Newmarket-Tay Power Distribution Ltd.

February 7, 2020

Interrogatory Responses

EB-2019-0055

INDEX

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

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General

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Ref: Newmarket-Tay Rate Zone and DVA Continuity Schedule

Midland Rate Zone and DVA Continuity Schedule

There are amounts shown under column "Principal Adjustments during 2017".

a) There are amounts shown under column "Principal Adjustments during 2017".

For Accounts 1588 and 1589, for each rate zone, please provide a breakdown between amounts related to opening balances and "principal adjustments" for each rate zone, to enable OEB staff to determine if any "principal adjustments" approved in a prior proceeding require to be reversed in this proceeding (as per the OEB guidance on Accounts 1588 and 1589).

b) There are no amounts shown under column "Principal Adjustments during 2018".

For accounts 1588 and 1589, for each rate zone, please explain why no "principal adjustments" are shown in 2018. Were there any post year-end true-up adjustments or differences in unbilled revenue to actuals or other adjustments made to the account balance that were included in the "transactions debit/(credit) for 2018, if so please separate and include in the principal adjustments column.

RESPONSE

a) The amounts shown under columns AV "Principal Adjustments during 2017" for both the Midland Rate Zone (MRZ) and the Newmarket-Tay Rate Zone (NTRZ) represent the opening principal and interest balances at January 1, 2018.

b) Newmarket-Tay Power Distribution Ltd. (NT Power) has updated the Rate Generator Model for MRZ on tab 3. Continuity Schedule in cell BF28-BF29 and BK28-BK29 to reflect an adjustment of $337,322 principal and $3,413 interest between accounts 1588 and 1589.

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.

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Ref: IRM Rate Application, Newmarket-Tay Rate Zone, page 12
IRM Rate Application, Midland Rate Zone, page 11
IRM Rate Application, Newmarket-Tay Rate Zone, page 36
IRM Rate Application, Midland Rate Zone, page 35

It its Midland Rate Zone (MRZ) application, Newmarket-Tay Power states that:

> In 2018, the Board Staff introduced the 1595 Analysis Workform as a requirement for rate applications if the distributor meets the requirements for disposition of residual balances. The purpose of the new workform is to assist the Board Staff to assess the residual balances in Account 1595 Sub-accounts for each vintage year are reasonable. NT Power - MRZ intends on meeting the requirements for disposition in the 2021 IRM application.

A similar statement is made in the Newmarket-Tay Rate Zone (NTRZ).

In Newmarket-Tay's last IRM application, the OEB Decision and Rate Order[1] stated:

> In its next IRM application, Newmarket-Tay Power should file the results of its 2018 year-end audit and provide a detailed breakdown of the Account 1595 balance proposed for disposition.

In addition, OEB staff notes that in MRZ, there are amounts shown for RRR for Account 1595, Sub-accounts 2015 and 2016. Both of these Sub-Accounts were disposed in Midland's 2019 proceeding.

The tables on pages 11 and 12 of the rate applications indicate that account 1595 is still not reconciled to the RRR.

a) Please explain why the requirement to complete the account 1595 workform is not being met in this application.

[1] EB-2018-0055, Decision and Rate Order, April 18, 2019, page 11.

b) Please confirm that in the MRZ, sub-accounts for 2015, 2016 have already been disposed of in 2019, that sub-accounts can only be disposed of once, and any residual balances are to be written off.
c) OEB staff notes that in the NTRZ, there was no disposition approved in 2013. Why is there a balance in Account 1595 - Sub-account 2013?
d) Pease prepare 1595 work forms for the NTRZ for 2012, 2014, 2015, 2017 and 2018
e) Pease prepare 1595 work forms for the MRZ rate zone for 2017 and 2018.
f) Please reconcile the tables on pages 11 and 12 of the rate application relating to account 1595 to the RRR filing for all sub-accounts from 2013-2018. Explanations are required for all unreconciled 1595 sub-accounts. If any changes are required to amounts entered in the DVA continuity schedules, please refile the rate generator models and explain changes made.

RESPONSE

a) NT Power has experienced staff turnover and is currently working with the external auditors to reconstruct NTRZ DVA account 1595 to ensure compliance for the December 31, 2019 financial records.
b) MRZ confirms the Account 1595 sub-accounts for 2015 and 2016 were disposed in the 2019 IRM (EB-2018-055) and the residual balances noted in this application will be written off within the 2019 financial records.
c) NTRZ has reviewed the 2.1.7 RRR submission for APH 1595 Group 1 Accounts and has determined the breakout by disposition year was incorrectly submitted. Further, NT Power submitted the APH 1595 Group Accounts within the 2.1.7 RRR submission for the disposition years 2008 to 2018. The rate generator model is displaying the RRR submissions for 2013 to 2019. Please refer to response Staff IR-2(f) for the updated reconciliation table.
d) Please refer to response Staff IR-2(a).
e) The MRZ 1595 workform (Appendix F) for 2017 is attached. The MRZ 1595 work form for 2018 is also attached (Appendix G). The 1595 workform for 2018 did not allow for the 2018 disposition year to be updated to 2018, therefore, we have provided the 2018 workform under Appendix G noting the year of the filing (2018) in the file name. The residual balance noted in the 2018 workform includes the balances up to December 31, 2018 only. In addition, the residual balance of this 1595 sub-account has not been audited, nor has one full year elapsed since the sunset date of the rate rider as required and noted in the July

18, 2019 Deferral & Variance Accounts & Supporting Models (GA & 1595 Workform) webinar provided by Board Staff.

f) NT Power has reviewed the sheet 3. Continuity Schedules for the NTRZ and MRZ within the rate generator model and has corrected the ending balances in cells BI31-37 to BD31-37 by disposition year to align with the financial records. The following table provides a reconciliation of the 2.1.7 RRR submission for MRZ and NTRZ APH 1595 Group 1 Accounts and the rate generator model sheet 3.

Updated Rate Gen Model sheet 3. Continuity Schedule

#	Description	Account	NT Power - NTRZ	NT Power - MRZ	Total	RRR 2.1.7	Variance
			A	B	C = A+B	E	F
1	Disposition Balances (2008)	1595	-	-	-	(16,440)	16,440
2	Disposition Balances (2009)	1595	-	-	-	(753,081)	753,081
3	Disposition Balances (2010)	1595	-	-	-	65,047	(65,047)
4	Disposition Balances (2012)	1595	-	-	-	(69,007)	69,007
5	Disposition Balances (2013)	1595	(769,812)	(3,668)	(773,480)	7,713	(781,193)
6	Disposition Balances (2014)	1595	170,944	-	170,944	189,971	(19,027)
7	Disposition Balances (2015)	1595	(14,842)	7,714	(7,128)	(1,668)	(5,460)
8	Disposition Balances (2016)	1595	-	19,026	19,026	30,628	(11,602)
9	Disposition Balances (2017)	1595	17,532	13,173	30,705	17,532	13,173
10	Disposition Balances (2018)	1595	499,436	30,628	530,064	499,436	30,628
	Total		(96,742)	66,873	(29,869)	(29,869)	(0)

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Ref: OEB's February 21, 2019 Accounting Guidance related to Accounts 1588 and 1589 and OEB Letter

On February 21, 2019, the OEB issued its letter entitled *Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment* (GA) as well as the related accounting guidance. In their 2020 applications, distributors are to provide a status update on the implementation of the new accounting guidance, a review of historical balances, results of the review, and any adjustments made to account balances.

The OEB set out its expectations for final disposition requests of commodity pass-through account balances as noted in the Addendum.[2]

The OEB letter on the accounting guidance stated the following:

> The new guidance is effective January 1, 2019. Distributors are expected to implement the new guidance no later than August 31, 2019 retroactive to January 2019. In its July 2018 letter, the OEB suspended final disposition of Group 1 accounts until such time as the OEB developed further accounting guidance. The OEB expects that distributors will consider the accounting guidance in the context of their historical balances (i.e. pre January 1, 2019 that have not been disposed on a final basis). If any distributor is of the view that there may be systemic issues with their RPP settlement and related accounting processes that may give rise to material errors or discrepancies, or if the OEB has identified issues with balances, those distributors are expected to correct those balances before filing for disposition in an annual rate application. Distributors not adjusting balances prior to January 1, 2019 should confirm in their rate application that they have considered the accounting guidance and are of the view that no adjustments are required.

a) For each rate zones, please confirm that the applicant has completed its review of the new Accounting Guidance and any required changes to the accounting and RPP settlement processes for Account 1588 and Account 1589 have been implemented.
b) For each rate zone, are any summary reports available (e.g. how the review was done)? If yes, please provide a copy.

[2] Addendum to Filing Requirements For Electricity Distribution Rate Applications - 2020 Rate Applications, dated July 15, 2019

c) Please indicate, the effective date of implementation of the accounting guidance at each rate zone.
d) For each rate zone, please confirm that there are no systemic issues with the applicant's RPP settlement and related accounting processes, if not confirmed please explain issues and describe and quantify adjustments made.
e) OEB staff notes that the OEB had identified issues with historical balances, and an external review was completed in 2018 for Newmarket Rate Zone. As per the February 21, 2019 OEB letter, please indicate whether the variances for the following years have been reviewed in light of the February 21, 2019 guidance:
    i. 2017 (which were disposed on an interim basis)
    ii. 2018

f) 2017 and 2018 variances were not reviewed in light of the new guidance, please explain why not?

RESPONSE

a) NT Power confirms a review of the new Accounting Guidance has been implemented for both MRZ and NTRZ. It has been determined a reconciliation of the financial and regulatory balances is warranted for the 2019 year-end financial records.
b) There are no summary reports available for MRZ or NTRZ.
c) The effective date of implementation of the accounting guidance for the NTRZ and MRZ was Jan 1, 2019.
d) NT Power has reviewed the RPP settlement and accounting processes for NTRZ and MRZ in light of the February 21, 2019 guidance and has determined a reconciliation of the financial and regulatory balances was warranted. As highlighted above within the guidelines, NTRZ and MRZ are not requesting disposition of the variance accounts at this time to facilitate the review of the 2017 to 2019 1588 and 1589 variance accounts.
e) Please refer to response Staff IR-3(a).
f) Please refer to response Staff IR-3(a).

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Ref: 2020 Rate Generator Model for Newmarket Rate Zone; 2020 Rate Generator Model for Midland Rate Zone

The balance in Account 1588 is too high for both rate zones. OEB staff notes that if the distributor performs its settlements and true-ups of settlements with the IESO correctly, the only variances that should remain in Account 1588 should be the differences in actual line losses and line losses built in rates. Please provide an explanation for the large balance in Account 1588 in each of the rate zones.

The applicant has the following balances in Account 1588 (net of interim dispositions in 2019 proceedings) as of December 31, 2018:

Newmarket Tay Rate Zone	$3,442,278
Midland	$(187,386)

On a net basis, this is a debit of $3,254,892. This is greater than 5% of the power charges recorded in Account 4705.

a) Please provide an explanation for the large balance in Account 1588 for each respective rate zone.

RESPONSE

NT Power determined NTRZ December 31, 2018 balance in Account 1588 was $3,442,278, however, as noted on page 28 of the application filing an adjustment of $893,751 in principal and $19,825 in interest is due to a reallocation of GA for RPP customers as a reconciling item for the 2018 GA analysis. Further, an incorrect application of the settlement process in 2018 resulted in an amount of $3.3m not received from the IESO. The settlement data gathering and reporting process was reviewed and corrected in 2019. When accounting for the GA reallocation and the settlement error the balance of 1588 will total $1,078,300, which is under the 5% of the power charges recorded in account 4705.

With respect to the MRZ the balance reported at December 31, 2018 in the continuity schedule was $(187,386), however, as noted on page 28 of the application filing an adjustment of $337,322 in principal and $3,413 in interest is due to a reallocation of GA for RPP customers as a reconciling item for the 2018 GA analysis. This adjustment will be reflected in the 2019 financial statements. Once this adjustment has been reflected, the balance in Account 1588 will total $153,349 which is under the 5% of the power charges recorded in Account 4705.

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Ref: IRM Rate Application, Newmarket-Tay Rate Zone, page 20

IRM Rate Application, Midland Rate Zone, page 19

In the NTRZ, Newmarket-Tay proposes not to dispose of its Group 1 variance accounts:

> NT Power has elected to not dispose of all Group 1 deferral and variance account balances in the NTRZ in this application as the balances are at the threshold test at a total claim per kWh of $0.0010.

While in the MRZ, Newmarket-Tay Power proposes to dispose of Group 1 variance accounts:

> The MRZ deferral and variance account balances do not exceed the threshold test with a total claim per kWh of $0.0009. NT Power is requesting disposal of the deferral and variance account balances for MRZ in an effort to mitigate potential future rate increases in 2021.

a) Please explain why Newmarket-Tay has opted to dispose of a balance in MRZ despite not quite having met the materiality threshold, and at the same time opted to not dispose of a balance in NTRZ while having just barely met the materiality threshold.

RESPONSE

MRZ has requested disposition of the balance in order to mitigate any future rate increases for customers. MRZ is requesting to collect $169,444 from the Group 1 accounts in order to lessen future increases for customers. The balance requested for disposition is slightly below the threshold of $0.0010 at $0.0009, therefore we would respectfully request disposition be approved.

NTRZ is not requesting disposition of the Group 1 balances for NTRZ. Please refer to response Staff 3(d).

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Re: IRM Rate Generator Models

Staff has made the following changes to your models.

- Sheet 11 column L was updated for the OEB approved 2020 Hydro One Sub-Transmission Rates.
- Sheet 16, Price escalator was updated to 2%
- Sheet 17, TOU pricing was updated for November 1, 2019 rates
- Sheet 20, bill impacts, updated to include the 31.8% Ontario Electricity Rebate.

a) Please confirm the changes and that Newmarket-Tay Power is in agreement with the changes.

