EB-2016-0085

ONTARIO ENERGY BOARD

InnPower Corporation

Application for electricity distribution rates and other charges beginning July 1, 2017

Final Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

31 October 2017

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Introduction

1. VECC is pleased to submit its final arguments to the Ontario Energy Board ("OEB" or "the Board") in the matter of EB-2016-0085, InnPower Corporation's Application for electricity distribution rates and other charges beginning July 1, 2017.

2. As a contextualizing note, much of the discussion to date revolves around the extent to which InnPower requires, or whether InnPower requires, the significant rise in rates that it has asked for. This is, of course, reasonable.

3. However, an equally relevant question the Board must not lose sight of is whether or not the ratepayers of Innisfil require their rates to remain where they are, or at least close, in light of the following: the fact that they already pay the fifth highest rate in the province; that many in the population are on low fixed incomes; that the provincial government has promised relief, as opposed to increased hardship; and the clear feedback and stories that resulted from the community meetings and community submissions. Can the people of Innisfil handle another rate increase, particularly one as high as what the application proposes? In our view the fact that InnPower has been identified under the provincial Fair Hydro Plan's Distribution Rate Protection (DRP) program puts special emphasis on the Board's consideration of the increases sought by this Utility

4. There would be little point in allowing higher rates in theory if those served cannot pay it in practice. Based on community stories as well as InnPower's own testimony at hearing,[1] such a rate increase is almost guaranteed to result in more and more people going further into arrears and potentially being disconnected—thus defeating the purpose of helping the utility "serve them better".

5. VECC has little to no issue with many proposed elements of InnPower's application, as noted below. However, the Board should give close scrutiny to what the final impact would be on the people of Innisfil, and assess the extent to which allowing such a rate increase would at the end of the day be more counterproductive, if not harmful, where the ratepayers who are meant to benefit are concerned at the end of the day.

1 Hearing Transcript, Vol. 1, at pages 38-40; see also OEB Staff Summary of Community Meeting (2 May 2017).

1.0 Planning

1.1 Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained….

6. InnPower claims the following to be the most up-to-date picture of the Utility's capital spending[2]:

	Historical					Forecast				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Category	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	1,750	1,039	1,263	896	1,084	1,757	2,534	1,658	1,709	2,129
System Renewal	654	987	697	487	999	1,216	1,140	2,919	2,400	2,109
System Service	586	1,377	2,819	2,944	1,743	245	79	961	1,006	824
General Plant	828	1,348	253	13,25	661	1,187	1,423	897	680	706
Total	3,818	4,751	5,031	17,57	4,487	4,405	5,176	6,434	5,794	5,769
System O&M	1,761	1,787	1,814	1,805	1,986	2,246	2,245	2,246	2,246	2,246

**0 months of actual data included in 2016.*

7. VECC sought to have 2017 capital spending updated to actuals. The Utility was unable to provide any comprehensive data after July 2017.[3] Yet it is clear that the 2017 capital budget will not be as forecast with some significant changes. For example InnPower acknowledges that it will not have a $490,000 bucket truck in service as of the end of 2017.[4]

8. InnPower suggest the Board should not make "selective" adjustments to the 2017 capital budget and associated rate base. Yet the Utility has done precisely this since its original filing of this application. It has made selective changes in May and Sept of 2017 to the System Access and System Service budget categories so as to reflect new information.

9. In our submission the Board is bound to use the best information available. It knows with certainty that the Utility will not have in service $490,000 in vehicle costs – therefore it is obliged, in our respectful submission, to eliminate the rate base implication of this change in 2017.

10. Further, in our submission InnPower's Distribution suffers from a common problem among utilities that have attempted asset condition assessments. In large the data

[2] Technical Conference Undertaking JT1.1
[3] Hearing Vol 2, page 9
[4] Undertaking JT1.15

from which these assessments are made is simply plant age. This is clear from an exchange between VECC and InnPower's ACA author (METSCO)[5]. Such assessments add little new information to the existing known depreciation life of assets.

11. As VECC has argued in similar cases that a Distribution System Plan is only as good as the information available on asset condition. Likewise the Asset Condition Assessments are only as good as the data used to construct them. All such modelling needs to guard against "garbage in, garbage out" risk, where flawed, faulty or incomplete data is used to produce asset health results with a misleading level of determination. Rather flawed input data necessarily produced flawed output results. In this case METSCO has not completed an assessment of the availability, reliability or relevance of the data provided to it by the Utility. In our submission the Board therefore needs to approach the recommended outcomes in InnPower's DSP with caution.

12. In our submission the Board should seek that an asset data analysis be completed by InnPower at the time of its next Distribution System Plan/Asset Condition Assessment. In the interim in our view the Utility should aim to maintain its system service, system renewal and general plant capital spending at the average of the past three years.

