EXHIBIT DG-3 CONTAINS CONFIDENTIAL INFORMATION AND IS NOT INCLUDED IN THE PUBLIC VERSION OF THIS FILING.

EXHIBIT DG-4

Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

Extra Large Industrial Active Demand Control Tariff Application

Nova Scotia Power

September 27, 2019

REDACTED

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APPENDICES

1.0 EXECUTIVE SUMMARY

Nova Scotia Power Incorporated (NS Power or the Company) seeks approval from the Nova Scotia Utility and Review Board (NSUARB, Board) of a proposed new tariff under which Port Hawkesbury Paper LP (PHP or the Mill) will take electric service from the Company. A copy of the proposed tariff is attached as **Appendix A**. The proposed Extra Large Industrial Active Demand Control (ELIADC) Tariff increases the value provided by PHP for the benefit of all other customers. It will allow PHP to continue to operate in Nova Scotia and continue to make an important contribution to the provincial economy, and will provide a substantial increase to the contribution made by PHP to system costs.

PHP is NS Power's largest customer, accounting for approximately 10 percent of the total NS Power system load. PHP is currently served under the provisions of a Load Retention Tariff (LRT) Pricing Mechanism.

The LRT applicable to PHP was approved in 2012 by the NSUARB to respond to the economic distress of the customer and is set to expire December 31, 2019. In advance of the LRT expiry date, PHP and NS Power have worked collaboratively to develop a new tariff framework that is appropriate for an industrial customer of PHP's size and flexibility, and NS Power's system characteristics.

The proposed ELIADC Tariff is an annually adjusted, below-the-line tariff[1] and will have an initial term from 2020-2023 inclusive.

The ELIADC Tariff has been designed to produce additional value for NS Power's other customers beyond the minimum \$2/MWh and maximum \$4/MWh contribution under the current LRT, and to be sustainable for PHP in order that all customers benefit from the flexible dispatch characteristics PHP's load provides to the NS Power system. NS Power is seeking approval of

[1] The concept of "below-the-line" rates is discussed in greater detail in section 3.3, below.

the ELIADC Tariff effective January 1, 2020; provided, however, in the event the NSUARB is unable to render a Decision prior to January 1, 2020, NS Power requests that the ELIADC Tariff be granted interim approval effective January 1, 2020 until the NSUARB is able to render its Decision.

Specifically, the proposed new tariff framework includes the introduction of Active Demand Control (ADC) service, which will be provided by PHP to NS Power as a condition of taking service under the ELIADC Tariff. Under the ADC service, NS Power, subject to specific protocols that will be approved in conjunction with the ELIADC Tariff, will be able to direct PHP to decrease or increase its load in response to system conditions and costs, to the benefit of the system and therefore to all customers. Under this Tariff, PHP will continue to take service as a Priority Interruptible customer. The ADC benefit combined with a forecast price adder is estimated to provide total value for NS Power customers of between $6 million and $13 million annually over the initial Tariff period (2020-2023); an average of $10 million annually.

At a time when the operation of the NS Power system is becoming increasingly complex (considering the significant addition of intermittent renewable energy resources, substantial planned increase in imports across the Maritime Link, and reduced energy production from baseload fossil fuel units), ADC service presents an important opportunity for NS Power and customers. It effectively adds a large new baseload resource to create flexibility to more cost-effectively integrate renewables, becoming the Company's first real-time 120+ MW demand response resource.[2]

The proposed ELIADC rate design as described in this Application, including the Evidence of Rate Design Consultant, The Brattle Group, (attached as **Appendix B)**, is grounded on well-established incremental cost-based pricing practices. It is enhanced by a utility-managed demand response mechanism designed to reduce costs for all customers and improve reliability of a changing, increasingly dynamic power system. The ELIADC Tariff was developed by PHP

[2] Demand response resource refers to customer load that NS Power is able to manage in real time in response to power system conditions.

and NS Power, informed by their experience operating under the real-time pricing-based LRT. It provides increased value for customers.

In order that FAM customers do not bear the risk of an under-recovery of PHP's fuel costs, the ELIADC Tariff ensures that the minimum recovery from PHP will be the actual annual cost to serve PHP plus $4/MWh. The actual cost to serve PHP will be determined annually following year-end.

Given that significant variances from the forecast cost to serve PHP for 2020, attributable to a change in the availability of the Nova Scotia Block energy import, could arise, the Tariff includes a provision to update the 2020 Customer Baseline Load (CBL) Energy Charge[3] should the timing of the arrival of this energy create a material change in the CBL Energy Charge forecast (positive or negative).

This Application places a new tariff form before the Board which is appropriate for a customer with load of PHP's magnitude and the ability and willingness to provide the ADC service. It increases the value provided by this customer for the benefit of all other customers, and recognizes that the power system in Nova Scotia is undergoing fundamental change requiring new, creative solutions in order to continue to deliver affordable and stable electricity rates for all customers while continuing to comply with all environmental requirements.

[3] The CBL Energy Charge is described in section 4.1.1.

NS Power respectfully requests NSUARB approval of:

(1) The Extra Large Industrial Active Demand Control Tariff, as provided in **Appendix A**, inclusive of the ADC Energy Supply Protocols, effective January 1, 2020 until December 31, 2023 inclusive; however, in the event the NSUARB is unable to render a decision prior to January 1, 2020, NS Power requests that the ELIADC Tariff be granted interim approval effective January 1, 2020 until the NSUARB is able to hear the Application and render its decision; and

(2) NS Power's proposed accounting treatment for revenues and costs associated with the ELIADC Tariff.

2.0 INTRODUCTION

PHP is a pulp and paper manufacturing facility located in Richmond County which operates three thermomechanical pulp lines and produces supercalendered paper, principally for the export market. Over the period of 2013 to 2018 the Mill consumed approximately 1 terawatt hour (TWh) of electricity per year at loads which ranged between 5 megawatts (MW) and 220 MW, averaging approximately 120 MW across the period.

The facility has been in operation in Nova Scotia since 1962, with several expansions over the interim period. The Mill has purchased electricity from NS Power during that time under various large customer electricity tariffs. Generally, these tariffs were developed for and applied to this single customer in recognition of the Mill's extraordinarily large electricity load and unique operating characteristics. Most recently, PHP has taken service under an LRT approved by the NSUARB in 2012.[4] The approval of the LRT recognized the challenging economic and market circumstances faced by PHP and the fact that all customers were better off with the Mill continuing to operate and making a reduced, but still significant, contribution to utility fixed costs, and that a requirement for a larger contribution may have prevented the Mill from operating.

During the period the LRT has been in effect, it has met the original goals for the LRT:

- Seven years later the Mill continues to operate in the highly competitive international paper market;

- In accordance with the terms of the LRT, PHP has contributed approximately $17 million to recovery of the fixed costs of NS Power; costs which would otherwise have been borne by other customers;

[4] The LRT, LRT Pricing Mechanism and the Energy Supply Protocol are provided in Appendix F.

- Despite the complexity associated with managing the response of a large customer's load to real-time pricing signals, the administration and operation of the LRT has been confirmed by the NSUARB's auditors to have been conducted accurately and within the spirit and intent of the NSUARB's original approval of the LRT. In its 2018 Decision on the LRT Pricing Mechanism Re-Opener, the NSUARB found:

> It should be noted that the LRT and related rate appear to be operating as originally intended. NS Power submitted:
>
> Although PHP's overall contribution to NS Power's fixed costs in the first five years of the Load Retention Tariff Pricing Mechanism (LRR) was less than $20 million, thereby triggering the current re-opener, the LRR has operated as originally designed. Further, it has achieved what was intended; it allowed for the mill to re-open and to continue to operate for the last five years while covering its incremental costs and contributing to the fixed costs of the system.
>
> [NS Power Reply Submission, May 22, 2018, pp. 1-2]
>
> Synapse, the Board Counsel's consultant, stated:
>
> We note that the PHP Load Retention Tariff has evolved considerably since its inception and seems to be working fairly well at the present time.
>
> [Synapse Submission, May 15, 2018, p. 2]
>
> It is instructive for the Board to remain mindful of this context in reviewing this application.[5]

A foundation has been laid for the continued operation of the Mill in a sustainable manner post-LRT, whereby NS Power and PHP are now able to create increased value for all customers under the proposed ELIADC Tariff, based on the skills and systems developed under the LRT's real-time pricing regime and the knowledge developed by the two companies as to the interplay of the Mill's load flexibility with NS Power's system operations and costs.

[5] M08519 – Port Hawkesbury Paper LP Load Retention Tariff Pricing Mechanism – Re-Opener of certain LRR Cost components and continuance of the $4/MWh Cap (P-203) Board Decision Letter, June 1, 2018, page 2.

The LRT expires at the end of 2019. NS Power and PHP have been working together over the past several months to develop a new tariff framework that will build on the processes and skills developed under the LRT regime to provide a sustainable cost of electricity for the Mill and increased value for all customers.

NS Power therefore respectfully requests the NSUARB's approval of the ELIADC Tariff, to become effective on January 1, 2020. The Tariff provides that the initial term of the Tariff will be 2020-2023 inclusive. A copy of the proposed ELIADC Tariff is attached as **Appendix A.** In accordance with the Tariff provisions, an annual report will be filed with the Board concerning the benefits derived from ADC during the year.

In support of the proposed ELIADC Tariff, the following information is provided in this Application:

- A list of key factors considered in the development of the ELIADC Tariff design in Section 3;
- A description of the proposed ELIADC Tariff structure in Section 4;
- The proposed ELIADC Tariff in **Appendix A;**
- The opinion of utility rate design expert Dr. Ahmad Faruqui of the Brattle Group in support of the Board's approval of the ELIADC Tariff, attached as **Appendix B**;
- A report by TD Securities on the financial outlook of Port Hawkesbury Paper attached as **Confidential Appendix C**;
- Support for the value of the ELIADC pricing elements, including the forecast CBL Energy Charge and forecast CBL Adder in **Confidential Appendix D;**
- Support for the Variable Capital Charge for 2020-2023 in **Appendix E;** and
- The currently effective Load Retention Tariff, provided for reference in **Appendix F**.

3.0 FACTORS INFLUENCING THE ELIADC TARIFF DESIGN

3.1 Nova Scotia's Changing Power System and the Potential Role of Demand Response

Since 2010 NS Power has:

- Installed or contracted capacity of over 600 MW of intermittent wind energy, which has the potential to swing from 0 MW of supply to 600 MW in a few hours.
- Witnessed the decommissioning of indigenous natural gas supply and a shift to reliance on imported natural gas to fuel the Company's natural gas generators, which are critical to the Company's peak load responsiveness.
- Seen significant tightening of environmental constraints with the resultant curtailment of thermal plant generation, presenting increased challenges with using these plants as peak load resources.
- Incorporated substantial annual load reduction as a result of Demand Side Management (DSM) Programming
- Seen increased distributed energy resource deployment across the province, principally in the form of small solar installations, with the outlook for further material increases in this area over the next 5 years.

Over the next year, with the anticipated arrival of energy from Muskrat Falls, the Company will:

- Serve approximately 30 percent of its annual load with electricity imports and as much as 45 percent in certain months; and
- Determine the decommissioning plan for a former baseload fossil fuel generating unit displaced by this new import energy source.

The implications of these developments for the NS Power system, NS Power and customers are that new tools will be required to address this increasingly challenging power system landscape in order to allow customer electricity requirements to continue to be met in the lowest cost manner while maintaining service reliability.

Nova Scotia traditionally relied on supply sources to meet this type of challenge; this has now been augmented by a large-scale DSM program. The next step in power system development, one being pursued by jurisdictions across North America, is to incorporate enhanced demand response to the Company's resource portfolio.

The ELIADC Tariff is NS Power's most innovative and significant foray into demand response since the introduction of the Large Industrial Customer Interruptible Rider. The expiration of the LRT and the lessons learned over the LRT period now place NS Power and PHP in a position to develop this opportunity.

3.2 Lessons Learned through LRT Operation

The Company's learnings from the LRT operation include the following:

1. PHP has unique potential among NS Power customers to shift its load within the day/week and across hours to materially affect the cost of electricity supply in Nova Scotia.

    (a) Over the course of the LRT, PHP has performed dramatic swings in load on an hour-to-hour basis in reaction to price signals supplied by NS Power. Aside from price response, in reacting to a request from the Nova Scotia Power System Operator (NSPSO), PHP has shown the ability to reduce load in a matter of minutes from very high load (200 MW+) to very low load (5-15 MW).

    (b) PHP can operate in different loading configurations including the nine operating modes identified as the basis of the ELIADC Tariff dispatch modeling. These modes range from 5 MW to 210 MW.

2. Under the LRT, demand planning is essentially completed on an hour-to-hour basis requiring PHP to choose to respond in the short term to price signals. Under the ELIADC Tariff, the planning window is expanded from the short term to include the rest of the year by means of the annual forecast of monthly demand profiles.

3. Resource planning in Nova Scotia, with load of the size of PHP responding to forecast price signals under the LRT is complex. While the Mill has shown a definite responsiveness to higher and lower price periods, there are limitations on the NSPSO's ability to rely on this price signal-driven response to create value for customers, compared to direct control of this load using schedules that are based on a forward-looking system-wide view.

4. There are decisions the customer may make based on their interpretation of the Company's price forecasts and experience operating under this regime, that in hindsight, could produce higher cost outcomes for PHP (e.g. PHP taking an amount of energy based on the expected wind generation and planning demand that may not follow what the forecast is presenting).

While the LRT model has produced a lower cost regime for PHP, there are limitations to the operational benefits that can be achieved under a price response signal. Additional savings are possible by allowing NS Power to control and direct the dispatch of PHP load based on both real-time operations and longer-term plans for the system. The ADC Protocols have been designed to extract this additional potential value for all customers.

3.3 Innovative Rate Design

Nova Scotia Practices

The standard embedded cost of service-based rates offered by NS Power do not reflect the unique operational characteristics of the Mill and cannot provide a rate which will support the sustained operation of the Mill.

In Nova Scotia, there are well-established practices for below-the-line (BTL) tariffs for electricity customers in unique circumstances. BTL rates are set annually based on pre-approved formulae and/or methodologies. The Generation Replacement and Load Following Rate is a BTL tariff which serves a small customer group of enterprises that generate their own electricity for most of their needs. The Shore Power Tariff serves a niche market by seasonally providing interruptible power for cruise ships in port.

Similarly, the ELIADC Tariff is a BTL tariff which takes into consideration the distinct attributes of one customer. Similar to other BTL rates, it is to be calculated on an annual basis using NS Power's forecast incremental costs.

Industry Trends

NS Power retained The Brattle Group to comment on NS Power's proposed ELIADC Tariff and to survey industry developments in demand response rates. The evidence of The Brattle Group (the Brattle Report) is attached as Appendix B. The Brattle Report found that there is an increasing trend of innovative approaches to demand response where customers can provide load flexibility.

