Ontario Energy Board | Commission de l'énergie de l'Ontario

BY E-MAIL

May 3, 2019

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: PUC Distribution Inc. (PUC Distribution)
2019 IRM Distribution Rate Application
OEB Staff Interrogatories
OEB File No. EB-2018-0219

In accordance with Procedural Order No.1, please find attached OEB Staff interrogatories in the above proceeding. The applicant and intervenors have been copied on this filing.

PUC Distribution's responses to interrogatories are due by May 17, 2019.

Yours truly,

Original Signed By

Georgette Vlahos
Advisor, Incentive Rate Setting & Accounting

Encl.

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PUC Distribution Inc. (PUC Distribution)
EB-2018-0219

Staff-1
Ref: Rate Generator Model

OEB staff notes that there was an error in the Rate Generator Model posted on the OEB's webpage. On Tab 6 - Class A Consumption Data under item 1, it states "Please select the Year the Account 1580 CBR Class B was Last Disposed." This is a typo and should instead note "Please select the Year the Account 1589 GA was Last Disposed." OEB staff has provided a revised Rate Generator Model with this correction.

Please confirm PUC Distribution Inc.'s acceptance of the updated model.

Staff-2
Ref: Rate Generator Model, Tab 1 – Information Sheet

PUC Distribution disposed of its deferral and variance accounts in its 2018 cost of service proceeding (EB-2017-0071). On Tab 1 of the Rate Generator Model in the current proceeding, PUC Distribution has selected 2016 as the rate year in which the Group 1 accounts were last cleared.

Please make the necessary correction to the Rate Generator Model provided in Staff-1 to indicate 2018 as the last year in which Group 1 accounts were last disposed.

Staff-3
Ref: Rate Generator Model, Tab 3 - Continuity Schedule

A portion of the directions in the reference above state:

> For all Group 1 Accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2018 rate application, DVA balances as at December 31, 2016 were approved for disposition, start the continuity schedule from 2016 by entering the 2015 closing balance in the Adjustment column under 2015. For all Account 1595 sub-accounts, complete the DVA continuity schedule for each Account 1595 vintage year that has a GL balance as at December 31, 2017 regardless of whether the account is being requested for disposition in the current application.

OEB staff notes that PUC has entered data beginning in column AT – Transactions Debit/(Credit) during 2016.

Please make the necessary adjustments to the model provided in Staff-1 by entering 2015 closing balances in the adjustment column under 2015 given that PUC Distribution was approved for disposition of its 2016 deferral and variance account balances in its 2018 rate application.

Staff-4
Ref: EB-2015-0098, Decision and Rate Order, Pages 7-8
Ref: Rate Generator Model, Tab 3 – Continuity Schedule

OEB staff notes that the OEB-approved principal and interest amounts for the Smart Meter Entity Variance Charge (Account 1551) approved in PUC Distribution's 2016 IRM application[1] of $23,019 and ($23,018), respectively, have not been entered in the Rate Generator Model in the current proceeding. Similarly, the OEB-approved principle and interest amounts for Accounts 1595 (2012) and 1595 (2013) that were approved in PUC Distribution's 2016 IRM application have not been entered in the Rate Generator Model in the current proceeding.

Please make the necessary corrections to the Rate Generator Model as provided in Staff-1.

Staff-5
Ref 1: Rate Generator Model, Tab 3 – Continuity Schedule
Ref 2: Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications, Appendix A

At reference 1, PUC Distribution shows a residual balance of $9,424 in Account 1595 (2013) of which PUC Distribution is seeking disposition. OEB staff notes that PUC Distribution received approval to dispose of a balance in Account 1595 (2013) as part of its 2016 rate application (EB-2015-0098).

Reference 2 states that:

> Applicants are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year only once, on a final basis. Distributors are expected to seek disposition of the audited account balances a year after a rate rider's sunset date has expired. No further transactions are expected to flow through the Account 1595 Sub-accounts once the residual balance has been disposed.

In accordance with the above paragraph, please remove the amount for disposition, or in the alternative, please provide an explanation for why PUC Distribution is requesting recovery of this balance again.

[1] EB-2015-0098

Staff-6
Ref: Rate Generator Model, Tab 3 – Continuity Schedule, Footnote 3

A portion of footnote 3 directs that for each Account 1595 sub-account, the transfer of the balance approved for disposition into Account 1595 is to be recorded in the "OEB Approved Disposition" column.

OEB staff notes that for the OEB-approved principal and interest amounts in 2016 and 2018, PUC Distribution has not entered the transfer of the principle and interest balances in the OEB-approved disposition column. For example, a principle amount of $1,608,511 was approved by the OEB in 2016. PUC Distribution should enter an amount of ($1,608,511) in the line for Account 1595 (2016).

Please make the necessary corrections to the Rate Generator Model as provided in Staff-1.

Staff-7
Ref: Rate Generator Model, Tab 3 - Continuity Schedule

There is a credit balance of $990,477 requested for disposition of Account 1580 WMS. Appendix F of the approved settlement proposal in EB-2017-0071 states “Any under or over-forecasts on embedded generation in a given month will be booked to Account 1580…”

(a) Please provide a breakdown of Account 1580 WMS principal by the revenues, expenses, rate riders refunded.
(b) Please provide the actual consumption for the embedded generation.

Staff-8
Ref: Rate Generator Model, Tab 3 - Continuity Schedule

For Account 1588:

(a) Transactions during 2017 for Account 1588 was a credit of $1,012,943. Typically, large balances are not expected in Account 1588. Please explain why there is such a large balance in PUC Distribution’s account.
(b) For revenues recorded in Account 1588, are the unbilled revenues trued up to actual revenues at year end? If not, please quantify the true up for the 2017 year end.

Staff-9
Ref: Rate Generator Model, Tab 6.2a - CBR B_Allocation

OEB staff notes that PUC Distribution's original filing showed immaterial amounts allocated to transition customers for CBR Class B. Therefore, a distributor is to transfer the entire OEB-approved CBR Class B amount into the Account 1580 WMS control account to be disposed through the general purpose Group 1 DVA rate riders. OEB staff notes that the Rate Generator Model is designed to automatically do this, however cell D20 on Tab 6.2a should be zeroed out to not show the immaterial allocation.

OEB staff has made this change to PUC Distribution's Rate Generator Model and has provided it along with these questions as part of Staff-1. Please confirm if PUC Distribution agrees with the updated model.