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained….

Source 4-SEC-24	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Test Year
Operations	1,234,230	1,323,999	1,342,978	1,377,569	1,352,091	1,531,128
Maintenance	506,161	463,151	471,477	427,525	731,242	647,761
Billing and Collecting	997,953	1,054,939	1,169,535	1,096,116	1,051,073	1,149,280
Community Relations	8,586	5,419	5,663	8,066	14,699	11,640
Administrative and General	2,143,263	2,147,695	2,234,998	2,648,314	2,539,709	2,650,546
Total	**4,890,192**	**4,995,203**	**5,224,651**	**5,557,591**	**5,688,814**	**5,990,356**
%Change (year over year)			4.59%	6.37%	2.36%	5.30%

[5] See for example, Hearing Vol 2., pages 19-29

13. InnPower is seeking a 22.5% increase in OM&A as compared to its last Board approved amount. This is significantly in excess of inflation and, in our submission, excessive even if one considers the recent customer growth in this franchise. With this Application InnPower maintains its place as one of the least cost efficient utilities in Ontario.

14. VECC believes that a reduction in OM&A of between $800,000 and $500,000 is warranted as there are no outstanding circumstances that warrant an increase in these costs in excess of inflation.

15. Had OM&A increased by the rate of inflation it would now be $5,187,649 in 2017 dollars.[6] That is a difference of $802,707 from what is being requested. If one allows for a 15% customer growth rate [7] with a cost value of 10% for this growth this would add less than $100,000 to the amount of OM&A required (i.e. $5.287M).

16. When questioned as to why InnPower's OM&A costs consistently exceeds inflation the Utility attributed at least part of the increase to the need to catch up on past maintenance.[8] This of course begs the questions of why they were behind in responsibly maintaining the Utility's assets. It is also counter intuitive to find a growing need for maintaining older assets in a Utility which is growing rapidly and has a disproportionate share of new assets.

17. In effect, due to the lateness of filing, filing revisions, and other delays it is unlikely that the Board will be in a positon to render a decision prior to January 1, 2018. Even if not in actuality, InnPower's application for 2017 rates is substantially being based on 2017 as a historical test year.

18. As can be seen from the table below as of July 31 2017 InnPower has spent a total of $3.244M as compared to $3.528M over the same period in 2016. This suggests that the Utility will not require the entire amount it is proposing for its 2017 OM&A budget. If the Board were to accept the proposed OM&A it likely to find, even prior to rates being set, that it has provided more costs in rates than have actually transpired. This surely cannot be a just or reasonable result.

[6] Calculated by using the Bank of Canada Inflation calculator http://www.bankofcanada.ca/rates/related/inflation-calculator/
[7] See Exhibit 3, page 7
[8] Technical Conference Vol. 1, pgs. 139-140

Appendix 2-JC
OM&A Programs Table

Programs	2017 Test Year	YTD July 31,2017	YTD July 31, 2017	YTD July 31, 2017	YTD July 31, 2016	Variance Y/Y
Reporting Basis	MIFRS	Labour	Non-Labour	Total	Total	
Operations						
1) Distribution Station	66,760	5,416	37,133	42,549	30,584	139%
2) Overhead Distribution Operations	169,591	107,872	14,157	122,029	65,800	185%
3) Underground Distribution Operations	136,637	9,306	32,172	41,479	52,316	79%
4) Distribution Meters	262,730	51,795	94,276	146,071	132,827	110%
5) Customer Workorders	173,206	27,603	37,158	64,762	72,715	89%
6) Engineering/Systems Ops/Line Constru/SCADA/Ops Admin	722,204	399,862	75,046	474,908	391,203	121%
Sub-Total	1,531,128	601,855	289,942	891,797	745,445	120%
Maintenance						
1) Overhead Distribution Lines/Feeders	410,167	69,587	75,837	145,424	429,811	34%
2) Underground Distribution Lines/Feeders	136,079	52,350	54,545	106,895	87,069	123%
3) Distribution Meters	27,888	279	13,274	13,553	11,975	113%
4) Distribution Transformers	73,628	6,025	8,886	14,911	7,992	187%
Sub-Total	647,761	128,241	152,542	280,784	536,846	52%
Community Relations						
1) Community Relations	11,640	0	1,827	1,827	5,576	33%
Sub-Total	11,640	0	1,827	1,827	5,576	33%
Customer Service						
1) Bad Debts	77,600	0	38,248	38,248	88,245	43%
2) Customer Service & Billings	702,939	187,052	137,770	324,822	341,923	95%
3) Customer Collections	368,742	165,531	43,937	209,468	201,109	104%
Sub-Total	1,149,280	352,582	219,955	572,537	631,277	91%
Administration						
1) Information Systems	335,309	0	176,230	176,230	186,358	95%
2) Insurance	106,700	0	65,797	65,797	65,716	100%
3) Audit, Legal and Consulting	175,667	0	121,198	121,198	130,002	93%
4) Building and Office Supplies	322,574	0	181,642	181,642	228,462	80%
5) Management, Administrative, Finance, Regulatory and IT	1,613,297	831,773	45,069	876,842	873,219	100%
6) Regulatory Affairs (assessment & application costs)	97,000	0	75,796	75,796	125,486	60%
Sub-Total	2,650,546	831,773	665,732	1,497,505	1,609,243	93%
Miscellaneous						
Total	5,990,356	1,914,451	1,329,999	3,244,450	3,528,387	92%