The Brattle Report concludes:

> NS Power's proposal is well aligned with an emerging industry trend toward developing customer offerings that increase load flexibility. Elements of NS

Power's proposal – such as the operational capability to increase load to avoid renewables curtailments while maximizing energy imports, and the control of end uses with short notice – have been observed in other programs recently introduced in other jurisdictions. Based on this consistency with industry practice, and the distinct advantages of the ELIADC tariff relative to the current LRT offering, we expect NS Power's proposed ELIADC tariff will create significant value for all NS Power customers.[6]

3.4 ELIADC Tariff Pricing Threshold

In the development of the ELIADC Tariff, the price paid under the LRT was informative in setting the original foundation as to 'sustainable' pricing levels for PHP. Pricing methodologies based on the conventional fully allocated costs approach would result in prices in excess of $80/MWh, which are substantially higher than those paid under the LRT and not financially viable for the Mill.

Based on this, the parties shifted to an incremental cost-based approach which retained some of the elements of the LRT (incremental cost plus a price adder). In light of the outlook for fuel prices, it was believed that an incremental cost-based approach, combined with enhanced value available from NS Power having direct control of the extraordinarily large electricity load of PHP could, in total, produce substantial new value for other customers.

Based on this understanding, NS Power and PHP agreed to develop a framework anchored on a price point which would be used to determine the annual price adder in the tariffed rate. The concept is that as the forecast cost to serve PHP falls below this Price Point, the price adder to be applied to the ELIADC Energy Charge will increase accordingly.

NS Power and PHP did not set the Price Point through the Tariff development process, rather agreeing to develop their positions on this pending the review of the PHP financial forecast by

[6] The Brattle Group: An Assessment of Nova Scotia Power's Proposed Extra Large Industrial Active Demand Control Tariff, in Appendix B.

TD Securities, the same entity that NS Power engaged to conduct due diligence in the 2012 LRT process.

As the discussions developed, recognizing that the price adder would be contingent on the forecast cost of electricity service to PHP, NS Power and PHP agreed that a minimum cost contribution should be implemented at $4/MWh, the maximum currently available under the LRT.

The TD Securities Report provided in Confidential **Appendix C** provides third-party forecasts of PHP's financial performance under various scenarios. The TD Securities Report Executive Summary confirms that the forecast net cost to PHP of $61.14/MWh provided by the ELIADC Tariff is in the range that:

> " ...under the ADC agreement, would position PHP to weather volatility in variable production costs, exchange rates, and SC [supercalendered paper] pricing."[7]

In light of this, and the substantial increased value enabled by PHP's provision of ADC service to NS Power (an average annual forecast value of $10 million), the Company submits the forecast cost to PHP of $61.14 over the initial Tariff period (2020-2023) is reasonable and in the interests of customers.

NS Power understands that contemporaneous with this filing, PHP will provide evidence in this matter, including its financial forecasts and other related information.

[7] TD Securities, PHP Financial Outlook Review, Confidential Appendix C, page 6.

4.0 ELIADC TARIFF STRUCTURE

The ELIADC Tariff provides the commercial and operational terms under which the Tariff is available and applied, including the ADC Energy Supply Protocols which will govern NS Power's dispatch of PHP load. The proposed Tariff is attached as **Appendix A**. Descriptions of the ELIADC Tariff pricing components and the ADC Protocols are provided in the following sections.

The pricing components of the ELIADC Tariff are the ELIADC Energy Charge and the ADC Load Shifting Credit. Each component is described below:

4.1 ELIADC Energy Charge

The ELIADC Energy Charge is the per megawatt-hour charge to be used to bill PHP through the year. It is the sum of three rate elements: the Customer Baseline Load (CBL) Energy Charge, the CBL Adder and the Variable Capital Charge.

Support for the forecast ELIADC Energy Charges for 2020-2023 is presented in **Confidential Appendix D.** The forecast figures reflect PHP load forecasts developed earlier this year. PHP will be developing an updated forecast for 2020. Based on the updated forecast, the Company will file the updated ELIADC charges for 2020 for Board approval in November 2019. For 2021 to 2023, the ELIADC Energy Charge will be calculated and submitted to the NSUARB in the fourth quarter each year for the next calendar year.

4.1.1 Customer Baseline Load Energy Charge

The cost to serve the Customer Baseline Load will be calculated based on the forecast incremental cost to meet PHP's forecast electricity consumption, expressed as a levelized Customer Baseline Load. The CBL Energy Charge will assume no economic load shifting (e.g. reductions in usage in high-cost hours and increased usage in low-cost hours) and will not contain any up-front credits to the customer for anticipated load shifting under the ADC service. The incremental cost will include fuel and purchased power, line losses and incremental operating and maintenance costs. Costing support for the CBL Energy Charge forecast is provided in Confidential **Appendix D.**

4.1.2 CBL Adder

A CBL Adder (CBLA) will be included in the ELIADC Energy Charge. The CBLA is designed to contribute to offsetting utility costs to the benefit of other customers.

The CBLA will be set annually, calculated with reference to the forecast CBL Energy Charge and a Price Point. The intent is that as the forecast CBL Energy Charge ($/MWh) decreases below the Price Point, PHP will make increased contributions to utility costs to the benefit of other electricity customers in Nova Scotia. In contrast, as the forecast CBL Energy Charge increases, a more modest cost contribution will be provided such that the ELIADC Tariff remains sustainable and PHP's load remains available to provide ADC service to the NS Power system.

When the CBL Energy Charge is less than the Price Point, the CBLA will be calculated as 75 percent of the value of the forecast CBL Energy Charge below the Price Point of $61.75/MWh. plus $1.00/MWh, referred to as the Constant. When the CBL Energy Charge is greater than or equal to the Price Point, the CBL Adder is $1.00/MWh.

If CBL energy Charge < Price Point:

$$CBL\ Adder = 0.75 * (Price\ Point - CBL\ Energy\ Charge) + Constant$$

If CBL Energy Charge ≥ Price Point:

$$CBL\ Adder = 1$$

The calculation of the forecast CBL Adder for 2020 to 2023 is summarized in **Figure 1** below.

Figure 1. CBL Adder forecast

		$/MWh			
Row		**2020**	**2021**	**2022**	**2023**
1	CBL Energy Charge	59.78	58.00	52.88	57.70
	Price Point	61.75	61.75	61.75	61.75
2	75% of (Price Point minus CBL Energy Charge)	1.48	2.81	6.65	3.04
3	Constant	1.00	1.00	1.00	1.00
4	CBL Adder (Row 2+Row 3)	2.48	3.81	7.65	4.04

4.1.3 Variable Capital Charge

A Variable Capital Charge (VCC) will be included in the ELIADC Energy Charge. The VCC will reflect the forecast of the incremental capital cost associated with serving PHP's load over the 2020 - 2023 period. NS Power proposes the VCC be set at $1.13/MWh. The methodology follows that used in the Load Retention Tariff. Support for this figure is presented in **Appendix E.**

4.1.4 Calculation of the ELIADC Energy Charge

Figure 2 below presents the ELIADC Energy Charge, comprised of the CBL Energy Charge plus CBLA plus VCC for the initial four-year Tariff period. As stated above, NS Power will update the Application with respect to the ELIADC Energy Charge for 2020 based on the updated energy forecast for 2020 from PHP. NS Power anticipates that it will be able to provide the information to the NSUARB in November 2019.

$$ELIADC\ Energy\ Charge = CBL\ Energy\ Charge + CBLA + VCC$$

Figure 2. Forecast ELIADC Energy Charge 2020-2023

	$/MWh			
Year	**2020**	**2021**	**2022**	**2023**
CBL Energy Charge	59.78	58.00	52.88	57.70
CBL Adder	2.48	3.81	7.65	4.04
Variable Capital Charge	1.13	1.13	1.13	1.13
ELIADC Energy Charge	63.39	62.94	61.66	62.87

Recognizing that the CBL Energy Charge will change annually as forecast amounts are updated and will vary from the above forecast amounts, **Figure 3** below provides an illustration of the calculation of the annual ELIADC Energy Charge at various CBL Energy Charge levels.

Figure 3. Illustration of ELIADC Energy Charge at Various CBL Energy Charges

CBL Energy Charge	CBL Adder		Variable Capital Charge	ELIADC Energy Charge
	75% of CBL Energy Charge Below Price Point*	Constant		
$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
50	8.81	1.00	1.13	60.94
55	5.06	1.00	1.13	62.19
60	1.31	1.00	1.13	63.44
65	0.00	1.00	1.13	67.13
70	0.00	1.00	1.13	72.13

*Set at $61.75

4.1.5 ADC Load Shifting Credit

In recognition of the value increase enabled by ADC and PHP's payment of a levelized CBL-based price, the ELIADC Tariff will provide a credit to PHP equal to 25 percent of the cost differential between the CBL Energy Charge and the actual annual cost to serve PHP. This ADC Load Shifting Credit (ADC Credit) will promote alignment between NS Power and PHP in efforts to maximize the value that can be achieved from the ADC service to the benefit of all customers. The balance of the load shifting benefit (75 percent) accrues to other customers.

The resultant change from PHP's current operational profile, which is driven by marginal pricing signals, to one in which the NSPSO controls PHP's load on the basis of a system-wide view will deliver greater system savings than can be obtained by PHP in its individual response to price signals under the current LRT regime.

The value of the ADC Credit will be calculated after the end of each calendar year and credited to PHP at that time.

Figure 4 below provides the ADC Credit forecast for the period 2020-2023. The ADC Credit is not intended to isolate that portion of the cost differential between the CBL Energy Charge and the actual cost to serve PHP solely attributable to NS Power's control of the PHP load. It will also reflect electricity and fuel market price changes and load variances across the year among other operational factors which ultimately determine system cost. Including all cost elements in the ADC Credit is appropriate as it recognizes that the ADC service provided by PHP will be fully integrated into the dispatch of NS Power's system with the objective of minimizing system cost across the year inclusive of load changes, market price changes and unit availability.

Support for the ADC forecast for the period 2020-2023 is presented in **Confidential Appendix D**.

Figure 4. Forecast Value of ADC Benefit over the Initial Tariff Period

		2020	2021	2022	2023	Average
Forecast CBL Energy Charge	$/MWh	59.78	58.00	52.88	57.70	57.09
Forecast Cost to Serve PHP with Shifted Load	$/MWh	55.74	52.08	47.09	48.20	50.78
ADC Load Shifting Benefit	$/MWh	4.04	5.92	5.79	9.50	6.31

		2020	2021	2022	2023	Average
ADC Load Shifting Benefit to NSP Customers (other than PHP) 75%	$/MWh	3.03	4.44	4.34	7.12	4.73
ADC Load Shifting Benefit to PHP 25%	$/MWh	1.01	1.48	1.45	2.38	1.58
ADC Load Shifting Benefit to NSP Customers* (other than PHP) 75%	$ million	3.31	4.85	4.74	7.78	5.17
ADC Load Shifting Benefit to PHP* 25%	$ million	1.10	1.62	1.58	2.60	1.73

* Assumes annual PHP load of 1.092 TWh

4.1.6 Summary

Based on the forecast information presented in this Application, the ELIADC Energy Charge, less the ADC Load Shifting Credit is forecast to yield an electricity cost to PHP of $61.14/MWh over the initial ELIADC Tariff term (2020-2023).

Figure 5 below provides a summary of the annual forecast cost of electricity to PHP and the forecast benefit to other customers.

Figure 5. Forecast ELIADC Tariff Cost of Electricity to PHP and Benefit to Other Customers

		2020	2021	2022	2023	Average
Forecast ELIADC Energy Charge (from Figure 2)	$/MWh	63.39	62.94	61.66	62.87	62.72
Forecast ADC Load Shifting Benefit to PHP (from Figure 4)	$/MWh	1.01	1.48	1.45	2.38	1.58
Forecast Net Cost of Electricity to PHP	$/MWh	62.38	61.46	60.21	60.49	61.14
Forecast Cost to Serve PHP with Shifted Load (From Figure 4) plus Variable Capital Charge	$/MWh	56.87	53.21	48.22	49.33	51.91
Forecast Benefit to Other Customers	$/MWh	5.51	8.25	11.99	11.16	9.23
Forecast Benefit to Other Customers*	$ million	6.02	9.01	13.09	12.19	10.08

* Assumes annual PHP load of 1.092 TWh.

4.2 Active Demand Control Protocols

In order to take service under the ELIADC Tariff, PHP will be required to effectively turn over control of the scheduling of its operations to NS Power. NS Power will schedule the timing and magnitude of PHP's electricity usage within an agreed set of protocols.

The applicable ELIADC Energy Supply Protocols (ADC Protocols) are attached as Schedule 1 to the proposed ELIADC Tariff provided in **Appendix A.** PHP and NS Power have worked collaboratively to develop the ADC Protocols in a manner which ensures that the significant potential value of this service offering by PHP is realized to the benefit of all customers, including PHP, while also ensuring that PHP will be supplied with electricity in a manner sufficient to meet the needs of its operations. Key elements of the ADC Protocols include:

1. Annual establishment of PHP weekly and monthly maximum and minimum energy requirements for the upcoming year, under a defined set of Operating Modes as set out in the ADC Protocols.

2. Regular calculation by NS Power of the forecast optimized dispatch of PHP demand co-optimized as part of the system dispatch, working within the system security requirements set by the NSPSO.

3. Processes for NS Power, the NSPSO and PHP to exchange information on an hourly, daily, weekly, monthly and annual basis including:

    - PHP key operational parameters including pulp storage levels, production levels and maintenance outage timing;
    - System demand forecasts;
    - Nova Scotia's base load and aggregate wind forecast;
    - NS Power's advice to PHP on the optimal timing for PHP production levels and planned outages; and
    - NS Power's provision of a load schedule to PHP.

4. Requirements for PHP, NS Power and the NSPSO scheduling and/or operations groups to be available to each other on a continuous 24 hour, 7 days a week basis. PHP's scheduling and operations team will have the authority to adjust PHP's load based on NS Power's supplied demand forecast;

5. The ADC Protocols do not supersede any requirement or obligation required by Nova Scotia Power Incorporated Open Access Transmission Tariff (NS OATT) or the Nova Scotia Wholesale and Renewable to Retail Market Rules.

6. The ADC Protocols detail what occurs in cases where PHP may for some reason be unable to respond to NS Power direction to shift load. Circumstances where this will be tracked are provided as Appendix 1 to the ADC Protocols.

4.3 Other Key ELIADC Tariff Provisions

4.3.1 Minimum Contribution

The ELIADC Tariff contains a requirement that the price charged to PHP will yield a minimum benefit of $4/MWh hour over the actual cost to serve PHP, as calculated at year-end. This minimum is equivalent to the maximum contribution to utility non-fuel costs as provided under the LRT.

Based on a forecast load of approximately 1 TWh, the minimum annual benefit of PHP operating under the ELIADC Tariff would result in $4 million. Though this is significantly below the forecast benefit for this Tariff in all years but 2020, it provides important assurance for other customers should the forecast cost to serve PHP change significantly, either across the Tariff period or within a year.

