to varying load conditions on the line. ULTCs consist of moving mechanical parts, a drive motor, linkages and voltage regulation sensing equipment. Instrument transformers include CT's and PTs for metering or control purposes. Power transformers are equipped with externally-mounted control cabinets for voltage and current control relay(s), secondary control circuits, and in some cases the tap changer motor and position indicators.

From the view of both financial and operational risk, power transformers are the most important asset deployed on the distribution and transmission systems. A significant proportion of power transformers employed by North American utilities were installed in the 1950s, 1960s or early 1970s. Despite the fact that the number of transformer failures arising due to End-of-Life (EOL) has to-date been relatively small, there is awareness that a majority of the transformer population will soon be reaching its end-of-life, which may significantly impact transformer failure rates.

1.1 Degradation Mechanism

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

Transformer oil is made up of complex hydrocarbon compounds, containing anti-oxidation compounds. Despite the presence of oxidation inhibitors, oxidation occurs slowly under normal operating conditions. The rate of oxidation is a function of internal operating temperature and age. The oxidation rate increases as the oil ages, reflecting both the depletion of the oxidation inhibitors and the catalytic effect of the oxidation products on the oxidation reactions. The products of oxidation of hydrocarbons are moisture, which causes further deterioration of the insulation system and organic acids, which result in formation of solids in the form of sludge. Increasing acidity and water levels result in the oil being more aggressive with regard to the paper and hence accelerate the ageing of the paper insulation. Formation of sludge adversely impacts the cooling capability of the transformer and adversely impacts its dielectric strength. An indication of the condition of insulating oil can be obtained through measurements of its acidity, moisture content and breakdown strength.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains; therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). However, this test can be performed only after de-tanking or the core and coil and therefore, is not a practical test. For a new transformer the DP value of the paper is normally greater than 1,000. As the paper ages this figure gradually decreases. When the DP value approaches below 250, the paper is in a very brittle and fragile condition. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharge (PD). PD can be initiated if the level of moisture is allowed to develop in the paper or if there are other minor defects within active areas of the transformer.
The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of Furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

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

Other condition assessment techniques for power 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 ultrasonics and/or electromagnetic detection and frequency response analysis.

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

There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Consequences of power transformer failure include customer interruptions over significantly long durations. Catastrophic failure of a transformer may also result in injury or death, fire and damage to property. There are also environmental risks due to oil spills during tank failures. These risks are more pronounced where transformers are located near water bodies or contain PCBs.

1.2 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GSH Substation Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

1.2.1 Condition and Sub-Condition Parameters

Table 1-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Insulation	6	4
2	Cooling	0*	4
3	Sealing & connection	3	4
4	Service Record	3	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

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

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Oil Quality	Table 1-6	8	4
2	Oil DGA	Table 1-7	10	4
3	Winding Doble	Table 1-8	10	4
4	Bushing	Table 1-9	5	4

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

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Cooling System Status	Table 1-10	1	4

Table 1-4 Sealing & Connection (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Visual Appearance	Table 1-9	1	4
2	General Condition	Table 1-9	1	4
3	Corrosion	Table 1-9	1	4
4	Dirt	Table 1-9	1	4
5	Paint	Table 1-9	1	4
6	Tank Oil Leak	Table 1-9	5	4
7	Primary Connection	Table 1-9	3	4

8	Secondary Connection	Table 1-9	3	4
9	Grounding	Table 1-9	4	4
10	IR Thermography	Table 1-10	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 1-5 Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Loading	Table 1-11	0*	4
2	Age	Figure 1-1	3	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

1.2.2 Condition Parameter Criteria

Oil Quality

Table 1-6 Oil Quality Test Criteria

CPF	Description
4	Overall factor is less than 1.2
3	Overall factor between 1.2 and 1.5
2	Overall factor is between 1.5 and 2.0
1	Overall factor is between 2.0 and 3.0
0	Overall factor is greater than 3.0

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

		Scores				
		1	2	3	4	**Weight**
Moisture PPM (T ^{o}C Corrected) (From DGA test)		<=20	<=30	<=40	>40	4
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

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

For example if all data is available, overall Factor = $\frac{\sum Score_i \times Weight_i}{12}$

Oil DGA

Table 1-7 Oil DGA Criteria

CPF	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

*In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

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

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	**2**
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	**1**
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	**1**

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

Winding Doble Test

Table 1-8 Winding Doble Test Criteria

CPF	Description
4	%PF < 0.5%
3	0.5% < %PF < 0.7%
2	0.7% < %PF < 1%
1	1.0% < %PF < 2.0%
0	%PF > 2.0%

Age

Assume that the failure rate for Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

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

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 45 and 60 years the probability of failures (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

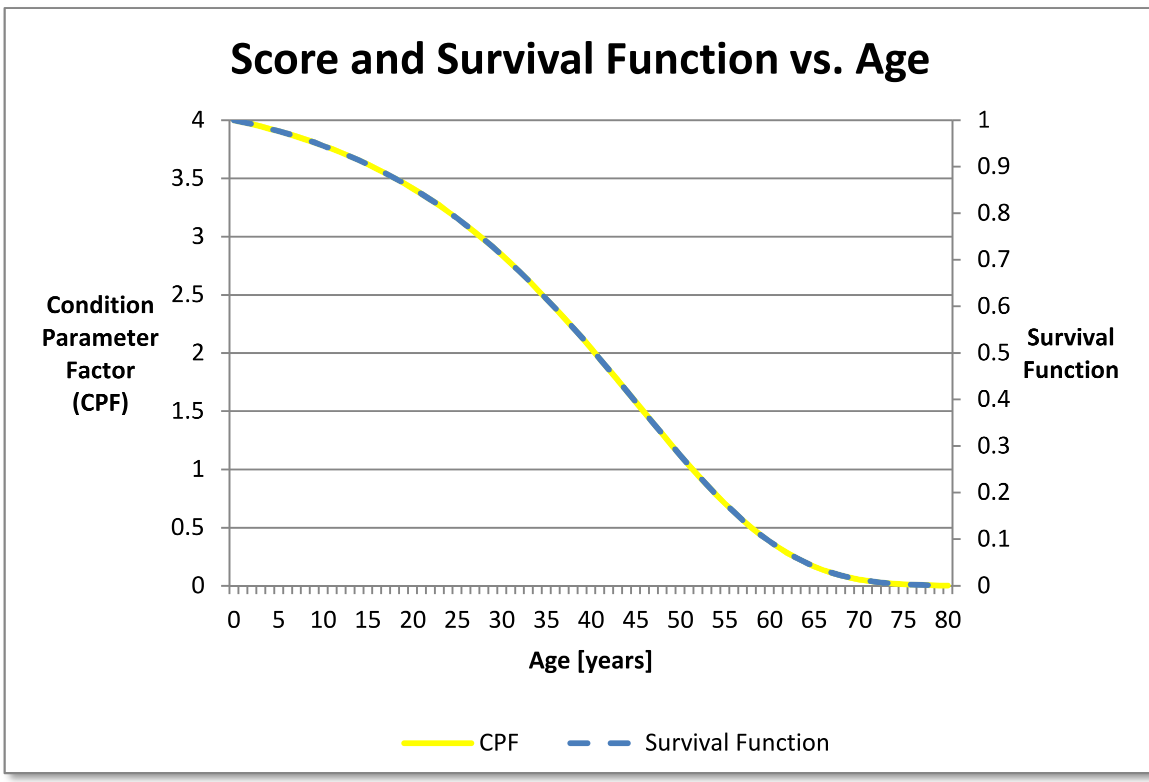


Figure 1-1 Substation Transformers Age Condition Criteria

Visual Inspections

Table 1-9 Inspection Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear, Working as Required
2	Wear or Failed, Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed, Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

OK or Not OK

Table 1-10 OK or Not OK Criteria

CPF	Condition Description
4	OK
0	Not OK

Loading History

Table 1-11 Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA\times 4+NB\times 3+NC\times 2+ND\times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

1.3 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 43 years.

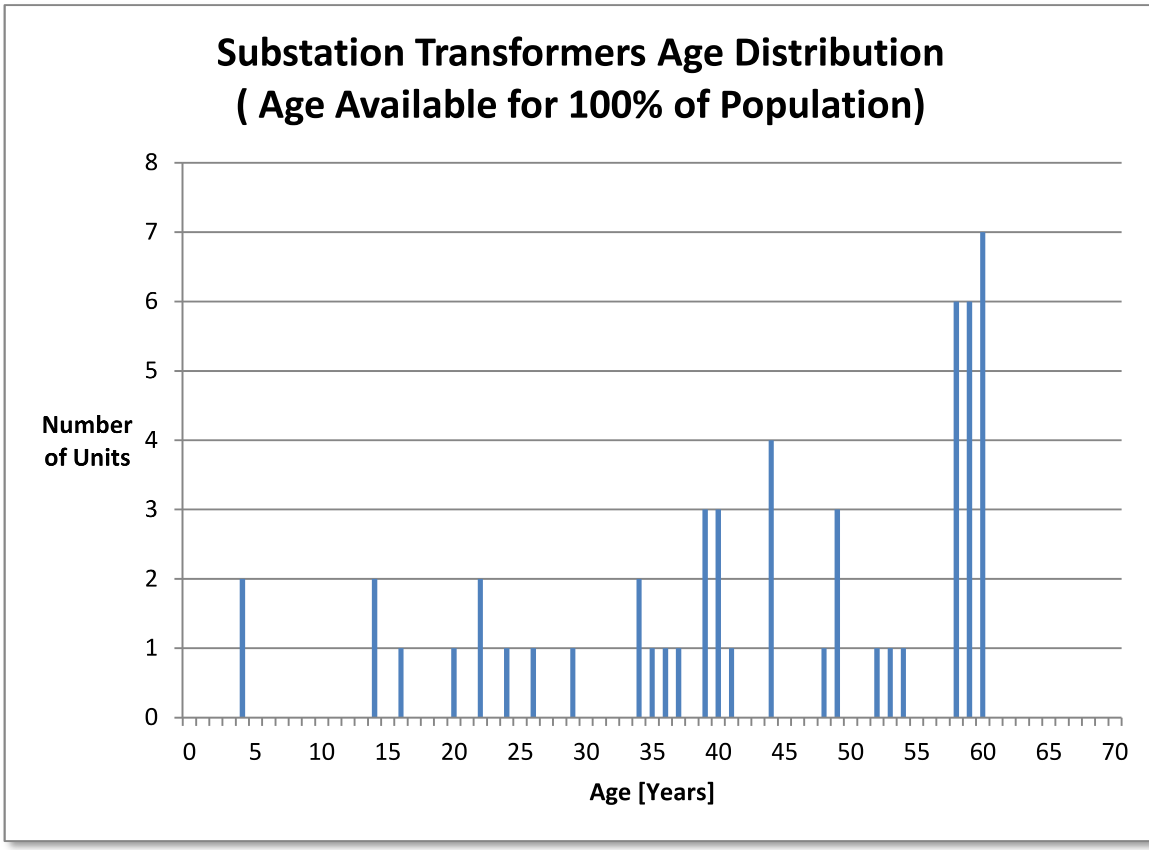


Figure 1-2 Substation Transformers Age Distribution

1.4 Health Index Results

There are 53 in-service Substation Transformers at GSH. Of these, 53 units had sufficient data for assessment.

The average Health Index for this asset group is 66%. Approximately 23% of the units were found to be in poor condition.

The Health Index Distribution is shown in Figure 1-3 through Figure 1-5.

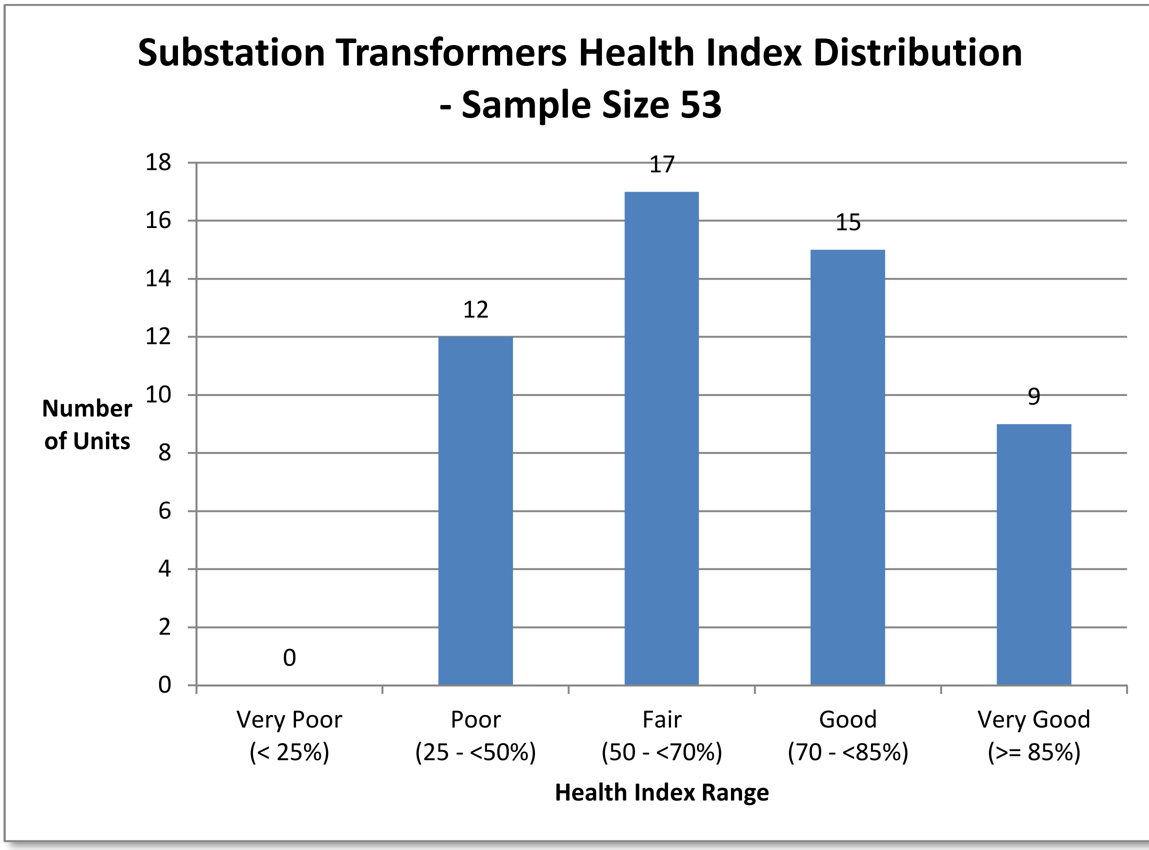


Figure 1-3 Substation Transformers Health Index Distribution (Number of Units)

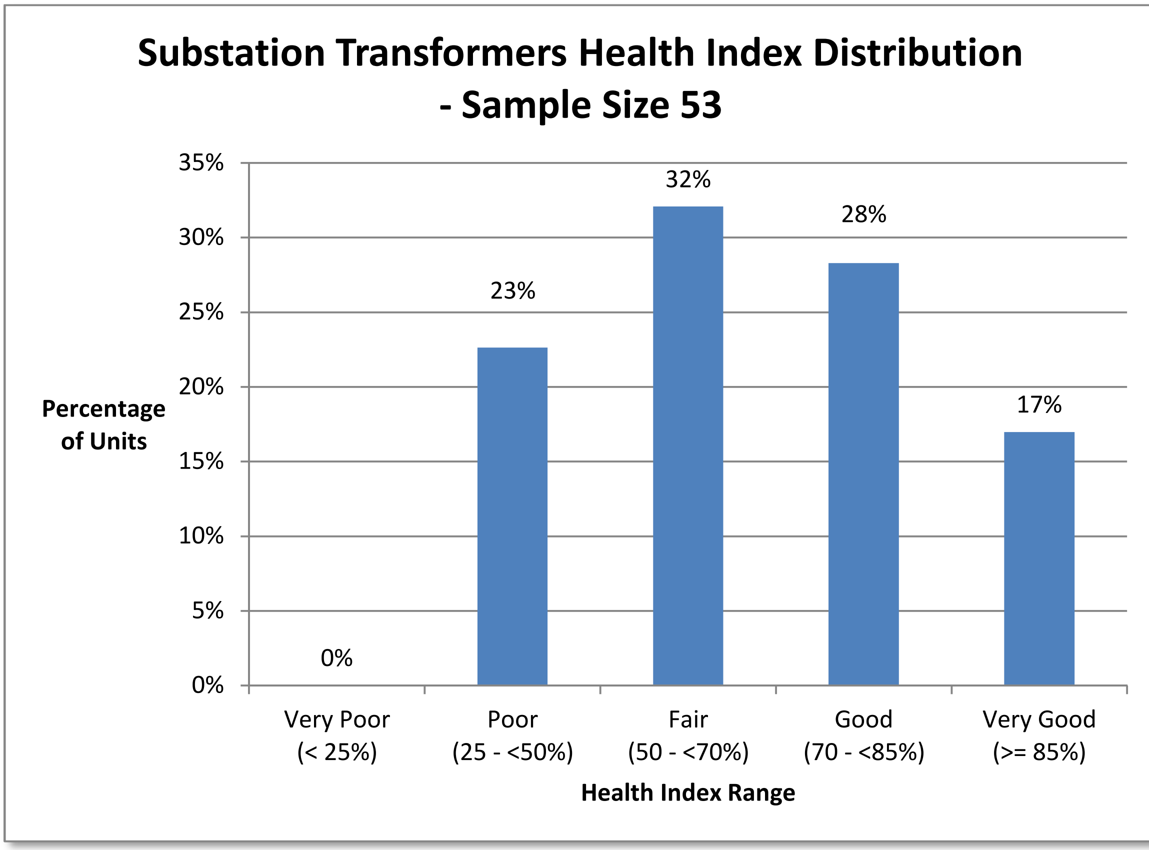


Figure 1-4 Substation Transformers Health Index Distribution (Percentage of Units)

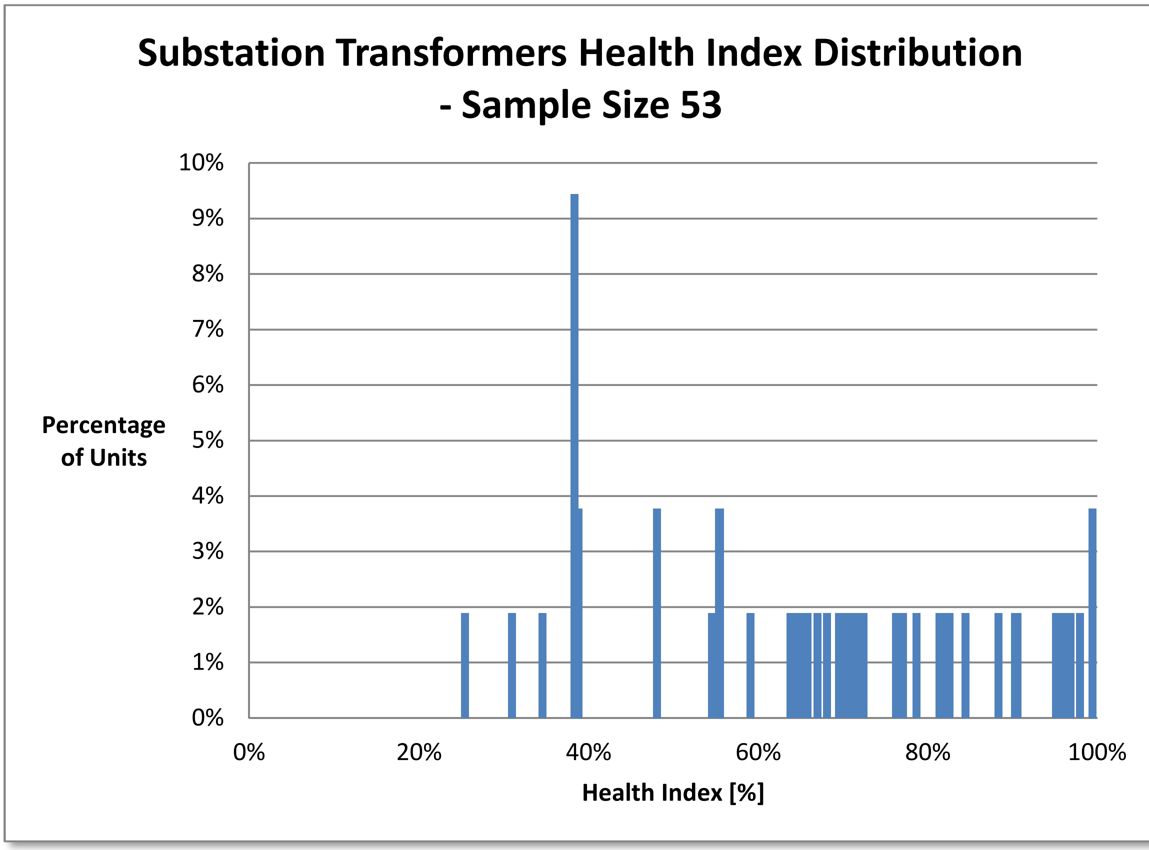


Figure 1-5 Substation Transformers Health Index Distribution by Value (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown below:

Table 1-12 Health Index Results for Each Substation Transformers Unit

	Transformer Name	Serial Number	Data Availability	Age	Health Index
1	West Nip 35T1	TAG6235298	52.3%	34	**25.4%**
2	Cressey 3T1 Blue Phase	165310	52.3%	60	**31.0%**
3	Cressey 3T1 Red Phase	166027	52.3%	60	**34.5%**
4	Cressey 3T1 White Phase	166026	52.3%	60	**38.4%**
5	Cressey 3T2 Red Phase	165309	52.3%	60	**38.4%**
6	Cressey 3T2 White Phase	166024	52.3%	60	**38.4%**
7	Cressey 3T2 Blue Phase	166023	52.3%	60	**38.4%**
8	Cressey 3T1 Spare	166019	52.3%	60	**38.4%**
9	Kathleen 2T1 Red Phase	506264	52.3%	59	**38.8%**
10	Kathleen 2T1 White Phase	150480	52.3%	59	**38.8%**
11	Kathleen 2T2 Red Phase	150483	52.3%	59	**48.1%**
12	Kathleen 2T2 Blue Phase	166025	52.3%	59	**48.1%**
13	Dash 19T2	291966	52.3%	34	**54.6%**
14	Upper Coniston 31T1 302396 Phase	286651	52.3%	40	**55.4%**
15	Upper Coniston 31T1 302395 Phase	T602231	52.3%	40	**55.4%**
16	Kathleen 2T1 Blue Phase	150482	52.3%	59	**55.5%**
17	Kathleen 2T2 White Phase	150481	52.3%	59	**55.5%**
18	Cressey 3T3	166021	52.3%	53	**59.1%**
19	Dash 19T1	3442	52.3%	34	**63.8%**
20	Gemmell 11T1	302396	52.3%	44	**64.2%**
21	Gemmell 11T2	None	84.8%	22	**64.5%**
22	Regent 9T1	166017	100.0%	49	**65.2%**
23	Main 17T2	293695	52.3%	14	**65.7%**
24	Centennial 14T1	238850	52.3%	44	**65.8%**
25	Upper Coniston 31T1 302397 Phase	T0621001	52.3%	40	**67.0%**
26	Ramsey 10T2	302395	52.3%	41	**68.1%**
27	Tedman 12T1	290990	100.0%	36	**69.5%**
28	Mansour Mining 29T1	238849	52.3%	39	**69.6%**
29	Martilla 8T1	165308	79.8%	49	**69.8%**
30	Robinson 15T1	65050	52.3%	22	**70.2%**
31	Richard Lake 21T1	S1388301	84.8%	44	**70.4%**
32	Capreol 32T1	T55101	81.1%	54	**71.2%**

	Transformer Name	Serial Number	Data Availability	Age	Health Index
33	West Nip 37T1	C10111	84.8%	22	**72.1%**
34	Arthur 5T1	166020	79.8%	52	**72.2%**
35	Lasalle 7T2	166018	52.3%	35	**72.4%**
36	Paris 13T1	S1418601	79.8%	44	**72.4%**
37	Copper Cliff 25T1	293655	84.8%	37	**76.3%**
38	Ramsey 10T1	64708	100.0%	48	**77.1%**
39	Broder 24T1	282072	52.3%	24	**78.6%**
40	West Nip Spare	1829510101	52.3%	17	**81.4%**
41	Falconbridge 33T1	285187	52.3%	29	**81.7%**
42	Long Lake 20T1	293694	52.3%	16	**81.7%**
43	Moonlight 18T1	302397	79.8%	49	**82.6%**
44	Lasalle 7T1	166016	52.3%	39	**84.4%**
45	Levert 6T1	166022	100.0%	39	**88.3%**
46	Main 17T1	1829610101	100.0%	14	**90.3%**
47	Mobile 99T1	1721410101	100.0%	26	**90.6%**
48	Lower Coniston 30T1	283312	52.3%	20	**95.1%**
49	West Nip 36T1	13669	84.8%	21	**96.0%**
50	West Nip 38T1	13710	52.3%	15	**96.8%**
51	West Nip 34T1	214436	52.3%	11	**97.9%**
52	Barrydowne 16T1	291983	52.3%	4	**99.4%**
53	Spare at Moonlight	A3S6923	52.3%	4	**99.4%**

1.5 Condition-Based Replacement Plan

As it is assumed that Substation Transformers are proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 was applied for this asset class.

As noted in Section II, a unit becomes a candidate for replacement when its risk, product of its *probability of failure* and *criticality*, is greater than or equal to one. The probability of failure is as determined by the Health Index. Criticality is determined as shown in the following section.

1.5.1 Criticality

The minimum criticality, $Criticality_{min}$, is 1.25. This value is selected such that a unit with a probability of failure of 80% becomes a candidate for replacement (i.e. 80% * 1.25 = 1). The maximum criticality, $Criticality_{max,}$ is twice the base criticality ($Criticality_{max,}$ = 1.25*2 = 2.5).

Each unit's criticality is defined as follows:

$$Criticality = (Criticality_{max} - Criticality_{min}) * Criticality\_Multiple + Criticality_{min}$$

where the Criticality_Multiple (CM) is defined by criticality factors, weights, and scores:

$$CM = \frac{\sum_{CF=1}^{\forall CF} (CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF} (WCF_{CF})}$$

Where

CFS	Criticality Factor Score
WCF	Weight of Condition Factor

The factors, weights and the score system of each factor are as follows:

Table 1-13 Criticality Factors

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)
Location (near waterbeds)	Environmental stewardship is of the utmost importance.	35	No = 0 Yes = 1
Number of Customers	Reliable service to the greatest number of customers is vital. Does the transformer service more than 1000 customers?	25	Low = 0 High = 1

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)
Bus Structure (open/enclosed)	Is the transformer under consideration located in an open-bus scheme within a residential subdivision? Can public safety be affected if a catastrophic failure were to occur?	20	No = 0 Yes = 1
Backup Capabilities	Can the transformer under consideration be backed-up with the portable?	10	Yes =0 No = 1
Oil Containment	All of our Stations (as of Oct 2011) do not have Oil Containment capabilities, hence the low relative score.	5	Yes =0 No = 1
Transformer Primary Protection	Is the unit's primary protection a fuse or breaker?	5	Breaker = 0 Fuse = 1

The table below shows examples of criticalities for three separate units.

Table 1-14 Criticality Multiple Examples

	Example 1			Example 2			Example 3		
Criticality Factor	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**
Location (near waterbeds)	No	0	0	Yes	1	35	Yes	1	35
Number of Customers	Low	0	0	High	1	25	High	1	25
Bus Structure (open/enclosed)	No	0	0	No	0	0	Yes	1	20
Backup Capabilities	Yes	0	0	Yes	0	0	No	1	10
Oil Containment	Yes	0	0	Yes	0	0	No	1	5
Transformer Primary Protection	Breaker	0	0	Breaker	0	0	Fuse	1	5
	Criticality Multiple		0	Criticality Multiple		0.6	Criticality Multiple		1
	$\text{Criticality}_{\text{Example1}}$		(2.5-1.25)*0 + 1.25 = 1.25	**$\text{Criticality}_{\text{Example2}}$**		(2.5-1.25) *0.6 + 1.25 = 2	**$\text{Criticality}_{\text{Example3}}$**		(2.5-1.25)*1 + 1.25 =2.5

1.5.2 Replacement Plan

The condition-based replacement plan for Substation Transformers is plotted in Figure 1-6 to Figure 1-8. Note that three different replacement scenarios are shown.

The "optimal" plan flags a unit for replacement in the year that its risk (product of POF and criticality) becomes greater than or equal to one. Details for each unit are shown in Table 1-15.

As it may not always be feasible to replace as per the optimal plan, a "levelized", or smoother replacement plan, may allow a utility to better manage capital investments. There are two levelized plans given: accelerated and deferred.

In the accelerated plan, asset replacements are moved forward by a maximum of 5 years. I.e. a unit may be flagged for replacement before its risk is equal to one.

In the deferred plan, replacements are pushed back or deferred such that a unit is flagged for replacement when its probability of failure is 85%.

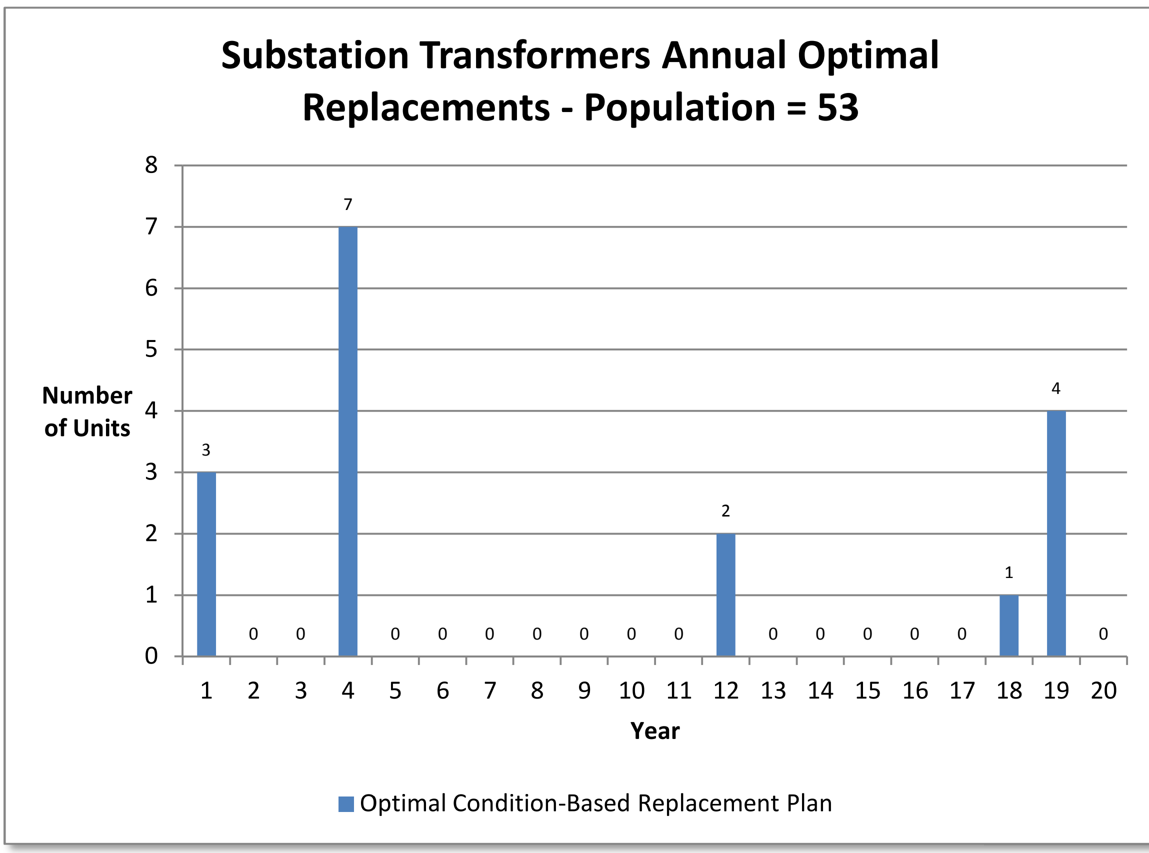


Figure 1-6 Substation Transformers Optimal Condition-Based Replacement Plan

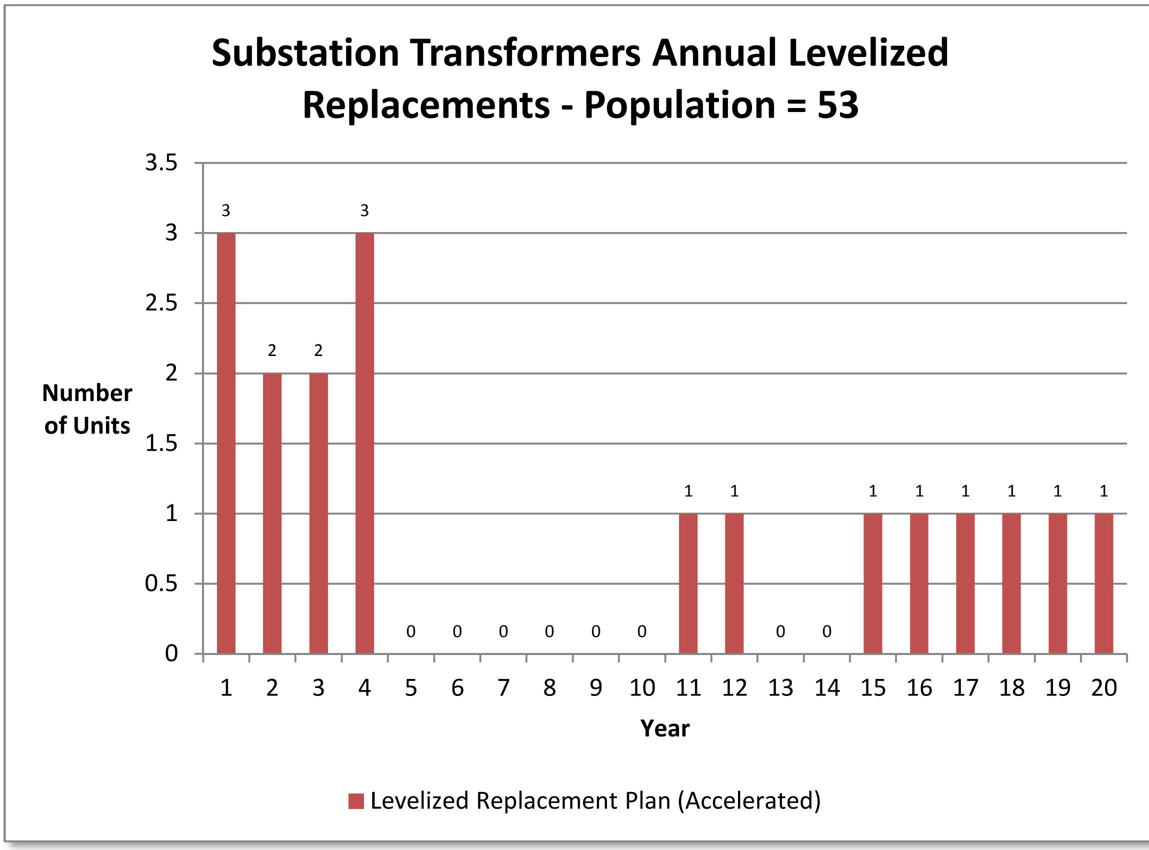


Figure 1-7 Substation Transformers Levelized (Accelerated) Condition-Based Replacement Plan

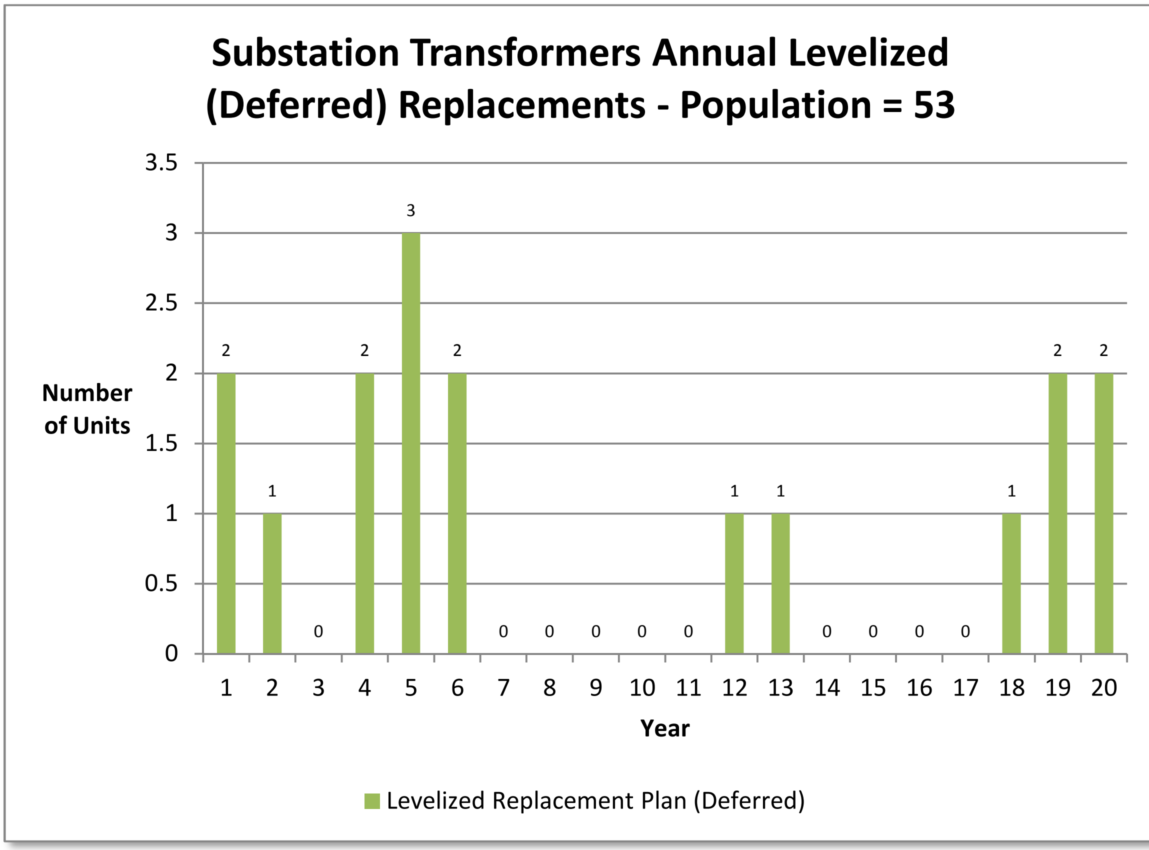


Figure 1-8 Substation Transformers Levelized (Deferred) Condition-Based Replacement Plan

The optimal criticality and replacement year for each unit is shown in the table below.

Table 1-15 Optimal Replacement for Each Substation Transformers Unit

Rank	Transformer Name	Serial Number	Age	Criticality Multiple	Health Index	Optimal Replacement Year
1	West Nip 35T1	TAG6235298	34	1.63	**25.4%**	**0**
2	Cressey 3T1 Blue Phase	165310	60	1.50	**31.0%**	**0**
3	Cressey 3T1 Red Phase	166027	60	1.50	**34.5%**	**0**
4	Cressey 3T1 White Phase	166026	60	1.50	**38.4%**	**3**
5	Cressey 3T2 Red Phase	165309	60	1.50	**38.4%**	**3**
6	Cressey 3T2 White Phase	166024	60	1.50	**38.4%**	**3**
7	Cressey 3T2 Blue Phase	166023	60	1.50	**38.4%**	**3**
8	Cressey 3T1 Spare	166019	60	1.50	**38.4%**	**3**
9	Kathleen 2T1 Red Phase	506264	59	1.50	**38.8%**	**3**
10	Kathleen 2T1 White Phase	150480	59	1.50	**38.8%**	**3**
11	Kathleen 2T2 Red Phase	150483	59	1.50	**48.1%**	**11**
12	Kathleen 2T2 Blue Phase	166025	59	1.50	**48.1%**	**11**
13	Dash 19T2	291966	34	1.56	**54.6%**	**17**
14	Upper Coniston 31T1 302396 Phase	286651	40	1.56	**55.4%**	**18**
15	Upper Coniston 31T1 302395 Phase	T602231	40	1.56	**55.4%**	**18**
16	Kathleen 2T1 Blue Phase	150482	59	1.50	**55.5%**	**18**
17	Kathleen 2T2 White Phase	150481	59	1.50	**55.5%**	**18**
18	Regent 9T1	166017	49	2.00	**65.2%**	**20**
19	Centennial 14T1	238850	44	2.00	**65.8%**	**20**
20	Cressey 3T3	166021	53	1.50	**59.1%**	**over 20 years**
21	Arthur 5T1	166020	52	2.25	**72.2%**	**over 20 years**
22	Dash 19T1	3442	34	1.56	**63.8%**	**over 20 years**
23	Gemmell 11T2	None	22	1.56	**64.5%**	**over 20 years**
24	Main 17T2	293695	14	1.56	**65.7%**	**over 20 years**
25	Ramsey 10T2	302395	41	1.69	**68.1%**	**over 20 years**
26	Copper Cliff 25T1	293655	37	2.31	**76.3%**	**over 20 years**
27	Upper Coniston 31T1 302397 Phase	T0621001	40	1.56	**67.0%**	**over 20 years**
28	Capreol 32T1	T55101	54	1.88	**71.2%**	**over 20 years**
29	Tedman 12T1	290990	36	1.56	**69.5%**	**over 20 years**
30	Robinson 15T1	65050	22	1.56	**70.2%**	**over 20 years**
31	Richard Lake 21T1	S1388301	44	1.50	**70.4%**	**over 20 years**

Rank	Transformer Name	Serial Number	Age	Criticality Multiple	Health Index	Optimal Replacement Year
32	Gemmell 11T1	302396	44	1.25	**64.2%**	**over 20 years**
33	West Nip 37T1	C10111	22	1.56	**72.1%**	**over 20 years**
34	Lasalle 7T2	166018	35	1.56	**72.4%**	**over 20 years**
35	Falconbridge 33T1	285187	29	2.06	**81.7%**	**over 20 years**
36	Mansour Mining 29T1	238849	39	1.38	**69.6%**	**over 20 years**
37	Ramsey 10T1	64708	48	1.69	**77.1%**	**over 20 years**
38	Martilla 8T1	165308	49	1.25	**69.8%**	**over 20 years**
39	Broder 24T1	282072	24	1.56	**78.6%**	**over 20 years**
40	Long Lake 20T1	293694	16	1.63	**81.7%**	**over 20 years**
41	Paris 13T1	S1418601	44	1.25	**72.4%**	**over 20 years**
42	Lasalle 7T1	166016	39	1.56	**84.4%**	**over 20 years**
43	Levert 6T1	166022	39	1.56	**88.3%**	**over 20 years**
44	West Nip 34T1	214436	11	1.63	**97.9%**	**over 20 years**
45	Main 17T1	1829610101	14	1.56	**90.3%**	**over 20 years**
46	Lower Coniston 30T1	283312	20	1.56	**95.1%**	**over 20 years**
47	West Nip 36T1	13669	21	1.56	**96.0%**	**over 20 years**
48	West Nip 38T1	13710	15	1.50	**96.8%**	**over 20 years**
49	West Nip Spare	1829510101	17	1.25	**81.4%**	**over 20 years**
50	Moonlight 18T1	302397	49	1.25	**82.6%**	**over 20 years**
51	Mobile 99T1	1721410101	26	1.25	**90.6%**	**over 20 years**
52	Barrydowne 16T1	291983	4	1.25	**99.4%**	**over 20 years**
53	Spare at Moonlight	A3S6923	4	1.25	**99.4%**	**over 20 years**

1.6 Data Analysis

The data available for Substation Transformers includes age, inspection results, oil quality, dissolved gas analysis, and Doble tests as per the GE tests and inspections.

1.6.1 Data Availability Distribution

The average DAI for Substation Transformers is 63%. All units had age, oil quality, and DGA tests available. A majority of the units, however, did not have Doble tests and the inspection data that indicates the condition components such as bushings, tank, and connections.

The data availability distribution for the population is shown in Figure 1-9. The DAI for each unit, as well as its Health Index, is shown in Figure 1-10.

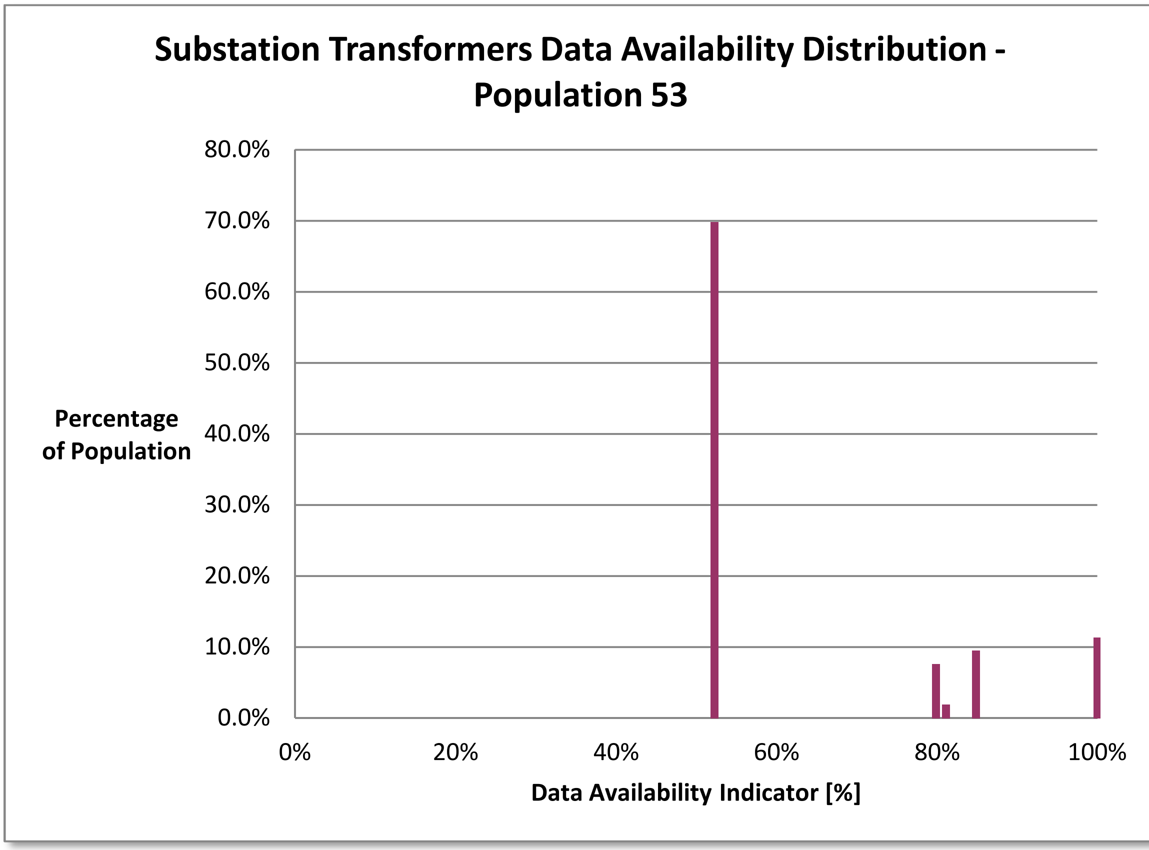


Figure 1-9 Substation Transformers Data Availability Distribution

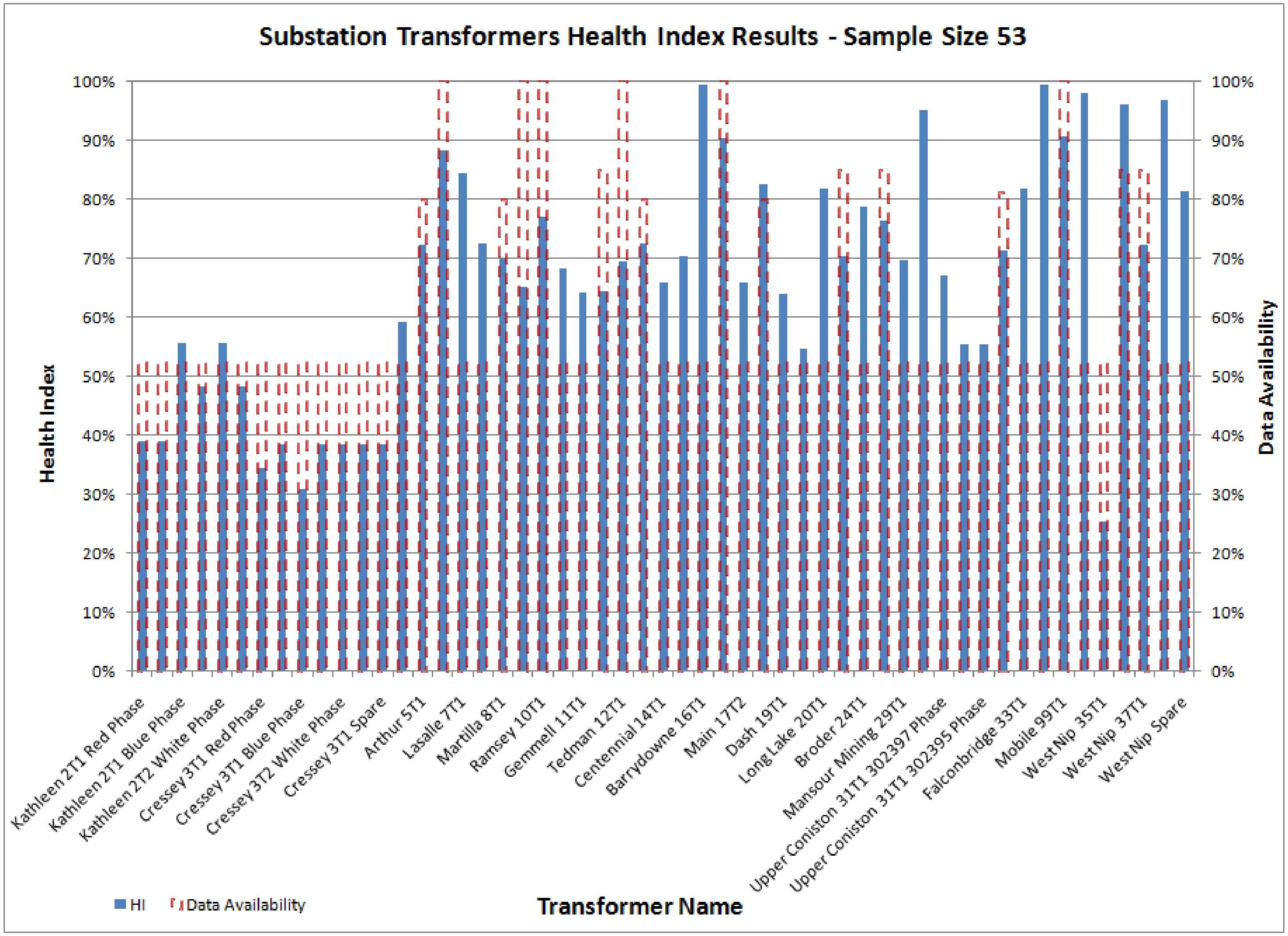


Figure 1-10 Data Availability Indicator and Health Index for Each Substation Transformers Unit

1.6.2 Data Gap

For this asset category, most of the critical data, namely test data, are already available and included in the Health Index formula.

Additional data are as follows:

Table 1-16 Substation Transformers Data Gaps

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Cooling	Cooling	☆☆☆	Cooling oil	Abnormal oil flow	Visual Inspection / On-site Reading
				Abnormal oil pump motor	
			Cooling fan	Abnormal fan operation	
			Radiator	Plugged radiator	
			Valves	Broken valves	
			Transformer tank	High top oil temperature	
			Winding	High winding temperature	
Infrared (IR) Thermography	Sealing & Connection	☆☆☆	Cooling system	Poor ventilation/circulation	IR Camera Scan
			Transformer connection	Poor connection	
Loading	Service Record	☆☆	Loading	Monthly 15 min peak load throughout years	Loading Records

This page is intentionally left blank.

2 Pole-Mounted Transformers

Pole-mounted distribution transformers convert power from the distribution primary line voltage to the 600\347 V or 120\240V utilization voltage employed by the customer. Single-phase pole-mounted transformers are commonly available in ratings from 5kVA to 167kVA but can be as high as 500kVA. They are available in voltages from 4.16\2.4kV to 34.5\19kV. Pole-mounted transformers are generally contained in cylindrical cans filled with insulating oil. The connection to the high voltage source is via a bushing, usually on the top of the unit. The transformer core is generally a wrapped sheet-type steel. Wound copper high voltage windings and sheet-type low voltage windings are wound concentrically on the core. Distribution transformers are self-cooled by air and occasionally have external cooling fins. Typically, pole-mounted transformers of size 100kVA and below are attached directly to the pole whereas higher ratings are mounted on cross-beams. Three or more transformers greater than 100kVA are typically mounted on platforms supported by 2 poles.

2.1 Degradation Mechanism

Degradation of pole-mounted transformers can occur due to the following mechanisms:

- Corrosion of the tank
- Deterioration or breakage of the bushings
- Deterioration of internal switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Tank corrosion can be problematic for overhead transformers particularly in areas of high contamination. Porcelain bushings can develop mechanical cracks or can be subject to breakage due to mechanical vibration and forces. Deterioration of the pole-mounted transformer can also be due to problems such as: breakage of switches and leakage of under-oil fuses.

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. 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. Insulation condition can also be affected by voltage and current surges.

Distribution pole-mounted transformers sometimes require replacement because of non-condition related factors such as customer load growth, pole replacement or road widening. If a transformer is simply overloaded, a decision is 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, labour cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors 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.

The consequences of distribution transformer degradation can be severe if it results in an eventful failure. Though rare, pole-mounted transformers can fail with sufficient energy release to rupture the tank and release oil into the surrounding environment.

2.2 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GSH Pole-Mounted Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

2.2.1 Condition and Sub-Condition Parameters

Table 2-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Physical Condition	2	4
2	Connection & Insulation	1	4
3	Service Record	7	4
	De-rating multiplier (DR) based on PCB and Proximity to Major Road	De-Rating Multiplier Table 2-9	Overall HI multiplier

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

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Corrosion	Table 2-5	3	4

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

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Oil Leak	Table 2-6	2	4
2	Connection	Table 2-5	4	4
3	Grounding	Table 2-5	1	4
4	Bushing	Table 2-5	4	4

Table 2-4 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 2-7	1	4
2	Age	Figure 2-1	2	4
3	Loading	Table 2-8	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

2.2.2 Condition Parameter Criteria

Visual Inspections

Table 2-5 Inspection Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear, Working as Required
2	Wear or Failed, Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed, Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Yes or No

Table 2-6 Yes or No Criteria

CPF	Condition Description
4	Yes
1	No

Overall Condition

Table 2-7 Overall Condition Criteria

CPF	CPF
4	Number of closed Corrective Maintenance (CM) Counts in past 3 years is 0
3	Number of closed CM Counts in past 3 years is $\leq$ 1
0	Number of closed CM Counts in past 3 years is $\geq$ 2
Note: A non-conformance log with an “issues resolved” date is counted as a closed corrective maintenance (CM) record.	

Age

Assume that the failure rate for Pole-Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

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

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 45 and 65 years the probability of failure (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

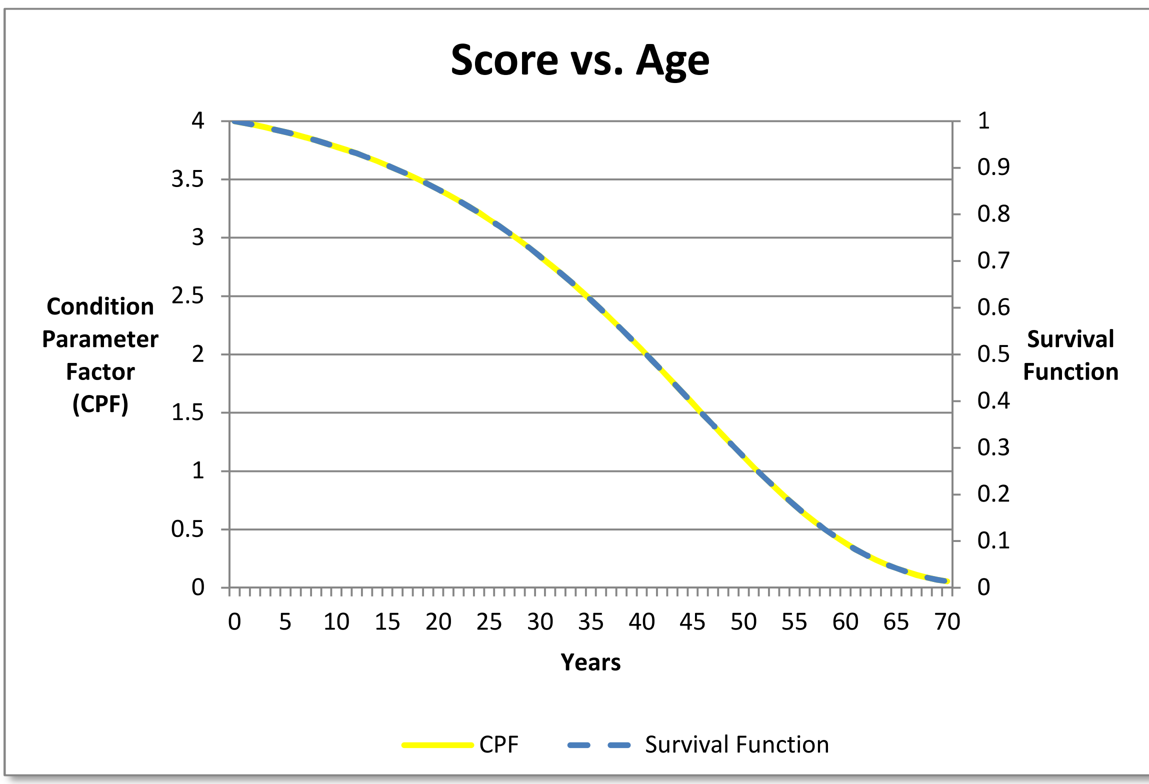


Figure 2-1 Age Condition Criteria

Loading History

Table 2-8 Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

De-Rating (DR) Multiplier

Table 2-9 De-Rating Multiplier

n	Sub-Condition Parameter	De-Rating Criteria Lookup Table	DR
1	PCB	Table 2-10	DR = MIN (DR1, DR2)
2	Major Road Vicinity	Table 2-11	

Table 2-10 De-Rating Multiplier Criteria (PCB)

Multiplier	Condition Description
1	PCB < 50 ppm
0.25	PCB > = 50 ppm

Table 2-11 De-Rating Multiplier Criteria (Major Road Vicinity)

Multiplier	Condition Description
1	Not close to major roads
0.8	Close to major roads

2.3 Age Distribution

The age distribution is shown in the figure below. Age was available for only 38% of the population. The average age was found to be 13 years.

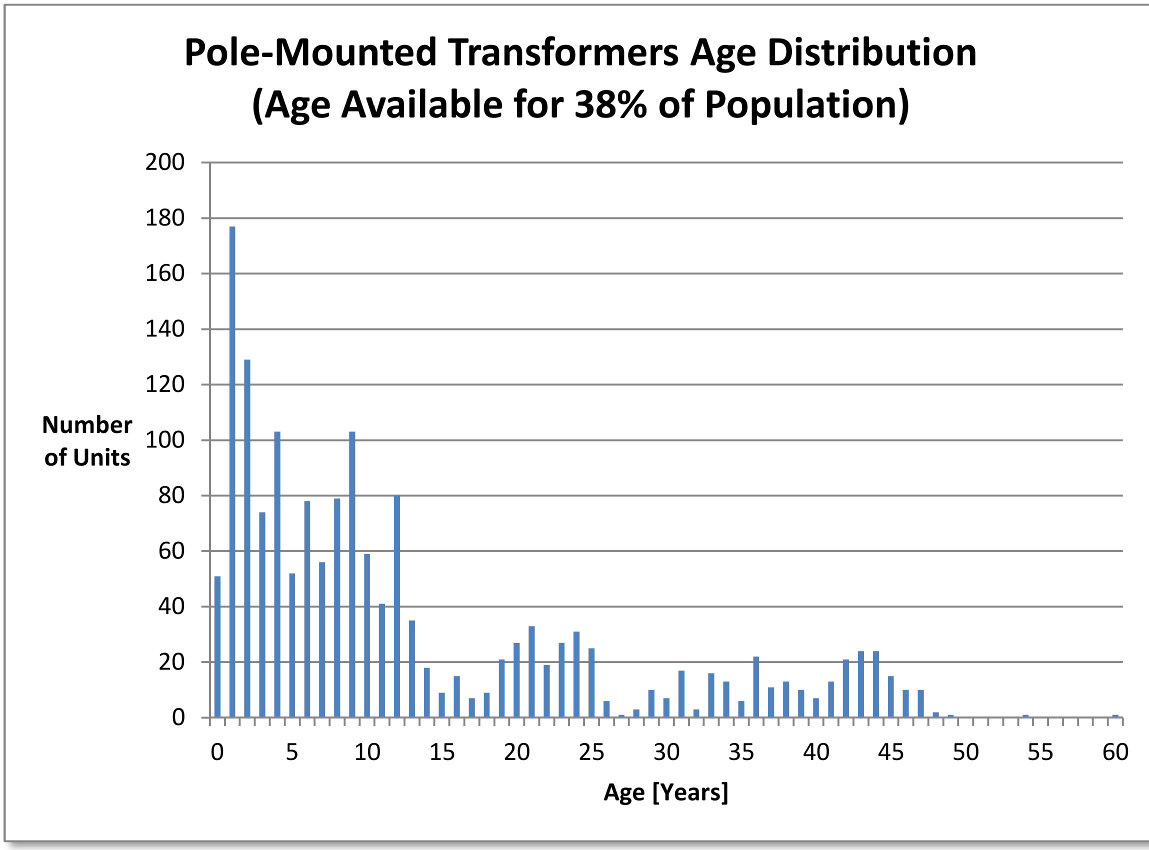


Figure 2-2 Pole-Mounted Transformers Age Distribution

2.4 Health Index Results

There are 4255 in-service Pole-Mounted Transformers at GSH. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. On that basis, all 4255 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 96%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

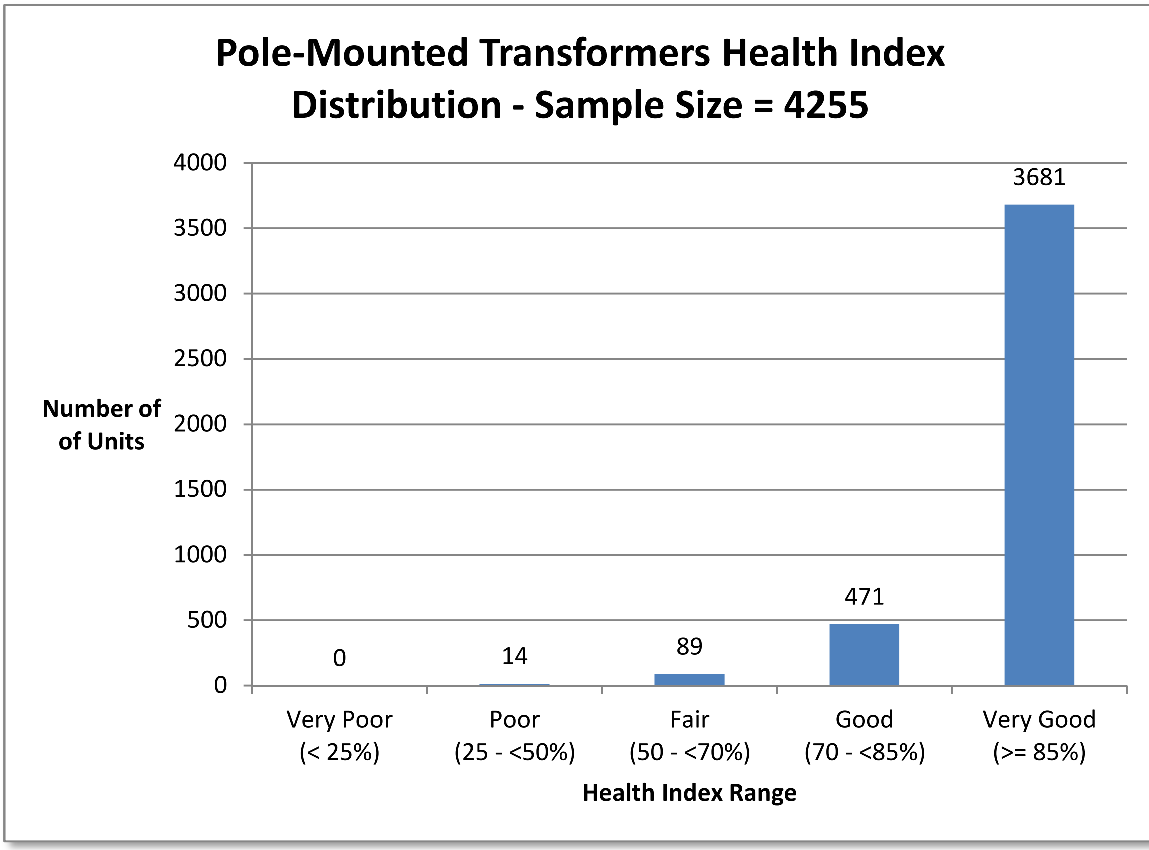


Figure 2-3 Pole-Mounted Transformers Health Index Distribution (Number of Units)

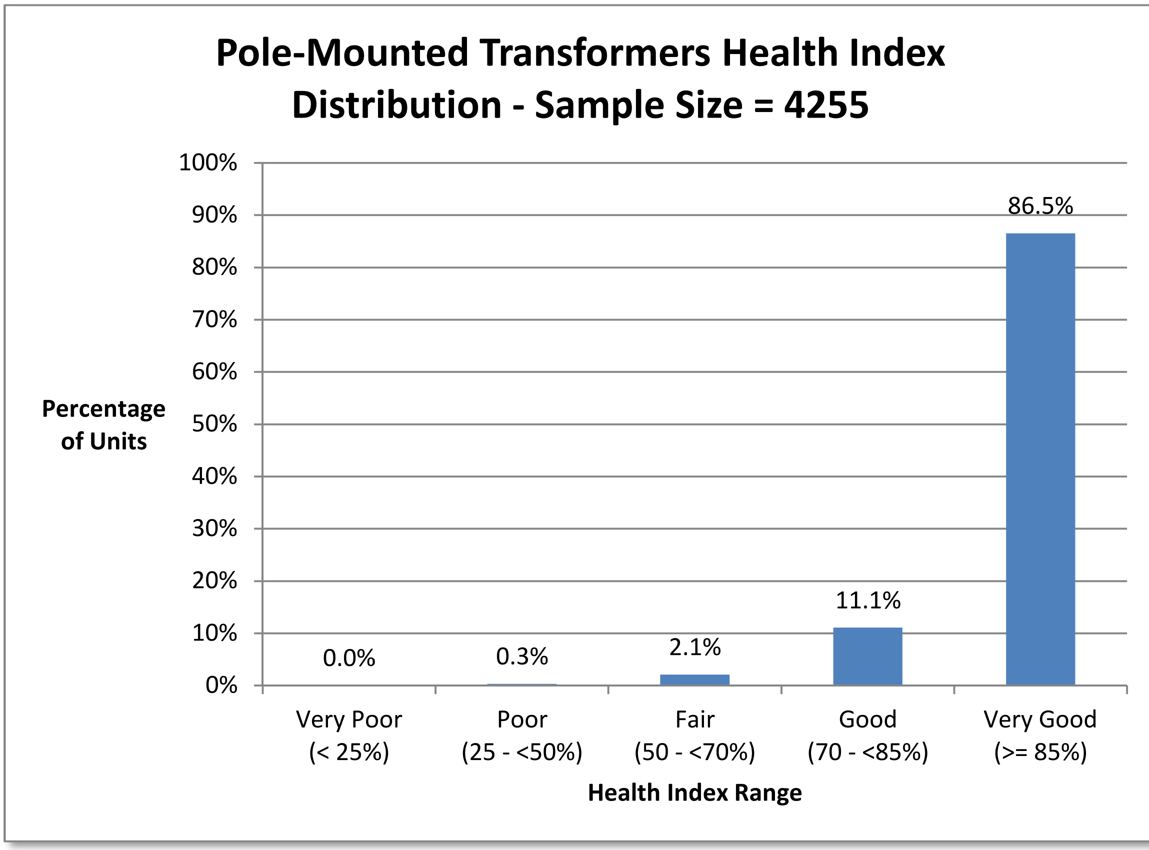


Figure 2-4 Pole-Mounted Transformers Health Index Distribution (Percentage of Units)

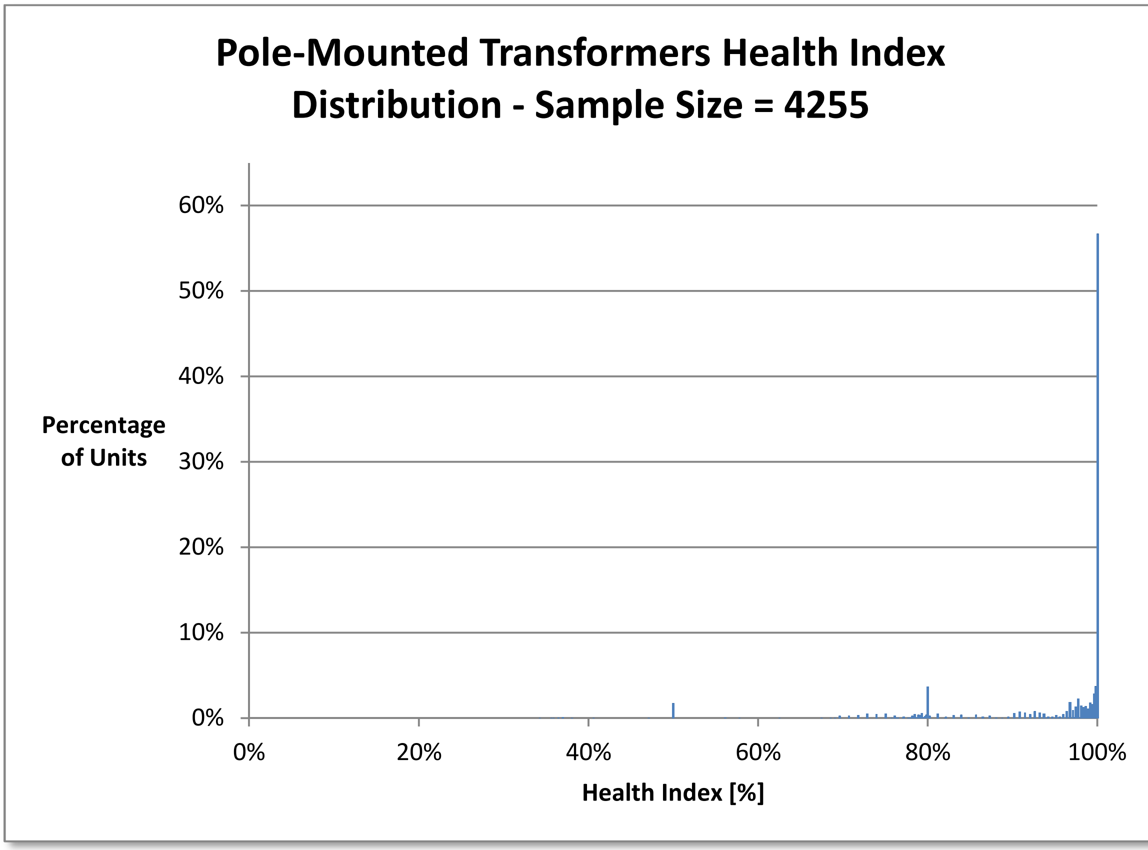


Figure 2-5 Pole-Mounted Transformers Health Index Distribution by Value (Percentage of Units)

2.5 Condition-Based Replacement Plan

As it is assumed that Pole-Mounted Transformers are reactively replaced, the replacement plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is also given.

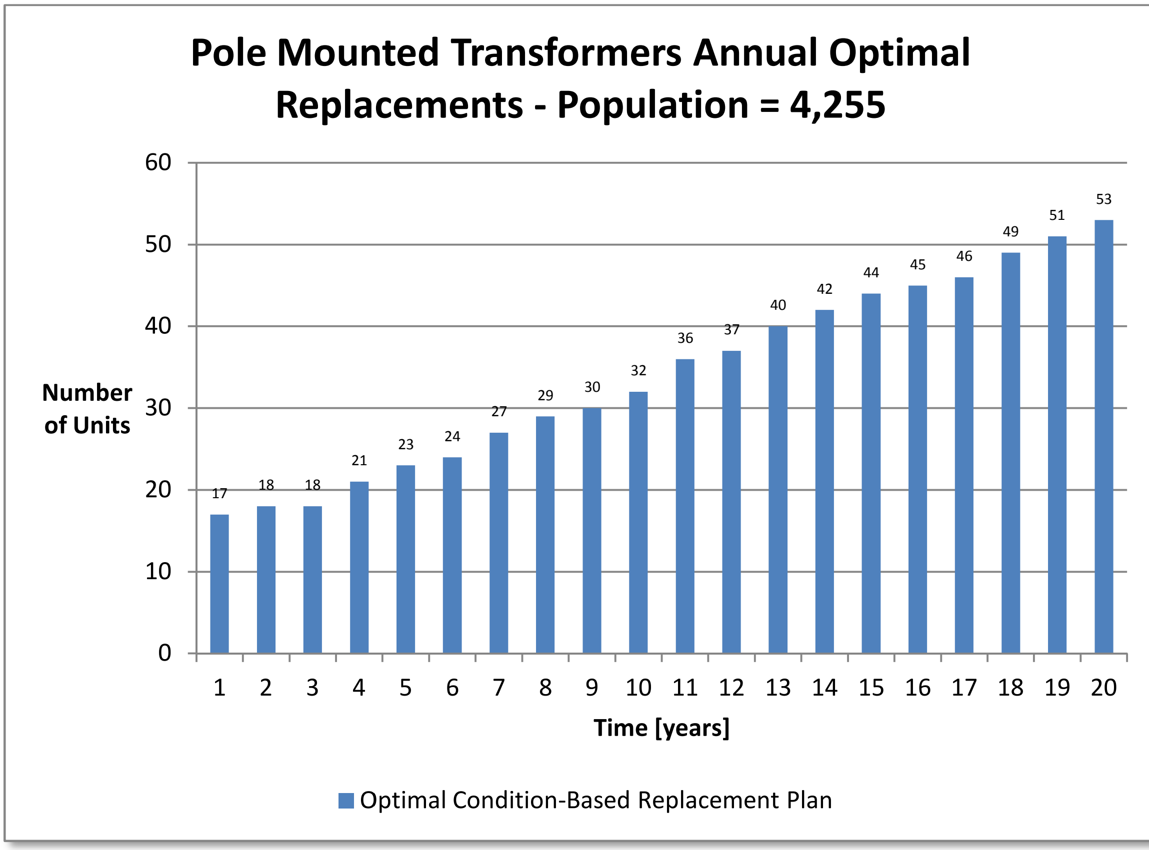


Figure 2-6 Pole-Mounted Transformers Optimized Condition-Based Replacement Plan

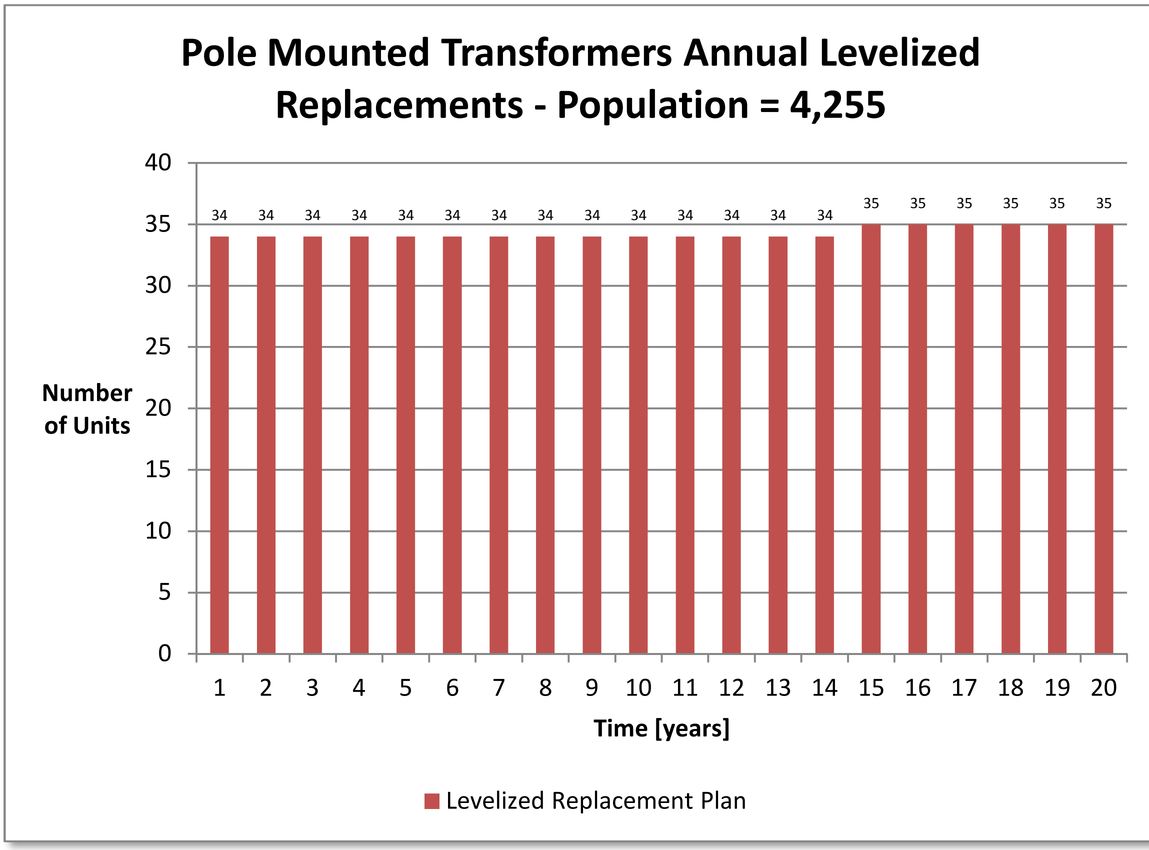


Figure 2-7 Pole-Mounted Transformers Levelized Replacement Plan

2.6 Data Analysis

The data available for Pole-Mounted Transformers includes age, inspections, PCB content and location.

2.6.1 Data Availability Distribution

Inspection information was taken from the Non-Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Corrosion
- Oil Leak
- Connection
- Grounding
- Bushing
- Overall Condition

Assuming all inspection-based parameters are available, the average DAI for Pole-Mounted Transformers is 71%. Note that Age, which has substantial weight in the Health Index Formula, is available for only 38% of the population.

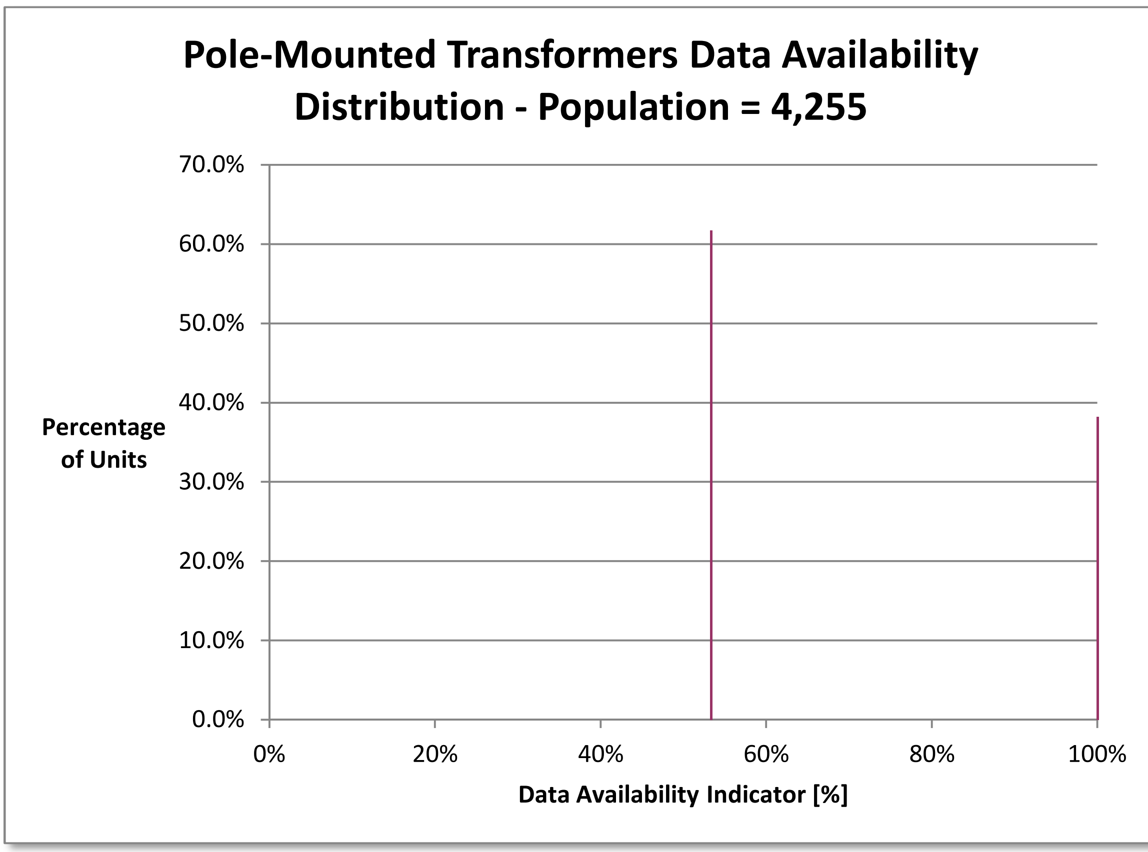


Figure 2-8 Pole-Mounted Transformers Data Availability Distribution

2.6.2 Data Gap

In this asset group, much of the required data have been incorporated into the Health Index formula. Still, additional helpful data that can be collected are:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Overall*	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection *Note that although the "Overall" parameter is already included in the current formulation, it is currently based on the number of closed CM counts in the past 3 years (Table 2-7). The "Overall" parameter referred to in this data gap is based on inspections, with criteria as shown in Table 2-5.	Operation Record
Loading		☆☆	Transformer load	Monthly 15 min peak load throughout years	Operation Record

This page is intentionally left blank.

3 Pad-Mounted Transformers

Pad-mounted transformers are used in underground distribution systems to step voltages down from primary system voltages (34.5kV to 4.2kV) to utilization voltages such as 120/240V and 600/347V.

Pad-mounted transformers are housed in low-profile metal enclosures which generally have an oil-filled compartment for the transformer windings and under-oil switches and protection as well as an air compartment under a hinged door for access to connections, switching and protection. The enclosure is placed on top of a below-grade concrete foundation which allows access for incoming cables. Foundations of 6'x6' by 3 feet deep are commonly utilized. Modern pad-mounted transformers are dead-front, with incoming and feed-through connections made using separable insulated connectors.

Fuses and switches are housed in the oil-filled compartment. Single-phase pad-mounted distribution transformers have ratings from 10 to 167kVA. Three-phase pad-mounted transformers are often used in industrial and commercial applications and are generally available in ratings from 45 to 2500kVA. Pad-mounted transformers are self-cooled and may have external cooling fins, albeit these are occasionally avoided because of potentially sharp external edges.

3.1 Degradation Mechanism

Degradation of pad-mounted transformers can occur due to the following mechanisms:

- Corrosion of the pad-mounted enclosure and tank
- Deterioration of foundations
- Deterioration of separable insulated connectors
- Deterioration of switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Pad-mounted transformers located in corrosive environments, such as next to major roads that are salted, are particularly prone to enclosure corrosion. Foundation shifting of pad-mounted transformers has been known to be problematic. Deep frost areas or unstable soil conditions can lead to movement of the foundation. Rubber encapsulated separable insulated connectors will deteriorate with multiple operations and are known to degrade if they are coated with transformer oil. Deterioration of the pad-mounted transformer can also be due to problems such as: switch breakage, leakage of under-oil fuses, and deterioration of dry-well canisters.

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. 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.

Insulation condition can also be affected by voltage and current surges. Therefore, a combination of condition, age and load-based criteria is commonly used to determine the useful remaining life of distribution transformers.

Distribution transformers sometimes need to be replaced because of non-condition related factors such as mechanical damage by vehicles or customer load growth. If a transformer is simply overloaded, a decision is 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, labour cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors 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.

The consequences of distribution transformer failure can be severe because of the street level location of this equipment. Though rare, pad-mounted transformers can fail with sufficient energy release to rupture the tank and release oil into the surrounding environment. Many utilities treat residential pad-mounted transformers as run-to-failure assets. However, larger pad-mounted 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.