Compensation Costs

19. With respect to labour costs shown below[9] VECC notes that, while the Utility is seeking rates to compensate for an additional 4.6 FTEs three of those positions are currently vacant[10].

[9] Undertaking J1.2
[10] 4-Staff-50 and Hearing Vol 1, pages 104-107

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	11.00	11.00	11.00	10.00	10.00	10.50
Non-Management (union and non-union)	28.00	29.00	28.32	33.20	34.20	33.12
Total	39.00	40.00	39.32	43.20	44.20	43.62
Total Salary and Wages including overtime and incentive pay						
Management (including executive)	$ 1,263,246	$ 1,367,623	$ 1,305,406	$ 1,289,707	$ 1,188,414	$ 1,140,261
Non-Management (union and non-union)	$ 1,876,914	$ 1,892,440	$ 2,109,248	$ 2,262,387	$ 2,514,913	$ 2,282,760
Total	$ 3,140,160	$ 3,260,063	$ 3,414,655	$ 3,552,094	$ 3,703,327	$ 3,423,021
Total Benefits (Current + Accrued) [2]						
Management (including executive)	$ 252,649	$ 252,649	$ 256,012	$ 260,564	$ 187,648	$ 232,278
Non-Management (union and non-union)	$ 375,383	$ 375,383	$ 417,326	$ 433,000	$ 385,257	$ 414,958
Total	$ 628,032	$ 628,032	$ 673,338	$ 693,564	$ 572,905	$ 647,236
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 1,515,895	$ 1,620,272	$ 1,561,418	$ 1,550,271	$ 1,376,062	$ 1,372,539
Non-Management (union and non-union)	$ 2,252,297	$ 2,267,823	$ 2,526,574	$ 2,695,387	$ 2,900,170	$ 2,697,718
Total	$ 3,768,192	$ 3,888,095	$ 4,087,993	$ 4,245,658	$ 4,276,232	$ 4,070,257

20. What Appendix 2-K shows is the actual FTE increase is 4.2 or 4.7 if one does not account for the now shared President and CEO position. Based on a simple division of the 2017 FTEs by their total costs one can calculate that InnPower will not expend approximately $93,312 on 3 unfilled positions. This, in and of itself, argues for a reduction in 2017 OM&A of around 280k.

<u>Expected earnings</u>

21. Finally, in determining the appropriateness of the Utility's request it is important that the Board understand the strategic direction this Application represents. This is best found in the most recent information provided to the Utility's Board of Directors as outlined in the following exchange.[11]

> MR. SHEPHERD: So you don't have a current five-year business plan.
>
> MR. MALCOLM: We do not have a current one.
>
> MR. SHEPHERD: And the one that you filed with your application, the 2016 to 2020 one, it's basically, I was 13 going to say no longer applicable, but that's probably overstating it. But it's certainly not the vision that you want to move going forward; right?

[11] Hearing Vol. 2, pages 43-44

MR. MALCOLM: That's correct.

MR. SHEPHERD: And the next one, you are basically going to skip the 2016 -- 2017 to 2021 plan. You are not doing that at all?

MR. MALCOLM: No, what we will be working at is the 21 2018 to 2021.

MR. SHEPHERD: So you are going to do one this year 23 for the next five years.

MR. MALCOLM: It will be an amended version similar to what we did last year, with the intention of doing the business planning in 2018 to start for 2019.

MR. SHEPHERD: So when you say you did an amended version last year, you amended the 2016 to 2020 plan?

MR. MALCOLM: No, we left the 2016 plan as is. What we stated was these are our strategic imperatives that we need to undertake as a utility and received direction from 4 the board of directors, as well as confirmation from the shareholders that they agree with that direction.

MR. SHEPHERD: And that document was some changes to your strategic direction and a 2017 budget.

MR. MALCOLM: That's correct.

MR. SHEPHERD: Is that filed on the record here?

MR. MALCOLM: Not here on the record, no.

MR. SHEPHERD: Is there any reason why it couldn't be? It's a document, right?