4.3.2 Intra-period CBL Adjustments

The ELIADC Tariff recognizes that circumstances may arise during the year which could drive a material change in the CBL that could require a change to the CBL Energy Charge during the year. The Tariff identifies explicitly the potential change in timing of the delivery of the Nova Scotia Block of energy in 2020 as one such item that could require a change to the CBL Energy Charge. Other circumstances are noted in the Tariff which would warrant a reassessment of the CBL Energy Charge within the year, with a resultant change in the value of the ELIADC Energy Charge.

4.3.3 Priority Interruption

Consistent with prior Tariffs approved for Extra Large Industrial customers, and in addition to the ADC Protocols, PHP's load shall remain priority interruptible for the purpose of system security (after only Generation Replacement and Load Following Tariff customers) and subject to the terms applicable to NS Power load interruptions previously approved by the Board. There is no specific credit in the ELIADC Energy Charge to compensate the customer for this interruptibility.

4.3.4 Reopener

Similar to the LRT, the proposed ELIADC Tariff contains a reopener provision that allows NS Power or PHP to seek Board approval for adjustments to the Tariff if either party determines the ELIADC Tariff is not operating effectively.

4.3.5 Reporting

The Tariff provides that NS Power will report annually to the NSUARB the amount of value achieved through Active Demand Control and to endeavour to provide this report to the NSUARB within 60 days after the end of a tariff year.

4.3.6 Term

The initial term of the ELIADC Tariff, including the pricing provisions (e.g. 75/25 benefit sharing, the Price Point) and operational parameters (e.g. the Protocols) is 2020-2023 inclusive. Subject to any Decisions of the NSUARB, which would change the Tariff, an application will be made by NS Power or PHP prior to the end of the initial term for approval of a subsequent term for this Tariff and the associated commercial and operational provisions.

4.4 Summary

The ELIADC Tariff is forecast to produce an average annual benefit of $10 million over the initial four-year Tariff period. This is a substantial increase over the current LRT regime which has provided an average contribution to fixed costs of less than $3 million annually. It also establishes a sustainable pricing regime for PHP and lays a foundation for PHP and NS Power to increase this benefit as experience operating with this new demand response tool grows. In addition, the Tariff provides assurance that the benefit to customers over the actual cost to serve PHP, will, at a minimum, equal $4/MWh, or approximately $4 million.

The ELIADC Tariff is an innovative development in Nova Scotia. It offers substantial new value for all customers including PHP and, as appropriate for a new tariff design, provides opportunity for amendment should the Tariff be determined not to be operating as originally contemplated or opportunities be identified for enhancements.

5.0 ACCOUNTING FOR ELIADC TARIFF REVENUES AND COSTS

NS Power is proposing that accounting for revenues and costs under the ELIADC Tariff remain consistent with the process established through the LRT; that the $4/MWh minimum contribution to utility costs, the Variable Capital Charge, and the operating and maintenance portion of the CBL Energy Charge be treated as non-fuel revenue to be applied to non-fuel costs and the cost of fuel and all remaining Tariff revenues and benefits, including 75 percent of the calculated annual ADC benefit and fixed cost contribution in excess of the $4/MWh minimum flow through the Fuel Adjustment Mechanism.

The Company anticipates that the accounting for revenues and expenses associated with this Tariff will be subject to review at the next General Rate Application.

6.0 REQUEST FOR INTERIM APPROVAL

The LRT expires at the end of 2019. A replacement tariff is required to take effect beginning January 1, 2020.

Advantages to all customers of implementing the new ELIADC Tariff January 1, 2020 include the following:

- The minimum contribution under the ELIADC Tariff ($4/MWh) is equal to the maximum under the LRT.
- The forecast benefit of the new Tariff in 2020 is $6.02 million; $1.7 million greater than the maximum benefit available under the LRT.
- 2020 is forecast to be the year with the lowest ELIADC Tariff value. However rather than being a reason not to proceed with the Tariff at the beginning of the year, 2020 presents an important opportunity to gain experience with the new tariff and operating processes to the long-term benefit of customers.
- The ELIADC Tariff structure is based on a calendar year, with the greatest opportunity to maximize the ADC benefit occurring in the first quarter of the year when system load and system costs are at their highest. Implementing the Tariff at the beginning of the year provides the greatest opportunity to increase savings beyond the minimum.

In the event the NSUARB is unable to render a decision on this Application prior to January 1, 2020, NS Power requests that the ELIADC Tariff be granted interim approval effective January 1, 2020 until the NSUARB is able to render its Decision. Interim approval may be amended, in whole or in part, and applied retroactively by the NSUARB in its final Decision on the ELIADC Tariff. Subject to a NSUARB Decision on this matter or other changes affecting the ELIADC Tariff in future years, the NSUARB Decision would establish the tariff framework, including the ADC Energy Supply Protocols, for the initial Tariff period 2020-2023 inclusive.

7.0 CONCLUSION

The Extra Large Industrial Active Demand Control Tariff introduces an innovative, large-scale demand response resource to Nova Scotia Power's resource portfolio. It provides a sustainable price for NS Power's largest customer and a substantial financial benefit for all other customers. Introduction of this new tariff design, as the LRT expires and the Nova Scotia electricity system is undergoing significant change, is timely.

The Tariff will present challenges for PHP. The customer will need to adapt to no longer having full control of its operations other than that allowed through the ADC Protocols. Administering the ELIADC Tariff will represent a challenge for NS Power to learn the full potential of this new demand response tool as an operations and planning input and seek to optimize the cost and reliability of our power system around this for the benefit of all customers.

It is expected that as we gain experience operating under this regime, refinements to the supporting processes will be required, potentially including changes to the Tariff framework. As these opportunities and challenges are identified, the two companies are committed to addressing them collaboratively in the interests of all customers and in a transparent manner before the NSUARB.

8.0 RELIEF SOUGHT

NS Power respectfully requests NSUARB approval of:

1. The Extra Large Industrial Active Demand Control Tariff as provided in **Appendix A** (subject to the 2020 ELIADC Energy Charge being updated), inclusive of the ADC Energy Supply Protocols effective January 1, 2020 until December 31, 2023 inclusive; however, in the event the NSUARB is unable to render a Decision prior to January 1, 2020, NS Power requests that the ELIADC Tariff be granted interim approval effective January 1, 2020 until the NSUARB is able to render its decision; and

2. NS Power's proposed accounting treatment for revenues and costs associated with the ELIADC Tariff.

The Extra Large Industrial Active Demand Control Tariff (ELIADC) provides a mechanism whereby Port Hawkesbury Paper LP (PHP, the Mill, the Customer) pays the forecast incremental costs of its annual forecast service expressed as a levelized Customer Baseline Load (CBL) plus makes a contribution to utility costs, while providing Nova Scotia Power (NS Power) with control of PHP's load such that NS Power's overall system costs can be reduced and system reliability can be improved for the benefit of all NS Power customers.

AVAILABILITY

(a) This Tariff is applicable to operations at PHP's mill site at Point Tupper, and is premised upon PHP's electricity requirements being exclusively served by NS Power.

(b) In addition to the priority interruptible service load reduction requirements prescribed in this Tariff, PHP's load shall be further managed by NS Power in accordance with the Active Demand Control – Energy Supply Protocols attached as Schedule 1 to this Tariff.

(c) The service voltage shall not be less than 138 kV, line to line, at each delivery point. Service is provided at the supply side of the Mill's transformation equipment. PHP must own the transformation facilities and no transformer ownership credit is applicable.

(d) This Tariff cannot be taken in conjunction with other tariffs unless approved by the Nova Scotia Utility and Review Board (Board).

COST OF ELECTRICITY UNDER THE ELIADC TARIFF

The price paid by PHP for electricity under this Tariff will be based on the forecast incremental cost to serve PHP at an assumed levelized baseline load level, plus an adder to contribute to the reduction of the cost of service to other NS Power customers, less a credit to recognize system savings enabled by PHP's granting Active Demand Control of its load to NS Power. The credit is also intended to incent PHP to assist NS Power in realizing the full potential value of Active Demand Control by allowing PHP to share in the resulting system savings.

The pricing elements comprising the ELIADC are:

- Customer Baseline Energy Charge (CBL Energy Charge)
- Customer Baseline Adder (CBLA)
- Variable Capital Charge
- Active Demand Control Credit

Minimum Payment

The ELIADC Tariff requires that a minimum payment shall be made by PHP in respect of each tariff year, which shall not be less than the sum of:

(a) NS Power's actual total incremental cost of serving PHP during the year (including the cost of fuel and purchased power, line losses, variable operating costs and variable capital costs for NS Power's incremental generation and delivery of electricity to the customer), plus

(b) $4.00 multiplied by the total number of MWh supplied in the year.

Any adjustments required to achieve this minimum payment amount will be determined and charged to PHP after year end.

Customer Baseline Energy Charge and Contribution to Utility Costs

In advance of each tariff year, PHP shall advise NS Power of its forecast annual and monthly energy requirements for the subsequent calendar year, including the anticipated dates and durations of PHP's major scheduled maintenance periods. Upon receipt of such forecast, NS Power will then calculate, in $/MWh, its forecast annual cost to serve PHP at a levelized baseline load level (i.e., the Customer's average demand will be assumed to be the same in each hour after taking into account major scheduled maintenance) to produce the CBL Energy Charge.

The CBL Energy Charge calculation will be inclusive of all incremental, non-capital costs to serve PHP and will assume no economic load shifting (e.g. no reductions in usage in high-cost hours or increased usage in low-cost hours). The CBL Energy Charge will include the forecast cost of fuel and purchased power, line losses, and variable operating costs for NS Power's incremental generation and delivery of electricity to PHP. The CBL Energy Charge will form the basis of the ELIADC Energy Charge for the upcoming calendar year.

A CBL Adder **(**CBLA**)** will be calculated with reference to the forecast CBL Energy Charge. As the forecast CBL Energy Charge ($/MWh) decreases, the CBLA increases.

- When the forecast CBL Energy Charge is under $61.75/MWh, the CBLA is calculated as 75 percent of the difference between the forecast CBL and $61.75/MWh, plus $1/MWh.
- When the forecast CBL Energy Charge is at or over $61.75/MWh, the difference between the forecast CBL Energy Charge and $61.75/MWh is assigned a value of zero and the CBLA is calculated as $1/MWh.

The CBL Energy Charge and the associated CBLA shall be submitted for Nova Scotia Utility and Review Board (Board) approval on an annual basis as part of the annual proceeding by which NS Power's Annually Adjusted Rates are established.

In addition to the CBL Energy Charge and CBLA, PHP will pay a Variable Capital Charge (VCC) for NS Power's incremental generation and delivery of electricity to PHP in the amount of $**1.13**/MWh.

In summary, the Tariff energy charge per MWh will be calculated as follows:

$$ELIADC\ Energy\ Charge = CBL\ Energy\ Charge + CBLA + VCC$$

INTRA-YEAR MODIFICATIONS TO THE CBL ENERGY CHARGE

NS Power will utilize its established forecasting methodology to determine the CBL Energy Charge. PHP will undertake commercially reasonable efforts to accurately forecast its energy usage.

If, during any year, certain circumstances, such as those described in the next paragraphs, change significantly resulting in a material impact on the appropriate CBL Energy Charge to be paid by PHP during the year, NS Power may, upon approval of the Board, revise the CBL Energy Charge on a prospective basis.

In recognition that the calculation of the CBL Energy Charge for 2020 may be materially impacted if there are delays to the start date of deliveries of the NS Block energy import beyond June 1, 2020, if NS Power determines that any such delay will have a material impact on the appropriate CBL Energy Charge to be paid by PHP for 2020, then the CBL Energy Charge will be subject to recalculation pursuant to this provision.

Additional circumstances which, if changed significantly, would warrant reassessment of the CBL Energy Charge could include, but are not limited to:

(a) It becomes apparent that the CBL Energy Charge plus the CBLA plus the Variable Capital Charge will not result in the recovery of the actual incremental cost to serve plus $4/MWh;

(b) Material and unexpected change in the cost of generation as compared to the CBL Energy Charge calculation;

(c) Material and unexpected increased electricity consumption by PHP during the year, such as significant physical plant modification (as signified by a specific capital expenditure beyond normal annual capital spending), a change in product line or a material non-forecast change in product demand; and

(d) Material and unexpected decrease in electricity consumption by PHP during the year (such as due to plant shutdowns, labour issues, or market downtime).

If PHP and NS Power are unable to agree on the required changes to the CBL Energy Charge as a result of any of the above modifications, the matter may be submitted to the Board by either party on an expedited basis for adjudication. Revisions to the CBL Energy Charge will not change the Minimum Payment to be made by PHP.

ACTIVE DEMAND CONTROL AND SCHEDULE VARIANCE

NS Power shall be entitled to actively manage PHP's load in accordance with the terms and conditions set out in the Active Demand Control – Energy Supply Protocol attached as Schedule 1 to this Tariff.

Annually, NS Power shall report to the Board to confirm the dollar value of system savings that have been achieved through Active Demand Control of PHP's load under the Protocol, taking account of the impacts of any variances by PHP from the dispatch schedules issued to it by NS Power and any adjustments arising from schedule variances if required. NS Power shall endeavor to submit this report no later than 60 days after the end of a tariff year.

PHP will be entitled to a credit equal to 25 percent of the cost differential between the CBL Energy Charge and the actual annual cost to serve PHP during the given tariff year. Such payments to the Customer will be made via an annual lump sum payment.

TERM

The initial term of this Tariff is 2020-2023 inclusive, unless revised per a Decision of the Nova Scotia Utility and Review Board (Term). Prior to the end of the initial term, NS Power or PHP may apply to the Board for approval of a subsequent term for this Tariff, including the approval of the pricing elements of the Tariff to be applied during the subsequent term.

REOPENER

If, at any time during the Term, NS Power or PHP determines that the ELIADC Tariff is not working effectively, the parties shall work together to try to resolve any such concerns. If the parties cannot resolve such concerns, either party may apply to the Board to adjust the Tariff, or the components thereof, on a prospective basis. If necessary, and to protect customers, the Board may grant such approval on an expedited basis. Following any adjustment, PHP would be provided the opportunity to determine whether to remain on the Tariff.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge is not applicable to PHP, and PHP will have no standing to participate in DSM-related proceedings.

FUEL ADJUSTMENT MECHANISM (FAM)

No FAM charges or credits shall be applicable to PHP, and PHP will have no standing to participate in FAM-related processes or proceedings unless it is proposed that a FAM-related charge be assessed against PHP or unless any such process or proceeding specifically deals with an issue that can directly impact on NS Power's incremental electricity costs.

MINIMUM LOAD REQUIREMENT

NS Power will withdraw the availability of this tariff, if, on a consistent basis, PHP is not maintaining a regular demand of 25,000 kVA.

INTERRUPTIBILITY

The Mill will reduce its load by, at a minimum, the amount requested by NS Power within 10 minutes of such request by NS Power. Following such interruption, service may only be restored by the Mill with the approval of NS Power.

PHP will make available suitable contact telephone numbers of a person or persons who are able to interrupt the required load within ten minutes.