Staff-10
Ref: Rate Generator Model, Tab 11 – UTRs & Sub-Tx

OEB staff has updated Tab 11 of the Rate Generator Model, as provided in Staff-1, for the current UTRs in accordance with the OEB's Decision and Interim Rate Order, EB-2018-0326, issued on December 20, 2018. The rates are set out below.

Please confirm PUC Distribution's acceptance of the updated model.

Current Approved UTRs (2019)	per kW
Network Service Rate	**$3.71**
Connection Service Rates	
Line Connection Service Rate	**$0.94**
Transformation Connection Service Rate	**$2.25**

Staff-11
Ref: EB-2018-0219, Application, Page 10

A portion of the above reference is reproduced below:

> Beginning July 1, 2017, two customers obtained Class A status, but contributed to the global adjustment variance balance prior to this date. The GA contribution of the Class A transition customers was $27,530 for the period of January 1, 2017 to December 31, 2017, including carrying charges using the OEB's prescribed interest rates.

Please confirm that the above should indicate that the two transitioning customers contributed to the GA variance for the period January 1, 2017 **to June 30, 2017**, given that effective July 1, 2017 they became Class A customers. **(emphasis added)**

Staff-12
Ref: EB-2018-0219, Application, Appendix 9, Question 2-a

Regarding CT 1142, the application notes: "PUC Distribution's billing system provides the kWh's billed to RPP customers each month, as well as the corresponding RPP revenue. The system also tracks corresponding amounts (not billed) for both HOEP and monthly GA. The settlement variance is calculated by subtracting the RPP revenues billed customers from the amounts calculated using HOEP plus the GA amount adjusted to reflect the final GA rate".

(a) The system provides the billed consumption for RPP each month. Please explain how the unbilled consumption for RPP customers in the month is accounted for in the settlement process and whether it is subject to true up.
(b) For the settlement calculation, please confirm that the Global Adjustment (GA) amount is adjusted to reflect the final GA rate in a future true up, not the initial settlement claim. If this is not the case, please explain.

Staff-13
Ref: EB-2018-0219, Application, Appendix 9, Question 2b and 2f

Regarding CT 1142:

(a) Response 2b only discusses the true up of the GA component in the RPP settlement. Please also discuss any true-ups of the RPP revenue and HOEP components as well as these components would have been based on estimates at the initial settlement.
(b) Total volume to be split between RPP and non-RPP is determined by taking actual kWh purchased from the IESO plus any embedded generation. In 2017, PUC Distribution had two customers that transitioned to Class A. Please confirm that Class A consumption was removed in the calculation of total volume to be split between RPP and non-RPP.
(c) Response 2f states that the true-up portion is included in the transactions during the year column for Accounts 1588 and 1589. Please explain how the true-up of CT 1142 would affect Account 1589 given that PUC Distribution only records CT 1142 in Account 1588 as per response 1.

Staff-14
Ref: EB-2018-0219, Application, Appendix 9, Question 3

Regarding CT 148:

(a) CT 148 is booked into Account 4705. The non-RPP portion is booked into Account 1589 and the remainder is booked into Account 1588. Please clarify whether Account 4707 Charges – Global Adjustment is used as required per the APH, Article 490. If not, please provide the journal entries PUC Distribution uses to record CT 148 and discuss the impact to Accounts 4705 and 4707.

(b) In question 3, part d, it states that both Accounts 1588 and 1589 are trued-up monthly using actual billing data. Please clarify if the accounts are trued-up to actual monthly consumption regardless of whether the consumption has been billed or not. If this is not the case, please explain.

Staff-15
Ref: EB-2018-0219, GA Analysis Workform

Columns G and H in the "Analysis of Expected Amount" are not filled in.

Please confirm that actual monthly consumption data is used in column F and not billed consumption. If not confirmed please revise the table and complete columns G and H.

Staff-16
Ref: EB-2018-0219, GA Analysis Workform
Ref: Rate Generator Model, Tab 3 - Continuity Schedule

In the GA Analysis Workform, the Net Change in Principal Balance in the GL is $468,260. This is adjusted by reconciling item 4, to remove $444,645 pertaining to GA for Class A customers. In the DVA Continuity Schedule, the transactions during the year for 2017 is also $468,260.

(a) Please clarify whether or not the $468,260 includes GA for Class A.

    I. If yes, please remove the amount for Class A GA in the principal adjustment column of the DVA Continuity Schedule as this should not be disposed to non-RPP Class B customers.

    II. If no, then please remove reconciling item 4 in the GA Analysis Workform and revise the Workform as needed.

Staff-17
Ref: EB-2018-0219, GA Analysis Workform

In the prior year's GA Analysis Workform, PUC Distribution identified reconciling items for unbilled to actual revenue differences. There is no reconciling item for unbilled to actual revenue differences in the current GA Analysis Workform. Please explain whether the unbilled revenue process has changed and why it is no longer causing a significant difference.

LRAMVA

Staff-18
Ref 1: EB-2018-0219, Application, Tab 3 of LRAMVA Workform
Ref 2: Rate Order for 2016 rates, EB-2015-0098
Ref 3: Rate Order for 2017 rates, EB-2016-0102
Ref 4: Rate Order for 2018 rates, EB-2017-0071

The 2017 distribution rates are calculated as the average of 2016 and 2017 rates effective for the January to December calendar year.

i) 2016 rates include:
- 2016 approved volumetric rate
- Rate rider for tax change (2016) (effective May 1, 2016 to April 30, 2017)
- Ride rider for tax change (2017) (effective May 1, 2017 to April 30, 2018)

ii) 2017 rates include:
- 2017 approved volumetric rate
- Rate rider for tax change (2017) (effective May 1, 2017 to April 30, 2018)
- Rate rider for tax loss carry forward (2018) (effective October 1, 2018 to April 30, 2020)

(a) Please explain the rationale for including the 2017 rate rider for tax change with the 2016 volumetric rates used in the LRAMVA calculation, given that the OEB approved this rider to be effective May 1, 2017 (EB-2016-0102). (Note: OEB staff compiled the following information based on the rates entered in Tab 3 of the LRAMVA Workform)

Rate classes	2016 volumetric rate (inclusive of 2016 tax change rate rider)	2017 rate rider (effective May 1, 2017)
GS<50 kW ($/kWh)	$0.0203	$0.0001
GS 50-4999 kW ($/kW)	$5.3708	$0.0101

Unmetered Scattered Load ($/kWh)	$0.0307	$0.0001
Sentinel lighting ($/kW)	$26.9643	$0.0793
Street lighting ($/kW)	$18.9614	$0.0620

(b) Please explain the rationale for including the 2018 rate rider for tax loss carry forward with the 2017 distribution rates used in the LRAMVA calculation, given that the OEB approved this rider to be effective October 1, 2018 (EB-2017-0071). (Note: OEB staff compiled the following information based on the rates entered in Tab 3 of the LRAMVA Workform)

Rate classes	2017 volumetric rate (inclusive of 2017 tax change rate rider)	2018 rate rider (effective October 1, 2018)
GS<50 kW ($/kWh)	$0.0206	$0.001
GS 50-4999 kW ($/kW)	$5.4473	($2.734)
Unmetered Scattered Load ($/kWh)	$0.0311	($0.0016)
Sentinel lighting ($/kW)	$27.4344	($1.3742)
Street lighting ($/kW)	$19.2356	($0.3701)

(c) If there are revisions required to adjust the 2016 and 2017 rates, please make the changes in Tab 3 of the LRAMVA Workform.

