EB-2018-0028
REDACTED VERSION

ONTARIO ENERGY BOARD

IN THE MATTER the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act*, *1998* for approval of its proposed distribution rates and other charges effective January 1, 2019.

CONTAINS CONFIDENTIAL INFORMATION

Responses of Toyota Motor Manufacturing Canada Inc. ("TMMC")

to

Interrogatories from OEB Staff (Updated Evidence)

March 1, 2019

Staff-TMMC-5

Ref: TMMC Updated Written Evidence of Jeffry Pollock, Introduction and Summary

Questions:

Mr. Pollock stated that it is appropriate to establish a separate customer class for TMMC because there are four key differences between how TMMC and the other Large Use customer receive distribution service and the characteristics of these services. (pp. 9-10)

a) Is Mr. Pollock aware of any precedents in other jurisdictions that a separate customer class was approved by a regulator based on similar reasons identified by Mr. Pollock for TMMC? If so, please provide these precedents.
b) Mr. Pollock stated that the first reason to establish a separate customer class for TMMC is that it operates a load displacement generation (LDG) facility while the other large use customer does not have any LDG facilities. Please discuss whether or not a separate customer class should be established for any customer in any of the GS>50 kW and above rate classes who installs a LDG.
c) Please describe the defining characteristic or characteristics of the new customer class for TMMC. In the future, if a new large use customer were to connect to Energy+, this description would enable a reader to understand whether the new customer should be added to the existing Large Use rate class, or the new one proposed for TMMC.
d) Is it Mr. Pollock's evidence that all four of the identified key differences need to be present in order to justify a separate class?
e) Should TMMC's two large use class proposal be accepted, what are TMMC's expectations of what will happen when the directly assigned assets, such as M24 and M30 feeders, need to be replaced? For example, would TMMC be responsible for the cost of the replacement assets?

Responses:

a) Yes. Although Mr. Pollock has not conducted an exhaustive review of all decisions by regulatory commissions, the three cases identified in response to Staff-TMMC-3 are examples where utilities have created a separate customer class for distribution service provided directly from a utility-owned substation (*i.e.,* Primary Substation) and/or have established different prices for Primary Substation and Primary Distribution services. The different type of distribution service alone supports establishing separate volumetric charges for Primary Substation and Primary Distribution services (assuming that both Large Use customers are kept in the same class) or establishing a separate Large Use customer class for TMMC. In Ontario, the Board has approved separate rate classes in at least two instances. Enwin Utilities Inc. ("**Enwin**") has had three separate Large Use customer classes since at least 2005: the Large Use-Regular class, the Large Use-3TS class and the Large Use-Ford Annex Service class. The Large Use-3TS and Large Use-For classes apply to two different automobile manufacturing companies who are connected to dedicated transformer stations.

   More recently, the Board approved a proposal by Horizon Utilities Corporation (as it then was) ("**Horizon**") to establish a new Large Use class for Large Use customers served by dedicated facilities.[1] Similar to TMMC's LU proposal in this case, Horizon's proposal for a new LU class was intended to address concerns regarding cost causality; some Large Use customers served via dedicated facilities were being allocated costs for pooled distribution facilities that they did not use but that were used by other customers in the existing Large Use class.

Initially, Horizon proposed a new LU(2) class comprising large users with a peak demand above 15 MW who received service via dedicated feeders. Creation of the LU(2) class would allow users in the class to be allocated 100% of the costs of these primary feeders. During the course of the proceeding, Horizon reduced the 15 MW demand threshold to 5 MW in light of the existence of one customer with a demand of only 9 MW but with similar load characteristics and who was served by the same dedicated feeders.