RESPONSE

NT Power is in agreement with the above noted changes.

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Please update the rate generator and LRAMVA models as required for all identified changes as a result of the interrogatories.

RESPONSE

NT Power has updated the rate generator models by rate zone as per the changes noted in the tables below.

NT Power has submitted an updated LRAMVA Workform and detailed the changes made in 'Tab 1-a. Summary of Changes' in accordance with the LRAMVA workform instructions.

NTRZ Rate Gen Model Changes

IR #	Tab	Cell Reference	Description of Change
Staff 1(b)	3. Continuity Schedule	BF28-29 & BK28-29	Updated to reflect adjustment.
Staff 2(f)	3. Continuity Schedule	BI31-37 & BD31-37	Corrected the ending balances by disposition year to align with the financial records.
Staff 23	3. Continuity Schedule	BF28-29 & BK28-29	Updated to reflect adjustment.
Staff 24	3. Continuity Schedule	Z43 to BL43	Updated LRAMVA values.
Staff 25	3. Continuity Schedule	BD43 & BI43	Revised LRAMVA values updated for 2018.
Staff 25	4. Billing Det for Def-Var	S17 to S21	Revised LRAMVA values by rate class.

MRZ Rate Gen Model Changes

IR #	Tab	Cell Reference	Description of Change
Staff 1(b)	3. Continuity Schedule	BF28-29 & BK28-29	Updated to reflect adjustment.
Staff 2(f)	3. Continuity Schedule	BI31-37 & BD31-37	Corrected the ending balances by disposition year to align with the financial records.
Staff 28	3. Continuity Schedule	BF28-29 & BK28-29	Updated to reflect adjustment.
Staff 29	3. Continuity Schedule	AV43 to BN43	Updated LRAMVA values.
Staff 30	3. Continuity Schedule	AV43 & BN43	Revised LRAMVA values updated for 2018.
Staff 30	4. Billing Det for Def-Var	S17 to S21	Revised LRAMVA values by rate class.

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Cost Allocation

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Ref: Cost Allocation Report, page 4

Newmarket-Tay Cost Allocation Model, Sheet O1 Revenue to Cost

Midland Cost Allocation Model, Sheet O1 Revenue to Cost

Newmarket-Tay states that "The cost allocation models contain the 2018 actual costs, customer numbers, kWh and kW values for each rate zone."

a) Please provide five years of historic actual energy by rate zone and rate class.
b) For rate classes that are demand billed, please provide five years of historic actual billing demand by rate zone and rate class.

RESPONSE

(a) & (b) The following table provides 2017 to 2013 of actual energy and demand billed by rate zone and rate class:

NTRZ Energy by rate class					
	2017	2016	2015	2014	2013
Residential-kWh	260,534,762	267,952,620	277,965,401	277,064,224	276,773,219
GS<50-kWh	88,737,652	87,282,578	92,196,807	92,626,021	92,616,326
GS>50-kWh	274,428,086	275,397,097	277,091,020	280,278,130	284,044,357
Street Light-kWh	2,624,147	2,683,399	3,485,724	5,201,095	5,431,512
Sentinel Light-kWh	278,160	287,405	286,012	292,367	296,963
USL-kWh	266,413	275,297	326,520	180,516	350,574
Total	626,869,220	633,878,396	651,351,484	655,642,353	659,512,951

NTRZ Demand by rate class					
	2017	2016	2015	2014	2013
GS>50-kW	740,036	701,463	699,724	711,695	730,718
Street Light-kW	7,065	7,341	14,476	14,476	15,121
Sentinel Light-kW	773	798	820	821	830
Total	747,874	709,602	715,020	726,992	746,669

MRZ Energy by rate class					
	2017	2016	2015	2014	2013
Residential-kWh	46,632,749	47,860,194	47,426,365	48,316,282	48,564,667
GS<50-kWh	22,630,791	23,415,877	23,916,365	23,627,440	24,014,883
GS>50-kWh	112,104,166	117,301,496	116,783,796	119,050,591	120,044,058
Street Light-kWh	519,882	541,578	666,042	843,045	1,021,454
Sentinel Light-kWh	-	-	-	-	-
USL-kWh	395,187	394,107	385,131	384,595	396,700
Total	182,282,775	189,513,252	189,177,699	192,221,953	194,041,762

MRZ Demand by rate class					
	2017	2016	2015	2014	2013
GS>50-kW	287,646	305,279	292,374	298,299	301,971
Street Light-kW	1,411	1,459	1,802	2,287	2,765
Sentinel Light-kW	-	-	-	-	-
Total	289,057	306,738	294,176	300,586	304,736

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Ref: Newmarket-Tay Cost Allocation Model, Sheet I4 BO Assets

2010 Newmarket-Tay Cost Allocation Model, Sheet I4 BO Assets

In the current cost allocation model, Newmarket-Tay Power has updated the proportion of distribution assets operating at the primary level (with the remainder operating at the secondary level).

	2020 IRM	2010 COS
1830 – Poles, Towers and Fixtures	85%	71%
1835 – Overhead Conductors and Devices	75%	71.29%
1840 – Underground Conduit	100%	64%
1845 – Underground Conductors and Devices	100%	75.75%

a) Please explain how Newmarket-Tay derived the primary vs secondary proportions in the current application.
b) Please explain the cause of the significant increase in the proportion of assets operating at the primary level vs the 2010 COS application.

RESPONSE

a) The following methodology was used for ***1830 – Poles, Towers and Fixtures***:
   i) extracted total number of poles from GIS
   ii) divided poles into primary and secondary level using pole height information
      - poles >35 ft were considered primary level as all have primary level assets.
      - poles ≤ 35 ft are a combination of poles with primary and secondary level assets and poles with only secondary assets.

- If the asset supports the primary equipment in any way, it was considered to be a primary asset even if it also supported secondary equipment. For example, a pole that supported primary and secondary lines was considered to be primary

iii) the resulting primary vs secondary proportions were then applied for ***1830 – Poles, Towers and Fixtures***.

The following methodology was used for ***1835 – Overhead Conductors and Devices***:

i) extracted total conductor lengths from GIS
ii) divided conductor lengths into primary and secondary level using conductor voltage
   - conductors >750V are primary level assets
   - conductors <750V and not supplying a service are secondary level assets

iii) the resulting primary vs secondary proportions were then applied for ***1835 – Overhead Conductors and Devices***.

For distribution asset classes ***1840 – Underground Conduit*** and ***1845 – Underground Conductors and Devices***:

i) NTRZ does not own <u>secondary level</u> distribution assets in ***1840 – Underground Conduit and 1845 – Underground Conductors and Devices***. As a result, 100% of the distribution assets are primary level.

b) The source data that supports the break out assets for 2010 is not available. Consequently, NT Power is unable to explain the difference from the 2010 COS application.

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Ref: Newmarket-Tay Cost Allocation Model, Sheet I6.2 Customer Data

Midland Cost Allocation Model, Sheet I6.2 Customer Data

Newmarket-Tay Power has not populated the Number of Connections, Line Transformer base or Secondary Customer base counts for Sentinel Lighting and Unmetered Scattered Load where these entries appear despite these customers being served by line transformer and secondary distribution assets.

a) Please revise the entries on sheet I6.2 Customer Data, row 19 to reflect the count of connections.
b) Please revise the entries on sheet I6.2 Customer Data, rows 24 and 25 to reflect the count of customers using line transformer and secondary assets.

RESPONSE

a) To the best of NT Power's knowledge, it appears the entries on sheet I6.2 Customer Data, row 19 already reflect the count of connections for Sentinel Lighting and Unmetered Scattered Load classes.
b) It is NT Power's understanding that these adjustments do not need to be made since the cost allocation model has been designed to assume the number of connections for Sentinel Lighting and Unmetered Scattered Load using line transformer and secondary assets is the same as the number of connections in row 19.

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Ref: Newmarket-Tay Cost Allocation Model, Sheet I6.2 Customer Data; Sheet I8 Demand

Newmarket-Tay Power indicates of 32,622 residential customers, 31,782 are served by utility owned line transformers, and 31,146 are connected to the secondary distribution system. With respect to load, it indicates that all 244,761 kW of 4 non-coincident peak (NCP) demand receives services of utility primary distribution, line transformers and secondary distribution.

a) Please reconcile the apparent inconsistency.

RESPONSE

NTRZ recognizes the inconsistency and updated the cost allocation model sheet I8 formula in the following cells:

D57, D58, D63, D64, D69, D70, E57, E58, E63, E64, E69, E70

NT Power is confirming an updated NTRZ cost allocation model is attached and reflects the above noted changes.

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Ref: Cost Allocation Report, page 7

Newmarket-Tay Cost Allocation Model, Sheet I6.1 Revenue

Midland Cost Allocation Model, Sheet I6.1 Revenue

Newmarket-Tay Power has populated the existing monthly charge for all rate classes using a weighted average of the 2017 rates and 2018 rates. This appears to reflect the rates in effect in calendar 2018.

Newmarket-Tay Power states that “Adjustments in row 37 have been included to insure the revenues in rows 39 to 41 match the actual 2018 distribution revenues.”

a) Please confirm the observation that the rates entered in I6.1 Revenue are designed to reflect calendar 2018, or explain the purpose and derivation of the rates used.
b) Please provide a derivation of the 2018 actual revenue by rate class at actual rates and volumes. In doing so, please identify the reason for the adjustment on row 37.
c) Please provide a cost allocation scenario where the existing rates entered are 2019 approved rates without any adjustments.

RESPONSE

a) NT Power confirms the rates entered in I6.1 for both the NTRZ and MRZ cost allocation models are the blended 2017 and 2018 and are designed to reflect the calendar 2018 distribution revenues. The rates are blended based on the months the rates are effective. 2017 rates are weighted 4/12 and 2018 rates are weighted 8/12.

b) The following tables provide the derivation of the 2018 actual revenue by rate class using blended rates and volumes for NTRZ and MRZ with a breakdown of the adjustment on row 37:

2019 Cost Allocation billing determinants - NTRZ							
	Residential	GS<50	GS>50	Street Light	Sentinel	USL	Total
kWh	282,139,763	91,548,982	278,825,252	2,565,174	275,116	552,037	655,906,324
kW			621,805	6,897	764		629,466
# of customers	32,622	3,186	384	9,091	32	46	
2017 approved rates	Residential	GS<50	GS>50	Street Light	Sentinel	USL	
Fixed	21.25	30.55	138.54	3.19	3.25	17.64	
Variable-Interval	0.0075	0.0200	4.7791	15.8699	12.4522	0.0203	
Variable-Thermal			4.9127				
2018 approved rate	Residential	GS<50	GS>50	Street Light	Sentinel	USL	
Fixed	24.36	30.73	139.37	3.21	3.27	17.75	
Variable-Interval	0.0038	0.0201	4.8078	15.9651	12.5269	0.0204	
Variable-Thermal			4.9422				
Blended Rates							
Fixed	23.32	30.67	139.09	3.20	3.26	17.71	
Variable	0.0050	0.0201	4.8653	15.9334	12.5020	0.0204	
Reconciliation	Residential	GS<50	GS>50	Street Light	Sentinel	USL	Total
Fixed revenue	9,130,245	1,172,575	640,942	349,458	1,253	9,778	11,304,252
Variable revenue	1,420,103	1,837,083	3,025,269	109,894	9,554	11,243	6,413,146
Transformer Ownership	-	-	(438,492)	-	-	-	(438,492)
Additional charges	(230,005)	(23,248)	281,158	52,060	3,256	1,097	84,318
Total	10,320,344	2,986,410	3,508,877	511,412	14,063	22,118	17,363,224
Additional charges	Residential	GS<50	GS>50	Street Light	Sentinel	USL	Total
Tax savings 2012-2018	166,778	51,232	75,986	9,704	1,031	-	304,731
Unbilled	(181,390)	-	-	-	-	-	(181,390)
LRAM 2012-2018	(478,308)	(758,352)	(726,055)	(167,047)	-	-	(2,129,762)
LRAM 2012-2017 reversal	373,028	601,643	547,587	119,065	-	-	1,641,323
IFRS 2012-2018	(275,519)	(91,385)	(274,653)	(3,455)	(283)	(324)	(645,620)
IFRS 2012-2017 reversal	524,823	174,075	523,173	6,581	539	617	1,229,808
Customer count and volume timing	(359,417)	(461)	135,120	87,212	1,969	804	(134,773)
Total additional charges	(230,005)	(23,248)	281,158	52,060	3,256	1,097	84,318
% addl chgs to total bill revenue	-3.4%	0.0%	3.7%	19.0%	18.2%	3.8%	-0.8%

2019 Cost Allocation billing determinants - MRZ						
	Residential	GS<50	GS>50	Street Light	USL	Total
kWh	50,684,558	24,374,249	113,618,428	519,881	395,009	189,592,125
kW			282,755	1,411		284,166
# of customers	6,395	772	108	1,492	11	8,778
2017 approved rates	Residential	GS<50	GS>50	Street Light	USL	
Fixed	23.20	22.62	63.93	3.87	10.46	
Variable	0.01070	0.01670	3.25810	8.93200	0.01120	
2018 approved rates	Residential	GS<50	GS>50	Street Light	USL	
Fixed	26.99	22.79	64.41	3.90	10.54	
Variable	0.0054	0.0168	3.2825	8.9990	0.0113	
Blended Rates						
Fixed	25.73	22.73	64.25	3.89	10.51	
Variable	0.0072	0.0168	3.2744	8.9767	0.0113	
Reconciliaiton	Residential	GS<50	GS>50	Street Light	USL	Total
Fixed revenue	2,009,923	212,934	82,169	87,371	1,407	2,393,804
Variable revenue	365,816	408,629	925,159	12,662	4,450	1,716,717
Transformer ownership			(116,073)			(116,073)
Additional charges	95,097	(29,392)	101,820	(18,078)	0	149,446
	2,470,836	592,171	993,074	81,956	5,857	4,143,895
Additional charges	Residential	GS<50	GS>50	Street Light	USL	Total
LRAM accrual 2018	95,097	(29,392)	101,820	(18,078)	0	149,446

c) NT Power is submitting Appendix H, the updated cost allocation schedules I6.1, I6.2, I8, O1 and O2 for MRZ and NTRZ, showing a cost allocation scenario where existing rates are the 2019 approved rates without adjustments.

