Newmarket-Tay Power Distribution Ltd.

February 9, 2021

# Interrogatory Responses for Newmarket- Tay Rate Zone and Midland Rate Zone

EB-2020-0041

# INDEX

# INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

# GENERAL BOARD STAFF IR - 1

**General:**

**G-Staff-1**

**Ref 1: Updated Rate Generator Models**

OEB staff has made the following generic updates to the Rate Generator Models. Please review and confirm the updates.

- Tab 11 – Updated 2021 Uniform Transmission Rates (UTRs) and 2021 Hydro One Sub-Transmission Rates
- Tab 17 – Updated 2021 Time-of-Use (TOU) Prices
- Tab 17 – Updated the Inflation Factor for Pole Attachment Charge to 0%
- Tab 20 – Updated the Ontario Electricity Rebate (OER) to 21.2%

## RESPONSE

NT Power has reviewed and confirms the updates for the Rate Generator Models.

# BOARD STAFF NTRZ IR - 1

## Newmarket-Tay Rate Zone (NTRZ):

### NTRZ-Staff-1

### Ref 1: Rate Generator Model, Tab 3 Continuity Schedule – 2019 OEB-approved Disposition

As stated in the Decision and Rate Order for Newmarket-Tay Power's 2019 rate application (EB-2018-0055), the Group 1 account balances (as shown in screenshot below) were approved for interim disposition. In Tab 3 Continuity Schedule file in the current application, Newmarket-Tay Power reported the OEB-approved disposition amounts for 2019 in columns BE (principal) and BJ (interest).

OEB staff notes that for Accounts 1551, 1580, 1580-CBR Class B, 1584, 1586, 1588 and 1589, the disposition amounts entered in columns BE and BJ are with the opposite directional sign (i.e. a credit balance was entered as a debit balance) when compared to the OEB-approved disposition balances in EB-2018-0055 Decision. Please correct the disposition column accordingly, or provide rationale for why those adjustments are not necessary.

**Ontario Energy Board** **EB-2018-0055**
**Newmarket-Tay Power Distribution Ltd.**

**Table 7.2: Newmarket-Tay Power Main Rate Zone**
**Group 1 Deferral and Variance Account Balances**

| Account Name | Account Number | Principal Balance ($) A | Interest Balance ($) B | Total Claim ($) C=A+B |
|---|---|---|---|---|
| LV Variance Account | 1550 | 657,362 | 28,331 | 685,693 |
| Smart Metering Entity Variance Charge | 1551 | 38,216 | 2,607 | 40,822 |
| RSVA - Wholesale Market Service Charge | 1580 | (3,111,963) | (131,998) | (3,243,961) |
| Variance WMS - Sub-account CBR Class B | 1580 | 487,036 | 17,889 | 504,925 |
| RSVA - Retail Transmission Network Charge | 1584 | (476,132) | (9,632) | (485,764) |
| RSVA - Retail Transmission Connection Charge | 1586 | 426,004 | 39,272 | 465,276 |
| RSVA – Power | 1588 | 1,366,310 | 78,711 | 1,445,021 |
| RSVA - Global Adjustment | 1589 | 1,162,970 | 56,163 | 1,219,133 |
| **Totals for all Group 1 accounts** | | 549,802 | 81,344 | 631,146 |

## RESPONSE

NT Power submits a revised Rate Generator Model for NTRZ with adjustments to correct the disposition columns BE and BJ in Appendix 1.

# BOARD STAFF NTRZ IR - 2

**NTRZ-Staff-2**

**Ref 1: Rate Generator Model, Tab 3 Continuity Schedule – 2019 OEB-approved Disposition and Adjustment in Account 1595 (2014 and pre-2014)**

In the Continuity Schedule, under 2019, Newmarket-Tay Power reported a debit balance of $12,281 and a credit balance of $12,281 for principal and interest dispositions in Account 1595 (2014 and pre-2014), respectively. A principal adjustment of $10,400 is also reported for this account. In Newmarket-Tay Power's 2019 Decision and Rate Order (EB-2018-0055), there is no disposition amount approved in Account 1595 (2014) (or residual balance in Account 1595 for any year before 2014).

Please provide explanations for the above-noted disposition and adjustment amounts and update the Continuity Schedule, as needed.

## RESPONSE

NT Power has revised the updated Rate Generator Model for NTRZ in Appendix 1.

The principal and interest adjustment in Account 1595 (2014 and pre-2014) for $12,281 was an incorrect allocation in the continuity schedule between principal and interest.

The principal adjustment of $10,400 was an incorrect allocation between the principal balances. The continuity schedule has been revised within the Rate Generator Model.

# BOARD STAFF NTRZ IR - 3

**NTRZ-Staff-3**

**Ref 1: Rate Generator Model, Tab 3 Continuity Schedule – Account 1595 Sub-accounts**

**Ref 2: 1595 Analysis Workform**

**Ref 3: Manager's Summary, page 60**

As noted in the Continuity Schedule and the Manager's Summary, Newmarket-Tay Power is seeking disposition of Account 1595 for the years 2014 and pre-2014, 2015 and 2017. Newmarket-Tay Power also filed the 1595 Analysis Workform for these years.

a) According to Newmarket-Tay Power's 2017 IRM decision (EB-2016-0275), there was no disposition amount approved for Group 1 DVAs as the disposition threshold was not exceeded. In the same decision, the Shared Tax amount pertaining to 2017 was approved to be disposed through a one-year rate rider. Therefore, there should not be balances recorded in Account 1595 (2017). The Shared Tax amount of $40,969 approved in the 2018 decision (EB-2017-0062 as noted in the Manager's Summary) should be included in Account 1595 (2018). Please provide explanation for the balances reported in Account 1595 (2017) in the Continuity Schedule and 1595 Workform in the current application. Please include any necessary updates.

b) According to Newmarket-Tay Power's 2015 IRM decision (EB-2014-0095), there was no disposition amount approved for Group 1 DVAs as the disposition threshold was not exceeded. In the same decision, the Shared Tax amount pertaining to 2015 was approved to be disposed through a one-year rate rider. Therefore, there should not be balances recorded in Account 1595 (2015). Please provide explanations (detailed information with related calculations and reference) for the balances reported in Account 1595 (2015) in the Continuity Schedule and 1595 Workform in the current application. Please include any necessary updates.

c) It is noted that there were no rate applications filed for 2011 or 2013. Therefore, there was also no Group 1 account disposition approved for 2011 or 2013 and there should not be balances recorded in Account 1595 (2011) or Account 1595 (2013). Newmarket-Tay Power filed data for 2011 and 2013 in 1595 Workform. Please provide explanations for the balances filed in these two tabs (OEB-approved disposition and rate rider amounts) with supporting references, and/or make necessary updates (in 1595 Workform and Continuity Schedule), if needed.

d) In Newmarket-Tay Power's 2014 Decision and Rate Order EB-2013-0153, the OEB approved disposition of a debit amount of $665,838 for the former Newmarket Hydro and a credit amount of $331,838 for the former Tay Hydro for the pre-harmonized balances as of December 31, 2010. The OEB also approved the disposition of the credit amount of $1,257,400 for Newmarket Tay Power's post-harmonized balance as of December 31, 2012 for a combined credit balance of $923,402 as of December 31, 2012. Please provide a detailed reconciliation for the principal and interest disposition amounts Newmarket-Tay reported for 2014 in the 1595 Workform. Please explain which DVA (2014) and GA (2014) rate riders are included in the analysis in the "Step 1" table.

e) Please review the instruction notes in the "Instructions" tab of the IRM model – in cells E28 and E30. Please ensure for each Account 1595, the data is input starting from the year the sub-account started to accumulate a balance (i.e. the vintage year). There is an example in the instruction note that the applicant may follow.

## RESPONSE

a) The Account 1595 (2017) balance is the net balance of the Shared Tax amount pertaining to the 2017 IRM Decision (EB-2016-0275) for $40,969 and rate rider refunded to customers for $42,026.

b) The 1595 (2015) balance is the net balance of the Shared Tax amount pertaining to the 2015 IRM decision (EB-2014-0095) for $72,752 and rate rider refunded to customers for $74,645.

c) The 2011 disposition year is from the Decision (EB-2009-0269) for rate recovery effective March 1, 2011. It is noted within the Decision (EB-2013-0153) page 7 "remaining balance of $(330,820) is due to the recovery of the regulatory amounts from the 2010 cost of service filing and as this recovery period ended in April of 2013, it should therefore be disposed to all customers as part of Newmarket Tay Power's next application." NT Power determined the over recovery has not been disposed of within future applications to date.

d) NT Power provides the following tables for NTRZ as of December 31, 2019:
   - Table 1a provides a reconciliation for rate orders by disposition year and related decision number and category

- Table 1b provides a reconciliation for the net principle balance by disposition year and the applicable decision number
- Table 1c provides a reconciliation for carrying charges by disposition year and the applicable decision number

**1595 DVA rate order by disposition year-NTRZ**

as at Dec 31, 2019

**Table 1a**

| Disposition year | Decision # | Total Rate order | Shared Tax | LRAM | Group 1 DVA | SPC variance | Pils |
|---|---|---|---|---|---|---|---|
| 2011 Disposition | EB-2009-0269 | 1,913,004 | | | 1,913,004 | | |
| 2013 Disposition | EB-2011-0184 | (1,397,942) | (77,291) | 22,784 | | (10,400) | (1,333,035) |
| 2014 Disposition | EB-2013-0153 | (996,152) | (72,752) | | (923,400) | | |
| 2015 Disposition | EB-2014-0095 | (72,752) | (72,752) | | | | |
| 2017 Disposition | EB-2016-0275 | (40,969) | (40,969) | | | | |
| 2018 Disposition | EB-2017-0062 | 1,156,319 | (40,969) | 1,197,288 | | | |
| 2019 Disposition | EB-2018-0055 | 1,057,185 | (40,969) | 467,008 | 631,146 | | |
| | **Total** | **1,618,693** | **(345,702)** | **1,687,080** | **1,620,750** | **(10,400)** | **(1,333,035)** |

**Table 1b**

| Disposition year | Decision # | Rate order principal | Rate Rider | Balance | Net principal | Interest | Total Rate order |
|---|---|---|---|---|---|---|---|
| 2011 Disposition | EB-2009-0269 | 1,900,722 | (2,243,824) | (343,102) | | 12,282 | 1,913,004 |
| 2013 Disposition | EB-2011-0184 | (1,152,335) | 1,348,137 | 195,802 | | (245,607) | (1,397,942) |
| 2014 Disposition | EB-2013-0153 | (1,036,964) | 973,526 | (63,438) | (210,738) | 40,812 | (996,152) |
| 2015 Disposition | EB-2014-0095 | (72,752) | 70,858 | (1,894) | (1,894) | - | (72,752) |
| 2017 Disposition | EB-2016-0275 | (40,969) | 42,026 | 1,057 | 1,057 | - | (40,969) |
| 2018 Disposition | EB-2017-0062 | 1,156,319 | (1,213,274) | (56,955) | (56,955) | - | 1,156,319 |
| 2019 Disposition | EB-2018-0055 | 961,069 | (703,657) | 257,412 | 257,412 | 96,117 | 1,057,186 |
| | **Total** | **1,715,090** | **(1,726,208)** | **(11,119)** | **(11,119)** | **(96,396)** | **1,618,694** |

**Table 1c**

| Disposition year | Decision # | Rate order interest | Carrying chges | Balance |
|---|---|---|---|---|
| 2011 Disposition | EB-2009-0269 | 12,282 | (48,630) | (36,348) |
| 2013 Disposition | EB-2011-0184 | (245,607) | (2,232) | (247,839) |
| 2014 Disposition | EB-2013-0153 | 40,812 | (1,273) | 39,539 |
| 2015 Disposition | EB-2014-0095 | - | 1,766 | 1,766 |
| 2017 Disposition | EB-2016-0275 | - | 363 | 363 |
| 2018 Disposition | EB-2017-0062 | - | 21,716 | 21,716 |
| 2019 Disposition | EB-2018-0055 | 96,117 | 6,750 | 102,867 |
| | **Total** | **(96,396)** | **(21,540)** | **(117,936)** |

NT Power reviewed the Rate Generator Model, Tab 3 Continuity Schedule – Account 1595 Sub-accounts and is resubmitting the Dec 31, 2019 principal and carrying charges balances due to an input error between the principal and carrying charges balances in Appendix 1. The table below notes the revisions.

| **NTRZ Rate Generator model, Tab 3 continuity schedule-Account 1595** | | | | | | |
|---|---|---|---|---|---|---|
| **as at Dec 31, 2019** | | | | | | |
| | | | | | | |
| | **Principal balances** | | | **Carrying charges balances** | | |
| | **Original** | **Revised** | **Variance** | **Original** | **Revised** | **Variance** |
| 2014 & pre | (223,019) | (210,738) | (12,281) | (232,367) | (244,648) | 12,281 |
| 2015 | (1,894) | (1,894) | - | 1,766 | 1,766 | - |
| 2017 | 1,057 | 1,057 | - | 363 | 363 | - |
| 2018 | (56,955) | (56,955) | - | 21,716 | 21,716 | - |
| 2019 | 257,412 | 257,412 | - | 102,867 | 102,867 | - |
| **Total** | **(23,399)** | **(11,118)** | **(12,281)** | **(105,655)** | **(117,936)** | **12,281** |

Please refer to Appendix 1 for the revised Rate Generator model and Appendix 2 for the updated 1595 Analysis Workform.

# BOARD STAFF NTRZ IR - 4

### NTRZ-Staff-4

### Ref 1: Rate Generator Model, Tab 6 Class A Consumption Data

As indicated in the application, Newmarket-Tay's Account 1589 GA was last disposed on a final basis for 2012 balances, and there were Class A/B transition customers during the period that the GA balance accumulated. Therefore, in Tab 6 of the IRM model, the applicant must enter the consumption and demand data for transition customers and Class A customers in tables 3a and 3b. This tab has now been updated by OEB staff to show the year columns (the period account balances accumulated – 2013 to 2019) in tables 3a and 3b. Please enter the required data in the two tables in Tab 6 and update Tab 6.1a, Tab 6.1, Tab 6.2a and Tab 6.2, as required.

## RESPONSE

NT Power entered the required data in Tab 6, Tab 6.1a, Tab 6.1, Tab 6.2a and Tab 6.2 of the Rate Generator Model for NTRZ in Appendix 1.

For Tab 6, table 3a of the NTRZ Rate Generator Model does not provide years 2013 and 2014 for customers 4 to customer 12. NT Power provides the required information in the table below for the update required in the NTRZ Rate Gen Model on Tab 6 by Board Staff.

| Customer | | 2015 | | 2014 | | 2013 | |
|---|---|---|---|---|---|---|---|
| | | January to June | July to December | January to June | July to December | January to June | July to December |
| Customer 1 | kWh | 3,319,264 | 4,400,753 | 3,389,108 | 3,850,827 | 3,448,389 | 4,511,310 |
| | kW | 7,373 | 8,648 | 7,142 | 8,142 | 7,771 | 9,165 |
| | Class A/B | B | B | B | B | B | B |
| Customer 2 | kWh | 9,372,266 | 10,940,100 | 9,689,586 | 10,857,967 | 10,201,065 | 12,072,998 |
| | kW | 15,435 | 19,481 | 16,577 | 19,573 | 17,335 | 22,181 |
| | Class A/B | B | B | B | B | B | B |
| Customer 3 | kWh | 2,269,439 | 2,497,078 | 2,320,547 | 2,701,670 | 2,350,668 | 2,741,546 |
| | kW | 5,264 | 5,920 | 5,387 | 6,258 | 5,144 | 6,285 |
| | Class A/B | B | B | B | B | B | B |
| Customer 4 | kWh | 1,743,676 | 2,300,950 | 1,294,877 | 1,608,825 | 1,290,061 | 1,517,424 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | kW | 3,581 | 4,946 | 2,767 | 3,642 | 2,720 | 3,563 |
| | Class A/B | B | B | B | B | B | B |
| Customer 5 | kWh | 1,643,946 | 1,991,731 | 1,718,543 | 1,647,981 | 1,593,212 | 1,850,227 |
| | kW | 3,433 | 4,145 | 3,748 | 3,631 | 3,583 | 4,093 |
| | Class A/B | B | B | B | B | B | B |
| Customer 6 | kWh | 2,373,633 | 2,341,225 | 2,322,793 | 2,542,703 | 1,916,154 | 2,258,669 |
| | kW | 5,079 | 4,707 | 5,220 | 5,540 | 4,793 | 5,289 |
| | Class A/B | B | B | B | B | B | B |
| Customer 7 | kWh | 2,523,995 | 2,613,634 | 2,479,629 | 2,811,270 | 2,378,498 | 2,554,609 |
| | kW | 4,347 | 4,268 | 4,498 | 4,718 | 4,335 | 4,468 |
| | Class A/B | B | B | B | B | B | B |
| Customer 8 | kWh | 2,049,153 | 2,161,147 | 2,353,113 | 2,373,496 | 1,973,702 | 2,397,078 |
| | kW | 4,083 | 4,241 | 4,944 | 4,670 | 4,084 | 4,718 |
| | Class A/B | B | B | B | B | B | B |
| Customer 9 | kWh | 2,150,524 | 1,957,790 | 1,955,439 | 2,233,096 | 1,722,095 | 1,808,492 |
| | kW | 3,782 | 3,416 | 3,699 | 4,024 | 3,381 | 3,505 |
| | Class A/B | B | B | B | B | B | B |
| Customer 10 | kWh | 1,625,640 | 1,390,568 | 1,615,117 | 1,347,577 | 1,380,249 | 1,241,774 |
| | kW | 5,584 | 5,111 | 5,057 | 4,819 | 5,118 | 4,517 |
| | Class A/B | B | B | B | B | B | B |
| Customer 11 | kWh | 745,133 | 882,796 | 2,920,858 | 1,889,448 | 2,820,116 | 3,642,414 |
| | kW | 1,829 | 2,366 | 5,261 | 4,622 | 5,460 | 7,401 |
| | Class A/B | B | B | B | B | B | B |
| Customer 12 | kWh | 3,257,311 | 3,626,698 | 3,563,593 | 3,764,059 | 3,509,605 | 3,780,996 |
| | kW | 6,922 | 7,442 | 7,568 | 7,855 | 7,229 | 7,740 |
| | Class A/B | B | B | B | B | B | B |

## BOARD STAFF NTRZ IR - 5

**NTRZ-Staff-5**

**Ref 1: Rate Generator Model, Tab 20 Bill Impacts – RTSR**

OEB staff updated the 2021 UTRs and Hydro One Sub-transmission rates in Tab 11 of the IRM model. As shown in Tab 20 Bill Impacts, the NTRZ's Retail Transmission Service Rate (RTSR) charges have relatively high bill impacts (greater than 5% for RTSR-Network and greater than (8%) for RTSR-Connection) for all classes. As flagged in red text in column N of Tab 20, a distributor is expected to provide reasons for the change in RTSRs in the application. Please provide explanations for the large changes in the NTRZ's RTSRs.

