Pacific Northern Gas (N.E.) Ltd.

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Via E-File

July 21, 2020

B.C. Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

File No.: 4.2(2020)

Attention: Marija Tresoglavic
Acting Commission Secretary

Dear Ms. Tresoglavic:

Re: Pacific Northern Gas (N.E.) Ltd.
Application for a Certificate of Public Convenience and Necessity to Implement Automated Meter Reading (AMR) Infrastructure
Response to BCUC Information Request No. 2

Accompanying, please find the response of Pacific Northern Gas (N.E.) Ltd. to the referenced information request.

Please direct any questions regarding the application to my attention.

Yours truly,

Original on file signed by:

Verlon G. Otto

Enclosure

Pacific Northern Gas (N.E.) Ltd.
Application for a Certificate of Public Convenience and Necessity to Implement Automated Meter Reading Infrastructure

INFORMATION REQUEST NO. 2 TO PACIFIC NORTHERN GAS (N.E.) LTD.

22.0 Reference: PROJECT ALTERNATIVES CONSIDERED
Exhibit B-3, BCUC IR 6.2,6.3;
Advanced Metering Infrastructure

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 6.2, Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) explains:

> In order for PNG(NE) to take advantage of existing network infrastructure from another utility, they would have to be on the same vendor's system, the locations would have to be suitable for PNG(NE), and PNG(NE) would be subject to terms and conditions and costs of JUAs to utilize that utility's collection infrastructure or shared towers. In general, except in certain unique circumstances, the sharing of existing network collection infrastructure is not practical.

Further, in response to BCUC IR 6.3, PNG(NE) states it "has not made any effort in regard to pursing fixed-network infrastructure for its AMR Project due to the challenges outlined in response to Question 6.2."

22.1 Please describe in detail any existing or planned fixed-network infrastructure in the Project area.

Response:

PNG(NE) understands that BC Hydro installed and operates an Itron OpenWay communication network as part of its smart meter infrastructure.

22.2 Please discuss whether any other company's fixed-network system in the Project area would be suitable for PNG(NE).

Response:

PNG(NE) has had discussions with Itron to understand the feasibility of piggybacking on the BC Hydro OpenWay network. As described in response to Question 23.1, with PNG(NE) now moving to the 500G ERT, it is technically possible for the 500G ERTs to communicate with BC Hydro's OpenWay network. However, from a practical standpoint, it is not a preferred option as a number of technical, commercial and financial issues would need to be addressed.

Technical Issues

Although some components of BC Hydro's existing OpenWay network can be utilized to communicate with the 500G ERT, research and development work would need to be undertaken by Itron for the 500G ERT to join that network as it is not a plug and play scenario for the 500G ERT to connect to the OpenWay network deployed by BC Hydro. Additional cost would be required to scope out the technical requirements to have the BC Hydro (older Openway) and PNG(NE) (newer Openway Riva) networks communicate, and a propagation study would be required to assess whether additional network gear would be required to ensure network coverage.

PNG(NE) also understands that BC Hydro operates a 'mesh' network whereby each meter captures and transmits its own data and also transmits data from other meters nearby to create a path to a router. While the 500G ERT is designed to mesh with Itron's Riva Network, the 500G ERTs to be installed by PNG(NE) would only be able to communicate directly to the network routers under the OpenWay network operated by BC Hydro. As such, and given PNG(NE)'s topology, additional network router infrastructure would be required to ensure all of PNG(NE)'s installed 500G ERTs are able to communicate direct to a field router to ensure data capture.

Commercial/Regulatory Issues

PNG(NE) understands that there are regulatory requirements that would need to be met for a third party to transport another party's data. In particular, a third party must be registered with the Canadian Radio-television and Telecommunications Commission (CRTC) as a carrier of data for third parties. In order to achieve this, work would be required and expenditures incurred by both PNG(NE) and BC Hydro for BC Hydro to obtain approval to transport data for PNG(NE).

PNG(NE) and BC Hydro would also need to come to commercial terms for PNG(NE) to use their smart meter infrastructure. Given the array of issues that would need to be addressed prior to entering into a commercial arrangement, PNG(NE) expects that it would significantly delay the project and add unnecessary costs, for no material benefit.

As noted in response to Question 23.1, PNG(NE) now plans to move to the 500G ERT, which will allow PNG(NE) to retain some optionality to further assess the potential of AMI in the future (i.e. if costs decrease, benefits increase, etc.). Itron's 500G ERT technology does provide an avenue for a future networked solution with BC Hydro, and could be considered if and when it meets both utilities economical goals. While no such plan presently exists, if such a project were to be contemplated, PNG(NE) would develop an appropriate business case, undertake stakeholder consultation and seek BCUC approval.