3.2 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GSH Pad-Mounted Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows:

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

Health Index condition and sub-condition parameters and condition criteria are as follows:

3.2.1 Condition and Sub-Condition Parameters

Table 3-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Physical Condition	2	4
2	Connection & Insulation	1	4
3	Service Record	7	4
	De-rating multiplier (DR) based on proximity to Major Road	Table 3-10	Overall HI multiplier

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

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Corrosion	Table 2-5	3	4

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

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Oil Leak	Table 3-6	2	4
2	Connection	Table 3-5	4	4
3	Grounding	Table 3-5	1	4
4	Bushing	Table 3-5	4	4
5	Elbow	Table 3-7	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

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

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 3-7	1	4
2	Age	Figure 3-1	2	4
3	Loading	Table 3-9	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

3.2.2 Condition Parameter Criteria

Visual Inspections

Table 3-5 Inspection Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear – Working as Required
2	Wear or Failed – Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed – Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Yes or No

Table 3-6 Yes or No Criteria

CPF	Condition Description
4	Yes
1	No

Overall Condition

Table 3-7 Overall Condition Criteria

CPF	Condition Description
4	Number of closed Corrective Maintenance (CM) Counts in past 3 years is 0
3	Number of closed CM Counts in past 3 years is ≤ 1
0	Number of closed CM Counts in past 3 years is ≥ 2
Note: A non-conformance log with an "issues resolved" date is counted as a closed corrective maintenance (CM) record	

OK or Not OK

Table 3-8 OK or Not OK Criteria

CPF	Condition Description
4	OK
1	Not OK

Age

Assume that the failure rate for Pad-Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

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

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 45 and 50 years the probability of failure (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

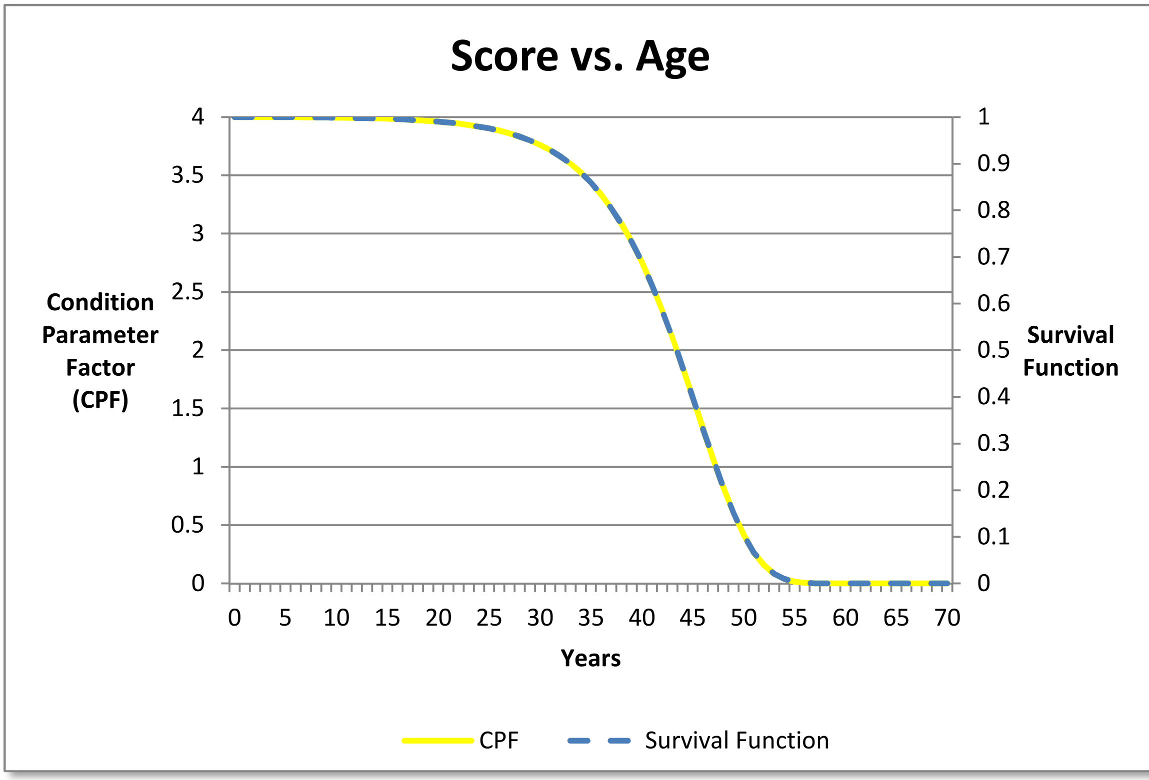


Figure 3-1 Pad-Mounted Transformers Age Condition Criteria

Loading History

Table 3-9 Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

De-Rating (DR) Multiplier

Table 3-10 De-Rating Multiplier (Major Road Vicinity)

Multiplier	Condition Description
1	Not close to major roads
0.8	Close to major roads

3.3 Age Distribution

The age distribution is shown in the figure below. Age was available for 93% of the population. The average age was found to be 19 years.

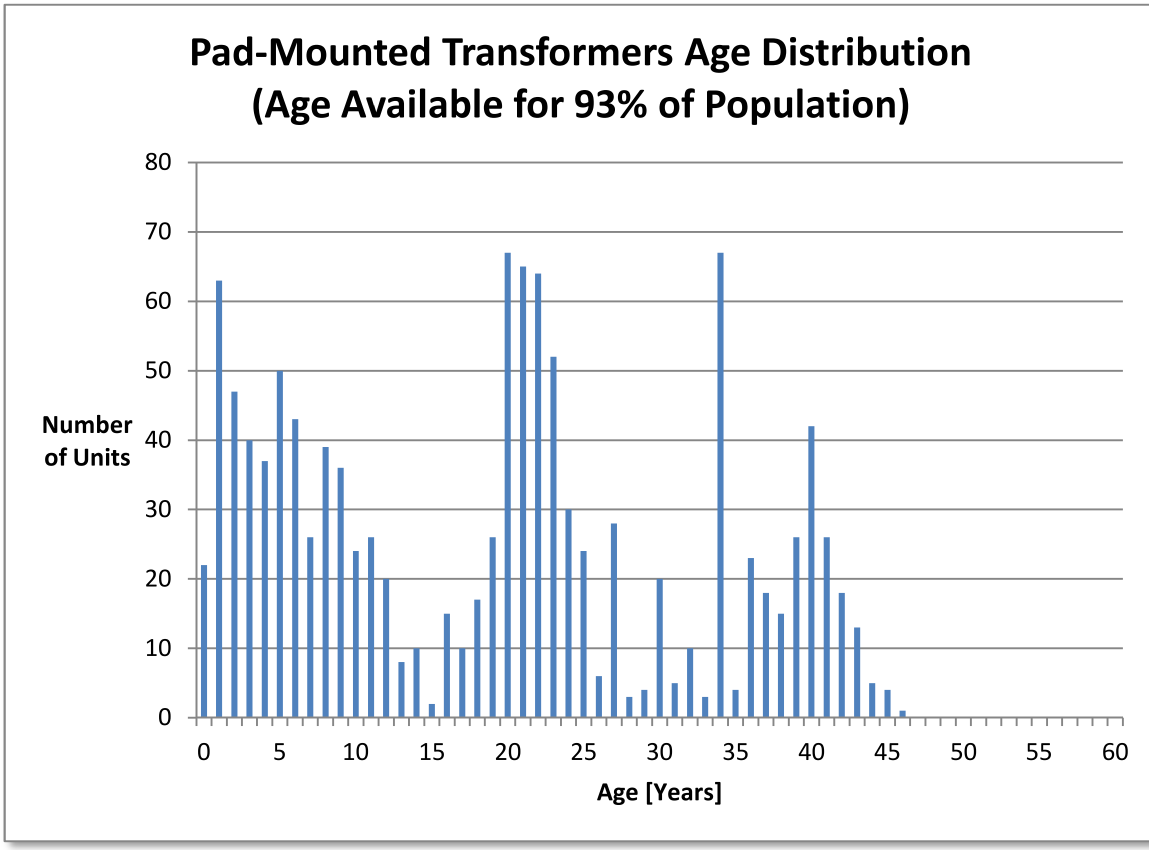


Figure 3-2 Pad-Mounted Transformers Age Distribution

3.4 Health Index Results

There are 1,288 in-service Pad-Mounted Transformers at GSH. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 1,288 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 97%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

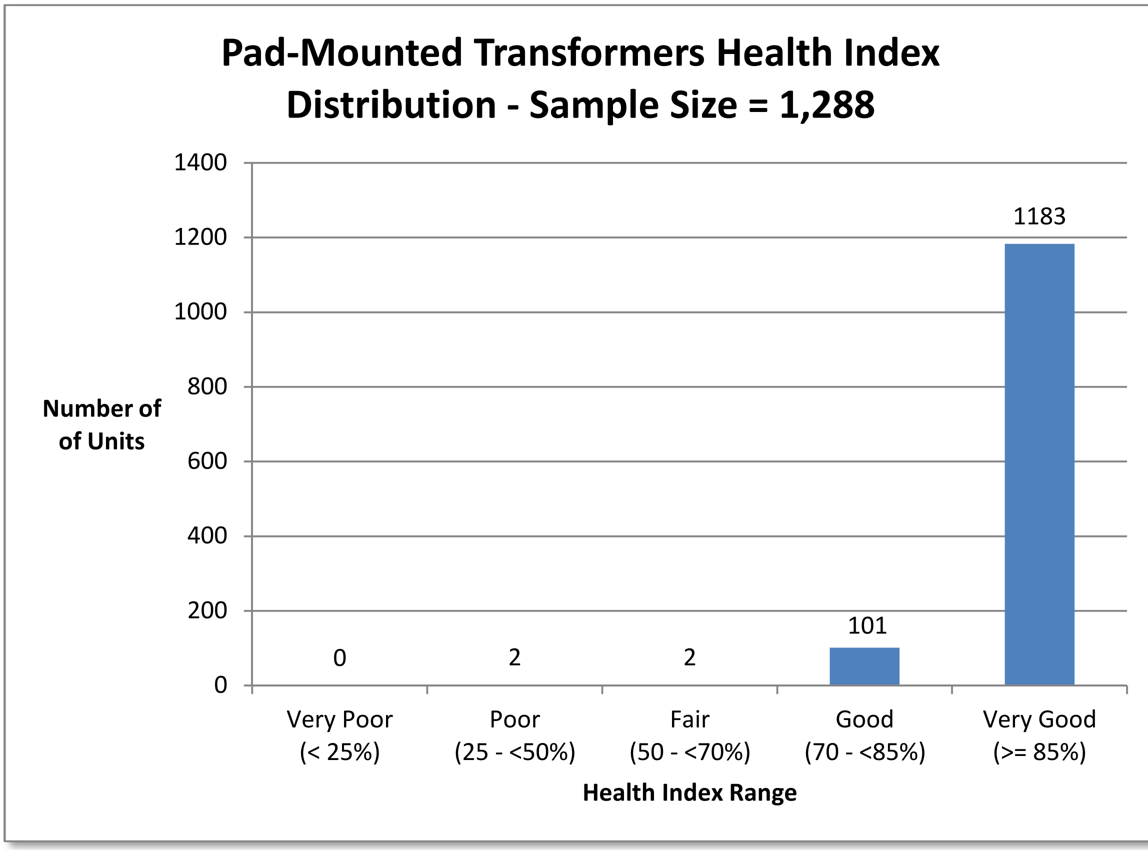


Figure 3-3 Pad-Mounted Transformers Health Index Distribution (Number of Units)

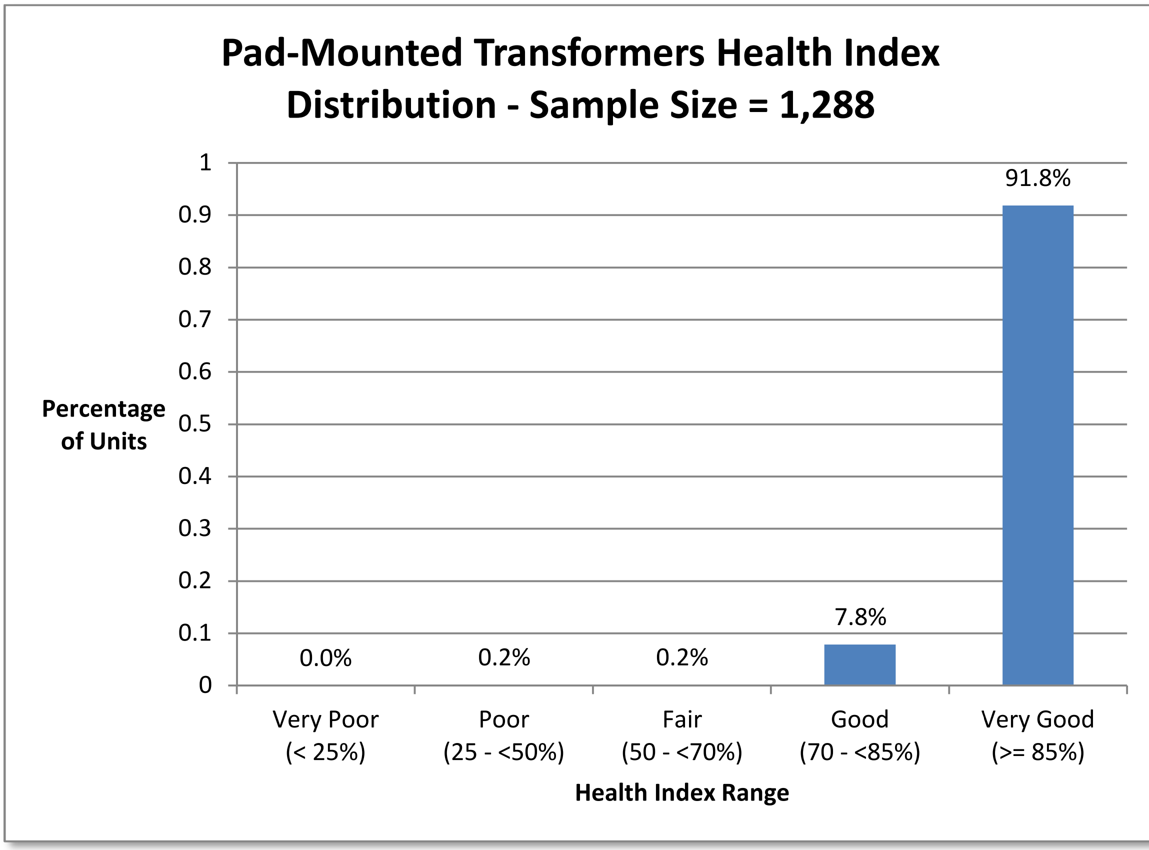


Figure 3-4 Pad-Mounted Transformers Health Index Distribution (Percentage of Units)

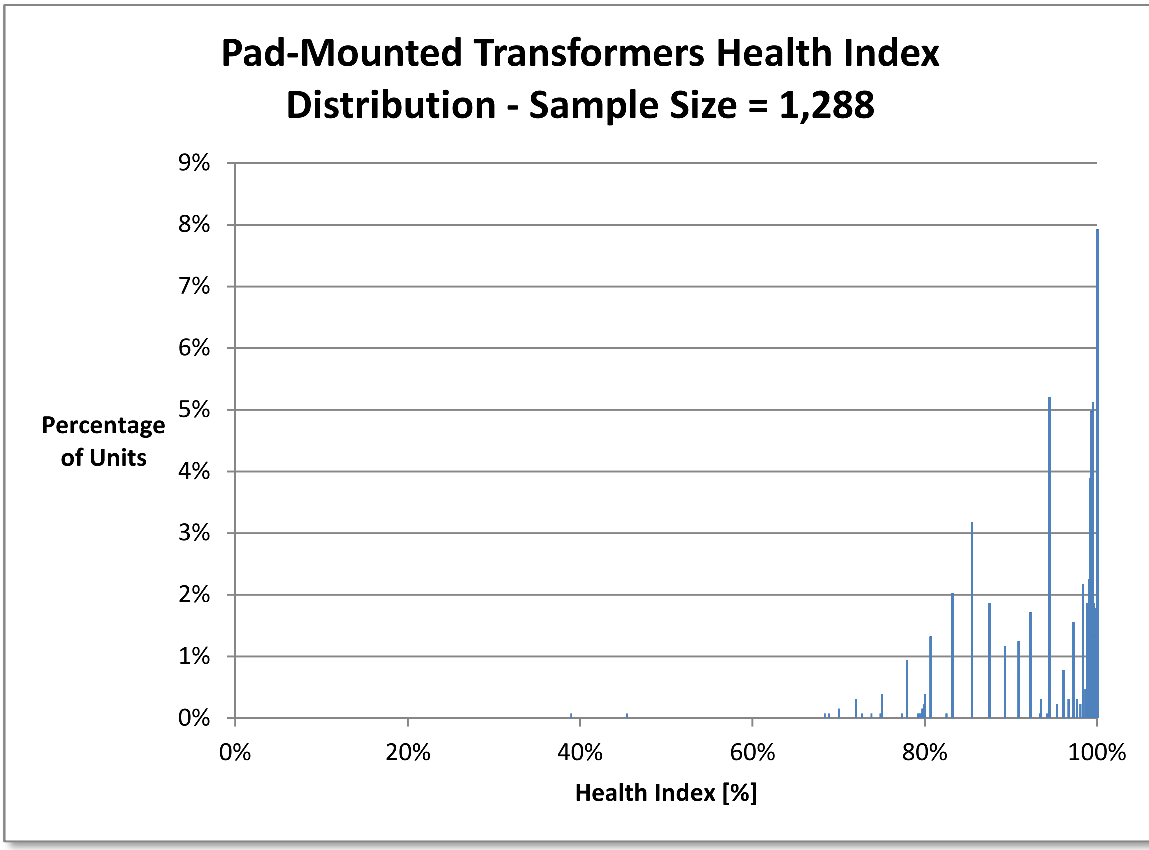


Figure 3-5 Pad-Mounted Transformers Health Index Distribution by Value (Percentage of Units)

3.5 Condition-Based Replacement Plan

As it is assumed that Pad-Mounted Transformers are reactively replaced, the replacement plan is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is also given.

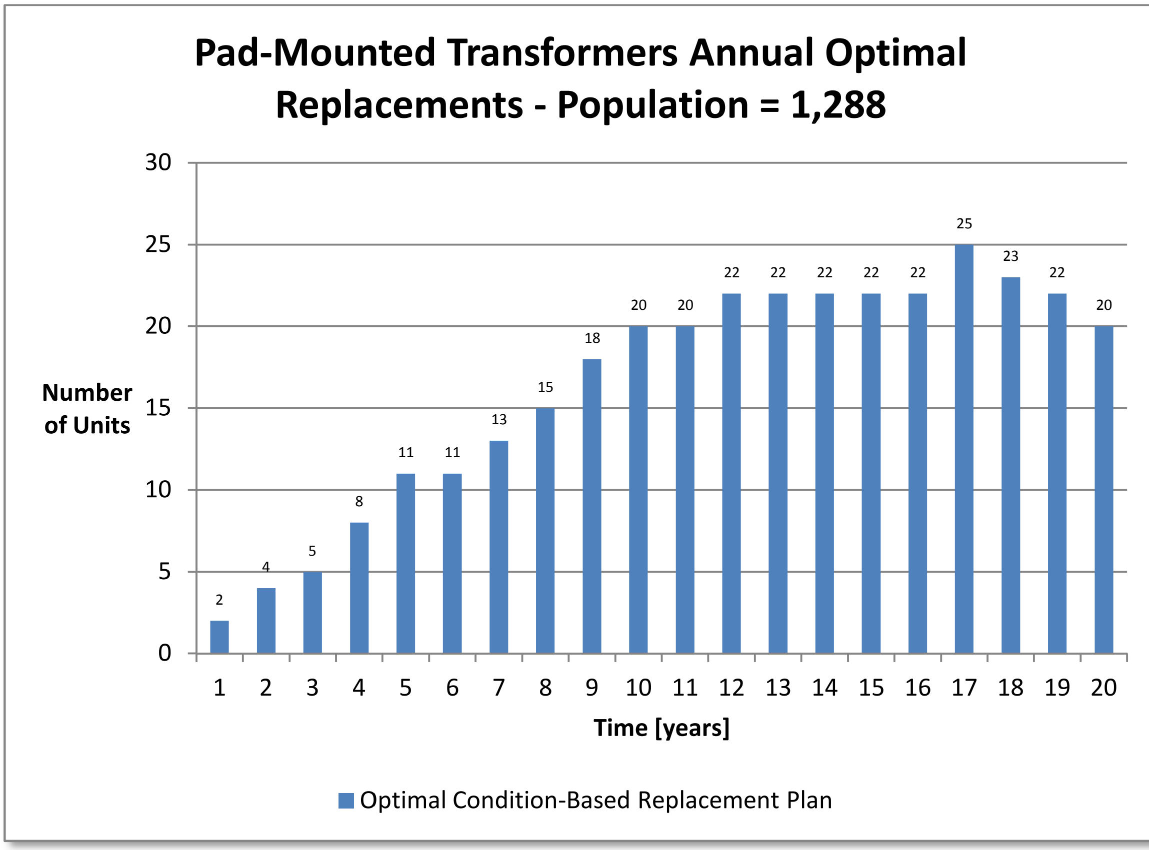


Figure 3-6 Pad-Mounted Transformers Optimal Condition-Based Replacement Plan

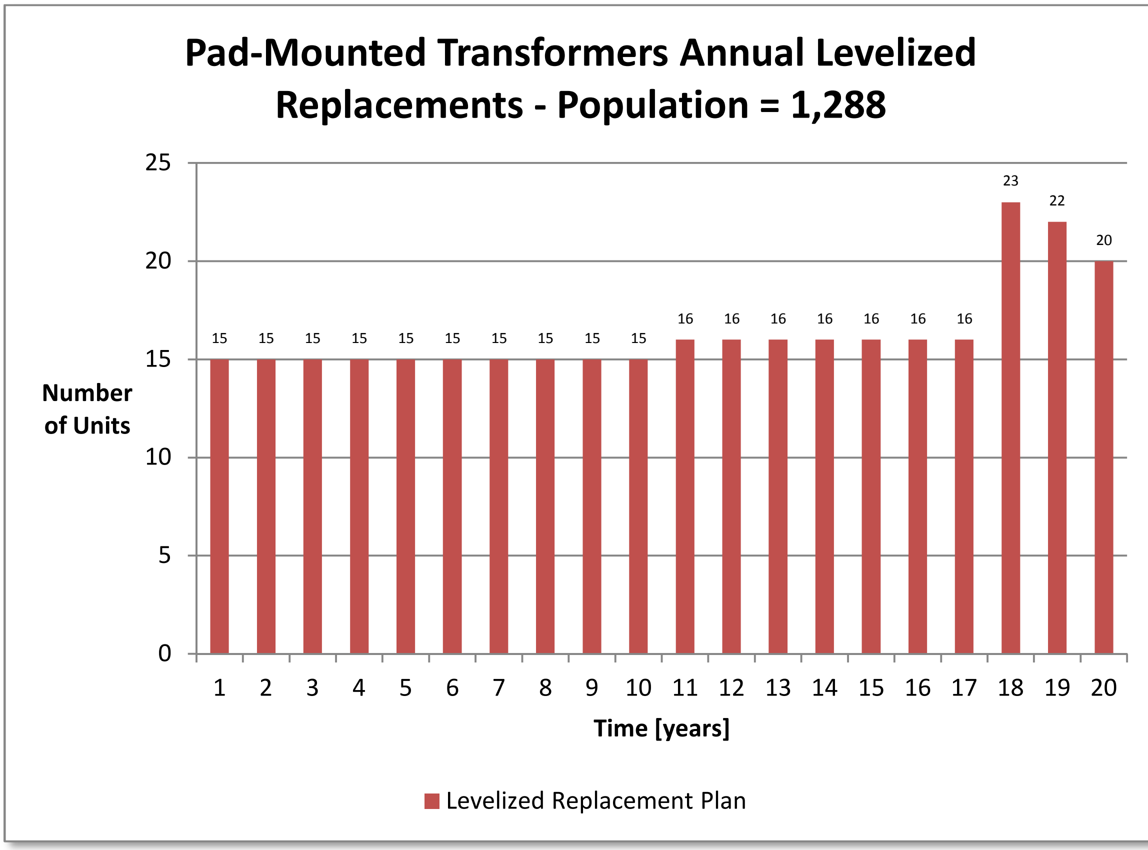


Figure 3-7 Pad-Mounted Transformers Levelized Replacement Plan

3.6 Data Analysis

The data available for Pad-Mounted Transformers includes age, inspections, PCB content and location.

3.6.1 Data Availability Distribution

Inspection information was taken from the Non-Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Corrosion
- Oil Leak
- Connection
- Grounding
- Bushing
- Overall Condition

Assuming all inspection-based parameters are available, the average DAI for Pad-Mounted Transformers is 97%.

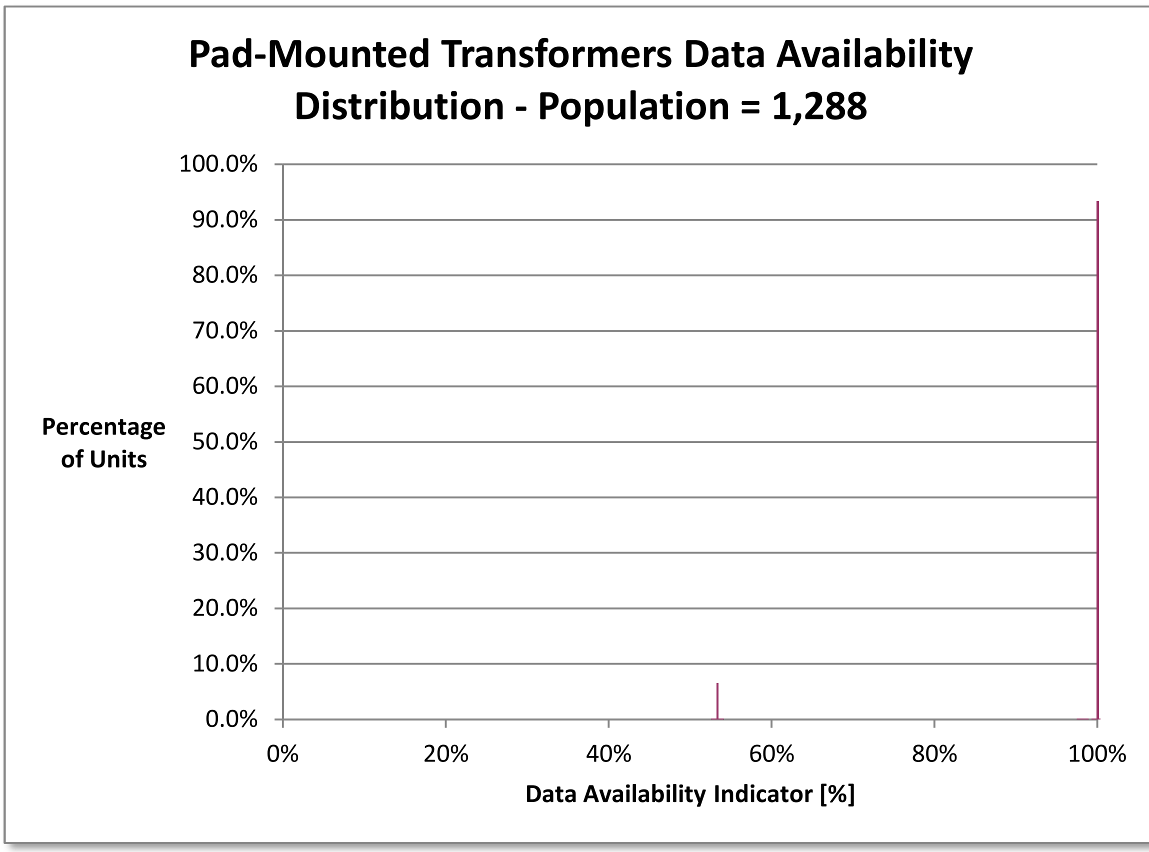


Figure 3-8 Data Availability Distribution

3.6.2 Data Gap

In this asset group, much of the required data have been incorporated into the Health Index formula. Still, additional helpful data that can be collected are:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Elbow	Connection and Insulation	☆ ☆	Elbow	Condition of elbow; damage or wear	Visual inspection
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection *Note that although the "Overall" parameter is already included in the current formulation, it is currently based on the number of closed CM counts in the past 3 years (Table 3-7). The "Overall" parameter referred to in this data gap is based on inspections, with criteria as shown in Table 3-5.	Operation record
Loading		☆ ☆	Transformer load	Monthly 15 min peak load throughout years	Operation record

4 Overhead Line Switches

The primary function of switches is to facilitate isolation of line sections or equipment for maintenance, safety or other operating requirements. Disconnect switches are relatively simple in design compared to circuit breakers because they are not typically required to interrupt fault current.

In general, line switches consist of mechanically-movable copper blades supported on insulators and mounted on metal bases. Their operating mechanism can be either a simple hook stick or a manually-driven mechanical mechanism to move the ganged contacts. Ambient air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with switch the handle locked in the “open” position.

Most distribution line switches are rated 600A continuous. While some switch categories are rated for load interruption, others are designed to operate under no-load conditions. Non-load break switches operate only when the current through the switch is zero. When used in conjunction with cutout fuses, switches provide short circuit interruption rating.

4.1 Degradation Mechanism

The main degradation processes associated with overhead 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
- Non functioning padlocks
- Insulator damage
- Missing ground connections

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

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

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

Consequences of overhead line switch failure may include customer interruption and/or health and safety consequences for operators.

4.2 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GSH Overhead Line Switches. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows:

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

4.2.1 Condition and Sub-Condition Parameters

Table 4-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Operating Mechanism	14	4
2	Arc Extinction	5	4
3	Insulation	2	4
4	Service Record	2	4

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

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Switch	Table 4-6	1	4
2	Manual Operation (manually operated switch)	Table 4-6	0*	4
3	Motor Mechanism (motorized switch)	Table 4-6	0*	4
4	Remote Operation (remotely operated switch)	Table 4-6	0*	4
5	Switch Mounting	Table 4-8	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 4-3 Arc Extinction (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Arc Interrupter	Table 4-6	1	4
2	Arc Horn	Table 4-6	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

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

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Insulator	Table 4-6	1	4

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

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 4-7	1	4
2	Age	Figure 4-1	3	4

4.2.2 Condition Parameter Criteria

Visual Inspection

Table 4-6 Switch Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear – Working as Required
2	Wear or Failed – Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed – Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Overall Condition

Table 4-7 Overall Condition Criteria

CPF	Condition Description
4	Number of closed Corrective Maintenance (CM) Counts in past 3 years is 0
3	Number of closed CM Counts in past 3 years is $\leq$ 1
2	Number of closed CM Counts in past 3 years is =2
0	Number of closed CM Counts in past 3 years is $\geq$ 3
Note: A non-conformance log with an "issues resolved" date is counted as a closed corrective maintenance (CM) record	

OK or Not OK

Table 4-8 OK or Not OK Criteria

CPF	Condition Description
4	OK
1	Not OK

Age

Assume that the failure rate for Overhead Line Switches exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 45 and 55 years the probability of failure (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

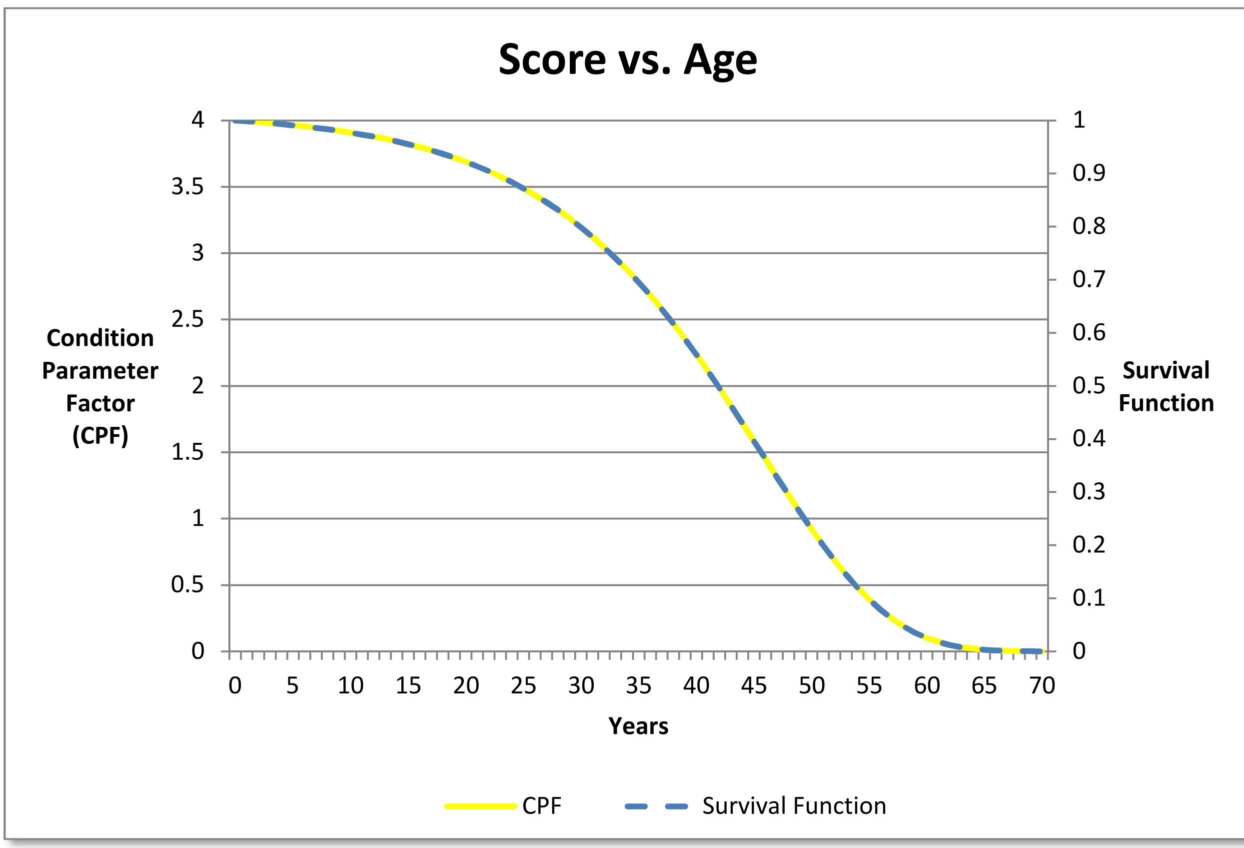


Figure 4-1 Overhead Line Switches Age Condition Criteria

4.3 Age Distribution

The age distribution is shown in the figure below. Age was available for only 28% of the population. The average age was found to be 5 years.

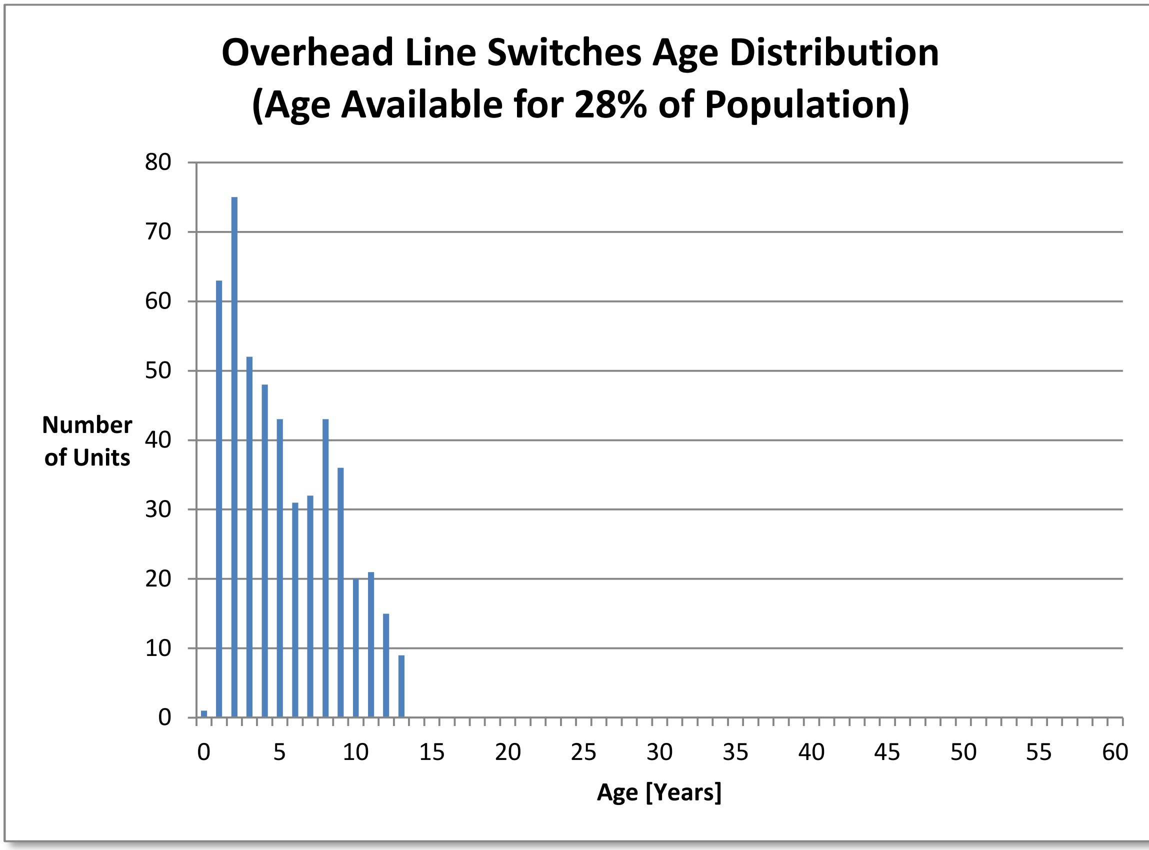


Figure 4-2 Overhead Line Switches Age Distribution

4.4 Health Index Results

There are 1,771 in-service Overhead Line Switches at GSH. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 1,771 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 99%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

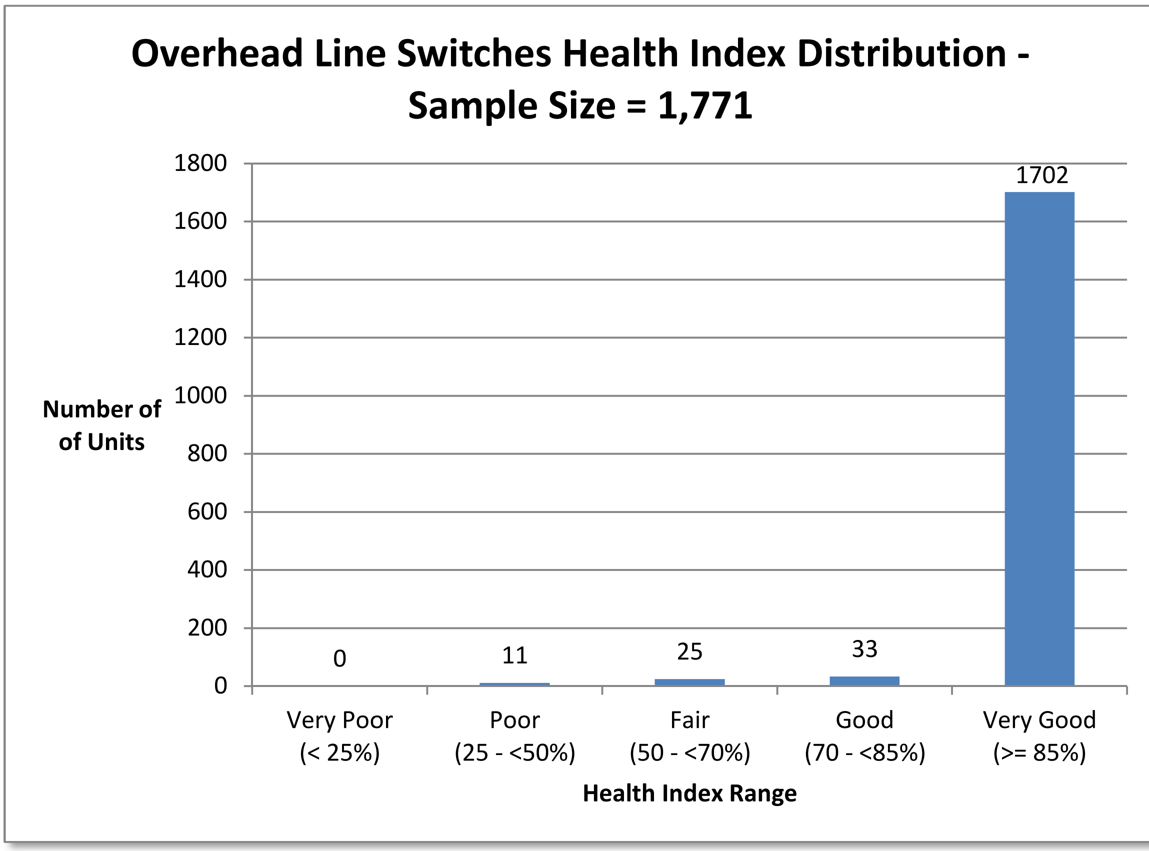


Figure 4-3 Overhead Line Switches Health Index Distribution (Number of Units)

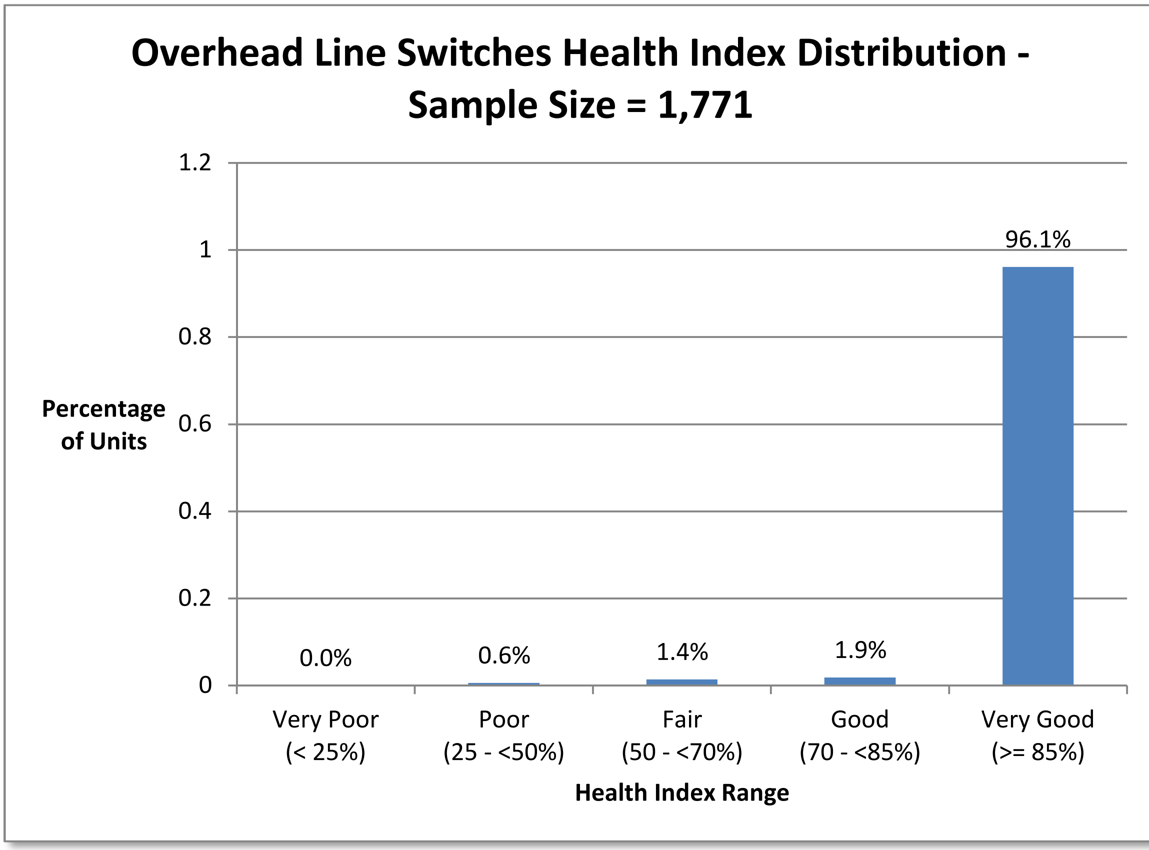


Figure 4-4 Overhead Line Switches Health Index Distribution (Percentage of Units)

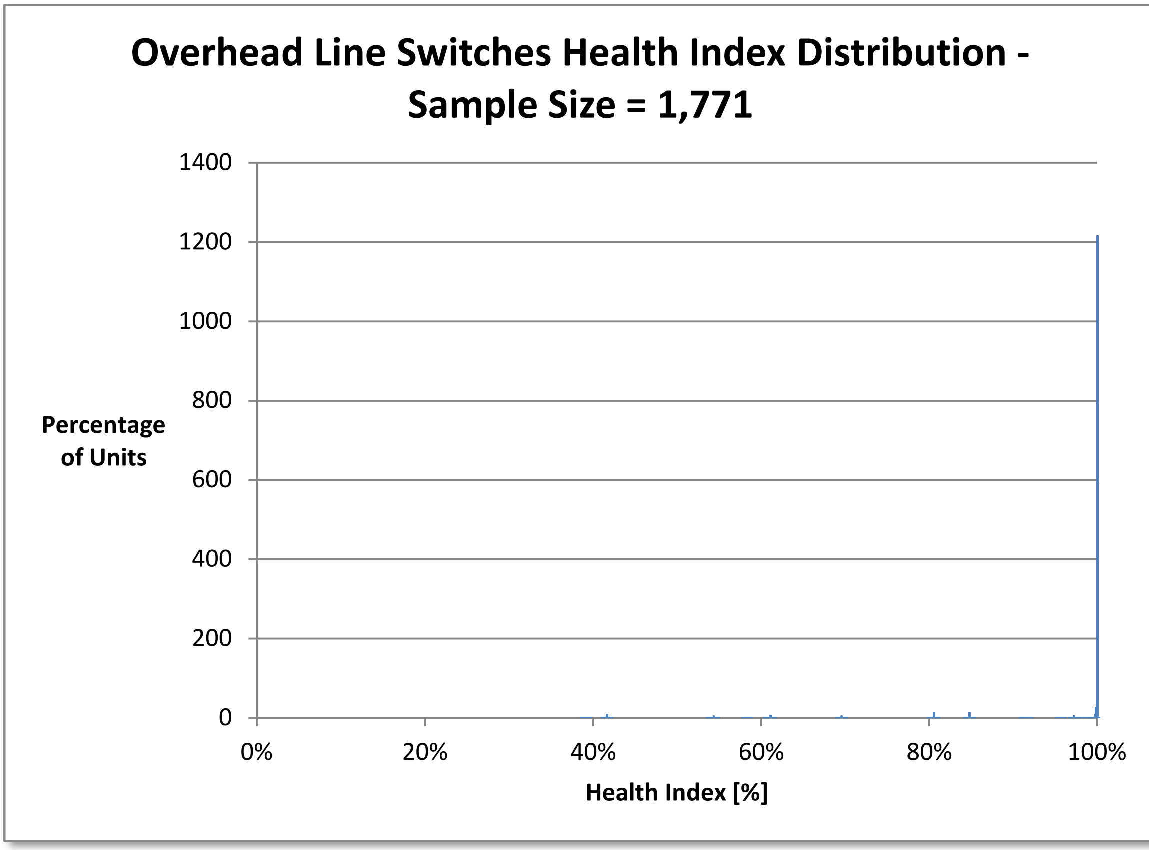


Figure 4-5 Overhead Line Switches Health Index Distribution by Value (Percentage of Units)

4.5 Condition-Based Replacement Plan

As it is assumed that Overhead Line Switches are reactively replaced, the replacement plan is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is also given.

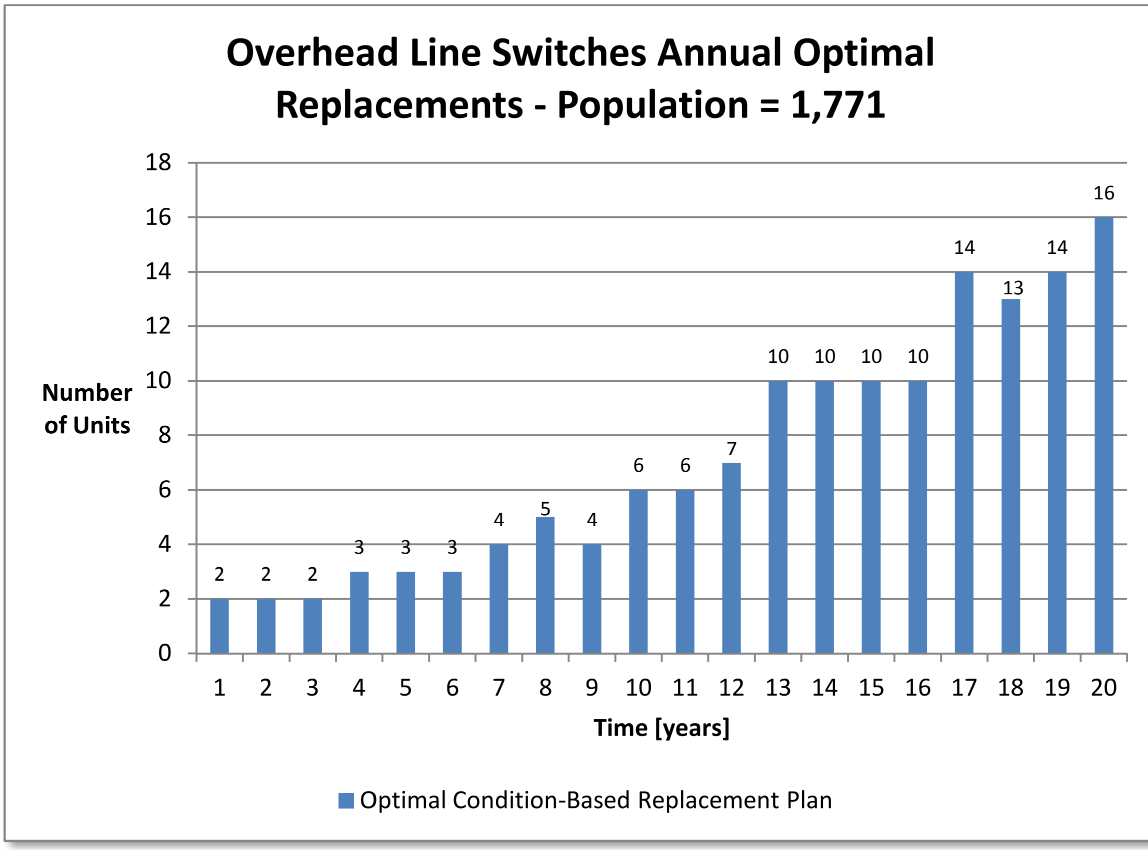


Figure 4-6 Overhead Line Switches Optimal Condition-Based Replacement Plan

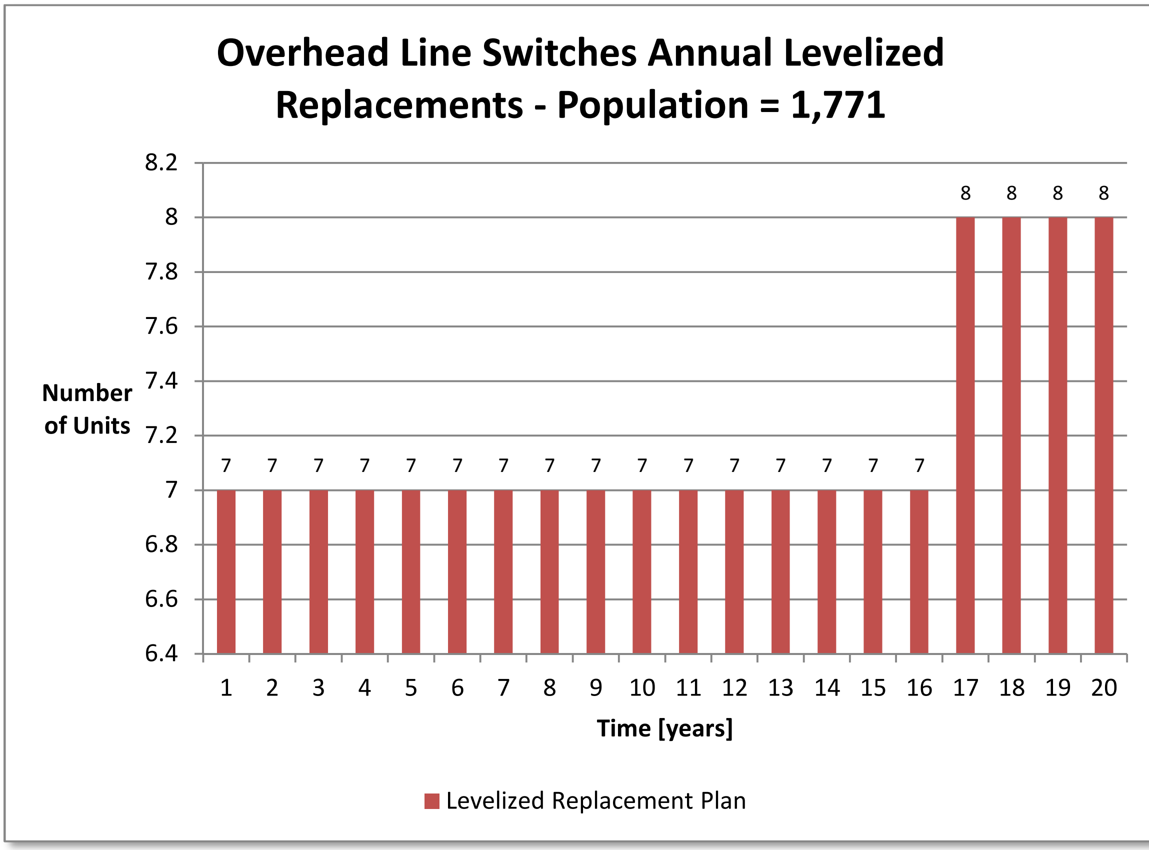


Figure 4-7 Overhead Line Switches Levelized Replacement Plan

4.6 Data Analysis

The data available for Overhead Line Switches includes age and inspections.

4.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Switch Condition
- Arc Interrupter Condition
- Insulation Condition

Assuming all inspection-based parameters are available, the average DAI for Overhead Line Switches is 94%. Although age is available for only 28% of the population, the weight of “Age” is such that it does not have a significant impact to the DAI.

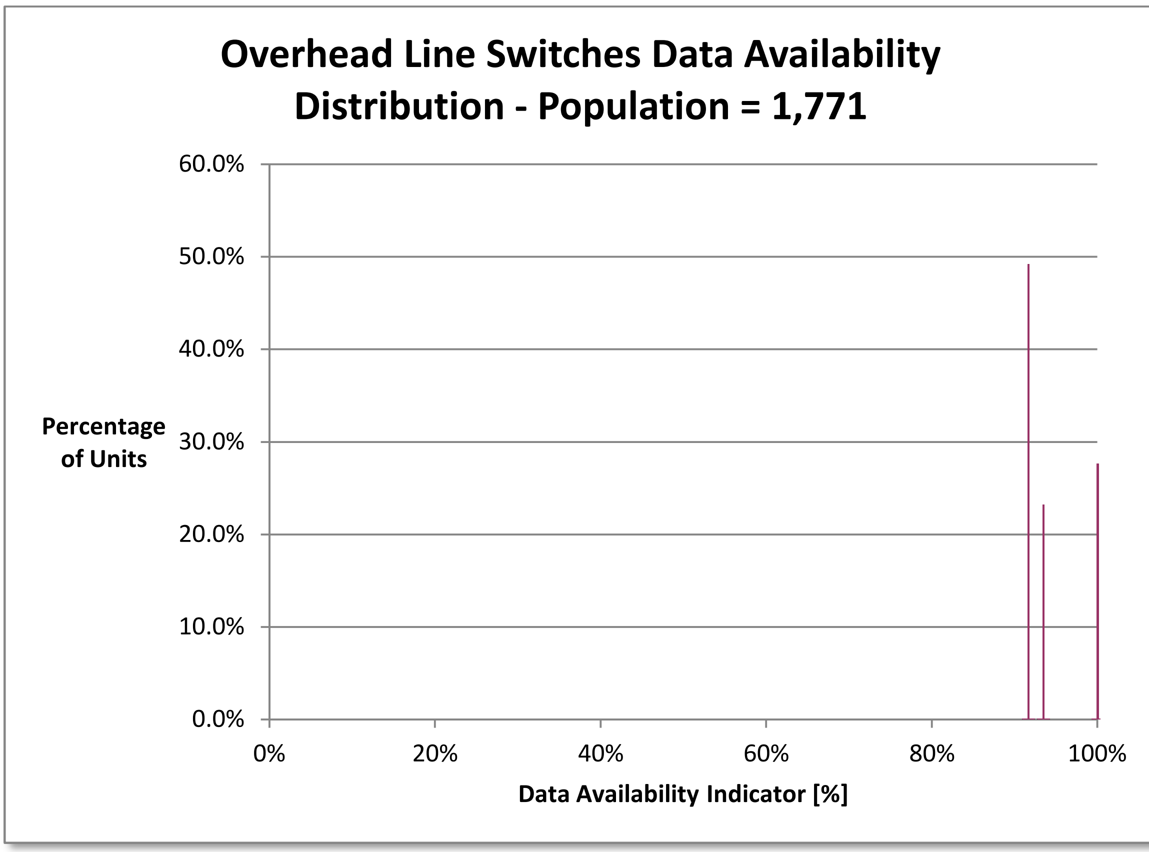


Figure 4-8 Overhead Line Switches Data Availability Distribution

4.6.2 Data Gap

The data gaps for this asset class are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Motor, Manual, Remote Operation	Operation Mechanism	☆☆☆	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection
Mechanical Support		☆	Switch Support	Loose installation	On-site visual inspection
Arc Horn	Arc Extinction	☆	Switch Operation	Arc horn surface worn-out	On-site visual inspection

5 Sudbury Hydro Wood Poles

This study considers several different types of poles, with several different owners. Greater Sudbury Hydro owns wood and concrete poles. Bell and Hydro One own wood poles only. Finally, there are wood, concrete, steel, and aluminum poles that are privately-owned.

Wood poles are used to support primary distribution lines at voltages from 4.16 kV to 44 kV. The wood species commonly used for distribution wood poles predominantly include Red Pine, Jack Pine and Western Red Cedar (WRC), either butt-treated or full-length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used.

Distribution line design standards dictate usage of poles of varying height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into Classes (1 to 7) which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable and/or other telecommunications facilities.

Concrete poles are used primarily in the construction of higher voltage distribution or sub-transmission overhead lines. They are available with round, square and octagonal cross-sections in lengths up to 60 feet. The strength of the pole is specified by a Class from A to D indicating light to heavy duty. They are supplied with a variety of pre-determined attachment patterns. Concrete poles are a relatively expensive option compared to wood or steel poles. They are heavy to transport and install. They have a clean matte appearance that is stable over long time periods and blends in to most environments. They have a longer expected service life than wood or steel. They are harder to climb and to make attachments to once they are in service.

Steel poles are primarily used for transmission lines and are only beginning to be used in distribution line and light pole construction. Generally, steel poles are stronger and more durable than their equivalent wood pole counterparts. They are resistant to insects and rot and can be galvanized or coated to mitigate corrosion. Such poles can be designed to meet specific loading criteria, are easier to install than wood, and require less maintenance.

Aluminum poles are often used as streetlight poles. A significant benefit of aluminum is that it is naturally corrosion resistant. Anodizing the aluminum further increases resistance to corrosion and abrasion. Aluminum is nearly one third the weight of steel, making it is easy to install. It has a higher strength to weight ratio than steel and like steel poles, aluminum poles are maintenance free.

5.1 Degradation Mechanism

Since wood is a natural material, the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Certain species of fungi are known to 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 the decay processes requires the presence of the water and oxygen, the area of the pole most susceptible to degradation is at and around the ground line or at the top of pole. Although it is possible in some circumstances for decay to occur in other locations, it is normal to concentrate inspection and assessment of poles in the most critical areas. In addition to the natural degradation processes, external damage to the pole by wildlife can also be a significant problem. Examples may include attack by termites, small mammals or woodpeckers.

To prevent attack and decay, wood poles are treated with preservatives prior to being installed. The preservatives have two functions; firstly, to keep out moisture vital to fungal attacks, and, secondly, as a biocide to kill off fungus spores. As wood pole use has evolved in the electricity industry, the nature of the preservatives used to treat the wood has also evolved, as the chemicals used previously have become unacceptable from an environmental viewpoint. Preservative treatments applied to poles prior to 1980 range from none on some WRC poles, to butt-treated and full-length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

As a structural item, the sole concern when assessing the condition of a wood pole is the native 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.

Although wood pole condition assessment is driven by the condition of the wood pole itself, replacement of the ancillary components, foundations, cross-arms, guys, anchors and insulators may also be required. The poles, foundations and cross-arms support the required insulators and phase conductors. The guys and anchors maintain the mechanical integrity of the structure and the insulators electrically insulate the conductors from ground potential.

There are many factors considered by utilities when establishing condition for wood poles. These include species 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 required safety and security obligations.

Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to the concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in); however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice resulting in cracking and separation of the concrete. The spun concrete process used in the manufacturing of poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

The degradation of directly-buried steel poles is mainly due to steel corrosion in-ground and at the ground line. In-ground situations are vastly different from one installation to another because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground. There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations. Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

Aluminum poles do not peel or rust. As with other types of poles, fatigue due to wind-induced vibration is a potential source of failure. For steel poles, rust in the area of the fatigue will be apparent. Red die penetration may be needed for aluminum poles, as they do not show signs of rust.

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

This section presents the Health Index Formula developed and used for wood, concrete, steel, and aluminum poles. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

5.2.1 Condition and Sub-Condition Parameters

Table 5-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Pole Strength**	0*	4
2	Physical Condition	3	4
3	Service Record	10	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.
**This parameter only applies for wood poles that are 20 years or older

Table 5-2 Pole Strength (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Pole Strength	Dependent on Strength Test Method	1	4

Table 5-3 Physical Condition (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Damage (vehicle, lightning, etc.)	Table 5-5	1	4
2	Lean	Table 5-6	1	4
3	Rot (wood pole)	Table 5-5	0*	4
4	Animal Damage (wood pole)	Table 5-5	0*	4
5	Spalling (concrete)	Table 5-5	0*	4
6	Rebar Corrosion (concrete)	Table 5-5	0*	4
7	Pole Corrosion (steel)	Table 5-5	0*	4
8	Separation	Table 5-5	0*	4
9	Voids / Holes	Table 5-5	0*	4
10	Cracks	Table 5-5	0*	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 5-4 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age***	Figure 5-1 or Figure 5-2	2	4

*** Age is determined by the pole installation date. If no Installation Date was available, the Date of Manufacture was used.

5.2.2 Condition Parameter Criteria

Visual Inspection

Table 5-5 Inspection Condition Criteria

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear – Working as Required
2	Wear or Failed – Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed – Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Yes or No

Table 5-6 Yes or No Criteria

CPF	Condition Description
4	Yes
1	No

Age

Assume that the failure rate for Sudbury Hydro Wood Poles exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 45 and 75 years the probability of failures (P_f) for this asset are 60% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for wood poles is also shown in the figure below:

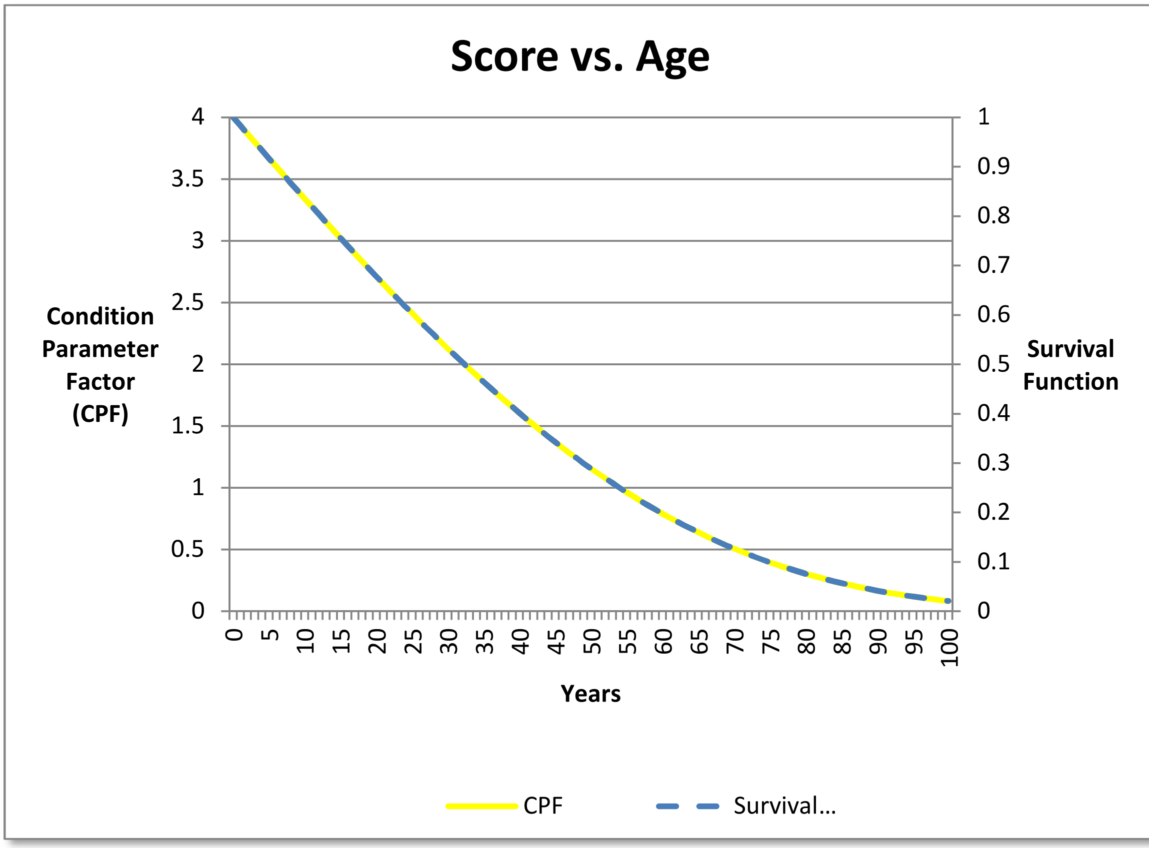


Figure 5-1 Wood Pole Age Condition Criteria

For Concrete, Steel, Aluminum, and Anodized Aluminum, probability of failures (P_f) at 60% and 90% are assumed to be at the ages 60 and 80 respectively:

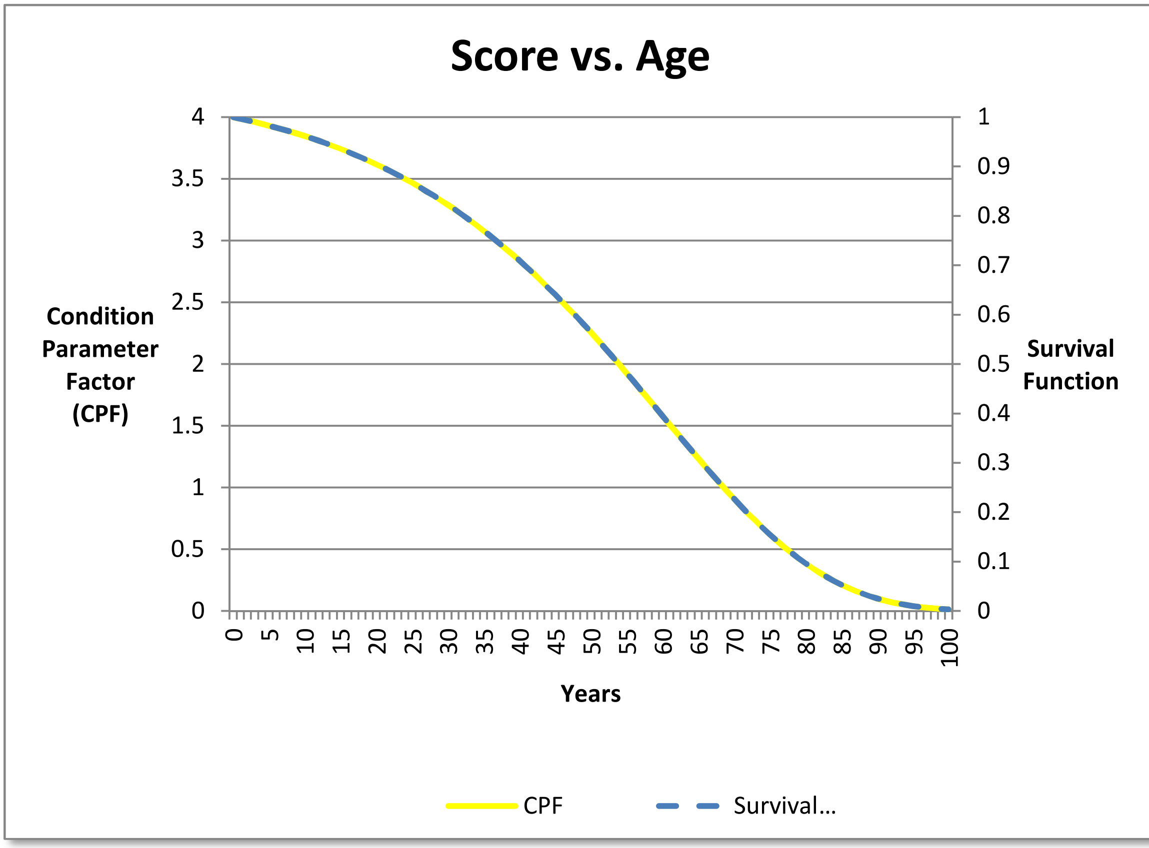


Figure 5-2 Concrete, Steel, Aluminum, and Anodized Aluminum Pole Age Condition Criteria

5.3 Age Distribution

The overwhelming majority of Sudbury Hydro's poles are wood. Of these, special consideration is given to 44 kV poles. The assessment for Sudbury Hydro Wood Poles is given in terms of "All" poles, "44 kV" poles, and "Non-44 kV" poles.

<u>All</u>

The age distribution is shown in the figure below. Age was available for 88% of the population. The average age was found to be 32 years.

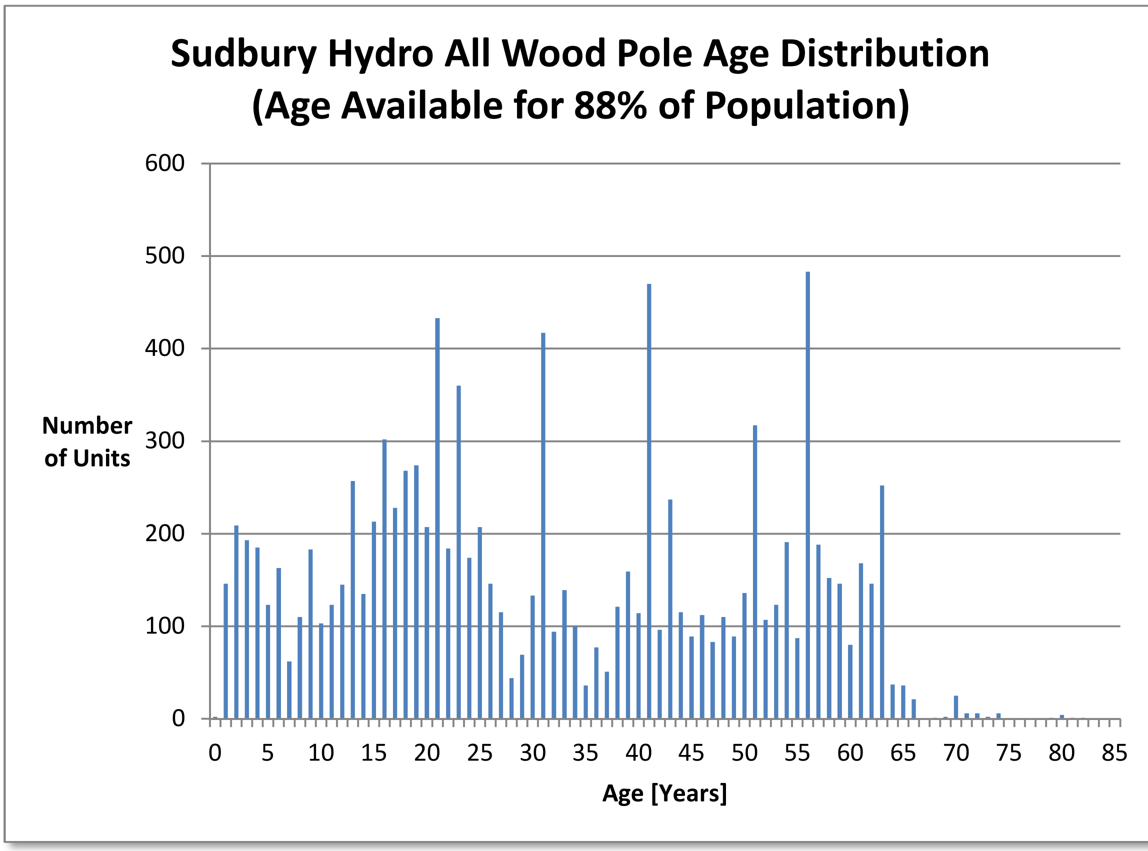


Figure 5-3 All Sudbury Hydro Wood Poles Age Distribution

44 kV

The age distribution is shown in the figure below. Age was available for 92% of the population. The average age was found to be 24 years.

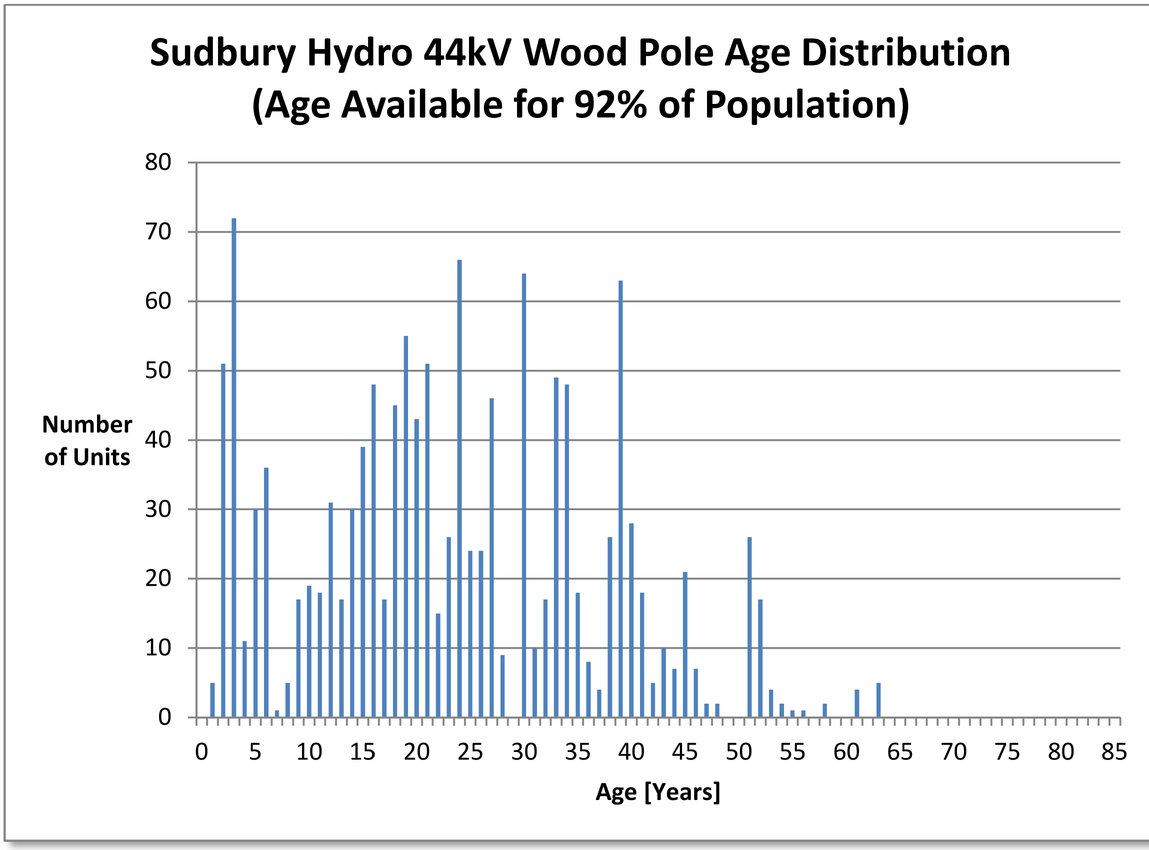


Figure 5-4 44kV Sudbury Hydro Wood Poles Age Distribution

<u>Non-44 kV</u>

The age distribution is shown in the figure below. Age was available for 88% of the population. The average age was found to be 33 years.

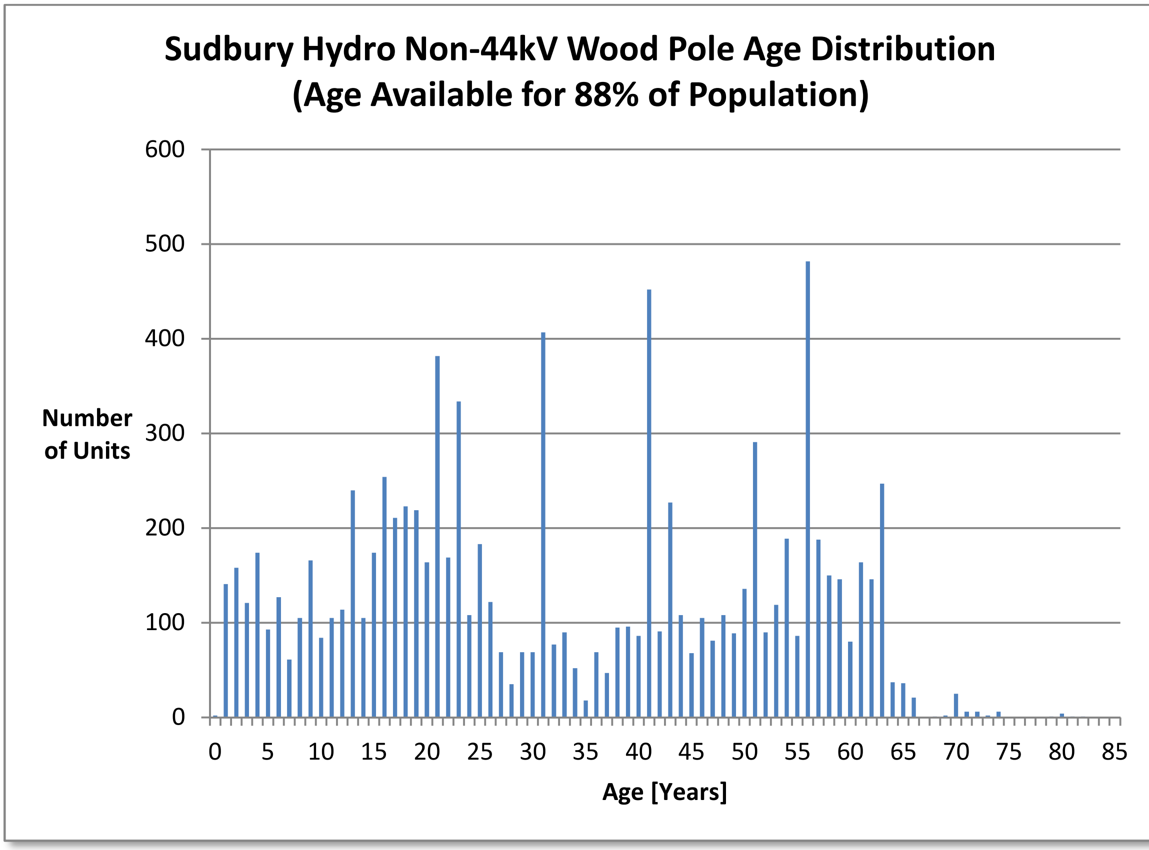


Figure 5-5 Non-44kV Sudbury Hydro Wood Poles Age Distribution

5.4 Health Index Results

<u>All</u>

There are 12,377 in-service Sudbury Hydro Wood Poles at GSH. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 12,377 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 68%. Approximately 26% of the units were found to be in poor condition.

The Health Index Results are as follows:

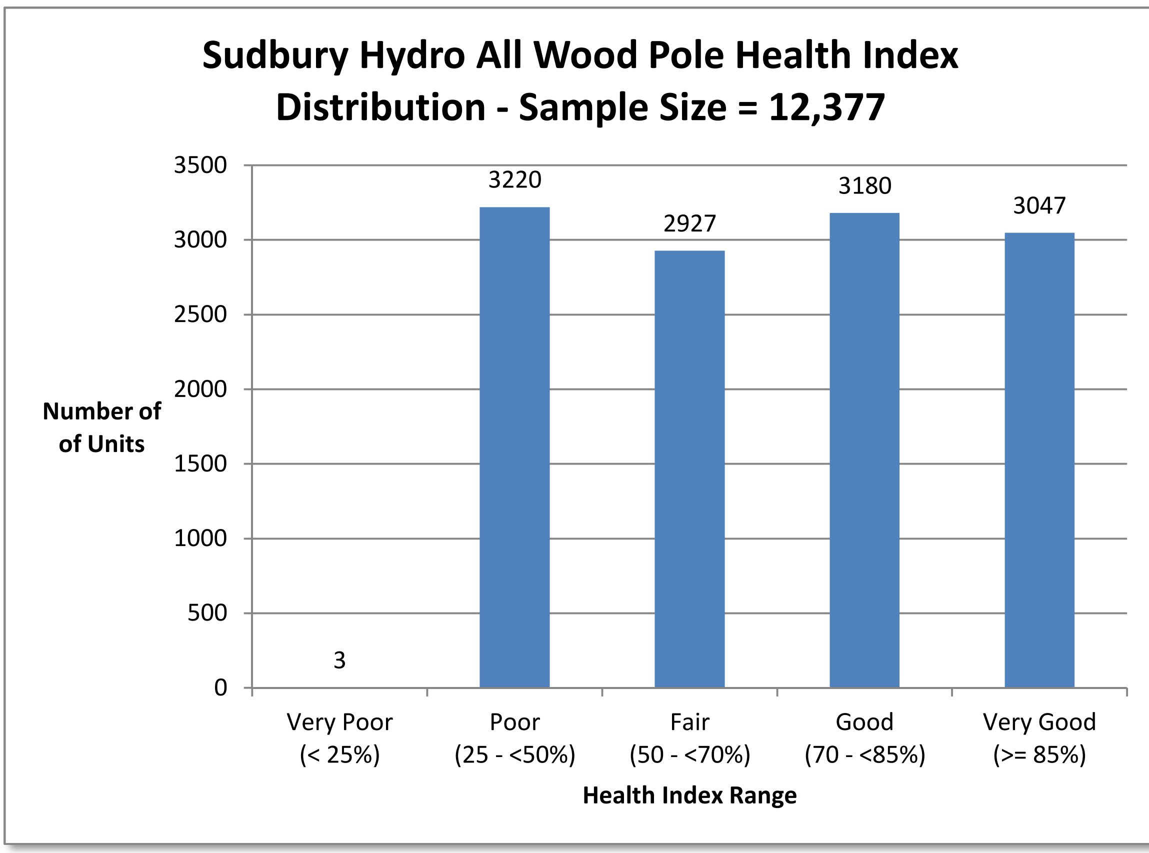


Figure 5-6 All Sudbury Hydro Wood Poles Health Index Distribution (Number of Units)

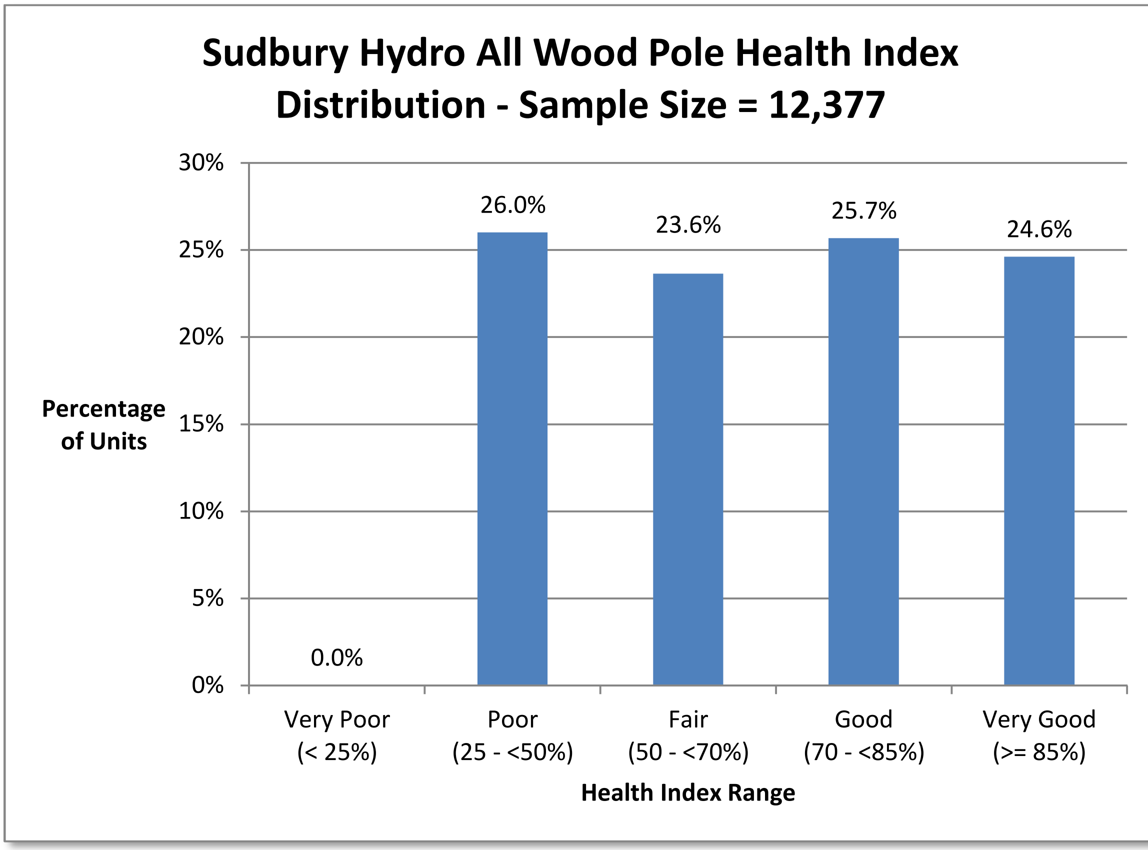


Figure 5-7 All Sudbury Hydro Wood Poles Health Index Distribution (Percentage of Units)

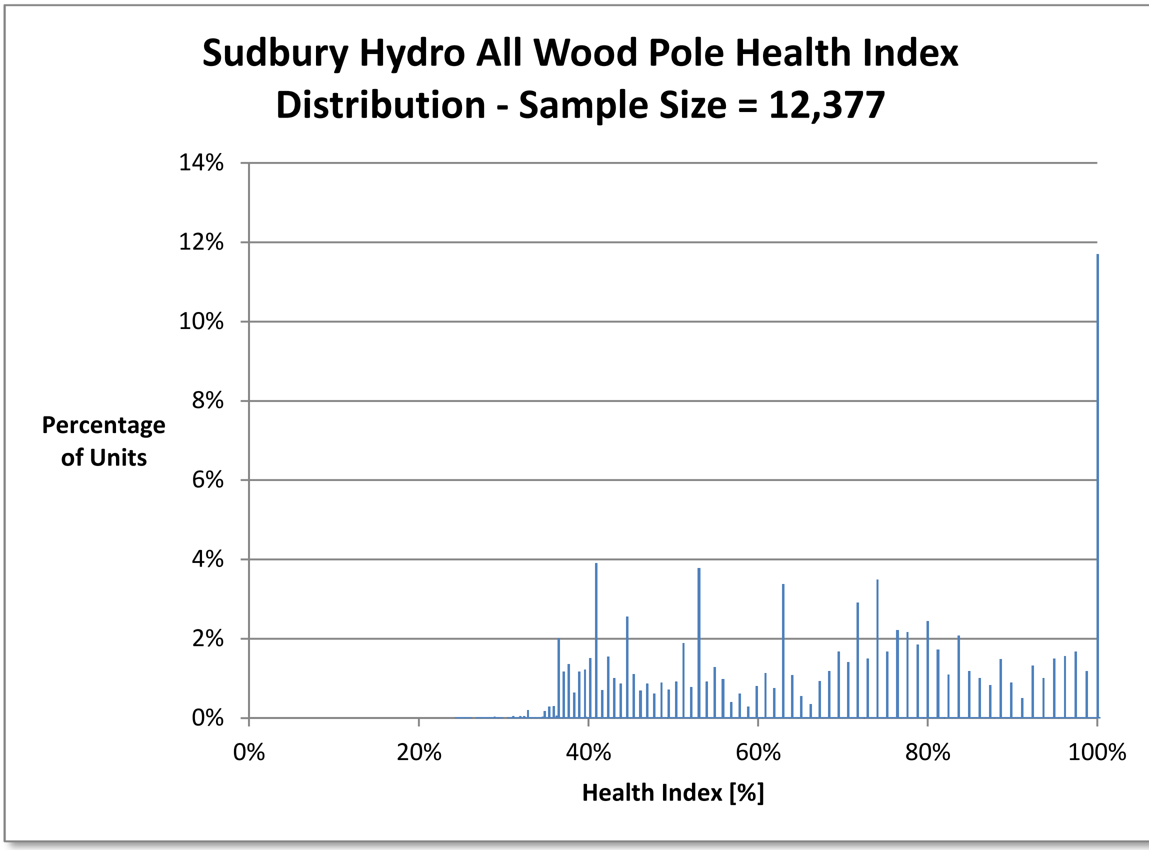


Figure 5-8 All Sudbury Hydro Wood Poles Health Index Distribution by Value (Percentage of Units)

44 kV

There are 1,431 in-service 44 kV Sudbury Hydro Wood Poles at GSH. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 1,431 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 74%. Approximately 7% of the units were found to be in poor condition.