MR. MALCOLM: Yes, it's part of our budget process. There was also a presentation in June of 2017 at the AGM 15 that a presentation was provided to the shareholders explaining the direction that we are moving in.

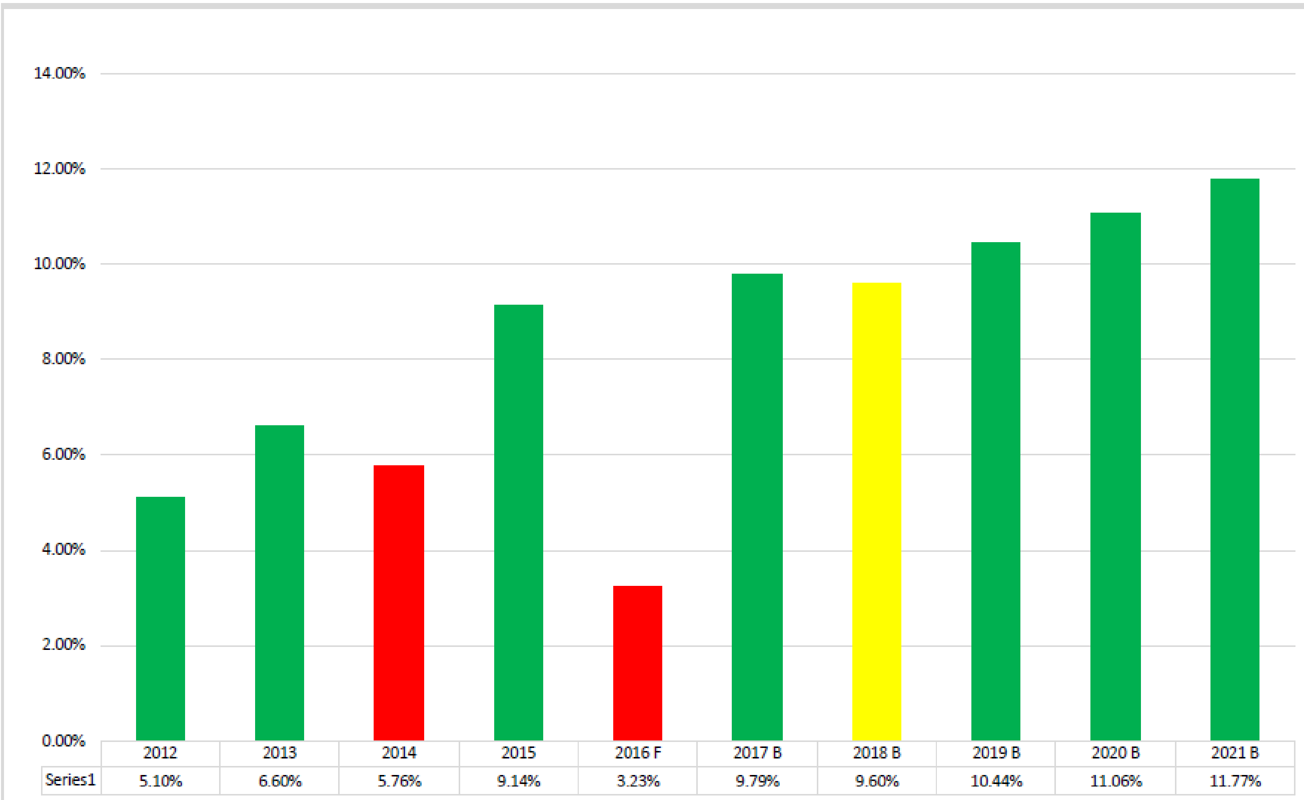
MR. SHEPHERD: But I am looking at the one, the 18 document that was approved by your board of directors.

MR. MALCOLM: Yes, that's a document that we can provide.

22. In that document the following is given[12]:

[12] Undertaking J2.1 – InnPower Corporation 2017 Operating & Capital Budget, December 13, 2016

RETURN ON EQUITY



23. The table is taken from the subsequently filed InnPower Corporations 2017 Operating & Capital Budget document as presented to InnPower's Board on December 13, 2016. It shows clearly shows that based on this Application the Utility expects to improve equity returns. In fact the expectation appears to be that based on proposed rates it will exceed current Board approved returns on equity during the course of the 5 year plan.

