THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 8-2018 **MAY 25, 2018**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF the Applications by the Northwest Territories Power Corporation respecting the 2016/17, 2017/18 and 2018/19 Phase I and II General Rate Application Compliance Filings and Review and Variance of Decision 16-2017.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	Gordon Van Tighem	Chairman
	Sandra Jaque	Vice-Chairman
	Charlie Furlong	Member
BOARD STAFF	Louise Beaulieu	Board Secretary
	Raj Retnanandan	Board Consultant
	Ayanna Catlyn	Board Counsel

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1. BACKGROUND

1. By letter dated June 30, 2016, the Northwest Territories Power Corporation ("**NTPC**" or the "**Corporation**") submitted to the Northwest Territories Public Utilities Board ("**the Board**") its Phase I General Rate Application ("**GRA, Application**"). The Application outlines forecast costs for providing electricity service for the 2016/17, 2017/18 and 2018/19 fiscal years (the **"Test Years"**). The Phase I application was updated on March 1, 2017 by NTPC.

2. In Decision 12-2016 the Board approved a 4.8% interim increase in energy rates for 2016/17, effective August 1, 2016. In Decision 4-2017 the Board approved a further interim increase of 4% for 2017/18, effective April 1, 2017. While the 4.8% increase for 2016/17 was applied on an across the board basis applicable to all energy rates, NTPC proposed to apply the combined 4.8% increase from 2016/17 and the 4% increase for 2017/18 to achieve certain target revenue to cost ratios by rate class. The target revenue to cost ratios proposed by NTPC in this context are addressed in this Decision.

3. The Board issued Decision 16-2017 dated December 15, 2017 determining the issues raised in the Phase I proceeding and directed NTPC to file a Compliance Application reflecting the findings and directions in the Decision by February 15, 2017.

4. By letter dated March 1, 2017, NTPC submitted its Phase II General Rate Application **("GRA Phase II"** or "**Phase II Application**") for the 2016/17, 2017/18 and 2018/19 Test Years for an order or orders of the Board:

    a) approving the Corporation's proposed rates for retail, wholesale and industrial customers set out in Schedules 3.1.1 and 3.1.2 for implementation effective April 1, 2017 and April 1, 2018 respectively; and

    b) approving as final, the interim rates approved for the 2016/17 Test Year that took effect August 1, 2016 as approved in Board Decision 12-2016.

    and for any such further and other orders within the Board's jurisdiction as the Corporation may request, and the Board determines proper. [16/19 PHII-NTPC-X001]

5. The Board issued Decision 1-2018 directing NTPC to file with the Board and interested parties a Phase II Compliance Application reflecting the findings and directions in the above referenced Phase II Decision and in the Board's Phase I Decision 16-2017, including a revised cost of service study, rate design, rate schedules and Terms and Conditions of Service, by February 15, 2018.

6. By letter dated February 16, 2018, NTPC requested approval for an extension to complete the compliance filing for the Phase I and II General Rate Application. NTPC also requested that the interim rates approved in Decision 4-2017 for 2017/18 continue past March 31, 2018 pending review and approval of the compliance filing. By way of Decision 5-2018 dated April 13, 2018, the Board approved continuation of the 2017/18

interim rates past March 31, 2018 pending review and approval of the compliance filing.

2. COMPLIANCE FILING APPLICATION

7. By letters dated March 16, 2018, NTPC filed its 2016/19 Phase I and II GRA Compliance Filings, as ordered by the Board in Decisions 16-2017 and 1-2018. NTPC also filed an application for Review and Variance ("**R&V application**") of Board Decision 16-2017. The R&V application requested that Directive 18 from Decision 16-2017 dealing with the amount of diesel generation to be included in rates for the Snare Yellowknife Zone, be reviewed and varied.

8. In view of the nature of the issues raised in the R&V application, the Board decided to dispense with submissions on the threshold question respecting admission of the R&V application. In the interest of regulatory efficiency, the Board decided to deal with all three applications concurrently. The Board established a schedule for consideration of the applications.

