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January 25, 2021

Delivered by Email & RESS

Ms. Christine Long, Registrar
Ontario Energy Board
P.O.Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: OEB File No. EB-2020-0249/EB-2018-0219 - PUC Distribution Inc. ("PUC Distribution")
SSG 2022 ICM Application
Interrogatory Responses

Pursuant to Procedural Order No. 6 dated November 16, 2020 and letter from the Ontario Energy Board ("**OEB**") dated January 11, 2021, please find attached PUC Distribution's Interrogatory Responses for the above proceedings.

Confidentiality Request

PUC Distribution is filing Attachment 11 - Corporate Structure Chart in response to CCC-5 in confidence. PUC Distribution is filing this information in confidence pursuant to the OEB's *Practice Direction on Confidential Filings* (the "**Practice Direction"**).

With its Application in this proceeding, PUC Distribution had filed Appendix AA3-7: EPC Appendix E – Form of Parent Guaranty in confidence as the Parent Guaranty document contains information on the guarantor and the guarantor is engaged in highly competitive business. The identity of the guarantor had also been redacted in Appendix AA3-7: EPC Contract.[1]

In its Decision on Revised Confidentiality Request ("**Decision**")[2] the OEB found that, among other things, the name of the Guarantor shall be treated as confidential information as it is commercially

[1] EB-2020-0249/EB-2018-0219 – Revised Confidentiality Request dated November 26, 2020 and Reply Submissions dated December 11, 2020.
[2] EB-2020-0249/EB-2018-0219 – Decision on Revised Confidentiality Request dated December 15, 2020.

sensitive third party information the disclosure of which would be contrary to the Practice Direction and *Freedom of Information and Protection of Privacy Act.*[3]

As such, consistent with the Decision, PUC Distribution is filing Attachment 11 – Corporate Structure Chart in confidence as it contains information related to the Guarantor, which the OEB has found to be commercially sensitive third party information.

Filing of Confidential Documents

In keeping with the requirements of the Practice Direction, PUC Distribution is filing confidential unredacted versions of Appendix 11 – Corporate Structure Chart with the Registrar only. The confidential version of the documents have been marked "Confidential". PUC Distribution requests that the confidential version of the document be kept confidential.

Redactions to Irrelevant Information

The information in Attachment 2 – PUC Distribution Inc. Board Meeting Closed Session Minutes that is irrelevant to the proceeding has been redacted. This information pertains to other items on the meeting agenda for the PUC Distribution Inc. Board and is irrelevant and contains no probative value to the proceedings.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Flora Ho

cc: Intervenors of record in EB-2020-0249/EB-2018-0219

[3] R.S.O. 1990, c. F.31.

PUC Distribution Inc.

EB-2020-0249/EB-2018-0219

Responses to Interrogatories

Filed: January 25, 2021

Table of Contents

PUC DISTRIBUTION INC.
INTERROGATORY RESPONSES

Ontario Energy Board Staff Interrogatories

Staff-1

Reference: Capital Module Applicable to ACM and ICM, Tab 1 – Information Sheet

Preamble:

On November 9th, 2020, the OEB announced the value of the inflation factor for use in 2021 rate adjustment applications (i.e. 2.2%).

Question:

(a) OEB staff has updated PUC Distribution's ICM model for the updated value and provided a copy with these interrogatories. Please confirm the accuracy of the updated model.

(b) Please confirm the updated materiality threshold, and maximum eligible incremental capital amounts.

Response:

(a) PUC Distribution has reviewed the model supplied by OEB Staff and confirms its accuracy.

(b) PUC Distribution has revised the materiality threshold, and maximum eligible incremental capital amounts. These amounts have updated correctly within the ICM Model.

Staff-2

Reference: Capital Module Applicable to ACM and ICM, Tab 2 – Rate Class Selection

Preamble:

As part of the updated ICM model provided in Staff-1, OEB staff has corrected the Residential rate class selection from "Residential R1" to "Residential".

Question:

Please confirm the accuracy of the updated model.

Response:

PUC Distribution confirms the accuracy of the updated model.

Staff-3

Reference 1: EB-2020-0249, Application, Page 38

Reference 2: Capital Module Applicable to ACM and ICM, Tab 3 – Growth Factor – NUM_CALC1

Reference 3: Capital Module Applicable to ACM and ICM, Tab 8 – Threshold Test

Preamble:

On Tab 3 of the ICM model, PUC Distribution entered 2019 actuals since 2020 actuals are not yet available.

OEB staff notes that because this is a 2022 rates request, on Tab 3 the model erroneously noted "2020 Actual Distribution Demand" in the heading, when it should have indicated "2019 Actual Distribution Demand".

Similarly, because this is a request for 2022 rates, on Tab 8 of the model, OEB staff notes that when calculating growth factor, the model should be factoring in one-year worth of growth as opposed to two.

Question:

OEB staff has made the above noted updates. Please confirm the updates to the model as provided in Staff-1 are correct.

Response:

PUC Distribution has reviewed the update on tab 8 of the ICM model and confirms that the calculations have been accurately updated to reflect this ICM request.

Staff-4

Reference: Capital Module Applicable to ACM and ICM, Tab 9b – Proposed ACM ICM Projects

Preamble:

PUC Distribution has provided an estimated 2022 capital budget, including the proposed ICM project, of $33,495,218. The ICM maximum eligible incremental capital is calculated based on this $33,495,218 amount.

Question:

(a) How confident is PUC Distribution with regard to its estimate of its 2022 capital budget of $33,495,218?

(b) In 2021, if PUC Distribution revises its forecast of its 2022 capital budget and it decreases, this could reduce the amount ICM maximum eligible incremental capital eligible to be recovered through the ICM. Please discuss how PUC Distribution proposes to address this issue. Will PUC Distribution refile its ICM rate rider calculations based on the revised maximum eligible incremental capital amount in 2021 for the OEB's approval?

Response:

The information mentioned in the responses to this question do not reflect the most up to date CWIP.

(a) PUC Distribution is very confident with regards to its estimate of its 2022 capital budget of $33,495,218.

The net cost of the SSG Project costs has been calculated to be $24,880,278. PUC Distribution is very confident in the SSG project estimates given its scope of work.

The net capital budget expenditure without the SSG project is approximately $8.6 million, which is consistent with PUC Distribution's prior capital expenditure levels and is consistent with what it had forecasted in its Distribution System Plan dated March 21, 2018 of $8.7 million for 2022.

(b) PUC Distribution has filed 2022 ICM project for OEB approval as part of this 2021 IRM application because PUC Distribution needs this regulatory approval in 2021 in order to be able to complete the SSG Project in 2022.

PUC Distribution recognizes that for a typical 2022 ICM, the Applicant would be applying in 2021 on a forward test year basis as part of its 2022 IRM.

PUC Distribution understands OEB Staff's question to be comparing the current forecast of the 2022 capital budget as against what that forecast might be at the time the 2022 IRM is filed, and the implications of this on the calculation of the maximum eligible incremental capital amount.

If the OEB approves the SSG Project ICM, it would be reasonable for the OEB to include the following as a condition of that approval:

- PUC Distribution will undertake to file an update to its forecasted 2022 capital budget as part of its 2022 IRM application and to re-calculate the maximum eligible incremental capital on the basis of this updated forecast. If the new maximum eligible incremental capital calculated based on 2022 capital budget minus the calculated materiality threshold for 2022 is less than the ICM approval for the SSG Project of $24,880,278 then the value of the approval will reduce to this new maximum eligible incremental capital.

Staff-5

Reference 1: EB-2020-0249, Application, Page 41

Reference 2: Capital Module Applicable to ACM and ICM, Tab 9b – Proposed ACM ICM Projects

Preamble:

PUC Distribution has provided the following table showing the net capital additions and calculations for depreciation and Capital Cost Allowance (CCA).

Table 5: Depreciation and CCA Calculations for Net Capital Expenditure

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	Eligible for ACM/ICM (Half Year*Prorated Amount)	CCA Class	CCA Rate	2022 CCA 8%	Eligible for ACM/ICM (Half Year*Prorated Amount)
1820 DS Equipment	$473,156	$116,497	$356,659	40	2.50%	$8,916	$4,458	47	8%	$28,533	$14,266
1830 Poles & Fixtures	$4,745,488	$1,168,400	$3,577,087	45	2.20%	$78,696	$39,348	47	8%	$286,167	$143,083
1835 OH Conductors & Devices	$15,943,059	$3,925,387	$12,017,672	60	1.67%	$200,695	$100,348	47	8%	$961,414	$480,707
1840 UG Conduit/Civil	$399,913	$98,464	$301,449	50	2.00%	$6,029	$3,014	47	8%	$24,116	$12,058
1845 UG conductors & Devices	$799,827	$196,928	$602,899	40	2.50%	$15,072	$7,536	47	8%	$48,232	$24,116
1850 Line Transformers	$7,097,338	$1,747,456	$5,349,882	40	2.50%	$133,747	$66,874	47	8%	$427,991	$213,995
1920 Computer S/W	$1,064,477	$262,088	$802,389	5	20.00%	$160,478	$80,239	12	100%	$802,389	$401,194
1980 System Supervisory Equipment	$2,483,780	$611,539	$1,872,241	20	5.00%	$93,612	$46,806	47	8%	$149,779	$74,890
In Service Dec. 31, 2022	$33,007,037	$8,126,759	$24,880,278			$697,246	$348,623			$2,728,620	$1,364,310

The net capital additions, depreciation and CCA amounts in Table 5 above don't match the entries in the ICM Model. The ICM Model indicates a net CAPEX of $24,828,660, depreciation of $695,799 and CCA of $2,722,959.

Question:

Please reconcile and update the ICM model or Table 5 as required.

Response:

Upon review of Table 5, PUC Distribution noticed that this table was not updated once the 2020 Q4 prescribed accounting interest rates applicable to the construction work in progress ("CWIP") rates were released by the OEB on September 15, 2020. PUC Distribution has since updated Table 5 which can be reviewed below. PUC Distribution reviewed the ICM Model and determined that in Tab 9b, the CAPEX amount of $33,495,218 was not updated to reflect this change. It has since been updated.

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	Eligible for ACM/ICM (Half Year*Prorated Amount)	CCA Class	CCA Rate	2022 CCA 8%	Eligible for ACM/ICM (Half Year*Prorated Amount)
1820 DS Equipment	$472,169	$116,250	$355,919	40	2.50%	$8,898	$4,449	47	8%	$28,474	$14,237
1830 Poles & Fixtures	$4,735,593	$1,165,927	$3,569,666	45	2.20%	$78,533	$39,266	47	8%	$285,573	$142,787
1835 OH Conductors & Devices	$15,909,816	$3,917,076	$11,992,739	60	1.67%	$200,279	$100,139	47	8%	$959,419	$479,710
1840 UG Conduit/Civil	$399,079	$98,255	$300,824	50	2.00%	$6,016	$3,008	47	8%	$24,066	$12,033
1845 UG conductors & Devices	$798,159	$196,511	$601,648	40	2.50%	$15,041	$7,521	47	8%	$48,132	$24,066
1850 Line Transformers	$7,082,539	$1,743,757	$5,338,783	40	2.50%	$133,470	$66,735	47	8%	$427,103	$213,551
1920 Computer S/W	$1,062,257	$261,533	$800,724	5	20.00%	$160,145	$80,072	12	100%	$800,724	$400,362
980 System Supervisory Equipment	$2,478,601	$610,244	$1,868,357	20	5.00%	$93,418	$46,709	47	8%	$149,469	$74,734
In Service Dec. 31, 2022	$32,938,213	$8,109,553	$24,828,660			$695,799	$347,900			$2,722,959	$1,361,480

Staff-6

Reference 1: EB-2020-0249, PUC_App_AA15_Cost of Power Forecast_20201029
Reference 2: EB-2020-0249, Application, Page 20, Table 1 – Customer Annual Net Benefit Summary

Preamble:

N/A.

Question:

(a) Please confirm if CBR A and CBR B amounts are embedded into the Cost of Power forecast as provided in reference 1. If not, please provide an updated forecast.

(b) Please calculate the following two scenarios, and use the resulting Cost of Power to show two versions of reference 2:

I. A calculation of the Cost of Power keeping the RPP constant to PUC Distribution's 2018 rebasing application. [TK]

II. Updating the Cost of Power forecast for the most recent RPP Price Report using a version similar to the OEB's Tab 2-ZB – Cost of Power in the 2021 Chapter 2 Appendices (and ensuring to take into account the updated Ontario Electricity Rebate). [TK]

Response:

a) CBR A and CBR B was embedded into the Cost of Power Calculation.

b) Table shows the original Cost of Power of $82,512,685, and the updated Cost of Power of $72,294,335 for January 2021 using the most recent RPP Price Report. The additional revenue from increased SSG asset base has changed from $1,754,862 to $1,751,221 upon updating to most recent CWIP rates.

Customer Net Benefit Summary			
	Original	**2018 RPP**	**Jan-21**
Cost of Power - updated to current estimate	$ 82,512,685	$ 73,272,755	$ 72,294,335
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,227,842	$ 1,978,364	$ 1,951,947
Projected system loss energy savings through SSG	$ 105,111	$ 93,077	$ 92,094
Total purchased power savings	$ 2,332,953	$ 2,071,441	$ 2,044,041
Additional revenue from increased SSG asset base	$ 1,751,221	$ 1,751,221	$ 1,751,221
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 296,400	$ 296,400	$ 296,400
Operating efficiency benefits due to SSG implementation	($30,816)	($30,816)	($30,816)
	$ 1,712,415	$ 1,712,415	$ 1,712,415
Annual net benefit to customers	$ 620,538	$ 359,026	$ 331,626
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,000
Total projected benefit to customers	$ 2,637,538	$ 2,376,026	$ 2,348,626

Staff-7

Reference: N/A.

Preamble:

COVID-19 Impacts

Given the ongoing state of the COVID-19 pandemic, and the uncertainly surrounding when it will abate, there is a possibility that economic and financial pressures could continue into 2022. During the unprecedented times of the current COVID-19 pandemic, many businesses and residents that are the customers of Ontario utilities have been adversely impacted.

Questions:

(a) In preparing its amended application, has PUC Distribution considered the impact on its customers of increasing rates further than what they otherwise would be (notwithstanding any noted potential savings after the SSG Project is "in-service"). If yes, please provide a discussion. If not, please explain why.

(b) Has PUC Distribution made any adjustment to this SSG proposal related to COVID-19?

Response:

(a) Yes, PUC Distribution has considered the importance of improving reliability while achieving no net bill increase as more important than ever.

Many PUC Distribution customers have been forced to work from home, making reliability of service for those customers an even more salient concern.

PUC Distribution has a limited time opportunity to take advantage of the NRCan funding to significantly reduce the total costs of the SSG Project for its customers, and achieve a no net bill increase outcome.

In December 2020, PUC Distribution surveyed its customers to determine whether they supported proceeding with the SSG Project as proposed in this application.

In response, a total of 153 of the 192 responses (80%) supported completing the project as proposed in this application over a two year period using NRCan funding while achieving a no net bill decrease.

PUC Distribution submits that the SSG project needs to be viewed under an entire perspective. The implementation of Voltage / VAR Optimization (VVO) optimize the voltage profiles along feeder lines and to minimize the reactive power in lines to reduce electricity consumption, demand, and losses. This in turn can help avoid future investments in traditional transmission and distribution infrastructure upgrades and reduce the need for manual switching operations.

The overall intention of the SSG project is to create cost benefit for customers.

(b) PUC Distribution has not made any adjustment to this SSG proposal related to COVID-19. See response in (a) above.

Staff-8

Reference: EB-2020-0249, Application, Page 9

Preamble:

At the reference above, the application states that PUC Distribution issued a Request for proposals (RFP) on October 4, 2019 seeking competitive proposals for engineering, procurement and construction (EPC) services for the implementation of the SSG Project.

PUC Distribution elected to award the EPC contract for the SSG Project to Black & Veatch.

The EPC contract was executed by Overland Contracting Canada Inc., a wholly owned subsidiary of Black & Veatch, and PUC Distribution on October 7, 2020.

Question:

(a) How was the RFP publicized and how was the decision made with respect to how the RFP would be publicized? Was the RFP posted on an electronic tendering platform? If not, please explain why.

(b) If the project was awarded to Black & Veatch, why was the EPC contract executed by its subsidiary? Please explain the rationale and decision-making process for executing the EPC contract with the subsidiary.

(c) Please clarify the roles and responsibilities of Black & Veatch versus those of Overland Contracting Canada Inc. in the development of the SSG.

Response:

(a) The RFP was publicized on the PUC website and MERX, in line with company practice for large capital projects. MERX markets their services as Canada's leading electronic tendering service.

(b) B&V is based in the United States and Overland Contracting Canada Inc. (OCCI) is a Canadian operating company that B&V uses to execute and perform contracts in Canada. It should be noted that OCCI is supported by a guaranty of all of its obligations under the EPC Contract.

(c) The EPC Contract was executed by Overland Contracting Canada Inc., which is a wholly owned subsidiary of Black & Veatch. As the EPC Contractor, Overland Contracting Canada Inc.

will be performing the contractual obligations stipulated in the EPC Contract. It should be noted that OCCI is supported by a guaranty of all of its obligations under the EPC Contract.

Staff-9

Reference: EB-2020-0249, Application, Appendix AA2-1 – Copy of SSG RFP, Page 14 of 37

Preamble:

At the above-noted reference, the application states:

> Each Respondent is requested to attach, in unlocked Word format, an agreement or agreements that they wish to have PUC consider for negotiation purposes. PUC will consider whether the form of those agreements is appropriate for the basis of negotiating the Contract. The attachment of any such forms of agreements in a Proposal shall not be considered to be acceptance by PUC, either as to form or substance, in whole or in part, of such agreement or agreements.[1]

Question:

Did Black & Veatch submit an agreement that it wanted to negotiate and is it the EPC contract that is included in the Amended Application?

Response:

Black & Veatch submitted major commercial terms and those terms formed the EPC contract. The EPC contract is included in the Amended Application at Appendix AA3-7.

[1] EB-2020-0249, Application, Appendix AA2-1 – Copy of SSG RFP, Page 14 of 37

Staff-10

Reference 1: EB-2018-0219, Exhibit KTC1_1_PUC Distribution_IRR Correction_20190619

Reference 2: EB-2018-0219, Transcripts_PUC_Technical Conference_20190619, Pages 109-110, Lines 27-28 and Lines 1-3

Reference 3: EB-2020-0249, Application, Page 10

Preamble:

At reference 1, PUC Distribution provided a presentation to City Council on the Sault Smart Grid on July 8, 2019. On one of the slides, part of the Resolution notes:

> WHEREAS the PUC Services Board has approved the Smart Grid Proposal as presented on June 26, 2018 subject to the following conditions precedent:
>
> - Federal/Provincial funding approved (>$9 million)
> - Shareholder approves the project
> - OEB approval for the first two consecutive ICMs in place[2]

At reference 2, in responding to questions regarding whether City Council has approved the ICM proposal (as per the original application), PUC Distribution noted:

> MR. BREWER: So when we presented it we presented possible funding, and as you can see in the resolution under the first bullet, they have required that there be federal or provincial funding approved greater than 9 million for them to approve this project.
>
> So we have met that criteria, because there is $11.8 million in federal funding. So we have met their resolution.[3]

In the current application (reference 3), PUC Distribution notes that:

> With the estimated cost of the SSG Project now reduced further with EPC pricing, pursuant to the NRCan (Natural Resources Canada) agreement the lesser of 25% of total project costs is applied so the total monetary value of the NRCan contribution will

[2] EB-2018-0219, Exhibit KTC1_1_PUC Distribution_IRR Correction_20190619
[3] EB-2018-0219, Transcripts_PUC_Technical Conference_20190619, Pages 109-110, Lines 27-28 and Lines 1-3

decrease accordingly (now estimated at $8,126,759 (emphasis added), which is 25% of current eligible cost project estimate of $32,507,038 ($33,007,038 less ~$500,000 as estimated ineligible to NRCan program as costs incurred before contribution eligibility period and estimated legal costs)).[4]

Question:

(a) In the time between the initial filing and the amended filing, has PUC Distribution brought this version of the proposed SSG Project (i.e. with an EPC Contractor, and the estimated revised federal funding amount) forward to City Council?

(b) Has the amended SSG Project been given Shareholder approval given that federal funding is projected to drop below the $9 million threshold noted in reference 2?

(c) If yes, please provide all relevant documentation of what PUC Distribution brought forth for approval based on the new structure of the SSG Project.

(d) If not, please explain why.

Response:

(a) No, it was not brought to City Council between the initial and amended filing. It does go to city council on January 25th. See attached Attachment 1 to these Interrogatory Responses for PUC Council Presentation for January 25 2021 slide deck.

(b) No, amended Shareholder approval was not required because the overall SSG Project got less expensive, and this is the only reason why the federal funding dollar value went down. Note the federal funding of 25% is still the same.

Shareholder approval is from the holding company, PUC Inc, which has approved the project. Since the funding level awarded was $11.8 million (25%), and the reduction in required funding was due to the project being less expensive, anything to City Council was an information note and not for approval.

(c) As explained in part (b) above, the information provided to the City Council was in the form of an information note and not for approval. Below are the relevant documentation:

[4] EB-2020-0249, Application, Page 10, Lines 19-27

- PUC Distribution Inc. Board Meeting Closed Session Minutes dated January 22, 2020 at Attachment 2 filed in confidence.
- Information Note dated February 26, 2020 at Attachment 3.
- Information Note dated May 13, 2020 – Sault Smart Grid (SSG) Project Update at Attachment 4.
- Sault Smart Grid Council Update slide deck - January 25, 2021 at Attachment 1.

(d) The project scope remains the same. Costing has decreased due to the different type of financing, and direct contract with EPC. Project remains on track for customer benefit, rate impact, and impact to the community, so no need for City Council to approve the same project again. However, an information note (update) is being given at the January 25th 2021 Council meeting.

Staff-11

Reference 1: EB-2014-0219, *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, Page 10

Reference 2: EB-2018-0219, Transcripts_PUC_Technical Conference_20190619, Page 201, Lines 11-15

Reference 3: EB-2020-0249, Application, Pages 11-12

Preamble:

The Renewed Regulatory Framework for Electricity Distributors states that distributors are expected to provide documentation on their efforts to engage customers on the necessary capital and operating costs and on the associated cost consequences that will be ultimately impacting customers.

In its original filing[5], PUC Distribution noted that it did not engage its customers specifically on this the SSG Project but asked the relevant questions that would drive the decision on whether to undertake this project.[6] This was done as part of its 2018 Cost of Service Application. [7]

Question:

(a) Given the over one-year that has elapsed since the initial application being placed in abeyance and the filing of this amended application, and that this is a community scale project which will drive substantial changes in how PUC Distribution will operate going forward, has PUC Distribution taken the opportunity between its initial filing and amended filing to engage its customers on the SSG Project specifically?

(b) If the answer to (a) is yes, please provide the results of that engagement.

(c) If the answer to (a) is no, please explain why not.

Response:

(a) and (b)

[5] EB-2018-0219
[6] EB-2018-0219, Transcripts_PUC_Technical Conference_20190619, Page 201, Lines 11-15
[7] EB-2017-0071

Yes, please see attached summary of survey and results at Attachment 5.

(c) Not applicable.

Staff-12

Reference 1: EB-2020-0249, Application, Page 7

Reference 2: EB-2020-0249, Appendix AA12-1 – Project Cost Summary

Reference 3: EB-2020-0249, Appendix AA4-2 – Contribution Agreement, Schedule B – Budget and Eligible Expenditures, Page 9

Preamble: N/A.

Questions:

The total capital cost of the SSG Project from the initial 2019 application was estimated to be $34,389,046. The revised total cost of the SSG Project in this application is estimated to be $33,007,038.

(a) Please describe what makes up the differences in cost between the original $34.3M and the revised $33.0M amount. Is it solely a change in pricing because of the EPC Contract as opposed to the previously proposed P3 structure?

In the amended Contribution Agreement with NRCan, the total cost of the SSG Project is listed at $42,806,000 of which $10,626,500 would be funded by NRCan (reference 3). OEB staff understands that the contribution amount is to be updated to approximately $8.1m (25% of $32,507,038).

(b) Please explain how the total cost of the project was able to be reduced from $42,806,000 to $33,007,038.

Response:

(a) The differences in cost estimate from the $34.3M to the revised $33.0M figure are due to several factors some of which are higher cost and some of which are lower. The visibility of how the EPC contractor combines and allocates internal project costs are potentially different than the estimates developed by the P3 project developer making a detailed line item comparison problematic but the following general observations help describe the major areas.

- Without the P3 structure there are no costs for independent engineering review, oversight and certification by the P3 developer. Including this effort, estimates for legal, regulatory, project management type costs are estimated to be about $3.5M lower.

- EPC construction contract costs are about $2M higher than P3 estimate.
- Engineering costs, including from EPC and PUC are about $1M higher. As some of the engineering and project management costs are now internal to the EPC contractor and subject to their internal allocation processes there could also be shifts between construction and engineering from prior estimate.
- PUC Distribution increased estimates for technical and engineering as a result of no longer having the P3 independent engineering included.

(b) The difference from the NRCan estimate of $42.8M and the current project estimate of $33.0M are mainly in the reduction in scope of work via removing major costs for substation renewal and no longer a term warranty program as was anticipated under the P3 structure.

Staff-13

Reference 1: EB-2020-0249, Application, Page 8

Reference 2: EB-2020-0249, Application, Appendix AA12-3 – SSG Revised Scope_Proj_Estimate Sum_20201029

Reference 3: EB-2018-0219, Application, Appendix K

Preamble:

In comparing this amended ICM application to PUC Distribution's original ICM application from 2019, PUC Distribution notes that "The scope of the SSG project remains the same."[8]

Question:

By comparing the project cost breakdown from the 2019 application to the current application, OEB staff notes several differences.

(a) Given that the scope has not changed, please explain how the cost for Voltage/VAR Optimization (VVM) has decreased from $15,959,480 to $9,463,794.
(b) Given that the scope has not changed, please explain how the cost for Distribution Automation (DA) has increased from $14,659,460 to $19,994,966.
(c) Please explain why the unit quantities of some of the line items has changed.
(d) Please explain how PUC Distribution derived the unit costs of each of the line items. How has PUC Distribution ensured that the unit costs listed are the best prices available?

OEB staff notes that the scope of DA includes switches, reclosers and poles.

(e) Does the scope of the equipment being replaced as part of the SSG Project overlap with any of PUC Distribution's system renewal programs? If so, has PUC Distribution removed the costs from the SSG Project?

[8] EB-2020-0249, Application, Page 8

Response:

(a) and (b) and (d)

PUC Distribution was able to lower the costs of the SSG project overall following a competitive RFP process.

Through that competitive RFP process, each proponent was required to provide unit costs in their proposed pricing as part of the competitive bid (see Schedule B, Part B, Section (b)(iv) of Appendix AA2-1 of the Amended Application).

As a result of this competitive RFP process these unit costs were not tied to the previous application, which was based on a sole source arrangement with IE/SSG Inc.

Each bidder in response to the RFP process had to make decisions of what unit costs to bid for DA and VVM.

The winning bidder was chosen based on the best available proposal, and that bidder's pricing proposal resulted in a higher unit cost being allocated to DA and a lower unit cost being ascribed to VVM.

All bidders in the competitive RFP process was required to make these decisions and provide their best cost estimate.

IE/SSG Inc. was invited to participate in the RFP process, but ultimately chose not to compete.

Through an RFP, PUC Distribution selected the best and most cost effective proposal.

(c) PUC Distribution identified some changes required in unit quantities to address changes in some station and feeder configurations that had occurred since the time of the original engineering estimates such as those arising from on-going voltage conversion program as well as those arising from the RFP and scope review.

(e) No, the scope of the equipment being replaced as part of the SSG Project does not overlap with any of the PUC Distribution's planned system renewal programs.

Staff-14

Reference 1: EB-2020-0249, Appendix AA12-2 – Project Cost Summary

Reference 2: EB-2020-0249, Application, Page 16

Preamble:

The total cost of the SSG Project is $33,007,038. The breakdown of the project costs can be seen in Table 1 of reference 1. Reference 2 notes that the EPC contract is styled as a "maximum price limit" project to ensure cost certainty for this main element of the project costs. EPC pricing has been fixed at $5,086,378 for Step 1 and $22,658,667 for Step 2. The total EPC maximum price is $27,745,044.

Table 2 of reference 1 shows a summary of how the total project cost estimate of $33,007,038 is being broken down by different categories of work for the SSG Project and the percentage of costs that will be spent on each category.

Question:

(a) Please provide a breakdown of the costs which make up the difference between the total cost of $33,007,038 and the EPC maximum price of $27,745,044 (i.e. $5,331,994).

(b) Please specify how much contingency is built into the total cost of the project for each component of VVO, DA, and Advanced Metering Infrastructure (AMI) integration.

Response:

The information mentioned in the responses to this question do not reflect the most up to date CWIP rates.

(a) Project estimate of $33,007,038 - $27,745,044 = $ 5,261,994.

- The $5,261,994 is the estimated additional costs to PUC Distribution over and above the EPC contract. The scope of work is described in the project cost memo (Appendix AA12-2 of the Amended Application) in Table 4. The cost estimate is broken down in part of Table 5 Engineering ($1,023,695+$1,768,000) and Table 6 Project Management ($1,266,000+$1,204,297).

(b) As the EPC contract has been developed to deliver the project at a firm price subsequent to completion of the Step 1 Engineering, allowance for contingency has been estimated by PUC Distribution but included in maximum EPC price estimate. Appendix AA12-1 in the Application breaks out specific contingency for VVO ($462,846) and DA ($844,036). There is no specific line item for AMI contingency.

Staff-15

NRCan Contribution Agreement

Reference 1: EB-2018-0219, PUC_ICM_IRR_20190531, Appendix 1 – Copy of Contribution Agreement

Reference 2: EB-2020-0249, Appendix AA4-2 – Contribution Agreement (amended)

Preamble:

At reference 1, PUC Distribution provided the original NRCan Contribution Agreement. At reference 2, PUC Distribution provides the amended Contribution Agreement.

OEB staff notes that reference 2 ends at section 9.1 Books and Records.

Question:

Please confirm if sections 10 to 35 in the original version of the Contribution Agreement are still to be applied as drafted.

Response:

PUC Distribution confirms that the Amending Agreement at Reference 2 should be read with the Contribution Agreement at Reference 1 and that any sections that were not amended by the Amending Agreement in Reference 2 would remain in full force and effect, as per section 19 of the Amending Agreement.

PUC Distribution is working with NRCan on a further amending agreement to update the details of the contribution agreement as a result of the extension to the eligible expense end date. A copy of this amending agreement will be filed with the OEB once it is available.

Staff-16

NRCan Contribution Agreement

Reference 1: EB-2020-0249, Application, Page 13

Reference 2: EB-2020-0249, Appendix AA4-2 – Contribution Agreement (amended)

Preamble:

An amended NRCan Contribution Agreement with revised Statement of Work, project structure and estimate was executed in December 2019. PUC Distribution notes that it is working with NRCan on a further amendment to update the details of the contribution agreement as a result of a program extension by NRCan (i.e. to March 31, 2023).

PUC Distribution notes that once the OEB rate process is complete, a subsequent amendment will be arranged with updated project estimates and timelines.

Questions:

(a) Is the amended agreement with NRCan complete with respect to the program extension? If yes, please file it with PUC Distribution's interrogatory responses. If not, please explain why it is not complete, and when PUC Distribution expects it will be completed.

(b) Please explain further what updated project estimates will be amended given the fixed price EPC contract that has already been filed as part of this proceeding which forms PUC Distribution's proposal for OEB approval.

(c) Please explain the $500k of "estimated ineligible to NRCan program as costs incurred before contribution eligibility period and estimated legal costs."

(d) How does PUC Distribution intend to cover the $500k of ineligible costs?

Response:

(a) No, the amended agreement with NRCan with respect to the program extension has not yet been completed. The Assistant Deputy Minister of Natural Resources has not yet executed the agreement yet. PUC Distribution will file a copy of the amended agreement once it is available.

(b) If the OEB approves less than the full value of the proposed SSG Project as part of this ICM application, then PUC Distribution will work with its EPC Contractor to negotiate an amendment to the EPC Contract to revise the scope to fit within the OEB approved budget (if possible) while achieving no net bill increase for ratepayers. Once complete NRCan will need to be updated on these revised estimates as well.

(c) Some costs incurred for the SSG project will not meet the eligibility criteria of the NRCan Program. The $500k has been used as a placeholder to reflect this estimate. As example some preliminary engineering work completed for the project was done before the NRCan contribution agreement was executed. According to the terms of the agreement costs *"Incurred before Eligible Expenditure period (between June 13, 2018 and August 28, 2018)"* are not eligible for program funding.

(d) The $500k is inegligible for the NRCan program but are still incurred costs that form part of the SSG project. As part of the project costs, these will be recovered through the proposed ICM rate riders.

Staff-17

NRCan Contribution Agreement

Reference 1: EB-2018-0219, PUC_ICM_IRR_20190531, Appendix 1 – Copy of Contribution Agreement

Reference 2: EB-2018-0219, Transcripts final_PUC_Technical Conference_20190620, June 20, 2019

Preamble:

The original Contribution Agreement indicates that Canada may reduce or cancel its contribution to the Project in the event that funding levels for the Department of Natural Resources are changed by Parliament during the course of the agreement between NRCan and PUC Distribution. It goes on further to note that if this occurs, the project would be amended to take into account the cancellation or the reduction.[9]

At reference 2, PUC Distribution noted:

> MR. BREWER: Well, it is our understanding that once there is a contribution agreement, that the funding is locked. But if there was no NRCan funding and if there was no reliability to the NRCan funding, we wouldn't have pursued the project.[10]

Question:

(a) Please provide a discussion on PUC Distribution's course of action if funding levels were to drop or be eliminated, given that the funding does not seem to be locked based on the wording in the Contribution Agreement.

(b) If the scope of the project were to change, please confirm that the anticipated benefits of the project would also likely change.

Response:

[9] Section 29(2) Appropriation
[10] EB-2018-0219, Transcripts final_PUC_Technical Conference_20190620, June 20, 2019, Page 13, Lines 21-25

(a) The Contribution Agreement is a standard form of NRCan funding agreement. Once signed by the Minister, PUC Distribution fully expects that NRCan will follow-through on its funding commitments.

PUC Distribution's action if NRCan funding was not available for the project would be the exact same as noted by Mr. Brewer in the quote in Reference 2 above.

(b) This question is too broad to answer in a meaningful way. But yes, if the scope of the project were to change it would be reasonable to conclude that the anticipated benefits of the project would change as well. For example, if the project does not proceed at all – then none of the anticipated benefits (reliability improvements, energy consumption savings, etc.) would occur.

Staff-18

NRCan Contribution Agreement

Reference 1: EB-2020-0249, Appendix AA4-2 – Contribution Agreement (amended)

Preamble:

Section 3.3 of Appendix AA4-2 states that the "Proponent undertakes to receive approval from the Ontario Energy Board for the Required Rate Adjustment by March 31, 2020."

Question:

(a) Is NRCan aware that PUC Distribution filed its application with the OEB in October of 2020?

(b) Please confirm that PUC Distribution is working with NRCan to update the date by which PUC Distribution must obtain OEB approval. What is the date in discussion to qualify for the funding?

Response:

(a) Yes.

(b) The date in proposed revision with NRCan contribution agreement which was executed by PUC Distribution on December 16th has PUC Distribution seeking approvals by March 31, 2021. The proposed date extensions will allow the program funding to be eligible for work completed by March 31, 2023.

Staff-19

NRCan Contribution Agreement

Reference: EB-2020-0249, Appendix AA4-2 – Contribution Agreement (amended)

Preamble:

Section 4.2 of Appendix AA4-2 notes that PUC Distribution shall complete this project by March 31, 2022. As noted above, PUC Distribution is working with NRCan on an amendment to update the details as a result of the extension by NRCan.

Section 6.3 of Appendix AA4-2 notes that in order to receive payment for any remaining portion of the Contribution, PUC Distribution must submit its final claim on or before June 22, 2022.

Questions:

Does PUC Distribution expect that the date of June 22, 2022 will be amended given that PUC Distribution expects work on the SSG Project to continue potentially into December of 2022?

Response:

Yes, PUC Distribution expects that the date of June 22, 2022 will be amended.

On September 17, 2020, NRCan informed the Smart Grid Deployment Program recipients (including PUC Distribution) that, inter alia, the eligible expense end date has been extended 1 year and is now March 31, 2023 (please see Appendix AA4-4 to the Amended Application). PUC Distribution is working with NRCan on a further amending agreement to update the details of the contribution agreement as a result of this extension. The date of June 22, 2022 will be updated to June 30, 2023 in this latest amending agreement.

A copy of this amending agreement will be filed with the OEB once it is available.

Staff-20

NRCan Contribution Agreement

Reference: EB-2020-0249, Appendix AA4-2 – Contribution Agreement (amended)

Preamble:

Section 6.2 of Appendix AA4-2 sets out the Fiscal Year Allocations for the contribution.

Question:

How does PUC Distribution expect the Fiscal Year Allocations to be assigned based on a contribution amount of approximately $8M as noted in this application?

Response:

PUC Distribution expects the NRCan capital contributions to be allocated to project CWIP accounting based on the quarterly invoicing less holdback provisions of the contribution agreement. Once OEB approval for the project is received PUC Distribution expects the first payment will include approved claims to date that have been held pending OEB approvals although specific dates have not been confirmed. Program revisions at NRCan has indicated early weighting and reduced holdback provisions would be available which would help reduce construction interest costs.

The current estimated schedule has been included in response to question SEC-23.

Staff-22

Reference 1: EB-2020-0249, Application, Appendix AA2-1 – Copy of SSG RFP, Page 22 of 37

Reference 2: EB-2020-0249, Application, Appendix AA2-1, Appendix A – Project Tasks, Pages 28-30 of 37

Reference 3: EB-2020-0249,Application, Appendix AA3-7 - EPC Contract, Appendix A – SSG Scope of Work, Article 5 – Owner's Specific Subcontractors and Materials

Preamble:

Reference 1 states:

> It is anticipated that PUC will be responsible for a portion of the deliverables pursuant to its labour agreements, as further described in Section 7 below (PUC Services Inc. Staff Engineering and Construction Work).

Reference 2 states:

> The following tables reflect the individual elements of the overall Project. It is anticipated that PUC will be responsible for a portion of the work pursuant to its labour agreements, as further described in Section 7 below (PUC Services Inc. Staff Engineering and Construction Work). These services are listed below under the column titled "PUC".

Reference 3 states:

> The Contractor will be required to engage PUC Services Inc., an Affiliate of the Owner as a Subcontractor for certain line construction work for the contract. The scope of this line construction work will be defined during the Upfront Engineering Services and approved by the Owner but will generally encompass the overhead line construction "make ready" work as well as some new pole installation and framing required to accommodate new equipment to be installed.

Questions:

(a) Please advise whether the scope of the work to be done by PUC Services has been defined and the estimated cost. If not defined, when is it expected that will be done?

(b) Does PUC Distribution expect that PUC Services can deliver the work for which it is responsible with the current resources or will it need to hire additional resources? If so, what is the estimated cost of doing so?

Response:

(a) PUC Services will be providing project management and some engineering services for the SSG project and this scope of work and cost estimate has been described previously in Staff-14. Additional "make ready" line construction is also expected to be completed by PUC Services. This scope of work and estimate will be developed during the Step 1 Engineering phase of the EPC contract.

(b) PUC Services anticipates the work will be accomplished with a combination of current staff and some hiring of technical and/or construction resources to support the project or backfill required to accomplish normal work program requirements. Resource needs and cost estimates will be finalized during the Step 1 Engineering and included in integrated resource planning processes.

Staff-21

NRCan Contribution Agreement

Reference 1: EB-2018-0219, PUC_ICM_IRR_20190531, Appendix 1 – Copy of Contribution Agreement

Reference 2: EB-2020-0249, Appendix AA12-2 – Project Cost Estimate Memo

Preamble:

Reference 1 notes that, to the extent that PUC Distribution derives any profit from the project, it will have to repay Canada for its financial assistance pursuant to the Contribution Agreement. The Contribution Agreement defines "profit" as:

> ...the net income of the Proponent received from any product or Intellectual Property derived from the Project, but in no event shall include any return on rate base earned by the Proponent, all of which is as determined whether using Generally Accepted Accounting Principles (GAAP) or International Financial Reporting Standards (IFRS).[11]

Question:

(a) Does PUC Distribution expect any profit, as defined above, in relation to the SSG Project?

(b) Does the Project Cost Estimate Memo included in reference 2 include any contingency for any potential repayment?

Response:

(a) No, PUC Distribution does not expect any profit as defined in Reference 1 above in relation to the SSG Project. Note that the definition of profit expressly excludes any return on rate base earned by the Proponent.

(b) No, the Project Cost Estimate Memo does not include contingency for any potential repayment.

[11] Section 1.1

Staff-23

Reference 1: EB-2020-0249, Application, Page 17

Reference 2: EB-2020-0249, Application, Appendix A3-7 – EPC Contract, Appendix B – Compensation, Pages 8-9

Preamble:

Reference 1 states: "The scope of work will be reduced by PUC Distribution if required to maintain the project capital cost limit set for the project."

A portion of reference 2, Section 6.1 states that "...As set forth in Section 6.3(c), the parties further acknowledge that the description of the *Balance of Work* set out in Appendix A – SSG Scope of Work is preliminary and does not represent a commitment by *Contractor* to deliver such scope of work to Owner for the estimated *Balance of Work Fixed Price*."

Questions:

(a) If it is necessary to reduce the scope, how will PUC Distribution determine the scope to be reduced (e.g. will it be the scope of VVO, DA, or AMI that will be affected)?

(b) How will the reduction in scope affect the amount of benefit PUC Distribution expects to deliver to customers? How will this affect PUC Distribution's "net zero" bill impact objective?

(c) Will the reduction of scope affect PUC Distribution's eligibility for NRCan funding?

Response:

(a) If it is necessary to reduce the scope to maintain the SSG Project capital cost limit, the scope of DA will be reduced. The DA system is used to provide PUC Distribution with better real-time visibility and monitoring of the distribution network, so that it can automatically locate and isolate faults, reconfigure feeder circuits and restore power more rapidly. As such, by reducing the scope of DA, it should not affect the overall function of the SSG Project, although it might lead to decrease in reliability improvements.

(b) The DA scope will be reduced by PUC Distribution if required to maintain the capital cost limit set for the SSG project. VVM is related to energy savings and is included in the calculation

of annual net benefits of customers (see Project Benefits Estimate Memo at Appendix AA13 of the Amended Application). DA is related to the reliability benefits to customers, which is not part of the calculation of the annual net benefit to customers. As such, reduction in DA scope will not affect the "no net bill increase" objective as reduction of scope would help maintain costs at the limit. The effect of a reduced scope of DA may be lower reliability improvements.
(c) No, the reduction of scope will not affect PUC Distribution's eligibility for NRCan funding as long as it does not affect the three performance indicators as provided in Appendix A – Statement of Work of the Contribution Agreement provided in Appendix 1 of the Interrogatory Responses to the Original Application.]

Staff-24

Reference: EB-2020-0249, Application, Page 18

Preamble:

The EPC Contract is structured as a two-step process. Step 1 – Upfront Engineering is the engineering stage with a **fixed price for project costs (emphasis added).** Step 2 – Balance of Work is the detailed engineering, procurement and construction stage with the project costs having a **fixed price limit (emphasis added)**. The EPC structure includes provision for scope of work adjustments so that the fixed price for Step 1 and Step 2 inclusive will not exceed the maximum fixed price limit set for the EPC Contract.

Questions:

(a) Please clarify if there is a difference between Step 1 and Step 2 based on the wording emphasized above.
(b) Please clarify whether either or both of Step 1 and Step 2 of the EPC contract pricing are fixed and firm, or whether one or both steps are estimates subject to variation.
(c) Is there a possibility that actual costs will be lower than the fixed costs in either Step 1 or Step 2?

Response:

(a) Yes, there is a difference. Step 1 involves a fixed and known scope of work and firm EPC pricing of $5,086,378. The scope of work is not yet known or fixed for Step 2. Step 2 is subject to the EPC maximum price is $27,745,044. In this context, the scope of work that can be completed during Step 2 must still be determined following the completion of the engineering work in Step 1.
(b) See response to (a) above.
(c) Yes, there is a possibility that actual costs will be lower than the maximum EPC price for Step 2.

Staff-25

Reference 1: EB-2020-0249, Application, Page 31
Reference 2: EB-2020-0249, Application, Appendix 3-7 – EPC Contract, Appendix B – Compensation, Page 13

Preamble:

On page 31, the application notes that Step 1 of the EPC contract is to develop an engineering package to a level of detail (~30%) that would provide enough information to estimate the price for Step 2.

Similarly, reference 2 discusses the "open to closed book" approach to develop a firm price for the Upfront Engineering and Balance of Work steps.

Questions:

(a) Given that Step 1 has not yet been completed and is subject to change, how did PUC Distribution determine the cost of $22,658,667 for Step 2?
(b) Given that the scope of the SSG Project has not changed, why does PUC Distribution need Step 1 of the EPC contract to develop 30% engineering when the Leidos Report already completed the 30% engineering?
(c) Given that the design is only at 30%, how reliable is the project cost estimate?

Response:

(a) PUC Distribution utilized the estimates arising from the detail scope review and discussions with PUC Distribution and the EPC contractor staff which was captured in the EPC contract project costs provided by the EPC contractor for Step 2.

(b) The Step 1 Engineering will include a review of the prior engineering work covered in the Leidos report for the feeders studied to confirm the scope and requirements and update for any changes to feeders since the original works. As PUC Distribution has not seen any substantial system growth, these changes are not anticipated to be large although there has been some regular capital work programs that have been completed and will need to be reviewed for impact on the design. In addition, as the Leidos work did not look at the complete PUC Distribution system, there is a requirement for additional engineering on the balance of feeders and subtransmission system to support the EPC contractor firm fixed price for the project.

(c) The project cost estimate is reliable as it was developed by PUC Distribution using a number of input sources, including early preliminary engineering works, the current EPC estimates, information from the Navigant reports as well as input from PUC Distribution project, engineering and operations staff. The commentary on the project costs and scope risks in the Navigant Review of Business Case report (see Appendix AA8 of Amended Application) as well as considerations from PUC Distribution staff were used to help consider contingency risk factor adjustment in non-fixed project cost estimates.

Staff-26

Reference 1: EB-2020-0249, Appendix AA3-7, Appendix A, Page 13

Reference 2: EB-2020-0249, Application, Page 20

Preamble:

Reference 1 describes the scope of the SSG Project and the EPC contract. Regarding "Step 1 Engineering," reference 1 notes that "This will evaluate the performance of 48 distribution feeders, how they could be improved with FDIR, the expected improvements, and estimating VVO savings for each distribution feeder..."

Questions:

(a) Please explain why it is necessary to reassess the impact of Fault Detection, Isolation and Recovery (FDIR) on PUC Distribution's feeders when this analysis was already done in the 30% as part of the Leidos Report.

(b) Please confirm whether the $2,017,000 in estimated reliability savings as noted in reference 2 is subject to change pending the results of the new analysis.

(c) Similarly, given that the new EPC contract is "estimating VVO savings for each distribution feeder," does that mean the 2.7% projected energy savings is also subject to change?

(d) What are PUC Distribution's plans if the new estimate of VVO savings is lower than 2.7% and it is not possible to achieve "no net bill increase"?

Response:

(a) The review of the Leidos FDIR analysis in the Step 1 Engineering will confirm the scope and requirements and update for any changes to feeders since the original works.

As mentioned in response to Staff-25(b), PUC Distribution has not seen any substantial system growth. Therefore, changes are not anticipated to be large although there have been some regular capital work programs completed and these will need to be reviewed for impact on the design. In addition, as the Leidos work did not look at the complete PUC Distribution system, there is a requirement for additional engineering on the balance of feeders and subtransmission system to support the EPC contractor firm fixed price for the project.

(b) As explained in Staff-54, calculation of $2,017,000 was done to include an equivalent annual value in the benefit summary table (a net present value string to approximate total

($33M) referenced in the Navigant report. The FDIR looks at specific feeders to quantify actual reliability benefits. As such, the amount of $2,017,000 will likely change. However, PUC Distribution notes that the assessment of reliability savings are not included in the assessment of no net bill increase.

(c) Yes 2.7% may also change, as the detailed engineering is completed. Please see also EPC Contract (Appendix AA3-7 of the Amended Application) Section 22.1(c), which was redacted and filed in confidence but is relevant to the question asked.

(d) Please see also EPC Contract (Appendix AA3-7 of the Amended Application) Section 22.1(c), which was redacted and filed in confidence but is relevant to the question asked. This will help ensure “no net bill increase” is maintained even if VVO savings are lower than expected. Please also see response to SEC-12.

Staff-27

Reference: EB-2020-0249, Appendix AA3-7, Appendix A, Page 14

Preamble:

The reference states that "VVO will require load flow and will optimize the following user-selectable objective functions subject to user-configurable constraints...". The reference then lists the following three items: Loss Minimization, Energy Conservation and Revenue Maximization.

Under Revenue Maximization, the reference notes that:

> Revenue Maximization: This objective maximizes the difference between energy sales (price of energy delivered to customers) and cost (cost of production or purchase). Voltage is raised until increased losses start to outweigh increased sales. Where this point falls depends on the actual mix of load types (constant current, constant impedance and constant power).[12]

Questions:

(a) Please explain how raising the voltage will increase revenues in the way that is described.

(b) The description appears to be referring to commodity prices, which shouldn't affect the revenues of an electricity distributor. Please explain how this objective benefits PUC Distribution.

(c) Please explain how revenue maximization benefits ratepayers.

Response:

(a) (b) and (c)

The VVO software is provided by Survalent and the Survalent VVO software allows the user to optimize user-selectable objective functions, which are subject to user configurable constraints. These objective functions are:

- Loss Minimization: This objective minimizes total losses (transformer losses at the substation and line losses along the feeders).

[12] EB-2020-0249, Appendix AA3-7, Appendix A, Page 14

- Energy Conservation: This objective reduces load by minimizing voltage throughout the network without violating constraints.
- Revenue Maximization: This objective maximizes the difference between energy sales (price of energy delivered to customers) and cost (cost of production or purchase). Voltage is raised until increased losses start to outweigh increased sales. Where this point falls depends on the actual mix of load types (constant current, constant impedance and constant power).

The SSG Project will be configured so as to achieve the objectives of loss minimization and energy conservation. While the software may allow the user to select revenue maximization, that is not PUC distribution's intended use of the VVO and would run counter to the no net bill impacts objective of the entire SSG project.

Staff-28

Reference: EB-2020-0249, Appendix AA3-7, Appendix A

Preamble:

This interrogatory concerns several items within the SSG Project's scope as presented in Appendix AA3-7, Appendix A:

Scope item VO4 (page 22): This item is to produce a report on the adequacy of existing substation SCADA implementations for the purpose of FDIR and VVO applications. Page 22 notes that the report will recommend corrections with an estimate of additional integration work, new substation equipment, programming, or other required work if the existing SCADA system is insufficient.

Scope item VO5 (pages 24-31): This item is to evaluate the software options from Survalent and "confirm whether a software upgrade from the currently installed version will be required to support the baseline proposal software or any selected options."

Scope item VO7 (pages 32-33): This item is to produce a report "outlining the cyber security requirements for the SSG Project including any impacts on project scope schedule, or budget."

Scope item VO10 (page 39): This item is to outline "recommendations for an enhanced CSR/customer toolset, including any impacts on project scope, schedule, or budget."

It appears that each of these items evaluate some aspect of the SSG Project. Based on the results of these items, it appears that changes and additions to the SSG scope may be required. For example, VO4 notes that it will provide an estimate of additional work and equipment if the existing SCADA system is insufficient. OEB staff has added emphasis on potential additions to the project scope.

Questions:

(a) For each of the items above, how will PUC Distribution accommodate the additions in scope and increased costs? Are these potential additional costs already embedded in the total cost estimate of the SSG Project?
   i. Will PUC Distribution accommodate the additional costs by reducing the scope of other items in the SSG Project? If so, does that mean the amount of forecasted benefits will decrease as a result?

(b) How was PUC Distribution able to estimate the cost of the SSG Project at $33,007,038 if it has not finalized the scope of the project?

Response:

(a) and (a)(i)

The scope items' costs referenced above have already been taken into account in the total cost estimate of the SSG Project. VO4, VO5, VO7 and VO10 are all part of Step 1 – Upfront Engineering Services, which is subject to a fixed price.

If following the completion of the Upfront Engineering Services in Step 1, the total price exceeds the maximum fixed price, then in Step 2 – Balance of Work, scope will be reduced. If any reduction of scope is required to accommodate any additional costs, the reduction of scope will be to the DA, which will not affect the amount of forecasted benefits.

(b) PUC Distribution developed the SSG Project cost estimate using the following: (1) the results of a competitive RFP process that PUC Distribution conducted in 2019 (representing approximately 85% of the project) which resulted in a fixed maximum price EPC Contract for $27,745,044 found at Appendix AA3-6 – EPC Pricing Summary of the Amended Application; and (2) an estimate of PUC Distribution's internal engineering, operations and project management costs directly attributable to the SSG Project (representing approximately 15% of the project) at $5,261,992 based on the preliminary engineering work of 30% found at Appendix AA12-2 Project Cost Estimate Memo of the Amended Application. Based on these inputs, PUC Distribution has estimated the total SSG Project cost of $33,007,038.

Staff-29

Reference 1: EB-2020-0249, Appendix AA3-7, Appendix A, Pages 39-40

Reference 1: EB-2020-0249, Appendix AA12-1 – Project Cost Summary

Preamble: N/A

Questions:

VO11 describes a lab facility for implementing and maintaining the SSG.

(a) Please provide a more detailed description of the function of the lab facility and why it is necessary.

OEB staff notes that no lab facility is listed in the project cost summary in Appendix AA12-1.

(b) Is the cost of a lab facility embedded in the SSG Project cost estimate?

(c) If no to (b), how will PUC Distribution pay for the lab facility?

Response:

(a) The lab facility is not anticipated to require a significant space/floor area and is expected to be accommodated within the existing PUC IT/OT building environment. As such no significant facility capital expenditure is expected. Specific equipment required will be included in the capital project costs. The facility is used to confirm equipment functionality and communication interconnectivity prior to deployment to field for installation.

(b) The cost is included in the project cost estimate.

(c) See response to part (b) above.

Staff-30

Reference 1**:** EB-2020-0249, Appendix AA3-7, Appendix A, Pages 41-43

Reference 2: EB-2020-0249, Appendix AA7, Leidos Preliminary Design, Utility Distribution Microgrid: Distribution Automation

Preamble:

Scope item VF1 is to produce a report that documents the historical feeder reliability indices for feeder and sub-transmission circuits. OEB staff notes that the Leidos Report had already performed a similar analysis, albeit with older data.

Question:

Please explain why it is necessary to redo this feeder analysis.

Response:

Please see response to Staff-25(b).

The new base line will support performance metrics to be developed with the Outage Management System implementation.

Staff-31

Reference: EB-2020-0249, Appendix AA3-7, Appendix A, Pages 43-54

Preamble:

Scope item VF2 is to develop a conceptual design so that the complete scope is understood. OEB staff notes that this item involves design work to detail the number of equipment required to implement the smart grid.

Question:

(a) Please explain why it is necessary to develop a new conceptual design rather than use the design provided in the Leidos Report.

(b) Please explain on what basis PUC Distribution estimated the SSG Project costs if it has not yet completed the conceptual design of the smart grid and does not yet know the exact quantity of equipment required.

Response:

(a) Please see response to Staff-25(b).

(b) The current EPC contract estimates have been provided by the EPC contractor with critical foundational knowledge of the Leidos engineering work and PUC information shared through the RFP process and subsequent contract negotiations. The EPC price plus estimated PUC costs, that combined represent the capital project estimate has been developed with the knowledge and experience gained through all phases and efforts on developing the SSG project.

Staff-32

Reference 1: EB-2020-0249, Appendix AA3-7, Appendix A, Pages 55-58

Reference 2: EB-2020-0249, Appendix AA13, Project Benefits Estimate Memo

Preamble: N/A

Question:

Scope item VF3 is to calculate the future reliability indices, FDIR cost and VVO savings.

(a) If PUC Distribution is reassessing the potential future reliability benefits and VVO savings, does that mean the project benefits estimate provided in Appendix AA13 may not be accurate?

(b) How will PUC Distribution proceed if the results of VF3 show that there are not enough VVO savings to achieve "no net bill increase?"

Response:

(a) The future reliability benefits and VVO savings are best estimates based on the assumptions and analysis as provided in the Project Benefits Memo (Appendix AA13 of the Amended Application). Actual reliability benefits and VVO savings may be greater than or less than these estimates.

In the event that there are changes to the reliability benefits following the implementation of the SSG Project, this is something that PUC Distribution can publicly report on so that other utilities looking to implement DA will have access to the PUC Distribution experience. In the interim, because reliability benefits are not factored in to the net benefits test in the project benefits memo at Appendix AA13 of the Amended Application, any fluctuations in the actual reliability benefits will not impact the net benefit analysis.

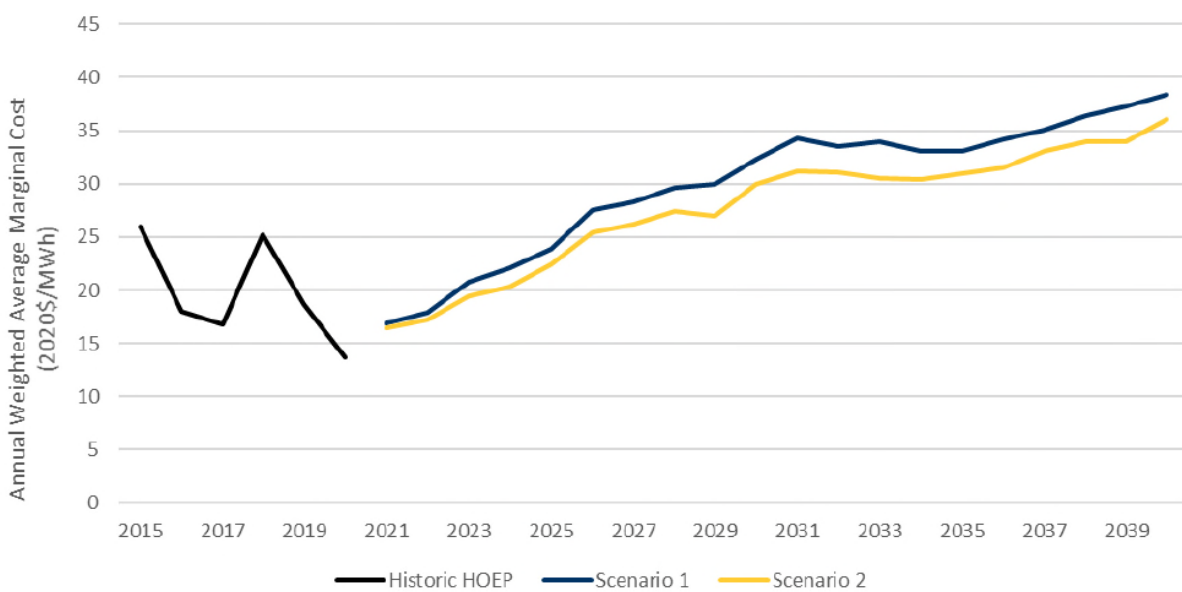
By contrast, the VVO savings play a very important role in the net benefit analysis. For this reason, PUC Distribution negotiated very specific performance obligations on its EPC Contractor to ensure that this minimum level of net benefit is achieved. Please see EPC Contract (Appendix AA3-7 of the Amended Application) Section 22.1(c).

(b) PUC Distribution will rely on its remedies available under the EPC Contract (Appendix AA3-7 of the Amended Application Section 22.1(c)) so as to reduce the total cost of the SSG Project to ensure "no net bill increase".

In addition, since the cost of power is forecasted by the IESO to steadily increase in the future whereas the costs associated with the SSG Project will generally decline as it depreciates the minimum net bill impact will be in year 1 and the benefits to ratepayers will accrue even more so over time.

Below is Figure 36 found in the IESO's Annual Planning Outlook - Ontario's electricity system needs: 2022-2040 dated December 2020 showing a forecast of HOEP:

Figure 36 | Weighted Average Marginal Costs Forecast, and Historical HOEP[31]



Please refer to response to SEC-12 for table showing the customer net benefit from 2022 to 2041.

Staff-33

Reference 1: EB-2020-0249, Appendix AA3-7, Appendix A, Pages 65-66

Reference 2: EB-2020-0249, Appendix AA12-1, Project Cost Summary

Preamble:

Scope item VP1 is to obtain quotes for the equipment and software required for the SSG Project. This includes the Survalent software, cellular equipment, field equipment, IVR software and service hardware.

Question:

Please explain how PUC Distribution estimated the unit costs of equipment in Appendix AA12-1 if it has not yet obtained quotes for the equipment.

Response:

PUC Distribution issued a Request for Proposals in October 2019 to seek competitive proposals for EPC services. Proposals were evaluated and PUC Distribution awarded the project to Black & Veatch, which was the most qualified proponent and had the lowest price proposal. PUC Distribution then entered into an EPC Contract with Overland Contracting Canada Inc. (wholly-owned subsidiary of Black & Veatch) with negotiated terms. PUC Distribution generally held the bidder to the bid prices and would not allow arbitrary price change. Appendix AA12-1 Project Cost Summary, was prepared based on the EPC cost estimate.

We trust the EPC Contractor's estimates because Overland Contracting Canada Inc., the EPC Contractor, is a wholly-owned subsidiary of the Black & Veatch. Black & Veatch is an experienced global EPC and consulting company that specializes in infrastructure development in, inter alia, power. It performs engineering and construction work all over North America and has executed projects in more than 100 countries. It would have easy access to quotes for equipment to develop estimated unit costs of equipment.

In addition, PUC Distribution trusts the estimated costs because the EPC Contractor had agreed to those costs as part of the fixed price EPC Contract.

Staff-34

Reference 1: EB-2020-0249, Application, Page 16, Lines 20-24

Reference 2: EB-2020-0249, Appendix AA12-2 – Project Cost Estimate Memo

Preamble:

In reference 1, PUC Distribution states that it acquired the rights to the studies and preliminary engineering works[13] of Infrastructure Energy (IE) that were previously filed with the OEB. Costs for the preliminary engineering are identified in the Project Cost Estimate at Appendix AA12-2.

Page 6 of reference 2 indicates that the costs to purchase the preliminary engineering work was $1,023,695, and is broken down as follows:

- DA: $595,791
- VVM: $331,203
- AMI: $116,701

Question

(a) Please specify which lines item(s) in Appendix AA12-2 these costs are located in.

(b) Are these costs referring to the Leidos Engineering LLC and Navigant Consulting Inc. Reports? Are there any other costs incurred by IE included in the $1,023,695?

(c) How were the amounts in the three bullet-points above determined?

Response:

(a) These costs are included in the project cost as part of line items for Engineering in each of VVM, DA and AMI.

(b) Yes, the costs are referring to the Leidos Engineering LLC and Navigant Consulting Inc. Reports. The cost of $1,023,695 is for the following:

a. The Navigant report "Review of Business Case for Smart Grid Project for PUC Distribution" dated April 15, 2015;

b. The Navigant report "Review of Project Costs for Smart Grid Project for PUC Distribution" dated June 23, 2015;

[13] Filed as Appendix AA7 in this application

c. The Leidos report "Utility Distribution Microgrid: Volt/VAR Management (VVM) – Preliminary Design" dated October 17, 2014;

d. The Leidos report "Utility Distribution Microgrid: Distribution Automation – Preliminary Design" dated November 20, 2014

e. The Leidos report "Utility Distribution Microgrid: AMI Integration – Preliminary Design" dated November 20, 2014

f. Energrid and Michael Baumann's completed NRCan application

g. The CYME distribution network system model files created to support the engineering studies prepared fort he Sault Smart Grid Project

There are other costs incurred by IE included in the $1,023,695, specifically PUC Distribution agreed to pay a modest 15% administration fee to IE in respect of its work to coordinate and administer the creation of the Leidos engineering reports.

(c) Engineering costs allocated approximately on estimated fixed asset for VVM, DA and AMI.

Staff-35

Reference: EB-2020-0249, Application, Appendices AA7, AA8, AA9, AA10

Preamble:

PUC Distribution last rebased for 2018 rates. The Leidos preliminary engineering reports and the Navigant reports were completed prior to PUC Distribution's 2018 rebasing application.

Question:

Please confirm that PUC Distribution has not to date recovered any costs associated with the reports or other costs in relation to the SSG Project from ratepayers.

Response:

Confirmed.

Staff-36

Reference: EB-2020-0249, Application, Page 20

Preamble:

PUC Distribution notes that customer net benefits achieved through efficiencies in terms of reduced energy consumption and system losses will off-set the additional revenue requirement requested.

Question:

Please confirm that if, for example, the SSG Project does not come "into service" until December 2022, the statement above would only hold true beginning in 2023, and customers would be paying the full additional revenue requirement requested in the interim.

Response:

PUC Distribution confirms that if the SSG Project does not come "into service" until December 2022, the benefits noted in the preamble above would not start until the beginning of 2023.

However, pursuant to the OEB's Accounting Direction,[14] the OEB's approach has been to apply the half-year rule in cases in which the ICM request coincides with the final year of a distributor's IRM plan term. PUC Distribution's next Cost of Service will be in 2023. As such, PUC Distribution has applied the half-year rule in this request for incremental revenue because this ICM request coincides with the final year of PUC Distribution's IRM plan term.

Eligible Incremental Capital for ACM/ICM Recovery was calculated using the half-year rule, but full costs were used to calculate the net benefits.

[14] Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, July 25, 2019

Staff-37

Bill Impacts

Reference: EB-2020-0249, Application, Page 57, Table 14: Total Bill Impacts

Preamble: The above reference is reproduced below:

Table 14: Total Bill Impacts

			With Consumption Savings		Without Consumption Savings	
Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %	Total Bill Increase/Decrease	Total Bill Impact %
Residential	750	0	-$1.21	-1.05%	$1.16	1.01%
Residential	825	0	-$1.44	-1.17%	$1.16	0.94%
Residential	367	0	$0.00	0.00%	$1.16	1.66%
Residential	2,000	0	-$5.15	-1.97%	$1.16	0.44%
GS<50	2,000	0	-$4.92	-1.68%	$2.56	0.87%
GS<50	272	0	$0.00	0.00%	$1.01	1.83%
GS<50	3,000	0	-$7.76	-1.80%	$3.45	0.80%
GS>50	19,740	55	-$62.85	-1.86%	$25.08	0.74%
GS>50	57,220	145	-$194.19	-2.07%	$56.42	0.60%
GS>50	142,465	452	-$487.42	-2.02%	$163.34	0.68%
GS>50	169,620	468	-$585.22	-2.10%	$168.91	0.61%

Question:

(a) Please clarify how the bill impacts are calculated. What are the going-in rates used to determine these impacts?

(b) OEB staff would like to see the potential bill impacts effective May 1, 2022. To do so please use PUC Distribution's proposed rates as per its 2021 IRM application, and calculate the bill impacts by applying a 1.90% proxy as the 2022 IPI adjustment and adding in the proposed ICM rate riders for the SSG Project. Please assume all else equal (for example, no deferral and variance account disposition, no change in RTSR rates etc.). Please provide the calculations in live Excel form.

Response:

a) These bill impacts were calculated using a replica of the OEB Bill Impact and Tariff Worksheet. All rates outlined in that worksheet are included in these calculations.

b) PUC Distribution has provided the requested calculations which are attached as Attachment 7. PUC Distribution has updated Table 14 above to reflect and IRM increase in addition to the ICM rate riders. The results are in the table below.

			With Consumption Savings		Without Consumption Savings	
Class	**Consumption (kWh)**	**Consumption (kW)**	**Total Bill Increase/Decrease**	**Total Bill Impact %**	**Total Bill Increase/ Decrease**	**Total Bill Impact %**
Residential	750	0	-$0.70	-0.61%	$1.67	1.45%
Residential	825	0	-$0.94	-0.76%	$1.67	1.34%
Residential	367	0	$0.51	0.72%	$1.67	2.36%
Residential	2,000	0	-$4.65	-1.78%	$1.67	0.64%
GS<50	2,000	0	-$3.82	-1.30%	$3.69	1.25%
GS<50	272	0	$0.43	0.78%	$1.46	2.60%
GS<50	3,000	0	-$6.29	-1.46%	$4.98	1.15%
GS>50	19,740	55	-$52.41	-1.55%	$35.93	1.06%
GS>50	57,220	145	-$170.87	-1.82%	$80.85	0.86%
GS>50	142,465	452	-$420.16	-1.74%	$234.06	0.97%
GS>50	169,620	468	-$515.67	-1.84%	$242.04	0.87%

Staff-38

Reference: EB-2020-0249, Application, Page 20, Table 1: Customer Annual Net Benefit Summary

Permeable: The SSG Project is anticipated to achieve an annual net benefit to PUC Distribution customers of over $616,897. This amount is made up of the following components:

Table 1: Customer Annual Net Benefit Summary

Cost of Power - updated to current estimate	$ 82,512,685	App [AA15]-Cost of Power Spreadsheet
Projected % energy savings with SSG implementation	2.70%	App [AA14]-Energy Savings Spreadsheet
Projected customer energy savings through SSG	$ 2,227,842	App [AA14]-Energy Savings Spreadsheet
Projected system loss energy savings through SSG	$ 105,111	App [AA14]-Energy Savings Spreadsheet
Total purchased power savings	$ 2,332,953	
ICM additional revenue from increased SSG asset base	$ 1,754,862	ICM Model output
Benefit of reduced capital expenditures witth SSG	($304,390)	APP [AA17] CAPEX Deferral Spreadsheet
Additional O & M expenses due to SSG implementation	$ 296,400	App [AA13]-Project Benefit Estimate Memo
Operating efficiency benefits due to SSG implementation	($30,816)	App [AA13]-Project Benefit Estimate Memo
	$ 1,716,056	
Annual net benefit to customers	$ 616,897	
Annual projected reliability benefit to customers	$ 2,017,000	App [AA10] -Navigant Report #3 (NPV $33M)
Total Annual projected benefit to customers w/reliability	$ 2,633,897	

Question:

Please replicate the table above with an additional column to show the estimated number of years PUC Distribution expects its customers would continue to receive the benefit of each line item.

Response:

Please find the table requested below. Note that the additional revenue from increased SSG asset base has decreased from $1,754,862 to $1,751,221 based on updated CWIP rates.

Customer Net Benefit Summary			
	Original	**Years**	
Cost of Power - updated to current estimate	$ 82,512,685	indefintely	*App [AA15] -Cost of Power Spreadsheet*
Projected energy savings with SSG implementation	2.70%	indefintely	*App [AA14] -Energy Savings Spreadsheet*
Projected customer energy savings through SSG	$ 2,227,842	indefintely	*App [AA14] -Energy Savings Spreadsheet*
Projected system loss energy savings through SSG	$ 105,111	indefintely	*App [AA14] -Energy Savings Spreadsheet*
Total purchased power savings	$ 2,332,953	indefintely	
Additional revenue from increased SSG asset base	$ 1,751,221	decreasing	*Full Year Revenue Requirement*
Benefit of reduced capital expenditures witth SSG	($304,390)	indefintely	*APP [AA17] CAPEX Deferral Spreadsheet*
Additional O & M expenses due to SSG implementation	$ 296,400	indefinitely	*App [AA13] -Project Benefit Estimate Memo*
Operating efficiency benefits due to SSG implementation	($30,816)	indefinitely	*App [AA13] -Project Benefit Estimate Memo*
	$ 1,712,415	indefinitely	
Annual net benefit to customers	$ 620,538	increasing	
Annual projected reliability benefit to customers	$ 2,017,000	indefinitely	*IRR App#7 -Navigant Report #3 (NPV)*
Total projected benefit to customers	$ 2,637,538	increasing	

With improved distribution system operation monitoring and control and associated data availability for system planning and asset operations to support asset management and renewal, further efficiencies are expected to be attainable. Long term CAPEX savings benefits have been identifed in smart grid project as an equivalent savings from PV projections for PUC but have not been incorporated in to the Distribution System Plan at this time.

Staff-39

Reference: EB-2020-0249, Application, Pages 20 and 38

Preamble: Page 20, Table 1 (as in the interrogatory above) provides an estimate of the annual incremental O&M expenses of $296,400 and operating efficiency benefits of ($30,816). On page 38, the application states "Ongoing operation and maintenance costs... are estimated at ~$29,250 per month."

Question:

On an annual basis, $29,250 per month is $351,000. OEB staff is unable to reconcile this amount with the amounts noted on page 20. Please reconcile the difference and provide the estimated incremental OM&A and efficiency benefits of the SSG Project.

Response:

(a) The estimated OM&A expense calculations are shown in Appendix AA13 in Table 8 of the Amended Application. The assumption of 2.5 FTE shown results in the $296,400 value. The OM&A value of 29,250 per month reflects a 3.0 FTE assumption. The differences in the OM&A values shown reflect change in assumption on the level of future FTE impact to OM&A of the equipment utilized in the project and missed editing during drafting. In developing the current project estimate the intent is to specify and select self-monitoring equipment technology wherever practicable to offset hands-on field operation and maintenance.

Staff-40

Reference: EB-2020-0249, Application Page 21-22 – CAPEX Savings Benefits

Preamble:

PUC Distribution notes that CAPEX savings benefits have been identified in industry smart grid projects through distribution automation initiatives. PUC Distribution has provided an estimate of reduced capital spending in its distribution system of $304,390 annually from the reduction of substations and transformer replacements.

Question:

OEB staff is interested in understanding what capital expenditures could be deferred or eliminated across the transmission and generation sectors as a result of the SSG Project. At the generation and transmission levels, has PUC Distribution identified capital savings benefits that will arise as a result of the SSG Project? Please explain.

Response:

PUC Distribution is not in a position to speculate on what capital expenditures could be deferred or eliminated across the transmission and generation sectors as a result of the SSG Project. PUC Distribution's role is strictly limited to the distribution of electricity in its service territory, whereas the IESO and Hydro One would be better positioned to opine on the potential impacts on the generation and transmission system.

Staff-41

Reference: EB-2020-0249, Application, Page 38

Preamble:

PUC Distribution predicts that ongoing operation and maintenance costs in terms of operating and maintaining the SSG Project, as well as any impacts on operating and maintaining other utility assets, are estimated at $29,250 per month (range of 2.5-4.5 FTEs).

Question:

Please confirm that the amount proposed for recovery in this application does not include any amounts relating to incremental OM&A, and that these costs will form part of PUC Distribution's proposed OM&A costs in its 2023 rebasing application.

Response:

Confirmed.

Staff-42

Reference: EB-2020-0249, Application, Pages 57-58

Preamble:

PUC Distribution indicated that it will record actual ICM amounts in the generic Account 1508 sub-accounts established for ICMs.

Question:

(a) Please explain how PUC Distribution will account for the capital contribution from NRCan, including whether PUC Distribution will need a new sub-account to track the capital contribution.

(b) If so, please provide a draft accounting order.

Response:

a) PUC Distribution will require three new sub accounts to handle the capital contributions from NRCan of which the details are provided in the draft accounting order.

b) The draft accounting order is provided in Attachment 8.

Staff-43

Bill Impacts and Savings – GS>50kW Customers

Reference 1: EB-2020-0249, Application, Page 57

Reference 2: EB-2020-0249, Application, Appendix AA13 – Project Benefits Estimate Memo, Pages 8-9

Preamble:

Table 14 on page 57 shows PUC Distribution's calculated total bill impacts at various consumption levels with or without "consumption savings."

Question:

(a) Please confirm: does "consumption savings" refer to the estimated 2.7% reduction in energy consumption for the implementation of the VVO?

At reference 2, PUC Distribution notes that reduced energy consumption only applies to customers drawing energy from PUC Distribution's 12.5 kV distribution system because the VVO only applies to the 12.5 kV system. PUC Distribution noted seven GS>50 kW sub-transmission customers that are connected to the 34.5 kV distribution system that would not receive any benefit from the VVO.

(b) Please confirm whether the "consumption savings" noted above apply to the seven customers on the 34.5kV system.

(c) If no to (b), please provide total bill impacts without "consumption savings" for the GS>50kW rate class using an average consumption of the seven customers.

Response:

(a) Yes. consumptions savings does refer to the estimated 2.7% reduction in energy consumption for the implementation of the VVO.

(b) The consumption savings of 2.7% will not apply to the seven customers on the 34.5kV system although they will share in the benefit from reduced system losses

(c) PUC Distribution has updated Table 14 which is provided below.

			With Consumption Savings		Without Consumption Savings	
Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %	Total Bill Increase/ Decrease	Total Bill Impact %
Residential	750	0	-$1.21	-1.05%	$1.16	1.01%
Residential	825	0	-$1.44	-1.17%	$1.16	0.94%
Residential	367	0	$0.00	0.00%	$1.16	1.66%
Residential	2,000	0	-$5.15	-1.97%	$1.16	0.44%
GS<50	2,000	0	-$4.92	-1.68%	$2.56	0.87%
GS<50	272	0	$0.00	0.00%	$1.01	1.83%
GS<50	3,000	0	-$7.76	-1.80%	$3.45	0.80%
GS>50	19,740	55	-$62.85	-1.86%	$25.08	0.74%
GS>50	57,220	145	-$194.19	-2.07%	$56.42	0.60%
GS>50	142,465	452	-$487.42	-2.02%	$163.34	0.68%
GS>50	169,620	468	-$585.22	-2.10%	$168.91	0.61%
GS>50 34.5kV Line	476,119	1158	$409.21	0.54%	$409.21	0.54%

Staff-44

Reference: EB-2020-0249, Application, Page 23

Preamble:

PUC Distribution notes that it will be able to utilize the new advanced distribution management system to operate with increased grid intelligence which will be critical in meeting new demands such as increasing uptake in Distributed Energy Resources (DERs) and electric vehicle requirements (EVs). PUC Distribution also notes that the SSG Project provides a platform for power system operating and control flexibility to support renewable energy and technology integration.

Question:

(a) Please provide specific examples of how PUC Distribution anticipates its new system will aid in the meeting of new demands related to renewable energy connections, DERs and EVs.

(b) Does PUC Distribution have a forecast of additional DER connections? If so, what is the forecast for DER connections in the next 2 years, 5 years and 10 years?

Response:

(a) Please see response to ED-4 (b) and (c).

(b) PUC Distribution completed and submitted to the IESO a Renewable Energy Generation Plan (REG Plan) on November, 30 2017 that outlined forecasted DER connections at that time. The following excerpt from that document is included here in response to question Staff-44:

Five Year 2018-2022 REG Forecast

PUC has produced a 5 year forecast of future REG connections. For the period 2018-2022 projections have been based on:

- *local economic and population data*
- *macro-economic conditions*
- *awareness of information from IESO and OEB regarding connection rates and programs*

Based on those factors, the five year forecast in Table 1 below has been established with an anticipated connection of one 250kW *generator per year for a total connection of 1.25MW over the next 5 year period.*

	Projected # of Connections	Installed MW
2018	1	0.25
2019	1	0.25
2020	1	0.25
2021	1	0.25
2022	1	0.25
2018-2022 Totals	5	1.25

Table 1 - Forecast REG for 2018-2022

PUC Distribution next plans to update its REG Plan with a Distributed Energy Resource Plan (DER Plan) in 2021 which will be used as an input to next 5-year Cost of Service filling in 2022. The DER plan will include a 5-year 2023-2027 forecast.

Staff-45

Reference 1: EB-2020-0249, Application, Page 27

Reference 2: EB-2018-0249, PUC_ICM_IRR_20190531, Response to VECC-24, Page 176

Preamble:

The evidence states that if the OEB does not approve this ICM, PUC Distribution would not proceed with the SSG Project and any NRCan funding would be forfeited.

In the 2019 ICM application, in response to the interrogatory noted in reference 2, PUC Distribution noted that it had spent $535,118 as of March 31, 2019 on the SSG Project - $199,428 for labour and expenses, and $335,690 for external engineering and legal costs.

Question:

(a) Please provide an updated breakdown of the project costs to date.

(b) In the event the OEB does not approve this ICM, how will these costs be recovered?

Response:

a) As of December 31, 2020, PUC Distribution has spent $2,262,556 on the SSG Project. $879,145 for labour and expenses, $1,311,529 for external engineering and legal costs. and $70,881 for regulatory costs.

b) If the application is not approved, we are not anticipating these costs to date will be recovered unless they can be applied to a future project.

Staff-46

SSG Project Scope of Work and Specifications

Reference 1: EB-2020-0249, Application, Page 36

Reference 2: EB-2018-0219, Application, Page 25

Reference 3: EB-2020-0249, Application, Appendix AA7, Leidos Engineering LLC. Report, Utility Distribution Microgrid AMI Integration, Page 16

Reference 4: EB-2018-0249, PUC_ICM_IRR_20190531, Response to VECC-25, Page 177

Preamble:

At reference 1, with respect to Data Analytics and Performance Reporting, the amended application notes that this was included in the original application, however PUC Distribution no longer anticipates this to be part of the contract. PUC Distribution notes that it will develop analytics and reporting over the long run.

The original application noted that SCADA, AMI, CIS, OMS, and GIS data will be loaded into a common platform in order to provide system analytics and key performance indicator reporting.[15]

In response to VECC-25 in the original application, PUC Distribution provided a list of initial planned project performance metrics. OEB staff notes that a portion of these metrics are also replicated in Schedule A of the Updated Statement of Work and Updated NRCan Contribution Agreement and Claim Form (Appendix AA4) under Performance Information in the current version of the Contribution Agreement.

PERFORMANCE INFORMATION:

Key Performance Indicators:	
1. GHG emissions reductions	Reduction in greenhouse gas emissions Reduced energy losses from GHG emitting supply (kWh)

2. Improved asset utilization and increased efficiency	Reduction in peak demand on utility assets
	Reduction in energy losses
	$ savings from deferred system upgrades
	$ energy savings to customers

3. Increased reliability and resiliency	# events Fault Location, Isolation and Restoration responded to # customer calls/complaints avoided due to fewer outages $ revenue loss avoided from outages avoided

[15] EB-2018-0219, Application, Page 25

It is OEB staff's understanding that PUC Distribution is required to provide the results of the above three performance indicators as part of its Contribution Agreement, and an explanation of the methodology for calculating these indicators.

<u>Question:</u>

(a) Please confirm that the above three noted metrics will be reported by PUC Distribution as part of its Contribution Agreement with Canada.

(b) Please regenerate the list of performance metrics provided in response to VECC-25 and add a column indicating which metrics PUC Distribution will maintain and which it will not. For each negative, please explain the decision behind not going forward with tracking that metric.

(c) Please confirm if SCADA, AMI, CIS, OMS, and GIS will be loaded into a common platform in order to provide system analytics and key performance indicator reporting in the current iteration of the SSG Project.

(d) Please explain how the removal of data analytics and performance reporting follows the recommendations noted in the Leidos Report, specifically, that for a Utility Distribution Microgrid (UDM) to be successful, clear internal metrics and reports will be required that track performance of the UDM, identify operational issues or inefficiencies and provide supporting detail for design, build and operational stages.

(e) How does PUC Distribution intend to track the success of the SSG Project in the short-term?

<u>Response:</u>

(a) Yes, PUC Distribution will be reporting on the noted metrics.

(b) List from VECC-25 (original application) with added column.

Metrics	Project Title:	SSG Plan to Utilize Metric
GHG Emission Reductions and other Environmental Benefits	**Process indicators-VVM:** Reduced energy losses from GHG emitting supply (kWh); reduced customer energy consumption (kWh) **Impact indicators-VVM:** Tons CO_2e avoided from reduced energy losses and reduced customer consumption **Process indicators-DA:** # of truck rolls avoided; reduced energy losses from GHG emitting supply (kWh), resulting from re-conductoring and phase-balancing	**Yes** **Yes** **Partly/To Be Determined** **Partly/To Be Determined**

	Impact indicators-DA: Tons CO_2e avoided from reduced vehicle emissions and reduced energy losses	
Improved Asset Utilization and Increased Efficiency	**Process indicators-VVM:** Reduced peak demand on utility assets (kW); Reduced need for grid reserve capacity (kW); Increased load factor on certain assets; Reduced energy losses (kWh) **Impact indicators-VVM:** $ savings from deferred system upgrades; $ reduced utility demand charges; $ energy savings to customers **Process indicators-DA:** # of truck rolls avoided (vehicle miles); reduced overtime (OT hours); # of customer minutes with outages avoided (minutes) **Impact indicators-DA:** O&M savings due to reduced truck rolls and overtime;	**Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined**
Increased Reliability and Resiliency	**Process indicators-VVM:** None **Impact indicators-VVM:** None **Process indicators-DA:** # of events Fault Location, Isolation and Restoration responded to; # customer calls/complaints avoided due to fewer outages **Impact indicators-DA:** $ revenue loss avoided from outages avoided; customer average interruption duration index (CAIDI) for customers served by the project; customer minute interruptions avoided	**Yes** **Yes**
Increased System Flexibility and Renewable Energy Penetration	**Process indicators-VVM:** # of feeders with VVM installed and operational **Impact indicators-VVM:** # of voltage actions taken annually to improve grid efficiency and mitigate renewable intermittency **Process indicators-DA:** # of feeders integrated into Fault Location, Isolation and Restoration (FLIR) system **Impact indicators-DA:** % of feeders with automation	**Yes** **Yes** **Yes** **Yes**
Cyber Security	**Process indicators-VVM:** Best practices developed or applied on system communications with AMI (qualitative indicator) **Impact indicators-VVM:** Real-time issue identification and reaction to cyber security threats	**Partly/To Be Determined** **Partly/To Be Determined**

	Process indicators-DA: best practices developed or adhered to **Impact indicators-DA:** real-time issue identification and reaction to cyber security threats	**Partly/To Be Determined** **Partly/To Be Determined**
Economic and Social Benefits	**Process indicators-VVM:** # jobs to implement system and highly qualified personnel trained, business case established/documented for VVM (Project) **Impact indicators-VVM:** Reduced customer charges due to improved (flatter, lower) voltage profile across the feeder (project); reduced customer charges or off-set increases to customer charges due to the lower demand charges and energy saved at the system level **Process indicators-DA:** # jobs to implement system and created to monitor the system; # customer jobs created due to higher reliability/resiliency **Impact indicators-DA:** $ customer value (e.g. avoided revenue loss) from avoided outages	**Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined**

(c) The method, process, design, etc. for collecting, analyzing and reporting program metrics has not been determined and will be developed by PUC Distribution as part of the project design and implementation.

(d) An overall integrated platform for data analytics and performance reporting has not been excluded from the project but is not specifically part of the current EPC contract. The EPC contract will include such data and analytics specific to the contracted elements. A specification for an integrated solution was challenging to set in the contract negotiation and PUC Distribution elected to consider this aspect as part of the future (outside EPC) design stage and consideration for a potentially different timeline for implementation although NRCan commitments will be met.

(e) VVM and DA tracking and reporting metrics required for project performance will be developed as part of the EPC contract. PUC Distribution will develop and supplement as required to measure project and system performance including those identified for the NRCan agreement.

<u>Staff-47</u>

<u>Reference 1</u>: EB-2020-0249, Application, Pages 34-37

<u>Reference 2:</u> EB-2014-0219, Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014

<u>Reference 3:</u> EB-2020-0249, Application, Page 46

<u>Preamble:</u>

At the pages notes above, in relation to the “Need” criteria for an ICM, PUC Distribution provides a discussion relating to the expectations of customers for cost control, improved reliability and communication and with their utility. PUC Distribution also discusses the increasing importance of the connections of DERs and how PUC Distribution believes the SSG Project will contribute to the four main performance outcomes of the OEB’s Scorecard.

Further, PUC Distribution notes that increasing development of distribution connected DER and EVs is expected to continue, and that these factors create requirements for better operational system monitoring, control and access to data. PUC Distribution notes that the SSG Project provides the tools and data to meet these challenges.

OEB staff notes that while the above may be potential outcomes of the SSG Project, the specific driver is unclear.

<u>Question:</u>

(a) Please specify what the specific driver(s) is in relation to the “Need” criteria as defined in reference 2.

(b) Did PUC Distribution investigate other technological and smart grid solutions to meet the challenges of DERs and EVs, other than what is proposed in this application? If so, what other solutions were investigated? Why did PUC Distribution select the VVO, DA and AMI Integration as the necessary components of the SSG Project as proposed in this application?

<u>Response:</u>

(a) The “Need” criteria is demonstrated by the Board objectives as set out in the *Ontario Energy Board Act, 1998* (the “Act”). Section 1(1) items 2 to 4 of the Act provides that the OEB’s objectives is to:

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate innovation in the electricity sector.

SSG Project is driven by the following three needs:

1. promote economic efficiency and cost effectiveness in the distribution of electricity;
2. promote electricity conservation and demand management while having regard to the consumer's economic circumstances; and
3. facilitate innovation in the electricity sector.

(b) The SSG Project was chosen because it was one where PUC Distribution could see net benefit to customers with "no net bill increases" and it required a scaled solution.

Staff-48

Reference 1: EB-2020-0249, Application, Pages 46-49

Reference 2: EB-2020-0249, Application, Page 24

Preamble: N/A.

Question:

Please reconcile the "Need" discussion at reference 1 to the statement in reference 2 which states "In the event that the OEB does not approve this ICM, PUC Distribution would not proceed with the SSG Project and any NRCan funding would be forfeited."

Response:

If the OEB determines that the SSG Project is not needed after considering the evidence put forth, including the evidence of no net bill increase, in consideration of the OEB's statutory objectives under Section 1(1) of the OEB Act, then PUC Distribution is not in a position to proceed with the SSG Project and any NRCan funding will be forfeited.

Staff-49

Reference 1: EB-2020-0249, Application, Pages 43-44

Reference 2: Chapter 3 Filing Requirements, May 12, 2020, Page 28

Preamble:

PUC Distribution has calculated the rate riders to recover the ICM amount as follows:

- The residential class rate rider is a fixed charge as per OEB policy
- The remainder of the classes are a combination of a fixed and variable charges

Reference 2 directs distributors to provide rationale for its proposed rider design.

Question:

Please provide a discussion on the rationale for the choice of the combination of fixed and variable riders, should the OEB approve the SSG Project.

Response:

PUC Distribution has used a combination of fixed and variable rate riders for all classes except Residential. PUC Distribution allocated the amount to be collected from each class based on the current percentages of distribution revenue collected within each rate class as presented in tab 11 of the ICM Model. PUC Distribution chose this combination of fixed and variable charges to remain consistent with how current distribution charges are collected from each class of customers.

Staff-50

Reference: EB-2020-0249, Application, Page 50

Preamble:

PUC Distribution notes that it considered three options for the SSG project: A) pursue the project and complete it within two years; B) develop the project over ten or more years; C) not proceed with the project. The application notes that option B would develop the project "...over ten years in order to spread out the costs of the SSG Project on PUC Distribution's ratepayers." OEB staff notes that a capital expenditure cannot be added to rate base until the asset is ready to be used.

Question:

(a) It appears to OEB staff that deploying the SSG Project over ten years would simply delay the recovery of the costs from ratepayers for ten years until the smart grid is fully functional. Please explain how developing the project over ten years would spread out the costs for PUC Distribution's customers.

(b) Does option B imply that the SSG Project can be parceled into smaller projects and that it is possible for PUC Distribution to incrementally introduce smart grid technology to its service territory?

Response:

(a) OEB Staff's assumption is incorrect. It is possible to deploy VVO and DA on a feeder by feeder basis such that the assets become used and useful as each feeder is completed. By deferring the SSG Project over ten years or more, PUC Distribution would effectively roll the project out feeder by feeder with subsets of the entire service area over the ten or more year period. This approach is quite similar to how other utilities would implement DA on its own across their system.

(b) Yes, that is what option B implies.

The challenge with doing this with VVO is that only those customers that are served by the feeder upon which the VVO is implemented will benefit from energy reductions, however, because of assumptions made in the OEB's rate setting process, all customers will be required to pay for those improvements. The only way to ensure that all customers benefit from the VVO upgrades is to implement the project across the entire service area at once to ensure all customers see no net bill increase.

In addition, if PUC Distribution pursues Option B, it will forfeit the NRCan Funding, since a 2031 in-service date for the SSG Project exceeds the required completion date of March 31, 2023 under the NRCan Funding.

Staff-51

Reference: EB-2020-0249, Application, Page 56

Preamble:

The reference notes that, if approximately a 50% reduction was made to the scope of DA coverage, it would reduce project costs by approximately $3-4 million and add $150,000 to $200,000 to the net benefit summary.

Question:

Please clarify, where the application says $150k-200k to be added to the net benefit summary, is this saying that the net benefit should be reduced by $150k-200k because of the reduction in DA scope? Or is this saying that, on a net basis, reducing the scope of DA would increase the amount of net benefits that could be realized?

Response:

As evidenced in the Project Benefits Estimate Memo at Appendix AA13 of the Amended Application, reliability improvements are not included in the calculation of annual net benefits to customers. As seen in Table 1 of Appendix AA13, reliability benefits of $2,017,000 is shown as a separate line item that is not incorporated in the net benefits calculation.

If the cost of the project is reduced by $3-4 million, the impact of the reduction is limited to reducing scope of DA. The result would be an improvement in the total net benefits calculated for customers of approximately $150k-200k per year.

It would be reasonable to assume that the reliability benefits will decrease by 50% if there was a reduction of scope of 50% of the DA coverage.

Staff-52

Reference: Appendix AA10, Page 12

Preamble:

In the reference, Navigant describes the cost saving benefit of VVM as reducing energy consumption by reducing the voltage delivered to customers from the VVM system.

Electricity customers don't all receive the same voltage – the household voltage received from the distribution system can range from 110V-125V as dictated by CSA guidelines. Unless there are voltage regulators, it is typically the customers located at the end of a feeder that receive the lowest voltage. Therefore, it is OEB staff's understanding that not all customers will receive the estimated 2.7% reduction in energy consumption. Some customers may experience a higher reduction, while other customers (e.g. those at the end of a feeder already receiving electricity around the lower limit of 110V) may experience less.

Question:

Please confirm if OEB staff's understanding is correct.

Response:

The estimated energy savings of 2.7% is an estimated average system value so it is correct that individual customer savings will vary. The Staff example above of voltage varying at the primary level over feeder length without voltage regulation is how feeder voltages are often depicted. Distribution transformer voltage control of +/- 5% can also be used to compensate for voltage losses in both the primary and secondary delivery. Utilization at the customer can thus be adjusted by transformer tap settings so a customer at the end of an unregulated feeder may have an adjusted voltage in a target range higher than the primary feeder level but balancing the target design for normal voltage fluctuations from high load to low load levels.

Staff-53

Reference 1: EB-2020-0249, Appendix AA12-1 – Project Cost Summary

Reference 2: EB-2020-0249, Appendix AA12-2 – Project Cost Estimate Memo

Reference 3: EB-2020-0249, Live Excel Model for SSG Revised Scope and Project Summary, PUC_App_AA12-3_SSG Revised Scope_Proj_Estimate Sum_20201029

Preamble:

OEB staff notes that in reference 1, there is a unit quantity of "1" for the "Add'l Scope & Contingency" line item under the AMI Integration breakdown, with a total associated unit cost of $185,277. However, this item is not in the "Total" column.

OEB staff notes that the $185,277 quantum is not noted in references 2 or 3.

Question:

Please reconcile.

Response:

Scope contingency estimate assumptions in original project were developed by PUC Distribution from known site specific field conditions. Allocation process in spreadsheet applied this estimate on the basis of fixed assets initially. In internal review it was noted that the contingency items were all related to field equipment and locations for DA and VVM installations. Revisions were completed but unit cost column was not updated for the contingency line items (i.e. $0.00 for the AMI section)

Revised summary included here for information but no impact to overall cost.

2020/2021 Smart Grid Project			
Project Costing w/ EPC & PUC Cost Estimate			
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**Unit Costs**	**Total**
DS with new LTC's (incremental)			-
48 feeders (note Sub 16 LTC)			
> Bus/Padmount /Feeder/ VReg's(per set of 3)	44	120,834	5,316,678
> feeder balancing Vregs	6	55,487	332,922
> feeder balancing Caps	6	42,634	255,802
			5,905,402
Engineering (check sum)	1	2,362,042	2,362,042
Add'l Scope & Contingency	1	462,846	462,846
			8,730,290
Project Mgmt/ Ext'l Commissioning Review	1	379,800	379,800
Contract/Regulatory/ Legal	1	334,433	334,433
VVM			**9,444,523**
			9,444,523
DA (excludes AMI, SCADA, Comm, etc.)			
Reclosers	40	99,573	3,982,933
SW's(pole)	40	93,279	3,731,157
2 way padmount SW's	12	62,231	746,775
4 way padmount SW's	8	304,825	2,438,597
OH FCI's	40	1,549	61,972
UG FCI's	40	1,931	77,220
Poles (added qty for adjacent lift/siting issues)	120	11,837	1,420,456
			12,459,110
Engineering (check sum)	1	5,205,849	5,205,849
Add'l Scope & Contingency	1	844,036	844,036
			18,508,995
Project Mgmt/ Ext'l Commissioning Review	1	759,600	759,600
Contract/Regulatory/ Legal	1	684,389	684,389
DA			**19,952,983**
			19,952,983
AMI Integration, SCADA, OMS, CIS, Comm, etc.)			
All IT H/W, S/W, SCADA, OMS, GIS, communication			
type work combined in to central sub-project.			
VVO/FLSIR/OMS/CIS/AMI	1	2,013,446	2,013,446
			2,013,446
Engineering (check sum)	1	1,284,009	1,284,009
Add'l Scope & Contingency	1	-	-
			3,297,455
Project Mgmt/ Ext'l Commissioning Review	1	126,600	126,600
Contract/Regulatory/ Legal	1	116,652	116,652
AMI			**3,540,707**
			3,540,707
Project Estimate Total System			**32,938,213**

Construction	Engineering	Ctct Legal/Reg	Project Mgmt	
21,684,840	8,851,900	1,135,473	1,266,000	32,938,213
65.8%	26.9%	3.4%	3.8%	
32,938,213				
	Note: Engineering includes EPC+PUCD			
	6,060,205	*2,791,695*	*8,851,900*	

Staff-54

Reference 1: EB-2020-0249, Appendix AA13 – Project Benefits Estimate Memo, Page 1

Preamble:

In the reference, PUC Distributions lists $2,017,000 in annual projected reliability benefit to customers. OEB staff is unable to find the calculations for the $2,017,000 in the reference listed (Appendix A10 – Navigant Report #3).

Question:

Please provide the calculations for the $2,017,000 amount or a reference to the calculations.

Response:

Calculation was done to include an equivalent annual value in the benefit summary table. (a net present value string to approximate total ($33M) referenced in the Navigant report.)

10							
11	Navigant Report #3 - Community Microgrid Business Case Review Report						
12	Navigant 20 year reliability NPV of $33.8M (pg. 15 chart) and 40 Year $52.7 (pg 10 chart)						
13	20 Year	1	2	3	18	19	20
14		2021	2022	2023	2038	2039	2040
15		2,017,000	2,017,000	2,017,000	2,017,000	2,017,000	2,017,000
16	2%						
17	$ 33,003,178						
18	=NPV(A16,B15:U15,B14:U14)						

Staff-55

Reference 1: EB-2020-0249, Appendix AA12-2 – Project Cost Estimate Memo, Page 5

Preamble:

Table 4 at the above noted reference provides a list of the items that make up PUC Distribution's engineering scope for the SSG Project. The items in the list are:

- Engineering & Technical Oversights & Approvals
- Regulatory material & equipment approval
- Perform design reviews for EPC Gates
- Regulatory Construction Verification Program
- Asset and GIS records management
- Perf management system oversight/installation

Question:

(a) Please describe each item and the work involved.

(b) Please provide an estimate of costs for each item and explain how PUC Distribution estimated the costs.

Response:

(a) The scope of work and responsibilities detailed in Appendix AA3-7 of the Application outlined in the Responsibility Matrix table in Appendix 2, page 123. The columns in the table include allocation for R=Responsible, A=Assist, and O=Oversight (includes Review/Approve).

i. PUC Distribution's engineering scope is predominately of the Oversight category throughout the project although the Stage 1 engineering phase is expected to be a more condensed period of activities there will be oversight requirements throughout he project duration.

ii. Material and equipment selected for use in the project must meet PUC Distribution's Electrical Distribution Safety program regulatory requirements under Ontario Regulation 22/04. Development of approved specification and application documentation management is required for any new material or equipment items required.

iii. Various steps and deliverables in the contract design process will require input, review and approvals as required by PUC Distribution.

iv. Similar to material and equipment approvals in (ii) all construction will require management under the PUC Distribution regulatory Construction Verification requirements prior to in-service use. Document management for regulatory requirements is required.

v. Asset and GIS records management will include recording all changes and additions to PUC Distribution data environments.

vi. Development and implementation of the project performance management system both during and post project will be a key focus for PUC Distribution engineering and operations staff involved.

(b) The categories above have not been estimated individually and will in many cases be integrated throughout design and construction for the project. Overall, the estimate reflects PUC Distribution's understanding of skills needed as input to the project design and prior experience in engineering effort required in supporting previous capital projects as applied to the EPC scope of work and overall project schedule.

Staff-56

Reference 1: EB-2020-0249, Appendix AA11 – 2016 Projection for Distribution Capital [JTC 1.13]

Reference 2: EB-2020-0249, Appendix AA5, JTC1.1 – Technical Conference Undertakings from EB-2018-0219

Preamble: N/A

Question:

In reference 1, PUC Distribution provided two spreadsheets, one "without UDM" and one "with UDM." OEB staff notes that the scenario "with UDM" shifts most capital expenditures to the 2017-2021 period.

(a) Please confirm that PUC Distribution is proposing to follow the capital expenditures shown in the "with UDM" spreadsheet.

(b) How many of these projects have been completed? For the projects that are yet to be completed, when does PUC Distribution plan to complete these projects?

(c) Are these projects funded through PUC Distribution's base rates?

In the Excel spreadsheet provided as part of JTC1.1, PUC Distribution calculates an annual saving of $304,390 in avoided capital expenditures. The assumptions listed in the model include: 1) reduction of distribution substation network from 18 to 16; 2) reduction of individual transformer replacement across network by 5; 3) avoided substation rebuilds in years 2025 and 2030.

(d) Given that the SSG Project is expected to help defer distribution station capital expenditures, please reconcile this with Appendix AA11, which suggests that distribution station spending should be accelerated. In particular, do the reductions listed in JTC1.1 include any of the distribution stations listed in Appendix AA11?

Response:

(a) PUC Distribution intends to follow the sequence for capital expenditures shown in the "with UDM" spreadsheet. However, the timing of the expenditures will be delayed in accordance with the delay in the start of the UDM (ie: the SSG) project.

(b) Please refer to the spreadsheet Ref 1: EB-2020-0249, Appendix AA11 – 2016 Projection for Distribution Capital [JTC 1.13]. Refer to Row 1. Retirement of Sub 14 was completed in 2018. Refer to Row 2. The rebuild of Sub 16, scheduled for 2017-2021 is underway and is to be complete and on-line by the end of 2021. Designs were completed, major materials were procured, and a construction contract was established in 2020. The contract calls for construction to proceed approximately between March and October 2021. Now, please refer to Row 2. For transformer station TS1, preliminary engineering is underway in 2020-2021. However, construction will now not begin until the 2022-2026 COS rate application period, at which time the proposed significant project will be included and an associated ICM will be filed as well.

(c) Within the projects in Appendix AA11, PUC Distribution had filed an ICM application for Sub 16 under EB-2019-0170. Sub 16 will be incorporated in PUC Distribution's rate base at its 2023 Cost of Service rebasing application. As for the rest of the projects, they are not currently included in PUC Distribution's base rates.

(d) The spreadsheet in Appendix AA11 was developed to examine the impact of an accelerated substation renewal program as could be potentially included in the UDM (ie. now SSG) at that time. The current project scope removed the major substation redevelopment work. As indicated above in (a) the sequence is still generally expected although timing has changed. The future deferral of station capital expenditures arising from the SSG project is anticipated to occur during selected voltage control design alternatives, which will include in some locations comparing base scope overhead voltage regulator solutions with alternatives using station bus regulators or station transformers with on-line tap changers, considering costs, space limitations and in some location's aesthetics. The reductions in Appendix AA11 reflect the same stations and assume 50% meet the voltage control design alternative review criteria.

Staff-57

Reference 1: EB-2020-0249, Application, Appendix 3-7 – EPC Contract, Page 8

Reference 2: EB-2020-0249, Application, Appendix 3-7 – EPC Contract, Page 12

Preamble:

Subsection (kkk) defines the *Scheduled Completion Date for Upfront Engineering* as "the date on which the *Upfront Engineering Services* are scheduled to be completed, which is the date that falls nine (9) months after the issuance of the *Notice to Proceed with Upfront Engineering*."

Subsection (lll) defines the *Scheduled Final Completion Date* as "the date on which the Work is scheduled to achieve *Final Completion*, which will be set out in the *Notice to Proceed with Balance of Work*."

At reference 2, Article 12.5 states that:

> It shall be a condition precedent of the issuance of the Notice to Proceed with Upfront Engineering that the Owner's ICM (Incremental Capital Module) application has concluded successfully in respect of rates and revenue recovery, as determined by the Owner in its sole discretion. The Owner will attest to the satisfaction of this condition precedent in the Notice to Proceed with Upfront Engineering, and the Contract may rely on such attestation without further inquiry.[16]

Interrogatory responses for this application are due mid-January. Subsequent case steps will follow as determined appropriate by the OEB. If for example, PUC Distribution receives OEB-approval in the Spring of 2021, OEB staff estimates that the Upfront Engineering Services would not be complete until late 2021, or early 2022.

Question:

(a) How long does PUC Distribution anticipate that Step 2 would take?

(b) What confidence can PUC Distribution provide the OEB that an in-service date in 2022 is reasonable?

(c) Please explain how PUC Distribution will address any delays in the project milestones.

Response:

(a) The timeline for the SSG Project, including Step 1 and Step 2 can be found in Appendix AA3-5 Project Schedule of the Amended Application.

[16] EB-2020-0249, Application, Appendix 3-7 – EPC Contract, Page 12

(b) PUC Distribution is confident that an in-service date in 2022 is reasonable although there may be external factors that may cause delay, such as weather or unforeseen system operating constraints, but PUC Distribution's project implementation plan includes comprehensive project management oversight and an EPC contract with liquidated damages clauses for performance and delay in place to mitigate any delays.

(c) Any delays in the project milestones will be protected by the liquidated damages for delay stipulated in the EPC Contract. The liquidated damages for delay shall protect PUC Distribution from losses associated with the EPC Contractor's failure to complete the SSG Project by the scheduled final completion date and thus not within the timeframe required under its funding arrangement with NRCan.

Staff-58

Reference: EB-2020-0249, Application, Appendix 3-7 – EPC Contract, Page 7

Preamble:

The following definitions are found on page 7 of the EPC Contract:

> (xx) Owner's Requirements means the description of the scope, standards, design criteria, Performance Requirements, Milestones and the programme of work set out in Appendix A – SSG Scope of Work to be further developed by the Parties during the course of the Upfront Engineering Services, as amended by any Changes;

> (bbb) Performance Requirements mean the performance requirements set out in the Owner's Requirements;

Question:

(a) As part of the EPC Contract, is there currently or will there be a minimum percentage of energy savings that must be achieved upon completion of the project?

(b) If not, what level of comfort can PUC Distribution provide the OEB that the SSG Project will provide customers the level of benefits noted in the current application or a level commensurate with the proposed costs?

Response:

(a) Yes, please see EPC Contract (Appendix AA3-7 of the Amended Application) Section 22.1(c). This information was redacted and filed in confidence but is relevant to the question asked.

(b) Not applicable.

Staff-59

Reference: EB-2020-0249, Application, Appendix 3-7 – EPC Contract, Page 19

Preamble:

Article 12.4 of the above noted reference states:

> The Contractor shall be entitled to receive a Change Order for a change in the Contract Time, including the Scheduled Final Completion Date, and an adjustment to *the Upfront Engineering Fixed Price* if the *Notice to Proceed with Upfront Engineering* is issued later than December 31, 2020. The *Upfront Engineering Fixed Price* will be adjusted by multiplying it by the Consumer Price Index, as published by Statistics Canada in Table: 18-10-0004-01 (“CPI Index”), for the month in which the Notice to Proceed with Upfront Engineering is issued and dividing it by the CPI Index for November 2020.

Question:

Please confirm the updated Step 1 project costs (currently $5,086,378) given that a *Notice to Proceed with Upfront Engineering* is subject to OEB approval of the SSG Project, and will not be issued, if applicable, prior to December 21, 2020.

Response:

The Step 1 project costs to be updated by the CPI calculation cannot be calculated until the CPI is published for the month that the Notice to Proceed is issued. The Notice to Proceed will be issued once PUC Distribution has OEB approval.

$5,086,378 x [_??_] (CPI in month NTP issued) / 137.7 (CPI Nov 2020)

See Section 12.4 of EPC Contract at Appendix AA3-7 of the Amended Application.

Consumers Council of Canada Interrogatories

CCC-1

Reference: Application, p. 6

Preamble:

On January 31, 2019 PUC Distribution filed an incentive rate-making application with the OEB seeking approval of its distribution rates effective May 1, 2029. As part of the Application PUC Distribution applied for an ICM to recover the costs associated with the implementation of the Sault Smart Grid project. Following the Technical Conference on June 28, 2019, PUC Distribution filed a letter indicating its intent to amend the ICM Application and file all outstanding Technical Conference undertakings a part of its amendment.

Question:

Please provide a detailed explanation as to why PUC Distribution decided to withdraw, and subsequently amend the original Application.

Response:

During the Technical Conference the EB-2018-0219 proceeding, PUC Distribution received valuable stakeholder input. Particularly, intervenors seemed to be concerned about the P3 project structure, which was an important part of the Original Application. In order to address this concern, PUC Distribution decided to improve and restructure the project delivery plan by conducting an RFP process to seek competitive proposals for EPC services. This also simplifies the project delivery plan by eliminating regulatory complications arising from the previously proposed P3 structure.

The RFP also allowed for innovative project financing structure, innovative financing arrangements, or other novel structures or proposals. Ultimately, after the RFP process, PUC Distribution selected a proposal that was based on a normal EP arrangement, where PUC Distribution would own and operate the assets as is normally the case in a regulated utility. As a result of this restructuring and EPC pricing, estimated cost of the SSG Project has now reduced further than what was estimated in the Original Application.

CCC-2

Reference: N/A.

Preamble: N/A.

Question:

Please provide all materials presented to PUC Distribution's Board of Directors regarding the initial application.

Please provide all materials presented to PUC Distribution's Board of Directors regarding the current amended Application.

Response:

Original Application:

Please see Amended Application Appendix AA5 - Appendix 5 JTC2_5 Smart Grid Overview BoD June 27 2018

Amended application:

Please see response to Staff-10 for the materials presented to PUC Distribution's Board of Directors regarding the current Amended Application.

CCC-3

Reference: Application, p. 9

Preamble: N/A.

Question:

The SSG project now has a revised total capital cost of $33 million. Please provide a detailed breakdown of the original capital cost ($34.4 m) and a detailed breakdown of the new total capital cost in one schedule.

Response:

The information mentioned in the responses to this question do not reflect the most up to date CWIP rates.

Please find breakdown below.

Revised Application

2020/2021 Smart Grid Project Project Costing w/ EPC & PUC Cost Estimate		
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**Total**
DS with new LTC's (incremental)		-
48 feeders (note Sub 16 LTC)		
> Bus/Padmount /Feeder/ VReg's(per set of 3)	44	5,316,678
>feeder balancing Vregs	6	332,922
>feeder balancing Caps	6	255,802
		5,905,402
Engineering (check sum)	1	2,362,042
Add'l Scope & Contingency	1	462,846
		8,730,290
Project Mgmt/ Ext'l Commissioning Review	1	379,800
Contract/Regulatory/ Legal	1	353,703
VVM		**9,463,794**
DA (excludes AMI, SCADA, Comm, etc.)		
Reclosers	40	3,982,933
SW's(pole)	40	3,731,157
2 way padmount SW's	12	746,775
4 way padmount SW's	8	2,438,597
OH FCI's	40	61,972
UG FCI's	40	77,220
Poles (added qty for adjacent lift/siting issues)	120	1,420,456
		12,459,110
Engineering (check sum)	1	5,205,849
Add'l Scope & Contingency	1	844,036
		18,508,995
Project Mgmt/ Ext'l Commissioning Review	1	759,600
Contract/Regulatory/ Legal	1	726,371
DA		**19,994,966**
AMI Integration, SCADA, OMS, CIS, Comm, etc.)		
All IT H/W, S/W, SCADA, OMS, GIS, communication type work combined in to central sub-project.		
VVO/FLSIR/OMS/CIS/AMI	1	2,013,446
		-
		2,013,446
Engineering (check sum)	1	1,284,009
Add'l Scope & Contingency	1	-
		3,297,455
Project Mgmt/ Ext'l Commissioning Review	1	126,600
Contract/Regulatory/ Legal	1	124,223
AMI		**3,548,278**
Project Estimate Total System		**33,007,038**

Construction	Engineering	Ctct Legal/Reg	Project Mgmt
21,684,840	8,851,900	1,204,297	1,266,000
65.7%	26.8%	3.6%	3.8%
33,007,038			
	Note: Engineering includes EPC+PUCD		
	6,060,205	*2,791,695*	*8,851,900*

Original Application

2019/20 Smart Grid Project (Appendix 1 reference to Leidos Preliminary Design - VVM 2014/10/17)		
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**Total**
DS with new LTC's (incremental)	2	120,000
40 feeders		
> Bus/Padmount /Feeder/ VReg's/	44	9,240,000
>feeder balancing Caps	6	49,500
>feeder balancing VRegs	6	565,800
		9,975,300
Engineering		3,205,800
Contingency		-
		13,181,100
Project Mgmt/ Ext'l Commissioning Review		1,645,550
Regulatory/ Financial/ Legal		1,132,830
VVM		**15,959,480**
DA (excludes AMI, SCADA, Comm, etc.)		
34.5 kV TT (10DS and TS?)	6	318,000
Reclosers	38	3,192,000
SW's(pole)	40	2,560,000
2 way padmount SW's	3	342,000
4 way padmount SW's	4	496,000
OH FCI's	32	230,400
UG FCI's	37	229,400
Poles (added qty for adjacent lift/siting issues)	90	1,035,000
		8,402,800
Engineering		3,456,800
Contingency (30% design)		-
		11,859,600
Project Mgmt/ Ext'l Commissioning Review		1,501,250
Regulatory/ Financial/ Legal		1,298,610
DA		**14,659,460**
AMI Integration, SCADA, OMS, CIS, Comm, etc.)		
All IT H/W, S/W, SCADA, OMS, GIS, communication type work combined in to central sub-project.		
34.5 kV TT SW	14	490,000
FLIR SW	1	450,000
AMI/OMS/CIS	1	637,500
		1,577,500
Engineering		1,337,400
Contingency (30% design)		-
		2,914,900
Project Mgmt/ Ext'l Commissioning Review		523,800
Regulatory/ Financial/ Legal		331,560
AMI		**3,770,260**
Project Estimate Total System		**34,389,200**

Construction	*Engineering*	*Reg/Fin/Legal*	*Project Mgmt*
19,955,600	*8,000,000*	*2,763,000*	*3,670,600*
58.0%	*23.3%*	*8.0%*	*10.7%*
34,389,200			

CCC-4

Reference: Application, p. 9

Preamble: N/A.

Question:

How did PUC Distribution make the RFP available to potential proponents?

Did Black & Veatch have any involvement in the project prior to being chosen?

Response:

The RFP was publicized on the PUC website and MERX, in line with company practice for large capital projects. MERX markets their services as Canada's leading electronic tendering service.

As mentioned at page 16 of the Amended ICM Application, various EPC contractors were invited by PUC Distribution to submit proposals for the SSG Project's EPC services (including the project development partner, Infrastructure Energy, LLC) in the Original Application. All the RFP submissions received were evaluated and rated internally to select the preferred EPC proponent to move to the next stage of the contract negotiation process.

As set out in the Original Application[17], Black & Veatch was engaged by the project development partner, Infrastructure Energy, LLC as the EPC Contractor performing all phases of design, build, and validation.

[17] EB-2018-0219, ICM Application dated January 31, 2019, page 14.

CCC-5

Reference: Application, p. 9

Preamble: N/A

Question:

The RFP was awarded to Black & Veatch. Please explain the rationale for executing the EPC contract through B&V's subsidiary Overland Contracting Canada Inc. Please provide a corporate chart setting out the relationship between B&V and Overland Contracting Inc. and other related companies.

Response:

The rationale for entering into the EPC Contract with Overland Contracting Canada Inc. ("OCCI") is that Black & Veatch is based in the United States and OCCI is a Canadian operating company, which B&V uses to execute and perform contracts in Canada. It should be noted that OCCI is supported by a parental guaranty of all of its obligations under the EPC Contract.

Please see corporate chart filed in confidence at Attachment 11.

CCC-6

Reference: Application, p. 7-9

Preamble: N/A

Question: In the initial Application the projected annual net benefit to PUC Distribution customers was “over $200,00 excluding forecasted reliability benefits of over $2.5 million”. The project is now projected to achieve an annual net benefit to PUC Distribution customers of over $616,897, excluding forecasted reliability benefits. Please explain what accounts for the increase projection of benefits. How will PUC Distribution ensure that these benefits flow through to customers?

Response:

(a) The change in net benefits arises mainly from increased purchase power cost forecasts (energy savings increased) and lower project costs (lowered incremental revenue).

(b) PUC Distribution will ensure that the benefits flow through to customers as there is a commitment built into the EPC Contract for performance. Please see EPC Contract (Appendix AA3-7 of the Amended Application) Section 22.1(c), which was redacted and filed in confidence but is relevant to the question asked.

CCC-7

Reference: Application, p. 10

Preamble: N/A

Question: Please explain how the final capital contribution from NRCan will be determined. Please explain the significance of extension of the eligible expense end date.

Response:

The information mentioned in the responses to this question do not reflect the most up to date CWIP rates.

As stipulated in the Contribution Agreement with NRCan (Appendix AA-1 of the Amended Application), NRCan agreed to fund the lesser of 25% of total project costs that meet the eligible expense incurred or $11,807,000. The final capital contribution will be based on the same provision. As stated in the Amended Application, the NRCan contribution is estimated at $8,126,759, which is 25% of current eligible cost project estimate of $32,507,038 ($33,007,038 less ~$500,000 as estimated ineligible to NRCan program as costs incurred before contribution eligibility period and estimated legal costs).

The significance of extension of the eligible expense end date to March 31, 2023 in the new amendment to the Contribution Agreement is that now the SSG Project will need to be completed by March 31, 2023, which is in line with the SSG Project's scheduled in-service date of December 31, 2022.

CCC-8

Reference: Application, p. 10

Preamble: N/A

Question: Please provide all correspondence (letters, emails, presentations etc.) between PUC Distribution and NRCan regarding the initial proposal and the amended proposal.

Response:

PUC Distribution has already provided the following information related to the NRCan funding:

- Information about the NRCan program and PUC Distribution's project description summary to NRCan (Appendix 11-A of the Original ICM Application);
- Contribution Agreement (Appendix 1 to IRRs of the Original Application);
- Updated Statement of Work (Appendix AA4-1 of the Amended Application);
- Amended Contribution Agreement (Appendix AA4-2 of the Amended Application); and
- Contribution Agreement Claim Form (Appendix AA4-3 of the Amended Application).

PUC Distribution trusts that this is sufficient information to inform the OEB about the NRCan program and the agreement between PUC Distribution and NRCan in relation to the NRCan funding. PUC Distribution submits that providing all correspondences between PUC Distribution and NRCan does not add any probative value for the OEB in making a determination on approval of the ICM Application.

CCC-9

Reference: Application, p. 13

Preamble: N/A

Question: What were the cost of the Navigant Reports and how were those costs recovered?

Response:

Please see response to Staff-34(b).

CCC-10

Reference: Application, p. 10

Preamble: N/A

Question: The evidence refers to $500,000 in costs that incurred before the NRCan contribution eligibility period and estimated legal costs. Please provide a detailed breakdown of this amount. How are these costs being recovered? Please provide a detailed schedule setting out all costs incurred to date and explain how those costs are to be/or have been recovered.

Response:

PUC Distribution incurred project costs before the eligibility date of June 13, 2018 in the NRCan Contribution Agreement. Those parts of the preliminary engineering and project management work are not eligible for NRCan contribution purposes. The NRCan agreement also categorizes certain expenses as ineligible for purposes of contribution calculation (e.g. legal expenses) although they are recognized as part of the Total Project Costs for purposes of PUC Distribution's contribution to the capital project.

For the period pre- June 13, 2018 PUC Distribution incurred expenses of $75,611.25 for preliminary engineering and project management. In 2019 to 2020-06 PUC Distribution has incurred additional project legal expenses that are not eligible for NRCan contribution in the amount of $119,064.

The SSG capital project costs net of NRCan capital contribution are being presented for rate recovery through the ICM application process.

CCC-11

Reference: Application, p. 12

Preamble: N/A

Question: The Navigant Reports were completed in 2015 and 2016. Did PUC sought any updated Reports from Navigant following its decision to modify the project scope? If not, why not? Does PUC Distribution believe that the Navigant reports are still relevant given ongoing advancements in technology?

Response:

PUC Distribution has not sought any updated reports from Navigant. The main change in the Amended Application is the change from using a P3 project finance structure to bringing the SSG Project in-house and using and RFP process to seek competitive proposals for EPC services. There has not been significant advancements with respect to smart grid technologies and therefore the technologies explored in the Navigant reports are still relevant. As such, it is not worth spending extra money on a Navigant report which will likely contain similar information.

CCC-12

Reference: Application, p. 13

Preamble: N/A

Question: The evidence refers to the "no net bill increase" criteria. Is PUC Distribution still committing to a "no net bill increase" with respect to the revised project? If so, how will PUC Distribution ensure that there will be no net bill increases arising from implementation of the project?

Response:

PUC Distribution's objectives for the project remain the same and the no net bill impact (on average) for our residential customers has not changed. PUC Distribution has secured an EPC contract which includes a maximum fixed price as well as a commitment to 2.7% energy savings (please see EPC Contract (Appendix AA3-7 of the Amended Application) Section 22.1(c), which was redacted and filed in confidence but is relevant to the question asked) to deliver a successful project. Net benefit calculations have been provided to show that the overall net benefits of the project are positive and that benefits will offset incurred ICM rate increases.

CCC-13

Reference: Application, p. 14

Preamble: N/A

Question: Please file the latest PUC Distribution DSP filed on March 29, 2018.

Response:

Please find attached PUC Distribution's DSP filed on March 29, 2018 attached at Attachment 9**.**

CCC-14

There is no CCC-14.

CCC-15

Reference: Application, p. 16

Preamble: N/A

Question: Please explain how the EPC pricing was derived. Specifically, how were the Step I and Step 2 prices determined?

Response:

The RFP submission was used as the base and a number of meetings conducted to review and ensure clarity on scope and expectations were completed. PUC Distribution generally had revisions to scope that raised level of expectation for contractor on-site project management and reporting throughout the project and that energy savings and scheduling dates would be critical contract terms and conditions. Adjustments for corrections in unit quantities were also developed through these reviews. Following this detailed review, the finalization of the detailed scope of work document was developed and the EPC pricing schedule was ultimately derived by the contractor and presented to PUC Distribution for approval for both Step 1 and Step 2.

CCC-16

Reference: Application, p. 16

Preamble: N/A

Question: The evidence indicates that, "Any price changes by the EPC contractor would be monitored by PUC Distribution using an open-to-closed book process in accordance with the fixed price as detailed in the EPC contract. The scope of work will be reduced by PUC Distribution if required to maintain the project capital cost limit set for the project":

1. Please explain what an open-to-closed book process is;

2. If the scope of work was reduced as set out in the contract, how would this impact the proposed benefits?;

3. Why is Black and Veatch not responsible for any cost overruns?

Response:

1. Please see Schedule 2 – Open-to-Closed-Book Process of Appendix AA3-7 EPC Appendix B – Compensation for a detailed explanation of the open-to-closed-book process.

2. Please see response to Staff-17(b).

3. Please see response to SEC-6 for description of Step 1 and Step 2 of EPC Contract.

   Black and Veatch will be responsible for any cost overruns for Step 1, and also for Step 2 after the scope of work is finalized and there is a Balance of Work Fixed Price set using the Open-to-Close book process pursuant to Schedule 2 of Appendix AA3-7 Appendix B of the Amended Application.

CCC-17

Reference: Application, p. 19

Preamble: N/A

Question: Please explain how PUC Distribution can ensure that the project "can be implemented without adversely impacting costs to customers". What if the proposed benefits do not materialize as projected?

Response:

PUC Distribution can ensure that the project "can be implemented without adversely impacting costs to customers" because of commitments made by the EPC Contractor in the EPC Contract. Please see also EPC Contract (Appendix AA3-7 of the Amended Application) Section 22.1(c), which was redacted and filed in confidence but is relevant to the question asked. This provision will help ensure "no net bill increase" is maintained.

To the extent the performance measures are not achieved pursuant to the EPC contract, PUC Distribution will exercise its rights to claim liquidated damages for performance, and those liquidated damages will go to reduce the cost of the SSG Project for customers and help ensure that "no net bill increase" is maintained.

CCC-18

Reference: Application, p. 20

Preamble:

The Applicant has indicated that the annual net benefit to customers is $616,987 and $2.63 million if annual reliability benefits are included.

Question:

Please provide an allocation of those projected benefits to PUC Distribution's rate classes. Who was responsible for determining the projected benefits?

Response:

Please see updated Table 2 of the Amended Application provided in response to SEC-13. The answer to SEC-13 does not include the impacts of the reliability benefit.

The allocation of reliability benefits of the estimated reliability benefits across different classes is not a simplistic modelling exercise, so these benefits have been excluded from the impacts in calculations such as SEC-13. Also see response to SEC-12 for customer net benefits from 2022 to 2041.

This updated Table 2 provides the allocation of bill impacts by rate class, including the Capex benefit, the operating efficiency benefits, and the additional O&M expenses but does not factor in any increases to the cost of power, transmission network, wholesale market service charge, RRRP charge.

PUC Distribution calculated the projected benefits based on best available information on the various components, such as cost of power, projected energy savings, ICM additional revenue from increased SSG asset base, reduced capital expenditure with SSG, additional O&M expenses, and operating efficiency benefits. See Project Benefits Estimate Memo at AA13 of the Amended Application.

CCC-19

Reference: Application, p. 22

Preamble: N/A

Question: For an average residential consumer in PUC Distribution's service territory, what are the benefits of the SSG project? Please provide a complete list of the risks that PUC Distribution's customers will bear with the implementation of this project. Please provide a list of all of the risks PUC Distribution's will bear with the implementation of the project. Please provide a complete list of all of the risks that Black & Veatch will bear with the implementation of the project.

Response:

Please see Table 14 of the Amended Application, which shows the total bill impacts on residential customers if they were receiving the full benefit from consumption savings. There will generally be a total bill decrease. Residential customers will also benefit from reliability improvements from the SSG Project. Please also see calculations in response to SEC-12.

- Cost overruns – Black & Veatch bears this risk once a Fixed Price is established through the Notice to Proceed with Balance of Work. PUC does bear this risk until that point, although Black & Veatch must justify price increases on an open-book basis.

- Schedule – This risk is shared. Black & Veatch bears this risk once the Notice to Proceed with Balance of Work is executed and a schedule agreed. If there is a delay then PUC Distribution customers will also risk not receiving the benefits of the SSG Project as scheduled. However, this is mitigated by the provision for PUC Distribution to claim Liquidated Damages for Delay (See Article 22 of the EPC Contract at Appendix AA3-7).

- Defects – Black & Veatch generally bears this risk through the Warranty Period (See Article 23 of the EPC Contract at Appendix AA3-7).

- Performance – Black & Veatch bears the responsibility to execute the Work properly. The risk of PUC Distribution customers not receiving net benefits due to energy savings is mitigated by the performance guarantee by Black & Veatch. There is a provision for PUC Distribution to claim Liquidated Damages for Performance (See Article 22 of the EPC Contract at Appendix AA3-7).

- Site Conditions – Black & Veatch bears this risk once the Notice to Proceed with Balance of Work is executed, as Black & Veatch will, at that time, accept the existing site conditions (or the parties agree to exceptions). (Articles 5.5, 5.6 of the EPC Contract at Appendix AA3-7). If Black & Veatch encounter unforeseen site conditions prior to that time, it may affect the Fixed Price. PUC Distribution bears the risk for Pre-existing Hazardous Material (Article 26.5 of the EPC Contract at Appendix AA3-7).

- Permits – This risk is shared. Black & Veatch generally has the responsibility to obtain all permits other than those related to land use aspects of the Work, which PUC Distribution bears (Article 24.4 of the EPC Contract at Appendix AA3-7).

-

CCC-20

Reference: Application, p. 23

Preamble: N/A

Question:

Please explain how the $33 million customer reliability benefit was derived.

Please provide PUC Distribution's reliability metrics for the past 10 years (SAIDI, SAIFI and CAIDI).

Response:

(a) The $33M customer reliability benefit was a 20 NPV calculation from the reliability improvements (reduced customer outage minutes) that would be incurred by implementation of DA as calculated by Navigant (see Appendix AA10 – Navigant Report #3). The DA system will provide improved outage performance through automated switching and self-healing capabilities. Section 4.2: Benefits Analysis in the report outlines the methodology and assumptions used from the estimated reliability improvements to SAIDI, SAIFI and CAIDI as developed by Leidos and using a value for customer outage costs Navigant referenced from a US study. Navigant commented in the report that the DA reliability improvements identified in the project were reasonable based on industry reports for DA implementation. Navigant included both a 40 year NPV value of $52.7M and a 20 year figure of $33.8M in the report.

(b) SAIDI, SAIFI, and CAIDI reliability metrics including loss of supply and major event days for PUC Distribution for the past 10 years are as follows:

OutageYear	SAIDI	SAIFI	CAIDI
2010	2.1	2.81	0.75
2011	8.41	4.59	1.83
2012	1.64	2.17	0.76
2013	2.66	3.54	0.75
2014	1.19	1.21	0.99
2015	3.34	1.84	1.82
2016	2.53	2.21	1.15
2017	1.96	1.61	1.22
2018	2.34	1.75	1.34
2019	13.01	3.45	3.77

CCC-21

Reference: Application, p. 23

Preamble:

The evidence indicates that the SSG project will increase the overall reliability of the Applicant's distribution system.

Question:

Please provide the results of any surveys or other customer engagement activities that indicate that PUC Distribution's customers are seeking increased reliability.

Response:

Please see Summary of Survey at Attachment 5.

In the attached Survey at Question 3, 78.68% of PUC Distribution customers indicated that they are more inclined to support the Smart Grid Project after learning that it will result in better power quality and significantly increase reliability.

In Question 4, 72.64% of PUC Distribution customers indicated that reliability is very important.

In Question 6, on a sliding scale of 0 to 100, with 0 being "keep costs low" and 100 being "investments to improve reliability", customers responses averaged 43, roughly even with respect to reliability and low costs.

CCC-22

Reference: Application, p. 29

Preamble:

The Leidos' Preliminary Design Report was completed on November 20, 2014.

Question:

Please provide evidence to demonstrate that the technology referred to in that report which informs the proposed design remains relevant and cost-effective.

Response:

The technology proposed in the Leidos' Preliminary Design Report consists primarily of hardware and software which is widely commercially available and has remained relatively unchanged since the time the report was written. This technology consists of non-specialized items including, protection relays, switch controllers, reclosures, OLTCs and associated controllers, fibre and wireless communications devices and SCADA software. What was proposed in the report remains relevant and cost effective.

The project scope review and negotiations in developing the final EPC contract project scope and pricing for the project confirmed that devices and locations would still generally be applicable with an update to current specification/versions. The one technology change adopted was to include more cellular based communication for field devices rather than the radio solution considered originally.

CCC-23

Reference: Application, p. 40

Preamble: The proposed funding from NRCan is $8.126 million.

Question: How will these amounts be treated from an accounting perspective?

Response:

Please see response to Staff-42.

CCC-24

Reference: Application, p. 53

Preamble:

The evidence indicates that the scope of work has been confirmed with the EPC Contractor, Black & Veatch, and reviewed extensively internally by PUC Distribution to deliver a successful project delivering the expected outcomes at the expected costs.

Question:

Has Black and Veatch undertaken similar work for any other distributors? If so, please provide a complete list of those projects and the scope of those projects. Please include the detailed projected costs for each of the projects and the completed costs.

Response:

PUC Distribution has sought input from B&V to try and address this question and the following information has been provided to illustrate the large range of projects and experience that B&V has in this area:

Further to our conversation Xcel Energy is an interesting example as they are planning capital expenditures totaling $524 million US ($697 million Cdn) to implement AMI, IVVO and FLISR across their distribution infrastructure and this cost does not include their implementation of an Advanced Distribution Management System which has its own capital budget.

Also interesting given this full blown implementation of DA and IVVO they are only planning to pilot Time-of-Use rates with their new AMI meters

BLACK & VEATCH Distribution Automation, Conservation Voltage Reduction/Volt Var Optimization Project Experience

In Ontario, Black & Veatch has worked extensively over the past 10 years with a number of utilities including Hydro One, Elexicon (Veridian), Milton and Hydro Ottawa. At Hydro Ottawa Black & Veatch lead the following Grid Modernization projects:

- Telecom Master Plan
- Engineering design Wide Area Network Fiber
- Engineering Study Field Area Network Wireless
- Integrated Volt Var Optimization (IVVO) pilot project
- Planning and development of Smart Utility and Advanced Metering Infrastructure (AMI) Program

In Canada and the United States Dominion voltage Inc. (DVI) engaged Black and Veatch to plan and implement their Integrated Volt Var Optimization (IVVO) solution which included the following projects:

- Hawaiian Electric (HI)
- Glendale Power and Water (CA)
- Hydro Ottawa, Canada
- Duck River Member Electric Cooperative (TN)
- Nevada Energy (NV)

Black & Veatch collaborated with DVI (Dominion Voltage Inc.) to implement the Conservation Voltage Reduction (CVR) pilots, which implemented CVR as applied to selected distribution circuits. This optimizes the substation voltage on the feeders, keeping them within the lower half of the ANSI service voltage limits, therefore implementing energy conservation. This approach leverages the EDGE automation technology, using the client's real time AMI metering systems, LTC Controls and SCADA controls to optimize the distribution system voltage. Analysis and recommendations for system improvements were made to the improve distribution system.

Black & Veatch performed similar work for Hawaiian Electric, Glendale Water & Power, Hydro Ottawa, by providing program management, engineering, including AMI metering, SCADA and direct control interfaces. Black and Veatch responsibilities included EDGE configuration, integration, AMI data validation, Outlier and Energy Savings report generation, Site Acceptance Testing, go-live execution, and training. At Duck River and Nevada Energy, additional substations and components implemented voltage regulators and capacitor controls.

Our on-going work with HECO, Hawaiian Electric Company, is a good example of a current and comprehensive integration program from planning through implementation across a wide variety of technologies to meet a unique set of circumstances.

Hawaiian Electric Company – Distribution Automation Strategy

Business Issue: HECO was in need of an analysis for the deployment of various Distribution Automation (DA) applications across all three operating companies on a system-wide basis to improve system reliability and performance.

Black & Veatch Solution: Black & Veatch developed a DA Strategy (DAS) that includes a business case for incorporation into the Hawaiian Electric Companies' overall smart grid business case. This includes the identification of critical assumptions and performing risk assessment evaluations of the different technologies, including:

- Substation SCADA
- Feeder SCADA
- Volt-VAR Optimization (VVO)
- Fault Location Isolation and Service Restoration (FLISR)
- Automated Switching
- Faulted Circuit Indicators (FCI)
- Asset Management
- Adaptive Relaying
- Power Quality Metering
- Cyber and Physical Security

Our work with Xcel Energy is a good example of a current and comprehensive integration program including secondary devices to further enhance the performance. In this case Black and Veatch provided engineering support to model targeted IVVO feeders, propose field device settings, and provide a high-level constructability analysis. The intent was to reduce voltage drop along the feeders and optimize power factor at the substation.

Xcel Energy is using an Integrated Volt Var Optimization (IVVO) program which deploys advanced technology to support the goals of enhancing reliability, improving outage management, and reducing energy consumption in the Denver Metro area of Xcel's Public Service Company of Colorado's ("PSCo") service region.

This program targets 450 Denver Metro area feeders and includes the following:

- Deploy new advanced field devices
- Enable existing field devices on Xcel's Field Area Network
- Research and clean up impedance data
- Enablement of IVVO within Xcel's Advanced Distribution Management System (ADMS).

Black & Veatch planned the IVVO program which includes on an annual basis approximately:

- 30 upgraded substation load tap changer ("LTC") controls
- 250 medium voltage capacitor banks – 1200 kVAr or 600 kVAr

- 1100 low voltage static VAr compensators ("LV SVCs") – 10 kVAr
- 1100 bellwether voltage sensors – proposed to be AMI meters

The engagement included the following:

1. Modeled Feeders

Use GIS data to create different seasonal models and loading conditions including solar generation. Black and Veatch used existing tools to ensure models represented feeder performance absent of any voltage support devices and to derive the feeder's "natural" power factor and voltage profile.

2. Perform IVVO Analysis

Black and Veatch was responsible for performing IVVO analysis for application of medium voltage capacitors. Black and Veatch modeled the system in the four seasonal scenarios to understand the impact of solutions over time and to generate an expected level of savings. A high-level constructability analysis was performed for each solution.

Black and Veatch analyzed the worst performing feeders and low voltage areas and proposed solutions to flattening feeder voltage profiles, optimizing feeder power factors, and creating voltage parity between feeders on a substation transformer. Solutions included: Load transfers to adjacent feeders, load transfers from one phase to another, replacement or addition of distribution transformers, installation of additional medium voltage capacitor banks, installation of LV SVC units.

3. Equipment Settings

Field devices required local settings in the event ADMS control or communications fail. Black and Veatch derived local and seasonal settings that allowed for multiple device coordination for projects such as Fault Location Isolation and Service Restoration. Medium Voltage Capacitor Bank settings included Voltage and VAr Based controls.

4. Reporting

After analysis was completed, BV reports on a substation transformer basis describing the expected yearly energy savings and average voltage margin improvement.

The following provides a high-level summary of some of our recent projects which are relevant to the requirements of Grid Modernization:

Black & Veatch	Project Role								Control Center Projects (SCADA Master /EMS / DMS)				Distribution Substation Projects						Grid Upgrade Projects Outside the Substation						
	SERVICES								TECHNOLOGY																
Representative Distribution Project Expertise and Experience	Program and Project Management	Solution Evaluation and Engineering	Cyber Security Assessment/Mitigation	Wide Area Network (WAN) Solution	Design Engineering	Procurement / Logistics	Construction/Installation	Testing and Integration	Hardware and Application Architecture	Operational System Planning/Implementation	Enterprise System Integration	Configuration for Grid Upgrades	Substation Integration / Automation	Substation SCADA	Substation Protection	Transformer Monitoring	LTC / Regulator SCADA	Local Area Network (LAN)	SCADA Controllable Line Switches	SCADA Controllable Reclosers	Line Sensor / Detectors	Network Transformer Monitoring	Network Protection Upgrades	Distributed Energy Resources	Field Area Network (FAN)
American Electric Power - Smart Circuit VVO	x	x		x				x					x	x			x	x						x	x
American Electric Power - Disturbance Monitoring					x	x							x	x	x			x							
American Electric Power - Revenue Metering					x	x							x	x	x			x							
American Electric Power - RTU Rehabilitation					x									x						x					
Azusa Light & Waterk - Kirkwall Substation		x			x	x							x	x		x	x								
BC Hydro - DMS Integration		x			x	x			x	x	x														
FirstEnergy - AMI Network Conceptual Design				x																					x
FirstEnergy - RTU Retrofit	x	x			x	x	x	x					x	x											
FirstEnergy Distribution SCADA				x	x	x	x	x						x		x	x	x							
FirstEnergy SCADA Line Switches					x	x		x											x						x
Hydro One - Advanced Distribution System		x				x			x	x	x														
Hydro One - Transport Network				x																					
Kansas City Power & Light - Rural Power Quality					x			x					x	x											
Keys Energy, Key West, FL Telecom Consulting		x		x						x								x						x	x
Madison Gas and Electric - Data System				x														x							
National Grid - RTU Rehabilitation					x	x								x											
Oncor Energy Delivery		x				x			x	x	x														
Pacific Gas & Electric - Substation SCADA Upgrades EPC	x				x	x	x	x					x	x	x		x	x							
Pacific Gas & Electric - Substation SCADA Upgrades Engr					x	x							x	x	x			x							
Portland General Electric					x	x	x	x					x	x	x		x	x							
Public Service Electric & Gas - Grid Modernization	x	x	x		x	x	x	x				x	x	x	x	x		x		x					x
Public Service Electric & Gas - Network Monitoring	x		x		x			x				x		x				x			x	x	x		x
Public Utility District No 1, Chelan Co., WA		x			x	x							x	x			x								
Public Utility District No 2, Grant Co., WA	x	x			x	x	x	x					x	x	x									x	
Public Works Commission, Fayetteville, NC - 900 MHZ Radio				x																					
United Illuminating - SCADA Master Replacement		x	x		x	x			x	x															
United Illuminating - Singer & Trumbull Substation	x	x	x		x	x	x	x					x	x	x	x	x	x							
United Illuminating - Network Protector				x														x							
USAID - Afghanistan SCADA Master & Substation RTU		x			x	x			x	x				x	x			x							

1

CCC-25

Reference: Application, p. 53

Preamble: N/A

Question: Please provide a complete list of the relative roles for both Black & Veatch and PUC Distribution regarding the proposed SSG Project.

Response:

Please see Appendix AA3-4 Responsibility Matrix to the Amended Application.

CCC-26

Reference: Re: Application, p. 56

Preamble: N/A

Question: Please confirm that PUC Distribution is seeking to recover an annual incremental amount of $514,438 in revenue from its residential consumers resulting from the implementation of the SSG Project.

Response:

Based on the half year rule, PUC Distribution is requesting to recover an annual incremental increment of $514,438 in revenue from its residential customers.

CCC-27

Reference: N/A

Preamble: N/A

Question: What is the current projected in-service date for the project? What factors or risks could potentially impact, or delay the in-service date? Please provide a complete list of those factors or risks and explain how PUC Distribution intends to mitigate them.

Response:

Project schedule covers about 20-21 months with start date depending on timing for rate approval. The substantial completion in-service date target is December 31, 2022 based on March 2021 approval.

Factors that could delay the in-service date of the SSG project include:

- Approval timing
- Equipment/material constraints
- Weather
- Unforeseen system operating constraints

The Step 1 engineering phase will be a key focus to complete and establish procurement requirements. Parallel path implementation and coordination is expected for a number of areas. The project implementation plan includes comprehensive project management oversight and an EPC contract with liquidated damages clauses for performance and delay.

Environmental Defence

ED-1

Reference: p. 20

Preamble: N/A

Question:

(a) The SSG project will result in energy savings and reduced losses. How much GHG emissions (t CO2e) will be avoided over (i) 10 years, (ii) 20 years, and (iii) 40 years. Please make and state assumptions as necessary. Please assume the average carbon content of electricity forecasted by the IESO in its latest annual planning outlook.

(b) The benefits summary estimates savings from avoided distribution system losses. In valuing these savings, did the utility account for the fact that losses are greatest at the time of system peak, and therefore at the time when electricity is the most expensive? If not, please provide a revised estimate that accounts for this, with any caveats as necessary.

(c) Please recreate table 1 on the assumption that electricity demand is 50% higher (e.g. due to the future electrification of fossil fuels used in transportation and space heating).

(d) Please provide a table showing total distribution system losses for the most recent 5 years available, including the 5-year average, in kWh, % of consumption, and % of peak demand. Please provide the forecast total distribution system losses following the implementation of the project as a 5-year average, in kWh, % of consumption, and % of peak demand.

Response:

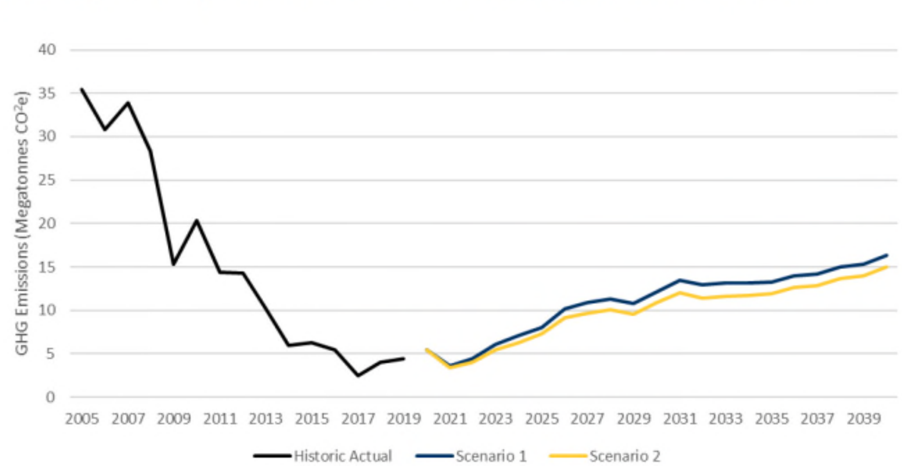
(a) The IESO Annual Planning Report (Dec 2020) was used for base data on historical and forecast energy and GHG emissions. The IESO report did note that they expected GHG emissions to be rising over time as noted in graph below from that report.

The referenced average carbon content of electricity above was not found directly in the IESO report so the following approach was developed.

From the Annual Planning Outlook excel data tables, using the Scenario 2 GHG output forecast (Megatonnes CO2e) in Figure 37 from 2022-2040 and divide that by the

Scenario 1 total annual energy demand (TWh) in Figure 2 from 2022-2040 – an annual carbon intensity (Megatonnes CO2e per TWh) for the Ontario electricity grid can be calculated – and then use that intensity value (an Annual Emission Factor or AEF) to calculate the multi-year savings. Note: Scenario 2 has a lower GHG value than Scenario 1.

Figure 37 | Electricity Sector Greenhouse Gas Emissions, Historical and Forecast[36]



The GHG calculation using the AEF (annual GHG over Annual system energy) provides the results shown below.

GHG Savings 10 years (2023-2032) 10,361 TCO_2e with AEF

GHG Savings 20 years (2023-2042) 24,010 TCO_2e with AEF
(assumed 2 additional years to IESO forecast at same level as 2040)

Further to the above question an average calculation of emissions is likely understating the GHG savings potential of energy efficiency savings. The next section provides a view of savings potential from a marginal generation perspective as the last generation dispatched is often a higher GHG source.

A report (*https://taf.ca/wp-content/uploads/2019/06/A-Clearer-View-on-Ontarios-Emissions-June-2019.pdf*) published by The Atmospheric Fund (TAF) in 2019 developed energy savings emission factors from IESO published data and their own methodology suggested use of a Marginal Emissions Factor (MEF) to quantify GHG savings from energy efficiency savings. As PUC has not completed any analysis on the time of day energy savings the referenced report was used to develop an MEF factor as a ratio to the Annual Emissions Factors from this report to apply against the IESO data.

Historical and forecast data for energy and GHG was utilized from the IESO report to calculate an AEF by year was then used to calculate an MEF (this was calculated using a ratio of AEF and MEF from the TAF Report - 2018 Annual MEF of 134 divided by the Annual MEF of 31). This ratio was applied to the IESO AEF data above to forecast emissions for the 10 and 20 years with calculated results shown below.

GHG Savings (10 years) 44,784 TCO_2e with MEF

GHG Savings (20 years) 103,786 TCO_2e with MEF

(b) No. PUC Distribution does not have the data necessary to calculate the savings at peak times. This is something that PUC Distribution would be willing to attempt to measure and monitor should the SSG Project be approved.

(c) Table 1 has been recreated with the assumption that electricity demand is 50% higher resulting in an updated Cost of Power of $123,769,027. This has translated into an increased net benefit to customers of $1,734,460 which can be reviewed in the table below. Please note that this table also show a decease in additional revenue from SSG asset base from $1,754,862 to $1,751,221. This is a result of an update to CWIP rates.

Customer Net Benefit Summary			
	Original	**END 1c**	
Cost of Power - updated to current estimate	$ 82,512,685	$ 123,769,027	*App [AA15] -Cost of Power Spreadsheet*
Projected energy savings with SSG implementation	2.70%	2.70%	*App [AA14] -Energy Savings Spreadsheet*
Projected customer energy savings through SSG	$ 2,227,842	$ 3,341,764	*App [AA14] -Energy Savings Spreadsheet*
Projected system loss energy savings through SSG	$ 105,111	$ 105,111	*App [AA14] -Energy Savings Spreadsheet*
Total purchased power savings	$ 2,332,953	$ 3,446,875	
Additional revenue from increased SSG asset base	$ 1,751,221	$ 1,751,221	*Full Year Revenue Requirement*
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	*APP [AA17] CAPEX Deferral Spreadsheet*
Additional O & M expenses due to SSG implementation	$ 296,400	$ 296,400	*App [AA13] -Project Benefit Estimate Memo*
Operating efficiency benefits due to SSG implementation	($30,816)	($30,816)	*App [AA13] -Project Benefit Estimate Memo*
	$ 1,712,415	$ 1,712,415	
Annual net benefit to customers	$ 620,538	$ 1,734,460	
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	*IRR App#7 -Navigant Report #3 (NPV)*
Total projected benefit to customers	$ 2,637,538	$ 3,751,460	

With improved distribution system operation monitoring and control and associated data availability for system planning and asset operations to support asset management and renewal, further efficiencies are expected to be attainable. Long term CAPEX savings benefits have been identifed in smart grid project as an equivalent savings from PV projections for PUC but have not been incorporated in to the Distribution System Plan at this time.

(d) PUC Distribution has provided the requested table in a similar format to that of Chapter 2 Appendices 2-R Loss Factors. The first represents the 5 historical years with the second providing the forecasted 5 year average. To determine the forecast the 2018 Weather Normalized load forecast was used as approved in PUC's last Cost of Service Application. The total purchases were adjusted for the 2.70% reduction in consumption. This reduction was not applied to the seven GS>50 customer who would not receive the VVO savings since they receive their power from the 34.5kV line. In Appendix AA-14_VVM Energy Savings Est for ICM (previously submitted), it outlines the system energy loss savings estimate to be 2.60%. This would reduce PUC Distribution's current loss factor for all customer, except the GS>50 on 34.5kv line, from 1.0481 to 1.0468. This loss factor has been combined with that of the 1.0481 to arrive at a new distribution system loss factor of 1.0469. Embedded Generation was not calculated in the forecast but is included in the forecasted total purchases. A forecast of peak demand as a percentage of distribution losses was not determined.

5 Historical Years

		Historical Years					5-Year Average
		2015	2016	2017	2018	2019	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	622,601,312	601,961,594	578,895,847	583,974,298	589,155,257	595,317,662
	Embedded Generation Delivered	75,916,065	67,996,867	74,074,624	82,762,000	71,267,915	
A(2)	"Wholesale" kWh delivered to distributor (lower value)	698,517,377	669,958,461	652,970,471	666,736,298	660,423,172	669,721,156
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	698,517,377	669,958,461	652,970,471	666,736,298	660,423,172	669,721,156
D	"Retail" kWh delivered by distributor	669,387,526	637,462,404	622,542,513	633,697,927	631,945,814	639,007,237
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	669,387,526	637,462,404	622,542,513	633,697,927	631,945,814	639,007,237
	DISTRIBUTION LOSSES	29,129,851	32,496,057	30,427,958	33,038,371	28,477,358	30,713,919
G	Loss Factor in Distributor's system = **C / F**	1.0435	1.0510	1.0489	1.0521	1.0451	1.0481
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.000	1.000	1.000	1.000	1.000	1.0000
	Total Losses						
I	Total Loss Factor = **G x H**	1.0435	1.0510	1.0489	1.0521	1.0451	1.0481
Peak Demand		138382	125408	125843	128698	132939	
Losses as % of Peak Demand		21050%	25912%	24179%	25671%	21421%	

Forecasted 5 Year Average

		Projected Years					5-Year Average
		2022	2023	2024	2025	2026	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	647,896,376	647,896,376	647,896,376	647,896,376	647,896,376	647,896,376
	Embedded Generation Delivered						
A(2)	"Wholesale" kWh delivered to distributor (lower value)	647,896,376	647,896,376	647,896,376	647,896,376	647,896,376	647,896,376
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	647,896,376	647,896,376	647,896,376	647,896,376	647,896,376	647,896,376
D	"Retail" kWh delivered by distributor	618,853,645	618,853,645	618,853,645	618,853,645	618,853,645	618,853,645
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	618,853,645	618,853,645	618,853,645	618,853,645	618,853,645	618,853,645
	DISTRIBUTION LOSSES	29,042,732	29,042,732	29,042,732	29,042,732	29,042,732	29,042,732
G	Loss Factor in Distributor's system = **C / F**	1.0469	1.0469	1.0469	1.0469	1.0469	1.0469
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.000	1.000	1.000	1.000	1.000	1.0000
	Total Losses						
I	Total Loss Factor = **G x H**	1.0469	1.0469	1.0469	1.0469	1.0469	1.0469

ED-2

Reference: p. 25

Preamble:

"In addition to PUC Distribution customer savings, provincial benefits will be achieved through reduced transmission grid and generation costs as less energy will be delivered to the PUC Distribution system."

Question:

(a) Please quantify value of this to the system as best as possible, and include calculations. The avoided cost tables in the annual planning outlook may be of assistance.
https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

Response:

Provincial benefits achieved from reduced transmission and generation costs from the reduced energy delivered to the PUC Distribution system are calculated using the IESO Annual Planning report and Table 37: Weighted Average Marginal Costs (Scenario 2 -lower value). A 20 year NPV avoided cost savings of $6,164,335 for 2023-2042 (assumed 5% discount rate and values for 2041, 2042 at the 2040 HOEP value).

Figure 37: Weighted Average Marginal Costs Forecast, and Historical HOEP ($2020/MWh)

Scenario		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Historic HOEP																					
Scenario 1		$20.79	$22.16	$23.82	$27.51	$28.36	$29.62	$29.94	$32.27	$34.34	$33.46	$33.91	$33.03	$33.06	$34.21	$35.12	$36.44	$37.24	$38.42		
Scenario 2		$19.40	$20.32	$22.45	$25.42	$26.20	$27.47	$26.99	$29.92	$31.24	$31.03	$30.48	$30.38	$30.91	$31.54	$33.03	$33.99	$34.01	$36.11		
*Note: 2020 Actual HOEP is year-to-date as of November 26, 2020																					
Avoided Cost per Yr		$338,660	$354,720	$391,903	$443,750	$457,366	$479,536	$471,157	$522,305	$545,348	$541,682	$532,081	$530,335	$539,587	$550,585	$576,595	$593,354	$593,703	$630,362	$630,362	$630,362
17,456,712	SSG kWh savings																				
$10,353,750	20 year Avoided Cost Savings																				
5%	Discount rate (societal discount rate used by Navigant in reporting)																				
$6,164,335	NPV of 20 yr avoided cost savings																				

ED-3

Reference: p. 26

Preamble: N/A

Question:

(a) Please compare the technology and approach for VVO/VVM with the pilot project that is wrapping up at Hydro Ottawa. For further details, see its recent rates case and the settlement reached therein.

Response:

We have reviewed JT 3.10 of Hydro Ottawa Limited's rate case EB-2019-0261, which is a pilot project involving Grid Edge Volt/VAr Control ("VVC") solution in Kanata North area.

PUC Distribution is unable to tell who the underlying technology vendors are to provide detailed comparison between the projects. However, from reviewing JT 3.10, Hydro One's pilot project appears to be the same idea as the SSG Project, where the outcome will be to deliver energy savings and improve power quality.

ED-4

Reference: Appendix AA13 - Project Benefits Memo, p. 6

Preamble: N/A

Question:

(a) Is the utility currently able to capitalize on the storage capacity of electric vehicles to reduce distribution system costs by: (i) communicating directly with charging stations to reduce load during peak periods, (ii) communicating directly with charging stations to allow power to be drawn from batteries during peak periods, (iii) drawing energy from car batteries connected to charging stations during peak periods, and (iv) communicating directly with charging stations to ensure energy is drawn from the LDC's system at the optimal times?

(b) Will the proposed project allow the utility to undertake the functions described in (a)? If yes, when? What financial benefit would this achieve if 50% of all residential customers had EVs capable of those functions?

(c) Will the project make it easier to carry out distributed energy resource connections? Please explain.

(d) Will the project make it easier to create a capacity map or capacity tool to allow customers to look up their feeder to determine, at least on a preliminary basis, whether there is capacity to connect a distributed energy resource?

(e) Please describe the degree to which certain benefits from the proposed project arise due to the utility-wide scale of the project?

(f) How many jobs will the project create?

(g) How much government revenue will be generated?

(h) How much economic growth will be generated?

Response:

(a) PUC Distribution is currently unable to capitalize on DG such as electric vehicles in any of the ways described in the question as we do not have the necessary software, processes, control systems, AMI integration or communications infrastructure in place.

(b) The proposed project would better position PUC Distribution to undertake the functions described in (a) in that it would provide some of the necessary AMI integration and communications infrastructure. Although we have not undertaken a detailed study to quantify the benefit if 50% of all residential customers had EV and contributed without a detailed study, from a simple quick calculation we would expect some benefit in that there would be the potential to reduce provincial peak events by an amount in the order of 112.5MWh. This assumes approximately 50% of residential customers (approximately 15,000) contribute 10% of a fully charged EV battery (the Tesla Model S 75D has a 75kWh battery) back to the grid during a single peak occurrence. PUC Distribution's peak load for 2019 was 133MW on so in the scenario contemplated, the EVs could be used to offset 85% of such a peak for a duration of one hour.

(c) The project will make it easier to carry out DER connections in that the project will provide:

- A live distribution system model to facilitate quick and cost-effective impact assessments to be completed whereas currently consulting services are required
- A real-time live SCADA system model that will allow for monitoring, dispatching and managing DERs
- A communications infrastructure backbone that would allow cost-effective integration of DER telemetry

(d) The SCADA and distribution system modelling software both are capable tools to form a strong foundation for either a customer self-serve or utility engineer managed capacity determination tool. Currently PUC Distribution's engineering relies on support a consultant to complete such determinations.

(e) Implementation of the SSG project across the full distribution system provides some synergistic benefits and cost savings in construction and commissioning but also and importantly to PUC Distribution, broader equitable opportunity and benefit to PUC customers.

In addition to contract cost savings in reduced mobilization/ demobilization for the project, the design and implementation of an integrated communication solution needed to support field device monitoring and control across both the voltage optimization and distribution automation systems as well as integration to existing AMI will allow an optimized solution for construction and long term operation. Upgrade to the SCADA/ and advanced distribution management platform will also integrate with these systems and a new Outage Management System, allowing similar implementation and operational cost savings.

(f) The project is anticipated to generate up to 3 new permanent jobs and 60 during implementation/ construction. Indirect jobs also related to construction have been estimated as equivalent to ~100 FTE's.

(g) Table below provides an approximation of how much government revenue will be created over 20 years.

	Government Revenue
Income Tax	$1,614,849
PILS	$2,319,935
HST on Equipment	$3,227,726
Total	$7,162,510

(h) PUC Distribution expects that the SSG Project will assist in economic growth. The SSG Project will improve the economic attractiveness of the community as a place to live and establish new business. The grid benefits will be attractive to industries requiring higher reliability and high quality power, such as electronics manufacturing, e-commerce, telecommunication services, data centres, multi-modal shipping, and distribution hubs.

In addition, as stated in response to part (f) above, the SSG project is anticipated to generate new jobs.

School Energy Coalition (SEC) Interrogatories

SEC-1

Reference: General

Preamble: N/A

Question:

SEC is interested in better understanding the rate impacts of the proposed SSG project. For a typical school in the GS>50 kW class with 100kW of monthly demand, please confirm:

a. The annual total of monthly fixed charges and volumetric charges at proposed 2021 rates, excluding the ICM riders, is $9,861.00 ($119.45 monthly fixed charge plus $7.023/kW demand charge).

b. At that level, for a customer with those characteristics, only four other distributors would have higher rates in 2021.

c. The Applicant is proposing to increase the charges for that customer for the SSG project by $432.72 in 2022 ($5.24 monthly fixed plus $0.3082/kW demand), a 4.39% incremental increase. This is in addition to any IRM increase for 2022.

d. When the Applicant rebases, and in addition to any other cost of service increases, it expects to increase the charges for that customer for the SSG project, when the half year rule is removed and the incremental OM&A is added, by a further amount of approximately $606.00 in 2020 ($8.00 monthly fixed plus $0.425/kW demand, bringing the total two year increase – not including the normal IRM increase – to 10.53%. If these estimates are not correct, please provide your best estimates of the incremental impact on distribution rates of the Smart Grid project at the time of rebasing.

Response:

a. The annual total of fixed monthly charges and volumetric charges at proposed 2021 rates is $9,861.

b. PUC Distribution does not agree that its GS>50 rate class is the 5th highest in 2021. PUC Distribution's distribution rates include recoveries for high voltage transformation stations and lines. As a result, customers do not pay the provincial transmission connection charge. In 2019, when factoring in transmission connection charge, PUC Distribution ranked 10th in distribution charges among 48 LDC's. PUC Distribution has provided its findings in the table below.

2019 Distribution Rates GS>50

Utility	Fixed Charge	volumetric Charge	Transaction Connection	Yearly Total (100kW)	Rank
Alectra Utilities Corporation-Horizon Utilities Rate Zone	389.40	2.6150	2.3873	$ 10,676	4
Alectra Utilities Corporation-PowerStream Rate Zone	143.95	4.2924	1.3338	$ 8,479	20
Atikokan Hydro Inc.	574.73	3.8202	1.6541	$ 13,466	3
Brantford Power Inc.	236.93	2.8643	1.8282	$ 8,474	21
Burlington Hydro Inc.	62.29	3.0664		$ 4,427	48
Canadian Niagara Power Inc.	164.23	7.2135	2.4011	$ 13,508	2
Chapleau Public Utilities Corporation	193.66	5.0231	0.6595	$ 9,143	15
Cooperative Hydro Embrun Inc.	186.77	3.9694	2.0297	$ 9,440	13
E.L.K. Energy Inc.	192.36	1.6274	1.8887	$ 6,528	42
Entegrus Powerlines Inc.-For Entegrus-Main Rate Zone	101.36	3.3573	2.1487	$ 7,824	29
Entegrus Powerlines Inc.-For Former St. Thomas Energy Rate Zone	76.48	3.6613	2.4560	$ 8,259	24
ENWIN Utilities Ltd.	107.93	4.9839	1.8611	$ 9,509	11
EPCOR Electricity Distribution Ontario Inc.	102.79	3.3617	1.3160	$ 6,847	40
Espanola Regional Hydro Distribution Corporation	196.43	3.7949	1.3939	$ 8,584	18
Essex Powerlines Corporation	235.83	2.2805	1.6690	$ 7,569	35
Festival Hydro Inc.	238.91	2.5792	1.7103	$ 8,014	28
Fort Frances Power Corporation	182.97	2.7604	0.7260	$ 6,379	44
Greater Sudbury Hydro Inc.	171.02	4.4434	2.5096	$ 10,396	5
Grimsby Power Incorporated	210.50	3.0783	1.3142	$ 7,797	30
Hydro 2000 Inc.	84.54	1.4631	1.9876	$ 5,155	46
Hydro Hawkesbury Inc.	102.50	2.1338	1.3674	$ 5,431	45
Hydro One Networks Inc.-Former Haldimand County Hydro Inc. Service Area	83.61	3.9339	2.2749	$ 8,454	22
Hydro One Networks Inc.-Former Norfolk Power Distribution Inc. Service Area	245.55	3.9602	1.3040	$ 9,264	14
InnPower Corporation	214.93	4.3555	2.0940	$ 10,319	6
Kingston Hydro Corporation	110.99	3.3261	2.4116	$ 8,217	25
Kitchener-Wilmot Hydro Inc.	183.23	4.7638	0.8449	$ 8,929	16
Lakeland Power Distribution Ltd.	233.31	2.6710	1.7804	$ 8,141	26
Lakeland Power Distribution Ltd.-Parry Sound Service Area	233.31	2.6710	1.7804	$ 8,141	26
London Hydro Inc.	161.11	2.7818	2.0113	$ 7,685	33
Newmarket-Tay Power Distribution Ltd.-For Former Midland Power Utility Rate Zone	65.09	3.3170	1.8945	$ 7,035	38
Niagara Peninsula Energy Inc.	107.30	3.5075	1.8384	$ 7,703	32
Niagara-on-the-Lake Hydro Inc.	281.65	2.3574	0.5327	$ 6,848	39
Northern Ontario Wires Inc.	196.81	1.1344	1.1491	$ 5,102	47
Orangeville Hydro Limited	171.43	2.3017	1.3337	$ 6,420	43
Orillia Power Distribution Corporation	340.60	3.5825	1.47	$ 10,150	8
Ottawa River Power Corporation	85.96	3.5601	1.5721	$ 7,190	37
Peterborough Distribution Incorporated	160.31	2.7323	1.9217	$ 7,509	36
PUC Distribution Inc.	115.66	6.8002		$ 9,548	10
Renfrew Hydro Inc.	202.22	3.0595	1.2448	$ 7,592	34
Rideau St. Lawrence Distribution Inc.	296.99	2.2867	1.8828	$ 8,567	19
Sioux Lookout Hydro Inc.	377.21	1.3165	0.5659	$ 6,785	41
Synergy North Corporation-Kenora Rate Zone	550.88	1.7553	0.64	$ 9,485	12
Tillsonburg Hydro Inc.	2,037.49	1.9251		$ 26,760	1
Wasaga Distribution Inc.	35.35	5.3335	1.2925	$ 8,375	23
Waterloo North Hydro Inc.	123.85	5.2545	0.8842	$ 8,853	17
Welland Hydro-Electric System Corp.	288.21	3.1078	2.1708	$ 9,793	9
Westario Power Inc.	234.80	2.4780	1.6249	$ 7,741	31
Whitby Hydro Electric Corporation	202.15	4.0374	2.4356	$ 10,193	7

c. The ICM rate rider increase is $432.72 annually assuming no consumption savings and $422.73 annually with consumption savings. This represents a total bill impact of negative $196.96 or negative 2.21%. This is also using a consumption of 57,220 as presented in the table below.

GS>50kW Bill Impacts

Customer Class:	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION				
RPP / Non-RPP:	Non-RPP (Other)				
Consumption	57,220	kwh	Consumption Decrease %	2.70%	Proposed consumption 97
Demand	100	kw			Proposed consumption 55,675
Current Loss Factor	1.0481		IPI Adjustment	0.00%	
Proposed/Approved Loss Factor	1.0481				

	PUC 2020 IRM Model - Pending Decision			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 119.45	1	$ 119.45	$ 119.45	1	$ 119.45	$ -	0.00%
Distribution Volumetric Rate	$ 7.0230	100	$ 702.30	$ 7.0230	97	$ 683.34	$ (18.96)	-2.70%
RRRP Credit	$ -	100	$ -		97	$ -	$ -	
DRP Adjustment	$ -	100	$ -		97	$ -	$ -	
Fixed Rate Riders	$ 1.41	1	$ 1.41	$ 1.41	1	$ 1.41	$ -	0.00%
ICM Fixed	$ -	1	$ -	$ 5.24	1	$ 5.24	$ 5.24	
ICM Variable	$ -	100	$ -	$ 0.31	97	$ 29.99	$ 29.99	
Volumetric Rate Riders	$ 0.0832	100	$ 8.32	$ 0.0832	97	$ 8.10	$ (0.22)	-2.70%
Sub-Total A (excluding pass through)			**$ 831.48**			**$ 847.52**	**$ 16.04**	**1.93%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	100	$ -	$ -	97	$ -	$ -	
CBR Class B Rate Riders	$ -	100	$ -	$ -	97	$ -	$ -	
GA Rate Riders		57,220	$ -	$ -	55,675	$ -	$ -	
Low Voltage Service Charge	$ -	100	$ -		97	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	57,220	$ (22.89)	-$ 0.0004	55,675	$ (22.27)	$ 0.62	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 808.59**			**$ 825.25**	**$ 16.66**	**2.06%**
RTSR - Network	$ 2.3582	100	$ 235.82	$ 2.3582	97	$ 229.45	$ (6.37)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	100	$ -	$ -	97	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,044.41**			**$ 1,054.70**	**$ 10.29**	**0.99%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	59,972	$ 203.91	$ 0.0034	58,353	$ 198.40	$ (5.51)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	59,972	$ 29.99	$ 0.0005	58,353	$ 29.18	$ (0.81)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -			$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1101	59,972	$ 6,602.95	$ 0.1101	58,353	$ 6,424.67	$ (178.28)	-2.70%
Total Bill on TOU (before Taxes)			**$ 7,881.50**			**$ 7,707.20**	**$ (174.30)**	**-2.21%**
HST	13%		$ 1,024.60	13%		$ 1,001.94	$ (22.66)	-2.21%
Total Bill on TOU			**$ 8,906.10**			**$ 8,709.14**	**$ (196.96)**	**-2.21%**

d. If this ICM project was not using the half year rule, the fixed ICM rate rider would be $10.48 and the variable rate rider $0.6164/kW. The incremental OM&A expenses would be $296,400 and operating efficiencies savings $30,816. This results in a net increase to OM&A of $265,584. The increase in OM&A of $265,584 plus the full year revenue requirement of $1,751,221 (at updated CWIP rates), would increase the overall revenue requirement to $2,016,805. Using the same methodology in the allocation of this revenue requirement would result in the following bill impacts to the GS>50 customer with a consumption of 57,220kWh and demand of 100kW.

Customer Class:	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION			
RPP / Non-RPP:	Non-RPP (Other)			
Consumption	57,220	kwh	Consumption Decrease %	2.70%
Demand	100	kw		
Current Loss Factor	1.0481		IPI Adjustment	0.00%
Proposed/Approved Loss Factor	1.0481			

Proposed consumption	97
Proposed consumption	55,675

	PUC 2020 IRM Model - Pending Decision			Proposed - ICM			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 119.45	1	$ 119.45	$ 121.04	1	$ 121.04	$ 1.59	1.33%
Distribution Volumetric Rate	$ 7.0230	100	$ 702.30	$ 7.1165	97	$ 692.44	$ (9.86)	-1.40%
RRRP Credit	$ -	100	$ -		97	$ -	$ -	
DRP Adjustment	$ -	100	$ -		97	$ -	$ -	
Fixed Rate Riders	$ 1.41	1	$ 1.41	$ 1.41	1	$ 1.41	$ -	0.00%
ICM Fixed	$ -	1	$ -	$ 10.51	1	$ 10.51	$ 10.51	
ICM Variable	$ -	100	$ 8.32	$ 0.62	97	$ 60.10	$ 60.10	
Volumetric Rate Riders	$ 0.0832	100	$ 8.32	$ 0.0832	97	$ 8.10	$ (0.22)	-2.70%
Sub-Total A (excluding pass through)			**$ 831.48**			**$ 893.59**	**$ 62.11**	**7.47%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	100	$ -	$ -	97	$ -	$ -	
CBR Class B Rate Riders	$ -	100	$ -	$ -	97	$ -	$ -	
GA Rate Riders		57,220	$ -	$ -	55,675	$ -	$ -	
Low Voltage Service Charge	$ -	100	$ -		97	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	-$ 0.0004	57,220	$ (22.89)	-$ 0.0004	55,675	$ (22.27)	$ 0.62	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 808.59**			**$ 871.32**	**$ 62.73**	**7.76%**
RTSR - Network	$ 2.3582	100	$ 235.82	$ 2.3582	97	$ 229.45	$ (6.37)	-2.70%
RTSR - Connection and/or Line and Transformation Connection	$ -	100	$ -	$ -	97	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,044.41**			**$ 1,100.78**	**$ 56.36**	**5.40%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	59,972	$ 203.91	$ 0.0034	58,353	$ 198.40	$ (5.51)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	59,972	$ 29.99	$ 0.0005	58,353	$ 29.18	$ (0.81)	-2.70%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -			$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1101	59,972	$ 6,602.95	$ 0.1101	58,353	$ 6,424.67	$ (178.28)	-2.70%
Total Bill on TOU (before Taxes)			**$ 7,881.50**			**$ 7,753.27**	**$ (128.23)**	**-1.63%**
HST	13%		$ 1,024.60	13%		$ 1,007.93	$ (16.67)	-1.63%
Total Bill on TOU			**$ 8,906.10**			**$ 8,761.20**	**$ (144.90)**	**-1.63%**

This table shows that the overall total bill impacts is still a net decrease of $145.08 or -1.63%. The increase of the OM&A expenses of $265,584 would need to be allocated to all rate classes. Thus, it would not increase the impacts of this customer alone substantially.

