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October 30, 2017

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - The Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Rolling 12 month performance of Hydro's generating units

In accordance with item 2.8 of the Liberty Report Recommendations dated December 17, 2014, please find attached the original plus 12 copies of the quarterly report *Rolling 12 Month Performance of Hydro's Generating Units*.

We trust the foregoing is satisfactory. If you have any questions or comments, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Michael Ladha
Legal Counsel & Assistant Corporate Secretary
ML/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Danny Dumaresque
ecc: Roberta Frampton Benefiel – Grand Riverkeeper Labrador
Dennis Browne, Q.C. – Consumer Advocate
Sheryl Nisenbaum – Praxair Canada Inc.
Dennis Fleming – Cox & Palmer

Quarterly Report on Performance of Generating Units

For the Quarter ended September 30, 2017

October 30, 2017

A Report to the Board of Commissioners of Public Utilities

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Table of Contents

1.0 Introduction

In this report, Newfoundland and Labrador Hydro (Hydro) provides data on forced outage rates of its generating facilities. This data is provided in relation to historical forced outage rates and as well as in relation to assumptions used for system planning purposes.

The forced outage rates are provided for individual generating units at hydraulic facilities, the three units at the Holyrood Thermal Generating Station, and Hydro's gas turbines, for the current 12-month reporting period of October 1, 2016 to September 30, 2017. The report also provides, for comparison purposes, the individual generating unit data on forced outage rates for the previous period October 1, 2015 to September 30, 2016. Further, total asset class data is presented on an annual basis for the years 2006-2015. This report provides data on outage rates for forced outages, not planned outages.

The forced outage rates of Hydro's generating units are presented using two measures: Derated Adjusted Forced Outage Rate (DAFOR) for the hydraulic and thermal units and Utilization Forced Outage Probability (UFOP) for the gas turbines.

Derated Adjusted Forced Outage Rate (DAFOR) is a metric that measures the percentage of the time that a unit or group of units is unable to generate at its maximum continuous rating due to forced outages. The DAFOR for each unit is weighted to reflect differences in generating unit sizes in order to provide a company total and reflect the relative impact a unit's performance has on overall generating performance. This measure is applied to hydraulic and thermal units. However, this measure is not applicable to gas turbines because of their nature as standby units, and relatively low operating hours.

Utilization Forced Outage Probability (UFOP) is a metric that measures the percentage of time that a unit or group of units will encounter a forced outage and not be available when required. This metric is used for the gas turbines.

The forced outage rates include outages that remove a unit from service completely, as well as instances when units are derated. If a unit's output is reduced by more than 2%, the unit is considered derated by Canadian Electricity Association (CEA) guidelines. Per CEA guidelines, to take into account the derated levels of a generating unit, the operating time at the derated level is converted into an equivalent outage time.

In addition to forced outage rates, this report provides outage details for those outages that contributed materially to forced outage rates exceeding those used in Hydro's generation planning analysis for both the short and long term.

2.0 Period Ending September 30, 2017 Overview

Table 1: DAFOR and UFOP Overview

Class of Units	October 1, 2015 to September 30, 2016 (%)	October 1, 2016 to September 30, 2017 (%)	Base Planning Assumption (%)	Near-term Planning Assumption[1] (%)
Hydraulic (DAFOR)	2.02	4.17	0.90	2.60
Thermal (DAFOR)	19.72	13.77	9.64	14.00
Gas Turbine (Combined) (UFOP)	5.54	7.06	10.62	20.00
Gas Turbine (Holyrood) (UFOP)	1.33	2.10	5.00	5.00

There was a decline in hydraulic DAFOR performance for the current 12-month period ending September 30, 2017, compared to the previous 12-month period ending September 30, 2016

[1] Near-term Generation Adequacy Report, May 15, 2017, see section 5.0 for further details.

(see Table 1). The combined[2] gas turbine UFOP performance shows a decline in performance for the current period compared to the previous period.

In the 10-year period prior to 2015, the hydraulic units showed a somewhat consistent DAFOR. The DAFOR of the current 12-month period compared to the previous 10 years is higher, primarily due to penstock issues experienced on Units 1 and 2 at Bay d'Espoir in 2016. The effect on the 12 month DAFOR results is still in the current period, and will be in the current 12 month period until after November 2017.

The Holyrood thermal units, in the 10-year period prior to 2015, exhibited more variability in DAFOR than the hydraulic units, but in many years were close to a consistent rate of approximately 10%. The forced outage rate of the current period ending September 2017 is 13.77%, which was above the base planning assumption of 9.64%, the sensitivity of 11.64%, but below the near-term planning assumption of 14.00%. This is primarily caused by an airflow derating on Unit 1 and Unit 2 that started in the fall of 2016 and continued until the units were taken down for maintenance in 2017.