### RESPONSE

NT Power's customers across all rate classes will experience an 8.07% to 9.09% rate decrease in RTSR - connection and or line and transformation connection. This impact was a result of a rate decreased in the UTR and Hydro One sub-transmission line connection service rates from 2020 to 2021.

In 2021, the network service rate and Hydro One sub-transmission rates for network service increased impacting all rate classes of customers by a 5.19% to 5.95% rate increase for RTSR – Network.

# BOARD STAFF NTRZ IR - 6

**NTRZ-Staff-6**

**Ref 1: LRAMVA Workform, Tab 5**

There were additional savings included in the LRAMVA calculation (such as the adjustment to the 2017 Process and Systems Update Initiative (PSUI) and 2019 savings) that were not identified in the Participation and Cost (P&C) Report.

a) Please explain how the 2017 adjustment to PSUI savings was derived, as savings of 631,244 kWh were not included in the P&C report.
b) Please explain why the 2019 savings were not included in the P&C report and why the additional project savings claimed would be eligible for lost revenue recovery.
c) Please provide supporting documentation (e.g. an excel copy of the CDM Information System (CDM-IS) report) to substantiate the additional project savings claimed in 2019, with the following data included:
    - Framework under which the savings will be delivered under (e.g. CFF wind-down framework, interim framework, etc.)
    - Date that the program was approved by the IESO
    - Expected completion date of the program
    - Expected kWh and kW savings (net)
    - Delivery agent for the program savings (e.g. LDC or IESO led)
    - Approval date of an IESO incentive
d) If supplemental reports cannot be provided in support of any project(s) identified above, please identify the project(s) and discuss the accuracy level of the savings estimates.
e) Please provide a discussion of how the persistence of 2018 energy and demand savings were estimated into 2019, including assumptions and reports used.

## RESPONSE

a) The adjustment savings of 631,244kWh were derived from the ‘Newmarket Tay projects’ file provided by the IESO and received by email on September 16, 2019. The savings were by year, program and energy savings on the ‘measures’ tab.

b) NT Power confirms the Save on Energy Heating and Cooling Program and the Save on Energy Retrofit Program savings are apart of the 2019 P&C report. Instant Savings Program was a pilot program and added to the CDM plan as part of the Conservation First Framework for approved pilot programs.

   NT Power notes that the Save on Energy High Performance New Construction Program for 2019 results is not included on the P&C report. NT Power current staff is not aware the reasoning why the IESO did not include all savings on the P&C report.

   NT Power confirms the savings are apart of the CDM-IS report submitted in Appendix 3.

   i. Conservation First Framework was in place January 1, 2015 to December 31, 2020 with an extension until June 30, 2021. Please refer to Staff IR NTRZ 6 b) ii.
   ii. Save on Energy High Performance New Construction Program – Jan 1, 2015, Instant Savings Local Program business case was approved by the IESO on March 29, 2018 with an in-market date of April 9, 2018.
   iii. These programs were no longer available from NT Power as of April 1, 2019 as they became centrally managed by the IESO. No savings are attributed to NT Power beyond April 1, 2019.
   iv. Please refer to Staff IR NTRZ 6 b) iii.
   v. Save on Energy High Performance New Construction Program – IESO led Instant Savings Local Program – LDC led
   vi. Please refer to Staff IR NTRZ 6 b) ii. The process for IESO reimbursement was originally upon project completion following the incentive paid to each customer. An invoice was sent monthly for IESO reimbursement. Within the framework the IESO changed the payments to be automatically billed to the IESO from the portal following each project application being closed monthly. For the Small Business Lighting program NT Power would invoice the IESO following the project completions.

c) NT Power submits the CDM-IS report related to NTRZ in Appendix 3.

d) Not applicable. Please refer to Staff IR NTRZ 6 b).

e) The LRAMVA historically has been based on the Final Verified Annual Results published by the IESO. Following the Ministry of Energy, Northern Development and Mines' decision on March 20, 2019 to conclude the Conservation First

Framework (CFF) led to the IESO not issuing the annual verified report format that was used historically.

The net energy savings is based on the Participation and Cost Report provided as of April 15, 2019 for the NTRZ. NT Power used the Detailed Project Level Savings file as provided by the IESO for the Net Demand Savings by program applying the outlined IESO saving calculation methodology and applicable reference table metrics with the conservative assumption that persistence for 2019 would be equal to 2018 current year savings.

# BOARD STAFF NTRZ IR - 7

**NTRZ-Staff-7**

**Ref 1: LRAMVA workform, Tabs 3 and 5**

NTRZ completed the transition to a fixed residential charge as of May 1, 2019, however, it is proposing to claim lost revenues from the residential class in 2019. As a result of the transition to the fixed residential charge, distributors will no longer experience lost revenues due to reduced consumption.

As the May 1, 2019 fixed residential charge is no longer a volumetric rate, the LRAMVA Workform calculates residential lost revenues in 2019 by taking the full year value of persisting savings from prior years into 2019 and multiplying that amount by 1/3 of the 2018 volumetric rate (i.e. Jan 1 to April 30, 2019) to calculate lost revenues for 2019, as this period was before the fixed residential charge was in place.

Please provide rationale for claiming lost revenues for the residential class for all of 2019 when the utility has transitioned to a fixed residential charge as of May 1, 2019.

## RESPONSE

NT Power requests to recover lost revenues from the residential class for the period of January 1, 2019 to April 30, 2019 based on the Board Staff’s recommended approach.

NT Power confirms it has transitioned to fully fixed residential rates as of May 1, 2019 and submitted $0.00 for cell L18 and M18 on tab 3. Distribution Rates for the LRAMVA Workform. NT Power confirms the rate allocations for CDM programs 2015- 2019 are accurate to where the savings were achieved by rate class.

# BOARD STAFF NTRZ IR - 8

**NTRZ-Staff-8**

**Ref 1: LRAMVA Workform, Tab 6**

The carrying charges on the principal balance are not calculated to May 1, 2021.

Please populate column H (cells 165-169) in Table 6-a with the corresponding monthly interest rate for the period to calculate projected carrying charges to May 1, 2021.

## RESPONSE

NT Power submits the revised LRAMVA Workform in Appendix 4 with the updated interest for 2021, Q1 on Tab 6 in cells C55, H165-169 and Tab 1a. Summary of Changes in Table A-2.

# BOARD STAFF NTRZ IR - 9

**NTRZ-Staff-9**

**Ref 1: LRAMVA Workform, Tab 1-a**

a) If Newmarket-Tay Power made any changes to the LRAMVA Workform for the NTRZ as a result of its responses to the above LRAMVA interrogatories, please file an updated LRAMVA Workform.
b) Please confirm that any changes to the LRAMVA Workform in response to any LRAMVA interrogatories are reflected in “Table A-2. Updates to LRAMVA Disposition (Tab 1-a)”.

## RESPONSE

a) NT Power submits the revised LRAMVA Workform for NTRZ in Appendix 4 with the revisions from Staff NTRZ IR -8.
b) NT Power has updated Tab 1-a. Summary of Changes.

# BOARD STAFF NTRZ IR - 10

**NTRZ-Staff-10**

**Ref 1: 2020 IRM Decision and Order EB-2019-0055, page 11**

**Ref 2: Manager's summary, page 25**

**Ref 3: Appendix 7: DVA Review External Auditor's Report**

Regarding the Group 1 DVA balances for the NTRZ, page 11 of Newmarket-Tay Power's 2019 IRM Decision and Order states the following:

> **Findings**
>
> The OEB agrees that there should be no disposition of the Group 1 DVAs in this proceeding for the NTRZ. The OEB expects Newmarket-Tay Power to ensure that all Group 1 balances for the entire period from 2013 to 2019 for the NTRZ have been thoroughly reviewed, and the results of that review are filed with the 2021 rate application. Newmarket-Tay Power undertook an independent special purpose audit for the Group 1 RSVAs for the NTRZ for the 2013 to 2017 period, before the OEB issued its accounting guidance. The OEB will leave it to Newmarket-Tay Power's discretion whether the review to be filed with the 2021 rate application is completed in-house or by an independent auditor. Whichever approach, the OEB expects sufficient detail to be filed with the OEB to support balances proposed for disposition. This review shall include an assessment of accounting and settlement practices for Accounts 1588 and 1589, all necessary workforms for the sub-accounts of Account 1595, and detailed explanations for any adjustments made.

Page 25 of manager's summary states that:

> NT Power engaged Baker Tilly an independent auditor to conduct a detailed review of Group 1 NTRZ balances for 2013 to 2019…The review includes an assessment of accounting and settlement practices for Account 1588, Account 1589 and all sub accounts of Account 1595. A review of RPP calculations, embedded generation settlement claims, CT 148 between RPP and non RPP that flow into Account 1588 and 1589 and the related controls were completed to ensure accuracy and identify any adjustments.

Regarding the scope of the engagement, OEB staff notes that the external auditor's review report in Appendix 7 states that:

> We have reviewed the accompanying Table 1: Adjustments for accounts 1588 and 1589 NTRZ, Table 2: Adjustments for account 1595 NTRZ, Table 2: GA Analysis Summary by Year, GA analysis work forms, and the 1595 analysis work forms for the period of January 1, 2013 to December 31, 2019 ("Schedules"), and

the summary other explanatory information for Newmarket-Tay Power Distribution Ltd., Newmarket-Tay Rate Zone. The Schedules have been prepared by management based on the financial reporting provisions of Article 490 of the Accounting Procedures Handbook (APH) for Electricity Distributors and other OEB accounting guidance including the APH's Frequently Asked Questions published July 2012, Guidance to the APH, issued March 2015 and new Accounting Guidance issued in February 2019 for Group 1 accounts.

OEB staff also notes that the external auditor has expressed a qualified opinion because the unreconciled difference on 2019 GA Analysis Workform is greater than 1%.

a) Please clarify whether the external auditor has reviewed the continuity schedules filed in this application for Account 1588 and Account 1589 for Main RZ?
b) Please explain whether the qualified opinion implies that there is no assurance being provided on the 2019 balances being requested for disposition in Accounts 1588 and 1589?
c) Please explain Newmarket-Tay Power's understanding of the implications, on disposition of the Group 1 balances, associated with the external auditor's basis for issuing a qualified conclusion.

## RESPONSE

a) An audit was not performed by the external accountants. The auditors performed a review engagement and as such, no audit opinion has been provided. A qualified conclusion, as per the independent practitioner's review engagement report was issued.

   The external accountants only reviewed the tables included in the IRM submission as outlined in their independent practitioner's review engagement report which was:

   *"Table 1: Adjustments for accounts 1588 and 1589 NTRZ, Table 2: Adjustments for account 1595 NTRZ, Table 2: GA Analysis Summary by Year, GA analysis work forms, and the 1595 analysis work forms for the period of January 1, 2013 to December 31, 2019"*

b) As a review engagement was performed, not an audit, a qualified conclusion, not a qualified opinion was issued.

   Limited assurance, as outlined in the independent practitioner's review engagement report has been provided on the account balances for the period of

2013-2018. The conclusion is qualified, and limited assurance cannot be provided for the 2019 balances only.

c) NT Power's understanding of the possible implications, on the disposition of the Group 1 balances, is the disposition for the 2019 balances could be deferred until the next IRM filing to ensure there are no further 2019 variances within the 2020 continuity schedules that NT Power has not identified within the 2019 continuity schedules. NT Power believes the 2013-2018 balances should be allowed for final disposition as the 2013-2018 unresolved differences are within the board's 1% guideline.

# BOARD STAFF NTRZ IR - 11

**NTRZ-Staff-11**

**Ref 1: Manager's summary, page 27**

**Ref 2: IRM Rate Generator, Tab 3. Continuity Schedule**

Page 27 of the manger's summary provides the adjustments table for both Account 1588 and Account 1589 as below:

Table 1: Adjustments for Accounts 1588 and 1589 for NTRZ

| | | Account 1588 | | | Account 1589 | | |
|---|---|---|---|---|---|---|---|
| **Year** | | **Original Balance** | **Revised Balance** | **Adjustments** | **Original Balance** | **Revised Balance** | **Adjustments** |
| **2013** | Principal | **$-** | -$17,157 | *-$17,157* | **$ -** | $ 17,157 | *$17,157* |
| | Interest | **$-** | **$-** | *$-* | **$ -** | **$-** | *$-* |
| | **Total** | **$-** | **-$17,157** | *-$17,157* | **$ -** | **$ 17,157** | *$17,157* |
| **2014** | Principal | **-$502,997** | -$460,287 | *-$42,709* | **$ -** | $ 42,709 | *$42,709* |
| | Interest | **$ 5,956** | **$ 5,956** | *$-* | **$ -** | **$-** | *$-* |
| | **Total** | **-$497,041** | **-$454,331** | *-$42,709* | **$ -** | **$ 42,709** | *$42,709* |
| **2015** | Principal | **-$502,997** | -$430,074 | *-$72,923* | **$ -** | $ 72,923 | *$72,923* |
| | Interest | **$ 5,956** | **$ 5,956** | *$-* | **$ -** | **$-** | *$-* |
| | **Total** | **-$497,041** | **-$424,118** | *-$72,923* | **$ -** | **$ 72,923** | *$72,923* |
| **2016** | Principal | **-$232,287** | -$96,810 | *-$135,478* | **$ -** | $ 135,478 | *$135,478* |
| | Interest | **$ 5,956** | **$ 5,956** | *$-* | **$ -** | **$-** | *$-* |
| | **Total** | **-$226,331** | **-$90,854** | *-$135,478* | **$ -** | **$ 135,478** | *$135,478* |
| **2017** | Principal | **-$ 1,002,809** | -$851,569 | *-$151,239* | **$ -** | $ 151,239 | *$151,239* |
| | Interest | **$ 31,856** | **$ 31,856** | *$-* | **$ 22,514** | **$ 22,514** | *$-* |
| | **Total** | **-$970,953** | **-$819,714** | *-$151,239* | **$ 22,514** | **$ 173,754** | *$151,239* |
| **2018** | Principal | **$3,330,363** | $2,438,799 | *$891,564* | **-$ 159,995** | -$ 1,051,559 | *-$891,564* |
| | Interest | **$ 116,516** | $ 116,516 | *$-* | **$ 26,095** | $ 26,095 | *$-* |
| | **Total** | **$3,446,879** | **$2,555,315** | *$891,564* | **-$ 133,900** | **-$ 1,025,464** | *-$891,564* |
| **2019** | Principal | **$ 907,098** | **$1,557,646** | *-$650,548* | **-$ 933,397** | -$311,789 | *$621,608* |
| | Interest | **$ 119,058** | **$ 119,058** | *$-* | **$ 8,469** | $ 8,469 | *$-* |
| | **Total** | **$1,026,156** | **$1,676,704** | *-$650,548* | **-$ 924,927** | **-$303,320** | *$621,608* |

OEB staff notes that the adjustments column for Account 1588 above is equal to the original balance minus the revised balance of Account 1588 while the adjustments column for Account 1589 is equal to the revised balance less the original balance of Account 1589. OEB staff notes that there are no adjustments for interest in either account.

From the review of the DVA continuity schedule for accounts 1588 and 1589, OEB staff notes that the opening balances on the continuity schedule from 2013 to 2019 match to the original balances in the adjustment table above. OEB staff also notes that the sum of the adjustments for Account 1588 of $(178,490) matches to the cell BF28 "Principal Adjustments during 2019" of the continuity schedule and the sum of the adjustments for Account 1589 for $149,500 matches to the cell BF29 "Principal Adjustments during 2019" of the continuity schedule.

a) Please confirm OEB staff's observation with respect to the formula for the adjustment columns in the Table 1.
   i) If confirmed, please confirm whether the formula for the "adjustments" columns should be consistent (i.e. the original balance less the revised balance) and update the Table 1 as necessary.
   ii) If not confirmed, please explain why the formula for the adjustment columns are not consistent for Account 1588 and Account 1589.
b) Please reconstruct the continuity schedule for Accounts 1588 and 1589 by entering the adjustments in the respective years instead of entering the sum of the adjustments in 2019. Please also recalculate the interest amounts based on the revised opening principal balances each year.