SEC-2

Reference: ICM Application, p. 12, 15, 60

Preamble: N/A

Question: The SSG project involves a significant change in the operation, performance, and configuration of the Applicant's distribution system, modernizing the grid, improving reliability, reducing system losses, and reducing effective energy usage. However, it comes at a net cost of $25 million (assuming all of the government funding is received), increasing the Applicant's net fixed assets by more than 25% in one shot, and increasing the Applicant's OM&A by about 2% at the same time. Please file a Distribution System Plan for the next five years showing how those additional expenditures fit into the overall plan for the design, operation, and management of the Applicant's distribution system. If the Applicant does not have such a DSP, please explain why, and please explain how the Board can consider this Application and carry out its statutory mandate absent the context of an applicable DSP.

Response:

Please see PUC Distribution's current DSP filed as attachment in response to CCC-13.

PUC Distribution disagrees with the suggestion that a new DSP is required at this time. The smart grid technologies used in the SSG Project are not novel technologies. The ongoing operating requirements for DA, VVO and AMI are well known and understood by the industry. PUC Distribution is due to file its next Distribution System Plan in 2023 (just one year after the SSG Project goes into service). The changes that arise as a result of the SSG Project will be reflected in that Distribution System Plan.

For clarity, our understanding is that the OEB does not "approve" a DSP. Rather, the OEB considers a DSP as evidence in connection with rate applications. In this case, the OEB has the benefit of the currently applicable DSP for PUC Distribution.

SEC-3

Reference: App. p. 12, 15

Preamble: N/A

Question: Please provide a description of all changes to the operational and organizational changes the Applicant expects to make as a result of the implementation of the SSG project, and provide an expected timeline for those changes.

Response:

PUC Distribution does not expect to have a full assessment of all changes to the operational and organizational structure until more detailed engineering work is completed for the project and a more fulsome assessment of the new equipment and systems being installed is completed. We do have confidence in some specific areas where changes will be required which are commented on below.

One of the most significant operational and organizational changes expected will occur in the system control operating function for the distribution system. Operational work planning and execution for lines and station work will be much more integrated in to the system control function for scheduling, P&C, and work protection with the DA and VVM systems in operation. An added day shift operator role is an anticipated need once the full system is in operation which may include data capture and analysis to improve efficiencies of existing monitoring and reporting functions such as outage management areas.

Engineering oversight for the integrated system operating systems as well as long term system planning function is expected. A longer term goal is to incorporate a live system model for use in improved access and assessments for distributed energy resource capacity and applications. A higher level overview of monitoring and control data will support both trouble shooting for events as well as scenario and contingency development. An engineering technical role is anticipated.

O&M programs will be reviewed and use of new data sources from the equipment and technology implemented with the SSG system. Although new equipment is being added to the distribution system with anticipated operating and maintenance requirements, new technology and processes will be utilized to complement existing programs and capture efficiencies. Long-term optimization and utilization of new technology as other aged equipment is renewed in the system is planned to continue to seek operating efficiencies.

SEC-4

Reference: App. p. 60

Preamble: N/A

Question: Please provide a detailed list of projects in the current DSP that will have to be modified in any way because of the SSG Project, and describe such modifications expected. Please provide a list of all assets that the Applicant expects to take out of service prior to the end of their useful life as a result of the SSG Project, and the forecast net book value of each at that time. Please provide details on the accounting treatment of those assets when they are taken out of service.

Response:

There are no projects in the current DSP that will be modified by the SSG project.

Assets that would be taken out of service as a result of the SSG Project primarily include:

- between approximately 80 and 100 wood distribution poles
- three pad-mount switchgear units and
- potentially up to 12 34.5kV/12kV 10MVA station transformers (at Substations 1, 2, 11, 18, 19, 20). Detailed design as part of the SSG project will be completed to determine if replacing a transformer with a new transformer with OLTCs or keeping the transformer in service and adding in-line voltage regulators downstream is the most viable option.

The vast majority of the wood distribution poles and all of the pad-mount switchgear and station transformers are at or beyond their useful service life and have no remaining material book value.

SEC-5

Reference: App. p. 16

Preamble: N/A

Question: Please provide the full agreement with IE under which the Applicant "acquired the rights to the studies and preliminary engineering works", including without limitation all attachments, appendices, and side letters or agreements.

Response:

Please find attached the full agreement with IE at Attachment 3.

SEC-6

Reference: App. p. 17

Preamble: N/A

Question: Please confirm that, if the cost to implement one part of the Smart Grid project exceeds the component of the fixed price originally planned for that part, the open-to-closed book process means that either a) savings must be achieved in another part of the project, b) the scope of another part of the project must be reduced, or c) the project will go over budget and the Applicant will seek to collect those cost overruns in rates. In the event that (a) or (c) are not possible or are rejected as options, please explain how the Applicant will deliver the full project benefits to the customers if the scope of any part of the project has been reduced.

Response:

Option (b) in the above question will be the likely option.

The EPC contract is styled as a “maximum price limit” project to ensure cost certainty for the main element of the project costs.

Step 1- Upfront Engineering is the engineering stage with a fixed price for project costs. To the extent that there are any cost overruns in Step 1, the EPC Contractor will be responsible for those costs.

Step 2-Balance of Work is the detailed engineering, procurement and construction stage with the project costs for this stage having a fixed price limit. The EPC structure includes provision for scope of work adjustments so that the fixed price for Step 1 and Step 2 inclusive will not exceed the maximum fixed price limit set for the EPC Contract. For Step 2 – Balance of Work, the open-to-close book process will be used to negotiate any adjustment in accordance with the EPC Contract maximum price.

In the case where a component of Step 2 exceeds the price originally planned, in order to ensure an overall “no net bill increase” project benefit target, the scope of the Distribution Automation (DA) in the SSG Project has been recognized by PUC Distribution as the area of project implementation that would be prioritized and reduced.

As discussed in Staff-51 and Appendix AA13 - Project Benefits Estimate Memo of the Amended Application, annual projected reliability benefit to customers are not included in the annual net benefit to customers.

If there is a reduction in scope of DA coverage, then it is reasonable to expect that there will be a decrease in reliability benefits. But it would not affect the annual net benefit to customers.

<u>SEC-7</u>

<u>Reference:</u> App. p. 18

<u>Preamble:</u> N/A

<u>Question:</u> Please provide a comparison table showing the percentage of renewable energy generation connected to each LDC in Ontario, in order to demonstrate that the percentage connection to the Applicant's system is "one of the largest".

<u>Response</u>:

PUC Distribution compared connected generation to its min and max total system load and expressed it as a percentage. The loading data used was from 2019 which is fairly representative of any year in the past 5-10 years. As can be seen, PUC Distribution is actually into a net export of power scenario at certain times of the year, often sunny days spring and fall as all the generation is solar and there is not yet the heavy winter heating load. This is to say there is more connected generation than annual minimum load.

PUC Total Connected Generation	63	MW	as of Dec 31, 2019
PUC 2019 Annual Peak Load	133	MW	January 28, 2019 at 19:00
PUC 2019 Annual Min Load	43	MW	September 1, 2019 at 04:00
Connected Generation to Peak Load Ratio	47%		
Connected Generation to Min Load Ratio	147%		

According to the IESO, Ontario demand peak is approximately 22,522MW[18] (this is the lowest of the peaks used, to be conservative). Total connected generation (distribution system) in Ontario is 3,163 MW[19], which is approximately 14% of the peak load for Ontario. In comparison, PUC Distribution's connected generation to peak load ratio is 47%. When PUC Distribution is operating near min load, it becomes a net exporter of renewable energy as there is more connected generation than annual minimum load.

[18] Independent Electricity System Operator, Ontario Demand Peak Tracker, online at: https://www.ieso.ca/peaktracker.

[19] Independent Electricity System Operator, Ontario's Energy Capacityhttps://www.ieso.ca/learn/ontario-supply-mix/ontario-energy-capacity

SEC-8

Reference: App. p. 19

Preamble: SEC is concerned that, while innovation is an important goal with potentially significant benefits for customers, it also implies significant risk. In this case, the Applicant makes clear that no-one else has proceeded with “the implementation of these distribution system improvements in a coordinated manner across the entire distribution system”.

Question: Please provide details of the due diligence the Applicant has undergone into the reasons why this kind of project has not been done before. Please include in those details a) the major sources used by the Applicant in that due diligence investigation, b) examples of distributors that have considered and rejected this kind of project, if any, c) the actual reasons why distributors have not implemented such a project, i.e. the barriers they have perceived, and d) the steps the Applicant is proposing to take to ensure that the risks associated with those barriers will not arise in this case.

Response:

In developing the SSG Project, PUC Distribution has performed a literature review on the technology and components of the SSG Project and has concluded that SSG Project will provide significant benefits for the customers. The risks associated with the SSG Project has also been taken into consideration through the reviewing of literature. The reports have been filed with this Amended Application at Appendix AA-8, AA9 and AA10.

PUC Distribution has performed its due diligence in developing the SSG Project by looking at business case scenarios and considered the various Navigant reviews (see Appendix AA8 to AA10 of the Amended Application).

With regards to distributors that have considered and rejected this kind of project and the reasons why they have not implemented the SSG Project, PUC Distribution is not in the position to speculate.

SEC-9

Reference: App. p. 20, and throughout

Preamble: N/A

Question:

With respect to the benefits of the project:

a. Please confirm that the Applicant is forecasting the following annual benefits to customers for the SSG Project:

i.	Customer Energy savings	-	$2,227,842
ii.	Reduced system losses	-	$ 105,111
iii.	Reduced annual capex	-	$ 304,390
iv.	Reduced annual opex	-	$ 30,816
v.	Reliability benefits	-	$2,017,000

b. For each of those benefits, please provide a detailed explanation of how the Applicant proposes to measure, test, report, and be held accountable for those benefits as they unfold. By way of example, if the VVM component is expected to deliver a 2.7% reduction in throughput due to voltage control, please show a) how the actual reduction in throughput resulting from the VVM will be isolated, tested and measured, b) how and when the Applicant will report to its customers and the Board on those results, and c) what consequences the Applicant is proposing – whether to the shareholders, the customers, or others - if the results fall short of projections.

c. For each of the proposed methods of measuring, testing and reporting, please estimate the annual cost of those activities, and describe how the Applicant proposes to recover those costs from customers.

d. Please confirm that the net annual benefits to customers of $2,633,897 are the forecast result of the five categories of savings set out above, less $1,754,862 of annual ICM charges to customers (of which only $875,610 is proposed to be implemented in this Application), and less $296,400 of annual OM&A increases to be implemented at the time of the next rebasing.

Response:

(a) PUC Distribution confirms the forecast of annual benefits listed above as per our ICM Application pg.20 Table 1.

(b) PUC Distribution recognizes DA (reliability) and VVM (energy savings) are of key interest to all stakeholders and during the Step 1 design phase of the project performance measures and KPI’s will be developed for these areas along with as many others as are practical and cost effective. In addition, PUC Distribution has reporting obligations on performance measures as part of our Contribution Agreement with NRCan. The NRCan technical performance report is required 6 months after project completion on areas in the table below.

Key Performance Indicators:	
1. GHG emissions reductions	Reduction in greenhouse gas emissions Reduced energy losses from GHG emitting supply (kWh)

2. Improved asset utilization and increased efficiency	Reduction in peak demand on utility assets
	Reduction in energy losses
	$ savings from deferred system upgrades
	$ energy savings to customers

3. Increased reliability and resiliency	# events Fault Location, Isolation and Restoration responded to # customer calls/complaints avoided due to fewer outages $ revenue loss avoided from outages avoided

The specific benefits described in the question above are further described below.

i. Energy Savings will be measured utilizing the IEEE guide - P1885™/D003 Draft Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems. The guide *"provides practical methods for assessing, evaluating and verifying the benefits and impact of electric power demand, energy consumption and loss reduction of volt-var control optimization on electric power distribution systems."*

ii. Reduced system losses is anticipated to be more of a long term trending value of savings than a direct measurable quantity. Assuming a starting point of ~5% system losses and the estimated system losses savings of 2.6%, the energy savings are about 0.13% on a feeder energy use and may not be practical to measure in any direct manner given the level of accuracy of available equipment and the inherent behaviour of customer energy use on feeder loading. These losses may be quantified as part of the work required for item (i).

iii. Given the reduced annual capex forecast value relies on a long term NPV calculation, so to the extent practical it may fit in to long term asset management and DSP planning when project decisions are executed and made over the long term capital cycle. Measurement and reporting methodology has not been developed at this time.

iv. Reduced annual opex forecast is not expected to be a directly measurable performance metric.

v. Reliability benefits can be calculated with some required assumptions but will be an accumulation by event process. In any planned or unplanned event a comparison to the "what would have happened without the DA" to the actual restoration data will be utilized. Annual benefits vs forecast will be more of a long term trending statistical calculation given the variability of outage occurrences over a number of years.

(c) PUC has not developed a specific cost estimate for the measurement and reporting processes which will be developed and which will become part of ongoing OM&A costs of the distribution system.

(d) During the review of the interrogatory questions, PUC Distribution noticed a small calculating error in the Full Year ICM Model. The Full year revenue requirement is $1,751,221 as compared to the previously submitted $1,754,862. This is a result of an update to the CWIP rates. Therefore the updated net annual benefit to customers is now $2,637,538.

SEC-10

Reference: App. p. 20, and throughout, also Appendix AA13

Preamble: N/A.

Question: Please provide a table allocating the dollars in the five categories of benefits to the various major parts of the SSG Project, i.e. VVM, DA, AMI integration, and ancillary components. In the case of AMI integration, please further break down those benefits between OMS, IVR, CSR Toolset, voltage reading module, and analytics platform. For each allocation, please identify any interdependencies with other parts of the project. Where the cost/benefit ratios of the different parts of the project are materially different, please explain why the Applicant is not proposing to proceed with the parts that are the most cost-effective, and not those that are less so.

Response:

The information mentioned in the responses to this question do not reflect the most up to date CWIP rates.

Allocation of the forecast savings in the five benefit categories summarized and described in the prior question against the major parts of the project and including a further breakdown to AMI subcomponent parts will entail a few assumptions given the interdependency of those components. In addition, some of the subcomponents are intended to address more subjective customer focus outcomes and may not be compatible with a financial cost/benefit cost-effective ranking.

PUC's utility-wide integrated project solution was part of our strategy in applying for funding through the federal Smart Grid Program and ultimately receiving a 25% capital contribution agreement for the project. The primary focus for purposes of evaluating the project was to consider the overall benefits to our customers achievable including the significant benefits with the NRCan contribution agreement savings vs. the revenue requirement from an integrated project solution as a superior cost/benefit approach. PUC did not receive the detail needed in the EPC process to breakout the costs to the level of a detail to develop a cost-effectiveness re-ranking approach of specific elements suggested in the question but has developed the following to try and address the question.

PUC provides the following narrative and assumptions to support the results shown in the table below.

AMI (cost allocation)

The AMI Integration portion of the project included a collection of all the IT, SCADA, and communications hardware and software elements, including the AMI metering system changes for meter and voltage data which enable the VVM and DA solution. The overall analytics solution will provide the data and reporting for KPI’s and specific project performance metric measurement and reporting. These elements are ~90% of this category costs which have been allocated 50/50 to the VVM and DA costs for the purposes of the cost/benefit calculation. They are inter -dependent with the VVM and DA solutions. The ~10% AMI remainder of costs are the estimated costs for the OMS/IVR and CSR solutions. Although the OMS/IVR system will support improved operational response and reporting for outage management, additional drivers for this expense are customer focus outcomes with a non-monetary benefit.

Benefit/Capital Cost Table

Bringing the benefits in to a summary by the VVM and DA project elements results are shown in the Table below. VVM benefits to be realized will include (1) and (2) plus an estimated 90% of (3). DA benefits to be realized will include 10% of (3) and (4) and (5).

	Annual Benefits		Benefits from VVM	Benefits from DA		Total Benefits	Annual VVM and DA Benefit	Total Project Costs w/AMI Allocation to VVM/DA	Annual Cost (Rev.Req. & OMA)	Benefit/Cost Ratio (with reliability)
Projected customer energy savings through SSG	$ 2,227,842	(1)	100%	0%	VVM	(1)+(2)+(3)	$ 2,606,904	$11,214,877	$ 697,179	3.74
Projected system loss energy savings through SSG	$ 105,111	(2)	100%	0%						
Benefit of reduced capital expenditures witth SSG	$304,390	(3)	90%	10%						
Operating efficiency benefits due to SSG implementation	$30,816	(4)		100%						
Annual projected reliability benefit to customers	$ 2,017,000	(5)		100%	DA	(3)+(4)+(5)	$ 2,078,255	$21,723,337	$ 1,350,442	1.54
	$ 4,685,159									
	Total						$ 4,685,159	$32,938,213	$ 2,047,621	

SEC-11

Reference: App. p. 20, and throughout

Preamble: N/A.

Question: Please show a side by side calculation of the impact of the additional capital on rates in the ICM period, and the impact of that additional capital on rates when the capital is added to rate base at the time of rebasing. Please confirm that the addition of that $33 million of capital to fixed assets at the time of rebasing is expected to increase revenue requirement (through depreciation, cost of debt, return on equity, and PILs, but excluding incremental OM&A) of approximately $2.6 million per year, or provide a full calculation showing a corrected impact on rebasing.

Response:

PUC Distribution has provided the side by side calculation of the impact of additional capital in rates in the ICM period and when this capital is added to rate base. Table below shows the incremental revenue requirement in 2022 (ICM Year) and 2023 (time of rebasing). In 2023, the incremental revenue requirement is $2,069,976 and not $2,600,000 per year. This is a result of decreased CCA for tax purposes that can be used in 2023. The effect of accelerated CCA in 2022 would be recorded in the 1592 variance account and present a further net benefit to customers at time of rebasing.

Incremental Revenue Requirement in 2022 (ICM Year) and 2023 (time of rebasing)

Current Revenue Requirement	**Rate Year:**	***2022***	***2023***
Current Revenue Requirement - Total		$ 19,273,165	$ 19,273,165
Eligible Incremental Capital for ACM/ICM Recovery			
	Total Claim	**Eligible for ACM/ICM (Full Year Prorated Amount)**	**Full Year Revenue**
Amount of Capital Projects Claimed	$ 24,828,660	$ 12,414,330	$24,828,660
Depreciation Expense	$ 695,799	$ 347,900	$ 695,799
CCA	$ 2,722,959	$ 1,361,480	$ 1,768,456
ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year		***2022***	***2023***
Return on Rate Base			
Incremental Capital		$ 12,414,330	
Depreciation Expense (prorated to Eligible Incremental Capital)		$ 347,900	
Incremental Capital to be included in Rate Base (average NBV in year)		$ 12,240,380	$24,132,861
	% of capital structure		
Deemed Short-Term Debt	4.0%	$ 489,615	$ 965,314
Deemed Long-Term Debt	56.0%	$ 6,854,613	$ 13,514,402
	Rate (%)		
Short-Term Interest	2.29%	$ 11,212	$ 22,106
Long-Term Interest	4.12%	$ 282,410	$ 556,793
Return on Rate Base - Interest		$ 293,622	$ 578,899
	% of capital structure		
Deemed Equity %	40.00%	$ 4,896,152	$ 9,653,144
	Rate (%)		
Return on Rate Base -Equity	9.00%	$ 440,654	$ 868,783
Return on Rate Base - Total		$ 734,276	$ 1,447,682
Amortization Expense			
Amortization Expense - Incremental		$ 347,900	$ 695,799
Grossed up Taxes/PILs			
Regulatory Taxable Income		$ 440,654	$ 868,783
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		$ 347,900	$ 695,799
Deduct CCA (Prorated to Eligible Incremental Capital)		$ 1,361,480	$ 1,768,456
Incremental Taxable Income		-$ 572,926	-$ 203,874
Current Tax Rate	26.5%		
Taxes/PILs Before Gross Up		-$ 151,825	-$ 54,027
Grossed-Up Taxes/PILs		-$ 206,565	-$ 73,506
Incremental Revenue Requirement			
Return on Rate Base - Total		$ 734,276	$ 1,447,682
Amortization Expense - Total		$ 347,900	$ 695,799
Grossed-Up Taxes/PILs		-$ 206,565	-$ 73,506
Incremental Revenue Requirement		$ 875,610	$ 2,069,976

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Reference: App. p. 20, 21, 50

Preamble: N/A.

Question: The Applicant notes that certain of the benefits of the SSG Project are estimated over a very long term and averaged or present valued, such as reliability and avoided capital spending. Certain of the costs and benefits will also have specific patterns of application, such as PILs (lower at the beginning, higher later on) and cost of capital (higher at the beginning, but declining as rate base declines). Please provide a continuity schedule showing, for each of the costs and benefits in Table 1, the forecast annual impact on customers from 2022 to 2041, i.e. showing and aggregating the pattern of each of the costs and benefits over time.

Response:

PUC Distribution has provided a schedule showing the customer net benefit from 2022 to 2041.

This results in a NPV of annual net benefit to customers of $12,506,291 and NPV of projected reliability benefits of $25,864,956, to a total NPV benefits of $38,371,247). The following assumptions were used in the calculation of this table:

- NPV at 6% discount rate.
- Ontario's 2017 Long-Term Energy Plan was used to forecast the increased cost of power from 2022 to 2041. This increase is a projection of the customers total bill increase based on a 750kwh customer.
- PUC Distribution did not apply any change in the price of its Transmission Network, Wholesale Market Service charge, RRRP charge and Smart Meter Entity Charge
- In the calculation of revenue requirement, PUC Distribution used cost of capital parameters from its 2018 Cost of Service Application.
- Additional OM&A expenses and operating efficiency benefits were adjusted by 1.90% per year which aligns with inflationary rate for PUC's 2021 IRM less the stretch factor of 0.30%.
- Additional revenue from increases SSG asset base was calculated each year by using Tab 9 of the ICM model. In 2028, the computer software would become fully depreciated. PUC has not included a calculation for the replacement of computer software in 2028.

- A projected energy savings of 2.7% was used for all years for Base Scenario 1, 2% was used for all years for Scenario 2 and 4% was used for Scenario 3 (see below).

The Snapshot below represent the Net benefit table from 2022 to 2041. Please note that in 2022 the difference between the CCA used ($1,361,480) for revenue requirement, and the CCA for tax purposes ($3,684,077) would create a credit to customers in the 1592 variance account. This benefit has not been factored into the total Net benefit to customers.

Customer Net Benefit from 2022 to 2041

(Base Scenario 1 – 2.7% projected energy savings)

Customer Net Benefit Summary					
	2022	2023	2024	2025	2026
Cost of Power - updated to current estimate (not including GS>5(	$ 77,574,554	$ 82,564,360	$ 88,666,180	$ 91,961,163	$ 94,531,250
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,094,513	$ 2,229,238	$ 2,393,987	$ 2,482,951	$ 2,552,344
Projected system loss energy savings through SSG	$ 98,821	$ 105,177	$ 112,950	$ 117,148	$ 120,422
Total purchased power savings	$ 2,193,334	$ 2,334,415	$ 2,506,937	$ 2,600,099	$ 2,672,765
Additional revenue from increased SSG asset base	$ 875,610	$ 2,069,976	$ 2,070,214	$ 2,066,371	$ 2,058,773
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 296,400	$ 302,032	$ 307,770	$ 313,618	$ 319,577
Operating efficiency benefits due to SSG implementation	($30,816)	($31,402)	($31,998)	($32,606)	($33,226)
Change In Revenue Requirement	$ 836,804	$ 2,036,216	$ 2,041,596	$ 2,042,992	$ 2,040,734
Annual net benefit to customers	$ 1,356,530	$ 298,199	$ 465,341	$ 557,107	$ 632,031
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000
Total projected benefit to customers	$ 3,373,530	$ 2,315,199	$ 2,482,341	$ 2,574,107	$ 2,649,031
NPV of Annual Net Benefit to customers	**$ 12,506,291**				
NPV of Projected Relaibaility Benefits	**$ 25,864,956**				
Total	**$ 38,371,247**				

Customer Net Benefit Summary					
	2027	2028*	2029	2030	2031
Cost of Power - updated to current estimate (not including GS>5(	$ 97,178,439	$ 99,912,392	$ 102,713,447	$ 105,606,102	$ 104,612,957
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,623,818	$ 2,697,635	$ 2,773,263	$ 2,851,365	$ 2,824,550
Projected system loss energy savings through SSG	$ 123,794	$ 127,124	$ 130,845	$ 134,530	$ 133,264
Total purchased power savings	$ 2,747,612	$ 2,824,758	$ 2,904,108	$ 2,985,894	$ 2,957,814
Additional revenue from increased SSG asset base	$ 1,941,702	$ 1,827,295	$ 1,821,830	$ 1,813,675	$ 1,803,046
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 325,649	$ 331,836	$ 338,141	$ 344,565	$ 351,112
Operating efficiency benefits due to SSG implementation	($33,857)	($34,500)	($35,156)	($35,824)	($36,504)
Change In Revenue Requirement	$ 1,929,103	$ 1,820,241	$ 1,820,425	$ 1,818,027	$ 1,813,264
Annual net benefit to customers	$ 818,508	$ 1,004,518	$ 1,083,683	$ 1,167,868	$ 1,144,551
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,001	$ 2,017,002	$ 2,017,003
Total projected benefit to customers	$ 2,835,508	$ 3,021,518	$ 3,100,684	$ 3,184,870	$ 3,161,554
	*does not include replacement for computer equipment.				

Customer Net Benefit Summary	2032	2033	2034	2035	2036
Cost of Power - updated to current estimate (not including GS>5(	$ 105,596,171	$ 105,596,171	$ 104,603,125	$ 103,620,010	$ 104,593,294
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,851,097	$ 2,851,097	$ 2,824,284	$ 2,797,740	$ 2,824,019
Projected system loss energy savings through SSG	$ 134,517	$ 134,517	$ 133,252	$ 132,000	$ 133,239
Total purchased power savings	$ 2,985,614	$ 2,985,614	$ 2,957,536	$ 2,929,740	$ 2,957,258
Additional revenue from increased SSG asset base	$ 1,790,140	$ 1,775,140	$ 1,758,214	$ 1,739,515	$ 1,719,185
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 357,783	$ 364,581	$ 371,508	$ 378,567	$ 385,760
Operating efficiency benefits due to SSG implementation	($37,198)	($37,905)	($38,625)	($39,359)	($40,107)
Change In Revenue Requirement	$ 1,806,336	$ 1,797,427	$ 1,786,707	$ 1,774,333	$ 1,760,448
Annual net benefit to customers	$ 1,179,278	$ 1,188,187	$ 1,170,829	$ 1,155,407	$ 1,196,810
Annual projected reliability benefit to customers	$ 2,017,004	$ 2,017,005	$ 2,017,006	$ 2,017,007	$ 2,017,008
Total projected benefit to customers	$ 3,196,282	$ 3,205,192	$ 3,187,835	$ 3,172,414	$ 3,213,818

Customer Net Benefit Summary	2037	2038	2039	2040	2041
Cost of Power - updated to current estimate (not including GS>5(	$ 105,576,311	$ 106,569,158	$ 107,571,934	$ 108,584,737	$ 109,607,668
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,850,560	$ 2,877,367	$ 2,904,442	$ 2,931,788	$ 2,959,407
Projected system loss energy savings through SSG	$ 134,492	$ 135,756	$ 137,034	$ 138,324	$ 139,627
Total purchased power savings	$ 2,985,052	$ 3,013,124	$ 3,041,476	$ 3,070,112	$ 3,099,034
Additional revenue from increased SSG asset base	$ 1,697,355	$ 1,674,144	$ 1,649,664	$ 1,624,015	$ 1,597,291
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 393,089	$ 400,558	$ 408,168	$ 415,924	$ 423,826
Operating efficiency benefits due to SSG implementation	($40,869)	($41,645)	($42,436)	($43,243)	($44,064)
Change In Revenue Requirement	$ 1,745,185	$ 1,728,667	$ 1,711,006	$ 1,692,306	$ 1,672,663
Annual net benefit to customers	$ 1,239,867	$ 1,284,457	$ 1,330,470	$ 1,377,806	$ 1,426,371
Annual projected reliability benefit to customers	$ 2,017,009	$ 2,017,010	$ 2,017,011	$ 2,017,012	$ 2,017,013
Total projected benefit to customers	$ 3,256,876	$ 3,301,467	$ 3,347,481	$ 3,394,818	$ 3,443,384

Scenario 2 - Projected Energy Savings at 2%

As part of its sensitivity analysis, PUC Distribution has performed the same analysis as above for a scenario where projected energy savings at 2% for all years. All other assumptions made in the base scenario above are the same. This results in a NPV of annual net benefit to customers of $3,729,534 and NPV of projected reliability benefits of $25,864,956, to a total NPV of benefits of $29,594,490)

Customer Net Benefit Summary	2022	2023	2024	2025	2026
Cost of Power - updated to current estimate (not including GS>50 on	$ 77,574,554	$ 82,564,360	$ 88,666,180	$ 91,961,163	$ 94,531,250
Projected energy savings with SSG implementation	2.00%	2.00%	2.00%	2.00%	2.00%
Projected customer energy savings through SSG	$ 1,551,491	$ 1,651,287	$ 1,773,324	$ 1,839,223	$ 1,890,625
Projected system loss energy savings through SSG	$ 98,821	$ 105,177	$ 112,950	$ 117,148	$ 120,422
Total purchased power savings	$ 1,650,312	$ 1,756,464	$ 1,886,274	$ 1,956,371	$ 2,011,047
Additional revenue from increased SSG asset base	$ 875,610	$ 2,069,976	$ 2,070,214	$ 2,066,371	$ 2,058,773
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 296,400	$ 302,032	$ 307,770	$ 313,618	$ 319,577
Operating efficiency benefits due to SSG implementation	($30,816)	($31,402)	($31,998)	($32,606)	($33,226)
Change In Revenue Requirement	$ 836,804	$ 2,036,216	$ 2,041,596	$ 2,042,992	$ 2,040,734
Annual net benefit to customers	$ 813,508	-$ 279,752	-$ 155,322	-$ 86,621	-$ 29,688
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000
Total projected benefit to customers	$ 2,830,508	$ 1,737,248	$ 1,861,678	$ 1,930,379	$ 1,987,312
NPV of Annual Net Benefit to customers	**$ 3,729,534**				
NPV of Projected Relaibaility Benefits	**$ 25,864,956**				
Total	**$ 29,594,490**				

Customer Net Benefit Summary	2027	2028*	2029	2030	2031
Cost of Power - updated to current estimate (not including GS>50 on	$ 97,178,439	$ 99,912,392	$ 102,713,447	$ 105,606,102	$ 104,612,957
Projected energy savings with SSG implementation	2.00%	2.00%	2.00%	2.00%	2.00%
Projected customer energy savings through SSG	$ 1,943,569	$ 1,998,248	$ 2,054,269	$ 2,112,122	$ 2,092,259
Projected system loss energy savings through SSG	$ 123,794	$ 127,124	$ 130,845	$ 134,530	$ 133,264
Total purchased power savings	$ 2,067,363	$ 2,125,371	$ 2,185,114	$ 2,246,652	$ 2,225,524
Additional revenue from increased SSG asset base	$ 1,941,702	$ 1,827,295	$ 1,821,830	$ 1,813,675	$ 1,803,046
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 325,649	$ 331,836	$ 338,141	$ 344,565	$ 351,112
Operating efficiency benefits due to SSG implementation	($33,857)	($34,500)	($35,156)	($35,824)	($36,504)
Change In Revenue Requirement	$ 1,929,103	$ 1,820,241	$ 1,820,425	$ 1,818,027	$ 1,813,264
Annual net benefit to customers	$ 138,259	$ 305,131	$ 364,689	$ 428,625	$ 412,260
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,001	$ 2,017,002	$ 2,017,003
Total projected benefit to customers	$ 2,155,259	$ 2,322,131	$ 2,381,690	$ 2,445,627	$ 2,429,263
	*does not include replacement for computer equipment.				

Customer Net Benefit Summary					
	2032	**2033**	**2034**	**2035**	**2036**
Cost of Power - updated to current estimate (not including GS>50 on	$ 105,596,171	$ 105,596,171	$ 104,603,125	$ 103,620,010	$ 104,593,294
Projected energy savings with SSG implementation	2.00%	2.00%	2.00%	2.00%	2.00%
Projected customer energy savings through SSG	$ 2,111,923	$ 2,111,923	$ 2,092,063	$ 2,072,400	$ 2,091,866
Projected system loss energy savings through SSG	$ 134,517	$ 134,517	$ 133,252	$ 132,000	$ 133,239
Total purchased power savings	$ 2,246,440	$ 2,246,440	$ 2,225,314	$ 2,204,400	$ 2,225,105
Additional revenue from increased SSG asset base	$ 1,790,140	$ 1,775,140	$ 1,758,214	$ 1,739,515	$ 1,719,185
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 357,783	$ 364,581	$ 371,508	$ 378,567	$ 385,760
Operating efficiency benefits due to SSG implementation	($37,198)	($37,905)	($38,625)	($39,359)	($40,107)
Change In Revenue Requirement	$ 1,806,336	$ 1,797,427	$ 1,786,707	$ 1,774,333	$ 1,760,448
Annual net benefit to customers	$ 440,105	$ 449,013	$ 438,607	$ 430,067	$ 464,657
Annual projected reliability benefit to customers	$ 2,017,004	$ 2,017,005	$ 2,017,006	$ 2,017,007	$ 2,017,008
Total projected benefit to customers	$ 2,457,109	$ 2,466,018	$ 2,455,613	$ 2,447,074	$ 2,481,665

Customer Net Benefit Summary					
	2037	**2038**	**2039**	**2040**	**2041**
Cost of Power - updated to current estimate (not including GS>50 on	$ 105,576,311	$ 106,569,158	$ 107,571,934	$ 108,584,737	$ 109,607,668
Projected energy savings with SSG implementation	2.00%	2.00%	2.00%	2.00%	2.00%
Projected customer energy savings through SSG	$ 2,111,526	$ 2,131,383	$ 2,151,439	$ 2,171,695	$ 2,192,153
Projected system loss energy savings through SSG	$ 134,492	$ 135,756	$ 137,034	$ 138,324	$ 139,627
Total purchased power savings	$ 2,246,018	$ 2,267,140	$ 2,288,473	$ 2,310,019	$ 2,331,781
Additional revenue from increased SSG asset base	$ 1,697,355	$ 1,674,144	$ 1,649,664	$ 1,624,015	$ 1,597,291
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 393,089	$ 400,558	$ 408,168	$ 415,924	$ 423,826
Operating efficiency benefits due to SSG implementation	($40,869)	($41,645)	($42,436)	($43,243)	($44,064)
Change In Revenue Requirement	$ 1,745,185	$ 1,728,667	$ 1,711,006	$ 1,692,306	$ 1,672,663
Annual net benefit to customers	$ 500,833	$ 538,473	$ 577,467	$ 617,713	$ 659,117
Annual projected reliability benefit to customers	$ 2,017,009	$ 2,017,010	$ 2,017,011	$ 2,017,012	$ 2,017,013
Total projected benefit to customers	$ 2,517,842	$ 2,555,483	$ 2,594,478	$ 2,634,725	$ 2,676,130

<u>Scenario 3 - Projected Energy Savings at 4%</u>

As part of its sensitivity analysis, PUC Distribution has performed the same analysis as above for a scenario where projected energy savings at 4% for all years. All other assumptions made in the base scenario above are the same. This results in a NPV of annual net benefit to customers of $28,805,983 and NPV of projected reliability benefits of $25,864,956, to a total NPV of benefits of $54,670,939)

Customer Net Benefit from 2022 to 2041
(Scenario 3 - 4% projected energy savings)

Customer Net Benefit Summary					
	2022	2023	2024	2025	2026
Cost of Power - updated to current estimate (not including GS>50 on	$ 77,574,554	$ 82,564,360	$ 88,666,180	$ 91,961,163	$ 94,531,250
Projected energy savings with SSG implementation	4.00%	4.00%	4.00%	4.00%	4.00%
Projected customer energy savings through SSG	$ 3,102,982	$ 3,302,574	$ 3,546,647	$ 3,678,447	$ 3,781,250
Projected system loss energy savings through SSG	$ 98,821	$ 105,177	$ 112,950	$ 117,148	$ 120,422
Total purchased power savings	$ 3,201,803	$ 3,407,752	$ 3,659,597	$ 3,795,594	$ 3,901,672
Additional revenue from increased SSG asset base	$ 875,610	$ 2,069,976	$ 2,070,214	$ 2,066,371	$ 2,058,773
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 296,400	$ 302,032	$ 307,770	$ 313,618	$ 319,577
Operating efficiency benefits due to SSG implementation	($30,816)	($31,402)	($31,998)	($32,606)	($33,226)
Change In Revenue Requirement	$ 836,804	$ 2,036,216	$ 2,041,596	$ 2,042,992	$ 2,040,734
Annual net benefit to customers	$ 2,364,999	$ 1,371,536	$ 1,618,002	$ 1,752,602	$ 1,860,937
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000
Total projected benefit to customers	$ 4,381,999	$ 3,388,536	$ 3,635,002	$ 3,769,602	$ 3,877,937
NPV of Annual Net Benefit to customers	**$ 28,805,983**				
NPV of Projected Relaibaility Benefits	**$ 25,864,956**				
Total	**$ 54,670,939**				

Customer Net Benefit Summary					
	2027	2028*	2029	2030	2031
Cost of Power - updated to current estimate (not including GS>50 on	$ 97,178,439	$ 99,912,392	$ 102,713,447	$ 105,606,102	$ 104,612,957
Projected energy savings with SSG implementation	4.00%	4.00%	4.00%	4.00%	4.00%
Projected customer energy savings through SSG	$ 3,887,138	$ 3,996,496	$ 4,108,538	$ 4,224,244	$ 4,184,518
Projected system loss energy savings through SSG	$ 123,794	$ 127,124	$ 130,845	$ 134,530	$ 133,264
Total purchased power savings	$ 4,010,931	$ 4,123,619	$ 4,239,383	$ 4,358,774	$ 4,317,783
Additional revenue from increased SSG asset base	$ 1,941,702	$ 1,827,295	$ 1,821,830	$ 1,813,675	$ 1,803,046
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 325,649	$ 331,836	$ 338,141	$ 344,565	$ 351,112
Operating efficiency benefits due to SSG implementation	($33,857)	($34,500)	($35,156)	($35,824)	($36,504)
Change In Revenue Requirement	$ 1,929,103	$ 1,820,241	$ 1,820,425	$ 1,818,027	$ 1,813,264
Annual net benefit to customers	$ 2,081,828	$ 2,303,379	$ 2,418,958	$ 2,540,747	$ 2,504,519
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,001	$ 2,017,002	$ 2,017,003
Total projected benefit to customers	$ 4,098,828	$ 4,320,379	$ 4,435,959	$ 4,557,749	$ 4,521,522
	*does not include replacement for computer equipment.				

Customer Net Benefit Summary										
		2032		**2033**		**2034**		**2035**		**2036**
Cost of Power - updated to current estimate (not including GS>50 on	$	105,596,171	$	105,596,171	$	104,603,125	$	103,620,010	$	104,593,294
Projected energy savings with SSG implementation		4.00%		4.00%		4.00%		4.00%		4.00%
Projected customer energy savings through SSG	$	4,223,847	$	4,223,847	$	4,184,125	$	4,144,800	$	4,183,732
Projected system loss energy savings through SSG	$	134,517	$	134,517	$	133,252	$	132,000	$	133,239
Total purchased power savings	$	4,358,364	$	4,358,364	$	4,317,377	$	4,276,800	$	4,316,971
Additional revenue from increased SSG asset base	$	1,790,140	$	1,775,140	$	1,758,214	$	1,739,515	$	1,719,185
Benefit of reduced capital expenditures witth SSG		($304,390)		($304,390)		($304,390)		($304,390)		($304,390)
Additional O & M expenses due to SSG implementation	$	357,783	$	364,581	$	371,508	$	378,567	$	385,760
Operating efficiency benefits due to SSG implementation		($37,198)		($37,905)		($38,625)		($39,359)		($40,107)
Change In Revenue Requirement	$	1,806,336	$	1,797,427	$	1,786,707	$	1,774,333	$	1,760,448
Annual net benefit to customers	$	2,552,028	$	2,560,937	$	2,530,670	$	2,502,467	$	2,556,523
Annual projected reliability benefit to customers	$	2,017,004	$	2,017,005	$	2,017,006	$	2,017,007	$	2,017,008
Total projected benefit to customers	$	4,569,032	$	4,577,942	$	4,547,676	$	4,519,474	$	4,573,531

1

Customer Net Benefit Summary										
		2037		**2038**		**2039**		**2040**		**2041**
Cost of Power - updated to current estimate (not including GS>50 on	$	105,576,311	$	106,569,158	$	107,571,934	$	108,584,737	$	109,607,668
Projected energy savings with SSG implementation		4.00%		4.00%		4.00%		4.00%		4.00%
Projected customer energy savings through SSG	$	4,223,052	$	4,262,766	$	4,302,877	$	4,343,389	$	4,384,307
Projected system loss energy savings through SSG	$	134,492	$	135,756	$	137,034	$	138,324	$	139,627
Total purchased power savings	$	4,357,544	$	4,398,523	$	4,439,911	$	4,481,714	$	4,523,934
Additional revenue from increased SSG asset base	$	1,697,355	$	1,674,144	$	1,649,664	$	1,624,015	$	1,597,291
Benefit of reduced capital expenditures witth SSG		($304,390)		($304,390)		($304,390)		($304,390)		($304,390)
Additional O & M expenses due to SSG implementation	$	393,089	$	400,558	$	408,168	$	415,924	$	423,826
Operating efficiency benefits due to SSG implementation		($40,869)		($41,645)		($42,436)		($43,243)		($44,064)
Change In Revenue Requirement	$	1,745,185	$	1,728,667	$	1,711,006	$	1,692,306	$	1,672,663
Annual net benefit to customers	$	2,612,359	$	2,669,856	$	2,728,906	$	2,789,408	$	2,851,271
Annual projected reliability benefit to customers	$	2,017,009	$	2,017,010	$	2,017,011	$	2,017,012	$	2,017,013
Total projected benefit to customers	$	4,629,368	$	4,686,866	$	4,745,917	$	4,806,420	$	4,868,284

2

SEC-13

Reference: App. p. 22

Preamble: N/A.

Question: Please restate Table 2 including the Capex benefit, the operating efficiency benefits, and the additional O&M expenses. Please provide the full calculations for all components of the table, in Excel format.

Response:

Table 2 has been restated below. This reduces the total revenue requirement from $1,751,221 (based on updated CWIP rates) to $1,712,415. The calculations have been provided in live excel format in Attachment 10 -SEC-13_Bill Impacts.

Table 2 – Restated

Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %
Residential	750	0	-$0.09	-0.08%
Residential	825	0	-$0.33	-0.27%
Residential	738	0	-$0.06	-0.05%
Residential	2,000	0	-$4.04	-1.55%
GS<50	2,000	0	-$2.44	-0.83%
GS<50	815	0	-$0.10	-0.08%
GS<50	3,000	0	-$4.42	-1.03%
GS>50	19,740	55	-$39.38	-1.17%
GS>50	57,220	145	-$141.58	-1.51%
GS>50	142,465	452	-$335.40	-1.39%
GS>50	169,620	468	-$428.02	-1.53%

SEC-14

Reference: App. p. 26

Preamble: N/A.

Question: Please provide a detailed breakdown of the scope adjustments between the 2014 report and the current SSG project.

Response:

Below is a comparison of the SSG Project scope description in Appendix A of the EPC Contract compared to the 2014 report referenced above. As stated in the Amended Application, The scope of the SSG project remains the same. The specific smart grid technologies include distribution automation systems, voltage / VAR management systems, line regulators and associated communication systems, all of which will be integrated into the Applicant's AMI system.

Leidos' Preliminary Design Report titled *Utility Distribution Microgrid:* 3 *Volt/VAR Management (VVM)* Dated October 17, 2014	**Current SSG Project VVO (See Appendix AA3-7 EPC Appendix A – SSG Scope of Work and Appendix AA3-1 SSG Scope Overview Summary)**
System Architecture • Centralized intelligence of the VVM system reside in the PUC Control Room, provided by the Survalent VVO system. • System will interface with GIS, MDM, and SCADA systems to exchange information. • Distributed intelligence of the VVM system provided by Load-Tap Changing (LTC) controllers at substations.	• Advanced Distribution Management System (ADMS) software that includes integrated FDIR (for both distribution and sub-transmission) and VVO applications. • Outage Management System (OMS) software that is tightly-integrated with the new ADMS to provide outage management functions. • SCADA-enabled line distribution equipment such as reclosers, switches,

VVM Software • Survalent VVM solution • Real-time voltage control accomplished by local controllers at LTC transformers and voltage regulators. • VVM Software would process AMI data at regular intervals and determine optimal settings for LTC and regulator controllers. • Three operating modes: Disabled; Semi-automatic and Full automatic. • Capacitor banks • Communication System – Fiber and/or radio communications to all substations.	and faulted circuit indicators (FCIs) to support FDIR. • SCADA-enabled voltage regulators and capacitors to support VVO. • FCIs that will support FDIR on the sub-transmission system where necessary. • Cellular communications to collect the data and provide control in support of FDIR and VVO and will be integrated into existing PUC communication networks. • Integration with the PUC's existing Customer Information System (CIS), Advanced Metering Infrastructure (AMI), and CYME distribution model. • Integration with the PUC's existing Geographic Information System (GIS) was originally planned, but based upon discussions with PUC staff and Survalent, the approach was changed so that GIS integration is no longer required • A cellular based communication system will be implemented by the EPC contractor to provide communication between field devices and the central software system. • Field integration of all equipment will be accomplished. LTC controller and regulator settings will be determined and applied to the associated equipment. • SCADA points list will be developed, and data acquisition system of these points will be established.

SEC-15

Reference: App. p. 31

Preamble: N/A.

Question: Please describe how an "open-to-close book process" is different from a cost plus materials contract. Please provide references that give independent definitions of the concept of "open-to-close book process".

Response:

Please see Schedule 2 – Open-to-Closed-Book Process of Appendix AA3-7 EPC Appendix B – Compensation for a detailed explanation of the open-to-closed-book process.

This was a negotiated process between the parties to the EPC Contract and the process is defined in the contract.

"Open-to-close book process", which is applied to Step 2 – Balance of Work of the SSG project is different from a cost plus materials contract because for Step 2, the EPC Contractor will have developed a firm scope using information from Step 1 and any adjustments negotiated using the open-to-close book process will be made in accordance with the EPC Contract maximum price.

By using the open-to-close book process, PUC Distribution will be able to perform a full review of how the firm scope and price are being developed for Step 2, while ensuring that it is within the EPC maximum price. The Open to Close Book process provides the necessary level of collaboration allowing changes in scope to be to evaluated prior to beginning the implementation phase of the Balance of the Work. This component is not available in a cost plus materials contract.

SEC-16

Reference: App. p. 34

Preamble: N/A.

Question: With respect to the description of the VVO scope, please identify which costs described in that description are included in the contract price, and which are not, if any. For example, is the Survalent software included, and is the cellular communication system included, etc.

Response:

The total contract price includes all engineering design, hardware and procurement, construction and installation costs identified in the VVO scope. This includes required Survalent software, interfaces with AMI and system models, field devices, controllers, cellular based communication system, device settings, including field integration and commissioning.

SEC-17

Reference: App. p. 30, 36

Preamble: N/A.

Question: The Applicant notes on p. 36 that the analytics has been removed from the project, but it is included on p. 30. Please reconcile. Please provide details of the nature and cost of all data analytics that has been removed from the project, and provide a forecast of when and at what cost those analytics will be added in the future.

Response:

The different context between the page 36 reference and the page 30 reference is in terms of the EPC contract and the SSG Project as a whole.

An overall integrated platform for data analytics and performance reporting has not been excluded from the project but is not specifically part of the current EPC contract. The EPC contract will include such data and analytics specific to the contracted elements. A specification for an integrated solution was challenging to set in the contract negotiation and PUC Distribution elected to consider this aspect as part of the future design stage and consideration for a potentially different timeline for implementation if some items were determined to be less critical. Description of metrics and measures can also be referenced to interrogatory question from OEB staff (Staff-46).

The method, process, design, etc. for collecting, analyzing and reporting program metrics has not been fully determined and will be developed by PUC Distribution as part of the project design and implementation in coordination with the EPC contractor.

VVM and DA tracking and reporting metrics required for project performance will be developed as part of the EPC contract. PUC will develop and supplement as required to measure project and system performance including those identified for the NRCan agreement.

<u>SEC-18</u>

<u>Reference:</u> App. p. 41

<u>Preamble:</u> N/A.

<u>Question:</u> Please recalculate Table 5 using the accelerated depreciation rules.

<u>Response</u>:

Table 5 has been provided showing the accelerated depreciation rules. Please note this table is also update to reflect the most recent CWIP rates.

	Cost of Addition	Contributed Capital	Net Addition	# Years	Deprec Rate	Deprec Exp	Eligible for ACM/ICM (Half Year*Prorated Amount)	CCA Class	CCA Rate	2022 CCA 8%	Eligible for ACM/ICM (Half Year*Prorated Amount)	Undeprec Capital Cost 2022	CCA Rate	2023 CCA	Bill C 97 rate	2022 CCA
1820 DS Equipment	$472,169	$116,250	$355,919	40	2.50%	$8,898	$4,449	47	8%	$28,474	$14,237	$327,445	8%	$26,196	12%	$42,710
1830 Poles & Fixtures	$4,735,593	$1,165,927	$3,569,666	45	2.20%	$78,533	$39,266	47	8%	$285,573	$142,787	$3,284,093	8%	$262,727	12%	$428,360
1835 OH Conductors & Devices	$15,909,816	$3,917,076	$11,992,739	60	1.67%	$200,279	$100,139	47	8%	$959,419	$479,710	$11,033,320	8%	$882,666	12%	$1,439,129
1840 UG Conduit/Civil	$399,079	$98,255	$300,824	50	2.00%	$6,016	$3,008	47	8%	$24,066	$12,033	$276,758	8%	$22,141	12%	$36,099
1845 UG conductors & Devices	$798,159	$196,511	$601,648	40	2.50%	$15,041	$7,521	47	8%	$48,132	$24,066	$553,516	8%	$44,281	12%	$72,198
1850 Line Transformers	$7,082,539	$1,743,757	$5,338,783	40	2.50%	$133,470	$66,735	47	8%	$427,103	$213,551	$4,911,680	8%	$392,934	12%	$640,654
1920 Computer S/W	$1,062,257	$261,533	$800,724	5	20.00%	$160,145	$80,072	12	100%	$800,724	$400,362	$0	100%	$0	100%	$800,724
1980 System Supervisory Equipment	$2,478,601	$610,244	$1,868,357	20	5.00%	$93,418	$46,709	47	8%	$149,469	$74,734	$1,718,888	8%	$137,511	12%	$224,203
In Service Dec. 31, 2022	$32,938,213	$8,109,553	$24,828,660			$695,799	$347,900			$2,722,959	$1,361,480	$22,105,701		$1,768,456		$3,684,077

SEC-19

Reference: App. p. 53

Preamble: N/A.

Question: Please provide evidence to show that all project costs that are going to the Applicant or any affiliates are incremental to costs currently included in rates. Please include details of additional FTEs expected, overtime and third party payments, etc.

Response:

PUC Distribution will use its affiliate, PUC Service Inc. to manage and perform the project work. PUC Services Inc. will track the project costs separately using work orders and timesheet charged to the SmartGrid project. These costs are accounted for directly and specifically to this project and therefore incremental to PUC Distribution.

SEC-20

Reference: Appendix AA2-1, p. 4

Preamble: N/A.

Question: Please provide a full list of the documents and materials that were at any time included on the secured project website.

Response:

The RFP site is no longer up but the type of documents posted are listed below.

Sault Smart Grid Drawings and Reference Documents

Drawing References: (Engineering)
System
a) DWG#-EST-1 REV 10 (Wall Map Sub-transmission Schematic)
b) DWG#-EPD-1 [21] (Wall Map Distribution Feeders)
TS
a) DWG#-A-TS1-04-001 [7] (TS1 Schematic)
b) DWG#-A-TS2-04-001 [6] (TS2 Schematic)
c) DWG#-D-TS1-03-001 [6] (TS1 3 Line)
d) DWG#-D-TS2-03-001 [13] (TS2 3 Line)

DS
a) DS Single Line Drawings
b) DS Schematic Drawings – to the relay level (not the detailed level)

Distribution
a) Feeder Book drawings
Reference Documents:
1. Station Communications (pdf)
2. Station Energy (pdf)
3. General Statistics)pdf)

RFP Documents
1. Notice – Expression of Interest (pdf)
2. RFP No. SSG2019 Engineering, Procurement & Construction Services (pdf)
3. RFP Pricing Matrix spreadsheet

SEC-21

Reference: Appendix AA2-1, p. 21

Preamble: N/A.

Question: Please file in confidence the MS Excel spreadsheet template included by the winning bidder in their proposal.

Response:

The numbers in the MS Excel spreadsheet template included by the winning bidder in their proposal were used to compare bids against each other, but were subsequently changed during the EPC Contract negotiation process, as details were negotiated. Consequently, this sheet provides no probative value.

There is more up-to-date and factually relevant information available on the public record (see Appendix AA3-7 – EPC Appendix B Compensation).

SEC-22

Reference: Appendix AA2-1, p. 26

Preamble: N/A.

Question: Please provide the ten year warranty service proposal of the successful bidder, and a comparison of that proposal to the final warranty service to be provided as per the final agreement.

Response:

The successful bidder did not include an option for a ten year warranty and did not include any pricing in that regard.

A ten year warranty service proposal is an optional requirement as identified in Appendix AA2-1 p. 26.

The warranty provided in the EPC contract under Article 23 could be generally characterized as a typical one year standard warranty.

SEC-23

Reference: Appendix AA$, Schedule B

Preamble: N/A.

Question: Please provide an update of this schedule with the expected final figures.

Response:

The information mentioned in the responses to this question do not reflect the most up to date CWIP rates.

Schedule with updated Estimate.

Approved Budget ($)	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-2023**	**TOTAL ($)**	
The Program (NRCan Contribution)	$493,104	$1,272,604	$2,750,000	$3,611,052	$0	$8,126,760	[1]
ELIGIBLE EXPENDITURES							
Salaries and Benefits	$0	$0	$0	$0	$0	**$0**	
Overhead	$0	$0	$0	$0	$0	**$0**	
Professional, Scientific & Contracting Services	$493,104	$1,272,604	$5,500,000	$15,000,000	$10,241,330	**$32,507,038**	
Travel, including Meals and Accomodations	$0	$0	$0	$0	$0	**$0**	
Equipment and Products	$0	$0	$0	$0	$0	**$0**	
Other Expenses	$0	$0	$0	$0	$0	**$0**	
Total by Fiscal Year:	**$493,104**	**$1,272,604**	**$5,500,000**	**$15,000,000**	**$10,241,330**		
Total Eligible Expenditures						**$32,507,038**	
INELIGIBLE COSTS							
INELIGIBLE EXPENDITURES	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**TOTAL ($)**	
Incurred before Eligible Expenditure period (between June 13, 2018 and August 28, 2018)	$300,000.00	$50,000.00	$100,000.00	$50,000.00		$500,000.00	
Ineligible Overhead Expenditures	-	$0.00	$0.00	$0.00		$0.00	
Total Ineligible Expenditures						**$500,000.00**	
IN-KIND COSTS							
In-kind Contribution from ABB Inc. of Equipment & Professional, Scientific and Contracting						$0.00	
Total In-Kind Costs						**$0.00**	
Total Ineligible Costs						**$500,000.00**	
TOTAL PROJECT COSTS						**$33,007,037.91**	

[1] Schedule Estimate will need to be updated once OEB approvals and NTP in place for EPC milestones

SEC-24

Reference: Appendix AA5, U/T JTC2.8

Preamble: N/A.

Question: Please provide details of what happened with each of the proposed projects listed in this response, e.g. full system implementation over ten years, or business case approved but not implemented, etc.

Response:

The reference refers to the undertaking to file additional studies that were considered by PUC Distribution of US-based pilot projects on VVM technology. In response, PUC Distribution provided the following list of projects. There has not been updated reports on the US-based pilot projects following those that were listed in the reference, but from research on information that is available, PUC Distribution has found the following relevant developments:

Evaluation of Conservation Voltage Reduction (CVR) on a National Level: Pacific Northwest National Laboratory for US Department of Energy (projected energy savings 3.04% https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf

The ACEEE's midrange estimate of 2.3% average savings is also very similar to the 2.4% average savings estimated by PNNL for a nationwide program that optimized the 40% of circuits where CVR has the highest value. For this reason the ACEE, in its 2015 report, applies the 2.3% average savings to all electricity put into the US electricity grid. For the low savings case we estimate average savings of 1.8%, based on the lowest savings estimate. In the high savings case the ACEE, in its 2015 report, estimates 2.9% average savings, based on a PNNL estimate that 3.04% can be saved on average if all circuits are optimized, but then multiply by 95% because PNNL estimates there will be very little savings in the 25% of circuits that provide the least benefit.[20]

Recent work on CVR began in the Pacific Northwest with a major project by the Northwest Energy Efficiency Alliance (NEEA). The NEEA project involved pilot demonstrations involving 6 utilities, 10 substations and 31 feeders (NWPCC 2009). The NEEA project found average

[20] ACEEE Report U1507, 2015 - https://www.aceee.org/sites/default/files/publications/researchreports/u1507.pdf

energy savings from voltage control of 2.07% of the consumption on the circuit, with savings higher in summer and lower in winter (NWPCC 2009).[21]

Using AMI-based Volt/VAR Optimization (VVO/CVR) to Drive Energy Efficiency and System Reliability (presentation at SmartGrid Canada Conference 2015 – EPRI research study table of feeders avg 2.13%; Glendale Case Study 2.95%;) (copy of presentation slide deck included in OEB ICM application at Appendix N)

As reported by the IEEE, Glendale Water and Power (GWP) implemented CVR as part of an AMI Initiative Project in 2014-2015. The pilot realized 2.95% in energy savings on two feeders over the baseline suggesting that a full-scale program could save a minimum 14,500 MWh a year, equivalent to net power costs savings of $470,000 to $1.2 million per year. After its CVR pilot, GWP started working with DVI to expand its CVR program system wide in 2015. As of June 2018, average savings per feeder is 2.2%.[22]

Utilidata paper on Voltage Optimization (2015) - American Electric Power VVO project in Ohio (reported energy savings of 4.27%) https://utilidata.com/wp-content/uploads/2015/08/AEP_CaseStudyVer88-14.pdf

As reported by the IEEE, AEP Ohio started its VVO program in 2014 by using Utilidata AdaptiVolt system and achieved an energy savings of 4.27% using a day-on/day-off basis.

AEP has deployed VVO on approximately 172 circuits, out of the 6,000 circuits on its system, as of March 2019, and has proposed 1600 more circuits for VVO implementation across the company's service territory. AEP affiliate operating companies show a range of 0.7-1.2% of energy demand reduction for each 1% voltage reduction. CVR program for AEP Ohio showed that 3-5% reduction in voltage, yields 2.9% energy reduction, while 3-4% drop in voltage, causes 2-3% peak demand reduction.[23]

Smart Grid Regional Business Case for the Pacific Northwest – Navigant report prepared for Bonneville Power Administration (Sept 2015) (general smart grid background "positive benefits over time"; LDC incentives noted of up to $0.18 /kwh)

[21] ACEEE Report U1507, 2015 - https://www.aceee.org/sites/default/files/publications/researchreports/u1507.pdf
[22] Conservation Voltage Reduction and Volt-VAR Optimization: Measurement and Verification Benchmarking – IEEE 2020 – https://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=9027815
[23] Conservation Voltage Reduction and Volt-VAR Optimization: Measurement and Verification Benchmarking – IEEE 2020 – https://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=9027815

https://www.bpa.gov/Projects/Initiatives/SmartGrid/DocumentsSmartGrid/Navigant-BPA-PNW-Smart-Grid-Regional-Business-Case-2013-White-Paper.pdf

The American Council for the Energy-Efficient Economy estimates that CVR programs can reduce US 2030 electricity consumption by 2.1%, assuming average savings of 2.3% but with some adjustments noted in table 18-3 below. The 2.3% figure is based on the 2.34% average savings estimated by EPRI for the 66 circuits examined in its Green Circuits program (EPRI 2011).[24]

Smart Grid Roadmap & Business Case – Hawaiian Electric – March 2014 (general background information and approaches)

http://www.solari.net/portfolio/Solari-Smart-Grid-Roadmap-&-Business-Case.pdf

Dominion voltage has been actively marketing voltage optimization services to other utilities and has a contract with Hawaiian Electric Company among other utilities. Savings vary from utility to utility and have ranged from 2-4%, with savings toward the lower end of the range for circuits in the moderate climates along the Pacific Coast and savings higher in East Coast applications. Dominion also notes that in Hawaii and California, CVR helps to stabilize the voltage in circuits with above-average saturations of photovoltaic systems.[25]

[24] ACEEE Report U1507, 2015 - https://www.aceee.org/sites/default/files/publications/researchreports/u1507.pdf
[25] ACEEE Report U1507, 2015 - https://www.aceee.org/sites/default/files/publications/researchreports/u1507.pdf

SEC-25

Reference: Appendix AA12-1

Preamble: N/A.

Question: Please add a column to this summary showing the amount of each cost line that is expected to be paid to the Applicant or any of its affiliates.

Response:

The information mentioned in the responses to this question do not reflect the most up to date CWIP rates.

Added column for cost estimated to PUC Distribution affiliate (PUC Services).

2020/2021 Smart Grid Project				**IR# SEC-25**
Project Costing w/ EPC & PUC Cost Estimate				
VVM (excludes AMI, SCADA, Comm, etc.)	***Qty***	**Unit Costs**	**Total**	
DS with new LTC's (incremental)			-	
48 feeders (note Sub 16 LTC)				
>Bus/Padmount /Feeder/ VReg's(per set of 3)	44	120,834	5,316,678	
>feeder balancing Vregs	6	55,487	332,922	
>feeder balancing Caps	6	42,634	255,802	
			5,905,402	
Engineering (check sum)	1	2,362,042	2,362,042	530,400
Add'l Scope & Contingency	1	462,846	462,846	
			8,730,290	
Project Mgmt/ Ext'l Commissioning Review	1	379,800	379,800	379,800
Contract/Regulatory/ Legal	1	353,703	353,703	247,500
VVM			**9,463,794**	
			9,463,794	
DA (excludes AMI, SCADA, Comm, etc.)				
Reclosers	40	99,573	3,982,933	
SW's(pole)	40	93,279	3,731,157	
2 way padmount SW's	12	62,231	746,775	
4 way padmount SW's	8	304,825	2,438,597	
OH FCI's	40	1,549	61,972	
UG FCI's	40	1,931	77,220	
Poles (added qty for adjacent lift/siting issues)	120	11,837	1,420,456	710,228
			12,459,110	
Engineering (check sum)	1	5,205,849	5,205,849	1,060,800
Add'l Scope & Contingency	1	844,036	844,036	
			18,508,995	
Project Mgmt/ Ext'l Commissioning Review	1	759,600	759,600	759,600
Contract/Regulatory/ Legal	1	726,371	726,371	495,000
DA			**19,994,966**	
			19,994,966	
AMI Integration, SCADA, OMS, CIS, Comm, etc.)				
All IT H/W, S/W, SCADA, OMS, GIS, communication				
type work combined in to central sub-project.				
VVO/FLSIR/OMS/CIS/AMI	1	2,013,446	2,013,446	
			2,013,446	
Engineering (check sum)	1	1,284,009	1,284,009	176,800
Add'l Scope & Contingency	1	-	-	
			3,297,455	
Project Mgmt/ Ext'l Commissioning Review	1	126,600	126,600	126,600
Contract/Regulatory/ Legal	1	124,223	124,223	82,500
AMI			**3,548,278**	
			3,548,278	
Project Estimate Total System			**33,007,038**	4,569,228

SEC-26

Reference: N/A.

Preamble: N/A.

Question: Please explain why, if this project is in part intended to enhance economic development opportunities in Sault Ste. Marie, the Applicant is not forecasting new customers or load growth as a result of the SSG Project.

Response:

Forecasted load is based on historical actual information that we have available. This project could attract economic development but that may not translate to actual load growth. It would not be feasible to predict what type of load growth that economic development might create.

Vulnerable Energy Consumers Coalition (VECC) Interrogatories

VECC-1

Reference: ICM Application P6

Preamble: The Sault Smart Grid (SSG) project was being developed using a P3 project finance structure using a special purpose vehicle known as Sault Smart Grid Inc. ("SSG Inc."). The SSG project was initially going to be funded through the North American Grid Modernization Fund, which is currently managed by Stonepeak Infrastructure Partners and Infrastructure Energy LLC ("IE"). The SSG Project funds were to flow through SSG Inc.

Question: Please summarize the roles of SSG Inc., North American Grid Modernization Fund, Stonepeak Infrastructure Partners and IE in the amended SSG project.

Response:

There are no longer roles for SSG Inc., North American Grid Modernization Fund, Stonepeak Infrastructure Partners and IE in the current SSG project.

The SSG Project is no longer developed by SSG Inc. or IE through a P3 project finance structure. PUC Distribution chose to depart from the P3 project structure and utilize an RFP approach to seek competitive proposals from qualified proponents for the SSG Project. As mentioned in response to Staff-13 and CCC-4, various EPC contractors were invited by PUC Distribution to submit proposals for the SSG Project's EPC services. Amongst the invitees was the project development partner, IE (also known as Energizing, LLC), that was involved in the Original Application. However, IE did not submit any proposal to PUC Distribution Inc.

VECC-2

Reference: ICM Application P8

Preamble: PUC indicates the scope of the SSG project remains the same.

Question:

a) Is the volume of work the same? Please discuss.

b) Is the coverage of PUC's Distribution System the same? Please discuss.

Response:

a) Yes, PUC Distribution confirms that the volume of work is the same, given that the scope of the SSG Project remains the same. The main difference compared to the Original Application is that the SSG Project will now be developed, owned and operated by PUC Distribution (rather than a special purpose vehicle, SSG Inc.).

b) The coverage is the same.

VECC-3

Reference: ICM Application P9

Preamble: PUC indicates proposals were received in response to the RFP in late 2019.

Question:

a) How many proponents were invited to respond to the RFP?

b) How many proponents responded?

c) What were the qualification scores for each proponent?

Response:

a) The invitation was open to the public. In addition, we notified specifically Black and Veatch and S&T Group, including the project development partner, IE (also known as Energizing, LLC), that was involved in the Original Application. However, IE did not submit any proposal to PUC Distribution Inc.

b) Two proponents responded with a proposal.

c) The qualification scores for each proponent are not relevant and have no probative value. The RFP process has concluded and the winning bidder was Black & Veatch. The EPC Contract was subsequently negotiated and executed.

VECC-4

Reference: ICM Application P12

Preamble: PUC indicates in the first quarter of 2014, the City of Sault Ste. Marie City Council passed a resolution supporting the concept of developing a smart grid in PUC's Distribution Service Areas.

Question:

a) Please provide all correspondence to Sault Saint Marie City Council regarding the amended SSG project.

b) Please provide a copy of any City Council resolutions related to the amended SSG project.

Response:

(a) See attached presentation to City Council slide deck, January 25, 2021 at Attachment 1.

(b) Amended shareholder approval was not required because the overall SSG Project got less expensive, and this is the only reason why the federal funding dollar value went down. Note the federal funding of 25% is still the same.

Shareholder approval is from the holding company, PUC Inc, which has approved the project. Since the funding level awarded was $11.8 million (25%), and the reduction in required funding was due to the project being less expensive, anything to City Council was an information note and not for approval.

VECC-5

Reference:

Appendix AA7 Leidos Preliminary Design

Appendix AA8 Navigant Report #1 – Review of Business Case for Smart Grid Project for PUC Distribution

Appendix AA9 Navigant Report #2 – Review of Project Costs for Smart Grid Project

Appendix AA10 Navigant Report #3 – Community Microgrid Business Case Review Report

Appendix AA11 2016 Projection for Distribution Capital [JTC 1.13]

Preamble: N/A.

Question: For each of the above Appendices, please summarize the key findings in each report that further impacted the design and net benefits of the amended SSG project.

Response:

The following are the key findings in each report that PUC Distribution has taken into consideration with regards to impact on the design and net benefits of the amended SSG Project

Leidos Preliminary Design:

VVM:

- Centralized intelligence of the VVM system reside in the PUC Control Room, provided by the Survalent VVO system.
- System will interface with GIS, MDM, and SCADA systems to exchange information.
- Distributed intelligence of the VVM system provided by Load-Tap Changing (LTC) controllers at substations.
- Survalent VVM solution (software)
- Real-time voltage control accom-plished by local controllers at LTC transformers and voltage regulators.
- VVM Software would process AMI data at regular intervals and deter-mine optimal settings for LTC and regulator controllers.
- Three operating modes: Disabled; Semi-automatic and Full automatic.
- Replace existing transformers with new LTC transformers. LTC controllers are important to VVM solution and provide a local control capability by dynamically controlling transfer tap positions based on configured settings, keeping the secondary voltage of the transformer within the desired voltage range.

- Two pad-mounted voltage regulators recommended to regulate the busbar regulators will be connected on the low side of each substation transformer.
- New capacitor banks required, which will be monitored and controlled by the VVM software.
- Communication System – Fiber and/or radio communications to all substations.

DA:

- Proposed DA system will significantly improve reliability on PUC Distribution's 12.5 kV and 34.5 kV systems. The DA system is designed to be expandable, so additional feeders and substations could be added to the DA system in the future.
- West and North sections of PUC's distribution system as the primary focus of DA design efforts.
- Script-based automation system is recommended for the 34.5 kV system to improve 34.5 kV reliability.
- Proposed system will perform automatic switching actions to accomplish source-transfer when the main source is lost at a 34.5/10.5 kV substation. This script will be developed in the DA controls software and use existing SCADA controls.
- Recommendation for 12.5 kV system with Centralized Fault Location Isolation and Restoration (FLIR) Software with GIS Interface & Load Flow (i.e. Survalent FLIR); 38 reclosers on 39 feeders; 40 pole-top load break switches at tie points; 4 4-way pad-mount switches; 2 2-way pad-mount switches; 28 UG fault current indicators; 20 O/H fault current indicators.
- Recommendation for 34.5 kV system – source transfer scheme in the centralized DA software.

AMI:

- Automated Outage Reporting – Load SCADA, AMI, and GIS data into a common platform so SCADA events can be auto reported for impact based on time and scale.
- Enhance CSR Toolset with AMI data – Better organize and present AMI data in a CSR friendly UI such that they can better answer a wider set of questions with defensible data. Specifically reliability and cost/usage trends, but also quality and AMCD.
- Enhance Customer Toolset with AMI data – Better organize and present AMI data in a consumer friendly UI such that they can better answer their own questions. Specifically reliability and cost/usage trends in a similar way to CSRs.
- Improve Voltage Measurement Granularity – Modify Sensus system to more frequently call-in supervisory messages with Voltage min/avg/max. include A3 if possible.
- Complete AMI electric rollout to get universal data feed – Migrate MV90 LP meters to A3 Sensus meters. Complete >50kW service locations.

- Implement water meters at scale to ease BP change – Accelerate water module implementation to accelerate business transformation and cost savings.
- Collect VARs in order to track PF – Upgrade meters in the field to measure additional engineering metrics including reactive power.
- Implement disconnect switches to address collections – Swap out meters with disconnect capable meters to optimize business process, reduce truck rolls, and address collections challenges.
- Expanded Data Export and Reporting – Join and connect a wider set of data so data reporting and bulk export becomes more timely and easier.

Navigant Report #1 – Review of Business Case for Smart Grid Project for PUC Distribution

- The proposed UDM project is characterized by distribution automation (DA) systems; Voltage/VAR management (VVM) systems; and integration and enhancement of the existing Advanced Metering Infrastructure (AMI).
- The objective of the VVM system is to optimize voltage profiles along feeder lines and to minimize the reactive power in lines; reducing electricity consumption, demand, and line losses. The DA system will provide PUC with better real-time visibility and monitoring of the network, and enable automatic re-configuration of feeders to reduce the duration, impact, and frequency of outages. The UDM project also includes the deployment of an Outage Management System (OMS), which will integrate existing Supervisory Control and Data Acquisition (SCADA), AMI, and PUC's Customer Information System (CIS) data, as well as incorporating an Interactive Voice Response (IVR) system. The project will also include an enhanced CSR/Customer toolset, improvement to the AMI platform which will be leveraged for the VVM systems, and an analytics platform to integrate and track SCADA, AMI, CIS, OMS and GIS data for better reporting and use.
- The AMI integration scope, which includes the deployment of an OMS, CSR tools, enhanced AMI data, and an analytics platform, will enable PUC to improve a number of elements of their distribution business. PUC and its customers will benefit from better outage management and customer communication, fault localization, asset monitoring, and improvements in system operation and maintenance.
- Customer engagement activities to increase customer awareness, educate customers of the new capabilities and resiliency of their local electricity grid and obtain feedback from customer and stakeholder groups in the community.

- Not taking action is not an option given the direction from the Ontario government and the OEB. PUC will be required to develop a Smart Grid Plan and make investments to introduce Smart Grid capabilities into its system.

Navigant Report #2 – Review of Project Costs for Smart Grid Project

- The substation upgrades will support the deployment of DA, VVM and AMI enhancements. Absent the UDM project, PUC would have to incur the costs of substation upgrades in the future.
- The total cost estimates for AMI, DA and VVM (and associated substation upgrades) each appear reasonable, particularly with regard to cost associated with major equipment components. However, there is potential for upgrades and additions that may not be identified during the preliminary design such as site related costs for substations and additional equipment needed to fully implement DA and VVM. Further, equipment costs may increase upon receipt of final quotes from equipment suppliers, both due to detailed specifications provided in formal requests for quotes, in addition to increases in supplier costs that may not be included in initial quotes or in prior cost estimates.
- Navigant's experience indicates the cost of software and related support are typically areas where potential variances are highest, particularly at the preliminary engineering design phase.
- Both Leidos' commentary and Navigant's review of prior Survalent experience in DA and VVM systems suggest that the proposed UDM project is more comprehensive than other projects reviewed both in terms of the level of coverage and project size relative to the size of PUC's distribution system. Navigant does not view the project scope as unreasonable and acknowledge that Leidos has the background and capability to perform requisite engineering and design of the UDM.

Navigant Report #3 – Community Microgrid Business Case Review Report

- Considered over the 40-year life of the primary assets, the core UDM project – comprising the capital costs for construction and ongoing costs for operation – provides a strong benefit-cost ratio from a customer perspective. Even with a 30% contingency on capital and operating costs, and including PUC financing costs, the benefit / cost ratio for the project is forecast to be 1.3 based on what Navigant believes are conservative estimates of the benefits.
- Explore smart grid grants from the federal and provincial governments to cover some of the cost of the UDM project.

2016 Projection for Distribution Capital

- one underlying goal has been to flatten expenditures as evenly as possible over time and that will continue to be the case with the implementation of the DSP.
- PUC would have upgraded eight (8) distribution substations and two (2) transmission substations from 2017 to 2041 absent of the UDM project.
- In order to implement the UDM project, the distribution substations upgrades would need to occur upfront concurrent with the UDM construction period.

VECC-6

Reference: ICM Application P13

Preamble: PUC indicates that following the Navigant Reviews, PUC concluded it needed to de-scope the smart grid project to lower costs. Accordingly, PUC set out to modify the project scope, for instance, by eliminating station upgrades and to seek funding through various grants.

Question: Please discuss if this de-scoping of the smart grid project is consistent with the amended SSG project.

Response:

Yes. In the amended SSG project, PUC Distribution has eliminated station upgrades and has sought funding from NRCan.

VECC-7

Reference: ICM Application P16

Preamble: The application states "Various EPC contractors were invited by PUC Distribution to submit proposals for the SSG Project's EPC services. Amongst the invitees was the project development partner, IE (also known as Energizing, LLC), that was involved in the Original Application. However, IE did not submit any proposal to PUC Distribution Inc."

Question: Please explain why IE did not submit a proposal.

Response:

PUC Distribution does not have information as to why IE did not submit a proposal. PUC Distribution sent out the invitation to IE but did not receive any proposal in response and they did not advise PUC Distribution why they chose not to respond to the RFP.

VECC-8

Reference: ICM Application P16

Preamble: PUC indicates the costs for IE's preliminary engineering are identified in the Project Cost Estimate Memo at Appendix AA12-2.

Question:

a) Please confirm IE's preliminary engineering costs.

b) Please provide a breakdown of costs to date by year for the SSG project.

Response:

a) IE's preliminary engineering costs is $1,023,695. Please see response to Staff-34 for details.

b) Please refer to response in Staff-45.

VECC-9

Reference: ICM Application P20 Table 1

Preamble: PUC indicates the Projected % of Energy Savings with SSG Implementation is 2.70%. At Appendix AA14, PUC shows the derivation of this percentage as a CVR factor of 0.9 multiplied by Voltage Savings of 3 volts.

Question: Please confirm the origin of the CVR factor of 0.9 and the Voltage Savings of 3 volts.

Response:

The origin of the CVR factor of 0.9 and voltage savings of 3 volts were drawn from several areas and studies reviewed. The calculated or resultant 2.7% energy savings was the main input criteria for the spreadsheet that was driving the energy savings. PUC Distribution elected to include the two factors (CVR and voltage) in the spreadsheet as part of PUC Distribution's sensitivity analysis.

A key report referenced by PUC was a study for the Ministry of Energy conducted by Navigant titled "Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario" that PUC Distribution had referenced in its Original Application (and Amended Application at Appendix AA13 – Project Benefits Estimate Memo). The study report described an overall average CVR of 0.91 and average voltage reduction of 2.7% (3.24 volts on a 120V base) across the studies and projects from their report.

VECC-10

Reference: ICM Application P20 Table 1

Preamble: N/A.

Question: Please provide the Benefit to Cost ratio for the amended SSG project from a billing perspective.

Response:

Benefit/Cost Ratio	
Benefits	
Projected customer energy savings through SSG	$2,227,842
Projected system loss energy savings through SSG	$105,111
Benefit of reduced capital expenditures witth SSG	$304,390
Operating efficiency benefits due to SSG implementation	$30,816
	$2,668,159
Costs	
Additional revenue from increased SSG asset base	$1,751,221
Additional O & M expenses due to SSG implementation	$296,400
	$2,047,621
Benefit/ Cost Ratio	1.30

VECC-11

Reference: ICM Application P20 Table 1

Preamble: The Customer Annual Net Benefit Summary includes a "Benefit of reduced capital expenditures with SSG in the amount of $304,390 with details at Appendix AA17 CAPEX Deferral Spreadsheet.

Question: VECC was unable to locate Appendix AA17 Capital Deferral Spreadsheet. Please provide a hard copy and excel version of Appendix AA17.

Response:

There was a typographical error in Table 1 at the abovementioned reference. The Capital Deferral Spreadsheet was filed with Appendix AA5 and is the spreadsheet on the OEB webdrawer titled: PUC_App_AA5_App_1 JTC1_1 CAPEX Deferral Value Cal_Revised from Early UDM est_20201029

VECC-12

Reference: ICM Application P22 Table 2

Preamble: N/A.

Question: Please provide the residential consumption (kWh) that corresponds to a positive total bill impact (%).

Response:

As seen in the reference mentioned above, Table 2 shows examples of bill impacts at various consumption levels once the SSG Project is included in rates.

Residential Class at 738 kWh consumption corresponds to a 0.00% total bill impact. As such, consumption levels lower than 738 kWh would correspond to a positive total bill impact (%).

The bill impacts in Table 2 is calculated using a full year revenue requirement of $1,751,221. The bill impacts incorporated the 2.7% energy reduction savings offsetting the revenue requirement but do not reflect the additional $38,806 net savings estimated from the CAPEX benefit, the operating efficiency benefit and the additional O&M expenses or any value for projected reliability benefits.

Table 14 of the Amended Application shows the bill impact of this ICM application as a result of the OEB Capital Module determined rate riders where PUC Distribution has applied the half-year rule (in accordance with OEB's Accounting Direction).[26] This results in an incremental revenue requirement of $875,610. Based on Table 14, Residential Class at 367 kWh consumption corresponds to a 0.00% total bill impact % (with consumption savings). Therefore, consumption levels lower than 367 kWh would correspond to a positive total bill impact (%) based on calculations in Table 14.

[26] *Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance,* July 25, 2019

VECC-13

Reference: ICM Application P22 Table 2

Preamble: N/A,

Question: Please provide Table 2 based on Distribution bill impacts.

Response:

Table 2 is updated below showing only distribution bill impacts.

Class	Consumption (kWh)	Consumption (kW)	Distribution Bill Increase/Decrease	Distribution Bill Impact %
Residential	750	0	$1.43	4.40%
Residential	825	0	$1.43	4.40%
Residential	738	0	$1.43	4.40%
Residential	2,000	0	$1.43	4.40%
GS<50	2,000	0	$1.70	2.32%
GS<50	815	0	$1.25	2.95%
GS<50	3,000	0	$2.07	2.09%
GS>50	19,740	55	$11.35	2.26%
GS>50	57,220	145	$21.36	1.89%
GS>50	142,465	452	$55.49	1.69%
GS>50	169,620	468	$57.27	1.69%

VECC-14

Reference: ICM Application P24

Preamble: N/A

Question: Please provide the forecast ROE for 2020, 2021 and 2022.

Response:

The Forecasted ROE for 2020, 2021 and 2022 is 7.89%, 7.04%, and 7.60% respectively.

VECC-15

Reference: ICM Application P38

Preamble: PUC indicates preliminary forecasts for operation management of the smart grid forecasts are include din the range of 2.5 to 4.5 FTS. The project net benefit analysis used a 3 FTE forecast.

Question: Please provide the impact on the project net benefit analysis if a 4.5 FTE forecast is used.

Response:

Assuming an FTE impact of 4.5 (with additions as trades roles) would increase forecast O&M expenses by ~$218k and therefore reduce the annual net benefits to ~$398k.

VECC-16

Reference: ICM Application P49

Preamble:

PUC has three options regarding its pursuit of the SSG project:

- Option “A” is for PUC Distribution to pursue and develop the SSG Project over two (2) years following OEB approval, as contemplated in this ICM.
- Option “B” is for PUC Distribution to pursue and develop the SSG Project over ten (10) or more years in order to spread out the costs of the SSG Project on PUC Distribution’s ratepayers.
- Option “C” is to not pursue or develop the SSG Project at all.

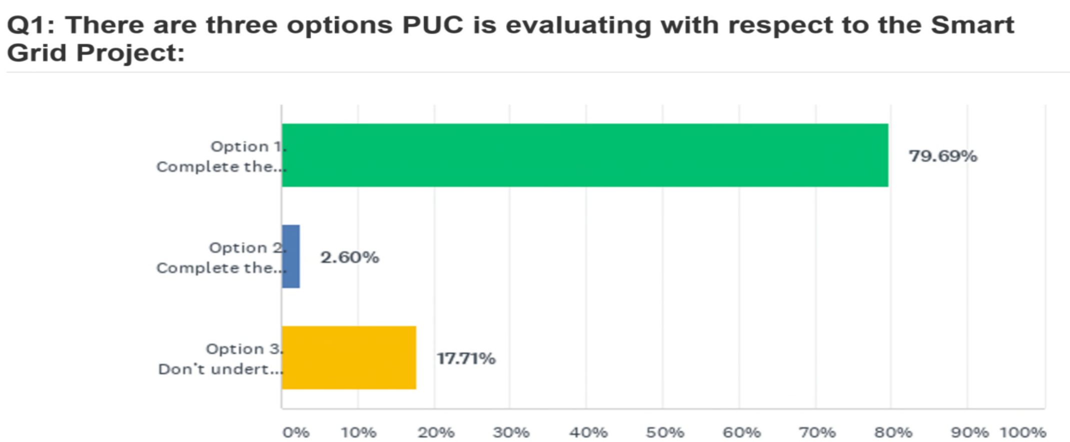
Question:

a) Did PUC carry out any customer engagement on the amended SSG project regarding customers’ preferences between the three options? If yes, please provide the results. If not, why not.

b) Did PUC advise City Council of the amended SSG project and the options? If yes, please provide all correspondence and any resolutions. If not, why not.

Response:

(a) See attached Survey Summary at Attachment 5. Question 1 of the survey asks customers’ preferences between the three options. The following is the result:



(b) See attached slide deck for presentation to City Council, January 25, 2021 at Attachment 1.

VECC-17

Reference: ICM Application P54

Preamble: PUC states "After internal discussion the decision to not overly rely on non-bill savings such as reliability improvements but focus on the customers' main perspective "the bottom line on their bill", a strong theme from customer engagement was reaffirmed and the "no net bill increase" became the primary metric for success using energy savings criteria for customers directly plus system losses savings.

Question: Please summarize PUC's position with respect to achieving reliability improvements as an indicator of success for the project.

Response:

PUC Distribution's position is to deliver as much benefit to customers as possible (including reliability benefits) through the SSG Project insofar that it does not affect the achievement of a "no net bill increase" outcome.

Reliability improvements are an important part of the SSG Project. However, as discussed in Staff-23, if scope reduction is required to maintain the capital cost limit set for the SSG project, the scope of DA may be reduced. This may in turn lower reliability improvements, but it will not affect the "net zero" bill impact objective as reduction of scope would help maintain costs at the limit.

VECC-18

Reference: ICM Application P55

Preamble: The evidence states "The scope of the Distribution Automation (DA) in the SSG Project has been recognized by PUC Distribution as the area of project implementation that would be prioritized and reduced if needed to ensure an overall "no net bill increase" project benefit target so it has been considered in this context."

Question: Please discuss and quantify the impact on reliability benefits if the scope of the DA work component was reduced by 50%.

Response:

PUC Distribution has not identified which feeders would be eliminated from the DA if scope was reduced by 50%. A worst-case assumption would be a ~50% reduction in such benefits. Cost and benefit optimization considering feeder reliability would likely result in a lessor impact.

VECC-19

Reference: Appendix AA7 Leidos Preliminary Design

Preamble: N/A

Question: Please discuss the involvement and role of Leidos Engineering LLC in the amended SSG Project.

Response:

Leidos Engineering LLC is not involved and does not have a role in the amended SSG Project, save and except that the 30% engineering design completed by Leidos and their scope of work developed provided the starting base which will be supplemented by additional engineering work by the EPC provider to cover the full distribution system and creation of a new 30% design stage of the project.

VECC-20

Reference: Appendix AA8 Navigant Report #1 – Review of Business Case for Smart Grid Project for PUC Distribution P1

Preamble: The UDM's overall system design, architecture and system components are comparable with DA and VVM systems that Navigant has reviewed or analyzed throughout the U.S. and Canada. The proposed solution for PUC however is a very comprehensive solution. Relative to PUC's service territory the proposed feeder coverage for DA and VVM, 84% and 68%; higher than many other systems Navigant has encountered.

Question:

a) Please provide the current coverage of DA and VVM in PUC's service territory.

b) Please provide the proposed feeder coverage for DA and VVM in the amended SSG project.

c) How has PUC evaluated and verified that the amended SSG project proposal represents the optimal economic level of VVM and DA?

Response:

(a) PUC Distribution Inc. currently has 0% DA and 0% VVM coverage in its service territory. It has only conventional stand-alone voltage regulation on two of its longer rural feeders which serve the exclusive function of maintaining voltage within allowable CSA limits and are not configured for VVM optimization.

(b) The amended application is proposed to cover all feeders for VVM and DA.

(c) The amended SSG project represents the optimal level of VVM and DA. For the SSG Project, all customers will be required to pay for a level of VVM and DA once the SSG Project is complete and all those same customers would receive benefits from that level of VVM and DA.

As mentioned in Staff-50, if PUC Distribution were to deploy VVM and DA on a feeder by feeder basis such that the assets become used and useful as each feeder is completed, then it will not be economically optimal for VVM because only those customers that are served by the feeder upon which the VVM has been implemented will benefit from energy reductions, however, because of assumptions made in the OEB's rate setting process, all customers will be required to pay for those improvements. The only way to ensure that all customers benefit from the VVM upgrades is to implement the project across the entire service area at once to ensure all customers see no net bill increase, which is what is proposed in the SSG Project.

VECC-21

Reference: N/A

Preamble: N/A

Question: Please explain how PUC and its customers are protected from significant cos overagest, scheduling issues, delays and lower than expected benefits for some segments of the system.

Response:

Please see response to Staff-32 and CCC-27.

VECC-22

Reference: N/A

Preamble: N/A

Question: Please provide PUC's proposed performance standard metrics for the project.

Response:

Copied from part of Staff-46.

PUC proposed metrics.

Metrics	Project Title:	SSG Plan to Utilize Metric
GHG Emission Reductions and other Environmental Benefits	**Process indicators-VVM:** Reduced energy losses from GHG emitting supply (kWh); reduced customer energy consumption (kWh) **Impact indicators-VVM:** Tons CO_2e avoided from reduced energy losses and reduced customer consumption **Process indicators-DA:** # of truck rolls avoided; reduced energy losses from GHG emitting supply (kWh), resulting from re-conductoring and phase-balancing **Impact indicators-DA:** Tons CO_2e avoided from reduced vehicle emissions and reduced energy losses	**Yes** **Yes** **Partly/To Be Determined** **Partly/To Be Determined**
Improved Asset Utilization and Increased Efficiency	**Process indicators-VVM:** Reduced peak demand on utility assets (kW); Reduced need for grid reserve capacity (kW); Increased load factor on certain assets; Reduced energy losses (kWh) **Impact indicators-VVM:** $ savings from deferred system upgrades; $ reduced utility demand charges; $ energy savings to customers **Process indicators-DA:** # of truck rolls avoided (vehicle miles); reduced overtime (OT hours); # of customer minutes with outages avoided (minutes) **Impact indicators-DA:** O&M savings due to reduced truck rolls and overtime;	**Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined**
Increased Reliability and Resiliency	**Process indicators-VVM:** None **Impact indicators-VVM:** None	

	Process indicators-DA: # of events Fault Location, Isolation and Restoration responded to; # customer calls/complaints avoided due to fewer outages **Impact indicators-DA:** $ revenue loss avoided from outages avoided; customer average interruption duration index (CAIDI) for customers served by the project; customer minute interruptions avoided	**Yes** **Yes**
Increased System Flexibility and Renewable Energy Penetration	**Process indicators-VVM:** # of feeders with VVM installed and operational **Impact indicators-VVM:** # of voltage actions taken annually to improve grid efficiency and mitigate renewable intermittency **Process indicators-DA:** # of feeders integrated into Fault Location, Isolation and Restoration (FLIR) system **Impact indicators-DA:** % of feeders with automation	**Yes** **Yes** **Yes** **Yes**
Cyber Security	**Process indicators-VVM:** Best practices developed or applied on system communications with AMI (qualitative indicator) **Impact indicators-VVM:** Real-time issue identification and reaction to cyber security threats **Process indicators-DA:** best practices developed or adhered to **Impact indicators-DA:** real-time issue identification and reaction to cyber security threats	**Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined**
Economic and Social Benefits	**Process indicators-VVM:** # jobs to implement system and highly qualified personnel trained, business case established/documented for VVM (Project) **Impact indicators-VVM:** Reduced customer charges due to improved (flatter, lower) voltage profile across the feeder (project); reduced customer charges or off-set increases to customer charges due to the lower demand charges and energy saved at the system level **Process indicators-DA:** # jobs to implement system and created to monitor the system; # customer jobs created due to higher reliability/resiliency **Impact indicators-DA:** $ customer value (e.g. avoided revenue loss) from avoided outages	**Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined** **Partly/To Be Determined**

1

VECC-23

Reference: N/A

Preamble: N/A

Question: Please provide all correspondence to PUC's Board of Directors regarding the amended SSG project.

Response:

Please see the following attachments:

Relevant pages of the September 25, 2019 President's Report at Attachment 6.

Information Note dated February 26, 2020 at Attachment 3.

Information Note dated May 13, 2020 – Sault Smart Grid (SSG) Project Update at Attachment 4.

VECC-24

Reference 1: Appendix AA5 - Appendix 4 JTC1_18 Copy of PUC SSM UDM Business Case Analysis_FINAL 20160504

Refereence 2: Appendix AA8 Navigant Report #1 – Review of Business Case for Smart Grid Project for PUC Distribution P41

Preamble: At reference#1, Navigant indicates it reviewed the following documents during the business case review.

1. Leidos BCA model
2. Reliability Statistics - METSCO
3. Distribution Load Forecast – METSCO
4. Ontario Energy Board Guidelines for Distribution System Planning
5. Infrastructure Ontario – Alternative Financing and Procurement
6. Infrastructure Ontario – Assessing Value for Money
7. ECo – UDM Project Bill Impact and CAPEX Offset Analysis
8. ECo – Cost Allocation & Evaluating Value of Risk-Transfer for UDM Project
9. Illume Advising - Customer Outreach Plan
10. ECo – PUC Board Brief
11. ECo – UDM Project Financial Analysis
12. Leidos – Technical Substantiation and Design Documents
13. Overview of Regulatory Framework and Rate-making process
14. Review of Project Costs for Smart Grid Project for PUC Distribution
15. UDM Project Review (Review of Leidos Technical Design documents)
16. Term sheet for the Provision of UDM Technology and Services to PUC Distribution Inc.
17. PUC Asset Management Plan via METSCO Energy Solutions
18. Parker Venture Management Inc. – Smart Energy Strategy

At reference #2, Navigant states "To assess the business case for the project, we have used information provided by Leidos and ECo to identify the costs and savings for the project, reviewed the reasonableness of those estimates based on other SG experience and identified potential areas of risk or uncertainty.

Question:

Please provide the following documents from the above list that Navigant reviewed during the business case review:

2. Reliability Statistics - METSCO

7. ECo – UDM Project Bill Impact and CAPEX Offset Analysis

9. Illume Advising - Customer Outreach Plan

15. UDM Project Review (Review of Leidos Technical Design documents)

Response:

PUC Distribution is unable to locate the materials cited in which Navigant reviewed during its business case review and in any case, these materials are no longer relevant as it relates to Eco's previous proposal for the project using a P3 project model.

VECC-25

Reference 1: AA5

At the Technical Conference, VECC requested undertakings JTC2.16, JTC2.17, JCT2.18 for PUC to provide copies of the following reports from the list of documents in VECC- that are not on the record.

8. ECo – Cost Allocation & Evaluating Value of Risk-Transfer for UDM Project below

10. ECo – PUC Board Brief

11. ECo – UDM Project Financial Analysis

In each undertaking response PUC states “Not applicable. PUC Distribution is no longer using P3 type project structure for the SSG Project and therefore the undertaking is now irrelevant to its ICM Application.”

Reference 2: Appendix AA8 Navigant Report #1 – Review of Business Case for Smart Grid Project for PUC Distribution P41

At reference #2, Navigant states “To assess the business case for the project, we have used information provided by Leidos and ECo to identify the costs and savings for the project, reviewed the reasonableness of those estimates based on other SG experience and identified potential areas of risk or uncertainty.

Preamble: N/A

Question: Please provide the requested reports above provided by Eco that Navigant used to assess the business case for the project.

Response:

Please see response to VECC-24.

VECC-26

Reference: Appendix AA3-5 Project Schedule

Preamble: N/A

Question:

a) Please provide the date of the Project Schedule.

b) Please provide and explain any task variances to date.

Response:

a) The date of the Project Schedule is October 7, 2020.

b) Work has not commenced yet and therefore there are no task variances to date. The project schedule will not become active until OEB approval and Notice to Proceed is issued by PUC Distribution. At that point adjusted dates will reflect new start date and proceed.

VECC-27

Reference: Appendix AA12-1

Preamble: N/A

Question: Please provide the date of the Project Cost Estimate.

Response:

The date of the Project Cost Estimate October 7, 2020.

VECC-28

Reference: Appendix AA12-3

Preamble: N/A

Question:

a) Please explain how the contingency of $462,846 related to VVM was derived.

b) Please explain how the contingency of $844,036 related to DA was derived.

c) Please explain why there is no allocation of contingency for AMI Integration.

Response:

(a)/(b) PUC Distribution considered two main areas for including in contingency for the VVM and DA parts of the project. The largest contingency related to known field conditions and constraints that needed to be considered on unit cost assumption for DS site egress. These are related to underground infrastructure and physical site constraints with railway rights-of-way. A miscellaneous hardware/ material of about 2% was also included. The VVM and DA proportions were based on project subtotal/asset value.

(c) The AMI integration section did not have a specific contingency included. This was considered to be covered in PUC Distribution's engineering direct cost estimates scope and the decision to pull a part of the work from the EPC contract for the integrated platform and performance reporting.

VECC-29

Reference: EB-2018-0219 ICM Application P33 Table 8

Preamble: N/A

Question: Please update Table 8.

Response:

The information mentioned in the responses to this question do not reflect the most up to date CWIP rates.

Table 8 update has been provided below.

	2019 Actual	2020 Projected	2021 Planned	2022 Planned
System Access as proposed in 2018 DSP	$ 1,615,276	$ 2,086,480	$ 1,603,804	$ 1,560,434
System Renewal as proposed in 2018 DSP	$ 6,905,898	$ 3,296,444	$ 4,532,889	$ 7,092,642
System Services as proposed in 2018 DSP	$ -	$ -	$ -	$ -
General Plant as proposed in 2018 DSP	$ 54,629	$ 61,932	$ 59,853	$ 55,100
Total as proposed in 2018 DSP	$ 8,575,803	$ 5,444,856	$ 6,196,546	$ 8,708,176
Revised work plan	$ (3,780,255)	$ (176,629)	$ 6,601,668	
SSG implementation	$ -	$ -	$ -	$ 24,880,278
	$ 4,795,548	$ 5,268,227	$ 11,230,545	$ 33,588,454

VECC-30

Reference: EB-2018-0219 CCC-16 Updated 20190619

Preamble: N/A

Question:

a) Please update Appendix 2-AA and from PUC's Distribution's 2018 COS Application to include 2018 and 2019 actuals.

b) Please provide Appendix 2-AA for the years 2020 to 2023.

Response:

(a) and (b)

PUC Distribution is of the view that the information requested related to an updated Appendix 2-AA for 2018 to 2023 (i.e. five years) is excessive (would take 3-4 individuals' full capacity over a period of several weeks or more) and the resulting information has no probative value to this ICM Application. Appendix 2-AA is a requirement for PUC Distribution's COS Application and will be updated accordingly at its next COS Application in 2023.

VECC-31

Reference: EB-2018-0219 VECC-1

Preamble: N/A

Question:

a) Please update the Table in part (a) to include data for the years 2019 and 2020.

b) Please update the Table in part (b) to include data for the years 2019 and 2020.

c) Please provide PUC's SAIDI and SAIFI results for the years 2009 to 2020.

d) Please provide PUC's SAIDI and SAIFI results for the years 2009 to 2020, excluding Major Event Days and Loss of Supply.

Response:

(a)

Year	Number of Sustained Outages
2010	390
2011	500
2012	504
2013	561
2014	710
2015	724
2016	558
2017	470
2018	352
2019	563
2020	Data not yet available

(b)

Year	Customer Hours of Interruptions
2010	69,287
2011	277,647
2012	54,264
2013	87,737

2014	39,660
2015	111,858
2016	84,824
2017	65,952
2018	78,699
2019	115,191
2020	Data not yet available

(c)

OutageYear	SAIDI	SAIFI
2009	n/a	n/a
2010	2.1	2.81
2011	8.41	4.59
2012	1.64	2.17
2013	2.66	3.54
2014	1.19	1.21
2015	3.34	1.84
2016	2.53	2.21
2017	1.96	1.61
2018	2.34	1.75
2019	13.01	3.45
2020	4.53	2.85

(d) The following table summarises 2009-2020 SAIDI and SAIFI excluding loss of supply and major event days (from OEB scorecards):

OutageYear	SAIDI	SAIFI
2009	n/a	n/a
2010	n/a	n/a
2011	2.92	3.61
2012	1.65	2.17
2013	1.42	1.78
2014	1.19	1.21
2015	1.37	1.03
2016	1.49	1.41
2017	1.43	1.21
2018	1.27	1.28

2019	1.68	1.70
2020	n/a	n/a

VECC-32

Reference: EB-2018-0219 VECC-1

Preamble: In the response to part (c), PUC indicates the annual reduced interruption frequency and duration projections (refer to Appendix 7 page 11) resulting from the SSG Project are:

- SAIFI reduced by 37%
- SAIDI reduced by 46%
- CAIDI reduced by 16%

Question:

a) Please explain how the above annual reliability projections are utilized in the reliability savings calculation.

b) Please provide the corresponding reductions in SAIFI and SAIDI resulting from the above reliability reduction projections.

Response:

a) Navigant describes the process in their report (see Appendix AA5 in section 4.2 Benefits Analysis). The percentage savings referenced above were applied to the PUC Distribution historical outage data work done by Leidos and resulted in an average annual reduction of 34,000 customer interruptions per year and an average reduction in customer minutes of interruption of 2.1 million minutes. Navigant applied the results to the referenced LBNL Study for a customer value and to calculate the NPV projections.

(b) The reduction in SAIFI and SAIDI using the percentages above would result in SAIFI=1.53 and SAIDI=1.11.

VECC-33

Reference: EB-2018-0219 VECC-15

Preamble: N/A

Question: Please update the response to part (a) resulting from implementation of the amended SSG Project in 2021 and 2022.

Response:

The project is now being implemented in 2022 and not expanded over multiple years. Therefore PUC Distribution has provided the requested table for the year 2022.

Class	Consumption (kWh)	Total Bill Increase/Decrease	Total Bill Impact %
Residential	400	$1.07	1.45%
Residential	750	-$0.04	-0.03%
Residential	806	-$0.21	-0.18%
Residential	1130	-$1.24	-0.78%
Residential	2000	-$3.98	-1.53%
Residential	3000	-$7.14	-1.89%

<u>VECC-34</u>

<u>Reference:</u> EB-2018-0219 VECC-23

<u>Preamble:</u> N/A

<u>Question:</u> Please update the response to VECC-23.

<u>Response</u>:

Revised Application IR VECC-34 : Request to update Original Appliction IR - VECC-23

Table from VECC-23 - Added Column with current Forecast

Existing equipment unchanged

Equipment Description	Existing Equipment Installed (Quantity)	Proposed Equipment to Install (Quantity)	Total (Quantity)	Increase (%)	Proposed Equipment to Install
15kV pole top switches w/controller	0	35-40	40	N/A	26
15kV pole top recloser w/controller	3	35-40	43	1333%	25
15kV 2-way pad mount switches w/controller	0	4-8	8	N/A	3
15kV 4-way pad mount switches w/controller	0	4-8	8	N/A	3
3 phase O/H FCI	0	~30	30	N/A	30
3 phase U/G FCI	0	~20	20	N/A	19
Substation Regulators w/controller	0	~48	48	N/A	32
Line Regulators w/controller	0	3-5	5	N/A	2
Capacitors	5	2-4	9	80%	2
3 phase O/H FCI - auto transfer	0	~15	15	N/A	16
SpeedNet 900 MHz radios	12	~45	57	375%	0
SpeedNet repeaters	2	~12	14	600%	0
SpeedNet 900 MHz gateway radios	2	~10	12	500%	0

VECC-35

Reference: EB-2018-0219 VECC-30

Preamble: The response to VECC-30 indicates PUC proposed a conservative 25% valuation of calculated reliability benefits in benefit estimates.

Question: Please confirm PUC used the same proposed conservative 25% valuation of calculated reliability benefits in benefit estimates for the amended SSG project.

Response:

PUC Distribution has not proposed to use any valuation for the reliability benefits in the calculation of Customer Annual Net Benefits Summary as shown in Table 1 of the application. For more information on how the $2,017,000 reliability benefits was calculated, please see response to Staff-54.

ATTACHMENT 1 – SLIDE DECK FOR CITY COUNCIL PRESENTATION - JANUARY 25, 2021

Sault Smart Grid

Council Update Jan 25, 2021

Background

- In July 2018, Sault Ste. Marie City Council was briefed on the Sault Smart Grid (SSG) project:
  - Two main components, Voltage Optimization (VVO) and Distribution Automation (DA)
  - Other grid benefits:
    - Grid Insight, increased accommodation of DER's (EV's, small home generation) and significantly reduced GHG emissions provincially (estimated at 2804 tonnes annually)
    - Project cost, customer rate benefits
- SSG was submitted to the OEB, and was then amended based on feedback received

Amended Application

- Primary differences from original application:
  - Financed through traditional financing rather than through a Public-Private Partnership model (P3).
    - Results in interest savings
    - PUC directly contracts to EPC contractor & issued RFP in mid 2020.
      - Black & Veetch was the successful bidder
      - EPC backing energy savings through contractual obligations
    - Simplifies project structure
  - Moves expertise and technology into PUC ranks.

Next Steps

- Currently working through Interrogatory questions from OEB staff and Intervenors
- Should have a project go or no-go from the OEB by summer.
- PUC will return to Council, if approved, with revised project schedule, financing, final budget and ratepayer impact/savings.


QUESTIONS?
PUC

ATTACHMENT 2 – CLOSED SESSION MINUTES – PUC DISTRIBUTION INC. JANUARY 22, 2020

January 22, 2020
Meeting No. 01

PUC DISTRIBUTION INC. BOARD MEETING CLOSED SESSION MINUTES

Concurrent with:	**PUC Services Inc., PUC Inc.,**	
Date and Time:	**Wednesday January 22, 20 20 – 4:30 p.m.**	
Location:	**PUC Board Room**	
Members Present:	Jim Boniferro, Acting Chair	Pat McAuley Mark Howson
Absent:	Christian Provenzano	
Staff Present:	Rob Brewer, President & CEO Kelly McLellan, VP Finance & Corporate Development Claudio Stefano, VP Operations & Engineering Kevin Bell, VP Business Development	Jessica Tett, Communications Coordinator Katie Elliott, Manager, Corporate Communications Mark Faught, Director, Finance
Guests:		

[redacted]

7.1 Smart Grid – Settlement with IE

On a **MOTION** moved by P. McAuley, seconded by M. Howson and carried:

That the Board of PUC Distribution authorizes the CEO to execute the presented Asset Purchase Agreement in a substantially similar form with Infrastructure Energy Inc.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

Draft: January 21, 2020

Infrastructure Energy Inc.

As Vendor

- and -

Energizing, LLC

- and -

Infrastructure Energy, LLC

As Guarantors

- and -

[Member 1]

[Member 2]

As Members

- and -

PUC Distribution Inc.

As Purchaser

ASSET PURCHASE AGREEMENT

[Date]

TABLE OF CONTENTS

List of Schedules

ASSET PURCHASE AGREEMENT dated [●]

BETWEEN:

Infrastructure Energy Inc.

As Vendor

- and -

Energizing, LLC

- and -

Infrastructure Energy, LLC

As Guarantors

- and -

[shareholder 1]

[shareholder 2]

As Members

- and -

PUC Distribution Inc.

As Purchaser

RECITALS:

A. The Vendor and Guarantors each carry on the business of developing and deploying utility infrastructure project and specifically community-scale microgrid projects.

B. The Members comprise all members who individually own 10% of the issued and outstanding membership interests of the Guarantors and all of the issued and outstanding shares of the Vendor.

C. The Vendor wishes to sell and the Purchaser wishes to purchase the Purchased Assets.

D. Immediately prior to the entry into this Agreement, the Guarantors and the Vendor entered into a purchase and sale agreement (the "**Preliminary Sale Agreement**") pursuant to which the Guarantors did sell, transfer, convey and assign to the Vendor and the Vendor did purchase and acquire from the Vendor, free and clear of all Encumbrances, all of the Guarantor's right, title and interest in and to the Purchased Assets.

E. The bill of sale executed by the Guarantors and Vendor pursuant to the Preliminary Sale Agreement (the "**Preliminary Bill of Sale**") has been delivered to the Purchaser.

F. The Members are parties to this Agreement for the sole purpose of providing the guarantee in Section 7.16.

G. The Guarantors and the Members will derive substantial economic benefits from the transactions contemplated by this Agreement.

THE PARTIES AGREE AS FOLLOWS:

ARTICLE 1
INTERPRETATION

1.1 Definitions. In this Agreement, including the Recitals to this Agreement, unless the context otherwise requires:

(1) "**Affiliate**" means an affiliated body corporate within the meaning of the following:

(a) one body corporate is affiliated with another body corporate if one of them is the subsidiary of the other or both are subsidiaries of the same body corporate or each of them is controlled by the same person; and

(b) if two bodies corporate are affiliated with the same body corporate at the same time, they are deemed to be affiliated with each other.

For purposes of this definition, a body corporate is controlled by a person or by two or more bodies corporate if (i) securities of the body corporate to which are attached more than 50% of the votes that may be cast to elect directors of the body corporate, are held, other than by way of security only, by or for the benefit of that person or by or for the benefit of those bodies corporate; and (ii) the votes attached to those securities are sufficient, if exercised, to elect a majority of the directors of the body corporate. For the purposes of this definition, a body corporate is a subsidiary of another body corporate if (i) it is controlled by (A) that other body corporate, (B) that other body corporate and one or more bodies corporate each of which is controlled by that other body corporate, or (C) two or more bodies corporate each of which is controlled by that other body corporate; or (ii) it is a subsidiary of a body corporate that is a subsidiary of that other body corporate.

(2) "**Agreement**" means this asset purchase agreement, including all Schedules, appendices and exhibits to this asset purchase agreement, as amended, supplemented, restated and replaced from time to time in accordance with its provisions.

(3) "**Ancillary Assets**" has the meaning attributed to that term in Section 2.1.

(4) “**Ancillary Intellectual Property**” has the meaning attributed to that term in Section 2.1.

(5) “**Applicable Law**” means:

(a) any domestic (federal, provincial or municipal) or foreign statute, law (including common and civil law), code, ordinance, rule, regulation, order-in-council, restriction or by-law (zoning or otherwise);

(b) any judgement, order, writ, injunction, directive, decision, ruling, decree or award;

(c) any regulatory policy, practice, standard or guideline;

(d) any published administrative position; or

(e) any permit or approval;

of any Governmental Authority, binding on or affecting the Person referred to in the context in which the term is used or binding on or affecting the property of that Person.

(6) “**Approvals**” means franchises, licences, qualifications, authorizations, consents, certificates, registrations, exemptions, waivers, filings, grants, notifications, privileges, rights, orders, judgments, rulings, directives, and other permits and approvals.

(7) “**Associate**” mean any of the following:

(a) the Guarantors;

(b) the Members;

(c) the Affiliates of the Vendor, the Guarantors or the Members;

(d) the officers, directors and employees of the Vendor, a Guarantor, a Member or any Affiliate of the Vendor, the Guarantors or the Members; and

(e) bodies corporate who are controlled by, whose Equity Interests are owned in whole or in part by, who employ or on whose board of directors sit any Associate described in paragraph (a), (c) or (d) of this definition;

(8) “**Business Day**” means any day, except Saturdays and Sundays, on which banks are generally open for non-automated business in Ontario, Canada.

(9) “**Closing**” means the completion of the Transactions on the Closing Date in accordance with this Agreement.

(10) “**Closing Date**” means the next Business Day following the date of execution of this Agreement or such other date as agreed to by the Purchaser and Vendor in writing.

(11) “**Constating Documents**” means, with respect to any Person, its articles or certificate of incorporation, amendment, amalgamation or continuance, memorandum and articles of

association, letters patent, supplementary letters patent, by-laws, partnership agreement, limited liability company agreement or other similar document, and all unanimous shareholder agreements, other shareholder agreements, voting trusts, pooling agreements and similar Contracts, arrangements and understandings applicable to the Person's Equity Interests, all as amended, supplemented, restated and replaced from time to time.

(12) "**Contract**" means any agreement, contract, indenture, lease, occupancy agreement, deed of trust, licence, option, undertaking, promise or any other commitment or obligation, whether oral or written, express or implied.

(13) "**CRA**" means the Canada Revenue Agency or any successor agency.

(14) "**Developers**" has the meaning attributed to such term in Section 5.1(13)(f)**.**

(15) "**ETA**" means the *Excise Tax Act* (Canada) and the regulations made thereunder.

(16) "**Encumbrance**" means any encumbrance, lien, charge, hypothec, pledge, mortgage, title retention agreement, security interest of any nature, prior claim, adverse claim, exception, reservation, restrictive covenant, agreement, easement (whether or not registered against title), lease, licence, right of occupation, option, right of use, right of first refusal, right of pre-emption, privilege or any matter capable of registration against title or any Contract to create any of the foregoing.

(17) "**Equity Interests**" means, with respect to any Person, any and all present and future shares, units, trust units, partnership or other interests, participations or other equivalent rights in that Person's equity or capital, however designated and whether voting or non-voting.

(18) "**Escrow Agent**" means Purchaser's Counsel or such other reputable escrow agent as the Purchaser may designate in writing.

(19) "**Escrow Agreement**" means the escrow agreement substantially in the form of Schedule 3.1 to be entered into among the Escrow Agent, the Purchaser and the Vendor.

(20) "**Escrow Release Date**" means the date on which the Purchaser is required to instruct the Escrow Agent to pay the Purchase Price or Supplemental Payment, as the case may be, to the Vendor pursuant to Section 3.2

(21) "**GST/HST**" means all Taxes payable under Part IX of the ETA (including where applicable both the federal and provincial portion of those Taxes) or under any provincial legislation imposing a similar value added or multi-staged tax.

(22) "**Governmental Authority**" means any domestic or foreign government, whether federal, provincial, state, territorial, local, regional, municipal, or other political jurisdiction, and any agency, authority, instrumentality, court, tribunal, board, commission, bureau, arbitrator, arbitration tribunal or other tribunal, or any quasi-governmental or other entity, body, organization or agency, insofar as it exercises a legislative, judicial, regulatory, administrative, expropriation or taxing power or function of or pertaining to government.

(23) "**Guarantors**" mean Infrastructure Energy, LLC, a limited liability company organized under the laws of Delaware and Energizing, LLC, a limited liability company organized under the laws of Delaware.

(24) "**Infringe**" means infringe (whether directly, contributorily, by inducement or otherwise), misappropriate, violate or otherwise conflict with or harm (whether direct, contributory, by inducement or otherwise) and "**Infringed**" and "**Infringement**" have a corresponding meaning.

(25) "**Intellectual Property**" means, individually and collectively, howsoever created and wherever located:

(a) all domestic and foreign patents and applications thereof and all reissues, divisions, continuations, renewals, extensions and continuations-in-part thereof;

(b) all inventions (whether patentable or not), invention disclosures, improvements, trade secrets, proprietary information, know-how, technology, technical data, schematics and customer lists, and all documentation relating to any of the foregoing;

(c) all copyrights in all works (including Software) and database right, copyright registrations and applications thereof, and all works of authorship and moral rights, and all other rights corresponding thereto throughout the world;

(d) all trade names, domain names, corporate names, trade dress, distinguishing guises, logos, slogans, brand names, trademarks (whether registered or common law and whether used with wares or services and including the goodwill attaching to such trademarks) and registrations and applications for registration thereof;

(e) all Software (in source code and object code form) and databases, and any proprietary rights in such Software and databases;

(f) all integrated circuit design, mask work, or topography registrations or applications thereof;

(g) all industrial designs and applications for and registration of industrial designs, design patents and industrial design registrations;

(h) other intellectual or industrial property whatsoever, including the intellectual property described in Schedule 5.1(13);

(i) all income, royalties, damages and payments now and hereafter due and/or payable with respect to any of the foregoing, including damages and payments for past or future Infringements thereof; and

(j) all rights to sue for past, present and future Infringements of any of the foregoing.

(26) "**Losses**" has the meaning attributed to that term in Section 6.1(8).

(27) “**Member**” means each of [Glen Martin and [member 2], as member[s] of Energizing, LLC] and [Glen Martin and [member 2], as member[s] of Infrastructure Energy, LLC].

(28) “**Other Agreements**” has the meaning attributed to that term in Section 7.6.

(29) “**Parties**” means collectively, the Purchaser, the Vendor, the Guarantors and the Members, and “**Party**” means any of them.

(30) “**Person**” is to be broadly interpreted and includes an individual, a corporation, a partnership, a joint venture, a trust, an association, a syndicate, an unincorporated organization, a Governmental Authority, an executor or administrator or other legal or personal representative, or any other juridical entity.

(31) “**Personal Information**” means information about an identifiable natural person, but does not include the name, title, business address or telephone number of an employee of the Vendor, that is to be disclosed to the Purchaser at Closing or that was disclosed to the Purchaser to permit the Purchaser to carry out its due diligence in connection with the Transactions.

(32) “**Preliminary Bill of Sale**” has the meaning attributed to that term in the recitals.

(33) “**Preliminary Sale Agreement**” has the meaning attributed to that term in the recitals.

(34) “**Proceeding**” means:

(a) any suit, action, dispute, investigation, claim, arbitration, order, summons, citation, directive, charge, demand or prosecution, whether legal or administrative;

(b) any other proceeding; or

(c) any appeal or application for review;

at law or in equity or before or by any Governmental Authority.

(35) “**Purchase Price**” has the meaning attributed to that term in Section 2.4.

(36) “**Purchased Assets**” has the meaning attributed to that term in Section 2.1.

(37) “**Purchaser**” means PUC Distribution Inc., a corporation incorporated under the laws of Ontario.

(38) “**Purchaser's Counsel**” means Borden Ladner Gervais LLP.

(39) “**Release Agreement**” means the release agreement to be entered into between the Vendor, the Guarantors, the Members and Purchaser, substantially in the form of Schedule 4.1(1)(d)(vii).

(40) “**Report**” has the meaning attributed to that term in Section 2.1.

(41) "**Report Author**" means the author or signatory of any Report.

(42) "**Representatives**" means, with respect to any Party, its Affiliates and, if applicable, its and their respective directors, officers, employees, agents and other representatives and advisors.

(43) "**Software**" means software, including all versions thereof, whether installed locally, on a local area network or delivered through the internet, and all related documentation, manuals, source code and object code, program files, data files, computer related data, field and data definitions and relationships, data definition specifications, data models, program and system logic, interfaces, program modules, routines, sub-routines, algorithms, program architecture, design concepts, system designs, program structure, sequence and organization, screen displays and report layouts, including any and all modifications, changes, release, versions, upgrades, updates or patches of any of the foregoing, and all other material related to such software.

(44) "**SSG Project**" means the project being undertaken by the Purchaser to introduce a Volt/VAR management system and feeder distribution automation system, among other system upgrades, from time to time referred to as the Sault Smart Grid Project.

(45) "**SSG Project Approval**" means the approval of the Incremental Capital Module application in respect of the SSG Project by the Ontario Energy Board, (1) substantially as submitted and (2) in a timeframe consistent with the requirements of the funding agreement currently in place between the Purchaser and Natural Resources Canada, in each case, so as not to effect the financial viability of the Project in the opinion of the Purchaser.

(46) "**Supplemental Condition Precedent**" means the condition precedent set forth in Section 4.2.

(47) "**Supplemental Payment**" has the meaning attributed to that term in Section 2.4.

(48) "**Supplementary Closing**" means, if applicable, the completion of the Transactions on the Supplementary Closing Date in accordance with this Agreement.

(49) "**Supplementary Closing Date**" means, if applicable, the date failing 14 days after the satisfaction of the Supplemental Conditions Precedent or such other date as agreed to by the Purchaser and Vendor in writing.

(50) "**Tax Act**" or any reference to a specific provision thereof means the *Income Tax Act* (Canada) and legislation of any legislature of any province or territory of Canada (including the *Taxation Act* (Québec)) and any regulations made thereunder in force of like or similar effect.

(51) "**Taxes**" means taxes, duties, fees, premiums, assessments, imposts, levies and other charges of any kind whatsoever imposed by any Governmental Authority, including all interest, penalties, fines, additions to tax or other additional amounts imposed in respect thereof (including those levied on, or measured by, or referred to as, income, gross receipts, profits, capital, transfer, land transfer, gains, capital stock, production, gift, wealth,

environment, net worth, utility, sales, goods and services, harmonized sales, use, consumption, valued-added, excise, stamp, withholding, premium, business, franchising, property, employer health, payroll, employment, health, social services, education and social security taxes, surtaxes, customs duties and import and export taxes, development, occupancy, social services, licence, franchise and registration fees and employment insurance, health insurance and Canada, Québec and other government pension plan premiums or contributions), and "**Tax**" has a corresponding meaning.

(52) "**Transactions**" means the purchase and sale of the Purchased Assets and all other transactions contemplated by this Agreement.

(53) "**Transmission**" has the meaning attributed to that term in Section 7.14(1).

(54) "**Vendor**" means Infrastructure Energy Inc., a corporation incorporated under the laws of Canada.

(55) "**Vendor's Counsel**" means WeirFoulds LLP.

1.2 Construction. This Agreement has been negotiated by each Party with the benefit of legal representation, and any rule of construction to the effect that any ambiguities are to be resolved against the drafting party does not apply to the construction or interpretation of this Agreement.

1.3 Certain Rules of Interpretation. In this Agreement:

(a) the division into Articles and Sections and the insertion of headings and the Table of Contents are for convenience of reference only and do not affect the construction or interpretation of this Agreement;

(b) the expressions "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this Agreement and not to any particular portion of this Agreement; and

(c) unless specified otherwise or the context otherwise requires:

(i) references to any Article, Section or Schedule are references to the Article or Section of, or Schedule to, this Agreement;

(ii) "including" or "includes" means "including (or includes) but is not limited to" and is not to be construed to limit any general statement preceding it to the specific or similar items or matters immediately following it;

(iii) "the aggregate of", "the total of", "the sum of", or a phrase of similar meaning means "the aggregate (or total or sum), without duplication, of";

(iv) references to Contracts are deemed to include all present amendments, supplements, restatements and replacements to those Contracts;

(v) references to any legislation, statutory instrument or regulation or a section thereof are references to the legislation, statutory instrument, regulation or section as amended, re-enacted, consolidated or replaced from time to time;

(vi) words in the singular include the plural and vice-versa and words in one gender include all genders.

1.4 Knowledge. In this Agreement, any reference to the knowledge of any Party means to the best of the knowledge, information and belief of the Party after reviewing all relevant records and making due inquiries regarding the relevant matter of all relevant Representatives of the Party, and any reference to the knowledge of the Vendor and the Members means to the best of the knowledge, information and belief of any of them after reviewing all relevant records and making due inquiries regarding the relevant matter of all their respective relevant Representatives.

1.5 Computation of Time. In this Agreement, unless specified otherwise or the context otherwise requires:

(a) a reference to a period of days is deemed to begin on the first day after the event that started the period and to end at 5:00 p.m. on the last day of the period, but if the last day of the period does not fall on a Business Day, the period ends at 5:00 p.m. on the next succeeding Business Day;

(b) all references to specific dates mean 11:59 p.m. on the dates;

(c) all references to specific times are references to Eastern time; and

(d) with respect to the calculation of any period of time, references to “from” mean “from and excluding” and references to “to” or “until” mean “to and including”.

1.6 Performance on Business Days. If any action is required to be taken pursuant to this Agreement on or by a specified date that is not a Business Day, the action is valid if taken on or by the next succeeding Business Day.

1.7 Currency and Payment. In this Agreement, unless specified otherwise:

(a) references to dollar amounts or “$” are to Canadian dollars;

(b) any payment is to be made by an official bank draft drawn on a Canadian chartered bank, wire transfer or any other method (other than cash payment) that provides immediately available funds; and

(c) except in the case of any payment due on the Closing Date, any payment due on a particular day must be received and available by 4:00 p.m. on the due date and any payment received and available after that time is deemed to have been made and received on the next succeeding Business Day.

1.8 Schedules. The following Schedules are attached to and form part of this Agreement:

Schedule 3.1	Escrow Agreement
Schedule 4.1(1)(d)(vii)	Release Agreement
Schedule 4.1(1)(d)(v)	Form of Bring-Down Certificate
Schedule 5.1(1)	Jurisdictions
Schedule 5.1(6)	Listed Reports
Schedule 5.1(7)	Listed Ancillary Assets
Schedule 5.1(11)	Preliminary Bill of Sale

ARTICLE 2
PURCHASE AND SALE

2.1 Agreement to Purchase and Sell. The Vendor does hereby sell, transfer, convey and assign to the Purchaser and the Purchaser does hereby purchase and acquire from the Vendor, free and clear of all Encumbrances, all of the Vendor's right, title and interest in and to the property and assets described below (collectively, the "**Purchased Assets**"):

(a) All report and studies commissioned by or paid for, or in the possession of the Vendor or an Associate that related to the SSG Project (the "**Reports**"), including the Listed Reports;

(b) All appendices, drawings, spreadsheets, data files, Contracts, invoices, payment receipts and other documents or records that relate to the Reports (such as those provided to a Report Author by the Vendor or an Associate, those cited in a Report or those developed by the Vendor or an Associate based information contained in a Report) (the "**Ancillary Assets**"), including the Listed Ancillary Assets; and

(c) All Intellectual Property that is contained in, or that is necessary to implement any engineering solution described in, the Reports or Ancillary Assets (the "**Ancillary Intellectual Property**").

2.2 Delivery of Purchased Assets. The Vendor shall deliver the Purchased Assets to the Purchaser on the Closing Date; provided that the Vendor shall deliver the Ancillary Assets to the Purchaser on the Closing Date or as soon as reasonably possible thereafter. The Purchased Assets will be delivered in form satisfactory to the Purchaser. Notwithstanding the payment of the Purchase Price or the Supplemental Payment to the Vendor, the Vendor's obligation to deliver the Purchased Assets to the Purchaser shall continue in respect of any Purchased Assets not delivered.

2.3 Liabilities. The Purchaser shall not assume or have any obligation to discharge, perform or fulfill any obligation or liability of the Vendor of any kind whatsoever (collectively, the "**Excluded Liabilities**") and all Excluded Liabilities remain the obligation and responsibility of the Vendor.

2.4 Purchase Price and Purchase Price Allocation.

(1) Subject to the terms and conditions of this Agreement, the aggregate purchase price (the "**Purchase Price**") to be paid by the Purchaser to the Vendor for the Purchased Assets is $511,847.57.

(2) Subject to the terms and conditions of this Agreement, the Purchase Price will be increased by $511,847.57 (the "**Supplemental Payment**") upon the satisfaction of the Supplemental Conditions Precedent.

(3) The Supplemental Payment is not a retainage or withholding against the Purchase Price or security for the performance of any obligation of the Vendor. Notwithstanding the transfer of the Purchased Assets to the Purchaser on the Closing Date, the Supplemental Payment shall not become due and owing unless and until the Supplemental Conditions Precedent.

2.5 Payment of Purchase Price.

(1) The Purchaser shall pay and satisfy the Purchase Price by payment of the Purchase Price to the Escrow Agent on the Closing Date.

(2) If applicable, the Purchaser shall pay and satisfy the increased Purchase Price by payment of the Supplemental Payment to the Escrow Agent on the Supplementary Closing Date.

2.6 Transfer Taxes. The Purchaser shall pay to the Vendor or, where permitted by Applicable Law, directly to the appropriate Governmental Authorities, all sales and transfer taxes, registration charges and transfer fees, including GST/HST, payable by it in respect of the purchase and sale of the Purchased Assets under this Agreement, and, on request of the Vendor, the Purchaser shall furnish to the Vendor proof of direct payment to a Governmental Authority. The Purchaser shall indemnify and save harmless the Vendor from any amounts, including interest and penalties, that may be assessed against the Vendor arising out of the failure of the Purchaser to pay, when due, any Taxes described in this Section.

2.7 GST/HST Election. The Purchaser and Vendor will use their best efforts to minimize (or eliminate) any taxes payable under the ETA in respect of the Closing by, among other things, making such elections and taking such steps as may be provided under those acts (including making a joint election in a timely manner under Section 167 of the ETA) as may be reasonably requested by the Purchaser in connection with the Closing.

ARTICLE 3
ESCROW ARRANGEMENTS

3.1 Escrow Agreement. At Closing, the Purchaser and Vendor will enter into an Escrow Agreement with the Escrow Agent substantially in the form set out in Schedule 3.1. The Escrow

Agreement will provide that amounts held by the Escrow Agreement will be paid to the Vendor or to its direction on the instruction of the Purchaser.

3.2 Release from Escrow.

(1) The Purchaser will instruct the Escrow Agent to pay the Purchase Price to the Vendor or to its direction upon satisfaction of the conditions precedent described in Section 4.1 on or after the Closing Date.

(2) The Purchaser will instruct the Escrow Agent to pay the Supplemental Payment to the Vendor or to its direction upon satisfaction of the conditions precedent described in Section 4.1 on or after the Supplemental Closing Date.

(3) The amounts that the Purchaser instructs the Escrow Agent to pay to the Vendor or to its direction pursuant to Section 3.2(1) and 3.2(2) are subject to adjustments and withholdings that the Purchaser is permitted to make by this Agreement or otherwise required to make by Applicable Law. The Purchaser and Vendor will jointly instruct the Escrow Agent with respect to any such adjustments or withholdings.

ARTICLE 4
CONDITIONS OF ESCROW RELEASE

4.1 Conditions for the Benefit of the Purchaser.

(1) The Purchaser shall be obliged to instruct the Escrow Agent to pay the Purchase Price or the Supplemental Payment, as the case may be, to the Vendor or to its direction, only if each of the following conditions precedent has been satisfied in full:

(a) all of the representations and warranties of the Vendor, the Guarantors and the Members made in or pursuant to this Agreement shall have been true and correct as of the date hereof and shall be true and correct as at the Escrow Release Date with the same effect as if made on and as of the Escrow Release Date;

(b) the Vendor, the Guarantors and the Members have complied with or performed all of the obligations, covenants and agreements under this Agreement to be complied with or performed by the Vendor, the Guarantors and the Members on or before the Escrow Release Date, to the satisfaction of the Purchaser, acting reasonably;

(c) there is no injunction or restraining order issued preventing, and no pending or threatened Proceeding, against any Party, for the purpose of enjoining or preventing, the completion of the Transactions or otherwise claiming that this Agreement or the completion of the Transactions is improper or would give rise to a Proceeding, under any Applicable Law or under any Contract;

(d) the Vendor, the Guarantors and the Members have caused to be delivered to the Purchaser the following:

(i) the Purchased Assets, in form satisfactory to the Purchaser;

(ii) in respect of the Vendor, each Guarantor and each corporate Member:

(A) a certificate of status or its equivalent under the laws of the jurisdiction of its incorporation or governing its corporate existence and

(B) a certificate of a senior officer certifying:

1. the corporate status of that Party;

2. the Constating Documents of that Party;

3. the existence or non-existence of unanimous shareholders' agreements and voting trust arrangements in respect of that Party;

4. the resolutions of the board of directors and/or (if required by Applicable Law) shareholders of that Party authorizing the execution, delivery and performance of this Agreement and of all contracts, agreements, instruments, certificates and other documents required by this Agreement to be delivered by that Party; and

5. the incumbency and signatures of the officers of that Party executing this Agreement and any other document relating to the Transactions.

(iii) all deeds, conveyances, bills of sale, assurances, transfers, assignments and any other documentation or action which in the opinion of the Purchaser are necessary or reasonably required to transfer the Purchased Assets to the Purchaser with good and marketable title, free and clear of all Encumbrances, in each case duly executed by the Vendor and in form and substance satisfactory to the Purchaser, acting reasonably;

(iv) evidence, satisfactory to the Purchaser of the release and discharge of all Encumbrances affecting any of the Purchased Assets;

(v) a certificate of the Vendor, the Guarantors and the Members in respect of their representations and warranties set out in Section 5.1 and their covenants and other obligations set out in this Agreement, substantially in the form of Schedule 4.1(1)(d)(v);

(vi) favourable opinions of Vendor's Counsel, addressed to the Purchaser and dated the Closing Date, in form and substance satisfactory to the Purchaser as to those matters relating to the Transactions as the Purchaser and the Purchaser's Counsel may reasonably request;

(vii) the Release Agreement, fully executed by the Vendor, the Guarantors and the Members, substantially in the form of Schedule 4.1(1)(d)(vii);

(viii) the Vendor's signed counterparty of a joint instruction of the Purchase and Vendor to the Escrow Agent described in Section 3.2(3);

(ix) such other documentation as the Purchaser reasonably requests in a timely manner in order to establish the completion of the Transactions and the taking of all corporate proceedings in connection with the Transactions (as to certification and otherwise), in each case in form and substance satisfactory to the Purchaser, acting reasonably; and

(x) all documentation relating to the Transactions is satisfactory to the Purchaser, acting reasonably.

(e) Each of the conditions set out in Section 4.1(1) is for the exclusive benefit of the Purchaser and the Purchaser may waive compliance with any such condition in whole or in part by notice in writing to the Vendor, the Guarantors and the Members, except that no such waiver operates as a waiver of any other condition.

4.2 Supplemental Condition Precedent. The Purchase Price shall be increased by the amount of the Supplemental Payment, and Purchaser shall be obliged to pay the Supplemental Payment to the Escrow Agent, only if the Purchaser has obtained the SSG Project Approval by the fifth anniversary of the Closing Date.

4.3 Termination Events. Subject to Section 4.4, this Agreement may be terminated by mutual consent of the Purchaser and the Vendor.

4.4 Effect of Termination. Each Party's right of termination under Section 4.2 is in addition to any other rights it may have under this Agreement or otherwise, whether at law, in equity or otherwise, and the exercise of that right of termination is not an election of remedies. If this Agreement is terminated pursuant to Section 4.2, all obligations of the Parties under this Agreement will terminate except that the obligations contained in this Section 4.4 and in Article 7 will survive.

4.5 Waiver of Conditions of Escrow Release. If any of the conditions set forth in Section 4.1 has not been satisfied as of the date that is 180 days after the Closing Date of the Supplementary Closing Date, as the case may be, the Purchaser may elect in writing to waive the condition and proceed with the completion of the Transactions. In such case:

(1) the Purchase Price will adjusted by an equitable amount based on the diminution of value of the Assets Purchased and any Losses incurred by the Purchaser as a result of the condition not having been satisfied; and

(2) the Purchaser will not be obliged to instruct the Escrow Agent to make any payment to the Vendor or its direction, as would be otherwise be required by Section 3.2, until the adjustment to the Purchase Price described in Section 4.5(1) has been determined by agreement of the Purchaser and Vendor or by arbitration.

ARTICLE 5
REPRESENTATIONS AND WARRANTIES

5.1 Representations and Warranties of the Vendor and the Members. The Vendor, the Guarantors and the Members jointly and severally represent and warrant to the Purchaser as follows and acknowledge that the Purchaser is relying on these representations and warranties in connection with its purchase of the Purchased Assets and that the Purchaser would not purchase the Purchased Assets and assume the Assumed Liabilities without these representations and warranties:

(1) Organization and Status of the Vendor and the Members. Each of the Vendor, the Guarantors and the corporate Members is duly [incorporated] and organized, and is validly subsisting, under the laws of the jurisdiction set out opposite its name on Schedule 5.1(1) and is up-to-date in the filing of all corporate and similar returns under the laws of that jurisdiction.

(2) Corporate Power. Each of the Vendor, the Guarantors and the Members has all necessary corporate power and authority to enter into this Agreement and the contracts, agreements and instruments required by this Agreement to be delivered by it, and to perform its obligations hereunder and thereunder.

(3) Authorization. All necessary corporate action has been taken by each of the Vendor, the Guarantors and the corporate Members or on its part to authorize its execution and delivery of this Agreement and the contracts, agreements and instruments required by this Agreement to be delivered by it and the performance of its obligations hereunder and thereunder.

(4) Enforceability. This Agreement has been duly executed and delivered by each of the Vendor, the Guarantors and the Members and (assuming due execution and delivery by the other Parties) is a legal, valid and binding obligation of it enforceable against it in accordance with its terms, except as that enforcement may be limited by bankruptcy, insolvency and other similar laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction. Each of the contracts, agreements and instruments required by this Agreement to be delivered by it will at the Closing have been duly executed and delivered by it and (assuming due execution and delivery by the other parties thereto) will at Closing be enforceable against it in accordance with its terms, except as that enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

(5) No Other Agreements to Purchase. No Person other than the Purchaser has any Contract or any right or privilege capable of becoming a Contract for the purchase or acquisition from the Vendor or the Guarantors of any of the Purchased Assets.

(6) No Other Reports. No Reports exist other than the Listed Reports.

(7) No Other Ancillary Assets. No Ancillary Assets exist other than the Listed Ancillary Assets.

(8) No Personal Information. The Purchased Assets do not contain any Personal Information.

(9) Bankruptcy. Each of the Vendor, the Guarantors and the Members is able to pay its debts generally as they become due, is not an insolvent Person within the meaning of the *Bankruptcy and Insolvency Act* (Canada) and has not made an assignment in favour of its creditors or a proposal in bankruptcy to its creditors or any class thereof, and no petition for a receiving order has been presented in respect of it. None of the Vendor, the Guarantors or the Member has initiated proceedings with respect to a compromise or arrangement with its creditors or for its winding up, liquidation or dissolution. No receiver or interim receiver has been appointed in respect of it or any of its undertakings, property or assets (including any of the Purchased Assets) and no execution or distress has been levied on any of its undertakings, property or assets (including any of the Purchased Assets), nor have any proceedings been commenced in connection with any of the foregoing.

(10) Absence of Conflict. The execution, delivery and performance of this Agreement by each of the Vendor, the Guarantors and the Members and the completion of the Transactions will not (whether after the passage of time or notice or both) result in:

(a) the breach or violation of any of the provisions of, or constitute a default under, or give any Person the right to seek or cause a termination, cancellation, amendment or renegotiation of any Contract to which it is a party or by which any of its undertakings, property or assets is bound or affected;

(b) the breach or violation of any of the provisions of, or constitute a default under, or conflict with any of its obligations under:

(i) any provision of its Constating Documents or resolutions of its board of directors (or any committee thereof) or shareholders;

(ii) any judgment, decree, order or award of any Governmental Authority having jurisdiction over it;

(iii) any Approval issued to, or held by, the Vendor or held, for the benefit of or necessary to the operation of its business; or

(iv) any Applicable Law;

(c) the creation or imposition of any Encumbrance over any of the Purchased Assets; or

(d) the requirement of any Approval from any of its creditors.

(11) Title to Purchased Assets. The Vendor has good and marketable title to all the Purchased Assets, free and clear of any and all Encumbrances. Immediately prior to the entry into the

Preliminary Agreement and Preliminary Bill of Sale, the Guarantors had good and marketable title to all the Purchased Assets, free and clear of any and all Encumbrances.

(12) Preliminary Bill of Sale. The Preliminary Bill of Sale set forth in Schedule 5.1(11) is a true and accurate copy of the bill of sale entered into between the Guarantors and Vendor pursuant to the Preliminary Sale Agreement in respect of the Purchased Assets and remains in full force and effect, unamended as of the date of this Agreement.

(13) Intellectual Property.

(a) The Vendor holds the entire right, title and interest in and to all of the Ancillary Intellectual Property throughout the world, free of all Encumbrances, and has the exclusive and unfettered right to use the Ancillary Intellectual Property. Immediately prior to the entry into the Preliminary Agreement and Preliminary Bill of Sale, the Guarantors held the entire right, title and interest in and to all of the Ancillary Intellectual Property throughout the world, free of all Encumbrances, and had the exclusive and unfettered right to use the Ancillary Intellectual Property.

(b) The Ancillary Intellectual Property is valid and the rights of the Vendor in the Ancillary Intellectual Property are enforceable. All registrations and applications for registration of the Ancillary Intellectual Property are in good standing, have been filed in a timely manner within the appropriate offices to preserve the rights thereto and assignments have been recorded in favour of the Vendor. No Ancillary Intellectual Property has expired, has been cancelled, expunged or impeached, or has lapsed for failure to be renewed or maintained. No Ancillary Intellectual Property has been used, not used, enforced or not enforced in a manner that could reasonably be expected to result in the abandonment, cancellation or unenforceability of any of the Ancillary Intellectual Property.

(c) No Ancillary Intellectual Property is subject to any outstanding order, award, decision, injunction, judgment, decree, stipulation or agreement materially restricting the transfer, use, enforcement or licensing thereof.

(d) Neither the use or the content of the Ancillary Intellectual Property nor the conduct of the Vendor or the Guarantors in relation to the Purchased Assets has Infringed or will Infringe the Intellectual Property of any other Person. Neither the Vendors nor the Guarantors has received any notice that the use of the Ancillary Intellectual Property or the conduct of the Vendor or the Guarantors in relation to the Purchased Assets Infringes any Intellectual Property of any other Person, and no Proceedings have been instituted or are pending or threatened, alleging any such infringement.

(e) To the knowledge of the Vendor and the Guarantors, no Person has Infringed any of the Ancillary Intellectual Property, neither the Vendor nor the Guarantors has not issued a notice to any Person alleging any such infringement, and no Proceedings have been instituted or are pending or threatened, alleging any such infringement.

(f) All of the Ancillary Intellectual Property that has been developed or created by employees or pursuant to Contracts with consultants or contractors (collectively, the "**Developers**") has been assigned exclusively to the Vendor in writing or in another enforceable manner. The Developers have waived in writing their moral and authors' rights they may have in the Ancillary Intellectual Property. No Person has claimed that any current or former Developer has, as a result of contribution to any Ancillary Intellectual Property, violated the terms and conditions of any Contract with that Person or disclosed or used any trade secret of that Person. No Developer has claimed any rights in the Ancillary Intellectual Property.

(g) The Ancillary Intellectual Property is not subject to any Proceedings, including any actual or threatened claim for cancellation, expungement, impeachment, re-examination, invalidity or any termination or limitation thereof.

(h) Entering into this Agreement will not alter, impair or extinguish any of the Ancillary Intellectual Property or trigger any rights of first refusal requiring the sale, assignment or transfer of any Ancillary Intellectual Property to another Person.

(14) No Default Under Contracts. Each of the Vendor and Associates has performed all of the obligations required to be performed by it and is entitled to all benefits under, and is not in default or alleged to be in default in respect of, any Contract relating to the Purchased Assets, to which it is a party or by which it is bound or affected. All such Contracts have been performed in full by the parties thereto. There is no dispute under any such Contract.

(15) Third Party Approvals. There is no requirement under any Contract relating to the Purchased Assets or the Vendor to which the Vendor or an Associate is a party or by which the Purchased Assets or the Vendor or Associate is bound or affected for any Approvals from any party to that Contract or from any other Person relating to the completion of the Transactions.

(16) Taxes.

(a) The Vendor is not a non-resident of Canada for purposes of the Tax Act.

(b) There are no outstanding liabilities for Taxes payable, collectible or remittable by the Vendor, whether assessed or not, which may result in an Encumbrance on or other claim against or seizure of all or any part of the Purchased Assets or would result in the Purchaser becoming liable or responsible for those liabilities.

(c) The Vendor is duly registered under Subdivision (d) of Division V of Part IX of the ETA and its registration number is [●].

(17) Litigation. There are no Proceedings (whether or not purportedly on behalf of the Vendor) pending or, to the knowledge of the Vendor, the Guarantors and the Members, threatened against or affecting, the Purchased Assets. To the knowledge of the Vendor, the Guarantors and the Members, there is not any factual or legal basis on which any Proceeding might be commenced with any reasonable likelihood of success.

(18) Ethical Practices. No Representative of the Vendor, the Guarantors or any other Person associated with the Vendor, the Guarantors or any Representative of any of them, has directly or indirectly:

(a) made or received any contribution, gift, bribe, rebate, payoff, influence payment, kickback, or other payment to or from any Person, private or public, regardless of form, whether in money, property or services (i) to obtain favourable treatment in securing business, (ii) to pay for favourable treatment in business secured, (iii) to obtain special concessions or for special concessions already obtained, for or in respect of the Vendor, or (iv) in violation of any Applicable Law; or

(b) established or maintained any fund or asset that has not been recorded in the Books and Records.

5.2 Representations and Warranties of the Purchaser. The Purchaser represents and warrants to the Vendor as follows and acknowledges that the Vendor is relying on these representations and warranties in connection with the sale by the Vendor of the Purchased Assets:

(1) Organization and Corporate Power. The Purchaser is a corporation duly incorporated and organized, and is validly subsisting, under the laws of Ontario and is up-to-date in the filing of all corporate and similar returns under the laws of that jurisdiction. The Purchaser has all necessary corporate power and authority to acquire the Purchased Assets, to enter into this Agreement and to perform its obligations hereunder.

(2) Authorization. All necessary corporate action has been taken by or on the part of the Purchaser to authorize its execution and delivery of this Agreement and the contracts, agreements and instruments required by this Agreement to be delivered by it and the performance of its obligations hereunder and thereunder.

(3) Enforceability. This Agreement has been duly executed and delivered by the Purchaser and (assuming due execution and delivery by the other Parties) is a legal, valid and binding obligation of the Purchaser enforceable against it in accordance with its terms, except as that enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction. Each of the contracts, agreements and instruments required by this Agreement to be delivered by the Purchaser will at the Closing have been duly executed and delivered by it and (assuming due execution and delivery by the other parties thereto) will be enforceable against it in accordance with its terms, except as that enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

(4) Bankruptcy. The Purchaser is not an insolvent person within the meaning of the *Bankruptcy and Insolvency Act* (Canada) and has not made an assignment in favour of its creditors or a proposal in bankruptcy to its creditors or any class thereof, and no petition for a receiving order has been presented in respect of it. The Purchaser has not initiated proceedings with respect to a compromise or arrangement with its creditors or for its

winding up, liquidation or dissolution. No receiver or interim receiver has been appointed in respect of it or any of its undertakings, property or assets and no execution or distress has been levied on any of its undertakings, property or assets, nor have any proceedings been commenced in connection with any of the foregoing.

(5) Absence of Conflict. The execution, delivery and performance by the Purchaser of this Agreement and the completion of the Transactions will not, (whether after the passage of time or notice or both), result in:

(a) the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the acceleration of any of its obligations, under:

(i) any provision of its Constating Documents or resolutions of its board of directors (or any committee thereof) or shareholders;

(ii) any Approval issued to, held by or for the benefit of, the Purchaser;

(iii) any Applicable Law; or

(b) the requirement for any Approval from any creditor of the Purchaser.

(6) ETA Registration. The Purchaser is duly registered under Subdivision (d) of Division V of Part IX of the ETA and its registration number is 86709 6778 RT0001.

5.3 Survival of Representations, Warranties and Covenants of the Vendor. The representations and warranties of the Vendor, the Guarantors and the Members, and, to the extent that they have not been fully performed at or prior to Closing, the covenants and other obligations of the Vendor, the Guarantors and the Members, in each case contained in this Agreement and in any contract, agreement, instrument, certificate or other document executed or delivered pursuant to this Agreement survive Closing and continue for the benefit of the Purchaser without limitation of time notwithstanding the Closing, any investigation made by or on behalf of the Purchaser or any knowledge of the Purchaser.

5.4 Survival of the Representations, Warranties and Covenants of the Purchaser. The representations and warranties of the Purchaser and, to the extent that they have not been fully performed at or prior to Closing, the covenants and other obligations of the Purchaser, contained in this Agreement and in any contract, agreement, instrument, certificate or other document executed or delivered pursuant to this Agreement survive Closing and continue for the benefit of the Vendor, the Guarantors and the Members notwithstanding the Closing, any investigation made by or on behalf of the Vendor, the Guarantors or the Members or any knowledge of the any of them, until the first anniversary of the Closing Date.

5.5 Termination of Liability.

(1) No Party or other Person is entitled to indemnification pursuant to this Agreement unless the Party or other Person has given written notice of its Claim for indemnification pursuant to Article 6, as the case may be, prior to the expiry of the relevant survival period prescribed

by Sections 5.3 and 5.4 and in that event, only on and subject to the terms and conditions of and to the extent provided for in Article 6.

(2) This Agreement constitutes a "business agreement" under the *Limitations Act 2002* (Ontario) and to the extent that the provisions of this Agreement are found to be an agreement to vary or exclude, or suspend or extend, a limitation period prescribed under such legislation, that limitation period will be deemed to be varied or excluded, or suspended or extended, as the case may be, to the extent necessary to give full force and effect to the provisions of this Agreement.

ARTICLE 6
INDEMNIFICATION

6.1 Definitions. In this Article 6:

(1) "**Claim**" means any act, omission or state of facts and any demand, action, investigation, inquiry, suit, proceeding, claim, assessment, judgment or settlement or compromise relating thereto which may give rise to a right of indemnification under this Agreement.

(2) "**Direct Claim**" means any Claim by an Indemnitee against an Indemnitor which does not result from a Third Party Claim.

(3) "**Increased Amount**" has the meaning attributed to that term in Section 6.8(3).

(4) "**Indemnitee**" means any Person entitled to indemnification under this Agreement.

(5) "**Indemnitees Representative**" means:

(a) in respect of the Purchaser Indemnitees, the Purchaser; and

(b) in respect of the Vendor Indemnitees, the Vendor.

(6) "**Indemnitor**" means any Party obligated to provided indemnification under this Agreement.

(7) "**Indemnification Notice**" means written notice by an Indemnitee to the applicable Indemnitor or Indemnitors of a Third Party Claim or Direct Claim, as the case may be.

(8) "**Losses**" means any and all loss, liability, obligation, damage, cost, expense, charge, fine, penalty or assessment, suffered, incurred, sustained or required to be paid by the Person seeking indemnification (including lawyers', experts' and consultants' fees and expenses), directly resulting from or arising out of any Claim, including the costs and expenses of any action, suit, proceeding, investigation, inquiry, arbitration award, grievance, demand, assessment, judgment, settlement or compromise relating thereto, but: (i) excluding any contingent liability until it becomes actual; (ii) reduced by any net Tax benefit; and (iii) reduced by any recovery, settlement or otherwise under or pursuant to any insurance coverage, or pursuant to any claim, recovery, settlement or payment by or against any other Persons.

(9) “**Payment**” has the meaning attributed to that term in Section 6.8(4).

(10) “**Purchaser Indemnitees**” means the shareholders and Representatives of the Purchaser, and related Persons.

(11) “**Third Party Claim**” means any Claim asserted against an Indemnitee by any Person who is not a Party or an Affiliate of a Party.

(12) “**Vendor Indemnitees**” means the Members, the Representatives of the Vendor, and related Persons.

6.2 Indemnification by the Vendor and the Members. In addition to any other indemnification provided by the Vendor and the Members contained in this Agreement and subject to this Article 6, the Vendor and the Members shall jointly and severally indemnify and save harmless the Purchaser and, to the extent named or involved in any Third Party Claim, the Purchaser Indemnitees from, and shall pay to the Purchaser and the Purchaser Indemnitees, on demand, the amount of any and all Losses, as a result of or arising in connection with:

(a) any inaccuracy of or any breach of any representation or warranty made by any of the Vendor and the Members in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement, whether or not the Purchaser relied on or had knowledge of it;

(b) any breach or non-performance by any of the Vendor and the Members of any covenant or other obligation contained in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement;

(c) any of the Excluded Liabilities, including any alleged responsibility of the Purchaser in respect thereof; and

(d) any breach or alleged breach of any Contract by the Vendor which occurred prior to the Closing Date or any such breach which occurs after the Closing Date but arises out of a continuation of a course of conduct which commenced prior to the Closing Date.

6.3 Notice of Claim.

(1) An Indemnitee, promptly on becoming aware of any circumstances that have given or could give rise to a Third Party Claim or a Direct Claim, shall give an Indemnification Notice of those circumstances to its Indemnitees Representative and to the applicable Indemnitor or Indemnitors. The Indemnification Notice will specify whether the Losses arise as a result of a Third Party Claim or a Direct Claim, and will also specify with reasonable particularity (to the extent the information is available) the factual basis for the Claim and the amount of the Losses, if known.

(2) The failure to give, or delay in giving, an Indemnification Notice does not relieve the Indemnitor of its obligations except and only to the extent of any prejudice caused to the Indemnitor by that failure or delay.

(3) Provided that the Indemnitee gives an Indemnification Notice of the Claim to the Indemnitor on or prior to the expiry of the applicable time period related to that representation and warranty or covenant, as the case may be, set out in Sections 5.3 and 5.4, liability of the Indemnitor for that representation, warranty or covenant will continue in full force and effect until the final determination of that Claim.

6.4 Third Party Claims.

(1) The Indemnitor has the right, by notice to the applicable Indemnitees Representative given not later than 30 days after receipt of the Indemnification Notice, to assume control of the defence, compromise or settlement of the Third Party Claim provided that:

(a) the Third Party Claim involves only money damages and does not seek any injunctive or other equitable relief;

(b) if the named parties in any Third Party Claim include both the Indemnitor and the Indemnitee, representation by the same counsel would, in the judgment of the Indemnitee, still be appropriate notwithstanding any actual or potential differing interests between them (including the availability of different defences);

(c) settlement of, or an adverse judgment with respect to, the Third Party Claim is not, in the judgment of the Indemnitee, likely to establish a precedent, custom or practice adverse to the continuing business interest of the Indemnitee; and

(d) the Indemnitor, from time to time, at the request of the Indemnitees Representative, gives security satisfactory to the Indemnitees Representative against any costs and other liabilities to which the Indemnitee may be or become exposed as a result of that Third Party Claim.

(2) On the assumption of control by the Indemnitor, it is conclusively established for purposes of this Agreement that the Third Party Claim is within the scope of, and is subject to, the indemnification pursuant to this Article 6, and:

(a) the Indemnitor will actively and diligently proceed with the defence, compromise or settlement of the Third Party Claim at the Indemnitor's sole cost and expense, including the retaining of counsel reasonably satisfactory to the Indemnitees Representative;

(b) the Indemnitor will keep the Indemnitees Representative fully advised with respect to the defence, compromise or settlement of the Third Party Claim (including supplying copies of all relevant documents promptly as they become available) and will arrange for its counsel to inform the Indemnitees Representative on a regular basis of the status of the Third Party Claim;

(c) the Indemnitee may retain separate co-counsel at its sole cost and expense and participate in the defence of the Third Party Claim (provided the Indemnitor shall continue to control that defence); and

(d) the Indemnitor will not consent to the entry of any judgment or enter into any settlement with respect to the Third Party Claim unless consented to by the Indemnitees Representative (which consent may not be unreasonably or arbitrarily withheld, delayed or conditioned).

(3) Provided all the conditions set forth in Section 6.4(1) are satisfied and the Indemnitor is not in breach of any of its obligations under Section 6.4(2), each of the Indemnitee and its Indemnitees Representative will, at the expense of the Indemnitor, co-operate with the Indemnitor and use its best efforts to make available to the Indemnitor all relevant information in its possession or under its control (provided that it does not cause the Indemnitee or its Indemnitees Representative to breach any confidentiality obligations) and will take such other steps as are, in the reasonable opinion of counsel for the Indemnitor, necessary to enable the Indemnitor to conduct that defence, provided always that:

(a) no admission of fault may be made by or on behalf of the Purchaser or any Purchaser Indemnitee without the prior written consent of the Purchaser;

(b) no admission of fault may be made by or on behalf of the Vendor or any Vendor Indemnitee without the prior written consent of the Vendor; and

(c) the Indemnitee and its Indemnitees Representative are not obligated to take any measures which, in the reasonable opinion of the Indemnitee's legal counsel, could be prejudicial or unfavourable to the Indemnitee.

(4) If (i) the Indemnitor does not give the relevant Indemnitees Representative the notice provided in Section 6.4(1), (ii) any of the conditions in Section 6.4(1) are unsatisfied, or (iii) the Indemnitor breaches any of its obligations under Sections 6.4(2) or 6.4(3), the applicable Indemnitees Representative may assume control of the defence, compromise or settlement of the Third Party Claim as in its sole discretion may appear advisable, and is entitled to retain counsel as in its sole discretion may appear advisable, the whole at the Indemnitor's sole cost and expense. Any settlement or other final determination of the Third Party Claim will be binding on the Indemnitor. The Indemnitor will, at its sole cost and expense, cooperate fully with the Indemnitee and its Indemnitees Representative and use its best efforts to make available to the Indemnitee and its Indemnitees Representative all relevant information in its possession or under its control and take such other steps as are, in the reasonable opinion of counsel for the Indemnitee, necessary to enable the Indemnitee to conduct the defence. The Indemnitor will reimburse the Indemnitee and its Indemnitees Representative promptly and periodically for the costs of defending against the Third Party Claim (including legal fees and expenses), and will remain responsible for any Losses the Indemnitee and its Indemnitees Representative may suffer resulting from, arising out of or relating to the Third Party Claim to the fullest extent provided in this Article 6.

6.5 Direct Claims. Following receipt of an Indemnification Notice in respect of a Direct Claim, the Indemnitor has 60 days to make such investigation of the Direct Claim as is considered necessary or desirable. For the purpose of that investigation, the Indemnitee shall make available to the Indemnitor the information relied on by the Indemnitee to substantiate the Direct Claim, together with such information as the Indemnitor may reasonably request. If the Indemnitor and Indemnitee agree at or prior to the expiry of this 60-day period (or prior to the expiry of any extension of this period agreed to by the Indemnitor and Indemnitee) as to the validity and amount of that Direct Claim, the Indemnitor shall immediately pay to the Indemnitee the full amount as agreed to by the Parties of the Direct Claim, failing which the matter shall be referred to binding arbitration in accordance with Section 7.11. For clarity, the Purchaser is deemed to have incurred or suffered Losses as of and from the Closing Date as a consequence of any reduction in the value of the Purchased Assets resulting from an inaccuracy or breach of any representation or warranty or any breach or non-fulfillment by the Vendor of any of its covenants or obligations under this Agreement.

6.6 Waiver. The Indemnitor waives any right it may have to require an Indemnitee to proceed against or enforce any other right, power, remedy or security or to claim payment from any other Person before claiming under the indemnity provided for in this Article 6. It is not necessary for an Indemnitee to incur expense or make payment before enforcing that indemnity.

6.7 Duty to Mitigate and Subrogation.

(1) Nothing in this Agreement in any way restricts or limits the general obligation under Applicable Law of an Indemnitee to mitigate any loss which it may suffer or incur by reason of a breach by an Indemnitor of any representation, warranty, covenant or obligation of the Indemnitor under this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement.

(2) The Indemnitee shall, to the extent permitted by Applicable Law, subrogate its rights relating to any Third Party Claim to the Indemnitor and shall make all counterclaims and implead all third Persons as may be reasonably required by the Indemnitor, the whole at the cost and expense of the Indemnitor.

6.8 Obligation to Reimburse.

(1) The Indemnitor shall reimburse to the Indemnitee the amount of any Losses, as of the later of (i) date that the Indemnitee incurs any such Losses and (ii) the date of demand by the Indemnitee, together with interest thereon from that date until payment in full, at the rate per annum equal to the prime lending rate of Royal Bank of Canada from time to time plus 2%, that payment being made without prejudice to the Indemnitor's right to contest the basis of the Indemnitee's Claim for indemnification.

(2) The amount of any and all Losses under this Article 6 are to be determined net of any amounts recovered or recoverable by the Indemnitee under insurance policies, indemnities, reimbursement arrangements or similar contracts with respect to those Losses. The Indemnitee shall take all appropriate steps to enforce that recovery. Each Party waives, to

the extent permitted under its applicable insurance policies, any subrogation rights that its insurer may have with respect to any indemnifiable Losses.

(3) If an Indemnitee is subject to Tax in respect of the receipt of an amount pursuant to this Article 6, after taking into account any offsetting deduction or tax credit available in respect of the applicable Losses, then the amount payable by the Indemnitor will be increased by an amount (the "**Increased Amount**") such that the Indemnitee will be in the same position after paying Tax on the amount received hereunder, including any Taxes payable on the Increased Amount, as the Indemnitee would have been in had the Losses giving rise to that payment not arisen and had that amount not been payable.

(4) If any payment (the "**Payment**") made pursuant to this Article 6 is subject to GST/HST or is deemed by the ETA or any similar provision of any Applicable Law to be inclusive of GST/HST, the Indemnitor will pay to the Indemnitee, in addition to the Payment, an amount equal to the GST/HST in connection with that Payment and that additional amount.

6.9 Exclusivity. Unless otherwise provided in this Agreement or any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement, the provisions of this Article 6 constitute the sole remedy available to the Vendor, any Member and the Purchaser to any Claim for breach of covenants, representation, warranty or other obligation or provision of this Agreement or any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement (other than a Claim for specific performance or injunctive relief) and to any and all other indemnities provided in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement.

6.10 Set-Off. A Party is entitled to set-off any Losses subject to indemnification under this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement against any other amounts payable by the Party to another party whether under this Agreement or otherwise.

6.11 Trust and Agency. The Purchaser accepts each indemnity in favour of any of the Purchaser Indemnitees that is not a Party as agent and trustee of that Purchaser Indemnitee and may enforce any such indemnity in favour of that Purchaser Indemnitee on behalf of that Purchaser Indemnitee. The Vendor accepts each indemnity in favour of any of the Vendor Indemnitees as agent and trustee of that Vendor Indemnitee and may enforce any such indemnity in favour of that Vendor Indemnitee on behalf of that Vendor Indemnitee.

ARTICLE 7
GENERAL

7.1 Confidentiality of Information.

(1) For the purposes of this Section 7.1, "**Confidential Information**" of a Party at any time means all information relating to that Party which at the time is of a confidential nature (whether or not specifically identified as confidential), is known or should be known by the other relevant Party or its Representatives as being confidential, and has been or is from time to time made known to or is otherwise learned by the relevant other Party or any of its Representatives as a result of the matters provided for in this Agreement. The existence

and the terms of this Agreement and of any other contract, agreement, instrument, certificate or other document to be entered into as contemplated by this Agreement shall be deemed to be Confidential Information of the Purchaser and not to be Confidential Information of the Vendor, the Guarantors or the Members.

(2) Notwithstanding the foregoing, Confidential Information does not include any information that at the time has become generally available to the public other than as a result of a disclosure by the other Party or any of its Representatives, any information that was available to the other Party or its Representatives on a non-confidential basis before the date of this Agreement or any information that becomes available to the other Party or its Representatives on a non-confidential basis from a Person (other than the Party to which the information relates or any of its Representatives) who is not, to the knowledge of the other Party or its Representatives, otherwise bound by confidentiality obligations to the Party to which the information relates in respect of the information or otherwise prohibited from transmitting the information to the other Party or its Representatives.

(3) Each Party shall (and shall cause each of its Representatives to) hold in strictest confidence and not use in any manner, other than as expressly contemplated by this Agreement, all Confidential Information of the other Parties.

(4) Subject to Section 7.2, Section 7.1(3) shall not apply to the disclosure of any Confidential Information where that disclosure is required by Applicable Law. In that case, the Party required to disclose (or whose Representative is required to disclose) shall, as soon as possible in the circumstances, notify the other Parties of the requirement of the disclosure including the nature and extent of the disclosure and the provision of Applicable Law pursuant to which the disclosure is required. To the extent possible, the Party required to make the disclosure shall, before doing so, provide to the other Parties the text of any disclosure. On receiving the notification, the other Parties may take any reasonable action to challenge the requirement, and the affected Party shall (or shall cause the applicable Representative to), at the expense of the other Parties, assist the other Parties in taking that reasonable action. Notwithstanding the foregoing, no disclosure shall be made of the amount of the Purchase Price, unless and to the extent required by Applicable Law.

(5) Following the termination of this Agreement in accordance with the provisions of Section 4.2, each Party shall (and shall cause each of its Representatives to) promptly, on a request from any other Party, return to the requesting Party all copies of any tangible items (other than this Agreement), if any, that are or that contain Confidential Information of the requesting Party, except that if the Party so obligated to return Confidential Information or its Representatives have prepared notes, analyses, compilations, studies or summaries containing or concerning any Confidential Information, then that Party may, instead of returning the notes, analyses, compilations, studies or summaries, destroy them and provide a certificate to that effect to the requesting Party.

7.2 Public Announcements. Neither the Vendor, nor the Guarantors or the Members shall make any public statement or issue any press release concerning the Transactions except as agreed by the Purchaser in its sole discretion or as may be necessary, in the opinion of counsel to the Party making that disclosure, to comply with the requirements of all Applicable Law. If any public statement or release is so required, the Vendor, Guarantor or Member making the disclosure shall consult with the Purchaser before making that statement or release, and the Parties shall use all reasonable efforts, acting in good faith, to agree on a text for the statement or release that is satisfactory to the Parties. The Purchaser may make any public statement or issue any press release concerning the Transactions without restriction.

7.3 Disclosure and Consultation. Before any public statement or press release concerning the Transactions, no Party shall disclose this Agreement or any aspect of the Transactions except to its board of directors, its senior management, its legal, accounting, financial or other professional advisors, any financial institution contacted by it with respect to any financing required in connection with the Transactions and counsel to that institution, or as may be required by any Applicable Law or as agreed by the Parties.

7.4 Expenses. Each Party shall pay all expenses (including Taxes imposed on those expenses) it incurs in the authorization, negotiation, preparation, execution and performance of this Agreement and the Transactions, including all fees and expenses of its legal counsel, bankers, investment bankers, brokers, accountants or other representatives or consultants.

7.5 No Third Party Beneficiary. Except as provided for in Section 6.11, this Agreement is solely for the benefit of the Parties and no third party accrues any benefit, claim or right of any kind pursuant to, under, by or through this Agreement.

7.6 Entire Agreement. This Agreement together with the other agreements to be entered into as contemplated by this Agreement (the "**Other Agreements**") constitute the entire agreement between the Parties pertaining to the subject matter of this Agreement and the Other Agreements and supersede all prior correspondence, agreements, negotiations, discussions and understandings, written or oral. Except as specifically set out in this Agreement or the Other Agreements, there are no representations, warranties, conditions or other agreements or acknowledgements, whether direct or collateral, express or implied, written or oral, statutory or otherwise, that form part of or affect this Agreement or the Other Agreements or which induced any Party to enter into this Agreement or the Other Agreements. There is no liability, either in tort or in contract, assessed in relation to the representation, warranty, opinion, advice or assertion of fact, except as contemplated in this Section.

7.7 Non-Merger. Except as otherwise provided in this Agreement, the covenants, representations and warranties set out in this Agreement do not merge but survive Closing and, notwithstanding such Closing or any investigation by or on behalf of a Party, continue in full force and effect. Closing does not prejudice any right of one Party against another Party in respect of any remedy in connection with anything done or omitted to be done under this Agreement.

7.8 Time of Essence. Time is of the essence of this Agreement.

7.9 Amendment. This Agreement may be supplemented, amended, restated or replaced only by written agreement signed by each Party.

7.10 Waiver of Rights. Any waiver of, or consent to depart from, the requirements of any provision of this Agreement is effective only if it is in writing and signed by the Party giving it, and only in the specific instance and for the specific purpose for which it has been given. No failure on the part of any Party to exercise, and no delay in exercising, any right under this Agreement operates as a waiver of that right. No single or partial exercise of any such right precludes any other or further exercise of that right or the exercise of any other right.

7.11 Arbitration. All disputes arising out of, or in connection with, this Agreement, or in respect of any legal relationship associated with it or derived from it, will be finally resolved by arbitration administered by ICDR Canada. The place of arbitration will be Sault Ste. Marie, Ontario or such other place as the Purchaser and the Vendor may agree in writing. The language of the arbitration will be English.

7.12 Jurisdiction. Subject to Section 7.11, the Parties irrevocably and unconditionally attorn to the exclusive jurisdiction of the courts of the province of Ontario sitting in Sault Ste. Marie or Toronto in respect of all disputes arising out of, or in connection with, this Agreement, or in respect of any legal relationship associated with it or derived from it.

7.13 Governing Law. This agreement is governed by, and interpreted and enforced in accordance with, the laws of the Province of Ontario and the laws of Canada applicable in Ontario, excluding the choice of law rules of that province.

7.14 Notices.

(1) Any notice, demand or other communication (in this Section 7.14, a "**notice**") required or permitted to be given or made under this Agreement must be in writing and is sufficiently given or made if:

(a) delivered in person and left with a receptionist or other responsible employee of the relevant Party at the applicable address set forth below;

(b) sent by prepaid courier service or (except in the case of actual or apprehended disruption of postal service) mail; or

(c) sent by facsimile transmission, with confirmation of transmission by the transmitting equipment (a "**Transmission**");

in the case of a notice to the Vendor, addressed to it at:

[●]
[●]
[●]

Attention: [●]
Facsimile No.: [●]

with a copy (not constituting notice) to:

[Vendor's Counsel]
[●]
[●]

Attention: [●]
Facsimile No.: [●]

and in the case of a notice to [Guarantors], addressed to it at:

[●]
[●]
[●]

Attention: [●]
Facsimile No.: [●]

with a copy to:

[Vendor's Counsel]
[●]
[●]

Attention: [●]
Facsimile No.: [●]

and in the case of a notice to [Members], addressed to it at:

[●]
[●]
[●]

Attention: [●]
Facsimile No.: [●]

with a copy to:

[Vendor's Counsel]
[●]
[●]

Attention: [●]
Facsimile No.: [●]

and in the case of a notice to the Purchaser, addressed to it at:

PUC Distribution Inc.
500 Second Line East
Sault Ste. Marie, ON
P6A 6P2

Attention: Robert Brewer
E-mail: Robert.brewer@ssmpuc.com

with a copy (not constituting notice) to:

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide St. W
Toronto, ON
M5H 4E3

Attention: John Vellone
E-mail: JVellone@blg.com

(2) Any notice sent in accordance with this Section 7.14 is deemed to have been received:

(a) if delivered prior to or during normal business hours on a Business Day in the place where the notice is received, on the date of delivery;

(b) if sent by mail, on the fifth Business Day after mailing in the place where the notice is received, or, in the case of disruption of postal service, on the fifth Business Day after cessation of that disruption; or

(c) if sent in any other manner, on the date of actual receipt;

except that any notice delivered in person or sent by Transmission not on a Business Day or after normal business hours on a Business Day is deemed to have been received on the next succeeding Business Day in the place where the notice is received.

(3) Any Party may change its address for notice by giving notice to the other Parties.

7.15 Joint and Several Liability. Except as expressly provided in this Agreement, all of the obligations and liabilities of the Vendor, the Guarantors and the Members under this Agreement and under any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement, including the representations and warranties and indemnities contained in this Agreement and in any such other contract, certificate or other document, are and are deemed to be joint and several obligations and liabilities of the Vendor.

7.16 Guarantor and Member Guarantee. The Guarantors and the Members guarantee (i) performance by the Vendor of the obligations of the Vendor under this Agreement, and (ii) payment of all amounts and other obligations due or owing to the Purchaser by the Vendor pursuant to this Agreement and any obligation of the Vendor to indemnify the Purchaser and the Purchaser Indemnitees under this Agreement.

7.17 Assignment.

(1) Subject to item (2), no party may assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Agreement to any Person.

(2) The Purchaser may assign all of its rights and obligation under this Agreement to a subsidiary wholly-owned by it, except that such assignment shall not relieve the Purchaser of any of its obligations under this Agreement.

7.18 Further Assurances. Each Party shall promptly do, execute, deliver or cause to be done, executed or delivered all further acts, documents and matters in connection with this Agreement that any other Party may reasonably require, for the purposes of giving effect to this Agreement.