Hydro's combined gas turbines' UFOP in the 10-year period prior to 2015 was generally consistent at approximately 10% until the year 2012 when the rate exceeded 50%. Since 2012, the UFOP has been improving each year. For the current 12-month period ending September 30, 2017, performance was affected by forced outages to the Hardwoods and Stephenville units.

Note that the data for 2006 to 2015 in Figures 1, 2 and 3 are annual numbers (January 1 to December 31), while the data for 2016 and 2017 are 12-month rolling numbers (for this report they are October 1 to September 30 for each year).

[2] Combined Gas Turbines include the Hardwoods, Happy Valley, and Stephenville units. The performance of the Holyrood GT was not included in the combined base planning or sensitivity numbers as these numbers were set prior to the Holyrood GT's in service date.

3.0 Generation Planning Assumptions

The DAFOR and UFOP indicators used in Hydro's generation planning model are representative of a historic average of the actual performance of these units. These numbers are noted in Table 2 under the column "Base Planning Assumption". This is a long term outlook.

Hydro also provides a sensitivity number for DAFOR and UFOP as part of its generation planning analysis. This number takes into account a higher level of unavailability, should it occur, to assess the impact of higher unavailability of these units on overall generation requirements. During the 12-month period ending September 30, 2017, the gas turbine units performed well within this sensitivity range for UFOP, while both the hydraulic and thermal classes performed outside of the sensitivity range for DAFOR.

The new gas turbine (Holyrood GT) has a lower expected rate of unavailability than the original gas turbines, (5% compared to 10.62%), due to the fact that the unit is new and can be expected to have better availability than the older units.[3]

As noted in Hydro's Near-term Generation Adequacy report, dated May 15, 2017, Hydro evaluated the appropriateness of the DAUFOP metric as an alternate or additional measure of gas turbine unit reliability. Hydro will present its findings and make a recommendation on this metric in its next Near-term Generation Adequacy report, to be filed with the Board on November 15, 2017.

Hydro's generation long term planning assumptions for DAFOR and UFOP for the year 2017 are noted in Table 2.

[3] Hydro selected a 5% UFOP for the new Holyrood GT following commentary on forced outage rates contained in the *Independent Supply Decision Review – Navigant (September 14, 2011).*

Table 2: 2017 DAFOR and UFOP Planning Assumptions

	DAFOR (%)		UFOP (%)	
	Base Planning Assumption	**Sensitivity**	**Base Planning Assumption**	**Sensitivity**
Hydraulic Units	0.90	0.90		
Thermal Units	9.64	11.64		
Gas Turbines - Existing			10.62	20.62
Gas Turbines - New			5.0	10.0[4]

As part of Hydro's analysis of energy supply up to Muskrat Falls interconnection, Hydro completes comprehensive reviews of, and produces reports on, energy supply for the Island Interconnected System. The Near-Term Generation Adequacy report, filed on May 15, 2017, contains analysis based on the near-term DAFOR and UFOP and the resulting implication for meeting reliability criteria until the interconnection with the North American grid.

The DAFOR and UFOP assumptions used in developing Hydro's Near-term Generation Adequacy report are noted in Table 3.

[4] In previous reports this sensitivity value was reported as 5.0%. The generation planning sensitivity for the Holyrood GT was updated to 10% in the September 2015 Q3 report for system planning purposes.

Table 3: DAFOR and UFOP Near-term Generation Adequacy Analysis Assumptions

	DAFOR (%)	UFOP (%)
	Near-term Generation Adequacy Assumption	**Near-term Generation Adequacy Assumption**
All Hydraulic Units	2.6	
Bay d'Espoir Hydraulic Units	3.9	
Other Hydraulic Units	0.7	
Holyrood Plant	14.0	
Holyrood Unit 1	15.0	
Holyrood Unit 2	10.0	
Holyrood Unit 3	18.0	
Hardwoods & Stephenville Gas Turbines		20.0
Holyrood Gas Turbine		5.0

4.0 Hydraulic Unit Forced Outage Rate Performance

The hydraulic unit forced outage rates are measured using the CEA metric, DAFOR. Detailed results for the 12-month period ending September 30, 2017, are presented in Table 4, as well as the data for the 12-month period ending September 30, 2016. These are compared to Hydro's short term generation adequacy assumptions, as used in the Near-term Generation Adequacy report, and Hydro's long-term generation planning assumptions for the forced outage rate.