24. A large portion of the increase in OM&A is driven by InnPower's new building as shown in the table below.

Table JT1.8 Building Expenses – 7251 Yonge Street vs 2073 Commerce Park Drive

Building Expenses - 7251 Yonge Street vs. 2073 Commerce Park Drive

	New Building			Old Building			2017 to 2014 Variance	2016 to 2014 Variance
	2017	**2016**	**2015**	**2016**	**2015**	**2014**		
Property Taxes	102,000.00	101,489.21	86,203.70		14,861.93	20,127.75	$ 81,872.25	$ 81,361.46
Insurance	56,000.00	55,208.16	43,942.58			36,678.00	$ 19,322.00	$ 18,530.16
Hydro/Water/Sewer	55,000.00	55,577.75	44,704.58		17,117.87	38,034.25	$ 16,965.75	$ 17,543.50
Gas	10,000.00	9,914.03	12,560.68			-	$ 10,000.00	$ 9,914.03
Security	1,044.00	1,044.00	1,044.00			1,044.50	-$ 0.50	-$ 0.50
Janitorial	22,500.00	22,500.00	25,477.94		813.48	14,100.00	$ 8,400.00	$ 8,400.00
Snow Plowing	11,000.00	10,499.72	9,609.42			13,111.90	-$ 2,111.90	-$ 2,612.18
Grass Cutting	420.00	420.00	420.00			480.00	-$ 60.00	-$ 60.00
Phone/Internet	32,000.00	32,124.91	25,706.25	18,480.00	-	33,042.75	-$ 1,042.75	-$ 917.84
Miscellaneous	22,000.00	21,801.22	2,658.94		2,456.54	16,630.93	$ 5,369.07	$ 5,170.29
	$ 311,964.00	**$ 310,578.99**	**$ 252,328.09**	**$18,480.00**	**$35,249.82**	**$173,250.08**	**$138,713.92**	**$ 137,328.91**

Net Incremental Costs at 7251 Yonge Street Vs 2073 Commerce Park Drive ($) **$138,713.92**

1. $101194.25 or 73% of the incremental cost of the new building for maintenance is directly attributable to the increase in property tax and insurance
2. Hydro/Water/Sewer have increased due to waste water as 2061 Commerce was on septic
3. The cost per Sq Ft for maintenance expense in the new building is $7.46 for 2017 exxpenses (311,964 /41,800 sq ft)
4. The cost per Sq Ft for the maintenance expense at the old building site was $21.32 (173,250/8,128 sq ft)

Notes:

1 All expenses exclude tax, except for hydro expenses
2 Insurance is property only.
3 Old building heated by electric, new building gas.
4 Old building was on septic, new building has sewer included in new rates
5 Internet at old building still exists for old building for communication network

25. As shown in this table the increase in operating costs related simply to the building are approximately 139k.

26. In our submission the Board should consider whether the increased OM&A cost of the new building are reasonable.

2.0 Revenue Requirement

2.1 Are all elements of the revenue requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

27. VECC has reviewed the submissions of Board staff with respect to the new building. Technically speaking we agree with Board Staff's analysis. However, the proposal of InnPower has equal if not greater benefits to ratepayers.

28. Ideally the "costs" of the leased area should be included in the revenue requirement as should the leasing revenues (as a revenue offset). This would be consistent not only with the Settlement Agreement from EB-2014-0086 but also with how the issue is generally treated in other COS applications. However, the fixed asset continuity schedule shows a net book value for 2017 for the new building of just under $10 M – which presumably is the about amount after taking off the 13.47% (per Staff 48) attributable to the leasing space. As a result, given that the cost of capital (after tax) is 6.05%, it is likely that the total costs (i.e. depreciation, return, income tax and O&MA) is close to, if not more, than $100,000. As a result, it is in our submission reasonable to accept InnPower's proposed approach.

3.0 Load Forecast, Cost Allocation and Rate Design

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of InnPower's customers?

29. The initial load forecast filed by InnPower, like other parts of the application, underwent subsequent revisions during both the interrogatory process and as a result of the Technical Conference. The purpose was primarily to incorporate more recent data.

30. VECC has overall no issues with InnPower's final load forecast or its associated methodology, based on actuals up to August 2017 and extrapolating the monthly value for the balance of the year.

31. Developing the 2017 volume forecast, provided in response to an undertaking from the Technical Conference, involved the following: First, forecasting total power purchases using an econometric model that related power purchases to weather—in InnPower's case, using average heating and cooling degree days over the past ten years to define "normal weather". This resulted in a forecast of 259.7 Gwh.

32. This power purchase forecast was then converted to billed kWh based on the average loss factor for the past ten years (7.31%), which yielded a billed energy forecast of 242.0 GWh. InnPower then allocated the forecast to customer classes based on historical usage by class, applying the same methodology that other distributors have applied in their "approved" load forecasts.

33. InnPower then adjusted forecasts for Residential, GS <50, and GS >50 classes to account for CDM impacts, using: i) 50% of the IESO-verified results for 2016 and ii) 50% of InnPower's projected CDM savings for 2017, based on its IESO-approved CDM plan for 2015-2019.

34. The resulting load forecast for 2017 is 239.7 Gwh. For classes that are billed on the basis of kW, conversion occurs by using the average ratio of kW/kWh over the past ten years.