## RESPONSE

a) NT Power confirms the formula for the adjustment's columns should be consistent and provides the updated Table 1 below.

| | | Account 1588 | | | Account 1589 | | |
|---|---|---|---|---|---|---|---|
| Year | | Original Balance | Revised Balance | Adjustments | Original Balance | Revised Balance | Adjustments |
| 2013 | Principal | - | (17,157) | (17,157) | - | 17,157 | 17,157 |
| | Interest | - | (282) | (282) | - | (282) | 282 |
| | Total | - | (17,439) | (17,439) | - | 16,875 | 17,439 |
| 2014 | Principal | (2,430,144) | (2,472,853) | (42,709) | (1,417,545) | (1,374,836) | 42,709 |
| | Interest | (80,048) | (80,898) | (850) | 5,237 | 6,087 | 850 |
| | Total | (2,510,192) | (2,553,751) | (43,559) | (1,412,308) | (1,368,749) | 43,559 |
| 2015 | Principal | (2,784,310) | (2,857,233) | (72,923) | (920,037) | (847,114) | 72,923 |
| | Interest | (44,416) | (46,000) | (1,584) | 16,214 | 17,798 | 1,584 |
| | Total | (2,828,726) | (2,903,233) | (74,507) | (903,823) | (829,316) | 74,507 |
| 2016 | Principal | (2,697,752) | (2,833,230) | (135,478) | (1,009,122) | (873,644) | 135,478 |
| | Interest | (80,702) | (83,653) | (2,951) | 57,248 | 60,199 | 2,951 |
| | Total | (2,778,454) | (2,916,883) | (138,429) | (951,874) | (813,445) | 138,429 |
| 2017 | Principal | 1,098,044 | 946,805 | (151,239) | (531,445) | (380,206) | 151,239 |
| | Interest | 41,017 | 6,453 | (34,564) | 24,218 | 32,797 | 8,579 |
| | Total | 1,139,061 | 953,258 | (185,803) | (507,227) | (347,409) | 159,818 |
| 2018 | Principal | 4,366,400 | 5,257,964 | 891,564 | 373,374 | (518,190) | (891,564) |
| | Interest | 68,668 | 99,906 | 31,238 | 58,823 | 27,585 | (31,238) |
| | Total | 4,435,068 | 5,357,870 | 922,802 | 432,197 | (490,605) | (922,802) |
| 2019 | Principal | 1,557,646 | 907,098 | (650,548) | (1,555,003) | (933,395) | 621,608 |
| | Interest | 117,569 | 113,557 | (4,012) | 9,958 | 13,319 | 3,361 |
| | Total | 1,675,215 | 1,020,655 | (654,560) | (1,545,045) | (920,076) | 624,969 |

The principal and interest adjustments for 2013 and 2014 are included in the 2014 cells of the continuity schedule within the Rate Generator Model in Appendix 1.

b) The continuity schedule has been reconstructed and filed including updated amounts for interest on the revised principal balances in the Rate Generator Model in Appendix 1.

## BOARD STAFF NTRZ IR - 12

**NTRZ-Staff-12**

**Ref 1: IRM Rate Generator, Tab 3. Continuity Schedule**

**Ref 2: Newmarket-Tay's 2020 IRM Application, IR Response, February 7, 2020**

Newmarket-Tay Power, for the NTRZ, entered a principal adjustment for 2018 of $913,576 and an interest adjustment for 2018 of $22,466 in the continuity schedule for Account 1588 and the adjustments with opposite signs are in the 2018 principal adjustment and interest adjustment columns for Account 1589.

In its response to OEB staff interrogatory G-Staff-1 in the 2020 IRM proceeding, which questioned why there were no adjustments in 2018, Newmarket-Tay Power stated that "NT Power has updated the Rate Generator Model for NTRZ on tab 3. Continuity Schedule in cell BF28-BF29 and BK28-BK29 to reflect an adjustment of $913,576 principal and $22,446 interest between accounts 1588 and 1589". OEB staff is unable to locate any further explanations for the nature of these adjustments in the 2020 IRM proceeding.

a) Please explain the nature of the principal adjustment of $913,576 in Account 1588 and the nature of the principal adjustment of ($913,576) in Account 1589.

## RESPONSE

a) NT Power confirms that the principal adjustment of $913,576 was not updated to reflect the revised adjustment for the 2018 GA Analysis. NT Power submits the Rate Generator Model with the revisions in Appendix 1. Please refer to Staff IR NTRZ – 11.

## BOARD STAFF NTRZ IR - 13

**NTRZ-Staff-13**

**Ref 1: NTRZ's GA Analysis Workform**

OEB staff has compiled the figures in the cell "Net Change in Principal Balance in the GL (i.e. Transactions in the Year)" for each of the 2013 to 2019 GA Analysis Worforms as shown below:

| Item | 2013 $ | 2014 $ | 2015 $ | 2016 $ | 2017 $ | 2018 $ | 2019 $ |
|---|---|---|---|---|---|---|---|
| Net Change in Principal Balance in the GL (i.e., Transactions in the Year) | 16,941 | 873,969 | 454,799 | (162,008) | 342,237 | 753,581 | 126,155 |

OEB staff notes that, with exception for the year of 2018, the "net change in principal balance in the general ledger" on the GA Analysis Workforms does not match to the "Transaction Debit/(Credit)" column corresponding to the respective year on the continuity schedule of Account 1589.

a) When reproducing the continuity schedule in response to NTRZ-Staff-11, please ensure that the "Transaction Debit/(Credit)" column for the respective year in Account 1589's continuity schedule reconciles with the net change in principal balance in the GL on the GA Analysis Workforms.

## RESPONSE

a) NT Power submits the updated 2021 IRM Continuity Schedule in Appendix 1 to include the net change in principal balance in the GL on the GA Analysis Workforms as noted above.

# BOARD STAFF NTRZ IR - 14

**NTRZ-Staff-14**

**Ref 1: NTRZ's GA Analysis Workform**

**Ref 2: Manager's Summary, page 32**

Newmarket-Tay Power, for its NTRZ, provides the following table summarizing the reconciling items (all of them are principal adjustments) on the GA Analysis Workforms of 2013 to 2019:

Table 2: GA Analysis Summary by Year

| | | | | $ Included within 2019 Principal Adjustment of Continuity Schedule | |
|---|---|---|---|---|---|
| Year | Unresolved Difference | Unresolved Difference as % of Expected GA Payments to IESO | Reconciling Item | RSVA - Global Adjustment 1589 | RSVA - Cost of Power 1588 |
| **2013** | -$167,231 | -0.90% | $17,157 | $17,157 | -$17,157 |
| **2014** | $3,316 | 0.02% | $42,709 | $42,709 | -$42,709 |
| **2015** | $123,483 | 0.52% | $72,923 | $72,923 | -$72,923 |
| **2016** | $211,973 | 0.73% | $135,478 | $135,478 | -$135,478 |
| **2017** | $170,018 | 0.67% | $151,239 | $151,239 | -$151,239 |
| **2018** | $200,331 | 0.98% | -$891,564 | -$891,564 | $891,564 |
| **2019** | $266,742 | 1.14% | $621,608 | $621,608 | -$650,548 |
| | | | **2019 Principal Adjustment for Accounts** | **$149,550** | **-$178,490** |

Newmarket-Tay Power explains that:

> The reconciling items for the years 2013 to 2017 was a calculation issue identified where the embedded generation kWh was incorrectly allocated to the regulated price plan kWh impacting the global adjustment split annually. In 2017 and 2018, there was a reconciling item of global adjustment pertaining to Class A customers of $25,055 and $5,648 respectively. In 2018, there is a ($897,212) reallocation for global adjustment related to regulated price plan customers. In
>
> 2019, the reallocation of global adjustment related to non-regulated price plan consumption from other months due to billing processing resulted in $650,548 reconciling item. In 2019, a settlement error was identified within the submission of Class A consumption that will be requested from the IESO resulting in a decrease in the disposition amount.

Per the review of the GA Analysis Workforms, OEB staff notes that there are no reconciling items in 2013 to 2019 for "Differences in actual system losses and billed TLFs" on the workforms of 2013 to 2019 while there are differences between the calculated and approved loss factors.

In explaining the 2019 unresolved difference of 1.14% which is greater than the 1% threshold, Newmarket-Tay Power states that;

> In 2019, the unresolved differences as a percentage of expected global adjustment payments to the IESO is 1.14%. NT Power adjusted the billing period for some cycles of customers from 30 to 45 days to achieve the objective of customers being billed on the calendar month. The purpose of this adjustment to the billing period was to align the processes between the NTRZ and MRZ and improve the settlement processes for NTRZ. This adjustment to the billing cycle was a onetime adjustment impacting only some customers with the majority in the residential rate class for the usage months of August to October, 2019 for the billing months of October and November, 2019.

a) OEB staff understands that the 2013 to 2017 reconciling/adjustment items are the adjustments for the embedded generation that was 100% allocated to the RPP customers from 2013 to 2017 and have been corrected by allocating to both RPP customers and Non-RPP customers. Please confirm OEB staff's understanding of these adjustments.
    i) If confirmed, please explain the basis of the allocation to RPP and Non-RPP customers.
    ii) If confirmed, please also explain why such adjustments are not included in 2018 and 2019.
    iii) If not confirmed, please clarify the nature of the adjustments for embedded generation.
b) Please provide a detailed explanation and calculation regarding the nature of the 2018 adjustment of ($897,212) for the reallocation for global adjustment related to RPP customers.
c) Please provide a detailed explanation and calculation for the 2019 adjustment of $650,548 for the reallocation of global adjustment related to non-RPP consumption from other months due to billing processing impacts.
d) Please explain if and how the billing cycle adjustment in 2019 impacts the 2019 GA revenues that are recorded in Account 1589.
e) Please calculate the reconciling item for the "Differences in actual system losses and billed TLFs" using the table below and update the GA Analysis Workforms accordingly:

| Year | Wholesale kWh delivered to Newmarket-Tay Main RZ's Non-RPP class customers (Note 1) | Retail billed kWh by Newmarket-Tay Main RZ to Non-RPP class B customers | Unaccounted for Energy Loss Consumption kWh | Weighted Average GA rate of the Year (Note 2) | The Calculated Line Loss $ for the year |
|---|---|---|---|---|---|
| | A | B | C= B-A | D | E = C X D |
| 2013 | | | | | |
| 2014 | | | | | |
| 2015 | | | | | |
| 2016 | | | | | |
| 2017 | | | | | |
| 2018 | | | | | |
| 2019 | | | | | |

Note 1: the wholesale kWh delivered to Newmarket-Tay Main RZ's Non-RPP class B customers is to be calculated as: (AQEW +Embedded Generation kWh) x Non-RPP class B customers' retail proportion of the total retail consumption

Note 2: the weighted average GA rate of the year is to be calculated as total $ consumption at GA rate billed divided by total billed consumption kWh for Non-RPP class B customers

## RESPONSE

a) NT Power confirms OEB Staff's understanding of the adjustments.
   i. Total consumption for splitting the GA expense was revised to include RPP and non- RPP consumption, excluding embedded generation.

      The 2013 to 2017 reconciling items for the total non-RPP Class B consumption is divided by the total Class B consumption to attain the percentage allocated to non-RPP consumption.

      The monthly GA expense is multiplied by the percentage of non-RPP consumption to determine the total non-RPP GA expense. Total RPP GA expense was the net of the monthly GA expense less total non-RPP GA expense.

The reconciling amounts per year are the differences in the original GA balance (included embedded generation) versus post revised GA balance (without embedded generation).

ii. During the review of Group 1 balances for 2013-2019 requested in Decision and Order (EB-2019-0055) a variance in methodology was identified for the allocation of RPP and Non- RPP within the years 2013 to 2017 compared to 2018 and 2019 years. NT Power confirms embedded generation was not allocated within the allocation of 2018 and 2019, therefore no adjustments are required.

iii. Not applicable.

b) The 2018 adjustment of ($897,212) was due to a reporting error that impacted the allocation of global adjustment for RPP customers. The GA modifier is a credit to non-RPP customers due to the Ontario Fair Hydro Plan. This credit was recorded to GA revenues in error and was revised resulting in the adjustment.

c) The allocation between RPP and Non-RPP was previously based on billing dates. The 2019 adjustment of $650,548 is calculated based on consumption per month. NT Power confirms this adjustment is related to the 2019 period to allocate the RPP split for the actual consumption month with the summation equaling the adjustment.

d) The billing period one time adjustment from 30 to 45 days creates a timing discrepancy between when the revenue was billed versus when the Hydro One invoice and the IESO invoice for cost of power were incurred. This one time change in read dates timing within the CIS system creates an impact to the timing of GA revenues recorded in Account 1589.

NT Power notes the proration has a limitation as it does not account for seasonality experienced with heating and cooling needs that occurred in the period August to October, 2019. The period alignment of the billing schedules between rate zones will improve the long term ability for NT Power to reconcile in future years more efficiently.

e) The reconciled items for the differences in actual system losses and billed TFL's have been calculated using the table, as per below:

| Year | Wholesale kWh delivered to Newmarket-Tay Main RZ's Non-RPP class customers (Note 1) | Retail billed kWh by Newmarket-Tay Main RZ to Non-RPP class B customers | Unaccounted for Energy Loss Consumption kWh | Weighted Average GA rate of the Year (Note 2) | The Calculated Line Loss $ for the year |
|---|---|---|---|---|---|
| | A | B | C= B-A | D | E = C X D |
| **2013** | 312,031,854 | 311,696,482 | 335,372 | 0.0572 | 19,196.31 |
| **2014** | 318,606,824 | 317,957,204 | 649,620 | 0.0531 | 34,517.77 |
| **2015** | 302,564,992 | 300,520,479 | 2,044,513 | 0.0751 | 153,557.65 |
| **2016** | 291,363,081 | 288,252,569 | 3,110,511 | 0.0979 | 304,601.88 |
| **2017** | 253,978,765 | 252,911,013 | 1,067,752 | 0.1030 | 109,961.84 |
| **2018** | 224,811,089 | 223,324,899 | 1,486,190 | 0.0938 | 139,361.49 |
| **2019** | 215,635,787 | 214,195,888 | 1,439,899 | 0.1060 | 152,589.26 |

The revised GA Analysis Workform has been provided in Appendix 5 for NTRZ.

# BOARD STAFF NTRZ IR - 15

## NTRZ-Staff-15

**Ref 1:Newmarket-Tay's 2020 IRM Application EB-2019-0055, Manager's Summary, Page 36**

**Ref 2: NRTZ_1576_2EC_2BA Excel File, Tab. Appendix 2-EC_Account 1576 Final**

**Ref 3: Manager's Summary, page 63**

**Ref 4: Newmarket-Tay's 2019 IRM Application EB-2018-0055, Account 1576 continuity schedule, dated November 23, 2018**

Page 36 of Newmarket-Tay Power's 2020 IRM Application EB-2019-0055 states that:

> NT Power is in agreement with the Board's recommendation and is preparing to request final disposition of Account 1576 following the 2019 fiscal audit for the 2021 IRM Application.

The OEB approved the request in its 2020 IRM decision and order.

OEB staff reproduced part of the Appendix 2-EC Account 1576 schedule as below:

| | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|
| Reporting Basis | | | | | |
| | Actual | Actual | Actual | Actual | |
| | $ | $ | $ | $ | |
| **PP&E Values under former CGAAP** | | | | | |
| Opening net PP&E - Note 1 | 56,429,287 | 56,715,640 | 52,926,580 | 51,243,940 | |
| Net Additions - Note 4 | 4,760,269 | -410,094 | 2,626,157 | 5,823,301 | |
| Net Depreciation (amounts should be negative) - Note 4 | -4,473,916 | -3,378,965 | -4,308,797 | -4,771,330 | |
| **Closing net PP&E (1)** | 56,715,640 | 52,926,580 | 51,243,940 | 52,295,911 | |
| **PP&E Values under revised CGAAP (Starts from 2012)** | | | | | |
| Opening net PP&E - Note 1 | 64,736,570 | 66,616,066 | 62,344,565 | 61,423,535 | |
| Net Additions - Note 4 | 4,760,269 | -410,094 | 2,626,157 | 5,823,301 | |
| Net Depreciation (amounts should be negative) - Note 4 | -2,880,773 | -3,861,407 | -3,547,187 | -4,080,917 | |
| **Closing net PP&E (2)** | 66,616,066 | 62,344,565 | 61,423,535 | 63,165,920 | |
| **Difference in Closing net PP&E, former CGAAP vs. revised CGAAP** | -9,900,426 | -9,417,984 | -10,179,595 | -10,870,009 | |
| **Effect on Deferral and Variance Account Rate Riders** | | | | | |
| Closing balance in Account 1576 | -1,593,143 | 482,442 | -761,611 | -690,414 | -10,870,009 |
| Return on Rate Base Associated with Account 1576 balance at WACC - Note 2 | -111,998 | 33,916 | -53,541 | -48,536 | -764,162 |
| **Total Amount included in Deferral and Variance Account** | -1,705,141 | 516,357 | -815,152 | -738,950 | -11,634,170 |
| | Rate rider refunded 2015-2020 | | | | 9,685,922 |
| | **Variance** | | | | **-1,948,249** |

Page 63 of Newmarket-Tay Power's manager's summary, for the NTRZ, states that:

> The proposed approach is similar in nature to that which would apply during a cost of service, whereby the balance for disposition would include audited actuals plus a forecasted bridge year. The forecast for 2020 relies on 2020 opening

balances plus projections for the remainder of the year. The disposition rate rider will ensure that credits are provided to customers on their bills prior to NT Power's next cost of service. As NT Power – NRZ has previously received approval for interim dispositions, Account 1576 has been used to track both the 1576 transactions as well as the impact of previous interim disposition rate riders (excluding the rate of return on rate base component).