BOARD STAFF IR - 13

CA-Staff-13

Ref: Newmarket-Tay Cost Allocation Model, Sheet I6.1 Revenue; Sheet I8 Demand Data

2010 Newmarket-Tay Cost Allocation Model, Sheet I6 Customer Data

On the Revenue worksheet, Newmarket Tay Power indicates that in the GS > 50 rate class, 34,038 kW out of 621,805 kW (5.5%) of billing demand are subject to transformer ownership allowance (TOA), implying that this load is served by customer owned transformers. In the previous application, 601,285 kW out of 788,495 kW (76.3%) of this billing demand was subject to TOA.

Demand Data worksheet, 116,459 kW of 182,532 kW (63.8%) of GS > 50 4 NCP load is served by Newmarket-Tay Power owned transformers.

a) Please explain how the proportion of billing demand for which TOA applies fell from 76.3% in the 2010 COS to 5.5% in the current application.
b) Please explain how 63.8% of 4 NCP demand is served by Newmarket-Tay owned transformers, and only 5.5% of billing demand is served by customer owned transformers.

RESPONSE

a) In reviewing the information for this question, NT Power has determined the TOA kW for NTRZ was incorrect. The TOA kW for NTRZ CA Sheet I6.1 is 515,873 kW. NT Power is confirming an updated cost allocation model is attached reflecting the following corrections to:
   a. CA Sheet I6.1 cell F27 updated from 34,038 to 515,873
   b. CA Sheet I6.1 cell F37 updated from ($128,401) to $281,158
   c. CA Sheet I8 cell F57, F63 and F69 to reflect Line Transformer NCP=Classification NCP from Load Data Provider (term used in I8) times (1- (GS > 50 kW transformer allowance kW/ total GS > 50 kW))

b) The noted inconsistency has been addressed in CA Sheet I8 as noted above.

BOARD STAFF IR - 14

CA-Staff-14

Ref: Newmarket-Tay Cost Allocation Model, Sheet I8 Demand Data

Midland Cost Allocation Model, Sheet I8 Demand Data

Newmarket Tay Power has provided NCP data for the GS < 50 rate class in the NTRZ as follows:

	1 NCP	4 NCP
Classification NCP from Load Data Provider	30,917	110,586
Primary NCP	30,917	110,586
Line Transformer NCP	24,318	86,983
Secondary NCP	2,348	11,059

The 1 NCP is the highest usage of a rate class for the entire year. The 4 NCP is to be determined by adding up the four highest monthly peaks for the rate class. One of these will be the annual peak, and the other three will not be higher than the annual peak. Newmarket-Tay Power has indicated a 4 NCP of 11,059 kW, which is 4.7 times the 1 NCP of 2,348 kW.

The Secondary 4 NCP in NTRZ of 11,059 kW is 10% of the Primary 4 NCP of 110,586 kW.

In the MRZ, there is no secondary demand associated with the GS < 50 rate class.

a) Given the above, please review the derivation of the Secondary 1NCP and Secondary 4NCP. If Newmarket-Tay believes the calculations are correct, please provide the derivation.
b) Please explain the typical connection of a GS < 50 customers that result in only 10% of 4 NCP load being served by the secondary distribution system in NTRZ and none of the 4 NCP load being served by the secondary distribution system in MRZ.

RESPONSE

a) In preparing the response to CA-Staff-11 it was discovered that the calculations for the NCP values for the GS<50 class also needed to be updated along with the NCP values for the Residential class. These updates are included in the revised model in response to Staff IR-18.

b) For both NTRZ and MRZ, GS<50 customers own the assets that serve the secondary distribution system. However, there are legacy GS<50 services where NT Power and Midland PUC own the secondary distribution assets. The secondary demand associated with the GS < 50 rate class for MRZ is updated in Sheet I6.2 cell E25 with a value of 84 to reflect this situation.

BOARD STAFF IR - 15

CA-Staff-15

Ref: Midland Cost Allocation Model, Sheet I6.1 Revenue; Sheet I8 Demand Data

On the Revenue worksheet, Newmarket Tay Power indicates that in the GS > 50 rate class, 193,455 kW out of 282,527 kW (68.5%) of billing demand are subject to TOA, implying that this load is served by customer owned transformers. Conversely, on the Demand Data worksheet, 52,829 kW of 72,148 kW (72.2%) of 4 NCP load is served by Newmarket-Tay Power owned transformers.

a) Please reconcile the apparent inconsistency that in depending on the measure of load, a larger majority of GS > 50 class load is served by customer owned transformers or by Newmarket-Tay Power owned transformers.

RESPONSE

a) MRZ has reconciled the inconsistency noted in the IR above. MRZ has adjusted the line transformer 1 NCP, 4 NCP and 12 NCP load served by MRZ owned transformers in Sheet I8 Demand Data cells F57, F63 and F69 to reflect the remaining 32% of the total load.

BOARD STAFF IR - 16

CA-Staff-16

Ref: Cost Allocation Report, page 11

Newmarket-Tay Rate Generator Model, Sheet 16. Rev2Cost

Newmarket-Tay indicates that it is proposing to adjust the revenue to cost ratios in the NTRZ to bring the revenue-to-cost ratios for Sentinel Lighting, Street Lighting, and Unmetered Scattered Load down to 120%, which is the top of the target range. The residential rate class, which is the only rate class with a revenue-to-cost ratio below 100% would receive an offsetting rate increase.

Rate adjustments are entered in the rate generator model for the corresponding rate classes.

a) Please provide a derivation of the rate adjustments used, and indicate how these result in the targeted revenue-to-cost ratios.

RESPONSE

NT Power submitted an updated Cost Allocation report dated November 11, 2019. Table 8 below provides the NTRZ revenue vs costs band adjustment analysis of the revenue-to-cost ratios before and after the proposed adjustments:

Table 8 - Revenue vs costs band adjustment analysis					
		Revenue vs Cost ratio			
Rate Class	OEB target bands	%	Difference between Revenues vs Allocated costs $	Adj $ to OEB target band	Revenue vs Cost ratio % incl adj
Residential - NTRZ	85-115%	92.76%	(969,688)	(363,802)	95.47%
General Service Less Than 50 kW - NTRZ	80-120%	116.94%	488,165	NA	116.94%
General Service 50 to 4,999 kW - NTRZ Therm & Int	80-120%	101.99%	77,243	NA	101.99%
Sentinel Lighting - NTRZ	80-120%	152.55%	5,350	3,313	120.00%
Street Lighting - NTRZ	80-120%	312.27%	385,630	349,296	120.00%
Unmetered Scattered Load - NTRZ	80-120%	226.27%	13,300	11,193	120.00%

The following table summarizes the 2019 proposed fixed and variable proportion breakout by rate class from tables 9, 11, 12 and 13 of the updated Cost Allocation report dated November 11, 2019 and are the same adjustments in the rate generator model Tab 16 Rev2Cost_GDPIPI:

2019 Proposed Fixed and Variable proportion by rate class (Tables 9, 11, 12 and 13)													
	Proposed annual band adj			2018 billing determinants (I6.1 & I6.2)				Proposed mthly band adj		Mthly fixed chges		Mthly variable chges	
Rate Class	Total annual band adj	Annual fixed split	Annual variable split	Fixed		Variable		Monthly fixed rate adj	Monthly variable rate adj	2019 Current	2019 proposed with band adj	2019 Current	2019 proposed with band adj
Residential - NTRZ	363,802	363,802	-	32,622	# of cust	282,139,763	kWh	0.93	-	27.61	28.54	-	-
General Service Less Than 50 kW - NTRZ	-	-	-	3,186	# of cust	91,548,982	kWh	-	-	31.01	31.01	0.0203	0.0203
General Service 50 to 4,999 kW-NTRZ	-	-	-	384	# of cust	621,805	kW	-	-	140.62	140.62	4.9867	4.9867
Sentinel Lighting - NTRZ	(3,313)	(384)	(2,928)	32	# of cust	764	kW	(1.00)	(3.8330)	3.30	2.30	12.6396	8.8066
Street Lighting - NTRZ	(349,296)	(265,732)	(83,564)	9,091	# of conn	6,897	kW	(2.44)	(12.1159)	3.24	0.80	16.1088	3.9929
Unmetered Scattered Load - NTRZ	(11,193)	(5,206)	(5,987)	46	# of cust	552,037	kWh	(9.43)	(0.0108)	17.91	8.48	0.0206	0.0098
Total	-	92,479	(92,479)										

The 2018 billing determinants were used in the updated cost allocation models. These billing determinants were used to determine the revenues by rate class in the cost allocation model. The rate class revenue was used to determine the resulting revenue to cost ratios which were then adjusted to be within OEB's acceptable range.
The adjustments to the revenue to cost ratios defined the total annual band adjustment and this amount was assigned to the fixed and variable components of the distribution revenue consistent with the current fix/variable proportion. These amounts were then divided by the appropriate 2018 billing determinant to determine the band adjustment on a customer/connection or volumetric basis.

BOARD STAFF IR - 17

CA-Staff-17

Ref: Cost Allocation Report, page 8

Newmarket-Tay Power has determined the meter reading weighting factor for a smart meter with demand to be 1.25 in MRZ, and 10.0 in NTRZ. It states that these meters are read manually in NTRZ.

a) Why are smart meters with demand read manually in NTRZ?
b) Does Newmarket-Tay Power have plans to start reading its smart meters with demand in NTRZ using an approach similar to what it uses in MRZ?

RESPONSE

a) Smart meters with demand are read manually in NTRZ due to metering and system restrictions. NT Power is working with their automated meter infrastructure providers to eliminate manual meter reads.

   NT Power is in the process of upgrading approximately 300 GS (>50 and <200) meters to smart meters with interval capability. These meters will be able to leverage cellular communication infrastructure to read the meters remotely in 2020.

b) Please refer to response Staff IR 17(a).

BOARD STAFF IR - 18

CA-Staff-18

Please update the cost allocation models for all identified changes as a result of the interrogatories.

RESPONSE

NT Power confirms the cost allocation models for NTRZ and MRZ have been updated for all identified changes as a result of the following interrogatories:

i. Updated the transformation allowance values for the GS > 50 kW class in tab I6.1 for the NTRZ model as per responses to Staff IR-13.
ii. Revised the calculations of NCP values in tab I8 for the NTRZ model as per responses to Staff IR-11 and Staff IR-14.
iii. Updated the information in MRZ and NTRZ tab E1 Categorization, rows 24 and 25 to be consistent with the information provided on page 51 of the Board Direction on Cost Allocation Methodology For Electricity Distributors (Cost Allocation Review – EB 2005 0317) dated September 29, 2006. It is respectfully suggested this change be made to the OEB's provincial cost allocation model since it appears this inconsistency has been in place for a number of years.
iv. Updated MRZ model Sheet I6.2 cell E25 with a value of 84 as per response to Staff IR-14.
v. Updated MRZ model Sheet I6.2 Customer Data cells D21 and E21 to reflect the correct number of 6,453 residential and 771 GS<50 customers
vi. Updated Sheet I6.2 and Tab I6.1 cells D37 and E37 to reflect adjustments to additional charges for residential ($17,906) and GS<50 customers $272 per response to VECC IR-2(a)(i)(ii)
vii. Updated MRZ Sheet I8 Demand Data cells F57, F63 and F69 to reflect the remaining 32% of the total load per response to Staff IR-15.

BOARD STAFF IR - 19

Newmarket-Tay Rate Zone

NTRZ-Staff-19

Ref: Newmarket-Tay Rate Zone, Application Summary (page 12)

Newmarket Tay DVA Continuity Schedule

There is a discrepancy for certain variance account balances as of December 31, 2018 as per the application and the DVA Continuity Schedule as indicated in the Table compiled below:

Account Descriptions	Account Number	Closing Principal Balance as of Dec 31, 2018 (Note (2))	Closing Interest Amounts as of Dec 31, 2018	Total Closing P+I	Application page 12	Difference	
Group 1 Accounts							
LV Variance Account	1550	829,406	23,166	852,571	852,571	0	
Smart Metering Entity Charge Variance Account	1551	(39,555)	1,283	(38,272)	(38,272)	0	
RSVA - Wholesale Market Service Charge[5]	1580	(2,700,813)	(97,991)	(2,798,804)	(2,800,189)	1,385	
Variance WMS – Sub-account CBR Class A[5]	1580	(0)	0	(0)		(0)	
Variance WMS – Sub-account CBR Class B[5]	1580	487,036	3,797	490,833	0	490,833	
RSVA - Retail Transmission Network Charge	1584	(605,518)	11,269	(594,249)	(594,249)	0	
RSVA - Retail Transmission Connection Charge	1586	680,396	38,077	718,473	718,473	(0)	
RSVA - Power[4]	1588	4,785,906	101,394	4,887,299	4,887,299	0	
RSVA - Global Adjustment[4]	1589	1,916,551	48,541	1,965,092	1,965,092	(0)	
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595 (2009)	63,648	1,400	65,048	0	65,048	Note (1)
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595 (2013)	(781,261)	(3,198)	(784,459)	0	(784,459)	
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595 (2014)	167,819	3,126	170,944	170,944	0	
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595 (2015)	(14,570)	(271)	(14,842)	(14,842)	0	
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595 (2016)	0	0	0	0	0	
Disposition and Recovery/Refund of Regulatory Balances (2017)	1595 (2017)	17,212	321	17,532	17,532	0	
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595 (2018)	490,304	9,132	499,436	499,436	(0)	
		5,296,558	140,044	5,436,603	5,663,795	(227,192)	
	(1)	this row is hidden on the continuity sch but there is an amount and it is included in the total.					
	(2)	This column is before disposition of 2017 balances disposed in 2019 rates.					

a) Please explain the differences and refile the corrected schedules.