Load interruption calls will be made to PHP in advance of all such calls to NS Power's Large Industrial Interruptible Rider customers. Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by NS Power, NS Power may hold this load as Operating Reserve as required by system conditions. When interruptions are required, NS Power will exercise the automated control of the customer's load to interrupt the customer load.

PHP is expected to comply with all calls for interruption. Failure to comply in whole or in part with a request to interrupt load will result in penalty charges, payable within 15 business days unless such penalty payment is being contested in good faith. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the amount of the applicable formula cost for energy taken under this Tariff effective at that time for the consumption used in the month.

The Performance Penalty which is based on PHP's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual demand (above that required by the interruption request) remaining in the third interval directly following two complete 5-minute intervals after the interruption call was delivered by telephone call.

"B" is PHP's average demand in excess of the compliance level based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A".

The total penalty will not exceed two times the cost of the formula amount, effective at that time for the consumption used in that month.

Should PHP fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should PHP desire to be served under any applicable firm service tariff, a five-year advance written notice must be given to NS Power so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by NS Power. NS Power may, however, permit an earlier conversion. If PHP desires to return to interruptible service in the future, PHP may convert to an interruptible service tariff following two years of service under the firm tariff schedule. NS Power may permit an earlier conversion from firm to interruptible service.

Order of Interruptibility

In the event an interruption call is required in order to avoid shortfalls in system electricity supply, interruptible load will be called upon to provide capacity to NS Power in the following order:

1. Generation Replacement and Load Following (GRLF) Tariff;
2. Extra Large Industrial Active Demand Control Tariff;
3. Shore Power Tariff;
4. Interruptible Rider to the Large Industrial Tariff.

In situations in which load of the customer under this Tariff is held as Operating Reserve, NS Power may change the above order of interruption by interrupting Large Industrial Interruptible Rider Tariff customers whose load is not held as Operating Reserve before interrupting the Customer.

MAINTAIN SYSTEM INTEGRITY

PHP will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

SECURITY FOR PAYMENTS

NS Power shall invoice PHP weekly, and PHP shall pay the billed amount net 7 days. As security for payment, PHP shall provide NS Power a letter of credit from time to time. The form, amount, and issuer of the letter of credit will be satisfactory to NS Power. To the extent that a letter of credit introduces a lag time and there are additional costs to NS Power, these will be paid by PHP not NS Power or its customers.

SEPARATE SERVICE AGREEMENT

NS Power reserves the right to have a separate service agreement if, in the opinion of NS Power, issues not specifically set out herein must be addressed for the ongoing benefit of NS Power and its customers.

POWER FACTOR CORRECTION

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total Mill load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the CBL Energy Charge:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

METERING COSTS

Metering will normally be at the low voltage side of the transformer and, for measurement and, where applicable, billing purposes, meter readings will be increased by 1.75%. Should the Mill's requirements make it necessary for NS Power to provide primary metering, PHP will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by PHP in connection with service under this Tariff shall be paid for by PHP as a capital contribution.

EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF

Part A – Definitions

ADC: Active Demand Control.

ADC Operating Procedure: Procedure document maintained by Nova Scotia Power System Operator (NSPSO) that describes the operation and usage of ADC for the NSPSO for Current Hour, Operating Hour 1 & Operating Hour 2.

CBL: Customer Baseline Load.

CBL & ADC Benefit Calculation: Process maintained by Nova Scotia Power (NS Power) to calculate the CBL Energy Charge, forecasted ADC benefit and actual ADC benefit.

Current Hour: The current hour of operation, which is only dispatchable by NSPSO.

Dispatchable Hours: All hours beyond Hour 2, as described (hour 3, 4 and beyond) in Section 4.3.10 of the NS Market Rules that are open for redispatch by NS Power.

Excess Energy: Generation which is in excess of the needs of the electric system and which cannot be stored.

Force Majeure: Any event or circumstance or combination of events or circumstances (including major equipment failure) that materially and adversely affects either party in the performance of its obligations in accordance with the terms of this Protocol, but only if and to the extent such events and circumstances are not within the affected party's reasonable control, and which the party claiming Force Majeure could not have prevented through reasonable skill and care.

Hour 1: The next hour, as described (hour 1) in Section 4.3.10 of the NS Market Rules. Dispatchable by NSPSO, and NS Power by exception only.

Hour 2: The next hour +1, as described (hour 2) in Section 4.3.10 of the NS Market Rules. Dispatchable by NSPSO, and NS Power by exception only.

Intra-Day Demand Schedule (ADC Schedule 4): An hourly demand profile that includes all Dispatchable Hours for a consecutive 24-hour duration. This will be provided by NS Power as a forecast to Port Hawkesbury Paper LP (PHP) and NSPSO for the upcoming period. NSPSO will confirm the schedule and only change dispatch if required for a change in system conditions.

Monthly Demand Schedule (ADC Schedule 1): A monthly, indicative, demand profile that includes a maximum and minimum demand profile for all months of the year, or all remaining months of the year if a system rerun is required. These forecasts will be performed annually and updated as required by NS Power. Refer to Part B. The results of these runs will be presented and shared with PHP as ADC Schedule 1.

NS Market Rules: Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules.

NS OATT: Nova Scotia Power Incorporated Open Access Transmission Tariff including the Standards of Conduct (Attachment E).

NS Power: Nova Scotia Power Groups – Fuels, Energy and Risk Management (FERM), Portfolio Optimization, Customer Solutions and any other non-System Operator Nova Scotia Power function.

NSPSO: Any Nova Scotia Power System Operator function.

Operating Mode Characteristics Schedule: The schedule referenced in Part D of this Protocol.

PHP: Port Hawkesbury Paper LP.

Seven Day Demand Schedule (ADC Schedule 3): An hourly demand profile produced and co-optimized as part of the system by NS Power each business day. The Seven Day Demand Schedule includes all Dispatchable Hours, starting 00:00 for the upcoming business day, for a 168-hour duration.

Tariff: The Extra Large Industrial Active Demand Control Tariff.

Weekly Demand Schedule (ADC Schedule 2): An annual, indicative, demand profile that includes a maximum and minimum demand profile for each week of the year or all remaining weeks of the year, if a system rerun is required. This will inform the development of the Seven Day Demand Schedule. These forecasts will be performed annually and updated as required by NS Power.

Part B – Protocol Forecasting and Operation

1. Annually, no later than the seventh business day of November, NS Power will forecast the Monthly Demand Schedule, Weekly Demand Schedule, and monthly and weekly limits based on PHP's demand forecast for the upcoming year (January 1 to December 31). The results of these forecasts will be published to PHP and NSPSO in ADC Schedules 1 & 2. As and when required during the year, NS Power will reforecast the Monthly Demand Schedule and Weekly Demand Schedule and update ADC Schedules 1 & 2. The values in ADC Schedules 1 & 2 will bound the daily forecast runs used to create the Seven Day and Intra Day Demand Schedules.

2. On a daily basis (non-statutory holiday weekdays), NS Power will provide PHP and NSPSO with a Seven Day Demand Schedule that is optimized as part of the NS Power system day-ahead planning process. PHP's demand will be co-optimized as part of the full NS Power portfolio. As part of this co-optimization:

   (a) With respect to forecast PHP annual capital shutdowns, PHP will provide a minimum of one month's advance notice of the timing and duration of the shutdowns; and
   (b) With respect to forecast PHP regular maintenance shutdowns, PHP will provide a minimum of seven days advance notice of the timing and duration of the shutdowns.

3. From time to time, a request may be made to PHP to adjust their daily demand from the Seven Day Demand Schedule in anticipation of significant events. An example of this would be a weather event that is forecasted. Such requests must fall within the agreed Operating Mode Characteristics Schedule and the ADC Operating Procedure.

4. Intra-Day, no later than the start of Hour 1, NS Power will provide PHP and NSPSO with an updated Intra-Day Demand Schedule when a dispatch change is required. This request will supersede the previously submitted requests.

5. If, during the Current Hour, Hour 1 and/or Hour 2, system conditions change unexpectedly such that they have a material impact (positive or negative) on system costs, NSPSO will contact PHP with a schedule change (an increase or reduction in demand) provided such changes fall within: the agreed Operating Mode Characteristics Schedule, the final communicated PHP shutdowns, and the ADC Operating Procedure. Otherwise the most recent schedule submitted by NS Power will be set as the hourly demand. This will represent the final demand schedule with any deviations tracked as a schedule variance.

6. As noted in the Tariff, if, during the current year, NS Power determines that there are significant adverse differences between the CBL Energy Charge (as defined in the Tariff) and the incremental costs of service, NS Power, with approval of the NSUARB, can adjust the rate on a prospective basis as provided for in the Tariff. In such circumstances, NS Power shall also update and communicate its expected forecast of ADC benefit for the remainder of the year.

7. NS Power, NSPSO and PHP will exchange the following information on a confidential basis through the methods described below:

   7.1. Intra-Day Demand Schedule (ADC Schedule 4) – NS Power;
   7.2. Seven Day Demand Schedule (ADC Schedule 3) – NS Power;
   7.3. Weekly Demand Schedule (ADC Schedule 2) – NS Power;

7.4. Monthly Demand Schedule (ADC Schedule 1) – NS Power;
7.5. Nova Scotia's Base load forecast – NSPSO;
7.6. Nova Scotia's aggregate wind forecast – NSPSO;
7.7. PHP pulp storage levels – PHP; and
7.8. PHP discrete line operation (i.e. what lines are in and out of service in a period) – PHP.

NS Power and PHP agree that, in order to (1) assist PHP to efficiently respond to any dispatch schedule changes that may be requested by NS Power and/or NSPSO in a manner that benefits the NS Power electric system, and (2) enhance collaboration between the parties when responding to unplanned system changes, NS Power will provide PHP with access to certain system information. On an automated basis, NS Power will provide PHP with information in respect of its system demand and the aggregation of generation types (specifically coal, gas, oil, combustion turbines, imports and hydro) as a snapshot of the current system condition. PHP agrees that such information is to be used exclusively for the foregoing purposes. During any period in which this data is unavailable due to technical issues, PHP will refer to the https://www.nspower.ca/en/home/about-us/todayspower.asp until NS Power is able to re-establish the provision of this data on a timeline that is reasonable, given NS Power's other business priorities. Any use of the data for purposes beyond operational preparedness can result in the suspension of the data sharing.

8. On an annual basis, NS Power will calculate the actual ADC benefit consistent with the CBL & ADC Benefit Calculation.

Part C – Conditions

9. Subject only to reasons of health, safety, environmental, system reliability, and Force Majeure events, PHP must not deviate from the NS Power/NSPSO final demand schedule. NS Power/NSPSO must comply with the weekly demand requirements as determined by the Weekly Demand Schedule. In the situation where the Weekly Demand Schedule requirements are not complied with, NSP/NSPSO will work collaboratively with PHP to address the discrepancy.

10. Following any health, safety, environmental, system reliability, or Force Majeure event, PHP and NS Power will use commercially reasonable efforts to restore their applicable operation to normal as soon as possible and without undue delay. In such circumstances, PHP will advise NS Power as soon as possible of any change in availability of PHP's operating modes to allow NS Power to adjust its dispatch schedules accordingly. PHP and NS Power will maintain, as a minimum, hourly contact with each other in the hours following Force Majeure events to keep each other aware of the other's status.

EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF

11. In the case of NS Power or PHP's inability to follow the dispatch plan that triggers one of the circumstances as set out in Appendix 1, the timing, magnitude, and reason for the deviation will be tracked and noted by NS Power/NSPSO. This Appendix may be updated by agreement between NS Power and PHP if other circumstances arise that require variances from the scheduled dispatch to be tracked. Updates to this Appendix will be filed with the NSUARB.

12. Subject to available generation or load, as the case may be, efforts will be made to reconcile variances in a timely manner, including by NS Power and PHP mutually agreeing to deviate from the previously agreed Operating Mode Characteristics Schedule, with the goal of achieving similar system costs and service to the Mill as would have been achieved if the original dispatch had been followed.

13. The overall impact on system costs (if any) for the tracked deviations will be initially estimated on a quarterly basis, and assessed at the end of the year by NS Power. If a cost is determined, the ADC credit payment to PHP will be adjusted accordingly.

14. PHP, NS Power and NSPSO shall maintain a scheduling and/or operations team available to each other on a continuous 24 hour, 7 days a week basis.

15. PHP's scheduling and operations team shall be empowered with the authority to acknowledge and adjust PHP's demand on behalf of PHP for the supplied Demand Schedule.

16. This Protocol does not supersede any requirement or obligation as defined in both the NS OATT (including the Standards of Conduct) and NS Market Rules. If a change to either NS OATT and/or NS Market Rules occurs, this Protocol will be updated to reflect any changes, if applicable.

17. For the purposes of planning, PHP will provide NS Power and NSPSO with its expected annual capital outage timing. This data will be provided in a timely manner, to be included in the NS Power/NSPSO annual planning process. The parties will work collaboratively to co-optimize the timing of PHP outages to provide the best fit for the system while respecting PHP's limitations and requirements consistent with Part B, section 2.

18. All energy dispatch decisions as they relate to system demand will be performed at the sole discretion of NS Power and/or NSPSO. This includes, but is not limited to, generation dispatch levels, unit commitments, outage planning and/or import/export energy.

19. The dispatch of PHP demand level will be performed by NS Power and/or NSPSO and must fall within the agreed Operating Mode Characteristics Schedule and the ADC Operating Procedure.

Part D – Operating Mode Characteristics Schedule

For the purpose of planning, dispatch and forecasting, PHP's loading levels will be separated into 9 distinctive operating modes. Only one mode will be able to operate at any given time.

The Operating Mode Characteristics Schedule will include (i) maximum and minimum, up and down time of each operating level, (ii) mill ramp rates, (iii) mill outages planning, (iv) pulp storage levels, and (v) individual line operating modes. This Schedule will be used in the preparation of the demand schedules, the calculation of the CBL incremental cost and the overall ADC benefit achieved as a result of the dispatch of PHP's load. NS Power and NSPSO will be required to dispatch PHP's load consistent with the Operating Mode Characteristics Schedule, including the maximum and minimum limits in ADC Schedules 1 & 2.

This schedule will also contain the maximum and minimum amounts of Annual, Monthly and Weekly energy requirements.

The Operating Mode Characteristics Schedule will be initially developed by PHP in consultation with NS Power and can be changed from time to time by agreement of PHP and NS Power.

Appendix 1

Circumstances in which Variances from Scheduled Dispatch Will Be Tracked

The variance from the scheduled dispatch results in:

- A change in NS Power unit commitment(s)
- A need for NS Power to rebalance a fuel position
- The redispatching of generation from Wreck Cove
- A reduction in the value of an NS Power export or import opportunity
- A condition of Excess Energy
- NS Power/NSPSO is forced to dispatch PHP outside the Operating Mode Characteristics Schedule

An Assessment of Nova Scotia Power's Proposed Extra Large Industrial Active Demand Control Tariff

PREPARED FOR

Nova Scotia Power, Inc.