The Health Index Results are as follows:

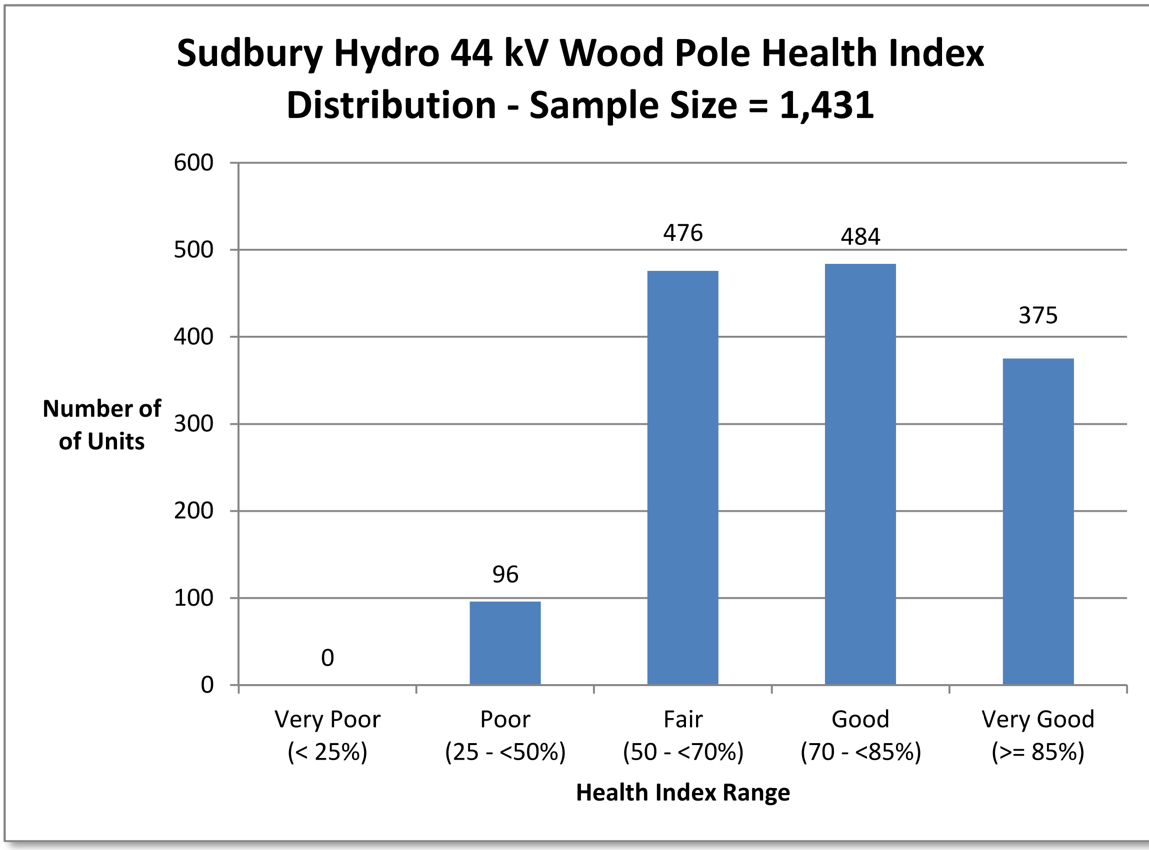


Figure 5-9 44 kV Sudbury Hydro Wood Poles Health Index Distribution (Number of Units)

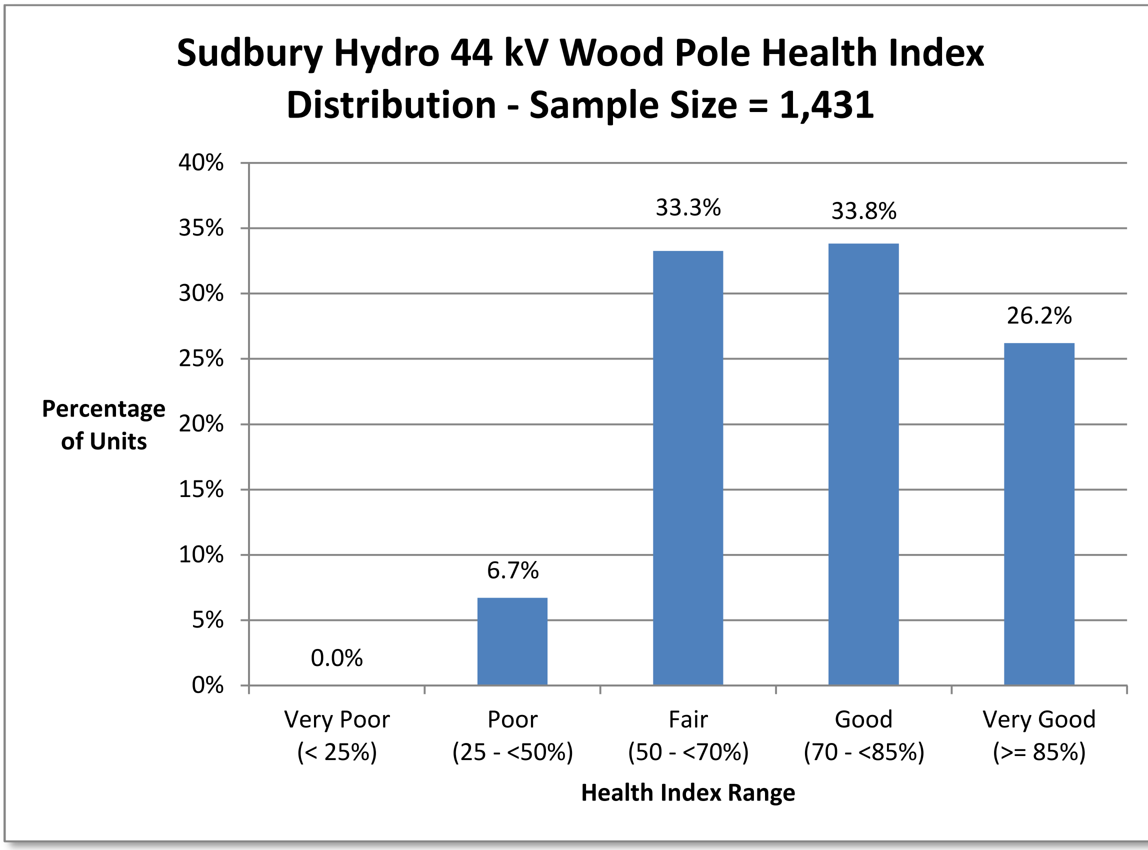


Figure 5-10 44 kV Sudbury Hydro Wood Poles Health Index Distribution (Percentage of Units)

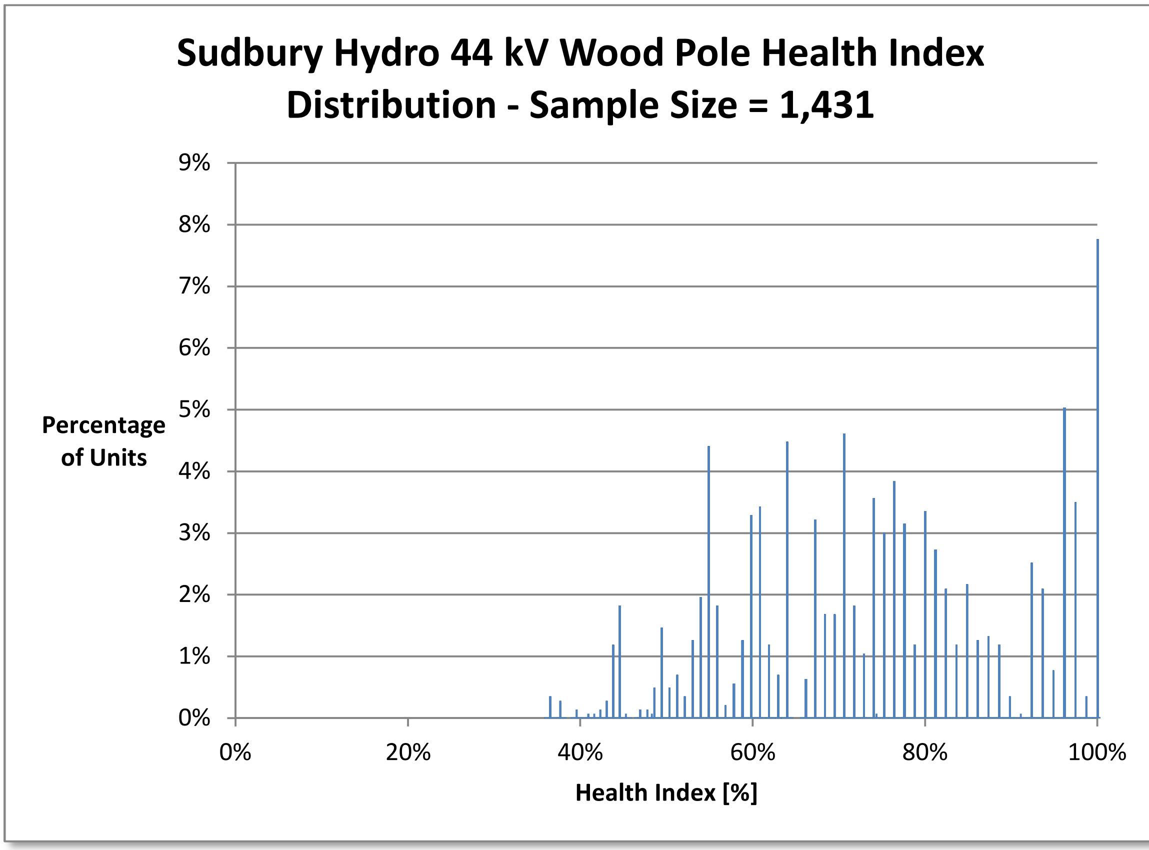


Figure 5-11 44 kV Sudbury Hydro Wood Poles Health Index Distribution by Value (Percentage of Units)

Non-44 kV

There are 10,946 in-service Non-44 kV Sudbury Hydro Wood Poles at GSH. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 10,946 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 67%. Approximately 29% of the units were found to be in poor condition.

The Health Index Results are as follows:

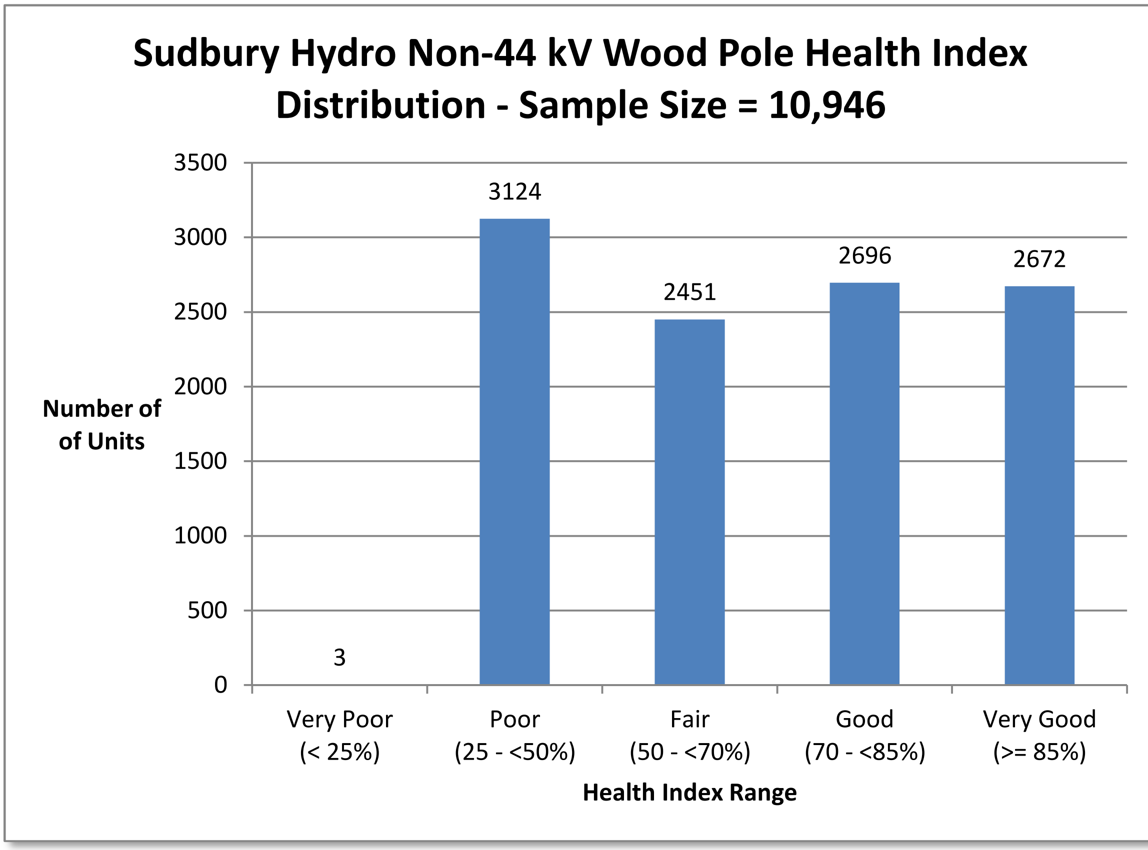


Figure 5-12 Non-44 kV Sudbury Hydro Wood Poles Health Index Distribution (Number of Units)

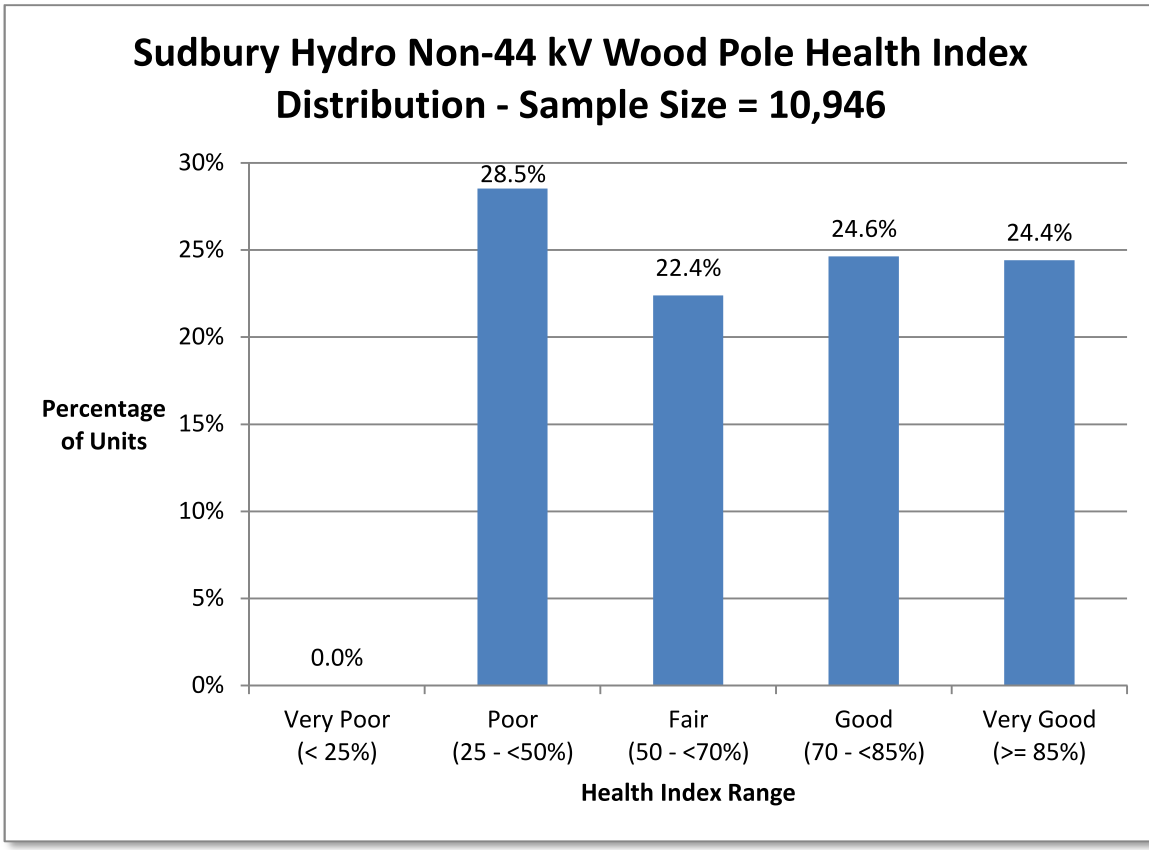


Figure 5-13 Non-44 kV Sudbury Hydro Wood Poles Health Index Distribution (Percentage of Units)

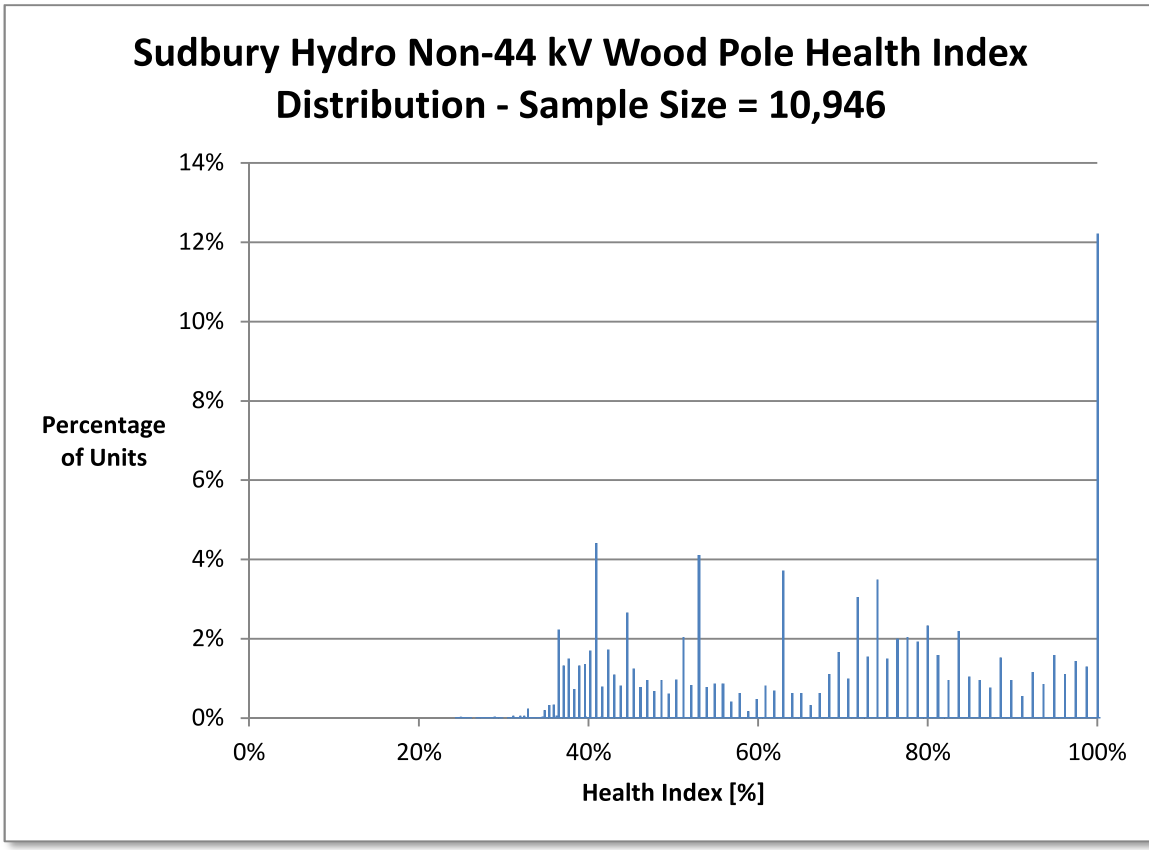


Figure 5-14 Non-44 kV Sudbury Hydro Wood Poles Health Index Distribution by Value (Percentage of Units)

5.5 Condition-Based Replacement Plan

Although Sudbury Hydro Wood Poles are proactively replaced, the number of expected replacements per year is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is also given.

All

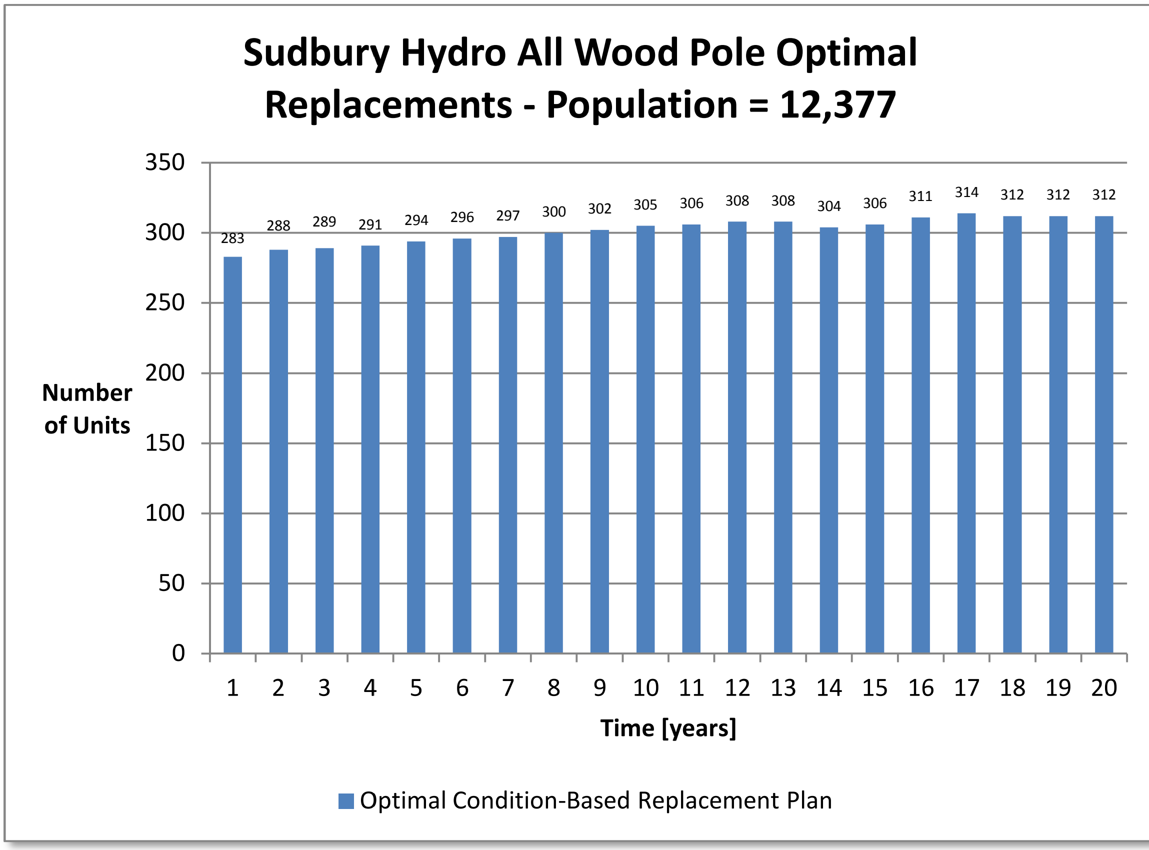


Figure 5-15 All Sudbury Hydro Wood Poles Optimal Condition-Based Replacement Plan

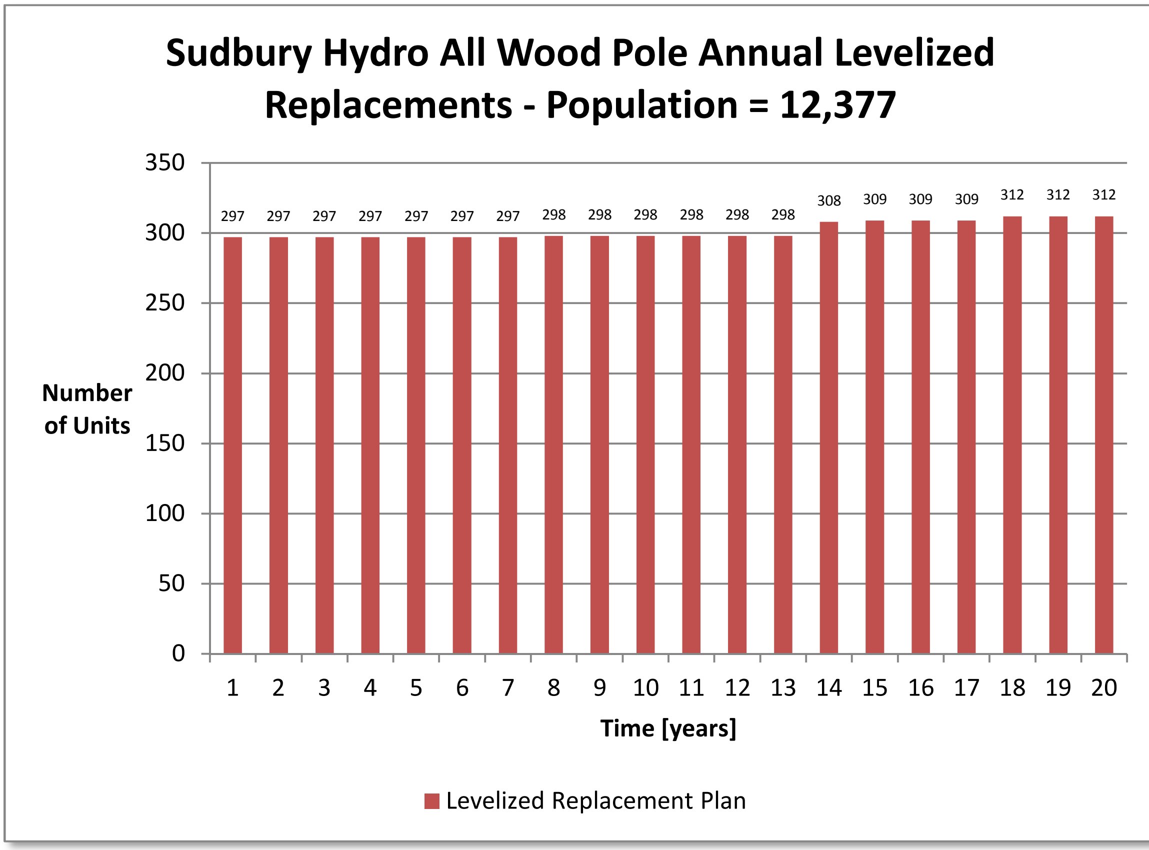


Figure 5-16 All Sudbury Hydro Wood Poles Levelized Replacement Plan

44 kV

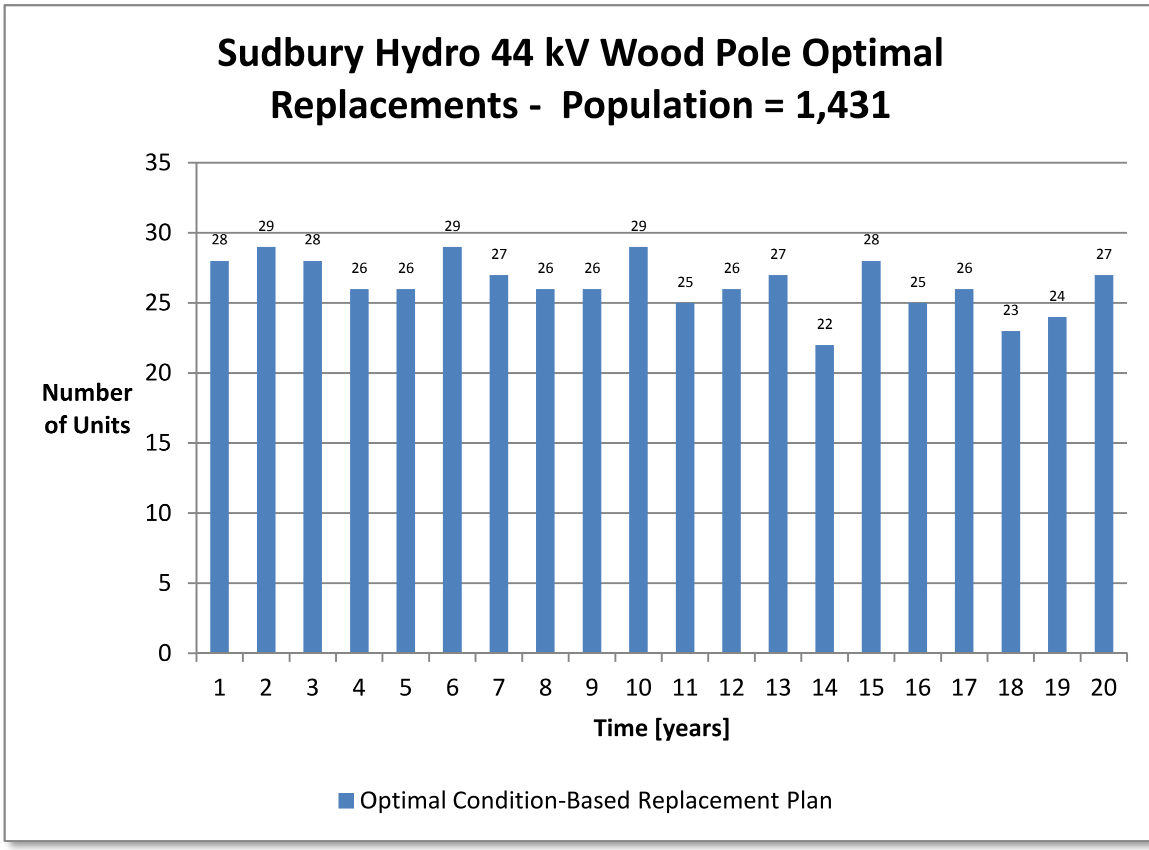


Figure 5-17 44 kV Sudbury Hydro Wood Poles Optimal Condition-Based Replacement Plan

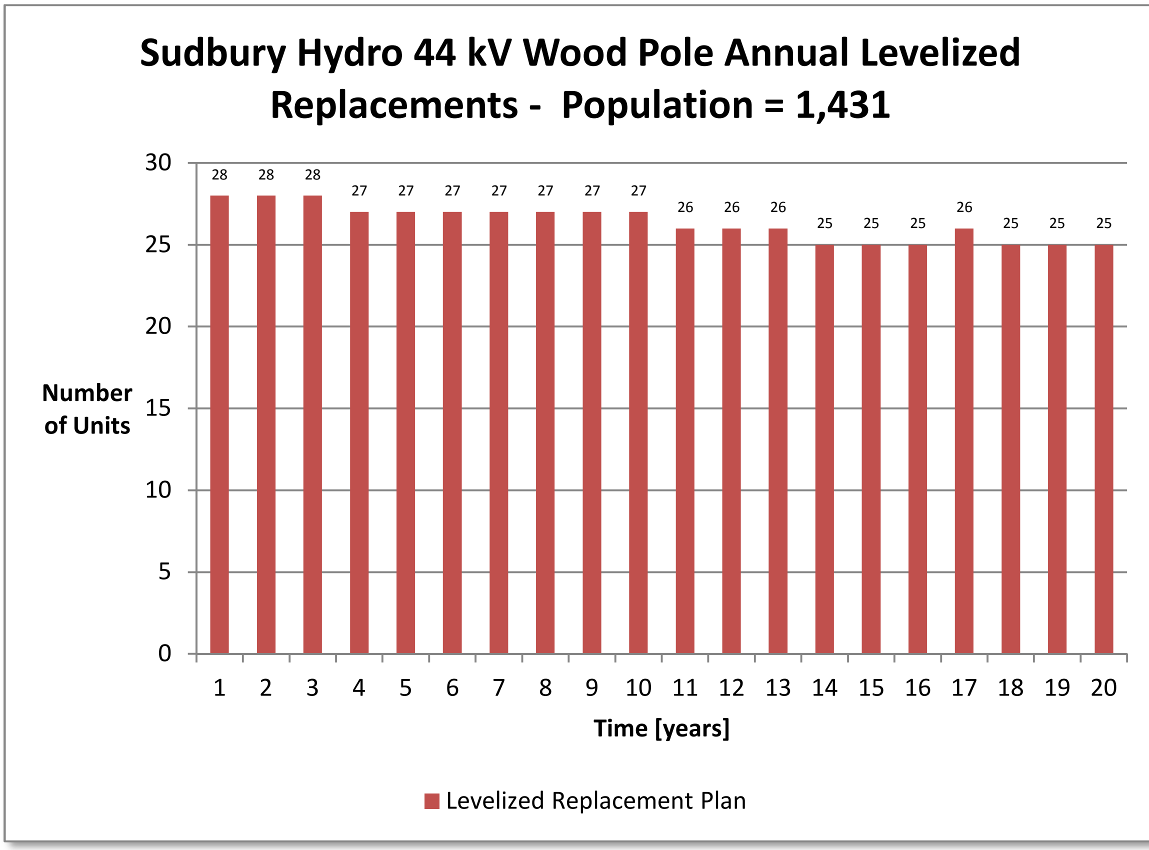


Figure 5-18 44 kV Sudbury Hydro Wood Poles Levelized Replacement Plan

Non-44 kV

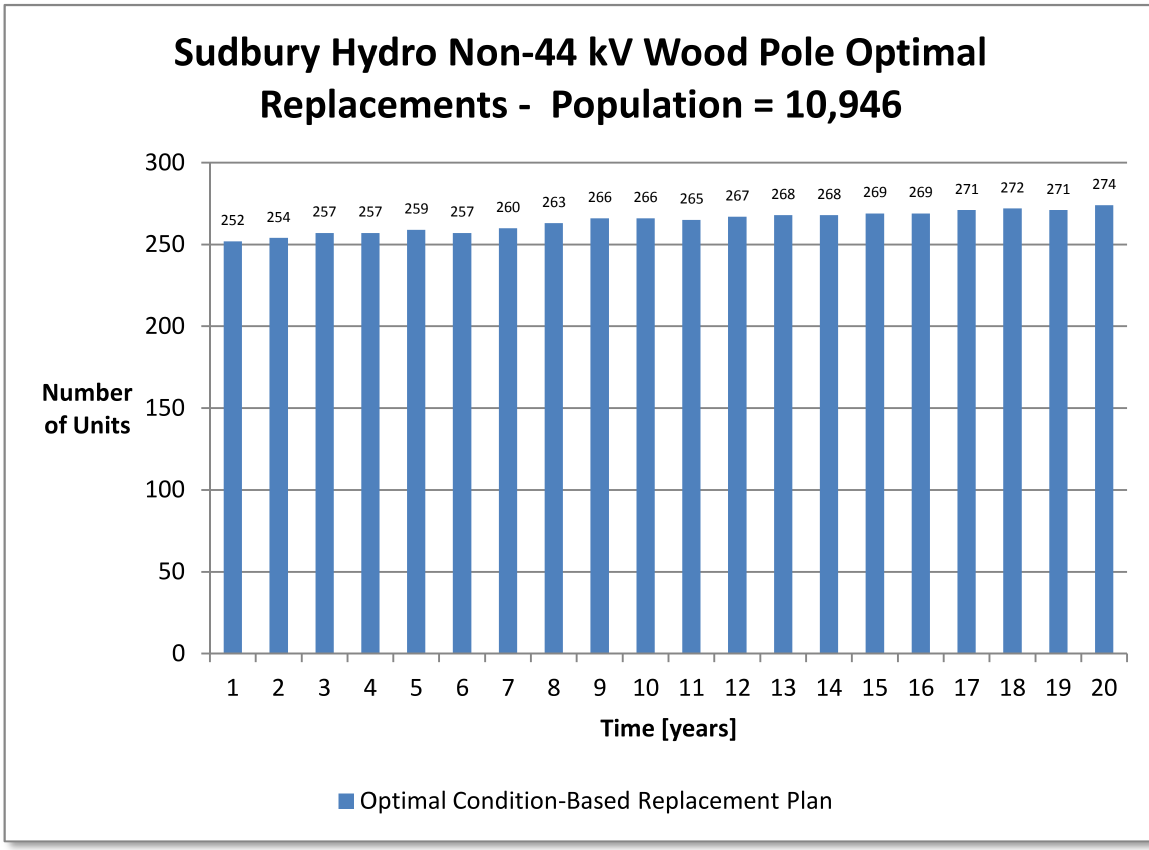


Figure 5-19 Non-44 kV Sudbury Hydro Wood Poles Optimal Condition-Based Replacement Plan

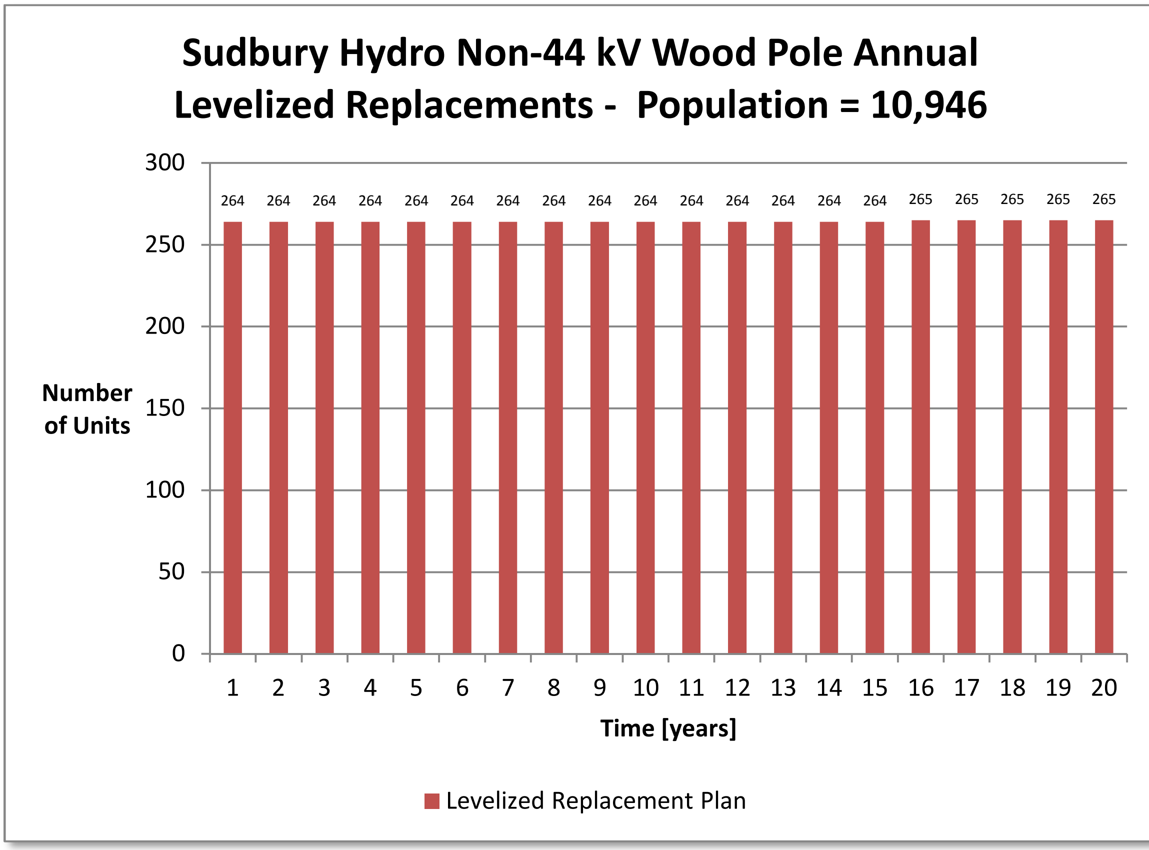


Figure 5-20 Non-44 kV Sudbury Hydro Wood Poles Levelized Replacement Plan

5.6 Data Analysis

The data available for Sudbury Hydro Wood Poles includes age and inspections.

5.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Damage
- Lean

All

Assuming all inspection-based parameters are available, the average DAI for All Sudbury Hydro Wood Poles is 91%.

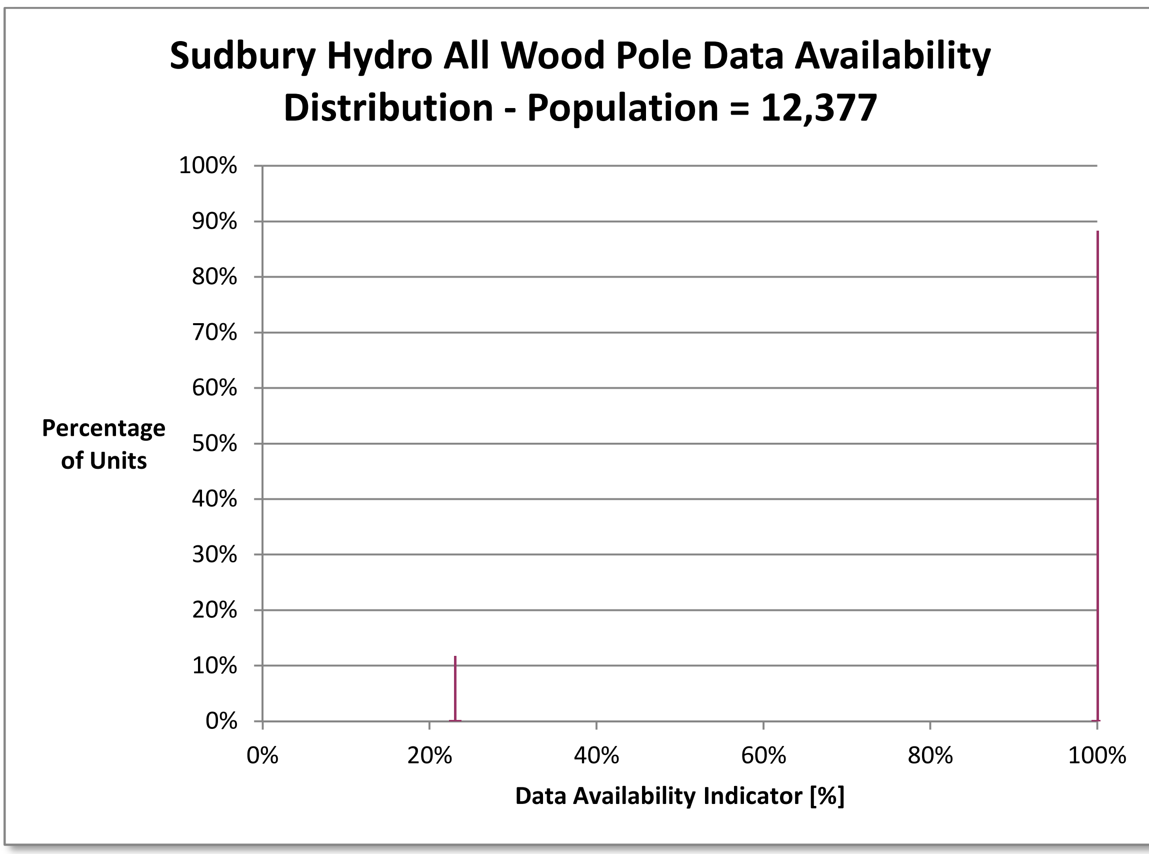


Figure 5-21 All Sudbury Hydro Wood Poles Data Availability Distribution

44 kV

Assuming all inspection-based parameters are available, the average DAI for 44 kV Sudbury Hydro Wood Poles is 94%.

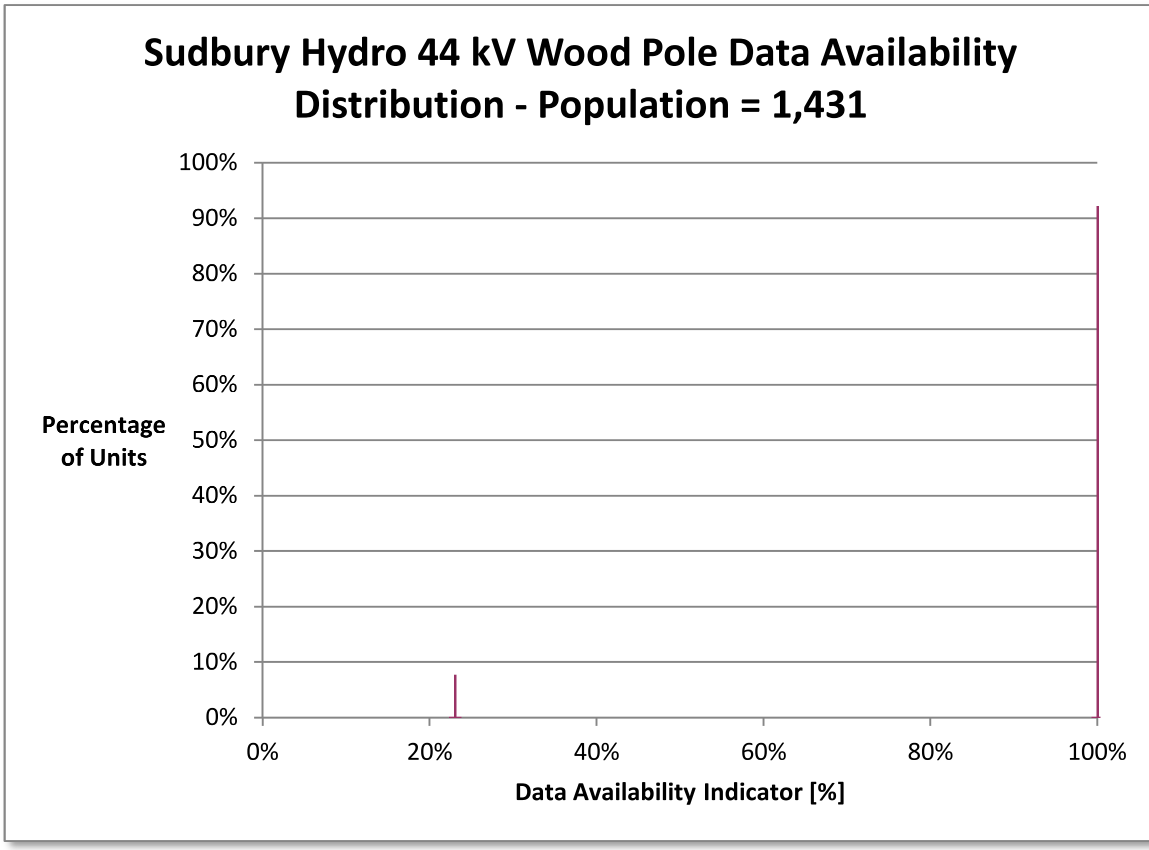


Figure 5-22 44 kV Sudbury Hydro Wood Poles Data Availability Distribution

Non-44 kV

Assuming all inspection-based parameters are available, the average DAI for Non-44 kV Sudbury Hydro Wood Poles is 91%.

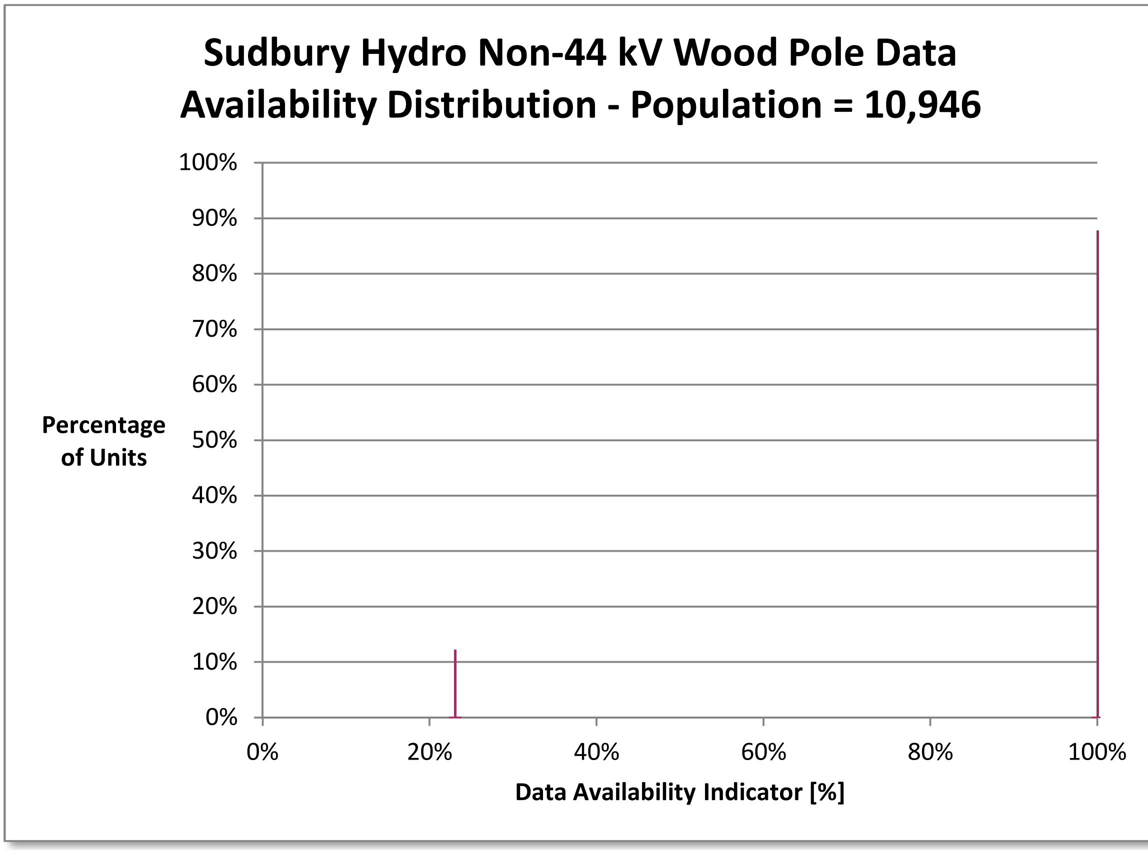


Figure 5-23 Non-44 kV Sudbury Hydro Wood Poles Data Availability Distribution

5.6.2 Data Gap

The data gaps for all pole types (wood, concrete, steel, and aluminum) are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Pole Strength	Pole Strength	☆☆☆	Pole Circumference	Ratio of actual circumference over the original circumference	On-site Testing
			Pole Strength	Ratio of actual strength (psi) over the design strength (psi) Primarily used for wood poles, however core sample tests may be possible for concrete poles	
Rot (wood pole)	Physical Condition	☆☆	Pole	Top feathering	On-site Visual Inspection
Animal Damage (wood pole)				Woodpecker, ant, or other type of animal damage	
Spalling (concrete)				Concrete spalling	
Rebar Corrosion (concrete)				Rebar visible and showing signs of corrosion	
Pole Corrosion (steel)				Pole showing signs of corrosion	
Separation				Pole breaking apart	
Voids / Holes				Hole due to degradation	
Cracks				Surface crack due to deterioration or fatigue	

This pate is intentionally left blank.

6 Sudbury Hydro Concrete Poles

There are no 44 kV Sudbury Hydro Concrete Poles.

6.1 Degradation Mechanism

Please refer to Section 5.1.

6.2 Health Index Formulation

Please refer to Section 5.2.

6.3 Age Distribution

The age distribution is shown in the figure below. Age was available for 55% of the population. The average age was found to be 38 years.

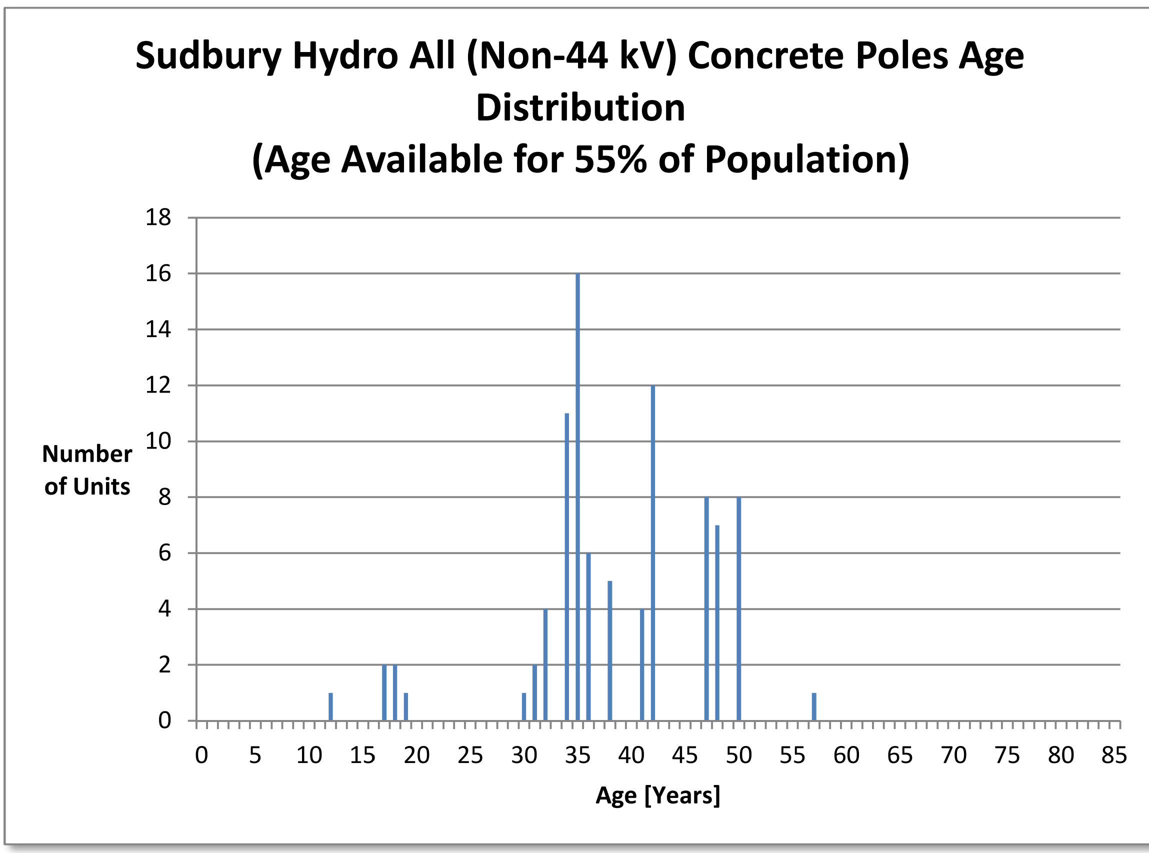


Figure 6-1 Sudbury Hydro Concrete Poles Age Distribution

6.4 Health Index Results

There are 165 in service Sudbury Hydro Concrete Poles at GSH. Because it is assumed that all units have, been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition, all 165 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 88%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

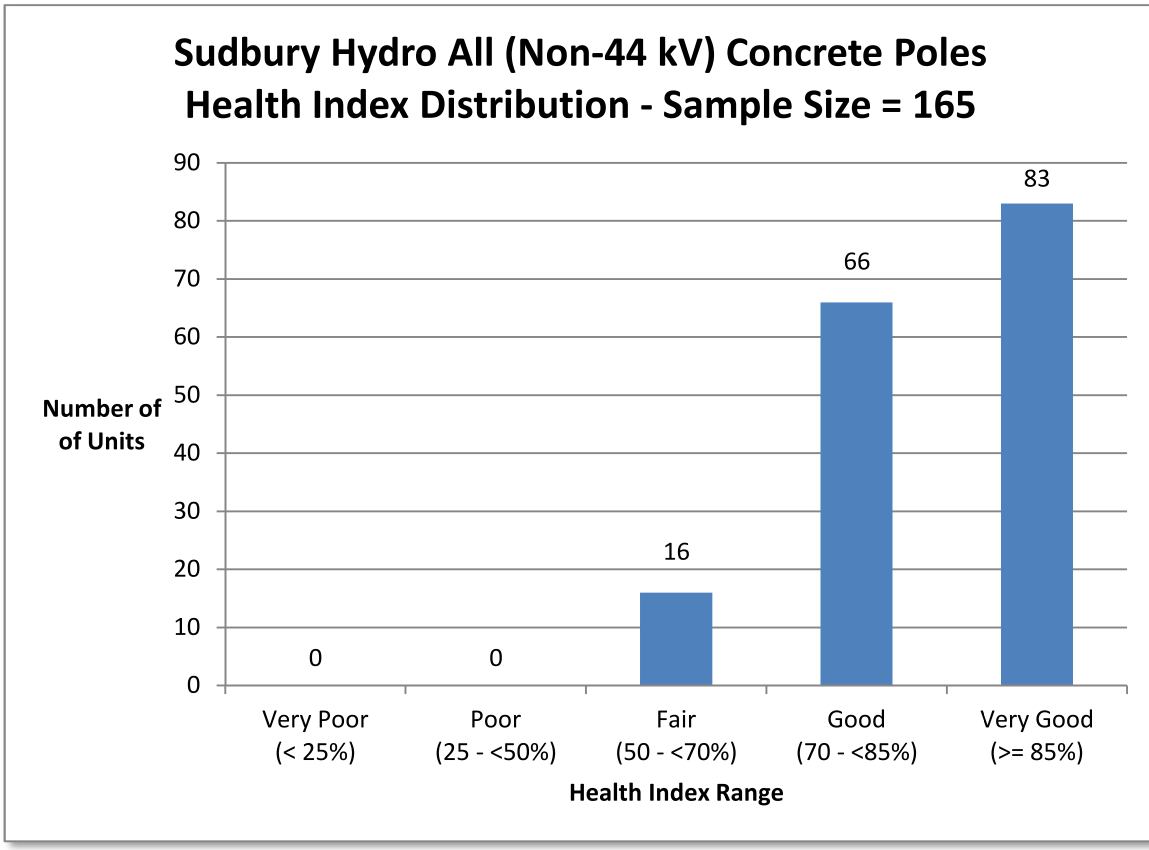


Figure 6-2 Sudbury Hydro Concrete Poles Health Index Distribution (Number of Units)

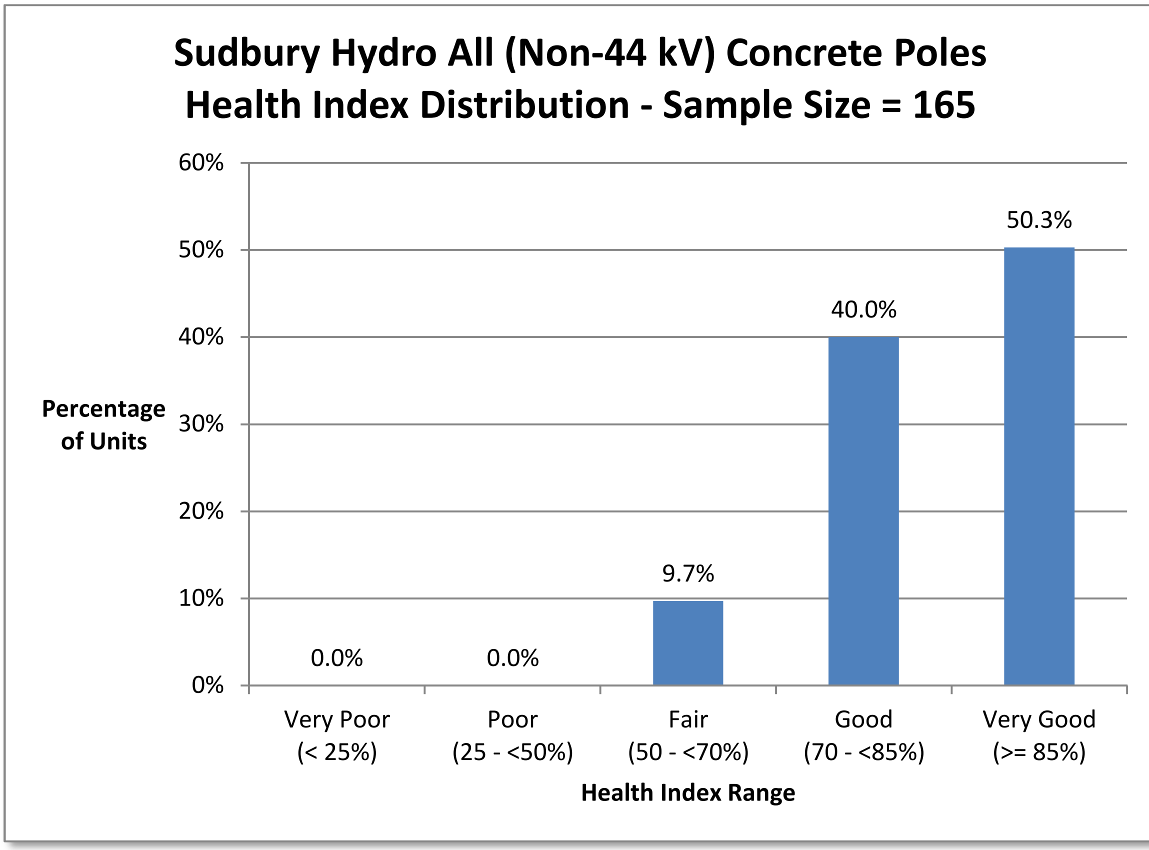


Figure 6-3 Sudbury Hydro Concrete Poles Health Index Distribution (Percentage of Units)

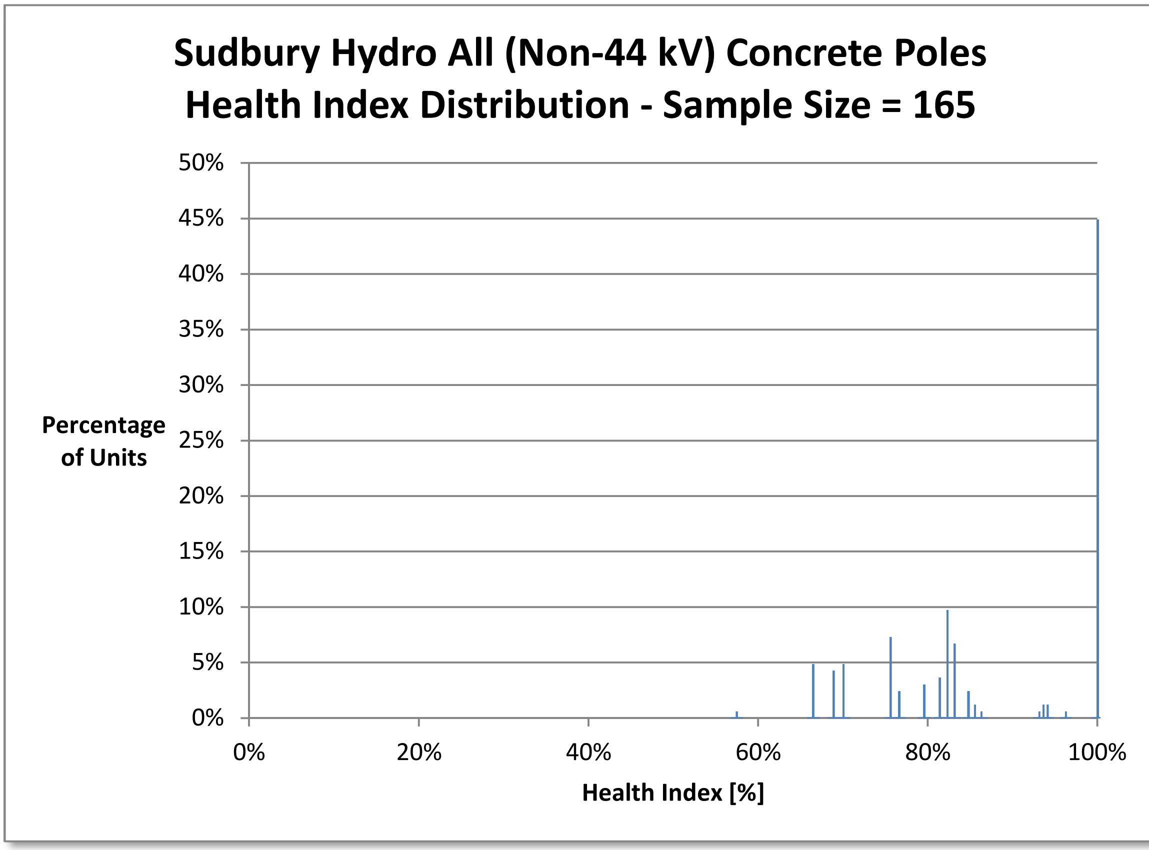


Figure 6-4 Sudbury Hydro Concrete Poles Health Index Distribution by Value (Percentage of Units)

6.5 Condition-Based Replacement Plan

Although Sudbury Hydro Concrete Poles are proactively replaced, the number of expected replacements per year is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. Because the expected replacements are fairly constant, levelization is not required.

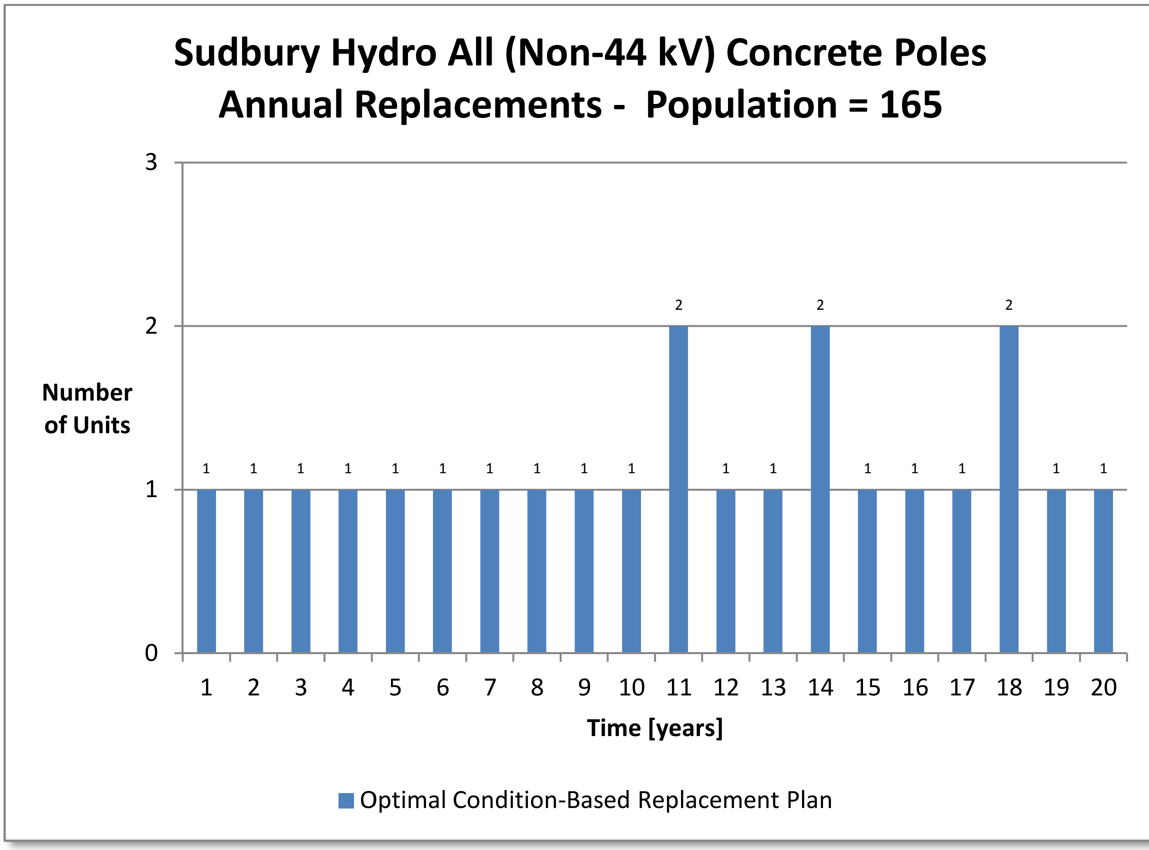


Figure 6-5 Sudbury Hydro Concrete Poles Optimal Condition-Based Replacement Plan

6.6 Data Analysis

The data available for Sudbury Hydro Concrete Poles includes age and inspections.

6.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Damage
- Lean

Assuming all inspection-based parameters are available, the average DAI for Sudbury Hydro Concrete Poles is 66%.

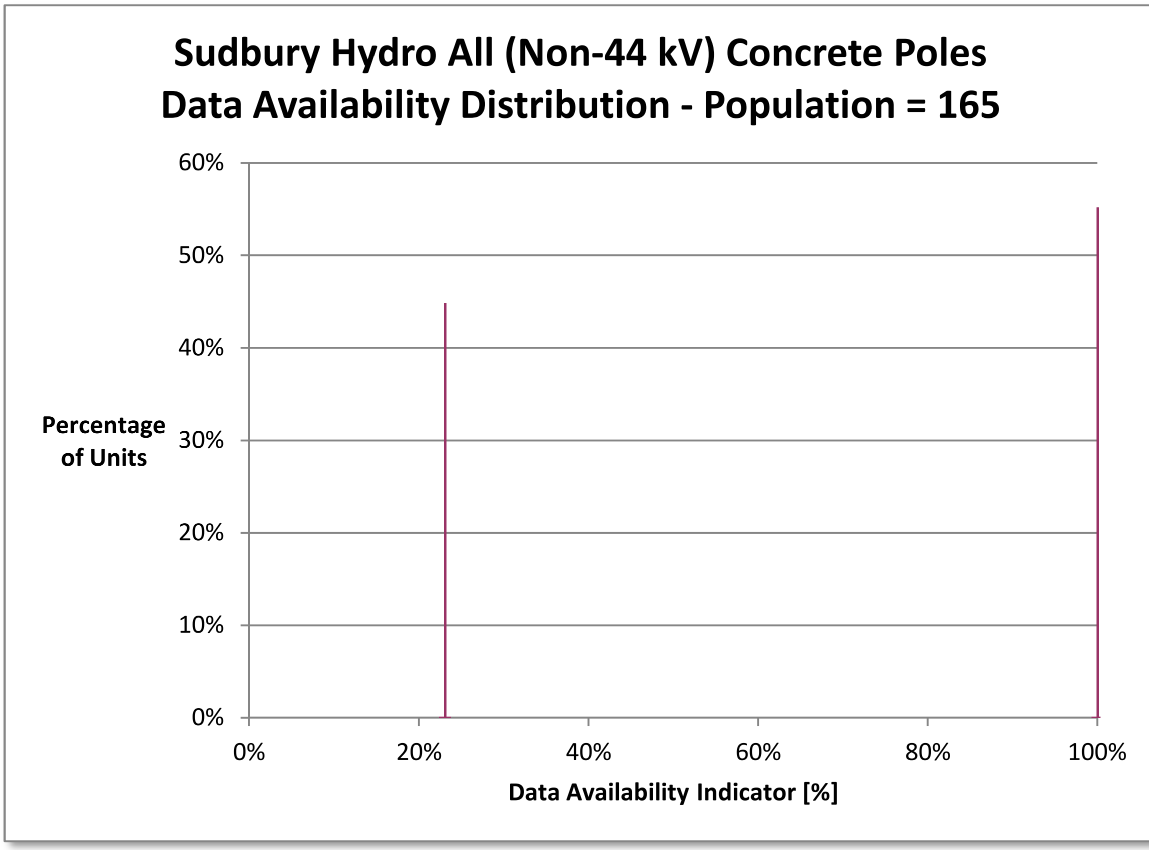


Figure 6-6 Sudbury Hydro Concrete Poles Data Availability Distribution

6.6.2 Data Gap

Please refer to Section 5.6.2.

7 Bell Wood Poles

The analysis for Bell Wood Poles is given in terms of “All”, “44 kV”, and “Non-44 kV” poles.

7.1 Degradation Mechanism

Please refer to Section 5.1.

7.2 Health Index Formulation

Please refer to Section 5.2.

7.3 Age Distribution

<u>All</u>

The age distribution is shown in the figure below. Age was available for 88% of the population. The average age was found to be 35 years.

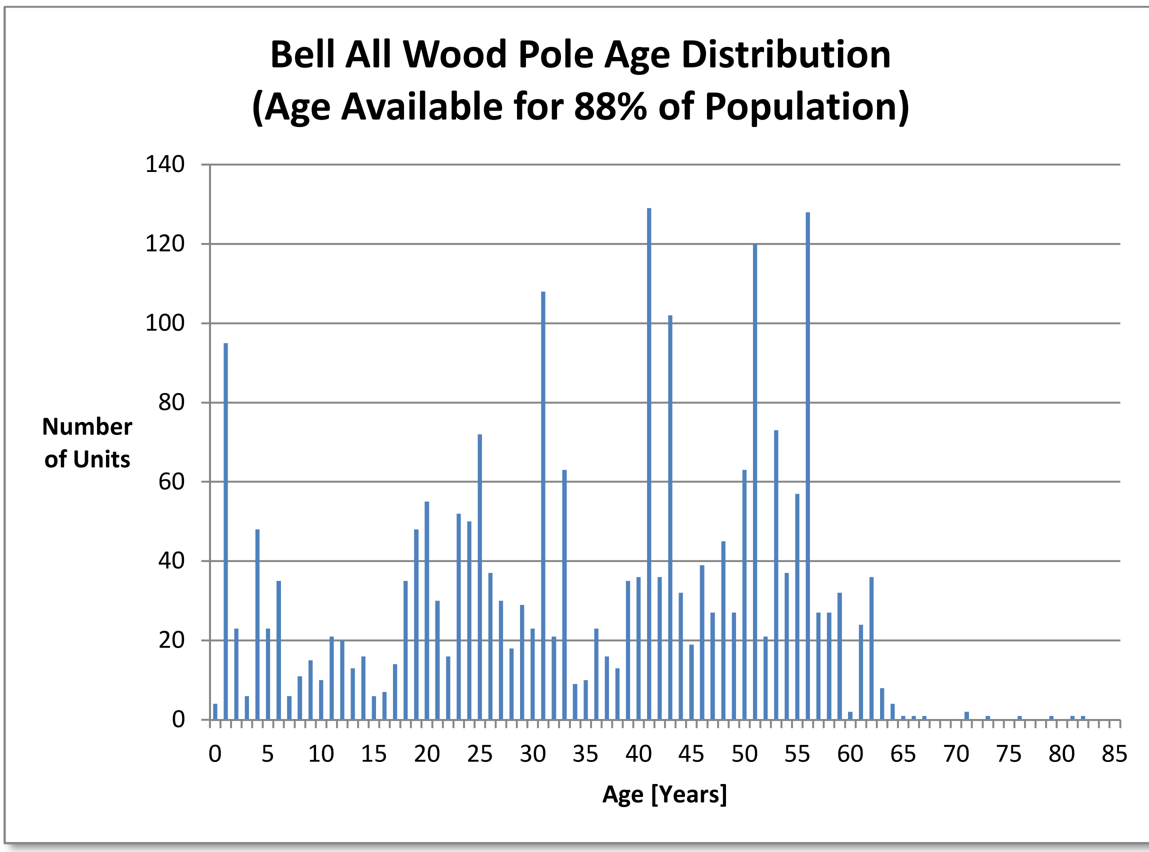


Figure 7-1 All Bell Wood Poles Age Distribution

<u>44 kV</u>

The age distribution is shown in the figure below. Age was available for 99% of the population. The average age was found to be 6 years.

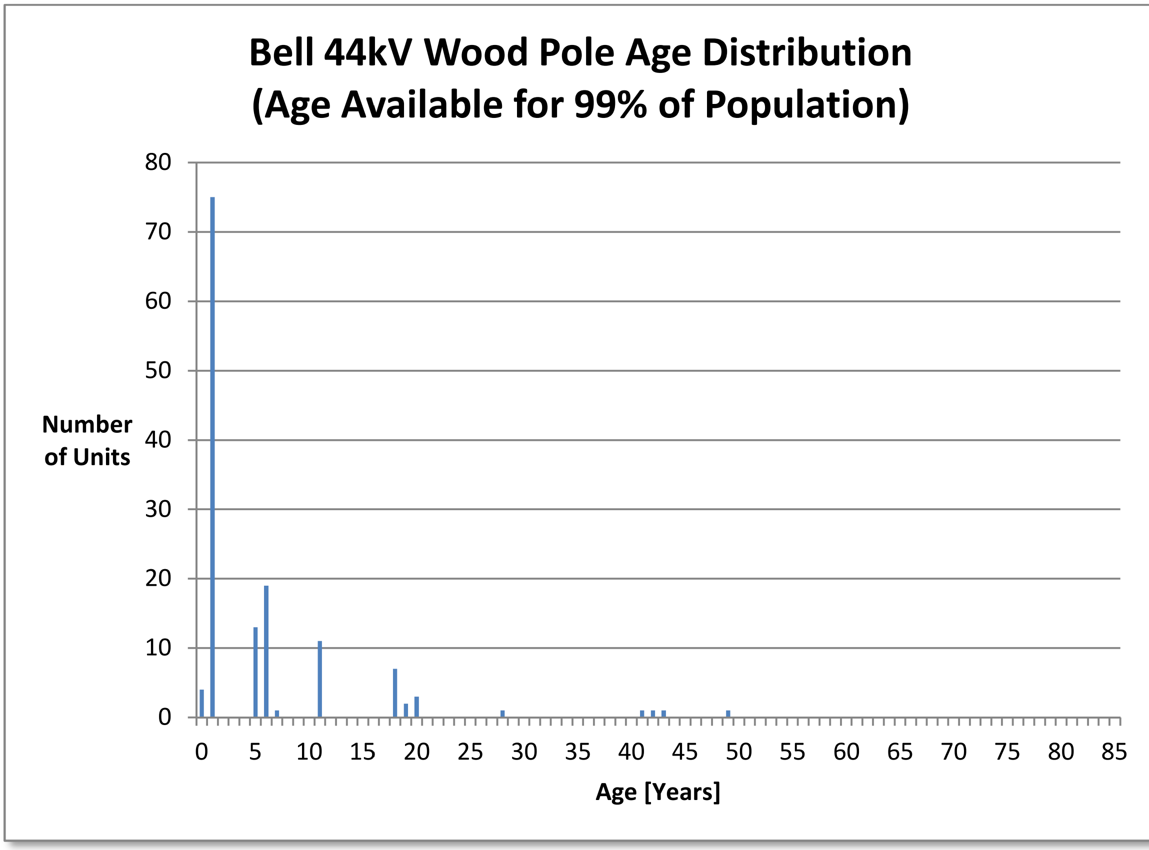


Figure 7-2 44 kV Bell Wood Poles Age Distribution

<u>Non-44 kV</u>

The age distribution is shown in the figure below. Age was available for 88% of the population. The average age was found to be 37 years.

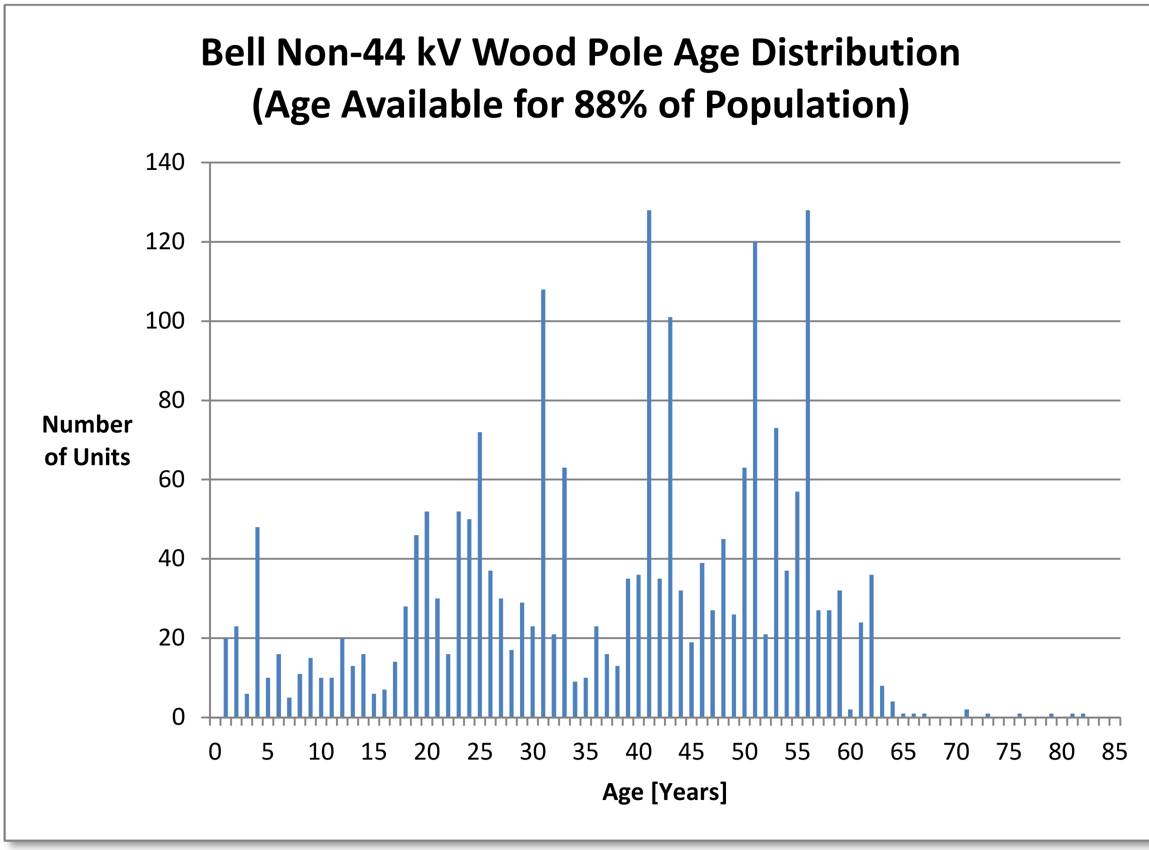


Figure 7-3 Non-44 kV Bell Wood Poles Age Distribution

7.4 Health Index Results

<u>All</u>

There are 2,639 in-service Bell Wood Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 2,639 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 65%. Approximately 31% of the units were found to be in poor condition.