22.2.1 If not, why not?

Response:

Please see the response to Question 22.2.

22.3 Please discuss whether PNG(NE) can be on the "same vendor's system" on another company's fixed network infrastructure.

Response:

Please see the response to Question 22.2.

22.3.1 If not, why not?

Response:

Please see the response to Question 22.2.

22.4 Please discuss any assessment undertaken to determine whether the location of any existing or planned network infrastructure would be suitable for PNG(NE).

Response:

Please see the response to Question 22.2.

22.4.1 If no assessment has been conducted, please discuss what resources would be required and how long it would take for PNG(NE) to complete such an assessment.

Response:

Please see the response to Question 22.2.

22.5 Please discuss the anticipated resources and time required for PNG(NE) to negotiate the terms for an agreement to utilize another company's fixed-network infrastructure, if found to be suitable.

Response:

Please see the response to Question 22.2.

22.6 Please discuss the estimated time and resources required for PNG(NE) to develop an Advanced Metering Infrastructure (AMI) cost estimate assuming utilization of another company's fixed-network infrastructure for the following:

i. System functionality limited to the automation of the meter reading function; and

ii. A complete, fully functioning AMI system.

Response:

Please see the response to Question 22.2. PNG(NE) does not believe it to be technically or operationally feasible or cost-effective to pursue opportunities to utilize existing fixed-network infrastructure in its service area.

PNG(NE) reiterates that the proposal to implement AMR technology in its service area has been presented as a cost-effective improvement to its current manual meter reading process that also provides a number of qualitative benefits as detailed in the Application. The incremental financial benefits of PNG(NE)'s proposal exceed the incremental costs and provide a tangible benefit to ratepayers. The mobile solution proposed by PNG(NE) is considered cost-effective, and incremental costs associated with joint use agreements and/or fixed network infrastructure would make PNG(NE)'s proposition uneconomic.

In any event, as to requested item ii., for illustrative purposes, PNG(NE) has rerun the financial analysis provided in response to BCUC IR 9.2, modified to reflect the removal of capital costs for network infrastructure. Upon doing so, PNG(NE) projects that over a 20-year project life plus the amortization of any undepreciated assets at the end of 20 years, an AMI project using existing BC Hydro infrastructure would result in a negative net present value of $10.9 million. While this is well below the negative net present value of $32.7 million in the original evaluation, it is still very uneconomic. Further, PNG(NE) notes that this revised evaluation does not include provision for any payments that are certain to be required under a joint use agreement with BC Hydro for hosting PNG(NE)'s AMI system on BC Hydro's infrastructure.

As to requested item i., for illustrative purposes, PNG(NE) has rerun the financial analysis provided in response to BCUC IR 9.2, modified to reflect the removal of capital costs for network infrastructure, as well as the removal of capital and operating costs specifically identified for operating and maintaining an AMI system. Upon doing so, PNG(NE) projects that over a 20-year project life plus the amortization of any undepreciated assets at the end of 20 years, an AMR system using existing BC Hydro infrastructure would result in a negative net present value of $6.2 million. Again, this is well below the negative net present value of $32.7 million in the original evaluation, but continues to be extremely uneconomic, even before giving consideration to any payments that are certain to be required under a joint use agreement with BC Hydro for hosting PNG(NE)'s AMR system.

23.0 Reference: PROJECT ALTERNATIVES CONSIDERED
Exhibit B-3, BCUC IR 4.2;
Automated Meter Reading

In response to BCUC IR 4.2, PNG(NE) states:

> Depending upon the technology vendor and the specifications of the ERT, some ERTs used in AMR implementations can be read via both mobile and fixed network receivers. PNG(NE) had given consideration to Itron's 500G ERT which would enable the ability to move from a mobile to fixed network system at some point in the future.
>
> However, PNG(NE)'s proposal to proceed with AMR is as a cost-effective and efficient replacement to the current manual meter reading process. Installation of the 500G ERT would come at a higher capital cost of approximately $85,000 with no certain financial benefit. On this basis, PNG(NE) is proceeding with the Vendor A Itron 100G ERT, and though it does not have the noted capability, this capability was never a consideration in PNG(NE)'s business case.

23.1 Please further explain the meter data transmission capability of the Itron 500G Encoder Receiver Transmitter (ERT) alternative, including whether the 500G ERT could allow for two-way communication via fixed-network infrastructure, if warranted.