7.19 Successors. This Agreement is binding on, and enures to the benefit of, the Parties and their respective successors.

7.20 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together constitute one agreement. Delivery of an executed counterpart of this Agreement by facsimile or transmitted electronically in legible form, including in a tagged image format file (TIFF) or portable document format (PDF), shall be equally effective as delivery of a manually executed counterpart of this Agreement.

IN WITNESS WHEREOF, the Parties have duly executed this Agreement on the date first above written.

INFRASTRUCTURE ENERGY INC.

By: ______________________________
Name:
Title:

ENERGIZING, LLC

By: ______________________________
Name:
Title:

INFRASTRUCTURE ENERGY, LLC

By: __________________________________
Name:
Title:

[MEMBER 1]

By: __________________________________
Name:
Title:

[MEMBER 2]

By: __________________________________
Name:
Title:

PUC DISTRIBUTION INC.

By: __________________________________
Name:
Title:

SCHEDULE 3.1 ESCROW AGREEMENT

[NTD: Form separately provided by Purchaser's Counsel]

SCHEDULE 4.1(1)(d)(vii) RELEASE AGREEMENT

[NTD: Form separately provided by Purchaser's Counsel]

SCHEDULE 4.1(1)(d)(v) FORM OF BRING-DOWN CERTIFICATE

CERTIFICATE

TO: **PUC Distribution Inc. (the "Purchaser")**

DATED: _______________

This certificate is delivered pursuant to Section 4.1(1)(d)(v) of the asset purchase agreement (the "**Asset Purchase Agreement**") dated [●] between [●], [●] and the Purchaser. Capitalized terms used and not defined in this certificate have the meanings given to them in the Asset Purchase Agreement.

Each of [Vendor], [Guarantor], [shareholder 1] and [shareholder 2] certifies to you that:

(1) all of the representations and warranties of each of the Vendor, the Guarantors and the Members made in or pursuant to Section 5.1 of the Asset Purchase Agreement are true and correct as at the date hereof with the same effect as if made at and as of the date hereof; and

(2) the Vendor, the Guarantors and the Members have complied with and performed all of the obligations, covenants and agreements under the Asset Purchase Agreement to be complied with or performed by the Vendor or the Members or any of them on or before the date hereof.

[●]

By: ______________________________
Name:
Title:

[●]

By: ______________________________
Name:
Title:

[●]

By: ______________________________
Name:
Title:

SCHEDULE 5.1(1) JURISDICTIONS

[NTD: To be completed by Vendor]

Legal Person	**Jurisdiction of Incorporation or Formation**
Infrastructure Energy Inc.	Canada
Infrastructure Energy, LLC	Delaware
Energizing, LLC	Delaware
[Member]	
[Member]	
[Member]	

SCHEDULE 5.1(6) LISTED REPORTS

The following are the Listed Reports:

(3) The Navigant report "Review of Business Case for Smart Grid Project for PUC Distribution" dated April 15, 2015

(4) The Navigant report "Review of Project Costs for Smart Grid Project for PUC Distribution" dated June 23, 2015

(5) The Leidos report "Utility Distribution Microgrid: Volt/VAR Management (VVM) – Preliminary Design" dated October 17, 2014

(6) The Leidos report "Utility Distribution Microgrid: Distribution Automation – Preliminary Design" dated November 20, 2014

(7) The Leidos report "Utility Distribution Microgrid: AMI Integration – Preliminary Design" dated November 20, 2014

(8) Black & Veatch report "Utility Distribution Microgrid (UDM) Project - Project Scope Description" dated April 5, 2017

(9) Energrid and Michael Baumann's completed NRCan application

SCHEDULE 5.1(7) LISTED ANCILLARY ASSETS

The following are the Listed Ancillary Assets:

(1) The CYME distribution network system model files created to support the engineering studies prepared for the Sault Smart Grid Project.

SCHEDULE 5.1(11) PRELIMINARY BILL OF SALE

[NTD: Vendor to attach executed Preliminary Bill of Sale substantially in the form separately provided by Purchaser's Counsel.]

FULL AND FINAL RELEASE AND CONFIDENTIALITY AGREEMENT

WHEREAS PUC Distribution Inc. ("**PUC**") and Energizing, LLC ("**Energizing**") entered into, and conducted work in connection with, non-binding Letters of Intent dated July 26, 2013 and December 16, 2015 relating to the design, building, construction, financing, maintenance and operation of a utility distribution microgrid project in Sault Ste. Marie, as further described in those Letters of Intent, and Energizing did not submit a proposal in response to a Request for Proposals issued by PUC on October 4, 2019 in connection with the Sault Smart Grid Project (all together, the "**Project**").

WHEREAS PUC has entered into an asset purchase agreement dated on or about the date hereof (the "**Asset Purchase Agreement**") with Infrastructure Energy Inc. (the "**Vendor**"), Energizing and Infrastructure Energy, LLC (the "**Guarantors**"), and [Glen Martin], [Member 1] and [Member 2] (the "**Members**") (the Vendor, Guarantors and Members hereinafter collectively referred to as the "**Releasors**").

IN CONSIDERATION of PUC entering into the Asset Purchase Agreement, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Releasors hereby release and forever discharge PUC and PUC Services Inc. and each of their agents, servants and employees, subsidiaries, affiliates, related entities, successors, assigns and insurers, (hereinafter referred to collectively as the "**Releasees**"), from any and all actions, claims, demands, damages, loss or injuries, interests and costs, howsoever arising, which heretofore may have been or may hereinafter be sustained by the Releasors, including any which are not now known or anticipated but may arise in the future and all effects and consequences thereof, in connection with or in any way relating to the Project.

AND FOR THE SAID CONSIDERATION, the Releasors further undertake and agree not to make or continue a claim or to take or continue any proceedings against any other persons or entities who might claim contribution or indemnity under the provisions of any statute, or at common law, from the Releasees, or any of them, including but not limited to Black & Veatch Corporation ("**Black & Veatch**"), or any subsidiary, affiliate or related entity of Black & Veatch. In the event that the Releasors have made or make any claims or take any proceedings against any other person or entity and that other person or entity claims contribution or indemnity from the Releasees, or any of them, the Releasors agree to indemnify and hold harmless the Releasees in respect of that claim, including, without limiting the generality of the foregoing, indemnification of the Releasees in respect of any claims advanced against the Releasees (or any of them), any prejudgment and postjudgment interests on the claims, any costs payable to the other persons or entity, and indemnification of the Releasees for their own costs on a full indemnity basis.

AND FURTHER FOR THE SAID CONSIDERATION the Releasors agree that this final release and indemnity shall be binding upon itself and its successors, beneficiaries and assigns.

IT IS UNDERSTOOD AND AGREED that the said consideration is deemed to be no admission whatsoever of liability on the part of the Releasees.

THE RELEASORS FURTHER UNDERSTAND AND AGREE that all communications regarding the Projects, and the sale of assets to the Releasees, shall remain strictly confidential and shall not be disclosed to any third party, aside from disclosure to the Releasors' professional legal advisors, and disclosure compelled by law, and for clarity the Releasors shall maintain the confidential nature of its dealings with the Releasees and shall not discuss them with any non-party to this Release (aside from the professional advisors previously listed).

AND IT IS FURTHER ACKNOWLEDGED that at the time of the execution of this Full and Final Release, the Releasors have had the opportunity to obtain legal advice, understands the full consequences of executing this Full and Final Release and Confidentiality Agreement, and has done so voluntarily.

IN WITNESS WHEREOF this Full and Final Release and Confidentiality Agreement has been signed this   day of January, 2020.

SIGNED IN THE PRESENCE OF:

INFRASTRUCTURE ENERGY INC.

By: ___________________________________
Name:
Title:

INFRASTRUCTURE ENERGY, LLC

By: ___________________________________
Name:
Title:

ENERGIZING, LLC

By: ___________________________________
Name:
Title:

[MEMBER 1]

By: ____________________________________
Name:
Title:

[MEMBER 2]

By: ____________________________________
Name:
Title:

PUC DISTRIBUTION INC.

By: ____________________________________
Name:
Title:

ATTACHMENT 3 – INFORMATION NOTE FEBRUARY 26, 2020

INFORMATION NOTE

SUBJECT: INFRASTRUCTURE ENERGY ASSET PURCHASE

PRESENTED TO: PUC INC/SERVICES AND DISTRIBUTION

MEETING DATE: FEBRUARY 26, 2020

RECOMMENDATION:

That the Board receive the attached documents as information.

REFERENCE/BACKGROUND:

As a follow up to the January 2020 Board Meetings the final documents in regard to the Infrastructure Energy Asset Purchase are attached for review.

Prepared by: R. Brewer
Date: February 21, 2020

Submitted by: R. Brewer
Date: February 26, 2020

Attachments: **Asset Purchase Agreement**
Bill of Sale
Bringdown Certificate
Escrow Agreement
Release Agreement

Execution Version

Infrastructure Energy Inc.

As Vendor

- and -

Energizing, LLC

- and -

Infrastructure Energy, LLC

As Guarantors

- and -

Blind Line Holdings, LLC

- and -

Glen Martin

As Members

- and -

PUC Distribution Inc.

As Purchaser

ASSET PURCHASE AGREEMENT

January 27, 2020

TABLE OF CONTENTS

List of Schedules

ASSET PURCHASE AGREEMENT dated January 27, 2020

BETWEEN:

Infrastructure Energy Inc.

As Vendor

- and -

Energizing, LLC

- and -

Infrastructure Energy, LLC

As Guarantors

- and -

Blind Line Holdings, LLC

- and -

Glen Martin

As Members

- and -

PUC Distribution Inc.

As Purchaser

RECITALS:

A. The Vendor and Guarantors each carry on the business of developing and deploying utility infrastructure project and specifically community-scale microgrid projects.

B. The Member Glen Martin owns 100% of the Equity Interest of the Member Blind Line Holdings, LLC; the Member Blind Line Holdings, LLC owns approximately 40% of the Equity Interest of the Guarantor Infrastructure Energy, LLC and is the only member who individually owns 10% or more of the Equity Interest of the Guarantor Infrastructure Energy, LLC; the Guarantors are the same legal entity; and the Guarantor Infrastructure Energy, LLC owns 100% of the Equity Interest of the Vendor.

C. The Vendor wishes to sell and the Purchaser wishes to purchase the Purchased Assets.

D. Immediately prior to the entry into this Agreement, the Guarantors and the Vendor entered into a purchase and sale agreement (the "**Preliminary Sale Agreement**") pursuant to which the Guarantors did sell, transfer, convey and assign to the Vendor and the Vendor did purchase and acquire from the Vendor, free and clear of all Encumbrances, all of the Guarantor's right, title and interest in and to the Purchased Assets.

E. The bill of sale executed by the Guarantors and Vendor pursuant to the Preliminary Sale Agreement (the "**Preliminary Bill of Sale**") has been delivered to the Purchaser.

F. The Members are parties to this Agreement for the sole purpose of providing the guarantee in Section 7.16.

G. The Guarantors and the Members will derive substantial economic benefits from the transactions contemplated by this Agreement.

THE PARTIES AGREE AS FOLLOWS:

ARTICLE 1
INTERPRETATION

1.1 Definitions. In this Agreement, including the Recitals to this Agreement, unless the context otherwise requires:

(1) "**Affiliate**" means an affiliated body corporate within the meaning of the following:

(a) one body corporate is affiliated with another body corporate if one of them is the subsidiary of the other or both are subsidiaries of the same body corporate or each of them is controlled by the same person; and

(b) if two bodies corporate are affiliated with the same body corporate at the same time, they are deemed to be affiliated with each other.

For purposes of this definition, a body corporate is controlled by a person or by two or more bodies corporate if (i) securities of the body corporate to which are attached more than 50% of the votes that may be cast to elect directors of the body corporate, are held, other than by way of security only, by or for the benefit of that person or by or for the benefit of those bodies corporate; and (ii) the votes attached to those securities are sufficient, if exercised, to elect a majority of the directors of the body corporate. For the purposes of this definition, a body corporate is a subsidiary of another body corporate if (i) it is controlled by (A) that other body corporate, (B) that other body corporate and one or more bodies corporate each of which is controlled by that other body corporate, or (C) two or more bodies corporate each of which is controlled by that other body corporate; or (ii) it is a subsidiary of a body corporate that is a subsidiary of that other body corporate.

(2) "**Agreement**" means this asset purchase agreement, including all Schedules, appendices and exhibits to this asset purchase agreement, as amended, supplemented, restated and replaced from time to time in accordance with its provisions.

(3) "**Ancillary Assets**" has the meaning attributed to that term in Section 2.1.

(4) "**Ancillary Intellectual Property**" has the meaning attributed to that term in Section 2.1.

(5) "**Applicable Law**" means:

(a) any domestic (federal, provincial or municipal) or foreign statute, law (including common and civil law), code, ordinance, rule, regulation, order-in-council, restriction or by-law (zoning or otherwise);

(b) any judgement, order, writ, injunction, directive, decision, ruling, decree or award;

(c) any regulatory policy, practice, standard or guideline;

(d) any published administrative position; or

(e) any permit or approval;

of any Governmental Authority, binding on or affecting the Person referred to in the context in which the term is used or binding on or affecting the property of that Person.

(6) "**Approvals**" means franchises, licences, qualifications, authorizations, consents, certificates, registrations, exemptions, waivers, filings, grants, notifications, privileges, rights, orders, judgments, rulings, directives, and other permits and approvals.

(7) "**Associate**" mean any of the following:

(a) the Guarantors;

(b) the Members;

(c) the Affiliates of the Vendor, the Guarantors or the Members;

(d) the officers, directors and employees of the Vendor, a Guarantor, a Member or any Affiliate of the Vendor, the Guarantors or the Members; and

(e) bodies corporate who are controlled by, whose Equity Interests are owned in whole or in part by, who employ or on whose board of directors sit any Associate described in paragraph (a), (c) or (d) of this definition;

(8) "**Business Day**" means any day, except Saturdays and Sundays, on which banks are generally open for non-automated business in Ontario, Canada.

(9) "**Closing**" means the completion of the Transactions on the Closing Date in accordance with this Agreement.

(10) “**Closing Date**” means the next Business Day following the date of execution of this Agreement or such other date as agreed to by the Purchaser and Vendor in writing.

(11) “**Constating Documents**” means, with respect to any Person, its articles or certificate of incorporation, amendment, amalgamation or continuance, memorandum and articles of association, letters patent, supplementary letters patent, by-laws, partnership agreement, limited liability company agreement or other similar document, and all unanimous shareholder agreements, other shareholder agreements, voting trusts, pooling agreements and similar Contracts, arrangements and understandings applicable to the Person's Equity Interests, all as amended, supplemented, restated and replaced from time to time.

(12) “**Contract**” means any agreement, contract, indenture, lease, occupancy agreement, deed of trust, licence, option, undertaking, promise or any other commitment or obligation, whether oral or written, express or implied.

(13) “**CRA**” means the Canada Revenue Agency or any successor agency.

(14) “**Developers**” has the meaning attributed to such term in Section 5.1(14)(f)**.**

(15) “**ETA**” means the *Excise Tax Act* (Canada) and the regulations made thereunder.

(16) “**Encumbrance**” means any encumbrance, lien, charge, hypothec, pledge, mortgage, title retention agreement, security interest of any nature, prior claim, adverse claim, exception, reservation, restrictive covenant, agreement, easement (whether or not registered against title), lease, licence, right of occupation, option, right of use, right of first refusal, right of pre-emption, privilege or any matter capable of registration against title or any Contract to create any of the foregoing.

(17) “**Equity Interests**” means, with respect to any Person, any and all present and future shares, units, trust units, partnership or other interests, participations or other equivalent rights in that Person's equity or capital, however designated and whether voting or non-voting.

(18) “**Escrow Agent**” means Purchaser’s Counsel or such other reputable escrow agent as the Purchaser may designate in writing.

(19) “**Escrow Agreement**” means the escrow agreement substantially in the form of Schedule 3.1 to be entered into among the Escrow Agent, the Purchaser and the Vendor.

(20) “**Escrow Release Date**” means the date on which the Purchaser is required to instruct the Escrow Agent to pay the Purchase Price or Supplemental Payment, as the case may be, to the Vendor pursuant to Section 3.2

(21) “**GST/HST**” means all Taxes payable under Part IX of the ETA (including where applicable both the federal and provincial portion of those Taxes) or under any provincial legislation imposing a similar value added or multi-staged tax.

(22) "**Governmental Authority**" means any domestic or foreign government, whether federal, provincial, state, territorial, local, regional, municipal, or other political jurisdiction, and any agency, authority, instrumentality, court, tribunal, board, commission, bureau, arbitrator, arbitration tribunal or other tribunal, or any quasi-governmental or other entity, body, organization or agency, insofar as it exercises a legislative, judicial, regulatory, administrative, expropriation or taxing power or function of or pertaining to government.

(23) "**Guarantors**" mean Infrastructure Energy, LLC, a limited liability company organized under the laws of Delaware and Energizing, LLC, a limited liability company organized under the laws of Delaware.

(24) "**Infringe**" means infringe (whether directly, contributorily, by inducement or otherwise), misappropriate, violate or otherwise conflict with or harm (whether direct, contributory, by inducement or otherwise) and "**Infringed**" and "**Infringement**" have a corresponding meaning.

(25) "**Intellectual Property**" means, individually and collectively, howsoever created and wherever located:

(a) all domestic and foreign patents and applications thereof and all reissues, divisions, continuations, renewals, extensions and continuations-in-part thereof;

(b) all inventions (whether patentable or not), invention disclosures, improvements, trade secrets, proprietary information, know-how, technology, technical data, schematics and customer lists, and all documentation relating to any of the foregoing;

(c) all copyrights in all works (including Software) and database right, copyright registrations and applications thereof, and all works of authorship and moral rights, and all other rights corresponding thereto throughout the world;

(d) all trade names, domain names, corporate names, trade dress, distinguishing guises, logos, slogans, brand names, trademarks (whether registered or common law and whether used with wares or services and including the goodwill attaching to such trademarks) and registrations and applications for registration thereof;

(e) all Software (in source code and object code form) and databases, and any proprietary rights in such Software and databases;

(f) all integrated circuit design, mask work, or topography registrations or applications thereof;

(g) all industrial designs and applications for and registration of industrial designs, design patents and industrial design registrations;

(h) other intellectual or industrial property whatsoever, including the intellectual property described in Schedule 5.1(14);

(i) all income, royalties, damages and payments now and hereafter due and/or payable with respect to any of the foregoing, including damages and payments for past or future Infringements thereof; and

(j) all rights to sue for past, present and future Infringements of any of the foregoing.

(26) "**Losses**" has the meaning attributed to that term in Section 6.1(8).

(27) "**Member**" means each of Glen Martin and Blind Line Holdings, LLC.

(28) "**Other Agreements**" has the meaning attributed to that term in Section 7.6.

(29) "**Parties**" means collectively, the Purchaser, the Vendor, the Guarantors and the Members, and "**Party**" means any of them.

(30) "**Person**" is to be broadly interpreted and includes an individual, a corporation, a partnership, a joint venture, a trust, an association, a syndicate, an unincorporated organization, a Governmental Authority, an executor or administrator or other legal or personal representative, or any other juridical entity.

(31) "**Personal Information**" means information about an identifiable natural person, but does not include the name, title, business address or telephone number of an employee of the Vendor, that is to be disclosed to the Purchaser at Closing or that was disclosed to the Purchaser to permit the Purchaser to carry out its due diligence in connection with the Transactions.

(32) "**Preliminary Bill of Sale**" has the meaning attributed to that term in the recitals.

(33) "**Preliminary Sale Agreement**" has the meaning attributed to that term in the recitals.

(34) "**Proceeding**" means:

(a) any suit, action, dispute, investigation, claim, arbitration, order, summons, citation, directive, charge, demand or prosecution, whether legal or administrative;

(b) any other proceeding; or

(c) any appeal or application for review;

at law or in equity or before or by any Governmental Authority.

(35) "**Purchase Price**" has the meaning attributed to that term in Section 2.4.

(36) "**Purchased Assets**" has the meaning attributed to that term in Section 2.1.

(37) "**Purchaser**" means PUC Distribution Inc., a corporation incorporated under the laws of Ontario.

(38) "**Purchaser's Counsel**" means Borden Ladner Gervais LLP.

(39) “**Release Agreement**” means the release agreement to be entered into between the Vendor, the Guarantors, the Members and Purchaser, substantially in the form of Schedule 4.1(1)(d)(vii).

(40) “**Report**” has the meaning attributed to that term in Section 2.1.

(41) “**Report Author**” means the author or signatory of any Report.

(42) “**Representatives**” means, with respect to any Party, its Affiliates and, if applicable, its and their respective directors, officers, employees, agents and other representatives and advisors.

(43) “**Software**” means software, including all versions thereof, whether installed locally, on a local area network or delivered through the internet, and all related documentation, manuals, source code and object code, program files, data files, computer related data, field and data definitions and relationships, data definition specifications, data models, program and system logic, interfaces, program modules, routines, sub-routines, algorithms, program architecture, design concepts, system designs, program structure, sequence and organization, screen displays and report layouts, including any and all modifications, changes, release, versions, upgrades, updates or patches of any of the foregoing, and all other material related to such software.

(44) “**SSG Project**” means the project being undertaken by the Purchaser to introduce a Volt/VAR management system and feeder distribution automation system, among other system upgrades, from time to time referred to as the Sault Smart Grid Project.

(45) “**SSG Project Approval**” means the approval of the Incremental Capital Module application in respect of the SSG Project by the Ontario Energy Board, (1) substantially as submitted and (2) in a timeframe consistent with the requirements of the funding agreement currently in place between the Purchaser and Natural Resources Canada, in each case, so as not to effect the financial viability of the Project in the opinion of the Purchaser.

(46) “**Supplemental Condition Precedent**” means the condition precedent set forth in Section 4.2.

(47) “**Supplemental Payment**” has the meaning attributed to that term in Section 2.4.

(48) “**Supplementary Closing**” means, if applicable, the completion of the Transactions on the Supplementary Closing Date in accordance with this Agreement.

(49) “**Supplementary Closing Date**” means, if applicable, the date failing 14 days after the satisfaction of the Supplemental Conditions Precedent or such other date as agreed to by the Purchaser and Vendor in writing.

(50) “**Tax Act**” or any reference to a specific provision thereof means the *Income Tax Act* (Canada) and legislation of any legislature of any province or territory of Canada (including the *Taxation Act* (Québec)) and any regulations made thereunder in force of like or similar effect.

(51) "**Taxes**" means taxes, duties, fees, premiums, assessments, imposts, levies and other charges of any kind whatsoever imposed by any Governmental Authority, including all interest, penalties, fines, additions to tax or other additional amounts imposed in respect thereof (including those levied on, or measured by, or referred to as, income, gross receipts, profits, capital, transfer, land transfer, gains, capital stock, production, gift, wealth, environment, net worth, utility, sales, goods and services, harmonized sales, use, consumption, valued-added, excise, stamp, withholding, premium, business, franchising, property, employer health, payroll, employment, health, social services, education and social security taxes, surtaxes, customs duties and import and export taxes, development, occupancy, social services, licence, franchise and registration fees and employment insurance, health insurance and Canada, Québec and other government pension plan premiums or contributions), and "**Tax**" has a corresponding meaning.

(52) "**Transactions**" means the purchase and sale of the Purchased Assets and all other transactions contemplated by this Agreement.

(53) "**Transmission**" has the meaning attributed to that term in Section 7.14(1).

(54) "**Vendor**" means Infrastructure Energy Inc., a corporation incorporated under the laws of Canada.

(55) "**Vendor's Counsel**" means such counsel as may be appointed from time to time to act on behalf of any or all of the Vendor, the Guarantors and the Members.

1.2 Construction. This Agreement has been negotiated by each Party with the benefit of legal representation, and any rule of construction to the effect that any ambiguities are to be resolved against the drafting party does not apply to the construction or interpretation of this Agreement.

1.3 Certain Rules of Interpretation. In this Agreement:

(a) the division into Articles and Sections and the insertion of headings and the Table of Contents are for convenience of reference only and do not affect the construction or interpretation of this Agreement;

(b) the expressions "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this Agreement and not to any particular portion of this Agreement; and

(c) unless specified otherwise or the context otherwise requires:

(i) references to any Article, Section or Schedule are references to the Article or Section of, or Schedule to, this Agreement;

(ii) "including" or "includes" means "including (or includes) but is not limited to" and is not to be construed to limit any general statement preceding it to the specific or similar items or matters immediately following it;

(iii) "the aggregate of", "the total of", "the sum of", or a phrase of similar meaning means "the aggregate (or total or sum), without duplication, of";

(iv) references to Contracts are deemed to include all present amendments, supplements, restatements and replacements to those Contracts;

(v) references to any legislation, statutory instrument or regulation or a section thereof are references to the legislation, statutory instrument, regulation or section as amended, re-enacted, consolidated or replaced from time to time;

(vi) words in the singular include the plural and vice-versa and words in one gender include all genders.

1.4 Knowledge. In this Agreement, any reference to the knowledge of any Party means to the best of the knowledge, information and belief of the Party after reviewing all relevant records and making due inquiries regarding the relevant matter of all relevant Representatives of the Party, and any reference to the knowledge of the Vendor and the Members means to the best of the knowledge, information and belief of any of them after reviewing all relevant records and making due inquiries regarding the relevant matter of all their respective relevant Representatives.

1.5 Computation of Time. In this Agreement, unless specified otherwise or the context otherwise requires:

(a) a reference to a period of days is deemed to begin on the first day after the event that started the period and to end at 5:00 p.m. on the last day of the period, but if the last day of the period does not fall on a Business Day, the period ends at 5:00 p.m. on the next succeeding Business Day;

(b) all references to specific dates mean 11:59 p.m. on the dates;

(c) all references to specific times are references to Eastern time; and

(d) with respect to the calculation of any period of time, references to "from" mean "from and excluding" and references to "to" or "until" mean "to and including".

1.6 Performance on Business Days. If any action is required to be taken pursuant to this Agreement on or by a specified date that is not a Business Day, the action is valid if taken on or by the next succeeding Business Day.

1.7 Currency and Payment. In this Agreement, unless specified otherwise:

(a) references to dollar amounts or "$" are to Canadian dollars;

(b) any payment is to be made by an official bank draft drawn on a Canadian chartered bank, wire transfer or any other method (other than cash payment) that provides immediately available funds; and

(c) except in the case of any payment due on the Closing Date, any payment due on a particular day must be received and available by 4:00 p.m. on the due date and any payment received and available after that time is deemed to have been made and received on the next succeeding Business Day.

1.8 Schedules. The following Schedules are attached to and form part of this Agreement:

Schedule 3.1	Escrow Agreement
Schedule 4.1(1)(d)(vii)	Release Agreement
Schedule 4.1(1)(d)(v)	Form of Bring-Down Certificate
Schedule 5.1(1)	Jurisdictions
Schedule 5.1(7)	Listed Reports
Schedule 5.1(8)	Listed Ancillary Assets
Schedule 5.1(12)	Preliminary Bill of Sale

ARTICLE 2
PURCHASE AND SALE

2.1 Agreement to Purchase and Sell. The Vendor does hereby sell, transfer, convey and assign to the Purchaser and the Purchaser does hereby purchase and acquire from the Vendor, free and clear of all Encumbrances, all of the Vendor's right, title and interest in and to the property and assets described below (collectively, the "**Purchased Assets**"):

(a) All report and studies commissioned by or paid for, or in the possession of the Vendor or an Associate that related to the SSG Project (the "**Reports**"), including the Listed Reports;

(b) All appendices, drawings, spreadsheets, data files, Contracts, invoices, payment receipts and other documents or records that relate to the Reports (such as those provided to a Report Author by the Vendor or an Associate, those cited in a Report or those developed by the Vendor or an Associate based information contained in a Report) (the "**Ancillary Assets**"), including the Listed Ancillary Assets; and

(c) All Intellectual Property that is contained in, or that is necessary to implement any engineering solution described in, the Reports or Ancillary Assets (the "**Ancillary Intellectual Property**").

2.2 Delivery of Purchased Assets. The Vendor shall deliver the Purchased Assets to the Purchaser on the Closing Date; provided that the Vendor shall deliver the Ancillary Assets to the Purchaser on the Closing Date or as soon as reasonably possible thereafter. The Purchased Assets will be delivered in form satisfactory to the Purchaser. Notwithstanding the payment of the Purchase Price or the Supplemental Payment to the Vendor, the Vendor's obligation to deliver the Purchased Assets to the Purchaser shall continue in respect of any Purchased Assets not delivered.

2.3 Liabilities. The Purchaser shall not assume or have any obligation to discharge, perform or fulfill any obligation or liability of the Vendor of any kind whatsoever (collectively, the "**Excluded Liabilities**") and all Excluded Liabilities remain the obligation and responsibility of the Vendor.

2.4 Purchase Price and Purchase Price Allocation.

(1) Subject to the terms and conditions of this Agreement, the aggregate purchase price (the "**Purchase Price**") to be paid by the Purchaser to the Vendor for the Purchased Assets is $511,847.57.

(2) Subject to the terms and conditions of this Agreement, the Purchase Price will be increased by $511,847.57 (the "**Supplemental Payment**") upon the satisfaction of the Supplemental Conditions Precedent.

(3) The Supplemental Payment is not a retainage or withholding against the Purchase Price or security for the performance of any obligation of the Vendor. Notwithstanding the transfer of the Purchased Assets to the Purchaser on the Closing Date, the Supplemental Payment shall not become due and owing unless and until the Supplemental Conditions Precedent.

2.5 Payment of Purchase Price.

(1) The Purchaser shall pay and satisfy the Purchase Price by payment of the Purchase Price to the Escrow Agent on the Closing Date.

(2) If applicable, the Purchaser shall pay and satisfy the increased Purchase Price by payment of the Supplemental Payment to the Escrow Agent on the Supplementary Closing Date.

2.6 Transfer Taxes. The Purchaser shall pay to the Vendor or, where permitted by Applicable Law, directly to the appropriate Governmental Authorities, all sales and transfer taxes, registration charges and transfer fees, including GST/HST, payable by it in respect of the purchase and sale of the Purchased Assets under this Agreement, and, on request of the Vendor, the Purchaser shall furnish to the Vendor proof of direct payment to a Governmental Authority. The Purchaser shall indemnify and save harmless the Vendor from any amounts, including interest and penalties, that may be assessed against the Vendor arising out of the failure of the Purchaser to pay, when due, any Taxes described in this Section.

2.7 GST/HST Election. The Purchaser and Vendor will use their best efforts to minimize (or eliminate) any taxes payable under the ETA in respect of the Closing by, among other things, making such elections and taking such steps as may be provided under those acts (including making a joint election in a timely manner under Section 167 of the ETA) as may be reasonably requested by the Purchaser in connection with the Closing.

ARTICLE 3
ESCROW ARRANGEMENTS

3.1 Escrow Agreement. At Closing, the Purchaser and Vendor will enter into an Escrow Agreement with the Escrow Agent substantially in the form set out in Schedule 3.1. The Escrow

Agreement will provide that amounts held by the Escrow Agreement will be paid to the Vendor or to its direction on the instruction of the Purchaser.

3.2 Release from Escrow.

(1) The Purchaser will instruct the Escrow Agent to pay the Purchase Price to the Vendor or to its direction upon satisfaction of the conditions precedent described in Section 4.1 on or after the Closing Date.

(2) The Purchaser will instruct the Escrow Agent to pay the Supplemental Payment to the Vendor or to its direction upon satisfaction of the conditions precedent described in Section 4.1 on or after the Supplemental Closing Date.

(3) The amounts that the Purchaser instructs the Escrow Agent to pay to the Vendor or to its direction pursuant to Section 3.2(1) and 3.2(2) are subject to adjustments and withholdings that the Purchaser is permitted to make by this Agreement or otherwise required to make by Applicable Law. The Purchaser and Vendor will jointly instruct the Escrow Agent with respect to any such adjustments or withholdings.

ARTICLE 4
CONDITIONS OF ESCROW RELEASE

4.1 Conditions for the Benefit of the Purchaser.

(1) The Purchaser shall be obliged to instruct the Escrow Agent to pay the Purchase Price or the Supplemental Payment, as the case may be, to the Vendor or to its direction, only if each of the following conditions precedent has been satisfied in full:

(a) all of the representations and warranties of the Vendor, the Guarantors and the Members made in or pursuant to this Agreement shall have been true and correct as of the date hereof and shall be true and correct as at the Escrow Release Date with the same effect as if made on and as of the Escrow Release Date;

(b) the Vendor, the Guarantors and the Members have complied with or performed all of the obligations, covenants and agreements under this Agreement to be complied with or performed by the Vendor, the Guarantors and the Members on or before the Escrow Release Date, to the satisfaction of the Purchaser, acting reasonably;

(c) there is no injunction or restraining order issued preventing, and no pending or threatened Proceeding, against any Party, for the purpose of enjoining or preventing, the completion of the Transactions or otherwise claiming that this Agreement or the completion of the Transactions is improper or would give rise to a Proceeding, under any Applicable Law or under any Contract;

(d) the Vendor, the Guarantors and the Members have caused to be delivered to the Purchaser the following:

(i) the Purchased Assets, in form satisfactory to the Purchaser;

(ii) in respect of the Vendor, each Guarantor and each corporate Member:

(A) a certificate of status or its equivalent under the laws of the jurisdiction of its incorporation or governing its corporate existence and

(B) a certificate of a senior officer certifying:

1. the corporate status of that Party;

2. the Constating Documents of that Party;

3. the existence or non-existence of unanimous shareholders' agreements and voting trust arrangements in respect of that Party;

4. the resolutions of the board of directors and/or (if required by Applicable Law) shareholders of that Party authorizing the execution, delivery and performance of this Agreement and of all contracts, agreements, instruments, certificates and other documents required by this Agreement to be delivered by that Party; and

5. the incumbency and signatures of the officers of that Party executing this Agreement and any other document relating to the Transactions.

(iii) all deeds, conveyances, bills of sale, assurances, transfers, assignments and any other documentation or action which in the opinion of the Purchaser are necessary or reasonably required to transfer the Purchased Assets to the Purchaser with good and marketable title, free and clear of all Encumbrances, in each case duly executed by the Vendor and in form and substance satisfactory to the Purchaser, acting reasonably;

(iv) evidence, satisfactory to the Purchaser of the release and discharge of all Encumbrances affecting any of the Purchased Assets;

(v) a certificate of the Vendor, the Guarantors and the Members in respect of their representations and warranties set out in Section 5.1 and their covenants and other obligations set out in this Agreement, substantially in the form of Schedule 4.1(1)(d)(v);

(vi) favourable opinions of Vendor's Counsel, addressed to the Purchaser and dated the Closing Date, in form and substance satisfactory to the Purchaser as to those matters relating to the Transactions as the Purchaser and the Purchaser's Counsel may reasonably request;

(vii) the Release Agreement, fully executed by the Vendor, the Guarantors and the Members, substantially in the form of Schedule 4.1(1)(d)(vii);

(viii) the Vendor's signed counterparty of a joint instruction of the Purchase and Vendor to the Escrow Agent described in Section 3.2(3);

(ix) such other documentation as the Purchaser reasonably requests in a timely manner in order to establish the completion of the Transactions and the taking of all corporate proceedings in connection with the Transactions (as to certification and otherwise), in each case in form and substance satisfactory to the Purchaser, acting reasonably; and

(x) all documentation relating to the Transactions is satisfactory to the Purchaser, acting reasonably.

(e) Each of the conditions set out in Section 4.1(1) is for the exclusive benefit of the Purchaser and the Purchaser may waive compliance with any such condition in whole or in part by notice in writing to the Vendor, the Guarantors and the Members, except that no such waiver operates as a waiver of any other condition.

4.2 Supplemental Condition Precedent. The Purchase Price shall be increased by the amount of the Supplemental Payment, and Purchaser shall be obliged to pay the Supplemental Payment to the Escrow Agent, only if the Purchaser has obtained the SSG Project Approval by the fifth anniversary of the Closing Date.

4.3 Termination Events. Subject to Section 4.4, this Agreement may be terminated by mutual consent of the Purchaser and the Vendor.

4.4 Effect of Termination. Each Party's right of termination under Section 4.2 is in addition to any other rights it may have under this Agreement or otherwise, whether at law, in equity or otherwise, and the exercise of that right of termination is not an election of remedies. If this Agreement is terminated pursuant to Section 4.2, all obligations of the Parties under this Agreement will terminate except that the obligations contained in this Section 4.4 and in Article 7 will survive.

4.5 Waiver of Conditions of Escrow Release. If any of the conditions set forth in Section 4.1 has not been satisfied as of the date that is 180 days after the Closing Date of the Supplementary Closing Date, as the case may be, the Purchaser may elect in writing to waive the condition and proceed with the completion of the Transactions. In such case:

(1) the Purchase Price will adjusted by an equitable amount based on the diminution of value of the Assets Purchased and any Losses incurred by the Purchaser as a result of the condition not having been satisfied; and

(2) the Purchaser will not be obliged to instruct the Escrow Agent to make any payment to the Vendor or its direction, as would be otherwise be required by Section 3.2, until the adjustment to the Purchase Price described in Section 4.5(1) has been determined by agreement of the Purchaser and Vendor or by arbitration.

ARTICLE 5
REPRESENTATIONS AND WARRANTIES

5.1 Representations and Warranties of the Vendor and the Members. The Vendor, the Guarantors and the Members jointly and severally represent and warrant to the Purchaser as follows and acknowledge that the Purchaser is relying on these representations and warranties in connection with its purchase of the Purchased Assets and that the Purchaser would not purchase the Purchased Assets and assume the Assumed Liabilities without these representations and warranties:

(1) Recitals. The statements of fact regarding the Vendor, Guarantors and Members in the recitals are true and correct.

(2) Organization and Status of the Vendor and the Members. Each of the Vendor, the Guarantors and the corporate Members is duly [incorporated] and organized, and is validly subsisting, under the laws of the jurisdiction set out opposite its name on Schedule 5.1(1) and is up-to-date in the filing of all corporate and similar returns under the laws of that jurisdiction.

(3) Corporate Power. Each of the Vendor, the Guarantors and the Members has all necessary corporate power and authority to enter into this Agreement and the contracts, agreements and instruments required by this Agreement to be delivered by it, and to perform its obligations hereunder and thereunder.

(4) Authorization. All necessary corporate action has been taken by each of the Vendor, the Guarantors and the corporate Members or on its part to authorize its execution and delivery of this Agreement and the contracts, agreements and instruments required by this Agreement to be delivered by it and the performance of its obligations hereunder and thereunder.

(5) Enforceability. This Agreement has been duly executed and delivered by each of the Vendor, the Guarantors and the Members and (assuming due execution and delivery by the other Parties) is a legal, valid and binding obligation of it enforceable against it in accordance with its terms, except as that enforcement may be limited by bankruptcy, insolvency and other similar laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction. Each of the contracts, agreements and instruments required by this Agreement to be delivered by it will at the Closing have been duly executed and delivered by it and (assuming due execution and delivery by the other parties thereto) will at Closing be enforceable against it in accordance with its terms, except as that enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

(6) No Other Agreements to Purchase. No Person other than the Purchaser has any Contract or any right or privilege capable of becoming a Contract for the purchase or acquisition from the Vendor or the Guarantors of any of the Purchased Assets.

(7) <u>No Other Reports</u>. No Reports exist other than the Listed Reports.

(8) <u>No Other Ancillary Assets</u>. No Ancillary Assets exist other than the Listed Ancillary Assets.

(9) <u>No Personal Information</u>. The Purchased Assets do not contain any Personal Information.

(10) <u>Bankruptcy</u>. Each of the Vendor, the Guarantors and the Members is able to pay its debts generally as they become due, is not an insolvent Person within the meaning of the *Bankruptcy and Insolvency Act* (Canada) and has not made an assignment in favour of its creditors or a proposal in bankruptcy to its creditors or any class thereof, and no petition for a receiving order has been presented in respect of it. None of the Vendor, the Guarantors or the Member has initiated proceedings with respect to a compromise or arrangement with its creditors or for its winding up, liquidation or dissolution. No receiver or interim receiver has been appointed in respect of it or any of its undertakings, property or assets (including any of the Purchased Assets) and no execution or distress has been levied on any of its undertakings, property or assets (including any of the Purchased Assets), nor have any proceedings been commenced in connection with any of the foregoing.

(11) <u>Absence of Conflict</u>. The execution, delivery and performance of this Agreement by each of the Vendor, the Guarantors and the Members and the completion of the Transactions will not (whether after the passage of time or notice or both) result in:

(a) the breach or violation of any of the provisions of, or constitute a default under, or give any Person the right to seek or cause a termination, cancellation, amendment or renegotiation of any Contract to which it is a party or by which any of its undertakings, property or assets is bound or affected;

(b) the breach or violation of any of the provisions of, or constitute a default under, or conflict with any of its obligations under:

(i) any provision of its Constating Documents or resolutions of its board of directors (or any committee thereof) or shareholders;

(ii) any judgment, decree, order or award of any Governmental Authority having jurisdiction over it;

(iii) any Approval issued to, or held by, the Vendor or held, for the benefit of or necessary to the operation of its business; or

(iv) any Applicable Law;

(c) the creation or imposition of any Encumbrance over any of the Purchased Assets; or

(d) the requirement of any Approval from any of its creditors.

(12) Title to Purchased Assets. The Vendor has good and marketable title to all the Purchased Assets, free and clear of any and all Encumbrances. Immediately prior to the entry into the Preliminary Agreement and Preliminary Bill of Sale, the Guarantors had good and marketable title to all the Purchased Assets, free and clear of any and all Encumbrances.

(13) Preliminary Bill of Sale. The Preliminary Bill of Sale set forth in Schedule 5.1(12) is a true and accurate copy of the bill of sale entered into between the Guarantors and Vendor pursuant to the Preliminary Sale Agreement in respect of the Purchased Assets and remains in full force and effect, unamended as of the date of this Agreement.

(14) Intellectual Property.

(a) The Vendor holds the entire right, title and interest in and to all of the Ancillary Intellectual Property throughout the world, free of all Encumbrances, and has the exclusive and unfettered right to use the Ancillary Intellectual Property. Immediately prior to the entry into the Preliminary Agreement and Preliminary Bill of Sale, the Guarantors held the entire right, title and interest in and to all of the Ancillary Intellectual Property throughout the world, free of all Encumbrances, and had the exclusive and unfettered right to use the Ancillary Intellectual Property.

(b) The Ancillary Intellectual Property is valid and the rights of the Vendor in the Ancillary Intellectual Property are enforceable. All registrations and applications for registration of the Ancillary Intellectual Property are in good standing, have been filed in a timely manner within the appropriate offices to preserve the rights thereto and assignments have been recorded in favour of the Vendor. No Ancillary Intellectual Property has expired, has been cancelled, expunged or impeached, or has lapsed for failure to be renewed or maintained. No Ancillary Intellectual Property has been used, not used, enforced or not enforced in a manner that could reasonably be expected to result in the abandonment, cancellation or unenforceability of any of the Ancillary Intellectual Property.

(c) No Ancillary Intellectual Property is subject to any outstanding order, award, decision, injunction, judgment, decree, stipulation or agreement materially restricting the transfer, use, enforcement or licensing thereof.

(d) Neither the use or the content of the Ancillary Intellectual Property nor the conduct of the Vendor or the Guarantors in relation to the Purchased Assets has Infringed or will Infringe the Intellectual Property of any other Person. Neither the Vendors nor the Guarantors has received any notice that the use of the Ancillary Intellectual Property or the conduct of the Vendor or the Guarantors in relation to the Purchased Assets Infringes any Intellectual Property of any other Person, and no Proceedings have been instituted or are pending or threatened, alleging any such infringement.

(e) To the knowledge of the Vendor and the Guarantors, no Person has Infringed any of the Ancillary Intellectual Property, neither the Vendor nor the Guarantors has not issued a notice to any Person alleging any such infringement, and no

Proceedings have been instituted or are pending or threatened, alleging any such infringement.

(f) All of the Ancillary Intellectual Property that has been developed or created by employees or pursuant to Contracts with consultants or contractors (collectively, the "**Developers**") has been assigned exclusively to the Vendor in writing or in another enforceable manner. The Developers have waived in writing their moral and authors' rights they may have in the Ancillary Intellectual Property. No Person has claimed that any current or former Developer has, as a result of contribution to any Ancillary Intellectual Property, violated the terms and conditions of any Contract with that Person or disclosed or used any trade secret of that Person. No Developer has claimed any rights in the Ancillary Intellectual Property.

(g) The Ancillary Intellectual Property is not subject to any Proceedings, including any actual or threatened claim for cancellation, expungement, impeachment, re-examination, invalidity or any termination or limitation thereof.

(h) Entering into this Agreement will not alter, impair or extinguish any of the Ancillary Intellectual Property or trigger any rights of first refusal requiring the sale, assignment or transfer of any Ancillary Intellectual Property to another Person.

(15) No Default Under Contracts. Each of the Vendor and Associates has performed all of the obligations required to be performed by it and is entitled to all benefits under, and is not in default or alleged to be in default in respect of, any Contract relating to the Purchased Assets, to which it is a party or by which it is bound or affected. All such Contracts have been performed in full by the parties thereto. There is no dispute under any such Contract.

(16) Third Party Approvals. There is no requirement under any Contract relating to the Purchased Assets or the Vendor to which the Vendor or an Associate is a party or by which the Purchased Assets or the Vendor or Associate is bound or affected for any Approvals from any party to that Contract or from any other Person relating to the completion of the Transactions.

(17) Taxes.

(a) The Vendor is not a non-resident of Canada for purposes of the Tax Act.

(b) There are no outstanding liabilities for Taxes payable, collectible or remittable by the Vendor, whether assessed or not, which may result in an Encumbrance on or other claim against or seizure of all or any part of the Purchased Assets or would result in the Purchaser becoming liable or responsible for those liabilities.

(c) The Vendor is duly registered under Subdivision (d) of Division V of Part IX of the ETA and its registration number is 75231 1878 RT0001.

(18) Litigation. There are no Proceedings (whether or not purportedly on behalf of the Vendor) pending or, to the knowledge of the Vendor, the Guarantors and the Members, threatened against or affecting, the Purchased Assets. To the knowledge of the Vendor, the Guarantors

and the Members, there is not any factual or legal basis on which any Proceeding might be commenced with any reasonable likelihood of success.

(19) Ethical Practices. No Representative of the Vendor, the Guarantors or any other Person associated with the Vendor, the Guarantors or any Representative of any of them, has directly or indirectly:

(a) made or received any contribution, gift, bribe, rebate, payoff, influence payment, kickback, or other payment to or from any Person, private or public, regardless of form, whether in money, property or services (i) to obtain favourable treatment in securing business, (ii) to pay for favourable treatment in business secured, (iii) to obtain special concessions or for special concessions already obtained, for or in respect of the Vendor, or (iv) in violation of any Applicable Law; or

(b) established or maintained any fund or asset that has not been recorded in the Books and Records.

5.2 Representations and Warranties of the Purchaser. The Purchaser represents and warrants to the Vendor as follows and acknowledges that the Vendor is relying on these representations and warranties in connection with the sale by the Vendor of the Purchased Assets:

(1) Organization and Corporate Power. The Purchaser is a corporation duly incorporated and organized, and is validly subsisting, under the laws of Ontario and is up-to-date in the filing of all corporate and similar returns under the laws of that jurisdiction. The Purchaser has all necessary corporate power and authority to acquire the Purchased Assets, to enter into this Agreement and to perform its obligations hereunder.

(2) Authorization. All necessary corporate action has been taken by or on the part of the Purchaser to authorize its execution and delivery of this Agreement and the contracts, agreements and instruments required by this Agreement to be delivered by it and the performance of its obligations hereunder and thereunder.

(3) Enforceability. This Agreement has been duly executed and delivered by the Purchaser and (assuming due execution and delivery by the other Parties) is a legal, valid and binding obligation of the Purchaser enforceable against it in accordance with its terms, except as that enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction. Each of the contracts, agreements and instruments required by this Agreement to be delivered by the Purchaser will at the Closing have been duly executed and delivered by it and (assuming due execution and delivery by the other parties thereto) will be enforceable against it in accordance with its terms, except as that enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

(4) Bankruptcy. The Purchaser is not an insolvent person within the meaning of the *Bankruptcy and Insolvency Act* (Canada) and has not made an assignment in favour of its creditors or a proposal in bankruptcy to its creditors or any class thereof, and no petition

for a receiving order has been presented in respect of it. The Purchaser has not initiated proceedings with respect to a compromise or arrangement with its creditors or for its winding up, liquidation or dissolution. No receiver or interim receiver has been appointed in respect of it or any of its undertakings, property or assets and no execution or distress has been levied on any of its undertakings, property or assets, nor have any proceedings been commenced in connection with any of the foregoing.

(5) Absence of Conflict. The execution, delivery and performance by the Purchaser of this Agreement and the completion of the Transactions will not, (whether after the passage of time or notice or both), result in:

(a) the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the acceleration of any of its obligations, under:

(i) any provision of its Constating Documents or resolutions of its board of directors (or any committee thereof) or shareholders;

(ii) any Approval issued to, held by or for the benefit of, the Purchaser;

(iii) any Applicable Law; or

(b) the requirement for any Approval from any creditor of the Purchaser.

(6) ETA Registration. The Purchaser is duly registered under Subdivision (d) of Division V of Part IX of the ETA and its registration number is 86709 6778 RT0001.

5.3 Survival of Representations, Warranties and Covenants of the Vendor. The representations and warranties of the Vendor, the Guarantors and the Members, and, to the extent that they have not been fully performed at or prior to Closing, the covenants and other obligations of the Vendor, the Guarantors and the Members, in each case contained in this Agreement and in any contract, agreement, instrument, certificate or other document executed or delivered pursuant to this Agreement survive Closing and continue for the benefit of the Purchaser without limitation of time notwithstanding the Closing, any investigation made by or on behalf of the Purchaser or any knowledge of the Purchaser.

5.4 Survival of the Representations, Warranties and Covenants of the Purchaser. The representations and warranties of the Purchaser and, to the extent that they have not been fully performed at or prior to Closing, the covenants and other obligations of the Purchaser, contained in this Agreement and in any contract, agreement, instrument, certificate or other document executed or delivered pursuant to this Agreement survive Closing and continue for the benefit of the Vendor, the Guarantors and the Members notwithstanding the Closing, any investigation made by or on behalf of the Vendor, the Guarantors or the Members or any knowledge of the any of them, until the first anniversary of the Closing Date.

5.5 Termination of Liability.

(1) No Party or other Person is entitled to indemnification pursuant to this Agreement unless the Party or other Person has given written notice of its Claim for indemnification pursuant

to Article 6, as the case may be, prior to the expiry of the relevant survival period prescribed by Sections 5.3 and 5.4 and in that event, only on and subject to the terms and conditions of and to the extent provided for in Article 6.

(2) This Agreement constitutes a "business agreement" under the *Limitations Act 2002* (Ontario) and to the extent that the provisions of this Agreement are found to be an agreement to vary or exclude, or suspend or extend, a limitation period prescribed under such legislation, that limitation period will be deemed to be varied or excluded, or suspended or extended, as the case may be, to the extent necessary to give full force and effect to the provisions of this Agreement.

ARTICLE 6
INDEMNIFICATION

6.1 Definitions. In this Article 6:

(1) "**Claim**" means any act, omission or state of facts and any demand, action, investigation, inquiry, suit, proceeding, claim, assessment, judgment or settlement or compromise relating thereto which may give rise to a right of indemnification under this Agreement.

(2) "**Direct Claim**" means any Claim by an Indemnitee against an Indemnitor which does not result from a Third Party Claim.

(3) "**Increased Amount**" has the meaning attributed to that term in Section 6.8(3).

(4) "**Indemnitee**" means any Person entitled to indemnification under this Agreement.

(5) "**Indemnitees Representative**" means:

(a) in respect of the Purchaser Indemnitees, the Purchaser; and

(b) in respect of the Vendor Indemnitees, the Vendor.

(6) "**Indemnitor**" means any Party obligated to provided indemnification under this Agreement.

(7) "**Indemnification Notice**" means written notice by an Indemnitee to the applicable Indemnitor or Indemnitors of a Third Party Claim or Direct Claim, as the case may be.

(8) "**Losses**" means any and all loss, liability, obligation, damage, cost, expense, charge, fine, penalty or assessment, suffered, incurred, sustained or required to be paid by the Person seeking indemnification (including lawyers', experts' and consultants' fees and expenses), directly resulting from or arising out of any Claim, including the costs and expenses of any action, suit, proceeding, investigation, inquiry, arbitration award, grievance, demand, assessment, judgment, settlement or compromise relating thereto, but: (i) excluding any contingent liability until it becomes actual; (ii) reduced by any net Tax benefit; and (iii) reduced by any recovery, settlement or otherwise under or pursuant to any insurance

coverage, or pursuant to any claim, recovery, settlement or payment by or against any other Persons.

(9) "**Payment**" has the meaning attributed to that term in Section 6.8(4).

(10) "**Purchaser Indemnitees**" means the shareholders and Representatives of the Purchaser, and related Persons.

(11) "**Third Party Claim**" means any Claim asserted against an Indemnitee by any Person who is not a Party or an Affiliate of a Party.

(12) "**Vendor Indemnitees**" means the Members, the Representatives of the Vendor, and related Persons.

6.2 Indemnification by the Vendor and the Members. In addition to any other indemnification provided by the Vendor and the Members contained in this Agreement and subject to this Article 6, the Vendor and the Members shall jointly and severally indemnify and save harmless the Purchaser and, to the extent named or involved in any Third Party Claim, the Purchaser Indemnitees from, and shall pay to the Purchaser and the Purchaser Indemnitees, on demand, the amount of any and all Losses, as a result of or arising in connection with:

(a) any inaccuracy of or any breach of any representation or warranty made by any of the Vendor and the Members in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement, whether or not the Purchaser relied on or had knowledge of it;

(b) any breach or non-performance by any of the Vendor and the Members of any covenant or other obligation contained in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement;

(c) any of the Excluded Liabilities, including any alleged responsibility of the Purchaser in respect thereof; and

(d) any breach or alleged breach of any Contract by the Vendor which occurred prior to the Closing Date or any such breach which occurs after the Closing Date but arises out of a continuation of a course of conduct which commenced prior to the Closing Date.

6.3 Notice of Claim.

(1) An Indemnitee, promptly on becoming aware of any circumstances that have given or could give rise to a Third Party Claim or a Direct Claim, shall give an Indemnification Notice of those circumstances to its Indemnitees Representative and to the applicable Indemnitor or Indemnitors. The Indemnification Notice will specify whether the Losses arise as a result of a Third Party Claim or a Direct Claim, and will also specify with reasonable particularity (to the extent the information is available) the factual basis for the Claim and the amount of the Losses, if known.

(2) The failure to give, or delay in giving, an Indemnification Notice does not relieve the Indemnitor of its obligations except and only to the extent of any prejudice caused to the Indemnitor by that failure or delay.

(3) Provided that the Indemnitee gives an Indemnification Notice of the Claim to the Indemnitor on or prior to the expiry of the applicable time period related to that representation and warranty or covenant, as the case may be, set out in Sections 5.3 and 5.4, liability of the Indemnitor for that representation, warranty or covenant will continue in full force and effect until the final determination of that Claim.

6.4 Third Party Claims.

(1) The Indemnitor has the right, by notice to the applicable Indemnitees Representative given not later than 30 days after receipt of the Indemnification Notice, to assume control of the defence, compromise or settlement of the Third Party Claim provided that:

(a) the Third Party Claim involves only money damages and does not seek any injunctive or other equitable relief;

(b) if the named parties in any Third Party Claim include both the Indemnitor and the Indemnitee, representation by the same counsel would, in the judgment of the Indemnitee, still be appropriate notwithstanding any actual or potential differing interests between them (including the availability of different defences);

(c) settlement of, or an adverse judgment with respect to, the Third Party Claim is not, in the judgment of the Indemnitee, likely to establish a precedent, custom or practice adverse to the continuing business interest of the Indemnitee; and

(d) the Indemnitor, from time to time, at the request of the Indemnitees Representative, gives security satisfactory to the Indemnitees Representative against any costs and other liabilities to which the Indemnitee may be or become exposed as a result of that Third Party Claim.

(2) On the assumption of control by the Indemnitor, it is conclusively established for purposes of this Agreement that the Third Party Claim is within the scope of, and is subject to, the indemnification pursuant to this Article 6, and:

(a) the Indemnitor will actively and diligently proceed with the defence, compromise or settlement of the Third Party Claim at the Indemnitor's sole cost and expense, including the retaining of counsel reasonably satisfactory to the Indemnitees Representative;

(b) the Indemnitor will keep the Indemnitees Representative fully advised with respect to the defence, compromise or settlement of the Third Party Claim (including supplying copies of all relevant documents promptly as they become available) and will arrange for its counsel to inform the Indemnitees Representative on a regular basis of the status of the Third Party Claim;

(c) the Indemnitee may retain separate co-counsel at its sole cost and expense and participate in the defence of the Third Party Claim (provided the Indemnitor shall continue to control that defence); and

(d) the Indemnitor will not consent to the entry of any judgment or enter into any settlement with respect to the Third Party Claim unless consented to by the Indemnitees Representative (which consent may not be unreasonably or arbitrarily withheld, delayed or conditioned).

(3) Provided all the conditions set forth in Section 6.4(1) are satisfied and the Indemnitor is not in breach of any of its obligations under Section 6.4(2), each of the Indemnitee and its Indemnitees Representative will, at the expense of the Indemnitor, co-operate with the Indemnitor and use its best efforts to make available to the Indemnitor all relevant information in its possession or under its control (provided that it does not cause the Indemnitee or its Indemnitees Representative to breach any confidentiality obligations) and will take such other steps as are, in the reasonable opinion of counsel for the Indemnitor, necessary to enable the Indemnitor to conduct that defence, provided always that:

(a) no admission of fault may be made by or on behalf of the Purchaser or any Purchaser Indemnitee without the prior written consent of the Purchaser;

(b) no admission of fault may be made by or on behalf of the Vendor or any Vendor Indemnitee without the prior written consent of the Vendor; and

(c) the Indemnitee and its Indemnitees Representative are not obligated to take any measures which, in the reasonable opinion of the Indemnitee's legal counsel, could be prejudicial or unfavourable to the Indemnitee.

(4) If (i) the Indemnitor does not give the relevant Indemnitees Representative the notice provided in Section 6.4(1), (ii) any of the conditions in Section 6.4(1) are unsatisfied, or (iii) the Indemnitor breaches any of its obligations under Sections 6.4(2) or 6.4(3), the applicable Indemnitees Representative may assume control of the defence, compromise or settlement of the Third Party Claim as in its sole discretion may appear advisable, and is entitled to retain counsel as in its sole discretion may appear advisable, the whole at the Indemnitor's sole cost and expense. Any settlement or other final determination of the Third Party Claim will be binding on the Indemnitor. The Indemnitor will, at its sole cost and expense, cooperate fully with the Indemnitee and its Indemnitees Representative and use its best efforts to make available to the Indemnitee and its Indemnitees Representative all relevant information in its possession or under its control and take such other steps as are, in the reasonable opinion of counsel for the Indemnitee, necessary to enable the Indemnitee to conduct the defence. The Indemnitor will reimburse the Indemnitee and its Indemnitees Representative promptly and periodically for the costs of defending against the Third Party Claim (including legal fees and expenses), and will remain responsible for any Losses the Indemnitee and its Indemnitees Representative may suffer resulting from, arising out of or relating to the Third Party Claim to the fullest extent provided in this Article 6.

6.5 Direct Claims. Following receipt of an Indemnification Notice in respect of a Direct Claim, the Indemnitor has 60 days to make such investigation of the Direct Claim as is considered necessary or desirable. For the purpose of that investigation, the Indemnitee shall make available to the Indemnitor the information relied on by the Indemnitee to substantiate the Direct Claim, together with such information as the Indemnitor may reasonably request. If the Indemnitor and Indemnitee agree at or prior to the expiry of this 60-day period (or prior to the expiry of any extension of this period agreed to by the Indemnitor and Indemnitee) as to the validity and amount of that Direct Claim, the Indemnitor shall immediately pay to the Indemnitee the full amount as agreed to by the Parties of the Direct Claim, failing which the matter shall be referred to binding arbitration in accordance with Section 7.11. For clarity, the Purchaser is deemed to have incurred or suffered Losses as of and from the Closing Date as a consequence of any reduction in the value of the Purchased Assets resulting from an inaccuracy or breach of any representation or warranty or any breach or non-fulfillment by the Vendor of any of its covenants or obligations under this Agreement.

6.6 Waiver. The Indemnitor waives any right it may have to require an Indemnitee to proceed against or enforce any other right, power, remedy or security or to claim payment from any other Person before claiming under the indemnity provided for in this Article 6. It is not necessary for an Indemnitee to incur expense or make payment before enforcing that indemnity.

6.7 Duty to Mitigate and Subrogation.

(1) Nothing in this Agreement in any way restricts or limits the general obligation under Applicable Law of an Indemnitee to mitigate any loss which it may suffer or incur by reason of a breach by an Indemnitor of any representation, warranty, covenant or obligation of the Indemnitor under this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement.

(2) The Indemnitee shall, to the extent permitted by Applicable Law, subrogate its rights relating to any Third Party Claim to the Indemnitor and shall make all counterclaims and implead all third Persons as may be reasonably required by the Indemnitor, the whole at the cost and expense of the Indemnitor.

6.8 Obligation to Reimburse.

(1) The Indemnitor shall reimburse to the Indemnitee the amount of any Losses, as of the later of (i) date that the Indemnitee incurs any such Losses and (ii) the date of demand by the Indemnitee, together with interest thereon from that date until payment in full, at the rate per annum equal to the prime lending rate of Royal Bank of Canada from time to time plus 2%, that payment being made without prejudice to the Indemnitor's right to contest the basis of the Indemnitee's Claim for indemnification.

(2) The amount of any and all Losses under this Article 6 are to be determined net of any amounts recovered or recoverable by the Indemnitee under insurance policies, indemnities, reimbursement arrangements or similar contracts with respect to those Losses. The Indemnitee shall take all appropriate steps to enforce that recovery. Each Party waives, to

the extent permitted under its applicable insurance policies, any subrogation rights that its insurer may have with respect to any indemnifiable Losses.

(3) If an Indemnitee is subject to Tax in respect of the receipt of an amount pursuant to this Article 6, after taking into account any offsetting deduction or tax credit available in respect of the applicable Losses, then the amount payable by the Indemnitor will be increased by an amount (the "**Increased Amount**") such that the Indemnitee will be in the same position after paying Tax on the amount received hereunder, including any Taxes payable on the Increased Amount, as the Indemnitee would have been in had the Losses giving rise to that payment not arisen and had that amount not been payable.

(4) If any payment (the "**Payment**") made pursuant to this Article 6 is subject to GST/HST or is deemed by the ETA or any similar provision of any Applicable Law to be inclusive of GST/HST, the Indemnitor will pay to the Indemnitee, in addition to the Payment, an amount equal to the GST/HST in connection with that Payment and that additional amount.

6.9 Exclusivity. Unless otherwise provided in this Agreement or any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement, the provisions of this Article 6 constitute the sole remedy available to the Vendor, any Member and the Purchaser to any Claim for breach of covenants, representation, warranty or other obligation or provision of this Agreement or any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement (other than a Claim for specific performance or injunctive relief) and to any and all other indemnities provided in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement.

6.10 Set-Off. A Party is entitled to set-off any Losses subject to indemnification under this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement against any other amounts payable by the Party to another party whether under this Agreement or otherwise.

6.11 Trust and Agency. The Purchaser accepts each indemnity in favour of any of the Purchaser Indemnitees that is not a Party as agent and trustee of that Purchaser Indemnitee and may enforce any such indemnity in favour of that Purchaser Indemnitee on behalf of that Purchaser Indemnitee. The Vendor accepts each indemnity in favour of any of the Vendor Indemnitees as agent and trustee of that Vendor Indemnitee and may enforce any such indemnity in favour of that Vendor Indemnitee on behalf of that Vendor Indemnitee.

ARTICLE 7
GENERAL

7.1 Confidentiality of Information.

(1) For the purposes of this Section 7.1, "**Confidential Information**" of a Party at any time means all information relating to that Party which at the time is of a confidential nature (whether or not specifically identified as confidential), is known or should be known by the other relevant Party or its Representatives as being confidential, and has been or is from time to time made known to or is otherwise learned by the relevant other Party or any of its Representatives as a result of the matters provided for in this Agreement. The existence

and the terms of this Agreement and of any other contract, agreement, instrument, certificate or other document to be entered into as contemplated by this Agreement shall be deemed to be Confidential Information of the Purchaser and not to be Confidential Information of the Vendor, the Guarantors or the Members.

(2) Notwithstanding the foregoing, Confidential Information does not include any information that at the time has become generally available to the public other than as a result of a disclosure by the other Party or any of its Representatives, any information that was available to the other Party or its Representatives on a non-confidential basis before the date of this Agreement or any information that becomes available to the other Party or its Representatives on a non-confidential basis from a Person (other than the Party to which the information relates or any of its Representatives) who is not, to the knowledge of the other Party or its Representatives, otherwise bound by confidentiality obligations to the Party to which the information relates in respect of the information or otherwise prohibited from transmitting the information to the other Party or its Representatives.

(3) Each Party shall (and shall cause each of its Representatives to) hold in strictest confidence and not use in any manner, other than as expressly contemplated by this Agreement, all Confidential Information of the other Parties.

(4) Subject to Section 7.2, Section 7.1(3) shall not apply to the disclosure of any Confidential Information where that disclosure is required by Applicable Law. In that case, the Party required to disclose (or whose Representative is required to disclose) shall, as soon as possible in the circumstances, notify the other Parties of the requirement of the disclosure including the nature and extent of the disclosure and the provision of Applicable Law pursuant to which the disclosure is required. To the extent possible, the Party required to make the disclosure shall, before doing so, provide to the other Parties the text of any disclosure. On receiving the notification, the other Parties may take any reasonable action to challenge the requirement, and the affected Party shall (or shall cause the applicable Representative to), at the expense of the other Parties, assist the other Parties in taking that reasonable action. Notwithstanding the foregoing, no disclosure shall be made of the amount of the Purchase Price, unless and to the extent required by Applicable Law.

(5) Following the termination of this Agreement in accordance with the provisions of Section 4.2, each Party shall (and shall cause each of its Representatives to) promptly, on a request from any other Party, return to the requesting Party all copies of any tangible items (other than this Agreement), if any, that are or that contain Confidential Information of the requesting Party, except that if the Party so obligated to return Confidential Information or its Representatives have prepared notes, analyses, compilations, studies or summaries containing or concerning any Confidential Information, then that Party may, instead of returning the notes, analyses, compilations, studies or summaries, destroy them and provide a certificate to that effect to the requesting Party.

7.2 Public Announcements. Neither the Vendor, nor the Guarantors or the Members shall make any public statement or issue any press release concerning the Transactions except as agreed by the Purchaser in its sole discretion or as may be necessary, in the opinion of counsel to the Party making that disclosure, to comply with the requirements of all Applicable Law. If any public statement or release is so required, the Vendor, Guarantor or Member making the disclosure shall consult with the Purchaser before making that statement or release, and the Parties shall use all reasonable efforts, acting in good faith, to agree on a text for the statement or release that is satisfactory to the Parties. The Purchaser may make any public statement or issue any press release concerning the Transactions without restriction.

7.3 Disclosure and Consultation. Before any public statement or press release concerning the Transactions, no Party shall disclose this Agreement or any aspect of the Transactions except to its board of directors, its senior management, its legal, accounting, financial or other professional advisors, any financial institution contacted by it with respect to any financing required in connection with the Transactions and counsel to that institution, or as may be required by any Applicable Law or as agreed by the Parties.

7.4 Expenses. Each Party shall pay all expenses (including Taxes imposed on those expenses) it incurs in the authorization, negotiation, preparation, execution and performance of this Agreement and the Transactions, including all fees and expenses of its legal counsel, bankers, investment bankers, brokers, accountants or other representatives or consultants.

7.5 No Third Party Beneficiary. Except as provided for in Section 6.11, this Agreement is solely for the benefit of the Parties and no third party accrues any benefit, claim or right of any kind pursuant to, under, by or through this Agreement.

7.6 Entire Agreement. This Agreement together with the other agreements to be entered into as contemplated by this Agreement (the "**Other Agreements**") constitute the entire agreement between the Parties pertaining to the subject matter of this Agreement and the Other Agreements and supersede all prior correspondence, agreements, negotiations, discussions and understandings, written or oral. Except as specifically set out in this Agreement or the Other Agreements, there are no representations, warranties, conditions or other agreements or acknowledgements, whether direct or collateral, express or implied, written or oral, statutory or otherwise, that form part of or affect this Agreement or the Other Agreements or which induced any Party to enter into this Agreement or the Other Agreements. There is no liability, either in tort or in contract, assessed in relation to the representation, warranty, opinion, advice or assertion of fact, except as contemplated in this Section.

7.7 Non-Merger. Except as otherwise provided in this Agreement, the covenants, representations and warranties set out in this Agreement do not merge but survive Closing and, notwithstanding such Closing or any investigation by or on behalf of a Party, continue in full force and effect. Closing does not prejudice any right of one Party against another Party in respect of any remedy in connection with anything done or omitted to be done under this Agreement.

7.8 Time of Essence. Time is of the essence of this Agreement.

7.9 Amendment. This Agreement may be supplemented, amended, restated or replaced only by written agreement signed by each Party.

7.10 Waiver of Rights. Any waiver of, or consent to depart from, the requirements of any provision of this Agreement is effective only if it is in writing and signed by the Party giving it, and only in the specific instance and for the specific purpose for which it has been given. No failure on the part of any Party to exercise, and no delay in exercising, any right under this Agreement operates as a waiver of that right. No single or partial exercise of any such right precludes any other or further exercise of that right or the exercise of any other right.

7.11 Arbitration. All disputes arising out of, or in connection with, this Agreement, or in respect of any legal relationship associated with it or derived from it, will be finally resolved by arbitration administered by ICDR Canada. The place of arbitration will be Sault Ste. Marie, Ontario or such other place as the Purchaser and the Vendor may agree in writing. The language of the arbitration will be English.

7.12 Jurisdiction. Subject to Section 7.11, the Parties irrevocably and unconditionally attorn to the exclusive jurisdiction of the courts of the province of Ontario sitting in Sault Ste. Marie or Toronto in respect of all disputes arising out of, or in connection with, this Agreement, or in respect of any legal relationship associated with it or derived from it.

7.13 Governing Law. This agreement is governed by, and interpreted and enforced in accordance with, the laws of the Province of Ontario and the laws of Canada applicable in Ontario, excluding the choice of law rules of that province.

7.14 Notices.

(1) Any notice, demand or other communication (in this Section 7.14, a "**notice**") required or permitted to be given or made under this Agreement must be in writing and is sufficiently given or made if:

(a) delivered in person and left with a receptionist or other responsible employee of the relevant Party at the applicable address set forth below;

(b) sent by prepaid courier service or (except in the case of actual or apprehended disruption of postal service) mail; or

(c) sent by facsimile transmission, with confirmation of transmission by the transmitting equipment (a "**Transmission**");

in the case of a notice to the Vendor, addressed to it at:

Infrastructure Energy Inc.
22 Leader Lane 402
Toronto, ON
M5E 0B2

Attention: Glen Martin

E-mail: glen.martin@infrastructure.energy

and in the case of a notice to either Guarantor or either Member, addressed to it or him at:

849 S. Broadway M09
Los Angeles, California 90014
U.S.A.

Attention: Glen Martin
E-mail: glen.martin@infrastructure.energy

and in the case of a notice to the Purchaser, addressed to it at:

PUC Distribution Inc.
500 Second Line East
Sault Ste. Marie, ON
P6A 6P2

Attention: Robert Brewer
E-mail: Robert.brewer@ssmpuc.com

with a copy (not constituting notice) to:

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide St. W
Toronto, ON
M5H 4E3

Attention: John Vellone
E-mail: JVellone@blg.com

(2) Any notice sent in accordance with this Section 7.14 is deemed to have been received:

(a) if delivered prior to or during normal business hours on a Business Day in the place where the notice is received, on the date of delivery;

(b) if sent by mail, on the fifth Business Day after mailing in the place where the notice is received, or, in the case of disruption of postal service, on the fifth Business Day after cessation of that disruption; or

(c) if sent in any other manner, on the date of actual receipt;

except that any notice delivered in person or sent by Transmission not on a Business Day or after normal business hours on a Business Day is deemed to have been received on the next succeeding Business Day in the place where the notice is received.

(3) Any Party may change its address for notice by giving notice to the other Parties.

7.15 Joint and Several Liability. Except as expressly provided in this Agreement, all of the obligations and liabilities of the Vendor, the Guarantors and the Members under this Agreement and under any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement, including the representations and warranties and indemnities contained in this Agreement and in any such other contract, certificate or other document, are and are deemed to be joint and several obligations and liabilities of the Vendor.

7.16 Guarantor and Member Guarantee. The Guarantors and the Members guarantee (i) performance by the Vendor of the obligations of the Vendor under this Agreement, and (ii) payment of all amounts and other obligations due or owing to the Purchaser by the Vendor pursuant to this Agreement and any obligation of the Vendor to indemnify the Purchaser and the Purchaser Indemnitees under this Agreement.

7.17 Assignment.

(1) Subject to item (2), no party may assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Agreement to any Person.

(2) The Purchaser may assign all of its rights and obligation under this Agreement to a subsidiary wholly-owned by it, except that such assignment shall not relieve the Purchaser of any of its obligations under this Agreement.

7.18 Further Assurances. Each Party shall promptly do, execute, deliver or cause to be done, executed or delivered all further acts, documents and matters in connection with this Agreement that any other Party may reasonably require, for the purposes of giving effect to this Agreement.

7.19 Successors. This Agreement is binding on, and enures to the benefit of, the Parties and their respective successors.

7.20 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together constitute one agreement. Delivery of an executed counterpart of this Agreement by facsimile or transmitted electronically in legible form, including in a tagged image format file (TIFF) or portable document format (PDF), shall be equally effective as delivery of a manually executed counterpart of this Agreement.

IN WITNESS WHEREOF, the Parties have duly executed this Agreement on the date first above written.

INFRASTRUCTURE ENERGY INC.

By: ______________________________

Name:
Title:

(8) Any Party may change its address for notice by giving notice to the other Parties.

Joint and Several Liability. Except as expressly provided in this Agreement, all of the obligations and liabilities of the Vendor, the Guarantors and the Members under this Agreement and under any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement, including the representations and warranties and indemnities contained in this Agreement and in any such other contract, certificate or other document, are and are deemed to be joint and several obligations and liabilities of the Vendor.

Guarantor and Member Guarantee. The Guarantors and the Members guarantee (i) performance by the Vendor of the obligations of the Vendor under this Agreement, and (ii) payment of all amounts and other obligations due or owing to the Purchaser by the Vendor pursuant to this Agreement and any obligation of the Vendor to indemnify the Purchaser and the Purchaser Indemnitees under this Agreement.

Assignment.

(9) Subject to item (2), no party may assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Agreement to any Person.

(10) The Purchaser may assign all of its rights and obligation under this Agreement to a subsidiary wholly-owned by it, except that such assignment shall not relieve the Purchaser of any of its obligations under this Agreement.

Further Assurances. Each Party shall promptly do, execute, deliver or cause to be done, executed or delivered all further acts, documents and matters in connection with this Agreement that any other Party may reasonably require, for the purposes of giving effect to this Agreement.

Successors. This Agreement is binding on, and enures to the benefit of, the Parties and their respective successors.

Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together constitute one agreement. Delivery of an executed counterpart of this Agreement by facsimile or transmitted electronically in legible form, including in a tagged image format file (TIFF) or portable document format (PDF), shall be equally effective as delivery of a manually executed counterpart of this Agreement.

IN WITNESS WHEREOF, the Parties have duly executed this Agreement on the date first above written.

INFRASTRUCTURE ENERGY INC.

By: ______________________

Name: GLEN MARTIN

Title: CEO

ENERGIZING, LLC

By: ______________________

Name: GLEN MARTIN

Title: CEO

INFRASTRUCTURE ENERGY, LLC

By: ______________________

Name: GLEN MARTIN

Title: CEO

BLIND LINE HOLDINGS, LLC

By: ______________________

Name: GLEN MARTIN

Title: MANAGING MEMBER

GLEN MARTIN

By: ______________________

Name:

Title:

ENERGIZING, LLC

By: ______________________________
Name:
Title:

INFRASTRUCTURE ENERGY, LLC

By: ______________________________
Name:
Title:

[MEMBER 1]

By: ______________________________
Name:
Title:

[MEMBER 2]

By: ______________________________
Name:
Title:

PUC DISTRIBUTION INC.

By: ______________________________
Name: Robert Brewer.
Title: President + CEO

PUC DISTRIBUTION INC.

By: ______________________________

Name:

Title:

SCHEDULE 3.1 ESCROW AGREEMENT

See attached.

SCHEDULE 4.1(1)(d)(vii) RELEASE AGREEMENT

See attached.

SCHEDULE 4.1(1)(d)(v)		FORM OF BRING-DOWN CERTIFICATE

CERTIFICATE

TO:		**PUC Distribution Inc. (the "Purchaser")**

DATED:		_______________

This certificate is delivered pursuant to Section 4.1(1)(d)(v) of the asset purchase agreement (the "**Asset Purchase Agreement**") dated January __, 2020 between Infrastructure Energy Inc. (the "**Vendor**"), Infrastructure Energy, LLC and Energizing, LLC (the "**Guarantors**"), Blind Line Holdings, LLC and Glen Martin (the "**Members**") and the Purchaser. Capitalized terms used and not defined in this certificate have the meanings given to them in the Asset Purchase Agreement.

Each of the Vendor, the Guarantors and the Members certifies to you that:

(1) all of the representations and warranties of each of the Vendor, the Guarantors and the Members made in or pursuant to Section 5.1 of the Asset Purchase Agreement are true and correct as at the date hereof with the same effect as if made at and as of the date hereof; and

(2) the Vendor, the Guarantors and the Members have complied with and performed all of the obligations, covenants and agreements under the Asset Purchase Agreement to be complied with or performed by the Vendor or the Members or any of them on or before the date hereof.

INFRASTRUCTURE ENERGY INC.

By: ______________________________
Name:
Title:

INFRASTRUCTURE ENERGY, LLC

By: ______________________________
Name:
Title:

ENERGIZING, LLC

By: ______________________________
Name:
Title:

BLIND LINE HOLDINGS, LLC

By: ______________________________
Name:
Title:

GLEN MARTIN

____

SCHEDULE 5.1(1) JURISDICTIONS

Legal Person	Jurisdiction of Incorporation or Formation
Infrastructure Energy Inc.	Canada
Infrastructure Energy, LLC	Delaware
Energizing, LLC	Delaware
Blind Line Holdings, LLC	Delaware

SCHEDULE 5.1(7) LISTED REPORTS

The following are the Listed Reports:

(1) The Navigant report “Review of Business Case for Smart Grid Project for PUC Distribution” dated April 15, 2015

(2) The Navigant report “Review of Project Costs for Smart Grid Project for PUC Distribution” dated June 23, 2015

(3) The Leidos report “Utility Distribution Microgrid: Volt/VAR Management (VVM) – Preliminary Design” dated October 17, 2014

(4) The Leidos report “Utility Distribution Microgrid: Distribution Automation – Preliminary Design” dated November 20, 2014

(5) The Leidos report “Utility Distribution Microgrid: AMI Integration – Preliminary Design” dated November 20, 2014

SCHEDULE 5.1(8) LISTED ANCILLARY ASSETS

The following are the Listed Ancillary Assets:

(1) The CYME distribution network system model files created to support the engineering studies prepared for the Sault Smart Grid Project.

SCHEDULE 5.1(12) PRELIMINARY BILL OF SALE

See attached.

Execution Version

BILL OF SALE

BILL OF SALE, dated as of January 27, 2020 (the "Bill of Sale"), by and among Infrastructure Energy, LLC, a Delaware limited liability company and Energizing, LLC, a Delaware limited liability company (collectively, "Seller") and Infrastructure Energy Inc., a federal Canadian corporation ("Buyer").

WITNESSETH:

WHEREAS, Seller and Buyer have entered into an agreement, dated January 27, 2020 (the "Sale and Purchase Agreement");

WHEREAS, pursuant to the Sale and Purchase Agreement, Seller has agreed to sell, and Buyer has agreed to purchase sell, all of Seller's right, title and interest in and to the Purchased Assets:

NOW, THEREFORE, in consideration of the payment of the purchase price set forth the Sale and Purchaser Agreement, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, it is hereby agreed by the parties hereto as follows:

1. Definitions. Capitalized terms used in this Bill of Sale and not otherwise defined in the body of this Bill of Sale shall have the meaning given to them in Appendix A.

2. Transfer of Purchased Assets. Seller does hereby sell, transfer, convey, assign and deliver to Buyer, free and clear of all Encumbrances, all of Seller's right, title and interest in and to, including without limitation the Listed Reports and Listed Ancillary Assets listed on Schedule B hereto.

3. Successors and Assigns. This Agreement shall inure to the benefit of and be binding upon the parties, their successors, assigns and transferees.

4. Governing Law. The parties have agreed that the validity, construction, operation and effect of any and all of the terms and provisions of this Agreement, and the respective rights, duties and obligations of the parties hereunder, shall be determined and enforced in accordance with the laws of the Province of Ontario without giving effect to principles of conflicts of law thereunder.

5. Counterparts. This Agreement may be executed in any number of counterparts, including by means of facsimile, and each counterpart hereof shall be deemed to be an original instrument, but all such counterparts together shall constitute but one agreement.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be signed by their respective officers thereunto duly authorized as of the date first written above.

Infrastructure Energy, LLC

By:

Name: GLEN MARTIN
Title: CEO

Energizing, LLC

By:

Name: GLEN MARTIN
Title: CEO

Infrastructure Energy Inc.

By:

Name: GLEN MARTIN
Title: CEO

APPENDIX A

(1) "**Affiliate**" means an affiliated body corporate within the meaning of the following:

(a) one body corporate is affiliated with another body corporate if one of them is the subsidiary of the other or both are subsidiaries of the same body corporate or each of them is controlled by the same person; and

(b) if two bodies corporate are affiliated with the same body corporate at the same time, they are deemed to be affiliated with each other.

For purposes of this definition, a body corporate is controlled by a person or by two or more bodies corporate if (i) securities of the body corporate to which are attached more than 50% of the votes that may be cast to elect directors of the body corporate, are held, other than by way of security only, by or for the benefit of that person or by or for the benefit of those bodies corporate; and (ii) the votes attached to those securities are sufficient, if exercised, to elect a majority of the directors of the body corporate. For the purposes of this definition, a body corporate is a subsidiary of another body corporate if (i) it is controlled by (A) that other body corporate, (B) that other body corporate and one or more bodies corporate each of which is controlled by that other body corporate, or (C) two or more bodies corporate each of which is controlled by that other body corporate; or (ii) it is a subsidiary of a body corporate that is a subsidiary of that other body corporate.

(2) "**Associate**" mean any of the following:

(a) the Members;

(b) the Affiliates of Seller or the Members;

(c) the officers, directors and employees of Seller, a Member or any Affiliate of Seller or the Members; and

(d) bodies corporate who are controlled by, whose Equity Interests are owned in whole or in part by, who employ or on whose board of directors sit any Associate described in paragraph (a), (b) or (c) of this definition;

(3) "**Contract**" means any agreement, contract, indenture, lease, occupancy agreement, deed of trust, licence, option, undertaking, promise or any other commitment or obligation, whether oral or written, express or implied.

(4) "**Encumbrance**" means any encumbrance, lien, charge, hypothec, pledge, mortgage, title retention agreement, security interest of any nature, prior claim, adverse claim, exception, reservation, restrictive covenant, agreement, easement (whether or not registered against title), lease, licence, right of occupation, option, right of use, right of first refusal, right of pre-emption, privilege or any matter capable of registration against title or any Contract to create any of the foregoing.

(5) "**Equity Interests**" means, with respect to any Person, any and all present and future shares, units, trust units, partnership or other interests, participations or other equivalent rights in that Person's equity or capital, however designated and whether voting or non-voting.

(6) "**Intellectual Property**" means, individually and collectively, howsoever created and wherever located:

(a) all domestic and foreign patents and applications thereof and all reissues, divisions, continuations, renewals, extensions and continuations-in-part thereof;

(b) all inventions (whether patentable or not), invention disclosures, improvements, trade secrets, proprietary information, know-how, technology, technical data, schematics and customer lists, and all documentation relating to any of the foregoing;

(c) all copyrights in all works (including Software) and database right, copyright registrations and applications thereof, and all works of authorship and moral rights, and all other rights corresponding thereto throughout the world;

(d) all trade names, domain names, corporate names, trade dress, distinguishing guises, logos, slogans, brand names, trademarks (whether registered or common law and whether used with wares or services and including the goodwill attaching to such trademarks) and registrations and applications for registration thereof;

(e) all Software (in source code and object code form) and databases, and any proprietary rights in such Software and databases;

(f) all integrated circuit design, mask work, or topography registrations or applications thereof;

(g) all industrial designs and applications for and registration of industrial designs, design patents and industrial design registrations;

(h) other intellectual or industrial property whatsoever;

(i) all income, royalties, damages and payments now and hereafter due and/or payable with respect to any of the foregoing, including damages and payments for past or future Infringements thereof; and

(j) all rights to sue for past, present and future Infringements of any of the foregoing.

(7) "**Listed Ancillary Assets**" means those Ancillary Assets described in Appendix B to the Bill of Sale.

(8) "**Listed Reports**" means those Reports described in Appendix B to the Bill of Sale.

(9) "**Member**" means each of [Glen Martin and [member 2], as member[s] of Energizing, LLC] and [Glen Martin and [member 2], as member[s] of Infrastructure Energy, LLC].

(10) "**Person**" is to be broadly interpreted and includes an individual, a corporation, a partnership, a joint venture, a trust, an association, a syndicate, an unincorporated organization, a governmental authority, an executor or administrator or other legal or personal representative, or any other juridical entity.

(11) "**Purchased Assets**" means:

(a) All report and studies commissioned by or paid for, or in the possession of the Seller or an Associate that related to the SSG Project (the "**Reports**"), including the Listed Reports;

(b) All appendices, drawings, spreadsheets, data files, Contracts, invoices, payment receipts and other documents or records that relate to the Reports (such as those provided to a Report Author by Seller or an Associate, those cited in a Report or those developed by Seller or an Associate based information contained in a Report) (the "**Ancillary Assets**"), including the Listed Ancillary Assets; and

(c) All Intellectual Property that is contained in, or that is necessary to implement any engineering solution described in, the Reports or Ancillary Assets (the "**Ancillary Intellectual Property**").

(12) "**Report Author**" means the author or signatory of any Report.

(13) "**SSG Project**" means the project being undertaken by PUC Distribution Inc. to introduce a Volt/VAR management system and feeder distribution automation system, among other system upgrades, from time to time referred to as the Sault Smart Grid Project.

(14) "**Software**" means software, including all versions thereof, whether installed locally, on a local area network or delivered through the internet, and all related documentation, manuals, source code and object code, program files, data files, computer related data, field and data definitions and relationships, data definition specifications, data models, program and system logic, interfaces, program modules, routines, sub-routines, algorithms, program architecture, design concepts, system designs, program structure, sequence and organization, screen displays and report layouts, including any and all modifications, changes, release, versions, upgrades, updates or patches of any of the foregoing, and all other material related to such software.

APPENDIX B

The following are the Listed Reports:

(1) The Navigant report "Review of Business Case for Smart Grid Project for PUC Distribution" dated April 15, 2015

(2) The Navigant report "Review of Project Costs for Smart Grid Project for PUC Distribution" dated June 23, 2015

(3) The Leidos report "Utility Distribution Microgrid: Volt/VAR Management (VVM) – Preliminary Design" dated October 17, 2014

(4) The Leidos report "Utility Distribution Microgrid: Distribution Automation – Preliminary Design" dated November 20, 2014

(5) The Leidos report "Utility Distribution Microgrid: AMI Integration – Preliminary Design" dated November 20, 2014

(6) Energrid and Michael Baumann's completed NRCan application

The following are the Listed Ancillary Assets:

(1) The CYME distribution network system model files created to support the engineering studies prepared for the Sault Smart Grid Project.

CERTIFICATE

TO: **PUC Distribution Inc. (the "Purchaser")**

DATED: January 28, 2020

This certificate is delivered pursuant to Section 4.1(1)(d)(v) of the asset purchase agreement (the "**Asset Purchase Agreement**") dated January 27, 2020 between Infrastructure Energy Inc. (the "**Vendor**"), Infrastructure Energy, LLC and Energizing, LLC (the "**Guarantors**"), Blind Line Holdings, LLC and Glen Martin (the "**Members**") and the Purchaser. Capitalized terms used and not defined in this certificate have the meanings given to them in the Asset Purchase Agreement.

Each of the Vendor, the Guarantors and the Members certifies to you that:

1. all of the representations and warranties of each of the Vendor and the Members made in or pursuant to Section 5.1 of the Asset Purchase Agreement are true and correct as at the date hereof with the same effect as if made at and as of the date hereof; and

2. the Vendor and the Members have complied with and performed all of the obligations, covenants and agreements under the Asset Purchase Agreement to be complied with or performed by the Vendor or the Members or any of them on or before the date hereof.

INFRASTRUCTURE ENERGY INC.

By: ______________________

Name: GLEN MARTIN

Title: CEO

INFRASTRUCTURE ENERGY, LLC

By: ______________________

Name: GLEN MARTIN

Title: CEO

ENERGIZING, LLC

By: ______________________

Name: GLEN MARTIN

Title: CEO

BLIND LINE HOLDINGS, LLC

By: ______________________

Name: GLEN MARTIN

Title: MANAGING MEMBER

GLEN MARTIN

____

ESCROW AGREEMENT

THIS AGREEMENT dated January 27, 2020

BETWEEN:

INFRASTRUCTURE ENERGY INC.

As Vendor

\- and -

PUC DISTRIBUTION INC.

As Purchaser

\- and -

BORDEN LADNER GERVAIS LLP

As Escrow Agent

RECITALS:

A. The Vendor and the Purchaser entered into a purchase agreement (the "**Asset Purchase Agreement**") dated January 27, 2020 providing for the purchase of certain reports and ancillary assets and intellectual property related to the Sault Smart Grid Project.

B. Pursuant to Section 3.1 of the Asset Purchase Agreement, the Vendor and the Purchaser agreed to enter into an escrow arrangement for the payment of the purchase price under the Asset Purchase Agreement.

C. The preceding recitals and statements of fact are made by the Vendor and the Purchaser and not by the Escrow Agent.

IN CONSIDERATION of the mutual covenants and agreements contained in this Agreement and for other good and valuable consideration (the receipt and adequacy of which are acknowledged), the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions. In this Agreement, including the Recitals to this Agreement, unless the context requires otherwise:

(1) "**Agreement**" means this escrow agreement as amended, supplemented, restated and replaced from time to time in accordance with its provisions.

(2) "**Business Day**" means any day, except Saturdays and Sundays, on which banks are generally open for business:

(a) for purposes of Section 4.7, in the place specified in that Section; and

(b) for all other purposes in this Agreement, in Ontario, Canada.

(3) "**Escrow Agent**" means Borden Ladner Gervais LLP, a law partnership duly constituted under the laws of the Province of Ontario.

(4) "**Escrow Property**" means the sum of $511,847.57.

(5) "**Parties**" means collectively the Vendor, the Purchaser and the Escrow Agent, and "**Party**" means any of them.

(6) "**Purchaser**" means PUC Distribution Inc., a corporation incorporated under the laws of the Province of Ontario.

(7) "**Asset Purchase Agreement**" has the meaning attributed to that term in the Recitals.

(8) "**Vendor**" means Infrastructure Energy Inc., a corporation incorporated under the federal laws of Canada.

1.2 **Certain Rules of Interpretation.** In this Agreement:

(a) the division into Articles and Sections and the insertion of headings are for convenience of reference only and do not affect the construction or interpretation of this Agreement;

(b) the expressions "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this Agreement and not to any particular portion of this Agreement; and

(c) unless specified otherwise or the context otherwise requires:

(i) references to any Article, Section or Schedule are references to the Article or Section of, or Schedule to, this Agreement; and

(ii) words in the singular include the plural and vice-versa and words in one gender include all genders.

1.3 **Performance on Business Days.** If any action is required to be taken pursuant to this Agreement on or by a specified date that is not a Business Day, the action is valid if taken on or by the next succeeding Business Day.

1.4 **Currency and Payment.** In this Agreement, unless specified otherwise references to dollar amounts or "$" are to Canadian dollars.

ARTICLE 2
ESCROW

2.1 **Appointment of Escrow Agent.** The Vendor and the Purchaser hereby appoint the Escrow Agent to act as escrow agent in accordance with the terms and conditions set out in this Agreement and the Escrow Agent hereby accepts that appointment.

2.2 **Delivery of Escrow Property into Escrow.** The Purchaser shall deliver the Escrow Property to the Escrow Agent on the date of this Agreement. The Escrow Agent shall hold and dispose of the Escrow Property in accordance with, and subject to the terms and conditions, of this Agreement.

2.3 **Interest on Escrow Property.** The Escrow Agent shall invest and retain the Escrow Property in its name, in a daily interest bearing account with any Canadian chartered bank listed on Schedule 1 of the *Bank Act* (Canada). Any interest earned in respect of the Escrow Property ("**Interest**") will accrue to the benefit of the Purchaser and shall be reported to such Party at the end of each calendar year.

2.4 **Release of Escrow Property and Interest.** The Escrow Agent shall retain the Escrow Property and Interest until:

(1) the Purchaser instructs the Escrow Agent in writing (including by e-mail communication) to pay the full amount of the Escrow Property to the Vendor, and upon the occurrence of this event, the Escrow Agent shall release the Escrow Property and Interest in accordance with the following:

- (a) payment of the full amount of the Escrow Property by wire transfer to a bank account specified by the Vendor in writing (including by e-mail communication)
- (b) payment of the Interest to the Purchaser by wire transfer to a bank account specified by the Purchaser in writing (including by e-mail communication)

(2) the Purchaser delivers an instruction jointly signed by the Purchaser and the Vendor to the Escrow Agent (including by e-mail communication) to pay an amount that is less than the full amount of the Escrow Property to the Vendor or to the Purchaser, and upon the occurrence of this event, the Escrow Agent shall release the Escrow Property and Interest in accordance with the following:

- (a) payment of the amount of the Escrow Property specified in the joint instruction to be paid to the Vendor by wire transfer to a bank account specified by the Vendor in writing (including by e-mail communication)
- (b) payment of the amount of the Escrow Property specified in the joint instruction to be paid to the Purchaser and Interest by wire transfer to a bank account specified by the Purchaser in writing (including by e-mail communication)

2.5 **Release of Escrow Property and Interest.** The Escrow Agent shall retain the Escrow Property and Interest until the Purchaser instructs the Escrow Agent in writing (including by e-mail communication) to pay the full amount of the Escrow Property to the Purchaser, and upon the occurrence of this event, the Escrow Agent shall release the Escrow Property and Interest in accordance with the following:

2.6 **Termination of Escrow.** Upon the release and disbursement by the Escrow Agent of the all of the Escrow Property and Interest in accordance with the terms of this Agreement, this Agreement will terminate and be of no further force and effect, except to the extent necessary in order for Sections 3.3, 3.5, 3.6, 3.7 and 3.10 to continue to be of full force and effect, and the Escrow Agent will be automatically released from all of its duties and liabilities under this Agreement.

ARTICLE 3
CONCERNING THE ESCROW AGENT

3.1 **Duties and Liability of Escrow Agent.**

(1) The Escrow Agent has no duties other than those duties expressly set forth in this Agreement. The Escrow Agent will not refer to, and is not bound by, the provisions of any agreement other than the terms of this Agreement and no implied duties or obligations of the Escrow Agent may be read into this Agreement.

(2) Notwithstanding anything contained in this Agreement or in the Asset Purchase Agreement to the contrary, the Escrow Agent has no duty to determine the performance or non-performance of any term or provision of the Asset Purchase Agreement, has no obligation or responsibility to determine any dispute or evaluate any equities between the parties regardless of any knowledge or any fact that the Escrow Agent may have or receive, and has no obligations, responsibilities or liability arising under any other agreement to which the Escrow Agent is not a party, even though reference to such other agreement may be made in this Agreement or the Asset Purchase Agreement.

(3) Nothing in this Agreement is to be construed as creating a relationship of trust between the Escrow Agent and the Vendor and Purchaser or either of them. The Vendor and the Purchaser understand and agree that the duties of the Escrow Agent under this Agreement are purely ministerial in nature and that the Escrow Agent is not liable for any error, judgement, or for any act done or step taken or omitted by it in good faith, or for any mistake of fact or law, or for anything which it may do or refrain from doing in connection herewith, except for its own fraud, gross negligence or wilful misconduct.

(4) The Escrow Agent is not under any duty to give the Escrowed Property held by it under this Agreement any greater degree of care than it gives its own similar property. The Escrow Agent's duties with respect to delivery of the Escrowed Property under this Agreement will be fully performed by delivering the Escrowed Funds in accordance with Section 2.4.

(5) The appointment of the Escrow Agent is a personal one and the duty of the Escrow Agent is only to the other Parties, their successors and assigns, and to no other Person whomsoever.

3.2 **Legal Counsel.** The Escrow Agent has the right to consult with counsel of its own choice and is not be liable for any action taken, suffered or omitted to be taken by it if the Escrow Agent acts in accordance with the advice of such counsel.

3.3 **Indemnity.** The Purchaser and the Vendor hereby jointly and severally indemnify and shall save harmless the Escrow Agent from and against any and all actions, causes of action, claims, losses, demands, damages, expenses, costs, liabilities, penalties and expenses whatsoever and to reimburse the Escrow Agent for any legal or related expenses, including those of its own partners and associates (collectively, the "**Claims**") which the Escrow Agent, its partners, associates, employees and agents may suffer or incur in connection with its acting as Escrow Agent under this Agreement, other than Claims arising as a result of the fraud, gross negligence or wilful misconduct of the Escrow Agent in the performance of its duties under this Agreement. The Escrow Agent, its partners, associates, employees and agents will in no event be liable for any loss, Claim or indirect, consequential, incidental or punitive damages to either the Vendor or the Purchaser, regardless of whether or not such losses, claims or damages were reasonably foreseeable by the Escrow Agent.

3.4 **Reliance.**

(1) The Escrow Agent may:

(a) act in reliance on any writing or instrument or signature which it, in good faith, believes to be genuine;

(b) assume the validity and accuracy of any statement or assertion contained in such a writing or instrument; and

(c) assume that any Person purporting to give any written notice, advice or instructions on behalf of any of the other Parties in connection with the provisions of this Agreement has been duly authorized to do so.

The Escrow Agent is not, as such, liable in any manner for the sufficiency or correctness as to form, execution, or validity of any document, nor as to the identity, authority, or right of any Person executing the document.

(2) Nothing in this Escrow Agreement makes the Escrow Agent responsible, or liable in any manner for the sufficiency, correctness, genuineness or validity of any document forming part of the Escrow Property.

(3) The Escrow Agent is not required to make any determination or decision with respect to the validity of any claim made by any Party, or of any denial thereof but is entitled to rely conclusively on the terms of this Agreement and the documents tendered to it in accordance with the terms of this Agreement.

3.5 **Disputes.** If there is any dispute as to whether the Escrow Agent is obligated to deliver the Escrow Property and Interest, the Escrow Agent shall hold such Escrow Property and Interest until receipt of an authorization in writing executed by each of the Vendor and the

Purchaser directing the delivery thereof, or in the absence of such authorization, the Escrow Agent may hold the Escrow Property and Interest until the final determination of the rights of the Parties in an appropriate court proceeding. If such written authorization is not given, or proceedings for such determination have not begun and been diligently continued, the Escrow Agent may bring, but is not required to bring, an appropriate action or proceeding pursuant to Section 3.6 for leave to deposit the Escrow Property and Interest in court, pending such determination. If a judicial proceeding is instituted by the Escrow Agent, the Escrow Agent will be entitled to reasonable solicitor's fees.

3.6 **Interpleader.** Without limiting Section 3.5, if:

(a) any action is threatened or instituted against the Escrow Agent;

(b) any dispute arises, or any action is threatened or instituted, concerning the entitlement of a Party to the Escrow Property and/or Interest; or

(c) if at any time the Escrow Agent is uncertain as to its obligations under this Agreement,

the Escrow Agent may apply to a court of competent jurisdiction in the Province of Ontario for clarification or directions with respect to its obligations under this Agreement, and in such event, or if any other person should apply to a court of competent jurisdiction (which must be in the Province of Ontario) on any matter affecting the obligations of the Escrow Agent under this Agreement or otherwise relating to the Escrow Property and/or Interest, the Escrow Agent may and is hereby authorized to release, deliver or otherwise deal with the Escrow Property and Interest in accordance with the directions, order, judgment or decree of such court.

3.7 **Court Orders.**

(1) The Escrow Agent is hereby authorized, in its sole discretion, to comply with all writs, orders or decrees entered or issued, whether with or without jurisdiction, which purport to:

(a) attach, garnish or be levied on any part of the Escrow Property and Interest;

(b) stay or enjoin the disbursement, payment or delivery of any part of the Escrow Property and Interest; or

(c) affect any part of the Escrow Property and Interest in any way.

The Escrow Agent is not liable to any of the other Parties or to any other Person because it obeys or complies with any such writ, order or decree, even if such writ, order or decree is subsequently reversed, modified, annulled, set aside or vacated.

3.8 **No Disqualification.** Each of the Vendor and the Purchaser acknowledges that the Escrow Agent:

(a) acts as counsel to the Purchaser and may continue to act as counsel to Purchaser in all matters including any matters in dispute between the Vendor and the Purchaser and any issue arising out of or in connection with this Agreement or the Escrow Property and Interest; and

(b) in so acting, is not disqualified from acting as Escrow Agent under this Agreement and is deemed not to be in conflict by reason of performing its duties under this Agreement.

3.9 **Resignation, Removal and Replacement of Escrow Agent.** The Escrow Agent may resign by notice to the other Parties. Upon the effective date of such resignation, the Escrow Agent shall deliver the Escrow Property and Interest then held by it under this Agreement to such Person as may be jointly designated in writing by the Vendor and the Purchaser as the new escrow agent (the "**Successor Escrow Agent**"). If the Vendor and the Purchaser fail to deliver such a written designation, the Escrow Agent will not resign its position until such designation is delivered or until the Escrowed Property then held are delivered to the control of a court of competent jurisdiction. Upon the delivery of the Escrowed Property to the Successor Escrow Agent or to the control of a court of competent jurisdiction, all of the Escrow Agent's obligations as escrow agent under this Agreement will cease and terminate.

3.10 **Fees and Out-of-Pocket Expenses.** The Escrow Agent is entitled to reimbursement of out-of-pocket expenses (the "**Escrow Fees**") for carrying out its duties under this Agreement. The Purchaser is liable for and agrees to pay to the Escrow Agent all Escrow Fees and the Escrow Agent shall be entitled to withhold from the interest earned in respect of the Escrowed Property an amount up to the amount of its Escrow Fees and the Purchaser will remain liable for any remaining unpaid Escrow Fees.

ARTICLE 4
GENERAL

4.1 **Time of Essence.** Time is of the essence of this Agreement.

4.2 **Amendment.** This Agreement may be supplemented, amended, restated or replaced only by a written agreement signed by each Party.

4.3 **Waiver of Rights.** Any waiver of, or consent to depart from, the requirements of any provision of this Agreement is effective only if it is in writing and signed by the Party giving it, and only in the specific instance and for the specific purpose for which it has been given. No failure on the part of any Party to exercise, and no delay in exercising, any right under this Agreement operates as a waiver of such right. No single or partial exercise of any such right precludes any other or further exercise of such right or the exercise of any other right.

4.4 **Arbitration.** All disputes arising out of, or in connection with, this Agreement, or in respect of any legal relationship associated with it or derived from it, will be finally resolved by arbitration administered by ICDR Canada. The place of arbitration will be Toronto, Ontario or such other place as the Parties may agree in writing. The language of the arbitration will be English.

4.5 **Jurisdiction.** Subject to Section 4.4, the Parties irrevocably and unconditionally attorn to the exclusive jurisdiction of the courts of the province of Ontario sitting in Toronto in respect of all disputes arising out of, or in connection with, this Agreement, or in respect of any legal relationship associated with it or derived from it.

4.6 **Governing Law.** This Agreement is governed by, and interpreted and enforced in accordance with, the laws of the Province of Ontario and the laws of Canada applicable in that province, excluding the choice of law rules of that province.

4.7 **Entire Agreement.** This Agreement constitutes the entire agreement between the Parties pertaining to the subject matter of this Agreement and supersede all prior correspondence, agreements, negotiations, discussions and understandings, written or oral. There are no representations, warranties, conditions or other agreements or acknowledgements, whether direct or collateral, express or implied, written or oral, statutory or otherwise, that form part of or affect this Agreement or which induced any Party to enter into this Agreement. No reliance is placed on any representation, warranty, opinion, advice or assertion of fact made either prior to, concurrently with, or after entering into, this Agreement by any Party to this Agreement to any other Party, except to the extent the representation, warranty, opinion, advice or assertion of fact has been reduced to writing and included as a term in this Agreement and none of the Parties has been induced to enter into this Agreement or any amendment or supplement by reason of any such representation, warranty, opinion, advice or assertion of fact. There is no liability, either in tort or in contract, assessed in relation to the representation, warranty, opinion, advice or assertion of fact, except as contemplated in this Section.

4.8 **Notices.**

(1) Any notice, demand or other communication (in this Section 4.7, a "**notice**") required or permitted to be given or made under this Agreement must be in writing and is sufficiently given or made if:

(a) delivered in person and left with a receptionist or other responsible employee of the relevant Party at the applicable address set forth below;

(b) sent by prepaid courier service or (except in the case of actual or apprehended disruption of postal service) mail; or

(c) sent by facsimile transmission, with confirmation of transmission by the transmitting equipment (a "**Transmission**");

in the case of a notice to the Vendor addressed to it at:

Infrastructure Energy Inc.
22 Leader Lane 402
Toronto, ON
M5E 0B2

Attention: Glen Martin

E-mail: glen.martin@infrastructure.energy

and in the case of a notice to the Purchaser, addressed to it at:

PUC Distribution Inc.
500 Second Line East
Sault Ste. Marie, ON
P6A 6P2

Attention: Robert Brewer
E-mail: Robert.brewer@ssmpuc.com

with a copy (not constituting notice) to:

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide St. W
Toronto, ON
M5H 4E3

Attention: John Vellone
E-mail: JVellone@blg.com

and in the case of a notice to the Escrow Agent, addressed to it at:

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide St. W
Toronto, ON
M5H 4E3

Attention: John Vellone
E-mail: JVellone@blg.com

with a copy (not constituting notice) to:

Attention: Patrick Dolan
Facsimile No.: PDolan@blg.com

(2) Any notice sent in accordance with this Section 4.7 shall be deemed to have been received:

(a) if delivered prior to or during normal business hours on a Business Day in the place where the notice is received, on the date of delivery;

(b) if sent by mail, on the fifth Business Day in the place where the notice is received after mailing, or, in the case of disruption of postal service, on the fifth Business Day after cessation of such disruption; or

(c) if sent in any other manner, on the date of actual receipt;

except that any notice delivered in person or sent by Transmission not on a Business Day or after normal business hours on a Business Day, in each case in the place where the notice is received, shall be deemed to have been received on the next succeeding Business Day in the place where the notice is received.

(3) Any Party may change its address for notice by giving notice to the other Parties.

4.9 **Assignment.** No Party may assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Agreement to any Person without the prior written consent of the other Parties.

4.10 **Further Assurances.** Each Party shall, at the expense of another Party, promptly do, execute, deliver or cause to be done, executed or delivered all further acts, documents and matters in connection with this Agreement that such other Party may reasonably require, for the purposes of giving effect to this Agreement.

4.11 **Successors and Assigns.** This Agreement is binding on, and enures to the benefit of, the Parties and their respective heirs, administrators, executors, successors and permitted assigns.

4.12 **Counterparts.** This Agreement may be executed in any number of counterparts, each of which is deemed to be an original and all of which taken together constitutes one agreement. To evidence the fact that it has executed this Agreement, a Party may send a copy of its executed counterpart to all other Parties by Transmission and the signature transmitted by Transmission is deemed to be its original signature for all purposes.

IN WITNESS WHEREOF, the Parties have duly executed this Agreement on the date first above written.

INFRASTRUCTURE ENERGY INC.

By: ______________________

Name: GLEN MARTIN
Title: CEO

PUC DISTRIBUTION INC.

By: ______________________

Name: Robert Brewer
Title: President & CEO

BORDEN LADNER GERVAIS LLP

By:

Name: John Vellone
Title: Partner

FULL AND FINAL RELEASE AND CONFIDENTIALITY AGREEMENT

WHEREAS PUC Distribution Inc. ("**PUC**") and Energizing, LLC ("**Energizing**") entered into, and conducted work in connection with, non-binding Letters of Intent dated July 26, 2013 and December 16, 2015 relating to the design, building, construction, financing, maintenance and operation of a utility distribution microgrid project in Sault Ste. Marie, as further described in those Letters of Intent, and Energizing did not submit a proposal in response to a Request for Proposals issued by PUC on October 4, 2019 in connection with the Sault Smart Grid Project (all together, the "**Project**").

WHEREAS PUC has entered into an asset purchase agreement dated on or about the date hereof (the "**Asset Purchase Agreement**") with Infrastructure Energy Inc. (the "**Vendor**"), Energizing and Infrastructure Energy, LLC (the "**Guarantors**"), and Glen Martin and Blind Line Holdings, LLC (the "**Members**") (the Vendor, Guarantors and Members hereinafter collectively referred to as the "**Releasors**").

IN CONSIDERATION of PUC entering into the Asset Purchase Agreement, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Releasors hereby release and forever discharge PUC and PUC Services Inc. and each of their agents, servants and employees, subsidiaries, affiliates, related entities, successors, assigns and insurers, (hereinafter referred to collectively as the "**Releasees**"), from any and all actions, claims, demands, damages, loss or injuries, interests and costs, howsoever arising, which heretofore may have been or may hereinafter be sustained by the Releasors, including any which are not now known or anticipated but may arise in the future and all effects and consequences thereof, in connection with or in any way relating to the Project.

AND FOR THE SAID CONSIDERATION, the Releasors further undertake and agree not to make or continue a claim or to take or continue any proceedings against any other persons or entities who might claim contribution or indemnity under the provisions of any statute, or at common law, from the Releasees, or any of them, including but not limited to Black & Veatch Corporation ("**Black & Veatch**"), or any subsidiary, affiliate or related entity of Black & Veatch. In the event that the Releasors have made or make any claims or take any proceedings against any other person or entity and that other person or entity claims contribution or indemnity from the Releasees, or any of them, the Releasors agree to indemnify and hold harmless the Releasees in respect of that claim, including, without limiting the generality of the foregoing, indemnification of the Releasees in respect of any claims advanced against the Releasees (or any of them), any prejudgment and postjudgment interests on the claims, any costs payable to the other persons or entity, and indemnification of the Releasees for their own costs on a full indemnity basis.

AND FURTHER FOR THE SAID CONSIDERATION the Releasors agree that this final release and indemnity shall be binding upon itself and its successors, beneficiaries and assigns.

IT IS UNDERSTOOD AND AGREED that the said consideration is deemed to be no admission whatsoever of liability on the part of the Releasees.

THE RELEASORS FURTHER UNDERSTAND AND AGREE that all communications regarding the Projects, and the sale of assets to the Releasees, shall remain strictly confidential and shall not be disclosed to any third party, aside from disclosure to the Releasors' professional legal advisors, and disclosure compelled by law, and for clarity the Releasors shall maintain the confidential nature of its dealings with the Releasees and shall not discuss them with any non-party to this Release (aside from the professional advisors previously listed).

AND IT IS FURTHER ACKNOWLEDGED that at the time of the execution of this Full and Final Release, the Releasors have had the opportunity to obtain legal advice, understands the full consequences of executing this Full and Final Release and Confidentiality Agreement, and has done so voluntarily.

IN WITNESS WHEREOF this Full and Final Release and Confidentiality Agreement has been signed this 27th day of January, 2020.

SIGNED IN THE PRESENCE OF:

INFRASTRUCTURE ENERGY INC.

By: ______________________

Name: GLEN MARTIN

Title: CEO

INFRASTRUCTURE ENERGY, LLC

By: ______________________

Name: GLEN MARTIN

Title: CEO

ENERGIZING, LLC

By: ______________________

Name: GLEN MARTIN

Title: CEO

BLIND LINE HOLDINGS, LLC

By: ______________________________

Name: GLEN MARTIN

Title: MANAGING MEMBER

GLEN MARTIN

____

PUC DISTRIBUTION INC.

By: ______________________________

Name:

Title:

BLIND LINE HOLDINGS, LLC

By: ______________________________
Name:
Title:

GLEN MARTIN

____

PUC DISTRIBUTION INC.

By: ______________________________
Name: Robert Brewer
Title: President & CEO

ATTACHMENT 4 – INFORMATION NOTE MAY 13, 2020

INFORMATION NOTE

SUBJECT: SAULT SMART GRID (SSG) PROJECT UPDATE

PRESENTED TO: PUC SERVICES INC. BOARD, PUC INC. BOARD, PUC DISTRIBUTION INC. BOARD

MEETING DATE: MAY 13, 2020

REFERENCE/ BACKGROUND

Update since December 9, 2019 Board Meeting:

In January 2020, negotiations were completed with Infrastructure Energy to purchase preliminary engineering works in support of the project. Settlement and agreement for this was shared with the Board at the February 26th Board meeting.

With completion of the RFP process for an EPC contractor for the Sault Smart Grid project in December 2019, PUC subsequently selected Black & Veatch (B&V) to proceed to the next stage of firming up project scope and pricing and commencing development of formal contract terms and conditions legal documents.

In January, the first on site meeting with PUC and B&V commenced to tackle the detailed review of the RFP submission and project pricing. Discussion to confirm project scope and cost drivers for clarity on assumptions, scope, and expectations with an objective of firming up scope, price, and schedule. Conference calls and email Q&A exchanges continued through February and in to March. The project scope expanded as compared to the original ICM application assumption to ensure we had pricing estimated for a 100% system coverage for both voltage optimization(VO) and feeder distribution automation(DA). COVID-19 business process changes had some impact to the timeline and what had been initially planned as wrap-up presentation meeting moved to virtual Team meeting in early April.

Final delivery of EPC scope and pricing documents to PUC occurred on April 8th with a confirmed two step price structure for the EPC portion of the project. The firm price for Step 1 plus the upset limit for Step 2 becomes the basis of the cost estimate for the EPC contract. Completion of Step 1 will develop the detailed engineering and procurement pricing to lock in a Step 2 scope and a firm price for the EPC contract and project to be executed.

Draft amended ICM application is with BLG, our regulatory consultant for review. Currently, we are considering a regulatory strategy for the application submission in terms of scope, cost, and benefits to present to the OEB. Options are being developed to provide OEB input to the value decision of reliability through DA and cost/benefits. Reduction in scope of feeder coverage to those with the most reliability benefit may result. Current project estimates are included in the attached reference table for information.

In parallel timeframe the work to develop the contract framework for the legal terms and conditions of the formal EPC document progressed. This effort paused during the past month with focus on the EPC specifications and application. We are now resuming work to incorporate scope and specifications developed into the framework and get to the final legal contract document.

RECOMMENDATION

That the PUC Services Board receives as information this report and update on the Sault Smart Grid (SSG) Project.

Prepared by: **Kevin Bell**
Date: **May 7, 2020**

Submitted by: **Kevin Bell**
Date: **May 13, 2020**

Attachments: **Reference tables**

Project Net Annual Benefits Summary

Projected customer energy savings through SSG	$	2,227,842
Projected system loss energy savings through SSG	$	105,111
Total purchased power savings	$	2,332,953
ICM additional revenue from increased SSG asset base	$	1,839,532
Additional O & M expenses due to SSG implemtation	$	351,000
Operating efficiency benefits due to SSG implmentation	-$	30,816
	$	2,159,716
Annual net benefit to customers	$	173,237

Customer Bill Impacts

Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %
Residential	750	0	$0.08	0.07%
Residential	825	0	-$0.16	-0.13%
Residential	775	0	$0.00	0.00%
Residential	2,000	0	-$3.87	-1.48%
GS<50	2,000	0	-$2.02	-0.69%
GS<50	890	0	$0.00	0.00%
GS<50	3,000	0	-$3.84	-0.89%
GS>50	19,740	55	-$35.81	-1.06%
GS>50	57,220	145	-$133.57	-1.43%
GS>50	142,465	452	-$312.28	-1.30%
GS>50	169,620	468	-$404.11	-1.45%

Project Estimate Summary

PROJECT ESTIMATE SUMMARY	
EPC Estimate	
Step 1 (Firm)	5,086,378
Step 2 (Estimate)	22,658,667
TOTAL	**27,745,045**
PUC Add'l scope estimate portion	
TT 34.5kV	350,000
UG Cct Allow	625,000
Misc Inv/Mat'l	687,998
	1,662,998
EPC + Add'l Scope and Contingencies	**29,408,043**
Add PUC costs	4,882,695
CWIP	398,630
PUC Cost Estimate	**5,281,325**
TOTAL SSG	**34,689,368**

ATTACHMENT 5 – SUMMARY OF SURVEY RESULTS

PUC Smart Grid Project - December 2020

Wednesday, January 06, 2021

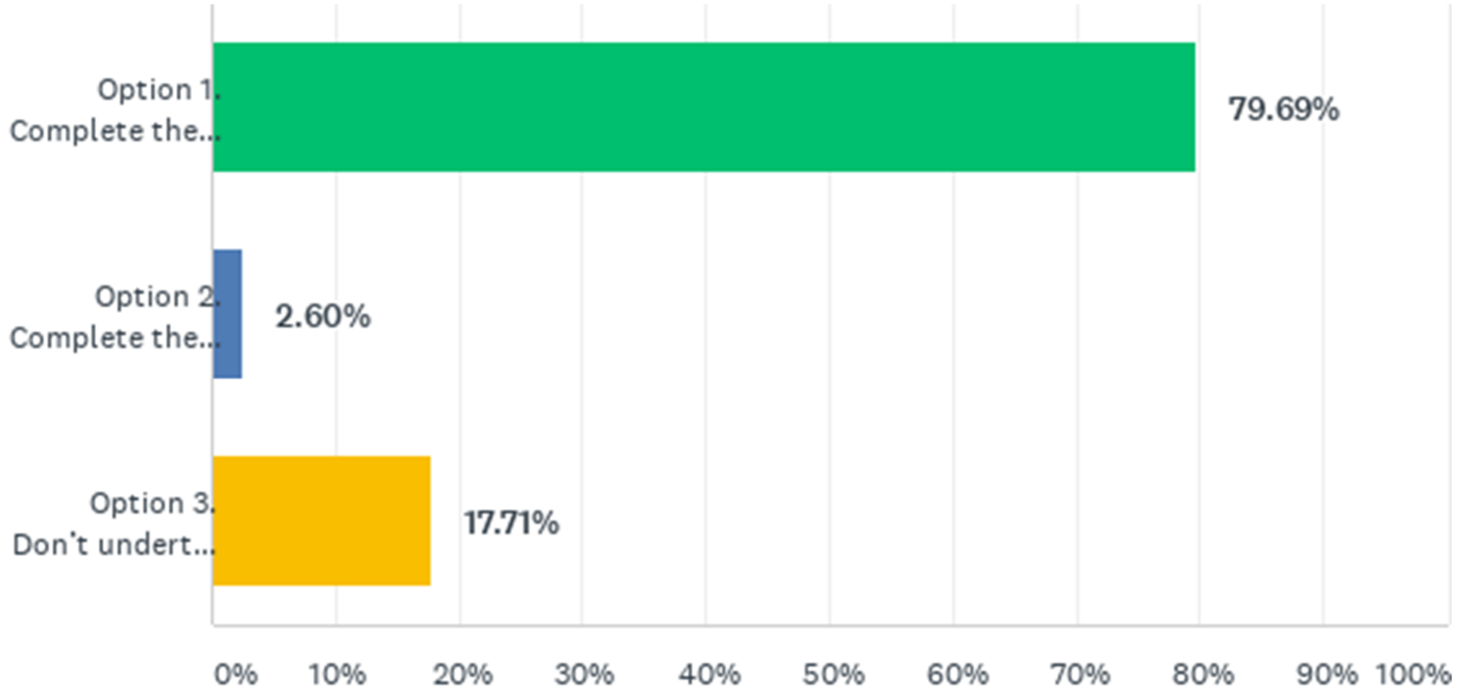
197

Total Responses

Date Created: Thursday, December 24, 2020

Complete Responses: 197

Q1: There are three options PUC is evaluating with respect to the Smart Grid Project:



Q1: There are three options PUC is evaluating with respect to the Smart Grid Project:

Option 1: Complete the project as proposed over a 2 year period, utilizing NRCan funding, and achieving a net bill decrease for PUC Distribution customers

Response: 79.69%

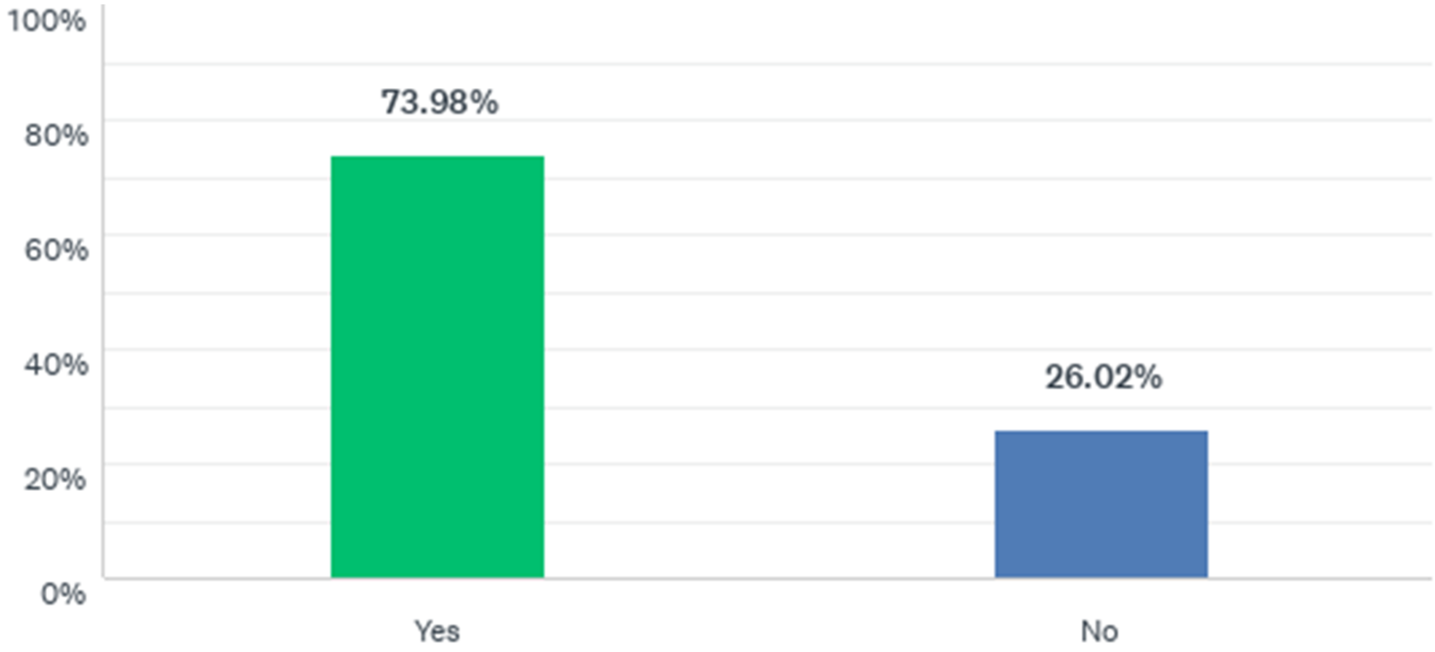
Option 2: Complete the project over ten years (not eligible for NRCan funding), and result in small increases on an annual basis to PUC Distribution customer bills

Response 2.60%

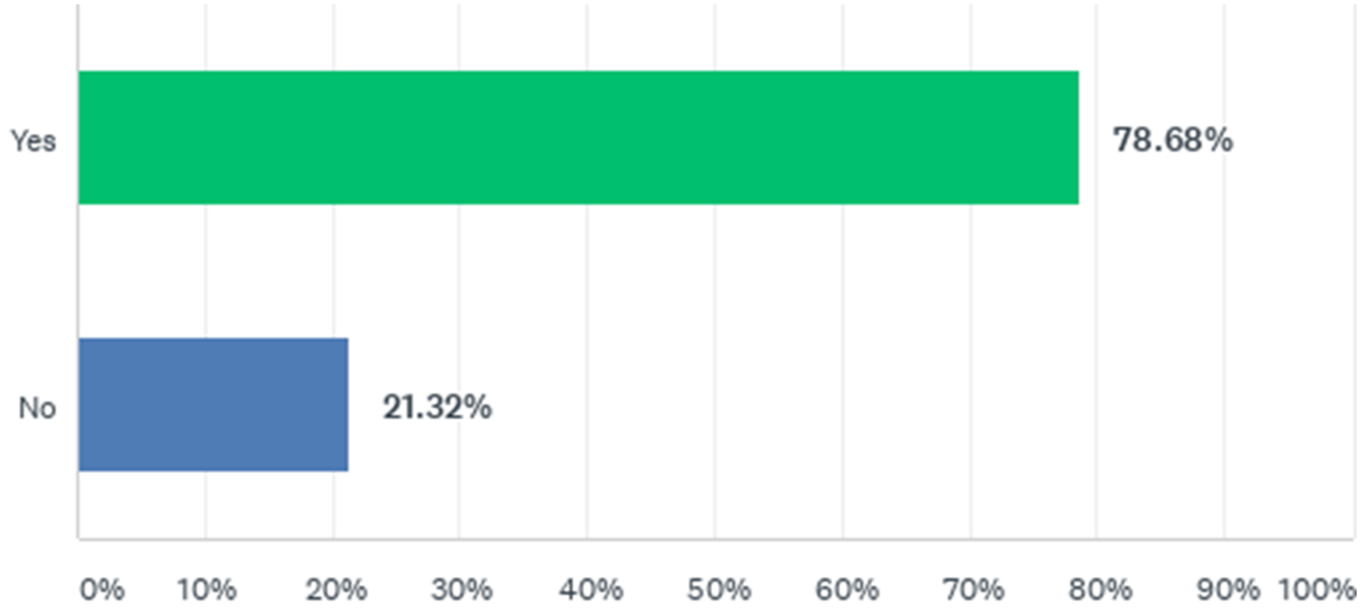
Option 3: Don't undertake the project. No bill changes. No improvement to reliability. No reduction in provincial carbon emissions.

Response 17.71%

Q2: After learning that the Smart Grid Project will result in considerable carbon savings in the province of Ontario, does that make you more inclined to support it?

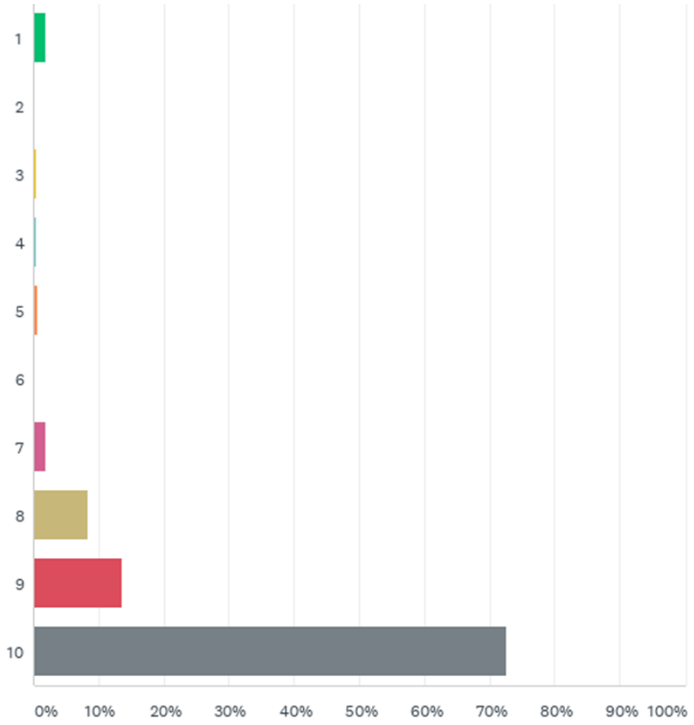


Q3: After learning that the Smart Grid Project will result in better power quality and significantly increased reliability, does that make you more inclined to support it?



Q4: On a scale from 1-10, how important is electrical reliability to you in your home and/or business? (1 being not important, 10 being very important)

From our July survey



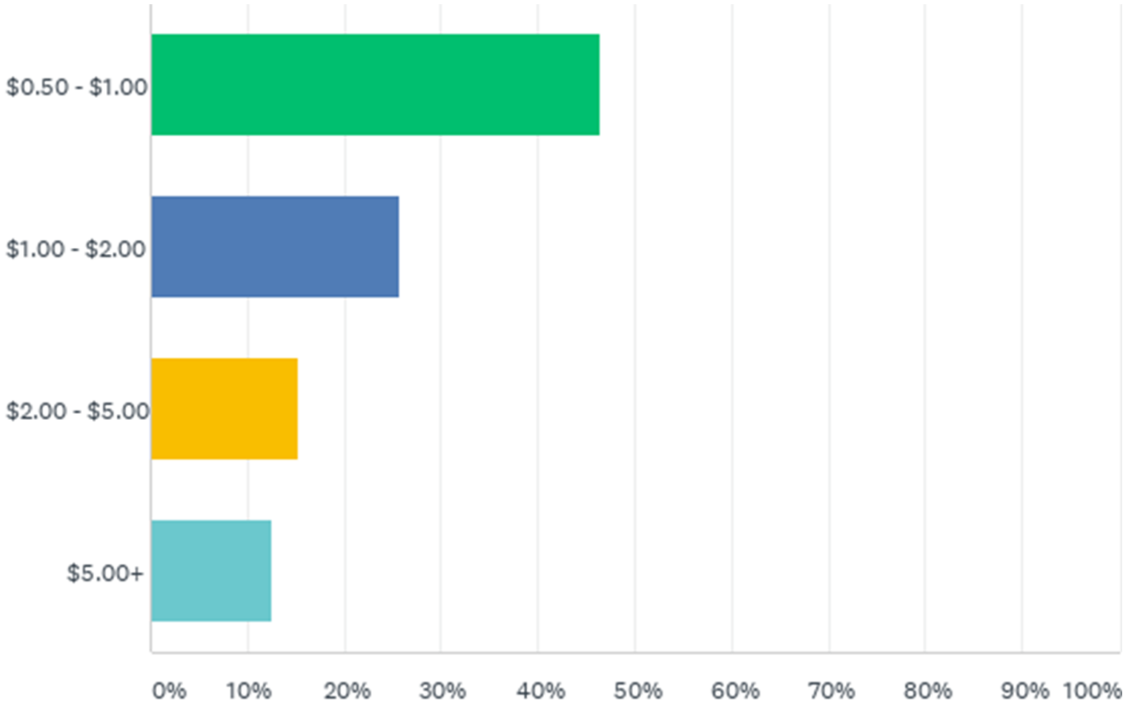
Q4: On a scale from 1-10, how important is electrical reliability to you in your home and/or business? (1 being not important, 10 being very important)

From our July survey

ANSWER CHOICES	RESPONSES	
1	1.95%	6
2	0.00%	0
3	0.33%	1
4	0.33%	1
5	0.65%	2
6	0.00%	0
7	1.95%	6
8	8.47%	26
9	13.68%	42
10	72.64%	223
TOTAL		307

Q5: What value would you place on future bills to improve reliability, efficiency and communications?

From our July Survey



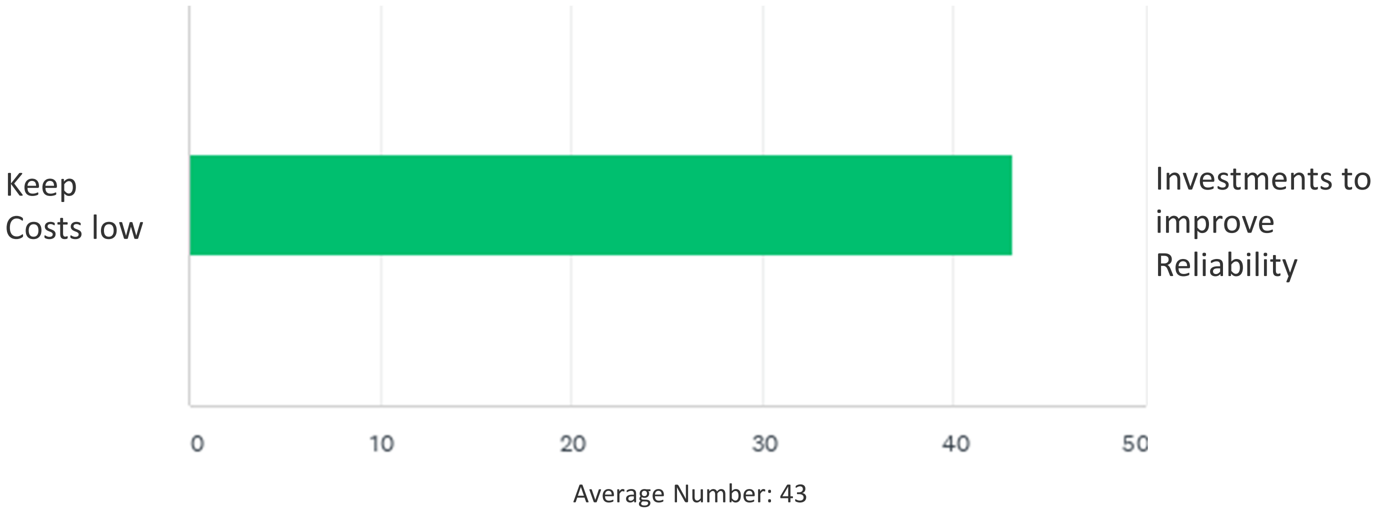
Q5: What value would you place on future bills to improve reliability, efficiency and communications?

From our July survey

ANSWER CHOICES	RESPONSES	
$0.50 - $1.00	46.34%	133
$1.00 - $2.00	25.78%	74
$2.00 - $5.00	15.33%	44
$5.00+	12.54%	36
TOTAL		287

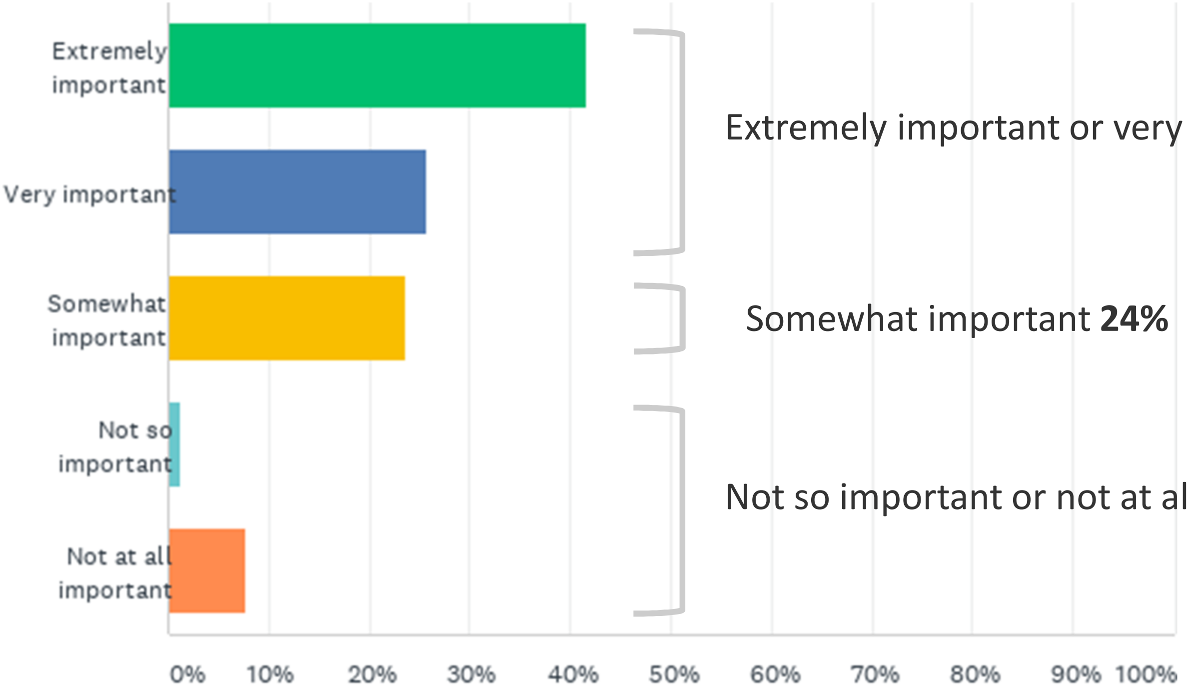
Q6: PUC is committed to keeping costs affordable, while providing safe and reliable electricity, water and wastewater services to our customers. PUC can increase system reliability by making investments that may result in minor rate increases (1-2%). On a sliding scale, what is more important to you?

From our November survey



Q7: How important is it to you that PUC play a role in the community to promote the reduction of greenhouse gas emissions?

From our November survey



Extremely important or very important **67%**

Somewhat important **24%**

Not so important or not at all important **9%**

ATTACHMENT 6 – RELEVANT PAGES OF PRESIDENT'S REPORT, SEPTEMBER 25, 2019

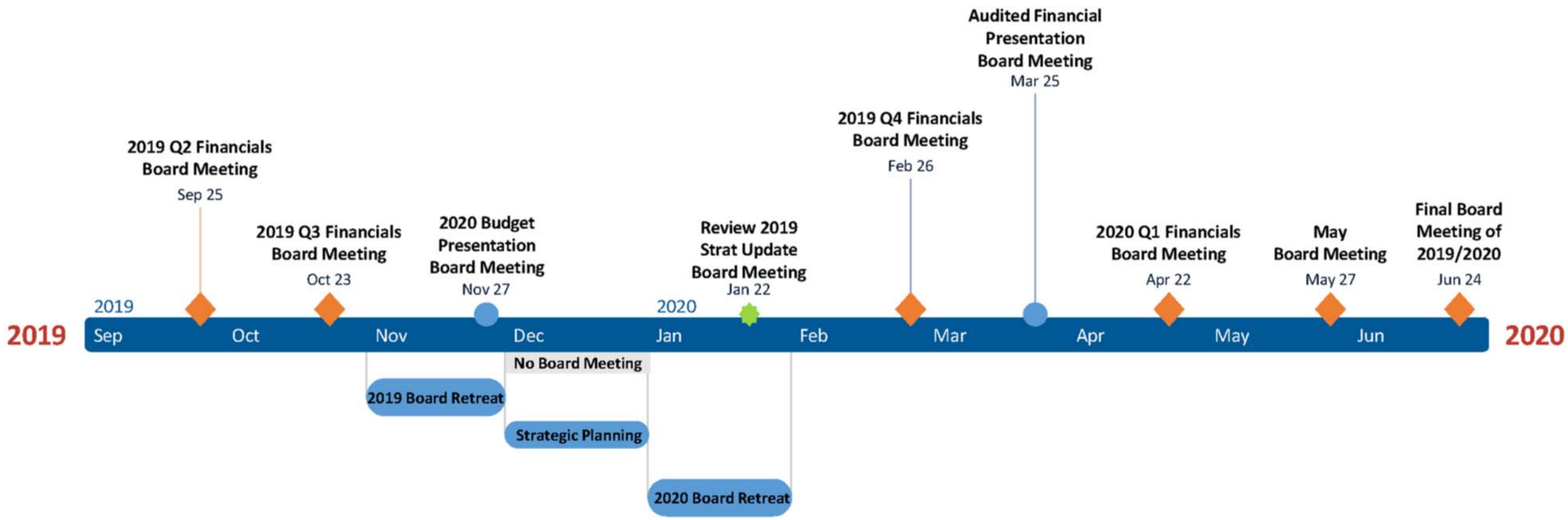
2019-2020 BOARD TIMELINE

2019-2020 Board Agenda Framework

Agenda Item	September	October	November	December	January	February	March	April	May	June
News & Recognition	X	X	X		X	X	X	X	X	X
Safety Update	X	X	X		X	X	X	X	X	X
Quarterly Financial Updates	2019 Q2	2019 Q3				2019 Q4		2020 Q1		
Audited Financial Statements								X		
Budget Presentation			X							
Strategic Plan Update						X				
Board Retreat			X		X					
Risk Registry			X						X	
Cyber Security Report		X					X			
Board Training	X	X	X		X	X	X	X	X	

2019-2020 Board Timeline

September - June



President's Report

September 2019

STRATEGIC PLAN UPDATE

Strategic Initiatives Update

Initiative #1: Develop and Implement SMART Grid Plan

- Preparing RFP for EPC Contract

Initiative #2: Streamline process to convert additional existing forms to electronic or digital versions.

- Work on forms identified in-house development is ongoing
- Clearion pilot project has been unbundled and re-released for routine use for Hydrant Inspections (Water Distribution) and Vault Inspections (Line Dept.)

Initiative #3: Implement ERP upgrade

- The ERP upgrade is behind schedule, but on budget.
- Main driver for the timing issue has been the “data breach” (suspected ransomware) at Harris Computer Corp. on Aug 23.
- As a result of this breach PUC cut off access to Harris systems to ensure the integrity of PUC network
- Work will not progress until PUC has a formal information release, in writing, from Harris on the Aug 23 issue.

ATTACHMENT 7 – OEB STAFF-37 – BILL IMPACTS CCA 8% HALF YEAR REVENUE REQUIREMENT

(FILED IN EXCEL SPREADSHEET)

ATTACHMENT 8 – DRAFT ACCOUNTING ORDER

PUC Distribution Inc.

2020 ICM Application – The Sault Smart Grid project

EB-2020-0249

Accounting Order

Account 1508 Other Regulatory Assets

Sub-accounts Contributed Capital

December 31, 2020

PUC Distribution Inc. - 2020 ICM Application – The Sault Smart Grid project

Accounting Order – Account 1508 Other Regulatory Assets

PUC shall establish three (3) variance accounts: Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue - Contributed Capital, Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue – Amortization, and Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue – Carrying Costs, effective May 1, 2021 for its Sault Smart Grid project.

These accounts will be used to record the deferred revenue and amortization associated with the funding received from the NRCan in respect to the Smart Grid capital project contribution. Carrying charges at the OEB's prescribed interest rates will be applied to these subaccounts and recorded in the Deferred Revenue – Carrying Costs sub-account at the prescribed OEB rates. These accounts will be discontinued after PUC's next rebasing application.

The accounting entries to be recorded are as follows:

USofA #	Account Description

Initial entry to record the principal capital contributed funds received from NRCan.

DR 2440	Deferred Revenue Liability
CR 1508	Other Regulatory – Sub-account "Deferred Revenue – Contributed Capital"

Entries to record amortization of deferred revenue over the life of asset.

DR 1508	Other Regulatory – Sub-account "Deferred Revenue – Contributed Capital"
CR 1508	Other Regulatory – Sub-account "Deferred Revenue Amortization

Entries to record carrying costs.

DR1508	Other Regulatory – Sub-account "Deferred Revenue – Carrying Costs"
CR 1525	Misc Deferred Debits

ATTACHMENT 9 – DISTRIBUTION SYSTEM PLAN DATED MARCH 29, 2018

PUC Distribution Inc.

Distribution System Plan

2018-2022

Prepared by

METSCO

MAKING IT POSSIBLE

March 21, 2018

File: PUC DSP 2018-03-21 final.docx

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Appendix A - Single Line Diagrams

Appendix B - Asset Condition Assessment & Asset Management Plan

Appendix C - PUC Distribution Customer Satisfaction Survey

Appendix D - OPA/IESO Comment Letter on DSP

Appendix E - Regional Infrastructure Planning Report

Appendix F - OEB Score Card Performance Measures

Appendix G - Project Descriptions for Specific Projects Exceeding Materiality Threshold

Appendix H - Customer Engagement

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1 Introduction

PUC Distribution Inc. (PUC Distribution) has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB's") Chapter 5 - Consolidated Distribution System Plan Filing Requirements, dated March 28, 2013 (the "Filing Requirements") as part of its 2018 Cost of Service Application (the "Application").

PUC Distribution is licenced to distribute electricity in its service territory which includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. Its service territory covers a service area of approximately 342 square kilometers, with a combined population of approximately 75,300. The service territory includes approximately 29,700 residential customers and approximately 3,800 general customer services for a total of approximately 33,500 customers.

The DSP was prepared to provide to the OEB and all interested stakeholders:

- An overview of PUC Distribution's asset planning objectives and goals;
- A review of PUC Distribution's operational performance in the five-year historical period;
- A preview of PUC Distribution's planned expenditures for the forecast period aimed at improving its asset-related performance to achieve the four performance outcomes established by the OEB; and
- A detailed justification of PUC Distribution's planned capital expenditures in the test year.

This DSP covers a planning horizon of five years starting in the test year, which is 2018 in the case of this filing. Employing this long-term approach requires PUC Distribution to consider future customer needs and any required changes to its distribution system in advance, thereby enhancing PUC Distribution's ability to plan ahead and respond to the evolving needs of customers in a timely manner, while managing and leveling the impacts of these expenditures on consumer rates to maintain affordability of its service.

Taking a performance-based approach for regulating electricity distributors under the Renewed Regulatory Framework for Electricity (RRFE), the OEB has established the following four performance outcomes to be achieved by electricity distributors:

- **Customer Focus:** services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness:** continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

- **Public Policy Responsiveness:** utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

- **Financial Performance:** financial viability is maintained; and savings from operational effectiveness are sustainable

PUC Distribution's vision is to be recognized as a progressive electric distribution company committed to delivering value, innovation, prosperity and excellence. In order to accomplish this, PUC Distribution's mission is to provide cost effective, efficient, safe and reliable delivery of high quality energy services and solutions consistent with customer needs and preferences. Our DSP has been informed and influenced through multiple avenues of customer engagement although system asset investment decisions are still primarily influenced by condition based factors to ensure a safe system and maintain or enhance reliability which customers value very highly. Our most recent customer survey focused on the Cost of Service application and the rate increase being sought in our application. Background on cost drivers and cost increases since our last application in 2012 were part of the education and feedback areas brought forward to customers. An integrated approach has been employed for investment planning with all of the investments pertaining to the following categories planned and optimized together:

- System Access,

- System Renewal,

- System Service, and

- General Plant.

As defined by OEB in its Chapter 5 filing requirements,

System Access investments are modifications to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system;

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

System Service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements including smart grid development; and

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

The DSP contents are organized using the Ontario Energy Board's Chapter 5 - Consolidated Distribution System Plan Filing Requirements. Section 2 provides an overview of the DSP and describes the process employed in its development, i.e. stakeholder consultations, collaboration with municipal/regional governments and transmitters, performance measurements and monitoring metrics. Section 3 describes in detail the asset management process employed to determine the scope of capital investments into asset sustainment and prioritize these investments into various assets. Section 4 documents the overall capital expenditure plan covering System Access, System Renewal, System Service, and General Plant, including justification for investments. Section [5.4.2] of the OEB's DSP filing requirements mandates detailed description of projects to be provided above the Distributor's materiality threshold.

The materiality threshold for PUC Distribution is $90,000 and detailed descriptions of specific projects exceeding the materiality threshold are provided in Section 4.5.2 and Appendix G. Other pertinent information relevant to this DSP is included in the Appendices.

2 Distribution System Plan [5.2]

Throughout this document, section headings are followed by references in square brackets, e.g.: [5.2], to cross reference the information provided in the DSP back to the OEB requirements, as indicated in the OEB document 'Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5 – Consolidated Distribution System Plan Filling Requirements'.

2.1 DSP Overview [5.2.1]

2.1.1 How Key Elements of the DSP Support Planning Objectives

Key elements of the DSP that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives [5.2.1 a]

Table 1 shows at a glance the customer mix served by PUC Distribution. In addition to the customer count indicated in the table, additional loads served from the distribution system include approximately 9314 streetlights and 295 unmetered scattered loads.

Table 1: Customer Count by Type

Customer Type	# of Customers
Residential	29708
GS<50	3419
GS>50	360
Total	33487

As indicated in Figure 1, the customer base of PUC Distribution is comprised of approximately 89% residential and 11% general service customers.

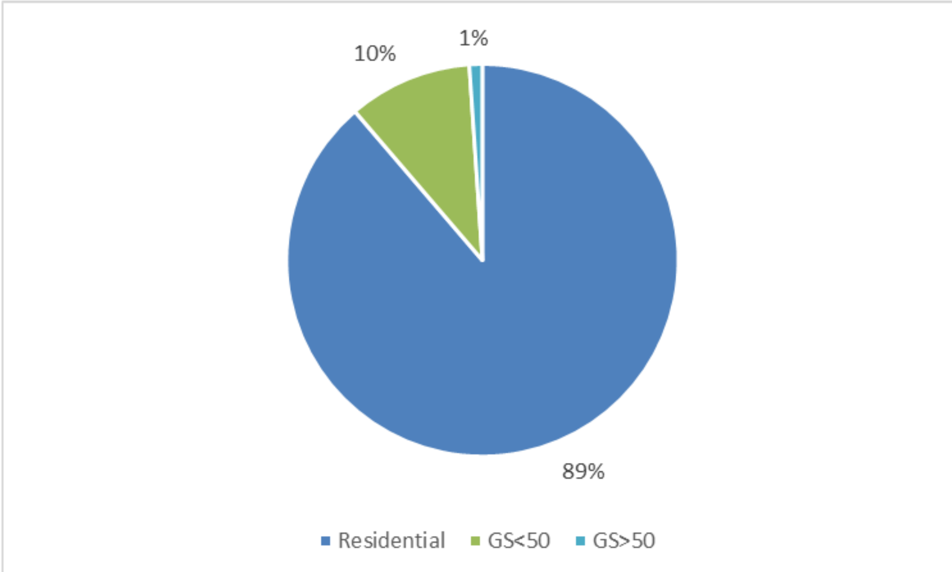


Figure 1: Customer Mix by Type

Historically, the local economy in PUC Distribution's service territory has been dominated by steelmaking. This industry has not experienced growth over the recent past and therefore, there hasn't been significant growth in the region's population. This trend is expected to continue during the next five-year period, covered by this DSP. Historically, electricity has been used for space heating in this region and therefore load on the electricity distribution grid peaks during the winter. For example, during the period from 2010 to 2014, the winter peak load was approximately 55% higher than the summer peak load. Shifting of space heating from electricity to natural gas, combined with the multiple energy conservation and demand management (CDM) initiatives implemented by residential and general service customers and expansion of natural gas distribution network in the region, has resulted in a steady decline in the peak demand on the electrical grid and this trend is expected to continue. There are currently no capacity constraints in the supply system that would prevent connection of anticipated load or generation customers during the next five years and therefore no investments are required to mitigate capacity constraints during that period. During recent years, the community has invested a significant amount of effort to diversify the local economy and these diversification efforts have resulted in development and growth of a call center industry. There has been significant effort to grow the tourism industry, with development of a major Casino in the downtown. The corporate head office of Ontario Lottery and Gaming Corporation (OLG) is also located in Sault Ste. Marie and Sault Ste. Marie has become a regional hub to provide services for the surrounding rural communities. Availability of reliable electricity supply at affordable prices is an essential ingredient, needed for the region's diversification efforts to succeed.

A significantly large portion of the existing infrastructure employed on PUC Distribution's supply network has reached a service age beyond its typical useful life. Through a recently completed asset condition assessment exercise, a significantly large fraction of critical power supply infrastructure components employed at distribution stations, overhead lines and underground distribution system have been determined to be in "poor" or "very poor" operating condition. In the absence of major investments into asset renewal, the existing infrastructure presents high risk of failure in service, affecting supply system reliability and public safety. However, renewal and replacement of all infrastructure components determined to be in "poor" or "very poor" condition during the next five years, would be difficult to manage through PUC Distribution's resources and it would lead to unaffordable increase in retail rates.

Given that the highest priority concern from almost all customer engagement activities is the high cost of electricity bills and an increasing worry over affordability followed by the importance placed on reliability and customer communications, our challenge is to seek an optimized balance of these somewhat opposing factors. Therefore, in preparing this DSP, PUC Distribution has focused on prioritizing the investments into renewal of the most critical infrastructure components, to achieve the balance required between keeping the power supply reliability from degrading while maintaining the electricity distribution rates at affordable levels. Advanced technology will be incorporated in system design selectively, where benefits outweigh the costs, during implementation of asset renewal projects, to meet the current and future needs of the customers, to improve operating efficiency and to support the integration of renewables and smart grid technologies.

The capital investment plan is discussed in detail in Section 4, but a summary of the proposed investment is presented in Table 2 below to provide context as to the level of proposed investment under each category:

Table 2: Proposed Capital Investments During the DSP Implementation Period

	2017	2018	2019	2020	2021	2022
System Access	$ 1,271,457	$ 1,511,028	$ 1,615,276	$ 2,086,480	$ 1,603,804	$ 1,560,434
System Renewal	$ 3,372,227	$ 3,761,033	$ 6,905,898	$ 3,296,444	$ 4,532,889	$ 7,092,642
System Service	$ 38,236	$ -	$ -	$ -	$ -	$ -
General Plant	$ -	$ 86,294	$ 54,629	$ 61,932	$ 59,853	$ 55,100
Total Capital Expenditure	$ 4,681,920	$ 5,358,355	$ 8,575,803	$ 5,444,856	$ 6,196,546	$ 8,708,176
System O&M Expenditure	$ 5,856,582	$ 6,212,629	$ 6,305,819	$ 6,400,406	$ 6,496,412	$ 6,593,858

Although a majority of the investments proposed in this DSP fall in the System Renewal category, the overall capital investment plan incorporates investment to the appropriate degree in each of the four general categories: (1) System Access; (2) System Renewal; (3) System Service and (4) General Plant.

The planned investments into System Access are intended to facilitate modest anticipated growth to allow connection of new customers to the grid, meeting requests of existing customers for increase in service size and meeting PUC Distribution's regulatory obligations for relocating distribution lines when requested by the municipality and for re-calibration and renewal of the revenue meters in compliance with the Measurement Canada regulations. The indicated investments in the System Access category represent net expenditure by PUC Distribution, after third party contributions have been subtracted from the total cost.

The planned investments into System Renewal are intended to mitigate a number of specific prevailing risks to distribution system reliability, public safety and adverse environmental impacts, due to very poor condition of some key assets, the in-service failure of which would lead to severe consequences.

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds, line rebuilds and SCADA and protection upgrades, will also introduce smart grid features, including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve multiple roles: System Access and System Service in addition to System Renewal.

PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover minor building renewal items. The scope and timing of the investments in each category has been determined by taking into account all information available at the time of preparation of the distribution plan.

System Access

The planned investments in the System Access category include expenditure required by PUC Distribution to meet its regulatory obligations. These investments consist of four main components:

- new subdivisions, new services and upgraded services to meet customer needs;
- line relocations required in conjunction with municipal road reconstruction programs;
- investments to add new meters and maintain existing revenue meters compliant with regulations; and
- "make-ready work", related to joint use applications by 3rd party telecommunications companies.

During the past five years, demand for new services has been relatively flat and there has not been a significant change in the number of customers served by PUC Distribution. There was modest growth in residential subdivision development in PUC Distribution's service territory, during 2012 and 2013, but extremely limited subdivision development activity took place from 2014 to 2016. During the past three years, demand for new services in existing subdivisions has also decreased moderately likely due to the economic difficulties encountered by the steel industry, which remains the major driver of local economy in PUC Distribution's service territory. At present, there is no backlog of customers requiring new services within PUC Distribution service areas.

A modest recovery in the local economy is anticipated during the next five years, primarily driven by macro-economic factors, resulting in a small increase in requests for new services from the existing levels. Discussions with developers indicate minimal growth in 2017 and modest growth in 2018 and 2019. There are presently two residential subdivision developments being planned for 2018 and 2019, and these will require capital investments in System Access category to meet the requests for new services.

Road reconstruction projects undertaken in the municipality require relocation of some power distribution lines, requiring capital investments by PUC Distribution, from time to time. PUC Distribution has employed the City's 5-year development plan to estimate capital expenditure required for line relocates and rebuilds to accommodate municipal infrastructure projects. The municipal development plans are subject to change, so there is some risk that the actual required expenditure in this category may be different from the amounts indicated in the DSP.

All existing residential and general service customers (< 50 kW) were equipped with smart meters between 2009 and 2010. PUC Distribution owns approximately 33,500 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption and demand of connected load for the purpose of billing. PUC Distribution plans to sample 600 meters in 2019, 200 in 2020 and 80 in 2021 all in accordance with Measurement Canada's "S-S-05—Performance Requirements Applicable to Meters Granted a Conditionally Lengthened Initial Reverification Period under S-EG-01" - sample its meter population to acquire an extension of up to 8 years. In addition, revenue meters will also be required to replace meters failed in service and based on the historic experience, the failure rate of revenue meters is expected to be approximately 0.6% per year. PUC Distribution is also required to equip all general service customers with >50kW to <500kW demand with MIST meters.

There are also steady requests from communication network companies that share PUC Distribution's network for "make ready work" and flow of such requests is anticipated to continue at the same pace. However there exists the possibility for an extremely significant demand change with relatively short notice as was experienced in the previous rate application period due to a 'fibre to the home' project that covered a large portion of PUC Distribution's system. The System Access category investments, therefore, also includes an allowance for the net contribution required from PUC Distribution.

System Renewal

PUC Distribution engaged METSCO Energy Solutions in 2016 to perform a comprehensive condition assessment of all distribution system assets and develop an asset management plan to mitigate risks associated with in-service failure of assets. The asset condition assessment, included in Appendix B, provides detailed results of the asset condition assessment initiative completed in 2016.

As described in greater detail in Section 3.2.3, those assets, the condition of which has already reached a state of impairment that they present a very high risk of failure in service are assigned "very poor" condition and those assets with significant impairment causing performance to degrade below acceptable level and presenting a high risk of failure in service in the absence of major repair or rehabilitation or renewal, are assigned "poor condition".

The scope of capital investments planned in the System Renewal category has been determined with the objective of keeping power supply reliability from deteriorating below an acceptable level. In order to keep the overall investment envelope for this DSP within a range, which would not result in retail rates escalations beyond the affordability of PUC Distribution's customer base and which could be successfully implemented without stretching beyond limit PUC Distribution's financial resources; investments required for renewal and rehabilitation of the assets found in "very poor" or "poor" condition have been spread out over a time period of longer than five years and assets with highest consequence of failure in service, have been prioritized for renewal or rehabilitation, during the next five years. Prioritized investments into asset renewal and rehabilitation included in this DSP are summarized below:

Due to the advanced service age, combined with "poor" and "very poor" operating condition of a vast majority of the power transformers, switchgear, protection and control equipment and other miscellaneous assets employed at both of the 115/34.5 kV transformer stations (TS-1 and TS-2), both stations require complete rebuilds with new power transformers, switchgear, protection and control equipment. However, rebuilding of these two transformer stations requires significant front-end planning and engineering to comprehensively assess all available alternatives with the objective of selecting the optimal alternative for re-development. Each of these stations employ equipment redundancies in their design, each station with four power transformers, which presently allows PUC Distribution to manage the reliability risk even during an 'N-1' contingency. Therefore, this 5-year DSP does not include funding to cover the construction cost of these two transformer stations, but includes capital investment required to perform a planning and engineering study to review all practical development options through completion of conceptual designs to identify the optimal station development alternative, for implementation during 2023 to 2027. Refurbishment options are not feasible as asset deterioration is broad-based at these two sites. Current observations indicate that a significant 'total rebuild' capital investment will need to be made to fully address the matter at least at one of the two sites during

2023-2027 rate application period and at the second during either that same or the subsequent 5-year period.

The condition of the power transformers and switchgear at seven of the twelve existing 34.5/12.5 kV as well as both remaining 4.2 kV distribution stations has been determined to be in “poor” or “very poor” condition. This DSP includes funding for upgrade of the distribution lines supplied from the 4.2 kV stations to 12.5 kV stations, which would allow the last remaining 4.2 kV stations to be retired from service after the voltage upgrade of distribution lines has been completed. It also includes provision for rebuilding two distribution stations during the five-year implementation period; one of which will replace both the 4.2 kV stations and the second will replace one of the existing 34.5/12.5 kV stations. These distribution station rebuild projects have been prioritized by taking into consideration the relative risk of equipment failures and the anticipated consequences of equipment failures on supply system reliability, public safety and operating costs. Subsequent to station renewal in this DSP and the recent retirement of Substation 14, five distribution stations will remain for inclusion in the renewal program during the next two DSP periods (2023 to 2032).

For the two transformer stations and the distribution stations found in “poor” or “very poor” condition but not included in the renewal program in the current DSP, PUC Distribution plans to manage the risk of equipment failures through proactive monitoring and testing of equipment. Accordingly, this DSP includes funding for proactive repair, refurbishment and component replacement activities as an outcome of station inspections as well as to address unplanned equipment failures. Annual funds budgeted are based on the past 5 years expenditures and are intended to maintain system reliability at current levels. In the event of a major equipment failure such as the loss of a distribution station or feeder, contingency plans are in place to ensure that load can be readily transferred to an alternate supply while repairs or replacements are completed. This risk based refurbishment strategy allows PUC Distribution to minimize expenditures over the life cycle of the assets, while meeting targeted performance levels including system reliability.

PUC Distribution’s primary overhead distribution network employs approximately 391 km of 3-phase and approximately 230 km of 1-ph lines. Approximately 28.5% of the overhead lines will reach the end of their typical useful life during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors. However, rather than proposing re-construction of all overhead lines that have reached the end of their design life, this DSP includes a small subset of the lines, prioritized for renewal based on the risk of failure in service. The lines included for renewal in this DSP have been prioritized by considering the impact of critical component failures on public safety, supply reliability and operating costs. Accordingly, in this

DSP priority for line re-construction has been given to: (a) replacement of poles in "very poor condition, (b) line sections built with restricted conductor, and (c) line sections determined to be in "very poor" condition and currently operating at 4 kV, which will undergo voltage upgrade upon reconstruction.

Copper and aluminum conductors with smaller cross-section area, and more specifically #6 AWG and #4 AWG (copper or aluminum) conductors have lower tensile strength in relation to larger conductors typically used in overhead line construction. Under tension, the tensile strength of these smaller cross-section conductors further degrades with service age. These conductors are known to fail in service and when they fail it creates a very serious safety risk for public when live conductors fall to the ground. #6 and #4 AWG conductors are no longer used for applications requiring conductor tensioning over full spans, and virtually all Canadian utilities have adopted programs to proactively phase out lines built previously with restricted conductors.

PUC Distribution had identified approximately 8 km of 3-phase lines and approximately 60 km of 1-phase lines on its distribution network, constructed with restricted conductors and adopted a program to phase out restricted conductor lines starting in 2010. Up to the end of 2015, approximately 26% of the lines with restricted conductor had been phased out. Work on reconstruction of the remaining lines with restricted conductor is scheduled to continue during this 5-year DSP, with a target date of 2027 for complete elimination of all restricted conductor lines from the network.

There are approximately 12,600 wood poles and about 80 other types of poles (including steel, concrete and fiberglass) employed on PUC Distribution's overhead lines. In 2016, approximately 328 poles had reached the service age of more than 60 years and an additional 857 poles had reached the service age more than 50 and less than 60 years. Wood poles experience degradation in strength due to wood decay with service age, but the relationship between pole strength and service age is not linear. In order to identify poles in "very poor" condition PUC Distribution periodically conducts in-situ testing of poles and these poles are then targeted for replacement. This DSP provides funding for annual renewal of approximately 30 poles determined to be in "very poor" condition.

Overhead lines employed on the 4 kV distribution system are the oldest infrastructure components on PUC Distribution's power supply network. Most of these lines have reached a service age of 50 or 60 years, well past their design life and they present the highest risk of failure in service. PUC Distribution has been gradually removing the 4 kV lines from its network by rebuilding the lines with voltage upgrades to 12.5 kV. This DSP provides funding for the voltage upgrade program with a target date of 2022 for completion of the program.

Because the planned overhead line renewal programs described in paragraph (iv), (v) and (vi) above target a sub-set of the overhead lines determined to be in "poor" or "very poor" condition, it is expected that some line sections would experience failures during storms and require emergency repairs to restore power. Therefore, this DSP includes funding to perform emergency repairs and refurbishment upon line failures in service.

For overhead distribution transformers, a “run to failure” strategy is proposed, where a transformer is replaced only after failure. This DSP includes investments to replace distribution transformers after they fail. Current PCB regulations in Canada permit the use of distribution transformers containing PCB content in oil of up to 50 parts per million and this use can continue up to December 31, 2025. All distribution transformers must be below 50 parts per million after December 31, 2025. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1984) for PCB content and replace those containing PCBs above the threshold, or (b) replace all suspect transformers (purchased prior to 1984). This DSP includes budgetary provision for testing suspect distribution transformers for PCB content but replacing transformers that fail the PCB test have been deferred to beyond 2022.

The underground distribution network at PUC Distribution employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase and 2-phase cable circuits. Approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems; generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service age are considered in poor condition. This DSP includes funding for proactive replacement of only a part of underground cables determined to be in very poor and poor condition, with priority given to direct buried cable circuits as well as in voltage conversion areas. However, it is expected the underground cables will require more significant ‘ramping up’ of investment beyond 2022 to keep the failures rates at acceptable levels.

Most of the cables employed on 4 kV system are past their 40-year typical useful service life and these cables are planned to be removed from service when these service areas are upgraded to 12.5kV.

For switching of underground circuits, PUC Distribution Inc. employs live-front pad-mounted switchgear as well as K-bar junction boxes. Based on the service age and visual inspections, five of the pad mounted switchgear units and 89 of the K-bar units were determined to be in poor or very poor condition in 2016. This DSP includes funding for the replacement of two pad-mounted switchgear units but no funding for renewal of the K-bar units. Upon renewal, the live front switchgear will be replaced with dead front switchgear, providing enhanced worker safety.

PUC Distribution's underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. Approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate a large percentage of these old vintage chambers are functionally obsolete. The submersible transformer vaults and splice vaults present a challenge in that outages are required to safely complete maintenance work thereby increasing costs and inconveniencing customers. Accordingly, funds have been included to make progress in the replacement of these vaults.

System Service

Because the existing plant has adequate capacity without any constraints to allow connection of new loads and generation from renewables during the next five years, this DSP does not include investments to mitigate capacity constraints.

General Plant

Approximately 5 years ago PUC consolidated all of its administrative offices and operational buildings into a newly constructed integrated facility and the retired aging facilities were put up for sale. For the most part the new facility is in excellent condition and meets all functional needs so only minimal incremental building infrastructure investments have been considered in this DSP. The entire motor vehicle fleet used for operations is owned by PUC Distribution Inc.'s non-regulated affiliate services company PUC Services Inc. Consequently, a modest level of capital investment for building improvements and refurbishment is required in this area. Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

Key Benefits of Investments

The capital investments planned for the 2018 to 2022 period are expected to yield the following benefits:

The investments into System Access category would allow PUC Distribution to meet its obligations to serve new customers, relocate lines in public right-of-way, upon receipt of requests for such services, perform "make ready" work for allowing third party attachments of electricity distribution poles and to have adequate supply of revenue meters to comply with the requirements of the Distribution System Code and Measurement Canada.

The investments into System Renewal will reduce the risk of critical assets' failure in service and help sustain the reliability at acceptable levels and ensure public safety. These investments will also help avoid an increase in operating costs by eliminating the increase in extent of emergency repairs upon asset failures. Retiring from service the distribution system infrastructure operating at 4 kV will eliminate duplication in spare part requirements and will result in improved operating efficiency.

Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

2.1.2 Sources of Cost Savings Derived from Good Planning

Sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution [5.2.1 b]

Cost savings have been considered through good planning and will be achieved through execution of this distribution plan:

Through careful evaluation of the risks, projects are prioritized for implementation to mitigate higher level risks during this DSP implementation period, while deferring the projects with lower level risks or risks that can be managed through alternative cost-effective mitigation measures. For example, although equipment at both of the transformer stations has been determined to be in poor and very poor condition, due to redundancy in their design, it has been possible to defer the approximately $25 million of the required investments for their rebuild. All practical options will be explored through a comprehensive planning and engineering study to identify the optimal station development alternative with highest economic value, for implementation. Subsequent to the implementation of this DSP, approximately $22 million of investments required for redevelopment of the five remaining distribution stations, where the equipment has been determined to be in poor condition has been deferred and priority has been given to address only the stations where incidents of equipment failure present risk of the highest consequence. In case of the underground distribution system, cables in direct buried configurations present higher risk upon failure in relation to cables installed in duct and therefore have been a given a priority in the cable renewal program and the required investments for renewal of cables in poor condition but installed in duct have been deferred. Cost savings derived from these initiatives have not been quantified because the value is based on the frequency and severity of equipment end of life failures, variables which are not measurable. However it is reasonable to expect that the 'bathtub curve' effect for reliability relied upon in asset life cycle planning across many industries is applicable in the case of these assets and that they are presently reaching the end of their cycle.

The reliability improvements through investments into infrastructure renewal will yield cost savings for customers through avoided power interruptions. Also, the deferral of investments, where possible, will yield savings in interest and depreciation costs, which will help reduce escalation in retail rates. Estimates of the deferred capital expenditures are provided in paragraph (a) above. PUC Distribution is unable to quantify the customer savings due to capital deferrals and also from avoided power interruptions at this time because customer reliability valuation surveys have not been performed.

Investments into System Renewal will reduce the number of in-service failure of assets and thus reduce the risk of emergency repair costs from going up. Considering the poor and very poor condition of infrastructure, in the absence of the investments proposed under System Renewal in this DSP, the emergency repair costs are expected to accelerate during the next five years.

Investments into infrastructure renewal will reduce the number of catastrophic equipment failures causing damage, the potential for injury to the public and reduce the risk of third party claims against PUC Distribution. It is impossible to predict the quantity of equipment failures that will result in third party claims and any associated costs or savings.

Proposed investments into General Plant will ensure efficiency of operations and reduce the risk of operating costs from going up. No savings are expected to result from this investment category but are expected to maintain worker productivity and work place safety at required levels.

2.1.3 Period Covered by DSP

Period covered by the Distribution System Plan (historical and forecast) [5.2.1 c]

This DSP covers a 5-year forecast period from 2018 to 2022. It includes historic financial expenditure for five complete years (2012 to 2016) and historic operating performance of PUC Distribution from 2012 to 2016.

2.1.4 Vintage of Information

Vintage of information on investment drivers used to justify investments identified in the application [5.2.1 d]

The Asset Management Plan as presented in Appendix B was finalized on September 30, 2016. This DSP is premised upon information contained in that document and is supplemented with additional information available from asset renewal projects completed as of September 30, 2017.

2.1.5 Important Changes to the Distributor's DSP

Indication of important changes to the distributor's asset management processes (e.g. enhanced asset data quality or scope; improved analytic tools, process refinements; etc.) since the last DS Plan filing [5.2.1 e]

This is PUC Distribution's first DSP under the new filing requirements. The methodology employed to support the level of investments and prioritize the investments into specific project categories differs from the methodology used in PUC Distribution's previous submission to OEB, in the following ways:

Enhanced Methodology

- The methodology used for prioritizing investments in this DSP, employs an objective, risk-based approach, which results in determining the scope and timing of investments to match the level of risk intended to be mitigated through the investment. To achieve improvements in this area over previous methodologies, Engineering resources were focused to a greater extent on developing associated programs and plans in areas including voltage conversion, restricted conductor replacement and station rebuilds.