The Health Index Results are as follows:

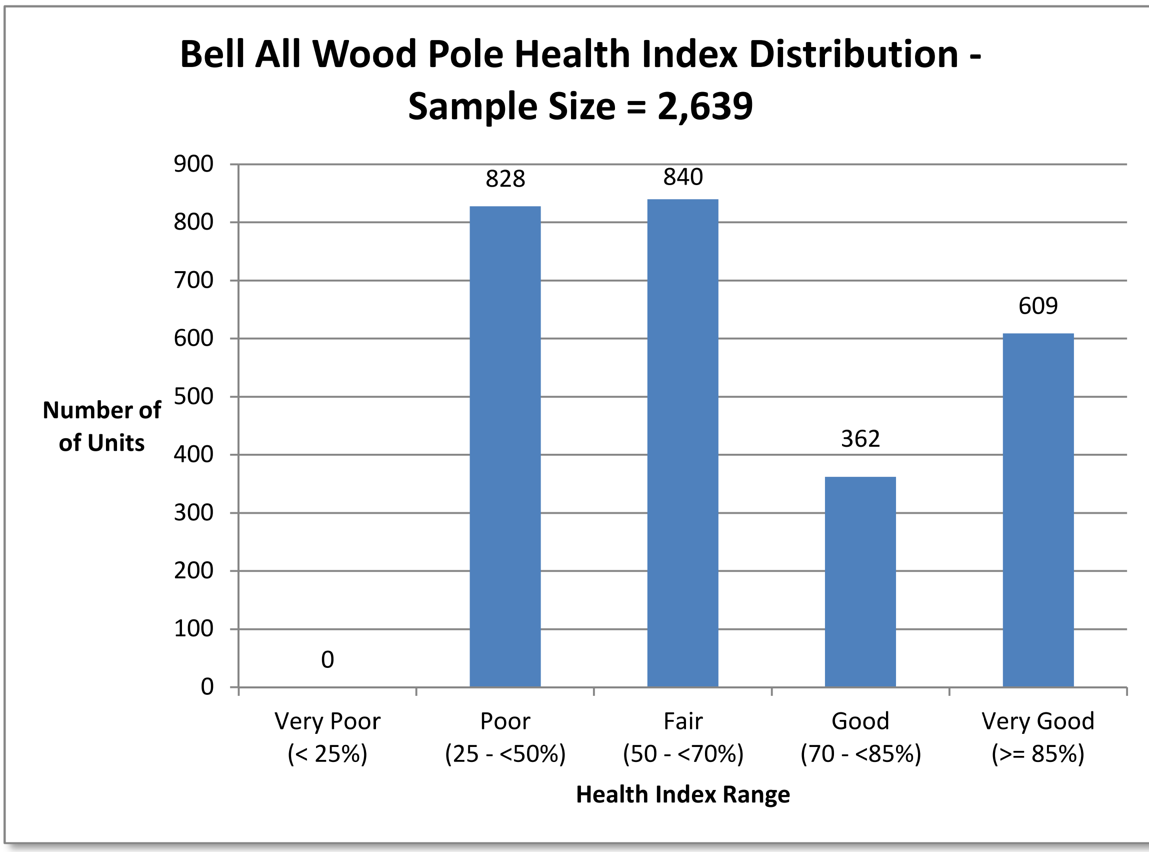


Figure 7-4 All Bell Wood Poles Health Index Distribution (Number of Units)

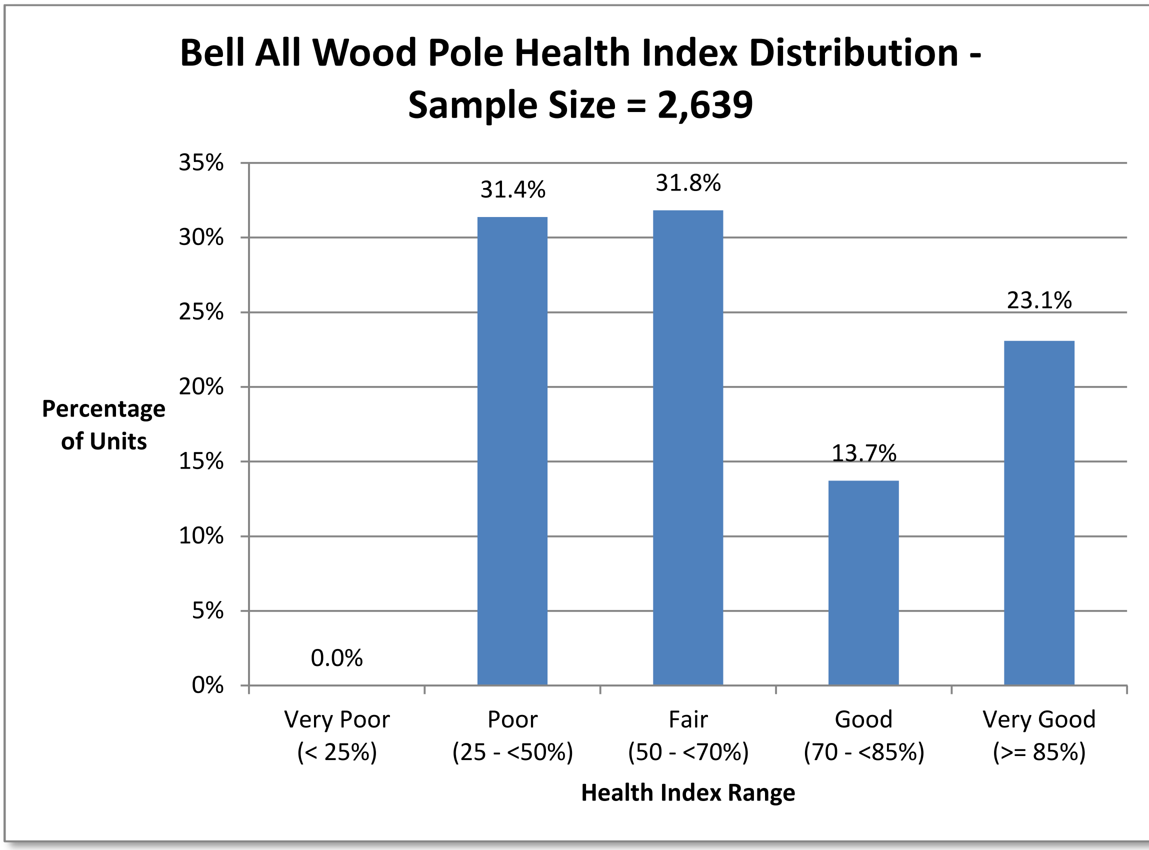


Figure 7-5 All Bell Wood Poles Health Index Distribution (Percentage of Units)

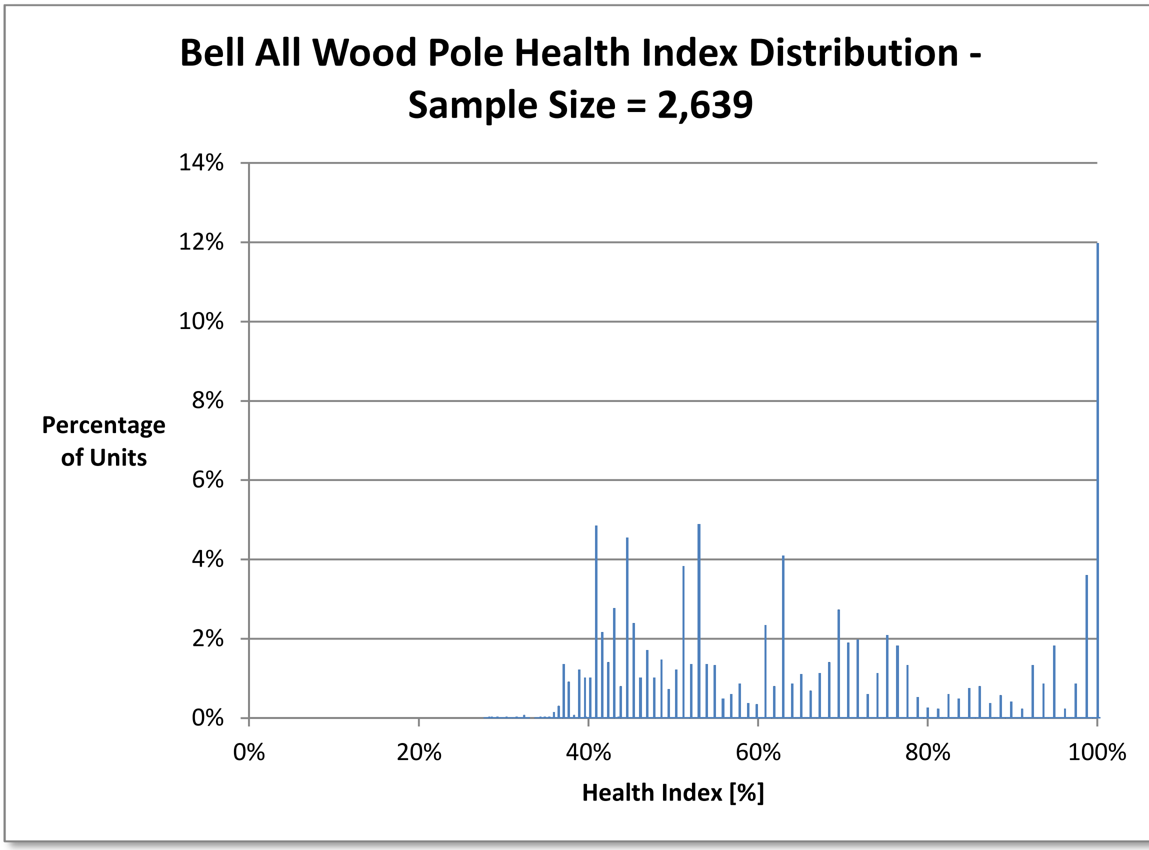


Figure 7-6 All Bell Wood Poles Health Index Distribution by Value (Percentage of Units)

<u>44 kV</u>

There are 141 in-service 44 kV Bell Wood Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 141 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 93%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

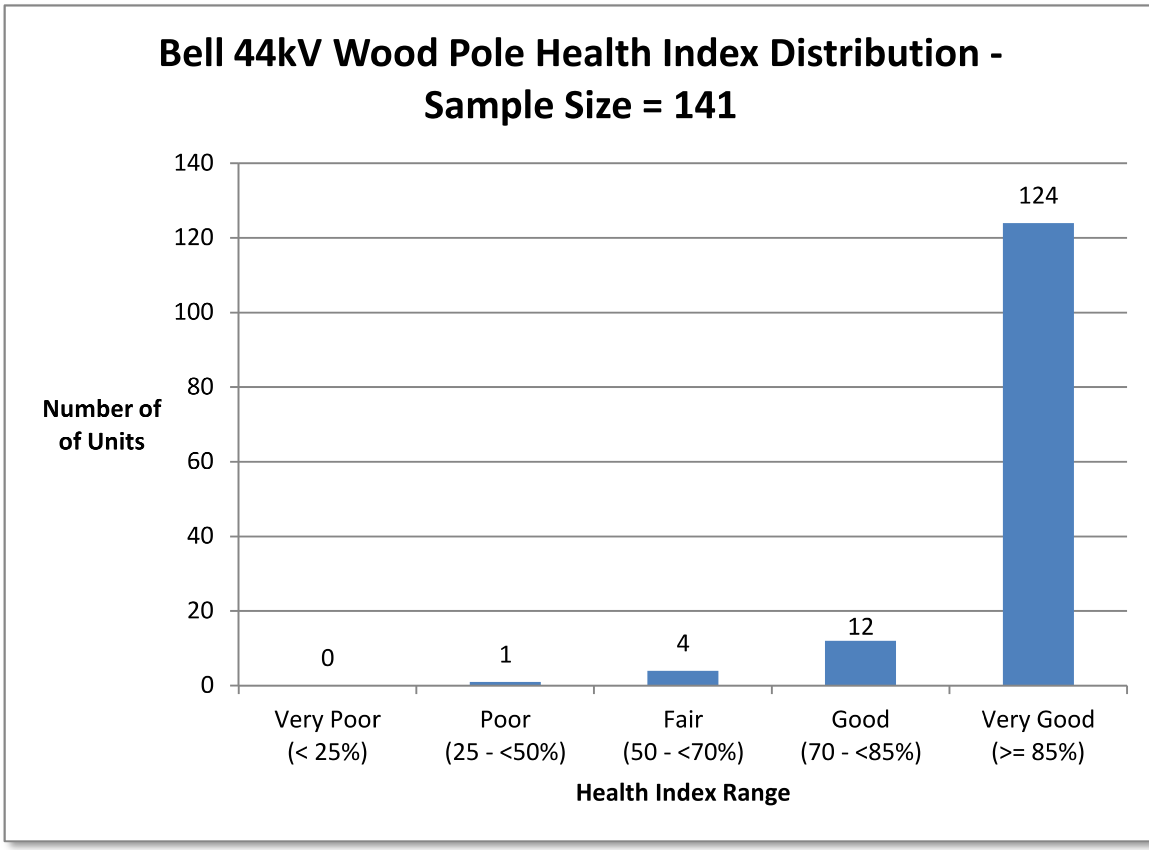


Figure 7-7 44 kV Bell Wood Poles Health Index Distribution (Number of Units)

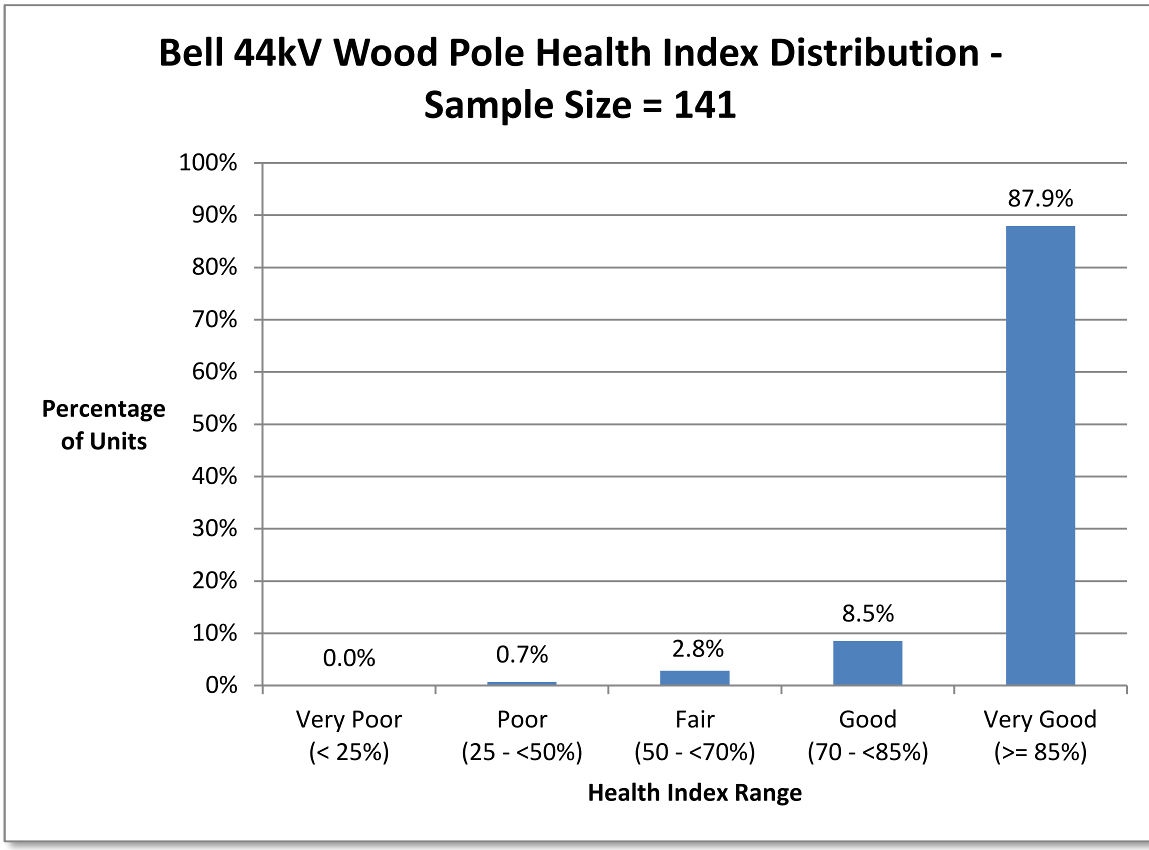


Figure 7-8 44 kV Bell Wood Poles Health Index Distribution (Percentage of Units)

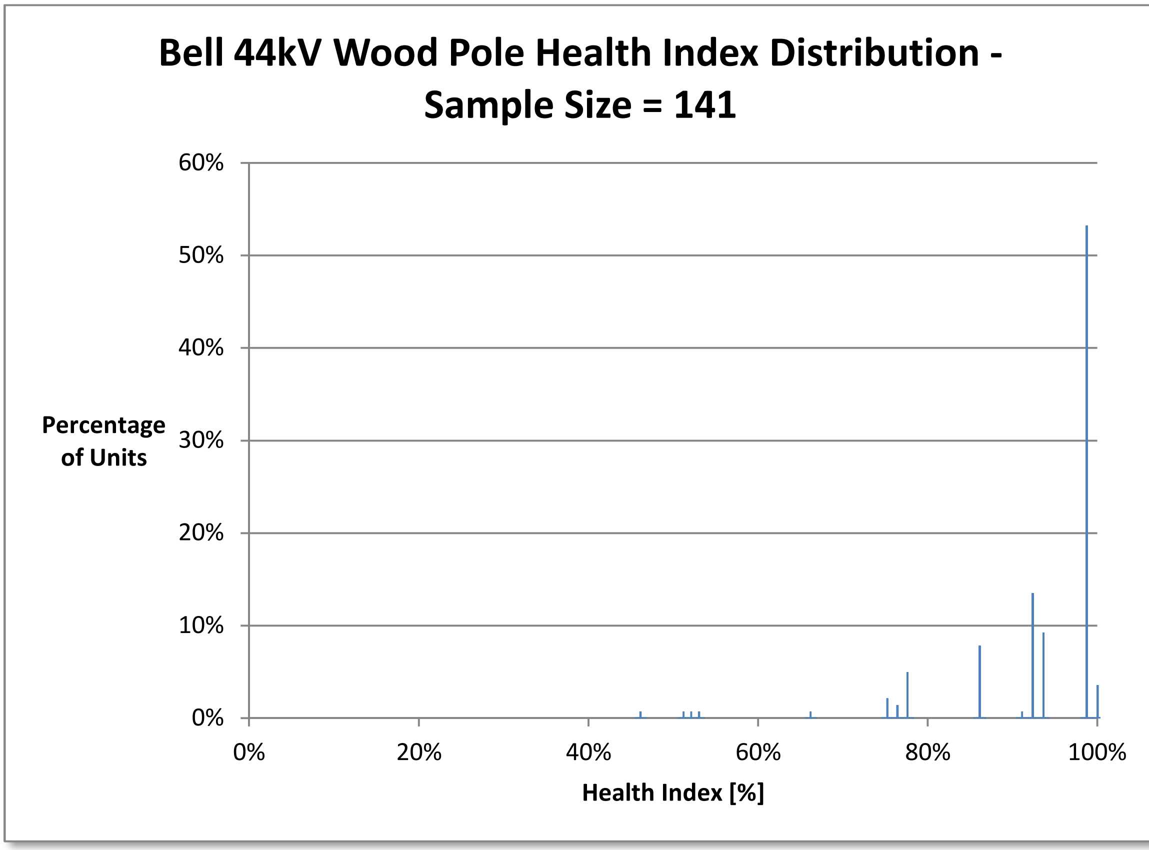


Figure 7-9 44 kV Bell Wood Poles Health Index Distribution by Value (Percentage of Units)

Non-44 kV

There are 2,498 in service Non-44 kV Bell Wood Poles. It is assumed that all units have, been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 2,498 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 63%. Approximately 33% of the units were found to be in poor condition.

The Health Index Results are as follows:

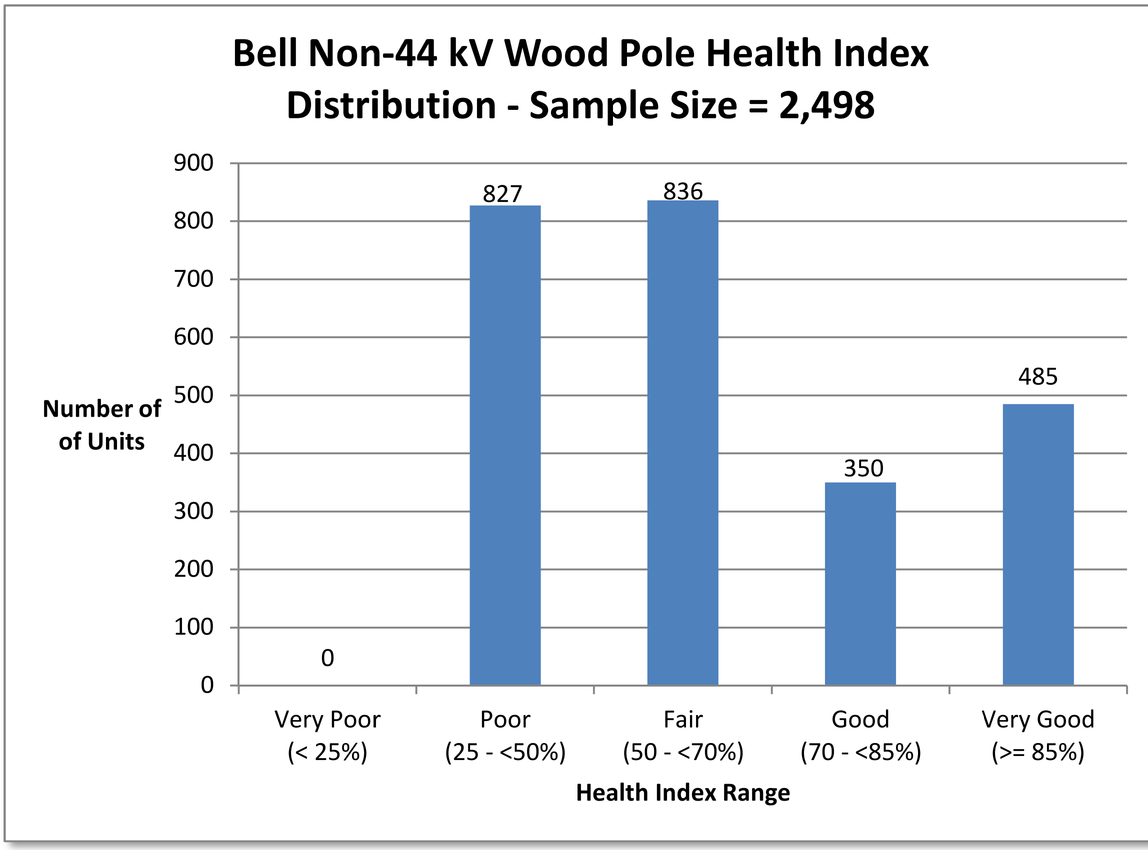


Figure 7-10 Non-44 kV Bell Wood Poles Health Index Distribution (Number of Units)

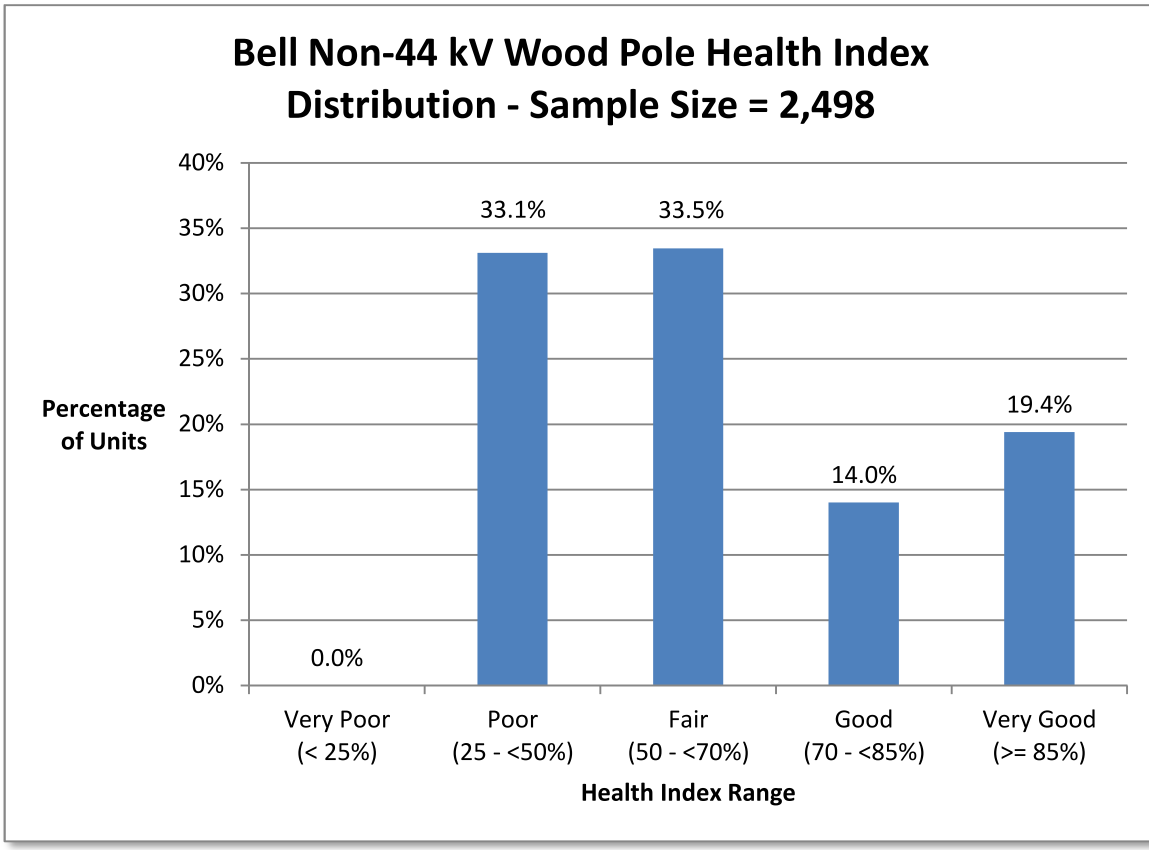


Figure 7-11 Non-44 kV Bell Wood Poles Health Index Distribution (Percentage of Units)

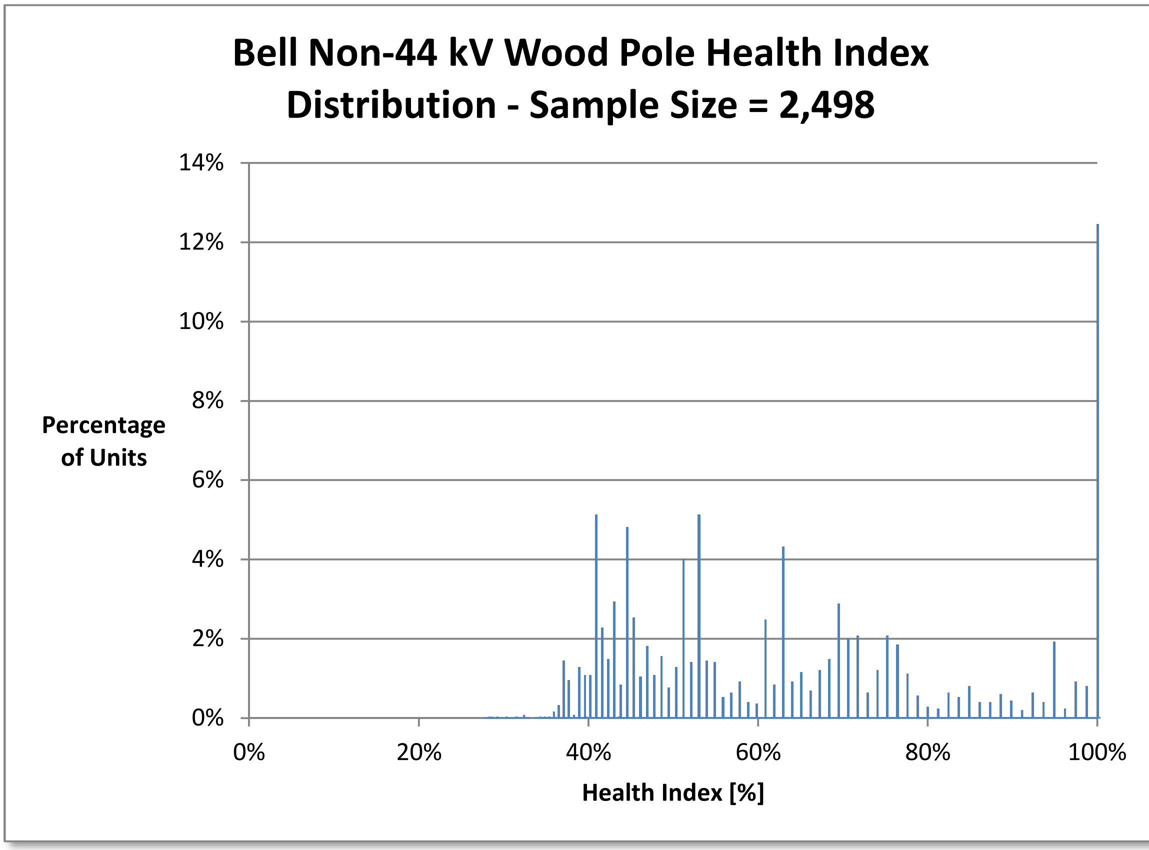


Figure 7-12 Non-44 kV Bell Wood Poles Health Index Distribution by Value (Percentage of Units)

7.5 Condition-Based Replacement Plan

Although Bell Wood Poles are proactively replaced, the number of expected replacements per year is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is also given.

<u>All</u>

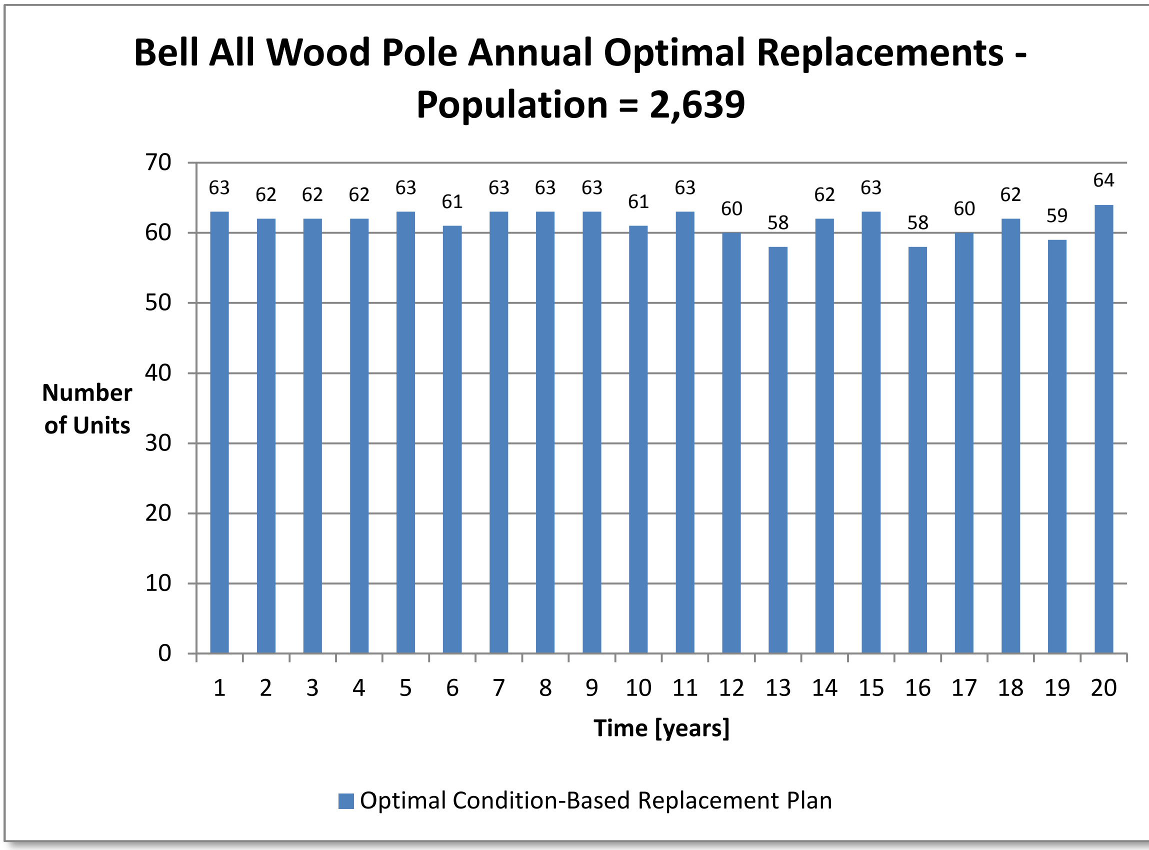


Figure 7-13 All Bell Wood Poles Optimal Condition-Based Replacement Plan

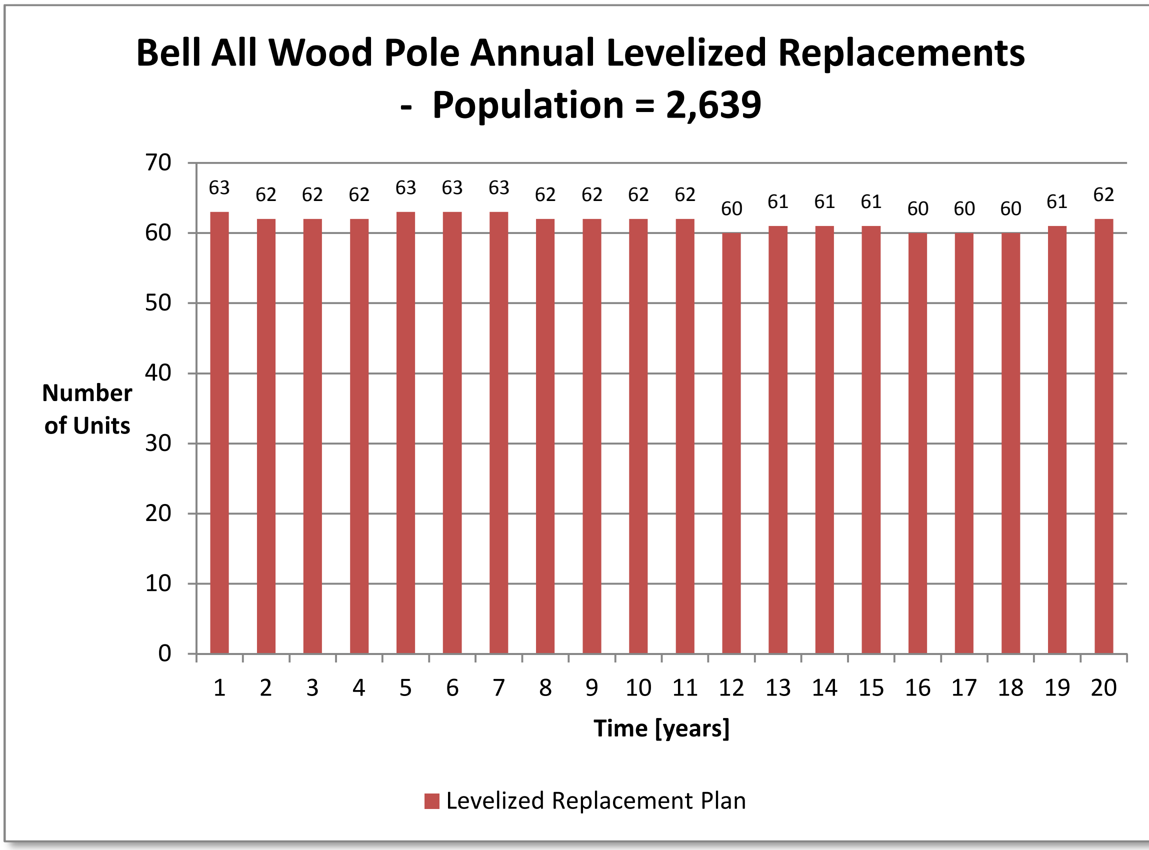


Figure 7-14 All Bell Wood Poles Levelized Replacement Plan

44 kV

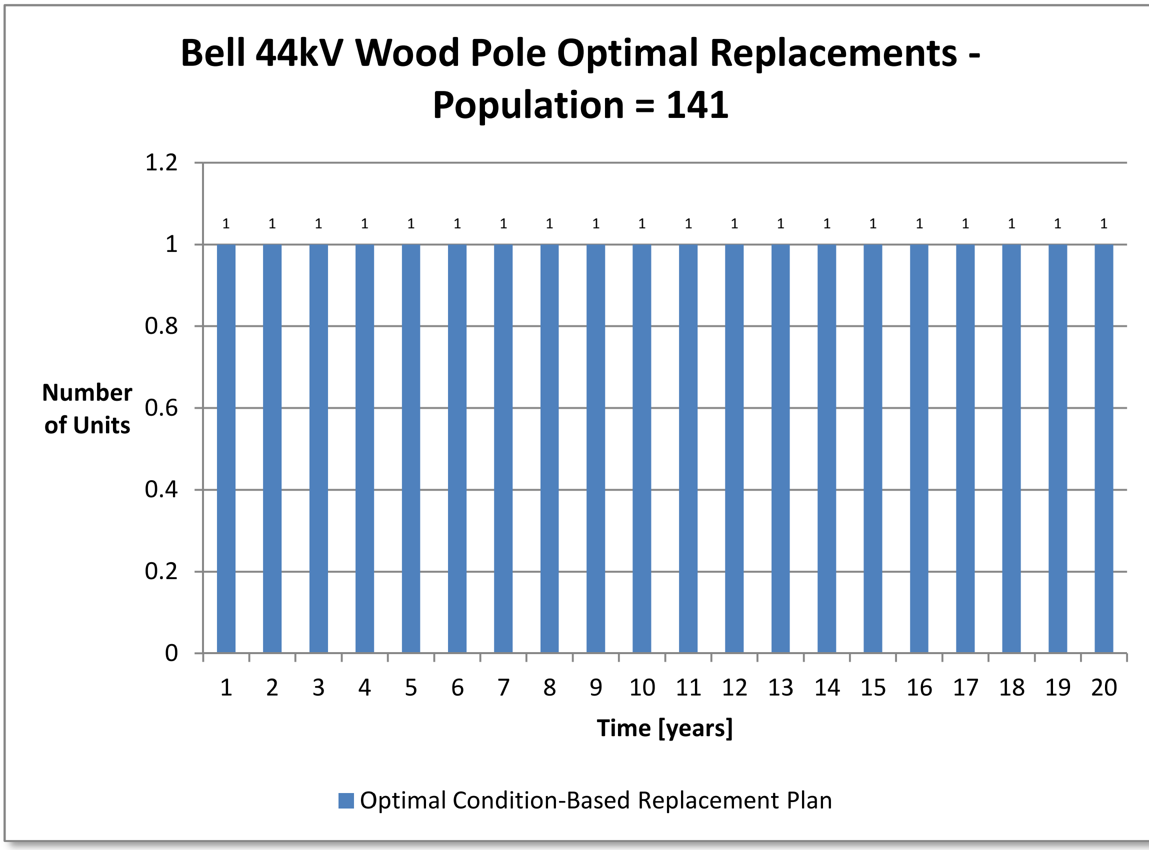


Figure 7-15 44 kV Bell Wood Poles Optimal Condition-Based Replacement Plan

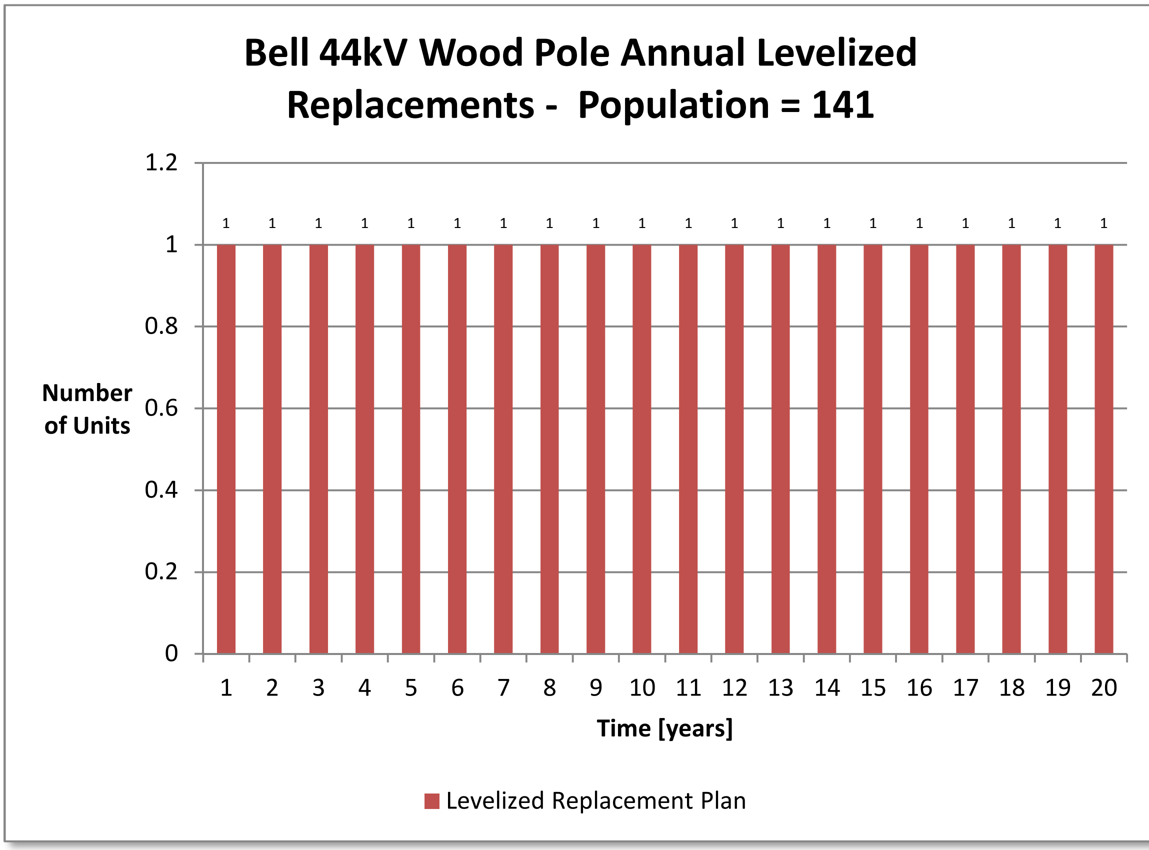


Figure 7-16 44 kV Bell Wood Poles Levelized Replacement Plan

Non-44 kV

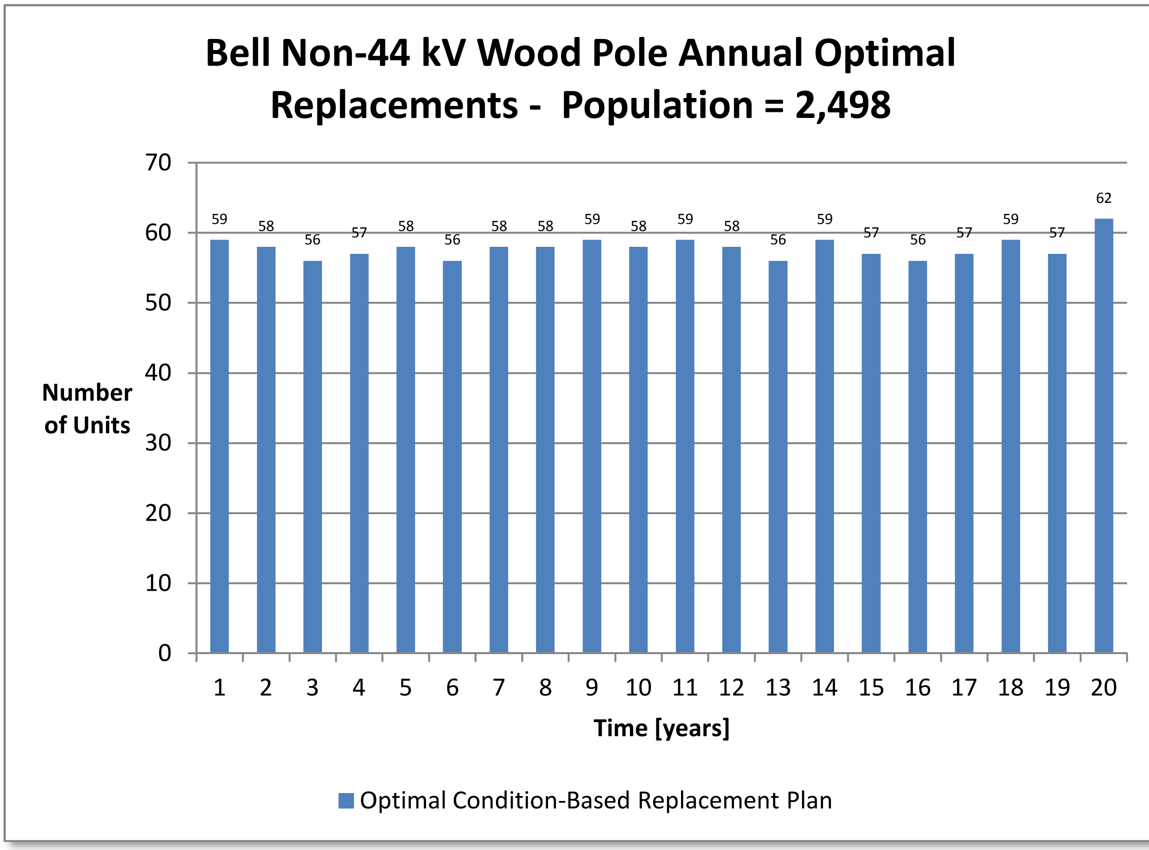


Figure 7-17 Non-44 kV Bell Wood Poles Optimal Condition-Based Replacement Plan

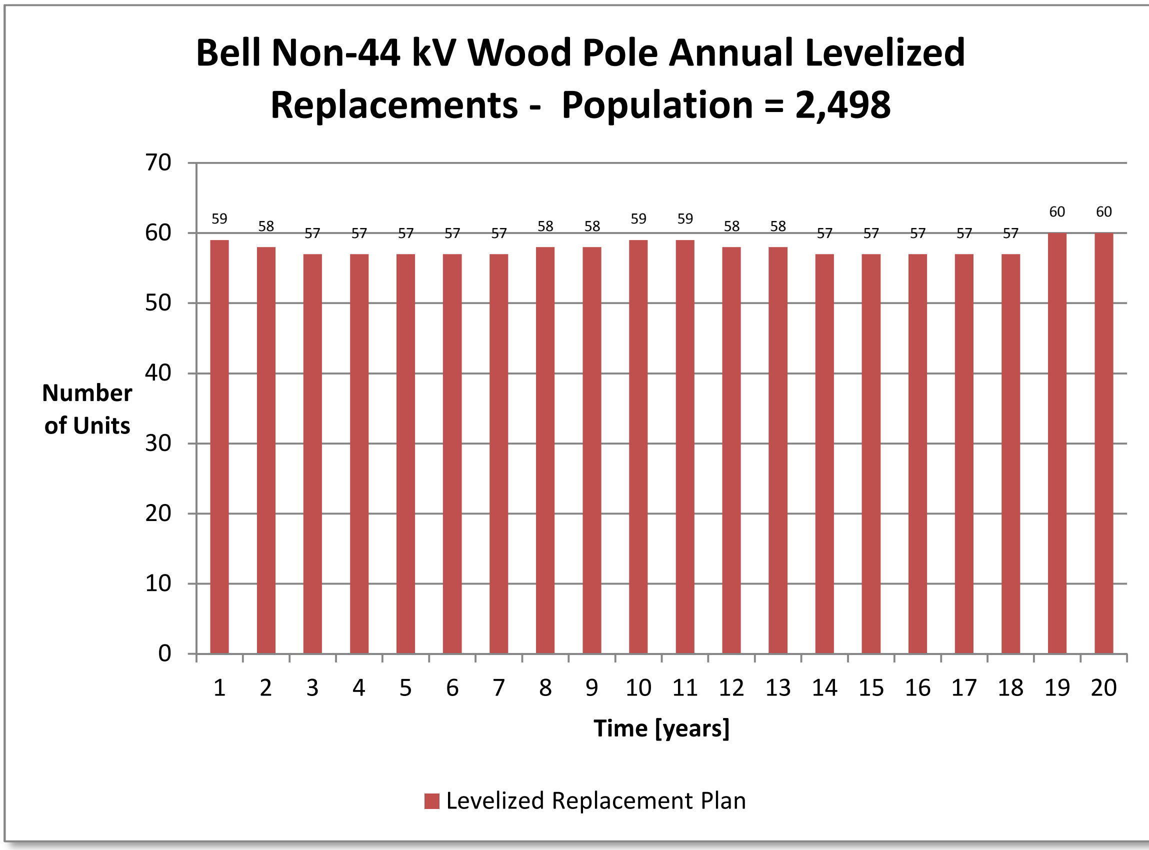


Figure 7-18 Non-44 kV Bell Wood Poles Levelized Replacement Plan

7.6 Data Analysis

The data available for Bell Wood Poles includes age and inspections.

7.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Damage
- Lean

<u>All</u>

Assuming all inspection-based parameters are available, the average DAI for All Bell Wood Poles is 91%.

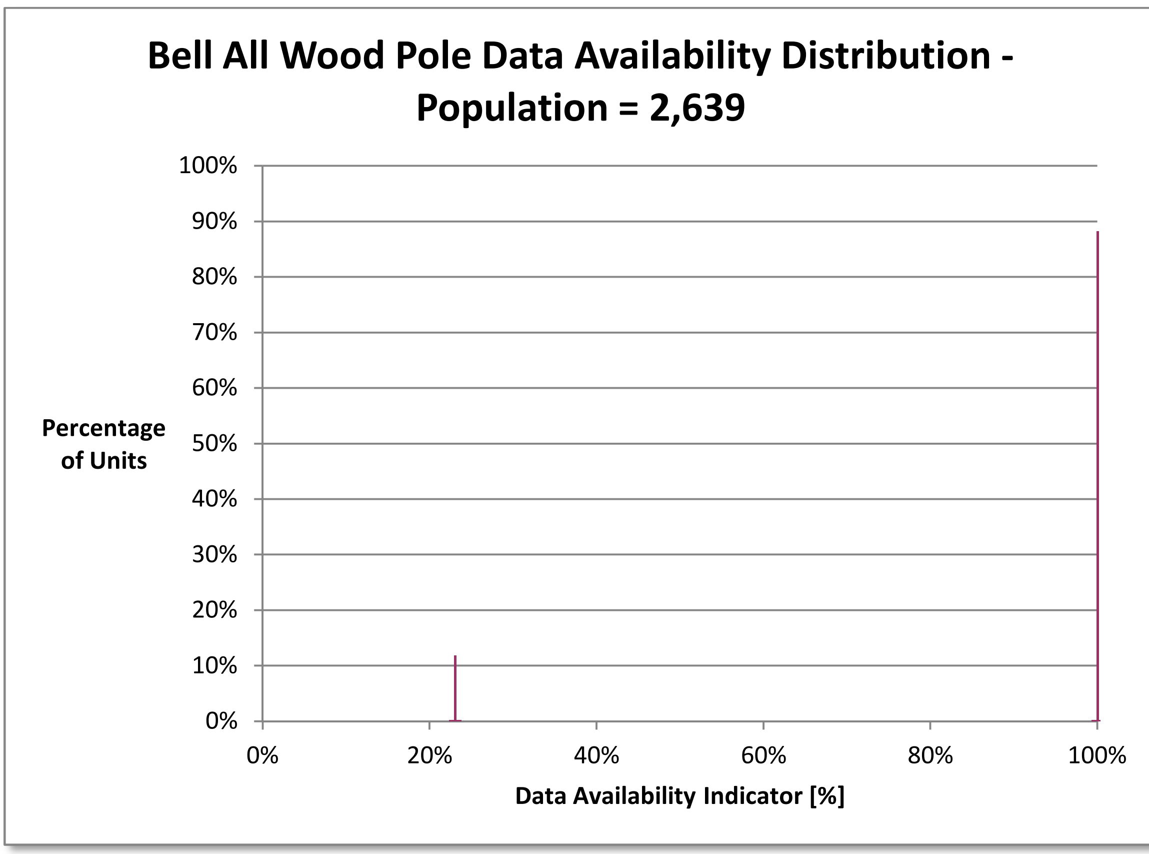


Figure 7-19 All Bell Wood Poles Data Availability Distribution

<u>44 kV</u>

Assuming all inspection-based parameters are available, the average DAI for 44 kV Bell Wood Poles is 99%.

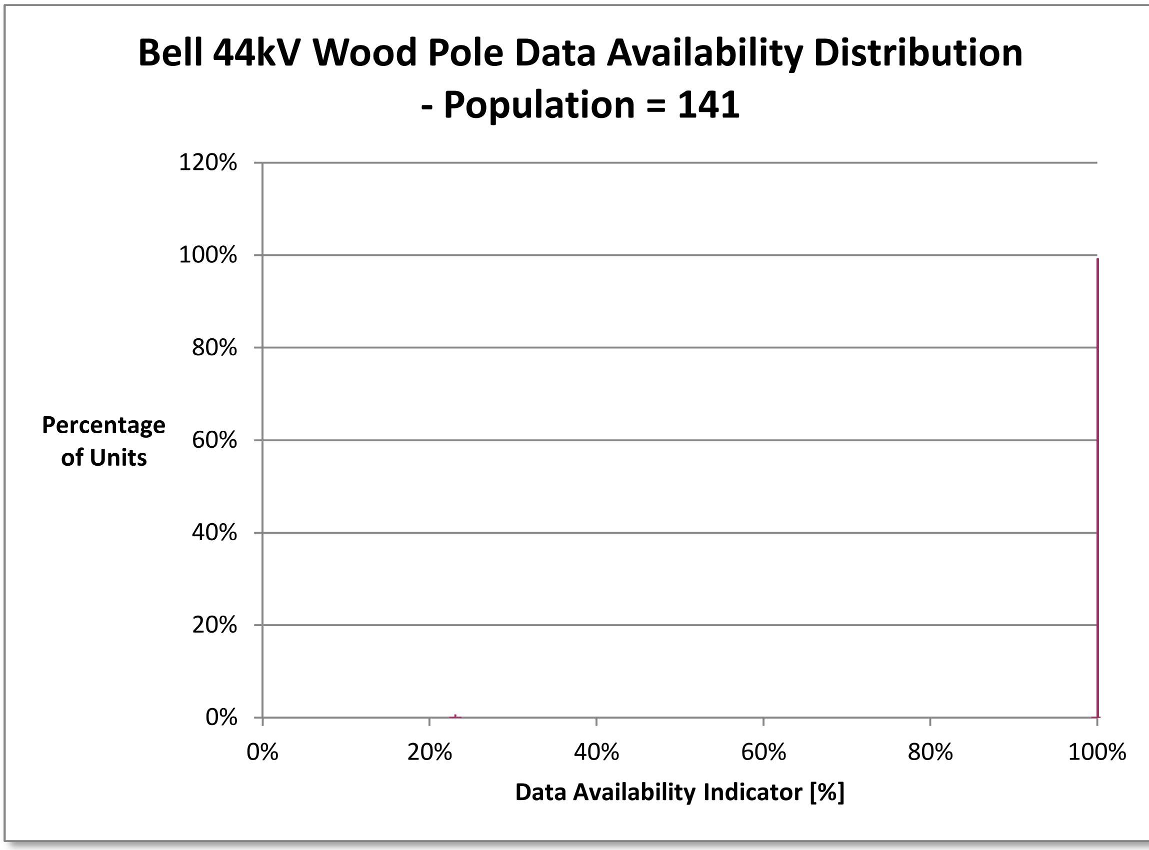


Figure 7-20 44 kV Bell Wood Poles Data Availability Distribution

Non-44 kV

Assuming all inspection-based parameters are available, the average DAI for Non-44 kV Bell Wood Poles is 90%.

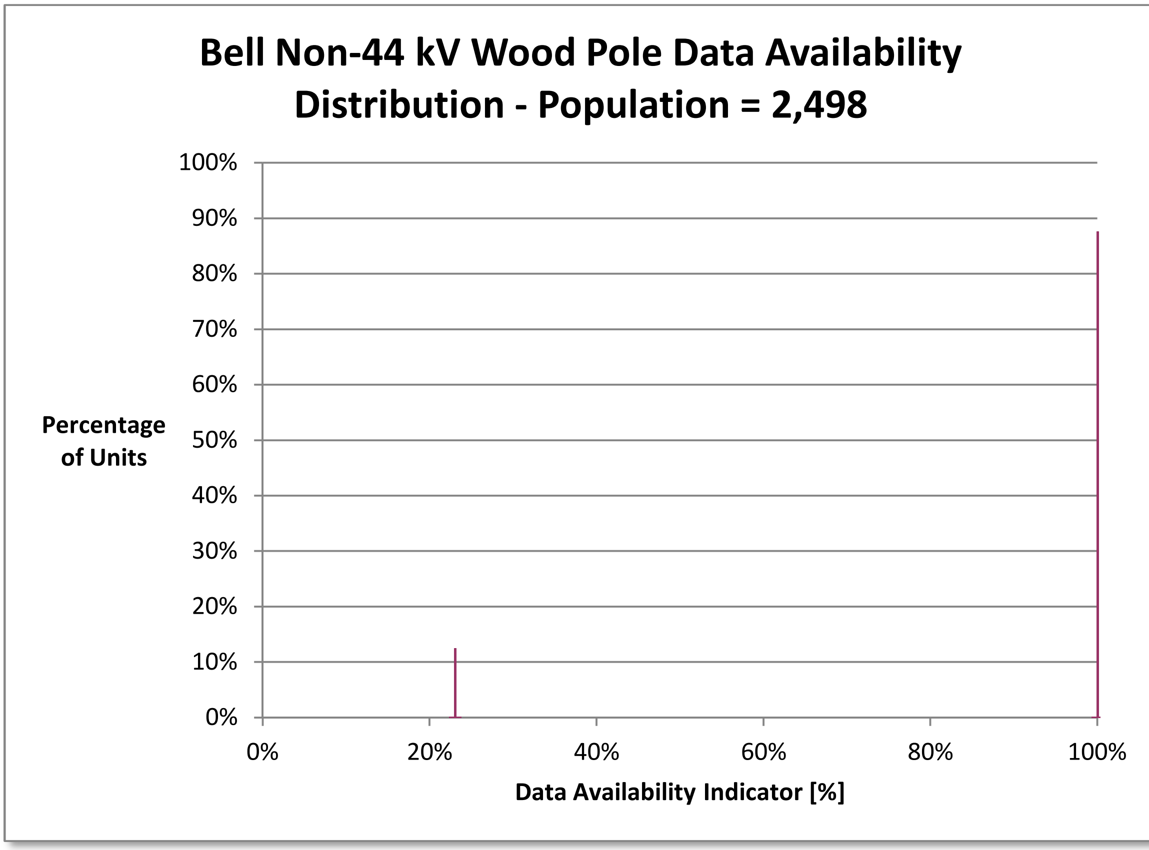


Figure 7-21 Non-44 kV Bell Wood Poles Data Availability Distribution

7.6.2 Data Gap

Please refer to Section 5.6.2.

This page is intentionally left blank.

8 Hydro One Wood Poles

The analysis for Hydro One Wood Poles is given in terms of "All", "44 kV", and "Non-44 kV" poles.

8.1 Degradation Mechanism

Please refer to Section 5.1.

8.2 Health Index Formulation

Please refer to Section 5.2.

8.3 Age Distribution

<u>All</u>

The age distribution is shown in the figure below. Age was available for 76% of the population. The average age was found to be 38 years.

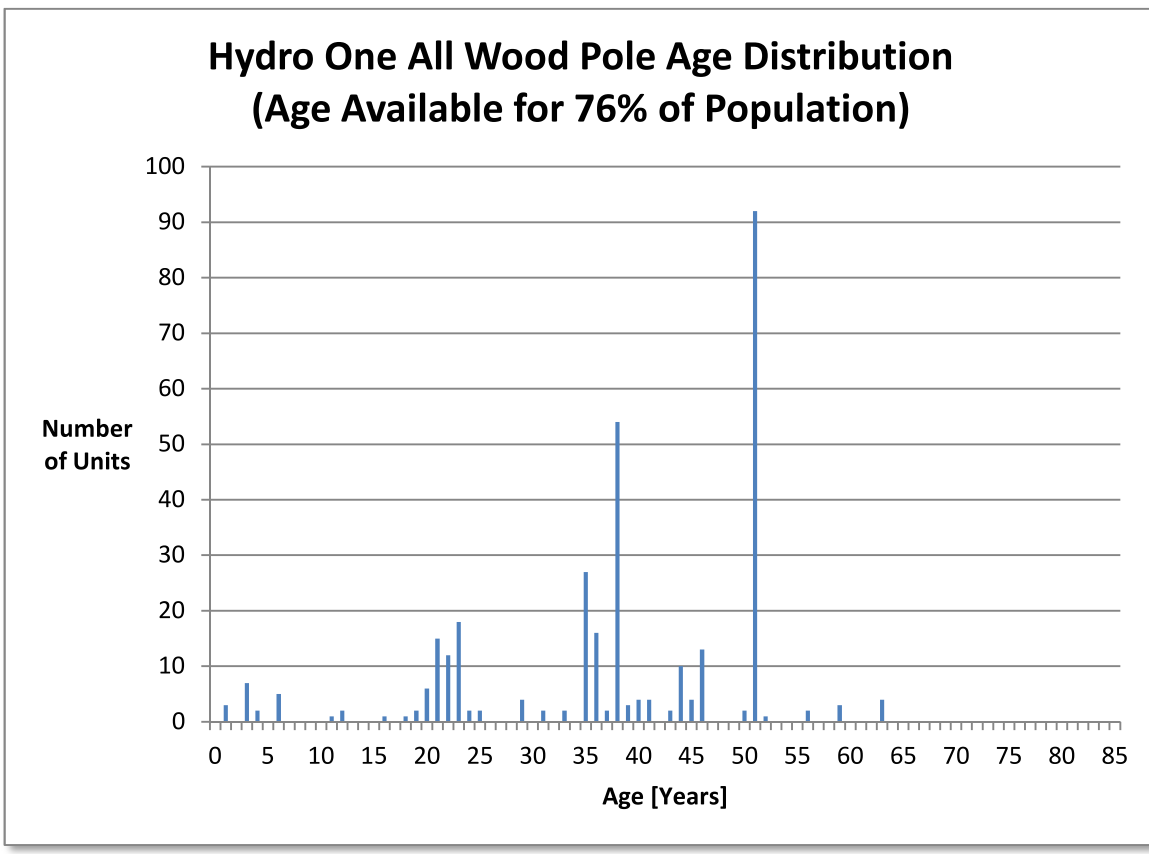


Figure 8-1 All Hydro One Wood Poles Age Distribution

<u>44 kV</u>

The age distribution is shown in the figure below. Age was available for 91% of the population. The average age was found to be 38 years.

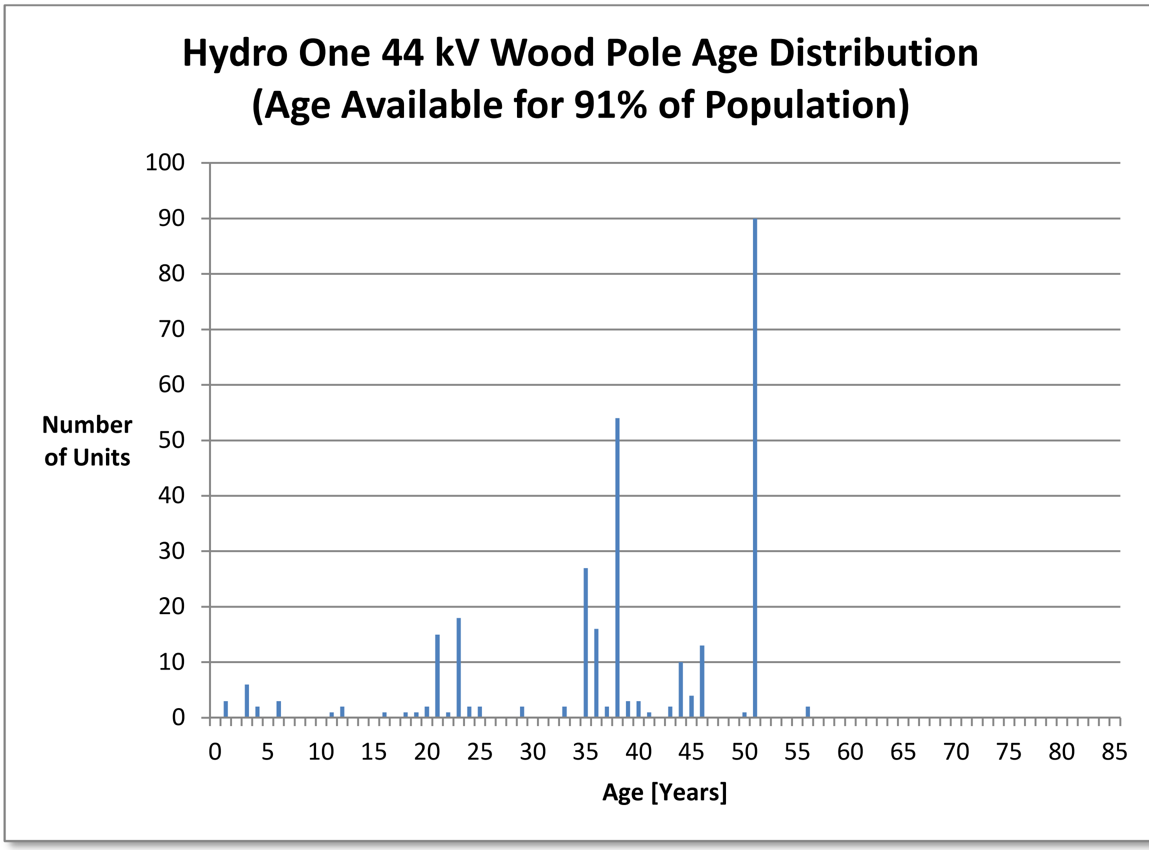


Figure 8-2 44 kV Hydro One Wood Poles Age Distribution

<u>Non-44 kV</u>

The age distribution is shown in the figure below. Age was available for 33% of the population. The average age was found to be 33 years.

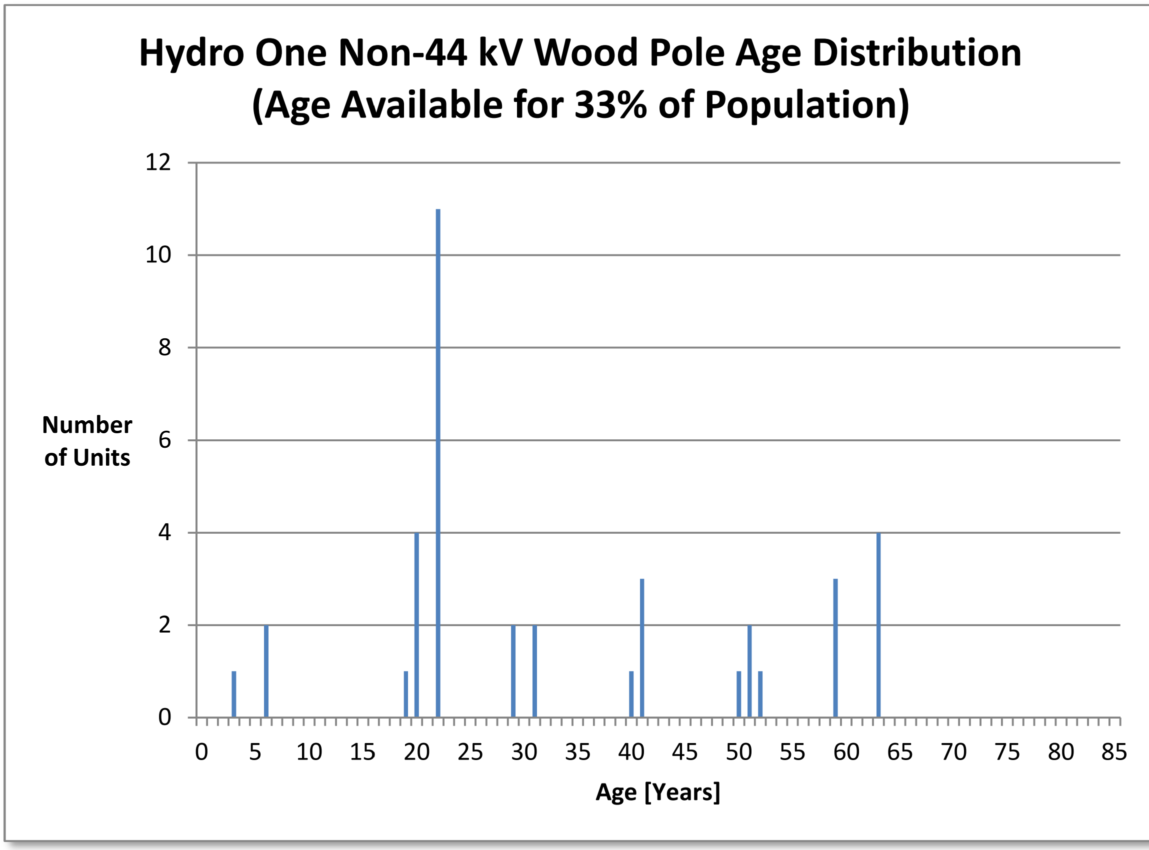


Figure 8-3 Non-44 kV Hydro One Wood Poles Age Distribution

8.4 Health Index Results

All

There are 436 in-service Hydro One Wood Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 436 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 67%. Approximately 28% of the units were found to be in poor condition.

The Health Index Results are as follows:

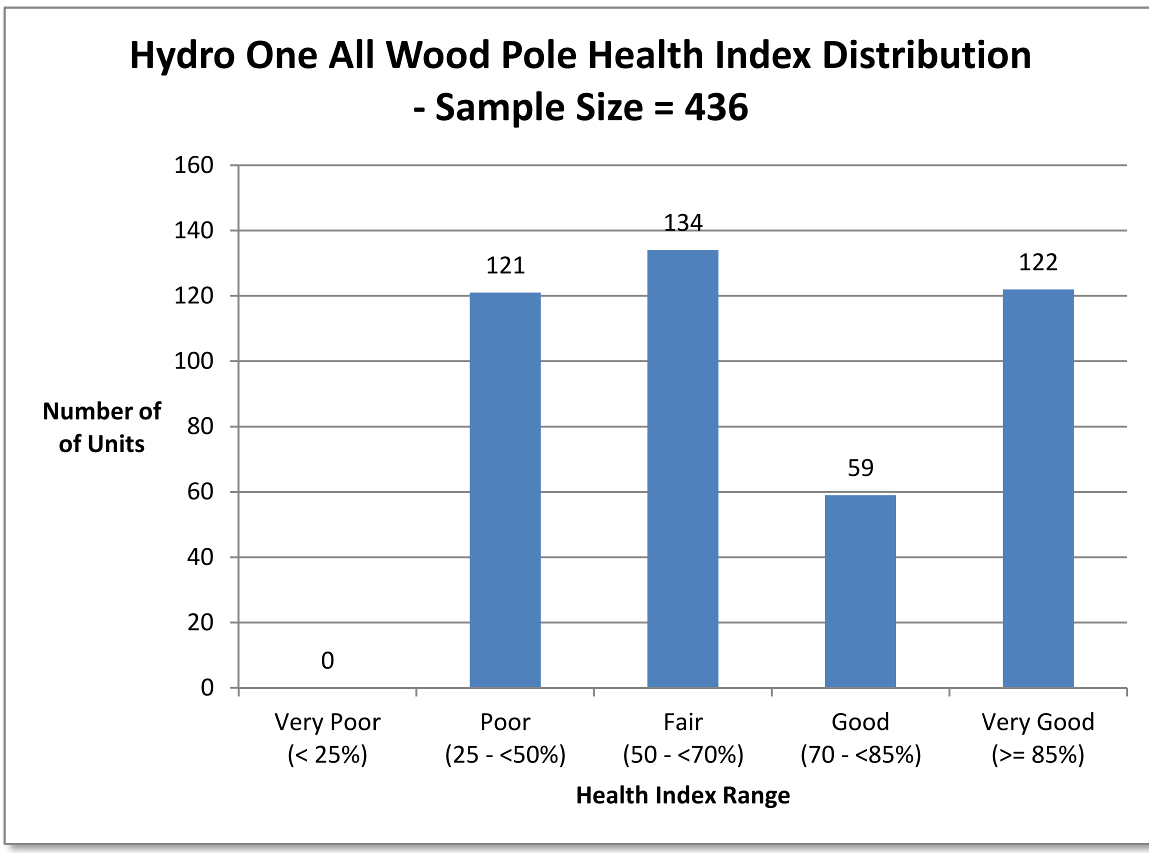


Figure 8-4 All Hydro One Wood Poles Health Index Distribution (Number of Units)

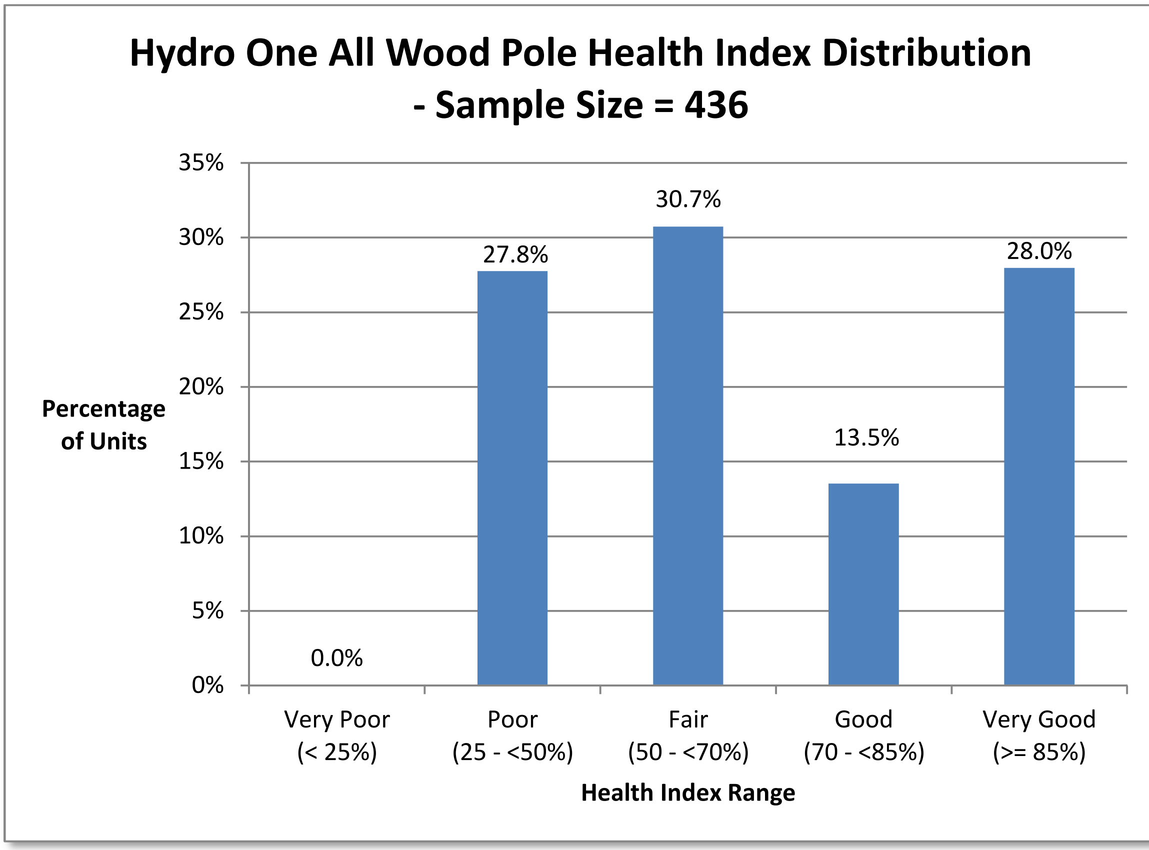


Figure 8-5 All Hydro One Wood Poles Health Index Distribution (Percentage of Units)

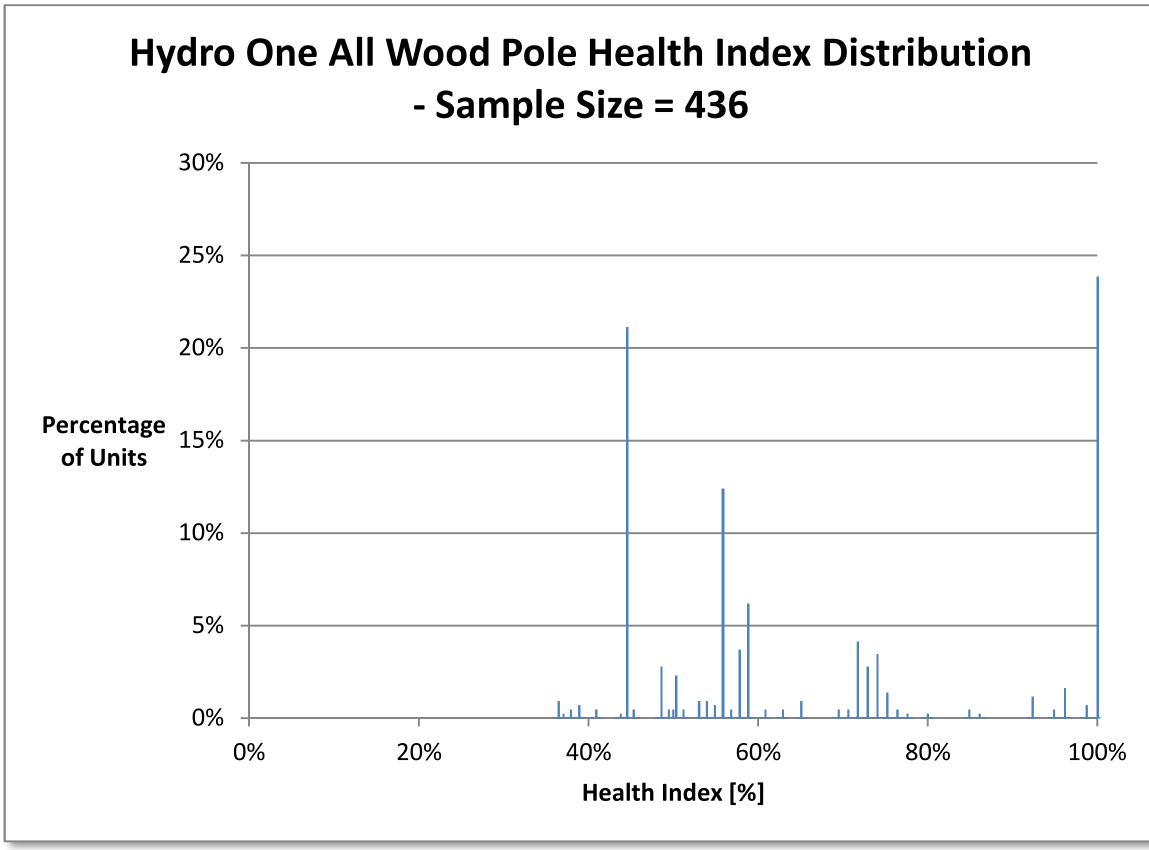


Figure 8-6 All Hydro One Wood Poles Health Index Distribution by Value (Percentage of Units)

<u>44 kV</u>

There are 320 in-service 44 kV Hydro One Wood Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 320 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 60%. Approximately 34% of the units were found to be in poor condition.