Staff-19
Ref: EB-2018-0219, Tab 8 of LRAMVA Workform

PUC Distribution provided a table in Tab 8 of the LRAMVA Workform showing the monthly total billed demand of its street lighting upgrades implemented over the course of 2015 and 2016.

(a) Please provide the number of light bulbs included in the forecast of street lighting savings (295 kW) in the 2013 load forecast, the type of bulbs expected to be replaced, and the number of actual conversions undertaken to date.
(b) Please discuss whether PUC Distribution has received reports from the City of Sault Ste. Marie confirming the number of bulbs, types of bulbs and timing of the bulbs replaced.
(c) Please discuss whether PUC Distribution has developed the ability to track the individual bulbs that were upgraded to a higher efficiency level due to the municipality's participation in the IESO's saveOnEnergy Retrofit program.
(d) Please explain how the current methodology of subtracting total billed demand, pre- and post-conversion, estimates incremental savings from street lighting

upgrades that were undertaken as a result of the municipality's participation in the IESO's saveOnEnergy Retrofit program.

(e) Please confirm whether there were street lighting upgrades completed outside of the IESO's saveOnEnergy Retrofit program that are counted in total billed demand. If yes, please quantify and remove the impact of these savings in the LRAMVA.
(f) Please indicate whether any new street lighting additions are captured in total billed demand. If yes, please quantify the impact of new additions included in total billed demand.
(g) Please provide in excel format the detailed, monthly calculations of billed demand by bulb replaced and exchanged that support the table included in Tab 8 of the LRAMVA Workform.

Staff-20

(a) Please file the full excel report of the "2017 Final Verified Annual CDM Program Results." An extract of the report was filed with the application.
(b) Please file the full excel report of "2011-2015 LDC CDM Program Persistence Results Report" to support the 2017 persisting savings included in the LRAMVA claim.

Staff-21

(a) Please confirm any changes to the LRAMVA Workform in response to these LRAMVA interrogatories in "Table A-2. Updates to LRAMVA Disposition (Tab 2)".
(b) If PUC Distribution made any changes to the LRAMVA Workform as a result of its responses to these LRAMVA interrogatories, please file an updated LRAMVA Workform.

<u>Incremental Capital Module</u>

Staff-22
Ref 1: EB-2018-0219, Appendix 11, Page 10
Ref 2: EB-2018-0219, Appendix D, Navigant Report #1, Page 1

PUC Distribution notes that the scope of the Sault Smart Grid (SSG) Project involves the coordinated rapid implementation of a combination of well understood and proven smart grid technologies.

Reference 2 notes that the overall system design, architecture and components are comparable with Distribution Automation (DA) and Voltage/VAR Optimization (VVO) systems that Navigant has reviewed or analyzed throughout the U.S. and Canada.

The main difference between this project and other similar “smart grid” projects is the proposed coverage of PUC Distribution’s service territory. Navigant notes that relative to PUC Distribution’s service territory, the proposed feeder coverage for DA and VVO, 84% and 68% respectively, is higher than many other systems Navigant has encountered.

(a) Please explain why PUC Distribution has not made on-going investments into its system over time, such like other distributors, to incorporate the components being asked for in this ICM.
(b) Please explain how this project meets the criteria for ICM funding, if the majority of other distributors have been making these investments over time through their respective capital budgets.
(c) Please explain whether PUC Distribution had considered implementing smart grid features as part of its capital budgets over a longer period of time, i.e. a phased-in approach rather than a community-wide implementation over a two-year period. If so, please provide details of options considered.

Staff-23
Ref: EB-2018-0219, ICM Application, Page 5

The following is an excerpt from the ICM Application:

> The total capital cost of the SSG Project is estimated to be $34,389,046, with 22% of the SSG Project ($7,655,053) to be in service by December 31, 2019 (Phase 1) with the remaining 78% ($26,733,992) to be in service by December 31, 2020 (Phase 2). Incremental funding for Phase 2 of the SSG Project will be requested by way of a 2020 ICM application.

(a) It is unclear which aspects of the SSG Project are included in each of Phase 1 and Phase 2 of the proposed ICM project. Please split the scope of the SSG Project into its respective phases and explain what benefits customers can expect to receive solely from Phase 1 given that it is only a portion of the SSG project.
(b) How did PUC Distribution determine which components would make up Phase 1 and Phase 2 of the SSG Project as outlined in part (a)?
(c) PUC Distribution notes that Phase 1 is expected to be in-service by December 31, 2019. Has PUC Distribution begun any work on this project to date? If not, how feasible is a 2019 in-service date?

Staff-24
Ref: EB-2018-0219, ICM Application, Page 40

At the above reference, PUC Distribution notes that “the direct savings due to improved energy efficiency through voltage regulation cannot be fully realized until the entire SSG Project is in-service”.

(a) When Phase 1 is completed, will any of the components of the SSG Project be functional or is completion of Phase 2 required in order for the SSG Project to come into service as a whole?
(b) In the event that Phase 2 cannot be carried out, for example if government funding is not continued, which aspects of Phase 1 can be brought into service?
(c) What benefits would customers receive if only Phase 1 was implemented? Are there savings included in the bill impacts provided that arise from the implementation of Phase 1 only? If so, how were these determined? If such savings have not been determined, please provide the bill impacts if only Phase 1 was successfully implemented.

Staff-25
Ref: EB-2017-0071, 2018 Cost of Service Distribution System Plan (DSP), Pages 107-109

The following is an excerpt from the reference above:

> …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.

Table 26 provides the following forecasted System Renewal budgets for 2018-2022 respectively: $3.761M, $6.906M, $3.296M, $4.533M, and $7.093M.