9. On April 16, 2018, NTPC filed its responses to all information requests. Written Argument was filed on April 30, 2018 and Written Reply Argument was filed on May 14, 2018.

3. EXAMINATION OF THE PHASE I AND PHASE II COMPLIANCE FILINGS AND REVIEW AND VARIANCE APPLICATION

10. The issues raised by parties and the Board findings with respect to the Phase I and Phase II compliance filings as well as the R&V application are set out in this section.

3.1 Minimum Diesel Generation for the Snare Zone

11. In its GRA Application, NTPC assumed a minimum of 5 GWh for diesel generation, required for peaking and other system support functions in the Snare zone. NTPC's forecast of minimum diesel generation was based upon a review of average actual diesel generation requirements for the years 2008/09 through 2012/13 being the years prior to the onset of the extreme low water period that commenced in 2013/14.

12. In view of NTPC's GRA proposal to use an average diesel generation of 5 GWh as the minimum diesel generation, which would replace the existing 1.2 GWh minimum diesel generation for the Snare zone and, by implication, would not be subject to adjustments if actual diesel generation were to be lower, the Board in Decision 16-2017 determined that the minimum diesel generation would remain at 1.2 GWh and any diesel generation above the minimum would be subject to deferral treatment.

13. In Decision 16-2017, the Board also determined that the cost risk associated with diesel generation above 5 GWh would flow to the Territory Wide Rate Stabilization Fund ("**RSF**") and the cost risk associated with

diesel generation between 1.2 GWh and 5 GWh would flow to the Snare Zone customers. However, given the NTPC proposal to use the 5 GWh as the minimum diesel generation, the Board found that there is insufficient evidence from NTPC to demonstrate that the average level of 5 GWh is the optimum level under normal hydro operating conditions. [Decision 16-2017; paragraph 210]

14. After filing its R&V application, NTPC offered the following further explanation by way of letter dated April 27, 2018 suggesting that the 5 GWh, which was proposed as a minimum in the 2016/19 GRA was intended as the average level of diesel generation subject to symmetrical plus or minus cost adjustments through the RSF if actual diesel generation were higher or lower:

> The Northwest Territories Power Corporation ("NTPC" or "Corporation") would like to offer clarification to the treatment of the Snare Diesel generation in Revenue Requirement and how diesel generation would be applied to the Territory Wide Rate Stabilization Fund ("RSF").
>
> The Corporation is requesting the RSF mechanics for the Snare diesel generation be a threshold of 5 GWh and if actual diesel generation is less than the 5 GWh in Revenue Requirement the RSF would be credited the volume difference. If diesel generation is greater than 5 GWh the extra diesel generation would flow to the RSF. The current RSF schedule 1 on line 24 indicates that only diesel generation above the 1.2 GWh or 5 GWh thresholds would flow to the RSF and the Corporation wishes to clarify that the RSF would be credited for volume differences below the 5 GWh proposed threshold.

15. The arguments and replies by the parties in respect to the R&V application are not summarized in this Board decision. It is the Board's view that the

R&V application would not have been required had NTPC provided explanation by way of its letter dated April 27, 2018 (as discussed in paragraph 14 of this decision) in the first instance.

Board Findings:

16. The Board considers the determination of the diesel versus hydro generation mix relates to the issue of risk allocation. When the 1.2 GWh diesel minimum generation was established, the result was, any actual diesel generation below 1.2 GWh would benefit NTPC's shareholder, while any diesel generation above 1.2 GWh would flow to the Snare Zone customers. Following establishment of the Government of the Northwest Territories ("**GNWT**") Guidelines (revised as of February 10, 2011) any diesel generation below the 1.2 GWh minimum would still benefit NTPC's shareholder, while any diesel generation above 1.2 GWh flows to the RSF, which means, all rate Zones share the costs of diesel generation above 1.2 GWh.