RESPONSE

a) NTZR is submitted an updated table based on response to Staff IR-7.

#	Description	Account	Closing Principal Balance as at Dec 31/18	Closing Interest Balance as at Dec 31/18	Total Closing P+I	Updated 3. Continuity Schedule	Variance
1	LV Variance Account	1550	829,406	23,166	852,571	852,571	-
2	Smart Metering Entity Charge Variance Account	1551	(39,555)	1,283	(38,272)	(38,272)	-
3	RSVA - Wholesale Market Service Charge	1580	(2,700,813)	(97,991)	(2,798,804)	(2,798,804)	-
4	Variance WMS - Sub account CBR Class A	1580	-	-	-	-	-
5	Variance WMS - Sub account CBR Class B	1580	487,036	3,797	490,833	490,833	-
6	RSVA - Retail Transmission Network Charge	1584	(605,518)	11,269	(594,249)	(594,249)	-
7	RSVA - Retail Transmission Connection Charge	1586	680,396	38,077	718,473	718,473	-
8	RSVA - Power	1588	5,699,482	123,840	5,823,321	5,823,321	-
9	RSVA - Global Adjustment	1589	1,002,975	26,095	1,029,070	1,029,070	-
10	Disposition Balances (2008)	1595	-	-	-	-	-
11	Disposition Balances (2009)	1595	-	-	-	-	-
12	Disposition Balances (2010)	1595	-	-	-	-	-
13	Disposition Balances (2012)	1595	-	-	-	-	-
14	Disposition Balances (2013)	1595	(766,615)	(3,198)	(769,813)	(769,813)	-
15	Disposition Balances (2014)	1595	167,819	3,126	170,944	170,944	-
16	Disposition Balances (2015)	1595	(14,570)	(271)	(14,842)	(14,842)	-
17	Disposition Balances (2016)	1595	-	-	-	-	-
18	Disposition Balances (2017)	1595	17,212	321	17,532	17,532	-
19	Disposition Balances (2018)	1595	490,304	9,132	499,436	499,436	-
	Total		**5,247,557**	**138,644**	**5,386,201**	**5,386,201**	**-**

BOARD STAFF IR - 20

NTRZ-Staff-20

Ref: Newmarket-Tay Rate Generator Model, Sheet 1. Information Sheet
Newmarket-Tay Rate Generator Model, Sheet 3. Continuity Schedule
Newmarket-Tay 2019 Rate Generator Model, Sheet 3. Continuity Schedule

In its 2019 rate generator model, Newmarket-Tay has populated Account 1595 Disposition and Recovery/Refund of Regulatory Balances (2012). No other sub-accounts of 1595 were populated with balances. In the current rate generator model, the same historic values are populated into the 2013 sub-account.

In addition, Newmarket-Tay has populated credit adjustments of $501,404 principal and $7,323 interest. This effectively results in the 2013 sub-account in the current model having exactly double the value that the 2012 sub-account had in the 2019 model, at the end of 2017.

Transactions have been entered for Account 1595 sub-accounts 2013, 2014, 2015, 2017 and 2018 having occurred in 2018. None of the 1595 sub-accounts for 2014, 2015, 2017 or 2018 had any transactions recorded for years prior to 2018.

a) Please confirm that all values recorded in 1595 (2013) are actually applicable to 2012, and none apply to 2013.
b) If part a) cannot be confirmed, please file a revised model which correctly records 2012 transactions in the 2012 sub-account and 2013 transactions in the 2013 sub-account.
c) Please explain whether the principal adjustments recorded for 1595 (2013) in 2017 were an error, and if not, please provide details regarding the source of these principal adjustments.

RESPONSE

a) NT Power has experienced staff turnover and is working with our external auditors to reconstruct NTRZ DVA account 1595 to ensure compliance for the December 31, 2019 financial records. NTRZ has reviewed the 2.1.7 RRR submission for APH 1595 Group 1 Accounts and has determined the breakout by disposition year was incorrectly submitted. Further, NT Power submitted the APH 1595 Group Accounts within the 2.1.7 RRR submission for the disposition years 2008 to 2018. The rate generator model is displaying the RRR submissions for 2013 to 2019. Please refer to response Staff IR-2(f) for the updated reconciliation table.

b) Please refer to response Staff IR-20(a).

c) Please refer to response Staff IR-20(a).

BOARD STAFF IR - 21

NTRZ-Staff-21

Ref: Newmarket-Tay Rate Zone, Application Summary, page 36

Newmarket-Tay Rate Generator Model, Sheet 9. Shared Tax – Rate Rider

Newmarket Tay Power states that “the IRM Rate Generator model generated a rate rider for each rate class for a total allocation of tax savings of ($41,095).” However, the filed rate generator model indicates $0.00 for all rate classes.

a) Please reconcile. If the model should generate a rate rider, please ensure that it does. If not, please confirm that the balance of $41,095 will be transferred to account 1595.

RESPONSE

NT Power NTRZ confirms that a rate rider was not generated for any rate class for the allocated tax sharing amount of ($41,095). NTRZ will transfer the tax sharing amount into account 1595 for disposition at a later date in accordance with the Filing Requirements, Appendix B.

BOARD STAFF IR - 22

NTRZ-Staff-22

Ref: Newmarket-Tay Rate Zone, Application Summary (GA Methodology Description, page 26)

In response to Question 2 f), the applicant has indicated that the 2018 November and December true-ups were recorded in the utility's GL in 2019. However, the true-up amounts are not shown on the DVA Continuity Schedule.

a) Please provide reasons for not including the variance amounts related to 2018 in 2018 under "principal adjustments' on the DVA Continuity Schedule for regulatory purposes.

RESPONSE

Please refer to response Staff IR-2(a). NT Power will be providing the variance amounts related to 2018 on the DVA Continuity Schedule following the external audit for December 31, 2019 financial results.

BOARD STAFF IR - 23

NTRZ-Staff-23

Ref: 2018 GA Workform – Newmarket Rate Zone

DVA Continuity Schedule - Newmarket Rate Zone

Reconciling item #7 shows a credit adjustment of $913,576. In accordance with the OEB guidance, this amount should be shown as a “principal adjustment” on the DVA Continuity Schedule. OEB staff notes that this adjustment would also impact Account 1588.

a) Please make the necessary corrections to the schedules and refile.

RESPONSE

NT Power has updated the Rate Gen Model for NTRZ on tab 3. Continuity Schedule in cells BF28-29 and BK 28-29 for Account 1588 and Account 1589 to reflect the credit adjustment of $913,576.

BOARD STAFF IR - 24

NTRZ-Staff-24

LRAMVA

Ref: Newmarket-Tay Rate Generator Model, Sheet 3. Continuity Schedule

Newmarket-Tay LRAMVA model

Newmarket-Tay has recorded $432,891 principal and $13,696 interest as 2018 transactions in the continuity schedule. These reflect the principal and interest to April 30, 2020 as reported in the LRAMVA model.

a) Please explain all other entries on the continuity schedule for account 1568.
b) If these amounts relate to disposed balances, please explain why these balances were not transferred to account 1595 in the year they were disposed.

RESPONSE

a) NTRZ has revised the entries for Account 1568 in the Generator Model on Tab 3. Continuity Schedule in cell address Z43-BL43 to reflect the disposition balances.
b) The amount in account 1568 does related to disposed balances. The balance in account 1568 is the 2018 LRAM accrual $479,424 (cell BT43). The variance between the 1568 account balance Generator Model and the approved disposition will be adjusted within the 2020 financial records.

BOARD STAFF IR - 25

NTRZ-Staff-25

LRAMVA

Ref: Newmarket-Tay LRAMVA model

Newmarket has requested approval of an LRAMVA amount for its NTRZ of $446,588. This amount is for lost revenues in 2018 from programs delivered in 2018 as well as lost revenues from persisting savings from programs delivered between 2011 and 2017.

a) Please review the 2018 incremental energy savings from the P&C Report and confirm that the 276,163 kWh of savings included under the Industrial - Process and Systems Upgrades Initiatives is correct and that these savings should not be applied to the Residential Heating and Cooling Program. If a change is required, please update the workform and indicate the impact to the LRAMVA total.

RESPONSE

NT Power confirms that the 276,163 kWh of savings should be applied to the Residential Heating and Cooling Program. The revised LRAMVA NTRZ principal is $434,272 and carrying charges are $13,740 totaling $448,012 resulting in a total impact $1,424 to the original claim as per the table below:

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$68,652	$2,172	$70,824
GS<50 kW	kWh	$142,390	$4,505	$146,895
GS>50 kW - Thermal Demand Meter	kW	$176,320	$5,579	$181,898
GS>50 kW - Interval Meter	kW	$7,488	$237	$7,725
Street Lighting	KW	$39,423	$1,247	$40,671
Total		**$434,272**	**$13,740**	**$448,012**

NTRZ has updated the Rate Gen Model with the revised values on Tab. 3 Continuity Schedule in cells BD 43 and BI 43. The revised LRAMVA amounts by rate class have been updated in Tab. 4 Billing Det for Def-Var in cells S17 to S21.

NTRZ has submitted an updated LRAMVA Workform and detailed the changes made in ‘Tab 1-a. Summary of Changes’ in accordance with the LRAMVA Workform instructions. Please refer to response Staff IR-7.

BOARD STAFF IR - 26

Midland Rate Zone

MRZ-Staff-26

Ref: Application summary – Midland Rate Zone, page 22

The evidence indicates that an annual true-up is performed to align the settlement submissions with the fiscal year.

a) OEB staff notes that the February 21, 2019 OEB accounting guidance requires the utilities to perform monthly true-ups based on actual consumption data. Please indicate if the applicant is following this guidance with respect to true-ups in the Midland rate zone.
   i. If yes, please indicate the effective date.

RESPONSE

a) MRZ confirms monthly true-ups are being performed based on actual consumption data for the MRZ. The effective date of monthly true-ups is prior to January 1, 2019.

BOARD STAFF IR - 27

MRZ-Staff-27

Ref: Application Summary – Midland Rate Zone, page 28

2018 GA Workform – Midland Rate Zone

DVA Continuity Schedule – Midland Rate Zone

The applicant has stated that there was an error discovered when completing the 2018 GA Workform and a reallocation of $337,322 is required between the two commodity accounts.

a) Please indicate if a review of 2017 was also performed to determine if similar error was made and affected 2017 variance.
   i. If no to part a), why not?
   ii. If yes, please provide further details of any adjustments that were required to 2017 variances as a result of the review.
   iii. Please indicate if any adjustments have been made to 2017 variances as a result of the review, and where are they shown on the continuity schedule.

RESPONSE

a) MRZ confirms a review of 2017 was not performed.

i. The 2017 variance was under the 1% threshold.

ii. Please see response Staff IR-27(i).

iii. Please see response Staff IR-27(i).

BOARD STAFF IR - 28

MRZ-Staff-28

Ref: 2018 GA Workform – Midland Rate Zone

DVA Continuity Schedule - – Midland Rate Zone

Reconciling item #7 shows a credit adjustment of $337,322. In accordance with the OEB guidance, this amount should be shown as a “principal adjustment” on the DVA Continuity Schedule. OEB staff notes that this adjustment would also impact Account 1588.

a) Please make the necessary corrections to the schedules and refile.

RESPONSE

a) MRZ has updated the Rate Generator Model Tab 3. Continuity Schedule in cells BF28-29 and BK 28-29 for Account 1588 and Account 1589 to reflect the credit adjustment of $337,322.

BOARD STAFF IR - 29

MRZ-Staff-29

LRAMVA

Ref: Midland Rate Generator Model, Sheet 3. Continuity Schedule

Midland LRAMVA model

Newmarket-Tay has recorded $90,126 principal and $2,852 interest as 2018 transactions in the continuity schedule. These reflect the principal and interest to April 30, 2020 as reported in the LRAMVA model.

a) Please explain all other entries on the continuity schedule for account 1568.

If these amounts relate to disposed balances, please explain why these balances were not transferred to account 1595 in the year they were disposed.

RESPONSE

a) MRZ has revised the entries for account 1568 on Tab 3. Continuity Schedule in AV43 to BN43 to accurately reflect the disposition balances. The balance is account 1568 are not disposed balances.

BOARD STAFF IR - 30

MRZ-Staff-30

LRAMVA

Ref: Midland LRAMVA model

Newmarket has requested approval of an LRAMVA amount for its Midland RZ of $92,978. This amount is for lost revenues in 2018 from programs delivered in 2018 as well as lost revenues from persisting savings from programs delivered between 2011 and 2017.

a) Please provide an explanation that supports the inclusion of persisting savings from 2011, 2012 and 2013 CDM programs in 2018 when the Midland RZ had an updated load forecast and CDM threshold approved as part of its 2013 COS. Please provide the basis for the 2013 LRAMVA threshold and clearly indicate that actuals from 2011, 2012 or 2013 were not factored into the load forecast.
b) Please review the 2018 incremental energy savings from the P&C Report and confirm that the 92,295 kWh of savings included under the Industrial - Process and Systems Upgrades Initiatives is correct and that these savings should not be applied to the Residential Heating and Cooling Program. If a change is required, please update the work form and indicate the impact to the LRAMVA total.