(a) How much of the System Renewal budgets for 2018-2022 is to fund smart grid work as described in the quote above? Please provide a breakdown by year of expenditures for smart grid related work included in the 2018-2022 budgets.
(b) It is not clear if amounts embedded in the System Renewal category of the DSP coincide with work that is being proposed in this ICM. Are the components of the SSG Project different from the smart grid aspects of the System Renewal budgets? If so, how do they differ?

(c) Are the smart grid aspects of the System Renewal activities being shifted from the DSP to the SSG Project? If so, please explain which components are to be shifted.
(d) Why is the paced replacement, as set out in the DSP, being replaced with a two-year project?
(e) Has PUC Distribution considered filing an updated and consolidated DSP with its ICM application that takes into consideration the proposed SSG Project and how it interacts with other aspects of the DSP?

Staff-26

(a) Are there any lower priority projects in the DSP, which are included in the existing capital budget, which may be lower priority than the SSG Project?
(b) Has PUC Distribution considered deferring lower priority projects included in its existing base capital budget envelope to create adequate headroom to implement the SSG Project, or some of its parts?
    i. If yes, please describe in detail the results of this consideration.
    ii. If no, why not?
(c) Does PUC Distribution's base capital (non-ICM) budget also include programs slated to include DA, VVO, substation upgrades, and integration and enhancement of Advanced Metering Infrastructure (AMI)?
    i. If yes, do the ICM line items represent an expansion of the programs already included in the base capital budget?

Staff-27
Ref: EB-2018-0219, ICM Application, Page 23

The scope of DA requires the addition of electrical switching equipment, e.g. reclosers and switches. These are common elements of an electric distribution system and should routinely be replaced by electricity distributors as required in an on-going basis.
(a) Does PUC Distribution have capital already allocated for the purposes of replacing and maintaining these types of equipment?
(b) If yes to (a), please explain why PUC Distribution is not funding this portion of the proposed SSG Project scope using this existing capital.
(c) If yes to (a), please explain why this is eligible for ICM treatment given that, as per ICM guidelines, ICM funding is not available for projects that are more related to recurring capital programs for replacements or refurbishments (i.e. business as usual projects).

Staff-28
Ref: EB-2018-0219, ICM Application, Pages 22-27

PUC Distribution presents three distinct components for the scope of the project: VVM, DA and AMI integration.

(a) Please provide a project costs breakdown that separates the total project costs into the three separate components.
(b) Does the scope of each of the three components rely on each other? Is PUC Distribution able to implement each of the three components as standalone projects?
(c) Has PUC Distribution assessed the benefits and OM&A costs of each of the three components individually?
(d) If yes to (c), please provide the analysis. If no, please explain how PUC Distribution decided that a project that combined all three components was the most prudent option.
(e) Would Natural Resources Canada (NRCan) funding be provided if only a portion of the ICM is approved? How would the amount of funding be determined if this is the case?
(f) How would the amount of NRCan funding be affected if the ICM is approved but the PUC-funded portion is less than requested in this application? Would the amount of NRCan funding be decreased or remain the same? Is there an opportunity to obtain increased NRCan funding?
(g) If only Phase 1 of the SSG Project is approved, is the NRCan funding for Phase 1 still available or is it contingent on OEB approval of both Phase 1 and Phase 2?

Staff-29
Ref: EB-2018-0219, ICM Application, Pages 5 and 38

PUC Distribution notes that the NRCan funding requires projects to be completed by March 31, 2022.

(a) Please provide the NRCan contribution agreement and any other documents related to the NRCan funding.
(b) Under what terms can the NRCan funding be revoked or cancelled? Does PUC Distribution have plans for these scenarios?
(c) Is PUC Distribution under any obligation to pay back the NRCan funding it receives?
(d) In the event of delays and shifting of in-service dates, would PUC Distribution still be eligible to receive NRCan funding?
(e) What if the in-service date is delayed past the March 31, 2022 NRCan deadline?

Staff-30
Ref: EB-2018-0219, ICM Application, Page 38

PUC Distribution states that the SSG project is structured to be completed over two years, with the majority of the funding to take place in Phase 2.

Has PUC Distribution considered implementation to take place over three years, with the in-service date to take place in 2022, but before the March 31 deadline? This would allow PUC Distribution to split the project costs and request funding in the third year, which would mitigate the impact on rates. If this option was not considered, why not?

Staff-31
Ref: EB-2018-0219, ICM Application, Page 14
Ref: EB-2018-0219, ICM Application, Appendix I
Ref: EB-2018-0219, ICM Application, Appendix D

PUC Distribution states that the SSG Project is being developed through a Special Purpose Vehicle called SSG Inc. and will be initially funded through the North American Grid Modernization Fund (Fund), currently managed by Stonepeak Infrastructure Partners (Stonepeak) and Infrastructure Energy LLC (IE).

Appendix I identifies six entities as part of the organization of the SSG Project.

(a) Please confirm that Stonepeak and/or IE, a private equity investment firm, contributed the funds that make up the Fund.
(b) Please confirm that Energizing Co (ECo), an energy infrastructure development company based in California, formed IE with Stonepeak and that IE is essentially a project financing platform for ECo's grid modernization projects.
    i. What is the role of ECo in the SSG Project? Please explain why it is not included in the organizational structure in Appendix I.
    ii. Will PUC Distribution pay ECo monthly payments for the duration of the Project (as referenced in the Navigant Report, Appendix D)? If so, what is the purpose of such payments and what are the amounts of the payments?
(c) Please provide all documents related to the establishment of SSG Inc., including information related to its officers, directors, governance structure as well as all agreements entered into by SSG Inc. with the Fund, Stonepeak, ECo and/or IE.
(d) Please provide all documents related to agreements between PUC Distribution and the Fund, Stonepeak, ECo and/or IE.

(e) Please elaborate on the organizational structure of the Project as noted in Appendix I and how Project funding flows to each company involved.
(f) Please explain why PUC Distribution chose to proceed with the organizational and financing structure as described in part (e). Why is this arrangement preferable to PUC Distribution securing loans and hiring consultants and contractors directly?
(g) Please explain what alternatives, if any, PUC Distribution considered for the development and financing of the SSG Project, in addition to the arrangement with SSG Inc., the Fund, Stonepeak, ECo and/or IE. Please provide details of alternatives considered.

Staff-32
Ref: EB-2018-0219, ICM Application, Page 36

PUC Distribution indicates that the Fund mentioned in the question above funded the Leidos Report.