Response:

PNG(NE) has recently been advised by Vendor A that Itron is transitioning away from the 100G ERT devices to focus solely on the 500G ERT devices and that Itron has recently announced that it will no longer be producing the 100G ERT devices.

In response to this development, Vendor A has agreed to provide the 500G ERT to PNG(NE) as a substitute for the 100G ERT, while maintaining the 100G ERT price structure presently in place. While PNG(NE) will not be using the entire functionality of the 500G ERT device, if economics are more favorable in the future to take advantage of the functionality, PNG(NE) will be in a better position to do so.

PNG(NE) notes that the radio frequency emissions of the 500G ERT are exactly the same as those of the 100G ERT. PNG(NE) further notes that the 500G ERT is capable of 2-way communication when in network mode, however this mode will not be activated as under the current AMR Project scope the ERTs will be deployed in the 100G mode. While PNG(NE) is not advancing a project with 2-way communication at this time, and does not have any current plans to do so, in the event such a project were to be contemplated in the future PNG(NE) would develop an appropriate business case, undertake stakeholder consultation and seek BCUC approval.

23.2 Please discuss whether the Itron 500G ERT would provide the ability to record other physical data or the ability to remotely shut off the gas supply, if PNG(NE) wished to utilize that ability in the future.

Response:

Both the 100G and 500G ERTs record similar gas usage information. In order to take advantage of the functionality for remote control and shut off of gas supply, PNG(NE) would require the replacement of all meters to solid state meters with controls and devices built in. Changing out all meters would be extremely costly and is not within the scope of the AMR Project.

23.2.1 If yes, please explain any additional equipment required and associated cost.

Response:

Please see the response to Question 23.2.

23.3 Please provide a cost breakdown on the additional $85,000 in capital required for the Itron 500G ERT alternative.

Response:

The additional $85,000 in capital cost identified in order to move from the Itron 100G ERT to the Itron 500G ERT relates to the incremental cost of the 500G ERT units, plus PST and budgetary overhead. As described in response to Question 23.1, PNG(NE) will now be installing the 500G ERT at no additional cost to that planned for the 100G ERT.

23.4 Did PNG(NE) solicit proposals from other vendors for ERTs with similar functions to the Itron 500G ERT?

Response:

Vendor A and B provided proposals for ERTs with similar capabilities, with Vendor A's proposed Itron 500G ERT having similar functionality to Vendor B's proposed Sensus FlexNet SmartPoint module although the proprietary technologies of the modules differ. PNG(NE) notes that Vendor A's cost proposal for both the 100G and the 500G ERTs were more favourable that Vendor B's cost proposal for their product comparable to the 500G. As described in response to Question 23.1, PNG(NE) will now be installing Vendor A's Itron 500G ERT.

23.4.1 If so, please provide the Vendor name, product, and cost.

Response:

Please see the response to Question 23.4. Vendor B's proposed Sensus SmartPoint module were quoted to $63.50 each for residential units and $159.00 each for commercial units.

23.4.2 If not, why not?

Response:

Not applicable. Please see the response to Question 23.4.

24.0 Reference: PROJECT DESCRIPTION
Exhibit B-3, BCUC IR 14.2;
Field Installation of ERTs

In response to BCUC IR 14.2, PNG(NE) explains it has not made provision in the Automated Meter Reading (AMR) project cost estimate for any additional resources required to support installation of ERTs in unfavorable weather conditions. However, PNG(NE) notes "the cost estimate includes a 15% contingency to accommodate uncertain or unknown items of this nature."

24.1 Please estimate the additional resources (equipment and staff) required to support ERT installation in unfavorable weather conditions.

Response:

As weather conditions at time of implementation are unknown and cannot be predicted with any certainty, costs above current estimates are extremely difficult to predict with precision. Upon successful award of the AMR Project, a full implementation plan will be developed with schedules and costs being considered. Based on weather conditions during this time, resources may be added to adapt to the weather or there may be modifications to the implementation schedule. PNG(NE) reiterates that potential incremental costs are expected to be within the 15% contingency.

PNG(NE) notes that project progress for the PNG-West Thornhill pilot project was not significantly impacted by suboptimal weather experienced during the installation of ERTs.

24.2 Please provide a capital cost estimate for the AMR Project assuming all ERT installations would be completed in unfavorable weather conditions.

Response:

Please see the response to Question 24.1.