Table 4: Hydraulic Weighted DAFOR

Generating Unit	Maximum Continuous Unit Rating (MW)	12 months ending September 2016 (%)	12 months ending September 2017 (%)	Hydro Generation Base Planning Assumption (%)	Near-Term Planning Assumption (%)
All Hydraulic Units - weighted	954.4	2.02	4.17	0.90	2.60
Hydraulic Units					
Bay D'Espoir 1	76.5	10.57	19.88	0.90	3.90
Bay D'Espoir 2	76.5	13.52	25.77	0.90	3.90
Bay D'Espoir 3	76.5	0.00	0.03	0.90	3.90
Bay D'Espoir 4	76.5	1.33	0.23	0.90	3.90
Bay D'Espoir 5	76.5	0.63	0.00	0.90	3.90
Bay D'Espoir 6	76.5	0.18	1.35	0.90	3.90
Bay D'Espoir 7	154.4	0.00	1.80	0.90	3.90
Cat Arm 1	67	0.13	1.06	0.90	0.70
Cat Arm 2	67	0.00	0.08	0.90	0.70
Hinds Lake	75	0.06	1.09	0.90	0.70
Upper Salmon	84	0.00	0.87	0.90	0.70
Granite Canal	40	1.72	0.00	0.90	0.70
Paradise River	8	5.16	4.05	0.90	0.70

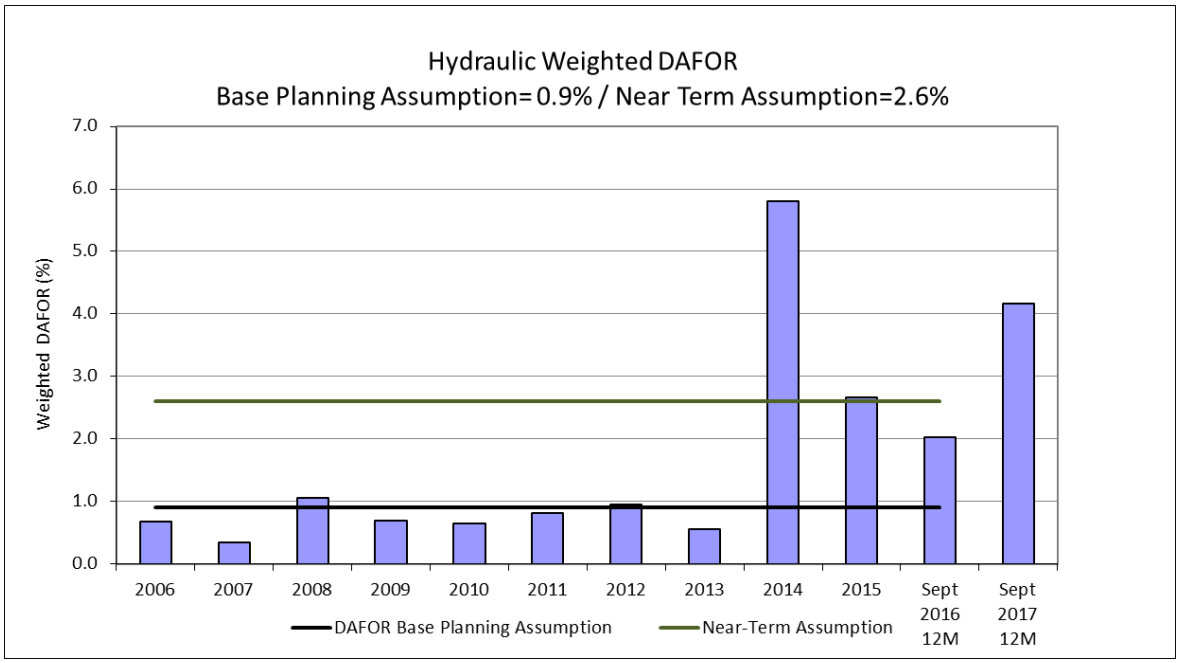

Figure 1: Hydraulic Weighted DAFOR

Considering the individual units' performance, the assumed Hydro generation base planning DAFOR was materially exceeded for Bay d'Espoir Unit 1 and Bay d'Espoir Unit 2. Also, there were exceedances compared to base planning assumption for Bay d'Espoir Unit 6, Bay d'Espoir Unit 7, Cat Arm Unit 1, Hinds Lake and Paradise River for the current period.

The Bay d'Espoir Unit 1 DAFOR of 19.88% and Unit 2 DAFOR of 25.77%, exceeded the base planning assumption of 0.9% and the near-term assumption of 3.9%, due to the units being removed from service on two separate occasions as a result of a leak in Penstock 1, which provides water to both Unit 1 and Unit 2. These penstock issues contributed 99.9% of the DAFOR for this period.

The investigation identified a major weld refurbishment of the penstock, which was completed to provide a long term solution. The investigation into this outage identified two additional long term recommendations to extend the reliable life of Penstock 1. The first recommendation is to add structural backfill to the upper portion of the penstock, planned for 2018. The second is to replace the internal protective coating, which is currently being planned as part of the capital refurbishment program to coincide with the generation outage schedules.