- For evaluation of the risk associated with aging assets, all available data relevant to the present condition of assets, i.e. demographic information, results of field inspections and in-situ testing has been used. This methodology has been enhanced by including better quality and more extensive asset condition data collected over the past five years.

New Methodology

- The methodology used for investment planning in this DSP integrates customer preferences and creates an optimal balance between the service levels provided by the distribution assets and the cost of services, meeting customers' needs of reliable power supply at affordable prices. The previous asset management plan did not consider customer feedback through a formal customer engagement process.

2.1.6 Interdependency of DSP to Ongoing Activities or Future Events

Aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional planning process) or event (Board decision, LTLT) and the expected dates by which such outcomes are expected or will be known [5.2.1 f]

None of the investments proposed in the DSP are contingent upon the outcome of ongoing activities or future events. The level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of stakeholder requests received for services, but such deviations are expected to be minor and the overall expenditure level during the next five years is not expected to be significantly different from what is proposed in this DSP. Since none of the investments involve addressing constraints in the transmission system or upstream distribution system and since there are no embedded distributors served from PUC Distribution's distribution system, the regional planning process has no impacts on this distribution plan and proposed investments.

2.2 Coordinated Planning with Third Parties [5.2.2]

Before preparing this DSP, PUC Distribution has consulted with all stakeholders affected by the DSP, with the objective of accurately assessing their needs and to confirm the adequacy of existing capacity of the distribution system; so that the investments could be focused into areas of the greatest need. The results of coordinated planning with third parties are documented in this section, by addressing the following questions for each consultation:

- the purpose of the consultation;
- whether the distributor initiated the consultation or was invited to participate in it;
- the other participants in the consultation process;
- the nature and prospective timing of the final deliverables, that are expected to result from or otherwise be informed by the consultation; and
- an indication of whether the consultation has or is expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.

This distribution plan has been prepared through a coordinated planning process with all major stakeholders. The stakeholders consulted by PUC Distribution during preparation of the DSP include:

- customers;
- municipal governments;
- CDM program partners; and
- OPA/IESO

2.2.1 Description of Consultations [5.2.2 a]

2.2.1.1 Customer Engagement

Purpose of Consultation

PUC Distribution conducts customer consultations to gather customers' opinions related to its services and to ensure that the customers' needs and preferences are taken into account during development of long term plans. PUC Distribution has conducted both formal and informal community engagement activities with its customers over the last five (5) years.

Who Initiated the Consultation?

All consultations with the customers were initiated by PUC Distribution, either through its own staff or through consultants.

Other Participants in Consultations

Other participants included residential and general service customers.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are included in the form of stand-alone reports in Appendix C and Appendix H.

Consultations Impact on this DSP

Customer feedback has been integrated into the preparation of this DSP. While a vast majority of PUC Distribution customers are fully satisfied and pleased with the power supply reliability, a majority of the customers are also sensitive to an increase in retail rates. Customer sensitivity to the retail rate increases has been taken into consideration in this DSP, by accepting some risk of asset failures in service and by deferring a number of projects in the asset renewal category and only including a relatively small number of projects in the current investment plan, which present the highest risk of asset failures during the next five years.

Brief Description of Customer Engagements

PUC Distribution believes that customer engagement is the backbone of its community-driven operations. PUC Distribution recognizes that providing opportunities for customers to share their feedback will not only strengthen their relationship with them, but also, improve the overall customer experience.

As a local distribution company (LDC), PUC Distribution understands that its role in planning for the future of the electrical distribution system involves more than just measuring equipment service life. It requires including customers in the planning process to ensure that they have considered their needs and preferences when it comes to developing long term plans. To that end, PUC Distribution is committed to growing and expanding on the success of its existing community service and customer engagement initiatives.

PUC Distribution has increased formal and informal community engagement activities with its customers over the last five (5) years. Those engagement opportunities identified a number of customer needs and preferences, along with room for improvements to be made. The areas identified that needed the most attention included improving customer communications, increasing customer consultations, maintaining or improving reliability and growing energy literacy in the community. Although many new ideas continue to be explored we have successfully implemented a number of improvement initiatives over the past five years that have been directly related to customer feedback and expectations.

2.2.1.2 Municipal Government Consultations

Purpose of Consultation

PUC Distribution interacts with the City of Sault Ste. Marie administration to coordinate infrastructure planning within its service territory, so that new connections to customers can be connected in a timely manner and projects involving line relocates to facilitate road reconstruction projects can be planned. PUC Distribution staff attends formal meetings with the City and other municipal stakeholders and local utilities, annually, to review budgets and work plans for the coming year and the coming 5 years. Other 'ad hoc' coordination sessions occur on an 'as needed' basis with the city and development stakeholders to look for synergies on specific projects and initiatives such as subdivision, commercial and institutional developments

Who Initiated the Consultation and Other Participants?

The annual coordination meetings are generally initiated by the City's administration and PUC Distribution along with other utilities participating in them. For large developments in the city, PUC Distribution is invited to Development Assistance Review Team (DART) meetings on a regular basis early in the planning stage. Additionally, PUC Distribution is included and invited to comment on all rezoning, severance and building applications allowing PUC Distribution to identify requirements early in the development stage.

Other Participants in Consultations

Other participants include general service customers, developers, other utilities including gas and telecommunications.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are in form of the development information such as plans and associated schedules, which are received during the meetings.

Consultations Impact on this DSP

The information obtained from the municipality has been used to identify investment level requirements in the System Access category, proposed in this DSP (subdivisions, joint use and general services).

2.2.1.3 Consultations with CDM Program Partners

Purpose of Consultation

The purpose of PUC Distribution's consultations with energy conservation and demand management (CDM) program partners is to implement the province of Ontario's policy on energy conservation and peak demand reduction on the electricity grid.

Who Initiated the Consultation and Other Participants?

PUC Distribution participates in periodic consultations initiated by IESO and also initiates consultations with its customers to promote and encourage energy conservation and identify and implement opportunities for demand management.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are the leads for specific CDM opportunities, which are then pursued by PUC Distribution for implementation.

Brief Description of the Consultation

PUC Distribution has been offering IESO (formerly OPA) prescribed save-ON-energy CDM programs since 2011. As per the Minister of Energy's directive on Conservation and Demand Management dated March 31, 2014, PUC Distribution collaborated with CustomerFirst, a group of local distribution companies (LDCs) that have submitted a joint plan to the IESO under the new conservation framework.

PUC Distribution is committed to helping its customers understand their energy usage and reduce their environmental footprint by offering programs that enable them to become more energy efficient. PUC Distribution has a conservation target of 26.4 Gigawatt hours by the end of 2020. Results for 2016 show progress of 55% towards that target. This achievement was made possible through on-going consultations with customers, prompting a strong participation by PUC Distribution's commercial and industrial customers in retrofit and energy auditing programs. Residential customers also participated in sufficiently large numbers in saveONenergy coupon events opting to replace lights in their homes to more energy efficient ones, as well purchasing other energy efficient equipment. PUC Distribution's collaborative efforts with the residents and business owners within its service territory made the achievement of substantial energy savings possible. Notable projects include the conversion of the City's street lighting system from HPS to LED, not only in Sault Ste. Marie but also Prince Township and Batchewana First Nations. Municipal parking lots followed suit with upgrading their parking lot lighting to LED, while small businesses began changing their florescent lamps and incandescent bulbs to efficient LED tubes and lamps.

As a member of CustomerFirst, PUC Distribution is part of a joint Conservation (CDM) Plan that has been approved by the IESO. The joint plan will achieve 141,877 MWh of savings which is equal to the combined targets that were allocated to each CustomerFirst member under the new framework. Through the CustomerFirst joint CDM Plan, PUC Distribution will continue to work collaboratively with the other CustomerFirst utilities to find efficiencies and reduce costs. The group will be sharing resources and working together in all areas of CDM including sales, marketing, customer and project support to provide value to ratepayers.

PUC Distribution remains committed to providing its customers with cost effective conservation programs to help them save electricity and lower their electricity bills. PUC Distribution will continue to innovate new ways to promote and support customers in reducing their consumption today and for the future. The CDM program has been effective in curtailing the rise in peak demand on the distribution system and this is one of the reasons why no investments are needed in the System Service category. In order to more effectively engage the residential customers into energy conservation programs, the effort will result in a slight increase in O&M expenditure from prior years' spending levels.

PUC Distribution actively participated in the saveONenergy CDM programs from 2011-2014, which were extended into 2015 to allow transition to a new 6-year framework. In complying with the Minister of Energy's directive on Conservation and Demand Management dated March 31, 2014, PUC Distribution collaborated with CustomerFirst, a group of LDCs, to submit a joint plan to the IESO to reduce peak demand under the new conservation first framework. As a member of the CustomerFirst LDCs, PUC Distribution continues to participate in evaluation of the conservation delivery, its impact of anticipated load growth as well as evaluation of the benefits of collaboration with LDCs in the partnership. Based on the results of customer consultations, a higher emphasis on residential conservation programs will be placed in the future, as the previous framework provided limited opportunities for energy conservation by the residential customer class.

Consultations Impact on this DSP

The consultations with CDM Program Partners have helped the peak demand on PUC Distribution's grid from increasing, and as a result the need for any associated investments has been avoided in this DSP.

2.2.1.4 IESO Consultations

Purpose of Consultation

The purpose of these consultations is to share information with IESO to facilitate and coordinate the connection of REG connections.

Who Initiated the Consultation and Other Participants?

The consultation was initiated by PUC Distribution in conjunction with preparation of this DSP. A renewable generation (REG) plan was prepared by PUC Distribution and submitted to IESO. IESO reviewed the REG plan and provided a comment letter.

Nature and Timing of Final Deliverables

PUC Distribution prepared and submitted the REG plan to IESO for review in November 2017. IESO provided a comment letter in December upon completion of its review, which is included in Appendix D.

Brief Description of the Consultation

PUC Distribution has been conducting communications in relation to the existing distributed generation connections connected to its network under OPA's RESOP, FIT and micro-FIT contracts as well as new applicants wishing to connect new renewable generation plant to PUC Distribution's network.

PUC Distribution has been a leader in actively promoting and facilitating Ontario's Green Energy program, which has resulted in the City of Sault Ste. Marie acquiring the title of the Alternative Energy Capital of North America. PUC Distribution has solar generation contribution of approximately 63MW connected to its distribution system, which results in near zero or net export conditions during their peak producing summer months when the distribution network is near its minimum load.

PUC Distribution has also worked closely with IESO in the integration of bulk energy storage on the grid. In April 2014, a private developer approached PUC Distribution to explore the possibility of connecting a 7MW/7MWh fast ramping energy storage facility to the provincial transmission system. The request was prompted by an IESO proposal call for such a project to be connected somewhere in the northeastern region. The facility was to be an experimental IESO venture to determine if bulk battery storage is an effective way to provide voltage stabilization and reactive power support in an environment with a relatively high ratio of renewable energy to traditional generation and a highly variable load/generation mix. PUC Distribution immediately recognized potential benefits for many stakeholders and developed terms of reference for a project to support connection at their St. Mary's transformer station TS1. The project proceeded successfully and the facility was put into operation in the fall of 2017.

To make the distribution grid more friendly to distributed generation and to provide customers greater access and control on their energy usage, PUC Distribution is also implementing affordable initiatives for smart grid development in a phased manner, to improve the stability and reliability of renewable generation connections and to meet customers' future needs. All of the customers have been equipped with smart meters. As the assets in existing distribution stations reach the end of their service life, during rebuilding of the distribution stations, modern automated switching and SCADA controlled devices are incorporated in the design.

Impact of the Consultation on this DSP

Because no constraints have been identified in PUC Distribution's grid preventing connection of renewable generation (REG) to the distribution grid, the consultations with IESO have not resulted in any investments proposed in this DSP to facilitate REG connections.

2.2.2 Regional Planning Process [5.2.2 b]:

Purpose of Consultation

The purpose of this consultation was to facilitate transmission system planning by identifying critical infrastructure needs of the transmission grid during the next 10 years from 2014 to 2023

Who Initiated the Consultation and Other Participants?

This consultation was initiated by the Hydro One Sault Ste. Marie LP (H1 SSM) (previously Great Lakes Power Transmission (GLPT), the lead transmitter. All electricity distributors in the region participated in the consultation as well as the IESO and OPA.

Nature and Timing of Final Deliverables

The final deliverable of this consultation was the Regional Infrastructure Planning Report, which is included in Appendix E.

Brief Description of the Consultation

PUC Distribution belongs to the "East Lake Superior Region (ELS-Region)", for which Hydro One Sault Ste. Marie LP (H1 SSM) (previously Great Lakes Power Transmission (GLPT) is the lead transmitter and primarily responsible for steering the regional planning in this region.

In response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013, regional infrastructure planning was triggered by H1 SSM on October 12, 2014 and was completed on December 12, 2014. PUC Distribution participated in the planning process and provided required data to H1 SSM. The scope of this planning initiative was to identify critical infrastructure needs of the transmission grid during the next 10 years from

2014 to 2023. The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans. A copy of the Regional Infrastructure Planning report is attached in Appendix E.

The regional planning report concludes the existing transmission infrastructure in the region supplying the PUC Distribution's supply network has sufficient capacity and the circuit loading on all 115 kV circuits remain within the assessment criteria limits throughout the study period.

Impact of the Consultation on this DSP

Consultations with the transmitter did not lead to any impact on the capital investments proposed in this DSP.

2.2.3 IESO Comment Letter [5.2.2 c]

PUC Distribution's Renewable Energy Generation (REG) Plan outlining the plan to support connection of renewables and smart grid technologies for the period 2018-2022 was provided to IESO in December 2017. The plan indicates the PUC Distribution grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period. The IESO acknowledged that PUC Distribution's system shows no concerns caused by local or regional issues that should constrain additional growth of REG as projected. The plan and response letter are attached in Appendix D.

2.3 Performance Measurement for Continuous Improvement [5.2.3 a to c; 5.4.3a]

In order to continually improve its operating performance, PUC Distribution continually measures and monitors its performance. The performance indicators employed by PUC Distribution in measuring its operating performance have evolved over the years and these are currently fully aligned with OEB's "Scorecard – Performance Measures" for electricity distributors, as listed below:

1) service quality;

2) customer satisfaction;

3) safety;

4) system reliability;

5) asset management;

6) cost control;

7) financial ratios;

8) conservation and demand management; and

9) connection of renewable generation.

For each of the performance indicators listed above, PUC Distribution has adopted the standard measurement metrics, used by OEB in its "Scorecard – Performance Measures". For definitions of the performance measures, please refer to Appendix F. The OEBs first year requiring LDCs to submit scorecards was for 2013 with the corresponding Management Discussion & Analysis introduced in 2014. Accordingly, only scorecards for 2013 and forward have been included.

PUC Distribution's operating performance during five years from 2012 to 2016, as reported in the 2016 Scorecard, is summarized in the following sections:

2.3.1 Service Quality

PUC Distribution measures and monitors service quality to ensure continued improvement, to achieve a level satisfactory to its customers and in accordance with its core value of being responsive to customer needs. OEB's directive to measure and report on service quality is the motivation for service quality measurements. PUC Distribution has aligned its service quality indicators and their measurement metrics with those mandated by OEB.

PUC Distribution monitors its service quality by measuring the following service quality indicators: (a) new residential services connected on time, (b) scheduled appointments met on time, and (c) telephone calls answered on time. The key purpose for tracking this metric is to determine how well PUC Distribution is able to meet its customers' requests for service in a timely manner. As indicated in Table 3, PUC Distribution's has met the performance target for each performance metric during each of the past five years.

Table 3: Service Quality Performance

Service Quality Metric	Target	Actual				
		2012	2013	2014	2015	2016
New LV Connections (<700 V) on time	90.0%	95.8%	96.5%	93.0%	97.2%	98.9%
Meeting Scheduled Appointments on time	90.0%	98.4%	97.1%	95.4%	97.4%	98.3%
Telephone accessibility (Answering calls within 30 seconds)	65.0%	74.6%	80.9%	81.9%	82.3%	81.3%

As a minimum performance standard for the connection of new services, new low-voltage (< 750 volts) services must be connected within 5 working days from the day on which all conditions of service are satisfied, including electrical safety inspection.

As a minimum standard, when it is necessary to meet a customer at the customer's premises or work site to conduct utility business, customers must be offered a choice of morning or afternoon appointments. The appointments must be met at least 90% of the time. If the appointed time cannot be met the customer must be notified.

As a minimum standard, incoming calls to the general inquiry telephone number must be answered within 30 seconds, at least 65% of the time.

No new investments are proposed in this DSP in response to PUC Distribution's performance on this metric.

2.3.2 Customer Satisfaction

PUC Distribution measures and monitors its customer satisfaction level to ensure customer needs are clearly understood and responded to. OEB's directive to report on customer satisfaction levels is the motivation for customer satisfaction monitoring and reporting. PUC Distribution has aligned its customer satisfaction indicators and their measurement metrics with its core value of being responsive to customer needs and with those of the OEB.

Three different OEB defined metrics are employed for customer satisfaction measurement: first contact resolution, billing accuracy and customer satisfaction surveys. The first two performance indicators were introduced by OEB in 2014 and the third performance indicator - "customer satisfaction surveys" was introduced in 2015. The key purpose for tracking First Contact Resolution is to determine how effectively customers' concerns are resolved by PUC Distribution. The key purpose for tracking Billing accuracy is to monitor PUC Distribution's performance in preparing and presenting the electricity bills to its customers accurately. PUC Distribution's performance during the past three years is indicated in Table 4 and as shown PUC Distribution's performance exceeds the defined targets.

Table 4: Customer Satisfaction Performance

Service Quality Metric	Target	Actual				
		2012	2013	2014	2015	2016
First Contact Resolution	N/A	N/A	N/A	99.89%	99.92%	99.58%
Billing Accuracy	98%	N/A	N/A	99.83%	99.36%	99.97%
Customer Satisfaction Suvey	N/A	N/A	N/A	N/A	79%	80%

PUC Distribution’s First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Senior Customer Care Representative or Supervisor/Manager.

Accurate bills issued expressed as a percentage of total bills issued. It is calculated as: = (Total number of bills issued for the year – Number of inaccurate bills issued for the year) / Total number of bills issued for the year. This requirement must be met at least 98% of the time on a yearly basis.

PUC Distribution engaged a consultant to conduct our customer satisfaction surveys.

No new investments are proposed in this DSP in direct response to PUC Distribution’s performance on this metric.

2.3.3 Safety

PUC Distribution measures and monitors safety related to its infrastructure and operations with the objective of minimizing the risk of accidents and injuries. OEB’s directive to report on safety indicators is the motivation for monitoring safety performance. PUC Distribution has aligned its safety performance indicators and their measurement metrics with those mandated by OEB and consistent with its own core values.

Three different safety performance indicators are in use: level of public safety awareness, compliance with Ontario Regulation 22/04 and serious electrical incident index.

Table 5 summarises PUC Distribution’s safety performance over the past five years, based on compliance with Regulation 22/04 and serious electrical incident index. The third measurement metric for this performance indicator – “level of public awareness of electrical safety” was introduced in 2015 and performance levels for this metric are not available for years prior to 2015. The purpose for tracking Level of Compliance with Reg. 22/04 is to monitor PUC Distribution’s performance in complying with Ontario Regulation 22/04, which specifies the safety requirements to be met by Electricity Distributors in Ontario. The purpose of tracking Incident Index is to benchmark PUC Distribution’s performance in operating its distribution lines safely; the metric monitors normalized number of incidents involving safety violations.

To improve public safety of power distribution systems, Regulation 22/04 was introduced in the province of Ontario in 2005. Since that time PUC Distribution has participated, as required, in an annual audit to assess compliance with the regulation. The auditor provides an assessment of compliance using one of the four designations: i) C – complies, ii) NI – Needs Improvement iii) NC – Non-compliance, iv) N/A – not applicable. As shown in Table 5, PUC Distribution has been found to be compliant with Regulation 22/04 in each of the past four years.

The 2016 results pertaining to the Serious Electrical Incident Index show a marked improvement from previous years in each of the (a) number of general public incidents and (b) rate per 10, 100, 1000km of line.

Table 5: Safety Performance

Safety Performance Indicator		2012	2013	2014	2015	2016
Level of Public Awareness		N/A	N/A	N/A	86%	86%
Level of Compliance with Ontario Regulation 22/04		NI	C	C	C	C
Serious Electrical Incident Index	Number of General Public Incidents	3	1	3	1	0
	Rate per 10,100,1000 km of line	0.407	0.135	0.405	0.134	0.000

To improve the level of public awareness about electrical safety, PUC Distribution employs a number of programs, including periodic electrical safety discussions at schools and relaying electrical safety messages to public through radio and print media. To maintain compliance with Regulation 22/04, strict project management procedures are followed; ensuring distribution systems are designed and constructed following approved engineering standards, meeting all applicable codes. All distribution system infrastructure is systematically inspected and tested when required and plans for repair or renewal of assets presenting safety risks are prepared and implemented.

Infrastructure assets found in poor and very poor condition present a high risk of failure in service. Maintaining public safety and ensuring PUC Distribution continues to meet its obligation to comply with the safety regulations is a driver for many of the projects included in the System Renewal category. For example, the following material projects, summarized in Table 22 to be implemented during the test year are intended to improve both safety and reliability performance:

Projects #5, #6, #7, #8, #9, #10, #11, #12 and #13.

2.3.4 System Reliability

PUC Distribution measures and monitors the reliability of power supply to its customers with the objective of maintaining reliability levels meeting its customers' needs. OEB's directive to report on supply system reliability is the motivation for monitoring supply system reliability. PUC Distribution has aligned its reliability performance indicators and their measurement metrics with those prescribed by the OEB. Currently, two reliability performance indicators are tracked on the OEB score card: System Average Interruption Frequency Index (SAIFI) and

System Average Interruption Duration Index (SAIDI). PUC Distribution's targets and actual performance in terms of SAIDI and SAIFI are summarized in Table 6. The table indicates reliability performance under three scenarios:

(a) By including all power interruptions

(b) By excluding interruptions due to loss of supply (OEB was monitoring reliability performance in this format from 2013 to 2015), and

(c) By excluding interruptions due to loss of supply and major climatic events (OEB started monitoring reliability in this format in 2016).

"Major Events" are defined by OEB as the events beyond the control of the distributor and are uunforeseeable, unpredictable; unpreventable; or unavoidable. Such events disrupt normal business operation occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers.

The OEB has established targets for SAIFI and SAIDI, against which actual performance is measured by PUC Distribution. There are no established targets for CAIDI. Targets and results are illustrated in Table 6. The following serves to identify the methodology used by the OEB to establish the annual targets for SAIFI and SAIDI:

- For 2012 there were no established targets for SAIDI and SAIFI

- For the years 2013 and 2014: targets were set to achieve the range of the actual minimum and maximum values over the 2009 to 2012 timeframe, by excluding interruptions due to loss of supply; results were within or better than the prescribed limits;

- For 2015: targets were set based on the fixed 5-year average from 2010 to 2014, by excluding interruptions due to loss of supply; SAIFI was below the target and SAIDI was above; and

- For 2016: targets were set based on the fixed 5-year average from 2010 to 2014, by excluding interruptions due to loss of supply and major events; results were better than the targets.

Table 6: Reliability Performance

(a) With all power interruptions Included

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
SAIDI Actual	1.65	2.65	1.19	3.35	2.53
SAIFI Target	N.A.	N.A.	N.A.	N.A.	N.A.
SAIFI Actual	2.17	3.53	1.21	1.84	2.21
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.75	0.98	1.82	1.14

(b) With Interruptions due to loss of supply excluded

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	1.65-2.92	1.65-2.92	2.07	N.A
SAIDI Actual	1.65	2.48	1.19	3.35	2.46
SAIFI Target	N.A.	2.17-3.61	2.17-3.61	2.50	N.A.
SAIFI Actual	2.17	2.67	1.21	1.84	2.11
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.93	0.98	1.82	1.17

(c) With interruptions due to loss of supply and major events excluded

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	N.A.	N.A.	N.A.	1.86
SAIDI Actual	1.65	1.42	1.19	1.37	1.49
SAIFI Target	N.A.	N.A.	N.A.	N.A.	2.32
SAIFI Actual	2.17	1.78	1.21	1.03	1.41
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.80	0.98	1.33	1.06

- SAIDI = (Total Customer Hours of Interruptions – Total Customer Hours of Interruptions caused by Loss of Supply events)/ Average Number of Customers Served.

- SAIFI= (Total Customer Interruptions – Interruptions caused by Loss of Supply events) / Average Number of Customers Served

- CAIDI = SAIFI/SAIDI

As shown in Table 6, there is significant year over year variation in SAIDI and SAIFI performance over the past five years. Equipment failures in service have been the predominant cause of outages on PUC Distribution's supply network during the past several years. All of the investments included under System Renewal category, are aimed at replacing assets in very poor and poor condition, with priority given to renewal of those assets that present the highest risk of failure in service with most serious consequences. For example Table 22 shows the prioritized list of the material projects to be implemented during the test year. From that table, the following projects are intended to keep supply system reliability from degrading below the acceptable range:

Project #5, #6, #7, #8, #9, #10, #11, #12, and #13.

Out of a total of 13 material projects planned to be implemented during the test year, nine are aimed at preventing reliability from deteriorating through replacement of assets, determined to be at the end of their useful service life.   Considering the large impact of substation equipment and feeder trunk line failures on reliability, the risk of a prolonged power outage will remain on the horizon until renewal of all assets determined to be in poor or very condition has been completed.

2.3.5 Asset Management

PUC Distribution monitors the effectiveness of its asset management practices to ensure planned projects related to infrastructure renewal, refurbishment and maintenance aimed at preventing asset impairment in service and to reduce the risk of asset failures in service, are implemented as planned on a timely basis. PUC Distribution's corporate strategy to achieve success requires the sustainability of assets and systems. The corresponding 2018 objectives include the achievement of budgeted capital programs and is the motivation for monitoring this performance indicator. Furthermore, good asset management practices align with PUC Distribution's core value of being responsive to customer's needs including service delivery and system reliability.

To measure the effectiveness of its asset management program, PUC Distribution measures the system plan implementation progress by comparing work accomplishment to plan as well as the actual capital and operating expenditure against the budget, analyzing the reasons for variance and taking corrective action, when required.

Table 7 shows the program level variance in PUC Distribution's actual expenditure from its planned expenditure during the past five years. All amounts shown are net of contributed capital from customers.

Although no historical expenditures are indicated in the System Service category, a number of investments are grouped in the renewal category which is considered the primary driver. More specifically this includes station rebuilds, voltage regulation, reclosers, line rebuilds, SCADA improvements and protection upgrades. These upgrades introduced smart grid features, including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve multiple roles: System Access and System Service in addition to System Renewal which was the primary driver.

Table 7: Program Level Variance – Budget Vs Actual Spending

	2012			2013			2014		
	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual	Variance
System Access	1,132,235	7,938,036	6,805,801	1,068,766	2,310,000	1,241,234	2,957,353	2,531,753	(425,600)
System Renewal	6,042,853	4,821,060	(1,221,793)	6,525,051	6,082,921	(442,130)	3,813,022	3,753,603	(59,419)
System Service	-	-	-	-	-	-	-	-	-
General Plant	17,802,500	23,269,373	5,466,873	1,313,518	2,028,344	714,826	175,445	375,693	200,248
Total Capital Expenditure	24,977,588	36,028,469	11,050,881	8,907,335	10,421,265	1,513,930	6,945,820	6,661,049	(284,771)
System O&M Expenditure	6,259,122	5,852,889	(406,233)	6,153,732	5,992,120	(161,612)	5,529,970	5,773,408	243,438

	2015			2016		
	Budget	Actual	Variance	Budget	Actual	Variance
System Access	1,265,490	1,549,411	283,921	1,214,680	1,211,917	(2,763)
System Renewal	4,752,934	4,639,948	(112,986)	4,542,992	4,243,808	(299,184)
System Service	-	-	-	-	-	-
General Plant	68,653	66,532	(2,121)	0	82,630	82,630
Total Capital Expenditure	6,087,077	6,255,891	168,814	5,757,672	5,538,355	(219,317)
System O&M Expenditure	5,819,316	5,977,598	158,282	5,955,321	5,977,871	22,550

2.3.5.1 Variance Analysis - Capital Expenditure

Capital Expenditure Variations in 2012

Table 7 indicates that in 2012, the actual expenditure in the “System Access” category exceeded the budget by over \$6.8 million. This variation is related to the smart metering project – Although the installation work was physically substantially complete at the end of 2010, the costs were not capitalized until 2012.

The actual expenditure in “General Plant” category exceeded the budget by over \$5.5 million. This variation in expenditure is related to the construction of the new office building, which was budgeted in 2011, but most of the work on it was completed in 2012.

The variation of (\$1.2 million) in the “System Renewal” category was primarily due to delays experienced during the reconstruction of the 12kV substation Sub 10. Engineering resource constraints, equipment deliveries and poor winter weather were primary contributors to pushing completion of this project out into 2013.

Capital Expenditure Variations in 2013

Table 7 indicates that in 2013, the actual expenditure in the System Access category exceeded the budget by over \$1.2 million. This variance was primarily a result of the utility having to support a substantially large and unplanned for joint-use project for one of the major telecommunications companies sharing space on its overhead infrastructure. A significant volume of make-ready work was completed to allow them to attach their fiber optic cables on PUC Distribution overhead poles. The scale of the project also led to resource constraints so that some projects in the System Renewal were not completed.

The actual expenditure in General Plant category exceeded the budget by approximately \$720,000. This variation in expenditure was solely related to the construction of the new office building referred to above in 2012 for which a number of small remaining outstanding items and deficiencies were not completed until early 2013.

In the System Renewal category actual expenditure was less than the budget by approximately \$440,000. This was primarily attributable to resource constraints experienced due to the joint use fibre project discussed in the System Access category above.

Capital Expenditure Variations in 2014

In 2014, the variation in overall capital expenditure from the budget was insignificantly small – less than 4% of the budget.

The actual expenditure in the System Access category was less than the budgeted amount by about 14%. This was attributable to a combination of two factors. Firstly, continuation of the large joint-use fibre project (that was mentioned in the section above) started in 2013 was budgeted for in 2014. However, as the project progressed, circumstances changed for the telecommunications company and they canceled the project at approximately the half-way point. This had the effect of being significantly underspent on associated make-ready work. The second lesser impacting, but mitigating factor was higher than anticipated customer demand and the addition of City reconstruction projects that required additional infrastructure relocation.

In the System Renewal category, the actual expenditure was less than the budget by 2%.

The actual expenditure in General Plant category exceeded the budget by approximately $200,000. This variation in expenditure is related to the purchase and installation of furnishings, fit-ups and equipment (FF&E) for the newly constructed office building that were not anticipated at the time of budgeting the project.

Capital Expenditure Variations in 2015

In 2015, the overall capital expenditure exceeded the budget by approximately 3% and this variation was caused primarily by an overrun of $285,000 in the System Access category. PUC Distribution was required to relocate lines to facilitate municipal projects for which information was not available in advance of preparing the 2015 budget.

Capital Expenditure Variations in 2016

In 2016, the variation in overall capital expenditure from the budget was small – less than 4% of the budget.

In the System Renewal category, the actual expenditure was less than the budget amount by about 7%, primarily due to equipment failures, leaking transformers and deteriorated poles.

2.3.5.2 Variance Analysis for O&M Expenditure

As shown in Figure 2, the variations in annual O&M expenditure from the budget are rather modest, ranging from -6.5% to +4%. During 2012 and 2013, due to the unexpected increase in the System Access category of capital projects consuming the limited resources of PUC Distribution, some of the maintenance activities planned for 2012 and 2013 were deferred to 2014 and 2015, which resulted in the variance.

There is an overall 2.1% increase in actual O&M expenditures from $5.85 million to $5.98 million over the 2012-2016 period.

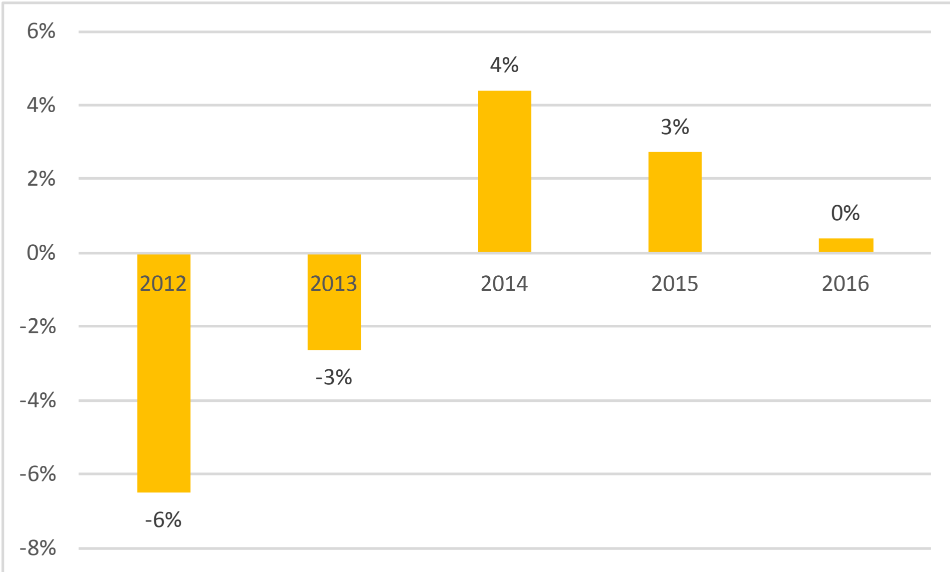


Figure 2: Variation in Actual O&M Expenditure from Budget

2.3.5.3 Initiatives to Reduce Project Variance in Future

Due to variability and uncertainty in the number of requests received for unplanned work under the System Access category, variance in actual expenditure from the planned amount cannot be eliminated. PUC Distribution intends to reduce such variances, through improved resource planning and project management.

A proactive project management approach was implemented between 2014 and 2016, to ensure continuous improvement in resource planning and project management on capital projects. Project and budget status meeting are held frequently throughout the year. Annual reviews are performed to identify reasons for variance and long-term corrective action is taken through implementation of or modification to existing processes and designs.

A review of the capital spending from 2014 to 2016 confirms that the recently implemented proactive project management initiative is yielding intended results with overall variances between -4% and +3%.

There are no capital investments proposed in this DSP related to PUC Distribution's performance on this performance measure.

2.3.6 Cost Control

PUC Distribution measures and monitors the cost efficiency for distributing electricity and serving customers within its service territory, with the purpose of benchmarking its recent performance and remaining economically efficient in the future. OEB's directive to measure and report on cost efficiencies as well as PUC Distribution's own vision and mission statements are the motivation for cost controls. PUC Distribution has aligned its cost control indicators and their measurement metrics with those prescribed by OEB.

PUC Distribution measures and reports on the following cost efficiency indicators, including its cost efficiency ranking among peers, total cost per customer and total cost per km of line; which are discussed here as follows:

2.3.6.1 Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs.

Table 8 summarizes the OEB rankings of the local electricity distributors based on cost efficiency in 2016:

Table 8: LDC Rankings Based on Cost Efficiency

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	14
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	32
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	13
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

In 2016, for the fourth year in a row, PUC Distribution was placed in Group 4. PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 14% in 2016 compared to 16.2% in 2015.

Included in PUC Distribution's operating, maintenance and administrative expenses is a charge from PUC Services that is based on depreciating and financing of the vehicles, tools, computer equipment, office equipment etc. that is utilized to provide services to PUC Distribution. For utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing costs. As the total costs would be the same, removing the depreciation and financing costs from PUC Distribution's operating costs would better align costs comparisons in the PEG model with other utilities. Projections for 2017 indicate that PUC Distribution would still be in Group 4 after removing the non-operating type costs from the PEG calculation. However, PUC Distribution's efficiency ranking improves to Group 3 in 2018 through to the end of the projection period in 2021 with the removal of the non-operating costs from the calculation.

PUC Distribution's target for 2018 is to improve efficiency performance in order to be rated as a Group 3 utility after the removal of the non-operating costs from the PEG calculation.

2.3.6.2 Total Cost per Customer

Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves. Figure 3 shows PUC Distribution performance during the past five years, based on total OM&A cost per customer.

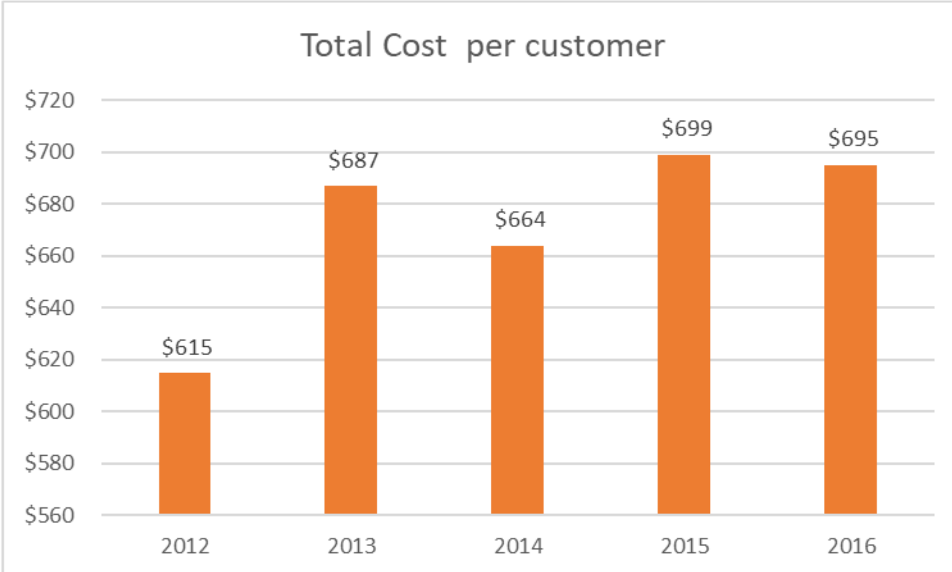


Figure 3: Operating Efficiency Performance (Total Cost per Customer)

Overall, the company's Total Cost per Customer has increased on average by 3.26% per annum over the period 2012 through 2016. For the period of 2013 to 2016, the Total Cost per Customer has increased by approximately 0.40% per year. The cost performance result for 2016 is $695 per customer which is a 0.57 % decrease over 2015.

PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2016 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

PUC Distribution's target for this metric in 2018 is $664 excluding the non-operating costs discussed above.

2.3.6.3 Total Cost per km of Line

This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. Figure 4 shows PUC Distribution's performance based on total Capital and OM&A cost per km and cost per customer.

Figure 4: Operating Efficiency Performance (Total Cost per km)

PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per km of line has increased an average of 3.45% since 2012 with the increase in capital and operating costs.

For the period of 2013 to 2016, the Total Cost per km of Line has increased by approximately 0.40% per year. PUC Distribution's total cost per km in 2016 was $31,314, which represents a 0.20% decrease over 2015. PUC Distribution's target for this metric in 2018 is $30,274 excluding the non-operating costs discussed above.

2.3.7 Financial Ratios

PUC Distribution measures and monitors the financial ratios for the business corporation, to ensure financial stability and economic efficiency to sustain its corporate operations in a responsible manner, providing services required by its customers in an effective and cost-efficient manner and providing a reasonable return on equity to its shareholders.

Monitoring and tracking these metrics both meets the OEB's directives pertaining to financial ratios and aligns with PUC Distribution Inc.'s own vision and mission statements.

PUC Distribution's financial ratios during the past five years are summarized in Figure 5 through Figure 7.

2.3.7.1 Liquidity: Current Ratio (Current Assets/Current Liabilities)

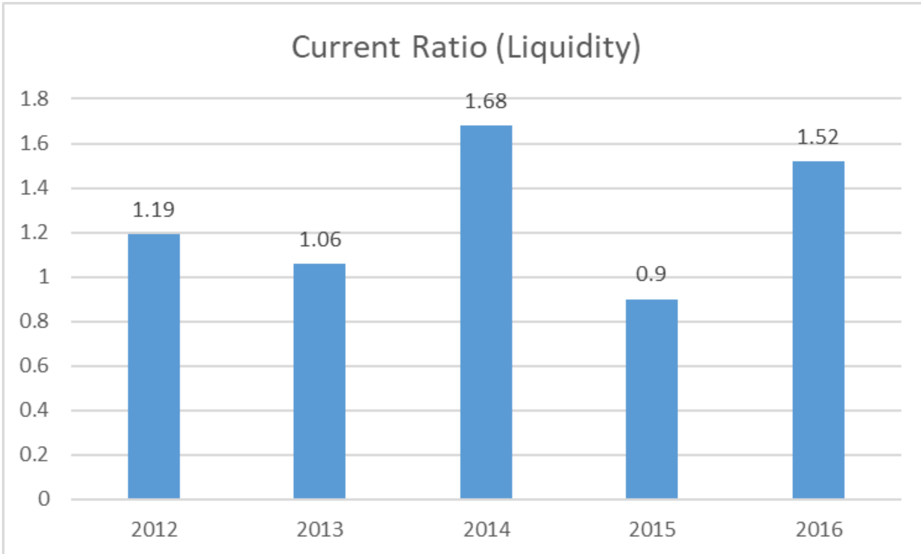


Figure 5: Current Ratio

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being “liquid”. The higher the number, the more “liquid” and the larger the margin of safety to cover the company’s short-term debts and financial obligations. PUC Distribution’s current ratio has increased from 0.90 in 2015 to 1.52 in 2016. By increasing over 1, PUC Distribution is in a good position to cover the company’s short-term debts and financial obligations.

2.3.7.2 Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring. PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2016 debt to equity ratio of 2.34. PUC Distribution’s long-range plan is to push the debt to equity towards the 60/40 level.

Figure 6 shows the overall debt/equity ratio and over the past five years PUC Distribution has maintained an average debt/equity ratio of 2.21. The following factors have contributed towards an increase in debt/equity ratio during the past five years:

- Reduced Return on Equity, since the last Cost of Service rate application in 2013, which has resulted in a lower equity position than anticipated.
- Loans from Infrastructure Ontario in 2013 (~$21 million) and 2015 ($15 million) have substantially increased PUC Distribution's long-term debt.
- PUC Distribution has a $26.5 million Note Payable to its parent (City of Sault Ste. Marie).

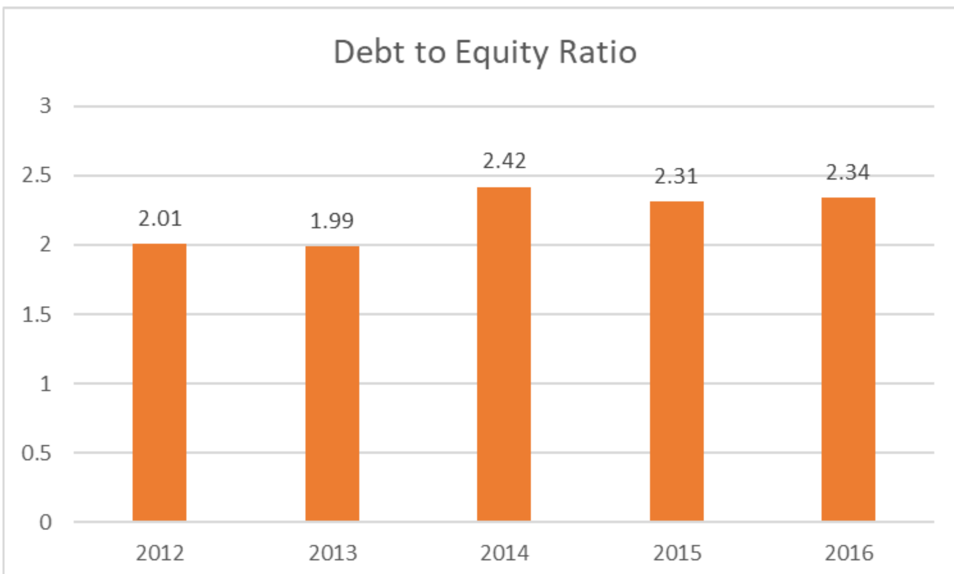


Figure 6: Total Debt to Equity Ratio

2.3.7.3 Profitability: Regulatory Return on Equity – Deemed (included in rates)

PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

2.3.7.4 Profitability: Regulatory Return on Equity – Achieved

PUC Distribution's return on equity in 2016 at 0.98% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2016 being approximately $1.4 million higher than included in the approved 2013 cost of service rate application. PUC Distribution's OM&A request for the 2013 Cost of Service rate application was $10.93; however this amount was reduced through the settlement process to the approved amount of $9.95. Although PUC Distribution did not receive approval for the full amount requested in rates for OM&A expenses in its last cost of service rate application in 2013, due to increased regulatory requirements and costs deemed necessary to service customers, PUC Distribution's expenditures in 2013 were $11.16 million compared to the approved amount in rates of $9.95 million. The increase of $1.21 million from 2012 to 2013 is detailed below in Table 9:

Table 9 - Incremental OM&A from 2012 to 2013

Area	Amount	
Labour	$444,000	Line and Engineering Dept. labour for capital projects was high in 2012 which required the delay in operating and maintenance programs that were resumed in 2013 (Line $298k, Engineering $88k), Meter Dept. labour was temporarily redirected to the smart meter project in 2012 but resumed regular operating and maintenance programs in 2013 ($72k)
Management Labour	$248,000	Engineering P&C Engineer not filled for full year in 2012, higher level of capital effort in 2012 for smart meters, etc.
Line clearing	$188,000	2012 was a low year for line clearing costs – was highly dependent on area to be cleared and number of contractors bidding – line clearing areas were revised in 2016 to a more consistent annual area and program moved from 3 years to 4 years
Bad Debts	$74,000	Increased cost of energy to customers has increased the amount of customer's bills – number of write-offs and amounts per w/o

		are higher
New Building Operating expenses – property taxes	$244,000	New building occupied in 2013 – resulted in higher property taxes
New Building Operating expenses – other operating expenses	$117,000	New building occupied in 2013 – resulted in higher operating costs – utilities, janitor, etc.
Misc.	-$105,000	
	$1,210,000	

Subsequent to the increase in 2013, OM&A expenses have increased marginally from $11.16 million in 2013 to $11.36 million in 2016. This equates to a three year average annual increase of 0.6%.

In addition, PUC Distribution did not increase its rates in one year of the current IRM rate period and postponed its Cost of Service rate application due to the local economic circumstances.

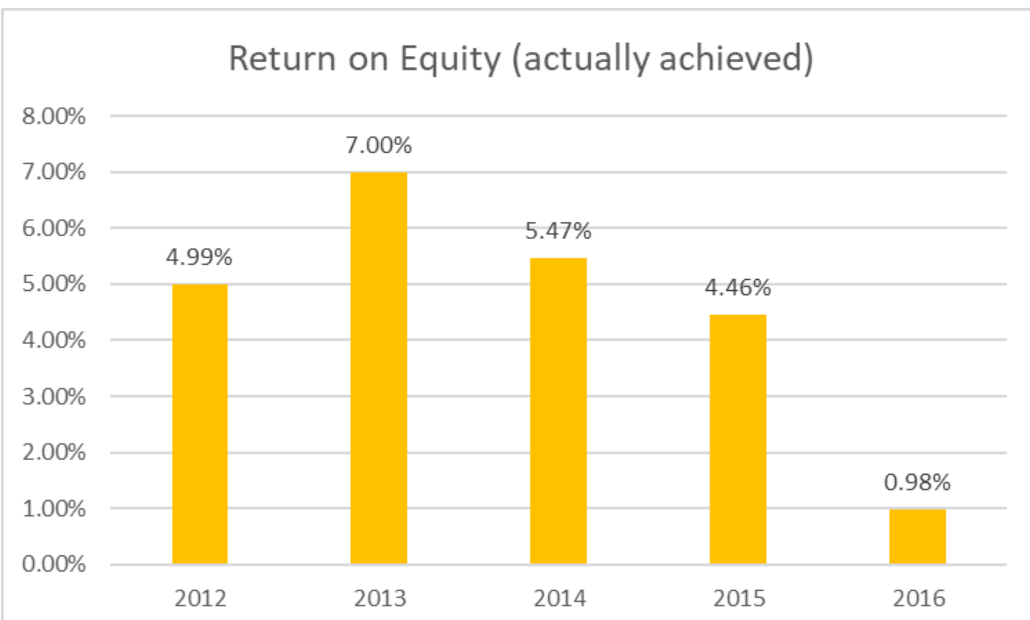


Figure 7: Regulatory Return on Equity

2.3.8 Conservation and Demand Management (CDM)

PUC Distribution measures and monitors its progress in implementing CDM program to ensure continued progress in meeting the assigned targets for its service territory for energy conservation and demand reduction. OPA/IESO's policy and guidelines and OEB's directive to comply with these policies and guidelines is the motivation for monitoring and reporting on the progress in meeting CDM targets. PUC Distribution reports on the CDM progress using IESO/OPA approved report formats. Furthermore, CDM initiatives are aligned with PUC Distributions core values of innovation and responsiveness. In conjunction with the CustomerFirst collaborative innovative approaches are implemented for the delivery of CDM programs to customers. This multi-utility approach also serves to ensure that collaborative programs are responsive to customer needs.

PUC Distribution has been actively participating in the province's energy conservation and demand management (CDM) programs, engaging all customer groups within its service territory. CDM continues to play a critical role in helping customers manage their electricity costs, while making a positive contribution in de-accelerating the rate of global warming and reducing the peak demand on the distribution grid. PUC Distribution participates in a number of IESO's incentive programs designed to reduce energy use and to promote effective environmental conservation. The current Save on Energy conservation framework has started to gain considerable momentum in PUC Distribution's service territory and a number of CDM programs have been successfully implemented.

Table 10 and Table 11, respectively, show the savings in peak demand and energy use, achieved during the first tranche of the program, from 2011 to 2014. CDM targets were redefined in 2015. Table 12 shows the performance achieved in relation to the new 2020 target for energy savings.

As indicated in those tables, PUC Distribution's proactive engagement in energy conservation and demand management programs has contributed significantly to province's CDM targets and more specifically in curtailing the peak demand on its distribution grid. The reduction in demand has resulted in no investment requirements to address any capacity constraints on the distribution network.

Table 10: PUC Distribution's Net Peak Demand Savings at End User Level 2011-14 (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.7	0.7	0.7	0.6
2012 - Verified†	0.0	0.8	0.8	0.8
2013 - Verified†	0.0	0.1	1.1	1.0
2014 - Verified†	0.0	0.0	0.0	0.9
Verified Net Annual Peak Demand Savings Persisting in 2014:				3.3
PUC Distribution Inc. 2014 Annual CDM Capacity Target:				5.6
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				59.5%

†Includes adjustments to previous years' verified results

Table 11: PUC Distribution's Net Energy Savings at End User Level 2011 – 14 (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.7	2.7	2.7	2.6	10.9
2012 - Verified†	-0.2	2.7	2.7	2.7	7.9
2013 - Verified†	0.0	0.3	3.9	3.9	8.1
2014 - Verified†	0.0	0.0	-0.05	3.7	3.7
Verified Net Cumulative Energy Savings 2011-2014:					30.5
PUC Distribution Inc. 2011-2014 Annual CDM Energy Target:					30.8
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					99.1%

†Includes adjustments to previous years' verified results

Table 12: PUC Distribution's Net Incremental Energy Savings 2015-2020 (kWh)

Year	Residential kWh	Non-Residential kWh	Local LDC Programs	LDC Innovation Pilots	IESO Verified Total (kWh)	OEB Target (kWh to 2020)	% of 2020 Target Achieved (Cumulative)
2015	1,969,397	3,431,349	0	0	5,400,746	26,410,000.00	20%
2016	3,822,336	5,307,038	0	270	9,129,644		55%

2.3.9 Renewable Generation (REG) Connections

PUC Distribution measures and monitors its progress in facilitating and implementing the renewable generation connections requested by customers in its service territory. OEB's directives follow the province's broader policy to encourage and facilitate REG connections and are the motivation for monitoring this performance indicator. PUC Distribution measures its operating performance for REG connections by confirming if the REG connection requests are processed within the time period specified by OEB as indicated in Table 13. Customers realize benefits associated with REG connections in the form of cost savings which is consistent with PUC Distributions strategic goal of delivering improved customer satisfaction.

Table 13: PUC Distribution's REG Connection Performance

	2012	2013	2014	2015	2016	Target
REG Connection Impact Assessments completed on Time	-	-	-	0%	100%	-
New Micro-Embedded Generation Facilities Connected on Time	-	100%	100%	100%	-	90%

PUC Distribution has proactively participated in Ontario's Green Energy program, by facilitating the connection of Renewable Energy Generation (REG) to the distribution grid. PUC Distribution currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load.

Section 25.37 of the Electricity Act, 1998 requires that connection assessments for renewable energy generation facilities be completed by electricity distributors within prescribed timelines, and it also requires distributors to report quarterly to the Board on their ability to meet those timelines. Ontario Regulation 326/09 (Mandatory Information re Connections) sets out details regarding the timing of, and reporting on, connection assessments. Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. All requests received in 2016 for connecting REG connections under province's FIT program have been successfully connected by PUC Distribution.

For generation facilities that are 10 kW or less, the OEB established a connection measure in amendments to the Distribution System Code that came into effect on June 13, 2013 (EB-2012-0246). A distributor shall connect an applicant's micro-embedded generation facility to its distribution system within 5 business days of which all applicable service conditions are satisfied, 90 percent of the time on a yearly basis, or at such later date as agreed to by the customer.

100% of the requests received to date for micro-FIT (<10kW) generation facilities have been successfully connected within the OEB mandated time period. No REG connection requests have been turned down due to capacity constraints.

3 Asset Management Process [5.3]

This section describes in detail PUC Distribution's asset management process and the direct links between the asset management process and the expenditure decisions that comprise the capital investment plan covered by this DSP.

3.1 Asset Management Process Overview [5.3.1]

3.1.1 Corporate Goals, Asset Management Objectives, and Investment Prioritization [5.3.1a]

In developing and implementing the asset management plan, PUC Distribution has aligned its key objectives with its corporate vision, mission and core values. PUC Distribution's vision is to be recognized as a progressive electric distribution company committed to delivering value, innovation, prosperity and excellence. PUC Distribution's mission is to provide cost effective, efficient, safe and reliable delivery of high quality energy services and solutions consistent with customer needs and preferences. Its core values are:

- **Responsive –** We believe that to be recognized as the leading service provider we need to not only respond quickly to our customers' needs but also anticipate and be proactive with our service delivery

- **Ownership** – to promote organizational excellence, everyone is empowered to take individual accountability and inspired to assume personal responsibility within the organization

- **Safety –** PUC Distribution has been and will continue to be a strong advocate for safety within our community. Safety is our top priority and we will never compromise on the safety of our employees or our community

- **Innovative –**We believe that in order to succeed in advancing a climate of innovation we must seek out new approaches or technologies, and apply ingenuity and creativity when confronting challenges

- **Entrepreneurial –** We recognize that exploring new business ventures and diversifying our service offerings is the best way to ensure we not only earn a fair return for our shareholder, but grow and add value as a community owned asset.

In conjunction with its mission, vision and core values, PUC Distribution has established the focus areas, corporate strategic goals and strategies to achieve the goals identified in Table 14:

Table 14: PUC Distribution's Focus Areas, Goals & Strategies

Focus Area	Strategic Goals	Strategy to Achieve Goal
Customers	Achieve A+ customer satisfaction Rating Meet or exceed all score card targets	Improve customer focus, customer satisfaction, communication, engagement and education Improve service quality
Employees	Be recognized as one of Canada's top 100 employers Organization Safety Excellence	Implement P3S0 organizational transformation - proactive employee engagement and training Continuous improvement of safety culture and performance
Shareholder	Achieve OEB deemed return on equity Increase value of company	Ensure sustainability of assets and system Productivity/business process improvements Explore permitted business opportunities

To achieve these strategic goals the key objectives on which the asset management plan is based have been ranked on a scale of 1 to 5. For further clarity, objectives ranked as a 1 have been classified as having the lowest priority for investment while those given a ranking of 5 are classified as having the highest priority. The ranking is meant to score the objectives on a relative basis. The following tactical objectives are intended to support and align with the broader strategic goals referenced above:

- ✓ Ensuring investment plans are aligned with the corporate goals - Ranking 5
- ✓ Ensuring investment plans are cost effective - Ranking 5
- ✓ Ensuring investment plans provides value to the customers - Ranking 5
- ✓ Ensuring investment plans are responsive to public policy - Ranking 5

- ✓ Maintaining public and employee safety - Ranking 5
- ✓ Maintaining reliability commensurate with customer needs - Ranking 5
- ✓ Providing customer service quality to satisfy customer needs - Ranking 5
- ✓ Maintain safe and ergonomic work place, tools and equipment - Ranking 5
- ✓ Controlling costs - minimizing asset life cycle costs - Ranking 4
- ✓ Minimizing risk of in-service failures - Ranking 4
- ✓ Minimizing environmental risks, - Ranking 4
- ✓ Aligning the DSP with regional planning objectives - Ranking 3
- ✓ Facilitating new renewable generation connections; - Ranking 3
- ✓ Facilitating the smart grid development - Ranking 2

Because there are no pending applications for connecting renewable generation, a lower ranking for investments into smart grid development and facilitating renewable generation connections has no significant adverse impact. Similarly, none of the investments proposed in this DSP conflict with the regional planning objectives and therefore lower ranking of the regional planning objectives has no adverse impact.

3.1.2 Asset Management Process Components [5.3.1 b]

3.1.2.1 Asset Management Strategy

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when “right sized” investments are planned and implemented into new assets involving system extension or capacity upgrades or renewal, rehabilitation, repair or preventative maintenance of existing assets, based on a “just-in-time” approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized, while fully addressing customer service quality and needs.

3.1.2.2 Investment Prioritization Process

As described previously in Section 1, Capital investments into infrastructure assets are classified into four categories, as defined in OEB's Chapter 5 filing requirements and these include: System Access, System Renewal, System Service and General Plant.

System Access Investments

System Access investments facilitate modifications to the distribution system infrastructure, to allow connection of new load or generation customers to the grid, permit joint-use of distribution infrastructure by allowing telecommunication companies to install their service equipment on power lines or underground ducts and allowing relocation of distribution infrastructure installed in public right-of-ways to permit road reconstruction projects. System Access investments are a regulatory obligation for distribution companies (as defined in the Distribution System Code and PUC Distributions Conditions of Service) and therefore these System Access investments receive the highest priority in the overall investment envelope.

To establish the investment level required for System Access, the scope of the required work in this category was identified by estimating the number of anticipated requests for new services both on existing developed streets and in new planned subdivision developments, through direct contact with customers and land developers as well as from the information collected from the municipal planning department. Information related to municipal road reconstruction projects requiring relocation of lines was also obtained from the municipal authorities. Local telecommunication companies were consulted to determine the scope of "make-ready" work for joint-use lines. This category also includes investments needed to comply with the OEB directive to equip all general service customers with >50kW and <500kW demand with MIST meters.

System Service Investments

System Service investments facilitate modifications to the distribution system to ensure that system assets continue to meet their functional needs, efficiently and safely. Electricity distribution companies must invest into capacity upgrades, when required to remove supply system constraints and to ensure electricity delivery at consumer connection points meets the applicable power quality standards (as defined in CSA standards, Distribution System Code). System Service investments may also be required to meet customers' evolving needs for services e.g. introduction of smart grid features to give customers greater access to manage their energy use, improve automation, reduce power restoration times upon asset failures and facilitate connection of renewable generation to the grid. Once it is determined that the existing system is no longer able to meet customers' functional needs, or distribution system standards, these investments become mandatory, gaining the same priority level as the System Access investments.

In order to assess the required level of System Service investments, ability of the distribution grid to supply the existing and anticipated load and generation customers was analysed. PUC Distribution has implemented a number of smart grid features during the previous years, such as smart meters, digital protection systems, voltage regulators and remote-controlled substation switchgear to facilitate automation. System Service investments include input from customers to drive investment decision making. Examples include implementation of voltage regulation improvements and recloser installations in response to customer feedback and needs. As indicated in Section 4, a number of investments under System Renewal will also serve the dual purpose of providing benefits typically derived from System Service investments. As such, there are no investments proposed in this DSP, specifically triggered by System Service objectives.

General Plant Investments

General Plant investments are modifications, replacements or additions to the assets that are not a part of the distribution system comprised of land and buildings used to support day-to-day business and operations activities. PUC Distribution leases its motor vehicle assets rather than owning them, therefore as indicated in Section 4.1.2, and a relatively small level of capital investment is required for renewal of General Plant, equipment and workplace buildings. Additionally, all of PUC Distribution works out of a single consolidated facility which was recently constructed in 2012/2013. General Plant projects are identified and assessed using a combination of inspections, policies and expert knowledge. Investments into building repairs are based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems.

System Renewal Investments

System Renewal investments involve replacing and/or refurbishing existing distribution system assets to extend the service life of assets, thereby maintaining the ability of the distribution system to provide customers with a safe and reliable supply of electricity in accordance with customer feedback and prescribed standards and codes (e.g.: Distribution System Code, OEB Scorecard metrics, CSA standards). As the existing assets age, their operating condition degrades and eventually reaches a level where the risk of assets failing in service becomes unacceptable. Since a significantly large part of PUC Distribution’s infrastructure assets have been determined to be in poor or very poor condition, prioritization of investments in the System Renewal category, required a comprehensive risk assessment approach, which is described below in detail.

Figure 8 summarizes the flow chart used to sift through the assets, to objectively identify the assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk.

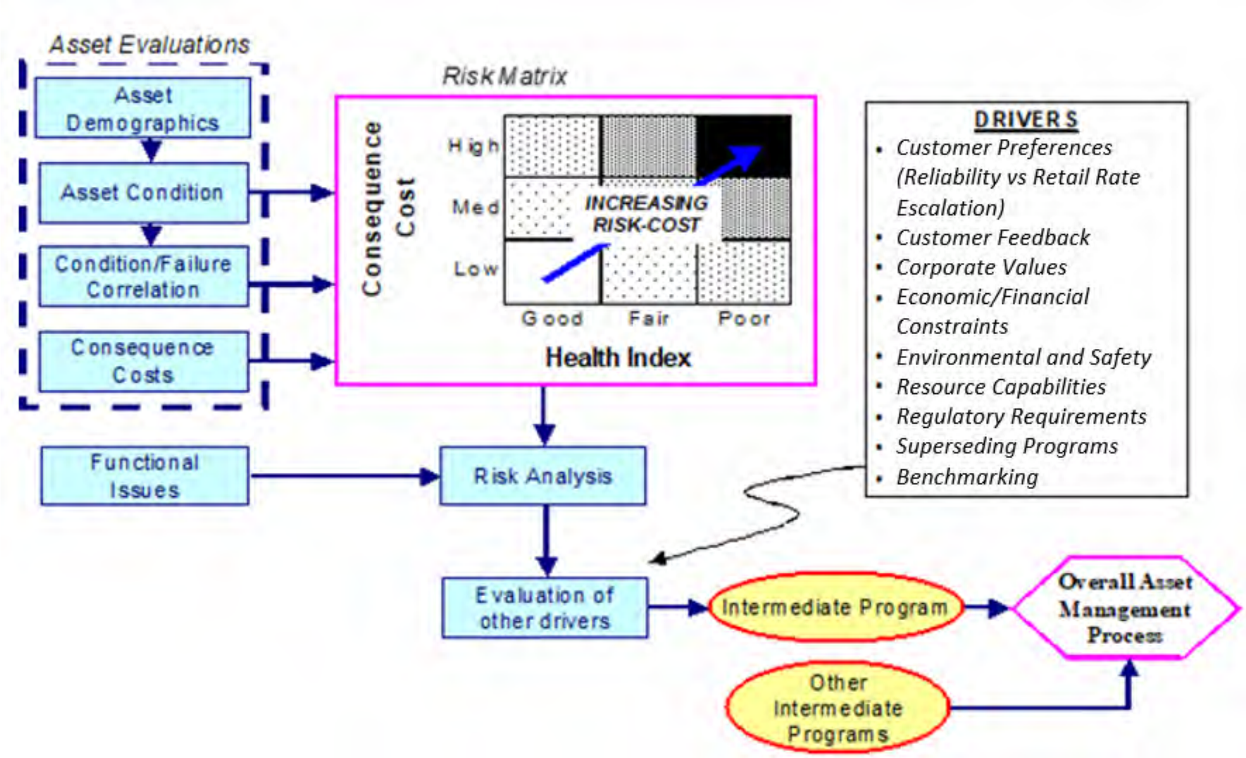


Figure 8: Flow Chart for Asset Management Plan

As shown in Figure 8, for establishing the overall investment level for System Renewal and prioritization of assets selected for renewal, condition assessment of all assets installed in stations, overhead lines and underground distribution systems, was performed by utilizing all available data, indicative of assets' operating condition and probability of failure. The asset condition assessment task was performed under the supervision of the "Engineering and Operations" division.

Data Sets

The data sets employed in prioritization of the investments include:

a) Asset registers, a geographical information system (GIS) station single line diagrams and operating maps, indicating line lengths, conductor sizes, equipment ratings and service age of assets

b) Station peak loading data, indicating equipment capacities and maximum load

c) Equipment inspection data sets, indicating operating condition of distribution system assets, and

d) Substation test result data sets

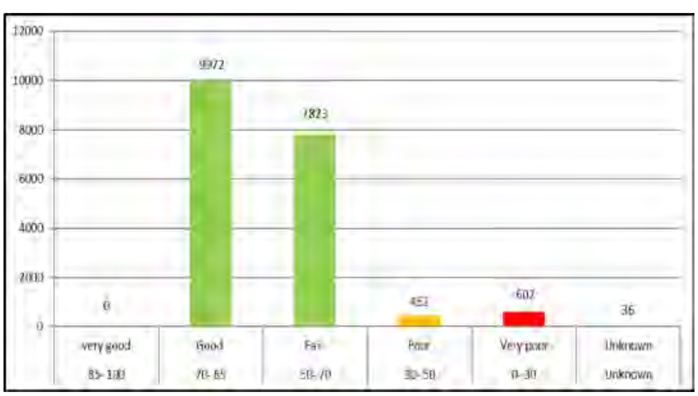
e) Asset condition assessment report (attached at Appendix B)

While data sets listed under a), b) and c) are maintained and updated by PUC Distribution's Operations and Engineering staff, data sets listed under d) and e) were compiled by third-party contractors and consultants.

Process Description

The asset management process employed for prioritization of investments is described in detail in Appendix B and is briefly summarized below.

Using asset demographic information from PUC Distribution's data sets as an input, service age profiles were developed for all categories of distribution system assets, including distribution stations, as well as the overhead and underground distribution system. PUC Distribution has been maintaining accurate records of station loading for more than 15 years. During preparation of the asset management plan in 2016, historic loading trends were analyzed and anticipated loading levels for distribution stations during the next five years were compared with the station ratings, to identify the potential for distribution system constraints. Results of physical inspections of distribution system performed by PUC Distribution staff were reviewed and supplemented by additional inspections of high risk assets performed by a third-party Professional Engineer. By taking into account asset demographic information, results of physical inspections and in-situ testing, the condition of each major asset in service was assessed. Numeric health indices, normalized to a scale of 100, were used to express the health and condition of assets; and this procedure allowed separation of the assets in "very good", "good" and "fair" condition that require minimal risk mitigation from those in "poor" and "very poor" condition, as illustrated by means of example in Figure 9, which summarizes the condition assessment of wood poles. For all distribution system assets a detailed Asset Condition Assessment is contained in Appendix B.



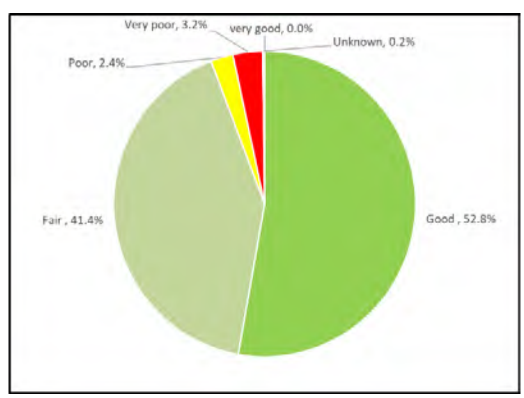


Figure 9: Illustrative Example – Condition Assessment of Wood Poles

For assets determined to be in poor or very poor condition, consequences of asset failures were assessed and those requiring renewal/rehabilitation were ranked in order of priority, with highest consequence of failure being assigned the highest priority. Economic analysis was carried out to determine the optimal response for risk mitigation, by taking into account the cost and life extension provided by renewal and rehabilitation.

In addition to the asset condition and risk assessment, customer engagement sessions were held under the direction of the Customer Engagement and Business Development division to receive feedback and determine customer preferences for service quality level and retail rate escalation. This information was employed by the Finance and Corporate Support division, to establish the overall spending envelope to be applied to the four investment categories. By subtracting the higher priority investments for System Access, System Service and General Plant, available investment level for asset renewal during the DSP period was established by the Operations and Engineering Division. And finally, from the prioritized list of projects, prepared previously through the risk based approach, considered in conjunction with the drivers identified in Figure 8 (i.e.: customer preferences, customer feedback, etc.), a list of projects to be included in the DSP was developed, which could be implemented within the available budget.

3.2 Overview of Assets Managed [5.3.2]

3.2.1 Key Features of the Distribution Service Area [5.3.2 a]

3.2.1.1 Distribution Service Area

PUC Distribution's service territory as shown in Figure 10 includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. Its service territory covers a total service area of approximately 342 square kilometers, including a rural service area 284 square kilometres and an urban service area of 58 square kilometres. The combined population served is approximately 75,300. The service territory includes approximately 29,700 residential customers and approximately 3,800 general customer services for a total of approximately 33,500 customers.

Of the total 743 circuit kilometres of line, 621 kilometres are overhead while the remaining 122 kilometres are underground.

3.2.1.2 Economic Growth

According to Statistics Canada census data, the City of Sault Ste. Marie's has experienced about a 2.1% decline in population between 2011 and 2016. The pace of economic growth is not expected to change during the next 5-year period, covered by the DSP.

3.2.1.3 Climate

The climate is typical of most towns in Northern Ontario and reaches temperature extremes of -40˚C during winter and +40˚C in summer. The normal monthly temperatures vary from -15˚C during winter and +25˚C in summer, with approximately 10 days of precipitation in a month. Both overhead and underground distribution systems are employed in PUC Distribution's service territory. The presence of a number of different soil types, the Canadian Shield, numerous clays, and muskeg often make excavation activities a challenge, particularly for installation of underground distribution systems. The region is vulnerable to commonly occurring strong wind storms, lake-effect snow and ice loading from Lake Superior, which poses a challenge to overhead lines. PUC Distribution's entire service territory is located within the CSA heavy loading area as described in CSA 22.3 No. 1-15 Overhead Systems. Accordingly, the corresponding CSA referenced heavy loading conditions of radial thickness of ice; horizontal wind loading and temperature are accounted for in line designs. Lines with the highest risk of failure consequences are included in the asset renewal program proposed in this DSP.

3.2.1.4 Electrical Loading

Electrical loading on the grid peaks during the winter in this region. Due to expansion of the natural gas distribution network and implementation of the CDM programs over the recent past, winter peak loading on the electricity grid has reduced, while the relatively small decline in the population has resulted in a modest increase during summer peak loading. As a result, the overall peak demand on the electricity has been trending downwards and no capacity constraints are anticipated during the next five years.

Although a number of investments in the System Renewal category will introduce many smart grid features during rebuild of the system and therefore will provide benefits typically provided by investments in System Service category, there are no investments in this DSP, for which System Service is considered the sole motivation and therefore no investments are shown in the System Service category.

3.2.1.5 System Voltage Levels (Voltage Conversion)

Approximately 25 years ago, PUC Distribution started a program to gradually upgrade its distribution system from 4.2 kV to 12.5kV. When the existing 4.2 kV infrastructure reaches the end of its service life, rather than like for like replacement of 4.2 kV rated equipment with 4.2 kV rated equipment, the voltage is upgraded to 12.5 kV, which results in greater operating efficiency. A vast majority of the distribution system has already been upgraded to 12.5 kV and at present relatively small pockets of service area with 4.2 kV network remain. Most of the existing distribution infrastructure operating at 4.2 kV is at the end of its service life and the poor condition of equipment has been resulting in frequent equipment failures with adverse impacts on reliability. Maintaining a distribution system with two operating voltages also results in duplication of lines and economic inefficiencies due to system energy losses. Therefore, this DSP includes investments to retire the remaining network equipment operating at 4.2 kV from the grid and upgrade all of the remaining line sections to 12.5 kV.

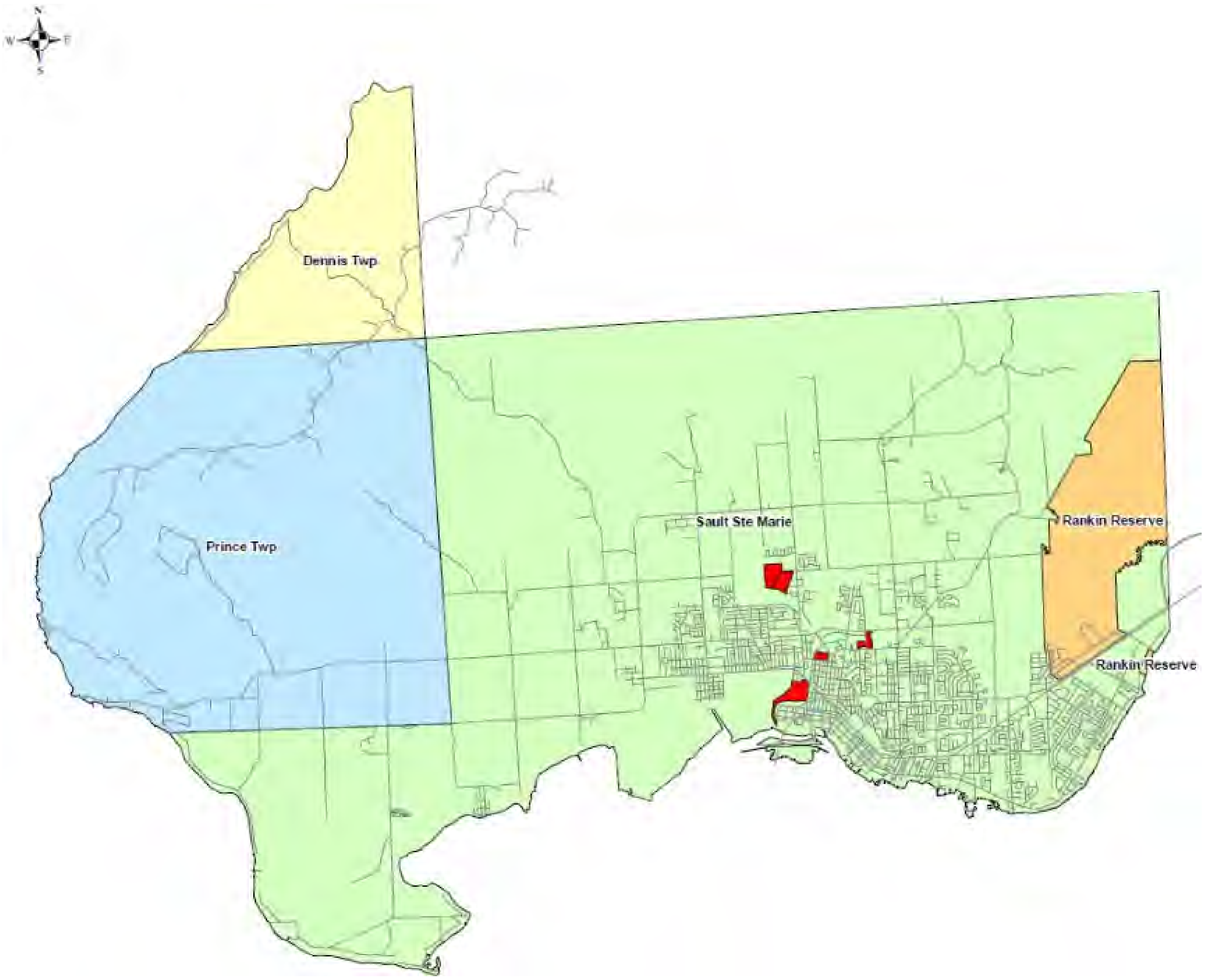


Figure 10: PUC Distribution Service Territory

3.2.2 Description of System Configuration [5.3.2 b]:

PUC Distribution owns and operates two transformer stations - TS1 and TS2, which step down power received from the transmitter at 115 kV to 34.5 kV. The 34.5 kV feeders supply a total of 12 distribution stations, which step down power from 34.5 kV to 12.5 kV. There are also two additional distribution stations; one of which steps down from 34.5kV to 4.2kV, the second steps down from 34.5kV to both 12.5kV and 4.2kV. A third 12.5kV to 4.2kV station, Substation 14 has been recently been retired. The remaining two 4.2 kV distribution stations are planned to be retired from service, upon completion of the distribution voltage upgrade program, during the next five years. Figure 11 below shows the geographic locations of transformer stations and distribution stations, within the PUC Distribution's service territory.

Figure 11: Distribution Station Locations

Table 15 shows the power transformer ratings and number of 34.5 kV feeders at each of the 115/34.5 kV transformer stations.

Table 15: 115/34.5kV Substation Ratings

Transformer Station	Capacity	Number of 34.5 kV Feeders
TS 1	4x30 MVA	5
TS 2	4x30 MVA	5

In addition to the four outgoing feeders, TS-1 also supplies Substation 19, which is located at the same site as TS-1. Both transformer stations are also equipped with power factor correction shunt capacitors. TS-1 employs shunt capacitors of 20 MVAR rating as well as a recently installed IESO controlled 7MW/+/-7MVAr/7MWh energy storage facility to provide dynamic Volt/VAR control. TS-2 employs shunt capacitors of 40 MVAR rating.

Table 16 shows the power transformer ratings and number of feeders at each of the distribution stations.

Table 16: Substation Ratings

12 kV Stations	Capacity	Number of 12.5 kV Feeders
Substation 1	2x10 MVA	4
Substation 2	2x10 MVA	4
Substation 4	1x10 MVA	2
Substation 10	2x10/13.3 MVA	4
Substation 11	2x10 MVA	4
Substation 12	2x10 MVA	4
Substation 13	2x10 MVA	4
Substation 15	2x10 MVA	4
Substation 16	2x7.5 MVA	4
Substation 18	2x7.5 MVA	4
Substation 19	2x10 MVA	4
Substation 20	2x10 MVA	4
Substation 21	2x10 MVA	4

4.2kV Stations	Capacity	Number of 4.2 kV Feeders
Substation 4	1x10 MVA	2
Substation 5	2x5 MVA	2

Major assets employed on the overhead and underground distribution network are summarized in Table 17. As indicated, the power supply network employs overhead lines operating at 115kV, 34.5 kV, 12.5 kV, 7.2 kV, 4.2 kV and 2.4 kV as well as low voltage (LV), i.e. less than 750V, and it employs insulated cable circuits installed in duct and direct buried configurations, operating at 34.5kV, 12.5 kV, 7.2 kV, 4.2 kV and 2.4 kV.

Table 17: PUC Distribution's Distribution System Assets

Asset	Quantity	Units
3-Phase 115 kV Overhead lines	15.5	km
3-Phase 34.5 kV Overhead lines	74.4	km
3-Phase 12.5 kV Overhead lines	278	km
3-Phase 4.2 kV Overhead lines	23.5	km
3-Phase LV Overhead lines	38.7	km
1-Phase 7.2 kV Overhead lines	219.4	km
1-Phase 2.4 kV Overhead lines	8.3	km
1-Phase LV Overhead lines	42.1	km
Number of poles on OH lines	12683	#
34.5 kV, 3-ph, UG, Cable Circuits	24.5	km
12.5 kV, 3-ph, UG, Cable circuits	49.2	km
7.2 kV, 1-ph, UG, Cable circuits	45.6	km
4.2 kV, 3-ph, UG, Cable circuits	1.4	km
2.4 kV, 1-ph, UG, Cable circuits	1.4	km
Number of 1-ph pole mounted transformers	5167	#
Number of 3-ph pad mounted transformers	547	#
Number of 1-ph pad mounted transformers	391	#
Number of submersible transformers	517	#
Number of pad-mounted switchgear	23	#
Number of K-bar Units	130	#
Number of concrete structures (pads and vaults)	1041	#

Table 18 provides information on the number of feeders that are installed in overhead (OH) or underground (UG) or mixed OH/UG configurations.

Table 18: Number of Feeders Installed in OH or UG Configurations

(a) 35 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
TS-1	5	5	0	0
TS-2	5	2	0	3

(b) 12.5 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
DS-1	4	1	1	2
DS-2	4	2	1	1
DS-4	2	2	0	0
DS-10	4	4	0	0
DS-11	4	3	0	1
DS-12	4	1	1	2
DS-13	4	3	0	1
DS-15	4	2	1	1
DS-16	4	1	0	3
DS-18	4	1	0	3
DS-19	4	2	0	2
DS-20	4	2	0	2
DS-21	4	0	0	4

(c) 4.2 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
DS-4	2	1	0	1
DS-5	2	2	0	0

3.2.3 Asset Demographics and Condition Assessment [5.3.2 c]:

The asset management plan, prepared in September 2016 and attached as a stand-alone report in Appendix B, provides complete demographic and asset condition information on fixed assets employed in PUC Distribution's substations, overhead distribution network and the underground distribution system. The asset condition assessment report documents the condition of all major assets in units of health indices and provides ranking of assets in designations rated "very good", "good", "fair", "poor" and "very poor". In determining the health indices of assets, all available information relevant to the assets' health, including age, results of visual inspections and results of diagnostic testing when available, have been utilized.

"Very Good" asset condition represents brand new asset in perfect operating condition, with no impairment. "Good condition" indicates an asset with service life equal to less than 25% of its typical useful life and with no impairment and no noticeable drop in operating performance. "Fair Condition" indicates an asset with service life equal to more than 25% but less than 80% of its typical useful service life, with normal wear and asset operating performance within acceptable tolerances and no significant impairment. "Poor Condition" signifies an asset with service life greater than 80% of its typical useful service life, appreciable wear or significant impairment in asset condition causing its performance to degrade below acceptable levels and presenting high risk of asset failure unless major repairs or asset rehabilitation is performed to restore asset condition to “Fair”. “Very Poor Condition” signifies an asset with serious impairment to its critical components and the asset presents very high risk of failure. Assets in “very poor” condition cannot be economically repaired and renewal is the only option to restore their operating condition.

All of the information provided in the following sections on asset condition is based on the asset condition assessment performed in September 2016.

3.2.3.1 Condition Assessment of Substation Assets:

In substations, power transformers and switchgear (complete with protection and control equipment) are the critical components, essential to safe and reliable operation of station functions. Figure 12 and Figure 13, reproduced below from the AM Condition Assessment report, indicate the existing condition of power transformers and switchgear employed at PUC Distribution’s 115/34.5 kV transformer stations and 34.5/12.5 kV distribution stations.

Due to the advanced service age, combined with “poor” or “very poor” operating condition of a vast majority of the power transformers and switchgear sets employed at both of the 115/34.5 kV transformer stations (TS-1 and TS-2), both of these stations require complete rebuild with new power transformers, switchgear, protection and control equipment. Rebuilding of these two transformer stations requires significant front-end planning and engineering before construction can begin, to ensure that supply system security is not adversely impacted during construction. Planning is also required to comprehensively assess all available development alternatives with the objective of selecting the optimal alternative for re-development meeting the future needs of PUC Distribution’s customers during the next 40-50 years. Therefore, capital investment into a planning and engineering study with the objective of reviewing all practical development options through completion of conceptual designs and recommending the optimal transformer station development alternative for implementation is proposed in this DSP.

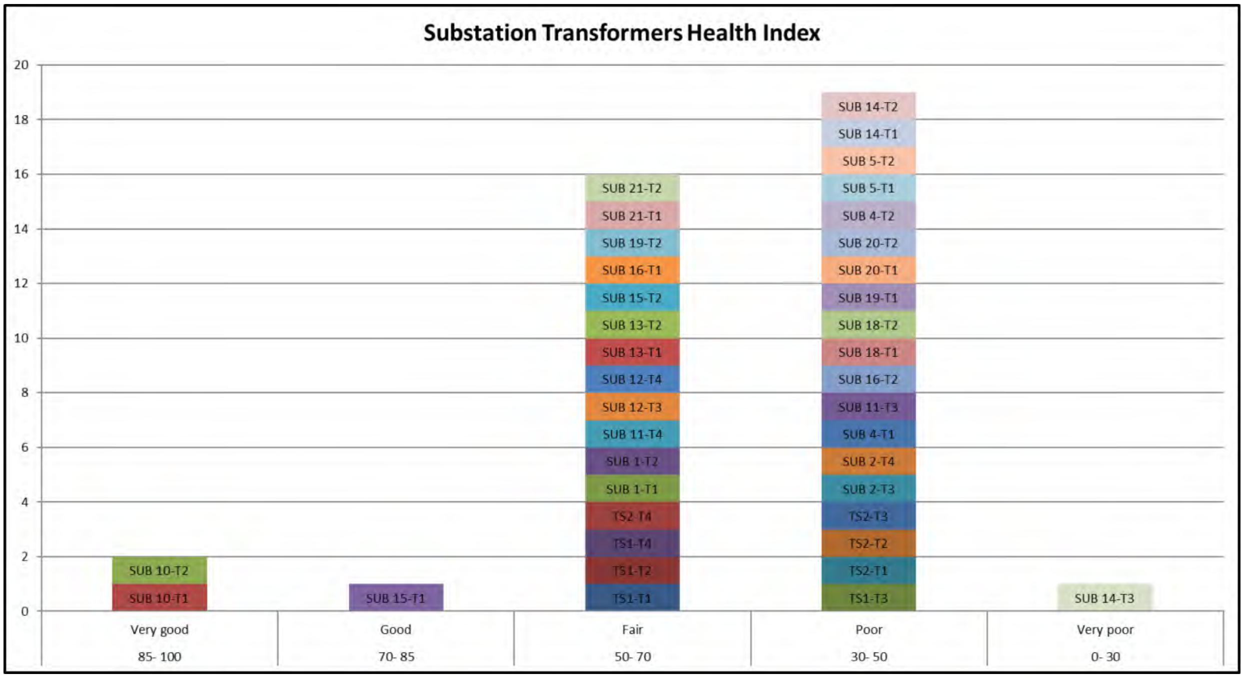


Figure 12: Substation Power Transformers - Condition Assessment

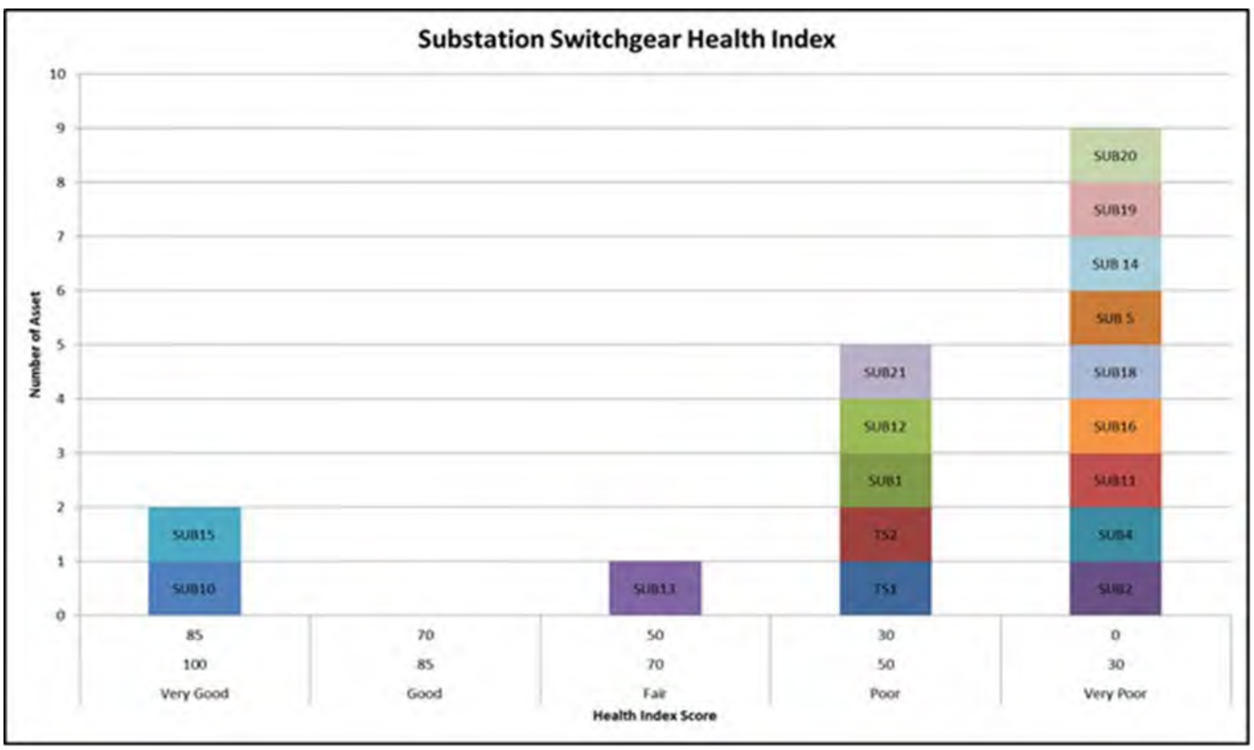


Figure 13: Substation Switchgear - Condition Assessment

Due to the “poor” or “very poor” condition of the power transformers, switchgear and other associated assets at seven of the twelve existing 34.5/12.5 kV distribution stations, these stations have been determined to be in “poor” or “very poor” condition, requiring complete rebuild of these stations during the next 10 years. However, given current revenue levels and lack of projected customer load growth it will be necessary to gradually ramp up the distribution station rebuild initiative over a longer period of time. This DSP includes capital investments for rebuild of two of the stations during next five years, those that present the highest risk of failure. The rebuild of remaining stations in “poor” or “very poor” condition has been deferred, for inclusion in subsequent DSPs.

For the two transformer stations and the distribution stations determined to be in “poor” or “very poor” condition but not included in the renewal program in the current DSP, PUC Distribution plans to manage the risk of equipment failures through proactive monitoring and testing of equipment and performing repairs, refurbishment and replacement of components when they fail, and this DSP includes funding for repair, refurbishment and component replacement activities.

3.2.3.2 Condition Assessment of Overhead Line Network Assets:

PUC Distribution’s overhead distribution network employs approximately 391 km of 3-phase and approximately 230 km of 1-ph lines, all operating at 115kV, 34.5 kV, 12.5kV, 7.2kV, 4.2kV and 2.4 kV. Figure 14 and Figure 15, respectively, show the age profile of overhead lines and as shown, approximately 28.5% of the overhead lines will reach the end of their design service life of 45 years during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors.

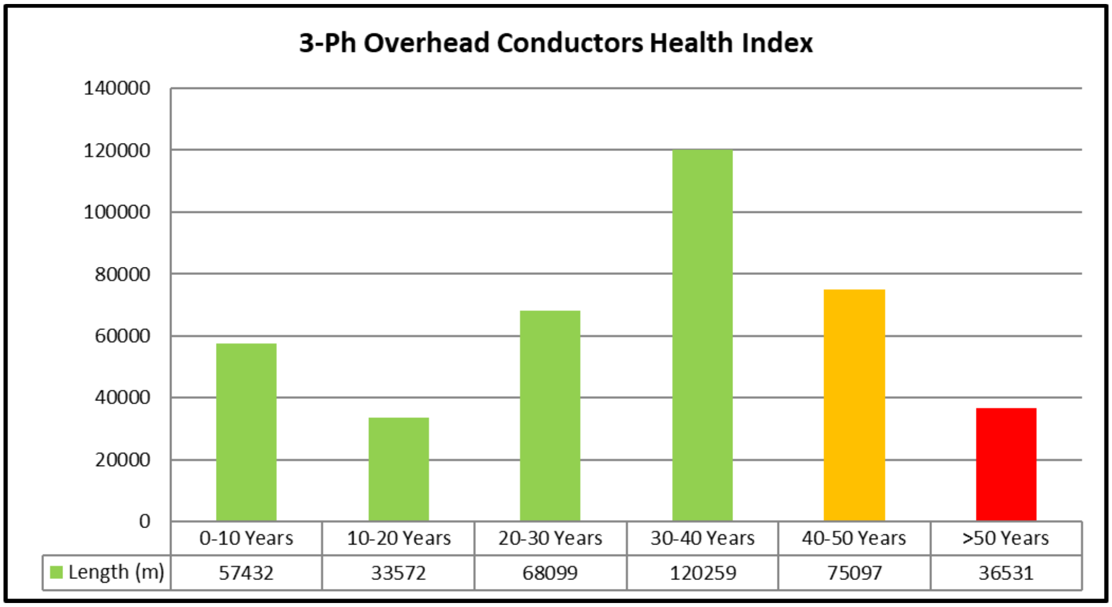


Figure 14: Age Profile – 3-Ph MV Overhead Lines

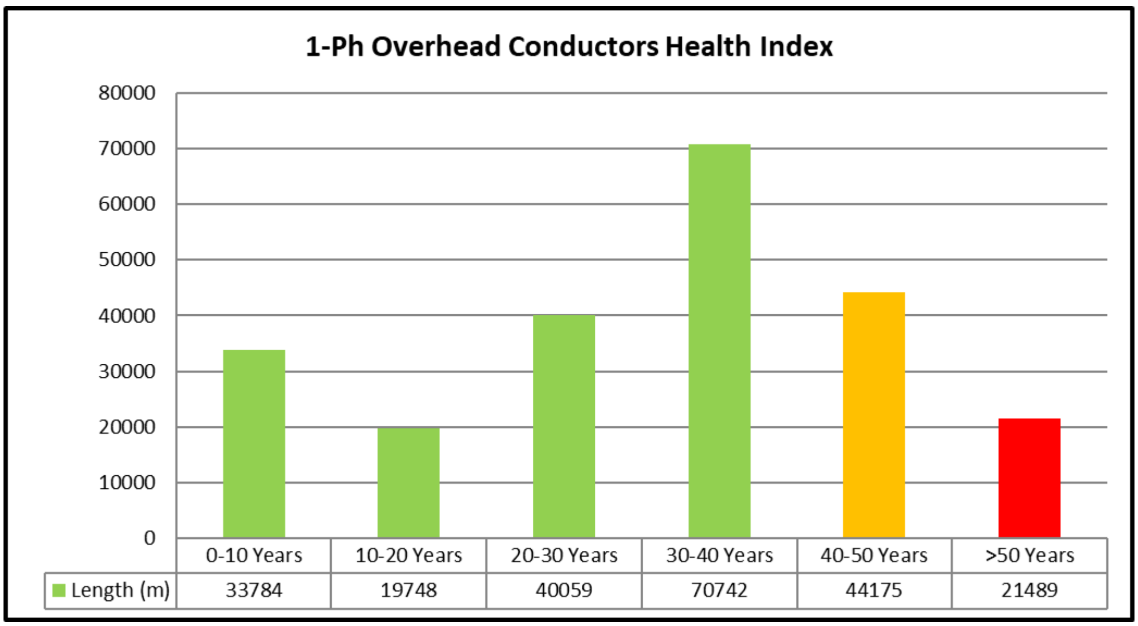


Figure 15: Age Profile – 1-Ph, MV Overhead Lines

Rather than proposing re-construction of all overhead lines that have reached the end of their design life, this DSP includes a small subset of the lines determined to be at the end of their service life. The lines included in the DSP for renewal have been prioritized by taking into account the probability of failure of a line section and the impact of line failures on public safety, supply reliability and operating costs. Since weakened poles with reduced structural strength, line sections with restricted conductors with reduced tensile strength, and the lines operating on 4.2 kV system, which are well past the end of their typical useful life, pose the highest risk of failure in service, priority for overhead line renewal has been given to projects, involving:

- line sections with poles in "very poor" condition,
- line sections built with restricted conductor, and
- lines determined to be in "very poor" condition and currently operating at 4 kV, which will undergo voltage upgrade upon reconstruction.

There are approximately 12,600 wood poles and about 83 other types of poles (including steel, concrete and fiberglass) employed on PUC Distribution's overhead lines. In order to identify poles in "poor" or "very poor" condition PUC Distribution periodically conducts in-situ testing of poles. The existing condition of the poles in 2016 is indicated in Figure 16. This DSP proposes renewal of approximately 30 poles, annually, determined to be in "very poor" condition, through pole testing.

Figure 16: Overhead Line Pole - Condition Assessment

Copper and aluminum conductors with smaller cross-section area, and more specifically #6 AWG and #4 AWG (copper or aluminum) conductors have lower tensile strength in relation to larger conductors typically used in overhead line construction. Under tension, the tensile strength of these smaller cross-section conductors further degrades with service age. These conductors are known to fail in service and when they fail, the downed lines pose a very serious safety risk for public. #6 AWG and #4 AWG conductors are no longer used for applications requiring conductor tensioning over full spans on overhead lines, and virtually all Canadian utilities have adopted programs to proactively phase out lines built previously with restricted conductors.

As shown in Figure 17 and Figure 18, PUC Distribution had identified approximately 8 km of 3-phase lines and approximately 60 km of 1-phase lines on its distribution network, constructed with restricted conductors and adopted a line renewal plan to phase out the restricted conductor on lines starting in 2009. On the PUC Distribution system the restricted conductor is primarily #6AWG copper. Up to the end of 2015, approximately 26% of the lines with restricted conductor had been phased out. Work on rebuilding of the remaining lines with restricted conductor is scheduled to continue during this 5-year DSP, with a target date of 2027 for complete elimination of all restricted conductor lines from the network. The lines for renewal are prioritized based on their location and the risk of public exposure to the downed lines.

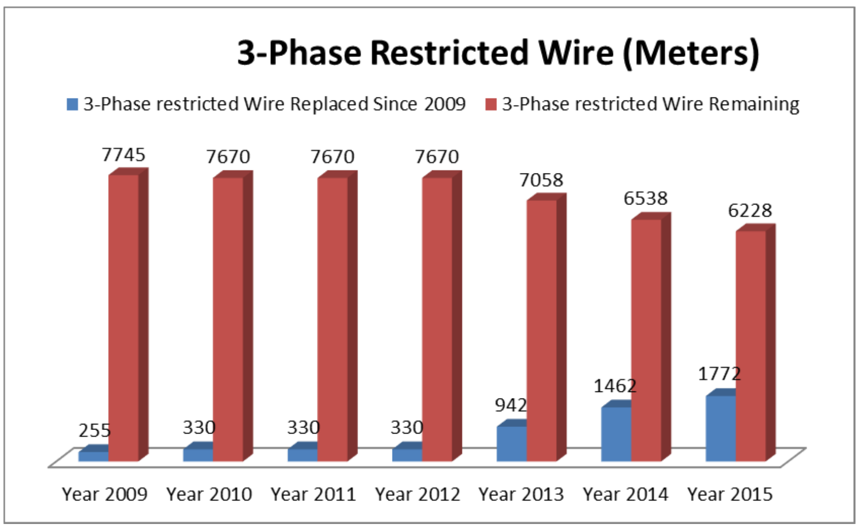


Figure 17: 3-Phase Lines with Restricted Wire on PUC System

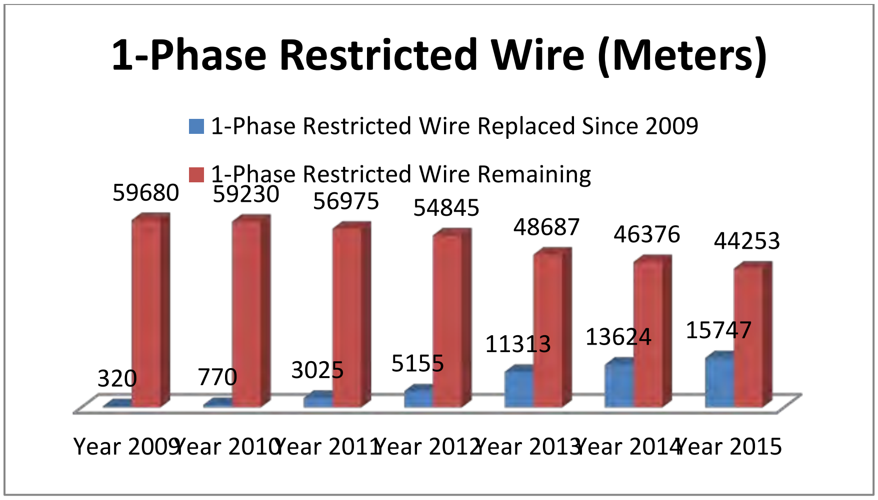


Figure 18: 1-Phase Lines with Restricted Wire on PUC System

Overhead lines employed on 4 kV distribution system are the oldest infrastructure components on PUC Distribution Inc.'s power supply network. Most of these lines have reached a service age of 50 or 60 years, well past their design life and they present the highest risk of failure in service. PUC Distribution has been gradually retiring from service the 4 kV lines at the end of their service life and rebuilding the lines with voltage upgrade to 12.5 kV. This DSP provides funding for rebuilding of 4 kV lines with voltage upgrade and when the proposed projects are implemented, it would allow PUC Distribution to retire all infrastructure operating at 4 kV by 2022.

Because the planned overhead line renewal projects described above, target only a subset of the lines determined to be in poor and very poor condition, this DSP also includes modest funds for renewal of components that are identified to be in unsafe condition during one-third plant inspections in accordance with the DSC as well as for emergency repairs and renewal of components that fail in service.

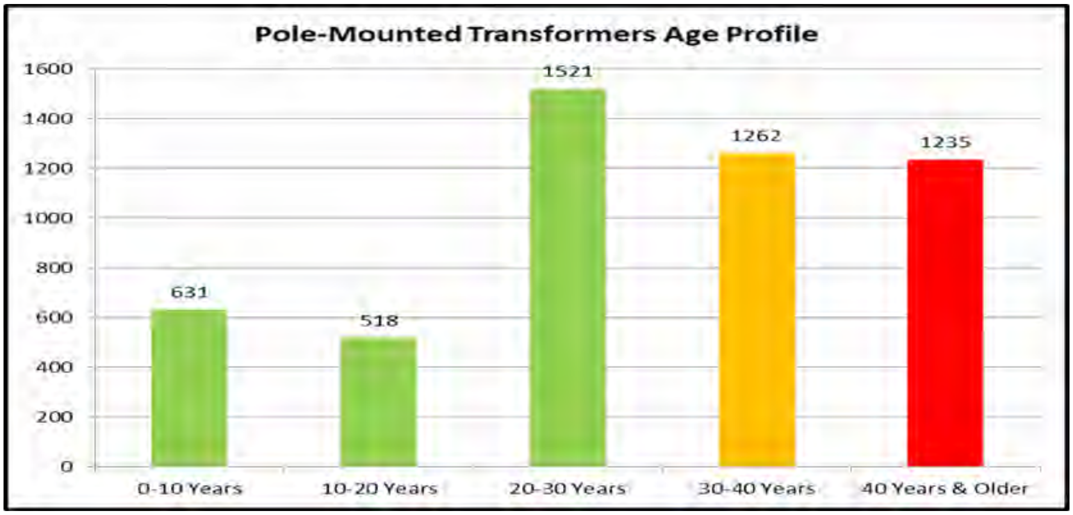


Figure 19: Age Profile of Pole-Mounted Distribution Transformers

Figure 19 indicates the age profile of pole mounted distribution transformers employed on the overhead distribution network. PUC Distribution employs "run-to-failure" strategy for distribution transformers due to the relatively low impact of transformer failures on reliability. Current PCB regulations in Canada permit the use of pole mounted distribution transformers containing PCB content in oil of over 50 parts per million and this use can continue up to December 31, 2025. Beyond that date, all distribution transformers must have a PCB level below 50 parts per million. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1980) for PCB content and replace those containing PCBs, or (b) replace all suspect transformers (purchased prior to 1984). This DSP includes budgetary provision for testing suspect distribution transformers for PCB content but replacing transformers that fail the PCB test have been deferred to beyond 2022.

3.2.3.3 Condition Assessment of Underground Distribution Assets:

The underground distribution network at PUC Distribution employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase circuits. Figure 20 shows the age profile of distribution cable on 3-phase circuits, operating at 34.5 kV and 12.5 kV and Figure 21 shows the age profile of single phase and two-phase cable circuits, operating at 12.5 kV circuits. As shown, approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service age are considered in poor condition. This DSP includes some funding for proactive replacement of underground cables with priority given to direct buried cable circuits as well as in voltage conversion areas. However, it is expected this will require more significant ‘ramping up’ of investment beyond 2022 to keep a failures rates level.

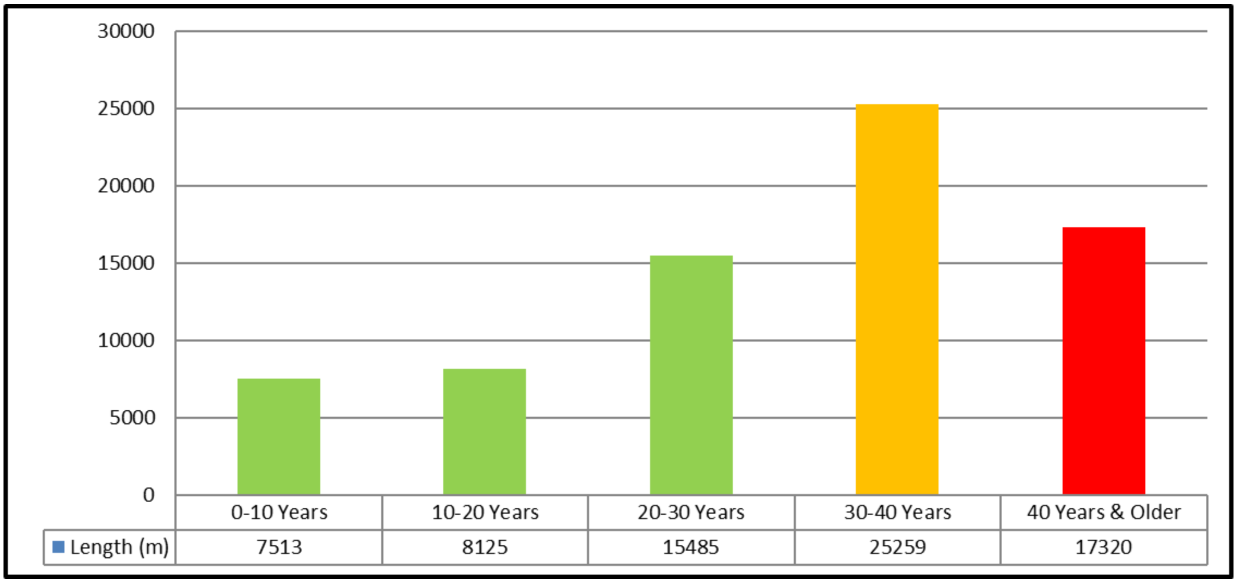


Figure 20: Age Profile of 3-Phase Cables on 34.5 kV and 12.5 kV System

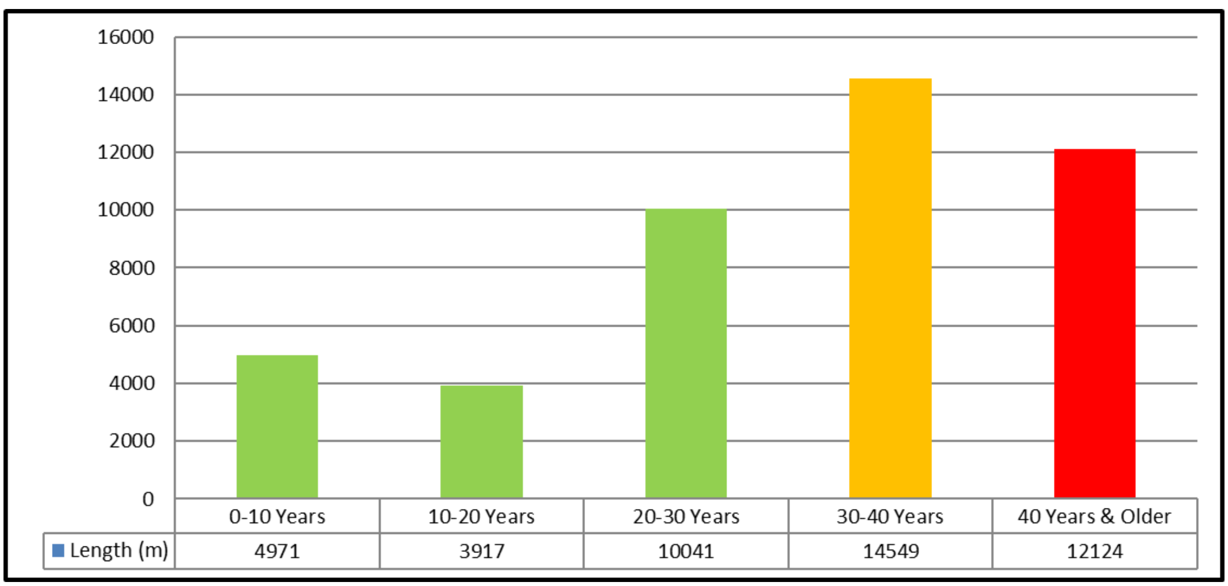


Figure 21: Age Profile of 1-Phase Cables on 12.5 kV System

Figure 22 and Figure 23, respectively, show the age profile of distribution cables employed on 3-phase and 1-phase circuits operating at 4.2 kV. As indicated, a majority of these cables are already past their 40-year typical useful service life. These cables will be removed from service when these service areas are upgraded to 12.5 kV and funding has been provided in this DSP for their renewal. The relatively small amount of cable circuits, with service age of less than 20 years on 4.2 kV system, are rated for use on 12.5 kV (in anticipation of the voltage conversion) and these circuits will remain in service after voltage conversion.

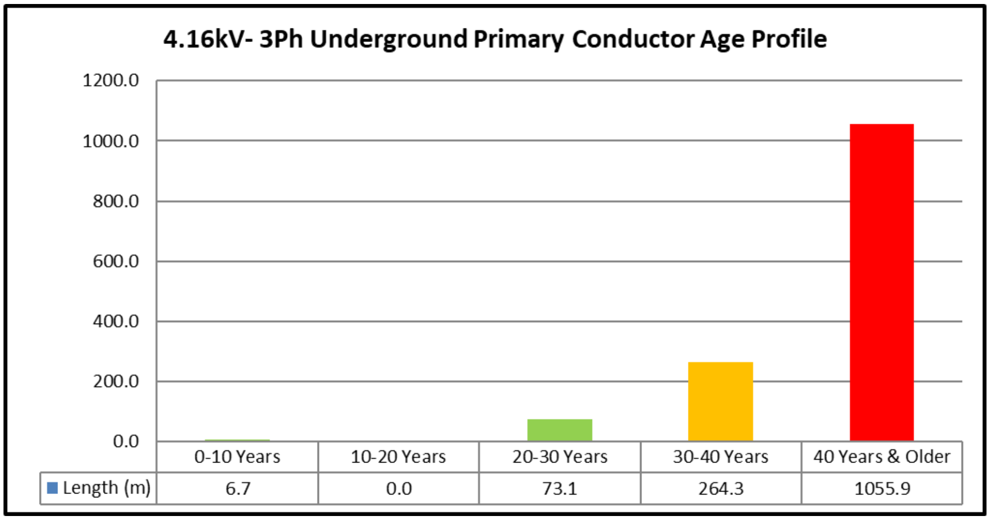


Figure 22: Age Profile of 3-Phase Cables on 4.2 kV System

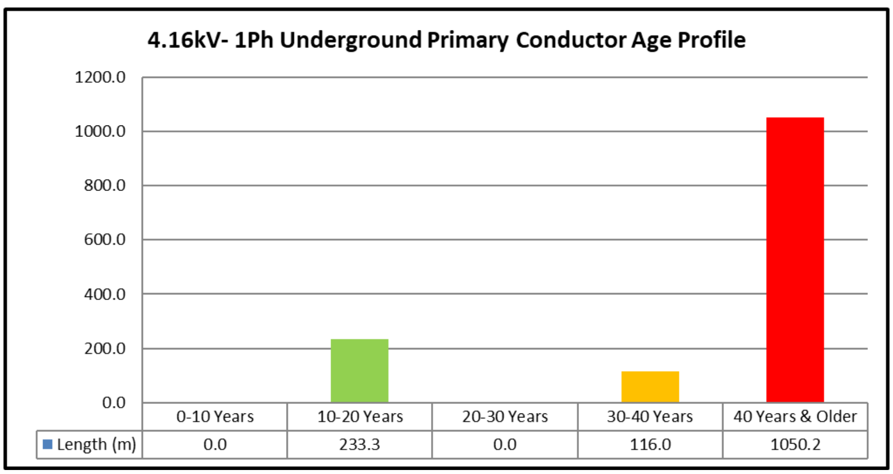


Figure 23: Age Profile of 1-Phase Cables on 4.2 kV System

Figure 24, Figure 25 and Figure 26, respectively, show the age profile of 3-ph pad-mounted transformers, 1-ph pad-mounted transformers and 1-ph submersible vault mounted transformers employed by PUC Distribution to serve customers supplied from the underground distribution system.

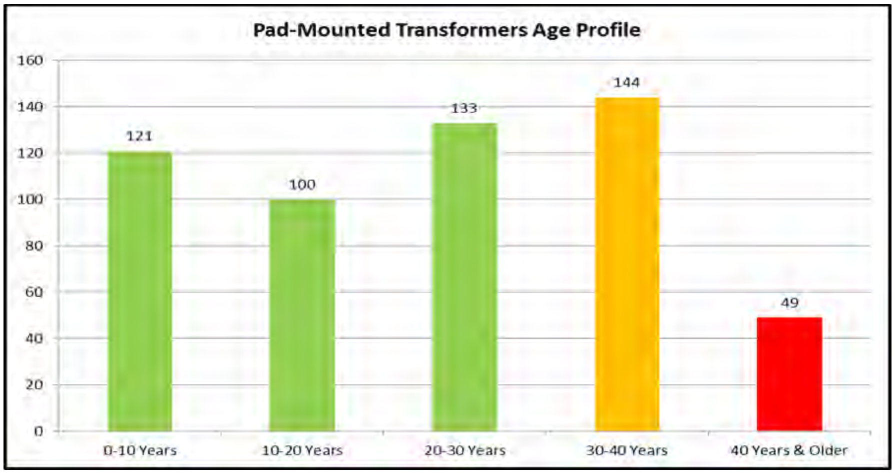


Figure 24: Age Profile of 3-Phase Pad-mounted Distribution Transformers

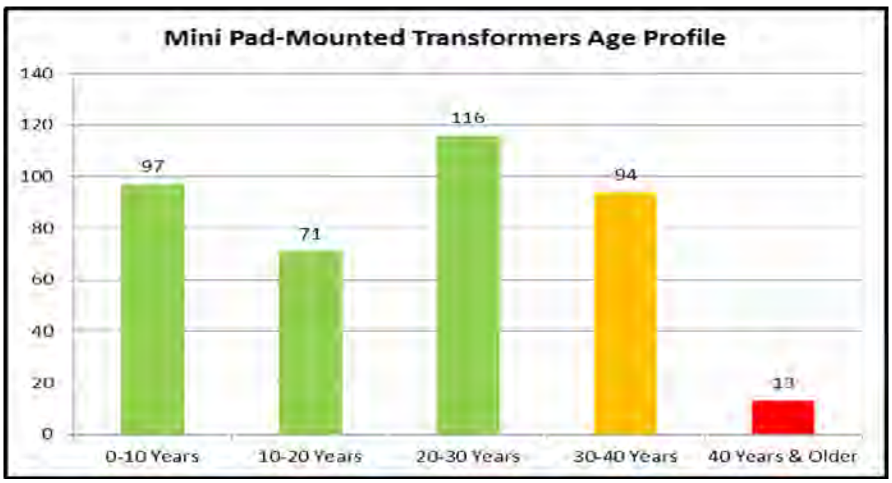


Figure 25: Age Profile of 1-Phase Pad-mounted Distribution Transformers

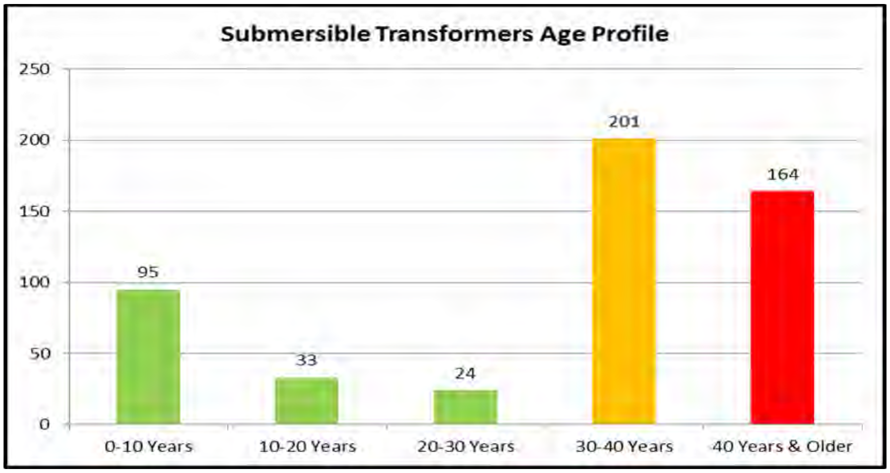


Figure 26: Age Profile of Vault-mounted Submersible Distribution Transformers

The Distribution System Plan does not target proactive replacement of distribution transformers, but rather a reactive approach, meaning transformers will be replaced after they have experienced a failure in service.

For switching of underground circuits, PUC Distribution Inc. employs live-front pad-mounted switchgear as well as ‘K-bar’ junction units. Based on the service age and visual inspections, five of the pad mounted switchgear units were determined to be in “poor” or “very poor” condition in 2016, as shown in Figure 27. This DSP includes funding for renewal of the pad-mounted switchgear found in very poor condition. Upon renewal, the live front switchgear will be replaced with dead front switchgear, providing enhanced worker safety.

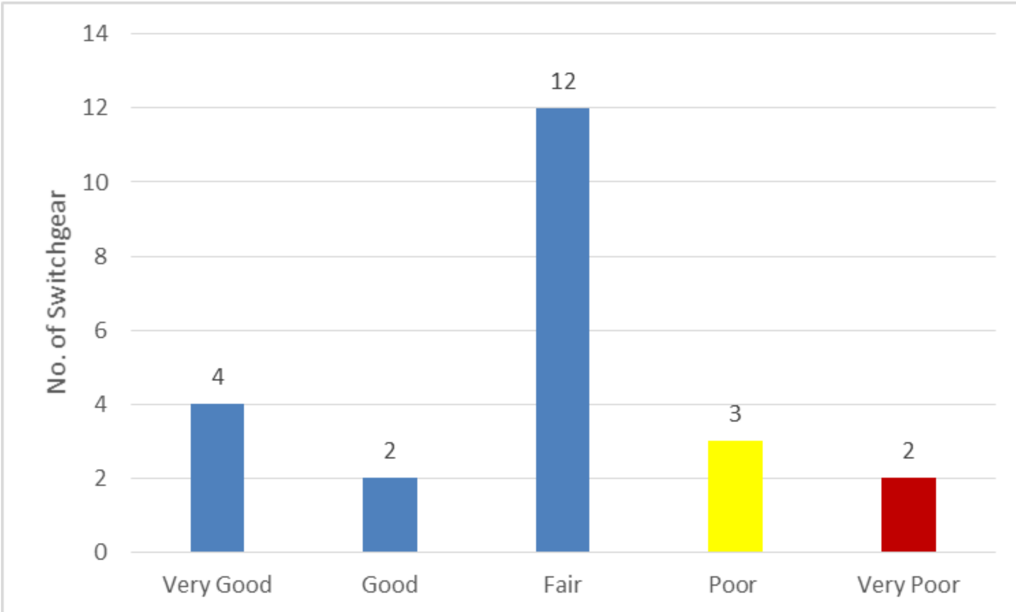


Figure 27: Condition Assessment of Pad-Mounted Switchgear

Figure 28 shows the age profile of junction units. As shown, 89 of the junction units had reached a service age of more than 35 years and these units will exceed the typical useful design life of 40 years during the next five years. During one-third plant inspections performed in compliance with Regulation 22/04, condition of the junction units will be assessed for safety and the DSP contains a modest budget to replace those found in unsafe operating condition.

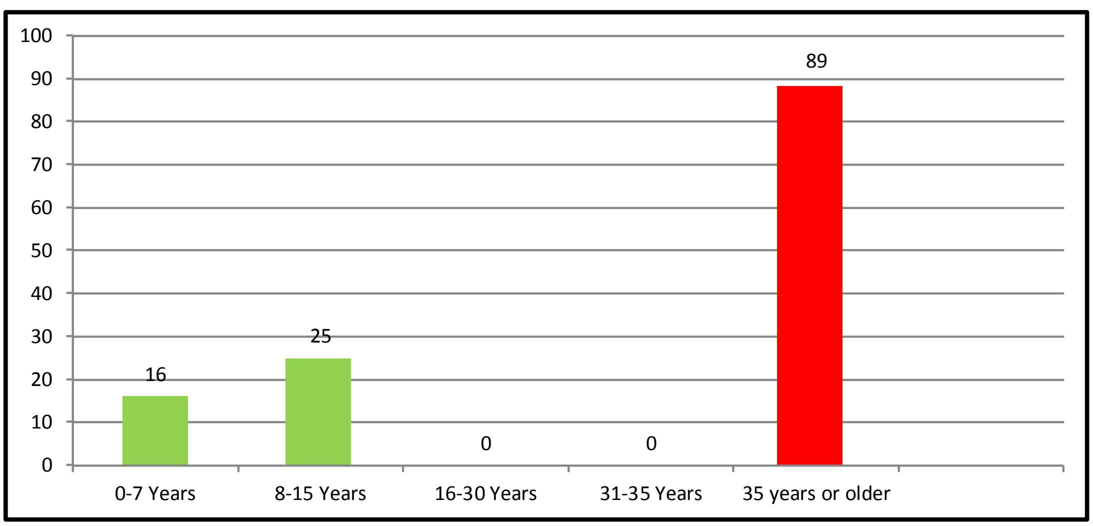


Figure 28: Age Profile of K-bar Units

PUC Distribution's underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. As shown in Figure 29, approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete. From the point of view of worker safety, the submersible transformer vaults and splice vaults present a challenge in that outages are required to complete maintenance work increasing costs and inconveniencing customers. Accordingly, funds have been included to make progress in the replacement of these vaults.

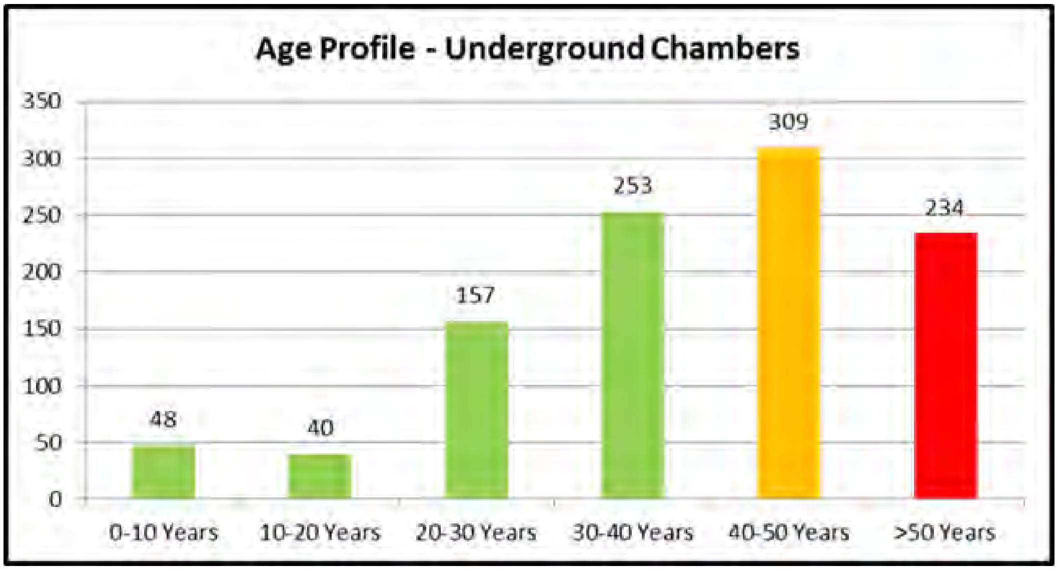


Figure 29: Age Profile of Underground Chambers

Figure 30: Typical Switching/Splice Vault on PUC Distribution System

The submersible transformer vaults and splice vaults of inadequate size and without concrete floors, as shown in Figure 30, present the highest risk to workers and therefore, have been given a priority for reconstruction in this DSP. After reconstruction, these vaults will be converted to vaults to support pad mounted equipment, mounted above grade.

In addition to the planned underground distribution System Renewal projects described above, this DSP also includes modest funds for emergency repairs and renewal of components that fail in service, during the next five years.

3.2.4 Capacity Assessment of Existing System [5.3.2 d]:

The chart in Figure 31 shows the historic peak load during each month over the past five years supplied from the PUC Distribution's supply network. As shown, the electrical load served by the supply system peaks during the winter season, typically in the month of January. The peak load served from the system during summer months, is typically about 55% less than the winter peak load. This prevailing seasonal loading pattern is desirable for avoiding equipment overloads, because loading capacity of the power equipment is higher during the winter months due to lower ambient temperature, when peak load occurs.

The figure also indicates a negative time trend in peak electrical demand on the distribution network. The peak load served from the system has experienced a decrease at the rate of approximately 2.8%, annually, due to a number of reasons, including the multiple CDM initiatives implemented by residential and general service customers, expansion of natural gas distribution network in the region and shifting of heating loads from electric heat to gas heating, and relatively slow growth in overall number of customers. Data in this figure was compiled in December 2016.

Figure 32 shows the forecasted peak electrical demand for the service area, based on which regional demand forecasts and planning have been completed and as indicated the peak demand served from the distribution network is expected to decrease from the current levels. Data in this figure was compiled in September 2014.

Table 19 indicates the peak load during the most recent winter of January 2017 for each of the power transformers and as indicated the peak loads are well within equipment nameplate ratings and there are no capacity constraints in the system. Due to negative time trend in peak demand, no capacity constraints are anticipated during the next five-year period covered by this DSP. Data in this table was compiled in June 2017.

Figure 31: PUC Distribution Service Territory – Past Five Year System Loading

		Peak Load (Net = Gross - DG - CDM)																	
TS Name or DP	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					Long Term Forecast (MW)					Power Factor
		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
[illegible] TS (T32)	Gross Peak Load				37.1	37.1	37.1	37.0	37.0	37.0	37.0	37.0	36.9	36.9	36.9	36.9	36.9	36.8	36.8	0.961
[illegible] (non-coincident)	Net Load	21.0	37.1	0.1																
[illegible] TS (T32)	Gross Peak Load				51.7	51.6	51.6	51.6	51.6	51.5	51.6	51.5	52.1	51.4	51.4	51.3	51.3	51.3	51.3	0.961
[illegible] (non-coincident)	Net Load	43.1	34.0	51.7																
[illegible] TS (T51)	Gross Peak Load				52.4	52.3	52.3	52.6	52.3	52.3	52.3	52.2	52.1	52.1	52.1	52.0	52.0	52.0	52.0	0.967
[illegible] (non-coincident)	Net Load	41.3	34.9	52.4																
[illegible] (T51)	Gross Peak Load				60.5	60.5	60.5	60.4	60.4	60.4	60.3	60.3	60.3	60.2	60.2	60.2	60.1	60.1	60.1	0.967
[illegible] (non-coincident)	Net Load	39.3	36.2	35.1																
Total PUC	Gross Peak Load				129.2	199.2	199.2	199.1	199.1	199.0	199.0	198.9	198.8	198.8	198.7	198.7	198.6	198.6	198.5	0.961
(coincident peak)	Net Load	149.9	132.2	159.2																0.967

Figure 32: PUC Distribution Service Territory – Peak Demand Forecast

Table 19: 34.5kV/12.5 kV Substation Ratings and Loading Level

Station #	Transformer #	Transformer MVA	Peak Load MVA	% Transformer Loading
TS-1	T1	30	16.33	54%
	T2	30	16.61	55%
	T3	30	19.22	64%
	T4	30	19.52	65%
TS-2	T1	30	19.73	66%
	T2	30	19.91	66%
	T3	30	14.03	47%
	T4	30	14.27	48%

Station #	Transformer #	Transformer MVA	Peak Load MVA	% Transformer Loading
Sub 1	T1	10	4.85	49%
	T2	10	3.68	37%
Sub 2	T3	10	7.31	73%
	T4	10	2.18	22%
Sub 4	T1	10	4.15	42%
	T2 (4kV)	10	1.68	17%
Sub 5	T1 (4kV)	5	0.05	1%
	T2 (4kV)	5	0.05	1%
Sub 10	T1	13.3	3.87	29%
	T2	13.3	4.74	36%
Sub 11	T1	10	4.64	46%
	T2	10	4.00	40%
Sub 12	T1	10	4.29	43%
	T2	10	4.94	49%
Sub 13	T1	10	5.76	58%
	T2	10	4.74	47%
Sub 14	T1	3	0.08	3%
	T2	3	0.08	3%
	T3	3	0.08	3%
Sub 15	T1	10	1.82	18%
	T2	10	2.95	30%
Sub 16	T1	7.5	6.57	88%
	T2	7.5	4.14	55%
Sub 18	T1	7.5	4.91	65%
	T2	7.5	5.01	67%
Sub 19	T1	10	2.57	26%
	T2	10	8.82	88%
Sub 20	T1	10	3.33	33%
	T2	10	6.45	65%
Sub 21	T1	10	4.91	49%
	T2	10	4.69	47%

3.3 Asset Lifecycle Optimization Policies and Practices [5.3.3]

In preparing the DSP, PUC Distribution's overarching objective was to develop a capital and preventative maintenance investment plan, which would result in optimal operating performance to meet various stakeholder needs and ensure regulatory compliance, while minimizing life cycle costs, as shown in Figure 33.

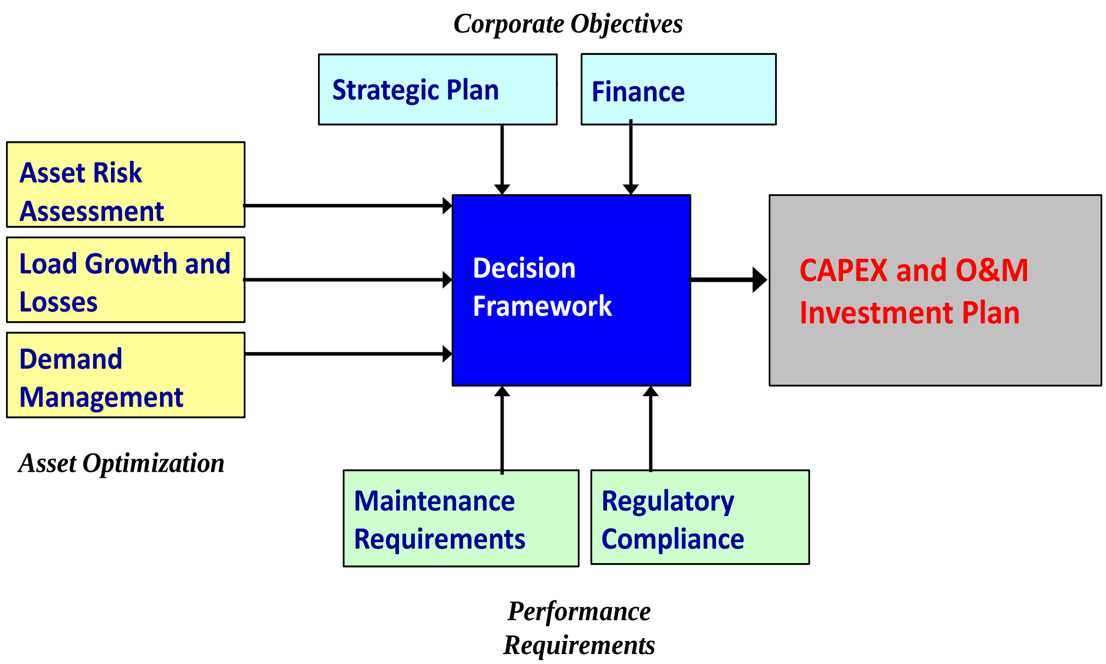


Figure 33: Multi-Prong Decision Framework

The life cycle optimization policies and procedures employed by PUC Distribution include determining the optimal time and scope of the most effective risk mitigation option, through trade-offs between capital expenditure, preventative maintenance and reactive maintenance. Figure 34 shows the basic decision support model employed by PUC Distribution in preparing this distribution plan, to determine the scope and timing of the investments. With increase in an asset's service age, its operating condition degrades, thus increasing the risk of the asset failing in service. In the absence of any intervention in form of asset renewal or asset refurbishment or repair, the consequential risk cost would continue to increase. When a risk mitigation intervention is implemented through an investment, the risk cost curve resets, triggering a benefit in form of reduced risk. In preparing the DSP, the timing and size of investments have been selected to minimize the "Total Cost" of the risk and the risk mitigation initiatives.

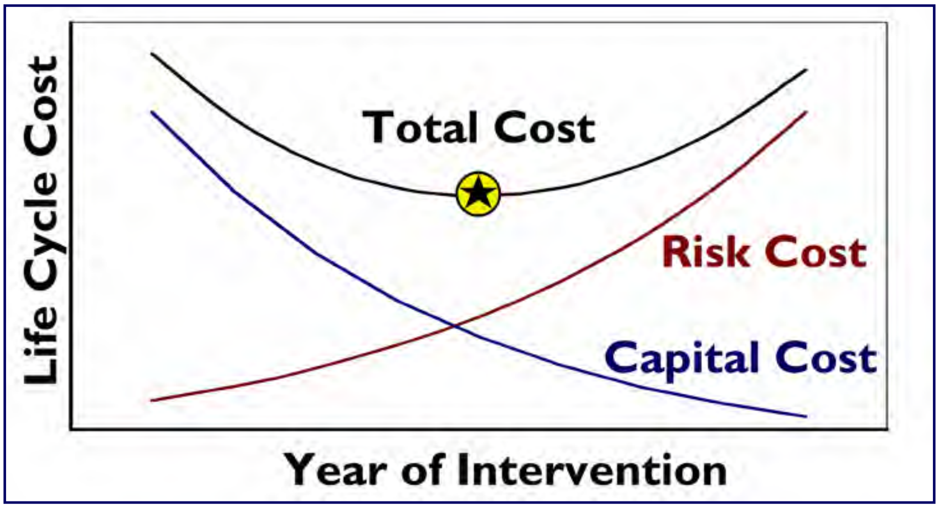


Figure 34: Risk Based Decision Support System

Figure 35 illustrates the impact of maintenance activities in extending the service life of an asset.[1] In Figure 35, Maintenance Policy 1 represents a reactive maintenance policy, in which no planned maintenance is carried out and asset components are repaired or refurbished only after they break down or reach a stage that they fail to perform their intended functions. Maintenance Policy 2 represents, proactive asset maintenance, in which condition of an asset's components are assessed periodically through inspections, testing and recent asset performance and maintenance activities are proactively performed to prevent impairment in asset performance with the intent of extending the economic service life of assets. Under Maintenance Policy 2, Optimization is carried out with the objective of minimizing overall life cycle costs of electricity distribution assets, while meeting the required performance levels, by taking into account all available information relevant to the condition of assets. As shown in Figure 35, Maintenance Policy 2 would be economically efficient, so long as the incremental asset value achieved through an assets' life extension is greater than the incremental maintenance cost resulting from Policy 2.

Following this value concept, PUC Distribution's maintenance planning criteria is rooted in adopting a maintenance policy that results in lowest life cycle cost for assets. For those assets, where the incremental value obtained in form of extended asset life is greater than the cost of maintenance activities, Policy 2 is adopted. These assets include high value power equipment installed in stations. Periodic inspections at more frequent intervals are performed and

[1] "Predicting Future Asset Condition Based on Current Health Index and Maintenance Level" Thor Hjartarson, Shawn Otal, IEEE 11th International Conference on Transmission & Distribution Construction, Operation and Live-Line Maintenance, 2006, ESMO, Oct. 20

maintenance activities are scheduled by taking into account the condition of assets. For lower value assets, maintenance activities are performed in a reactive mode and the scope of repairs is limited to rectifying deficiencies found during safety inspections. Periodic asset inspections and testing provide valuable information on assets' health and probability of assets' failures, allowing appropriate risk management initiatives to be implemented over the lifecycle of each asset.

As an example PUC Distribution has employed this model as follows for in-situ testing of wood poles. All poles are tested and inspected on a seven year cycle. Poles that are determined to be in acceptable condition are deemed satisfactory until the next test cycle. Poles that exhibit significant deterioration but are still structurally sound are treated or maintained using boron rods to extend their service life. Poles that are more significantly deteriorated are scheduled for replacement.

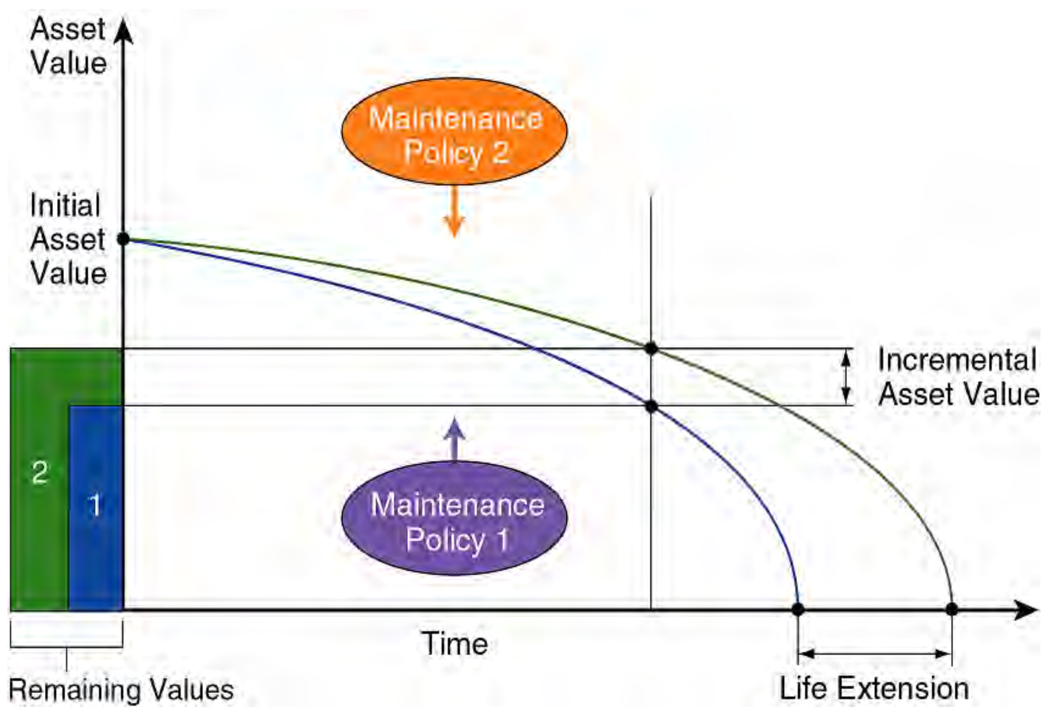


Figure 35: Risk Based Decision Support System

PUC Distribution's Operations & Maintenance ("O&M") programs are designed to follow the guidelines set out in the OEB's Appendix-C DSC for the inspection and maintenance of all key distribution system assets. PUC Distribution reviews its O&M programs annually in order to best align with our capital programs and aligning the program with the best industry practices and standards. Inspection and testing of assets is critical for the prioritization of operations and maintenance spending and optimization of the total life cycle asset cost. The results of inspections and testing are used to identify and prioritize system rehabilitation projects, resulting in selection of the optimal decision to either replace, repair or do-nothing. Assets for which replacement is identified as the optimal solution are included in the capital plan for replacement. For assets where replacement during the next five years is not determined to be the optimal solution, PUC Distribution's O&M programs include minor repairs and maintenance work designed to economically extend the life of assets. In both cases, planned replacement projects and planned operations and maintenance activities are selected in order to align with the budget envelopes by optimizing the scope and timing of work during project prioritization and selection processes.

PUC Distribution employs the results of visual inspections, in-situ testing and service age of assets to determine the condition of assets by deriving a health index for each asset. The health index is related to the probability of failure for the asset by relating the health of the asset to an effective age and corresponding known failure curve. The probability of failure data is multiplied by the consequences of failure for assets within a project area to arrive at a risk score. Consequences of failure are derived from the analysis of each project area and classification in terms of potential impacts to worker and public safety, the environment, reliability and operational effectiveness that could arise if a failure event occurs. Once the risk of each project area has been established it is placed into a prioritization and selection process that determines which projects require action and the extent of the action that is necessary to minimize unacceptable risks.

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process. Assets with unacceptably high risk scores are monitored closely and plans are included in project scope to alternatively maintain, refurbish or replace the assets to reduce the risk to an acceptable level. It is noteworthy that some assets carry an inherently higher risk than others, for example, power transformers at stations have a higher nominal risk level associated with them in relation to pole mount transformers. Assets with low health indices and higher consequence risk are given a priority for replacement, while assets with low health indices but lower consequence risk are given a lower priority for replacement. The top projects in each category are identified in the prioritization process and scrutinized using further investigation and expert opinion to eliminate data inconsistencies and determine appropriate scopes of work.

3.3.1 Preventative Maintenance and Safety Inspections

Proper maintenance is essential to prolong asset lifecycles and maintain system reliability. PUC Distribution's maintenance program employs equipment manufacturer's recommendations as well as best industry practices in determining the scope and frequency of maintenance on power equipment. Maintenance programs comply with all regulated requirements as prescribed in the Distribution System Code. In distribution and transformer stations, where applicable, maintenance also meets IESO and NERC requirements and is completed in accordance with associated elements from the Transmission System Code and best practice IEEE guidelines. Many new requirements have been introduced due to the recent implementation of an IESO mandated under-frequency load shedding (UFLS) scheme.

3.3.1.1 Preventative Maintenance of Critical Equipment in Substations

PUC Distribution's planned substation maintenance schedule is summarized in Table 20.

Table 20: Substation Preventative Maintenance

	Visual Inspection of Assets	Testing of Insulating Oil Samples, and Infrared Scanning	DC System Maintenance	Full Off-line Substation Maintenance (Annual Cycle Tests)
Distribution Stations	Monthly	Annually	Quarterly	Once in six years
Transformer Stations	Weekly	Annually	Quarterly	Once in four years

Monthly inspections at distribution substations and weekly inspections at transformer stations include the following tasks;

- Inspect substation security (gates locked, fence condition, warning signs and emergency contact information posted).
- Inspect substation yard and building condition, including vegetation growth, snow bank accumulation, garbage, vandalism, etc.
- Inspect substation electrical safety, including fence grounds, bonds, equipment grounds, insulators, foundations, ancillary equipment, metal clad fastenings and corrosion related impairment of assets
- Power Transformer Inspections, including checking and recording oil level, oil temperature, equipment grounds, feeder load readings (Amps)
- Inspect Access and Egress Riser Poles
- Verify AC voltage to Battery Banks
- Inspect Batteries

- Inspect and record Relay Voltage, Amps etc.

The annual cycle maintenance of substation equipment includes thorough inspection, testing and maintenance of all power equipment installed at substations. The substation is taken out of service typically for an extended period to perform maintenance. The station maintenance work includes;

- Oil Testing of Transformers (standard 5 part ASTM and DGA)
- Clean and lubricate switches and fusing
- Conduct Insulation Resistance Testing
- Protection Relays are injection tested to verify settings and ensure operating times adhere to the manufacturers specifications
- Clean and lubricate switchgear, ensure proper operation
- Conduct IR scans of all high voltage electrical equipment (insulators, switches, cables, connections and riser poles)
- Oil Testing of Transformers (standard 5 part ASTM and DGA)
- DC System batteries are maintained as per manufacturers specifications on a quarterly basis at all distribution and transformer stations

3.3.1.2 Vegetation Management Program

PUC Distribution's service territory is divided into 4 sections in order to delineate the areas for the purpose of maintaining safe clearance of trees and branches from distribution system lines and equipment. Vegetation growth around distribution system lines is managed according to our Utility Vegetation Management program on a 4-year cycle by attending to each section in succession on a yearly basis.

- Line clearing activities are predominantly completed via a contract that specifies removal of vegetation growth within 3m of primary conductors and 1.5m of secondary conductors. Identification and removal of danger trees, as well as brushing and herbicide treatment of right-of-way where appropriate are included to ensure a comprehensive program.
- Substation herbicide treatment (as required)

During 1/3 plant inspections PUC Distribution line crews sometimes identify dead or unstable trees that could impact public safety or system reliability. The identified "danger" trees are then removed by PUC Distribution line crews or facilitated during the contract period depending on urgency. Although danger tree and customer requested removals are predominantly completed within the scope of an outside contract, PUC Distribution line crews will also perform work to maintain safe clearances throughout the year in response to urgent safety or reliability issues or storm damage. All customer requests for tree related issues are tracked as Customer Service Orders through the Customer Information System.

3.3.1.3 Safety Inspections of Overhead and Underground Distribution Assets

PUC Distribution lines and underground distribution system plant are inspected on a 3-year cycle, to comply with the Distribution System Code requirements. One third of the distribution assets employed on PUC Distribution's supply network are inspected each year. Structural defects, clearance issues and electrical problems and hazards are identified through visual inspections and where problems are revealed, either repair work is scheduled or capital work is planned, as needed. Where the inspections determine an immediate hazard to the public, immediate follow up action is taken to mitigate the problem.

4 Detailed Capital Investment Plan [5.4]

This section summarizes PUC Distribution's capital expenditure plan, which has been developed to meet PUC Distribution's strategic corporate objectives. The capital expenditure plan was developed based on the outputs of the risk-based asset management process, described in detail in Section 3 Projects have been divided into the four categories as outlined in the OEB Filing Requirements.

4.1 Key Information about Capital Expenditure Plan [5.4.1]

4.1.1 Distribution System Capability to Connect New Load or Generation [5.4.1a]

As previously described in Section 3.2, PUC Distribution's distribution system has adequate capacity to connect all anticipated loads and generation customers during the next five-year period, covered by this DSP. Currently there are no applications in queue from distributed generation customers waiting to be connected to the grid under any IESO REG programs; and all previous requests received to date have been successfully connected to the system.

4.1.2 Summary of Annual Capital Expenditures by Investment Category [5.4.1b]

The capital investments (net of contributed capital) for the bridge year (2017) and the forecast period (2018 to 2022) are summarized in Table 21. Additional detailed information on the proposed capital projects exceeding the materiality threshold for projects in the test year (2018) is provided in Table 22 and Appendix G.

Table 21: Proposed Capital Investments during DSP Implementation Period

	2017	2018	2019	2020	2021	2022
System Access	$ 1,271,457	$ 1,511,028	$ 1,615,276	$ 2,086,480	$ 1,603,804	$ 1,560,434
System Renewal	$ 3,372,227	$ 3,761,033	$ 6,905,898	$ 3,296,444	$ 4,532,889	$ 7,092,642
System Service	$ 38,236	$ -	$ -	$ -	$ -	$ -
General Plant	$ -	$ 86,294	$ 54,629	$ 61,932	$ 59,853	$ 55,100
Total Capital Expenditure	$ 4,681,920	$ 5,358,355	$ 8,575,803	$ 5,444,856	$ 6,196,546	$ 8,708,176
System O&M Expenditure	$ 5,856,582	$ 6,212,629	$ 6,305,819	$ 6,400,406	$ 6,496,412	$ 6,593,858

Table 21 shows the planned capital investments broken down into each of the four general categories: System Access, System Renewal, System Service, and General Plant.

The planned investments into System Access are intended to facilitate the anticipated growth and allow connection of new customers to the grid, meeting requests of existing customers for increase in service size, meeting PUC Distribution's regulatory obligations for relocating distribution lines when requested by the municipality, for joint use make-ready work for telecommunications and for re-calibration and renewal of the revenue meters in compliance with the Measurement Canada regulations. A modest recovery in the local economy is anticipated during the next five years, resulting in a small increase in requests for new services from the existing levels. There are presently two residential subdivision developments being planned for 2018 and 2019, and these will require capital investments in System Access category to meet the requests for new services. Road reconstruction projects undertaken in the municipality require relocation of some power distribution lines, requiring capital investments by PUC Distribution. PUC Distribution has employed the City's 5-year development plan to estimate capital expenditure required for line relocates and rebuilds to accommodate municipal infrastructure projects. The planned System Access investments include funding for residential revenue meters, required to replace meters failed in service as well as to equip all general service customers with >50kW to <500kW demand with MIST meters. The planned investments in this category also include funding for "make ready work" to allow joint sharing of the distribution facilities by the communication network companies. The indicated investments in the System Access category represent net expenditure by PUC Distribution, after third party contributions have been subtracted from the total cost.

The planned investments into System Renewal are intended to mitigate a number of specific prevailing risks to distribution system reliability, safety and adverse environmental impacts, due to very poor condition of some key assets, the in-service failure of which would lead to significant negative outcomes. As described in greater detail in Section 3.2.3, those assets, the condition of which has already reached a state of impairment that they present a very high risk of failure in service are assigned "very poor" condition and those assets with significant impairment causing performance to degrade below acceptable level and presenting a high risk of failure in service in the absence of major repair or rehabilitation or renewal, are assigned "poor condition". The scope of capital investments planned in the "System Renewal" category has been determined with the objective of keeping power supply reliability from deteriorating below the acceptable level, as indicated by SAIFI and SAIDI targets. In order to keep the overall investment envelope for this DSP within a range, which would not result in retail rates escalations beyond the affordability of PUC Distribution's customer base and which could be successfully implemented without stretching beyond limit PUC Distribution's financial resources; investments required for renewal and rehabilitation of the assets found in "very poor" or "poor" condition have been spread out over a time period of longer than five years and assets with highest consequence of failure in service, have been prioritized for renewal or rehabilitation, during the next five years.

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds and voltage upgrade, will also introduce smart grid features including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve a dual role: System Renewal as well as System Service.

PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover minor building renewal items. The scope and timing of the investments in each category has been determined by taking into account all information available at the time of preparation of the distribution plan.

The capital investments proposed for the 2018 to 2022 period are expected to yield the following benefits:

i. The investments into the System Access category would allow PUC Distribution to meet its obligations to serve new customers, relocate lines in public right-of-way, upon receipt of requests for such services, perform "make ready" work for allowing third party attachments of electricity distribution poles and to have adequate supply of revenue meters to comply with the requirements of the Distribution System Code and Measurement Canada.

ii. The investments into the System Renewal will reduce the risk of critical assets' failure in service and help sustain the reliability at acceptable levels and ensure public safety. These investments will also help avoid an increase in operating costs by eliminating the increase in extent of emergency repairs upon asset failures. Retiring from service the distribution system infrastructure operating at 4 kV will eliminate duplication in spare part requirements and will result in improved operating efficiency.

iii. Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

Planned investments into O&M are aimed at providing customer services matching the service quality and power supply reliability targets. These investments not only including funding for power restoration with adequate speed, following interruptions, but also include funding for safety inspections, tree trimming, equipment testing to prevent and reduce the incidents of power interruptions. O&M investments also including funding for preventative maintenance of high value assets to prevent asset impairment and ensure the assets don't fail pre-maturely.

4.1.3 Capital Expenditure Relation to Asset Management Plan [5.4.1c]

The capital expenditure proposed in this DSP and summarized in Table 21 is in response to the following primary drivers:

- System Access;
- System Renewal;
- System Service; and
- General Plant Upgrades.

System Access Investments

System Access investments comprise about 24% of the proposed capital investments during the forecast period [Table 21]. The planned investments in the System Access category are required for PUC Distribution to meet its regulatory obligations inclusive of the Distribution System Code and PUC Distribution's Conditions of Service and are, therefore, mandatory expenditures. Planned investments in this category are included to connect new generation and load customers, permit service upgrades requested by customers, allow line relocates in response to requests from municipalities, support joint-use installations by third party communications parties and fund investments into revenue metering. Planned expenditure into System Access in 2020 is markedly greater than the rest of the years to allow for the needed investments to facilitate calibration and replacement of revenue meters and equipping customers with a demand greater than 50kW with meters capable of supporting 'Metering Inside the Settlement Timeframe' (MIST) to comply with the recent changes in regulatory requirements. PUC Distribution has considered a number of factors from their asset management and capital expenditure process to determine the allocation of investment in System Access:

- Consultation with major stakeholders including customers, municipal governments, CDM program partners and the OPA/IESO. These consultations allowed PUC to coordinate infrastructure planning with the City of Sault Ste. Marie and identify investment level requirements required to support projects for subdivisions, joint use and general services.
- Consultation with existing customers both residential and general service, through formal and informal community engagement activities. The reports from these consultations inform the PUC's understanding of current and future electrical needs and helps PUC plan the system accordingly in support of System Access investments.

Due to the fact that planned investments in the System Access category are mandatory, the full annual estimated expenditures have been included. Investments in the remaining three categories (System Renewal, System Service and General Plant) have been prioritized utilizing the asset management strategy described in Section 3 and have been allocated the balance of available capital funds premised on the available financial envelope.

System Renewal Investments

System Renewal investments contribute the largest portion, at 75%, of the proposed capital investment budget Table 21. Planned investments into System Renewal are based on reducing the risk associated with asset failures to optimal levels, based on the results of asset condition assessment which is included in Appendix B. The asset health information is also one of the inputs for the prioritization process described in Section 3.1.2 Consultations with existing customers and the resulting information about customer preference is taken into account to ensure that only the projects with the highest risk of failure in the next five years are included in the System Renewal plan. While, optimal risk considerations required the System Renewal investments to be greater than the planned amount indicated in Table 21, the investment level in this category was reduced from the optimal amount to keep retail rate escalation from reaching an unacceptable level. Furthermore as indicated in Table 22 forced overhead and underground renewal are mandatory for the purpose of restoring service to customers. Investments into System Renewal during 2019 and 2022 are significantly greater than the rest of the years because they includes investments for a distribution station rebuild during each of these years.

System Service Investments

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds and voltage upgrades, will also introduce smart grid features including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve a dual role: System Renewal as well as System Service.

General Plant

General Plant makes up only about 1% of the proposed capital investment budget. PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover equipment and minor building renewal items.

4.1.4 Material Capital Expenditure Projects/Activities [5.4.1d]

Proposed investments during the test year into individually identifiable projects, exceeding the materiality threshold for PUC Distribution are summarized in Table 22. The table also provides an indication of the spending level by category (System Access, System Renewal) for projects above the materiality threshold in relation to the total spending, including projects above and below the materiality threshold.

Priority rankings for each of the projects above the threshold of materiality have been determined using a two-step process. Firstly, utilizing the methodology presented in Section 3.1.2., a shortlist of the most critical projects was determined for the test year. This shortlist of projects was then ranked by applying a second set of refinement criteria also aligned with the same methodology. The refinement criteria and the relative weighting of each is identified below;

- **Public safety** (40%) - safety risks and consequences of equipment failure
- **Customer outage impact** (10%) - quantity of customers affected and duration of outage
- **Customer value per dollar** (15%) - quantity of customers affected as a function of total project cost
- **System Service improvements** (10%) - projects exhibit value in supporting the OEB System Service category as a secondary driver to System Renewal e.g.: station upgrades will support the connection of REG through new protective equipment upgrades
- **Project interdependence** (25%) - projects that, if not completed, would negatively impact the ability to complete future planned projects

System Access investments are a regulatory obligation for distribution companies (as defined in the Distribution System Code and PUC Distribution's Conditions of Service) and therefore the first four projects in Table 22 in the System Access category, received the highest priority in the overall investment envelope. System Renewal is the primary driver for the next 9 projects planned to be implemented during the test year. Out of these the first two projects involve renewal of assets in a reactive mode, e.g. replacing a distribution transformer or underground cable etc. after an asset has failed in service, in order to restore power. These projects also received the highest priority score, because their implementation is mandated in order for PUC Distribution to fulfill its regulatory obligations to supply electricity to all customers connected to the grid. The next seven projects, listed in order of priority, involve proactive asset renewal to prevent failure of critical assets in service.

As described in detail, in Section 4.1.8, all of the material System Renewal projects in Table 22 re in response to customer preference. Of those customers willing to consider additional costs the highest preference was towards replacement of aging equipment to maintain or improve reliability. Therefore, the focus of the investments proposed in this DSP is to preserve the existing supply security and reliability levels and prevent them from degrading. In addition, the Substation 16 rebuilt project takes advantage of technology based solutions to improve operational efficiency and potential to integrate additional distributed generation and complex loads. Detailed descriptions for each of these projects exceeding the threshold of materiality are provided in Appendix G.

Table 22: Proposed Capital Investments during Test Year - Projects over Materiality Threshold

Category	#	Project Code	Project Description	Priority Ranking	Planned Expenditure in 2018
System Access	1	1C100-1	Customer Demand - Services	1	$ 912,047
	2	1C100-2	Customer Demand - New Subdivisions	1	$ 107,153
	3	1C100-3	Customer Demand - Joint Use	1	$ 97,153
	4	1C100-4	Customer Demand - City Projects	1	$ 224,305
			Total (Material Projects Only)	-	$ 1,340,658
			Grand Total (Material and Non-material)	-	$ 1,511,028
System Renewal	5	1C200-1-1	Forced Overhead Renewal	1	$ 252,343
	6	1C200-1-2	Forced Underground Renewal	1	$ 308,593
	7	1C300-3-7 - A	Substation 16 Rebuild	2	$ 419,687
	8	1C300-1-2	Overhead Renewal - Poles	3	$ 314,765
	9	(2018) 1C300-1-4C	Overhead Renewal - Restricted Wire (Wallace Terr., 2nd, 5th, 6th Ave., Devon Rd. & Woodcroft Ave.)	4	$ 433,676
	10	(2018) 1C300-2-4	Underground Renewal - Voltage Conversion (Laronde Ave., Koprash Crt.)	5	$ 531,603
	11	(2018) 1C300-1-4B	Overhead Renewal - Restricted Wire (Red Pine Drive - North of Pnt. Of Pins)	6	$ 349,739
	12	(2018) 1C300-1-3A	Overhead Renewal - Voltage Conversion (MacDonald Ave - Lake St. to Moluch St.)	7	$ 288,020
	13	(2018) 1C300-1-4A	Overhead Renewal - Restricted Wire (Carpin Beach Rd - Base Line to Herkimer, Phase 1 of 2)	8	$ 185,155
			Total (Material Projects Only)	-	$ 3,083,581
			Grand Total (Material and Non-material)	-	$ 3,761,033
Total Expenditure on Material Projects During Test Year					**$ 4,424,239**
Total Expenditure on Capital During Test Year (System Access, System Renewal, System Service and General Plant Inclusive)					**$ 5,358,355**

The project prioritization criteria along with scoring to determine project priority rankings are shown in Table 23. Some details as to how the specific projects for the test year were scored are as follows:

Sub 16 Rebuild – Phase II of III

Other than safety, all of the remaining criteria contributed significantly to making this the highest priority planned project. This station serves approximately 2400 customers therefore outage impacts, and customer value for dollar received corresponding high ratings. This project also brings value in the form of improved System Service; protective relays and communications technology will allow for the future connection of REG and smart grid opportunities.

Deteriorated Poles

The predominant criteria that served to rank deteriorated poles as the second highest priority project was public safety due to the potential failure mode of this asset class.

Restricted Wire Projects

Three restricted wire projects were identified in the test year above the materiality threshold. They are ranked fourth, sixth and eighth in terms of overall priority. Public safety impact is the predominant driver. The differentiator between projects in this category is premised on number of customers impacted by each project and the corresponding value for money.

Voltage Conversion

There are two voltage conversion projects selected for construction in 2018 that are ranked fifth and seventh. Project interdependence was the primary criteria that impacted the scoring. These projects need to proceed to allow the retirement of two end-of-life 4.16kV substations (Substations 4 and 5). These and are planned for removal from service during the latter part of the 2018-2022 rate application period.

Table 23: Prioritizing Matrix for Test Year Projects over Materiality Threshold

Rank	Primary Factor[10]	Area	Program	Project	Public Safety Impact				Outage Customer Impact				Customer Value for $				System Service Improvements				Project Interdependance				Score
					Weight			40.0%	Weight			10.0%	Weight			15.0%	Weight			10.0%	Weight			25.0%	
					R	C	PSI	PSI (n)	QTY	HRS	COI	COI (n)	$K	C	CV	CV (n)	QTY	SIV	SSI	SSI (n)	SQI	FI	PI	PI (n)	
1	Customer Preference	System Access	N/A	N/A	Ranked as first priority as these are non discretionary																				N/A
1	Customer Preference	Forced Renewal (System Renewal)	N/A	N/A																					N/A
2	Customer Preference, Technology Based	Planned Projects & Programs (System Renewal)	DX Stations	Sub 16 Rebuild - Phase II of III	2	5	10	1.0%	2417	3	7251	8.3%	420	2417	5.8	10.5%	2417	5	12085	9.5%	5	10	50.0	7.4%	36.7%
3	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Poles - Det. Poles	10	10	100	9.7%	160	1.5	240	0.3%	210	160	0.8	1.4%	160	1	160	0.1%	1	5	5.0	0.7%	12.2%
4	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Wallace Terrace/2nd Ave./5th Ave./6th Ave./Devon Rd./Woodcroft Ave.	7.5	10	75	7.3%	254	3	762	0.9%	442	254	0.6	1.0%	254	1	254	0.2%	5	1	5.0	0.7%	10.1%
5	Customer Preference	Planned Projects & Programs (System Renewal)	UG Renewal	Volt. Conv. - Laronde/Koprash	1	1	1	0.1%	79	1.5	119	0.1%	542	79	0.1	0.3%	79	1	79	0.1%	5	10	50.0	7.4%	8.0%
6	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Red Pine Dr. (N of Pnt of Pins)	7.5	10	75	7.3%	32	3	96	0.1%	357	32	0.1	0.2%	32	1	32	0.0%	3	1	2.5	0.4%	8.0%
7	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Volt. Conv. - MacDonald (Lake to Moluch)	1	1	1	0.1%	26	1.5	39	0.0%	294	26	0.1	0.2%	26	1	26	0.0%	5	10	50.0	7.4%	7.7%
8	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Carpin Beach Rd. (Base Line to Herkimer) PH 1 of 2	5	10	50	4.9%	12	6	72	0.1%	189	12	0.1	0.1%	12	1	12	0.0%	1	1	1.0	0.1%	5.2%

Notes Regarding Ranking Methodology

1) Public Safety Impact (PSI) due to failure = Risk (R) x Consequence (C) where (R = (1 = low, 10 = high)= - 1, C = (1 = low, 10 = high)
2) Customer Outage Impact (COI) = (Qty Customers Affected (QTY) x anticipated outage hours/year (HRS))
3) Customer Value (CV) = Cutomers Served (C) / $100,000($K)
4) System Service Improvements (SSI) = Qty Customers Affected (QTY) x Service Improvement/Enhancement Value (SIV) factor, (1 = low, 5 med, 10 = high)
5) Project Interdependence (PI) = Impact of a project not proceeding negatively impacting the ability to complete other future planned work = (SQI = service quality impact x FI = financial impact), values (1 = low, 10 = high)
6) Score = Sum of five factors above (Public Safety, Outage Customer Impact, Customer Value after weighting each equally (ie: 20%) allowing for a maximum atainable score of 100%
7) (n) represents a normalized score where for the ranked projects, each is normalized to a scale of 0%-20%
8) Rank is determined by placing Scores for all planned capital projects in a rank ordered list. A rank of 1 represents the highest priority. Non-discretionary customer demand work and capital work driven by unplanned repairs have all been weighted equally and assigned a Rank of 1
9) It is noted that the projects within this matrix are those previously screened through the Asset Management Plan process and they therefore represent only the most critical projects identified and prioritized throug that process
10) Primary Factor categories include (a) Customer Preference, (b) Technology Based and (c) Innovative Process

4.1.5 Impact of Regional Planning Process [5.4.1e]

The regional planning process identified no system constraints in the upstream system and has no impact on the investments proposed in this DSP.

4.1.6 Impact of Customer Engagement Activities on DSP [5.4.1f]

As described in Section 2.1.1, during customer engagement sessions, a vast majority of PUC Distribution's customers have generally indicated satisfaction with the current reliability and service quality levels. Even so, it was also identified that the customer priority and preferences were directed at improving reliability, better communications and consultations (including related to outages and projects) and a managed approach to infrastructure renewal (replace before failure respecting safety and large reliability impacts). Customer surveys also indicated sensitivities towards rising electricity prices and indicated preference to lower electricity rates. Of those customers willing to accept additional costs, the highest preference was towards replacement of aging equipment to maintain or improve reliability and lower preference to smart grid features allowing customers opportunities to manage their electricity use.

In view of this feedback, this DSP has been prepared to keep the retail rate escalations at a modest level, by accepting a greater level of risk of asset failures in service where impacts can be mitigated through spares and alternative supply. In view of the customer sensitivities to rising electricity prices, only a subset of the assets determined to be in "poor" or "very poor" condition have been prioritized and included in this DSP for renewal or refurbishment. Because the peak demand in this service territory is expected to decrease rather than increase, no investments are proposed in this DSP for capacity upgrades or smart grid features allowing customers greater access to control their electricity use or curtail peak demand.

Based on customer feedback, the focus of this DSP has been on the need to prudently plan investments to maintain utility operations at optimal level.

4.1.7 Distribution system development [5.4.1g]

Because no capacity constraints currently exist in the distribution system and none are expected to arise during the next five years for connecting load or generation customers, no investments are proposed into system capacity upgrades. There are presently no applications in queue for REG connections. There is adequate capacity in the system to accept all projected generation connection requests for the coming 5 years.

4.1.8 Distribution system development [5.4.1h]

As described previously in Section 2.1.1, during customer engagement sessions, a vast majority of PUC Distribution's customers have indicted satisfaction with the current reliability and customer service levels. Customer surveys also indicated sensitivities towards rising electricity prices and indicated preference to lower electricity rates. Of those customers willing to consider additional costs the highest preference was towards replacement of aging equipment to maintain or improve reliability. Therefore, the focus of the investments proposed in this DSP is to preserve the existing supply security and reliability levels and prevent them from degrading. Project budgets also reflect the increased emphasis on communications and engagement with customers throughout the project cycle from planning through execution to closure.

PUC Distribution has implemented tools to address customer preferences with respect to data access and visibility. For example, the Customer Connect software application implemented in conjunction with the introduction of smart meters allows customers visibility into their consumption usage on a daily and hourly basis.

Keeping in view the customer's preference for low electricity prices, no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level at this time. As mentioned earlier, PUC Distribution's distribution system already has adequate capacity to accept distributed generation customers and PUC Distribution is proactively participating in the province's CDM program for load management. Because the peak demand in the region has been decreasing and this trend is expected to continue, investments into technology to reduce peak demand would yield low benefits in this service territory. PUC Distribution is already employing technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads and no additional investments are considered necessary in this area.

Sault Smart Grid Project

PUC Distribution has been exploring an innovative and large scale system smart grid project for a few years that could provide significant benefit to our customers. The project would include elements for distribution automation, voltage control and improved customer care and outage management capabilities. The project conceptually has included a "no net bill increase" hurdle for customers as a primary evaluation criteria recognizing the high concern for customers on current costs for electricity. To meet this hurdle a significant level of financial support is being sought and will be needed for internal project approval. It is anticipated that PUC Distribution would be utilizing the Incremental Capital Module process for this project should the analysis and financial feasibility criteria, including the "no net bill increase" be achieved. Should the project funding applications be approved and OEB approval attained, and subject to final PUC Board of Directors approval this 2 to 3 year project would represent a substantial advancement in smart grid technologies being implemented by PUC Distribution.

4.2 Capital Expenditure Planning Process Overview [5.4.2]

For reference, the capital expenditure for projects above the materiality threshold in the test year are shown in Table 22.

4.2.1 Planning Objective, Criteria and Assumptions [5.4.2 a]

The capital expenditure plan proposed in this DSP has been developed by ensuring that the DSP objectives are aligned with its corporate goals, using the feedback from customer engagement sessions, conclusions of the asset management plan and the regional grid planning as an input, which allowed alignment of the overall corporate vision, mission statement and values with the proposed investment plan.

PUC Distribution's investment planning objectives into each investment categories are listed below:

1) Ensure appropriate level of investment allocation to meet the regulatory obligations of the System Access such as metering, system relocations for municipal road work, future system requirements for residential, commercial and industrial load customers as well as generation customers and joint-use customer requests. ;
2) Ensure adequate level of objectively prioritized investments into distribution System Renewal to maintain optimal risk levels related to asset failures in service, particularly those impacting safety, reliability and environment, as determined through the continued condition assessment of assets;
3) Ensure the acceptable level of expenditures required to maintain sufficient system capacity to meet existing and future capacity demand levels, including adequate capacity to allow connection of renewable generation;
4) Ensure proper allocation of investments into General Plant assets to maintain employee safety and productivity.
5) Review overall expenditures to ensure retail rate impacts and adjust spending as required to ensure retail rates remain affordable.

Because the distribution system has adequate capacity to allow connection of anticipated load and generation customers, no REG investments are proposed for system capacity upgrades to accept new generation or load customers. Because there are no capacity related system constraints and no investments are required to mitigate capacity constraints, use of non-distribution system alternatives to relieve system capacity or operational constraints is not necessary. The Regional Planning Process has been completed and it did not identify any issues requiring any investments by PUC Distribution. A copy of the Regional Infrastructure Planning Report is included in Appendix E. Also, because customers have indicated preference for lower electricity prices no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level. As mentioned earlier, PUC Distribution is proactively participating in the province's CDM program for load management.

PUC Distribution has determined that there are a number of important inputs required in order to support investment decisions to ensure the investment level is appropriate and is targeted into the appropriate area. As such, planning criteria inputs are utilized to support investments into each of the four categories, as indicated below:

- Consultation with municipal officials to understand future projects requiring relocation of distribution lines in support of System Access investments;

- Incorporating customer growth forecasting into capital expenditures for anticipated residential and commercial developments in support of System Access investments;

- Ongoing dialogues and open communications between large load general service customers and PUC Engineering department to gain perspective on any changes in their electrical demand in support of System Access investments;

- Asset Condition Assessments to support expenditures related to asset renewal to maintain the system as designed in support of System Renewal investments;

- System capacity assessments to identify requirements for System Service investments; and

- Individual assessments on key areas in General Plant such as buildings and facilities required to support expenditures in General Plant.

The investment requirements to facilitate new customer connections, service upgrades, joint use requests and line relocates in response to municipal requests are difficult to predict accurately, so the expenditure requirements in these categories have been estimated based on knowledge of past expenditures and knowledge gained through stakeholder engagement.

The overarching objective of PUC Distribution's asset management plan is to identify and implement the optimal time and scope of investments into asset maintenance, refurbishment and replacement. Each of the asset management objectives described in Section 3.1 are considered during prioritization of the investments into System Renewal, with appropriate weights assigned to each objective, as indicated. A prioritized list of the projects above the materiality threshold and planned to be implemented during the test year is provided in Table 22.

4.2.2 Policy for Relieving System Capacity and Operational Constraints [5.4.2 b]:

Because the distribution system has adequate capacity to allow connection of anticipated load and generation customers, no REG investments are proposed for system capacity upgrades to accept new generation or load customers.

The peak system demand is expected to decrease and not increase. Because there are no capacity related system constraints and no investments are required to mitigate capacity constraints, use of non-distribution system alternatives to relieving system capacity or operational constraints is not necessary. The Regional Planning Process has been completed and it did not identify any issues requiring any investments by PUC Distribution.

Also, because customers have indicated preference for lower electricity prices no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level. As mentioned earlier, PUC Distribution is proactively participating in the province's CDM program for load management.

4.2.3 Processes, Tools and Methods to Select, Prioritize and Pace Projects [5.4.2 c]:

Please refer to Section 3.1.1 and 3.1.2, where processes, tools and methods used to select, prioritize and pace different categories of investments are described in greater detail. In addition reference to Appendix H will provide detail of mechanisms used to engage customers in identifying their needs, priorities and preferences and the relationship to the projects listed for the DSP test year where applicable.