35. VECC notes that InnPower's volume forecast includes Long-Term Load Transfer customers who are in its service area, but in fact served by Hydro One. These customers are excluded from the customer count, which InnPower explained is due to the fact that although Hydro One bills and collects the revenues from these customers, InnPower invoices Hydro One at the end of each year, based on the approved volumetric rates and customers' billed energy. These load transfers represent approximately 0.4% of the 2017 forecast load.

36. Additionally, it appears that for the CDM adjustment, there is a minor discrepancy between the 2017 savings value used in the forecast (317.6 MWh) and the values in the actual approved plan (316.7 MWh), in the Residential class. However, this would have negligible impact, so long as consistent values are used in subsequent LRAMVA calculations (and VECC notes that the LRAMVA is also no longer an issue in this application).

3.2 Is the proposed cost allocation methodology, and are the allocations and revenue-to-cost ratios, appropriate?

<u>Cost Allocation</u>

37. InnPower's cost allocation methodology is appropriate. It is based on the Board's cost allocation model, and includes weighting factors for Services, Billing & Collection, and Meter Reading, which are specific to the utility, and which InnPower explained the weighting methodology behind at the Technical Conference.[13]

38. As noted above, InnPower has used the values from its load forecast for purposes of cost allocation. Consequently, the load for Long-Term Load Transfer Customers was

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13 Exhibit 7, pages 5-7; Technical Conference Transcript, Vol. 2, at page 93 and 17.

included, despite the fact these customers are not served using InnPower's facilities. In theory, it would be more appropriate to exclude the load associated with these customers, and to treat the associated revenues as revenue offset. However, these customers amount to only a small percentage of InnPower's total load forecast and would likely not have material impact on overall costs allocation to each customer class. InnPower's approach in this case is thus acceptable.

Revenue-to-Cost Ratio

39. The results of the cost allocation model and InnPower's proposed revenue-to-cost ratios are set out below:

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
Residential	97.60%	99.21%	99.29%	85 - 115
GS < 50	120.00%	103.99%	103.99%	85 - 115
GS > 50 to 4,999	120.00%	87.10%	99.29%	80 - 120
Sentinel Lights	97.60%	102.27%	102.27%	80 - 120
Streetlights	97.60%	196.69%	120.00%	80 - 120
USL	120.00%	97.69%	99.29%	80 - 120

40. InnPower has reduced the ratio to Street Lights to the upper boundary of the Board's policy range, and increased the ratios for all classes that are below 100% to a common value of 99.29%. VECC has no issues with this approach, and it is consistent with accepted proposals from past proceedings.

3.3 Are InnPower's proposals for rate design appropriate?

Residential Rates

41. VECC has no issue with InnPower's proposed rate design for residential rates, given that the most recent version again includes the additional transition year to result in a fixed charge below $4, as discussed at hearing.[14]

14 Hearing Transcript, Vol. 1, at pages 19-20.

Fixed-Variable Split: Other Customer Classes

42. For the GS>50 class, the proposed split is 20.51% fixed and 79.49% variable. It is not clear where this value comes from as it does not reflect the current fixed variable split (76.55% variable) or the split in the Settlement Agreement. This split results in a fixed charge of $200.72; however, the maximum value calculated by the cost allocation model is $106.42, and the current value is $151.60.

43. The Board should keep $151.60 as the appropriate monthly charge for this class, given that it already lies beyond the upper boundary of the Board's policy.

3.4 Are the proposed Retail Transmission Service Rates and Low Voltage service rates appropriate?

44. VECC has no submissions with respect to the proposed Retail Transmission Service Rates or Low Voltage service rates.

4.0 Accounting

4.1 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

45. VECC is satisfied that InnPower's application meets the criteria in this issue.

4.2 Are InnPower's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts and the continuation of existing accounts, appropriate?

46. VECC finds acceptable InnPower's proposal with respect to the disposal of its deferral and variance account balances as of December 31, 2015, including the withdrawal of disposing Accounts 1588 and 1589. However, this is provided that InnPower addresses and resolves the discrepancies and clarifications that OEB staff raised in its final submission, regarding specific amounts used and that InnPower proposes no new accounts.[15]

15 Final Submission of OEB Staff, at page 39.

5.0 Other

5.1 Are the proposed specific service charges appropriate?

47. VECC remains particularly concerned with InnPower's practices around disconnection notices, electricity shut-downs, late payments, and fees charged to customers related to any of the above. InnPower has not alleviated concerns in this respect, whether through written responses, at the Technical Conference, or at the hearing. Especially in light of feedback from the community of InnPower's customers on this matter, and given InnPower's own stated commitment to be responsive to customers, it seems this practice and its various elements warrant further scrutiny from the Board.