The Bay d'Espoir Unit 6 DAFOR of 1.35% exceeded the base planning assumption of 0.9% and is less than the near-term assumption of 3.9%. This is a result of the unit being unavailable from February 22, 2017, to February 25, 2017, due to a high turbine bearing alarm, which caused the unit trip protection to operate and shut the unit down in a controlled fashion. An investigation was completed, and it was determined that the Babbitt bearing was damaged. The bearing was repaired and the unit was returned to service. The results of the investigation found no issues for long term bearing reliability.

The Bay d'Espoir Unit 7 DAFOR of 1.80% exceeded the base planning assumption of 0.9% and is less than the near-term assumption of 3.9%, as a result of the unit being unavailable from July 3, 2017, to July 9, 2017, due to a failure in the collector assembly, which caused the unit protection to operate and isolate the unit from the system. An investigation was completed, and it was determined that the there was a flash over between the positive and negative slip rings which was caused by excessive brush wear. The investigation resulted in improvements to the preventive maintenance (PM) program for brush gear inspections across the hydraulic

generation fleet of assets. As a short term measure, all brush gear assemblies have been scheduled for an additional inspection prior to December 1, 2017. The PM Program for the brush gear assemblies will also be reviewed during the 2017/2018 winter season with a revised program in place prior to the start of the 2018 maintenance season.

The Cat Arm Unit 1 DAFOR of 1.06% exceeded the base planning assumption of 0.9% and the near-term assumption of 0.7%, as a result of the unit being unavailable from November 23, 2016, to November 25, 2016, due to a governor oil pump trip. An investigation into the issue revealed that the internal seals in the pump had failed, preventing the pump from maintaining the governor oil pressure. The oil system was completely cleaned, flushed and replaced with new oil. A new oil pump was installed and the unit returned to service, and the issue has been resolved. An additional consideration to improving the system is with respect to changing how the plant alarms are grouped. This will permit minor anomalies to be initiated as such, and not as major anomalies, which have the potential to take the unit off line. Recommendations will be finalized by end of Q4.

The Hinds Lake Unit DAFOR of 1.09% exceeded the base planning assumption of 0.9% and the near-term assumption of 0.7%, as a result of the unit being unavailable from April 19, 2017, to April 22, 2017, due to water in the generator bearing oil. An investigation revealed that the generator bearing oil cooler experienced a leak, which resulted in water getting into the bearing oil. Testing revealed that three of the six coolers were leaking. The damaged coolers were isolated from the system, with tests conducted to confirm adequacy of reduced cooling capacity. These tests confirmed that cooling with the three remaining coolers were adequate at ambient air and water temperatures. A planned maintenance outage was arranged from May 24, 2017 to May 30, 2017, to repair the damaged coolers, as well as to conduct extensive testing of the three in-service coolers. All work was completed, with no further issues being identified, and the unit was returned to service with 100% cooling capacity. Further testing is planned during the November maintenance outage. A complete set of spare coolers (6) are also

presently being purchased as part of the critical spares program. Hydro is planning to replace these coolers in 2018.

The Paradise River unit DAFOR of 4.05% exceeded the base planning assumption of 0.9% and the near-term assumption of 0.7%, primarily as a result of a forced outage from September 23, 2016, to September 30, 2016, which was related to a governor low oil level alarm. This alarm was caused when a seal broke on one of the governor servo motors, releasing oil from the governor oil sump into the powerhouse sump system. A new seal was installed and oil was added to the governor system. The results of the investigation found no issues regarding long term governor reliability.

5.0 Thermal Unit Forced Outage Rate Performance

The thermal unit forced outage rates are measured using the CEA metric, DAFOR. Detailed results for the 12-month period ending September 30, 2017, are presented in Table 5, as well as the data for the 12-month period ending September 30, 2016. These are compared to Hydro's short term generation adequacy assumptions, as used in the Near-Term Generation Adequacy report, and Hydro's long-term generation planning assumptions for the forced outage rate.