A brief summary of the processes, tools and methods used to identify, select, prioritize and pace projects in each investment category is provided below:

4.2.3.1 System Access

Identification

Projects are identified through contact with customers wishing to connect new services, service upgrades, requests from municipal landowners to relocate assets to accommodate road reconstruction or requests for services from joint use communication companies. As described in greater detail in Section 2.2.1.1, Appendix C and Appendix H, customer engagement sessions have generally indicated high customer satisfaction for delivery of services under System Access category and therefore no changes are considered necessary to the existing processes.

Selection

Investments into System Access projects are non-discretionary in nature and are required to fulfil PUC Distribution's regulatory obligations and projects in this category.

Prioritization

Given that these projects are mandatory, they are therefore given the highest priority for implementation. Project prioritization is based on the expected date when all service requirements are fulfilled by the customer and consideration of the customer's schedule for implementation, as identified through regular contact between both parties.

Pacing

For new service additions or service upgrades, projects are planned and executed to ensure that low voltage connections are completed within 5 days of the fulfillment of all service conditions and high voltage services are connected within 10 days of the fulfillment of all service conditions. In the case of make-ready work for communication company applications, pacing is premised on the terms and conditions of joint-use agreements as well as ongoing consultations. Road reconstruction projects are paced through close coordination with the City planning and engineering departments and in accordance with the associated project schedules.

4.2.3.2 System Renewal

PUC Distribution identifies asset repair, refurbishment and replacement requirements through asset condition assessment as described in more detail in Section 3. Projects have been identified, selected, prioritized and paced using the decision matrix presented in Figure 8, which is fully aligned with PUC Distribution's corporate goals, and as summarized below:

Identification

By taking into account all relevant information related to assets' operating condition, including service age, physical condition, results of visual inspections and testing, recent failure rates of similar assets in service, condition of all infrastructure assets were assessed and expressed on a normalized index in the form of a Health Index.

The Health Index was related to probability of failure values for each project, using a weighted average approach, as described in detail in Appendix B and each asset was assigned a health indicator expressed as "very good", "good", "fair", "poor" and "very poor."

Selection

Risk consequence related to reliability, safety, operating efficiency, etc. for each project area with assets found in "poor" or "very poor" condition were identified and calculated by multiplying composite probability of asset failure with consequence of failure. Costs for the scope of work to mitigate risk in each project area are determined, using distribution system estimating data.

Prioritization

A preliminary list of prioritized projects was produced, based on the risk score and risk mitigation cost for each project.

Based on the customer preferences, particularly those related to service quality, reliability, and retail rates, overall capital spending was established to align rate escalation to customer expectations. Budget availability for System Renewal projects was determined by subtracting from the overall capital spending level the higher priority projects in System Access.

The tools used to prioritize investments in this category include a project prioritizing matrix developed using Microsoft Excel.

Pacing

The selected projects on the preliminary project prioritized list were paced for implementation, based on the funding available for asset renewal and by taking into account the resources required for project implementation for the type of work predominantly involved (overhead, underground or substations).

Due to their non-discretionary nature, System Access projects will take priority in the event that there are competing demands with System Renewal projects. The use of a regularly updated integrated resource plan allows this process to be managed in an effective manner with the objective of successfully completing all projects planned for in the DSP.

4.2.3.3 System Service

Identification

Through careful planning processes including system capacity assessments, the development of a REG plan, and participation in preparing a Regional Infrastructure Plan, it has been identified that PUC Distribution's supply network has adequate capacity without any constraints to allow connection of new loads and generation from REG during the next five years. PUC Distribution has implemented a number of smart grid features during the previous years, such as smart meters, digital protection relays, voltage regulators, reclosers and remote-controlled substation switchgear to facilitate automation. A number of investments planned under System Renewal will serve to further expand the smart grid features, typically provided by System Service investments.

During customer engagement sessions, customers have indicated preference for lower retail rates as opposed to additional smart grid features, e.g. providing greater access to customers to manage and control their electricity use.

In view of the above, no investments are planned in this DSP, in the System Service category.

4.2.3.4 General Plant

There is only a small level of investments proposed in this DSP for General Plant category representing 1% of total investment. Approximately 5 years ago PUC consolidated all of its administrative offices and operational buildings into a newly constructed integrated facility and retired all of its aging facilities. For the most part the new facility is in excellent condition and meets all functional needs so only minimal incremental building infrastructure investments have been considered in this DSP. The entire motor vehicle fleet used for operations is owned by PUC Distribution Inc.'s non-regulated affiliate services company PUC Services Inc.

Identification, Selection, Prioritization & Pacing

General Plant projects are identified, selected, prioritized and paced based on cost/benefit analysis, using a combination of inspections, policies and expert knowledge. Investments into building repairs are based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems.

4.3 System Capability Assessment for Renewable Energy Generation [5.4.3]

As previously described in Section 2.3.9, PUC Distribution currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load. PUC Distribution also hosts an IESO controlled 7MW/7MWh battery energy storage facility.

PUC Distribution has prepared and submitted a REG Plan to the IESO. The associated IESO comment letter in response to the REG Plan is attached in Appendix D.

4.3.1 Applications for REG Connections Greater than 10kW [5.4.3a]

The connection history for all REG installations connected to the PUC Distribution system over 10kW is summarized in Table 24 below. Of all the applications made, those that were not connected had applications terminated by the applicant and in no case was any application for connection rejected due to unavailable capacity.

Table 24: Summary of REG Applications >10kW

	Application Date		Application MW		Connection Date		Connection MW	
Pre-2013	1985		0.25		1985		0.25	
	4/15/2007		9.95		10/15/2010		9.96	
	4/17/2007		9.95		10/15/2010		9.96	
	6/3/2007		9.95		8/30/2011		9.96	
	6/3/2007		9.95		8/30/2011		9.96	
	6/3/2007		9.95		7/27/2011		9.96	
	6/3/2007		9.95		11/22/2011		9.96	
	7/24/2007		0.045		2008		0.045	
	2007		9.95		N/A		0	
	2007		9.95		N/A		0	
	1/8/2008		0.037		7/8/2008		0.037	
	9/9/2011		0.035		11/23/2012		0.035	
	6/7/2011		0.5		7/20/2011		0.5	
	9/26/2011		0.25		8/29/2012		0.25	
	2/28/2011		0.1		6/9/2011		0.1	
	6/14/2011		0.135		11/14/2011		0.135	
	Quantity	16	Total MW	80.952	Quantity	14	Total MW	61.112
2013	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2014	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2015	2/18/2015		0.1		8/23/2016		0.1	
	Quantity	1	Total MW	0.1	Quantity	1	Total MW	0.1
2016	6/17/2016		0.07		7/20/2011		0.07	
	3/11/2016		0.25		8/29/2012		0.25	
	3/11/2016		0.25		6/9/2011		0.25	
	3/11/2016		0.25		11/14/2011		0.25	
	Quantity	4	Total MW	0.82	Quantity	4	Total MW	0.82
2017	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2013-2017 Totals	Quantity	5	Total MW	0.92	Quantity	5	Total MW	0.92
Grand Total	Quantity	21	Total MW	81.872	Quantity	19	Total MW	62.032

4.3.2 Applications for REG 10kW or less

Currently there are no applications in the queue from REG connections <10kW, under the Micro-FIT program and all requests for Micro-FIT generation received to date have been successfully connected to the system. There appears to be a growing interest in net metering and some discussions about that in conjunction with energy storage behind the meter as the gap closes between Micro-FIT contract pricing and the Residential class load energy costs.

4.3.3 System Capacity to Support REG [5.4.3c]

Primarily based on thermal ratings of conductors and transformers, PUC Distribution has developed and submitted to the IESO, the following table of available capacity, Table 25. The IESO uses this for planning and as an input to preparing a Transmission Availability Table (TAT) which is posted online to assist prospective REG applicants in selecting a site for their project. Table 25 summarizes available capacity at the 34.5kV feeder and station bus levels. It can be seen that at present there is still capacity available for the future connection of approximately 27MW more generation between circuits out of TS1 and TS2 combined.

Table 25: Available System Capacity for Accepting Additional REG Connections

Station	Bus Name	Capacity (MW)	Allocated Capacity (MW)	Available Capacity (MW)	Supply Circuit 1	Supply Circuit 2
TS1 (St. Mary's)	**Total**	**45**	**41.310**	**3.690**	**GL1SM**	**GL2SM**
	West	30	21.009	3.690		
	East	30	20.300	3.690		
TS2 (Tarentorus)	**Total**	**45**	**21.663**	**23.337**	**GL1TA**	**GL2TA**
	West	30	21.015	8.985		
	East	30	0.647	23.337		

34.5 kV Feeder Name	Bus Connection	Capacity (MW)	Allocated Capacity	Available Capacity (MW)	Notes:
SM-5	West	30	10.214	3.690	TS Limiting (45-D5) MW
SM-7	West	30	9.960	3.690	TS Limiting (45-D5) MW
Sub 19 West	West	N/A	0.835	N/A	no feeder, direct bus connection
SM-9	East	30	10.034	3.690	TS Limiting (45-D5) MW
SM-11	East	30	10.017	3.690	TS Limiting (45-D5) MW
Sub 19 East	East	N/A	0.250	N/A	no feeder, direct bus connection
TS1			**41.310**		
TA-6	West	30	0.139	23.337	TS Limiting (45-D8) MW
TA-7	West	30	20.876	8.985	West Bus Limiting (30-D9) MW
TA-9	East	30	0.028	23.337	TS Limiting (45-D8) MW
TA-10	East	30	0.188	23.337	TS Limiting (45-D8) MW
TA-11	East	30	0.431	23.337	TS Limiting (45-D8) MW
TS2			**21.663**		

4.3.4 Proposed Plan and Investments to Support REG [5.4.3b, d and e]

There are no applications in hand and PUC Distribution is not currently aware of any customers wishing to connect renewable generation plant to the grid.

PUC Distribution has produced a 5 year forecast of future REG connections as part of its Renewable Energy Generation Plan. For the period 2018-2022 projections have been based on:

- local economic and population data
- macro-economic conditions
- awareness of information from IESO and OEB regarding connection rates and programs

Based on those factors, a five year forecast has been established with an anticipated connection of one 250kW generator per year for a total connection of 1.25MW over the next 5 year period.

The PUC Distribution grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period.

4.4 Capital Expenditure Summary [5.4.4]

The actual capital and system O&M expenditure for the historic years from 2012 to 2016, as well as the proposed capital and system O&M expenditure for the bridge year (2017), the test year (2018) and the forecast period (2019 to 2022), is summarized in Table 26. For 2017, the data presented in each capital investment category and the system O&M category is the budgeted amount for the full 12 month period.

Table 26 reveals appreciable variations in the historic capital spending levels from one year to the next in each of the categories. The reasons for these variations are described below:

- The expenditure in the "System Access" category in 2012 far exceeds the average annual expenditure in this category for the five historic years. The excess expenditure in 2012 is related to the smart metering project. Although the installation work for the smart metering project was physically substantially complete at the end of 2010, the costs were not capitalized until 2012.

- The expenditure in the "System Access" category during 2015 and 2016 declined significantly in relation to the previous three years. This is related partly due to general slowdown in housing construction activity in this region and partly due to higher than normal requests in 2013 and 2014 for "make ready" work to allow joint-use of the poles lines for one of the major telecommunications companies.

- The expenditure in "System Renewal" category in 2013 is significantly higher in relation to the average expenditure in this category during the five historic years, which is related to the Sub 10 rebuild costs, capitalized during 2013.

- The expenditure in "General Plant" category in 2012 far exceeds the average expenditure in this category during the five historic years. The extraordinary high expenditure in 2012 in this category is related to the construction of the new office building.

As indicated in the System Service category in Table 26, there has been no expenditure during the past five years and minimal funds allocated during the forecast period. However, PUC Distribution has implemented a number of smart grid features on its network, during the previous years, such as smart meters, digital protection systems, voltage regulators and remote-controlled substation switchgear to facilitate automation, but because all of these projects involved replacement of old infrastructure at the end of its service life with new assets, these were included in the System Renewal category as it was the primary driver. System Service investments include input from customers to drive investment decision making. Examples include implementation of voltage regulation improvements and recloser installations in response to customer feedback and needs. The ability of the distribution grid to supply the existing and anticipated load and generation customers was analysed and it was concluded that there are no anticipated capacity constraints for the forecast period. As such, there are no investments proposed in this DSP, specifically triggered by System Service requirements.

Table 26: Capital and O&M Expenditure Summary

First year of Forecast Period: 2018

CATEGORY	Historical Period (budget & actual)															Bridge	Forecast Period (planned)				
	2012			2013			2014			2015			2016			2017[1]	2018	2019	2020	2021	2022
	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual[2]	Var						
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000					
System Access	1,132	7,938	601.1%	1,069	2,310	116.1%	2,957	2,532	-14.4%	1,265	1,549	22.4%	1,215	1,212	-0.2%	1,271	1,511	1,615	2,086	1,604	1,560
System Renewal	6,043	4,821	-20.2%	6,525	6,083	-6.8%	3,813	3,754	-1.6%	4,753	4,640	-2.4%	4,543	4,244	-6.6%	3,372	3,761	6,906	3,296	4,533	7,093
System Service	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--	38	-	-	-	-	-
General Plant	17,803	23,269	30.7%	1,314	2,028	54.4%	175	376	114.1%	69	67	-3.1%	-	83	--	-	86	55	62	60	55
TOTAL EXPENDITURE	24,978	36,028	44.2%	8,907	10,421	17.0%	6,946	6,661	-4.1%	6,087	6,256	2.8%	5,758	5,538	-3.8%	4,682	5,358	8,576	5,445	6,197	8,708
System O&M	$ 6,259	$ 5,853	-6.5%	$ 6,154	$ 5,992	-2.6%	$ 5,530	$ 5,773	4.4%	$ 5,819	$ 5,978	2.7%	$ 5,955	$ 5,978	0.4%	$ 5,857	$ 6,213	$ 6,306	$ 6,400	$ 6,496	$ 6,594

Notes to the Table:

1. For 2017 (bridge year), the data presented in each capital investment category and the system O&M category is the budgeted amount for the full 12 month period.

2. All values are net of contributed capital.

Explanatory Notes on Variances

Notes on shifts in forecast vs. historical budgets by category

The capital expenditure during the historic five years, after removing the extra ordinary expenditure related to construction of the office building and upgrade of the revenue meters with smart meters in 2012 and 2013, and it amounts to average annual capital expenditure of $6,680,745. These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. This compares to the forecast average amount of $6,856,747 for the 2018 to 2022. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. Average annual capital for System Access has been forecast at 88% of historical average actual expenditures (2013-2016). Average annual capital for System Renewal has been forecast at 109% of historical average actual expenditures (2013-2016) due primarily to the planned construction of two substations in the forecast period. General Plant for the forecast period is generally unchanged from 2015 and 2016 actual expenditures.

Notes on year over year Budget vs. Actual variances for Total Expenditures

Refer to Section 2.3.5.1 for a high level summary of the budget versus actual capital variances on an annual basis. The key extraordanary expenditures pertained to the construction of a new office building as well as the upgrade of revenue meters with smart meters. The impacts of these one-time projects primarily impacted 2012 and 2013. There was an overall 2.1% increase in actual O&M expenditures from $5.85 million to $5.98 million over the 2012-2016 period.The variability of budgeted to actual O&M over the 5 year historical period ranged from -6.5% to 4.4%.

Notes on Budget vs. Actual variance trends for individual expenditure categories

In the System Access category, variance trends are contingent upon variable customer demand. For the years 2013 to 2016 for the System Renewal category, the general trend is that actual expenditures are slightly below budget.

The planned capital expenditure for the five-year forecast period, shown in Table 26, indicates capital expenditure by PUC Distribution, net of the customer or third-party contributions. As shown below in Figure 36, the planned expenditure will result in an average annual capital expenditure of approximately $6,856,747 during the period covered by this DSP.

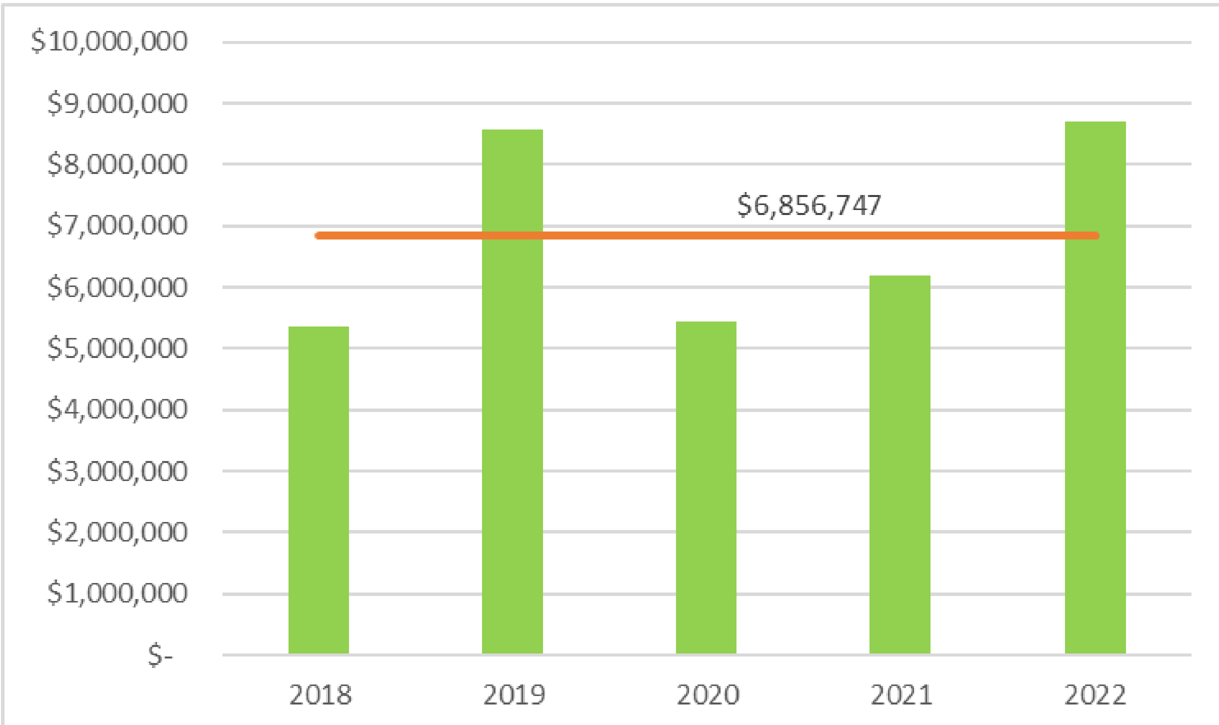


Figure 36: Proposed Capital Expenditure during the DSP Period

Figure 37 shows the capital expenditure during the historic five years, after removing the extra ordinary expenditure related to construction of the office building and upgrade of the revenue meters with smart meters in 2012 and 2013, and as shown it amounts to average annual capital expenditure of $6,680,745. These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. This compares to the forecast average amount of $6,856,747.

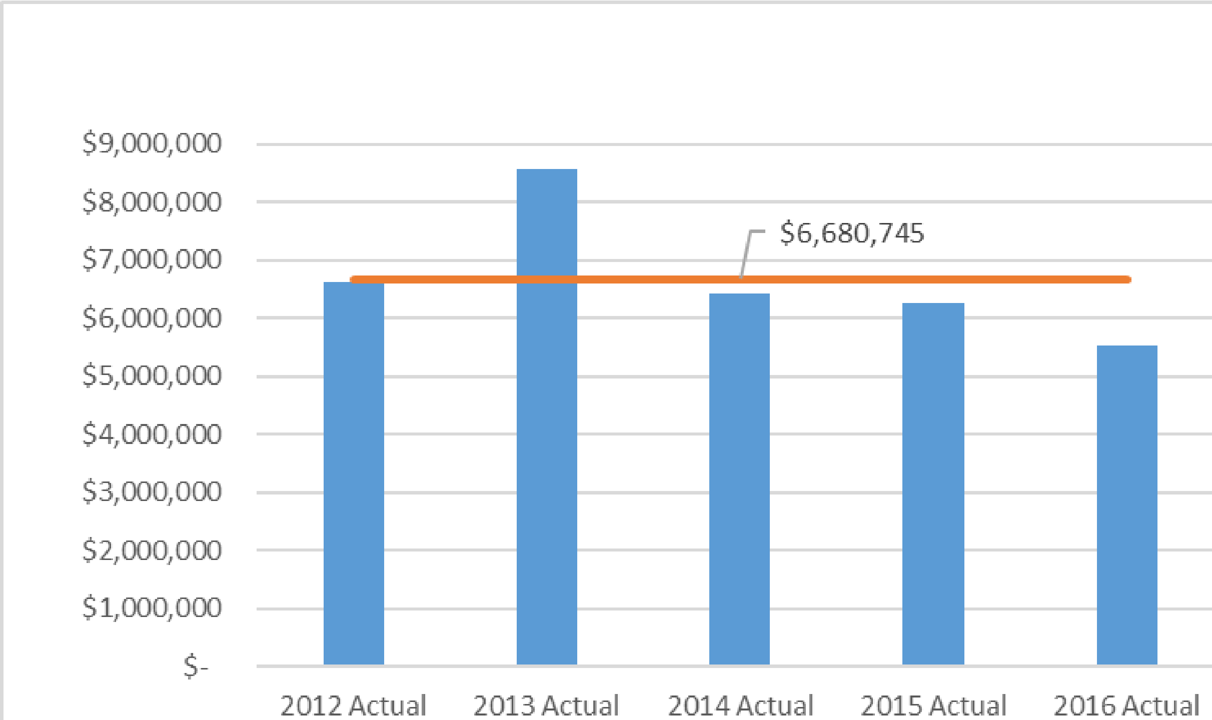


Figure 37: Historic Capital Expenditure (After Removing Office Building and Smart Meter Expenditure)

The proposed average annual expenditure during the DSP period, thus, represents an increase of 2.6% from the average annual capital expenditure during the historic five years. This figure does not account for inflationary increases. The impact of proposed capital expenditure in various categories on system O&M expenditure is described below:

4.4.1.1 System Access

These investments include capital investments to implement customer service requests, joint-use requests from third party communication companies; line relocates to facilitate municipal infrastructure developments, such as road reconstruction projects and investments into revenue metering. It is difficult to accurately determine the quantitative impact of the System Access investments on future O&M expenditure. However, investments into System Access generally result in an increase in future O&M expenditure. To connect new customers, in existing subdivisions, requires additional assets in the form of service lines, underground dips and revenue meters, all of which require safety inspections on a 3-year cycle and therefore, would result in an increase in O&M expenditure. New customers in new subdivisions require additional assets in the form of line extensions and distribution transformers in addition to service lines and revenue meters and thus result in an increase in O&M expenditure.

Equipping all general service customers with MIST meters is a regulatory requirement that will result in an increase in communication costs to each MIST meter and a corresponding increase in annual O&M expenditure.

4.4.1.2 System Renewal

The proposed investments into System Renewal are summarized in Table 21, with project level detail for the test year provided in Table 22 and in Appendix G. As shown, the proposed expenditure includes both reactive expenditures for replacement of the assets that have failed in service, as well as proactive replacement of assets where the risk of an assets' failure in service is unacceptable.

It is not possible to accurately determine the quantitative impact of capital investments on future O&M expenditure qualitatively, but in general when adequate level of investments is maintained into System Renewal to maintain the median age of asset base at the same level as in the previous year, it allows the asset's operating condition to be maintained at the same level as the previous year, preventing asset impairment from progressing further and preventing O&M costs from escalating further. When adequate investments are not made for renewal of assets which are at the end of their economic useful life, it results in an increase in equipment failures in service and an increase in the expenditure into emergency repairs and power restoration. Therefore, when correctly prioritized investments into asset renewal are made for renewal of assets at the end of their useful economic life, they prevent or slow down the rate of escalation of O&M costs in the coming years.

The infrastructure renewal projects involving distribution system operating voltage upgrade from 4.2 kV to 12.5 kV would result in a reduction in O&M expenditure due to the removal of duplicate lines and the replacement of three 4.2 kV distribution stations with a single 12.5 kV station.

4.4.1.3 System Service

Since there are no planned investments in the System Service category there is no expected change in O&M expenditure levels.

4.4.1.4 General Plant

Since the investments in General Plant are quite modest, they are not expected to have any material impact on O&M expenditure level.

4.4.1.5 Historic and Forecast O&M Expenditure

Figure 38 shows PUC Distribution's expenditure into system O&M activities during the historic five-year period. The chart indicates the mean annual O&M expenditure of $5, 914,777.

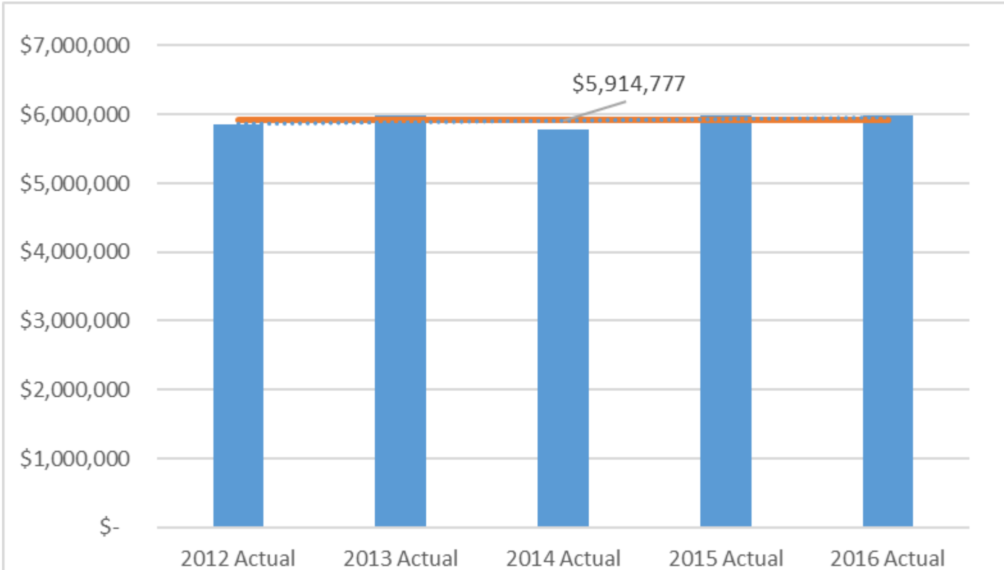


Figure 38: Historic O&M Expenditure

As shown, the deviations in year to year O&M expenditure from the mean are minor – maximum deviation from the mean in any year is less than 2.4%.

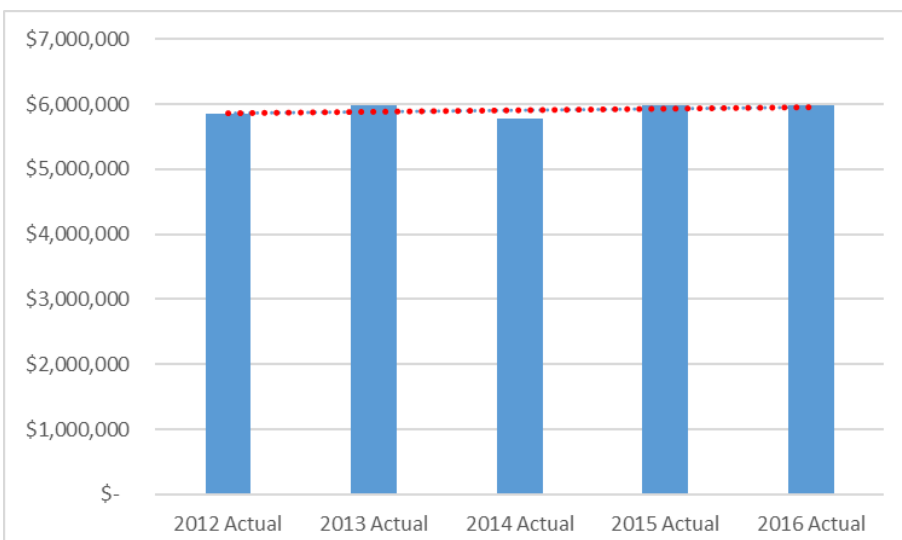


Figure 39: Historic O&M Expenditure with Trend line

Figure 39 shows the historic O&M expenditure with trend line – showing mean annual increase of 0.4% in O&M expenditure.

The forecast O&M expenditure as presented in Table 26 is displayed in Figure 40. Included in the O&M projections from 2019 to 2022 is an annual inflationary increase of 1.5%.

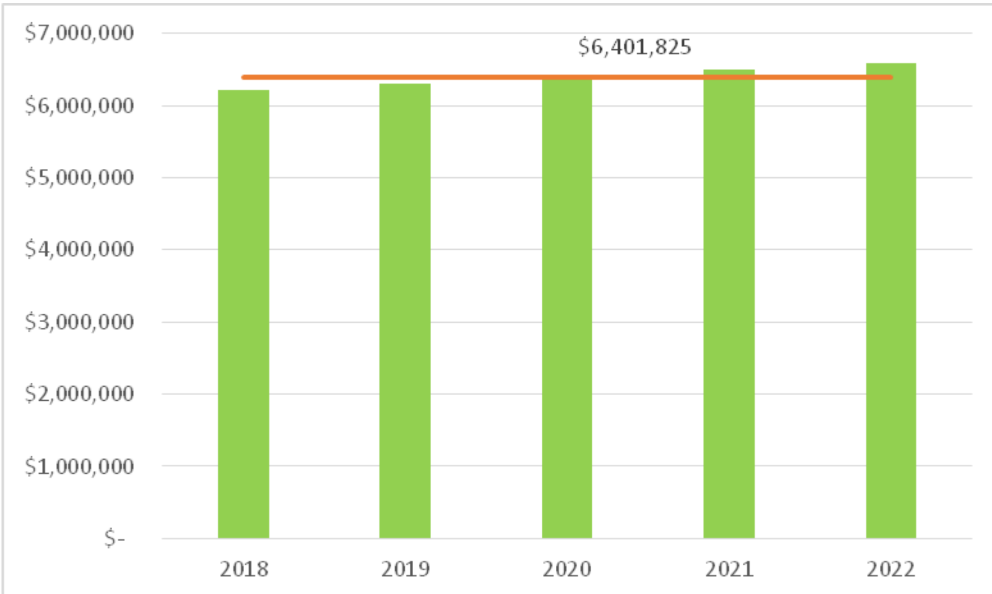


Figure 40: Forecast O&M Expenditure During DSP-Period

4.5 Capital Expenditure Justification [5.4.5]

4.5.1 Overall Plan Expenditure Justification [5.4.5.1]

As described in Section 4.4, the investment portfolio during the forecast period includes investments into System Access, System Service, System Renewal and General Plant upgrades. The capital investment plan proposed in the DSP amounts to a 2.6% increase in average annual expenditure during the forecast 5-year period from the historic 5-year period (after removing the extra ordinary expenditure for building construction and smart meters from the expenditure during the historic years). These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. This compares to the forecast average amount of $6,856,747. Considering inflationary pressures, the overall average forecast spend is consistent with historical spending levels.

Because sufficient system capacity is available to meet existing and future capacity demand levels, including adequate capacity to allow connection of renewable generation and the economically efficient and customer desired smart grid features are being implemented during asset renewal; there are no new investments required in the System Service category.

Expenditure in System Access is driven by the need to meet regulatory obligations. The proposed expenditure level is estimated based on the historic spending levels and the specific information available about planned projects at the time of preparation of this DSP, related to new requests for services, line relocates, joint-use requests, MIST meters and requirements for revenue meter replacement.

Power supply reliability and public safety are the key drivers for the proposed investments into System Renewal. These investments are prioritized and paced based on objective, risk-based criteria, and the methodology employed for prioritization of the investments is aligned with the best industry practices. The investment level in this category has been determined to maintain risk related to asset failures in service, particularly those impacting safety, reliability and environment, at an optimal level.

Investment level into General Plant has been determined based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems

For more detailed information on investment drivers and prioritization please refer to Section 2.1, Sections 3.1, 3.2, 3.3, 4.1 and 4.2.

4.5.2 Justification of Projects Exceeding the Materiality Threshold [5.4.5.2]

All capital projects, proposed to be implemented during the test year, with investments level exceeding the materiality threshold, are listed in Table 22 The first four projects in the table fall in the System Access category for which meeting the regulatory obligations is the primary driver and the next 9 projects on the list belong to the System Renewal category, for which supply system reliability and public safety are the primary drivers.

Detailed scope of each project along with its key driver and justification are described in detail in Appendix G and briefly summarized below:

Project #1, #2, #3, and #4 (System Access)

These projects are required to fulfil PUC Distribution’s regulatory obligations to provide services. The first project involves fulfilling customer requests for new services or upgrade of existing services. The second project covers requests from land developers involving servicing of multiple lots within subdivisions. The third project covers requests from telecommunication companies in the City for make ready work to facilitate joint use of distribution infrastructure by third parties. The fourth project involves meeting requests from the municipality to relocate overhead or underground lines installed in the public right-of-way to coordinate with road widening projects.

Project #5 and #6 (System Renewal – Forced)

These two projects involve reactive expenditure to restore power following a power interruption caused by equipment failures by replacing the failed distribution system assets with new equipment. The key drivers for these projects are supply system reliability and public safety, because when equipment has failed in service, the proposed expenditure becomes necessary to restore power and remove the unsafe equipment from service. Project #5 is intended to cover expenditure for renewal of failed assets on overhead lines and Project #6 is intended to cover expenditure for renewal of assets on underground distribution system.

Project #7

This project involves replacement of poles determined to be "unsafe" due to degradation of their structural strength, based on in-situ testing of the poles.

Project #8

This project involves rebuild of distribution station Sub 16. As detailed in the Asset Management Plan, this substation has been determined to be in very poor condition and at the end of life. The power transformers and switchgear at Sub 16 will reach a service age of 50 years by 2019, which is 10 years more than the typical life of this equipment. Due to the state of the existing station infrastructure, the switchgear is deemed to be unsafe to operate while energized and must be isolated and de-energized prior to operation. This results in isolation out on the 34.5kV distribution lines, which can impact system reliability whenever operating the existing Sub 16 is required. The planned Sub 16 rebuild will be a new 34.5kV - 12.47/7.2kV, 26.6MVA municipal substation that will have two incoming 34.5kV supplies, two 10/13.3 MVA power transformers, and four outgoing 12.47kV feeders supplied by arc resistant metalclad switchgear.

Projects #9

This project involves renewal of overhead distribution system assets through rebuilding of the overhead lines currently operating at 4.2 kV. The lines will be rebuilt to operate at 12.5 kV upon completion of the projects. As detailed in PUC Distribution's asset condition assessment report, PUC Distribution has over 30km of 4.16/2.4kV circuits in service, all of which are at the end of their service life. Additionally, the two stations supplying these overhead lines are also beyond their useful service life, requiring replacement. In an effort to streamline system voltages, three 4.2 kV stations will be replaced with a single station producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all distribution lines operating at 4.2 kV will be converted to 12.5 kV. Power system reliability and public safety are the primary driver for these projects, although they will also help reduce operating costs when the two 4.2 kV stations are retired from service.

Projects #10, #11, and #12

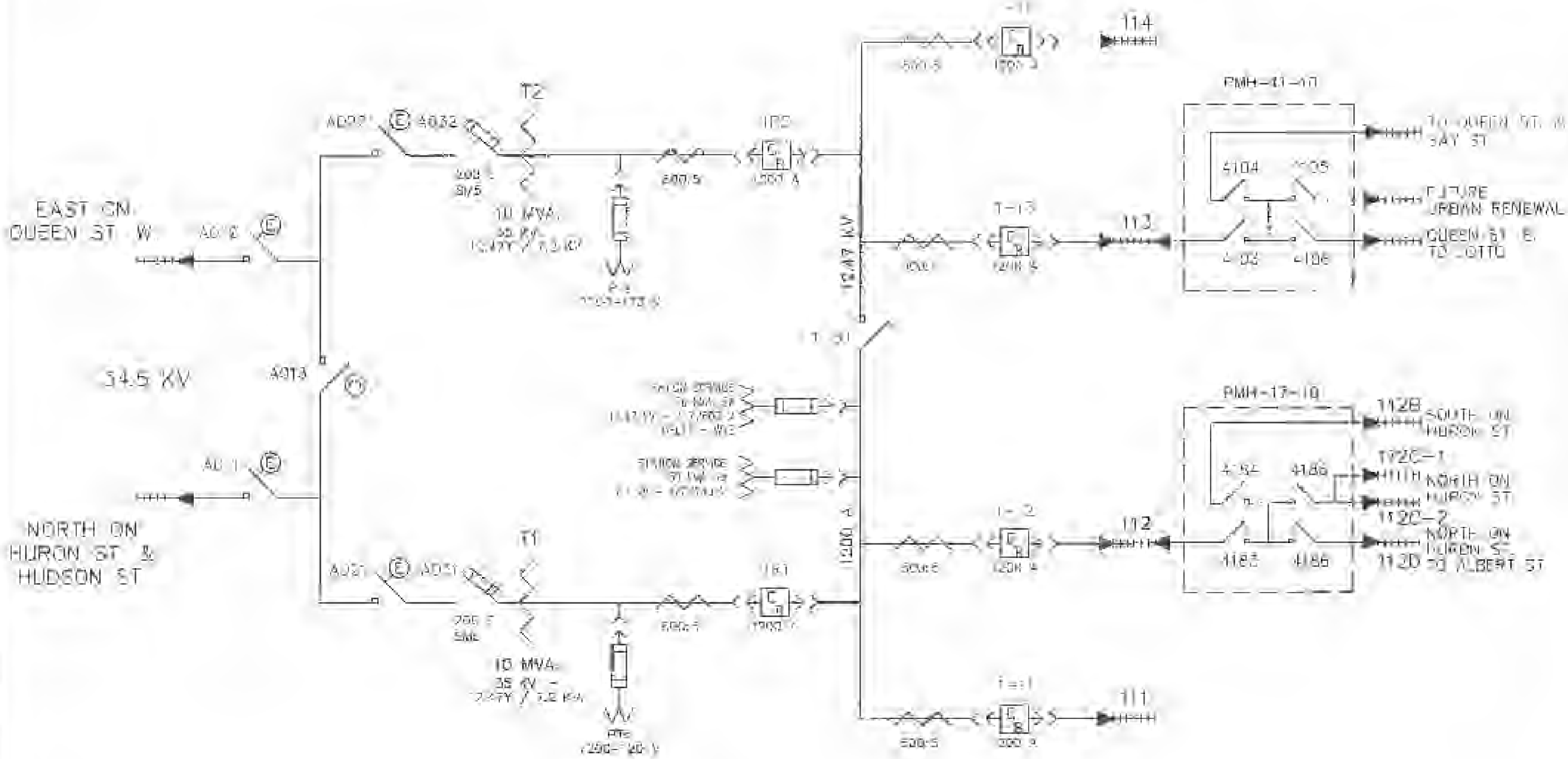
PUC Distribution has identified #6 copper overhead primary conductor as a safety hazard. It is classified by PUC Distribution as "restricted wire". Due to the nature of the conductor, it being small and constructed of copper, its tensile strength is known to degrade over years of use. Due to this, the conductor is prone to failure. Additionally, when the conductor fails, due to its nature, the fault current dissipates quickly and therefore may not trigger the nearest protective equipment. This may cause the conductor to remain energized in an area where staff or the public may come into contact. The conductor is replaced with #2ACSR, along with related insulation and aged infrastructure. The specific project areas covered by these projects have been identified as a high priority. Public and worker safety is the primary investment driver for this project.

Projects #13

This project involves renewal of underground distribution system assets by rebuilding of the existing underground distribution system currently operating at 4.2 kV. The underground lines will be rebuilt to operate at 12.5 kV upon completion of the projects. As detailed in PUC Distribution's asset condition assessment report, PUC Distribution has approximately 3km of 4.16/2.4kV underground circuits in service, all of which are at the end of their service life. Additionally, the 4.2 kV stations supplying these underground lines are also beyond their useful service life, requiring replacement. In an effort to streamline system voltages, three stations will be replaced with a single station producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all underground feeder cables operating at 4.2 kV will be converted to 12.5 kV. Power system reliability and public safety are the primary driver for these projects, although they will also help reduce operating costs when the two 4.2 kV stations are retired from service.

Appendix A

Single Line Diagrams



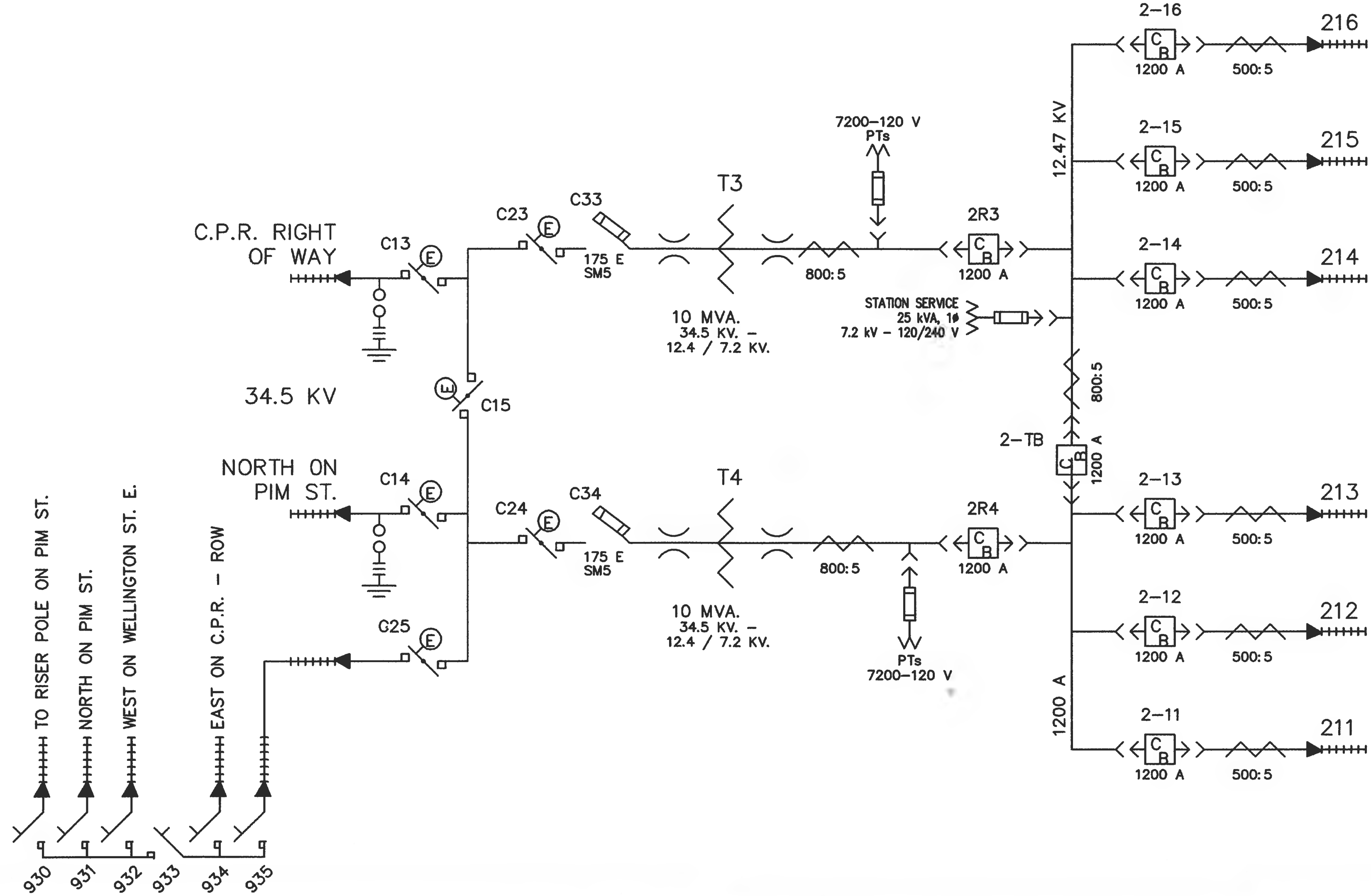
Scale:	NTS

1	REVISED STATION SERVICE INFO., PTs, DOPSTR AND DRAWING NUMBER	MAY 18/06	JJ
No.	Revision	Date	Init's

SUBSTATION #1

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: JAN. 26/88
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: May 25/06
Drawing Number: A-ES01-04-001	Rev. 1



Scale: NTS

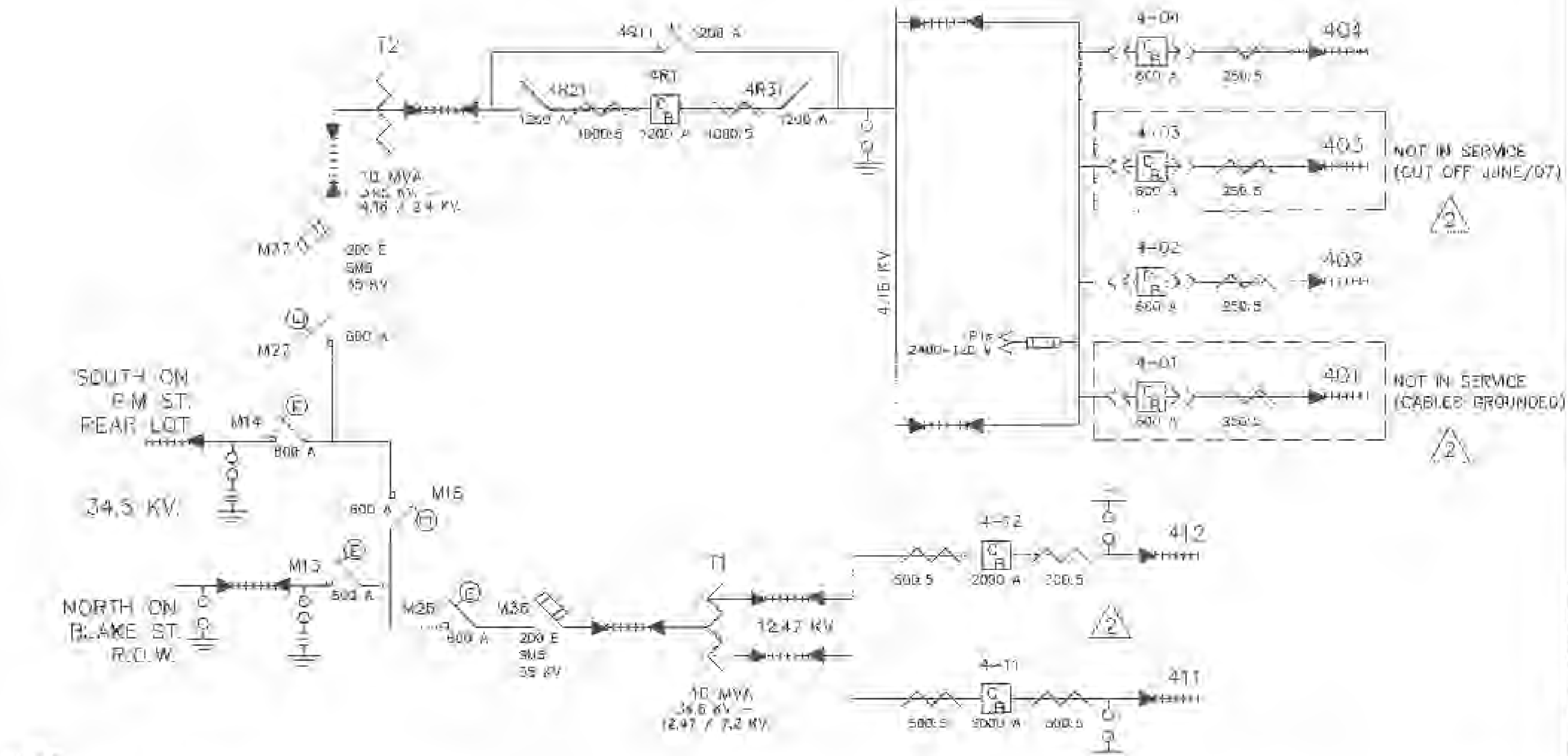
No.	Revision	Date	Initial
2	MOVED STATION SERVICE TO OTHER SIDE OF TIE BREAKER	OCT. 18/15	M.P.
1	REVISED BORDER AND DRAWING NUMBER AND ADDED STATION SERVICE.	MAY. 18/06	J.T.

PUC

SUBSTATION #2

SCHEMATIC DIAGRAM

Drawn by:	J.R.	Date:	JAN. 13/88
Checked by:	K.B.	Date:	MAY 18/06
Approved by:		Date:	2018/01/04
Drawing Number:	A-ES02-04-001	Rev.	2



NOTE:

STATION SERVICE FED FROM CIRCUIT 411 AT POLE W12103.

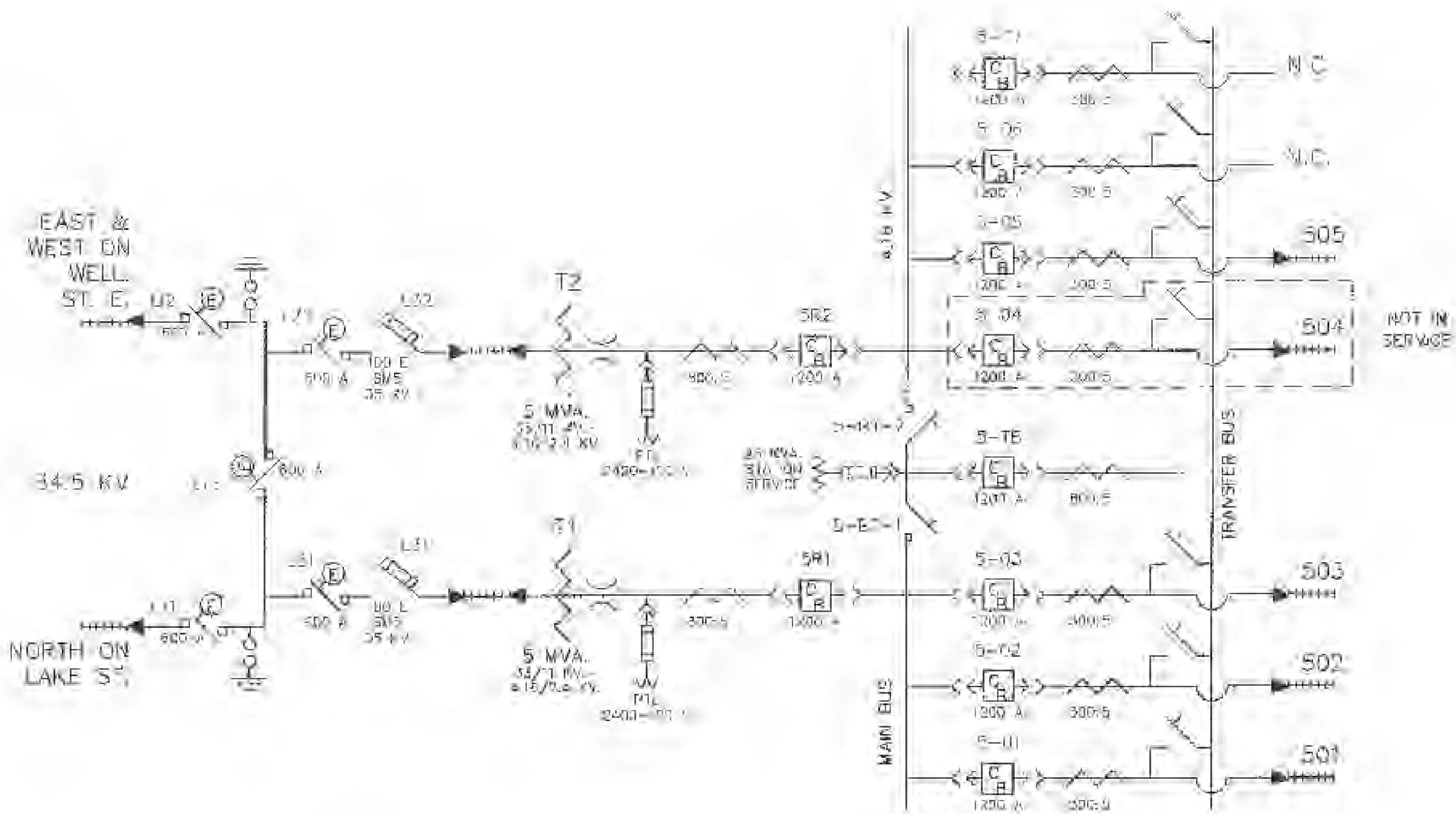
2	RELOCATED ARRESTORS AT CCTS. 411, 412, CCTS. 401 & 403 NOW N.I.S.	MAR 9/18	
1	REVISED BORDER AND DWG NUMBER. ADDED PTs AND STA. SERV. NOTE.	MAY 18/06	
No.	Revision	Date	

PUC

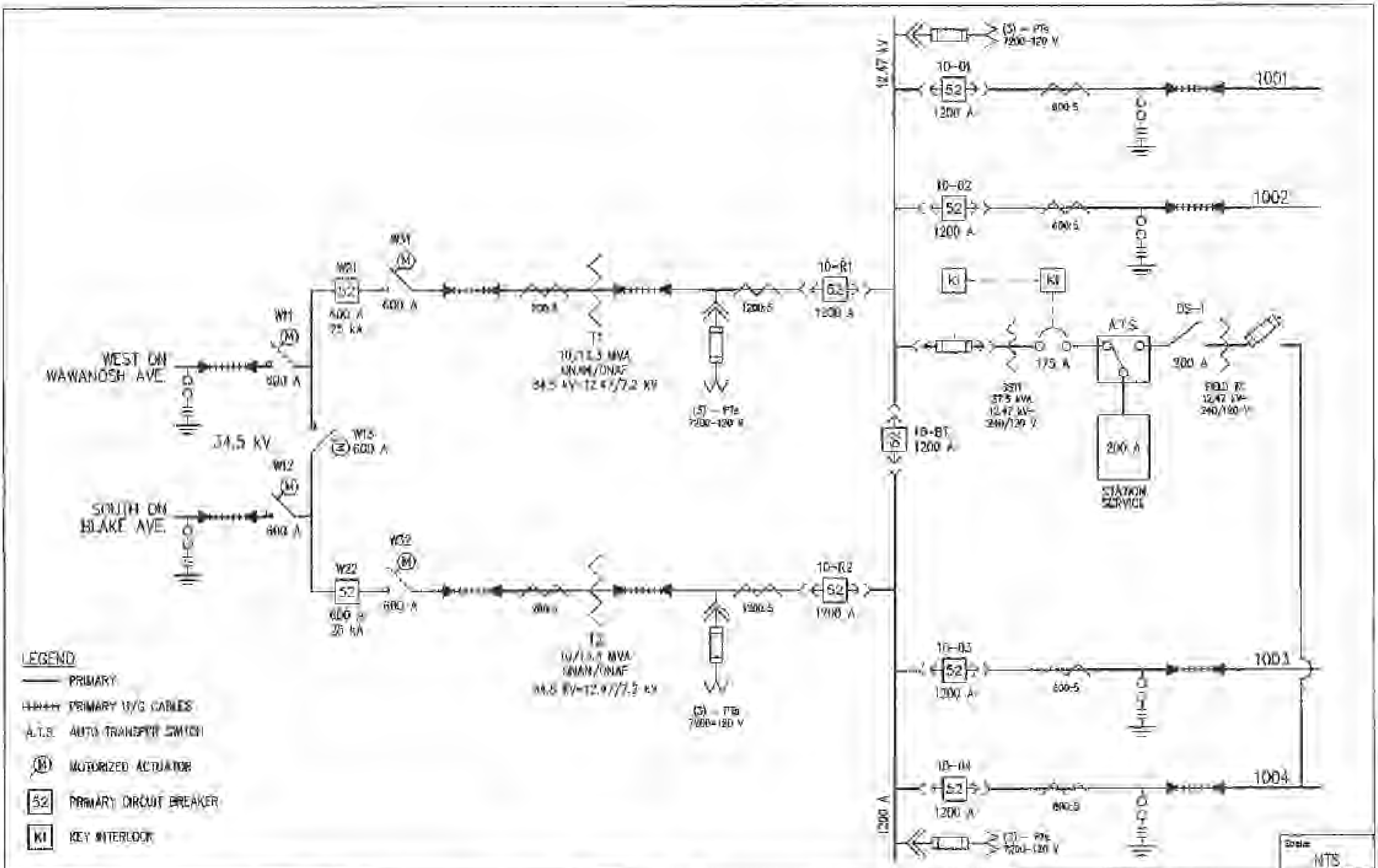
SUBSTATION #4

SCHEMATIC DIAGRAM

Scale: NTS	
Drawn by: J.R.	Date: SEP. 11/86
Checked by:	Date: MAY 18/06
Approved by:	Date:
Drawing Number: A–ES04–04–001	Rev. 2



	REVISED BREAKER AND DWG. NUMBERS. REMOVED 5-T, 5-04 FROM SERVICE	MAY 16/05	J.R.	PUC	SUBSTATION #5	Drawn by: J.R.	Date: SEP. 11/88	Scale: NTS
					SCHEMATIC DIAGRAM	Checked by: K.B.	Date: MAY 16/06	
						Approved by:	Date: May 25/06	
No.	Revision	Date	Initial			Drawing Number: A-ES05-04-001	Rev: 1	



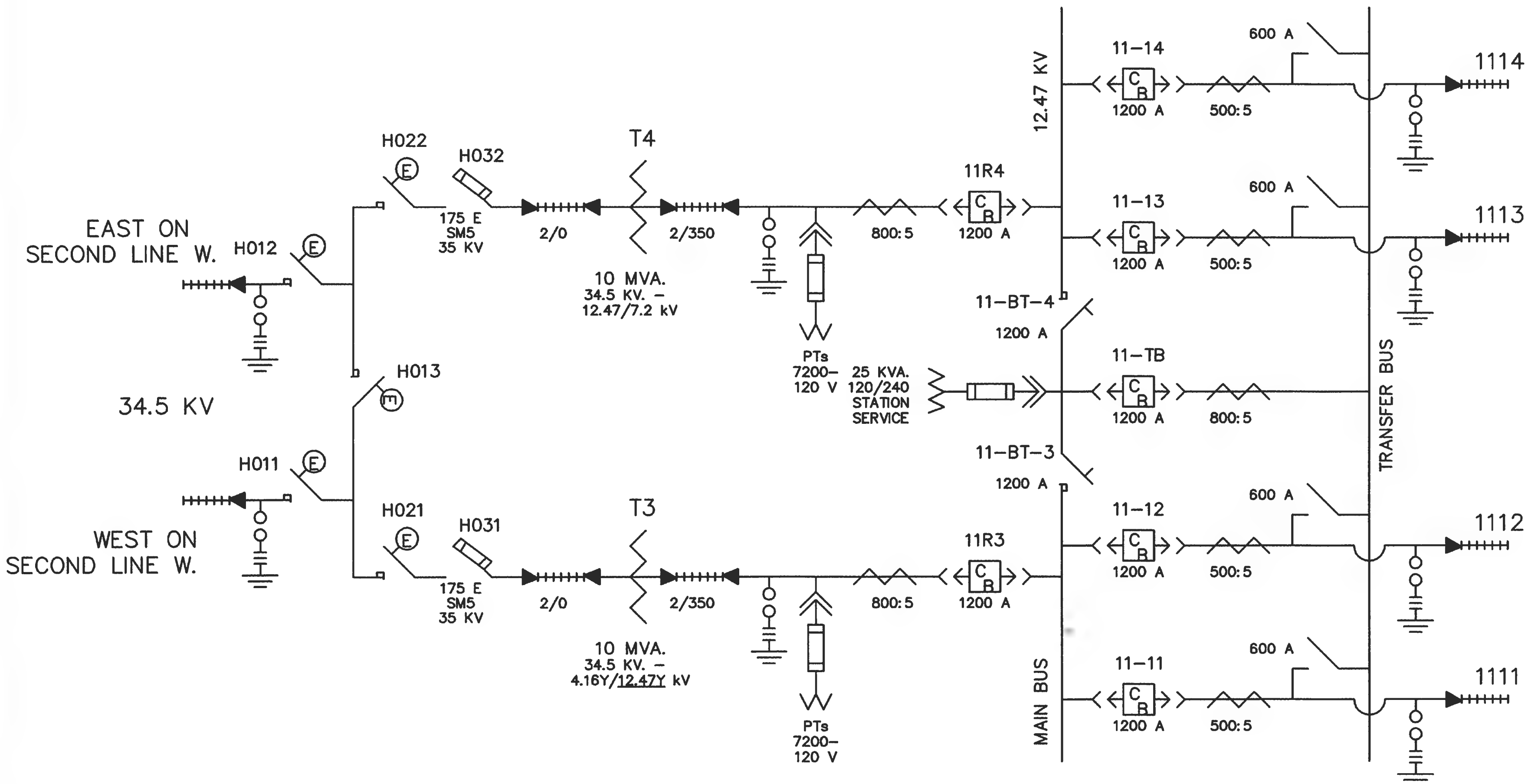
No.	Revision	Date	Initial
2	SUBSTATION REBUILT	NOV 24/97	A.T.
1	REVISED INCOMING SOURCE AND VOLTAGE, WIRES, ONE & PTS AND SOL SERV.	MAY 12/08	A.T.

PUC

SUBSTATION #10

SCHEMATIC DIAGRAM

Scale: NTS	
Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date:
Drawing number: A-ES10-04-001	Rev. 2



No.	Revision	Date	Initial
2	REVISED VOLTAGE RATING ON T3.	JAN. 4/18	J.T.
1	REVISED BORDER AND DWG NUMBER. REMOVED REFERENCE TO SUB. 6.	MAY 18/06	J.T.

PUC

SUBSTATION #11

SCHEMATIC DIAGRAM

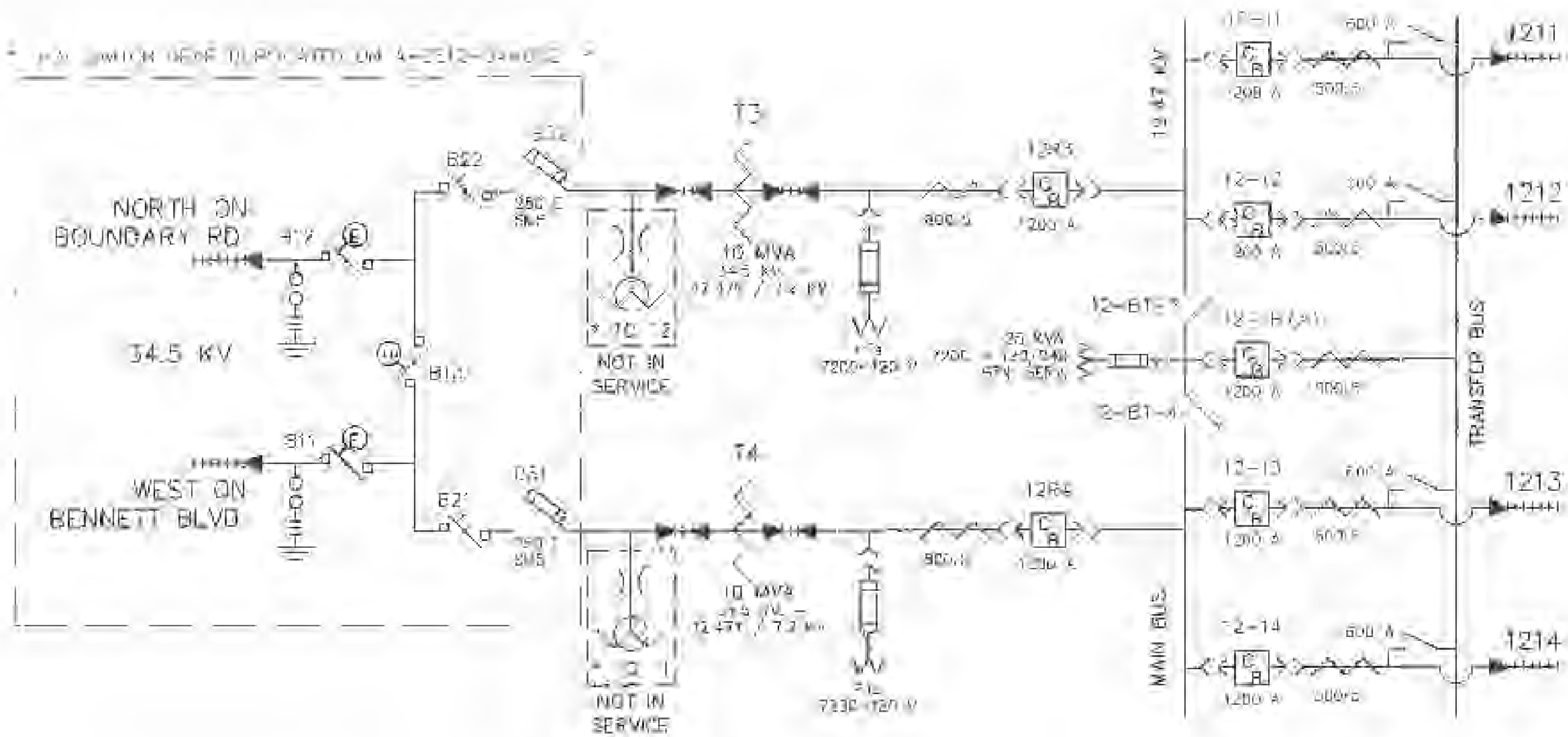
Scale: NTS

Drawn by: J.R. Date: SEP. 11/86

Checked by: K.B. Date: MAY 18/06

Approved by: Date: 2018/01/04

Drawing Number: A–ES11–04–001 Rev. 2



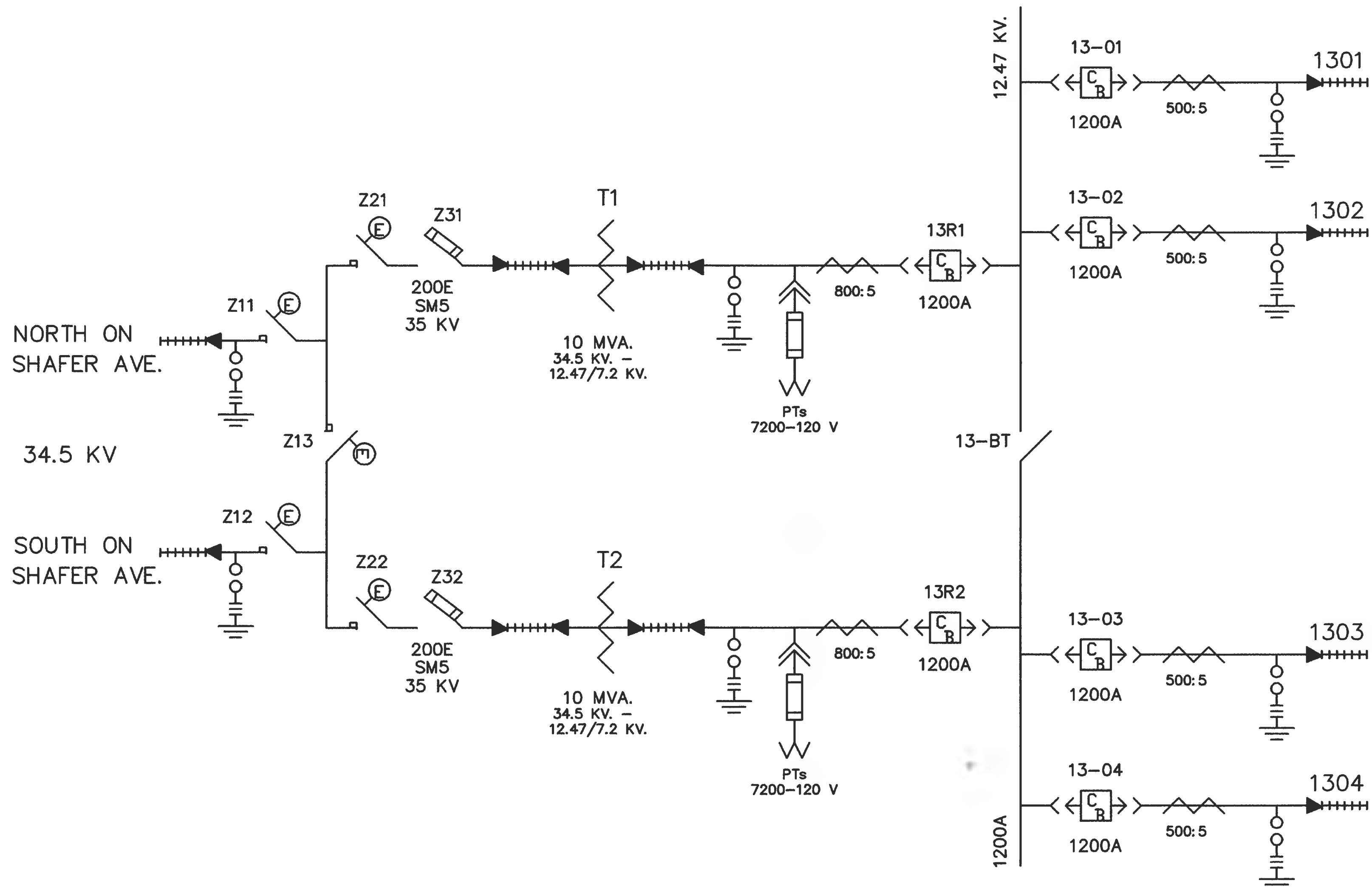
Scale:	NTS

SUBSTATION #12

SCHEMATIC DIAGRAM
12.47 KV

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: May 25/06.
Drawing Number: A-ES12-04-001	Rev: 1

No.	Revision	Date	Initial
1	REVISED BORDER AND DRAWING NUMBER, REMOVED T1 & T2 FROM SERVICE	MAY 18/06	J.R.



NOTE:
STATION SERVICE NORMALLY FED FROM CIRCUIT 1301 ON SHAFER AVE. TRANSFORMER LOCATED AT INTERSECTION OF SHAFER AND BAINBRIDGE.

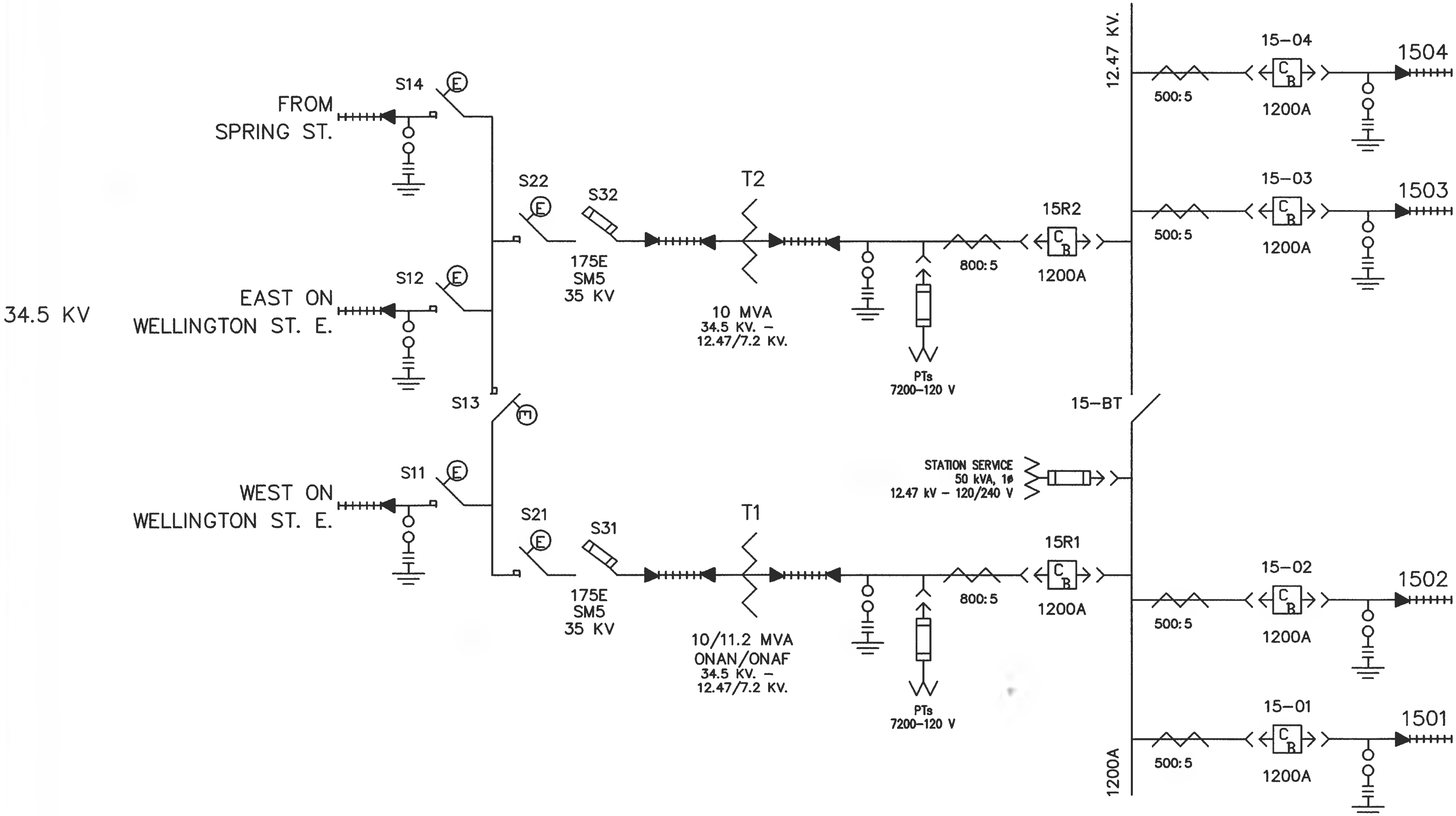
No.	Revision	Date	Initial
2	ADDED STATION SERVICE NOTE	JAN. 4/18	J.T.
1	REVISED BORDER AND DRAWING NUMBER	MAY 18/06	J.T.

PUC

SUBSTATION #13

SCHEMATIC DIAGRAM

Scale: NTS		
Drawn by: J.R.	Date: APR. 10/87	
Checked by: K.B.	Date: MAY 18/06	
Approved by:	Date: 2018/01/04	
Drawing Number: A-ES13-04-001	Rev. 2	



Scale: NTS

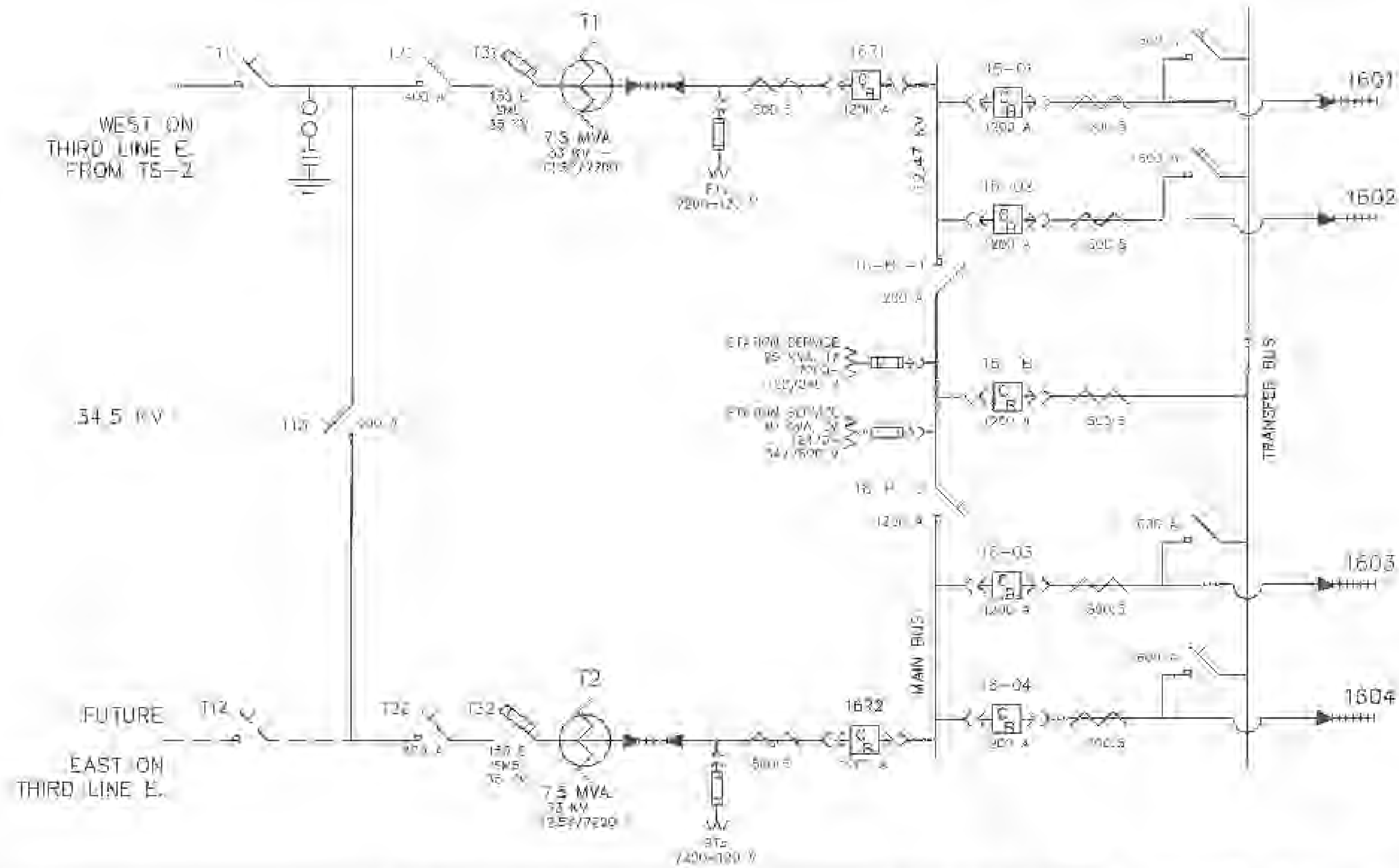
SUBSTATION #15

SCHEMATIC DIAGRAM

PUC

Drawn by: V.F.	Date: JUN. 15/95
Checked by: R.H.	Date: FEB. 14/13
Approved by:	Date: 2018/01/04
Drawing Number: ~~A-~~ES15-04-001	Rev. 2

No.	Revision	Date	Initial
2	PLACED T1 IN SERVICE	FEB. 14/13	J.T.
1	REVISED BORDER & DWG No., ADDED STA. SERV. & REVERSED FEEDER CBs & CTs.	MAY. 18/06	J.T.



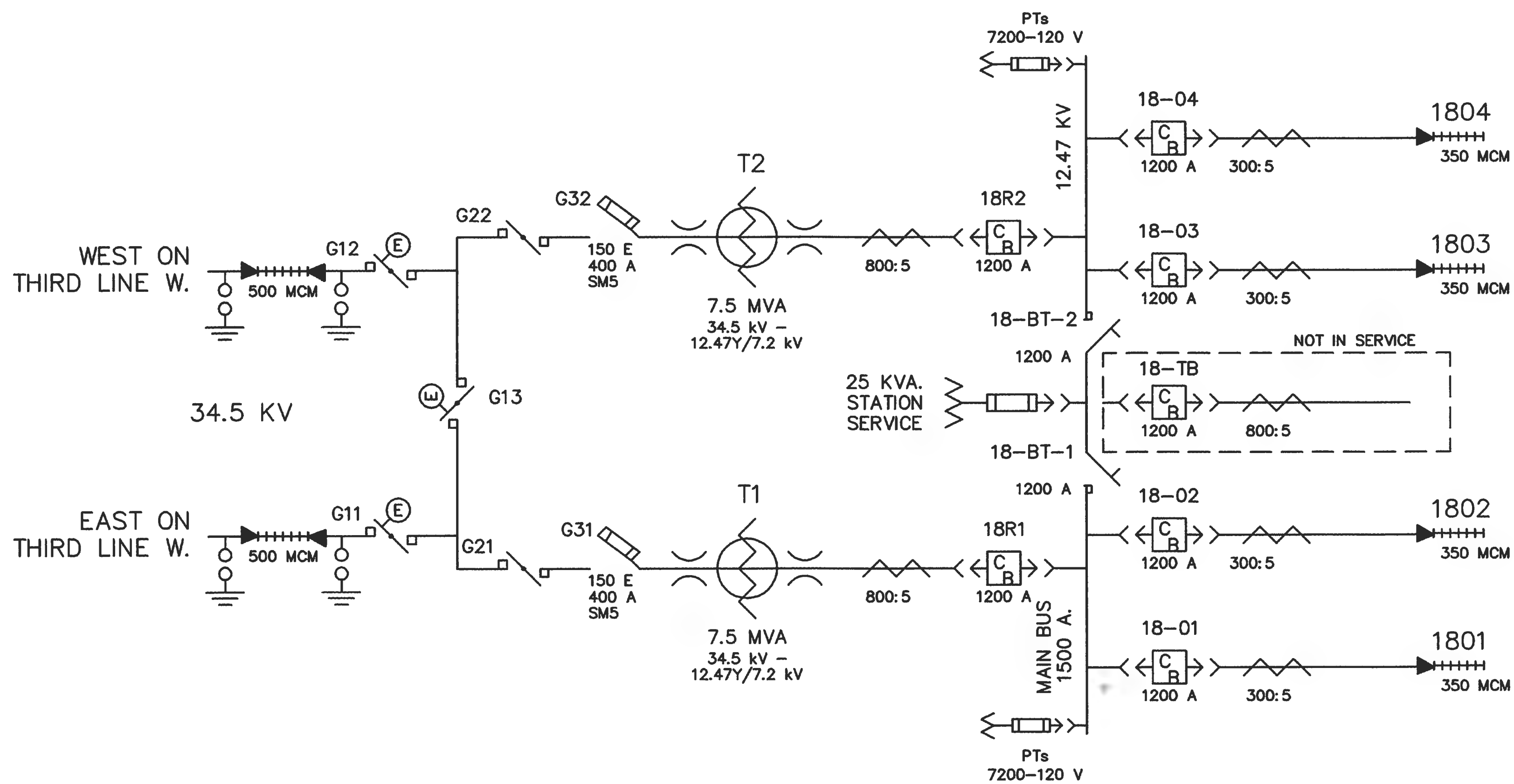
1	REVISED BORDER AND DWG NUMBER, REVISED STATION SERVICE XFMRS	MAY ..../05	J.R.
No.	Revision	Date	Initial

SUBSTATION #16

SCHEMATIC DIAGRAM

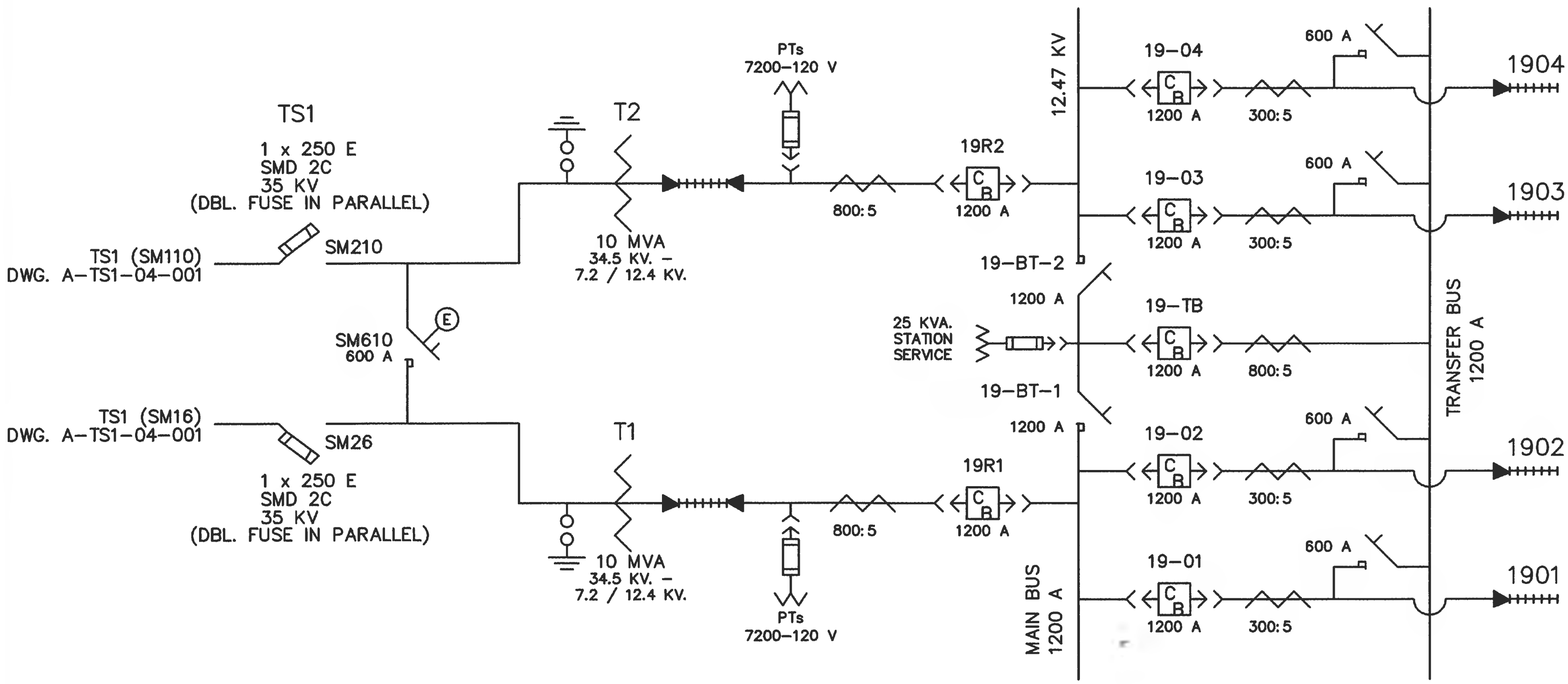
Scale: NTS	
Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date:
Drawing Number: A-ES16-04-001	Rev: 1

X:\Engineering Data\Drawings\TS1, 152 000 Substations\Substation #... Schematics\A-ES16-04-001 ... REV. 01.dwg



				SUBSTATION #18	Drawn by: J.R.	Date: SEP. 11/86
				SCHEMATIC DIAGRAM	Checked by: K.B.	Date: MAY 18/06
					Approved by:	Date: 2013/01/04
2	UPDATED TX RATINGS	JAN. 4/18	J.T.		Drawing Number: A–ES18–04–001	Rev. 2
1	REVISED BORDER AND DWG. No., REMOVED TRANSFER BUS AND SWITCHES.	MAY 18/06	J.T.			
No.	Revision	Date	Initial			

Scale: NTS



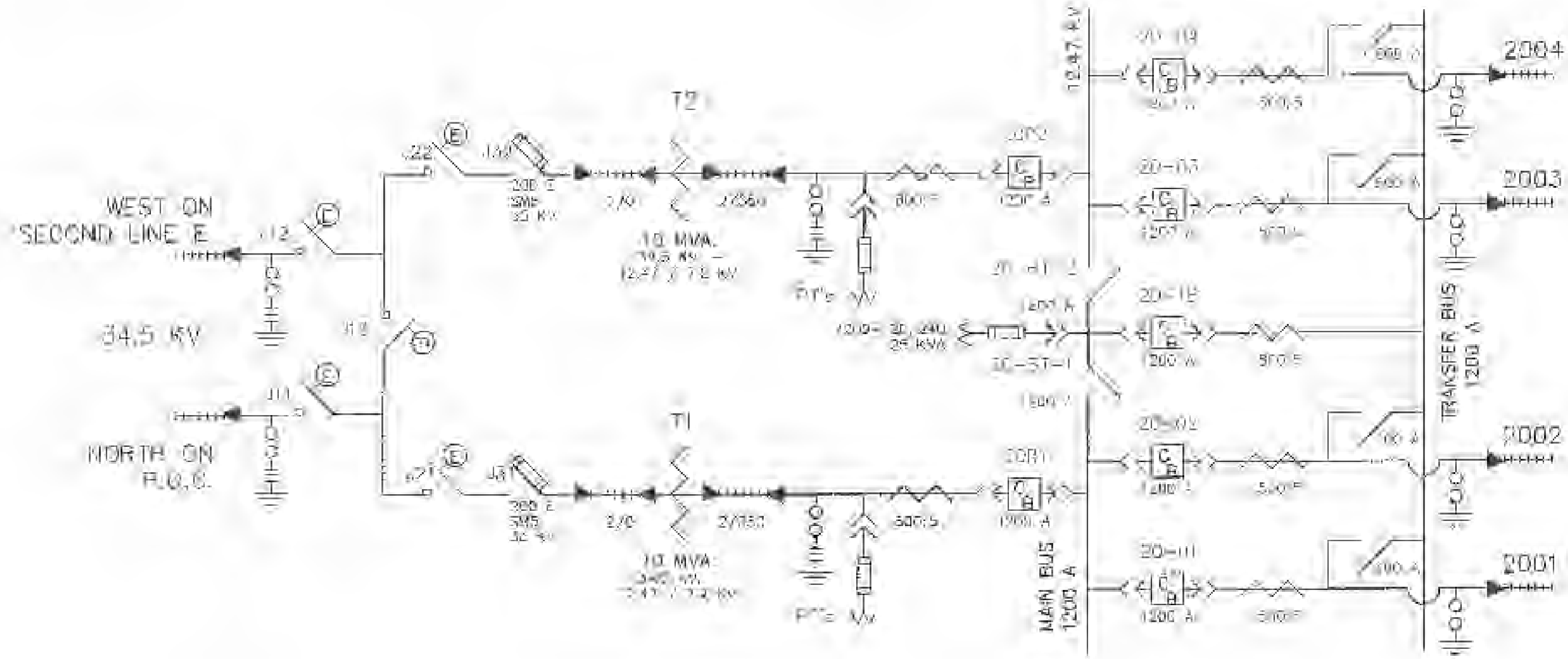
No.	Revision	Date	Initial
2	TS1 CONNECTIONS REVISED	JAN. 4/18	J.T.
1	REVISED BORDER AND DRAWING NUMBER.	MAY 18/06	J.T.

SUBSTATION #19

SCHEMATIC DIAGRAM

Scale: NTS

Drawn by: J.R.	Date: JUN 18/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: 2018/01/04
Drawing Number: A–ES19–04–001	Rev. 2

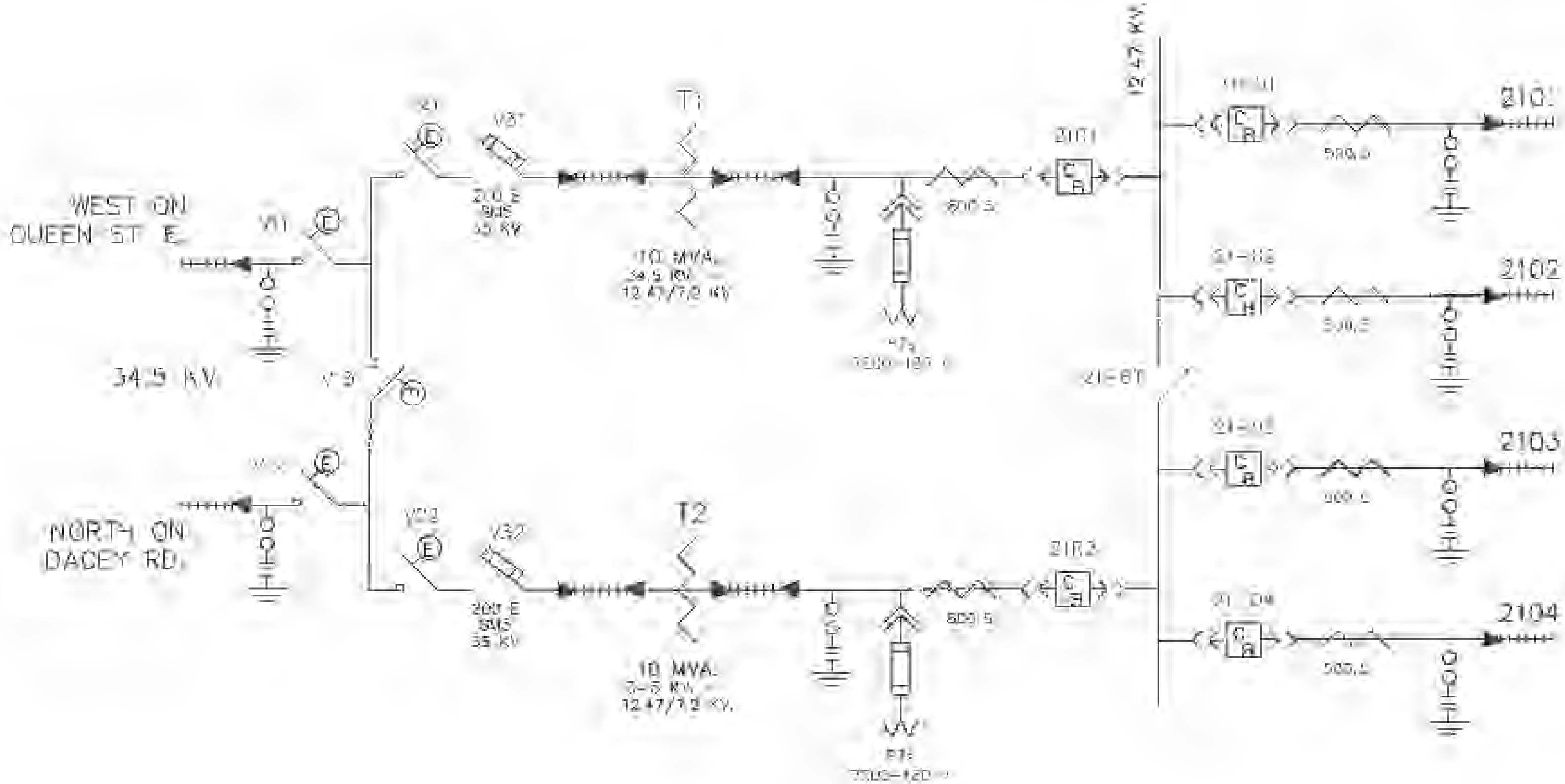


1	REVISED BORDER AND DRAWING NUMBER	MAY 16/06	
Rev.	Revision	Date	Initial

SUBSTATION #20

SCHEMATIC DIAGRAM

	Scale: NTS
Drawn by: J.R.	Date: SEP 11/86
Checked by: K.B.	Date: MAY 16/06
Approved by: [signature]	Date: May 25/06
Drawing Number: A-ES20-04-001	Rev. 1



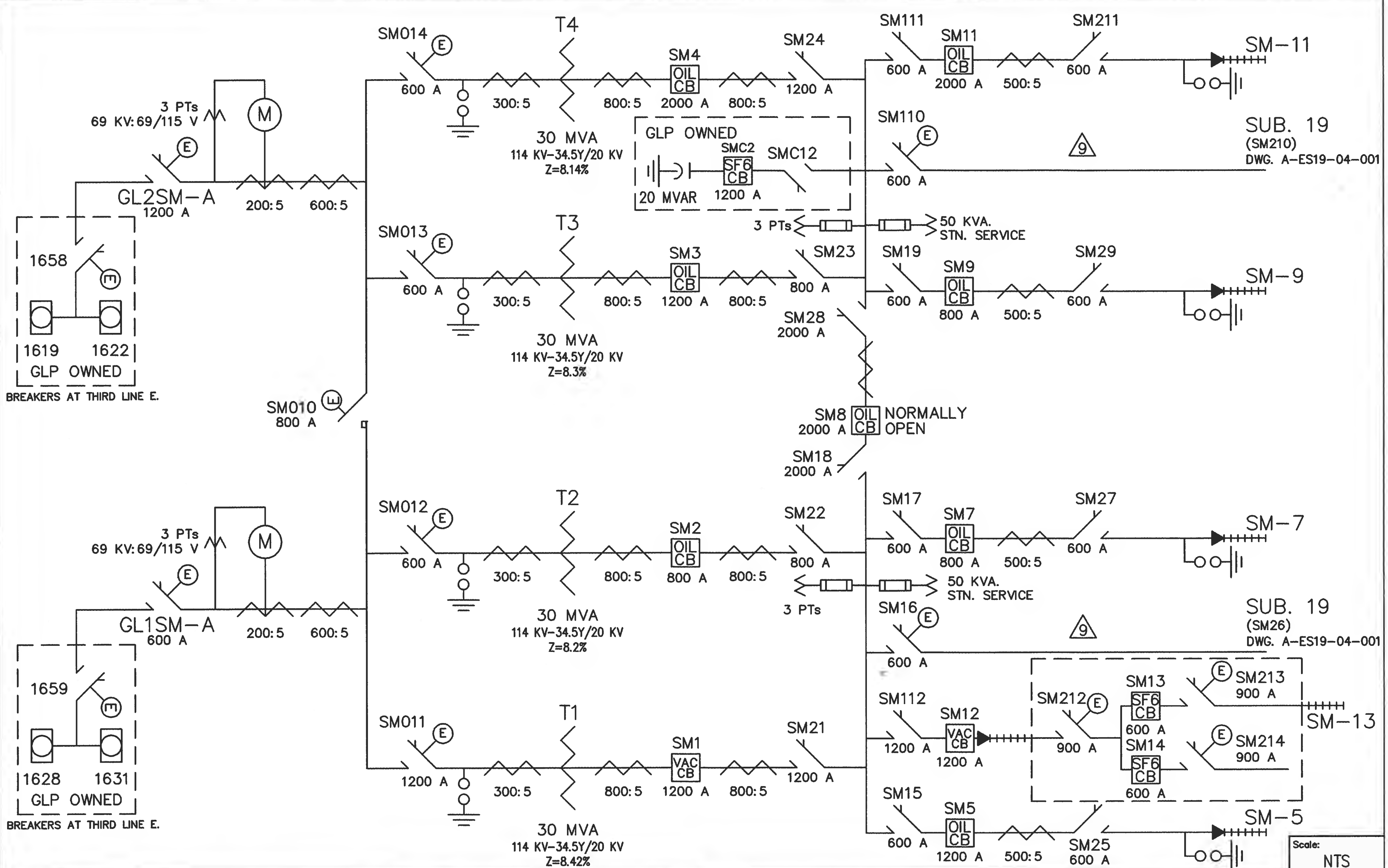
1	REVISED BORDER AND DRAWING NUMBER, ADDED RATINGS.	MAY 15/06	J.T.
No.	Revision	Date	Int./For

Scale: NTS

SUBSTATION #21

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 15/06
Approved by:	Date: May 25/06.
Drawing Number: A-ES21-04-001	Rev. 1



No.	Revision	Date	Initial
9	SUB 19 CONNECTIONS REVISED	JAN. 4/18	J.T.
8	ADDED CBs SM12, SM13 & SM14. REMOVED CB SMC1 & CAP. BANK.	JUL 12/17	J.T.
7	SWITCH REPLACEMENT PROJECT	JUNE 3/13	JFK
6	REVISED GLPT NOMENCLATURE AND ADDED PTs	FEB. 13/13	J.T.
5	REMOVED GROUND SWITCH AND ADDED WHOLESALE METERING	MAY 22/12	J.T.
4	REVISED RATING ON SM21	JUN 23/06	J.T.
3	REVISED RATINGS ON GL2SM−A, SM013, SM24, SM7, SM9 & SM610.	MAY 23/06	J.T.

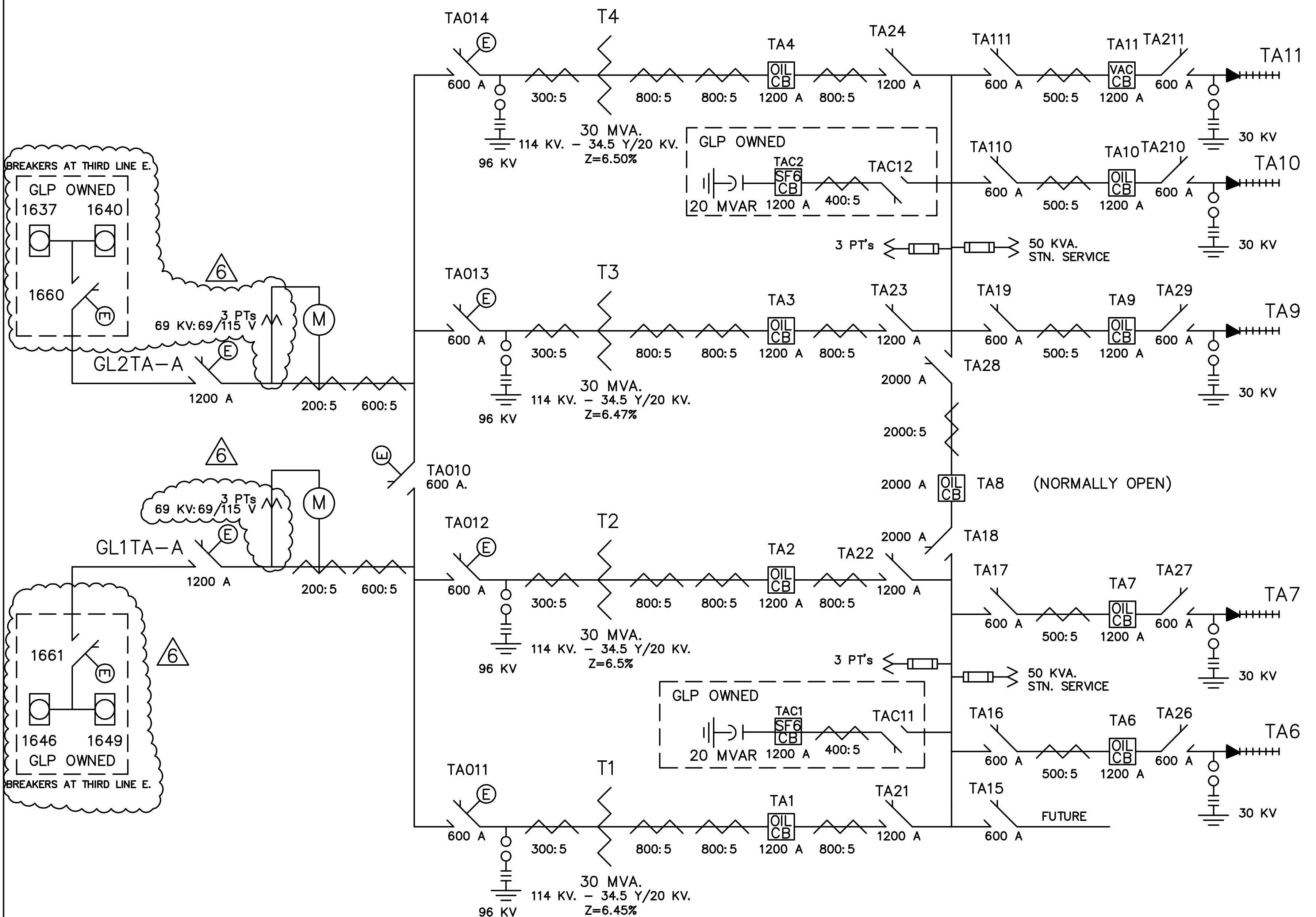
PUC

TRANSFORMER STATION TS-1

ST. MARY'S TRANSFORMER STATION SCHEMATIC DIAGRAM

Scale: NTS

Drawn by: J.R.	Date: SEP. 11/86
Checked by: M.P.	Date: JUL. 12/17
Approved by:	Date: 2018/01/04
Drawing Number: A−TS1−04−001	Rev. 9



Scale: NTS

No.	Revision	Date	Initial
6	REVISED GLPT NOMENCLATURE AND ADDED PTs	FEB. 13/13	J.T.
5	REVISED OIL CIRCUIT BREAKER CT RATIOS	MAY 31/12	J.T.
4	ADDED WHOLESALE METERING	MAY 22/12	J.T.
3	REVISED RATING ON TA15.	JUN 23/06	J.T.
2	REMOVED INCOMER CTs, REVERSED CTs & CBs ON CAP BANKS, ADDED TA15 & REVISED TA21	MAY 23/06	J.T.
1	REVISED DWG. # & RATINGS FOR TAC1, TAC2, TA21, TA22 AND TA24	APR. 18/06	J.T.

PUC

TRANSFORMER STATION TS2

TARENTORUS TRANSFORMER STATION
SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: R.H.	Date: FEB. 13/13
Approved by:	Date:
Drawing Number: A–TS2–04–001	Rev. 6

Appendix B

Asset Condition Assessment & Asset Management Plan

Asset Condition Assessment and

Asset Management Plan 2017 – 2021

PUC Distribution Inc.

September 2016

Prepared by

METSCO Energy Solutions
215-2250 Matheson Blvd East
Mississauga ON L4W 4Z1

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www.metsco.ca

Contents

List of Figures

EXECUTIVE SUMMARY

This report summarizes the results of the Asset Condition Assessment study performed during the second and third quarter of 2016, by METSCO Energy Solutions Inc. on behalf of PUC DISTRIBUTION Inc. The study was performed with the objective of determining the current condition of fixed assets to identify the assets that present unacceptably high risk of failure in service and develop an investment plan for asset renewal, to mitigate the risk.

Decisions involving investment into fixed assets play a major role in determining the optimal performance of a distribution system. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets. In either case, investments that are either oversized or made too far in advance of the actual system need result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement are planned and implemented based on a "just-in-time" approach. The risk based Asset Management Strategy, on which this investment plan is based, determines the risk of assets' failure in service, by taking into account assets' service age as well as current asset condition based on test results and inspections.

The study reveals that the power transformers and switchgear employed in PUC DISTRIBUTION's step-down stations present the highest risk of failure in service. As detailed in Section 4.1, out of 39 transformers employed at PUC DISTRIBUTION's stations, 20 have been determined to be in "poor" or "very poor" condition. Station switchgear has also been determined to be in "poor" or "very poor" condition at 14 of the 17 stations, currently supplying PUC's distribution system.

Since the in-service failure of power transformers and switchgear in step-down stations has the largest impact on power supply security and reliability, a long term proactive program is recommended to gradually reconstruct all of the stations, determined to be in poor or very poor condition. In the absence of a proactive plan for renewal, aging infrastructure assets employed at stations and particularly those employed at 115/34.5 kV stations, present an elevated risk of a cascaded equipment failure event, which could potentially lead to a black out of an extended duration and therefore, both of the 115/34.5 kV transformer stations (TS-1 and TS-2) will require rebuild during the next five to ten years. However, to maximize the benefit/cost ratio of this major investment, significant front-end planning and engineering is required to successfully implement the rebuild of these stations. Therefore, we are recommending a planning/engineering study be commissioned to review all practical development options and identify the optimal option for implementation.

For the 34.5 / 12.47 kV stations, we recommend at least two stations be included in the next five-year plan for rebuild, based on the condition of power transformers, switchgear and auxiliary equipment. Although the power transformers and switchgear at each of the three 4 kV distribution stations are also currently in poor and very poor condition, no provision is made in the investment plan for renewal of these stations, as these are recommended to be retired from service.

In case of overhead lines, assets posing a high risk of failure in service can be grouped into three main categories: (a) structurally weak wood poles, (b) copper conductors of #6 AWG cross-section (restricted conductor) and (c) porcelain cut-outs and insulators. Wood poles experience reduction in their structural strength with age, due to a number of factors, including wood rot, termite or wood pecker damage and mechanical damage during storms or vehicular accidents. Poles with reduced strength are identified through non-destructive in-situ testing and when the strength of a pole is determined to fall below its design load, it is identified for replacement. A significant number of overhead lines employ restricted conductors, which have a history of failures in service, due to reduced tensile strength, bringing live conductors down and posing a serious safety risk to public. PUC DISTRIBUTION has been actively rebuilding lines, replacing the restricted conductor during the past five years. This program is recommended to be expedited with the objective of removing all restricted conductor from existing lines during the next 10 years. PUC DISTRIBUTION has been gradually replacing porcelain cut-outs and insulators, which are also known to experience failures in service, during the past five years and this program is scheduled to be completed during 2016. In addition to the above indicated renewal initiatives, some of the existing 4 kV lines will need to be rebuilt through implementation of the voltage upgrade program and some additional lines experiencing high failure rates due to advanced asset age will also require re-construction.

On the underground distribution system, approximately 25% of the cable circuits have reached a service life of greater than 40 years, which is the typical useful life for this type of cable. There are no practical tests available, which could be economically performed in field to accurately assess the remaining useful life of cables, however, cross-linked polyethylene (XLPE) insulated cables generally begin to experience an increase in failure rates when they get past 40-year service age. Therefore, the investment plan includes provision for selectively replacing and rejuvenating cables (through insulation injection where economical) in subdivisions, experiencing high cable failure rates. PUC DISTRIBUTION's underground system employs concrete chambers for various functions, including pre-cast pull-boxes, poured-in-place manholes, concrete vaults and bases for switchgear and K-bar junctions. Approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete and some are unsafe and will need to be rebuilt. After reconstruction, these vaults should be converted to pads to support pad mounted equipment, mounted above grade. The investment plan also includes provision for replacement of a small number of pad-mounted switchgear and k-bar junction boxes, that are determined to be near the end of their service life.

For distribution transformers, PUC DISTRIBUTION employs a "run-to-failure" strategy and due to the relatively low impact of transformer failures on reliability, this strategy serves well for pole mounted and pad mounted transformers and it is also in line with all other LDCs. However, because vault mounted transformers are not generally replaced with the same type of transformer upon failure, some degree of pre-planning is required to replace these with pad mounted transformers. Therefore, a proactive program is required to replace the submersible transformers with pad mounted transformers.

A vast majority of PUC DISTRIBUTION's electric meters were installed in 2009 and have a seal year of 2019. In order to confirm accuracy of these meters, sample batches of revenue meters will require testing in 2019, in accordance with Measurement Canada's guidelines to acquire an extension of meter seals for 8 more years. To facilitate this, PUC DISTRIBUTION will need to purchase approximately 400 1-phase meters and approximately 50 3-phase meters. In addition to the above, spare revenue meters would be required to replace meters that fail in service.

An estimate of the overall investment level required to implement the asset renewal program recommended in this report is summarized below. The cost estimates were prepared based on 2016 costs and the costs for future years were projected based on annual inflation rate of 2%.

Asset Renewal	2017	2018	2019	2020	2021	Five Year Total
Total Capital Investment Required	$ 4,088,114	$ 8,497,108	$ 4,465,516	$ 4,510,663	$ 9,062,246	$ 30,623,646
Capital Investment Requirement by Excluding Expenditure into Stations	$ 3,862,898	$ 3,940,156	$ 4,018,959	$ 4,099,338	$ 4,181,325	$ 20,102,677

Implementation of the proposed investment plan for asset sustainment would result in an average annual expenditure of $6,124,729.

1 INTRODUCTION

This report summarizes the results of the Asset Condition Assessment study performed by METSCO Energy Solutions Inc. (METSCO) on behalf of PUC DISTRIBUTION Inc. (PUC DISTRIBUTION) during the second and third quarter of 2016. The study was performed with the objective of establishing the health and condition of fixed assets to identify those assets that present unacceptably high risk of failure in service and to develop an investment plan for asset renewal to mitigate the risk.

This report covers the following assets:

a) Power transformers, switchgear, auxiliary equipment, buildings, fences and ground grids employed at Transformer Stations (TS) and Distribution substations
b) Overhead distribution lines;
c) Underground distribution system;
d) Distribution transformers; and
e) Revenue meters.
f) Facilities (office building)

The capital investment plan provided in this report covers the capital expenditure needed for sustainment of existing assets. Expenditure requirements for system growth and new services are not included in this report but these will be included in the Distribution System Plan, based on the anticipated number of requests for new services and load growth.

The report is organized into six (6) sections including this introductory section. Section 2 describes the general principles of the risk based asset management strategy to achieve optimal operation of the distribution grid. Section 3 describes the methodology for ranking and benchmarking the health of assets. Section 4 documents the results of asset condition assessment exercise and Section 5 presents the capital investment plan for renewal and replacement of assets found in poor or very poor condition. Section 6 reviews the preventative maintenance program.

2 STRATEGIC MANAGEMENT OF DISTRIBUTION FIXED ASSETS

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In either case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk based Asset Management Strategy, therefore, determines the risk of assets' failure in service, based on the condition of the assets, which is commonly measured with the help of a yard stick of "Asset Health Indices", and computes the valuation of the risk based on the consequences of assets' failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the asset's service life – and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

PAS-55, a specification for asset management, was developed by the British Standards Institute (BSI) and offers one of the best-in-class strategies for risk management associated with fixed assets of electricity distribution systems. To be compliant with the PAS-55 asset management standard, the asset management approach must contain the essential elements documented in Figure 2.1.

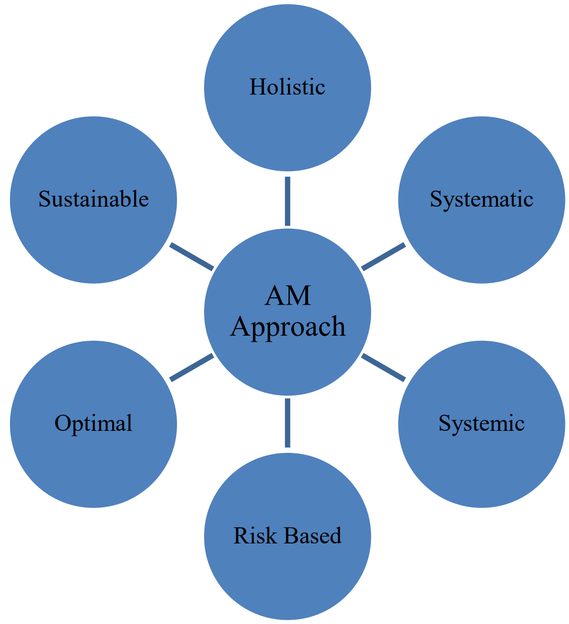


Figure 2-1: Essential Elements of Asset Management Strategy

The overarching objective is to develop capital and preventative maintenance investment plans, which could be implemented over a period of five to ten years to achieve optimal system performance by placing appropriate weights on stakeholder objectives and performance requirements, as shown in Figure 2-2.

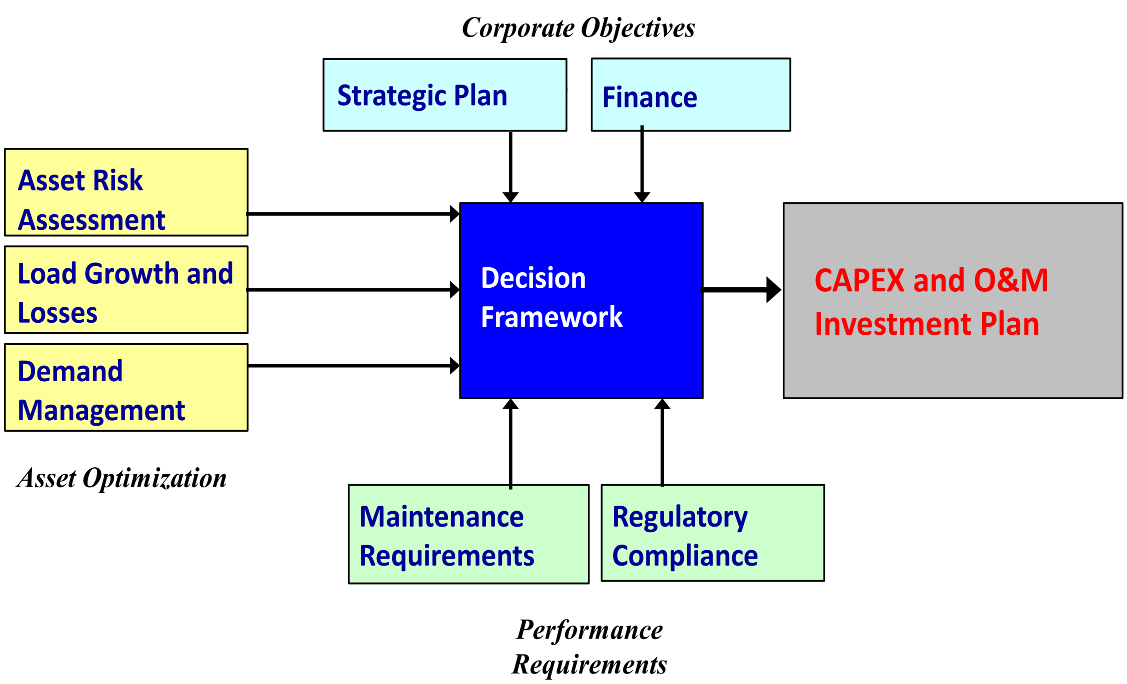


Figure 2-2: Multi-Prong Decision Framework

For regulated transmission and distribution (T&D) businesses, the key considerations in development of a Strategic Asset Management Plan include:

a) Regulatory Compliance
b) Public and Employee Safety
c) Operating Efficiency
d) Reliability and Supply System Security
e) Customer Service Quality
f) Getting Full Life out of Assets
g) Minimizing Asset Life Cycle Costs
h) Minimizing Risk of Premature Failures
i) Minimizing Environmental Risks

Figure 2-3 shows the basic decision support model employed under a risk based strategy. The timing and size of investments are selected to minimize the "Total Cost" of risk and risk mitigation initiatives.

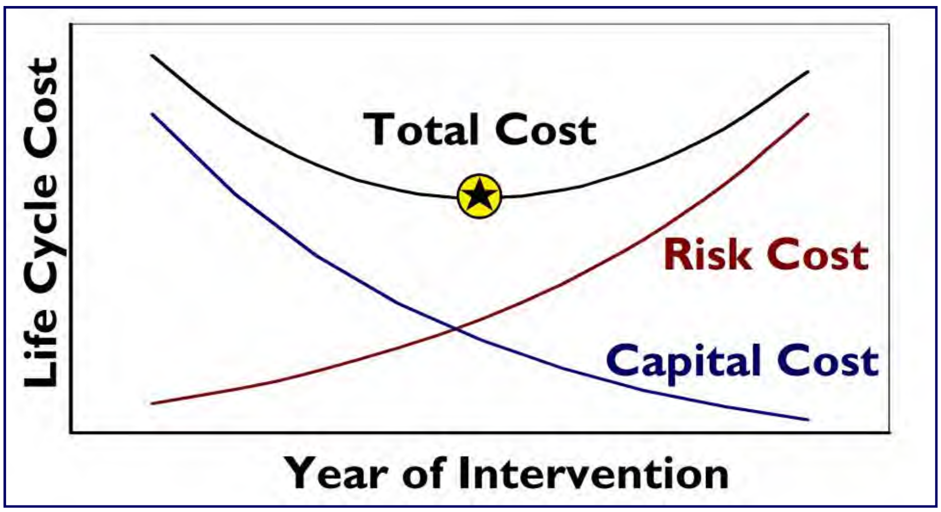


Figure 2-3: Risk Based Decision Support System

Figure 2-4 summarizes a practical matrix to sift through a large number of assets, typically employed on T&D systems to objectively identify assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk. Numeric health indices, typically normalized to a scale of 100, are used to express the health and condition of assets, as shown in Figure 2-5 and this allows separation of the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan for implementation over a 5 year period.

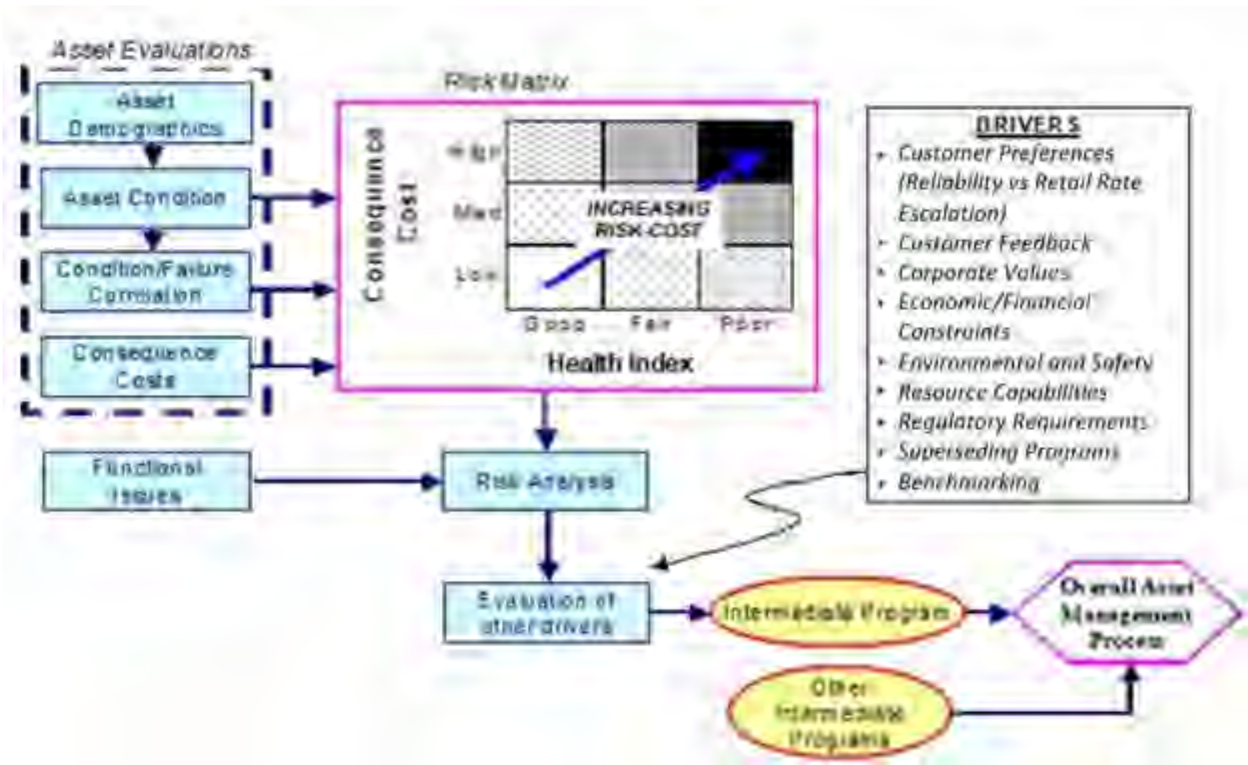
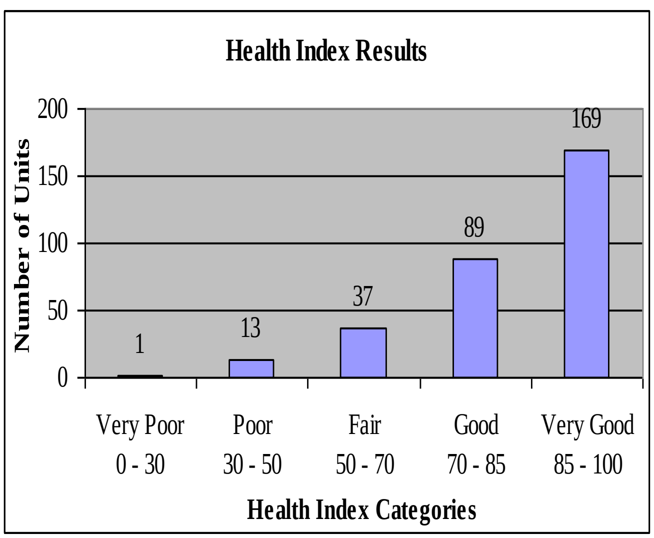


Figure 2-4: Model to Identify Assets with Highest Risks



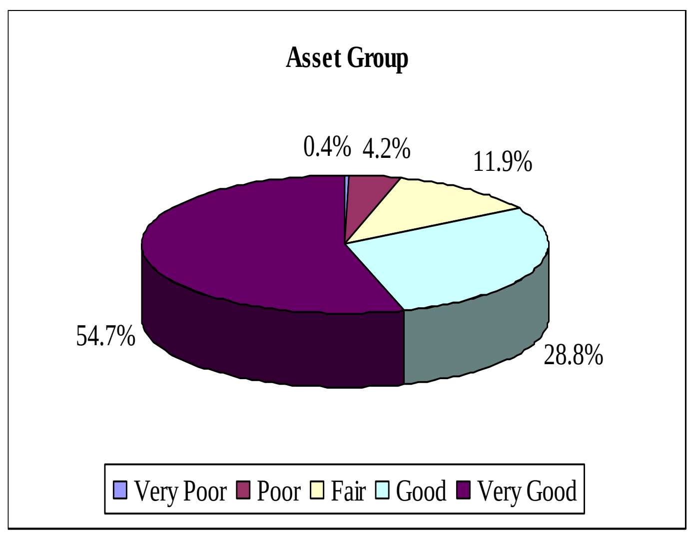


Figure 2-5: Graphs to Identify Assets with Highest Risks

3 ASSET CONDITION ASSESSMENT METHODOLOGY

This section describes in detail an asset condition assessment methodology for different categories of fixed assets employed on the distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Asset Condition Assessment methodologies are described below for the following distribution system asset categories:

a) Substations
b) Overhead Lines
c) Underground Lines
d) Distribution Transformers (pole mounted, pad mounted, and submersibles in underground vaults)
e) Distribution Switches and Fused Cut-outs
f) Low Voltage system

Asset health condition indicators and tests shown in the tables are weighted based on their importance in determining the assets end-of-life. For purposes of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

A= 5
B = 4
C = 3
D = 2
E = 1

These condition rating numbers (i.e., A = 5, B = 4, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset. Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This allows for determining condition category for each asset in groups of "Very Poor", "Poor", "Fair", "Good" and "Very Good" depending upon the resulting score. "Very Good" asset condition represents brand new asset in perfect operating condition. "Good condition" indicates an asset with service life equal to less than 25% of its typical useful life and with no impairment and no noticeable wear. "Fair Condition" indicates an asset with service life equal to more than 25% but less than 80% of its typical useful service life, with normal wear and asset performance within acceptable tolerances and no significant impairment. "Poor Condition" signifies an asset with service life greater than 80% of its typical useful, appreciable wear or significant impairment causing asset performance to degrade below acceptable levels and presenting high risk of asset failure in the absence of major repairs or asset rehabilitation to restore asset condition to "Fair". "Very Poor Condition" signifies an asset with serious impairment to its critical components and presenting very high risk of failure. Assets in "very poor" condition cannot be economically repaired and renewal is the only option to restore their operating condition.

3.1. Substations

The major assets employed in transformer stations and distribution stations include:

- Station Transformers
- Switchgear (Circuit breakers, circuit switchers and reclosers, including protection relays)
- Other assets including station building, fences, ground grids, Bus work, control batteries etc.
- SCADA and Network infrastructure

3.1.1 Condition Assessment Criteria for Station Transformers

The key role of station transformers is to step down transmission or sub-transmission voltage to distribution voltage. PUC DISTRIBUTION has two types of stations: transformer stations and distribution stations. The transformer stations step down from 115 kV to 34.5 kV and the distribution stations step down from 34.5 kV sub-transmission voltages to 12.47 kV or 4.16 kV.

The key components of power transformers installed at transformer and distribution stations include:

- primary and secondary coils, made of copper conductors,
- magnetic core made of low loss iron laminations,
- insulation system, commonly consisting of cellulose paper and mineral oil,
- transformer tank, either sealed or breather type,
- primary and secondary bushings, and
- auxiliary devices.

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and cellulose paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature and degree of contamination with moisture. High operating temperature and presence of moisture content in insulating oil decomposes the insulation to form acids, which causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Condition assessment of transformer oil, through measurement of the dielectric strength, insulation power factor, moisture content, acidity level, and surface tension measurement provides extremely useful information in assessing the health and condition of a transformer.

The paper insulation consists of long cellulose chains, that break up as the paper ages (oxidizes). Tensile strength and ductility of insulation paper are important properties that are determined by the average length of the cellulose chains. As the paper oxidizes, its mechanical strength is gradually reduced, making it weak and brittle. This can lead to sudden insulation failure if the transformer is subjected to a mechanical shock, that are common in normal operating conditions, in form of external faults on lines supplied from the transformer. Insulation degradation and failure can also result from electrical activity inside insulation, such as partial discharge activity, which is initiated if the level of moisture in oil builds up or if other minor defects develop within the insulation. Service age and operating temperature during the service life also provide indication of the condition of insulation system in transformers. Power transformers are known to typically provide a service life of approximately 40 to 45 years.

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).

Computing the Health Index for a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) **Age Related Scoring**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Table 3-1: Station Transformers – Age Related Health Score

Condition Rating	Station Transformer Age
A	0 to 10 years
B	11 to 20 years
C	21 to 35 years
D	36 to 50 years
E	Older than 50 years

(b) Scoring Based on Loading Level:

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformers expressed in % of nameplate rating can therefore be employed as an indicator of transformer health:

Table 3-2: Station Transformers – Load Related Health Score

Condition Rating	Component Condition
A	Peak load less than 50% of its rating
B	Peak load of 51% to 70% of its rating
C	Peak load of 71% to 85% of its rating
D	Peak load of 86% to 100% of its rating
E	Peak load of greater than 100% of its rating

(c) Scoring Based on Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Table 3-3: Station Transformers – Health Score Based on Visual Inspections

Condition Rating	Visual Inspections

A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank or radiator badly rusted or damage to bushing or significant oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

(d) Scoring Based on Testing of the Insulating Oil

Various insulation tests, including dissolved gas in oil analysis (DGA), dielectric strength or water content measurement test can be interpreted by an expert to rank the overall condition of transformer insulation system:

Table 3-4: Station Transformers – Health Score Based on Oil Tests

Condition Rating	Test Results
A	Test results indicate excellent insulation condition, no indication of moisture, arcing, overheating or degradation of paper
B	Tests indicate normal aging, no concerns about insulation health
C	Tests indicate slightly above average but stable moisture content or presence of arcing overheating related gases
D	Some of the tests indicates significant concerns about insulation condition
E	Two or more of the tests indicate rapidly deteriorating insulation condition

3.1.2 Condition Assessment Criteria for Substation Switchgear

High voltage or medium voltage circuit breakers provide local or remote control for closing and opening of power supply circuits and in conjunction with protective relays provide an important safety function to automatically detect and isolate faulty circuits in order to provide safe, stable and reliable operation with desired selectivity. While its design is significantly different, the recloser employs the same operating principle as a circuit breaker. In case of low short circuit levels, circuit switchers are used in lieu of circuit breakers to provide the same function.

When a circuit breaker interrupts current, an electrical arc is produced in the ionized insulation medium. In order for the circuit breaker action to succeed, the large amount of energy contained in the arc must be successfully extinguished by the breaker's interrupting medium. Depending on the type of arc interrupting medium employed, circuit breakers (or reclosers) are classified as oil circuit breakers, magnetic air circuit breakers, SF-6 circuit breakers or vacuum circuit breakers. In order to deliver the desired functions, circuit breakers and reclosers are required to possess the following properties and characteristics:

- Highly conductive contact material, capable of withstanding repeated arcs;
- High quality of contact make with extremely low resistance;
- Adequate contacts parting distance in open position for the rated voltage;
- Adequate line to ground insulation for the rated voltage;
- Stable insulating medium, capable of withstanding repeated arcs;
- Fast speed during opening and closing of contacts;
- Appropriate arc blowing techniques to extinguish arcs;
- Adequate energy imparting mechanisms for making or breaking of short circuit currents.

The operating mechanism of circuit breakers and reclosers consists of numerous moving parts that are subject to wear and tear during breaker operation. Because circuit breakers are required to frequently "make" and "break" heavy currents, the contacts are subjected to arcing that accompanies such operations. Each time a circuit breaker opens or closes, the contact surfaces undergo some degradation and degraded contacts produces higher degree of arcing in subsequent operations. Heat produced during contact arcing also decomposes the metal surface from the contacts as well as the insulation medium and the by-products so decomposed are deposited in surrounding insulation materials. The mechanical energy required to generate high contact velocities also results in wear and tear of the mechanical parts in operating mechanism.

A number of factors influence the overall rate of wear and severity of degradation of circuit breakers, including type of the insulating medium, design of the contacts, operating environment, and the duty cycle of the circuit breaker. Load current switching or fault current interruption seldom lead to sudden failure of circuit breakers, but repeated operations result in overall wear and tear which lead to eventual end of life.

Circuit breakers mounted outdoors may experience adverse environmental conditions that may further contribute to the rate and severity of degradation. The following factors represent environmental degradation of outdoor mounted circuit breakers:

- Corrosion of enclosures and metal parts;
- Potential ingress of moisture into operating parts and insulating system;
- Bushing/insulator deterioration under the influence of moisture, fog, ice; and
- Deterioration of mechanical parts;

Oil Circuit Breakers (OCBs) typically have longer current interruption duration compared with other types of designs. Contacts and the insulation medium are therefore subjected to severe arcing, resulting in deterioration of the contact surface as well as insulation. Thus, both contacts and oil degrade more rapidly in case of OCBs than they do in either SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions under fault or heavy load will cause contact erosion and oil carbonisation, requiring contact maintenance and possibly oil filtration. OCBs have therefore higher operating costs compared to other designs.

Different types of circuit breakers employed on PUC DISTRIBUTION's transformer and distribution stations are described below:

(i) Oil Circuit Breakers (OCB) or Oil Filled Reclosers

In minimum oil circuit breakers, insulating oil provides the role of arc quenching only, but in bulk oil circuit breakers, the insulating oil provides both the arc quenching and the insulation functions. OCBs generally perform well at low ambient temperatures. They also provide long and reliable service life when the number of loading switching or fault interruption operations is infrequent. However, frequent switching fault interruption applications must be accompanied by frequent preventative maintenance. OCBs do not perform well in switching capacitive loads, during switching operations of which high peak recovery voltages are produced.. The manufacture of new OCBs has been discontinued for at least 30 years now. The original equipment manufacturers (OEMs) provided service support and spares for these OCBs until the late 1990s. Many utilities in North America continue to successfully employ older vintages of OCBs on their systems.

(ii) Air Magnetic Circuit Breakers (Air Magnetic Breakers)

Air magnetic breakers employ the magnetic effect of the current in their design, by forcing the electric arc produced during opening on the contacts into an arc chute. The arc chute causes elongation of the arc path and allows cooling, splitting and eventual extinction of the arc. In some designs, an auxiliary puffer is employed to blast air into the arc, which allows successful interruption of low-level currents with weaker magnetic fields. Air magnetic breakers represent the second oldest technology in circuit breaker design, next to OCBs. They are also no longer in manufacture and have been superseded by SF6 and vacuum technologies since the late 1970s.

(iii) Vacuum Circuit Breakers or Reclosers

In a vacuum circuit breaker, vacuum interrupters are employed to make or break load or fault current. Upon separation of the contacts, the current initiates a metal vapour arc discharge and flows through the plasma until the next current zero. The arc is extinguished at current zero and the conductive metal vapour condenses on the metal surfaces during a very short time interval measured in micro seconds. Therefore, the dielectric strength in the breaker builds up very rapidly. The effectiveness of vacuum interrupter depends largely on the material and form of the contacts. In modern designs, oxygen free copper chromium alloy is commonly employed as it is believed to be the best material for the application. This material combines good arc extinguishing characteristic with a reduced tendency to contact welding.

(iv) SF_6 Circuit Breakers

A SF_6 circuit breaker is designed to direct a constant gas flow to the arc that extracts heat from the arc and so allows achieving its extinction at current zero. The gas flow de-ionises the contact gap and establishes the required dielectric strength to prevent an arc re-strike. The direction of the gas flow either parallel or across to the axis of the arc has an influence on the efficiency of the arc interruption process. Research has shown that an axial flow creates a turbulence causing an intensive and continuous interaction between the gas and plasma as current approaches zero. Recent developments concentrated on employing the arc energy itself to create directly the differential pressure needed, without using an external piston. Parallel to the self-pressurising design, the rotating arc SF_6 interrupter was also developed. In this design, a coil sets the arc in rotation while the quenching medium remains stationary. The relative movement between the arc and the gas is no longer axial but radial; it is a cross-flow mechanism.

Computing the Health Index for circuit breakers requires collection of data on a number of condition indicators:

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of circuit breakers and reclosers. Since the outdoor mounted reclosers, exposed to the weather elements experience a faster rate of aging, two separate sets of criteria are provided for outdoor and indoor mounted circuit breakers / reclosers:

Table 3-5: Outdoor Circuit Breakers or Reclosers – Age Related Health Score

Condition Rating	Age
A	0 to 7 years
B	8 to 15 years
C	16 to 30 years
D	31 to 35 years
E	35 years or older

Table 3-6: Indoor Circuit Breakers – Age Related Health Score

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years (or
D	31 to 40 years
E	41 years or older

(b) Scoring based on Visual Inspections

Visual inspections can provide a good indication of the physical condition of circuit breakers or reclosers, which can be ranked as indicated below:

Table 3-7: Circuit Breakers – Visual Inspections Based Health Score

Condition Rating	Visual Inspection Indicators
A	No rust on tank/enclosure, no damage to bushings, no leaks, controls and wiring in excellent condition
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation

D	Tank/enclosure badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

(c) Scoring Based on Evaluation of the tests

Various interruption chamber tests can be interpreted by an expert to rank the overall condition of breaker insulation system:

Table 3-8: Circuit Breakers and Recloser – Testing Based Health Score

Condition Rating	Test Results
A	Test results indicate excellent condition of contacts, operating mechanism, insulation condition and controls
B	Normal aging, each of the four indicators, identified in A above, within specified limits
C	One of the above four indicators is slightly beyond the specified limits
D	Two or more of the above four indicators beyond the specified limits
E	Two or more of the indicators beyond specifications and cannot be brought to comply with the specifications

(d) Scoring Based on Condition of the protection relay calibration tests

Calibration tests can be interpreted by an expert to rank the overall condition of protection relays:

Table 3-9: Protection Relays – Testing Based Health Score

Condition Rating	Test Results
A	Excellent operating condition, calibration well within specified limits
B	Normal aging, calibration within the specified limits
C	Frequent calibration required, but it is possible to meet specified limits
E	Not possible to calibrate the relays to bring settings to specified limits

3.1.3 Condition Assessment Criteria of Other Key Substation Assets

a) Ground Grids

The purpose of a substation ground grid is to provide a low resistance ground electrode for system neutral, for equipment case grounding and to maintain safe potential gradients within the station yards during abnormal operating conditions, i.e. line-to-ground faults.

The station ground electrode consist of multiple ground rods driven into the ground and located strategically and connected with underground copper conductors to make a mesh of sufficiently low resistance. All feeder neutrals are connected to the electrode. Cases of each piece of power equipment are also bonded to the ground electrode. All fences and gates are bonded to the perimeter ground grid.

Where the ground potential rise (GPR) exceeds safe limits, surface stone of high resistivity is used in the substation yard to maintain step potential within safe limits.

Buried ground rods, conductors and connectors are subject to corrosion, which reduces the effectiveness of the ground electrode with passage of time. Above ground components of the electrode and copper conductors are subject to vandalism and damage. The surface stone can degrade in quality due to growth of weeds.

i. Ground Grid Condition Rating Based on Evaluation of the tests

Table 3-10: Ground Grid – Testing Related Health Score

Condition Rating	Test Results
A	Ground electrode resistance and GPR within safe limits, all electrode components pass integrity test
C	Ground electrode resistance and GPR within safe limits but a few electrode components do not pass integrity test
E	Ground electrode resistance or GPR not within safe limits or many electrode components do not pass integrity test

ii. Rating Based on Condition of Surface Stone

Table 3-11: Ground Grid – Surface Stone Health Score

Condition Rating	Test/Inspection Results
A	Resistivity of Surface Stone >3000 Ohm-m, no sign of vegetation growth
C	Resistivity of Surface Stone marginally less than <3000 Ohm-m, but no sign of vegetation growth
E	Resistivity of Surface Stone significantly less than <3000 Ohm-m, and signs of vegetation growth

b) Substation Fences

The purpose of substation fences is to provide security for substation assets by not allowing entry into the yard to unauthorized people or wild life. To achieve this objective the fence has to be of a minimum height of 1.8 m to comply with the Ontario Electrical Safety Code and topped with three rungs of barbed wire covering a height of 0.3 m. The fence must be secured with posts of adequate strength and should limit the crawl space between the fence and ground to 0.1 m or less. Where a substation fence connects into another steel fence, an insulated section should be added to prevent transfer of harmful potential to remote locations. The fence should be grounded and bonded throughout. The gates should be lockable and locked and warning signs should be provided.

The common degradation mode for station fences are rusting and corrosion, damage to fence posts and gates, soil erosion increasing the crawl space under the fence and vandalism to damage and deface warning signs. The following criteria is recommended for condition assessment of station fences:

Table 3-12: Ground Grid – Fences Health Score based on Visual Inspections

Condition Rating	Inspections
A	No deficiencies in the fence
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

c) Substation Buildings

Substation buildings provide protection to critical substation assets, i.e. circuit breakers and protection relays against weather elements. While the switchgear is commonly located on the main floor, the basements serve as an oversized manhole to provide exit for feeder cables.

The common degradation mode for substation buildings is deterioration of roofs, sidings, doors and windows. A small leak in the roof can cause a lot of harm to electrical equipment and defeat the very purpose of the substation building.

The health and condition of a substation building can be measured through visual inspections:

Table 3-13: Substation Buildings Health Score

Condition Rating	Inspections
A	No deficiencies in the building
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

3.1.4 Health Index Formulation for Substation Equipment

Since each piece of substation equipment can be independently replaced or rehabilitated, rather than developing an overall health index for substations, methodology for developing health indices for key substation assets is provided below:

For purposes of formulating the Health Index for major substation assets, it is proposed to assign the following weights to various health index criteria described in the previous sections:

Table 3-14: Station Transformers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A - E	5	6	30
2	Peak loading	A - E	5	4	20
3	Visual inspection	A - E	5	2	10
4	Testing	A - E	5	8	40
	Total				100

Table 3-15: Station Switchgear (Circuit breaker / Recloser) Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age	A - E	5	6	30
2	Visual inspection	A - E	5	4	20
3	Breaker Testing	A - E	5	6	30
4	Protection Relay Testing	A - E	5	4	20
	Total				100

Table 3-16: Other Station Asset Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Ground Grid	A - E	5	8	40
2	Surface Stone	A - E	5	8	20
3	Fences	A - E	5	4	20
4	Buildings	A - E	5	4	20
	Total				100

3.2. Overhead Lines

Condition assessment methodologies for the following components employed on overhead lines are discussed below:

- Poles
- Insulators
- Hardware
- Conductors and splices

3.2.1. Condition Assessment Criteria for Poles, Insulators and Pole Hardware:

a) Poles:

As wood is a natural material, its degradation processes are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather. Fungi attack both external surfaces and the internal heartwood of wood poles. The process of fungal decay requires the presence of fungus spores in the presence of water and oxygen. For this reason, the area of the pole most susceptible to fungal decay is at and around the ground line, although pole rot is also known to begin at the top of the pole. To prevent the decay of wood poles, utilities treat them with preservatives before installation. Wood preservatives have two basic functions:

- keep out moisture that supports fungi by sealing the surfaces, and
- kill off the fungal spores.

Most power companies install only fully treated wood poles these days, however this was not always the case and the lines constructed 40 years ago or earlier may not have been constructed with fully treated poles but only butt treated poles may have been used. Typically, fully treated poles are expected to provide a longer service life in relation to butt treated poles.

The following factors represent some of the more critical factors affecting wood pole strength as poles age:

- Original type and class of wood pole;
- Original defects in wood (e.g. knots, cracks or rot);
- Rate of decay in service life which depends on type of treatment and environmental conditions;
- Pole damage by woodpeckers, insects, and other wildlife; and
- Wood burns.

Several types of damage can also deform bolt holes in poles. Generally, such deformities do not present immediate problems. However, in some cases deformed holes can result in both failure of the structure and failure of other components attached to the pole. Bolts also can become loose, elongated, bent, cracked, sheared/broken and lost.

Visual inspection can detect the following types of wood pole damage readily:

- Fibre damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;
- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in service with a reduced factor of safety.
- Wood splits from various causes that may accelerate the end of a pole's life, depending upon the extent of the split damage;
- Mis-orientation from excessive transverse forces that may result in pole tilting as well as "stretching" (i.e., loosening) and breaking of guys and guying systems;
- Burning from conductor faults and insulator flashovers that may damage wood poles, wooden support cross-braces and timber, reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire; and
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter.

Utilities have sought objective and accurate means to assess pole condition and remaining life, as a result of which, a wide range of wood pole assessment and diagnostic tools and techniques has developed. These include techniques designed to apply traditional probing and hammer tests in more controlled, repeatable and objective ways. Indirect and non-destructive techniques such as ultrasonics, X-rays, and electrical resistance have received widespread testing.

b) Condition Assessment Criteria for Insulators

The types of insulators and configurations typically used in distribution systems include dead-end, suspension, post and pin types. The insulating portion may consist of porcelain or polymer. The metallic parts usually are made from zinc coated ductile or malleable iron. Both electrical and mechanical stresses may affect insulators. Degradation and eventual failure generally result from the loss of either dielectric or mechanical strength. Mechanical loading on suspension and line post insulators consists of a combination of tensile, torsional, cantilever, vibration and compression forces resulting from factors such as conductor vibration and galloping, accumulation of high density snow or ice, and sudden ice shedding. Line post, strut and pin type insulators are unique since they may experience a combination of cantilever, transverse and tensile forces simultaneously. Impact or contact induced damage also may occur.

Contamination of insulator surface with road salt, freezing rain, and snow accumulation may induce flashovers resulting in dielectric failure of insulators. Electrical flashovers can cause both external and internal damage to porcelain and composite insulators. Visual inspection can detect the following external insulator damage readily:

- Broken porcelain from the shell caused by a flashover (lightning) or impact damage (vandalism);
- Flashover burn markings on the porcelain shell resulting from burns/arcing damage/galvanizing;

Latent damages, typically internal to the porcelain shell, metal fitting and hardware include:

- Internal cracks under the metal cap or inside the porcelain head from lightning flashovers or line galloping, which in essence cause electrical shorts in the insulator that can distort the insulator string's voltage profile;
- Radial cracks (come from cement growth) through the porcelain shell;

Composite insulators consist of a glass fibre reinforced rod covered in either EPDM or silicone rubber weather sheds with appropriate end fittings. While the composite insulators offer a great range of mechanical strengths and much lower weight than other types of insulators, the EPDM or silicone rubber material also is soft and easily cut, ripped or punctured by sharp objects. The integrity of the sheath and weather sheds is critical. Failure commonly occurs when moisture enters into the glass fibre rod area.

Noticeable damage to insulator includes cuts, splits, holes, erosion, tracking, or burning of the rubber shed and sheath material, plus separation or degradation of the rubber sheath material where it meets the metal end fittings. Any signs of power arc, lightning damage, or corrosion on the metal end fittings also indicate deterioration of the component.

c) Condition Assessment Criteria for Metal Cross Arms or Hardware

Degradation or reduction in strength of insulator hardware may occur due to the following:

- Loss of galvanization and corrosion of steel members;
- Loss in strength due to fatigue;
- Loosening of hardware due to conductor vibrations; or
- Hardware failure during major storm events.

Close-up visual inspections generally can determine the extent of degradation. Laboratory testing can further corroborate results of visual investigations.

3.2.2. Ranking Condition of Poles, Insulators and Pole Hardware

The condition assessment process includes scoring based on multiple parameter criteria as described below:

a) Age Related Score:

Since the service age provides a reasonably good measure of the remaining strength of wood poles, cross arms, hardware and insulators, it is employed as an assessment parameter, with the following scores:

Table 3-17: Overhead Lines – Age Related Health Score

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 60 years
E	Older than 60 years

b) Scoring Based on Preservative Treatment of Wood Poles

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed in Health Index formulation of line sections, as indicated in the table below:

Table 3-18: Overhead Lines – Pole Treatment Based Health Score

Condition Rating	Type of Pole Treatment
A	Fully Treated
C	Butt Treated
E	No Treatment

c) Condition Rating Based on Visual Examinations of Pole Line Components

Different components of the pole line, including wood poles, cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By taking into account the results of these inspections, the health and condition of each component is scored in accordance with the following table:

Table 3-19: Overhead Lines – Visual Inspections Based Health Score

Condition Rating	Component Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Component has many minor problems or a major problem that requires close attention and monitoring
D	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Component has damaged/degraded beyond repair and will require replacement

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3.2.3. Condition Assessment Criteria for Conductors

a) Condition Assessment Criteria for Line Conductors:

Conductors allow flow of current through them facilitating the movement of power from substations to customers' premises. Overhead line conductors are typically supported on wood pole structures to which they are attached by insulators suitable for the voltage at which the lines operate. The conductors on a line are sized by taking into account the amount of current to be carried. The maximum current carrying capacity of conductors is determined by their thermal rating. However distribution line conductors are commonly sized to provide the right balance between energy loss in conductors (copper loss) and the capital cost of conductors. As a result the distribution lines often operate under loads significantly below the thermal rating of the conductors.

Overhead line conductors must have adequate tensile strength, enabling them to be stretched between poles. Distribution lines typically have span length of 40 m to 60 m. Three different types of conductors are commonly used on distribution lines:

- Aluminium Conductors Steel Reinforced (ACSR),
- Aluminium Stranded Conductors (ASC),
- Aluminium Alloy Conductors (AAC).

Steel reinforced aluminium conductors have galvanized steel core strands that supply most of their tensile strength. The steel core has both tensile and ductile properties, allowing the core to withstand both longitudinal forces and bending movements without failure. AAC conductors cost less in relation to ACSR conductors, but their tensile strength is significantly lower than those of the ACSR conductors. Both the price and tensile strength of AAC conductors lie in between those of ASC and ACSR conductors.

As current passes through the conductors, the resistance causes its temperature to rise, the temperature change is proportional to the square of the load current passing through the conductor. The rise in temperature causes the conductor to lengthen and sag between points of support, reducing the height of the conductor above ground. Although it seldom happens on distribution lines, line operation at loads beyond conductors' thermal rating of approximately 90° C may lead to annealing of conductors, resulting in permanent loss of its tensile strength.

To provide their intended functions on distribution lines, conductors must retain both their conductive properties and mechanical (i.e., tensile) strength. Aluminium conductors have three primary modes of degradation; corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor as well as environmental and operating conditions.

Generally, corrosion represents the most critical life-limiting factor for ACSR conductors. Environmental conditions affect degradation rates from corrosion. Both aluminium and zinc-coated steel core conductors are susceptible to corrosion from chlorine-based pollutants, even in low concentrations, but the rate of corrosion of steel core is significantly greater than that of aluminium. While fatigue degradation is a serious concern for transmission lines that are strung with significantly higher tension, it is commonly not a serious issue for distribution lines.

Overloaded lines operating beyond their thermal capacity can suffer from a loss of tensile strength due to annealing at elevated operating temperatures. Each elevated temperature event adds cumulative damage to the conductors. After loss of 10% of a conductor's rated tensile strength, significant sag occurs, requiring either re-sagging or replacement of the conductor. ACSR conductors can withstand greater annealing degradation compared to ASC.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminium strands, reducing strength at those sites and potentially leading to conductor failures.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Bird-caging.

On distribution lines, constructed to CSA standards, it is rare for conductors on entire line sections to experience degradations described above. Although laboratory tests are available to determine the degree of corrosion and assess the tensile strength and remaining useful life of conductors, distribution line conductors rarely require testing. Conductors on distribution lines often outlive the poles and are not usually on the critical path to determine end of life for a line section.

The only exception to the above rule might be where small copper conductors susceptible to frequent breakdowns are in use or where line conductors are too small for line loads resulting in sub optimal system operation due to high line loss.

b) Condition Assessment Criteria for Splices

Conductor splices generally have a larger cross-sectional area than the conductor itself. When properly installed, splices should outlast the conductor. However, when improperly installed, splices can reduce a conductor's life. Improperly crimped splices represent the weakest link in conductors under tension.

In extreme cases, splice failures lead to excessive conductor annealing that may cause the conductor's strands to be pulled from the compression splice. Any strand damage that occurs during splice installation may lead to localized weakening of the conductor and premature splice failure. Failure to use non-oxidizing grease in splices also may lead to the development of hot spots and splice failure.

3.2.4. Ranking Condition of Conductors and Splices through Multiple Criteria

Computing the Health Index for overhead line conductors and splices requires developing end-of-life criteria for conductors. The condition assessment process includes scoring based on the risk of conductors breaking and falling.

Since small sized conductors pose a serious safety risk, the value of this risk is scored separately with help of the table below:

Table 3-20: Overhead Lines - Small Conductor Related Health Score

Condition Rating	Age
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 copper)

3.2.5. Health Index Formulation for Overhead Lines

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for overhead line sections, it is proposed to assign the following weights to various Health Index criteria described in Section 3.2.1 through 3.2.4.

Table 3-21: Overhead Lines Health Index Algorithm

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of pole line	A - E	5	3	15
2	Pole treatment	A - E	5	1	5
3	Visual inspection of poles	A - E	5	1	5
4	Pole testing	A - E	5	4	20
5	Visual inspection of insulators	A - E	5	1	5
6	Visual inspection of hardware	A - E	5	1	5
7	Small conductor risk	A - E	5	5	25
	Total				80

3.3. *Underground Distribution System*

The major assets employed on underground distribution systems can be grouped into the following categories:

- Cables, splices and terminations
- Manholes and vaults

3.3.1. Condition Assessment Criteria for Cables, Splices and Terminations

Safety, reliability, aesthetics and operating costs govern the design and construction standards for underground distribution lines. Underground cables can be constructed in a number of configurations, including direct buried cables, cables installed in direct buried conduits and cables installed in a concrete encased duct manhole system. Medium voltage underground cables have the following key components:

- Cables
- Cable Splices
- Cable Terminations

a) Cables

Medium voltage cables may employ either copper or aluminium conductors. They may be constructed in either single phase or three phase configurations. Two major types of cables are in common use in Canada: paper insulated lead covered (PILC) and cross linked polyethylene (XLPE).

Polymer insulations for cables were introduced as an economic alternative to PILC cables in 1970's. The insulation system in these cables consists of a semi-conducting sheath over the conductor, the insulation, another semi-conducting layer over the insulation, a metallic shield tape or concentric neutral and a jacket. For the early generation of these cables, manufactured in the 1970's, two unexpected factors entered into the failure mechanism: presence of impurities in the insulation system and ingress of moisture that made these cables susceptible to premature failures due to water treeing. Corrosion of concentric neutral conductors is another potential mode of failure. Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This has been the reason for poor reliability and relatively short lifetimes of early polymeric cables.

As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved. In addition to manufacturing improvements, development of tree retardant TRXLPE cables and designs to incorporate metal foil barriers and water migration control have further reduced the rate of deterioration due to treeing.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Although a number of test techniques, such as partial discharge (PD) testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs become higher than the annualized cost of cable replacement, the cables are replaced.

b) Cable Splices and Terminations

Cable splices and terminations are subject to the same type of insulation degradation and aging as the cables themselves. Improperly made splices may be susceptible to moisture ingress and as a result may experience higher failure rates compared to cables.

3.3.2. Ranking Condition of Cables and Splices through Multiple Criteria

Computing the Health Index for an underground cable section requires developing end-of-life criteria for its various components. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining useful life of cables, splices and terminations, it can be employed as an assessment parameter, with the following scores:

Table 3-22: Underground Cables - Age Related Score

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Historic Rates of Circuit Failures

Historic failure rates on a cable circuit are an excellent indicator of the cable health and condition and its useful remaining life and therefore employed in cable Health Index formulation as indicated below:

Table 3-23: Underground Cables – Failure Related Score

Condition Rating	Component Condition
A	Less than 0.5 Failures per 10 km in the last 5 years
B	0.5 to 1.0 Failures per 10 km in the last 5 years
C	1.0 to 1.5 Failures per 10 km in the last 5 years
D	1.5 to 2.5 Failures per 10 km in the last 5 years
E	2.5 or more Failures per 10 km in the last 5 years

(c) Condition of Cable Splices or Stress Cones

Physical condition of cable splices or stress cones can be employed in assessing overall condition of the cable circuit:

Table 3-24: Underground Cables - Splice or Stress Cone Related Health Score

Condition Rating	Component Condition
A	Splice or Stress Cone appears in good condition, no indication of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
E	Poor condition, potential moisture ingress or IR indicates hot spot

3.3.3. Condition Assessment Criteria for Manholes and Vaults

Manholes provide the junction point on underground ducts to facilitate cable pulling and provide access for inspection of cable splices. Vaults provide below grade space of installation of electrical equipment such as submersible transformers or switches. In the case of both manholes and vaults, steel reinforced concrete is used for walls, roofs and floors. In locations subject to flooding floor drains and sump pumps are provided. Vaults where heat generating equipment such as distribution transformers are installed are also equipped with ventilation grates. Man access is provided through the top. When vaults and manholes are located in road ways, parking lots or other areas open to vehicular traffic, the structures must be designed by a structural engineer. Since manholes and vaults are confined spaces, they must be adequately sized to rescue trapped workers during a fire or explosion inside the vault or manhole.

The common degradation mode for manholes and vaults is the deterioration of concrete structures due to concrete spalling and corrosion of rebar, sinking of the roof top surfaces allowing rain water to collect and flood the manhole and vaults. Functional obsolescence, where the size of the manhole or vault no longer meets the space requirements can also lead to end of life of a structure.

3.3.4. Ranking Condition of Manholes and Vaults through Multiple Criteria

The health and condition of manhole and vaults can be measured through visual inspections, looking for:

- Structural damage to concrete walls or roof
- Frequent flooding incidents of the vaults or manholes
- Non-functioning drains or sump pumps
- Inadequate space

(a) **Structural Condition**

Table 3-25: Manhole and Vaults – Structural Health Score

Condition Rating	Inspections
A	No deficiencies in the vault or manhole
C	Only minor deficiencies
E	Major deficiencies requiring immediate repairs/replacement

(b) **Flooding Incidents, Drains, Sump Pumps**

Table 3-26: Manhole and Vaults - Flooding Related Health Score

Condition Rating	Inspections
A	No incidents of Flooding at this location
C	Occasional Flooding, working sump pumps and drains
E	Frequent Flooding, No sump pumps or drains

(c) **Vault Size and Access:**

Table 3-27: Manholes and Vaults – Size Related Health Score

Condition Rating	Inspections
A	Adequate ergonomic size and safe access to vault
C	Vault size slightly smaller than ideal, but adequate for safe working and reasonable access to vault
E	Vault size or access inadequate for safe working or worker rescue during an accident immediate repairs/replacement

3.3.5. Health Index Formulation for Underground Cables, Manholes and Vaults

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for underground cables and manholes/vaults, it is proposed to assign the following weights to various health index criteria:

Table 3-28: Cables, Splices and Terminators Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Cable Circuit	A – E	5	3	15
4	Historic Failure rates	A – E	5	8	40
5	Visual inspection of splices or stress cones	A – E	5	1	5
	Total				60

Table 3-29: Manholes and Vaults Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Structural Integrity	A – E	5	8	40
2	Flooding and Its mitigation	A – E	5	4	20
3	Size and Access	A – E	5	8	40
	Total				100

3.4. Distribution Transformers

3.4.1. Different Types of Distribution Transformers

Four (4) main types of distribution transformers are commonly employed on distribution system:

- Pole mounted transformers
- 1-Phase Pad mounted transformers
- 3-Phase Pad mounted transformers
- Submersible transformers in vaults

Aside from the different design and construction standards employed in their manufacture and installation, each type of transformer serves the same functions and the same asset management strategy can be employed for these assets as described below:

Distribution transformers step down to the medium voltage distribution power to final utilization voltage of either 120/240V, 120/208V or 347/600 V. Both single phase and three phase transformers are in use. In pole top applications, three single phase transformers are commonly employed to create a three phase bank, however for pad mounted applications, three phase transformers are used for three phase applications.

The key components of a distribution transformer are:

- primary and secondary coils, made of copper or aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of paper and mineral oil
- sealed transformer tank
- primary and secondary bushings or bushing wells to accommodate elbows
- auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Distribution transformers commonly fail when the age weakened insulation system is subjected to a voltage surge during lightning.

Most utilities run the distribution transformers to failure, i.e. replace them only after they fail. With the exception of rust proofing and painting of the tanks, replacing a damaged bushing or repairing a leaky gasket, very little invasive preventative maintenance or testing is carried out on distribution transformers.

3.4.2. Ranking the Condition of Distribution Transformers through Multiple Criteria

Just as in case of substation transformers multiple criteria, including service age, loading levels, results of oil testing and physical inspections can be employed for assessing the condition of distribution transformers. However, since the consequences of in-service failure of distribution transformers are relatively minor, most distribution utilities, including PUC DISTRIBUTION employ run-to-failure strategy for distribution transformers, thus avoiding costs related to oil testing or measuring load levels.

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

(a) Condition Assessment Based on Age

Table 3-30: Distribution Transformer Age Based Scoring

Condition Rating	Distribution Transformer Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Table 3-31: Distribution Transformers – Inspections Based Health Scoring

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad mounted transformers
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects

3.4.3. Health Index Formulation for Distribution Transformers

Table 3-32: Distribution Transformers Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A – E	5	10	50
3	Visual inspection	A – E	5	10	50
	Total				100

3.5. Disconnect Switches and Cut-outs

3.5.1. Different Types of Switching Devices

This asset class includes pad and vault mounted medium voltage switchgear, K-bars, as well as pole mounted ganged disconnect switches and single phase solid blade or cutouts. Disconnect switches and K-bars provide means of load disconnect and isolation for equipment, such as underground laterals or distribution transformers.

The key components of a distribution switch are:

- Switch blades
- Operating handle and mechanism
- Insulator bushings
- Grounding and bonding conductors

Pad mounted disconnects have the following additional components:

- Pad or vault mounted metal enclosure
- Inter-phase glass polyester barriers
- Padlocks

K-bars have the following main components

- Insulator bushings and buses
- Grounding and bonding conductors
- Pad mounted metal enclosure

The most critical components in the disconnect switch are the switch blades and operating mechanism. Misaligned or poorly surfaced contacts can result in excessive arcing during switch opening or closing, resulting in further deterioration of the blades. Corrosion may cause rusting of the links and pins in the operating mechanism reducing the blade movement speed. Broken grounds or damaged insulators are some other defects that may appear with age.

Pad or vault mounted disconnect switch enclosures are vulnerable to corrosion due to road salt spray. Non-functioning padlocks or broken inter-phase barriers are other serious defects that may develop with aging.

In case of K-bars, corrosion of steel enclosures and degradation of bushings with service age are the key degradation modes.

3.5.2. Ranking Condition of Disconnect Switches through Multiple Criteria

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of disconnect switches and K-bars, it is employed as an assessment parameter, with the following scores:

Table 3-33: K-bar, Disconnect Switches and Cutouts – Age Based Health Scoring

Condition Rating	Disconnect Switch Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of disconnect switches or K-bars. Infrared (IR) scan can provide indication of hot spots resulting from misaligned blades.

Table 3-34: K-bar or Disconnect Switches or Cutouts – Inspections Based Scoring

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, padlocks in good condition on pad mounted switchgear, operating mechanism and blades in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

3.5.3. Health Index Formulation for Disconnect Switches

Table 3-35: Distribution Switches and Cutouts – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of disconnect	A – E	5	10	50
2	Visual inspections and IR Scan	A – E	5	10	50
	Total				100

4 ASSET DEMOGRAPHICS AND CONDITION ASSESSMENT

The methodology described in detail in section 3 provides means of accurate and comprehensive condition assessment of all major assets employed on the distribution system. This section of the report, documents the health indices for fixed assets employed on the distribution system, determined by taking into account all available information about assets from testing, inspections, service age and other demographic information, retrieved from the GIS system. Where complete information required for condition assessment of an asset class through methodologies described in Section 3 was not available, the health index algorithm was appropriately modified to make use of the available information, to determine health indices of assets.

4.1. *Transformer Stations and Distribution Substations*

Figure 4.1 shows the location of transformer stations and distribution stations owned and operated by PUC DISTRIBUTION. There are two transformer stations TS1 and TS2, which step down power received from the transmitter at 115 kV to 34.5 kV, and 12 distribution stations, which step down power from 34.5 kV to 12.47 kV. There are also three additional distribution stations; one which steps down from 34.5kV to 4.16kV, one which step down from 12.47 kV to 4.16 kV, and one which steps down from 34.5kV to both 12.47kV and 4.16kV. The three 4.16 kV distribution stations (Sub 4, Sub 5 and Sub 14) will be retired from service, upon completion of the distribution voltage upgrade program and replaced with a single 34.5/12.47 kV station.

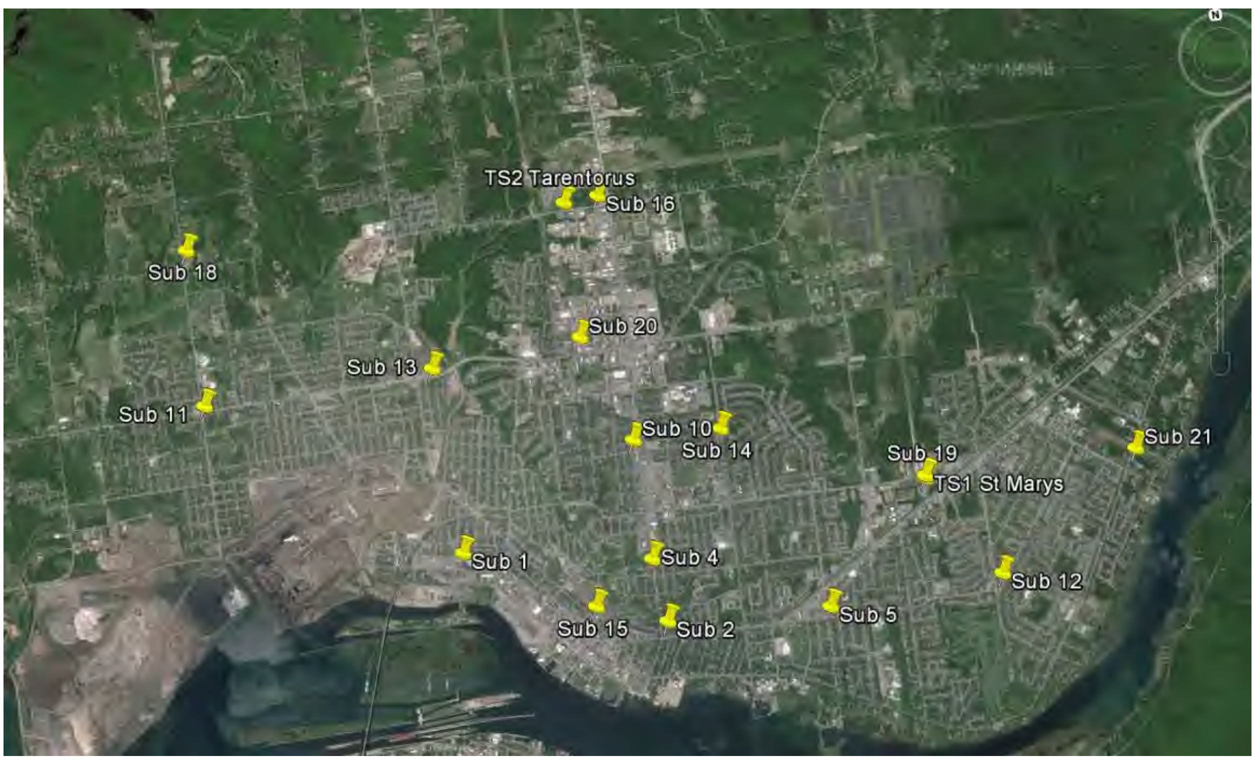
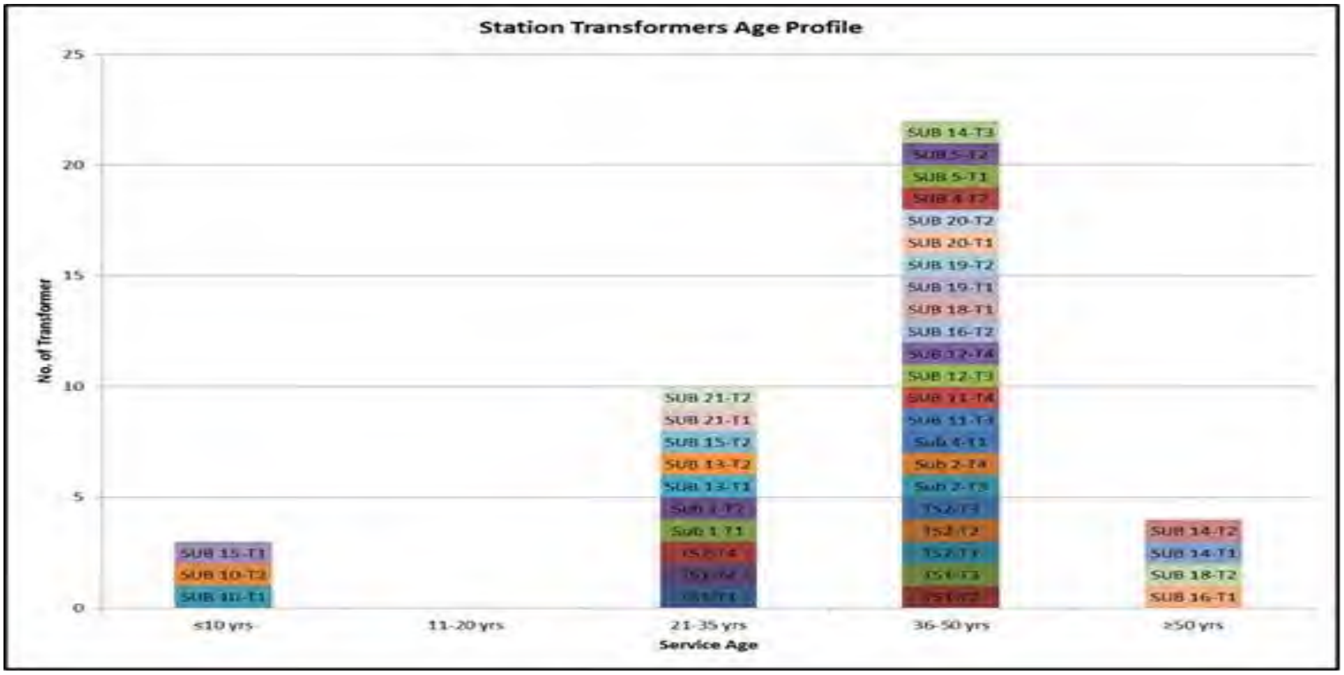


Figure 4-1: Distribution Station Locations

The results of condition assessment of major equipment employed at step-down stations are described below in detail.

4.1.1. Station Transformers

Figure 4-2 presents the age profile of power transformers employed at PUC DISTRIBUTION's step-down stations. As shown, approximately two thirds of the power transformers have reached a service age of greater than 35 years and four of the power transformers have been in service for more than 50 years. The transformer numbers in Figure 2 are not stacked in any priority order.



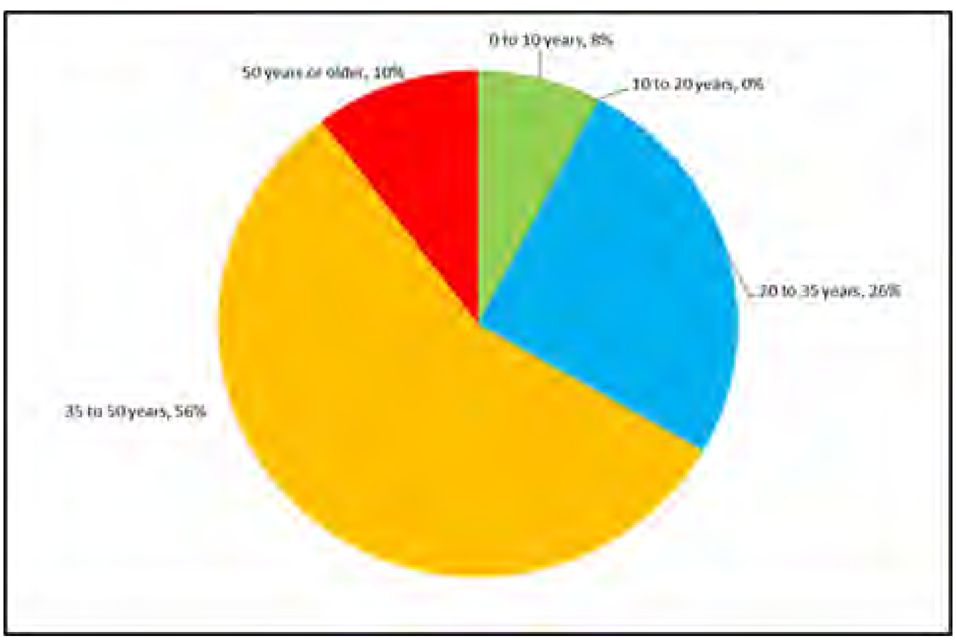


Figure 4-2: Age Profile of Station Transformers

Based on the condition assessment criteria detailed in Section 3, Health Index score has been calculated for each of the substation transformers and the results are summarized in Figure 4-3. It is noteworthy that the following transformers have undergone rehabilitation of the coil, which has been taken into account during calculation of the health index for these transformers:

- Sub 16-T1 (2013)
- Sub 13-T1 (2010)
- Sub 18-T1 (2008)
- Sub 19-T1 (2003)
- TS2 - T4 (1998)
- Sub 11-T4 (1992)

As shown, a total of 20 power transformers have determined to be in "poor" or "very poor" condition, 16 power transformers have been determined to be in fair condition and 3 transformers have been determined to be in in good or very good condition.