The Board approved Horizon's two LU class proposal on the basis that it reflected principles of cost causality.[2]

b) Whether a separate customer class should be created for any of the GS>50 kW and above customers if they were to install a LDG would depend on the type of LDG and how that LDG affects the customer's load characteristics and whether the per-unit customer and demand-related costs are significantly different as between the LDG customer and the other customers in the class.

c) The defining characteristics of the TMMC LU class are: (i) it comprises a customer that is served entirely from an overhead radial distribution system that is directly connected to a Hydro One transmission station and <u>not</u> electrically interconnected with the rest of the Energy+ distribution system; (ii) the customer has a load that is many times larger than Energy+'s other LU customer; (iii) the customer operates an LDG facility; and (iv) the discrete costs of the dedicated assets used to serve the customer can be identified and directly assigned. If a new customer with similar characteristics (*i.e*., LDG, size of load, served by a radial overhead system and directly assignable costs) were to materialize, then, based on the principles described in Mr. Pollock's evidence, Energy+ would have the option of creating a new and separate LU class for that customer or adding it to the TMMC LU class (recognizing that if the latter, there would have to be a three-part rate because the M24 and M30 Feeders cannot serve other customers (*i.e*. shared) and accordingly, their costs cannot be pooled).

d) The four characteristics would not necessarily all have to be present to justify establishing a separate class. It would depend on the extent of the differences in one or more of the four characteristics. For example, if a customer has LDG and is served from dedicated facilities, while a similarly sized customer has no LDG and is not served from dedicated facilities, the differences in these two characteristics alone would support creating a separate customer class.

e) Yes it would. Assuming TMMC's Two-Large Use Class/Direct Assignment cost-of-service study is adopted, TMMC would expect its rates to reflect the actual costs of the dedicated facilities that are directly assigned to TMMC, including the cost of any replacement assets.

[1] *EB-2014-0002 Decision and Order (December 11, 2014), pp. 14-16.*

[2] *Id*., p. 16.

Staff-TMMC-6

Ref: TMMC Updated Written Evidence of Jeffry Pollock, Revised Class Cost of Service Study

VECC-TCQ-70

Questions:

Mr. Pollock used Energy+'s Direct Assignment Study to directly assign distribution costs to the TMMC class in Schedule JP-11. (page 13)

Mr. Pollock did not allocate any underground investment (i.e. conduit and conductors) and related expenses to TMMC. (page 17)

a) Please compare Schedule JP-11 with the cost allocation model prepared by Energy+ as part of its responses to TMMC technical conference IR-2 part (a) and list and describe all differences between these two cost allocation models.
b) Energy+ confirmed in VECC-TCQ-70 that there are many Energy+ customers that are solely supplied using overhead primary distribution service. Energy+ also confirmed that for purposes of allocating underground assets, the total load for each customer class is used regardless of whether overhead facilities, underground facilities or a combination of both are actually used to deliver the load. Given that TMMC is not the only customer that is solely suppled using overhead assets, please explain why TMMC should be treated differently for cost allocation purpose (i.e. In Schedule JP-11, costs in Account 1840 did not allocate to TMMC).
c) Please provide a revised Schedule JP-11 cost allocation model in which TMMC shares the costs in Account 1840 (underground conduit).

Responses:

a) The primary difference between Energy+'s Direct Assignment Study and Schedule JP-11 is that Energy+ directly assigned all distribution costs, including the primary poles used to support Feeders M24 and M30, to TMMC whereas in Schedule JP-11, TMMC allocated a portion of all primary poles using the 4NCP method.

b) To the best of TMMC's knowledge, TMMC is the only load that is served from an overhead radial distribution system (for which it paid a capital contribution) that is not electrically connected to any Energy+ underground distribution facilities or for that matter, to any other primary distribution feeders that serve Energy+'s remaining customer base. In other words, the radial distribution system is not part of Energy+'s integrated distribution system.

c) The requested cost allocation model is attached as Schedule JP-11-OEB Staff-6(c). This model is based on Schedule JP-11 Revised, which is being provided to all parties.

Staff-TMMC-7

Ref: TMMC Updated Written Evidence of Jeffry Pollock, Supplementary Distribution Service Rate Design

Question:

Mr. Pollock reasons that a proposed 1.15 revenue-to-cost ratio "will provide a more than ample cushion above a purely cost-based rate to offset any additional incidental costs that the Direct Assignment Study does not account for." (page 14)

a) Please explain what range of revenue-to-cost ratios would be appropriate for this new rate class in future rebasing rate applications.