Table 5: Thermal DAFOR

Generating Unit	Maximum Continuous Unit Rating (MW)	12 months ending September 2016 (%)	12 months ending September 2017 (%)	Hydro Generation Base Planning Assumption (%)	Near-Term Planning Assumption (%)
All Thermal Units - weighted	490	19.72	13.77	9.64	14.00
Thermal Units					
Holyrood 1	170	25.46	18.23	9.64	15.00
Holyrood 2	170	25.64	18.27	9.64	10.00
Holyrood 3	150	2.86	4.44	9.64	18.00

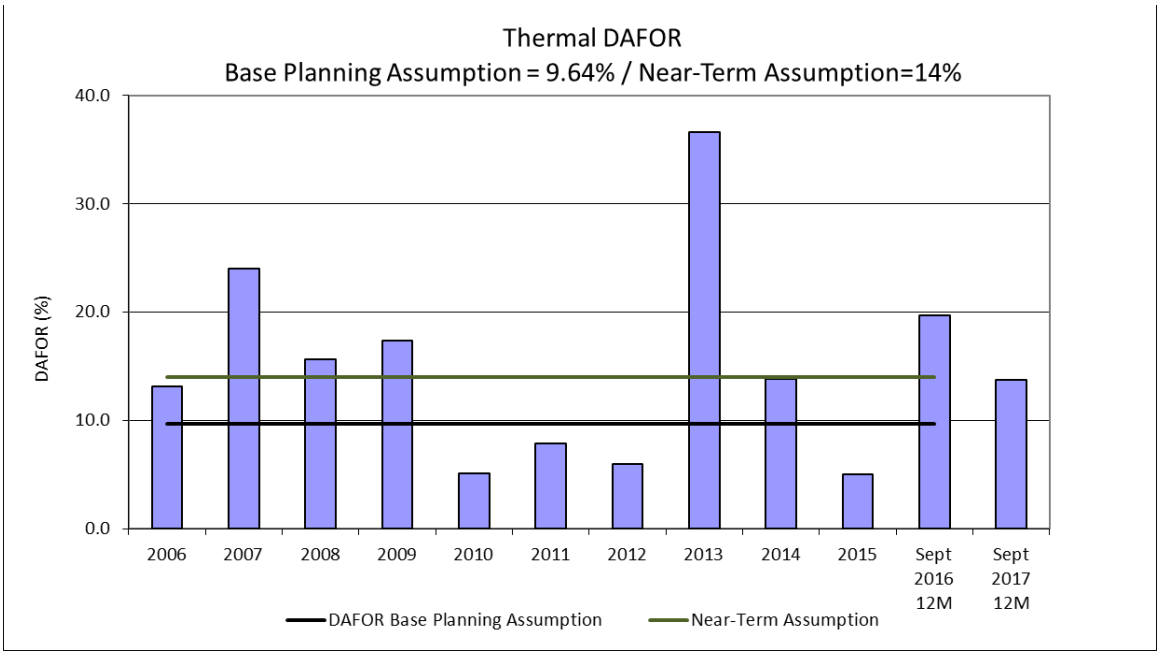

Figure 2: Thermal DAFOR

For the 12-month period ending September 30, 2017, the weighted DAFOR for all thermal units, 13.77%, was above the assumed Hydro generation base planning DAFOR value of 9.64%; however, below the near-term assumption of 14.00%. Unit 1 DAFOR was 18.23% and Unit 2 DAFOR was 18.27%.The performance for both Units 1 and 2 was above the base planning assumption of 9.64% and the near-term assumption of 15% (Unit 1) and 10% (Unit 2). Unit 3 DAFOR was 4.44%, which is better than the base planning assumption of 9.64% and near-term assumption of 18.0%. The majority of the 13.77% DAFOR for the plant is due to deratings from airflow issues in the 2016/2017 winter season on Unit 1 and Unit 2.

The DAFOR performance for Holyrood Unit 1 (170 MW) was affected by the following events in the current 12 month to date period:

During return to service from annual maintenance on October 29, 2016, a turbine control system (Mark V) governor control card failed, causing a forced outage. The failed card was replaced and the unit was synchronized on November 2, 2016.

When Unit 1 was first returned to service after the 2016 annual outage, it remained derated due to air flow issues, although there was an improvement to 160 MW from 155 MW before the outage. As planned, combustion tuning was completed during the week of November 14, 2016, to diagnose the air flow issues on this unit. Tuning was completed by an expert from Foxboro (supplier of the distributed control system) with assistance from a boiler field expert from Babcock & Wilcox (B&W.) They determined that the air flow issues that Hydro was experiencing are due to fouling through various stages of the boiler and air heater leakage. Further improvements required an outage to fully correct this, which was completed during the 2017 annual planned maintenance outage. Work included boiler cleaning and air heater upgrades. Full load capability is expected after completion of this work and at the end of the reporting period the unit had returned to service with encouraging results. The furnace pressure was much lower than seen at comparable loads during the previous operating season, which indicated a significant reduction in fouling through the boiler and air heaters. The unit has not been load tested due to system constraints.