17. In the 2016/19 GRA, NTPC requested that the 1.2 GWh minimum be increased to 5 GWh based on historical average diesel use. The request by NTPC to increase the minimum diesel generation to 5 GWh would have, if approved, resulted in any diesel generation below 5 GWh benefiting NTPC's owner, while any diesel generation above 5 GWh flowing to the RSF. After filing the R&V application, NTPC offered the further explanation that the 5 GWh is not intended as a minimum but rather should be treated as an average level of diesel generation and subject to plus or minus cost adjustments through the RSF, if actual diesel generation were higher or lower.

18. Had the explanation that the 5 GWh diesel generation was being proposed by NTPC as an average level of diesel generation, rather than as a minimum to replace the 1.2 GWh, been provided by NTPC at the time of the GRA application, a great deal of confusion and time spent by all parties in filing and debating an R&V application could have been avoided.

19. The Board notes NTPC's proposal in its April 27, 2018 letter that if actual diesel generation were less than 5 GWh, the RSF would be credited the costs associated with the volume difference and, if actual diesel generation were greater than 5 GWh the extra diesel generation costs would flow to the RSF.

20. The Board notes from Guideline 7 of the Revised Guidelines dated February 10, 2011 provided by the GNWT that the RSF is intended to include costs arising from low water conditions:

> 7) The Board should consider establishing territorial fuel and low water riders on a per utility basis.

21. The Board interprets Guideline 7 to mean that the RSF is to be charged for costs arising from low water conditions only. Based on NTPC's evidence, the Board determines that the 5 GWh average use reflects normal diesel use other than due to low water conditions. Therefore, any diesel use above 5 GWh may be considered as relating to low water conditions and therefore recoverable through the RSF. The Board considers however, that since the RSF is only intended to reflect costs arising from low water conditions, any diesel use below the 5 GWh level may not be included in the RSF fund.

22. Since the original intent of the 1.2 GWh minimum diesel generation, prior to the 2016/19 GRA, appears to be to provide an incentive for NTPC to efficiently use its diesel resources for providing operating reserves and for back up supply in the event of scheduled our unscheduled outages, NTPC was allowed to retain as a shareholder benefit, any diesel generation below the 1.2 GWh minimum. This risk allocation between shareholder and customer is also reflected in Decision 16-2017.

23. Decision 16-2017 determined that the minimum diesel generation would remain at 1.2 GWh and the cost risk associated with diesel generation above 5 GWh would flow to the RSF consistent with Guideline 7 of the GNWT Guidelines; the cost risk associated with diesel generation between 1.2 GWh and 5 GWh would flow to the Snare Zone customers.

24. The Board is not persuaded that the risk allocation determined in Decision 16-2017, between NTPC's shareholder, NTPC's Snare Zone customers and Territory wide customers needs to change following NTPC's R&V application. However, in view of NTPC's new evidence that the 5 GWh diesel generation represents the average rather than the minimum, the Board accepts NTPC's request to include 5 GWh as the average diesel generation other than due to low water conditions, to be included in the Snare zone revenue requirement and base rates.

25. In order to preserve the same risk allocation as approved in Decision 16-2017, the Board directs that any diesel generation higher than 5 GWh be flowed through to the RSF and any diesel generation below 5 GWh, but

higher than 1.2 GWh, be included in a Snare zone diesel generation deferral account. Any diesel generation below 1.2 GWh minimum, would flow to NTPC's shareholder.

26. The Board directs that the credits, (if any) accumulated in the Snare zone diesel generation deferral account are to be refunded to the Snare zone customers over a reasonable period of time by way of a rider at the end of each fiscal year, having regard to materiality, rate impacts and administrative effort, among other rate design criteria.

27. The Board notes that, other than the use of certain historical information respecting diesel generation levels, NTPC did not provide evidence, including modeling analysis, on the optimum level of use for diesel resources for providing operating reserves and other system support services which could be used as a target minimum diesel generation on a forecast basis, in order to incent NTPC to efficiently manage its hydro versus diesel mix. In the Board's view such a target may be used to establish the minimum diesel generation level for risk allocation between shareholder and customers, based on more current data. NTPC is therefore directed to provide this information at the time of the next GRA.