Newmarket-Tay Power's 2019 IRM application shows the approved balance in Account 1576 as at December 31, 2017 which was derived in the table below (copied from the revised Account 1576 continuity schedule dated November 23, 2018):

| | |
|---|---|
| **Effect on Deferral and Variance Account Rate Riders** | |
| Closing balance in Account 1576 | -8,960,160.27 |
| Return on Rate Base Associated with Account 1576 balance at WACC - Note 2 | - 629,899.27 |
| **Amount included in Deferral and Variance Account Rate Rider Calculatio** | -9,590,059.54 |
| **2017 - 1576 Disposition for Rate Rider Calculation** | -7,976,031.21 |
| **Request for 2018 - 1576 Disposition for Rate Rider Calculation** | **-1,614,028.33** |

OEB staff has compared the 2017 balance in Account 1576 between the schedule filed in the 2019 IRM application and the schedule filed in this rate application and noted the following discrepancies:

| | Rate Rider refunded $ | Difference in Closing Net PP&E as at 2017 Year end $ |
|---|---|---|
| **Per Account 1576 schedule in 2019 IRM Application** | (9,579,357) | (8,950,160) |
| **Per Account 1576 schedule in 2021 IRM Application (Current)** | (9,685,922) | (9,900,426) |
| **Difference** | (106,565) | (950,266) |

a) Please provide the 2019 Audited Financial Statements (AFS) and show how the 2019 balance of ($815,152) per the Account 1576 schedule above aligns with the balance reported in the 2019 AFS. If the balance cannot be directly matched to the 2019 AFS, please explain and provide a reconciliation.

b) Please provide the basis for the 2020 projections (Net additions and Net Depreciation).

c) Please provide the unaudited actual net additions and net depreciation for 2020 and compare these figures with the 2020 projected figures that are used in the schedule of Account 1576.

d) Please explain why 2020 net additions of $5,823,301 is significantly higher than 2019 net additions of $2,626,157.

e) Please confirm the table above compiled by OEB staff and explain the differences as applicable.

## RESPONSE

a) NT Power is providing the 2019 audited financial statements in Appendix 6.

   The ($815,152) is the 2019 annual change for Account 1576. The 2019 audited balance for Account 1576 is ($1,221,290) per RRR 2.1.7 and 2.1.13 trial balance mapping to audited financial statements filing.

   This is equal to the following:

   i. Difference in closing net PP&E CGAAP & revised CGAAP ($10,256,293)
   ii. Rate riders refunded to customers as of December 31, 2019 equalling $9,035,003.

b) The basis for the 2020 projections were provided by the management team during the 2021 budget process based on the currently filed DSP.

c) The following tables provide the unaudited actual net additions and net depreciation for 2020 compared to the 2020 projected figures used in schedule of Account 1576:

## Appendix 2-EC unaudited capital additions and depreciation

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **Reporting Basis** | IRM | IRM | IRM | IRM | IRM | | | | | |
| | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | |
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| **PP&E Values under former CGAAP** | | | | | | | | | | |
| Opening net PP&E - Note 1 | 51,625,726 | 52,002,568 | 51,583,549 | 49,735,534 | 57,873,949 | 56,429,287 | 56,715,640 | 52,926,580 | 51,243,940 | |
| Net Additions - Note 4 | 4,050,759 | 3,989,479 | 2,727,802 | 12,491,420 | 2,955,376 | 4,760,269 | -410,094 | 2,626,157 | 1,320,886 | |
| Net Depreciation (amounts should be negative) - Note 4 | -3,673,917 | -4,408,498 | -4,575,818 | -4,353,005 | -4,400,038 | -4,473,916 | -3,378,965 | -4,308,797 | -4,085,351 | |
| **Closing net PP&E (1)** | 52,002,568 | 51,583,549 | 49,735,534 | 57,873,949 | 56,429,287 | 56,715,640 | 52,926,580 | 51,243,940 | 48,479,475 | |
| **PP&E Values under revised CGAAP (Starts from 2012)** | | | | | | | | | | |
| Opening net PP&E - Note 1 | 51,625,726 | 53,883,098 | 55,285,337 | 55,135,557 | 64,799,717 | 64,736,570 | 66,616,066 | 62,344,565 | 61,423,535 | |
| Net Additions - Note 4 | 4,050,759 | 3,989,479 | 2,727,802 | 12,491,420 | 2,955,376 | 4,760,269 | -410,094 | 2,626,157 | 1,320,889 | |
| Net Depreciation (amounts should be negative) - Note 4 | -1,793,386 | -2,587,241 | -2,877,581 | -2,827,260 | -3,018,523 | -2,880,773 | -3,861,407 | -3,547,187 | -3,241,977 | |
| **Closing net PP&E (2)** | 53,883,098 | 55,285,337 | 55,135,557 | 64,799,717 | 64,736,570 | 66,616,066 | 62,344,565 | 61,423,535 | 59,502,447 | |
| **Difference in Closing net PP&E, former CGAAP vs. revised CGAAP** | -1,880,530 | -3,701,788 | -5,400,023 | -6,925,768 | -8,307,283 | -9,900,426 | -9,417,984 | -10,179,595 | -11,022,973 | |
| **Effect on Deferral and Variance Account Rate Riders** | | | | | | | | | | |
| Closing balance in Account 1576 | | | | -6,925,768 | -1,381,515 | -1,593,143 | 482,442 | -761,611 | -843,378 | -11,022,973 |
| Return on Rate Base Associated with Account 1576 balance at WACC - Note 2 | | | | -486,882 | -97,120 | -111,998 | 33,916 | -53,541 | -59,289 | -774,915 |
| **Total Amount included in Deferral and Variance Account Rate Rider Calculation** | | | | -7,412,650 | -1,478,635 | -1,705,141 | 516,357 | -815,152 | -902,667 | -11,797,888 |
| **Total LTD difference for PPE CGAAP vs REVISED CGAAP** | | | | -7,412,650 | -8,891,285 | -10,596,426 | -10,080,068 | -10,895,221 | -11,797,888 | |

## Appendix 2-EC original submission

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **Reporting Basis** | IRM | IRM | IRM | IRM | IRM | | | | | |
| | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | |
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| **PP&E Values under former CGAAP** | | | | | | | | | | |
| Opening net PP&E - Note 1 | 51,625,726 | 52,002,568 | 51,583,549 | 49,735,534 | 57,873,949 | 56,429,287 | 56,715,640 | 52,926,580 | 51,243,940 | |
| Net Additions - Note 4 | 4,050,759 | 3,989,479 | 2,727,802 | 12,491,420 | 2,955,376 | 4,760,269 | -410,094 | 2,626,157 | 5,823,301 | |
| Net Depreciation (amounts should be negative) - Note 4 | -3,673,917 | -4,408,498 | -4,575,818 | -4,353,005 | -4,400,038 | -4,473,916 | -3,378,965 | -4,308,797 | -4,771,330 | |
| **Closing net PP&E (1)** | 52,002,568 | 51,583,549 | 49,735,534 | 57,873,949 | 56,429,287 | 56,715,640 | 52,926,580 | 51,243,940 | 52,295,911 | |
| **PP&E Values under revised CGAAP (Starts from 2012)** | | | | | | | | | | |
| Opening net PP&E - Note 1 | 51,625,726 | 53,883,098 | 55,285,337 | 55,135,557 | 64,799,717 | 64,736,570 | 66,616,066 | 62,344,565 | 61,423,535 | |
| Net Additions - Note 4 | 4,050,759 | 3,989,479 | 2,727,802 | 12,491,420 | 2,955,376 | 4,760,269 | -410,094 | 2,626,157 | 5,823,301 | |
| Net Depreciation (amounts should be negative) - Note 4 | -1,793,386 | -2,587,241 | -2,877,581 | -2,827,260 | -3,018,523 | -2,880,773 | -3,861,407 | -3,547,187 | -4,080,917 | |
| **Closing net PP&E (2)** | 53,883,098 | 55,285,337 | 55,135,557 | 64,799,717 | 64,736,570 | 66,616,066 | 62,344,565 | 61,423,535 | 63,165,920 | |
| **Difference in Closing net PP&E, former CGAAP vs. revised CGAAP** | -1,880,530 | -3,701,788 | -5,400,023 | -6,925,768 | -8,307,283 | -9,900,426 | -9,417,984 | -10,179,595 | -10,870,009 | |
| **Effect on Deferral and Variance Account Rate Riders** | | | | | | | | | | |
| Closing balance in Account 1576 | | | | -6,925,768 | -1,381,515 | -1,593,143 | 482,442 | -761,611 | -690,414 | -10,870,009 |
| Return on Rate Base Associated with Account 1576 balance at WACC - Note 2 | | | | -486,882 | -97,120 | -111,998 | 33,916 | -53,541 | -48,536 | -764,162 |
| **Total Amount included in Deferral and Variance Account Rate Rider Calculation** | | | | -7,412,650 | -1,478,635 | -1,705,141 | 516,357 | -815,152 | -738,950 | -11,634,170 |
| **Total LTD difference for PPE CGAAP vs REVISED CGAAP** | | | | -7,412,650 | -8,891,285 | -10,596,426 | -10,080,068 | -10,895,221 | -11,634,170 | |

## Appendix 2-EC variance original submission vs unaudited capital additions and depreciation

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **Reporting Basis** | IRM | IRM | IRM | IRM | IRM | | | | | |
| | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | |
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| **PP&E Values under former CGAAP** | | | | | | | | | | |
| Opening net PP&E - Note 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Net Additions - Note 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -4,502,415 | |
| Net Depreciation (amounts should be negative) - Note 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 685,979 | |
| **Closing net PP&E (1)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -3,816,436 | |
| **PP&E Values under revised CGAAP (Starts from 2012)** | | | | | | | | | | |
| Opening net PP&E - Note 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Net Additions - Note 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -4,502,412 | |
| Net Depreciation (amounts should be negative) - Note 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 838,940 | |
| **Closing net PP&E (2)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -3,663,472 | |
| **Difference in Closing net PP&E, former CGAAP vs. revised CGAAP** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -152,964 | |
| **Effect on Deferral and Variance Account Rate Riders** | | | | | | | | | | |
| Closing balance in Account 1576 | | | | 0 | 0 | 0 | 0 | 0 | -152,964 | -152,964 |
| Return on Rate Base Associated with Account 1576 balance at WACC - Note 2 | | | | 0 | 0 | 0 | 0 | 0 | -10,753 | -10,753 |
| **Total Amount included in Deferral and Variance Account Rate Rider Calculation** | | | | 0 | 0 | 0 | 0 | 0 | -163,717 | -163,718 |
| **Total LTD difference for PPE CGAAP vs REVISED CGAAP** | | | | 0 | 0 | 0 | 0 | 0 | -163,717 | |

d) The 2020 net capital additions are higher than the 2019 net capital additions due to:

- 2020 net forecasted capital additions do not include asset disposals and 2019 does include asset disposals. NT Power asset disposals are recorded in the financial records at year end and were not available when developing the 1576 continuity schedule.
- NT Power deferred 2019 capital due to large customer driven projects such as the Yonge Street revitalization and VIVA rapid bus project which were mainly funded via capital contributions.
- Two large vehicles being purchased in 2020 ($1M).

e) The table provided by board staff comparing 2019 IRM application vs 2021 IRM application Rate Rider refunded $ is comparing 2019 application difference in closing net PP&E former CGAAP vs revised CGAAP with WACC to 2021 application rate rider refunded as of Dec 31, 2020.

NT Power is providing the following table to assist understanding the changes of the 2017 balances filed within the 2021 and 2019 IRMs':

| **Comparing 2021 vs 2019 IRM filings for account 1576** | | | |
|---|---|---|---|
| | Rate Rider refunded $ | Dif Closing Net PP&E at 2017 YE $ | Closing Net PP&E at 2017 YE $ incl WACC |
| Per Account 1576 schedule in 2019 IRM Application | (7,976,031) | (8,950,160) | (9,579,357) |
| Per Account 1576 schedule in 2021 IRM Application | (9,685,922) | (9,900,426) | (10,596,426) |
| **Difference** | **1,709,891** | **950,266** | **1,017,069** |

The rate raider refunded difference is due to the 2019 IRM application rate rider balance is as of December 2017 and the 2021 IRM application rate rider balance is as of December 2020.

The difference in the 2017 Closing Net PP&E between the 2019 IRM and 2021 IRM is due to the updates within the asset records as follows:

- The CGAAP asset records were maintained within excel spreadsheets by month/year and amount of capital expenditure. The net capital additions were not correctly updated within the excel spreadsheets.
- The CGAAP capital asset depreciation expense formulas were not updated for a new year of depreciation.

- The change to revised CGAAP depreciation effective 2017 due to rolling stock depreciation.  Please see board Staff IR NTRZ 17a).

The difference in the Closing Net PP&E at 2017 year-end amount including WACC is the difference in the 2017 Closing Net PP&E between the 2019 IRM and 2021 IRM include WACC.

The following table compares the 2012 to 2017 Account 1576 balances filed in the 2021 IRM to the 2019 IRM filing for PP&E values in CGAAP versus revised CGAAP:

| 2021 IRM | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| Reporting Basis | IRM | IRM | IRM | IRM | IRM | |
| | Actual | Actual | Actual | Actual | Actual | Actual |
| | $ | $ | $ | $ | $ | $ |
| **PP&E Values under former CGAAP** | | | | | | |
| Opening net PP&E - Note 1 | 51,625,726 | 52,002,568 | 51,583,549 | 49,735,534 | 57,873,949 | 56,429,287 |
| Net Additions - Note 4 | 4,050,759 | 3,989,479 | 2,727,802 | 12,491,420 | 2,955,376 | 4,760,269 |
| Net Depreciation (amounts should be negative) - Note 4 | (3,673,917) | (4,408,498) | (4,575,818) | (4,353,005) | (4,400,038) | (4,473,916) |
| **Closing net PP&E (1)** | 52,002,568 | 51,583,549 | 49,735,534 | 57,873,949 | 56,429,287 | 56,715,640 |
| | | | | | | |
| **PP&E Values under revised CGAAP (Starts from 2012)** | | | | | | |
| Opening net PP&E - Note 1 | 51,625,726 | 53,883,098 | 55,285,337 | 55,135,557 | 64,799,717 | 64,736,570 |
| Net Additions - Note 4 | 4,050,759 | 3,989,479 | 2,727,802 | 12,491,420 | 2,955,376 | 4,760,269 |
| Net Depreciation (amounts should be negative) - Note 4 | (1,793,386) | (2,587,241) | (2,877,581) | (2,827,260) | (3,018,523) | (2,880,773) |
| **Closing net PP&E (2)** | 53,883,098 | 55,285,337 | 55,135,557 | 64,799,717 | 64,736,570 | 66,616,066 |
| | | | | | | |
| **Difference in Closing net PP&E, former CGAAP vs. revised CGAAP** | (1,880,530) | (3,701,788) | (5,400,023) | (6,925,768) | (8,307,283) | (9,900,426) |
| **Return on rate base WACC** | | | | | | (696,000) |
| **Total Amt incl in Deferral & Variance Acct Rate Rider Cal** | | | | | | (10,596,426) |

| 2019 IRM | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| Reporting Basis | IRM | IRM | IRM | IRM | IRM | |
| | Actual | Actual | Actual | Actual | Actual | Actual |
| | $ | $ | $ | $ | $ | $ |
| **PP&E Values under former CGAAP** | | | | | | |
| Opening net PP&E - Note 1 | 51,625,726 | 52,120,129 | 52,165,032 | 50,542,211 | 58,836,636 | 57,284,425 |
| Net Additions - Note 4 | 4,050,759 | 4,336,894 | (415,324) | 12,661,667 | 2,955,376 | 4,760,269 |
| Net Depreciation (amounts should be negative) - Note 4 | (3,556,355) | (4,291,992) | (1,207,497) | (4,367,243) | (4,507,587) | (4,309,215) |
| **Closing net PP&E (1)** | 52,120,129 | 52,165,032 | 50,542,211 | 58,836,636 | 57,284,425 | 57,735,479 |
| | | | | | | |
| **PP&E Values under revised CGAAP (Starts from 2012)** | | | | | | |
| Opening net PP&E - Note 1 | 51,625,726 | 53,883,098 | 55,285,337 | 55,135,557 | 64,799,717 | 64,736,570 |
| Net Additions - Note 4 | 4,050,759 | 3,989,479 | (470,121) | 12,491,420 | 2,955,376 | 4,760,269 |
| Net Depreciation (amounts should be negative) - Note 4 | (1,793,386) | (2,587,241) | 320,342 | (2,827,260) | (3,018,523) | (2,811,200) |
| **Closing net PP&E (2)** | 53,883,098 | 55,285,337 | 55,135,557 | 64,799,717 | 64,736,570 | 66,685,640 |
| | | | | | | |
| **Difference in Closing net PP&E, former CGAAP vs. revised CGAAP** | (1,762,969) | (3,120,305) | (4,593,346) | (5,963,081) | (7,452,145) | (8,950,160) |
| **Return on rate base WACC** | | | | | | (629,196) |
| **Total Amt incl in Deferral & Variance Acct Rate Rider Cal** | | | | | | (9,579,357) |

| Variance | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| Reporting Basis | IRM | IRM | IRM | IRM | IRM | |
| | Actual | Actual | Actual | Actual | Actual | Actual |
| | $ | $ | $ | $ | $ | $ |
| **PP&E Values under former CGAAP** | | | | | | |
| Opening net PP&E - Note 1 | (0) | (117,561) | (581,483) | (806,678) | (962,687) | (855,138) |
| Net Additions - Note 4 | 0 | (347,415) | 3,143,126 | (170,247) | (0) | (0) |
| Net Depreciation (amounts should be negative) - Note 4 | (117,561) | (116,507) | (3,368,321) | 14,238 | 107,549 | (164,701) |
| **Closing net PP&E (1)** | (117,561) | (581,483) | (806,678) | (962,687) | (855,138) | (1,019,839) |
| | | | | | | |
| **PP&E Values under revised CGAAP (Starts from 2012)** | | | | | | |
| Opening net PP&E - Note 1 | - | - | - | (0) | (0) | (0) |
| Net Additions - Note 4 | - | - | 3,197,923 | - | - | - |
| Net Depreciation (amounts should be negative) - Note 4 | - | - | (3,197,923) | - | - | (69,574) |
| **Closing net PP&E (2)** | - | - | (0) | (0) | (0) | (69,574) |
| | | | | | | |
| **Difference in Closing net PP&E, former CGAAP vs. revised CGAAP** | (117,561) | (581,483) | (806,677) | (962,687) | (855,138) | (950,266) |