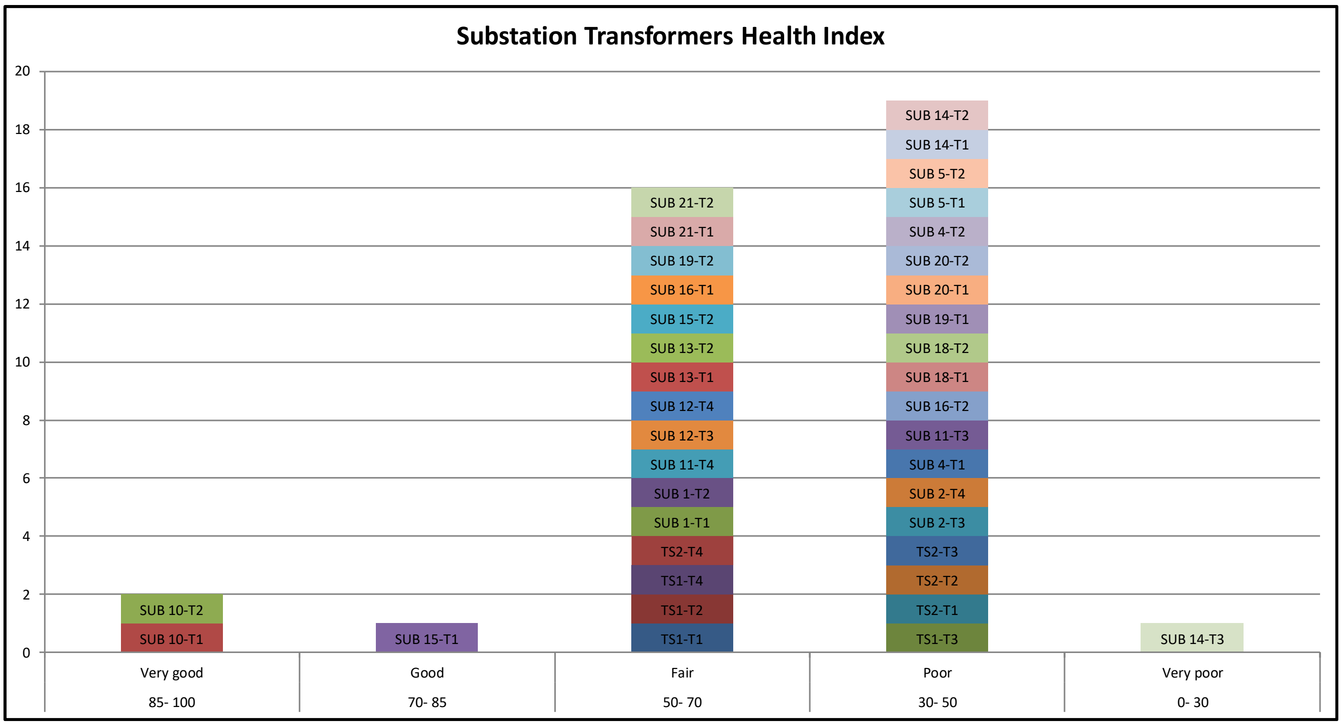


Figure 4-3: Health Index of Power Transformers Employed at Stations

4.1.2. Station Switchgear - Circuit Breakers

By taking into account the service age, the results of visual inspections and maintenance test reports (where available), Health Index score has been calculated for switchgear employed at the stations and the results are summarized in Figure 4-3. As indicated, switchgear at 14 of the stations has been determined to be in poor or very poor condition.

Although protection relays at most of the stations have been upgraded to modern solid state relays in the past, many stations employ switchgear designed and constructed using technologies, which are now considered obsolete. For example, both of the 115/34.5 kV stations employ oil circuit breakers for switching and protection on 115 kV bus. This type of circuit breaker design does not only require extensive preventative maintenance, but since the manufacture of circuit breakers using this technology has been abandoned for over 30 years, the spare parts are difficult to obtain and are costly. Similarly, a majority of the 34.5/12.47 kV stations employ magnetic air circuit breakers, which also require more frequent preventative maintenance in relation to modern technologies, employing vacuum circuit breakers and it is difficult and costly to obtain spare parts for the old vintage switchgear. Also the arc flash regulations under CSA Standard Z462 have undergone change over the years. The switchgear of older designs require complicated work methods to perform maintenance.

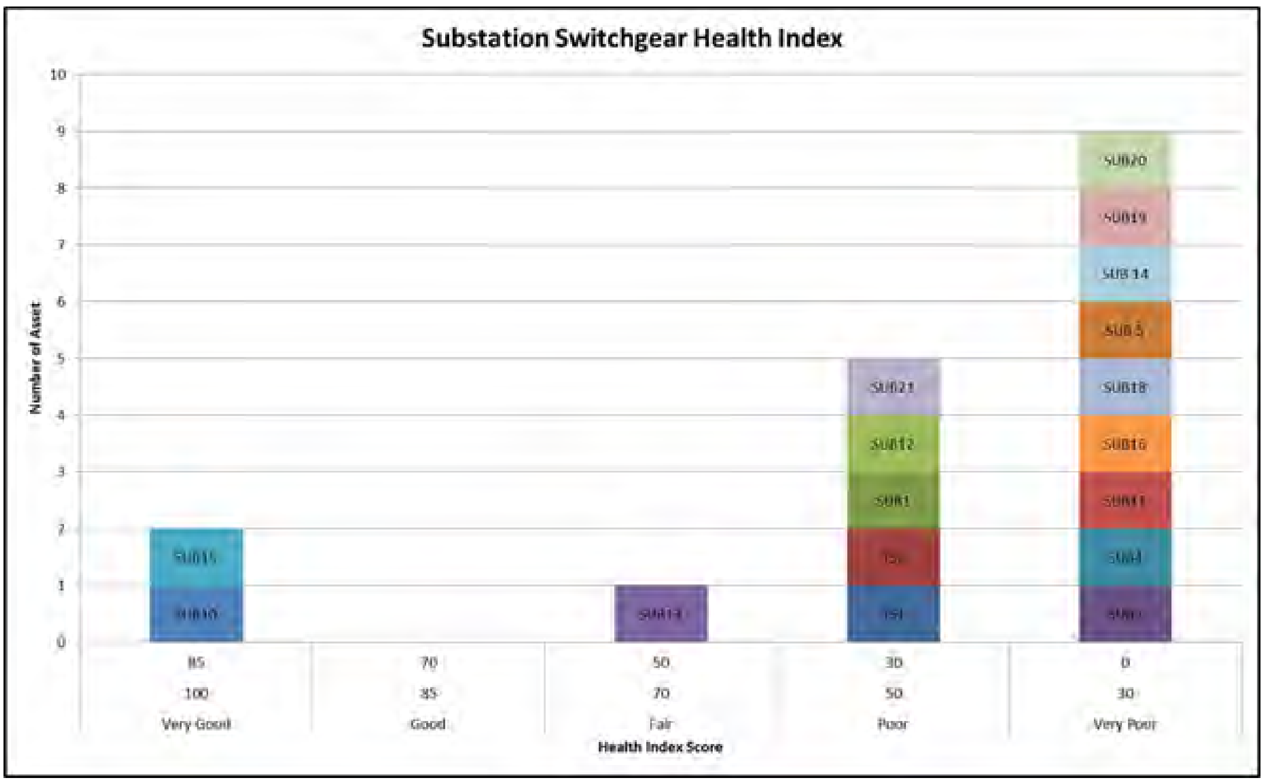


Figure 4-4: Condition Assessment of Station Switchgear

4.1.3. Stations Supervisory Control (SCADA) and Communication System

PUC DISTRIBUTION's SCADA network is comprised of 42 nodes in the form of remote terminal units (RTU's). The main SCADA server and operator's station is located at PUC's head office and a backup server and operator's station located at PUC's affiliate company's Water Treatment Plant. The interconnection between the servers, stations, and distributed devices is based on a fibre network with radio system tie-ins for sites where fibre is not cost effective. 9 of the 17 distribution and transmission stations are connected via fibre with the remaining 8 being on a MDS radio network. There are three distributed voltage regulators and three reclosures that are also on the MDS radio network. PUC also has 15 motor operated switches connected to SCADA via a Speednet radio system, which includes 3 repeaters.

Most of the network infrastructure has been upgraded since 2009 and it has expected design life of 15 years. The MDS master radio, which provides the interconnection between the remote MDS radios and fibre core, is planned to be replaced in 2016.

Each of the distribution stations is equipped with DC battery backup of adequate rating to run the station network infrastructure and RTU's for a minimum of 8 hours in the case of an AC power outage. Control battery typically provides a service life of approximately 15 years. PUC has taken the approach of replacing 1 distribution station battery bank and charger on an annual basis. The DC system chargers have a lifespan of 25 to 30 years. PUC requires redundant DC systems at each of the 2 transmission stations and has taken the approach of replacing 1 of the 4 total TS DC systems every 3 years. The cost of 115/34.5 kV station DC systems is substantially greater than 34.5/12.47 kV station DC systems due to the size required to run an entire transmission station.

4.1.4. Other Assets Employed at Stations:

Other important assets employed in stations include buildings, fences, ground grids and surface stone in station yards. Although a majority of the stations are old, the buildings are well maintained and in satisfactory condition.

The station ground grids have not been tested over the recent years to provide an accurate assessment of their condition. The condition assessment of ground grid, building and fences is based on visual inspections only.

By taking into account the service age and results of visual inspections, composite Health Index score for the buildings, yards, fences and ground grids was calculated and the condition of these assets is indicated is Figure 4.5. Two additional substations MS-5 and MS-14 are also in poor condition, but these are not included in Figure 4.5, as both of these stations are planned to be retired upon completion of the voltage conversion project and therefore these are not considered candidates for asset renewal.

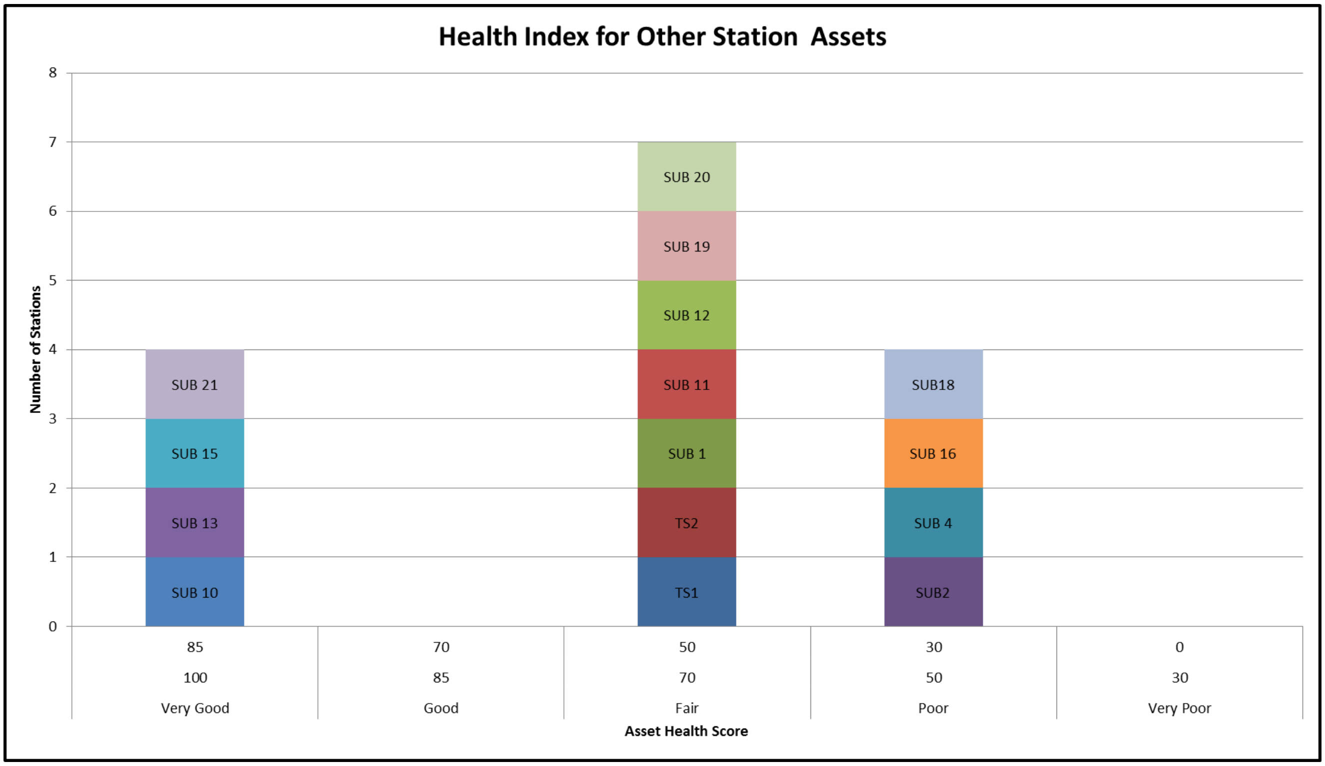


Figure 4-5: Condition Assessment of Auxiliary Assets

4.2. *Overhead Lines*

4.2.1. Distribution Line Support Poles

Based on the demographic information retrieved from the GIS system, there are approximately 12,600 wood poles and about 80 other types of poles (including steel, concrete and fiberglass) employed on PUC DISTRIBUTION's electricity distribution system. Figure 4-6 displays the age profile of line support poles employed on the distribution system. Approximately 328 poles (shown in red) have been in service for more than 60 years and an additional 857 poles (shown in yellow) have been in service for more than 50 and less than 60 years. More than 28% of the poles currently in service have a service age of 40 years more.

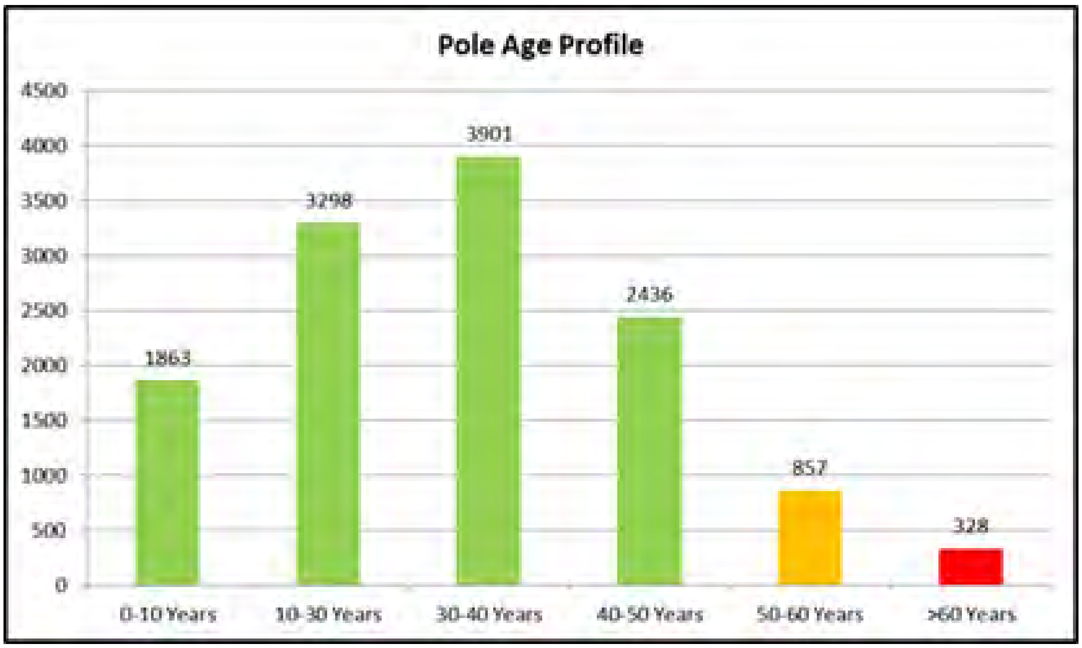


Figure 4-6: Age Demographics of Distribution Line Poles

Poles on distribution lines are employed in different configurations; some support only low voltage circuits, while others may support multiple circuits of different voltages, requiring taller poles. Figure 4-7 indicates the approximate percentage of different pole heights employed on the distribution system. As indicated, 35ft, 40ft and 45ft poles are used most commonly.

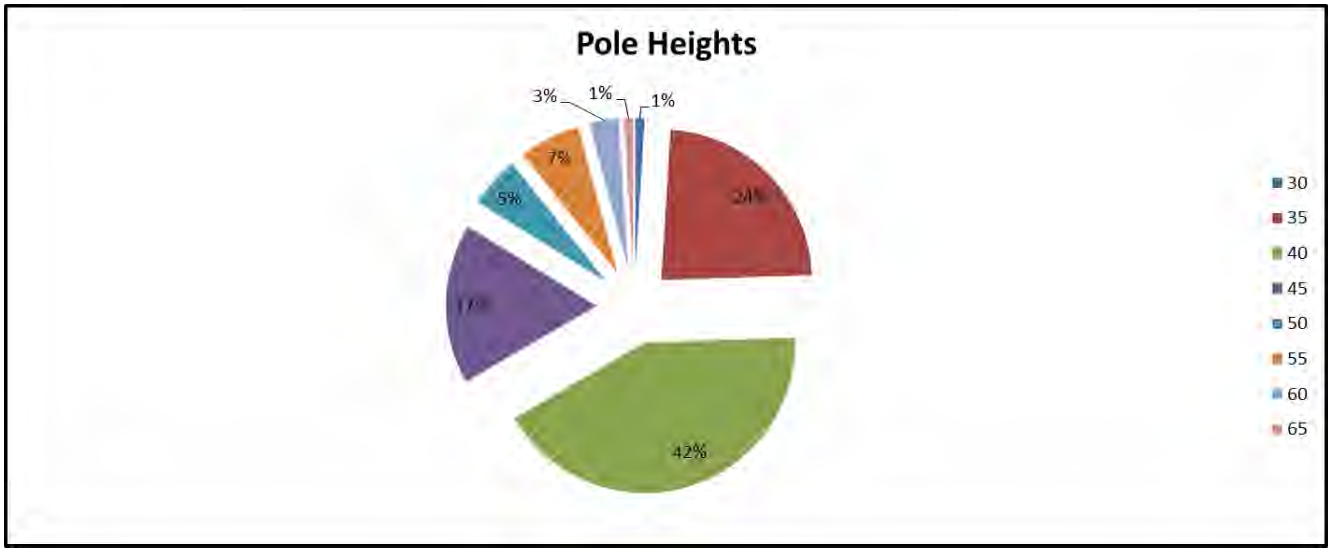


Figure 4-7: Distribution Pole Heights

Figure 4-8 displays the age profile of the poles with respect to their heights and as indicated a majority of the poles that have reached more than 50 years of service age fall within the 35', 40' and 45' height ranges.

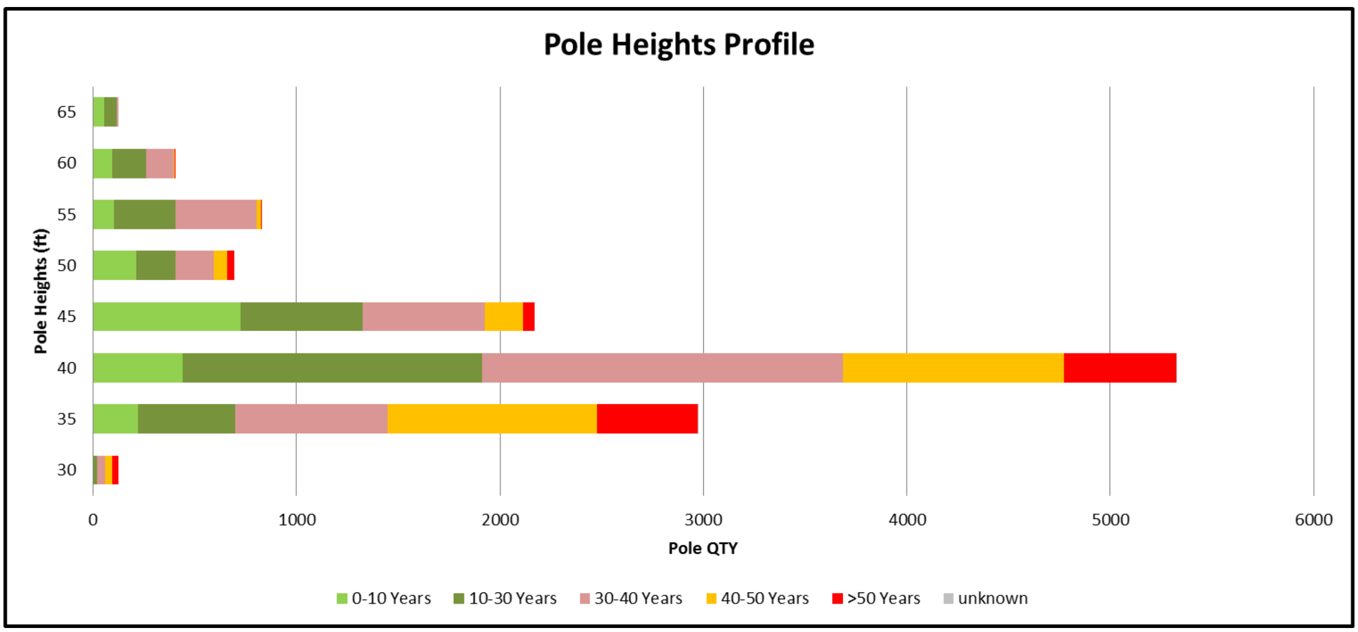


Figure 4-8: Age Profile of Poles of different Heights

PUC DISTRIBUTION has an on-going non-destructive pole testing program since 2003. Figure 4.9 shows the percentage of poles found in various conditions of strength through pole testing from 2003 to 2013. In this case, the Health Index score is calculated based on the remaining strength of the pole, where "very poor" equates to less than 3 years of remaining useful life, "poor" equates to less than 5 years of anticipated remaining useful life and "fair equates to anticipated remaining useful life of "5 to 20" years.

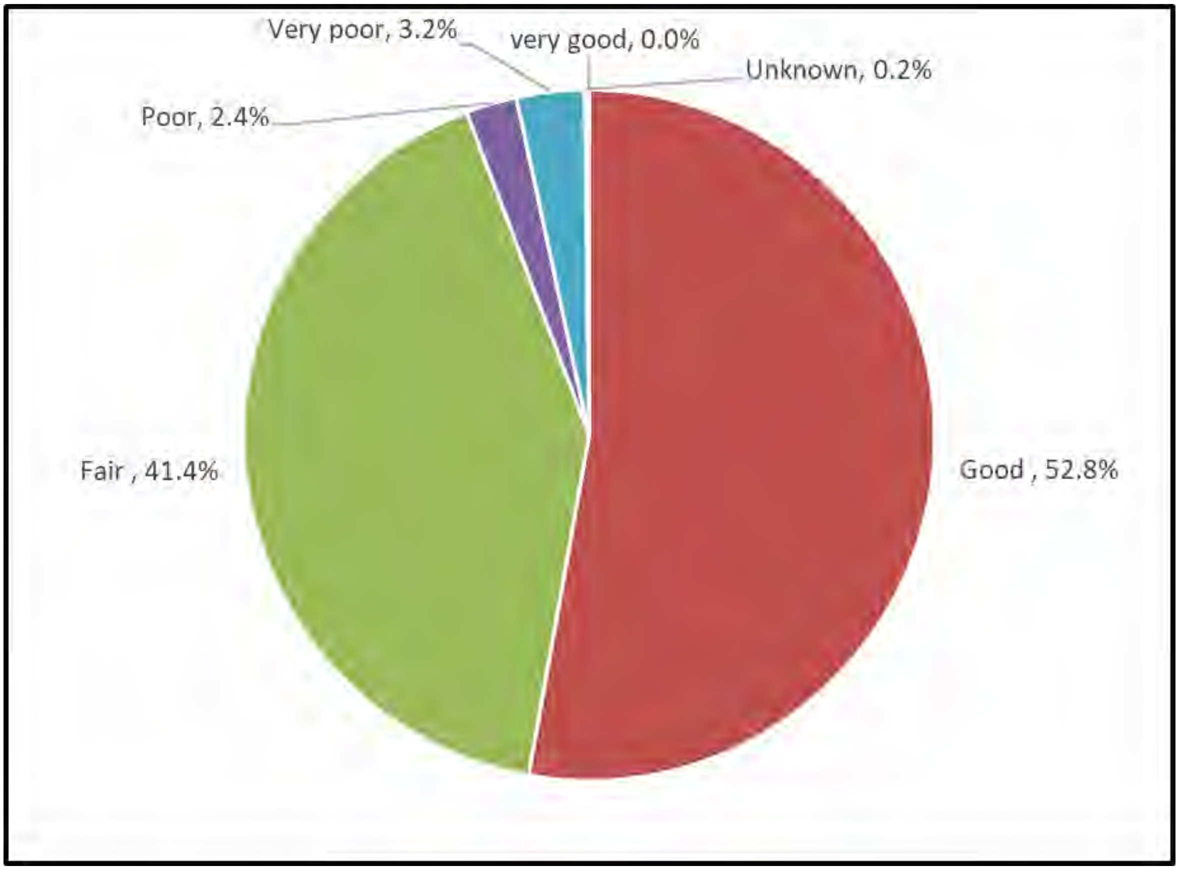


Figure 4-9: Condition Assessment of Wood Poles 2003 to 2013 Test Results

After the pole testing is completed poles found in very poor and poor condition are replaced during the following years. Pole testing has not been done during 2014 and 2015, but the tests during the previous ten years were performed on the entire population of poles. The results of this analysis are presented in Figure 4-10., indicating that approximately 700 poles were found to have reached "poor" or "very poor" condition over a period of ten years, requiring replacement of approximately 70 poles each year. Since a portion of the poles found in poor condition are employed on 4 kV lines, approximately half of the poles found in poor condition are simply retired from service during implementation of voltage upgrade program.

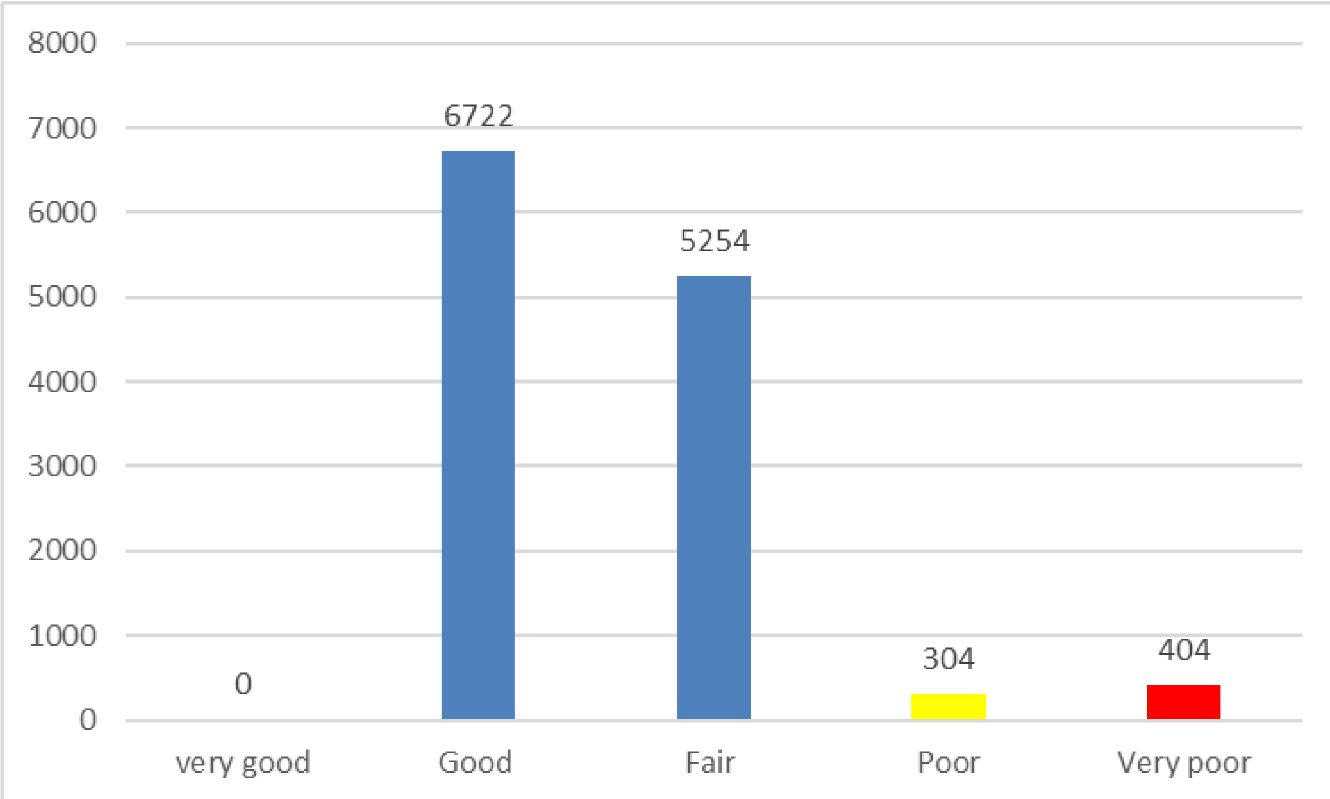


Figure 4-10: Wood Poles Health Index Score for Entire Pole Population

4.2.2. Overhead Line Conductors

PUC DISTRIBUTION's overhead distribution network employs approximately 391 km. of 3-phase and approximately 230 km of 1-ph lines, all operating at 115kV, 34.5 kV, 12.5kV, 7.2kV, 4.2kV and, 2.4 kV. Figure 4-11 and Figure 4-12, respectively, show the age profile of overhead lines and as shown, approximately 29% of the 3-ph lines and approximately 29% of the 1-ph lines will reach the end of their design service life of 45 years during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors.

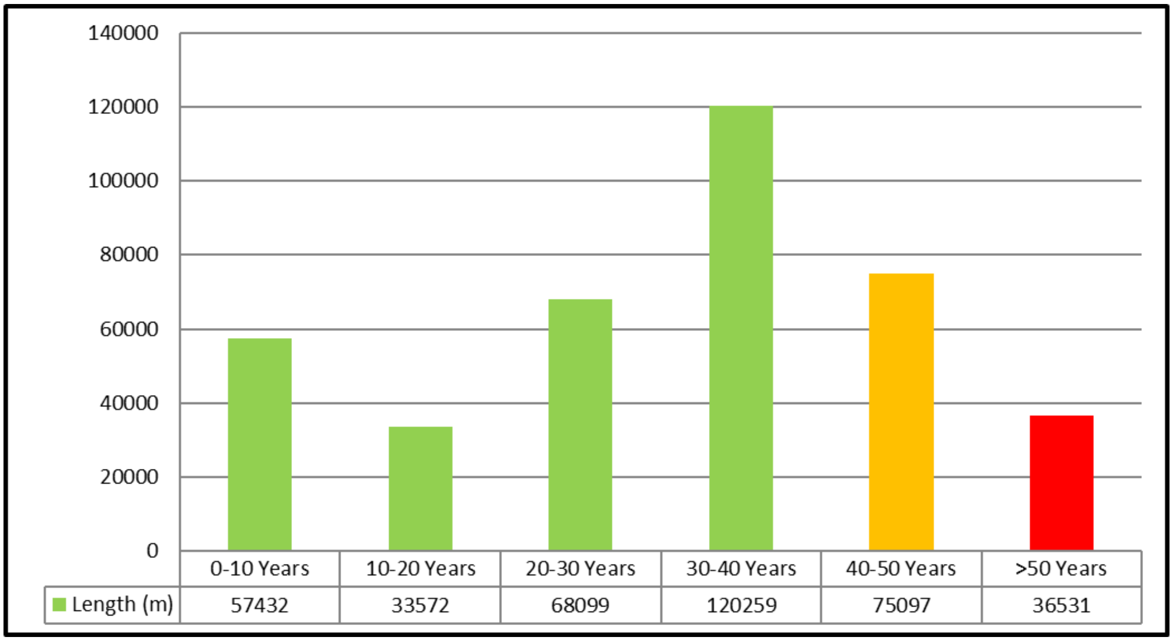


Figure 4-11: Age Profile – 3 Phase Overhead Lines

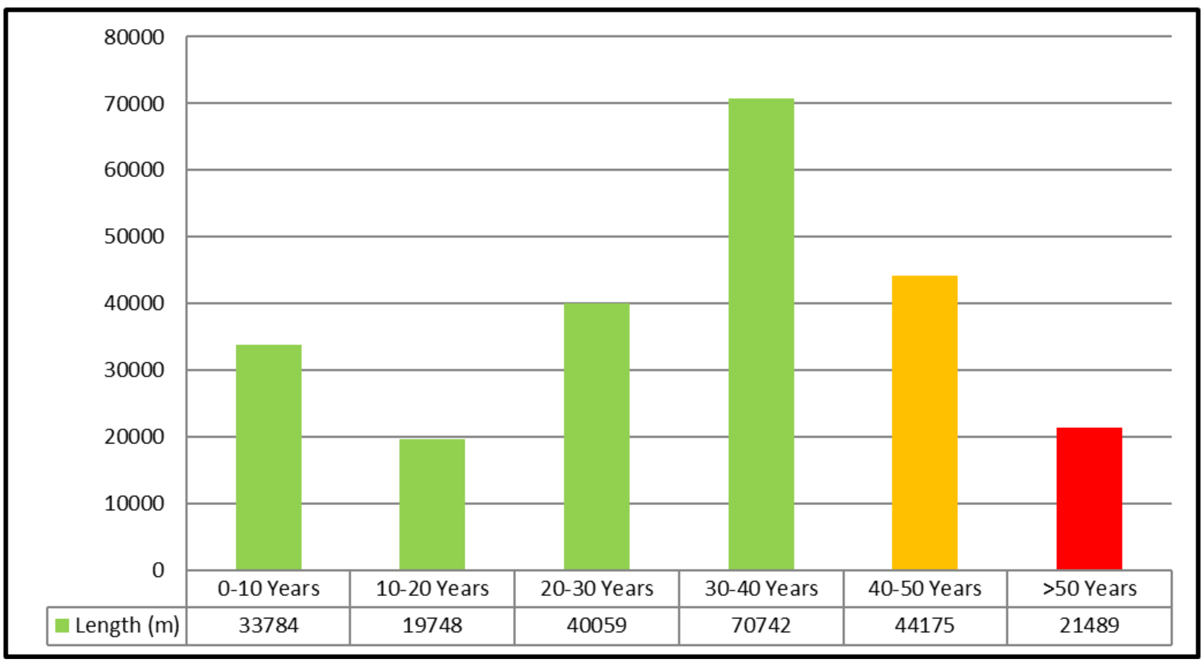


Figure 4-12: Age Profile – 1 Phase Overhead Lines

While the service age of ACSR or aluminum conductors is not generally on the critical path to determine the end of service life of overhead distribution lines, a small fraction of the PUC DISTRIBUTION's overhead lines employ copper conductors of small cross-section (#6 or smaller). These conductors are commonly referred to as "restricted conductors" and they are known to degrade in mechanical strength with service age, due to reduction in their tensile strength.

Recognizing the high risk of failure in service of restricted conductors, PUC DISTRIBUTION adopted a program for replacing the restricted conductors in 2009. Figure 4-13 and Figure 4-14 show the progress made to date in replacing the restricted conductors and the extent of lines with restricted conductors still in service as of the end of 2015. All existing overhead lines with restricted conductors are determined to be in poor condition and it is recommended the work of reconstructing these lines with aluminum conductor should continue.

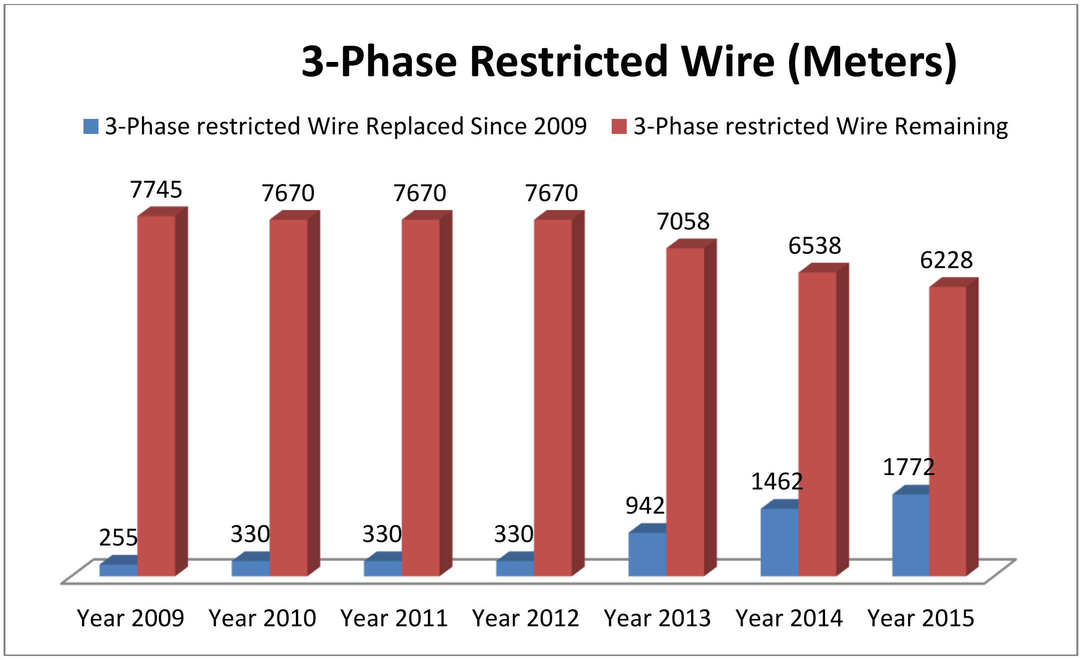


Figure 4-13: 3-Phase Overhead Line Lengths with Restricted Conductors

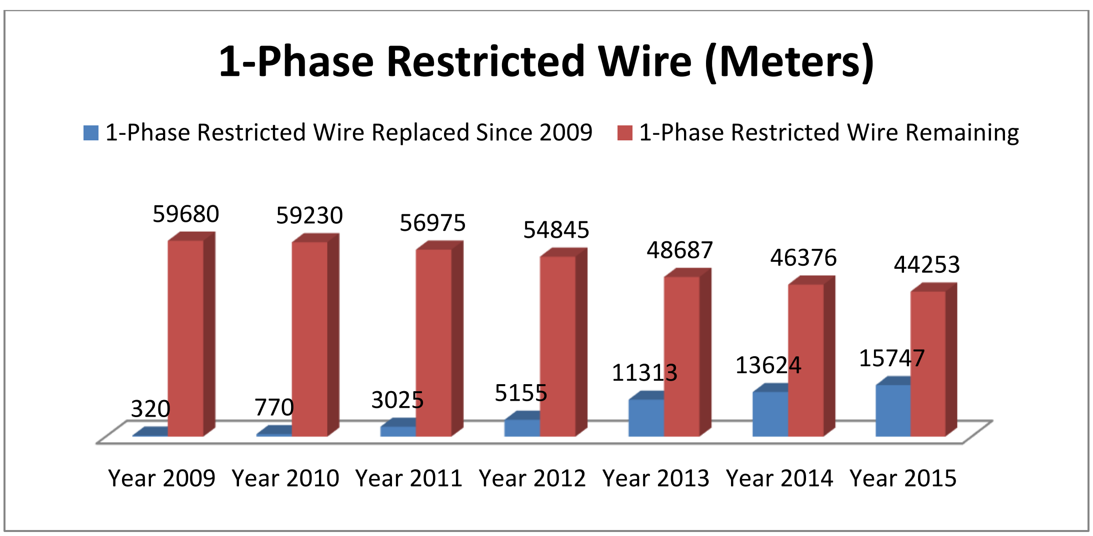


Figure 4-14: 1-Phase Overhead Line Lengths with Restricted Conductors

4.2.3. Overhead Distribution Switches and Cut-outs

PUC DISTRIBUTION's overhead lines are well equipped for disconnecting and isolating, load-breaking, and fault interrupting to provide means of isolation during power interruptions and operational functions and adequately protect the circuits during system faults. A majority of the line switches are pole type. Hook-switch operated cutouts are used for switching and isolating pole mounted transformers. The age data for the overhead switches and cutouts was unavailable, but the line switches and cutouts are typically replaced at the time of reconstruction of the line.

Porcelain insulated cut-outs have been in use in the electrical industry for many decades. Porcelain was also the material of choice for most other electrical equipment that required insulation, i.e. line insulators, arresters and bushings. In the early 1980's large numbers of porcelain insulators began failing, particularly in cold climate regions. "Cement growth" was causing insulators to crack. The expansion and contraction of the adhesive interface which joined the porcelain to the hardware (connector) caused stresses on the porcelain. These stresses caused small cracks to appear in the porcelain which eventually lead to an electrical and/or mechanical failure of the porcelain insulator.

Distribution insulators had been the focus of the industry's attention throughout the past 30 years, resulting in expenditure of millions of dollars to rectify the problem of defective porcelain. During the past several years many utilities throughout North America have seen increasing failures of their porcelain insulated cut-outs. The mode of failure is very similar to that of insulators. Small cracks in the porcelain initially appear near the interface between the porcelain and hardware. These fractures eventually lead to a mechanical failure of the cut-out. Cement growth is the likely cause of the initial cracks. The breakage of porcelain insulated cut-outs is a concern from a safety and reliability perspective. During cut-out operation the porcelain can break causing the cut-out to separate into two parts. This creates a hazard to line personnel operating the cut-out and can cause outages to customers. The common industry solution to this problem has been replacement of the porcelain insulated cut-outs with polymer insulated cut-outs, as shown in Figure 4-15.

Figure 4-15: Porcelain (Left) and Polymer (Right) Insulated Cut-outs

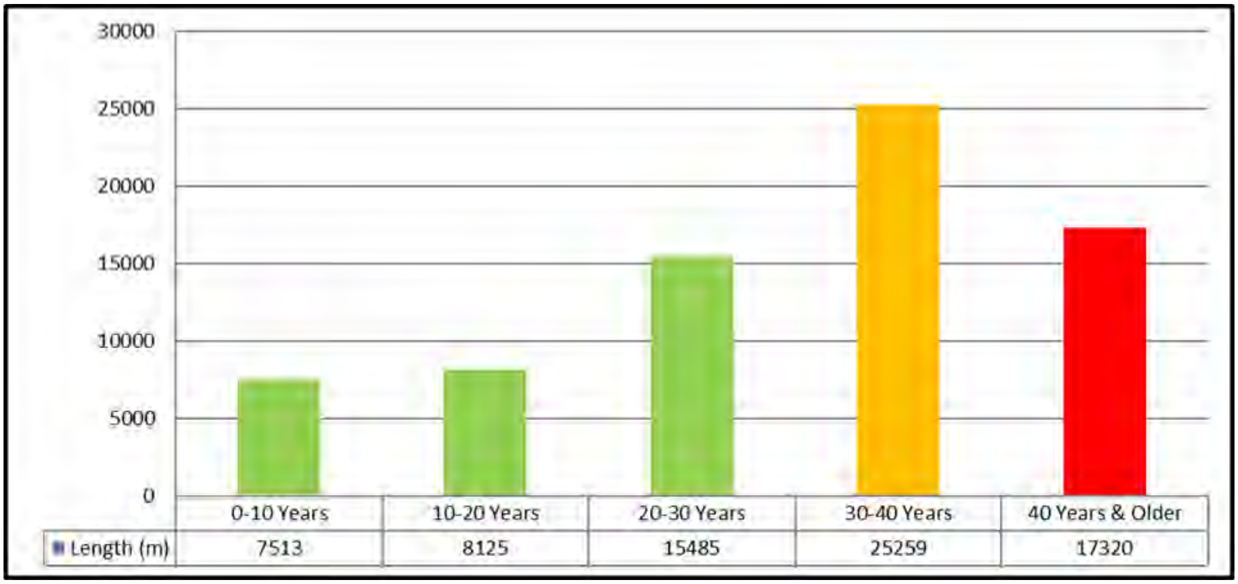
PUC DISTRIBUTION has also been systematically replacing the porcelain cut-outs and switches with polymer cut-outs switches since 2010. Approximately 2700 defective switches and cut-outs were identified for replacement under this program and by the end of 2015 replacement of all but about 100 of the defective switches and cut-outs had been completed. The remaining 100 defective switches and cut-outs are scheduled for replacement in 2016 and this program will be complete by the end of 2016.

4.3. *Underground Distribution System*

4.3.1. Underground Primary Conductors

The underground distribution network at PUC DISTRIBUTION employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase and 2-phase cable circuits. Figure 4-16 and Figure 4-17, respectively, show the age profile of distribution cable on 3-phase and on 1-phase and two phase 12.5 kV distribution circuits as of 2015. Approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems, generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service age are considered in poor condition.

Figure 4-18 and Figure 4-19, respectively, show the age profile of distribution cables employed on 3-phase and 1-phase circuits at 4.16 kV. As indicated, a majority of these cables are past their 40 year typical useful service life. These cables are generally planned to be removed from service when these service areas are upgraded to 12.47 kV. The relatively small amount of cable, with service age of less than 20 years age, is rated for use on 12.5 kV (in anticipation of the voltage conversion) and these circuits will remain in service after voltage conversion.



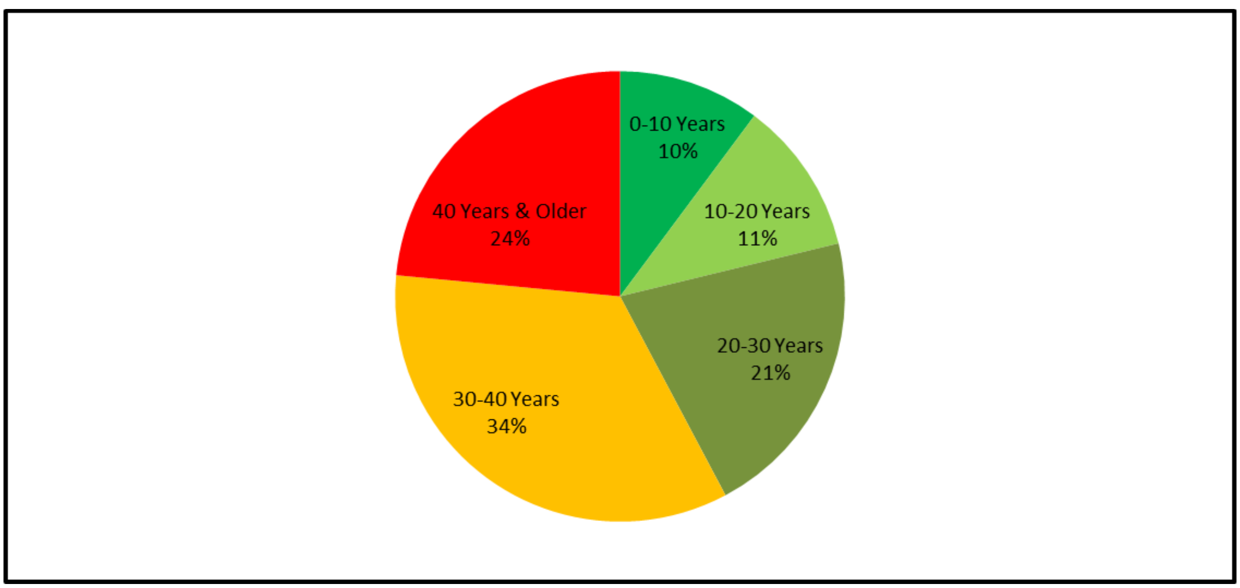
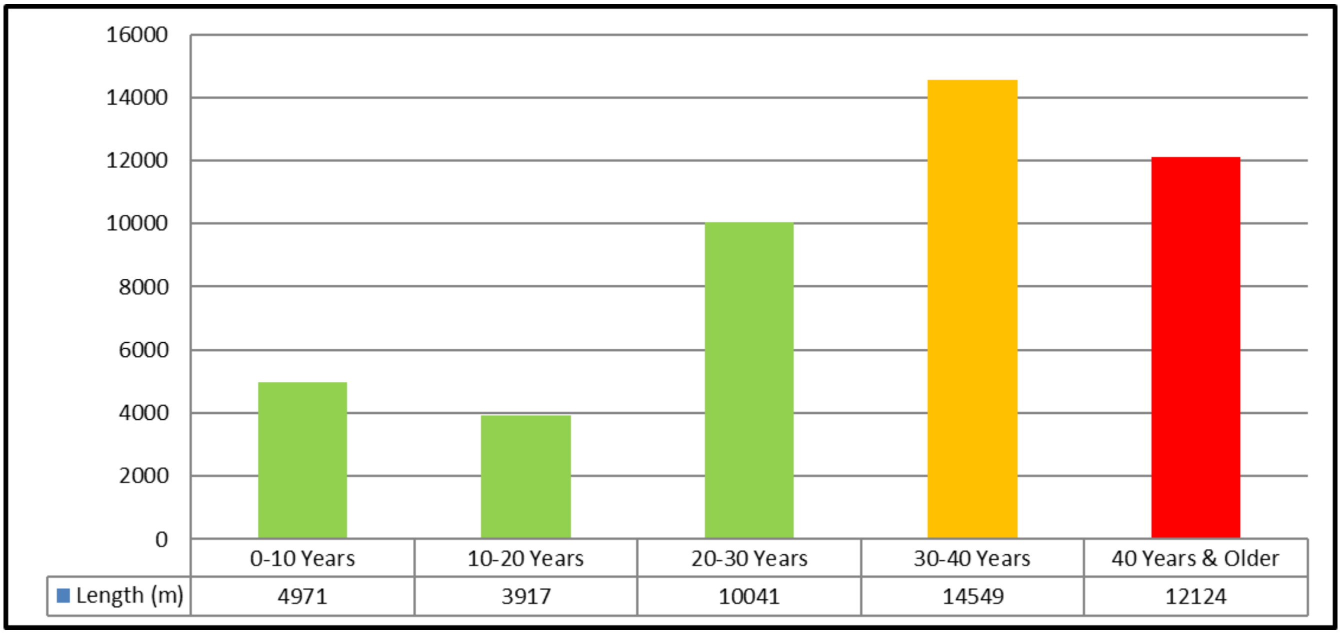


Figure 4-16: Age Profile – 34.5 kV and 12.47kV, 3-Phase Underground Cable Circuits



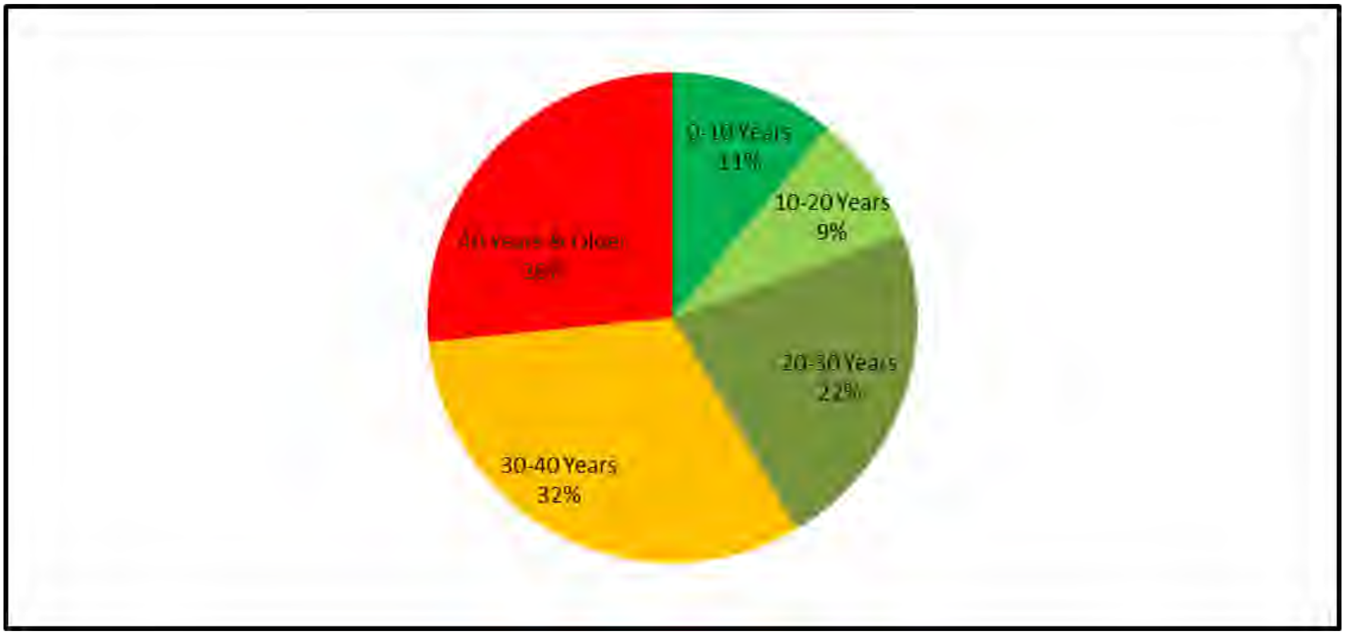
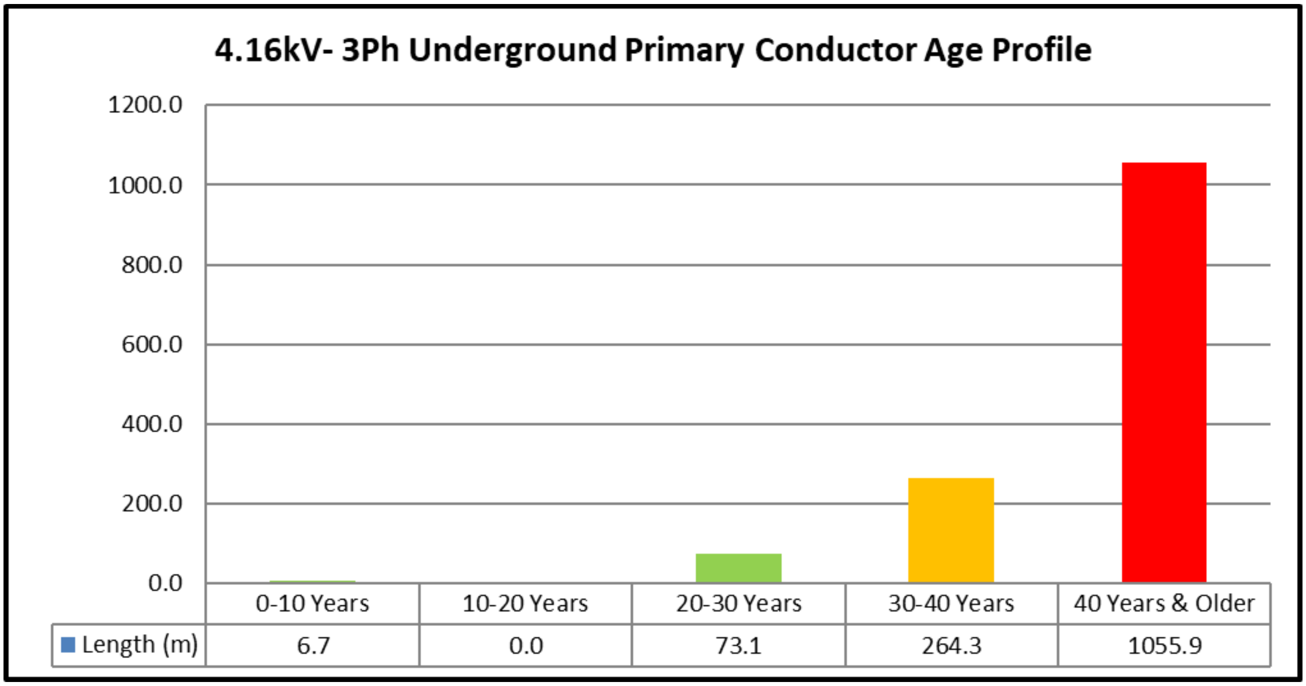


Figure 4-17: Age Profile – 12.47kV, 1-Phase Underground Cable Circuits



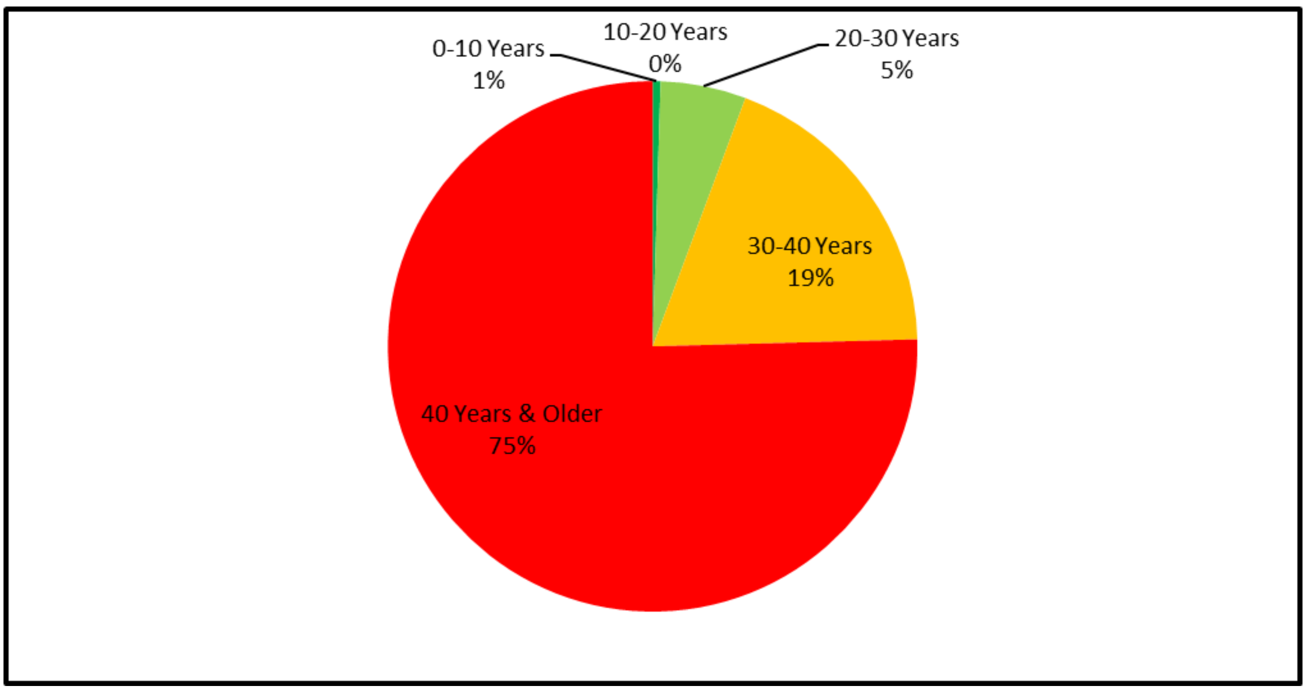
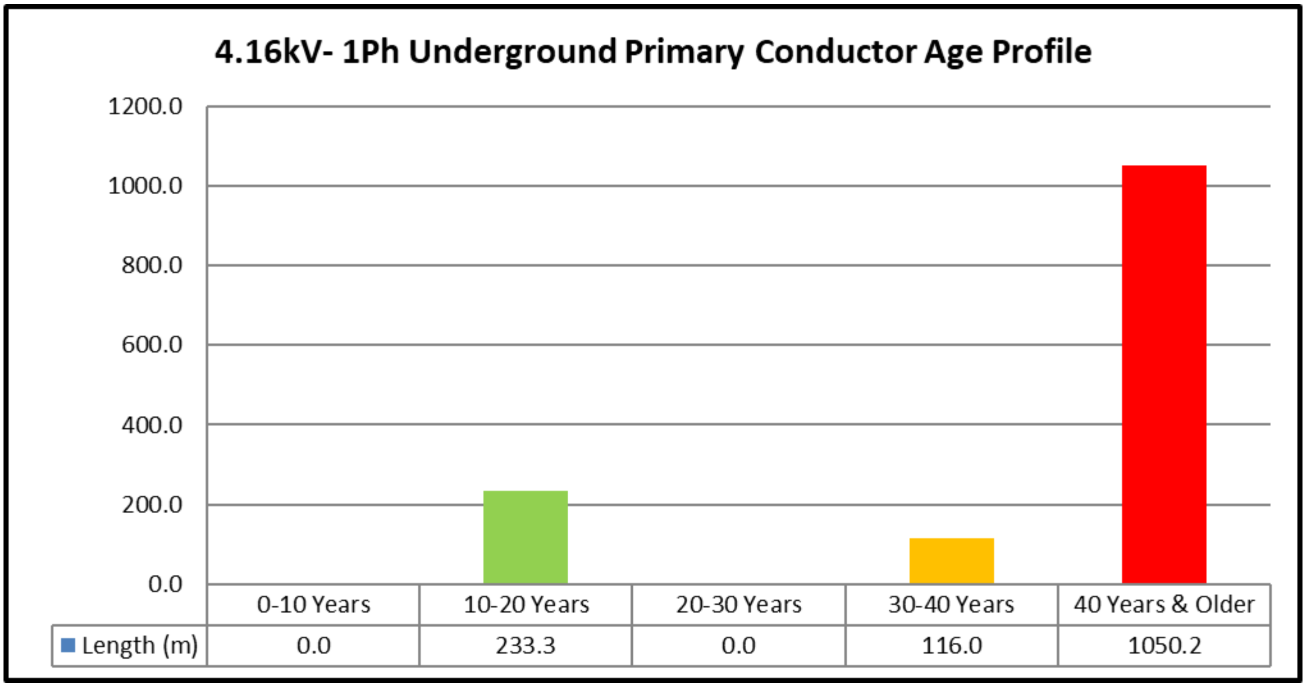


Figure 4-18: Age Profile – 4.16kV, 3-Phase Underground Cable Circuits



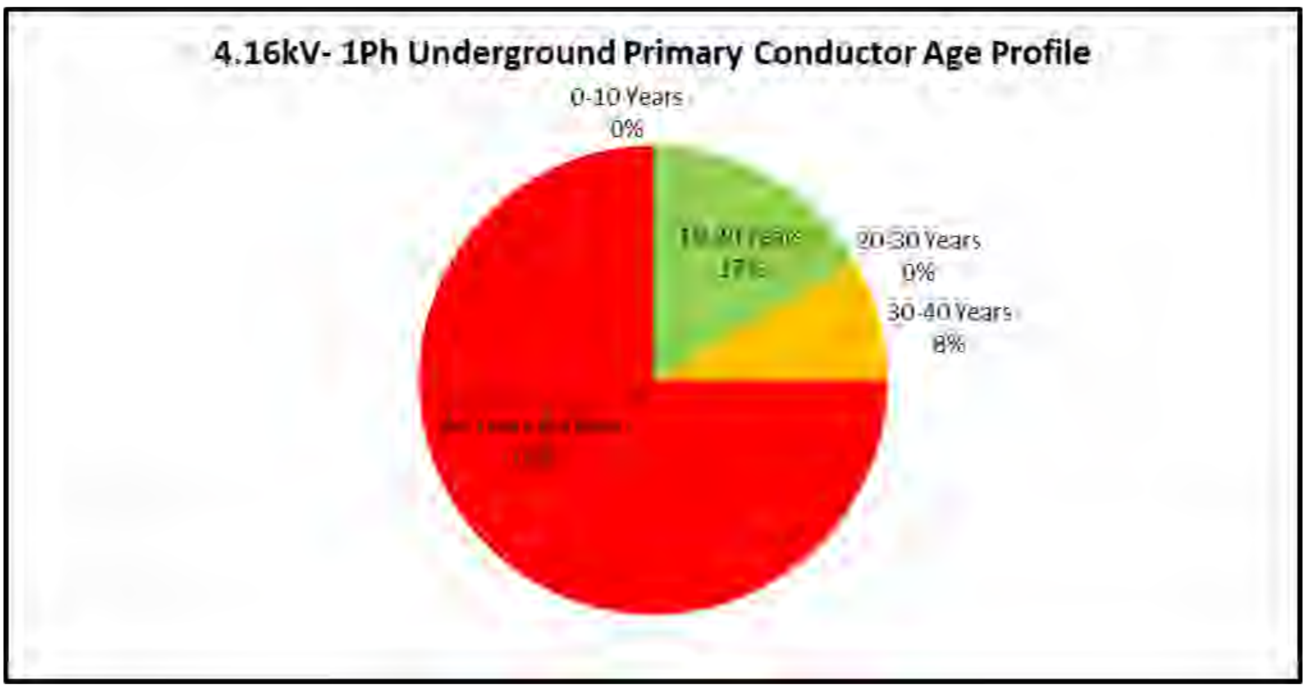


Figure 4-19: Age Profile – 4.16kV, 1-Phase Underground Cable Circuits

4.3.2. Pad-mounted Switchgear

At PUC DISTRIBUTION, live front pad-mounted switchgear, is the most commonly employed pad-mounted switchgear on underground distribution system, with a recent move towards dead front. Figure 4-20 indicates the age profile of pad-mounted switchgear. This type of switchgear provides reliable service life of about 35 years. Based on service age and visual inspections, 5 of the pad mounted switchgear units, are determined to be in poor or very poor condition, as shown in Figure 4-21.

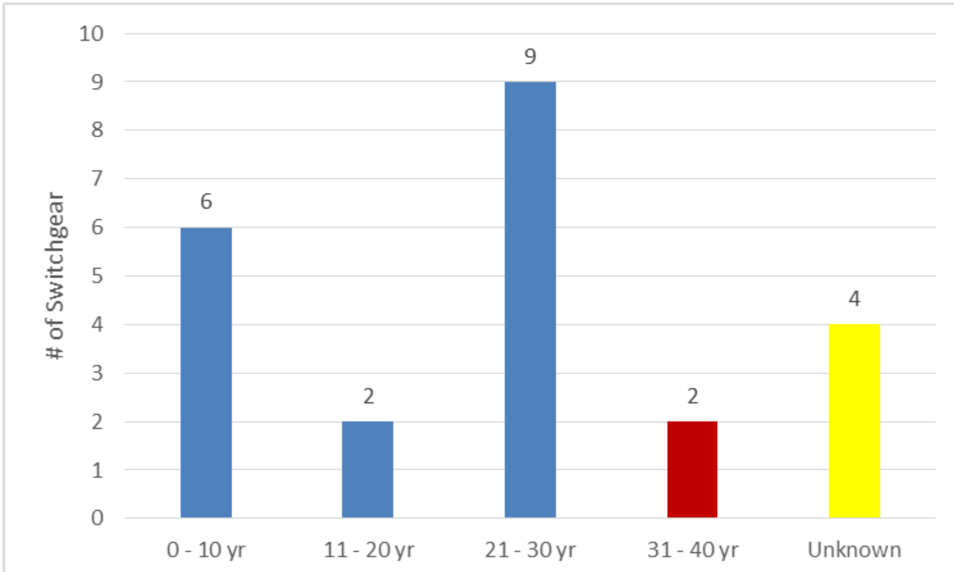


Figure 4-20: Age Profile – Pad-mounted Switchgear

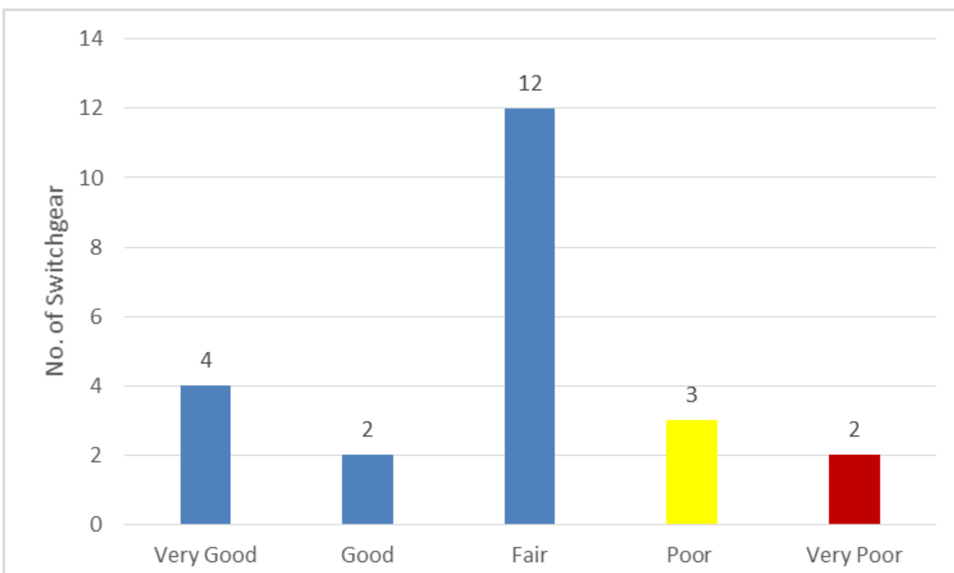


Figure 4-21: Condition Assessment of Pad-mounted Switchgear

Exact installation year for a majority of K-Bar junction boxes with service age of greater than 35 years is not known with certainty, but the estimated age profile for K-bar units is indicated in Figure

4-22. A majority of the junction boxes will reach the end of their typical service life of 40 years during the next five years.

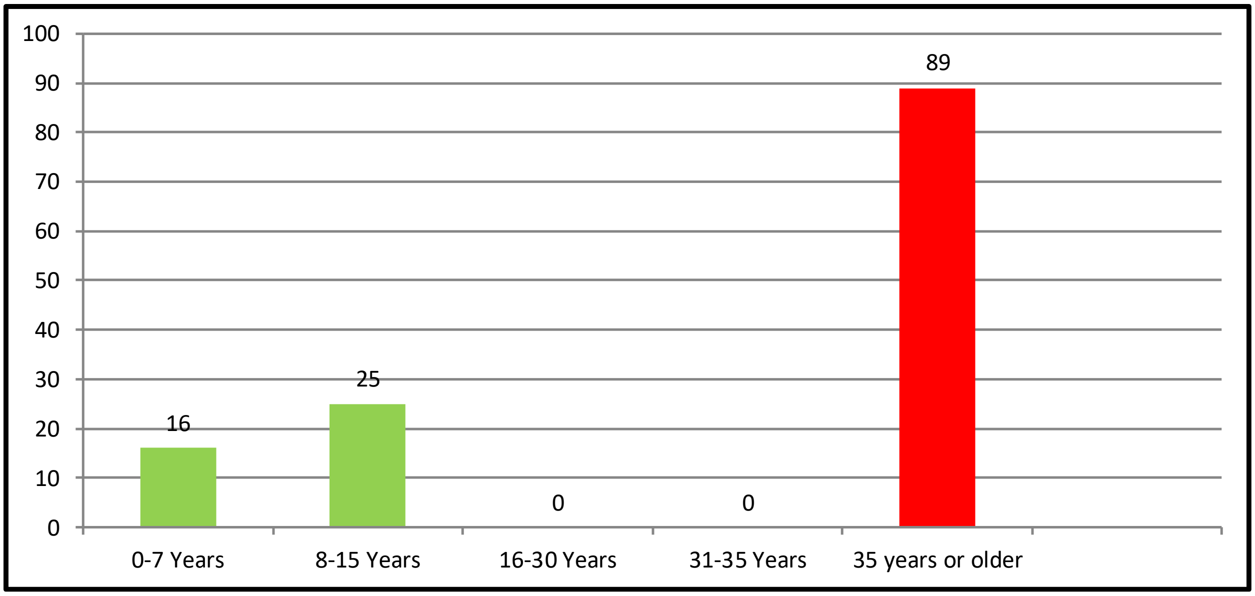


Figure 4-22: Age Profile – Pad-mounted K-Bar Units

4.3.3. Underground Concrete Chambers

PUC DISTRIBUTION's underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. As shown in Figure 4-23, there approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete. From the point of view of worker safety, the submersible transformer vaults and splice vaults present a challenge in that outages are required to complete maintenance work increasing costs and inconveniencing customers.

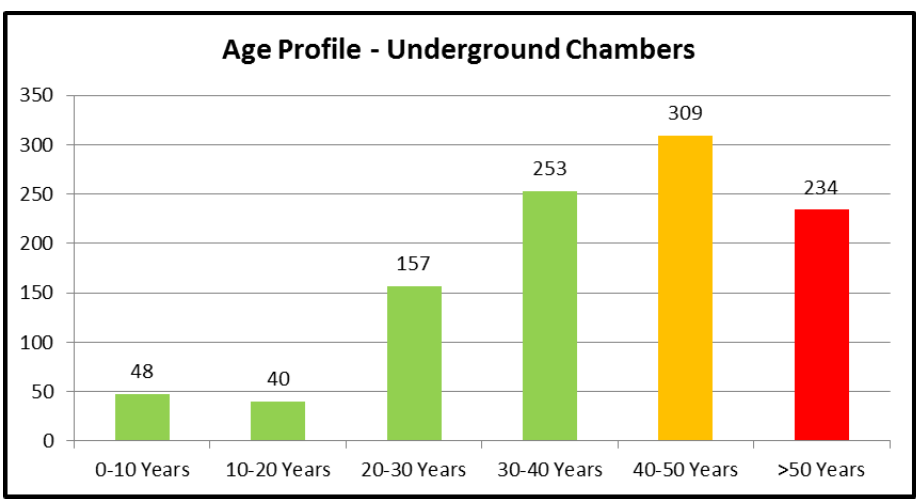


Figure 4-23: Age Profile of Underground Concrete Chambers

The submersible transformer vaults and splice vaults of inadequate size and without concrete floors, as shown in Figure 4-24, present the highest risk to workers and therefore, have been given a priority for reconstruction.

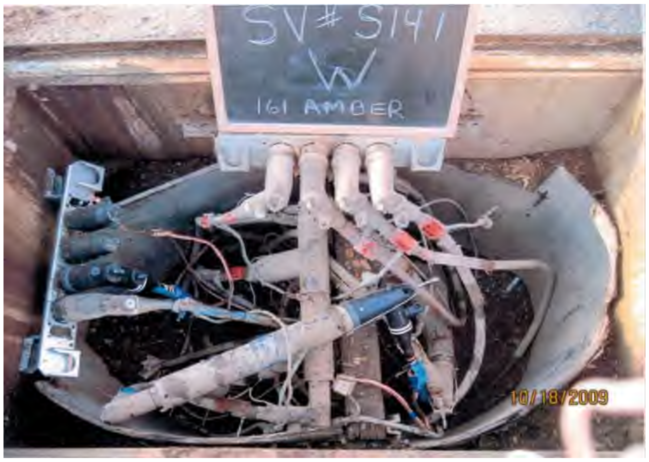


Figure 4-24: Underground Splice/Switching Vault

4.4. *Distribution Transformers*

PUC DISTRIBUTION has four different types of transformers in service: Pole-mounted, 1-phase Pad-mounted (mini-pad mount), 3-phase pad mounted and submersible vault type. Figure 4-25 through Figure 4-28 indicate the age profiles of transformers in each class.

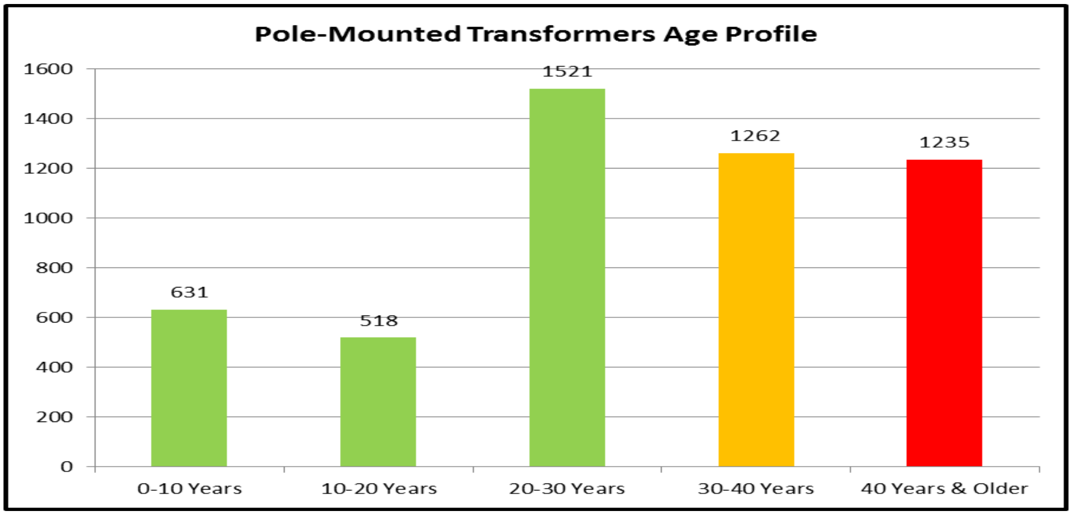


Figure 4-25: Pole Mounted Transformers – Age Profile

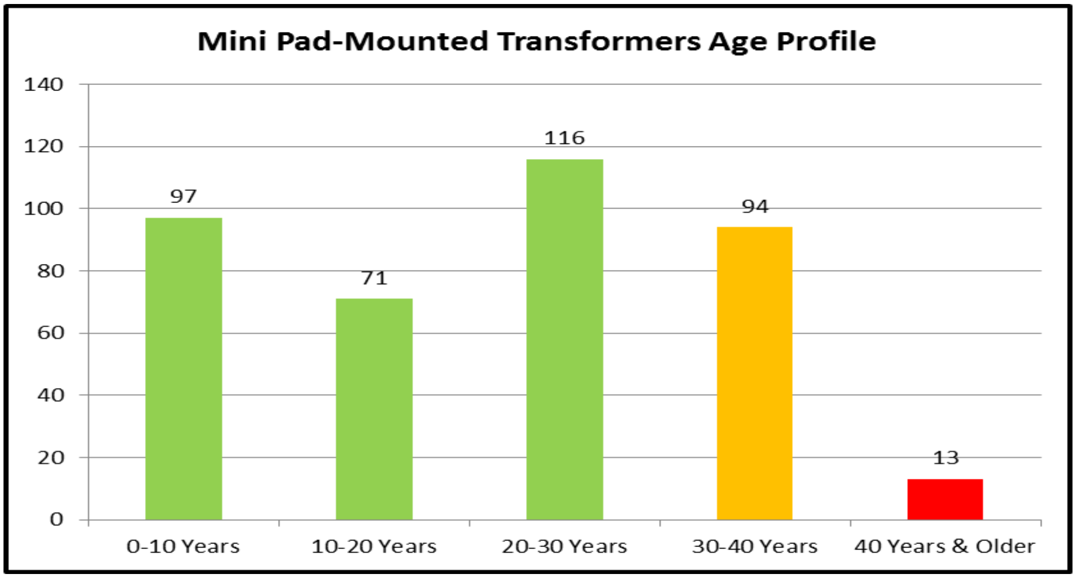


Figure 4-26: 1-Ph Pad-mounted Transformers – Age Profile

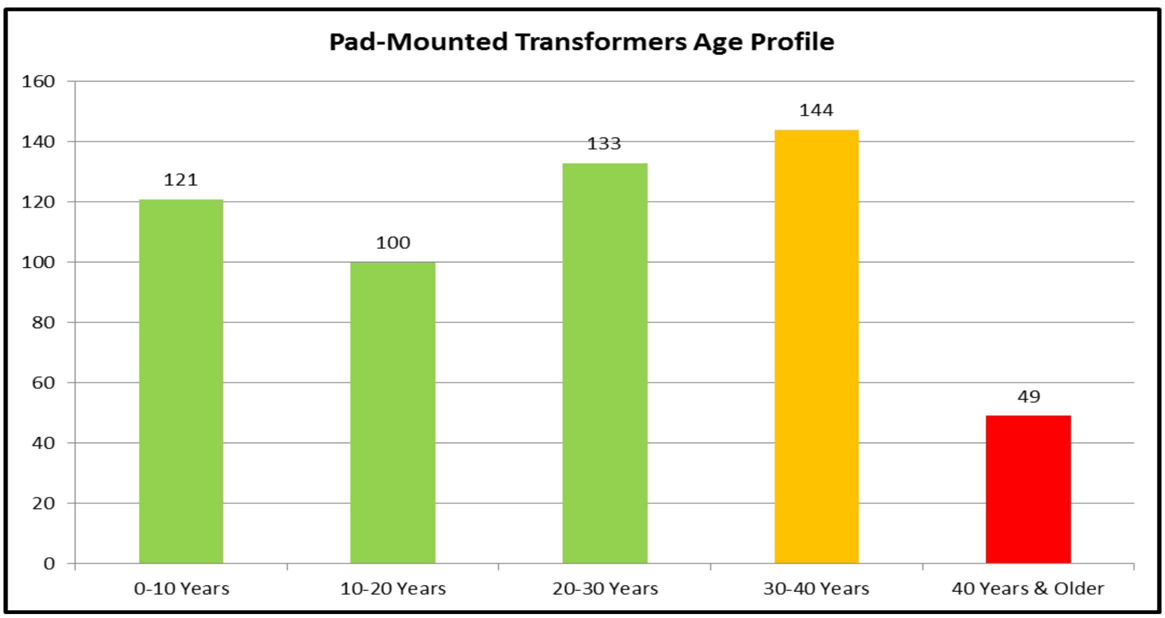


Figure 4-27: 3-Ph Pad-mounted Transformers – Age Profile

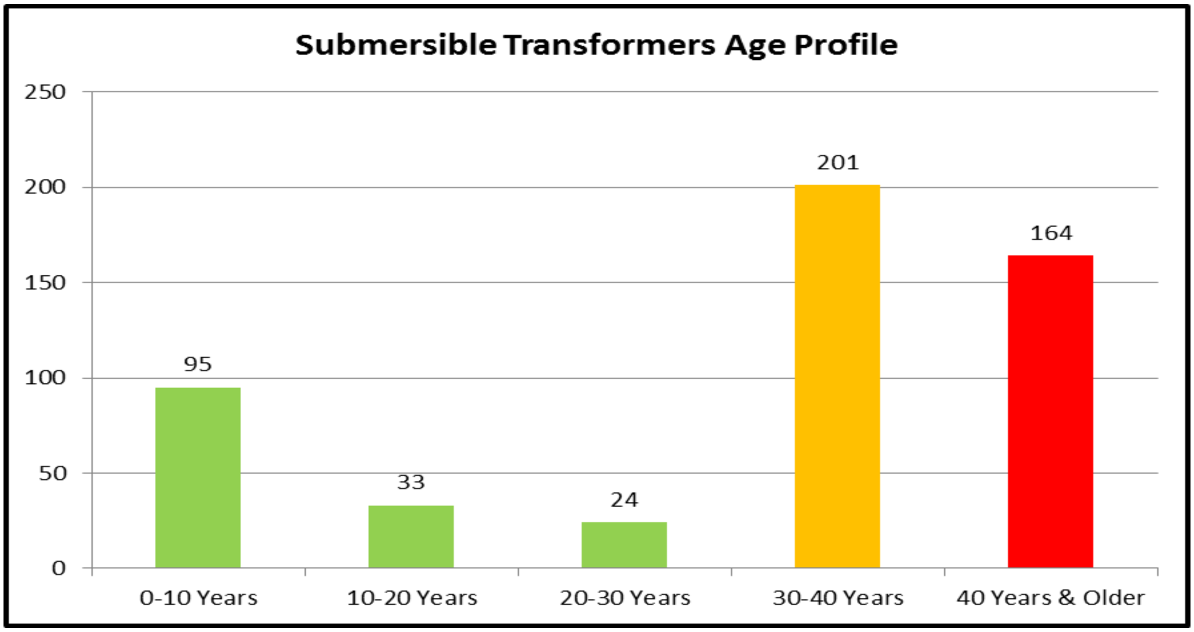


Figure 4-28: Submersible Vault Mounted Transformers – Age Profile

PUC DISTRIBUTION employs "run-to-failure" strategy for distribution transformers and due to the relatively low impact of transformer failures on reliability, this strategy serves well for the first three types of transformers and it is also in line with all other LDCs. However, because vault mounted transformers are not generally replaced with the same type of transformer upon failure, some degree of pre-planning is required to replace these with pad mounted transformers. Therefore, a proactive program is required to replace the submersible transformers with pad mounted transformers.

4.5. *Revenue Meters*

PUC DISTRIBUTION owns approximately 33,500 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption, demand, and billing of connected load. The meters vary in type depending on the connection type and customer class, and are capable of measuring kWh consumption, for TOU customers, kW and KVA demand for GS >50, as well as bi-directional meters for renewable generation applications. PUC DISTRIBUTION completed the installation of all of its Residential and General Service <50kW Smart Meters by December 2010 as part of the Province of Ontario's mandated Smart Meter initiative.

Table 4-1: Revenue Meter Quantities

Customer Type	# of Customers
Residential	29708
GS<50	3419
GS>50	360
Total	33487

Table 4-1 shows the breakout of PUC DISTRIBUTION's active meters by customer/meter types. A vast majority of PUC DISTRIBUTION's electric meters were installed in 2009 and have a seal year of 2019. PUC DISTRIBUTION plans to sample 600 meters in 2019, 200 in 2020 and 80 in 2021 all in accordance with Measurement Canada's "S-S-05—Performance Requirements Applicable to Meters Granted a Conditionally Lengthened Initial Reverification Period under S-EG-01" - sample its meter population to acquire an extension of up to 8 years. It is planned on testing and recalibrating 50 three-phase meters in 2020.

PUC is also required to equip all general service customers with >50kW to <500kW demand with MIST meters

In addition, revenue meters will also be required to replace meters failed in service and the failure rate of revenue meters is expected to be approximately 0.6% per year.

In addition to the above, spare revenue meters would be required to replace meters that fail in service. Table 4-2 shows the revenue meter failures on PUC DISTRIBUTION's network during the past six years. As shown in Table 4-2, the average number of meter failures per year between 2009 and 2015 has been 216.

Table 4-2: Revenue Meter Failures

Year	Number of meter failures
2010	332
2011	332
2012	240
2013	102
2014	195
2015	92
Average number of failures per year	216

Table 4-3 summarizes the revenue meter requirements to facilitate replacement of meters failed in service as well as removal from service of the required batch size of revenue meters for calibration, prior to expiry of the meter seals. It is noteworthy that the meters purchased in 2017 to facilitate calibration check will be transferred to general inventory and will become available for replacement of failed meters in subsequent years.

Table 4-3: Revenue Meter Requirements

Year	2016	2017	2018	2019	2020	2021
1-phase meters to replace meters failed in service	220	220	220	220	220	220
1-phase meters required to facilitate recalibration				200		
3-phase meters to replace meters failed in service	5	5	5	5	5	5
3-phase meters required to facilitate recalibration					50	

5 ASSET INVESTMENT PLAN

Based on the results of condition assessment of major assets employed in step down stations, overhead lines and underground distribution system, described in detail in Section 4, this section provides the budgetary estimates of capital investment required during the next six years to replace and rebuild those assets, that present high risk of failure in service, posing a threat to supply system reliability, public and employee safety and operating efficiency.

5.1. Step-down Station Assets:

Since the in-service failure of power transformers and switchgear in step-down stations has the largest impact on power supply security and reliability, a long term proactive program is recommended to gradually reconstruct all of the stations, determined to be in poor or very poor condition.

Both of the 115/34.5 kV transformer stations (TS-1 and TS-2) will require rebuild during the next five to ten years. However to maximize the benefit/cost ratio of this major investment, significant front-end planning and engineering is required to successfully implement the rebuild of these stations. Therefore, we are recommending a planning/engineering study be commissioned to review all practical development options and identify the optimal option for implementation. For the 34.5 / 12.47 kV stations, we recommend at least two stations be included in the next five-year plan for rebuild, based on the condition of power transformers, switchgear and auxiliary equipment. Although the power transformers and switchgear at each of the three 4 kV distribution stations are also currently in poor and very poor condition, no provision is made in the investment plan for renewal of these stations, as these are recommended to be retired from service.

To minimize the risk of in-service equipment failures at the transformer stations and distribution stations, we recommend equipment condition be closely monitored through inspections and testing backed with repair and refurbishment, as required.

5.2. Overhead Distribution System:

Proposed investments into overhead distribution system, include re-construction of lines determined to be in "poor" and "very poor" condition. Because lines constructed with restricted conductors present a growing safety risk, it is recommended all 3-phase and 1-phase lines constructed with restricted conductors be rebuilt during the next eight to ten years. The five-year budget includes provision for rebuilding of 75% of all existing lines with restricted conductors. Proposed investment for line rebuilds also includes projects initiated through voltage conversion to facilitate retiring of the 4 kV stations as well as forced line rebuilds after failure of assets on existing lines. The investment plan also includes funding to replace poles found in poor and very poor condition during pole testing

5.3. Underground Distribution System:

Underground distribution cables in a number of subdivisions have reached a service age beyond their typical useful service life. Cables at the end of their useful life are expected to experience an increase in failure rates with adverse impact on reliability. Therefore, we recommend an increase in funding to replace or rejuvenate cables in this investment plan. The investment plan also includes funding for rebuilding of underground transformer vaults and splice vaults which present safety hazards to workers. Investment plan also includes funding for replacement of pad mounted switchgear and k-bar junction boxes found in poor condition.

5.4. Distribution Transformers:

For distribution transformers, a "run to failure" strategy is proposed, where a transformer is replaced only after failure. This Investment plan includes budgetary provisions to replace distribution transformers after they fail. Current PCB regulations in Canada permit the use of distribution transformers containing PCB content in oil of up to 50 parts per million and this use can continue up to December 31, 2025. All distribution transformers must be below 50 parts per million after December 31, 2025. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1984) for PCB content and replace those containing PCBs above the threshold, or (b) replace all suspect transformers (purchased prior to 1984). The five-year investment plan includes budgetary provision for testing suspect distribution transformers for PCB content.

5.5. Miscellaneous Assets:

Investment plan includes budgetary provision for purchase of revenue meters, required to replace revenue meters failed in service as well as for calibration of meters upon expiry of meter seals. A small and reasonable amount has also been included for tools and equipment and for capital repairs to office buildings.

Table 5-1 summarizes the overall scope of capital investments proposed for the next six years. The cost estimates are based on unit-cost in 2015, and include an allowance for inflation at an annual rate of 2%.

Table 5-1: Investment Plan (2017 to 2021)

System Component	Project Description	Units of Measurement	Quantity (2017 - 2021)	Unit Cost in 2016 $	Budget in 2016 $ (2017 to 2021)	Annual Cost in 2016 $	Inflation adjusted Expenditure in Each Year 2017	2018	2019	2020	2021
Overhead Lines	3-Ph Line rebuild - restricted conductor	m	3,100	$ 200	620000	$ 124,000	$ 126,480	$ 129,010	$ 131,590	$ 134,222	$ 136,906
	1-Ph Line rebuild - restricted conductor	m	22,100	$ 100	2210000	$ 442,000	$ 450,840	$ 459,857	$ 469,054	$ 478,435	$ 488,004
	3-Ph Line rebuild - voltage upgrade	m	3,000	$ 200	$ 600,000	$ 120,000	$ 122,400	$ 124,848	$ 127,345	$ 129,892	$ 132,490
	1-Ph Line rebuild - voltage upgrade	m	20,000	$ 100	$ 2,000,000	$ 400,000	$ 408,000	$ 416,160	$ 424,483	$ 432,973	$ 441,632
	3-Ph Line rebuild - Lines in poor/very poor condition	m	24,000	$ 200	$ 4,800,000	$ 960,000	$ 979,200	$ 998,784	$ 1,018,760	$ 1,039,135	$ 1,059,918
	1-Ph Line rebuild - Lines in poor/very poor condition	m	6,000	$ 100	$ 600,000	$ 120,000	$ 122,400	$ 124,848	$ 127,345	$ 129,892	$ 132,490
	Replace degraded poles	#	200	$ 7,500	$ 1,500,000	$ 300,000	$ 306,000	$ 312,120	$ 318,362	$ 324,730	$ 331,224
	Forced asset replacement upon Failures (capitalized repairs)	#	5	$ 250,000	$ 1,250,000	$ 250,000	$ 255,000	$ 260,100	$ 265,302	$ 270,608	$ 276,020
	Subtotal overhead lines				**$10,750,000**	**$2,150,000**	**$2,193,000**	**$2,236,860**	**$ 2,281,597**	**$ 2,327,229**	**$ 2,373,774**
Underground Distribution System	Replacement of 3-phase cables in poor/very poor condition	m	4,980	$ 360	$ 1,792,800	$ 358,560	$ 365,731	$ 373,046	$ 380,507	$ 388,117	$ 395,879
	Replacement of 1-phase cables in poor/very poor condition	m	6,420	$ 150	$ 963,000	$ 192,600	$ 196,452	$ 200,381	$ 204,389	$ 208,476	$ 212,646
	Rejuvenation of 3-phase cables (Silicone injection)	m	3,320	$ 180	$ 597,600	$ 119,520	$ 121,910	$ 124,349	$ 126,836	$ 129,372	$ 131,960
	Rejuvenation of 1-phase cables (Silicone injection)	m	4,280	$ 75	$ 321,000	$ 64,200	$ 65,484	$ 66,794	$ 68,130	$ 69,492	$ 70,882
	Replacement of 3-phase cables for voltage upgrade	m	1,300	$ 360	$ 468,000	$ 93,600	$ 95,472	$ 97,381	$ 99,329	$ 101,316	$ 103,342
	Replacement of 1-phase cables for voltage upgrade	m	1,150	$ 150	$ 172,500	$ 34,500	$ 35,190	$ 35,894	$ 36,612	$ 37,344	$ 38,091
	Pad-mounted switchgear replacement	#	5	$ 15,000	$ 75,000	$ 15,000	$ 15,300	$ 15,606	$ 15,918	$ 16,236	$ 16,561
	k-bar replacement	#	40	$ 8,000	$ 320,000	$ 64,000	$ 65,280	$ 66,586	$ 67,917	$ 69,276	$ 70,661
	Vault rebuilds	#	60	$ 12,500	$ 750,000	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365	$ 165,612
	Forced asset replacement upon Failures (capitalized repairs)	#	5	$ 300,000	$ 1,500,000	$ 300,000	$ 306,000	$ 312,120	$ 318,362	$ 324,730	$ 331,224
	Subtotal underground system				**$ 6,959,900**	**$1,391,980**	**$1,419,820**	**$1,448,216**	**$ 1,477,180**	**$ 1,506,724**	**$ 1,536,858**
Stations	TS Rebuild - Planning and Engineering		1	$ 800,000	$ 800,000			$ 208,080	$ 212,242	$ 216,486	$ 220,816
	MS Rebuild - 2 x 10/13 MVA	#	2	$4,000,000	$ 8,000,000			$4,161,600			$ 4,416,323
	Protection Relay and SCADA miscellaneous capital upgrades	#	1	$ 400,000	$ 400,000	$ 80,000	$ 81,600	$ 83,232	$ 84,897	$ 86,595	$ 88,326
	DC Control battery and charger upgrades	#	5	$ 100,000	$ 500,000	$ 100,000	$ 102,000	$ 104,040	$ 106,121	$ 108,243	$ 110,408
	Miscellaneous building, fence, yard repairs	#	3	$ 40,000	$ 120,000		$41,616.00		$ 43,297.29		$ 45,046
	Subtotal station investments				**$ 9,820,000**	**$ 180,000**	**$ 225,216**	**$4,556,952**	**$ 446,556**	**$ 411,324**	**$ 4,880,920**
Distribution Transformers	Pole mounted transformers	#	48	$ 5,000	$ 240,000	$ 48,000	$ 48,960	$ 49,939	$ 50,938	$ 51,957	$ 52,996
	Pad mounted 1-ph transformers	#	24	$ 7,500	$ 180,000	$ 36,000	$ 36,720	$ 37,454	$ 38,203	$ 38,968	$ 39,747
	Pad mounted 3-ph transformers	#	6	$ 18,000	$ 108,000	$ 21,600	$ 22,032	$ 22,473	$ 22,922	$ 23,381	$ 23,848
	Testing transformers for PCB contamination	#	1,375	$ 185	$ 254,375	$ 50,875	$ 51,893	$ 52,930	$ 53,989	$ 55,069	$ 56,170
	Subtotal Distribution Transformers				**$ 782,375**	**$ 156,475**	**$ 159,605**	**$ 162,797**	**$ 166,053**	**$ 169,374**	**$ 172,761**
Miscellaneous Assets	Revenue Meters 1-ph	#	1300	$ 145	$ 188,500	$ 37,700	$ 38,454	$ 39,223	$ 40,008	$ 40,808	$ 41,624
	Revenue Meters 3-ph	#	75	$ 600	$ 45,000	$ 9,000	$ 9,180	$ 9,364	$ 9,551	$ 9,742	$ 9,937
	Miscellaneous building upgrades	#	1	$ 60,000	$ 60,000	$ 12,000	$ 12,240	$ 12,485	$ 12,734	$ 12,989	$ 13,249
	Miscellaneous tools and equipment	#	1	$ 150,000	$ 150,000	$ 30,000	$ 30,600	$ 31,212	$ 31,836	$ 32,473	$ 33,122
	Subtotal Miscellaneous investments				**$ 443,500**	**$ 88,700**	**$ 90,474**	**$ 92,283**	**$ 94,129**	**$ 96,012**	**$ 97,932**
Total Capital Investments Requirements into asset renewal					**$28,755,775**	**$3,967,155**	**$4,088,114**	**$8,497,108**	**$ 4,465,516**	**$ 4,510,663**	**$ 9,062,246**

6 PREVENTATIVE MAINTENANCE PLAN:

We have reviewed the fixed asset preventative maintenance program currently in use at PUC DISTRIBUTION and determined that it is in line with the best utility practices. However, PUC DISTRIBUTION is currently in the process of installing an under-frequency loads shedding system (UFLS) in accordance with IESO requirements. Upon placing this system in service, maintenance requirements at the 12kV distributions stations will need to be increased in accordance with regulatory requirements. The existing preventative maintenance program is briefly described below:

(a) Assets installed in transformer stations and distribution stations are inspected and maintained in accordance with the schedule shown in Table 6-1.

Table 6-1: Substation Preventative Maintenance Program

Activity	Description	Frequency	Supporting Documents
Oil Testing	Oil sample are drawn from station transformers and sent for analysis. The results are reviewed and an action plan is established	Annually	Oil test results and summaries
Infrared Scanning	Infrared scanning is performed on various stations and Line equipment annually.	Annually	Exception reports and equipment lists
Battery Maintenance	Quarterly Inspection and testing of the inter-cell connections	Quarterly	Battery test results
ESA Inspections	Inspection by ESA Inspectors of stations and equipment.	1/3 of the stations annually	Inspection results
General Inspections	Inspection by Stations staff to ensure property security, proper operation and other physical aspects.	Monthly for distribution stations, weekly for Transformer Stations	Inspection Orders
Station Maintenance	Cleaning, testing Inspection and Maintenance of relays, breakers, switchgear, transformers, buss work, motor operators, switches etc. to meet NPCC requirements	5 year rotation (3 stations annually)	Inspection and test results

Oil Breaker inspection and Maintenance	Inspection and maintenance of the oil-filled circuit breakers at our two transformer stations, includes oil testing, removal of the tank, electrical and visual inspection of contacts, bushing testing etc.	5-year cycle	Inspection and test results
115 KV Switch Inspection and Maintenance	Inspection and maintenance of the 115 KV switches including alignment of the operating mechanism, lubrication, inspection of contact surfaces etc.	5- year cycle	Inspection and test results

(b) Overhead lines and underground pads and vaults are inspected on a 3-year cycle, to comply with Distribution System Code regulations. One third of the distribution assets employed on overhead distribution system are inspected each year. Structural defects, clearance issues and electrical problems and hazards are identified through visual inspections and where problems are revealed, either repair work is scheduled or capital work is planned, as needed. Where the inspections determine an immediate hazard immediate follow up action is taken to mitigate the problem. Field inspection records are kept on file in the line department until the next cycle of inspections.

(c) On overhead distribution lines, the following deficiencies/defects are identified on various assets:

Poles/Supports:

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Distribution Transformers:

- Paint condition and corrosion
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Flashed or cracked insulators
- Contamination/discolouration of bushings
- Ground lead attachments

- Damaged disconnect switches or lightning arresters
- Ground wire on arresters unattached

Switches and Protective Devices:

- Bent, broken bushings and cutouts
- Damaged lighting arresters
- Ground wire on arresters unattached

Hardware and Attachments:

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated (difficult to see)
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Conductors and Cables:

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag
- Insulation fraying on secondary

Third Party Plant:

- Attachment not secure
- Infringing on clearances
- Compromising access to electrical equipment
- Unapproved/unsafe occupation or secondary use

General Conditions & Vegetation:

- Leaning or broken "danger" trees
- Growth into line of "climbing" trees
- Accessibility compromised
- Vines or brush growth interference (line clearance)
- Bird or animal nests

(d) On underground distribution lines, the following deficiencies/defects are identified on various assets:

Pad Mounted Transformers and Switching Kiosks:

- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta bolt in place or damage
- Grading changes
- Access changes (Shrubs, trees, etc.)
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Lid damage, missing bolts, cabinet damage
- Cable connections
- Ground connections
- Nomenclature
- Animal nests/damage
- General conditions

Right of Way

- Accessibility compromised
- Grade changes that could expose cable
- Excessive vegetation on right of way

(a) Tree trimming has been carried out on a 3–year cycle in the past, which we consider to be satisfactory.

(b) In accordance with the best utility practices, thermograph inspections of distribution assets are carried out with infra-red cameras and any hot spots are promptly attended. The thermograph inspections appear to be extremely effective in detecting incipient faults and we recommend these should be continued as part of the maintenance program.

PHOTOGRAPHS OF STATION ASSETS

TS1

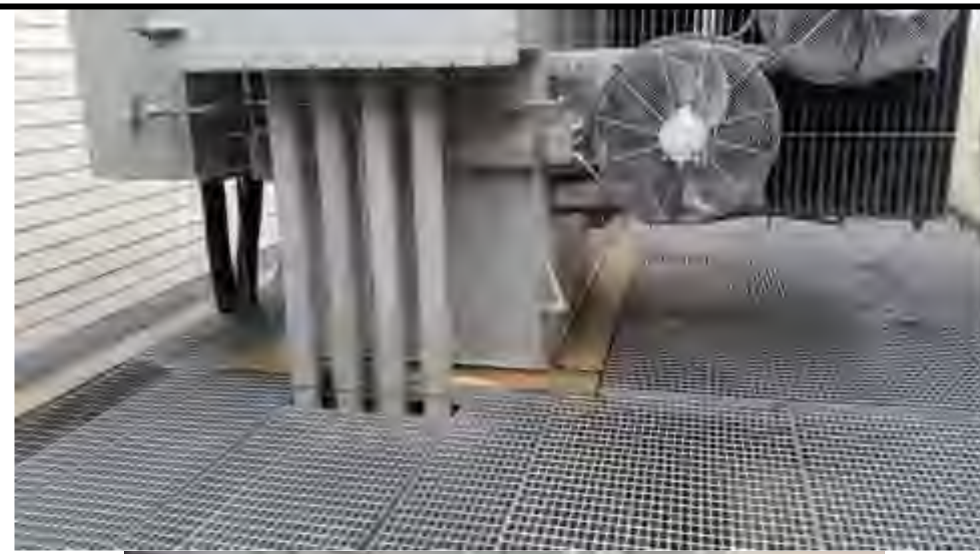
TS2

Substation #1

Substation #2




Substation #4



Substation #10




Substation #11




Substation #12

Substation #13

Substation #15




Substation #16

Substation #18

Substation #20

Substation #21

Appendix C

PUC Distribution Customer Satisfaction Survey

PUC Distribution Inc.

2017 Electric Utility Customer Satisfaction Survey

Summary Report

UtilityPULSE

The purpose of this report is to profile the connection between PUC Distribution Inc. (PUC Distribution) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information to support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Survey Observations & Insights

In the 19 years UtilityPULSE has been conducting research in Ontario's LDC market, we have not seen the residential/small commercial customer base as negative – and some would say angry – as it is right now. Over the past 10 weeks UtilityPULSE has completed 6,000+ Residential and Small Commercial customer surveys – satisfaction results are ugly. Though not news to your call-centre professionals, more customers are worried about the cost of electricity and more customers are finding it difficult to pay their bill. This survey does ask respondents to pick from 3 statements the one which best describes their ability to pay. In 2015, 59% [Ontario Benchmark] and 55% [PUC Distribution] selected *"Paying for electricity is not really a worry"*, in 2017 the numbers are 53% [Ontario Benchmark] and 51% for PUC Distribution. Survey respondents are looking through the lens of costs, more specifically affordability, therefore ratings for 2017 have been impacted.

Ability to pay is a highly correlated factor to overall satisfaction, and given the steep rise in electricity costs (those costs beyond the control of your LDC), satisfaction is dropping. It is clear industry events are affecting how customers see your LDC. Customers have told us, despite spending money to assist in reducing consumption, their bill continues to go up. This double whammy is increasing the "worry" factor. We recommend everyone at PUC Distribution remain professional and demonstrate empathy and as we know about human nature, worry can easily turn into a severe erosion of trust which then leads to anger.

Though your survey is about gathering the opinions of your customers, the reality is, erosion of trust in institutions in other sectors is also contributing to the worry and angst factor your customers are experiencing – the good news is 78% of PUC Distribution's customers agree your LDC is trusted and trustworthy. Today's heroes, when customers have problems or issues, are "everyday people" whose actions show they understand and are doing everything in their power to solve the problem. We've said this to our clients many times: "where understanding stops, stress, irritation, anger and conflict begin."

Your survey was conducted from January 26 - February 24, 2017 and is based on one-on-one telephone interviews with individuals who pay or look after the electricity bill. Data for this report came from conducting a telephone interview with 401 of your residential and small commercial customers. In addition, survey findings for PUC Distribution have been enhanced with the inclusion of data from our UtilityPULSE database and the independently produced Ontario and National benchmarks.

Base: total respondents:
Top 2 Boxes: "Strongly agree + agree"

Despite an angry environment towards the electricity industry as a whole, i.e., satisfaction levels and concern over costs; survey respondents gave PUC Distribution excellent operational scores.

Operational Attributes			
	PUC Distribution	**National**	**Ontario**
Provides consistent, reliable energy	91%	89%	89%
Quickly handles outages and restores power	90%	87%	85%
Accurate billing	81%	83%	80%

Base: total respondents with an opinion

However, PUC Distribution representatives also did their part:

Representative Attributes			
	PUC Distribution	**National**	**Ontario**
Deals professionally with customers' problems	85%	83%	81%
Is 'easy to do business with'	85%	81%	77%
Customer-focused and treats customers as if they're valued	73%	75%	73%

Base: total respondents with an opinion

Attributes strongly linked to Credibility & Trust

	PUC Distribution	National	Ontario
Keeps its promises to customers and the community	76%	77%	73%
Pro-active in communicating changes and issues affecting Customers	77%	76%	73%
Is a trusted and trustworthy company	78%	81%	74%

Base: total respondents with an opinion

We have seen a social shift in the customer base, wherein there is a high expectation they will be involved in the decisions affecting them. The higher the intensity of worry that people have about their future, the higher the likelihood they will want a say in the things which could affect them.

As such human beings will primarily act out of self-protection and self-interest which, in-turn, causes polarization of views. For LDCs it becomes much more difficult to generate a consensus view for items that are clearly in the best interest of the majority. Asking people who are very worried about paying their bill to support items which promote the “greater good” is a daunting task.

Customer engagement is not about getting agreement (though it would be nice to do so), customer engagement is about ensuring there is an understanding of customer wants and needs; particularly when the possibility of an increase in cost is involved.

Utility Customer Centric Engagement Index (CCEI)

	PUC Distribution	National	Ontario
CCEI	78%	78%	74%

Base: total respondents

Engagement is how customers think, feel and act towards the organization. Ensuring customers respond in a positive way requires they be rationally satisfied with the services provided AND emotionally connected to the LDC and its brand.

The Customer Experience Performance rating (CEPr) score is an effectiveness rating and is affected by many dimensions of service. Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. While an excellent transaction today creates a positive experience today, the perception created is, future transactions will be excellent too.

Of course a negative transaction creates the perception, future transactions will be negative.

Customer Experience Performance rating (CEPr)			
	PUC Distribution	**National**	**Ontario**
CEPr: all respondents	83%	82%	80%

Base: total respondents

Customer satisfaction is one dimension for measuring the effectiveness of an enterprise. But focusing on customer satisfaction as a sole measure is not enough to gain a picture about how well an operating unit/enterprise might be doing. Customer satisfaction as a measure is an effectiveness measure (not an efficiency measure) on the historical relationship or delivery of services to customers.

“Satisfaction happens when an enterprise’s core services meet or exceed customer’s needs, wants, or expectations.”

Customer Satisfaction

SATISFACTION SCORES – Electricity customers’ satisfaction			
Top 2 Boxes: ‘very + fairly satisfied’	**PUC Distribution**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	82%	89%	84%
POST: End of Interview	80%	86%	76%

Base: total respondents

Customer Commitment

Electricity customers’ loyalty – … Is a company that you would like to continue to do business with			
	PUC Distribution	**National**	**Ontario**
Top 2 Boxes: ‘Definitely + Probably’ would continue	72%	78%	69%

Base: total respondents

Customer Advocacy

Electricity customers’ loyalty – … is a company that you would recommend to a friend or colleague			
	PUC Distribution	**National**	**Ontario**
Top 2 boxes: ‘Definitely + Probably’ would recommend	67%	71%	59%

Base: total respondents

It could be said, some problems can actually anger customers. As a mnimum, a problem is an inconvenience to the customers – and they want it solved/resolved. When the problem is solved with the first interaction (often called first call resolution) overall customer satisfaction can improve.

Problems: Power Outages

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	PUC Distribution	National	Ontario
2017	32%	37%	37%
2016	-	53%	51%
2015	45%	47%	49%
2014	-	41%	35%
2013	-	44%	46%

Base: total respondents / (-) not a participant of the survey year

Problems: Billing issues

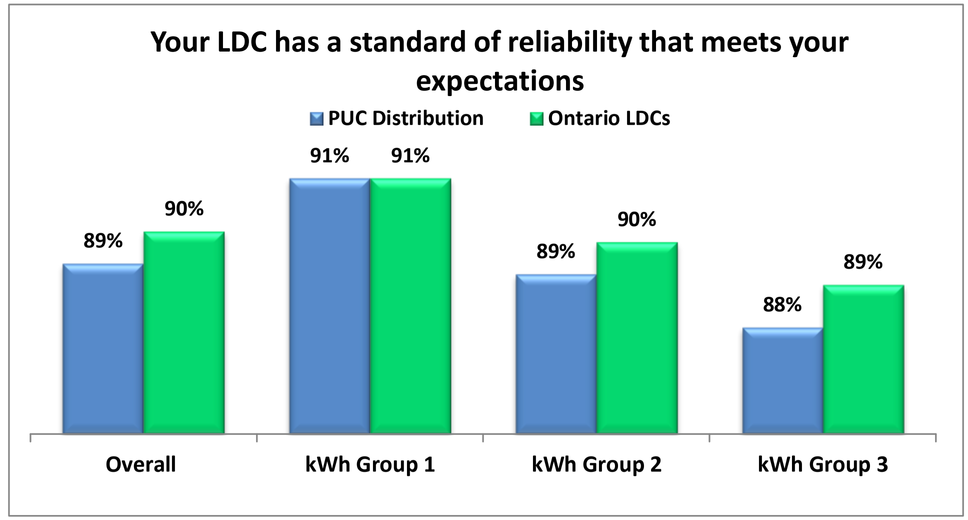
Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	PUC Distribution	National	Ontario
2017	25%	15%	25%
2016	-	9%	15%
2015	13%	16%	25%
2014	-	8%	10%
2013	-	12%	13%

Base: total respondents / (-) not a participant of the survey year

Outage Management

The perception of competency and value of the LDC are certainly linked to the frequency and duration of power outages. Recognizing the importance of this topic to customers, a question about LDC reliability standards was asked in the survey.

Scores for PUC Distribution indicate the vast majority of customers feel the utility is consistent in meeting their expectations.



Base UtilityPulse Database / total respondents

If the utility were to improve reliability should they put more emphasis on reducing the number of unplanned outages or reducing the duration of the unplanned outage? Or both which requires an increase in costs and potentially rates. Dealing with the pain of high bills is far and away more important to customers than the pain of outages which explains the high percentage (55%) of not willing to pay more.

However, this survey was completed prior to the Ontario Government's March 2, 2017 announcement about reducing electricity bills by 25%.

Emphasis on Outage Management

	PUC Distribution
Reduce the number of outages	4%
Reduce the duration of outages	4%
Both	32%
Neither, not willing to pay more	55%
Don't know	4%

Base: total respondents

PUC Customer respondents give PUC Distribution excellent ratings as it relates to the job/task of dealing with outages.

LDC effectiveness responding to outages: Top 2 Boxes: "Very + Somewhat effective"

	PUC Distribution	Ontario LDCs
Responding to the power outage	92%	85%
Restoring power quickly	94%	86%
Using media channels for updates	69%	54%
Providing information about the outage	72%	61%

Base: total respondents/ 2017 UtilityPULSE Database

Customer Service

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**PUC Distribution**	**National**	**Ontario**
The time it took to contact someone	72%	67%	63%
The time it took someone to deal with your problem	64%	64%	60%
The helpfulness of the staff who dealt with you	71%	67%	64%
The knowledge of the staff who dealt with you	72%	63%	59%
The level of courtesy of the staff who dealt with you	84%	74%	69%
The quality of information provided by the staff who dealt with you	63%	65%	64%

Base: total respondents who contacted the utility

Everyone in the LDC affects a customer's perception, not just call-centre employees. Employees in other departments interact with customers and so do outside-workers. Employees, at all levels and departments of the LDC are not immune to the frustration and anger customers feel about their bills and the industry as a whole. Therefore, it is imperative everyone remain professional and focused on doing everything very well – including the little things.

Upset or angry people are critical people and they will look for behaviours which reinforce or validate their negative view. It is more important than ever to ensure every interaction with a customer is an excellent one. Demonstrating understanding through active listening is a good start.

PUC Distribution's UtilityPULSE Report Card®

Performance

	CATEGORY	PUC Distribution	National	Ontario
1	**Customer Care**	**B**	**B**	**C+**
	Price and Value	C+	B	C
	Customer Service	B+	B+	B
2	**Company Image**	**B+**	**B+**	**B**
	Company Leadership	B	B+	B
	Corporate Stewardship	B+	B+	B
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A+	A	A
	OVERALL	**B+**	**B+**	**B**

Base: total respondents

Lowest scoring attributes

Low scoring attributes			
Top 2 Boxes: 'Strongly + Somewhat agree'	**PUC Distribution**	**National**	**Ontario**
Adapts well to changes in customer expectations	68%	71%	68%
Operates a cost effective electricity system	62%	70%	56%
Provides good value for your money	57%	62%	56%
Cost of electricity is reasonable when compared to other utilities	44%	61%	48%

Base: total respondents with an opinion

Highest scoring attributes

High scoring attributes			
Top 2 Boxes: 'Strongly + Somewhat agree'	**PUC Distribution**	**National**	**Ontario**
Provides consistent, reliable electricity	91%	89%	89%
Makes electricity safety a top priority for employees and contractors	91%	87%	86%
Quickly handles outages and restores power	90%	87%	85%
Has a standard of reliability that meets expectations	89%	88%	86%

Base: total respondents with an opinion

Use of Technology

Where will technology take us in the future? What effect will technology have on people's lives?

The effect of technological changes on people's lives will lead to a future that is …	
	PUC Distribution
Mostly better	39%
Mostly worse	9%
Neither	46%
Don't know	5%

Base: total respondents

As customers increasingly demand greater empowerment, utilities seek to improve interactions and relationships in their entire operation by enhancing software capabilities for collaboration, gaining deeper customer and market insight and improving process management. Respondents were asked how important having online access to the following features was to them:

Importance of online access for the following features:

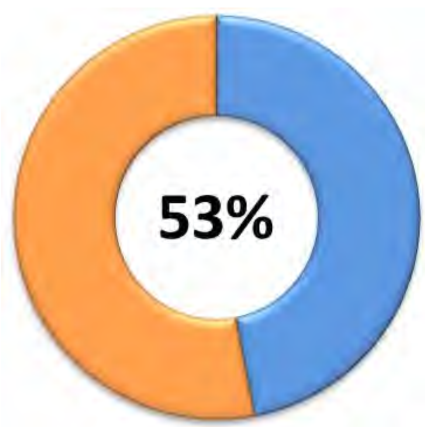
Top 2 Boxes: 'very + somewhat important'	PUC Distribution	UtilityPULSE Database
Reporting or inquiring about an issue	53%	71%
Researching information about energy conservation	58%	79%
Having a web chat feature on the website	32%	50%
Automated alerts when electricity usage exceeds a prearranged threshold	54%	71%
Review and pay your bill online (through utility's website)	53%	68%
Power outage alerts	61%	80%
Tools and calculators to help you manage your electricity consumption	44%	67%
Comparison of your electricity consumption with your neighbours	41%	51%
Automated alert to predict your upcoming bill	40%	59%
Automated alert to remind you of your bill due date	34%	59%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

Confidence in the Industry

Respondents have a perception about the electricity industry as a whole. That image influences how people (customers) think and feel about various industry participants. Confidence represents a filter affecting customers' perception about their LDC. For example on the subject of customer satisfaction, the UtilityPULSE database shows those survey respondents who had high confidence levels scored 14% higher than those who had low confidence. This variance has little to do with the actual numbers or facts about the LDCs performance.

'Customers are well served by the electricity system in Ontario' – do you agree? Base: total respondents



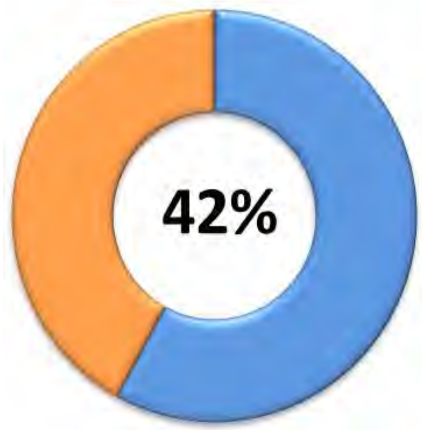
53% Agree ('strongly + somewhat') customers are well served by the electricity system in Ontario

5% neither agree nor disagree

39% Disagree ('strongly + somewhat') they are well served

1% did not render an opinion or did not know

‘Customers are confident in the electricity industry’s ability to meet their future expectations regarding quality, reliability and price’ – do you agree? Base: total respondents



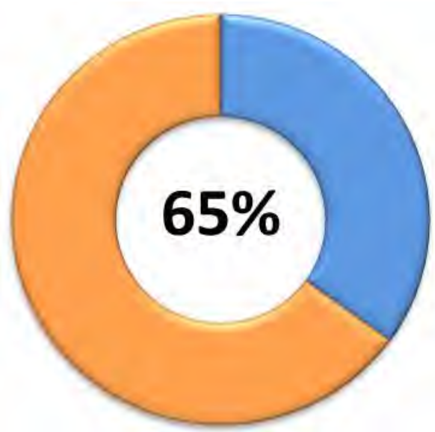
42% Agree (‘strongly + somewhat’) customers are confident the electricity industry has the ability to meet future expectations regarding quality, reliability and price

6% neither agree nor disagree

48% Disagree (‘strongly + somewhat’) the industry can deliver on future expectations

2% did not render an opinion or did not know

‘Customers are confident in the electricity industry’s ability to keep up with technological changes’ – do you agree? Base: total respondents



65% Agree (‘strongly + somewhat’) customers are confident the electricity industry is able to keep up with technological changes

7% neither agree nor disagree

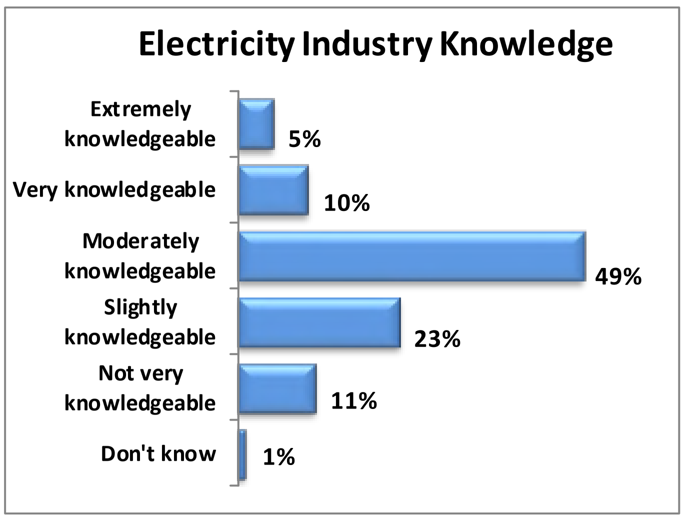
23% Disagree (‘strongly + somewhat’) the industry will keep up with changing technology

4% did not render an opinion or did not know

Electricity Industry Knowledge

16% of respondents for PUC Distribution described themselves as Extremely or Very knowledgeable about the electric utility industry. 49% claim they are moderately knowledgeable.

Approximately 1 in 5 (17%) survey participants in the UtilityPULSE database describe themselves as Extremely knowledgeable or Very knowledgeable. Only 50% of this knowledgeable group said they agree 'strongly + somewhat' customers were well served by the electricity system.



Base: total respondents

Approximately 1 in 3 survey respondents describe themselves in the bottom 2 categories of knowledge, and 58% of this group said they agree 'strongly + somewhat' customers are well served.

The data is clear; those who considered themselves more knowledgeable are also much less likely to say they have confidence in the industry to meet their needs and in the industry's ability to keep up with technology. Being knowledgeable is not necessarily a path to better appreciation of the electricity industry. However it does seem to be a path which creates more polarization of viewpoints thereby making it more difficult to generate support for various items/activities.

Some customers will want to understand what is going on in the industry; just like there are some customers who want to know the inner workings of an automobile. However, the vast majority of people do not want to know how their automobile or the electricity industry works. What they want to know is, when there is a problem where they can access professionals who can fix them.

Loyalty Groups

Customer Loyalty Groups				
PUC Distribution	**Secure**	**Favorable**	**Indifferent**	**At Risk**
2017	19%	18%	44%	19%
2016	-	-	-	-

Base: total respondents / (-) not a participant of the survey year

Paying for electricity

For 19 years, the highest factor correlated to satisfaction is ability to pay.

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
PUC Distribution	51%	30%	17%	1%
National	65%	20%	12%	1%
Ontario	53%	25%	18%	1%

Base: total respondents

Confidence Prioritizing Investments

Survey respondents are looking through the lens of costs & affordability when providing answers to questions about investing in their LDC to ensure the reliable and safe delivery of electricity and the efficient running of operations. Understanding customer expectations, concerns, and desires does help an LDC to build their plans to ensure they remain relevant, viable, and valuable to customers, employees and other stakeholders.

85% **of Secure and Favourable respondents are confident that PUC Distribution is using good judgment to prioritize investments**

Gathering support for making capital and operational investments is going to be a challenge for items other than those linked to replacing aging equipment to improve safety and reliability. This is where customer affinity plays an important role.

Loyal customers are more likely to see the world the way management sees it. Committed customers feel their interests and those of their utility are often in common. When customers are committed, they voluntarily tell others how they feel; they are more tolerant and more supportive. Relative to ‘good judgment to prioritize investments’, 85% of Secure and Favourable respondents are confident (‘very + somewhat’) that PUC Distribution is using good judgment to prioritize investments.

Capital Expenses

It is true, customers (but not all) can tell you what they want, but they have a very difficult time telling you what they need. On the one hand many customers **"want"** lower prices, but they **"need"** reliability and responsiveness.

Hence, it is up to the professionals in the LDC to use their experience and judgment to determine what needs to be done and when it should be done. No easy task – especially with a customer base that is focused on costs. Yet, about 2 out of 3 survey respondents opted for "pro-active replacement" which is consistent with the UtilityPULSE database average of 65%.

Strategy for replacing equipment

PUC Distribution	2017	2015
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	20%	19%
Pro-active replacement, even though it may cost more, should ensure reliable power	64%	72%
Don't Know	16%	10%

Base: total respondents

Which of the following CAPITAL items would you be willing to pay more for?

Preventive maintenance has been more popular in principle than in practice. It gets hard to argue with the idea of keeping equipment well maintained to extend its expected life and avoid future repair costs. Less clear is an understanding of the actual relationship between the cost of preventive maintenance and the returns such activities can be expected to deliver.

The following summarizes those respondents answering **'yes'** they were willing to pay more for the listed capital expenditures:

- 69% - Replacing aging equipment to improve safety and reliability
- 50% - Upgrading equipment to accommodate future growth in the community
- 45% - Adding automation and technology to reduce outage time
- 37% - Investing in technology to deal with cyber security issues

Quantifiable data from the telephone survey about paying more for capital items indicates:

- 14% respondents were willing to pay more for 1 item
- 20% willing to pay more for 2 items
- 41% willing to pay more for 3 or 4 items
- 25% were not willing to pay more for any items.

Operating Expenses

PUC Distribution has to focus on day-to-day operations while it builds, re-builds, re-furbishes and prepares the organization for a changed future. In addition, LDCs need to think in terms of decades, not just today, this week, this month, or this quarter. They need to do so in a regulated environment that is a 5 year planning environment. Respondents were asked to identify the items they were willing to pay more for and, they were asked "how much" they would be willing to pay.

Which of the following items are you willing to pay more for per month …

PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
A proactive outage management system	23%	74%	3%	23%	27%
Increased self-service options on the website	13%	85%	2%	13%	12%
Educating customers about energy conservation	23%	76%	1%	23%	22%

Base: total respondents

Quantifiable data from the telephone survey about paying more for operational items indicates:

- 18% respondents were willing to pay more for 1 item
- 12% willing to pay more for 2 items
- 6% willing to pay more for 3 items
- 64% were not willing to pay more for any items.

Elasticity in willingness to pay more per month

It is true; self-interest will drive the choices people make. If an operational or capital item directly affects the respondent, then there is a willingness to support paying more per month. This indicates there is a need to be clear about what customers get from any additional cost – especially for the 3 operational items surveyed.

PUC Distribution customers, given the responses are through the lens of costs, are worried about the impact of additional costs will have on them. It is not the amount of the investment i.e., millions of dollars that the LDC may invest, but rather the impact of that investment on the customer i.e., dollars per month. .

About 1 in 4 customer respondents indicated they do not support any increase for any capital expense which is in line with the UtilityPULSE database, however 2 out of 3 customers are not willing to support any of the 3 operational items is significantly higher than the UtilityPULSE database average of 24%.

Numbers at a Glance

	PUC Distribution	National	Ontario
Customer Satisfaction: Initial	82%	89%	84%
Customer Satisfaction: Post	80%	86%	76%
Overall Satisfaction with most recent experience	61%	72%	63%
Customer Experience Performance Rating (CEPr)	83%	82%	80%
Customer Centric Engagement Index (CCEI)	78%	78%	74%
Credibility & Trust Index	80%	80%	77%
UtilityPULSE Report Card©	B+	B+	B

While electricity industry insiders could agree there has been a tremendous amount of change in the past 10-15 years the reality is, there is no let-up in sight. Shifts in demographics and customer expectations coupled with dramatic changes in how & where electricity is generated, stored and distributed will add to the to the level of challenge everyone in the LDC face.

Marketing communications need to be comprised of simple language elements which demonstrate the LDC understands the concerns and worries of customers, and shows the LDC is doing meaningful work to address those concerns and worries. In times of disruption or uncertainty, higher levels of customer affinity are the result of a corporate culture where PUC Distribution people feel empowered to act and are focused on the results which matter to all stakeholders.

In a polarized world, LDCs must consistently communicate their values to customers. Customer affinity grows when LDCs show they understand the worries, concerns and issues customers face because of the current state of the electricity market. A communication strategy demonstrating congruency with customer values will help build the brand and reputation of the LDC.

As we look into the future, and recognizing the high degree of attention the electricity industry is getting, we recommend the LDC review its processes and standards around activities/projects – and the supporting marketing communications - which could have an impact on customer perceptions regarding the attributes of “easy to do business with”, “keeps its promises”, “pro-active communications”, “provides information to help customers reduce electricity costs”, “adapts well to changes in customer expectations”, “credibility & trust” and, “reliability”.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2017 customer satisfaction survey derived from speaking with 401 PUC Distribution customers [January 26 - February 24, 2017]. Thoughtful discussion turns data into information and insights which lead to benefits for all parties.

UtilityPULSE
Sid Ridgley
Simul/UtilityPULSE
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March 2017

Appendix D

OPA/IESO Comment Letter on DSP

IESO Letter of Comment

PUC Distribution Inc.

Renewable Energy Generation Plan

December 21, 2017

Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

PUC Distribution Inc. – Renewable Energy Generation Plan

On November 30, 2017, the IESO received the REG Plan ("Plan") of PUC Distribution Inc. ("PUC") as part of its 5-year (2018-2022) Distribution System Plan. The IESO has reviewed the Plan and provides the following comments.

OPA FIT/microFIT Applications Received

The Plan indicates that PUC currently has approximately 63 MW of REG connected to its distribution system, and that over the Plan period it is capable of connecting all of its anticipated REG projects forecast to be a total of 1.25 MW of additional capacity.

According to the IESO's information, as of November 30, 2017, the IESO has offered contracts to 107 microFIT projects, 9 FIT projects and 6 RESOP projects totalling approximately 62 MW of capacity, all of which have reached commercial operation. The difference in renewable energy generation connections information in PUC's Plan, compared to the IESO's information, is that PUC has an additional four Net Metering/Load Displacement projects that do not have contracts with the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

For regional planning purposes, the IESO notes that PUC is part of the East Lake Superior Region (Group 2).

Status of Regional Planning

As part of the OEB's Regional Planning Process the transmitter Great Lakes Power Transmission LP (now Hydro One Sault Ste. Marie) led the Needs Assessment Report for the region which was completed in 2014. The final report recommended that the issues identified in the area did not require further regional coordination. As a result of this recommendation, the IESO was not required to pursue the development of an Integrated Regional Resource Plan ("IRRP").

The IESO notes that PUC participated as part of the Needs Assessment study team along with Hydro One Networks Inc. (Transmission), the former Ontario Power Authority, the former IESO, Algoma Power Inc., and Chapleau Public Utilities Corporation.

With respect to REG investments, Section 4 of the Plan outlined the analysis done to conclude that over the Plan period, PUC's system shows no concerns caused by local or regional issues that should constrain additional growth of REG as projected. As a result, PUC has not included any associated infrastructure investment for the 2018-2022 period.

While the regional planning process for this area is now complete, it is expected to commence again in 2019 based on the OEB's 5-year cycle, unless there is an event that triggers the need for the process to begin earlier.

The IESO appreciates the opportunity to comment on the REG information provided by PUC Distribution Inc. as part of its 5-year Distribution System Plan.

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Appendix E

Regional Infrastructure Planning Report

NEEDS ASSESSMENT REPORT

East Lake Superior Region

Revision: FINAL R0
Date: December 12, 2014

Prepared by: East Lake Superior Region Study Team

DISCLAIMER

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

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

NEEDS ASSESSMENT SUMMARY REPORT

NEEDS ASSESSMENT SUMMARY REPORT			
NAME	East Lake Superior Region Study		
LEAD	Great Lakes Transmission LP (GLPT)		
REGION	East Lake Superior		
START DATE	October 12, 2014	**END DATE**	December 12, 2014

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the East Lake Superior Region (ELS-Region), determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary such needs will be addressed among the relevant Local Distribution Companies (LDCs), GLPT and other parties as required.

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

2. REGIONAL ISSUES/TRIGGER

The Needs Assessment for the East Lake Superior Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. East Lake Superior Region belongs to Group 2 and the Needs Assessment for this Region was triggered on October 12, 2014 and was completed on December 12, 2014.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023. Needs emerging over the near-term (0-5 years) and mid-term (6-10 years) should be further assessed as part of the OPA-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year plan and strategic direction for the Region.

The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans.

4. INPUTS/DATA (INFORMATION REQUIRED TO COMPLETE ASSESSMENT)

Study team participants, including representatives from Local Distribution Companies (LDC), the Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO) and Hydro One Networks Inc. (Hydro One) provided information and input to GLPT for the East Lake Superior Region. The information provided includes the following:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

5. ASSESSMENT

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

6. RESULTS

A. 230kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at the one 230kV connected load station throughout the study period. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

- Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

- East-West Tie lines are to be upgraded within the time period of this Needs Assessment. Hydro One's Customer Impact Assessment (CIA) entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customer in the area.

B. 230/115kV Autotransformers

- No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

C. 115kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

- Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the increased demand forecast from one large industrial customer in Sault Ste. Marie projecting an increase in peak. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

D. System Reliability, Operation and Restoration Review

- Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

- There is a concern about transformer failure in the region where there are some load stations with just one transformer supplying customer load. The Ontario Resource and Transmission Assessment Criteria (ORTAC) restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

E. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)

- Tarentorus TS (equipment & relaying)

7. RECOMMENDATION

The Team Recommends:

The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution continue to be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

The potential needs identified regarding the capacity of the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS do not require further regional coordination. The study team recommends that a "localized wire only solution be developed in the near-term to address the above need through planning between GLPT and the impacted customer.

The potential need identified for the restoration of load (ORTAC 8 hours violated) after a single supply transformer failure does not require further regional coordination. The study team recommends that a "localized" wire only solution be developed by GLPT and the impacted distributor.

PREPARED BY: East Lake Superior Region Study Team

PARTICIPANTS: LISTED BELOW

COMPANY	NAME
Great Lakes Power Transmission LP (Lead)	**Jim Tait**
Ontario Power Authority	**Bob Chow**
Independent Electricity System Operator	**Phillip Woo**
Hydro One Networks Inc. (Transmitter)	**Ajay Garg**
PUC Distribution Inc.	**Rob Harten**
Algoma Power Inc.	**Greg Beharriell**
Chapleau Public Utility Corporation	**Alan Morin**

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

1. INTRODUCTION

This Needs Assessment report identifies needs in the East Lake Superior Region ("ELS-Region"). For needs that require coordinated regional planning, the OPA will initiate the Scoping process to determine the appropriate regional planning approach. The approach can either be the OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP), which focuses on the development of "wires" solutions. It may also be determined that the needs can be addressed more directly through localized planning between the transmitter and the specific distributor(s) or transmission connected customer(s). The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements.

This report was prepared by the ELS-Region Needs Assessment study team (Table 1) and led by the transmitter, Great Lakes Power Transmission LP (GLPT). The report captures the results of the assessment based on information provided by the Local Distribution Companies (LDCs), Ontario Power Authority (OPA), Hydro One Network Inc. and the Independent Electricity System Operator (IESO) to determine possible needs in the ELS-Region.

Table 1: Study Team Participants for ELS-Region

Company
Great Lakes Power Transmission LP (GLPT) (Lead Transmitter)
Ontario Power Authority (OPA)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Hydro One) (Transmitter)
PUC Distribution Inc. (PUC)
Algoma Power Inc. (API)
Chapleau Public Utility Corporation (CPUC)

Figure 1: East Lake Superior Region

2. REGIONAL ISSUE / TRIGGER

The Needs Assessment for the ELS-Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. The ELS-Region belongs to Group 2. The Needs Assessment for this ELS-Region was triggered on October 12, 2014 and was completed on December 12, 2014.

Additional information about Regional Planning can be found on the GLPT website:
http://www.glp.ca/content/regional_planning_new/history-40236.html

3. SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the ELS-Region over an assessment period of 2014 to 2023. The scope of the Needs Assessment includes a review of system capability which covers transformer station loading and transmission thermal and voltage analysis based on recent detailed studies. Asset sustainment issues and other considerations were taken into account as deemed necessary.

3.1. EAST LAKE SUPERIOR REGION DESCRIPTION AND CONNECTION CONFIGURATION

Figure 2a – Wawa TS/Anjigami TS Northern Area – Hydro One 230/115 kV autotransformers at Wawa TS, Hydro One 115 kV circuit supplying CPUC load and GLPT 115 kV lines and stations connected via Anjigami TS.

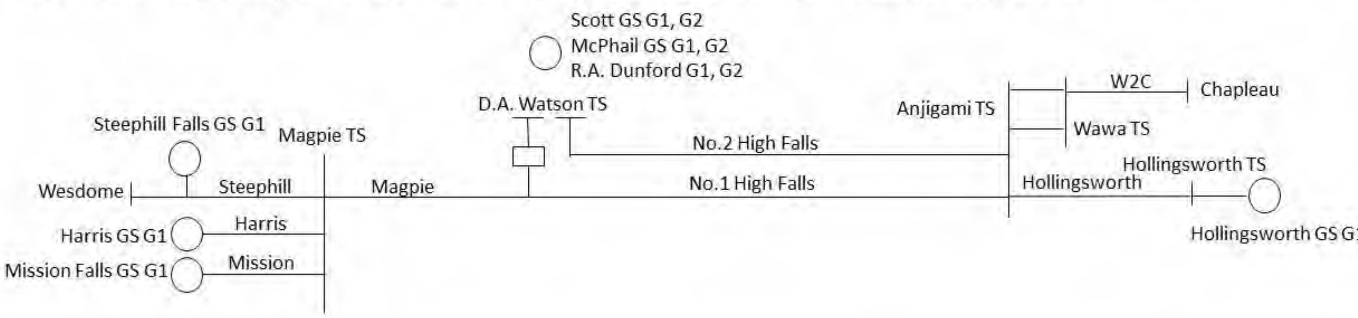


Figure 2b – MacKay TS South Central Area – GLPT 230/115 kV autotransformer at Mackay TS and 115 kV lines/stations connected via Mackay TS and two transformer stations connected to No.3 Sault.

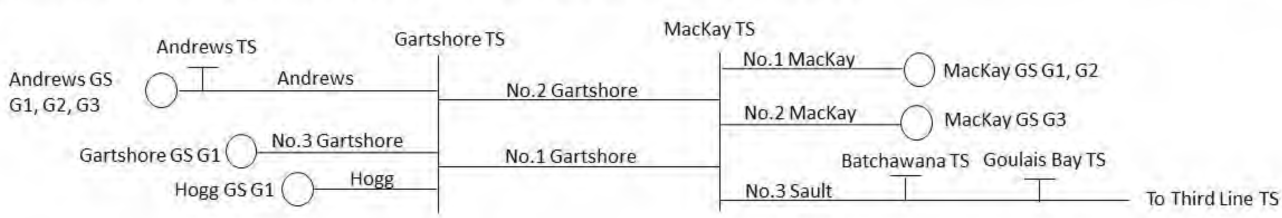


Figure 2c – Sault Ste. Marie Southern Area – GLPT 230/115 kV autotransformers at Third Line TS and 115 kV lines/stations in Sault Ste. Marie.

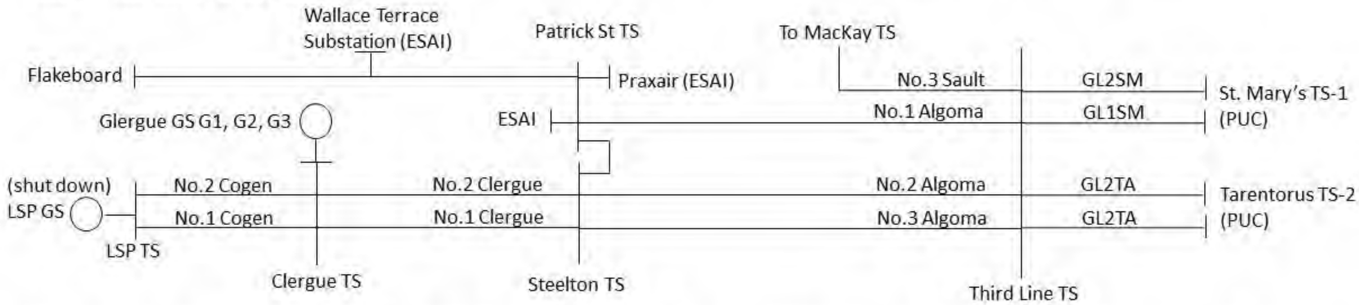
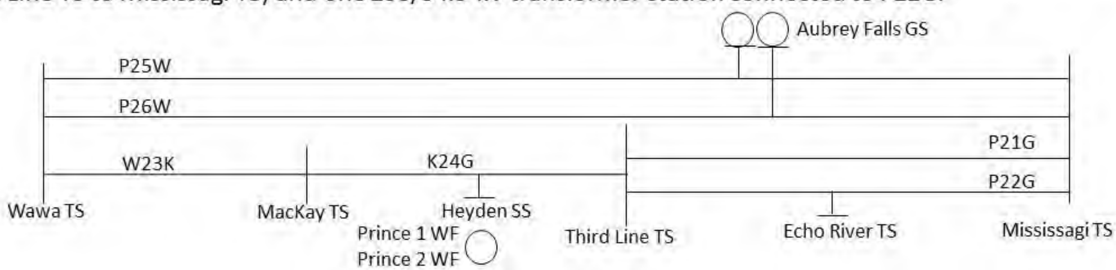


Figure 2d – GLPT and Hydro One 230 kV Eastern Area – Hydro One 230 kV lines P25W and P26W from Wawa TS to Mississagi TS, GLPT 230 kV lines W23K (Wawa TS to MacKay TS), K24G (MacKay TS to Third Line TS), P21G and P22G (Third Line TS to Mississagi TS) and one 230/34.5 kV transformer station connected to P22G.



4. INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to GLPT:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- GLPT provided transformer, station and line ratings
- Hydro One provided Wawa TS autotransformer ratings
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1. LOAD FORECAST

As per the data provided by the LDCs, the load in the ELS-Region is expected to grow at a rate varying from -0.1% to 2.5% plus some larger customer load increases.

Table 2: Annual Load Growth for ELS-Region

LDC	Approximate % Growth Rate 2013 to 2018	Approximate % Growth Rate 2019 to 2023
PUC	Slightly Negative	Slightly Negative
API	0.0 to 2.5%	0.0 to 2.5%
CPUC	0%	0%

Large Industrial Customer Load Increases	Approximate MW Increase 2013 to 2018	Approximate MW Increase 2019 to 2023
Sault Ste. Marie Southern Area	19.4	3.2
Wawa TS/Anjigami TS Northern Area	20.85	0

The Needs Assessment considered gross loads at individual stations based on the 2013 summer or winter peak non-coincident load and the peak summer or winter load forecast for stations within the Region. The station load forecast was developed by using data provided by the LDC's load forecasts and other customer load forecasts.

5. ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Assessment:

1. The Region is winter peaking, but this assessment includes both summer and winter peak loads where one is more critical than the other due to equipment ratings.

2. Forecast loads are provided by the LDCs and other customers.

3. Stations having negative load growth over the study period are assumed to have steady load.

4. In developing a worst-case scenario, DG and CDM contributions were not considered.

5. Review and assess impact of any on-going or planned development project in the ELS-Region during the study period.

6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables and stations.

7. Station capacity adequacy is assessed assuming a 90% lagging power factor on the HV and non-coincident station loads.

8. Transmission line adequacy to be assessed using non-coincident peak station loads in the region.

9. The needs were first identified by looking at the total normal supply capacity (TNSC) of the elements that supply a specific LDC or other customer compared to the three month average peak over the last 5 years and the peak load over the last five years. This was used to identify any planning issues based on the existing peak loads. The 2023 peak load was then compared to the TNSC and if peak loads were greater than 75% of the TNSC for specific station/line(s), these station/line(s) were identified for further study. The TNSC takes into consideration one element out of service where load is not supplied via a single line/station.

10. Transmission adequacy assessment is primarily based on:

    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their continuous ratings and transformers within their summer 10-Day limited time ratings (LTR) if there are two transformers and 10 day LTR's exist.
    - All voltages and voltage declines must be within pre- and post-contingency ranges as per ORTAC criteria.

11. The ELS-Region has a considerable amount of hydro generation connected to the 115 kV system and wind generation connected to the 230 k system. Two new wind farms are in the process of connecting to the Gartshore 115 kV lines (58.3 MW) and K24G 230 kV lines (25.3 MW). Both have had recent detailed IESO System Impact Assessments (SIA) and GLPT Customer Impact Assessments (CIA) completed which did not identify concern in the area regarding overload of facilities. Generation in the area is generally more critical to line overload than LDC and other customer load. These studies were reviewed as part of this Needs Assessment process.

12. For the Sault Ste. Marie Southern section of the ELS-Region, the 98% dependability of generation from Clergue GS was used in this assessment. Glergue GS dependable generation was assumed to be 10 MW. This is based on an IESO Feasibility Study (Confidential) undertaken to assess the Algoma lines for adequate capacity.

This Needs Assessment was conducted to identify emerging needs and determine whether or not further coordinated regional planning should be undertaken for the Region or electrical areas. It is expected that further studies in the subsequent regional planning process will undertake detailed analysis and also assess ORTAC performance requirements.

6. RESULTS

6.1. Transmission Capacity Needs

6.1.1. 230kV Connection Facilities

Based on the demand forecast, there is sufficient capacity throughout the study period at Echo River TS which is a 230kV connected load station. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

East-West Tie lines are to be upgraded in 2019. Hydro One's CIA entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customers in the area. The Hydro One CIA assessed the Short-Circuit Impact, Voltage Impact and Supply Reliability Impact.

6.1.2. 230/115kV Autotransformers

No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

6.1.3. 115kV Connection Facilities

Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the demand forecast from one of the other customer in Sault Ste. Marie projecting an increase in peak load. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

6.2. System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

There is a concern about transformer failure in the region where there are many load stations with just one transformer supplying customer load. The ORTAC restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

6.3. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)
- Tarentorus TS (equipment & relaying)

6.4. Other Considerations

Restoration of most of the GLPT transmission system can be accomplished from a black start procedure which energizes the Sault Ste. Marie Southern Area load/generation and eventually up to MacKay TS South Central Area to load/generation and run as an island. It is expected that for the loss of Wawa TS T1 and T2 transformers and by configuration the Wawa TS/Anjigami TS Northern Area, the delay in restoration of GLPT connected load/generation can be greater than the ORTAC standard of 8 hours. There is a need to study if this area could be operated as an island until the supply from Hydro One Wawa TS can be restored.

7. RECOMMENDATIONS

The study Team Recommends:

7.1. The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

7.2. The potential needs identified for the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS does not require further regional coordination. The study team recommends that a “localized” wire only solution be developed by GLPT and the impacted customer.

7.3. The potential need identified for the restoration of load after a single supply transformer failure which could violate the ORTAC criteria of restoring load within 8 hours does not require further regional coordination. The study team recommends that GLPT and the impacted distributor continue to work on this need.

8. NEXT STEPS

Following the Needs Assessment process, the next regional planning step, based on the results of this report, are:

8.1. GLPT and the relevant LDC’s are to further assess and/or develop local wires solution as identified in the needs outlined in Section 7.1 and 7.3.

8.2. GLPT and the relevant customers will further assess and/or develop local wires solution as identified in the needs outlined in Section 7.2.

9. REFERENCES

Planning Process Working Group (PPWG) Report to the Board

IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

IESO Feasibility Study (Confidential) for Algoma Lines Redevelopment

IESO System Impact Assessment (SIA) Report and Addendum Report for Bow Lake Wind Farm (CAA ID#: 2010-392)

IESO System Impact Assessment Report and Addendum Report for Goulais Wind Farm (CAA ID#: 2010-397)

GLPT Customer Impact Assessment (CIA) Report for RTK Canada, ULC (Rentech) increased 44 kV load dated April 23, 2014.

Customer Impact Assessment (CIA) Report for Hydro One New East-West Tie Project dated October 29, 2014.

10. KEY TERMS AND DEFINITIONS

Key terms and definitions associated with this Needs Assessment are cited here.

Normal Supply Capacity (NSC): The maximum loading that electrical equipment may be subjected to continuously under nominal ambient conditions such that no accelerated loss of equipment life would be expected.
Coincident Peak Load: The electricity demand at individual facilities at the same specific point in time when the total demand of the region or system is at its maximum.

Contingency: The prevalence of abnormal conditions such that elements of the power system are not available.

Conservation and Demand Management (CDM): Programs aimed at using more of one type of energy efficiently to replace an inefficient use of another to reduce overall energy use, and influencing the amount or timing of customers' use of electricity.

Distributed Generation (DG): Electric power generation equipment that supplies energy to nearby customers with generation capacity typically ranging from a few kW to 25 MW.

Gross Load: Amount of electricity that must be generated to meet all customers' needs as well as delivery losses, not considering any generation initiatives such as CDM and DG. It is usually expressed in MW or MVA.

Limited Time Rating (LTR): A higher than nameplate rating that a transformer can tolerate for a short period of time

Load Forecast: Prediction of the load or demand customers will make on the electricity system

Net Load: Net of generation (e.g. CDM and DG) deducted from the Gross load

Non-Coincident Peak Load: The maximum electricity demand at an individual facility. Unlike the coincident peak, non-coincident peaks may occur at different times for different facilities.

Peak Load: The maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.

Total Normal Supply Capacity (TNSC): The maximum loading that electrical equipment may be subjected to post contingency (n-1) under nominal ambient conditions such that an acceptable accelerated loss of equipment life would be expected. For a single element supply system the TNSC equals the NSC.

11. ACRONYMS

CDM Conservation and Demand Management

CIA Customer Impact Assessment

DG Distributed Generation

DSC Distribution System Code

IESO Independent Electricity System Operator

IRRP Integrated Regional Resource Planning

kV Kilovolt

LDC Local Distribution Company

LTR Limited Time Rating

LV Low-voltage

MVA Mega Volt-Ampere

MW Megawatt

NA Needs Assessment

NSC Normal Supply Capacity

OEB Ontario Energy Board

OPA Ontario Power Authority

ORTAC Ontario Resource and Transmission Assessment Criteria

PF Power Factor

PPWG Planning Process Working Group

RIP Regional Infrastructure Planning

SIA System Impact Assessment

SS Switching Station

TNSC Total Normal Supply Capacity

TS Transformer Station

TSC Transmission System Code

PUC SERVICES INC.
500 SECOND LINE EAST, P.O. Box 9000
SAULT STE. MARIE, ONTARIO, P6A 6P2

September 29, 2014

Great Lakes Power Transmission LP
Transmission System Planning
Asset Management and Engineering Dept.
2 Sackville Rd., Suite B
Sault Ste. Marie, ON
P6B 6J6

Attn: Jim Tait
Technical Supervisor Engineering

Cc: Claudio Stefano, V.P Operations & Engineering (PUC)

**Re: OEB Regional Infrastructure Planning (RIP) Process
Information for Needs Screening Process**

Dear Mr Tait,

We are providing the following submission in response to your letter dated 2014/08/12 in which you request information to support the needs screening portion of the Regional Infrastructure Planning process. In that letter you request:

1. Gross and Net Load forecast for the next 10years, provided on the following basis:
   a. In megawatts ("MW") with power factor assumptions provided;
   b. At the supply Transformer station or delivery point
2. Regional system reliability and performance issues.
3. Any additional information considered relevant.

Historical and Forecast loading is summarized in the attached spreadsheet which was completed on the standard Load Forecast Template file provided by GLPT. Supporting information is also included to substantiate our assumptions. This information consists of:

PUC DISTRIBUTION INC. • PUC SERVICES INC. • PUBLIC UTILITIES COMMISSION
Tel. (705) 759-6500 www.ssmpuc.com

- Conservation demand management information in form of email from CDM Officer dated 2014/09/19, entitled ‘2011-2013 CDM Demand Savings’
- Metering data extracted from wholesale metering points in the form of a spreadsheed, filename ‘0509.6 OEB RIP2014-09-25 load Forecast.xlsx’

In general terms, based on the forecast, we do not see any near term needs for a change in capacity of the 115kV transmission assets connecting our LDC to your transmission system. Loads are generally trending moderately in the negative direction in winter and moderately in the positive direction in the summer. Since the winter load is significantly larger than the summer load, the overall trend for the period of the forecast is in the negative direction.

We wish to point out that our demand forecast excludes the contribution of any distribution system connected distributed generation. As you are aware, we presently have a significant solar contribution of approximately 62MW to our distribution system. This generation results in near zero or net export conditions during their peak producing summer months when our system is near its minimum load. The generation was connected as part of the OPA RESOP and FIT programs. Because of its significant degree of penetration, distributed generation may be material to the RIP process.

Furthermore, with respect to distributed generation, there continues to be a strong interest in developing green energy in our community and this is being pursued on a number of municipal and private interests. We expect this will continue and may lead to requests to connect additional significant projects in the near to long term future (3 to 10 years).

One final topic we wish to draw your attention to is the age of our four 115kV lines and the two 115kV/34.5kV stations that connect us with GLPT. This infrastructure was installed about 40 years ago in the 1970s. Although we believe the transmission lines have several decades of serviceable life left, it is our belief that the two stations will require a major upgrade within 5 to 15 years. Although we currently do not have a specific asset management plan in place for these assets, we do intend to develop one in 2014.

We trust this submission meets all of the current requirements of the RIP process and look forward to working with you on this matter. Should you require anything further please direct your inquiries to my attention.

Best Regards,

Rob Harten, P. Eng.
Manager of Engineering

Load Forecast Template

Customer Name: Sault Ste Marie PUC
Region Name: East Lake Superior

Notes:

1	Enter data for the transformer stations supplying your LDC and if there is a missing transformer station please add it to the current list
2	For LDCs directly connected to the transmission facilities, load forecasts should factor in the load forecasts of any embedded distributor. Include a list of all embedded distributors
3	For LDCs that are embedded in another distributor's system, DO NOT include your embedded load in forecasts submitted to the transmitter; instead, submit the embedded load forecasts to the host distributor for inclusion in their submission to the transmitter.
4	Provide coincident load forecast aggregated for all your feeders at the Station Level.
5	For Historical Data, LDCs are to provide the Net Load, i.e. Gross Peak Load minus any EXISTING Conservation & Demand Management (CDM) and Distributed Generation (DG), available during the time of peak demand.
6	For Forecasted Data, LDCs are to only provide the Gross Peak Load (which is the Forecasted Load from their Historical Net Load). OPA will provide Forecasted DG and CDM.
7	Provide load forecast in MWs and include power factor assumptions, if any.
8	List all assumptions made in preparing this load forecast.

		Peak Load (Net = Gross - DG - CDM)													
TS Name or DP	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					Power Factor
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
Tarentorus T.S. (TS2)	Gross Peak Load				37.1	37.1	37.1	37.0	37.0	37.0	37.0	37.0	36.9	36.9	0.967
GL1TA(non-coincident)	Net Load	21.1	37.1	0.1											
Tarentorus T.S. (TS2)	Gross Peak Load				51.7	51.6	51.6	51.6	51.5	51.5	51.5	51.5	52.1	51.4	0.967
GL2TA(non-coincident)	Net Load	48.1	24.0	51.7											
St. Mary's T.S. (TS1)	Gross Peak Load				52.4	52.3	52.3	52.3	52.2	52.2	52.2	52.2	52.1	52.1	0.967
GL1SM(non-coincident)	Net Load	41.3	34.9	52.4											
St. Mary's T.S. (TS1)	Gross Peak Load				60.5	60.5	60.5	60.4	60.4	60.4	60.3	60.3	60.3	60.2	0.967
GL2SM(non-coincident)	Net Load	39.3	36.2	35.1											
Total PUC	Gross Peak Load				139.3	139.2	139.2	139.1	139.1	139.0	139.0	138.9	138.8	138.8	0.967
(coincident peak)	Net Load	149.9	132.2	139.2											0.967

LDC Assumptions:

1) Assumed that Generation and CDM are accounted for in Net Load Forecast of the Historical Data.
2) Assumed that the full benefit of Generation and CDM are active during peak loads.
3) Peeks for individual circuits are NOT coincident peaks with system peak; they are case by case worst case peaks for the individual feeders in a given year based on the maximum feeder load for the period 2011-2013
4) As it is unknown to PUC as to how power factor relates to load, a power factor based on the average historical value has been assumed for the forecast

From: Brooke Suurna
To: Rob Harten; Claudio Stefano
Subject: 2011-2013 CDM Demand Savings
Date: Friday, September 19, 2014 10:50:42 AM
Attachments: image003.jpg

I was originally going to provide quarterly data for 2011-2013 however upon review of the data I don't believe the quarterly numbers from the OPA are accurate because they were changed as subsequent quarterly reports were released. The only numbers I am 100% confident in are the final annual results released by the OPA.

Year	Demand Savings (MW)
2011	0.7
2012	0.8
2013	1.1

Please let me know if you require anything further

Brooke Suurna, P.Eng
Conservation & Demand Management Officer
PUC Services Inc.
500 Second Line E., P.O. Box 9000
Sault Ste Marie, ON P6A 6P2
Phone: 705.759.3314
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Email: brooke.suurna@ssmpuc.com

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Forecast Calculations

System Total Peak Load

	Year	Net Peak Load	Gross Peak Load
Actual	2007 Actual	139,708	139,708
	2008 Actual	139,124	139,124
	2009 Actual	147,108	147,108
	2010 Actual	141,244	141,244
	2011 Actual	149,857	149,952
	2012 Actual	132,164	132,154
	2013 Actual	139,248	139,361
Projected	2014	139,171	139,303
	2015	139,095	139,245
	2016	139,018	139,187
	2017	138,942	139,129
	2018	138,865	139,072
	2019	138,789	139,014
	2020	138,713	138,956
	2021	138,637	138,899
	2022	138,560	138,841
	2023	138,484	138,784

Feeder Peak Loads (Non-Coincident Net)

	Year	Net Peak Load (MW) GL1TA	Net Peak Load (MW) GL2TA	Net Peak Load (MW) GL1SM	Net Peak Load (MW) GL2SM
Actual	Maximum of Calendar Years 2011 - 2013	37.12	51.68	52.39	60.57
Projected	2014	37.10	51.65	52.36	60.54
	2015	37.08	51.62	52.34	60.50
	2016	37.06	51.60	52.31	60.47
	2017	37.04	51.57	52.28	60.44
	2018	37.02	51.54	52.25	60.40
	2019	37.00	51.51	52.22	60.37
	2020	36.98	51.48	52.19	60.34
	2021	36.96	51.45	52.16	60.31
	2022	36.94	51.43	52.13	60.27
	2023	36.92	51.40	52.11	60.24

Growth Rate

Year	Rate (Net)	Rate (Gross)
2007 - 2008	0.9958	0.9958
2008 - 2009	1.0574	1.0574
2009 - 2010	0.9601	0.9601
2010 - 2011	1.0610	1.0617
2011 - 2012	0.8819	0.8813
2012 - 2013	1.0536	1.0545
Geomean	0.9995	0.9996

Notes: growth rate was used to calculate project growth

Total System Electric Loading History

	Energy 2001 kWh	Energy 2002 kWh	Energy 2003 kWh	Energy 2004 kWh	Energy 2005 kWh	Energy 2006 kWh	Energy 2007 kWh	Energy 2008 kWh	Energy 2009 kWh
YTD Totals	718,680,760	744,156,060	755,126,020	757,685,852	749,219,032	728,093,333	738,093,576	740,966,488	732,869,986
January	78,253,278	75,783,700	85,049,952	89,226,840	88,287,600	76,234,176	78,292,016	79,006,867	85,774,977
February	71,056,718	69,010,564	76,788,076	73,066,340	71,065,788	71,202,696	75,583,244	75,126,906	71,566,146
March	70,086,644	73,544,560	75,545,096	71,196,888	73,186,104	70,367,240	71,668,468	74,573,962	72,767,317
April	58,715,640	61,508,916	63,274,204	61,357,220	56,446,820	56,652,640	60,506,916	58,751,936	59,966,274
May	50,799,464	56,801,704	52,784,032	55,571,152	53,664,344	52,446,572	51,273,936	53,931,566	52,676,063
June	49,362,308	50,055,824	49,325,848	49,366,380	51,111,168	49,917,449	50,644,216	48,466,639	49,196,439
July	49,714,844	53,526,780	51,148,508	51,210,208	53,387,012	53,606,640	51,622,068	50,725,083	48,238,905
August	51,535,500	51,335,848	50,113,412	50,192,756	52,102,684	51,038,392	51,764,316	50,225,177	49,652,791
September	48,974,448	50,111,652	49,728,476	50,272,804	49,504,120	49,455,772	48,836,864	48,690,797	48,812,970
October	56,653,116	57,639,776	58,883,124	57,641,764	55,381,484	58,920,568	54,192,940	56,073,866	57,724,020
November	61,414,444	67,404,840	66,040,876	64,887,008	65,851,664	63,979,576	65,729,492	63,785,625	59,532,749
December	72,114,356	77,431,896	76,444,416	83,696,492	79,230,244	74,271,612	77,979,100	81,608,064	76,961,335
3-month total	150,612,652	154,918,452	150,587,768	150,769,344	156,600,864	154,562,481	154,030,600	149,416,898	147,088,135
Summer Average	50,204,217	51,639,484	50,195,923	50,256,448	52,200,288	51,520,827	51,343,533	49,805,633	49,029,378

	2010			2011			2012			2013			2014		
	Wholesale Meter Energy 2010 kWh	Distributed Gen Energy 2010 kWh	Total System Energy 2010 kWh	Wholesale Meter Energy 2011 kWh	Distributed Gen Energy 2011 kWh	Total System Energy 2011 kWh	Wholesale Meter Energy 2012 kWh	Distributed Gen Energy 2012 kWh	Total System Energy 2012 kWh	Wholesale Meter Energy 2013 kWh	Distributed Gen Energy 2013 kWh	Total System Energy 2013 kWh	Wholesale Meter Energy 2014 kWh	Distributed Gen Energy 2014 kWh	Total System Energy 2014 kWh
YTD Totals	710,857,306	2,305,988	713,163,294	693,045,100	36,883,588	729,928,688	635,223,994	78,072,955	713,296,949	659,215,628	70,879,868	730,095,496	359,501,319	35,392,364	394,893,683
January	79,854,697	0	79,854,697	82,648,728	685,685	83,334,413	75,554,837	830,876	76,385,713	76,231,996	1,215,534	77,447,531	83,292,308	784,023	84,076,331
February	68,437,902	0	68,437,902	70,439,804	1,633,071	72,072,875	64,040,984	3,779,719	67,820,704	68,219,789	1,575,061	69,794,850	70,305,579	2,977,471	73,283,050
March	63,113,132	0	63,113,132	68,440,898	3,244,798	71,685,695	58,334,633	5,542,828	63,877,461	62,222,455	7,041,704	69,264,159	69,150,658	6,785,778	75,936,435
April	53,088,771	0	53,088,771	57,001,677	3,031,773	60,033,450	47,033,398	9,901,424	56,934,822	56,115,257	6,375,267	62,490,524	54,009,639	6,936,289	60,945,928
May	51,130,272	0	51,130,272	48,309,149	3,345,715	51,654,863	41,538,463	10,563,057	52,101,520	42,336,726	8,924,016	51,260,742	45,055,529	8,072,055	53,127,584
June	47,896,130	0	47,896,130	44,474,216	3,325,220	47,799,435	40,321,370	10,262,554	50,583,924	38,741,499	9,504,552	48,246,051	37,687,605	9,836,750	47,524,355
July	53,062,397	0	53,062,397	49,476,613	4,002,802	53,479,415	44,339,537	11,305,974	55,645,511	42,744,917	9,501,815	52,246,732			0
August	53,165,646	0	53,165,646	48,089,241	4,651,619	52,740,860	41,430,538	9,785,385	51,215,923	40,863,333	10,239,998	51,103,331			0
September	48,475,869	0	48,475,869	44,365,173	6,150,436	50,515,609	40,740,588	7,746,529	48,487,116	39,805,113	8,252,743	48,057,856			0
October	53,271,933	806,084	54,078,017	50,577,506	2,624,178	53,201,684	50,702,525	4,734,240	55,436,765	49,039,469	5,154,603	54,194,072			0
November	61,524,030	1,105,052	62,629,082	58,264,120	2,342,368	60,606,488	59,933,496	2,488,914	62,422,410	62,214,471	2,461,092	64,675,563			0
December	77,836,527	394,852	78,231,379	70,957,977	1,845,923	72,803,900	71,253,625	1,131,456	72,385,081	80,680,603	633,483	81,314,086			0
3-month total	154,124,173	0	154,124,173	142,040,069	11,979,641	154,019,710	126,091,445	31,353,913	157,445,358	122,349,749	29,246,365	151,596,114	37,687,605	9,836,750	47,524,355
Summer Average	51,374,724	0	51,374,724	47,346,690	3,993,214	51,339,903	42,030,482	10,451,304	52,481,786	40,783,250	9,748,788	50,532,038	12,562,535	3,278,917	15,841,452

	Demand 2001 kW	Demand 2002 kW	Demand 2003 kW	Demand 2004 kW	Demand 2005 kW	Demand 2006 kW	Demand 2007 kW	Demand 2008 kW	Demand 2009 kW
January	136,152	133,624	147,064	150,828	156,336	137,316	137,364	139,124	147,108
February	128,524	132,204	142,840	133,168	132,028	131,504	139,708	137,099	140,994
March	122,084	129,004	143,188	121,748	132,728	121,328	138,956	126,361	134,710
April	104,040	110,624	118,652	108,156	99,876	110,744	120,464	113,370	109,073
May	88,452	102,020	89,152	103,988	98,032	95,184	90,156	93,108	91,475
June	91,560	91,424	97,240	90,496	96,532	88,948	100,876	86,634	97,507
July	95,032	98,244	91,376	90,784	100,440	99,704	100,184	91,419	82,098
August	96,272	91,912	89,224	89,708	98,928	94,792	101,464	92,154	92,161
September	94,488	97,104	91,968	92,732	96,484	87,132	94,760	95,412	90,184
October	101,716	106,588	107,616	100,520	95,520	104,856	93,000	101,744	102,250
November	125,460	126,200	120,924	120,900	136,364	119,060	133,912	119,819	111,244
December	130,692	137,444	134,140	159,136	141,964	134,212	135,708	144,796	134,470
System Winter Peak	147,690	133,624	147,064	150,828	159,136	141,964	139,708	139,124	147,108
Peak Month	December' 2000	January' 2002	January' 2003	January' 2004	December' 2004	December' 2005	February' 2007	January'2008	January'2009

	Wholesale Meter Demand 2010 kW	Adjusted for DG Demand 2010 kW		Wholesale Meter Demand 2011 kW	Adjusted for DG Demand 2011 kW		Wholesale Meter Demand 2012 kW	Adjusted for DG Demand 2012 kW		Wholesale Meter Demand 2013 kW	Adjusted for DG Demand 2013 kW		Wholesale Meter Demand 2014 kW	Adjusted for DG Demand 2014 kW	
January	141,244			149,857	149,857		132,090	132,154		138,936	138,936		143,061	143,172	
February	129,450			136,294	136,294		115,178	126,117		129,404	129,440		139,986	140,075	
March	109,694			124,344	124,344		117,881	118,115		115,636	115,710		135,918	135,983	
April	97,996			104,965	107,493		49,908	98,975	49.6%	111,773	111,959	0.2%	106,629	106,738	0.1%
May	97,193			90,361	92,646		36,736	94,353	61.1%	90,856	93,804		88,990	89,101	
June	87,013			94,306	94,306		52,482	104,308	49.7%	59,677	95,568	38%	59,003	87,494	33%
July	96,868			95,135	100,702		50,311	104,552		78,335	104,736				
August	101,492			88,991	97,338		69,686	92,694		64,298	99,844				
September	93,047			89,277	97,824		66,742	92,013		89,768	90,949				
October	96,934	96,934		94,283	94,370		102,667	102,702		98,465	98,465				
November	123,865	123,865		112,491	112,491		118,381	118,527		124,726	124,838				
December	141,147	141,147		128,372	128,372		122,761	122,935		139,248	139,361				
System Winter Peak	141,244				149,857			132,154							
Peak Month	January'2010				January'2011			January'2012							

Note: Winter is defined as December of the previous year to February of the current year

	LF 2001	LF 2002	LF 2003	LF 2004	LF 2005	LF 2006	LF 2007	LF 2008	LF 2009	LF 2010	LF 2011
January	77.3%	76.2%	77.7%	79.5%	75.9%	74.6%	76.6%	76.3%	78.4%	76.0%	74.1%
February	82.3%	77.7%	80.0%	78.8%	80.1%	80.6%	80.5%	78.7%	72.9%	76.0%	74.3%
March	77.2%	76.6%	70.9%	78.6%	74.1%	78.0%	69.3%	79.3%	72.6%	77.3%	74.0%
April	78.4%	77.2%	74.1%	78.8%	78.5%	71.1%	69.8%	72.0%	76.4%	75.2%	75.4%
May	77.2%	74.8%	79.6%	71.8%	73.6%	74.1%	76.4%	77.9%	77.4%	70.7%	71.9%
June	74.9%	76.0%	70.5%	75.8%	73.5%	77.9%	69.7%	77.7%	70.1%	76.5%	65.5%
July	70.3%	73.2%	75.2%	75.8%	71.4%	72.3%	69.3%	74.6%	79.0%	73.6%	69.9%
August	72.0%	75.1%	75.5%	75.2%	70.8%	72.4%	68.6%	73.3%	72.4%	70.4%	72.6%
September	72.0%	71.7%	75.1%	75.3%	71.3%	78.8%	71.6%	70.9%	75.2%	72.4%	69.0%
October	74.9%	72.7%	73.5%	77.1%	77.9%	75.5%	78.3%	74.1%	75.9%	73.9%	72.1%
November	68.0%	74.2%	75.9%	74.5%	67.1%	74.6%	68.2%	73.9%	74.3%	69.0%	71.9%
December	74.2%	75.7%	76.6%	70.7%	75.0%	74.4%	77.2%	75.8%	76.9%	74.1%	74.3%

Total System Electric Loading

	2011			2012			2013		
	Wholesale Meter Energy 2011 kWh	Distributed Gen Energy 2011 kWh	Total System Energy 2011 kWh	Wholesale Meter Energy 2012 kWh	Distributed Gen Energy 2012 kWh	Total System Energy 2012 kWh	Wholesale Meter Energy 2013 kWh	Distributed Gen Energy 2013 kWh	Total System Energy 2013 kWh
YTD Totals	693,045,100	36,883,588	729,928,688	635,223,994	78,072,955	713,296,949	659,215,628	70,879,868	730,095,496
January	82,648,728	685,685	83,334,413	75,554,837	830,876	76,385,713	76,231,996	1,215,534	77,447,531
February	70,439,804	1,633,071	72,072,875	64,040,984	3,779,719	67,820,704	68,219,789	1,575,061	69,794,850
March	68,440,898	3,244,798	71,685,695	58,334,633	5,542,828	63,877,461	62,222,455	7,041,704	69,264,159
April	57,001,677	3,031,773	60,033,450	47,033,398	9,901,424	56,934,822	56,115,257	6,375,267	62,490,524
May	48,309,149	3,345,715	51,654,863	41,538,463	10,563,057	52,101,520	42,336,726	8,924,016	51,260,742
June	44,474,216	3,325,220	47,799,435	40,321,370	10,262,554	50,583,924	38,741,499	9,504,552	48,246,051
July	49,476,613	4,002,802	53,479,415	44,339,537	11,305,974	55,645,511	42,744,917	9,501,815	52,246,732
August	48,089,241	4,651,619	52,740,860	41,430,538	9,785,385	51,215,923	40,863,333	10,239,998	51,103,331
September	44,365,173	6,150,436	50,515,609	40,740,588	7,746,529	48,487,116	39,805,113	8,252,743	48,057,856
October	50,577,506	2,624,178	53,201,684	50,702,525	4,734,240	55,436,765	49,039,469	5,154,603	54,194,072
November	58,264,120	2,342,368	60,606,488	59,933,496	2,488,914	62,422,410	62,214,471	2,461,092	64,675,563
December	70,957,977	1,845,923	72,803,900	71,253,625	1,131,456	72,385,081	80,680,603	633,483	81,314,086
3-month total	142,040,069	11,979,641	154,019,710	126,091,445	31,353,913	157,445,358	122,349,749	29,246,365	151,596,114
Summer Average	47,346,690	3,993,214	51,339,903	42,030,482	10,451,304	52,481,786	40,783,250	9,748,788	50,532,038

	Wholesale Meter Demand 2011 kW	Adjusted for DG Demand 2011 kW		Wholesale Meter Demand 2012 kW	Adjusted for DG Demand 2012 kW		Wholesale Meter Demand 2013 kW	Adjusted for DG Demand 2013 kW	
January	149,857	149,857		132,090	132,154		138,936	138,936	
February	136,294	136,294		115,178	126,117		129,404	129,440	
March	124,344	124,344		117,881	118,115		115,636	115,710	
April	104,965	107,493		49,908	98,975	49.6%	111,773	111,959	0.2%
May	90,361	92,646		36,736	94,353	61.1%	90,856	93,804	
June	94,306	94,306		52,482	104,308	49.7%	59,677	95,568	38%
July	95,135	100,702		50,311	104,552		78,335	104,736	
August	88,991	97,338		69,686	92,694		64,298	99,844	
September	89,277	97,824		66,742	92,013		89,768	90,949	
October	94,283	94,370		102,667	102,702		98,465	98,465	
November	112,491	112,491		118,381	118,527		124,726	124,838	
December	128,372	128,372		122,761	122,935		139,248	139,361	

System Winter Peak
Peak Month

2011	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	23-Jan-11	19	149,952	0.966	21079.1	48127.5	41337.4	39313.2	95	149857.2
February	9-Feb-11	19	136,345	0.996	15227.3	43511.1	38978.6	38577.2	51	136294.2
March	2-Mar-11	20	124,406	0.968	15474	39853.4	33384.8	35631.3	63	124343.5
April	17-Apr-11	16	107,694	0.968	13923.5	31958.1	31615.5	27467.5	2,730	104964.6
May	3-May-11	17	92,850	0.966	35558.2	26713.2	0	27540	3,039	89811.4
June	7-Jun-11	21	94,493	0.938	33735.2	0	0	60571.1	187	94306.3
July	18-Jul-11	17	100,702	0.945	23159.7	18832.3	0	47599.5	11,111	89591.5
August	5-Aug-11	16	97,338	0.899	0	15454.6	16255.1	47806.3	17,822	79516
September	12-Sep-11	16	97,824	0.908	0	18184.1	25314.4	26833.1	27,492	70331.6
October	17-Oct-11	19	94,480	0.965	10996.5	32506.1	25727	25053	197	94282.6
November	21-Nov-11	18	112,692	0.973	23848.1	35231.3	19989	33422.9	201	112491.3
December	28-Dec-11	19	128,565	0.973	24425.1	40660.8	23866.2	39420.3	192	128372.4

2012	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	19-Jan-12	20	132,154	0.968	37119.5	23950.6	34856.7	36237.6	(10)	132164.4
February	11-Feb-12	11	126,117	0.969	9823.6	34053.6	39068.5	32232.5	10,939	115178.2
March	5-Mar-12	9	118,115	0.973	12352	34383.2	40389.2	30756.8	234	117881.2
April	17-Apr-12	12	98,975	0.877	0	7267.6	17853	24787.8	49,066	49908.4
May	10-May-12	14	94,353	0.571	0	0	5547.3	31188.5	57,617	36735.8
June	11-Jun-12	13	104,308	0.76	0	13435.1	11544.8	27501.8	51,826	52481.7
July	4-Jul-12	13	104,552	0.757	0	7427	13106.8	29777.6	54,241	50311.4
August	30-Aug-12	16	92,694	0.899	3566.8	19500.8	6814.5	40207.8	22,604	70089.9
September	4-Sep-12	17	92,013	0.902	3146.9	28714.4	34798.8	81.5	25,271	66741.6
October	30-Oct-12	19	102,702	0.969	10245.5	29446.6	35513.3	27461.1	35	102666.5
November	30-Nov-12	18	118,527	0.969	20618.6	37103.4	31972.7	28686.5	145	118381.2
December	11-Dec-12	18	122,935	0.97	21169.4	38407	33611.1	29573.1	174	122760.6

2013	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	22-Jan-13	20	138,936	0.971	13846.8	41386.6	48307	35395.9	-	138936.3
February	6-Feb-13	20	129,440	0.972	13212.6	41578.7	36942.7	37669.7	37	129403.7
March	3-Mar-13	20	115,710	0.97	9391.7	39529.5	36944.1	29770.2	75	115635.5
April	2-Apr-13	20	111,959	0.973	11613	29754.6	38519.7	31885.6	186	111772.9
May	12-May-13	11	93,804	0.971	24895	7788.3	30606.5	27566.1	2,948	90855.9
June	26-Jun-13	16	95,568	0.865	43	21043.1	19149.9	20658.4	34,673	60894.4
July	17-Jul-13	16	105,070	0.89	0	23950.5	22783.8	31601	26,735	78335.3
August	29-Aug-13	16	100,086	0.869	1064.9	19540.3	24308.3	19729.4	35,443	64642.9
September	10-Sep-13	17	91,012	0.945	19524.1	18962.7	31934.2	19346.9	1,244	89767.9
October	29-Oct-13	19	98,633	0.998	71.8	35553.7	37925.5	24913.7	168	98464.7
November	24-Nov-13	18	124,838	0.972	13351.1	35814.5	44595.7	30964.4	112	124725.7
December	14-Dec-13	18	139,361	0.967	69.7	51681.6	52393.5	35103	113	139247.8

	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
Maximum Value over three year period 2011-2013	37119.5	51681.6	52393.5	60571.1	57616.74	149857.2

Appendix F

OEB Score Card Performance Measures

Scorecard - PUC Distribution Inc.