3.2 Common Costs

28. The TGC submitted that account level information supporting Corporate and Regional Common Costs similar to the detailed account level information provided with respect to Plant Level O&M costs, is relevant and necessary to test the veracity of forecasts. The TGC recommended

that the Board direct NTPC to provide, at its next GRA, details of Corporate and Regional Common Costs at an account level, much like NTPC provides for Plant Level O&M costs. [TGC Argument paragraphs 9, 10]

29. NTPC submitted that TGC is fully aware that the Board approved Minimum Filing Requirements ("**MFR**") that included a review in 5 years; if there are concerns that the standard set of documents required to be filed by the utilities in the NWT are not sufficient, then the MFR review is the appropriate process to assess those concerns. [NTPC Reply page 2]

Board Findings:

30. The Board recognizes that an MFR review is likely to be undertaken prior to NTPC's next GRA. The next MFR review would provide a forum for review of filing requirements respecting future GRAs including the level of detail required to be provided respecting Corporate and Regional Common Costs. Therefore, the Board will not include the TGC requested direction in this Decision.

3.3 Risk Register

31. TGC noted NTPC's proposal to update its capital planning process to include the addition of a risk register to assess contingencies for larger scale projects $5 million and above as part of NTPC's project permit application process. TGC noted that projects less than $5 million and greater than or equal to $0.400 million, would be reviewed by NTPC for

project specific risks on a case by case basis when setting the contingency reserve for capital projects.

32. TGC submitted, NTPC's proposal to use judgment in place of a risk register is an inferior approach, one that is hard to quantify and test in a public hearing process and carries with it a potential to overstate the appropriate financial liabilities associated with each specific risk. [TGC Argument, paragraph 15]

33. TGC recommend the Board direct NTPC to update its capital planning processes and employ a detailed risk register for all major capital projects, consistent with its direction in Decision 16-2017 (Directive 5). [TGC Argument, paragraph 17]

34. NTPC submitted that it would comply with the Board's direction by using a two tier contingency approach which involves use of a risk register for all projects with a value over $5 million and, for the majority of NTPC's projects that fall within the range of $0.400 million to $5 million, contingency would be assessed using professional judgement on a case by case basis, in light of the specific project risks; this case by case review would also ensure that potential risk mitigation measures are considered and factored into the contingency reserve level. [NTPC Reply, page 3]

Board Findings:

35. In the interest of administrative efficiency, the Board accepts NTPC's proposal to use a risk register for all projects with a value over $5 million and, to assess contingency amounts on a case by case basis for the

majority of NTPC’s projects that fall within the range of $0.400 million to $5 million based on project specific risks. The Board considers that, once NTPC’s formal risk assessment systems are in place and are systematized, the Corporation may then be in a position to extend those methods to other projects in a cost efficient manner. Accordingly, the Board will not include the requested direction at this time.

3.4 Overhead Costs

36. TGC submitted that the lack of visibility of identification and makeup of expenses under the direct overhead costs does not allow the Board an opportunity to assess the reasonableness of O&M costs charged directly to capital, or year over year changes of these amounts. Accordingly, TGC recommended that NTPC be directed to provide this information in its O&M schedules in its next GRA which reflect the full amount of the expense and show separately a credit related to capital overhead.

37. TGC submitted further that information provided in response to Directive 11, Attachment 1 is also useful and should be provided in all future GRA filings in order to help better understand the derivation of total O&M costs which are deemed capital overhead costs. [TGC Argument, paragraphs 24, 25]

38. NTPC submitted Schedule 11.6 has the overhead percentage and this percentage is made up of all the indirect and direct costs that are included in the overhead account.

Board Findings:

39. The Board notes that although Schedule 11.6 provides the overhead information on the capital side it does not reflect details of expenses included in the overhead pool as set out in NTPC's response to Directive 11. However, the Board recognizes that an MFR review is likely to be undertaken prior to NTPC's next GRA. The next MFR review would provide a forum for review of filing requirements respecting future GRAs including the level of detail required to be provided respecting overheads. Therefore, the Board will not include the TGC requested direction in this Decision.