Response:

a) Mr. Pollock would support a fully cost-based rate (*i.e.,* a revenue-to-cost ratio of 1.0) depending on the circumstances in the next rate case. He has not undertaken any analysis to determine what range of ratios may be appropriate in the event that deviation from a fully cost-based rate is permitted or allowed.

Staff-TMMC-8

Ref: TMMC Updated Written Evidence of Jeffry Pollock, Supplementary Distribution Service Rate Design

Questions:

Mr. Pollock recommends a 1.15 revenue to cost ratio and no change in the current-OEB approved Service Charge for TMMC to reflect the OEB's policy. (page 21)

a) Please provide Mr. Pollock's recommended revenue-to-cost ratio for all customer classes and the corresponding revenues to be collected from each class.
b) Please also provide Mr. Pollock's recommended revenue-to-cost ratio resulting from the cost allocation model requested in Staff-TMMC-6 part c, for all customer classes and the corresponding revenues to be collected from each class.

Responses:

a) & b) Mr. Pollock has not formulated an opinion on the appropriate revenue-to-cost ratios for customer classes other than TMMC.

Staff-TMMC-9

Ref: TMMC Updated Written Evidence of Jeffry Pollock, Standby Distribution Service Rate Design

Questions:

Mr. Pollock stated that it would establish a standby contract demand of 6,900 kW (page 28).

a) Schedule JP-16 shows the standby contract demand of 55,200 kW (rather than 6,900x12=82,800 kW), please clarify whether or not the billing units in Schedule JP-16 should be 82,800 kW. If so, please revise Schedule JP-16. If not, why not.
b) Please explain how the contract demand will be determined for a GS >1,000 to 4,999 kW customer who will own load displacement generation in 2019 but has no historical standby service demand data.
c) Please specify Energy+'s revenues from providing supplementary distribution service to TMMC and provide supporting calculations.
d) Please describe how the billing units for the daily volumetric rate were determined.

Responses:

a) The Contract Volumetric billing units shown on Schedule JP-16 should have been 82,200 kW. Schedule JP-16 Revised will be provided to all parties.

b) Mr. Pollock's view is that it should be up to the individual customer to determine the level of standby contract demand appropriate to the customer's circumstances up to the nameplate rating of the customer's LDG facility. The standby contract demand can be reset by negotiation to reflect circumstances where, in past periods, a customer has under or over estimated its standby requirements.

c) Under TMMC's proposed rate design, the revenues from Supplementary Distribution Service would be $360,039. This is the sum of the Service Charge revenue ($107,713) and the Distribution Volumetric revenues ($[redacted]), which is the product of the Distribution Volumetric Rate ($[redacted] per kW) and the Supplementary Billing Demand ([redacted] kW). NOTE: any differences are due to rounding). A revised Schedule JP-13 will be provided.

d) The derivation of the billing units for the Daily Volumetric rate is shown in Schedule JP-7, which was attached to the original written evidence. They are based on the difference in the maximum monthly weekday on-peak demand when an outage occurs and the previously established maximum monthly weekday on-peak demand when there were no outages. See pages 28-29 of Mr. Pollock's Updated Evidence and on pages 44, 45 and 52 of the original Evidence.

Staff-TMMC-10

Ref: TMMC Updated Written Evidence of Jeffry Pollock, Standby Distribution Service Rate Design

Questions:

Mr. Pollock states that "the term "Standby" refers to the additional delivery service required when TMMC's LDG sustains an outage and there is a net increase in TMMC's peak demand as a result of the outage." (page 25)

a) In TMMC's opinion, does the capability of Energy+ to provide service in the event of an outage have value whether an outage happens or not?
b) On page 23 of the evidence Mr. Pollock states that "there is more than sufficient capacity to service TMMC's total (Supplementary and Standby service) requirements..." and "…there are no incremental costs to provide Standby service to TMMC" Would Mr. Pollock agree that because Energy+ is having to reserve the Standby capacity for TMMC, there is lost opportunity for Energy+ to use the spare capacity on the feeders to serve other customers and therefore lost revenue? If Mr. Pollock does not agree please explain why.
c) On page 31 of the evidence refers to a demand forgiveness provision. Please explain why the higher demand during off-peak hours should be ignored.
d) On page 31 of the evidence refers to the Standby Contract Demand being increased if the daily demand were to exceed the Standby Contract Demand.
    i. Please provide an illustrative example of how this would work.
    ii. Would the Standby Contract Demand change for the following month or only for the following year?