After the tuning, and prior to the planned 2017 outage, the Unit 1 load capability continued to deteriorate as a result of fouling. Load capability was reduced to 145 MW on January 20, 2017, due to increased fouling, particularly in the air heater. An air heater wash was completed on a maintenance outage from January 26, 2017 to January 27, 2017, which restored the load capability to the pre-wash condition of 160 MW. However, the capability was further reduced due to continued fouling in the economizer, and at the end of February the unit was derated to 150 MW. On March 4, 2017, the unit capability was rated at 140 MW, and by the end of March this had further reduced to 135 MW. When the unit was taken off-line for the 2017 maintenance outage at the end of June, it was capable of 120 MW. For the coming 2017/2018 winter season, the 2017 annual maintenance outage is expected to materially reduce the effects of fouling discussed here.

On March 8, 2017, it was necessary to take a short forced outage to repair two air heater bearing cooling water leaks. The unit was taken off-line in a controlled manner and was returned to service approximately 23 hours later after completion of the repairs.

The 2017 maintenance outage on Unit 1 was from July 5, 2017 until September 11, 2017. The unit was put on-line on September 17, 2017 to allow for on-line commissioning of the new exciter controls system by the Original Equipment Manufacturer, ABB.

The Unit tripped at 70 MW on September 18, 2017, during commissioning of the new exciter controls on that unit. The unit was de-rated to 50 MW (below Under Frequency Load Shed limits) until September 21, 2017, when the cause of the trip was determined. This was to ensure that any further trips would not impact customers. Investigation determined that this trip, which happened when starting a boiler feed pump, was due to low unit board voltages. Starting the pump caused the already low voltage to drop below acceptable levels and this engaged under voltage protection and a unit trip. Voltages had been reduced intentionally as part of the exciter commissioning and were not returned to normal levels prior to starting the pump. This issue has been addressed with commissioning activities to ensure that it will not reoccur.

The DAFOR performance for Holyrood Unit 2 (170 MW) was primarily affected by the following events:

On November 6, 2016, the main steam inlet flange to the upper control valves was found leaking and the unit was derated to 70 MW until it was removed from service for gasket replacement on November 8, 2016. The unit was returned to service on November 10, 2016, but had to be taken off-line for another failure of the same gasket on November 16, 2016. This time the gasket was changed and a contractor was hired to provide a supplementary seal of the gasket, further encapsulating the replaced gasket. The unit was returned to service on November 21, 2016. This problematic joint was removed and replaced with a section of pipe during the planned outage in 2017.

On November 18, 2016, when attempting to go back on line after repair of the November 16, 2016, inlet flange leak, there was an issue discovered with turbine speed indication. After trouble shooting, it was determined that the speed probes had to be repositioned. The unit was returned to service at full capacity on November 21, 2016. During an outage on June 3, 2017 (see below) a GE expert ensured the proper adjustment of these probes.

On January 20, 2017, the unit load capacity was reduced to 150 MW due to boiler fouling, particularly in the air heater and economizer. An air heater wash was completed on February 18, 2017, but due to economizer fouling, the unit remained derated to 150 MW at the end of February. Continued fouling during operation further reduced the load capability of the unit. On March 6, 2017, the capability was rated at 140 MW. On March 21, 2017, this was further reduced to approximately 135 MW. Hydro completed an early two week duration outage on Unit 2 on April 23, 2017. The outage addressed the fouling related air flow issues that were considered to be a significant effort and could not be completed during an air heater wash, or during peak winter season demand. Activities included, but were not limited to, cleaning and removal of hardened ash in the economizer section of the gas path. Issues affecting air flow restrictions were addressed and Unit 2 was then rated at 165 MW following this work, as tested on April 26, 2017. Additional work was scheduled for the 2017 planned annual outage to further address air flow issues.

On April 22, 2017 there was a brief outage required to repair a section of flexible ductwork on the ignitor air system that had come apart during start-up after the boiler cleaning outage.

On May 1, 2017 the unit experienced a forced outage when a section of flexible ductwork adjacent to the location that failed on April 22, 2017, also failed and allowed hot gas to escape from the boiler. This hot gas caused a cable tray fire adjacent to the north east corner of the boiler on the second floor. Refurbishment work was completed by May 28, 2017 and included asbestos abatement, as loose asbestos fibres were found in the cable

tray. While the unit was off line for repairs, work protection permits were issued to allow other work, which was planned for the annual outage, to proceed in parallel. Also Unit 3 was re-called from its planned outage to provide generation to satisfy system requirements.

In parallel to the refurbishment work noted above, the cause of the failure of the ignitor flex hoses was investigated. This was the first such incident on record at the plant. All of the Unit 2 flexible hoses on the ignitor system were upgraded as required. This included extending the rigid pipe in the corner that failed such that the gap could be spanned by one flexible hose length. Two had been spliced together in the area of the failure and this was concluded to be part of the reason for the failure. On Unit 1, which was in operation at the time, additional clamps were installed to verify the hoses were secure. During the annual 2017 outages all hoses on Unit 2 and Unit 1 were positively secured to ensure this failure can not re-occur. Unit 3 is not of the same design, does not have flexible ignitor air ducting, and is not susceptible to a similar failure.