4. COMPLIANCE FILING

40. Having reviewed the Compliance Filing and accompanying schedules, the Board accepts and approves the 2016/17, 2017/18 and 2018/19 revenue requirements and rate schedules as proposed by NTPC in its Phase I and Phase II compliance filing. Since NTPC did not request a true up of the revenues arising from difference between interim and final rates for the months of April and May 2018, the Board approves the final rates set out in Appendix 1 effective June 1, 2018. The interim rates that were in place from August 1, 2016 to May 31, 2018 are approved as final rates.

41. The 2016/19 GRA proceedings involved two phases which began in August 2016 and was completed with this compliance filing Decision. In order to provide an over view of the entire proceedings an executive summary of the proceedings is set out in Appendix 2.

5. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

42. Northwest Territories Power Corporation's Rate Schedules, attached hereto as Appendix 1, is approved, effective June 1, 2018.

43. Executive Summary of the Northwest Territories Power Corporation's 2016/19 General Rate Application, attached hereto as Appendix 2.

44. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

Gordon Van Tighem
Chairman

Dated May 25, 2018

FOLLOWING IS

APPENDIX 1

ATTACHED TO AND FORMING PART OF

THE PUBLIC UTILITIES BOARD

OF THE NORTHWEST TERRITORIES

DECISION 8-2018

DATED May 25, 2018

Zone: Snare System

Wholesale Primary Service:	**Northland Utilities (Yellowknife) Ltd.**
Demand Charge:	$8.10 /kVA
Energy Charge:	21.27 ¢/kWh
Minimum Monthly Bill:	$8.10 /kVA

Notes:

1. NUL-Yellowknife is subject to a 100% demand ratchet beginning April 1, 2002. Therefore, billing demand for NUL-Yellowknife shall be the greater of the current month's maximum Demand or the maximum Demand experienced during the 12-month period ending with the current billing month.

Zone: Snare System

Industrial Primary Service:	**Envir. Protection Div./Con Mine**
Demand Charge:	$11.76 /kVA
Energy Charge:	18.70 ¢/kWh
Minimum Monthly Bill:	$11.76 /kVA

Notes:

1. Billing Demand for Industrial customers shall be the greater of the current month's maximum Demand or the maximum Demand experienced during the 12-month period ending with the current billing month.

Zone: Snare System

Residential Government

Monthly Service Charge:	$18.00

Energy Charge

Behchoko	37.94 ¢/kWh
Dettah	42.28 ¢/kWh

Minimum Monthly Bill:	$18.00

Residential Non-Government

Monthly Service Charge:	$18.00
Energy Charge:	34.97 ¢/kWh
Minimum Monthly Bill:	$18.00

Zone: Snare System

General Service Government

Demand Charge:	$8.00/kW

Energy Charge

Behchoko	43.71 ¢/kWh
Dettah	49.11 ¢/kWh
Minimum Monthly Bill:	$40.00
Stand-by Charge:	$24.00 /kW

General Service Non-Government

Demand Charge:	$8.00 /kW
Energy Charge:	34.37 ¢/kWh
Minimum Monthly Bill:	$40.00
Stand-by Charge:	$24.00 /kW

* General Service – Billing Demand shall be the greater of the current month's maximum Demand or the maximum Demand experienced during the 12 month period ending with the current billing month.

* Stand-by eligibility is negotiated with NTPC on a per customer basis and subject to all applicable energy rates and riders.