25.0 Reference: PROJECT DESCRIPTION
Exhibit B-3, BCUC IR 15.1, 15.7;
Radio-off Option for Customers

In response to BCUC IR 15.1, in the second scenario in which a customer could opt-out of AMR (i.e. after the deployment and an ERT is already install at the customer premise), PNG(NE) estimates that the cost of setting up the customer is $63.33 based on an assumed average travel time to the customer of 20 minutes.

In response to BCUC IR 15.7, PNG(NE) states that the customer located the furthest distance away is 380 kilometers from PNG(NE)'s regional office, and the assumed travel time to this customer is 285 minutes.

25.1 Please provide the rationale for assuming an average travel time of 20 minutes to customer premise in scenario two. What is the distribution of travel time to customer premises?

Response:

PNG(NE)'s current business job standards for other tasks such as meter recalls and meter lock/unlock have defined the average travel time as 20 minutes when developing costs for the tasks. The 20 minutes considers that travel time within some of the more populous areas is very short while travel time to the more remote areas will take longer. PNG(NE) also endeavours to dispatch resources in an efficient manner such as scheduling tasks together for the more remote areas to minimize the amount of travel required.

26.0 Reference: PROJECT COST ESTIMATES
Exhibit B-3, BCUC IR 17.1, 17.2;
Annual Vehicle Operating Cost Savings

In response to BCUC IR 17.1, PNG(NE) states:

> The average fuel and maintenance costs are based on 2017 average costs of $6,000 and $4,000, respectively, escalated to 2020 at 2% annual inflation. The vehicle capital cost is was [sic] based on a 2017 average cost of $55,000 escalated to 2020 by 2% annually for inflation.

26.1 Please explain why PNG(NE) used the 2017 average cost as the basis for fuel, maintenance and vehicle capital costs to determine annual vehicle operating cost savings.

Response:

PNG(NE) notes that at the time the initial financial model was created, only 2017 figures were available and observes that these amounts were not updated prior to submission of the Application. PNG(NE) further notes that the cost estimate was based on actual results for one vehicle in the meter reader fleet as a representative vehicle for all, with fuel costs rounded to $6,000 and maintenance/insurance costs rounded to $4,000. As can be seen in the table provided in response to Question 26.2, the 2017 average fuel, maintenance and insurance costs for the five meter reader vehicles were $9,788, comparable to the $10,000 figure used in the analysis.

Further, as can be seen in the table provided in response to Question 26.2, the 2019 average fuel and maintenance cost of $8,607 is lower than the 2017 $10,000 figure used in the analysis. Using the 2019 fuel and maintenance costs of $8,607 and inflated by 2% each year, the net present value of customer benefits would decline by $92,545. Despite this illustrative impact, PNG(NE) submits that the $10,000 figure used in its analysis remains a reasonable proxy for these costs given an increasing trend in these costs in recent years, other than the decrease observed for 2019.

PNG(NE) further notes that in responding to this question it identified that it should have assumed a positive salvage value for the vehicle capital costs applied in its analysis. Applying a 15% positive salvage to the average capital cost of the vehicles as is PNG(NE)'s practice in accounting for depreciation of vehicles, the net present value of customer benefits declines by $68,640.

26.2 Please provide a table showing PNG(NE)'s historical annual average cost of fuel, maintenance and vehicle capital costs for the past five years.

Response:

Please see the table that follows.

Cost Element	2015	2016	2017	2018	2019	Total
Fuel & Maintenance	$ 33,725	$ 39,912	$ 44,790	$ 44,798	$ 38,703	$ 201,929
Insurance	4,000	4,075	4,150	4,250	4,330	20,805
Total Cost for 5 Vehicles	$ 37,725	$ 43,987	$ 48,940	$ 49,048	$ 43,033	$ 222,734
Average Annual Cost per Vehicle	$ 7,545	$ 8,797	$ 9,788	$ 9,810	$ 8,607	$ 8,909

In response to BCUC IR 17.2, PNG(NE) states it has included 40 percent of the vehicle fuel and maintenance associated with a meter reader Full-Time Equivalent (FTE) position in the expected future cost of vehicle fuel and maintenance after deployment.

26.3 Please provide the rationale for using 40 percent of existing vehicle fuel and maintenance associated with a meter reader FTE as the expected future cost as opposed to some other percentage.

Response:

PNG(NE) notes that the use of 40 percent of existing vehicle fuel and maintenance associated with a meter reader FTE as the expected future cost was derived by estimating the amount of time the planned FTE would spend on meter reading activities.