Performance Outcomes	Performance Categories	Measures		2009	2010	2011	2012	2013	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		98.20%	96.70%	97.80%	95.80%	96.50%	↓	90.00%	
		Scheduled Appointments Met On Time		96.10%	92.40%	97.20%	98.40%	97.10%	↑	90.00%	
		Telephone Calls Answered On Time		65.10%	70.10%	76.70%	74.60%	80.90%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution									
		Billing Accuracy									
		Customer Satisfaction Survey Results									
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Public Safety [measure to be determined]									
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		2.14	2.11	2.92	1.65	2.48	↑		at least within 1.65 - 2.92
		Average Number of Times that Power to a Customer is Interrupted		2.97	2.83	3.61	2.17	2.67	↓		at least within 2.17 - 3.61
	Asset Management	Distribution System Plan Implementation Progress									
	Cost Control	Efficiency Assessment					3	4			
		Total Cost per Customer [1]		$456	$485	$513	$615	$687			
		Total Cost per Km of Line [1]		$20,445	$21,729	$22,981	$27,523	$30,950			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Annual Peak Demand Savings (Percent of target achieved) [2]				12.00%	14.00%	19.20%			5.58MW
		Net Cumulative Energy Savings (Percent of target achieved)				35.00%	61.00%	87.20%			30.83GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	66.67%					
		New Micro-embedded Generation Facilities Connected On Time						100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.38	1.39	1.43	1.19	1.06			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.52	1.53	1.44	2.01	1.99			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)			8.57%	8.57%	8.98%			
			Achieved			8.16%	4.99%	7.00%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings do not include any persisting peak demand savings from the previous years.

Legend:
- up
- down
- flat
- target met
- target not met

Scorecard - PUC Distribution Inc.

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		96.70%	97.80%	95.80%	96.50%	93.00%	down	90.00%	
		Scheduled Appointments Met On Time		92.40%	97.20%	98.40%	97.10%	95.40%	up	90.00%	
		Telephone Calls Answered On Time		70.10%	76.70%	74.60%	80.90%	81.90%	up	65.00%	
	Customer Satisfaction	First Contact Resolution						99.89%			
		Billing Accuracy						99.83%	flat	98.00%	
		Customer Satisfaction Survey Results						In progess			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	NI	NI	C	C	up		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	3	1	3	up (target not met)		1
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.407	0.135	0.405	up (target not met)		0.132
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		2.11	2.92	1.65	2.48	1.19	down		at least within 1.65 - 2.92
		Average Number of Times that Power to a Customer is Interrupted		2.83	3.61	2.17	2.67	1.21	down		at least within 2.17 - 3.61
	Asset Management	Distribution System Plan Implementation Progress						In progress			
	Cost Control	Efficiency Assessment				3	4	4			
		Total Cost per Customer [1]		$485	$513	$615	$687	$664			
		Total Cost per Km of Line [1]		$21,729	$22,981	$27,523	$30,950	$29,886			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			11.19%	24.67%	43.55%	59.52%	target not met		5.58MW
		Net Cumulative Energy Savings (Percent of target achieved)			35.22%	60.88%	87.17%	99.06%	target not met		30.83GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	66.67%						
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.39	1.43	1.19	1.06	1.68			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.53	1.44	2.01	1.99	2.42			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.57%	8.57%	8.98%	8.98%			
			Achieved		8.16%	4.99%	7.00%	5.47%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: up, down, flat, target met, target not met

Appendix A – 2014 Scorecard Management Discussion and Analysis ("2014 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2014 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

For the year 2014, PUC Distribution exceeded prescribed targets for most scorecard measures. In particular, system reliability performance for the year 2014 was the best achieved since 1999. This notable improvement in reliability is primarily the result of ongoing efforts related to replacing aging or defective infrastructure and improved vegetation management.

For 2014, average interruption duration (SAIDI) decreased 52% compared to 2013, while average interruption frequency (SAIFI) decreased 55%. Moving forward, PUC Distribution plans to continue efforts aimed at improving reliability for its customers thereby delivering greater value for the service provided to them.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2014, PUC Distribution connected 213 eligible low-voltage residential and small business customers (connections under 750 volts) to its system, 93% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is a 3.5% decrease from the previous year but still above the OEB-mandated target of 90%. PUC Distribution is undergoing process reviews for the purpose of identifying any potential areas of improvement and to continue to ensure that the New Service performance measures are exceeded.

- **Scheduled Appointments Met On Time**

  In 2014, PUC Distribution scheduled 1,466 appointments with customers to complete customer requested work (e.g. meter re-reads, reconnections, meter locates, etc.). Although a slight decrease from 2013, PUC Distribution met 95.4% of these appointments on time, which exceeds the OEB-mandated target of 90%.

- **Telephone Calls Answered On Time**

In 2014, PUC Distribution's Customer Care Department received 39,681 calls from its customers – that's over 159 calls per working day. Of those calls, a Customer Care Representative answered the call in 30 seconds or less, 81.90% of the time. This result significantly exceeds the OEB-mandated 65% target for timely call response. The 2014 result amounts to a 1% improvement over 2013, driven primarily by a reduction in the number of calls, due primarily to fewer outages in 2014. Also, the reduction in call volume can, in part, be attributed to the introduction of automated emergency messaging employed during large scale power outages. Additionally, the shift towards email as the communication medium of choice for customers has also contributed to the reduction.

Customer Satisfaction

Specific customer satisfaction measurements have not been previously defined across the industry. The OEB has instructed all electricity distributors to review and develop measurements in these areas and begin tracking by July 1, 2014 so that information can be reported in 2015. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each distributor may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

- **First Contact Resolution**

  First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

  PUC Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Supervisor/Manager and a Senior Customer Care Representative. This was done by creating two specific call types in our Customer Information System (CIS) which could then be queried to provide the number of customer concerns which were escalated.

  To establish the number of calls which were handled without escalation, the CIS was queried based on the associated call types to arrive at the number of customer calls handled by the Customer Care Team.

  To determine the number of repeat calls for the same issue, a review of the escalated calls was conducted on the premise that if the call reached the Senior Customer Care level the concern would not have been satisfactorily resolved at the time of first contact.

- **Billing Accuracy**

  Until July 2014 a specific measurement of billing accuracy had not been previously defined across the industry. After consultation with some electricity distributors, the OEB has prescribed a measurement of billing accuracy which must be used by all distributors effective October 1, 2014. For the period from October 1, 2014 – December 31, 2014 PUC Distribution issued more than 100,000 bills and achieved a billing accuracy of 99.83%. This compares favorably to the prescribed OEB target of 98%.

PUC Distribution continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

The OEB introduced the Customer Satisfaction Survey Results measure beginning in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year. At this time the OEB is allowing distributors discretion as to how they implement this measure.

PUC engaged a third party to conduct the customer satisfaction survey. The survey was conducted in April 2015 and completed in June 2015, therefore, survey results along with the mangement discussion will published on the 2015 Scorecard.

Safety

- **Public Safety**

The OEB introduced the Safety Measure in 2015. This measure looks at safety from a customer's point of view as safety of the distribution system is a high priority. The Safety measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04 and the Serious Electrical Incident Index.

  - **Component A – Public Awareness of Electrical Safety**

    This Component of the public safety measure does not have performance data for the 2014 scorecard as the public awareness of electrical safety survey was not required to be conducted in the subject year. 2016 will be the first year that data for this measure will be reported on the scorecard for the 2015 results.

- **Component B – Compliance with Ontario Regulation 22/04**

  Component B is comprised of: the External Audit, the Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All these elements are evaluated as a whole and determine the status of compliance. Over the past two years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety and adherence to company policies and procedures. Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, and specifications and the inspection of construction to ensure there are no undue hazards before they are put in service.

- **Component C – Serious Electrical Incident Index**

  PUC Distribution reported three (3) serious electrical incidents involving members of the public in 2014. There were no injuries associated with these incidents. A detailed analysis of the data and root cause evidence has helped steer PUC Distribution's efforts to increase public awareness in an effort to eliminate future incidents. PUC Distribution offers electrical safety awareness outreach via newspaper and radio ads, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  Average duration of outages for the year 2014 demonstrated a marked improvement compared to 2013. In fact, 2014 system reliability was the best achieved since 1999. The notable improvement in reliability is due primarily to ongoing efforts related to replacing aging or defective infrastructure and improved vegetation management. Continued improvement is anticipated moving forward.

  Average interruption duration for 2014 decreased 52% compared to 2013.

- **Average Number of Times that Power to a Customer is Interrupted**

  Average frequency of outages for the year 2014 also demonstrated a marked improvement compared to 2013. Average interruption frequency for 2014 decreased 55% compared to 2013.

Asset Management

- **Distribution System Plan Implementation Progress**

All distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. Accordingly, PUC Distribution plans to file an application with the OEB for a full review of its rates effective May 1, 2017, which will include a complete DSP.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings.

Group	Demarcation Points for Relative Cost Performance	% of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	8
2	Actual costs are 10% to 25% below predicted costs	20
3	Actual costs are within +/-10% of predicted costs	47
4	Actual costs are 10% to 25% above predicted costs	18
5	Actual costs are 25% or more above predicted costs	7

In 2014, as in 2013, PUC Distribution was placed in Group 4, where a Group 4 distributor is defined as having actual costs between 10% and 25% of predicted costs under the PEG model. Group 3 is considered "average efficiency".

PUC Distribution's efficiency performance improved from 22.7% in 2013 to 14.6% in 2014.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves. The cost performance result for 2014 is $664/customer which is a 3.4 % decrease over 2013.

Overall, the company's Total Cost per Customer has increased on average by 7.3% per annum over the period 2010 through 2014. Similar to most distributors in the province, PUC Distribution has experienced increases in its total costs required to deliver quality and reliable services to customers. Province-wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in new information systems technology and the renewal of the distribution system, have all contributed to increased operating and capital costs.

PUC Distribution will continue to replace distribution assets proactively in a manner that balances system risks and customer rate impacts. PUC Distribution's capital and operating programs will be further defined in its 2017 rate application to be filed in 2016. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2015 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. PUC Distribution's 2014 rate is $29,886 per Km of line, a 3.4% decrease over 2013.

PUC Distribution has experienced a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased since 2010 with the increase in capital and operating costs.

Conservation & Demand Management

- **Net Annual Peak Demand Savings (Percent of target achieved)**

PUC Distribution achieved 59.52% of its 2011-2014 Peak Demand target of 5.58 MW. It was a challenge to meet the peak demand target due to the fact PUC Distribution is a winter peaking utility. PUC Distribution was pleased with its efforts as peak demand savings results aligned fairly well with the provincial average.

- **Net Cumulative Energy Savings (Percent of target achieved)**

PUC Distribution achieved 99.06% of its 2011-2014 net cumulative energy savings target of 30.83 GWh. Much of this success can be attributed to the successful promotion of energy efficiency programs and strong participation by commercial customers in the Retrofit and Small Business Lighting Programs. PUC Distribution looks forward to promoting energy efficiency programs and assisting its customers in saving money and conserving energy throughout the new 2015-2020 Conservation First Framework.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. For the year 2010 one CIA request was received and processed within the prescribed timelines.

In 2011 three requests were received. Two were processed within the prescribed timelines and the progress of the third was not adequately documented so it could not be determined whether it was or was not completed on time. To minimize the likelihood of similar future reporting anomalies, refinements have been made to our CIA application processes and process documents.

No requests for CIAs were received for the years 2012 through 2014.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2014, PUC Distribution connected seven new micro-embedded generation facilities (microFIT projects of less than 10 kW) 100% of time within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time.

Our process to connect these projects is very streamlined and transparent for our customers. PUC Distribution works closely with its customers and their contractors to address any connection issues and ensure projects are connected in a timely manner.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  PUC Distribution's current ratio increased from 1.06 in 2013 to 1.68 in 2014 as a result of long term borrowing that was completed late in 2014. PUC Distribution's current ratio in subsequent years is expected to be in line with 2014 results.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

  PUC Distribution has a debt to equity structure of 71% to 29% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2014 debt to equity ratio of 2.42. PUC Distribution's long range plan is to push the debt to equity towards the deemed 60% to 40%.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review by the OEB of the distributor's revenues and costs structure.

- **Profitability: Regulatory Return on Equity – Achieved**

  PUC Distribution's return on equity in 2014 at 5.47% was more than 3% lower than the expected return of 8.98%. The variance in return on equity is the result of the company's OM&A expenses in 2014 being approximately $1.1 million higher than included in the approved 2013 cost of service rate application.

Note to Readers of 2014 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Scorecard - PUC Distribution Inc.

9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		97.80%	95.80%	96.50%	93.00%	97.20%	↓	90.00%	
		Scheduled Appointments Met On Time		97.20%	98.40%	97.10%	95.40%	97.40%	↓	90.00%	
		Telephone Calls Answered On Time		76.70%	74.60%	80.90%	81.90%	82.30%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution					99.89%	99.92%			
		Billing Accuracy					99.83%	99.36%	↓	98.00%	
		Customer Satisfaction Survey Results					In progess	79%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						86.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	C	C	C	↑		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	3	1	3	1	→		1
			Rate per 10, 100, 1000 km of line	0.000	0.407	0.135	0.405	0.134	→		0.151
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.92	1.65	2.48	1.19	3.35	↑		2.07
		Average Number of Times that Power to a Customer is Interrupted [2]		3.61	2.17	2.67	1.21	1.84	↓		2.50
	Asset Management	Distribution System Plan Implementation Progress					In progress	In Progress			
	Cost Control	Efficiency Assessment			3	4	4	4			
		Total Cost per Customer [3]		$513	$615	$687	$664	$699			
		Total Cost per Km of Line [3]		$22,981	$27,523	$30,950	$29,886	$31,377			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]						17.18%			26.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		66.67%				0.00%			
		New Micro-embedded Generation Facilities Connected On Time				100.00%	100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.43	1.19	1.06	1.68	0.90			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.44	2.01	1.99	2.42	2.31			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.57%	8.57%	8.98%	8.98%	8.98%			
			Achieved	8.16%	4.99%	7.00%	5.47%	4.46%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend:
5-year trend: ↑ up ↓ down → flat
Current year: target met, target not met

Appendix A – 2015 Scorecard Management Discussion and Analysis ("2015 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2015 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

For the year 2015, PUC Distribution met or exceeded all prescribed targets for scorecard measures except one, the outage duration index, SAIDI. This metric was significantly impacted by a late-year winter storm that hit Sault Ste. Marie and surrounding area in the early morning hours of December 24th. With wind gusts up to 90 kph, many trees came down onto PUC distribution lines interrupting power to approximately 10,000 customers for varying time durations. PUC Distribution crews worked extensive hours late into the day on Christmas Eve to restore all affected customers in time for their Christmas Eve dinners. We are very grateful to our staff for their extensive efforts in responding to this demanding weather event and we extend our praise for the excellent work they did in restoring service to all our customers as quickly as possible.

One particular area of performance where PUC Distribution is especially proud of is in the area of safety, both in regards to the general public and in the area of our workers. Of the 36 LDC's that participated in the 2015 electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%. Our efforts in awareness education for elementary school students and the use of general safety promotions through the various media venues play an important part in this achievement.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2015, PUC Distribution connected 144 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, 97.20% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is an improvement of 4.2 percentage points over 2014 and exceeds the OEB mandated target of 90%. PUC Distribution remains committed to a process of continuous improvement to ensure performance targets are not only met, but exceeded.

- **Scheduled Appointments Met On Time**

  In 2015, PUC Distribution scheduled 1,240 appointments with customers to complete customer requested work (e.g. meter installs or removals, service disconnects or reconnects, and meter locates). As a result of our continuous improvement efforts, PUC Distribution met 97.40% of scheduled appointments, an improvement over 2014 by 2 percentage points, and exceeded the OEB target of 90%.

- **Telephone Calls Answered On Time**

  In 2015, PUC Distribution's Customer Care Department received 38,874 calls from customers. Our Customer Care Representatives answered those calls in 30 seconds or less, 82.30% of the time. This result significantly exceeds the OEB mandated target of 65%. The five year trend has shown continuous improvement for this performance measure in part due to a concerted effort to proactively communicate with our customers. Additionally, the PUC Distribution website is being used more effectively.

Customer Satisfaction

- **First Contact Resolution**

  For 2015, PUC Distribution handled 99.92% of calls without escalating the calls to a; Senior Customer Care Representative, Supervisor, or Manager. However, it's important to note that First Contact Resolution can be measured in a variety of ways, and further regulatory guidance is necessary in order to achieve a meaningful statistic that is comparable across electricity distributors.

  First Contact Resolution was determined by creating two specific call types in our Customer Information System (CIS) which could then be queried to provide the number of customer concerns which were escalated. To establish the number of calls which were handled without escalation, the CIS was queried based on the associated call types to arrive at the total number of customer calls handled by the Customer Care Team.

  To determine the number of repeat calls for the same issue, a review of the escalated calls was conducted on the premise that if the call reached the Senior Customer Care level the concern would not have been satisfactorily resolved at the time of first contact.

- **Billing Accuracy**

  PUC Distribution issued approximately 400,000 bills for the period from January 1, 2015 – December 31, 2015 and achieved an accuracy of 99.36%. This exceeds the prescribed OEB target of 98%. PUC Distribution continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  PUC Distribution engaged the UtilityPulse Division of Simul Corporation to conduct our 2015 customer satisfaction survey. The UtilityPulse Electric Utility Survey is in its 17th year of annual surveys and is used by a significant number of Ontario distributors. The final report on our customer satisfaction survey was received in June and PUC Distribution received a customer satisfaction score of

79% (post survey result). The survey asked customers questions on a wide range of topics, including: overall satisfaction with reliability, customer service, outages, billing and corporate image. These customer satisfaction surveys provide information that supports discussions surrounding improving customer service at all levels and departments within PUC Distribution.

Safety

- **Public Safety**

  The OEB introduced the Safety Measure in 2015. This measure looks at safety from a customer's point of view as safety of the distribution system is a high priority. The Safety Measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04 and the Serious Electrical Incident Index.

  - **Component A – Public Awareness of Electrical Safety**

    In 2015, PUC Distribution participated in a public electrical safety awareness survey. A representative sample of PUC Distribution's service territory population was surveyed to gauge the public's awareness level of key electrical safety concepts related to distribution assets (the survey was based on a template provided by the Electrical Safety Authority). Of the 36 LDC's that participated in the electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness, and identify opportunities where additional education and outreach may be required.

    With several major public safety awareness events held in 2015, PUC Distribution's commitment to education and public safety was highlighted once again. Below are the electrical safety initiatives PUC Distribution participated in over the last year:

    - Elementary School Electrical Safety Program for Grade 3 – 5 within our geographic service territory (24 schools involving 1,863 students and their teachers participated)
    - Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
    - Sault Ste. Marie Science Festival (approx. 500 adults and children participated)
    - Sault Ste. Marie PUC website – Safety tab
    - Advertisements in the geographic service territory consists of: newspaper and radio ads

  - **Component B – Compliance with Ontario Regulation 22/04**

    Component B is comprised of; an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and

Compliance Investigations. All these elements are evaluated as a whole to determine the status of compliance. Over the past three years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety and continued adherence to company policies and procedures.

Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of; equipment, plans, and specifications, and the inspection of construction to ensure there are no undue hazards before installations are put in service.

- **Component C – Serious Electrical Incident Index**

  For 2015, PUC Distribution was below the serious electrical incident target rate of 0.151 incidents per kilometer. PUC Distribution reported one (1) serious electrical incident involving members of the public last year, which is a decrease in the quantity (3) of incidents reported during the previous year. Fortunately, there were no injuries associated with this incident. In following up on this incident, PUC Distribution reached out to the ESA to offer assistance in educating first responders with respect to electrical safety. Additionally, PUC Distribution continues to increase public awareness in an effort to eliminate future incidents. PUC Distribution offers electrical safety awareness outreach via; newspaper and radio, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  The System Average Interruption Duration Index (SAIDI) of 3.35 in 2015 was higher than the target of 2.07. Outage performance for 2015 was significantly impacted by a severe windstorm that hit the Sault Ste. Marie area early on December 24, 2015. The events of that one day accounted for 42% of the outage duration performance for the entire year.

  Excluding the windstorm, SAIDI would have been 1.94. There are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**

  The System Average Interruption Frequency Index (SAIFI) of 1.84 in 2015 was lower than the target of 2.50. Consistent with SAIDI, outage performance for the year was significantly impacted by a severe windstorm that hit the Sault Ste. Marie area on December 24, 2015. The events of that one day accounted for 31% of the outage frequency performance for the entire year. Excluding the windstorm, SAIFI would have been 1.27.

Asset Management

- **Distribution System Plan Implementation Progress**

  All Distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. We expect that implementation of this standardized approach will re-inforce our existing commitment to long term planning and sustainable asset management. PUC Distribution is presently engaged in reviewing, updating, and migrating its Asset Management Plan into the creation of an integrated DSP which will meet all OEB requirements. Accordingly, PUC Distribution plans to file an application with the OEB in 2017 which will include a complete DSP.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings for 2015.

Group	Demarcation Points for Relative Cost Performance	% of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	8
2	Actual costs are 10% to 25% below predicted costs	20
3	Actual costs are within +/-10% of predicted costs	51
4	Actual costs are 10% to 25% above predicted costs	15
5	Actual costs are 25% or more above predicted costs	6

In 2015, for the third year in a row, PUC Distribution was placed in Group 4. Group 3 is considered "average efficiency".

PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 16.2% in 2015 compared to 14.6% in 2014.

- **Total Cost per Customer**

  Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves. The cost performance result for 2015 is $699 per customer which is a 5.3 % increase over 2014.

  Overall, the company's Total Cost per Customer has increased on average by 7.3% per annum over the period 2011 through 2015. Similar to most distributors in the province, PUC Distribution has experienced increases in its total costs required to deliver quality and reliable services to customers. Province-wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in new information systems technology and the renewal of the distribution system, have all contributed to increased operating and capital costs.

  PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. PUC Distribution's capital and operating programs will be further defined in its 2018 rate application to be filed in 2017 The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2015 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. PUC Distribution's 2015 rate is $31,377 per Km of line, a 5.0% increase over 2014.

  PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased since 2011 with the increase in capital and operating costs.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

  2015 was a transition year from the previous framework to the new Conservation First Framework. This framework will continue until 2020 with a new MWh target. This transition year allowed LDC's to close out projects from the previous framework and submit new projects under the new framework.

PUC Distribution worked diligently with businesses and channel partners to complete all outstanding projects in addition to updating the changes in rules and submission process for the new framework. As a result of this work, the final net savings for 2015 was 4,538 MWh, slightly better than double our target for the year, and giving us a head start going forward to 2020.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for the project from the Electrical Safety Authority. For the year 2015, one CIA request was received and processed, however, not within the prescribed timelines. PUC Distribution has adjusted its established process for Generator CIAs to address this issue going forward. .

- **New Micro-embedded Generation Facilities Connected On Time**

  In 2015, PUC Distribution connected six new micro-embedded generation facilities (microFIT projects of less than 10 kW). For those projects, 100% were connected within the prescribed timeframe of five business days. The minimum acceptable performance level for this measure is 90%. PUC Distribution achieved this metric by working closely with our customers and their contractors to ensure the connection process for these types of projects are as streamlined and transparent as possible.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  PUC Distribution's current ratio decreased from 1.68 in 2014 to 0.90 in 2015. A construction loan of $15M which was in current liabilities was converted to a long term loan in 2016 as planned. The result of this is a reduction of current liabilities of $15M which would increase the current ratio to 2.19.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2015 debt to equity ratio of 2.31. PUC Distribution's long range plan is to push the debt to equity towards the 60/40 level.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

  PUC Distribution's return on equity in 2015 at 4.46% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2015 being approximately $1.3 million higher than included in the approved 2013 cost of service rate application.

Note to Readers of 2015 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Scorecard - PUC Distribution Inc.

9/11/2017

Performance Outcomes	Performance Categories	Measures	2012	2013	2014	2015	2016	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time	95.80%	96.50%	93.00%	97.20%	98.90%		90.00%	
		Scheduled Appointments Met On Time	98.40%	97.10%	95.40%	97.40%	98.30%		90.00%	
		Telephone Calls Answered On Time	74.60%	80.90%	81.90%	82.30%	81.30%		65.00%	
	Customer Satisfaction	First Contact Resolution			99.89%	99.92%	99.58%			
		Billing Accuracy			99.83%	99.36%	99.97%		98.00%	
		Customer Satisfaction Survey Results			In progess	79%	80%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness				86.00%	86.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]	NI	C	C	C	C			C
		Serious Electrical Incident Index: Number of General Public Incidents	3	1	3	1	0			1
		Serious Electrical Incident Index: Rate per 10, 100, 1000 km of line	0.407	0.135	0.405	0.134	0.000			0.151
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]	1.65	1.42	1.19	1.37	1.49			1.86
		Average Number of Times that Power to a Customer is Interrupted [2]	2.17	1.78	1.21	1.03	1.41			2.32
	Asset Management	Distribution System Plan Implementation Progress			In progress	In Progress	In progress			
	Cost Control	Efficiency Assessment	3	4	4	4	4			
		Total Cost per Customer [3]	$615	$687	$664	$699	$695			
		Total Cost per Km of Line [3]	$27,523	$30,950	$29,886	$31,377	$31,314			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]				17.18%	52.97%			26.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time				0.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%			90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)	1.19	1.06	1.68	0.90	1.52			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	2.01	1.99	2.42	2.31	2.34			
		Profitability: Regulatory Return on Equity: Deemed (included in rates)	8.57%	8.98%	8.98%	8.98%	8.98%			
		Profitability: Regulatory Return on Equity: Achieved	4.99%	7.00%	5.47%	4.46%	0.98%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:

5-year trend: up, down, flat

Current year: target met, target not met

Appendix A – 2016 Scorecard Management Discussion and Analysis ("2016 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2016 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2016 PUC Distribution Inc. (PUC) met or exceeded all prescribed targets for scorecard measures. PUC continued with strong performance in the Customer Focus, Operational Effectiveness and Public Policy Responsiveness areas of our scorecard. This has generally been reflected in good customer satisfaction survey measure results.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2016, PUC Distribution connected 349 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, 98.90% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is a 1.7% increase from the previous year and exceeds the OEB mandated target of 90%. The improved performance over 2015 can be partly attributed to a reduction in capital works projects which allowed additional resources to focus on low volume connections. PUC Distribution has demonstrated our commitment to continuous improvement through staff education to ensure customer satisfaction is a top priority.

- **Scheduled Appointments Met On Time**
  In 2016, PUC Distribution scheduled 1,468 appointments with customers to complete customer requested work (e.g. meter installs/removals, service disconnects/reconnects, and meter locates). As a result of our emphasis on customer satisfaction, PUC was able to meet 98.30% of scheduled appointments on time, which exceeds the OEB target of 90%.

- **Telephone Calls Answered On Time**
  In 2016, PUC Distribution's Customer Care Department received 40,787 calls from its customers. This represents an increase in call volume of approximately 1,900 calls from 2015, due in part, to the utility switching to automated reminder calls for past due accounts.

Of the 40,787 calls, a Customer Care Representative answered the call within 30 seconds or less, 81.30% of the time. This result significantly exceeds the OEB mandated 65% target for timely call response.

Customer Satisfaction

- **First Contact Resolution**
  PUC Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Senior Customer Care Representative or Supervisor/Manager. This was accomplished by creating two specific call types in our Customer Information System (CIS) which would then be queried to provide the number of customer concerns which were escalated.

  In 2016, PUC had 40,787 calls, of which, 171 contacts were escalated to a higher level of management. This resulted in a First Contact Resolution percentage of 99.58%.

  To establish the number of calls which were handled without escalation, the total number of calls which were escalated to a higher level of management was subtracted from the total number of calls received. However, it should be noted that First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

- **Billing Accuracy**
  PUC issued approximately 395,000 bills for the period from January 1, 2016 – December 31, 2016, and achieved an accuracy of 99.97%. This score compares favourably to the prescribed OEB target of 98%. PUC continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**
  PUC Distribution engaged the UtilityPulse Division of Simul Corporation to conduct our 2016 customer satisfaction survey. The UtilityPulse Electric Utility Survey is in its 19th year of annual surveys and is used by a significant number of Ontario distributors. The final report on our customer satisfaction survey was received in March 2017, and PUC Distribution received a B+ customer satisfaction score of 80% (post survey result) which is above the Ontario benchmark survey that had a grade of "B".

  The raw score had a slight increase from our last survey of 79%. The survey asked customers questions on a broad range of topics, including overall satisfaction with reliability, customer service, outages, billing and corporate image. These customer satisfaction surveys are an important element in our overall customer engagement strategy providing further insight towards planning and supporting customer service improvement at all levels within PUC Distribution.

Public Safety

The Public Safety measure was introduced by the OEB in 2015 and focuses on the safety of the distribution system from a customer's point of view. The Electrical Safety Authority (ESA) provides an assessment as it pertains to Component B – Compliance with Ontario Regulation 22/04 and Component C – Serious Electrical Incident Index.

- **Component A – Public Awareness of Electrical Safety.**

  A representative sample of PUC Distribution's service territory population was surveyed in late 2015 to gauge the public's awareness level of key electrical safety concepts related to distribution assets. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness, and identify opportunities where additional education and outreach may be required. The results of the survey were analyzed in 2016, a number of opportunities to improve our existing outreach programs were identified and an action plan was developed.

  One item of note from the survey results indicated that more emphasis was required to ensure public awareness of Ontario One Call. In an effort to improve this metric, PUC approved a budget in 2016 (for 2017) to purchase promotional Dig Safe decals for the entire operations fleet, and through participation with the Association of Electrical Utility Professionals (AEUSP) has contributed to the production of a series of Electricity Safety videos for television broadcast in our service area. (Expected for 2017)

  PUC Distribution continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Below are examples of PUC Distribution's public safety communication initiatives in 2016:

  - Elementary School Electrical Safety Program for Grade 3 – 5 within our geographic service territory. Participation included 24 schools. (73 classes, and 1,874 students)
  - Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
  - Sault Ste. Marie Science Festival (approx. 500 adults and children attended)
  - Sault Ste. Marie PUC website – Safety tab with particular activities aimed at educating young people on electrical safety
  - Advertisements in the geographic service territory consists of newspaper and radio ads

- **Component B – Compliance with Ontario Regulation 22/04**

  Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the Regulation requires the approval of equipment, plans, and specifications and the inspection of construction to ensure there are no undue hazards before they are put in service.

  Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and Compliance Investigations. ESA evaluates all these elements as a whole to determine the status of compliance. In each of the past four years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). PUC attributes this continued success to our strong commitment to safety, and adherence to company policies and procedures.

- **Component C – Serious Electrical Incident Index**

  Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. For the 2016 reporting period, PUC Distribution did not experience any serious electrical incidents.

  To increase public safety awareness, PUC Distribution offers electrical safety awareness outreach via; newspapers, radio, public events, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

A key change for 2016, as required by the OEB, is the revised reporting of reliability data with respect to Major Events. Specifically the change serves to adjust the reliability data to remove the impact of Major Events. Additionally, distributors are required to report criteria to monitor the distributor's performance related to the Major Event.

The 2016 Scorecard system reliability data, excludes both Loss of Supply and Major Events. The adjusted reliability measures capture interruptions caused by circumstances within the distributor's control and are published in the 2016 scorecard.

A "Major Event" is defined as an event that is beyond the control of the distributor and is; unforeseeable, unpredictable, unpreventable, or unavoidable. Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, take significantly longer than usual to repair, and affect a substantial number of customers.

In 2016 there were two major event days. The first happened on March 6 (foreign interference) and the second on June 20 (adverse weather).

- **Average Number of Hours that Power to a Customer is Interrupted**
  The System Average Interruption Duration Index (SAIDI) of 1.49 in 2016 was below the target of 1.86. There are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**
  The System Average Interruption Frequency Index (SAIFI) of 1.41 in 2016 was substantially below the target of 2.32. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

Asset Management

- **Distribution System Plan Implementation Progress**
  Although PUC has employed distribution system planning for several years, the OEB instituted a mandatory requirement for this activity to be practised provincially, along with associated performance measures, beginning in 2013. We expect that implementation of this standardised approach will allow us to strengthen our commitment to responsible long term planning and sustainable asset management and to align our objectives with those of the of the OEB ultimately maximising benefit to our ratepayers.

  All distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. PUC is presently engaged in migrating and expanding upon its existing distribution system planning to create a formal DSP that meets all OEB requirements. The new DSP will be accompanied by performance measures and once completed will be filed with PUC’s next OEB rate application to be filed in 2017.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings for 2016:

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	14
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	32
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	13
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

In 2016, for the fourth year in a row, PUC Distribution was placed in Group 4. PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 14% in 2016 compared to 16.2% in 2015.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves.

The cost performance result for 2016 is $695 per customer which is a 0.57 % decrease over 2015. Overall, the company's Total Cost per Customer has increased on average by 3.26% per annum over the period 2012 through 2016. For the period of 2013 to 2016, the Total Cost per Customer has increased by approximately 0.40% per year.

PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. PUC Distribution's capital and operating programs will be further defined in its 2018 rate application to be filed in 2017. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2016 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution’s capital spending plans.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. PUC Distribution's 2016 rate is $31,314 per Km of line, a 0.20% decrease over 2015.

  PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased an average of 3.45% since 2012 with the increase in capital and operating costs. For the period of 2013 to 2016, the Total Cost per Km of Line has increased by approximately 0.40% per year.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

  PUC is committed to helping its customers understand their energy usage by offering programs that enable them to become more energy efficient. PUC has a conservation target of 26.4 Gigawatt hours by the end of 2020. Results for 2016 show progress of 52.97% towards that target. This achievement was made possible by the strong participation by local commercial/industrial customers in retrofit and auditing programs. Residential customers also participated in saveONenergy coupon events opting to replace lights in their homes to more energy efficient ones, as well as purchasing other energy efficient equipment. The combined efforts of participants from both the residential and business sectors made the achievement of substantial energy savings possible.

  Notable projects where city wide street lighting, not only in Sault Ste. Marie but Prince Township and Batchewana First Nations. Municipal parking lots followed suit with upgrading their parking lot lighting to LED, while small businesses began changing their florescent lamps and incandescent bulbs to efficient LED tubes and lamps.

  PUC remains committed to providing its customers with cost effective conservation programs to help them save electricity and lower their electricity bills. PUC will continue to innovate new ways to promote and support customers in reducing their consumption today and for the future.

As a member of CustomerFirst, PUC is part of a joint Conservation (CDM) Plan that has been approved by the IESO. The joint plan will achieve 141,877 MWh of savings which is equal to the combined targets that were allocated to each CustomerFirst member under the new framework. Through the CustomerFirst joint CDM Plan, PUC will continue to work collaboratively with the other CustomerFirst utilities to find efficiencies and reduce costs. The group will be sharing resources and working together in all areas of CDM including sales, marketing, customer and project support to provide value to ratepayers.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**
  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. For the year 2016 four CIA requests were received for a total of 820kW of FIT generation, and all applications were processed within the prescribed timelines.

- **New Micro-embedded Generation Facilities Connected On Time**
  In 2016, interest in the micoFIT program was much lower than in previous years. PUC Distribution Inc. received only one application and provided an offer to connect, but no follow-up request for connection was received. Outside of the micoFIT program, one application for a net metering load displacement installation was made.

  PUC's process to connect these projects is very streamlined and transparent for its customers. PUC works closely with customers and contractors to address any connection issues and ensure projects are connected in a timely manner.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  PUC Distribution's current ratio has increased from 0.90 in 2015 to 1.52 in 2016. By increasing over 1, PUC Distribution is in a good position to cover the company's short-term debts and financial obligations.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

  PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2016 debt to equity ratio of 2.34. PUC Distribution's long range plan is to push the debt to equity towards the 60/40 level.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**
  PUC Distribution's return on equity in 2016 at 0.98% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2016 being approximately $1.4 million higher than included in the approved 2013 cost of service rate application. PUC plans on filing a 2018 Cost of Service Rate Application for rates effective in 2018.

Note to Readers

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Appendix G

Project Descriptions for Specific Projects Exceeding Materiality Threshold

A. General Information						
Project/Activity	#1 - Customer Demand - Services					
Project Number	1C100-1					
Investment Category	System Access					
	2018	**2019**	**2020**	**2021**	**2022**	
Capital Cost (5.4.5.2 A.1)	$ 1,165,797					
Capital Contribution	$ 253,750					
Net Cost	$ 912,047					
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**	
	NA	NA	NA	NA	NA	

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent upon quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request		**In Service Date (5.4.5.2 A.3)**		Dependent on request
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 174,870	$ 408,029	$ 408,029	$ 174,870	

Project Summary

In an effort to comply with Distribution System Code (DSC) requirements and to support ongoing customer demand, the above values have been budgeted for using historical expenditures and predictions from the City of Sault Ste. Marie regarding projected development. Budgeted expenditures include installations of new/upgraded residential services, commercial services, new transformers to support services, replacement/relocation of infrastructure due to customer requests and other miscellaneous requests from customers. All requests are reviewed against the DSC and reasonableness to determine PUC's contribution level.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by customers. Risks include internal and contractor resource constraints due to fluctuation of customer requests. PUC is regulated to connect customers who lie along the line within a specified timeframe. In an effort to mitigate the risk of not complying with timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Compared to the previous 5 years, PUC's investment to customer demand, specific to services and accommodating relocation requests is estimated to be low for the next five years. The city has been impacted by uncertainty of local steel industry which, in turn, has impacted the economy. Due to the impact, the housing industry, commercial development and overall spending in the economy has been impacted, reducing the anticipated expenditures in the immediate future to support customer demand. Due to the nature of the economy, this is a prediction and is subject to change.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Services will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is regulated by the OEB Distribution System Code (DSC). The DSC states that all customer that lie along the line of the existing electrical distribution line shall be provided the ability to connect. PUC considers and complies with this requirement to connect new customers as required. PUC provides new connections with the basic connection allowance as specified in the DSC.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

New customer connections, increased revenue and customer relations are the secondary driver for the project. This project will increase quantity of customers supplied by PUC and revise service sizes affecting revenue stream. Replacing/relocating assets to accommodate customers provides PUC with an opportunity to increase customer relations and replace assets at a reduced cost through customer contributions.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with all regulations, secure more customers and improve customer relations.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The City of Sault Ste. Marie is currently preparing a revised population projection for their Official Plan. A preliminary review of the population projection predicts that the population of Sault Ste. Marie will plateau at approximately 75,000 causing a negligible change from today's population. PUC has also referenced the Regional Infrastructure Plan. These documents were referenced when estimating expenditures for the period identified within this cost of service.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a very high priority, immediately behind emergency replacements. This is due to regulatory compliance and customer satisfaction.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews options for new/revised services on a case by case basis to ensure the solution is implemented is safe, low maintenance and economical for all parties.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively identified but are unable to quantitatively calculate at this stage.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from this project. Very minor upgrades to individual services should result in less long term outages for the individual customer.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

Safety (5.4.5.2 B2)

New/upgraded services are installed to the most current safety standards available ensuring safety for all.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers

Services will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements

Services and supporting infrastructure are designed to be constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5)

By assuring sustainable, reliable, cost effective electrical services to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers different technologies when installing services and supporting infrastructure inclusive of vacuum trucks and directional drilling. These technologies cause less disturbance to the area and in turn less environmental impacts. Additionally, PUC considers environmental impacts when specifying material to be installed.

C. Category-Specific Requirements - System Access

Factors Affecting Timing/Priority (5.4.5.2 SA-C1)

This project receives a very high priority in order for PUC to comply with regulations. Scheduling tasks is dependent on complying with regulations and accommodating customers.

Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)

PUC informs customers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to customer for the customer to obtain benefits of installing multiple utilities in the same excavation. PUC installs services as per USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.

Factors Affecting the Final Cost (5.4.5.2 SA-C3)

There are many factors that affect the final cost of the project. Costs are affected by how the economy responds, customer requests, regulatory compliance, existing asset life and customer contributions. These costs are vairable and fluctuate annually.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)

PUC considers all options when services are installed/revised in an effort to provide the most practical solution for all parties. PUC has recently began purchasing large, pad mount transformers with integral group operated switches to minimize costs of pole mounted group operated switches and pole changes to obtain the increased space required on the pole. This is one example considered when new/revised services are installed.

Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)

PUC considers other projects when installing new services. If the service is within the area of an upcoming project, it is considered to revise timing of projects to gain overall economic efficiencies. Additionally, adjacent services are grouped together in an attempt to improve efficiency.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)

Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.

Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)

Options are considered on a case by case basis.

Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)

If an expansion is identified, PUC will perform an economic evaluation as per section 3.2 of the Distribution System Code. Results of economic evaluation are made available to the customer requesting the expansion.

System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)

Impacts to the system when connecting a new/revised customer are considered on a case by case basis ensuring the capacity of the system is adequate and impacts to adjacent customers is minimal or positive. Costs and cost recovery is considered on a case by case basis, affected by regulations and corporate practices.

A. General Information

Project/Activity	#2 - Customer Demand - Subdivisions				
Project Number	1C100-2				
Investment Category	System Access				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 137,153				
Capital Contribution	$ 30,000				
Net Cost	$ 107,153				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request	**In Service Date (5.4.5.2 A.3)**	Dependent on request

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 20,573	$ 48,004	$ 48,004	$ 20,573

Project Summary

In an effort to comply with Distribution System Code (DSC) requirements and support ongoing customer demand, the above values have been budgeted for using historical expenditures and predictions from the City of Sault Ste. Marie on development. Budgeted values include installations of new subdivisions inclusive of the expansion of our distribution system and transformation up to property lines for projected residential customers. All requests are reviewed against the DSC and reasonableness to determine PUC's contribution level.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by customers. Risks include internal and contractor resource constraints due to fluctuation of customer requests. PUC provides commitments to subdivision developer's in ways of formal agreements. In an effort to mitigate the risk of not complying with timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Compared to the previous 5 years, PUC's investment to customer demand, specific to subdivisions is estimated to be low/moderate for the next five years. The city has been impacted by uncertainty of local steel industry which, in turn, has impacted the economy. Due to the impact, the housing industry, commercial development and overall spending in the economy has been impacted, reducing the anticipated expenditures in the immediate future to support customer demand. Due to the nature of the economy, this is a prediction and is subject to change.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Services will be constructed using USF standards, PUC standards, in coordination with municipal road allowance standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is regulated by the OEB DSC. The DSC regulates PUC to provide offers for expansions inclusive of contestable work offered to the developer. PUC considers and complies with all requirements while ensuring all installations add to a safe, efficient, reliable system.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

New customer connections, increased revenue and customer relations are the secondary driver for the project. This project will increase quantity of customers supplied by PUC affecting revenue stream. Expanding the distribution system to connect new subdivisions and in turn, individual customers, provide PUC with an opportunity to improve customer relations.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with all regulations, secure more customers and improve customer relations.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The City of Sault Ste. Marie is currently preparing a revised population projection for their Official Plan. A preliminary review of the population projection predicts that the population of Sault Ste. Marie will plateau at approximately 75,000 causing a negligible change from today's population. PUC has also referenced the Regional Infrastructure Plan. These documents were referenced when estimating expenditures for the period identified within this cost of service. Additionally, PUC communicates frequently with primary subdivision developers inquiring about upcoming plans to ensure PUC is prepared.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a very high priority, immediately behind emergency replacements. This is due to regulatory compliance and customer satisfaction.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews options for system expansions on a case by case basis to ensure the solution is designed and constructed in a safe, low maintenance and economical manner for all parties.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively identified but are unable to quantitatively calculate at this stage.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from typical subdivision developments. Some expansions caused by subdivision developments provide PUC with an opportunity to further loop our system providing additional system redundancy allowing PUC to more effectively reduce outage areas as they occur. Expansions also allow PUC to review circuit and system imbalances and further balance the electrical system through connection of additional demand.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

Safety (5.4.5.2 B2)

System expansions consider safety as paramount by designing and installing to USF standards, PUC standards, in coordination with municipal road allowance standards and/or specifics approved by a Professional Engineer.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers

System expansions will be designed and constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements

System expansions are designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.

Economic Development (5.4.5.2 B.5)

By assuring sustainable, reliable, cost effective electrical services to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers different technologies when installing services and supporting infrastructure inclusive of vacuum trucks and directional drilling. These technologies cause less disturbance to the area and in turn less environmental impacts. Additionally, PUC considers environmental impacts when specifying material to be installed.

C. Category-Specific Requirements - System Access

Factors Affecting Timing/Priority (5.4.5.2 SA-C1)

This project receives a very high priority in order for PUC to comply with regulations. Scheduling tasks is dependent on complying with regulations and accommodating customers.

Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)

PUC informs developers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to developer for the developer to obtain benefits of installing multiple utilities in the same excavation. PUC designs and installs as per USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.

Factors Affecting the Final Cost (5.4.5.2 SA-C3)

There are uncontrollable factors that affect the final cost of the project. Costs are affected by how the economy responds, customer requests for new developments, regulatory compliance and increased costs in material.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)

PUC strives to manage controllable costs such as labour, equipment and optimizing designs. PUC has started eliminating underground hand boxes from our designs by identifying increased long term O&M costs.

Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)

When designing new system expansions to accommodate subdivisions, PUC considers our system as a whole identifying opportunities to improve safety, reliability and system redundancy.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)

Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.

Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)

Options are considered on a case by case basis.

Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)

Values for the OEB regulated Economical Evaluation are completed on a project by project basis. The final values are made available and reviewed with the developer. The costs for the majority of most new expansions to accommodate subdivisions are primarily absorbed by PUC due to quantity of projected future consumption and revenue.

System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)

Impacts to the system when expanding to accommodate new subdivision developments are considered on a case by case basis ensuring the capacity of the system is adequate and impacts to adjacent neighborhoods are minimal or positive. Cost and cost recovery is considered on a case by case basis, affected by regulations and corporate practices.

A. General Information					
Project/Activity	#3 - Customer Demand - Joint Use				
Project Number	1C100-3				
Investment Category	System Access				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 137,153				
Capital Contribution	$ 40,000				
Net Cost	$ 97,153				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request	**In Service Date (5.4.5.2 A.3)**	Dependent on request

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 34,288	$ 34,288	$ 34,288	$ 34,288

Project Summary

PUC is a partner with multiple third party communication companies in Sault Ste. Marie. Third party communication companies request to attach to PUC poles in an effort to minimize infrastructure. In doing so, PUC charges a monthly rental fee established in agreements between each company. On a regular basis third party companies will apply for revisions to their existing attachments or for new attachments to be added to coordinate with their business's objectives and customer demand. When applications are received, it is identified whether or not the existing PUC infrastructure is adequate to support the new/revised infrastructure in a safe manner. If PUC's infrastructure requires revisions (make ready work), the work is performed by PUC on a time and material basis.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by third party companies. Risks include internal and contractor resource constraints due to quantity of requests and other projects occurring. PUC discusses preferred completion dates with the third party companies in an effort to more effectively schedule work. In an effort to mitigate the risk of not achieving discussed timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical values for this project vary substantially over the past five years. In 2013 and 2014, Bell Aliant had a business plan to attach fibre optic cable throughout the city to attach to all residential and most commercial customers offering a more advanced service. This project was terminated at approximately 50% completion due to cost. This affected PUC immensely and cause a significant fluctuation in our costs. As these special projects are typically unknown to PUC until last minute, it is near impossible to adjust long term budgets, but react when it occurs. Slight fluctuation is projected from high level discussions with one company.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

New/Revised attachments will be reviewed against CSA, USF and PUC specific standards. Infrastructure revisions to accommodate third party requests will be completed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is a partner with multiple third party communication companies in Sault Ste. Marie. All attachment points from third party companies result in revenue for PUC. It is important to work collectively to find the optimal solution for all parties. PUC does increase revenue with new third party attachments.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

In being partners with third party communication companies, it is important to minimize infrastructure required to support our systems. This may require shared conduit structures and shared poles in lieu of standalone systems. This provide less conflict in the field and improved customer relations.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with contractual requirements and obtain additional revenue through increased quantity of third party attachments.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical averages on expenditures are referenced while eliminating the unique large projects (i.e. Bell Aliant Fibre to the Home) in addition to ongoing conversations with third party communications companies. As majority of their business plans are confidential, PUC is primarily unaware of large projects prior to projects commencing.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. This priority is based on continuing good working relationships with third party partners.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews each application for new/revised attachments on a case by case basis to maximize system operation efficiency and cost effectiveness. Make ready work is reviewed and analyzed to maximize benefit for both parties while ensuring cost effectiveness.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

While ensuring safety and reliability of the system are not negatively affected, PUC is able to offset costs with revenue received from third party companies, reducing the impact to customer rates.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from third party attachment requests. On a case by case review, if PUC observes an opportunity to improve the system for minimal cost in conjunction with the make ready work ready to support the request, the improvement will generally be completed improving system performance.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

Safety (5.4.5.2 B2)

Make ready work to allow new/revised third party attachments on PUC's infrastructure consider safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers

Infrastructure revisions will be designed and constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements

All make ready work to support new/revised third party attachments is designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.

Economic Development (5.4.5.2 B.5)

By permitting third party companies to attach to PUC's infrastructure in a safe, economical manner this project allows third party communication companies to supply communications throughout PUC's area and beyond, contributing towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental benefits with each design and installation to minimize environmental impacts.

C. Category-Specific Requirements - System Access

Factors Affecting Timing/Priority (5.4.5.2 SA-C1)

This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. Scheduling tasks is dependent on complying with contractual requirements, while balancing other projects.

Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)

PUC currently limits quantity of attachments on a PUC pole to three. Ensuring a single attachment company resides on a maximum of one attachment position allows other third party companies the same potential benefit.

Factors Affecting the Final Cost (5.4.5.2 SA-C3)

There are uncontrollable factors that affect the final cost of the project. Costs are affected by partnering companies and their confidential business plans. Additionally, current state and orientation of PUC's infrastructure in the area of the attachments contributes to the fluctuation of costs.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)

PUC strives to manage controllable costs such as labour, equipment and optimizing designs. PUC continues to review techniques for design (ex. in house vs. external), excavation (ex. vacuum truck), installation (ex. crane use in rear lot) to minimize controllable costs.

Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)

When receiving make ready suggestions during the permit application process, PUC reviews and considers other programs, age of existing infrastructure and customer impacts. PUC ensures that the solution provides benefit to the system to all parties.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)

Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.

Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)

Options are considered on a case by case basis. Least cost option is not always selected as it is not the most practical.

Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)

Not applicable

System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)

Impacts to the system when make ready work is completed for a new/revised third party attachment are considered on a case by case basis ensuring the safety and reliability of the system are not negatively impacted. Costs and cost recovery is as per existing agreements between PUC and third party company.

A. General Information						
Project/Activity	#4 - Customer Demand - City Projects					
Project Number	1C100-4					
Investment Category	System Access					
	2018	**2019**	**2020**	**2021**	**2022**	
Capital Cost (5.4.5.2 A.1)	$ 274,305					
Capital Contribution	$ 50,000					
Net Cost	$ 224,305					
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**	
	NA	NA	NA	NA	NA	

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on specific projects.

Start Date (5.4.5.2 A.3)	April 1, 2018 (typical)	**In Service Date (5.4.5.2 A.3)**	October 31, 2018 (typical)

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 27,431	$ 137,153	$ 82,292	$ 27,431

Project Summary

Much of PUC's infrastructure is located within the municipal right of way in Sault Ste. Marie and some on right of way owned by the Ministry of Transportation. The City of Sault Ste. Marie conducts complete road reconstructions, storm sewer replacement, curb and asphalt work annually. During these projects, PUC's infrastructure may require relocation/replacement to support the excavation. Due to the "Municipal Act" and specifically the "Public Service Works on Highways Act", PUC is required to relocate/replace infrastructure to support these projects upon request. A cost apportionment is identified in the "Public Service Works on Highways Act" as 100% material and 50% labour to be absorbed by the utility. Extent of the project areas vary from year to year depending on the City's overall plan and dependent on the nature of PUC's infrastructure in the area being addressed.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks typically occur between Spring and Fall with majority of the work occurring in early summer in preparation for the road excavations. PUC is regulated to complete the work stated and not completing the work in a reasonable time places PUC at risk of delay charges from the City's contractor. In order to mitigate risks, PUC discusses scope and schedule early in the process to anticipate when work will be required. Placing the project in priority and schedule as well as reallocating resources as required mitigates risk of not completing the work within required timelines.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical values are used in conjunction with the City's five year plan. Within the five year plan, specific jobs are identified as large impacts to PUC. Expenditures can significantly vary annually dependent on the areas being addressed, whether PUC's infrastructure will be affected, if PUC's infrastructure is underground or overhead, etc.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

PUC coordinates and references the City of Sault Ste. Marie's five year capital works program to identify approximate scope of work and requirements for upcoming years. As this plan is subject to change without PUC's approval, PUC's projected expenditures are variable. When revisions occur to PUC's infrastructure to accommodate the above project, all areas revised are reviewed and constructed in compliance with CSA, USF and/or PUC specific standards.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is required to relocate infrastructure to support highway improvements as defined by the Public Service Works on Highways Act. Scope of work is dependent on the City of Sault Ste. Marie's long term plan.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

During the relocation, it is a possibility for PUC to update infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to relocate/revise PUC's infrastructure to support City/MTO projects. This allows the projects to progress smoothly while minimizing or eliminating potential safety hazards relating to PUC's infrastructure.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

PUC is required to relocate infrastructure to support highway improvements as defined by the Public Service Works on Highways Act. Scope of work is dependent on the City of Sault Ste. Marie's long term plan. Cost apportionment is generally as per Public Service Works on Highways Act. Historical expenditures have been reviewed in conjunction with the City's five year plan to estimate the required investment.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. This priority is based on continuing good working relationships with the City and mitigating risks of delay costs.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Project has negligible effects on system operation efficiency as the infrastructure is typically replaced in kind after the contractor work has been completed. PUC attempts to coordinate projects to optimize cost effectiveness is feasible.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers continue to benefit from PUC infrastructure located on municipal road allowances, minimizing cost for PUC to install electrical services.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Frequency of outages once the project has been completed may reduce due to new assets installed.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

Safety (5.4.5.2 B2)

All relocation/replacement work to accommodate City projects consider safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers

The project is specific to coordination with the municipality and other utilities to relocate PUC infrastructure to accommodate conflicts. The relocation(s) is designed and constructed to USF standards and/or PUC specific standards, which are in line with industry standards allowing other utilities and third parties reasonable separation and access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements

All relocations to support City projects are designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.

Economic Development (5.4.5.2 B.5)

In coordination with the City, relocating PUC's infrastructure to accommodate road work assist the City to construct municipal infrastructure that will support economic development.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental benefits with each design and installation to minimize environmental impacts.

C. Category-Specific Requirements - System Access

Factors Affecting Timing/Priority (5.4.5.2 SA-C1)

This project receives a high priority, behind emergency replacement and balanced within general customer demand and subdivisions. As PUC is not regulated to have this work completed in a defined time, scheduling and coordination is essential to mitigate financial risks to PUC and potential safety risks to contractors.

Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)

Third party companies are invited to planning, design and construction meetings to ensure they are aware of the relocations. Third party companies are able to discuss specifics with PUC at all stages in an effort to minimize costs for all parties.

Factors Affecting the Final Cost (5.4.5.2 SA-C3)

Final cost of this project are extremely variable. The costs depend on the impacts each project area has on PUC infrastructure, whether it is approved by City Council to proceed and/or the Contractor's requirements during the project.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)

PUC reminds the City of the importance to have PUC in the planning and design meetings to ensure everyone is aware of the impacts and potential costs to relocate the infrastructure. This allows the design team to revise the design to minimize impacts to PUC's infrastructure if feasible. If relocation requirements remain, coordination and scheduling are essential to minimize delays, and in turn, costs.

Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)

PUC always considers adjacent projects and programs when relocating infrastructure to maximize benefits. Adjusting priority of projects may be a possibility to maximize benefits for all parties.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)

Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.

Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)

Options are considered on an area by area basis to ensure the most practical option is chosen.

Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)

Not applicable

System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)

Impacts to the system when relocating PUC infrastructure to accommodate City projects is minimal. Cost recovery is typically based upon the cost apportionment set out in the Public Service Works on Highways Act.

A. General Information					
Project/Activity	#5 - Forced Overhead Renewal				
Project Number	1C200-1-1				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 308,593				
Capital Contribution	$ 56,250				
Net Cost	$ 252,343				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on outage areas.

Start Date (5.4.5.2 A.3)	1-Jan-18		**In Service Date (5.4.5.2 A.3)**	31-Dec-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 77,148	$ 77,148	$ 77,148	$ 77,148

Project Summary

Overhead forced renewal project is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from weather related occurrences and/or vehicle accidents. When an occurrence occurs, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC identifies and mitigates risk of outages whenever possible. Through system inspection and asset testing, PUC understands where the majority of our concerning assets are located and place the replacement of those assets in priority. As it is not practical to have a system so robust that no outages occur, complete elimination of outages is not feasible.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC compares historical values for each category to budget for a recent average. As this budget is dependent on externally driven aspects such as weather and traffic accidents, the expenditures are considered on an annual basis and become difficult to predict.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Safety to the public and workers when a fault occurs in the system is the investment main driver. Although the system is protected via fusing, reclosers, relays and breakers, it is imperative that PUC attend site to ensure the site is safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

System reliability is a secondary driver. When a fault occurs, it typically causes an outage for a number of customers. PUC strives to provide a reliable system for all of our customers. Minimizing the outage duration contributes to a reliable system improving our CAIDI and SAIDI statistics.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages, providing a safe and reliable electrical system to consumers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical expenditures have been analyzed in conjunction with age and condition of existing infrastructure. As the infrastructure ages increased forced renewal expenditures should be expected to increase.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives the highest priority as it is primarily caused by system outages and safety concerns. Tasks are typically considered emergency in nature.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Investment to replace assets in an emergency nature will provide increased system reliability as the asset has now been replaced. The investment is not typically performed in a cost effective manner as it is due to emergency. PUC does attempt to make it as cost effective as possible by performing minimal repairs during after hours in an effort to complete full replacement during regular hours at regular rates. Additionally, transformers are set at a run to failure scheme, which is predicted to be the most cost effective method for transformer failure.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from this project in having outage times reduced and safety concerns managed in a timely fashion. Benefits have not been quantitatively calculated.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project has a significant impact on reliability performance. Although this project does not impact the frequency of outages (SAIFI) it does limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective alternatives to this project. This project is a reactive based project that receives a very high priority when tasks arise.

Safety (5.4.5.2 B2)

Public and worker safety is a primary driver in this project. By attending the site, making it safe and replacing the failed infrastructure, reduces hazards for both the public and workers. Final installation will be completed as per CSA, USF and/or PUC specific standards which adhere to a high level of safety standards.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Emergency replacement of assets will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outage durations to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when performing emergency repairs/replacements. These benefits/impacts are balanced with safety and reliability to come to the most practical solution.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project is non-discretionary and has been allocated a very high priority due to safety and system reliability concerns once a failure has arisen.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Information is not proactively available regarding assets that will be replaced due to the nature of the project. Typically, assets that fail on their own are older in nature, with some exceptions. Assets that fail due to external impacts may be any age.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

The number of customers affected by each failure is dependent on the location of the failure and the assets affected. If a single distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a distribution pole supporting the sub transmission line (34.5kV), the customers affected could be up to 50% of the City. Number of customers immediately affected is not within PUC's control. PUC attempts to limit the quantity of customers that experience extended outages by switching, repairing and/or replacing assets.

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of the failure up to the complete distribution and/or sub transmission circuit will be affected by potential power outages caused by failed assets. PUC will strive to minimize duration of all outages by responding and repairing safe and effectively.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers vary on a case to case basis. Some examples are extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC responds to each case effectively with the goal to minimize the duration of outages for all customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project has been given the highest priority as the failure may cause a safety concern or a system outage.

Consequences for system O&M costs (5.4.5.2 SR-C3)

This project has minimal long term effects on O&M costs. Asset replacements due to failure should not require significant O&M attention in the future. In retrospect, when a rebuild is required, the pole replaced may require additional work which would not be required if the pole was replaced at the same time.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

Reliability performance statistics are immediately impacted by this project as it is a project initiated by failures. Safety is also impacted by this project as failures usually may create safety concerns until our staff arrive to fix the problem.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

Project timing is generally considered emergency as the majority of the tasks are based upon system outages or safety concerns. This ranks highest on all of PUC's projects. This project does have a benefit of reacting to outages versus planned replacement for some assets. Transformers are an asset where PUC has chosen to apply a "run to failure" approach. This maximizes the life of the transformer, obtains additional value from the transformer while paying only a slight premium for reactive replacement.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

Like for like replacements are typical for majority of tasks that arise from outages or safety concerns due to typical timing of tasks. To have the asset designed on the spot after the failure has occurred is not a practical alternative. Proactively designing all potential failure assets is another alternative that is not practical.

A. General Information

Project/Activity	#6 - Forced Underground Renewal					
Project Number	1C200-1-2					
Investment Category	System Renewal					
	2018	**2019**	**2020**	**2021**	**2022**	
Capital Cost (5.4.5.2 A.1)	$ 308,593					
Capital Contribution	$ -					
Net Cost	$ 308,593					
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**	
	NA	NA	NA	NA	NA	

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on outage areas.

Start Date (5.4.5.2 A.3)	1-Jan-18		**In Service Date (5.4.5.2 A.3)**	31-Dec-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 77,148	$ 77,148	$ 77,148	$ 77,148

Project Summary

Underground forced renewal project is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from failed underground and/or pad mounted assets and/or vehicle accidents. When an occurrence occurs, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC identifies and mitigates risk of outages whenever possible. Through system inspection and asset testing, PUC understands where the majority of our concerning assets are located and place the replacement of those assets in priority. As it is not practical to have a system so robust that no outages occur, complete elimination of outages is not feasible.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC compares historical values for each category to budget for a recent average. As this budget is dependent on externally driven aspects such as traffic accidents, the expenditures are considered on an annual basis and become difficult to predict. Limited investment into aging underground infrastructure should result in increased forced replacement and maintenance costs.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Safety to the public and workers when an asset failure occurs in the system is the investment main driver. Although the system is protected via fusing, reclosers, relays and breakers, it is imperative that PUC attend site to ensure the site is safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

System reliability is a secondary driver. When an asset failure occurs, it typically causes an outage for a number of customers. PUC strives to provide a reliable system for all of our customers. Minimizing the outage duration contributes to a reliable system improving our CAIDI and SAIDI statistics.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages, providing a safe and reliable electrical system to consumers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical expenditures have been analyzed in conjunction with age and condition of existing infrastructure. As the infrastructure ages increased forced renewal expenditures should be expected.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives the highest priority as it is primarily caused by system outages and safety concerns. Tasks are typically considered emergency in nature.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Investment to replace assets in an emergency nature will provide increased system reliability as the asset has now been replaced. The investment is not typically performed in a cost effective manner as it is due to emergency. PUC does attempt to make it as cost effective as possible by performing minimal repairs during after hours in an effort to complete full replacement during regular hours at regular rates. Additionally, transformers are set at a run to failure scheme, which is predicted to be the most cost effective method for transformer failure.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from this project in having outage times reduced and safety concerns managed in a timely fashion. Benefits have not been quantitatively calculated.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project has a significant impact on reliability performance. Although this project does not impact the frequency of outages (SAIFI) it does limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective alternatives to this project. This project is a reactive based project that receives a very high priority when tasks arise.

Safety (5.4.5.2 B2)

Public and worker safety is a primary driver in this project. By attending the site, making it safe and replacing the failed infrastructure, reduces hazards for both the public and workers. Final installation will be completed as per CSA, USF and/or PUC specific standards which adhere to a high level of safety standards.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Emergency replacement of assets will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outage durations to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when performing emergency repairs/replacements. These benefits/impacts are balanced with safety and reliability to come to the most practical solution.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project is non-discretionary and has been allocated a very high priority due to safety and system reliability concerns once a failure has arisen.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Information is not proactively available regarding assets that will be replaced due to the nature of the project. Typically, assets that fail on their own are older in nature, with some exceptions. Assets that fail due to external impacts may be any age.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

The number of customers affected by each failure is dependent on the location of the failure and the assets affected. If a single distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a pad mounted sub transmission switch, the customers affected could be up to 50% of the City. Number of customers immediately affected is not within PUC's control. PUC attempts to limit the quantity of customers that experience extended outages by switching, repairing and/or replacing assets.

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of the failure up to the complete distribution and/or sub transmission circuit will be affected by potential power outages caused by failed assets. PUC will strive to minimize duration of all outages by responding and repairing safe and effectively.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customer vary on a case to case basis. Some examples are extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC responds to each case effectively with the goal to minimize the duration of outages for all customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project has been given the highest priority as the failure may cause a safety concern or a system outage.

Consequences for system O&M costs (5.4.5.2 SR-C3)

This project has minimal long term effects on O&M costs. Asset replacements due to failure should not require significant O&M attention in the future. In retrospect, when a rebuild is required, the underground asset replaced may require additional work which would not be required if the entire area was rejuvenated at the same time.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

Reliability performance statistics are immediately impacted by this project as it is a project initiated by failures. Safety is also impacted by this project as failures usually may create safety concerns until our staff arrive to fix the problem.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

Project timing is generally considered emergency as the majority of the tasks are based upon system outages or safety concerns. This ranks highest on all of PUC's projects. This project does have a benefit of reacting to outages versus planned replacement for some assets. Transformers are an asset where PUC has chosen to apply a "run to failure" approach. This maximizes the life of the transformer, obtains additional value from the transformer while paying only a slight premium for reactive replacement.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

Like for like replacements are typical for majority of tasks that arise from outages or safety concerns due to typical timing of tasks. To have the asset designed on the spot after the failure has occurred is not a practical alternative. Proactively designing all potential failure assets is another alternative that is not practical.

A. General Information					
Project/Activity	#7 - Substation 16 Rebuild				
Project Number	1C300-3-7 - A				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 419,687				
Capital Contribution	$ -				
Net Cost	$ 419,687				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**

Customer Attachments and Load (5.4.5.2 A.2)

Number of Customers fed from Sub 16 Feeders: Approximately 2417
Load Impacted: Approximately 10MW annual average

Start Date (5.4.5.2 A.3)	1/7/2016		**In Service Date (5.4.5.2 A.3)**	12/20/2019
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 104,922		$ 209,844	$ 104,922

Project Summary

As detailed in the Asset Management Plan, this substation has been in service for just under 50 years, is in very poor condition and has reached end of life. The planned Sub 16 rebuild is an upgrage from a 34.5k -12.47/7.2kV, 15MVA station to a 34.5kV - 12.47/7.2kV, 26.6MVA substation that will have two incoming 34.5kV supplies, two 10/13.3 MVA power transformers, and four outgoing 12.47kV feeders supplied by arc resistant metalclad switchgear. Due to the state of the existing station infrastructure, the switchgear is deemed to be unsafe to operate while energized and must be isolated and de-energized prior to operation. This results in isolation out on the 34.5kV distribution lines, which significantly reduces reliability and contigency buffers for connected customers.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC does not have the resource requirements to design and construct substations. The work of the detailed design and construction will be outsourced to an experienced and reputable consultant and contractor to mitigate risks during the project implementation. No risks are anticipated with the proposed outsourcing plan. PUC plans to bypass the Sub 16 34.5kV feeds during the construction phase in order to keep the dual feed supplying affected customers, as referenced above in the Project Summary section.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC's Substation 10 rebuild was completed in 2015 for a total of $4,483,000 and the total estimated cost of the Sub 16 rebuild is $3,910,244.00. Sub 16 is estimated to be less than Sub 10 due to a different switchgear type being used which will allow the building sfootprint to be reduce by about 40%.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

The protection relays are modern micro-processor and IP based relays that are capable of reverse power flow to accommodate REG applications.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project does not fall in the category requiring leave to construct.

Attach other project reference material i.e. images, drawings and or reference material

"1C300-3-7 - EST 3707 - DSP Material Capital Asset Justification - Sub 16 Rebuild Attachment 1"

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the key driver for this project. This project will reduce the risk of prolonged power interruptions and reduce the frequency of power interruptions due to equipment failure at Sub 16.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Operating efficiency is the secondary driver to this project. New switchgear and protection and control equipment will improve operating abilities, and reduce operating costs.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate the risk of power outage duration and frequency falling below PUC's performance targets as outlined on it's OEB annual LDC scorecard.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The source for information for justification of this project is the Asset Management Plan, which was prepared by taking into account all relevant information pertaining to the condition of station and and lines assets.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project has been determined as a high priority due to the old age and very poor condition of power transformers and switchgear at the existing Sub 16.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

There are no economical alternatives to this project.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively described above but have not been quantitatively calculated because accurate information on customer interruption costs is not readily available.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project, by reducing the risk of in-service equipment failures, will reduce the risk of prolonged or highly frequent outages. It mitigates the risk of reliability performance falling below PUC's targets as outlined on its OEB annual scorecard.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective design or funding alternatives, or co-ownership options available. This project received a high priority based on the criteria presented in the Asset Management Plan.

Safety (5.4.5.2 B2)

Modern protection and controls, capable of automatically responding to mitigate unsafe conditions on the distribution system will be implemented, thus mainting public safety in PUC's service territory.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

The SCADA and protection and control systems will be connected to PUC's fibre network connecting most of PUC owned facilities. This fibre network is protected by PUC's corporate IT managed services which utilizes NIST cybersecurity standards and regulations.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

The protection and controls meeting interoperability standards will be specified and implemented for this project. Power transformers and switchgear conforming to ESA, CSA, and IEEE standards will be utilized.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

The protection relays are modern micro-processor and IP based relays that are capable of reverse power flow to accommodate REG applications. The relays are also capable of being incorporated into PUC's IESO mandated Under-Frequency Load Shedding scheme.

Economic Development (5.4.5.2 B.5) (where applicable)

The substation will be sized with consideration for future load growth within its service territory. By assuring a sustainable reliability of the power system in PUC's service territory, this project contributes towards economic development in the region. Also, the protection and control system will be able to support large REG applications. Lastly, residents or businesses will not have an issue developing near the substation as the layout and design is non obtrusivecally with landscaping and brick type exterior matched to the surrounding land uses. The transformer bays will also have barrier walls to limit transformer hum to below MOE limits.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

Transformer Oil Containment systems will be built into the design to mitigate the environmental risks caused by a transformer failure and oil spill.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project was prioritized through asset life cycle optimization techniques as detailed in the PUC's Asset Management Plan.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

As seen in the Asset Management Plan, the condition of the existing assets at Sub 16 has been determined as poor or very poor, presenting a high risk of failure. Sub 16's SCADA RTU has been failed since the winter of 2017 which results in all troubleshooting and operations being performed through site visits and there is a lack of real time knowledge when equipment fails. Also, 24VDC protection relays are no longer available and a workaround power supply conversion was required aroud 2013 to allow newer 125VDC relays to be installed where several 1980s vintage relays were failing timing tests. Lastly, one of the two 7.5MVA transformers failed and wos repaired approximately 7 years ago at considerable expense.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 1975
Number of General Service <50kW: 396
Number of General Service >50kW: 46

Quantitative customer impacts (5.4.5.2 SR-C1.4)

The main impact of this project on customers served from Sub 16 are mitigating the risk of SAIFI and SAIDI worsening due to the anticipated failures of the equipment determined to be in poor or very poor condition.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customer satisfaction will improve with the rebuild of Sub 16 as the risk of failure and the potential for reduced outage impacts.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

The station currently supports one of the fasted growing areas of development in the city along the north Highway 17 corridor and this growth is expected to continue for the foreseeable future. A new hospital was added in the area about 7 years ago and both C&I and subdivision developments continue to spring up. With the poor condition of assets in the existing Sub 16 and the growing customer base, impacts of reliability are affecting more and more customers as time goes on.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project is given a high priority when compared to other projects. Substation 16 is on the edge of town with some long distance feeders and PUC will be pushing other stations, that are picking up the load during the construction, to their limits if the rebuild extends into the winter (high loading) months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The new Sub 16 will reduce O&M when compared to the existing Sub 16 O&M requirements. The existing station contains open bus and switches on lattice structures with equipment exposed to the harsh northern Ontario environment. The new station will have all equipment except transformers fully enclosed and the type of switchgear to be utilized has monitoring capabilities and minimal maintenance requirements.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

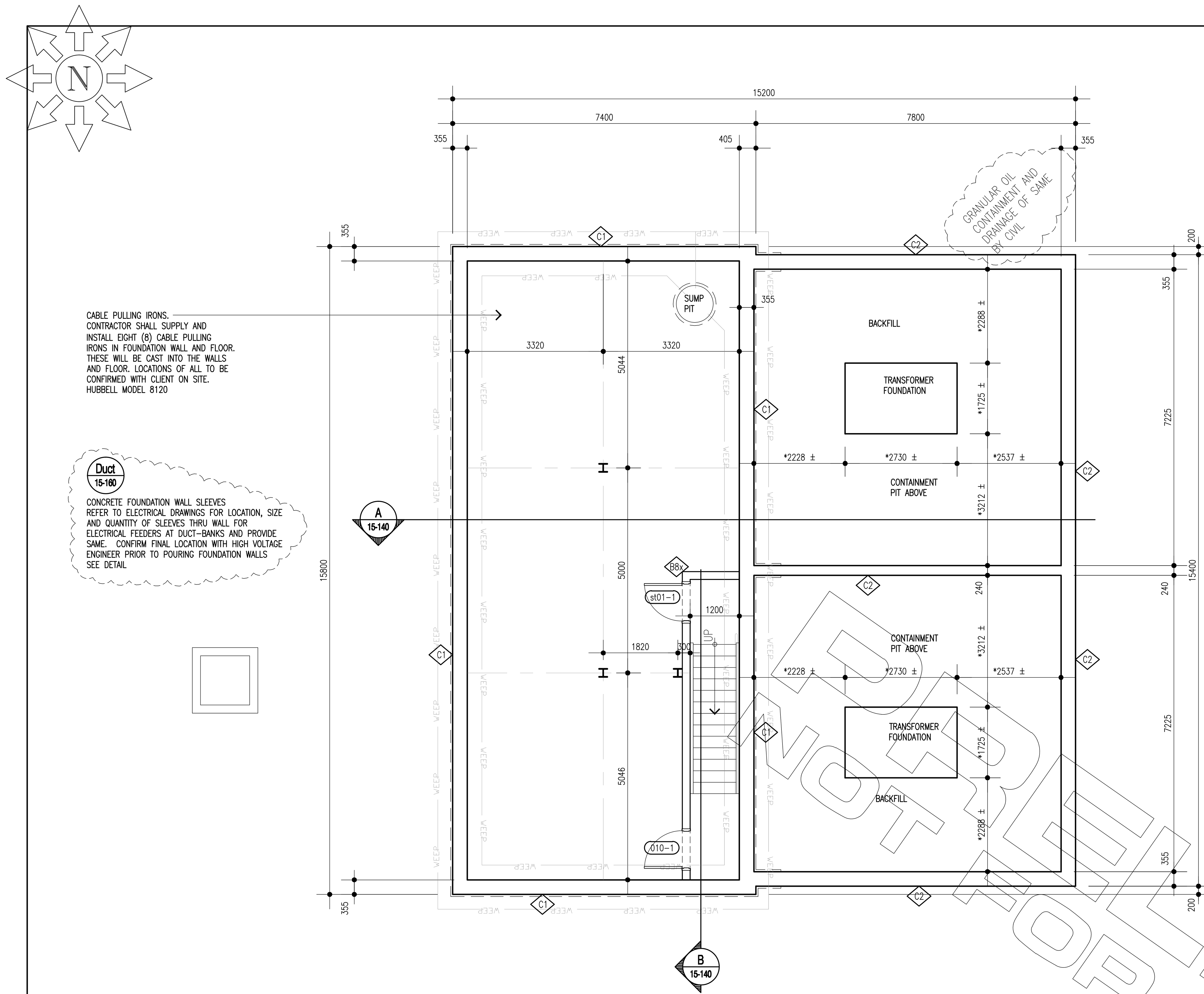
As mentioned above the modern micro-processor based protection relays and new switchgear will offer major benefits for operating safety and public safety by reacting to faults on the system. Also, the transformers will be separated by a firewall, have oil containment, and be surrounded by noise reducing exterior walls. The rebuild of Sub 16 will increase system reliability and safety.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

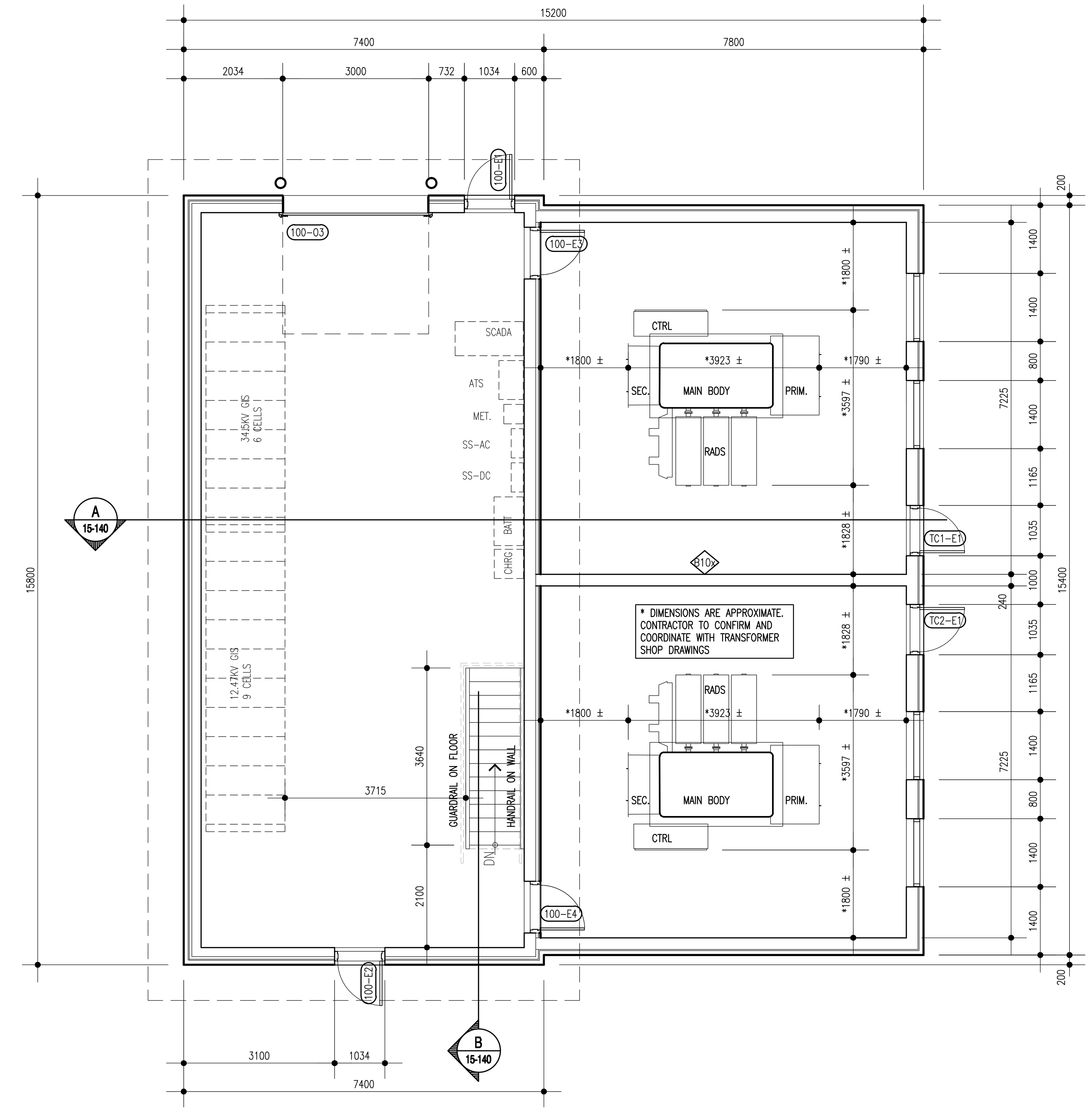
This project has been given a high priority because it offers a high benefit for risk mitigation and the health its existing equipment was ranked as poor and very poor.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

The station rebuild will not be like for like as new technology and designs are available to increase operating and maintenance efficiencies. All of the equipment and designs will be specified to meet the current version of applicable standards and to fully meet the current and future needs of customers.



Level 0 Floor Plan
Scale 1:75



Level 1 Floor Plan
Scale 1:75

NO.	REVISION	DATE	INITIAL

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Professional Seal

This drawing has been prepared solely for the use of PUC and there are no representations of any kind made by IBI Group to any party with whom IBI Group has not entered into a contract

Check Scale (may be photo-reduced)
0 1 inch 0 10mm

IBI Group
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Toronto ON M9W 5P3 Canada
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IBI Project No.: 24RX12.0195

PUC

SUBSTATION 16

ARCHITECTURAL
FLOOR PLANS

SCALE: 1:75	
DRAWN BY: K.OLIVER	DATE DRAWN:
CHECKED BY: K.OLIVER	DATE CHECKED:
APPROVED BY:	DATE APPROVED:
DWG. NO.: D-ES16-15-120	REV.: A.B.

A. General Information

Project/Activity	#8 - Overhead Renewal - Poles				
Project Number	1C300-1-2				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 314,765				
Capital Contribution	$ -				
Net Cost	$ 314,765				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on identified deteriorated poles, pole locations and which circuit poles are located on.

Start Date (5.4.5.2 A.3)	1-Jan-18		**In Service Date (5.4.5.2 A.3)**	31-Dec-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 125,906	$ 31,477	$ 31,477	$ 125,906

Project Summary

PUC has s significant amount of overhead electrical infrastructure. Within that overhead infrastructure, PUC owns approximately 12,500 poles and are currently joint use on another 3350 Bell Poles. As of 2016 approximately 6% of PUCs poles were either in poor or very poor condition. PUC obtains a third party to perform pole testing on 1/7 of our poles annually that are 10 years or older to determine poles that require immediate attention, short term attention and poles to continue to monitor. Through third party testing and field identification by staff and the public, poles are identified as requiring replacement. This results in the scope of work for the deteriorated pole project for the year. It is estimated that 30 poles will be identified annually for replacement.

Risk Identification & Mitigation (5.4.5.2 A.4)

This project is based on deteriorated pole identification and level of risk identified in the field. Dependent on the level of risk for the poles identified, they may be considered emergency replacements, short term replacements (<1year) or long term replacements (<5years). Dependent on the risk identified, each task will be given a relative priority in an effort to mitigate risks. Resources play a factor in designing and replacing the identified poles. Reallocating resources may be required to mitigate risks.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical information is used to average out the cost of a single pole replacement as well as averaging out the quantity of poles that are anticipated to be identified as deteriorated. Estimated expenditure may require revision due to a higher level of identified poles caused by our system aging faster than replacements occurring. Ensuring pole testing is included in O&M budget to effectively retrieve pole strength results should minimize risks of quantity of poles significantly increasing.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary driver for this project. Proactively identifying poles that are close to failure and proactively replacing them minimizes the risk of a failure occurring. This reduces the risk of prolonged, uncontrolled power outages. Without this project PUC's reliability statistics would be negatively affected.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Public safety is the secondary driver for this project. Proactively replacing identified poles mitigates the risk of the pole failing in service and controls the hazards to a reasonable level.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by controlling hazards and outages through proactively replacing poles nearing the end of their life.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Using the age distribution of PUC's poles in conjunction with previous pole testing data and historical quantities of deteriorated poles identified in the field, PUC attempts to accurately predict the quantity of poles that will require replacement. Using historical average costs per pole replacement with the estimated quantity of poles, PUC estimates the expenditures required. Cost vary depending on the quantity of the poles identified and the nature of the poles (ex. 35ft pole vs 65 ft. pole).

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a pole failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole fails. PUC reviews identified deteriorated poles and prioritizes each pole within the project.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

The project has minimal effect on system operation efficiency. The project is considered with other projects in an attempt to coordinate projects for cost effectiveness. If this is not practical, the single pole replacements occur. There are no practical alternatives to this project as not replacing the poles will result in asset failures, system reliability concerns and potential public safety concerns.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Proactive pole replacements provide system reliability benefits to customers. Additionally, proactive pole replacements reduce the cost in comparison to reactive replacements upon failure, reducing PUC's overall costs and minimizing impacts to customer's monthly bill.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Proactive replacement of poles identified as deteriorated reduces the unplanned frequency of outages and significantly reduces the duration of outages. Proactive replacements allow for limited, planned outages to transfer infrastructure in lieu of the unplanned outage. This allows PUC to advise effected customers to allow them to plan for the outage versus react to an outage. Proactive replacements positively impacts reliability statistics.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Each pole replacement is reviewed on a case by case basis to identify any available alternatives. Some alternatives may include the replacement of two poles with one, additional coordination with adjacent pole owners, etc. Generally, there are no practical alternatives to pole replacements.

Safety (5.4.5.2 B2)

Public safety is a secondary driver for this project. Proactively replacing deteriorated poles reduces the risk of in service failures and the risk of poles and/or live conductors falling to the ground.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Pole replacements will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Pole replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing poles. This is one of the considerations during the planning stage, selecting installation methods. As much as practical, PUC attempts to minimize environmental impacts.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a pole failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole fails. PUC reviews identified deteriorated poles and prioritizes each pole within the project.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Conditions of pole to be replaced are all below acceptable, sustainable condition. The condition is based on visual inspections and third party pole testing. Asset life relative to the typical life cycle is on a case by case basis. Generally, deteriorated poles are beyond the 45 years old, but some poles are identified as deteriorated prior to this due to ground line rot, infestation, woodpecker damage, etc.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

The quantity and class of customers is unknown at this time and is dependent on the poles that are identified as requiring replacement. The quantity and class is variable if the poles are secondary cross over poles versus supporting sub transmission lines (34.5kV)

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of the deteriorated poles identified will benefit from increased system reliability dependent on the nature of the pole.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers vary on a case to case basis. Some examples reducing the extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC reviews each identified pole on a case by case basis relating to reliability and safety risks and place poles within replacement schedule.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal.

Consequences for system O&M costs (5.4.5.2 SR-C3)

Replacement of deteriorated poles that are beyond 10 years old, reduces O&M costs as PUC tests poles only that are over 10 years old. Treatment of poles has an increased O&M cost which extends the life of certain poles minimizing the required cost within this project.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

Reliability performance is directly benefited from replacement of deteriorated poles. This reduces the quantity of unplanned outages which typically result in longer duration outages. This project increases safety by minimizing the risk of pole failures causing potential maintenance and electrical hazards.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

Project timing is generally immediately after emergency replacements and customer demand. System benefits from reducing the quantity of unplanned outages resulting from pole failures.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

PUC attempts to have all poles replaced within this project designed to USF and/or PUC specific standards. Alternatives are reviewed on a case by case basis to maximize benefits and minimize costs.

A. General Information					
Project/Activity	#9 - Overhead Renewal - Restricted Wire (Wallace Terr., 2nd Ave., 5th Ave., 6th Ave., Devon Rd. & Woodcroft Ave.)				
Project Number	(2018) 1C300-1-4C				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 433,676				
Capital Contribution	$ -				
Net Cost	$ 433,676				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 240
Number of General Service Customers (<50kW): 14
Load Impacted (Tx Ratings): 1007.5kVA

Start Date (5.4.5.2 A.3)	1-Mar-18		**In Service Date (5.4.5.2 A.3)**	31-Dec-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 173,470	$ 43,368	$ 43,368	$ 173,470

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4C for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical alternatives available for this project area and project as a whole.

Safety (5.4.5.2 B2)

Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

Reducing downtime of PUC's system contributes positively towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution and would not bring the value of economies of scale.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 240
Number of General Service Customers (<50kW): 14
Load Impacted (Tx Ratings): 1007.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the nature of this project in coordination with other projects, this project is scheduled to be constructed early in 2018 and then again late in 2018 with resources shifted to more difficult access projects in the summer.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

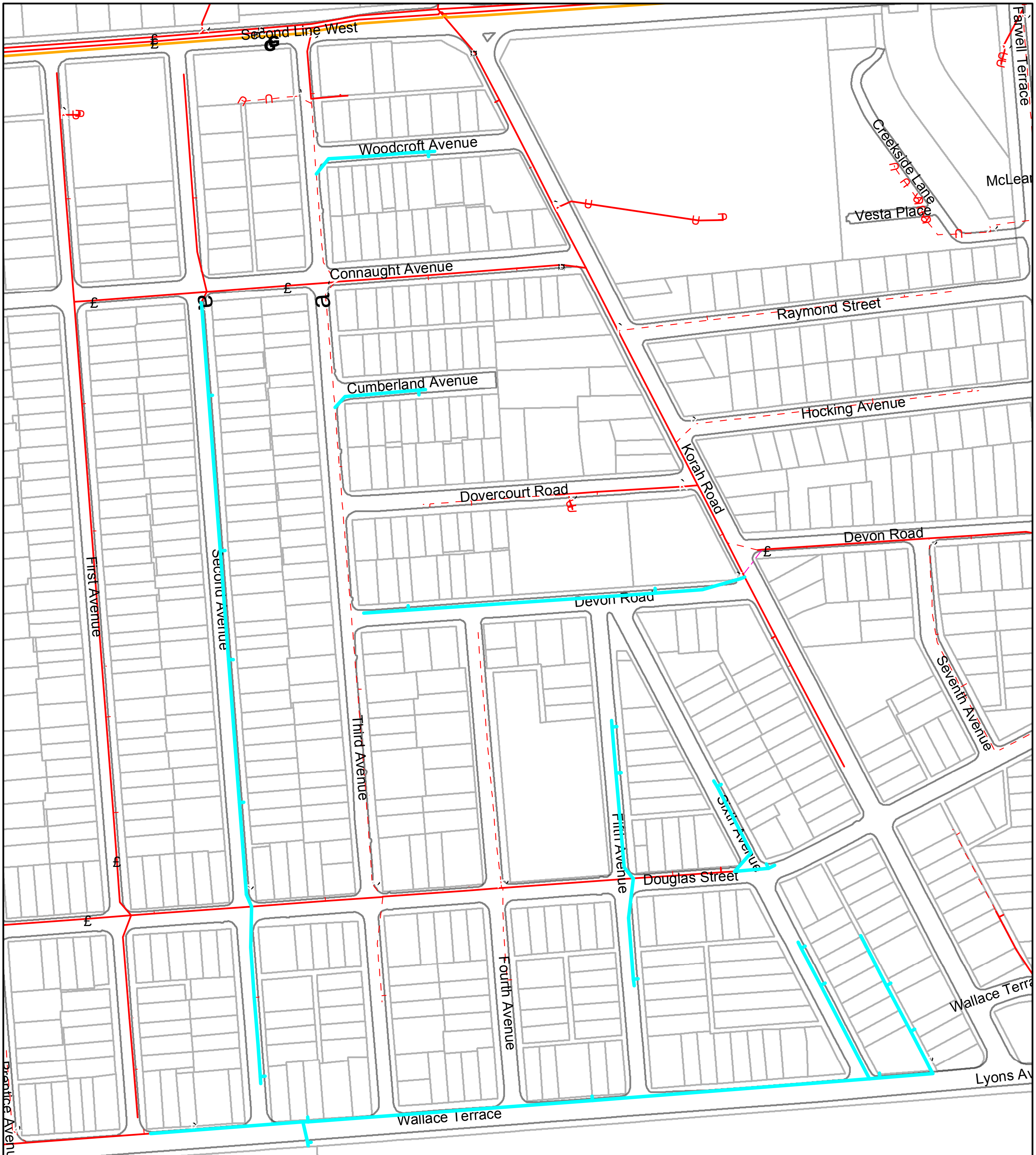
As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.



Notes:
All locations are approximate as final design has yet to be completed.

N W E S
SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
WALLACE TERR, SECOND AVE, FIFTH AVE, SIXTH AVE, DEVON RD AND WOODCROFT AVE

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 12/17	JT

PUC

DRAWN BY: J. TEVC	DATE: SEP. 12/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.:	**REV**
(2018)-1C300-1-4C	**A**

A. General Information					
Project/Activity	#10 - Underground Renewal - Voltage Conversion (Laronde Ave., Koprash Crt.)				
Project Number	(2018) 1C300-2-4				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 531,603				
Capital Contribution	$ -				
Net Cost	$ 531,603				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 79
Load Impacted (Tx Ratings): 825kVA

Start Date (5.4.5.2 A.3)	1-Jun-18		**In Service Date (5.4.5.2 A.3)**	31-Aug-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
		$ 132,901	$ 398,702	

Project Summary

As shown in PUC's asset management plan, PUC has near 3km of 4.16/2.4kV underground circuits and two 4.16kV distribution stations in service. As the two stations are beyond their anticipated lifespan, replacement will be required. In an effort to bring stations to industry standard, the stations will be replaced with stations producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds all of 4.16/2.4kV underground lines will be required to be converted. Additional to the reliability concerns related to the stations, there are other benefits to convert voltages to a standard 12.47kV including less power losses and standardized equipment allowing for purchasing efficiencies. Coordinating the voltage conversion program with replacing aged, direct buried cables and deteriorated underground vaults provides opportunities through synergies.

Risk Identification & Mitigation (5.4.5.2 A.4)

The underground voltage conversion project inclusive of direct buried cable replacement is fairly new to PUC. PUC has completed two similar projects in the past and have experienced significant variables during the projects. As PUC continues to learn from the variables as they arise and communicate with similar utilities, there are risks of unknowns that may arise. In an effort to mitigate these risks, PUC attempts to include all parties that will be affected early in the planning stage and obtain all information for consideration in designs and planning stages. This project will require construction during the summer months when resources and minimal and resource demands are highest. Reallocating resources to ensure construction is accomplished may be required to mitigate risks of delays.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has minimal history on similar projects and therefore rely on contractor rates and discussions with other utilities. Customer impacts, restoration, conflicts with adjacent utilities and municipal consent are large factors that can affect expenditures. During design, estimated expenditures are revised to more accurate values. After design, prior to construction, scope of project will be adjusted within or expenditures reassigned as required.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

As customer meters will not be replaced, existing REG customers will not be affected. Transformers will be sized accordingly to accommodate all existing REG customers.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-2-4 for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary investment driver of this project. As stated in the project summary, the supplying stations are beyond their rated life, causing significant reliability concerns. In order to replace the stations to industry standard stations, they will be replaced with a higher distribution voltage. To support these station replacements, the existing 4.16kV lines will require conversion. Additionally, replacement of aged direct buried underground distribution cables, vaults and transformers significantly increase the reliability of the distribution system within the area.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Cost effectiveness is the secondary investment driver. As the conductors are operating at a lower voltage (4.16kV vs 12.47kV), it is required to feed a larger amount of current through conductors to supply the same amount of power. Voltage conversion will result in a reduction in losses. Additionally, standardizing material allows PUC to store less material, requiring less inventory.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate risk of power supply reliability from degrading below PUC's targets by allowing for end of life distribution stations to be replaced as well as replacing underground cables, vaults and transformers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

As shown in PUC's asset management plan, distribution stations 4 and 5, currently operating at 4.16kV distribution voltage are nearing end of life. As stated above, this project is to support the replacement of said distribution stations. Additionally, as shown in the asset management plan, PUC has a significant length of underground direct buried cables approaching, if not beyond their rated life. Replacing these cables will mitigate the risk of cable failures occurring.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the condition of the distribution systems, it is important to ensure that this project be completed in the budgeted year. Not completing this project in the budgeted year will delay the voltage conversion program, delay the replacement of the 4.16kV distribution stations, continue to operate cables beyond their rated life and, in turn, increase risk of system reliability decreasing.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and in turn the distribution station replacements will have a significant positive effect on system operational efficiency, decreasing power loss costs, improving reliability and decreasing stations maintenance costs. Alternatives are observed on a case by case basis. Installing step down transformers is an alternative reviewed for each area. This is used more for scheduling purpose versus a final solution as it is expenditures that would be lost.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a more reliable distribution system with additional supply points and new assets in their immediate subdivision. This should result in less outages, and when an outage occurs, the duration will be limited. Benefits have not been quantitatively calculated for this project.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project will positively impact system reliability performance. The project will result in the ability to replace existing, aged distribution stations with new. Additionally, this project will replace all underground cables, vaults and transformers currently installed. Upon completion of the project, the area will be supplied from the 12.47kV system, which has many distribution stations available, resulting in shorter duration outages, if they occur. Additionally, as submersible transformers will be replaced with above ground, minipad transformers, time to complete switching operations and transformer replacements will be reduced.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are many project alternatives available for this project, including the installation of step down transformers, cable injection versus replacement, directional drilling verses trenching and replacing submersible transformers in kind verses above ground, minipad transformers. All options are reviewed to ensure the most practical, long term solution is selected.

Safety (5.4.5.2 B2)

In replacement of underground cables, vaults and transformers with new, accommodating a voltage upgrade, the transformers are replaced with above grade, minipad transformers. This provides an increased level of safety around multiple areas. PUC staff are able to operate the minipad transformers in a more ergonomic fashion and less risk to City sidewalk plows from damaging submersible vault lids leaving energized transformers exposed.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards. PUC coordinates early with third party utilities including communication companies, gas, water and municipality to ensure all parties are both aware of the construction that will be occurring and allow them to coordinate work to provide the maximum benefit to all parties.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively. Future operational requirements are projected to decrease as maintaining above ground, minipad transformers require significantly less effort than below grade submersible transformers.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

Replacing underground direct buried cables with new, replacing underground submersible transformers in vaults with above ground, minipad transformers has environmental benefits as a potential leaking below grade transformer may go unnoticed for a long time versus an above grade transformer. Additionally, environmental impacts will be considered when installation options are reviewed.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a distribution system infrastructure failure and the immediate reliability impact. Additionally, each area is reviewed in relation to the age of underground infrastructure, history of cable failures, whether cables are direct buried or not and immediate customer impacts. If below grade vaults are causing safety concerns in the area, the project priority is increased within the program.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Assets within this area are generally approach or beyond their rated life-cycle. This is based on the age of installation of 4.16kV systems and when cables were direct buried versus installed in conduit. Due to the age of the assets in conjunction with the requirement to increase voltage, most infrastructure is due for replacement.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 79
Load Impacted (Tx Ratings): 825kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of this project will benefit from a more reliable distribution system from new substation builds as well as new cables and transformers in the immediate subdivision.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project requires a significant amount of excavation and therefore is most efficient to complete the replacement during summer months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

Replacement of direct buried cables and aged transformers and vaults with new infrastructure including above ground, minipad transformers should reduce system O&M costs. It is expected that anticipated upcoming cable failures will not occur minimize reactive O&M costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

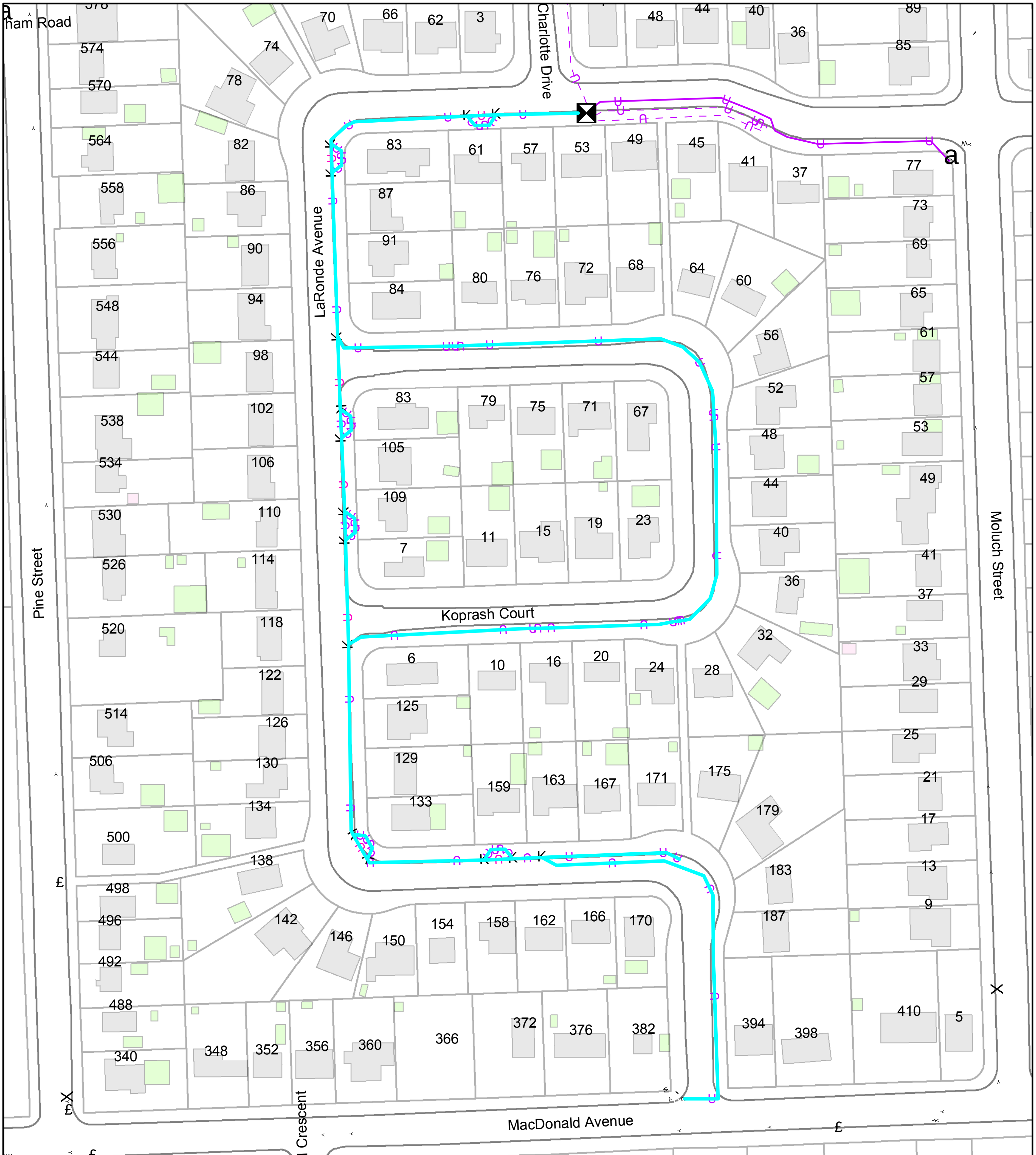
As described above, this project, incoordination with distribution station replacements, should result in improved system reliability and safety.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project should be completed in summer months to ensure cost effectiveness. Project will allow aged distribution substations to be replaced and will replace aged distribution cables and transformers resulting in a higher level of reliability.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

Like-for-like renewal is not an option. Many alternative designs will be considered prior to detailed design including step down transformers, cable injection and directional drilling. After review, PUC will select the most practical solution for the specific project. It is essential to complete this project in the budgeted year as the projects to accommodate the complete voltage conversion have been prioritized and scheduled in conjunction with substation renewals.



Notes:
All locations are approximate as final design has yet to be completed.

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SYSTEM PLANNING
2018 - UG RENEWAL - VOLTAGE CONVERSION
LaRONDE AVE AND KOPRASH CRT

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 13/17	JT

DRAWN BY: J. TEVC	DATE: SEP. 13/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.:	REV
(2018)-1C300-2-4	A

A. General Information

Project/Activity	#11 - Overhead Renewal - Restricted Wire (Red Pine Drive - North of Pnt. Of Pins)				
Project Number	(2018) 1C300-1-4B				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 349,739				
Capital Contribution	$ -				
Net Cost	$ 349,739				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 32
Load Impacted (Tx Ratings): 212.5kVA

Start Date (5.4.5.2 A.3)	1-May-18		**In Service Date (5.4.5.2 A.3)**	31-Aug-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ -	$ 174,870	$ 174,870	$ -

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4B for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

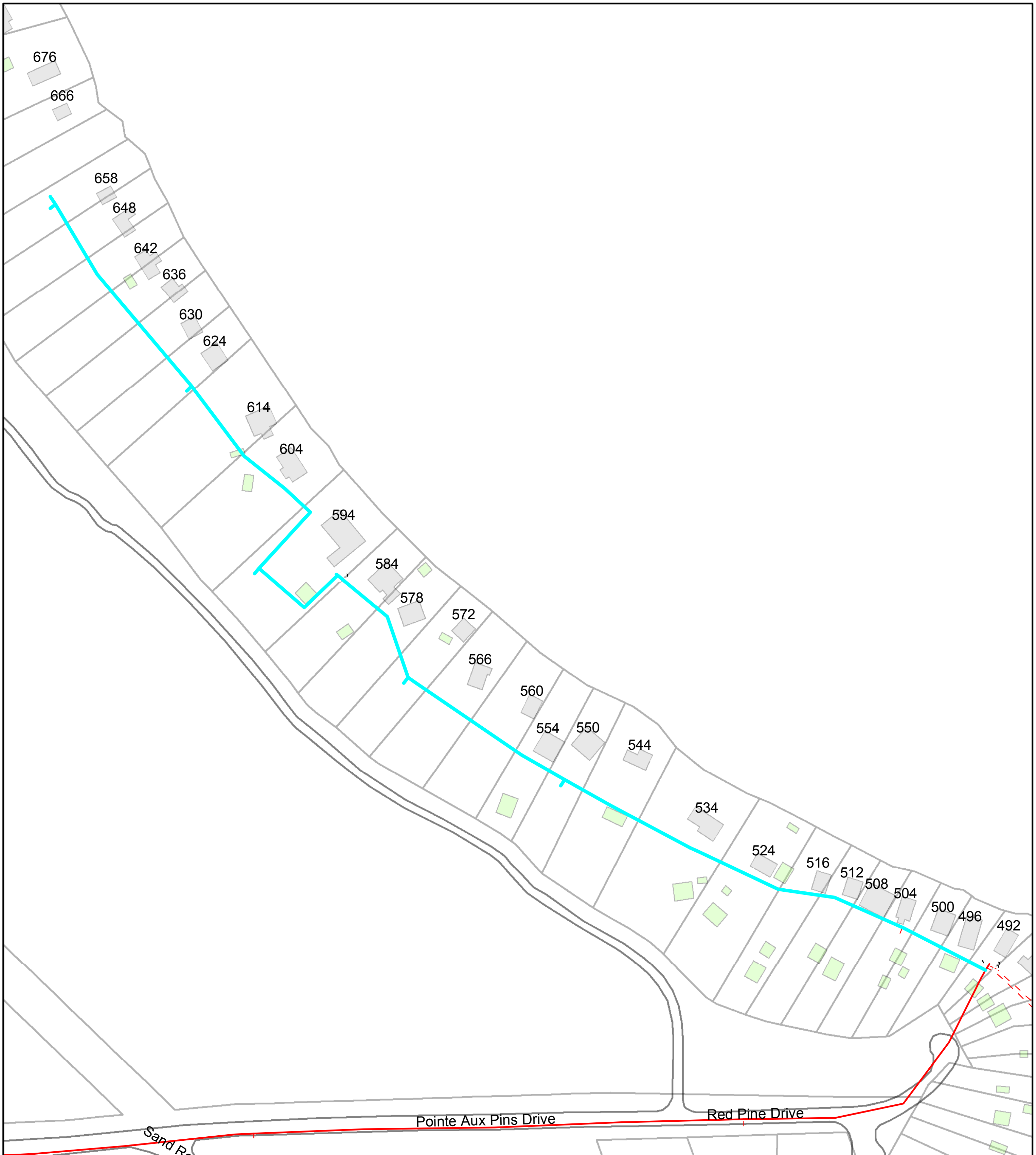
This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)
Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.
Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)
Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
There are no practical alternatives available for this project area and project as a whole.
Safety (5.4.5.2 B2)
Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)
Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.
Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)
Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.
Economic Development (5.4.5.2 B.5) (where applicable)
Reducing downtime of PUC's system contributes positively towards economic development in the region.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal
Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)
This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)
The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution and would not bring the value of economies of scale.
The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)
Number of Residential Customers: 32 Load Impacted (Tx Ratings): 212.5kVA
Quantitative customer impacts (5.4.5.2 SR-C1.4)
It is not feasible to determine quantitative customer impacts for this project ahead of time.
Qualitative customer impacts (5.4.5.2 SR-C1.5)
Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.
Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)
Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.
Timing and Priority of Project (5.4.5.2 SR-C2)
This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a complex project due to currently being constructed across private property near the shore of Lake Superior. Due to access constraints, it will be optimal to complete project during summer months.
Consequences for system O&M costs (5.4.5.2 SR-C3)
The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.
Impact on reliability performance and/or safety (5.4.5.2 SR-C4)
As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.
Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)
This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.
Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)
While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.



Notes:
All locations are approximate as final design has yet to be completed.

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SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
RED PINE DR
NORTH OF POINTE AUX PINS DRIVE

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 12/17	JT

PUC

DRAWN BY: J. TEVC	DATE: SEP. 12/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.:	REV
(2018)-1C300-1-4B	**A**

A. General Information							
Project/Activity	#12 - Overhead Renewal - Voltage Conversion (MacDonald Ave - Lake St. to Moluch St.)						
Project Number	(2018) 1C300-1-3A						
Investment Category	System Renewal						
	2018	**2019**	**2020**	**2021**	**2022**		
Capital Cost (5.4.5.2 A.1)	$ 288,020						
Capital Contribution	$ -						
Net Cost	$ 288,020						
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**		
	NA	NA	NA	NA	NA		
Customer Attachments and Load (5.4.5.2 A.2)							
Number of Residential Customers: 25 Number of MicroFit Customers: 1 Load Impacted (Tx Ratings): 187.5kVA							
Start Date (5.4.5.2 A.3)	1-Jan-18			**In Service Date (5.4.5.2 A.3)**		30-Apr-18	
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**			
	$ 216,015	$ 72,005	$ -				

Project Summary

As shown in PUC's asset management plan, PUC has over 30km of overhead 4.16/2.4kV circuits and two 4.16kV distribution stations in service. As the two stations are beyond their anticipated lifespan, replacement of the stations will be required. In an effort to bring stations to industry standard, the stations will be replaced with stations producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all 30km of line will be required to be converted. Additional to the reliability concerns related to the stations, there are other significant benefits to convert voltages to a standard 12.47kV including less power losses and standardized equipment allowing for purchasing efficiencies.

Risk Identification & Mitigation (5.4.5.2 A.4)

This voltage conversion project should be a typical PUC line rebuild, in which PUC has extensive experience designing and constructing. In using standardized framing standards, the design should be efficient and completed as required. Project implementation may be delayed dependent on unplanned, higher priority work arising. No risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on voltage conversion projects and projects of similar nature. Using this information, the length of conductor to be converted/removed, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within projects may occur that will affect budget, but anticipate that program cost variances will even out between projects.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project. If existing REG customers are attached to the 4.16kV system, they will be transferred over to the 12.47kV system. As they will all be connected on the low voltage side, this will have negligible impacts to the project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-3A for an understanding of the area to be converted.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary investment driver of this project. As stated in the project summary, the supplying stations are beyond their rated life, causing reliability concerns. In order to replace the stations to industry standard, they will be replaced with a higher distribution voltage. To support these station replacements, the existing 4.16kV lines will require conversion.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Cost effectiveness is the secondary investment driver. As the conductors are operating at a lower voltage (4.16kV vs 12.47kV), it is required to feed a larger amount of current through conductors to supply the same amount of power. Voltage conversion will result in a reduction in losses. Additionally, standardizing material allows PUC to store less material, requiring less inventory.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate risk of power supply reliability from degrading below PUC's targets by allowing for end of life distribution stations to be replaced.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

As shown in PUC's asset management plan, distribution stations 4 and 5, currently operating at 4.16kV distribution voltage are nearing end of life. As stated above, this project is to support the replacement of said distribution stations.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the condition of the distribution systems, it is important to ensure that this project area be completed in the budgeted year. Not completing this project area in the budgeted year will delay the voltage conversion project, delay the replacement of the 4.16kV distribution stations and increase risk of system reliability decreasing.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and in turn the distribution station replacements will have a significant positive effect on system operational efficiency, improving reliability and decreasing stations maintenance costs. Alternatives are observed on a case by case basis. Installing a step down transformer is an alternative reviewed for each area. This is used more for scheduling purpose versus a final solution as expenditures would be lost once final conversion occurs.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a more reliable distribution system with additional supply points. This should result in less outages, and when an outage occurs, the duration will be limited. Benefits have not be quantitatively calculated for this project.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project will positively impact system reliability performance. The project will result in the ability to replace existing, aged distribution stations with new. Additionally, this project will replace each distribution transformer and insulator used within the 4.16kV system to support the higher voltage resulting in new assets with lower risk of failures. Upon completion of the project area, the area will be supplied from the 12.47kV system, which has many distribution stations available, resulting in shorter duration outages, if they occur.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical and cost effective alternative designs for this project that provide the same level of benefits to customers.

Safety (5.4.5.2 B2)

In order to convert voltages within this project, many transformers will require replacement. Framing, inclusive of separations on existing poles may be well below current standards. In order to ensure separations are achieved and working space is considered, many poles beyond their useful life will require replacement. In replacing poles, safety is increased for both the work (working space) and the public (new asset).

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Many existing 4.16/2.4kV, pole mounted transformers are well aged transformers, typically manufactured prior to the 1980's, resulting in a posibility of containing PCB levels exceeding the acceptable 50ppm. During this project, all 4.16kV transformers will be removed, mitigating environmental risks in an occurance of transformer oil leaking.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a distribution system infrastructure failure and the immediate reliability impact. Additionally, each area is reviewed in relation to the age of infrastructure, deteriorated poles, restricted wire, etc. to ensure all aspects are considered during prioritization. Increased safety concern would increase project prioritization.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Assets within this projects are generally beyond their typical life-cycle. This is based on the age of installation of 4.16kV systems, specific to these areas. Due to this, in conjunction with pole testing records, most of the infrastructure is due for replacement. This is considered during conversion for efficiencies.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 25
Number of MicroFit Customers: 1
Load Impacted (Tx Ratings): 187.5kVA

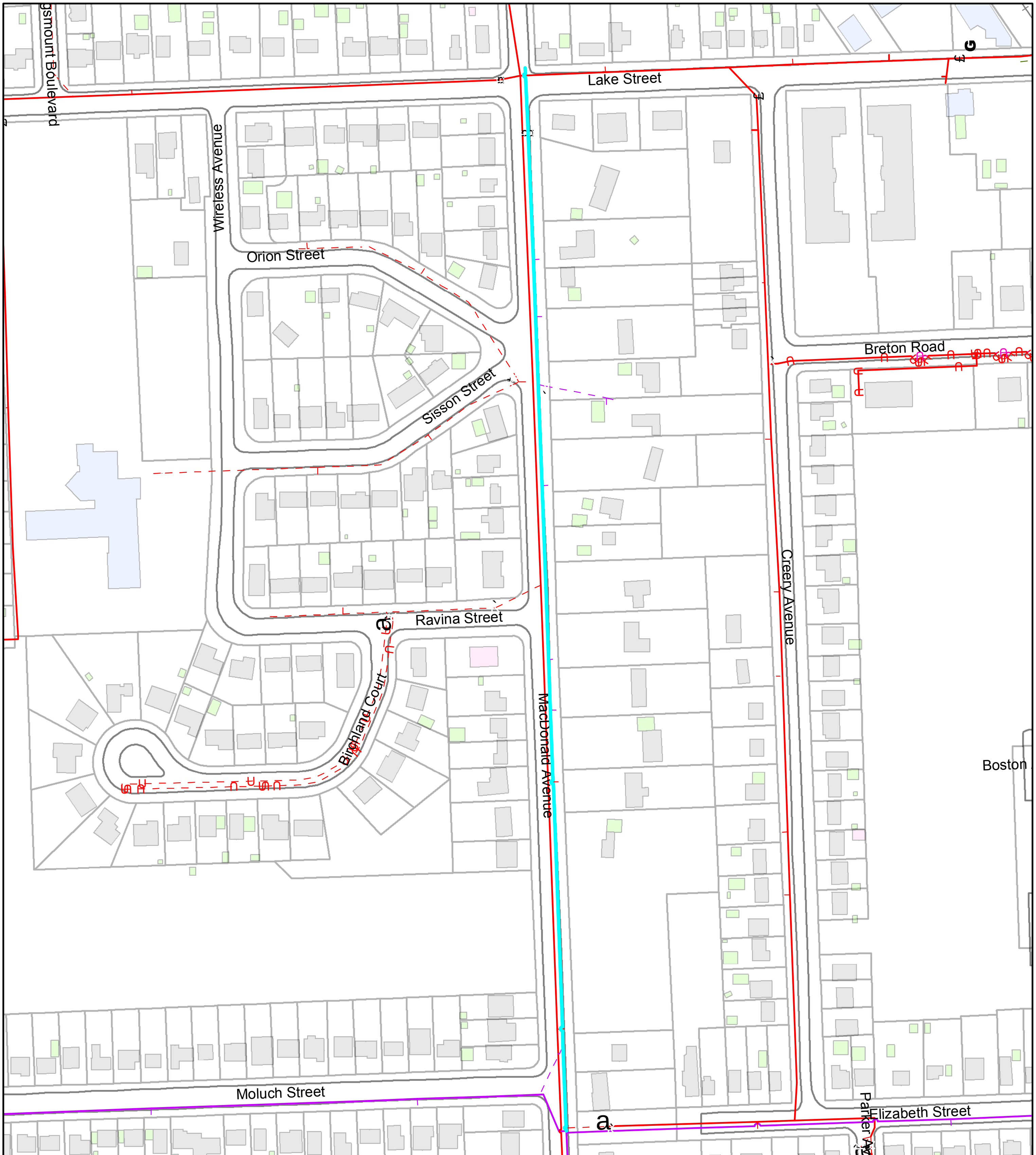
Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of this project will benefit from a more reliable distribution system as well as new infrastructure providing for a higher level of safety.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)
Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.
Timing and Priority of Project (5.4.5.2 SR-C2)
This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the nature of this project in coordination with other projects, this project is scheduled to be constructed during Q1 of 2018.
Consequences for system O&M costs (5.4.5.2 SR-C3)
This project will convert an existing line with similar length of a new line causing negligible O&M impacts. Replacement of poles and infrastructure during the project should be a positive contributing factor pertaining to outages and repairs, reducing potential O&M costs.
Impact on reliability performance and/or safety (5.4.5.2 SR-C4)
As described above, this project, in coordination with distribution station replacements, should result in improved system reliability and safety.
Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)
This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.
Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)
While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives are reviewed on a case by case basis to maximize benefits and minimize costs.



Notes:
All locations are approximate as final design has yet to be completed.

N E S W

SCALE: NTS

SYSTEM PLANNING
2018 - VOLTAGE CONVERSION
MacDONALD AVE.
LAKE ST. TO MOLUCH ST.

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 08/17	JT

DRAWN BY: J. TEVC	DATE: SEP. 08/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.:	REV
(2018)-1C300-1-3A	A

A. General Information						
Project/Activity	#13 - Overhead Renewal - Restricted Wire (Carpin Beach Road - Base Line to Herkimer, Phase 1 of 2)					
Project Number	(2018) 1C300-1-4A					
Investment Category	System Renewal					
	2018	**2019**	**2020**	**2021**	**2022**	
Capital Cost (5.4.5.2 A.1)	$ 185,155.00					
Capital Contribution	$ -					
Net Cost	$ 185,155.00					
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**	
	NA	NA	NA	NA	NA	

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 12
Load Impacted (Tx Ratings): 137.5kVA

Start Date (5.4.5.2 A.3)	1-Sep-18		**In Service Date (5.4.5.2 A.3)**	31-Oct-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ -	$ -	$ 92,577.50	$ 92,577.50

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4A for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical alternatives available for this project area and project as a whole.

Safety (5.4.5.2 B2)

Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

Reducing downtime of PUC's system contributes positively towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution and would not bring the value of economies of scale.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 12
Load Impacted (Tx Ratings): 137.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the extensive ditches in the rural areas well as the lack of snow storage in the area, this project is preferred to be completed in the non-winter months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.

Notes:
All locations are approximate as final design has yet to be completed.

N
W E
S
SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
CARPIN BEACH RD
BASE LINE TO HERKIMER ST.
PHASE 1 OF 2

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 08/17	JT

PUC

DRAWN BY: J. TEVC	DATE: SEP. 08/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.:	REV
(2018)-1C300-1-4A	A

Appendix H

Customer Engagement

Customer Engagement Overview

OVERVIEW

PUC Distribution Inc. (PUC) believes that customer engagement is the backbone of its community-driven operations. PUC recognizes that providing opportunities for customers to share their feedback will not only strengthen their relationship with them but also, improve the overall customer experience.

As a Local Distribution Company (LDC), PUC understands that its role in planning for the future of the electrical distribution system involves more than just measuring equipment service life. It requires including customers in the planning process to ensure that they have considered their needs and preferences when it comes to developing long-term plans. To that end, PUC is committed to growing and expanding on the success of its existing community service and customer engagement initiatives.

PUC has increased formal and informal community engagement activities with its customers over the last five (5) years. Those engagement opportunities identified a number of customer needs and preferences, along with room for improvements to be made. The areas identified that needed the most attention were improving customer communications, increasing customer consultations, and growing energy literacy in the community. Although many new ideas continue to be explored, we have successfully implemented a number of improvement initiatives over the past five years that have been directly related to customer feedback and expectations.

For the purposes of this summary, formal engagement is described as a direct, focused method to obtain detailed customer feedback pertaining to specific issues. For example, surveys, focus groups, and information sessions.

Informal engagement is described as an indirect method of engagement that supports two-way communications with customers. Customers are encouraged to share their opinions, feedback, and anecdotal experiences in an informal environment, such as a trade show, community festival, or retail consultation event.

CUSTOMER ENGAGEMENT (Formal)

The customer engagement program at PUC has gradually become more integrated into the operations of the company. It has evolved from a basic business-to-consumer relationship to a more strategic and informed partnership. This has been accomplished by the increased communications and outreach through surveys, media releases, and community speaking engagements, such as community information sessions. The formal customer engagement methodology is derived from the need to improve our community's overall energy literacy, especially pertaining to the electrical distribution system, its assets, and PUC's operations. We utilize the following to gain feedback from our customers, and to promote open discussion of customer issues, so that we may ensure we are continuously adapting to a customer-driven environment.

a. Customer Surveys

Additional efforts to inform, educate and engage with customers have been conducted through public surveys. The surveys gauge the understanding of the electricity bill, the electrical distribution system, PUC operations, well as the overall public perception and customer satisfaction.

i. Customer Engagement Survey (COS Application)

Purpose: This survey was developed to inform customers of the proposed rate increase associated with the 2018 Cost of Service application. It provided a short overview of PUC operations, cost drivers, bill breakdown, and a variety of capital projects needed to be completed. It allowed customers to comment, and open two-way communication between PUC and its customer base, in order to move forward with efficient customer engagement strategies.

Initiated By: PUC, third party consulting company

Participants: 2,004 (1,321 completed surveys)

Nature and Timing of Deliverables: PUC wanted to target 1,000 respondents regarding service reliability, COS application and most importantly, the proposed rate increase. The customer engagement survey was meant to open discussion about operations, and capital projects needed for system reliability. The survey results will be used as a benchmark to address customer concerns, and measure/track improvements.

DSP-related: Customers agreed that keeping rates as low as practical while maintaining good quality electrical service was the most important priority for PUC. The DSP was revised several times to ensure that the proposed rate increase was as low as possible, while taking the Asset Management Plan into consideration for necessary system renewal projects.

- The survey detailed the Operations, Maintenance and Administrative cost drivers, including new Regulatory Requirements, utility costs, bad debt, industry regulations, and inflationary increases which have all increased since 2012/2013. For that reason specifically, the DSP includes an additional staff member to assist with Rates and Regulatory needs. Currently, there is one person tasked with the R&R responsibilities.

- 48% of respondents agreed that they had a better understanding of the proposed rate increase to cover the OM&A costs, and another 12% that were interested in obtaining more information. The 5th project in the DSP complies with the OEB mandate requiring general service customers >50kW to be equipped with MIST revenue meters.
- Customers were informed of capital projects such as the overhead/underground system renewal, pole replacements, substation builds, and the voltage conversion replacement plan. One of the capital projects included in the DSP is the building of a new 12kV distribution station to replace two 4kV existing distribution stations that are currently in very poor condition and at the end of their useful service life. This will help reduce operating costs when the two 4kV stations are retired from service.

Future Considerations: PUC will expand on the DSP-related customer engagement through information sessions regarding projects listed in the DSP, including a Q&A discussion for customer input and concerns to be addressed. Furthermore, customer engagement related to the DSP framework and ongoing implementation will be conducted with timely, effective discussion.

Customer Engagement Survey - KEY FINDINGS

PUC, along with the assistance of a third party consultant, developed the Cost of Service, Customer Engagement survey to distribute to its customers. The survey provided PUC an opportunity to expand on its customer engagement, and provide customers with information on the proposed rate increase. The survey provided a short overview of PUC operations, cost drivers, the breakdown of a customer's electricity bill, and a variety of capital projects to be completed.

The survey had informational videos embedded within it. The videos included pertinent information related to the COS application, such as the cost drivers associated with operations, and planned capital projects. The survey was designed to provide two-way engagement between the PUC and its customer base. It allowed customers to provide feedback about existing services, and to share their thoughts about a proposed increase.

Some of the recurring themes in the survey analysis were:

- The cost of electricity
- Seniors on fixed incomes
- Dislike Smart Meter System (inefficient, costly)
- TOU discrimination (seniors, families, shift workers)
- High electric heating costs in Northern Ontario winters
- Government Assistance (should assist more with infrastructure renewal)
- PUC should be advocating/lobbying for customers with the Government
- Internal spending; cut costs before requesting an increase (provide evidence of doing so)
- Operation transparency (customers want more details and information on where money will be used)

The cost of electricity is a large concern for customers, and ensuring that good service is provided in the most cost-effective way needs to be a priority for PUC. The survey data indicates a large percentage of customers are on fixed incomes and are struggling to afford their electricity bills.

As a follow-up to the survey, and as an enhancement to the customer engagement element of PUC's operations, there are plans to host public information sessions. These will open discussion about the COS application, proposed increase, and most importantly address some of the customer comments received in the survey. PUC wants to ensure that their customers know they are listening to them, and care about their opinions. There will be specific sessions to ensure PUC engages larger business customers as well.

The following is a breakdown of the survey data, as well as the analysis of over 3,500 customer comments.

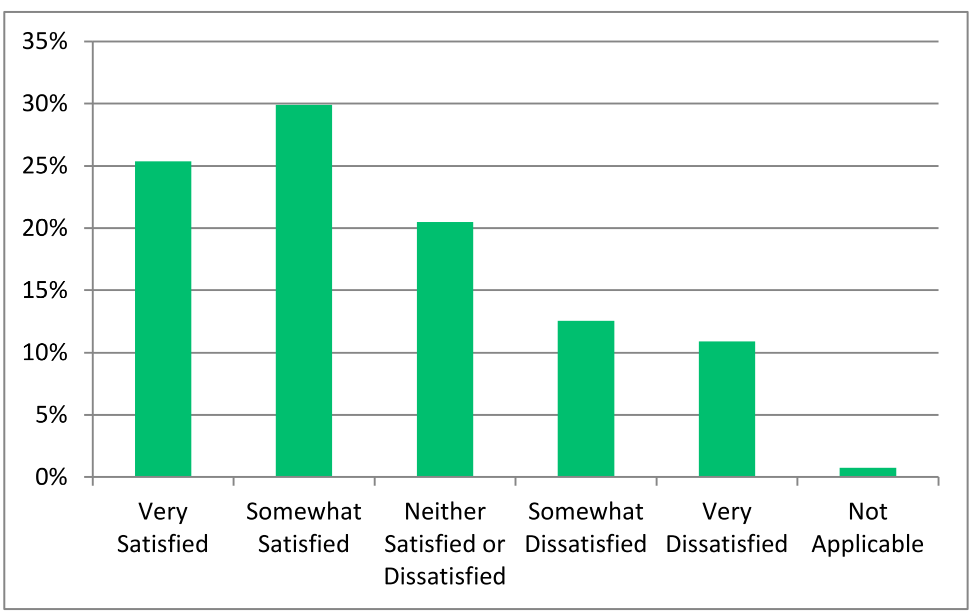
Customer Engagement Survey - DEMOGRAPHICS & SEGMENTATION

As of January 24, 2018, PUC Distribution's Customer Engagement survey had a combined total of 1,962 participants with 1,321 completed responses. The majority of respondents were aged 55-74, and based on the comments received in the survey, most are retired and living on a set income. The second largest contributors are ages 35-54. There was an equal amount of male and female participants.

The largest group of participants were homeowners at 85%, with the second largest being tenants at 12%. Unfortunately, the response from PUC business customers was low, so with that in mind, PUC plans on coordinating information sessions, specifically targeted to inform business customers on how the increase may affect them.

97% of survey participants were located in the City of Sault Ste. Marie, while another 3% of respondents were PUC customers in surrounding areas. PUC Distribution's customers are serviced by a multi-utility service provider, including electricity, water and the sewer charge for the City of Sault Ste. Marie, all included on a common bill. 85% of participants receive both electricity and water services. This is evident through the survey comments received, as many mention both electrical and water services.

Customer Engagement Survey - OVERALL SATISFACTION



Question 8

When asked about the overall customer satisfaction, results showed that 56% of respondents said that they were "very" or "somewhat satisfied" with the overall service(s) they received from PUC, while 24% were somewhat or very dissatisfied.

Out of the 342 comments received, participants elaborated on the factors they were unhappy with, or what they wanted more information about.

With the main concern identified in the comments as the 'High Cost of Electricity', PUC has worked hard to ensure that the proposed rate increase in the COS application, is as low as possible while still balancing infrastructure needs with customer affordability.

Additionally, many comments were received requesting more information about PUC's operations and transparency with internal spending. The Customer Engagement team will be delivering public information sessions to answer some of these and other questions that were raised in the survey comments.

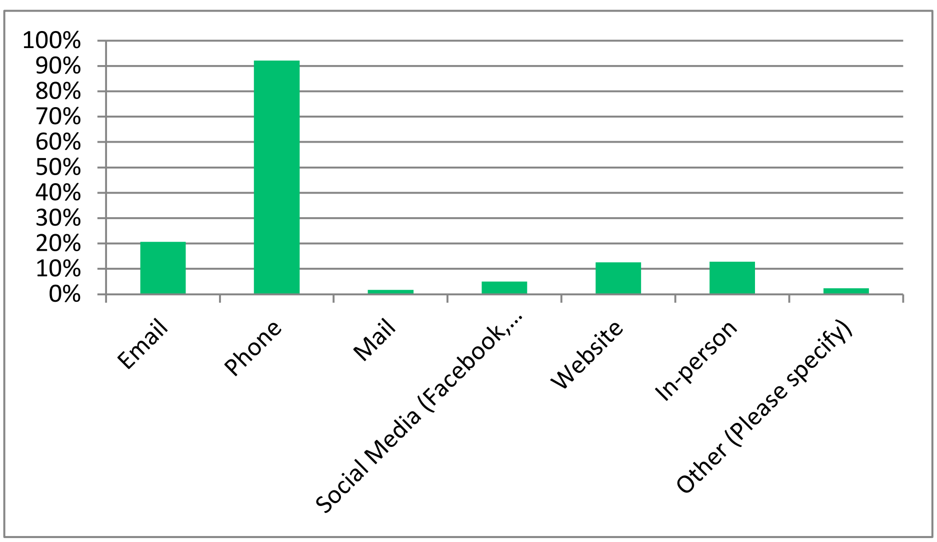
Customer Engagement Survey - PUC PRIORITIES

The OEB requires LDC's to understand customers' preferences so customers were asked to place PUC priorities in order of importance to them. The results support the importance of keeping costs as low as possible without sacrificing system reliability.

Out of the 1,321 respondents, these are the top three customer priorities:

1. 58% of respondents selected; "**Keep rates as low was practical while maintaining good quality electrical service**" as their number one priority. This supports the belief that customers want reliability, but want to ensure that it is done in a cost-effective way.
2. 34% of respondents selected; "**Maintaining reliable electrical service (e.g. prevent/reduce power outages)**" as their number two priority.
3. 34% of respondents selected; "**Helping customers reduce/manage consumption and by doing so reducing costs**" as their number three priority.

Customer Engagement Survey - COMMUNICATION

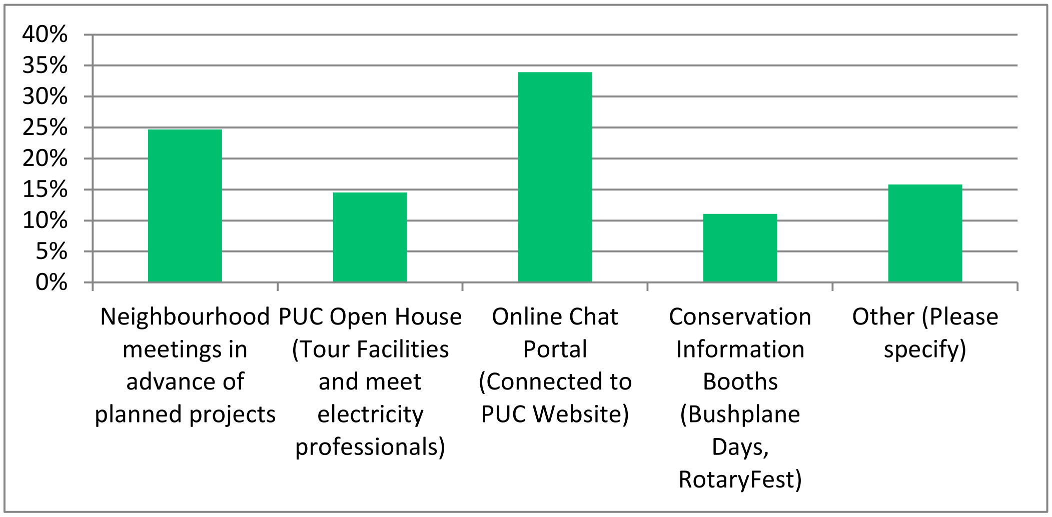


Question 14

Customers indicated overwhelmingly that their preferred method for contacting PUC for service issues was via the phone. However, some customers mentioned in the comments that they would appreciate the opportunity to speak with a PUC employee face-to-face, at their home.

In 2017, in an effort to improve customer service, PUC introduced a new stage in the planning process. Engineering technicians are now required to include customers whose property will be impacted by infrastructure renewal in the design phase of the project. Customer input will now be included directly into the design phase. The first example of this new engagement process occurred in 2017, with a number of submersible transformer being converted to a pad-mounted transformers in a neighborhood.

Improved customer communications is needed; this is evident through comments received and the overall perception customers have about PUC. However, while customers indicated that they would like PUC to improve communications and engagement, they do not want it at a significant cost to their bills.



Question 27

34% of customers responded in favour of an online chat portal as an improvement in communications, wanting to be connected to a live representative when they do have an issue. In response to this feedback, PUC is actively exploring options for integrating an online chat portal into its website by the end of 2018.

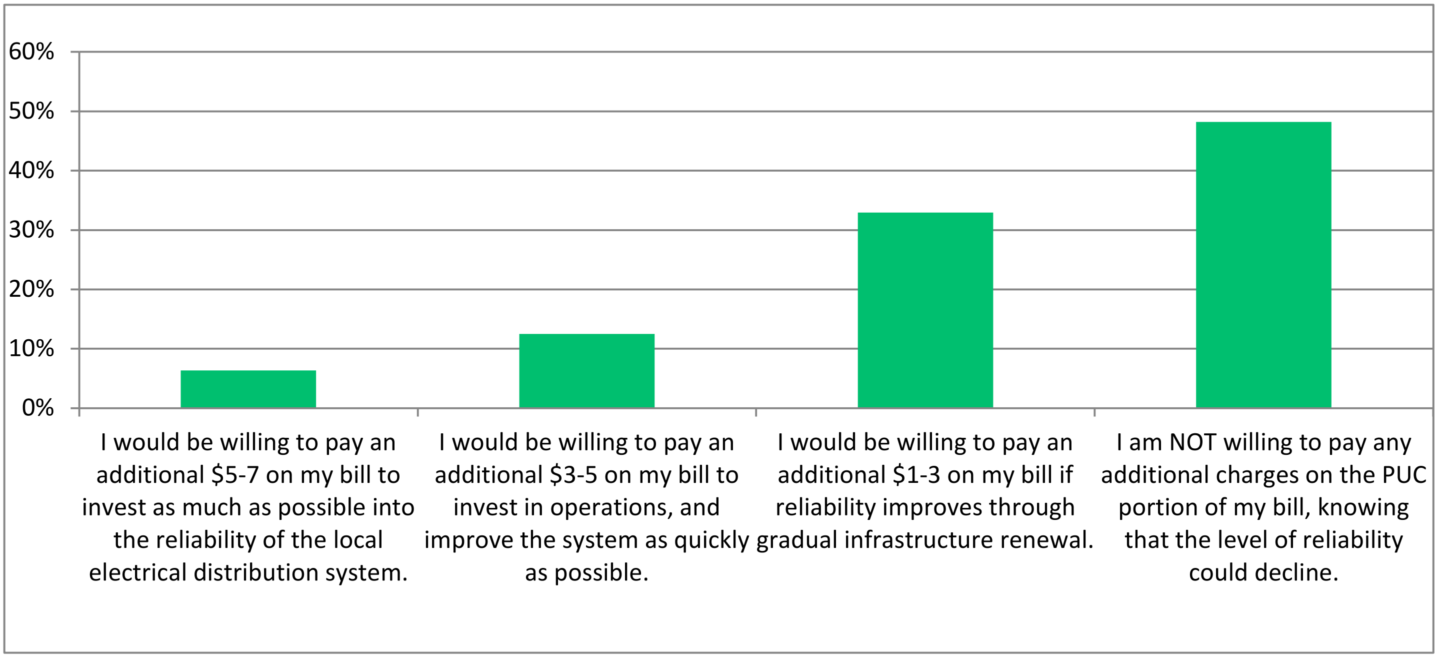
Customer Engagement Survey - OPERATIONS, MAINTENANCE & ADMINISTRATION

Participants were provided information on the cost drivers behind the PUC's proposed rate increase in the OM&A video. The goal was to provide customers with a better understanding of the reasons behind the proposed rate increase. After reviewing comments, it was evident that customers want more information, some questioning the validity of each cost increase, others not understanding regulations pertaining to the LDC. The survey results show that the majority of customers have a better understanding of the reasons behind the rate increase. However, there are still a large amount of customers that need more information, before they can support it.

This is another reason why PUC plans to host information sessions, release the survey results, address comments received, and provide clarification about operations. It will ensure customers have adequate knowledge of how PUC is regulated, what measures are in place to reduce spending, and how costs were reduced internally before requesting a rate increase.

<u>Customer Engagement Survey - CAPITAL INVESTMENT PROJECTS</u>

The participants were provided information on cost drivers related to infrastructure renewal, including voltage conversion, and sub-station rebuilds. After which, they were asked if they would be willing to pay any additional amount to assist with maintaining reliability, improving reliability, or not paying anything knowing that reliability of the system could decline.



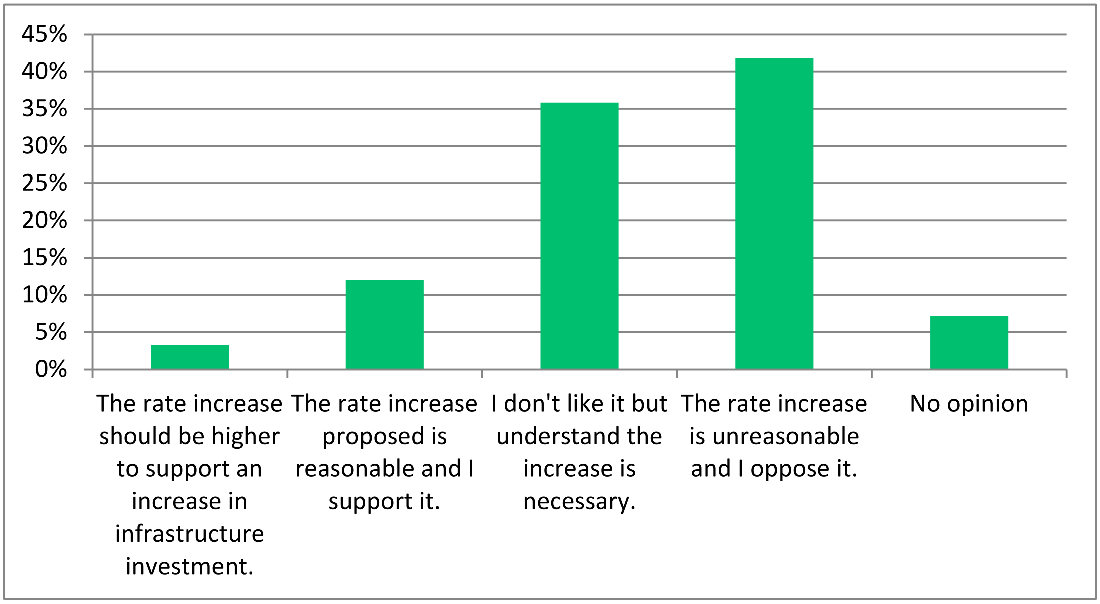
Question 22

The results represent an almost evenly divided group of customers 52% willing to pay something to improve reliability, and 48% unwilling to pay any additional amount for an increase in reliability.

While there were positive comments received from customers indicating that they understand the necessity of upgrading, along with maintaining equipment to ensure reliable service. There were also customers who stated that they need more information to support an increase of any kind; not that they oppose it.

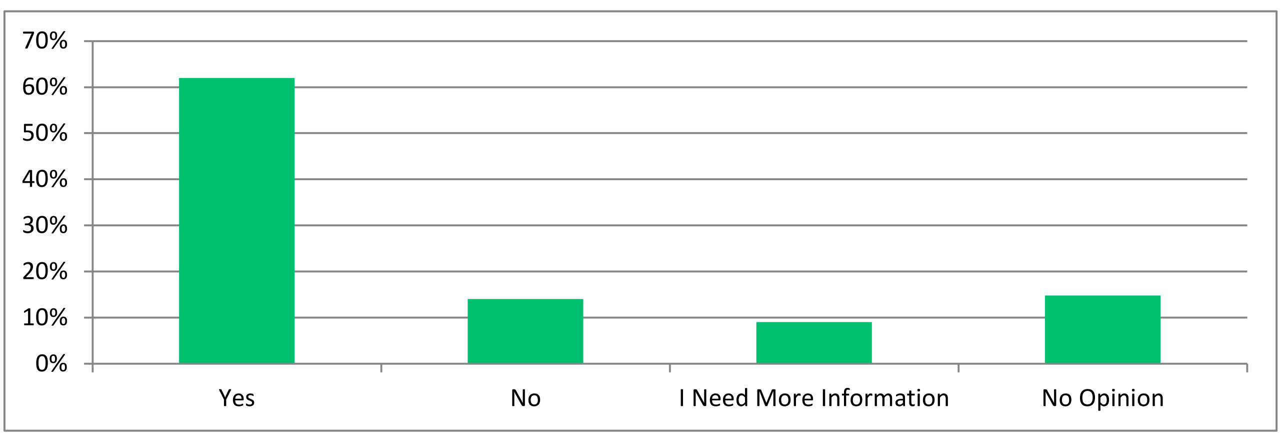
Customer Engagement Survey - PROPOSED INCREASE

When asked, ***Now that you're familiar with some of the planned projects, what do you think of the proposed rate increase to support infrastructure investment?*** A large segment of customers believe it to be unreasonable and do not support it. After reviewing comments, there were participants who once again mentioned needing clarification to make an informed decision to support or oppose the increase.



While a majority of customers either support the increase, or understand the necessity behind it – PUC recognizes that more needs to be done to engage with customers.

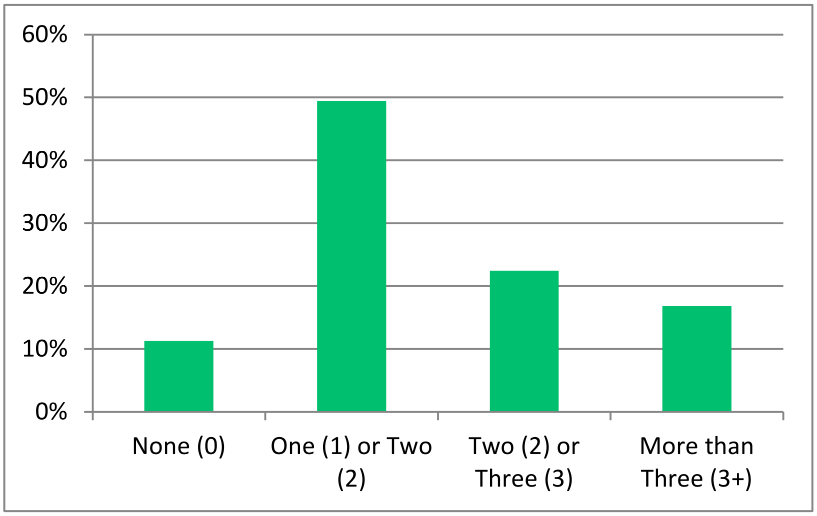
Most participants did state that they were provided with enough information in the survey to understand the reasons behind the proposed rate increase. This supports the previous question of customers understanding the rate increase is necessary, but not liking it or supporting it, based on the information provided to them. PUC will continue to provide information and address comments received in the survey to ensure customer concerns are addressed.



Question 24

Customer Engagement Survey - RELIABILITY

Customers chose "maintaining reliable electrical service" as the second priority for PUC. When customers were asked; ***In the Past Year, How Many Power Outages Have You Experienced?*** The results show that the majority of customers do not experience many outages.



Question 25

Customers rarely experience outages more than 3 times in a year. These statistics correspond with PUC's the reliability data for SAIDI and SAIFI. When asked; ***What was the longest power outage they had in the past year?*** 72% of participants indicated that they had only experienced short outages, up to 90 minutes.

When asked if they contacted PUC about the power outage, 71% of customers commented that they did not, stating that they trust the organization knowing that the problem will be reported, acknowledged, and fixed as soon as possible. 79% of customers agree that the reliability is "very good" or "good" when it comes to PUC response times for outages.

Reliability means more than maintaining quality electrical service; it also relates to PUC's responsiveness to customer needs and preferences. PUC has increased the amount of calls it can handle through software upgrades, provided an updated outage notification system, and improved services such as service orders for real-time metering.

Customer Engagement Survey - Exhibits

- Cost of Service Survey Master Script See: EXHIBIT 1
- Cost Of Service Survey Storyboard: EXHIBIT 2

ii. Customer Satisfaction Surveys (2015 and 2017)

Purpose: Gauge overall customer satisfaction, the utility's performance, public perception, and utilize as an engagement tool to collect quantitative data. Customers were also consulted about the willingness to pay an increase for expenses such as capital, and operational items.

Initiated By: PUC, through the Utility Pulse Division of Simul Corporation

Participants: **2017** - 1,553 Households (401 Completed Interviews) – Residential (85%) Commercial (15%)
2015 – 1,600 Households (403 Completed Interviews) – Residential (85%) Commercial (15%)

Nature and Timing of Deliverables: The survey allowed PUC to gain valuable insight from the results, including customer preferences about system reliability, infrastructure replacement, and PUC priorities. <u>Unless otherwise stated, the results listed below are based on the most recent (2017) Electric Utility Customer Satisfaction Survey data.</u>

DSP-related: 91% *(pg. 25 – 2017 UtilityPULSE CS Survey)* of ALL respondents with an opinion agree that PUC provides consistent, reliable electricity, and continues to meet customer expectations. Over the last 5 years, PUC has improved reliability for customers through voltage conversion projects, substation rebuilds, outage management system improvements and upgrades to the overhead/underground distribution system.

The amount of customers that believe a pro-active replacement of equipment to ensure reliable power (even though it may cost more) has declined by 8% from 72% in 2015 *(pg. 93 – 2015 UtilityPULSE CS Survey)* to 64% in 2017*(pg. 38 – 2017 UtilityPULSE CS Survey)*, based on **ALL** respondents. Although 89% of PUC customers *(pg. 16 – 2017 UtilityPULSE CS Survey)* agree that reliability is consistent with their expectations, 69% of all respondents *(pg. 41 – 2017 UtilityPULSE CS Survey)* (69% Residential and 70% Small Commercial) are willing to pay more to replace aging equipment to improve safety and reliability. As a result of customer input, this DSP focuses on equipment in poor or very poor condition, or near the end of its service life, in alignment with the Asset Management Plan.

The DSP includes a variety of projects that are driven in part by safety. For example, one of these projects is the rebuild of a substation (16), in very poor condition, and at the end of its service life. Due to the state of the existing station infrastructure, the switchgear is deemed to be unsafe to operate while energized and must be isolated and de-energized prior to operation. This results in isolation out on the 34.5kV sub-transmission lines, the path for one of two circuits feeding the local hospital.

Future Considerations: We have identified future opportunities to include more specific questions related to projects in the DSP. The biggest challenge is ensuring that the electrical engineering terms are communicated clearly enough for customers to understand equipment, processes and how the system works, which will be part of our customer education efforts.

Here are some of the results that compare 2015 and 2017 survey data (residential and businesses):

2015 *UtilityPULSE Customer Satisfaction Survey*	**2017** *UtilityPULSE Customer Satisfaction Survey*	**Variance**
* 89% agree PUC provides consistent, reliable electricity (pg. 14)	* 91% agree PUC provides consistent, reliable electricity (pg. 25)	+2% increase in reliability
* 89% agree PUC quickly handles outages and restores power (pg. 14)	* 90% agree PUC quickly handles outages and restores power (pg. 25)	+1% increase in outage management
* 89% agree electricity safety is a top priority for employees and contractors (pg. 14)	* 91% agree PUC ensures electricity safety is a top priority (pg. 25)	+2% increase in safety as a top priority
** 45% indicated they had a blackout or outage problem in the last year (pg. 9)	** 32% indicated they had a blackout or outage problem in the last year (pg. 12)	-13% decrease in blackout or outage issues; coincides with outage management and less occurrences
* 81% agree PUC is “easy to do business with” (pg. 15)	* 85% agree PUC is “easy to do business with” (pg. 5)	+4% increase in ease of doing business
* 75% agree PUC is customer-focused and treats customers as if they’re valued (pg. 15)	* 73% agree PUC is customer-focused and treats customers as if they’re valued (pg. 5)	- 2% decrease in being customer focused and treat customers as if they’re valued
* 50% agree that the cost of electricity is reasonable when compared to other utilities (pg. 15)	* 44% agree that the cost of electricity is reasonable when compared to other utilities (pg. 25)	-6% decrease One of the lowest LDC rates in Ontario; customer perception remains a challenge.
** 13% had a billing problem in the last year; with majority stating the amount owing was too high (pg. 8)	** 25% had a billing problem in the last year; with majority stating the amount owing was too high (pg. 13)	+12% increase Generally, our analysis suggests the “problem” is high cost rather than billing errors.

*Based on **ALL** respondents with an opinion* ***Based on **ALL** respondents*

Reliability

- 89% of **ALL** respondents agree PUC has a standard of reliability that meets their expectations *(pg. 16 – 2017 UtilityPULSE CS Survey)*
- 92% of **ALL** respondents agree that PUC is effective in responding to outages *(pg. 19 – 2017 UtilityPULSE CS Survey)*
- 94% of **ALL** respondents agree PUC restores power quickly *(pg. 19 – 2017 UtilityPULSE CS Survey)*
- 57% of **ALL** respondents with an opinion agree PUC provides good value for money *(pg. 25 – 2017 UtilityPULSE CS Survey)*

We have identified this as an opportunity to educate customers about operations and what is done with the amount that PUC retains on their bill. This is evident through CDM initiatives such as funded programs, in-store retail product consultations, and information sessions for understanding the electricity bill. It is our responsibility, in the position of trust and public interest that we communicate what PUC is doing to improve the electric system, ways we are trying to keep the rates at reasonable levels and improvements to expect with capital investments.

PUC is increasing customer engagement and improving the methodology used to do so, including an interactive customer survey that provides a detailed overview of operational and capital costs for customers to understand. Based on the results of our formal engagement, PUC has implemented several customer-driven changes which are as follows:

Better prices/lower rates

PUC customers are increasingly focused on their electricity costs, with emphasis on receiving better prices and lower rates. There has been a dramatic increase, from 36% of total respondents with suggestions in 2015 *(pg. 75 – 2017 UtilityPULSE CS Survey),* and now 67% of **ALL** respondents in 2017 *(pg. 46 – 2017 UtilityPULSE CS Survey)*. PUC does not believe our customers want to see us sacrificing their electrical distribution system's reliability and service levels for the lowest rate. PUC believes its obligation to the public is to provide a safe, reliable, and efficient service as well as meeting regulatory requirements as an LDC.

During 2015/2016 operations, PUC declined a potential rate increase, recognizing in part severe concerns on the state of the local economy. Our largest employer, a steel manufacturer experienced a time of financial hardship. Knowing that a vast majority of customers rely on income from the steel manufacturer, we understood that it was not a good time for the suggested rate increase, even though it was needed.

Most customers are unaware of the ageing of the electrical distribution system infrastructure, operational costs, and asset renewal. With that in mind, we have introduced engagement opportunities to provide energy literacy. The price of electricity has also risen provincially in the last few years, and customers are feeling the effects on their bills. Although the Provincial 25% cost reduction has been of great assistance to residential customers, small business has not seen the same reduction and have been hit hard by local economic conditions.

Although a large percentage of our assets are part of an aging electrical distribution system, we have held off on capital investments for large-scale infrastructure such as the transformer stations, based on customer concern for increasing costs. PUC has developed its DSP to include asset renewal at a steady pace, rather than a significant increase that would affect the customers more advertently. Especially being in the North, where heating costs can be highly impacted during the winter months, and the local economy is still reeling from the effect of the steel industry.

Customer Communication = Online Access *(2017 UtilityPULSE CS Survey Results)*

- 83% of total respondents access the internet for information; 71 % use online banking *(pg. 27)*
- 72% of **ALL** respondents agree PUC effectively provides information about the outage *(pg. 19)*
- 75% of **ALL** respondents agree PUC provides information to help customers reduce their costs *(pg. 47)*
- 69% of **ALL** respondents agree PUC is using media channels for updates *(pg. 19)*
- 58 % of **ALL** respondents agree researching information about energy conservation *(pg. 28)*
- 53% of **ALL** respondents agree that it was important to review their bill online *(pg. 28)*
- 44% of **ALL** respondents agree that tools and calculators are important to help manage consumption *(pg. 28)*
- 34% of **ALL** respondents agree automated alerts to remind you of your bill date *(pg. 28)*

We have increased our online presence for power outage notification and conservation on our website and local media outlets. The introduction of the customer portal, Customer Connect, was implemented to aid customers in understanding usage, utilized as a tool to change consumption habits based off TOU data, and to ensure customers had the information to make choices about usage.

Trust

Overall, 85% of Secure and Favourable respondents are confident that PUC Distribution is using good judgment to prioritize investments *(pg. 37 – 2017 UtilityPULSE CS Survey Results)*

Willing to Pay For

In 2015, customers (*based on 90% of **ALL** respondents from the PUC), top **operational** items they were willing to pay more for *(pg. 96 – 2017 UtilityPULSE CS Survey Results)*

- 54% increased tree trimming
- 46% a proactive outage management system
- 46% educating customers and the public about electricity safety
- 45% educating customers about energy conservation

In 2017, customers (based off **ALL** respondents), top **operational** items they were willing to pay more for: *(pg. 44 – 2017 UtilityPULSE CS Survey Results)*

- 23% a proactive outage management system
- 23% educating customers about energy conservation
- 13% increased self-service options on the website

In 2017, customers (based off **ALL** respondents), top **capital** items they were willing to pay more for: *(pg. 41 - 2017 UtilityPULSE CS Survey Results*)

- 69% replacing aging equipment to improve safety and reliability
    - Of those who answered YES = Residential 69% / Small Commercial 70%
- 50% upgrading equipment to accommodate future growth in the community
    - Of those who answered YES = Residential 47% / Small Commercial 63%

Which of the following OPERATIONAL items would you be willing to pay more for?					
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
A proactive outage management system	23%	74%	3%	23%	27%
Increased self-service options on the website	13%	85%	2%	13%	12%
Educating customers about energy conservation	23%	76%	1%	23%	22%

(pg. 44 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Which of the following CAPITAL items would you be willing to pay more for?					
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
Replacing aging equipment to improve safety and reliability	69%	29%	2%	69%	70%
Upgrading equipment to accommodate future growth in the community	50%	48%	2%	47%	63%
Adding automation and technology to reduce outage time	45%	52%	2%	43%	55%
Investing in technology to deal with cyber security issues	37%	58%	5%	37%	33%

(pg. 41 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Strategy for replacing equipment

PUC Distribution	Residential	Small Commercial
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	21%	13%
Pro-active replacement, even though it may cost more, should ensure reliable power	63%	68%
Don't Know	16%	18%

(pg. 39 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Strategy for replacing equipment

PUC Distribution	2017	2015
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	20%	19%
Pro-active replacement, even though it may cost more, should ensure reliable power	64%	72%
Don't Know	16%	10%

Base: total respondents

(pg. 38 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

iii. Strategic Direction Plan Survey (2016)

Purpose: PUC started the process of developing a new Corporate Strategic Plan to set direction and priorities for the utility over the coming years. Customers were asked their opinions on the organization's strategic direction, and what they believed were key challenges for the utility. PUC wanted to gain feedback to support the development of the strategic plan.

Initiated By: PUC, through Ironside Consulting Services Inc.

Participants: 194 Respondents (Customers and other Stakeholders)

Nature and Timing of Deliverables: The survey allowed PUC to gain valuable insight from the results, including input to align the utility's vision, values and PUC priorities.

DSP-related: 83% of survey participants agree that PUC's key challenges include rate increases, 67% agree aging electric infrastructure, and 55% state the uncertain local economy. 92% of customers are aware that PUC does not set the price of electricity, although 76% believe the cost for electricity is not reasonable.

65% of respondents determined that in order to meet these challenges, PUC must ensure that rates are kept fair and competitive. PUC elected to defer a rate increase in 2016 based on the state of the local economy.

52% of respondents believe that rate increases must be reasonable in order to address aging infrastructure. The DSP includes necessary system improvements that will occur gradually, and not at a substantial cost increase to PUC customers, due to their concerns about affordability. PUC has worked to balance the infrastructure and affordability drivers with a proposed rate increase that will affect the total average (using 750kWh) residential electricity bill, by less than $3.00/month.

Customers spoke about the importance of including Customer Service Sensitivity Training, which PUC implemented in 2017 as part of the entire organization's participation in C.A.R.E. Training. Customers wanted more information on bills, residential, commercial and industrial electricity rates in Ontario which PUC introduced at the Public Library information sessions, as well as the Innovation Centre presentations. Comments were received about the importance of affordability as well as money allocation going towards infrastructure improvements.

Customers mentioned online services for moving of service, rather than having to come into the office to initiate service change. They would like to see more incentive programs to get rid of older, inefficient appliances, and more conservation awareness to improve public education and customer outreach. There were also customers who spoke of accountability as an organization; striving to decrease spending internally with overtime, fleet vehicles, and purchasing. The PUC underwent Accountability and Leadership training in 2017 to improve management and employee responsibility. An internal Business Improvement Committee was struck with a mandate to review internal business and process efficiencies. Lastly, customers wanted to eliminate TOU based on discrimination with stay at home parents, large families, aged, ill and unemployed demographics.

iv. Public Awareness of Electrical Safety Survey (2015 and 2016)

Purpose: PUC Distribution participated in a public electrical safety awareness survey to provide a benchmark level concerning the public's electrical safety awareness and identify opportunities where additional education and outreach may be required.

Initiated By: PUC, through the Utility Pulse Division of Simul Corporation

Participants: A representative sample of PUC Distribution's service territory population was surveyed to gauge the public's awareness level of key electrical safety concepts related to distribution assets (the survey was based on a template provided by the Electrical Safety Authority).

Nature and Timing of Deliverables: In 2016 the results of the survey were further analyzed, and a number of opportunities to improve our existing outreach programs were identified. One item of note from the survey results indicated that more emphasis was required to ensure public awareness of Ontario One Call. Of the 36 LDC's that utilized Utility Pulse for the electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%.

In an effort to improve the Ontario One Call awareness, PUC approved a budget in 2016 (for 2017) to purchase promotional Dig Safe decals for the entire operations fleet. Additionally, in partnership with the Association of Electrical Utility Professionals (AEUSP), PUC contributed to the production of a series of Electricity Safety videos for television broadcast in our service area.

PUC Distribution continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Below are examples of PUC Distribution's public safety communication initiatives:

- Elementary School Electrical Safety Program (Caution and Chance) for Grade 3 – 5 within our geographic service territory. Participation included 24 schools. (73 classes, and 1,874 students)
- Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
- Sault Ste. Marie Science Festival (approx. 500 adults and children attended)
- Sault Ste. Marie PUC website – Safety tab with particular activities aimed at educating young people on electrical safety

DSP-related: The DSP includes a variety of system renewal projects that are driven by system reliability, public and worker safety. In addition, the DSP includes ongoing operating costs to support community and public safety engagement.

Future Considerations: PUC has identified the importance of continuing the Caution and Chance Electrical Safety Program and ensuring that Public Service Announcements along with other advertising are utilized to promote safety as a top priority. PUC will also ensure that customers understand the validity of safety behind projects, such as those included in the DSP, by providing more detail and clarification of projects driven by safety.

b. **INFORMATION SESSIONS**

i. Sault Ste. Marie Public Library (April 2017)

Purpose: PUC has received a variety of customer comments regarding issues with bills being too high, and requests to help with lowering utility costs, through customer care calls, surveys, and event interactions. PUC advertised and held a free informational workshop hosted at the Centennial Library. This was timed in accordance with the recent news from the OEB about disconnection bans. The workshop was divided into two parts; the first part focused on breaking down an average PUC bill and explaining how the charges are set. The second part of the workshop provided customers information and ideas to control their energy usage, which included Save on Energy tips and tools.

Initiated By: PUC, (Community Engagement and CDM teams) in partnership with the Sault Ste. Marie Public Library

Participants: There were approximately 40 attendees. Both the Communications and Conservation teams were on-site to speak with customers and answer any questions they had regarding the industry, and PUC's electrical distribution services. The Q&A period allowed customers to share concerns about rates, rising electricity costs, and overall customers mentioned they were pleased with the amount of information supplied.

Nature and Timing of Deliverables: PUC's objective to inform and engage customers was delivered precisely after the media release of the disconnection ban. It is the organization's responsibility to act as a key ambassador for the public, when delivering information that will affect them or their bills.

DSP-related: The DSP was not directly affected by this engagement opportunity, it does take into account the overall concern from customers about affordability by keeping the proposed rate increase as low as practical while focusing on necessary system renewal.

Future Considerations: We have identified future opportunities to increase the number of sessions held and plan to target different groups and organizations like service clubs and the local Chamber of Commerce (business customers).

ii. Community Energy Learning Series Presentations (February 2017)

Purpose: PUC identified a need through customer interactions, to address assistance needed to lower bills, understand bill charges, and the electricity industry and its operations. The PUC was involved with the SSM Innovation Centre, as its Energy Innovation Hub conducted by the Smart Energy Business Strategist who provided public presentations to increase “energy education” using industry facts/trends to reduce energy consumption through energy efficiency and conservation. The overall goal was to improve understanding of consumption habits, tips on lighting, air sealing, appliances, insulating, water heating, heating and cooling, windows and alternative energy technologies available such as solar panels. One presentation focused on understanding what goes into the cost of electricity**,** geared toward the general public and people who desire a greater understanding of what goes into their electricity bill while discussing both government and consumer forces impacting the cost of electricity. The other presentation focused on how to use less energy and save money since the residential cost of electricity has risen significantly in the past decade. Its goal was to teach homeowners and businesses how to save energy and money.

Initiated By: Sault Ste. Marie Innovation Centre, in association with the PUC

Participants: There were approximately 15 attendees.

Nature and Timing of Deliverables: The SSM Innovation Centre recognized that there was a need during the winter months to educate the public about conservation, alternative energy sources, and the electricity industry.

DSP-related: The DSP was not directly affected by this engagement opportunity, it does take into account the overall concern from customers about affordability by keeping the proposed rate increase as low as practical while focusing on necessary system renewal.

Future Considerations: We will continue to develop new partnership opportunities where these types of presentations can be delivered to the community. PUC will utilize advertising and promotions to assist with future events, as the sessions had low attendance.

iii. Neighbourhood Project Meetings

Purpose: In 2017, PUC held customer consultations in neighbourhoods affected by the system renewal projects. PUC engaged customers to discuss the overall program objectives, as well as logistics and possible impact to their property. The consultations were aimed to speak with customers about rear-lot pole replacement and underground conversion for pad-mount equipment location placement.

Initiated By: PUC

Participants: There were approximately 20 of customers spoken to.

Nature and Timing of Deliverables: PUC's objective was to inform and engage with customers through individual consultations before work began. The feedback was positive; the project was completed successfully and with customer involvement in the decision-making process.

DSP-related: The neighbourhood consultations confirm that the execution of projects was enhanced by including this form of customer engagement, and will be included in all future projects.

Future Considerations: PUC found that the one-on-one engagement not only led to a successful project but also improved the level of customer satisfaction from those impacted. We have identified future opportunities to incorporate these interactions on upcoming infrastructure renewal projects, like those mentioned in the DSP. PUC will need to restructure its engagement, and ensure that consultations occur with work planners, engineers, and eventually filter through a standardized engagement process involving customers.

iv. Focus Groups (2016 and 2017)

Purpose: Focus groups were conducted to promote the HEAR (Home Energy Assessment and Retrofit), CDM pilot program and obtain qualitative research data about the current perception of PUC and the Save on Energy program. The first focus group was geared to addressing the substantial amount of homes in Northern Ontario that utilize electric heat. The second focus group was conducted to help improve marketing communications for both residential and small business customers.

Initiated By: PUC, in partnership with the Customer First (group of LDC's)

Participants: 16 respondents, the group was mixed with residential and small business individuals. The customers involved in the focus groups use mostly electric heat in their homes and identified that as their main source of heating.