PREPARED BY

Ahmad Faruqui

Ryan Hledik

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I. Introduction

Nova Scotia Power ("NS Power") is proposing to introduce a new tariff, known as the Extra Large Industrial Active Demand Control ("ELIADC") Tariff for its largest customer, Port Hawkesbury Paper ("PHP"). PHP accounts for approximately 10% of system load.

The ELIADC tariff, by providing greater control to NS Power over PHP's load, will provide NS Power with improved system flexibility, which is going to become increasingly important as a means of effectively integrating intermittent renewable generation resources once renewable energy imports become a bigger part of the resource mix in the province, displacing existing fossil fuel based generation. NS Power forecasts that the improved load flexibility enabled by the ELIADC tariff will lead to overall system cost savings which cannot be achieved under the existing PHP Load Retention Tariff (LRT).

In this report, we provide an assessment of NS Power's proposed ELIADC tariff. First, we present our understanding of the key features that differentiate the proposed ELIADC tariff from the existing LRT and explain the advantages of the ELIADC tariff. Second, we discuss an emerging industry trend toward "load flexibility" programs similar to the ELIADC tariff. Third, we conclude with our assessment of the ELIADC tariff.

II. Overview of the ELIADC Tariff

Under the LRT, PHP pays NS Power the sum of:

1. The hourly incremental cost of electricity
2. Incremental operating and capital costs of providing service to PHP
3. A contribution to utility fixed costs

The LRT also includes elements of an "interruptible tariff," which allows NS Power to interrupt PHP's load when system reliability is threatened.

NS Power has proposed to replace the LRT with the new ELIADC tariff to improve the value of the tariff to the NS Power system. The ELIADC tariff gives NS Power direct control over PHP's load. NSP forecasts that direct load control will yield greater benefits to NS Power's other customers through reduced system costs. The new tariff also provides PHP with more price certainty, in the form of a flat rate. Key differences between the current LRT and the proposed ELIADC tariff are summarized in Table 1.

Table 1: Key Differences between LRT and ELIADC Tariff

	LRT	ELIADC Tariff
Load control	PHP is a Priority Interruptible customer during periods of system constraint During non-system-constrained periods, customer responds to price signals at its discretion	PHP is a Priority Interruptible customer during periods of system constraint During non-system-constrained periods, Daily/Hourly operating schedule provided by NS Power to PHP
Price signal	Hourly prices forecast on a Day Ahead and Real Time basis and finalized through ex post analysis of marginal system costs	Flat price, based on one-year forecast of cost of serving PHP's load
Fixed cost recovery	Under the LRT, PHP contributes to a portion of the fixed costs as determined in the tariff	PHP pays a larger share of costs than under the LRT

Benefits to other customers	PHP costs are reduced through PHP's load flexibility in response to realtime energy prices. Benefit of the LRT to other customers is limited to PHP's contribution to fixed costs.	The reduction in overall system costs resulting from control of PHP's load will be calculated by NS Power. PHP receives 25% of the cost savings. The remaining 75% will accrue to all other customers.
Shut down days	PHP schedules their own shutdown days, without accounting for NS Power system needs.	A portion of forecasted shutdown days will be scheduled collaboratively to maximize benefit to the overall system.

PHP has provided NS Power with a set of nine operating modes for system modeling purposes. These operating modes consist of combinations of three production lines, bleacher plant, and the paper machine, each of which come with specific load profiles and specific constraints on minimum and maximum operating hours. NS Power will schedule PHP's operations, choosing from the specified operating modes and respecting the constraints, to optimize system operations in the presence of intermittent renewable energy resources and high levels of import energy.

NS Power will perform this scheduling each business day, generating a load profile for the following week. Additionally, NS Power (through the Nova Scotia Power System Operator) can request changes hour by hour if system conditions change. During periods of supply shortfalls, NS Power can interrupt PHP's load on a priority basis. This scheduling, which is analogous to day-ahead and hour-ahead scheduling in deregulated energy markets, allows NS Power to build load when there is wind generation and minimize load when there is not. The timeframes of the agreement allow for quick adjustments if, for example, wind forecasts are proven to be incorrect. This scheduling flexibility is expected by NS Power to allow the utility to effectively lower costs relative to the current LRT. NS Power will be able to optimize its system to avoid the curtailment of non-dispatchable renewables and reduce load during the times of day when the cost of serving load is otherwise high. Alternatively, under the present LRT arrangement, PHP is allowed to run the plant as needed to finish production runs.

A transparent method is being used to define PHP's baseline energy consumption (i.e., consumption in the absence of the ELIADC tariff). The baseline is defined as a flat load profile, with full-day outages. By using the flat baseline, NS Power's methodology is transparent and minimizes administrative overhead.

NS Power will calculate the system cost savings attributable to the ELIADC tariff through a year-end comparison of the flat baseline and PHP's actual load under ADC in each hourly interval. The difference between these two load profiles will be valued at the actual system marginal cost in each hourly interval. Following the assessment of ADC benefit to the system, 25% of these benefits will be provided to PHP in the form of an incentive payment, with the remaining 75% of the accrued benefit remaining with other customers. According to NS Power's calculations, the system-wide cost reduction attributable to the ELIADC tariff, relative to the flat baseline, is expected to average approximately $10 million per year over the period from 2020 through 2023.

It is important to note that, while the currently applicable LRT also provides cost savings to PHP through load shifting, higher savings are expected by NS Power to be realized for all customers under the proposed ELIADC tariff. Under the LRT, revenues from PHP have exceeded the costs of serving PHP by approximately $3 million per year. Under the ELIADC tariff, revenues from PHP are expected to exceed fuel costs by $6 to $13 million per year. Based on NS Power's calculations, net revenues are expected to be higher under the ELIADC tariff due to greater cost savings associated with NS Power's improved control over PHP's load around-the-clock.

III. The Industry Trend Toward Load Flexibility

NSP's proposed ELIADC tariff is consistent with a broader industry trend toward an increased emphasis on load flexibility. A recent Brattle assessment of the U.S. potential for cost-effective load flexibility programs identified three factors that are leading to increased interest in programs similar to NS Power's ELIADC tariff:

1. Growth in renewable energy resources
2. Grid modernization
3. Electrification

These issues, and their relevance to the need for load flexibility, are summarized in Figure 1.

Figure 1: Industry Mega-Trends Contributing to the Need for Load Flexibility[1]

Mega-trend	Challenges	Load Flexibility Solution
Renewables growth	• Low net load leads to renewables curtailment and/or inefficient operation of thermal generation • Intermittency in supply contributes to increased need for grid balancing	• Electricity consumption can be shifted to times of low net load • Fast-responding demand response can provide ancillary services
Grid modernization	• Costly upgrades are needed to improve resiliency and accommodate growth in distributed energy resources	• Geographically-targeted demand response can help to defer capacity upgrades
Electrification	• Rapid growth in electricity demand may introduce new capacity constraints	• Controlling new sources of load can reduce system costs while maintaining customer comfort and adding value to smart appliances and electric vehicles

A recent study by the Smart Electric Power Alliance (SEPA) also highlights the industry transition toward a new, more flexible form of demand response (DR). The SEPA study surveys annual DR developments across North America and internationally. According to the study, "DR is playing a growing role in helping to balance fluctuations in energy production in areas with high levels of renewable generation (e.g., reverse DR and load shifting pilot measures)."[2]

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1 Ryan Hledik, Ahmad Faruqui, Tony Lee, and John Higham, "The National Potential for Load Flexibility," The Brattle Group report, June 2019. https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf

2 SEPA, "2018 Utility Demand Response Market Snapshot," September 2018, page 11.

Among commercial and industrial (C&I) customers, the SEPA study notes that automated load control accounts for a significant share of the segment's total DR capacity. The study specifically highlights a cutting-edge program being offered by HECO in Hawaii, through which automated load reductions can be achieved with short notice. The program is similar to the ELIADC tariff both in terms of the short response time and the options available to the utility for controlling customer load.[3] HECO received regulatory approval in 2017 to increase the size of this pilot project from 0.2 MW to 5 MW on Maui (with an additional 7 MW on Oahu), signaling success with the program.

Similar programs being offered by utilities in other jurisdictions also share common elements with the ELIADC tariff. In California, the three investor-owned utilities, PG&E, SCE, and SDG&E, each offer eligible commercial and industrial customers incentives of up to $200 per dispatchable kilowatt of demand for the purchase and installation of automated demand response measures. Once installed, those measures can connect to and control lighting, air conditioning/heating units, and temperature controls.[4] Customers may then earn additional incentives for energy savings during demand response events.

NS Power's ability to utilize the ELIADC tariff to *increase* load during times of renewables curtailment is also a program characteristic that has been observed in utility offerings in other jurisdictions. In Great Britain, National Grid (the electric system operator) recently implemented a Demand Turn Up (DTU) program. The DTU program pays large energy users to increase demand (through load shifting) during times of high renewable output when net demand is low.[5]

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3 Hawaiian Electric, "Fast Demand Response," https://www.hawaiianelectric.com/products-and-services/demand-response/fast-demand-response.

4 SCE, "Automated Demand Response," https://www.sce.com/business/savings-incentives/automated-demand-response-with-open-adr; PG&E, "Automated Demand Response Program Fact Sheet," https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/fs_autodr.pdf; San Diego Gas & Electric, "Technology Incentives," https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response/technology-incentives.

5 National Grid ESO, "Demand Turn Up," https://www.nationalgrideso.com/balancing-services/reserve-services/demand-turn.

IV. Conclusion

Conceptually, the ELIADC tariff offers a number of advantages over the current LRT. The ELIADC tariff provides NS Power with greater control over PHP's load-around-the-clock. This is expected to yield greater system cost savings and better align with NS Power's operational needs in an environment of growing renewables adoption and a significant shift to imported energy. Additionally, the ELIADC tariff provides an explicit savings sharing mechanism which ensures that the majority of the cost savings – 75% – associated with this improved load flexibility will accrue to other customers.

NS Power's proposal is well aligned with an emerging industry trend toward developing customer offerings that increase load flexibility. Elements of NS Power's proposal – such as the operational capability to increase load to avoid renewables curtailments while maximizing energy imports, and the control of end uses with short notice – have been observed in other programs recently introduced in other jurisdictions. Based on this consistency with industry practice, and the distinct advantages of the ELIADC tariff relative to the current LRT offering, we expect NS Power's proposed ELIADC tariff will create significant value for all NS Power customers.

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NS Power ELIADC Tariff Application Appendix C has been removed due to confidentiality.

NS Power ELIADC Tariff Application Appendix D has been removed due to confidentiality.

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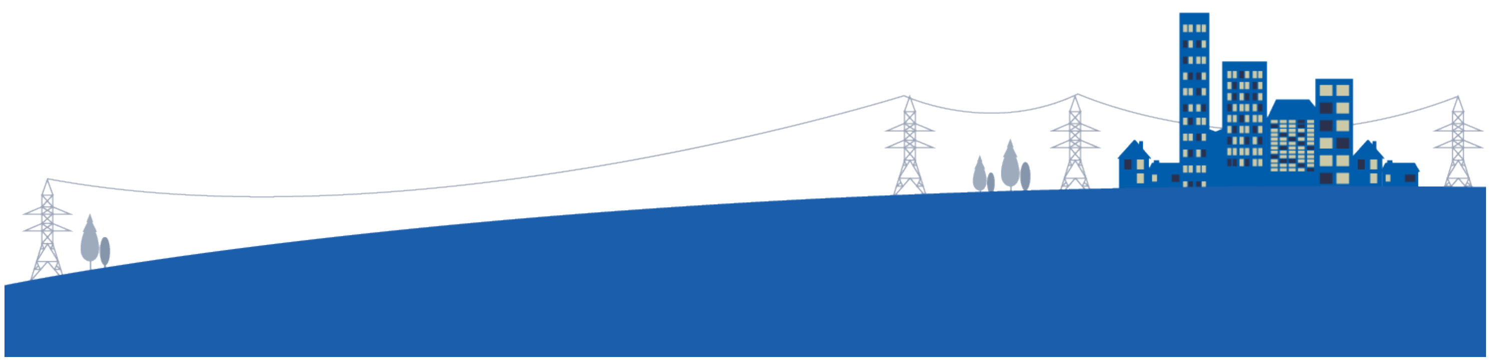
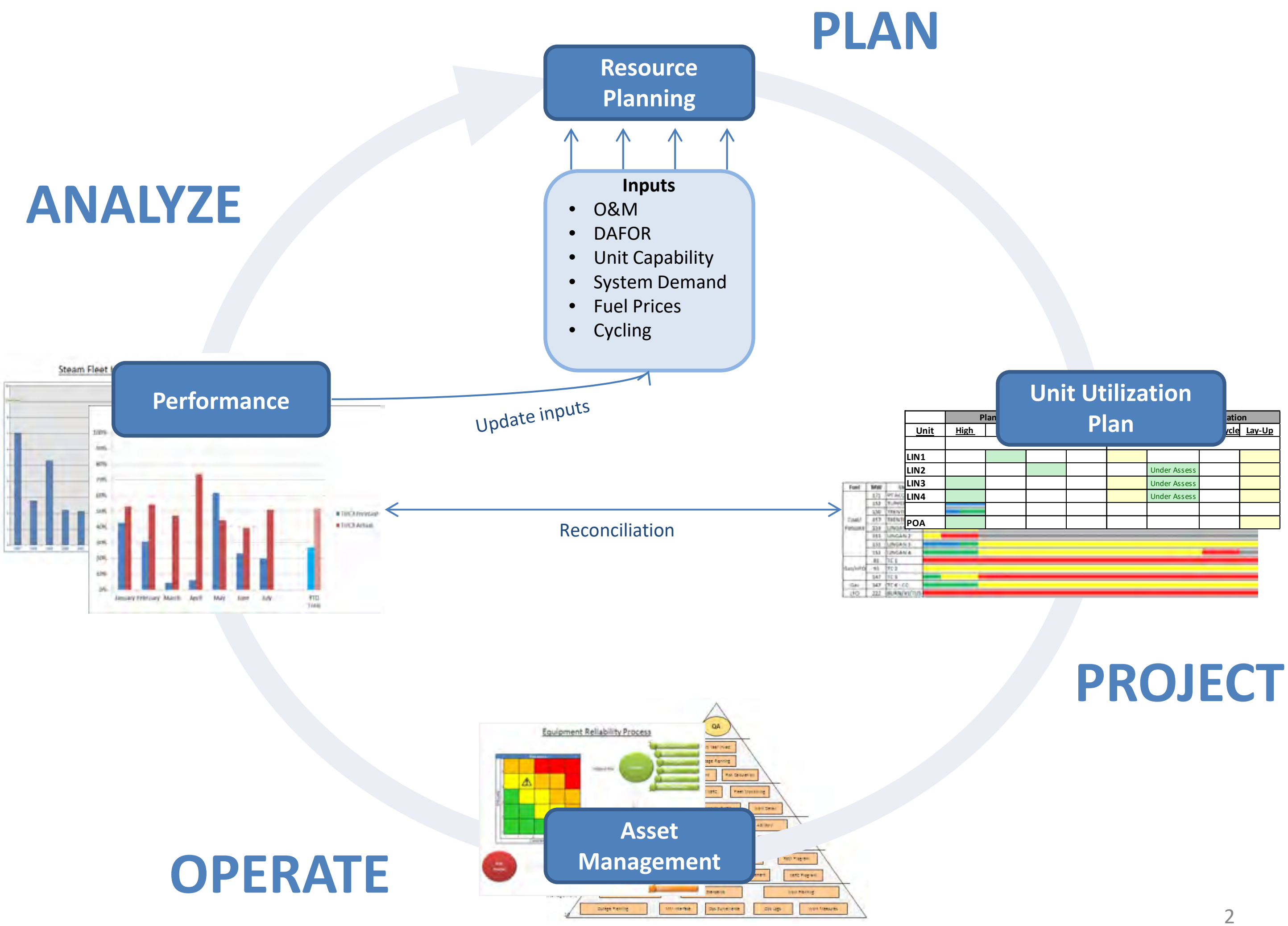
Extra Large Industrial Active Demand Control Tariff Variable Capital Charge