# BOARD STAFF NTRZ IR - 16

**NTRZ-Staff-16**

**Ref 1: Manager's summary, page 64**

Newmarket-Tay Power, for the NTRZ, explains the assumptions used in its componentized asset and accumulated depreciation subledgers as follows:

The IFRS componentalized asset and accumulated depreciation subledger assumptions are as follows:

- Development of a componentalized asset register of cost and accumulated depreciation as of December 31, 2017.
- An identifiable componentalize asset information was provided by NT Power's Engineering team. This included a unique asset number and an installation date. Also provided was an estimated 2017 fully installed cost for the major componentalized asset. The componentalized asset information was sourced from NT Power's GIS system.
- A useful remaining life of 14 years was used for all distribution assets effective Jan 1, 2014.
- Asset costs are assumed to be recorded to the correct APH general ledger account.
- An annual discounting price factor of 1.25% was utilized to determine the componentalized asset cost. If the decade of installation was only known, the componentalized asset cost was discounted to the mid year of the decade of installation.
- Depreciation is based on:
  - the typical useful life per Kinetrics 2010 report
  - first and last year ½ year rule
  - starts mid year of the estimated decade
- Determined accumulated depreciation was understated by $1,229,806 as of December 31, 2017.The correction was recorded within the financial records in 2018.

a) Please explain whether these assumptions have been incorporated in the AFS since the adoption of the IFRS in 2015.

   i) If not, why not?

ii) If not, please provide rationale for the following two assumptions used:

- A useful remaining life of 14 years was used for all distribution assets effective Jan 1, 2014.
- An annual discounting price factor of 1.25% was utilized to determine the componentized asset cost.

b) Please explain why there is an understatement of the accumulated depreciation as of December 31, 2017 in the amount of $1,228,806. Please also confirm if and whether this understatement has been recorded in the 2018 AFS, and explain which cell the understatement can be found on the Account 1576 schedule.

## RESPONSE

a) The IFRS componentalized asset and accumulated depreciation subledger assumptions are reflected within the audited financial statements as of December 31, 2018.

   i. The assumptions were not incorporated within the AFS in 2015 because the project was started in 2017 and completed in 2018.
   ii. To clarify, a **minimum** useful remaining life of 14 years was used for all distribution assets effective Jan 1, 2014. It was determined the minimum useful life for the distribution assets by 2018 would be 9 years left. This would provide planning time for the Engineering and Operations team to determine and manage asset replacement.
   iii. The 1.25% discount factor was determined by comparing the Bank of Canada inflation rate for the period 1995 to 2014 and reduced to account for cost efficiencies in technology and installed assets as far back as the 1930s'. The discount factor was applied to current asset replacement cost and discounted to determine asset cost based on the year installed. Mid year of the decade was assumed the install date when only the decade of install was known.

b) NT Power's asset subledger was based on a month/year and amount of capital expenditure. The applied associated useful life was within the Kinetics useful life study range.

   NT Power developed a componentalized assets using the Kinetics typical asset useful life as of Dec 31, 2017. This resulted in an understatement of depreciation expense within the revised CGAAP asset records. The correction is reflected within the Appendix 2-EC ‘Difference in Closing net PP&E, former CGAAP vs. revised CGAAP row 26 in Appendix 7.

# BOARD STAFF NTRZ IR - 17

**NTRZ-Staff-17**

**Ref 1: Manager's summary, page 66 and page 70**

**Ref 2: the Cost of Capital Parameter Update for 2021 issued by the OEB**

Page 66 of the manager's summary states that:

NT Power capitalization practice includes capitalization of costs such as materials, outside services (external contractors), labour and fleet costs. These costs are directly attributed to capital projects and the accounting treatment does not change under MIFRS requirements. NT Power does not capitalize costs that are not directly attributed to the capital projects. NT Power reviewed the depreciation expense related to transportation vehicles and determined the annual depreciation is to be allocated to rolling stock effective January 1, 2017.Rolling stock costs are allocated 90% capital vs 10% expense.

Newmarket-Tay Power, for the NTRZ, states that, with respect to one of the assumptions used to calculate a "proxy" revenue requirement adjustment related to Account 1576, "[t]he 2011 cost of capital parameters are used to determine the deemed interest and equity (net income)".

OEB staff also notes that the NTRZ uses a working capital allowance of 15% to calculate the revenue requirement adjustments.

OEB staff compiles a table below showing the comparison between the 2011 cost of capital parameters and the 2021 cost of capital parameters:

| | **2011 Cost of Capital Parameters** | **2021 Cost of Capital Parameters[1]** |
|---|---|---|
| **Short-term Debt Rate** | 2.43% | 1.75% |
| **Long-term Debt Rate** | 5.48% | 2.85% |
| **Return on Equity** | 9.66% | 8.34% |
| **Weighted Average Cost of Capital** | 7.03% | 5.00% |

[1] https://www.oeb.ca/industry/rules-codes-and-requirements/cost-capital-parameter-updates.

OEB staff notes that the adjustment to the base distribution revenue is calculated as $196,105, which represents and increase to base rates. The calculation is reproduced below:

| Determination of 2021 Proxy Revenue Requirement for 1576 | |
|---|---|
| Depreciation Expense- CGAAP | (4,771,330) |
| Depreciation Expense -MIFRS | 4,080,917 |
| Deemed Interest Expense | 333,215 |
| Income Tax Expense | 146,625 |
| Utility Net Income | 406,678 |
| Distribution Revenue | **196,105** |

a) Please explain why Newmarket-Tay Power had changed “the depreciation expense related to transportation vehicles and determined the annual depreciation is to be allocated to rolling stock effective January 1, 2017” and whether this change was made to comply with any IFRS requirement.

b) Given that OM&A expenses are not included in the determination of 2021 proxy revenue requirement in the table above, please confirm that the change in a) effective January 1, 2017 has no impact on OM&A expenses.

c) Please recalculate the adjustment to base distribution revenue using the 2021 cost of capital parameters and updated working capital allowance of 7.5%.

d) Please compare the result of b) to the proposed adjustment to the distribution revenue of $196,105.

e) Please provide Newmarket-Tay Power’s position with respect to using the 2021 cost of capital parameters and updated working capital allowance percentage to calculate the adjustment to the base rates.

f) Similarly, please provide rationale for using the 2011 approved cost of capital parameters in calculating the adjustment to the proxy revenue requirement in 2021 and going forward.

## RESPONSE

a) NT Power changed the deprecation expense related to transportation vehicles to being charged to rolling stock expense. This change was made to comply with IFRS requirement that assets be recorded at cost. Cost is defined to include costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating.

b) NT Power submits the following updated table for informational purposes only to include the impact of allocating rolling stock with vehicle depreciation expense to the OM&A expenses for the determination of 2021 proxy revenue requirement.

| **NTRZ 1576 Revenue Requirement** | | | | |
|---|---|---|---|---|
| **Determination of 2021 Proxy Revenue Requirement for 1576** | | | | |
| Depreciation Expense- CGAAP | | | | (4,771,330) |
| Depreciation Expense -MIFRS | | | | 4,080,917 |
| Deemed Interest Expense | | | | 333,332 |
| Income Tax Expense | | | | 146,676 |
| Utility Net Income | | | | 406,821 |
| OM&A Impact | | | | 24,655 |
| Distribution Revenue | | | | **221,071** |
| **Determination of 2021 Rate Base Impact and Cost of Capital** | | | | |
| **Rate Base** | | | | |
| **Net Fixed Assets** | | | | |
| Opening difference (1576) | | | | 10,179,595 |
| Closing difference (1576) | | | | 10,870,009 |
| Average difference (1576) | | | | **10,524,802** |
| | | | | |
| **Allowance for Working Capital (B)** | | | | |
| Controllable Expenses | | | | 24,655 |
| Working Capital Rate % | | | | 15% |
| Working Capital Allowance | | | | 3,698 |
| **Rate Base** | | | | **10,528,500** |
| **Capitalization/ Cost of Capital** | | | | |
| | **%** | **$** | **%** | **$** |
| Long Term Debt | 56% | 5,895,960 | 5.48% | 323,099 |
| Short Term Debt | 4% | 421,140 | 2.43% | 10,234 |
| **Total Debt** | 60% | **6,317,100** | **5.28%** | **333,332** |
| | | | | |
| Equity | 40% | **4,211,400** | **9.66%** | **406,821** |
| | | | | |
| Total | | **10,528,500** | **7.03%** | **740,154** |
| **Determination of Taxable Income** | | | | |
| Utility Net Income | | | | 406,821 |
| A. Income Taxes - 26.5% | | | | 107,808 |
| B. Gross up of Income Taxes | | | | 38,868 |
| Income tax expense (A+B) | | | | **146,676** |
| **Determination of OM&A Impact for Rolling Stock** | | | | |
| 2019 rolling stock depreciation | | | | 246,547 |
| OM&A % | | | | 10% |
| OM&A Impact | | | | **24,655** |

c) The following table recalculates the adjustment for informational purposes only to the base distribution revenue using the 2021 cost of capital parameters and updated working capital allowance of 7.5% impact:

| NTRZ 1576 Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| **Determination of 2021 Proxy Revenue Requirement for 1576** | | | | | |
| | | | | Cost of Capital parameters | |
| | | | | 2021 | 2011 |
| Depreciation Expense- CGAAP | | | | (4,771,330) | (4,771,330) |
| Depreciation Expense -MIFRS | | | | 4,080,917 | 4,080,917 |
| Deemed Interest Expense | | | | 175,343 | 333,332 |
| Income Tax Expense | | | | 126,589 | 146,676 |
| Utility Net Income | | | | 351,107 | 406,821 |
| Distribution Revenue | | | | **(37,374)** | **221,071** |
| | | | | | |
| **Determination of 2021 Rate Base Impact and Cost of Capital** | | | | | |
| | | | | | |
| **Rate Base** | | | | | |
| **Net Fixed Assets** | | | | | |
| Opening difference (1576) | | | | 10,179,595 | 10,179,595 |
| Closing difference (1576) | | | | 10,870,009 | 10,870,009 |
| Average difference (1576) | | | | **10,524,802** | **10,524,802** |
| | | | | | |
| **Allowance for Working Capital (B)** | | | | | |
| Controllable Expenses | | | | - | - |
| Working Capital Rate % | | | | 7.5% | 15.0% |
| Working Capital Allowance | | | | - | - |
| **Rate Base** | | | | **10,524,802** | **10,528,500** |
| | | | | | |
| **Capitalization/ Cost of Capital** | | | | | |
| | **%** | **$** | **%** | **$** | **$** |
| Long Term Debt | 56% | 5,893,889 | 2.85% | 167,976 | 323,099 |
| Short Term Debt | 4% | 420,992 | 1.75% | 7,367 | 10,234 |
| **Total Debt** | 60% | **6,314,881** | **2.78%** | **175,343** | **333,332** |
| | | | | | |
| Equity | 40% | **4,209,921** | **8.34%** | **351,107** | **406,821** |
| | | | | | |
| Total | | **10,524,802** | **5.00%** | **526,451** | **740,154** |
| | | | | | |
| **Determination of Taxable Income** | | | | | |
| Utility Net Income | | | | 351,107 | 406,821 |
| A. Income Taxes - 26.5% | | | | 93,043 | 107,808 |
| B. Gross up of Income Taxes | | | | 33,545 | 38,868 |
| Income tax expense (A+B) | | | | **126,589** | **146,676** |

d) Please refer to Staff IR NTRZ 17 c).

e) Please refer to Staff IR NTRZ 17 f).

f) NT Power is using the 2011 approved cost of capital parameters in calculating the adjustment to the proxy revenue requirement in 2021 and going forward. The most recent approved cost of capital parameters for NTRZ is the cost of capital parameters from the NT Power's cost of service application (EB-2009-0269). This approach is consistent with Whitby Hydro's Decision on December 20, 2018 for final disposition of Account 1576, Settlement Proposal Table 1 on page 8 and Application page 14-15 (EB-2018-0079).

# BOARD STAFF NTRZ IR - 18

**NTRZ-Staff-18**

**Incremental Capital Module (ICM)**

**Ref 1: 3.3.2 Incremental Capital Module, p. 41-57**

**Ref 2: EB-2014-0138 Rate-making Associated with Distributor Consolidation, March 26, 2015**

**Ref 3: EB-2017-0269 Decision and Order, August 23, 2018**

In reference 2 it states “The OEB believes that its proposal to allow a combined entity who is operating under an Annual IR plan to make use of the ICM is reasonable, effective and will address distributors’ concerns over capital investment during a deferred rebasing period which may encourage consolidation efforts.”

In 2018, the OEB approved the amalgamation of the former Newmarket-Tay Power Distribution Ltd. and former Midland Power Utility. In this application, Newmarket-Tay Power is seeking ICM amounts for two true-up payments made to Hydro One, one in 2015 and one in 2021.

a) Please explain why Newmarket-Tay Power believes it is eligible for ICM costs that were incurred in 2015, which was prior to the ICM being available to Newmarket-Tay Power as a consolidated utility.

b) Newmarket-Tay Power showed that the true-up amount in 2015 was 174.8% above its capital expenditure plan. Please explain why Newmarket-Tay Power decided not to rebase between 2015 to 2018 in light of this incremental capital need.

## RESPONSE

a) NT Power was ordered to construct Holland TS by the OEB on Nov. 22, 2005 (EB-2005-0315). The station construction was for the purpose of ensuring adequate supply for York Region. The construction of that project was for the direct benefit of NT Power customers which have been using the Holland TS continuously since its in-service date.

   Both the 2015 and 2021 true-up payments to Hydro One meet all the criteria for ICM funding.

NT Power does not have the financial capacity to carry the 2015 true up amounts any longer without rate recovery. Ratepayers should no longer receive service from the Holland TS for free.

The continuation of status quo will negatively impact the ongoing financial viability of NT Power. Evidence in Table 2 of the ICM Application demonstrates that NT Power's achieved ROE since the 2015 true-up was paid has been on-average 2.25% less than the OEB's deemed ROE.

The final audits for 2020 financials are pending, the achieved ROE for 2020 is currently forecasted to be 6.41%, which is 3.25% less than the deemed rate of return applicable to NT Power of 9.66%.

Lack of ICM funding for the 2015 Holland TS true-up would also materially impact forecasted 2021 ROE, falling to 4.81% if the OEB denies ICM funding for the 2015 Holland TS true-up. This is 485 basis points less than the Board's deemed ROE applicable to NT Power, which would normally trigger an off-ramp in the OEB's standard rate setting process.

The use of the ICM funding mechanism is a much less costly and disruptive method to address the ongoing financial viability of NT Power while ensuring ratepayers that are benefiting from the Holland TS station would be paying for the remaining undepreciated value of the 2015 Holland TS true-up on a going forward basis.

It addresses the serious issues of financial viability of NT Power which have been created by this situation. This ensures that the customers of NT Power and Midland continue to get the benefit of the deferred rebasing commitments made in the MAAD's application without the need for a costly and cumbersome early rebasing.

b) As the management involved in the original CCRA and first true up are no longer with the organization we can not speak to any considerations that may or may not have happened in regard to filing an ICM application or a rebasing application before this opportunity.