RESPONSE

a) NT Power MRZ has excluded the persisting savings from 2011, 2012, 2013 CDM programs. MRZ has submitted an updated LRAMVA Workform and detailed the changes made in ‘Tab 1-a. Summary of Changes’ in accordance with the LRAMVA workform instructions.
   MRZ has updated the Rate Gen Model with the revised values on Tab. 3 Continuity Schedule in cells AV43 and BN43. The revised LRAMVA amounts by rate class have been updated in Tab. 4 Billing Det for Def-Var in cells S17 to S21.

b) MRZ confirms that 92,295 kWh of savings should be applied to the Residential Heating and Cooling Program. This revision resulted in a total impact $685 to the original claim and is providing the following updated table:

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$34,583	$1,094	$35,677
GS<50 kW	kWh	-$19,245	-$609	-$19,854
GS>50	kW	$48,876	$1,546	$50,423
Street Lights	kW	$283	$9	$292
Total		**$64,497**	**$2,041**	**$66,538**

NT Power MRZ has submitted an updated LRAMVA Workform and detailed the changes made in ‘Tab 1-a. Summary of Changes’ in accordance with the LRAMVA Workform instructions.

Please refer to response Staff 7.

INTERROGATORIES OF THE SCHOOL ENERGY COALITION

SCHOOL ENERGY COALITION IR – 1

1.0-SEC-1

1. [Update November 11, 2019, p. 4] Attached to these interrogatories is a side-by-side comparison of the cost allocation results (Sheet O1) from the Applicant's last Board-approved CAM compared to the CAM filed in this proceeding. A live Excel version of the comparison is also filed with these interrogatories. With respect to that comparison:

   a. Please confirm that the table accurately reflects the results in the respective CAMs, except for lines 16, 17, 28, and 37, and columns K, M and O, which are calculated amounts.

   b. Please confirm that the calculations in lines 16, 17, 28, and 37, and columns K, M and O, are accurate.

   c. Please provide a detailed explanation of all of the reasons why the Net Plant allocated to GS>50 customers increased by 60.60% (and 67.92% per customer), while the Net Plant allocation to Residential increased by only 18.84% (6.86% per customer), and the Net Plant allocation to GS<50 increased by only 10.49% (0.42% per customer). If any of the reasons are changes in assumptions or allocators, please provide the rationale for each such change.

   d. Please explain why Gross Distribution Plant decreased from 2010 to 2018 for Residential and GS<50, despite increases in the number of customers, and yet increased over the same period for GS>50 despite a decline in the number of customers.

   e. Please provide a complete calculation of the impact on the results in lines 27 and 28 of the unequal changes in allocation of Net Plant to the three general service classes as set forth above, including but not limited to allocation of interest, PILs, net income, depreciation expense and distribution expenses.

   f. Please provide a rate base continuity schedule, in the Board's standard format, from 2010 Board approved to the figures used for the 2018 CAM.

   g. Please confirm that, on the transition to IFRS, the Applicant zeroed out its accumulated depreciation and reduced its gross plant accordingly. If not already provided in the continuity schedule, please provide a detailed breakdown of the timing and amounts of all such adjustments, including in addition any adjustments to accumulated capital contributions.

h. Please provide a comprehensive list of all allocators between the three general service classes that changed from 2010 to 2018, other than those that changed in the same percentages for each of those three classes. In each case, explain the reasons for the changes in allocators.

RESPONSE

a) The response to these questions has used an updated version of the cost allocation comparison file (Appendix D) that was originally provided with the SEC interrogatories. The updated file reflects changes to the NT Power NTRZ cost allocation model resulting from the responses to interrogatories. A list of changes is provided in response to Staff IR-18. In addition, rows 54 to 62 has been revised to reflect the correct information from NTP's last Board-approved CAM.
b) It is confirmed that the calculations in lines 16, 17, 28, and 37, and columns K, M and O, are accurate.
c) In the revised comparison file the Net Plant allocated to GS>50 customers increased by 47.33% (and 54.04% per customer), while the Net Plant allocation to Residential increased by only 23.00% (10.61% per customer), and the Net Plant allocation to GS<50 increased by only 11.72% (1.53% per customer).

   The allocator used in the cost allocation model to allocate Net Plant is titled the Net Fixed Asset allocator ("NFA"). In tab SEC 1c of the attached Excel live spreadsheet named Appendix E Cost Allocation Comparison Analysis the NFA allocator is provided for Case 1 and 2. Case 1 is NT Power's last Board-approved CAM and Case 2 is the current NTP's CAM for the NTRZ. The information in tab SEC 1 c provides the data and calculations that support the NFA allocator for both cases. A review of this data indicates the following.

   i. The net plant in Case 2 has increased by $10.0 million.
   ii. Net plant for the Street Lightning class has reduced by $2.5 million in Case 2. This results from the Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads dated December 19, 2013 (EB-2012-0383). The report indicated a change to the street lighting cost allocation method was needed which has been implemented in the current model. This change has caused net plant to be moved away from the Street Lighting class to the other classes between Case 1 and 2.

iii. The number of connections for the Sentinel Lighting and Unmetered Scattered Load has reduced between Case 1 and 2 causing a reduction in net plant to these classes.
iv. The demand values used in tab I8 of the cost allocation model for the GS < 50 kW class have reduced in Case 2 which supports the percentage increase of 11.7% being lower than the average of 19.4%. This result in a net plant increase this class of only $1.1 million.
v. The net plant for Residential class has an increase by $6.8 million and the net plant for the GS > 50 kW class has increase by $4.8 million since these are the two classes that are being assigned the net plant from other classes. The $6.8 million translate into a 23.0% increase for the Residential class. The $4.8 million increase means a 47.3% increase for the GS > 50 kW since the base to which it is being applied is smaller.

d) The updated cost allocation comparison file which reflects changes to the NT Power NTRZ cost allocation model resulting from the responses to interrogatories indicates the Gross Distribution Plant also decreases for GS>50.

e) Tab SEC 1 e of the Excel referenced in c) provides each line of the revenue requirement that supports the total revenue requirement shown in line 27 for both cases. The information in line 28 is also provided in tab SEC 1 e. A review of this information indicates the following.

i. The allocation of PILs, Interest and Allocated Net Income is based on the NFA allocator discussed above in part c)
ii. Distribution expenses are allocated similar to NFA, which generally is the case, since these expenses are related to the assets that contribute to the NFA allocator.
iii. Customer expenses are customer related costs such as billing, collections, meter reading. Each of these expenses have specific allocator that are defined by the weighting factors defined as inputs in the cost allocation model.
iv. The allocation of general and administration expense falls between the allocation factors for distribution and customer expense since general and administration expense is allocated based on the weighted average of distribution and customer expenses.

v. A review of the method of allocating depreciation in the cost allocation model indicates it is a generally consistent with the allocation of the gross plant shown in tab SEC 1c.

f) NT Power is providing NTRZ rate base continuity schedule in the Board's standard format from 2009 to 2018 as Appendix A.

g) NT Power confirms, on transition to IFRS in 2014, the opening balance of accumulated depreciation was zeroed out and reduced gross plant accordingly. Please see Appendix A for the 2014 detailed breakout of all adjustments by asset and accumulated depreciation accounts.

h) Tab SEC 1 h of the Excel file referenced in c) provides a comparison of the main allocators used in the cost allocation model for Case 1 and 2. A review of this information indicates the following

i. The 4NCP allocator is the main demand allocator in the cost allocation model and reflects the demand information provided in I8 of the model. The information in tab I8 is reduced by the PLCC adjustment, which is 400 watts per customer/connection. In Case 1, this adjustment essentially eliminates the demand allocator for Street Lighting, Sentinel Lighting and Unmetered Scattered Load class since the connection number is higher. In Case 2, these classes have lower connection counts based on 2018 actual data and the change to cost allocation for Street Lighting. This results in 4NCP values for these classes in Case 2.

ii. The customer allocators reflect the customer/connections values in each case based on the number of customer/connections using the various types of assets as defined by the inputs in tab I6.2 of the cost allocation model. The customer allocator for Street Lighting for primary and line transformer assets reflect a substantially reduced number of connections for these assets in accordance with the updated cost allocation method for Street Lighting.

iii. In Case 1, the allocators for services, billing and collecting reflect the default weighting factors at the time. The meter related costs were allocated based on simplistic approach to smart meters. In case 2, the allocators for services, billing and collecting reflect LDC specific factors. The meter related costs were allocated based on comprehensive approach to smart meters.

iv. The NFA allocator has been discussed above in c).

SCHOOL ENERGY COALITION IR - 2

1.0-SEC-2

2. [Page 4] Attached to these interrogatories is a side-by-side comparison of the demand allocators (Sheet I8) from the Applicant's last Board-approved CAM compared to the CAM filed in this proceeding. A live Excel version of the comparison is also filed with these interrogatories as the second sheet in the one combined spreadsheet. With respect to that comparison:

   a. Please explain in detail why the demand allocators for GS<50 dropped significantly more than the demand allocators form GS>50.

   b. Please provide the sources of the data for each of the previous and current demand allocators listed.

Please advise all assumptions that have changed in determining demand numbers from 2010 to 2018.

RESPONSE

a) The source data that supports the demand allocators for 2010 is not available which means NT Power is unable to answer this question along with the question relating to the comparison of assumptions.
b) The source data that supports the 2018 case has been provided in Appendix C, a live Excel file named Newmarket Load Profile scaling 2004 to 2018.

SCHOOL ENERGY COALITION IR - 3

1.0-SEC-3

3. [Page 4] Please confirm that the data contained in the 2018 CAM is from the 2018 RRR filing of the Applicant for the Newmarket Rate Zone. If this is not the case, or if there are any differences between the RRR filing and the CAM, please provide details including any material differences between the RRR filings and the CAM. In either case, please provide a full copy of the 2018 RRR filing, in live Excel format.

RESPONSE

The 2018 RRR filing for NT Power is based on:

1. January 1 to December 31, 2018 NTRZ financial results
2. September 7 to December 31, 2018 MRZ financial results

The cost allocation models for NTRZ and MRZ is based on:

1. January 1 to December 31, 2018 NTRZ financial results (NT Power audited financials)
2. January 1 to September 6, 2018 (MPUC audited financial results)
3. September 7 to December 31, 2018 MRZ financial results (NT Power audited financials)

Please refer to response VECC IR-1(a-c) for differences between the RRR filing and the CAM for NTRZ and MRZ.

NT Power is providing Appendix B of the 2018 RRR 2.1.7 filing in live Excel format.

SCHOOL ENERGY COALITION IR - 4

1.0-SEC-4

4. [Page 6] Please explain why 80% of the NTRZ meters for GS>50 are still being read manually. Please advise how this percentage compares to the manual meter reading percentages of other similar LDCs.

RESPONSE

Please see response Staff IR-17. NT Power does not know how the percentage compares to the manual meter reading percentages of other similar LDCs.

SCHOOL ENERGY COALITION IR - 5

1.0-SEC-5

5. [Page 7 and Sheet I7.1] Please explain why residential meter capital per customer increased 36.28% ($176.00 to $239.86), while GS<50 meter capital decreased 24.45% ($584.79 to $441.83) and GS>50 meter capital increased 69.65% ($1,313.57 to $2,228.47). Please describe in detail all operational changes, if any, that caused these changes. Please reconcile the GS>50 increase in meter capital with the 80% manual reads statement.

RESPONSE

Meter capital costs provided in the 2019 cost allocation submission are based on current metering practices and material costs.

The increase in residential meter capital per customer can be attributed to inflation and the currency exchange rate between USD and CAD since the last cost allocation submission.

In the previous application, the records that support the meter capital costs are not available and staff involved in preparing the previous application are no longer with the company. However, it appears the meter capital costs per customer may have been incorrectly catergorized for GS<50 and GS>50 rate classes based on our current understanding. In the current application, the correct meter types and capital costs have been allocated to the applicable rate classes.

SCHOOL ENERGY COALITION IR - 6

1.0-SEC-6

6. [Page 9] Please provide a more detailed explanation why new load profiles were not done. Please confirm that the Applicant is proposing to defer new load profiles until 2028.

RESPONSE

As outlined in the application, NTRZ was not able to update its load profiles at this time due to metering and system restrictions primarily related to consumption data for some meter types that still require manual reads. NT Power is in the process of upgrading approximately 300 GS (>50 and <200) meters to smart meters with interval capability. These meters will be able to leverage cellular communication infrastructure to read the meters remotely in 2020.

NT Power confirms that it intends to put plans in place to update its load profiles for the next time a cost allocation model is filed which is expected to be 2028.

SCHOOL ENERGY COALITION IR - 7

1.0-SEC-7

7. [Sheet O2] Please explain why

   a. The Customer Directly Related monthly costs generated by the model increased for Residential 418% ($2.09 to $10.83), for GS<50 1615% ($1.52 to $26.07), and for GS>50 757% ($9.40 to $80.57),

   b. The fixed charge ceiling (Min. Sys. plus PLCC adjustment) increased for Residential 49% ($9.48 to $14.08), for GS<50 320% ($8.71 to $27.92), and for GS >50 252% ($31.31 to $110.28).

RESPONSE

a) NT Power attempted to answer this question but was unable to locate a reference to the Residential Customer Directly Related monthly cost of $2.09 The Residential $10.83 appears to be the Customer Directly Related monthly costs from the 2010 model. The same situation is the case for the other two classes. As a result, NT Power is unable to answer this question. However, NT Power would be glad to address this question before the scheduled settlememt conference if clarification could be provided.

b) NT Power attempted to answer this question but was unable to locate a reference to the Min. Sys. plus PLCC adjustment monthly costs of $9.48 The Residential $14.08 appears to be the Min. Sys. plus PLCC adjustment monthly costs from the 2010 model.. The same situation is the case for the other two classes. As a result, NT Power is unable to answer this question. However, NT Power would be glad to address this question before the scheduled settlememt conference if clarification could be provided.

SCHOOL ENERGY COALITION IR - 8

1.0-SEC-8

8. [Page 18] Please confirm that the Applicant is proposing to increase the distribution bill for a GS>50 interval-metered customer with 100 kW of monthly demand in the Newmarket rate zone from 2018 to 2019 by 6.7%, from $7,188.72 annually to $7,671.48 annually, but then reduce that amount from 2019 to 2020 by 1.2% to $7,576.44 annually, for a combined increase over two years of $387.72, a 5.4% increase in the annual bill.

