October 22, 2002

G. Cheryl Blundon
Board Secretary
Board of Commissioners of Public Utilities
Suite E210, Prince Charles Building
120 Torbay Road
P.O. Box 21040
St. John's, NF
A1A 5B2

Dear Ms. Blundon:

Re: Newfoundland & Labrador Hydro's 2003 Capital Budget Application

Enclosed please find fifteen (15) copies of Newfoundland and Labrador Hydro's responses to Requests for Information numbers PUB 1.0 to PUB 9.2.

Yours truly,

Newfoundland and Labrador Hydro

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Maureen P. Greene, Q.C.
Vice-President & General Counsel

MPG/jc

cc: Janet M. Henley Andrews
Stewart McKelvey Stirling Scales
Fax: 722-4565

Joseph S. Hutchings
Poole Althouse
Fax: 634-8247

Q. B-20 Replace Loader/Backhoe, Bay d'Espoir (2003 - $3,100; Future Expenditures – 2004 - $120,600)

1.1 How many loader/backhoes are presently located at Bay D'Espoir?

1.2 How many other pieces of heavy equipment that could presently do this same type of work are presently located in the area? What are their ages and condition?

A. 1.1 There is one loader/backhoe at the Bay D'Espoir facility, which is the one proposed to be replaced.

1.2 There is no other piece of heavy equipment at Bay D'Espoir that could do this work. There is other equipment available at the facility, but it does not have the ability of the loader/backhoe.

Q. B-26 Purchase Mobile Ambient Monitoring System – Holyrood ($184,200)

2.1 Provide examples of the anecdotal evidence that had led to the belief that a mobile ambient monitoring system is necessary. How has this evidence been supported?

2.2 What results have been shown by the permanent ambient monitoring stations since their installation in 1997?

2.3 Has the company performed a cost benefit analysis of the movement of the permanent ambient monitoring stations?

2.4 Has the company considered deferring this project until the completion of the Flue Gas Particulate Removal Study referred to on page B-28?

A. 2.1 Concerns have been raised during public information sessions, individual public complaints, and general discussions with nearby community residents. This evidence has been supported through the documentation of public complaints, visits to the area to check ambient conditions when alerted that there appears to be some immediate impacts and the installation of a temporary monitoring site to measure concentrations of sulphur dioxide. The temporary site, which provided indicative levels, but was not a US Environmental Protection Agency (USEPA) standard installation, was installed for approximately six months to confirm whether the complaints were founded on fact. They provided enough data to warrant further investigation through a USEPA compliant system, as there were indications of levels being above expected levels. The decision to pursue a mobile site is to permit future relocation to other areas if they appear to be affected so as to limit the number of permanent sites with the attendant increase in operation and maintenance costs.

2.2 The permanent ambient monitoring stations have generally shown the concentrations of sulphur dioxide and total suspended particulate to be below the regulatory limits, at these specific locations.

2.3 A certain number of permanent sites are required. The existing permanent sites were located based on preliminary dispersion modeling of stack emissions and are essential to validate and fine tune the prediction of overall emission impingement levels. These sites were accepted by the Provincial Department of Environment who frequently visit and evaluate the site equipment performance. They remain valuable in establishing a long-term record of air quality in accessible areas adjacent to the Holyrood Generating Station. As stated in the response to PUB 2.1, a mobile site will provide flexibility for future testing of additional sites. Based on the foregoing, an evaluation of relocation of an existing permanent site was considered unnecessary.

2.4 This particular proposal is related to monitoring of impingement levels that are reasonably assumed attributable to burning fossil fuel at Holyrood. The study on the other hand is intended, if successful, to identify a relatively low cost method for the removal of the heavier particulate matter. Such a method will not remove oxides of nitrogen or sulphur nor will it remove fine particulate matter, which will be monitored at the mobile site and relates more directly to long-term health effects.