## BOARD STAFF NTRZ IR - 19

**NTRZ-Staff-19**

**Incremental Capital Module (ICM)**

**Ref 1: NTPower_NTRZ_2021 ACM ICM Model 2015 contribution_20201123**

**Ref 2: NTPower_NTRZ_2021 ACM ICM Model 2021 contribution_20201123**

**Ref 3: Reporting and Record Keeping Requirements (RRR) 2.1.5.4 (2020)**

Newmarket-Tay Power is requesting an ICM of $6M in reference 1 for 2015 and requesting an ICM of $6.1M in reference 2 for 2021.

a) Please explain why Newmarket-Tay Power finds it appropriate to have the two ICM amounts in two models when Newmarket-Tay Power is requesting a total of $12.1M in 2021. Please file the amounts in one model.
b) Newmarket-Tay Power used an inflation rate of 1.2%, however, the OEB's inflation factor for 2021 is 2.2%. Please update the inflation rate for the model.
c) In tab 3 of the model, Newmarket-Tay Power used 287,574,484kWh for the GS 50 to 4,999kW rate class. The 2020 RRR filing shows 280,813,981kWh. Please confirm which value is correct.
d) In tab 3 of the model, Newmarket-Tay Power used 780,649kW for the GS 50 to 4,999kW rate class. The 2020 RRR filing shows 737,077kW. Please confirm which value is correct.
e) Please provide a copy of the load forecasting model from the 2010 cost of service settlement proposal.
f) If Newmarket-Tay Power intends to update the Distribution System Plan CAPEX, please provide justification.

## RESPONSE

a) NT Power believes it is appropriate to file two models because a single model does not properly include 2015 maximum eligible incremental capital within the 2021 maximum allowed incremental capital. A single model calculates the 2021 maximum allowed incremental capital by assuming both contributions were paid in 2021. The contributions payments are made in 2015 and 2021 respectively.

NT Power is providing the one model for the 2015 and 2021 contributions as requested as file name Staff 19 a 2021 ACM ICM Model 2021 and

2015 contributions in Appendix 8. The following updates are provided within the one model:

- Inflation factor is updated to 2.2% from 1.2%.
  Please refer to Staff IR NTRZ 19 b).
- GS<50 kWh and kW is updated to 280,813,982 and 737,078 from 287,574,484 and 780,648, respectively.
  Please refer to Staff IR NTRZ 19 b).
- 2021 Distribution System Plan CAPEX is increase by $5,587,756 to account for 2015 maximum allowed incremental capital. Please refer to Staff IR NTRZ 19 b).

b) NT Power is submitting revised excel models for the 2015 and 2021 contributions in Appendix 9 and Appendix 10 updating the inflation rate within the models to 2.2% and correcting the 2019 GS<50 kWh and kW per the 2020 RRR filing with file names Staff 19 b c d Appendix F.

The following table provides a summary of the impact to the incremental revenue requirement by contribution year by updating the inflation rate to 2.2% and correcting the GS<50 kW and kWh per the 2020 RRR filing:

| **Impact for 2015 and 2021 contribution** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Inflation rate to 2.2% from 1.2% and corrected GS<50 kWh and kW | | | | | | | | | |
| | | | | | | **Total impact infla and GS<50 correction** | | | |
| | **Inflation rate** | **GS<50 kWh** | **GS<50 kW** | **ACM/ICM** | **2021 DSP CAPEX** | **Materiality threshold** | **Max EIC** | **Max allowed IC** | **Incremental RR** |
| 2015 Contribution update | 2.2% | 280,813,982 | 737,078 | 6,001,560 | 12,496,855 | 6,909,099 | 5,587,756 | 5,587,756 | 548,518 |
| 2015 Contribution previous | 1.2% | 287,574,484 | 780,648 | 6,001,560 | 12,496,855 | 6,141,611 | 6,355,244 | 6,001,560 | 589,138 |
| **2015 impact** | | | | - | | **767,488** | **(767,488)** | **(413,804)** | **(40,620)** |
| | | | | | | | | | |
| 2021 Contribution update | 2.2% | 280,813,982 | 737,078 | 6,100,000 | 12,496,855 | 6,909,099 | 5,587,756 | 5,587,756 | 554,701 |
| 2021 Contribution previous | 1.2% | 287,574,484 | 780,648 | 6,100,000 | 12,496,855 | 6,141,611 | 6,355,244 | 6,100,000 | 605,552 |
| **2021 impact** | | | | - | | **767,488** | **(767,488)** | **(512,244)** | **(50,851)** |

c) Please refer to Staff IR NTRZ 19 b).

d) Please refer to Staff IR NTRZ 19 b).

e) NT Power 2010 COS weather normalized distribution system load forecast with the 2010 test year was provided by the Elechus Research Associates report dated March 10, 2010 and the 2010 cost allocation model (EB-2009-0269). NT Power has been unable to locate a load forecast from the settlement proposal.

f) Please refer to Staff IR NTRZ 19 a).

# BOARD STAFF NTRZ IR - 20

**NTRZ-Staff-20**

**Incremental Capital Module (ICM)**

**Ref 1: ICM Appendix A – CCRA NT Power and Hydro One dated February 2008**

**Ref 2: ICM Appendix C – Summary of Contribution Calculations – Transformation Pool 1st True-up from Hydro One**

In appendix A the Transformation Connection Pool work allocated to Newmarket-Tay Power was $8.459M, the Line Connection work allocated to Newmarket-Tay Power was $0.958M, and the Network Customer Allocated work was $0.14M. The total amount was $9.557M. In total, Newmarket-Tay Power forecasts to have incurred $14.28M as a result of differences in the load forecasted provided in the CCRA and the actual load in 2015 and 2020. Newmarket-Tay Power is requesting a total of $12.1M from the ICM and this is due to the limitations of the materiality threshold Newmarket-Tay Power provided for 2015.

a) Please provide the load forecasts Newmarket-Tay Power provided Hydro One for 2009, 2014, and 2020 used for the DCF calculations.

b) Please provide the DCF table Hydro One provided Newmarket-Tay Power for the 2021 true-up calculation, preferably in excel format.

c) In reference 2, the updated load forecast shows a final loading of 37.7MW as compared to the CCRA final loading of 54.6MW. Please provide the assumptions used to forecast the 54.6MW and the changes in those assumptions that resulted in the new forecast of 37.7MW. For each change in assumption please explain how it was not foreseeable at the time of the original forecast of 54.6MW.

d) For the 2021 DCF table provided, please explain the changes in assumptions used for the load forecast in the 2015 DCF table as compared to the 2021 DCF table. For each change in assumption explain how it was not foreseeable at the time of the 2015 DCF calculation.

e) Based on the historical over forecast of load, does Newmarket-Tay Power anticipate a true-up amount in year 15? If not, please explain why not.

f) Please explain why it is appropriate for Newmarket-Tay Power customers to be responsible for the difference in time value of money between the capital contribution amount that should have been paid in 2009 and the time the true-up payment is paid, given that this resulted from Newmarket-Tay Power's inaccurate load forecasting.

## RESPONSE

a) The load forecasts NT Power provided Hydro One has been provided. Supporting documents are also provided for reference.
    - 2009 load forecast can be found in ICM Appendix B: Hydro One CCRA Actual Cost Revised Schedule B, submitted as Appendix 11
    - 2014 load forecast can be found in Hydro One 5-year true up contribution model, submitted as Appendix 12
    - 2020 load forecast in Hydro One 10-year true-up customer input package, submitted as Appendix 13

b) Hydro One is currently reviewing the data provided by NT Power in the 10-year true-up customer input package. Based on conversations in mid-January, Hydro One anticipates providing the final 10-year true-up calculation within the next two months.

c) At the time when the load forecast was provided to Hydro One for the CCRA the demand for electricity in York Region exceeded the capacity of the existing electricity infrastructure in the region. NT Power was experiencing an average yearly load growth of 3.5%.

   The Board directed the York Region Utilities and Hydro One to identify the optimal transmission and/or distribution infrastructure investment to serve York Region (EB-2005-0315 Decision and Order dated November 22, 2005, pg. 3). By the time the station was constructed and in-service, the Town of Newmarket experienced an economic downturn, similar to the rest of the province, which resulted the loss of customers and about a 10% (13MW) decrease in system load. Since then, NT Power has not experienced the type of load growth that was seen in the years prior to the connection of the new station.

d) For the 2021 DCF, a more conservative load forecast (0.7% yearly growth) was used to take into account the decelerated load growth experienced since the original CCRA was executed.

e) Based on the 2020 load forecast and preliminary data calculated in the Hydro One true-up contribution model, NT Power does not anticipate a true-up amount in year 15. However, if the load does not materialize in the next five years then a true-up payment may be required in year 15.

f) The Load Forecast used in the Connection Cost Recovery Agreement (CCRA) with Hydro One was the best information available at the time. NT Power in good faith made the best estimation at the time for continued growth in the Newmarket/York Region. CCRA agreements are designed with the knowledge that estimating load growth over a 25 year period is inherently difficult and therefore includes true-up provisions in years 5, 10 and 15. The models also include an OEB approved time value of money competent which recognizes the cost of payments being spread out over time as opposed to making a single payment at the beginning of the project. NT Power does not believe there is anything unique in it's ask to include total costs recovery within its ICM application.

Hydro One, as a transmitter, is required to calculate any capital contribution to be made by the load customer using the economic evaluation methodology set out in section 6.5 of the Transmission System Code[1]. Specifically, section 6.5.6 provides that:

> "Where a true-up calculation shows that a load customer's actual load and updated load forecast is lower than the load in the initial load forecast, and does not generate the initial forecast connection rate revenues, a transmitter shall require the load customer to make a payment to make up the shortfall, adjusted appropriately to reflect the time value of money."

This methodology is consistent with how Hydro One calculated CCRA true-up payments for other local distribution companies in Ontario and is not unique to NT Power. These CCRA true-up payment capital contributions have been previously approved by the Ontario Energy Board in the following proceedings:

- EB-2020-0002 - Goreway TS CCRA true-up for Alectra Utilities Corporation;
- EB-2017-0024 - Pleasant TS CCRA true-up for Alectra Utilities Corporation;
- EB-2015-0065 - Churchill Meadows CCRA true-up for Enersource Hydro Mississauga; and
- EB-2018-0021 - Tremaine TS CCRA true-up for Burlington Hydro Inc.

The OEB has never previously denied the time value of money component of the true-up payment for any other LDC in Ontario. To do so in this case would be to treat Newmarket-Tay Power both unjustly and unreasonably, in a manner inconsistent with other LDCs in Ontario.

[1] Ontario Energy Board, Transmission System Code Last Revised December 18, 2018 (Originally Issued on July 14, 2000).

# BOARD STAFF NTRZ IR - 21

**NTRZ-Staff-21**

**Distribution System Plan (DSP)**

**Ref 1: Newmarket-Tay Power DSP – Table 2 – Modified Capital Investment Summary, p. 13**

**Ref 2: Newmarket-Tay Power DSP – Table 25 – DSP Spending Program Variances, p. 58**

**Ref 3: Newmarket-Tay Power DSP – Table 58 – Material Capital Expenditures 2020-2024**

Newmarket-Tay Power provided a total capital expenditure of $7.37M in 2021, which excludes the CCRA true-up amount to Hydro One. The average capital expenditures between 2020 to 2024 is $7.27M. The historical average actual capital expenditure is $4.09M between 2016 and 2019.

a) Please explain the driver(s) for the forecasted increase in average capital spending of $7.27M and how Newmarket-Tay Power has paced its capital projects to minimize the increase.
b) Please prioritize the list of capital investments in reference 3.

## RESPONSE

a) The main driver behind the increased DSP forecast related to the Asset Condition Assessment (ACA) carried out by NT Power. The ACA showed that NT Power's historical asset spending was unsustainable in maintaining asset condition. NT Power was cognisant of the results of the ACA and understands the realities of ramping up a capital program. As such NT Power has paced all categories of replacement to levels under the recommendation of the ACA. NT Power believes this strategy provides a balance between maintaining system infrastructure and pacing required system investments.

b) Refer to DSP section 5.3.1 and 5.4.1b for an understanding of how NT Power prioritizes projects. As NT Power is underspending, the requirements of the ACA, all listed projects maintain priority.

# BOARD STAFF NTRZ IR - 22

**NTRZ-Staff-22**

**Customer Preferences**

**Ref 1: Newmarket-Tay Power DSP – Table 44 – Customer Service Preferences, p. 101**

The UtilityPULSE Survey shows that on average 46% of customers want better prices/lower rates.

a) Please explain how Newmarket-Tay Power has reduced capital expenditures from historical years to address customers' concerns.

## RESPONSE

a) NT Power has not rebased in over a decade, meaning NT Power contribution to cost increase over that time frame has been less then inflation. NT Power's ranking in the annual PEG Benchmarking Report's demonstrates NT Power's cost have run 10% lower based on the stretch factor assignment. This type of underinvestment in a utility can be managed for short periods of time but is not sustainable for the long-term health and viability of the utility.

# BOARD STAFF NTRZ IR - 23

**NTRZ-Staff-23**

**System Renewal**

**Ref 1: Newmarket-Tay Power DSP – 5.4.3 Justifying Capital Expenditures, p. 123**

**Ref 2: Newmarket-Tay Power DSP – Material Investments – Planned Pad mount Transformer Replacement, pp. 140-141**

Newmarket-Tay Power stated that it used an Asset Condition Assessment (ACA) to inform its development of the DSP. Newmarket-Tay Power also stated that its strategy is to gradually increase its replacement of end-of-life assets over a 10-year period.

a) Please provide the ACA used for the DSP.

b) Please explain why the gradual increase to the system renewal budget cannot begin after 2021

In reference 2, Newmarket-Tay Power shows the number of units of pad mount transformers it plans to purchase and replace each year along with the net capital cost. The average cost per pad mount transformer based on the table provided is $4,095 for 2020, $5,719 for 2021, and $3,606 for 2022-2024.

c) The average unit cost per pad mount transformer in 2021 ranges between 40%-59% higher than other years. Please explain the reason for the higher unit cost.

## RESPONSE

a) NT Power submits the ACA used for the DSP in Appendix 14. The ACA data assessment contains eleven recommendations for NT Power. The recommendations state action is required within 5 years for three substation transformers, 58 pole mounted transformers, 109 pad mounted transformers, 565 poles, and 110 conductor km.

b) Deferring this required system investment increases the risks to reliability and security of the supply beyond to point where management would no longer be operating the assets in a prudent and responsible manner.

   It is important to note that under the OEB’s rate setting policies customers are not currently funding these 2021 base capital expenditures in excess of depreciation, and that any increases are funded entirely through returns until the time of the next rebasing. In this context, there is a very strong financial incentive on management to strike an appropriate balance between managing

2021 capital expenditure levels and ensuring the reliability and security of supply of the distribution system over the long term.

The ACA clearly identifies an under investment in system assets across multiple types of assets. The utility is also having to step up investment in areas like metering (MIST meter project and smart meter resealing program) and IT (cyber security preparedness and corporate integration). The longer NT Power pushes off these types of investments the greater the risk becomes to the organization to meet its obligations for system renewal, regulatory compliance and cyber security investment. NT Power recognizes the investment is required for the future success of the utility.

c) Padmount transformers vary in price based on the number of phases, capacity rating, voltage and configuration. The typical cost of a single phase transformer is between $4,500 to $6,500 whereas three phase transformers range in price from $14,000 to $20,000. However, the average labour and equipment cost to replace a padmount transformer is approximately $3,000, irrespective of number of phases and size.

The lead times associated with the delivery of transformers is typically quite long (6-10 months). As a result, padmount transformers are ordered well in advance to ensure adequate inventory for the replacement program.

In anticipation of replacements beginning in 2021, a larger than average purchase order of three phase transformers was placed in 2020. Due to the higher typical cost of three phase transformers, the average unit cost for 2021 was greater in comparison to other years.

# BOARD STAFF NTRZ IR - 24

**NTRZ-Staff-24**

**System Service**

**Ref 1: Newmarket-Tay Power DSP – Material Investments – Station System Service, pp. 156-157**

Newmarket-Tay Power has two projects planned in reference 1 for 2021, both of which appear to be related to reliability concerns.

a) Please explain the operational risk, if any, of deferring these two projects by one year.

## RESPONSE

a) The primary driver is to replace and modernize legacy station infrastructure (protection relays, recloser switch) that have exceeded their useful life and are both technically and functionally obsolete. Many are no longer supported by their manufacturer and there are limited parts available to continue to repair these assets moving forward. In addition, the older station protection and control components have electromechanical mechanisms that require periodic recalibration and lack modern communications and fault recording capabilities that support high speed fault restoration and analysis.

   In recent years, there have been recurring issues with electromechanical relays on the NT Power distribution system. Deferring the upgrades will increase the probability of station relay failure, which would result in prolonged customer outages. Replacement of end of life infrastructure with modern technology will support more sophisticated protection schemes and provide additional fault information at higher speeds. This will allow system controllers to make more informed decisions in order to safety operate the system and respond to outages within a reasonable timeframe.