48. Furthermore there is no evidence the current policies contribute to a reduction in bad debt costs. In our submission these policies should be reviewed by the Board. This is especially true in light of government policies prohibiting winter disconnection. As shown below disconnection notices have increased considerably over the past few years as shown below.

	2014	2015	2016
Disconnection Notices	2761	3408	3344
YOY Increase/Decrease		23%	-2%
Disconnections	230	244	251
YOY Increase/Decrease		6%	3%
Late Payment Revenues	$ 84,703	$ 96,925	$ 109,071
YOY Increase/Decrease		14.43%	12.53%

<u>The Policy</u>

49. InnPower bills monthly and allows 16 days after the date of the bill issued as a due date. Four (4) days after the due date, InnPower makes an automated reminder call to customers to remind them that at that time their account is past due and outstanding[16]" The Utility sends a customer a disconnection notice if a bill is unpaid 10 days after the due date[17].

[16] 1-Staff-13
[17] Technical Conference, Sept 12, page 15

50. That is, if a bill is not paid approximately 26 days after it is issued c a disconnection notice. The customer is charged $15 for this notice irrespective of whether payment is subsequently made. Though the customer may plea for relief from the $15 payment it is at the Utility's discretion.

51. That is unlike many other utilities, InnPower prohibits a customer from carrying a month's arrears on its account. Furthermore the $15 "disconnection letter fee" is in addition to any late payment interest charges.[18] InnPower suggest that the interest charge of 19.56% it applies, the maximum available under Canadian law, is "[A]*ccording to the OEB requirements*."[19] Further fees and costs are incurred if actual disconnection and reconnection is carried out.

52. InnPower derives between $43 and $48 thousand dollars per year from disconnection fees alone[20].

USoA#	USoA Description	Charge Type	2013	2014	2015	2016
		Disconnect Notices	3047	2761	3408	3344
		YOY Increase/Decrease		**-9%**	**23%**	**-2%**
		Disconnects	399	230	244	251
		YOY Increase Decrease		**-42%**	**6%**	**3%**
4235	Specific Service Charges	Disconnect Notice Delivery Charges	$43,020	$39,975	$48,510	$47,750
4235	Specific Service Charges	Disc/Reconnect Charges	$10,880	$7,688	$11,095	$13,009
4225	Late Payment Charges	Overdue Interest/NSF Charges	$73,904	$84,703	$96,925	$109,071

53. In effect InnPower derives a significant amount of revenue from threatening customers with disconnection four weeks after they receive their bill. In our submission such a "customer unfriendly" policy would only be taken by a monopoly and only if allowed by its regulator. It is especially egregious to low income customers who may, from time to time, need to carry a utility bill balance.

54. VECC submits that is unusual for a utility (of any sort) to effectively prohibit the holding of at least one month balance on their account. We think it not too bold to suggest that more than a few people (perhaps some even at the OEB) periodically miss or forget to make a monthly bill payment. What one might expect in such cases is to find an accumulated balance on the next bill. Such a balance attracts a late payment interest charge - though we note in passing we do not think it true, as suggested by InnPower, that the OEB requires Utilities to apply the maximum allowable interest rate of 19.56% on any outstanding balances.

[18] Hearing Vol. 1, page 36-39

[19] Ibid, page 35
[20] Undertaking JT1.4

55. In our submission not only is the policy of InnPower adding a $15 "disconnection letter fee" 10 days after the due date unreasonable, it may in fact be illegal. Arguably the application of the $15 disconnection fee if paid along with late payment effectively exceeds a rate of 19.56% per annum.

56. Based on feedback from the two community meetings and letters from members of the community, the above practices are a source of not insignificant distress and anger to InnPower's customers, many of whom are elderly citizens who live on a fixed income. Part of customers' ire also seem to be connected to InnPower's new corporate headquarters, when juxtaposed against the positions of low-income Ontarians struggling to make ends meet. The following excerpts from some of their letters to the Board make this clear:

> In January we had someone come to our door to serve a shutoff notice to us. First of all we did not receive an InnPower Bill for that period. Second of all we were only 10 days late. Third we were charged 15 dollars for the delivery. Fourth I phoned InnPower to inquire & no one phoned us back. We had to keep on phoning to get any information & how much we actually owed."[21]

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> InnPower is much too eager now to threaten to and/or disconnect their customers – 2 days after payment due date customers receive a passive aggressive call which is a payment reminder /disconnection threat. 10 days after payment due date they give customers a disconnection notice and bill the customer $16.95 + HST for this notice 23 days after payment due they disconnect their customers. If you allow them to [increase] charges for disconnect/reconnect they will become even more eager![22]