NORTHWEST TERRITORIES POWER CORPORATION

RATE SCHEDULE

Effective Date: June 1, 2018
Supersedes: April 1, 2018

Zone: Thermal

Residential Government

Monthly Service Charge: $18.00

Energy Charge

Wha Ti	118.51	¢/kWh
Gameti	181.88	¢/kWh
Lutsel K'e	110.05	¢/kWh
Fort Simpson	102.91	¢/kWh
Fort Liard	109.38	¢/kWh
Wrigley	193.27	¢/kWh
Nahanni Butte	233.17	¢/kWh
Jean Marie River	208.37	¢/kWh
Inuvik	84.57	¢/kWh
Tuktoyaktuk	99.21	¢/kWh
Fort McPherson	114.33	¢/kWh
Aklavik	90.85	¢/kWh
Deline	116.59	¢/kWh
Fort Good Hope	101.47	¢/kWh
Paulatuk	172.24	¢/kWh
Sachs Harbour	213.16	¢/kWh
Tsiigehtchic	157.94	¢/kWh
Colville Lake	322.66	¢/kWh
Ulukhaktok	99.14	¢/kWh
Tulita	125.43	¢/kWh

Minimum Monthly Bill: $18.00

Zone: Thermal

Residential Non-Government

Monthly Service Charge:	$18.00
Energy Charge:	68.37 ¢/kWh
Minimum Monthly Bill:	$18.00

Zone: Thermal

General Service Government

Demand Charge: $8.00/kW

Energy Charge

Wha Ti	111.42	¢/kWh
Gameti	211.73	¢/kWh
Lutsel K'e	103.65	¢/kWh
Fort Simpson	91.31	¢/kWh
Fort Liard	99.87	¢/kWh
Wrigley	209.33	¢/kWh
Nahanni Butte	304.65	¢/kWh
Jean Marie River	284.78	¢/kWh
Inuvik	76.19	¢/kWh
Tuktoyaktuk	89.24	¢/kWh
Fort McPherson	105.93	¢/kWh
Aklavik	87.93	¢/kWh
Deline	111.42	¢/kWh
Fort Good Hope	90.01	¢/kWh
Paulatuk	164.85	¢/kWh
Sachs Harbour	202.37	¢/kWh
Tsiigehtchic	141.70	¢/kWh
Colville Lake	284.23	¢/kWh
Ulukhaktok	90.89	¢/kWh
Tulita	122.71	¢/kWh

Minimum Monthly Bill: $40.00

Stand-by Charge: $24.00 /kW

* General Service – Billing Demand shall be the greater of the current month's maximum Demand or the maximum Demand experienced during the 12 month period ending with the current billing month.

* Stand-by eligibility is negotiated with NTPC on a per customer basis and subject to all applicable energy rates and riders.

Zone: Thermal

General Service Non-Government

Demand Charge:	$8.00 /kW
Energy Charge:	58.60 ¢/kWh
Minimum Monthly Bill:	$40.00
Stand-by Charge:	$24.00 /kW

* General Service – Billing Demand shall be the greater of the current month's maximum Demand or the maximum Demand experienced during the 12 month period ending with the current billing month.

* Stand-by eligibility is negotiated with NTPC on a per customer basis and subject to all applicable energy rates and riders.

Zone: Norman Wells

Residential Government

Monthly Service Charge:	$18.00

Energy Charge

Norman Wells	62.65 ¢/kWh
Minimum Monthly Bill:	$18.00

Residential Non-Government

Monthly Service Charge:	$18.00
Energy Charge:	53.43 ¢/kWh
Minimum Monthly Bill:	$18.00

Zone: Norman Wells

General Service Government

Demand Charge:	$8.00/kW
Energy Charge	
Norman Wells	57.65 ¢/kWh
Minimum Monthly Bill:	$40.00
Stand-by Charge:	$24.00 /kW

General Service Non-Government

Demand Charge:	$8.00 /kW
Energy Charge:	49.08 ¢/kWh
Minimum Monthly Bill:	$40.00
Stand-by Charge:	$24.00 /kW

* General Service – Billing Demand shall be the greater of the current month's maximum Demand or the maximum Demand experienced during the 12 month period ending with the current billing month.

* Stand-by eligibility is negotiated with NTPC on a per customer basis and subject to all applicable energy rates and riders.