On June 3, 2017 the Unit 2 tripped. The unit was returned to service a few hours later on June 3, 2017 but was limited to 50 MW until the reason for the trip could be confirmed and mitigated. A GE representative was brought to site to diagnose the problem and determined that during the trip, the control valves closed while the governor was calling for them to remain open. This pointed to three possibilities; loose wire, control card failure, or servo failure. A card failure was ruled out since all other functions of the card were working normally. The wires were tested with the unit at 25 MW and no issues were found. An outage was then completed on June 8, 2017, to June 11, 2017, to replace the servo and change out the hydraulic fluid and filters. During this same outage, the turbine speed probe cables were replaced and probe clearance gaps were adjusted. This corrected a reliability issue that previously occurred on November 18, 2016 and was planned to be done during the annual outage.

On June 16 there was an incident on one of the two approximately 50% duty boiler feed pumps. It appeared that some debris went through one of the bearings of the west pump and caused a spike in temperature and vibration. The temperature and vibration returned to normal, but the pump was taken out of service to change the oil and clean out the lube oil tank. The unit was derated to 70 MW while the pump was out of service. It was successfully tested and returned to service on June 17.

On June 29, 2017 vibration and temperature excursions occurred on the same motor inboard bearing. At this point failure of the bearing was suspected. The pump was again taken out of service causing another de-rate to 70MW. Failure of the bearing was confirmed, and the spare boiler feed pump motor was brought to site and installed in place of the motor with the failed bearing. This was the most expedient option to get the pump back in service. This work was completed on July 2, 2017 and the unit returned to 165 MW capability. Additional checks have been added to pump rebuilds to check for issues witnessed on this pump.

Unit 2 was removed from service at the end of July, 2017 to accommodate the planned total plant outage and the unit annual maintenance outage. During the unit outage additional work was completed to address air flow issues. This included additional boiler cleaning and air heater upgrades. At the time of writing of this report, Unit 2 was in the process of coming back online following its annual maintenance, which included several upgrades.

6.0 Gas Turbine UFOP Performance

The combined UFOP for the Hardwoods, Happy Valley and Stephenville gas turbines was 7.06% for the 12-month period ending September 30, 2017 (see Table 6). This is below the base planning assumption of 10.62%, and the near-term assumption of 20.00%. The current period UFOP declined from the previous period UFOP of 5.54%. The Hardwoods UFOP for the current period is 6.47%, which is better than the base planning assumption of 10.62%. Happy Valley's

UFOP is 6.81% for the current period compared to 5.59% in the previous period. Hydro will begin using DAUFOP as a reliability measure in addition to UFOP going forward. Beginning in January, 2018 Hydro will report on the gas turbines using DAUFOP. Targets for this measure will be set based on historical data as well as planned improvements. This will discussed further in Hydro's next Near-Term Generation Adequacy Report, to be filed with the Board on November 15, 2017.

Table 6: Gas Turbine UFOP

Gas Turbine Units	Maximum Continuous Unit Rating (MW)	12 months ending September 2016 (%)	12 months ending September 2017 (%)	Hydro Generation Base Planning Assumption (%)	Near-Term Planning Assumption (%)
Combined Gas Turbines	125	5.54	7.06	10.62	20.00
Stephenville	50	12.03	8.02	10.62	20.00
Hardwoods	50	2.16	6.47	10.62	20.00
Happy Valley	25	5.59	6.81	10.62	20.00

The Holyrood gas turbine UFOP of 2.10% for the current period is better than the base planning and near-term assumptions of 5.00% (see Table 7).

Table 7: Holyrood GT UFOP

Combustion Turbine Units	Maximum Continuous Unit Rating (MW)	12 months ending September 2016 (%)	12 months ending September 2017 (%)	Hydro Generation Base Planning Assumption (%)	Near-Term Planning Assumption (%)
Holyrood CT	123.5	1.33	2.10	5.00	5.00