Q. B-33 Upgrade Civil Structures – Holyrood ($1,991,000)

3.1 Provide a summary of the evaluation of the options considered to upgrade the steel liner.

A. 3.1 Please see the attached summary of the review done regarding the replacement of the stack steel liner.

NEWFOUNDLAND & LABRADOR HYDRO

Holyrood Generating Station

Evaluation of Options to Upgrade Stack Liner #1

Prepared By:

Generation Engineering

October 2002

1.0 Stack Liner

The existing steel liner, which is held in position laterally by the concrete shell, is 33 years old and was constructed from ¼" thick mild steel to a vertical height of 300 ft.

A combination of many factors, such as age, chemical composition and velocity of the flue gas, temperature variations, proximity to marine climate (salt), etc., has lead to its present state of deterioration.

1.1 Identification of Major Maintenance and Liability Issues

Annual inspections, and in particular those of recent years, have identified several areas of concern. These include:

- 34 locations of thin steel (less than 60% of original thickness);
- 3 thin rings (4 ft – 7 ft high for the full circumference);
- 9 locations of buckling (from elevation 62 ft to 263 ft);
- Failed connections between the liner support structure and its base ring beam;
- Numerous locations of pitting of the steel surface;
- Numerous locations of missing insulation (including the top half that cannot be easily or economically replaced); and
- Substantial loss of metal through out its full height such that the ability to support its own weight (originally 60 tons) is much more questionable.

It is estimated that it would take 3 months to replace the stack liner (on-site) on a planned basis. A catastrophic failure of the stack liner (buckling) will likely result in an outage that could extend beyond 6 months, assuming that the failure does not cause any damage to the concrete shell or any consequential damage to the ductwork or the boiler. This would depend on the failure mechanism. It could possibly affect the whole plant, if it failed during operation. Additional factors that could affect the length of the outage include: material availability, time of the year, weather, removal of steel liner and components, etc.

2.0 Alternatives

Various alternatives have been investigated for the upgrade of the Stack #1 liner at the Holyrood Generating Station. These include:

1. Reinforcement and continue with current practice consisting of inspection, maintenance and repair to the stack liner;
2. Perform immediate repair and maintenance to the stack liner;
3. Replace the entire stack liner.

2.1 Reinforcement and Continue with Current Practice

Under the current practice the entire stack, including the stack liner, concrete shell, breeching and associated utilities are inspected on an annual basis by an experienced chimney/stack inspection company. The inspection identifies stack maintenance requirements and only the repairs that are deemed to be necessary to maintain generation for the immediate operating season are performed.

To continue with this practice and to provide the minimum reliability for this liner will require the reinforcement of the 3 identified thin rings ($130,000) as well as the addition of 4 vertical support columns and ring stiffening beams ($250,000) during the major outage in 2003. The base ring beam will require substantial upgrade ($50,000) no later than 2006. Subsequent maintenance and repair costs are expected to increase as the age of the steel liner increases.

These expenditures are considered adequate in the next few years to provide an acceptable level of reliability but may not be sufficient to extend the life of the stack liner until 2020.

2.2 Perform Immediate Repairs and Continue Inspection and Maintenance

This option is similar to the option described above, except that all repair work identified will be completed, including the repair of isolated thin areas of steel liner ($309,000), repair of thin rings (entire circumference of stack, various heights, $130,000), and repair of buckled areas ($89,000). The base ring beam will require substantial upgrade ($50,000) no later than 2006. This option however does not provide for any additional vertical reinforcement ($250,000) until 2009, the next major outage for Unit #1. It is expected that annual maintenance will still be required and that the repair costs are expected to increase as the age of the steel liner increases.

This option should also provide an acceptable level of reliability for the next few years but is dependent on the continued rate of deterioration of the 33 year old mild steel in a very harsh environment.