The Health Index Results are as follows:

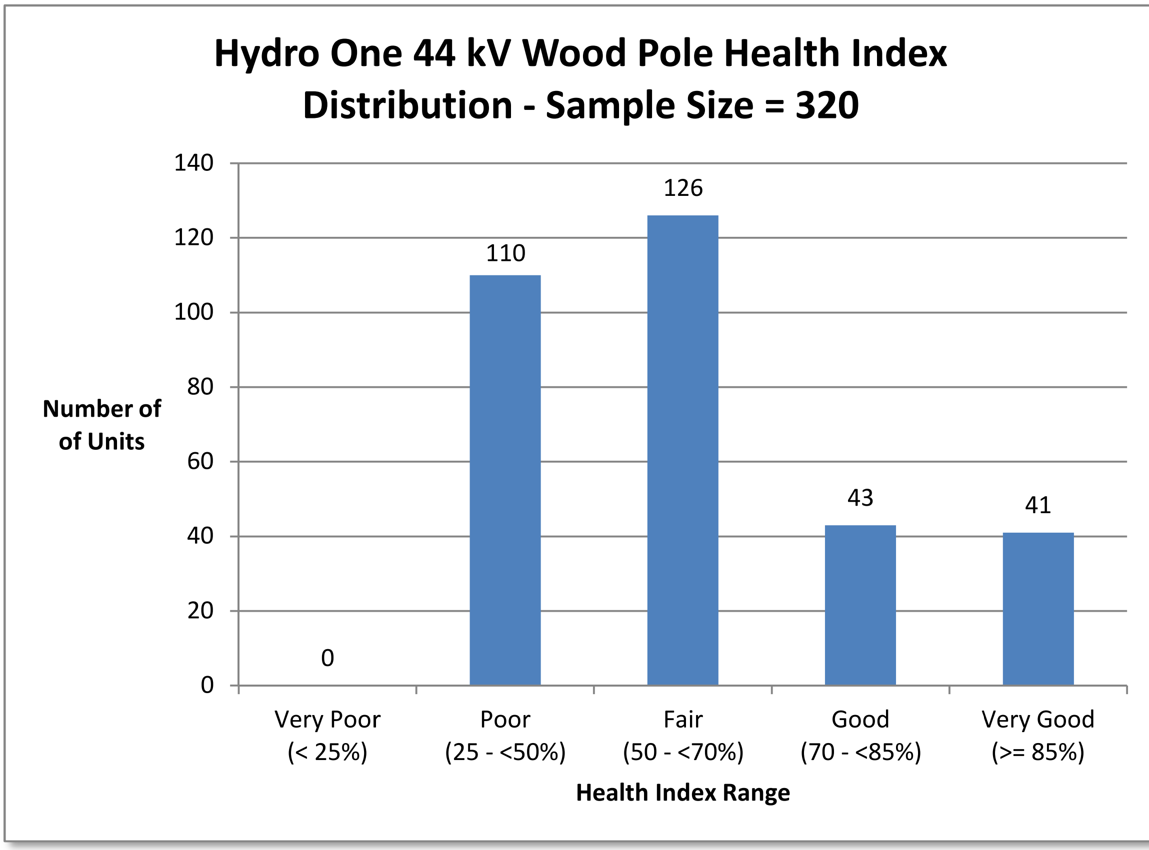


Figure 8-7 44 kV Hydro One Wood Poles Health Index Distribution (Number of Units)

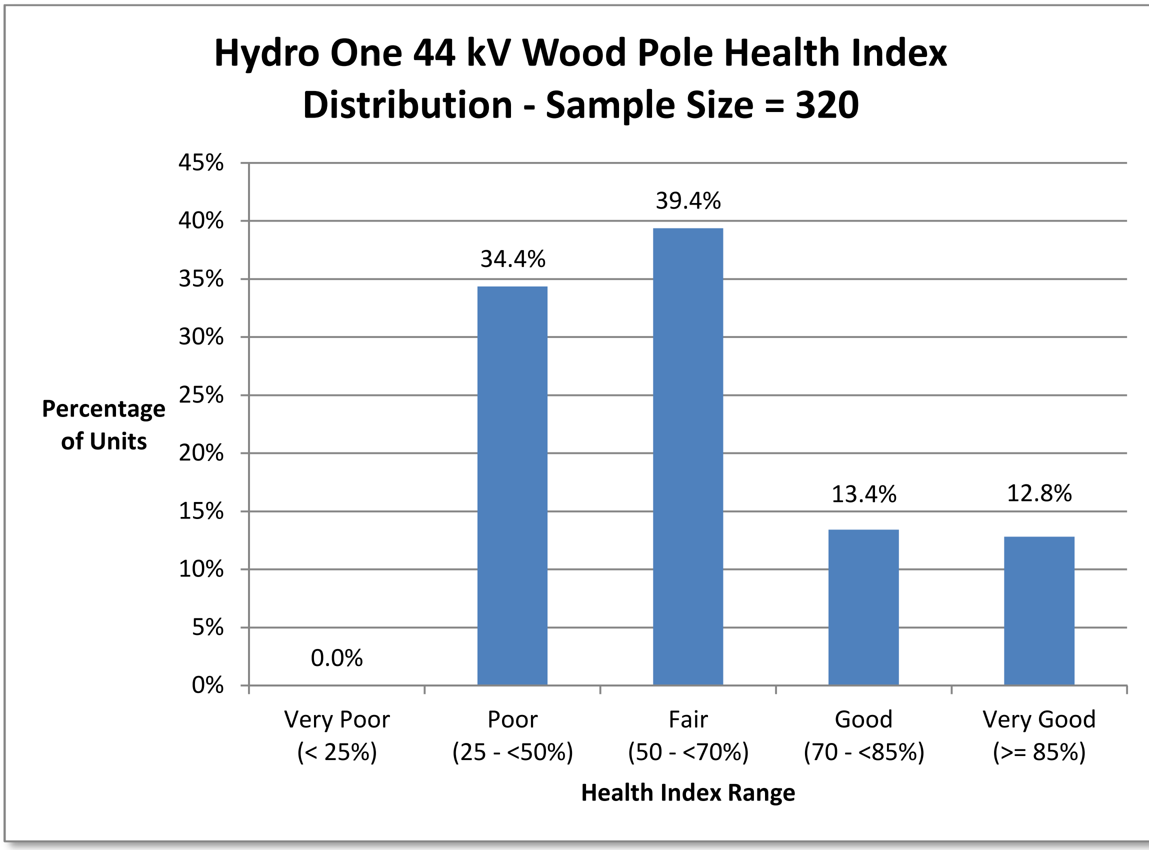


Figure 8-8 44 kV Hydro One Wood Poles Health Index Distribution (Percentage of Units)

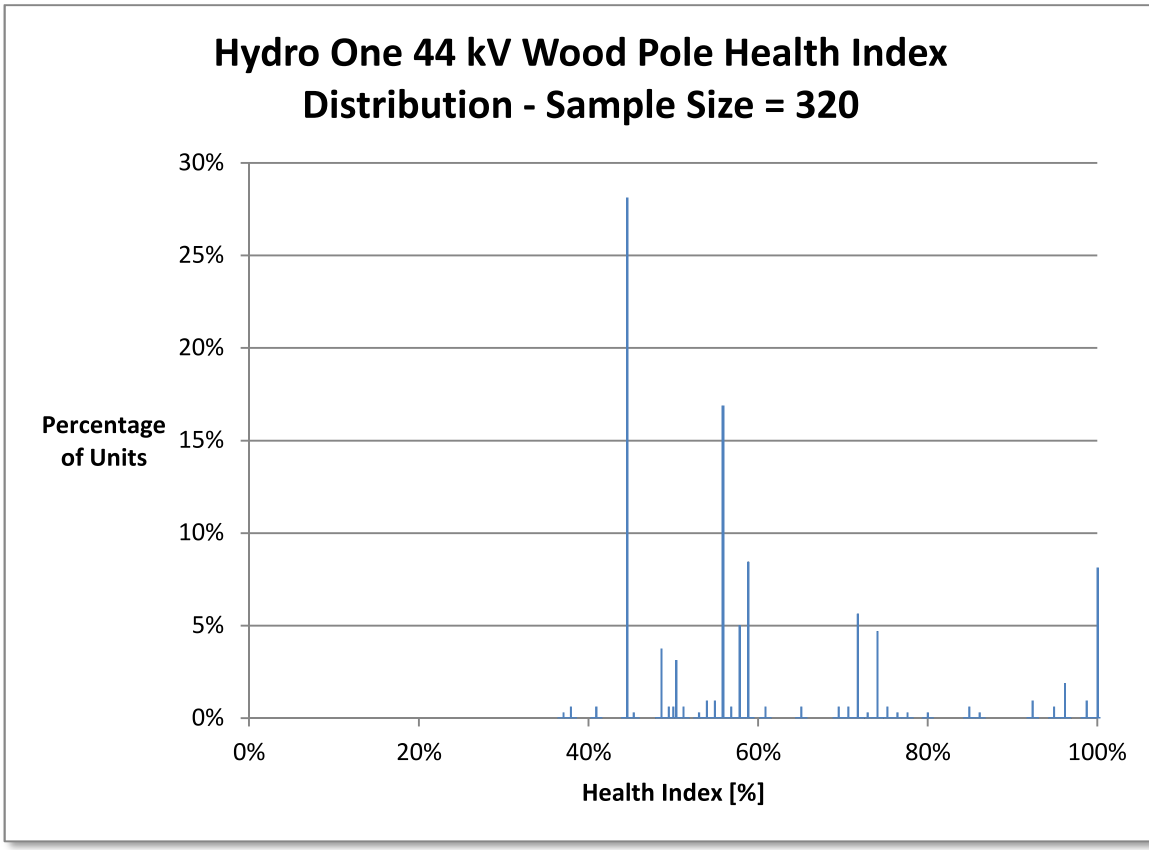


Figure 8-9 44 kV Hydro One Wood Poles Health Index Distribution by Value (Percentage of Units)

<u>Non-44 kV</u>

There are 116 in-service Non-44 kV Hydro One Wood Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 116 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 88%. Approximately 9% of the units were found to be in poor condition.

The Health Index Results are as follows:

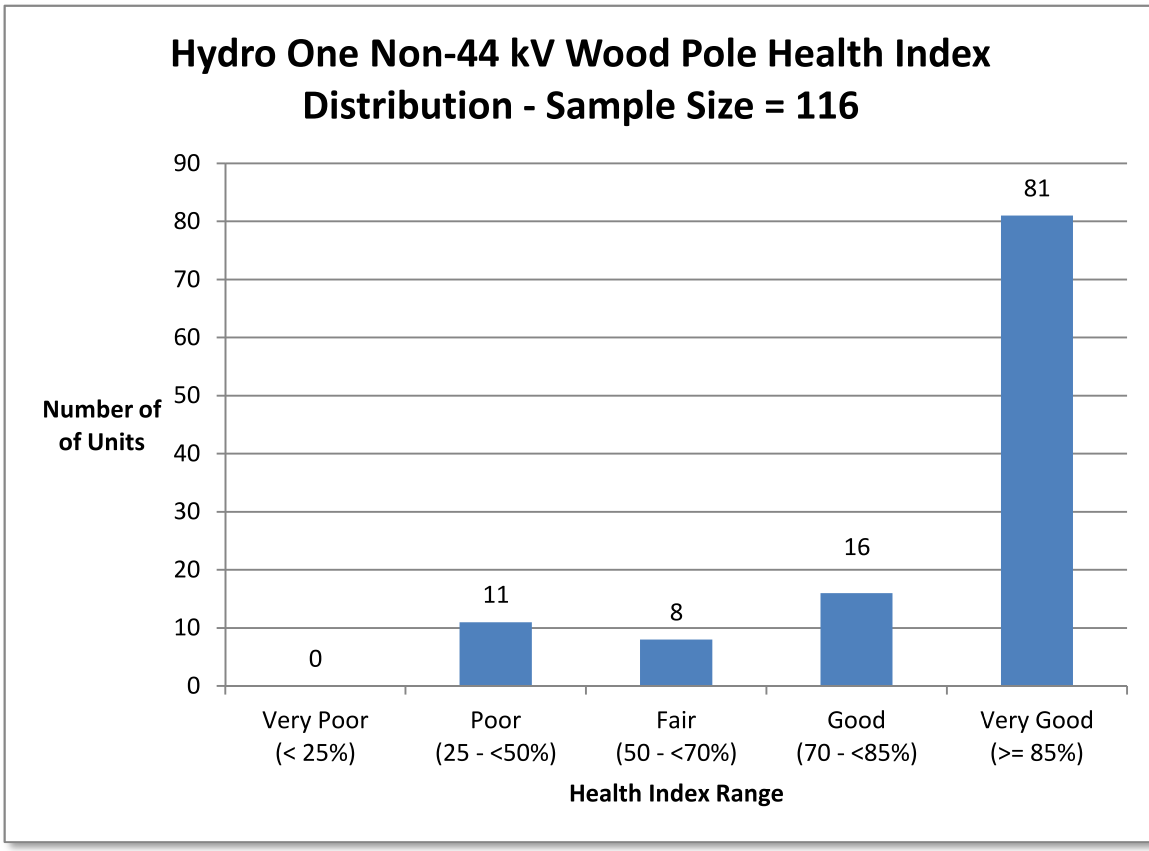


Figure 8-10 Non-44 kV Hydro One Wood Poles Health Index Distribution (Number of Units)

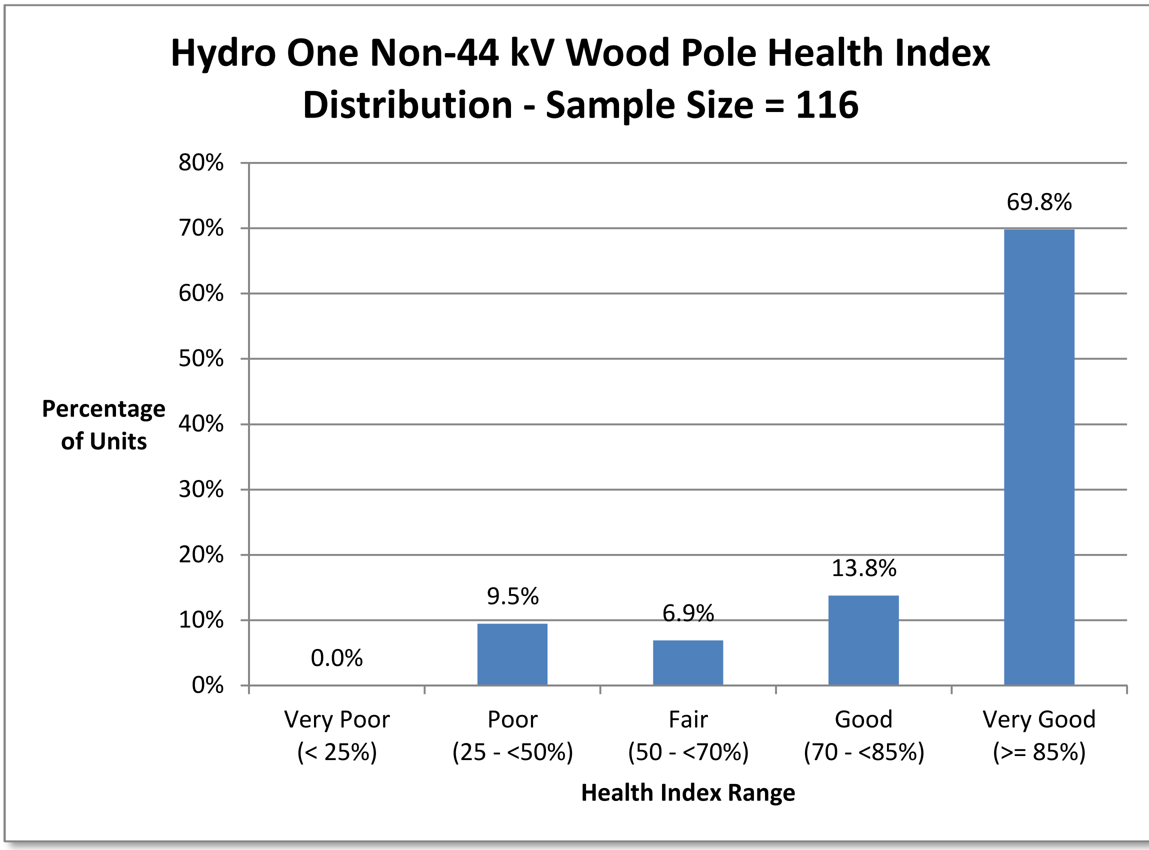


Figure 8-11 Non-44 kV Hydro One Wood Poles Health Index Distribution (Percentage of Units)

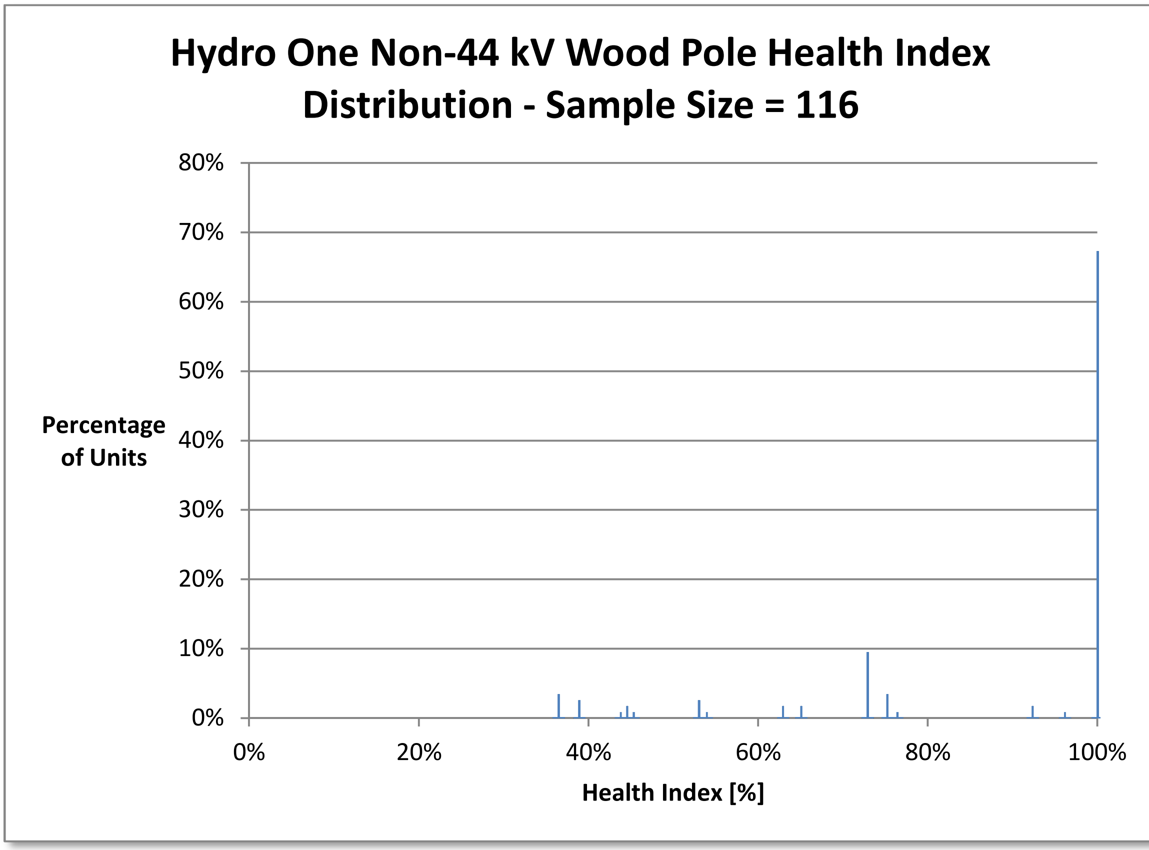


Figure 8-12 Non-44 kV Hydro One Wood Poles Health Index Distribution by Value (Percentage of Units)

8.5 Condition-Based Replacement Plan

Although Hydro One Wood Poles are proactively replaced, the number of expected replacements per year is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year.

All

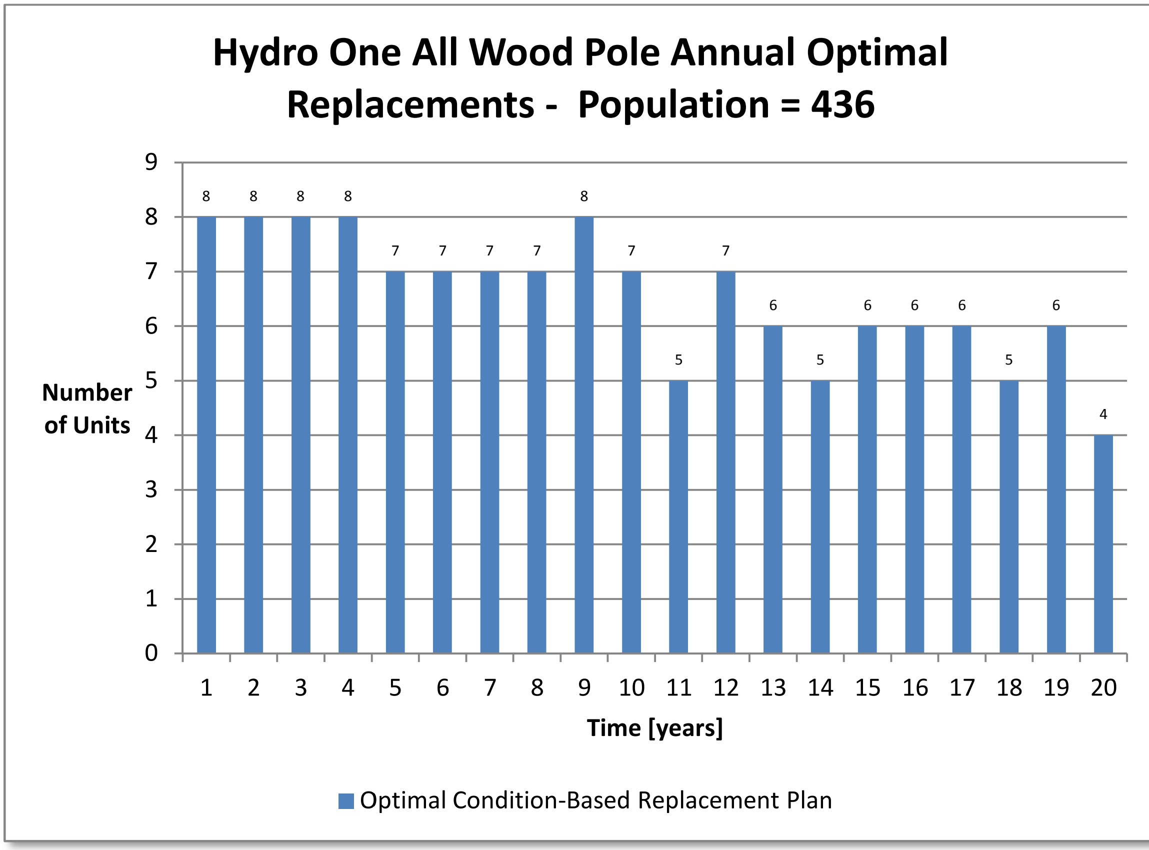


Figure 8-13 All Hydro One Wood Poles Optimal Condition-Based Replacement Plan

Although there is little variation in expected replacements, a levelized plan is given below:

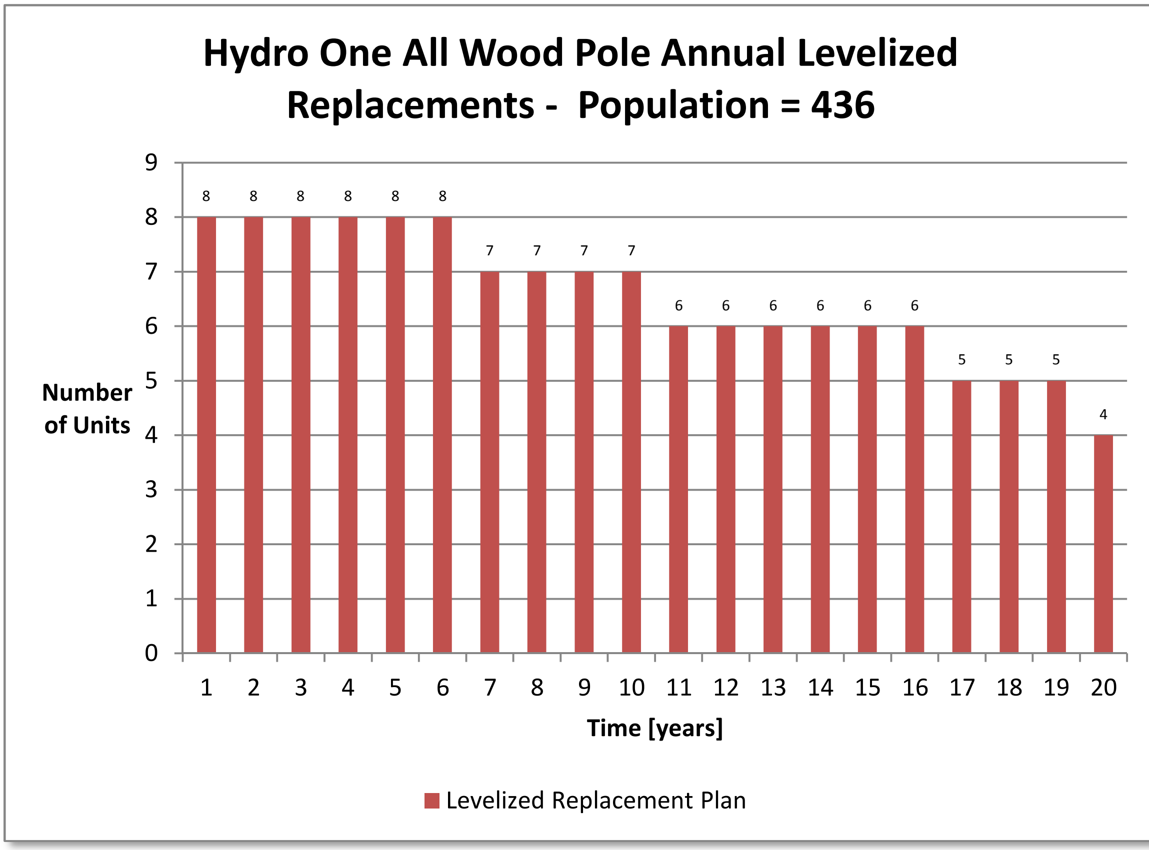


Figure 8-14 All Hydro One Wood Poles Levelized Replacement Plan

<u>44 kV</u>

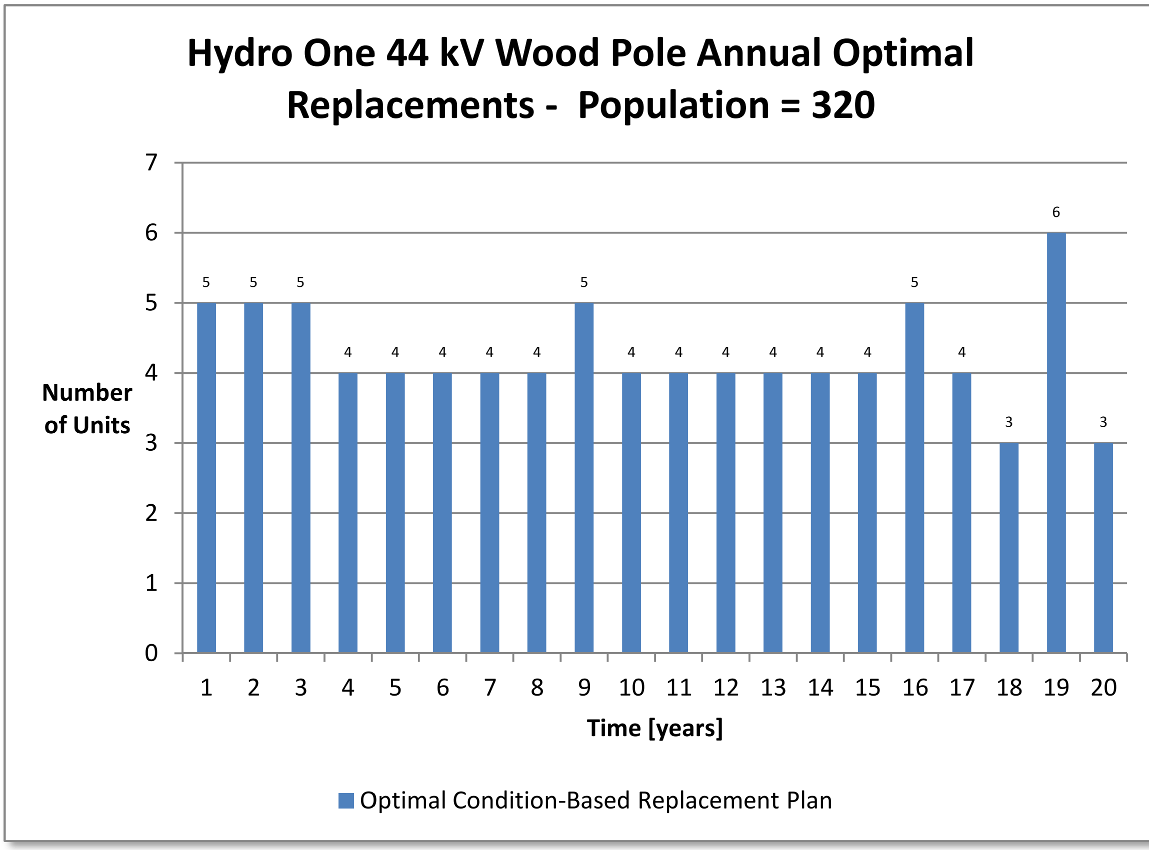


Figure 8-15 44 kV Hydro One Wood Poles Optimal Condition-Based Replacement Plan

Although there is little variation in expected replacements, a levelized plan is given below:

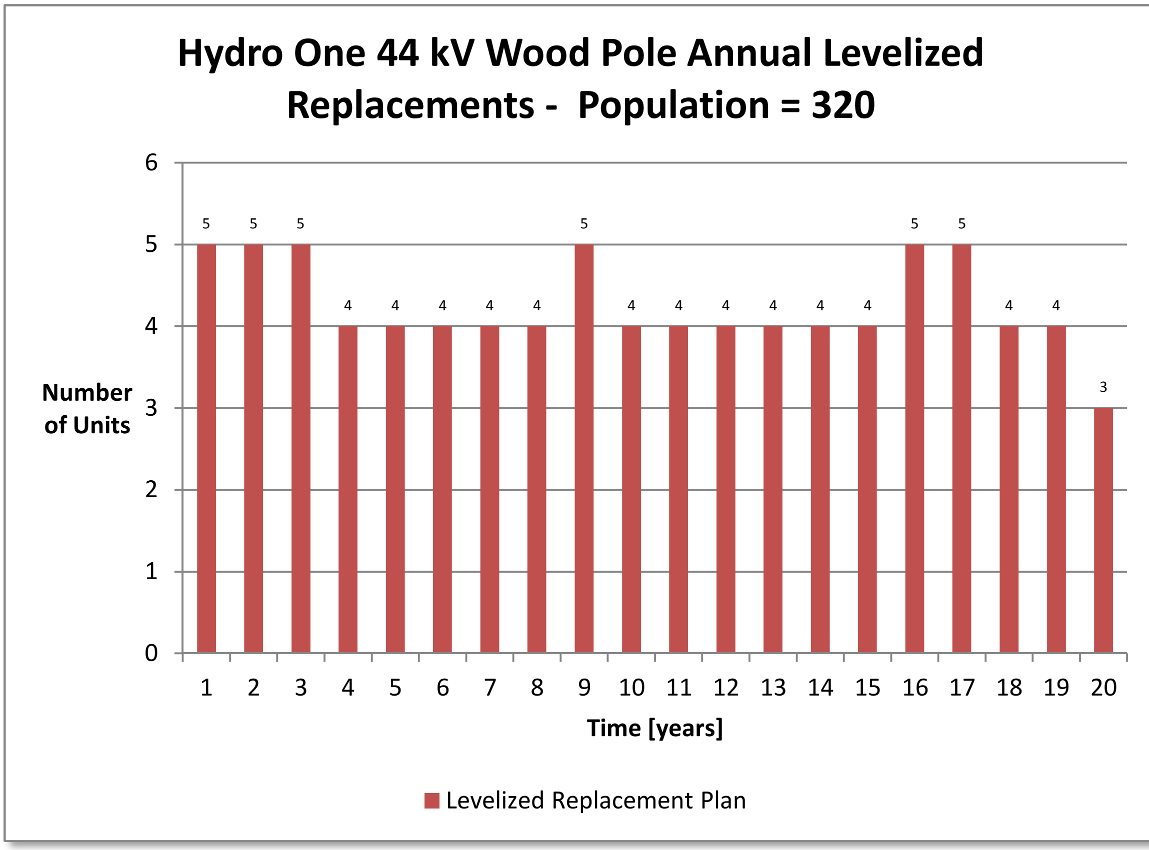


Figure 8-16 44 kV Hydro One Wood Poles Levelized Replacement Plan

Non-44 kV

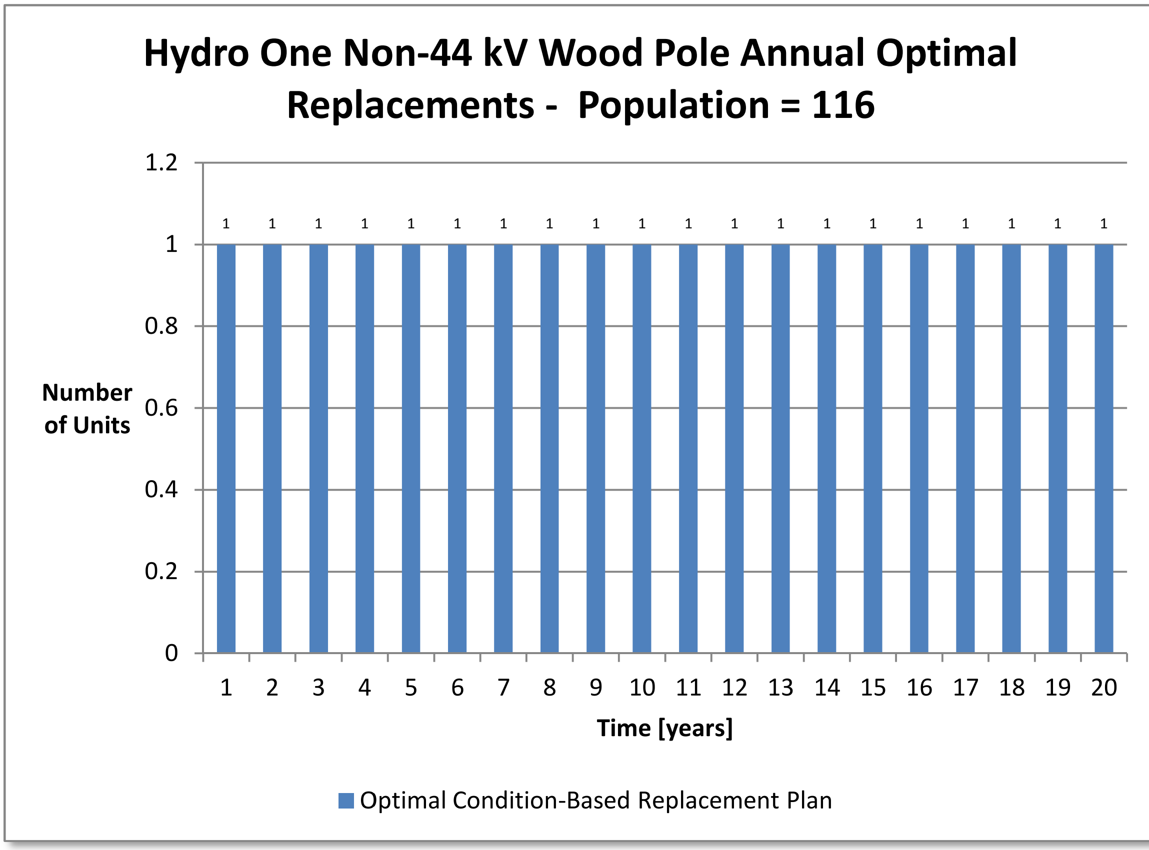


Figure 8-17 Non-44 kV Hydro One Wood Poles Optimal Condition-Based Replacement Plan

Because there is no variation in expected replacements, a levelized plan is not required.

8.6 Data Analysis

The data available for Hydro One Wood Poles includes age and inspections.

8.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Damage
- Lean

All

Assuming all inspection-based parameters are available, the average DAI for All Hydro One Wood Poles is 81%.

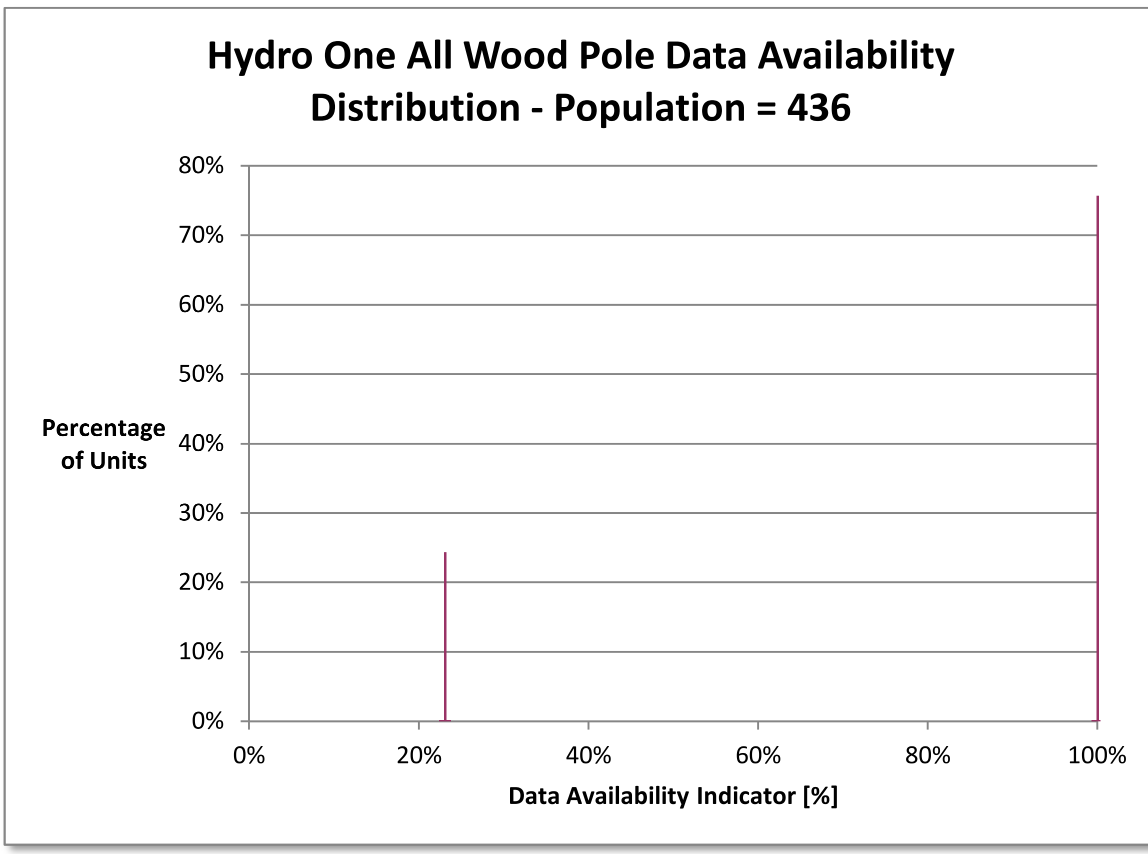


Figure 8-18 All Hydro One Wood Poles Data Availability Distribution

<u>44 kV</u>

Assuming all inspection-based parameters are available, the average DAI for 44 kV Hydro One Wood Poles is 93%.

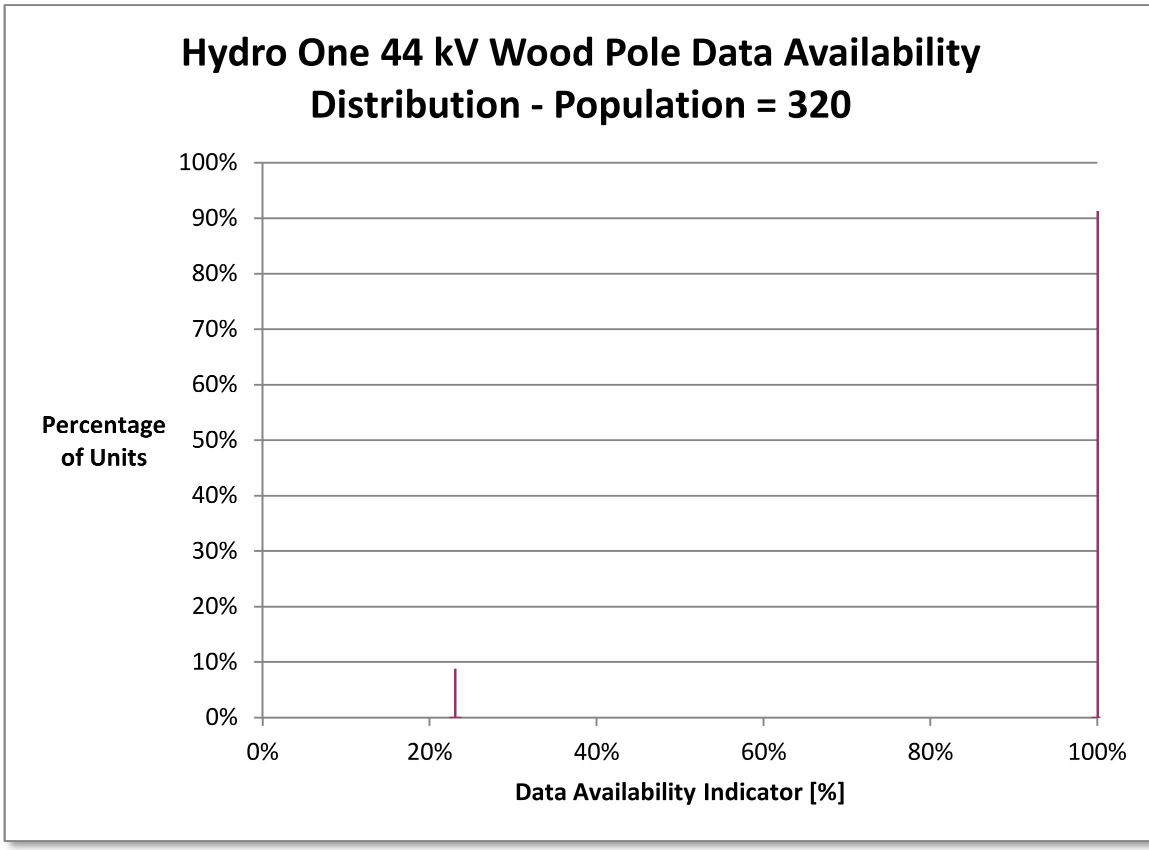


Figure 8-19 44 kV Hydro One Wood Poles Data Availability Distribution

<u>Non-44 kV</u>

Because age was available for only 33% of the population and only inspection data was available, the average DAI for Non-44 kV Hydro One Wood Poles is only 48%.

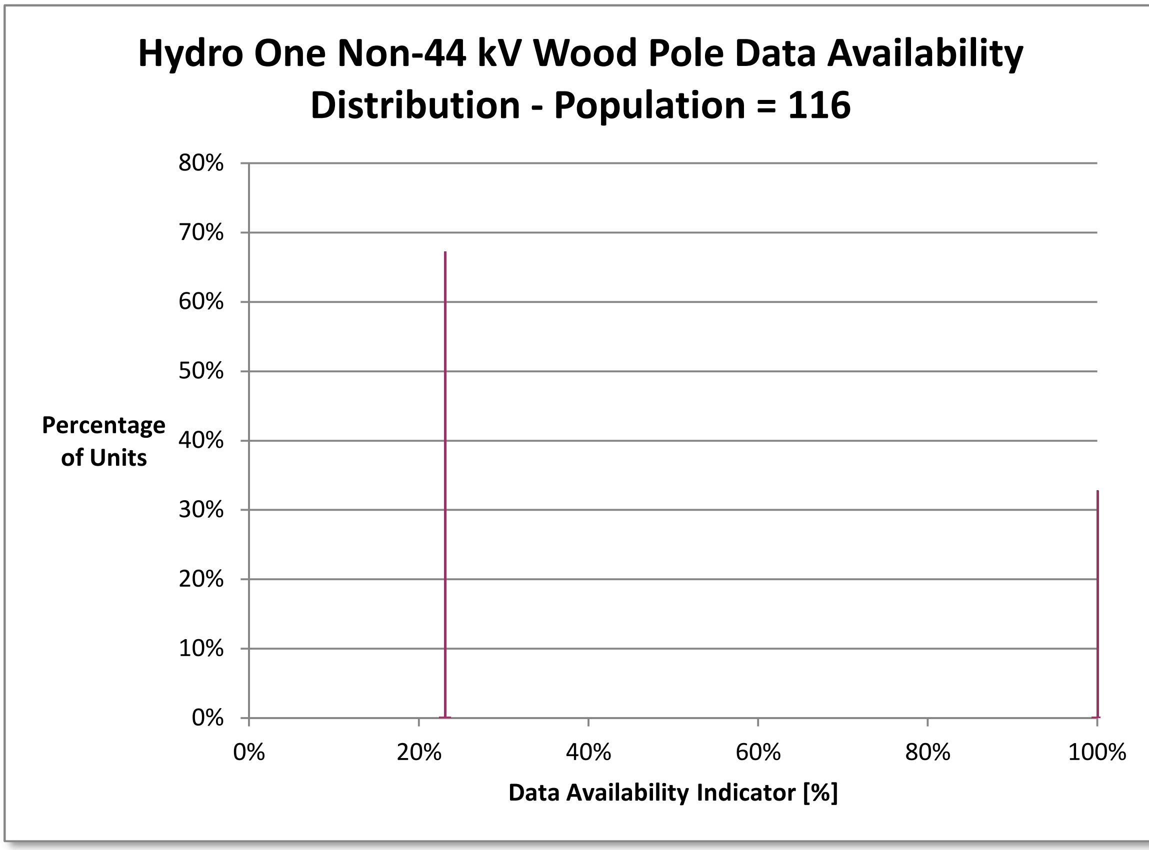


Figure 8-20 Non-44 kV Hydro One Wood Poles Data Availability Distribution

8.6.2 Data Gap

Please refer to Section 5.6.2.

9 Private Wood Poles

The analysis for Private Wood Poles is given in terms of “All”, “44 kV”, and “Non-44 kV” poles.

9.1 Degradation Mechanism

Please refer to Section 5.1.

9.2 Health Index Formulation

Please refer to Section 5.2.

9.3 Age Distribution

All

The age distribution is shown in the figure below. Age was available for 79% of the population. The average age was found to be 34 years.

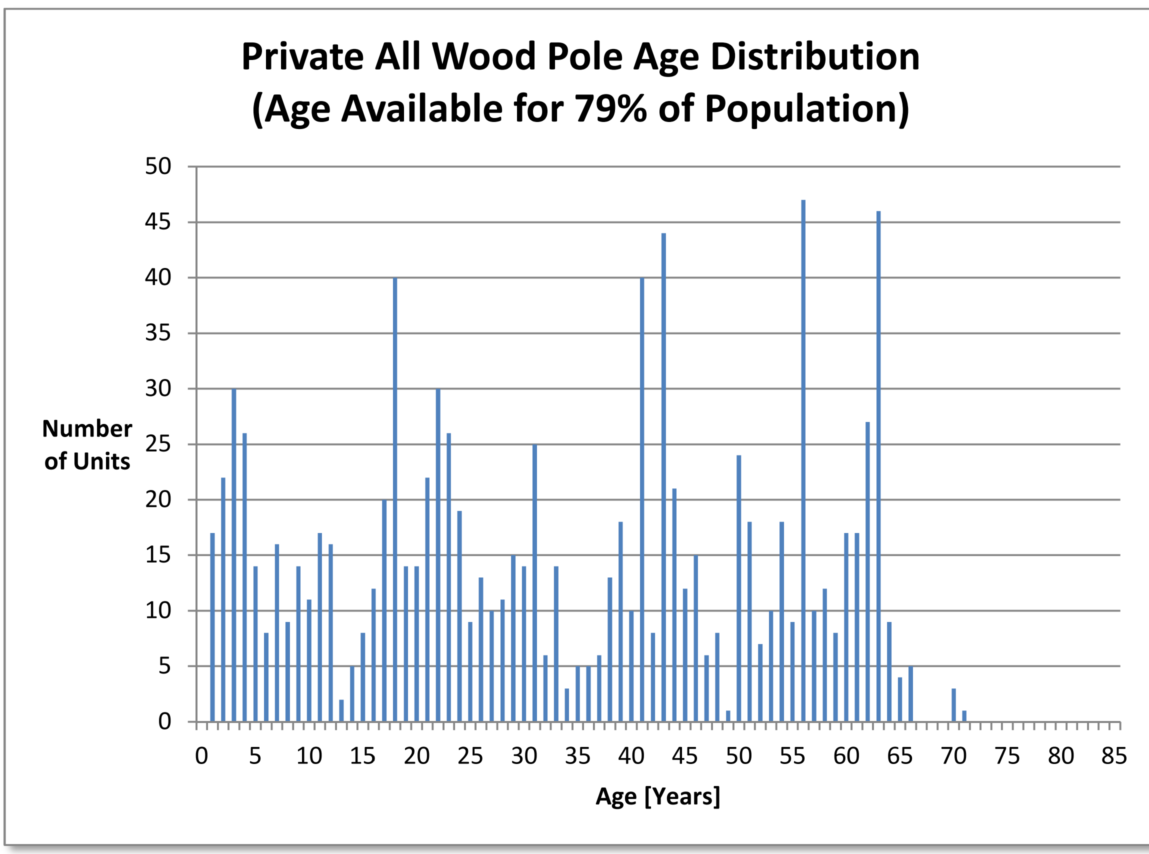


Figure 9-1 All Private Wood Poles Age Distribution

44 kV

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 23 years.

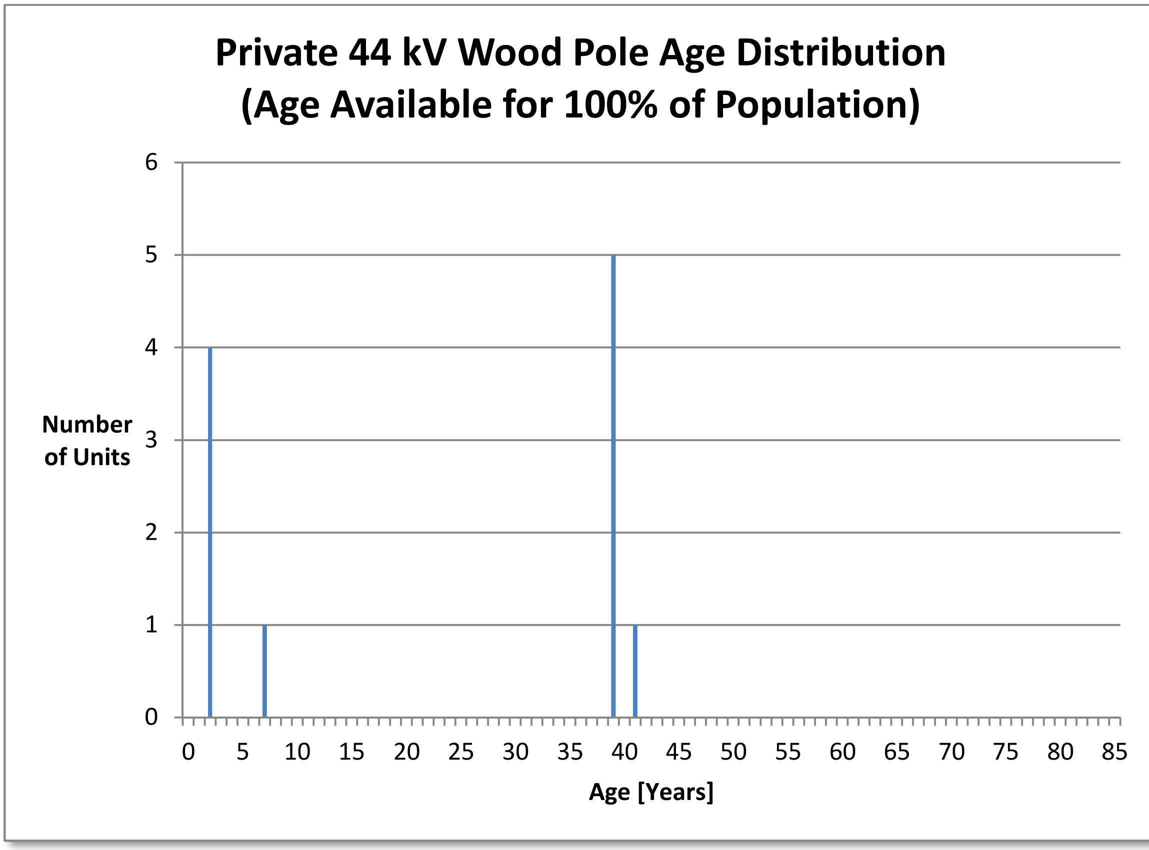


Figure 9-2 44 kV Private Wood Poles Age Distribution

Non-44 kV

The age distribution is shown in the figure below. Age was available for 79% of the population. The average age was found to be 34 years.

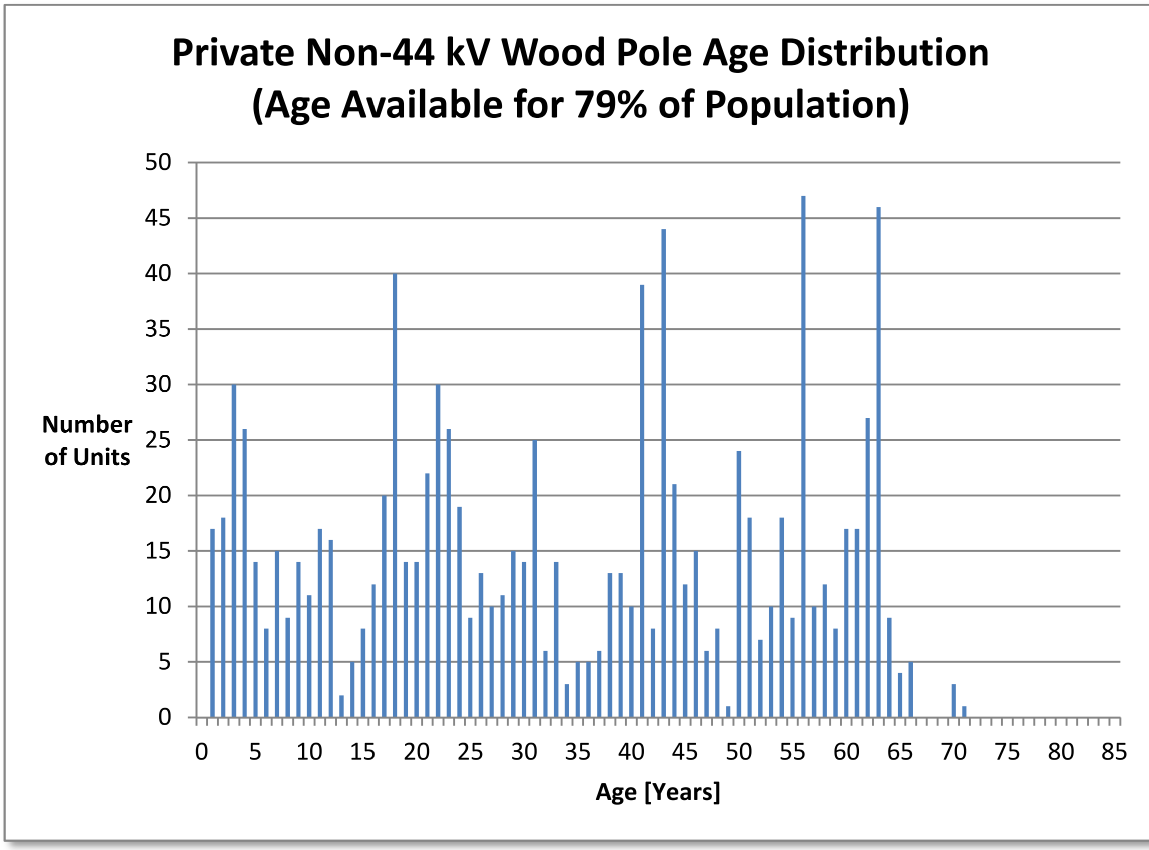


Figure 9-3 Non-44 kV Private Wood Poles Age Distribution

9.4 Health Index Results

<u>All</u>

There are 1,307 in-service Private Wood Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 1,307 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 70%. Approximately 26% of the units were found to be in poor condition.

The Health Index Results are as follows:

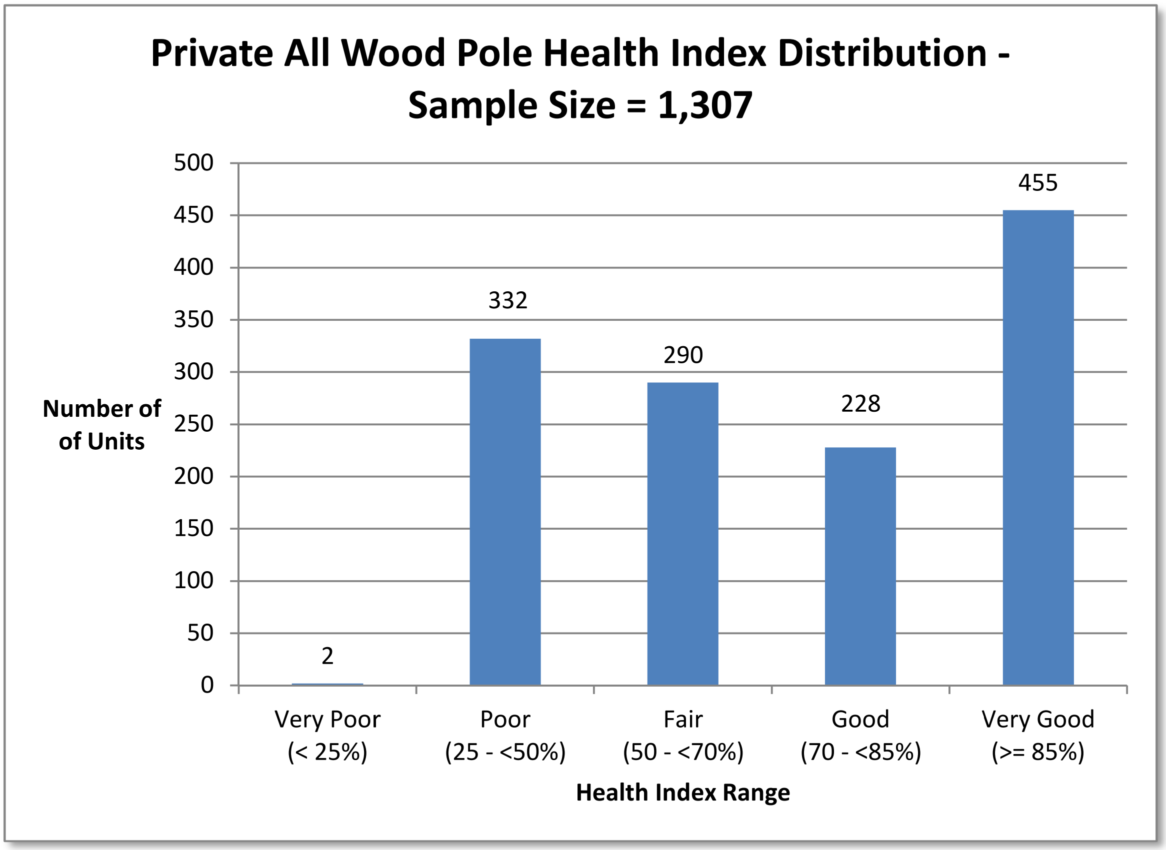


Figure 9-4 All Private Wood Poles Health Index Distribution (Number of Units)

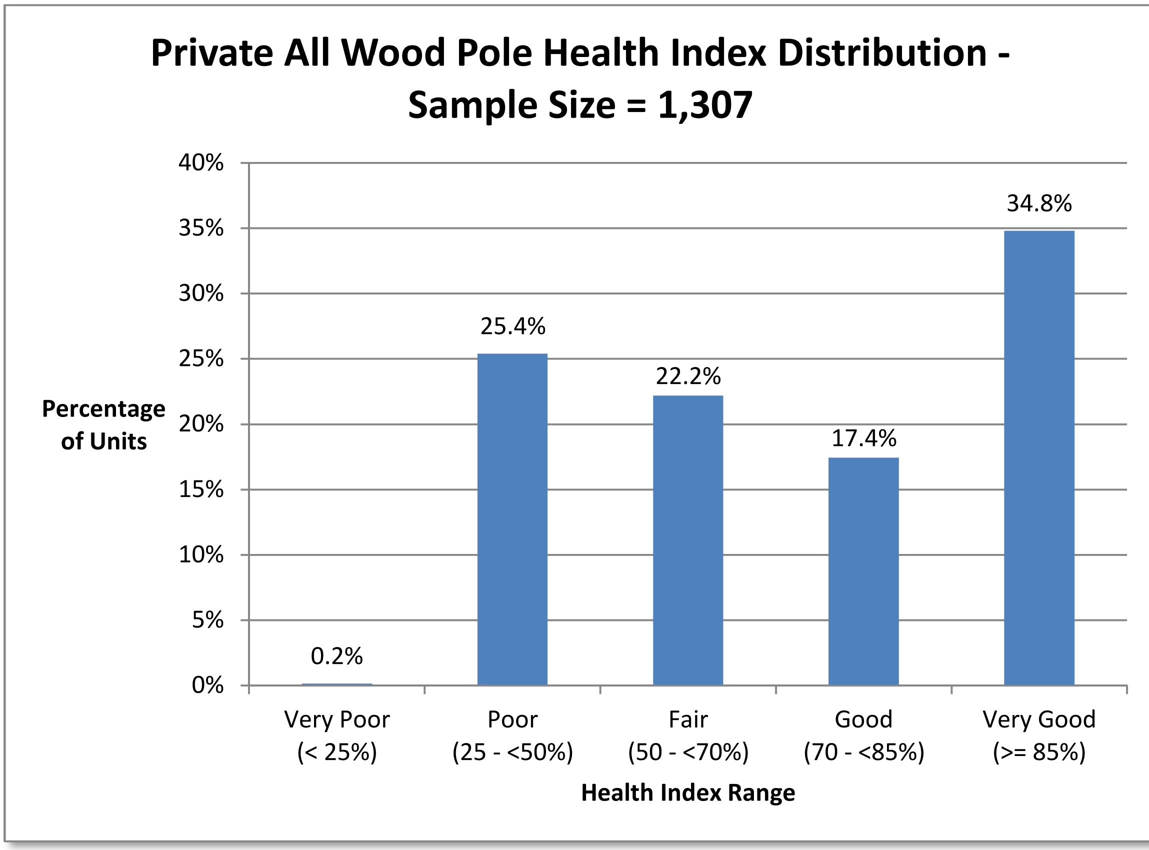


Figure 9-5 All Private Wood Poles Health Index Distribution (Percentage of Units)

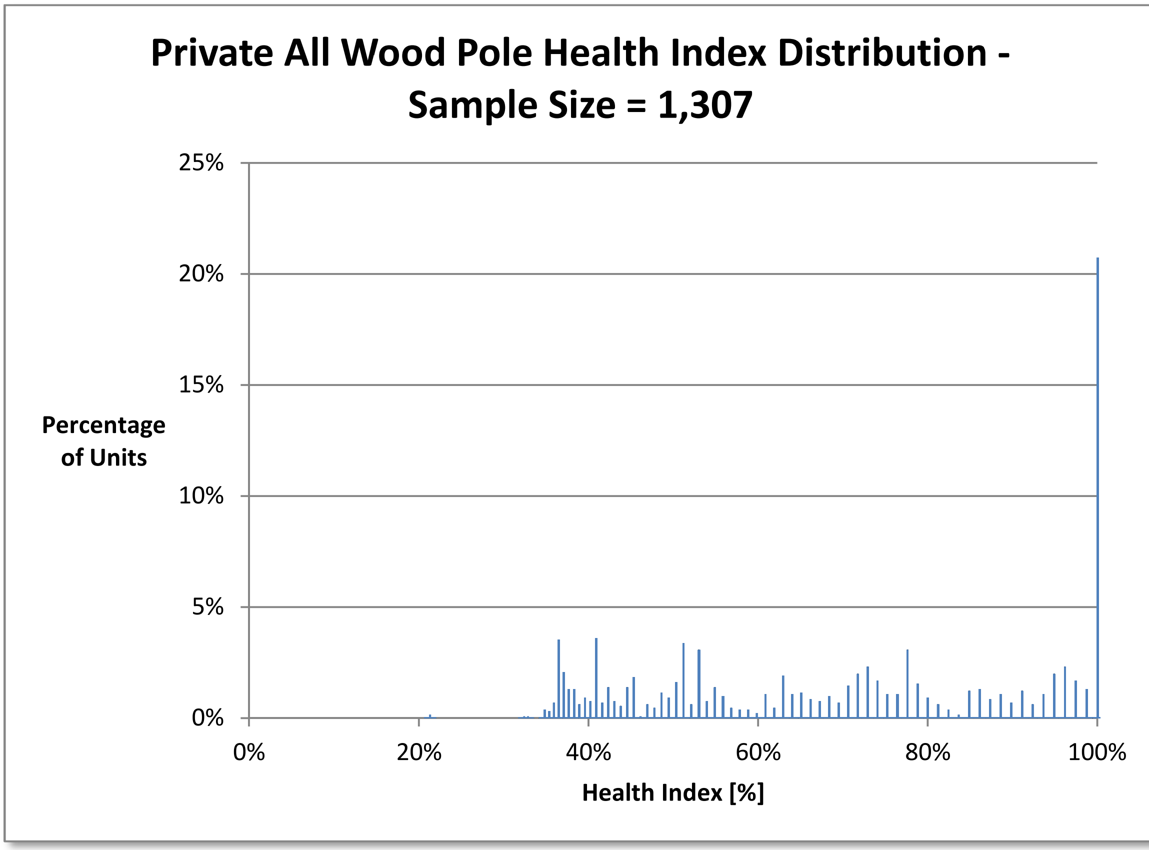


Figure 9-6 All Private Wood Poles Health Index Distribution by Value (Percentage of Units)

<u>44 kV</u>

There are 11 in-service 44 kV Private Wood Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 11 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 73%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

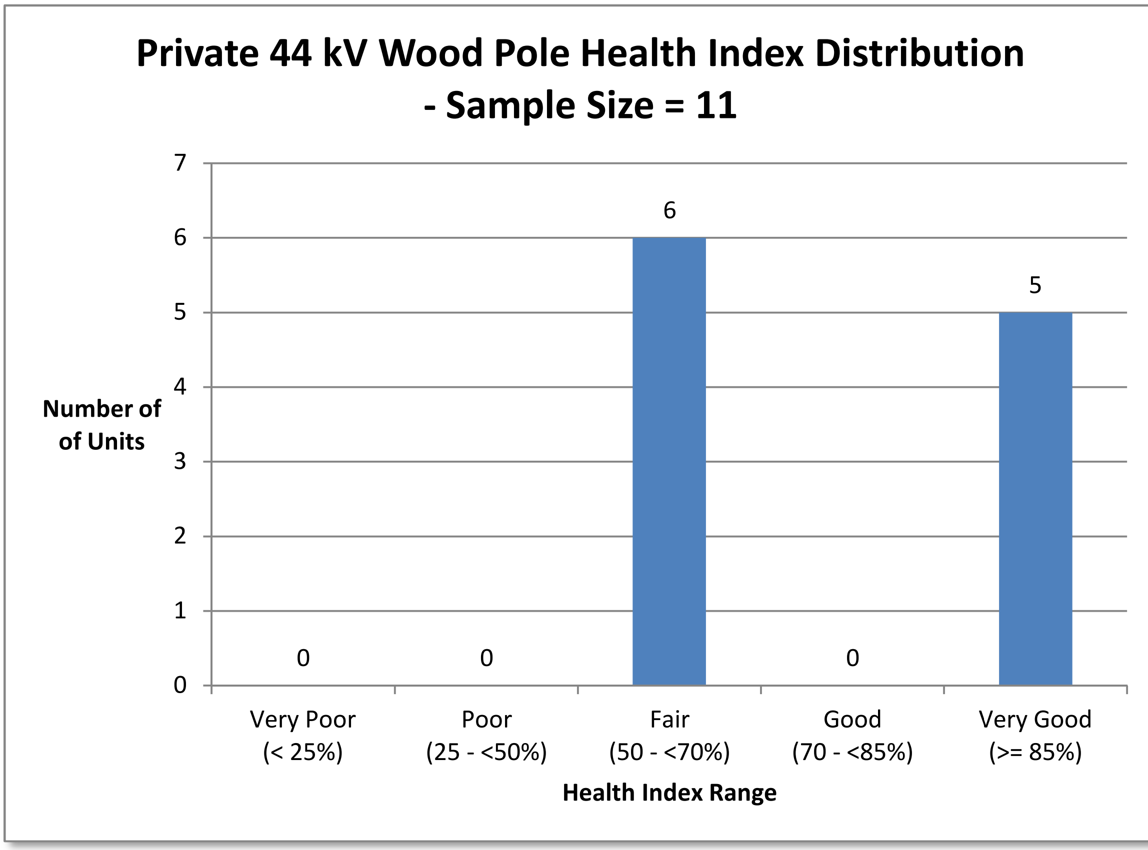


Figure 9-7 44 kV Private Wood Poles Health Index Distribution (Number of Units)

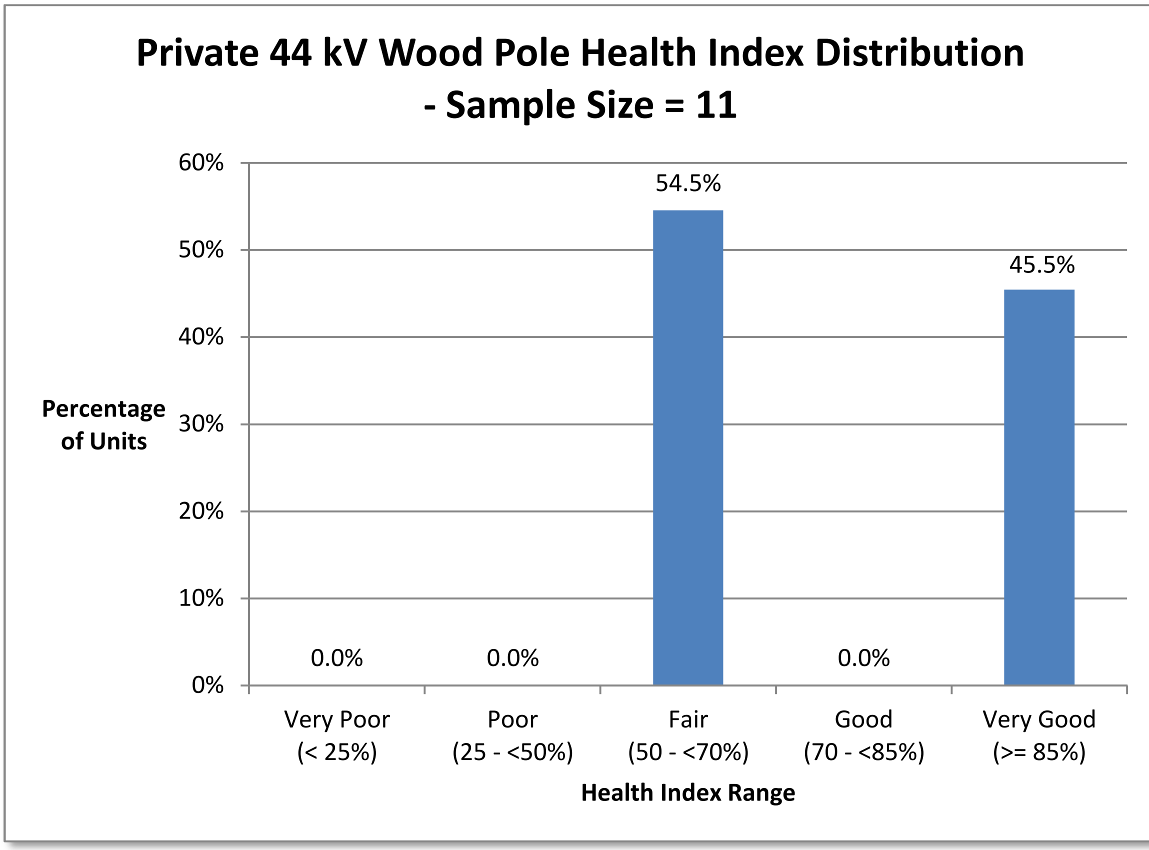


Figure 9-8 44 kV Private Wood Poles Health Index Distribution (Percentage of Units)

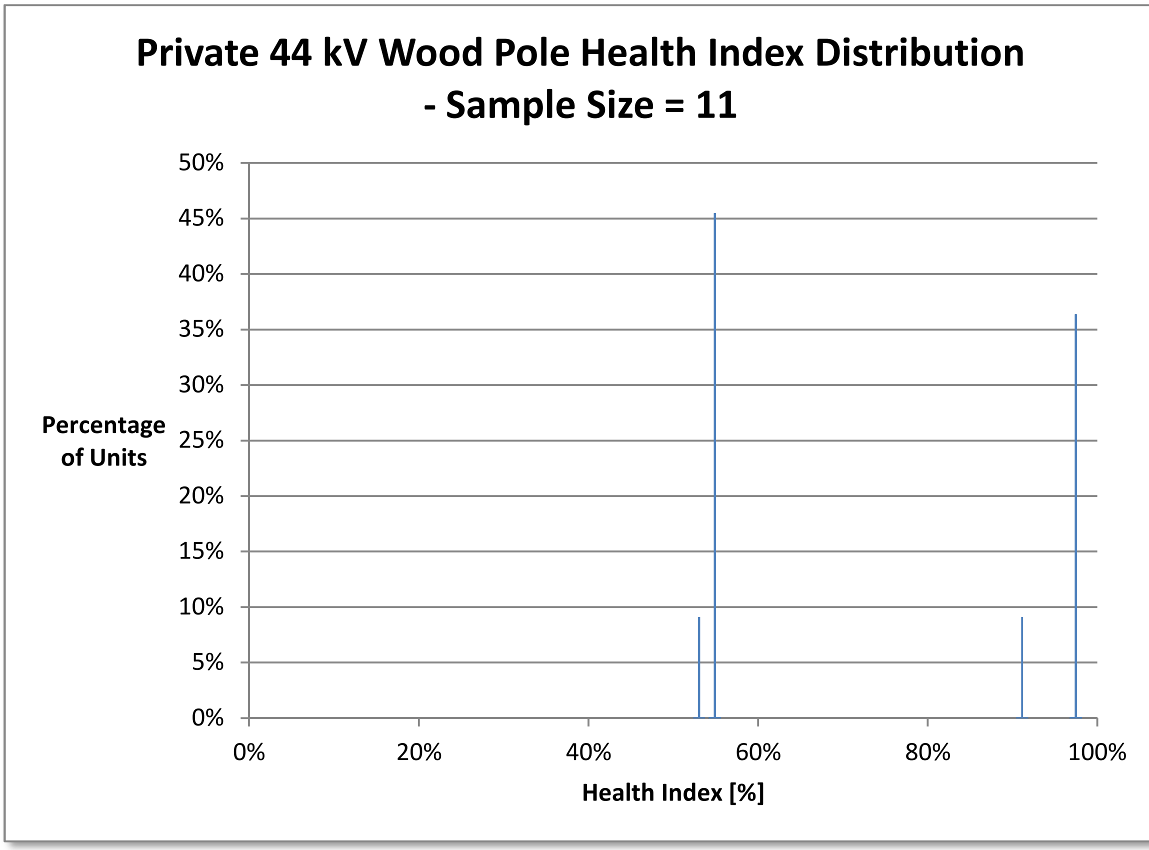


Figure 9-9 44 kV Private Wood Poles Health Index Distribution by Value (Percentage of Units)

Non-44 kV

There are 1,296 in service Non-44 kV Private Wood Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 1,296 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 70%. Approximately 26% of the units were found to be in poor condition.

The Health Index Results are as follows:

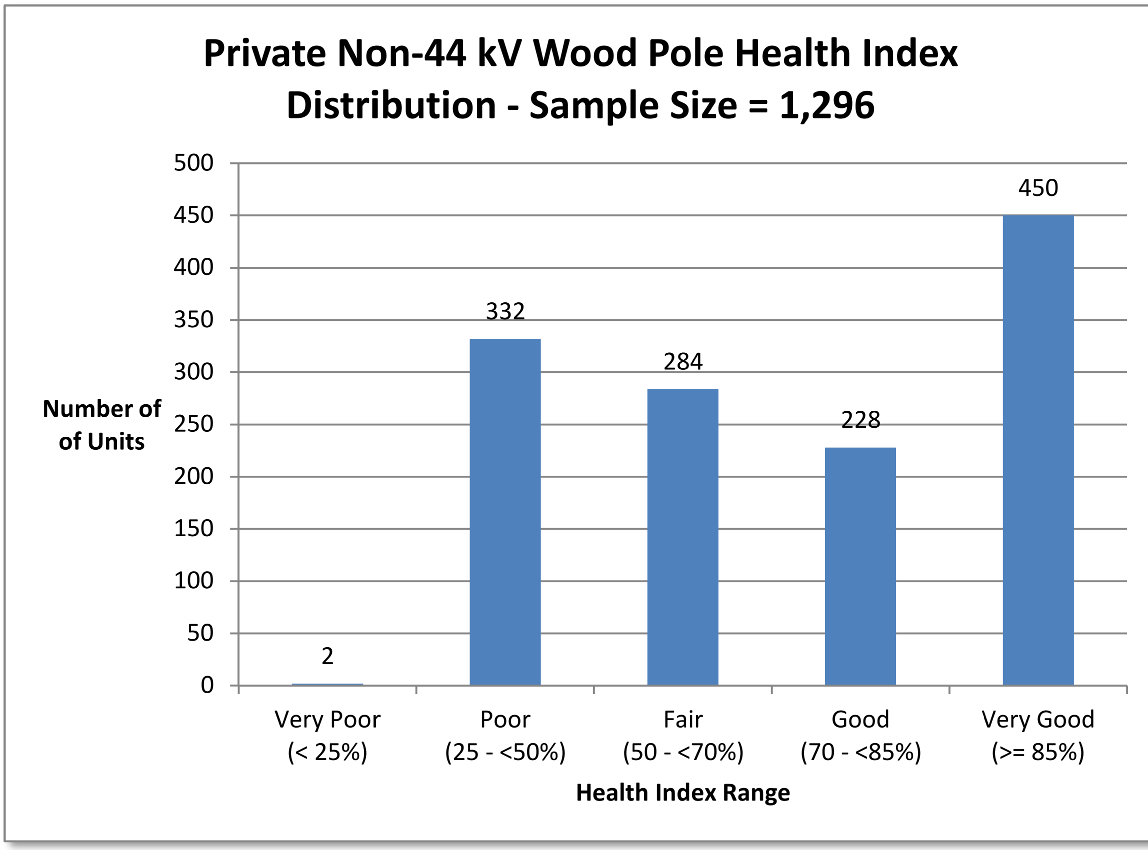


Figure 9-10 Non-44 kV Private Wood Poles Health Index Distribution (Number of Units)

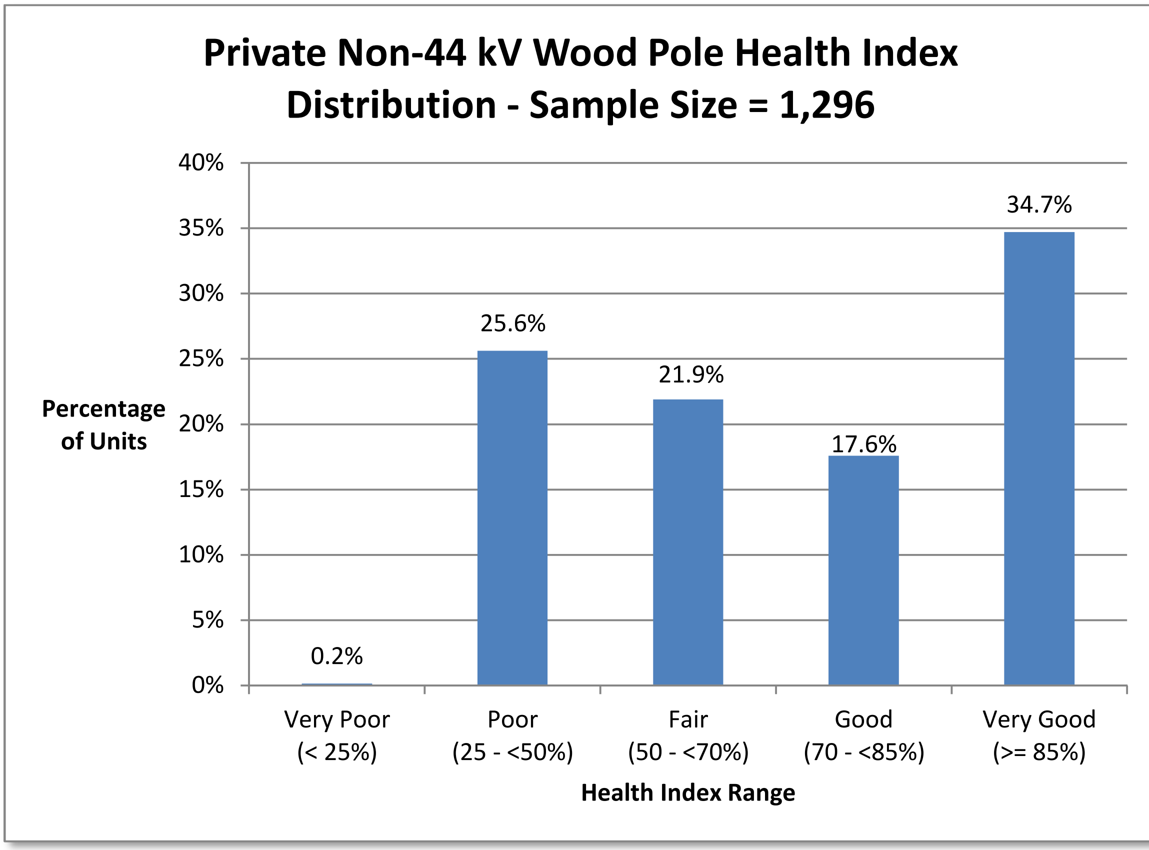


Figure 9-11 Non-44 kV Private Wood Poles Health Index Distribution (Percentage of Units)

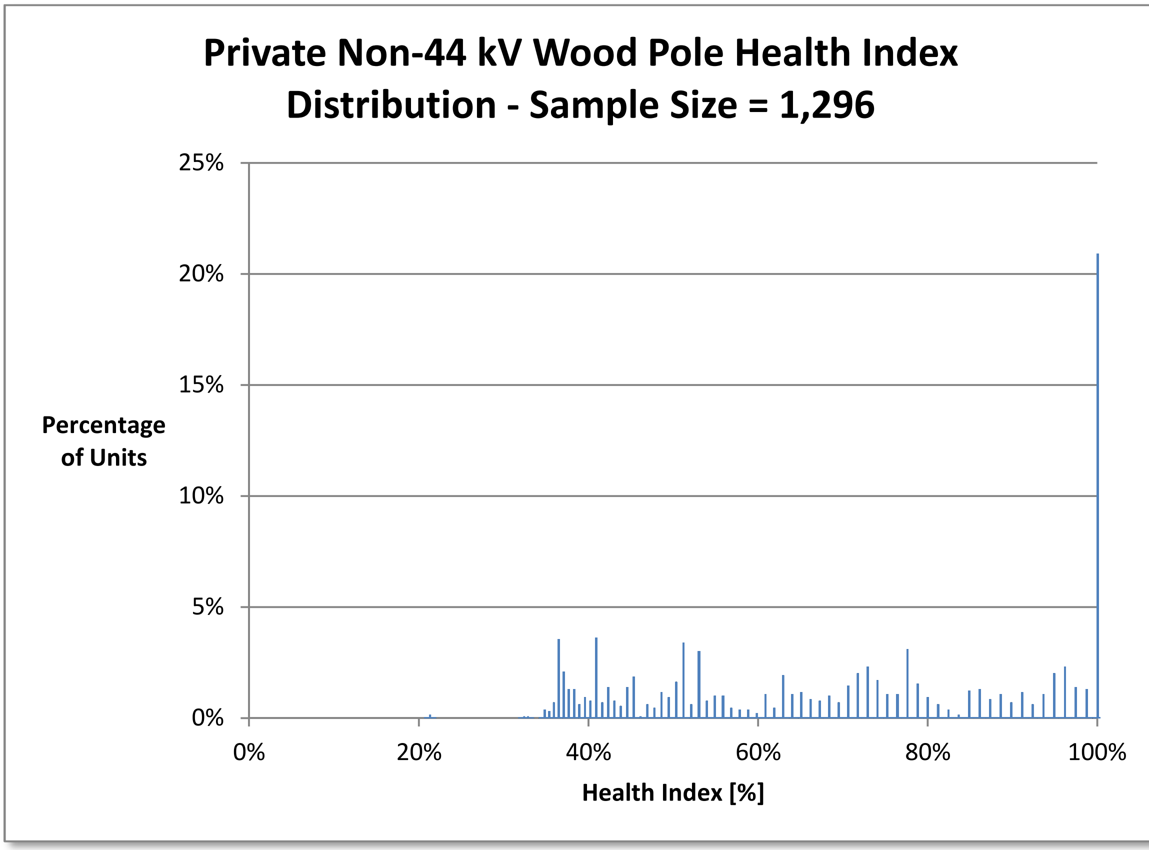


Figure 9-12 Non-44 kV Private Wood Poles Health Index Distribution by Value (Percentage of Units)

9.5 Condition-Based Replacement Plan

Although Private Wood Poles are proactively replaced, the number of expected replacements per year is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. As it may not always be feasible to replace as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected failures, is also given.

All

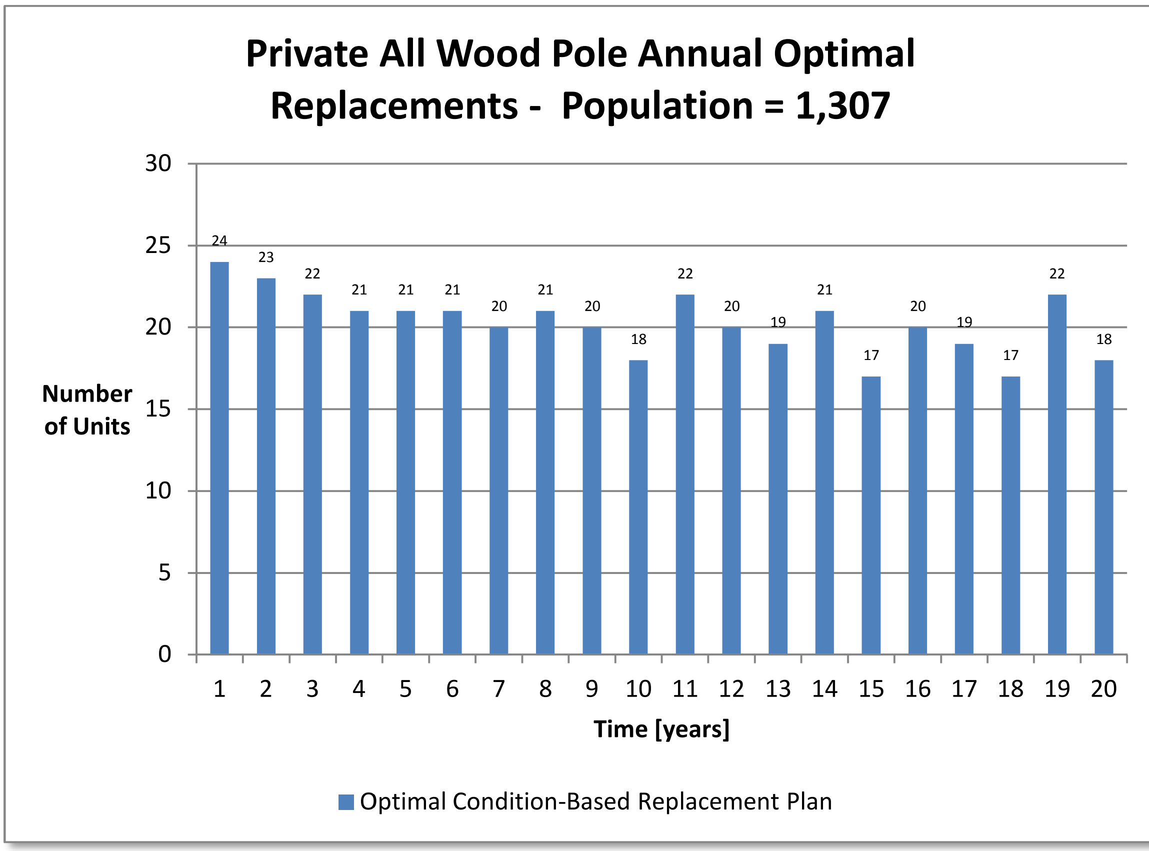


Figure 9-13 All Private Wood Poles Optimal Condition-Based Replacement Plan

Although there is little variation in expected replacements, a levelized plan is given.