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• DAFOR
• Unit Capability
• System Demand
• Fuel Prices
• Cycling
ANALYZE
Performance
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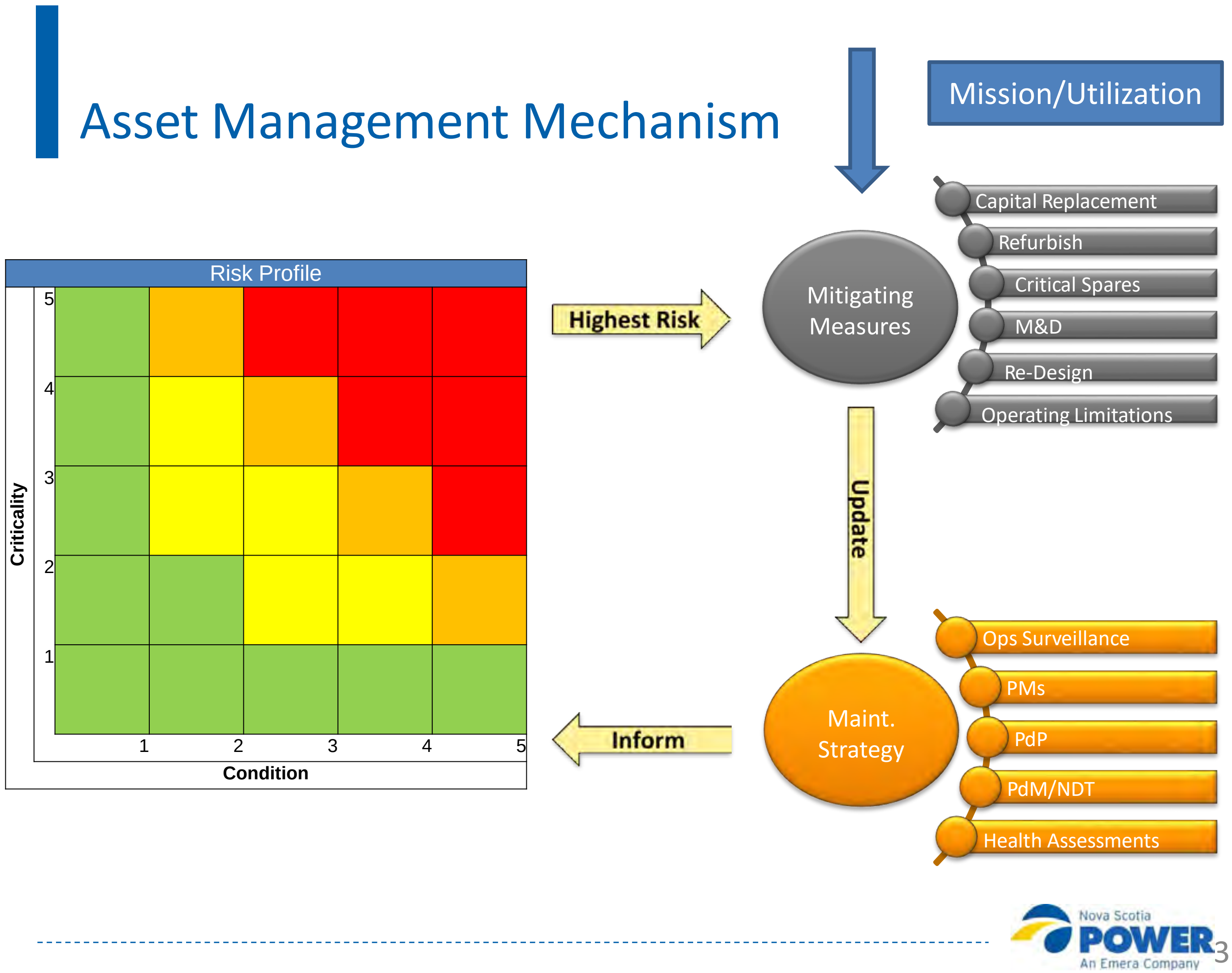
Unit Utilization Plan
Reconciliation
PROJECT
OPERATE
Asset Management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2
3
4
5
Highest Risk
Mitigating Measures
Capital Replacement
Refurbish
Critical Spares
M&D
Re-Design
Operating Limitations
Update
Maint. Strategy
Ops Surveillance
PMs
PdP
PdM/NDT
Health Assessments
Inform
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3

Incremental Capital Calculation: Method and Result

- Significantly impacted units identified
- Change in utilization factor (UF) determined
- Duration of impact determined over the 4 year period(2020-2023)
- Incremental cost analysis conducted
  - Investments influenced by incremental utilization
    - 8 primary categories identified across the units with incremental utilization with PHP
      - Boiler
      - Circulating Water
      - Environment & Emissions
      - Fuel Systems
      - Feedwater Systems
      - Generator
      - Turbine
      - Combustion Turbines
- Associated investment prorated by change in utilization

Incremental Capital Calculation: 2017 Method vs 2019 Method

The decrease from the previous model is due to utilization of thermal fleet remaining materially unchanged with and without PHP. However there is increased utilization on the more flexible generation units of TUC4,5,6 and Biomass. See slide 11 for detailed UF comparisons.

Item	Value
PHP Variable Capital Cost (2020-2023)	$ 5,100,063
PHP Load Est. (2020-2023)	4,528,000
Proposed PHP VC / MWh	$ 1.13
Current Variable Capital Charge (LRT)	$ 1.39
Proposed VCC Change	$ (0.26)
ELIADC Annual Forecasted Load	1,132,000
Forecasted ELIADC Impact / Year	$ (294,320)

Other considerations:
It should be noted that investment in power plants is not homogeneous from year to year. Investment intervals vary by asset class and are typically many years. As a result, some variation should be expected when assessing different periods

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Unit Utilization – Utilization Factor

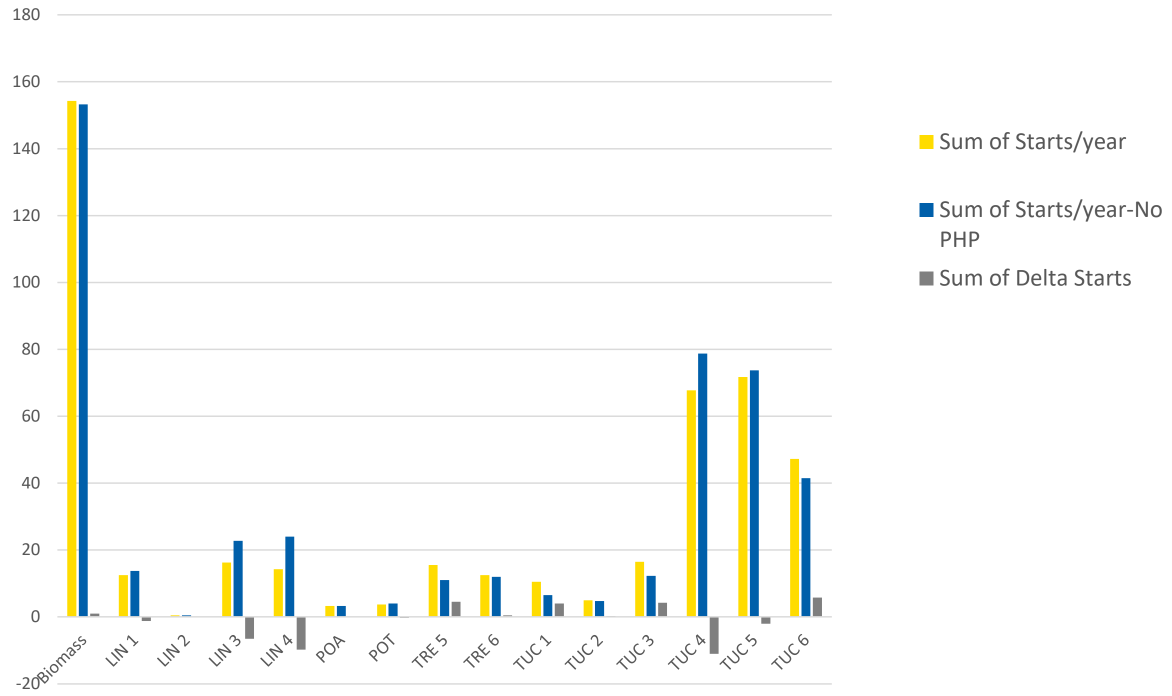
- Traditionally capacity factor was used to estimate future demand on units
- Given increasing renewables and required flexibility, necessary to also consider the effects of unit starts, operating hours, and unit health

$$U^{\text{tilization}}_{F^{\text{actor}}} = fn\left\{ \boxed{\text{Capacity Factor}} \ \boxed{\text{Service Hours}} \ \boxed{\text{Cycles}} \ \boxed{\text{Asset Health}} \right\}$$

Unit Utilization – Utilization Factor Criteria

UF	Cost Factor	Unit Starts	Op Hours	CF
H	1.00	>50	>5000	>75
M	0.75	21-50	2500-5000	50-75
L	0.50	0-20	1000-2500	25-50
UL	0.25		0-1000	<25

Delta Starts



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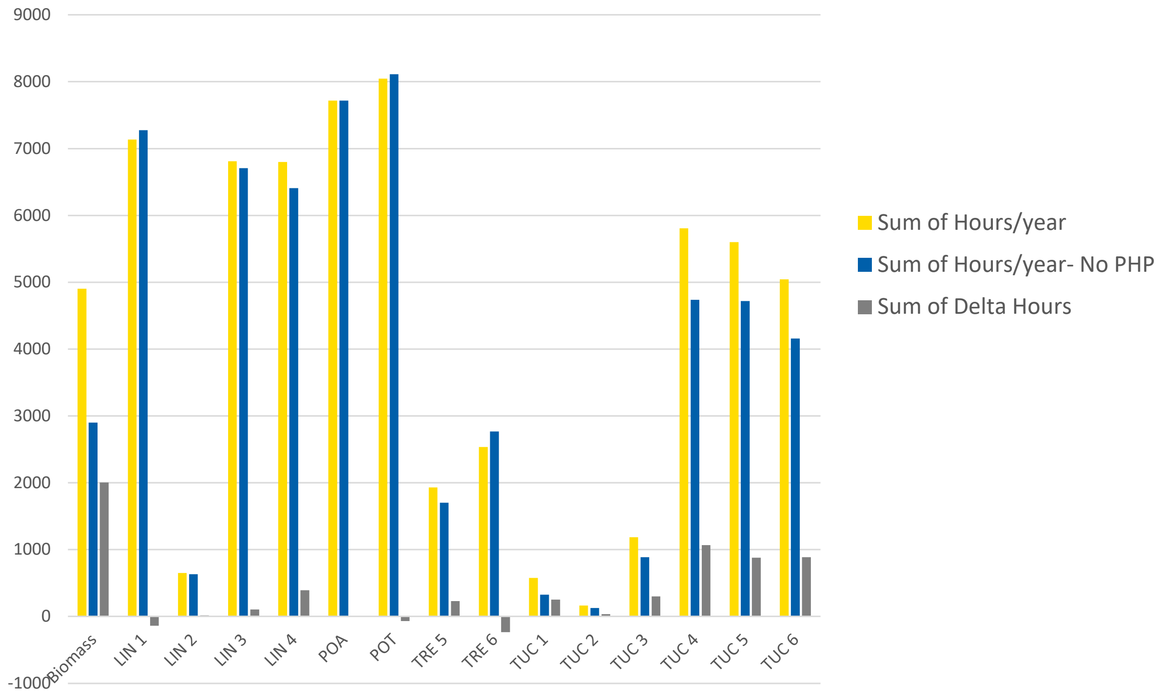
Delta Operating Hours



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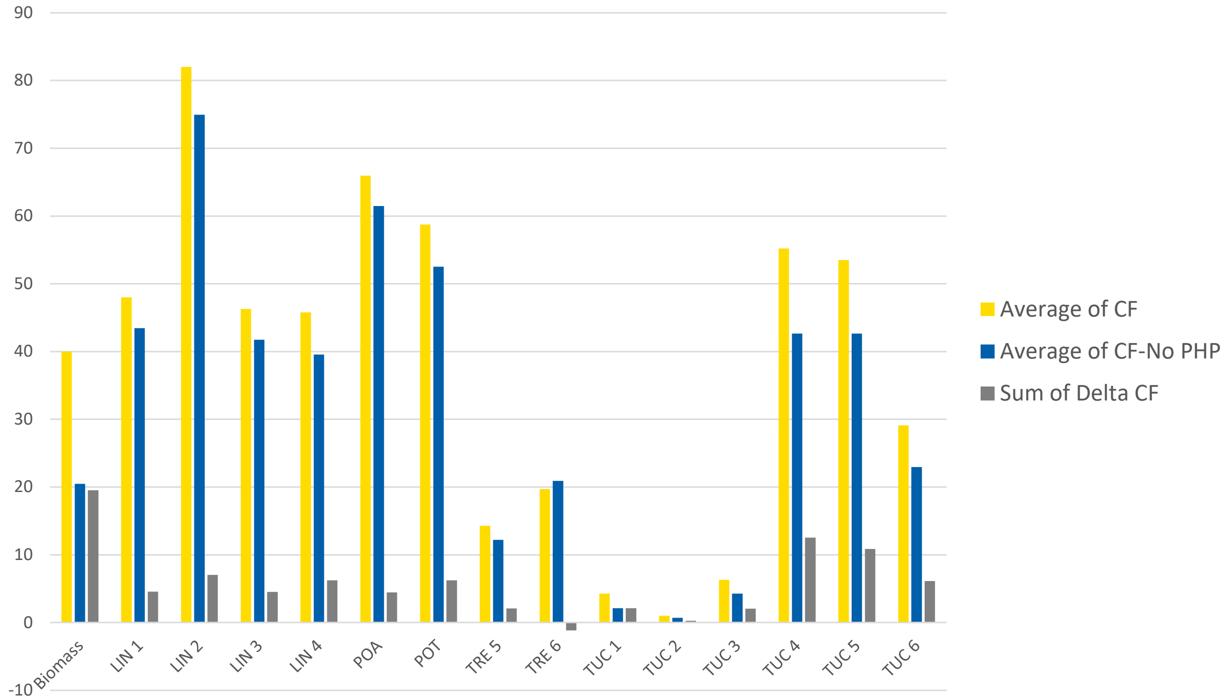
Delta Capacity Factor