2.3 Replace Steel Liner

This option involves the removal of the existing stack liner and support structure and the installation of a new stack liner ($1,200,000). This option will be provide the greatest reliability with respect to the stack liner and hence generation availability. It is expected that bi-annual inspections of the new liner will be required for the next 18 years.

3.0 Evaluation of Alternatives

The previous section presented three different alternatives for the upgrade and repair of the stack liner. These options are evaluated below to determine the most cost effective solution.

3.1 Evaluation

All alternatives were evaluated on their respective capital and operating costs.

The table below indicates each alternative and associated cost.

	Option #1	**Option #2**	**Option #3**
	Reinforcement and Continue Current Practice	Perform Immediate Repairs and Current Inspection and Maintenance	Replace Stack Liner
Capital Cost**	$380,000	$528,000	$1,200,000
		$250,000 Vertical Reinforcement - 2009	
O & M Costs	$70,000/Year	$30,000/Year (2004-2009)	$20,000/Bi-Annual
		$90,000/Year (2010-2014)	
		$120,000/Year (2015-2020)	

** Capital cost does not include internal engineering, internal construction, environment, overhead or contingency.

3.2 Cost Comparison

A cumulative present worth comparison was conducted for the three options listed above. The cumulative present worth calculation assumed an 18-year horizon, discount rate of 8%, average inflation rate of 2%, and an increase in annual maintenance and repair costs of 3% due to larger areas requiring repairs.

The results of this calculation revealed that the replacement of the stack liner is the least cost option over the 18-year evaluation period. The results of this comparison are shown in Appendix A, Cumulative Present Worth Comparison.

3.3 Summary

The analysis does not include the possibility of a catastrophic failure, which, assuming there is an overall plant impact would make the unit unavailable for at least six months and have an increased cost to repair due to the additional resources required to clean up and remediate damages at the site.

As well, any shortfall in power or energy supply has to be replaced by the gas turbines, provided that sufficient capacity is available, at a cost approximately double that of Holyrood.

The option that provides the best reliability (lowest risk) and availability until 2020 and at the lowest cost is the replacement of the liner (Option #3) during the major outage scheduled in 2003. This, as well, avoids the risk of catastrophic failure and its associated increased direct cost and potential increased operating cost.

APPENDIX A

CUMULATIVE PRESENT WORTH COMPARISON

Annual Stats		Notes
Annual Escalation (%)	2	Inflation
Annual Discount Rate	8.0	Hydro

Option #1

Capital Cost (2002 dollars)	
Construction	380,000

Operating Cost (2002 dollars)	
Annual Inspection & Maintenance	70,000
Annual Maintence Cost (%)	3
Repair Base Ring Beam (2006)	50,000

	Year	Cash Flow	CPW
0	2003	$380,000	$380,000
1	2004	$73,500	$448,056
2	2005	$77,175	$514,221
3	2006	$131,034	$618,239
4	2007	$85,085	$680,780
5	2008	$89,340	$741,583
6	2009	$93,807	$800,697
7	2010	$98,497	$858,169
8	2011	$103,422	$914,045
9	2012	$108,593	$968,368
10	2013	$114,023	$1,021,183
11	2014	$119,724	$1,072,530
12	2015	$125,710	$1,122,451
13	2016	$131,995	$1,170,986
14	2017	$138,595	$1,218,172
15	2018	$145,525	$1,264,048
16	2019	$152,801	$1,308,649
17	2020	$160,441	$1,352,011

Option #2

Capital Cost (2002 dollars)	
Construction	528,000

Operating Cost (2002 dollars)	
Annual Inspection & Maintenance (2004-2009)	30,000
Annual Inspection & Maintenance (2010-2014)	90,000
Annual Inspection & Maintenance (2015-2020)	120,000
Annual Maintence Cost (%)	3
Repair Base Ring Beam (2006)	50,000
Install Vertical Reinforcement (2009)	250,000