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> In 2016 I was in the home of people who were experiencing a hard time and had fallen behind in their electricity payment. An InnPower employee came to the door to shut off the power. This could be avoided if the bill was paid within the hour. I immediately went to the Innpower building to pay their bill. I was completely gobsmacked when I saw the building. It looked more like a place that would be suited for New York or even Toronto.[23]

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> Residents of Innisfil have the second lowest per capital household income. Many have difficulty paying their hydro bills. When Innpower moved their bill date forward last December, it created hardship and anxiety for many; I can't imagine the impact of a nine-month retroactive increase for them. Add to all of this the fact that a customer has just 16 days from the date of the bill before a late payment charge is applied. After 25 days, a customer receives a hand delivered notice with a $17 charge, threatening to disconnect service on the 38th day if still

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21 Letter from Sandra Bingley in OEB Staff Summary of Community Meeting (2 May 2017), at page 49 ["Community Summary"].
22 Letter from Natalie Craig in Community Summary, at pages 54-55.
23 Schedule D, Patrick Morley, in Community Summary.

> unpaid. Reconnection would cost $254; and on a weekend or after hours, this charge balloons to $678.
>
> [Example Scenario:] "A customer with an excellent record of payment, except for some late payment charges over 28 years, gets a hydro bill while away on a job. He lives alone. [sets out timeline of events according to InnPower's policy] If customer hadn't arrived home from his job for another couple of days, his house might be left without power and heat. Pipes might freeze and burst, causing thousands of dollars in damage. ... For most vendors, a customer has 30 days after the bill date to pay. An overdue notice is mailed perhaps 15 days later; and collection activity commences around 25-30 days after due date. InnPower's schedule is extreme—even for a customer with a less than excellent payment history.[24]

57. When questioned on the above at hearing, InnPower's responses did not alleviate the concerns expressed above, contrary to the utility's ostensible new commitment to be led by customer feedback and needs. For example, there are no set operational procedures in place to ensure utmost efforts are made to contact a customer before they are disconnected and ensure they have been informed.[25] The implementation of the policy and its consequences is not subject to performance metrics or tracking, such as if particular areas are overrepresented in disconnection notices.[26] Additionally, InnPower stated that some of these measures are not coded correctly in its systems, or activities that do not engage these concerns are coded as disconnections.[27]

58. Given how much the customers in question have at stake when it comes to whether or not they can continue having electricity, it seems all involved would benefit from deliberate efforts to add clarity of process and tracking to InnPower's late payment and disconnection process. Without such measures, it is difficult to know if the policy is operating as intended and with the minimal necessary distress to ratepayers, or if there would be a more customer-friendly method that would still address the issue of late payments.

59. Above all, however, discussion regarding InnPower's late payment and disconnection policy revolved around details of the policy itself, how it is carried out, and what the different components mean. There was no discussion of amending or eliminating and replacing the policy itself, despite the resounding opportunity this would offer InnPower to demonstrate that it is indeed listening to its community.

60. In our view this harsh and restrictive policy is a carry-over from the time when many if not most Ontario electricity distributors billed bi-monthly. We are unaware of any review carried out by the Board of the issue of carrying a billing period balance since the Board mandated monthly billing. We would respectfully ask the Board to order InnPower to discontinue this policy and to allow customers to carry a minimum of one

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24 Letter from Stan Daurio, in Community Summary, at pages 77-78.
25 Hearing Transcript Vol. 1, at pages 33-34.
26 *Ibid*., and at page 58, lines 1-12.
27 *Ibid.*, at page 57, lines 4-10, 24-27.

month's balance (with late payment interest applying). Rather than the current policy which is, in our submission, is made at the expense of the most vulnerable customers of this Utility.

5.2 Are the proposed pole attachment charges and microFIT charges appropriate, as per Procedural Order No. 3.

61. In light of Procedural Order No. 6, VECC reserves comment on Issue 5.2 at this stage of the proceeding.

5.3 What is the appropriate effective date for 2017 rates?

62. VECC agrees with OEB staff that October 1, 2017, would be a fair and appropriate effective date for InnPower's application. As OEB staff's submission lays out,[28] many of the delays that will lead to a later decision are directly attributable to InnPower, including a 5-week delay to file interrogatory responses, and several of them may have been preventable.

63. In OEB staff's submission, they present the October 1 effective date as a fair compromise between InnPower's requested effective date of July 1, 2017, and OEB staff's recommendation of significantly reducing the requested OM&A. The alternative would be to set the effective date for the first of the month following the Board's decision in this matter.

64. VECC would suggest that the Board remain open to a later effective date depending on its determinations on the issue of OM&A. If it decides not to order the reduction that OEB staff recommends, for instance, then that suggests that the effective date should no longer be October 1, 2017, but the first of the month following the Board's decision.

6. Cost Incurred

66. VECC respectfully submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

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28 OEB Staff Final Arguments, at pages 4-5.