Unit Utilization Summary 2020-2023

Unit	CF	Starts/year	Hours/year	UF	CF-No PHP	Starts/year-No PHP	Hours/year-No PHP	UF-No PHP	UF Delta	Sustaining Capital Delta
LIN 1	48.00	13	7135.5	High	43.45	14	7274.25	High	0	
LIN 2	82.00	1	650	High	74.96	1	632	High	0	
LIN 3	46.30	16	6810.25	High	41.76	23	6706	High	0	
LIN 4	45.80	14	6800.25	High	39.57	24	6407.25	High	0	
POT	58.75	4	8045.5	High	52.51	4	8113.75	High	0	
POA	65.96	3	7719.25	High	61.50	3	7719.25	High	0	
TRE 5	14.30	16	1932.25	Low	12.20	11	1703.5	Low	0	
TRE 6	19.73	13	2534.5	Med	20.90	12	2768	Med	0	
TUC 1	4.26	11	576.5	Low	2.13	7	324.5	Low	0	
TUC 2	1.00	5	163.75	UL	0.72	5	128.75	UL	0	
TUC 3	6.31	17	1184.5	High	4.27	12	885.75	High	0	
TUC 4	55.20	68	5805.5	High	42.67	79	4737.75	Med	-0.25	$ 1,625,000
TUC 5	53.50	72	5601.5	High	42.64	74	4720.25	High	0	
TUC 6	29.09	47	5042.75	High	22.96	42	4157.5	Med	-0.25	$ 1,263,275
Biomass	40.00	154	4905.25	High	20.47	153	2900	Med	-0.25	$ 2,211,788
										$ 5,100,063

Variable Capital Investment Summary Delta

	Asset Class	Investment with PHP	Investment w/o PHP	Delta
Biomass	Boiler	$ 4,225,000	$ 3,168,750	$ 1,056,250
	CW	$ 464,750	$ 348,563	$ 116,188
	Env&Emiss	$ 1,183,000	$ 887,250	$ 295,750
	Fuel Systems	$ 1,791,400	$ 1,343,550	$ 447,850
	FW	$ 676,000	$ 507,000	$ 169,000
	Generator	$ 169,000	$ 126,750	$ 42,250
	Turbine	$ 4,238,000	$ 4,153,500	$ 84,500
TUC 4	Combustion Turbine	$ 13,000,000	$ 11,375,000	$ 1,625,000
TUC 6	Boiler	$ 1,402,700	$ 1,052,025	$ 350,675
	Env&Emiss	$ 1,521,000	$ 1,140,750	$ 380,250
	Fuel Systems	$ 101,400	$ 76,050	$ 25,350
	FW	$ 1,352,000	$ 1,014,000	$ 338,000
	Turbine	$ 1,726,000	$ 1,557,000	$ 169,000
			Total Capital Delta	$ 5,100,063

Note: This comparative analysis includes the investment items that are only affected by unit utilization

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Schedule "A"

RNLW

DEMAND CHARGE

To be determined as specified in Special Condition (1).

ENERGY CHARGE

To be determined as specified in Special Condition (1).

AVAILABILITY

(1) This rate shall be granted only in circumstances where it can be shown that:

- The customer's option to use a supply of power and energy (alternate supply) other than NSPI's is both technically and economically feasible, or the rate is required to respond to the competitive challenge of business closure due to economic distress; and

- Retaining the customer's load, at the price offered by this rate, is better for other electric customers than losing the customer load in question; and

- The revenue from service to a customer under this rate shall be greater than the applicable incremental cost to serve such customer and shall make a significant positive contribution to fixed costs.

The procedure for establishing that this test is satisfied is outlined in Attachment A.

(2) This rate shall be available only to customers who have a minimum load of and/or who are considering an alternate supply of at least 2000 KVA or 1800 KW. Where the rate is required to respond to the competitive challenge of business closure due to economic distress this rate shall be available only to Extra-Large Industrial customers.

(3) The customer shall apply in writing to take service under this rate.

(4) This rate shall be available only to customers whose electricity needs, at the date of application, are being supplied by NSPI and have been supplied by NSPI for at least two consecutive years at the time of the request. It is not available for new load.

MINIMUM LOAD REQUIREMENT

All customers must agree to maintain a minimum level of load while taking service under the rate, subject to (i) any terms or conditions relating to supply interruption that may be outlined in the pricing conditions of the rate, (ii) the customer's requirement to take downtime for maintenance purposes and (iii) market downtime, labour disruption and other matters beyond the reasonable control of the customer.

SECURITY FOR PAYMENT OF ACCOUNT

A customer taking service under this rate must provide security for payment of the customer's account, regardless of payment history. Appropriate security shall be satisfactory to Nova Scotia Power Inc. Acceptable security will be described in the pricing of the rate, and may be revised or updated from time to time upon approval of the UARB.

DISCONNECTION OF ELECTRIC SERVICE

In the event of non-payment, NSPI may disconnect a customer on two business days' notice. In the event of a dispute under the tariff, the complaint will be made directly to the Board for resolution, as opposed to the Dispute Resolution Officer.

SPECIAL CONDITIONS

(1) The price, terms and conditions (including any modification in special conditions associated with the rate(s) under which the customer purchased power and energy prior to taking service under this rate) shall be established jointly by NSPI and the customer, following the procedure outlined in Attachment A.

(2) The price, terms and conditions offered under this rate shall be determined on a customer by customer basis.

(3) The price, terms and conditions offered under this rate shall be submitted by NSPI to the UARB for approval.

ATTACHMENT A

This attachment outlines procedures by which the requirements of Availability Clause (1) and Special Condition (1) are to be satisfied.

(1) The customer shall apply in writing to take service under this rate, outlining the available alternate supply option or the potential for closure due to economic distress and the rationale for seeking service under the load retention rate.

(2) Upon written application by a customer to take service under this rate which meets the requirements of clause (1) above, the UARB shall direct that NSPI conduct a screening to determine whether the implementation of these procedures is warranted.

(3) Subject to (2), NSPI and the customer shall proceed to implement these procedures and establish a load retention price, with appropriate terms and conditions.

(4) Should there be disagreement between NSPI and the customer with respect to the decision to proceed, the customer may ask the UARB to adjudicate.

(5) These procedures shall be applied on a customer by customer basis.

(6) To protect confidential NSPI and customer data, none of the data or analysis used in the implementation of these procedures, nor any results thereof, including the recommended price, terms and conditions, shall be required to be publicly disclosed.

(7) The economic feasibility of the customer's option to supply some or all of its own load shall be established where it can be shown that under reasonable assumptions the cost of electricity to the customer from that option is expected to be lower than the cost to the customer of continuing to purchase electricity from NSPI.

(8) The cost to the customer of the alternate supply shall reflect all appropriate factors, including but not limited to:

- Capital costs
- Fixed and Variable Operating costs
- Fuel costs (short and long term, contracts, etc.)
- Ancillary Services costs (electric)
- Steam production and steam backup costs (where appropriate)
- Contributions-in-aid of construction (where NSPI's system must be modified to accommodate the customer's generator)
- Expected Service Life

- Salvage Value
- Electric sales/purchases (where the customer's generator output does not match customer requirements)
- Depreciation and/or Capital Cost Allowance
- Taxes
- Appropriate return

(9) The technical feasibility of the customer's alternate supply shall reflect all appropriate factors, including but not limited to:

- Technology maturity and proven performance level
- Site specific considerations (space requirements, availability of cooling water, fuel handling, etc.)
- Environmental acceptability (air emissions, solid waste management, etc.)
- Modifications to NSPI's transmission and/or distribution system to accommodate the new generation and/or to supply ancillary services.
- Metering systems
- Where cogen is involved, compatibility of steam versus electric requirements.

(10) If the customer is applying for a load retention rate on the basis of economic distress, the customer shall provide NSPI and the UARB proof of economic distress, the adequacy of which shall be determined by the UARB prior to approving any proposed rate, including:

- Current and historical financial information for a minimum of at least three (3) fiscal years of the customer
- Evidence of activities undertaken by the customer in the last three (3) years to reduce costs
- Affidavit of a senior executive of the customer or its parent indicating the need for the requested load retention rate. Whether the affidavit is provided by an executive of the customer or the parent must be consistent with whether it will be the customer or parent who will make the decision to leave NSPI's system in the absence of the load retention rate. Further the affidavit should include
    - An analysis of the market in which the customer operates
    - Identification of the factors other than electricity costs that are contributing to the economic hardship
    - The customer's plan to address the above factors
    - An estimate of the electricity price that could alleviate the economic hardship
    - An estimate of the probability that the customer will leave NSPI's system if the requested load retention rate is not granted

- Such other information as reasonably requested by NSPI or the UARB.

(11) The impact on NSPI's other customers of losing the customer load in question, shall be determined using NSPI's forecasting and planning models (as appropriate) to compare scenarios that include either the customer's move to an alternate supply or cessation of operations, as the case may be, with scenarios that assume the customer continues to be supplied by NSPI.

(12) Where the impact on NSPI's other customers can be mitigated by offering the customer in question a load retention rate, NSPI and the customer shall determine an appropriate rate for the customer. This shall include the price (which may be formula-driven), and any other terms and conditions, including (where relevant) a suggested term and any appropriate renewal guidelines.

AVAILABILITY:

1. This Load Retention Tariff Pricing Mechanism ("Mechanism") is available only to a partnership (referred to as "PHP") a limited partner of which is Port Hawkesbury Paper Inc., and which shall operate the Port Hawkesbury paper mill ("Mill") and shall be the customer on the rate.

2. The service voltage shall not be less than 138kV, line to line, at each delivery point. Service is provided at the supply side of the Mill's transformation equipment. PHP must own the transformation facilities and no transformer ownership credit is applicable.

3. PHP shall reduce its electrical load in accordance with the provisions for load reduction below.

4. The term of the arrangements contemplated by this Mechanism shall be from approval by the Utility and Review Board (the "Board") to December 31, 2019.

5. This Mechanism cannot be taken in conjunction with other Tariffs unless approved by the Board.

MECHANISM:

The intent of this rate is to create a mechanism whereby PHP pays the variable incremental costs of service, plus a significant positive contribution to fixed costs, such that other customers are better off by retaining PHP rather than having PHP depart the system and make no contribution to fixed cost recovery.

REOPENER:

Should PHP's contribution to fixed cost be less than $20 million after five full fiscal years of operation under this Mechanism, the Mechanism will be re-opened to provide an opportunity to adjust the cost components for the final two years. PHP will have the discretion to make additional contributions in 2017 to ensure that a contribution to fixed costs of $20 million is made over the 2013 to 2017 period. If any adjustment to the rate is approved by the Board, such adjustment will be effective (and, if necessary, retroactive) to January 1, 2018.

If at any time during the term NSPI determines that there are significant adverse differences between the Load Retention Rate and the incremental costs of service (for reasons other than the Variable Capital Cost or variable operating costs), NSPI, with approval of the Board, can adjust the rate on a prospective basis. If necessary, and to protect ratepayers, the Board could grant such approval on an expedited basis. Following any adjustment, PHP would be provided the opportunity to determine whether to remain on the rate.

CHARGES:

Administration Fee

The monthly administration fee is $30,000 paid in weekly advance installments of $6923.08.

Energy Related Payments

The amount to be paid by PHP to NSPI to purchase electricity shall be calculated based on the following ("Formula"):

Amount = (Hourly Incremental Cost/kWh + Variable Capital Cost + Contribution to Fixed Costs) * kWh actual load where:

> Hourly Incremental Cost/kWh represents NSPI's incremental cost of electricity, as determined after the fact, consumed by PHP, which is deemed to be the incremental marginal load on the NSPI system at the time the electricity is actually taken. This cost includes the cost of fuel, line losses and variable operating costs for NSPI's incremental generation and for delivery of the electricity to PHP. The variable operating costs included in the Hourly Incremental Cost is 0.153 cents/kWh; and
>
> the Variable Capital Cost associated with the electricity to be consumed by PHP as the deemed incremental marginal load on the NSPI system is 0.139 cents/kWh; and
>
> the Contribution to Fixed Costs shall be a minimum of 0.20 cents/kWh. Commencing for the fiscal year 2013, PHP shall pay 18% of PHP's net earnings before tax determined in accordance with PHP's audited financial statements, such that the maximum Contribution to Fixed Costs will be 0.40 cents/kWh, inclusive of the guaranteed 0.20 cents/kWh, for the first five full fiscal years of operation under this Mechanism. At year five, PHP will have to justify, to the satisfaction of the Board, the continuance of the $0.40 cents/kWh cap; otherwise the cap will be removed and potential additional contributions to fixed costs permitted.

Any payment in excess of 0.20 cents/kWh will be via an annual lump sum payment. PHP will provide, in confidence to the Board and NSPI, financial statements audited by a nationally recognized accounting firm, and PHP shall respond to reasonable inquiries by NSPI or the Board in order to satisfy NSPI or the Board that ratepayers are receiving the contribution to fixed costs to which they are entitled.

Any non-arm's length transactions by PHP will be carried out at terms and conditions, including those relating to price, rent or interest rate, that might reasonably be expected to apply in a similar transaction between parties who are at arm's length and who are acting willingly, and any related party transactions are required to be disclosed in the financial statements. PHP's external auditor is to be made aware of this condition.

Imported Energy Adjustment

Should PHP in any hour cause NSPI to reduce output from generation serving other load, by virtue of using less energy than previously committed to, for any reason other than a supply curtailment requested by NSPI, thereby stranding NSPI with unavoidable import energy cost, the incremental cost will be added to the total cost for that hour. The incremental cost will be equivalent to the difference between the import price per MWh and the marginal cost per MWh associated with the reduction of output required to balance the system.

IMPORTS OFFERED TO PHP

The following are circumstances when NSPI may offer imported energy to PHP:

- If NSPI receives a response to an energy RFP which it does not intend to accept;
- If NSPI receives an unsolicited offer of energy which it does not intend to accept;
- If PHP requests that NSPI search the market for a specific volume of energy for a specific period of time and the import is not economic for NS Power's other customers.
- If NS Power searches the market for PHP for a specific volume of energy for a specific period of time and the import is not economic for NS Power's other customers.

If PHP accepts an import energy offer, it is responsible to cover the full cost of the purchase.

If PHP does not run at a sufficient load level to accept its entire purchase commitment, for any reason other than a supply curtailment requested by NSPI, then NSPI takes the excess import energy and backs down its own generation. When this occurs, PHP is still required to pay for the entire import purchase, but NSPI will buy the energy back from PHP at NSPI's marginal cost associated with the PHP load level reduction. For purposes of this calculation, NSPI's marginal cost shall be determined as provided for by the differential system cost methodology as approved by the Board.