26.4 Please provide the sensitivity of the net present value (NPV) of customer benefits for Vendor A to a +/- 10 percent change in the expected future cost of vehicle fuel and maintenance.

Response:

The impact on the NPV of customer benefits for Vendor A of a +10 percent change in the expected future cost of vehicle fuel and maintenance (i.e. 50 percent of existing vehicle fuel and maintenance associated with a meter reader FTE rather than 40 percent) is a reduction in NPV to $2,166,928 from $2,178,576, or by $11,648 or 0.53 percent.

The impact on the NPV of customer benefits for Vendor A to a -10 percent change in the expected future cost of vehicle fuel and maintenance (i.e. 30 percent of existing vehicle fuel and maintenance associated with a meter reader FTE rather than 40 percent) is an increase in NPV to $2,190,223 from $2,178,576, or by $11,647 or 0.53 percent.

27.0 Reference: PROJECT COST ESTIMATES
Exhibit B-3, BCUC IR 2.3, 2.4.1, 17.2;
Cost of Service

In response to BCUC IR 2.3, PNG(NE) states:

> Currently PNG(NE) has approximately 1,700 off-cycle manual reads annually. These off-cycle reads primarily pertain to move in/move out, special requests and meter re-reads. Moving to a monthly read cycle will provide accurate daily consumption information and thereby is expected to eliminate the need for off-cycle reads for these items. [*Emphasis Added*]

PNG(NE) further states, in response to BCUC IR 2.4.1, "On a day to day basis at least one meter reader would be tasked with the off-cycle reads with any overload being assigned to CSTs [Customer Service Technicians]."

In response to BCUC IR 17.2, PNG(NE) confirms the financial analysis provided in Appendices B and C, respectively, do not include any incremental annual labour cost associated with employing an existing non-meter reader FTE to assume meter reading responsibility.

27.1 Please elaborate on the reasons why moving to a monthly read cycle is expected to eliminate the need for off-cycle reads with respect to move in/move out and special requests. Is it PNG(NE)'s expectation that the information obtained at monthly meter reads is sufficient to meet the requirements of move in/move out reads and special requests? Please explain.

Response:

The Itron 500G ERT to be installed for the AMR Project will be operated in the 100G mode which will allow the ERT to store up to 40 days of hourly data. By collecting this data monthly, PNG(NE) will have access to the consumption information from any date within the 40-day period which will allow PNG(NE) to accurately bill the tenant moving out for consumption up to the move-out date and bill the tenant moving in for consumption after the move-in date. This will eliminate the need to dispatch a technician for a manual meter read for the off-cycle billing reads that are currently required to finalize the bill in each instance of a move out.

27.2 Please provide a breakdown of the approximately 1,700 annual off-cycle manual reads into move in/move out, special requests and meter re-reads.

Response:

In preparing the response to this question, PNG(NE) has determined that the number of off-cycle manual reads provided in the response to BCUC IR 2.3 was underreported.

Manual off-cycle reads are generally required in three scenarios: (i) to finalize billings on customer move-outs; (ii) a re-read/special read made at the customer request; and (iii) when there is an indication of a meter problem due to low/no consumption read. PNG(NE) does not generally perform manual reads for move-ins, but rather the billing system estimates the move-in read based on premise historical consumption and the manual read taken for the prior move-out. PNG(NE) notes that service orders are prepared for each of the manual read instances. Based on a review and analysis of recent data, PNG(NE) notes that, in total, an average of 4,100 service orders have been generated and closed in each of the past three recent years related to manual reads, broken down as follows:

Event	2019	2018	2017	Average
Customer move-out	3,601	3,913	3,772	3,762
Re-read/Special read	308	282	300	297
Consumption check	107	61	44	71
	4,016	4,256	4,116	4,129

PNG(NE) observes that though the number of move-outs reported in each period appears significant, this in fact reflects the impacts of a transient workforce associated with the oil and gas industry that is prevalent in the region.

27.3 Please elaborate on why it is not necessary to include any incremental annual labour cost associated with employing an existing non-meter reader FTE to assume meter reading responsibility considering existing off-cycle meter read volumes.

Response:

Technician attendance at customer premises vary for multiple reasons. PNG(NE) presently takes advantage of technician proximity to make visits to gather reads where there is an opportunity to increase efficiency in obtaining this data. Similar to processes presently in place, going forward, when efficient to do so, PNG(NE) anticipates special reads/meter checks to be tasked to other technicians who are scheduled to be or find themselves at or near a premise requiring a meter-read related visit, at no incremental cost to PNG(NE).