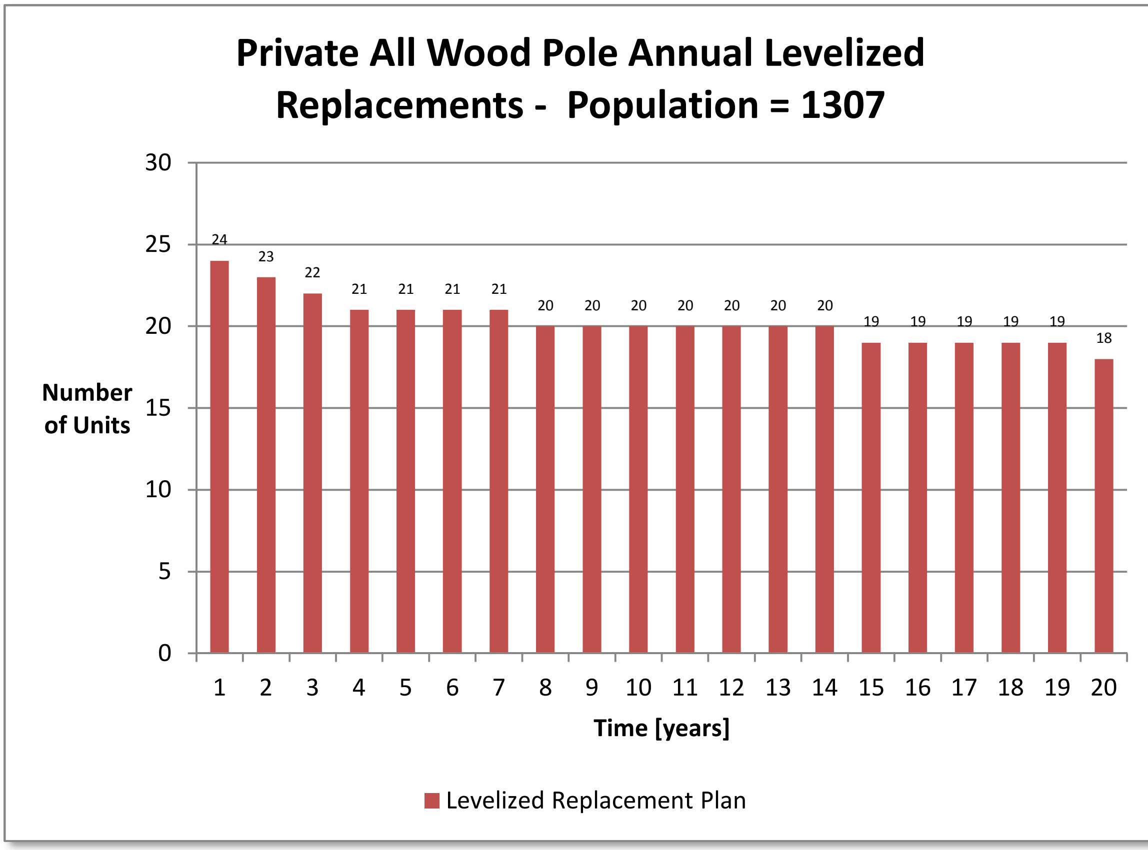


Figure 9-14 All Private Wood Poles Levelized Replacement Plan

44 kV

No 44 kV Private Wood Poles are expected to be replaced in the next twenty years.

Non-44 kV

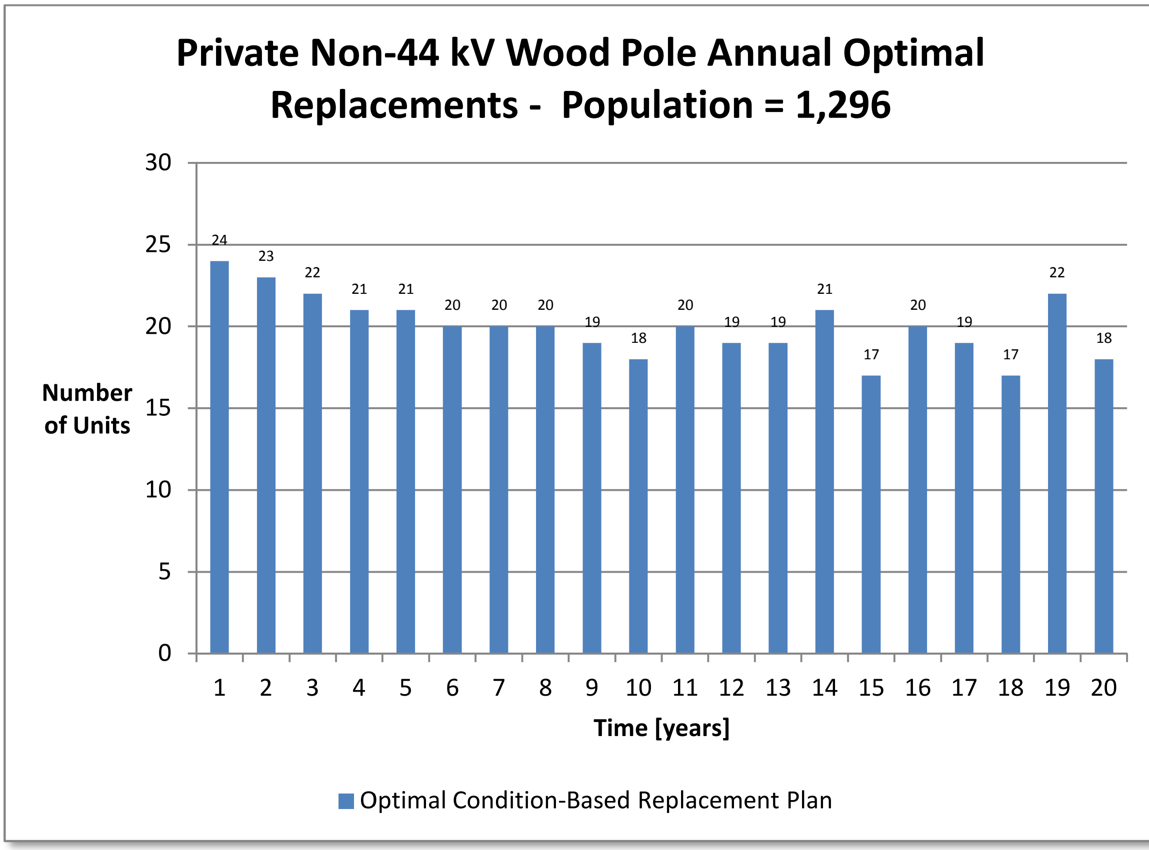


Figure 9-15 Non-44 kV Private Wood Poles Optimal Condition-Based Replacement Plan

Although there is little variation in expected replacements, a levelized plan is given.

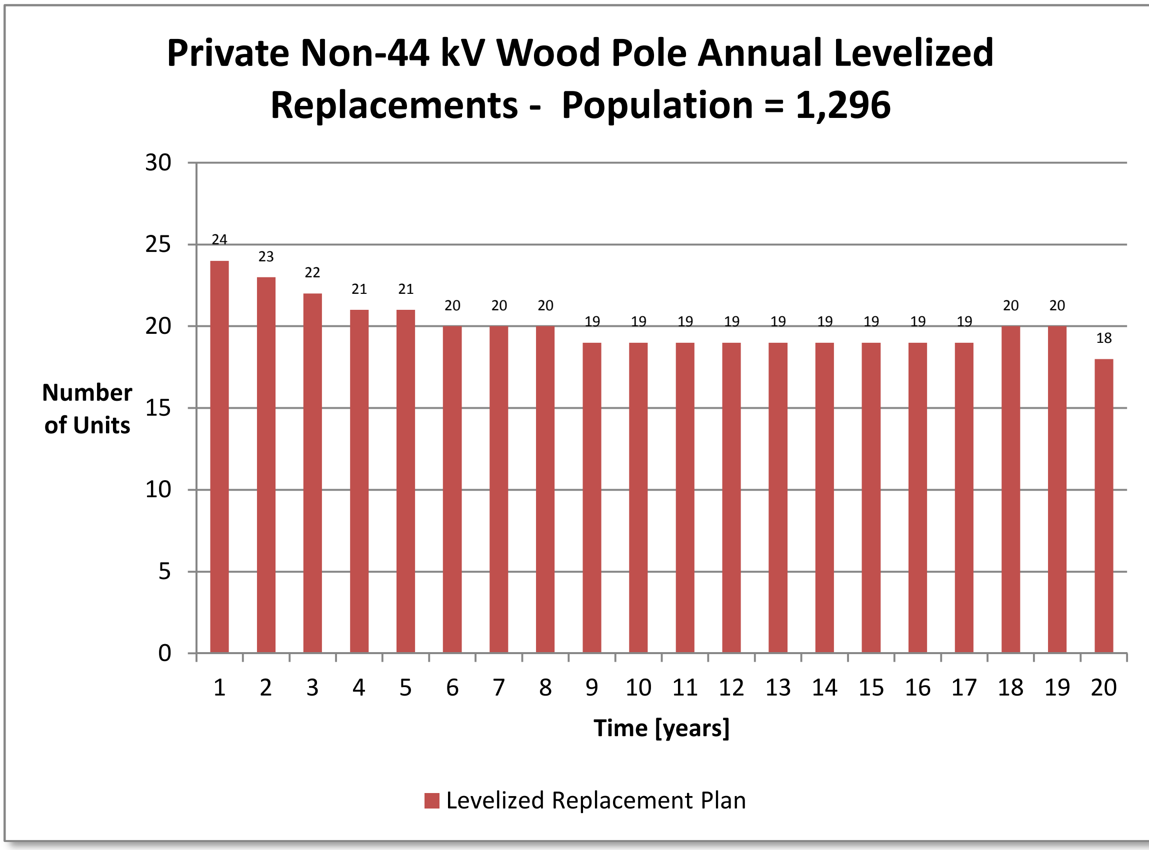


Figure 9-16 Non-44 kV Private Wood Poles Levelized Replacement Plan

9.6 Data Analysis

The data available for Private Wood Poles includes age and inspections.

9.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Damage
- Lean

All

Assuming all inspection-based parameters are available, the average DAI for All Private Wood Poles is 84%.

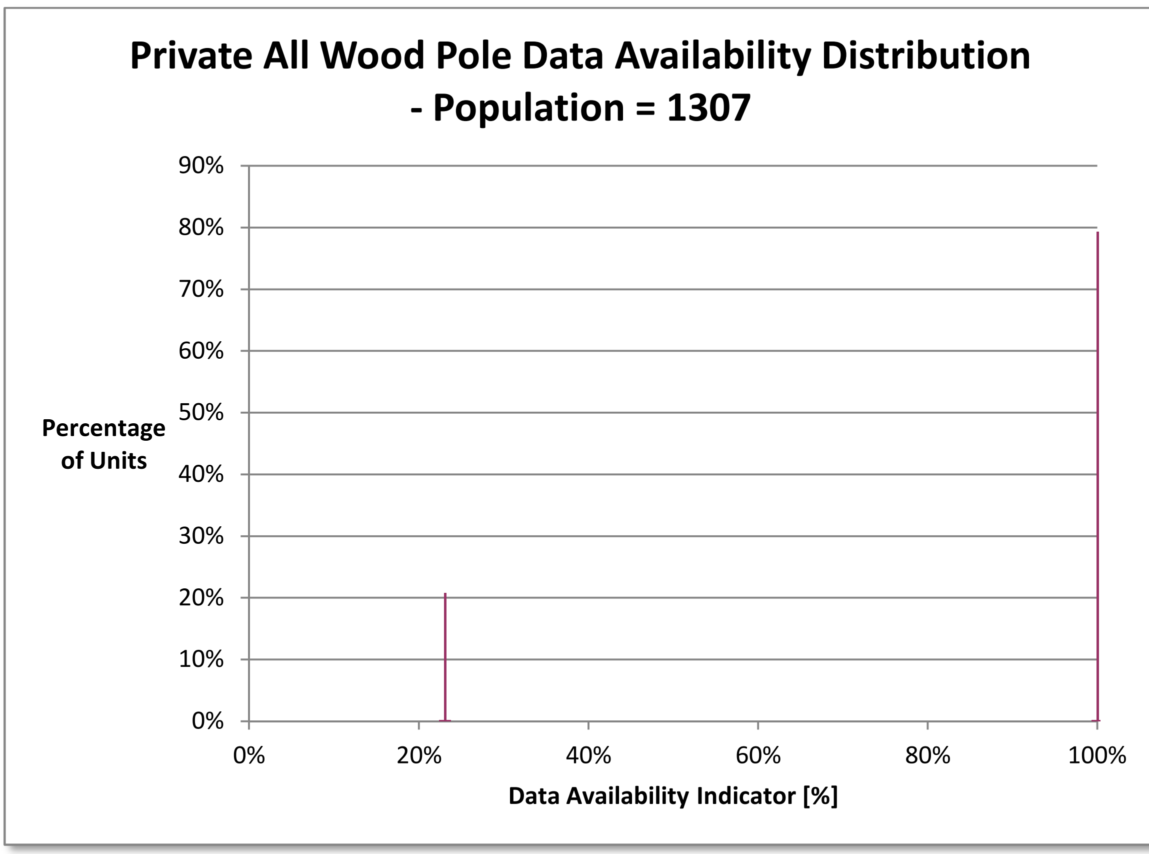


Figure 9-17 All Private Wood Poles Data Availability Distribution

44 kV

Assuming all inspection-based parameters are available, the average DAI for 44 kV Private Wood Poles is 100%.

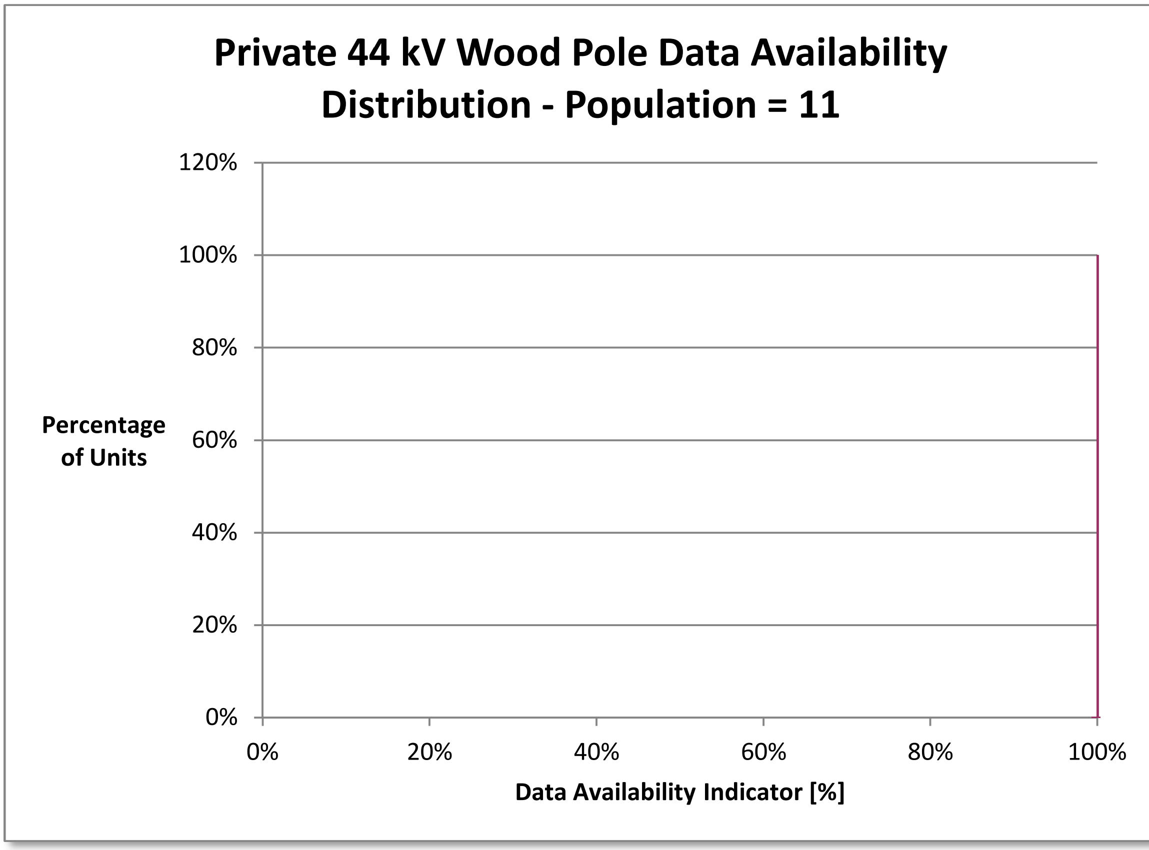


Figure 9-18 44 kV Private Wood Poles Data Availability Distribution

Non-44 kV

Assuming all inspection-based parameters are available, the average DAI for Non-44 kV Private Wood Poles is 84%.

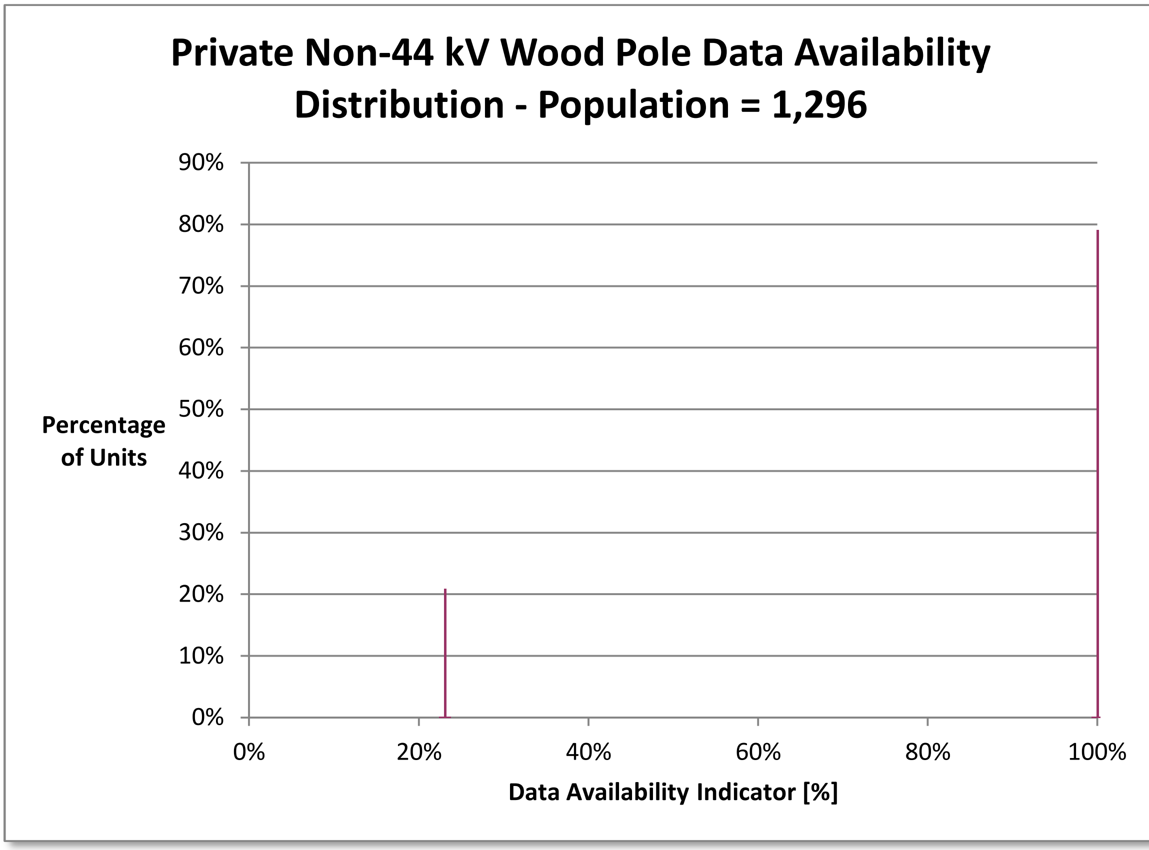


Figure 9-19 Non-44 kV Private Wood Poles Data Availability Distribution

9.6.2 Data Gap

Please refer to Section 5.6.2.

This page is intentionally left blank.

10 Private Concrete Poles

The analysis for Private Concrete Poles is given in terms of "All", "44 kV", and "Non-44 kV" poles.

10.1 Degradation Mechanism

Please refer to Section 5.1.

10.2 Health Index Formulation

Please refer to Section 5.2.

10.3 Age Distribution

<u>All</u>

The age distribution is shown in the figure below. Age was available for 46% of the population. The average age was found to be 2 years.

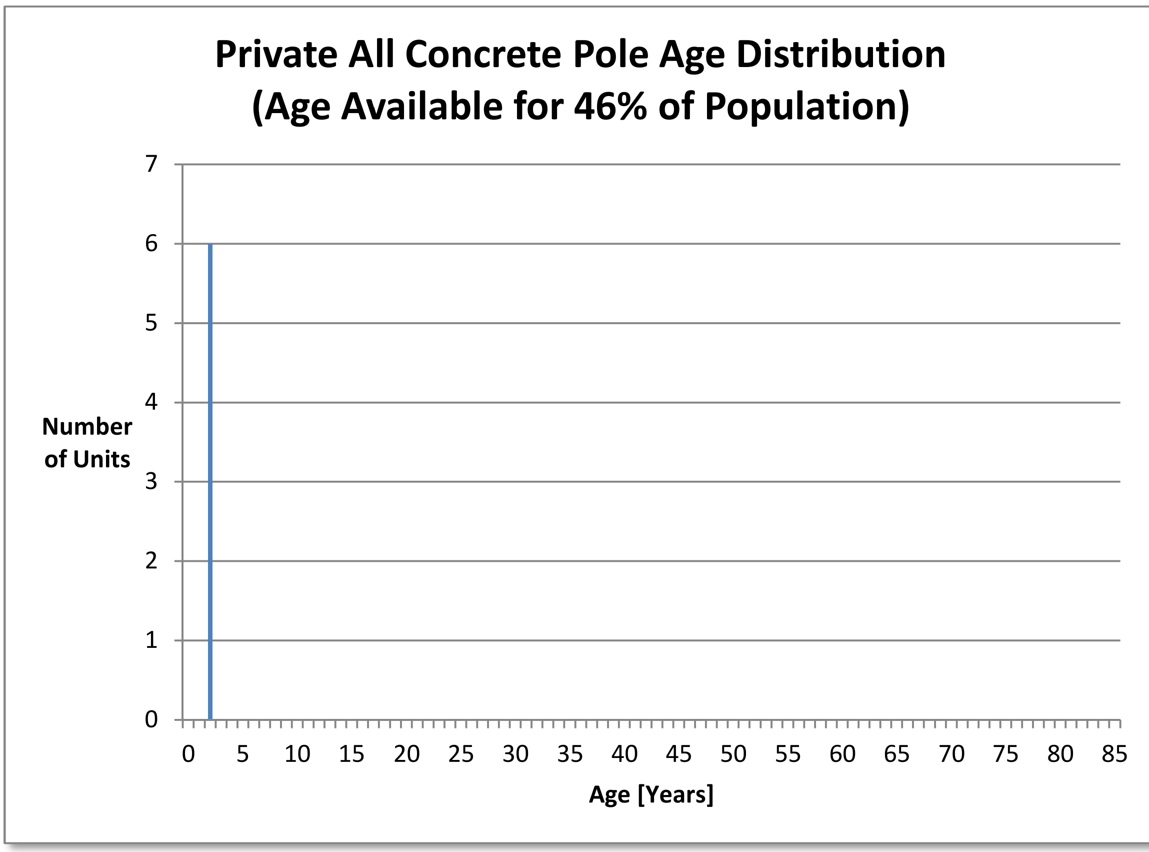


Figure 10-1 All Private Concrete Poles Age Distribution

<u>44 kV</u>

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 2 years.

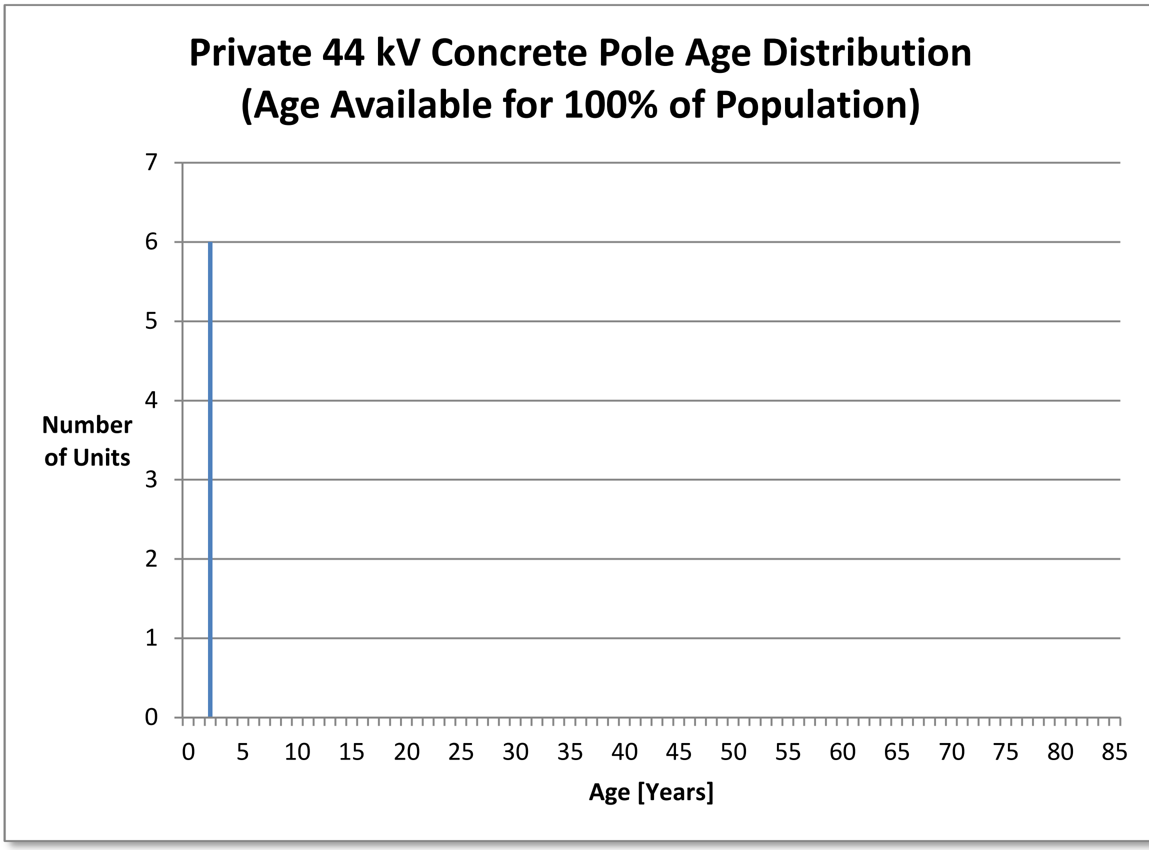


Figure 10-2 44 kV Private Concrete Poles Age Distribution

<u>Non-44 kV</u>

Age was not available for any of these poles.

10.4 Health Index Results

All

There are 13 in-service Private Concrete Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 13 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 100%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

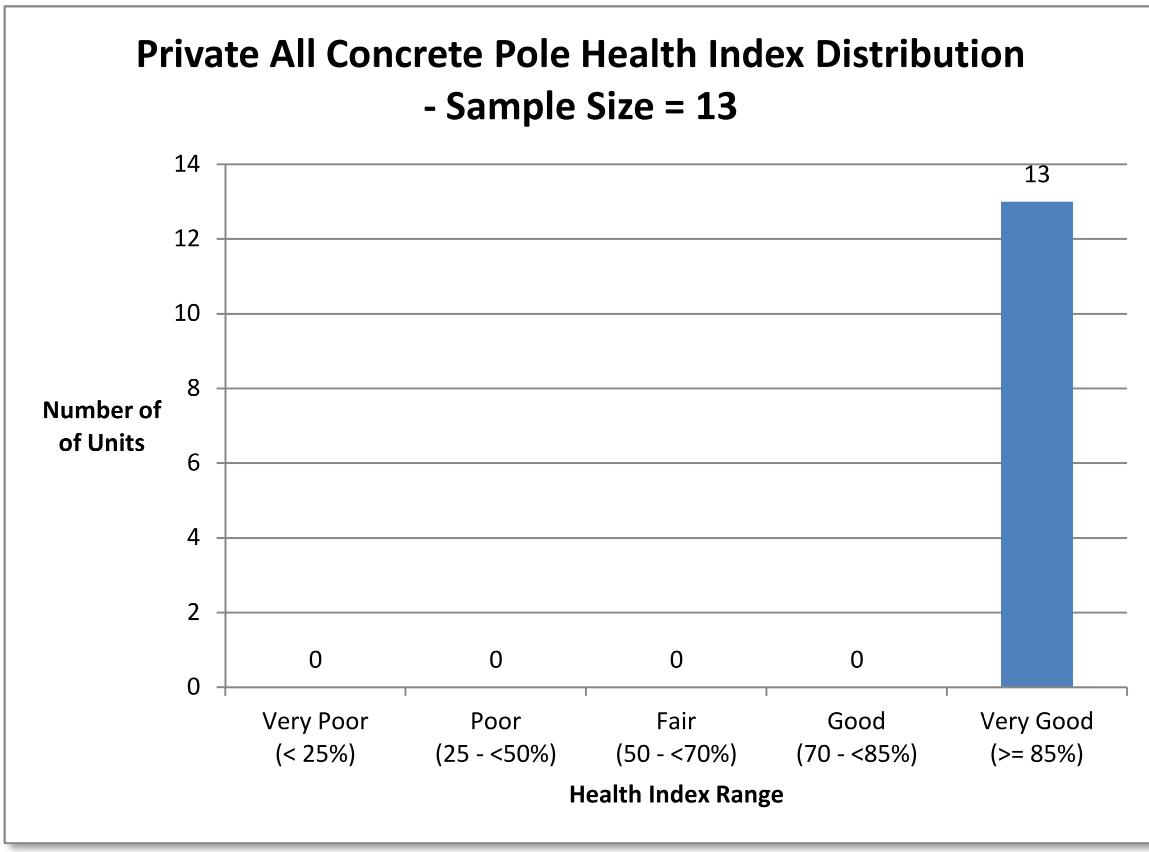


Figure 10-3 All Private Concrete Poles Health Index Distribution (Number of Units)

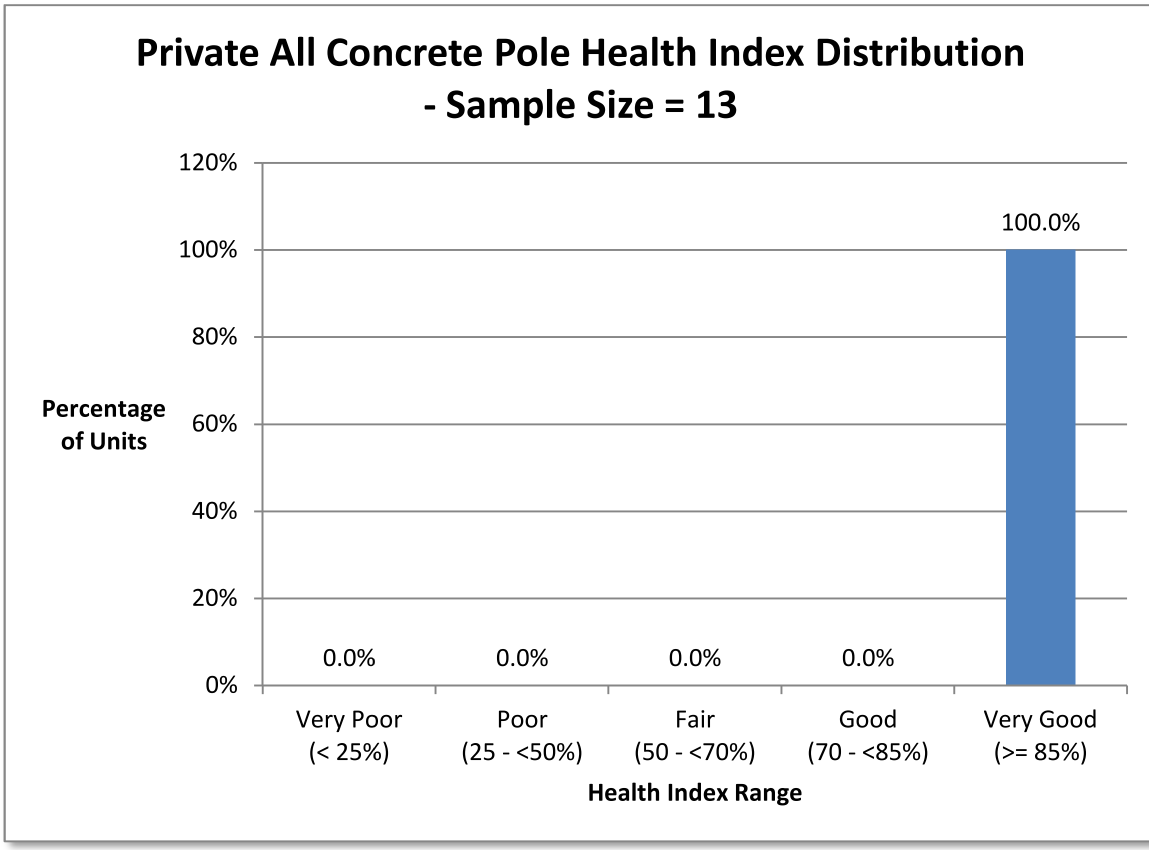


Figure 10-4 All Private Concrete Poles Health Index Distribution (Percentage of Units)

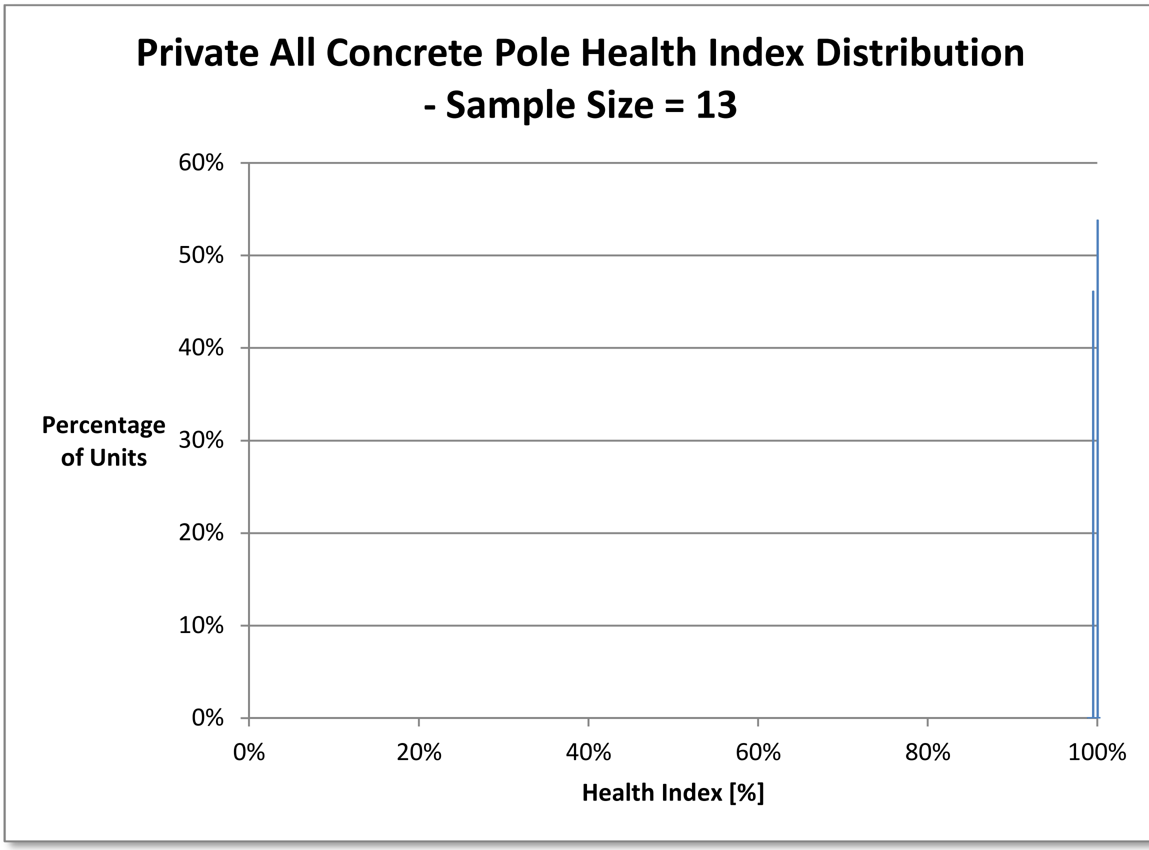


Figure 10-5 All Private Concrete Poles Health Index Distribution by Value (Percentage of Units)

Non-44 kV

There are 6 in-service 44 kV Private Concrete Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 6 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 99%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

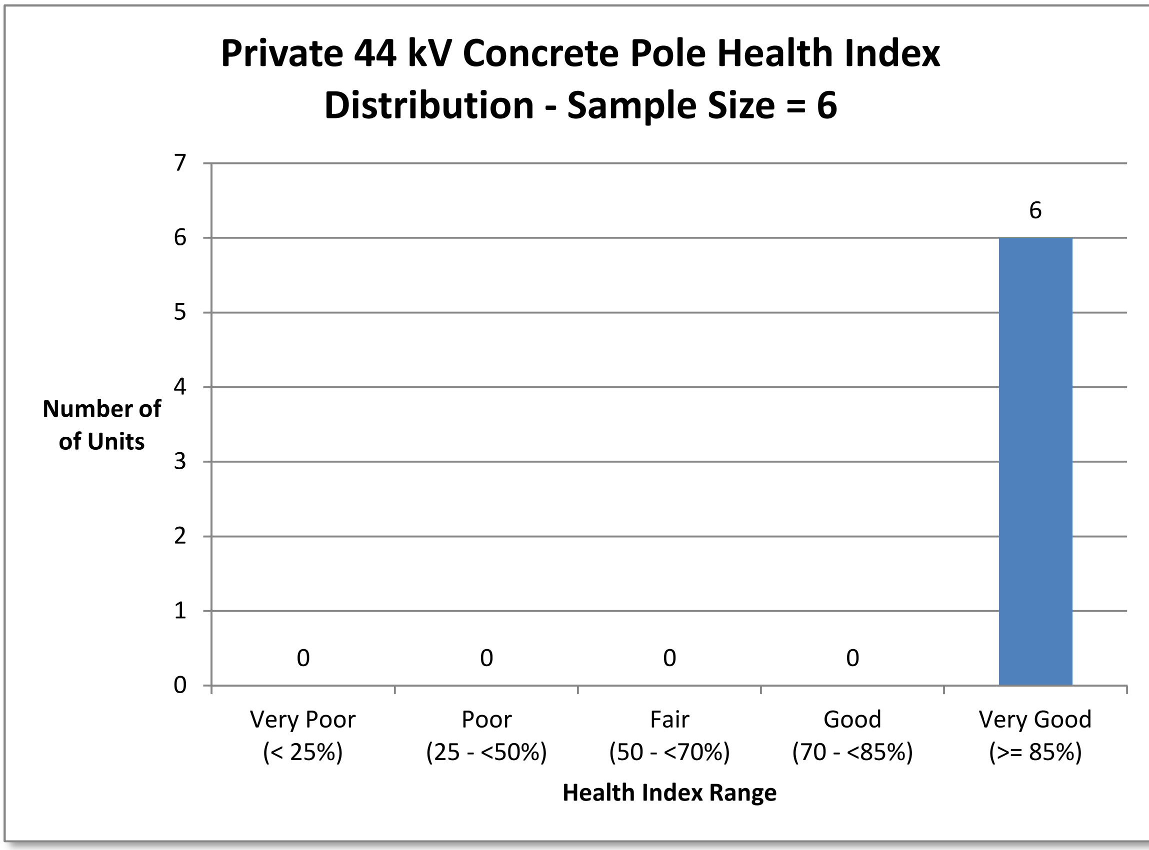


Figure 10-6 44 kV Private Concrete Poles Health Index Distribution (Number of Units)

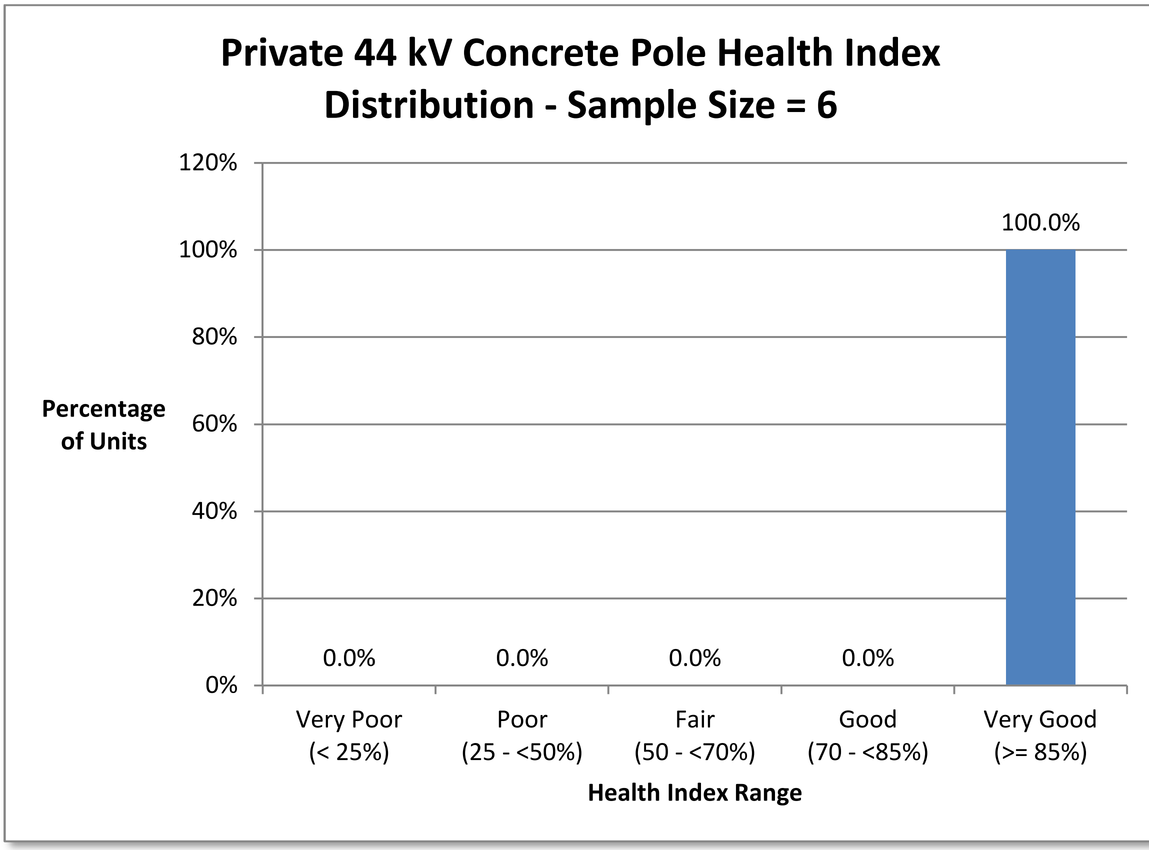


Figure 10-7 44 kV Private Concrete Poles Health Index Distribution (Percentage of Units)

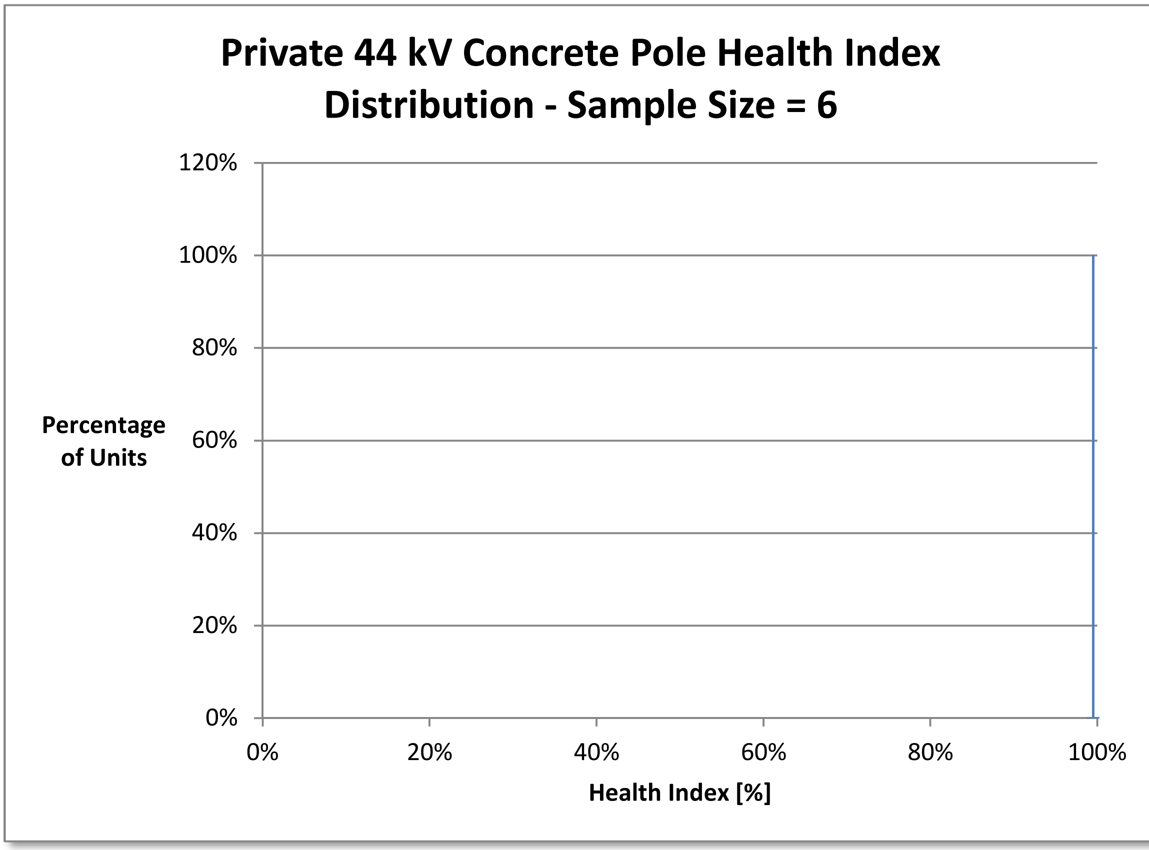


Figure 10-8 44 kV Private Concrete Poles Health Index Distribution by Value (Percentage of Units)

Non-44 kV

There are 7 in-service Non-44 kV Private Concrete Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 7 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 100%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

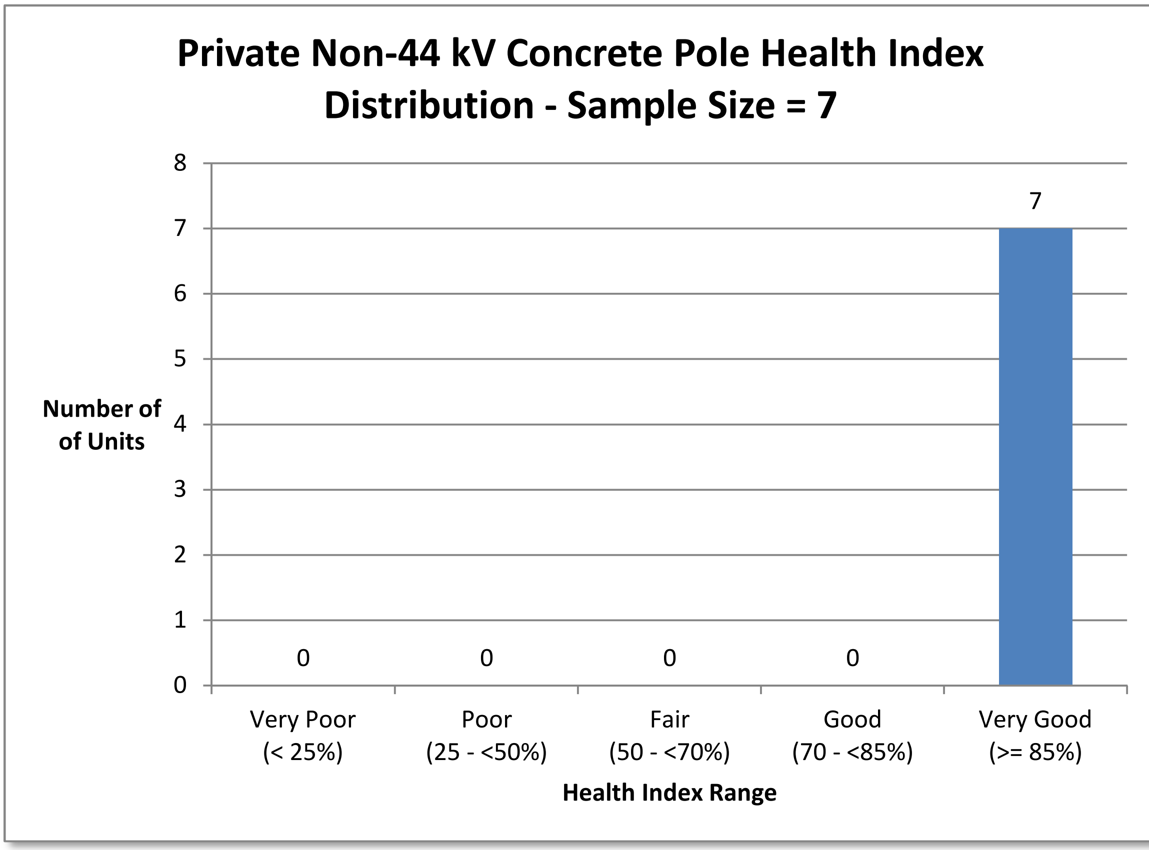


Figure 10-9 Non-44 kV Private Concrete Poles Health Index Distribution (Number of Units)

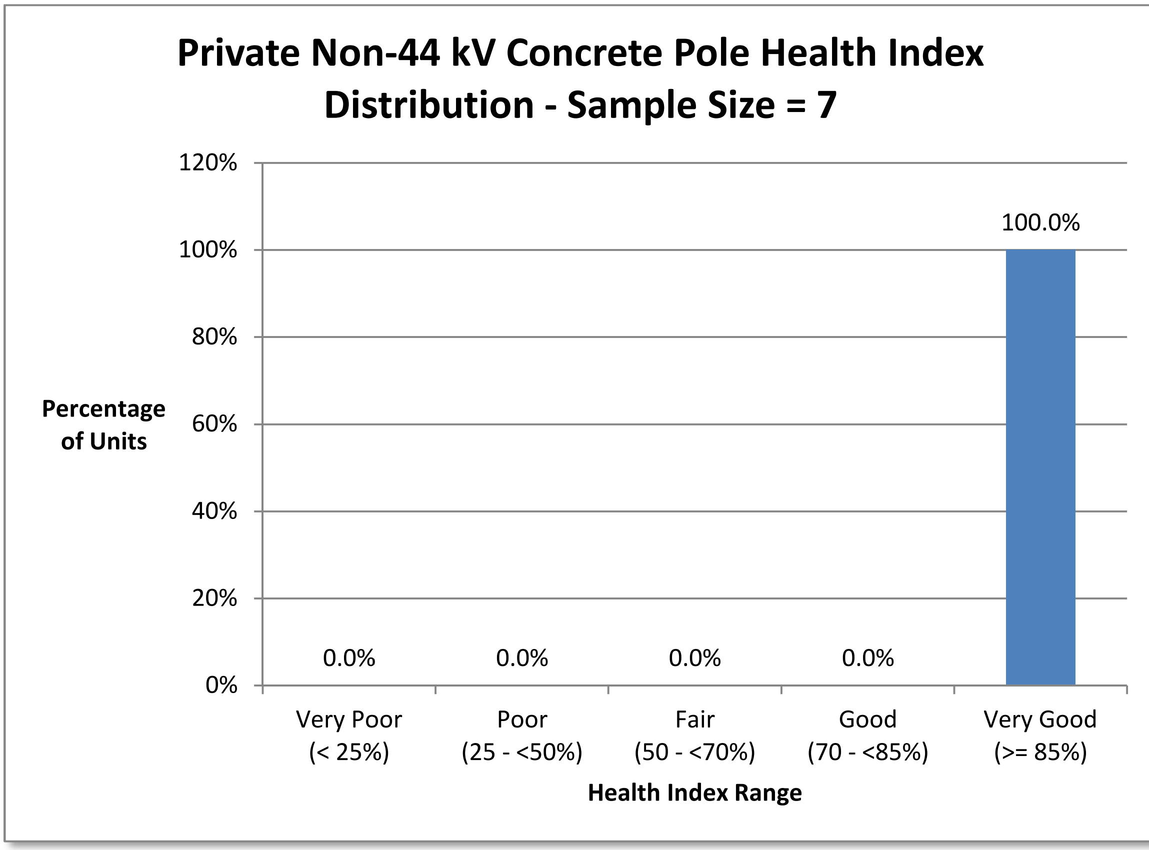


Figure 10-10 Non-44 kV Private Concrete Poles Health Index Distribution (Percentage of Units)

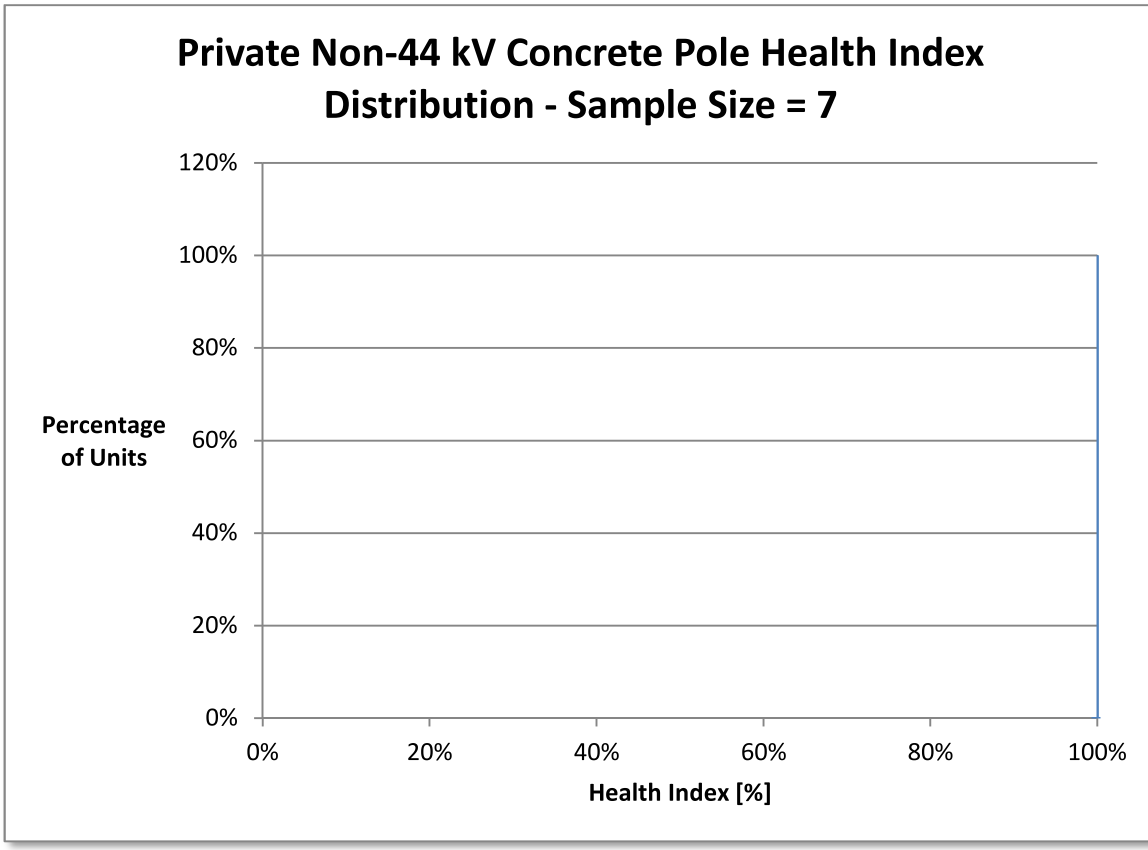


Figure 10-11 Non-44 kV Private Concrete Poles Health Index Distribution by Value (Percentage of Units)

10.5 Condition-Based Replacement Plan

No Private Concrete Poles are expected to be replaced in the next 20 years.

10.6 Data Analysis

The data available for Private Concrete Poles includes age and inspections.

10.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Damage
- Lean

All

Assuming all inspection-based parameters are available, the average DAI for All Private Concrete Poles is 59%.

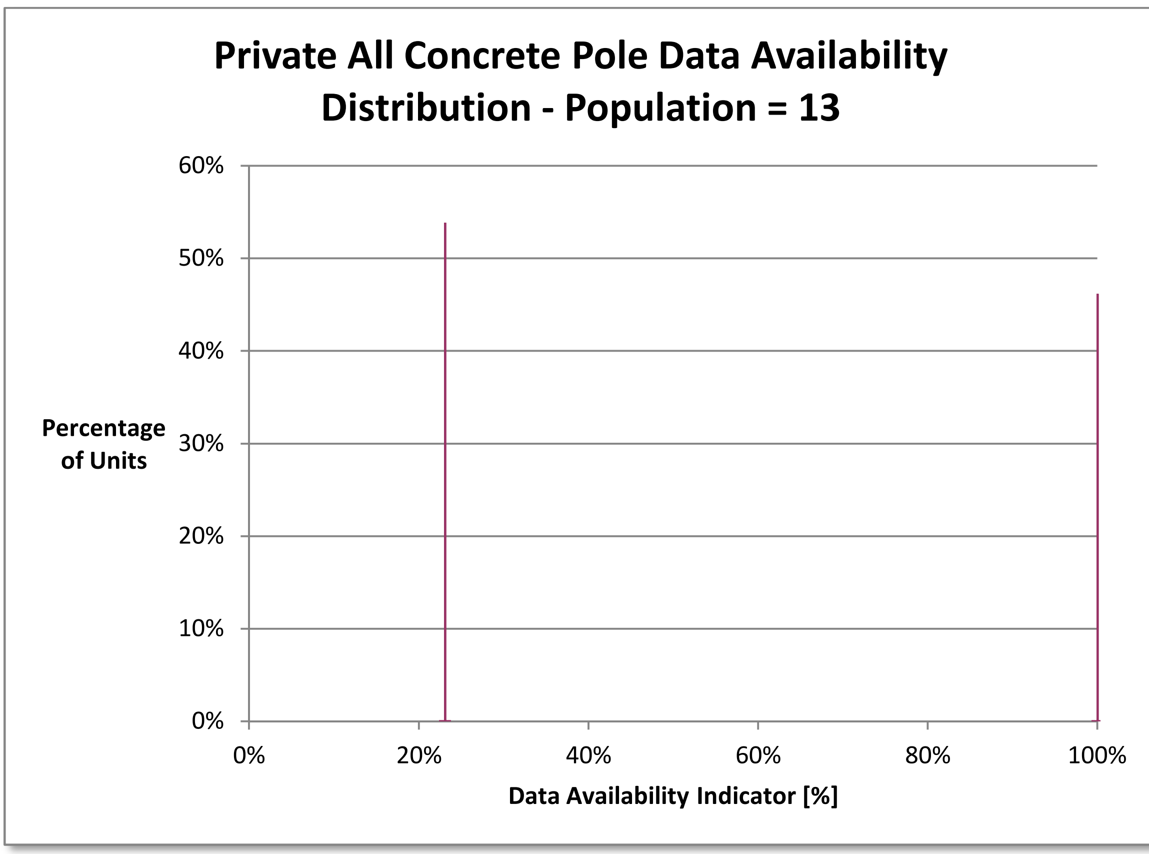


Figure 10-12 All Private Concrete Poles Data Availability Distribution

44 kV

Assuming all inspection-based parameters are available, the average DAI for 44 kV Private Concrete Poles is 100%.

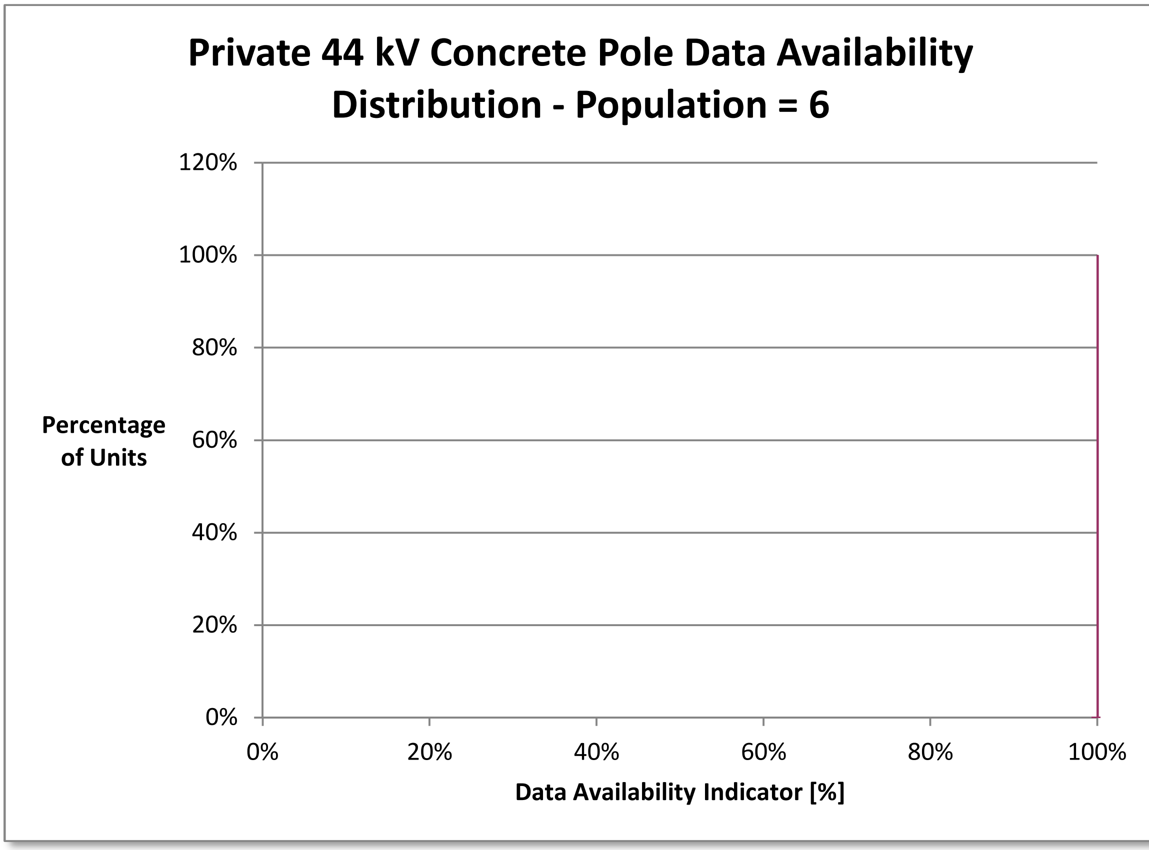


Figure 10-13 44 kV Private Concrete Poles Data Availability Distribution

Non-44 kV

Because age was not known for any of the units and only inspection-based parameters were available, the average DAI for Non-44 kV Private Concrete Poles is 23%.

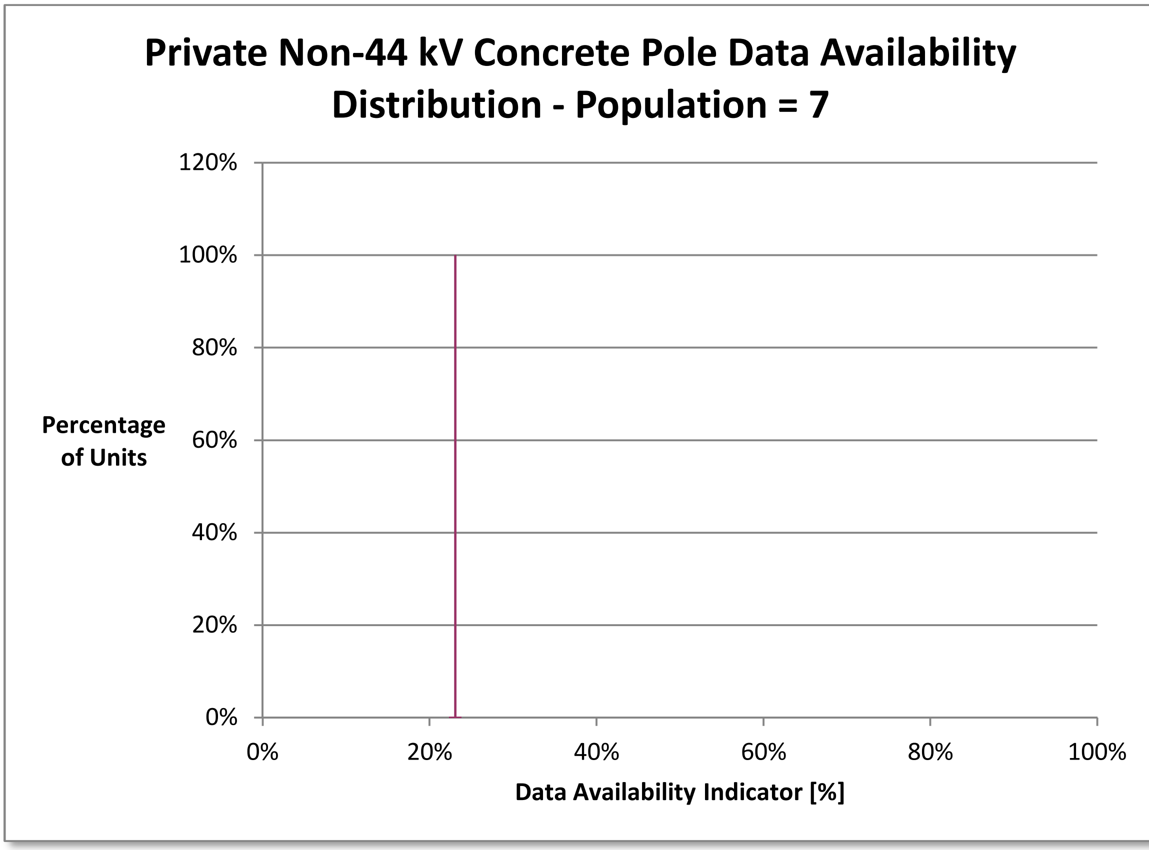


Figure 10-14 Non-44 kV Private Concrete Poles Data Availability Distribution

10.6.2 Data Gap

Please refer to Section 5.6.2.

11 Private Steel Poles

There are no 44 kV Private Steel Poles.

11.1 Degradation Mechanism

Please refer to Section 5.1.

11.2 Health Index Formulation

Please refer to Section 5.2.

11.3 Age Distribution

The age distribution is shown in the figure below. Age was available for 63% of the population. The average age was found to be 45 years.

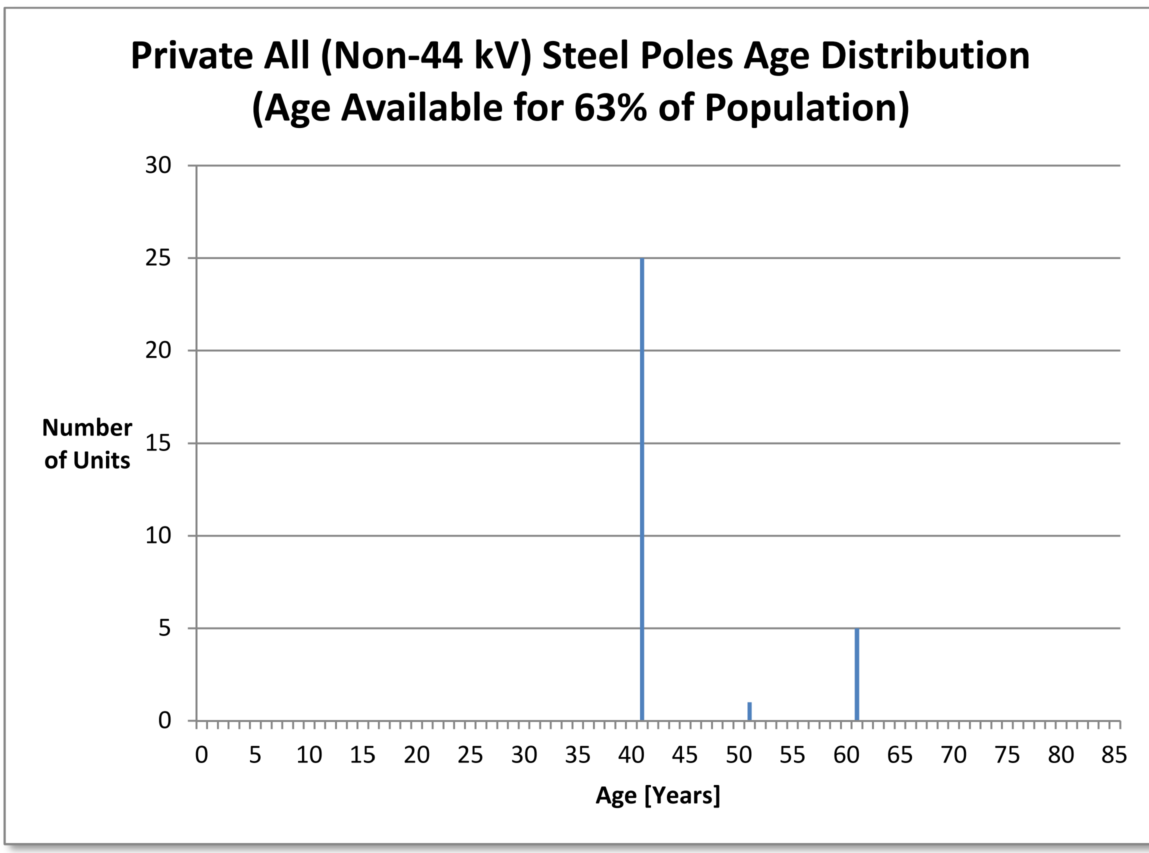


Figure 11-1 Private Steel Poles Age Distribution

11.4 Health Index Results

There are 49 in-service Private Steel Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 49 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 82%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

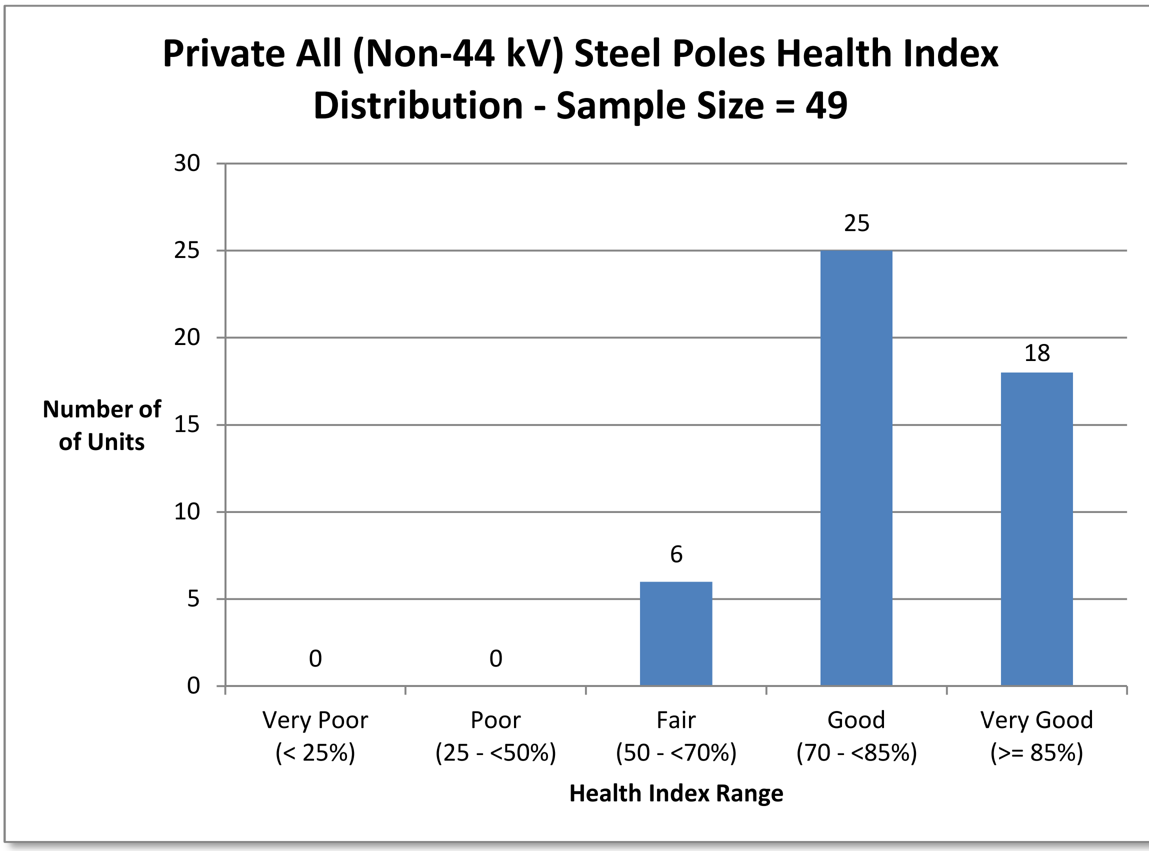


Figure 11-2 Private Steel Poles Health Index Distribution (Number of Units)

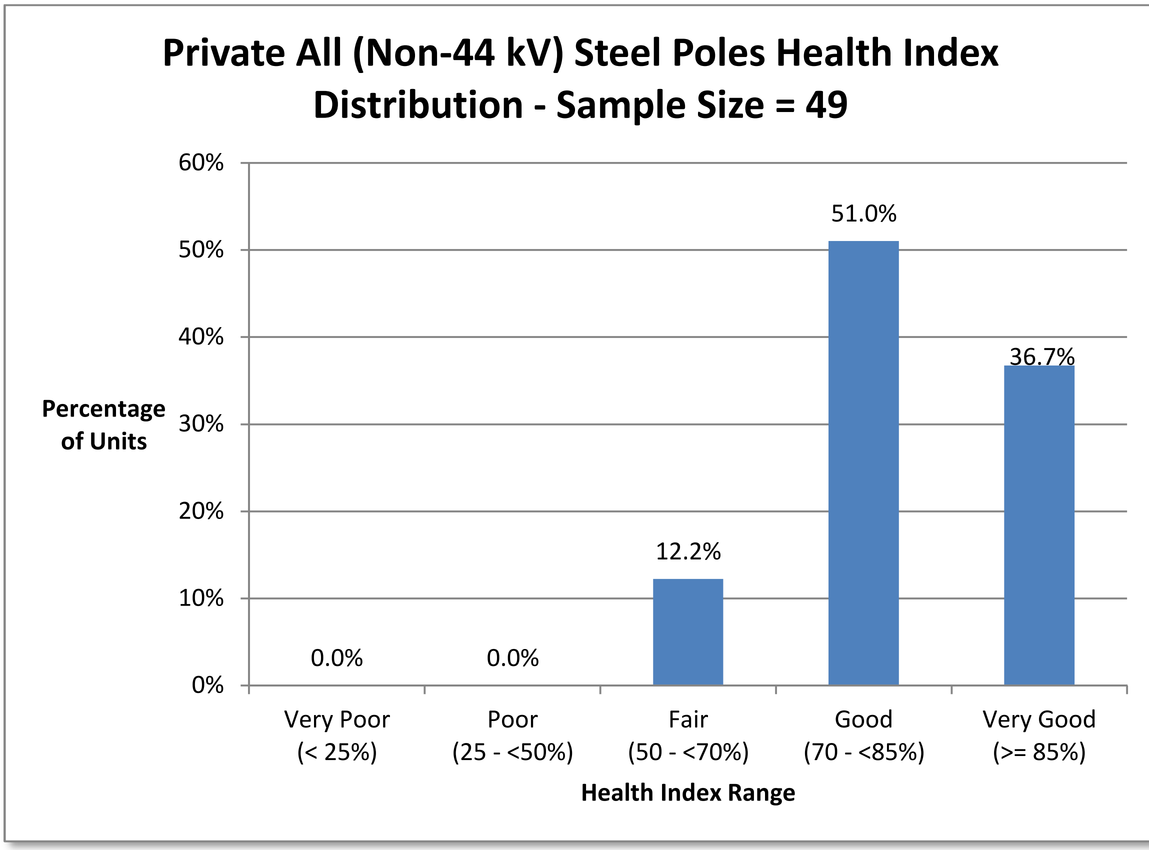


Figure 11-3 Private Steel Poles Health Index Distribution (Percentage of Units)

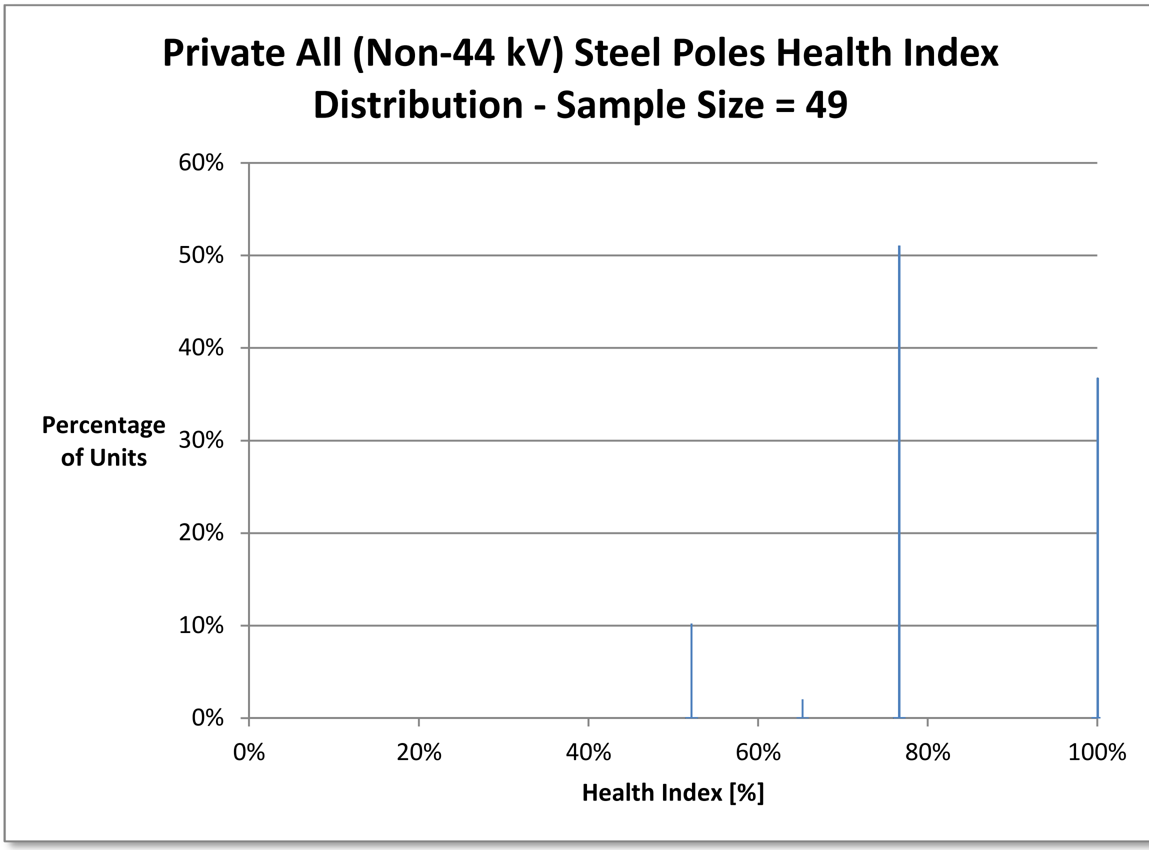


Figure 11-4 Private Steel Poles Health Index Distribution by Value (Percentage of Units)

11.5 Condition-Based Replacement Plan

Although Private Steel Poles are proactively replaced, the number of expected replacements per year is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. Because there is little variation in expected replacements, levelization is not required.

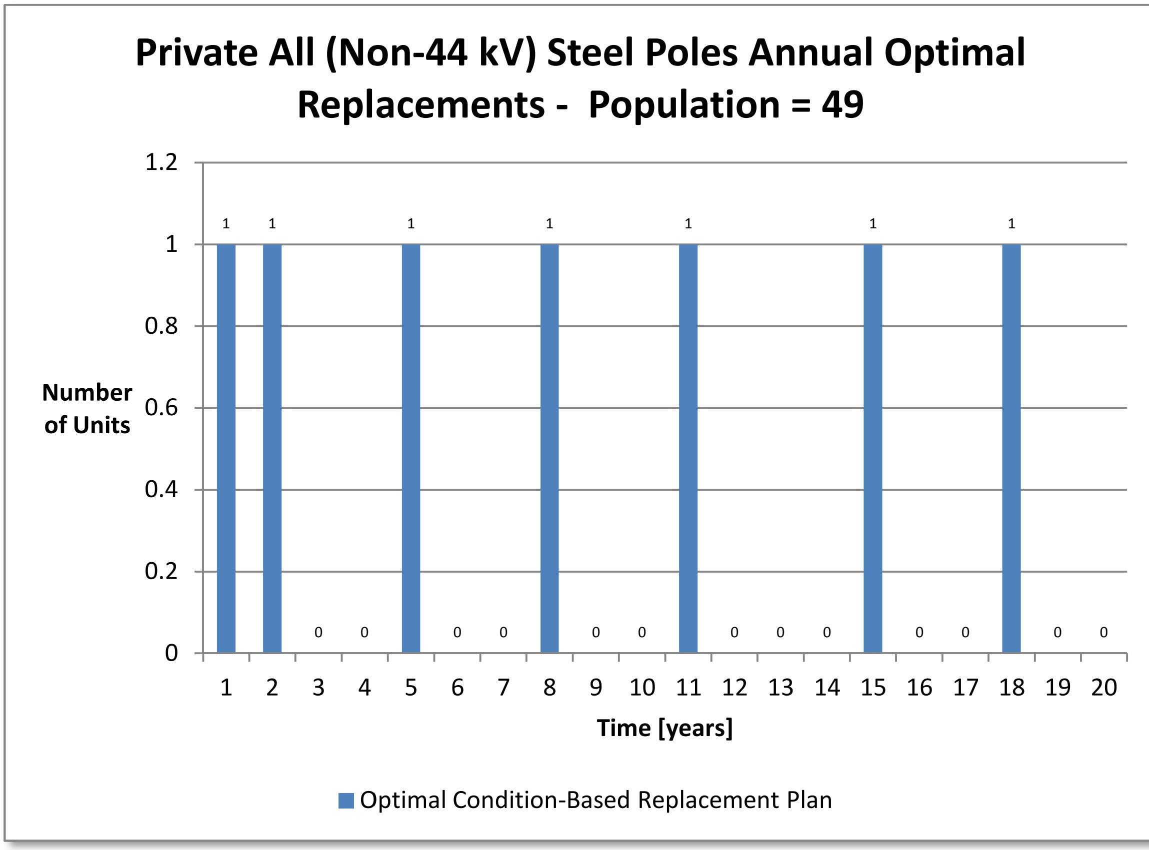


Figure 11-5 Private Steel Poles Optimal Condition-Based Replacement Plan

11.6 Data Analysis

The data available for Private Steel Poles includes age and inspections.

11.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Damage
- Lean

Assuming all inspection-based parameters are available, the average DAI for Private Steel Poles is 72%.

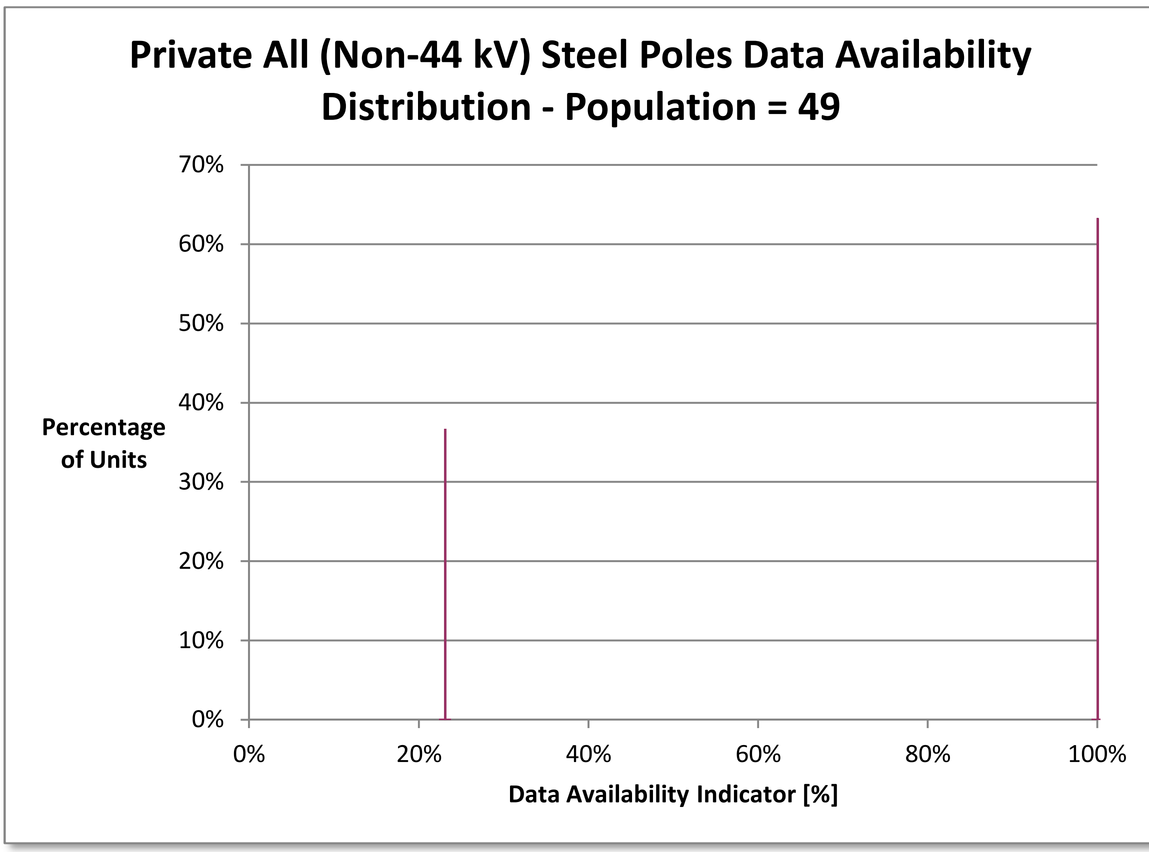


Figure 11-6 Private Steel Poles Data Availability Distribution

11.6.2 Data Gap

Please refer to Section 5.6.2.