Responses:

a) Energy+ must have the facilities in place to accommodate TMMC's Supplementary and Standby Distribution service requirements. As discussed in Mr. Pollock's Updated Evidence, the dedicated Feeders M24 and M30 have sufficient capacity to meet TMMC's requirements even during a full simultaneous outage. Further, distribution rates should be designed to recover the cost of providing distribution service and not the perceived value of that service.

b) TMMC is unaware of any need to reserve capacity on any other Energy+ facilities, other than the dedicated feeders, that are used to serve TMMC. The dedicated feeders serve only TMMC. It is important to remember that, as a practical matter, other customers cannot be connected to the M24 and M30 Feeders because of differences in the protection equipment specific to TMMC and because it would cause power quality problems. Please see TMMC – Response to VECC-9 for a further description of this protection equipment and Energy+'s Response to Technical Conference TMMC IR-3, which confirms that feeders M24 and M30 are not integrated with the rest of Energy+'s distribution system.

c) As discussed on page 63 of Mr. Pollock's Updated Evidence, ignoring the demands during off-peak hours would provide a price signal that encourages a customer to defer/schedule outages during the off-peak hours. The benefits of shifting load to off-peak hours were articulated in a Staff

Discussion Paper, Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors (EB-2015-0043, Mar. 31, 2016).

d) Assuming TMMC's Standby Contract Demand is 6,900 kW and further assuming that TMMC's maximum weekday on-peak demand during an outage in June 2019 was 7,500 kW, the Contract Volumetric rate would apply to 7,500 kW beginning in July 2019. This higher Standby Contract Demand would remain in effect until TMMC and Energy+ were to negotiate a different amount. This open-ended ratchet provision would provide a strong incentive for TMMC to manage its load during an outage.

Staff-TMMC-11

Ref: TMMC Updated Written Evidence of Jeffry Pollock, Standby Distribution Service Rate Design Schedule JP-11; Schedule JP-13; Schedule JP-14

Questions:

Schedule JP-13 proposes a derivation of rates to recover a total of $452,649 from TMMC. $452,649 represents 115% of the allocated revenue requirement of $393,607.

This schedule uses supplementary billing demand to determine a rate for Shared Facilities, and total primary substation billing demand to determine a rate for Local Facilities. The difference between these two volumes is 82,000 kW or 6,900 kW – TMMC's proposed contract standby volume times 12.

Please confirm that if a different contract standby volume were used:

a) The proposed Local Facilities Rate would change.
b) The total proposed revenue from TMMC would not change
c) If part a) or b) cannot be confirmed, please explain why not.

Responses:

a) Confirmed.

b) Confirmed.

c) Not applicable.

Staff-TMMC-12

Ref: TMMC Updated Written Evidence of Jeffry Pollock, Standby Distribution Service Rate Design Schedule JP-15

Questions:

Schedule JP-15 illustrates the derivation of standby rates for the GS 50-999 kW class.

a) Please specify the recommended distribution volumetric rate for GS 50-999 kW class and explain how the rate was determined (please specify the revenue requirement and billing units).
b) Table 9 shows a revenue to cost ratio of 135.4% for GS 50-999 kW class, please explain why 100% revenue to cost ratio was used in Schedule JP-15 page 2.

Responses:

a) Mr. Pollock has not developed a recommended Distribution Volumetric rate for the GS 50-999 kW class.

b) The 100% revenue-to-cost ratio was an assumption. If the Board decides that the GS 50-999 kW class should produce a different revenue-to-cost ratio, the Contract Volumetric rate would also be different.