RESPONSE

NT Power has been able to derive the numbers referenced in the question with the following table:

SEC IR-8 Annual distribution bill for GS>50 interval-metered 100 kW customer							
		KW Demand/mth	KW Demand/yr	Fixed Rate per mth	Variable Rate	Total	%
2018 blended distribution rates	GS>50 Interval/Thermal	100	1200	134.22	4.6484	$ 7,188.72	
2019 distribution rates	GS>50 Interval	100	1200	140.62	4.9867	$ 7,671.48	
				2018 vs 2019		$ 482.76	6.7%
2020 IRM submitted distribution rates	GS>50 Thermal	100	1200	141.89	4.8948	$ 7,576.44	
				2018 vs 2020 submitted		$ 387.72	5.4%

The information in the above table is confusing due to the fact there is a mix of thermal and interval rates by year. The 2018 rate above, is provided within the Cost Allocation submission Table 10 page 14, is blended two ways for the GS>50 class. The first blending is the 2017 and 2018 rates. The second blending is the blending of interval and thermal metered customer rates. The 2019 GS>50 volmetric rate shown above, is the 2019 tarriff rate Generator model sheet 2. Current Tariff Schedule for the interval customer. The 2020 rate above is a thermal volumetric rate. The 2019 and 2020 volumetric rates are from the the OEB Rate Generator model. This issue between thermal and interval rates is addressed by OEB staff each year when the final rate order is issued. This means the above comparision in the table is an apples to oranges comparision.

In order to provide a 2018 to 2020 GS>50 interval-metered customer with 100 kW comparison, the following table is provided:

Annual distribution bill for GS>50 interval-metered 100 kW customer							
		KW Demand/mth	KW Demand/yr	Fixed Rate per mth	Variable Rate	Total	%
2018 distribution rates	GS>50 Interval	100	1200	139.09	4.9324	$ 7,587.96	
2019 distribution rates	GS>50 Interval	100	1200	140.62	4.9867	$ 7,671.48	
				2018 vs 2019		$ 83.52	1.1%
2020 IRM submitted distribution rates	GS>50 Interval	100	1200	141.89	5.0316	$ 7,740.58	
				2018 vs 2020 submitted		$ 69.10	2.0%

As per the above table, the increase for the 2018 to 2020 annual distribution bill of the GS>50 interval-metered 100 kW customer is 2.0%. The 2020 IRM submitted GS>50 interval-metered volumetric rate is calculated based on a 0.9% to the 2019 approved rates.

INTERROGATORIES OF THE VULNERABLE ENERGY CONSUMERS COALITION (VECC)

VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR-1

VECC-1

Reference: NT November 11, 2019 Letter re: Updated Cost Allocation Models, page 4
NTRZ Cost Allocation Model (November 11, 2019), Tab O1
MRZ Cost Allocation Model (November 11, 2019), Tab O1

a) Please provide the “audited financial data” used to populate Worksheet I3 in both Cost Allocation Models.

b) Were there separate 2018 audited statements for the Newmarket-Tay and Midland Rate Zones?

c) If there were separate audited statements, please provide and reconcile the OM&A, Depreciation, Financing, PILs and Net Income reported for the NTRZ and the MRZ with those set out in Tab O1of the respective Cost Allocation Models for each Rate Zone.

d) If there were not separate audited statements for the two Rate Zones how did NT determine the costs/revenues to be attributed to each of the Rate Zones? Please provide all working papers that support the attribution of costs to the two Rate Zones and reconcile the results with the OM&A, Depreciation, Financing, PILs and Net Income reported for the NTRZ and the MRZ as set out in Tab O1of the respective Cost Allocation Models for each Rate Zone.

RESPONSE

a) Below is a reconciliation of the “audited financial data” used to populate worksheets I3 in both Cost Allocation Models:

Audited FS							
	NT Power audited FS	NTRZ (Jan - Dec/18)	MRZ (Sept 7-Dec/18)	Total NT Power	MPUC (Jan - Sept 6/18)	Total Midland (Jan-Dec/18)	Total NT Power & MPUC
Distribution revenue	21,616,917	20,385,453	1,231,463	21,616,916	2,937,180	4,168,643	24,554,096
Cost of power	80,224,152	75,708,764	4,515,387	80,224,152	15,559,955	20,075,342	95,784,107
	101,841,069	96,094,217	5,746,850	101,841,068	18,497,135	24,243,985	120,338,203
Purchased power	(85,026,423)	(80,511,036)	(4,515,387)	(85,026,423)	(15,832,548)	(20,347,935)	(100,858,971)
Gross profit	16,814,646	15,583,181	1,231,463	16,814,645	2,664,587	3,896,050	19,479,232
Other income	2,225,644	2,116,988	108,657	2,225,645	300,065	408,722	2,525,710
Gross income from operations	19,040,290	17,700,169	1,340,120	19,040,290	2,964,652	4,304,772	22,004,942
Expenses							
Amortization	(6,127,765)	(5,883,579)	(244,186)	(6,127,765)	(529,102)	(773,288)	(6,656,867)
Operating Expenses	(11,592,217)	(10,438,956)	(1,153,261)	(11,592,217)	(1,764,364)	(2,917,625)	(13,356,581)
Loss on interest rate swap	(1,296,751)	(1,296,751)	-	(1,296,751)	-	-	(1,296,751)
Gain on disposal of PP&E	469,800	474,802	(5,002)	469,800	186,266	181,264	656,066
Total Expenses	(18,546,933)	(17,144,484)	(1,402,449)	(18,546,933)	(2,107,200)	(3,509,649)	(20,654,133)
Total operating profit	493,357	555,685	(62,329)	493,357	857,452	795,123	1,350,809
Finance income	412,185	395,621	16,564	412,185	22,264	38,828	434,449
Finance costs	(1,845,190)	(1,605,034)	(240,156)	(1,845,190)	(124,193)	(364,349)	(1,969,383)
Provision for income taxes - current	(877,089)	(877,089)	-	(877,089)	(109,081)	(109,081)	(986,170)
Provision for income taxes - deferred	(3,397,449)	(3,406,853)	9,404	(3,397,449)	-	9,404	(3,397,449)
Net movement in regulatory	6,786,489	6,786,489		6,786,489	201,718	201,718	6,988,207
Total Audited FS income	1,572,303	1,848,819	(276,517)	1,572,303	848,160	571,643	2,420,463

Cost Allocation Model	NTRZ (Jan - Dec/18)	Total Midland (Jan-Dec/18)	Total
Total Distribution Revenue at Existing Rates per CA (I6.1)	17,363,225	4,146,939	21,510,164
Cost of power revenue	54,489,177	15,159,112	69,648,289
Total COP purchased (Sheet O1 Revenue to cost RR)	(80,511,036)	(22,693,080)	(103,204,116)
Total Miscellaneous Revenue in CA model (I6.1)	2,985,613	643,752	3,629,365
Total Amortization (dep) (Sheet O1)	(4,273,253)	(773,288)	(5,046,541)
Distribution Costs (di) (Sheet O1)	(2,807,591)	(1,069,800)	(3,877,391)
Customer Related Costs (cu) (Sheet O1)	(2,314,333)	(561,978)	(2,876,311)
General & Admin (ad) (Sheet O1)	(5,283,157)	(1,307,140)	(6,590,297)
Interest income acct# 4405 - (Sheet I3 TB)	566,837	33,247	600,084
Interest on LT Debt acct# 6035 - (Sheet I3 TB)	(1,832,657)	(336,289)	(2,168,946)
Income Taxes (Sheet I3)	(877,089)	(109,081)	(986,170)
Total CA Model	(22,494,264)	(6,867,606)	(29,361,870)

b) There were separate 2018 audited statement for the NTRZ and MRZ. The 2018 audited statements were as follows:

   a. MRZ - Audited statements for the period ended September 6, 2018
   b. NTRZ – audited financial statements for the year ended December 31, 2018. These financial statements included the MRZ data for the period September 7, 2018 – December 31, 2018

c) Please see the schedules below for the Distribution & Other income, Revenue & Cost of power, OM&A & Depreciation, Financing, PILs and Net Income reported for the NTRZ and MRZ as set out in Tab O1:

Reconciliation Audited FS and CAM	NTRZ (Jan - Dec/18)	Total Midland (Jan-Dec/18)	Total
Distribution revenue per CAM	17,363,225	4,146,939	21,510,164
Other income per CAM	2,985,613	643,752	3,629,365
IFRS 2012-2017 Adjustment to distributon revenue	1,610,325	-	1,610,325
IFRS 2012-2017 Adjustment to cc	(380,516)	-	(380,516)
IFRS 2012-2017 Adjustment to other income re: cc	380,516	-	380,516
LRAM 2012-2017	1,641,323	-	1,641,323
Account# 4355 Gain	(474,802)	(186,266)	(661,068)
Account# 4360 Loss	-	5,002	5,002
Account# 4405 Interest Income reclass	(566,837)	(33,247)	(600,084)
Account# 4225 Late Payment Charges reclass	(188,977)	-	(188,977)
Account# 4335 Profit/Loss from Financial Ins reclass	132,571	-	132,571
Account# 4082-Retail Service Revenue	-	2,677	2,677
Account# 4084-Service Transaction Request Revenue	-	(1,492)	(1,492)
Total Distribution revenue and other income	22,502,441	4,577,365	27,079,806
Audited Distribution revenue	20,385,453	4,168,643	24,554,096
Audited Other income	2,116,988	408,722	2,525,710
Total Audited Distribution revenue & other income	22,502,441	4,577,365	27,079,806
Variance	-	0	0
Revenue cost of power per CAM	54,489,177	15,159,112	69,648,289
Revenue Adjustment - Variance accounts	21,219,587	4,916,230	26,135,817
Total Reveneue cost of power	75,708,764	20,075,342	95,784,106
Audited Revenue cost of power	75,708,764	20,075,342	95,784,106
Variance	(0)	(0)	0
Purchase power per CAM	(80,511,036)	(22,693,080)	(103,204,116)
GA Negate Account #4706-9999 (COP) (Sept7 - Dec31/18)	-	2,407,249	2,407,249
GA Negate Account #4708-9999 (WMS) (Sept7 - Dec31/18)	-	1,515	1,515
GA Negate Account #4714-9999 (NW) (Sept7 - Dec31/18)	-	1,214	1,214
GA Negate Account #4714-9999 (NC) (Sept7 - Dec31/18)	-	935	935
GA Negate Account #4714-9999 (LV) (Sept7 - Dec31/18)	-	51,217	51,217
Auditors IFRS Adjustment	-	(116,985)	(116,985)
Account #4710 - Regulatory Movement	-	-	-
Total Purchase power	(80,511,036)	(20,347,935)	(100,858,971)
Audited Purchase power	(80,511,036)	(20,347,935)	(100,858,971)
Variance	-	-	-

Reconciliation Audited FS and CAM	NTRZ (Jan - Dec/18)	Total Midland (Jan-Dec/18)	Total
Expenses per CAM	(14,678,334)	(3,712,206)	(18,390,540)
Gain on disposal	474,802	181,264	656,066
Account #6010 - interest on customer deposits	-	4,739	4,739
Account #6035-8105 - TD Credit Line Interest	-	21,965	21,965
Account #6035-8300 - Variance account interest	-	(4,226)	(4,226)
Account #5340-1000 misc. cust exp retailer	-	(1,185)	(1,185)
IFRS 2012-2017 Adjustment to amortization	(1,610,325)	-	(1,610,325)
Loss on interest rate swap	(1,296,753)	-	(1,296,753)
Non-distribution expense accounts #5165	(14,378)	-	(14,378)
Non-distribution expense accounts #5170	(2,996)	-	(2,996)
Non-distribution expense accounts #6205	(16,500)	-	(16,500)
Total Expenses	(17,144,484)	(3,509,649)	(20,654,133)
Audited Expenses	(17,144,484)	(3,509,649)	(20,654,133)
Variance	-	-	-
Finance income and expense per CAM	(1,265,820)	(303,042)	(1,568,862)
Account# 6035-8300 Other interest exp variance accts	(360,192)	5,581	(354,611)
Account# 4225 (NTP)	188,977		188,977
Account# 6035-8105 - interest on TD credit line	-	(21,965)	(21,965)
Acct# 6035-8300 Other int exp var accts (Jan-Sept 6/18)	-	(1,356)	(1,356)
Account# 6010 - interest on customer deposits	-	(4,739)	(4,739)
Acct# 6035-00002 Interest exp reclass to finance income	360,194	-	360,194
Gain/Loss on Swap Account# 4335	(132,572)	-	(132,572)
Total Finance income and expense	(1,209,413)	(325,521)	(1,534,934)
Audited Finance income and expense	(1,209,413)	(325,521)	(1,534,934)
Variance	-	-	-
Provision for income taxes per CAM	(877,089)	(109,081)	(986,170)
Deferred Taxes	(3,406,853)	9,404	(3,397,449)
Total Provision for income taxes	(4,283,942)	(99,677)	(4,383,619)
Audited Provision for income taxes	(4,283,942)	(99,677)	(4,383,619)
Variance	-	-	-
Net movement in regulatory per CAM	-	-	-
Regulatory movement	6,786,489	201,718	6,988,207
Total Net movement in regulatory	6,786,489	201,718	6,988,207
Audited Net movement in regulatory	6,786,489	201,718	6,988,207
Variance	-	-	-
Total audited net income NT Power and MPUC	1,848,820	571,643	2,420,463

d) Please see response VECC IR-1(c) above.

VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 2

VECC-2

Reference: NT November 11, 2019 Letter re: Updated Cost Allocation Models, page 4
OEB 2018 Yearbook of Electricity Distributors
NTRZ Cost Allocation Model (November 11, 2019), Tabs I6.1, I6.1 and O1
MRZ Cost Allocation Model (November 11, 2019), Tabs I6.1, I6.1 and O1

a) Please provide a schedule that sets out: i) the 2018 customer/connection count by rate class as reported in the OEB 2018 Yearbook for Newmarket-Tay's Residential, GS<50, GS>50 and Unmetered Scatter Load, ii) the customer/connection count by rate class as set out in Tab I6.2 of the NTRZ Cost Allocation Model for Residential, GS<50, GS>50 and Unmetered Scatter Load, iii) the customer/connection count by rate class as set out in Tab I6.2 of the MRZ Cost Allocation Model for Residential, GS<50, GS>50 and Unmetered Scatter Load and iv) the total for items (ii) and (iii). Please reconcile any differences between the values reported in the OEB Yearbook and the total per item (iv).

b) Please provide a schedule that sets out: i) the 2018 kWh by rate class as reported in the OEB Yearbook for Newmarket-Tay's Residential, GS<50, GS>50 and Unmetered Scatter Load, ii) the 2018 kWh by rate class as set out in Tab I6.1 of the NTRZ Cost Allocation Model for Residential, GS<50, GS>50 and Unmetered Scatter Load, iii) the 2018 kWh by rate class as set out in Tab I6.1 of the MRZ Cost Allocation Model for Residential, GS<50, GS>50 and Unmetered Scatter Load and iv) the total for items (ii) and (iii). Please reconcile any difference between the values reported in the OEB Yearbook and the total per item (iv).

c) Please provide a schedule that sets out: i) the Depreciation and Amortization as reported in the OEB Yearbook for Newmarket-Tay, ii) the 2018 Depreciation and Amortization per Tab O1 of the NTRZ Cost Allocation Model, iii) the 2018 Depreciation and Amortization as set out in Tab O1 of the MRZ Cost Allocation Model and iv) the total for items (ii) and (iii). Please reconcile any difference between the values reported in the OEB Yearbook and the total per item (iv).

d) Please provide a schedule that sets out: i) the total 2018 Operating, Maintenance and Administrative Expense as reported in the OEB Yearbook for Newmarket-Tay, ii) the total 2018 Operating, Maintenance and Administrative Expense per Tab O1 of the NTRZ Cost Allocation

Model, iii) the total 2018 Operating, Maintenance and Administrative Expense per Tab O1 of the MRZ Cost Allocation Model and iv) the total for items (ii) and (iii). Please reconcile any difference between the values reported in the OEB Yearbook and the total per item (iv).

RESPONSE

a) The schedule below provides a reconciliation between the customer counts reported in the OEB 2018 Yearbook and the NTRZ and MRZ Cost Allocation filings in Tab I6.2.:

Customer Count					
	2018 OEB Yearbook	NTRZ - Tab I6.2	MRZ - Tab I6.2	Total NTRZ & MRZ	Variance
Residential	39,075	32,622	6,395	39,017	58
GS Less Than 50	3,957	3,186	772	3,958	- 1
GS Greater Than 50	492	384	108	492	-
USL	57	46	11	57	-
	43,581	36,238	7,286	43,524	57

The variance noted above is the result of incorrect customer counts in the MRZ Tab I6.2. The residential customer count for MRZ should total 6,453 and the GS<50 customer count should be 771. The MRZ Cost Allocation model has been updated in the following tabs:

i. Tab I6.2 Customer Data cells D21 and E21 to reflect the number of 6,453 residential and 771 GS<50 customers

ii. Tab I6.1 cells D37 and E37 to reflect adjustments to additional charges for residential ($17,906) and GS<50 customers $272.

b) The schedule below provides a reconciliation between the kWh consumption amounts reported in the OEB 2018 Yearbook and the NTRZ and MRZ Cost Allocation filings in Tab I6.2:

kWh					
	2018 OEB Yearbook	NTRZ - Tab I6.2	MRZ - Tab I6.2	Total NTRZ & MRZ	Variance
Residential	332,824,319	282,139,763	50,684,557	332,824,320	- 1
GS Less Than 50	115,923,228	91,548,982	24,374,246	115,923,228	-
GS Greater Than 50	392,443,679	278,825,252	113,618,428	392,443,680	- 1
USL	947,046	552,037	395,009	947,046	-
	842,138,272	653,066,034	189,072,240	842,138,274	- 2

c) The schedule below provides a reconciliation between the depreciation and amortization reported in the OEB Yearbook and the NTRZ and MRZ Cost Allocation filings in Tab O1.:

	2018 OEB Yearbook	NTRZ - Tab I6.2	MRZ - Tab I6.2	Total NTRZ & MRZ	Variance
Depreciation & Amortization	5,747,249	4,273,253	773,288	5,046,541	700,708
MRZ Amortization Jan 1, 2018 - Sept 6, 2018			- 529,102		
Amort on Contributed Capital		- 380,516			
NTRZ 2012-2017 IFRS Adjustment to amortization		1,610,325			
	5,747,249	5,503,062	244,186	5,747,248	1

The reconciling items between the OEB Yearbook and the CA model includes:

1. NTRZ one-time adjustment for amortization expense understated for the period of 2012-2017 totalling $1,229,809 that was recorded in 2018.
2. MRZ model includes the addition amortization for the period Jan 1/18 – Sept 6/18 prior to the sale of Midland PUC to NT Power.

d) The schedule below provides a reconciliation between OM&A expenses reported in the OEB Yearbook and the NTRZ and MRZ Cost Allocation filings in Tab O1.

Expenses					
	2018 OEB Yearbook	NTRZ - Tab I6.2	MRZ - Tab I6.2	Total NTRZ & MRZ	Variance
OM&A	11,592,217	10,405,082	2,938,918	13,344,000	- 1,751,783
MRZ Expenses - Jan 1/ - Sept 6/18			- 1,764,364	- 1,764,364	1,764,364
Non-distribution expense account #5165 not included in CA model		14,378.00		14,378	- 14,378
Non-distribution expense account #5170 not included in CA model		2,996.00		2,996	- 2,996
Non-distribution expense account #6205 not included in CA model		16,500.00		16,500	- 16,500
Account #6035 - Other interest expense			- 22,478.00	- 22,478.00	22,478
Non-distribution expnese account for retailer expenses not included in CA model			1,185.00	1,185.00	- 1,185
	11,592,217	10,438,956	1,153,261	11,592,217	-

Reconciling items between the OEB Yearbook and CA filings include:

1. MRZ Jan 1/18 – Sept 6/18 expenses
2. NTRZ and MRZ reallocation of non-distribution expenses which are not included in the CA model.

VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 3

VECC-3

Reference: NT November 11, 2019 Letter re: Updated Cost Allocation Models
NTRZ Cost Allocation Model (November 11, 2019)

a) With respect to Tab I4, please explain why for Account 1830 (Poles, Towers and Fixtures) 85% of the costs are deemed to be Primary while for Account 1835 (Overhead Conductors and Devices) only 75% of the costs are deemed to be Primary.

b) With respect to Tab I5.2 and the November 11, 2019 Letter, page 5 – please explain the circumstances that lead to only 10% of NTRZ customers in the GS<50 class having legacy services owned by NT Power.

c) With respect to Tab I5.2 and the November 11, 2019 Letter, page 5 – please provide the reference to NT Conditions of Service that requires all general service 50kW or greater, street light, sentinel light and unmetered scattered load services in the NTRZ to own their services.

d) With respect to Tab I5.2 and the November 11, 2019 Letter, page 6 – please provide the analysis that demonstrates that the fact there are no collection costs reduces the billing and collecting weighting factor for the sentinel lighting, street lighting and unmetered scattered load classes to 0.4.

e) With respect to Tab I8, please explain why the GS>50 class has a Line Transformer 4NCP value of 116,459.22 but a Secondary 4NCP value of zero (i.e., why while some customers use a NTRZ transformer none use secondary lines).

f) With respect to Tab I8, please explain why the GS<50 class has a Line Transformer 4NCP value of 86,983.21 but a Secondary 4NCP value of 11,059.

g) With respect to Tab I6.1 and Tab I8, please explain why when the GS<50 Line Transformer 4NCP value is less than the Primary 4NCP value (per Tab I8.1) that none of customers receive a transformer ownership credit (per Tab I6.1).

RESPONSE

a) Please see response Staff IR-9.

b) Please see response Staff IR-14. As per NT Power NTRZ's Conditions of Service, GS<50 customers own the assets that serve the secondary distribution system. However, there are 242 legacy services where NT Power NTRZ owns the secondary distribution assets.

c) Please see Appendix I for NT Power NTRZ's Conditions of Service reference documents:
    a. COS–230–04 – "Standard Voltage Offerings"
    b. Appendix 'B' – "Demarcation Points & Charges for Connection Assets"

d) The following table provides the NTRZ and MRZ analysis determining the billing and collecting weighting factor by customer class in Tab I5.2:

Billing and collecting weighting factors by customer class CA sheet I5.2									
	Residential	GS<50	GS>50	Sentinel	Street	USL	Total		
# of customers	32,622	3,186	384	32	3	46	36,273		
Billing weighting	1	1	3	1	1	1			
Collection weighting	1	1	1	-	-	-			
Billing Aph 5315	$ 514,859								
Collecting Aph 5330	$ 651,496								
Cost by APH	Weighted customer count	Cost per	Residential	GS<50	GS>50	Sentinel	Street	USL	
Billing aph 5315	37,041	13.90	13.90	13.90	41.70	13.90	13.90	13.90	
Collecting aph 5330	36,192	18.00	18.00	18.00	18.00	-	-	-	
Total cost per customer			31.90	31.90	59.70	13.90	13.90	13.90	
Weighting factor			1.0	1.0	1.9	0.4	0.4	0.4	

e) With respect to Tab I8, the Line Transformer 4NCP for the GS>50 class has been updated to reflect the revised information in Tab 16.1. The Secondary 4NCP for this class remains at zero since no GS > 50 kW customer use NTRZ owned secondary lines.

f) Please see response VECC IR-3(b).

g) In the NTRZ, there exists GS<50 rate class customers who are supplied by Line Transformers that are not owned by NTRZ and are located in developments such as commercial malls. However, the Line Transformer is not owned by the GS < 50 customer. The Line Transformer is owned by the owner of the commercial mall which is a GS > 50 kW customer. Only the owner of the Line Transformer is entitled to a transformer ownership credit. Consequently, none of the GS<50 customers downstream of a customer-owned transformer receive a transformer ownership credit. This explains why the GS<50 Line Transformer 4NCP value is less than the Primary 4NCP value (per Tab I8.1) but none of customers receive a transformer ownership credit (per Tab I6.1).

VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 4

VECC-4

Reference: NT November 11, 2019 Letter re: Updated Cost Allocation Models
MRZ Cost Allocation Model (November 11, 2019)
EB-2012-0147, Midland's Cost Allocation Model per Settlement Proposal

a) With respect to Tab I4, please explain why for Account 1830 (Poles, Towers and Fixtures) 82.1% of the costs are deemed to be Primary while for Account 1835 (Overhead Conductors and Devices) only 72.9% of the costs are deemed to be Primary.

b) With respect to Tab I5.2 and the November 11, 2019 Letter, page 5 – please explain the circumstances that lead to only 10% of MRZ customers in the G<50 class having legacy services owned by NT Power.

c) With respect to Tab I5.2 and the November 11, 2019 Letter, page 5 – please provide the reference to the former Midland Conditions of Service that required all general service 50kW or greater, street light, sentinel light and unmetered scattered load services in the MRZ to own their services.

d) It is noted that in its last COS Application (EB-2012-0147) Midland used Service Weighting Factors of 1.5 for GS<50 and 2.0 for GS>50. Please explain the change in weightings used in the current filing.

e) With respect to Tab I5.2 and the November 11, 2019 Letter, page 6 – please provide the analysis that demonstrates that the fact there are no collection costs reduces the billing and collecting weighting factor for the street lighting and unmetered scattered load classes to 0.7.

f) With respect to Tab I8, please explain why the GS<50 class has a Line Transformer 4NCP value of 19,797 but a Secondary 4NCP value of zero (i.e., why while some customers use a MRZ transformer none use secondary lines).

g) With respect to Tab I8, please explain why the GS>50 class has a Line Transformer 4NCP value of 52,829.11 but a Secondary 4NCP value of zero (i.e., why while some customers use a MRZ transformer none use secondary lines).

h) With respect to Tab I6.1 and Tab I8, please explain why when the GS<50 Line Transformer 4NCP value is less than the Primary 4NCP value (per Tab I8) that none of customers receive a transformer ownership credit (per Tab I6.1).

i) With respect to the two Cost Allocation Models (Tab I8), please explain why the current model has zero as the Secondary 4NCP value for the GS<50 class whereas the EB-2012-0147 Model has a positive value.

j) With respect to the two Cost Allocation Models (Tab I8), please explain why the current model has zero as the Secondary 4NCP value for the GS>50 class whereas the EB-2012-0147 Model has a positive value.

RESPONSE

a) With respect to Tab I4, the following methodology was used to calculate the proportions for ***1830 – Poles, Towers and Fixtures***:
   iv) extracted total number of poles from GIS
   v) divided poles into primary and secondary level using pole height information
      - poles >35 ft were considered primary level as all have primary level assets.
      - poles ≤ 35 ft are a combination of poles with primary and secondary level assets and poles with only secondary assets.
      - If the asset supports the primary equipment in anyway, it was considered to be a primary asset even if it also supported secondary equipment. For example, a pole that supported primary and secondary lines was considered to be primary
   vi) the resulting primary vs secondary proportions were then applied for ***1830 – Poles, Towers and Fixtures***.