Zone: Taltson System

Residential Government

Monthly Service Charge:	$18.00

Energy Charge

Fort Smith	24.85 ¢/kWh
Fort Resolution	31.59 ¢/kWh
Minimum Monthly Bill:	$18.00

Residential Non-Government

Monthly Service Charge:	$18.00
Energy Charge:	23.86 ¢/kWh
Minimum Monthly Bill:	$18.00

Zone: Taltson System

General Service Government

Demand Charge:	$8.00/kW

Energy Charge

Fort Smith	19.62 ¢/kWh
Fort Resolution	27.48 ¢/kWh
Minimum Monthly Bill:	$40.00
Stand-by Charge:	$24.00 /kW

General Service Non-Government

Demand Charge:	$8.00 /kW
Energy Charge:	18.84 ¢/kWh
Minimum Monthly Bill:	$40.00
Stand-by Charge:	$24.00 /kW

* General Service – Billing Demand shall be the greater of the current month's maximum Demand or the maximum Demand experienced during the 12 month period ending with the current billing month.

* Stand-by eligibility is negotiated with NTPC on a per customer basis and subject to all applicable energy rates and riders.

NORTHWEST TERRITORIES POWER CORPORATION

RATE SCHEDULE

Effective Date: June 1, 2018
Supersedes: April 1, 2018

Zone: Taltson System

Wholesale Service:	**Northland Utilities (NWT) Ltd.**
Demand Charge:	N/A
Energy Charge:	
Firm Power	11.98 ¢/kWh
Interruptible Power	6.00 ¢/kWh

Rate Schedule: Streetlighting
Community: All

	Mercury Vapour				High Pressure Sodium			
	125w	**175w**	**250w**	**400w**	**c100**	**c150**	**c250**	**c400**
Snare System	656	804	1136	1780	508	756	1200	1880
Behchoko	33.80	41.43	58.53	91.71	26.17	38.95	61.83	96.87
Dettah	33.80	41.43	58.53	91.71	26.17	38.95	61.83	96.87
Taltson System								
Fort Smith	18.77	23.01	32.51	50.94	14.54	21.63	34.34	53.80
Fort Resolution	22.45	27.52	38.88	60.92	17.39	25.87	41.07	64.34
Norman Wells								
Norman Wells	43.61	53.45	75.53	118.34	33.77	50.26	79.78	124.99
Thermal System								
Wha Ti	101.43	124.31	175.64	275.22	78.55	116.89	185.54	290.68
Gameti	121.85	149.34	211.01	330.64	94.36	140.43	222.90	349.21
Lutsel K'e	91.22	111.80	157.96	247.51	70.64	105.12	166.86	261.41
Fort Simpson	60.17	73.74	104.19	163.26	46.59	69.34	110.06	172.43
Fort Liard	87.97	107.82	152.34	238.70	68.12	101.38	160.92	252.11
Wrigley	140.27	171.92	242.91	380.62	108.63	161.66	256.60	402.01
Nahanni Butte	186.51	228.59	322.98	506.08	144.43	214.94	341.18	534.52
Jean Marie River	195.76	239.92	338.99	531.17	151.59	225.60	358.09	561.01
Inuvik	51.70	63.36	89.53	140.28	40.03	59.58	94.57	148.16
Tuktoyaktuk	70.16	85.99	121.50	190.37	54.33	80.85	128.34	201.07
Fort McPherson	66.57	81.59	115.28	180.63	51.55	76.72	121.77	190.77
Aklavik	63.78	78.17	110.45	173.06	49.39	73.50	116.67	182.78
Deline	52.11	63.86	90.24	141.39	40.35	60.05	95.32	149.33
Fort Good Hope	61.66	75.58	106.78	167.32	47.75	71.06	112.80	176.72
Paulatuk	99.41	121.84	172.15	269.74	76.98	114.57	181.85	284.90
Sachs Harbour	119.11	145.98	206.26	323.19	92.24	137.26	217.88	341.35
Tsiigehtchic	104.34	127.88	180.69	283.12	80.80	120.25	190.87	299.03
Colville Lake	418.53	512.96	724.78	1135.65	324.11	482.33	765.61	1199.46
Ulukhaktok	68.25	83.65	118.19	185.19	52.85	78.66	124.85	195.60
Tulita	75.37	92.37	130.52	204.51	58.36	86.86	137.87	216.00