Schedule JP-11-OEB Staff-6(c)
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Sheet O1 Revenue to Cost Summary Worksheet - Two Large Use Classes/Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate

			1	2	3	5	6	7	8	9
Line	**Description**	**Total**	**Residential**	**GS <50**	**GS> 50- 999 kW**	**GS> 1,000 - 4,999 kW**	**Large Use 1**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
1	Distribution Revenue at Existing Rates	$33,454,352	$17,528,595	$4,131,617	$7,466,138	$2,140,493	$259,214	$671,811	$14,573	$64,042
2	Miscellaneous Revenue (mi)	$2,022,079	$1,357,244	$222,273	$244,879	$90,823	$9,865	$56,444	$1,326	$4,532
		Miscellaneous Revenue Input equals Output								
3	**Total Revenue at Existing Rates**	$35,476,431	**$18,885,839**	**$4,353,891**	**$7,711,017**	**$2,231,316**	**$269,079**	**$728,255**	**$15,899**	**$68,573**
4	Factor required to recover deficiency (1 + D)	1.0261								
5	Distribution Revenue at Status Quo Rates	$34,327,788	$17,986,236	$4,239,487	$7,661,066	$2,196,378	$265,982	$689,351	$14,953	$65,714
6	Miscellaneous Revenue (mi)	$2,022,079	$1,357,244	$222,273	$244,879	$90,823	$9,865	$56,444	$1,326	$4,532
7	**Total Revenue at Status Quo Rates**	$36,349,867	**$19,343,481**	**$4,461,760**	**$7,905,945**	**$2,287,201**	**$275,847**	**$745,795**	**$16,279**	**$70,245**
	Expenses									
8	Distribution Costs (di)	$4,860,260	$2,891,198	$495,674	$920,427	$366,693	$37,080	$89,504	$4,097	$13,536
9	Customer Related Costs (cu)	$4,893,912	$3,864,514	$637,554	$290,384	$88,328	$3,679	$1,531	$181	$1,388
10	General and Administration (ad)	$8,577,377	$5,832,927	$982,888	$1,075,062	$402,906	$36,354	$82,020	$3,850	$13,381
11	Depreciation and Amortization (dep)	$6,376,711	$3,699,760	$786,494	$1,229,730	$423,645	$44,126	$102,809	$5,032	$16,586
12	PILs (INPUT)	$768,693	$436,704	$84,710	$154,995	$55,542	$5,606	$14,645	$679	$2,237
13	Interest	$4,420,641	$2,511,424	$487,154	$891,354	$319,411	$32,240	$84,221	$3,904	$12,865
14	**Total Expenses**	$29,897,594	**$19,236,527**	**$3,474,474**	**$4,561,952**	**$1,656,525**	**$159,085**	**$374,728**	**$17,742**	**$59,993**
15	**Direct Allocation**	$245,744	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
16	Allocated Net Income (NI)	$6,206,530	$3,526,011	$683,959	$1,251,451	$448,450	$45,265	$118,245	$5,481	$18,062
17	**Revenue Requirement (includes NI)**	$36,349,867	$22,762,538	$4,158,433	$5,813,403	$2,104,975	$204,350	$492,973	$23,223	$78,055
	Rate Base Calculation									
	Net Assets									
18	Distribution Plant - Gross	$197,935,948	$113,632,476	$22,336,633	$39,577,923	$14,174,525	$1,457,630	$3,758,664	$172,867	$569,200
19	General Plant - Gross	$15,515,903	$8,850,578	$1,714,483	$3,098,875	$1,102,328	$114,309	$297,560	$13,780	$45,262
20	Accumulated Depreciation	($25,245,338)	($14,436,819)	($3,123,435)	($4,891,381)	($1,844,775)	($175,763)	($422,873)	($18,397)	($61,999)
21	Capital Contribution	($31,975,089)	($18,763,440)	($3,610,008)	($6,115,194)	($2,086,713)	($249,721)	($638,927)	($29,448)	($95,138)
22	**Total Net Plant**	$156,231,424	**$89,282,796**	**$17,317,673**	**$31,670,223**	**$11,345,365**	**$1,146,456**	**$2,994,424**	**$138,802**	**$457,325**
23	**Directly Allocated Net Fixed Assets**	$898,672	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
24	**Working Capital**	$16,695,208	**$5,236,765.81**	**$1,953,720**	**$4,709,544**	**$2,183,152**	**$293,893**	**$48,064**	**$1,783**	**$23,128**
25	**Total Rate Base**	$173,825,304	**$94,519,562**	**$19,271,394**	**$36,379,767**	**$13,528,518**	**$1,440,348**	**$3,042,488**	**$140,584**	**$480,453**
26	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	**84.98%**	**107.29%**	**136.00%**	**108.66%**	**134.99%**	**151.29%**	**70.10%**	**89.99%**