PHP's request for import energy may cause NSPI to be transmission constrained from making imports into Nova Scotia to support provincial system stability which NSPI would have been able to make but for the import made on PHP's behalf. If NSPI interrupts that import power it will compensate PHP for the redirected energy. The compensation will be 95% of the ISO New England Salisbury node applicable hourly price.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge is not applicable to PHP, and PHP will have no standing to participate in DSM-related proceedings unless it is proposed that a DSM-related charge be assessed against PHP.

FUEL ADJUSTMENT MECHANISM (FAM)

No FAM charges or credits shall be applicable to PHP, and PHP will have no standing to participate in FAM-related processes or proceedings unless it is proposed that a FAM-related charge be assessed against PHP or unless any such process or proceeding specifically deals with an issue which can directly impact on NSPI's real time incremental electricity costs.

SPECIAL CONDITIONS:

Major Scheduled Maintenance Periods

PHP will annually provide NSPI with information on the timing, duration and magnitude of its anticipated periods of major scheduled maintenance. PHP will also provide NSPI with three (3) weeks' notice in advance of commencing each scheduled maintenance period, clearly indicating the date and time of the commencement and termination of the maintenance period.

Day Ahead Forecast

PHP shall supply NSPI a 24 hour forecast for the following day of PHP's hourly requirements in MW no later than 2 hours following receipt of NSPI's day-ahead forecast pursuant to the Energy Supply Protocol.

Minimum Load Requirement:

NSPI will withdraw the availability of this tariff, if, on a consistent basis, PHP is not maintaining a regular demand of 25 000 kVA.

Load Reduction:

The Mill will reduce its load by, at a minimum, the amount requested by NSPI within ten (10) minutes of such request by NSPI. Following such reduction, service may only be restored by the Mill with the approval of NSPI.
PHP will make available suitable contact telephone numbers of a person or persons who are able to reduce the required load within ten minutes.

Load reduction calls will be made to PHP in advance of all such calls to its Interruptible Rider (LIR) customers and on an equitable and transparent basis with all customers on NSPI's Load Retention Tariff. Where the customer has provided NSPI with the ability to monitor and reduce its load under

terms and conditions determined by NSPI, NSPI may hold this load as Operating Reserve as required by system conditions. When interruptions are required, NSPI will exercise the automated control of the customer's load to reduce the customer load.

PHP is expected to comply with all calls for load reduction. Failure to comply in whole or in part with a request to reduce load will result in penalty charges, payable within 15 business days unless such penalty payment is being contested in good faith. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the amount of the applicable Formula cost for energy taken under this tariff effective at that time for the consumption used in the month.

The Performance Penalty which is based on PHP's performance during the load reduction event is calculated as per the formula below:

> Performance Penalty = ($15/kVA x A) + ($30/kVA x B)
>
> Where:
>
> "A" is any residual demand (above that required by the load reduction request) remaining in the third interval directly following two complete 5-minute intervals after the load reduction call was delivered by telephone call.
>
> "B" is PHP's average demand in excess of the compliance level based on 5-minute interval data during the entire load reduction event excluding the interval used to determine "A"

The total penalty will not exceed two times the cost of the Formula amount effective at that time for the consumption used in that month.

Should PHP fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to reduce load.

Load reductions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Reducible Load to Firm

Should PHP desire to be served under any applicable firm service rate, a five (5) year advance written notice must be given to NSPI so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by NSPI. NSPI may, however, permit an earlier conversion. In the event that PHP desires to return to interruptible service in the future, PHP may convert to an interruptible service tariff following two (2) years of service under the firm tariff schedule. NSPI may permit an earlier conversion from firm to interruptible service.

Order of Load Reduction:

In the event a load reduction is required in order to avoid shortfalls in system electricity supply, interruptible load will be called upon to provide capacity to NSPI in the following order:

1. Generation Replacement and Load Following (GR&LF) Rate;

2. Load Retention Tariff;

3. Shore Power Tariff;

4. Interruptible Rider to the Large Industrial Rate.

In situations where load of the customer under this tariff is held as Operating Reserve, NSPI may change the above order of interruption by interrupting LIIR customers whose load is not held as Operating Reserve before interrupting the customer.

Maintain System Integrity

PHP will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Sole Supplier

NSPI reserves the right to be the sole supplier of all external power requirements (i.e. excluding self-generation) for the Mill. Notwithstanding the foregoing, PHP shall not be precluded from obtaining electricity supply from another party if there is a provincial government opening of the Nova Scotia electricity marketplace which is applicable to the Mill.

Security for Payments

PHP shall provide weekly electricity purchase payments to NSPI in advance. NSPI shall provide PHP with a reasonable estimated weekly payment amount for each week based on estimates for the upcoming week of NSPI's hourly incremental electricity costs to serve PHP's load (as determined by NSPI, acting reasonably) and PHP's consumption (as determined by PHP, acting reasonably). Any overpayment or underpayment that arises because of a difference between actual amounts and estimated amounts will be taken into account in determining the amount of a subsequent weekly cash payment. Prior to the start of each week, PHP shall make a payment by wire transfer to NSPI's account equal to that week's estimated amount as provided by NSPI. If NSPI does not provide the applicable weekly estimate to PHP in advance of the electricity purchase payment requirement, PHP shall make payment in accordance with the immediately prior week's estimate.

PHP shall be entitled to provide NSPI a letter of credit from time to time as an optional method of satisfying its security for payment. Where a letter of credit is proposed to be utilized, the timing and invoicing of payments shall be agreed between NSPI and PHP consistent with the amount of the letter of credit posted as security for payment. The form, amount, and issuer of the letter of credit will be satisfactory to NSPI. To the extent that a letter of credit introduces a lag time and there are additional costs to NSPI, these will be paid by PHP not NSPI or its ratepayers.

Separate Service Agreement

NSPI reserves the right to have a separate service agreement if, in the opinion of NSPI, issues not specifically set out herein must be addressed for the ongoing benefit of NSPI and its customers.

Power Factor Correction

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total Mill load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the energy charges comprising the Hourly Incremental Cost:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

Metering Costs

Metering will normally be at the low side of the transformer and, for measurement and, where applicable, billing purposes, meter readings will be increased by 1.75%. Should the Mill's requirements make it necessary for NSPI to provide primary metering; PHP will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by PHP in connection with service under this tariff shall be paid for by PHP as a capital contribution.

NSPI Port Hawkesbury Paper Mill

Energy Supply Protocol

The purpose of this Protocol is to ensure that the **Port Hawkesbury Paper Mill** ("PHP") covers the actual incremental cost of electricity for all electricity taken from NSPI's system and that NSPI's customers do not incur any additional cost as a result of PHP load requirements. Whenever this Protocol can be interpreted in multiple ways, the option that best protects the interests of NSPI's customers (which for clarity does not include PHP) shall prevail.

PHP and NSPI agree to operate on the basis of the forecast electricity information provided by NSPI under the Tariff (including the week-ahead, day-ahead and intra-day CQ pairs) trued up to actual costs on an after the fact basis. NSPI will provide PHP with hourly price forecasts for specific blocks of incremental load on a day-ahead basis and PHP shall provide NSPI its forecast load requirements based on these price forecasts. NSPI shall also provide PHP with additional information as described in this Protocol to support PHP's operational decision-making and allow it to extrapolate potential prices in real time. For purposes of the true-up billing to PHP, NSPI will apply actual costs as determined using the differential system cost methodology approved by the Board.

DEFINITIONS:

APT: "Atlantic Prevailing Time" – Atlantic Time, either Daylight Savings Time, or Standard Time, depending upon which seasonal time protocol prevails for the Hour in question.

BLOCK 0: NSPI's total system load prior to accounting for any PHP load.

CQ-PAIR: "Cost-Quantity Pair", an hourly electricity cost – incremental load combination representing the forecast electricity cost (comprising either fuel and variable operations and maintenance cost, or import purchase cost) to serve PHP's load within a specific incremental block of energy on NSPI's system. These blocks will be set to be approximately equal to the Mill's operating modes.

DAILY BASIS: each calendar day, including weekends and holidays.

DAY: The day upon which the forecast is provided.

DAY-AHEAD DEMAND FORECAST: PHP's forecast hourly demand for each Hour of Day+1.

DAY-AHEAD COST FORECAST: NSPI's best commercial efforts forecast hourly CQ-Pairs for each Hour of Day+1 subject to the terms of this Protocol. The Day-Ahead Cost Forecast will be generated using data from the GenOps modeling run, which includes Block 0 (No PHP load) and six additional PHP blocks based on PHP's typical run levels. In addition to the hourly cost ($/MWh), the Day-Ahead Cost Forecast will identify the percentage of generation source (i.e. coal, gas, oil, etc.) that is forecasted to serve each block of PHP's load.

FORCE MAJEURE: means (a) loss of load caused by interruption or supply disturbance on the NSPI system ("power bumps") or (b) breakdown of the Mill's major equipment.

HOUR or HOURS: Hours of a Day beginning at 0000 and ending at 2400, APT, in sixty minute increments.

IMPORT: A specific block of energy that is purchased from a counterparty rather than generated on NSPI assets.

Off-Peak Hours: Hours of a Day from 0000 to 0700 APT and 2300 to 2400 APT.

On-Peak Hours: Hours of a Day from 0700 to 2300 APT.

SEVEN DAY DEMAND FORECAST: PHP's On and Off Peak demand forecast for each of seven forecast days, beginning on Day+2 and ending on Day+9. The Seven Day Demand Forecast is provided for information and planning purposes only and does not represent a commitment by PHP to actually adhere to this forecast operationally.

SEVEN DAY COST FORECAST: NSPI's best commercial efforts On and Off-Peak period forecast hourly average CQ-Pairs. For clarity, this represents two sets of hourly CQ-Pairs for each day of the seven day forecast period; one set for On-Peak Hours and one set for Off-Peak Hours.

The Seven Day Cost Forecast will begin on Day+2 and will end on Day+9 to avoid any potential conflict with the Day Ahead Cost Forecast, but will use the same level of data required for the Day-Ahead Cost Forecast. The Seven Day Cost Forecast is provided for information and planning purposes only and does not represent a commitment by NSPI to actually quote the costs forecast, but NSPI will provide notes with respect to relevant issues for the week ahead to assist PHP with any maintenance or operational planning. The Seven Day Cost Forecast CQ-Pairs will generally not include Import or wind considerations. NSPI and PHP agree to work together to determine the extent to which Imports and Wind forecasts are utilized in this forecast.

PROTOCOL:

1. On a Daily Basis, no later than 1300 Hours, NSPI will provide PHP with a Seven Day Cost Forecast. No later than 2 hours following receipt of NSPI's Seven Day Cost Forecast, PHP will provide NSPI with its Seven Day Demand Forecast.

2. On a Daily Basis, no later than 1300 Hours and in the same communication as the Seven Day Cost Forecast, NSPI will provide PHP with a Day-Ahead Cost Forecast. No later than 2 hours following receipt of NSPI's Day-Ahead Cost Forecast, PHP will provide NSPI with its Day-Ahead Demand Forecast.

   The applicable line losses will be calculated after the flow of energy in an hour using proprietary software with the specific utility-grade capability to evaluate line losses and pursuant to the line loss methodology approved by the Board.

3. Together with the Day-Ahead Cost Forecast, NSPI will provide PHP with the following additional information for each Hour:

   - The forecasted Block 0 load.
   - The forecasted Block 0 generation from NSPI's wind (purchased and owned), coal, gas, oil, combustion turbines ("CTs") and hydro facilities.
   - Term Imports scheduled prior to the Day-Ahead Cost Forecast.
   - The forecasted minimum gas generation required to serve other NSPI customers.
   - NSPI's expectations regarding the return to service of any generating units that may be offline.
   - NSPI's expectations regarding the timing and duration of potential outages of any generating units.

4. If there is a material change from the forecast system conditions used by NSPI in the calculation of the Day-Ahead Cost Forecast, NSPI will provide that information to PHP in a proactive and timely manner. For purposes of the Protocol, "material" shall mean:

   - Expectations of de-rates or outages (in advance).
   - De-rates/unexpected outages of generating units.
   - Updates on return to service times of generating units.
   - Forecast dispatch of expensive generation that was not included in the Day-Ahead Cost Forecast (e.g. CTs, expensive gas-fired or oil-fired generation, etc.)

- The volume and duration of imports scheduled real time for other NSPI customers.
- The volume and duration of potential export opportunities.

5. NSPI and PHP will exchange the following information through the use of a real-time digital exchange or a similar information transfer method, as agreed between NSPI and PHP:

    - NSPI's Base load (total MWs in real-time);
    - NSPI's level of generation from wind (purchased and owned), coal, gas, oil, combustion turbines ("CTs"), and hydro facilities (total MWs in real-time);
    - PHP silo and storage levels; and
    - Transmission constraints.

6. If, during the course of an operating Hour, system conditions change unexpectedly such that they have a material impact (positive or negative) on pricing, for example requiring that a CT be utilized in that Hour, NSPI will contact PHP as soon as possible. PHP will have the option of continuing to operate at their current demand level, covering the increased cost, if applicable, in that Hour, or to curtail sufficient load for NSPI to avoid or reduce the material price impact. In the event that the Mill does not declare its preferred option and/or does not curtail demand, the Mill will assume responsibility for the cost for that Hour.

7. If NSPI is unable to import energy needed to support provincial system stability, and the Mill is utilizing the available transmission capacity having contracted through NSPI to secure import energy, NSPI may redirect such import energy. The Mill will be compensated for such redirection as described in the PHP Load Retention Tariff Pricing Mechanism.

CONDITIONS:

1. For purposes of the true-up billing to PHP, NSPI will apply actual costs as determined using the Board-approved differential system cost and line loss methodologies.

2. On a daily basis, NSPI's Day-Ahead marketer will meet with the administrator of the tariff to review the assumptions used in the planning and calculation of the Day-Ahead Cost Forecast to ensure that the assumptions used in the weekly billing process are consistent.

3. Following Force Majeure events, PHP will endeavor to restore the Mill's operation to normal as soon as possible and without undue delay. PHP will maintain, as a minimum, hourly contact with NSPI in the hours following Force Majeure events to keep NSPI aware of the Mill's status.

4. The Mill's load is considered reducible, and is subject to reduction at NSPI's request on the same basis as other load served under the Load Retention Tariff.

5. PHP shall maintain a scheduling and operations team available to NSPI's energy marketers and operators on a continuous 24 hour, 7 days a week basis. PHP shall maintain dedicated telephone capability for their scheduling and operations team and NSPI shall maintain and utilize recorded telephone capability for all telephone communications with PHP's scheduling and operations team.

6. PHP's scheduling and operations team shall be empowered with the authority to transact on behalf of PHP.

7. NSPI will not include PHP in its planning considerations, including future capacity additions or the restart of generation which has been seasonally shut down.

8. NSPI and PHP shall work cooperatively to establish economic imports and enhance the efficient operation of both companies.

9. This Protocol is subject to revision in the event that the Nova Scotia energy scheduling market moves from one based on hourly intervals to 30 minute intervals. Such revision is expected to affect only the required timing of transactions.