(a) Does PUC Distribution expect to receive any additional funding from the Fund, Stonepeak and/or IE?
(b) Is PUC Distribution or SSG Inc. expected to repay the Fund, Stonepeak and/or IE for its initial capital contribution for the Leidos Report?

Staff-33
Ref: EB-2018-0219, ICM Application, Pages 57-58

The reference provides the following quote: “[PUC President and CEO Rob] Brewer said that PUC is almost positive that they will be receiving $14,340,000 in federal and provincial government funding to subsidize the project[…]” PUC Distribution clarified in the same reference that the funding expected from NRCan is $11,807,000.

Please explain why the amount of federal funding PUC Distribution expected to receive changed from $14,340,000 to $11,807,000.

Staff-34
Ref: EB-2018-0219, ICM Application, Page 14

PUC Distribution indicates that it has chosen Black & Veatch (B&V) to act as the Engineering Procurement and Construction (EPC) contractor on the SSG project.

(a) Please explain how B&V was chosen to be the EPC contractor and what processes PUC Distribution used to make its selection.
(b) Were other EPC contractors considered? If not, why not?

(c) If other EPC contractors were considered, please provide quotes submitted by other contractors. If response to this interrogatory involves confidential information, PUC Distribution should file redacted documents on the public record and request confidential treatment for the unredacted versions.
(d) Please clarify if PUC Distribution will be paying a one-time lump sum to B&V upon completion of the project, or if there is some type of monthly payment arrangement.
(e) If there is a monthly payment arrangement, has this amount been determined? If yes, how?

Staff-35
Ref: EB-2018-0219, ICM Application, Page 30

The application notes that payment for the SSG Project will financed over a twenty-five year term through long term debt financing.

(a) Please provide details of the long-term debt financing, including sources of financing, terms and rates of repayment and provide all documents related to the financing. How does this financing fit in the payment structures to B&V noted above?
(b) Has PUC Distribution secured the debt financing, or is it pending OEB approval of both Phases 1 and 2 of the SSG project?

Staff-36
Ref 1: EB-2018-0219, ICM Application, Page 14
Ref 2: EB-2018-0219, Appendix J

The Application states that “BV assumes the risk of project completion and performance of design…” It also states that “the risk of cost overruns will be borne by the developer and their EPC contractor.”

Appendix J has several references to PM4 Change Management and in several locations, e.g. under the CYME Integration Workshop, states that: “any required scope changes will be input into the task PM4 Change Management.”

(a) Please reconcile how PUC Distribution expects no risks in bearing cost overruns if there is PM4 Change Management.
(b) Is there a contingency amount included in the Project estimate?
(c) If yes to (b), please indicate how much.
(d) How does PUC Distribution plan to manage possible scope changes?

Staff-37
Ref: EB-2018-0219, ICM Application, Page 5

PUC Distribution has indicated that the total capital cost of the smart grid projected is estimated to be $34,389,046.

(a) Please confirm if this total project cost is based on a firm price secured from B&V.
(b) If the answer to (a) is no, and PUC Distribution is yet to confirm a final price, what is the amount of variance expected?
(c) How will any variance in pricing be addressed?

Staff-38
Ref 1: OEB 2017 Yearbook of Electricity Distributors
Ref 2: EB-2018-0219, Appendix D, Navigant Report #1, Page 33

The OEB's 2017 Yearbook of Electricity Distributors indicates that PUC Distribution has 284 square km of rural service area and 58 square km of urban service area.

The Navigant Report notes that: "Radial circuits connected to a single substation may not be able to transfer un-faulted sections to another feeder."

(a) Feeders are generally sparser in rural areas with less tie points between feeders when compared to feeders in urban areas. Given that the majority of PUC Distribution's service area is rural, please provide a discussion on whether PUC Distribution has sufficient tie points between feeders in its distribution system to allow for load transfers in the event of faults. What percentage of feeders would be able to support load transfers?
(b) Please confirm if PUC Distribution's feeders, especially those within PUC Distribution's rural service areas, are radial. If so, please explain how PUC Distribution intends to leverage load transfers as part of the DA system to improve reliability.
(c) Please indicate whether PUC Distribution's feeders have sufficient capacity to accommodate short-term load transfers in the event of faults.
(d) Please indicate the impact on reliability PUC Distribution expects to have through load transfers in the event of faults as part of DA.

Staff-39

(a) Please provide a table showing the number of interruptions by cause code for each of the years 2013 to 2017.

(b) If available, please also provide the number of interruptions by cause code for individual feeders for each of the years 2013 to 2017.
(c) How long does it currently take for PUC Distribution's field crews to locate faults? Please provide longest, shortest and average times.

Staff-40
Ref: EB-2018-0219, ICM Application, Page 11

The bulk of the annual net benefit to customers as shown in Table 1 in the ICM application is calculated using the estimated 2.7% reduction in energy consumption.

(a) How likely is it that PUC Distribution will achieve a 2.7% reduction on energy consumption?
(b) Has the entire VVO implementation been analysed for the expected benefit per feeder based on the real load characteristics of each feeder? If so, please provide this information.

Staff-41
Ref 1: EB-2018-0219, ICM Application, Page 11

In Table 1, PUC Distribution assumes a 2.7% reduction in energy consumption.

The reduced energy consumption would have the added benefit of reducing the charge customers pay for volumetric distribution rates. However, not all of PUC Distribution's rate classes are billed on a kWh basis – Residential customers are on a fixed basis while certain other rate classes are billed on a kW basis. In light of this, please explain how costs savings in distribution charges are expected to be allocated fairly across all rate classes.

Staff-42
Ref: EB-2018-0219, ICM Application, Pages 5 and 11

The ICM application states that reduced energy consumption is a benefit of the smart grid project that will help lower customers' bills.

Currently, PUC Distribution recovers a portion of its revenue requirement through volumetric rates in all rate classes. The only change in the near future, is the transition to fully fixed rates for residential customers – the remainder of PUC Distribution's rate classes are expected to continue to have volumetric distribution rates.

(a) What is the impact of the reduced energy consumption as a result of the SSG project on the amount of revenue PUC Distribution recovers through its volumetric rates?
(b) Has PUC Distribution performed an analysis on the potential in shortfall of revenue resulting from the reduced energy consumption? If yes, please provide the analysis.
(c) If the reduced energy consumption is expected to result in a shortfall of revenue for PUC Distribution, how does PUC Distribution expect to make up the shortfall?

Staff-43
Ref: EB-2018-0219, ICM Application, Page 12, Table 2

The bill impact for a typical residential customer consuming 750 kWh per month is shown in Table 2 to be an increase of $1.08, or 1.00% of the total bill.