   The following methodology was used was used to calculate the proportions for ***1835 – Overhead Conductors and Devices***:
   iv) extracted total conductor lengths from GIS
   v) divided conductor lengths into primary and secondary level using conductor voltage
      - conductors >750V are primary level assets
      - conductors <750V and not supplying a service are secondary level assets
   vi) the resulting primary vs secondary proportions were then applied for ***1835 – Overhead Conductors and Devices***.

b) Please see response Staff IR-14. As per NT Power MRZ’s Conditions of Service, GS<50 customers own the assets that serve the secondary distribution system. However, there are 84 legacy services where MRZ own the secondary distribution assets.

c) Please see Appendix I for NT Power MRZ’s Conditions of Service, section 3.3.5.1.

d) The Service Weighting Factors for GS<50 and GS>50 were provided in error in its last COS Application (EB-2012-0147). As per the instructions in the Cost Allocation model for Tab I5.2, capital costs and ownership of the secondary level distribution assets must both be considered when calculating the Service Weighting Factors.

   As per VECC-4 (b) and VECC-4 (c), a majority of GS<50 customers and all GS>50 customers own the assets that serve the secondary distribution system The values of 1.5 for GS<50 and 2.0 for GS>50 in the last COS Application were a direct correlation of capital costs with Residential services. It did not take into account the ownership of the secondary assets as required by the model.

   The Service Weighting Factors for GS<50 and GS>50 in the current Cost Allocation model are based on the instructions and example provided in OEB Cost Allocation Model, version 3.6.

e) Below is the analysis that demonstrates the weighting factors for the customer classes. No weighting for collection costs have been allocated to the Street Light and USL customer classes. No collection related costs including notices, bad debts, etc. are attributed to the Street Light and USL customer classes based on the past collection related history of these customer classes.

Billing weighting factors by customer class - MRZ								
			Residential	GS<50	GS>50	Street	USL	Total
# of customers			6,395	772	108	4	11	7,290
Billing weighting			1	1	2.5	1	1	
Collection weighting			1	1	1	-	-	
Billing Aph 5315	$ 209,233							
Collecting Aph 5320 & 5340	$ 65,456							
Cost by APH	Weighted cust	Cost per	Residentia	GS<50	GS>50	Street	USL	
Billing aph 5315	7,452	28.08	28.08	28.08	70.19	28.08	28.08	
Collecting aph 5330	7,275	9.00	9.00	9.00	9.00	-	-	
	Total cost per customer		37.07	37.07	79.19	28.08	28.08	
	Weighting factor		1.00	1.00	2.14	0.76	0.76	

f) Secondary 4NCP value of zero was provided in error. Legacy services exist in the MRZ where 84 GS<50 customers own the secondary distribution assets. The CA Model Sheet I6. Customer Data has been updated accordingly. Please refer to response Staff IR-14.

g) As per NT Power MRZ's Conditions of Service, GS>50 customers own the assets that serve the secondary distribution system.

h) It appears this question is similar to VECC IR 3(g) NTRZ and is not applicable for the MRZ.

i) Please refer to response VECC IR-4(f).

j) Secondary 4NCP value for GS>50 was provided in error in EB-2012-0147 model. As per NT Power MRZ's Conditions of Service, GS>50 customers own the assets that serve the secondary distribution system. Consequently, the cost allocation model does not have any GS > 50 customers using seconday level distribution assets.

VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 5

VECC-5

Reference: NT November 11, 2019 Letter re: Updated Cost Allocation Models
NTRZ Cost Allocation Model (November 11, 2019)
NT Power Cost Allocation Model – Settlement Jan 2011

a) With respect to Tab I8 in both models, please explain why for the GS>50 class the 4NCP Secondary value in the current model is zero but in the 2011 model the value is greater than zero.

b) With respect to Tab I8 in both models, please explain why for the Residential class the 4NCP Line Transformer and Secondary values are equal to the Primary 4NCP value in the current model but were less than the Primary 4NCP value in the 2011 model.

c) With respect to Tab I4 in both models, please explain why for Acct. 1830 the portion of primary assets has increased from 71% to 85%.

RESPONSE

a) The GS > 50 kW class 4NCP Secondary value in the current model is zero since there are no GS > 50 kW customer using the secondary systems as outlined in tab I6.2. Regarding the comparison to the 2011 model, please see response to SEC IR-2(a).
b) Please see response Staff IR-11 and SEC IR-2(a).
c) Please see response Staff IR-9.

VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 6

VECC-6

Reference: NT November 11, 2019 Letter re: Updated Cost Allocation Models, pages 14-15
NTRZ Cost Allocation Model (November 11, 2019), Tab I6.1

a) With respect to pages 14-15, is it the "Total annual revenue with addn chgs" for each NTRZ customer class that reconciles with the audited revenues? If not, what value reconciles with the audited revenues?

b) Is it the fact that the rates used to determine the "Total annual revenue excl addn chgs" are a simple monthly weighted average of the rates in effect over the year that gives rise to the need for the "addn chgs" adjustment? If not, what gives rise to the need for the adjustment?

c) Please explain how the NTRZ 2018 monthly fixed and variable rates set out in Table 10 were determined and why they were not used directly in the Cost Allocation.

RESPONSE

a) Table 10 provides the 2018 fixed and variable proportions of revenue by rate class. The total annual revenues used in the CA model is different from the revenue in the audited financial statements as the revenue groupings in the audited financial statements include non- distribution revenues.

Below is a reconciliation of the total revenues used in the CA model to the audited financial statements.

Revenue							
Audited FS	NTP (Jan-Dec18) (Includes MPUC Sept 7-Dec18)	NT Zone (Jan - Dec18)	MPUC (Sept 7-Dec18)	Total	Midland (Jan - Sept 6/18)	Total MPUC (Jan-Dec18)	Total
Distribution Revenue	21,616,917	20,385,453	1,231,463	21,616,916	2,937,180	4,168,643	24,554,096
Other Income	2,225,644	2,116,988	108,657	2,225,645	300,065	408,722	2,525,710
Total Audited FS		22,502,441				4,577,365	27,079,806
Cost Allocation Model							
Total Distribution Revenue at Existing Rates per CA (I6.1)		17,363,225				4,146,939	21,510,164
Total Miscellaneous Revenue in CA model (I6.1)		2,985,613				643,752	3,629,365
Total CA Model		20,348,838				4,790,691	25,139,529
Reconciling Items:							
IFRS 2012-2017 Adjustment to distributon revenue	Reversal	1,610,325					1,610,325
IFRS 2012-2017 Adjustment to cc	Reversal	- 380,516					- 380,516
IFRS 2012-2017 Adjustment to other income re: cc	Reclassification	380,516					380,516
LRAM 2012-2017	adjustment	1,641,323					1,641,323
Account # 4355 Gain	Gain on Disposal - reclassification	- 474,802				- 186,266	- 661,068
Account # 4360 Loss	Gain on Disposal - reclassification	-				5,002	5,002
Account # 4405 Interest Income	Finance Income - reclassification	- 566,837				- 33,247	- 600,084
Account # 4225 Late Payment Charges	Finance Income - reclassification	- 188,977					- 188,977
Account # 4335 Profit/Loss from Financial Ins.	Finance Cost - reclassification	132,572					132,572
Account#4082 - Retail Service Revenue						2,677	2,677
Account #4084 - Service Transaation Request Revenue						- 1,492	- 1,492
Total Reconciling Items		2,153,604				- 213,326	1,940,278
Adjusted CA Model		22,502,442				4,577,365	27,079,807

The 2012-2017 one-time IFRS and LRAM adjustments have been removed from revenue as these are prior period adjustments. Gains and losses along with finance income and costs and retailer revenue and expenses have also been removed from the 2018 revenue as they are not considered distribution revenue.

b) The adjustment required on Tab I1.6 Revenue are outlined in response Staff-12.

c) The NTRZ 2018 monthly fixed and variable rates set out in Table 10 were calculated using the same blended rates as were used in Table I6.1 of the CA model. The additional charges were prorated using the fixed and variable revenues per class and were allocated accordingly to the “annual fixed $ with addl chgs” and “annual variable $ with addl chgs” in Table 10 on page 14-15 of the CA application.

VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 7

VECC-7

Reference: NT November 11, 2019 Letter re: Updated Cost Allocation Models, pages 14-15
MRZ Cost Allocation Model (November 11, 2019), Tab I6.1

a) With respect to pages 14-15, is it the "Total annual revenue with addn chgs" for MRZ each customer class that reconciles with the audited revenues? If not, what value reconciles with the audited revenues?

b) Is it the fact that the rates used to determine the "Total annual revenue excl addn chgs" are a simple monthly weighted average of the rates in effect over the year that gives rise to the need for the "addn chgs" adjustment? If not, what gives rise to the need for the adjustment?

c) Please explain how the MRZ 2018 monthly fixed and variable rates set out in Table 10 were determined and why they were not used directly in the Cost Allocation.

RESPONSE

a) Please see response VECC IR-8 (a).

b) The adjustment required on Tab I1.6 Revenue are outlined in response Staff IR-12.

c) Please see response VECC IR-8 (c).

VULNERABLE ENERGY CONSUMERS COALITION (VECC) IR - 8

VECC-8

Reference: NT November 11, 2019 Letter re: Updated Cost Allocation Models, page 19
EB-2009-0269 Settlement Agreement

a) Please provide a schedule that sets out the load forecast (customer/connection count, kWh and kW (where applicable) for each customer class per the EB-2009-0269 Settlement Agreement. Please also provide a reference for the evidence from EB-2009-0269 that supports this load forecast.

b) Based on the load forecast per part (a), please provide a schedule that sets out the revenues per class and in total using: i) the approved 2019 rates and ii) the approved 2019 rates with the proposed band adjustments.

c) If the total revenues for the two scenarios set out in part (b) are not the same, please comment on whether or not the proposed band adjustments can be viewed as "revenue neutral".

RESPONSE

a) The following table sets out the load forecast for each customer class per the EB-2009-0269 Settlement Agreement:

Load forecast per EB-2009-0269 settlement agreement							
	Residential	GS<50	GS>50	Street Light	Sentinel	USL	Total
kWh	277,978,370	93,701,712	309,550,101	5,230,133	310,359	374,072	687,144,747
kW			770,221	14,578	866		
# of customers	29,336	2,896	402	8,453	420	125	

NT Power could not locate a reference for the evidence from EB-2009-0269 that supports this load forecast.

b) The following table sets out the revenues per class and in total using the approved 2019 rates and the 2019 rates with the proposed band adjustments based on the Settlement agreement forecast:

2019 approved rates	Residential	GS<50	GS>50	Street Light	Sentinel	USL	
Fixed	27.61	31.01	140.62	3.24	3.3	17.91	
Variable	0	0.0203	4.9867	16.1088	12.6396	0.0206	
2019 rates w band adj	Residential	GS<50	GS>50	Street Light	Sentinel	USL	
Fixed	28.54	31.01	140.62	0.8	2.3	8.48	
Variable	0	0.0203	4.9867	3.9929	8.8066	0.0098	
Revenue by customer class based on load forecast per settlement agreement							
2019 approved rates	Residential	GS<50	GS>50	Street Light	Sentinel	USL	Total
Fixed	9,719,604	1,077,660	678,351	328,653	16,632	26,865	11,847,764
Variable	-	1,902,145	3,840,861	234,834	10,946	7,706	5,996,492
Total	9,719,604	2,979,804	4,519,212	563,487	27,578	34,571	17,844,255
2019 rates w band adj							
Fixed	10,046,993	1,077,660	678,351	81,149	11,592	12,720	11,908,464
Variable	-	1,902,145	3,840,861	58,208	7,627	3,666	5,812,507
Total	10,046,993	2,979,804	4,519,212	139,357	19,219	16,386	17,720,971
						Variance	123,284

c) The following table sets out the revenues per class and in total using the approved 2019 rates and the 2019 rates with the proposed band adjustments based on the 2018 cost allocation load:

Billing determinants per EB-2019-0055 IRM filing							
	Residential	GS<50	GS>50	Street Light	Sentinel	USL	Total
kWh	282,139,763	91,548,982	278,825,252	2,565,174	275,116	552,037	655,906,324
kW			621,805	6,897	764		
# of customers	32,622	3,186	384	9,091	32	46	
Revenue by customer class based on load forecast EB-2019-0055							
2019 approved rates	Residential	GS<50	GS>50	Street Light	Sentinel	USL	Total
Fixed	10,808,321	1,185,574	647,977	353,458	1,267	9,886	13,006,484
Variable	-	1,858,444	3,100,755	111,102	9,657	11,372	5,091,330
Total	10,808,321	3,044,019	3,748,732	464,560	10,924	21,258	18,097,814
2019 rates w band adj							
Fixed	11,172,383	1,185,574	647,977	87,274	883	4,681	13,098,772
Variable		1,858,444	3,100,755	27,539	6,728	5,410	4,998,877
Total	11,172,383	3,044,019	3,748,732	114,813	7,611	10,091	18,097,648
						Variance	166

The 2018 billing determinants were used in the updated cost allocation models. These billing determinants were used to determine the revenues by rate class in the cost

allocation model. The rate class revenue was used to determine the resulting revenue to cost ratios which were then adjusted to be within OEB's acceptable range.
The adjustments to the revenue to cost ratios defined the total annual band adjustment and this amount was assigned to the fixed and variable components of the distribution revenue consistent with the current fix/variable proportion. These amounts were then divided by the appropriate 2018 billing determinant to determine the band adjustment on a customer/connection or volumetric basis. When the 2018 billing determinants are applied the pre and post adjustment rates the revenue difference should be zero. There could be a small difference resulting from rounding which happens to be case as shown in the table 8(c) above.

However, if the billing determinants from the EB-2009-0269 Settlement Agreement are applied to the pre and post adjustment rates, it is expected there would be a difference in the revenues since these billing determinants were not used to determine the adjustment on a customer/connection or volumetric basis which also happens to be the case as shown in table 8(b) above.