# BOARD STAFF NTRZ IR - 25

**NTRZ-Staff-25**

**General Plant**

**Ref 1: Newmarket-Tay Power DSP – Material Investments – Replacement of Fleet Equipment, pp. 160-161**

In reference 1, Newmarket-Tay Power showed a list of fleet equipment planned to be replaced between 2020 to 2024. These replacements are assessed to be at economic end-of-life.

a) Are the replacements of fleet vehicles based on a condition assessment? If so, please provide the condition assessment for the vehicles listed in reference 1. If not, how does Newmarket-Tay Power assess economic end-of-life?

## RESPONSE

a) NT Power submits vehicle condition assessments for the 2020-2024 timeframe in Appendix 15.

*Midland Rate Zone (MRZ):*

## BOARD STAFF MRZ IR - 1

**MRZ-Staff-1**

**Ref 1: 1595 Workform – Account 1595 (2017)**

**Ref 2: Rate Generator Model, Tab 3 Continuity Schedule – Account 1595 (2017)**

In Tab 1595 2017 of the 1595 Workform for MRZ, Newmarket-Tay Power reported Carrying Charges on Net Principal and Total Residual Balances in columns I and J (as shown below).

| Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition | Carrying Charges Recorded on Net Principal Account Balances | Total Residual Balances |
|---|---|---|
| $803 | $36 | **$839** |
| $11,867 | $1,698 | **$13,565** |
| $12,670 | $1,734 | **$14,404** |
| | **Total residual balance per continuity schedule:** | $14,404 |
| | **Difference (any variance should be explained):** | **$0** |

a) Please provide explanation for the Carrying Charges of $36 and $1,698 (or the total of $1,734) and how these amounts can be reconciled with the interest transaction amounts in Account 1595 (2017) in the Continuity Schedule.

b) Please explain the "Total Residual balance per continuity schedule" amount of $14,404 and how it can be reconciled with the balances reported in the Continuity Schedule.

## RESPONSE

a) The following table outlines the interest balance as per the continuity schedule.

| Dispostion year | Rate order interest | Rate Rider | Carrying charges on net dispositon balance | Balance |
|---|---|---|---|---|
| 2017 Disposition - Group 1 accounts | (19,012) | 18,799 | | (213) |
| 2017 Disposition - GA | 3,940 | | 1,698 | 5,638 |
| 2017 Shared Tax Savings | | | 36 | 36 |
| 2012-2016 Shared tax savings | | | (728) | (728) |
| Total | (15,072) | 18,799 | 1,006 | 4,733 |

Decision and Rate Order (EB-2016-0092) approved Group 1 interest of ($19,012) and GA interest $3,940.00. The Decision (EB-2016-0092) also approved the calculated shared tax savings amount of $1,017. The $36 represents the carrying charges on the net principal account balance of the 2017 shared tax savings amount. The carrying charges calculated on the net principal GA account balance total to $1,698.

The Group 1 account balances approved for disposition totaled ($1,297) in principal and ($19,012) in interest (EB-2016-0092). No carrying charges were calculated on these balances during the disposition period.

Shared Tax Savings 2010-2016 approved in previous applications provide for principal balances of ($5,108) and interest of ($728). These balances were grouped with the 2017 disposition amounts in the RRR filing. These shared tax savings balances from 2010-2016 have not been included in any previous Account 1595 dispositions due to the small balances.

b) The total residual balance in the 1595 Workform does not include the 2010-2016 Shared Tax Savings principal balance of ($5,108) and interest balance of ($728) which are included in the continuity schedule balance of $8,568.

# BOARD STAFF MRZ IR - 2

**MRZ-Staff-2**

**Ref 1: LRAMVA Workform, Tab 5**

There were additional savings in 2019 included in the LRAMVA calculation that were not identified in the P&C Report.

a) Please explain why the 2019 savings were not included in the P&C report and why the additional project savings claimed would be eligible for lost revenue recovery.

b) Please provide supporting documentation (e.g. an excel copy of the CDM-IS report) to substantiate the additional project savings claimed in 2019, with the following data included:

- Framework under which the savings will be delivered under (e.g. CFF wind-down framework, interim framework, etc.)
- Date that the program was approved by the IESO
- Expected completion date of the program
- Expected kWh and kW savings (net)
- Delivery agent for the program savings (e.g. LDC or IESO led)
- Approval date of an IESO incentive

c) If supplemental reports cannot be provided in support of any project(s) identified above, please identify the project(s) and discuss the accuracy level of the savings estimates.

d) Please provide a discussion of how the persistence of 2018 energy and demand savings were estimated into 2019, including assumptions and reports used.

## RESPONSE

a) The P&C report demonstrates the savings for the Save on Energy Heating and Cooling program for 2019.

   NT Power current staff is unaware the reason the IESO did not include all savings on the P&C report.

NT Power submits the CDM- IS report for the CDM savings in Appendix 16 for MRZ.

b) NT Power submits the CDM-IS report related for MRZ in Appendix 16.
   i. Conservation First Framework
   ii. All Programs were province wide programs and began Jan. 1, 2015 as part of the Conservation First Framework (CFF)
   iii. These programs were no longer available from NT Power as of April 1, 2019 as they were taken over by the IESO and managed centrally. No savings will be attributed to NT Power beyond April 1, 2019. Save on Energy Heating and Cooling Program ended March 21, 2019.
   iv. Please refer to Staff IR NTRZ 2 b) iii.
   v. Save on Energy Retrofit Program – LDC led
      Save on Energy Heating and Cooling Program – IESO led
      Save on Energy Small Business Lighting Program – LDC led
   vi. Please refer to Staff IR NTRZ 6 b) vi.

c) Not applicable.

d) The LRAMVA historically has been based on the Final Verified Annual Results published by the IESO. Following the Ministry of Energy, Northern Development and Mines' decision on March 20, 2019 to conclude the Conservation First Framework (CFF) led to the IESO not issuing the annual verified report format that was used historically.

   The net energy savings is based on the Participation and Cost Report provided as of April 15, 2019 for the NTRZ. NT Power used the Detailed Project Level Savings file as provided by the IESO for the Net Demand Savings by program applying the outlined IESO saving calculation methodology and applicable reference table metrics with the conservative assumption that persistence for 2019 would be equal to 2018 current year savings.

## BOARD STAFF MRZ IR - 3

**MRZ-Staff-3**

**Ref 1: LRAMVA workform, Tabs 3 and 5**

Newmarket-Tay Power, for its MRZ, completed the transition to a fixed residential charge as of May 1, 2019, but it has claimed lost revenues from the residential class in 2019. As a result of the transition to the fixed residential charge, distributors will no longer experience lost revenues due to reduced consumption.

As the May 1, 2019 fixed residential charge is no longer a volumetric rate, the LRAMVA Workform calculates residential lost revenues in 2019 by taking the full year value of persisting savings from prior years into 2019 and multiplying that amount by 1/3 of the 2018 volumetric rate (i.e. Jan 1 to April 30, 2019) to calculate lost revenues for 2019, as this period was before the fixed residential charge was in place.

Please provide rationale for claiming lost revenues for the residential class for all of 2019 when the utility has transitioned to a fixed residential charge as of May 1, 2019.

### RESPONSE

NT Power requests to recover lost revenues from the residential class for the period of January 1, 2019 to April 30, 2019 based on the Board Staff's recommended approach.

NT Power confirms it has transitioned to fully fixed residential rates as of May 1, 2019 and submitted $0.00 for cell L18 and M18 on tab 3. Distribution Rates for the LRAMVA workform. NT Power confirms the rate allocations for CDM programs 2015-2019 are accurate to where the savings were achieved by rate class.

# BOARD STAFF MRZ IR - 4

**MRZ-Staff-4**

**Ref 1: LRAMVA Workform, Tab 6**

The carrying charges on the principal balance are not calculated to May 1, 2021.

Please populate column H (cells 165-169) in Table 6-a with the corresponding monthly interest rate for the period to calculate projected carrying charges to May 1, 2021.

## RESPONSE

NT Power submits the revised LRAMVA Workform in Appendix 17 with the updated interest for 2021, Q1 on Tab 6 in cells C55, H165-169 and Tab 1a. Summary of Changes in Table A-2. NT Power submits a revised Rate Generator Model with the updates of LRAMVA on Tab 4, cells S17:21 in Appendix 18.

## BOARD STAFF MRZ IR - 5

**MRZ-Staff-5**

**Ref 1: LRAMVA Workform, Tab 1-a**

a) If Newmarket-Tay Midland RZ made any changes to the LRAMVA Workform as a result of its responses to the above LRAMVA interrogatories, please file an updated LRAMVA Workform.

b) Please confirm that any changes to the LRAMVA Workform in response to any LRAMVA interrogatories are reflected in "Table A-2. Updates to LRAMVA Disposition (Tab 1-a)".

---

### RESPONSE

a) NT Power submits the revised LRAMVA Workform for MRZ in Appendix 17 with the updates from MRZ IR 4.

b) NT Power has updated Tab 1-a. Summary of Changes in the LRAMVA Workform for MRZ in Appendix 17.

# BOARD STAFF MRZ IR - 6

## MRZ-Staff-6

## Ref 1: Manager's Summary, page 24

Newmarket-Tay Power, for the MRZ, provides the audited adjustments for Accounts 1588 and 1589 in the table below:

Table 1: Adjustments for Accounts 1588 and 1589 for MRZ

| | | Account 1588 | | | Account 1589 | | |
|---|---|---|---|---|---|---|---|
| Year | | Original Balance | Revised Balance | Adjustments | Original Balance | Revised Balance | Adjustments |
| 2017 | Principal | $62,099 | $62,099 | $- | $191,475 | $191,475 | $- |
| | Interest | $4,007 | $4,007 | $- | $7,430 | $7,430 | $- |
| | Total | $66,106 | $66,106 | $- | $198,905 | $198,905 | $- |
| 2018 | Principal | -$113,822 | $223,500 | $337,322 | $480,036 | $142,714 | -$337,322 |
| | Interest | $5,103 | $8,516 | $3,413 | $8,957 | $5,544 | -$3,413 |
| | Total | -$108,719 | $232,016 | $340,735 | $488,993 | $148,258 | -$340,735 |
| 2019 | Principal | $375,591 | -$137,465 | -$513,056 | -$265,490 | $71,832 | $337,322 |
| | Interest | $6,382 | -$4,452 | -$10,834 | $2,413 | $5,826 | $3,413 |
| | Total | $381,972 | -$143,918 | -$525,890 | -$263,077 | $77,658 | $340,735 |

Newmarket-Tay Power, for the MRZ, explains that:

> The 2018 adjustments of principal and interest for Account 1588 and 1589 are the result of a reallocation which was recorded in the financial records in 2019.
>
> The 2019 principal adjustment of ($513,056) for Account 1588 consists of the following:
>
> - Reversal of the 2018 adjustment noted above ($337,322)
> - Settlement correction of ($175,734)
>
> The 2019 interest adjustment of ($10,834) for Account 1588 consists of the following:
>
> - Reversal of the 2018 adjustment noted above ($3,413)
> - Settlement correction of ($7,421)
>
> The 2019 principal adjustment of $337,322 and interest adjustment of $3,413 for Account 1589 represent the reversal of the adjustments from 2018 noted above.

a) Please clarify which cells in the continuity schedules the “Principal” and “Interest” rows in the adjustment table for Accounts 1588 and 1589 represent which cells in the continuity schedules.

b) Please provide a detailed explanation and calculation for the 2018 adjustment of $337,322 in Accounts 1588 and 1589 which is stated as “result of a reallocation which was recorded in the financial records in 2019”.

c) Please provide a detailed explanation for the 2019 principal adjustment in Account 1588 for the settlement correction pf ($175,734). Please confirm if and when Newmarket-Tay Midland RZ has submitted the settlement correction with the IESO.

## RESPONSE

a) Cell AV28 contains the 2018 Account 1588 principal adjustment of $337,322 and cell AV29 contains the corresponding Account 1589 principal adjustment of ($337,322). Cell BA28 contains the 2018 Account 1588 interest adjustment of $3,413 and cell BA29 contains corresponding Account 1589 interest adjustment of ($3,413)

   Cell BF28 contains the 2019 Account 1588 principal adjustment of ($513,056) and cell BF contains the Account 1589 principal adjustment of $337,322. Cell BK28 contains the 2019 Account 1588 interest adjustment of ($10,834) and cell BK29 contains the Account 1589 interest adjustment of $3,413.

b) The calculation of the 2018 adjustment of $337,322 was the result of incorrect calculations of the GA values between 1588 and 1589. The table below references the adjustments:

| Month | Original Allocation GA Allocation to Power | Revised Allocation GA Allocation to Power | Adjustment |
|---|---|---|---|
| Jan-18 | 567,401 | 567,401 | 0 |
| Feb-18 | 581,457 | 571,679 | 9,778 |
| Mar-18 | 677,113 | 551,280 | 125,833 |
| Apr-18 | 670,031 | 670,031 | 0 |
| May-18 | 631,163 | 631,163 | 0 |
| Jun-18 | 737,246 | 737,246 | 0 |
| Jul-18 | 597,097 | 597,097 | 0 |
| Aug-18 | 563,377 | 563,377 | 0 |
| Sep-18 | 548,271 | 548,271 | 0 |
| Oct-18 | 726,148 | 524,437 | 201,711 |
| Nov-18 | 711,992 | 524,437 | 187,556 |
| Dec-18 | 586,156 | 773,712 | (187,556) |
| | 7,597,453 | 7,260,131 | 337,322 |

c) The 2019 adjustment in Account 1588 of $175,734 is the result of the incorrect application of the two-tiered rates to the monthly GA consumption versus the time of use rates. This error was discovered during DVA review conducted.

The settlement correction adjustment will be filed upon receiving the Decision and Rate Order for 2021-2022 rates.

# BOARD STAFF MRZ IR - 7

### MRZ-Staff-7

### Ref 1: Newmarket-Tay Midland RZ's GA Analysis Workform

OEB staff notes that there are no reconciling items on the GA Analysis workforms for 2017 to 2019 for the "Differences in actual system losses and billed TLFs" while there appear to be differences between the actual approved line loss factors and the approved line loss factor.

a) Please calculate the reconciling item for the "Differences in actual system losses and billed TLFs" using the table below and update the GA Analysis Workforms accordingly:

| Year | Wholesale kWh delivered to Newmarket-Tay Midland RZ's Non-RPP class customers (Note 1) | Retail billed kWh by Newmarket-Tay Midland RZ to Non-RPP class B customers | Unaccounted for Energy Loss Consumption kWh | Weighted Average GA rate of the Year (Note 2) | The Calculated Line Loss $ for the year |
|---|---|---|---|---|---|
| | A | B | C= B-A | D | E = C X D |
| **2017** | | | | | |
| **2018** | | | | | |
| **2019** | | | | | |

Note 1: the wholesale kWh delivered to the MRZ's Non-RPP class B customers is to be calculated as: (AQEW +Embedded Generation kWh) x Non-RPP class B customers' retail proportion of the total retail consumption

Note 2: the weighted average GA rate of the year is to be calculated as total $ consumption at GA rate billed divided by total billed consumption kWh for Non-RPP class B customers

## RESPONSE

a) The reconciled items for the differences in actual system losses and billed TFL's have been calculated using the table, as per below:

| Year | Wholesale kWh delivered to Newmarket-Tay MRZ's non-RPP class customers (Note 1) | Retail billed kWh by Newmarket-Tay MRZ to Non-RPP class B customers | Unaccounted for Energy Loss Consumption kWh | Weighted Average GA rate of the Year (Note 2) | The Calculated Line Loss $ for the year |
|---|---|---|---|---|---|
| | A | B | C = A - B | D | E = C x D |
| **2017** | 91,423,766 | 91,358,392 | 65,374 | 0.0977 | 6,387.51 |
| **2018** | 65,312,111 | 65,109,341 | 202,770 | 0.0924 | 18,733.58 |
| **2019** | 56,897,659 | 56,843,482 | 54,177 | 0.1058 | 5,733.35 |

The revised GA Analysis Workform has been provided in Appendix 19 for MRZ.

## BOARD STAFF MRZ IR - 8

**MRZ-Staff-8**

**Ref 1: Manager's summary, Appendix 7, External Auditor's DVA Review Report**

The external auditor's review report states the following:

> **Report on the Midland Rate Zone 1588, 1589 Continuity Schedule and 1595 work forms (Schedules)**
>
> We have reviewed the accompanying Table 1: Adjustments for accounts 1588 and 1589 MRZ, Table 2: GA Analysis Summary by Year, GA analysis work forms, and the 1595 analysis work forms for the period of January 1, 2017 to December 31, 2019 ("Schedules"), and the summary other explanatory information for Newmarket-Tay Power Distribution Ltd., Midland Rate Zone. The Schedules have been prepared by management based on the financial reporting provisions of Article 490 of the Accounting Procedures Handbook (APH) for Electricity Distributors and other OEB accounting guidance including the APH's Frequently Asked Questions published July 2012, Guidance to the APH, issued March 2015 and new Accounting Guidance issued in February 2019 for Group 1 accounts.

a) Please clarify whether the external auditor has reviewed the continuity schedules filed in this application for Account 1588 and Account 1589?

---

## RESPONSE

An audit was not performed by the external accountants. They performed a review engagement and as such, no audit opinion has been provided. A qualified conclusion, as per the independent practitioner's review engagement report was issued.