12 Private Aluminum Poles

There are no 44 kV Private Aluminum Poles.

12.1 Degradation Mechanism

Please refer to Section 5.1.

12.2 Health Index Formulation

Please refer to Section 5.2.

12.3 Age Distribution

The age distribution is shown in the figure below. Age was available for 91% of the population. The average age was found to be 10 years.

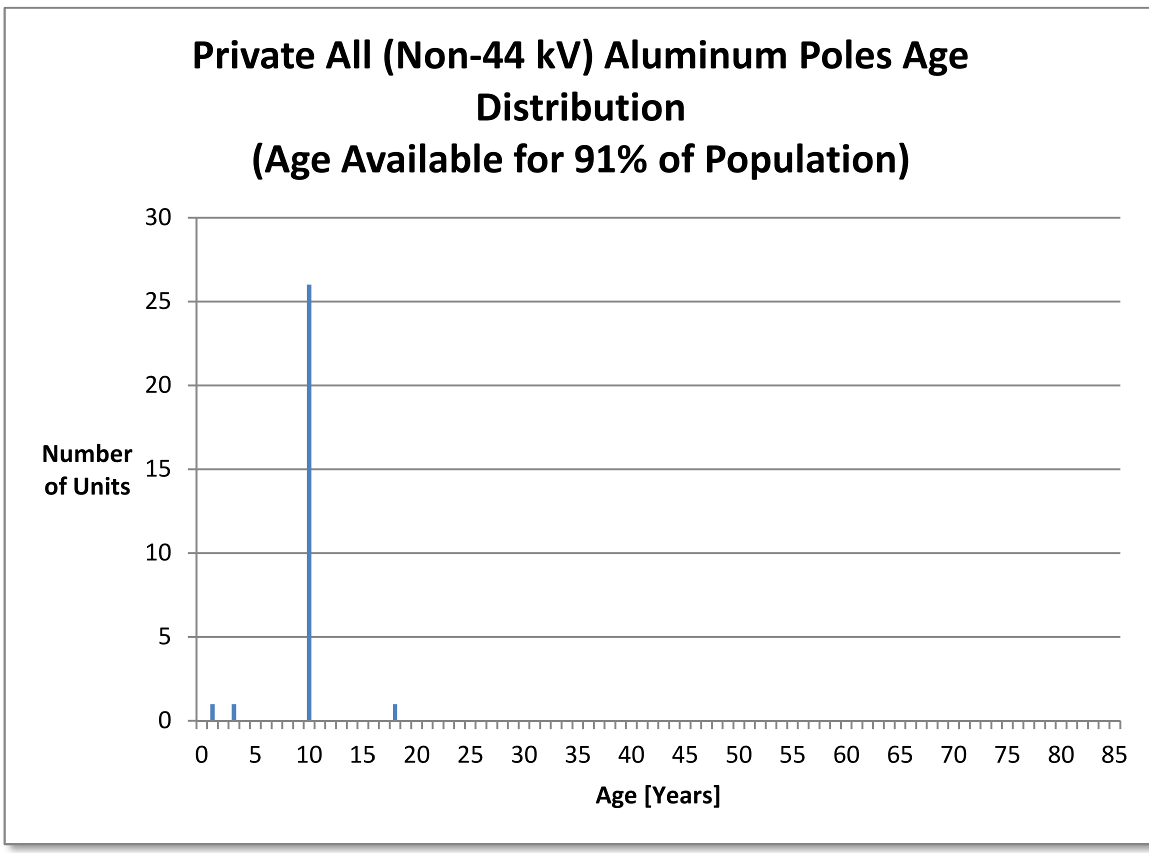


Figure 12-1 Private Aluminum Poles Age Distribution

12.4 Health Index Results

There are 32 in-service Private Aluminum Poles. It is assumed that all units have been inspected and that the absence of an entry in the Non-Conformance Log implies that a unit is in very good condition. All 32 units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 97%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

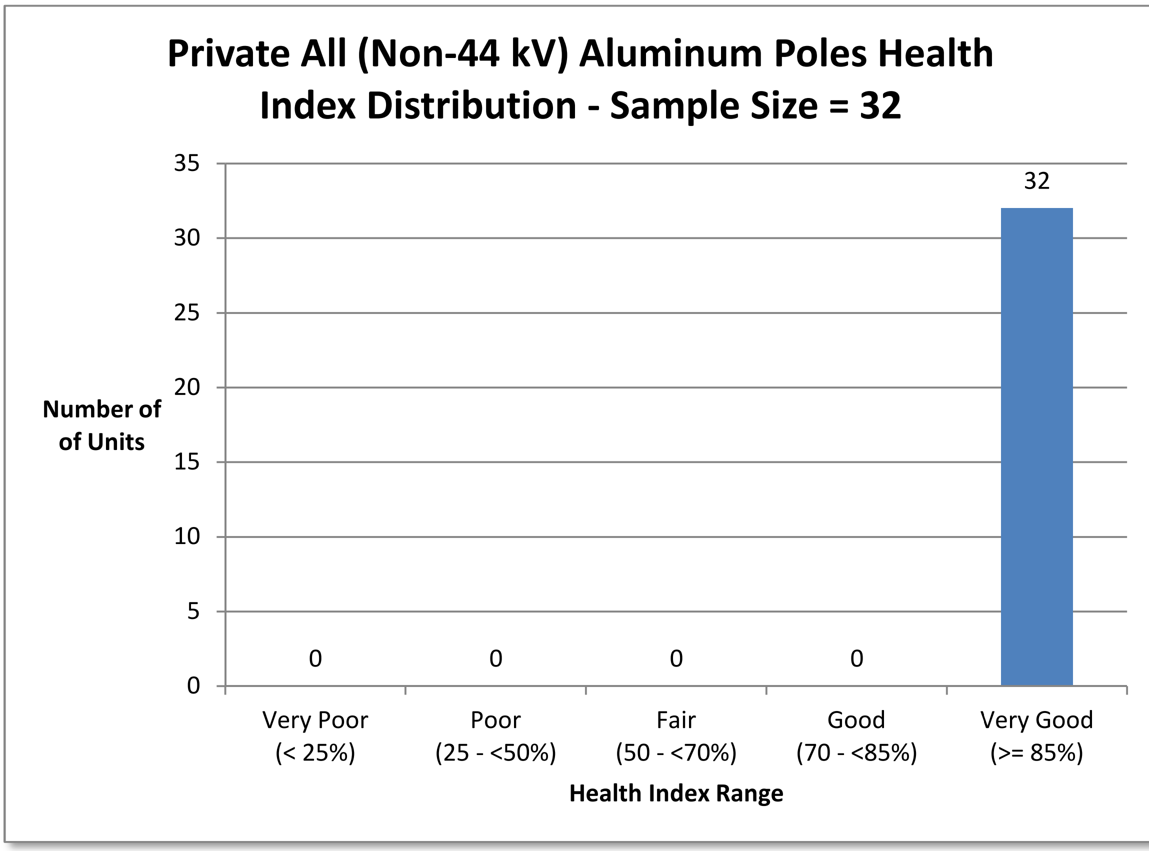


Figure 12-2 Private Aluminum Poles Health Index Distribution (Number of Units)

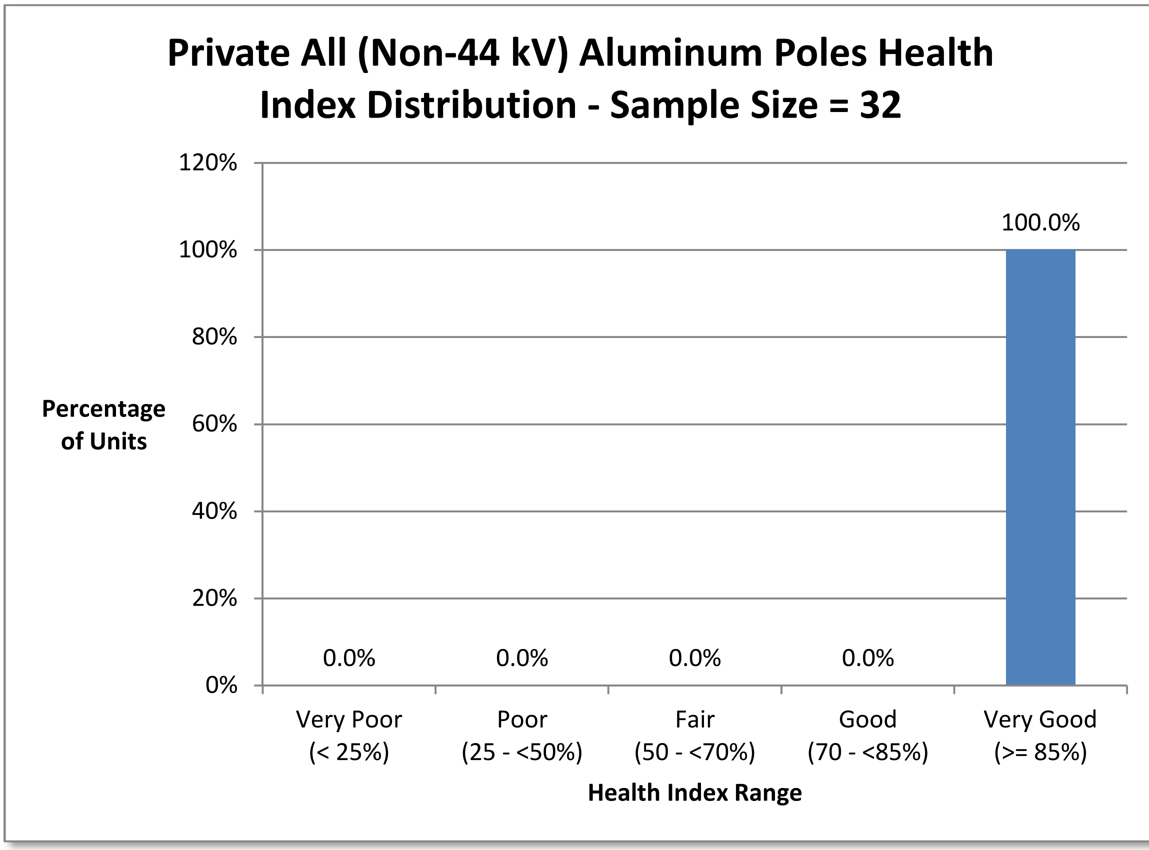


Figure 12-3 Private Aluminum Poles Health Index Distribution (Percentage of Units)

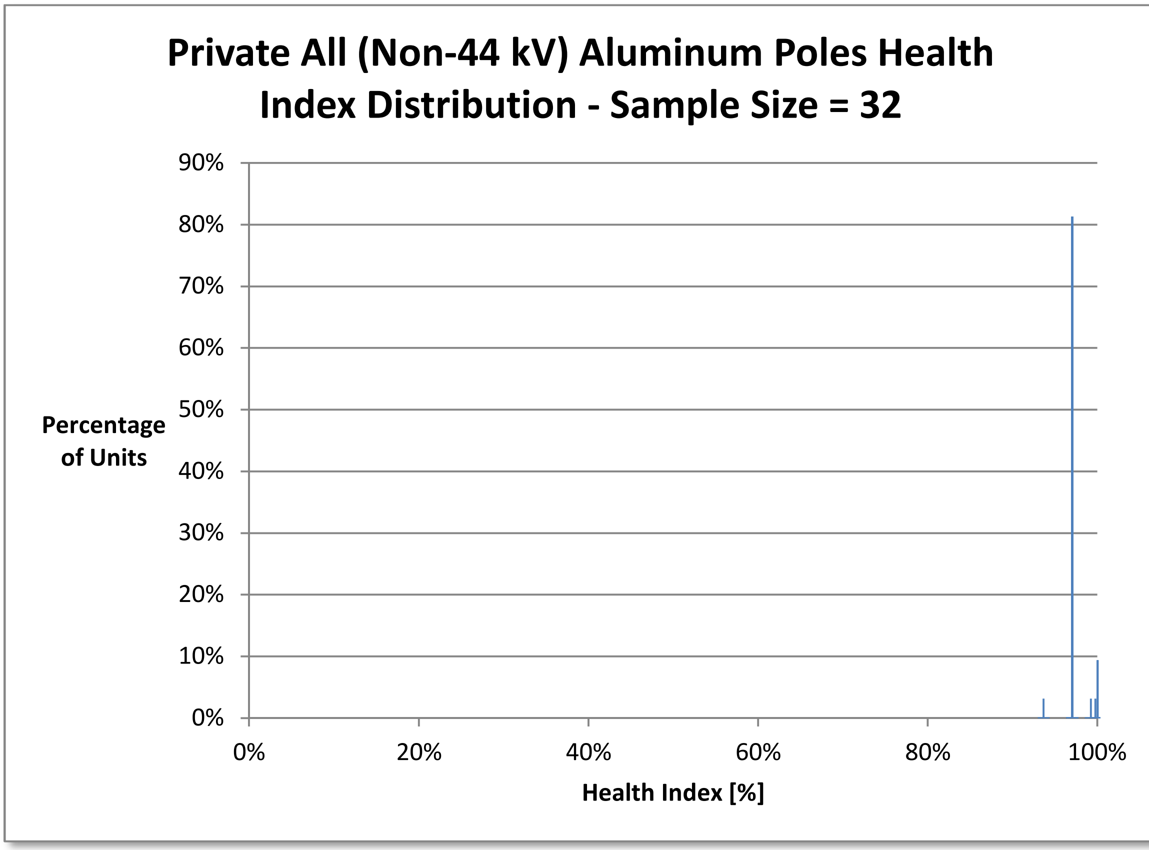


Figure 12-4 Private Aluminum Poles Health Index Distribution by Value (Percentage of Units)

12.5 Condition-Based Replacement Plan

Although Private Aluminum Poles are proactively replaced, the number of expected replacements per year is based on asset failure rate, f(t), as described in Section II.2.2.

The optimal replacement plan is based on the number of expected failures in a given year. Because there is little variation in expected replacements, levelization is not required.

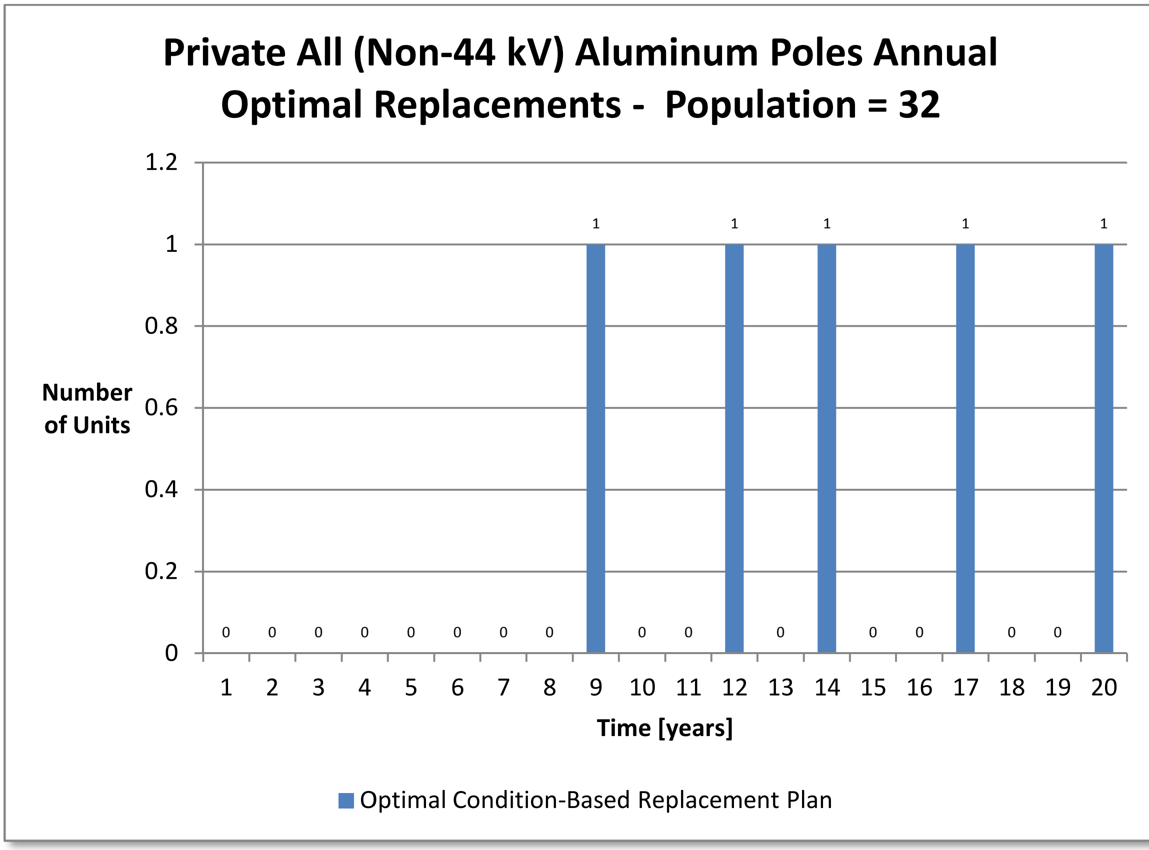


Figure 12-5 Private Aluminum Poles Optimal Condition-Based Replacement Plan

12.6 Data Analysis

The data available for Private Aluminum Poles includes age and inspections.

12.6.1 Data Availability Distribution

Inspection information was taken from the Non Conformance Logs. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Damage
- Lean

Assuming all inspection-based parameters are available, the average DAI for Private Aluminum Poles is 93%.

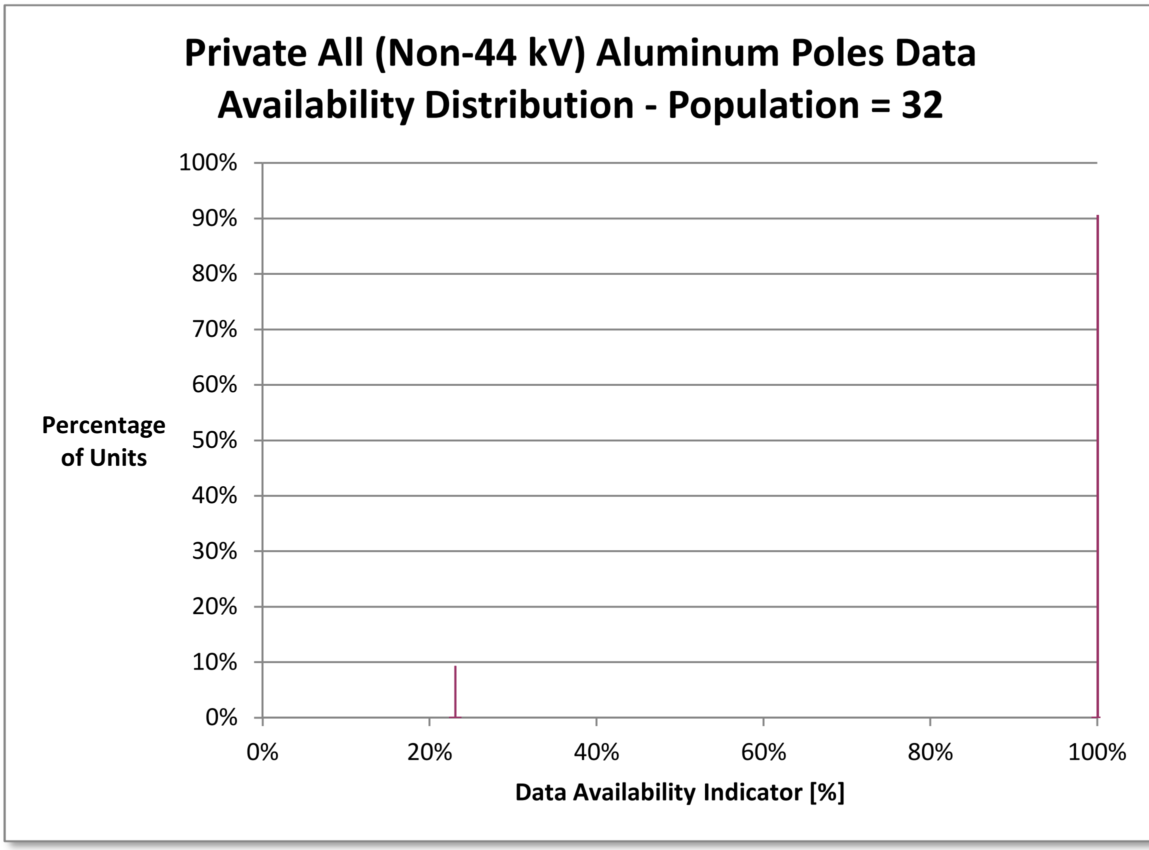


Figure 12-6 Private Aluminum Poles Data Availability Distribution

12.6.2 Data Gap

Please refer to Section 5.6.2.

VII APPENDIX B: CONDITION DATA FOR ADDITIONAL ASSET GROUPS

This page is intentionally left blank.

VII Appendix B: Condition Data for Additional Asset Groups

Breaker and Reclosers

The following parameters and properties are useful in determining the condition of Breakers and Reclosers (types: Air Blast, Oil, SF6, Vacuum, and Air Magnetic):

- Operating Mechanism Condition, namely condition of:
  - Lubrication
  - Linkage
  - Cubicle / Cabinet

- Contact Performance, as determined by:
  - Closing Time
  - Trip Time
  - Contact Resistance
  - Arcing Contact

- Arc Extinction Properties, namely condition of:
  - Moisture (air blast, oil, SF6 only)
  - Leakage (air blast, oil, SF6 only)
  - Tank (air blast, oil, SF6 only)
  - Air Pressure (air blast)
  - SF6 Pressure (SF6)
  - Oil Quality test (oil)
  - Vacuum bottle (vacuum)
  - Dewpoint (air blast, SF6)

- Insulation Condition, as determined by:
  - Power Factor test

- Service Record, as determined by:
  - Number of Operations
  - Age
  - Loading

Pad-Mounted Switchgear

The following parameters and properties are useful in determining the condition of Pad-Mounted Switchgear:

- Physical Condition, namely:
  - Degree of Corrosion
  - Accessibility
  - Condition of Base
  - Degree of Dirt and Debris

- Switch Condition, as determined by condition of:
  - Switch
  - Arc Suppressor
  - Bonding

- Insulation Condition, as determined by condition of:
  - Insulators
  - Barriers

- Service Record, as determined by:
  - Age

- Tests, e.g.
  - IR Scans
  - Ultrasonic

Underground Cables

The following parameters and properties are useful in determining the condition of Underground Cables:

- Physical Condition, namely:
  - Presence of Cable Splices and Terminations

- Operating Condition, as determined by condition of:
  - Loading

- Service Record, as determined by:
  - Age
  - Vintage
  - Fault Rate

VIII REFERENCES

This page is intentionally left blank.

VIII References

Aichinger, Richard F. and Huang, John C. Introduction to Steel Utility Poles. http://www.pdhonline.org/courses/s114/s114.htm

B. Gompertz, "On the Nature of the Function Expressive of the Law of Human Mortality, and on a New Mode of Determining the Value of Life Contingencies," Philosophical Transactions of the Royal Society of London, Vol. 115, pp. 513-585, 1825

Cress S.L. et al, "Utility Guide to Root Cause Analysis of Distribution Failures" CEATI Report No. T074700-5068, February 2010.

Hjartarson T, Jesus B, Hughes D.T., Godfrey R.M., "The Application of Health Indices to Asset Condition Assessment", presented at IEEE-PES Conference in Dallas, September 2003.

Tsimberg, Y., et al, "Asset Depreciation Study for the Ontario Energy Board", Kinectrics Inc. Report No: K-418033-RA-001-R000, July 8, 2010

W. M. Makeham, "On the Law of Mortality and the Construction of Annuity Tables," J. Inst. Actuaries and Assur. Mag. 8, 301-310, 1860

Wang F., Lotho K., "Condition Data Requirements for Distribution Asset Condition Assessment", CEATI International, 2010

Willis H.L., Welch G, Randall R. Schrieber, " Aging power delivery infrastructures", Marcel Decker Inc., 2001

This page is intentionally left blank.

TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

Greater Sudbury has included information supporting the final disposition of smart meter costs with this Application. Included in this is the removal of stranded meter costs in accordance with the Board's guidance in G-2011-0001 *Smart Meter Funding and Cost Recovery - Final Disposition.*

Greater Sudbury is seeking to recover $1,193,861, through a rate rider over a two year period with respect to stranded meters.

Greater Sudbury has removed the stranded meter value from fixed assets and the amount is not included in calculation of the 2013 rate base. See Exhibit 9, Tab 1, Schedule 3 for further details related to Stranded Meters.

GREEN ENERGY PLAN

The Board's filing requirements, at Section 2.2.3 require each distributor filing a cost of service rate application to include a Green Energy Act (GEA) Plan with the Application. Additionally, applicants are required to include a letter of support from the Ontario Power Authority (OPA) with their plan. Greater Sudbury's GEA Plan and OPA letter are attached to this application as Exhibit 2, Tab 4, Schedule 5, Attachment 1.

The Board considered cost responsibility for renewable connections pursuant to O. Reg. 330/09 in its Connection Cost Responsibility for Renewable Generation deliberations EB-2009-0077. The result of the Board's consultation in EB-2009-0077 was a revision to the Distribution System Code that set cost responsibility to parties depending on the nature of the costs.

The Board established 3 general categories of cost and assigned the party responsible for costs as follows:

- Connection assets - generator
- Expansions - with Board-approved plan distributor 100%, all other cases distributor up to $90,000 per MW of capacity of the connecting generator "renewable energy expansion cost cap"
- renewable enabling improvements - Distributor responsible 100%

Greater Sudbury has included $284,913 in its capital budget for purposes of facilitating renewable connections. This capital amount is Greater Sudbury's estimate of its obligation to provide expansions up to the renewable energy expansion cost cap and for renewable enabling improvements. There are a number of additional expenses included in Greater Sudbury's GEA Plan that Greater Sudbury will seek to recover through provincial funding as it is believed they are of a benefit to all consumers in the Province.

Greater Sudbury Hydro Inc
Hydro du Grand Sudbury Inc

empowering communities
le pouvoir aux communautés

A GSU company

Basic Plan to Enable Bill 150

The

Green Energy and Economy Act

March 2012 – Rev FINAL

1.0 Executive Summary

In accordance with the Ontario Energy Board's (OEB) filing requirements under the *Green Energy and Green Economy Act, 2009* (the Act). Greater Sudbury Hydro Inc. (GSHI) has prepared the following Basic GEA Plan. The GSHI Basic GEA Plan should reduce or eliminate connection delays by mitigating distribution system constraints caused by high penetrations of distributed generation.

The connection of high penetrations of distributed renewable generation on to a distribution system creates bi-directional real and reactive power flows that the existing unidirectional distribution system was not designed to accommodate. Creating a transitional path from the existing system to the "smart grid" is the greatest challenge Distribution Engineers have faced in the past half century.

In preparing this plan, we have considered how to prudently approach this challenge. We have endeavoured to educate ourselves by joining a number of well recognized industry organizations and participating in conferences, seminars and training. A complete list is found in Appendix C.

The following describes the types of expenditures resulting from GSHi's GEA plan. Table 1 provides a summary of the proposed five year spending levels. Each of these investments is discussed in more detail in the body of the plan.

There are two types of capital projects envisioned in this plan;

- Mitigation of sustained, localized high voltages by installing Community Energy Storage (CES) units (not yet commercially available);
    - Estimated Installed Capital Costs $62,500 per 25 kVA CES
        - Estimated installed units – 4 in 2014, 17 in 2015, 20 in 2016, and 24 in 2017.
    - Purchase of Distribution Management System (DMS), at an estimated cost of $250,000, to control the CES units.
- Installation of transfer trip and monitoring equipment on FiT projects;
    - Estimated Installed Capital Costs $25,000 per project;
        - Estimated installed units 2 per year – 2013, 2014, 2015, 2016 and 2017.

There are four types of OM&A envisioned in this plan:

- Hi speed fiber communication costs associated with each CES and each FiT transfer trip and monitoring – estimated at $75 per installation per month;
- Smart grid/distributed generation education and training;
- One additional Engineering FTE to cope with the quantity of MicroFiT applications;
- DMS annual license and maintenance fees.

Table 1: Renewable Enabling Investment Costs proposed in the GSHI GEA Plan

Renewable Enabling Investment Costs						
	2013	2014	2015	2016	2017	Total
Capital	$50,000	$550,000	$1,112,500	$1,300,000	$1,550,000	$4,562,500
Mitigation of Sustained, Localized High Voltages		$500,000	$1,062,500	$1,250,000	$1,500,000	
Monitoring, Control and Transfer Trip - 2 per year	$50,000	$50,000	$50,000	$50,000	$50,000	
OM&A	$174,850	$184,000	$241,313	$265,091	$292,589	$1,157,842
One Engineering FTE	$125,000	$128,750	$132,613	$136,591	$140,689	
Communication Costs	$1,800	$7,200	$24,300	$44,100	$67,500	
DMS Software Maint Fees			$45,000	$45,000	$45,000	
Smart Grid Education & Training	$48,050	$48,050	$39,400	$39,400	$39,400	
Total	$224,850	$734,000	$1,353,813	$1,565,091	$1,842,589	$5,720,342

2.0 Introduction and Objectives of the Act

On September 9, 2009, the Green Energy and Green Economy Act, 2009 (the "GEA") was proclaimed into force. The GEA amended a number of Provincial statutes including the Ontario Energy Board Act, 1998 and the Electricity Act 1998, seeking to implement policies that would, inter alia, facilitate the connection of renewable generation and the development of a smart grid.

One of the mechanisms, prescribed the GEA, for accomplishing the goals of increased renewable supply and smart grid implementation is the addition of a deemed license condition on all Local Distribution Companies (LDC) in the province. Section 70(2.1)2-3 include provisions requiring the filing of plans for the expansion or reinforcement of the distribution system for the connection of renewables and the development of the smart grid.

This document details Greater Sudbury Hydro's (GSHi) efforts and intentions relative to the objectives noted above and constitutes GSHi's Distribution System Plan for purposes of the GEA.

3.0 Current Assessment – Greater Sudbury Hydro's Distribution System

Greater Sudbury Hydro (GSHI) owns, operates and maintains a distribution system, currently serving over 46,500 customers, in portions of the City of Greater Sudbury and the Municipality of West Nipissing. GSHI distributes power from transformer stations owned by Hydro One Networks Inc (HONI) to its customers either directly or through its substations. The service territory includes the old City of Sudbury (mainly urban with some rural feeders), the former Town of Coniston, the former town of Capreol, the former Town of Falconbridge, the former Town of Sturgeon Falls and the former Town of Cache Bay all of which are not contiguous.

The GSHI SCADA system provides our System Control Center with real-time information to monitor and operate the distribution system. System monitoring and operation was accomplished by the installation of supervisory control and data acquisition hardware at municipal substations and 44 kV switches throughout the system.

Table 2 summarizes general statistics of GSHI's distribution system;

Table 2: GSHI system and asset statistics.

System Characteristics	Description
Sub-Transmission Voltage(s)	22/44kV
Distribution Voltage(s)	4.16kV; 12.47kV
Winter Peak (All-Time High)	206 MW
Summer Peak	154 MW

Annual Energy Delivered (5-year Average)	951 GWh
Total Customers (2010 year-end) • Residential Customers • Commercial Customers	46,502 42,068 4,444
Asset Description	**Quantity**
Distribution Stations	31
Power Transformers	54
SCADA Systems	1
Distribution Transformers	4,739
Distribution Poles	16,949
Underground Cables (equivalent 3-phase km)	228
Overhead Conductors (equivalent 3-phase km)	745
Submersible Cables (equivalent 1-phase km)	4.5
Electrical Meters	~47,000

4.0 Enabling Renewable Generation Connections

Ensuring that renewable generation project can be readily connected to the LDCs distribution system without undue delay is a major focus of the *Act*. Unfortunately this government policy is way ahead of commercially available technology that will permit significant penetration levels without adverse effects on some load customers.

The Smart Grid is purported to provide the solution to this dilemma. The US Department of Energy defines the Smart grid as meeting seven principles:

- The grid will heal itself.
- The grid will motivate customers to be an active grid participant and will include them in grid operations.
- The grid will resist attack
- The grid will provide the level of power quality desired by 21st century users.
- The grid will accommodate all generation and storage options.
- The grid will enable markets to flourish.

- The grid will optimize its assets and operate efficiently.

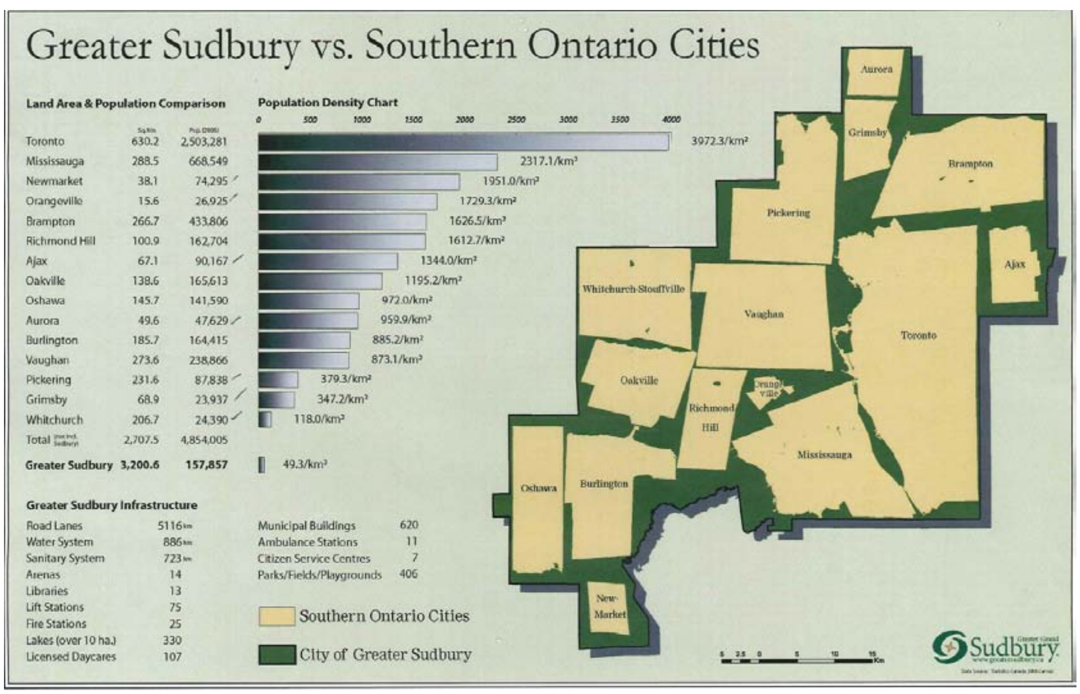
Any grid that meets these principles will support significant amounts of renewable generation.

4.1 Projecting Embedded Generation Growth with a Limited Historical Base and an Ever Changing , Politically Dynamic Future

4.1.1 Greater Sudbury Hydro – Renewable Generation Connection Historical Context

Greater Sudbury Hydro has a geographically non-contiguous service territory consisting of seven separate and distinct operating systems. The largest of these separate and distinct electrical systems is defined by the 304 square kilometers within the boundaries of the former City of Sudbury. Over 60% of this land mass is undeveloped, low cost, non-arable lands well suited for large wind or solar farms. Even within the "urban" areas of the former City significant tracts of bush, mining brown lands, grasslands and marshes exist. Figure 1 illustrates the size of the new City of Greater Sudbury in comparison to several southern Ontario Cities.

Figure 1: The land mass and population density – City of Greater Sudbury versus Fifteen (15) Southern Ontario Cities.



Focusing in on the former City of Sudbury, it is instructive to recall what happened before FiT, with RESOP. After RESOP was announced GSHI received two (2) 10 megawatt solar farm applications, one of which had progressed to an approved Customer Impact Assessment (CIA), at the time that FiT was announced. Subsequent to the FiT announcement the CIA was rescinded. In addition, GSHI had received official RESOP applications for connection of over 120 megawatts of wind generation. The wind proponents proposed to construct a large wind farm approximately 45 km from the boundaries of GSHI service territory, but within the boundaries of the new City of Greater Sudbury and connect to all available Hydro One and GSHI 44 kV sub-transmission systems within the Sudbury basin. The proponent was backed by Lehman Bros and liquidated their assets after the market meltdown of November 2008. However, we believe the genie is out of the bottle and distributed renewable generation will continue to request connection to the distribution system for the foreseeable future. The question is in what quantum and at what pace?

4.1.2 Other Factors Affecting the Generation Forecast

Constraints

- General Constraint Considerations

Since their inception, distribution systems have been planned, designed and constructed for unidirectional power flows from a single source to the loads. Existing distribution systems were never designed for bi-directional power flows and were never intended to facilitate the connection and management of a large number of discrete embedded generators. As such, the amount of generation capacity to be connected to any part or portion of a distribution system will be constrained by a variety of engineering factors, such as feeder ampacity, short circuit capacity, and power quality; the lack of commercially available equipment to mitigate the engineering factors will limit connection in specific locations for the foreseeable future. Upstream factors at the transmission system level such as limits on reverse power flow and short circuit capability will also act to constrain renewable generation development.

It is anticipated that in these early days the connection of small-scale inverter-based renewable generation will not impose many limitations, but that over time high penetrations of micro-generators, or several medium-sized generators on the same feeder or station will have a noticeable, negative impact on the distribution system and upstream elements. Large scale projects will have an immediate impact and will require detailed study and analysis, with software that may or may not yet exist, to understand the impact of the proposed connection.

Other General Constraints

- Suitable voltage control technology does not yet exist to allow high penetrations of highly variable distributed renewable generation connected to and impacting secondary buses.
- Existing distribution Engineering Analysis software is inadequate in performing the type of analysis required to predict the kinds of problems that will be encountered as distributed generation grows. Although it is getting better.
- The generation capacity of a feeder or station is not a fixed value; it is a time variable function of the time variable actual load on the station or circuit. Therefore load decreases due to customer behavioral response to TOU rates and/or Conservation and Demand Response initiatives may have an adverse effect on power quality at the transformer, line section, feeder, station or sub-transmission feeder level if said reductions raise penetration levels, relative to load, above the aforementioned as yet undefined level of high penetration.
- Initial analysis indicates that the quantum and pace of FiT and MicroFiT applications will be unaffected by FiT 2.0 announcements. However, the planned two year reviews may skew actual connections as the time for each review approaches and future reviews may reduce the financial incentive to proceed with or initiate a new renewable generation project.

Constraint Considerations Specific to the GSHI Service Territory

- The OPA has allocated all available transmission capacity in Northeastern Ontario.
- Martindale TS represents 52% of the available renewable generation connection points in the old City of Sudbury, Capreol and Falconbridge. The TS is, as of March 23, 2012, constrained by short circuit capability. Recent correspondence with Hydro One confirms that an OPA approved transmission connected renewable generation project is scheduled to be in-service by “the end of 2012”. As part of the project approval, the proponents must pay for upgrades to reduce the short circuit currents at Martindale TS. This will have two effects;
    - Pro -- With the short circuit constraint relieved, all the pent up renewable generation projects have the potential to move forward quickly and,
    - Con – It would appear that application of sections of the Transmission System Code and the Distribution System Code will require that all embedded, distribution connected,

renewable generation (on both the Hydro One and the GSHI distribution System) be apportioned their fair share of the cost to relieve the constraint and that all amounts collected by Hydro One Distribution and GSHI apportioned customer costs flow back to Hydro One (Transmission) to be rebated to the proponents. This new cost may act as a constraint or may be a non-issue depending on its quantum. Regardless, the administrative cost of the required economic evaluations to Hydro One and GSHi will be significant.

- Coniston TS is constrained by thermal capacity. Hydro One Networks transmission systems has stated that they are reviewing Coniston TS and plan to replace or relocate the end of life station by 2014. If Coniston TS is moved the Coniston load and generation will have to be served by a 44 kV feeder from Martindale TS.

Accelerators

4.1.3 Accelerant Considerations Specific to the GSHI Service Territory

- Significant tracts of bush, mining brown lands, grasslands, marshes and other vacant lands exist within GSHI's service territory. Depending upon the interpretation of section 4.3(b) of the FiT Two-Year Review Report, these lands may be prime for solar and wind farms if little or no acceptable lands exist in southern Ontario or may not matter if stand alone solar and wind farms are not permitted under 4.3(b). We choose to interpret the clause as accelerating renewable generation projects in our service territory.
- In September 2009 the then Energy Minister announced a significant expansion to the transmission system which included a third 500 kV line from Sudbury to Essa TS. This transmission project will relieve the transmission system generation allocation constraint in Northeastern Ontario and result in accelerated FiT and microFiT projects in GSHI's service territory. This project is not expected to be completed within the five (5) year planning horizon of this Green Energy Act plan and will therefore not have any impact upon our plan. Should the in-service date be brought forward there may be a significant impact upon this plan.
- Similarly, March of 2012 finds the mining sector strong and growing. Significant load growth in the Northeast will allow connection of more, large distribution embedded renewable energy projects. Should transmission loads grow elsewhere in the Northeast, this may have an impact upon renewable generation projects within GSHI's service territory.
- When Northeastern transmission constraints are relieved it is possible that significant amounts of wind generation may wish to connect at market rates. These projects will

not be applying for FiT contracts as they do not meet the domestic content rules of the FiT program. In Texas wind generation has flourished at markets rates in the $25 to $45 megawatt hours range. With a strong Canadian dollar improving the American proponent's economics and with large tracts of cheap, non-arable land and available transmission capacity in Northern Ontario, we may become the poster boy for wind turbines.

4.2 Greater Sudbury Hydro Feeder and Station Available Generation Capacity

The following tables show the substation generation connection limitations as well as "available generation capacity" by feeder for those feeders directly connected to Hydro One transformer stations and those embedded feeders which have a FiT application. Substation and feeder "available generation capacity" (generation penetration) to receive highly variable renewable generation is dependent on;

- Feeder Minimum Load at time of maximum Generation Ratio (MLGR).
    - Used for Ground Fault Overvoltage Suppression Analysis when DG is not effectively grounded and;
    - Used for Islanding Analysis.
- Fault Ratio Factor – ISCUtility/ISCDG
    - Used to recognize when overcurrent device coordination will be affected by adversely affected by DG and;
    - Used to recognize when overcurrent device ratings may be adversely affected by DG.
- Stiffness Factor - ISCUtility/IRated DG
    - Used to recognize when voltage regulation may be adversely affected by DG.
- Ground Source Impedance Ratio (NOTE: Only important on protection schemes involving feeder ground current measuring CT ‐ VERY RARE at Ontario LDCs using the old Ontario Hydro distribution overcurrent protection standard where overcurrent condition is detected by zero sequence current flowing through the phases.)
    - DG ground sources act like a current divider in the zero sequence path and;
    - Used to recognize when the system overcurrent protection system may be desensitized by DG and;
    - Used to recognize when overcurrent device coordination and rating may be adversely affected by DG.

- The thermal limits of the Municipal Substation transformer and the conductors emanating from the station.

These feeder “available generation capacities” are subject to change as Greater Sudbury Hydro continues to study generation capacity on its distribution system. These feeder “available generation capacities” are also subject to transformer station generation capacity limits established by Hydro One and publicly available on Hydro One’s website.

Tables 3, 4 and 5 (next three pages) – Available generation capacities on various 44 kV feeders connected to the IESO controlled grid.

					Fault Ratio Factor										Stiffness Factor						
					Three Phase					Single Phase					Three Phase				Single Phase		
Feeder or Device	Voltage (kV)	Distance (km)	Max kW of 3 Ph DG	Max kW of 1 Ph DG	$I_{SCUtility}$ 3Ph Amps	I_{SCDG}	Minimum $I_{SCUtility}/I_{SCDG}$	Total I_{dg}	Total 3Ph kW_{dg}	$I_{SCUtility}$ Min 1 Ph Amps	I_{SCDG}	Minimum $I_{SCUtility}/I_{SCDG}$	Total I_{dg}	Total 1Ph kW_{dg}	$I_{SCUtility}$ 3Ph Amps	I_{rated} PV/Wind	Minimum $I_{SCUtility}/I_{rated\ PV/Wind}$	Total 3 Ph kW_{dg}	$I_{SCUtility}$ Min 1 Ph Amps	I_{rated} PV/Wind	Total 1 Ph kW_{dg}
28M6			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
44-LI43	44	4.517	11035	0	7240	362	20	289.6	22070		0	20	0	0	7240	144.8	50	11035	0	0	0
9T1-L	44	6.609	8857	0	5811	290.55	20	232.44	17714		0	20	0	0	5811	116.2	50	8857	0	0	0
44 -LI44	44	6.507	8930	0	5859	292.95	20	234.36	17860		0	20	0	0	5859	117.2	50	8930	0	0	0
44-LI45	44	5.589	9858	0	6468	323.4	20	258.72	19717		0	20	0	0	6468	129.4	50	9858	0	0	0
44-LS47	44	6.777	8497	0	5575	278.75	20	223	16994		0	20	0	0	5575	111.5	50	8497	0	0	0
44-LI48	44	7.051	8301	0	5446	272.3	20	217.84	16601		0	20	0	0	5446	108.9	50	8301	0	0	0
44-LI32	44	7.603	7933	0	5205	260.25	20	208.2	15867		0	20	0	0	5205	104.1	50	7933	0	0	0
44-LI30	44	7.923	7735	0	5075	253.75	20	203	15470		0	20	0	0	5075	101.5	50	7735	0	0	0
44-LI105	44	9.526	6872	0	4509	225.45	20	180.36	13745		0	20	0	0	4509	90.18	50	6872	0	0	0
17T1-L	44	9.627	6840	0	4488	224.4	20	179.52	13681		0	20	0	0	4488	89.76	50	6840	0	0	0
44-LI77	44	9.599	6839	0	4487	224.35	20	179.48	13678		0	20	0	0	4487	89.74	50	6839	0	0	0
2T2-H-A	44	7.28	8145	0	5344	267.2	20	213.76	16290		0	20	0	0	5344	106.9	50	8145	0	0	0
2T1-H-A	44	7.28	8145	0	5344	267.2	20	213.76	16290		0	20	0	0	5344	106.9	50	8145	0	0	0
12T1-L	44	6.366	9023	0	5920	296	20	236.8	18046		0	20	0	0	5920	118.4	50	9023	0	0	0
			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
28M4			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
44-LI86	44	3.663	12346	0	8100	405	20	324	24691		0	20	0	0	8100	162	50	12346	0	0	0
3T3-L	44	3.909	11978	0	7859	392.95	20	314.36	23957		0	20	0	0	7859	157.2	50	11978	0	0	0
44-LI42	44	4.46	11233	0	7370	368.5	20	294.8	22466		0	20	0	0	7370	147.4	50	11233	0	0	0
44-LI96	44	5.679	9645	0	6328	316.4	20	253.12	19290		0	20	0	0	6328	126.6	50	9645	0	0	0
44-LI99	44	6.647	8552	0	5611	280.55	20	224.44	17104		0	20	0	0	5611	112.2	50	8552	0	0	0
44-LI71	44	8.529	7354	0	4825	241.25	20	193	14708		0	20	0	0	4825	96.5	50	7354	0	0	0
8TI-L	44	8.61	7319	0	4802	240.1	20	192.08	14638		0	20	0	0	4802	96.04	50	7319	0	0	0
44LI-35	44	8.617	7307	0	4794	239.7	20	191.76	14614		0	20	0	0	4794	95.88	50	7307	0	0	0
44-LI23	44	10.195	6543	0	4293	214.65	20	171.72	13086		0	20	0	0	4293	85.86	50	6543	0	0	0
44-LI22	44	10.304	6497	0	4263	213.15	20	170.52	12995		0	20	0	0	4263	85.26	50	6497	0	0	0
20T1-L	44	13.102	5502	0	3610	180.5	20	144.4	11004		0	20	0	0	3610	72.2	50	5502	0	0	0
15T1-L	44	6.881	8406	0	5515	275.75	20	220.6	16811		0	20	0	0	5515	110.3	50	8406	0	0	0
25T1-L	44	12.09	5726	0	3757	187.85	20	150.28	11453		0	20	0	0	3757	75.14	50	5726	0	0	0
14T1-L	44	5.618	9784	0	6419	320.95	20	256.76	19567		0	20	0	0	6419	128.4	50	9784	0	0	0
44-LI66	44		11152	0	7317	365.85	20	292.68	22305		0	20	0	0	7317	146.3	50	11152	0	0	0

2012/03/27, 1:30 PM

					Fault Ratio Factor										Stiffness Factor						
					Three Phase					Single Phase					Three Phase				Single Phase		
Feeder or Device	Voltage (kV)	Distance (km)	Max kW of 3 Ph DG	Max kW of 1 Ph DG	$I_{scutility}$ 3Ph Amps	I_{scDG}	Minimum $I_{scutility}/I_{scDG}$	Total I_{dg}	Total 3Ph kW_{dg}	$I_{scutility}$ Min 1 Ph Amps	I_{scDG}	Minimum $I_{scutility}/I_{scDG}$	Total I_{dg}	Total 1Ph kW_{dg}	$I_{scutility}$ 3Ph Amps	$I_{rated\ PV/Wind}$	Minimum $I_{scutility}/I_{rated\ PV/Wind}$	Total 3 Ph kW_{dg}	$I_{scutility}$ Min 1 Ph Amps	$I_{rated\ PV/Wind}$	Total 1 Ph kW_{dg}
			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
28M5			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
3-A58	44	3.986	11869	0	7787	389.35	20	311.48	23737		0	20	0	0	7787	155.7	50	11869	0	0	0
44-LI41	44	4.489	11196	0	7346	367.3	20	293.84	22393		0	20	0	0	7346	146.9	50	11196	0	0	0
44-LI50	44	5.831	9724	0	6380	319	20	255.2	19448		0	20	0	0	6380	127.6	50	9724	0	0	0
44-LI49	44	5.075	10501	0	6890	344.5	20	275.6	21003		0	20	0	0	6890	137.8	50	10501	0	0	0
44-LI66	44	5.176	10390	0	6817	340.85	20	272.68	20780		0	20	0	0	6817	136.3	50	10390	0	0	0
44-LI39	44	5.534	10015	0	6571	328.55	20	262.84	20031		0	20	0	0	6571	131.4	50	10015	0	0	0
44-LI36	44	6.397	9191	0	6030	301.5	20	241.2	18381		0	20	0	0	6030	120.6	50	9191	0	0	0
44-LI78	44	7.167	8584	0	5632	281.6	20	225.28	17168		0	20	0	0	5632	112.6	50	8584	0	0	0
44-LI79	44	7.167	8584	0	5632	281.6	20	225.28	17168		0	20	0	0	5632	112.6	50	8584	0	0	0
44-LI105	44	8.992	7430	0	4875	243.75	20	195	14861		0	20	0	0	4875	97.5	50	7430	0	0	0
44-LI88	44	9.005	7423	0	4870	243.5	20	194.8	14845		0	20	0	0	4870	97.4	50	7423	0	0	0
44-LI89	44	9.045	7401	0	4856	242.8	20	194.24	14803		0	20	0	0	4856	97.12	50	7401	0	0	0
44-LI75	44	12.251	6283	0	4122	206.1	20	164.88	12565		0	20	0	0	4122	82.44	50	6283	0	0	0
13T1-L	44	12.542	6208	0	4073	203.65	20	162.92	12416		0	20	0	0	4073	81.46	50	6208	0	0	0
44-LS107	44	12.42	6216	0	4078	203.9	20	163.12	12431		0	20	0	0	4078	81.56	50	6216	0	0	0
44-LI42	44	14.557	5479	0	3595	179.75	20	143.8	10959		0	20	0	0	3595	71.9	50	5479	0	0	0
44-LI22	44	12.8	6071	0	3983	199.15	20	159.32	12141		0	20	0	0	3983	79.66	50	6071	0	0	0
10T2-L	44	9.078	7403	0	4857	242.85	20	194.28	14806		0	20	0	0	4857	97.14	50	7403	0	0	0
10T1-L	44	9.032	7423	0	4870	243.5	20	194.8	14845		0	20	0	0	4870	97.4	50	7423	0	0	0
22T1T2-L	44	7.167	8584	0	5632	281.6	20	225.28	17168		0	20	0	0	5632	112.6	50	8584	0	0	0
3T2-H	44	3.986	11869	0	7787	389.35	20	311.48	23737		0	20	0	0	7787	155.7	50	11869	0	0	0
44-LI44	44	3.003	13448	0	8823	441.15	20	352.92	26895		0	20	0	0	8823	176.5	50	13448	0	0	0
			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
9M4			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
44-LS67	44	5.012	10041	0	6588	329.4	20	263.52	20082		0	20	0	0	6588	131.8	50	10041	0	0	0
43-LS102	44	5.122	9916	0	6506	325.3	20	260.24	19832		0	20	0	0	6506	130.1	50	9916	0	0	0
18T1-L	44	5.142	9909	0	6501	325.05	20	260.04	19817		0	20	0	0	6501	130	50	9909	0	0	0
44-LS68	44	5.114	9922	0	6510	325.5	20	260.4	19845		0	20	0	0	6510	130.2	50	9922	0	0	0
44-LI20	44	12.413	5382	0	3531	176.55	20	141.24	10764		0	20	0	0	3531	70.62	50	5382	0	0	0
21T1-L	44	12.665	5298	0	3476	173.8	20	139.04	10596		0	20	0	0	3476	69.52	50	5298	0	0	0
44-LS68	44	5.114	9922	0	6510	325.5	20	260.4	19845		0	20	0	0	6510	130.2	50	9922	0	0	0
44-LI21	44	12.874	5231	0	3432	171.6	20	137.28	10462		0	20	0	0	3432	68.64	50	5231	0	0	0
24T1-L	44	16.924	4196	0	2753	137.65	20	110.12	8392		0	20	0	0	2753	55.06	50	4196	0	0	0
44-LI72	44	17.024	4173	0	2738	136.9	20	109.52	8346		0	20	0	0	2738	54.76	50	4173	0	0	0
9M1-M4	44	0	23760	0	15589	779.45	20	623.56	47520		0	20	0	0	15589	311.8	50	23760	0	0	0
			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
9M3			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
44-LI31	44	6.825	8727	0	5726	286.3	20	229.04	17455		0	20	0	0	5726	114.5	50	8727	0	0	0
44-LI32	44	7.109	8503	0	5579	278.95	20	223.16	17007		0	20	0	0	5579	111.6	50	8503	0	0	0
44-LI33	44	8.654	7459	0	4894	244.7	20	195.76	14918		0	20	0	0	4894	97.88	50	7459	0	0	0
19T1-L	44	9.458	7069	0	4638	231.9	20	185.52	14138		0	20	0	0	4638	92.76	50	7069	0	0	0
44-LI34	44	9.322	7083	0	4647	232.35	20	185.88	14166		0	20	0	0	4647	92.94	50	7083	0	0	0
44-LI50	44	11.132	6071	0	3983	199.15	20	159.32	12141		0	20	0	0	3983	79.66	50	6071	0	0	0
19T2-L	44	10.498	6639	0	4356	217.8	20	174.24	13278		0	20	0	0	4356	87.12	50	6639	0	0	0
1-A51	44	9.451	7014	0	4602	230.1	20	184.08	14028		0	20	0	0	4602	92.04	50	7014	0	0	0

					Fault Ratio Factor										Stiffness Factor						
					Three Phase					Single Phase					Three Phase				Single Phase		
Feeder or Device	Voltage (kV)	Distance (km)	Max kW of 3 Ph DG	Max kW of 1 Ph DG	$I_{SCUtility}$ 3Ph Amps	I_{SCDG}	Minimum $I_{SCUtility}/I_{SCDG}$	Total I_{dg}	Total 3Ph kW_{dg}	$I_{SCUtility}$ Min 1 Ph Amps	I_{SCDG}	Minimum $I_{SCUtility}/I_{SCDG}$	Total I_{dg}	Total 1Ph kW_{dg}	$I_{SCUtility}$ 3Ph Amps	$I_{rated\ PV/Wind}$	Minimum $I_{SCUtility}/I_{rated\ PV/Wind}$	Total 3 Ph kW_{dg}	$I_{SCUtility}$ Min 1 Ph Amps	$I_{rated\ PV/Wind}$	Total 1 Ph kW_{dg}
			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
9M2			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
44-LI27	44	1.8	16362	0	10735	536.75	20	429.4	32724		0	20	0	0	10735	214.7	50	16362	0	0	0
44-LS28	44	1.961	15941	0	10459	522.95	20	418.36	31882		0	20	0	0	10459	209.2	50	15941	0	0	0
7T1-L	44	2.069	15792	0	10361	518.05	20	414.44	31584		0	20	0	0	10361	207.2	50	15792	0	0	0
44-LS29	44	3.844	12247	0	8035	401.75	20	321.4	24493		0	20	0	0	8035	160.7	50	12247	0	0	0
44-LI69	44	4.814	10939	0	7177	358.85	20	287.08	21878		0	20	0	0	7177	143.5	50	10939	0	0	0
44-LI77	44	6.039	9637	0	6323	316.15	20	252.92	19275		0	20	0	0	6323	126.5	50	9637	0	0	0
17T2-L	44	6.074	9634	0	6321	316.05	20	252.84	19268		0	20	0	0	6321	126.4	50	9634	0	0	0
5T1-L	44	4.584	11222	0	7363	368.15	20	294.52	22445		0	20	0	0	7363	147.3	50	11222	0	0	0
7T2-L	44	2.027	15899	0	10431	521.55	20	417.24	31797		0	20	0	0	10431	208.6	50	15899	0	0	0
			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
9M1			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
44-LI80	44	2.317	14786	0	9701	485.05	20	388.04	29572		0	20	0	0	9701	194	50	14786	0	0	0
44-LI76	44	3.323	12305	0	8073	403.65	20	322.92	24609		0	20	0	0	8073	161.5	50	12305	0	0	0
44-LI74	44	4.142	10806	0	7090	354.5	20	283.6	21613		0	20	0	0	7090	141.8	50	10806	0	0	0
44-LS26	44	4.378	10437	0	6848	342.4	20	273.92	20875		0	20	0	0	6848	137	50	10437	0	0	0
44-LS104	44	6.441	8026	0	5266	263.3	20	210.64	16052		0	20	0	0	5266	105.3	50	8026	0	0	0
6T1-L	44	6.881	7630	0	5006	250.3	20	200.24	15260		0	20	0	0	5006	100.1	50	7630	0	0	0
44-LI73	44	6.665	7828	0	5136	256.8	20	205.44	15656		0	20	0	0	5136	102.7	50	7828	0	0	0
11T2-L	44	4.2	10771	0	7067	353.35	20	282.68	21542		0	20	0	0	7067	141.3	50	10771	0	0	0
11T1-L	44	4.182	10800	0	7086	354.3	20	283.44	21600		0	20	0	0	7086	141.7	50	10800	0	0	0
16T1-L	44	2.553	14222	0	9331	466.55	20	373.24	28444		0	20	0	0	9331	186.6	50	14222	0	0	0
			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0
			0	0		0	20	0	0		0	20	0	0	0	0	50	0	0	0	0

2012/03/27, 1:32 PM

4.3 Renewable Generation Forecast

Where - As the government has removed the constraint of the Planning Act from the renewable generation siting equation, it is impossible to predict where the generation will appear. We have received requests for connections from brown fields, green fields, residential and commercial rooftops and there is no pattern. We have received applications where the proponent's site is outside our service territory and they plan to build kilometers of express feeders to connect to the GHSI distribution system. We cannot reasonably predict where the generation will want connection.

Quantum and Pace – The Utilities Standards Forum (USF) analysis, see Appendix B, of the impact of Fit 2.0 on the pace of renewable generation connections indicates that there will be no measureable effect on the pace or quantum of connection applications due to the revised pricing. Therefore we can predict the quantum and pace of future connections based on recent history, with one modification. All connections and applications on Martindale TS have been at a standstill since late 2010. An OPA approved transmission connected renewable generation project will remove the Martindale constraint in late 2012. We postulate that applications and connection in the period Q4 2010 to date are approximately 50% of what they would have been if Martindale had not been constrained. The adjusted historic data is found below in Table 6. The adjusted historic data is graphed in Figure 2 and a quadratics regression is performed to arrive at a best fit curve. The best fit curve is used to calculate the generation forecast. The resultant generation forecast is found in Table 7 below;

Table 6: Historic renewable generation connection data, adjusted for Martindale constraint by quarter.

Historic Data Adjusted for Martindale Constraint		
Period	Cumulative kW	kW Added in Quarter
2009Q4	4.8	4.8
2010Q1	4.8	0
2010Q2	14.304	9.504
2010Q3	31.704	17.4
2010Q4	154.244	122.54
2011Q1	206.164	51.92
2011Q2	266.064	59.9
2011Q3	812.944	546.88

Figure 2 : Quadratic regression calculation based on historic renewable generation connection data adjusted for Martindale constraint.

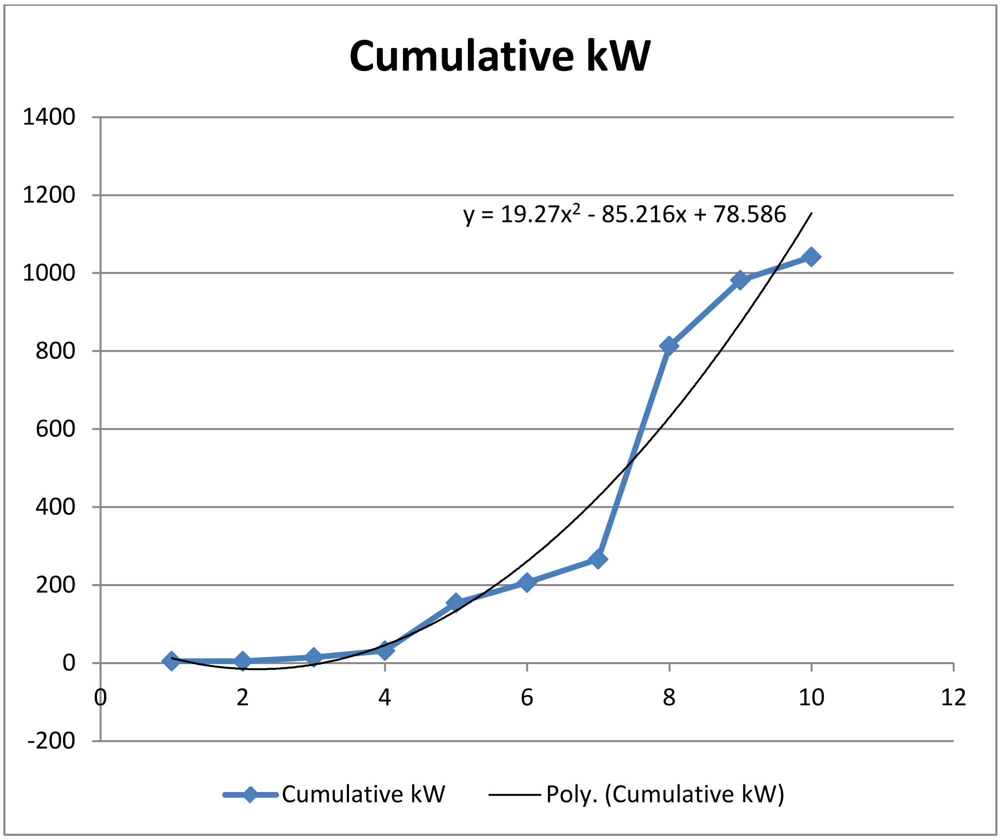


Table 7: Renewable generation forecast by quarter based on quadratic regression of adjusted historical data.

Forecast Renewable Generation Assuming Polynominal Regression		
YYYYQQ	**Cumulative Connected kW**	**kW Added in Quarter**
2012Q3	925.23	112.286
2012Q4	1119.82	78.516
2013Q1	1332.93	213.11
2013Q2	1564.56	231.63
2013Q3	1814.71	250.15
2013Q4	2083.38	268.67
2014Q1	2370.57	287.19
2014Q2	2676.28	305.71
2014Q3	3000.51	324.23
2014Q4	3343.26	342.75
2015Q1	3704.53	361.27
2015Q2	4084.32	379.79
2015Q3	4482.63	398.31
2015Q4	4899.46	416.83
2016Q1	5334.81	435.35
2016Q2	5788.68	453.87
2016Q3	6261.07	472.39
2016Q4	6751.98	490.91
2017Q1	7261.41	509.43
2017Q2	7789.36	527.95
2017Q3	8335.83	546.47
2017Q4	8900.82	564.99

4.4 Consultation with Affected Distributors or Transmitters

Greater Sudbury Hydro (GSHI) has had discussions with Hydro One, the affected transmitter, with respect to the Hydro One "List of Station Capacity" and Threshold Connection Impact Assessments, and is planning to have additional discussions with Hydro One.

GSHI is an embedded distributor in the Hydro One distribution system in several locations; Sturgeon Falls, Cache Bay, Capreol, Coniston, Falconbridge and Mansour Mining. GSHI has had discussions with the Host distributor, Hydro One.

4.5 Planned Developments to Enable Renewable Embedded Generation Connections

Many planned and anticipated projects can be accommodated with existing available capacity. For capacity allocation exempt applications, no connection impediments currently exist; save and except the transmission station constraints already discussed at Martindale TS and Coniston TS. However, a single large FiT project , Fit clusters, microFiT clusters or some combination thereof on a sub-transmission feeder, primary feeder or Municipal Substation will eventually result in issues that; (i) cannot be foreseen with existing distribution system engineering analysis software, (ii) have no commercially available mitigation equipment; or (iii) will require expensive solutions that are unproven at the distribution level. It is highly probable that completed FiT and/or microFiT projects will have to be disconnected from the distribution system at some point in this evolution.

Small scale photovoltaic (PV) project applications to GSHI under the microFiT program have been averaging 7.5 kW per residential rooftop installation. This is significantly higher than the typical 1 kW residential load occurring between 1 and 3 pm on weekends in spring and fall. As generation clusters begin to form we anticipate that sustained, localized high secondary voltages (120/240 volts) will result in customer high voltage complaints and potential damage claims as sensitive electronic equipment could be damaged by the high voltage. We do not know when or where these clusters will begin to form. There is no commercially available technology to mitigate this problem, although pilot projects have been proposed under the provincial Smart Grid Fund, and no distribution engineering analysis software can predict the problem at this time. The problem exists because of a fundamental conflict between CSA 22.2 No. 107.1 – 01, Table 16 (equivalent to IEEE 1547) and CSA CAN-3-C235-83, Table 2 and 3 (equivalent to ANSI C84.1). CSA C22.2 No. 107.1 is the standard to which renewable generation inverters are built. CSA C235 is the standard which defines the voltage an LDC must deliver to its customer's homes and businesses. CSA C235 requires that LDCs maintain a maximum voltage of 125 volts at customer utilization points. CSA C22.2 No. 107.1 - 01 allows inverter based generators to operate up to 132 volts without tripping on overvoltage. Further CSA 22.2 No.107.1 (like IEEE 1547) does not permit the inverter to control the voltage at the point of common coupling; it will simply keeping putting out watts till the bus voltage rises to or above 132 volts. The IEEE paper included Appendix B describes this phenomenon from a primary voltage perspective; the effect is greater at a secondary bus level.

The solution proposed in this plan is Community Energy Storage (CES). Having an electrical storage unit associated with each installation that suffers sustained, localized high voltage issues is a viable, but expensive solution. This LDC has had discussions with an Ontario CES manufacturer who expects to bring CES to market within the next year to eighteen months at a cost of about $2000 per kilowatt. These mitigation costs are included in this plan. However, since there is no commercial technology available today that an LDC could install to mitigate this problem, the costs are estimates only. When the problem occurs, MicroFiT renewable generators may have to be disconnected until a solution is available.

Small FiT projects that are expected to connect to the distribution system within the five (5) year planning horizon may create problems throughout the distribution system and may be delayed or deferred if the engineering analysis software fails to identify the problem. NRCanada or others must be incented to help distribution system analysis software manufacturers develop and bring to market suitable distribution engineering analysis software to help predict these problems before customers invest thousands of dollars in PV systems that will have to sit idle. Alternatively they will be built, connected, found to create problems and will have to be disconnected until commercially available mitigation equipment becomes available.

There are other solutions available, but these solutions are not attainable by this LDC. They include a revision to CSA C22.2 N0.107.1 (and IEEE 1547) to allow inverters to control the voltage at the point of common coupling by varying the inverter output power factor. This will mean lower revenues for the generator within the current pricing structure. As power factor is varied from unity to some +/- value less than one to keep voltages within the CSA C235 boundaries, the number of watts generated by the inverters falls ergo the revenue falls. The OPA may want to revise the pricing regime to pay for kilovolt amperes and not kilowatts. Metering will be an issue as no Industry Canada approved single phase kilovolt ampere-hour metering exists at this time.

This LDC has included GEA Plan costs to attend IEEE, USF, CEATI, NRCanada and other conferences, technical sessions and technical committees. Attendance at these technical events is a key training and professional development activity that also allows GSHi engineering staff to help spread the word that new mitigation technologies are needed; that existing standards need significant revisions and to seek innovative solutions to the dilemma that will unfold in the not too distant future if we do not act prudently and expeditiously now.

We estimate that sustained, localized, high voltage problems will begin to manifest themselves when connected renewable generation reaches about 5% of weekend afternoon load (5% of 70 MW). Five percent (5%) of weekend afternoon load was chosen because:

1. It represents about 333 MicroFiT installations, at the current average installed size of 7.5 kW;
2. Presentations at the past two IEEE Power & Energy Society Annual General Meetings typically describe clusters of early adopters;
3. It is generally thought that about 25% of all rooftops are suitable for renewable generation, due to orientation or shading issues;
4. Greater Sudbury Hydro has about 39,000 residential customers;
5. Early adopters may be considered the first 2.5% to 5% to market of the available market segment;

Therefore it can be concluded that early adopter clusters, which can cause localized sustained high voltages, will form at or before the point at which connected renewable generation reaches 5% of weekend afternoon load.

From Table 8, we would expect this need to appear in 2014 Q4 or 2015 Q1. We anticipate that approximately 25% of the kW added per quarter thereafter will require voltage support. At this time the only viable voltage support is Community Energy Storage at an estimated cost of $2500 per kilowatt, installed. The minimum increment that CES comes in is 25 kVA therefore the cost estimates reflect this lumpy cost.

Table 8: Estimated timing and costs for CES mitigation of sustained, localized high voltages due to renewable generation clusters that create high generation penetrations during periods of low loads, typically noon to 3 pm on a weekend afternoon in May or September.

CES Mitigation of Sustained, Localized High Voltage Renewable Generation				
YYYYQQ	Kw Added in Quarter	25% of kW Added in Quarter	Number of CES Units	Installed Cost Estimate to Nearest CES Increment
2014Q4	342.75	85.7	4.0	$ 250,000.00
2015Q1	361.27	90.3	4.0	$ 250,000.00
2015Q2	379.79	94.9	4.0	$ 250,000.00
2015Q3	398.31	99.6	4.0	$ 250,000.00
2015Q4	416.83	104.2	5.0	$ 312,500.00
2016Q1	435.35	108.8	5.0	$ 312,500.00
2016Q2	453.87	113.5	5.0	$ 312,500.00
2016Q3	472.39	118.1	5.0	$ 312,500.00
2016Q4	490.91	122.7	5.0	$ 312,500.00
2017Q1	509.43	127.4	6.0	$ 375,000.00
2017Q2	527.95	132.0	6.0	$ 375,000.00
2017Q3	546.47	136.6	6.0	$ 375,000.00
2017Q4	564.99	141.2	6.0	$ 375,000.00

Projects in this GEA plan that are not capacity allocation exempt are subject to the availability of generation capacity on the transmission system. The transmission system in Northeastern Ontario is currently constrained as the OPA has allocated all available generation capacity. Four large capacity allocation required FiT projects totaling over 35 MW are currently being held in FAME having failed TAT. Until the third 500 kV line from Sudbury to Essa TS is built or some other factor allows generation to be connected, these projects cannot proceed. However, when they proceed they may cause issues at the distribution level.

Based on information gained through inquiries that have not resulted in OPA applications and Pre-Fit Consultations, generation projects totaling 80+ MW are being considered in the GSHI service territory by various proponents.

MicroFiT projects have resulted in an increased workload in Engineering, to the point where one FTE is fully employed processing connections and dealing with project installers and engineers. GSHI is applying to add one engineering FTE in this rate application.

4.6 Prioritization Method

Projects will be prioritized to align with the intent of the OPA FiT and MicroFiT programs. Prioritization of FiT projects is based on project applications dates and the ongoing status of new development. GSHI intends to prioritize expansion and renewable enabling projects that will expedite the connection of projects that are "shovel ready". To date project timeline information has not been made available and as such GSHI has not prioritized any of the proposed work.

4.7 Direct Benefits for Customers

GSHI is proposing that costs incurred to make eligible Renewable Enabling Investments (REI) for the purpose of enabling the connection of renewable electricity generation be recovered partly from provincial ratepayers rather than solely from GSHI customers in accordance with EB-2009-0349. In particular the proposed monitoring of FiT installations and the installation of CES units to mitigate sustained, localized high voltages is consistent with Section 3.3.2 (h) and (i) of the Distribution System Code, which reads in part:

"*3.3.2 Renewable enabling improvements to the main distribution system to accommodate the connection of renewable energy generation facilities are limited to the following:*

(h) any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows; and
(i) communication systems to facilitate the connection of renewable energy generation facilities."

<u>Capital Expenditures</u>

$	2013	2014	2015	2016	2017
Gross Cost	$ 50,000	$ 300,000	$ 1,112,500	$ 1,300,000	$ 1,550,000
Less Generator Contribution	$ -	$ -	$ -	$ -	$ -
Less Provincial Recovery	$ 47,000	$ 282,000	$ 1,045,750	$ 1,222,000	$ 1,457,000
Net Distributor Cost	$ 3,000	$ 18,000	$ 66,750	$ 78,000	$ 93,000

Operations, Maintenance & Administration

$	2013	2014	2015	2016	2017	
Gross Cost	$ 174,800	$ 184,000	$ 241,313	$ 265,091	$ 292,589	
Less Generator Contribution	$ -	$ -	$ -	$ -	$ -	
Less Provincial Recovery	$ 164,312	$ 172,960	$ 226,834	$ 249,186	$ 275,034	
Net Distributor Cost	$ 10,488	$ 11,040	$ 14,479	$ 15,905	$ 17,555	

4.8 Budget

Anticipated costs to support the objectives of the Act with respect to ensuring that renewable generator connection requests can be accommodated in a reasonable timeframe are broken down by category and year in the following table:

Renewable Generation Incremental Costs						
	2013	2014	2015	2016	2017	Total
Capital	$50,000	$550,000	$1,112,500	$1,300,000	$1,550,000	$4,562,500
Mitigation of Sustained, Localized High Voltages		$500,000	$1,062,500	$1,250,000	$1,500,000	
Monitoring, Control and Transfer Trip - 2 per year	$50,000	$50,000	$50,000	$50,000	$50,000	
OM&A	$174,850	$184,000	$241,313	$265,091	$292,589	$1,157,842
One Engineering FTE	$125,000	$128,750	$132,613	$136,591	$140,689	
Communication Costs	$1,800	$7,200	$24,300	$44,100	$67,500	
DMS Software Maint Fees			$45,000	$45,000	$45,000	
Smart Grid Education & Training	$48,050	$48,050	$39,400	$39,400	$39,400	
Total	$224,850	$734,000	$1,353,813	$1,565,091	$1,842,589	$5,720,342

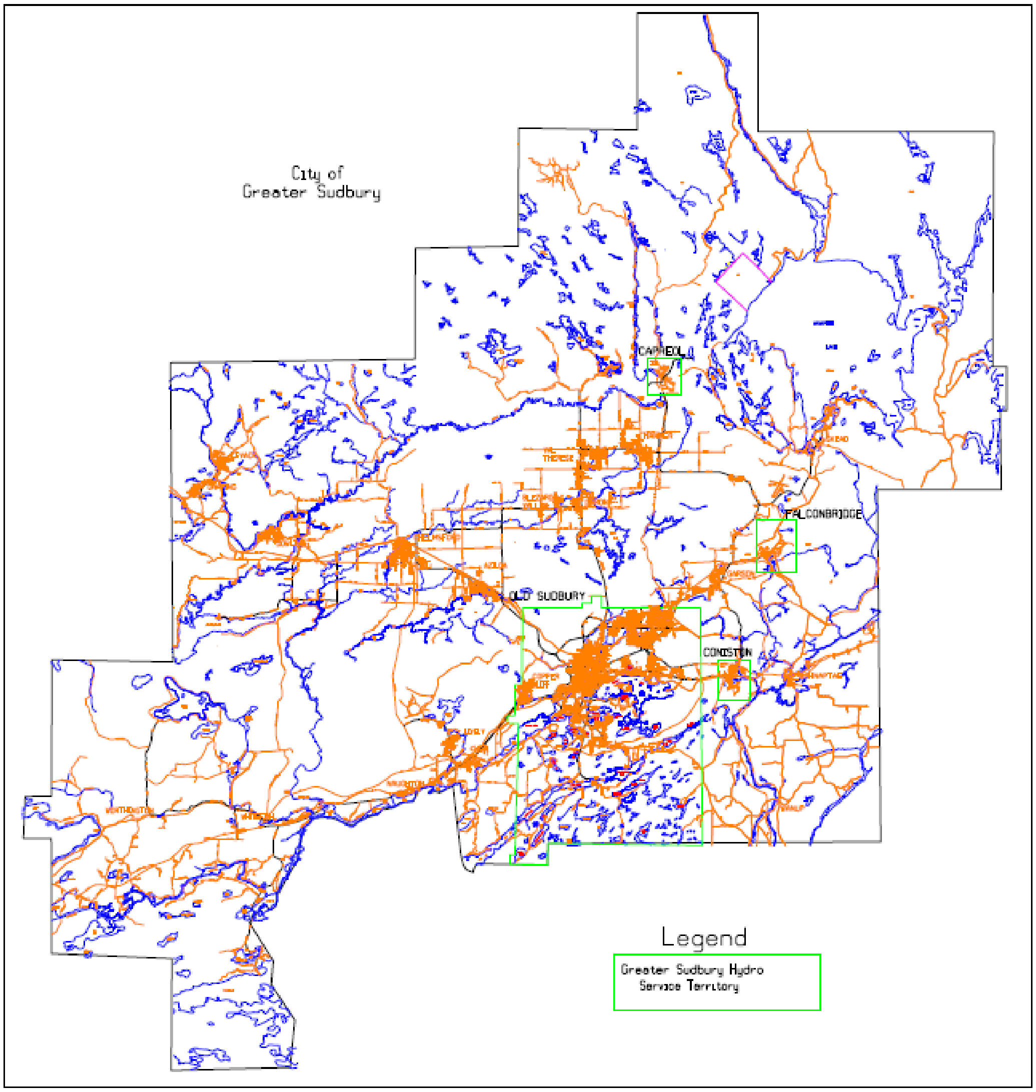
5.0 OPA Letter of Comment

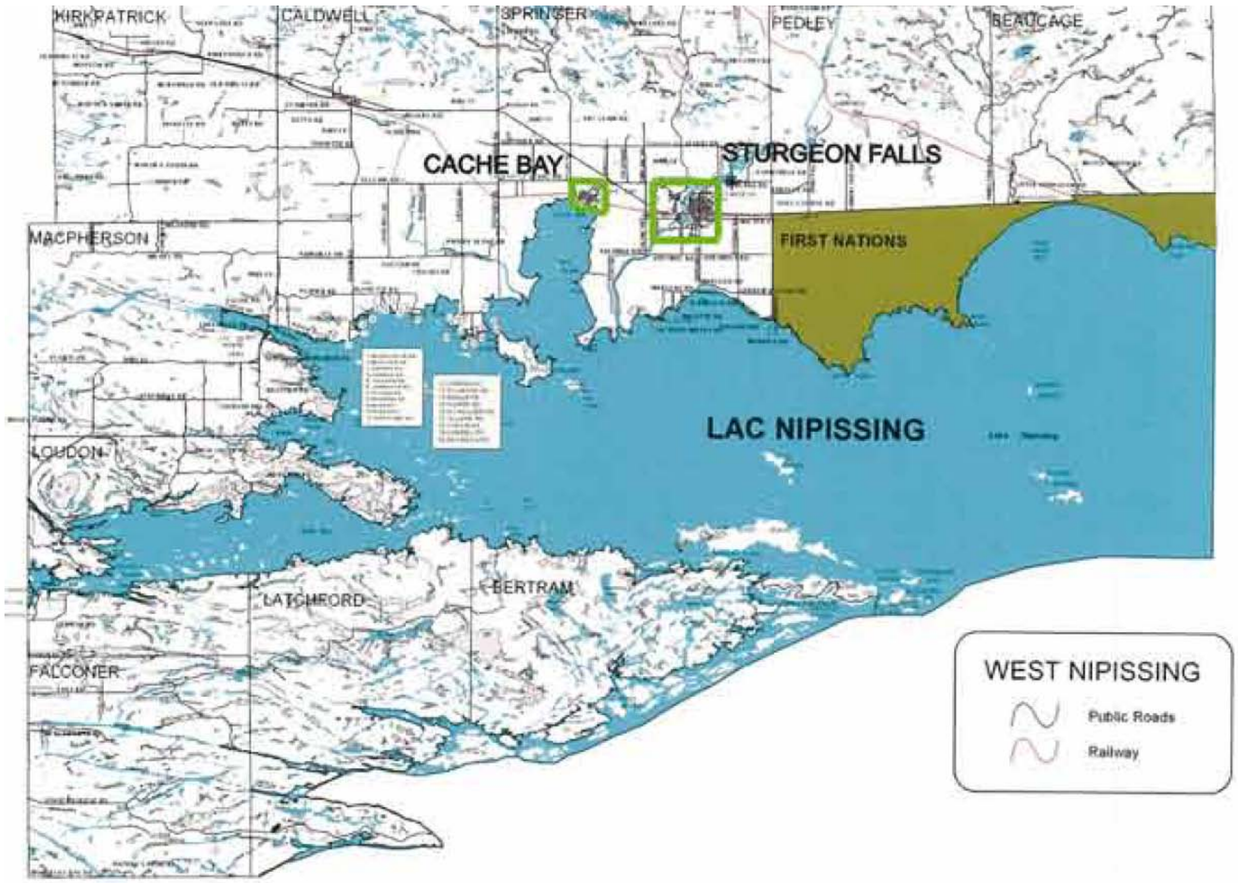
Consultation with the OPA has been completed and their letter is attached.

B.A. (Brian) McMillan, P. Eng.,
Vice-President Distribution Electrical Systems
Greater Sudbury Hydro

Appendix A

A map of the Greater Sudbury Hydro Incorporated service territory.




KIRKPATRICK
CALDWELL
SPRINGER
PEDLEY
BEAUCAGE
CACHE BAY
STURGEON FALLS
MACPHERSON
FIRST NATIONS
LAC NIPISSING
LOUDON
LATCHFORD
BERTRAM
FALCONER
WEST NIPISSING
Public Roads
Railway

Appendix B

Supporting studies and analysis.

Implications of the FIT Review

There are four main factors that affect the success of the OPA's Feed-In-Tariff Program.

1) Number of applications Submitted

The OPA is targeting the procurement of 10,700 MW of non-hydro, renewable energy by 2015.

Since the start of the FIT program September 2010, the OPA has received approximately 60,000 applications, representing over 21,700 MW of generating capacity. However, only 21% of applications, or 3% of that capacity, is commercialized, or is very near commercial status. Meanwhile, more than 17,750 applications totalling 5,800 MW of capacity have yet to be reviewed and a further 21,560 applications worth over 11,300 MW are in the process. Regardless of how many new applications are submitted, there are many projects to get through and much work yet to be done.

From the utility's perspective, it is a daunting task to evaluate this many applications, let alone connect them and manage that many new accounts.

2) Application Cycle Time

98% of the microFIT applications have been for solar PV systems. It takes approximately one year to complete such a project.