Nature and Timing of Deliverables: Customers state that utilizing electric heat as their main source of heating in Northern Ontario is costly, ranging anywhere from $100 to $500/per month. This pilot program offered residential home assessments and the installation of programmable thermostats, low flow shower heads, pipe wrap, and block timers.

DSP-related: The DSP was not directly affected by the focus groups.

Future Considerations: PUC has been approached by the local college to partner with their Public Relations and Event Management program to conduct future focus groups on a wide range of energy-related issues.

Focus Group Findings/Results:
The focus group results show that some PUC customers believe they are doing as much as possible to save energy; most commonly by switching light bulbs, using Time-Of-Use savings, and turning off or unplugging unused equipment/machinery. Some are utilizing technology, and interest in capabilities to do so is high with participants. Most thought that some of the large-scale efforts, such as renovations, may not be worth up-front costs vs. the length of time it would take to recoup as an investment.

The participant's overall impression is favourable towards the LDC being the preferred face of energy saving programs in comparison to the Government, whom they associate larger negative issues with Ontario's electrical system. Customers wanted to see relevant comparisons between older vs. newer high-efficiency appliances, before/after cost-savings, detailed usage based on specific electronic/appliance, testimonials from home/businesses that have utilized the program, technology that provides warnings for excessive usage and specific targets for each customer (E.g. Restaurant owners with fridges, coolers, stoves and apartments with refrigerators, air conditioners, etc.).

The CDM department at PUC provided a testimonial from a local automotive dealership that utilized an energy efficiency program to capitalize on lighting savings for its business. We have identified future opportunities that include a customer-focused survey in our COS Application to present opinions and feedback to the Ontario Energy Board; acting as a voice for the customer to the Government. Customers stated that PUC priorities should be: ensuring fair and competitive rates, enhancing quality and reliability of electricity services and ensuring the electrical infrastructure is maintained for future generations.

CUSTOMER ENGAGEMENT (Informal)

PUC's informal customer engagement program includes; industry-related events, community event partnerships, and awareness programs that allow PUC to connect with its customers. PUC utilizes these engagement opportunities to interact with customers, listening to their concerns, and maintaining a presence in the community it serves.

a. COMMUNITY EVENT PARTICIPATION

i. Retail Product Consultation Coupon Campaigns

Through the focus group, PUC customers mentioned that they are unsure what to change or upgrade in their home/business to increase energy efficiency. PUC's CDM team supports the retail product coupon and consultation campaign, where it works alongside local hardware and home supply stores, to promote energy efficient products, provide coupons to purchase those items and provide conservation tips. The customers were pleased with the amount of conservation knowledge received and small improvements such as changing their light bulbs that they could do.

ii. Bush plane Days Festival

This engagement opportunity supports the community's need for social responsibility and is scheduled in September, so we can allocate this time to speak with families about back-to-school consumption habits, new assistance programs available, and provide electrical safety tips to children. The Canadian Bushplane Heritage Centre draws thousands for its Annual Bushplane Days Festival. We provide information about power outages, line work, energy awareness, Caution and Chance for children, and offer giveaways such as TOU stickers.

iii. Rotary Fest Summer Festival

This customer outreach supports the community's need for corporate social responsibility, community sponsorship, and fostering the growth of community festivals. This event is scheduled in the summer with the Rotary Service Club, and we utilize this opportunity to promote children's electrical safety, program assistance for families, and sign-up people for available programs.

iv. Home and Trade Shows

The customer engagement during the Annual Home and Trade Show in our community promotes maintenance and sustainability for home and businesses. During this event, we are able to communicate with customers that may not visit or call PUC offices. This opportunity enables face-to-face communications in an intimate setting for people to ask questions and feel comfortable doing so. Most customers wanted information about rates, the cost of electricity, and how to save. PUC staff offer information about the Save on Energy/HEAR program, CDM initiatives, and explain the time-of-use, smart meter operations, online services such as Customer Connect, capital projects, and sign-up customers for save-on-energy programs when eligible.

v. Caution and Chance Electrical Safety Awareness Program

Safety is a top priority for PUC operations. Internally, PUC fosters a culture of safety across the entire organization and continues to support community awareness through safety campaigns such as "Give Our Workers a Brake" and "Call Before You Dig.". Since 1995, PUC has invested in the Caution and Chance Electrical Safety program. This educational program supports our organization's priority of safety, starting with children in elementary schools. These safety awareness presentations are conducted at local schools by our employees. We attribute, in part, our high score in the public safety awareness survey, (86%), to this investment and commitment to safety education and awareness.

vi. Chamber of Commerce Business Networking Events

The survey and focus group responses from business customers wanted more information to assist in lower costs and increasing energy efficiency. The CDM team provided business customer support, awareness and program eligibility to minimize costs. There was a breakfast event and presentations for small business incentive information, such as lighting, retro-fit programs and save on energy promotions. We have identified future opportunities that include increased involvement with Chamber of Commerce events to reach a broader business network, open discussion about business issues, and promote the Save on Energy brand.

COMMUNITY SUPPORT

PUC believes in sustaining a positive relationship with the community it serves, and social responsibility as an organization. The following engagement activities relate to PUC's charitable involvement in the community, as we take into account how important our customers feel about giving back to the community. Along with various event sponsorships, these are some of the charitable events that PUC is involved in:

a. The Sault Ste. Marie Downtown Association

PUC employees install banners year round on streetlights in the downtown sector. PUC is also a proud sponsor of the DTA outdoor street party festival event that includes live bands, music, food and beverage, and activities.

b. SSM Community Tree Lighting sponsorship

PUC employees attend the lighting of the community Christmas tree and sponsor the star in recognition of the energy savings, especially during the holidays

c. Sault Ste. Marie Christmas Lighting Awards Program

PUC co-sponsors this event that encourages community pride and recognizes the efforts of residents who light up their home/business for the Christmas season. Winners are awarded a plaque and a credit on their PUC bill.

d. The Lung Association Festival of Trees

PUC employees submit a decorated holiday tree with energy efficient products (thermostats, power bars, lighting, and a PUC electricity credit) in support of the Lung Association

e. SSM Santa Claus Parade

PUC employees decorate a line truck and volunteer for the annual local holiday tradition

f. Bon Soo Festival (event sponsorship)

PUC sponsors the area's largest winter carnival tradition, which has been around since 1964.

g. ARCH Hospice

The PUC Employee Association fundraised over $7,500 for ARCH through an annual golf tournament. The Association was formed in 1976 to look after the welfare of its colleagues, consists of 9 representatives from various departments across the utility, and has a current membership total of 148, out of 178 employees.

h. Christmas Safety Breakfast

This PUC employee event includes a donation of canned goods for the Local Sault Ste. Marie Food Bank.

i. United Way

From 2008 to 2016, **$301,222** has been raised by PUC employees, and Corporate has matched contributions.

j. LEAP program

PUC Distribution participates in the LEAP Emergency Financial Assistance Program, delivered by United Way - Community Assistance Trust. The funds provided by PUC to the United Way are used locally to provide grants to eligible low-income customers of PUC Distribution that qualify. Since 2012, we have donated over $130,000 to the program, supporting customers who have difficulty paying their electricity bills.

COMMUNICATION

Through customer interactions, engagement activities and community support initiatives, we have identified one of the most important customer needs is to keep our customers informed. Information about operational transparency, capital projects, bill changes, regulations, service improvements and what our company is doing to ensure we can provide safe, reliable, and efficient electrical service to the community. Community refers to those affected by decisions made by our organization, and also our stakeholders in a community-owned asset. PUC considers "Engagement" as a continuum of community involvement, moving towards greater community collaboration and evolving as a partnership.

As a proud community partner for the last 100 years, we maintain that we provide a safe, reliable, and efficient electrical distribution system to our service territory. It is our responsibility as a community-owned asset to deliver service, provide information, and continue to communicate with those affected by our operations. Communication is a key element to share knowledge, inform of any changes, and develop a trusting relationship with our customers.

a. Communications and Community Engagement FTE (Full-time Employee)

PUC understands the need for improved communications with customers to ensure we are encouraging their feedback and growing as a customer-driven utility. PUC has established the role of a full-time, community engagement and communications employee, who was hired to focus on outreach in daily operations, both internal and external. The Supervisor of Customer Engagement was trained in public relations and has shown advocacy for customers when speaking to the media about concerns, and providing clarification on PUC operations that the public can understand. This pro-active and dedicated voice works alongside the management team, engineering, customer care and CDM to promote energy literacy, industry changes and transparency in PUC operations for customers.

This ensures that communication flows from PUC, to inform and educate customers through the various channels. The role encompasses community engagement through public speaking events, media releases, and escalated customer care issues. Most importantly, the position represents the centralized source for information and knowledge of operations to relay to media and the public. We have released information that speaks to a variety of operational issues, as well as industry changes. For example, Public Service Announcements about electrical safety, and media releases that provide knowledge about the Ontario Energy Board disconnect legislative changes.

b. Power Outages

Through customer interactions, PUC has recognized that our customers are concerned about response times, waiting for assistance during outages, and reliability.

i. The implementation and utilization of smart meter data provided an opportunity to leverage these assets for improvement. Today, we are able to utilize the AMI data to provide Outage and Restoration alerts to the Operations and Customer Care staff to efficiently dispatch crews in advance of the “wait until they call” approach. This helps to ensure that PUC is pro-active in delivering service. This also provides System Operators with a mapping view to help identify the precise area and feeders that are impacted for a direct response. We have identified future opportunities to enhance these systems that include the development of a mapping view for customer access.

ii. During an outage, customers would call in and become upset when they received a busy signal or long wait times, during an already stressful time. In response to these concerns, PUC upgraded the phone system to increase capabilities of handling more customer calls. This meant that customers would not have to hear a busy signal, and could be connected to a representative. Upgrading the system allowed for more calls to be handled with an expanded call sorting and queue capability to assist with managing customer calls. It also introduced an automated messaging service that can be customized to detail the current situation. “We are aware of the current power outage in the Queen Street area, and crews are currently on site working to restore power.”

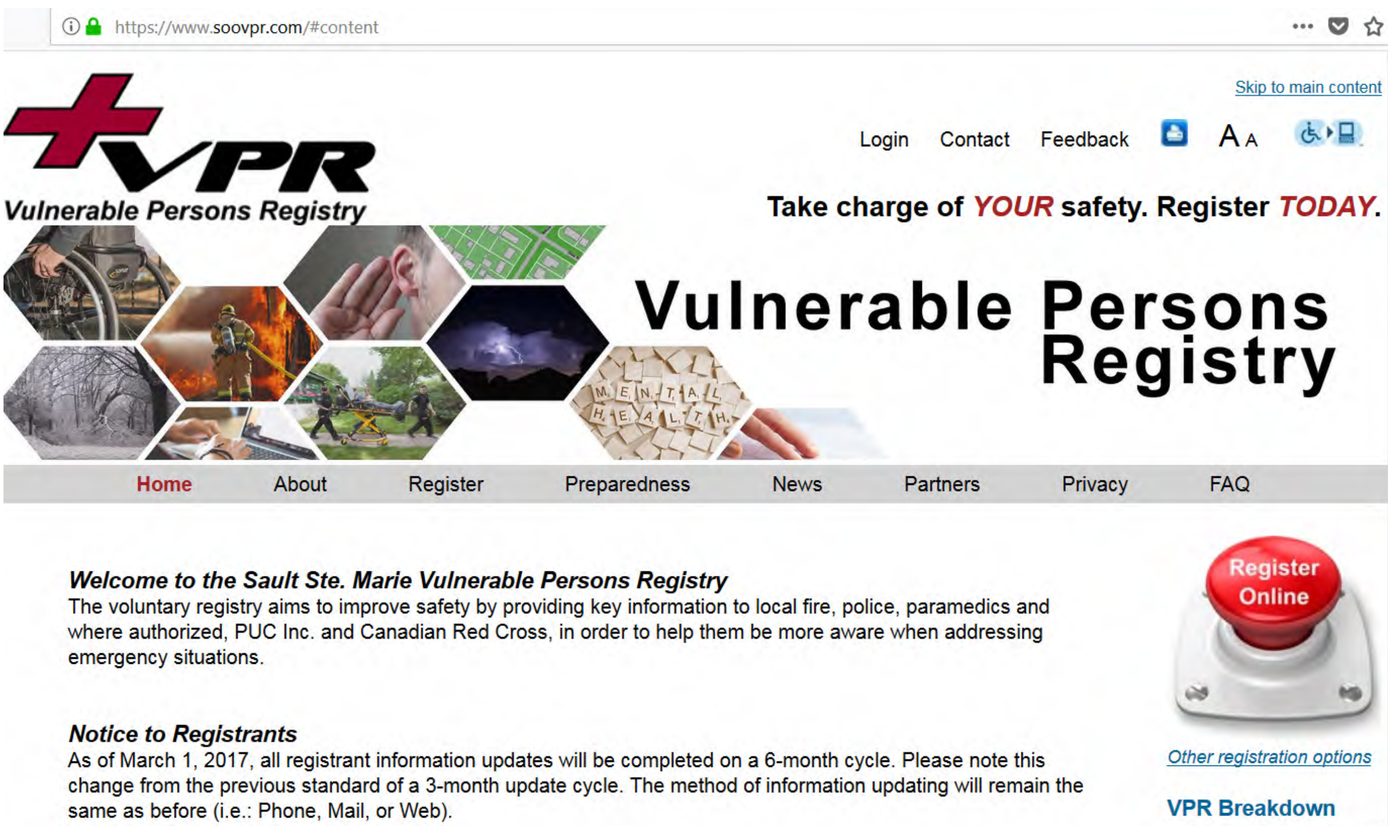
iii. While improvements were made to the emergency, unplanned outage notification system, customers expressed the desire for improvements to be made in PUC's planned outage notification process. PUC addressed these concerns by developing the Atlas Notification System. Implementing this new system required the planning and incorporation of three different components including a geographic mapping system, PUC's customer information database and an automated dialing system. The Atlas Notification System is three separate systems; a geographic information system (GIS), PUC's customer information database and an Interactive Voice Response system (auto-dialer). When work involving service interruption to customers is being planned, PUC staff will identify which area will be affected by the disruption. The electric meters in the identified area will be cross-referenced with the PUC customer database, and a call list will be compiled. That list will be used by the auto-dialer to notify affected customers

We have identified future opportunities that include the ability to increase notification through various devices, for example, text messages, or emails to alert customers of a power outage in their area. We would also like to include an option for communication with renters/multi-renters/apartment buildings with single meter so that those directly affected are contacted, and the onus does not fall directly on the landlord or building owner.

c. Vulnerable Person's Registry (VPR)

PUC services a community with an ageing mature demographic. With this in mind, PUC partnered with the Canadian Red Cross and the SSM Community Geomatics Centre for an innovative service for vulnerable persons. This significant customer-focused initiative utilizes the AMI outage information system to provide vital information to emergency responders. The cooperation of all three entities created a confidential database for "Vulnerable Person Registration" that links to PUC's GIS, providing an email alert to Operations and Customer Care staff whenever an outage impacts a VPR customer. If a VPR customer registers with this service, their status becomes a part of PUC's operational planning and response. This has proven to be of immense value during planned outages to look for additional options when practical for these customers and especially vital during emergency restoration. A standard operating procedure has been developed in cooperation with local emergency services that includes escalation criteria for weather conditions and duration, which allows PUC operations to contact first responders to provide VPR check-ins and support when required. This program can be used by first responders in localized emergency situations including but not limited to; extended power outages, Fire and 911 response, and boil water advisories. It sets a new standard of care, concern, and responsiveness for persons with disabilities who may experience emergencies in our community.

www.soovpr.com



d. Website

Through our community engagement activities, Customer Care department interactions, as well as the 2017 Utility Pulse survey results noting that "83% of customers access the internet for information," PUC has recognized the need for online services. Over the last few years, PUC has invested in a variety of online initiatives to improve communication with customers, based on an increase in online usage and the advantages of self-serve options, like reviewing usage online. Our commitment to serving customers includes providing access to information, 24/7/365.

We strive to improve our online presence through website enhancements that improve the overall customer experience, making it user-friendly, visually stimulating and encouraging customers to monitor usage. In 2013, comments received through customer interactions suggested a user-friendly website experience was needed. There was a need for improvement in the communication of outages and duration information. PUC updated the website with a refresh project which also included a customer-focused portal; Customer Connect. This refresh included improved outage notification, project awareness, tree trimming work areas, conservation awareness, and program initiatives for homes and businesses that were easily accessible.

We have identified future opportunities that include the development of an outage map/grid, specific page for system renewal projects (as included in capital investment projects detailed in DSP), social media links for conservation awareness promotions, and self-serve options such as opening, closing and relocating an account.

e. Social Media

The introduction of Social Media accounts such as Facebook, in 2013 and Twitter in 2012 allowed PUC to communicate with a larger online audience and reach different target markets with messages about; worker safety, electrical shock and safety, home renovation/upgrades, energy-efficient products, electricity industry information, conservation tips, community engagement events such as retail product consults/coupon giveaways, and charitable fundraising.

f. Public Notices

Customers want a reliable electrical service, and through interactions have spoken to the inconvenience of outages. PUC ensures that any changes in service are communicated so that our customers are able to pre-plan beforehand. We provide advanced notification of planned projects and service modifications. These include, but are not limited to hand-delivered notices in the affected neighbourhood. We have identified future opportunities that include possible email notifications and text messages to serve as a convenient method for PUC to communicate any project information or service changes that may affect them.

g. Media Interviews/Press Releases

Our PUC Communications is tasked with continuously providing customers with information about changes that may affect their bill, projects, consumption rates, operations, regulations/legislation and current energy industry events. In order to ensure that information reaches all of our audiences, we utilize multiple media channels. This communication is supported through media relations within our community, such as media interviews and press releases. These interviews are arranged through the Department and include the CEO and the Supervisor of Communications/Community Engagement. Each interview is an opportunity for PUC to address and speak to issues affecting customers.


NEWS LOCAL

Lower power costs, PUC tells Thibeault

By Brian Kelly, Sault Star
Friday, February 17, 2017 3:47:00 EST PM

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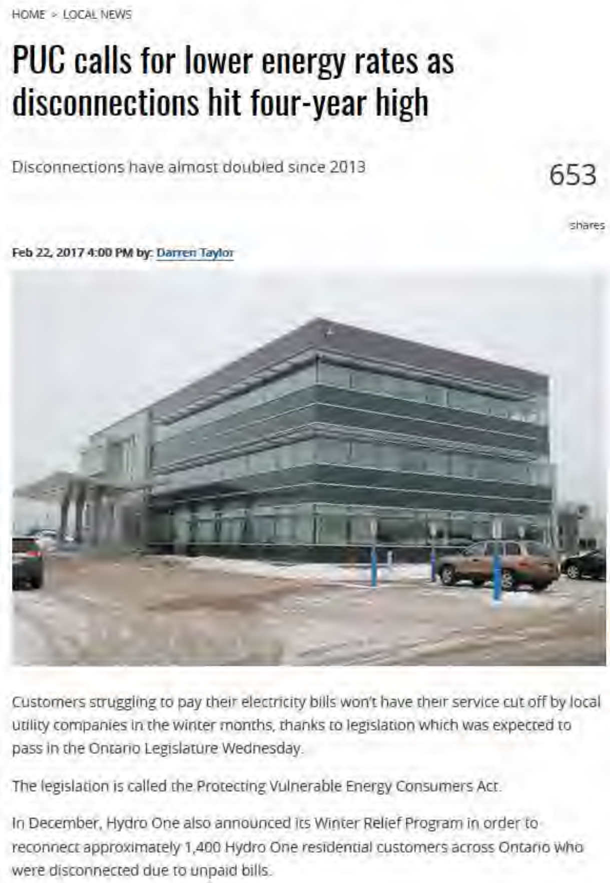
Rather than asking utilities to stop cutting power off to delinquent customers during the cold winter months, Giordan Zin wants the provincial government to dim electricity's cost to ease strained pocketbooks.

The supervisor of customer engagement with PUC Services says the price of electricity has climbed 70 per cent between 2006 and 2014.

http://www.saultstar.com/2017/02/17/lower-power-costs-puc-tells-thibeault


HOME > LOCAL NEWS

PUC calls for lower energy rates as disconnections hit four-year high

Disconnections have almost doubled since 2013

653 shares

Feb 22, 2017 4:00 PM by: Darren Taylor

Customers struggling to pay their electricity bills won't have their service cut off by local utility companies in the winter months, thanks to legislation which was expected to pass in the Ontario Legislature Wednesday.

The legislation is called the Protecting Vulnerable Energy Consumers Act.

In December, Hydro One also announced its Winter Relief Program in order to reconnect approximately 1,400 Hydro One residential customers across Ontario who were disconnected due to unpaid bills.

https://www.sootoday.com/local-news/puc-calls-for-lower-energy-rates-as-disconnections-hit-four-year-high-543044

h. Advertising

To ensure we provide our customers with the most updated information, we support local advertising through a variety of outlets such as print, online, radio and television. The advertising campaigns promote our community brand as well as building awareness with conservation tips, PSA's (Public Service Announcements), Time-of-Use, tree trimming and worker safety to name a few. We ensure that there is a strategic alignment with our advertising campaigns that promote significant issues to our customers. For example, during December, we advise of high costs due to entertaining during the holidays, holiday lighting and TOU changes. We have identified future opportunities that include obtaining specific feedback from customers for communication outlet preference.

i. Bill Inserts

We include inserts for increased communication about provincial legislation, regulations, the Atlas program, services, changes, conservation program initiatives, etc. and it is a direct line of communication to the customers, as well as a record of information provided through paperwork. We have identified future opportunities that include adding this as a focus group initiative. This would allow us to understand how many customers find this method of communication efficient as well as the overall retention of information.

j. Paperless Billing (E-Billing)

This initiative was introduced based on customer feedback and the importance of reducing the environmental footprint and improving accessibility. Those registered will receive their monthly bill via email. Some customers have made comments about the availability of credit card payment. Based on the cost analysis in comparison to the number of customer requests received, covering those costs would be at a loss for the organization at this time. However, in the event of a collection situation where they need to pay with credit card, there is a fee that accompanies using that payment method and a third party that provides the availability of the credit card service. We have identified future opportunities that include a paperless billing campaign, introducing bill email reminders which have the customers' bill in a short breakdown so they can pay or log on to Customer Connect and review.

CUSTOMER CARE/CONTROL

Over the years, electricity costs have risen, and customer concerns have escalated as a result. Our challenge as a local utility is to encourage customers to curb their consumption habits and help them manage their electricity usage. PUC understands that each touchpoint with customers on the phone, website, social media, or in-person influences what customers think and feel about our organization. It is our responsibility to provide information to help customers understand how the system works, what costs are associated with operations, as well as lowering their electricity bill.

Over the last 3 years, PUC's Customer Service department has rebranded itself to Customer Care, with more focus on caring for the customer rather than just serving the customer. The website, inbound/outbound scripts, and templates have shifted to represent this value. PUC will continue to encourage its employees to see the value in every customer interaction, in order to enhance customer experiences, and overall public perception of the PUC.

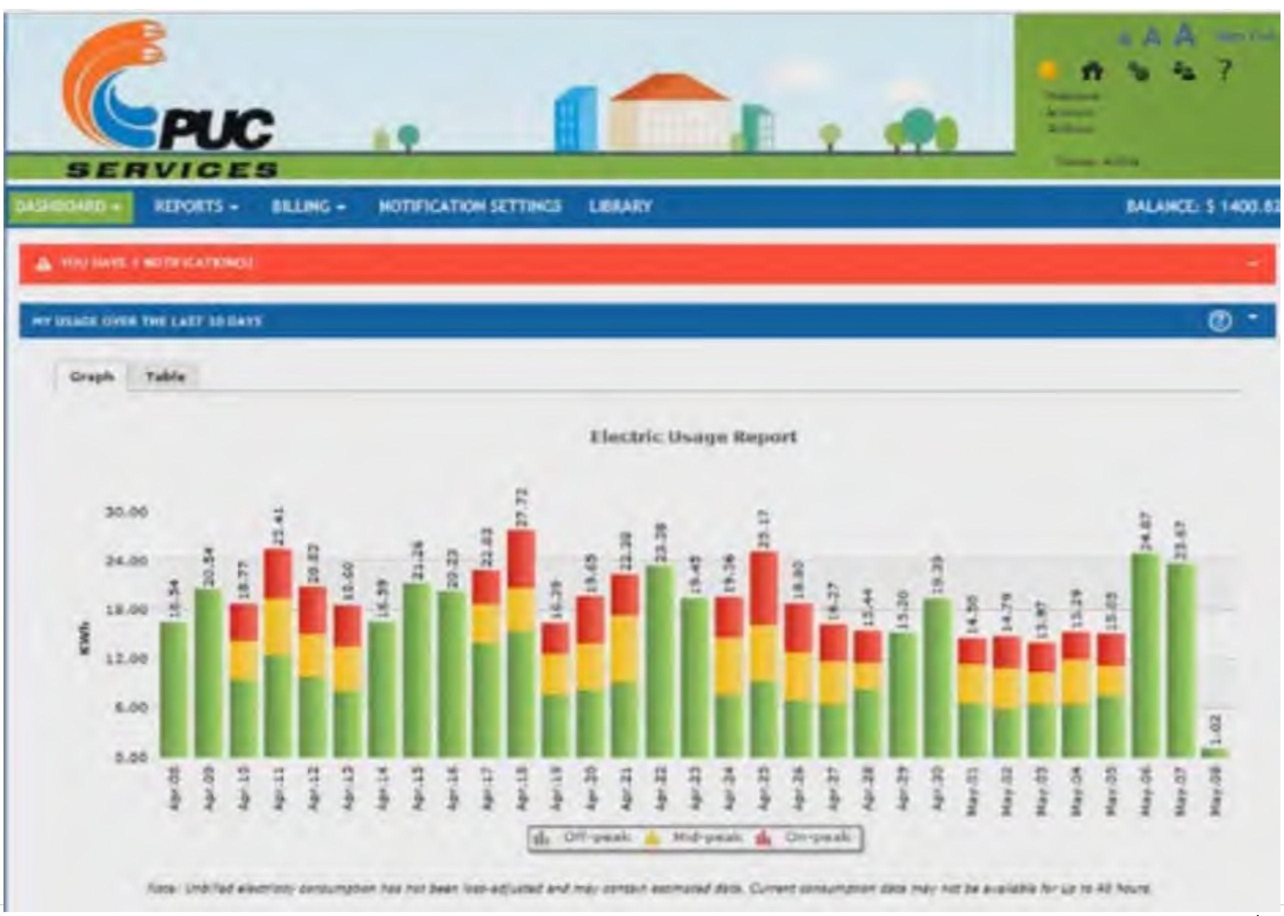
Our commitment to customer care goes beyond the Customer Care department; it involves the entire organization and includes our core value of responsiveness to our community. We are fortunate enough to have a local office where a customer can speak to an engineer about a technical question, a billing representative for their statement, a planner about upcoming neighbourhood projects, and even a forestry technician about tree trimming near their home or business, all in one place of business.

The top 3 customer issues we receive are; high bills, billing inquiries and moving of services. We often get questions about government initiatives as well, such as the 25% rebate. PUC recognizes that there is room for improvement. According to the 2017 Utility Pulse survey, “68% believe we adapt well to changes in customer expectations.” Customers want “their problem solved quickly, to have a personal interaction with a customer care representative and to speak with a knowledgeable and courteous customer care representative.” “73% said that PUC is customer-focused and treats customers as if they’re valued.” To improve our operations to support a customer-driven culture, we have invested in the following elements so customers can be reassured that we are here to serve them.

a. Customer Connect

PUC receives the most calls concerning the cost of electricity during the winter months when the weather is the coldest. The Customer Connect platform was designed to help those customers monitor their consumption, bill, and review historical data to stay informed about their energy usage. As of November 2017, 8,596 or 26% of customers are signed up for Customer Connect.

The Customer Care department also uses this tool directly with customers as a walk-through for understanding the bill, and specific charges on dates or times of high utilization. It allows for real-time access, to advise people of various spikes, TOU, and in-person, to add a visual representation of consumption, when a customer comes to the office. The customers can better understand once provided with the knowledge, and possibly change consumption habits if necessary, or realize why their bill charges were at the amounts listed. This element is critical to operations during the winter months in the North when the weather is coldest, and costs are highest.



b. Front Desk Support

PUC ensures that customer care is offered through face-to-face interaction, based on our population and ageing demographics. Customers are able to come to the administrative offices and go through their bill step-by-step with a Customer Care Representative. In a city with a mature demographic, this asset is becoming more vital to our operations as each day passes. PUC has the advantage of having local representatives that can speak to the same environment, especially during the cold winter months when everyone is trying to keep warm. When customers are experiencing difficulty, we offer a walk-in service. This helps us to ensure we take the extra time to better serve our customers' needs and help them with understanding industry and operational information. This element has worked efficiently with the Customer Connect online tool so that our representatives can provide a visual representation of what the electrical usage looks like with hourly, daily and weekly viewpoints. Although we offer this walk-in service, many customers would prefer online and self-serve options. We have identified future opportunities that include more online forms and email correspondence such as contracts, as currently, we request customers come into the office to sign a paper contract that is kept on file.

c. Customer Service Training

PUC decided to invest in customer care training for the entire organization in 2017 after a variety of customer interactions, and engagement opportunities reflected customers' negative perception of the utility. Our entire organization underwent CARE Training (Customers Are the Reason we Exist). This interactive training program encouraged customer-centred operations, customer loyalty, communication skills, resolving customer disputes and concerns as well as changing the overall attitude towards customers, understanding the vital role they have in our operations. This training was provided by the Simul Corporation, in mixed department group sessions and was well-received by staff. The training provided staff with up-to-date insights into customer satisfaction and what customers were saying about the utility. We have identified future opportunities which include annual investment in company-wide refresh training with the C.A.R.E. model to improve customer satisfaction and support the commitment to customer care being one of our top priorities.

d. Internal Training

Customers want to have knowledgeable, professional staff that can provide the most up-to-date information about the industry and changes that may affect them. PUC holds monthly staff meetings that include the latest industry and company information such as the winter disconnects, OEB backgrounders and any rate changes that may affect a customer's bill. Our Conservation (CDM) and Line departments provide the Customer Care, Billing and Metering departments with presentations to review upcoming program initiatives offered. The Line department provides the Customer Care department with presentations to help with terminology and understanding of the electrical distribution system. Additionally, our Customer Care department representatives shadow the Metering and Line departments in field operations so that they can experience firsthand, the exact equipment and processes that are used. This enables representatives to speak with customers if they are having trouble with affordability, understanding the electrical system, and any other technical questions that may require a broader field of experience to answer. Throughout the organization, our employees, from frontline to management, are encouraged to respond to escalated customer concerns and to assist with finding solutions. This reassures our customers that they are a priority.

e. Customer Information System (CIS) and MCare (Electronic Service Orders)

PUC received customer complaints that the metering service process did not work efficiently with the Customer Service Order paperwork, and ensuring reliability with meter reading times. Customer Care, Billing and Metering departments were receiving complaints about the meters being wrong, incorrect readings, billing issues, and overall dissatisfaction with the meter service. In conjunction with the Customer Connect upgrade, PUC decided to upgrade the Customer Information System from its existing “Harris” system to the “Northstar” system. This provided electronic metering service orders and real-time electronic communication with Meter department staff to improve services. This has improved communication and response times between the customer, Customer Care department, and the meter reading technicians.

CONCLUSION

PUC Distribution believes that its customers trust in its ability to make decisions to ensure a safe, reliable and efficient electrical service is delivered to their homes and businesses. Through various customer engagement opportunities, PUC has been able to implement customer-driven initiatives into our operations.

These activities include customer satisfaction and strategic planning surveys, focus groups, information sessions, residential and business awareness events, and innovative community partnerships to drive sustainable growth. We have supported customer-driven initiatives such as Customer Connect, the online usage platform, Atlas, the outage notification system,

As a local distribution company, PUC has developed and enhanced its customer engagement over the last five years. We understand that customers would rather not pay more for their electricity bills; however, the reality is that the ageing infrastructure in our community needs to be revitalized, in order to provide that reliability.

Each interaction with customers allows us to grow as a community-owned asset, and better align our operations with our customers’ needs. As such, PUC will continue to search for new opportunities to engage customers and provide them access to more information about our activities, which will allow for an improved flow of communication.

<u>EXHIBIT 1 – Cost of Service Survey Master Script</u>

Introduction Page (text for screen, not verbally – LANDING PAGE)

Welcome,
Thank you for participating in PUC Distribution's Customer Engagement Survey.

We are applying to the Ontario Energy Board (OEB) for approval to increase PUC's portion of the electricity bill, also known as the delivery rate. If approved, a (750kWh) residential electricity bill would increase by approximately $2.17 per month.

The purpose of this survey is to give you a better understanding of the details behind our proposed rate increase, and to provide you with an opportunity to share your feedback.

The survey is broken down into a few sections. Most sections have a short video that provides a quick summary and are followed by a "YOUR SAY" segment. These segments provide you with the opportunity to share your thoughts.

<u>Please keep in mind that all numbers are preliminary and may change prior to final submission as we consider customer feedback.</u>

Your feedback will also be shared with the OEB, the independent energy regulator that ultimately approves the rate that PUC can charge on the bill.

Help us get to know you a little better!

1) What are the first three digits of your postal code?
    a. P6A
    b. P6B
    c. P6C
    d. Other (please specify)

2) What is your age?
    a. 18 to 34
    b. 35 to 54
    c. 55 to 74
    d. 75 +
    e. Prefer not to answer

3) Are you?
    a. Male
    b. Female
    c. Other
    d. Prefer not to answer

4) Which of the following best describes you?
    a. Homeowner
    b. Tenant (Renter)
    c. Landlord
    d. Business
    e. Other (Please specify)

5) Including yourself, how many people live in your household?
    a. 1
    b. 2
    c. 3
    d. 4
    e. 5+

6) Where do you live within PUC Distribution's service area?
    a. City of Sault Ste. Marie
    b. Prince Township
    c. Dennis Township
    d. Batchewana First Nation Rankin Reserve
    e. I reside outside of PUC's service territory (Please specify your location below)

7) If you are a PUC customer, what services do you currently receive from PUC?
    a. Electricity
    b. Electricity and Water
    c. I am not a PUC customer.

8) How satisfied are you with the overall service(s) you receive?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied or dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not applicable

    Please explain why you feel that way.

9) Which of the following is your **primary** source of heating?
    a. Electricity
    b. Natural Gas
    c. Propane
    d. Oil
    e. Wood
    f. I'm not sure
    g. Other (Please specify)

Please watch the following video before completing the questions below. Ensure your volume is on and turned up, so you can hear the information. Closed Captioning is available for those that need it.

INTRODUCTION - VIDEO 1

Hi, I'm Jordan and I'd like to thank you for participating in PUC Distribution's customer engagement survey. This survey is part of our Cost of Service application to the Ontario Energy Board. The Ontario Energy Board (or OEB) regulates the electricity industry in the province. This includes local distribution companies, or LDC's, like PUC.

The OEB's Cost of Service application occurs every five years and determines what each LDC can charge for its distribution rate. PUC is currently applying to the OEB for approval to increase the average residential electricity bill, by approximately $2.17 per month.

This short survey will guide you through our Cost of Service Application, and more importantly, get your feedback on it. We are looking for valuable information from you, our customer, to better understand your needs and how we can provide you with the best possible service.

YOUR SAY

10) Among the following PUC priorities, place what you think each is in order of importance. Using the scale 1 = Most Important and 5 = Least Important

    Community Engagement/Communication
    Providing more information during power outages
    Maintaining reliable electrical service (e.g. prevent/reduce power outages)
    Keep rates as low as practical while maintaining good quality electrical service
    Helping customers reduce/manage consumption and by doing so reducing costs

11) Where do you currently find information on topics such as electricity rates, conservation tips, and consumption/usage information? Please select **ALL** that apply.

    a. Local Media
    b. Call, Email or In-person at the PUC Office
    c. PUC Website
    d. PUC Information Booths (Home/Trade Shows)
    e. Open Houses/Information Sessions
    f. Government of Ontario Website
    g. Ontario Energy Board Website
    h. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

YOUR ELECTRICITY BILL – VIDEO 2

Let's start by taking a look at your electricity bill.
Did you know that every charge on your hydro bill is either mandated by the provincial government or regulated by the Ontario Energy Board?
Here is a breakdown of a PUC customer's 2017 electricity bill, using the Provincial average of 750kwh per month. The bill is made up of 5 components:

- Energy, which = 53% of the bill - this is the cost of the actual electricity you use. PUC does not keep this amount; instead, it's paid to provincial agencies.
- Distribution = 27% of the bill. This is PUC's portion; it covers the costs of the poles, wires and transformers that are used to deliver electricity.
- Transmission, which = 4%. This covers the cost of transmitting high voltage electricity from generation sites across the province, to our community. PUC does not keep this charge as it is paid to the transmission companies.
- Regulatory fees, which = 4% PUC does not keep this, as this fee must be paid to regulators
- and Taxes, which = 12%

You'll notice that the delivery line from your bill isn't on this chart, that's because the delivery charge is made up of both the distribution and transmission fees. As you can see, PUC's portion (or the distribution charge) is only about 27% of the total bill. This charge is the ONLY fee that PUC has any control over and the ONLY charge we keep - the remaining 73% of the bill is passed on to power generation companies, transmission companies, the provincial government and regulatory agencies.

This means, 27% of the electricity bill covers the total cost of operating our community's utility. Everything from financing capital projects, day-to-day operations, infrastructure replacement, and employee wages. To help put this in perspective; 27₵ from every dollar on the electricity bill covers the entire cost of operating PUC's electric utility.

YOUR SAY

12) Do you think the amount ($0.27 cents from each dollar on an average 750kWh residential bill), that PUC Distribution keeps for operating and maintaining safe, local electricity service is reasonable?
    a. Very Reasonable
    b. Somewhat Reasonable
    c. Neither Reasonable or Unreasonable
    d. Somewhat Unreasonable
    e. Very Unreasonable

    Please explain why you feel that way.

13) How familiar are you with the Time-Of-Use information about off-peak, on-peak and mid-peak usage rates?
    For example, holidays are off-peak and if the holiday is on a weekend then the following weekday is off-peak in lieu of.
    a. Very familiar
    b. Somewhat familiar
    c. Not very familiar
    d. Not at all familiar

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

ELECTRICAL DISTRIBUTION OVERVIEW – VIDEO 3

Did you know that PUC Distribution's service territory includes more than just the City of Sault Ste. Marie? It actually extends to parts of Prince and Dennis Townships and the Batchewana First Nation Rankin Reserve.

Before we get into what we need the rate increase for, let's talk about how electricity is delivered across PUC's service territory to your home or business.

We receive power from the provincial transmission grid at 115 thousand volts which supply our two transformer stations. Here we step-down the voltage to 34 thousand volts and transmit it to 14 neighbourhood distribution stations or substations. These substations further reduce power to 12 thousand volts or in some cases, 4 thousand volts. Power is then delivered to neighbourhoods through overhead or underground wires along the streets and roadways. The last step in the journey is the individual distribution transformers that lower the voltage one more time, before the electricity is used by you, the customer.

YOUR SAY

14) When you have an electrical service issue, what is your preferred method to contact PUC for assistance? Please select **ALL** that apply.
    a. Email
    b. Phone
    c. Mail
    d. Social Media (e.g. Facebook, Twitter)
    e. Website
    f. In-Person
    g. Other (Please specify)

15) If you've ever contacted PUC about an electrical service issue, how satisfied were you with the customer care you received?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied nor dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable
    Please explain why you feel that way.

16) If you've ever had a PUC Field Representative visit your home or business concerning an electrical service issue (e.g. power outage, overhead or underground system work), how satisfied were you with the service level provided?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied nor dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable
    Please explain why you feel that way.

17) As we move forward, PUC Distribution would like to improve communications and engagement with our community. Of the following ideas, what would you prefer to see?
    a. Neighbourhood meetings in advance of planned projects
    b. PUC Open House (e.g. Tour PUC facilities and meet electricity professionals)
    c. Online Chat Portal (Connected to PUC website)
    d. Conservation Information Booths (e.g. Bushplane Days, RotaryFest)
    e. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

PROPOSED RATE INCREASE – VIDEO 4

Now that we've reviewed the bill breakdown, let's take a look at our proposed rate increase.
Since 2013's application, our service revenue requirements have increased, by approximately $3.3 million, up from $18.8 million to $22.1 million. This is largely driven by increases in operation, maintenance, and administrative costs, as well as a number of infrastructure renewal projects.

While we understand the concerns around rising electricity costs, the unfortunate reality is, additional financial resources are needed for us to continue addressing our community's electrical distribution needs.

If the rate increase is approved, an average residential customer, using the Provincial average of 750 kWh a month, will see an approximate two dollar and seventeen cent increase on their monthly electricity bill. This represents a sixteen point five percent increase on the PUC portion of the bill or a two point one percent increase on the total electricity bill. And, for the duration of the following five-years – distribution rate increases would be held to less than the rate of inflation.

As mentioned earlier, this rate increase is largely driven by increased costs which we will be breaking down in the upcoming videos.

YOUR SAY

18) In order to improve our customer communication, please choose your **preferred** method for PUC to communicate with you.
    a. TV (e.g. CTV)
    b. Online (e.g. Sootoday)
    c. Print (e.g. Sault Star)
    d. Radio
    e. PUC Website
    f. Social Media
    g. Information Sessions
    h. Bill Inserts
    i. Email Blasts
    j. Other (Please specify)

19) To increase awareness of electricity usage, PUC offers an online energy usage tool called, Customer Connect. Have you ever used it to monitor your hourly, daily and weekly electrical usage?

    (If you would like more information about Customer Connect, please contact Customer Care at 705-759-6522)
    a. Yes, I find it useful to visually track usage.
    b. Yes, I've used it a few times.
    c. I don't have access to a computer.
    d. No, I'm not interested in online services.

20) Have you visited the PUC website for any of the following in the last 6 months? Please select **ALL** that apply.
    If not, please choose Not Applicable.
    a. Customer Connect
    b. Paperless Billing (E-Billing)
    c. Conservation Programs and Information
    d. Power Outage Inquiry
    e. Project Information Search (e.g. Overhead line work in your neighbourhood)
    f. Not Applicable
    g. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

OPERATIONS, MAINTENANCE & ADMINISTRATION – VIDEO 5

In previous videos, we've talked about the 3.3 million dollar increase in our service revenue requirements. Approximately, 61% or 2 million dollars of this increase is driven by operational, maintenance and administrative costs. Here's a breakdown of those costs:

21 percent of the 2 million dollar increase is made up of new Regulatory Requirements.
These include things like:

- PCB chemical testing for overhead transformers, to ensure they are all PCB-free by 2025.
- New meter reading requirements for large general service customers.
- Newly mandated initiatives, like the Under Frequency Load Shedding program – which is designed to improve the reliability of the Provincial electricity grid.
- And finally, the hiring of an additional staff member to assist with growing OEB requirements – all contribute to the increased costs in Regulatory Requirements

10 percent of the increase covers the rising cost of utilities since our last application. This accounts for basic utilities for the transmission and distribution stations, and the administrative building and service center.

5 percent of the increase is a result of the growing cost of utilizing the Smart Meter Network, which include things like the automated meter-reading software fees.

Another 7 percent of the increase is needed to cover Bad Debt, which has grown, due to the rising number of customers unable to pay their electricity bill. This can be attributed to the combination of; the rising cost of electricity, the moratorium on winter disconnections, and the state of our local economy.

9 percent of the increase accounts for the growing costs of meeting Industry Regulations. For example, costs for things like; OEB Annual Assessments, Cost of Service Applications, and mandated Customer Engagement Programs have all grown since 2012.

7 percent of the increase covers the cost to operate our Vegetation Management or Tree Trimming program. While, PUC has extended this program to a four-year cycle to reduce costs annually, costs fluctuate based on the total area needing to be cleared, and the number of contractors bidding on that year's cycle.

The remaining 41% of the increase in service revenue requirements is driven largely by inflationary growth in things like; employee wages, benefits, contracted services, insurance costs, and fuel expenses.

YOUR SAY

21) Now that you're familiar with the rising costs associated with our operational, maintenance, and administrative needs. Do you feel you have a better understanding of the proposed rate increase, to cover those costs?
    a. Yes
    b. No
    c. I Need More Information
    d. No Opinion

    Please explain why you feel that way.

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

CAPITAL INVESTMENT PROJECTS – VIDEO 6

As mentioned, operations, maintenance and administrative expenses account for two-thirds of the total service revenue requirement increase. The remainder is driven by Capital Investments in infrastructure renewal. Let's explore some of the infrastructure renewal projects PUC has planned for the next few years.

Probably, the most visible components of the electrical distribution system are the overhead lines and poles. PUC has about 621 km of overhead lines using about twelve thousand, seven hundred poles. Of those, approximately 102 poles have been in service for more than 60 years. Over the next five years, our plan is to replace approximately 150 poles, identified as being in poor or very poor condition.

Additionally, some of the older overhead lines in our system were constructed with a type of copper wire, which no longer meets reliability and safety standards. Our proposed plan would see those lines replaced within the next ten years.

The underground electrical distribution system is comprised of approximately 122 kms of cable, 30 kms of which are approaching the end of their service life. Additionally, underground infrastructure like switches, concrete vaults, and submersible transformers are also a priority for replacement based on their condition. Our plan will continue addressing this aging infrastructure, and focus on neighbourhoods with high equipment failure rates.

Substations are a critical part of any electrical system, as they supply entire neighbourhoods with power. A single substation can provide enough power for 2,000 homes. Replacing a sub-station costs approximately three point five million dollars and takes about two years to complete.

It's important to note that the average service life for a transformer is 40 years so special attention needs to be paid to those located within our substations, as 66% of station transformers have been in service longer than 35 years. With that in mind, we plan on replacing two substations by 2022.

Locally, our substations transform electricity from 34 thousand volts to twelve or four thousand volts. Over the last few years, PUC has been converting the four thousand volt system to a twelve thousand volt system. This is because the four thousand volt system is at, or very near, the end of its service life.

PUC is proposing a replacement plan that will completely retire the 4 thousand volt system by 2022; including poles, wires and transformers and replace it with the more efficient and reliable 12 thousand volt system.

YOUR SAY

22) The long-term plan that includes operational and maintenance costs, asset renewal and replacements to ensure reliability and system performance will include a monthly bill price increase.

Which statement best represents your point of view?

a. I would be willing to pay an additional $5-7 on my bill to invest as much as possible into the reliability of the system.
b. I would be willing to pay an additional $3-5 on my bill to invest in operations, and improve the system as quickly as possible.
c. I would be willing to pay an additional $1-3 on my bill if reliability improves through gradual infrastructure renewal.
d. I am NOT willing to pay any additional charges on the PUC portion of my bill knowing that the level of reliability could decline.

Please explain why you feel that way.

23) Now that you're familiar with some of the planned projects, what do you think of the proposed rate increase to support infrastructure investment?
    a. The rate increase should be higher to support an increase in infrastructure investment.
    b. The rate increase proposed is reasonable and I support it.
    c. I don't like it but understand the increase is necessary.
    d. The rate increase is unreasonable and I oppose it.
    e. No opinion

    Please explain why you feel that way.

24) Are you satisfied with the amount of information we provided you in this survey to understand the reasons behind the proposed rate increase?
    a. Yes
    b. No
    c. I Need More Information

    Please explain why you feel that way.

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

POWER OUTAGES AND SYSTEM RELIABILITY – VIDEO 7

Power outages are an unfortunate reality in the electricity industry. That said, at PUC we work very hard to keep outages to a minimum and if required, as short as possible.

One of the annual industry measurements for system reliability is the System Average Interruption Duration Index, or SAIDI. This is measured by the average number of hours the power to a customer is interrupted. In 2016, the total time the average customer was without power was 90 minutes. This is below our target of 112 minutes, per year.

The other annual industry measurement is the System Average Interruption Frequency Index, or SAIFI. This is measured by the average number of times the power to a customer is interrupted.
In 2016, the total number of times the average customer experienced an interruption was 1.4 times. This is well below the target of 2.3 interruptions per year.

As you can see, PUC's reliability metrics are trending in a positive direction. We attribute these results to our ongoing commitment to improving system reliability through infrastructure renewal and a successful vegetation management program, better known as tree trimming.

PUC knows that reliability is important to customers, and that's why we plan to increase our investment in infrastructure renewal to improve system reliability. This will ensure we continue to provide a safe, reliable and efficient electrical system for the community we serve.

YOUR SAY

25) In the past year, how many power outages have you experienced?
    a. None (0)
    b. One or Two (1 or 2)
    c. Two or Three (2 or 3)
    d. More than Three (3 +)

26) What was the longest power outage you had in the past year?
    a. Less than 30 minutes
    b. 30 – 60 minutes
    c. 1 – 1.5 hours
    d. More than 1.5 hours

27) Did you contact PUC about the power outage?
    a. Yes
    b. No
    c. I can't remember

28) If you contacted PUC about a power outage, how satisfied were you with the way PUC responded to the outage?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied or dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable

   Please explain why you feel that way.

29) On average a PUC customer loses power due to outages for less than 90 minutes over the year. Do you feel this level of reliability is?
    a. Very good
    b. Good
    c. Poor
    d. Very poor
    e. No opinion

   Please explain why you feel that way.

Final Thoughts (text for screen, not verbally)

YOUR SAY

30) Is there anything in particular that PUC Distribution can do to improve its electricity service for you?

31) Outstanding Questions – Do you have any further **questions, concerns you would like to share?**

Thank you for your time, we know how valuable it is and we appreciate your feedback and input.

Click on the link below to enter for a chance to win one (1) of five (5) credits of $100.00 (One hundred Canadian dollars), towards your PUC bill.

MUST be a PUC customer (residential or business) at the time of the draw.

Limit one (1) entry per household.

Please note that survey responses are NOT associated with your draw entry information.

https://www.surveymonkey.com/r/WIN100PUCCREDIT

Thank you!

PUC Distribution Inc. Customer Engagement Survey Contest

Official Contest Rules

The Customer Engagement Survey contest is sponsored and administered by PUC Services Inc. ("PUC") on behalf of PUC Distribution Inc. The contest begins on January, 9, 2018 at 11:00 a.m. E.S.T. and ends on February 11, 2018 at 11:59 E.S.T. By participating, entrants agree to be bound by these contest rules and the decisions of PUC, which are binding and final, without right of appeal, on all matters relating to this Contest. Contest is subject to all applicable federal, provincial and local laws. Void where prohibited by law. **NO PURCHASE IS NECESSARY**.

Eligibility

- Must be a PUC customer (residential or business) at the time of the draw.
- Must be 18 years of age or older.
- Limit one (1) entry per household.
- All Contest entries must be submitted by February 11, 2018 at 11:59 E.S.T. to be eligible to win.
- By entering this contest, all participants are deemed to have accepted the Contest Rules.
- Must not be an employee, representative, agent or Board member of PUC Services Inc., PUC Distribution Inc., or any of its affiliates.
- Must correctly answer a skill-testing question on the contest entry page.
  (2x4) + (100/5)

How to Enter

During the contest period, participants may enter the contest once by completing the PUC Distribution Customer Engagement Survey. Once participants have completed the survey, there will be a Survey Draw Link to click on that will redirect participants to the contest entry page where participants will fill in and complete the requested information. Participants must also correctly answer a skill-testing question on the contest entry page in order to be eligible to win. Participants are allowed only one entry to the contest. Multiple entries from the same participant or from the same household will void all of such participant's or participants' entries.

Prizes

There are five (5), $100 bill credit grand prizes, to be randomly drawn on February 12, 2018 at 9:00 a.m. E.S.T., after the Contest Period has ended. The total approximate value of all prizes is $500.00. The Prize will be applied directly to the winner's next PUC electricity bill and will appear as a line item on their bill. PUC will notify the winner when the credit has been applied. The prize must be accepted as is, has no cash value and is non-transferable. Winners must attend PUC head office located at 500 Second Line East, Sault Ste. Marie, Ontario and show proof of identification, along with their account number, to claim their prize. The $100 credit will be applied to the winner's next PUC bill.

Odds of Winning

The odds of winning a prize depends on the total number of eligible entries received during the contest period.

How to Win

There will be a random drawing for each of the five (5) grand prizes conducted by PUC at the following date, time and location: February 12, 2018 at 9:00 a.m. EST at PUC Head Office located at 500 Second Line East, Sault Ste. Marie, Ontario. Five Entrants will be selected from all eligible entries received. The selected Entrants must also provide proof of identity (driver's license or other government issued photo identification). Failure to provide such proof of identity shall disqualify the selected Entrant.

Notification
Selected Entrants will be notified by telephone using the phone number provided in the Contest entry form. If a participant is identified as a selected Entrant then such selected Entrant must respond to claim the prize within ten (10) business days. A prize will be forfeited if it goes unclaimed for ten (10) business days, from the date a phone call is made. In the event the prize is not claimed within the allotted time period or the selected Entrant is disqualified or the prize is otherwise forfeited, PUC will re-draw and choose a new selected Entrant randomly from all remaining entries until a winner is declared. PUC shall have no liability if the winner notification is lost, intercepted or not received by a selected Entrant

Use of Information
All personal information collected herein will be used only for the administration of determining the eligibility for the contest draw in accordance with the requirements of Municipal Freedom of Information and Protection of Privacy Act (MFIPPA). By participating in this Contest, Contest winners are deemed to have consented to the disclosure of their names and photos, without compensation, being included in any publicity carried out by PUC. Each participant consents to the collection, use and disclosure of his/her personal information for the purposes of this Contest and grants permission for PUC to disclose personal information to its related and affiliated companies, contractors and agents to assist in the Contest.

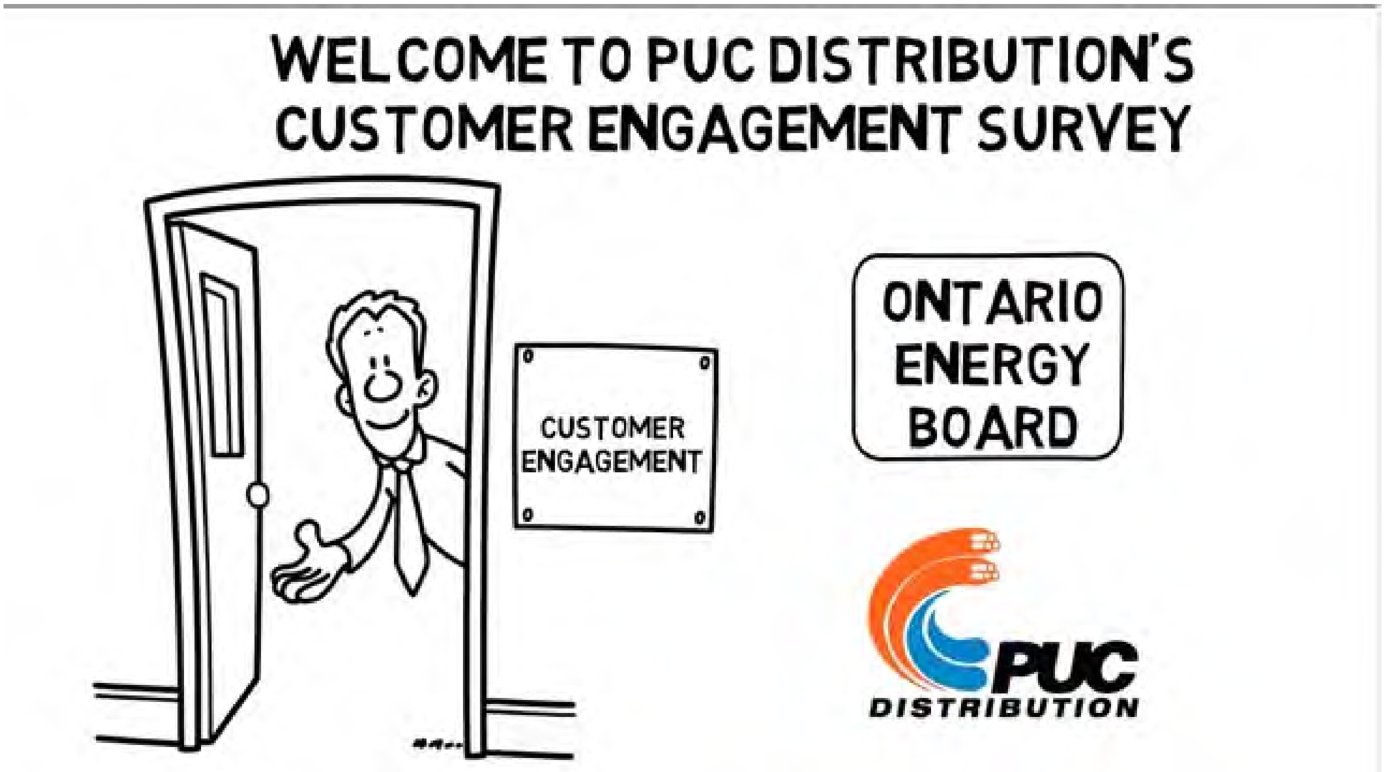
Limitation of Liability
PUC assumes no responsibility for late, lost, incomplete, incorrect, delayed or misdirected entries or for any failure of any website, for any problems or technical malfunction of any computer online systems, servers, access providers, computer equipment, software, failure of any e-mail or entry to be received by PUC on account of technical problems or traffic congestion on the Internet or at any website, or any combination thereof, including any injury or damage to a participant's or any other person's computer, mobile device or other electronic device related to or resulting from this Contest. In the event the Contest is compromised by a virus, non-authorized human intervention, tampering or other causes beyond reasonable control of PUC which corrupts or impairs the administration, security, fairness or proper operation of the Contest, PUC reserves the right in its sole discretion to suspend, modify or terminate the Contest.

General Conditions
Participants agree, by participating, (I) to be bound by the terms of these Contest Rules and the decisions of PUC, which are final and binding, without right of appeal, on all matters relating to this Contest; and (ii) to indemnify, release and hold harmless PUC and its parent companies, affiliates, subsidiaries, officers, directors, agents, representatives and employees from any liability, for any injuries, losses or damages of any kind, including death, to persons, or property resulting in whole or in part, directly or indirectly, from participation in this Contest or acceptance, misuse, non-use or use of any Prize. By accepting a Prize, winners release PUC from any and all liability, loss or damage incurred with respect to the awarding, receipt, or possession of any prize, and acknowledge that PUC is not responsible in any way for any issues in connection with the prizes awarded or any losses, damages, or claims relating to the Contest. Any and all issues, questions, disputes, claims and causes of action arising out of this contest or any prize award shall be resolved in accordance with the laws of the Province of Ontario.
If there are any questions or concerns about the contest rules and regulations, please contact:
customer.care@ssmpuc.com or 705-759-6522, Monday – Friday, 9:00 a.m. E.S.T. to 4:30 p.m. E.S.T.

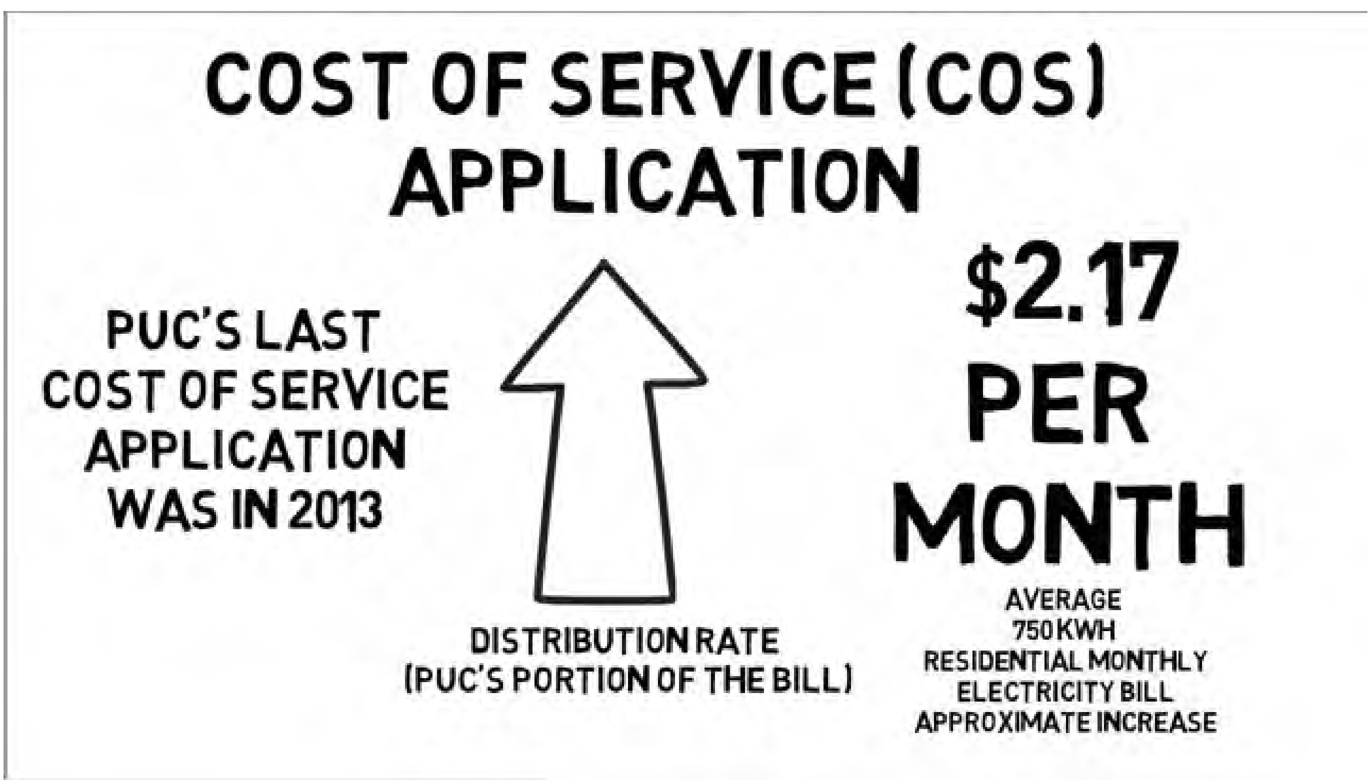
EXHIBIT 2 – COST OF SERVICE SURVEY STORYBOARD

INTRODUCTION - VIDEO 1

Hi, I'm Jordan and I'd like to thank you for participating in PUC Distribution's customer engagement survey. This survey is part of our Cost of Service application to the Ontario Energy Board. The Ontario Energy Board (or OEB) regulates the electricity industry in the province. This includes local distribution companies, or LDC's, like PUC.



The OEB's Cost of Service application occurs every five years and determines what each LDC can charge for its distribution rate. PUC is currently applying to the OEB for approval to increase the average residential electricity bill, by approximately $2.17 per month.

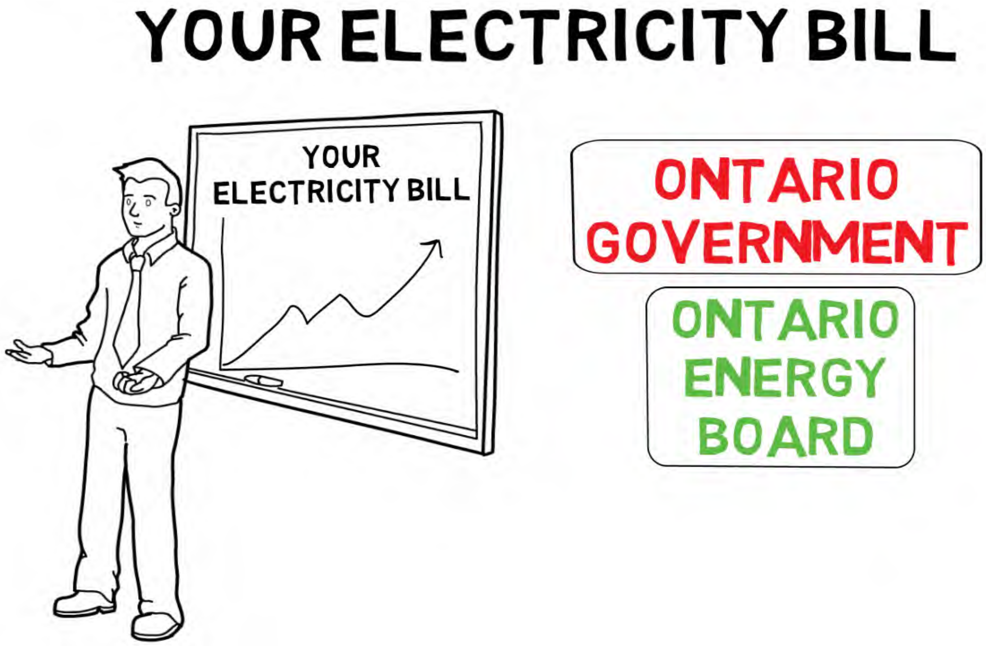


This short survey will guide you through our Cost of Service Application, and more importantly, get your feedback on it.

We are looking for valuable information from you, our customer, to better understand your needs and how we can provide you with the best possible service.

YOUR ELECTRICITY BILL - VIDEO 2

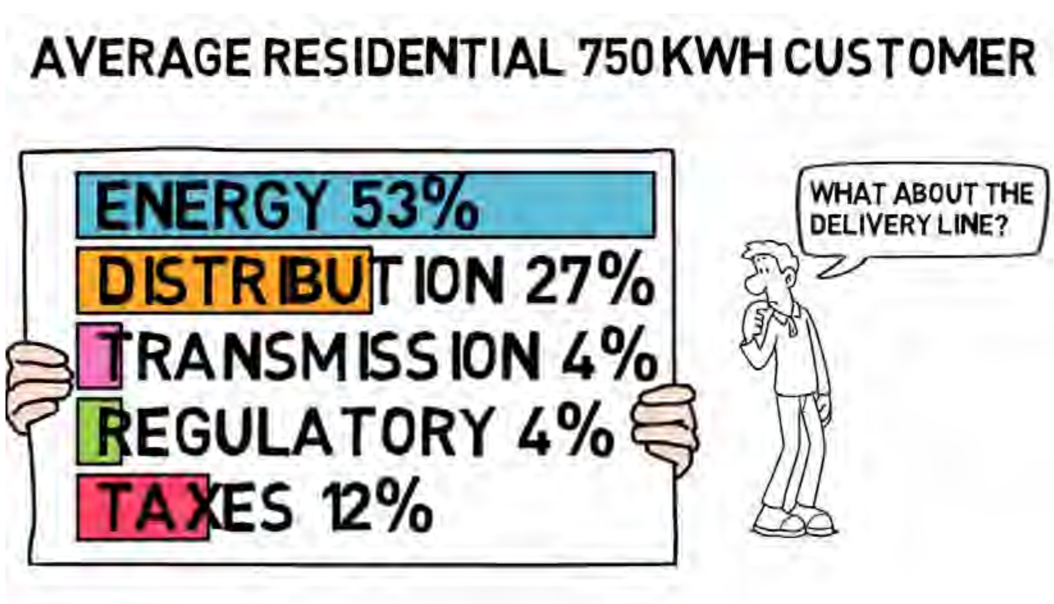
Let's start by taking a look at your electricity bill.
Did you know that every charge on your hydro bill is either mandated by the provincial government or regulated by the Ontario Energy Board?



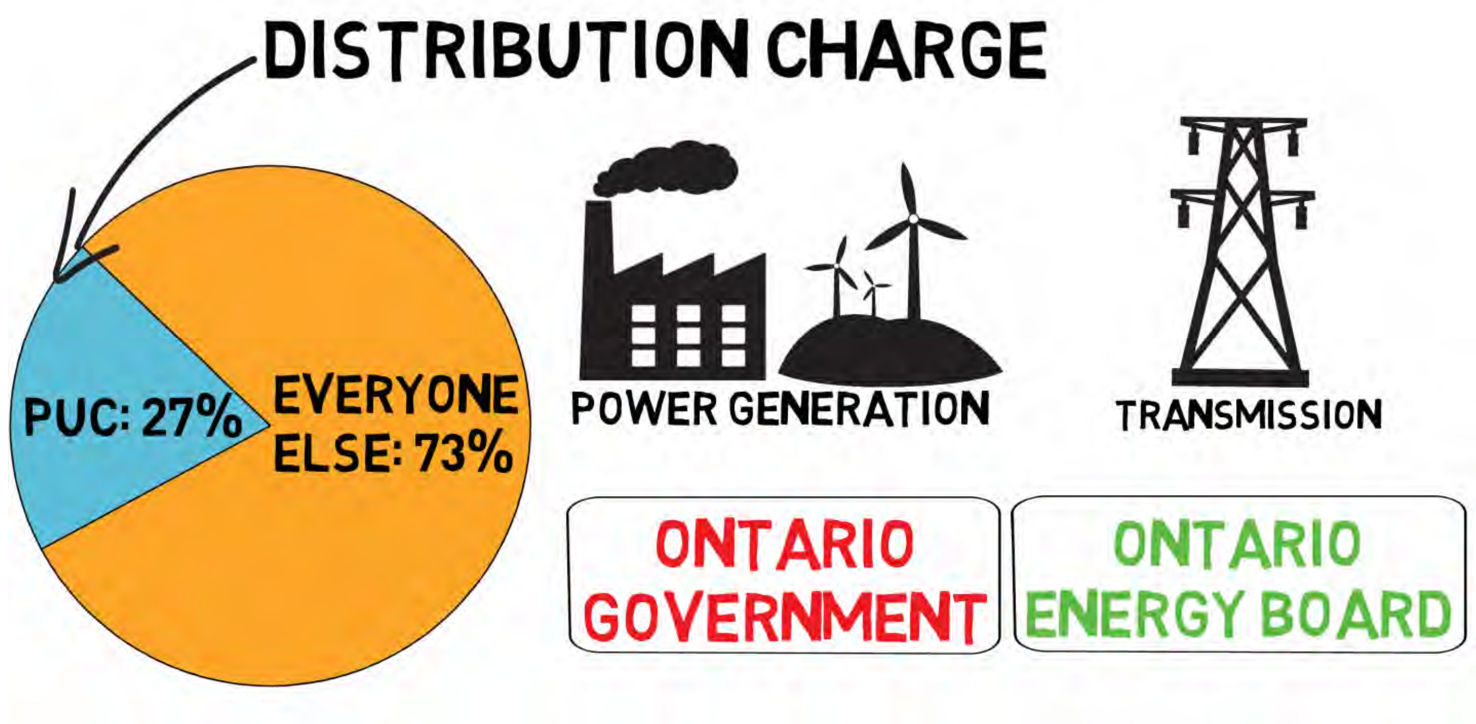
Here is a breakdown of a PUC customer's 2017 electricity bill, using the Provincial average of 750kwh per month. The bill is made up of 5 components: Energy, which = 53% of the bill - this is the cost of the actual electricity you use. PUC does not keep this amount; instead, it's paid to provincial agencies.

Distribution = 27% of the bill. This is PUC's portion; it covers the costs of the poles, wires and transformers that are used to deliver electricity. Transmission, which = 4%. This covers the cost of transmitting high voltage electricity from generation sites across the province, to our community. PUC does not keep this charge as it is paid to the transmission companies. Regulatory fees, which = 4% PUC does not keep this, as this fee must be paid to regulators. and Taxes, which = 12%.

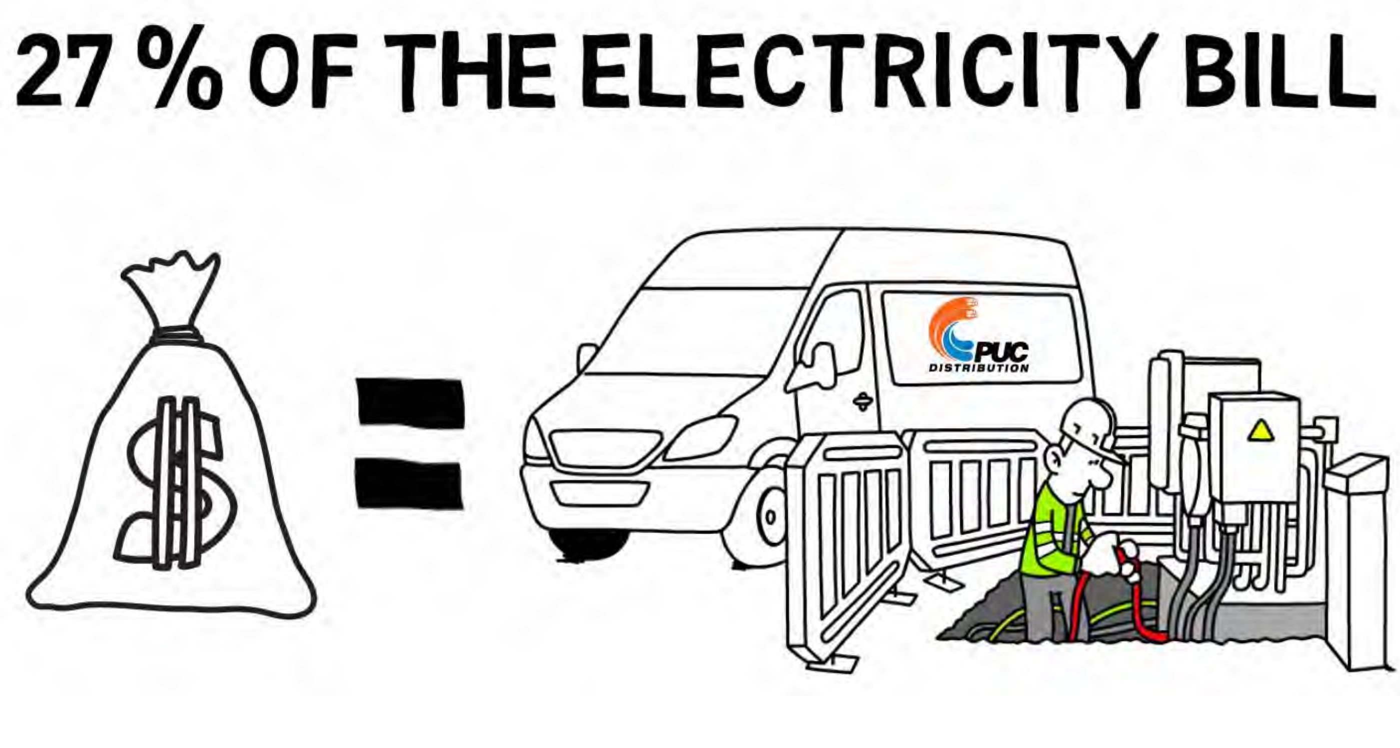
You'll notice that the delivery line from your bill isn't on this chart, that's because the delivery charge is made up of both the distribution and transmission fees .



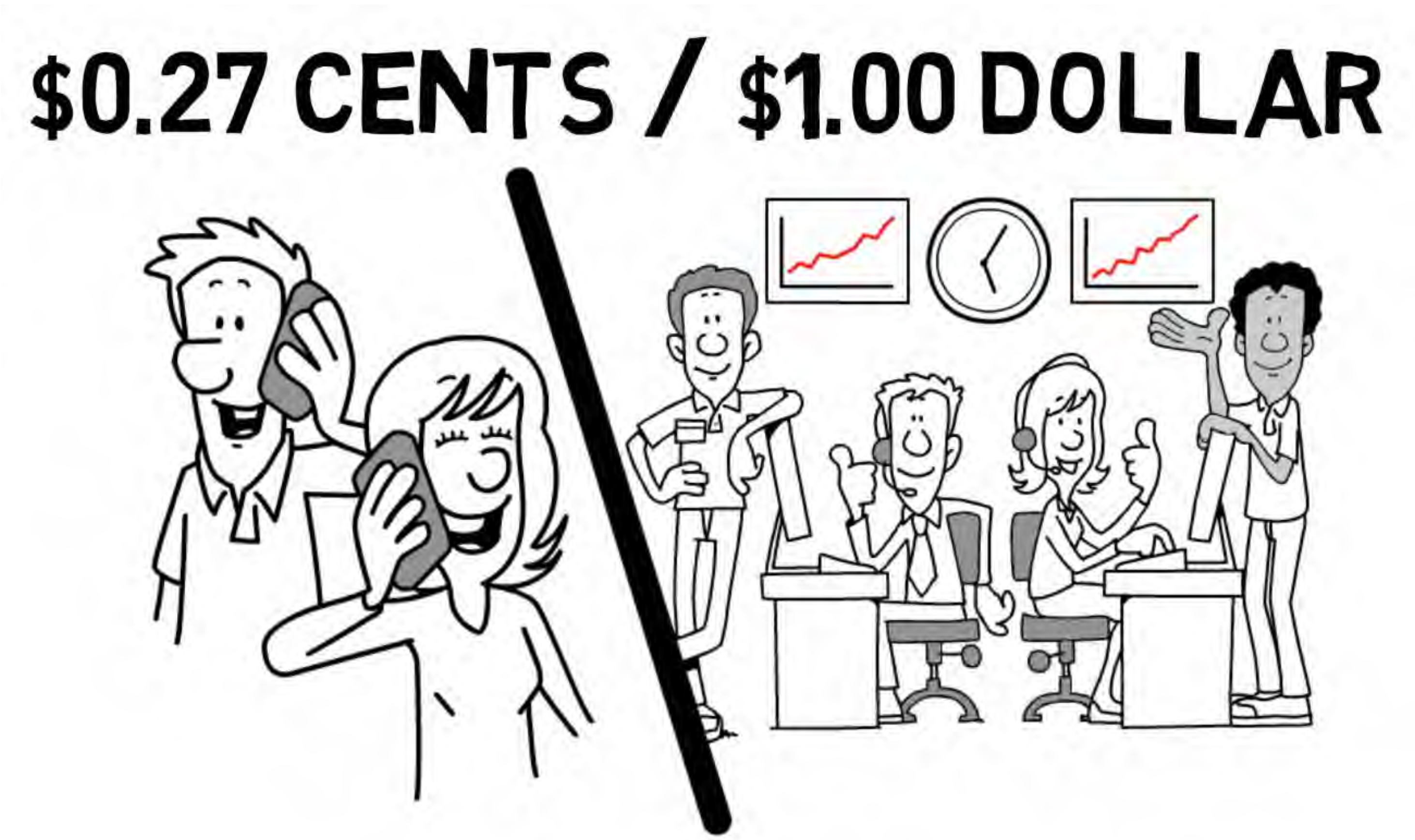
As you can see, PUC's portion (or the distribution charge) is only about 27% of the total bill. This charge is the ONLY fee that PUC has any control over and the ONLY charge we keep - the remaining 73% of the bill is passed on to power generation companies, transmission companies, the provincial government and regulatory agencies.



This means, 27% of the electricity bill covers the total cost of operating our community's utility. Everything from financing capital projects, day-to-day operations, infrastructure replacement, and employee wages.

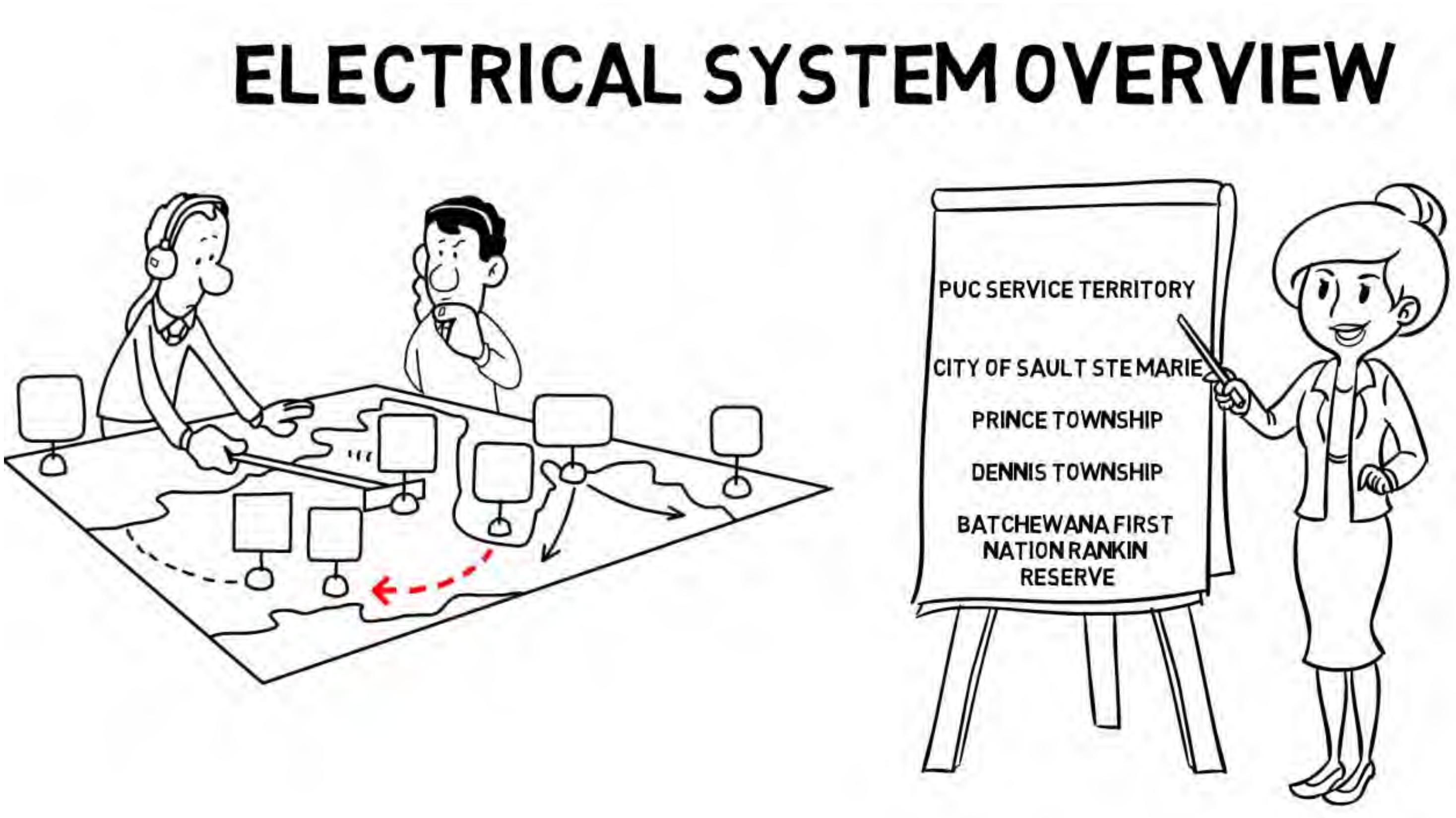


To help put this in perspective; 27¢ from every dollar on the electricity bill covers the entire cost of operating PUC's electric utility.



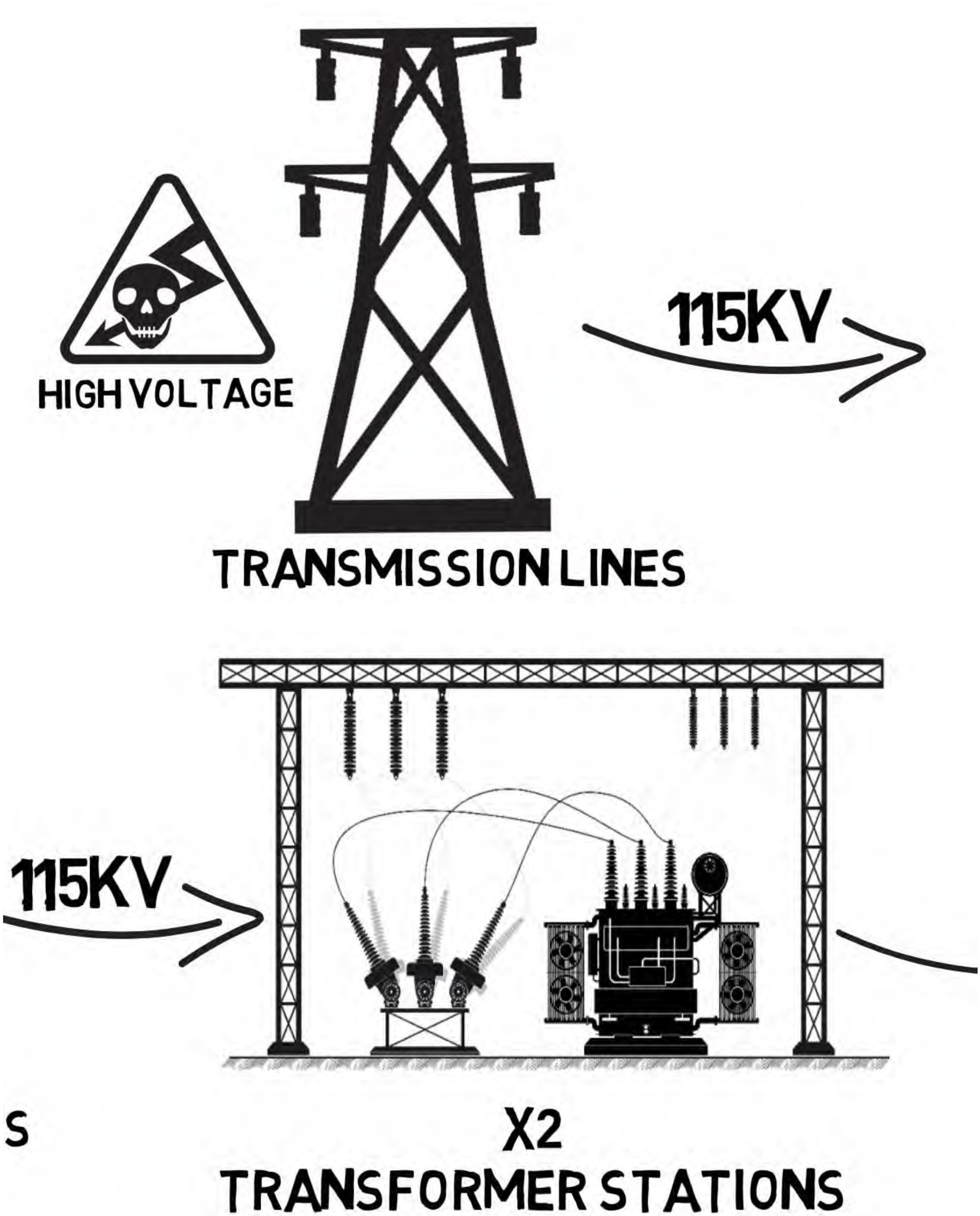
ELECTRICAL DISTRIBUTION OVERVIEW - VIDEO 3

Did you know that PUC Distribution's service territory includes more than just the City of Sault Ste. Marie? It actually extends to parts of Prince and Dennis Townships and the Batchewana First Nation Rankin Reserve.

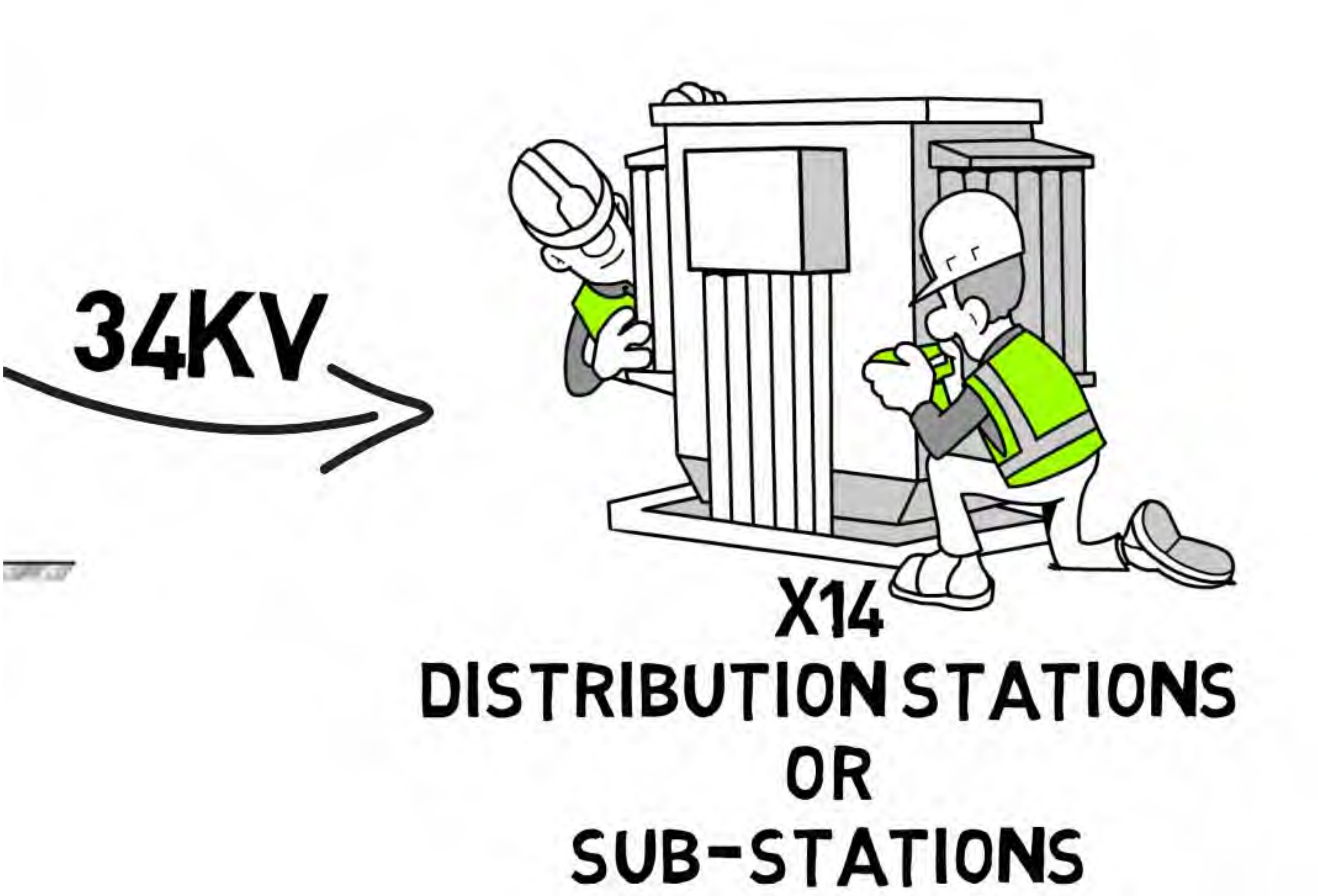


Before we get into what we need the rate increase for, let's talk about how electricity is delivered across PUC's service territory to your home or business.

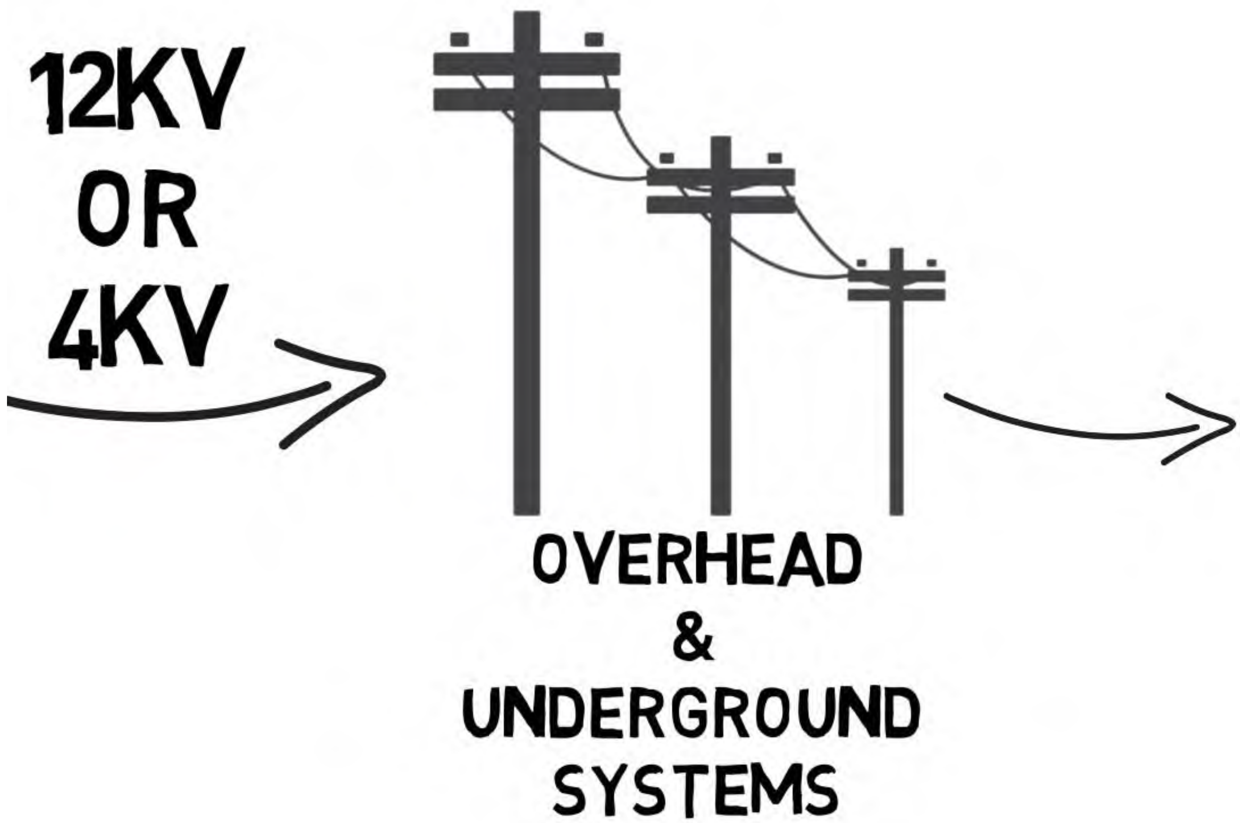
We receive power from the provincial transmission grid at 115 thousand volts, which supply our two transformer stations.



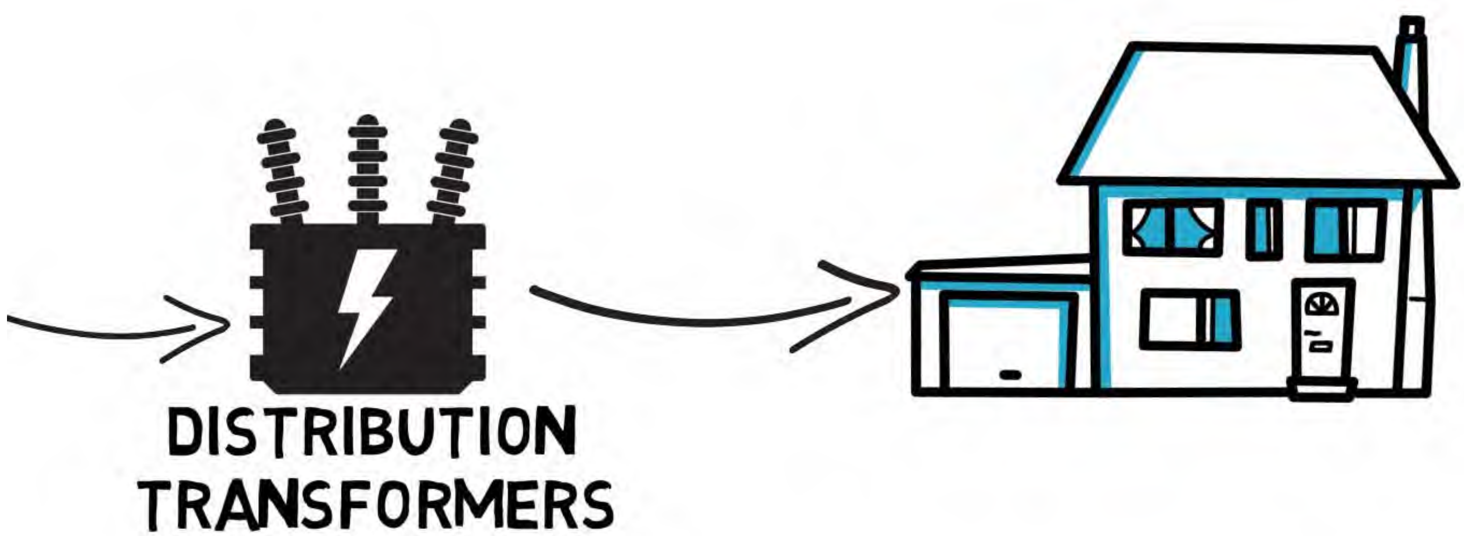
Here we step-down the voltage to 34 thousand volts and transmit it to 14 neighbourhood distribution stations or substations. These substations further reduce power to 12 thousand volts or in some cases, 4 thousand volts.



Power is then delivered to neighbourhoods through overhead or underground wires along the streets and roadways.

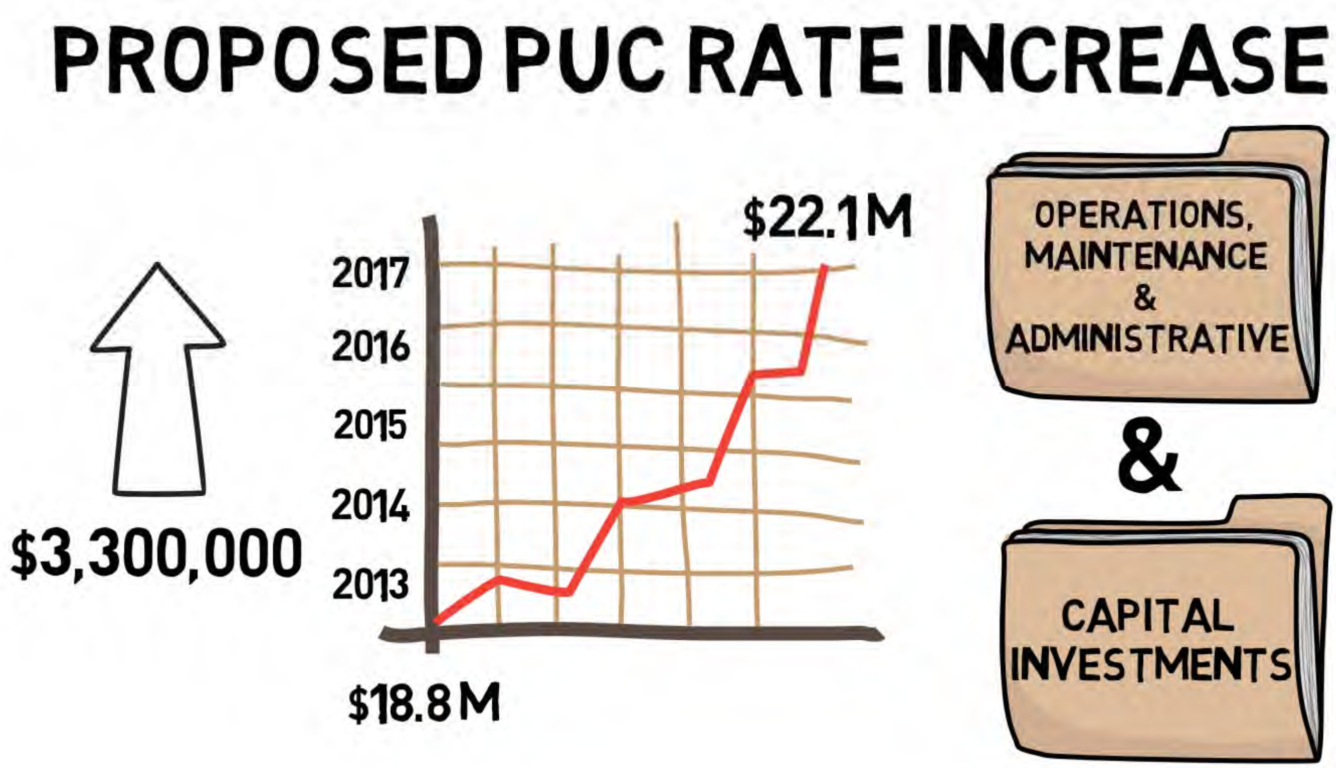


The last step in the journey is the individual distribution transformers that lower the voltage one more time, before the electricity is used by you, the customer.

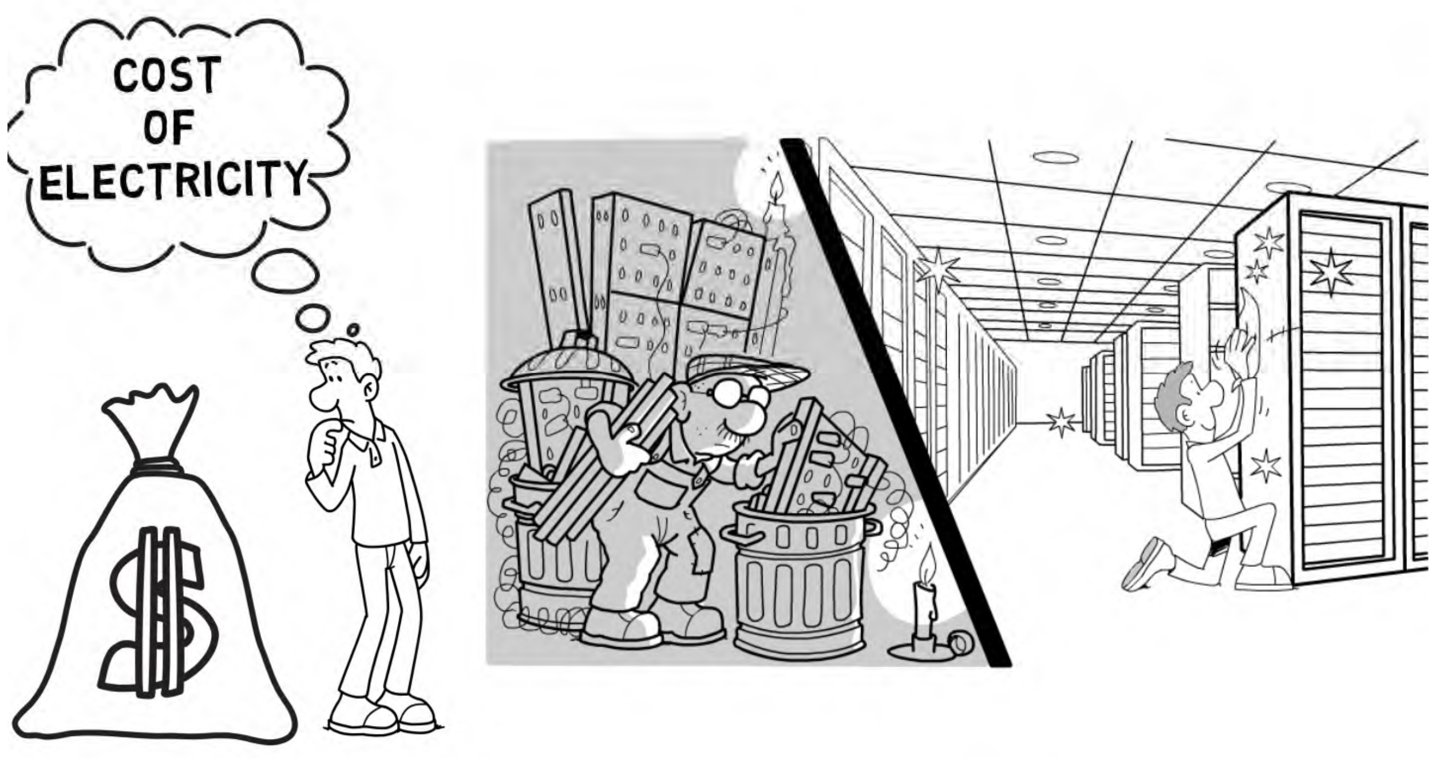


PROPOSED RATE INCREASE - VIDEO 4

Now that we've reviewed the bill breakdown, let's take a look at our proposed rate increase. Since 2013's application, our service revenue requirements have increased, by approximately $3.3 million, up from $18.8 million to $22.1 million. This is largely driven by increases in operation, maintenance, and administrative costs, as well as a number of infrastructure renewal projects.



While we understand the concerns around rising electricity costs, the unfortunate reality is, additional financial resources are needed for us to continue addressing our community's electrical distribution needs.

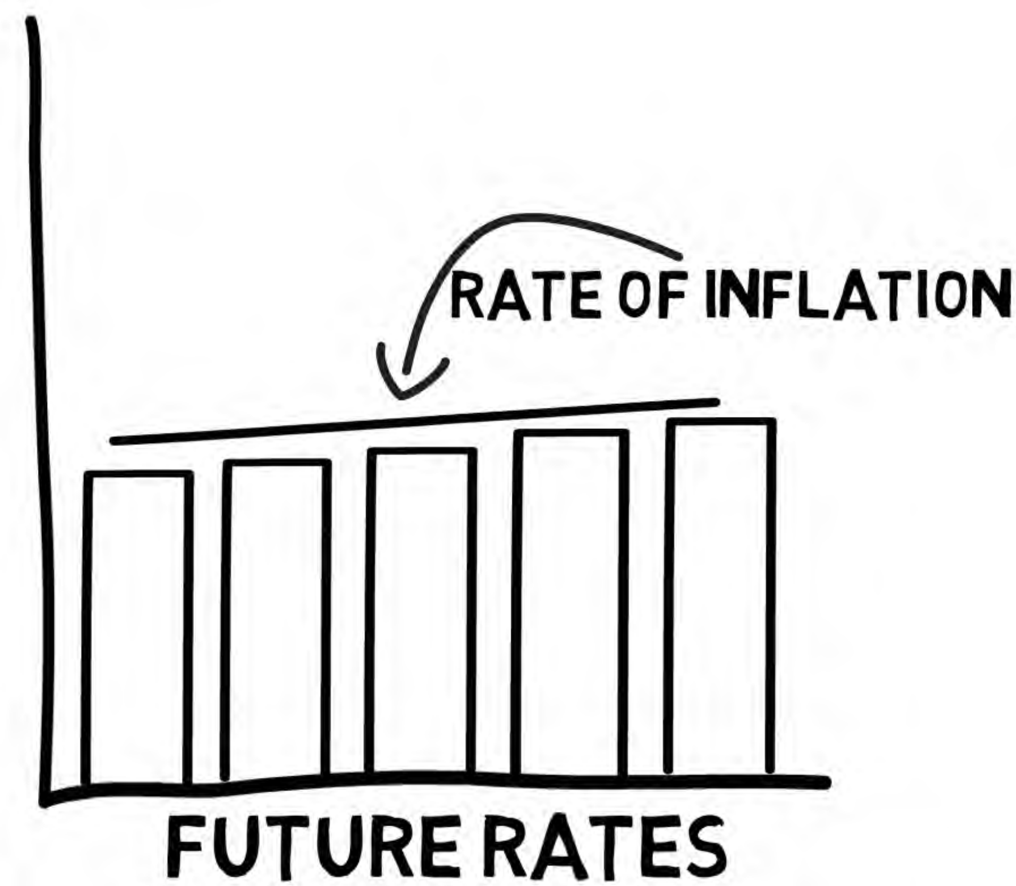


If the rate increase is approved, an average residential customer, using the Provincial average of 750 kWh a month, will see an approximate two dollar and seventeen cent increase on their monthly electricity bill.

This represents a sixteen point five percent increase on the PUC portion of the bill or a two point one percent increase on the total electricity bill.

16.5%	2.1%
PUC PORTION OF THE ELECTRICITY BILL	TOTAL ELECTRICITY BILL

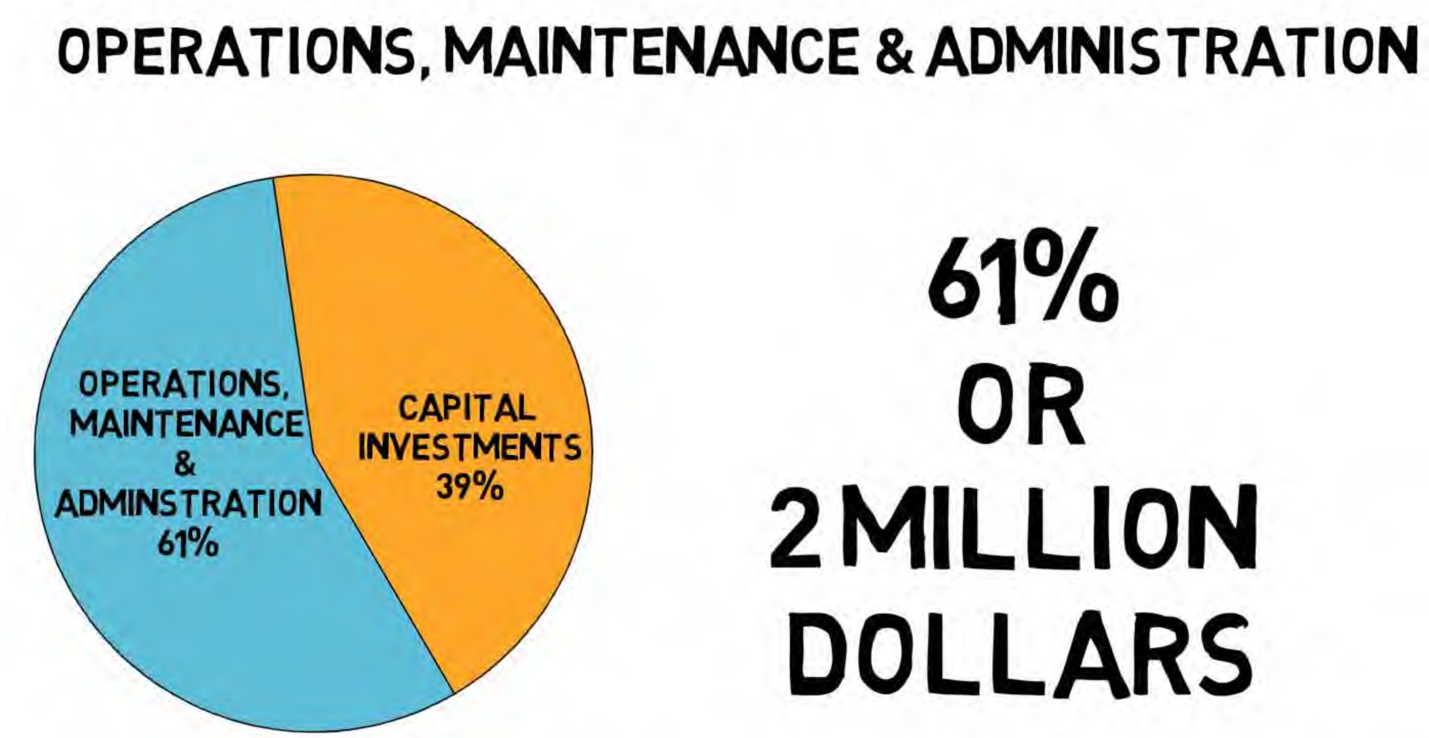
And, for the duration of the following five-years – distribution rate increases would be held to less than the rate of inflation.



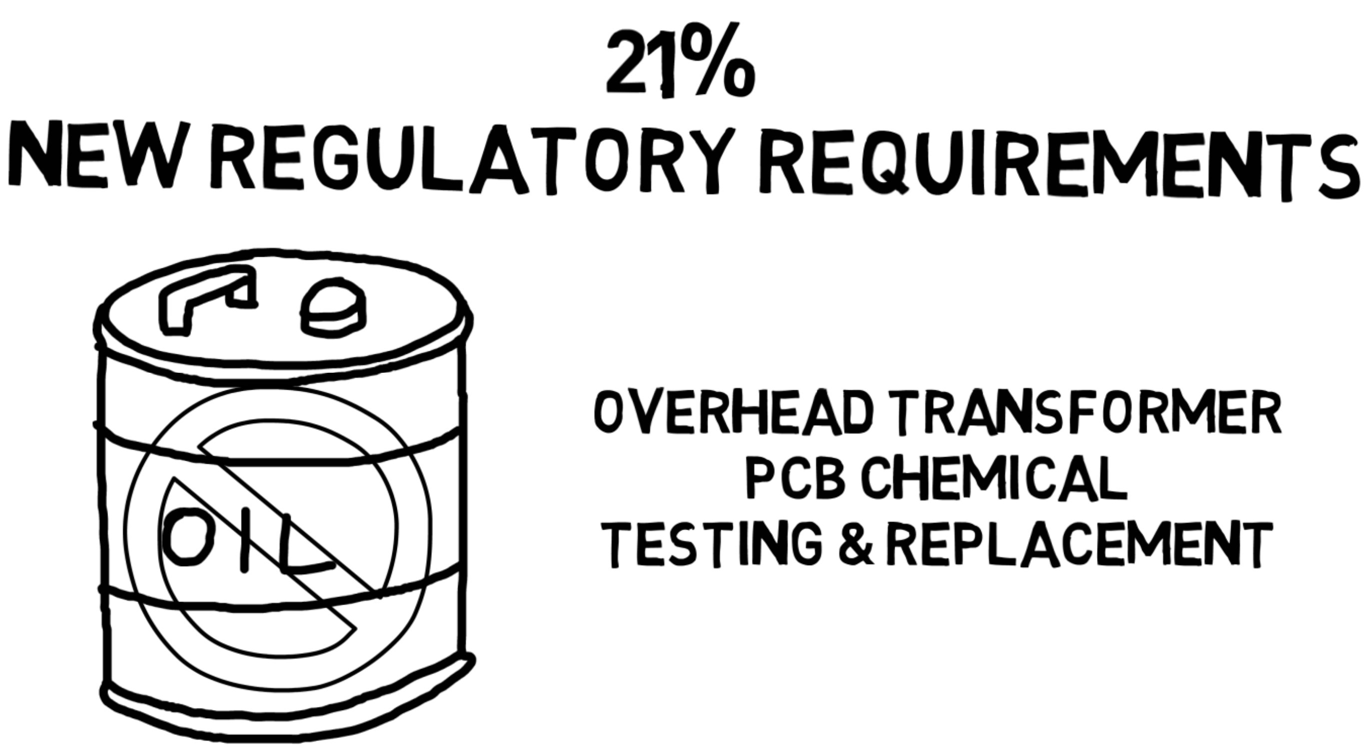
As mentioned earlier, this rate increase is largely driven by increased costs which we will be breaking down in the upcoming videos.

OPERATIONS, MAINTENANCE & ADMINISTRATION – VIDEO 5

In previous videos, we've talked about the 3.3 million dollar increase in our service revenue requirements. Approximately, 61% or 2 million dollars of this increase is driven by operational, maintenance and administrative costs. Here's a breakdown of those costs:



21 percent of the 2 million dollar increase is made up of new Regulatory Requirements.
These include things like: PCB chemical testing for overhead transformers, to ensure they are all PCB-free by 2025.



New meter reading requirements for large general service customers.

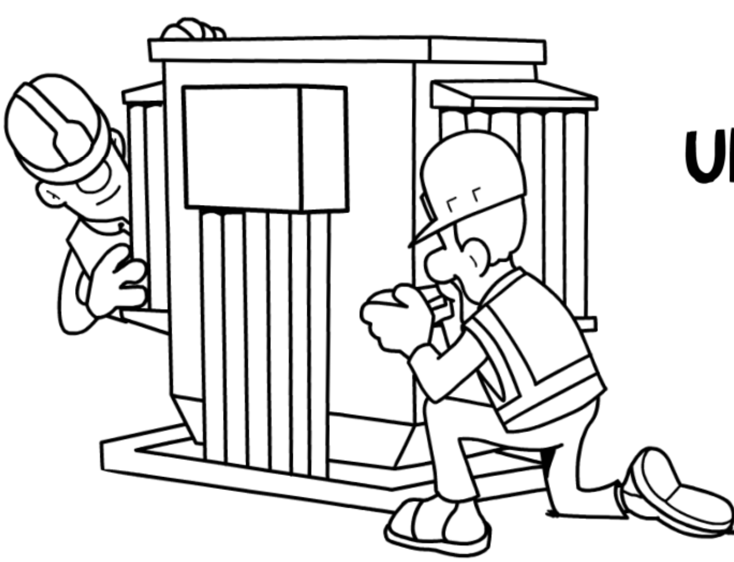
21%
NEW REGULATORY REQUIREMENTS (CONT'D)

NEW METER READING REQUIREMENTS

FOR LARGE GENERAL SERVICE CUSTOMERS

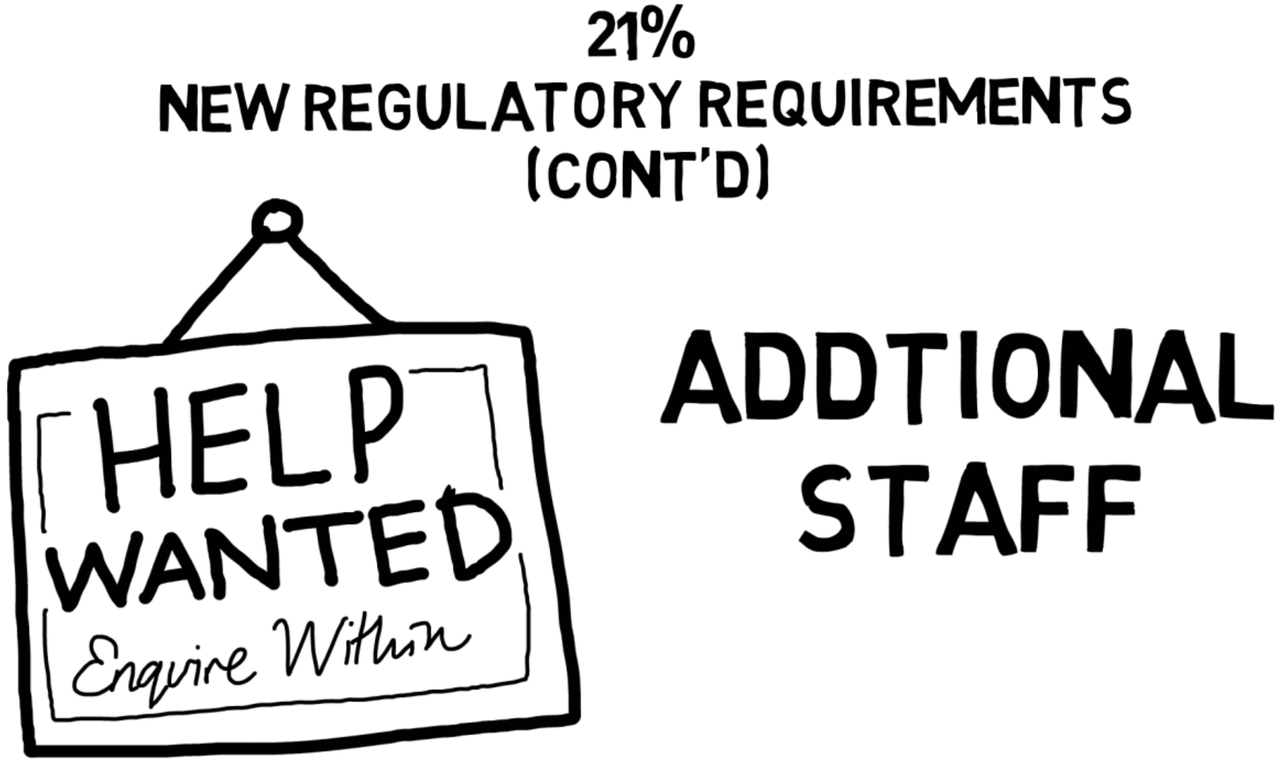
Newly mandated initiatives, like the Under Frequency Load Shedding program – which is designed to improve the reliability of the Provincial electricity grid.

21%
NEW REGULATORY REQUIREMENTS (CONT'D)

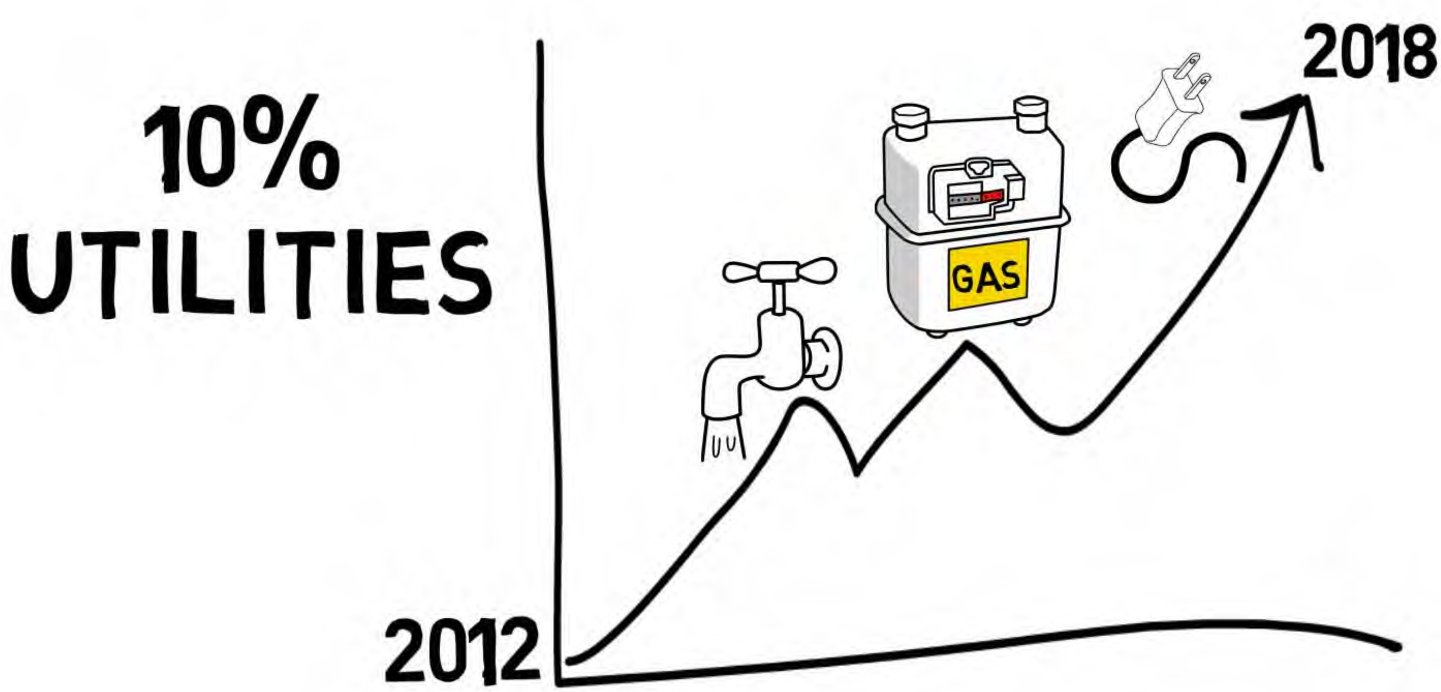


UNDER FREQUENCY LOAD SHEDDING

And finally, the hiring of an additional staff member to assist with growing OEB requirements – all contribute to the increased costs in Regulatory Requirements.

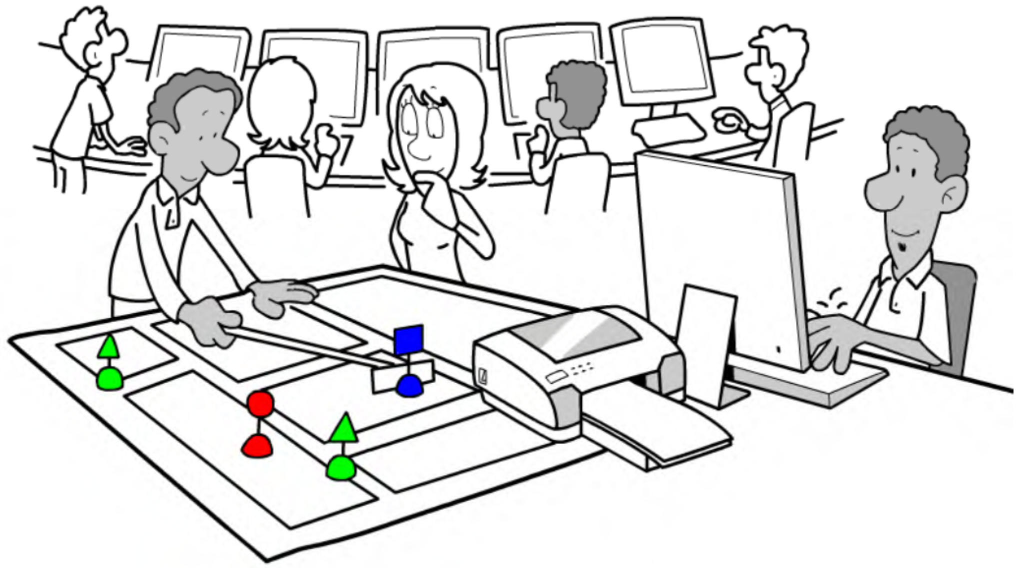


10 percent of the increase covers the rising cost of utilities since our last application. This accounts for basic utilities for the transmission and distribution stations, and the administrative building and service center.



5 percent of the increase is a result of the growing cost of utilizing the Smart Meter Network, which include things like the automated meter-reading software fees.

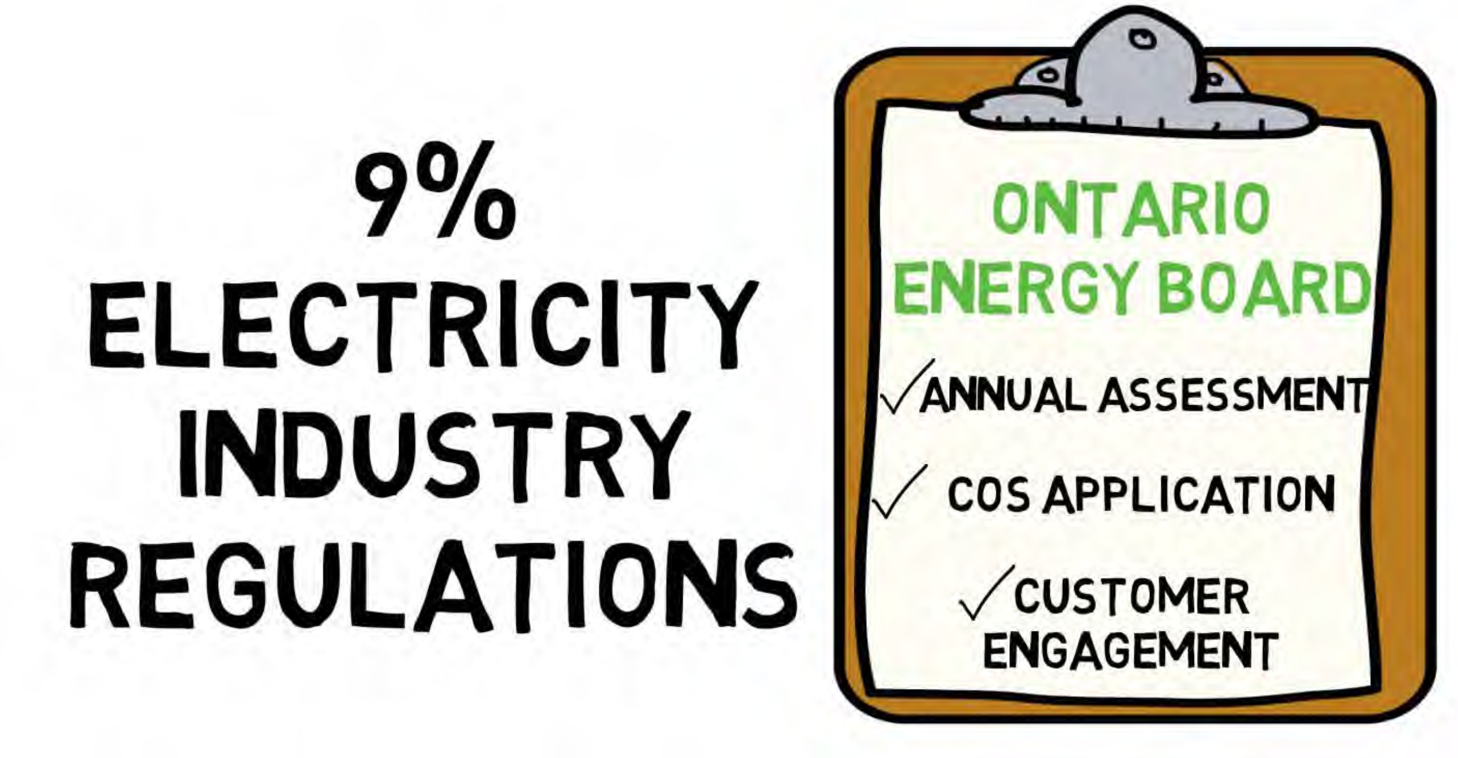
5%
SMART
METER
BILLING
SYSTEM



Another 7 percent of the increase is needed to cover Bad Debt, which has grown, due to the rising number of customers unable to pay their electricity bill. This can be attributed to the combination of; the rising cost of electricity, the moratorium on winter disconnections, and the state of our local economy.

7%
BAD
DEBT

9 percent of the increase accounts for the growing costs of meeting Industry Regulations. For example, costs for things like; OEB Annual Assessments, Cost of Service Applications, and mandated Customer Engagement Programs have all grown since 2012.



7 percent of the increase covers the cost to operate our Vegetation Management or Tree Trimming program. While, PUC has extended this program to a four-year cycle to reduce costs annually, costs fluctuate based on the total area needing to be cleared, and the number of contractors bidding on that year's cycle.

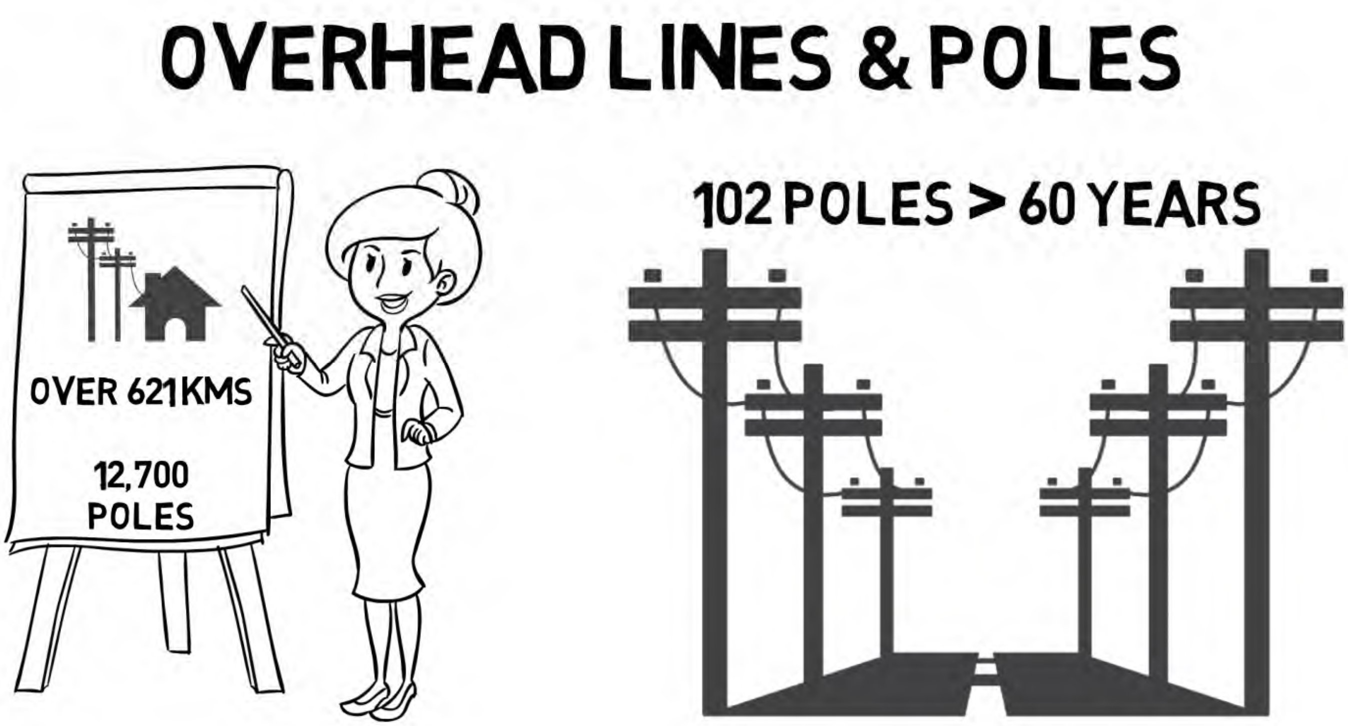
The remaining 41% of the increase in service revenue requirements is driven largely by inflationary growth in things like; employee wages, benefits, contracted services, insurance costs, and fuel expenses.

41%
INFLATIONARY GROWTH

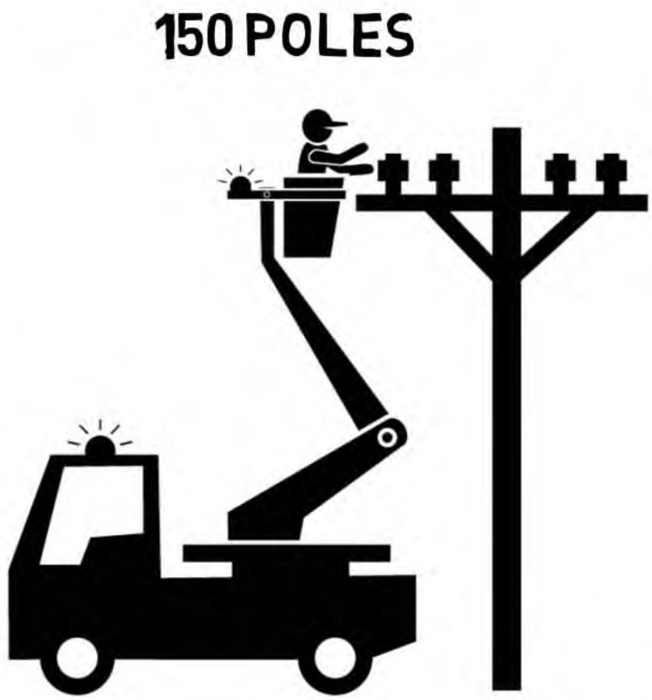
CAPITAL INVESTMENT PROJECTS – VIDEO 6

As mentioned, operations, maintenance and administrative expenses account for two-thirds of the total service revenue requirement increase. The remainder is driven by Capital Investments in infrastructure renewal. Let's explore some of the infrastructure renewal projects PUC has planned for the next few years.

Probably, the most visible components of the electrical distribution system are the overhead lines and poles. PUC has about 621 km of overhead lines using about twelve thousand, seven hundred poles. Of those, approximately 102 poles have been in service for more than 60 years.



Over the next five years, our plan is to replace approximately 150 poles, identified as being in poor or very poor condition. Additionally, some of the older overhead lines in our system were constructed with a type of copper wire, which no longer meets reliability and safety standards. Our proposed plan would see those lines replaced within the next ten years.

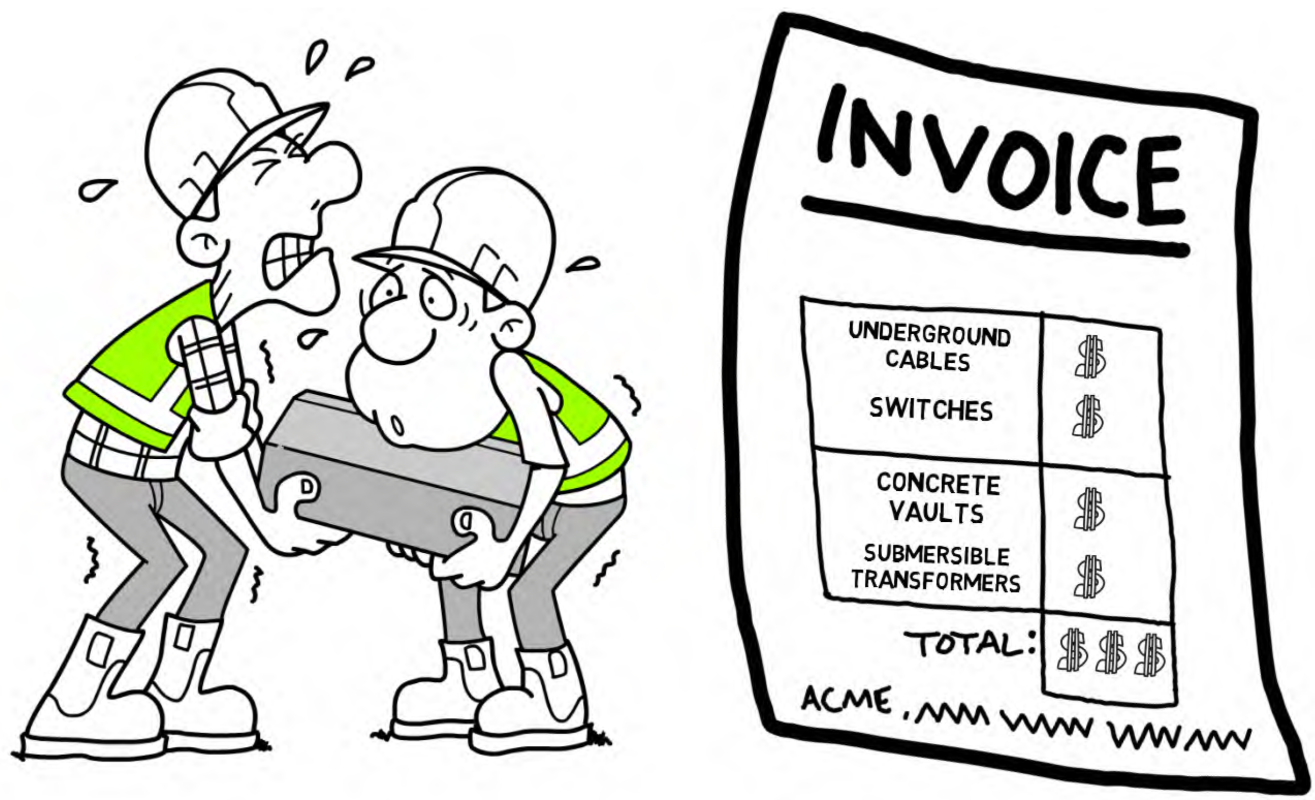


The underground electrical distribution system is comprised of approximately 122 kms of cable, 30 kms of which are approaching the end of their service life.

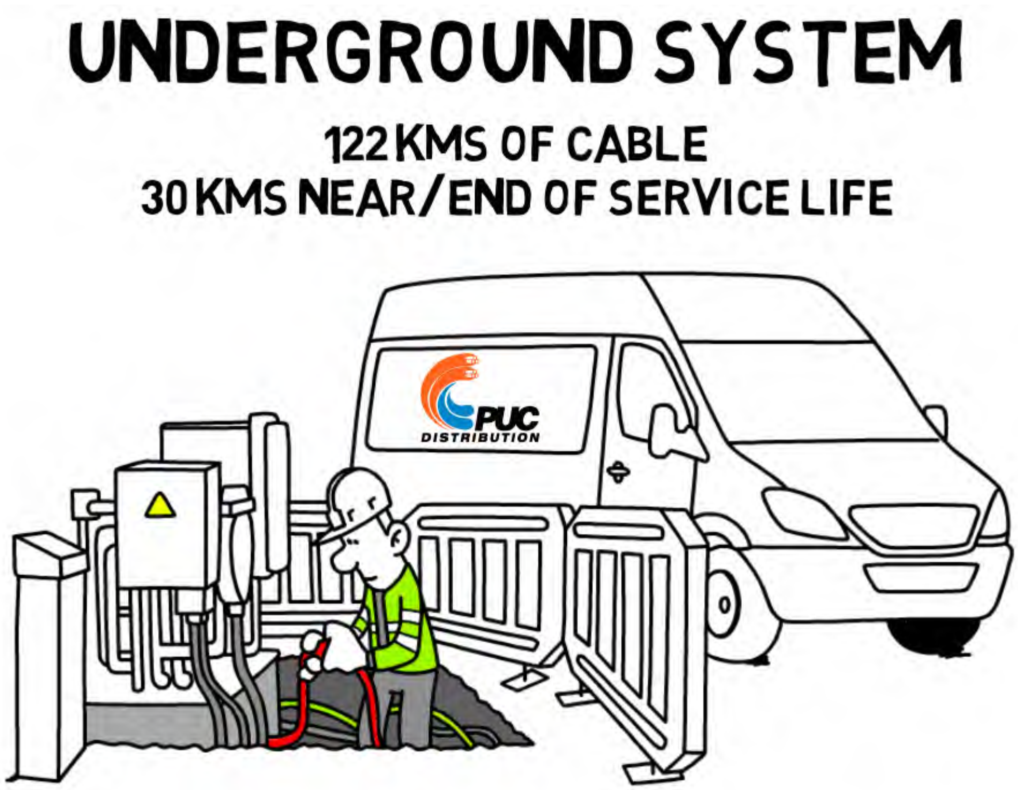
UNDERGROUND SYSTEM

122 KMS OF CABLE
30 KMS NEAR/END OF SERVICE LIFE

Additionally, underground infrastructure like switches, concrete vaults, and submersible transformers are also a priority for replacement based on their condition.



Our plan will continue addressing this aging infrastructure, and focus on neighbourhoods with high equipment failure rates.



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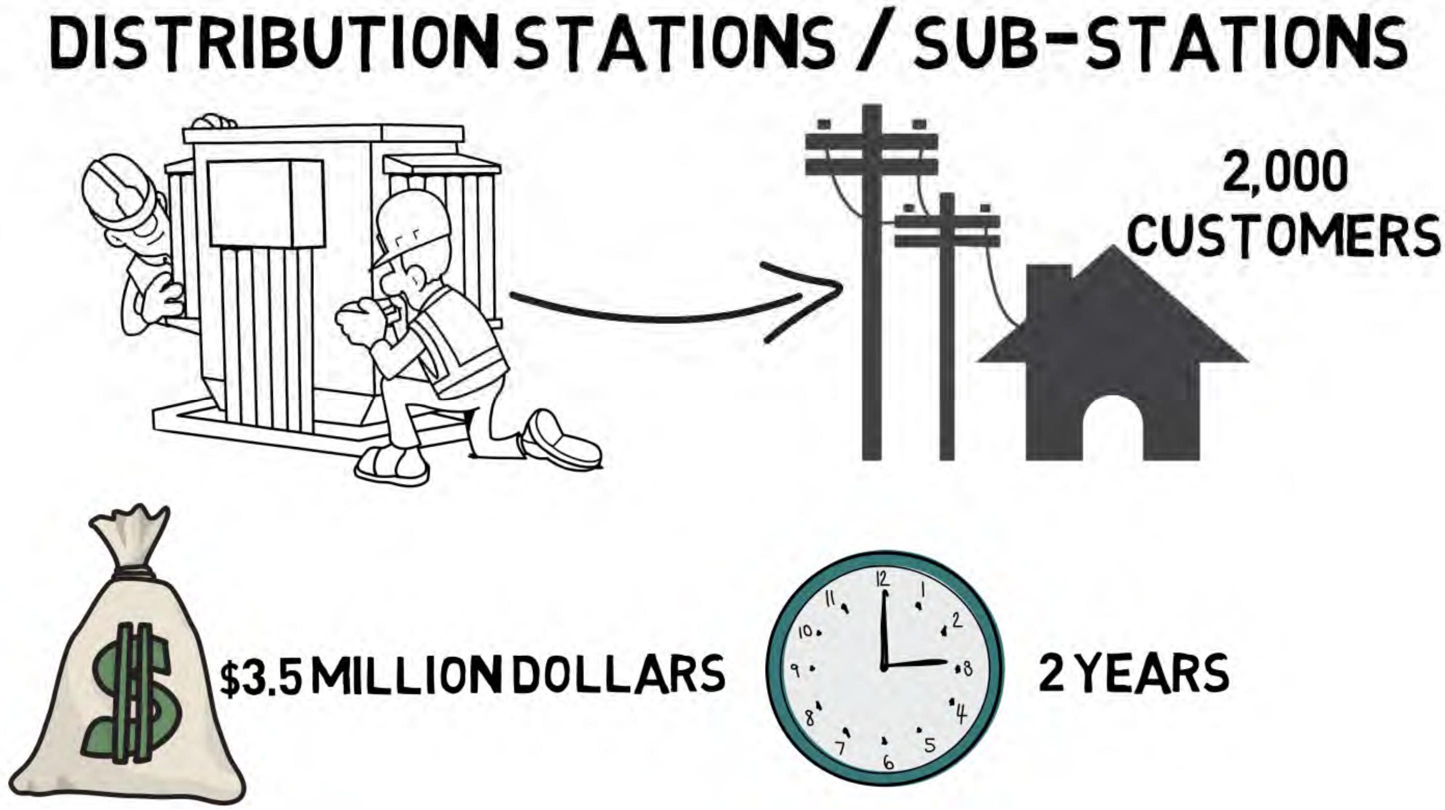
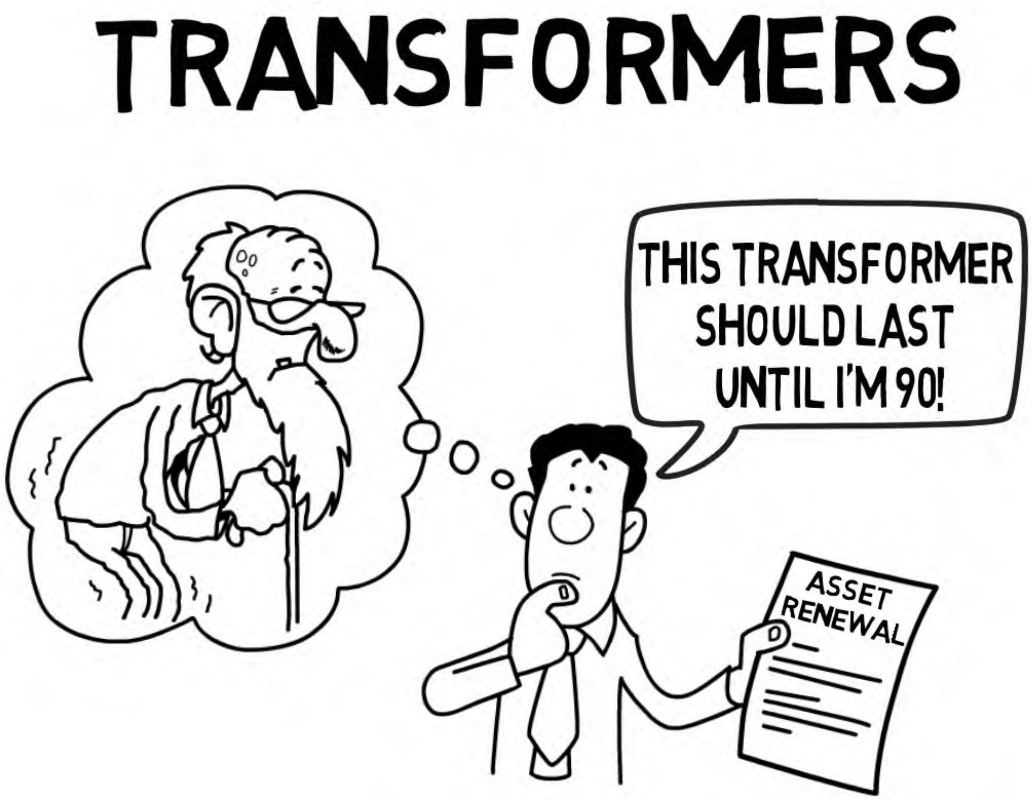
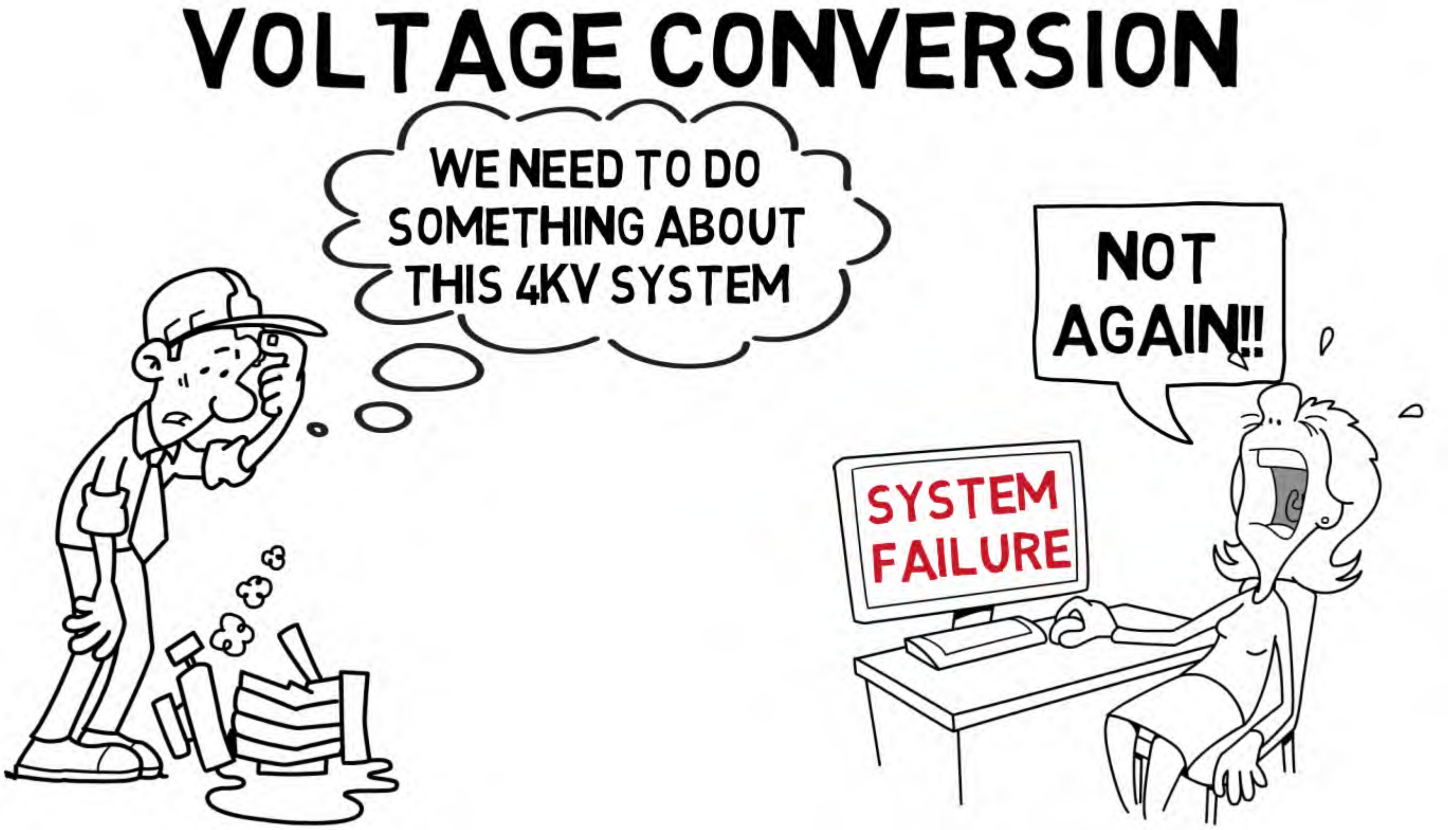


It's important to note that the average service life for a transformer is 40 years so special attention needs to be paid to those located within our substations, as 66% of station transformers have been in service longer than 35 years. With that in mind, we plan on replacing two substations by 2022.



Locally, our substations transform electricity from 34 thousand volts to twelve or four thousand volts. Over the last few years, PUC has been converting the four thousand volt system to a twelve thousand volt system. This is because the four thousand volt system is at, or very near, the end of its service life.



PUC is proposing a replacement plan that will completely retire the 4 thousand volt system by 2022; including poles, wires and transformers and replace it with the more efficient and reliable 12 thousand volt system.

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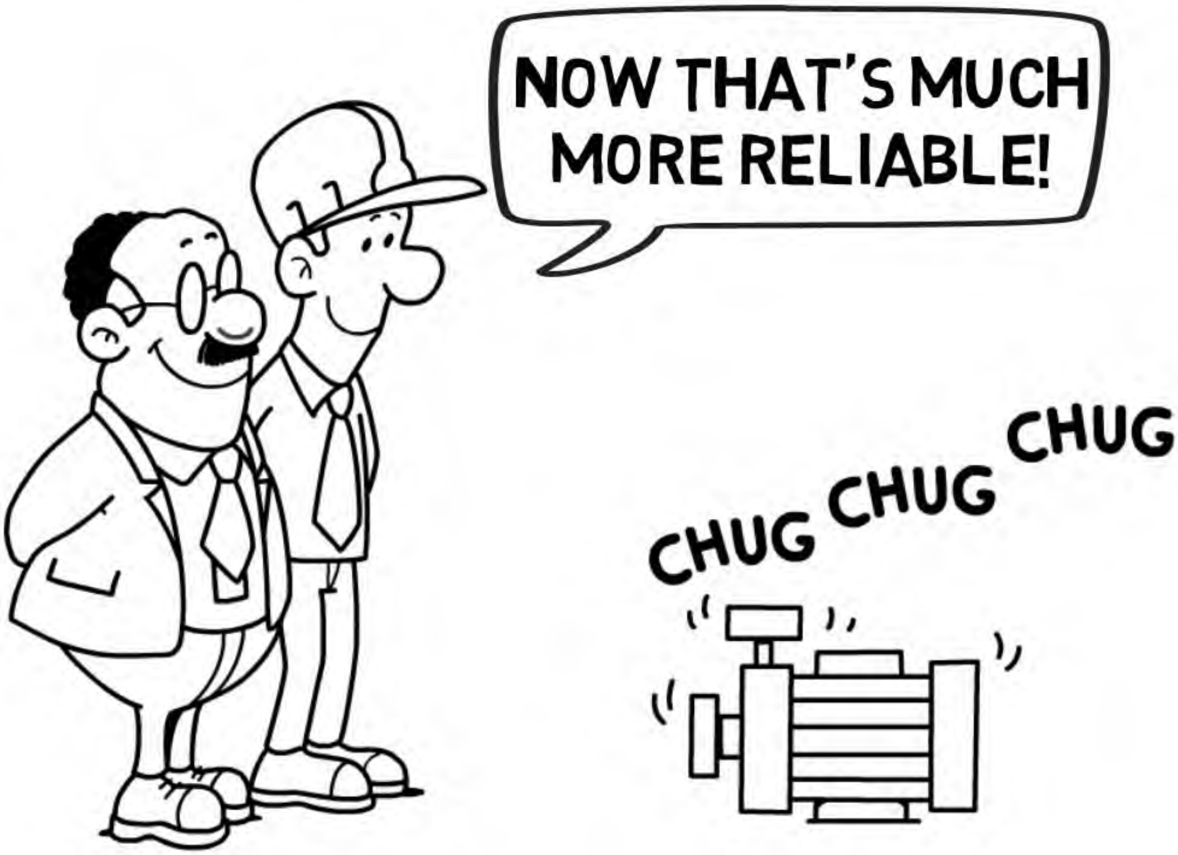
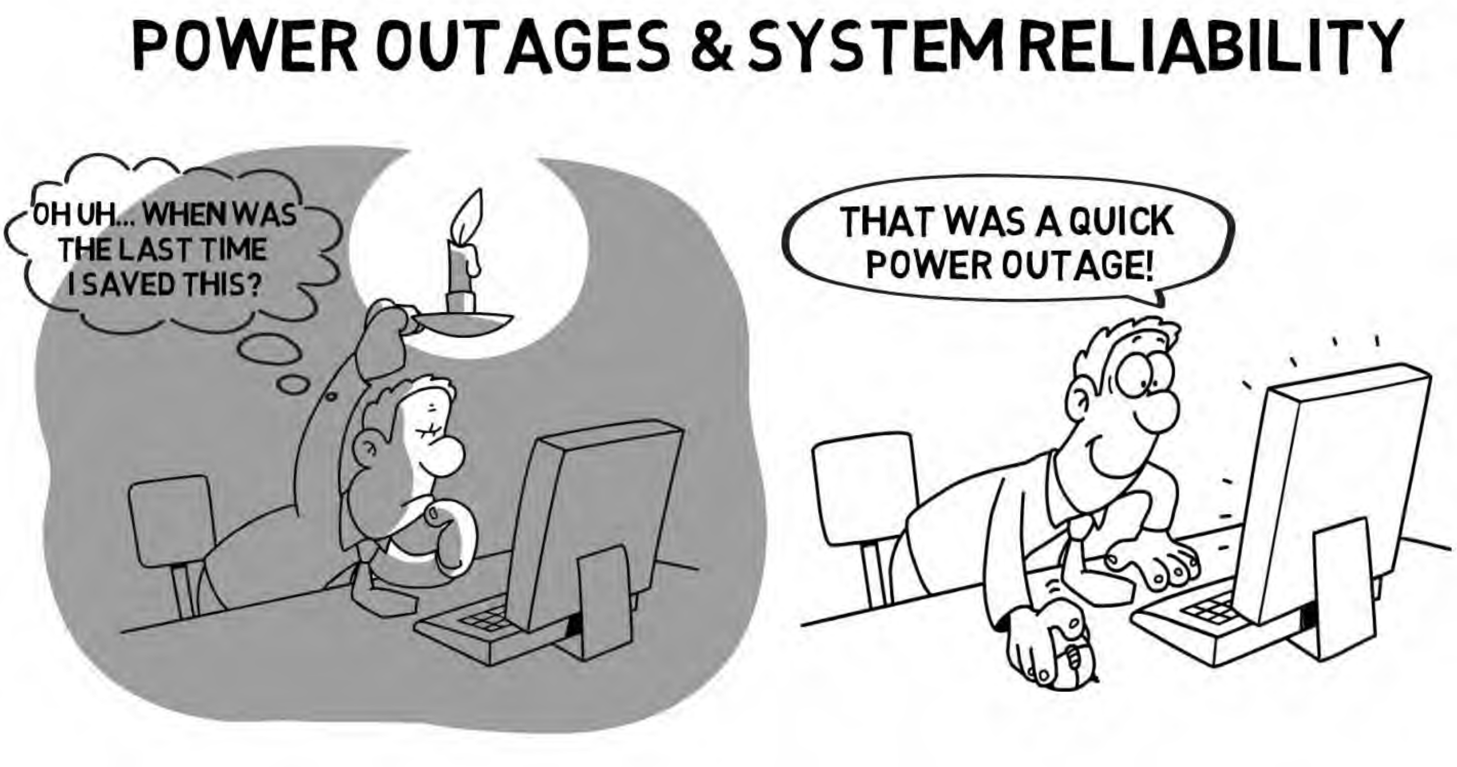
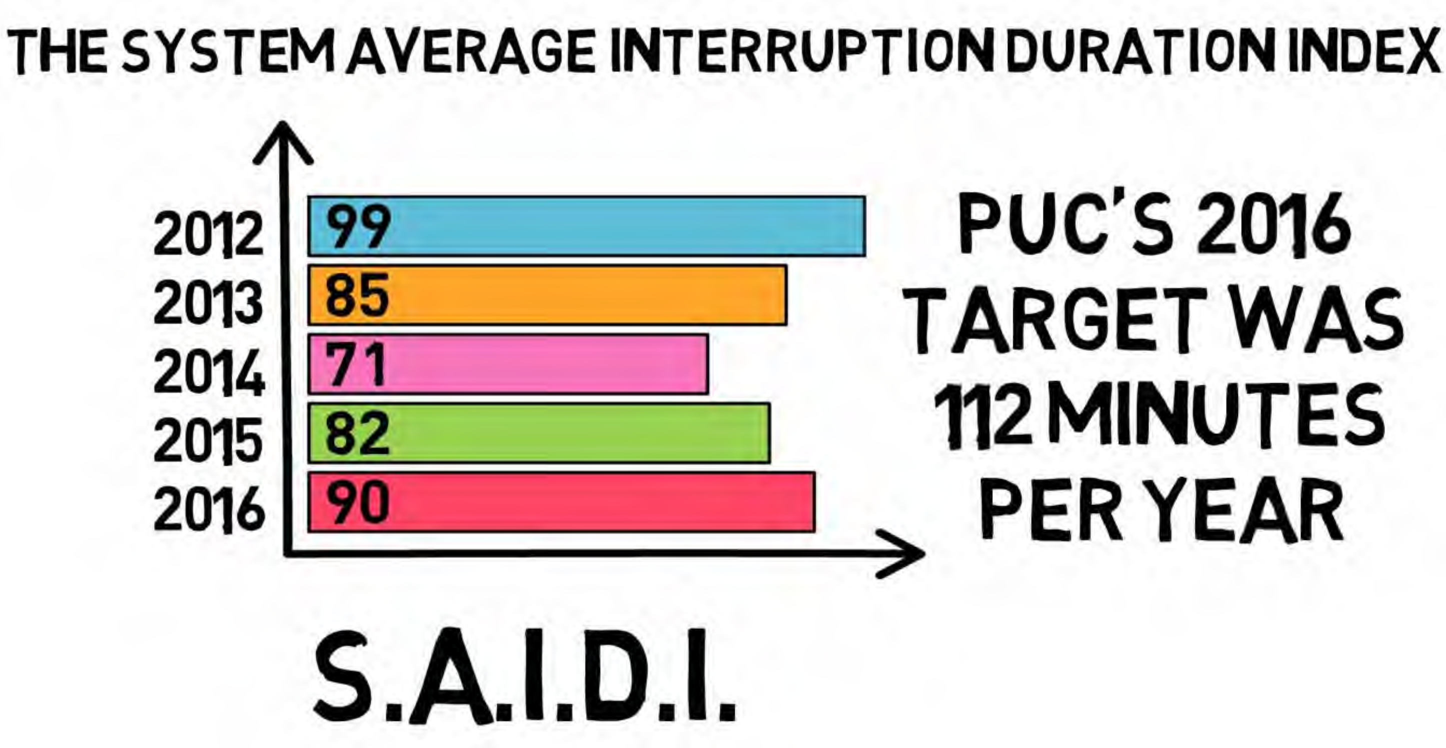


POWER OUTAGES AND SYSTEM RELIABILITY – VIDEO 7

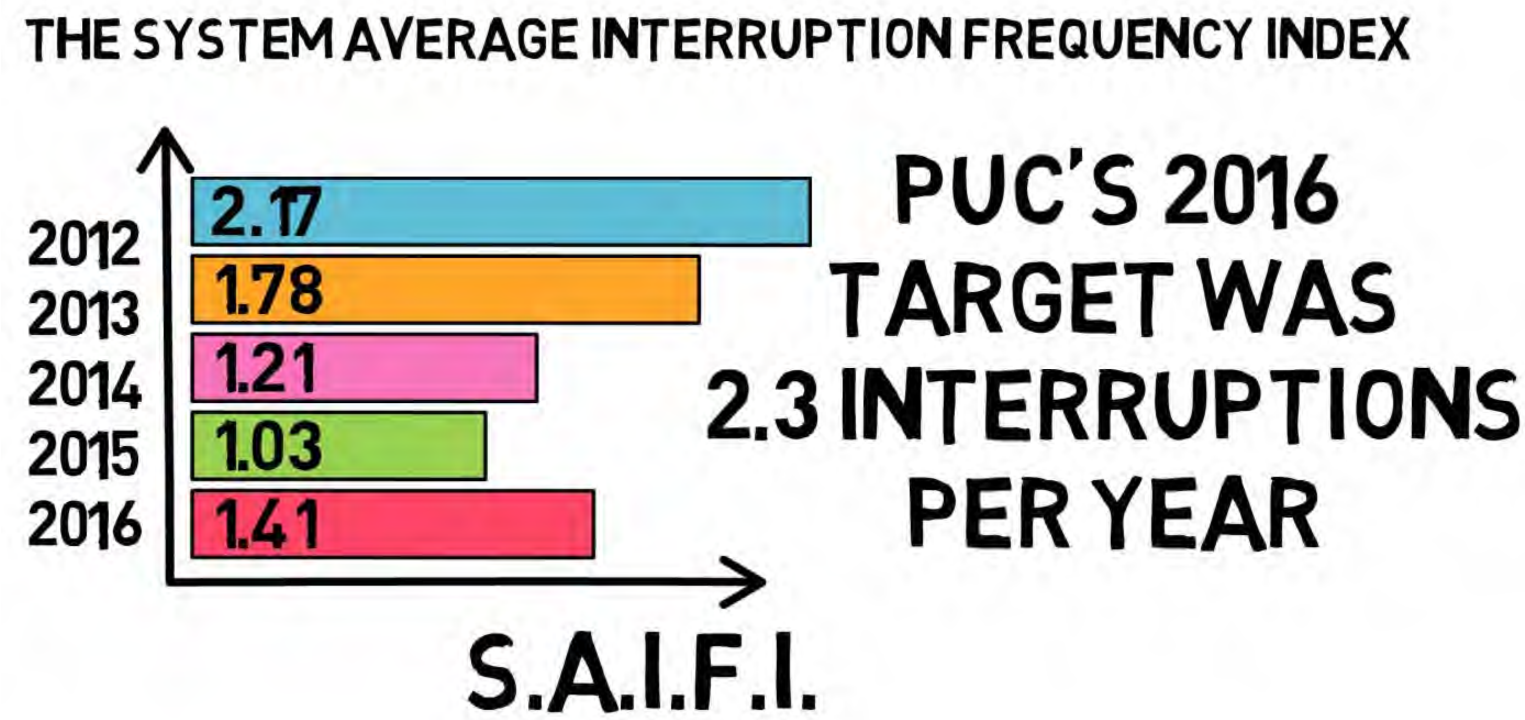
Power outages are an unfortunate reality in the electricity industry. That said, at PUC we work very hard to keep outages to a minimum and if required, as short as possible.



One of the annual industry measurements for system reliability is the System Average Interruption Duration Index, or SAIDI. This is measured by the average number of hours the power to a customer is interrupted. In 2016, the total time the average customer was without power was 90 minutes. This is below our target of 112 minutes, per year.

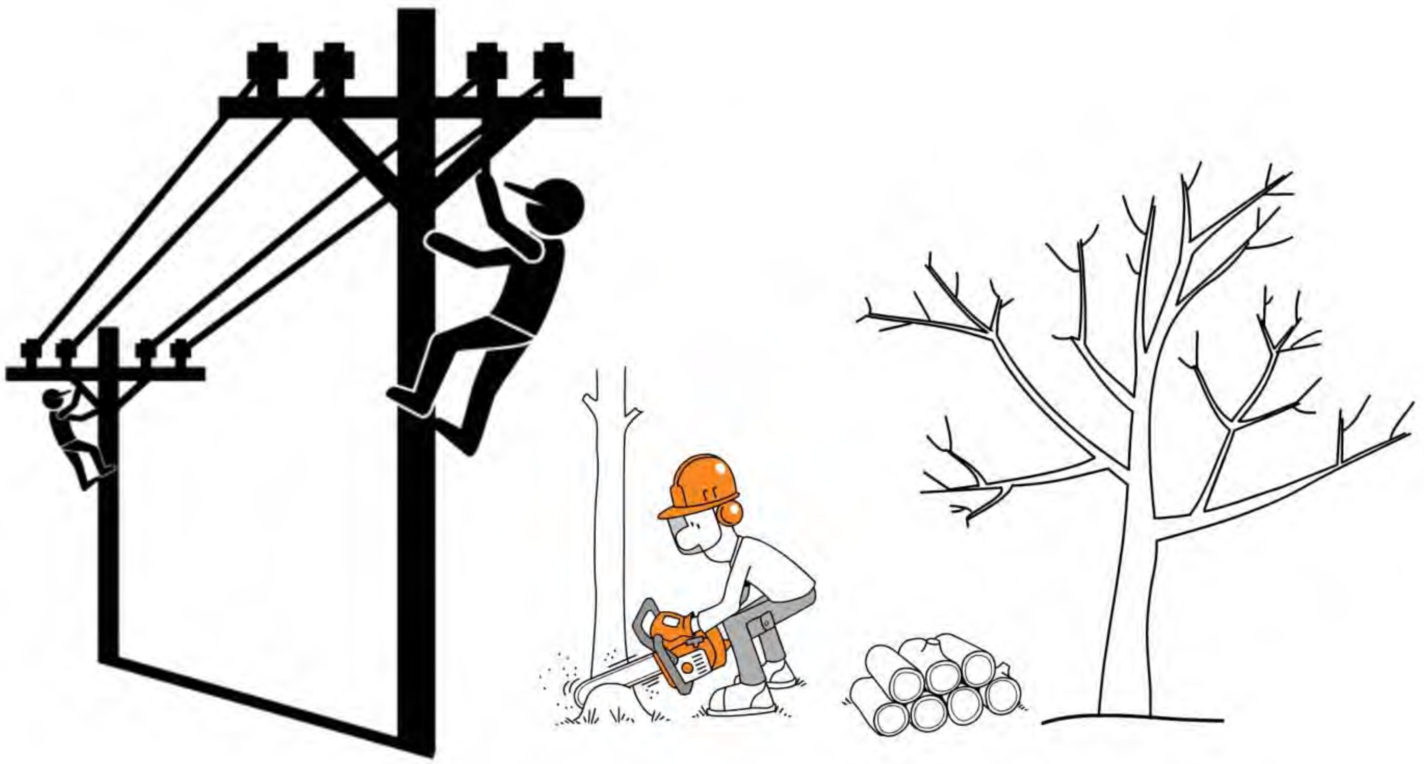


The other annual industry measurement is the System Average Interruption Frequency Index, or SAIFI. This is measured by the average number of times the power to a customer is interrupted. In 2016, the total number of times the average customer experienced an interruption was 1.4 times. This is well below the target of 2.3 interruptions per year.

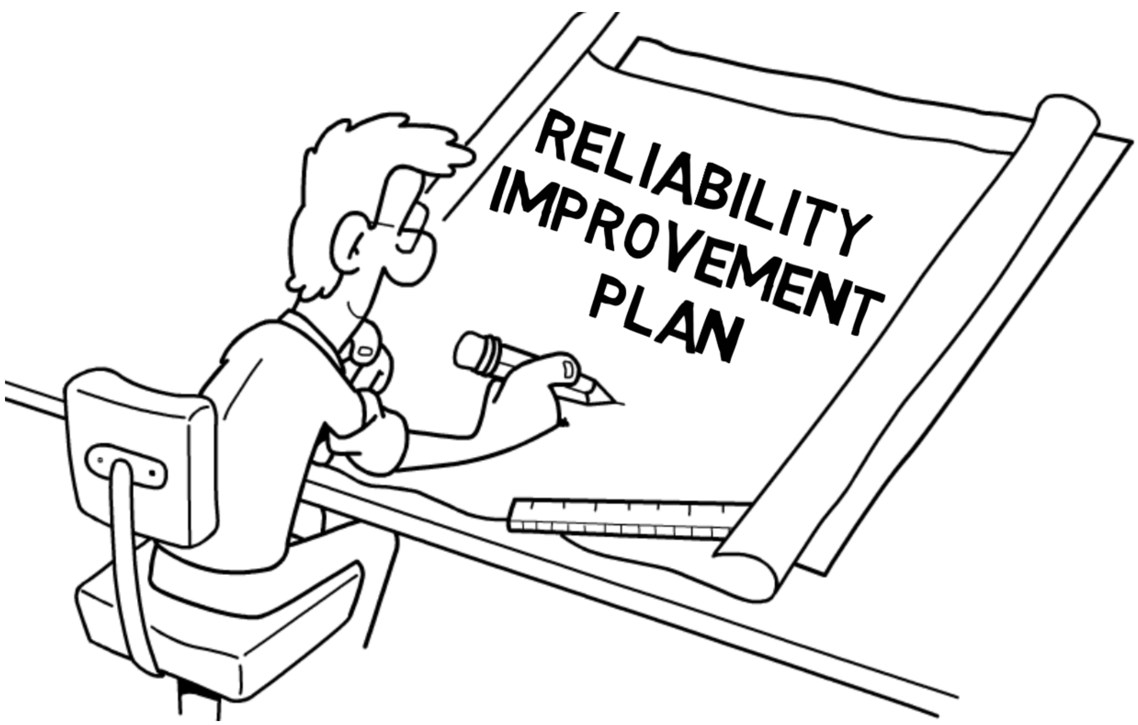


As you can see, PUC's reliability metrics are trending in a positive direction.

We attribute these results to our ongoing commitment to improving system reliability through infrastructure renewal and a successful vegetation management program, better known as tree trimming.



PUC knows that reliability is important to customers, and that's why we plan to increase our investment in infrastructure renewal to improve system reliability. This will ensure we continue to provide a safe, reliable and efficient electrical system for the community we serve.



ATTACHMENT 10 – SEC-13 BILL IMPACTS

(FILED IN EXCEL SPREADSHEET)

ATTACHMENT 11 – CORPORATE STRUCTURE CHART

(FILED IN CONFIDENCE)