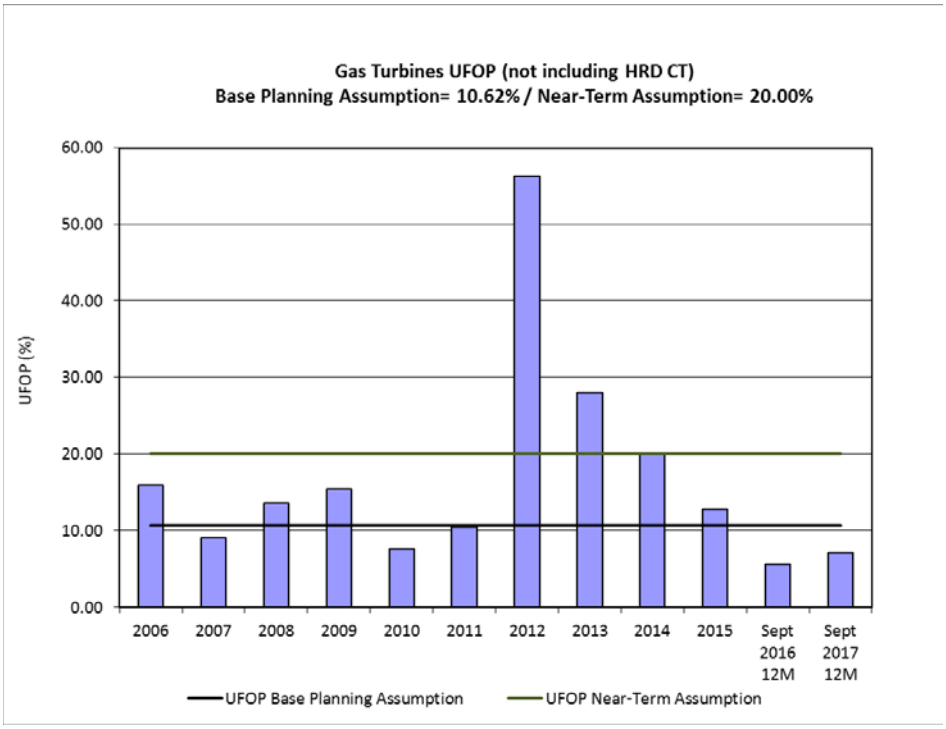

Figure 3: Gas Turbine UFOP – Hardwoods/Happy Valley/Stephenvile Units

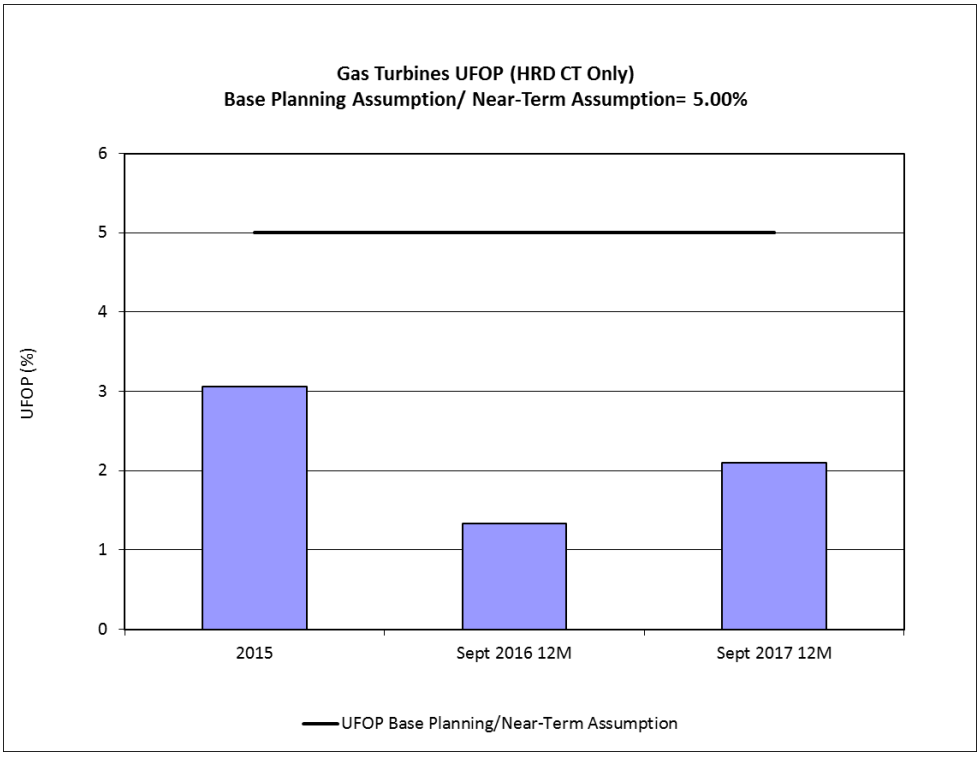

Figure 4: Gas Turbine UFOP – Holyrood Gat Turbine Only

Hydro continues to mitigate extended outages to the Hardwoods and Stephenville gas turbines by utilizing spare engines to allow for timely replacement of failed engines to return the units to full or near-full capacity. During the winter 2017/2018, Hydro will have two spare engines available for this purpose.