	Light-Emitting Diode (LED)		
	50w	100w	274w
Snare	9.89	19.78	54.21
Taltson	5.49	10.99	30.11
Thermal	20.44	40.87	111.99

Zone: Taltson System

Interruptible Energy For Heating - Retail

Monthly Service Charge	N/A
Demand Charge:	N/A

Energy Charge:

Interruptible Energy	8.98 ¢/kWh

Interruptible Energy For Heating - Wholesale

Monthly Service Charge	N/A
Demand Charge:	N/A

Energy Charge:

Interruptible Energy	6.70 ¢/kWh

FOLLOWING IS

APPENDIX 2

ATTACHED TO AND FORMING PART OF

THE PUBLIC UTILITIES BOARD

OF THE NORTHWEST TERRITORIES

DECISION 8-2018

DATED May 25, 2018

Appendix 2 to Decision 8-2018

Executive Summary of the Northwest Territories Power Corporation's 2016/17, 2017/18 and 2018/19 General Rate Application

By letter dated June 30, 2016, the Northwest Territories Power Corporation (**NTPC)** submitted to the Northwest Territories Public Utilities Board (**Board**) its' Phase I General Rate Application. The Phase I application involves the determination of the Corporation's revenue requirement based on a forecast of costs of providing electricity service for the 2016/17, 2017/18 and 2018/19 fiscal years and, the determination of the level of revenues required to meet the revenue requirement in each year.

By letter dated March 1, 2017, NTPC submitted its Phase II General Rate Application which involves the design of rates by rate Zone and by rate class based on their respective costs of providing service.

NTPC requested to transition customers to a higher level of rates over a three-year period commencing in 2016/17. Specifically, the NTPC proposed increases in energy rates were approximately 4.8% for 2016/17, 4% for 2017/18 and 4% in 2018/19, for an aggregate increase of 12.8%. NTPC also requested to realign rates by rate Zone and by rate class to reflect the corresponding costs of providing service.

The hearing of the Phases I and II proceedings was held in the City of Yellowknife from July 10 – 13, 2017. During the course of the hearing, members of the public who had not requested intervener status were invited to participate. There were several members of the public who made presentations to the Board.

The Board's public interest mandate requires the Board to balance the interests of NTPC and those of its diverse classes of customers and Zones who were represented by Interveners. Following exchange of written interrogatories, a technical meeting and oral hearing, the Board received written Argument and Reply Argument from parties summarizing their positions with respect to the various issues considered during the proceedings.

As a result of the Phase I Decision and Compliance filing, the Board reduced NTPC's requested revenue shortfall by approximately $2 million in each of the test years. The Board also provided a number of directives to NTPC designed to improve cost accountability for NTPC's capital program and to improve efficiency of operations.

As a result of the Board's Phase I Decision and compliance filing, NTPC's requested average increase in energy rates for 2018/19 of 4% was reduced to about 2%, on average. Although the revenue requirement was reduced by about $2 million in each of 2016/17 and 2017/18, the corresponding rates were not impacted since the interim rate increases for those years would still recover less than the approved revenue requirements.

The Board's Phase II Decision and compliance filing gave effect to a realignment of rates among the rate Zones and rate classes in order to gradually move rate class rates and revenues closer towards their respective costs of providing service. As a result, the Snare Zone and Taltson Zone wholesale rates would see an increase of 1.5% effective June 1, 2018. This increase is lower than the average increase of 2% and, is intended to move the wholesale rate classes closer towards cost recovery. The Non Government residential and general service rates for all rate Zones would increase by 3% effective June 1, 2018, to move them closer towards cost recovery based on their respective costs of providing service.