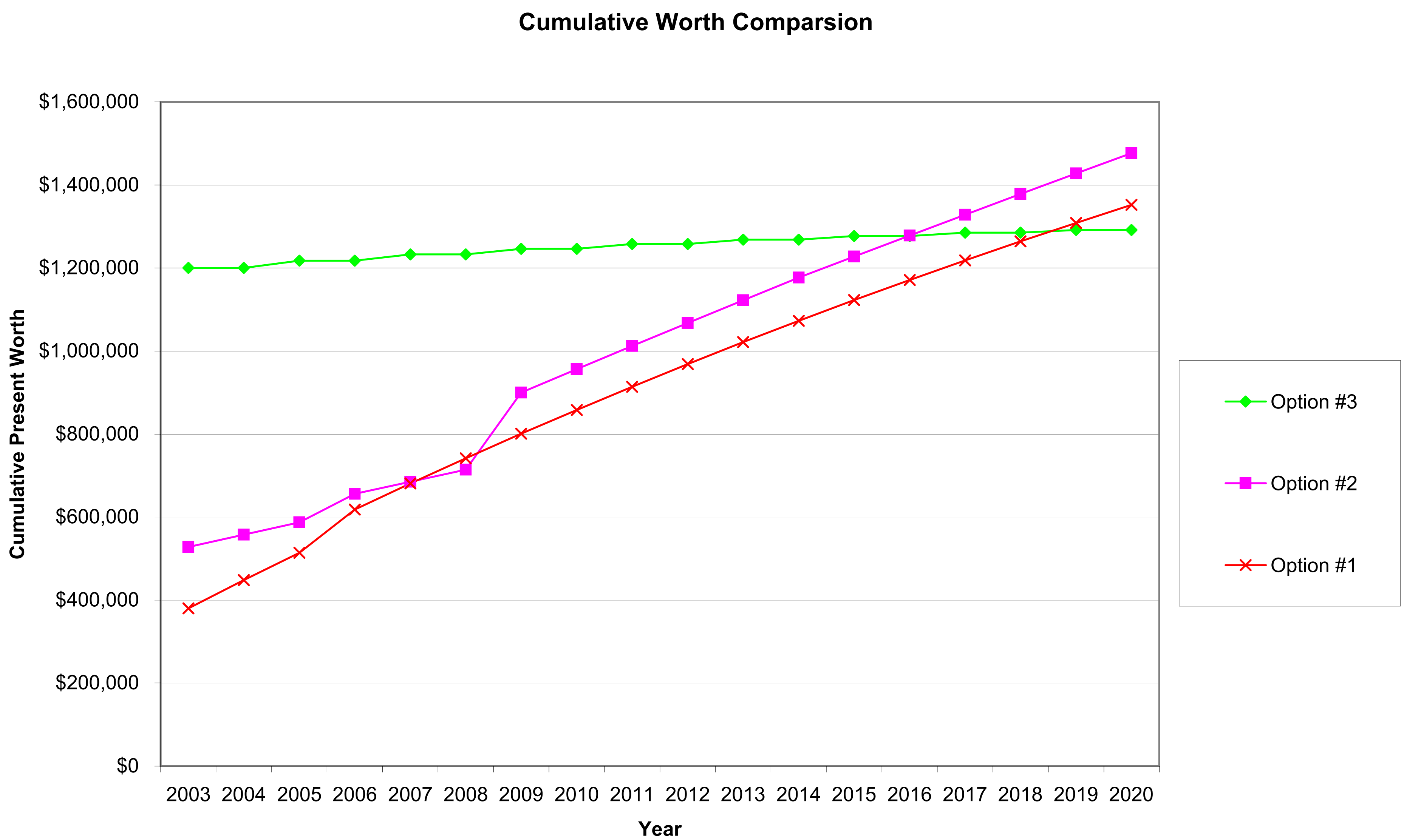
	Year	Cash Flow	CPW
0	2003	$528,000	$528,000
1	2004	$32,130	$557,750
2	2005	$34,411	$587,252
3	2006	$86,854	$656,200
4	2007	$39,471	$685,212
5	2008	$42,274	$713,983
6	2009	$295,275	$900,056
7	2010	$96,390	$956,299
8	2011	$103,234	$1,012,073
9	2012	$110,563	$1,067,382
10	2013	$118,413	$1,122,230
11	2014	$126,821	$1,176,622
12	2015	$128,520	$1,227,659
13	2016	$137,645	$1,278,270
14	2017	$147,418	$1,328,460
15	2018	$157,884	$1,378,232
16	2019	$169,094	$1,427,589
17	2020	$181,100	$1,476,535