(a) If the full implementation of the SSG project results in a bill increase for typical residential customers, please explain how this reconciles with PUC Distribution's policy of "no net bill increase."
(b) Please explain how PUC Distribution generated the bill impacts in Table 2.
(c) Please provide a table showing the customer bill impacts after the full implementation of Phase 1 and Phase 2 of the SSG project, <u>excluding</u> any benefits associated with the SSG project.

Staff-44
Ref: EB-2018-0219, Appendix D, Navigant Report #1, Pages 35-36

The following is an excerpt from the Navigant Report:

> The effect of reduction in voltage levels is largely dependent on the type of end-use equipment. Resistive and inductive loads will react differently to reductions in voltage, as will loads with and without a thermal cycle. For example, lighting fixtures behave as simple resistive load. A decrease in voltage translates proportionally to a reduction in the current flowing through the wire filament, dimming the light. In contract, a water heater, through a resistive load, has a thermal cycle. That is, it[s] behavior is dependent on a time-variant cycle. At lower voltages, a water heater will run at a lower power rating and, hence, will take longer to heat water to a specified temperature and use more energy.

As the Navigant Report notes, the amount of benefit from Conservation Voltage Regulation as part of VVO is largely dependent on the type of load.

(a) Please confirm that certain types of load would use more energy as a result of lowered voltage, e.g. water heaters.

(b) Given that the types of loads can vary between customers, and between customers of different rate classes, please explain how the energy reduction from VVO is expected to benefit all customers fairly.
(c) Please explain how the "no net bill increase" commitment would be achieved if the anticipated benefits of the SSG Project are not realized. How does PUC Distribution intend to address such a scenario? How does PUC Distribution intend to address potential rate increases if the benefits of the Project are not realized?

Staff-45
Ref: EB-2018-0219, Appendix E, Navigant Report #2, Page 9

The following is an excerpt from the Navigant Report:

> [Navigant] note[s] that the proposed feeder coverage for DA and VVM – 84% and 68% is higher than many other systems Navigant has encountered […] This coverage should maximize the total amount of benefits that can be achieved by DA and VVM on PUC's distribution system, though it may not represent the optimal economic level of VVM and DA.

(a) In light of Navigant's comments above, has PUC Distribution evaluated the option of a smaller scaled project with the intent of achieving greater economic efficiency?
(b) If yes to (a), please provide the evaluation/report.
(c) If no to (a), please explain why not.

Staff-46
Ref: EB-2018-0219, ICM Application, Page 23

The ICM application notes that the DA system "provide(s) a capability to locate and isolate a fault, and restore power to the entire upstream section of the feeder and as much of the downstream feeder as possible."

(a) Please indicate if PUC Distribution currently performs protection coordination studies on its distribution feeders.
(b) If yes to (a), please explain what additional benefits the DA system is expected to provide in isolating faults given that electrical protective equipment, along with protection coordination studies, already work to isolate faults.
(c) Please explain in what way this is considered a smart grid technology given that protection coordination is a common element of the electricity distribution system.
(d) Please indicate whether PUC Distribution currently employs sectionalizing equipment, e.g. reclosers, along feeders to minimize the number of customers experiencing sustained outages.

(e) If yes to (d), please provide the percentage of PUC Distribution feeders that currently benefit from sectionalizing equipment.

Staff-47
Ref: EB-2018-0219, ICM Application, Page 23

(a) Please provide PUC Distribution's Distribution Operating Maps.
(b) Please explain to what extent PUC Distribution is able to restore to sectionalized feeder segments by operating existing tie switches. What percentage of feeders have this capability, and are those feeders located in urban or rural sections?

Staff-48
Ref: EB-2018-0219, ICM Application, Page 23

The ICM application notes that the scope of VVO includes phase balancing of feeders.
(a) Please explain why PUC Distribution has not performed phase balancing already as a normal part of its system planning work.
(b) If phase balancing work has already been completed, please confirm whether any work already completed has been removed from the Project scope.

Staff-49
Ref: EB-2018-0219, ICM Application, Page 23

System losses can be reduced by increasing conductor sizes and having adequately sized conductors for loads and load transfers. Larger conductors also help reduce voltage drop along the feeder.
(a) Does PUC Distribution currently review conductor sizes as a method of minimizing system losses and voltage drops?
(b) If yes to (a), what work has PUC Distribution already completed to reduce line losses in this way?
(c) If no to (a), please explain why not.

Staff-50
Ref 1: EB-2018-0219, Appendix D, Navigant Report #1, Page 17
Ref 2: EB-2018-0219, ICM Application, Page 34

The ICM Model includes an entry for an ICM project expected to take place in 2020 for the substation 16 upgrade. The Navigant Report further elaborates on substation upgrades as part of the scope of the SSG project.

(a) Please indicate if costs related to substation upgrades have been included in this ICM request.
(b) If so, please indicate the amounts, the specific substations, and the scope of the upgrades.
(c) Were substation upgrades already part of the DSP and capital budget but their upgrading is now being ‘accelerated’, as indicated in Navigant Report, Appendix D, page 1)?
(d) Please confirm that any substation upgrades already included in PUC Distribution’s capital budget have not been included in this ICM request.

Staff-51
Ref: EB-2018-0219, ICM Application, Page 33, Table 8

In Table 8 of the ICM application, there is an entry indicating that the $3,300,000 substation 16 rebuild, which was included in the DSP, has been rescheduled to 2020 and increased by $300,000.

(a) Please explain why the substation 16 rebuild was delayed given that it was identified as a high priority project in the DSP.
(b) Please explain why the cost has increased by $300,000 and whether the increase is caused by accelerating the upgrade to accommodate the SSG Project.
(c) Please provide the capital work that was planned for 2019 per the DSP amount at the time of filing and the current plan for those projects.

Staff-52
Ref 1: EB-2017-0071, 2018 Cost of Service Application, Exhibit 1, Page 16
Ref 2: EB-2017-0071, 2018 Cost of Service Application, Appendix 11 – Customer Engagement Survey, Page 27
Ref 3: EB-2018-0219, Appendix C, Leidos Report, Utility Distribution Microgrid: AMI Integration

As part of its 2018 cost of service application, PUC Distribution noted that it implemented automated and upgraded phone systems and the Atlas system. References one and two above describe these systems as tools to provide customers with automated notifications and outage information.

The Leidos Report in reference three above mentions, among other things, the following three areas: Automated Outage Reporting, Enhance CSR Toolset with AMI data and Enhance Customer Toolset with AMI data.