83% of FIT applications have been solar PV Capacity Allocation Exempt, meaning they are less than 500kW and the application process is streamlined compared to a project that is in the MW size. For a FIT Rooftop solar project to reach full commercialization, at minimum 2 years has passed from the time of application. Also, while the name suggests capacity, or connection ability, is unquestioned, this certainly is not the case for many projects.

Larger projects that are not Capacity Allocation Exempt must complete a number of steps, therefore extending the process to between 2 and 3 years. These projects often have a large number of individuals and companies involved, increasing the complexity and time to complete the project. For example, there have been 299 wind applications totalling 12,000 MW. Only 10 projects totalling 280 MW have reached commercialization under the FIT program.

In the FIT Review, an effort has been made to improve the cycle time of projects.

A Renewable Energy Committee made of senior officials from relevant ministries is being created to help drive projects through the approval process in order to shorten the process by 25%.

Projects with defined Community or Aboriginal participation or Municipal support will receive prioritized processing in a new points system. Therefore higher priority projects may see shorter wait times, but will require significant effort prior to the application.

Implications of the FIT Review

The intention is to improve throughput of applications. However, the amount of administration required and resources allocated to the program at the OPA have not changed, so the average cycle time will likely not be dramatically affected.

3) New Applications

Regardless of the media and public response, interest in the FIT program has not reduced (*Applications Yr 1: 23,122; Yr 2: 23, 514; Yr 3 (6 months):13,083*). However, the changes brought on by FIT Review may slow the number of applications being made to the program.

The program will now limit microFIT the applications to one per Individual or Farmer. Previously, the rule was one application per deed and many land/ building owners applied for multiple projects. This change will inhibit growth of the program, especially in rural communities where farmers tend to own several locations or severed lots and have been known to apply for all deeds they hold.

Tariff pricing was reduced for microFIT and FIT solar and wind projects. Tariff prices for all other types of renewable energy projects were not affected by the Review.

Ontario solar component manufacturers have dramatically improved production efficiency and therefore total cost to the end consumer over the past year. As intended, the new solar microFIT and FIT tariff rates continue to offer an attractive return in the 10 – 13% rate for a rooftop solar system. This return accounts for all operating costs and depends on the amount of structural upgrades required for the roof, and highly variable connection costs.

4) Grid Capacity

The FIT Review indicated that the evaluation of distribution system limitations with respect to the loading vs. generating balance, (otherwise known as Hydro One's "7% rule" preventing anti-islanding) will not be challenged. This has caused significant controversy in the industry and will cause the greatest limitation to the FIT program's ability to connect and commercialize non-hydro, renewable energy generation.

With that in mind, most utilities, outside of Hydro One, have capacity to accept microFIT projects.

The ability for FIT projects to connect is very difficult to predict. However, capacity is considered highly constrained west of London, the Niagara area and the Ottawa area. Enhancing the grid to be able to accept more generation, under the current evaluation of acceptable distributed generation levels, is a very costly endeavour. Therefore, unless upgrades are made, the success of the program could mean the demise of the program.

Solar Plant Modeling Impacts on Distribution Systems PV Case Study

G. J. Shirek, *Senior Member, IEEE,* B. A. Lassiter

Abstract* – With the vast increase of distributed energy resources (DER) on utility systems not only due to renewable portfolio standard requirements but also the potential to delay distribution upgrade expenditures, the distribution engineer is confronted with the very challenging task of fulfilling the scope of a system impact study to determine if there exists potential for the DER to create any adverse operational or voltage issues, both now and in the future as system changes occur. Fortunately, there are industry standards and guides that describe how to fulfill the technical study requirements with some step-by-step guidance. The complexity of the system impact study also depends heavily upon the type and size of DER, its operating modes. An all-encompassing study might cover a vast number of areas with just a few of these being voltage and stability analysis, harmonics, transients, distribution system protection, and DER relaying requirements. Predicting PV generation profiles for different seasons and hours of the day rests heavily on the plant design and layout. Ways to determine those load levels will be discussed. Distribution system and PV inverter modeling complexities will be presented, along with why they are important for impact studies. An actual field installation of a large PV plant will be used to evaluate some distribution system impact issues, with a focus on loading scenarios and voltages. Various operating modes of inverters will be discussed with focus on how they may help or hinder the operation of the system. These operating modes and their effects on voltage regulating device interactions will be presented to demonstrate how more commonly used regulator control settings without DER may cause voltage violations with DER.

***IndexTerms*– Solar Energy, Distributed Energy Resources, Reactive Power, Distributed Resources, Photovoltaic Inverter, Inverter Modeling, IEEE 1547, Interconnection Standards, Voltage Rise, Distribution Systems.**

I. INTRODUCTION

Solar photovoltaic DER integration assessment has become increasingly challenging as larger PV plants with capacities exceeding local load levels are becoming quite common. The required areas addressed during the impact study are much more vast and complicated than the case with conventional induction or synchronous generators as a result of the different operational mode capabilities, with each one affecting the distribution system significantly different. Therefore, each of these possibilities may need to be separately addressed to determine the system voltage consequences. Each mode may cause different power flows to occur and may both positively and negatively impact the system with tradeoffs between voltage improvements and loss increases.

Developing reasonable power generation profiles for intermittent DER is another complication as it has a direct affect on voltage profiles and how regulating devices will operate. Investigating a variety of settings for this equipment in tandem with the DER control mode is necessary.

II. INTERCONNECTION STANDARDS AND GUIDES

There are several standards available to provide information and assistance regarding DER interconnections with the distribution system.

A. IEEE 1547 Series

Most noteworthy is the IEEE 1547 series of interconnection standards to assist in the planning, engineering, implementation and maintenance of distributed generation resources [1]. The following four publications are most relevant for providing system impact study assistance.

The *IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems* is mostly a summary in that it simply lists the rules or interconnection policies such as voltage limits, voltage regulation, flicker levels, harmonics, frequency, disconnection rules, fault and protection considerations, as well as rules on grounding. Overall, this standard provides the distribution system performance needs and DER technical specifications or criteria.

The *1547.2 Application Guide for IEEE 1547* provides much more technical details and includes the rationale behind each of the rules and how they were developed. Furthermore, some justification is provided on why and how the actual values in each rule were created. Different forms of DG, such as synchronous, induction, and inverter based generation are described to help educate the engineer on how each one may impact the distribution system differently. This application guide overall helps the engineer understand how to meet the

G. J. Shirek is with Milsoft Utility Solutions, Inc., Abilene, TX. (email: greg.shirek@milsoft.com).

B. A. Lassiter is with Milsoft Utility Solutions, Inc., Abilene, TX. (email: brian.lassiter@milsoft.com).

 978-1-4673-0337-8-5/12/$31.00 ©2012 IEEE

1547 rules through some informative tips, techniques, and rules of thumb.

The *1547.7 Draft Guide for Conducting Distribution System Impact Studies for DR Interconnection* provides engineering assistance and insight on what should to be included in the scope and criteria prior to conducting a full study, along with recommended steps to ensure all potential impacts are covered. Also provided are data requirements along with how the data is applied to the study. Overall, it provides a methodology with accompanying potential impacts the generation can have on the system [2].

The *1547.8 Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Std. 1547* was developed to provide guidance when the requirements of the IEEE 1547 may limit the potential operational benefits. Rather than circumventing the rules set forth in IEEE 1547, this recommended practice provides unique methods and other flexible designs to expand the usefulness of the IEEE 1547. Much of the focus, content, and discussion areas of this document relate to the IEEE 1547 rule that the DR shall not actively regulate the voltage at the PCC since industry has found this to be a significant barrier.

B. NRECA

The NRECA provides a technical application guide to the IEEE 1547 standard and is intended to be a supplement to the IEEE 1547 [3]. The purpose of this guide is to clarify the requirements of the IEEE 1547 and provide the necessary information as it applies to electric cooperatives. This guide is part of the DG Toolkit provided by the NRECA which also includes other guides involving sample contracts and applications, business guides, rates manuals, and consumer guidelines.

III. DISTRIBUTION SYSTEM MODELING

A. Circuit Model

Distribution systems are very complex to analyze due to the nature of the unbalanced impedances and loads. Most distribution analysis software packages use unbalanced phase impedance matrices and load flow solutions [4]. This is especially important not only for conventional unidirectional load flows, but also when incorporating DER since bi-directional kW and kVAR power flows are now possible. The software needs to calculate voltage rise due to reverse kW flow and voltage drop due to forward kVAR flow on different phases. The voltage imbalance is also important since the interconnection standards list requirements pertaining to maximum or minimum voltage or flicker levels, and therefore violations may occur on only one phase rather than all three.

B. Time Series Simulations

Traditional distribution planning makes use of single point in time load flow analyses, which is adequate for peak power planning. However, now, when adding a significant number of, or a significantly sized, DER to the distribution system, this increases complexity since bi-directional power flows can occur based on the amount of generation as well as the location. Furthermore, the active and reactive power flow directions and levels can change every minute due to the intermittency of renewable generation such as PV DER.

Overall, there is need to use batch processes where both customer loads and DER outputs at various times of the day, or in certain steps, can be ran in sequence to see the time-varying nature between them. Stepping these loads through a small enough time sequence with completely and accurately defined voltage regulating device and DER controls with proper time delays and set points, in order to capture the operations of all active elements, will result in much more useful and informative conclusions to be drawn as to what is expected to occur on the distribution system.

C. Step Voltage Regulators

When running time series load flow analyses, settings related to time are needed, and for SVR's this is the time delay. If the voltage remains outside the bandwidth for longer than the time delay setting the regulator will attempt to change taps to buck or boost the voltage. With intermittent generation, the voltage at the regulator may change so quickly that it may not take corrective actions with longer time delays.

Another important setting is line drop compensation (LDC). As the active power (P) and reactive power (Q) flow changes in small time increments, LDC will be affected since it is dependent not only on the active and reactive power flows, but also upon whether the flow is in a forward or reverse direction.

There are many control modes on SVR's with bi-directional capabilities, such as co-generation and reactive bi-directional modes, usually employed with DER. Some of these modes will be demonstrated during the PV case study later in the report.

Regulators are motor operated mechanical devices so tap changes will not be instantaneous. SVR's may take between 1-1.5 seconds to move one step, so with a 32 step regulator, almost a minute will elapse when moving from one extreme to the other.

Lastly, SVR's have first house high and first house low voltage settings that, when reached, force the regulator to instantly start changing taps, thus bypassing the time delay setting.

D. Capacitors

Capacitor banks may either be fixed or switched. Usually fixed capacitor banks cause less potential voltage problems than with switched banks.

Switched banks have many control options such as time of day, voltage, real amps or reactive amps. The voltage and amp options have on and off settings so that when these set levels are reached, the capacitor switches on or off. Voltage controlled capacitors usually will not interfere if the DER control is set to operate in unity power factor mode.

Comparable to SVR's LDC settings, capacitors that have been programmed to switch based on real or reactive amps may cause issues with DER, regardless if the DER is in unity

 978-1-4673-0337-8-5/12/$31.00 ©2012 IEEE

power factor or voltage regulating mode. This is because intermittent DER generation profiles are constantly changing and the current through the capacitor control will not reflect the downline load current profile initially used to establish the settings. For a capacitor operated in reactive amp mode with a downline DER exporting only active power, the capacitor may switch on based on the reactive amp settings, which was properly set for no DER, but with the DER active power contribution raising the voltage, the capacitor kVAR will also raise the voltage thus causing a high voltage condition near the circuit extremities.

Similar to SVR's, capacitor controls also have time delay settings and bandwidths that need to be incorporated to see the correct interactions with SVR's and DER.

IV. PV MODELING

A. *Intermittency*

PV intermittency, or discontinuity of power output, is one of the most important traits used to evaluate and many times could be the largest barrier to introducing DER on a utility system.

Irradiance is the amount of incident electromagnetic power received per unit area of a given surface, usually in units of W/m^2. Insolation is a measure of the irradiance within a given time period expressed in units such as $W\text{-}h/m^2$.

Panels are rated in peak watts, which is the power generated at a reference insolation level of 1000 W/m^2. A 1 kW nameplate rating on a panel will produce that much power if perpendicular to the sun's rays at peak insolation periods. Insolation levels need to be gathered at the location where the PV will be installed to best approximate insolation profiles. Readings can be obtained from a variety of resources such as TMY2 (Typical Meteorological Year), NREL PVWatts, and NSRDB (National Solar Radiation Database).

Insolation levels at the panels vary based on their angle and tracking method if used. This needs to be known when analyzing the data since the collectors may have been oriented differently. Figure 1 reflects measured data taken from the TMY2 METSTAT database for direct axis tracking and fixed horizontal arrays, with the horizontal collector showing more insolation during the summer months and less during the winter months, as expected.

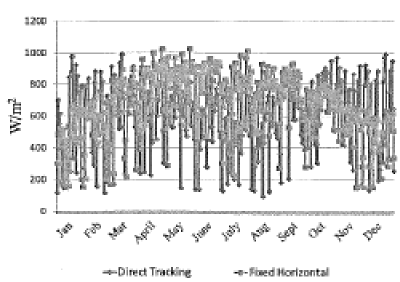


Fig. 1. Horizontal and Direct Insolation Levels

A review of the specifications, spacing, and orientation of the PV arrays is needed to most accurately represent the nature of its power output characteristics and intermittencies. The compass direction, or azimuth angle, is the angle from a true north direction. In order to obtain the most cumulative energy output, it is optimal for an array to be directly south facing or 180 degrees (for northern hemisphere) so that it can capture sunlight from sunrise to sunset.

Tracking arrays can either be one or two axis tracking. One axis tracking systems rotate along the azimuth angle while having a fixed tilt angle. Two axis tracking systems can adjust both tilt and azimuth to always be perpendicular to the sun's rays maximizing generation.

B. *Ramp Rates*

Cloud cover or shading levels are the main reasons for solar ramping and produce the fastest ramp rate output power fluctuation. As can be expected, assessing this dynamic can be incredibly difficult since weather patterns are constantly changing. In addition, one needs to know how many types of cloud patterns exist, the shadowing coverage area, the cloud height and optical transmission insolation rates, in addition to the speed at which the clouds are moving [5].

Ramp rates need to be predicted or calculated to improve the accuracy in generation profiles. To calculate this rate of change, the cloud travel direction needs to be known in addition to the PV array length in parallel with the cloud direction. Dividing the speed of cloud travel into the PV array linear distance will result in the rate of change.

Studies have shown that squall line clouds and cumulus clouds produce the worst problems for PV. The squall line type, described as a solid line of dark clouds, produces almost a complete loss of PV generation. Conversely, cumulus types, which are faster moving and more well-defined with clear skies between them, in turn producing less ground shading area, produce a smaller percentage loss of PV output but at a much more random rate of change. This may be worst case since voltage regulation devices may not have time to operate. The intermittency caused by these cumulus clouds is much less predictable than the squall line clouds. There are many sources of information and programs available that will predict cloud coverage over a defined area [5]-[6].

Many government agencies have been recording insolation rates in one second, up to one hour, increments, with one hour intervals being much more common. This data has been recorded with single collectors or arrays, so the intermittency for a single point can be obtained, but a second step is needed to apply these change rates to the larger PV plant area [7].

Determining reasonable ramp rates to include in the PV evaluation is not trivial. For example, cloud patterns, wind speeds, PV cell angle, azimuth tracking, plant land area, total surface area of PV arrays and shading between arrays should be considered.

With lack of available data, an alternative is to use recordings from nearby similarly sized plants. However, this may be difficult given that this data is usually proprietary to the PV owner [8].

 978-1-4673-0337-8-5/12/$31.00 ©2012 IEEE

C. Derating Factors

PV cells completely rely on a clear sky with no haze, rain, or humidity to generate their rated power. This, along with derating factors inherent to the PV plant facilities, will cause a derating of the PV nameplate output. Items such as inverter efficiency, AC and DC wiring losses, snow or ice buildup and transformer losses need to be applied to obtain a derating factor.

V. PV INVERTER DESIGN

Typically, inverters used in PV installations are designed to accommodate unity power factor operation. This limits the capabilities and design of inverter operation. Many inverters can and do have the ability to provide reactive power to the utility system in addition to the active power. Therefore, the inverters capabilities for providing voltage stability, load curve leveling, loss reduction, and other ancillary services such as ride-through during system faults are very much underutilized.

An important reason the IEEE 1547 states that DER shall not regulate voltage is to avoid conflicts between the controls at the DER and the controls of traditional voltage regulation devices such as voltage regulators, capacitor banks, and on-load tap changers (OLTC). On the contrary, inverters that are allowed to actively regulate voltage may help hold system voltage levels and reduce the needed number of tap changes on regulators Every situation is unique depending on the system impedances and X/R as well as the power factors of the loads. [9]

Overall, only minor attempts have been made to fully take advantage of the unique capabilities of the reactive power output of inverter based DER due to the IEEE 1547 [10]. If the voltage regulation controlled equipment is analyzed and coordinated properly to circumvent potentially harmful interactions, there can be substantial benefit to allowing DER voltage regulation [11]. In these cases, a mutual agreement between the DER owner and the interconnect utility to allow voltage regulation may be beneficial [12].

Inverters have been designed to meet UL-1741 certification, which also incorporates IEEE-1547 and IEEE-519 compliance. UL-1741 requires the inverter shut down for not only abnormal voltages, but also for loss of voltage at the PCC. This again is reasonable for small scale DER, but vastly limits the potential for large scale DER. As a result of industry questioning some of the regulations, the IEEE 1547.8 was opened to provide recommended practices for implementation strategies for expanded use of the IEEE 1547 Standard. [13] – [14] In essence the IEEE 1547.8 takes into consideration applicable real-world experiences of those with utility system DG design, installations, and operation backgrounds, know the limitations, and have contrary beliefs to a few of the technical areas of the IEEE 1547. Many countries outside the U.S. are proactively changing their interconnection rules for large scale PV so that inverters may beneficially regulate and support voltage during system faults and transients [10].

A. Inverter Capabilities and Operating Modes

Inverter designs for both small and large scale applications typically size the inverter to match the DC rating of the PV cells, after applying derating factors as previously discussed. This is because the inverter does not need to be controlled to manage the reactive power export. For power flow analysis, this means that the inverters are to be modeled as current source inverters operating at unity power factor, or simply negative active load.

However, inverters can export or import reactive power and then are to be modeled as voltage source inverters [16]. If the inverter is oversized relative to the total dc-rated output of the PV array(s), it will be able to provide some reactive power in addition to the entire PV array active power rating. The inverter can then exhibit dynamic inductive and capacitive behavior by design [17].

For example, if an inverter is simply increased by just 5% from 100 kVA to 105 kVA, this will enable the inverter to supply or absorb 32 kVAR while still supplying 100 kW of active power, resulting in a power factor range of $\pm$ 95%. This is a minimal increase in inverter size to gain significant reactive power capability.

B. Operating Modes

As discussed, if inverters are designed and operated with reactive power capacity, much more versatility will exist and more operational modes can be deployed. [18]. Operating modes are described below.

1) *Fixed Power Factor with Q=0*

The most commonly used operational mode is simply unity power factor. The inverter will output active power based on the insolation levels captured by the PV arrays. This mode meets IEEE 1547 and is most common.

2) *Fixed Power Factor with Q≠0*

This mode simply allows the kVAR to follow the kW output linearly. Based on the power factor of the load and the X/R of the system, utilities have found that a leading power factor for instance (absorbing VARs) can mitigate voltage rises due to excessive active power export during periods of minimum local load on the circuit.

3) *Variable Power Factor*

The power factors can be adjusted based on the amount of kW generated or also set up differently for various hours of the day. Note that this mode also meets IEEE 1547 since the inverter is not actively regulating utility voltage.

4) *Voltage Control Mode with Reactive Power Capability*

Without argument this dynamic control mode has the greatest potential for distribution load serving and voltage support benefits. This mode simply adjusts the reactive power import or export of the inverter to help regulate a set point voltage level at the PCC.

 978-1-4673-0337-8-5/12/$31.00 ©2012 IEEE

VI. DISTRIBUTION SYSTEM CASE STUDY FOR PV VOLTAGE IMPACTS

An example case study is now presented with various regulator settings and generator modes to address possible impacts a PV solar generation plant may have on the local distribution system. At the time of this writing, this PV project was still in the design stage. For purposes of the examples that follow, the anticipated arrays, inverters, and panel orientation that will be included in the installation have been used to develop the generation curves and inverter operating modes. At this time, a full distribution system impact study has not been completed, and more data is still being collected.

Commercially available software, Milsoft's WindMil®, is used for the power flows for the study. The system model is fully detailed down to the customer meter including distribution transformers and secondary services with 120/240 volt center-tapped transformers [19].

Energy, demand, and load class shapes for the various customer classes were used to allocate load throughout the circuit for the minimum and maximum summer and winter demands from the most recent year.

A. System Characteristics

Figure 2 shows the one-line diagram of the distribution system.

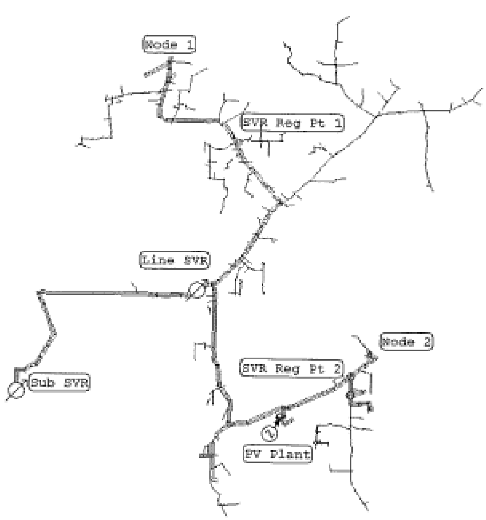


Fig. 2. Circuit One-Line Diagram

The existing system has characteristics of a typical rural circuit, with some noteworthy items below.

- 12.47/7.2 kV primary system voltage
- 16 miles of 3/0 ACSR to two three-phase extremities (Node 1 and Node 2 on the one-line)
- Eight foot cross-arms and conductor spacing
- 450 consumers
- Step voltage regulators at the low side bus and also five miles out on the circuit (Sub SVR and Line SVR)

B. PV Plants Specifications

The PV plant specifications are listed below.

- 18,000 panels each rated 132 DC Watts (STC rating) for a total rating of 2,376 kW DC
- 10 panels per collector
- Collector size of 5 ft. x 48 ft.
- 2,000 kVA transformer, 12,470 - 480V 5.75%Z
- Eight 265 kVA inverters
- 20 Acre Site

C. Orientation of Panels

As previously discussed, knowing the orientation and tracking of the collectors is important for determining the potential power generated at various insolation levels. Each collector in this plant is horizontal but has the ability to rotate up to 55 degrees both east and west to track the sun. With the panels titled zero degrees at horizontal, they will be more efficient and generate more power during the summer months than the winter. However, due to the +- 55 degree azimuth tracking, more power can be generated in the early morning and late afternoon hours compared to fixed panels. Figure 3 illustrates insolation levels on a clear-sky day for various panel orientations.

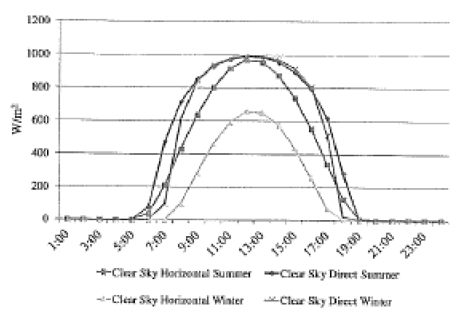


Fig. 3. Insolation Curves Based on Array Orientation

Note that since the PV arrays are horizontal the panel rating output will only be possible during the summer months as the sun travels directly overhead at 12 p.m. During the winter months, since the sun is located more in the southern direction, the horizontal arrays will not capture as much irradiance so the output will be less than the total panel rating.

Hourly insolation data for a full year was accessed to develop the potential maximum hourly output for the entire PV plant. For the case study purposes, January and August data was used since these months represent the peak summer and winter periods. Since the PV arrays are fixed horizontal but track on the azimuth, interpolating insolation data points between the fixed horizontal and two-axis tracking systems from the database was accomplished. Figure 4 shows the final insolation curves for the PV plant.

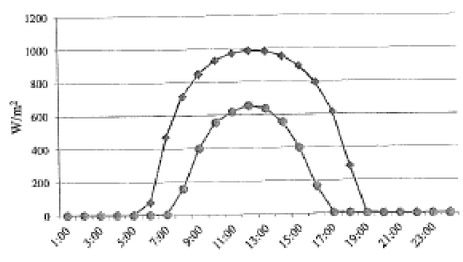


Fig. 4. Insolation Curves for PV Plant

D. Derating Factors

Many loss factors will affect the total DC-AC derating and resultant power rating of the PV plant [20]. The case study used the following derating factors with corresponding values shown in Table I.

TABLE I
DERATING FACTORS FOR PLANT

Item	Factor
Module nameplate DC rating	0.95
AC and DC wiring	0.97
Inverter Mismatch	0.98
Inverter Efficiency	0.965
Transformer Losses	0.95
Dirt and Debris	0.95
Total Derating	**0.79**

These produce a cumulative derating factor of 79 percent. Therefore, the total DC rating of 2,376 kW will have peak AC potential at the PCC of 1,877 kW during max insolation.

E. Load Levels

Presented in Figures 5 and 6 are the historical demands for minimum and maximum, summer and winter, in addition to the peak potential insolation profile for a clear sky day. Also shown are the net minimum and net maximum load profile curves, which is the circuit load minus the PV generation. These net load profiles help to determine what periods to analyze. Note the possible load on this circuit may lie anywhere between the summer or winter maximum curves and the net minimum curves.

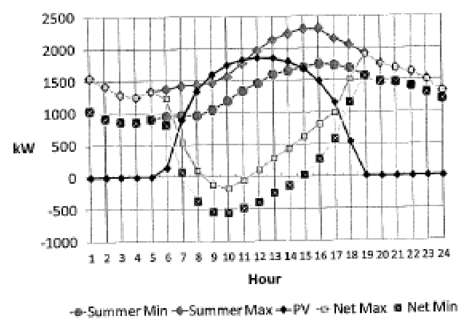


Fig. 5. Summer Circuit Load Profile

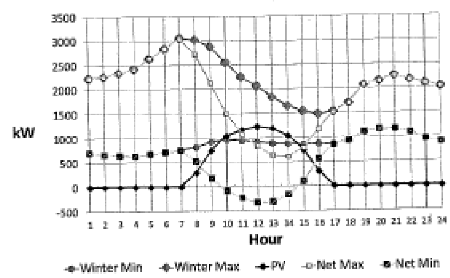


Fig. 6. Winter Circuit Load Profile

VII. CASE STUDY EXAMPLES

Cases are now presented by addressing voltage problems caused by load flow changes on the distribution from the DER contributions. For simplicity, the summer loading was used for the cases, however for worst case voltage flicker during periods of PV ramping, or complete disconnection, both summer and winter loads were analyzed.

A. PV Downstream from SVR with LDC

This circuit traditionally deployed line drop compensation (LDC) on the Line SVR not only to help hold a more constant voltage at the load centers, but to also provide conservation voltage reduction (CVR) benefits by attempting to hold voltages near the lower limits of the ANSI Range A levels. The Line SVR base output voltage is set to 119 volts. The X/R ratio from the SVR to the load center regulation point is 1.3 so SVR LDC settings of 7.1 and 5.7 volts for X and R, respectively, were programmed for the 219 amp SVR.

The following analysis was conducted assuming both the Sub SVR and the Line SVR had the necessary length of time to ride through any ramping or intermittency of the PV. In other words, this is a steady-state load flow condition with 2,300 kW of local load and 1,600 kW of PV generation at 3 p.m.

As expected, during max PV generation, the active power export from the PV plant creates a situation which reduces the active current through the Line SVR, in turn, causing the regulator to operate on a lower tap decreasing the delivered voltage. Figures 7 and 8 represent the voltage profiles for Node 1 and Node 2 with and without the PV contribution. Voltages on all three phases at Node 1 are now lower than the ANSI Range A minimum of 118 volts.

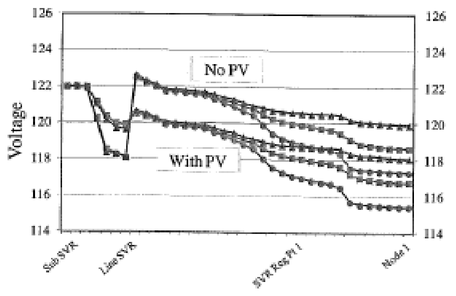


Fig. 7. Node 1 Peak Summer with and without PV

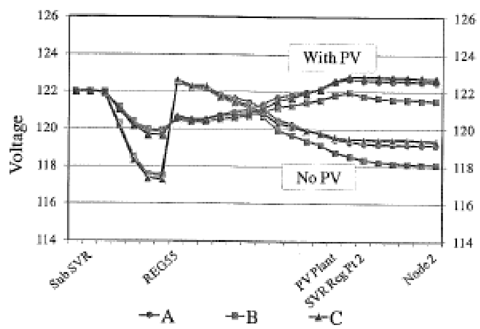


Fig. 8. Node 2 Peak Summer with and without PV

Essentially, the active power from the PV plant causes the regulated load centers to shift towards the substation. As expected, the voltage profile from the SVR to the end of line near the PV plant is now seeing a voltage rise due to the reverse power flow. Essentially, the SVR delivers lower voltage due to decreased active power through the R component of the LDC control.

B. Reverse Power Flow with Bi-Directional Settings

A normally-open gang operated air break switch (GOAB) is located at Node 2 which connects this circuit to a nearby substation for contingency purposes. In addition to providing contingency service to this circuit, the adjacent substation has the capability to provide backup to other circuits on this substation during a transformer failure at off-peak hours. Therefore, to alleviate extreme voltage drops during this configuration, the bi-directional capabilities of the Line SVR are used. Due to low voltage extremes that may occur, the bi-directional reverse power settings are set to the maximum ANSI Range A voltage level of 126 volts.

Historically, before the introduction of the PV, this SVR would only transition into reverse power mode during contingency periods when the power flow was still from only one direction, or more importantly, one stiff power source. Now, with the addition of the PV, during non-contingency periods, the main substation is still providing power, but now the PV creates potential problems between the Sub SVR and Line SVR during reverse power flow.

These issues may be expected during maximum insolation periods coincident with minimum circuit loads. As seen in Figures 5 and 6, historically, 9 a.m. to 3 p.m. in winter and 7 a.m. until 3 p.m. in summer shows the potential for the PV generation to exceed the local load.

When the regulator shifts into reverse mode, it attempts to maintain voltage levels at the substation side of the regulator, rather than at the PV side during forward mode. This can be detrimental to the voltage profile on the circuit since the main substation is still the rigid source trying to maintain 122 volts at the low-side bus, whereas the Line SVR is trying to sustain 126 volts at the substation side of the regulator.

The Line SVR substation side voltage will then always be lower than the 126 volts, and will attempt to tap up or boost the voltage. Since the Sub SVR is holding the rigid voltage, basically 126 volts cannot be maintained at both regulators. As a result, the Line SVR will then tap down the required number of steps trying to achieve 126 volts. Initially, if the Line SVR is sensing less than this, it will step to obtain that voltage, but will actually be lowering the voltage on the PV side of the Line SVR, just the opposite of what the control algorithm expects. This will continue until the regulator reaches its maximum step, or in this case will cause a 10% voltage change across the regulator.

Figure 9 represents the profile for this case assuming enough time constants have occurred for each regulator to step through the necessary tapping sequences.

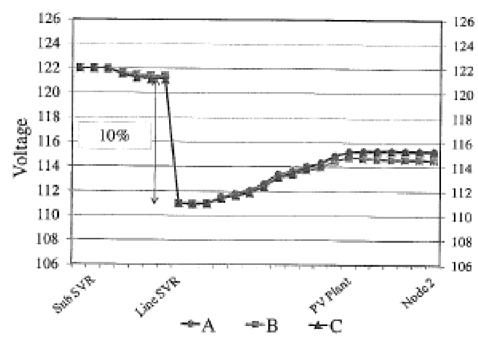


Fig. 9. Reverse Power Case with Line SVR Reverse Power Mode

 978-1-4673-0337-8-5/12/$31.00 ©2012 IEEE

C. Reverse Power Flow with Co-Generation Mode and Unity PF Inverter

In attempts to circumvent the previous problem, SVR's co-generation mode can be beneficial. This mode regulates the PV side of the regulator, not the substation side, during both forward and reverse power flow. A possible co-gen mode set to 120 volts is investigated.

Note the PV is in fixed unity power factor mode. During the summer peak load profile during daylight hours, the net forward reactive power flow will always exceed the level of net reverse active power flow through the substation. This is due to a rather consistent 95% power factor on the circuit during daylight hours. Thus, a voltage drop will always be seen from the substation to the Line SVR since forward reactive power exceeds reverse active power.

Not only do the range of voltage drop ranges need to be found near the PV during these cases, but also the voltage profiles from the Line SVR to Node 1 to ensure ANSI limits are met.

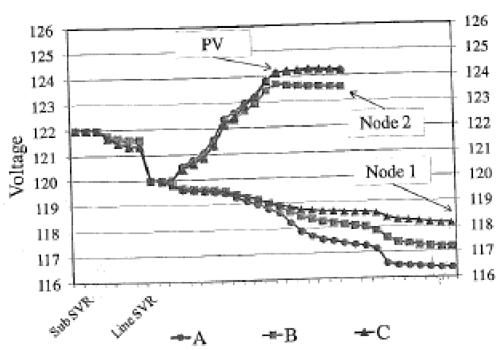


Fig. 10. Line SVR Co-Gen Mode with Unity Power Factor Inverter

There will always be a voltage rise from the Line SVR to the PV plant during periods of reverse power when the PV inverter is in unity power factor mode. This requires that the co-generation mode voltage level be set to ensure that high voltages do not occur. Figure 10 shows the voltage profile for a co-gen mode set to 120 volts. In this case, there is less chance of negative interaction between the Sub SVR and Line SVR.

However, notice that there is a four volt rise between the Line SVR and the PV. This helps keep the voltage within limits at Node 2, but the voltage at Node 1 now encounters low voltage violations, dropping below 118 volts.

D. Inverter PQ Mode

To reduce the four volt rise encountered during max insolation, a study is conducted to see whether or not voltage improvements will occur if the inverter is operated in a mode that supports reactive power capabilities. For this case, an adjustable power factor mode with voltage regulating capabilities is assumed.

This PV plant is equipped with eight 265 kVA inverters, for a total of 2,120 kVA. The expected peak negative net load on this circuit is approximately 600 kW which is a result of 1,180 kW customer load and 1,750 kW of PV generation. So at a generated 1,750 kW active power by the PV arrays, the inverter has the capacity to export or import 1,200 kVAR.

Figure 11 shows the P and Q flows for both inverter operating modes, and Figure 12 illustrates the voltage improvement with PQ mode. The SVR co-generation mode voltage setting was increased to 122 volts to help increase the low voltage levels at Node 1. Notice the inverter simply needs to absorb more reactive power from the distribution system to help reduce the four volt rise from the SVR to the PV as was the case with inverter unity power factor mode. Since the SVR is holding 122 volts at the PV side of the regulator, the inverter needs to absorb 1000 kVAR so that only a two volt rise occurs between the SVR and the PV.

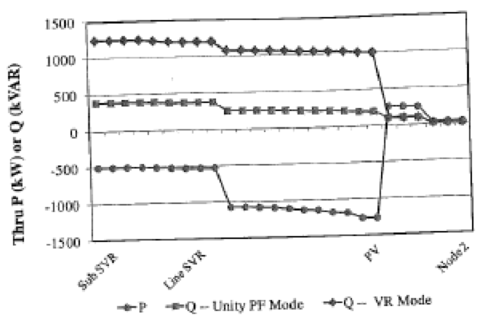


Fig. 11. Power Flow with Unity PF and PQ Modes

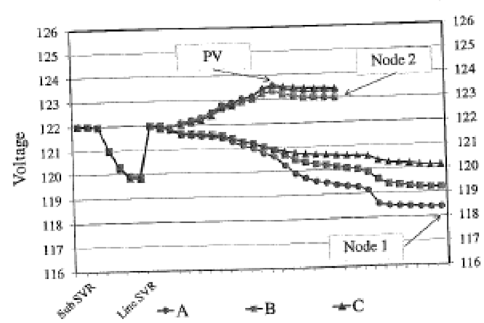


Fig. 12. Line SVR Co-Gen Mode with PQ Mode

Running a variety of other load scenarios is warranted to assist with the development of the Line SVR and PV inverter settings, especially when operating in a voltage regulating mode. If this is not done, excessive reactive power exporting or importing may occur at the PV site causing excessive tapping or hunting of the SVR.

E. Ramping or Tripping of PV

The IEEE 1547 states that the DER must disconnect from the distribution system for any abnormal system conditions, and remain disconnected for five minutes. Consequently, this anti-islanding requirement can create very large voltage changes with significantly sized DER.

Also consider the ramping that occurs due to cloud shading. As discussed, a reasonable ramp rate for this installation is 30 seconds and was developed through discussions with the PV plant developer, and also was considered valid as calculated with [5]. With longer time delays set on regulators, the voltage change on the system would be comparable to when the PV is completely disconnected due to abnormal voltage events.

Both summer and winter load and generation profiles were referenced to determine the worst case periods for both months in which the PV could be either disconnected or fully ramped producing excessive voltage flickers on the system. Load flows for the following scenarios were investigated.

- Peak load w/ maximum coincidental PV kW
- Minimum load w/ maximum coincidental PV kW
- Peak PV at 12 p.m. with maximum coincidental circuit load

The process for each of the above was to run a load flow in order to find the tap position of the regulators for the steady-state condition. Next, the regulators tap positions were locked, the PV generation dropped, followed by a new power flow to find the voltage change. Note in Figure 13 the worst case voltage change of nine volts, or about eight percent, occurs on Phase B at Node 2.

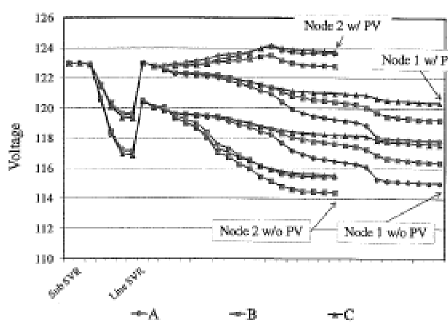


Fig. 13. Voltage Change for PV Ramping or Disconnection

VIII. SUMMARY

Distributed renewable energy resources such as PV have significantly changed the landscape from the traditional method of planning or operating the system for one-way power flows. As production costs decrease and renewable portfolio standards become more stringent, the size of these DER plant additions will only get bigger, surpassing the local load of the system. This will complicate the system impact review process, further justifying more robust time-series capable power flow programs.

The IEEE 1547 series, as well as the NRECA DG Toolkit, provides invaluable insight into the possible operational or safety issues that may result when renewable generation is integrated with the distribution system. Actions to help remediate some of these potentially harmful situations are also provided. The NRECA DG Toolkit even takes it one step further and provides some interpretations of what each section or rule of the IEEE 1547 is really aiming to accomplish, or how and why the rule was developed.

Determining the potential power generation curves from PV at various times through the daylight hours and seasons is not a trivial task since they are dependent upon many factors such as solar irradiance, ambient temperatures, location of the sun, the arrays tilt and azimuth, PV plant location, and site size. The inverters ratings, design and operating modes also need to be considered since they can vary greatly. Coupling this with the local load profile to develop a wide variety of net circuit load levels with and without generation is needed with follow-up investigation to determine any issues with negative interactions between voltage regulation devices, which in turn will assist with the development of new control settings to accommodate the DER enhanced system.

Examples were presented with traditional voltage regulator settings normally used for one-way steady-state load flows, resulting in voltage problems when introducing intermittent generation, especially with reverse power flow during periods of peak insolation. Also demonstrated were the effects of operating PV inverters in voltage regulating mode rather than the more commonly used unity power factor mode.

IX. REFERENCES

1. IEEE Standard 1547™-2008, *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.*
2. Bob Saint, "Update on IEEE 1547 Series of Standards for Distributed Resources Interconnection" IEEE PES General Meeting, 2011.
3. Application Guide for Distributed Generation Interconnection, The NRECA Guide to IEEE 1547, Sept. 2011.
4. W. H. Kersting, *Distribution System Modeling and Analysis,* 2nd Edition, CRC Press, Boca Raton, Florida, 2007.
5. Jewell W., Ramakumar R., "The Effects of Moving Clouds on Electric Utilities with Dispersed Photovoltaic Generation," IEEE Transactions on Energy Conversion, Vol. EC-2, No. 4, Dec. 1987.
6. National Renewable Energy Laboratory, *Factors Relevant to Utility Integration of Intermittent Renewable Technologies,* Yih-huei Wan and Brian K. Parsons, August 1993.
7. J.W. Smith, R. Dugan, W. Sunderman, "Distribution Modeling and Analysis of High Penetration PV", IEEE PES Conference, July, 2011.
8. S. Steffel, A. Dinkel, R. Sherwood, "Utility Tools and Design Modifications to Mitigate the Impact of PV on the Distribution System," Utility/Lab Workshop on PV Technology and Systems, Tempe, Arizona, November 8-9, 2010.
9. Department of Energy Renewable Systems Interconnection Series, T. Ortmyer, R. Dugan, D. Crudele, T. Key, P. Barker, *Utility Models, Analysis, and Simulation Tools,* Sandia Contract 715908, Feb. 2008.
10. C. Schauder, "Impact of FERC 661-A and IEEE 1547 on Photovoltaic Inverter Design", IEEE PES General Meeting, July, 2011.
11. E.H. Camm, S.E. Williams, "Solar Power Plant Design and Interconnection", IEEE PES General Meeting, July, 2011.

12. R. A. Walling, B. Saint, R. Dugan, J. Burke, L. Kojovic, et. al, "Summary of Distributed Resources Impact on Power Delivery Systems," IEEE Transactions on Power Delivery, Vol. 23, No. 3, July 2008.
13. F. Katiraei, J. Aguero, "Solar PV Integration Challenges," IEEE Power and Energy Magazine, May/June 2011.
14. T. Rizy, Yan Xu, Huijuan Li, Fangxing Li, P. Irminger, "Volt/Var Control Using Inverter-based Distributed Energy Resources," IEEE PES General Meeting, July, 2011.
15. National Renewable Energy Laboratory, *Distribution System Voltage Performance Analysis for High-Penetration Photovoltaic*, Subcontract Report NREL/SR-581-42298, Feb. 2008.
16. M. Begovic, A. Pregelj, A. Rohatgi, D. Novosel, "Impact of Renewable Distributed Generation on Power Systems", presented at the 34th Hawaii International Conference on System Sciences, 2001.
17. M. McGranaghan, T. Ortmeyer, D. Crudele, T. Key, J. Smith, P. Barker, "Renewable Systems Interconnection Study: Advanced Grid Planning and Operations", Sandia National Laboratories, SAND2008-0944, Feb. 2008.
18. J. Smith, W. Sunderman, R. Dugan, B. Seal, "Smart Inverter Volt/Var Control Functions for High Penetration of PV on Distribution Systems," IEEE Power Systems Conference and Expo, March, 2011.
19. G. Shirek, B. Lassiter, W. Carr, W. H. Kersting, "Modeling Secondary Services in Engineering and Mapping," IEEE Rural Electric Power Conference, April 2010.
20. http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/derate.cgi.

X. BIOGRAPHY

Greg Shirek, P.E., (M'1999, SM'2011) received his B.S. in Electrical Engineering from the University of Wisconsin-Platteville in 1999. He has broad experience in distribution system planning and protection, transmission planning, DG interconnection studies, arc flash analysis, harmonic assessment and mitigation, and reliability analysis having worked for 10 years as an electric utility consultant for Power System Engineering. In 2008, he joined Milsoft Utility Solutions, Inc. as an Engineering Analysis Support Engineer and is currently Lead Support Engineer in the Engineering Analysis product line. Greg is the Secretary of the IEEE Distribution System Analysis Subcommittee of the PSACE committee and is also an active member of the IEEE 1584 Arc Flash committee. He is a registered professional engineer in the state of Wisconsin and a senior member of IEEE.

Brian Lassiter received his B.S. in Computer Science from North Carolina State University in 2003. He gained experience in distribution system planning studies, protection studies, system modeling, and utility integration while working at Booth & Associates, Inc., in Raleigh, NC for 3 years as an Engineering Technician. He joined Milsoft in 2004 as an Engineering Support Specialist and is currently Director of Engineering Analysis.

 978-1-4673-0337-8-5/12/$31.00 ©2012 IEEE

Appendix C

Training, Committee Work, Task Forces and Conferences that GSHi staff have participated in to learn as much as possible about the state of renewable generation connection challenges.

International Research and Training

CEATI *– GSHI joined CEATI in late 2009. The DALCM interest group routinely discussed Smart Grid issues and problems and has initiated a few research projects that GSHI co-sponsored. DALCM meetings regularly included Utility representatives from across Canada (Newfoundland Power, New Brunswick Power, Hydro Quebec, Hydro One, Manitoba Power SaskPower, Fortis Alberta, BC Hydro and others) and the United States (Southern Company, Duke Energy , San Diego Gas and Electric, and others) and occasionally representatives from Australia.*

> *CEATI Mission Statement - The Centre for Energy Advancement through Technological Innovation (CEATI) is a user-driven organization committed to providing technology solutions to its electrical utility participants, who are brought together to collaborate and act jointly to advance the industry through the sharing and developing of practical and applicable knowledge.*
>
> **CEATI International Inc.** brings electrical utility industry professionals together, through focused interest groups and collaborative projects, to identify and address technical issues that are critical to their organizations. Participants can undertake projects that respond to their strategic goals at a fraction of the cost of doing so independently. The need for international breadth and inter-industry applicability in technology development is addressed through a practical, dynamic and cost effective program.

GSHI Participation

- Joined Distribution Asset Life Cycle Management (DALCM) interest group.
- Attended DALCM business meeting - February 2010.
- Attended DALCM business meeting and DALCM sponsored Distribution Planning Training (focused on integration of Renewable Generation into the Distribution System) – June 2010.
- Attended DALCM business meeting – October 2010.
  - Co-Sponsors of the following research
    - Nanotechnology with Utility Benefits
    - Solar Power Variability Impacts on the Distribution System
    - Impacts of Intermittent Distributed Generation on Distribution Systems
- Attended DALCM business meeting – February 2011.
- Attended DALCM business meeting and spoke at DALCM sponsored Technical Session entitles “Utility Training Requirements for the Smart Grid Evolution” – June 2011

- Joined Smart Grid Task Force in September 2011 – the Task Force then evolved into an interest group separate from DALCM.
- Joined the Smart Grid Task Force interest group in December 2011

IEEE – The GSHI Vice-President Distribution Electrical Systems has been a member of the IEEE Power & Energy Society (PES) since the mid 1970's.

IEEE is the world's largest professional association dedicated to advancing technological innovation and excellence for the benefit of humanity. IEEE and its members inspire a global community through IEEE's highly cited publications, conferences, technology standards, and professional and educational activities.

IEEE, pronounced "Eye-triple-E", stands for the Institute of Electrical and Electronics Engineers.

- Attended IEEE PES Transmission & Distribution (T&D) Conference in Calgary in July 2009 – Smart Grid was a major theme of a number of conference super sessions and workshops.
- Joined the group writing IEEE 2030.1 – "Guide for Electric-Sourced Transportation Infrastructure" in early 2010. Assigned to Task Force 2 and reassigned to Task Force 3.
- Attended IEEE PES General Meeting in New Orleans in April 2010- - Smart Grid was a major theme of a number of conference super sessions and workshops. Attended Smart Distribution technical sessions.
- Attended IEEE PES General Meeting in Detroit in July 2011 - Smart Grid was a major theme of a number of conference super sessions and workshops. Attended technical sessions and IEEE Smart Grid Training.
    - Joined the following IEEE Committees or Task Forces at the Detroit PES GM
        - Volt VAR task force.
        - Smart Distribution working group.
        - Distribution Management System Task Force.

Canadian Research and Training

Natural Resources Canada (NRCAN) has formed the NRCan Protection and Safety Study Group. The Group has representation from three provincial utilities, two relay manufacturers, three private consultants and two NRCan staff members. The focus of the Group is to address technical issues that are seen as obstacles to the interconnection of alternate energy technologies to the grid. The enclosed

- Joined Natural Resources Canada (NRCan) Protection and Safety Study Group in March 2010. By mid -2010 the group had expanded to include representatives from New Brunswick Power, IREQ-Hydro Quebec, Hydro One, Greater Sudbury Hydro, and BC Hydro.
    - Presented at NR Canada sponsored workshop "Distribution Grid Codes with High Penetration PV" in Mississauga on January 18th 2011.
- GSHI was asked by Natural Resources Canada (NRCan) to join a High Penetration Photovoltaic (PV) Research Group in July 2011
    - The group will set R&D priorities related to high penetration PV.

    - Includes access to the International Energy Agency – Photovoltaic Power System Programme (IES_PVPS).
- High Penetration Photovoltaic (PV) Research Group members include:
    - Utilities - Hydro One, Greater Sudbury Hydro, Bluewater Power, IREQ – Hydro Quebec, Toronto Hydro.
    - Cyme – makers of distribution system engineering analysis software.
    - Inverter Manufacturers – Schneider, GE, Bofiglioliusa
    - Concordia university
    - CANSIA

Ontario Research and Training

Utilities Standard Forum (USF) – Greater Sudbury Hydro joined in 2005. USF is the collaboration of 49 Ontario Utilities to produce Distribution Standards in response to Ontario Regulation 22/04. Members Utilities tend to be small to medium LDCs but the membership serves over 1 million Ontario Customers. The group also tackles many other technical issues, including but not limited to Smart Grid.

Greater Sudbury Hydro holds the position of Chair on the Smart Grid Committee. The Smart Grid Committee was formed in 2010 to provide member Utilities with technical direction on implementing the Smart Grid in Ontario.

Other Groups, Meetings and Conferences

IESO Stakeholder SE91 – Participant
CANSIA FiT Meeting
Electromobility Canada – member
EDA EDIST Conference – 2009, 2010, 2011
EDA Niagara Grand Metering Workshop
EDA NE/NW Joint Fall Conference – 2010, 2011
EDA Smart Grid Planning Approaches Seminar – July 2010
EDA Annual general Meeting – 2010, 2011
EDA Enercom Conference 2010
EDA Northeast District Engineering/Operations Workshop
EDA Canadian Utility Equipment Exposition - 2010
Hydro One Large Users Conference
Hydro One LDC Fit MicroFiT Working Group
International Sensus Users Group Conference – Nashville – November 2011
Smart Grid Interoperability Conference – Speaker – June 2011
Distributech – San Diego – February 2011
EUSA – Member of Board of Directors – July 2009 to December 2010
Electrical Safety Authority – Utility Advisory Committee

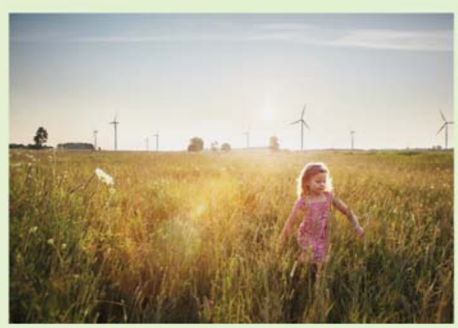
Appendix D

OPA Letter of Comment.

OPA Letter of Comment:

Greater Sudbury Hydro Inc.

Basic Green Energy Act Plan



June 6, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Greater Sudbury Hydro Inc. - Basic Green Energy Act Plan

On May 14, 2012 the OPA reviewed the Basic GEA Plan from Greater Sudbury Hydro Inc. ("GSHI") dated March 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

GSHI's GEA Plan did not provide detailed information on current FIT or microFIT activity.

According to the OPA's information, as of May 16, 2012, there are 4 capacity allocation exempt ("CAE") contracts, representing 0.8 MW of capacity, proposing to connect to GSHI's system. There are also 4 capacity allocation required ("CAR") applications, and 11 CAE applications, totalling 38 MW of capacity, submitted prior to the Feed-in Tariff ("FIT") Program Two-Year Review. According to the FIT 2.0 draft rules posted on April 5, 2012, these applications will have the opportunity to be revised and re-submitted in order to meet the requirements in the FIT 2.0 draft rules.

For microFIT, according to the OPA's information, there are 41 connected projects, totalling 0.3 MW of capacity in GSHI's territory. There are also 108 microFIT projects, totalling 1 MW of capacity, that have applied to connect to GSHI's system.

Starting on December 8, 2010, all microFIT applications were required to have an Offer to Connect from their LDC before receiving a microFIT Conditional Offer from the OPA. A similar process may continue under microFIT 2.0, in which the OPA will issue an Application Approval Notice after an Offer to Connect is provided by the LDC.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

According to the feedback received on the FIT Program Two-Year Review and depending on the final outcome of the FIT 2.0 draft rules, the FIT program rules may entail a capacity limit moving forward. In addition, CAE applications may require a transmission and distribution connection assessment before receiving a FIT contract from the OPA.

If these changes in the FIT program are implemented, with the proposed microFIT program Application Approval Notice, some of the concerns raised in Section 4.5 of GSHI's GEA Plan related to unforeseen FIT and microFIT connections could be mitigated.

For details on the Feed-In Tariff Program Two-Year Review results, please refer to the information available on the Ministry of Energy website: http://www.energy.gov.on.ca/en/fit-and-microfit-program/2-year-fit-review/

For details on the FIT 2.0 draft rules, please refer to the information available on the FIT website: http://fit.powerauthority.on.ca/comments-welcome-draft-fit-program-rules-and-contract

For details on the microFIT 2.0 draft rules, please refer to the information available on the microFIT website: http://microfit.powerauthority.on.ca/comments-welcome-draft-microfit-program-rules-and-contract

Upstream Transmission Constraints

Section 4.1.2 of GSHI's GEA Plan states that Martindale TS is constrained by short circuit capacity, and Coniston TS is constrained by thermal capacity. The OPA is aware of these constraints. It is the OPA's understanding that Hydro One has plans to address these constraints.

Section 4.1.2 of the Plan also indicates that there is no available transmission capacity in Northeastern Ontario. According to the updated Transmission Availability Table ("TAT") published by the OPA on April 5, 2012, 200 MW of capacity is available to contract small FIT projects in the Northeast. However, specific applications may be limited by available capacity at the station depending on where the project proposes to connect.

Further details on capacity may be found in the updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows:
http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

Opportunities for Integrated Solutions

The OPA is not aware of any opportunity for integrated solutions among neighbouring LDCs at this time.

Conclusion

In light of the potential changes to the FIT program, which may affect future renewable generation connection activity, the OPA suggests that the renewable generation forecast in Section 4.3 of GSHI's GEA Plan may be somewhat high.

The OPA appreciates the opportunity to comment on GSHI's Basic GEA Plan.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

HARMONIZED SALES TAX

Greater Sudbury's capital additions in 2009 and up to and including June 30, 2010 includes PST. Any capital additions in the remainder of 2010 and 2011 do not include PST due to the implementation of HST. The 2012 and 2013 forecast capital additions do not include any amounts relating to PST. Further details are explained in Deferral Account 1592 ‘PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) found in Exhibit 9, Tab 1, Schedule 4.

Exhibit 2: Rate Base

Tab 5 (of 6): Allowance for Working Capital

DERIVATION OF WORKING CAPITAL ALLOWANCE

On April 12, 2012 the Board issued a letter providing Distribution Companies with guidance related to the derivation of working capital allowances in Cost of Service filings. Previously the Board had indicated that it was reviewing the requirement for applicants to perform lead/lag studies as a means of determining what their working capital should be. In the April letter the Board indicated that it would not require all CoS filers to perform the lead/lag study, however, the factor that would be used for the simplified approach would be lowered from 15% to 13%. Greater Sudbury has used this approach in calculating its proposed working capital allowance for the Test Year of $14,362,335.

Table 1 - Working Capital Allowance

Expenses for Working Capital	**2009 Approved**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2012 Actual**	**2013 Actual**
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	3,571,216	3,652,054	3,432,872	3,763,302	5,156,619	6,914,732
3550-Distribution Expenses - Maintenance	1,745,098	1,502,331	1,681,643	1,497,531	2,339,512	2,163,820
3650-Billing and Collecting	2,515,358	2,194,104	1,937,276	2,321,708	1,779,703	3,146,864
3700-Community Relations	206,736	142,484	343,169	439,836	-	78,108
3800-Administrative and General Expenses	3,631,137	3,943,844	512,111	4,929,864	3,047,169	3,261,093
3950-Taxes Other Than Income Taxes	200,000	166,452	23,784	(656)	-	-
Total Eligible Distribution Expenses	11,869,545	11,601,270	7,930,855	12,951,585	12,323,003	15,564,617
3350-Power Supply Expenses	77,697,760	77,140,065	79,191,698	85,008,941	90,687,113	94,914,882
Total Expenses for Working Capital	89,567,305	88,741,335	87,122,553	97,960,526	103,010,116	110,479,500
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	13.0%
Working Capital Allowance	**13,435,096**	**13,311,200**	**13,068,383**	**14,694,079**	**15,451,517**	**14,362,335**

The increase in working capital allowance between the 2009 approved amount and 2013 Test year projection is $927,239 or 6.9%. The increase is partly due to an increase in allowable distribution expenses, for which a thorough discussion relating to the increase is included at Exhibit 4, Tabs 1, 2 and 3. Also driving the fluctuation is the increase in the expected power supply expense, driven mostly by the change in the commodity price. The 2009 cost of service application assumed a commodity rate of $0.0603. Per the Regulated Price Plan Price Report for November 1, 2012 to October 31, 2013 dated October 17, 2012 released by the Ontario Energy Board, the commodity price is forecasted to be $0.07932, an increase of approximately 32%. Greater Sudbury's calculation of projected power expenses is included at Exhibit 2, Tab 5, Schedule 1, Attachment 1. Those increases are partly offset by the decrease in the working capital factor from 15% to 13%.

Projected Power Supply Expenses

Sudbury (ED-2002-0559)
2013 EDR Application (EB-2012-0126) version: 1
November 9, 2012

C8 Pass-through Charges

Enter rates for pass-through charges and estimated Low Voltage revenues

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)	**Customer**	**Revenue**	**Expense**	**2012**	*rate ($/kWh):*	**$0.07298**	**2013**	*rate ($/kWh):*	**$0.07932**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4006	4705	430,664,488		31,429,894	423,035,895		33,555,207
kWh	General Service < 50 kW	4035	4705	153,184,006		11,179,369	149,513,151		11,859,383
kWh	General Service > 50 to 4999 kW	4035	4705	414,297,915		30,235,462	406,284,307		32,226,471
kWh	Unmetered Scattered Load	4035	4705	1,619,689		118,205	1,515,242		120,189
kWh	Street Lighting	4025	4705	9,070,445		661,961	8,416,200		667,573
kWh	Sentinel Lighting	4030	4705	492,288		35,927	485,505		38,510
	TOTAL			**1,009,328,832**		**73,660,818**	**989,250,300**		**78,467,334**
Transmission - Network	**Customer**	**Revenue**	**Expense**		**2012**			**2013**	
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	430,664,488	$0.0059	2,540,920	423,035,895	$0.0057	2,411,305
kWh	General Service < 50 kW	4066	4714	153,184,006	$0.0043	658,691	149,513,151	$0.0041	613,004
kW	General Service > 50 to 4999 kW	4066	4714	972,216	$3.2979	3,206,271	969,057	$3.1753	3,077,047
kWh	Unmetered Scattered Load	4066	4714	1,619,689	$0.0043	6,965	1,515,242	$0.0041	6,212
kW	Street Lighting	4066	4714	24,040	$1.7724	42,608	22,306	$1.6120	35,957
kW	Sentinel Lighting	4066	4714	1,287	**$1.6742**	2,155	1,269	**$1.7065**	2,166
	TOTAL			**586,465,726**		**6,457,611**	**575,056,920**		**6,145,691**
Transmission - Connection	**Customer**	**Revenue**	**Expense**		**2012**			**2013**	
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4068	4716	430,664,488	$0.0037	1,593,459	423,035,895	$0.0036	1,522,929
kWh	General Service < 50 kW	4068	4716	153,184,006	$0.0027	413,597	149,513,151	$0.0026	388,734
kW	General Service > 50 to 4999 kW	4068	4716	972,216	$2.0401	1,983,418	969,057	$1.9917	1,930,071
kWh	Unmetered Scattered Load	4068	4716	1,619,689	$0.0027	4,373	1,515,242	$0.0026	3,940
kW	Street Lighting	4068	4716	24,040	$1.0962	26,353	22,306	$1.0109	22,549
kW	Sentinel Lighting	4068	4716	1,287			1,269	**$1.0702**	1,358
	TOTAL			**586,465,726**		**4,021,199**	**575,056,920**		**3,869,581**
Wholesale Market Service	**Customer**	**Revenue**	**Expense**	**2012**	*rate ($/kWh):*	**$0.00520**	**2013**	*rate ($/kWh):*	**$0.00520**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4062	4708	430,664,488		2,239,455	423,035,895		2,199,787
kWh	General Service < 50 kW	4062	4708	153,184,006		796,557	149,513,151		777,468
kWh	General Service > 50 to 4999 kW	4062	4708	414,297,915		2,154,349	406,284,307		2,112,678
kWh		4062	4708	1,619,689		8,422	1,515,242		7,879
kWh	Street Lighting	4062	4708	9,070,445		47,166	8,416,200		43,764
kWh	Sentinel Lighting	4062	4708	492,288		2,560	485,505		2,525
	TOTAL			**1,009,328,832**		**5,248,510**	**989,250,300**		**5,144,102**
Rural Rate Protection	**Customer**	**Revenue**	**Expense**	**2012**	*rate ($/kWh):*	**$0.00110**	**2013**	*rate ($/kWh):*	**$0.00110**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4062	4730	430,664,488		473,731	423,035,895		465,339
kWh	General Service < 50 kW	4062	4730	153,184,006		168,502	149,513,151		164,464
kWh	General Service > 50 to 4999 kW	4062	4730	414,297,915		455,728	406,284,307		446,913
kWh	Unmetered Scattered Load	4062	4730	1,619,689		1,782	1,515,242		1,667
kWh	Street Lighting	4062	4730	9,070,445		9,977	8,416,200		9,258
kWh	Sentinel Lighting	4062	4730	492,288		542	485,505		534
	TOTAL			**1,009,328,832**		**1,110,262**	**989,250,300**		**1,088,175**
Debt Retirement Charge	**Customer**	**Revenue**	**Expense**	**2012**	*rate ($/kWh):*	**$0.00700**	**2013**	*rate ($/kWh):*	**$0.00700**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	TOTAL								
Low Voltage Charges	**Customer**	**Revenue**	**Expense**		**2012**			**2013**	
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4075	4750	408,611,069	**$0.0002**	81,722	401,373,120	**$0.0002**	78,764
kWh	General Service < 50 kW	4075	4750	145,339,777	**$0.0001**	14,534	141,856,898	**$0.0001**	20,314
kW	General Service > 50 to 4999 kW	4075	4750	972,216	**$0.0937**	91,097	969,057	**$0.1027**	99,484
kWh	Unmetered Scattered Load	4075	4750	1,536,748	**$0.0001**	154	1,437,650	**$0.0001**	206
kW	Street Lighting	4075	4750	24,040	**$0.0475**	1,142	22,306	**$0.0521**	1,162
kW	Sentinel Lighting	4075	4750	1,287	**$0.0503**	65	1,269	**$0.0552**	70
	TOTAL			**556,485,137**		**188,713**	**545,660,300**		**200,000**
GRAND TOTAL						**90,687,113**			**94,914,882**

Exhibit 2: Rate Base

Tab 6 (of 6): Service Quality and Reliability Performance

SERVICE QUALITY

In accordance with Chapter 7 of the DSC, Greater Sudbury monitors and reports on specific service quality indicators (SQI's), and follows the requirements for Reporting and Record Keeping as updated March 7, 2012. Greater Sudbury collects and reviews the statistical results on a monthly basis and reports the results to the OEB on an annual basis. Greater Sudbury tracks additional service quality data by completing a weekly sampling of customer satisfaction as a result of customer contacts for its Quality Management System as described at Exhibit 4, Tab 3, Schedule 1, Attachment 2.

The SQI's related to Customer Service are as follows:

1. Connection of New Services: low voltage service (<750 V)
2. Connection of New Services: high voltage service (>750 V)
3. Appointment Scheduling
4. Appointments Met
5. Rescheduling a Missed Appointment
6. Telephone Accessibility
7. Telephone Call Abandon Rate
8. Written Response to Inquiries
9. Emergency Response
10. Reconnection Standards

As is evidenced in Table 1 below, Greater Sudbury met or significantly exceeded the minimum standard prescribed in all areas and years but for 1 instance, namely Telephone Accessibility in reporting year 2011.

.

Table 1 - Customer Service Indicators

Service Quality Indicator	Minimum Standard	2009	2010	2011
Connection of New Services – Low Voltage	90% or better	100%	100%	100%
Connection on New Services – High Voltage	90% or better	N/A	N/A	N/A
Appointments Scheduling	90% or better	100%	100%	98%
Appointments Met	90% or better	100%	100%	100%
Rescheduling a Missed Appointment	100%	N/A	N/A	N/A
Telephone Accessibility	65% or better	78.7%	74.5%	46.8%
Telephone Call Abandon Rate	Less than 10%	2.40%	.90%	6%
Written Response to Inquiries	80% or better	100%	100%	100%
Emergency Response – Urban	80% or better	98.2%	98.3%	100%
Emergency Response – Rural	80% or better	N/A	N/A	N/A

Telephone Accessibility Failure 2011 - In 2011 Greater Sudbury experienced a period of extreme call volume owing to a number of issues that built one on the other as follows.

- In early December 2010 Greater Sudbury converted from its previous billing software system to the current system, NorthStar. As is common with these major software conversions billing was delayed and customers began to call in the New Year to determine what had happened to their anticipated bill.

- During the NorthStar transition period the collection module in NorthStar could not be used as it required a previous bill calculated in the system to determine which accounts were delinquent. This meant that collections could not be implemented until March 2011, resulting in a higher than normal level of collection activity as customers who had previously relied on reminder letters to pay their bill had slipped further behind. This compounded an already heavier call volume as billing volumes were increased to catch up from the billing delay described in bullet 1 above.

- In April and May, just as Greater Sudbury's billing stream was beginning to normalize, staff began to prepare for what looked like an inevitable disruption of mail service. After investigation it was decided that Greater Sudbury would contract with a third party to deliver bills, thereby bypassing Canada Post and avoiding the effects of any disruption in the normal postal service. Greater Sudbury moved to the alternate delivery service in June. In July it became apparent that the alternate delivery service was not effective when disconnect notices were delivered to homes that had not as of yet received a bill. A Corrective Action was launched immediately using Greater Sudbury's Quality Management System (QMS). During the investigation of the root cause and development of alternatives, staff reversed late payment charges and began to manually work all collections to avoid further disconnection activity for customers with good payment histories.

- Naturally this event caused a flood of calls to the call centre causing the failure in the SQI requirement.

The Corrective Action is included as Exhibit 2, Tab 6, Schedule 1, Attachment 1 for a fuller description of the event and Greater Sudbury's response.

Greater Sudbury QMS Customer Service SQIs

As noted above, Greater Sudbury surveys its customer's levels of satisfaction on a weekly basis as a component of its ISO 9001 compliant Quality Management System. Selection of customers for inclusion in the survey is random based on a list of customers who have contacted Greater Sudbury in the weeks prior to the survey for a particular service. The survey is intentionally brief asking only two questions:

1) How do you rate our service on a scale of 1-10?
2) How can we improve?

It is believed that by being brief, Greater Sudbury maintains a higher response rate that would be the case if the survey were to take more than a few minutes.

Survey results are reviewed by the President and CEO on a weekly basis. Where warranted, Non-Conforming Service Actions or Corrective Actions are taken out and assigned to the appropriate personnel.

Table 2 below shows the results of Greater Sudbury's Customer Satisfaction Surveys to date.

Table 2 – Customer Satisfaction Survey Results

Service Type	**Service Rating (%)**	**Number of Samples**
Conservation & Demand Management	83	156
Customer Connections	89	142
Underground Locates	87	138
Customer Service Phone Calls	83	211
Utility Wide Rating	**86**	**647**

Greater Sudbury Hydro Inc
9 November, 2012
EB-2012-0126
Exhibit 2
Tab 6
Schedule 1
Attachment 1

CORRECTIVE ACTION REPORTS

Select Car / Par #

CA-11-0050 Search Print

GSU

Assigned to: Kallonen, Frank

INITIALIZATION

Car / Par #	CA-11-0050
Initiator	Frank Kallonen
Action Report Stage	3
Project Name	CS/Billing
Date	2011-09-12
MS Procedure	GSU MP 7.2 Customer Oriented Processes Procedure
MS Policy	GSU MM 7.0 Service Delivery Policy
Problem Brief Description	Customers receiving disconnect notices etc without having received a bill.
Problem Explanation	GSU bills in excess of 60,000 accounts for water/wastewater, electricity or both water and electric commodities on a bi-monthly billing schedule. The collection process is complex and time consuming. Typically an actual physical disconnect will not take place until more than 45 days have passed from the date that the bill was printed. The usual process is as follows: • Bill is calculated and printed - Day 1 • Bill is due - Day 23 • Reminder notice is printed - Day 31 • Disconnect notice is printed - Day 39 • Collection Trip - Day 48 • Physical Disconnect - Day 51 The system was brought on in stages so that each new function set could be tested, training provided and problems resolved if they were found. The part of the system that automates the collection function was turned on in mid-March of this year and the collection process began. There were a large number of accounts that had fallen behind since they had last received a reminder notice to pay their bill. Staff continued to work to bring these accounts current right up until June when the postal strike began to become an issue. When the postal strike appeared to be imminent staff began to have bills and notices delivered directly to each customer's home by a contractor. Unfortunately, the contractor had difficulty maintaining delivery in the volumes that Hydro required and some customers bills and/or notices did not reach them in a timely fashion. As a result, there were occasions where collection trips were processed for customers who had not received either a bill, notice (example attached) or disconnect letter (example attached). In these instances where customers have a good payment history, staff have been reversing any charge associated with collection activity and have offered payment arrangements to help the customer get back on track with regular payments. As soon as the mail strike was resolved, staff reverted to the practice of having bills and notices sent out through the post office believing that this would quickly resolve the issue by getting bills and collections to customers in a timely manner. This was not the case, the mail was very delayed and similar problems occurred. It appears that the mail is slowly getting back on track. Staff have continued to work with customers to reverse charges where appropriate and to assist customers with payment arrangements
Suggested Solution	Correct billing, collections processes so that bills arrive in a timely fashion.

ROOT CAUSE ANALYSIS

Root Cause	Root Causes 1) Postal disruption (first a slowdown in late May then a lockout in June) caused management to review potential alternate delivery methods early in the year. The most apparent alternative was the use of a contractor URB Olameter who had experience with deliveries in other Ontario LDC territories. GSHi switched to the contract service in late May expecting that it would avoid any bill delivery problems. During the transition period some bills may have been "lost" in postal sorting stations 2) URB Olameter did not deliver the goods a) Geographic area of Sudbury is much larger and less densely populated than the other areas that Olameter had experience with in Southern Ontario, delivery was more challenging and time consuming. b) staffing was a problem for Olameter - likely because they were paying by the piece delivered and at rates that were calculated for the denser municipalities that they had experience with in the South. As a result they had trouble attracting sufficient numbers of staff and in certain instances it appeared that staff disposed of rather than deliver customer bills. 3) New billing system issues a) GSHPi introduced a new billing system in late 2010. Conversion to the new system produced numerous issues that delayed billing. On March 6 GSHPi implemented the Collection Module for the new billing system. this module essentially reviews all accounts to ensure that they are paid up. If the account is not paid past a specified number of days from the date of the issuance of the bill the system automatically puts customers into the collection stream. The system continues to advance the customer towards disconnection unless it is determined that the customer has paid the bill or the customer calls to talk to a service representative to make arrangements to pay. b) The new billing system has no credit history in it as it requires at least one year of payment history to rate customers on a credit scale. i) even if a credit history were available the new system is not configured to treat a customer differently if they have a high credit score. c) The collection procedure requires that a "friendly" reminder notice be sent out before any forceful collection action is taken. i) The practice is to send the friendly reminder out via Canada Post or during the service disruption via the Contractor Olameter - see causes 1 & 2 above. d) The change to the new billing system and attendant problems caused the billing cycle in general to be delayed. 4) Customers received their "unfriendly" disconnect notices. a) These notices are hand delivered via a separate process that did work and in many cases were the first contact customers had from GSHPi related to their bill. b) These notices were sent to customers regardless of their payment history with the Utility. c) These notices cause a "trip charge" to be applied to the customer's account. d) These notices caused a negative credit score to be assessed against each customer's account. Ancillary Issue Due to the billing delay caused by the system conversion and a $4.1M payment required to be made to the CGS GSU was in a very difficult cash position. Essentially the organization was in over draft and in serious jeopardy of not being able to meet its obligations.

	Cash flow was a huge issue at this time and we simply needed to continue with some form of collection activity.
Approved By	Frank Kallonen
Approved Date	2011-12-20
Proposed Action	Immediate Response 1) Manual intervention in collection process. a) as soon as the extent of the issue became known billing staff began to review collection batch reports against customer history to understand the customers payment history. i) where the customer had a good payment history (1) they were removed from the collection stream and an attempt was made to contact the customer (2) trip charges and late payment penalties were reversed from the account 2) Staff contacted large commercial customers a) by phone to determine if they had received their bills and if not to send them copies - all cycle 90 3) Discontinued use of the delivery contractor a) as soon as the postal disruption was over all bills were delivered immediately to the postal sorting station for delivery b) This caused further delays as Canada Post took a long time to get service back to normal. c) staff began to survey customers by phone to determine if they had received their bills. Continuing Response 1) Implement IVR capability a) staff are in the process of implementing systems that will allow us to replace the friendly reminder letter with a friendly reminder phone call. Due to the number of calls the system needs to be automated therefore software that will integrate the billing system to the call management system is required to be implemented. An additional issue is the validity of the phone numbers in the data base. 2) Implement On-line presence a) customer self service website has been implemented and is being advertised to allow customers to sign up for self service via the internet. 3) Refine configuration of Collection Processing in CIS System a) staff are completing a thorough review of the system in an attempt to provide differential treatment for customers based on their credit rating. It should be noted that this will only be effective once sufficient customer payment is available on the system.
Action Approved By	Frank Kallonen
Action Approved Date	2011-12-20

Follow up for Effectiveness

Follow up for Effectiveness	Generally the issue of disconnect letters arriving before bills or friendly reminders has been resolved as mail service returned to normal. the other Customer Service improvements noted above continue to be ongoing projects.
Approved By	Frank Kallonen
Approved Date	2011-12-20 12:00:00 AM

Comments

RELIABILITY PERFORMANCE

There are three **Service Reliability Indicators** that are tracked and reported to the OEB annually, as required, and are described below:

1) System Average Interruption Duration Index ("SAIDI") - this is an indicator of the length of interruptions that customers experience in a year, on average.

2) System Average Interruption Frequency Index ("SAIFI") - this is an indicator of the number of sustained interruptions that customers experience in a year, on average.

3) Customer Average Interruption Duration Index ("CAIDI") - this is an indicator of the speed at which power is restored to a customer having experienced an outage.

The OEB has indicated that a Distributor's reliability performance should remain within the range of its historical three-year performance. Table 1 and Table 2 below detail the 2011 indices along with the previous three years of historical data, either inclusive (or exclusive) of Loss of Supply:

Table 1 - Service Reliability Indices - Including outages caused by Loss of Supply

	2011	**2010**	**2009**	**2008**
SAIDI	1.26	1.1	1.4	1.4
SAIFI	1.25	1.04	1.42	1.09
CAIDI	1.01	1.06	0.99	1.29

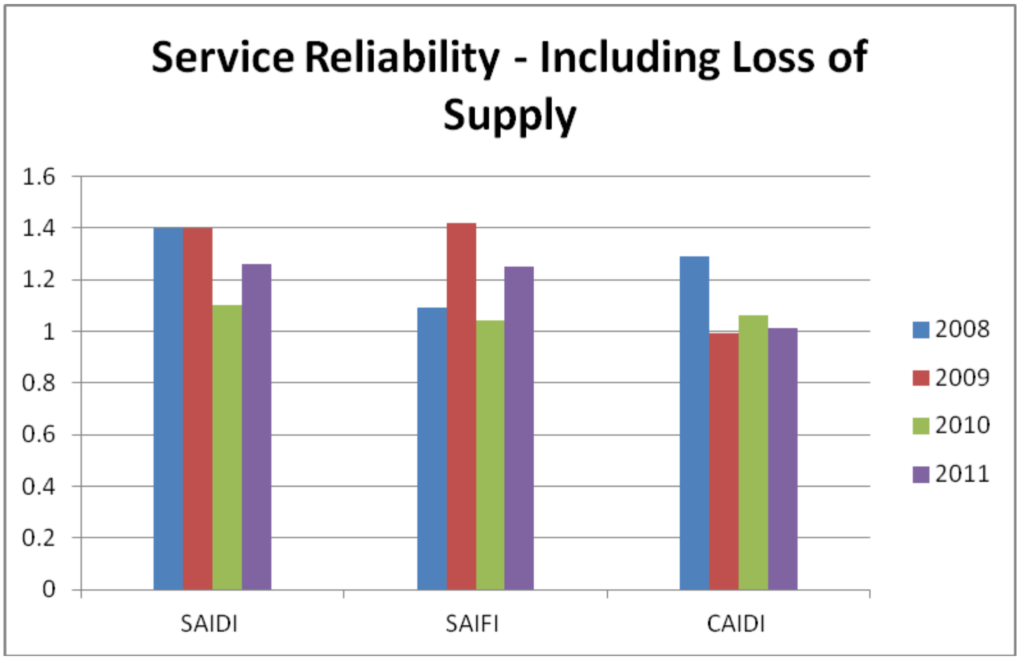
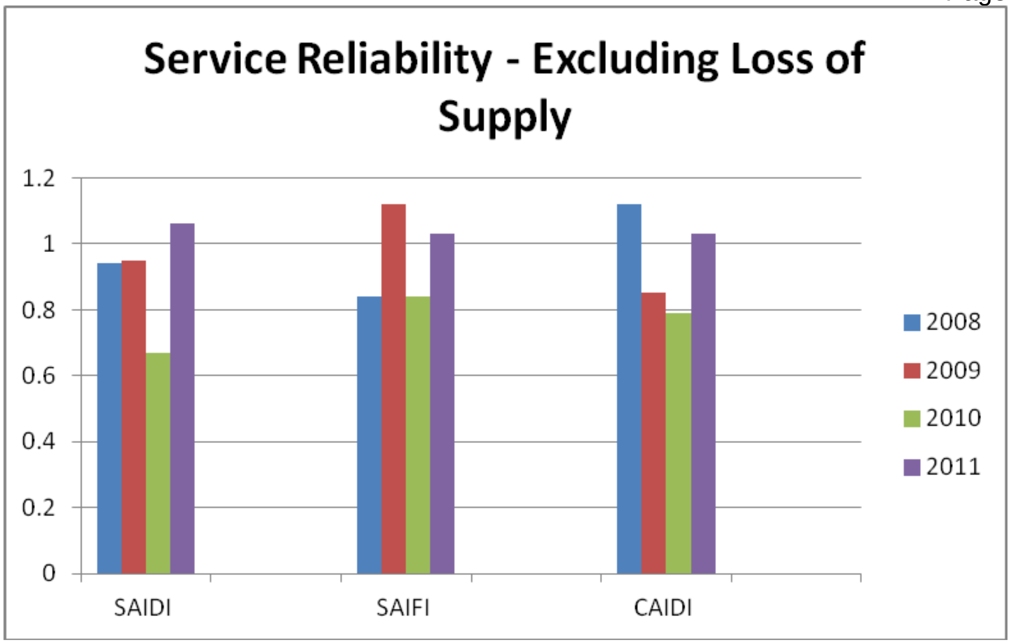


Table 2 - Service Reliability Indices - Excluding outages caused by Loss of Supply

	2011	2010	2009	2008
SAIDI	1.06	0.67	0.95	0.94
SAIFI	1.03	0.84	1.12	0.84
CAIDI	1.03	0.79	0.85	1.12



Despite annual variations in the System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"), the three-year reliability averages have remained relatively constant. The two leading causes affecting outage duration continue to be Loss of Supply (LoS) and Defective Equipment. The two causes that seem to be trending upward affecting frequency are Unknown/Other and Scheduled Outages.

Greater Sudbury is higher in 2011 for all the factors. This can be explained by the following Major Incidents:

Incident on July 1, 2011 - Loss of Supply

A major power interruption occurred on July 1, 2011 at 12:01pm when the incoming supply from Crystal Falls T.S was completely lost.

This affected approximately 2,706 customers and resulted in 343,662 customer minutes of interruption.

All customers were restored within 127 minutes.

Incident on September 20, 2011 and February 13, 2011- Loss of Supply

A major power interruption occurred on September 20, 2011 at 7:53pm when the supply to Upper and Lower Coniston MS (MS 30 and MS31) were completely lost.

This affected approximately 929 customers and resulted in 131,828 customer minutes of interruption.

All customers were restored within 141 minutes.

Previously, on February 13, 2011 at 6:45am, a complete loss of supply for both MS30 and MS31 resulted in a major power interruption.

This affected 929 customers and resulted in 26,941 customer minutes of interruption.

All customers were restored within 58 minutes.

Incident on January 17, 2011- Loss of Supply

A major power interruption occurred on January 17, 2011 at 10:06am when Hydro One switching problems caused a loss of supply to the MS33 T1 transformer.

This affected approximately 933 customers and resulted in 34,521 customer minutes of interruption.

All customers were restored within 37 minutes.

The number of *Scheduled Outages* has increased for two reasons: more rigorous safety procedures regarding worker safety and the type of work being undertaken. The *Occupational Health & Safety Act* requires that an Employer do "Everything reasonable in the circumstances for the safety of the worker" and the Infrastructure & Safety Association has embarked on "ZeroQuest", a path to zero Lost-Time Injuries (LTI) in the sector by 2011. Sudbury Hydro has embraced both these concepts over the years. The worker and supervisory culture has moved slowly, but steadily, towards the performance of Hazard Analysis and Job Planning that have resulted in more frequent (and longer) Planned Outages. This practice is **fully** supported by Senior Management at Sudbury Hydro. Of the 545 outages logged by the Control room, 245 (45%) were due to a *Scheduled Outage*.

There were 5 notable events which had a significant impact on the 2011 SAIDI/SAIFI results. These events occurred on March 23, June 1, July 15-16, July 25 and August 24 and resulted in approximately 1.3 million customer minutes of interruption. They are each described in some detail below:

Incident on June 1, 2011

A major power interruption occurred on June 1, 2011 at 4:17pm when an overhead 44kV line switch broke free of a pole and fell to the ground.

This affected approximately 283 customers and resulted in 425,349 customer minutes of interruption.

All customers were restored within 1,503 minutes.

Incident on July 15-16, 2011

A major power interruption occurred on July 15, 2011 at 4:39pm when a burnt underground dip connection on the 17-LC1 resulted in multiple customer outages.

This affected approximately 6,033 customers and resulted in 279,512 customer minutes of interruption.

All customers were restored within 69 minutes.

The next day, at 9:01am, damaged underground cable on the 17F4 feeder (as a result of the previous disturbance) caused 648 customers to experience 92,811 minutes of interruption.

All customers were restored within 387 minutes.

Incident on August 24, 2011

A major power interruption occurred on August 24, 2011 at 8:01am when a pole fire took down part of the 17F3 and 17F5 feeders.

This affected 2,050 customers and resulted in 189,319 customer minutes of interruption.

All customers were restored within 524 minutes.

Incident on March 23, 2011

A major power interruption occurred on March 23, 2011 at 4:37pm when the Gemmell T2 Transformer suffered an internal fault.

This affected 1,669 customers and resulted in 182,973 customer minutes of interruption.

All customers were restored power within 121 minutes.

Incident on July 25, 2011

A major power interruption occurred on July 25, 2011 at 9:44pm when a tree located along the 20F3 feeder fell on the overhead line.

This affected 433 customers and resulted in 150,251 customer minutes of interruption.

All customers were restored power within 347 minutes.

Reliability Initiatives

Greater Sudbury has a number of programs and initiatives in place to address the reliability of our distribution system. These are discussed fully in our Asset Management Plan. An example is the incremental addition of automation to the overhead system. Specifically, the installation of remotely-controlled overhead line switches allow our control room operators to perform switching instructions to quickly get customer power restored.

Annually, 1/3 of the distribution system assets are inspected, including, but not limited to, poles, transformers and substations. Thermovision inspections are completed annually to identify potential problem areas, which are rectified as needed.

Our Outage Management Database tracks outages by feeder/cause to help identify locations where specific reliability initiatives may be needed, such as increased animal protection or tree trimming.

Reliability analysis by Greater Sudbury is focusing on improving reliability measures. Joint-planning efforts between ourselves and Hydro One Networks are continuing to focus on reliability of supply to Greater Sudbury's service area to reduce impacts of Loss of Supply (LoS).