Option #3

Capital Cost (2002 dollars)	
Construction	1,200,000

Operating Cost (2002 dollars)	
Bi-Annual Inspection & Maintenance	20,000

	Year	Cash Flow	CPW
0	2003	$1,200,000	$1,200,000
1	2004	$0	$1,200,000
2	2005	$20,400	$1,217,490
3	2006	$0	$1,217,490
4	2007	$20,808	$1,232,784
5	2008	$0	$1,232,784
6	2009	$21,224	$1,246,159
7	2010	$0	$1,246,159
8	2011	$21,649	$1,257,855
9	2012	$0	$1,257,855
10	2013	$22,082	$1,268,083
11	2014	$0	$1,268,083
12	2015	$22,523	$1,277,027
13	2016	$0	$1,277,027
14	2017	$22,974	$1,284,849
15	2018	$0	$1,284,849
16	2019	$23,433	$1,291,689
17	2020	$0	$1,291,689


Cumulative Worth Comparsion
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$0
Cumulative Present Worth
2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020
Year
Option #3
Option #2
Option #1

Q. B-46 Upgrade Station Services – Long Harbour Terminal Station ($82,700)

4.1 Under what circumstances was power initially provided to the one customer supplied from the Long Harbour Terminal Station? How has this situation changed?

A. 4.1 Long Harbour was initially an industrial site operated by Albright & Wilson. The facility had a peak load of approximately 130 MW supplied at 46 kV under the terms of an industrial power contract. The industrial site was decommissioned in the early 1990s and the facility is now operated as a small commercial operation that has a load of less than 1 MW. The facility has been a general service customer of Hydro since 1998 and some of the Hydro owned infrastructure used to serve the current customer is the same as was used to serve the large industrial customer.

Station service at the Long Harbour Terminal Station has historically been supplied indirectly via customer owned equipment within the Long Harbour facility. With the downgrading of the Long Harbour industrial facility, the customer owned equipment that supplies the station service has deteriorated and the integrity of the supply and the safety of personnel working on this equipment are concerns. For the utility system reliability and security, the station service supply should be integral to the station and not dependant on the integrity of the customer's equipment. This is the only station on the Hydro system that does not have the station service supply integral to the station.

Q. B-66 Protection Upgrades – Isolated Systems – Grey River, Francois, Petites, McCallum, Little Bay Islands, Black Tickle, Paradise River, Postville, Norman Bay, St. Lewis, William's Harbour and St. Brendan's ($720,000)

5.1 How has utility industry standard to provide automatic line-to-ground protection for distribution lines been determined?

5.2 Over the past five years have there been problems that could have been avoided if this protection had been in place?

5.3 What are the plans of the company with regard to installation of automatic line-to-ground protection on other isolated systems? On interconnected systems?

A. 5.1 The most common operating problems with overhead distribution systems are caused by the weather. These problems occur in periods of high winds when the conductors may contact each other or during freezing rain when the conductor may break and fall to the ground. The majority of the problems are line-to-ground faults caused by conductor breakage.

This has resulted in the standard utility design concept to install protection systems to protect against and isolate line-to-ground faults. Because of the history, this has become a standard design practice used by utility system designers.