(a) Please elaborate on how the systems mentioned in the 2018 Cost of Service application and the areas described in the Leidos Report differ in scope.
(b) Have any of the functionalities described in the Leidos Report already been implemented?
(c) If yes to (b), please confirm that any costs associated with the functionalities described in (b) have been removed from the SSG Project.

Staff-53
Ref 1: EB-2018-0219, Appendix C, Leidos Report, Utility Distribution Microgrid: AMI Integration, Section 4.2.4
Ref 2: EB-2018-0219, Appendix K, Project Cost Estimate

Section 4.2.4 of Appendix C states that: "[the Enhanced CSR/Customer Toolset] project is in motion at PUC and a 2015 CIS/CC upgrade is already planned to provide many of the required features and functionality."

The project cost estimate in Appendix K includes a line item for "AMI/OMS/CIS" with a unit cost of $1,275,000 and installation costs of $637,500.
(a) Please indicate which functionalities have already been implemented for enhancing the CIS and CSR systems as part of the 2015 upgrade.
(b) Please indicate what further improvements to the CIS and CSR systems are expected to be carried out as part of the SSG Project.
(c) Please explain why the work described in (b) was not performed during the 2015 CIS/CC upgrade.
(d) Please provide a breakdown of the "AMI/OMS/CIS" cost in Appendix K and show the individual costs of the CIS portion.
(e) Please confirm that the costs in (d) excludes any work that has already been performed in the 2015 upgrade, as described in (a).

Staff-54
Ref: EB-2017-0071, 2018 Cost of Service Application, Appendix 5 – Customer Satisfaction Survey, Pages 5, 17, 41, 44, 46

The following are UtilityPulse Customer Satisfaction Survey results filed as part of PUC Distribution's 2018 Cost of Service application:

> 91% of respondents indicated "strongly + somewhat agree" that PUC Distribution "provides consistent, reliable electricity."
>
> 90% of respondents indicated "strongly + somewhat agree" that PUC Distribution "quickly handles outages and restores power."

55% of respondents indicated that they are not willing to pay more to reduce the number of outages or the duration of outages.

The majority of respondents indicated that they are not willing to pay more to: add automation and technology to reduce outage time, invest in technology to deal with cyber security issues or add a proactive outage management system.

67% of respondents indicated that “better prices/lower rates” as one of the most important things PUC Distribution can do to improve service.

In light of the customer feedback listed above, please discuss why PUC Distribution is proposing to spend additional capital on the following areas:

- Reliability improvements
- Addition of automation and technology
- Addition of a proactive outage management system
- Additional technology to deal with cyber security issues

Staff-55
Ref: EB-2018-0219, Appendix D, Navigant Report #1, Page 1

The Navigant Report notes that the smart grid project includes “an extensive 3-year community engagement process for community outreach and stakeholder education.” At various references, it is noted that customer engagement will be done in the first three years of the project.

(a) Please describe the engagement activities undertaken to date with respect to the SSG Project?
(b) Did customer engagement as part of PUC Distribution’s most recent DSP solicit customer feedback on the proposed SSG Project and the associated impacts?
(c) Given the dates of the Leidos and Navigant Reports, which are 2014 and 2015 respectively, please explain why PUC Distribution did not begin its customer engagement on the proposed Project prior to filing this application, rather than after the Project is in-service.

Staff-56
Ref: EB-2017-0071, 2018 Cost of Service Application DSP, Pages 22 and 59

The DSP indicates that PUC Distribution connected a new 7MW/7MWh energy storage facility in the fall of 2017 which provides “dynamic Volt/VAR control.”

(a) Given that this new energy storage facility was connected after the Leidos and Navigant Reports, does the new energy storage facility duplicate any of the proposed benefits from the VVO component of the SSG Project?

(b) If yes to (a), please explain whether PUC Distribution has considered changing the scope of VVO to avoid duplication of efforts and spending capital on benefits which can already be achieved through the energy storage facility.

Staff-57
Ref 1: EB-2017-0071, 2018 Cost of Service Application DSP, Page 98
Ref 2: EB-2018-0219, ICM Application, Pages 24-25

The following is an excerpt from the DSP:

> 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.

The ICM application mentions that the AMI Integration portion of the Project will include: Data Analytics and Performance Reporting, Enhanced CSR/Customer Toolset, Improved Voltage Measurement Granularity and Data Analytics and Performance Reporting.

(a) Please confirm whether the scope of AMI Integration includes the type of functionality to "provide additional data access and visibility" as described in the DSP.
(b) If yes to (a), please explain why PUC Distribution did not change the Project scope to reduce project costs of AMI Integration, consistent with the DSP and customer preferences that PUC Distribution has already identified.
(c) Does any part of the "investments planned under System Renewal" as described in the DSP coincide with the project in this application?
(d) If yes to (c), please explain how the project in this application meets the ICM criteria of being discrete and outside of the Rate Base.
(e) If no to (c), please explain how the smart grid work described in the DSP is distinct from this smart grid project.

Staff-58
Ref 1: EB-2018-0219, ICM Application, Page 7
Ref 2: EB-2018-0219, Appendix H, Page 3

The ICM application notes that, following the Navigant Reviews, PUC Distribution modified the scope of the SSG Project from the scope laid out in the Leidos Preliminary Design Reports and Navigant Reports. On page 7, the application states that "following the Navigant Reviews, PUC Distribution concluded that it needed to de-scope the smart grid project to lower costs."

On page 3 of Appendix H, the application notes that as part of the scope change, work was scaled from 8 to 12 DS's, and from 32 to 48 feeders.

(a) Please provide a list of all the changes between the original scope evaluated by Leidos and Navigant and the current scope of the SSG Project proposed in this application.
(b) Please reconcile the scope additions listed in Appendix H with the statement that "PUC Distribution concluded that it needed to de-scope the smart grid project to lower costs."
(c) In increasing the scope to include more DS's and feeders, what are the marginal costs and benefits of the additional DS's and feeders?

Staff-59
Ref: EB-2018-0219, Appendix J – General Assumptions

Under the General Assumptions section in Appendix J, the document notes that:

> This Design and Construction Specification document includes the PUC's required 35% reduction in cost. The corresponding reduction in benefits has not been calculated and is not included.

(a) Please explain whether or not the project benefits presented in this application reflect the updated project scope which includes the 35% reduction in cost.
(b) If the response to part (a) is negative, please provide an updated estimate of project benefits that reflects the reduction in cost.

Staff-60
Ref 1: EB-2018-0219, Appendix J, Footnote 3

Footnote 3 in Appendix J indicates that GIS integration is no longer required for the SSG Project.