The external accountants only reviewed the tables included in the IRM submission as outlined in their independent practitioner's review engagement report which was:

> *"Table 1: Adjustments for accounts 1588 and 1589 MRZ, Table 2: GA analysis summary by Year, GA analysis work forms and the 1595 analysis work forms for the period of January 1, 2017 to December 31, 2019"*

# INTERROGATORIES OF THE VULNERABLE ENERGY CONSUMERS COALITION (VECC)

# VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR-1

## VECC-1

Ref:

a) Newmarket-Tay Power changed its depreciation and capitalization policies effective January 1, 2012. In accordance with OEB policy, Newmarket - Tay Power recorded the financial difference arising from changes to its depreciation and capitalization policies in Account 1576 effective January 1, 2012.

VECC seeks to understand the disposition history of Account 1576 from past to present. Please provide a table that sets out the schedule of requested dispositions of Account 1576 to date, and include the OEB Proceeding number, the amounts requested compared to approved, indicate whether interim or final, and identify and explain any subsequent adjustments made regarding the disposition amounts or rate riders implemented in any given year.

b) Please discuss if Newmarket-Tay Power has made any changes in this application to the methodology used to calculate Account 1576 balances.

## RESPONSE

a) The following schedule provides requested and approved disposition amounts for Account 1576 by OEB proceeding number.

**NTRZ disposition history for account 1576**

| EB# | Year of dispostion | Interim/Final | Amount requested |
|---|---|---|---|
| EB-2016-0275 | May 2017 | Interim 1 year | 6,382,286 |
| | | | |
| EB-2017-0062 | May 2018 | Interim 1 year | 1,593,745 |
| | | Interim 1 year | 3,353,748 |
| | | Total | 4,947,493 |
| | | | |
| EB-2018-0055 | May 2019 | Interim 1 year | 1,603,325 |
| | | | |

A subsequent adjustment was required relating to rate order EB-2016-0275. This is noted within EB-2017-0062, page 15, "After the record closed for this proceeding, Newmarket-Tay Power notified the OEB of an error that it found in the calculation of the Account 1576 rate riders approved for 2017 rates. In the 2017 rates proceeding, the OEB approved disposition of $6,382,286 on an interim basis, for the Account 1576 balance accumulated from 2012 to 2015. Newmarket-Tay Power explained that in calculating the disposition rate riders, the annual kilowatt-hours and kilowatts for all customer classes, except for the residential class, were divided by 12 and should not have been. This is not an issue for the residential class because the rate riders are based on the monthly fixed charge. Newmarket-Tay Power forecast that by April 30, 2018, it will have credited customers by a shortfall of $3,353,748.

Newmarket-Tay Power proposed that this shortfall be added to the credit amount of $1,593,745 in Account 1576 at the end of 2016. This results in a total disposition from Account 1576 proposed for 2018 rates of a credit amount of $4,947,493. Consistent with the OEB's decision for 2017 rates, Newmarket-Tay Power proposed that the amount be disposed on an interim basis over a one-year period."

The EB-2017-0062 findings on page 15 further state, "The 2012 to 2016 balances in Account 1576 were disposed on an interim basis. The OEB approves including the shortfall credit from 2017 of $3,353,748 with the 2016 Account 1576 balance of $1,593,745 in the calculation of the rate riders to be credited on a prospective basis. The rate riders will be effective from May 1, 2018 to April 30, 2019".

b) NT Power has developed the following methodology to calculate Account 1576 balances:
    a. The revised CGAAP PP&E values are based on a componentalized capital asset register utilizing the typical useful life with the 2010 Kinetics study to determine the revised CGAAP annual depreciation from 2012 to 2020.

b. The former CGAAP capital asset register and annual depreciation based on the methodology of depreciating distribution capital assets for 25 years.
c. A return on rate base of 7.03% is calculated on the difference between the closing net PP&E for CGAAP and revised CGAAP. The return on rate base of 7.03% is based on the 2010 cost of service filing.

# VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 2

## VECC-2

Ref: DSP P 114 Table 49 –2015 – 2020 Key Material Capital Projects

a) Please provide an updated version of Table 49 with 2019 and 2020 actuals.

b) Please provide Appendix 2-AA for the years 2020 to 2024.

## RESPONSE

a) The original version of Table 49 included 2019 actual spend. Due to the timing of its 2020 year-end financial close-out, NT Power is unable to provide 2020 actuals within the interrogatory deadline. The 2020 actuals will be provided when available, which is expected to be March, 2021.

b) Appendix 2-AA for the years 2020 to 2024 is submitted as Appendix 20.

# VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 3

## VECC-3

Ref: DSP P 126 Table 58 – Material Capital Expenditures 2020 – 2024.

a) Please provide an excel version of Table 58 – Material Capital Expenditures 2020 – 2024.

b) Please discuss how Newmarket-Tay Power took into consideration the significant CCRA True-up costs in prioritizing work and setting the capital budget for 2021.

c) Please discuss if any projects in 2021 are considered discretionary.

d) Please discuss if any projects in 2021 could reasonably be decreased in scope.

e) Please discuss if any projects in 2021 could reasonably be deferred.

f) If the OEB does not approve the ICM request, what is the impact on the forecast 2021 capital spending?

g) Please discuss the pace of asset renewal over the period 2015 to 2019 compared to 2020 to 2024.

## RESPONSE

a) Excel version of Table 58 – Material Capital Expenditures 2020 – 2024 is submitted as Appendix 21.

b) NT Power looked to balance the needs of the ACA and our obligations for the CCRA true-up. The levelized ACA called for spending levels $8.6MM per year higher then NT Power submitted as part of the DSP Plan. NT Power understands the need to step up asset investment while being mindful of our ability to execute on the DSP and true-up the costs of Holland TS.

c) Please refer to Staff IR NTRZ 24 response.

d) Please refer to Staff IR NTRZ 24 response.

e) Please refer to Staff IR NTRZ 24 response.

f) Without the 2015 ICM request the return on equity would be 4.81% potentially impacting the long-term viability of the utility. Please refer to Staff IR NTRZ 18- a) and IR CCC 5.

   Regardless of the OEB decision on the ICM, NT Power needs to begin ramping up it's capital investment plan as was highlighted by the ACA. NT Power would use every available means to ensure capital spending levels meet those highlighted in the DSP submission.

g) From 2015 to 2019, NT Power took an approach to defer some of its capital program due to large customer driven projects such as the VIVA rapid bus project and the Yonge Street revitalization. This approach is not sustainable in perpetuity and NT Power needs to begin increasing capital spending to close the gap between the required investment as highlighted in the ACA and the current capital program. It should be noted that the 2020 – 2024 DSP spending level is still well below the recommended levelized ACA recommendation ($8.6M/year).

## VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 4

### VECC-4

Ref: ICM Appendix D: Hydro One Invoice

Please provide the Hydro One invoice for the 10-year True-Up and provide Hydro One's calculation of the True-Up.

### RESPONSE

Please refer to Staff IR NTRZ 21 b) response.

# VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 5

## VECC-5

Prior to this application, did Newmarket-Tay Power notify the OEB of future ICM projects for the 5 and 10 year True-Ups for Holland TS? Please provide all documentation.

## RESPONSE

NT Power notified the OEB of its ICM request with the filing of this EB-2020-0041 application. All relevant documentation is on the public record already.

On November 22, 2005, the OEB ordered that the utilities serving York Region, Newmarket Hydro (the predecessor to NT Power), Aurora Hydro Connections Limited, Power Stream Inc. and Hydro One Networks Inc. (Distribution) (collectively, the "York Region Utilities") and Hydro One Networks Inc. (Transmission) ("Hydro One") to implement the Holland Junction Transformer Station (EB-2005-0315 Decision and Order dated November 22, 2005, pg. 13).

NT Power is under the Annual IR Rate-setting method. According to the Chapter 3 Filing Requirements for 2015 Rate Applications[2], ICM was not available to distributors on Annual IR Index. In fact, it is still currently unavailable to non-merged distributors on Annual IR[3]. As such, NT Power was unable to bring an ICM for the First True-up at the time it occurred because it was not an available option.

However, pursuant to the Board's policy changes in its 2015 Consolidation Report, distributors who are party to a MAADs transaction, and are operating under an Annual IR plan have the option to use the ICM during the deferred rebasing period.[4] NT Power and Midland Power became party to a MAADs transaction in 2018 and are therefore eligible for ICM during the deferred rebasing period.

[2] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications – Chapter 3 Incentive Regulation dated July 25, 2014 at page 2.

[3] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications – Chapter 3 Incentive Rate-Setting Applications, May 14, 2020 at page 2.

[4] Consolidation Report at page 12.

# VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 6

## VECC-6

Ref: Manager's Summary P44

Table 1 in evidence shows the revenue Newmarket-Tay Power has voluntarily foregone associated with the First True-Up from 2015 to 2020.

Table 1: Foregone Revenue and Incremental Revenue Requirement

| **Foregone Revenue for 2015 Contribution by year** | | |
|---|---|---|
| **Application Table 1** | | |
| | **2015** | |
| 2015 | 659,973 | |
| 2016 | 659,973 | |
| 2017 | 659,973 | |
| 2018 | 659,973 | |
| 2019 | 659,973 | |
| 2020 | 659,973 | |
| **Total** | **3,959,839** | |

Please provide the calculation that underpins Table 1.

## RESPONSE

NT Power is providing the excel file showing the annual incremental revenue requirement of $659,973, VECC IR 6, NTP 2021 ACM ICM Model 2015 contribution foregone revenue in Appendix 22. This is based on the 2015 maximum eligible incremental capital of $6,842,513 compared to the actual contribution of $8,180,000. The incremental revenue requirement components are:

| | |
|---|---|
| • Return on Rate Base | $475,654 |
| • Amortization Expense | 152,901 |
| • Grossed-Up Taxes/PILs | 31,418 |
| Total | $659,973 |

# VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 7

**VECC-7**

Ref: Manager's Summary P46 Table 3

Please explain the drivers of the significant increase in capital expenditures from $3,385,518 in 2019 compared to $6,280,006 in 2020.

## RESPONSE

From 2015 to 2019 NT Power took an approach to defer some of its capital program due to large customer driven projects such as the VIVA rapid bus project and the Yonge Street revitalization. This approach is not sustainable in perpetuity and NT Power needs to begin increasing capital spending to close the gap between the required investment as highlighted in the ACA and the current capital program. It should be noted that the 2020 – 2024 DSP spending level is still well below the recommended levelized ACA recommendation.

# VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 8

**VECC-8**

Ref: Manager's Summary P49

The evidence states "…the First True-Up was calculated by Hydro One to be $8,180,000."

Please provide the calculation from Hydro One.

## RESPONSE

Refer to Staff IR NTRZ 20 a), 2014 load forecast - Hydro One 5-year true up contribution model.

# INTERROGATORIES OF CONSUMERS COUNCIL OF CANADA (“CCC”)

# COUNSUMERS COUNCIL OF CANADA IR - 1

**CCC-1**

**Application/p. 44**

Please explain, in detail, what changed between 2008 and 2015 leading to the revenue shortfall of $9,243,400.

## RESPONSE

Please refer to Staff IR NTRZ 20 f) response.

# COUNSUMERS COUNCIL OF CANADA IR - 2

**CCC-2**

**Application/p. 44**

Please provide the following:

1. The original total capital cost of constructing the Transformer Station and the projected revenue established when the project began;
2. The updated capital cost of constructing the project and the revenue forecast in 2015 when the shortfall payment was determined to be $9,243,400;
3. The revenue shortfall associated with the 10 year/ Second True-Up; and
4. What entity was responsible for each of revenue forecasts.

## RESPONSE

1. Refer to ICM Application Appendix B page 234. Staff IR NTRZ 21 a), Hydro One Connection and Cost Recovery Agreement.

2. The capital cost of constructing the project was provided in 2010, as per CCC IR 2 1). The cost did not change in 2015 when the shortfall payment was determined to be $9,243,400. Regarding the updated revenue forecast in 2015, please refer to the 5 year true-up contribution model in Staff IR NTRZ 21 a).

3. Refer to Staff IR NTRZ 20 b). Based on the preliminary data provided by NT Power in the 10-year true-up customer input package, the second-true up payment is estimated to be approximately $6.1 million.

4. The true-up contribution models are provided by Hydro One. It is the responsibility of NT Power and Hydro One to ensure the actual load is accurate and the load forecast is reasonable when calculating the revenue forecasts and true-up payments.

# COUNSUMERS COUNCIL OF CANADA IR - 3

## CCC-3

### Application/p. 44

The evidence states that it has now been over ten years since the Holland TS has been used and useful and serving the ratepayers of that area. Ratepayers have been benefitting from the Holland TS without having to pay anything associated with the First True-Up since 2015. On what date did NT Power know that there was a revenue shortfall? Did NT Power at anytime since 2015 consider filing a COS rebasing application? If not, why not? Why did NT Power not bring an ICM application forward in 2019 or 2020 if NT Power and Midland Power determined they were eligible for an ICM once they consolidated?

## RESPONSE

NT Power would have been made aware of the first true up around 2014-2015 through the CCRA 5 year true-up with Hydro One. Please refer to Staff IR NTRZ 20 f).

NT Power was under the Annual IR Rate-setting method at that time. According to the Chapter 3 Filing Requirements for 2015 Rate Applications[5], ICM was not available to distributors on Annual IR Index. In fact, it is still currently unavailable to non-merged distributors on Annual IR[6]. As such, NT Power was unable to bring an ICM for the First True-up at the time it occurred because it was not an available option.

However, pursuant to the Board's policy changes in its 2015 Consolidation Report, distributors who are party to a MAADs transaction, and are operating under an Annual IR plan have the option to use the ICM during the deferred rebasing period.[7]

NT Power and Midland Power became party to a MAADs transaction in 2018 and are therefore eligible for ICM during the deferred rebasing period.

As is expected, after 2018 NT Power and Midland Power had to address a huge number of issues post-consolidation issues, including harmonizing asset management, financial and regulatory standards across the organizations and addressing the

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[5] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications – Chapter 3 Incentive Regulation dated July 25, 2014 at page 2.

[6] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications – Chapter 3 Incentive Rate-Setting Applications, May 14, 2020 at page 2.

[7] Consolidation Report at page 12.

departure of key personnel and a transition among the senior management team. Please refer to Staff IR NTRZ 18 b).

In this circumstance, 2021 was the earliest realistic date for NT Power to bring the ICM request for the 2015 True-up. Doing it as part of this same application also presents regulatory efficiencies, since the need and prudence evidence for both the 2015 and 2021 true-ups are identical.

Finally, it is worth noting that NT Power has calculated the ICM rate rider for the 2015 true-up in a way that ensures that customers are not paying retroactively for the years from 2018-2021. NT Power is seeking recover of the depreciated 2015 true-up on a going-forward basis only. Please refer to CCC IR 5.

## COUNSUMERS COUNCIL OF CANADA IR - 4

### CCC-4

### Application/p. 45

Please explain how the foregone revenue amounts, set out in Table 1, were calculated. NT Power is effectively seeking forgone revenue for the period 2015-2020 through this application arising from the First True Up. NT Power is seeking to recover amounts in 2021 and beyond related to a payment in 2015. What is this not considered retroactive rate-making? Can NT Power provide any examples of cases where the OEB approved an ICM retroactively, going back five years?

### RESPONSE

Please refer to VECC IR 6 for how the foregone revenue amounts were calculated.

NT Power is not seeking to recover foregone revenue for the period 2015-2020 through this application. NT Power is seeking to recover the incremental revenue requirement for the 2015 contribution effective 2021. This is based on the 2015 maximum eligible incremental capital that would have be allowed for the 2015 contribution, amortized to 2020 and compared to the 2021 maximum eligible incremental capital.

NT Power is requesting incremental revenue requirement for the amount of 2015 contribution that is being funded by NT Power as of 2021 and therefore is not retroactive rate-making.

# COUNSUMERS COUNCIL OF CANADA IR - 5

**CCC-5**

**Application/p. 45**

In 2018 NT Power achieved an ROE of 11.19%, or 1.53% above the allowed ROE of 9.66%. Please explain the reasons that NT Power over-earned in that year. What is the actual ROE for 2020?

## RESPONSE

In 2018, NT Power recognized LRAMVA relating to the 2011-2017 fiscal periods in the amount of $1,250,000 after tax. The achieved ROE is 7.23% compared to the allowed ROE of 9.66% when the 2011-2017 LRAM is removed.

The 2020 forecasted ROE % is 6.41%. NT Power's 2021 forecasted ROE excluding recovery for the 2015 Hydro One contribution is 4.81%.

# COUNSUMERS COUNCIL OF CANADA IR - 6

**CCC-6**

**Application/p. 46**

The evidence states that, “Based on discussions with Hydro One, NT Power expects the Second True-Up will be made in early 2021.” What is the status of those discussions with Hydro One and when will the final payment amount be determined? How was the $6.1 million derived?

## RESPONSE

Please refer to CCC IR 2 - 3).

# COUNSUMERS COUNCIL OF CANADA IR - 7

**CCC-7**

**Application/p. 57**

Are the rate riders set out in Table 9 monthly riders? Are they only applicable to NT Power customers and not Midland Power RZ customers?

## RESPONSE

NT Power confirms the monthly rate riders set out in Table 9 in the "NT Power_APPL_NTRZ_2021IRM_20201123' application pertaining to the Newmarket-Tay Rate Zone are not applicable to Midland Rate Zone customers.