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Sheet O1 Revenue to Cost Summary Worksheet - Two Large Use Classes/Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate

			10	12	13	14	15	16
Line	**Description**	**Total**	**Embedded Distributor Hydro One - CND**	**Embedded Distributor Waterloo North Hydro - CND**	**Embedded Distributor Hydro One 1 - BCP**	**Embedded Distributor Brantford Power - BCP**	**Embedded Distributor Hydro One 2 - BCP**	**Large Use 2**
1	Distribution Revenue at Existing Rates	$33,454,352	$50,527	$221,287	$115,168	$5,388	$4,655	$780,844
2	Miscellaneous Revenue (mi)	$2,022,079	$634	$1,666	$351	$201	$224	$31,617
		Mis						
3	**Total Revenue at Existing Rates**	$35,476,431	**$51,160**	**$222,954**	**$115,519**	**$5,589**	**$4,879**	**$812,462**
4	Factor required to recover deficiency (1 + D)	1.0261						
5	Distribution Revenue at Status Quo Rates	$34,327,788	$51,846	$227,064	$118,174	$5,529	$4,777	$801,231
6	Miscellaneous Revenue (mi)	$2,022,079	$634	$1,666	$351	$201	$224	$31,617
7	**Total Revenue at Status Quo Rates**	$36,349,867	**$52,479**	**$228,731**	**$118,525**	**$5,730**	**$5,000**	**$832,848**
	Expenses							
8	Distribution Costs (di)	$4,860,260	$0	$0	$0	$0	$0	$42,052
9	Customer Related Costs (cu)	$4,893,912	$2,419	$405	$405	$705	$1,620	$799
10	General and Administration (ad)	$8,577,377	$6,040	$17,599	$3,502	$1,820	$1,358	$117,671
11	Depreciation and Amortization (dep)	$6,376,711	$2,921	$4,561	$836	$602	$0	$59,610
12	PILs (INPUT)	$768,693	$675	$2,682	$491	$199	$0	$9,528
13	Interest	$4,420,641	$3,882	$15,424	$2,826	$1,142	$0	$54,793
14	**Total Expenses**	$29,897,594	**$15,936**	**$40,672**	**$8,060**	**$4,468**	**$2,978**	**$284,452**
15	**Direct Allocation**	$245,744	**$22,095**	**$95,569**	**$17,510**	**$6,787**	**$0**	**$103,784**
16	Allocated Net Income (NI)	$6,206,530	$5,450	$21,656	$3,968	$1,604	$0	$76,928
17	**Revenue Requirement (includes NI)**	$36,349,867	$43,481	$157,897	$29,537	$12,859	$2,978	$465,164
	Rate Base Calculation							
	Net Assets							
18	Distribution Plant - Gross	$197,935,948	$21,826	$0	$0	$3,252	$0	$2,230,953
19	General Plant - Gross	$15,515,903	$14,580	$57,785	$10,587	$4,285	$0	$191,490
20	Accumulated Depreciation	($25,245,338)	($15,707)	($33,215)	($6,085)	($3,555)	$0	($211,335)
21	Capital Contribution	($31,975,089)	($3,739)	$0	$0	($557)	$0	($382,206)
22	**Total Net Plant**	$156,231,424	**$16,960**	**$24,571**	**$4,502**	**$3,426**	**$0**	**$1,828,901**
23	**Directly Allocated Net Fixed Assets**	$898,672	**$121,453**	**$525,336**	**$96,250**	**$37,305**	**$0**	**$118,327**
24	**Working Capital**	$16,695,208	**$117,405**	**$539,518**	**$113,175**	**$3,505**	**$399,953**	**$1,071,603**
25	**Total Rate Base**	$173,825,304	**$255,819**	**$1,089,425**	**$213,927**	**$44,235**	**$399,953**	**$3,018,831**
26	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	120.69%	144.86%	401.27%	44.56%	167.90%	179.04%