(a) Please explain the original intended purpose and benefit of GIS Integration.
(b) Please indicate whether there will be repeated entry of GIS data into both the existing GIS system and the new ADMS systems now that GIS integration is not included.
(c) If yes to (b), please indicate the impact this will have on OM&A expenses.

Staff-61
Ref: EB-2018-0219, ICM Application, Page 11, Table 1

The application notes in Table 1 that the annual projected reliability benefit of the SSG project is $2,550,000.

Please provide the methodology and data PUC Distribution used to arrive at this number.

Staff-62
Ref 1: EB-2018-0219, ICM Application, Page 11, Table 1
Ref 2: EB-2017-0071, 2018 Cost of Service Application, Exhibit 2, Page 49

Table 1 of the ICM application indicates that there is an expected annual benefit of $342,708 for “reduced future capital expenditures due to SSG implementation.”

In its 2018 cost of service application, PUC Distribution provided its forecasted annual expenditures for 2019-2022 in four categories: System Access, System Renewal, System Service and General Plant. System Service expenditures is expected to be minimal for PUC Distribution as it is experiencing a period of reduction in system load. The bulk of capital expenditures set out in the can be attributed to System Access and System Renewal. System Access relates to “must do” projects for PUC Distribution to fulfill its statutory, regulatory and other obligations to provide customers with access to its distribution system. System Renewal relates to “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.”

Given that PUC Distribution is expected to continue spending on System Access and System Renewal projects, please indicate what types of projects that were part of the cost of service application could be deferred or not required as a result of SSG implementation that would result in the annual benefit of $342,708.

Staff-63
Ref: EB-2018-0219, ICM Application, Page 13

As specified in the DA section of the application, the SSG Project improves reliability by locating and isolating faults, and rapidly restoring power to customers on faulted feeders. While this reduces the duration of outages, please explain how the SSG Project will help to reduce the number of interruptions, both sustained and momentary.

Staff-64
Ref: EB-2018-0219, ICM Application, Page 10

(a) Please explain how the benefit to cost ratio of 1.1:1 from a billing perspective is determined? Please explain the calculation and assumptions made.
(b) Please explain what is meant by “the ratio results is 1.4:1” in the cited reference.
    i. How does reliability factor into the ratio?
    ii. Please explain how the ratio is calculated and the assumptions made

Staff-65
Ref: EB-2018-0219, Appendix H, Page 4

The net benefits calculation starts with PUC Distribution's cost of power, reduced by 34.5kV customers from its 2018 cost of service application. Using the 2017 and 2018 cost of power reported in RRR and assuming all other figures in the net benefits calculation remains the same, OEB staff has calculated the revised net benefits to be as follows:

	2018 CoS	2017 RRR	2018 RRR
4705-Power Purchased	$ 71,366,511	$ 68,428,558	$ 61,672,851
4708-Charges-WMS	$ 2,372,973	$ 2,620,200	$ 2,253,664
4714-Charges-NW	$ 3,769,244	$ 3,797,613	$ 3,844,116
4716-Charges-CN	$ -	$ -	$ -
4730-Rural Rate Assistance	$ 197,748	N/A	N/A
4750-Low Voltage		$ -	$ -
4751 - Smart Metering Entity charge	$ 18,950	$ 322,910	$ 238,211
Total COP	$ 77,725,426	$ 75,169,281	$ 68,008,842
GS>50kW for 34.5kV	$ (4,847,999)		
Adjusted COP	$ 72,877,427	$ 75,169,281	$ 68,008,842
	2.7%	2.7%	2.7%
Projected COP Savings	$ 1,967,691	$ 2,029,571	$ 1,836,239
Difference from 2018 CoS COP Savings		$ (61,880)	$ 131,452
Net benefit to customers	$ 205,067	$ 266,947	$ 73,615

The above calculation based on 2017 and 2018 RRR cost of power did not remove the cost of power for 34.5kV customers.

If the adjustment to remove cost of power for 34.5kV customers is made, please explain whether the net benefits to customers would be further reduced and become possibly negative. Please explain how potentially negative net benefits correlate "no net bill increase" objective.

Staff-66
Ref: EB-2018-0219, Appendix J

Appendix J notes the use of Bellwether meters to report voltage and other data. For VVO, there is a need for Bellwether meter voltage readings at, or close to, the end of the feeder.

(a) OEB staff notes that alternate end of feeder locations can be created during abnormal configurations i.e. when a faulted feeder is sectionalized and load from the non-faulted section is transferred to another feeder. Please confirm that alternate end of feeder locations must still be kept within CSA voltage limits and whether PUC Distribution has accounted for this aspect of design.

(b) How does this impact the number of voltage readings that are required of the AMI system and can this system accommodate the frequency of readings required (more than hourly) by the VVO application?

Staff-67
Ref: EB-2018-0219, Appendix C, Utility Distribution Microgrid: AMI Integration, Section 4.3.3

Section 4.3.3 of Appendix C states that the SSG Project will need to improve the granularity of voltage measurement readings to an hourly frequency.

(a) Given that voltage fluctuates and is affected by customer electricity consumption at any given time, are hourly voltage readings sufficient to maintain voltages within CSA limits during the hour between voltage readings?
(b) Does PUC Distribution have any contingencies or protections in place within its VVO control schema to address any risks described in (a)?
(c) Will any of contingency/protection techniques described in (b) affect the expected benefits of VVO?

Staff-68
Ref: EB-2018-0219, Appendix C - Utility Distribution Microgrid: AMI Integration, Section 4.4.5

In the Leidos Report on AMI Integration, section 4.4.5 notes that: “data analytics will be performed from Leidos datacenters in the USA.” The analytics platform will consume customer information and store this data in the USA.

Please explain how PUC Distribution will address the differences in privacy laws between Canada and the USA and concerns about data privacy associated with sending customer data to the USA.

<u>ICM Model</u>

Staff-69
Ref: EB-2018-0219, ICM Model, Tab 1 – Information Sheet

Please provide an updated ICM Model with the IPI applicable to 2019 applications (i.e. 1.50%.

Staff-70
Ref 1: EB-2018-0219, ICM Model, Tab 6 – Rev_Requ_Check
Ref 2: EB-2017-0071, 2018 Cost of Service Application, Revenue Requirement Workform (RRWF)

OEB staff is unable to reconcile the OM&A expenses of $11,543,633, as filed in the ICM Model, to PUC Distribution's RRWF from its 2018 cost of service proceeding which indicates a figure of $11,474,633.

Please explain this discrepancy.