5.2 Adverse weather conditions such as high winds and freezing rains have caused overhead lines to break and line-to-ground faults to occur. The most recent of these was the May 2002 storm in northern Newfoundland and southern Labrador. This storm caused damage to power lines in several isolated communities and there were instances of energized conductors breaking and falling to the ground without being automatically de-energized.

If these isolated systems had been equipped with line-to-ground protection systems, then the conductors would have been automatically de-energized when the line-to-ground fault occurred.

5.3 Hydro operates 25 isolated diesel systems. Over the years, as other upgrade work was being done, the line-to-ground protection was installed at 13 of these sites. The remaining 12 sites are being upgraded in this one-year program proposed for 2003.

All the distribution lines on the interconnected system have line-to-ground protection installed. There are no plans for any further upgrades on these systems.

Q. B-76 Fire Alarm Systems – Rigolet and Postville Diesel Plants ($97,900)

6.1 When was a fire alarm system installed in the isolated diesel plant at Rencontre East? At what cost?

6.2 How was the system of benefit during the recent fire in the plant at Rencontre East?

A. 6.1 There was no fire alarm system in the Rencontre East plant. It was scheduled to be installed in 2003. The only fire related equipment in the plant was a heat detector in the engine hall and a heat activated automatic shut off valve on the fuel transfer line. These items were installed as part of the fuel system upgrade program in the early 1990s. The purpose of this program was to upgrade the fuel delivery systems to meet environmental regulations and to prevent fuel spills in the event of a fire in the plant.

6.2 There was no fire alarm system however the detector and heat activated automatic shut off value performed according to design and interrupted the fuel supply to the plant and the engines. This prevented any fuel spills and arrested the progress of the fire by eliminating the fuel supply.

Q. B-113 Replace Battery System - Multiple Sites - Ebbegunbaeg, North Salmon Dam, Upper Salmon (2) & Springdale Production ($223,900)

7.1 Why has the company standardized on Argus rectifiers and control panels for the telecommunications system? What others were considered? Provide a cost benefit analysis, if available.

A. 7.1 Since the mid 1990s, Hydro has standardized on the Argus rectifiers because of the proven performance and reliability experienced with these units, and to reduce training and spares costs. The control panels are normally matched to the rectifier and supplied as part of the charger system. Consideration has been given to sourcing modular rectifiers to reduce size and weight but there has been no advantage in performance and reliability identified. A cost benefit analysis was not completed.

Q. B-115 Replace Remote Terminal Unit for Hydro - Phase 4 - Buchans, Doyles, Howley and Upper Salmon ($285,000)

8.1 Why has the company standardized on the General Electric line of Remote Terminal Units? What others were considered? Provide a cost benefit analysis, if available.

A. 8.1 Since the mid 1990s, Hydro has standardized on the General Electric (formerly Harris Controls) line of Remote Terminal Units because of its proven performance and reliability, and to reduce training, spares and configuration costs. It is also one of the few manufacturers that provides a unit with the proprietary Harris protocol necessary for communications to the Energy Control Center Energy Management System which was manufactured by Harris Controls. Alternate manufacturers have been considered but few support the Harris protocol and far fewer approach the functionality of the GE product. A cost benefit analysis was not completed.

Q. B-120 Replacement of Operational Data & Voice Network - Phase 1 - St. John's ($291,800)

9.1 Does Hydro intend to use an outside consultant to undertake the study of alternatives to the existing operational data (SCADA) and operational voice network currently using General DataComm (GDC) infrastructure?

9.2 Have there been discussions with NP regarding opportunities to share this infrastructure? Please provide documentation.

A. 9.1 Yes, Hydro intends to use an outside consultant to undertake the study of alternatives to the existing operational data (SCADA) and operational voice network.

9.2 To date, there has not been any discussion with NP to share this infrastructure. At this point in time, the detailed design has not been completed to determine the viability of infrastructure sharing opportunities.